AFRICA INFRASTRUCTURE COUNTRY DIAGNOSTIC

BACKGROUND PAPER 5 (PHASE II)

Powering Up: Costing Power Infrastructure Spending Needs in Sub-Saharan Africa

SUMMARY

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About AICD

This study is a product 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 better empirical foundation for prioritizing investments and designing policy reforms in Africa's infrastructure sectors.

AICD is based on an unprecedented effort to collect detailed economic and technical data on African infrastructure. The project has produced a series of reports (such as this one) on public expenditure, spending needs, and sector performance in each of the main infrastructure sectors—energy, information and communication technologies, irrigation, transport, and water and sanitation. *Africa's Infrastructure—A Time for Transformation*, published by the World Bank in November 2009, synthesizes the most significant findings of those reports.

AICD was commissioned by the Infrastructure Consortium for Africa after the 2005 G-8 summit at Gleneagles, which recognized the importance of scaling up donor finance for infrastructure in support of Africa's development.

The first phase of AICD focused 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, Côte d'Ivoire, the Democratic Republic of Congo, Ethiopia, Ghana, Kenya, Lesotho, Madagascar, Malawi, Mozambique, Namibia, Niger, Nigeria, Rwanda, Senegal, South Africa, Sudan, Tanzania, Uganda, and Zambia. Under a second phase of the project, coverage is expanding to include as many other African countries as possible.

Consistent with the genesis of the project, the main focus is on the 48 countries south of the Sahara that face the most severe infrastructure challenges. Some components of the study also cover North African countries so as to provide a broader point of reference. Unless otherwise stated, therefore, the term “Africa” will be used throughout this report as a shorthand for “Sub-Saharan Africa.”

The World Bank is implementing AICD with the guidance 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, the Development Bank of Southern Africa, and major infrastructure donors.

Financing for AICD is provided by a multidonor trust fund to which the main contributors are the U.K.’s Department for International Development, the Public Private Infrastructure Advisory Facility, Agence Française de Développement, the European Commission, and Germany’s KfW Entwicklungsbank. The Sub-Saharan Africa Transport Policy Program and the Water and Sanitation Program provided technical support on data collection and analysis pertaining to their respective sectors. A group of distinguished peer reviewers from policy-making and academic circles in Africa and beyond reviewed all of the major outputs of the study to ensure the technical quality of the work.

The data underlying AICD’s reports, as well as the reports themselves, are available to the public through an interactive Web site, www.infrastructureafrica.org, that allows users to download customized data reports and perform various simulations. Inquiries concerning the availability of data sets should be directed to the editors at the World Bank in Washington, DC.

Summary

Sub-Saharan Africa will require substantial investments in the power sector—on the order of 4 percent of the region's gross domestic product (GDP) annually before 2015—if it is to meet the demands of economic development, keep pace with population growth, and expand electrification beyond the 2005 regional average of just 34 percent. Developing a regional power-trading market that exploits the vast hydropower potential of the subcontinent may be the best way to bring those costs down while also protecting against increases in oil prices and curbing carbon emissions. Expanding electrification is a daunting challenge, but the costs associated with extending the transmission network are minor in comparison with the investments in generation needed to accompany the demand of Africa's growing economies.

A model to inform energy policy decisions

Nowhere in the world is the gap between available energy resources and access to electricity greater than in Sub-Saharan Africa. The region as a whole is rich in oil, gas, and hydropower potential, yet 66 percent of its population lacks access to electricity, with coverage especially low in rural areas. National authorities and international organizations have drawn up plans to increase access, but key policy choices underpin these plans. Which type of power generation is right in which settings? Should individual countries move ahead independently, or should they aim for coordinated development? What are the benefits of regional trade in power, and who are the main beneficiaries? How should major global trends, such as rising oil prices and looming climate change, affect decisions about power generation in Africa? How rapidly can Africa electrify? How sensitive are power investment decisions to broader macroeconomic conditions?

To answer these questions, we developed a model to analyze the costs of expanding the power sector over the course of 10 years under different assumptions. The model simulates optimal (least-cost) strategies for generating, transmitting, and distributing electricity in response to demand increases in 43 countries of Sub-Saharan Africa, grouped into four power pools. The Southern Africa Power Pool (SAPP) consists of Angola, Botswana, Democratic Republic of Congo, Lesotho, Mozambique, Malawi, Namibia, South Africa, Zambia, and Zimbabwe. Within SAPP, South Africa clearly occupies a dominant position, accounting for 80 percent of overall power demand. The Nile Basin–East Africa Power Pool (EAPP) consists of Burundi, Djibouti, Egypt, Ethiopia, Kenya, Rwanda, Sudan, Tanzania, and Uganda. Here, Egypt is the driving force, accounting for 70 percent of power demand within EAPP. The Western Africa Power Pool (WAPP) consists of Benin, Burkina Faso, Côte d'Ivoire, Gambia, Ghana, Guinea, Guinea-Bissau, Liberia, Mali, Mauritania, Niger, Nigeria, Senegal, Sierra Leone, and Togo. In WAPP, Nigeria dominates, with two-thirds of electricity consumption in the region. The Central Africa Power Pool (CAPP) consists of Cameroon, the Central African Republic, Chad, the Republic of Congo, Equatorial Guinea, and Gabon. In CAPP, the Republic of Congo and Cameroon are the major players, sharing 90 percent of power demand. Finally, Cape Verde, Madagascar, and Mauritius are included in our study as island states.

