Powering Africa: Meeting the financing and reform challenges

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Abstract

Sub-Saharan Africa faces chronic power problems, including insufficient generation capacity, low connectivity, poor reliability, and high costs, all of which constrain development. The investment requirements to meet Africa’s power needs are noted and strategies to address the funding gap are set out. The time for an ideological debate on public versus private investment is over—both are needed. Africa’s key challenges are the management of hybrid power markets, the reform of state-owned utilities, cost-reflective pricing, better targeting of subsidies, the nimble rollout of electrification, and stronger regional integration.

1. Africa underpowered

Sub-Saharan Africa is in the midst of a power crisis characterized by inadequate, unreliable, and costly electricity infrastructure. Household connections to the power grid are lower than in any other region. The weakness of the power sector has constrained economic growth and development in the region.

The combined power generation capacity of the 48 countries of Sub-Saharan Africa is about 80 gigawatts (GW); a single country—Spain—has more. The installed capacity per capita in Sub-Saharan Africa (excluding South Africa) is a little more than a third of South Asia’s (the two regions were equal in 1980) and about a tenth of that of Latin America (Fig. 1). Capacity growth has been largely stagnant during the last three decades, with growth rates of barely half those found in other developing regions. This has widened the gap between Sub-Saharan Africa and the rest of the developing world, even compared to other country groups in the same income bracket (Yepes et al., 2008).

Less than three in every ten people living in Sub-Saharan Africa have access to electricity, compared to more than half in South Asia and 90 percent in East Asia. Progress in extending new connections has also been slow. On current trends, fewer than 45 percent of African countries will achieve universal access to electricity by 2050 (Banerjee et al., 2008).

Per capita consumption of electricity averages just 40 kWh per month in the region, and only 10 kWh if South Africa is excluded (Eberhard et al., 2011, p. 6). By contrast, the average per capita consumption is 100 kWh per month in the developing world and close to 1000 kWh per month in high-income countries. If South Africa is excluded, Sub-Saharan Africa is the only world region in which per capita consumption of electricity is falling. Not only is total electricity generation and consumption in Africa very small, it is also unequally distributed between countries. South Africa’s power infrastructure stands in stark contrast to that of the region as a whole. With a population of 47 million people, South Africa has a total generating capacity of about 40 GW (850 W per person), accounting for about 60 percent of the region’s electricity consumption. Nigeria, with a population of 140 million, is the region’s second largest generator, with an effective utility operating capacity of about 4 GW (28 W per person). Comparative data for other African countries is given in Fig. 2.

Power supply in Sub-Saharan Africa is notoriously unreliable. About 15 percent of installed capacity is not operational, mainly as a result of ageing plant and lack of maintenance (Eberhard et al., 2011, p. 189). Power outages are frequent (Fig. 3). For these reasons, own generation constitutes a significant proportion of total installed power capacity in the region. In the Democratic Republic of Congo, Equatorial Guinea, and Mauritania, backup generators account for half of total installed capacity, and for West Africa as a whole, 17 percent (Fig. 4).

The increasing use of grid-connected temporary emergency power in the region reflects the gravity of the power crisis. Countries experiencing pressing power shortages can enter into short-term leases with specialized operators who install new capacity typically in shipping containers within a few weeks.
Emergency, temporary generators now account for an estimated 750 MW of capacity in Sub-Saharan Africa, and they constitute a significant proportion of total capacity in some countries. Emergency power is relatively expensive, typically around $0.20–0.30 per kWh. In some countries, the cost of emergency power is a considerable percentage of GDP.

Power in Sub-Saharan Africa is generally expensive by international standards. The average power tariff in Sub-Saharan Africa is $0.12 per kWh, which is around twice that in other parts of the developing world, and almost as high as in OECD countries (Fig. 5). There are exceptions: Angola, Malawi, Zambia, and Zimbabwe have maintained low prices that are well below costs (SADELEC, 2006). Electricity costs are high as a result of the small size of generation and supply systems (33 out of 48 countries have a total installed generation capacity of less than 500 MW and 11 have an installed capacity of less than 100 MW), low densities of connections, especially rural areas, inefficient utilities, and low levels of regional integration resulting in non-optimal system design choices.

In summary, Sub-Saharan Africa, as a region, is a global outlier with respect to power infrastructure and is literally without adequate power (Fig. 6).

2. Deficient power infrastructure constrains social and economic development

There is now extensive evidence that the weaknesses within the power sector have constrained economic growth and development in the region. Based on panel data analysis, Calderon (2008) provides a comprehensive assessment of the impact of infrastructure stocks on growth in Sub-Saharan Africa between the early 1990s and the early 2000s. Calderon finds that if African countries were to catch up with the regional leader, Mauritius, in terms of infrastructure stock and quality, their rate of economic growth per capita would be enhanced on average by 2.2 percent per year. Catching up with the East Asian median country, Korea, would bring gains of 2.6 percent per year in economic growth per capita. In a number of countries—including Côte d’Ivoire, the Democratic Republic of Congo, and Senegal—the effect would be even greater.

