

BACKGROUND PAPER 6

AFRICA INFRASTRUCTURE COUNTRY DIAGNOSTIC

Underpowered: The State of the Power Sector in Sub-Saharan Africa

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May 2008

This report was produced by the World Bank, with funding and other support from (in alphabetical order): the African Union, the Agence Française de Développement, the European Union, the New Economic Partnership for Africa's Development, the Public-Private Infrastructure Advisory Facility, and the U.K. Department for International Development.



About AICD

This study is part of the Africa Infrastructure Country Diagnostic (AICD), a project designed to expand the world's knowledge of physical infrastructure in Africa. AICD will provide a baseline against which future improvements in infrastructure services can be measured, making it possible to monitor the results achieved from donor support. It should also provide a more solid empirical foundation for prioritizing investments and designing policy reforms in the infrastructure sectors in Africa.



AICD will produce a series of reports (such as this one) that provide an overview of the status of public expenditure, investment needs, and sector performance in each of the main infrastructure sectors, including energy, information and communication technologies, irrigation, transport, and water and sanitation. The World Bank will publish a summary of AICD's findings in spring 2008. The underlying data will be made available to the public through an interactive Web site allowing users to download customized data reports and perform simple simulation exercises.



The first phase of AICD focuses on 24 countries that together account for 85 percent of the gross domestic product, population, and infrastructure aid flows of Sub-Saharan Africa. The countries are: Benin, Burkina Faso, Cape Verde, Cameroon, Chad, Congo (Democratic Republic of Congo), Côte d'Ivoire, Ethiopia, Ghana, Kenya, Madagascar, Malawi, Mali, Mozambique, Namibia, Niger, Nigeria, Rwanda, Senegal, South Africa, Sudan, Tanzania, Uganda, and Zambia. Under a second phase of the project, coverage will be expanded to include additional countries.



AICD is being implemented by the World Bank on behalf of a steering committee that represents the African Union, the New Partnership for Africa's Development (NEPAD), Africa's regional economic communities, the African Development Bank, and major infrastructure donors. Financing for AICD is provided by a multi-donor trust fund to which the main contributors are the Department for International Development (United Kingdom), the Public Private Infrastructure Advisory Facility, Agence Française de Développement, and the European Commission. A group of distinguished peer reviewers from policy making and academic circles in Africa and beyond reviews all of the major outputs of the study, with a view to assuring the technical quality of the work.



This and other papers analyzing key infrastructure topics, as well as the underlying data sources described above, will be available for download from www.infrastructureafrica.org. Free-standing summaries are available in English and French.

Inquiries concerning the availability of datasets should be directed to vfoster@worldbank.org.

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Acknowledgments

This paper developed from an earlier version that was prepared as a contribution to the spring 2008 African Regional Economic Outlook publication of the International Monetary Fund (IMF). Tjaarda Storm van Leeuwen, Rob Mills, and Gabriel Goddard contributed significantly to the policy recommendations for that earlier version.

Summary

Sub-Saharan Africa is in the midst of a power crisis marked by insufficient generating capacity, unreliable supplies, high prices, and low rates of popular access to the electricity grid. The region's capacity for generating power is lower than that of any other world region, and growth in that capacity has stagnated. The average price of power in Sub-Saharan Africa is double that of other developing regions, but supply is unreliable. Because new household connections in many countries are not keeping up with population growth, the electrification rate, already low, is actually *declining*.

The manifestations of the current crisis are symptoms of deeper problems that are explored in this study of power sector institutions in 24 countries of Sub-Saharan Africa, which draws extensively on a new body of research undertaken as part of the multi-donor Africa Infrastructure Country Diagnostic (AICD).

Africa unplugged

At 68 gigawatts (GW), the entire generation capacity of the 48 countries of Sub-Saharan Africa is no more than that of Spain. Without South Africa, the total falls to a mere 28 GW, equivalent to the installed capacity of Argentina. As much as 25 percent of these 28 GW of installed capacity are not currently available for generation owing to a variety of causes, including aging plants and lack of maintenance.

Normalized per million people, the installed capacity of 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. Capacity has remained largely stagnant during the last three decades, registering growth rates of barely half those found in other developing regions. As a result, the gap between Sub-Saharan Africa and the rest of the developing world has widened over time. As a general rule, generation capacity should grow at about the same rate as the economy in order to keep pace with demand. However, this has not been the case. The region's GDP has grown at an annual rate of about 5 percent in recent years, whereas generation capacity has grown at an annual rate of less than 3 percent since 1980.

The low level of power generation is accompanied by correspondingly low rates of electrification. Less than a quarter of the population of Sub-Saharan Africa has access to electricity, versus about half in South Asia and more than 80 percent in Latin America. Once again, progress in Sub-Saharan Africa lags behind other regions, and the gap is widening. With current trends, fewer than 40 percent of African countries will reach universal access to electricity by 2050.

Given the region's low levels of generation and access, it is not surprising that per capita consumption of electricity averages just 457 KWh annually, with the average falling to 124 KWh if South Africa is excluded. By contrast, the annual average per capita consumption in the developing world is 1,155 KWh and 10,198 kWh 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.

Sub-Saharan Africa's power supply is famously unreliable. Manufacturing enterprises experience power outages on an average of 56 days per year. By comparison, a typical power security standard in the

United States is one day in ten years. As a result many firms are forced to maintain back-up generation capacity. Frequent power outages result in significant losses for enterprises in forgone sales and damaged equipment, 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 their own backup generation.

The deficiencies of the region's power sector are a serious drag on long-term growth and competitiveness. If all 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.

The extent of the power crisis is revealed in countries' growing recourse to so-called emergency power. To cope with power shortages, countries enter into short-term leases for generation capacity. These contracts are extremely expensive, with costs approaching 3–4 percent of gross domestic product (GDP) in some countries. Ultimately, the prevalence of emergency power represents a planning and procurement failure on a colossal scale.

The subcontinent's power problems are deeply rooted, and concerted effort will be required to resolve them. Resolving those problems—and powering up the region—will require vast sums of investment capital. The keys to attracting that capital are sounder power sector institutions (achievable through a smart new approach to reform) and greatly expanded cross-border trade in power. Development finance institutions and bilateral donors have key roles to play in both areas.

Persistent dysfunction despite some reform

Sub-Saharan Africa has gradually conformed to the global trends in power sector reform that began in the 1980s. By 2006, all but a few of the 24 countries of Sub-Saharan Africa covered by the Africa Infrastructure Country Diagnostic (AICD) had enacted a power sector reform law; three-quarters had introduced some form of private participation in power; two-thirds had corporatized their state-owned power utilities; a similar number had established some kind of regulatory oversight body; and more than a third had independent power producers in operation.

But the extent and payoff of reform remain limited. Nowhere in Sub-Saharan Africa does one encounter the “standard” reform model, that is, unbundling, privatization, and wholesale and retail competition. Instead one finds what might be termed hybrid power markets. In most countries, the national state-owned utility retains its dominant market position, serving as the single buyer of electricity and maintaining its own generation plants. Private sector cooperation is either temporary—for example, a limited-term management contract—or marginal, in the form of independent power producers (IPPs) that contract with the state-owned national utility.

There are nearly 60 medium- to longer-term power sector projects involving the private sector in the region—excluding leases for emergency power generation. Almost half of these are IPPs. Involving more than \$2 billion of private sector investment, these IPPs have added early 3,000 MW of new capacity. A few IPP investments have been particularly well structured and contribute reliable power to the national grid. But these are the exceptions.

The other half of the PPI transactions in Sub-Saharan Africa have taken the form of concession, lease, or management contracts, typically for the operation of the national power system as a whole. These projects have been characterized by a relatively high rate of disappointment, with around a third of the contracts either currently in distress or already cancelled.

The emphasis on independent regulation has not delivered, either. Regulators are far from independent in many situations. Governments still pressure regulators to modify or overturn decisions. In some countries, turnover among commissioners has been high, with many resigning under pressure before completing their full term. The gap between law (or rule) and practice is often wide. Tariff-setting remains highly politicized, and governments are sensitive to popular resentment against price increases that are often necessary to cover costs.

The poor payback from reform has forced reconsideration of whether certain reform principles and programs—notably the unbundling of the incumbent power utility to foster competition—are appropriate for Sub-Saharan Africa. Restructuring the power sector for competition makes sense only in countries large enough to support multiple generators operating at an efficient scale. As noted above, the power systems in most of Sub-Saharan Africa are too small to meet that criterion.

The region's unexploited energy resources

With 12 percent of the world's population and 18 percent of its land area, Sub-Saharan Africa has slightly less than its proportionate share of global energy reserves. But those reserves remain largely unexploited. In 2004, the power plants of Sub-Saharan Africa generated only 2 percent of the world's electricity, nearly three-fourths of which was generated in South Africa's coal-fired stations. When South Africa is excluded, hydropower accounts for close to 70 percent of electricity production (or about 50 percent of installed generation capacity), with the remainder split more or less evenly between oil and natural gas generators.

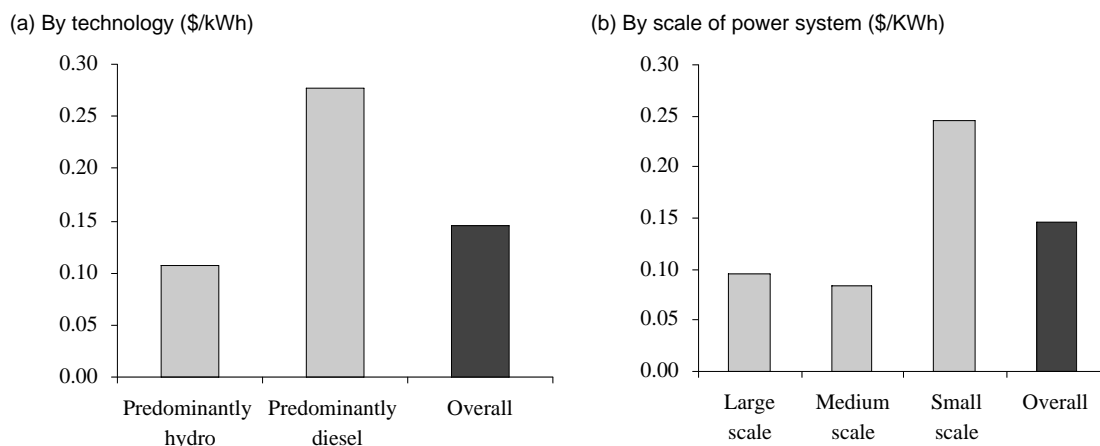
Africa's energy future lies in hydropower. At present, however, 93 percent of the continent's economically feasible hydropower potential (estimated at 937 TWh/year, about a tenth of the world's total) remains unexploited. Natural gas reserves are concentrated primarily in Nigeria (5.2 trillion cubic feet, Tcf). Significant discoveries have also been made in Southern Africa, Mozambique, Namibia, and Angola. Proven oil reserves are concentrated in Nigeria (36 billion barrels), Angola (9 billion barrels), and Sudan (6.4 billion barrels). There are a number of smaller deposits in other countries, but Sub-Saharan Africa accounts for less than 5 percent of global oil reserves.

The bottom line is that the unexploited energy resources of the region are concentrated in a handful of countries that are geographically removed from the centers of power demand. There are exceptions: South Africa relies on its own coal, Nigeria on its oil and gas. But most countries of Sub-Saharan Africa lack domestic resources. Much of the region's hydroelectric potential lies in the Democratic Republic of Congo and Ethiopia, both of which are far from the main economic centers in southern, western, and northern Africa, and their economies are small relative to the multibillion dollar investments that would be needed to develop their hydropower potential.

Uneven distribution of resources and the distance separating hydropower points from economic centers have forced many countries in Sub-Saharan Africa to adopt technically inefficient forms of

generation powered by expensive imported diesel or heavy fuel oil to serve small domestic power markets (figure A), even though, in many cases, the hydro and gas resources of neighboring countries could support much cheaper forms of generation.

Figure A Operating cost drivers for power systems in Sub-Saharan Africa, 2005



Source: Africa Infrastructure Country Diagnostic (AICD Power Sector Database), 2008.

The high (and often hidden) costs of inefficient generation

The price of power in Sub-Saharan Africa is high by international standards. The average tariff in the region rose from \$0.07 per kWh in 2001 to \$0.13 per kWh in 2005, around twice that found in other parts of the developing world, and almost on par with the high-income countries. Tariff increases have been particularly large in countries reliant on diesel-based power-generation systems, where prices have risen from \$0.08 to \$0.17 per kWh on average in response to escalating oil prices. In spite of these increases, however, the average tariff in these countries, at \$0.17 per kWh, still falls significantly short of average operating costs, at \$0.27 per kWh (figure B).¹

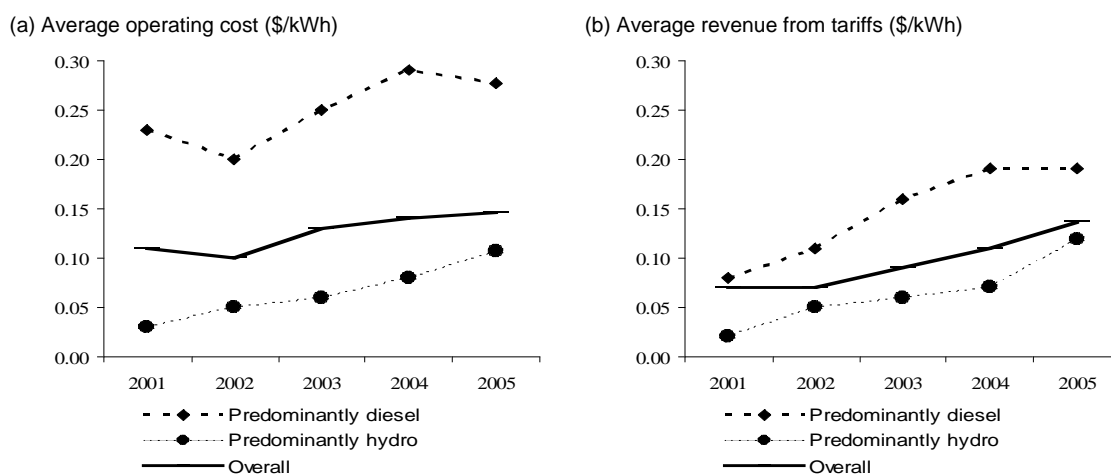
Nowhere in Sub-Saharan Africa do residential or commercial and industrial customers pay full cost-recovery prices, a mixed legacy of subsidies based on concern for the poor and outdated industrial policy. Some countries have historically priced power at highly discounted rates of just a few cents per kWh to large-scale industrial and mining customers. Salient examples include the aluminum smelting industry in Cameroon and Ghana and the mining industry in Zambia.

But the substantial power-consumption subsidies provided by the region's utilities leave millions of African households in the dark. Across the bottom half of the income distribution, barely 10 percent of households have access to electricity, while three-quarters of households *with* electricity come from the top two quintiles of the income distribution. Further disparities are evident across geographic areas.

¹ Countries with small national power systems (of less than 200 MW installed capacity) face an operating cost penalty of as much as \$0.15 per kWh relative to countries with large national power systems (above 500 MW installed capacity). Landlocked countries and island states face a further cost penalty attributable to the high cost of transporting fossil fuels.

Around 70 percent of households in urban areas have access to electricity, but barely 10 percent of rural households are connected to the grid (figure C).

Figure B Trends in electricity costs and revenues by type of power system, 2001–05



Source: AICD Power Sector Database, 2008.

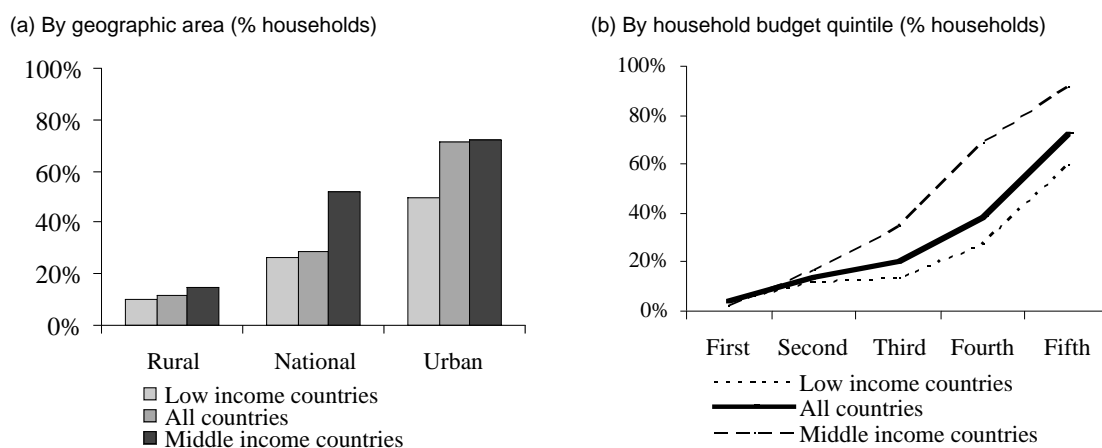
Subsidies have missed their mark because of widespread use of increasing block tariffs that provide relatively large blocks of highly subsidized power to all consumers, regardless of income, and because so few poor households are connected to the grid. To the unconnected, cheap power is as inaccessible as costly power.

The concentration of household connections to the power grid among upper-income customers might lead one to believe that full cost-recovery pricing would be the way forward. But the complex reality hinges on a critical distinction between countries where the cost of power is very high and those where it is substantially lower.

In the high-cost countries, where today’s full cost of power provision can easily amount to \$0.25 per kilowatt hour (kWh), moving to full cost-recovery tariffs would absorb more than 5 percent of household budgets and would therefore present a major social and political problem.² It is clear that the first step is to bring costs down to provide the basis for ultimate cost recovery. This presents the challenge of finding the substantial bridge financing needed in the short run to bring down sector costs in the long run.

² In the low-income countries of Sub-Saharan Africa, even households in the highest-income quintile have monthly budgets of only \$260 to support families typically comprising five people. Even a very modest consumption of 50 kWh per month² at a full cost-recovery price of \$0.25 per kWh (found in some countries of Sub-Saharan Africa) would mean an electricity bill of \$12 per month, representing close to 5 percent of the income of a relatively well-to-do family living on \$260 per month. (Five percent is often considered to be the affordability threshold for electricity services.) A very substantial share of the population in most countries would be unable to afford cost-recovery tariffs. If costs could be reduced to \$0.12/kwh—in line with the region’s average incremental cost of power—the resulting monthly bill of \$6 would be affordable for most of the population, except in the lowest-income countries.

Figure C Patterns of electricity service coverage in Sub-Saharan Africa



Source: Banerjee and others, 2008; AICD Power Sector Database, 2008.

In the continent’s larger countries, and in those that rely on hydropower and coal-based generation, costs are already within the \$0.12 per kWh benchmark cited above. As a result, these countries—with the exception of a handful of the poorest cases—have the opportunity to move quickly toward cost recovery, without facing major affordability problems.

The quickest way to recover costs is to reduce inefficiency. The inefficiencies of Sub-Saharan Africa utilities, combined with the widespread practice of charging below-cost prices for power, generate substantial hidden (or “quasi-fiscal”) costs for the economy. These hidden costs, on average, amount to 1.8 percent of GDP in Sub-Saharan Africa and may be as large as 4 percent of GDP in some countries. Around half of these costs stem from the underpricing of services and nearly 30 percent from distribution losses, with the balance attributable to inefficiencies in billing and collection. These estimates suggest that the dividend from improving utility performance is in many cases very high.

Development finance institutions should consider how they can assist African regimes and utilities in reducing system losses and increasing collection rates—thus raising internal funds. That effort should be complemented by efforts to improve the supervisory and planning agencies responsible for the utility, as described in the next section. Combined, these measures would increase utilities’ ability to attract external funding, public and private, domestic and international.

Ending power subsidies for higher-income groups and for industries that do not need them to compete would free up additional fiscal resources. The new-found resources could be used to subsidize the expansion of power networks to serve lower-income rural and periurban communities, or for other poverty-alleviation programs.

Major investments needed, but from where?

The countries of Sub-Saharan Africa, on average, spend 2.7 percent of their GDP on the power sector; with a number of countries spending in excess of 4 percent. But high levels of spending have not ensured adequate financing for the sector. With revenues barely covering operating costs, utilities contribute little

or nothing to capital costs, which historically have been almost entirely subsidized by the state or by donors.

But the contribution of official development assistance (ODA) to public investment in the power sector has averaged only \$700 million per year in the last decade, far below the level needed to keep pace with economic growth, let alone to expand popular access to electricity. Nor has the private sector fulfilled the promise expected of it, perhaps naively, in the 1990s. The overall value of private investment in the sector has averaged just \$300 million per year during the last decade, and flows have been highly volatile. Taking aid and private investment together, external capital flows to the power sector in Sub-Saharan Africa, amount to no more than 0.1 percent of the region's GDP.

In recent years, the China Ex-Im Bank has emerged as a major new financier of power infrastructure in Sub-Saharan Africa. Over the period 2001–06, Chinese financing commitments to the Sub-Saharan African power sector averaged \$1.7 billion per year—equivalent to around 0.2 percent of the region's GDP and more than official aid and other private investment combined. The major focus of Chinese support has been the development of six large hydropower projects with a combined generating capacity of over 7,000 MWs of electricity. Once completed, these projects should increase the region's installed hydropower capacity by 40 percent. An additional 2,500 MWs of thermal power are being financed by China. The India Ex-Im Bank has also financed some significant thermal generation projects in Nigeria and Sudan. If sustained such investment could conceivably close the financing gap, but such an outcome is by no means assured.

Trading up to larger markets

By creating large regional markets for electric power, greater cross-border trade could help stimulate needed investment in low-cost generation.

Four regional power pools already operate in Sub-Saharan Africa, but the quantities of electricity production traded between countries are still very small. Most of today's trade occurs within the Southern Africa Power Pool (SAPP). The main exporting countries generate electricity from hydropower (the Democratic Republic of Congo, Mozambique, Zambia), natural gas (Côte d'Ivoire and Nigeria), or coal (South Africa).

Despite limited progress, the potential benefits of increased trade are significant. For example, in the SAPP alone, the volume traded internationally could rise from the current 45 to 141 TWh per year with additional investments in the regional transmission lines needed to bring cheaper power to consumption centers. Although the overall savings in the annualized cost of the power sector under trade are relatively small, at less than 10 percent, the gains from cheaper power may be substantial for individual countries. Under trade, most countries would see reductions in the average cost of power of a few cents per kWh, representing savings of 20–60 percent. For a handful of countries, the gains would be as much as \$0.10 per kWh, representing a saving of more than 60 percent.

The main effect of increased cross-border trade in power would be to support the development of large-scale hydropower schemes that would not be viable at the national level. The additional hydropower would displace natural gas generation in Eastern Africa and coal generation in Southern Africa. A related

consequence would be to increase the share of power coming from key export countries such as Ethiopia in East Africa and the Democratic Republic of Congo in Southern Africa.

