SUMMARY OF BACKGROUND PAPER 5

AFRICA INFRASTRUCTURE COUNTRY DIAGNOSTIC

Powering Up: Costing Power Infrastructure Investment Needs in Southern and Eastern Africa

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May 2008

This report was produced by Econ Pöyry, in association with Norplan and Power Planning Associates (PPA), at the request of 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.

Powering up

Costing Power Infrastructure Investment Needs in Southern and Eastern Africa

Orvika Rosnes and Haakon Vennemo

Substantial investments—on the order of 2–3 percent of GDP annually through 2015—will be needed if the power sector in southern and eastern Africa is to meet the demands of economic development, keep pace with population growth, and expand electrification beyond today's regional average of just 24 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. The region faces a daunting challenge to expand electrification, but the good news is that the costs associated with extending the network are minor in comparison with the investments in generation needed just to stay even with 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 76 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 must be made to underpin these plans. Which mode 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 through 2015, under different assumptions. The model simulates optimal (least cost) strategies for generating, transmitting, and distributing electricity in response to demand increases in each of 20 countries participating in the power pools of southern and eastern Africa. The Southern Africa Power Pool (SAPP) consists of Angola, Botswana, Democratic Republic of Congo, Lesotho, Mozambique, Malawi, Namibia, South Africa, Zambia, and Zimbabwe. Within the 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, Sudan, Rwanda, Kenya, Tanzania, and Uganda. Here, Egypt is the driving force, accounting for 70 percent of power demand within the EAPP. Finally, Madagascar is also included in our study as an island state. A similar examination of the West African and Central African trading regions is in preparation.

The exercise begins by projecting power demand through to 2015. 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 the ubiquitous practice of power rationing; and (c) *social demand,* as expressed in political targets for increasing popular access to electricity. Based on historic trends, demand is projected to grow at 5 percent per year in SAPP and 7 percent per year in EAPP to reach levels of 400 and 170 terawatt hours (TWh) respectively by the year 2015. In both cases, market demand accounts for the great bulk of demand growth over the period.

The model then looks for the least cost 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. Mini-hydro, diesel, and solar PV are off-grid alternatives, that is, they not connected to the central power grid. Nuclear power is not considered.

The main value of the model is that it can be run under a number of different scenarios, so as to highlight the varying policy implications. 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, the model can be used to quantify the gains from trade. The model can also be used to evaluate the feasibility of alternative electrification targets, ranging from maintaining access rates constant at 2005 levels, raising electrification to a uniform level of 35 percent by 2015, and pursuing a range of national electrification targets. The impact of higher oil prices 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

As a starting point, how much will it cost to meet market demand for power in 2015 while maintaining current rates of access to electricity?

Just to keep electricity access rates at today’s level—that is, to meet the growth in demand for electricity that stems from general economic development, population growth, and suppressed demand, without appreciably increasing rates of access to electricity among the population—will require very substantial investments in the power sector before 2015.

In the SAPP region, some 28,000 MW of existing generating capacity will have to be refurbished by 2015. In addition, more than 31,000 MW of new generating capacity will have to be built, an increase of about 70 percent over the 2005 level (table A). In EAPP, the needs for refurbishment are minimal, but 23,000 MW of new generation will be required, essentially doubling the installed capacity of the region.

Table A Generating capacity in southern and eastern Africa in 2015, under various trade, access, and growth scenarios

	Trade expansion scenario			Trade stagnation scenario	Low-growth scenario
Generation capacity (MW)	Constant access rate	35 percent 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
East 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	48	28	48

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

The annualized capital investment costs are 2 percent of GDP for the SAPP region, and 2 to 3 percent of GDP for the EAPP region (table B). The costs of operating the entire power system are of a similar order of magnitude—just under 2 percent of GDP for the SAPP region, and around 3 percent of GDP in the EAPP region. Thus, total spending would amount to just under 4 percent of GDP in the SAPP and close to 6 percent of GDP in the EAPP. Around two-thirds of overall system costs are associated with generation infrastructure, and the remaining third with transmission and distribution infrastructure.

