WHY PRIVATE FINANCE IS NOT FILLING THE ELECTRICITY SUPPLY FUNDING GAP IN SUB-SAHARAN AFRICA

KEITH PALMER

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About Keith Palmer

Keith has been a development economist, corporate and project finance adviser and investor in the energy, infrastructure and agribusiness sectors in developing countries for many years. Most recently he has been centrally involved in the creation and development of the Private Infrastructure Development Group (PIDG) and AgDevCo (www.agdevco.com). Previous relevant positions held include Vice Chairman of Rothschild, working for the World Bank and IMF and senior roles working for the host governments in Tanzania and Papua New Guinea. He is also founder and chair of trustees of Enterprise for Development.

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CHALLENGING THE CONVENTIONAL WISDOM

The woeful state of electricity supply in sub-Saharan Africa is well known.[1] Billing costs are high and quality of service poor. Less than a third of households have access to electricity and the number without access is increasing. Per capita consumption of electricity is the lowest of any region in the world and has not increased for decades. High cost and poor reliability of electricity supply to business customers is frequently cited as one of the biggest obstacles to investment and growth.

The conventional wisdom is that:

- the way to increase consumption of electricity and grid access is to increase investment in generating capacity;
- the funding requirement is huge – \$40–\$50 billion per annum according to some estimates – and since this vastly exceeds the sums that can be mobilised by host governments and State utilities;
- privately-financed independent power projects (IPPs) can and should be used to fill a large part of the "electricity supply funding gap".

However, despite sustained efforts by host governments and donors/DFIs over decades, the amount of investment committed to fund IPPs is a small fraction of this amount – \$1.3 billion per annum on average over the 2011–2014 period. The key reason for the low rate of IPP investment, it is argued, is lack of private finance, the result of market and government failures.

The analysis set out here challenges this conventional view. It shows that increasing investment in generating capacity will not increase electricity consumption or grid access unless, as a result, billing costs fall and/or incomes rise. In fact, most IPP capacity contracted over recent decades has achieved the opposite result – reduced consumption of electricity for the vast majority of households and reduced ability to access the grid. The slow growth of IPP investment is the inevitable consequence of slow growth of electricity demand, the result of high billing costs and low incomes, not lack of finance. If electricity consumption and grid access are to increase more rapidly and environmental outcomes to improve, actions will be needed (i) on the supply side to drive down generation costs and increase the share of renewables in generation portfolios and (ii) on the demand side to reduce the cost and improve the reliability of electricity supply to priority business customers so as to stimulate more investment, job creation and income growth. It outlines ways that host governments with support from donors/DFIs can achieve these desired outcomes.

ELECTRICITY SUPPLY SYSTEMS

In most countries in sub-Saharan Africa the State-owned utility (hereafter, Utility) has sole or primary responsibility for developing and operating the electricity supply system. Typically it finances, builds and operates its own generating plant and the transmission and distribution (T&D) network; is the sole purchaser of output purchased from IPPs; and in most cases is the sole or dominant seller of electricity to end-customers. The cost of purchasing IPP output is set in long term power purchase agreements (PPAs); and revenue from end-customers is set in regulated tariff schedules set or approved by the host government (or independent regulator).

The Utility has to generate revenue from sales to end-customers sufficient to fund its operating costs, the costs of maintaining and upgrading the system, contractual payments to IPPs and interest and principal payments on loans used to fund its capital programme. If revenue were insufficient to fund planned expenditure then, unless additional funding was provided by the host government, discretionary spending to upgrade and extend the system and/or replace generation assets would have to be cut (or else risk the Utility becoming insolvent).

High system costs

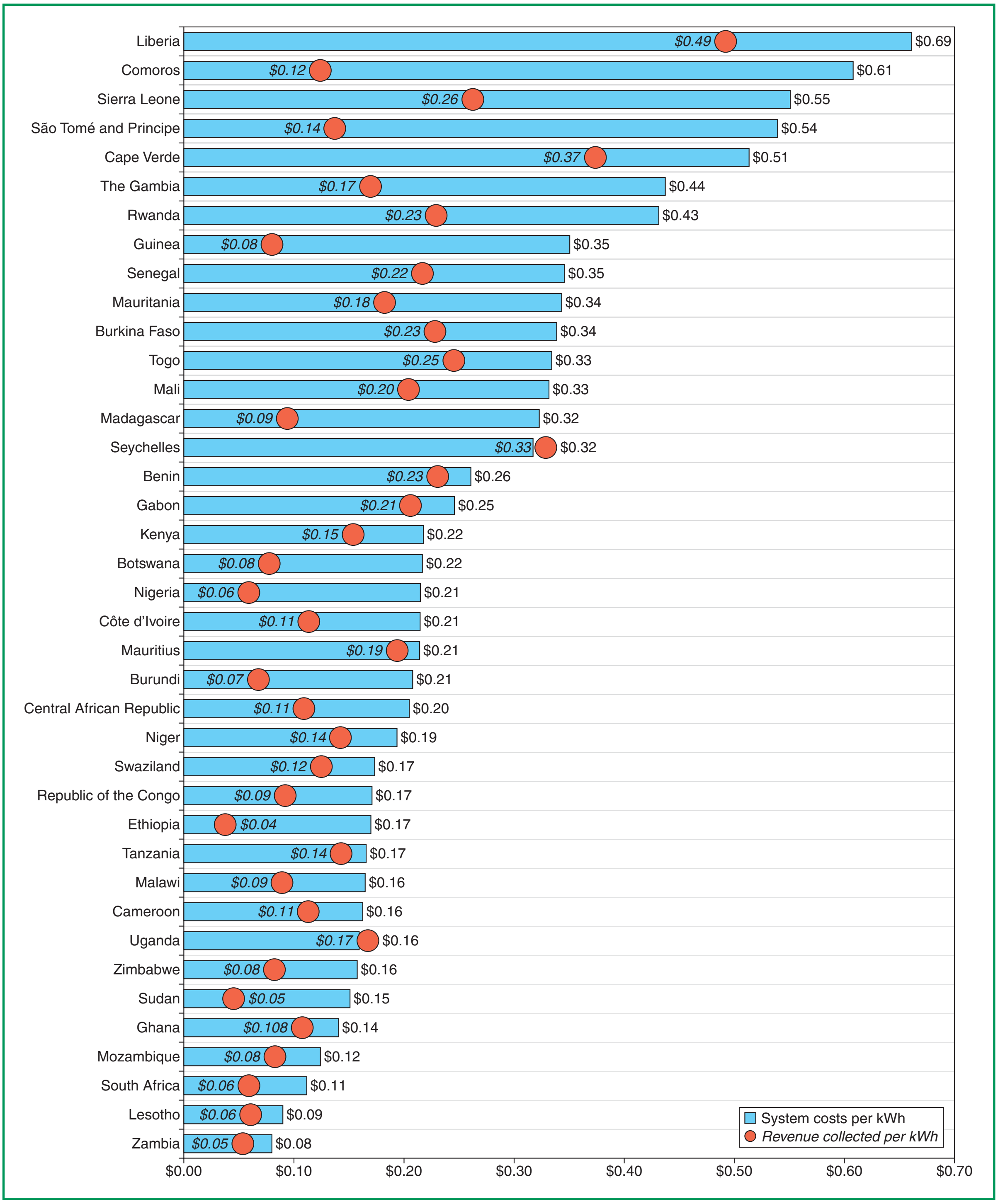
System costs are high in almost all countries in sub-Saharan Africa. It is commonly supposed that the main reason is because Utilities are inefficient and poorly governed. Although it is true that many Utilities are inefficient and poorly governed, that is not the main reason system costs are so high. The main reason is that most (but not all) countries have intrinsic characteristics which make them high cost even if operated efficiently and well governed, regardless of whether they are publicly or privately financed.

One such characteristic is that systems are very small, hence lack economies of scale. Just 13 have total generating capacity greater than 1000 MW and more than 30 have less than 500 MW. (For comparison, 1000 MW is a single medium size generating plant in Europe.) Another is that most countries do not have access to major rivers and hence the potential to develop large baseload hydropower facilities. Instead they have had to rely heavily on small, low thermal efficiency, oil fired power stations using imported fuel which are inherently high cost.