Development finance institutions should consider accelerating investments in cross-border transmission links and large hydroelectric projects, which the private sector has found too risky because of their high capital costs, long payback periods, and multiple country risks related to the enforceability of power-purchase agreements.

Reform redux: smart regulation for hybrid markets

Africa's hybrid electricity markets pose new challenges in policy, regulation, planning, and procurement. Traditionally, planning and procurement of new power infrastructure were the province of the state-owned utility. With the advent of power sector reforms and the introduction of IPPs, those functions were often moved to the ministry of energy or electricity. A simultaneous transfer of skills did not always occur, however, resulting in plans that were not adequately informed by the complexities on the ground—namely the new hybrid market, composed of private and public actors.

Poor understanding of the hybrid market deprives policy makers of clear and transparent criteria for allocating new plants between the incumbent, state-owned utility and IPPs. New plants are rarely ordered on a timely basis, opening power gaps that prompt recourse to temporary power and discourage investors. When procurement is (finally) undertaken, the authorities may not take the trouble to conduct international competitive bidding. This is unfortunate, because a rigorous bidding process lends credibility and transparency to the procurement and results in more competitively priced power.

Hybrid power markets will not disappear from the African landscape anytime soon. To make the best of them, African governments and their development partners must strive to develop a robust institutional foundation for the single-buyer model, with clear criteria for power purchase (offtake) agreements and dispatches of power under those agreements. They must nurture their planning capabilities, establish clear policies and criteria for allocating new plant opportunities, and commit to competitive and timely bidding processes. Institutions built on the new hybrid models also should reduce discretion in regulatory decision-making through more explicit rules and procedures, or through regulatory contracts and the outsourcing of regulatory functions to advisory regulators and expert panels.

Development partners can help by providing advice on transparent contracting frameworks and processes, and by lending expertise to governments and utilities as they seek to reach financial closure with project sponsors and private investors.

The prerequisite for solid sector financing is better operating performance and thus greater financial viability by the incumbent utilities. Several avenues to better performance are open—among them a new generation of performance contracts; closer monitoring of the operations and finances of state-owned enterprises by supervising ministries and regulators; and new approaches, based on recent reforms in Indian, European, and U.S. power corporations, to attack system losses, raise collection rates, and improve customer service.

Staunching the fiscal hemorrhage caused by misdirected subsidies would complement operational reforms. Decades of subsidies to the power sector in Sub-Saharan Africa have failed to meet the goal of

making electricity affordable, largely because access to service is almost entirely confined to the wealthier segments of society. Ending power subsidies for higher-income groups would free up scarce fiscal resources—a major accomplishment. The new-found resources could be used to subsidize the expansion of power networks to serve lower-income rural and periurban communities.

Some of the policies we have proposed have been advocated for decades. But the persistence of state-owned power utilities in Africa, coupled with the pressing power needs of firms and households, means that the policy challenge can no longer be skirted. Combined, the measures proposed here would increase utilities' ability to attract external funding, public or private, domestic or international—and thus to develop cheaper and more sustainable forms of energy for a power-hungry subcontinent.

Sub-Saharan Africa is in the midst of a power crisis marked by insufficient generating capacity, unreliable supplies, high prices, and low rates of connection to the electricity grid. The region's capacity for generating power is lower than that of any other world region. Growth in that capacity has stagnated in comparison with other developing regions. Household connections to the power grid are scarcer in Sub-Saharan Africa than in any other developing region. And because growth of new connections is slower than population growth in the region, the connection rate is actually *declining*. The average price of power in Sub-Saharan Africa is double that of other developing regions, but the supply of electrical power is unreliable throughout the region.

The extent of the power crisis is revealed in countries' growing recourse to so-called emergency power. To cope with power shortages, countries enter into short-term leases for generation capacity. These contracts are extremely expensive, with costs approaching 3–4 percent of gross domestic product (GDP) in some countries. Ultimately, the prevalence of emergency power represents a planning and procurement failure on a colossal scale.

The manifestations of the current crisis are symptoms of deeper problems that are explored in this study, which draws extensively on a new body of research undertaken as part of the multi-donor Africa Infrastructure Country Diagnostic (AICD). In field visits to power sector institutions in 24 countries of Sub-Saharan Africa, researchers administered a survey composed of more than 200 variables documenting the sector's institutional, regulatory, and governance framework, as well as the technical and financial performance of its utilities.³ In parallel, researchers carried out a full review of public expenditure in the power sector. The authors of related research constructed a simulation model of the regional power sector that made it possible to estimate investment needs under alternative demand and trading scenarios. This review of the state of the sector draws extensively upon all three sources of information.

After situating the region's power sector in its international context, this study explores Africa's chronic power problems, including low levels of generating capacity and popular access to electricity, poor reliability, and high cost. It then identifies a series of paradoxes that further expose the contradictions and challenges facing the power sector. Finally, the study suggests a way forward for the continent.

³ The first phase of the AICD incorporated the following countries: Benin, Burkina Faso, Cameroon, Cape Verde, Chad, the Democratic Republic of Congo, Côte d'Ivoire, Ethiopia, Ghana, Kenya, Lesotho, Madagascar, Malawi, Mozambique, Namibia, Niger, Nigeria, Rwanda, Senegal, South Africa, Sudan, Tanzania, Uganda, and Zambia.

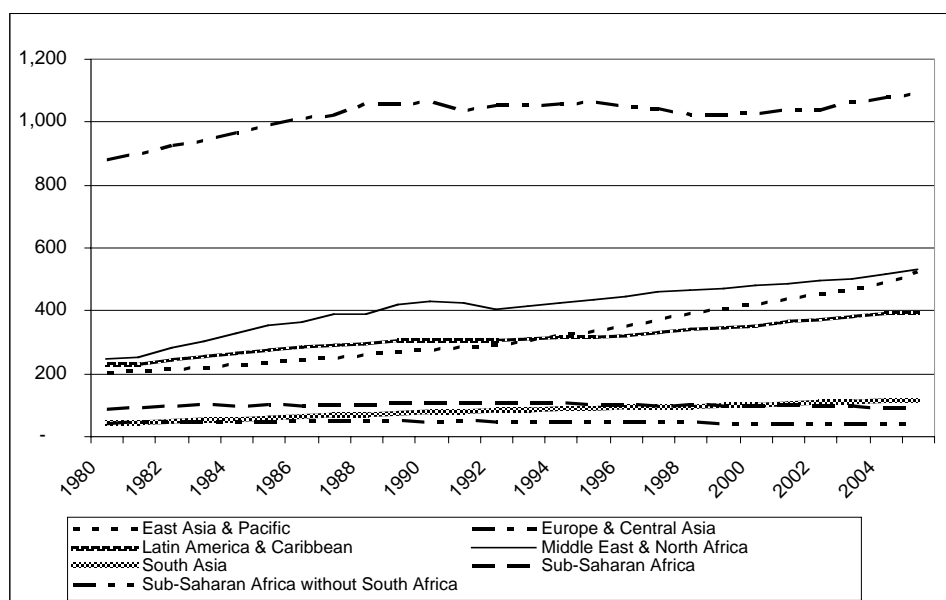
1 The power sector of Sub-Saharan Africa in its international context

The power sector of Sub-Saharan Africa is starkly underdeveloped compared with that of other world regions. The results of that underdevelopment, as just noted, are the world's lowest levels of popular access to electricity and of consumption of electric power. Costs are high, and service quality low. Over the past three decades, the region has lagged behind all others in sector performance.

At 68 gigawatts (GW), the entire generation capacity of the 48 countries of Sub-Saharan Africa is no more than that of Spain. Without South Africa, the total falls to a mere 28 GW, equivalent to the installed capacity of Argentina (EIA, 2005). Moreover, as much as 25 percent of these 28 GW of installed capacity are not currently available for generation owing to a variety of causes, including aging plants and lack of maintenance.

Normalized per million people, the installed capacity of 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 (figure 1.1). Capacity has remained largely stagnant during the last three decades, registering growth rates of barely half those found in other developing regions. As a result, the gap between Sub-Saharan Africa and the rest of the developing world has widened over time. The region's deficit remains even when compared with other country groups in the same income bracket (Yepes and others, 2008).

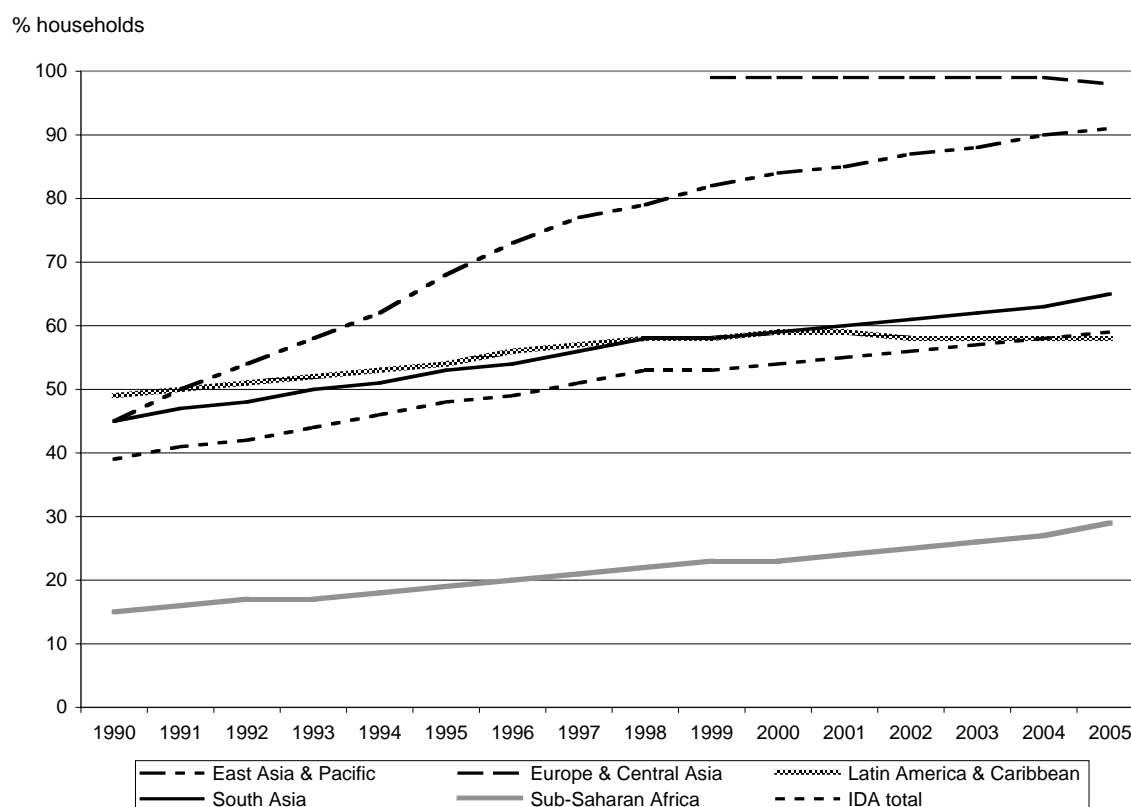
Figure 1.1 Generation capacity (megawatts, MW, per million inhabitants)



Source: Compiled by authors from EIA, 2005, and World Bank, 2007a.

The low level of power generation is accompanied by correspondingly low rates of electrification. Less than a quarter of the population of Sub-Saharan Africa has access to electricity, versus about half in South Asia and more than 80 percent in Latin America. Once again, progress in Sub-Saharan Africa lags behind other regions. Since 1990, East Asia, Latin America, and the Middle East all have added at least 20 percentage points to their electrification rates, while overall access levels in Sub-Saharan Africa are now declining as population growth and household formation exceed the number of new connections (figure 1.2). With current trends, fewer than 40 percent of African countries will reach universal access to electricity by 2050 (Banerjee and others, 2008).

Figure 1.2 Household electrification rate in world regions, 1990–2005



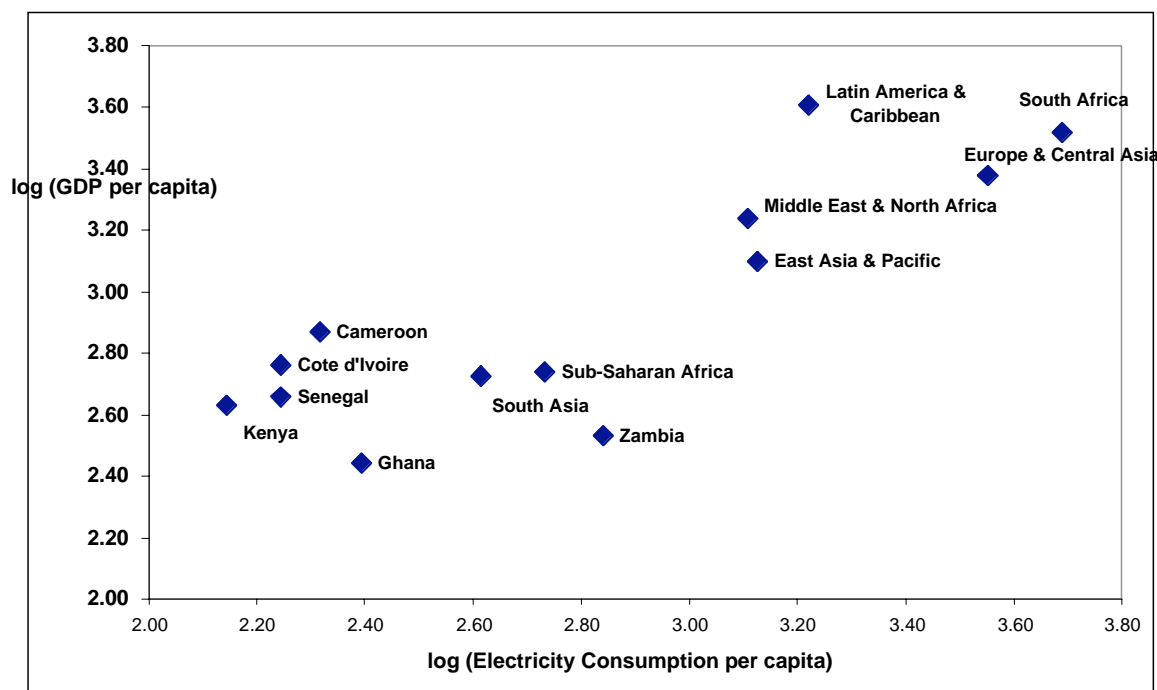
Source: World Bank, IDA RMS Web site.

Given the region’s low levels of generation and access, it is not surprising that per capita consumption of electricity averages just 457 KWh annually, with the average falling to 124 KWh if South Africa is excluded (World Bank, 2005). By contrast, the annual average per capita consumption in the developing world is 1,155 KWh and 10,198 kWh 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. Figure 1.3 indicates the broad relationship between electricity consumption and economic development, with all countries of Sub-Saharan Africa (except South Africa) lagging far behind other regions.

Because of its low consumption of electric power, among other factors, Sub-Saharan is a very minor contributor to carbon dioxide emissions and climate change, having the lowest per capita emissions and

among the lowest emissions in terms of GDP output. Indeed, if South Africa is excluded, the power sector of Sub-Saharan Africa contributes less than 1 percent of global carbon dioxide emissions.

Figure 1.3 Per capita electricity consumption and GDP in selected countries of Sub-Saharan Africa and world regions, 2004



Source: Compiled by authors from the World Bank, 2007a.

The price of power in Sub-Saharan Africa is high by international standards. The average power tariff of \$0.13 per kWh is around twice that found in other parts of the developing world, and almost on par with the countries of the Organisation for Economic Co-operation and Development (OECD). The high price that African consumers pay for electricity is compounded by additional costs caused by the unreliability of supply. One of the few available sources of cross-country evidence on the reliability of power supply comes from the World Bank's Investment Climate Assessments, which survey manufacturing enterprises around the world. According to that source, African manufacturing enterprises experience power outages on an average of 56 days per year. By comparison, a typical power security standard in the United States is one day in ten years (World Bank, 2007a).

The deficiencies of the region's power sector are seriously affecting long-term growth and competitiveness. 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.

Deficient power infrastructure dampens economic growth, especially through its detrimental effect on firm productivity. Using enterprise survey data collected through the World Bank's Investment Climate Assessments, Escribano and others (2008) estimate the impact of infrastructure on firm productivity relative to other investment climate variables, and also decompose the contribution of various components of infrastructure. They find 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. Moreover, in half of the countries analyzed, the power sector accounted for 40–80 percent of the infrastructure effect.

2 The chronic power problems of Sub-Saharan Africa

The subcontinent's power problems are deeply rooted, and concerted effort will be required to resolve them. Chief among those problems are the underdevelopment of the region's energy resources, the high costs of power, the unreliability of power supplies, the region's vulnerability to high oil prices, and the exacerbating effect of drought and conflict. We will deal briefly with each of these issues in turn.

The region's energy resources and power infrastructure are underdeveloped

With 12 percent of the world's population and 18 percent of its land area, Sub-Saharan Africa has slightly less than its proportionate share of global energy reserves (including hydropower). But those reserves remain largely unexploited.

In 2004, the power plants of Sub-Saharan Africa generated 339 terawatt hours (TWh) of electricity, approximately 2 percent of the world's total. About 71 percent of that was generated in South Africa (World Bank, 2007b). As 93 percent of that country's electricity is produced by coal-fired stations, coal is the dominant fuel for generating electricity in the region. Most of the subcontinent's coal reserves are located in the south, mainly in South Africa, which has the fifth-largest reserves globally and also ranks fifth in annual production (BP, 2007). Few other countries in the region rely on coal; Botswana and Zimbabwe are among the exceptions.⁴ Total coal reserves in Africa constitute just 5.6 percent of global reserves.

If South Africa is excluded, the electricity-generation picture in Sub-Saharan Africa looks very different. Hydropower accounts for close to 70 percent of electricity production (or about 50 percent of installed generation capacity), with the remainder split more or less evenly between oil and natural gas generators.

It is estimated that 93 percent of Africa's economically feasible hydropower potential remains unexploited. The economically feasible potential is estimated at 937 TWh/year, about a tenth of the world's total. Much of that potential is located, in descending order, in the Democratic Republic of Congo, Ethiopia, Cameroon, Angola, Madagascar, Gabon, Mozambique, and Nigeria. Some of the largest

⁴ Niger, Mauritius, Namibia, and Tanzania also have small coal-generation plants.

operating hydropower installations are in the Democratic Republic of Congo, Mozambique, Nigeria, Zambia, and Ghana. The total installed capacity is, however, only 4,347 megawatts (MW) (Bartle, 2006). Burundi, Lesotho, Malawi, Rwanda, and Uganda also rely heavily on hydroelectricity.

Natural gas reserves are concentrated primarily in Nigeria (5.2 trillion cubic feet, Tcf). Significant natural gas discoveries have also been made in Southern Africa, Mozambique, Namibia, and Angola, with reserves of 4.5 Tcf, 2.2 Tcf, and 2.0 Tcf, respectively. Small amounts have also been discovered in Tanzania. Gas reserves in Sub-Saharan Africa make up less than 4 percent of the world's total proven reserves, and actual gas production is an even smaller proportion of the world's total production (BP, 2007).

Proven oil reserves are concentrated in Nigeria (36 billion barrels), Angola (9 billion barrels), and Sudan (6.4 billion barrels). There are a number of smaller deposits in the Republic of Congo, Equatorial Guinea, Gabon, Chad, and Cameroon. Sub-Saharan Africa accounts for less than 5 percent of global oil reserves. Actual oil production is similar (BP, 2007).

There is only one nuclear power plant on the continent: the 1,800 megawatt (MW) Koeberg station in South Africa. Africa's natural uranium reserves are located mainly in South Africa, Namibia, and Niger, and constitute approximately one-fifth of global reserves.

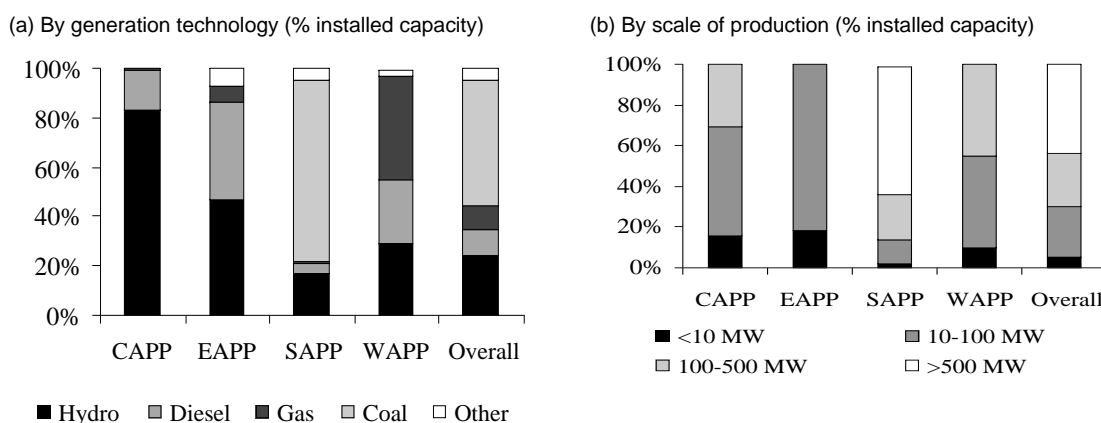
There is also unexploited geothermal potential in the Rift Valley area, as well as abundant solar energy across the continent.

The abundant unexploited energy resources of Sub-Saharan Africa are concentrated in a handful of countries that are geographically removed from the centers of power demand. There are exceptions: South Africa relies on its own coal, Nigeria on its oil and gas. But most countries of Sub-Saharan Africa lack domestic fossil-fuel reserves, and hydro resources are unevenly distributed. The Democratic Republic of Congo and Ethiopia command much of the region's hydroelectric potential. Both countries are situated far from the main economic centers in southern, western, and northern Africa, and their economies are small relative to the multibillion dollar investments that would be needed to develop their hydropower potential.

Uneven distribution of resources and the distance separating hydropower points from economic centers have forced many countries in Sub-Saharan Africa to adopt technically inefficient forms of generation powered by expensive imported fuels to serve small domestic power markets (figure 2.1). Expensive diesel or heavy fuel oil generators make up about a third of the installed capacity in Eastern and Western Africa. These are typically installed by countries that lack adequate domestic energy resources, even though, in many cases, the hydro and gas resources of neighboring countries could support much cheaper forms of generation.

Few countries are able to exploit economies of scale in generation plant size. For example, 33 out of 48 countries in Sub-Saharan Africa have national power systems that produce and consume less than 500 MW; 11 countries have national power systems of less than 100 MW. The result is that most countries of Sub-Saharan Africa suffer significant diseconomies of scale in power generation.

