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Study on Programme for Infrastructure Development in Africa (PIDA)

AFRICA ENERGY OUTLOOK 2040

SOFRECO

in consortium with

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Africa Energy Outlook 2040

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Abbreviations & acronyms

AFD	Agence Française de Développement *(French Development Agency)*
AfDB	African Development Bank
AFREC	African Energy Commission
AFSEC	African Standards Electro-Technical Commission
AFUR	African Forum for Utility Regulators
AICD	Africa Infrastructure Country Diagnostic
APF	African Petroleum Fund
AU	African Union
AUA	African Union Assembly
AUC	African Union Commission
CAPP	Central African Power Pool
CAR	Central African Republic
CCGT	Combined cycle gas turbine
CEB	Compagnie d'Electricité du Benin
CEMA	Commission of Energy Ministers for Africa
CEPGL	Communauté Economique des Pays des Grands Lacs
CO_2	Carbon dioxide
COMELEC	Communauté du Maghreb de l'Electricité (North African Power Pool)
COMESA	Common Market for Eastern and Southern Africa
CSP	Concentrating Solar Power
DBSA	Development Bank of South Africa
DFID	Department for International Development (UK aid agency)
DII	Industrial Initiative
DRC	Democratic Republic of Congo
EAC	East African Community. It comprises Kenya, Uganda and Tanzania
EAPP	East African Power Pool. It comprises Uganda, Djibouti, Eritrea and Libya.
ECA	Economic Commission for Africa (United Nations)
ECCAS	Economic Community for Central African States
ECOWAS	Economic Community of West African States

EDM	Electricité du Mali *(Mali's power utility)*
EGL	Energie des Grands Lacs
EIA	Environmental Impact Assessment
EIB	European Investment Bank
EIRR	Economic internal rate of return
EPC	Engineering, Procurement and Construction Contract
ERERA	ECOWAS Regional Electricity Regulatory Authority
ESIA	Environmental and Social Impact Assessment
ESKOM	South African utility
ESMAP	Energy Sector Management Assistance Program
EU	European Union
EUR	Export-Import Bank
EWSA	Energy Water and Sanitation Authority. Power utility of Rwanda
FUNAE	Energy Trust Fund of Mozambique
GDP	Gross Domestic Product
GHG	Greenhouse Gas
GTZ	Deutsche Gesellschaft für Technische Zusammenarbeit *(a German company devoted to technical Co-operation)*
IBRD	International Bank for Reconstruction and Development
IDA	International Development Agency
IDB	Islamic Development Bank
IE	Infrastructure and Energy Department
IEA	International Energy Agency
IFI	International Financial Institution
IGCC	Integrated gasification combined cycle
IUMoU	Inter-Utility Memorandum of Understanding
KfW	Kreditanstalt für Wiederaufbau *(German financial institution for reconstruction)*
kV	kilovolt
kWh	kilowatt-hour
LNG	Liquid Natural Gas
LOLP	Loss of Load Probability
MDG	Millenium Development Goals
Med Ring	Mediterranean Electricity Ring
MIGA	Multilateral Investment Guarantee Agency
MOU	Memorandum of Understanding
MW	Megawatt
MWh	Megawatt-hour
NEPAD	New Partnership for Africa's Development

NGO	Non-Governmental Organization
O & M	Operation and maintenance
OCGT	Open cycle gas turbine
ODA	Official Development Assistance
OECD	Organization for Economic Cooperation and Development
OMVS	Office de mise en valeur du Sénégal
PAP	Priority Action Plan
PIDA	Program for Infrastructure Development in Africa
PMEDE	Domestic Electricity Markets for Consumption and Export Project of the World Bank, DRC
PPA	Power Purchase Agreement
PPP	Public-Private Partnership
PROPARCO	Investment and Promotions company for Economic Cooperation of France
PV	Photovoltaic electricity
RDC	République Démocratique du Congo *(CDR - Congo Democratic Republic)*
REC	Regional Economic Community
RECO	Rwanda Electicity Company (Became part of EWSA)
REGIDESO	Régie de production et de distribution d'eau et d'Électricité Power utility of Burundi
RERA	Regional Electricity Regulators Association of Southern Africa
SADC	Southern Africa Development Community
SAPP	Southern African Power Pool
SCC	Social cost of carbon
SINELAC	Société International d'Electricite des Pays des Grands Lacs
SNEL	Société Nationale d'Electricite *(Democratic Republic of Congo)*
SOFRECO	Société Francaise d'Etudes Economiques *(French Consulting firm)*
SOGEM	Société de Gestion de Manantali
SSA	Sub-saharan Africa
tC	ton of carbon
tCO_2	ton of carbon dioxide
TW	Terawatt
TWh	Terawatt-hour
UNECA	United Nations Economic Commission for Africa
UNIDO	United Nations Industrial Development Organization
US$	U.S. Dollar
USAID	US Agency for International Development *(US Economic development Agency)*
USD	U.S. Dollar
US$	U.S.Dollar
WACC	Weighted average cost of capital

WAGP	West African Gas Pipeline
WAPCO	West African Gas Pipeline Company limited
WAPP	West African Power Pool

1. KEY MESSAGES

1.1 The Starting Point for the Analysis:

The African continent's energy profile has the following features:

- Abundant energy resources in oil, gas, coal, and especially hydro potential –but which are unevenly distributed across the continent
- Underexploited energy resources and under- served demand, compared to the rest of the world: Africa has 15% of world population but only 3% of primary energy consumption
- Low access rates to basic energy services, especially in sub-Saharan Africa (SSA), where access rates are barely 39% and throttle socio-economic development;
- A fragmented energy market;
- A low capacity to mobilize financing for investment, especially from private sources, due to low country and utility creditworthiness and high political risks;
- The lowest CO2 emissions per capita reflecting the low energy intensity of the economy as well as low per capita consumption levels;
- Only 125 GW of capacity in all Africa (comparable to the UK), of which 20% hydro (highest continent), in small, inefficient units
- Total power transmission system is only 90,000 km
- Gas and petroleum product pipeline system limited.

1.2 Primary Resources Potential

- Main oil and gas reserves in North and West Africa, with potential expanding to other countries
- Hydro potential in East, Central Africa and in West Africa, but sufficient only to 2035
- Coal reserves in the south
- Wind limited mainly to Morocco and Egypt
- Solar potential in the north mainly, and significant geothermal in the east.

1.3 Continental Energy Outlook 2040

Primary energy demand increases by 8.9% per annum. Nuclear will increase significantly, whereas coal will increase only slowly. Overall, dependence on fossil fuel will increase despite the 5.8% per annum growth of hydro.

Electricity energy demand is projected to increase by 5.7% per annum (less than GDP due to energy efficiency gains which will save 139 GW of capacity), still a 5.4 fold increase, and capacity will increase by 6% per annum. It compares to a 2.4% per annum increase in the past, with increasing power shortages. Per capita consumption will increase at an un-precedented 3.7% per annum.

At the REC level, Eapp will see the fastest increase in primary energy demand because of its growing exports to other regions, whereas SAPP growth is slower, as the demand in South Africa is projected to be moderate, but with a notable increase in nuclear.

A Summary Comparison between the **three energy supply and integration** scenarios shows the following results:

- Higher Integration scenarios require **more capital investment** because they allow the implementation of more and larger hydro plants, which produce at lower cost power but are more capital intensive than thermal plants;
- Regional integration allows large **savings in fuel costs**, because the maintenance and operation of hydro plants is less expensive than for thermal plants.
- Overall, full integration and unlimited trade would save a significant **US$ 1,117 billion over the 2011-2040 period (US$43 billion per year)**, or **21%** of the cost of electricity.
- The more realistic Moderate integration scenario still saves **US$ 861 billion over the 2011-2040 period (US$ 33 billion a year)**, or **17%** of the cost of electricity
- High and moderate integration scenarios lead to more thermal generation temporarily during the 2014-20 period while large low cost hydro plants are being developed and come on stream in 2020 and later years, leading to large fuel cost savings in the 2020-40 period.

1.4 Energy Outlook 2040 by Sub-continental Entities

- The main findings of the regional Outlooks are the following:
- **COMELEC** will experience an increase in demand by 6.2% per annum because demand from additional connections will be limited (access already close to 95%), requiring an additional 298 GW. Limited increase in its already high access rate is forecast, but will still need an investment of US$ 8 billion to bring its access rate to 97%, taking into account demographic growth.
- **SAPP** total demand will increase by only 4.4% only because of slower growth rate in South Africa; it will still require an additional 129 GW. It will experience a significant increase in access from 24% to 64%. Per capita consumption will increase modestly.
- **WAPP** demand will increase by a high 8.9%, requiring an additional 90 GW because of high growth rates of the low income countries of the region. It will experience a significant increase in access from 44% to 67%. Per capita consumption will increase significantly.
- **CAPP's** overall demand will increase significantly by 7.3% per year, and some 26 GW will have to be installed. Access rate will increase considerably from 20% to 63% as a number of countries start from a very low level of access. Per capita consumption will also increase significantly.

- **EAPP's** demand will increase by a moderate 6.5% because of relatively slow growth in Egypt, requiring still an increase of a significant 140 GW. Access rate will increase substantially from 36% to 68% (due to Egypt), requiring an investment of US$ 44 billion in access.

1.5 Infrastructure Needs to Meet the Demand

- Investment in Access to achieve the average 69% access rate within the PIDA time horizon will be 3.7 billion to connect 800 million people.
- The investment implications of the challenge to meet both rapid energy demand growth and increased access are formidable. The main components of the investment challenge are:
- A huge capital investment is required in the power sector ($33 billion per year compared with a current level of less than ¼)
- A substantial, upfront investment of $ 4.5 billion per year in transmission is needed to meet forecast demand prior to 2025
- The main challenge will be financing the large capital investment requirements of the power sector, especially the need to increase private sector financing and sector cash flow by some 7-10 fold their current levels
- No significant increase in average wholesale tariff is required to finance the sector program, which would remain around $8-10 cents /kWh However, tariff estimates assume a major improvement in collection performance and much larger sector cash flow volumes generated by the utilities

1.6 Inter-sectoral Synergies

- The energy sector program has a large hydro component which should be developed jointly with the Water sector and the regional Water Basin Agencies when deciding on the project development structure and timing, taking into account the implementation schedule of the regional power ector development plan and of the water basin development program.
- In coordination with the ICT sector, all high capacity transmission lines should be equipped with optic fibre cable, as it is envisaged in WAPP and SAPP in particular
- Coordination between the development fo the railway and road sector and the pipeline sub0sector should be explored for sharing rights of way.

1.7 Environmental Perspective: CO2 emissions

- The share of Africa in world emissions will increase, despite the priority granted to hydro and the development of nuclear, and increase from 3 to 4% of world emissions.
- GHG emissions will increase slower than GDP, though, as Africa shifts toward lower GHG emissions (hydro, nuclear, gas and less coal).

- In addition to energy efficiency actions, priority should be granted to prioritize low GHG technologies, including geothermal (coming in the systems after 2030) and CSP, although it is unlikely to be cost competitive on the planning horizon without external financial support.

1.8 Financing Outlook

- The energy sector will need US$ 43.6 billion per year, of which 42.3 in the power sector.
- Significant investment in transmission will be needed particularly in the 2011-2020 period to allow the development of electricity trade.
- The critical period is 2011-2020 when the sector has a financing gap of 50% of the needs, even if the utilities improve their financial performance and are able to contribute to their investment programs.
- ODA, non-traditional financing and private sector will meet about 50% of the financing needs over the 2014-2040 period, but only 20% of the needs over th 2014-2020 period.
- The gap in the 2011-2030 period will have to be met by special initiative from donors, matching efforts by the sector to boost its cash flow.
- Under realistic assumptions, it appears that at a wholesale tariff level of USCents 10 to 12/kWh, the sector should be able to contribute to investment fincing a needed and to service its debt, provided the pervasive billing and collection issue is addressed.

1.9 Outlook related Risks

- The main Outlook risks relate to the choice of fuel technology
- Decisions on the choice of fuel technology have an important bearing on the cost of meeting power demand
- Critical decisions need to be taken in regard to the respective roles of Hydro, Gas, Coal and Renewables;

Africa's large hydro sites offer the lowest cost electricity but high capital costs, lengthy implementation, and drought vulnerability need also to be assessed in the risk strategy

2. INTRODUCTION

- The overall objective of PIDA is to facilitate increased regional integration in Africa through improved regional and continental infrastructure
- The scope of the study for the energy sector covers the supply, demand, production and transport of commercial energy to the extent that they have a regional dimension
- The Energy Sector Outlook 2040 comprises:
  - An overview of the energy demand and supply outlook 2040
  - A discussions on the energy outlook by sub-region;
  - An analysis of the major issues that are likely to affect the balance between energy demand and supply.
- The starting point for energy sector development in Africa:
  - Under-exploited energy resources and under-served demand
  - A fragmented regional and continental market
  - Low access to and poor availability of modern energy throttle economic and social development.
  - High cost of energy (electricity and petroleum products) penalizes competitiveness and makes modern energy unaffordable for many.
  - A low capacity to attract commercial financing to meet investment needs.
  - The lowest CO2 emission per kWh produced, and both high and low GHG potential
  - Fragmented and inefficient petroleum product sector with highly penalizing transport costs.

2.1 Background of the PIDA Energy Study

The AUC, NEPAD Secretariat and ADB are jointly sponsoring the Programme for Infrastructure Development in Africa (PIDA).The overarching objective of PIDA is to facilitate increased regional integration in Africa through improved regional and continental infrastructure. More specifically PIDA will:

- Establish a strategic framework for the development of regional and continental infrastructure in four sectors (Energy, Transport, Information and Communication Technologies (ICT), and Trans-boundary Water Resources (TWR)), based on a development vision for Africa, strategic objectives and sector policies;
- Establish an infrastructure development program over a time horizon up to 2040 using the strategic framework/sector policies; and

- Prepare an implementation strategy and processes, including in particular a priority action plan.

2.2 Scope of the Study and Report Structure

The scope of the study for the energy sector covers the supply, demand, production and transport of commercial energy (primary and secondary electricity, hydrocarbons, renewable energies) to the extent that they have a regional dimension.

The Africa Energy Sector Outlook 2040 attempts to project the balance between energy demand and supply for the 53 [1]African countries with a focus on the potential of regional energy market integration and for regional trade of energy, and a special consideration of synergies between different infrastructure modes. However, in line with the focus on energy systems integration and interconnections, the island nations of Cape Verde, Madagascar, Seychelles, Mauritius and Comoros Islands are not included in the study. The outlook results have been established by country, but for more clarity in the presentation of results, they are presented by region or Power pool, and at the continental level.

The membership of the Power Pools has been defined as follows (where countries in italics are member of more than one pool):

- WAPP: Senegal, Mali, Liberia, Guinea, Sierra Leone, Guinea Bissau, Côte d'Ivoire, Togo, Gambia, Niger, Benin, Burkina Faso, Nigeria and Ghana.
- SAPP: Namibia, Botswana, Swaziland, South Africa, Lesotho, Mozambique, Zimbabwe, *Angola*, *DRC,* Tanzania, Zambia, Malawi.
- CAPP: *Rwanda*, Cameroon, Equatorial Guinea, *DRC, Angola*, CAR, Gabon, Chad, *Burundi,* Congo.
- EAPP: *Egypt*, Sudan, Djibouti, *DRC*, Ethiopia, Tanzania, Kenya, Uganda, *Rwanda, Burundi*, Somalia, Eritrea.
- COMELEC/North Africa: Morocco, Algeria, Tunisia*, Libya, Egypt.*

In order to allow the comparison between the figures and conclusions produces by REC/Pool and the figures and policies of each REC/Pool, the duplication has been maintained in each pool, although the totals for Africa eliminate all duplications. The total for Africa is therefore not the sum of the RECs/Pools.

In line with the mounting concern on the sustainability of economic development and the impact of Green House Gas (GHG) emissions on climate, the projected energy supply options to meet the demand take specifically into account scenarios with, and without, consideration of CO_2 emissions and the impact of environmental considerations on investment requirements. These comparisons will offer a basis for policy making and development planning geared toward sustainable economic development in the African continent, taking into account the energy affordability issue (additional cost of low carbon scenarios and possible sources of financing).

The Africa Energy Sector Outlook 2040 comprises:

- An overview of the energy demand and supply outlook at the 2040 horizon, covering electricity, gas and petroleum products, CO_2 emissions and energy investment outlooks;
- A discussion on the energy outlook by region for Southern Africa, West Africa, East Africa, Central Africa and North Africa;

[1]South Sudan, which achieved independence in July 2011, is not included in the 53 countries

- An analysis of the major issues which are likely to affect the balance between energy demand and supply, with a focus on energy access, energy security, energy efficiency, and financing.

The structure of the Energy Sector Outlook 2040 is the following:

- Current situation in the sector: existing power plants, transmission systems 110kV and above, gas and petroleum pipelines at continental and REC levels
- Assumptions, scenarios, methodology for the development of Outlooks 2040
- Primary resources potential (hydro, oil, gas, coal, geothermal, wind, and solar)
- Energy Sector Outlook 2040 at the continental level (Electricity, gas, petroleum products)
- Energy Sector Outlook 2040 by sub-continental entities (PP, REC)
- Infrastructure needs to meet demand
  - Quantified infrastructure investment needs 2040 for power generation transmission, and for access
  - Quantified infrastructure investment in gas pipelines and petroleum products infrastructure
- Inter sector synergies (e.g with Transport, Water and ICT)
- Environmental perspective
- Financing Outlook
- Outlook related risks
  - Challenges, options for future developments in the power, gas and petroleum products sectors
  - Lessons to be learned from a review of selected regional investments and regional projects and a review of policy, regulatory and institutional arrangements
  - Policies, institutional arrangements and regulatory framework improvements and
- Project implementation and operation of regional projects
- Conclusions

2.3 Objectives of the Energy Sector Outlook 2040

2.3.1 The approach

The underlying vision of the Energy Sector Outlook 2040 is the vision articulated by the African Union (AU) since 2000 and reaffirmed recently by Africa's Ministers in charge of energy in the Maputo Declaration of November 5, 2010, namely the "*integration of the continent and to enhance access to modern energy services for the majority of the African population*". These objectives would be achieved by

- Developing major regional and continental hydroelectric projects;
- Implementing high capacity oil refineries and oil pipeline projects; and
- Developing renewable energy resources.

The Energy Sector Outlook 2040 will present:

- A continental vision of how the geographically allocated growth in energy demand resulting from economic development and increased access to modern energy will be met through the development of continental energy resources and of regional energy transport infrastructure,
- The main policy, institutional and financial challenges to be met to achieve the energy sector's long term vision, and options to meet the identified challenges
- The Energy Sector Outlook 2040 covers the power, domestic gas, and petroleum products sectors. It will be prepared at the Continental and Regional (REC) levels as the main purpose of the study is to promote integration of the continental energy market through transport between low cost production centres and demand centres.

Several sector development scenarios will be established, depending upon key policy options, detailed below with one central scenario representing the preferred option. Projected demand will be determined as follows:

- For the power sector, primarily through the underlying GDP growth for each country, industrialization prospects, population growth, access rate to modern energy, and expansion of grid-connected electricity;
- For the gas sector, based on projected gas consumption from the power sector and development of gas-based industries on the demand side, and prospects for gas resources development on the supply side;
- For petroleum products, based on demand for power generation and transport, and on the supply side, on prospects for the development of continental refining capacities and imports.

For the power sector, the Energy Sector Outlook will be developed using an economic optimization model for electricity supply-demand balance, with a separate transmission optimization model. The methodology used is similar to the approach adopted in the recent AICD study and in the Long Term Least Cost Development plans developed by the various power pools over the past three years2, adapted as needed to cover the entire continent. The PIDA approach integrates inter-pool exchanges add a focus on regional production/generation for energy security and transmission/transport projects, taking into account environmental, financial and energy security considerations.

2.3.2 The Starting Point

Under-exploited energy resources and under-served demand

Africa has 15% of the world's population but accounts for only 3% of the world's primary energy consumption (traditional energy and waste excluded) and 5-6% of world's final energy consumption (traditional energy and waste included). Electricity **consumption per capita is 1/6 of world overall average.** The continent therefore needs to bring about a major expansion of its already well identified energy potential.

Low access to modern energy throttles economic and social development

Access to modern forms of energy is essential for the provision of clean water, sanitation, and healthcare and is central to addressing today's global development challenges. Access enables the provision of vital services needed for development in the form of lighting, heating, cooking, mechanical power, transport and telecommunications services. It is estimated that 1.4 billion people- or 20% of the world population-currently lack access to electricity. Most of these people i.e. 585 million, or 42%, live in sub-Saharan Africa, where only 31% has access to electricity, the

[2] The SAPP, WAPP, EAPP, CAPP and the Maghreb countries, in particular

lowest percentage anywhere in the world (see Table). Of these, almost 80% live in rural households[3]

Table 1: ELECTRICITY ACCESS BY GEOGRAPHICAL REGION

REGION	People without Access (millions)	Percentage without Access
AFRICA	587	59
(Sub-Saharan Africa)	(585)	(69)
DEVELOPING ASIA	799	21
(China)	(8)	(1)
(India)	(404)	(33)
(Other Asia)	(387)	(10)
LATIN AMERICA	31	5
DEVELOPING COUNTRIES	1,438	24
WORLD	1,441	20

SOURCE: IEA Data Base and Analysis

High cost makes modern energy unaffordable for many and penalizes competitiveness

Outside of North Africa, the cost of energy services is much higher in Africa than in other parts of the developing world, where costs range from US$ 0.05-0.10 per kWh. There are several reasons for the high cost of electricity supply in SSA countries: (i) a majority of these countries are dependent on imported oil; (ii) the frequent recourse to high cost, emergency power generation often following drought conditions; and (iii) the poor quality of electricity supply in many networks which has led to investment in captive power plant generation. Average historical costs of different SSA power networks show wide variations: a few networks are based on low cost, indigenous energy (e.g. South Africa on coal and Zambia on hydro) while a much larger number of SSA networks have significantly higher total costs, in particular operating costs, reflecting their dependence on higher cost imported fuels for thermal power generation.

Table 2 : Average Electricity Costs, 2005 (US cents/kWh)

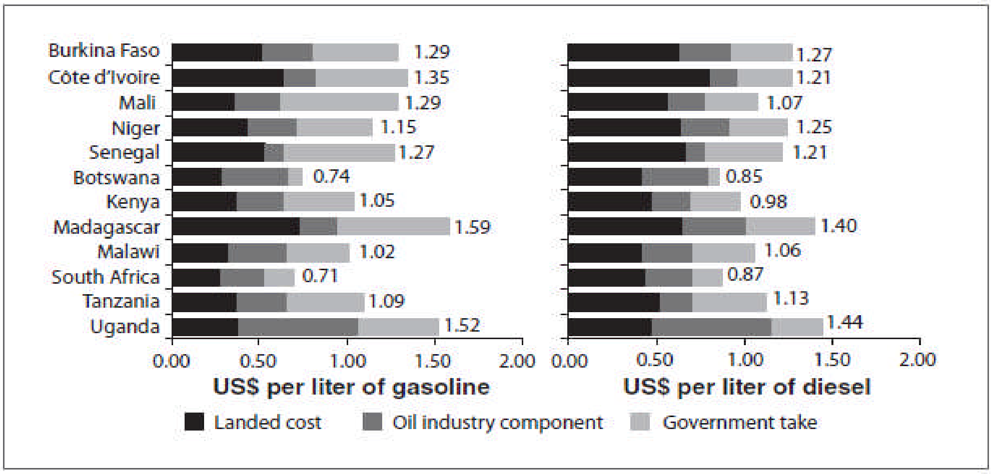
COUNTRY	Capital Costs	Operating Costs	TOTAL COSTS
Burkina Faso	7.0	17.0	24.0
Ghana	6.0	8.0	14.0
Kenya	5.0	8.0	13.0

[3]Energy Poverty How to make Energy Access Universal, IEA, Paris 2010

Tanzania	8.0	8.0	16.0
South Africa	2.0	3.0	5.0
Zambia	4.0	4.0	8.0

SOURCE: Briceno-Shkaratan, 2005

Costs of petroleum products are also high. A number of studies have documented the higher landed costs of these products i.e. before tax, in SSA countries when compared with global prices for the same products. Landed shipping costs of diesel at ports in SSA are typically 10-15% higher than in Europe4. In addition, the transport cost of petroleum products from African coastal ports to landlocked SSA countries adds further costs. The table below shows the variations in 'landed' i.e. pretax, gasoline and diesel prices for different SSA countries.



SOURCE: Petroleum Markets in Sub-Saharan Africa, ESMAP, 2010

The lowest SSA pretax costs (in South Africa) are much higher than the corresponding retail prices (in 2011) for gasoline and diesel in the North African countries of Algeria, Libya and Egypt.

A fragmented regional and continental market

Cross border power trade has yet to take off outside of the Southern Africa Power Pool (SAPP). In SAPP about 10% of total consumption came from trade activities in 2008, but this share dropped significantly thereafter due to generalized capacity shortages (see Table 2). However, even in the SAPP most of the trade – e.g., South Africa-Mozambique, Zambia-Namibia – is governed primarily by bilateral contracts. In West Africa, power trade is only 5% of total consumption.

Table3: Regional Electricity trade, 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

[4]Sub-Saharan Petroleum Transportation Corridors, UNDP/World Bank 2003

Source: EIA, 2008.

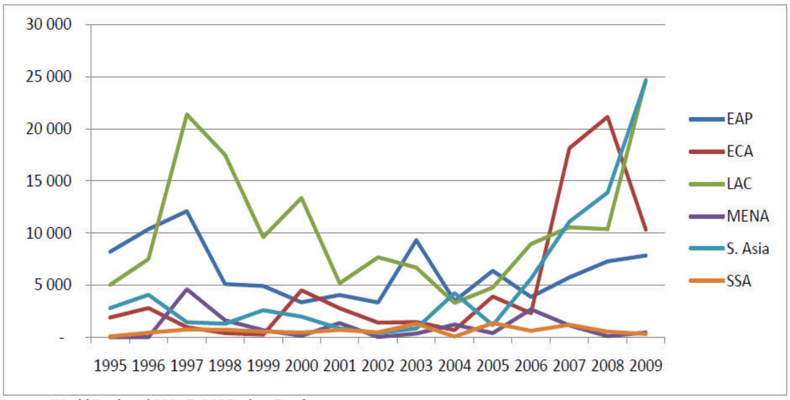
In the meantime, many sub-Saharan African countries continue to experience an acute shortage in energy supply, which will take time to eliminate. Expanding regional energy integration is an essential step to improve availability at households level if these universal access goals are to be achieved.

The incentive to pool energy resources is thus strong and led to the formation of regional power pools in the 1990s.

A low capacity to attract commercial financing to meet investment needs

Africa's investment needs in the energy sector are enormous, with the bulk of this investment required in electric power. Estimates in the context of the PIDA study indicate that US$39 billion annually will be needed in new investment to meet the access targets by 2040, which compares with a current investment of less than US$ 5 billion annually. Given the magnitude of future needs, private sector participation in power sector investment is unavoidable. Globally, the power sector has been successful in attracting private investment. In 2009, the power sectors in South Asia and Latin America were able to attract $68.5 billion through private participation. In contrast, private sector participation in 2009 contributed only US$ 450 million (equivalent to 10% of total investment). Unless SSA countries are able to attract private participation in significant amounts, the ambitious investment targets in power will not be achieved. A comparison of PPI by developing region over the period 1995-2009 is shown below.

Figure1: PPI Investment in Power by Region, 1995-2009



Source: World Bank and PPIAF, PPI Project Database

The high perceived risk of investment in the power sector results from a combination of: (i) high sovereign country risk of African countries5; and (ii) generally weak finances of the electric utilities in most African countries. The issue of the high country risk is confirmed by the very low credit rating granted by rating agencies indicating that amongst those African countries rated, only six (marked in green in the table below) are rated "investment grade". A similar conclusion is reached by the Export Credit rating of the OECD6, which gives the highest risk mark of 6 or 7 to most African countries, with few exceptions7, sending a clearly negative message to potential private investors.

[5] The prominence of sovereign political risk in the failure of private sector investment in the energy sector is established in Ananda Covindassamy *"Designing Strategies and Instruments to Address Power Project Stress Situations"* ESMAP Formal Report 329-09, 2009, which shows that more than half of power projects that failed, or went through stress situations, were confronted by political risk, and that the frequency of occurrence of the political risk is higher in Africa than in other regions.

[6] See http://www.oecd.org/dataoecd/47/29/3782900.pdf for export credit risk rating as of 2011.

[7] Algeria: 3; Botswana: 3; Egypt: 4; Gabon: 5; Morocco: 3; Namibia: 3; Nigeria: 5; South Africa: 3; Tunisia: 3

Table 4: Rating risk

Country	S&P equivalent rating	Notches below IG
Angola	B+	4
Benin	B	5
Botswana	A	
Burkina	B	5
Cameroon	B	5
Cape Verde	B+	4
Egypt	BB+	1
Gabon	BB-	3
Gambia	CCC	8
Ghana	B+	4
Kenya	B+	4
Lesotho	BB-	3
Libya	BBB+	
Malawi	CCC+	7
Mali	B-	6
Morocco	BBB-	
Mozambique	B+	4
Namibia	BBB-	
Nigeria	BB-	3
Rwanda	B	5
Senegal	B+	4
South Africa	BBB+	
Tunisia	BBB	
Uganda	B	5

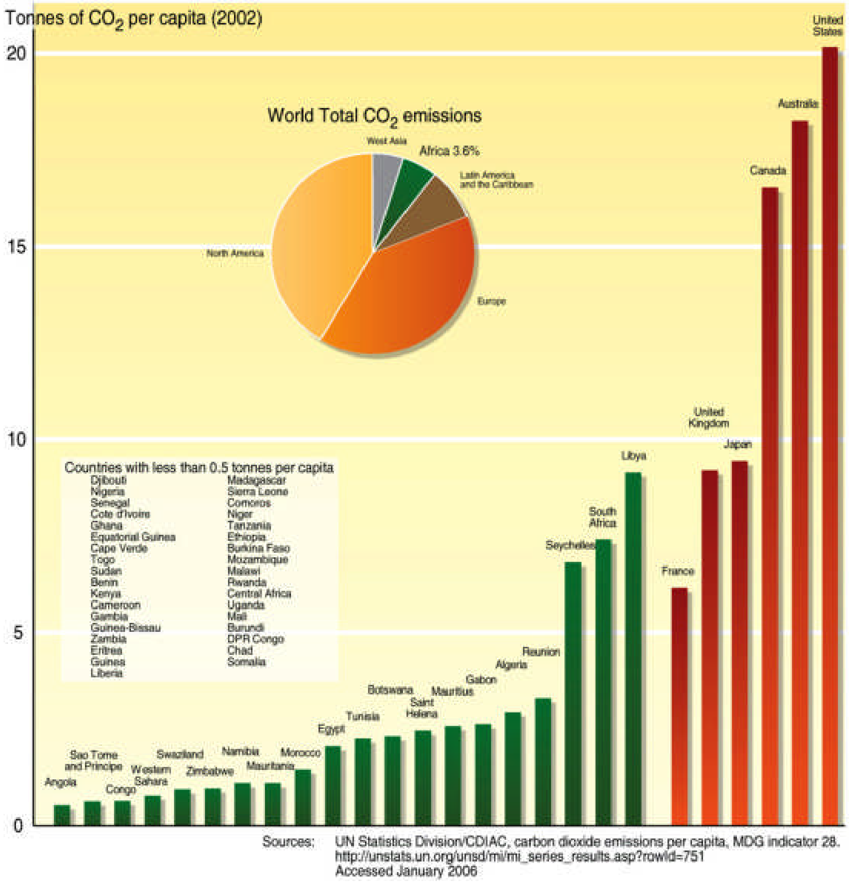
Moreover, the evaluation of the creditworthiness of the energy sectors in Africa on its own is generally discouraging, despite more than two decade of attempted reforms. Most African utilities are under financial stress, with the exception of the utilities of South Africa, Morocco, Tunisia, Egypt, Namibia, Rwanda, and Cameroun (which demonstrates that, with the right Government policies and right management, African utilities, either private or public, can be creditworthy).

As a result of well-known sector issues, including a culture of non-payment of electricity by public as well as private consumers and poor utilities' governance, compounded by political tariffs, the cash flow of the utilities is too weak to make them partners in good standing for private investors.

A continent with the lowest CO2 emission per capita

Africa represents only a small fraction-just 3.6%- of global carbon dioxide (CO_2) emissions per year, even though it has 14% of world population, reflecting the low energy intensity of the economy as well as the low level of access to basic energy services. South Africa is the largest single emitter of CO_2 emissions in the African continent, reflecting the predominance of coal in power generation and the economy's higher energy intensity. Most African countries have emissions per capita at very low levels compared to other countries.

Figure2: Emissions of Carbon Dioxide in Africa in comparison with OECD Countries



Africa should be able to maintain its low contribution to global carbon emissions as demand for energy grows through (i) developing its large hydro resources; (ii) gradual replacement of coal-based power generation by lower carbon emitting fossil fuels such as natural gas; and (iii) development of its significant geothermal, wind, and solar potential.

3. CURRENT SITUATION: EXISTING STOCK OF REGIONAL INFRASTRUCTURE AND SERVICES

- Africa has the lowest electricity capacity per capita in the world (123 MW/million population).
- Installed capacity is 125 GW, of which 20% hydro (low, but highest of any continent).
- Most power generation units are too small to be efficient (250 MW on average, 166 MW for hydro plants).
- Hydro is strong in the central area (70% in CAPP) but much less so in other regions (only 10% in COMELEC) which have a strong endowment in coal (SAPP) or gas (WAPP, EAPP, and COMELEC).
- Transmission system is limited in length (89 000 km only)
- Regional systems have primarily a country focus and tend not to be interconnected; nor are they designed for facilitating regional systems integration
- Future plans of the RECs for generation include a number of plants for regional integration, but do not include plans for expanding inter-REC transmission capacity
- Gas and petroleum products pipelines are limited .

The development of the PIDA Energy program builds upon the existing energy infrastructure (power, gas and petroleum pipelines), and take into account the lessons learned from the implementation and operation of regional infrastructure projects, in order to accelerate project preparation and implementation, and improve the sustainability of their operation.

The study also takes into account the priorities in regional projects established by the RECs and integrating it in an optimized continental program. The present section will therefore identify, in addition to existing energy infrastructure, priority projects retained by the RECs for (i) capacity building;(ii) preparatory work needed for regional energy investments; and (iii) specific power generation, transmission and gas pipeline investments.

3.1 Continental and Regional Energy Infrastructure:

As long as national energy systems are interconnected, as is the case for most of the power systems of Africa, except for a few isolated national systems such as Guinea, it is difficult to separate regional infrastructure from national infrastructure. It was therefore decided to review all the major energy infrastructure of the continent with a view to assessing the extent to which they have played, or could play, a role in the development of an integrated continental energy system. The inventory has been conducted on the basis of information available from three main sources:

- Information collected under the AICD program in 2007-08

- Data available in the long term development plans of the RECs/Pools prepared between 2007 and 2010 depending upon the Regions
- Updates collected directly from the RECs and Pools during field visits

Information concerning the North Africa power system was collected from the recent study prepared under EU financing for the integration of the market of the Maghreb countries undertaken by SOFRECO[8].

The information collected on continental energy infrastructure has been entered into a data base suitable for periodic updating under a GIS system which was delivered to the ADB. Some summary maps are given in the sections below.

3.1.1 Power systems

The description focuses on national and regional power systems, which have the potential to play a role at the regional and continental level. It covers transmission lines above 110 kV, considering that lines with a capacity below 110 kV may not have a capacity sufficient to contribute significantly to regional exchanges of electricity. Small power plants are unlikely to contribute significantly to regional integration and exchanges. The inventory of plants has therefore been limited to those with a capacity above 50 MW. In this regard, it should be noted that in many cases, small plants with a capacity below 50 MW supply local isolated systems and therefore, cannot contribute to regional electricity trade.

Generation

In line with the AU vision for the energy sector, which focuses in particular on energy security and low carbon emissions, the description of the African generation system distinguishes technologies that increase energy security and have low carbon emissions. The plants are therefore classified by size (large plants with a capacity above 500 MW, medium size plants with a size between 100 MW and 499 MW, and smaller plants, with limited potential regional role, and with a capacity below 99 MW and above 50 MW) and technology using three categories: thermal plants, hydro, and other (biomass, geothermal, wind, solar) .

Continental overview

The supporting tables with a list of all African power plants are given in Annex 8.1 and summarized in the overall map and table below.

It indicates that, at the continental level, most of the existing capacity is thermal (88%) because of the size of the North African and South African systems, which are predominantly thermal, whereas the central and eastern regions of Africa have a larger proportion of hydro plants. The small contribution of ‘Other’ technologies (wind, solar, biomass) is also conspicuous, although this category is starting to develop rapidly, with large developments of wind in Morocco and Egypt in particular, and of geothermal in Kenya.

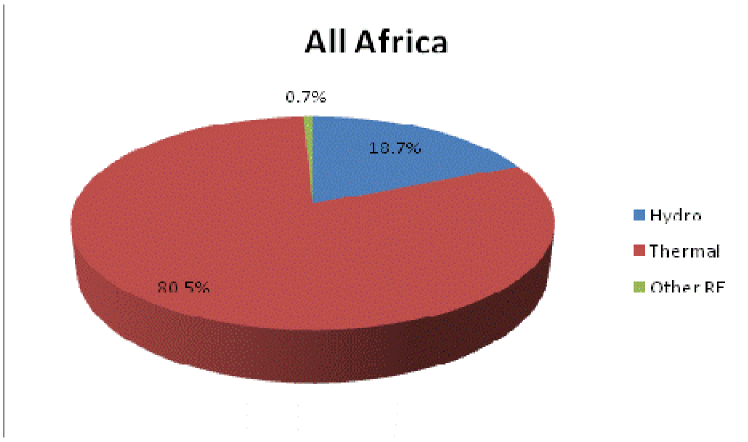
[8]« Intégration progressive des marchés d'électricité de l'Algérie, du Maroc et de la Tunisie dans le marché intérieur de l'électricité de l'Union Européenne » SOFRECO, Europaid, May 2010

Table 5: Existing Installed Generation Capacity of Africa in MW (plants> 50 MW)

Plant Type	Installed Capacity
Thermal	100,939
Hydro	24,273
Other	906
Total Africa	125,318

Source: PIDA Data Base

Figure 3: Technological mix of Africa in %



The comparison between Africa and other continents highlight the low levels of installed power generation capacity per capita, and per unit of GDP, leading to the conclusion that there is clearly under-investment in Africa in terms of power generation infrastructure.

Table 6: Generation capacity per capita and per unit GDP, Africa and Rest of the World

Continent	Capacity per capita (MW/million population)	Capacity per unit of GDP (MW/billion of GDP)
Africa	123	106
Asia	3,600	121
Latin America	515	60
Eastern Europe/Cent. Asia	1,078	144

Source: EIA Statistics

Compared to other continents and based on 2008 data, Africa stands out as the continent with the largest share of hydro. In the long term, the share of hydro in Asia is projected to decrease further to less than 12% by 2030. Africa is already the continent with the largest share of hydro in its generation mix, and this feature is projected to be sustained in the future.