Unreliable electricity supply has direct and negative effects on business. Frequent power outages result in forgone sales and damaged equipment for businesses. This causes significant losses, equivalent to 6 percent of turnover on average for firms in the formal sector, and as much as 16 percent of turnover for informal sector enterprises that lack backup generators (Eberhard et al., 2011, p. 7). Businesses must incur additional expense, which could otherwise be invested productively. The overall economic costs of power outages are substantial. Based on load-shedding1 data from the World Bank’s Investment Climate Assessments and estimates of the value of lost load or unserved energy, power outages cost Sub-Saharan African countries an average of 2.1 percent of gross domestic product (GDP). In those countries that were part of the Africa Infrastructure Country Diagnostic (AICD) study (managed by the World Bank), and where we were able to make our own calculations (about 50 percent of the total countries in Sub-Saharan Africa) the costs ranged from less than 1 percent of GDP in countries such as Niger to 4 percent of GDP and higher in countries such as Tanzania (Eberhard et al., 2008, p. 12).

Deficient power infrastructure and power outages dampen economic growth, especially through their detrimental effect on firm productivity. Using enterprise survey data collected through the World Bank’s Investment Climate Assessments, Escribano et al. (2008) found that in most countries of Sub-Saharan Africa, infrastructure accounts for 30–60 percent of the effect of investment climate on firm productivity—well ahead of most other factors, including red tape and corruption. In half of the countries analyzed, the power sector accounted for 40–80 percent of the infrastructure effect.

Infrastructure is also an important input into human development. Better provision of electricity improves health care because vaccines and medications can be safely stored in hospitals and food can be preserved at home (Jimenez and Olson, 1998). Electricity also improves literacy and primary school completion rates because students can read and study in the absence of sunlight (Barnes, 1988;
Brodman, 1982; Foley, 1990; Venkataraman, 1990). Similarly, better access to electricity lowers costs for businesses and increases investment, driving economic growth (Reinikka and Svensson, 1999).

Because of its low electricity consumption, Sub-Saharan Africa is an insignificant contributor to carbon dioxide emissions and climate change, having the lowest per capita emissions among all world regions and among the lowest emissions in terms of GDP output. Excluding South Africa, the power sector in Sub-Saharan Africa accounts for less than one percent of global carbon dioxide emissions (IEA, 2011).

External factors have exacerbated the crisis in many countries. Drought has seriously reduced the power available to hydro-dependent countries in Western and Eastern Africa. Countries with significant hydropower installations in affected catchments—Burundi, Ghana, Kenya, Madagascar, Rwanda, Tanzania, and Uganda—have had to switch to expensive thermal power. High international oil prices have put enormous pressure on all of the oil-importing countries of Sub-Saharan Africa, especially those dependent on diesel and heavy fuel oil for their power generation needs. War has seriously
damaged power infrastructure in Sierra Leone, Liberia, the Central African Republic, Somalia, and the Democratic Republic of Congo. In Zimbabwe, political conflict and economic contraction have undermined the power system as investment resources have dried up. Yepes et al. (2008) document that countries in conflict perform worse in the development of infrastructure than do countries at peace.

In summary, Sub-Saharan Africa suffers from chronic power problems, including insufficient investment in generation capacity and networks, slow progress in connectivity, poor reliability, high costs, and prices that do not cover costs (constraining maintenance, refurbishment, and system expansion). Drought, conflict, and high oil prices have exacerbated the crisis. The overall deficiency of the power sector has constrained economic and social development. While the extent of the problems and the challenges differ across regions and countries, Sub-Saharan Africa has generally lagged behind other regions of the world in terms of infrastructure and power sector investment and performance.

3. Funding challenge

As part of the AICD study, Rosnes and Vennemo (2009) developed a model to analyze the costs of meeting power demand in Sub-Saharan Africa over the course of 10 years. The model simulated optimal (least cost) strategies for generating, transmitting, and distributing electricity in response to demand increases in each of the 43 countries participating in the four power pools of Sub-Saharan Africa: the Southern Africa Power Pool (SAPP), the Nile Basin–East Africa Power Pool (EAPP), the Western African Power Pool (WAPP), and the Central African Power Pool (CAPP). Cape Verde, Madagascar, and Mauritius were also included as island states. Each power pool has dominant players: South Africa accounts for 80 percent of overall power demand in SAPP; Egypt for 70 percent in EAPP/Nile Basin; Nigeria for 66 percent in WAPP; and Republics of Congo and Cameroon account for a combined 90 percent of power demand in CAPP.

