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Kenya's lessons from two decades of experience with independent power producers

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ABSTRACT

Adequate, secure, and competitively priced electricity is vital for powering economic growth and development. Privately funded, independent power producers (IPPs) are now making an important contribution to meeting overall power needs in developing countries, including in Africa. Our aim in this article is to explore what may be learned from Kenya's experience with IPPs and what lessons might be applied to other developing countries. We consider how Kenya's IPPs measure up to their public counterparts in terms of reliability and costs and possibilities for scale-up. Kenya's two decades of experience with power sector reform and IPPs makes it possible to compare changing policies, sector unbundling, regulatory frameworks, planning, and investment over a relatively long period. Kenya is also host to IPPs with different technology bases, which allow for an evaluation of their relative costs and reliability. Finally, the mix of directly negotiated and competitively bid projects facilitates a comparison of procurement practices. While power sector reform in Kenya created an enabling environment for IPPs, probably more important was the development of effective planning, tendering, and contracting capabilities, which attracted investment at competitive prices. The challenge for Kenya and other developing countries is to maintain and sustain these capabilities within clear policies that provide regular opportunities for the private sector to contribute to meeting power deficits.

1. Introduction

Most African countries have insufficient electricity to power economic development and to extend access to all of their population. Traditionally, governments and public utilities have funded new power generation capacity, but not at the rate required. Independent power producers (IPPs), or privately funded electricity generation projects, are now complementing these sources and are present in 20 countries across the continent (Eberhard et al., 2016).[1] Kenya has more experience with IPPs than most countries in Sub-Saharan Africa. Between 1996 and the end of 2015, the country developed 12 IPP projects for a total of approximately 1106 megawatts (MW) (worth over US$2.3 billion in investment) and more are in development. After almost two decades, IPPs account for 28 percent of installed generation and 23 percent of production (see Fig. 1 for a visual representation of the structure of the Kenyan electricity sector). Most of the IPPs procured since 1996 are medium-speed diesel/heavy fuel oil (MSD/HFO), and Kenyan authorities have gained considerable expertise in running and awarding international competitive bids (ICB) (Kapika and Eberhard, 2013). More recently, however, the procurement of new geothermal and wind power has occurred via less transparent channels, and with less than optimal results (Eberhard et al., 2017).

Our aim in this article is to explore what may be learned from Kenya's experience with power sector reform and IPPs and which factors are important in facilitating private investment in power. Further, we consider how IPPs measure up to their public counterparts in terms of reliability and costs. After briefly outlining our methodology and the article's limitations, we provide a short overview of the drivers for IPPs across Sub-Saharan Africa. This is followed by a description of the development of Kenya's power sector since 1996, its current structure, planning processes, and capacity. Prices, performance data, and funding sources are also presented. In subsequent sections, the analysis

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[1] Independent power producers and independent power projects are used interchangeably and are characterized as independent (non-utility/state-financed) electricity generation. Projects typically have a long-term power purchase agreement (PPA) with the utility and are financed with non-recourse loans. Further definition is provided in the methodology section below.

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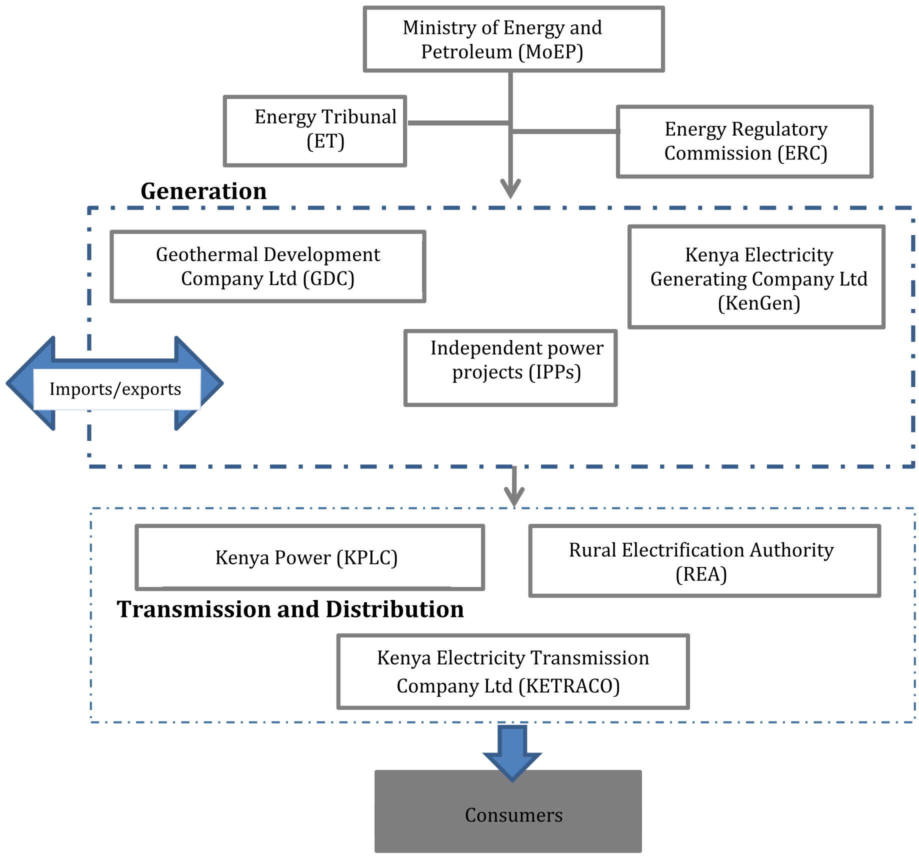

Fig. 1. Overview of Kenya's electricity sector.

focuses on mechanisms for the procurement and funding of capacity, and sketches future plans that have been made public. Findings are offered related to the different IPP typologies based on the type of procurement, ownership and financing structures, technologies, and risk mitigation measures.

In the conclusion, we assess the factors that have contributed to and detracted from power generation development in Kenya. We then consider what policy lessons may be drawn from Kenya for other countries seeking to ramp up their power generation capacity using private capital.

2. Methodology

All of the IPPs discussed are greenfield, grid-connected installations of 5 megawatts (MW) or more, that have reached financial close, are under construction, or are in operation. A significant amount of data on these installations was collected and analysed, spanning nearly 20 years (1996–2016). To gather project data, authors started with a series of World Bank databases, including the Private Participation in Infrastructure (PPI) database, and databases prepared by AidData and the Energy Information Administration (EIA), among others. These data were complemented by information on individual projects gathered from various primary and secondary sources, including up to 20 interviews with project sponsors and stakeholders at Iberafrica, Tsavo, OrPower4, Rabai, Triumph, Gulf, Kinangop, as well as present and former personnel at KenGen, Kenya Power and Lighting Company (KPLC), the Energy Regulatory Commission (ERC), and the World Bank. Unless otherwise indicated, all information was given anonymously, at the request of the stakeholder. All data was reconfirmed by at least two sources to ensure the robustness of data on each project and the sector more generally, with all participating stakeholders reviewing the findings. Data gathered include information concerning the composition of investments by source, the terms of IPP contracts (which remain mostly confidential) and the size, composition, and types of investment.

It is important to note that IPPs are not uniform. Although the typical IPP structure is understood as a privately sponsored project with nonrecourse or limited recourse project financing, IPPs in Sub-Saharan Africa do not always follow this model (Eberhard et al., 2016). Instead, governments typically hold some portion of equity or debt, bringing IPPs closer to a model of a public-private partnership (PPP) than that of the more traditionally conceived IPP. For the purposes of this analysis, IPPs are defined as power projects that are, primarily, privately developed, constructed, operated, and owned; have a significant proportion of private finance; and have long-term power purchase agreements with a utility or another off-taker.

2.1. Limitations of this article

Our focus is on power generation, as opposed to transmission or distribution. In many markets globally, transmission and distribution are considered natural monopolies and therefore not open to competition. Generation, although historically considered part of an integrated monopoly, has come to be seen as a place where producers can compete in an organized market. That makes the generation sector much more suitable for IPPs as opposed to other segments in the value chain. Furthermore, it is easier to fund generation projects (than transmission and distribution) as they are specific and easier to manage. A detailed discussion of the environmental externalities attached to specific power generation technologies, which pose growing concern, lies outside the purview of this article.