Table 7: Generation Technology Mix by Continent, 2008

Plant Type	Hydro	Thermal
Africa	19%	80%
Asia	13%	87%

Power plants in Africa are generally small, reflecting the fragmented nature of African power systems and the tradition of national autonomy of power systems, even for small systems. This characteristic of African power generation plants imposes a cost penalty on African power systems, as smaller units tend to be less efficient and more costly per kW installed. This general rule applies both to thermal plants and hydro plants[9].

Table 8: Average Size of Plants in MW

Plant Type	Average Plant Size (MW)
Thermal	306
Hydro	159
Other	70
Overall Average	**255**

Source: PIDA Data Base

The overall map of power plants in Africa is given below, and details are available in the PIDA Data base.

[9] The analysis of construction costs and efficiency by unit size is summarized below (based on 2008 ESMAP Study of Equipment Price in the Power Sector):

	Diesel		Gas turbine		CCGT		Steam coal	
Size	100 kW	5 MW	25 MW	150 MW	100 MW	400 MW	300 MW	500 MW
Efficiency	38%	43%	36.6%	34%	51%	54%	40.9%	41.5%
Cost/kW	640	600	970	530	700	550	1 690	1 440

Regional Power Generation

The allocation of power generation by REC shows that the regions are very diverse in terms of installed capacity, with the COMELEC, EAPP and SAPP regions dominating the WAPP and CAPP regions because of the presence of Egypt in COMELEC and EAPP and South Africa in SAPP[10]. The disparity is even stronger when considering installed capacity per capita.

Power plants in Africa 2011

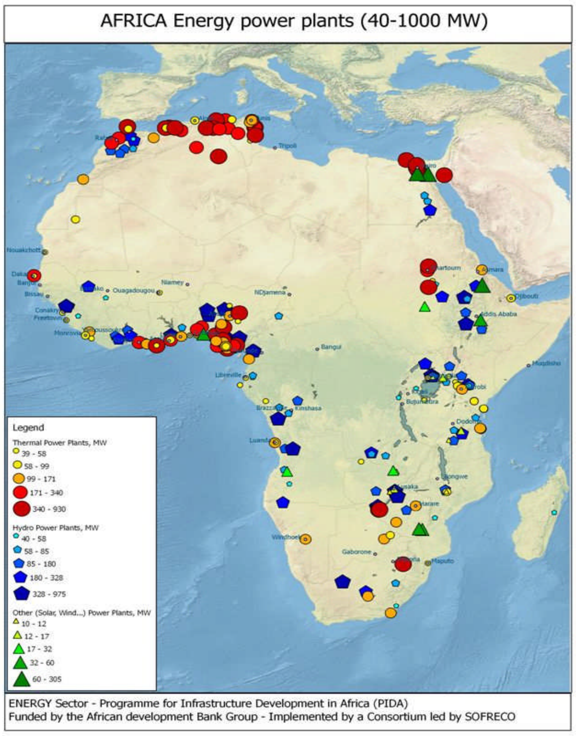


Table 9: Installed capacity per REC and per capita

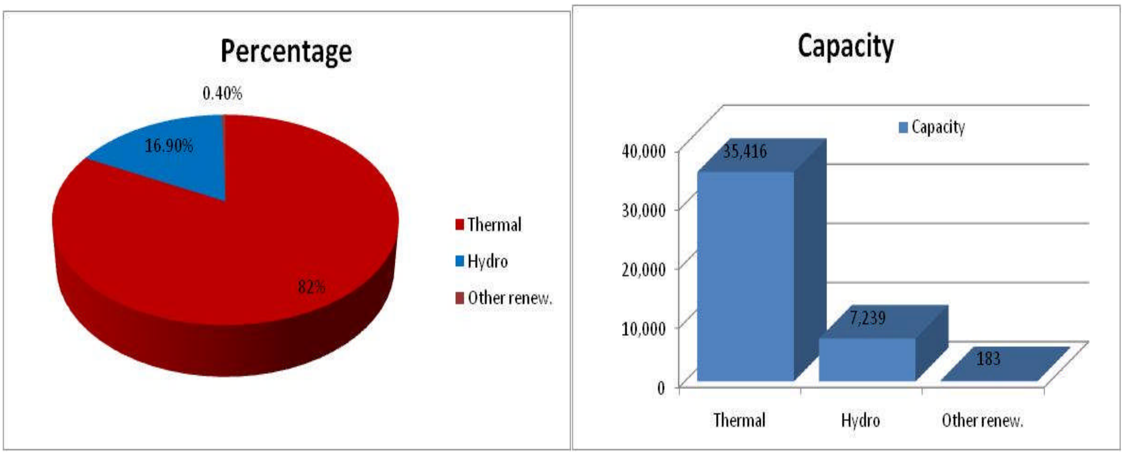
REC/Pool	Installed Capacity (MW)	Installed Capacity/capita (MW/million)
COMELEC	53,558	339
WAPP	13,456	48
EAPP	42,838	213
CAPP	3,584	27
SAPP	49,316	110

[10] There is come overlap in the membership of the various Regional entities. Egypt is included in North Africa/COMELEC and EAPP; DRC in included in SAPP, EAPP and CAPP; Angola is included in SAPP and CAPP; Burundi is included in CAPP and EAPP. Rwanda is a member of EAPP and CAPP; and Tanzania is a member of SAPP and EAPP

Eastern Africa Power Generation System

The generation systems of most EAPP countries have a high share of hydro, particularly Ethiopia and to a lesser extent Tanzania, Kenya and Uganda, but the presence of Egypt, which is mainly thermal, leads to an overall share of hydro of only 17%. EAPP has also some non-hydro renewable energy in geothermal (Kenya) and wind (Egypt and Kenya).

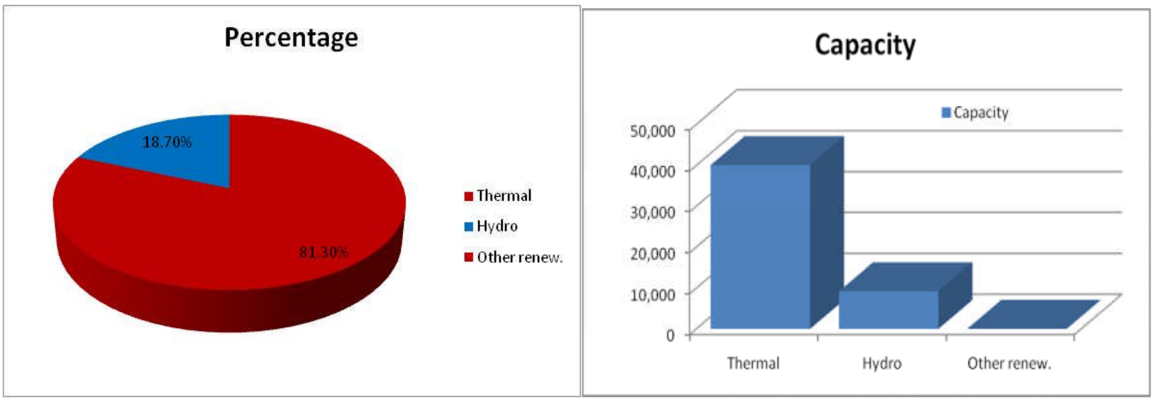
Figure 4: Generation technologies in EAPP (% and capacity in MW)



Southern Africa Power Generation System

The Southern Africa Power System is dominated by South Africa, which represents 37,897 MW (76%) of installed capacity compared to a regional total of 49,316 MW. The generation system comprises of a large proportion of thermal plants, mainly coal fired capacity in South Africa, although the region has a substantial hydro potential in the Zambezi basin, where Cahora Bassa and Kariba are already developed.

Figure 5: Generation technologies in SAPP (% and capacity in MW)

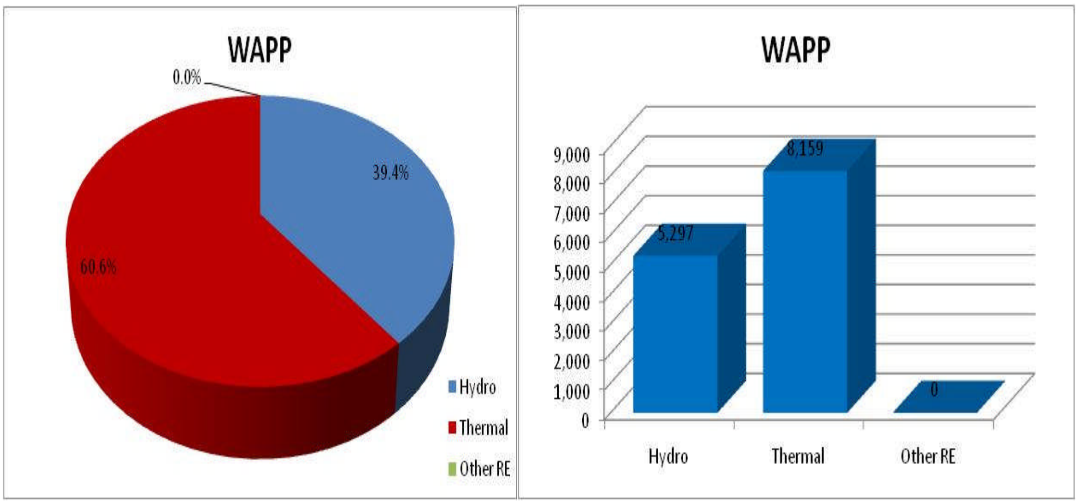


Western African Power System

The WAPP generation system is small compared to other regional systems, and is dominated by thermal generation capacity. Most power plants use imported Diesel and HFO, except Nigeria, which uses gas for power generation.

The hydro potential of the region is significant in Guinea, (though not yet developed) and in the Senegal, Gambia and Niger basins (which are under development).

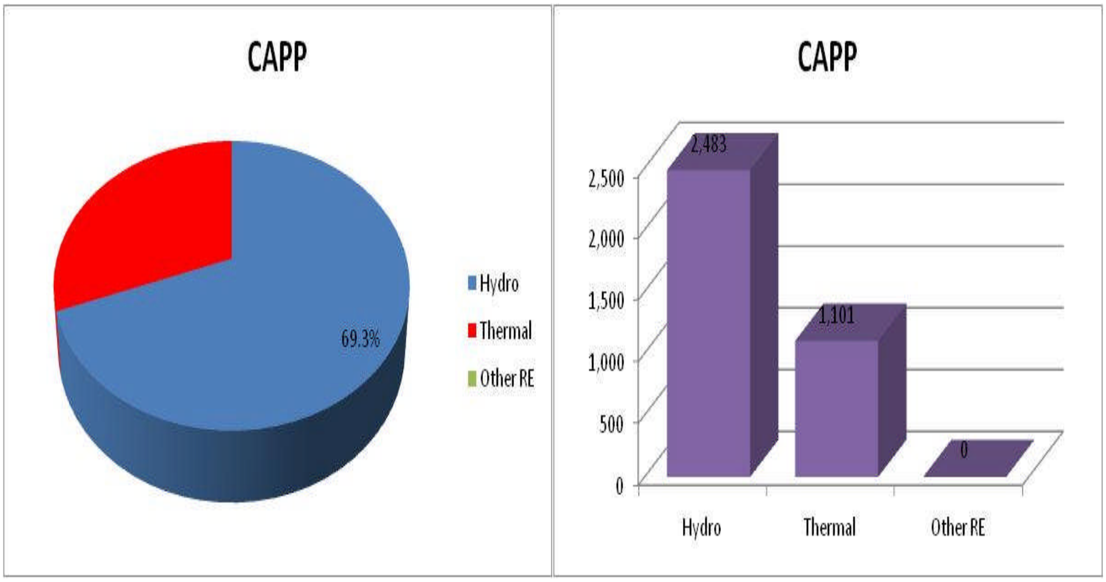
Figure 6: Generation technologies in WAPP (% and capacity in MW)



Central African Power System

The CAPP is small compared to other regional systems. It has the largest share of existing hydro generation because of the large share of hydro in the systems of Cameroon and the DRC.

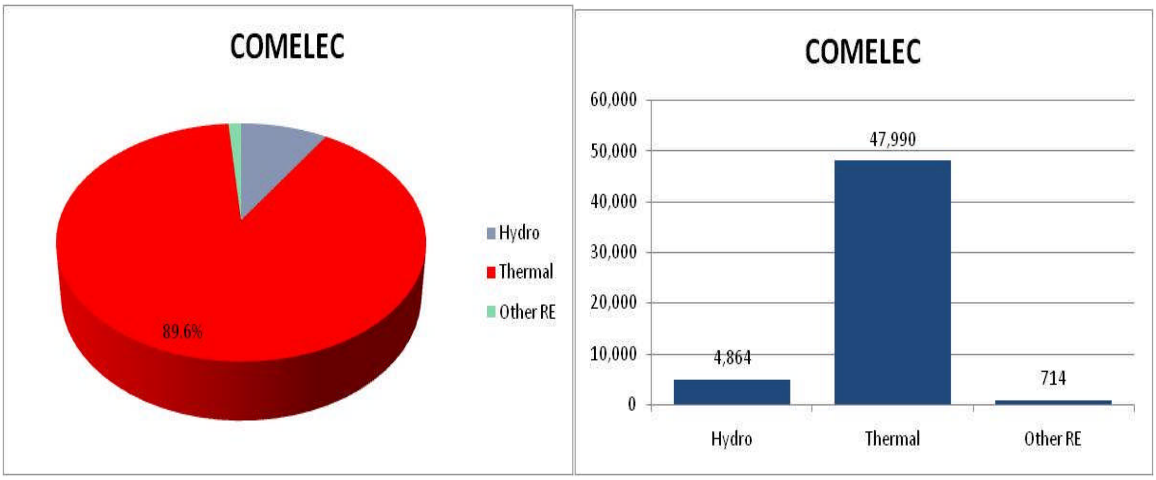
Figure 7: Generation technologies in CAPP (% and capacity in MW)



North Africa COMELEC

The COMELEC region is relatively large at the continental level because of the importance of Egypt and to a lesser extent, Morocco. Thermal capacity is dominant because of the poor hydro endowment of the region (despite the hydro potential of the Nile River, in Egypt, already exploited) and the significant gas endowment of Egypt and Algeria, and to some extent, of Tunisia. Morocco, which has no significant hydrocarbon resources, has developed most of its thermal capacity based on imported coal. COMELEC has started developing its non-hydro renewable energy potential with wind plants in Morocco and Egypt (under development) and, to a lesser extent, in Tunisia. Large solar developments are being considered but are still at the conceptual stage.

Figure 8: Generation technologies in COMELEC (% and capacity in MW)



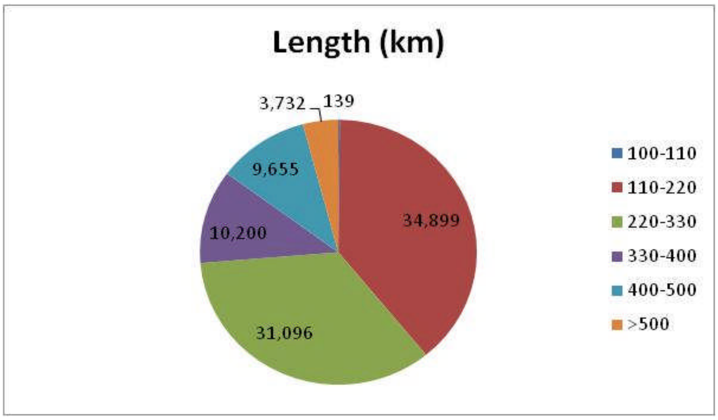
Except for the North Africa and Southern Africa regions where the high proportion of thermal in the generation mix reflects the natural endowment of these regions, the generation mix in the other regions does not reflect the regions' natural endowment, mainly because of poor planning, which favours the development of thermal capacity over hydro because of the shorter construction period of thermal plants and low upfront investment.

Transmission

Overview of continental transmission system

The existing African transmission system (defined as lines with a voltage equal or above 100 kV) has a total length of 89,731km. It is small compared to the area of the continent, corresponding to a density of 3.29 meters of transmission line per square km (details in Annex 8-2).

Figure 9: African Transmission System

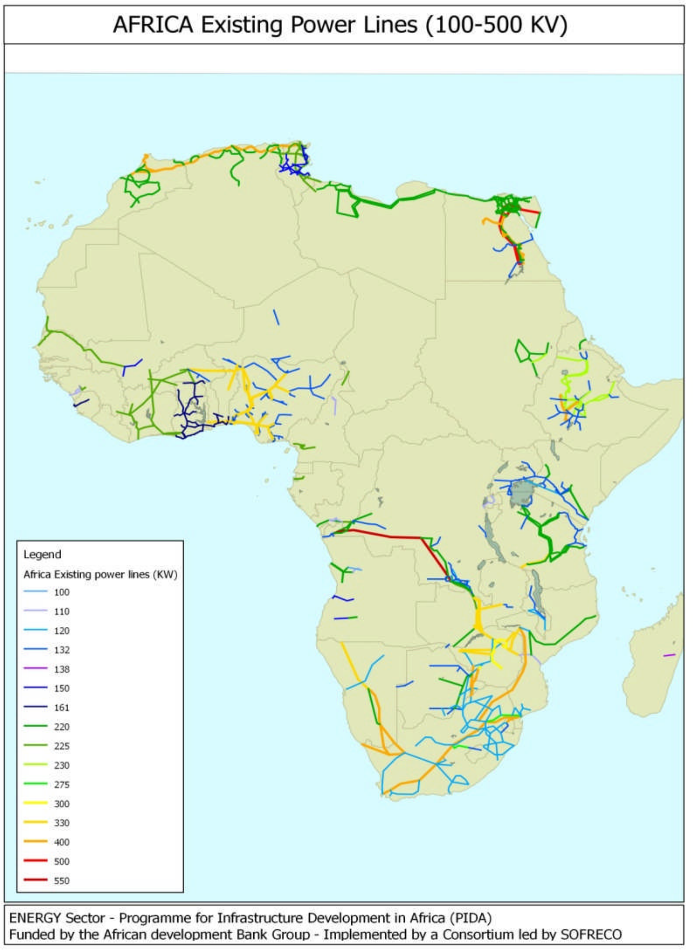


Besides the low density of the transmission system, the other striking feature is the absence of unified or standardized specifications. Africa has at least 15 levels of transmission line voltages from 110 kV to 700 kV.

The transmission systems as of 2009, as shown in the map below (and further detailed in the PIDA Data Base and in Annex 8.2) do not represent a continental or regional network. They were developed as independent systems, mainly structured from the coast to the interior, except for the Southern Africa system, which is structured as a national network. Even the North Africa system runs essentially along the Mediterranean coast, with a few spurs inland. The map below shows that the North Africa and Southern Africa systems could nevertheless allow for significant intra-regional exchanges, while this is not the case for the West Africa and East Africa systems.

The continental transmission system includes primarily lines with a voltage of about 110 kV, with some sections at 220 kV and only a few sections at 400 kV. The transmission capacity of the system for regional exchanges is therefore very limited. Overall, the key conclusion is that, at the continental level, the present transmission system is inadequate to provide for the long distance transmission services needed to allow the development of regional generation capacity and system integration, and will be a major bottleneck for systems integration.

Figure 10: Main existing transmission lines

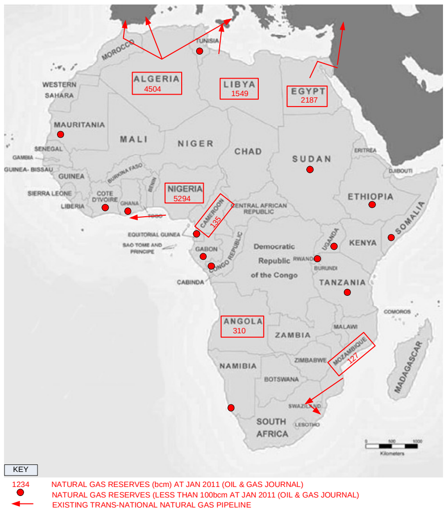


3.1.2 Natural Gas and Petroleum Products Infrastructure

Africa's Natural Gas Pipeline Network

The African continent's main regional gas pipeline network is in North Africa, where gas is being exported from Algeria and Libya via Morocco to southern Europe. Regional gas pipeline systems also exist in Southern Africa between Mozambique and South Africa as well as in West Africa between Nigeria and Ghana, with spur connections to Benin and Togo. These gas pipeline systems are summarized in Annex 8.3.

Figure 11: African Continent's Natural Gas Pipeline Network



NORTH AFRICA

Algeria has three existing export pipeline systems as follows:

- **Medgaz**, the most recently completed, takes gas from the pipeline system at Arzew and crosses the Mediterranean from Beni Saf to a landfall near Almeria in southern Spain;
- **PDF (Maghreb)**, which goes direct from the major gas fields at Hassi R'Mel in central Algeria, crosses Morocco to Tangiers and from there across the Straits of Gibraltar to Tarifa in Spain;
- The **Trans-Mediterranean** Pipeline system, supplied by the **GEM** (Gazoduc Enrico Mattei) pipelines from Hassi R'Mel which cross Tunisia, consists of 4 parallel lines from south of Tunis to Sicily in Italy.

Proposals exist for another pipeline system, GALSI, across the Mediterranean from El Kala in Algeria, crossing to Sardinia and from there to a more northerly landfall in Italy south of Livorno. Algeria exported approximately 60 bcm of gas by pipeline or LNG to Europe in 2010, a volume which is projected to rise to 72 bcm by 2030. If GALSI is also completed, Algeria's total export pipeline capacity would probably be sufficient to accommodate the projected volumes available through the proposed Trans-Sahara pipeline from Nigeria (see below).

Libya exports gas through the **Green Stream** pipeline which crosses from Mellitta to Sicily where it connects to the Italian transmission system. Libya exported around 10 bcm in 2009, mostly by pipeline with 0.7 bcm as LNG.

Egypt exports gas by pipeline (to Jordan, Syria and Lebanon as well as to Israel) and as LNG to Europe.

WEST AFRICA

The **West African Gas Pipeline** (WAGP)is owned and operated by the West African Gas Pipeline Company and transports gas from the Escravos to Lagos system (ELPS) in**Nigeria** to consumers in **Benin, Togo and Ghana**. It is 620 km in length and consists of both offshore and onshore sections. There is also interest in expanding the pipeline further west to the **Cote d'Ivoire**. The pipeline was completed in 2009 and its current throughput is 100 mmscf/day.

Ghana has recently discovered significant oil and gas reserves in its offshore waters. The National Petroleum Corporation (GNPC) is planning an offshore gas gathering system for the associated gas feeding into a gas processing plant at Domini and from there to power stations at Effasu and Aboadze. GNPC also sees the possibility of Ghanaian gas being transported through the WAGP. The expected increase in reserves following the new field discoveries could also generate other export opportunities, both regionally and for LNG export.

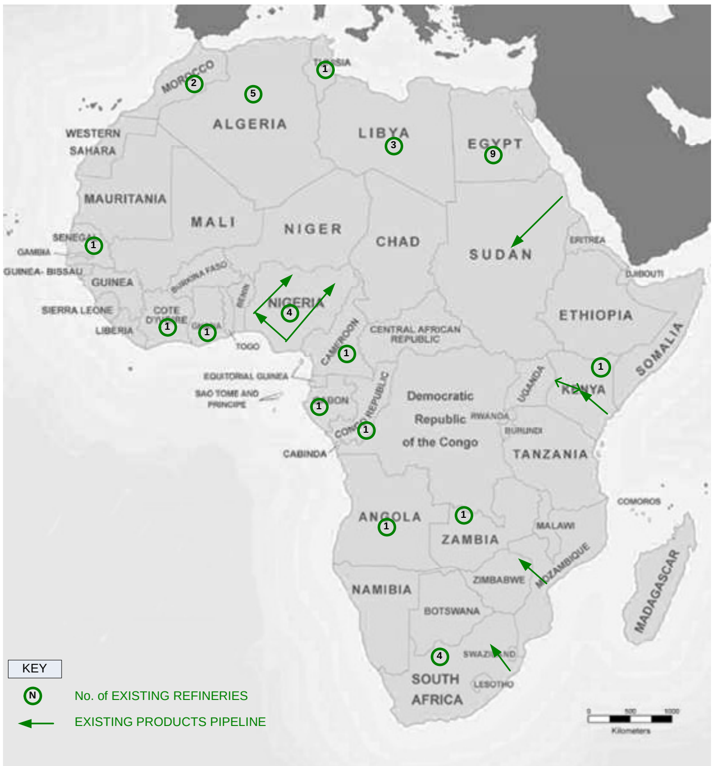
SOUTHERN AFRICA

The **Mozambique – South Africa Pipeline** exports gas from the Pande and Temane fields in Mozambique to the SASOL coal to liquids plant in Secunda and from there to Richard's Bay and Durban in South Africa. This southern Africa regional gas project was first developed in 2004 to supply natural gas from two fields in Mozambique, discovered during the 1960s, to the SASOL plant in South Africa.

Petroleum Products Pipelines

Existing regional or continental petroleum products pipelines in Africa are very limited, with most of the existing petroleum products pipelines serving national markets. Annex 8-5 lists the existing products pipeline systems.

Figure 12: Africa's Oil Products Pipeline Network



NORTH, WEST and CENTRAL AFRICA

The existing product pipelines in these three regions are for national distribution only and are **not extensive.**

SOUTHERN AFRICA

Mozambique (Biera) to **Zimbabwe** (Mutare/ Harare) is a regional products pipeline used by Zimbabwe and Malawi to import refined products through the port of Beira. Products are transported by road from Mutare to Malawi.

South Africa's products pipeline network is extensive but serves its domestic market. There have also been studies into a possible products pipeline from Maputo (Mozambique) to Witbank (near Pretoria) in South Africa, which would utilize part of the route of the existing gas pipeline.

EASTERN AFRICA

Kenya has an internal products pipeline distribution system, which links the port of Mombasa and its refinery to Nairobi. The system extends through two further pipelines to Eldoret and Kisumu. There are proposals to connect this system from Eldoret to Kampala in Uganda (see below).

Tanzaniais proposing the construction of an oil refinery anda 1200 km long pipeline from Dar es Salaam to Mwanza on the southern shores of Lake Victoria. If the pipeline project is successful, it could be extended to Uganda, Burundi, and Rwanda in the future. There exists a crude oil pipeline between Dar es Salaam (Tanzania) to Ndola (Zambia). The Zambian Government has commissioned a study to examine upgrading options.

Refineries

Annex 10-4 tabulates a list of the existing oil refineries, with nameplate capacity, in Africa, by country and the map above shows their relative locations around the continent. The locations of the major refineries are predominantly in the oil producing regions in West and North Africa although a number of other refineries, using imported crude oils operate as well.

Of the 38 total number, 25 are simple processing plants and mostly low capacity, although some of those in Egypt have significant capacity. The total nameplate capacity is over 3 million barrels per day (bpd) but the actual production capacity is significantly lower than that figure.

3.2 Inventory of all projects under implementation and preparation (project Brief /Project Sheets)

3.2.1 Project locations

A list and map of regional energy projects under implementation, preparation or at planning stage (past conceptual stage) by REC and by type of project (transmission, hydro power, thermal power, renewable, capacity building) has been prepared and is attached in Annex 8.1. A distinction has been made between (a) projects in support of the preparation of a physical investment (preparatory studies and capacity building), and (b) projects financing the physical implementation of regional investments.

In the case where a project is recognized as a priority by several regional institutions (AUC and RECs), it is listed under the program of both institutions. A major challenge was to obtain information on regional projects from various institutions at the same cut-off date. Information were collected and updated to the extent possible asof end-2010 date. Priority was given to projects included in the programs of continental and regional institutions. Programs of Development partners (IFIs such as AfDB, World Bank, EIB, IDB, DBSA, etc) and bilateral partners (AFD, KfW/GTZ, DFID, China EXIM, etc) were not considered as primary sources of information because they may not reflect exactly the priorities of African political organizations. They were used, however, to update the regional energy programs when needed.

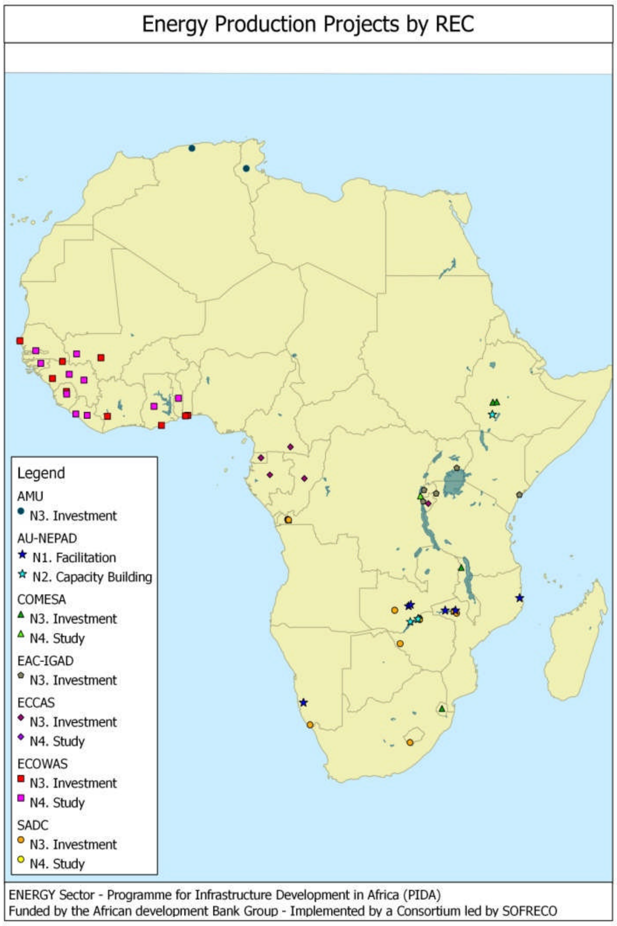
Regional generation projects

The portfolio of projects supported by the RECs indicates a strong focus on hydro projects and also an un-even geographical distribution. However, the hydro option, despite its positive aspect in terms of low GHG emissions, ease of operation, contribution to energy security, raises also several challenges:

- A more complex, costly and time consuming preparation requiring careful advance planning;
- A stronger institutional and technical capability for project preparation;
- More financing per unit of capacity, in a region where capital scarcity is the main challenge, and there is less interest from the private sector; and
- An ambivalent attitude of donors towards large regional hydro projects, welcoming the low GHG impact, but easily deterred by the potential controversial aspects of hydro project, long preparation time, costly development, socio-environmental impact, and high upfront financing requirements.

In terms of regional distribution, new generation projects are concentrated in West Africa and in the EAPP region-but with few regional projects identified at the level of regional entities.

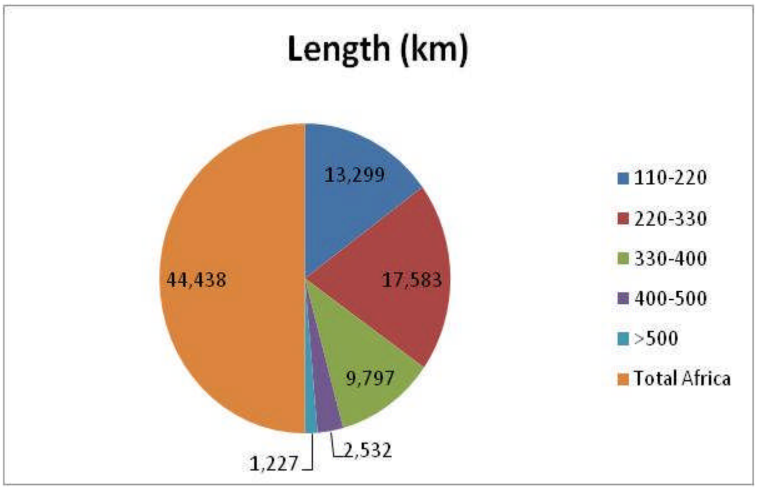
Figure 12: Energy production projects



Regional Transmission projects

The consolidated list of transmission projects under consideration by the RECs indicates that new lines would contribute significantly to the integration of the African transmission systems but it focuses more on the densification of intra-regional systems than on continental integration. The length of the proposed transmission projects is given in the graph below.

Figure 13: Length of regional transmission system by voltage level



The projects envisaged by the RECs would contribute to integration through

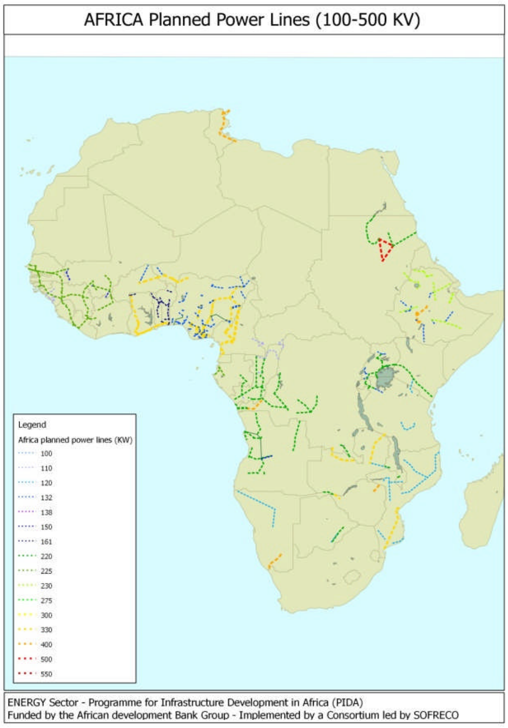
- The interconnection of the Egyptian systems with Ethiopia and Eritrea;
- The connection of the northern EAPP countries with Kenya and the southern countries
- The connection of eastern EAPP countries with the Great Lake region
- The connection of the Great lake region with the SAPP countries
- The densification of the regional system in West and Central Africa

However, a number of gaps remain, particularly:

- The connection of SAPP to CAPP on the western side,
- The interconnection between CAPP and WAPP
- An EAPP to WAPP connection, and
- The interconnection between COMELEC and WAPP

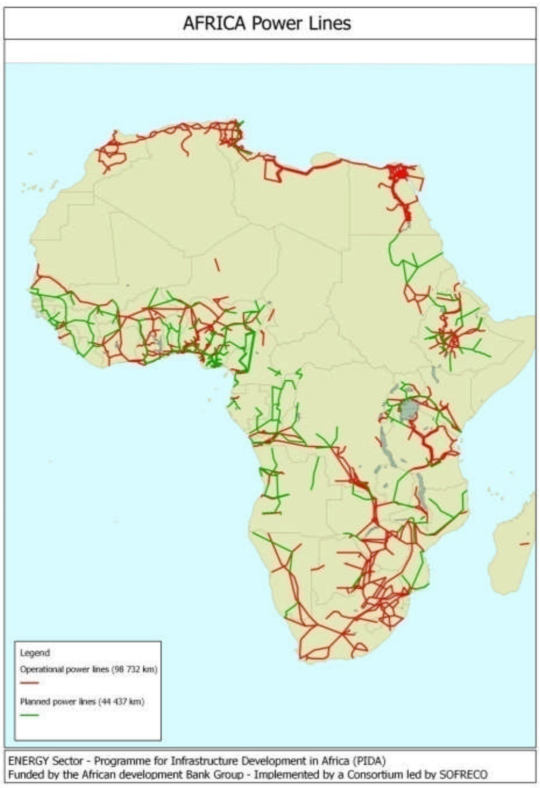
Overall, the effort of the RECs seems to be more inward than outward looking for inter-REC interconnections and continental exchanges.

Figure 14: Development of the Transmission System planned by the Pools



The complementarity between the existing power lines and the developments envisaged by the RECs/Pools is clear in the map below, which confirms that the extensions of the transmission systems aim mainly at the densification of the intra-REC/Pool systems than at the interconnection of Power Pools.

Figure 15: Africa Transmission Lines



3.2.2 Project Sheets

A set of regional project sheets has been prepared and is given in Annex 8.4 following a standardized format. The sheets cover most of the projects listed in the preceding section, with the exception of projects at the conceptual stage, which cannot be documented in detail. The sheets are presented by REC and include the estimated costs of preparatory studies as well as estimated investment costs, including starting and expected completion dates. Information presented in the sheets was provided by the RECs' development plans, updated by information provided by financial institutions.

4. METHODOLOGY, ASSUMPTIONS AND SCENARIOS

- Average GDP growth was taken as 6.2% for all Africa, differentiated by country
- GDP elasticity of demand has been estimated through an econometric model as ranging from 0.8 to 1.3 with an average of 1.25, which is normal for economies in the process of modernization
- Access to electricity is projected to increase so all countries will have an access rate above 60% by 2040. Average access will improve from 40% at present (including North Africa) to 69% by 2040
- Increase in access will be faster in EAPP, SAPP and CAPP, because they start from a lower level, but then converge to the African average.
- Investment needed to connect 140 million households (800 million people) is a relatively modest US$ 3.5 billion per year, mainly in EAPP, WAPP and SAPP
- The additional demand resulting from an aggressive continental access policy is only 7% of demand in 2020 and 13% in 2030
- Despite the development of mineral resources, the share of industry in demand is projected to decrease from 69% to 57%, as most extractive industries are self-generators and do not rely on the grid for their electricity supply
- All candidate plants for meeting future demand are considered with their site specific costs and characteristics, except for generic gas turbine costs for peaking purposes, with fuel costs adjusted for delivery at the plant door
- Key planning parameters are:
  - Energy efficiency gains of up to 20% will materialize over the coming 20 years
  - Improving energy security by reducing imports of fuels through regional trade: three trade development scenarios (Low, High, Medium). The Medium trade development is taken as the base case with imports allowed to increase to between 30% and 100% of demand (except for South Africa) Fuel prices are projected based on future oil price reaching US$ 820 per tonne (US$ 113.bbl) in 2000 prices
  - Although Africa represents only 4% of world GHG emissions, CO_2 emissions is a concern and is one of the evaluation criteria for future supply scenario. A sensitivity analysis with a shadow price f CO_2 of US$ 30/tone was run.
  - The difficulty of financing large hydro projects in small countries is examined under a variant limiting project size to less than 3% of GDP.