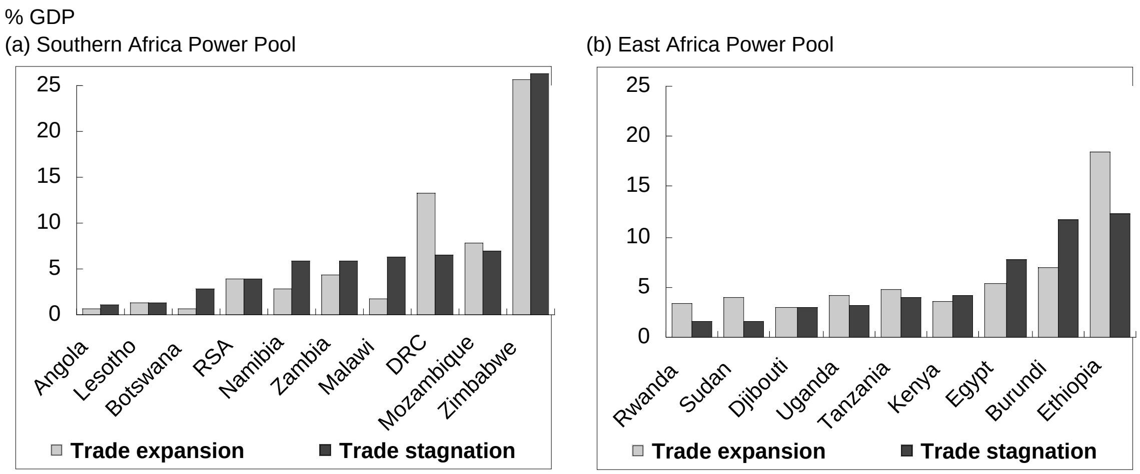
Table B Estimated cost of meeting power needs of Southern and East Africa through 2015 under two trade scenarios

US$ billions (% GDP)	Southern Africa Power Pool				East Africa Power Pool			
	Trade stagnation		Trade expansion		Trade stagnation		Trade expansion	
Total estimated cost	19.5	(3.9)	18.4	(3.7)	16.0	(6.0)	15.0	(5.6)
of which total								
Capital costs	10.0	(2.0)	10.0	(2.0)	6.3	(2.3)	8.2	(3.1)
Operating costs	9.4	(1.9)	8.4	(1.7)	9.7	(3.6)	6.8	(2.5)
of which total								
Generation	12.6	(2.6)	11.1	(2.3)	11.6	(4.4)	10.5	(3.9)
Transmission and distribution	6.9	(1.3)	7.3	(1.4)	4.4	(1.7)	4.5	(1.7)

Note: Assumes expansion of access to power to national electrification targets. Subtotals may not add to totals because of rounding.

The overall cost of developing the power system appears high, but not so high as to be unattainable relative to the GDP of each of the regional trading areas as a whole. However, 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 very 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, similar levels may be reached by countries such as Egypt, Burundi, and Ethiopia. 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 infusions are not likely to materialize unless trade in power expands.

Figure A Overall power spending needs under alternative trade scenarios by country



What is the cost impact of expanding electrification?

We considered the impact of raising electrification levels to a uniform 35 percent across the region or to the levels specified in national electrification targets. Due to relatively low power consumption by households, the impact of expanding electrification targets is quite modest, raising the power-generating requirement from 6 percent in SAPP (to meet the 35 percent target) to 11 percent in EAPP. However, significant investments would be needed to develop transmission and distribution networks, amounting to an additional $0.9 billion per year in SAPP and $2.4 billion per year in EAPP (because of EAPP's lower starting point for electrification). About 40 percent of that amount would be spent in rural areas (compared with only 10 percent in the constant access scenario). As a result, meeting national electrification targets would entail an additional commitment of just 0.3 percent of GDP in the SAPP area, but as much as 1.4 percent of GDP in the EAPP area.

How sensitive are power investments to economic growth?

Higher 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 was assumed to be 50 percent lower than in the base case. In SAPP, by far the largest part of the reduction in demand for power 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 are 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 virtually all the hydropower capacity considered in the base case.

Overall, the reductions in power spending needs resulting from lower growth are only 10 percent in EAPP and just over 20 percent in SAPP. In fact, in the EAPP, the share of GDP needed to cover power sector expenditures actually *increases* under a lower growth scenario—under-scoring the importance of growth to sector finance.