The exercise begins with a projection of power demand over 10 years, 2005–15. Demand consists of (a) *market demand* associated with different levels of economic growth, structural change and population growth; (b) *suppressed demand* created by frequent blackouts and ubiquitous power rationing; and (c) *social demand*, as expressed in political targets for increasing access to electricity. Based on historic trends, demand is projected to grow at 5 percent per year in Sub-Saharan Africa, reaching levels of 680 terawatt-hours (TWh) by 2015. Demand is projected to grow at 4–5 percent per year in SAPP and EAPP to reach levels of 400 and 170 TWh, respectively. The other regions have even higher electricity demand growth: 7 percent per year in CAPP, 9 percent per year in the island states and 12 percent per year in WAPP. The absolute demand levels, however, are lower in these regions: 20 TWh in CAPP, 3 TWh in the island states combined, and about 100 TWh in WAPP. In all cases except the islands, market demand accounts for the great bulk of demand growth over the period.

The model then looks for the least costly way of meeting the new demand based on investments in electricity generation, transmission, and distribution. Those investments include refurbishment of existing capacity for electricity generation and construction of new capacity for cross-border electricity transmission. Our analysis covers four modes of thermal generation (natural gas, coal, heavy fuel oil, and diesel) and four renewable generation technologies (large hydropower, mini-hydro, solar photovoltaic [PV], and geothermal). Minihydro, diesel, and solar PV are off-grid alternatives; that is, they are not connected to the central power grid. Operation, but not new investment, of current nuclear power is considered.

The main value of the model is that it can be run under a number of different scenarios to highlight the implications of various policies. For example, by comparing a "trade-stagnation" scenario under which no further cross-border transmission capacity is built with a trade-expansion scenario under which all economically viable cross-border transmission capacity is developed, we can quantify the gains from trade. The model can also be used to evaluate the feasibility of alternative electrification targets, ranging from maintaining constant access rates, to raising electrification to a uniform level over ten years, to pursuing a range of national electrification targets. The impact of higher oil prices, higher investment costs and lower rainfall can be gauged through their effects on the relative cost of different generation technologies, while the consequences of slower economic growth on power sector investment needs can also be readily quantified.

A high price tag

How much will it cost to meet market demand for power in 2105 while eliminating power shortages and achieving national policy targets for access to electricity?

It is clear that these achievements will require substantial investments in the power sector, demanding about 82,000 MW new generation capacity in total. This entails almost a doubling of current capacity, which for the whole of Sub-Saharan Africa stands at 87,000 MW (2005 data).

Since many power installations in Africa are old, much of the capacity operational in 2005 needs to be refurbished before 2015. In the SAPP region, a 2005 capacity of 48,000 MW is expected to be reduced to 17,000 MW, and some 28,000 MW of generating capacity will have to be refurbished (Table A, column “National targets for access rates”). In addition, more than 33,000 MW of new generating capacity will have to be built, an increase of about 70 percent over the 2005 level. In EAPP, the needs for refurbishment are minimal, but 26,000 MW of new generation will be required, essentially doubling the installed capacity of the region. The investment requirements are even larger in WAPP and CAPP: 18,000 MW new capacity will have to be built in WAPP, corresponding to 180 percent of current capacity, while CAPP requires investments of more than 2.5 times 2005 capacity, or 4,400 MW in total. More than half of current capacity must be refurbished both in WAPP and CAPP (7,000 MW and 900 MW, respectively).

It is clear that each region, particularly West and Central Africa, require significant investment. The good news is that economic growth drives most demand. Therefore, at least according to the projections, the financial strength to finance investments should emerge alongside new investment needs.

The *annualized capital investment costs* in Sub-Saharan Africa are 2.2–2.4 percent of the region’s GDP in 2015. There is, however, considerable variation between the different regions. The annualized capital investment costs are 2 percent of GDP for the SAPP region, and 2 to 3 percent of GDP for the EAPP and WAPP regions, but below 2 percent in CAPP (table B).

The costs of *operating* the entire power system are similar to investment costs, around 1.7–2.1 percent of GDP in total. The variation between regions is even more pronounced here: the costs are just under 2 percent of GDP for the SAPP region, and about 3 percent of GDP in the EAPP region, while they are about 1.5 percent in WAPP and a negligible amount in CAPP (0.2–0.4 percent of GDP).