3. Recent literature on IPPs in Sub-Saharan Africa

The standard model for power sector reform has been roughly defined as a series of steps that move vertically-integrated utilities towards competition, and generally include the following activities: corporatisation, commercialisation, passage of the requisite legislation, establishment of an independent regulator, introduction of IPPs, restructuring/unbundling, divestiture of generation and distribution assets and introduction of competition (Adamantiades et al., 1995; Bacon, 1999; Besant-Jones, 2006; Williams and Ghanadan, 2006; Gratwick and Eberhard, 2008). This model, which motivated power sector globally, starting in the 1970s in industrialized nations, was brought to bear across Sub-Saharan Africa, from the 1990s onward (Appendix A provides a more detailed review).

Despite reform efforts, in most sub-Saharan African cases, state utilities remained vertically integrated and maintained a dominant share of the generation market, with private power invited only on the margin of the sector. Policy frameworks and regulatory regimes, necessary to maintain a competitive environment, were limited. IPPs have taken root in less than two dozen countries in Sub-Saharan Africa. Several such early cases were documented and analysed as part of a global study on IPPs by Stanford University's Program on Energy and Sustainable Development (Woodhouse, 2006) and which largely described the incomplete reform process and how IPPs fit precariously into that imperfect structure. International competitive bids for those IPPs that were developed were often not conducted because of tight timeframes, resulting in limited competition for the market and, due to long-term PPAs, no competition in the market (Malgas and Eberhard, 2011; Kapika and Eberhard, 2013). These long-term PPAs and often government guarantees and security arrangements, such as escrows and liquidity facilities, exposed countries to significant exchange-rate risks. Although Africa has seen private participation in greenfield electricity projects continue, private investment has been erratic, with a spike in 2007, largely due to the financial close of one large project, Bujagali, followed by a trough and then another flurry of activity from 2012 onward (Eberhard et al., 2016).

Most research on IPPs has mainly been focusing on their associated investment (i.e., return on investment) and development (i.e. cost of power, environmental impact) outcomes in developing countries (Dunkerley, 1995; Gupta and Sravat, 1998; Kashi, 2015; Kumar et al., 2005; Phadke, 2009; Qudrat-Ullah, 2015; Woo, P.Y., 2005; Woodhouse, 2006), with Africa being no exception (Clark et al., 2005; Cooksey, 2017; Gratwick and Eberhard, 2008; Karekezi and Kimani, 2002). Many of these authors have attempted to not only understand these investment and development outcomes but also to identify the factors that enable and sustain private power investment in developing countries, including in Kenya (Eberhard and Gratwick, 2005).

Building on the earlier work at Stanford, Eberhard and Gratwick (2011) developed a set of country and project specific success factors to evaluate IPPs in Africa, which were refined in 2016 (Eberhard et al.) in the context of sub-Saharan Africa. At the country-level, the investment climate, sector policies and reform, and regulatory certainty are all relevant – but more prosaic issues such as least-cost power planning, namely an evaluation of the total costs and benefits of projects (and their alternatives) followed by a timely initiation of competitive procurement for new power (with the operative words being 'timely' and 'competitive') are perhaps more significant. At the project level, traditional project finance concerns remain important - for example, equity and debt structuring, secure revenue flows, robust power purchase agreements (PPAs) with appropriate risk allocations, credit worthy off-takers or credit enhancement, guarantees and other security and risk mitigation mechanisms.

In this paper, we evaluate those success factors in the Kenyan IPP context, with the aim of both explaining outcomes as well as improving our understanding of the influence of these success factors Thus, as we examine the record of IPPs in Kenya, we pay particular attention to the relevance of planning and procurement issues in securing and sustaining private investment as well as the host of project finance concerns cited above, to determine outcomes. Kenya's experience both affirms and improves the refinement of IPP success factors, showing in particular how decisions around planning and procurement (at the country level) as well as concerns about contracts and risk mitigation (at the project level) have played key roles in determining IPP investment and development outcomes.

4. An overview of Kenya's electricity sector

The structure of Kenya's electricity sector may be traced back to reforms that swept the industry in the mid-1990s. As the country emerged from an aid embargo, one of the state's main objectives was to attract much-needed private sector investment to complement limited public sector investment. In a policy paper at the time (Government of Kenya, 1996), the government stated its intention to separate the regulatory and commercial functions of the sector, facilitate restructuring, and promote private-sector investment, including via IPPs (following the recommendations of the World Bank and the IMF). Consequently, the Electric Power Act of 1997 was passed.

The government's primary function, through the Ministry of Energy and Petroleum (MoEP), became policy formation, and its regulatory authority was devolved to the newly established Electricity Regulatory Board (ERB) that became functional in 1998. At the industry level, rationalisation and unbundling redefined the scope of the Kenya Power and Lighting Company (KPLC) (now branded as Kenya Power), which had operated as an integrated utility since 1954. From 1997, KPLC began to focus exclusively on transmission and distribution, while a separate entity known as KenGen took over all public power generation activities.

In 2003, the government expressed dissatisfaction with the performance of the energy sector (Government of Kenya, 2003), noting that, despite the reforms, including the introduction of IPPs, electricity in Kenya was still unreliable and expensive. To remedy this, deeper reforms were recommended and subsequently detailed in the national energy policy of 2004 (Government of Kenya, 2004), which set out the government's commitment to:

- Establish a rural electrification authority;
- Accelerate the increase in the rural electrification rate by 10 percent a year;
- Facilitate the development of a competitive market structure for the generation, distribution, and supply of electricity;
- Establish the Geothermal Development Company to assess Kenya's geothermal resources, including steam-field appraisal and development;
- Enact new legislation to, among other things, dissolve the ERB and create a new energy sector regulator—the Energy Regulatory Commission (ERC); and
- Partially privatize KenGen through an initial public offering of 30 percent of its equity through the Nairobi Stock Exchange.

By 2007, most of these measures were implemented, including KenGen's listing on the Nairobi Stock Exchange in 2006. Exceptions were the development of a fully competitive market structure and the ambitious rural electrification target. In 2008, the Kenya Electricity Transmission Company Limited (KETRACO) was established to focus on the construction of new transmission projects and facilitate funding by the government and donors through concessionary financing, while KPLC retained responsibility for operating the grid.

Further reforms and strategic targets followed. In 2008, Kenya's Vision 2030 (encompassing social and economic goals) set a new generation target of 23,000 MW by 2030 (up from 1310 MW in 2008). Rural electrification efforts aimed to bring electricity to every home in Kenya (Ongwae, 2012), with interim targets set for 2013 and 2022 (these have since been moved out to 2017 and beyond). In 2010, the government began work on a nuclear power project that has since been formalised through the Kenya Nuclear Electricity Board (KNEB), an institution within the MoEP. The initial aim was to generate 1000 MW of nuclear energy by 2023 (Energy Monitor Worldwide, 2014; Government of Kenya, 2014: 46), but by 2016, little progress had been made.

In September 2013, the MoEP launched the '5000 + MW' programme with the goal of bringing at least 5000 MW online within 40 months. The programme was heralded by the Kenyan government as the means to 'transform Kenya, by providing adequate [generation] capacity at a comparative rate' (MoEP, 2013). As shown in Section 7, this programme has proven difficult to implement and points to some weaknesses of coordination and planning in Kenya's power sector.

Meanwhile, at the generation level, the ERC (2014) affirmed that 'electricity generation in Kenya is liberalized', with IPPs given an opportunity to enter the sector and compete alongside the state-run KenGen. A competitive market structure is a stated goal, and the National Energy and Petroleum Policy and Energy Bill of 2015 suggested further reforms to legal and institutional frameworks to facilitate a competitive wholesale market structure in the country. For now though, even with 12 IPPs in the industry, KenGen and KPLC (both state-owned entities with significant private shareholding) remain the dominant players. We found no evidence of attempts to scale back or redefine their roles in the hybrid (part private, part public) market, which now defines Kenya's power sector.