Figure 1, taken from Trimble *et al.* (2016), shows system replacement costs per kWh in 39 countries in sub-Saharan Africa in 2014. (System replacement costs are the average cost of replacing existing State-owned generation, transmission and distribution assets including a 10% real cost of capital amortised over the economic life of the assets.) Total system costs vary widely between countries and the variation is largely explained by the composition of the generation portfolio. The lowest system costs (<15 c/kWh) are exclusively in the handful of countries with access to plentiful supplies of cheap baseload hydropower from high dams on major rivers – the Nile, Zambezi and Volta. Costs are higher (15–30 c/kWh) in countries with a mix of run of river hydropower and small oil-fired thermal power stations; and highest (>30 c/kWh) in countries with small systems and the heaviest reliance on small oil-fired thermal power stations.

A further reason why system costs are high in some countries is that host governments have resorted to leasing very expensive emergency power plant. This was in response to the surge in electricity demand from grid-connected customers which resulted from the commodity price induced consumer boom over the 2000–2012 period (Palmer

Figure 1 System costs and cash revenue per kWh in sub-Saharan Africa.



Source: Trimble *et al.* (2016).

(2017)). Installing expensive emergency power plant was a temporary expedient to reduce power outages until cheaper more permanent capacity could be procured. This further increased average system costs, for example, in Tanzania more than 300 MW of emergency plant was leased at a reported cost of 40 c/kWh.

Since generation costs (including fuel costs) account for 70–80% of total system costs in most countries, and high system costs are the result of heavy reliance on small, inefficient oil fired power plant, it follows that the most effective way to reduce system costs is to reduce reliance on thermal plant and increase the share of cheaper renewables in the generation portfolio.

Tariffs lower than system replacement costs

Electricity tariffs are high in absolute terms in all countries in sub-Saharan Africa. In many of them, they are more than twice as high as tariffs in comparable countries in South and South East Asia. But, although tariffs are high, they are also much lower than system replacement costs per kWh in almost all countries. The red circles in Figure 1 (also taken from Trimble *et al.* (2016)) show average cash revenue per kWh superimposed on system replacement costs per kWh in 2014. (Average cash revenue per kWh is the sum of tariff revenue from sales to industrial, commercial, government and household customers and other revenue received e.g. grid connection charges, divided by the total number of kWh sold). Average revenue (and hence average tariffs since they account for the bulk of total revenue) was *much lower than average system replacement costs in 38 of 39 countries* in 2014. In half of them, revenue was insufficient to fund operating costs, hence the Utility had to rely on government subsidy just to remain solvent. Revenue was only *sufficient to fund half or more of system replacement costs* in *3 of 39 countries*.

The wide variation in average revenue mirrors the variation in average system costs. With few exceptions, tariffs were higher in countries with high system costs and lower in countries with lower system costs. The pattern reflects a consistent pattern where tariffs have been set or approved by the government at a level just high enough to fund the Utility's immediate cash costs (but not high enough to fund system maintenance and the cost of replacing existing assets).

The reason why so many Utilities could finance their activities despite revenue being far lower than system replacement costs is because they have had access to: cheap loans to fund their capital programmes (mostly from multilateral institutions and foreign governments); and government subsidies to fund operating cash flow deficits. Despite cheap capital and government subsidy almost all Utilities have chronically weak finances.

Tariffs are too low to generate the internal cash flow needed to repair, maintain and extend the system – which is one reason why quality of service is so poor. Tariffs are also too low to generate the cash flow needed to replace existing assets *if finance was provided on commercial terms*. Figure 1 shows that 38 of the 39 Utilities are unable to generate the cash flow needed to fund debt service payments on commercial loans with a 10% interest rate. If they were to borrow on commercial terms there would be insufficient cash flow to fund debt service costs. The result would be further deterioration in already-weak Utility finances and/or a requirement to increase tariffs.

One familiar response to weak Utility finances has been to urge them to improve efficiency and governance. Both are clearly desirable and necessary but neither are sufficient. Kojima and Trimble (2016) show that, even if efficiency were improved to international benchmark levels and the necessary actions were costless, "In two thirds of the countries studied, the funding gap cannot be bridged simply by eliminating operational inefficiencies" (p. viii). In reality efficiency improvements are never costless so the funding gap, net of restructuring costs, would be even greater. The reason is that even major efficiency improvements cannot fully offset the high intrinsic system costs associated with lack of scale and the need to rely heavily on high cost thermal plant.

The other familiar response has been to urge Utilities and host governments/regulators to increase tariffs to cost recovery levels i.e. to the level where the Utility can generate enough revenue to sustain and expand the system. However, as the next section shows, increasing already-high tariffs creates problems of a different sort.

Tariffs already unaffordable for many households

Kojima *et al.* (2016) show that tariffs in most countries in sub-Saharan Africa in 2014, although too low to fund system replacement costs, were also too high to be affordable for large numbers of households in most countries. They evaluated the maximum amount of electricity that households could afford to purchase in descending quintiles of the income distribution in 20 countries, taking into account maximum affordable expenditure (5% of total cash expenditure) and applicable billing costs (including subsidised lifeline tariffs). They argued that the minimum amount of electricity that households would be willing to purchase is 30 kWh/month – just enough for a few lights and a phone charger. If a household could not afford to purchase 30 kWh/month, demand would be zero even if the household is already connected to the grid.

Figure 2 summarises some of their results. Shaded values in Figure 2(a) show categories of households where the cost of purchasing 30 kWh/month exceeds 5% of their total expenditure i.e. is unaffordable. *All rural households in 9 of 16 countries* and *more than half of urban and rural households* in *6 of 15 countries* could not afford to purchase 30 kWh/month. None of these households would purchase any electricity even if already grid-connected. (This deduction is supported by observations of household behaviour in several countries where households have chosen not to purchase any electricity from the grid despite being connected.)

Figure 2(b) uses the same methodology to determine the proportion of households that

Figure 2 Expenditure share of monthly consumption of households by location, quintile and poverty status in 2014.

(a) Share of total expenditure needed to purchase 30 kWh/month.

	All households				
Country	**Urban**	**Rural**	**Total**	**Q1**	**Q5**
Botswana	2.4	6.8	4.2	16.7	1.4
Burkina Faso	7.8	15.0	13.0	22.3	7.8
Côte d'Ivoire	1.6	3.2	2.4	6.5	1.1
Ethiopia	1.3	3.7	3.3	7.2	1.4
Ghana	1.2	2.4	1.8	4.4	0.9
Malawi	1.6	4.0	3.6	6.3	1.9
Niger	2.6	5.3	4.8	7.7	3.0
Rwanda	6.8	15.3	14.1	26.9	5.1
Senegal	2.2	4.4	3.3	7.8	2.0
Sierra Leone	3.9	7.6	6.2	10.6	3.7
Tanzania	1.6	5.8	4.5	10.0	1.5
Uganda	4.3	9.2	7.9	15.9	3.3
Zambia	2.4	11.1	8.0	17.4	1.9

(b) Share of total expenditure needed to purchase 100 kWh/month.

	All households				
Country	**Urban**	**Rural**	**Total**	**Q1**	**Q5**
Angola	0.5	1.0	0.7	1.4	0.3
Botswana	5.0	11.8	7.8	33.0	2.1
Burkina Faso	20.4	28.9	26.5	47.2	16.2
Côte d'Ivoire	6.3	9.5	7.9	20.0	4.2
Ethiopia	3.7	4.3	4.2	9.0	2.1
Ghana	6.8	10.7	8.6	18.4	4.8
Malawi	4.4	7.8	7.2	12.6	4.2
Mozambique	4.9	8.7	7.6	18.2	2.6
Niger	6.8	11.7	10.9	15.8	7.4
Rwanda	17.8	31.8	29.8	55.9	12.5
Senegal	6.7	11.7	9.2	20.4	6.0
Sierra Leone	12.5	19.7	16.9	28.9	10.2
Tanzania	6.6	11.8	10.2	19.9	5.6
Uganda	11.5	18.2	16.4	31.7	8.6

Source: Adapted from Kojima *et al.* (2016).