4.1 Methodology

4.1.1 General methodology

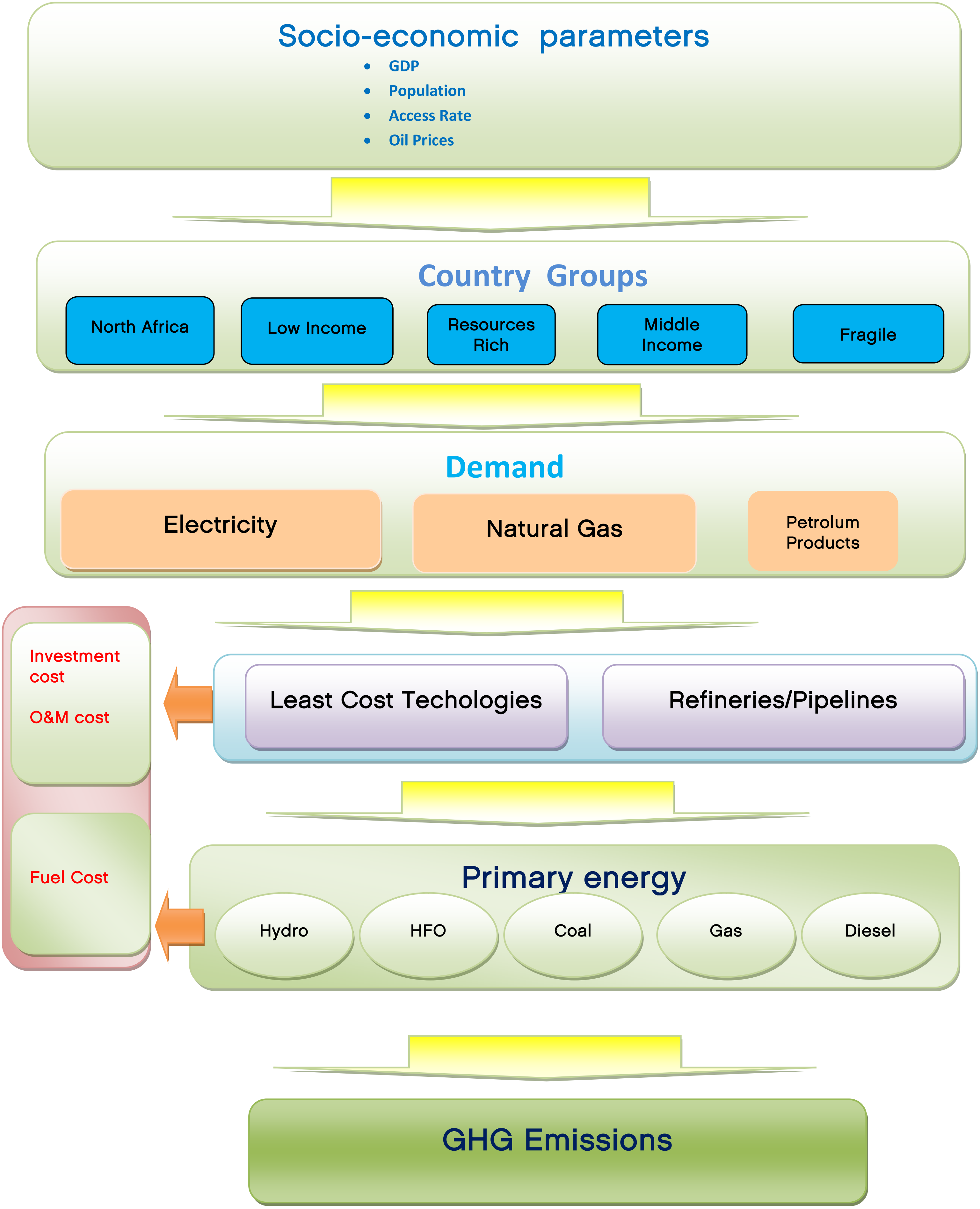
The development of a set of options to feed in the formulation of a Regional Investment Program includes the evaluation of the prospects for future demand of energy and the determination of how this demand will be met on the supply side. It follows three steps:

- The formulation of a Regional Energy Demand, including *inter alia* energy and capacity demand for the period 2009-2040. To forecast energy demand, an econometric approach was applied. Demand equations are econometrically estimated using the historical data of countries allocated in homogeneous groups, while future values are projected using the explanatory variables. The steps taken to forecast energy demand and supply are explained below.
- The identification of key economic and policy parameters affecting the supply side which will define alternative scenarios
- The discussion of alternative electricity technologies considered in the Outlooks, covering nuclear energy, traditional electricity generation technologies and Renewable Energy technologies.

The formulation of a Regional Energy Demand and preparation of demand projections is prepared for the period 2009-2040, in annual increments, with a special focus on the first ten years.

The overall methodology consists in:

- Determining the main economic parameters for each country and for Africa,
- Evaluating the demand for energy (electricity, and direct demand for gas and petroleum products excluding demand from the power sector) through an econometric model applied to homogenous groups of countries;
- Converting demand into capacity needed (adding technical losses and reserve margins);
- Determining the optimal technology mix to meet the need for capacity, using an optimization model for power generation and electricity transmission in the power sector and a technical simulation model for the petroleum product sector, and deriving:
  - The capital investment costs, and
  - The O&M costs;
- Deriving from the energy demand, the optimal technology mix and energy transport requirements:
  - The volume of fuels consumed; and
  - The fuel costs
- Evaluating the GHG emissions based on the consumption of the various fuels.


Socio-economic parameters
GDP
Population
Access Rate
Oil Prices
Country Groups
North Africa
Low Income
Resources Rich
Middle Income
Fragile
Demand
Electricity
Natural Gas
Petrolum Products
Investment cost
O&M cost
Least Cost Techologies
Refineries/Pipelines
Fuel Cost
Primary energy
Hydro
HFO
Coal
Gas
Diesel
GHG Emissions

In addition, the demand projection model estimate the electricity demand from the industrial sector based on the structure of the economy of each country and the anticipated medium term development of specific energy intensive industries.

4.1.2 Electricity sector methodology

The energy demand is determined by country specific macroeconomic forces. Some of these factors can be quantified objectively– e.g., GDP and population growth – while others are more dependent on country policy objectives, such as the target for access to electricity in all countries except North Africa, where access is already close to universal coverage and others are more country specific, such as the development of large and extractive industries, when they are grid-connected and the implementation of energy conservation measures.

The gross energy demand functions that were used for projecting country demand are:

$$D_t = D_{t-1} * \left(\varepsilon \frac{\Delta GDP}{GDP} + 1 \right) + k.C_t + \Delta M_t$$

Where:

D_t is the unconstrained demand in year t;

is the GDP elasticity of electricity demand ;

k is the average annual consumption of electricity of one household;

C_t is the number of new connections in year t ; and

ΔM_t is the additional demand from the natural resources sector in year t to reflect the significant impact on the demand of new mine developments, provided they draw their electricity from the power grid.

The impact of energy efficiency actions is applied to gross energy demand to estimate the net energy demand. Based on several country studies evaluating the potential for energy conservation, and the experience with the implementation period of such programs, it was assumed that the overall potential for energy conservation is 20%, to be achieved over a five-year periods starting in 2012.

The net demand is converted into generation capacity and energy needed by adding to the gross demand 20% system losses, and a reserve margin suitable to ensure that the LOLP (Loss of Load Probability) is less than 2%.

On the supply side, the technical and cost characteristics of each power plant in Africa, including planned retirement date, are entered in a sector database. All possible energy generation projects are entered in a separate database of "candidate" projects, with their investment cost estimate specific to each site and their technical performance characteristics11.

Next, the generation capacity needs of each African country, the description of the existing plant and the list of candidate plants are entered in an optimization model (GAP) which establishes the least cost schedule of investments to meet the generation capacity needs at the lowest cost. A transmission optimization model is run to allow the transport of energy under stable conditions and at the least cost, using the NAP (Network Analysis and Planning) flow optimization model.

[11]The cost, load factor, estimated operating costs of each identified plant are site specific, based on available feasibility, pre-feasibility or preliminary studies. For peaking plants (generally, gas turbines), generic investment costs have been entered, adjusted for geographical access cost. Fuel costs are also adjusted for access cost to plant site.

The cost of each scenario includes the generation and transmission cost, O&M costs and fuel costs. Based on the fuel consumption pattern of each scenario, the GHG performance of each alternative is evaluated.

4.1.3 Gas and Petroleum sector methodology

For the gas and petroleum product sectors, the projected demand is based on the fuel demand of the retained power sector least cost plan supplemented by the autonomous demand of industries (gas) and transport (petroleum products).

The autonomous demand of industries is projected on the basis of the power consumption of the industrial sector (assuming that the gas demand of industries follows the same growth pattern as the power demand of industries).

The petroleum product demand for transportation is assumed to be driven by GDP growth with a GDP elasticity of transport demand of 1.1, in line with the estimate used for the PIDA Transport Sector analysis.

The location and size of pipeline and refineries are established on the basis that a minimum level of gas or petroleum product flow is required to justify the construction of a gas pipeline or a refinery.

4.2 Assumptions for the Electricity sector

4.2.1 GDP Growth

GDP growth scenarios are based on a projected average annual growth rate of 6.2% for Africa. The annual growth rate is differentiated by country based on the PIDA Country macroeconomic projections. The GDP projections for each country affect the demand forecast primarily through the income elasticity of demand. The income elasticity parameters were estimated through an econometric analysis based on the series of the 2000-2009 period. As the African countries are a heterogeneous population including middle income countries (Morocco, South Africa), low income countries (Guinea, Eritrea), post conflict countries (DRC, Rwanda, Burundi), oil producing countries (Algeria, Nigeria), they have been classified into five categories, following the AICD categorization, and adjusted to include North African countries:

Table 9: Countries categories

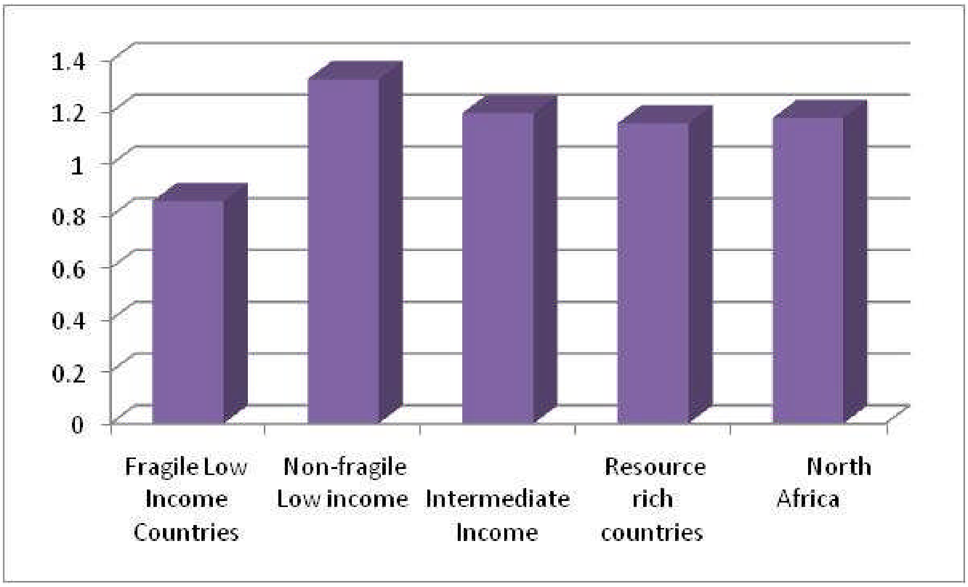
Country groups	Member Countries
Fragile Low Income Countries	CAR, DRC, Liberia, Burundi, Sierra Leone, Guinea Bissau, Côte d'Ivoire, Togo, Djibouti, Eritrea and Somalia
Non-fragile Low income	Mauritania, Mali, Niger, Senegal, Burkina Faso, Benin, Ghana, Ethiopia, Tanzania, Kenya, Uganda, Mozambique, Rwanda
Intermediate Income Countries	Botswana, Namibia, Swaziland, South Africa, Lesotho
Resource rich Countries	Nigeria, Cameroun, Equatorial Guinea, Angola, Zambia, Malawi, Gabon, Chad, Sudan, Congo
North Africa	Morocco, Algeria, Tunisia, Libya, Egypt

4.2.2 GDP elasticity of electricity demand

In the statistical analysis, only countries where demand was relatively unconstrained by lack of capacity were considered, using the number of hours of load shedding as an indicator of unconstrained demand. The results were compared to the estimates available in the literature, including World Bank12 and academic research13 on electricity income elasticity of demand.

The elasticities evaluated by an econometric method14 are given in the graph below.

Figure 16: GDP Elasticity of Electricity Demand



These estimates are consistent with estimates found in the literature ranging from 1.1 to 1.3 for non-fragile, developing countries, and with the general conclusion that GDP elasticity of electricity demand decreases with per capita GDP, except for post-conflict countries, and that the demand for electricity increases faster than GDP when the economy is on a modernization path. For South Africa, direct estimates of GDP elasticities were available, indicating an elasticity below one, which was adopted for the estimate of demand, in line with the evaluation prepared under the South Africa 2nd IRP of 2010.

4.2.3 Fuel prices

The projection of petroleum products prices is made based on future crude oil prices (Annex 9-3). The methodology retained is:

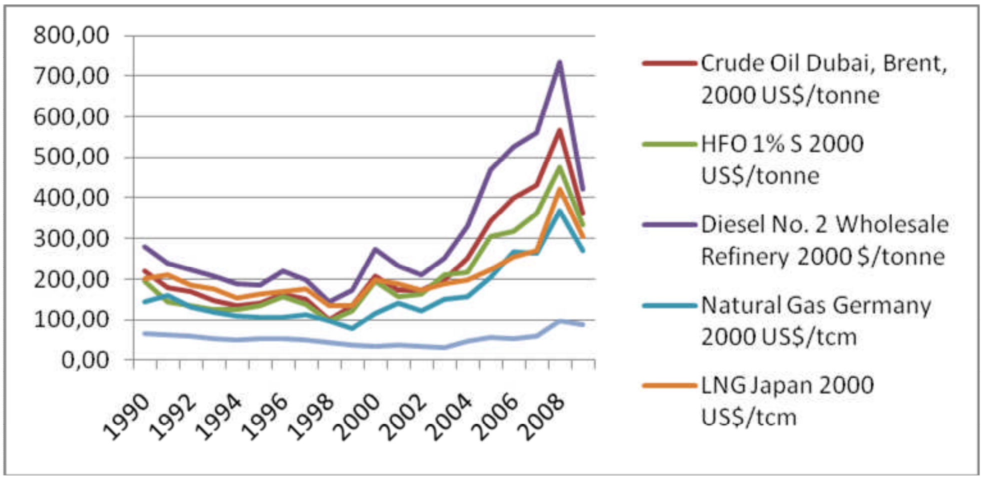
- Establish the relationship between crude oil prices and prices of Diesel, HFO, LNG, gas and coal in the past;
- Develop projections for future crude oil prices based on projections prepared by reputable institutions; and
- Project future petroleum product and coal prices based on future oil prices

[12] cf. César Calderón, "Infrastructure and Growth in Africa", Washington, World Bank, 2009.
[13] See, for example, Vishal C. Jaunky, "Income Elasticities of Electric Power Consumption: Evidence from African Countries", Department of Economics and Statistics, University of Mauritius December 2006
[14] Least square regression analysis pooling data from countries in each group.

Methodology

The model is based on the analysis of the price series for the period 1990-2009, expressed in 2000 US$ and converted into consistent physical units under the International System, that is, in metric tonnes and cubic meters. Based on the observation of oil and petroleum prices in the past (see graph below), the model tests the hypothesis that there is a linear relationship between the price of crude oil and the price of petroleum products, because oil is the main input in the cost structure of petroleum products, which includes also refining costs and logistics costs. For coal, it was observed in the past that the price of coal is also affected by crude oil, because when oil and petroleum product prices increase, the demand for coal increases as some of the primary fuel demand switches from petroleum products to coal.

Figure 17: Comparison of the price of crude oil and fuels for power generation, 1990-2009



The projection model uses a linear function linking crude oil price with the various fuels used for power generation. For each product, the function is:

- P(i,t)= k(i).P(oil,t)+ j(i)
- Where P(i,t) is the price of fuel i in year t expressed in year 2000 US$
- k(i) is the proportionality factor between crude oil price and the price of fuel i
- P(oil,t) is the price of crude oil in year t expressed in year 2000 US$
- (i) is a constant specific to each fuel.

The model is therefore based on five fuel price functions (HFO, Diesel, LNG, gas, coal).

Table 11: Projections results

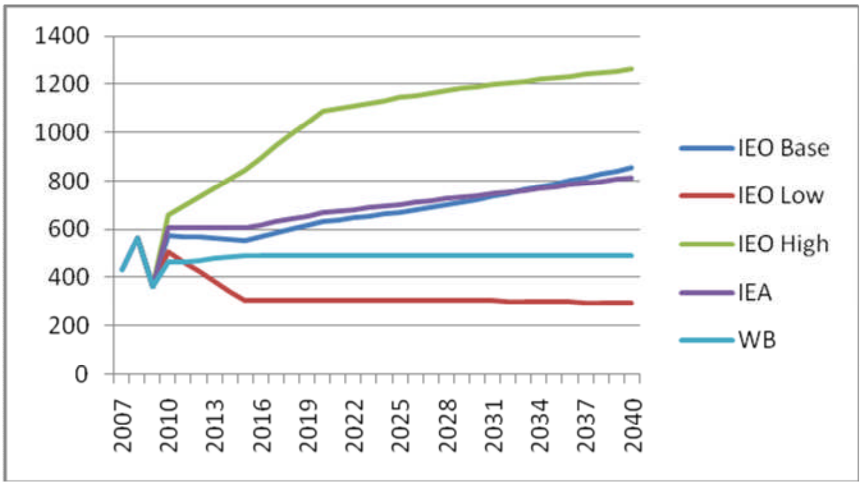
	HFO	DIESEL	LNG	GAS	COAL
PROPORTIONALITY COEFFICIENT	0.81	1.26	0.50	0.59	0.09
CONSTANT	16.1	8.95	89.68	22.98	32.44
R2	0.98	0.99	0.88	0.94	0.44

The calculation shows that Diesel is more affected by fluctuations of oil prices and more unstable than HFO, with a proportionality coefficient of 1.2 and 0.8 respectively; that LNG and gas are less affected by changes in crude oil prices with a proportionality coefficient close of 0.5, and that coal is even less affected by oil price fluctuations. As might be expected, the price component independent of crude oil prices corresponding to logistics and processing cost is larger for coal and gas, and much higher for LNG than for HFO and Diesel.

Projections

To apply the price functions in the future, crude oil price projections have to be established first. The long term projections of the IEA, the International Energy Outlook of the US EIA and the World Bank were examined (see graph below).

Figure 18: Projected Crude oil Prices 2009-2040 (in 2000 $ per tonne)



The comparison between the price projections show that the "high" and "low" scenarios of IEO are extreme compared to projections by other institutions. The 2040 range of $ 292 per tonne in the low scenario and $1 261 per tonne in the high scenario is so wide that it becomes essentially meaningless in terms of alternative scenarios. It was therefore decided to use the IEA projection as "high" scenario, and the World Bank projections as "low" scenario.

The corresponding graph is given below.

Figure 19: Crude Oil price projections 2011-2040 (in 2000 US$ per tonne)

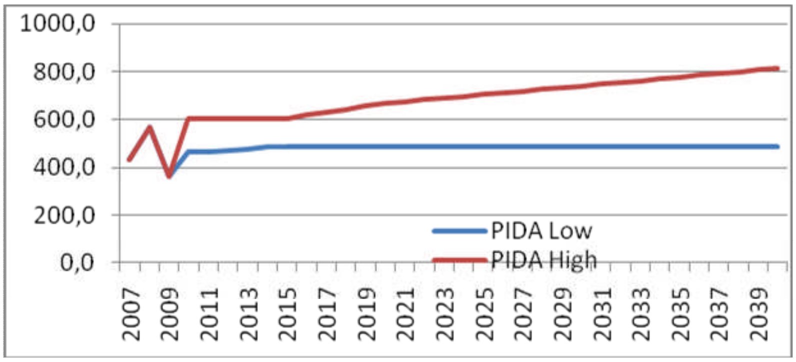
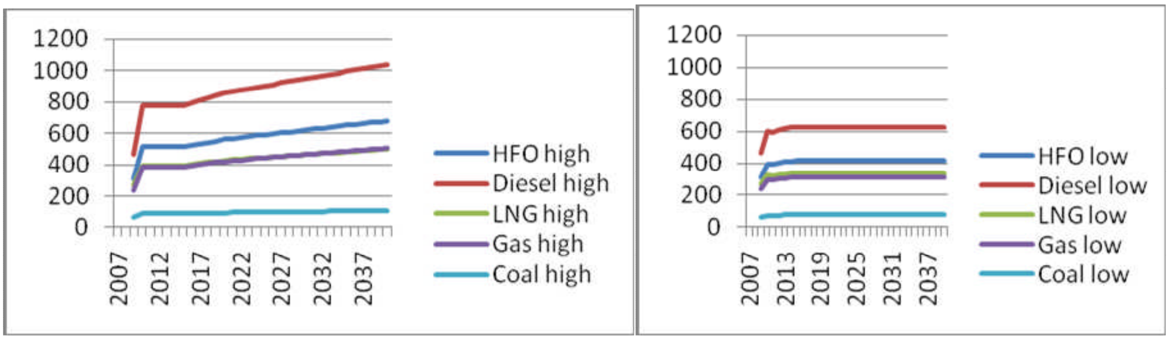


Figure 20: Fuel Prices Projections 2011-2040 (in 2000 US$/tonne or tcm)

High scenario ***Low Scenario***



For the determination of the optimum technology mix to meet future demand, the high scenario has been retained, as agreed in Libreville.

4.2.4 Increase in electricity access.

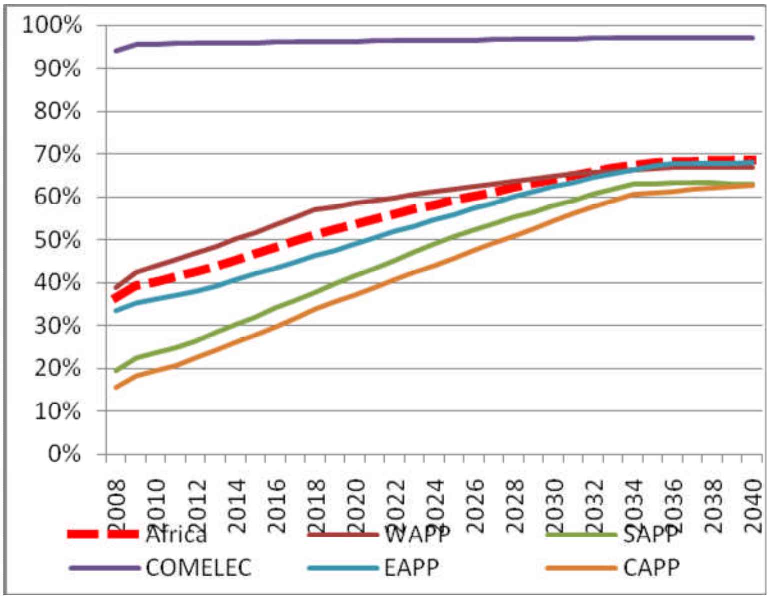
The outlook for electricity access was developed separately for each country, based on the present level of access and the access objectives of each Government. The evaluation of the present access rate was based on the estimates provided by a 2009 World Bank study, which was an input to the AICD analysis15 (See Annex 9-4). All countries project significant increases in electricity access rate, but there are national differences. Except for North Africa where the access rate is already high, the electrification rate in Africa is projected to increase rapidly between 2008 and 2040 from 39% to 69%, in line with the AU priority granted to access to electricity, and in sharp contrast with the past trend, which showed only slow electrification progress. The assumption retained for the demand projections is that all countries will have an access rate above 60% by 2030, and that the increase in access will be 2% per year, until the level of 60% is reached. The time required to achieve this level depends upon the starting point specific to each country. Subsequently, access is projected to plateau and increase slowly until 2040.

Table 12: Access Rate 2010-2040

	2010	2020	2030	2040
COMELEC	96%	96%	97%	97%
WAPP	44%	58%	65%	67%
SAPP	24%	41%	58%	63%
CAPP	20%	37%	54%	63%
EAPP	36%	49%	62%	68%
Africa	39%	54%	64%	69%

[15]ASK Data Base Annex IV. The national access rates are not well documented in most countries: it is rarely clear whether the official access rate relates to the official number of households connected, or to the actual number of households with access, bearing in mind that in many countries, several households access electricity through a single connection. For example, in Guinea, the number of officially connected households is about 140,000, whereas it is estimated that at least 300,000 households have effective access to electricity. Another challenge is whether access covers only households with access to electricity through the national grid, or also households with individual or community generators (often un-recorded in official statistics) and using car batteries. Depending upon the definition retained and the quality of statistics, access rates may vary considerably from one source to the other.

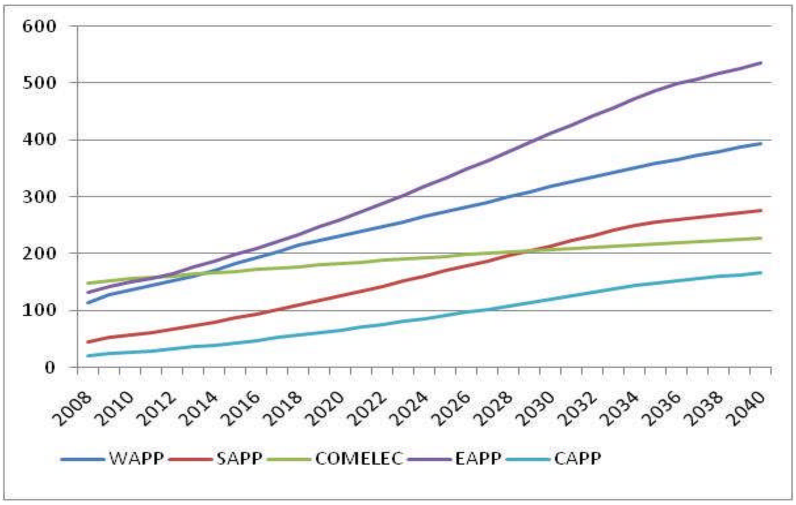
Figure 21: Access Rate for Africa and by REC, 2010-2040



The projected increase in access rate (Annex 9-5) is particularly significant in the SAPP and the CAPP regions, which start from a very low average level of 24% and 20% respectively although in SAPP, South Africa has already an access rate of 43% and in CAPP, Cameroun has an access rate of 47%.

The increase in the number of persons with access to electricity by region is shown in the graph below.

Figure 22: Number of people connected by REC 2011-2040 (in million)



The priority granted to accelerated access to electricity leads to a high number of new connections (140 million new connections by 2040) and an addition to the power demand when compared to a "no access rate increase" scenario. The demand from the new connections comes in addition to the increase in demand due to GDP growth, as it is the result of a 'voluntarist' AU, REC and Governments' policy. The additional demand from the access programs has been estimated separately based on the number of connections and the average consumption of electricity per connection.

The electricity demand per newly connected residential household depends on income level. The annual consumption retained in most least cost development plans are between 300 kWh for low income households,600 kWh for middle income households and 1,200 kWh for high income households. As no allocation by household income level was available for each of the African countries, a weighted average of650 kWh per household per year was retained, based on the estimates available in the recent long term development plans of the EAPP and CAPP, applied to all Africa. This low figure is justified in the Plans on the basis that new connection programs target in particular low and intermediate income communities, as higher income groups are often already connected. However, one needs to consider, in addition to the direct consumption of households, the electricity consumption of social and community services associated with electrification. It was assumed that each new connection would generate an additional demand from local social institutions of 100 kWh per new connection, bringing the estimated demand generated by each household connection to 750 kWh per year. It is further assumed that the consumption per household will increase in each country with GDP, as electricity consumption increases with income. The growth factor applied to consumption per new household connected is the same as the real GDP growth of each country, bringing the consumption of new consumers from 750 kWh in 2011 to about 2,500 kWh per year by 2040 (depending upon the GDP growth of each country).

The resulting demand from the access programs is in fact modest, increasing as the access programs unfold, from 1% of the total African demand in 2012 to 16% by 2040.

Table 13: Additional Electricity Demand from Access programs (GWh)

	2012	2020	2030	2040
Total Demand	658,008	1,027,354	1,828,819	3,168,910
Demand from Access	13,005	72,621	237,494	513,205
Additional Access as % total demand	2%	7%	13%	16%

The priority granted to Access in the Energy Outlook 2040 will have a dramatic socio-economic impact, but only a modest impact on the sector prospects in terms of additional investment requirement and need for additional generation capacity.

4.2.5 Outlook for Mineral Resources Development.

The rich endowment of Africa with minerals is well known, as well as the under-exploitation of these resources. With the soaring demand for mineral from Asia, it is expected that there will be acceleration in the development of extractive industries in Africa.

Table 14: Prospects for mining sector development in Africa

Mineral	Production	Rank	Reserves	Rank
PGMs*	54%	1	60+%	1
Phosphate	27%	1	66%	1
Gold	20%	1	42%	1
Chromium	40%	1	44%	1
Manganese	28%	2	82%	1
Vanadium	51%	1	95%	1
Cobalt	18%	1	55+%	1
Diamonds	78%	1	88%	1
Aluminium	4%	7	45%	1

Source: Africa Mining Vision, AfDB, February 2009

The development of extractive industries in a number of African countries will consume a significant amount of energy, particularly electricity, as mining is very energy intensive. In addition, mining activities generate supporting maintenance activities, which also require additional energy.

The main countries where extractive industries are expected to develop on a significant scale are: Morocco, Mauritania, Guinea, Ghana, South Africa, Angola, Niger, DRC, Zambia, Namibia, Botswana and Zimbabwe16.The main minerals likely to expand in the medium and long term are copper, iron ore, bauxite, uranium, nickel, phosphate, although other metals minerals are also present (gold, cobalt, manganese, diamonds, etc.). Most of mining and natural resources related companies have a strong preference for developing their own captive power generation capacity and to call on the grid, in some cases, as an interruptible supply of electricity. The oil industry traditionally has its own power generating capacity, using oil and petroleum products from their own production. It is therefore highly speculative to evaluate the additional firm demand which may originate from mining activities: the likelihood and date of commissioning of new mining activities being highly uncertain, and even if projects materialize, it is difficult to estimate what firm demand will come to the grid. In practice, the emerging model is that new mining activities apply to develop their own generation capacity and finance them entirely from their own cash flow. Considering the mining projects under physical implementation which have agreed to sign firm supply contracts with utilities, the first point to recognize is that limited additional firm demand seems to be coming to the grid, except in the case of Inga 3 in DRC. In most countries, the pattern seems to be rather for mining companies to produce their own electricity and to sell surplus capacity to the grid (several mining projects in DRC, and in Guinea for example). Future grid-connected demand for electricity will be affected indirectly by the outlook for the development of mineral resources, as sub-contractors to mining companies generally do not have their own captive generation capacity. For the calculation of the additional demand from the mining activities and ancillary industries, it was assumed that the additional demand to the grid will be 10 GWh per mining unit, and 10 GWh for associated activities applied to the estimated number of new mining activities in each of the twelve countries with most likely mining developments in the medium to long term. Except for this additional demand to the grid, the development of mining industries is unlikely to affect significantly power demand and sector financing needs.

Concerning other significant industrial activities, the impact of their development on electricity demand is already included in the country annual GDP growth rate, which is generally higher than the African continental average17.

The estimated electricity demand from the industrial sector is isolated in the energy demand of each country, based on the historical share of industry in GDP, and the additional demand resulting from the points discussed above. The contribution of demand from industries is presented in the table below for specific years.

	2012	2020	2030	2040
Percentage of Industry in Demand	69%	65%	60%	57%

The projected decrease, despite a number of industrial projects in Africa, is in line with the trend for modernizing countries, which see a decrease in the demand from industries and traditional activities such as agriculture, as their share in GDP decreases as well, whereas the demand from the sector of services and residential increases in the share of overall demand18.

Government and utilities may consider that building generation capacity in expectation of a mining step-load, without a firm conditional contract in hand, is a risky proposition. Projects for

[16] Source " *Africa's Path to Growth: Sector by sector*", McKinsey, 2010

[17] For example, the annual growth rate of Angola is estimates at 7% p.a; the figure is 6.3% for Mauritania; up to 6.5% for Zambia; up to 6.7% for Botswana.

[18] The share of industry in electricity demand is 37% in the EU and 23% in North America.

the development of mineral resources are often highly uncertain and many such investments have been under discussion for decades.

4.2.6 Evaluation of Generation Capacity needed.

The country energy demand in MWh, aggregated at REC and continental levels as needed, was converted into peak capacity demand in MWto determine the investment in capacity needed to meet the demand. Each country has a specific system load factor depending upon the structure of its economy and the importance of industry, its income per capita level, climate, and other factors. Systems load factors tend to be higher in countries with significant energy consuming industries, which have a high load factor and a lower load factor in countries where the demand comes mainly from households. Country load factor are expected to decrease (less effective utilization of installed generation capacity) with the development of appliances and air conditioning equipment with households, and a secular shift from heavy intensive industries to less energy intensive service activities, and in addition, the elimination of the un-served demand which artificially reduce the peak demand may contribute to reduce the system load factor. In contrast, countries try to increase the system load factor through load management policies to eliminate the peaks in the demand through time of the day billing, interruptible contracts and other measures. In summary, it is difficult to make a documented assumption whether country system load factors will increase, or decrease, in the long run. It was therefore assumed they would remain constant over the projection period.

Once the peak demand of each system is determined, it has to be converted into needed capacity. The system capacity needed by each country is calculated by adding the technical losses to the peak demand, which was estimated as 20% for all countries, and then by adding the reserve margin needed to meet the peak demand, with an acceptable level of reliability. In line with common practice in system planning in Africa, it has been assumed that the probability for a capacity shortage should not be more than 2%. The optimization model calculated the reserve capacity needed to achieve this level of reliability.

Table 15: System Load Factor %

Country	Load Factor	*Country*	Load Factor	*Country*	Load Factor	*Country*	Load Factor
Algeria	53	*Cote d'Ivoire*	58	*Lesotho*	65	*Senegal*	66
Angola	41	*Egypt*	63	*Liberia*	19	*Sierra Leone*	24
Benin	60	*Eq. Guinea*	25	*Libya*	49	*Somalia*	39
Botswana	84	*Eritrea*	24	*Malawi*	56	*South Africa*	72
Burkina	45	*Ethiopia*	60	*Mali*	25	*Sudan*	59
Burundi	21	*Gabon*	42	*Mauritania*	30	*Swaziland*	23
Cameroon	50	*The Gambia*	57	*Morocco*	30	*Tanzania*	50
CAR	22	*Ghana*	55	*Mozambique*	70	*Togo*	96
Chad	46	*Guinea*	32	*Nomibia*	46	*Tunisia*	51
DRC	82	*Buinea B.*	33	*Niger*	70	*Uganda*	90
Congo	34	*Kenya*	58	*Nigeria*	74	*Zambi*	85
				Rwanda	80	*Zimbabwe*	54

4.2.7 Assumptions for future power plants characteristics

The characteristics of the plants to be considered for integration in the long term least cost program are essential parameters, as they determine the levelized cost of production of each plant, which is the main selection criteria and the marginal production cost of each plant which determines its future rank in the merit order for meeting the energy demand.

For all identified potential plant, the characteristics are specific to each unit, based on the cost and performance estimates given in existing feasibility studies, pre-feasibility studies or preliminary studies. Additional data were found in the long term development plans of the Power Pools and through direct discussions with the Ministry of Energy of selected countries with a large hydro potential, particularly, Guinea and DRC. Site-specific data for Ethiopian sites for which preliminary studies are not available were obtained through discussions with donors.

In addition to identified plants and sites, "generic" plants are considered when no identified site has the required characteristics or cost in the year when the capacity is needed (hydro plants have time constraints on availability due to long preparation and construction period of five years or more). The data assumed for these generic plants are given in Annex 9-1.

For most peaking plants, no specific sites are identified. In general, peaking capacity (10% on top of peak demand) is provided by gas turbines using diesel fuel or gas. Reciprocating diesel engines can also be envisaged as well as some hydro plants. For peaking gas turbines and reciprocating engines, the data given in Annex 9.1 have been retained. For each country, the cost of fuel has been adjusted to reflect the access cost, particularly for landlocked countries by adding a surcharge to the CIF price of fuel, depending upon the transport distance.

The nuclear technology option is considered along with other alternatives and discussed in Annex 9.2, leading to the conclusion that nuclear power is unlikely to be competitive in the envisaged time horizon, particularly taking into account the likely increase in construction costs after Fukushima.

A special case concerns Inga. The characteristics, possible phasing and cost of the Grand Inga project are still being studied, but the on-going study by RWE, EdF and Nodalis will not produce results until late in 2011. The best presently available data were used, after consultation with the Ministry of Energy of DRC, leading to the following assumptions:

Plant	Inga 3		Grand Inga						
Phase	*A*	*B*	*I*	*II*	*III*	*IV*	*V*	*VI*	*VII*
Capacity (MW)	2,100	2,100	5,000	5,000	5,000	5,000	5000	5,000	5,000
Investment US$ million	3,000	3,000	12,000	8,000	8,000	8,000	8,000	8,000	8,000
Cost/kWh (USCents.kWh)	3.0	3.0	5.0	3.4	3.4	3.4	3.4	3.4	3.4
Earliest date	2020	2021	2022	2024	2026	2028	2030	2032	2034

4.2.8 Planning scenarios

Considering several scenarios serves two purposes:

- Evaluating alternative scenarios in terms of:
  - Capital investment requirements in each year;
  - Full cost of electricity including fuel cost
  - Pattern of fuel consumption
  - CO2 emissions
- and comparing the economic cost of alternative policy choices to select a preferred scenario, taking into account the cost of supply as well as feasibility and environmental performance, and
- For the preferred scenario, establishing the list, sequence and timing of optimal investment in generation and transmission to minimize the electricity supply cost while meeting the demand with an acceptable level of reliability.

The key parameters characterizing alternative outlook for meeting the electricity demand were discussed with the stakeholders at the Libreville PIDA workshop.

Energy Efficiency

- Many African countries are paying special attention to improving efficiency in the use of electricity to curb investment requirements for the utilities and the energy bill for consumers. The potential for economically justified energy efficiency gains in the use of electricity has been estimated in several studies at 20%in industries (Sidi Bernoussi ESMAP Study, 2005, for example and Tunisia's experience under the Tunisia Energy efficiency and Biomass project, 2010) and also at least 20% for lighting through high efficiency bulbs and LEDs and use of energy efficient appliances (promoted through labelling programs).
- Based on experience with the implementation of Energy Efficiency programs, improvement in efficiency materialize gradually over time and country energy intensity improves rather slowly. It is clear that different countries may progress at different speed depending upon Government policy, but considering the large number of countries and the difficulty to assess Government policies country by country under PIDA, it was decided to consider that progress with energy efficiency will be 1% per year over the entire planning period.