4.1. Installed generation capacity

As of June 2017, Kenya's total installed capacity stood at 2333 MW. Of this, KenGen's share amounted to 1610 MW (69 percent), and IPPs provided most of the balance, as detailed in Tables 1 and 2, respectively.

Kenya's shift to a mix of publically and privately financed energy supply has increased the country's reliance on geothermal energy and encouraged the emergence of wind energy. KenGen's total installed capacity of geothermal energy increased from 12 percent in 2006 to 31 percent by June 2017. Installed wind capacity, although still relatively small (at 1.6 percent in 2017) is expected to increase significantly in the future. The share of traditional thermal gas and diesel (at 16 percent) is thus becoming less significant.

IPP capacity has grown considerably since 2005, when it accounted for only 12 percent of installed capacity. As shown in Table 2, sponsors and technology types are relatively diverse. In 2017, IPPs accounted for approximately 30 percent of the installed capacity in Kenya (696 MW). Most of this (75 percent) was supplied by diesel generators, followed by a geothermal installation (OrPower4 at 30 percent), and a co-generation installation (at 3 percent).

Kenya's total installed generation capacity also includes emergency power projects (EPPs), which typically are temporary thermal-powered installations, contracted for 1–2 years to address an immediate power crisis. Dependence on EPPs has fluctuated considerably between 2005 and 2017, peaking in 2008 and 2009, when EPP installed capacity rose to 11 percent of the total. In 2016/2017, EPPs produced just 0.8GWh (see Table 3).

Table 1
KenGen's installed generation capacity, June 2017.
Source: Based on KPLC (2017: 179-81)

Technology	% of capacity	Project	MW	PPA (years)	COD
Hydro	50.08%	Various	806.3	20	Various
Small hydro	0.73%	Various	11.7	15	2009
Wind	1.58%	Ngong I Phase I& II	11.9	15	2009
		Ngong II	13.6	20	2015
Geothermal	31.87%	Olkaria I (Units 1, 2, and 3)	45	4	2013
		Olkaria II	105	20	2008
		Olkaria IV	140	25	2014
		Olkaria I (Unit 4 and 5)	140	25	2014
		Well head 37/39	20	15	2012
		Well head 43	12.8	15	2012
		Well head 905/914/915/919	47.8	15	2012/2013
		Eburru	2.5	20	2012
Thermal/diesel	12.02%	Kipevu Diesel Power I	73.5	15	2008
		Kipevu Diesel Power III	120	20	2011
Thermal/gas	3.73%	Embakasi/Muhoroni Gas Turbines	60	3	2013
Total	1		1610.1		

Notes: PPA = power purchase agreement. COD refers to the commercial operation date of the latest power purchase agreements, as some plants, especially hydropower plants, have been redeveloped; Olkaria I (Unit 1), for example, has been in operation since 1981.

5. Power sector performance

In this section, we compare the state-run KenGen with Kenya's IPPs in terms of their capacity as well as the availability and price of the electricity produced.

5.1. Electric power production

From July 2016 to June 2017, the latest period for which complete data were available, Kenya Power purchased 7513 gigawatt-hours (GWh) of electricity from KenGen, or 74 percent of the total GWh produced in Kenya this period (approximately 44 percent of this came from hydro installations, 44 percent from geothermal plants and the balance largely from KenGen's thermal). IPPs produced 24 percent, EPPs less than 1 percent (as noted above), and another 1 percent was contributed by imports and the government's rural electrification programme (KPLC, 2017). Although this represented a marked decrease for IPPs from 2013 to 2014 when the IPP component increased to 30 percent, it is largely in sync with trends over the past 3–4 years.

The most noteworthy development with regard to electric power purchased in the recent past, however, relates to the role of geothermal energy. By the end of 2014, geothermal production (public and private combined) surpassed hydropower for the first time in Kenya's history (see Table 4). This was also the case in 2015–2016 and 2016–2017, and has ramifications for future supply as well.

Table 5 highlights the contribution of different IPPs to the electric power production mix, with a notable increase in the role of OrPower, but also some notable declines in IPPs.

Between 2014 and 2015, OrPower4 ramped up its geothermal production. The country also witnessed a drop in energy purchased from both Iberafrica and Tsavo IPP roughly over the same period. Tsavo's portion was relatively small due to merit-order dispatch and transmission constraints.

5.2. Power availability

Availability is among the best indicators of performance[2] and Kenya offers an interesting opportunity to directly compare the performance of state-owned power plants with that of IPPs, using similar technologies. In 2015, with the exception of Kipevu I, both public and IPP diesel

[2] The availability factor is the amount of time the plant is capable of producing electricity over a given time period, expressed as a percentage of total amount of the time in the period. The time the plant is down for planned maintenance plus the time it is down for unplanned maintenance or forced outage constitutes the time the plant is considered unavailable for electricity production.

Table 2
IPPs' installed generation capacity, June 2017.
Source: Based on KPLC (2017:181).

Technology	% of capacity	Project	MW	PPA (years)	COD
MSD/HFO	75.2%	Iberafrica Power Company (plant 1)	56	7 + 15	2004*
		Iberafrica Power Company (plant 2)	52.5	25	2009
		Tsavo Power Company Ltd.	74	20	2001
		Rabai Power	90	20	2010
		Thika Power (Melec)	87	20	2014
		Gulf Power	80.3	20	2014
		Triumph	83	20	2015
Geothermal	20.0%	Orpower 4 Inc.	13	20	2000
		Orpower 4 Inc.	35	20	2009
		Orpower 4 Inc.	36	20	2013
		Orpower 4 Inc.	26	20	2014
		Orpower 4 Inc.	29	20	2016
Cogeneration	3.7%	Mumias Sugar Company Ltd.	26	10	2010
Various small RE	1.1%	Biojule, Regen-Terem, Imenti Tea, Gikira	7.814	Various	Various
Total	1		695.6		

Notes: *15-year PPA starting in 2004. MSD/HFO = medium-speed diesel/heavy fuel oil; PPA = power purchase agreement; COD = commercial operation date.

Table 3
Energy purchased by Kenya Power, 2009–2017, %.
Source: Based on KPLC (2015:125-6 and 2017:179-81).

Source	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17
Kengen	53.9%	69.0%	70.5%	73.8%	67.1%	74.6%	78.7%	73.6%
IPPs	28.9%	26.6%	23.7%	22.1%	30.5%	23.3%	19.7%	24.2%
EPPs	16.4%	3.7%	5.0%	3.2%	1.1%	0.9%	0.5%	0.0%
Imports	0.6%	0.4%	0.5%	0.5%	1.0%	0.9%	0.7%	1.8%
Off-grid/RE	0.3%	0.3%	0.3%	0.3%	0.4%	0.4%	0.4%	0.4%
Total GWh	6692	7303	7670	8087	8840	9280	9817	10205

Table 4
Total production by technology/fuel (%), public and private 2012 and 2017.

Technology/fuel	2012/ 2013	2013/ 2014	2014/ 2015	2015/ 2016	2016/ 2017
Thermal	21.9%	29.4%	18.1%	12.3%	20.8%
Hydro	53.1%	44.6%	35.6%	38.5%	32.7%
Geothermal	19.8%	22.7%	43.7%	46.9%	43.6%
Various (cogen, wind, off-grid, exports)	5.2%	3.20%	2.5%	2.8%	2.9%

Data source: KPLC (2017).

plants met their availability targets (see Table 6). Of the eight diesel power plants, six are IPP-based and all more than met their technical performance targets. The remaining two publicly-owned (KenGen) diesel plants either match the best performing IPPs (Kipevu III), or fail to meet the availability target.