Figure 2.1 Profile of power-generation assets in Sub-Saharan Africa



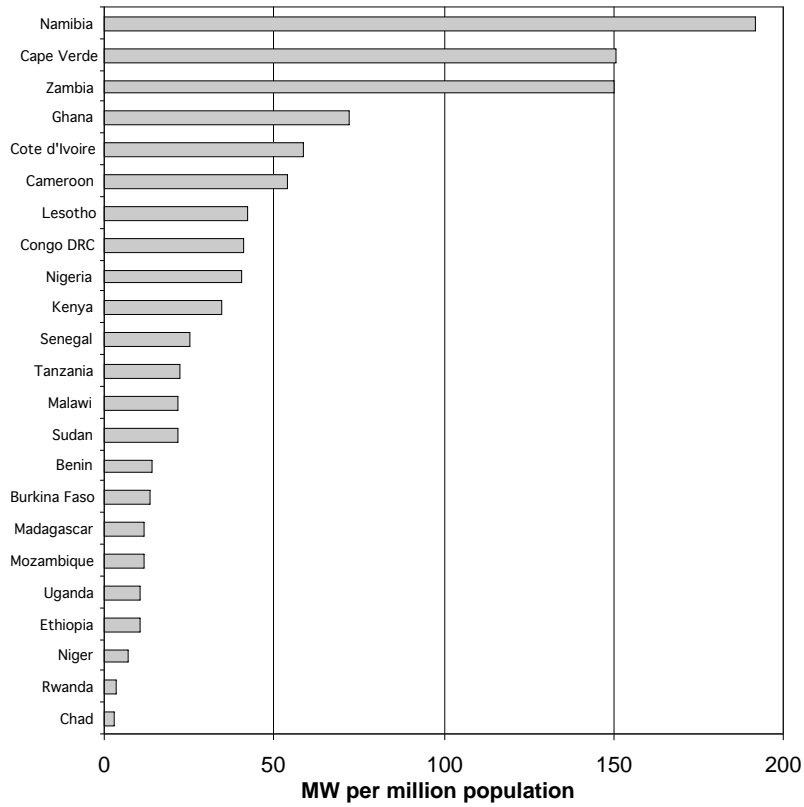
Source: Platts, 2007; EIA, 2007.

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 net generating capacity of about 40,000 MW. Nigeria comes in second, with less than 4,000 MW, despite its much larger population of 140 million. There is a handful of medium-sized systems: the Democratic Republic of Congo (2,443 MW), Zimbabwe (2,099 MW), Zambia (1,778 MW), Ghana (1,490 MW), Kenya (1,211 MW), and Côte d'Ivoire (1,084 MW)—although not all of their capacity is operational. Capacity is sharply reduced in the remaining countries: Mali (280 MW), Burkina Faso, (180 MW), Rwanda (31 MW), and Togo (21 MW) (EIA, 2007). Per capita generation capacity also varies significantly, as shown in figure 2.2.

Power costs are high

The consequences of this technically inefficient pattern of power generation become clear when comparing the operating costs of power systems (figure 2.3). The average operating cost of predominantly diesel-based power systems is as much as \$0.20 per kilowatt hour (kWh)—more expensive than the costs of hydro-based systems. Similarly, countries with small national power systems (of less than 200 MW installed capacity) face an operating cost penalty of as much as \$0.15 per kWh relative to countries with large national power systems (above 500 MW installed capacity). Landlocked countries and island states face a further cost penalty attributable to the high cost of transporting fossil fuels.

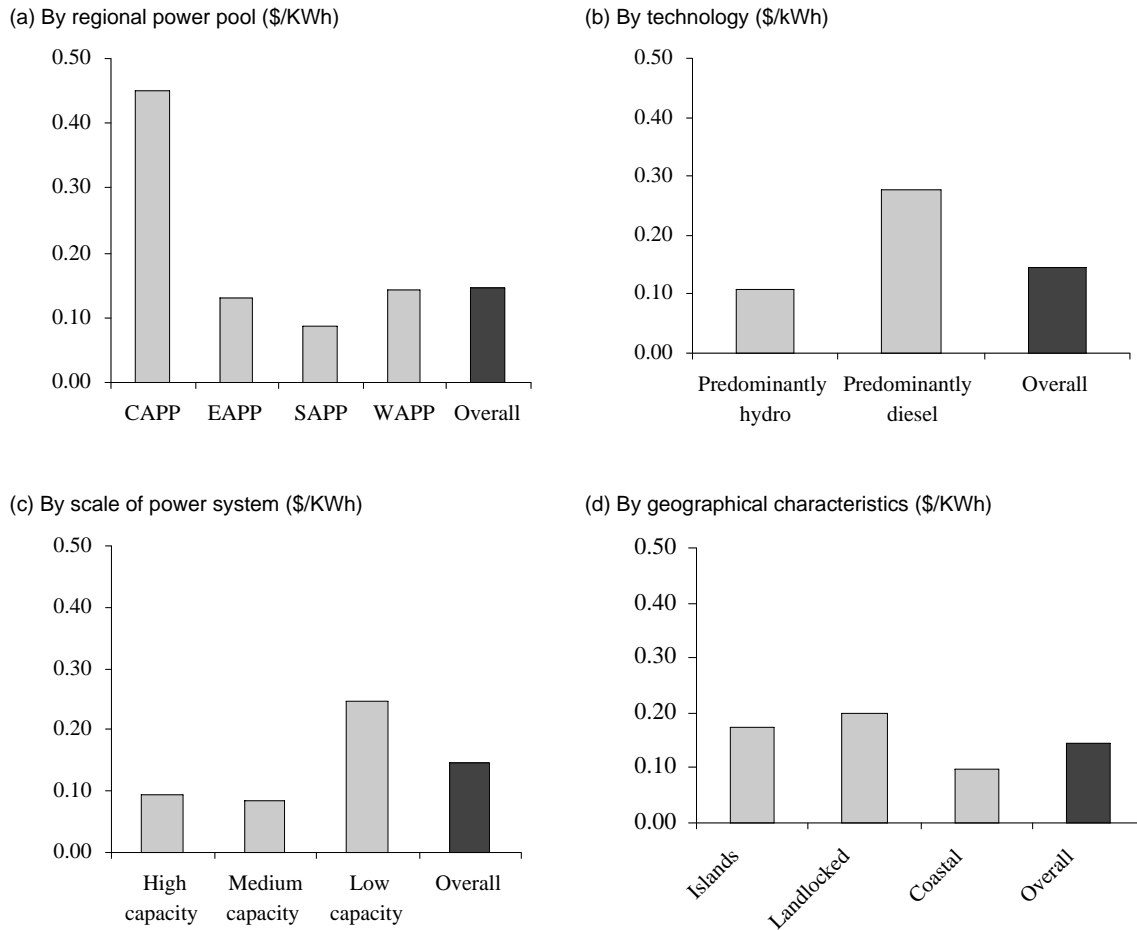
Figure 2.2 Generation capacity, megawatts (MW) per million inhabitants, 2005



Source: EIA, 2007.

Note: By comparison, South Africa's figure is 863 MW per million inhabitants.

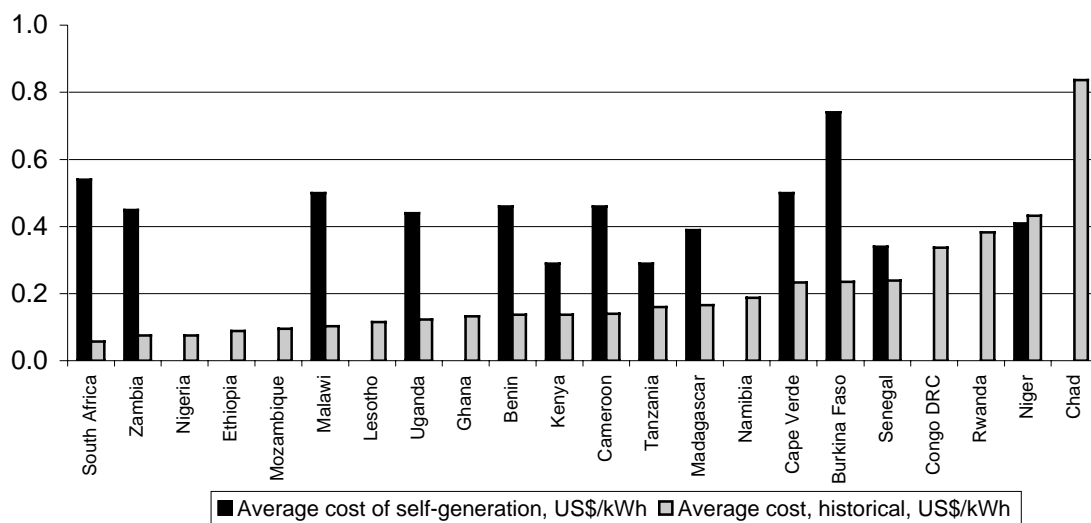
Figure 2.3 Operating cost drivers for power systems in Sub-Saharan Africa, 2005



Source: Africa Infrastructure Country Diagnostic (AICD Power Sector Database), 2008.

The actual power costs borne by African consumers are higher, as Africans must rely on backup generators when the main grid fails. Power from such generators is much more expensive than grid power (figure 2.4) pushing the weighted average cost of power to consumers above the figures quoted above.

Figure 2.4 Average cost of grid and backup power in Sub-Saharan Africa

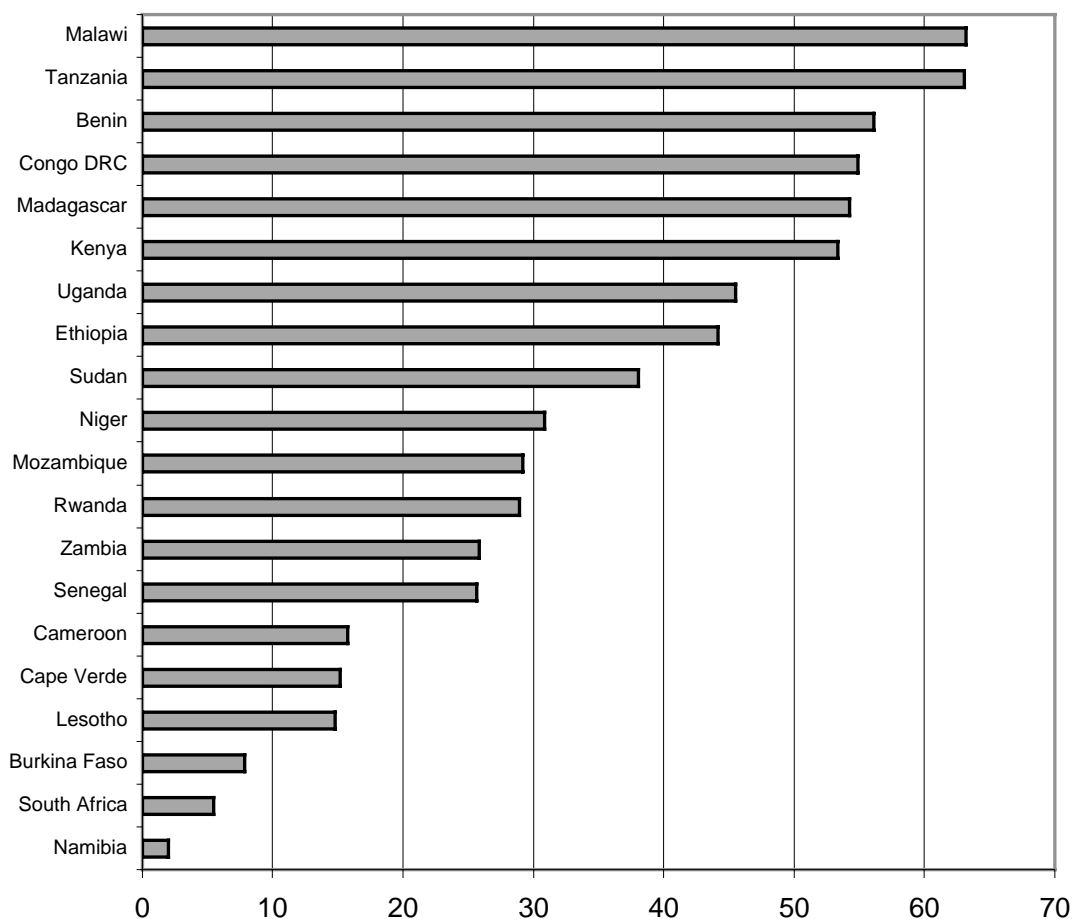


Source: Briceno-Garmendia, QFC, 2008; and authors' own calculations of own-generation costs based on Foster and Steinbuks, 2008.

Electricity supply is unreliable

Sub-Saharan Africa's power supply is famously unreliable. The reliability of power systems is conventionally measured in terms of the unplanned-capacity-loss factors (UCLF) of generators, the number of interruptions in transmission, and indices of the frequency and duration of interruptions in power distribution. But these data are still not collected and reported systematically or accurately by most African countries. The World Bank Enterprise Surveys provide a useful alternative measure of the reliability of grid-supplied power, however. The surveys indicate that most African enterprises experience frequent outages. For example, in 2007, firms in Senegal experienced power outages for 25 days in a year, on average. In Tanzania, the figure was 63 days, and in Burundi, 144 days (figure 2.5).

Figure 2.5 Power outages, days per year, latest year available



Source: World Bank Enterprise Survey Database.

Firms in countries reporting more than 60 days of power outages per year identify power as a major constraint to doing business and are more likely to own generators. The size (figure 2.6), sector, and export orientation of the firm also influences the likelihood of own-generation.

Own-generation constitutes a significant proportion of total installed power capacity—as great as 17 percent in West Africa (figure 2.7). In the Democratic Republic of Congo, Equatorial Guinea, and Mauritania, backup generators make up half of total installed capacity. While the figure for Southern Africa is much lower, it is likely to increase as the region experiences unprecedented power outages. South Africa—which for many years maintained surplus capacity—is experiencing acute power shortages, and load shedding is now common across the region (see box 2.1). The value of in-house generating capacity in Sub-Saharan Africa, expressed as a percentage of gross fixed capital formation, ranges from 2 percent to as high as 35 percent (Foster and Steinbuks, 2008).

Figure 2.6 Generator ownership, by firm size

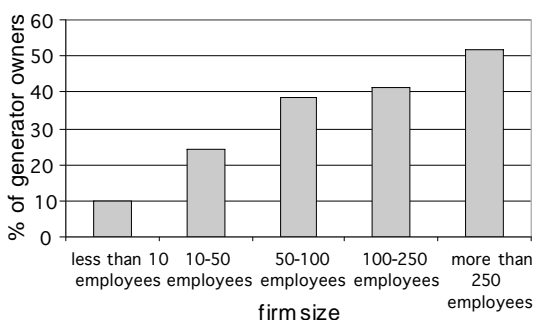
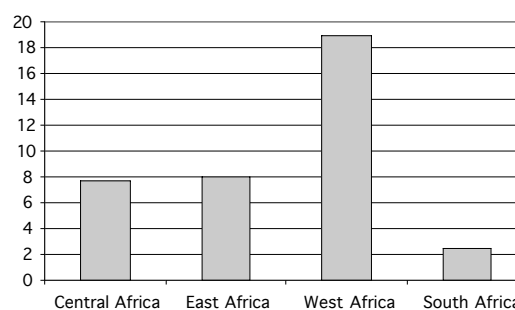


Figure 2.7 Own-generation as share of total installed capacity, by subregion, 2006



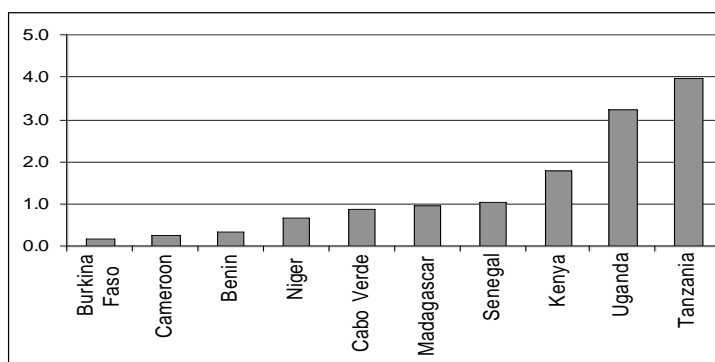
Source: World Bank Enterprise Survey Database.

Frequent power outages result in significant losses for enterprises in forgone sales and damaged equipment, 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 their own backup generation (Foster and Steinbuks, 2008).

The overall economic costs of power outages are substantial. Calculations based on load-shedding data from the World Bank’s Investment Climate Assessments and estimates of the value of lost load or unserved energy reveal that costs, on average, amount to 2.1 percent of gross domestic product (GDP). In those countries where we were able to make our own calculations (about 50 percent of the total), the cost was less than 1 percent of GDP. In East Africa, losses are much higher, particularly in Uganda (3.3 percent of GDP) and Tanzania (4 percent of GDP).

The persistence, depth, and gravity of the power crisis are reflected in the growing phenomenon of grid-connected temporary emergency power, whereby countries enter into short-term leases for emergency power generation with global operators (table 2.1). Unlike traditional power-generation projects, this capacity can be put in place within a few weeks, providing a quick solution to pressing shortages. The equipment is leased for up to two years and sometimes longer, after which it reverts to the private sector provider. It is estimated that at least 750 MW of emergency generation are currently operating in Sub-Saharan Africa, and in some countries this type of capacity constitutes a significant proportion of nationally installed capacity. The cost is typically around \$0.20–0.30 per kWh—relatively expensive

Figure 2.8 Economic cost of outages as share of GDP, 2005



Source: AICD Power Sector Database, 2008.

power. In some countries, the overall price registers as a considerable percentage of GDP.⁵ There have been instances of corruption and bribery in procurement of emergency power. The Tanzanian prime minister and energy minister recently resigned after a parliamentary investigation revealed that lucrative contracts for emergency power had been placed with a fictitious company.

Table 2.1 Overview of emergency power generation in Sub-Saharan Africa

Country	Date	Contract duration (years)	Emergency capacity	Percentage total installed capacity	Estimated annual cost as % GDP
Angola	2006	2	150	18.1	1.04
Gabon			14	3.4	0.45
Ghana	2007	1	80	5.4	1.90
Kenya	2006	1	100	8.3	1.45
Madagascar	2004	Several	50	35.7	2.79
Rwanda	2005	2	15	48.4	1.84
Senegal	2005	2	40	16.5	1.37
Sierra Leone	2007	1	20	133.3	4.25
Tanzania	2006	2	180	20.4	0.96
Uganda	2006	2	100	41.7	3.29

Source: AICD Power Sector Database, 2008.

The power crisis is exacerbated by drought, conflict, and high oil prices

In recent years, the already precarious situation has been exacerbated by natural, economic, and social shocks. 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 rely on expensive thermal power. Cameroon and Ethiopia have also had to increase their thermal capacity.

High international oil prices have put enormous pressure on all of the oil-importing countries of Sub-Saharan Africa, especially Benin, Burkina Faso, Cape Verde, Chad, Comoros, Eritrea, Gambia, Guinea-Bissau, Liberia, Mauritania, Senegal, Seychelles, Sierra Leone, Somalia, Sudan, and Togo.

War has left power infrastructure severely damaged 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. Yepes and others (2008) document that countries in conflict perform worse in the development of infrastructure stocks than do countries at peace.

Other countries are experiencing a structural crisis because of rapid economic growth combined with prolonged underinvestment in the sector. Poor sector planning has frustrated the expansion of new capacity necessary to accommodate burgeoning demand. South Africa and the middle-income countries in its immediate neighborhood are the most salient examples of this phenomenon (box 2.1). Other countries, notably Nigeria, have seen full national system power failures in recent years.

⁵ Spending on emergency power can displace expenditures on social services such as health and education. For example, the government of Sierra Leone has not been able to meet the minimum targets for expenditures in health and education that are required for continued budget support by the European Union (EU) and other donors, and it is widely recognized that an overpriced emergency diesel-based power supply contract is largely to blame. (There are only 28,000 electricity customers in a country of 6 million!)

Box 2.1 The regional and economic effects of South Africa's power-supply crisis

South Africa has long been a sizeable producer of low-cost electricity, thanks to its abundant coal reserves. By far the region's largest producer and consumer of electricity, South Africa accounts for 70 percent of electricity production in Sub-Saharan Africa. Electricity prices for both households and industry are exceptionally low, an important factor in the development of South Africa's energy-intensive mining and mineral-processing sectors.

But in recent years South Africa's electricity supply remained stagnant while demand continued to grow, causing power shortages. Delays in investment by the state-owned electricity provider, Eskom, coupled with breakdowns in its existing generation plant and negligence in coal contracting, eroded spare capacity in the system, leaving the country prone to periodic rounds of rolling power cuts—sometimes with very little warning.

The government had earlier imposed a moratorium on building new plants while it considered unbundling the utility and introducing private participation and competition. The new market arrangements, however, were never implemented, and with average prices far below the marginal cost of new generation, private investors had no way of entering the sector without special contracting arrangements. After a four-year hiatus, the government abandoned the idea of a competitive market and once again made Eskom responsible for expanding capacity (while retaining the option of contracting a few independent power producers in the future).

The power outages have brought gridlock on the roads as traffic lights fail. Millions of rands are lost because businesses cannot operate. Houses are dark. Electricity supply to large industrial users was reduced in January 2008, causing a temporary shutdown of mining operations and sending global prices for gold and platinum soaring. South Africa exports about 5 percent of its electricity production to neighboring countries. Botswana, Namibia, and Swaziland, for example, import at least half of their electricity from South Africa. These countries have been affected by a similar regime of rolling blackouts. Some South African unions and political groups have called for a complete halt on power exports.

The government's response to the crisis centers on a new investment program, with \$45 billion to be committed over the next five years. Meanwhile, Eskom will enter into cogeneration contracts, while rationing power in a manner modeled on Brazil's response to its energy crisis in 2001. Large mines have already been rationed to 90 percent of their normal electricity supply, and municipal redistributors are now also required to reduce demand by 10 percent. (Presently, the latter target is being achieved largely through preemptive load shedding.) Electricity prices are likely to increase substantially over the next several years to help finance investment and reduce demand. Eskom has requested a second reopening of the current multiyear tariff determination and has submitted an application to the regulator for a 60 percent increase in 2008. The supply-demand balance is likely to remain tight for at least the next seven years.

Source: Eberhard, 2008; IMF staff, 2008.

3 Power sector paradoxes in Sub-Saharan Africa

The crises in the continent's power sector, are symptoms of deeper problems that must be addressed if the region's energy imbalances are to be righted. The complex challenges facing Sub-Saharan Africa may be expressed as a series of paradoxes:

- Power sector reforms have not brought improvements in the performance of most utilities.
- Power prices are high, but utilities' costs are even higher.
- Electric power remains out of reach for millions of households, despite extensive subsidies.
- Spending to expand electrification has not markedly increased African's access to power.