Thus, *total spending* amounts to 4.2–4.4 percent of GDP in Sub-Saharan Africa. The total spending is about the same magnitude in SAPP and WAPP, but around 6 percent of GDP in EAPP and 2 percent in CAPP. Around two-thirds of overall system costs are associated with generation infrastructure, and the remaining third with transmission and distribution infrastructure.

Table A Generating capacity in Sub-Saharan Africa in 2015, under various trade, access, and growth scenarios

	Trade-expansion scenario			Trade-stagnation scenario	Low-growth scenario
Generation capacity (MW)	2005 access rate	Regional target access rate	National targets for access rates	National targets for access rates	National targets for access rates, trade expansion
Southern Africa Power Pool					
Installed capacity [a]	17,136	17,136	17,136	17,136	17,136
Refurbished capacity	28,029	28,035	28,046	28,148	28,046
New capacity	31,297	32,168	33,319	32,013	20,729
Hydropower share (%)	33	33	34	25	40
Eastern Africa Power Pool					
Installed capacity [a]	22,132	22,132	22,132	22,132	22,132
Refurbished capacity	1,369	1,375	1,375	1,381	1,375
New capacity	23,045	24,639	25,637	17,972	23,540
Hydropower share (%)	49	47	46	28	48
Western Africa Power Pool					
Installed capacity [a]	4,096	4,096	4,096	4,096	4,096
Refurbished capacity	5,530	6,162	6,972	6,842	5,535
New capacity	15,979	16,634	18,003	16,239	17,186
Hydropower share (%)	82	79	77	73	80
Central Africa Power Pool					
Installed capacity [a]	260	260	260	260	260
Refurbished capacity	906	906	906	1,081	906
New capacity	3,856	4,143	4,395	3,833	3,915
Hydropower share (%)	97	97	97	83	97
Island states					
Installed capacity [a]	282	282	282	282	282
Refurbished capacity	83	83	83	83	83
New capacity	189	369	368	368	353
Hydropower share (%)	25	19	19	19	20
Total Sub-Saharan Africa					
Installed capacity [a]	43,906	43,906	43,906	43,906	43,906
Refurbished capacity	35,917	36,561	37,382	37,535	35,945
New capacity	74,366	77,953	81,722	70,425	65,723
Hydropower share (%)	48	47	47	36	52

a. "Installed capacity" refers to installed capacity as of 2005 that will not undergo refurbishment before 2015. Existing capacity that will be refurbished before 2015 is not included in the installed capacity figure, but in the refurbishment figure.

Table B Estimated annualized cost of meeting power needs of Sub-Saharan Africa under two trade scenarios (national targets for electricity access)