The country's geothermal plants perhaps offer a clearer performance distinction between private- and publicly owned plants, although it is important to note that the technology is not comparable: KenGen plants are flash while Orpower4 uses binary technology (which offers better availability) (see Table 7). KenGen's Kipevu I was available only 70.56 percent of the time in 2014/2015—far below its own target and the performance of its private-sector counterparts. Historically, this plant has had relatively low availability.

It is important to note that KenGen's PPA conditions are similar to those of IPPs and KenGen is under as much pressure to avoid financial penalties as the IPPs. The relative age of plants is certainly a factor for KenGen's Kipevu I and Olkaria I performance. Although not definitive, KenGen plants have to follow public procurement procedures; delayed payment processes tend to prevent quick access to critical parts in an emergency, and this may well affect overall performance.

Table 5
Percentage of energy purchased from IPPs 2009–2017.
Source: Based on KPLC (2017:181).

IPPs	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17
Iberafrica	32.1%	37.2%	38.8%	33.1%	24.5%	10.6%	6.9%	11.0%
Tsavo	25.6%	18.9%	15.6%	10.0%	6.8%	4.4%	2.1%	5.3%
OrPower	20.7%	19.1%	21.6%	28.1%	37.9%	51.2%	57.3%	51.1%
Rabai	16.5%	20.3%	18.6%	24.8%	28.2%	32.6%	28.8%	26.4%
Mumias	5.1%	4.5%	5.5%	4.0%	2.5%	0.8%	0.0%	0.0%
Triumph	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	4.4%	3.6%
Gulf	0.0%	0.0%	0.0%	0.0%	0.0%	0.3%	0.4%	2.7%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
IPP total (GWh)	1933	1945	1820	1788	2698	2160	1934	2466

Note: Small producers (Imenti Tea Factory, Gikira, Biojoule, and Regen-Terem) are excluded though part of the overall total.

Table 6
Actual and targeted availability of public and private diesel plants, 2014/2015.

Plant	COD	Ownership	Actual availability (%)	Targeted availability (%)
Tsavo Power Company Ltd.	2001	IPP	97.21	85.00
Thika Power (Melec)	2014	IPP	95.72	85.00
Kipevu Diesel Power III	2011	KenGen	95.57	85.00
Iberafrica Power Company (plant 2)	2009	IPP	93.92	85.00
Gulf Power	2014	IPP	93.60	85.00
Rabai Power	2010	IPP	91.65	85.00
Iberafrica Power Company (plant 1)	2004	IPP	87.95	85.00
Kipevu Diesel Power I	2008	KenGen	70.56	85.00

Data source: KPLC (2015) and KenGen (2015).
Note: IPP = independent power project.

Table 7
Actual and target availability of public and private geothermal plants, April 2015.

Project	COD	Ownership	Actual availability (%)	Targeted availability (%)
Orpower 4 Inc. (16 MW)	2000	IPP	99.79	96.00
Orpower 4 Inc. (48 MW)	2009	IPP	99.17	96.00
Orpower 4 Inc. (36 MW)	2013	IPP	97.82	96.00
Olkaria IV	2014	KenGen	91.05	94.00
Olkaria I (Unit 4 and 5)	2014	KenGen	91.05	94.00
Olkaria II	2008	KenGen	90.71	94.00

Data source: KPLC (2015) and KenGen (2015).
Note: OrPower4 represents only one project, of which different units are recorded above.

5.3. Electricity pricing

Electricity prices[3] offer a more nuanced picture. The different amounts they pay for capital makes a direct comparison difficult—KenGen has raised private capital by issuing bonds, and has accessed loans from development finance institutions (DFIs). Nevertheless, Table 8 compares KenGen, IPP and EPP diesel plants; the values listed represent the sum of energy, fuel, capacity charge, and forex adjustment.

Taking the cost of capital into account, the two KenGen plants were more competitive than the IPPs in 2015, but Rabai Power distinguished itself as the cheapest of all. Additional qualifiers related to specific technologies and location help to explain some of the other cost discrepancies. Rabai has a heat recovery system, which improves efficiency and the plant's location close to the port of Mombasa reduces the cost of transporting the fuel. The heat recovery system accounts for part of the cost difference when Rabai is compared with Tsavo Power and KenGen's Kipevu I and Kipevu III plants, also located in Mombasa. Thika Power and Gulf Power also have heat recovery systems, but their plants are located near Nairobi (about 500 km from Mombasa), so transport costs are a factor. Iberafrica is also located in Nairobi and it has no heat recovery system.

Among the geothermal plants, three of KenGen's plants are more competitive than OrPower4 IPP, with Olkaria II being a notable exception (see Table 9).

To sum up, KenGen remains Kenya's dominant producer, but IPPs are making a vital contribution. The geothermal IPPs' technical performance, as gauged by actual and target plant availability, shows that the two are competitive. In terms of costs, public geothermal plants seem to be more competitive than the IPPs, but this comparison is hampered by differences in the cost of capital, technologies used, and the location of power plants. Meanwhile, supply (from both private and public sources) is changing as reliance on geothermal power increases.

6. IPPs, EPPs, and publicly sponsored power plants

Private participation in generation is not new in Kenya. What is new is the extent to which the government expects IPPs to scale up. The government's 5000 + MW programme envisaged the private sector as developing 70 percent of new build generation capacity, with KenGen and GDC developing the remaining 30 percent. In this context, it is instructive to review how private and public plants have been procured so far, and how this might inform future procurements.

6.1. The first wave: stopgap IPPs, circa 1996

In 1996, the first wave of privately financed power involved the procurement of two diesel IPPs: Westmont (46 MW) was sponsored by a Malaysian firm and Iberafrica (44 MW) was a partnership between Union Fenosa (Spain, 80 percent) and KPLC Pension Fund (Kenya, 20 percent). A small number of bidders were invited to compete. With a relatively short tenure of seven years, these first two IPPs were considered a stopgap, and were aimed at addressing the power crisis caused by drought and construction delays with other plants. Westmont did not renew its contract in 2004 after failing to reach agreement on new tariff levels. Iberafrica did renew (on terms more favourable to Kenya) and increased its capacity, reaching 108.5 MW in 2015.

6.2. The second wave and a KenGen comparison, c. 1997–1999

Prior to 1996, all power projects had been implemented by the public sector through concessionary funding from bilateral and multilateral funding agencies. Amid moves to reform and liberalise the sector, and a corresponding lack of state funding, the private sector was invited to develop generation projects unrelated to the stopgap measures described above. In 1996, KPLC resumed an ICB (initiated in 1995) for two projects—Olkaria III and Kipevu II—which came to be known as OrPower4 (varying MW/geothermal) and Tsavo (74 MW/diesel), respectively. Orpower4 was exclusively developed by Ormat (Israel/USA), while Tsavo represented a consortium of international investors. Although both projects were procured via ICB, only three bids were received for Tsavo and two for what became OrPower4.

Despite tightening purse strings and the shift toward privately financed generation, KenGen developed Kipevu I (a 75 MW diesel-fired plant), securing backing from Japan's International Cooperation Agency (JICA). An ICB for the engineering, procurement, and construction (EPC) was conducted for Kipevu I, and this has since become standard practice for all public and private plants, unless procured through feed-in tariffs (FiTs) or conditions prescribed by other procurement laws.

[3] Electricity prices for generators, bulk suppliers and retail are regulated by ERC, one of the major inputs being the respective revenue requirements and reasonable return on investment.

Table 8
The electricity prices of public and private diesel plants, 2015

Project	Technology*	Location	Ownership	Kshc/kWh	US$kWh†
Iberafrica Power (plant 1)	MSD/HFO	Nairobi	IPP	22.82	0.25
Iberafrica Power (plant 2)	MSD/HFO	Nairobi	IPP	22.61	0.25
Temporary power (Aggreko)	MSD/HFO		EPP	20.99	0.23
Gulf Power	MSD/HFO*	Near-Nairobi	IPP	20.43	0.22
Thika Power (Melec)	MSD/HFO*	Near-Nairobi	IPP	19.86	0.22
Tsavo Power Ltd.	MSD/HFO	Mombasa	IPP	19.84	0.22
Kipevu Diesel Power I	MSD/HFO	Mombasa	KenGen	17.70	0.19
Kipevu Diesel Power III	MSD/HFO	Mombasa	KenGen	15.86	0.17
Rabai Power	MSD/HFO*	Mombasa	IPP	12.74	0.14

Data source: KPLC (2015).
Notes: * Gulf, Thika, and Rabai have heat recovery systems and thus greater efficiency rates.
† Assuming the average conversion rate in April 2015 of US$1 = 91.57 Kenya shillings (Ksh).
EPP = emergency power project; HFO = heavy fuel oil; IPP = independent power project; Ksh = Kenya shillings; KWh = kilowatt-hour; MSD = medium-speed diesel; USc = US cents.