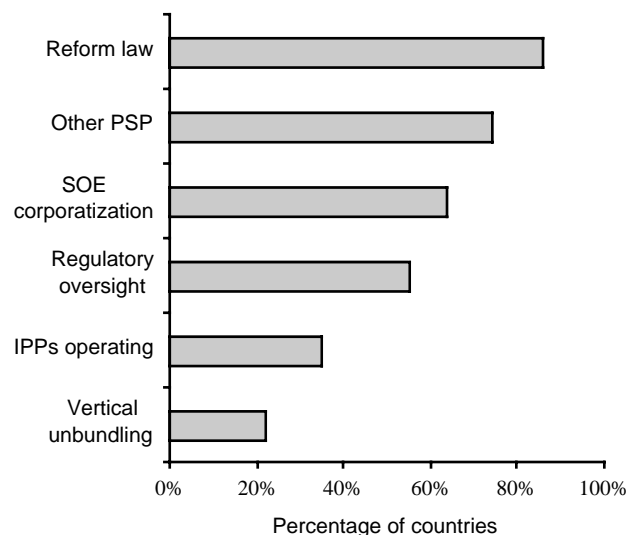
- High spending for power at the national level coexists with a shortage of financing.
- Regional power pools have not succeeded in raising cross-border trade in power beyond token levels.

Power sector and governance reforms have begun, but most utilities still perform poorly

Power sector reform in Sub-Saharan Africa

Sub-Saharan Africa has gradually conformed to global trends in power sector reform that began in the 1980s. The tenets of the reform orthodoxy are legislation, independent regulation, and restructuring to foster competition in generation and private sector participation across the electricity-supply chain. As of 2006, all but a few of the 24 countries of Sub-Saharan Africa covered by the Africa Infrastructure Country Diagnostic (AICD) had enacted a power sector reform law; three-quarters had introduced some form of private participation in power; two-thirds had corporatized their state-owned power utilities; a similar number had established some kind of regulatory oversight body; and more than a third had independent power producers in operation (figure 3.1). But while most countries have made some progress toward reform, with about a third of the countries adopting three or four of the reform components, few have adopted the full range of reform measures—and the extent of reform remains limited (figure 3.2). Indeed, in most countries, the national state-owned utility retains its dominant market position. Private sector cooperation is either temporary (for example, a limited-period management contract) or marginal (in the form of independent power producers that contract with the state-owned national utility). The national utility still serves as the single buyer and continues to maintain its own generation plants. There is no wholesale or retail competition in Africa.⁶

Figure 3.1 Prevalence of power sector reform components



Source: AICD Power Sector Database, 2008.

Note: "Other PSP" means forms of private sector participation other than independent power producers (IPPs), namely, concessions or management contracts.

The lack of results has forced reconsideration of whether certain reform principles and programs—notably the unbundling of the incumbent power utility to foster competition—are appropriate for Sub-Saharan Africa.⁷ Besant-Jones (2006), in his global review of power sector reform, concludes that

⁶ The only minor exception is a short-term energy market in the Southern Africa Power Pool (SAPP). The quantities traded, however, are extremely small.

⁷ 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). Nigeria has *de jure* unbundled its utility, although in practice there is still a high level of coordination between the different entities. For historical reasons, part of distribution in Namibia and South Africa is undertaken separately by the local government.

power sector restructuring for competition makes sense only in countries large enough to support multiple generators operating at an efficient scale. As noted above, the power systems in most of Sub-Saharan Africa are too small to meet this criterion. Even South Africa and Nigeria, however, where a case for unbundling could be made, there has not been 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 longer-term power sector transactions involving the private sector in the region—excluding leases for emergency power generation.

Almost half of these projects are independent power projects (IPPs) (table 3.1). Nearly 3,000 MW of new capacity has been added, involving more than \$2 billion of private sector investment. Côte d’Ivoire, Ghana, Kenya, Mauritius, Nigeria, and Tanzania all currently support two or more IPPs. A few IPP investments have been particularly well structured and contribute reliable power to the national grid; the Tsavo power plant in Kenya and Azito in Côte d’Ivoire are two prominent examples.

Gratwick and Eberhard (2008) predict that IPPs will continue to expand generation capacity on the continent, although they have been relatively costly because of technology choices, procurement problems, and currency devaluation. Some have been subject to renegotiation. Major success factors are: policy reforms, a competent and experienced regulator, timely and competitive bidding and procurement processes, good transaction advice, a financially viable offtaker, a solid power-purchase agreement, appropriate credit and security arrangements, the availability of low-cost and competitively priced fuel, and development-minded project sponsors. Gratwick and Eberhard (2008) also suggest possible policy reforms and strategies to attract private investment for new generation capacity.

Table 3.1 Overview of private participation in the power sector in Sub-Saharan Africa

Type of private participation	Countries affected	Number of transactions	Number of cancelled transactions	Investment in facilities (\$ millions)
Management or lease contract	Chad, Gambia, Gabon, Ghana, Guinea-Bissau, Kenya, Lesotho, Madagascar, Malawi, Mali, Namibia, Rwanda, Sao Tome, Tanzania, Togo	17	4	5
Concession contract	Cameroon, Comoros, Côte d’Ivoire, Gabon, Guinea, Mali, Mozambique, Nigeria, Sao Tome, Senegal, South Africa, Togo, Uganda	16	5	1,598
Independent power project	Angola, Burkina Faso, Republic of Congo, Côte d’Ivoire, Ethiopia, Ghana, Kenya, Mauritius, Nigeria, Senegal, Tanzania	34	2	2,457
Divestiture	Cape Verde, Kenya, South Africa, Zambia, Zimbabwe	7	—	n.a.
Overall		74	11	4,060

Source: World Bank’s Private Participation in Infrastructure (PPI) Database, 2007; AICD Power Sector Database, 2008.

— = data not available; n.a. = not applicable.

The other half of the PPI transactions in Sub-Saharan Africa have taken the form of concession, lease, or management contracts, typically for the operation of the national power system as a whole. These projects have been characterized by a relatively high rate of disappointment, with around a third of the contracts either currently in distress or already cancelled. Long-term private leases or concessions have survived only in Cameroon, Cape Verde, Côte d’Ivoire (box 3.1), Gabon, Mali, and Uganda (Boston Institute for Development Studies, 2006). Private management contracts are found today only in Kenya,

Madagascar, and Gambia. Upon completion of management contracts in several other countries (including Namibia, Lesotho, Malawi, Tanzania, and Rwanda) management reverted to state-owned utilities; Kenya is likely to follow suit. Management contracts in Africa's power sector are explored in detail in box 3.2.

Nowhere in Sub-Saharan Africa does one encounter the "standard" reform model, that is, unbundling, privatization, and wholesale and retail competition. Instead one finds what might be termed "hybrid" power markets. In most cases, the old state-owned utility remains intact and in a dominant market position. The private sector is being introduced (typically in the form of IPPs) primarily because governments and utilities lack sufficient investment resources. The resulting hybrid electricity markets create challenges in policy, regulation, planning, and procurement that, if not addressed, may lead to confusion and inefficient investment decisions.

Sector reform, sector performance

Have the reforms just described improved utilities' performance and attracted new investment into the sector? We have already demonstrated that Sub-Saharan Africa lags other regions in indicators such as installed capacity, electricity production, access rates, costs, and reliability of supply. Other performance indicators are also mostly negative. For example, the average number of customers per employee is only 147, compared to more than 500 in the countries of the Organisation for Economic Co-operation and Development (OECD). Transmission and distribution (T&D) losses average 25 percent, and, in some countries, are as high as 50 percent. And, as we shall see below, commercial efficiency, collection rates, and cost recovery are poor.

Normally, power sector reform would be expected to improve performance (Gboney, 2008). An analysis of data collected in the initial sample of 24 AICD countries indicates that power sectors in countries with regulators do indeed perform better than those without (figure 3.2). But in critical areas such as cost recovery, T&D losses, and reserve margins, however, no improvement can be found. We must not read too much into these results. Cost-recovery calculations rest on a number of assumptions. Reporting on T&D losses is not always reliable. And those countries without regulators (for example, Benin, Burkina Faso, Chad, the Democratic Republic of Congo, Mozambique, and Sudan) are among the poorest on the continent and face a host of additional challenges that affect the performance of their power sectors.

The overall effect of PPI, while generally positive, is nevertheless ambiguous, as shown in figure 3.3. When the effect of different forms of PPI is disaggregated, however, it becomes clear that countries with IPPs almost always fare better and that concessions are far more effective than MCs. Countries with MCs fail to make any consistent improvements (except in labor productivity).

Box 3.1 Côte d'Ivoire's independent power projects survive civil war

Compagnie Ivoirienne de Production d'Electricité (CIPREL), a 210 MW open-cycle plant fired by domestically produced natural gas, was among the first independent power projects (IPPs) in Africa. With major shares held by SAUR Group and Electricité de France (EDF), CIPREL began producing power in 1994.

At the time, Côte d'Ivoire's investment climate was among the best in the region, and the economy was growing at an annual rate of 7.7 percent. This favorable climate, coupled with CIPREL's success, stimulated interest in the second IPP, Azito, during its international competitive bid in 1996. Ultimately a consortium headed by Cinergy and Asea Brown Boveri was selected to develop the plant, with the deal safeguarded by a sovereign guarantee and a partial risk guarantee from the World Bank. In 2000, when Azito's 330 MW gas-fired, open-cycle plant came online, it was the largest IPP in West Africa.

Just months after Azito's deal with sealed and well before the plant was completed, the country suffered a political coup. During the years of civil unrest between 1999 and 2007, the revenues of the national utility, Compagnie Ivoirienne d'Electricité (CIE), were reduced by approximately 15 percent, reducing the state's ability to invest in new, and much needed, electricity infrastructure. The turmoil had no impact on the IPPs, however. The plants continued to produce electricity and make payments to CIE. Both IPPs are keen to expand their interest in the generation sector.

Why have IPPs in Côte d'Ivoire fared so well? A stable currency pegged to the euro (and earlier to the French franc) minimizes the exchange-rate risks that have taxed other Sub-Saharan African IPPs. Coherent power sector planning after the droughts of the 1980s helped the country achieve a good mix of hydro and thermal power sources, and enough power to supply itself and help out its neighbors in their darkest hours (while generating further revenue). Containing the political instability to the north of the country, where there are relatively fewer consumers than in the south, helped maintain the utility when revenues stopped flowing in from rebel-controlled areas. The presence of domestic gas also helped keep power prices down. The involvement of IPP sponsors SAUR and EDF throughout the entire power supply chain may explain why there have been no disruptions and why interest continues. Of critical importance has been the role of development partners (the World Bank via the International Development Association and the International Finance Corporation; the West African Bank for Development; PROPARCO (Promotion et Participation pour la Cooperation Economique); and firms with a development mandate, such as IPS and Globeleq) in sealing and sustaining the deals.

IPPs provide more than half of Côte d'Ivoire's generating capacity. They have been instrumental in helping the country to avert the consequences of drought in a region where hydropower is dominant.

Source: Gratwick and Eberhard, 2008.

Box 3.2 Management contracts in the power sector of Sub-Saharan Africa: winning the battle, losing the war

Management contracts (MCs) were once regarded as the entry point for private participation in infrastructure. The reasoning was as follows. First, since the state retained full ownership of the assets in question, the political fuss inevitably produced by divestiture would be minimized or avoided. Second, since the private management contractor would neither acquire equity nor incur commercial risk, it should be simple to hire competent professionals, pay them a fee for their services (plus, usually, bonuses for fulfillment of specified performance targets), and enjoy the resulting financial and operational improvements.

That was the theory. In practice, MCs have proved complex and contentious. While widely applied (17 contracts in 15 different countries) and usually productive—in terms of improving utility collection rates and revenues, and reducing system losses—MCs have not been able to overcome the broader policy and institutional deficiencies of the sector. They have not been instrumental in generating much-needed investment funds. Most tellingly, they have not proven sustainable. Of the 17 African MCs, 4 were cancelled before the originally designated expiration date, and at least 5 more reverted to state operation after their initial term (but note that in Gabon and Mali, MCs were followed by concessions). Only three MCs remain in operation, and the long-term fate of one is already known: Kenya has announced that the MC in its electricity-distribution company will not be renewed at the conclusion of the initial two-year term.

In sum, the supposedly easy measure has proven more difficult to implement and sustain than anticipated, and enthusiasm for applying the mechanism has declined considerably. What is the problem?

The major issue is the disconnect between the conceptions and expectations of the parties involved. Donors and development finance institutions, which have been involved in almost all MCs, regarded the contract as an initial step toward greater liberalization and privatization of the utility, which occurred only in Gabon and Mali. Even in countries where concessions or divestitures were clearly not an option, the donor perspective was that the MC was part of a larger reform process and would be renewed and extended long enough to allow parallel policy and institutional changes to take root. African governments, on the other hand, tended to perceive MCs as discrete, time-bound actions they were obliged to undertake to receive crucial donor funding. In their view, MCs were not a first and easy step; rather, they were a wrenching measure that they could not avoid but did not wish to prolong.

Assessments of the impact of African electricity MCs indicate improved performance; that is, greater labor productivity, better collection rates, and somewhat lower system losses. For example, between mid-2002 and mid-2005, under the MC in Tanzania, collection rates rose from 67 to 93 percent, system losses fell by 5 percent, 30,000 new connections were installed (at a pace far greater than the previous expansion rate), costs fell by 30 percent, and annual revenues rose by 35 percent. Labor relations improved, despite the layoff of more than 1,300 workers, whose departure was eased by a generous severance package. Working capital overdrafts were cleared and the utility even managed to secure small loans from private commercial banks—contingent on the continued presence of the management contractors. A “poverty tariff” was introduced for consumers using 50 KWhs or less (Ghanadan and Eberhard, 2007). An MC in the rural, northern part of Namibia also produced significant gains: under private management between 1996 and 2002 customer numbers doubled, again, at a rate far higher than under the previous management, and—without changing the size of the workforce—labor productivity soared; 85 percent of customers surveyed in 1998 expressed satisfaction with the reliability and quality of the service provided under the MC (Econ and Emcon, 2002).

Based on this and other promising information from other MCs, donors concluded that the device was working. But some country officials were more skeptical. They acknowledged the gains, but argued that they were largely due to foreign managers being allowed to lay off excess staff, cut service to delinquent customers, and raise tariffs. African managers in publicly owned utilities, they said, had not been allowed to employ these powers widely. This became the main African counterargument to MCs: little that the foreign managers did to improve performance was new or unknown. If public managers had the same authority, they could do as good a job at a much lower price.

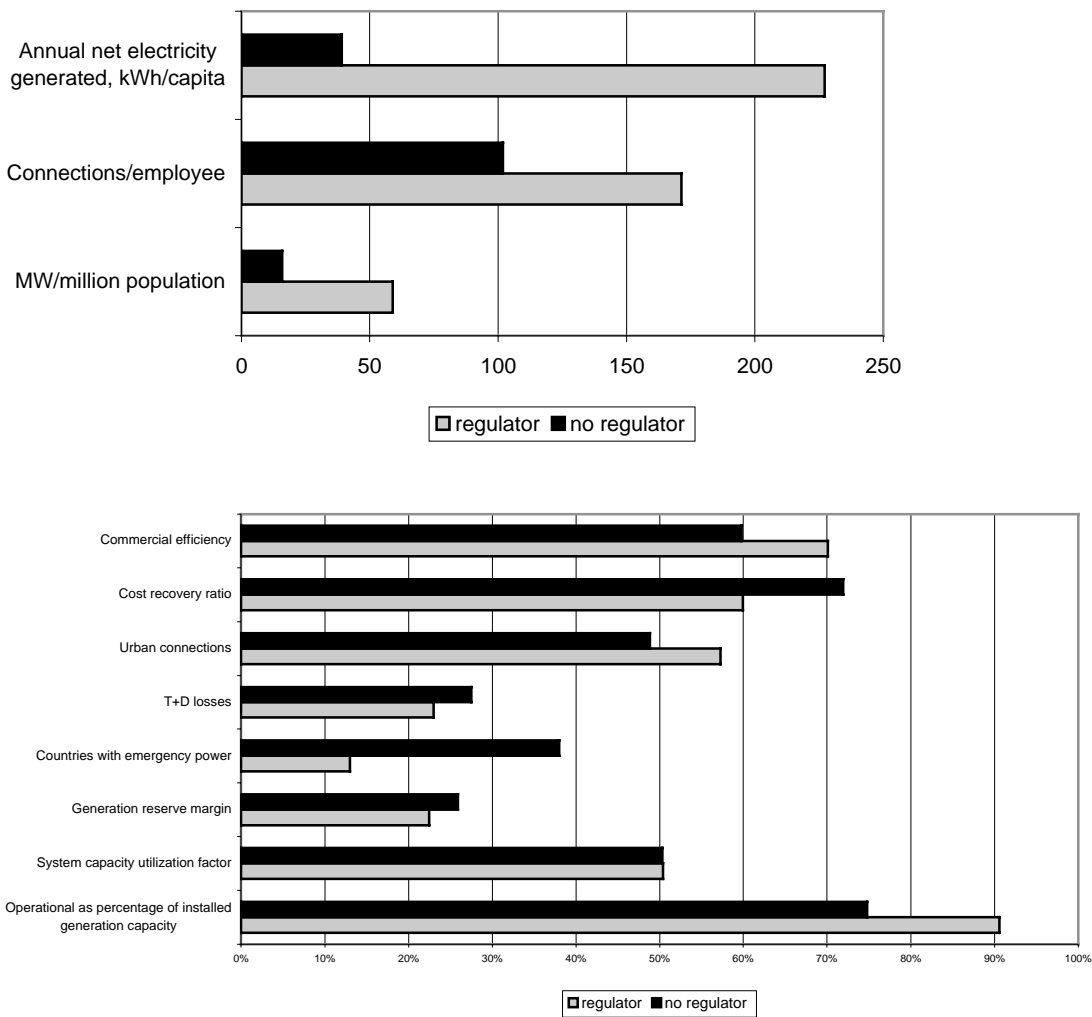
MCs might have overcome such tensions and proved easier to sustain had they been accompanied or followed by large amounts of investment funding, or had they led to cost cuts so dramatic as to generate (from retained earnings) investment capital for network rehabilitation and expansion, or had they produced a massive turnaround in service quality. None of this happened, partly because of the low starting points, and partly because the implementation of MCs often coincided with a series of cost-raising factors—for example, regional drought, soaring oil prices, the arrival of IPPs with very high capacity charges—that were beyond the control of utility managers.

African ministries of finance were doubtless pleased with the financial and efficiency gains observed under the MCs. But most customers were unaware or indifferent to the financial improvements; they were concerned with service quantity, quality, and price. In these areas, changes were slow in coming (if they came at all) and modest in size. Critics of privatization and even private participation, including some who had been displaced from management posts by the MCs, protested the continued load shedding, the indignity of having to rely on imported managers, and the supposed loss of sovereignty, and made great political hay of the large sums of money paid to the contractors—for example, during the 56 months the Tanzanian MC was in operation the contractor earned \$8.5 million in fixed fees and \$8.9 million in performance-based fees. (Those fees accounted for a small fraction of the financial gains produced under the MC, and a large portion of the performance-based reward was paid by the Swedish donor, SIDA.) Faced with such pressures, policy makers were not persuaded that the benefits of MCs outweighed the costs; and the contracts were allowed to lapse.

So, MCs can produce financial and efficiency gains. But alone they cannot overcome the obstacles posed by broader policy and institutional weaknesses. Moreover, the gains produced are distributed, over time, to a mass of amorphous and unorganized consumers, while the costs—both material and psychological—are immediate and fall on a vocal and organized few, whose protests often win the day. It would thus appear that African MCs have tended to win the economic battles and lose the political wars. The issue is how to restructure the device to make it more palatable and enduring.

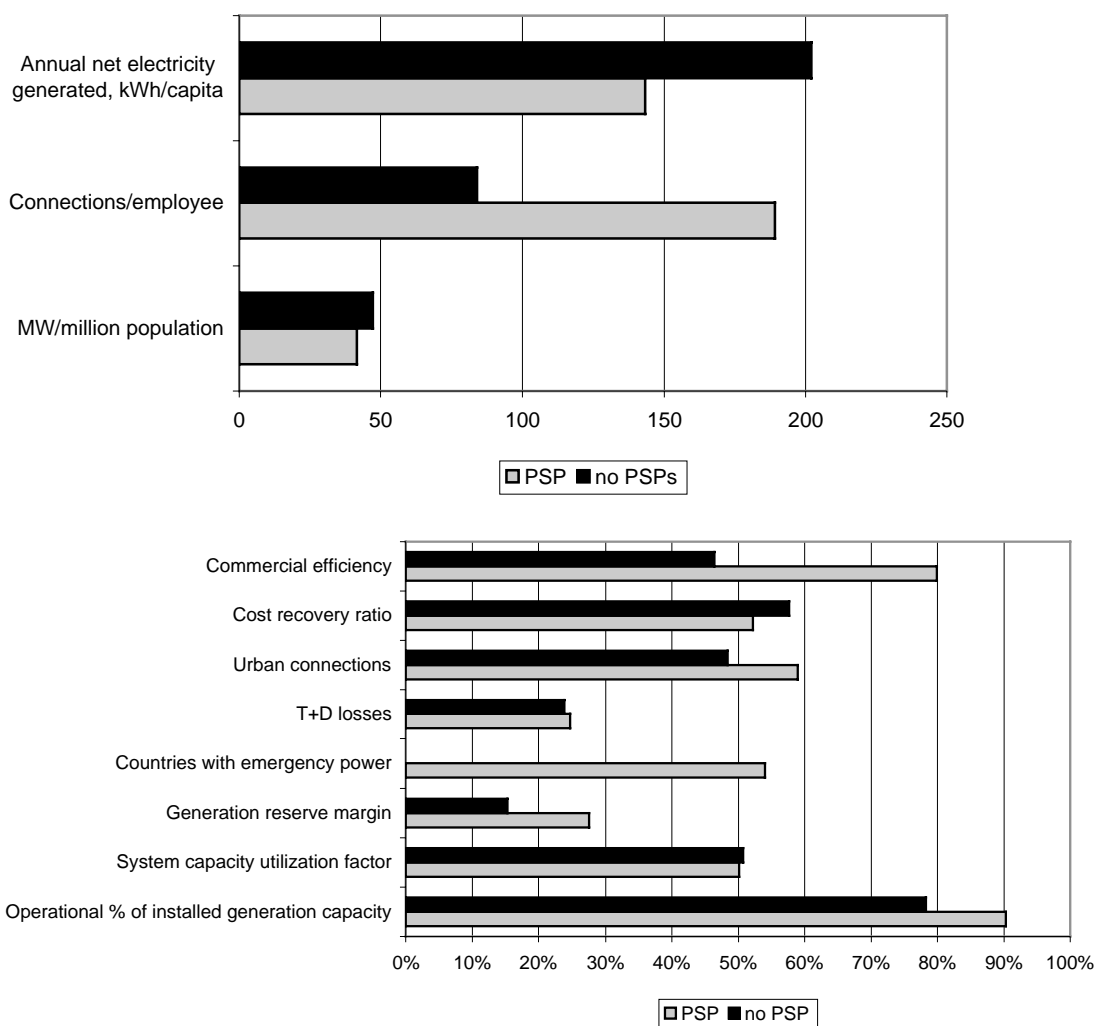
Source: Nellis, 2008.