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 development of the cheapest resources in the region as a whole. By stimulating the development of hydropower, expanded regional trade in power would lower the costs of generating power, reduce carbon emissions from generating plants, and insulate countries from hikes in the price of fossil fuels. Expanded trade would also encourage investments that might not otherwise be made.

Further development of power trade will entail significant infrastructure costs to develop the missing cross-border transmission capacity. It is estimated that some 12 GW of needed interconnectors are lacking in SAPP and 14 GW in EAPP. Building those lines would cost around $350 million per year in SAPP and $130 million in EAPP.

However, the benefits of building them would be substantial. Their existence would make it possible to shave 5–6 percent off annualized power system costs. The savings would be on the order of $1 billion per year each for the SAPP and the EAPP (table B). These savings come largely from substituting hydro for thermal plant, which substantially reduces the operating cost of the power system, even if it does entail higher investment requirements in the short run (table B). In EAPP, for example, the operating cost savings of power trade amount to 1 percent of the area's GDP.

The savings on operating costs can be regarded as a return to the additional capital investments made under the trade scenario. In the two regions in focus here, that return is substantial. In SAPP, the additional investment cost under trade is recouped in less than a year, and the investment in trade yields a return of 167 percent. The return is lower in EAPP, but still generous at around 20 percent. Here, the additional investment cost of the trade scenario is recouped over four years.

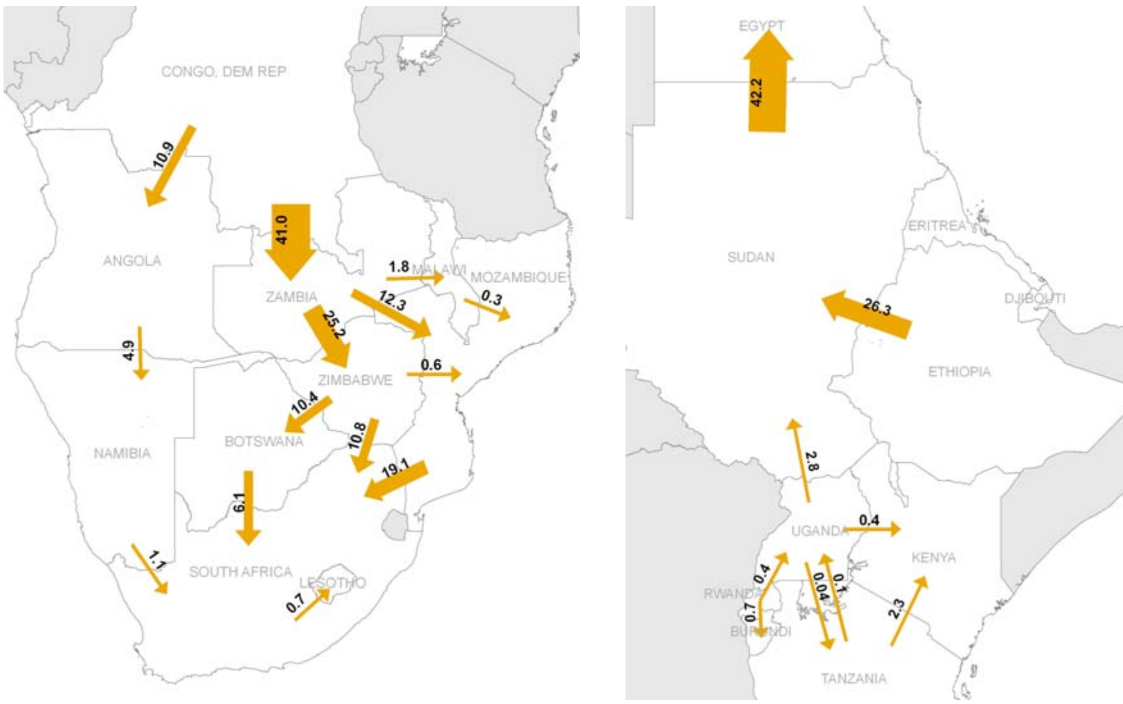
Moreover, the gains from trade increase as fuel prices rise, since trade reduces the use of thermal power plants and thus saves fuel. As fuel prices rise, more and more hydropower projects become profitable. At an oil price of $75/barrel (instead of $46/barrel in the base case), the gains from trade in EAPP amount to almost $3 billion. Given recent developments in the price of oil, $75/barrel seems more likely than $46/barrel in 2015.