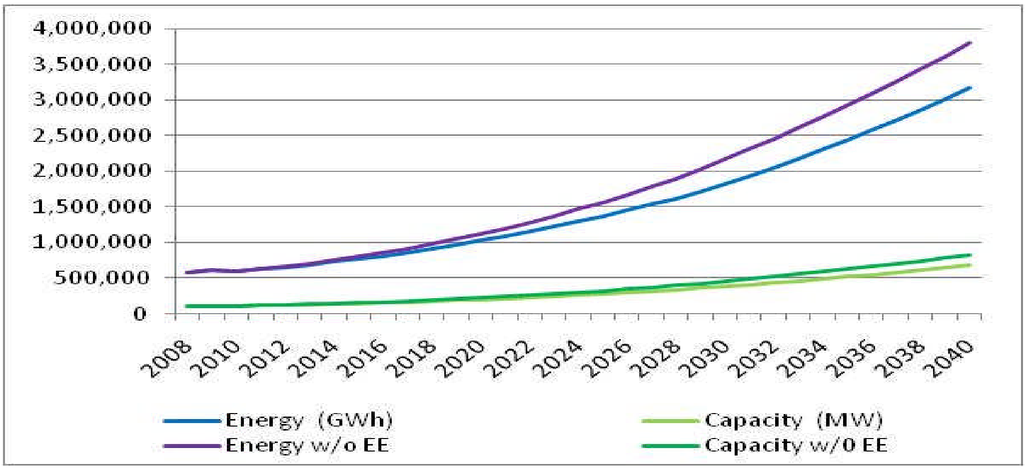
Under the Energy Efficiency PIDA scenario, the impact of energy efficiency policies on electricity demand was taken as 1% p.a with a ceiling when 20% efficiency gains compared to the projected demand without energy efficiency are achieved. The comparison between energy demand with energy efficiency and without energy efficiency gains is given below in terms of energy and capacity.

The evaluation of the annual gains from energy efficiency in typical years is presented below.

Table 16: Gains from Energy Efficiency policies

	2020	2030	2040
Energy gains (in GWh)	92	347	633
Capacity gains (in TW)	19	75	138

Figure 23: Energy and Capacity demand with and without Energy Efficiency



Considering that all governments are already engaged in energy efficiency improvement policies, it was decided not to compare an electricity demand with and without energy efficiency action, but to use only the "with energy efficiency" case as a base case for the PIDA Long Term Development Plan.

Energy security

Energy security is one of the main components of the AU energy sector vision and objectives. It has two components:

- Security in regard to fuel prices, that is, managing the risk of sharp fluctuations on imported fuel prices as happened in the first decade of the century; and
- Security in regard to the availability of energy.

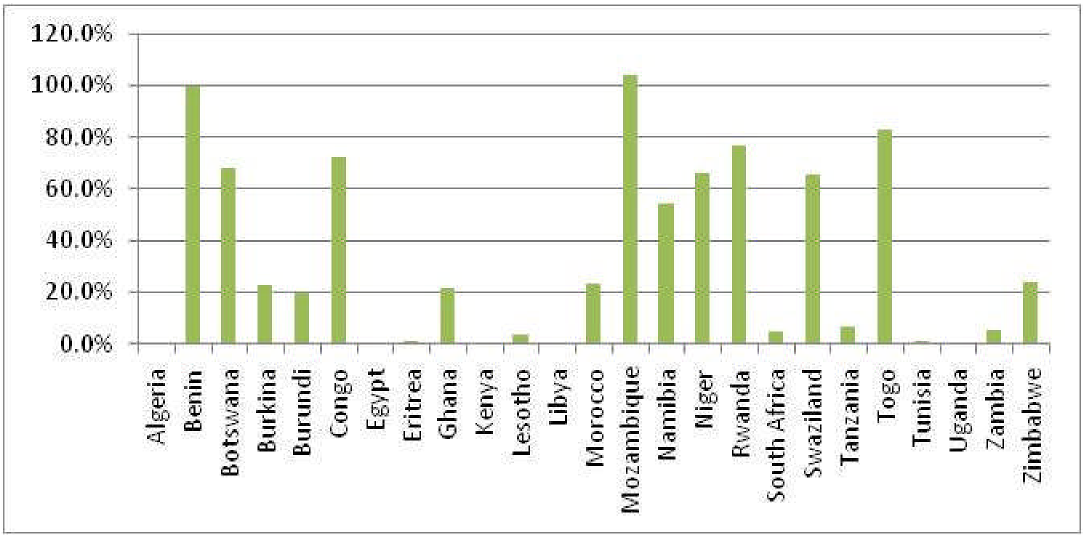
To manage the first type of risk, African countries seek to reduce their dependence on (i) imported fuel purchased on the world market and (ii) imported electricity (to the extent the price of imported electricity is also subject to variations). However, since the price of imported electricity is generally less directly linked to the price of petroleum products as it is generally produced through the transformation of local primary energy, the substitution of imported electricity for imported fuels reduces price volatility risk. The availability risk for imported fuel by non-landlocked countries is limited, as fuels are readily available on world market in physical terms. For landlocked countries, the availability risk is linked to the transit risk. For imported electricity, the availability risk (under energy and capacity supply contracts) is linked to (a) the political risk of Government interference in flows of electricity across borders which can be managed through suitable contractual provisions and insurance, and (b) the risk of physical disruption of the transmission lines. The tolerance level in regard to these various risks varies from country to country. Statistics on electricity imports indicate that generally, small countries are more willing to bear the energy security risk through a high dependence on imports of electricity19, whereas large countries seem to prefer a lesser dependence on imported electricity20 (Annex 9-4).

For the purpose of the PIDA Long Term Development Plan, it is proposed to run three alternative scenarios:

- A Low Integration scenario under which the level of electricity imports remain at the 2008 level and additional electricity demand is met from domestic plants. Under this scenario, the dependence of Africa on imported fuels would not be given a high priority and countries would rather import fuel from outside Africa than trade more energy. The share of electricity imports from African countries would be limited to the percentages of demand listed below, and regional trade would be minimized, each country (except the few large importers) seeking to produce their own electricity from domestic primary energy transformation or imported fuel. Under this scenario, the low level of dependency on imported energy is counterbalanced by a high level of dependency on imported fuel, and a higher cost of electricity, as cost effective large regional project are not developed.

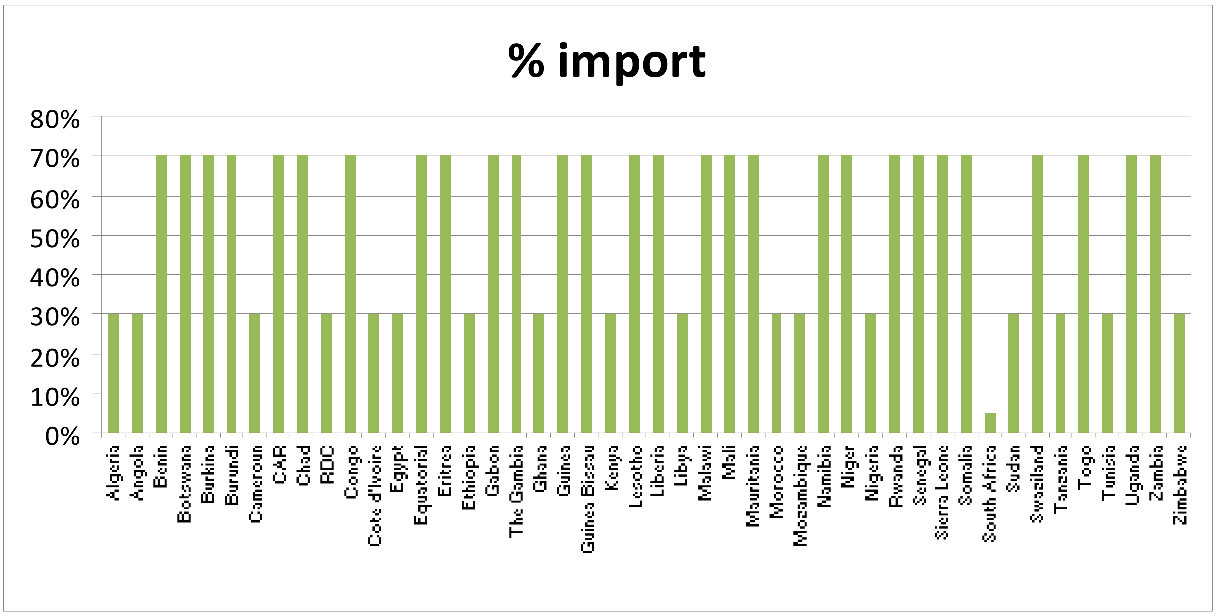
[19]Share of imports of electricity of small countries 2007 : Benin 99.8%; Botswana: 68%, Burkina Faso: 23%; Namibia 54%; Niger 66%; Swaziland 65%; Togo 82%.
[20]Share of import of electricity of large countries 2007: Algeria: 0.9%; Egypt 0.1%; Ethiopia: 0%; Nigeria: 0%; Tanzania: 6.8%; South Africa : 4.9%;

Figure 24: Share of imports in domestic demand for electricity 2008



- A High Integration scenario under which all constraints to power exchanges are removed and any African country can import from 0 to 100% of its electricity, based only on the comparative cost of domestically produced and imported electricity and the risk of dependency on imported electricity is considered acceptable. Under this scenario, electricity trade is maximized as well as dependency on imported electricity, but the dependency on imported fuel is lower, and the cost of electricity is lower as more cost effective regional projects are systematically developed; and
- A Moderate Integration scenario under which the share of imported energy is allowed to increase compared to present level, but most countries do not depend entirely on imported electricity. Under this scenario, the maximum dependency on imports would be as per the graph below.

Figure 25: Maximum share of imported energy in domestic demand



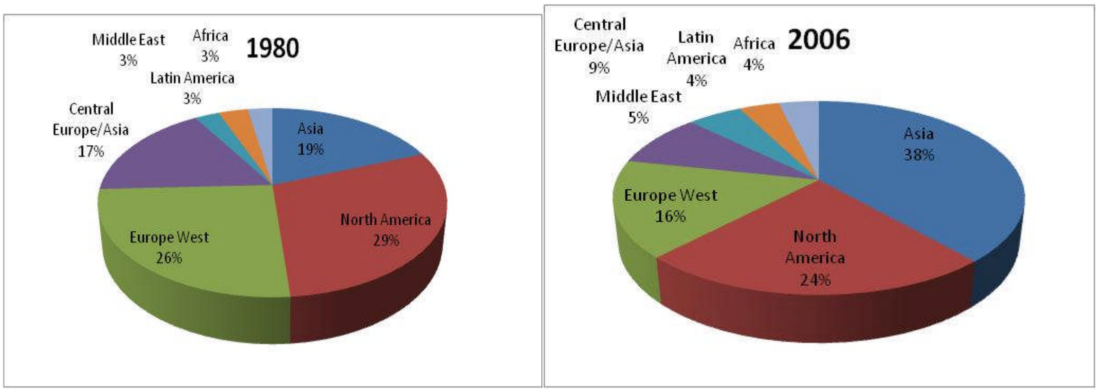
This scenario is a compromise between the objective of reducing dependency on imported fuels and the risk of dependence on imported electricity. It allows the development of regional power plants and electricity trade, although not to the maximum extent theoretically possible.

Environmental aspects

It is well documented that Africa's contribution to GHG emissions is very low, and, therefore, the reduction of the continent's emissions may not be a top priority when competing with other aspects of energy supply such as access, affordable cost and energy security. Africa's fossil-fuel CO2 emissions are low in both absolute and per capita terms. Total emissions for Africa have increased twelve-fold since 1950 reaching 310 million tonnes of carbon in 2007, still less than the emissions for some single nations including China, the U.S., India, Russia, and Japan. Although per capita emissions in 2007 (0.33 tonnes of carbon), were three times those in 1950, they were still only 6.4% of the comparable value for North America.

On the other hand, Africa's emissions have increased from 3% (0.55 million tones) of a world total emissions of 18.3 million tonnes of CO2, to 4% (1.16 million tones) of a world total emissions of 29.1 million tones of CO2 over the 1980-2006 period and the growth rate of emissions is one of the highest in the world (after Asia and the Middle East).

Figure 26: CO2 emissions of Africa compared to the rest of the world- Comparison 1980-2006

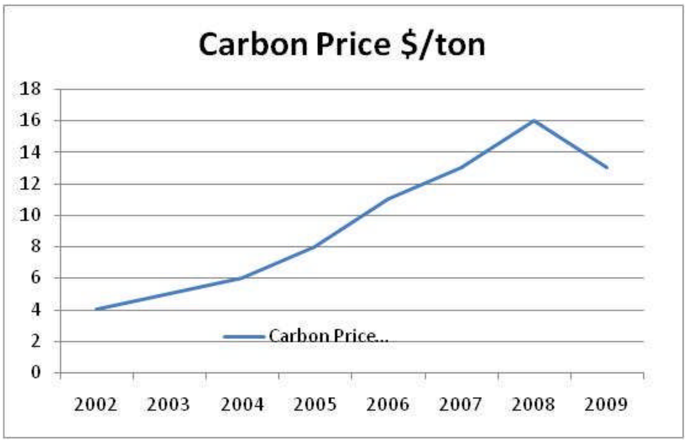


World emissions 1980:18.3 billion tonnes ***World emissions 2006:29.1 billion tonnes***

Nevertheless, the environmental impact of the PIDA power sector long term investment plan is an important consideration for all African countries, the RECs and the AU, as evidenced by the reference to the environmental foot print of energy projects in all sector policies and the priority granted to low-carbon emissions approaches. The PIDA Energy program integrates the environmental concern through (i) comparing the GHG emissions of the alternative scenarios for meeting projected demand; and (ii) developing a special scenario under which a negative value is assigned to CO2 emissions, penalizing in the planning process high CO2 emitting technologies compared to the cleaner ones.

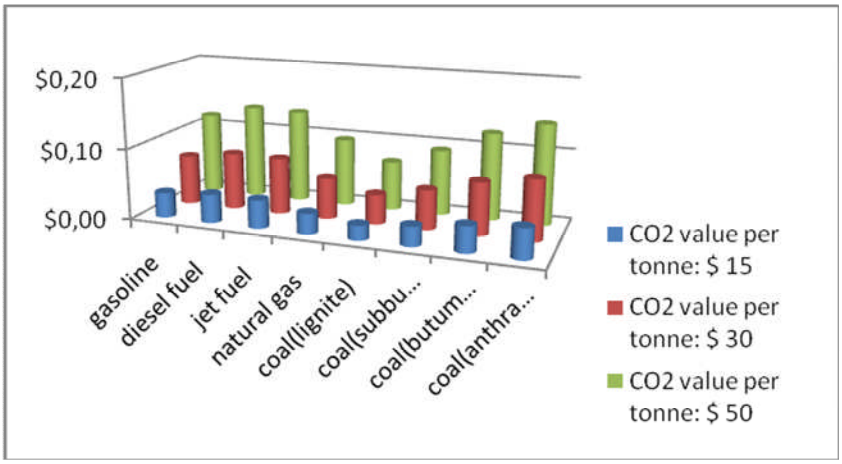
With regard to carbon price, historical figures peaked at USD 16/tonne of CO2 in 2008 but decreased thereafter. Most projections anticipate a long term increase in carbon prices. Projections range between US$ 30/tonne of CO2 (in the SAPP Long term plan) and up to US$ 50/tonne of CO2 (in the case of South African 2nd IRP).

Figure 27: Historical Carbon price US$/tonne



The PIDA Energy Study tests a development scenario with carbon price of US$ 30/tonne, added to the cost of fuel for the sake of comparison in terms of electricity cost and CO2 emissions with the Base case scenario. The corresponding fuel price surcharge is given below.

Figure 28: Fuel price surcharge for carbon value, per liter, kg or m3



Likelihood of Financing

Experience demonstrates that high cost projects located in countries with a small GDP are difficult to finance, and take longer to develop, particularly under PPP financing arrangements. For public sector projects, this is due to the limit in country and sector exposure applied by bilateral and multi-lateral donors and to the practice of allocating country financing "envelopes" to each country based on several criteria including country size of population, progress with reforms, governance, etc. For private sector projects financed under PPP, lenders relate the political risk to the capacity of a Government to buy the project if needed. Lenders and investors will therefore be concerned with financing a large project in a country where the Government is unlikely to be capable of bearing the cost of possible penalties or cancellation of the project under extreme un-insured circumstances.

It is important to examine the possible impact of a financing constraint on the investment program, and to ponder the advantage of the least cost of supply of electricity with the likelihood that the selected program will be financeable and implemented on time It was decided to test a scenario where there is a country specific ceiling on the maximum cost of a project likely to be financed in any given year in relation to GDP. In order to set a realistic financing ceiling, recently financed PPP projects in Africa have been considered. The Kounoune project in Senegal, with a cost of US$ 70 million was financed with relative ease; it represented about 0.3% of the GDP of Senegal; SONEL's US$ 450 million financing was also raised with relative ease, representing about 1% of Cameroon's GDP; Bujagali in Uganda at a cost of USD 860 million was more difficult to finance, took a long time to structure, and attracted interest from only two potential investors: it represented close to 3% of the GDP of Uganda. The case of DRC is relevant: the financing of the rehabilitation of Inga 1 and 2 for a cost of about US$ 600 million under the Domestic Electricity Markets for Consumption and Export Project of the World Bank (PMEDE) project, despite the economic attractiveness of the project, has been a challenge and is not fully funded yet; the Inga 3 project illustrates the difficulty of financing a project with a cost of about 13% of the GDP of DRC. The conclusion was that a limit of 3% of a country's GDP for any single project may be realistic. The corresponding maximum project cost for each African country resulting from this principle is given in the table below, leading to the conclusion that a number of large projects may need to be deferred until the country's GDP growth allows the economy to bear larger projects.

Figure 29: Impact of a 3% of GDP limit on the size of investments in the energy sector

	2007		2020		2030	
Country	GDP 2007 million $	Max Invest Energy (million $)	GDP 2020 million $	Max Invest Energy (million $)	GDP 2030 million $	Max Invest Energy (million $)
Algeria	214,243	6,427	393,892	11,817	841,421	25,243
Angola	62,745	1,882	144,227	4,327	295,903	8,877
Benin	11,686	351	23,748	712	52,388	1,572
Botswana	17,997	540	32,435	973	66,325	1,990
Burkina Faso	20,445	613	44,612	1,338	107,869	3,236
Burundi	5,400	162	10,629	319	24,565	737
Cameroon	46,998	1,410	87,762	2,633	192,887	5,787
Cape Verde	3,287	99	6,820	205	9,859	296
Central African Rep.	3,780	113	7,062	212	13,999	420
Chad	24,123	724	35,639	1,069	51,518	1,546
Comoros	1,243	37	1,867	56	2,698	81
Congo, Dem. Rep. of	25,118	754	61,158	1,835	143,380	4,301
Congo, Republic of	12,692	381	23,571	707	45,477	1,364
Côte d'Ivoire	43,988	1,320	87,743	2,632	187,004	5,610
Djibouti	2,120	64	4,597	138	8,656	260
Egypt	458,565	13,757	1,048,870	31,466	2,214,635	66,439
Equatorial Guinea	13,836	415	18,747	562	22,388	672
Eritrea	3,178	95	4,157	125	5,819	175
Ethiopia	88,770	2,663	265,989	7,980	614,907	18,447
Gabon	11,447	343	16,311	489	26,204	786
Gambia, The	2,387	72	4,929	148	10,895	327
Ghana	37,911	1,137	86,512	2,595	202,743	6,082
Guinea	34,299	1,029	55,917	1,677	123,606	3,708
Guinea-Bissau	917	28	1,570	47	3,679	110
Kenya	74,725	2,242	155,864	4,676	357,440	10,723
Lesotho	4,962	149	8,835	265	17,767	533
Liberia	1,232	37	2,963	89	6,469	194
Libya	115,213	3,456	249,407	7,482	415,113	12,453
Madagascar	16,652	500	30,135	904	66,915	2,007
Malawi	17,062	512	41,653	1,250	89,530	2,686
Mali	15,265	458	30,861	926	69,457	2,084
Mauritania	6,860	206	13,217	397	28,898	867
Mauritius	25,288	759	46,336	1,390	69,278	2,078
Morocco	183,300	5,499	391,149	11,734	896,792	26,904
Mozambique	46,382	1,391	118,718	3,562	276,255	8,288
Namibia	13,231	397	22,499	675	42,679	1,280
Niger	12,225	367	26,130	784	60,785	1,824
Nigeria	362,278	10,868	833,911	25,017	1,779,811	53,394
Rwanda	11,248	337	27,398	822	65,396	1,962
São Tomé & Principe	879	26	1,799	54	3,223	97
Senegal	24,673	740	47,889	1,437	95,796	2,874
Seychelles	1,558	47	2,415	72	3,935	118
Sierra Leone	11,589	348	24,897	747	54,098	1,623
South Africa	507,052	15,212	900,172	27,005	1,771,338	53,140
Sudan	89,620	2,689	192,465	5,774	395,770	11,873
Swaziland	8,268	248	12,177	365	20,680	620
Tanzania	36,295	1,089	91,994	2,760	224,444	6,733
Togo	4,950	148	8,450	253	17,058	512
Tunisia	104,058	3,122	211,998	6,360	401,536	12,046
Uganda	35,431	1,063	98,032	2,941	259,443	7,783
Zambia	22,703	681	55,665	1,670	141,965	4,259
Zimbabwe	21,678	650	25,787	774	47,309	1,419

The proposed scenarios

The following scenarios for the development of energy supply to meet the projected demand have been carried out:

- **Scenario 1**: Energy efficiency applied to future demand for electricity; electricity imports of each country limited to the present percentage of demand (**Low Integration**); no price assigned to CO2; no financing constraint;
- **Scenario2**: Energy efficiency applied to future demand for electricity; electricity imports of each country unconstrained (**High Integration**); no price assigned to CO2; no financing constraint;
- **Scenario 3**: Energy efficiency applied to future demand for electricity; electricity imports of each country allowed to increase compared to the present situation, but within limits (**Moderate Integration**); no price assigned to CO2; no financing constraint; **this scenario is considered as the Base Case**, as it is the most realistic while meeting the AU and REC objectives and priorities.
- **Scenario 4**: Energy efficiency applied to future demand for electricity; electricity imports of each country allowed to increase compared to the present situation, but within limits (**Moderate Integration**); **price of US$ 30/tonne assigned to CO2**; no financing constraint;
- **Scenario 5:** Energy efficiency applied to future demand for electricity; electricity imports of each country allowed to increase compared to the present situation, but within limits (**Moderate Integration**); no price assigned to CO2; **financing constraint of 3% of GDP per project applied.**

The Low Integration and High Integration scenarios are two extreme cases, helpful to assess the impact of imposing a restriction of regional trade on investment needs and electricity cost. The Scenarios 4 (with CO2 emission penalty) and 5 (with limit on individual investments) are variants of the Scenario 3, which is considered as the base case for the selection of PIDA projects under Phase 2 of the study.

The scenarios for meeting the demand are characterized and compared based on the main objectives of the AU and REC vision:

- The **energy security** reflected in the fuel mix and dependence on imported fuel
- The **role of hydro** in the technology mix
- The **GHG emissions** measured by the CO2 emissions
- The full **production cost**
- The **contribution to regional integration** measured by the level of regional trading
- The **capital investment** cost in generation and transmission

4.3 Gas and Petroleum Products

In projecting demand for natural gas and petroleum products outside of the power sector, a similar set of growth assumptions were used as used for projecting electricity demand namely:

- *GDP Growth scenarios* are based on the same, projected average annual growth rate of 6% for Africa described in Section 9.a.2.1;
- *GDP elasticity of demand*

- *Natural Gas*: Since more than 70% of Africa's gas consumption is found in two middle income countries of North Africa, Egypt and Algeria, an elasticity of demand of 1.1 is appropriate for such countries; it is also appropriate for Nigeria, whose consumption of gas in power generation is growing rapidly though from a lower base. Finally, it is assumed that demand for gas in the power and industrial sectors will follow similar growth paths;
- *Transport:* Petroleum product demand for transportation is assumed to be driven by GDP growth with a GDP elasticity of transport demand of 1.1, in line with the estimate used for the PIDA Transport Sector analysis as noted above.

- *Volume of Natural Gas Consumed in Power Generation and in Industrial Sectors: The proportion of gas consumed in power was assumed to be 50%. The justification for this percentage was based on 2010 data for gas consumed in power in Africa, which indicated that 53.6 bcm out a total consumption in Africa of 105 bcm were consumed in power generation. Furthermore, Africa's two main gas consuming countries –Algeria and Egypt- accounted for over 70% of Africa's gas consumption in 2010, of which 50% was also used in power generation. With future gas consumption likely to increase in these two countries as well as in other middle income countries such as Libya, Tunisia and Nigeria that have growing industrial sectors, it is assumed that the proportion of gas used between the power and industry sectors would remain at 50:50.*
- *Volume of Oil Products used in Transport Sector: In order to project consumption of oil products in transport, the 2010 road sector fuel consumption data for 17 African countries from all the main regional areas was obtained. This data included actual fuel consumption data of the main consuming countries in each regional area. The aggregate fuel consumption in 2010 for the remaining countries in each regional area was then calculated by assuming that fuel consumption in transport was proportional to the GDP of these countries. A 2010 fuel consumption volume in transport for each regional area was then calculated, which was used as the starting point to project oil products consumption to the year 2040.*

5. PRIMARY RESOURCES POTENTIAL

- Africa's traditional primary resources potential is considerable, but unevenly distributed:
  - Large Oil and Gas reserves are located in the northern regions of the continent and also in West Africa, particularly in Nigeria. Smaller but still promising discoveries of oil and gas have been made recently in West and East Africa
  - Hydro potential is mainly in East and Central Africa, and to some extent in East Africa (Guinea, DRC, Ethiopia and the Zambezi basin).
  - Coal reserves are abundant but mostly confined to a single country, South Africa, with 3.5% of world reserves. In the rest of Africa, coal potential is limited.
  - Wind energy developments are limited to Morocco, Egypt and, to a lesser extent Tunisia. Wind energy is now starting to be developed in South Africa.
  - Renewable energy potential lies mainly with solar, although it is not yet commercially viable without substantial subsidies. There is also geothermal potential located in the Rift Valley and already partially developed in Kenya.
- CURRENTLY IDENTIFIED ECONOMICAL HYDRO RESOURCES WILL MATCH DEMAND ONLY UNTIL 2035.

5.1 Crude Oil Resources

Continental Africa has an abundance of proven crude oil reserves. However, as with natural gas, they are largely concentrated in the northern parts of the Continent, and also in West Africa though further oil reserves are still being identified in new locations and, in some cases, have been developed commercially (see map below). The Table below gives the estimates of proven oil reserves in Africa at the end of 2010. Libya and Nigeria alone have by far the largest share, accounting for about 63% of the African total, with Algeria and Angola adding another 20%.

Table 16: Proved oil reserves in Africa

	End 2010 bn Tonnes	bn bbls	Share of world total	R/P ratio*
Algeria	1.5	12.2	0.9%	18.5
Angola	1.8	13.5	1.0%	20.0
Chad	0.2	1.5	0.1%	33.7
Rep. of Congo	0.3	1.9	0.1%	18.2
Egypt	0.6	4.5	0.3%	16.7
Equatorial Guinea	0.2	1.7	0.1%	17.1
Gabon	0.5	3.7	0.3%	41.2
Libya	6.0	46.4	3.4%	76.7
Nigeria	5.0	37.2	2.7%	42.4
Sudan	0.9	6.7	0.5%	37.8
Other Africa	0.3	2.7	0.2%	44.2
Total Africa	**17.4**	**132.1****	**9.5%**	**35.8**

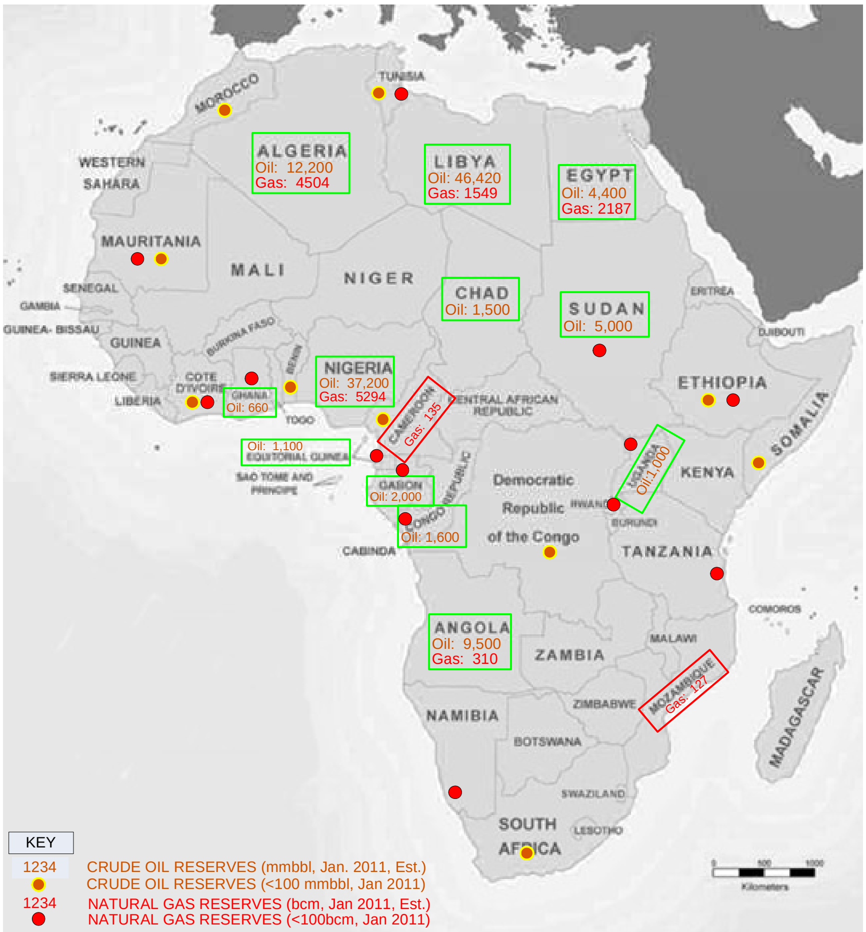
Source: BP Statistical Review of World Energy, 2011

*Reserves:Production (R:P) ratios show number of years the proved reserves would last at current output levels

** The reserve estimates are broadly consistent with those published by the Oil & Gas Journal (January 2011), which lists total Africa oil reserves of about 124 billion bbls at Jan 1 2011. The main difference between the two is the estimate for Angola, which BP states to be 4bn bbls higher than that estimated by O&GJ.

"Other Africa" covers smaller reserves in another 11 countries across the Continent, mostly in West and East Africa where new discoveries have become commercially viable in the recent past. Most notable amongst these are Ghana (660 million bbls) and Uganda (1bn bbls); it is possible that proven reserves of both these countries will increase further as more discoveries are added and as operational data from the newly producing fields becomes clear. There is still significant exploration taking place throughout SSA, with good prospects of at least maintaining current levels of reserves, or even increasing these levels further. Producers are looking more towards export opportunities for the crude oil than for investment in new refining plants.

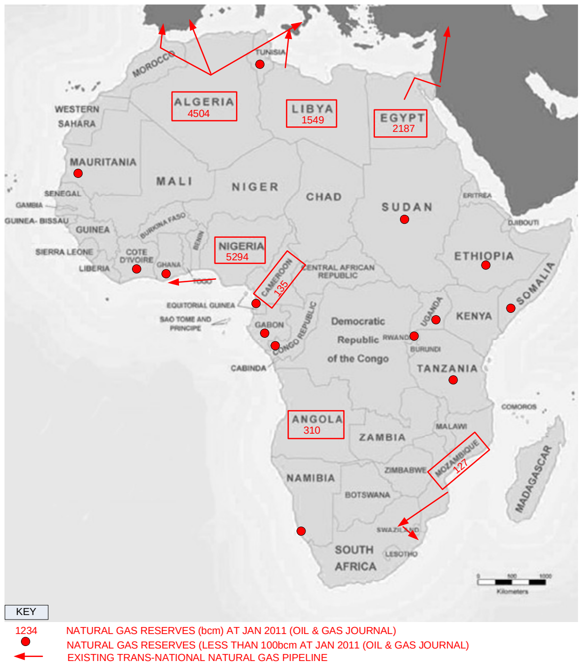
Figure 30: AFRICA: CRUDE OIL RESERVES



5.2 Natural Gas Resources

Continental Africa has an abundance of proven natural gas reserves, largely concentrated in the northern parts of the Continent and also in West Africa. Algeria, Libya, Egypt and Nigeria are amongst the largest gas producers in the world but other reserves are being identified in new locations and, in some cases, have been developed in recent times. Nigeria, Cameroon and Algeria also have significant associated gas, which has historically been flared in the earlier years of oil production due to the lack of commercial opportunities. This situation is now changing as the value of natural gas has increased since the early oil exploitation in the middle of the last century.

Figure 31: Africa's Natural Gas Reserves (and Existing Pipelines)



The Table below gives the recent estimates of proven gas reserves in Africa at the end of 2010. Nigeria is shown to have the largest share, accounting for 36% of the African total. The three North African countries of Algeria, Egypt and Libya account for 56% of the total with other African countries account for only 8%.

Table 17: Proved gas reserves in Africa

	trillion cubic feet	trillion cubic metres	R:P ratio*
Algeria	159.1	4.5	56.0
Egypt	78.0	2.2	36.0
Libya	54.7	1.5	98.0
Nigeria	186.9	5.3	157.7
Other Africa	41.4	1.2	65.7
Total Africa	**520.1**	**14.7**	**70.5**

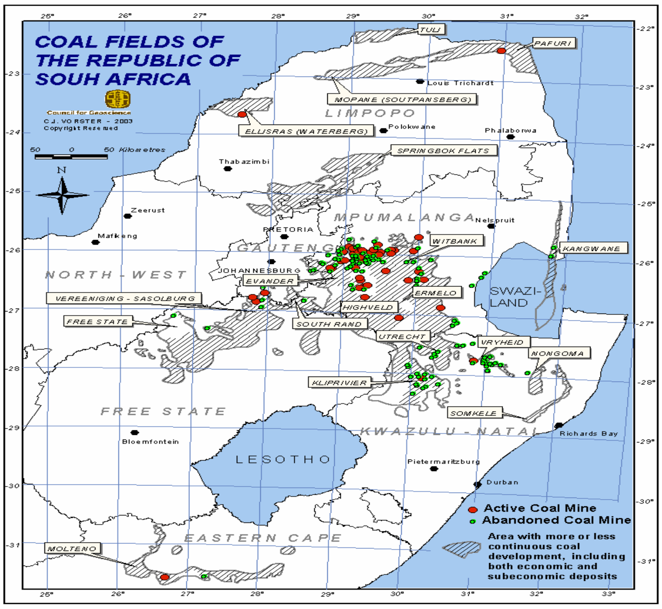
Source: BP Statistical Review of World Energy, 2011

*Reserves:Production (R:P) ratios show the number of years proved reserves would last at current output levels.

5.3 Coal Resources

Africa's coal reserves represent 3.7% of the world's coal reserves, more than 95% of which are found in a single country, South Africa. Africa produced 144.9 million tons of oil equivalent (toe) in 2010, of which 143 million tons (98.7%) were produced in South Africa, 1.1 million toe in Zimbabwe, and 0.8 million toe in the remaining African countries of the continent. South Africa, by far the largest producer in Africa is also a major global producer, after China, Australia, Canada, USA, India, Russia and Indonesia (BP Statistical Review of World Energy, June 2011).

Figure 32: South Africa's Coal Fields



Source: CJ Vorster 2003

Of the other African coal producing countries, Zimbabwe's single mine, Wankie, is an important coal producer; Zambia has a single operation, the Maamba colliery; Niger operates a single coal mine whilst Malawi produces approximately 50 000 tons (of coal) per year. Swaziland has two small collieries which produce around 400 000 tons (of coal) annually. Botswana has a single coalmine dedicated to supplying a coal fired power station. Isolated coal-bearing sequences in **Niger, Nigeria, and Egypt** represent the only other significant coal bearing potential in Africa.

Table 18: Coal production by country

	CountryProduction 2000 (mtoe)	Production 2010 (mtoe)	2010 Share of Total (%)
South Africa	126.6	143.0	3.8
Zimbabwe	2.8	1.1	0.05
Other Africa	1.2	0.8	0.05
Total Africa	130.6	144.9	**3.9**
Total World	2,353.5	3,731.4	**100.0**

South Africa is also a major consumer of coal. Some 88.7 million toe was consumed in 2010, an increase of almost 20% since 2000, of which more than 93% was used in generating electricity. Coal consumption in the rest of Africa is small, only 6.7 million toe. South Africa is the largest single emitter of Greenhouse Gases (GHG) in Africa. The main challenge ahead for South Africa is to stem growth in GHG emissions as its economy grows on average at 5%, which will require reduction in the use of coal for power generation and active promotion of renewable sources of energy.

5.4 Hydro Resources

Africa's hydo potential is significant and has been well known for many years. The combination of a vast resource at low economic cost (estimated in the range of US$ 0.03-0.10/kWh compared with a cost of diesel generated power in Africa between US$ 0.15-0.30/kWh) has led to hydropower being viewed as the energy resource that could reduce Africa's dependence on imported oil, lower the overall cost of energy, stem GHG emissions as the continent develops, and provide the needed impetus for expanded access, which remains a pressing socio-economic goal of all sub-Saharan African nations. Electricity demand projections show, however, that the large hydro potential of Africa will be substantially exhausted by 2032-35, and that after this date, Africa will have to rely on more thermal power to meet the growing demand, except if meanwhile, Renewable energy (solar) has become cost competitive.

Africa's hydro potential is located in four main hydroelectric hubs and involving seven main river basins:

- West Africa on the Niger and Senegal rivers and in Guinea;
- Central Africa on the Congo river, in particular the Inga scheme;
- Eastern Africa, the Nile river basin development; and
- Southern Africa, involving the Orange, Limpopo and Zambezi rivers.

The development strategy for these hydro resources envisages a program of regional electricity connections to minimize transaction costs, attract investment, and promote energy security.

This potential is far from being realized. Only a small fraction of the continent's hydro potential has been so far developed, with an installed capacity of 22,000 MW in 2008 compared with a conservatively estimated economic potential that is more than 7 times current, annual hydro generation. Large, upfront capital investment requirements, weak project management capacity for technically complex construction works, poor country and utility creditworthiness, and unstable political environments have been some of the factors that have impeded progress.

For example, the Inga site on the Congo River has an estimated potential of between 39,000 and 44, 000 MW- more than twice the equivalent of the power of the world's largest dam (Three Gorges in China). However, only a small portion of this potential is used (1,774MW) and less than half is operational. The Zambezi River is another strategic area, with a potential of 12,000 MW, which includes two further planned developments to the existing Cahora Bassa dam (2,075 MW) and Kariba dam (1,266 MW): Mpanda Nkuwa (1,300 MW) and another plant of 850 MW, north of Cahora Bassa.