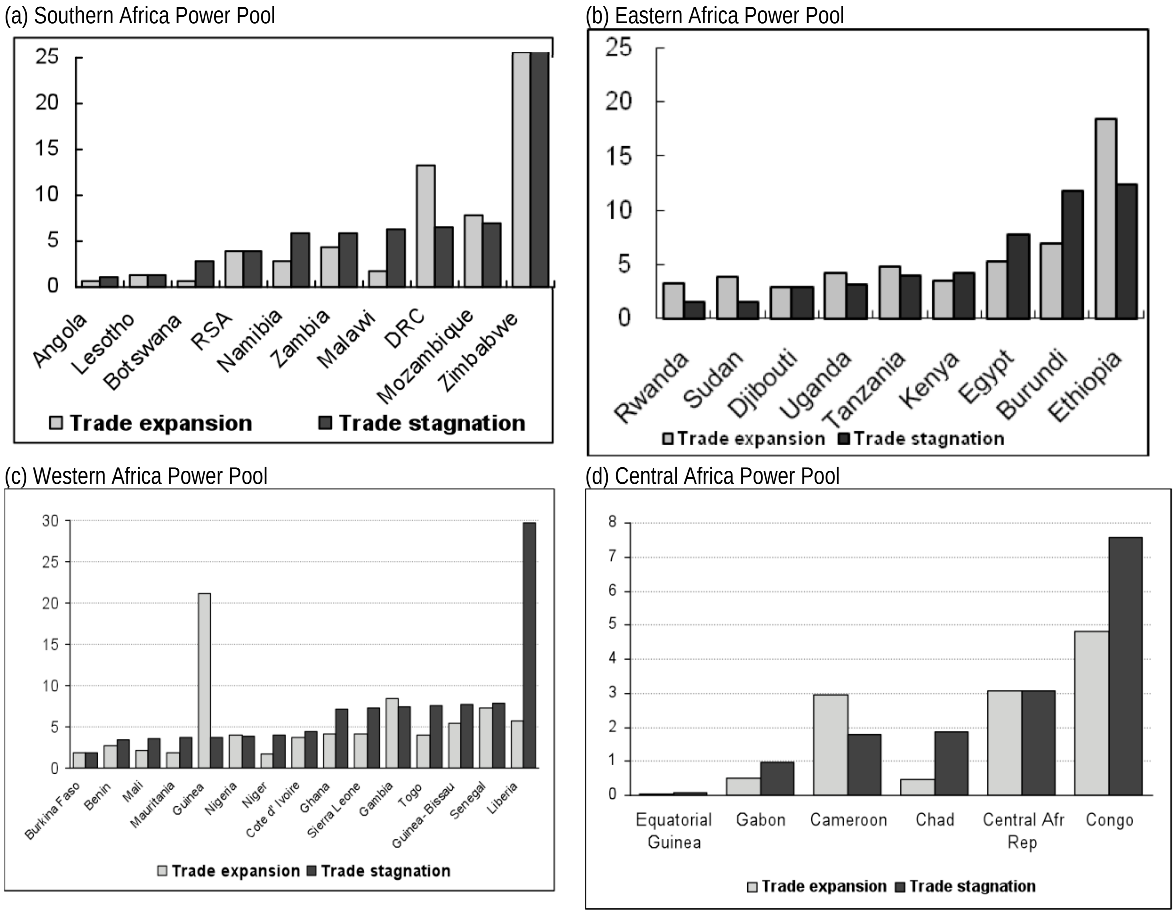
US$ billions and % of GDP	Southern Africa Power Pool		Eastern Africa Power Pool		Western Africa Power Pool		Central Africa Power Pool		Island states		Total Sub-Saharan Africa	
Trade expansion												
Total estimated cost	18.4	3.7%	15	5.7%	12.3	4.2%	1.4	2.0%	0.6	3.1%	47.6	4.2%
of which total												
Capital costs	10.0	2.0%	8.2	3.1%	8.2	2.8%	1.2	1.8%	0.2	1.4%	27.9	2.4%
Operating costs	8.4	1.7%	6.8	2.6%	4.0	1.4%	0.2	0.2%	0.3	1.7%	19.7	1.7%
of which total												
Generation	11.1	2.2%	10.5	4.0%	6.5	2.2%	1.0	1.4%	0.4	2.0%	29.5	2.6%
Transmission and distribution	7.3	1.5%	4.5	1.7%	5.8	2.0%	0.4	0.6%	0.2	1.1%	18.1	1.6%
Trade-stagnation												
Total estimated cost	19.5	3.9%	16	6.0%	12.7	4.4%	1.5	2.2%	0.6	3.1%	50.3	4.4%
of which total												
Capital costs	10.0	2.0%	6.3	2.4%	8.0	2.7%	1.1	1.6%	0.2	1.4%	25.6	2.2%
Operating costs	9.4	1.9%	9.7	3.7%	4.8	1.6%	0.4	0.6%	0.3	1.7%	24.7	2.2%
of which total												
Generation	12.6	2.5%	11.6	4.4%	7.1	2.4%	1.2	1.7%	0.4	2.0%	32.8	2.9%
Transmission and distribution	6.9	1.4%	4.4	1.7%	5.7	1.9%	0.3	0.5%	0.2	1.1%	17.5	1.5%

Note: Subtotals may not add up to the totals because of rounding.

The overall cost of developing the power system appears high, but not unattainable relative to the GDP of each regional trading area. But both GDP and power investment requirements are very unevenly distributed within the regional pools. As a result, under certain scenarios, some countries face power spending requirements that are burdensome relative to the size of their economies (figure A). In SAPP, depending on the electrification target and other variables, spending requirements may exceed 6 percent of GDP in the Democratic Republic of Congo, Mozambique, and Zimbabwe. In EAPP, countries such as Egypt, Burundi, and Ethiopia may require similar levels of spending. About half of the countries in WAPP have investment requirements of almost 10 percent of GDP, and Guinea and Liberia stand out at almost 30 percent. In CAPP, only the Republic of Congo requires investments of more than 5 percent of GDP. Some of these countries have the potential to become major exporters of power, provided they receive cross-border injections of capital to develop their power infrastructure. The necessary capital is not likely to materialize, however, unless trade in power expands.

Figure A Overall power spending needed to reach national targets for electricity access under alternative trade scenarios by country

% of GDP in 2015



What is the cost of expanding electrification?

We considered the impact of raising electrification levels from 2005 access levels to a uniform level across each region or to the levels specified in national electrification targets. The regional target levels roughly add 1 percent access every year over a ten-year period.

Due to relatively low power consumption by households, the impact of expanding electrification is quite modest. For instance, if national access targets are reached across Sub-Saharan Africa, the region's power generating requirement (in terms of MW) will only increase 10 percent, or $4 billion per year. The development of transmission and distribution networks, however, would require significant additional investment amounting to $5 billion per year across the region. The cost of transmission and distribution for access is particularly high in EAPP.

As a result, raising electrification levels to meet national electrification targets would entail a commitment of $9 billion per year, or 0.8 percent of GDP of Sub-Saharan Africa. There are, however, regional differences. In SAPP and CAPP the cost would be 0.3 and 0.4 percent of GDP, compared to 1 percent in WAPP and as much as 1.5 percent in EAPP.