Figure 3.2 Sector performance with and without a regulator



Source: AICD Power Sector Database, 2008.

Figure 3.3 Private sector participation (PSP) and sector performance



Source: AICD Power Sector Database, 2008.

Note: Only one bar appears for “countries with emergency power” because emergency plants recorded here are all private.

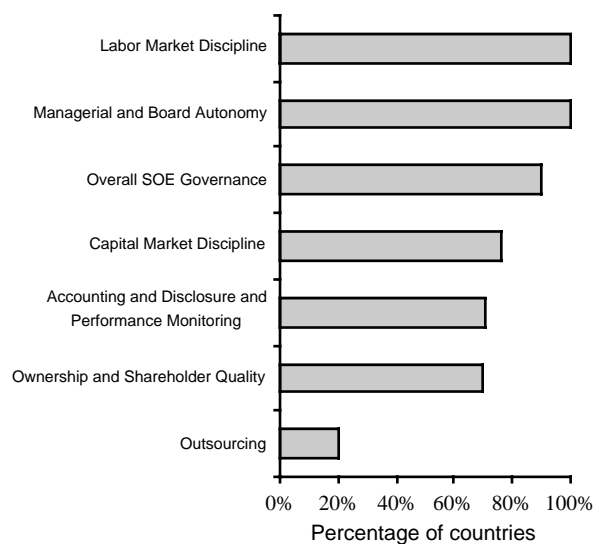
Improving the performance of state-owned utilities

Given the power sector reform context in Sub-Saharan Africa—as previously outlined—and the ongoing presence of state-owned utilities in the majority of countries, it is important to consider additional steps to improve utility performance. Reforms of state-owned enterprises (SOEs) merit a second look (Gomez-Ibanez, 2008).

SOE governance may be assessed using a number of criteria, including (a) ownership and shareholder quality; (b) managerial and board autonomy; (c) accounting, disclosure, and performance monitoring; (d) outsourcing; (e) labor market discipline; and (f) capital market discipline (Vagliasindi, 2008).

The prevalence of these good governance practices is not universal in Sub-Saharan Africa utilities. The most prevalent practices are those relating to managerial autonomy, with a majority of the utilities reporting freedom with respect to labor policies and a sizeable minority reporting free to make market decisions (figure 3.4). While most utilities report requirements to be profitable and pay market rates for debt, in practice the vast majority benefit from sizeable subsidies and tax breaks and are not even in a position to borrow at all. In terms of accountability, only 60 percent of the sample utilities publish audited accounts, and stock exchange listing is virtually unheard of (Kenya’s Kengen and KPLC being the exception). Overall, the typical utility in the sample meets only about half of the criteria.

Figure 3.4 Incidence of good-governance characteristics among state-owned utilities

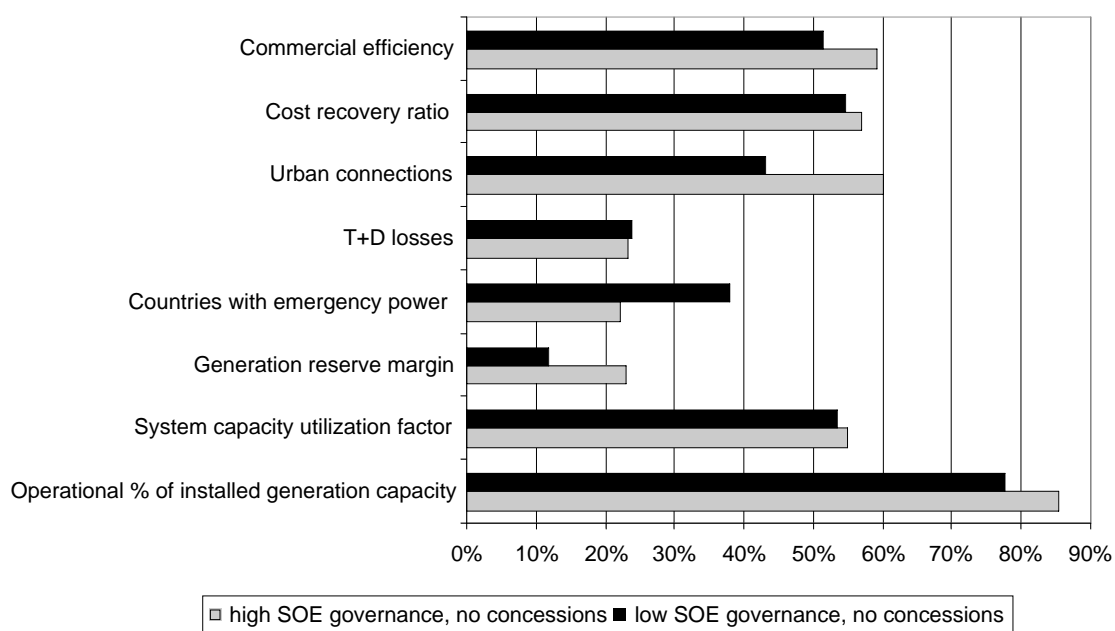
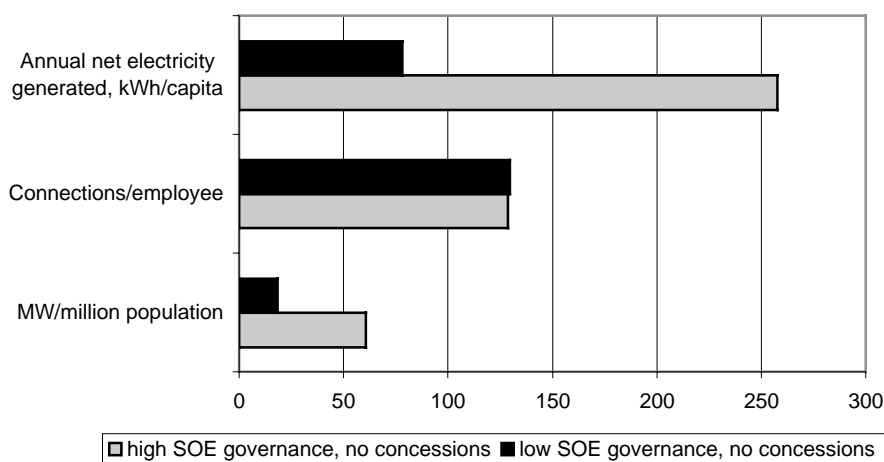


Source: AICD Power Sector Database, 2008.

We produced governance scores for the SOEs in the AICD sample based on 35 different governance indicators, and then divided the sample into two groups with higher or lower scores. Cross-tabulations comparing the performance of the two groups produces striking and consistent evidence that good governance improves performance in most areas, although surprisingly not in labor productivity (figure 3.5).

In summary, our data indicate that SOE governance and regulatory reforms, and the introduction of private sector participation, generally result in improvements. When Sub-Saharan Africa is compared with other regions, however, its overall performance remains poor.

Figure 3.5 SOE governance and utility performance



Source: AICD Power Sector Database, 2008.

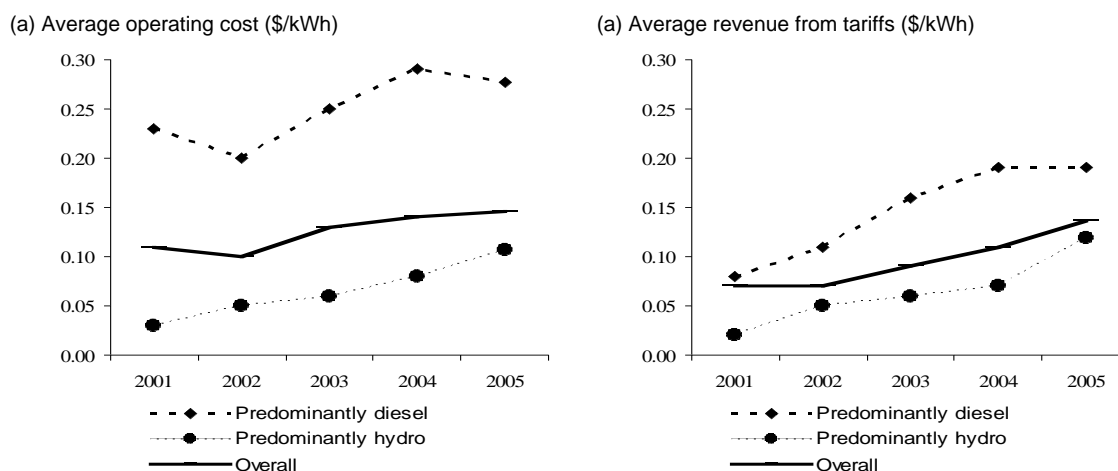
Prices are high, but not high enough to cover costs

The high price of power in Sub-Saharan Africa has already been noted. There are, of course, exceptions to the general trend. Some countries, such as Angola, Malawi, South Africa, Zambia, and Zimbabwe have maintained very low prices, prices that were well below economic costs (Sadelec, 2006).

The high prices found in most countries reflect substantial increases in oil prices since 2000 and tightening supply conditions. The overall average tariff rose from \$0.07 per kWh in 2001 to \$0.13 per

kWh in 2005. Tariff increases have been particularly large in countries reliant on diesel-based power-generation systems, where prices have risen from \$0.08 to \$0.17 per kWh on average in response to escalating oil prices. In spite of these increases, however, the average tariff in these countries, at \$0.17 per kWh, still falls significantly short of average operating costs, at \$0.27 per kWh (figure 3.6). Average revenue for power utilities ranges from less than \$0.10 per kilowatt hour (kWh) (in countries with hydropower-based systems or major domestic hydrocarbon resources) to about \$0.20 per kWh (in landlocked countries, island states, and countries that rely heavily on diesel generation).

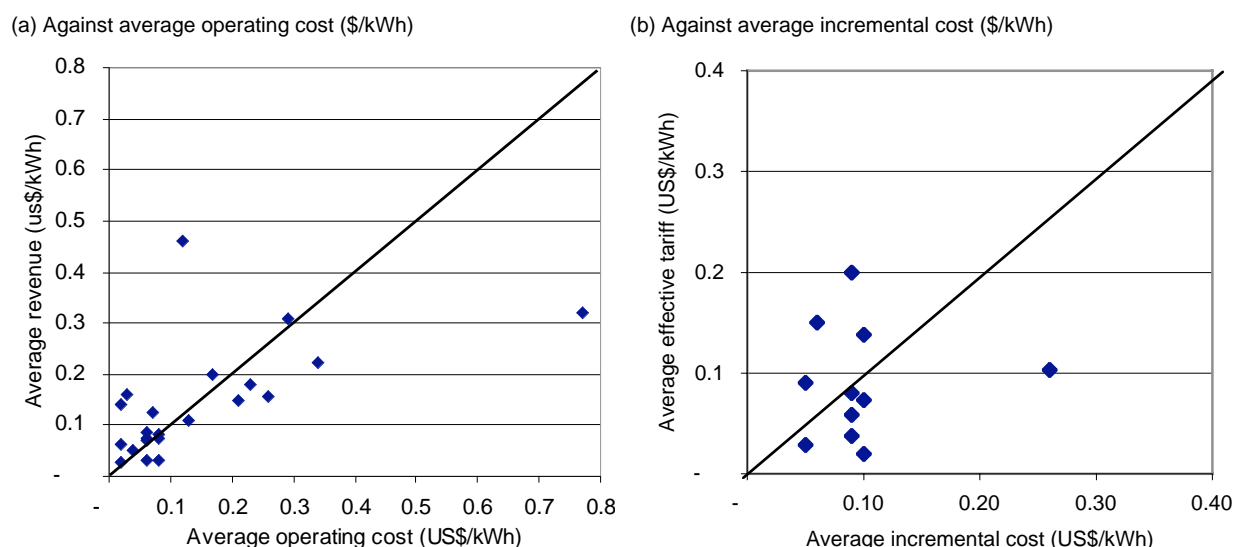
Figure 3.6 Trends in electricity costs and revenues by type of power system, 2001–05



Source: AICD Power Sector Database, 2008.

Note: "Overall" means the average of all AICD countries. "Predominantly diesel" means the average operating cost and revenue in countries where most generation is fueled by diesel.

Despite comparatively high power prices, most Sub-Saharan Africa countries are doing little more than covering their average operating costs (figure 3.7a). The close correlation between average revenue and average operating cost across the countries of Sub-Saharan Africa (as high as 90 percent) indicates that recovery of operating costs is the driving principle behind power pricing in most cases. Countries with average operating costs in excess of \$0.20 per kWh tend to set prices somewhat below this level; those countries fall below the 45 degree line in figure 3.7a.

Figure 3.7 Average power sector revenue against various cost benchmarks

Source: AICD Power Sector Database, 2008.

But a simple comparison of current average revenues and average operating costs misrepresents the long-term cost-recovery picture for two critical reasons. First, owing to major failures in utility revenue collection, the average revenue *collected* from customers per unit of electricity sold is substantially lower than the average tariff that is being *charged* to customers per unit of electricity sold. Second, for many countries in Sub-Saharan Africa, the average total cost associated with power developments in the *past* is actually higher than the average incremental cost of producing new power in the *future*. This is because historic power development has been done using small scale and inefficient generation technologies, which could be superseded as countries become able to trade power across national frontiers, thereby harnessing larger scale and more efficient forms of production. Thus, a truer picture of the long-term cost-recovery situation is gained by comparing the average tariff that consumers are already being charged (but not yet fully paying) today with the average incremental cost of developing power tomorrow (as in figure 3.7b). That comparison reveals that, in some countries, even the current tariff would be adequate for cost-recovery purposes if only revenues were fully collected and if the power system moved toward a more efficient structure of production.

Given that current residential tariffs do not cover the costs of historic capital investments, in the past these have been almost entirely subsidized by the state or by donors, as will be discussed in the next section.⁸ Although the residential sector accounts for 95 percent of power utility customers in Africa, it contributes only about 50 percent of sales revenue. Thus, tariffs charged to commercial and industrial consumers are just as important to the utility in terms of guaranteeing the requisite revenues for cost

⁸ One of the casualties of insufficient revenue is maintenance expenditure. Utility managers often have to choose between paying salaries, buying fuel, or purchasing spares (often resorting to cannibalizing parts from functional equipment). For example, in Sierra Leone, the overhead distribution network for the low-income eastern part of the town has been cannibalized for spare parts to repair the network of the high-income western part of the town. Thus, even with the advent of emergency generators, many previous customers remain without power.

recovery. It is more difficult to assess whether commercial and industrial customers are currently paying tariffs high enough to contribute to the full costs of service provision. The limited evidence available suggests that the average revenue raised from low- and medium-voltage customers is very similar, while high-voltage customers tend to pay around half as much. This relative price differential, which is not unusual from a global perspective, reflects the fact that high-voltage customers do not make use of the distribution network and hence do not create such high costs for the power utility..

In addition, a number of countries have historically priced power at highly discounted rates of just a few cents per kWh to large-scale industrial and mining customers. These arrangements were initially justified as ways of locking in base-load demand to support the development of very large-scale power projects that went beyond the immediate demands of the country, but they have become increasingly questionable as competing demands have grown to absorb this capacity. Salient examples include the aluminum smelting industry in Cameroon and Ghana and the mining industry in Zambia (box 3.3).

Box 3.3 Electricity subsidies to large users in Zambia

On average the effective power tariff in Zambia—at \$0.03 per kWh—is among the lowest in Africa. The current average tariff does not recover operating costs, let alone total costs, even though Zambia has one of the lowest average costs in the region because of its felicitous combination of hydropower technologies and excess generation capacity.

The inefficient pricing is compounded by the exceptionally favorable prices that the power utility (ZESCO) offers to mining companies, particularly Copperbelt Energy Corporation. A long-term agreement sets mining tariffs at \$0.02 cents per kWh, one-third lower than the effective tariff for an average residential customer (100 kWh per month).

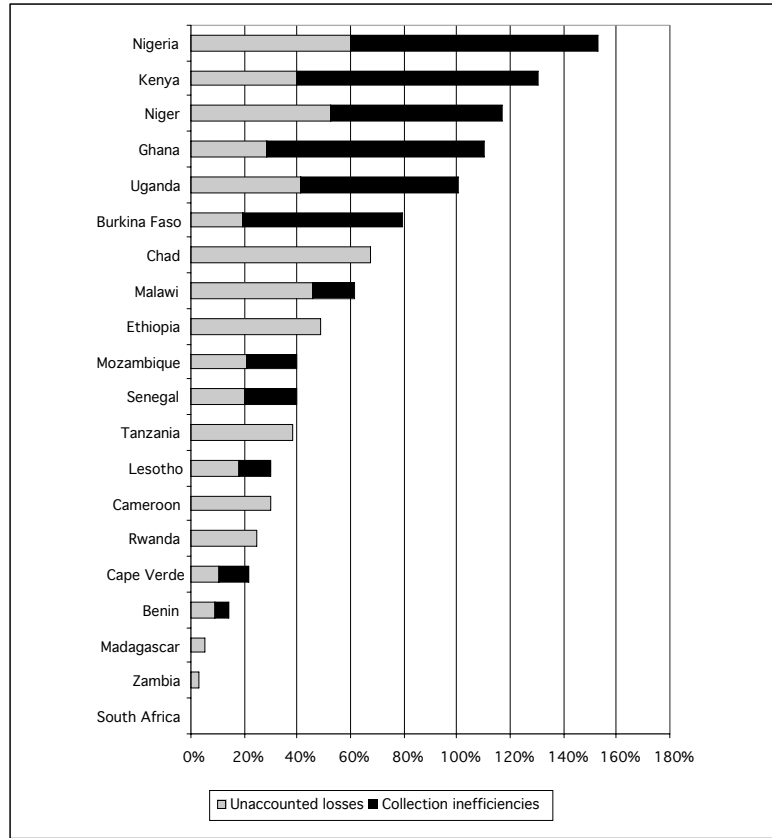
The mining sector accounts for 50 percent of the utility’s total sales and receives, by conservative estimate, \$30 million in annual subsidies. Cumulative deficits of \$926 million are projected over the next 10 years.

Source: Zambia Electricity Regulator Board, 2008; World Bank, 2008; Chivakul and York, 2006.

The underpricing and inefficiency of Sub-Saharan Africa utilities generate substantial hidden (or “quasi-fiscal”) costs for the economy. By aggregating the overall costs of inefficiencies attributable to distribution losses and undercollected revenues and expressing these as a percentage of utility turnover, it is possible to get an idea of the inefficiency of the different utilities in the sample (figure 3.8). The median utility presents inefficiencies equivalent to 50 percent of turnover, meaning that only two-thirds of revenues are captured. Performance varies across different utilities, with the highest level of inefficiency found in Nigeria, where inefficiencies amount to 150 percent of revenues. In other words, the utility is capturing only 25 percent of the revenues owed.

Following Ebinger (2006), these hidden costs may be quantified by comparing the revenues raised by each utility against those raised by an ideal reference utility that prices at full economic cost and keeps distribution and collection losses at best-practice levels. Applying this methodology, we find that these hidden costs, on average, amount to 1.8 percent of GDP in Sub-Saharan Africa and may be as large as 4 percent of GDP in some countries (figure 3.9). Around half of these costs stem from the underpricing of

Figure 3.8 Overall magnitude of utility inefficiencies as a percentage of turnover

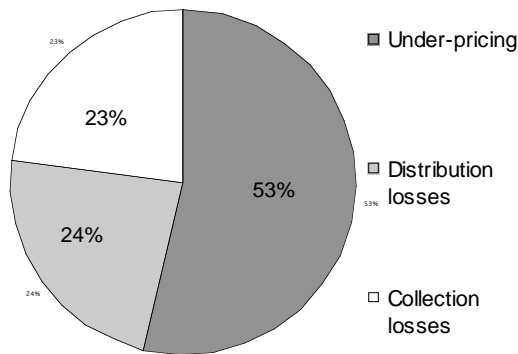


Source: AICD Power Sector Database, 2008.

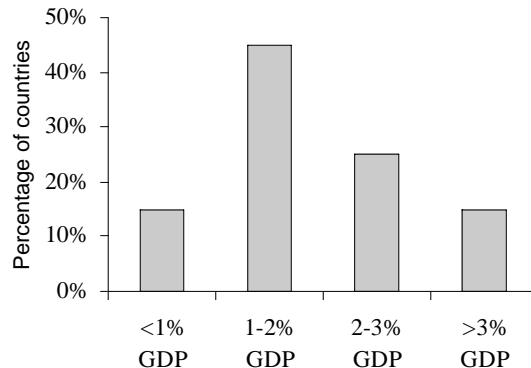
services and nearly 30 percent from distribution losses. These estimates suggest that the dividend from improving utility performance is in many cases very high (Briceño-Garmendia, 2008).

Figure 3.9 Hidden costs of power sector inefficiency by source and share of GDP

(a) Source of inefficiency



(b) Frequency distribution by scale of inefficiency

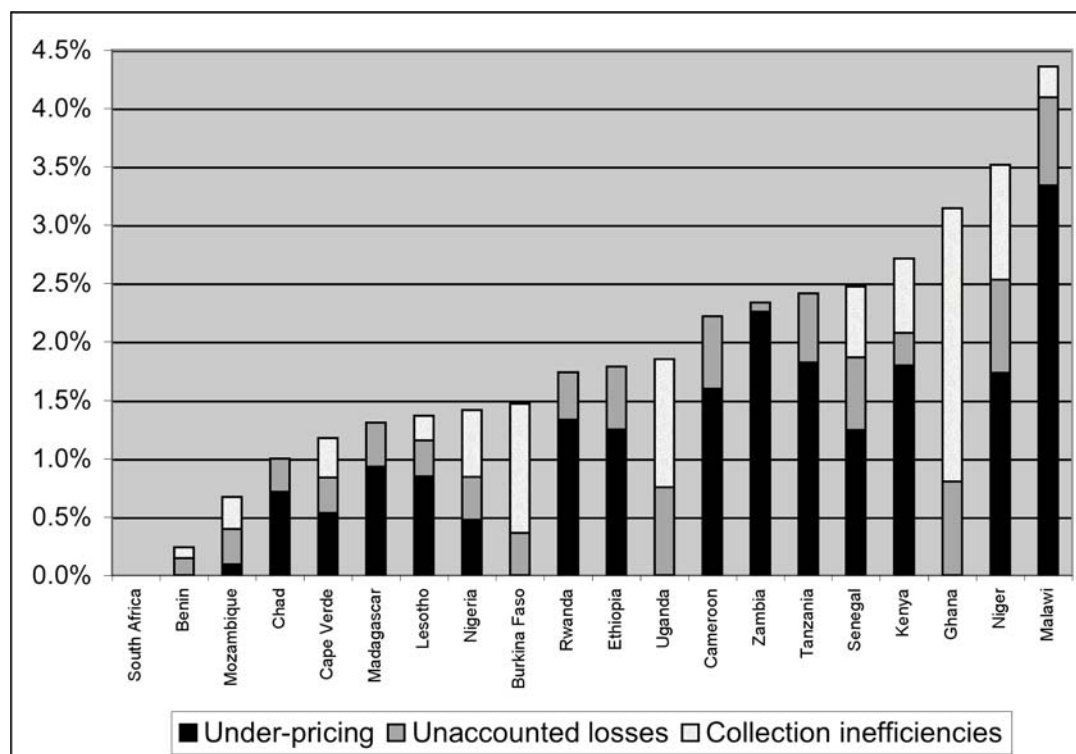


Source: AICD Power Sector Database, 2008.