Table 9
Prices of public and private geothermal plants.
Source: Based on data received from KPLC (2015).

Project	Ownership	Kshc/kWh	US$/kWh
Olkaria II	KenGen	12.97	0.14
Orpower4 Inc.	IPP	8.99	0.10
Olkaria IV	KenGen	6.14	0.07
Olkaria I (Units 4 and 5)	KenGen	5.91	0.06
Olkaria I (Units 1, 2, and 3)	KenGen	3.09	0.03

Note: IPP = independent power project; Ksh = Kenya shillings; kWh = kilowatt-hour; USc = U.S. cents.

6.3. Emergency power installations, c. 2000–2010

Amid worsening hydrological conditions, the MoEP arranged EPPs. Limited competitive bids were invited from a shortlist of known international EPP providers. Contracts were signed with Aggreko, Cummins, and Deutz for a combined rental capacity of 105 MW for supply in 2000 and 2001. In 2006, Aggreko was asked to provide 80 MW, and in 2007, its contract was extended. By 2009, Aggreko was supplying 290 MW of emergency power. By mid-2010, however, this was reduced (to 60 MW), and the plan was to retire all emergency power by November of that year. Ongoing drought necessitated a reconsideration of this plan, and a further 60 MW was installed. In 2012, EPPs supplied 120 MW, but this was reduced to just 30 MW by 2014 (KPLC, 2006; 2007, 2008; 2009, 2010; 2011, 2012; 2013, 2014).

6.4. A brief hiatus and complementary developments, c. 2004–09

Although no new IPPs were procured between 1996 and 2004, Iberafrica and OrPower developed additional capacity. Iberafrica also renegotiated the terms of its tariff and signed a second PPA starting in 2004. In 2007, the next IPP to be developed was Rabai (90 MW diesel). An ICB was conducted and elicited just four bids. Legal challenges, combined with the changing political climate and post-election violence in Kenya and the meltdown of global financial markets, threatened to delay the project but negotiations closed in 2008. The plant came on stream in 2009.

During this period, KenGen made progress with the Olkaria II geothermal installation. In 2003–2004, the first 70 MW came online, followed by 35 MW in 2009. This complemented KenGen's existing geothermal capacity (namely, Olkaria I's three 15 MW units built in the 1980s). At the same time (2009), KenGen was tasked with the Kipevu III extension (120 MW diesel). KenGen issued a Public Infrastructure Bond (PIBO) for building this power plant. The initial target was $200 million, but it was oversubscribed and through a green-shoe option KenGen picked another $150 million for the project. This was the first power plant to be fully-funded by local currency and therefore hedged against any currency fluctuations. The plant also took 14 months to build (which included an ICB for its EPC), the fastest ever in Kenya (pers comm. 2 February 2016).

In all these instances, public and private procurements were considered complementary, not competitive. Decisions were made by the government in consultation with KPLC, the World Bank, and other donors. With KPLC at the helm, Kenya's procurement of thermal capacity has been considered positive, specifically with regard to running effective competitive bids. Finally, noteworthy is the experience of KenGen's Kipevu III extension project, which prompts the question: should public utilities that are in vibrant capital markets not also follow this route?

6.5. A renewed push from the private sector, c. 2010

In 2010, KPLC began two new procurement processes, each via an ICB. The first related to three diesel plants (Kitengela I, Kitengela II, and Nairobi, commonly known as Triumph, Gulf, and Thika) of approximately 80 MW. In all, 31 expressions of interest were received, followed by 23 pre-qualifying bids, for all three plants. Subsequently, five bids were received for Kitengela I, five for Kitengela II, and two for Nairobi, which was re-tendered. The second procurement related to a 52 MW extension at OrPower4.

The competition for the three diesel generators indicates how much the sector had evolved. However, for OrPower4, while the initial procurement of 48 MW was done using an ICB, a further 91 MW in capacity has been added to the plant since, and none of which included a competitive bid. Thus, while OrPower4's pricing has become a benchmark for private geothermal plants in Kenya (and across Sub-Saharan Africa), it is worth noting that this benchmark has had no direct competition since 1997.

7. Changes in IPP procurement

Up until this point, there was a general progression with Kenya's IPP program; however, it is important to record a significant shift, before reporting any further procurement. As signaled from the outset (Sections 1, 3 and 6), the planning and procurement nexus is critical, and has been identified as a success factor. Kenya has reasonably good mechanisms for planning least-cost generation and transmission capacity.[4] However, since approximately 2008, the ERC's demand estimates

[4] The 2006 Energy Act states that one of the ERC's objectives is to 'prepare indicative national energy plans' (Government of Kenya, 2006: Clause 5g). To fulfil this mandate, the ERC established the Least Cost Power Development Planning (LCPDP) Committee in 2009, with representatives from the ERC (which chairs and provides the Secretariat); KPLC; KenGen; KETRACO; GDC; the MoEP; the Ministry of State for Planning, National Development and Vision 2030; the Rural Electrification Agency (REA); and Kenya's National Bureau of Statistics. Bringing these stakeholders together should enable the ERC to leverage the diverse skills and resources (including data) required for robust planning and provide a platform for building consensus and credibility (Ministry of Energy of Kenya, 2010).

have used optimistic economic data inputs from government, resulting in demand projections that have tended to be unrealistically high. The 2011–2031 LCPDP was modified to support the MoEP's 5000+ MW programme, (as first described in Section 4), and to champion the development of indigenous resources, including geothermal power, wind power, coal, and gas. Integral to the new generation programme was the promise that it would be possible to cut electricity tariffs almost in half (ERC, 2014).

The implementation of Vision 2030 started in 2008. There was, therefore, a major change in the methodology used to project electricity demand. This was to account for electricity requirements of Vision 2030 flagship projects and accelerated electricity access to households, resulting in very optimistic electricity demand projections. With slower implementation of these projects, demand has remained below forecast.

Just two years after its inception, the 5000+ MW programme was radically scaled back. Plans for a liquefied natural gas (LNG) project were shelved, and a coal project was postponed (Platts, 2015; Daily Nation, 2014). Together, these two developments represented 3000 MW of the projected new capacity; meanwhile most of the balance (2000 + MW) related to the development of an existing pipeline of projects. Industry experts, including several former KPLC employees and local and international consultants, had long warned that massive capacity additions could pose high risks to the sector's sustainability unless matched by demand. The ideal supply profile in Kenya's critical dry season is an available capacity of 15–20 percent more than the peak demand.[5] Thus, the inclusion of large new coal and LNG projects would potentially have distorted Kenya's electricity generation supply landscape.

The announcement and subsequent scaling back of the 5000+ MW programme shed some light on how planning and procurement are presently handled, as well as on the role of the private sector. The LCPDP had identified no specific criteria for the allocation of new build opportunities — a common challenge in hybrid markets (although the 5000+ programme had loosely envisioned 70 percent by the private sector and 30 by the public sector, as noted previously). As a general rule of thumb, when KenGen has been unable to finance new investments, the private sector has been invited to participate. Typically, bids for IPPs are requested by KPLC, and winners are selected via a competitive process, but in cases such as for the large LNG and coal plants considered in 2014, procurement was handled by the government directly and through its appointed agent, KenGen. The government, through the Ministry of Energy and Petroleum, also considered unsolicited bids, as detailed in Section 8.2 below.