The cost estimates were based on projections of power demand over ten years. Demand was assumed to have three components: market demand associated with different levels of economic growth, structural change, and population growth; suppressed demand created by frequent blackouts and the ubiquitous power rationing; and social demand, which is based on political targets for increased access to electricity. Different scenarios for suppressed and social demand were modeled. However, market demand, which was projected to grow at five percent per year in Sub-Saharan Africa, accounted for the bulk of demand growth over the period.

To estimate supply, the model simulated the least expensive way of meeting projected demand. Calculations were based on cost assumptions for various investments, including refurbishment of existing capacity for electricity generation and construction of new capacity for cross-border electricity transmission. The model included four modes of thermal generation—natural gas, coal, heavy fuel oil, and diesel—and four renewable generation technologies—large hydropower, mini-hydro, solar photovoltaic (PV), and geothermal. Operation of existing nuclear capacity was included but it was assumed that there would be no new investment in this technology over the ten years.

Investment requirements were calculated for both new plant as well as refurbishment of existing capital stock. Operating, fuel, and maintenance costs were also calculated. The model calculated that 74–82 GW of new generation capacity would be required over a 10-year period, depending on the demand scenario. The main differences in the demand scenario relate to different electrification targets and the extent of regional integration assumed for new generation capacity (called the “trade expansion” scenario in the modeling).

The overall costs for the power sector in Sub-Saharan Africa, plus Egypt, over a 10 year period (based on the trade expansion scenario and national targets for electrification) are an estimated...
$47.6 billion a year—$27.9 billion for investment and $19.7 billion for operations and maintenance, or 40.8 billion for Sub-Saharan Africa excluding Egypt (Rossnes and Vennemo, 2009).

About half of the investment cost is for development of new generation capacity, about 37 percent for new transmission and distribution networks, and the remaining for refurbishment of existing generation and transmission assets.

Existing spending aimed at addressing power infrastructure needs is higher than previously thought and adds up to an estimated $11.6 billion. Approximately 80 percent of existing spending is domestically sourced from taxes or user charges. The rest is split among Official Development Assistance (ODA) financing, six percent of total, funding from countries outside the Organization for Economic Co-operation and Development (non-OECD funding), nine percent of total, and private sector contributions, four percent of total. Almost 75 percent of domestic spending goes to operations and maintenance. Capital spending is financed from four sources: one half comes from the domestic public sector; approximately one quarter is received from non-OECD financiers; and the rest is contributed by OECD and the private sector.

There is a funding gap of $29.2 billion as a result of the difference between the investments required to meet demand of $40.8 billion and current annual investments of $11.6 billion in Sub-Saharan Africa. The gap is so significant that it requires that the ideological debate of public versus private be set aside and all mechanisms and resources to reduce the gap be mobilized.

There are six areas that require focus. All must be aggressively pursued. Firstly, current under-pricing must be corrected and subsidies more effectively targeted. Secondly, new electrification strategies need to be nimbler and smarter, learning from the rapid increase achieved in communications infrastructure over the last two decades. Thirdly, inefficiencies within the current delivery mechanisms, dominated by state-owned utilities, need to be substantially reduced through governance reforms. Fourthly, sector reforms must be deepened to allow for greater private sector participation within a clear regulatory environment, contributing private equity and debt finance as well as management and technical capacity. Fifthly, new private generation capacity must be encouraged and facilitated through the careful management of hybrid power markets. Lastly, regional integration must be aggressively pursued to reduce overall costs and realize broader economic and political benefits.

Much research has already been undertaken on each of these aspects. What is needed is an integrated and concerted effort across all of these areas.

4. Powering Africa

4.1. Getting the pricing right

Sound pricing is the prerequisite for raising the finance necessary to meet the investment requirements. Under-recovery of costs has serious implications for the financial health of utilities and slows the pace of service expansion. Many of Africa’s power utilities capture only two thirds of the revenue they need to function sustainably. This revenue shortfall is rarely covered through timely and explicit fiscal transfers. Instead, maintenance and investment activities are cut back to make ends meet, which starves the utility of funds to expand service coverage and cuts the quality of service to existing customers.

By setting tariffs below the levels needed to cover actual costs, Sub-Saharan African countries forego revenue of at least $3.62 billion a year at present (Eberhard et al., 2011, p. 158), or 0.56 percent of Africa’s gross domestic product. As costs and coverage increase, this amount will rise rapidly unless prices are adjusted accordingly. At a minimum, average electricity prices across an electricity grid should reflect the average historical cost of operations and maintenance, the cost of depreciating assets, and adequate provisions for bad debt and a return on assets. In many cases, average incremental costs of new capacity are much higher than historical costs. In these cases, prices need to reflect these costs in order to incentivise and finance new investments.