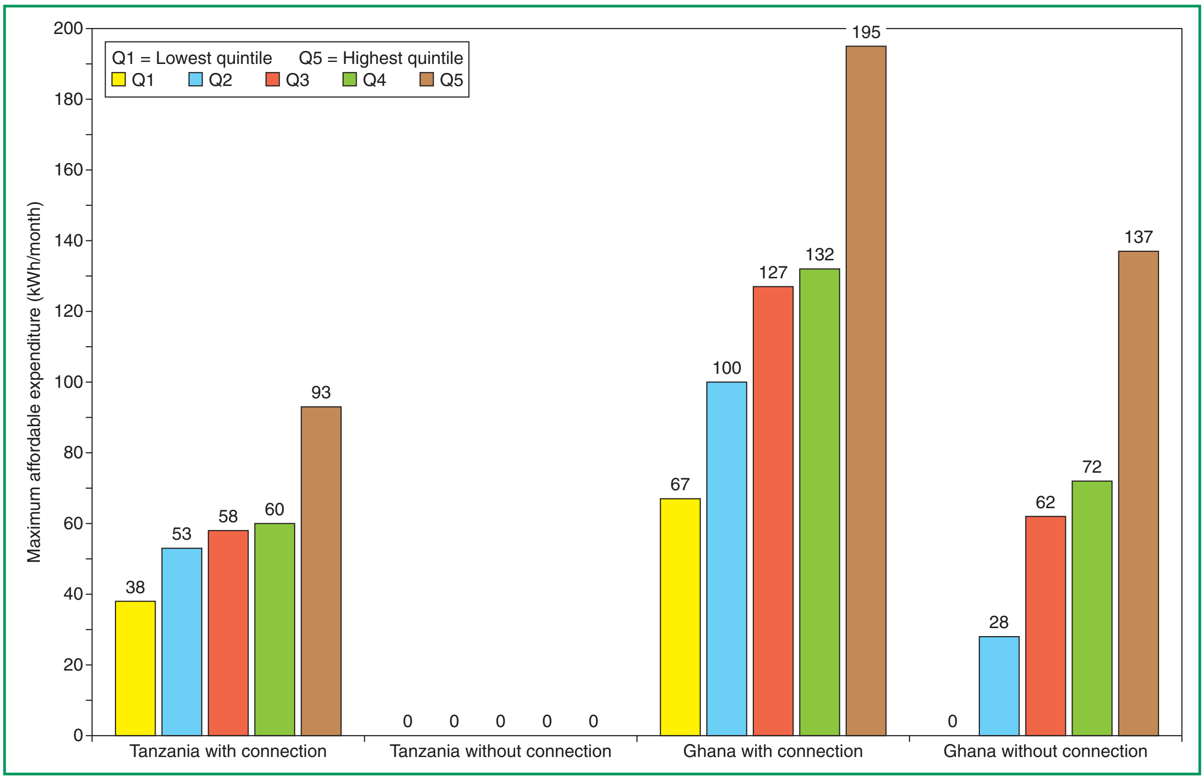
Note
Q1 = Lowest income quintile, Q5 = Highest income quintile.
Shaded values shows the categories of household unable to afford to purchase 30 kWh/month (2a) and 100 kWh/month (2b).

could afford to purchase 100 kWh/month – just enough electricity to use one hotplate 2 hours/day for cooking as well as a few lights and a phone charger. It shows that *all urban households in 7 of 20 countries* and *all rural households in 18 of 20 countries* could not afford the 100 kWh/month needed to cook with electricity as well as light their homes. This helps explain why so many households continue to cook on open wood or charcoal fires despite the obvious health and environmental consequences. It also explains why so many households, even in low middle income countries, for example Kenya, consume so little electricity even though they are grid connected. It is because their billing costs are high and incomes of households in the lower quintiles of the income distribution are low.

Similar analysis has been undertaken by the author for Tanzania and Ghana (Figure 3). It shows that in low income Tanzania all of the 16% of households connected to the grid could afford to purchase at least 30 kWh/month but about half of them could do so only because they could purchase electricity at the heavily subsidised lifeline tariff rate. In Ghana, where incomes are higher, of the 65% of households connected to the grid in 2014 about 80% could afford to purchase at least 100 kWh/month. But when in 2015 tariffs increased sharply (by about 59% for reasons explained later) maximum affordable consumption fell sharply throughout the income distribution and the share of grid-connected households able to afford 100 kWh/month fell from 80% to 20%.

The key point is that *low household consumption of electricity is caused by lack of effective demand*, the result of high billing costs and low household incomes. Many grid-connected households, especially in low income countries, cannot afford to purchase even subsistence amounts of electricity unless they can purchase it at heavily subsidised lifeline rates. Even in low-middle income countries a large number of grid-connected households cannot afford to purchase the amount of electricity needed to cook with electricity as well as light their homes. Even in relatively higher income Ghana, households with incomes in the top quintile of the income distribution could not afford to purchase 200 kWh/month (which is less than a third of the average electricity consumption in OECD countries).

Figure 3 Maximum affordable expenditure (kWh/month) in Tanzania and Ghana.



Source: Author calculations.

Figure 4 Access rates by country, location and income level.

	All households				
Country	**Urban**	**Rural**	**Total**	**Q1**	**Q5**
Angola	67	10	41	6	73
Botswana	60	21	43	15	74
Burkina Faso	46	2	11	1	35
Ethiopia	94	8	19	5	38
Ghana	88	44	66	35	89
Malawi	38	3	9	0	30
Niger	48	2	10	1	37
Rwanda	46	5	11	1	43
Senegal	90	25	53	26	83
Sierra Leone	35	0	13	2	37
Tanzania	50	4	16	1	53
Togo	77	9	34	5	73
Uganda	33	2	9	1	31
Zambia	55	4	22	1	71

Source: Kojima *et al.* (2016)

Grid access is similarly constrained by lack of purchasing power. Households not already connected to the grid must pay higher billing costs – connection charges as well as tariffs – and typically have lower incomes than already-connected households. Higher billing costs and lower incomes *reduce the share of households that can afford to pay connection charges and purchase the minimum 30kWh/month*. Figure 3 shows that in Tanzania, of the 84% of households that are not connected to the grid, none of them could afford to pay connection charges and purchase 30kWh/month. In Ghana the much higher grid access rate in 2014 reflected higher incomes throughout the income distribution and low billing costs made possible over earlier decades because the Utility had access to cheap hydropower from the Volta. The large tariff increase in 2015 made grid connection for the 35% of households without access even less affordable.

Figure 4 shows how grid access rates have been determined by ability of households to pay. Access is highest in countries where incomes are higher and billing costs lower, and lowest in countries where incomes are lower and billing costs higher. Similarly access in rural areas is much lower than in urban areas because incomes are generally lower and billing costs higher.

The analysis shows that household consumption of electricity and grid access are constrained by lack of demand, not lack of supply. Consumption can only increase if billing costs fall and/or incomes rise. Ability to access the grid can only improve *if billing costs of households not currently connected to the grid fall and/or their incomes rise*. Access cannot be increased much by reducing connection charges because doing so will further weaken the Utility's finances as revenue falls and costs rise.

The story so far

Tariffs are high because system costs are high but also too low to sustain and expand the system. If tariffs of household customers were increased to improve Utility finances, there would be a reduction in consumption of electricity and reduced ability to access the grid. If tariffs of business customers were increased, there would be reduced incentive for them to invest, create more jobs and grow incomes faster. If lifeline tariffs were left unchanged to protect low income households, government subsidy payments would increase.

It follows that increasing investment in generating capacity can only increase consumption and access *if*, as a result, *billing costs fall and/or incomes rise*. Conversely, if investment to increase generating capacity results in higher billing costs for household and business customers, there will be reduced household consumption of electricity, reduced ability to access the grid, and reduced incentive for businesses to invest and grow.

INDEPENDENT POWER PROJECTS (IPPs)

Power Purchase Agreements

Practically all IPPs use project finance structures to raise the debt and equity needed to build and operate privately-financed power stations. A Special Purpose Vehicle (SPV) is created to fund the investment and a long term Power Purchase Agreement (PPA) executed between the SPV and the Utility. The PPA is the principal asset of the SPV and satisfactory terms are a pre-requisite for raising the debt and equity needed to build and operate the plant.