The wide divergence in hidden costs across the countries of Sub-Saharan Africa is clearly illustrated in figure 3.10. One factor to note is the extent to which different countries face very different challenges

in reducing these costs. For example, in Cameroon, Tanzania, and Zambia, underpricing seems to be the major issue, whereas in Burkina Faso and Ghana, the problem is largely one of collection inefficiencies.

Figure 3.10 Country-level decomposition of hidden costs



Source: AICD Power Sector Database, 2008.

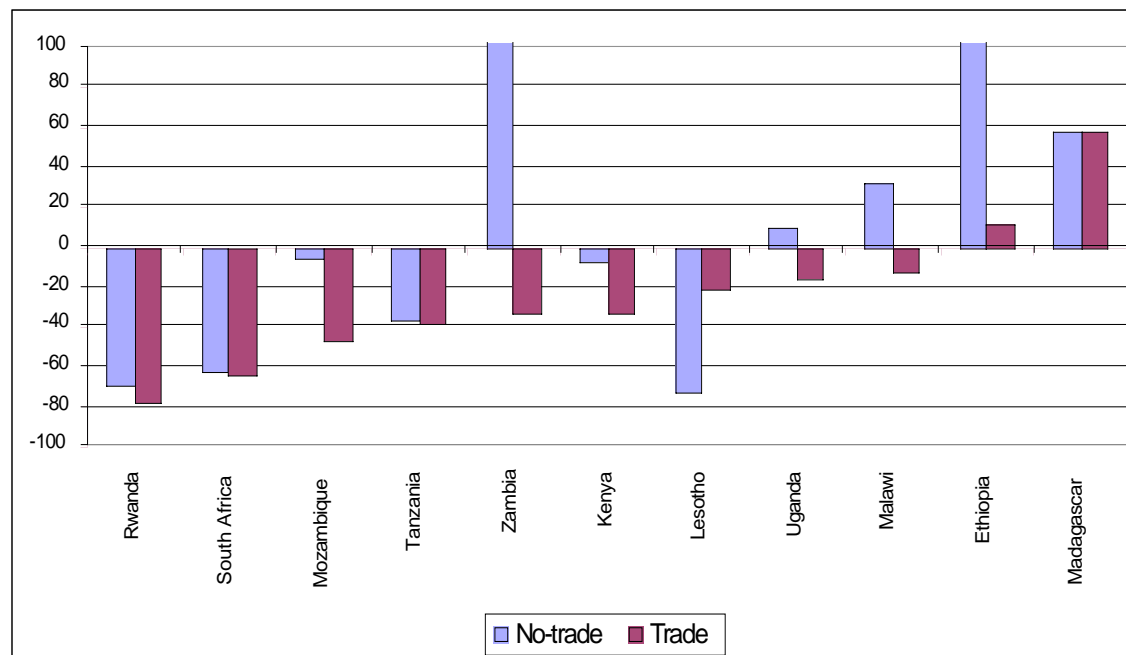
In most countries, underpricing is the main reason for the gap between costs and revenues, accounting on average approximately 1 percent of GDP, or 60 percent of total hidden costs in the sector. While this gap reflects subsidies that may serve worthy social purposes, the gap (and its source) is not generally revealed in the budget and is therefore hidden. The highest hidden costs from underpricing are found in Malawi (3.3 percent of GDP), Zambia (2.3 percent of GDP), Niger (1.7 percent of GDP), and Cameroon (1.6 percent of GDP) (Briceno-Garmendia, 2008).

What causes underpricing? Are tariffs too low? Are costs too high? Or are tariff structures inefficient? To answer these questions, we compare effective tariffs with cost-recovery tariffs and incremental costs, and then discuss the tariff structure.

Average tariffs and historical costs. Only in 10 out of 21 AICD countries (using available data) do effective tariffs cover historical operating costs, and only in 6 of these countries do effective tariffs cover total historical costs (annex 1, table 6). This means that for more than half of the countries in the sample, costs are not covered by tariffs even if capital requirements are not included in the costs. For more than three-quarters of the sampled countries, covering capital requirements would require at least partial subsidization. Given that tariffs are already high when compared with those in more developed regions,

and incomes are lower,⁹ further increases in effective tariffs are not likely to be affordable; the only feasible solution is to reduce hidden costs due to pricing inefficiencies.

Figure 3.11 Percentage change of average incremental costs relative to average historic costs with and without increased reliance on trade



Source: C. Briceno-Garmendia, 2008, based on data from the AICD Database.

Average tariffs and incremental costs. Although current tariffs are not high enough to cover the historic costs of power production, these costs could be significantly reduced if countries were able to access larger scale and lower cost generation options, in particular by regional power trade. The AICD Power Investment Needs studies estimates least cost investment plans both with and without greater reliance on power trade and finds that, with few exceptions, incremental costs of future power development are significantly lower than historical costs. If power trade is pursued to its fullest economically viable extent, all countries (except Madagascar and Ethiopia) would face lower average costs, reduced by about 40 percent on average (figure 3.11). Salient beneficiaries of trade would be Zambia, Uganda, and Malawi, which could cut their current average costs by about 25 percent under the trade-expansion scenario. (The effects of trade on power costs in the region are discussed further on in this paper.)

⁹ For comparison, recent residential prices in world regions are as follows: \$0.04/kWh in South Asia; \$0.07/kWh in East Asia and Pacific, Europe and Central Asia, and Latin America and the Caribbean; \$0.13/kWh in Sub-Saharan Africa; and \$0.15/kWh in the high-income countries (Foster and others, 2008). Gross national income per capita in purchasing power parity terms is \$1,861 in Sub-Saharan Africa, \$2,289 in South Asia, \$4,359 in East Asia, \$6,710 in the Middle East and North Africa, \$8,682 in Latin America, \$9,791 in Europe and Central Asia, and \$35,586 in the high-income countries.

Hidden costs can be reduced by one-fourth if power technologies are improved and production costs reduced. When factoring forward-looking investments, hidden costs, as a result of underpricing, decrease by 40 percent (to about 1.7 percent of GDP in the trade scenario) (table 3.2). These results suggest that hidden costs reflect not postponed investment plans but rather operational inefficiencies. Reducing the hidden costs of underpricing may be a significant source of fiscal space or resources in the power sector.

Table 3.2 Contribution of underpricing to hidden costs in power sector under different cost benchmarks

	Historical	Incremental, no-trade (% GDP)	Incremental, trade	Historical	Incremental, no-trade	Incremental, trade
				(% contribution to total quasi-fiscal costs)		
Lesotho	0.8	0.0	0.1	61.9	0.0	34.7
South Africa	9.6	0.0	0.0	99.9	0.0	0.0
Mozambique	0.1	0.0	0.0	14.0	0.0	0.0
Tanzania	1.8	0.6	0.6	75.3	61.4	59.4
Rwanda	1.3	0.0	0.0	76.8	0.0	0.0
Kenya	1.8	1.5	1.2	66.2	63.1	48.0
Uganda	0.0	0.0	0.0	0.0	0.0	0.0
Malawi	3.3	5.0	4.6	76.6	79.9	74.3
Zambia	2.3	6.2	6.1	96.5	97.4	95.1
Ethiopia	1.2	3.8	3.6	70.0	73.3	70.6
Madagascar	0.9	2.3	2.3	71.1	79.8	79.8
AVERAGES	2.11	1.77	1.69	64.39	41.34	41.99

Source: Briceno-Garmendia, 2008, based on data from the AICD Database.

Tariff structures. Residential tariff structures differ substantially across AICD countries. Eleven of twenty-two AICD countries with available data have increasing block tariffs, eight have flat tariffs, and three have decreasing block tariffs. The tariffs range from \$0.01/kWh to \$0.25/kWh, depending on the country and the consumption level. In addition to tariffs, in thirteen out of twenty-two countries residential customers pay a fixed monthly charge for power,¹⁰ which ranges from \$0.15 per month to \$22 per month. Considering the low usage of the majority of customers, a high fixed charge can substantially increase effective tariffs and make the tariff structure inefficient, with customers in higher-consumption brackets paying approximately the same, or even a lower effective tariff, than those in the low-consumption brackets, and with low-income households cross-subsidizing higher-income ones.¹¹

These outcomes resemble the conclusions of a more detailed analysis based on different data sources (mostly household surveys) carried out by Wodon and others (2008). The authors show that for three levels of household consumption (50 kWh/month, 100 kWh/month, and 150 kWh/month) the average unit cost per kWh is essentially the same—for three main reasons: (a) all households benefit from the subsidized lower part of their consumption, (b) price differences between the various tariff blocks are not

¹⁰ The following countries have monthly charges for electricity: Burkina Faso, Ghana, Kenya, Madagascar, Malawi, Mozambique, Namibia, Nigeria, Senegal, South Africa, Tanzania, Uganda, and Zambia.

¹¹ Because of high fixed monthly charges or decreasing block tariffs, effective tariffs decrease with increased consumption in the following ten countries, causing low-consumption groups to subsidize higher-consumption and higher-income groups: Burkina Faso, the Democratic Republic of Congo, Ethiopia, Madagascar, Malawi, Namibia, Senegal, South Africa, Tanzania, and Zambia (annex 1, table 4).

necessarily high, and (c) the lower blocks of consumption tend to be high, so a large share of total consumption is subsidized. The authors conclude that electricity tariff structures in Africa tend not to be highly differentiated by consumption levels, preventing the implicit subsidies in those tariffs from helping those who consume the least.

Comparing effective residential tariffs with effective low-voltage commercial tariffs, one can see that the latter are higher for six out of nine AICD countries with currently available data¹² and lower in South Africa, Tanzania, and Uganda, suggesting a possibility of cross-subsidization from domestic to low-voltage commercial consumers in these three countries. Similarly, effective commercial low-voltage tariffs in most countries with available data differ only very modestly, if at all, depending on the volume consumed. In fact, in seven out of nine countries with available data, effective low-voltage commercial tariffs decrease at higher levels of consumption (Malawi, South Africa, Kenya, Lesotho, Namibia, Tanzania, Uganda, and Zambia) (SADELEC, 2006; AICD, 2008). This suggests that within the commercial sectors in these countries, customers with lower consumption levels cross-subsidize those with higher ones.

Break-even levels of consumption (measured in kWh) are generally high and in many countries exceed average consumption levels—the reasons being the same as for the earlier observed decrease in effective tariffs with increased consumption volume. Table 4 in annex 1 presents break-even consumption levels based on historical operating and total costs. Break-even consumption ranges from 12.5 kWh in Ethiopia (operational costs) to 722 kWh in the Democratic Republic of Congo (total costs). For most of the AICD countries the break-even points based on operational and total costs are not dramatically different. Only for 6 of 22 countries (with available data) did the break-even level of monthly consumption based on total cost fall below 100 kWh, a commonly used benchmark for residential customers. Only in 11 countries is the break-even consumption level based on operational costs below 100 kWh.

Extensive subsidies are in place, but power remains expensive for many

Power is expensive for millions of African households, despite near-universal subsidies, because those the great bulk of those subsidies never reaches the poor—and because so many poor households are not connected to the power grid and thus cannot benefit from consumption subsidies.

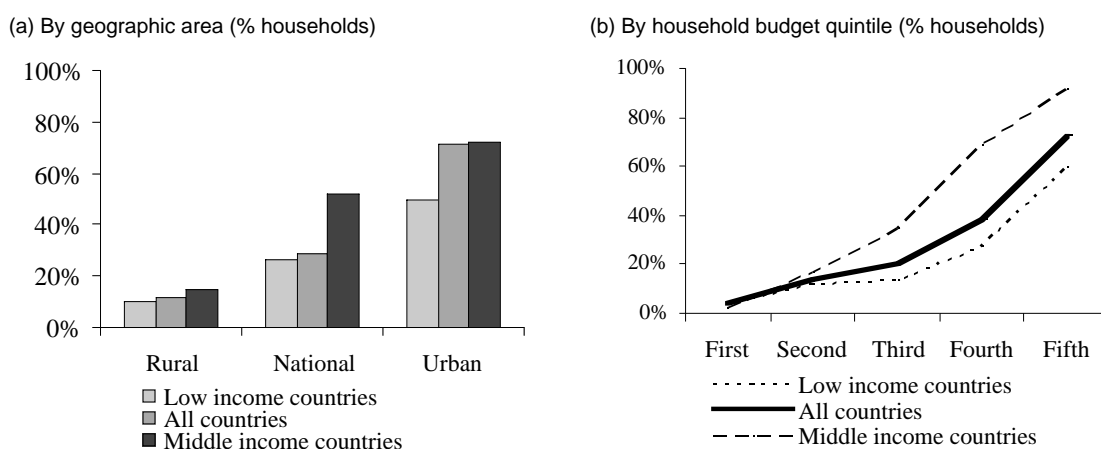
Wodon and others (2008) use evidence from household surveys to analyze the distribution of power sector subsidies in 18 countries of Sub-Saharan Africa. To measure targeting performance, the authors use a coefficient, Ω , that represents the share of the subsidies received by the poor divided by the proportion of the population in poverty. A value of Ω less than 1 implies that the poor receive a proportion of the benefits smaller than their weight in the population, and hence the subsidy is regressive. A value of Ω greater than 1 conversely implies that the subsidy is progressive. The results of the study

¹² The data source for low-voltage commercial customers is SADELEC (2006). The countries with available commercial data are Kenya, Lesotho, Malawi, Mozambique, Namibia, South Africa, Tanzania, Uganda, and Zambia. We do not include here a comparison with large industrial consumers, as the role of effective tariffs is very different for that group.

find that in all countries considered, the Ω coefficient takes a value well below 1, indicating that power sector subsidies are highly regressive.

The reasons for this finding are clear enough when one considers the patterns of access to electricity in Sub-Saharan Africa (figure 3.12). Across the bottom half of the income distribution, barely 10 percent of households have access to electricity; indeed, three-quarters of households with electricity come from the top two quintiles of the income distribution. Similarly, disparities are evident across geographic areas. Thus, while around 70 percent of households in urban areas have access to electricity, barely 10 percent of rural households are connected to the grid. Because poorer households are almost entirely excluded from the power grid, they cannot benefit from subsidies embedded in electricity prices. In many cases, targeting performance is further exacerbated by poor tariff design, with widespread use of increasing block tariffs that provide relatively large blocks of highly subsidized power to all consumers.

Figure 3.12 Patterns of electricity service coverage in Sub-Saharan Africa



Source: Banerjee and others, 2008; AICD Power Sector Database, 2008.

The concentration of household connections to the power grid among upper-income customers might lead one to believe that full cost-recovery pricing would be the way forward. But the reality is more complex. In the low-income countries of Sub-Saharan Africa, even households in the highest-income quintile have monthly budgets of only \$260 to support families typically comprising five people. Even a very modest consumption of 50 kWh per month¹³ at a full cost-recovery price of \$0.25 per kWh (found in some countries of Sub-Saharan Africa) would mean an electricity bill of \$12 per month, representing close to 5 percent of the income of a relatively well-to-do family living on \$260 per month. (Five percent is often considered to be the affordability threshold for electricity services.)

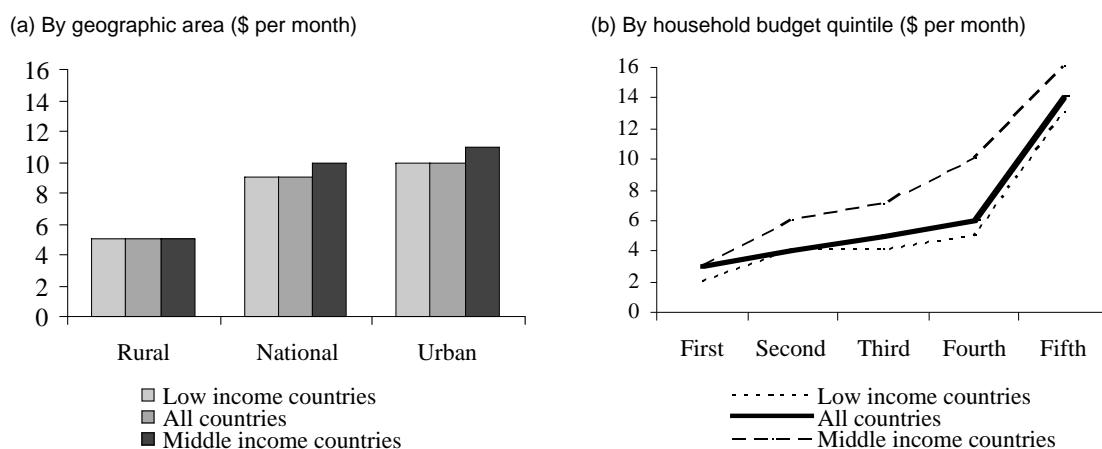
Banerjee and others (2008) perform this type of affordability analysis based on household survey evidence across a wide range of Sub-Saharan Africa countries and conclude that, with the exception of a relatively small group of the middle-income and better-off low-income countries (such as Cameroon, Cape Verde, Côte d'Ivoire, the Republic of Congo, Senegal, and South Africa), a very substantial share of the population in most countries would be unable to afford cost-recovery tariffs. Indeed, as of today,

¹³ 50 kWh per month would power lights and perhaps a television but little more; it would not be enough for cooking, refrigeration, air-conditioning, or heating.

expenditure levels among households with electricity service are significantly below this level (figure 3.13).

If costs could be reduced to \$0.12/kwh—in line with the region’s average incremental cost of power—the resulting monthly bill of \$6 would be affordable for most of the population, except in the lowest-income countries (such as Burundi, the Democratic Republic of Congo, Ethiopia, Malawi, and Uganda).

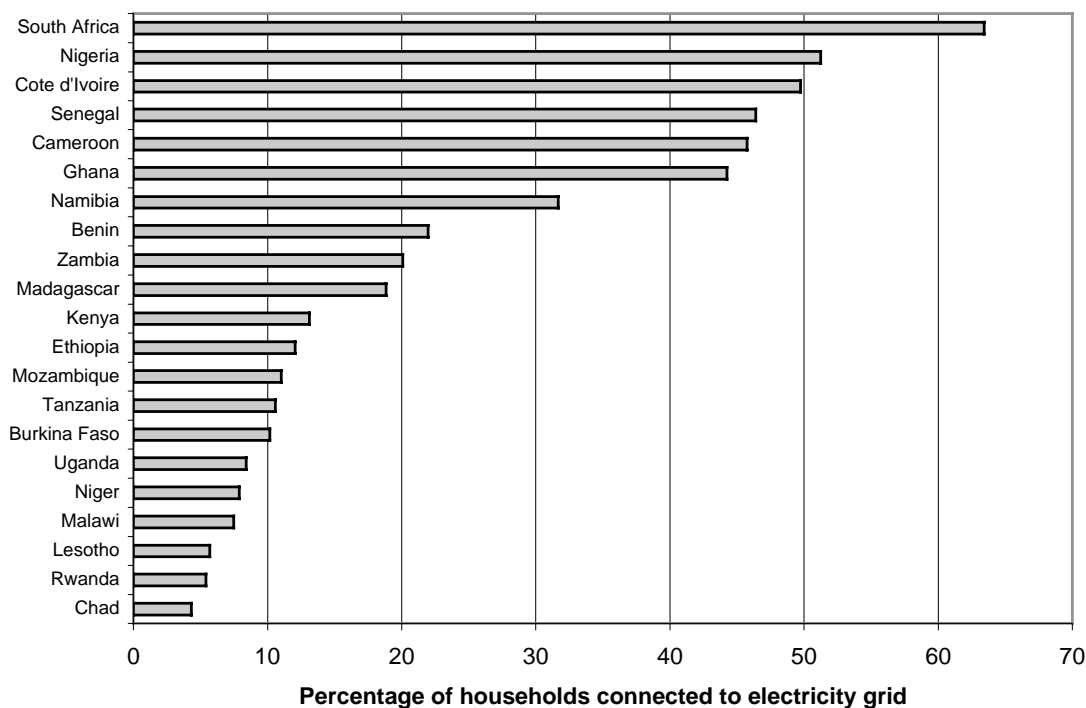
Figure 3.13 Patterns of electricity service expenditure in Sub-Saharan Africa



Source: Banerjee and others, 2008; AICD Power Sector Database, 2008.

Electrification agencies and funds abound, but access rates remain low

Electrification rates remain pitifully low in Sub-Saharan Africa. On average, only a fifth of the population has access to electricity (figure 3.14). A few countries—such as Cameroon, Côte d’Ivoire, Ghana, Nigeria, and Senegal—have made some progress, and close to half their people now have access. Over the past 15 years, South Africa has more than doubled its access rates from a third of households to around 70 percent. Gabon has even higher rates. But these are exceptions, and most countries of Sub-Saharan Africa lag far behind. For example, Kenya’s figure is only 13, Uganda’s is 8, and Chad’s is 4 percent.