The 0.8 percent of GDP needed to increase access is included in the 4.2 percent estimate that we gave above on the cost of providing electricity for market and social needs. This shows that the majority of electricity needs is driven by market demand needs.

How sensitive are power investments to economic growth?

Economic growth creates greater demand for electricity, while also providing some of the resources needed to pay for it. Lower growth reduces demand. We explored a low-growth scenario in which economic growth per capita was assumed to be 50 percent lower than assumed in our base case. In SAPP, the largest reduction in power demand would occur in South Africa, where investments in new coal-fired plants would be put on hold. In EAPP, lower demand growth would first reduce investments in gas-fired power plants in Egypt. Hydropower investments would be only slightly reduced under the low-growth scenario, implying that even with slower economic growth the market remains large enough to justify the expansion of almost all the hydropower capacity considered in the base case. In WAPP, less of the old gas-fired capacity in Nigeria would be refurbished and less of the hydropower in Côte d'Ivoire would be exported to Ghana. In CAPP, hydropower investments in the Republic of Congo would be reduced by almost 30 percent, but imports from Cameroon would increase to partly replace them.

Overall, the reductions in annual power spending needs resulting from lower growth are 10 percent in EAPP and CAPP, about 15 percent in WAPP, and almost 25 percent in SAPP. For all of Sub-Saharan Africa the reduction is 20 percent. The cuts may seem modest compared to a 50 percent cut in economic growth per capita, but keep in mind that economic growth for the country is much higher than economic growth per capita since the population is continually increasing. In fact, the low growth scenario lowers spending needs more than it lowers GDP, and spending needs as a share of GDP would decrease from 4.2 to 4.0 percent.

Why trade power?

African countries have different endowments of natural resources: some have abundant hydropower resources, while others have domestic resources of coal or natural gas. Some have no domestic energy resources but depend on imported diesel fuel to generate power. Trade with neighboring countries enables power production from the cheapest sources in the region. By stimulating the development of hydropower, expanded regional trade in power would lower the generation costs, reduce carbon emissions from power plants, and insulate countries from hikes in the price of fossil fuels. Expanded trade would also encourage investment. For example, the optimal size of a new hydropower plant is often so large that domestic demand cannot absorb the large capacity expansion, so the new plant will not be built.

Further development of power trade will incur significant infrastructure costs to develop cross-border transmission capacity. It is estimated that some 12 GW of needed interconnectors are lacking in SAPP and 14 GW in EAPP. The interconnector needs are less in the other areas: some 5.5 GW in WAPP and only 800 MW in CAPP. Building those lines would cost around $380 million per year in SAPP, $130 million in EAPP, $120 million in WAPP, and $40 million in CAPP.

The benefits of building the interconnectors would be substantial, reducing annualized power system costs by between 5 and 11 percent in the trading regions. The savings would be the largest in CAPP at 11.5 percent, compared to 7–8 percent in SAPP and EAPP and 5.1 percent in WAPP. Keep in mind, however, that operation of existing equipment contributes to the annual cost in 2015. The cost of running this equipment adds to the annualized system cost, but it cannot reasonably be expected to be influenced by future trade.

Power trade would save Sub-Saharan Africa an estimated $2.7 billion annually, or 5.3 percent of the annual cost of meeting power needs (or 7.2 percent of the cost when the operation of existing equipment is deducted; see table B). The savings come largely from substituting hydro for thermal plants, which substantially reduces the operating cost of the power system, although it requires more investment in the short run. For example, power trade would provide operating cost savings of 1 percent of the area’s GDP in EAPP and almost 0.5 percent of the area’s GDP in CAPP. In EAPP and WAPP the hydropower plants substitute for gas-fired power plants, while in CAPP the new hydropower replaces thermal power fueled by heavy fuel oil (HFO), which is more expensive and more polluting than gas-fired plants.

The savings on operating costs can be considered a return on the additional capital investments made under the trade scenario. In SAPP, the additional investment cost under trade is recouped in less than a year, yielding an annual return of 167 percent. The return is lower in the other three regions, but still generous at around 20–34 percent; the additional investment cost of the trade scenario is recouped over three to four years. For Sub-Saharan Africa as a whole the return on trade investment is 27 percent.