It is sometimes argued that increasing electricity prices will increase poverty levels. However, for most countries, electricity spending accounts for only a tiny fraction of total consumption. At the national level, the impact of a 50 percent increase in tariffs or even of a doubling of tariffs is marginal; the share of the population living in poverty increases barely one tenth of a percentage point (Banerjee et al., 2008, p. 40). Among households with a connection to the network, the impact is larger but still limited. Indeed, there is rarely more than a one or two percentage point increase in the share of households in poverty. And because the households that benefit from a connection tend to be richer than other households (Fig. 7), the impact of electricity tariff increases on poverty is further limited. The small impact of an increase in tariffs on poverty can be offset by reallocating utility subsidies to other areas of public expenditure with a stronger pro-poor incidence. The net effect of setting prices to reflect costs together with a reallocation of some or all of the existing subsidies in the sector is undoubtedly pro-poor given the broader social and economic benefits of a financially viable electricity sector.

The reason countries often tolerate and, in some cases, actively resist movement to cost-reflective tariffs may be precisely because the status quo favors the relatively few, better off consumers who are actually connected to the grid. These consumers are mostly urban dwellers with the power to mobilize against governments and manipulate policies for their own benefit (Fritz et al., 2009; World Bank, 2007).

4.2. Targeting subsidies to be pro-poor

Notwithstanding the above argument, a case can be made for carefully targeted electricity subsidies for the poorest households. Subsidies should be allocated preferentially to the costs of connecting poor households and perhaps also for a basic monthly amount of electricity use. One potentially effective method of targeting is to allocate subsidies through self-selection, for example, by making subsidies available for load-limited supplies only rather than standard domestic supplies. The theory is that more affluent customers will eschew services that limit their demand rather than standard domestic supplies. The theory is that more affluent customers will eschew services that limit their demand rather than standard domestic supplies. The theory is that more affluent customers will eschew services that limit their demand rather than standard domestic supplies. The theory is that more affluent customers will eschew services that limit their demand rather than standard domestic supplies. The theory is that more affluent customers will eschew services that limit their demand rather than standard domestic supplies. The theory is that more affluent customers will eschew services that limit their demand rather than standard domestic supplies. The theory is that more affluent customers will eschew services that limit their demand rather than standard domestic supplies. The theory is that more affluent customers will eschew services that limit their demand rather than standard domestic supplies. The theory is that more affluent customers will eschew services that limit their demand rather than standard domestic supplies. The theory is that more affluent customers will eschew services that limit their demand rather than standard domestic supplies.
The level of subsidies needs to be fiscally affordable. Providing a use-of-service subsidy of just $2 to all household connections would absorb, on average, 1.1 percent of GDP over and above existing spending. The cost of providing a once-off capital subsidy of $200 to cover network connection costs for all unconnected households over 20 years would be substantially lower, at 0.35 percent of GDP. A key difference is that the cost of this once-off subsidy would disappear at the end of the decade, whereas the use-of-service subsidy would continue indefinitely (Banerjee et al., 2008, p. 34).

Getting the prices right, and targeting subsidies more effectively, are fundamental to meeting the investment challenge. However, pricing reform is heavily dependent on other sector reforms. These are addressed below.

4.3. Being smarter about how electrification is rolled out

Household surveys show only modest gains in access to modern infrastructure services between 1990 and 2005 (Fig. 8). Africa's low coverage of infrastructure services to some extent reflects its relatively low urbanization rates, since urban agglomeration greatly facilitates the extension of infrastructure networks. Two-thirds of the Sub-Saharan Africa population lives in rural areas.

Electricity grid connections to rural households are much more expensive than for urban areas given the lower population densities. A significant trend over the last decade has been the establishment of special purpose agencies and funds for rural electrification. Half the countries in the AICD sample have rural electrification agencies and more than two thirds have dedicated rural electrification funds. The majority of countries have full or partial capital subsidies for rural connections, as well as explicit planning criteria (usually population density, least cost, or financial or economic returns). On average, greater progress has been made in those countries with electrification agencies and, especially, dedicated funds (Eberhard et al., 2011, p. 107).

The existing approaches to expanding service coverage in Africa are not working well enough. Reversing this situation will require rethinking the approach to service expansion in four ways. First, coverage expansion is not just about network rollout. There is a need to address demand side barriers such as high connection charges or legal tenure. Second, it is important to remove unnecessary subsidies to improve cost recovery for household services and ensure that utilities have the financial basis to invest in service expansion. Third, as noted above, it is desirable to rethink the design of utility subsidies to target them better and to accelerate service expansion. Fourth, progress in rural electrification cannot rely only on decentralized options; it requires a sustained effort by national utilities supported by systematic planning and dedicated rural electrification funds.