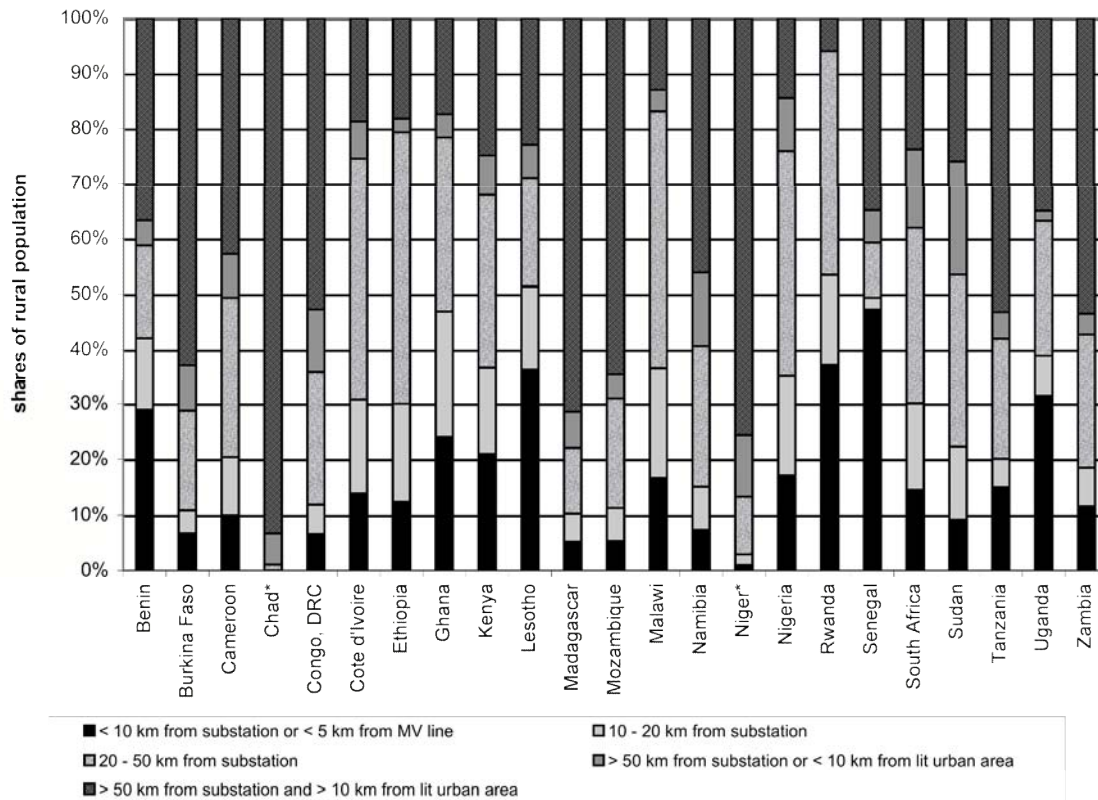
Figure 3.14 Electrification rates in the countries of Sub-Saharan Africa, latest year available

Source: AICD Power Sector Database, 2008.

Despite accelerating urbanization, the region's rural areas still account for about two-thirds of the total population, presenting significant challenges in raising access rates. It is obviously cheaper to electrify urban areas, followed by higher-density rural areas. Off-grid technologies such as solar photovoltaic panels become an option in remote areas, but are still very expensive—typically \$0.50–0.75 per kWh. Minigrids, where feasible, are more attractive options in remote areas, especially when combined with small-scale hydropower facilities (ESMAP, 2007).

Some countries have a much higher potential for making rural electrification advances more cost effective, as a higher proportion of their population lives close to existing networks (figure 3.15). Thus Benin, Ghana, Lesotho, Rwanda, Senegal, and Uganda are more favorably positioned than, for example, Burkina Faso, Chad, Madagascar, Mozambique, Niger, Tanzania, or Zambia.

Figure 3.15 Potential rural access: distribution of population by distance from substation



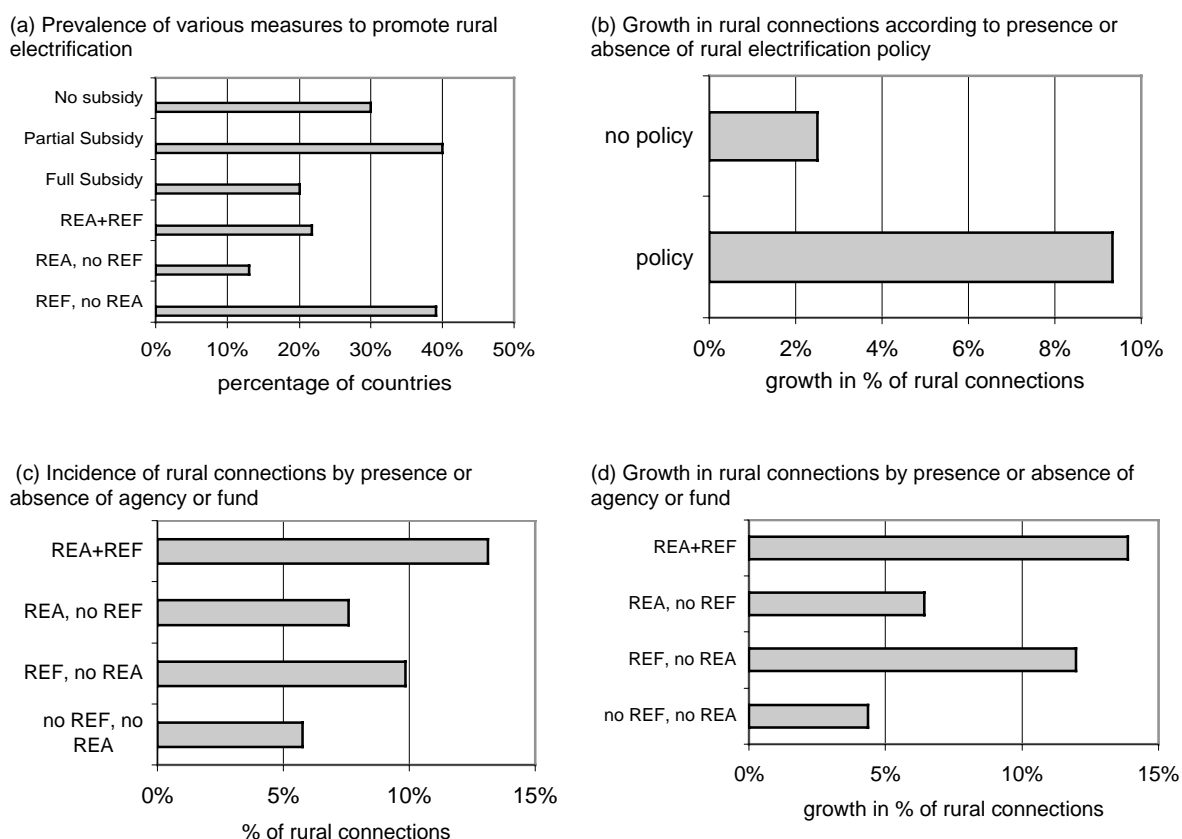
Source: AICD 2008.

Note: TX lines not available for Chad or Niger, so "remote" potential service area is overestimated.

Incumbent national utilities—mostly state owned and vertically integrated—are responsible for urban electrification and often for rural electrification as well. A significant trend over the last decade, however, has been the establishment of special-purpose agencies and funds for rural electrification. Half the countries in the AICD sample have rural electrification agencies (REAs) and more than two-thirds have dedicated rural electrification funds (REFs). Funding sources for REFs may be levies, fiscal transfers, donor contributions, or combinations of these. 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). In some cases, political pressures trump these criteria.

How effective have these institutional and funding mechanisms been in accelerating rural electrification? On average, greater progress has been made in those countries with electrification agencies and, especially, dedicated funds (figure 3.16). Having a clear set of electrification criteria also makes a difference.

Figure 3.16 Rural electrification agencies, funds, and rates in Sub-Saharan Africa



Source: AICD (Power Sector Database), 2008.

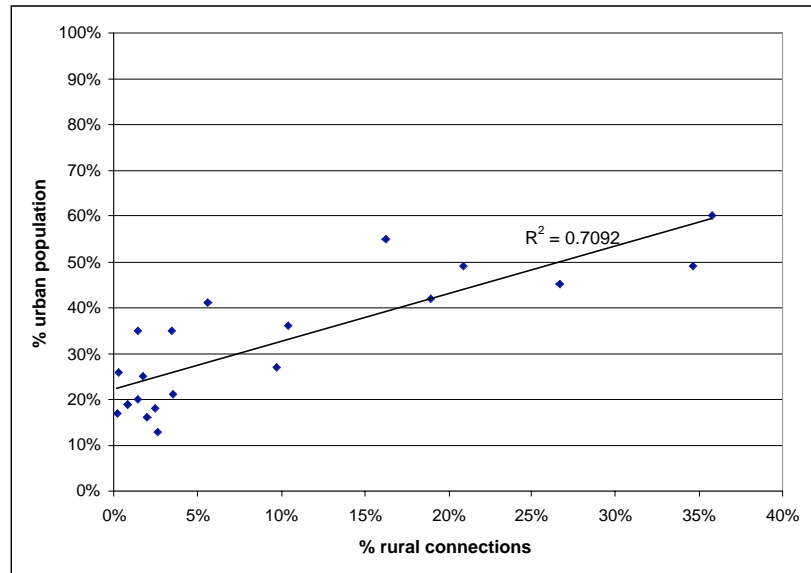
Note: REA = rural electrification agency; REF = rural electrification fund.

Countries with higher urban populations also tend to have higher levels of *rural* electrification, because urban customers tend to cross-subsidize rural electrification (figure 3.17). Surprisingly, we could find no correlation between the proportion of utility income derived from nonresidential electricity sales and the level of or growth in residential connections. One would have expected that increased revenue from industrial and commercial customers would also allow for the cross-subsidization of rural electrification.

A recent review of electrification agencies in Africa has concluded that centralized approaches, in which a single utility is responsible for national rural electrification, have been more effective than decentralized approaches involving several utilities or private companies (Mostert, 2008)—provided the national utility is reasonably efficient. Ghana and Côte d’Ivoire are examples of countries that have made good progress with a centralized approach to rural electrification. South Africa, too, has relied mainly on its national utility, Eskom, to undertake rural electrification, with considerable success. In contrast, countries such as Burkino Faso and Uganda have made slow progress, and rural electrification rates remain very low. These are obviously very poor countries, but it is also noteworthy that they have allowed their REFs to recruit multiple private companies on a project-by-project basis rather than making their national utilities responsible for extending access.

At first glance, the findings of the Mostert study (2008) would appear to contradict our previous findings that countries with electrification funds (and to a lesser extent, agencies) tend, on average, to perform better in electrification. It should be noted, however, that Mostert's categorization of countries that rely on central utilities for electrification, on the one hand, versus those with REFs and REAs, on the other, doesn't match the situation in many countries where the two approaches complement each other. For example, South Africa

Figure 3.17 Countries' rural electrification rates by percentage of urban population



Source: AICD Power Sector Database, 2008.

has an electrification fund, but Eskom is responsible for rural electrification. The purpose of the fund is to ring-fence subsidy sources from commercial revenue earned by the utility. Electrification funds create transparency around subsidies and thus help avoid situations where utilities face mixed social and commercial incentives.

Decentralized rural electrification often makes most sense when applied to the implementation of off-grid projects and as a way of exploiting the private initiatives of small-scale entrepreneurs and motivated communities. Mostert (2008) cites successful examples of this approach in Ethiopia, Guinea, and Mozambique. The lesson is that it may be unrealistic to allocate responsibility for *all* electrification to separate electrification agencies, but that these agencies should focus mainly on minigrid or off-grid options, complementing the efforts of the main utility charged with extending grid access.

Box 3.4 Ghana's electrification program

Ghana boasts a national electrification rate of nearly 50 percent. Urban rates of access hover around 80 percent, and rural rates at approximately 20 percent. With popular access to electricity access at less than 25 percent in the region, Ghana's recent electrification experience may be instructive for other countries of the region.

Starting in 1989, when Ghana's access rates were estimated at 20 percent and grid supply covered only one-third of the country's land area, electrification efforts were intensified under the National Electrification Scheme (NES) designed to connect all communities with a population of more than 500 to the national grid between 1990 and 2020.

The National Electrification Master Plan subsequently laid out 69 projects spanning 30 years that would realize the stated policy goal. The first two five-year phases of the plan were undertaken between 1991 and 2000, with the country's two state-owned utilities, Electricity Company of Ghana (ECG) and the Volta River Authority (VRA), charged with implementation. A rural electrification agency was not used. Project costs of \$185 million were covered largely via concessionary financing from several multilateral and bilateral donors.

In addition to the central role of the utilities and the prominence of concessionary lending, noteworthy was the Self-Help Electrification Programme (SHEP) in advancing the aims of the NES. SHEP was the means by which communities, within a certain proximity to the network and otherwise not targeted for near-term electrification, were able to be connected by purchasing low-voltage distribution poles and demonstrating the readiness of a minimum number of households and businesses to receive power. SHEP was further supported by a 1 percent levy on electricity tariffs.

As of 2004, efforts under the NES led to the electrification of more than 3,000 communities. Contrary to expectation, however, an indigenous industry to supply products for the electrification program has not taken off. Furthermore, SHEP is now considered defunct, having not been able to sustain itself financially. The NES continues, however, cofinanced by development finance institutions and local Ghanaian banks, and with an increasing emphasis on minigrids and stand-alone systems.

Source: Eberhard and others, 2005; Mostert, 2008.

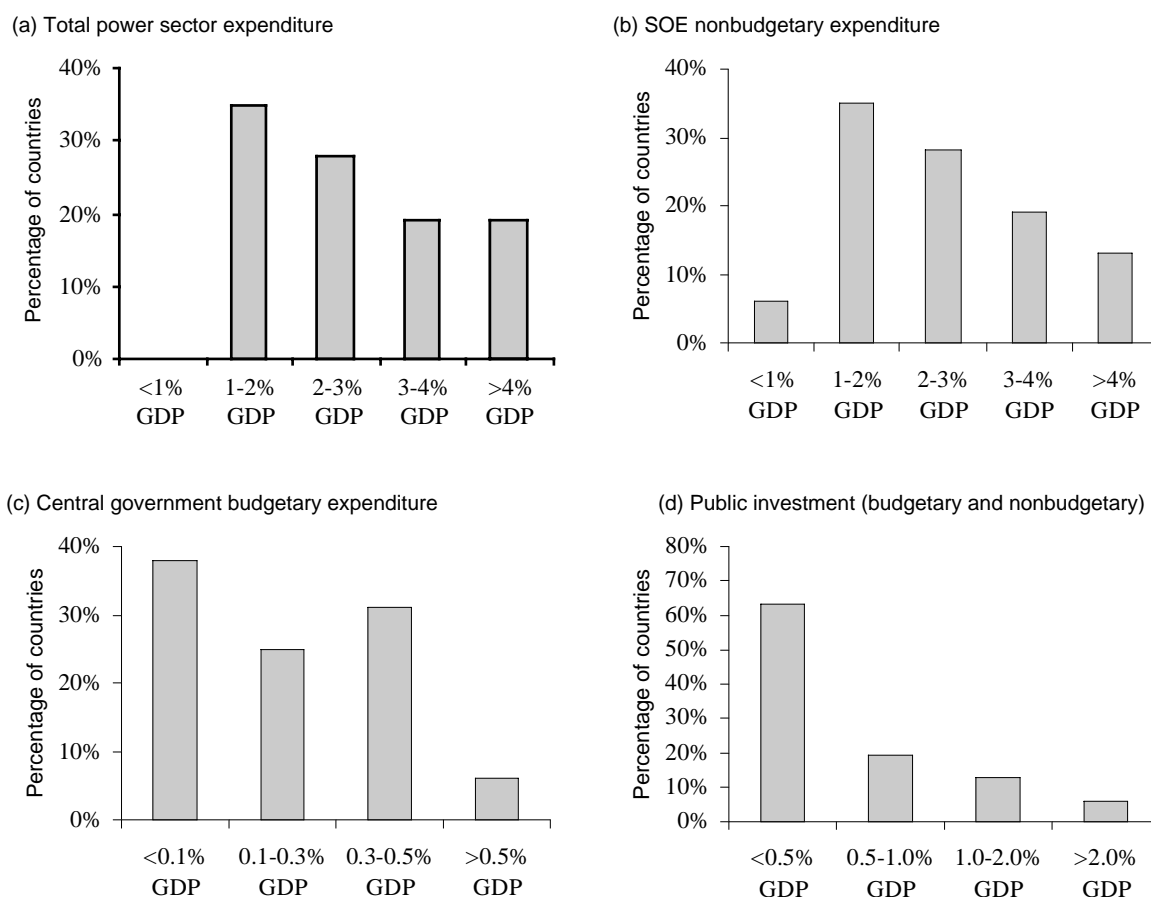
High levels of spending do not ensure adequate financing

The countries of Sub-Saharan Africa, on average, spend 2.7 percent of their GDP on their power sector; with a number of countries spending in excess of 4 percent (figure 3.18). Typically more than 90 percent of that spending is channeled through the national state-owned power utility, with less than 10 percent appearing in the central government budget. With operating costs absorbing 75 percent of total spending, public investment in the sector is very low—invariably less than 0.5 percent of GDP. Most of the public investment that does occur is undertaken by SOEs, even though these devote less than 20 percent of their spending to capital. Some 80 percent of the small share of funding that moves through central government budgets is also devoted to capital investment (Briceño-Garmendia and Smits, 2008).

The contribution of official development assistance (ODA) to public investment in the power sector has been modest, averaging only \$700 million per year in the last decade. Support has also been highly volatile, descending into a trough of only a few hundred million dollars per year in the late 1990s and rising back toward the \$1 billion mark in the late 2000s. Notwithstanding the substantial number of private sector transactions documented above, the overall value of private investment in the sector has averaged just \$300 million per year during the last decade; once again the flows have been highly volatile. Total external capital flows to the power sector in Sub-Saharan Africa, taking ODA and PPI together,

amount to no more than 0.1 percent of the region’s GDP, according to statistics compiled by the OECD Development Assistance Committee (OECD, 2006).

Figure 3.18 Frequency distribution of power sector expenditure



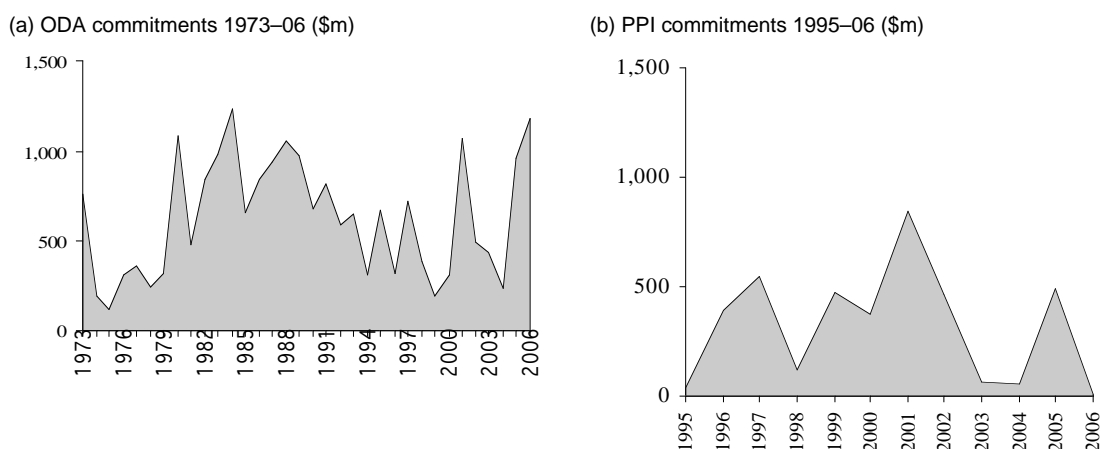
Source: Briceño-Garmendia and Smits, 2008; AICD Power Sector Database, 2008

In recent years, the China Ex-Im Bank has emerged as a major new financier of power infrastructure in Sub-Saharan Africa. Over the period 2001–06, Chinese financing commitments to the Sub-Saharan African power sector averaged \$1.7 billion per year—more than ODA and PPI combined, and equivalent to around 0.2 percent of the region’s GDP. The major focus of Chinese support has been the development of six large hydropower projects with a combined generating capacity of over 7,000 MWs of electricity. Once completed, these projects should increase the region’s installed hydropower capacity by 40 percent. An additional 2,500 MWs of thermal power are being financed by China. The India Ex-Im Bank has also financed some significant thermal generation projects in Nigeria and Sudan (Foster and others, 2008).

It is instructive to compare historic spending trends with the estimated investments needed to reverse the region’s current power shortages. Numerous econometric analyses indicate that the elasticity of power sector demand with respect to economic growth is around unity. With recent, sustained GDP growth rates in Sub-Saharan Africa of around 5 percent per year, power-generation capacity should be growing at a

similar rate to keep pace with the demands of the growing economy. Since 1980, however, the annual growth rate of generation capacity in Sub-Saharan Africa has averaged only 2.9 percent.

Figure 3.19 Long-term trends in external finance for the power sector in Sub-Saharan Africa



Source: OECD, 2006; Infrastructure Consortium for Africa, 2007; and World Bank PPI Database, 2007.

Regional power pools, but little current trade

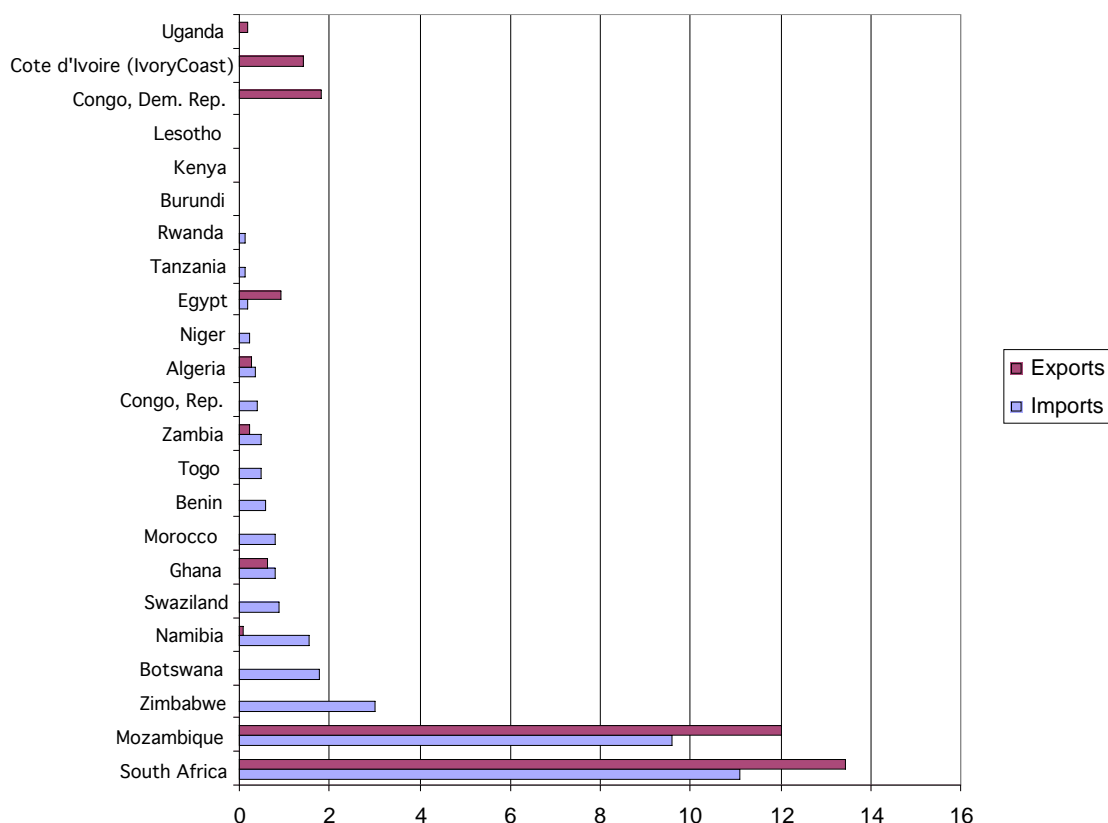
Four regional power pools operate in Sub-Saharan Africa, established for the purpose of promoting mutually beneficial cross-border trade in electricity. The theory was that enlarging the market for electric power beyond national borders would stimulate investment in economic generation in countries with a comparative advantage. The pools would also serve to smooth out temporary irregularities in supply and demand within national markets.