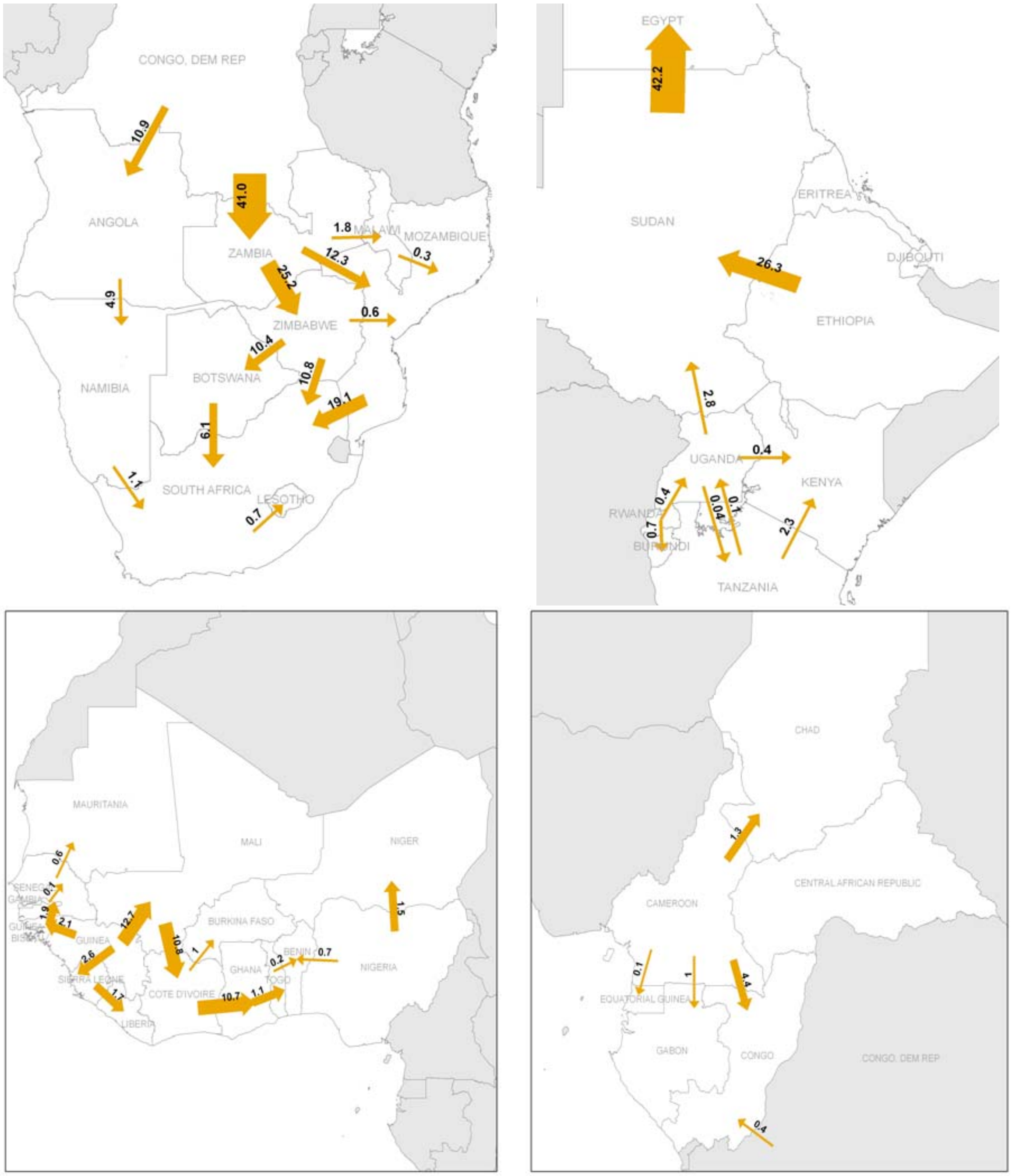
Moreover, the gains from trade increase as fuel prices rise, since trade reduces the use of thermal power plants and thus saves fuel. As fuel prices rise, hydropower projects become more profitable. At an oil price of $75/barrel (instead of $46/barrel in the base case), the gains from trade in EAPP amount to almost $3 billion annually.

What patterns of trade would emerge?

The expansion of power trade, as in our trade-expansion scenario, would allow countries with significant hydropower potential to develop their capacity and meet demand elsewhere.

In SAPP, the hydropower share would rise from 25 to 34 percent of the generation capacity portfolio. The Democratic Republic of Congo becomes the major exporter of hydropower, exporting three times as much as its domestic consumptions, while Mozambique continues to be a significant exporter. Hydropower from the Democratic Republic of Congo flows southward along three parallel routes through Angola, Zambia, and Mozambique (figure B). Countries such as Angola, Botswana, Lesotho, Malawi, and Namibia would become reliant on imports to meet more than 50 percent of power demand. In addition, South Africa would import large volumes of power, which would still account for only 10 percent of domestic demand.

Figure B Maximum potential for cross-border power trading in Sub-Saharan Africa, 2015 (TWh)



A similar shift from thermal to hydropower would occur in the EAPP region, pushing hydropower from 28 to 48 percent of the generation capacity portfolio and displacing gas-fired power capacity in Egypt and Kenya. Ethiopia and Sudan would become the major power exporters, trading more than what they produced for domestic consumption and sending their power northward into Egypt (figure B). While Egypt and Kenya would import significant volumes of power, Burundi would be the only country to become largely dependent on traded electricity.