Figure 33: Hydro Power Potential of Africa

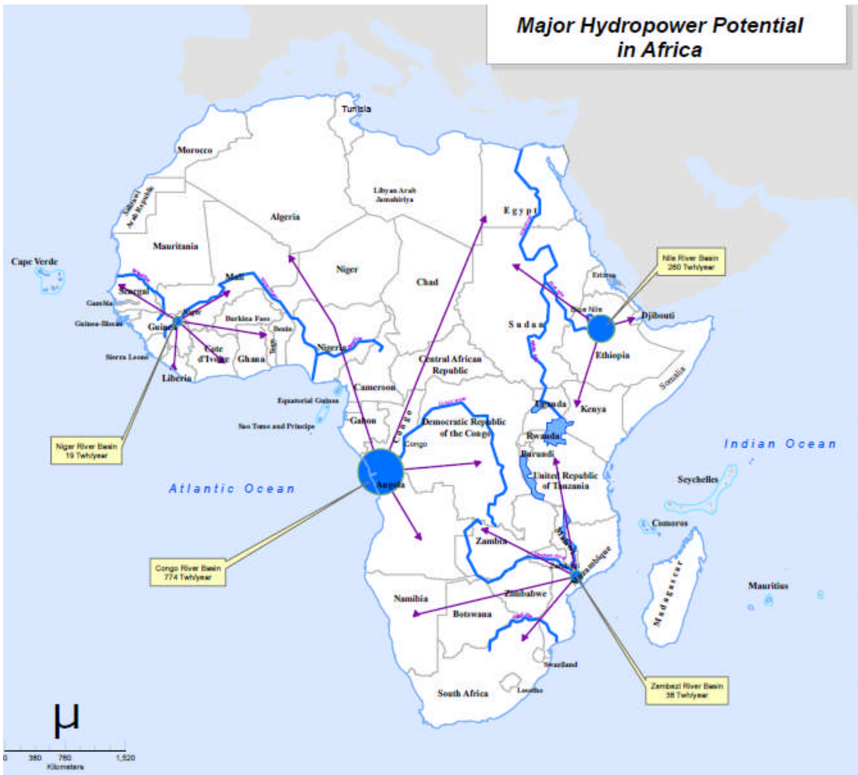


Table19: Hydro Potential*

	Installed Capacity		Generation 2008	Construction	Planned
COUNTRY	(GWh/yr)	(MW)	(Wh/yr)	(MW)	(MW)
Cameroon	105,000	729	3,827	0	1,819
DRC	145,000**	2,410	7,303	>162	43,000
Egypt	50,000	2,842	15,510	0	48
Ethiopia	62,000	669	2,700	1,277	10,000
Guinea	18,000	123	519	n/a	>240
Mozambique	31,717	2 ,179	14,710	0	5,000
Nigeria	29,800	938	7.645	3,300	11,500
Zambia	20,000	1,672	11,000	570	4,400
All Africa* **	**724,000**	**22,180**	**102,107**	**7.961**	**97,000**

* *Economically Feasible*

** *Gross theoretical hydro potential, 1,397,000 GWh/yr*

*** *Excludes Madagascar*

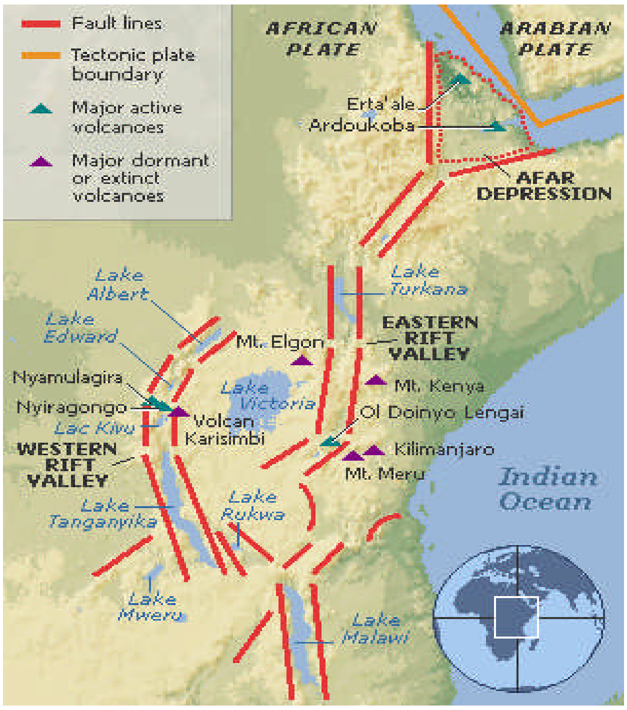
SOURCE: Hydropower and Dams: World Atlas 2009

5.5 Geothermal Resources

Africa's geothermal energy potential is mostly concentrated in eastern Africa though there are also several areas of geothermal potential spread across the continent. The main geothermal potential is found in the Great Rift Valley, roughly 3,700 miles in length and spanning several countries in East Africa including *Eritrea, Ethiopia, Djibouti, Kenya, Uganda, and Zambia* . The US Geothermal Energy Association estimates that Africa's Rift Valley could represent an untapped potential ranging from 2,500 to 6,500 MW of electric power while the United Nations Environment Programme considers its potential may be as high as 14,000MW.

Less than 200 MW of this potential has been developed for electricity generation, mainly in Kenya, which had an installed capacity of 167 MW in 2010; Ethiopia has less than 10 MW developed. While geothermal development has been exclusively for national electricity markets, the geothermal potential, if fully exploited, could also benefit regional markets in East Africa.

Figure 34: Geothermal Energy in Africa



SOURCE: Status of Geothermal Energy in East Africa Rift System. Jonas Mwano ***ICS-UNIDO December 2008***

5.6 Wind Energy Resources

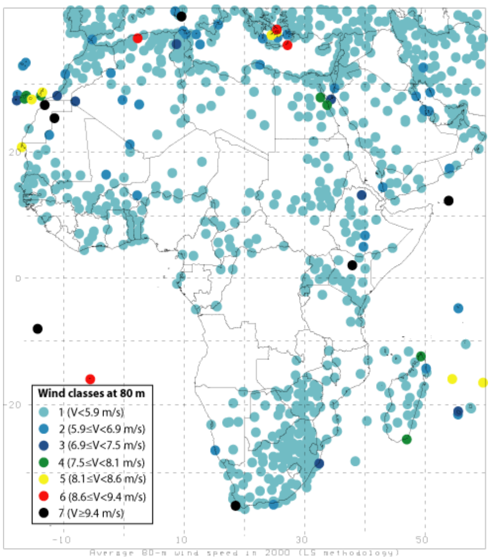
Africa's wind energy potential is substantial. However, this potential is less uniformly distributed than Africa's solar resources, with the best prospects for the development of wind power located near special topographical funnelling features close to coastal locations, mountain ranges, and other natural channels in the northern and southern regions of the African continent[21].

[21]Cassedy, Edward S. Prospects for Sustainable Energy: A Critical Assessment. New York Cambridge UP, 2000

The three main African countries that have developed wind energy are Egypt, Morocco and Tunisia, which together supply around 95 percent of the 563 MW of installed capacity. Egypt has set a target for wind to make up 12 percent of its total energy by 2020, with wind farms adding 7,200 MW to the grid. The largest single wind farm in Africa was inaugurated in Northern Morocco in June 2010 with a production capacity of 140 MW. South Africa is planning to develop its wind energy potential through by independent producers and add 400 MW to the grid by 2015.

Considering that an average wind speed of 7m/s is the minimum needed for efficient operation of wind turbines, it is clear that wind potential exists only in Morocco and Egypt, with some in some in Tunisia, South Africa and Tanzania.

Figure 35: Wind map of Africa



*Source: GENI library*http://www.geni.org/globalenergy/library/renewable-energy-resources/world/africa/wind-africa/index.shtml

5.7 Solar Energy Resources

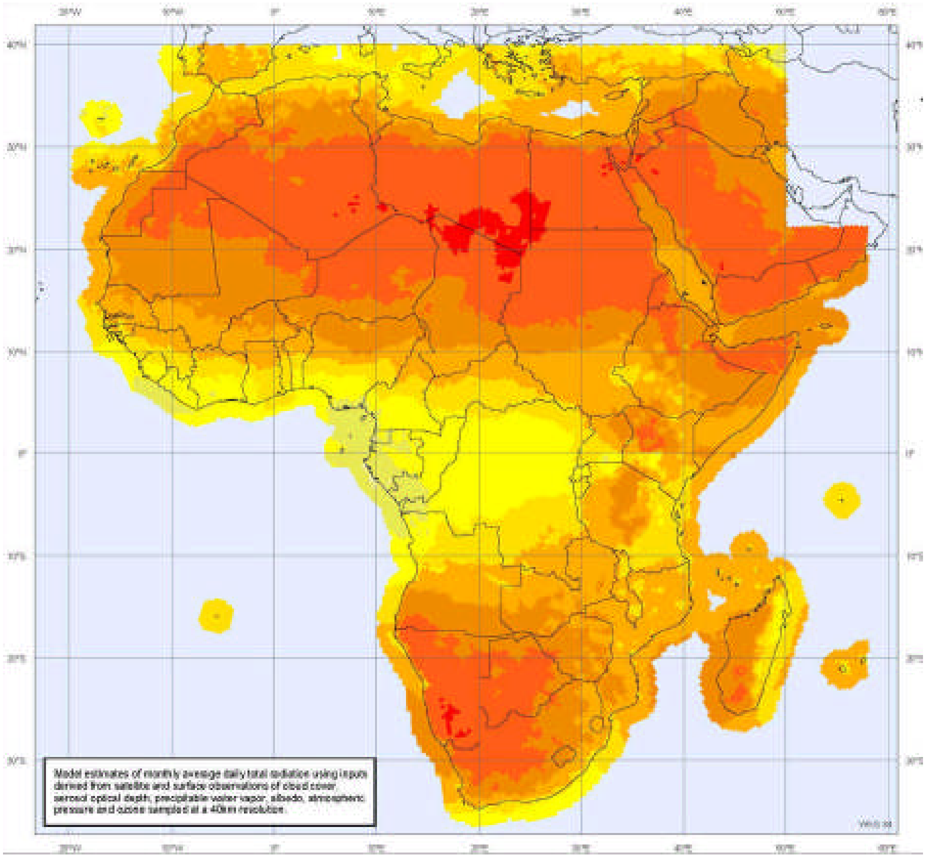
The potential for solar-based renewable energy technologies- photovoltaics (PV) and concentrating Solar Power (CSP) - to reduce Africa's energy gap has been recognized for a long time. The sunlight distribution of solar resources across Africa is fairly uniform, with more than 80 percent of Africa's landscape receiving almost 2000 kWh per square meter per year. This gives solar power the potential to bring energy to most locations in Africa without the need for expensive large scale grid infrastructure.

Africa's solar energy potential has been reinforced by a recent GIS technical analysis undertaken by the US Department of Energy's National Renewable Energy Laboratory (*International Congress on Renewable Energy, October 16-17, 2008)*. The results from this analysis are shown below:

- CSP generating potential for 17 countries in Africa, with variations from a low of 7 TWh/yr in Eritrea to a high of 40,500 TWh/yr in Libya; the main potential is in Libya, Egypt, Kalahari desert and some in Algeria.

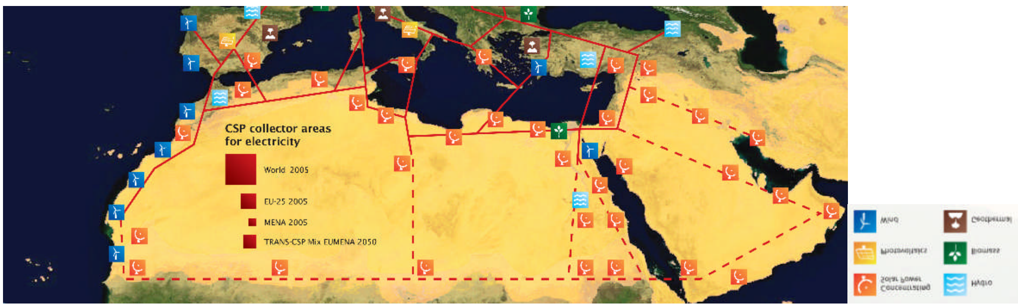
- PV electricity generation potential varied from a low of 33TWh/yr in Gambia to a high of 8,700 TWh/yr in Sudan, with the main potential in Algeria, Sudan, DRC.

Figure 35 : Africa's solar energy potential



The main project concept for developing the solar energy potential of the Sahara is the *Desertec* project. The objective of the *Desertec* project is to develop clean, sustainable and climate friendly energy sources from the deserts in North Africa using concentrating solar power (CSP) technology. The solar-based electricity would be supplied to regional markets in Africa and exported to Europe. The project concept is on a massive scale and envisages up to $400 billion investment over the period 2020-2050. The concept has been under development for a number of years and has received further impetus since 2007, with strong European support.

Figure 36: Desertec Solar Energy Project



6. CONTINENTAL ENERGY OUTLOOK 2040

Continental Energy Outlook

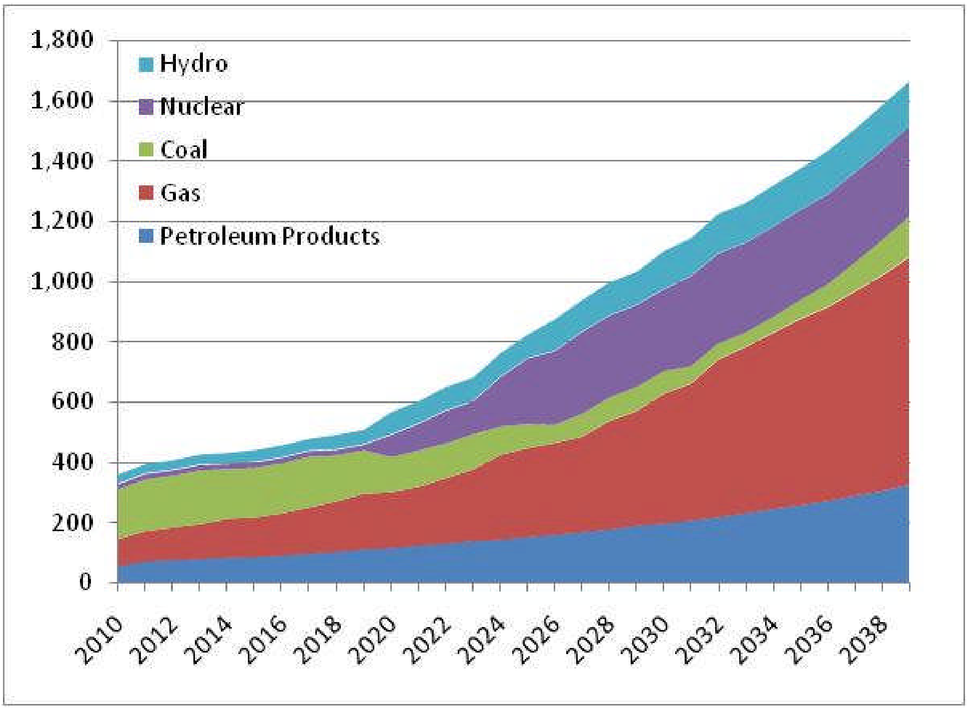
- Energy demand is projected to increase by an average of 5.7% per year over the 2011-2040 period to 3,188 TWh, a 5.4 fold increase; the needed generation capacity would increase by 6% per year to 694 GW by 2040, a 6 fold increase.
- Global electricity demand is projected to increase much faster than the past growth rate of 2.6%. The past growth rate was heavily constrained by a shortages of capacity.
- Energy efficiency policies are expected to save 139 GW (16.7%) in capacity needs and 634 TWh in energy produced (16.6%), highlighting the importance of diligent implementation of energy efficiency policies in the Outlook 2040.
- The modernization of the African economies and social progress will result in a significant increase in per capita energy consumption, corresponding to an unprecedented 3.7% increase per year,
- Three main alternatives for the Supply Outlook 2040 were analysed: Low integration, High integration and Moderate Integration.
  - Full integration and unlimited trade would save US$ 1 117 billion over the 2014-2040 period (US$ 43 billion per year), or 21 % of the cost of electricity.
  - High and moderate integration scenarios lead to more thermal generation temporarily during the 2014-20 period while large low cost hydro plants are being developed, leading to large fuel cost savings in the 2020-40 period.
  - The Moderate scenario is considered the most realistic for planning purposes and generates savings of 16% on production cost, even though it requires 15% more capital investment than the Low Trade scenario (more hydro).

6.1 Primary Energy Demand

6.1.1 Primary Energy demand by Type of Fuel

The demand for primary energy (excluding biomass) of Africa will increase by 8.9% p.a, including Industry, Power and Transport. It will see a decrease in the role of coal, as gas for power and industry and liquid petroleum products for transport and power develop as well as nuclear in South Africa and later, in Egypt. Gas is projected to increase gradually while coal will decrease even in South Africa as cleaner sources of energy (nuclear) are introduced in the country's energy mix. The rapid increase in consumption of liquid petroleum products is due to the development of transport mainly.

Figure 37: Consumption fossil and hydro primary energy of Africa (in million TOE)



The challenge for Africa will be to meet the continued and increasing dependence on petroleum products from continental petroleum resources through the development of refineries supplied by African crude, and of petroleum products pipelines to transport economically increasing volumes of petroleum products.

An important conclusion for Africa is that despite the significant hydro potential of the continent, as this potential is exhausted by 2030-32, the continent will continue to depend on fossil fuels, particularly gas, and increasingly so after 2030 and on nuclear (see graph above).

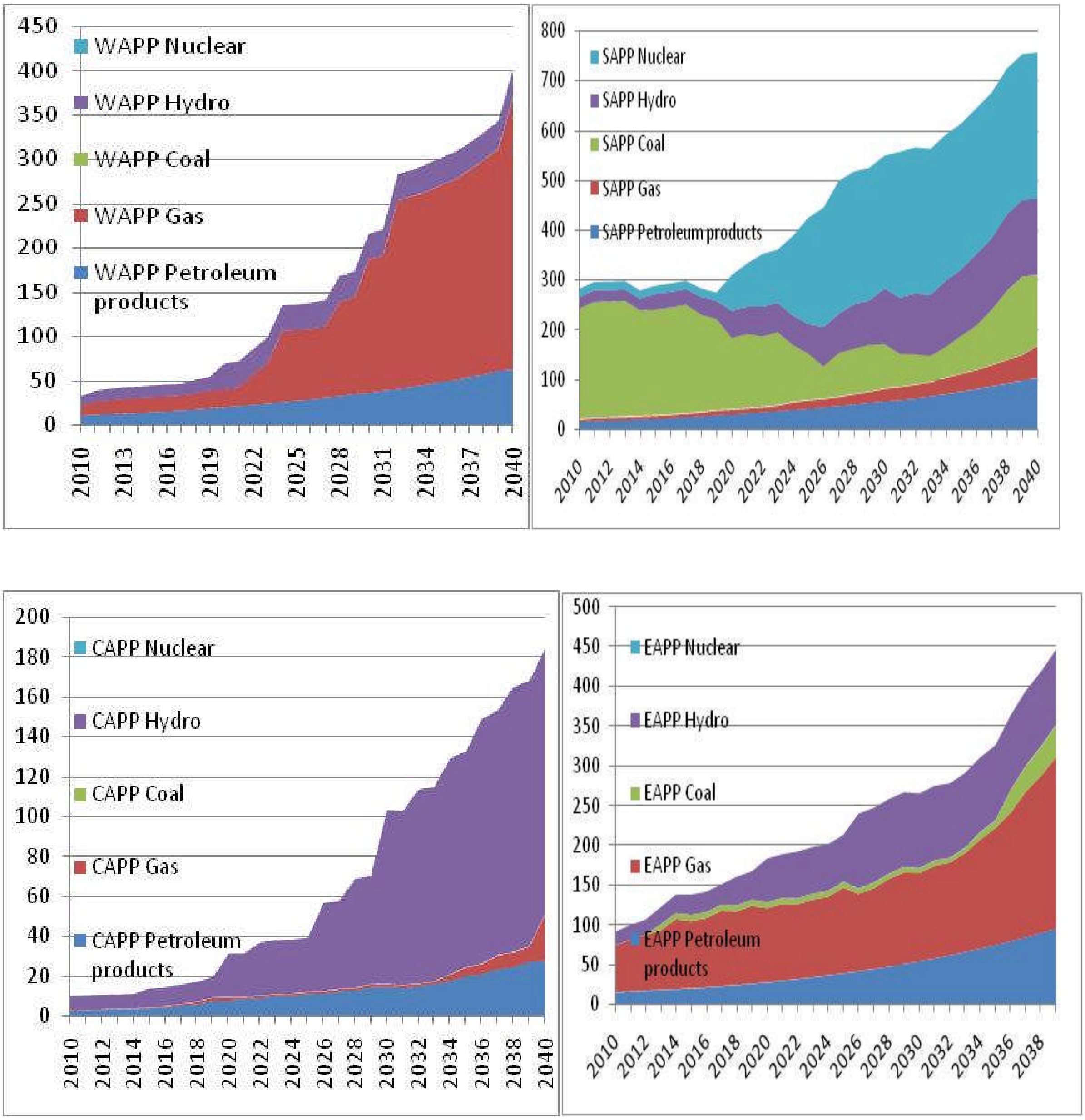
Table 20: Annual Growth of Primary Energy consumption (%)

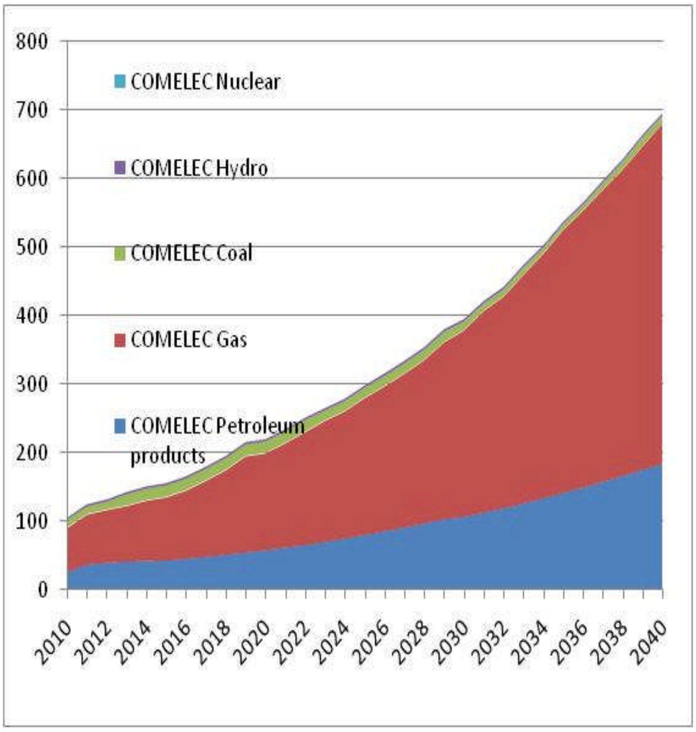
Primary Energy	Annual Growth Rate %
Petroleum products	6.5%
Gas	8.6%
Coal	2.7%
Nuclear	18.5%
Hydro	5.8%
Total	**8.9%**

6.1.2 Primary Energy Demand by REC

Except in SAPP (with a continuing, though decreasing, high consumption of coal) and COMELEC (with a strong presence of gas), most RECs will continue to rely on petroleum products for transport and power generation. This continued and increasing dependence on petroleum products would nevertheless be even higher in the absence of the accelerated development of renewable resources (hydro) as noted below.

Figure 38: Primary Energy Demand by REC (in million TOE equivalent)





The RECs will continue to have very diverse primary energy mixes, with COMELEC and EAPP (Egypt) relying heavily on gas and petroleum products, while WAPP has a more balanced mix with petroleum products, gas and coal, CAPP relies essentially n petroleum products and SAPP reduces its consumption of coal but increases the share of nuclear in its energy mix..

6.2 Electricity Demand

The electricity demand projections were estimated for each country and aggregated by REC and at the continental level (see Annex 11-1 for details).

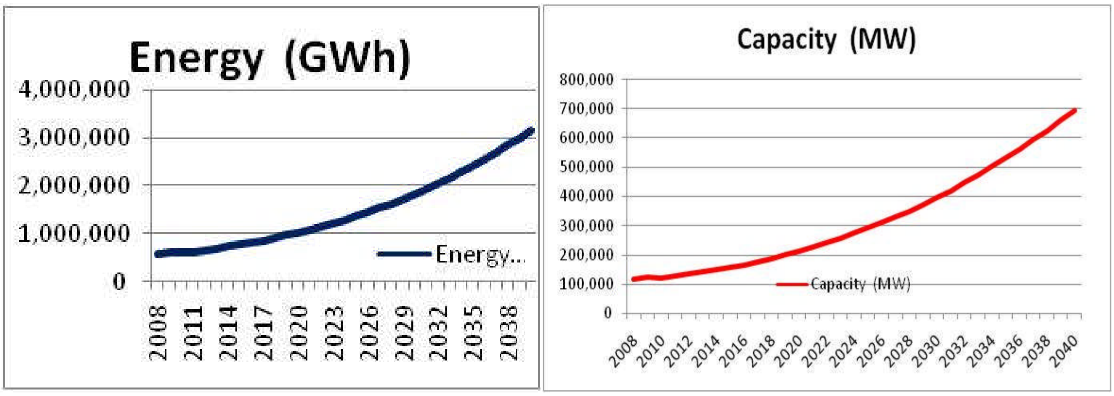
The increase in energy and capacity demand includes the additional demand due to the increase in access, which is part of the policy priority of all Governments in Sub-Saharan Africa. Overall access is projected to increase, from 40% at present to 69% by 2040.

The continental demand for electricity is projected in terms of energy, which drives the fuel consumption, CO2 emissions and in terms of generation capacity needed to meet the peak demand. Under the PIDA GDP growth projections of 6.2% per annum on average for Africa, and the PIDA population growth projections, energy demand after taking into account the potential for energy efficiency gains is projected to increase by an average 5.7% per year over the 2011-2040 period, a 5.4 fold increase to 3,188 TWh by 2040, and the generation capacity needed by 6.2%, a 6 fold increase to 694 GW by 2040.

6.2.1 Continental Electricity Demand

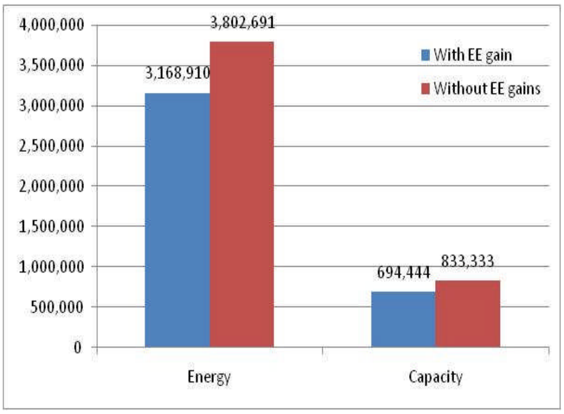
Continental electricity demand is projected to increase much faster than in the past, when the growth rate was 2.6% according to IEA statistics. This growth rate in the past, however, should not be considered as the natural growth rate of demand, as it was heavily constrained in most African countries, including South Africa and Morocco, by a shortage of capacity and rationing of demand through brown-outs and load shedding. The amount of un-served demand is difficult to evaluate with certainty, but an overall un-served demand of 5% to 10% is probably realistic for Africa, with the implication that the growth of demand has been under-estimated by at least 1% per year for the past five years, bringing the natural growth rate of demand to about 3.6% per year in the past. The projected growth rate represents a new trend for energy in Africa, but it is required to sustain the overall economic growth rate of 6%.[22]

Figure 39: Projected African electricity demand in energy and capacity, 2011-2040



The impact of energy efficiency policies on demand is presented below.

Figure 40: Impact of Energy Efficiency Gains on Demand

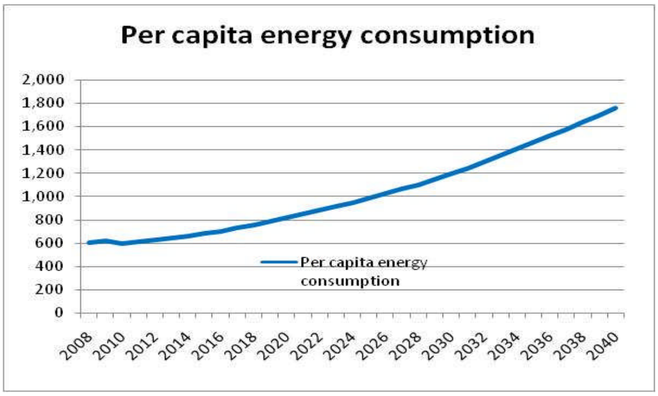


Energy efficiency policies are expected to save 139 MW (16.7%) in capacity needs and 634 TWh in energy produced (16.6%), highlighting the importance of diligent implementation of energy efficiency policies in the Outlook 2040.

The modernization of the African economies and social progress will result in a significant increase in per capita energy consumption, which is projected to increase from its present world lowest level of 612 kWh per capita in 2011 to 1,757 kWh per capita by 2040, corresponding to an unprecedented 3.7% increase per year, aligned with the priority granted to access to modern energy in the AU and REC energy policies.

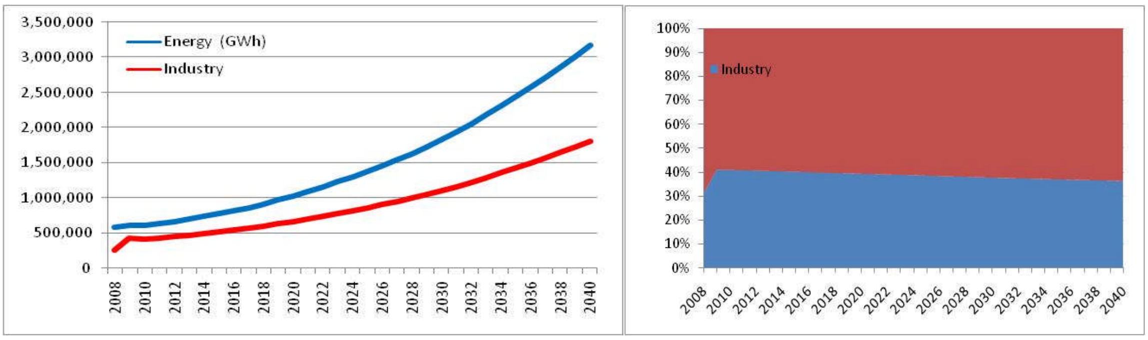
[22]The Investment Climate Surveys of African countries prepared under the auspices of IFC highlight that poor infrastructure is considered a major obstacle to business development and investment in most African country, and within infrastructure, the quality and reliability of electricity supply ranks first, aheadof transport infrastructure.

Figure 41: Africa energy consumption per capita 2011-2040



The energy intensity of Africa will not change significantly. It will decline slightly from 0.181 TWh/billion GDP in 2011 to 0.157 in 2040 TWh/billion GDP, as the decrease in the energy intensity of industries linked to their modernization and improved energy intensity is offset by the increase in energy intensity of non-industrial activities and as a result of energy efficiency gains.

Figure 42: Energy demand from the industrial sector compared to total energy demand



The total demand from industries is projected to increase from 431 TWh in 2011 to 1,806 TWh by 2040, a 5.1% annual growth. It should be noted that this trend is not contradictory with the expected rapid development of extractive industries, as the bulk of the demand from these industries is projected to be met by self-generation and only the demand from ancillary industries is considered in the projection above, which relates to the power grid.

6.3 Electricity Generation

6.3.1 Benefits and challenges of Alternative Options for Power Supply

On the generation side, the Outlook 2040 is determined by the supply option selected amongst the several alternatives described in Section 9.a.3 above, based on the evaluation criteria listed at the end of that section, namely:

- Energy security
- Role of hydro
- GHG emissions
- Production cost
- Contribution to regional integration
- Capital investment

Three main alternatives for supply have been examined and compared: the Low Trade, High tTade and Moderate Trade Options in order to determine the best option for PIDA.

Low Integration

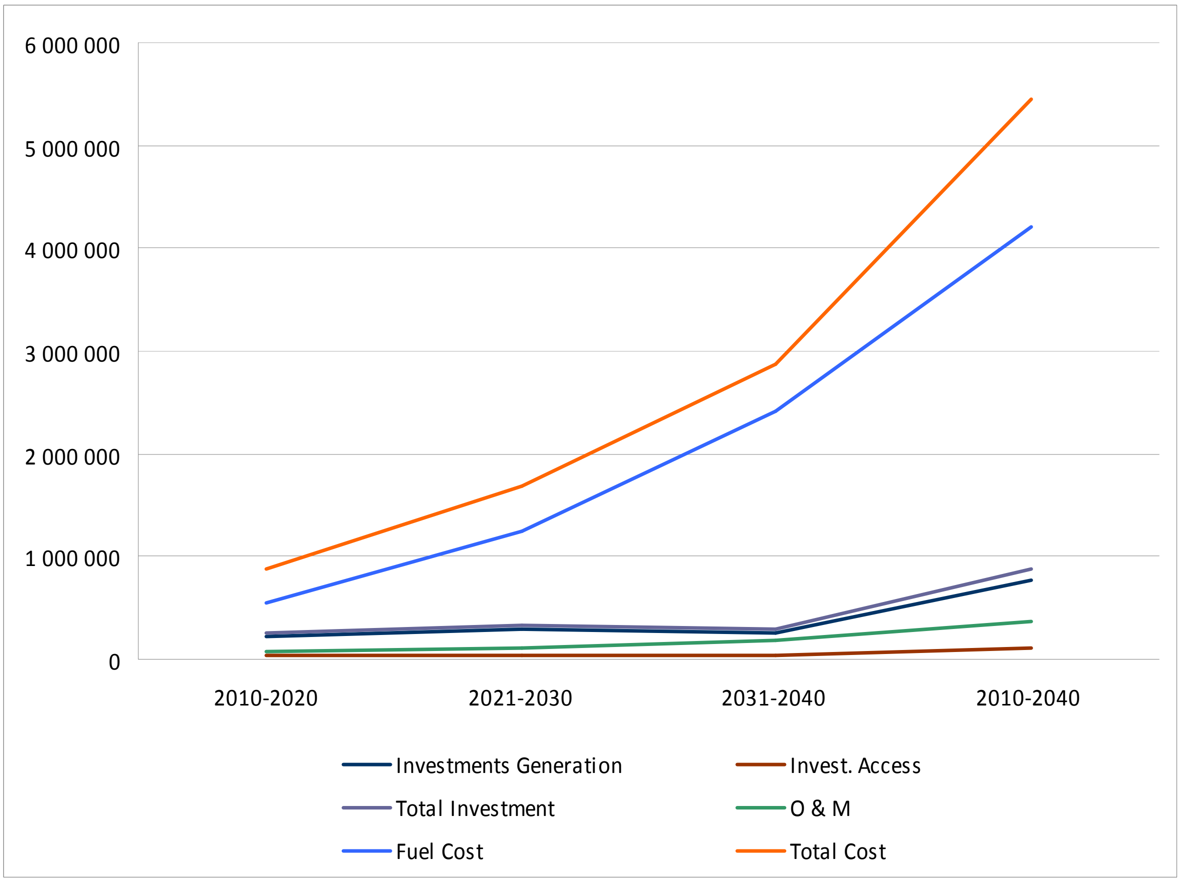
Table 21: Investment and Generation Costs: Low Trade (million US$)

	Investments Generation	Invest. Access	Total Investment	O & M	Fuel Cost	Total Cost
2014-2020	194 282	23 388	217 670	53 702	430 142	701 514
2021-2030	294 763	39 046	333 809	111 792	1 245 275	1 690 875
2031-2040	255 546	34 110	289 656	180 684	2 406 584	2 876 924
2014-2040	**744 591**	**96 544**	**841 135**	**346 178**	**4 082 001**	**5 269 313**

Table 22: Investment and Generation Costs per annum: Low Trade (million US$)

	Investments Generation	Invest. Access	Total Investment	O & M	Fuel Cost	Total Cost
2014-2020	**27,755**	**3,341**	**31,096**	**7,672**	**61,449**	**100,216**
2021-2030	**29,476**	**3,905**	**33,381**	**11,179**	**124,527**	**169,088**
2031-2040	**25,555**	**3,411**	**28,966**	**18,068**	**240,658**	**287,692**
2014-2040	***28,638***	***3,713***	***32,351***	***13,315***	***157,000***	***202,666***

Figure 43: Investment and Generation Costs: Low Integration Scenario



High Integration

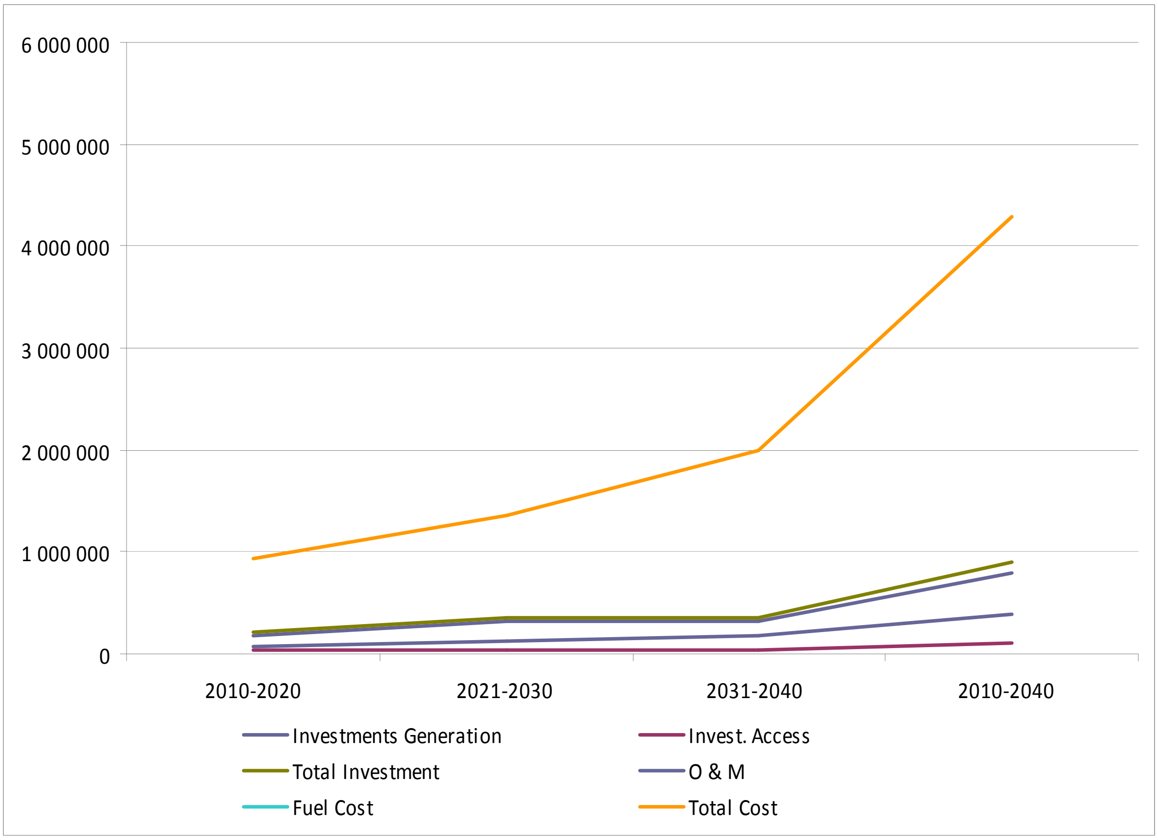
Table 23: Investment and Generation Costs: High Trade (million US$)

	Investments Generation	Invest. Access	Total Investment	O & M	Fuel Cost	Total Cost
2014-2020	150,771	23388	174,159	51,705	432,866	658,730
2021-2030	309,348	39046	348,394	114,929	857,269	1,320,592
2031-2040	313,422	34110	347,532	196,557	1,628,116	2,172,204
2014-2040	**773,541**	**96544**	**870,085**	**363,191**	**2,918,251**	**4,151,527**