Expanding coverage is not just about network engineering. This requires a skills base that goes beyond standard expertise in network engineering to encompass sociological, economic, and legal analysis of—and engagement with—the target populations to understand customers and demand better. The most cost effective way of increasing coverage may be to pursue densification programs that aim to increase hookup rates in targeted areas that already have grid infrastructure.

Careful thought should be given to how connection costs might be recovered. Options such as repaying connection costs over several years through an installment plan, socializing connection costs by recovering them through the general tariff and hence sharing them across the entire customer base, or directly subsidizing them from the government budget should be considered.

The potential for extending access in a given situation depends on population density, distance from the grid, economic activity, and developmental needs. Because those circumstances differ widely across regions and countries, the most successful rural electrification will be selective and detailed. In short, they will be carefully planned. Our data show that those countries with clear planning criteria have generally been more successful at rural electrification.

In an African context, it is legitimate to ask how far it is possible to make progress with rural electrification when the urban electrification process is still far from complete. Across countries, there is a strong correlation between urban and rural electrification rates, as well as a systematic lag between the two. Countries with seriously underdeveloped generation capacity and tiny urban customer bases are not well placed to tackle the challenges of rural electrification, either technically due to power shortages, or financially due to the lack of a basis for cross-subsidization. Dedicated electrification funds should also be made available for peri-urban connections.

Finally, the difficult question needs to be posed as to whether aggressive electrification will exacerbate the financial problems of the sector. Diverting scarce capital to network expansion can easily result in a familiar situation where investments barely generate adequate revenues to support operating and maintenance costs, with no contribution to refurbishment or capital replacement requirements. The resulting cash drains on the utility could be serious. Ultimately, difficult choices need to be made on how to allocate scarce capital. Should it go to network expansion or are investments in new generation capacity more important? Careful trade-offs will be required.

4.4. Improving efficiencies through the reform of state-owned enterprises

Most electricity utilities in Sub-Saharan Africa are state-owned. Yet most of these are inefficient and incur significant technical and commercial losses. Combining the costs of distribution losses and uncollected revenues and expressing them as a percentage of utility turnover provides a measure of the inefficiency of utilities.
Over-manning

KPLC absorbed as much as 1.4 percent of Kenya's GDP per year. Particularly striking. In the early 2000s, hidden costs in the form of $0.07 in 2000 to $0.15 in 2006 and $0.20 in 2008. As a result of reforms, hidden costs in Kenya's power sector fell to 0.4 percent of GDP by 2006 and to almost 0 by 2008, among the lowest totals of any African country (Eberhard et al., 2011, p. 138).

There is increasing evidence that governance reform of state-owned utilities can improve their performance. Governance may be assessed using a number of criteria, including ownership and shareholder quality; managerial and board autonomy; accounting standards; performance monitoring; outsourcing to the private sector; exposure to labor markets; and the discipline of capital markets (Vagliasindi, 2010).

Two broad sets of governance reforms are important to ensure that improvements to the performance of state-owned utilities are sustainable. First, roles and responsibilities need to be clarified. This involves clear identification, separation, and management of government's different roles as policy maker, asset owner, and regulator; public entity legislation; corporatization; codes of corporate governance; performance contracts; effective supervisory/monitoring agencies; transparent transfers for social programs; and independent regulator.

The second broad set of reforms revolves around what Gomez-Ibanez (2007) refers to as "changing the political-economy of the utility". By this he means strengthening the role of other stakeholders in the power sector, such as tax payers, customers, and private investors. This can be promoted through improved transparency, commercialization practices, structural reform, direct competition, and mixed-capital enterprises (Table 1).

Improved utility performance will not only lead to reduced costs and increased revenues (and in so doing directly reducing the funding gap), but also lead to better credit ratings, thereby increasing utilities' access to private debt markets. Improved credit-worthiness also means that state-owned utilities can be more reliable counter-parties to Independent Power Producer (IPP) investors, thus increasing investment flows into the sector through another channel.

State-owned electricity utilities are here to stay. Improved utility performance is thus key to meeting the investment challenges previously outlined.

4.5. Deepen sector reforms to allow for greater private sector participation

By 2006, all but a few of the 24 countries of Sub-Saharan Africa covered by the AICD study had enacted a power sector reform law; three-quarters had introduced some form of private participation; two-thirds had established a regulatory oversight body; and more than a third had independent power producers. In most cases, the national utility is the mandated buyer of privately produced electricity, while still maintaining its own generation plants. There is no wholesale or retail electricity competition in Africa.\(^4\)

Many countries are reconsidering whether certain reform principles and programs—notably the unbundling of the incumbent utility to foster competition—are appropriate for Sub-Saharan Africa.\(^5\) Besant-Jones (2006), in his global review of power sector reform,

\(^4\) The only exception is a short-term energy market in the Southern Africa Power Pool (SAPP). The quantities traded, however, are extremely small.