A small number of core provisions apply to (almost) all PPAs. They impose a binding long term obligation on the Utility to purchase and pay for all or most of the IPP capacity over the typically 20–25 year contract life. It specifies a Base Price set to recover the IPP's development, construction and operating costs including the weighted average cost of debt and equity capital (WACC); plus, in the case of thermal plant, full pass through of fuel costs. All or a high share of the Base Price is denominated in dollars and indexed to a measure of US dollar inflation. And lenders to the SPV invariably require a government guarantee of the Utility's performance or payment obligations.

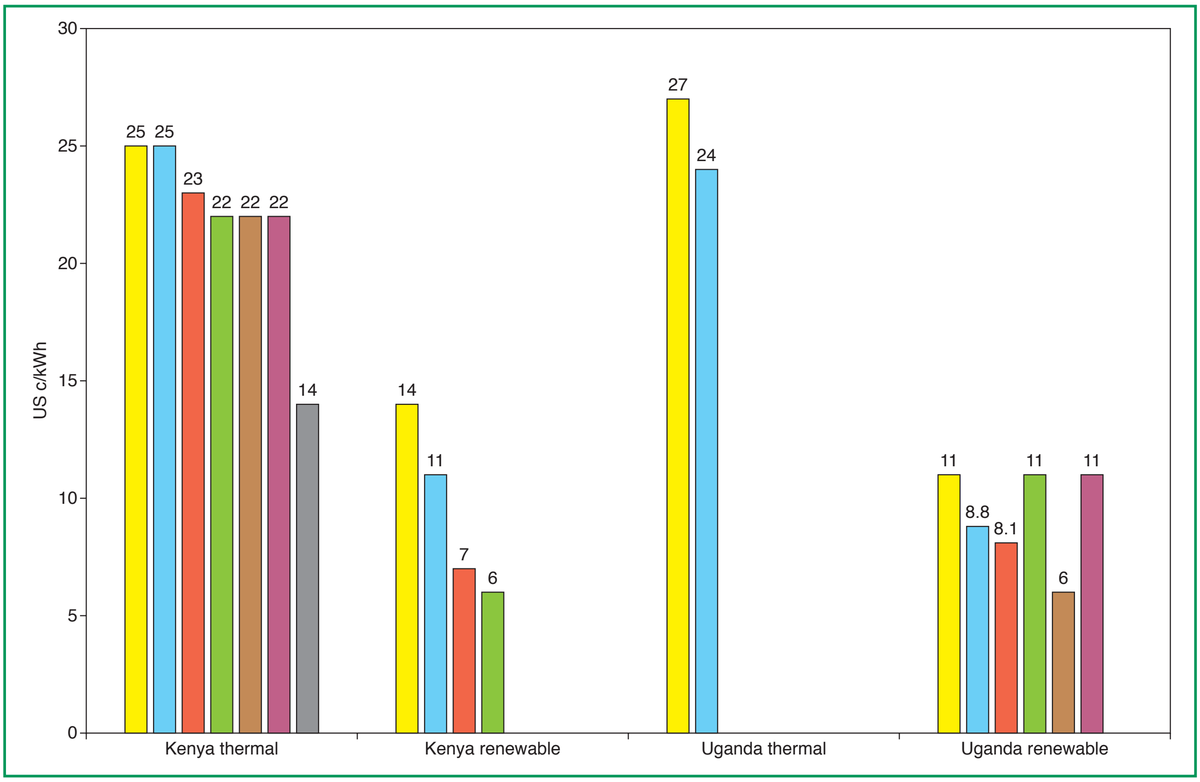
These provisions transfer all or most of the demand risk from the IPP sponsors to the Utility so, regardless of whether the Utility is able to generate sufficient revenue from sales to end-customers, it remains obliged to pay the PPA purchase costs. In addition the dollar-denominated Base Price and indexation provisions transfer all or most of the exchange rate risk to the Utility. Devaluation increases the claim on local currency needed to fund dollar PPA purchase costs. Since tariffs are denominated in local currency, devaluation will either result in deterioration in the Utility's finances or tariffs will have to increase. The higher the dollar-denominated purchase costs and the greater the devaluation, the higher the revenue that must be recovered from end-customers by increasing tariffs. If the Utility were unable to generate the revenue needed to fund its PPA payment obligations the host government, as guarantor, would be liable to fund any shortfall.

Thermal power IPPs are high cost

Eighty per cent of all IPP capacity contracted in sub-Saharan Africa since 2000 is oil fired thermal power plant – almost all of it is high cost. Figure 5 (adapted from Eberhard *et al.* (2016)) summarises calculations of the levelised cost of thermal power IPPs in Kenya and Uganda (which together account for more than 50% of all contracted IPP capacity in sub-Saharan Africa). Almost all of them had levelised costs well in excess of 20 c/kWh in 2014 (and remained above 20 c/kWh in 2016 after adjustment to allow for the fall in oil prices since 2014). Kenya and Uganda are not exceptions – similar high costs are also reported for thermal power IPPs in other countries (e.g. Ghana).

Project-financed thermal power IPPs are bound to be high cost for several reasons. As noted earlier, small oil fired thermal plant using imported fuel are intrinsically high cost, however financed and developed. In addition small project financed IPPs will be even higher cost because: pre-financial close development costs, legal and financing transaction costs, and construction costs all tend to be higher per MW when projects are small and developed "one off"; and the WACC is bound to be high in sub-Saharan Africa because of the high political and regulatory risks, the operationally and financially weak counterparties, and often, the sub-investment grade credit ratings of

Figure 5 Levelised cost of thermal and renewable power in Kenya and Uganda.



Source: Adapted from Eberhard *et al.* (2016).

host governments. The WACC of a typical project-financed IPP in sub-Saharan Africa – about 10% in real dollar terms – is more than twice the cost of capital available to utilities in OECD countries. This substantially increases the levelised cost of these projects, for example, if a project could be funded with capital requiring a 5% return rather than 10%, the levelised cost would be 40–50% lower.

Contract prices can be even higher if PPAs are bilaterally negotiated, rather than competitively bid, because there is a lack of competitive tension. There is evidence from Kenya that shows that prices agreed for negotiated IPPs are higher than comparable IPPs procured using competitive bidding.

The other 20% of contracted IPP capacity is renewable power. As Figure 5 shows, all of it has much lower levelised costs than thermal power plant. The reason is that the technical costs of these projects are much lower than the cost of thermal plant and this more than compensated for the high project finance-related costs. Despite being much cheaper than thermal power, aggregate contracted renewable IPP capacity was only 20% of the total because until recently only a relatively few renewable projects in favourable situations were cheaper than thermal power, for example, high wind speeds in Lake Turkana, geothermal resource in the Rift Valley, bagasse adjacent to sugar plantations.

Since 80% of total IPP capacity was high cost, the weighted average of thermal and renewable IPP capacity was also high cost. In countries with significant amounts of contracted IPP capacity this further contributed to increasing average system costs.

Impact of IPPs on end-customers and the Utility

The delivered cost of IPP output is the sum of the contract price into-grid, a margin to cover Utility on-costs and an adjustment for system losses. If the cost into-grid is 20 c/kWh, the delivered cost will be about 23–25 c/kWh.

The impact on end-customers and the Utility of purchasing high cost IPP output differs depending on the circumstances in each country from time to time. If even more expensive emergency plant can be displaced with cheaper IPP capacity, there will be short term financial savings for the Utility but no immediate impact on end-customers. The cheaper the IPP capacity and the greater the quantity of emergency plant displaced, the greater the financial savings. However, short term savings may be more than offset by medium term costs if inflexible, long term PPAs lock-in high contract prices, eliminating the option to procure cheaper capacity for the remainder of the contract life.