Table 24: Investment and Generation Costs per annum: High Integration (million US$)

	Investments Generation	Invest. Access	Total Investment	O & M	Fuel Cost	Total Cost
2014-2020	**21,539**	**3,341**	**24,880**	**7,386**	**61,838**	**94,104**
2021-2030	**30,935**	**3,905**	**34,839**	**11,493**	**85,727**	**132,059**
2031-2040	**31,342**	**3,411**	**34,753**	**19,656**	**162,812**	**217,220**
2014-2040	**29,752**	**3,713**	**33,465**	**13,969**	**112,240**	**159,674**

Figure 44: Investment and Generation Costs: High Integration Scenario



Moderate Integration

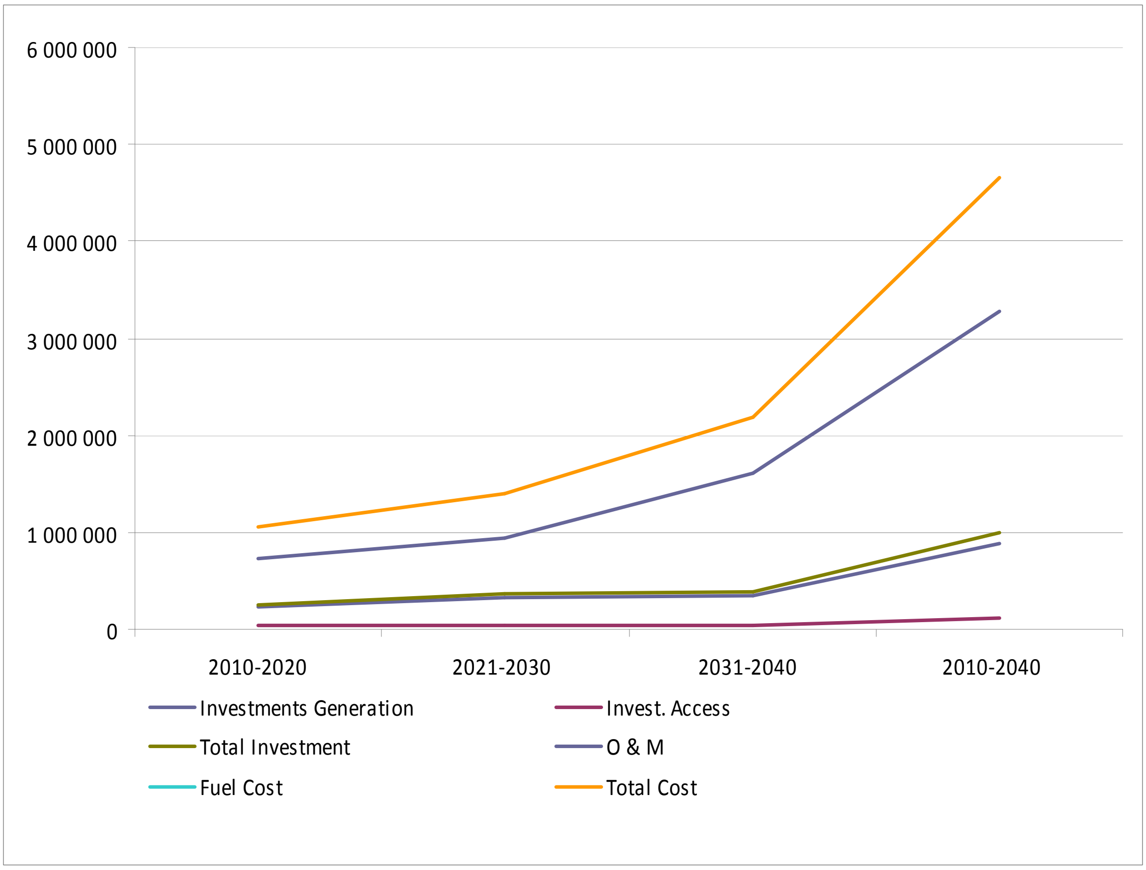
Table 25: Investment and Generation Costs: Moderate Trade (million US$)

	Investments Generation	Invest. Access	Total Investment	O & M	Fuel Cost	Total Cost
2014-2020	191,874	23388	215,262	50,638	509,756	775,657
2021-2030	324,194	39046	363,240	112,246	941,197	1,416,684
2031-2040	345,656	34110	379,766	194,672	1,640,876	2,215,313
2014-2040	**861,725**	**96544**	**958,269**	**357,556**	**3,091,829**	**4,407,654**

Table 26: Investment **and Generation Costs per annum: Moderate Integration (million US$)**

	Investments Generation	Invest. Access	Total Investment	O & M	Fuel Cost	Total Cost
2014-2020	**27,411**	**3,341**	**30,752**	**7,234**	**72,822**	**110,808**
2021-2030	**32,419**	**3,905**	**36,324**	**11,225**	**94,120**	**141,668**
2031-2040	**34,566**	**3,411**	**37,977**	**19,467**	**164,088**	**221,531**
2014-2040	**33,143**	**3,713**	**36,856**	**13,752**	**118,917**	**142,182**

Figure 45: Investment and Generation Costs: Moderate Integration Scenario



6.3.2 Benefits of Regional Integration in terms of electricity costs

The comparison between the three scenarios is presented below. It shows that in terms of capital investment, the higher trade scenarios require more capital investment, because they allow the implementation of more and larger hydro plants, which are low cost but more capital intensive than thermal plants; on the other hand, they require less reserve margin to achieve the targeted 2% LOLP level, but the gains are less than the additional capital cost required by hydro plants. The Moderate trade scenario requires more capital investment than the High trade scenario because it requires more reserve capacity than the full trade scenario, as less reserve capacity can be pooled. Integration allows large savings in fuel and O&M costs, because the maintenance and operation of hydro plants is less expensive than for thermal plants and fuel costs are negligible. Overall, full integration and unlimited trade would save a significant US$ 1 117 billion over the 2011-2040 period (US$ 43 billion per year), or 21 % of the cost of electricity. The high and moderate integration scenarios lead temporarily to more thermal generation during the 2014-20 period while large low cost hydro plants are being developed and come on stream mainly in 2020 and later years, leading to large fuel cost savings in the 2020-40 period.

Recognizing that full integration and unlimited trade (the High trade scenario) may not be realistic, the Moderate trade scenario is preferable. It still yields significant gains compared to the Low Trade scenario (US$ 861 billion or US$ 33 billion per year). This gain of US$ 33 billion is US$ 10 billion a year lower than the gain of US$ 43 billion a year of the Full Integration scenario. The gains compared to the Low Integration scenario is still 17%.

Table 27: Comparison between the alternative Trade scenarios

	Investments Generation	Invest. Access	Total Investment	O & M	Fuel Cost	Total Cost
Low trade	744,591	96,544	841,135	346,178	4,082,001	***5,269,313***
High trade	773,541	96,544	870,085	363,191	2,918,251	***4,151,527***
Moderate trade	861,725	96,544	958,269	357,556	3,091,829	***4,407,654***
Gain of Full integration	-28,950	0	-28,950	-17,014	1,163,750	***1,117,787***
Gain of Moderate integration	-117,133	0	-117,133	-11,378	990,171	***861,660***
Loss of Moderate Integ. Compared to full Integration.	88,184	0	88,184	-5,635	173,579	***256,127***

6.4 Electricity Trade

6.4.1 Electricity trading

The tables below indicate the main exchanges of electricity between. The flows are indicated in MW.

It indicates that the total flows in 2020 will be 61 GW, or 30%% of electricity demand. This compares to multiplication by a factor of six of the share of regional trade compared to the less than 5% at present allowed by the accelerated development of the regional transmission system.

By 2040, the volume traded increases to about 93 GW, but only 14% of electricity demand as regional exchanges stabilize while demand met by intra-REC and national demand increase.

2020

From	*CAPP*	*EAPP*	*NAPP*	*SAPP*	*WAPP*	*Total*
To						
CAPP		10 537	3 398		6 542	20 477
EAPP						0
NAPP		619				619
SAPP	26 379	12 258				38 637
WAPP			1 764			1 764
Total	26 379	23 415	5 162	0	6 542	61 498

2040

From	*CAPP*	*EAPP*	*NAPP*	*SAPP*	*WAPP*	*Total*
To						
CAPP		299	1 523		9 202	11 024
EAPP						0
NAPP		12 327				12 327
SAPP	50 143	17 561				67 703
WAPP			5 001			5 001
Total	50 143	30 186	6 524	0	92 02	96 055

Note: For the evaluation of the flows, it was assumed that:

- DRC is part of CAPP only,
- Angola is part of SAPP only
- Burundi is part of EAPP only
- Libya is part of Comelec only
- Comelec and Egypt are grouped into a category called "NAPP" and both Libya and Egypt are considered as part of NAPP only
- Tanzania was included only in EAPP.

7. ENERGY OUTLOOK 2040 BY SUB-CONTINENTAL ENTITIES

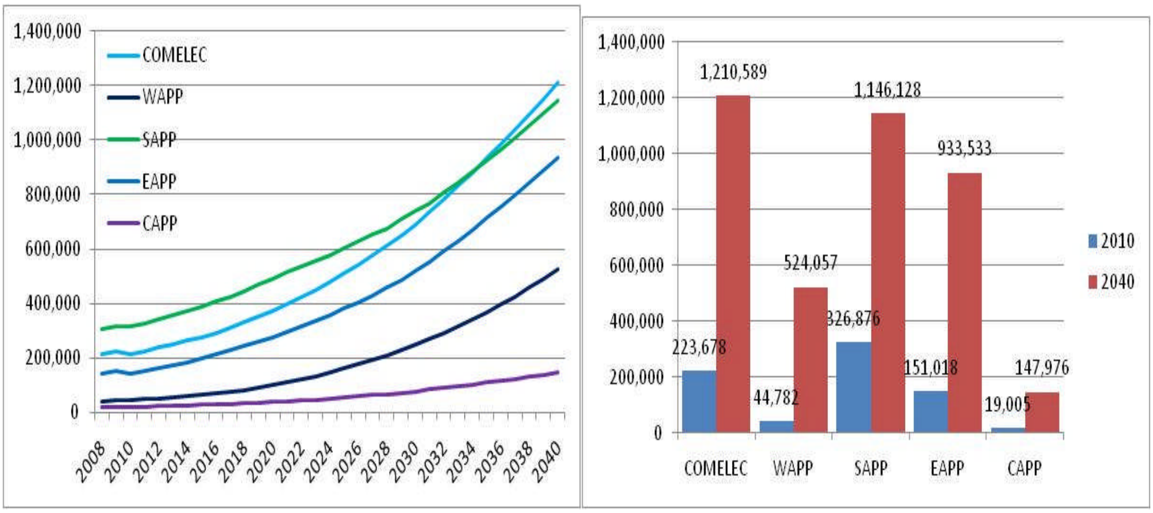
- Demand increases faster in WAPP (8.9%) and CAPP (7.3%) compared to SAPP (4.4%), EAPP (6.5%) and COMELEC (6%), because the demand of large countries, including South Africa's and Egypt's, is moderate and low income countries catch-up with more advanced countries.
- In terms of consumption per capita, the rapid demographic growth of Sub-Saharan Africa pulls down the per capita consumption of electricity.
- COMELEC will experience a limited increase in the already high access rate, but will still need an investment of US$ 8 billion to bring its access rate to 97%. Total capacity will increase by an average 6.2%, requiring an additional 298 GW of capacity. Per capita consumption of electricity will increase significantly.
- SAPP will experience a significant increase in access from 25% to 63%, provided it invests US$ 27 billion in access. Total demand will increase by 4.4% only because of a slower growth rate in South Africa; it will still require an additional 129 GW of new capacity. Per capita consumption will increase modestly because of the fast increase in the population.
- WAPP will experience a significant increase in access from 45% (because of Ghana and Nigeria, in particular) to 67% with a substantial investment in access of US$ 32 billion. Demand will increase by a high 8.9%, requiring 90 GW of additional capacity, because of the high growth rates, particularly in low income countries of the region. Per capita consumption will increase significantly as the demand will increase significantly faster than the population of the region.
- CAPP's access rate will increase considerably from 21% to 63% as a number of countries start from a very low level of access and are expected to catch-up over the period. Some US$ 15 billion will have to be invested in access. Overall demand will increase significantly by 7.3% per year, and some 26 MW will have to be installed. Per capita consumption will also increase significantly over the period.
- EAPP's access rate will increase substantially from 37% (relatively high because of the presence of Egypt in the region) to 68%, requiring an investment of US$ 44 billion in access. Demand will increase by a moderate 6.5% because of relatively slow growth in Egypt, requiring still an increase of a significant 140 GW. Per capita consumption will increase moderately over the period.

7.1

7.2 Comparison by REC/Pool

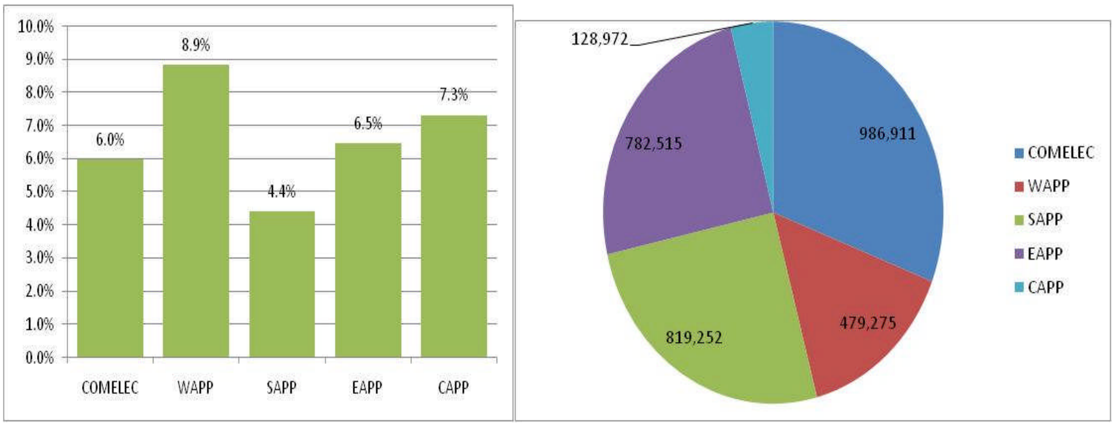
COMELEC, SAPP and EAPP will have a strong growth in absolute terms compared to WAPP and CAPP (See Annex 8-1 for details).

Figure 46: Electricity demand by REC/Pool (in GWh)



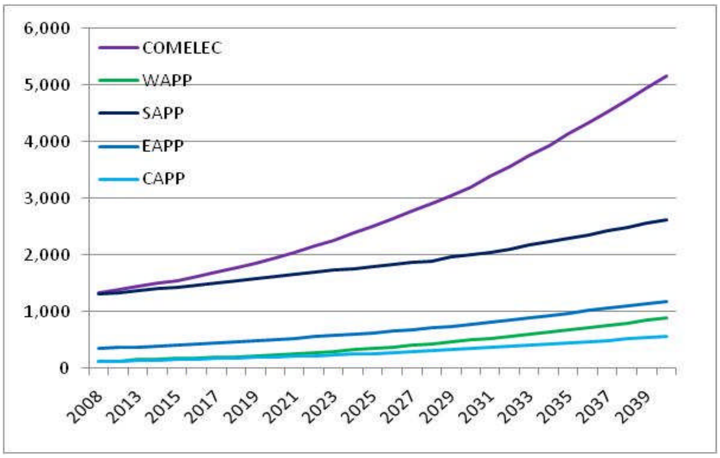
In annual growth rate, WAPP and CAPP perform better than the other RECs/Pools, though starting from a lower level in terms of energy consumption and per capita consumption. The higher growth rate of some of the pools compared to others will have an impact on the investment requirements to meet the high growth in demand, which will be examined in the next section.

Figure 47: Annual Growth Rate by REC/Pool 2011-2040 Increase in demand in RECs/Pools 2011-2040 (in GWh)



Considering that the increase in consumption of energy per capita is an indicator of economic and social progress, the RECs/Pools are compared in terms of absolute level and trend in per capita energy consumption.

Figure 48: Per capita Electricity Consumption by REC/Pool 2011-2040 (in kWh)



COMELEC has a faster growth of per capita energy consumption, because its population growth is significantly lower than for the rest of Africa, at 1.2% per annum compared to more than 2% for the rest of Africa, while demand is projected to increase at a similar rate of 6%.

7.3 Outlook by REC/Pool

The Outlook 2040 for each REC/Pool is characterized by:

- The peak load including network losses needed and its growth rate;
- The increase in generation capacity;
- The electricity access rate.

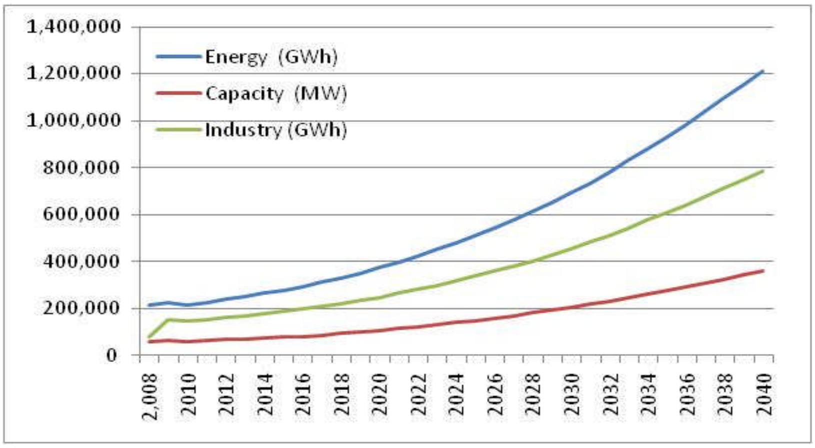
7.3.1 COMELEC

Capacity is projected to increase by 6.2% over the 2011 to 2040 period and the additional capacity needed is298 GW. Access is projected increase slightly by 1% to 97%, but US$ 8 billion will have to be invested in access to maintain the access rates achieves, with a growing population, and to progress by another 1%.

Table 27: Outlook of COMELEC Energy Demand 2011-2040

	2011	2020	2030	2040	Total Period
Peak Load including losses (MW)	62,364	105,219	204,758	360,786	
Annual Growth rate in Capacity preceding 10 years		6.7%	6.9%	5.8%	**6.2%**
Increase over the period (GW)		42.8	99.5	156.0	**298.4**
Access Rate	96%	96%	97%	97%	**+1%**
Investment in Access (previous period, million US$)		3,048	2,747	2,218	**8,013**

Figure 49: Future Energy and Capacity demand COMELEC 2009-2040



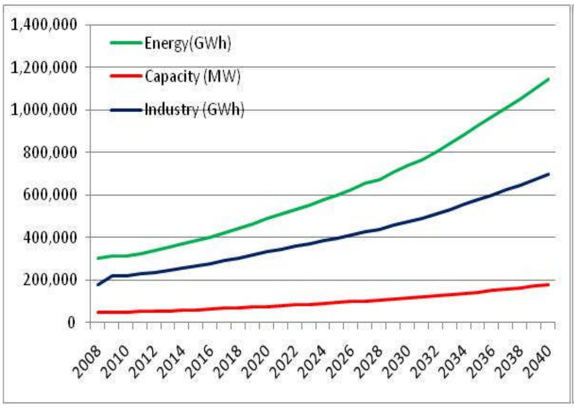
7.3.2 SAPP

The future demand pattern in SAPP is dominated by the prospects for South Africa. With an average annual growth of capacity of 4.4%, the system will need an additional 129 GW for a 250% increase of capacity over the 2011-2040 period. This additional capacity will be able to sustain an increase in access from 25% in 2011 to 63% by 2040, for an investment in access of US$ 27 billion.

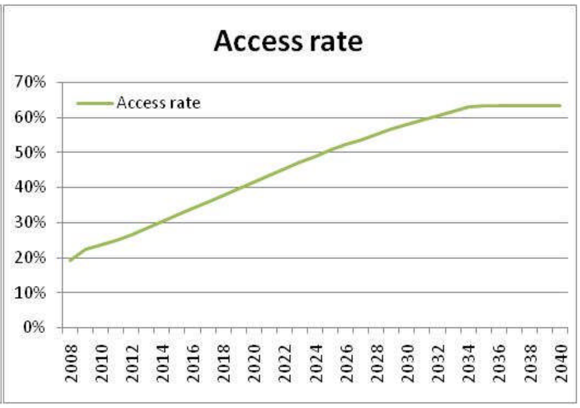
Table 28: Outlook of SAPP Energy Demand 2011-2040

	2011	2020	2030	2040	Total Period
Peak Load including losses (MW)	50,957	76,610	116,049	179,794	
Annual Growth rate Capacity preceding 10 years		5.2%	4.2%	4.4%	4.4%
Increase over the period (GW)		25.6	39.4	63.7	128.8
Access Rate	25%	41%	58%	63%	+38%
Investment in Access (previous period, million US$)		8,510	11,144	7,816	27,470

Future Energy and Capacity 2011-2040



Access Rate 2011-2040 (%)



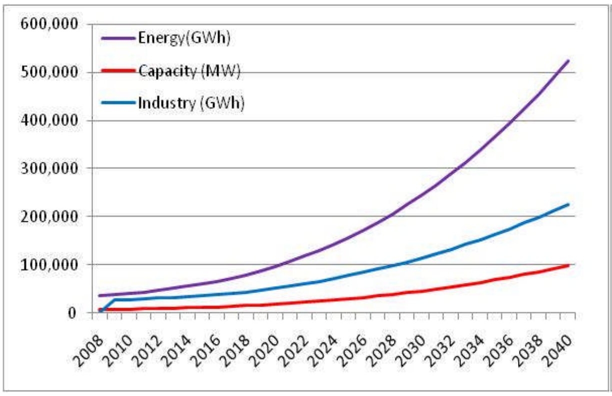
7.3.3 WAPP

With an average annual growth of capacity of 8.9%, the system will need an additional 90 GW for a 1200 % increase of capacity over the 2011-2040 period. This high expansion is due to the projected high GDP growth and to the increase in access rate. This additional capacity will be able to sustain an increase in access from 45% in 2011 to 62% by 2040, provided US$32 billion are invested in access.

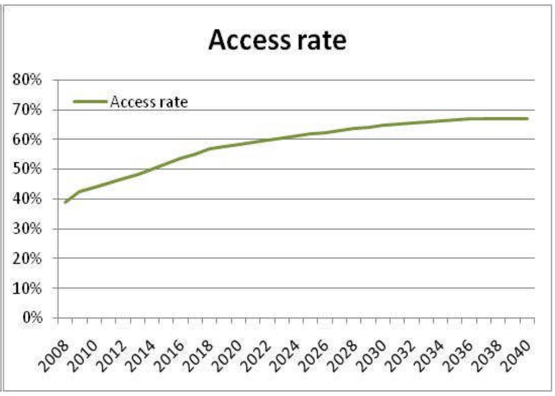
Table 29: Outlook of WAPP Energy Demand and Access growth 2011-2040

	2011	2020	2030	2040	Total Period
Peak Load including losses (MW	8,204	17,864	45,748	98,157	
Annual Growth rate Capacity preceding 10 years		10.8%	9.8%	7.9%	**8.9%**
Increase over the period (GW)		9.6	27.8	52.4	**89.9**
Access Rate	45%	58%	65%	67%	**+22%**
Investment in Access (previous period, million US$)		11,724	10,927	9,583	**32,234**

Future Energy and Capacity WAPP 2011-2040



Access Rate 2011-2040



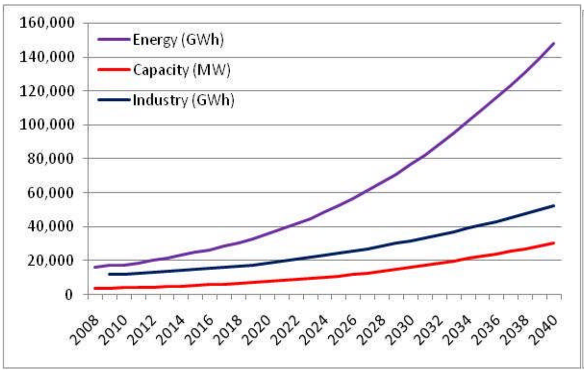
7.3.4 CAPP

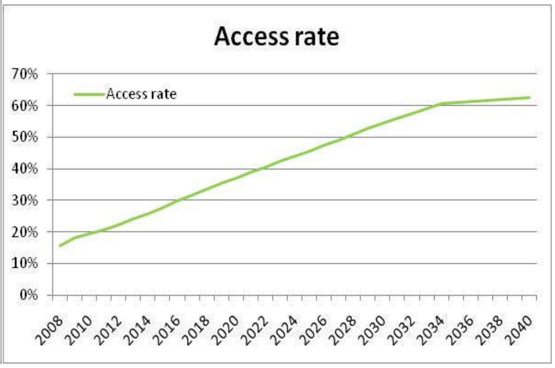
With an average annual growth of capacity of 7.3%, the system will need an additional 26 GW for a 670 % increase of capacity needs over the 2011-2040 period. This high expansion is due to the projected high GDP growth and to the increase in access rate. This additional capacity will be able to sustain an increase in access from 21% in 2011 to 63% by 2040, provided US$ 14 billion are invested in access.

Table 30: Outlook of CAPP Energy Demand and Access growth 2011-2040

	2011	2020	2030	2040	Total Period
Peak Load including losses (MW)	3,915	7,409	15,713	30,114	
Annual Growth rate Capacity preceding 10 years		8.3%	7.8%	6.7%	**7.3%**
Increase over the period (GW)		3.4	8.3	14.4	**26.1**
Access Rate	21%	37%	54%	63%	**+42%**
Investment in Access (previous period, million US$)		4,102	5,689	5.022	**14,813**

Future Energy and Capacity CAPP 2009-2040 ***Access Rate 2011-2040***





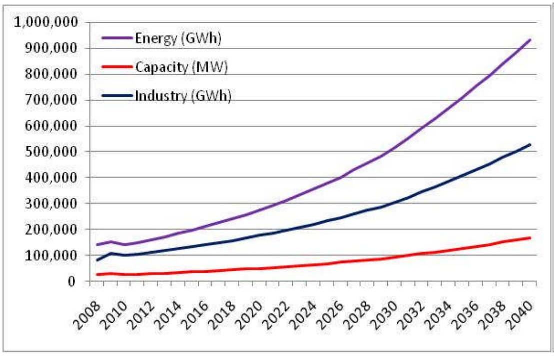
7.3.5 EAPP

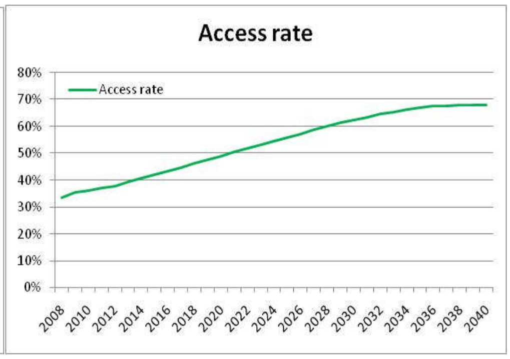
With an average annual growth of capacity of 6.5%, the system will need an additional 140 GW to meet a 525 % increase of capacity needs over the 2011-2040 period. This high expansion is due to the projected high GDP growth and to the increase in access rate. This additional capacity will be able to sustain an increase in access from 37% in 2009 to 68% by 2040, provided US$ 44.5 billion are invested in Access.

Table 31: Outlook of EAPP Energy Demand and Access growth 2009-2040

	2011	2020	2030	2040	Total Period
Peak Load including losses (MW)	26,906	49,625	93,728	169,192	
Annual Growth rate Capacity preceding 10 years		7.9%	6.6%	6.1%	**6.5%**
Increase over the period (GW)		22.7	44.1	75.4	**140.2**
Access Rate	37%	49%	63%	68%	**+31%**
Investment in Access (previous period, million US$)		12,683	17,537	14,084	**44,304**

Future Energy and Capacity EAPP 2011-2040 ***Access Rate***





8. INFRASTRUCTURE NEEDS TO MEET THE DEMAND

Energy Infrastructure Investment Needs 2040

An estimated $44 billion per year will be needed to meet forecast energy demand for Africa to the year 2040 as follows:

- *Power Sector* The average annual investment needs for the power sector are estimated at $43 billion, with the largest proportion for generation ($31.7 billion), $4.5 billion in interconnections and $ 3.7 billion in access.
- *Pipelines An estimated $1.3 billion per year will be needed for gas and petroleum product pipelines.*
- *Interconnection* investment is urgent and needed up front to meet the forecast energy demand in 2020 for an average of US$ 4.5 billion per year
- *Access* A small investment i.e. US$ 3.7 billion per year is needed to ensure no country has an access rate below 60 percent by 2040;

The infrastructure needed to meet the demand will be analyzed in terms of generation capacity, transmission capacity and pipeline/refineries needed to meet the demand. In addition, the technological mix of infrastructure for generation (with a particular attention to the role of hydro power generation, in line with the AU priorities) and transmission (with a particular attention to regional integration) will be examined.

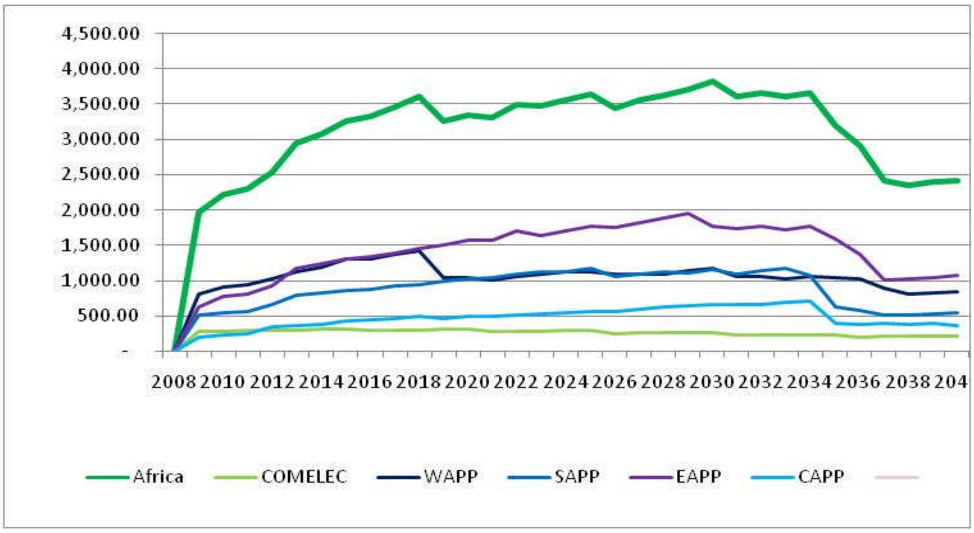
8.1 Infrastructure Investment Needs 2040 for Power Access, Generation, and Interconnections

8.1.1 Access

The investment cost associated with the projected increase in access has been estimated for the transmission and distribution components. The cost of new connections is highly variable, depending upon the technical standards enforced, the nature of the terrain, and the dispersion of connections. An average connection cost of US$ 700, including distribution cost and the reinforcement of the transmission system has been retained.

The investment cost for all Africa and for each REC is given below. In total, Africa needs to invest 96 billion over the 2011-2040 period to reach an access rate of 69%. The investment needs are concentrated in the 2011-2035 period, reaching a relatively modest US$ 3.7 billion a year investment to connect 140 million households or 800 million persons, compared with the socio-economic importance of increasing access to electricity in Africa. The cost estimate suggests that funding may not be the main challenge to meeting the AU and REC priorities of accelerated access. Moreover, it should be noted that only a fraction of that cost is to be borne by the utilities or governments in the short run, as consumers are expected to bear about half of the cost as connection charges to be paid partly upfront and partly through deferred payments.

Figure 50: Annual Investment in Access needed to achieve access rate objectives 2011-2040 (million US$)



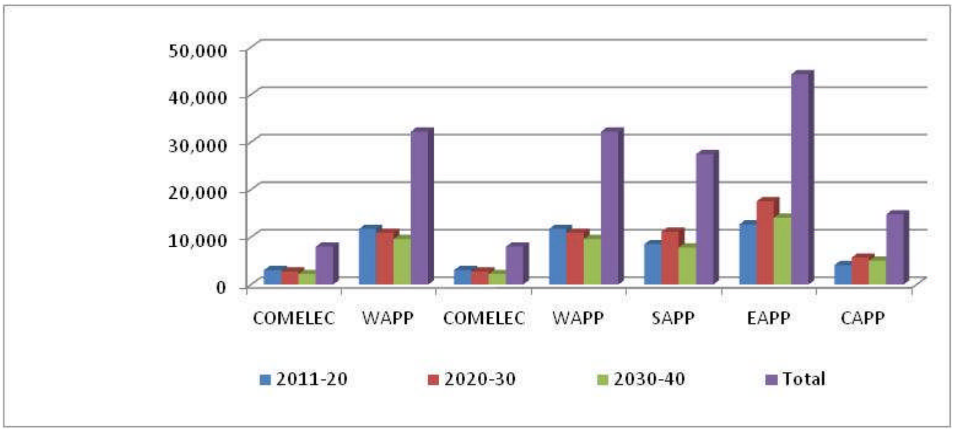
The evaluation of the investment required to achieve the access target of 69% access for all Africa by 2040 in line with the AU vision and priorities is given below. The level of investment for each REC depends on the access rate already achieved and the overall REC population as explained below.

- EAPP with a large population of 400 million and a low access rate of 37% needs most investment (US$ 1.52 billion per year);
- WAPP, with a smaller population of 300 million and a low access rate of 45% needs significant but lower investment (US$ 1.1 billion per year);
- SAPP has a lower population of 244 million, but the low access rate of 25% requires nearly as much investment as WAPP; it needs US$ 0.95 billion per year;
- CAPP has a low access rate of 21% and needs to make special efforts to reach the 60% plus access level, but because of its relatively small population of 150 million, it needs to invest only US$ 0.95 billion per year; and
- COMELEC, with a population of only 160 million and a current access rate of 96% needs relatively little investment in access (US$ 0.276 billion per year).

Table 32: Investment in access by REC, 2011-2040 in million US$

	2014-20	2020-30	2030-40	Total
COMELEC	3,048	2,747	2,218	8,013
WAPP	11,724	10,927	9,583	32,234
SAPP	8,510	11,144	7,816	27,470
EAPP	12,683	17,537	14,084	44,304
CAPP	4,102	5,689	5,022	14,813

Figure 51: Investment in Access 2014-40

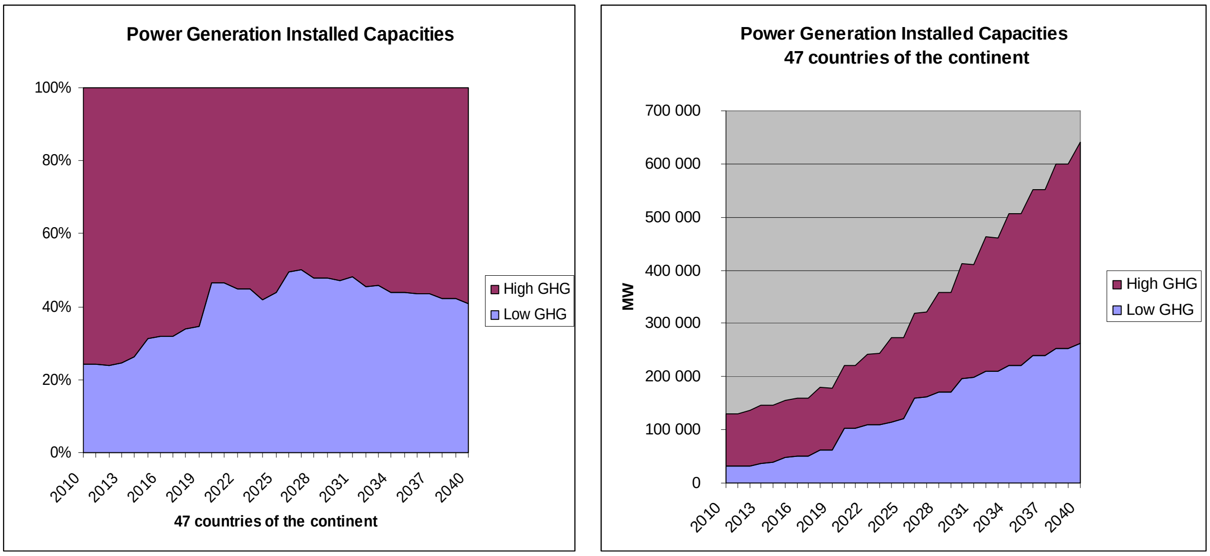


8.1.2 Generation

Technology mix

The technological alternatives for Africa are hydro, thermal (gas, HFO, diesel, coal), nuclear and renewable energy. The share of each technology in the supply is given in the graph below, under the Medium Trade scenario.

Figure 52: Share of High GHG and Low GHG Technologies - High and Low GHG installed capacity

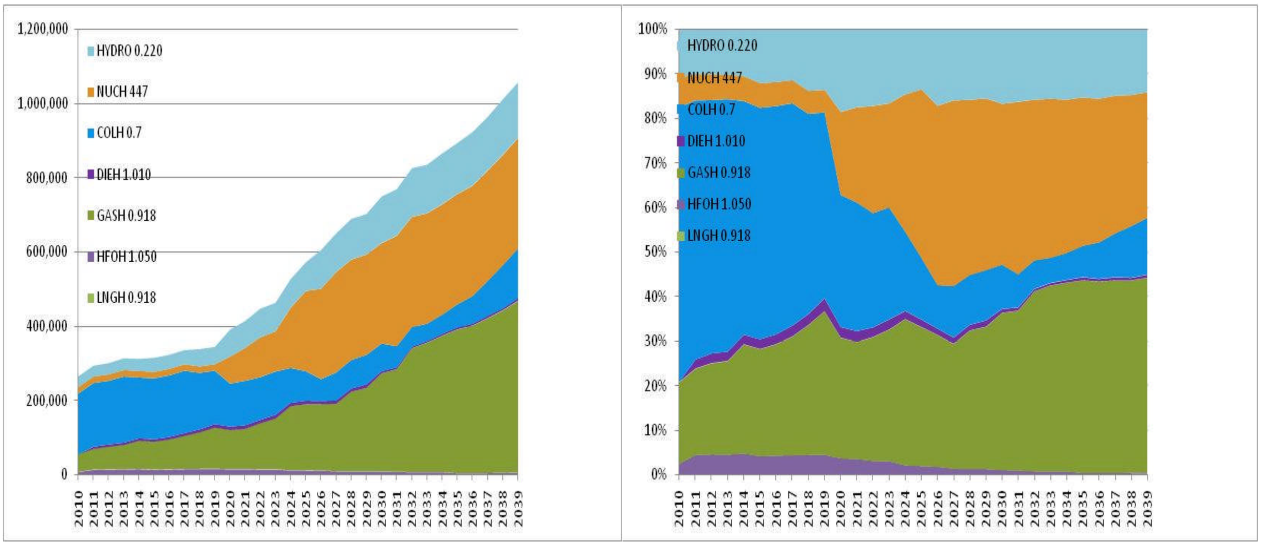


It indicates that the share of low GHG technologies will increase from about 23% in 2011 to 50% by 2027, then, as the most economical hydro sites will have been equipped, the share of low GHG decreases to 40% by 2040 as a significant share of the additional demand has to be met by thermal high GHG technology plants. .