\(^5\) Uganda is one of the exceptions where generation, transmission, and distribution were fully unbundled. In Kenya, generation (KenGen) has been separated from transmission and distribution (KPLC). Ghana has unbundled its transmission company and has a separate distribution company. Nigeria has technically unbundled its utility, although the separate entities still fall under a
concludes that power sector restructuring to promote competition should be limited to countries large enough to support multiple generators operating at an efficient scale, which excludes most countries in Sub-Saharan Africa. Even South Africa and Nigeria, which are large enough to support unbundling, have not seen much progress.

An examination of the database on private participation in infrastructure (PPI) maintained by the Public–Private Infrastructure Advisory Facility (PPIAF), which covers all countries in Sub-Saharan Africa, unearthed nearly 60 medium- to long-term power sector transactions involving the private sector in the region—excluding leases for emergency power generation. Almost half are independent power projects (IPPs) (Table 2), accounting for nearly 3 GW of new capacity and involving more than $2 billion of private sector investment. Côte d’Ivoire, Ghana, Kenya, Mauritius, Nigeria, Senegal, Tanzania, and Uganda each support at least two or more IPPs.

Gratwick and Eberhard (2008a) predict that IPPs will continue to expand generation capacity on the continent, although they have sometimes been costly because of technology choices, procurement problems, and currency devaluation. Some have been subject to renegotiation. Several factors contribute to the success of IPPs: policy reforms, a competent and experienced regulator, timely and competitive bidding and procurement processes, good transaction advice, a financially viable entity purchasing the electricity, a sound power-purchase agreement, appropriate credit and security arrangements, the availability of low-cost and competitively priced fuel, and development-minded project sponsors.

The other half of the PPI transactions in Sub-Saharan Africa have been concessions, leases, or management contracts, typically for the operation of the entire national power system. Many of these projects have been unsuccessful; around one-third of the contracts either is in distress or has already been canceled. Long-term private leases or concessions have survived only in Côte d’Ivoire, Cape Verde, Gabon, Mali, and Uganda. The only remaining private management contracts in the power sector in Sub-Saharan Africa are in Madagascar and Gambia. After the expiration of management contracts in several countries (including Namibia, Lesotho, Kenya, Malawi, Tanzania, and Rwanda) utilities reverted to state operation.

Management contracts were once regarded as the entry point for private participation in infrastructure. In reality, however, management contracts have proved complex and contentious. While widely used (there were 17 contracts in 15 countries in the region) and usually productive in terms of improving utility collection rates and revenues and reducing system losses, management contracts have failed to generate much-needed investment funds, either through generating sufficient revenue or through improving investment ratings and attracting private debt. Neither have they proven sustainable. Of the 17 African management contracts, 4 were canceled before their expiration date, and at least 5 more were allowed to expire after their initial term. (In Gabon and Mali management contracts were followed by concessions.)

Although management contracts can improve the efficiency and sustainability of utilities, they cannot overcome the obstacles posed by broader policy and institutional weaknesses. Moreover, the performance improvements are gradually distributed to unorganized and unorganized consumers, while the costs immediately affect a vocal and organized few, whose protests often overcome rational debate. African management contracts appear to have won the economic battle but lost the political war.

While management contracts can be a narrow tool to improve financial and technical efficiencies, the use of the private sector to achieve these gains comes with a high political cost. Given that greater private sector participation is absolutely necessary to meet the investment challenges, the appropriate approach is to use the private sector more effectively and in a more politically savvy way. This implies a dual strategy. Incumbent public utilities need to be reformed through improved public management (mainly achieved through governance reform and changing the political-economy of the entity, as discussed above). Simultaneously, generation capacity, a critical constraint in many countries, can and should be augmented through the introduction of new privately funded and managed facilities. This approach does not involve a displacement of existing public ownership and management in the sector with private involvement, but rather the introduction of additional capacity in terms of generation facilities and management expertise otherwise not attainable.

### 4.6. Learning to manage hybrid markets

The standard sector reform model advocated in the 1990s, consisting of utility unbundling and privatization and followed by wholesale and retail competition, was not effective in Africa. Most of the region’s power systems are too small to support meaningful competition. Hybrid power markets, with the incumbent state-owned utility designated as the single-buyer of electricity from IPPs, have become the most common industry structure in Africa. In this model the state-owned utility remains intact and occupies a dominant market position, while private sector participation (typically in the form of IPPs) compensates for the lack of investment on the part of governments and utilities. These hybrid markets pose new challenges in policy, regulation, planning, and procurement, which are exacerbated by widespread power shortages and an increasing reliance on emergency power throughout the region (Gratwick and Eberhard, 2008b).