In WAPP, the increase in trade would not significantly increase reliance on hydropower, but hydropower in Guinea would replace hydropower projects dispersed throughout the other countries. Also, trade would reduce the development of gas-fired power plants in countries such as Ghana, Benin, Togo and Mauritania. Guinea would emerge as the major exporter of hydropower, exporting more than 5 times domestic consumption.

In CAPP, the share of power production from hydropower would increase from 83 percent to 97 percent. Cameroon emerges as the major power supplier in CAPP, exporting about half of its production. Hydropower capacity in Cameroon replaces the HFO-fired thermal capacity in the other countries, in addition to some hydropower in the Republic of Congo. The other countries in the region, except Central African Republic, import a considerable share of their consumption: Chad and Equatorial Guinea import all of their power from Cameroon, while the Republic of Congo imports about one third and Gabon almost half of its consumption.

The Central African region borders the Democratic Republic of Congo and therefore could be expected to benefit from hydropower development there. In this study, the Democratic Republic of Congo is part of the SAPP region and only the 2005 level of imports from the Democratic Republic of Congo to the Republic of Congo was included in the base case. Even if higher imports from the Democratic Republic of Congo to the CAPP region are possible, Cameroon still remains the major supplier in CAPP (depending on the level of imports from the Democratic Republic of Congo). Instead, investments and production in the Republic of Congo are replaced by the increased imports.

Who gains most from power trade?

There are substantial differences in the long-run marginal cost (LRMC) of power across power pool areas, and those differences are differentially affected by trade (table C). The SAPP and CAPP regions have considerably lower average LRMC ($0.07 per kWh) than the EAPP and WAPP regions: the average LRMC of power in the EAPP region is around $0.12 per kWh and $0.18 per kWh in WAPP. The LRMC is also quite high on islands, between $0.14 and 0.19 per kWh. Of course, these numbers are estimates, with a considerable degree of uncertainty at the country level. The range within each power pool is also wide, though trade tends to narrow that range.

Two types of countries benefit from trade. Countries with very high domestic power costs can obtain significantly cheaper electricity by importing. Perhaps the most striking examples are in WAPP, where Guinea-Bissau, Liberia and Niger each can save up to $0.06–$0.07 per kWh by importing electricity. Countries in other regions also benefit from considerable savings: Angola in SAPP, Burundi in EAPP, and Chad in CAPP can all save up to $0.04–$0.05 per kWh by importing electricity. But even countries with smaller unit cost differentials, such as Burundi, Malawi, Ghana, Sierra Leone, and Togo, can generate important savings by moving from self-reliance to heavy imports.

On the other hand, countries with very low domestic power costs can also generate substantial revenues by exporting power. The most salient examples are the Democratic Republic of Congo for SAPP, Ethiopia for EAPP, Guinea for WAPP, and Cameroon for CAPP. Power export revenues could amount to 6 percent of GDP for Ethiopia and 9 percent of GDP for the Democratic Republic of Congo.

Table C Long-run marginal costs of power in Sub-Saharan Africa

U.S. dollars per kWh	Trade expansion	Trade-stagnation	U.S. dollars per kWh	Trade expansion	Trade-stagnation
SAPP average	*0.06*	*0.07*	*WAPP average*	*0.18*	*0.19*
Angola	0.06	0.11	Benin	0.19	0.19
Botswana	0.06	0.06	Burkina Faso	0.25	0.26
Congo, Dem. Rep.	0.04	0.04	Cote d'Ivoire	0.15	0.15
Lesotho	0.06	0.07	Gambia	0.08	0.07
Malawi	0.05	0.05	Ghana	0.10	0.10
Mozambique	0.04	0.06	Guinea	0.07	0.06
Namibia	0.11	0.12	Guinea-Bissau	0.09	0.16
South Africa	0.06	0.07	Liberia	0.08	0.14
Zambia	0.08	0.08	Mali	0.25	0.28
Zimbabwe	0.08	0.09	Mauritania	0.14	0.15
EAPP average	*0.12*	*0.12*	Niger	0.25	0.30
Burundi	0.11	0.15	Nigeria	0.13	0.13
Djibouti	0.07	0.07	Senegal	0.43	0.47
Egypt	0.09	0.09	Sierra Leone	0.09	0.10
Ethiopia	0.19	0.16	Togo	0.10	0.11
Kenya	0.12	0.13	*CAPP average*	*0.07*	*0.09*
Rwanda	0.12	0.12	Cameroon	0.07	0.06
Sudan	0.13	0.13	Central African Republic	0.11	0.11
Tanzania	0.10	0.08	Chad	0.07	0.11
Uganda	0.12	0.11	Congo, Rep.	0.06	0.08
Island states			Equatorial Guinea	0.08	0.10
Cape Verde	0.19	0.19	Gabon	0.07	0.07
Madagascar	0.14	0.14			
Mauritius	0.18	0.18			

Note: In some cases power exporting countries report higher LRMC under trade expansion. Even if the cost of meeting domestic power consumption may be higher with trade than without, the higher revenues earned from exports would more than compensate for that increment.