8. Emerging renewable technologies, and the next phase of Kenya's IPPs

Apart from hydropower, which has always been publicly funded in Kenya, small investments were made in public and private geothermal activities in the 1980s and the late 1990s, but the development of other renewable forms of power has been limited. Recent wind and new geothermal activities represent a departure from this trend and have ushered in a new era in Kenyan IPPs. This section looks at how these technologies have played and continue to play a role in the shift in planning and procurement discussed in section 7, analyses the implementation and outcomes of different procurement methods aimed at renewable energy, and provides a more in-depth discussion on one of Kenya's most important sources of renewable power: geothermal energy. This analysis aims to not only identify the major trends and outcomes of this “new” phase of Kenyan IPPs, but in the process also seeks to shed some light on what the next phase of IPPs might look like (more fully unpacked in the concluding section).

8.1. Feed-in tariffs and support for renewables

Interventions to accelerate renewables began in 2008, with the development of a FiT policy. The first iteration of this policy attracted no investors but after a tariff review, a second FiT regime was introduced stipulating that wind projects' must reach 50 MW, and the tariff of USc12/kWh (fixed over the term of the PPA) was capped at the weighted average long-run marginal cost of generation (Climatescope, 2014). In 2015, the tariff was lowered to USc 11/kWh, with 12 percent of this scalable according to the US dollar CPI. It is also noteworthy that the FiT in Kenya acts as a price ceiling, and not a guaranteed price to the project; actual tariffs are therefore negotiated on a project-by-project basis (Meyer-Renschhauen, 2013).

Renewable energy projects approved by 2015 included Kinangop Wind Farm (60 MW), Kipeto Wind (100 MW), Kwale Sugar Mill (18 MW), and several other small 0.5–2.0 MW projects. None of these projects involves a specific payment security instrument, such as a letter of credit from KPLC. They do, however, have a letter of project support from the government, which, while not a guarantee, does carry some weight.

Kinangop, Kenya's first FiT project (developed by Aeolus Wind Kenya and funded primarily by AIIF2, Norfund, and Stanbic) reached financial closure in 2013. During the development stage, Aeolus made agreements with several landowners, but other landowners in the area made additional claims. In February 2015, a series of protests occurred, and an altercation between the community and police resulted in the death of a civilian (Njoroge, 2015). The Kenyan government made attempts to resolve the issues; however, a year later in February 2016, the project was eventually canceled (McGovern, 2016).

Donors and financiers such as Power Africa, the World Bank (via the International Development Association (IDA)), Agence Française de Développement (AFD), the African Development Bank (AfDB), the German Development Bank (KfW), the European Investment Bank (EIB), and JICA, among others, are increasingly providing support and advisory services to help similar projects reach financial close. Looking at the broader electricity landscape, however, an increase in wind capacity seems to make little economic sense for Kenya at prevailing FiT price levels.

8.2. Directly negotiated renewable projects

In 2011, the MoEP departed from the well-defined procurement process used for thermal IPPs and negotiated a PPA with the Lake Turkana Wind Project (LTWP). The LTWP was not part of the LCPDP. Instead, it was initiated via an unsolicited bid at a time when the state was actively promoting renewable energy but before it had formulated its FiT policy or the Public Private Partnerships Act of 2013. Notably, the ERC was not involved in the project's initiation. Given the absence of a valid comparator—that is, a private wind project procured via an ICB — the LTWP's outcomes and cost effectiveness are difficult to assess (The next large wind project that was expected to be established, Kinangop Wind Farm, was a FiT, not an ICB). The tariff negotiated for the LTWP under the PPA has a base rate of 7.52 €c/kWh up to 1684 GWh and 3.76 €c/kWh for any additional power, with 14 percent of the base tariff scalable linked to the Eurozone CPI. This is competitive with the 2015 FiT wind tariff of USc 11/kWh (Eberhard et al., 2016). However, the capacity factor assumed for the LTWP is significantly higher than that for the FiTs, which makes the comparison less accurate (per comm. August 25, 2015). Nevertheless, although Kinangop is now moot, both were relatively expensive when compared with other recent competitively bid wind FiTs, including the South African Renewable Energy IPP Programme at USc 4.7/kWh (Naude and Eberhard, 2016).

[5] This number refers to the reserve margin, one of the three reliability criteria used in the planning model for the LCPDP. Other criteria are the loss-of-load-probability (LOLP) and the expected energy not served (ENS). In previous LCPDP studies since 1986, a reserve margin of 15 percent was applied. According to LCPDP 2011–2031, a higher reserve margin of 25 percent was prescribed without offering a justification for the change.

8.3. Geothermal developments

8.3.1. GDC plans

In 1997, after the unbundling of KPLC, KenGen assumed ownership of Kenya's public generation facilities, and, as noted, 30 percent has since been privatised as part of power sector reforms. Another significant development was the creation of the Geothermal Development Corporation (GDC), which became operational in 2009. The GDC is fully government-owned and holds all mining rights for geothermal steam, except those held by KenGen and Ormat (at Olkaria) as well as those that had previously been concessioned by the government (Longonot, Akiira, and Suswa). The GDC was expected to handle the risky exploration, appraisal, and production-drilling aspects, thereby removing much of the risk from project development. It was also expected that the GDC would then sell steam to IPPs and KenGen.

A diverse array of multilateral, bilateral, and regional development partners, most notably the World Bank/IDA, EIB, AFD, AfDB, and JICA have since funded the GDC. Revenue generated from steam sales should eventually make it financially viable, although some form of government subsidy may continue to be necessary for exploration. Of course, viability hinges on the success of geothermal power projects, as well as a steam-pricing strategy that attracts investors. Despite multimillion-dollar investments, and pressure to meet the power supply targets associated with Kenya's 5000+ MW programme (by providing steam to IPPs and KenGen), the company has so far been able to source only limited steam. Between 2010 and 2014, six expressions of interest (EOIs) were invited as follows: Menengai Phase I (400MW); Emergency Menengai modular power plant (5–10MW); Menengai Phase II (800MW), Bogoria-Silali Phase I (800MW), 3 modular power plants (each 30MW) and Suswa Phase I (300MW). However, as of 2014, the GDC had managed to award just three contracts of 35 MW each, for a total of 105 MW at the Menengai field.

The large gap between what was originally invited by the GDC—namely, 2400 MW of geothermal activity (between 2010 and 2014)—and the 105 MW that is expected to reach financial closure is noteworthy. While initial capacity targets may have been inflated, two issues related to the GDC and its business model might also have hampered the procurement process. First, the availability of the requisite steam supply was uncertain. Second, no government guarantee or support was initially extended for the projects. This might have detracted from their viability since the GDC itself has no equity — all the funds the GDC has invested come from the Kenyan government and as soft loans from development partners. The 105 MW Menengai project has since received backing from the AfDB, which provided $12.7 million in partial risk guarantees (PRGs). This should help secure financial backing for three projects sponsored, respectively, by the Sosian Menengai Geothermal Power Ltd., Quantum Power East Africa (QPEA) GT Menengai Ltd., and OrPower (AfDB, 2014). QPEA GT and Sosian are Kenyan firms, and their indicative price is 8.5 USc/kWh (inclusive of the steam price of 3.0 USc/kWh).

8.3.2. KenGen reality

Although the GDC remains unable to stand on its own, progress is being made on geothermal development. The first target of new capacity additions set under the 5000+ MW programme — namely, 176 MW by October 2014 — was met, albeit not by the GDC. By the end of 2014, KenGen had connected the entire 280 MW from Olkaria I and IV to the national grid — with geothermal historically surpassing hydropower as a source of electricity for the first time, as previously noted.

The dynamics of KenGen's geothermal developments deserve further mention here. The government ostensibly de-risked the project by providing funding from the national budget for drilling. This was done in 2004 and 2005, and KenGen started drilling in 2006. In total the government provided $330 million which unlocked US$ 1 billion in funding from: the World Bank ($120m); JICA ($323m); EIB ($166m); AFD ($210m); KfW($99m) and KenGen ($138m). Due to an innovative tendering process, a savings of $300 million was ultimately realised (per comm. 2 February 2016).