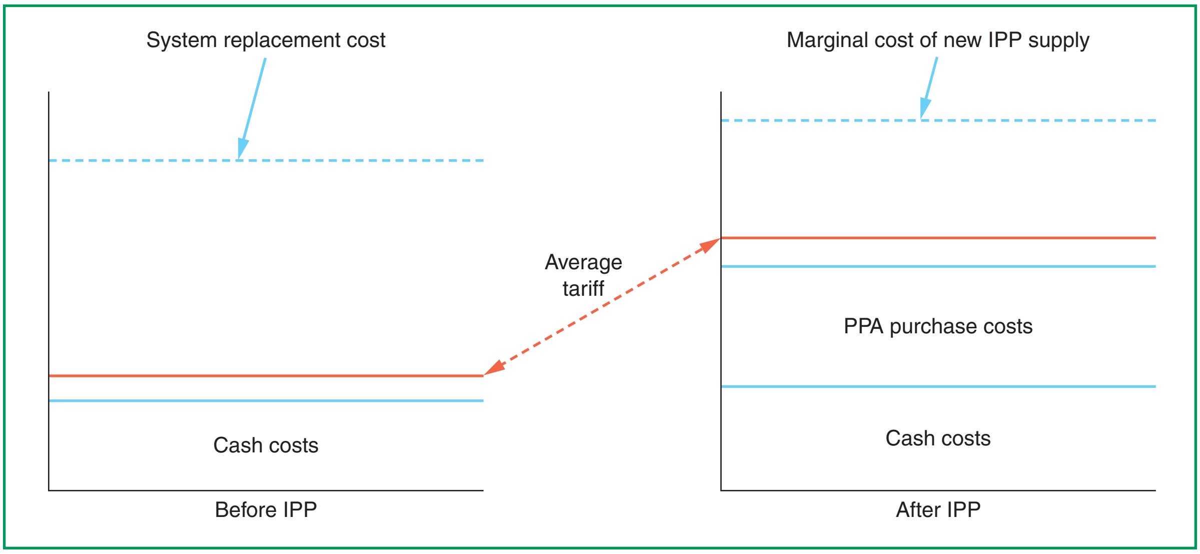
If there is no more emergency plant to be displaced the impact of more high cost IPP output will invariably be to increase billing costs. As Figure 1 shows, the delivered cost per kWh is much higher than tariffs in all but one of 39 countries. Since the marginal cost of IPP supply is also much greater than marginal revenue from sales, the Utility will incur losses on every kWh of contract output sold if tariffs are left unchanged. Since Utility finances are already weak it will not be able to absorb the losses and so tariffs would have to be increased (Figure 6). The greater the contract capacity and the higher the contract price, the greater the increase in tariffs needed to fund the PPA purchase costs.

The impact of tariff increases on end-customers also differs depending on the circumstances of each category of customer and the extent to which their tariffs increase. Households on the highest incomes will generally benefit even if the delivered cost of IPP output is high so long as resulting tariff increases leave their billing costs lower than the cost of stand-by generation. This is because most high income households have been able to deal with power outages by installing and operating stand-by generation. So long as tariffs remain cheaper than stand-by generation these households will benefit by reducing use of even more expensive stand-by plant and increasing purchases from the grid.

Grid-connected households on lower incomes will see a reduction in power outages but also an increase in billing costs. As shown earlier, their maximum affordable consumption of electricity will fall as billing costs rise. Even fewer households will now be able to afford to cook with electricity as well as light their homes; many will be able to consume only as much electricity as they are permitted to purchase at the subsidised tariff rate; and some may no longer be able to afford to purchase 30 kWh/month and will cease to purchase any electricity from the grid. Households not already connected to the grid will be even less able to afford to connect.

The impact of tariff increases on business customers differs depending on whether or not they are able to pass-on higher electricity costs to their customers. Many existing industrial and commercial customers have already been forced to install and operate stand-by generation; but since they mostly sell non-tradable goods and services they

Figure 6 High cost thermal power IPPs reduce electricity consumption and grid access.



have been able to pass-on those costs to their customers. Like high income households they will similarly benefit even if tariffs increase so long as billing costs remain cheaper than stand-by generation. However, many SME and informal businesses are not in that position; so, although power outages will reduce, higher billing costs will increase their costs and in many cases reduce their profitability and, potentially, their output.

Businesses producing tradable goods and services, for example, agribusiness and manufacturing, have little if any scope to pass-on higher costs to their customers. Already the high cost of electricity has been a factor slowing the rate of investment of these businesses. Even higher electricity tariffs will further reduce both profitability and the incentive to invest and grow these tradable businesses.

The impact on Utility finances depends in large part on whether tariff increases are sufficient to generate in full the extra revenue needed to fund higher purchase costs. If yes, there may be neither improvement nor deterioration in the Utility's finances. But if extra revenue is less than extra purchase costs, there will be further deterioration in already-weak Utility finances despite the tariff increases. This would increase the risk of insolvency and the probability that the government guarantees will be called.

Tariff increases will also further increase the cost of government subsidies if lifeline tariffs are kept low to protect low income households (as the gap between marginal supply cost and the lifeline tariff rate increases).

Brief case studies

Ghana is a good example of where contracting high cost IPPs had large adverse impacts on end-customers. Decades ago ample cheap hydropower from the Volta enabled the Utility to set low tariffs and connection charges, and still generate sufficient cash flow to fund grid extension (resulting in one of the highest access rates in sub-Saharan Africa). As demand grew and the capacity of the Volta was exhausted there was a need to procure more generation capacity. After long delays a number of bilaterally negotiated thermal power IPPs reached financial close in the 2012–2014 period. Their contract prices were high, denominated in dollars and indexed to US dollar inflation; then the cedi devalued sharply. The result was the average 59% tariff increase in 2015 noted earlier.

The 2016 Annual Report of the Ghana Energy Commission summarised the outcome as "Prevailing electricity tariff moves Ghana from once among the least expensive countries to very expensive … current energy tariffs for industries rang[e] from 18–26 US cents per kWh … for commercial customers tariff range [from] 26–43 US cents per kWh… [which will make it] cheaper running own diesel alternative if available" (pp. 20–21). The net result was a sharp reduction in household consumption of electricity and ability to access the grid, much higher billing costs for business customers and hence reduced incentive for businesses producing tradable goods and services to invest and grow. Moreover, since approved tariff increases were less than requested, the already-weak finances of the Utility (ECG) deteriorated even further.

Kenya is a good example of how long term high cost IPPs lock-in high contract prices and reduce options to contract cheaper capacity for the remainder of PPA contract lives. The high contract prices of IPP output shown in Figure 5 will increase over time in line with the PPA indexation provisions and depreciation of the exchange rate against the dollar. Since the PPAs were contracted, much cheaper capacity is now becoming available from, for example, geothermal projects along the Rift Valley and Lake Turkana wind power. If enough cheaper capacity were available to displace more expensive thermal power IPPs, this option could not be exercised because the PPA payments would have to be made regardless.

WHY HIGH COST IPPs CANNOT FILL THE ELECTRICITY SUPPLY FUNDING GAP

There are two fundamental reasons why high cost IPPs cannot fill the electricity supply funding gap: slow growth of electricity demand and limits to government guarantee capacity.

Slow growth of electricity demand

The conventional view that more investment in IPP capacity will increase consumption of electricity and grid access assumes there will be sufficient end-customer demand regardless of the cost of the output. That assumption is not correct. Investment in IPP capacity can only be sustainable if there are sufficient end-customers able and willing to purchase the IPP output given the billing costs they face. If the Utility were unable to generate enough revenue from sales to fund the PPA purchase costs, it would incur increased losses unless tariffs were further increased. As more high cost IPPs were contracted, tariffs would continue to rise, choking of end-customer demand and causing further increases in Utility losses. At some point the Utility would be unable and unwilling to contract any more IPP capacity because the *growth of IPP capacity has exceeded the growth of end-customer demand.*

A simple analogy helps clarify the point. Consider a car importer/dealer who imports luxury cars, call them Jaguares, from a major car manufacturer. The dealer contracts unconditionally to purchase 10 vehicles per annum at a fixed high price for 20 years and sells them to 10 customers per annum at a profit. Things are going well. He then (rashly) contracts unconditionally to purchase 500 of the same vehicles per annum at the same fixed high price for 20 years. He then discovers that although there are many customers who would like to own a Jaguare, there are not 500 customers each year able to afford to buy one. The dealer has fixed high purchase costs and too little sales revenue to pay the costs – so he goes broke! The problem is not lack of supply of Jaguares, the manufacturer can easily produce many more, nor is it lack of finance to manufacture the cars. The problem is lack of demand, too few customers able and willing to pay the price of this high cost vehicle.