How will less hydropower development influence the trade flows?

In the trade-expansion scenario, cheap hydropower from Guinea supplies much of the power in the WAPP region (except Nigeria). But it might be unrealistic to develop such a huge amount of hydropower in one country in a short time span. In a reduced hydropower development sceanrio, we assume that only three projects, 375 MW in total, can be completed in Guinea before 2015 (instead of the 4,300 MW in the base case).

If hydropower development in Guinea is restrained, new trade patterns emerge in the WAPP region. Côte d'Ivoire emerges as the major power exporter, while Ghana increases domestic production considerably to reduce net imports. Mauritania and Sierra Leone also become exporters.

Hydropower investments in Côte d'Ivoire only increase by just below 200 MW, but production from existing gas-fired power plants also increases, so total power production increases by 3 TWh. Production in Ghana almost doubles to 16 TWh. Like in Côte d'Ivoire, the increase comes partly from new gas-fired power plants and partly from existing plants.

Total annualized costs increase by only 3 percent (just above $300 million). There is, however, a huge trade-off between lower capital costs and higher variable costs: while capital costs are $500 million less (mainly due to lower generation investments), variable operation costs of production are $850 million (30 percent) more. This clearly illustrates the trade-off between hydro and thermal capacity. With less hydropower capacity, more of the existing thermal capacity is used with lower efficiency and higher costs than new plants.

What are the environmental impacts of trading power?

Trade in power also offers potential environmental benefits. In the SAPP region, our model predicts that trade would increase the share of hydropower generation capacity from 25 to 34 percent, reducing CO_2 emissions by about 40 million tons. In the EAPP region, CO_2 emissions would drop by 20 million tons, even as power production rose by 2.4 TWh. In the WAPP and CAPP regions, the CO_2 savings are smaller, 5.2 and 3.6 million tons respectively, since the regions' total production is smaller.

The combined savings are 70 million tons of CO_2 annually. By comparison, the Energy Information Administration (EIA) estimates current emissions from power and heat production in Africa to be 360 million tons. The savings from trade is therefore 20 percent of this volume. Our estimates do not, however, include greenhouse gas emissions from hydropower in the form of methane from dams.

How would CDM affect generation technology choices?

Created pursuant to the Kyoto Protocol, the Clean Development Mechanism (CDM) allows industrialized countries that have made a commitment under the protocol to reduce greenhouse gases to invest in projects that reduce emissions in developing countries instead. The investment covers the difference in cost between a polluting technology and a cleaner but more expensive alternative. The CDM difference in cost is divided by emissions saved to work out the cost of certified emission reduction credits (CERs) associated with a given project. Focusing on SAPP, we analyzed the potential for CDM in the power sector of Sub-Saharan Africa, operating under the trade-expansion scenario.

CDM has not been widely used in the power sector in Sub-Saharan Africa. An illustrative simulation shows that at a CER price of $15/ton CO_2, investments in the Democratic Republic of Congo, Malawi, Zambia, and Namibia would lead to the development of an additional 8,000 MW (producing 42 TWh) of hydropower.

A CER price of $15 has the potential to reduce CO_2 emissions by 36 million tons—equivalent to 10 percent of Africa's emissions from power and heat production. That amount is significant but still less than the carbon reduction brought about by trade, which reduces CO_2 emissions by 40 million tons in SAPP. Trade and CDM are not mutually exclusive, of course. Starting from a trade-stagnation position, moving to a trade-plus-CDM position could reduce CO_2 emissions by 76 million tons.

One facet of the CDM model limits its contribution. System costs for Africa after CDM finance are still higher than before CDM finance. The reason seems to be that transmission and distribution costs increase after CDM (because hydropower plants are located far from consumption centers), but those costs are not addressed by the mechanism.

How might climate change affect power investment patterns?

By affecting weather patterns and making hydropower less reliable, climate change could increase the costs of generating and delivering power in Africa.

Focusing on the EAPP region, we performed an illustrative analysis to examine some of the key issues posed by climate change. Because exact numbers are lacking, we performed simulations in which climate change was assumed to reduce so-called firm hydropower production (in GWh per MW of installed capacity) by up to 25 percent. The reduction was assumed to apply both to existing capacity and to new capacity.

Lower firm power would increase the unit cost of hydropower, causing gradual substitution away from hydropower and increasing the total annualized cost of the power sector. It is perhaps some comfort that a reduction of 25 percent in firm hydropower availability would increase the annual costs of satisfying the region’s power needs by only 9 percent. But it is decidedly not comforting that climate change would increase East Africa’s dependency on thermal power—production in gas-fired power plants would increase 40 percent in EAPP. In other words, the solution to the power supply problem brought about by climate change implies an acceleration of the climate problem.