Despite the high hopes for the regional power pools, the quantities of electricity production traded between countries are still very small. Most of today's trade occurs within the Southern Africa Power Pool (SAPP), largely between South Africa and Mozambique. Much of the electricity that South Africa imports from Mozambique is reexported to Mozambique's aluminum smelter. A few countries are highly dependent on imports. In the SAPP, Botswana, Namibia, and Swaziland all depend on imports from South Africa (figure 3.20). In the West Africa Power Pool (WAPP), the second-largest trading pool, Benin, Togo, and Burkina Faso import power from Côte d'Ivoire and Ghana, while Niger buys from Nigeria. Miniscule amounts of power are traded in Central Africa, although Burundi, Rwanda, and Republic of Congo depend on imports from the Democratic Republic of Congo. Electricity trade in East Africa is also tiny.

The main exporting countries generate electricity from hydropower (the Democratic Republic of Congo, Mozambique, Zambia), natural gas (Côte d'Ivoire and Nigeria), or coal (South Africa), South Africa reexports imported electricity from hydropowered sources. No country that relies mainly on oil or diesel generators exports electricity.

Figure 3.20 Electricity imports in Sub-Saharan Africa, 2005

terawatt hours, TWh



Source: Energy Information Administration, 2007.

Despite only modest trade to date, power pools such as the SAPP have made some progress in developing the standard agreements that will be necessary if trade is to grow. A short-term energy market has also been developed by the SAPP, which enables daily Internet trading. The overall volumes are

small, however. The Regional Electricity Regulators Association has as one of its aims the harmonization of regulatory regimes in the region, but progress has been limited to agreement on basic principles rather than detailed regulations. The WAPP also aims to achieve closer regulatory integration in West Africa.

Despite limited progress, the potential benefits of increased trade are significant. A recent study constructed a series of optimization models for each of Africa's major regional power pools in order to

Table 3.3 Regional trade in electricity, 2005

	Consumption TWh	Imports, TWh	Exports, TWh	Percentage electricity traded
CAPP	8.80	0.01	1.80	0.1
EAPP	13.41	0.28	0.18	2.1
SAPP	233.97	22.71	25.74	9.7
WAPP	28.63	1.63	2.04	5.7

Source: EIA, 2008.

estimate the investments required in the electricity sector (Econ Analysis, 2008). The model is flexible enough to accommodate the effects of different assumptions about the extent of regional power trade, the pace of economic growth, access targets, and the price of key inputs, notably oil and gas.

To achieve an overall electrification rate of 35 percent by 2015 while taking full advantage of regional power trade, the countries in the SAPP would need to add around 32,000 MW of new capacity and to refurbish 28,000 MW of existing capacity. Transmission and distribution lines would have to be extended and refurbished to transport power to consumers. The subregion's total investment requirement through 2015 would be \$68 billion. To reach similar levels of access by 2015, the East Africa Power Pool (EAPP) would have to invest \$51 billion to add 25,000 MW in new generating capacity, refurbish existing capacity, and beef up transmission and distribution infrastructure. The annualized costs of system expansion (investment and refurbishment) in that scenario would be more than \$17 billion in the SAPP, corresponding to 2 percent of GDP, and more than \$13 billion in the EAPP, or 2.5 percent of GDP (table 3.4). Notwithstanding significantly expanded access, the bulk of the expenditure requirements are associated with the generation segment.

Table 3.4 Overview of annualized power sector expenditure requirements to 2015

\$ million	Total	Investment	Refurbishment	Operating expenditure	Generation	Transmission and distribution
EAPP	13,158	6,133	485	6,540	9,971	3,187
SAPP	17,681	6,797	2,554	8,330	10,956	6,724

Source: Econ Analysis, 2008.

These regional averages for expenditure requirements conceal huge variations across countries. In particular, because of the strong geographical concentration of energy sources, the burden of investment as power trade develops will fall disproportionately on those countries with abundant energy resources. To justify those investments, the legal and institutional mechanisms underpinning the regional power pools will have to be strengthened.

In a handful of cases (and under certain scenarios) the annualized power sector investment requirement exceeds 10 percent of GDP, driven largely by investment in power-generation assets for export. The most prominent examples are Ethiopia and the Democratic Republic of Congo, which, if trade developed toward economic optimality, would each become the major exporters of hydropower in the EAPP and the SAPP, respectively. Because the projects would be designed to meet foreign as well as domestic demand, a sizeable chunk of the financing might be underwritten to some degree by importing countries. Even so, the financing requirements are huge, and various obstacles may be foreseen, including governments reluctant to expose their electricity supply to the vagaries of regional politics and potential risks of conflict.

From a strictly economic point of view, however, the model reveals the major potential that exists for the expansion of cross-border power trade in Sub-Saharan Africa. For example, in the SAPP alone, the volume traded internationally could rise from the current 45 to 141 TWh per year (table 3.5) (Econ Analysis, 2008).

To accommodate expanded trade in power, additional investments in cross-border transmission links would be required, but these would pay for themselves by opening access to cheaper power. In this sense it is possible to calculate the gains from trade as the rate of return on additional cross-border investments. These vary considerably across regions—from 20 percent in Eastern Africa to 167 percent in Southern Africa (table 3.5)—but in all cases the rates of return exceed typical hurdles for public investment. Under a regime of optimal trade, several smaller countries would come to depend on imports to satisfy more than 50 percent of domestic demand for power.

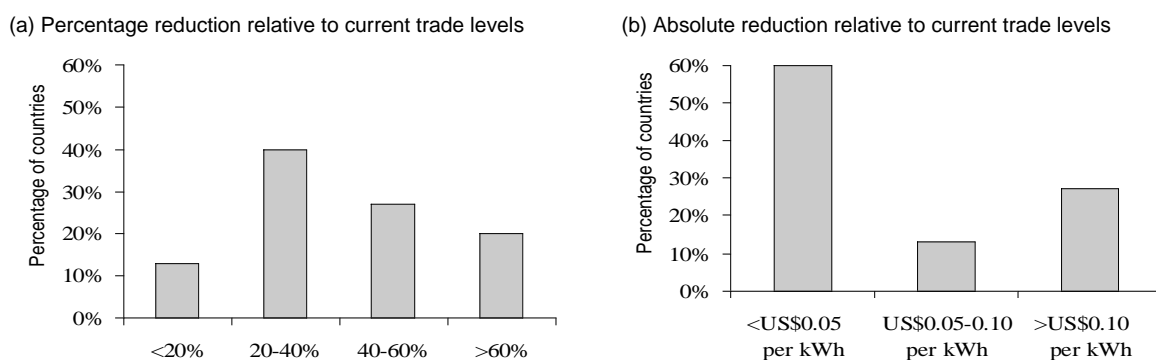
Table 3.5 Overview of power trade flows under different trading scenarios

	Benefits of power trade		Absolute trade flows (TWh per year)	
	Rate of return on investment (%)	Annualized cost saving (%)	Current	Potential
EAPP	20	7.6	0.5	75.2
SAPP	167	8.2	45.2	141.6

Source: AICD Power Sector Database, 2008, Econ Analysis, 2008.

The overall savings in the annualized cost of the power sector under trade is relatively small, at less than 10 percent. But for individual countries the gains from cheaper power may be substantial. Under trade, most countries would see reductions in the average cost of power of a few cents per kWh, representing savings of 20–60 percent (figure 3.21). For a handful of countries, however, the gains would be as much as \$0.10 per kWh, representing a saving of more than 60 percent.

Figure 3.21 Frequency distribution of savings in the average incremental cost of power resulting from trade



Source: Econ Analysis, 2008; AICD Power Sector Database, 2008.

The main effect of cross-border trade in power would be to support the development of large-scale hydropower schemes that would not be viable at the national level. As a result, the composition of the generation portfolio with expanded trade would shift toward hydropower by 10–15 percentage points relative to the case if trade stagnated at present levels. The additional hydropower would displace natural gas generation in Eastern Africa and coal generation in Southern Africa. A related consequence would be to increase the share of power coming from key export countries such as Ethiopia in East Africa and the Democratic Republic of Congo in Southern Africa. Nevertheless, irrespective of trade development, the major power consumers—Egypt, Nigeria, and South Africa—would continue to be, by far, the main producing countries in each respective regional power pool.

In modeling the investment required to meet future demand, we have focused on the supply side in the form of capacity-expansion options. The financial constraints to meeting these huge investment needs are obvious, and it may not be realistic to expect that all of the required finance will materialize. A pragmatic approach would need to supplement supply-side investments with demand-side measures that would help improve energy efficiency, reduce the need for some supply-side investments, and strengthen the basis for sustainable development in Sub-Saharan Africa.

4 The way forward

No country in Sub-Saharan Africa has an unbundled, private electricity sector with wholesale and retail competition. Instead, one finds what might be termed “hybrid” power markets. In most cases, the old state-owned utility remains intact and occupies a dominant market position. At the same time, because many governments and utilities lack sufficient investment resources, the private sector is being introduced, typically in the form of independent power producers (IPPs). Africa’s hybrid electricity markets pose new challenges in policy, regulation, planning, and procurement. The widespread power shortages across the continent and the increasing reliance on emergency power are indicative of the seriousness of those challenges.

Wanted: ways to make hybrid markets work

Traditionally, planning and procurement of new power infrastructure were the province of the state-owned utility. With the advent of power sector reforms and the introduction of IPPs, those functions were often moved to the ministry of energy or electricity. A simultaneous transfer of skills did not always occur, however, resulting in plans that were not adequately informed by the complexities on the ground, namely the new hybrid market, composed of private and public actors. In many cases planning has collapsed. Where still present, planning tends to take the form of outdated, rigid master plans.

In the absence of strong political leadership, good information, and the requisite planning capability, incumbent state-owned utilities often undermine the entry of IPPs by arguing that they are able to supply power more cheaply or quickly than private alternatives, even if they lack the resources to do so. Poor understanding of the hybrid market deprives policy makers of clear and transparent criteria for allocating new plants between the incumbent, state-owned utility and IPPs. New plants are rarely ordered on a timely basis, opening power gaps that prompt recourse to temporary power and discourage investors. When procurement is (finally) undertaken, the authorities may not take the trouble to conduct international competitive bidding. This is unfortunate, because a rigorous bidding process lends credibility and transparency to the procurement and results in more competitively priced power.

Hybrid power markets will not disappear from the African landscape anytime soon. To make the best of them, African governments and their development partners must strive to develop a robust institutional foundation for the single-buyer model, with clear criteria for power purchase (offtake) agreements and dispatches of power under those agreements. They must nurture their planning capabilities, establish clear policies and criteria for allocating new plant opportunities between the state-owned utilities and IPPs, and commit to competitive and timely bidding processes. Development partners can help by providing advice

on transparent contracting frameworks and processes, and by lending expertise to governments and utilities as they seek to reach financial closure with project sponsors and private investors.

Development finance institutions and bilateral donors must tread carefully here. If done without adequate attention to the peculiarities of the hybrid market, lending to public utilities may have the unintended effect of deepening the contradictions inherent in those markets and even crowding out private investment. What is needed above all is to strengthen public institutions to enable them to engage effectively with the private sector.

The effectiveness of state-owned enterprises must be improved

State-owned utilities are still prevalent across Africa, and their performance is generally poor compared with other regions. Fortunately, better governance of state-owned enterprises (SOEs) can improve performance. Further reform efforts seem justified.¹⁴

Over the years, substantial sums have been spent on institutional reforms, including management training, improved internal accounting and external auditing, more effective boards of directors, financial and operational information and reporting systems, creation and reinforcement of supervisory and regulatory agencies, and so on. Some enduring successes have been registered. The Botswana Power Corporation (BPC), which is state-owned and -operated, has long provided reliable and high-quality service, expanded the power network both in urban and rural areas, while covering its costs and posing no burden on the government budget. It has minimized system losses and earned a decent return on assets. While part of the explanation for BPC's good performance has been the availability of cheap imported power from South Africa (now severely threatened), analysts give institutional factors equal weight: a strong, stable economy; tariffs that reflect costs; lack of government interference in managerial decisions; good internal governance; and competent, well-motivated staff and management. BPC shows that state-owned utilities can perform well (Power Planning Associates, 2005).

In too many countries, however, reform efforts have not taken hold, or have not endured. Financial reporting systems, reformed boards, new accounting procedures, and other reforms disappear after a few years. What can be done in countries still in acute need of institutional reform? Three steps are recommended.

Performance contracts. Initial attempts to improve African SOEs through performance contracts were minimally effective, but recent efforts in the water sector (in Uganda, for example) have had a stronger and much more positive impact.¹⁵ The revised performance contract should be studied and, if necessary, modified for application in African electricity utilities. Its advantage is that it simultaneously addresses institutional deficiencies at and above the level of the service provider.

¹⁴ This section is based on a note prepared by John Nellis

¹⁵ Not to be confused with a management contract, a performance contract specifies, for a limited time, the obligations and responsibilities of a government agency or enterprise, on the one hand, and the "owner" (that is, the ministry, the supervisory body, the regulator) on the other. Performance contracts normally cover tariffs, investments, subsidies, and noncommercial objectives and their funding; they sometime include rewards for good managerial (and staff) performance, and more rarely, sanctions for nonfulfillment of objectives.

CREST. The Commercial Reorientation of the Electricity Sector Toolkit (CREST) is an experiment underway in several localities served by West African electricity providers. Based on good practices from recent reforms in Indian, European, and U.S. power corporations, CREST is a “bottom-up” approach designed to attack system losses, low collection rates, and poor customer service. It does this through a combination of technical means (replacing low-tension with high-tension lines, for example, and installing highly reliable armored and aerial bunched cables on the low-tension consumer point to reduce theft) and managerial changes (introducing “spot billing” and combining the four transactions of recording, data transfer, bill generation, and distribution). Transaction times are reduced and cash flows improved (Tallapragada, n.d.). Early applications of CREST have reportedly produced positive changes in several neighborhoods in Guinea and Nigeria, two difficult settings. The application of the toolkit should be closely monitored and evaluated and, if successful and replicable, employed elsewhere.

Better monitoring. Efforts to strengthen financial and operational monitoring of SOEs in government supervising ministries and ministries of finance should be bolstered. The sad fact is that the costs and inefficiencies of poor and wasteful performance in many African power systems are simply not known. That is, basic operational and financial data on firm performance are either not collected, not sent on to supervisors, not tabulated and published by the supervising bodies, or not acted upon. In the absence of information—or of action taken on the basis of what information is produced—one cannot expect improved outcomes.

Institutional change is a long-term matter. Victories on this front will be small in size and slow in coming. Donors may prefer the large and quick, but they must recognize that positive changes in this field lie at the heart of African power sector reform.

Regulatory institutions and mechanisms must be redesigned

Separate and nominally independent regulatory agencies have been established in most (but not all) countries of Sub-Saharan Africa. The original aim of regulation was to encourage efficient, low-cost, and reliable service provision, while ensuring financial viability and attracting new investment. It was hoped that regulatory agencies would insulate tariff setting from political opportunism and would improve the climate for private investment through more transparent and predictable decision making. While our data indicate that utilities in countries that have regulators tend to perform better than those in countries without regulators, it is far from clear whether regulators have facilitated the introduction of new private investment.

Some critics argue that regulatory agencies have exacerbated the problems they were meant to address, while creating a new, regulatory risk for investors. But it would be wrong to pin the blame on regulation *per se*. Rather, the new risk appears to arise from incompetent regulators who make unpredictable or noncredible decisions, or, more charitably, from regulators who have been given excessively wide discretion and overly broad objectives, and who then must make difficult decisions with important social and political consequences (Eberhard, 2007).

It is clear, however, that problems have emerged with utility regulation in developing countries. While the creation of separate regulatory agencies was intended to foster independent decision making, regulators are far from independent in many situations. Governments still pressure regulators to modify or

overturn decisions. In some countries, turnover among commissioners has been high, with many resigning under pressure before completing their full term. The gap between law (or rule) and practice is often wide. Tariff-setting remains highly politicized, and governments are sensitive to popular resentment against price increases that are often necessary to cover costs. Establishing new, “independent” regulatory agencies in contexts where prices are not high enough to ensure sufficient revenue, and where the sector is being reformed, may be a risky strategy for all stakeholders—governments, utilities, investors, and customers. In some ways, it is not surprising to find political interference and pressure on regulators.

The challenge of establishing new public institutions in developing countries is often underestimated. It takes time to build enduring systems of governance, management, and organization, and to create new professional capacity. Many regulatory institutions in developing countries are no more than a few years old. Few are older than ten years. Many of these institutions are still quite fragile and lack capacity. What to do?

Independent regulation requires strong political commitment to independent regulation and competent institutions and people. Where some or all of which are lacking, as in many developing countries, it seems wise to consider complementary, transitional, or hybrid regulatory options and models that are appropriate to individual country contexts and challenges. These options would have the effect of reducing discretion in regulatory decision-making through more explicit rules and procedures, or the outsourcing of regulatory functions to advisory regulators and expert panels. The options could be built into new legislation or into new regulatory contracts with the objective of creating more regulatory certainty for operators and investors (Eberhard, 2007).

Cost-recovery can coexist with well-targeted subsidies

Subsidies to the power sector in Sub-Saharan Africa have failed to meet the goal of making electricity affordable, in large part because access to service is almost entirely confined to the wealthier segments of society. Does that mean that utilities can and should move immediately to implement cost-recovery tariffs? Yes and no. In many countries, power sector tariffs are already very high by global standards, yet fail to cover costs because generation technologies are inefficient and markets small. Moreover, although power access is heavily skewed toward the upper-income groups, those groups are not particularly wealthy in absolute terms.

It is therefore important to distinguish between low-cost and high-cost countries, and, in the latter, between short-term and long-term tariff and subsidy policies.

In the high-cost countries, where today’s full cost of power provision can easily amount to \$0.25 per kilowatt hour (kWh), moving to full cost-recovery tariffs would absorb more than 5 percent of household budgets even for higher-income households, and would therefore present a major social and political problem. It has been shown, however, that in many of these countries the average incremental cost of power could fall toward \$0.12 per kWh if the benefits of regional power trade could be fully harnessed. At these levels, cost recovery would not represent a major affordability problem for much of the population, except in a handful of the poorest countries in the region.

For the high-cost countries, it is clear that the first step is to bring costs down to provide the basis for ultimate cost recovery. This presents the challenge of finding the substantial bridge financing needed in

the short run to bring down sector costs in the long run. The countries that most need to make these investments are precisely those where the operating costs of current power generation are highest, leaving little fiscal space to undertake the needed public investments.

Not all African countries face such high costs. In the continent's larger countries, and in those that rely on hydropower and coal-based generation, costs are already within the \$0.12 per kWh benchmark cited above. As a result, these countries—with the exception of a handful of the poorest cases—have the opportunity to move quickly toward cost recovery.

Ending power subsidies for higher-income groups would free up scarce fiscal resources—a major accomplishment. The new-found resources could be used to subsidize the expansion of power networks to serve lower-income rural and periurban communities, or for other poverty-alleviation programs.

Electrification strategies, too, must be better targeted

The countries of Sub-Saharan Africa have compiled a mixed record in meeting the uniformly enormous challenge of widening access to electricity, particularly in rural and periurban areas.

Countries that have dedicated rural electrification funds have achieved higher rates of electrification than those that do not. Of greatest interest, however, are the differences among the countries that have funds. Case studies indicate that the countries that have taken a centralized approach to electrification—with the national utility made responsible for extending the grid—have been more successful than those that followed decentralized approaches, where a rural electrification agency attempted to recruit multiple utilities or private companies into the electrification campaign. It may thus be unrealistic to expect specialized agencies to solve the rural electrification challenge on their own. They may be most productive in promoting minigrids and off-grid options as extensions of the national utility's efforts to extend the grid.

The potential for extending access in a given situation depends on population density and distance from the grid. 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.

Greater cross-border trade in power can help the region boost its generation capacity while lowering costs

Our study confirms the major potential of cross-border trade in power to lower costs and stimulate investment. In the short run, greater investments in cross-border transmission links will be needed to accommodate the higher volume of trade, but those investments would be quickly repaid as countries gain access to cheaper power, notably in Southern Africa. While the overall savings in the annualized cost of the power sector under trade are relatively small, at less than 10 percent, the gains for individual countries may be substantial. Development finance institutions should consider accelerating investments in cross-border transmission links and large hydroelectric projects, which the private sector has found too risky

because of their high capital costs, long payback periods, and multiple country risks related to the enforceability of power-purchase agreements.

The availability of financing rests on utilities' financial viability

The prerequisite for solid sector financing is financial viability by the incumbent utilities, which must gain the ability to fully cover operating costs and at least some share of capital costs. We have already drawn a distinction between countries with low-cost power systems, where an immediate move toward cost recovery should be feasible, and those with high-cost power systems, which must lower the cost of generation before aspiring to full cost recovery. The surest way to lower the cost of generation is to exploit, through regional trade, the comparative advantage of low-cost power producers.

Raising tariffs and developing sources of cheaper energy are two steps toward financial viability for utilities. A third step, entirely complementary with the others, is to reap the efficiency dividend available to utilities that can improve collection efficiency and contain distribution losses. The median utility in Sub-Saharan Africa captures only two-thirds of the revenue owed it—closing the gap could raise revenues by half in the short term, provided institutional and managerial reforms are successful.

Capital investment in African electricity systems from traditional sources has been, and may continue to be, modest. Even if aid were doubled or tripled over the next few years, it would not come close to meeting regional needs. Most governments in the region lack the fiscal space to contemplate a large increase in public spending for power generation and distribution. China's recent investments in the sector, if sustained and combined with investments of similar scale from India and other emerging powers, could conceivably close the financing gap, but such an outcome is by no means assured.

In the meantime, the best medium-term solution may be to assist African regimes and utilities in reducing system losses and increasing collection rates—thus raising internal funds. That effort should be complemented by efforts to improve the supervisory and planning agencies responsible for the utility. Dedicated interventions must be made to overcome the conflicts and contradictions that arise in hybrid power markets, where the incumbent public operator survives alongside independent power producers and other schemes involving private participation.

Combined, these measures would increase utilities' ability to attract external funding, public or private, domestic or international. Some of the policies we have proposed have been advocated for decades. But the persistence of state-owned power utilities in Africa, coupled with the pressing power needs of firms and households, means that the policy challenge can no longer be skirted.

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Annex 1 Cross-country annexes

See separate file.

Annex 2 Country annexes

See separate file.