Fuel mix

Under the Moderate Trade scenario for supply, the consumption of fuel by the thermal plants will cause a decrease on the share of coal from nearly 70% at present to about 40%. This decline with be offset by an increase in gas consumption from North African countries, Nigeria and smaller producers (Cote d'Ivoire, Ghana, Tanzania) from 25% of the total to 40%, and an increase in nuclear from less than 5% at present to nearly 30%% by 2040 because of the South African nuclear program, and the development of nuclear plants in the late '30s in Egypt and Kenya.

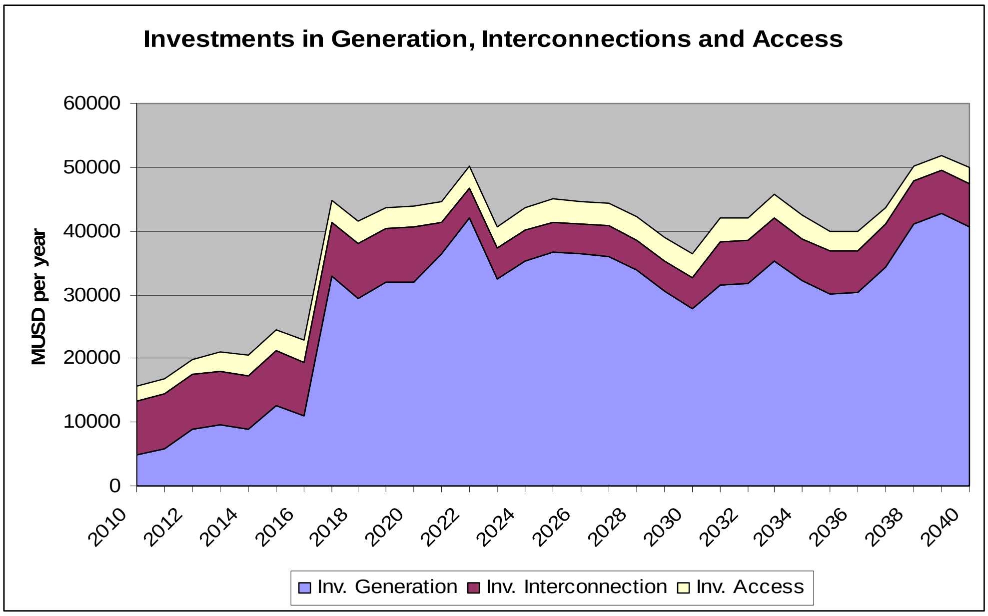
Figure 53: Fuel Mix of thePower Sector 2011-2040 in thousand TOE and in %



Capital Investment

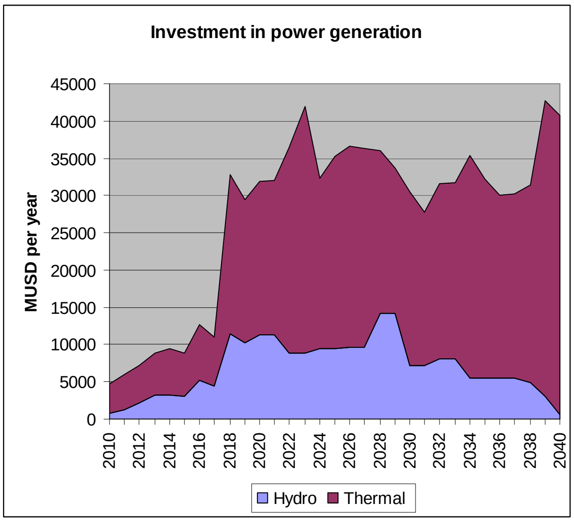
Over the 2011-2020 period, investment needs are mainly in generation and transmission, whereas after 2020 investment in transmission diminishes while investment in generation increases substantially. Throughout the period, investments in access remain small in comparison.

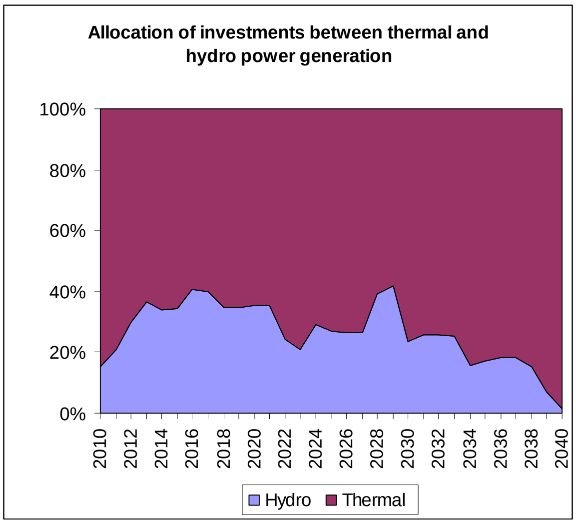
Figure 54: Africa Capital Investment in the Power Sector (million US$)



In the generation sector, the allocation of investment between hydro and thermal shows that hydro is concentrated in the pre 2030 period, although thermal remains significant, mainly for peaking capacity, and that thermal becomes predominant in the post-2030 period while hydro decreases as the economical sites are exhausted.

Investment in Power Generation (in million US$) ***Allocation of investment between thermal and hydro (%)***





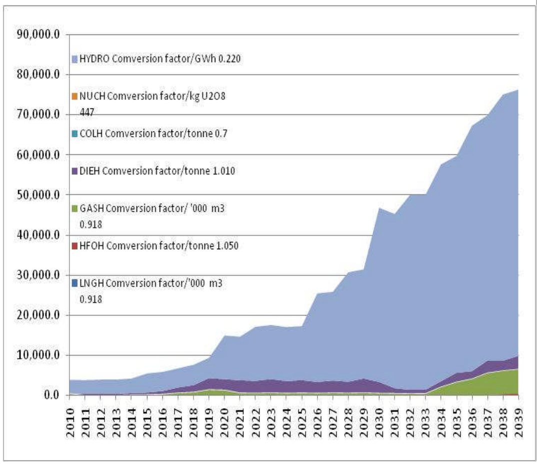
8.1.3 Fuel mix by REC

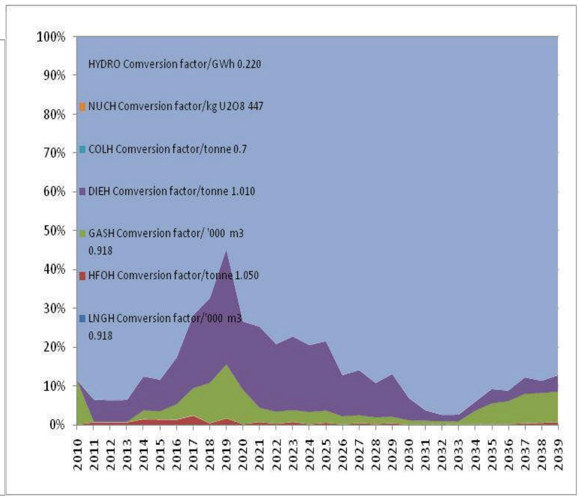
At the Regional level, the fuel mix is highly differentiated between RECs, depending upon their natural endowment in gas, coal and hydro. The mix by REC is given below.

CAPP

The primary fuel mix of CAPP will see an increase in the share of hydro in it fuel mix with the development of capacities in DC and Cameroon. Before 2020, diesel and HGO plants will be needed to meet the demand while the lrge hydro projects are developed.

Fuel Mix CAPP (in '000 TOE) ***Percentage of Fuels in CAPP***

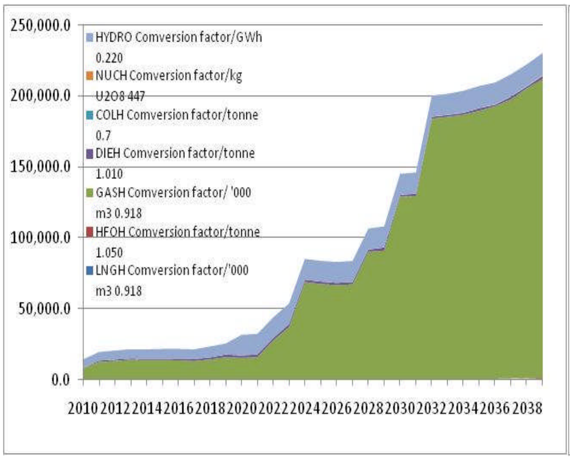




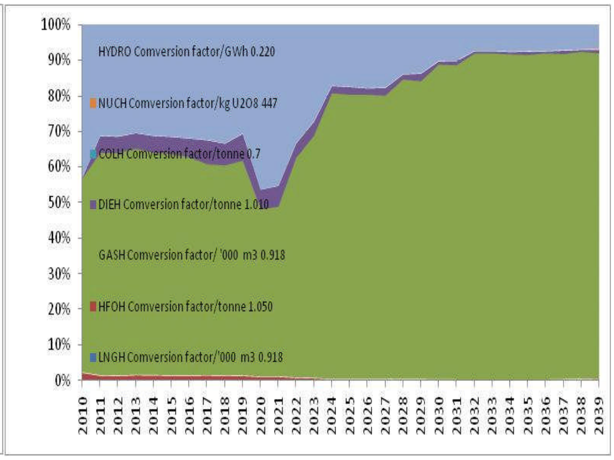
WAPP

The fuel mix in WAPP will change significantly as most of the increase in demand is met with gas fired capacities in Nigeria, Ghana and Côte d'Ivoire as the hydro potential will be gradually exhausted after 2024.

Fuel Mix WAPP (in '000 TOE)



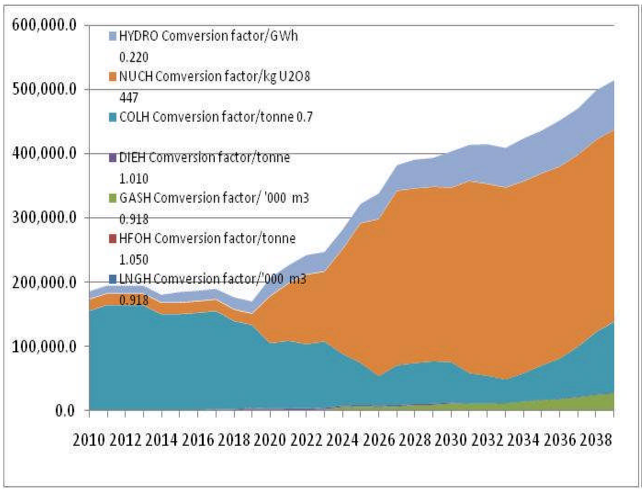
Percentage of Fuels in WAPP



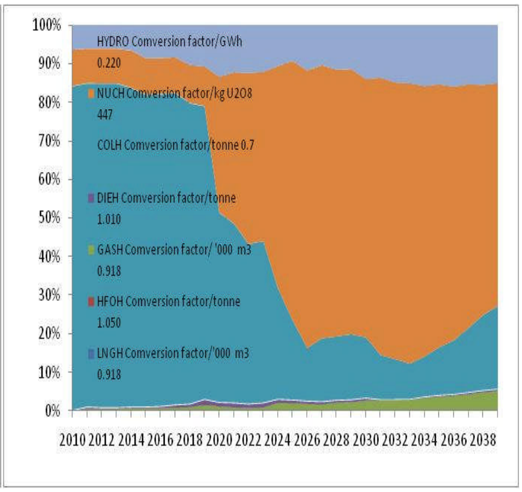
SAPP

The fuel mix in SAPP is dominated by the increase in nuclear after 2020, which displace coal, and the moderate increase in hydro in countries other than South Africa.

Fuel Mix SAPP (in '000 TOE)



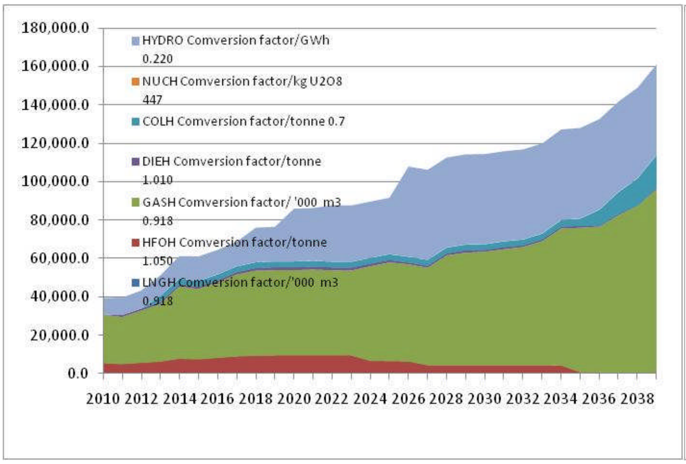
Percentage of Fuels in SAPP

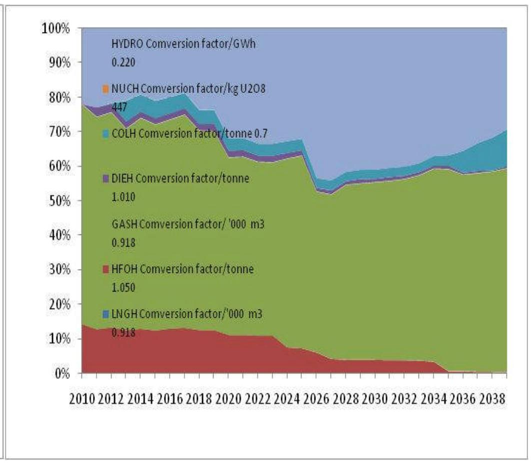


EAPP

The fuel mix in EAPP is dominated by Egypt, which uses gas and Ethiopia with a large hydro potential, while petroleum products decrease. In the long run, nuclear appears in Egypt and Kenya.

Fuel Mix EAPP (in '000 TOE) ***Percentage of Fuels in EAPP***

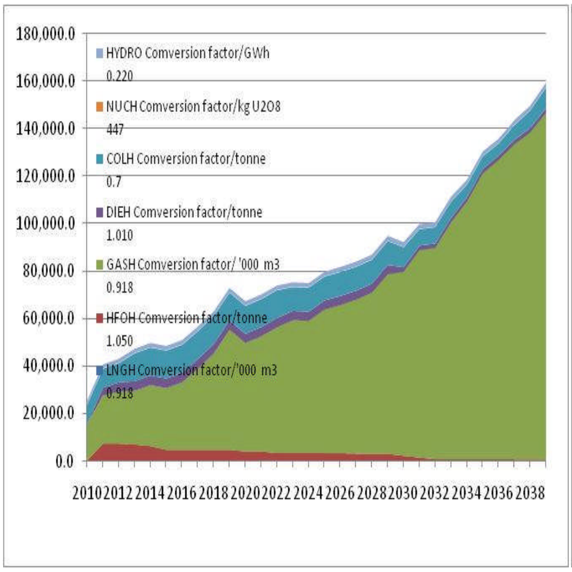


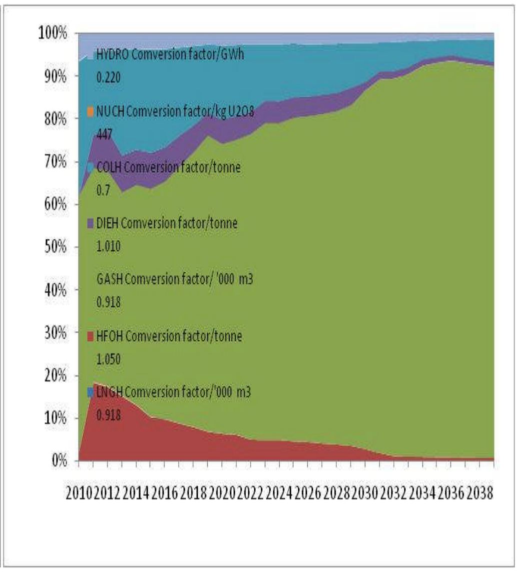


COMELEC

COMELEC continues to rely mainly on gas, and gradually replaces coal and petroleum products, while hydro remains marginal.

Fuel Mix COMELEC (in '000 TOE) ***Percentage of Fuels in COMELEC***



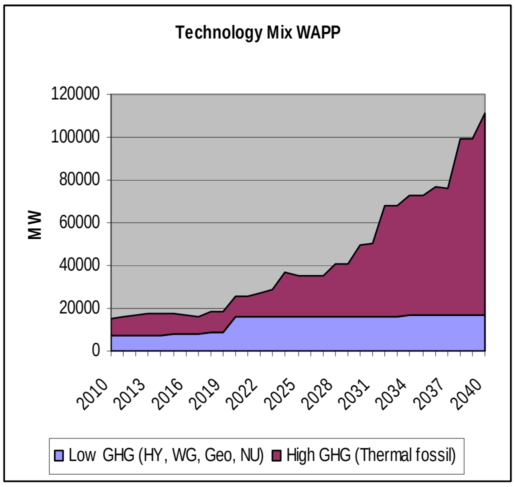


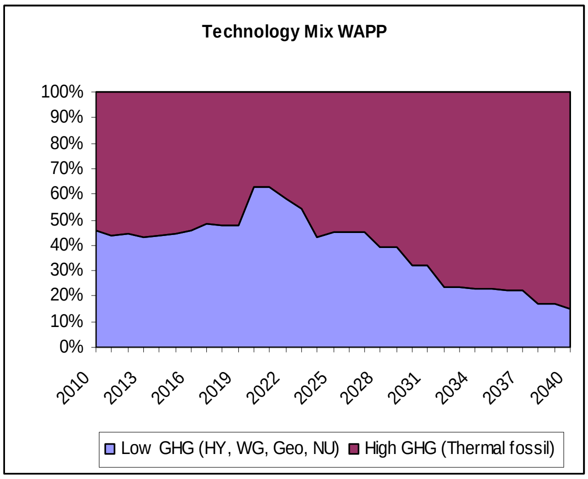
8.1.4 Technology mix by REC

WAPP

The high share of low GHG technology (40 to 50%) will be maintained until 2020, then, as the economical sites of Guinea and the Senegal Basin are equipped, the increase in demand will have to be met through thermal capacities, which will increase in share to 80% by 2040

Technology Mix WAPP (in MW of capacity and %)

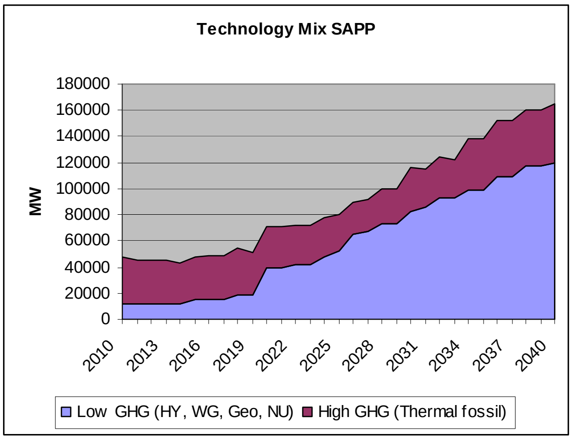


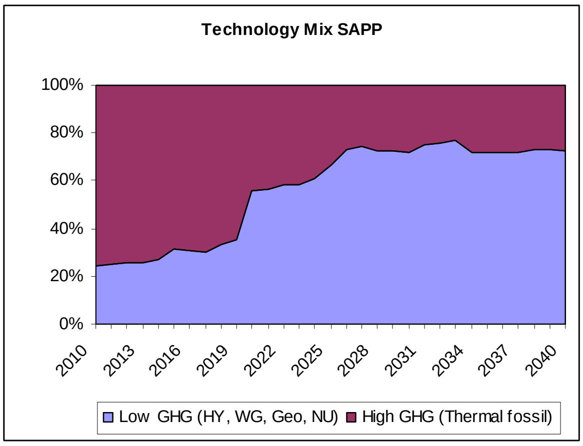


SAPP

In SAPP, the share of low GHG technology will increase rapidly and reach 80% by 2034 and stabilize thereafter. This is due to the accelerated equipment of the potential of the Zambeze basin and to the commissioning of a number of nuclear plants in South Africa in 2020 and after.

Technology Mix SAPP (in MW of Capacity and %)

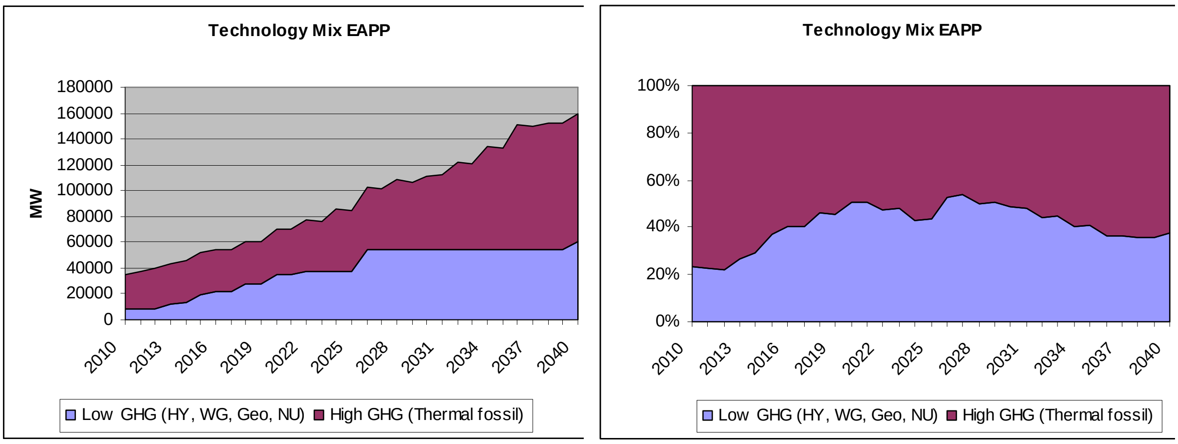




EAPP

The share of low HG technology will increase until 2028 up to 55%, as the large hydro sites of Ethiopia and the upper Nile basin are equipped, and decrease to less than 40% by 2040 as the economical hydro sites are exhausted

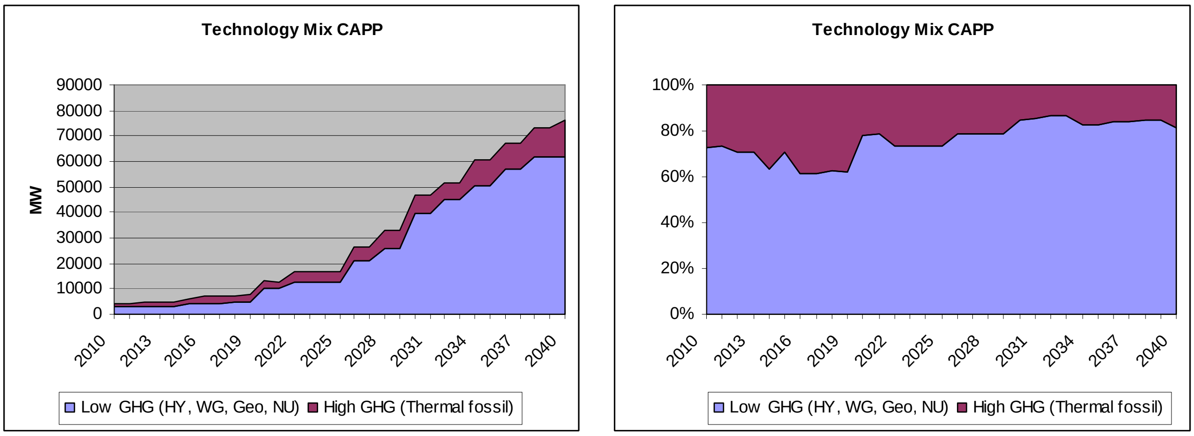
Technology Mix EAPP ((in MW of capacity and %)



CAPP

In CAP, the share of low GHG technology will remain high above 70% as the large hydro sites of DRC (particularly Inga) are equipped by steps starting in 2020 and until 2030.

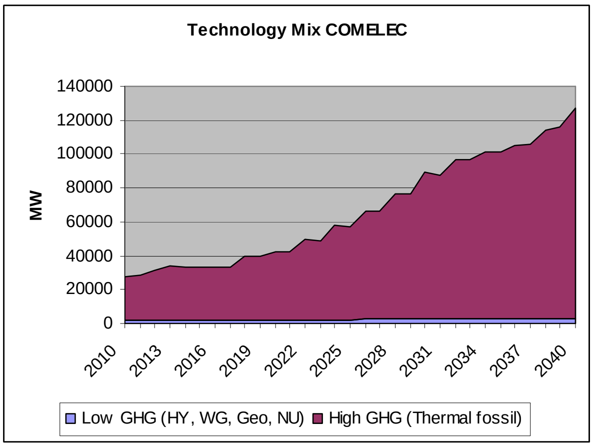
Technology Mix CAPP (in MW of Capacity)

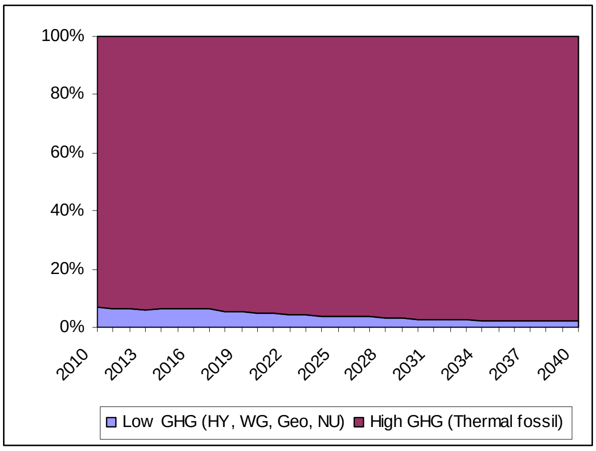


COMELEC

In COMELEC, the demand will be met through thermal plants, with renewable and hydro playing only a marginal role.

Technology Mix COMELEC (in MW of capacity and %)





8.1.5 Development of the interconnection system

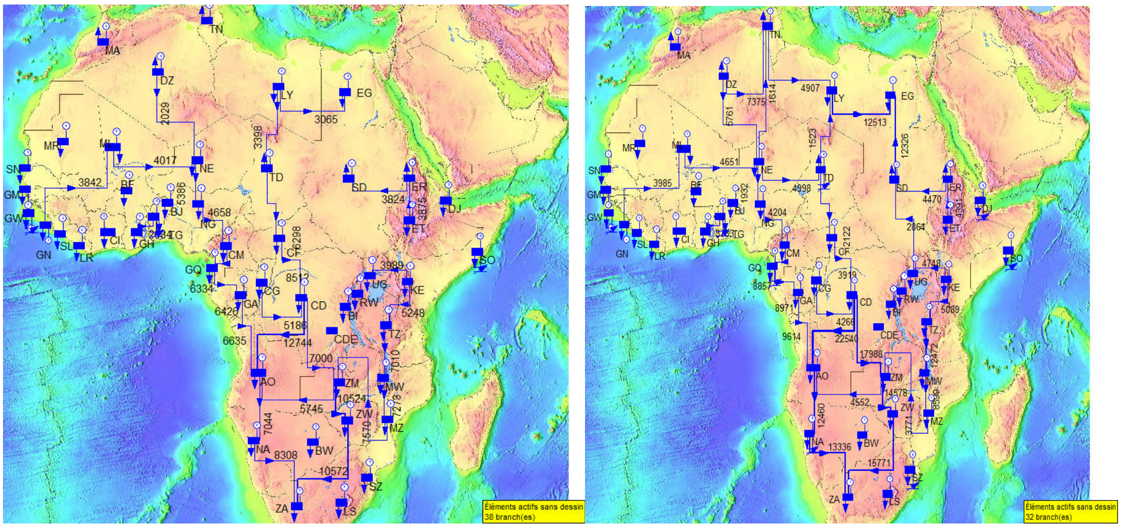
The regional network

The maps below show the need for reinforcement of existing lines, or the construction of new lines, with the flows indicated in MW. More detailed maps are given in Annex 11-2 and present all cross-border transfers while these maps present only transfers larger than 1900 MW. The conclusions are:

- Systems integration requires the development of a network with “loops” rather than the construction of “transmission highways” between major supply and demand centres. The network approach is in fact more secure than the highway approach and better serves the regional integration objective and the development of a regional market rather than bilateral exchanges.
- By 2020, transmission capacity is needed between Zambia, DRC and South Africa; EAPP and SAPP should be inter-connected through Sudan and DRC; and CAPP and SAPP need to be interconnected through a Cameroon, Gabon, Angola line. The needs for interconnections are smaller in West Africa and COMELEC.
- By 2040, the connection between Ethiopia and the Great Lake region to Egypt through Sudan should be reinforces; the coastal line between Morocco and Egypt should be reinforces; the WAPP system should be connected to Egypt through Libya; and the connection from Guinea through the West African landlocked countries should be reinforced.

Figure 55

Interconnection system and flows 2020 **Interconnection and flows 2040**



Investment Needs

The investments in regional transmission are heavier in the 2014-2020 period with a total of US$ 140 billion (US$ 4.5 billion per year), when REC interconnection is implemented, and intra-REC smaller lines are reinforced. The high estimated cost of reinforcement of the transmission system to allow an optimal development of the power systems and their integration illustrates the domestic focus of transmission systems and the backlog in transmission capacity due to insufficient financing.

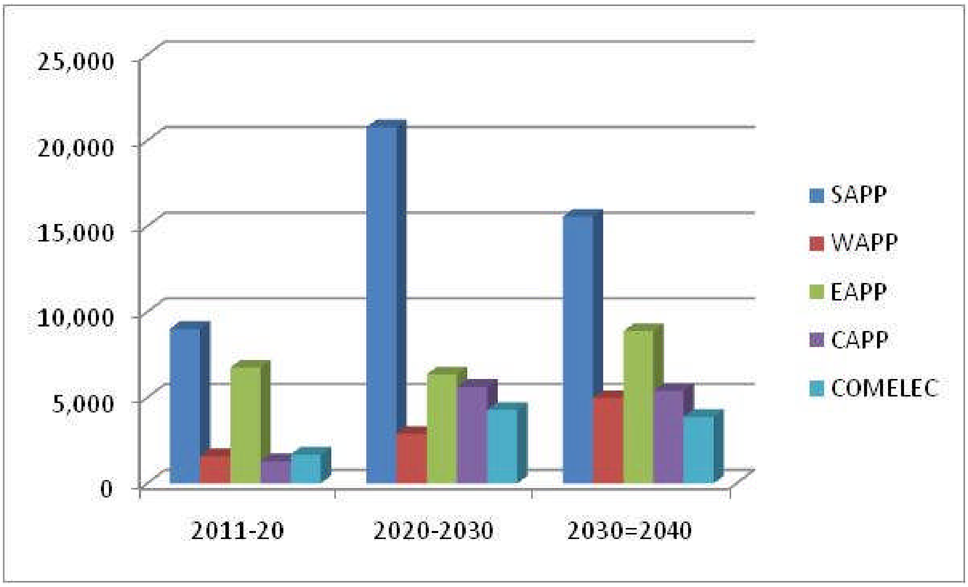
Table 33: Investment in Interconnection (million US$)

Invest. In Interconnections	
Investment over the period	
2014-2020	85,312
2021-2030	48,464
2031-2040	6,741
2014-2040	**140,517**
Annual investment	
2014-2020	7,756
2021-2030	4,846
2031-2040	674
2014-2040	**4,533**

8.1.6 Investment in Generation by REC

Investments in power generation under the Moderate Integration scenario have been allocated by REC/Pool, based on the location of the plants. The regional allocation of investments to be implemented as national as well as regional projects is given below.

Figure 56: Annual Investment in generation by Power Pool in US$ million per year

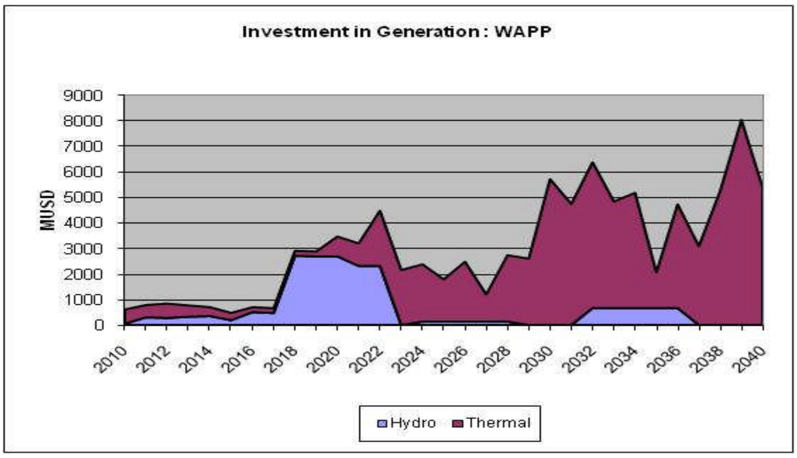


WAPP Investment in Generation

WAPP needs to invest US$ 3.2 billion annually, mainly in thermal generation because of its limited hydro potential and the important role of gas fired plants in Nigeria. Investment in hydro tend to be concentrated in the 2011-20 period, then, the hydro potential is exhausted and thermal takes over.

WAPP investment in Generation in million US$

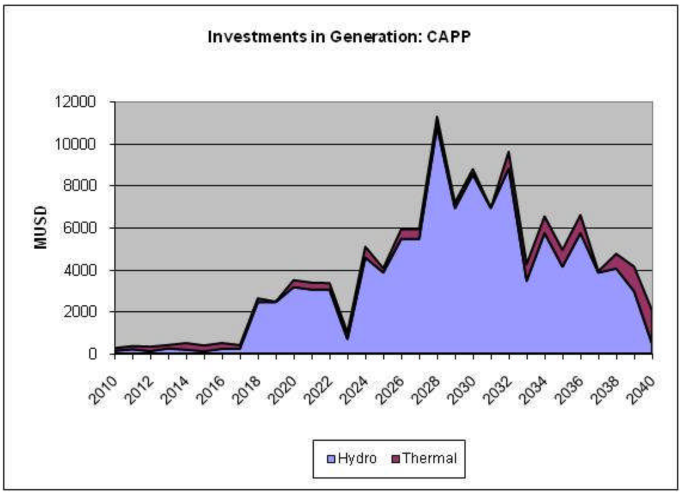
	Hydro	Thermal	Total	Annual investment
2014-20	10,539	3,693	14,232	1,581
2020-30	5,324	23,483	28,807	2,881
2030-40	3,348	46,468	49,816	4,982
2014-40	19,210	73,643	92,854	3,202



CAPP Investment in generation

CAPP needs to invest US$ 4.2 billion per year, mainly in hydro power and after 2020, due to the long development of large hydro projects including Inga. To the difference of other RECs, investments are heavier in the post-2020 period.

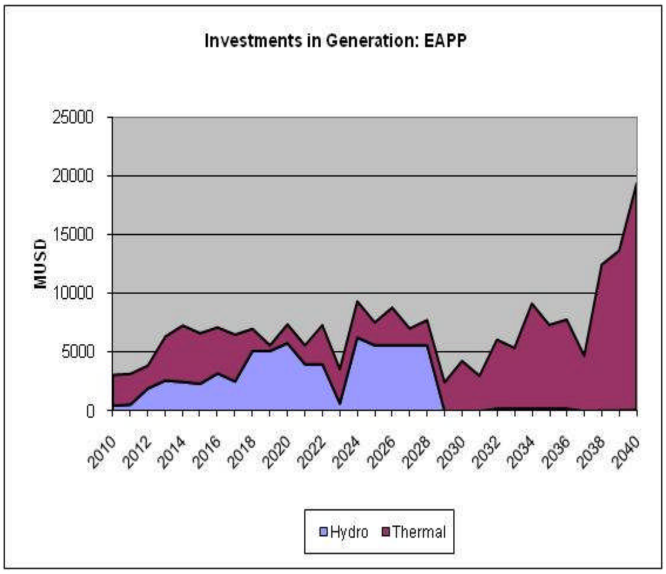
	Hydro	Thermal	Total	Annual investment
2014-20	9,592	2,142	11,734	1,304
2020-30	52,659	3,584	56,244	5,624
2030-40	46,382	7,597	53,979	5,398
2014-40	108,634	13,323	121,956	4,205



EAPP Investment in Generation

EAPP's investment program is significant, with US$ 7.3 per year, mainly in thermal in Egypt in particular. Large hydro plants in Ethiopia are concentrated in the pre-2030 period, by which time the main hydro sites are fully developed and future demand is met through thermal capacities.

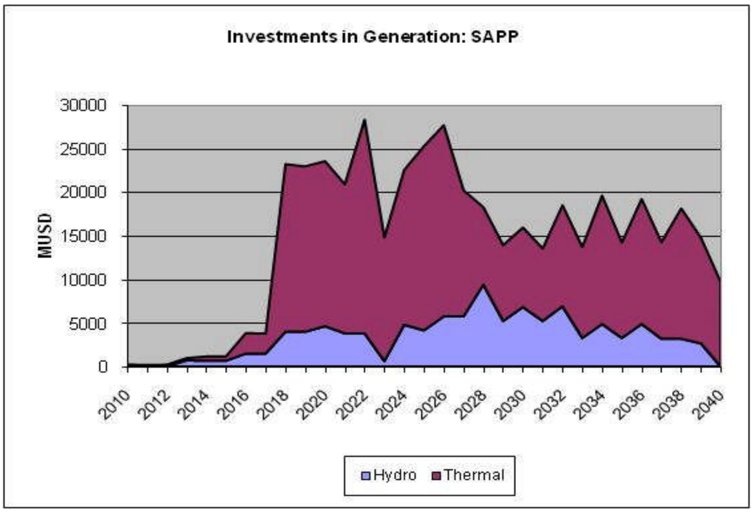
	Hydro	Thermal	Total	Annual investment
2014-20	31,648	29,163	60,811	6,757
2020-30	37,265	26,293	63,559	6,356
2030-40	1,273	87,512	88,785	8,879
2014-40	70,186	142,969	213,155	7,350



SAPP Investment in generation

SAPP's investment program in generation amounts to a large US$ 15.3 billion annually. It is mainly thermal, due to the development of a large number of nuclear plants in South Africa, particularly after 2020.