### Table 2

Overview of public–private transactions in the power sector in Sub-Saharan Africa.

<table>
<thead>
<tr>
<th>Type of private participation</th>
<th>Countries affected</th>
<th>Number of transactions</th>
<th>Number of canceled transactions</th>
<th>Investment in facilities ($ millions)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Management or lease contract</td>
<td>Chad, Gabon, Ghana, Guinea-Bissau, Kenya, Lesotho, Madagascar, Malawi, Mali, Namibia, Rwanda, Sao Tome, Tanzania, Togo</td>
<td>17</td>
<td>4</td>
<td>5</td>
</tr>
<tr>
<td>Concession contract</td>
<td>Cameroon, Comoros, Côte d’Ivoire, Gabon, Guinea, Mali, Mozambique, Nigeria, Sao Tome, Senegal, South Africa, Togo, Uganda</td>
<td>16</td>
<td>5</td>
<td>1598</td>
</tr>
<tr>
<td>Independent power project</td>
<td>Angola, Burkina Faso, Republic of Congo, Côte d’Ivoire, Ethiopia, Ghana, Kenya, Mauritius, Nigeria, Senegal, Tanzania, Togo, Uganda</td>
<td>34</td>
<td>2</td>
<td>2457</td>
</tr>
<tr>
<td>Divestiture</td>
<td>Cape Verde, Kenya, South Africa, Zambia, Zimbabwe</td>
<td>7</td>
<td>–</td>
<td>n.a.</td>
</tr>
<tr>
<td>Overall</td>
<td>74</td>
<td>11</td>
<td>4060</td>
<td></td>
</tr>
</tbody>
</table>

*Note: data not available; n.a. = not applicable.*
The allocation of responsibility for ensuring adequate and reliable supply is often ambiguous in hybrid power markets. Few countries in Africa have an explicit security of supply standard, and while incumbent state-owned national utilities have typically assumed responsibility as supplier of last resort, few government departments or regulators explicitly monitor adequacy and reliability of supply. If monitoring were institutionalized, then regulators would be in a better position to assess the need for investment in new capacity. Incumbent state-owned utilities often argue that they are able to supply power more cheaply or quickly than private alternatives (even if they lack the resources to do so). Yet rigorous analysis that assigns appropriate costs to capital seldom supports such claims, which undermine the entry of IPPs. Regardless, most African utilities have not supplied adequate investment in much needed generation capacity. Poor understanding of hybrid power markets prevents policymakers from devising clear and transparent criteria for allocating new building opportunities among the incumbent state-owned utility and IPPs. The failure to order new plants on a timely basis discourages investors and results in power shortages that prompt recourse to expensive emergency power. This has been the case in Tanzania and Rwanda, for example. When authorities finally begin procurement, they may not take the trouble to conduct international competitive bidding. This is unfortunate, because a rigorous bidding process provides credibility and transparency and results in more competitively priced power, and unsolicited bids can lead to expensive power.

Hybrid power markets will not disappear from the African landscape in the near future. To maximize their benefit, African governments and their development partners must develop a robust institutional foundation for central power purchases with clear criteria for offtake agreements. They must also improve their planning capabilities, establish clear policies for allocating new investment opportunities among the state-owned utilities and IPPs, and commit to competitive and timely bidding processes.

Development finance institutions and bilateral donors can provide advice and expertise to governments and utilities on establishing transparent frameworks and procedures for contracting and reaching financial closure with project sponsors and private investors. Yet they must be careful to pay sufficient attention to the peculiarities of the hybrid market. Otherwise lending to public utilities may unintentionally deepen hybrid markets’ inherent contradictions and crowd out private investment. The sector requires stronger public institutions that can engage effectively with the private sector.

While a dominant national utility can play a useful role in aggregating demand and entering into long-term contracts with new investors, there are few advantages in assigning it exclusive buying rights. Instead, IPPs should be able to enter into willing seller–buyer arrangements and supply directly to both the national utility and large customers. Large customers should also have choice and should be able to contract directly with IPPs or import power. Such an arrangement would require non-discriminatory access to the grid. In other words, instead of a single-buyer there should be a central non-exclusive buyer.

Thought also needs to be given to the long-term implications of signing 25 or 30 year contracts with IPPs. It may be advantageous to migrate to a more short-term market in the future and hence sunset clauses should be considered when signing PPAs. These may enable and encourage IPPs to trade at least part of their production on a power exchange in the future.