What patterns of trade would emerge?

If conditions were to permit trade in power to expand, as in our trade expansion scenario, demand would elicit development of hydropower in countries with significant hydropower potential. In the SAPP, the hydropower share would rise from 25 to 34 percent of the generation 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 represent only 10 percent of domestic demand.

Figure B Maximum potential for cross-border power trading in southern and eastern Africa, Twh in 2015



A similar shift from thermal to hydropower would occur in the EAPP region, pushing hydropower from 28 to 48 percent of the generation portfolio and displacing gas-fired power capacity in Egypt and Kenya. Ethiopia and Sudan would become the major power exporters, trading more than 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.

Who gains most from power trade?

There are substantial differences in the long-range marginal cost (LRMC) of power across power pool areas, and those differences are differentially affected by trade (table D). The average LRMC of power in the EAPP region is around $0.11 per kWh versus $0.07 per kWh in the SAPP. On an island such as Madagascar it rises to $0.16 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 considerable, though it tends to be narrower with trade.

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 Angola in SAPP and Burundi in EAPP, both of which can save $0.04 per kilowatt-hour by importing electricity. However, even countries with smaller unit cost differentials can make important overall savings. These are estimated at more than 4 percent of GDP for countries such as Burundi and Malawi and more than 2 percent of GDP for countries such as Botswana and Egypt (figure A).

On the other hand, countries with very low domestic power costs can obtain substantial revenues from power exports. Again the most salient examples are Democratic Republic of Congo for the SAPP and Ethiopia for the EAPP. The potential value of power export revenues could amount to 6 percent of GDP for Ethiopia and 9 percent of GDP for the Democratic Republic of Congo.

Table D Long-run marginal costs of power in southern and eastern Africa

U.S. cents per kwh	Trade expansion	Trade stagnation
SAPP average	0.06	0.07
Angola	0.07	0.11
Botswana	0.06	0.06
Congo, Dem Rep	0.04	0.04
Lesotho	0.06	0.07
Malawi	0.05	0.05
Mozambique	0.04	0.06
Namibia	0.11	0.12
South Africa	0.06	0.07
Zambia	0.08	0.08
Zimbabwe	0.08	0.09
EAPP average	0.12	0.12
Burundi	0.11	0.15
Djibouti	0.07	0.07
Egypt	0.09	0.09
Ethiopia	0.19*	0.16
Kenya	0.12	0.13
Rwanda	0.12	0.12
Sudan	0.13	0.13
Tanzania	0.10*	0.08
Uganda	0.12*	0.11
Madagascar	0.16	0.16

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.

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 from 25 to 34 percent, leading to annual savings in CO_2 emissions of 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. The combined savings are equivalent to a reduction of 7 percent in projected emissions for Sub-Saharan Africa by 2015. However, these numbers to not include greenhouse gas emissions from hydropower in the form of methane from dams, which could significantly alter the picture.

How would CDM affect generation technology choices?

Created pursuant to the Kyoto Protocol, the 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. 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 had 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, some 8,000 MW (producing 42 TWh) of additional hydropower would be brought online thanks to investments in the Democratic Republic of Congo, Malawi, Zambia, and Namibia.

A CER price of \$15 thus has the potential to cut 36 million tons of CO_2—equivalent to 6 percent of Africa's current CO_2 emissions. That sounds significant, but it is 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, one might save 76 million tons by moving to a trade-plus-CDM position.

One facet of the CDM model limits its contribution. System costs for Africa after CDM finance are still higher than those of thermal power. 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. An integrated model of generation and transmission across African countries is necessary to discover the additional costs associated with cleaner generation.

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. Ironically, climate change would imply more thermal generation.

Focusing on the EAPP region, we performed an illustrative analysis to capture 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 5 percent 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 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.