Plans are now taking shape for an additional 350 MW to come online by 2017 (Herbling, 2014; KenGen, 2014). It is anticipated that this will be a combination of private and public plants. KenGen plans to (1) rehabilitate and upgrade Olkaria I units 1,2,3 from 45 to 51MW, (2) develop Olkaria I, unit 6 of 70MW, and (3) Olkaria V of 140MW. These developments are to be funded by KenGen and the donor community. KenGen is also pursuing new developments at Olkaria and Eburru. Further developments in Olkaria in partnership with the private sector under the PPP model include 140MW Olkaria VI and a similar plant: Olkaria VII. All other prospects, i.e. other than Olkaria or Eburru, are assigned to GDC or IPP concessions. Two concessions have been granted to private developers AGIL (Longonot prospect) and Akiira Ranch next to KenGen's Olkaria V site. The concessionaires own and have full control of development from exploration to power plant operation. KenGen and GDC have no role, though the initial purpose of de-risking geothermal development via the public sector (i.e. GDC) is also not being availed.

8.3.3. Summary: the next phase of Kenyan IPPs?

While the renewable energy sector holds a great deal of promise for the Kenyan IPP landscape, the reality thus far has been challenging. Wind power projects have had a particularly hard time, and have introduced a fair amount of uncertainty and controversy to the sector. Results from the geothermal sector are much more promising, but is still being hampered by limited government support for the key institution (GDC) meant to drive development of the sector. The result is that Kenya has been slow to benefit from these “new” technology IPPs.

9. IPPs: risk-mitigation and other contingencies

The Kenyan government has long maintained that sovereign guarantees are a heavy liability and that IPPs should be financed and guaranteed independently. This has been contested by developers and other sector stakeholders and different approaches have been tried over the years, as noted below, to help secure investment. Of the two stopgap IPPs, Westmont and Iberafrica, the first involved an escrow account and the second an advance-payment. Thereafter, in the initial phase of IPP development (1997–1998), KPLC had to provide two-tier payment securities in the form of a standby letter of credit (SBLC) and escrow accounts (ring-fencing, or separating out part of the receivables of the coastal-areas, including Mombasa, as a payment guarantee). This double security was necessary because of Kenya's poor credit rating and KPLC's weak balance sheet (a weakness exacerbated by the severe drought of 1999–2001). During this time, KPLC was not able to pass its purchase costs onto the customers due to limitations by ERB (now ERC), which caused the company to incur financial losses over four consecutive fiscal years.

The two-tier payment security arrangement quickly proved too costly. Instead, for the three medium-speed diesel generators procured from 2010, KPLC provided a World Bank/IDA-backed partial risk guarantee with a government letter of support for an off-taker termination default. According to stakeholders at Thika Power: ‘These [three diesel generator] projects would have taken ages to close without a PRG’ (pers comm., 7 May 2014).

For the LTWP, the AfDB extended a PRG of €20 million (US$24.69 million) for timely completion of the transmission line. This also covered the off-taker risk related to non-payment of monthly invoices and the risk of the PPA's termination (AfDB, 2013). Meanwhile, payment security for the LTWP was provided via an escrow account, funded through a tariff increase starting in 2013.

For the three 35 MW geothermal projects that comprise Menengai Phase I, initially the only security was a government letter of support in the case of termination due to KPLC/GDC default. The idea of not providing liquid security was to remove the contingent liability of SBLC (as KPLC intended to use the available SBLC capacity to support distribution expansion projects). Also, by this time, the Kenyan IPP market was believed to be sufficiently mature. However, the GDC proved too financially fragile. The project has since required the backing of the AfDB, in the form of a PRG covering a KPLC payment default as well as any default stemming from a failure by GDC to supply enough steam. Going forward, PRGs appear to be the most likely form of risk mitigation.

Most prospective investors appear to be satisfied with KPLC's timely payments of IPP invoices, and KPLC has never defaulted. There is, however, concern that KPLC's creditworthiness could be affected by the large surplus capacity if the 5000 + MW programme eventually materialises and a wholesale market takes shape. In some of the PPAs under negotiation, KPLC has introduced a clause moving the market risk from KPLC to the government (through a letter of support) and another stating that, should a wholesale market be established, the parties can consult with a view to opting out of the PPA in a mutually acceptable manner.

10. Conclusions and policy implications

IPPs provide an important complementary source of financing to meet developing countries' power needs. More countries in Africa could benefit from the growth in private investment in power and need to put in place appropriate policies, sector reforms, regulatory certainty and effective planning, procurement and contracting mechanisms. The experience of Kenya, especially in the first decade of this century, provides an example of what can be achieved in attracting IPP investments. The recent period in Kenya also provides a valuable lesson of how investment can be slowed through policy confusion and a degrading of planning, procurement, and contracting capabilities.

Previous studies and published literature have identified a range of country and project specific success factors for IPPs (Woodhouse, 2006; Eberhard and Gratwick, 2011; Eberhard et al., 2016). This updated study of IPPs in Kenya has demonstrated the ongoing relevance of these factors, including investment climate, policy and regulatory certainty, power sector reform, least-cost power planning, competitive procurement, structured financing, and protection of revenue streams through robust PPAs, appropriate credit enhancement, security measures and other risk mitigation. This study has further highlighted the importance of a number of these factors in facilitating investment in IPPs. These include: the unbundling of state generation from transmission to remove conflicts of interests in procuring IPPs, linking least-cost power planning to the timely initiation of competitive procurement of IPPs (which was done more effectively until 2008), clear allocation criteria for deciding between state and private investments in power, and further developments in credit enhancement and guarantees to de-risk projects.

10.1. Power sector reform and unbundling

Unbundling of national utilities is a useful way of removing potential conflicts between the aspirations of state-owned generators to continue investing in new power capacity and the need to close the funding gap by also procuring IPPs. An unbundled transmission company/system operator can procure generation capacity transparently and fairly.

Kenya embarked on the classic process of power sector reform by unbundling its power generation company (KenGen) from the transmission and distribution wires utility (KPLC) and partly privatising them through IPOs on the Nairobi Stock Exchange – effectively making them mixed-capital enterprises. This separation removed potential conflicts around procuring private power. While KenGen continued to invest in new power generation plant, KPLC also built capacity to run competitive tenders for IPPs. Furthermore, Kenya put in place a national power planning system, under the leadership of the regulator but with the involvement of key stakeholders. The LCPDP was regularly updated.

For some time these arrangements appeared to work well. The least-cost plan indicated what power was required when. If KenGen was able to raise sufficient capital, either through development finance institutions or bond issues, it built new power plants. KPLC's tenders for IPPs mobilised additional private investment.

Since 1996, private developers have been critical in financing electric generation and have complemented publicly owned projects. Although the first stopgap IPPs were procured in a context of limited competition, a strong track record of international competitive bidding was built by KPLC for procuring thermal IPPs such as Tsavo, Rabai, Thika, Gulf, and Triumph.

Separate from KenGen, and housing the system operator, KPLC faces no generation investment conflicts and can procure new power in a fair, transparent, and competitive fashion. KPLC has also built up considerable internal procurement and contracting capabilities.

Power sector reforms have been important in Kenya – but equally relevant are the issues of least-cost power planning linked to the timely procurement of new capacity and effective contracting capabilities.

10.2. Least-cost power planning

One of the most important challenges for electricity utilities in developing counties is to procure adequate power at the least cost. The planning function could be assigned to any capable institution, but a logical location is the transmission company/system operator. The system operator is responsible for balancing the system and short-term security of supply. These responsibilities could easily be extended to medium and long-term planning and the integration of generation and transmission planning. Planning needs to dynamic and flexible, and should include the latest realistic demand forecasts and up-to-date data on least-cost options.