4.7. Rethinking regulatory design

Utility regulation in developing countries has coincided with the emergence of new problems. In many cases, regulators are far from independent and are subjected to pressure from governments to modify or overturn decisions. Turnover among commissioners has been high, with many resigning under pressure before completing their full term. The disconnect between law (or rule) and practice is often wide. Tariff setting remains highly politicized, and governments are sensitive to popular resentment against price increases, which are often necessary to cover costs. Establishing independent regulatory agencies may be particularly risky for all stakeholders (governments, utilities, investors, and customers) in sectors that are being reformed, especially when prices are not already high enough to ensure sufficient revenue. In some ways, it is not surprising to find political interference and pressure on regulators.

Governments in developing countries often underestimate the difficulty of establishing new public institutions. Building enduring systems of governance, management, and organization and creating new professional capacity are lengthy processes. Many regulatory institutions in developing countries are no more than a few years old, and few are older than ten. Many are still fragile and lack capacity.

Independent regulation requires strong regulatory commitment and competent institutions and people. The reality is that developing countries are often only weakly committed to independent regulation and face capacity constraints (Trémolet and Shah, 2005). It may be prudent in such cases to acknowledge that weak regulatory commitment, political expediency, fragile institutions, and capacity constraints necessitate limits on regulatory discretion. This does not imply that independent regulation is undesirable. But because of limited institutional capacity in the sector, complementary, transitional, or hybrid regulatory options and models (such as regulatory contracts or outsourcing of regulatory functions) may be a better starting point (Eberhard, 2007).

Each country therefore must choose from a menu of regulatory options to create a hybrid model that best fits its particular situation. The model must be flexible enough to evolve according to growth in a country’s regulatory commitment and capacity. In the end, designing and implementing legitimate, competent regulatory institutions in developing countries will always be a challenge. Nevertheless, establishing an effective regulatory system is essential to the region’s strategy of increasing private participation in the power sector.

More effective regulation of incumbent state-owned utilities will remain a critical challenge. Regulators can play a useful role in ensuring that tariffs are cost-reflective while encouraging utilities to reduce costs and improving efficiencies. Improved financial performance impacts positively on credit ratings, and helps position utilities to raise private debt and fund capacity expansion.

4.8. Realizing the benefits of regional trade

Only a small fraction of the ample hydropower and thermal energy resources in Sub-Saharan Africa have been developed into power generation capacity. Some of the region’s least expensive sources of power are far from major centers of demand in countries too poor to develop them. For example, 61 percent of regional hydropower potential is found in just two countries: Democratic Republic of Congo and Ethiopia. In addition, few countries in the region have sufficient demand to justify power plants large enough to exploit economies of scale. Based on the economic geography of the power sector in Sub-Saharan Africa, regional power trade has many potential benefits. Four regional power pools in Sub-Saharan Africa have already been established but power trade among countries in the region is still very limited.

Rosnes and Vennemo (2009) performed detailed simulations to estimate the potential benefits of regional power trade in Sub-Saharan Africa. In the trade expansion scenario annualized power...
system costs in the trading regions would be between three and ten percent lower. Since trade reduces the use of thermal power plants, the gains from trade increase as fuel prices rise and more hydropower projects become profitable.

If regional power trade were allowed to expand, rising demand would provide incentives for several countries to develop their significant hydropower potential. However, water resource management for hydropower is challenging for at least two reasons. First of all, it often requires multi-national efforts and joint decision-making by several countries. Secondly, hydropower must compete with other demands for water resources. Therefore, development of hydropower resources will require an established legal and regulatory framework to facilitate international cooperation and multi-sectoral management.

5. Summary and conclusions

Africa’s inadequate generation capacity and inadequate, unreliable transmission and distribution networks constrain economic growth and limit the social benefits of electricity use. The economic costs are significant at more than two percent of GDP and a further two percentage points reduction in economic growth.

The total investment requirements for the power sector in Sub-Saharan Africa over a 10 year period are an estimated $40.8 billion a year. About half of the investment cost is for development of new generation capacity. Current spending aimed at addressing power infrastructure needs is an estimated $11.6 billion, leaving a funding gap of $29.2 billion. The gap is significant, which means that the ideological debate of public versus private be set aside and all mechanisms and resources to reduce the gap be mobilized.

There are six areas that require focus. Firstly, current under-pricing must be corrected and subsidies more effectively targeted. Secondly, new electrification strategies need to be nimble and smarter. Thirdly, inefficiencies within the current delivery mechanisms, dominated by state-owned utilities, need to be substantially reduced through governance reforms. Fourthly, sector reforms must be deepened to allow for greater private sector participation within a clear regulatory environment, contributing private equity and debt finance as well as management and technical capacity. Fifthly, new private generation capacity must be encouraged and facilitated through the careful management of hybrid power markets. Lastly, regional integration must be aggressively pursued to reduce overall costs and realize other economic and political benefits.

References