So it is with electrons except that the problem is much worse because the Utility contracts unconditionally to purchase IPP output at a higher price than the regulated price at which it can be sold. The Utility not only loses money if there is insufficient demand, it also loses money on every kWh actually sold. The Utility would soon have to stop contracting more capacity and since, as it is an essential service, it cannot go broke the government guarantee would have to be called. As with Jaguares, the constraint is not lack of investment or lack of finance to fund it – the problem is lack of enough customers able and willing to pay the high billing costs.

There is unmet demand even for high cost IPP output in the short term but it is limited largely to the amount needed to displace emergency plant and to reduce power outages of mostly high-income grid-connected customers. Once that demand has been met IPP capacity can only grow as fast as the medium term growth of demand for electricity.

Growth of electricity demand over the medium term is principally a function of the trajectory of billing costs (which is largely determined by the trajectory of average generation costs) and the rate at which incomes grow. The greater the amount of high cost IPPs contracted, the greater the likelihood that the trajectory of generation costs will rise over time (especially if local currencies devalue against the dollar). This will tend to slow the growth of demand for electricity.

The primary determinants of the growth of disposable income are the external terms of trade and the rate of domestic investment. Over the 2000–2012 period high export prices and high exchange rates resulted in strong growth of disposable incomes and rapid growth of electricity demand. However, even during that period, incomes of households below the top few per cent of the income distribution did not grow strongly which is one of the reasons why their demand for electricity was so low in 2014. Since 2012 weaker export prices and exchange rates in many countries have further slowed the growth of disposable incomes and contributed to continuing slower growth of demand for electricity.

Domestic investment and job creation were slow over the 2000–2012 period despite high headline rates of GDP growth. This was true especially of investment by businesses producing tradable goods and services (e.g. agribusiness and manufacturing). As noted earlier, one of the most frequently cited explanations is the high cost and poor reliability of electricity supply. Higher billing costs are even less likely to result in strong growth of domestic investment or job creation. The combination of weaker external terms of trade and low rates of domestic investment, and high and rising billing costs, is likely to result in continued slow growth of electricity demand for electricity and hence continued slow rates of investment in IPP capacity over the medium term.

Limits to government guarantee capacity

The other fundamental reason that high cost IPPs cannot fill the electricity supply funding gap is that there are limits to government guarantee capacity. In almost all cases IPP sponsors require a government guarantee of the Utility's PPA obligations because the Utility is not a creditworthy entity on a stand-alone basis. Providing a guarantee to a single IPP may have little adverse impact on the government's ability to borrow. But, as aggregate PPA obligations increase, so does the total government guarantee exposure. Moreover, if IPPs are high cost, guaranteeing additional IPP capacity will not only increase aggregate guarantee exposure but also the risk that the guarantees will be called. The point will soon be reached where either the host government is no longer willing to offer further guarantees or lenders to IPPs are no longer willing to accept them or, in countries with IMF programmes, the IMF is no longer willing to give consent to the government offering them. Either way, no more new IPPs will be contracted.

Implications

Growth of IPP capacity is constrained by the slow growth of demand for electricity, the result of high and rising billing costs and slow growth of incomes; and by the limited ability of host governments to offer ever more PPA guarantees. This is the opposite of the conventional view that more IPP investment will increase electricity consumption and grid access. More IPP capacity cannot be contracted sustainably unless there is faster growth of business and household demand for electricity. Increased consumption of electricity and improved grid access can only be achieved if ways can be found to reduce end-customer billing costs and to increase the growth of business and household incomes.

The frequently cited \$40–\$50 billion per annum "electricity supply funding gap" is not a meaningful measure of effective demand for IPP investment.[2] The funding requirement for privately-financed IPP investment is determined by demand for the output which in turn is determined by the ability and willingness of end-customers to pay. The slow rate at which PPAs have been executed, and the limited demand for private finance, are the result of high contract prices and low incomes. They are not evidence of market or government failures in the supply of finance. Similarly the future growth of IPP capacity, and the demand for private finance, will be determined by the ability to drive down the trajectory of billing costs and achieve faster growth of business and household incomes.

ACHIEVING BETTER OUTCOMES FOR CUSTOMERS AND THE ENVIRONMENT

To achieve better outcomes for end-customers and the environment, actions are needed on the *supply-side* to increase the share of renewables in the generation portfolio and drive down generation costs, and on the *demand-side* to reduce the cost and improve the reliability of electricity supply to priority business customers so as to strengthen incentives for them to invest, create more jobs and grow incomes faster.

Increasing the share of lower cost renewables in the generation portfolio

The most important supply-side actions that can be taken involve pro-actively seeking to procure more renewable capacity and using competitive procurement to drive down their costs. This will require: shifting away from responding to proposals submitted by IPP developers in favour of a more pro-active selection and bid preparation of renewable opportunities; and shifting away from bilateral negotiation of IPPs in favour of adopting competitive procurement processes.

Rapid technical progress and "learning by doing" associated with rapid deployment of renewable technologies around the world have resulted in marked improvements in efficiency and costs of a range of renewable technologies. The design and adoption of well-structured competitive procurement processes has shown that these efficiencies and cost savings can result in much lower contract prices of renewable IPPs in sub-Saharan Africa. The key to success is a well-prepared pre-bid stage in which the "rules of the game", and bid process and timetable (including bid evaluation criteria) are clearly set out prior to commencement of bidding. This provides potential bidders with clarity about the opportunity and risks involved, and the host government/ Utility with a sound basis for comparing and evaluating bids.

The results of adopting the approach in sub-Saharan Africa have been little short of spectacular. It was first used in South Africa to competitively procure a range of renewable technologies. Almost $20 billion of private investment was committed and successive bidding rounds drove down renewable contract prices by 50% in wind and 70% in solar. The IFC-supported Scaling Solar initiative in Zambia showed that competitive bidding of renewables can succeed even in a much lower income, and less financially sophisticated, country. Seven of the world's leading renewables developers competed to build Zambia's first large-scale solar plant. Winning bids were reported to be as low as 6–8 cents per kWh and the procurement process was much faster than is usually the case with bilaterally negotiated IPPs.

A somewhat different approach adopted in Uganda involved setting fixed Feed in Tariffs (FiTs) for different renewable technologies. The aim was to cap prices at levels much lower than the cost of existing generation but high enough that private investors would be prepared to invest. The problem with fixed-price contracts is that prices turn out either to be too low to attract investment or too high, allowing investors to earn "excess" returns. In Uganda this problem was addressed by combining FiTs with a modified competitive procurement process. The KfW-supported GETFiT programme involved agreeing a time-limited premium payment funded by KfW aimed at closing the gap between the FiT price and the levelised cost of energy. The premium was set using a competitive process and the lowest premium bids were chosen for final negotiation. The process resulted in financial closure of 15 small-scale renewable projects amounting to 128 MW of capacity at prices in the range of 8–13 cents per kWh and, like Scaling Solar, a faster end-to-end procurement process.

These approaches have some limitations. Different renewable technologies have different load characteristics and none of them provide reliable year round power supply. To match as far as possible the annual load duration curve, a portfolio of technologies is needed and they may still need to be supplemented with some oil fired plant. Other limitations include: a large number of small and medium size renewable IPPs must close to make a significant difference at the system level, which increases transaction costs; if small IPPs are too far from the grid the connection costs may make the delivered cost into-grid too expensive; and many of these small projects are not well-suited to project finance structures or to incurring debt pre-completion so developers may find it difficult to secure the equity and construction finance needed to build the plant. Despite these limitations, the evidence shows that adopting this approach can successfully result in much lower average generation costs (and hence billing costs) and much lower carbon emissions per MW of capacity.

Chinese financed renewable investments

Another recent major development that has potential to reduce average generation costs is the explosive growth of large-scale Chinese finance and build renewable power projects. Since 2008 about $6 billion of Chinese capital has been committed to build more than 4000 MW of mostly large-scale hydropower capacity in sub-Saharan Africa. This exceeds considerably the aggregate funding commitments of all privately financed IPPs over the same period.