Kenya developed a relatively strong track record of least-cost planning. Since approximately 2008, however, power planning has been based less on solid and independent technical analysis. Instead, the government's demand estimates have tended to be unrealistically high. Also, the link between planning and competitive procurement has weakened in recent years; some generation projects have been procured directly and without thorough technical and financial analyses to determine whether integration and system requirements are in line with least-cost planning standards.

10.3. Clear allocation of new-build opportunities, state vs. private power

A second element of planning that is presently falling short is a clear allocation of new projects between the private and public sector based on transparent criteria. Incumbent state-owned utilities invariably seek new generation opportunities for themselves, claiming that they can deliver cheaper power. However, many utilities struggle to raise adequate investment and often execute capital projects inefficiently, with cost and time overruns (Eberhard et al., 2016). IPPs should be given a fair opportunity for new investment and can serve as a useful benchmark for publicly procured power.

This area has been a key weakness of the Kenyan power sector, as the LCPDP has no criteria for allocating new-build opportunities. Instead, the private sector has either "filled the gaps" where KenGen has been unable to finance investments, or has directly negotiated deals with the government (and not necessarily KPLC). This has proven to be an important but weak link between the least-cost planning and procurement processes.

10.4. Competitive procurement

Least-cost power plans need to be translated into the timely initiation of international competitive bids. There is now compelling evidence that competitive tenders or auctions for standard technologies such as diesel or HFO power plants, more often than not, yield better investment and price outcomes than directly negotiated projects (Eberhard et al., 2016). The exceptions are the few instances where there are competent state-owned utilities with access to concessionary finance. Kenya's KenGen is a case in point; it has been able to raise capital and delivers competitively priced electricity, although it should be noted that a number of its power stations have performed more poorly than private IPPs.

The case for competitive tenders is even stronger for renewable energy technologies such as solar where international evidence demonstrates that reverse auctions are delivering prices well below administratively set feed-in tariffs or directly negotiated projects (Eberhard et al., 2016).

Although unsolicited bids have been justified as being simpler, cheaper and quicker than competitive tenders, in practice, they often take longer to negotiate and the lack of transparency can result in non-optimum deals.

The links among the transparency of procurement, price outcomes, and project sustainability are evident (Eberhard et al., 2016). In general, prices for power projects in Kenya have declined since the first IPPs were procured. This is most obviously the case in standard technologies such as diesel or heavy fuel power plant. The correlation between increased IPP investments and price declines could potentially signal the benefits of increased competition in procurement - a finding that would be in line with international evidence (Eberhard et al., 2016).

The landscape for new-build geothermal opportunities has been particularly affected by procurement problems. GDC has been minimally successful in attracting investment, in large part due to the fact the transfer of responsibility for geothermal IPP procurement to GDC from KPLC was not accompanied by a concurrent transfer of procurement capacity and experience. This has resulted in non-transparent and unpredictable procurement processes, ultimately failing to result in the targeted capacity additions. Further concerns have also arisen due to non-competitively bid wind projects, which have proven to be more expensive than comparable projects in other countries.

10.5. Risk mitigation

Project financed IPPs require secure revenue streams that will service debt and reward equity. Payment defaults and termination risks need to be adequately mitigated, as do political and regulatory risks. Kenya has shown that it is possible to do this without a full sovereign guarantee through mechanisms such as escrow accounts and letters of comfort and credit, partly because the off-taker utility, KPLC, performs reasonably well in terms of billing and collections, and tariffs have moved towards cost-reflectivity. However, there are limits on the amount of revenue that can be escrowed in successive IPPs. The partial risk guarantees of DFIs have been an important element of risk mitigation in recent IPP investments. It will continue to be important to de-risk projects if we are to accelerate growth in private investment in power across Africa.

In summary, Kenya is one of the leading destinations in Sub-Saharan for IPPs and offers many valuable lessons for spreading these investments across the continent. This paper helps explain the factors that are important in accelerating IPP investment in sub-Saharan Africa.

Appendix A

At the beginning of the 1990s, virtually all major power generation throughout Africa was financed by public coffers, including concessionary loans from development finance institutions (DFIs). These publicly financed generation assets were considered one of the core elements in state-owned, vertically integrated power systems (Yergin and Stanislaw, 2002). In the early 1990s, however, a confluence of factors brought about change. The main drivers were identified as insufficient public funds for new generation and decades of poor performance by state-run utilities (Jhirad, 1990; Moore and Smith, 1990; World Bank, 1993; Bacon, 1995; Wolak, 1998; Kessides, 2004; Besant-Jones, 2006; Victor and Heller, 2007). African countries began to adopt a new ‘standard’ model for their power systems, influenced by pioneering reformers in the US, the UK, Chile and Norway (Patterson, 1999; World Bank, 2003).

Urged on by multilateral and bilateral development institutions, which largely withdrew from funding state-owned projects, a number of countries adopted plans to unbundle their power systems and introduce private participation and competition (World Bank, 1993) (DFID, 2002). IPPs with long-term power purchase agreements (PPA) with the state utility, became a priority within overall power sector reform (World Bank, 1993; World Bank and USAID, 1994). IPPs were considered a solution to persistent supply constraints, and could also potentially serve to benchmark state-owned supply and gradually introduce competition (APEC Energy Working Group, 1997). IPPs could be undertaken before sector unbundling. An independent regulator was also not a prerequisite since the PPA laid down a form of regulation by contract.

In 1994, Côte d’Ivoire became one of the first African countries to attract a foreign-owned IPP to sell power to the grid under a long-term contract with the state utility (Malgas and Gratwick, 2008). Ghana, Kenya, Nigeria, Senegal, Tanzania and Uganda, among others, also opened their doors to private sector participation; however private investment has been erratic (Eberhard and Gratwick, 2005; Malgas, 2008; Gratwick et al., 2006; Kapika and Eberhard, 2013).

Several factors explain the recent trends in investment. Private sector firms were deeply affected by the Asian and subsequent Latin American financial crises in the late 1990s. The Enron collapse and its aftershocks also featured prominently in influencing American and European-based firms to reduce risk exposure in emerging and developing-country markets and refocus on core activities at home. The financial crisis of 2008/9 also had its toll. Furthermore, DFIs began to reconsider their position of restricted infrastructure investment, which had predominated throughout the 1990s (Malgas and Eberhard, 2011). As concessionary financing became available again, many countries opted for a hybrid solution—part public, part private. Kenya represents among the clearest examples, with KenGen, the state-owned generator, building alongside IPPs, with support from DFIs (Gratwick and Eberhard, 2008).

Despite this revival of concessionary lending and ongoing financing from the private sector, investments are insufficient to address Africa's power needs: two out of three households in Sub-Saharan Africa, close to 600 million people, have no electricity connection at all. With only 37 percent of the population currently with electricity access (36 percent in Kenya), and poor supply is the rule, not the exception (World Bank, 2017). The cost of meeting Africa's power sector needs has been estimated at between $40.8 billion[6] (Eberhard and Shkaratan, 2012; Castellano et al., 2015) and $75 billion a year (Bazilian et al., 2012), equivalent to at least 6.35 percent of Africa's GDP. Approximately two thirds of the total spending is needed for capital investment ($26.7 billion a year); the remainder is for operations and maintenance (OandM). Of capital investment, about $14.4 billion is required for new power generation each year, and the remainder for refurbishments and networks (Eberhard et al., 2011: 60). Existing investment is far below what is needed (Eberhard and Shkaratan, 2012).

Tackling existing utility inefficiencies, which include system losses, under-pricing, under-collection of revenue and over-staffing would make an additional $8.24 billion available, but a funding gap of $20.93 billion would still remain (Eberhard et al., 2011).

[6] According to Eberhard and Shkaratan, “The model used to calculate these estimates was run under the assumption of expanded regional power trade and takes into account all investments needed for the increase in trade and all cost savings achieved as a result,” (2012: 149).

Closing Africa's power infrastructure funding gap inevitably requires undertaking reforms to reduce or eliminate system inefficiencies. This will help existing resources to go farther and create a more attractive investment climate for external and private finance, which still has the potential to grow. With the original drivers for market reform are still present, private sector involvement appears inevitable in the future.

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