These projects are not IPPs. They are undertaken as EPC contracts between Chinese contractors and the host government/Utility, and financed as loans to the host government from Chinese financial institutions. The rapid growth is the result of two things: Chinese contractors are increasingly available and interested in exporting their civil construction/hydro development expertise to sub-Saharan Africa; and large amounts of low cost, long term finance is available principally from China ExIm Bank (responsible for export credit and soft loans) to fund these developments.

Loans are cheaper and longer term than the loans available to IPP developers.[3] Typical terms are: loans of up to 85% of the funding requirement as a mix of commercial and soft loans with repayment periods of 15–20 years. (A recently closed hydro project in Uganda had total loan finance $1.4 billion (85% of project cost), 45% as a commercial loan at LIBOR + 3.5% repayable over 15 years with 5 years grace and 55% as "preferential export-based credit" with interest rate of 2% repayable over 20 years with 5 years grace.) The capital cost per MW of successful bids is about the same as the capital cost per MW of large privately-financed renewable IPPs. The major difference is the much lower cost and longer tenor of Chinese finance which, as noted earlier, markedly reduces the levelised cost of power.

Despite the attractive headline terms, without knowing the detailed terms of the EPC and financing agreements, the extent to which the host government and Utility will incur unexpected extra costs and risks over the project life is unclear. Questions that would need to be answered include: whether the EPC contract terms will leave the government responsible for a high share or all of the cost overrun and delay risks pre-completion; what costs and risks the host government and Utility will incur post-completion and what recourse they will have to the Chinese contractor if things go wrong; and whether appropriate safety and social responsibility standards will be put in place and maintained, and who will be liable if they are not. It is clearly important that host governments have access to experts to help them address these issues before the EPC contract and financing agreements are signed.

Despite these qualifications it seems likely that many host governments will find the

Chinese finance and build offers attractive. If so, and if the capacity turns out to be as low cost as claimed, the result should be a marked reduction in average generation costs, and hence billing costs, in the countries where the investments are made. A related implication is that privately-financed large-scale renewable IPPs will rarely be able to offer contract prices as low as Chinese finance and build offers. Therefore, it is probable that most privately financed renewable IPPs will be small or medium-size investments, where Chinese contractors have less interest, in which case the demand for private finance to fund renewable IPPs will also be relatively limited.

Off-grid supply and micro-solar

In recent years there has been renewed interest in the potential of privately-financed off-grid supply especially in rural areas. The interest has been stimulated by the increased scope to develop cheaper small-scale renewables and the recognition that supply from the national grid is likely to be too delayed and too expensive in rural areas.

The analysis set out earlier offers a cautionary note. Almost all households in rural areas can barely afford to purchase the subsistence minimum 30 kWh/month to light their homes even if grid connection is provided at no cost and even then only if they can purchase electricity at a heavily subsidised lifeline rate. Unless the delivered cost of supply from a mini-grid is improbably low, prices set to recover the levelised costs of generation and mini-grid supply will be unaffordable for most rural households and so revenue from sales to them will be minimal. Conversely, if prices are set low enough to be affordable for rural households, very few mini-grid investments will be financially sustainable without permanent subsidies. If an equivalent subsidy were provided to enable the supplier to offer a subsidised rate to households, the cost of the subsidy to government would increase as the number of connected households increased, so it is unlikely that scaling the mini-grid will be financially sustainable.

It is highly likely that to be financially sustainable, mini-grid investors will need to contract with “anchor” business customers which are able and willing to pay user charges at a level sufficient to fund a high share of the generation and mini-grid costs. Although feasible in theory, in practice the challenges are formidable. Matching the level and pattern of supply with the demand requirements of anchor customers is non-trivial; and the cost of extending the mini-grid is a function of distance so anchor customers and the source of generation must not be too far apart. Few anchor customers are likely to be able and willing to enter into the medium term “take or pay” purchase agreements which are what are needed for the generator/supplier to be able to fund its investment. The reality in sub-Saharan Africa is that there are few businesses that fit these requirements so the opportunity to scale up mini-grids is likely to be limited.

Mini-grids compete with micro-solar applications to provide lighting for village households. If micro-solar expands rapidly in rural areas it will further reduce demand for electricity for household lighting from mini-grids and/or the national grid. Since micro-solar without battery storage cannot provide the power to drive electric motors, it cannot enable electrification of agriculture nor realise the potential increases in agricultural productivity and rural incomes. Micro-solar with battery storage is currently much too expensive to facilitate electrification of agriculture. Hence, paradoxically micro-solar may delay the introduction of mini-grids and the electrification of agriculture which could have stimulated more rapid growth of rural incomes and their demand for electricity.

Interconnectors and CCGTs

There is also much discussion about the potential of interconnectors and gas-fired CCGTs to reduce generation costs. The analysis also throws light on demand constraints facing these investments. In Ethiopia there are well-advanced plans to build a major interconnector to export hydropower to adjacent countries. There will need to be agreement about, *inter alia*, the sales/purchase terms for the export of the electricity. The price will need to be high enough to recover the operating and capital costs of the hydro facilities and part of the cost of the interconnector. Since the costs will usually be incurred in dollars the export price must also be denominated in dollars. The government in the purchasing country will have to agree the amount of capacity to be purchased and the dollar-denominated price, and provide an explicit or implicit government guarantee. Hence, the inter-connection agreement will have close similarities to signing a long term PPA with a domestic IPP; and will raise the same challenges.

If the purchasing government contracts more interconnector output than it can sell given the contract price then it will incur losses that it will have to fund out of public resources. If the selling government contracts to sell at prices that recover less revenue than is needed to fund the levelised cost of the facilities then it will incur losses that it will have to fund out of public resources. If the selling government encounters delays in selling some of the capacity then it will incur additional losses as a consequence of the deferral of revenue and the high fixed costs (especially of debt service payments).

Similar challenges face governments in East Africa contemplating contracting gas-fired CCGTs. Tanzania and Mozambique are planning to build medium-size gas-fired CCGTs fuelled by their recently discovered offshore gas reserves. If the agreed gas price is low enough, and given the high thermal efficiency of CCGTs, the output should be much cheaper than oil-fired thermal plant. CCGT output that displaces more expensive thermal plant will generate financial savings for the host government/Utility. However, once all of the more expensive oil fired thermal plant has been displaced, profitable extra sales will depend on there being sufficient effective demand for the output.

However, as the earlier analysis showed, household demand for electricity is low because household incomes are low throughout the income distribution in these countries. Even if the levelised cost of CCGT capacity is much cheaper than oil fired plant there is unlikely to be much additional household demand for electricity to purchase the extra output. Hence, as well as contracting more gas fired CCGT capacity the government/Utility will also have to contract with major anchor customers that are able and willing to invest to expand the capacity of energy intensive industries. Failure to do so would result in an excess of supply over demand and increasing financial deficits that would have to be funded by the government.

Stimulating demand for electricity

To increase electricity consumption and grid access, actions are needed to stimulate higher incomes as well as lower generation costs. More rapid growth of incomes requires higher rates of domestic investment but one of the key impediments to faster growth of investment in sub-Saharan Africa is the high cost and poor reliability of electricity supply to business customers.

In Asia a generation ago governments invested low cost public capital to develop the electricity supply system "ahead of demand". The idea was to invest to create affordable and reliable electricity supply as a means of stimulating high rates of private investment. Keeping user charges low initially boosted investment and stimulated faster growth of incomes; and in due course allowed recovery of the investment costs out of rising user charges and higher tax revenues. A similar strategy was adopted in India to stimulate growth of agriculture by financing rural electrification "ahead of demand". The idea was to stimulate greater use of electric pumps to irrigate small farmers' fields by investing public funds to provide electricity supply and by keeping charges affordable for rural farmers. This resulted in sustained increases in agricultural productivity and rural incomes and also enabled much higher consumption of electricity and grid access of rural households.

A similar approach has rarely been adopted in sub-Saharan Africa because the high cost of private finance makes user charges for business customers unaffordable and governments have rarely been able or willing to provide the public finance that would be required. A "second best" solution that aims to replicate in part the Asian strategy with more limited resources would be to reduce the cost and improve the reliability of electricity supply to designated priority customers only. The aim would be to stimulate investment, job creation and growth of businesses with the potential to grow profitably to scale (e.g. agribusiness and manufacturing). The means to do so would be: to reduce their tariffs to levels that would stimulate new investment (but no greater than the marginal cost of the cheapest source of supply) and to stabilise them over the medium term; to provide or strengthen grid connection to the sites of proposed investments; and to recover connection costs incurred via user charges levied over the medium term.

These actions would strengthen incentives to invest and create more jobs by reducing the "front end" cost and risk of making the investment; and benefit the host government and Utility over the medium term by stimulating higher household incomes and in due course more rapid growth of business and household demand for electricity.

Short term reductions in tariffs for priority customers could be offset either by slight rebalancing of tariffs (increasing them for the higher income households only) or by leaving tariffs of all other customers unchanged and funding tariff reductions of priority customers out of savings as cheaper renewables reduce the average cost of generation. Financing of grid connection or strengthening could be part funded by the host government and part funded using patient capital provided by donors/DFIs.

Agribusiness is a good example of how this approach would benefit the nation. Irrigation can generate large improvements in agricultural productivity and farm incomes, and benefit a large number of smallholder farmers. However, in sub-Saharan Africa there has been almost no investment in irrigation in recent decades. One major reason is that, in the absence of affordable access to the grid, agribusinesses contemplating investment in irrigated agriculture would either have to use expensive diesel generators to drive the pumps (which would make the investment unprofitable) or fund connection to the grid and pay standard tariffs (which also makes investment unprofitable in many cases). The result has been that these potentially profitable investments have not taken place.

ROLE OF DONORS AND DFIS

Donors and DFIs have long sought to use their expertise and resources to promote more private investment in the power sector in SSA. They generally share the conventional view that the priority is to increase the rate of investment in IPPs and that lack of private finance is the key constraint slowing it down. Key instruments to address the constraints have been: funding project preparation to help bring more investments to financial close more quickly; and capital and/or guarantees at financial close whose aim has been to catalyse additional private finance.

Until recently most project preparation and funding has been to support bilaterally negotiated project financed thermal power IPPs. As explained earlier, most of these IPPs have made outcomes worse for most end-customers and for the environment. Although there is now a prominent shift in favour of supporting investment in renewables, mostly because of environmental concerns, there has been limited recognition of the need to use competitive procurement to drive down generation costs and no recognition of the importance of stimulating more rapid growth of demand for electricity.

If donors/DFIs wish to help host governments adopt the strategic shifts described here they will need to make substantial changes to the way they provide their support. Project preparation support should shift away from helping host governments and Utilities negotiate bilateral agreements with IPPs in favour of providing support to design and implement competitive procurement processes. Bilaterally negotiated PPAs do not drive down contract prices as effectively as competitive procurement. In fact there is a risk that focus on closing projects quickly can result in pressure to transfer more risk and more cost to the Utility and via the guarantee to the host government.

The way that donors/DFIs provide finance or guarantees at financial close should also change, away from providing support on a project by project basis in favour of providing funding as part of a competitive procurement process. This would involve offering finance or guarantees to shortlisted bidders on a "level playing field" basis prior to submission of final bids, followed by negotiation of final documentation with the winning bidder. This would allow bidders to decide whether or not they wish to take up the offer of donor/DFI support and ensure that if the support is provided that it benefits the nation, rather than inflating investors' returns.

The IFC-supported Scaling Solar and KfW-supported GETFiT programmes provide good examples in different ways of how this new type of project preparation and funding support can be provided consistent with supporting a competitive procurement process. Adaptation and replication of these approaches offers a better way to use donor/DFI finance to speed up procurement and to drive down generation costs.

The approach will also help answer the question about whether donor/DFI funding is additional. The frequently made assertion that DFI funding is additional is difficult to assess with bilaterally negotiated IPPs. Certainly the argument that long delays in reaching financial close shows there is a lack of private finance is extremely weak. There are very few cases where sponsors have been unable to finance a project at financial close once PPA terms have been agreed. Most delays are attributable to delays in agreeing PPA terms (and the reason for the delays are nothing to do with lack of finance); and delays reaching financial close once PPAs are agreed are generally attributable to, for example, fuel supply issues, finalisation and multi-party approvals of complex project finance documentation, eliminating conditions precedent etc., but rarely to lack of finance. Offering donor/DFI funding as part of a competitive process provides a stronger test of additionality – if sponsors choose not to take it up donor/DFI funding is clearly not additional.

As noted earlier, many renewable IPPs will be small or medium in size and require less project debt, and more equity and construction finance. Since the market for this type of private finance for projects in sub-Saharan Africa is thin, donors/DFIs may need to play an expanded role filling this funding gap. In the past donors/DFIs have shown they have limited appetite for either small transactions or for much exposure to higher risk equity and construction finance. If they are to play an expanded role they will need to re-assess their investment criteria and risk appetite. Since in most cases these IPPs will not benefit from a sovereign guarantee, donors/DFIs may also need to consider creating or extending existing guarantee mechanisms to mitigate payment and transfer risks.

If host governments choose to bilaterally negotiate new IPPs, donors/DFIs should ensure that their funding decisions take explicit account of the expected impact of the IPP on end-customers, the Utility and the host government. They should no longer be willing to use donor resources to support a project just because a PPA has been agreed unless it is clear that sufficient wider benefits for end-customers and for the environment will be realised.

In some cases host governments will decide to negotiate Chinese finance and build large-scale renewable investments. Donors/DFI should consider supporting host governments to help ensure that they are able to negotiate balanced and equitable agreements.

For the reasons given earlier it is also important that donors/DFIs are willing to support host governments and Utilities to explore ways of increasing demand for electricity. If host governments decide to pursue the sort of approach outlined earlier, donors or DFIs could play an important role helping design and implement suitable agreements between the host government and priority investors, acting as an honest broker and where appropriate co-funding with patient capital investments to extend/reinforce/connect priority customers to the grid.

CONCLUSIONS

Increasing investment in generating capacity cannot increase consumption of electricity of most households or improve grid access unless billing costs fall and/or incomes rise as a result. Most of the IPP capacity contracted in sub-Saharan Africa has achieved the opposite result – reduced consumption and grid access and reduced incentive to invest and grow as well as high carbon emissions per MW.

High cost IPPs cannot fill the electricity supply funding gap because investment is constrained by the slow growth of electricity demand, the result of high billing costs and low incomes, and by limits to government guarantee capacity. Generating capacity can only grow rapidly over the medium term if ways can be found to both drive down average generation costs and stimulate more private investment, job creation and faster growth of incomes.

There is now much greater potential to develop cheaper and cleaner renewable energy in sub-Saharan Africa. All or most of new privately-financed IPP capacity should be competitively procured renewable capacity.

Chinese finance and build projects are likely to provide much of the large-scale renewable capacity because Chinese contractors have access to favourable financing terms. Therefore much of the privately-financed renewable IPPs are likely to be small or medium size investments.

Even if billing costs can be driven down steadily, there will be limited increases in consumption of electricity or grid access unless household incomes rise sharply as well. Since the best way to generate faster income growth is to stimulate more investment and job creation by businesses producing tradable goods and services, actions are needed to reduce the cost and improve the reliability of electricity supply to these priority customers.

Donors and DFIs will need to make major changes to the way they provide their support if they wish to help host governments and Utilities adopt the strategic shifts that are needed to bring about major improvements in outcomes for end-customers and for the environment.

Notes

1 See e.g. Africa Progress Panel 2015. Note references to sub-Saharan Africa exclude South Africa and Nigeria because their economies and electricity supply systems have different characteristics to those of other countries south of the Sahara.

2 The $40–$50 billion per annum investment requirement is a theoretical calculation of the “need” for capital investment to expand and improve the system without reference to the cost of supply or demand from end-customers. In effect it assumes that capital funding is provided free as grants.

3 It is worth noting that, although the terms of the Chinese finance are more attractive than capital available to IPP developers, they are not dissimilar to those provided by governments of OECD countries to support their exporters/importers in the past.

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