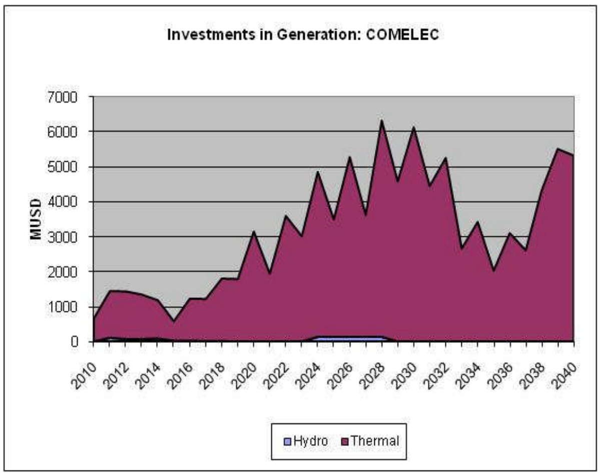
	Hydro	Thermal	Total	Annual investment
2014-20	17,838	63,247	81,085	9,009
2020-30	50,211	157,556	207,766	20,777
2030-40	37,571	118,015	155,586	15,559
2014-40	105,619	338,818	444,437	15,325



COMELEC Investment in Generation

COMELEC's capital investment of US$ 3.3 billion annually, is mainly in thermal generation, through the development of gas fire capacities. Investments are concentrated in the post-2018 period when the export capacity to Sub Saharan Africa will develop,

	Hydro	Thermal	Total	Annual investment
2014-20	402	14,747	15,149	1,683
2020-30	675	42,121	42,796	4,280
2030-40	0	38,656	38,656	3,866
2014-40	1,077	95,524	96,601	3,331



8.2 Infrastructure Investment Needs 2040 in Gas pipelines and Petroleum Products Infrastructure

As discussed above, the projected primary energy demand for fuels in Africa will see a decrease in the role of coal as natural gas consumption expands in power generation and industrial use while the consumption of liquid petroleum products, mainly for transport but also in power generation, increases rapidly. These developments will require further investment in both gas and petroleum products pipelines as well in new refinery capacity. A particular challenge for Africa will be whether it is able to meet its continued, and increasing, dependence on petroleum products from continental petroleum resources through the development of new refinery capacity based of African crude oil. The investment implications of these infrastructure requirements are summarized in the Table and discussed further below.

Table 35: Infrastructure Pipeline and Refinery Investment Needs, 2010-2040

	2020	2030	2040	Total Period
Regional Gas Pipelines ('000 km)	4	3	3	10
Petroleum Product Pipelines ('000 km)	2	8	10	20
Gas pipeline investment ($ Billion)	6	*4*	4	14
Products pipeline investment ($ Billion)	2	8	11	21
Refining capacity investment($ Billion)	10	-	-	10

8.2.1 Investment in Natural Gas Pipelines

There is considerable potential for expanding the use of natural gas within Africa. North Africa, with the major gas producing countries of Algeria, Libya and Egypt, is already a mature gas producing province, and has an extensive, existing regional pipeline network, as discussed above. These middle income countries are forecast to have significant and growing gas consumption in electric power generation, which will make a major contribution to continental gas demand in 2040.

In Sub-Saharan Africa (SSA), the major gas producing country is Nigeria where consumption in natural gas for power generation is growing rapidly. The majority of gas production in Sub-Saharan Africa (SSA) is from associated gas in Nigeria. The focus to date has been therefore on large scale flaring reduction programs and exporting the gas as LNG. However, LNG market opportunities for West African exports are declining because of the technological breakthrough which has allowed the commercialization of shale gas or 'unconventional' gas, particularly in the USA. In the future, the best opportunities for African exports will be in Europe where gas from the proposed Trans Sahara Gas Pipeline (TSGP)- see below- and/or LNG would have to compete with existing North African suppliers (who enjoy much shorter transportation distances whether for LNG or gas by pipeline) and supplies from Russia. Nevertheless, declining European production will create further opportunities for SSA LNG.

Notwithstanding the likelihood of continuing gas exports outside the African continent, there should be opportunities for the expansion of gas utilization throughout SSA, particularly as the reserves of gas are growing outside of the historical production from Nigeria. As primary energy, gas can be efficiently transported over relatively long distances by pipeline with minimal losses compared to power transmission provided there is a large enough market in both power and industrial use to justify the high capital investment in gas pipelines.

The expanding gas infrastructure in countries such as Nigeria, and more recently Ghana as well as other SSA countries is still national but offers opportunities for regional links, which are summarized below

- **In Tanzania**, there are proposals to double the existing 207 km **Songas Pipeline**, which is the onshore section of Tanzania's **Songo Songo – Dar es Salaam Pipeline**depending on the results of the Songo Songo West drilling campaign. In addition, the final draft feasibility report for the **Dar es Salaam – Tanga – Mombasa Gas Pipeline** project has been submitted to the project's stakeholders for consideration. The report identifies five different pipeline routes ranging in lengths from 124–430 km, as well as a 360 km offshore route. Based on demand for gas, the pipeline has been estimated to be a 24 inch diameter line from Ubungo in Dar es Salaam to Vipingo in Mombasa.
- **Namibia** The **Kudu** gas field off the coast of Namibia was discovered in 1974 but is a relatively small field with c. 30 bcm (1 Tcf) proven reserves. There have been proposals developed for pipeline connections to Cape Town but the small volumes and long distances make the project economics very marginal. The most likely current proposal is for the development of an 800 MW power station with electricity being exported to South Africa and some utilized locally in Namibia.
- The **Trans-Saharan Gas Pipeline** (TSGP) has been under consideration for several years and is the only major trans-national gas pipeline development which is in the public domain. If constructed, it would open up a new route to export gas to Europe by connecting the Niger Delta in Southern Nigeria to Algeria's Mediterranean coast at Beni Saf through Niger and Hassi R'Mel and on to Europe. The 4400 km line would include ten compressor stations and transport up to 30 bcm of gas from Nigeria to Europe. Cost estimates for the project range US$10-$13 billion but the economics are sensitive to European gas market prices because of potentially high transit fees, depending on the location of the end-users. In 2009 the Nigerian National Petroleum Corporation (NNPC) signed a memorandum of understanding (MoU) with Sonatrach, the Algerian national oil company in order to proceed with plans to develop the pipeline.

In summary, there appears to be good prospects for developing gas transmission systems in SSA, particularly if a sub-Continental strategy could be agreed for their overall development. Clearly, the relative economic benefits of such systems will need to be compared to export alternatives for the gas and much will also depend on the ability to finance projects on such a scale where the benefits are likely to be medium to long term. In summary, the following regional gas infrastructure investments appear to be the most promising:

- Extend West Africa Gas Pipeline (WAGP) to Cote d'Ivoire and then to Senegal/ Mauritania
- Tanzania –Kenya with subsequent links to Uganda and Rwanda
- Nigeria – Cameroon – Gabon – Congo - Angola
- Angola – Zambia/ Zimbabwe/ Botswana –Tanzania/ Mozambique

The overall strategy, therefore, would be to establish a pipeline "ring" in SSA to provide security of supply and enable the development of distributed gas fired power stations throughout the region. However, the capital costs of such a system would be very high and the investments would have to be viewed on a long term economic development basis rather than on normal commercial terms.

8.2.2 Investment in Petroleum Products Pipelines

As discussed, existing regional or continental petroleum products pipelines in Africa are very limited, with most of the existing petroleum products pipelines serving national markets. However, the rapid growth in petroleum product demand forecast for the transport sector in most regional areas of the African continent will require large new investment in products pipeline networks especially to meet the growth of demand forecast for the period 2030-2040. Very few of these products pipeline investment have yet been identified. They include:

- **Kenya-Uganda Products Pipeline** The Ugandan Government is inviting bids from international firms for the construction of the 230 km long refined-fuel products **Hoima – Kampala Pipeline** which is expected to be linked with Kenya's **Mombasa – Eldoret Pipeline**, and later extended to Rwanda (Kigali), Burundi (Bujumbura) and mineral-rich eastern Congo. The plan is to transport refined products from the proposed refinery in Uganda, as well as the existing refinery in Mombasa and through international markets.
- **Two Products Pipeline concepts include**:
- A products pipeline system linking **Angola's refinery to Zambia/ Zimbabwe/ Botswana/ Malawi** and possibly to the existing East African products pipeline systems. This would provide some flexibility of operations (assuming bi-directional flow capability) especially if linked with strategic storage depot developments.
- An analogous pipeline system to interlink the **West African markets** subsequent to upgrading the refining facilities in Nigeria.

If pipeline distribution systems are established, they have big advantages over traditional transportation systems, i.e. road and rail. There are environmental benefits through reduced emissions but also social and safety benefits through reduction, in particular, of road tanker movements.

8.2.3 Investment in New Refineries

Despite the abundance of oil reserves, Africa is an importer of refined products. This problem is exemplified in Nigeria where, despite massive crude oil reserves and four, nominally world scale complex refineries, the majority of its refined products are imported because the refineries are operating generally at less than 30% capacity. Whilst there are clear opportunities for the development of new refineries in SSA, the principal barrier is the level of commercial risk for any developer. In order to secure the level of investment required, most developers would be looking for sovereign guarantees from national governments as a minimum and since the credit rating of many of these countries is low, even these guarantees are likely to be insufficient to enable commercial financing of such projects. In SSA, the track record of State-owned Refineries is poor and a lack of maintenance has resulted in very low operating efficiencies and financial performance. Equally, very few SSA Governments are able to provide the level of investment required for such a capital intensive industry.

In North Africa, and Egypt in particular, the State-owned Refineries operate more efficiently and reliably. However, Egypt also has a large demand for fuel in its own domestic market and is more industrialized. At the same time, Egypt's refineries do not meet all of domestic demand as it is still an importer of refined products, including gasoline, diesel and LPG.

There have been many proposals for the establishment of new, world-scale refineries in SSA. However, very few will come to fruition since most investors in new refinery capacity will be viewing the scope for export of refined products outside of Africa. Nevertheless, within these constraints, new refinery capacity is under consideration in South Africa- with a primary focus on the expanding national market- and the need for further investment in refining capacity to supply a growing African demand for petroleum products is strong. However, given the problematic past history with refineries in SSA and the difficulties in attracting private investment, the investment plans assume only one major investment for a modern 350,000 b/d refinery.

9. INTER-SECTOR SYNERGIES

The main synergies of the energy sector with other infrastructure modes are with:

- ICT Sector through the coordinated development of fibre optic cable in parallel with transmission lines;
- Transport Sector through coordinated investment in petroleum products pipelines with investment in road, rail and ports;
- Water basin management since hydro development will impact water basin management in terms of regulation of water flows, flood control and allocation of water uses;

It is recommended that a multi-sector approach be adopted between the Water and Energy sectors to develop joint mechanisms for the:

- Planning of energy, water and telecommunications regional investment programs;
- Prioritization of the preparation and development of hydro projects for power, water basin management or irrigation.

The main synergies of the energy sector are with:

- The ICT sector through the parallel and coordinated development of fibre optic cable with transmission lines and the facilitation of the development of high-speed broadbandby the provision abundant electricity. The improvement in the quality of electricity supply compared to the present situation will also facilitate the development of ICT, as the poor quality of electricity supply is highly damaging to ICT equipment.
- The Transport sector also has significant synergies with the energy sector. Investment in petroleum products pipelines will help decongest heavily transited road corridors in many SSA countries while investment in gas pipelines will displace diesel and heavy fuel oil, which is typically transported by road and rail.
- The Water Basin management sector and the power sector will have significant synergies, as hydro power projects will contribute to water basin management and will be developed taking into account the objectives of water basin management in terms of regulation of water flows, flood control and allocation of water between alternative (and not necessarily exclusive) uses.

A multi-sector approach between the Water and Energy sectors involves developing joint mechanisms for

- planning of energy, water and telecommunications regional investment programs; and
- Prioritization of development and implementation of joint energy and water sector for hydro projects.

The proposed responses to the institutional challenges presented above are:

- For the development of regional transmission and thermal generation projects, the Pools would establish, as soon as the regional project is identified in the updated PIDA Priority Action Plan (PAP), a Project Development Special Purpose Entity (PDSPE) between the member countries of the Pool that have a stake into the development of the project. The creation of a PDSPE with a membership narrower than the membership of the Pool is recommended in order to ensure that the decision makers in the project development have a direct stake in its successful development. The early establishment of the PDSPE at the initiative of the Pools is aimed at reducing the long time gap between project identification and the emergence, through an informal consultation process, of a consensus between stakeholder countries for a joint project development.
- For the development of hydro projects, the main challenge is that they are considered by the Pools as power producers, and by the River Basin Organizations (RBO) as water management investments. The project development process needs therefore to take into account the energy production and water management functions of new hydro projects. The proposed procedure to ensure coordination between both the energy and water aspects of new projects is to:
  - Retain under the PIDA PAP only hydro projects which are both in the development plan of the Pool and of the RBO and, thus, exclude projects which are a priority for only one of these entities;
  - Assign to the project a priority level based on the highest level granted by any of the two sectors, that is, if for example, a project is rated top short term priority by the Water Basin Agency and medium priority by the Pool, the project will be rated top priority in the PIDA PAP;
  - Establish for hydro projects *Project Development Special Purpose Entities (PDSPE)* at the joint initiative of the Pool and the RBO. The PDSPEs would include the broader set of member countries between those affected members of the Pool and the members of the RBO; and
  - The lead of the PDSPE will be entrusted to the sector which will benefit most from the project, from an economic stand point (that is, to the water sector if the main purpose of the project is water basin regulation or irrigation, or to the power sector, if the purpose of the project is mainly the production of electricity.

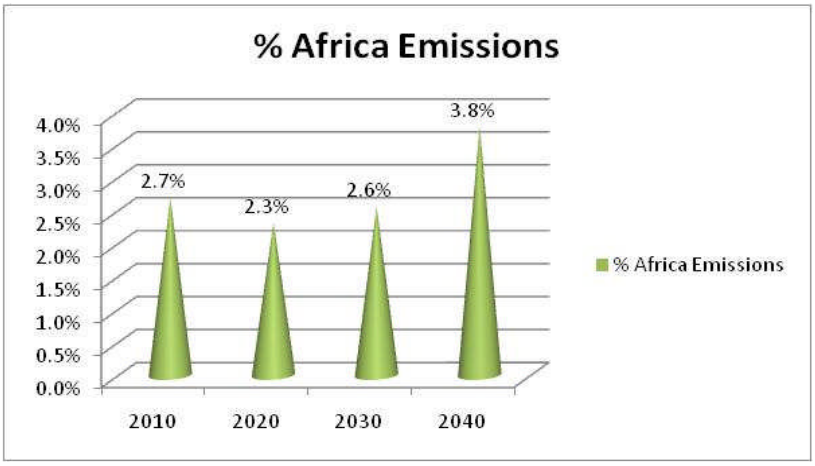
10. ENVIRONMENTAL PERSPECTIVE: CO2 EMISSIONS

- Africa's power sector emissions increase in share of world emissions after 2030 when the hydro potential becomes gradually exhausted
- Overall CO2 emissions increase slower than GDP and electricity demand, though, as the share of hydro in the energy mix increases, and particularly countries like South Africa shift to Low GHG technologies
- In the long term the main source of CO2 emissions in the power sector will be WAPP, as hydro resources are limited, and the region uses more gas.
- Support to low GHG technologies will be important to curb the increase in GHG emissions per capita and the increase of Africa's share in world emissions without limiting availability or raising prices.

CO2 emissions in Africa from the power sector will increase from 692Mt CO2 in 2011 to 1,731 Mt CO2 in 2040, growing at an annual rate of 3.1%. The emissions of the power sector, which represented about

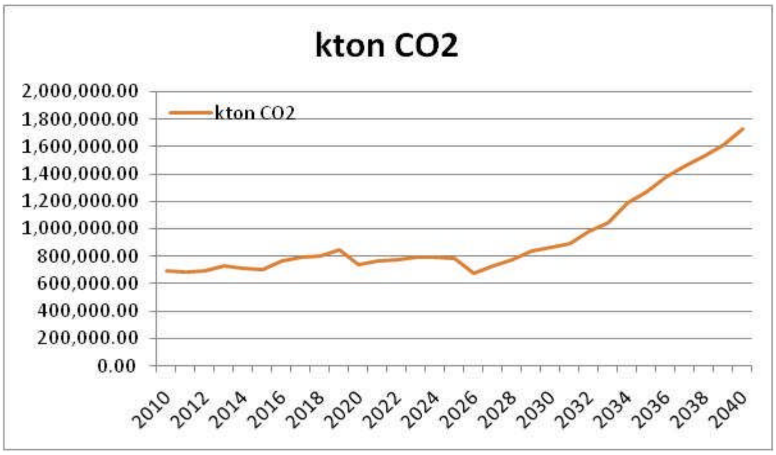
2.7% of world emissions decrease until 2020, but increase thereafter to reach 3.8% by 2040, highlighting the relevance of low GHG policies for Africa, within affordability limits.

Figure 57: Emissions of the power sector of Africa compared to World emissions



The projected growth rate of CO2 emissions is substantially slower than the projected electricity demand at 6.6%, because of the shift to natural gas and nuclear (in South Africa, Egypt and Kenya) and the increase in low GHG technology which increases from 25% at present to nearly 40% by 2040. As a result of this growth, per capita CO2 emissions of Africa in the power sector will average 0.960 tons of CO2 in 2040, up from 0.724 tons in 2011, a very small increase of less than 1% per year, as access to energy improves and per capita GDP increases but technologies become less GHG intensive.

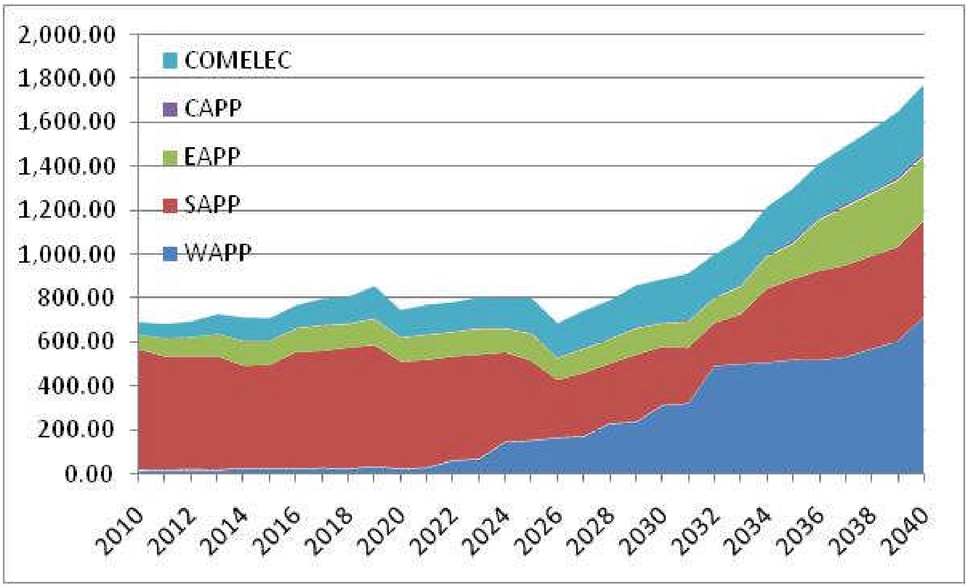
Figure 58: CO2 emissions of the power sector (in 000 Tonnes)



The graph above clearly illustrates the impact on CO2 emissions of the near exhaustion of the hydro potential by 2030 resulting from the high growth in demand.

CO2 emissions by REC/Pool are shown below.

Figure 59: CO2 Emissions by REC (in thousand Tonnes)



In terms of the incremental CO2 emissions, the biggest incremental emissions may come from WAPP, as it shifts to a larger proportion of gas in its fuel mix after exhaustion of its hydro potential, followed by EAPP and COMELEC, while SAPP's emissions decrease because of the nuclear program of South Africa, and CAPP remains very small compared to other RECs.

11. FINANCING OUTLOOK

Financing Outlook

- A huge capital investment of US$ 43.6 billion per year is required in the energy sector
- $42 billion per year is needed in the power sector compared with a current level of less than ¼ of this amount
- A substantial, upfront investment of $5.4 billion per year in transmission is needed to meet forecast demand prior to 2025
- An investment of $3.7 billion per year in access is needed to achieve an access rate of no less than 60% in all African countries by 2040
- Investments of $1.3 billion per year in gas and products pipelines will be needed
- The main challenge will be financing the large capital investment requirements of the power sector, especially the need to increase private sector financing and sector cash flow by some 7-10 fold their current levels
- No significant increase in average tariff is required to finance the sector program, which would remain around $8-10 cents /kWh due to the large amounts of low cost hydro which would become available
- However, tariff estimates assume a major improvement in collection performance and much larger sector cash flow volumes generated by the utilities

11.1 Main findings on investment needs

The investment implications of the challenge to meet both rapid energy demand growth and increased access are formidable.

- ***A huge capital investment is needed in the power sector*** to meet future demand: US$ 42 billion of annual capital investment required which compares with a current annual investment of less than one quarter of this amount.
- ***Investment in transmission is substantial, at US$ 5.4 billion per year***. However, it should be emphasized that the investment pattern for transmission is different from the pattern for generation: the transmission investment program is heavily front loaded, whereas the generation program tends to be back loaded. The investment pattern in transmission is explained by the need to provide access to regional generation facilities even in small quantities early in the process to avoid investment having to be made in small generation units to meet the demand in the years prior to 2025. After 2025, transmission investments are needed more for reinforcement of existing lines. A very important conclusion is that investment for regional integration should focus initially, and heavily, on transmission;
- ***A small investment amount i.e. US$ 3.7 billion per year is needed to ensure no country has an access rate below 60 percent by 2040;***

- ***Investment in regional gas pipelines, petroleum product transport represents a significant US$ 1.3 billion per year***, considerably more than in the past, but a smaller amount compared to the power sector. It should be noted that PPP financing is generally easier in the hydrocarbon transport sector than in the power sector, so meeting the financing requirements for the development of this sector is likely to be less challenging.

Table 35: Total National and Regional Capital investment, in million 2011 USD

In MUSD	Investments Generation	Invest. Access	Interconnection	Invest gas & PP Pipelines	Total Investment
INVESTMENT OVER THE PERIOD (US$ BILLION)					
2014-2020	191,874	23,388	85,312	8,000	308,574
2021-2030	324,194	39,046	48,464	12,000	423,704
2031-2040	345,656	34,110	6,741	15,000	401,507
2014-2040	***861,724***	***96,544***	***140,517***	***35,000***	***1,133,785***
ANNUAL INVESTMENT (US$ MILLION)					
2014-2020	31,979	3,898	14,219	1,333	51,429
2021-2030	32,419	3,905	4,846	1,200	42,370
2031-2040	34,566	3,411	674	1,500	40,151
2014-2040	***33,143***	***3,713***	***5,405***	***1,346***	***43,607***

- **Financing the large capital investment requirements of the power sector will be the main challenge over the 2011-2020 period in particular.** Only one quarter of this amount is currently being invested. Consequently, with limits on the availability of increased financial resources from IFIs and bilateral donors and despite the projected increase in financing from non-conventional sources (China, India, and Brazil, …), new sources of finance will need to be opened up, in particular domestic energy sector generated resources and both domestic and international commercial sources of finance. The magnitude of these new resource requirements can be understood by comparison with current sources of finance.
  - Even if international aid (OECD, non-OECD and international organizations) continues increasing by 6 to 8 percent annually they will not cover more than 20% of the needs particularly in the early period. There remains *a very large financing gap of US$ 38 billion per year over the 2014-2020 period,* which will decrease after 2020.
  - Private sector financing per year will have to increase at least ten-fold from its present level of US$ 1 billion per year (including gas and petroleum products) on average over the 2014-2040 period
  - Sector cash flow per year would have to increase five-fold from its present level of US$ 3 billion per year to cover the investment gap over the 2011-2040 period. At present, only a very small number of national utilities contribute to their investment program on a significant scale.

- The remaining gap of US$ 38 billion per year over the 2011-20 period and US$ 12 billion per year over the 2020-2030 period will have to be met through extraordinary support from donors, accelerated recovery of the sector cash flow and private sector financing, provided the sector cash flow does improve and business climate improves to allow more energy sectors to meet private sector financing criteria and secure an improved credit rating to give access of the energy sector to the international financial market (allowing the issuance of bonds or similar financing instruments).

Table 36: Financing needs of the energy sector, in billion 2011 USD

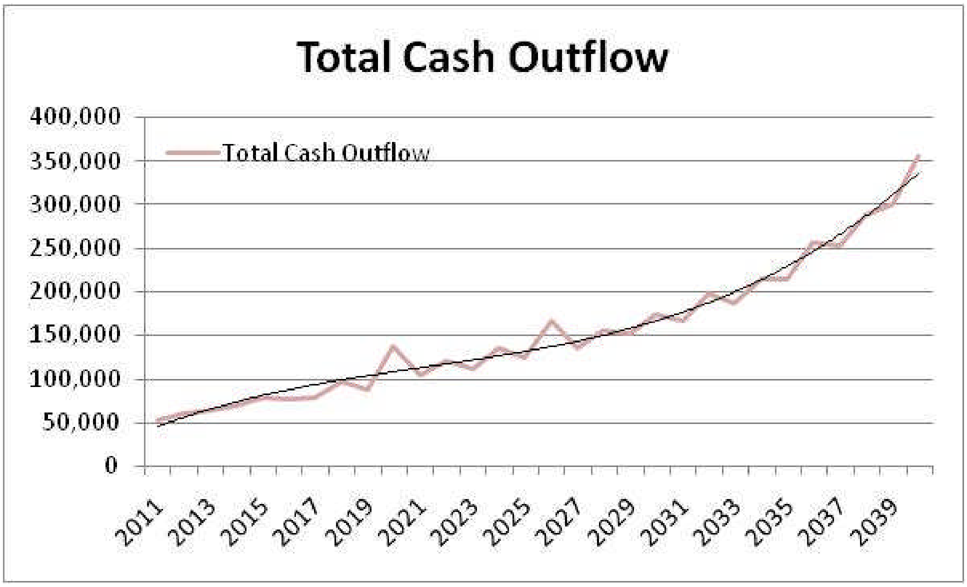
	2014-20	2021-20	2031-40	Average
Resources				
ODA	5.0	8.0	14.0	**9.6**
Non-OECD	4.0	10.0	15.0	**10.5**
TOTAL Annual financing from Donor Sources	*9.0*	*18.0*	*29.0*	**20.2**
Private Sector	1.0	5.0	10.0	6.0
Sector cash flow	3.0	7.0	15.0	9.2
TOTAL Resources	***14.0***	***30.0***	***54.0***	***35.3***
Financing Needs				
Financing Needs Power	50.1	41.2	38.7	42.3
Financing Needs Pipelines	1.3	1.2	1.5	1.3
Financing Needs Petroleum P.	0.2	0.2	0.2	0.2
GAP	*(38.6)*	*(12.6)*	*13.6*	*(8.5)*

11.1.1 Sector Long Term Financial Sustainability

Based on the investment program for the Moderate Trade Scenario, including investment in access, O&M costs, fuel costs for the same scenario, and assuming that 70% of future investment will be financed through debt with a maturity of 20 years and an interest rate of 7%, and 30% from sector equity[23], a preliminary estimate of the sector cash flow needs has been prepared and is presented in the graph beow.

Figure 60: Sector Cash Outflows (in million US$)

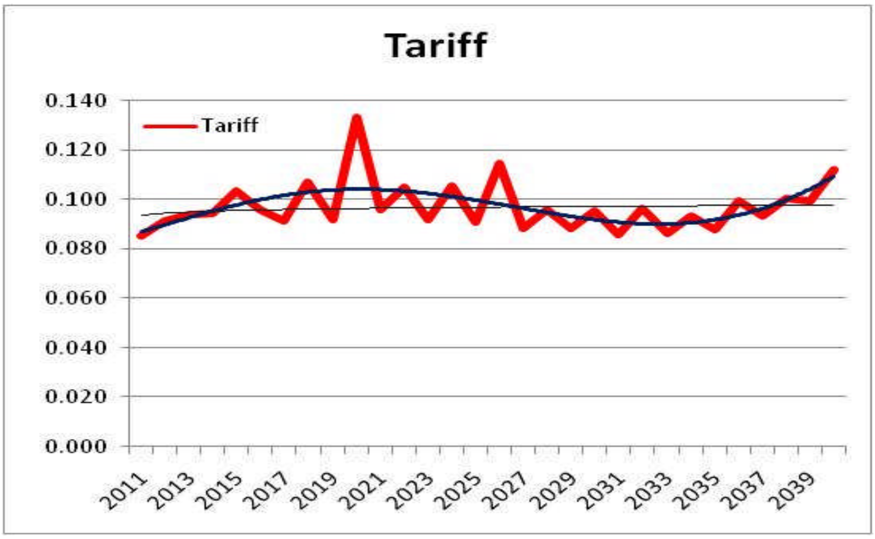
[23]The interest and service on the existing debt is not taken into account



The conclusion is that the sector cash outflows at the wholesale level (excluding distribution costs) increase slowly until 2035 and accelerate thereafter. The reason is that by 2035, the best, known, economical hydro potential of Africa has been exhausted to satisfy the growing demand, and higher cost thermal plants have to be developed jointly with less economical hydro plants from 2035 to 2039, and after 2039 all hydro opportunities have been exhausted and all sites equipped, so the additional demand has to be met entirely from thermal capacities.

The corresponding wholesale tariff excluding distribution costs has been calculated, based on the future demand of the Energy Outlook 2040. The corresponding tariff is presented in the graph below.

Figure 61: Projected Average Wholesale Tariff (US$/kWh)



Several important conclusions emerge from the average Africa tariff outlook:

- No significant wholesale tariff increase is needed to finance the sector expansion and access program: tariff remains between US cents 8 and 11/kWh, which is reasonable by international standards and comparable to Europe; Adding an estimated USCents 2 to 3 USCents/kWh for distribution, the tariff at consumer level would be UScents 12 to 14/kWh. There are obviously regional difference, and the figure above is a continental average, covering significantly higher tariffs in energy poor landlocked countries and lower tariffs in countries with large low cost power generation potential (hydro or gas).
- The integration will maintain the tariff at an affordable level, but will not allow a significant reduction compared to the present level;
- The period 2014-2019 sees an increase in tariff, as large low cost sites are not ready to produce for another 5 to 6 years and thermal plants have to be brought in to fill the gap. The 2019-2035 period sees a slow decrease in tariff due to the development of large low cost hydro sites, but after 2035 tariffs increase as the best investment opportunities are exhausted;
- The power sector can afford the envisaged investment program **provided the collected tariff matches the nominal tariff.**

12. OUTLOOK RELATED RISKS

Outlook Related Risks

Choice of Fuel Technology

- Decisions on the choice of fuel technology have an important bearing on the cost of meeting power demand
- Critical decisions need to be taken regarding the roles of Hydro, Gas, Coal and Renewables

Risk Mitigation Steps

- Coordinate planning and development of national and regional energy investments
- Achieve, with support from donors, effective coordination between (i) national and regional planning priorities through an
- Develop specific mechanisms for facilitating the development and financing of large regional projects:
- Establish a continental or regional project development financing facility to allow faster preparation of regional projects
- Establish a continent-wide risk guarantee facility funded by donors (as an alternative to direct financing of regional projects).
- Consider investment in new petroleum refineries only if financed with private sector participation and/or a strategic partner

12.1 Challenge, Options for Future Developments in Power, Gas and Petroleum Products Sectors

Decisions on the choice of fuel technology have an important bearing on the cost of meeting power demand. The different implications of these choices are discussed below.

- ***The respective roles of hydro, gas, and coal for power generation***. With the level of future demand set, the key investment decisions still to be made concern the respective roles of hydro, gas, and coal in future power generation. Too strong a focus on hydro beyond the economically optimum level will increase upfront financing needs, compounding the issue of mobilizing scarce financial resources and increasing the cost of supply to populations with limited capacity to pay. On the other hand, a reasonable focus on hydro will increase energy security and reduce the carbon foot print of power generation. Hence, a balance needs to be found.

The options are therefore to:

- Give a special role to hydro *per se*, favouring those countries with large hydro potential against countries with either:
  - > Non-tradable gas resources (i.e. small or medium sized fields, not large enough for export) or

> Coal resources (whose quality is below international grade or too distant from export points) or

- Establish the optimum hydro/non hydro mix based on the
  > Minimization of the cost of supply, (including possibly the cost of CO_2 emissions),
  > Vulnerability to drought of many of Africa's hydro power systems, and
  > Taking into account the longer implementation period of hydro-based investments when compared to thermal based systems, especially natural gas.

Whichever option is agreed will have to be endorsed, and complied with, at national as well as regional levels, and its cost implications accepted.

- *The adoption of mandatory targets for generation from higher cost, non-hydro renewable energy.* While the cost of these technologies may decrease in the long term, the issue now for Africa is whether to prioritize these technologies at a cost, or to defer investment until they have become price competitive and can be included in the energy mix without penalizing consumers or the competitiveness of its economies.

- *The pace of increase in access.* The objective of achieving universal access for all African countries is a cornerstone of the continental energy policy. The time horizon for achieving this objective is not set under the AUC vision, so the time horizon for achieving the AUC objective is an important parameter for sector planning purpose. As mentioned earlier, the main issue may not be financing of access programs (just USD 3.7 billion per year for all of Africa), but the technical and administrative capacity to multiply by twenty or more the annual number of connections compared to the present situation. One alternative is to adopt a very ambitious implementation schedule aiming at universal access within fifteen or twenty years. Under this option, major capacity building efforts in the public as well as private sector will be required to develop technical and managerial capacities quickly. Significant Government subsidies to the utilities or to private operators will also be needed to accelerate implementation and motivate new entrepreneurs. Alternatively, a more gradual approach may be considered, aiming at universal access in the longer run. This approach will be less demanding on technical and management capacities, which will build over time, and require less financial support from the Government to accelerate implementation. On the other hand, it implies that a significant proportion of the population will get access at a later date. Between the accelerated access alternative and the "business as usual" alternative, a balance needs to be found to improve rapidly access rate without depleting other energy sector activities or scarce technical, financial and managerial resources.

- *In regard to refineries, the choice is between a policy of developing an African refinery capacity for continental needs, or the development of refineries in Africa to capture business opportunities on the world market as new oil discoveries are made on the African continent.* In both cases, refineries should be developed on a purely commercial basis to avoid repeating past experience, which led to the development of state owned refineries, with significant underutilized capacity that is subsisting on massive government subsidies. The risks with investment in new refinery capacity aimed at meeting demand on the African continent is that any new refineries may need economic protection from imported products to maintain their competitiveness- at a cost to the African economies; also, they tend to lead to the development of vertically integrated monopolies, at a cost to consumers. In contrast, the development of privately owned refineries operating on a competitive world market would ensure that the refineries operate efficiently and avoids the additional cost to the economies brought about by any need for import protection. However, the private sector will only invest in refineries oriented toward the African market provided there are fundamental guarantees, such as 'take-or-pay' contracts with up-front payments. Typically, markets in Africa will need support to achieve the requisite credit-worthiness to support such investors.

- **In regard to Petroleum Products Pipelines, these pipeline systems have significant advantages over traditional transportation systems, i.e. road and rail, because of their lower unit transportation costs. However, offsetting part of these advantages are the high upfront capital investment costs, large distances across Africa, the often difficult terrain, and the need for a guaranteed minimum market before committing to investment.** For these reasons, the selection of pipeline investments needs to be made judiciously. Given the lack of crude oil resources in most Southern and Eastern African countries and the higher demand growth for petroleum products, this region would benefit most from new investment in product pipeline infrastructure. Priority investment options include :
  - A products pipeline linking Kenya/Uganda/Rwanda;
  - A products pipeline linking Southern Africa with the East African market, based on new refinery capacity in South Africa; and
  - A pipeline network interlinking several West African countries based on upgraded production from Nigeria's refineries.

12.2 Lessons learned from selected regional energy infrastructure

12.2.1 Policies, institutional arrangements and regulatory framework improvements

A review of the existing policy framework for regional electricity trade identified a number of issues that are impeding power system integration in Africa. Not all of these issues are policy concerns. Issues of regional institutional capacity and political commitment to regional integration are also important. Another important issue is the large resource requirements of regional investment plans and the inability of regional institutions to mobilize the financing needed. Finally, there continue to be significant differences in the extent of political commitment to regional integration across regions and within member states. Thus, both energy security and national autonomy concerns- reflected in an unwillingness to entrust a country's energy supply to a neighbouring country or to delegate investment decisions to a regional body-continue to affect the pace of regional electricity integration.

12.2.2 Lessons Learned

The policy review raises a fundamental question in regard to the areas of future emphasis in Africa's strategy to increase energy trade. For nearly a decade or more, the main continental and regional bodies have been actively involved in putting in place a sound policy and institutional framework for promoting regional energy trade. Despite capacity and funding constraints, there has been strong commitment as well as measurable progress in establishing a policy framework. However, the impact of these regional policies on electricity trade has been negligible.

A clear lesson emerges from regional trade data: regional electricity trade cannot expand without sufficient overall power capacity at the regional level to meet demand. Consequently, there is a priority need to accelerate the construction of generation and transmission facilities in order to expand, and reinforce, the geographical coverage of regional grids.

In conclusion, these findings point to **three areas** for future emphasis in Africa's strategy to accelerate regional electricity integration:

- Develop a Financing Strategy- by preparing realistic financing plans that examine, inter alia, the feasibility of mobilizing non-government resources from the sector's own cash flow and external sources24 to help meet the overall financing requirements of the investment plans;
- Strengthen Regional Institutions –by addressing the capacity weaknesses and budget needs of key regional institutions for their operation and for the preparation and development of regional projects, with priority given to the East Africa and Central Africa regional agencies.
- Step-up Regional Investment- through construction of regional generation and transmission facilities based on least cost regional investment plans.

12.2.3 Project preparation, implementation and operation of regional projects

The findings from a detailed review of a number of existing regional energy projects (Annex 12-1 and 12-2) indicate a mixed performance in terms of development effectiveness (very long gestation periods), and sustainability (most regional schemes are facing major financial crisis) The most important aspects for success in development and operation of the investment program presented above are discussed below, in particular issues of political and commercial risk.

Need for Strong Government Support, in political and financing terms

Strong government support, in political and financing terms, is essential for large hydroelectric schemes to be developed successfully. **Cahora Bassa** was able to move ahead because of the clear commitment of Portugal and South Africa to the project. The **WAGP** project is another example of agreed interdependence as a political goal. In both cases, the Governments backed their political commitment with financial support since they were the only parties with the capacity to assume responsibility for an investment the size of **Cahora Bassa**, or for the political risk of the **WAGP**.

Political Risk

Political consensus reached during the construction period of a large project has to sustained. **Cahora Bassa** illustrates the fragility of such consensus, the exposure of large high visibility projects, and the potentially devastating impact of a change in political alliances on the finances of a regional project. Similarly, in the case of **SINELAC**, the political consensus during the development and construction phase did not persist through the project operation phase and resulted in each country putting their national political interest ahead of the project's interest.

The **WAGP** case illustrate another type of political risk, which is the change in Government policies due to economic factors: the lack of gas for domestic uses in Nigeria and the discovery of hydrocarbons in Ghana may result in a change of Government commitment toward the project. An important lesson is that the design of a mechanism to deal with the long term political and policy risks associated with large projects is an essential aspect that needs to be handled prior to integrating such projects into a regional development plan.

12.2.4 Institutional Arrangements for regional projects

Governments need to delegate substantial management authority to an ad-hoc entity in charge of project development early in project preparation. EGL played a key role in the development of the **SINELAC** project, in particular for consensus building between the three countries involved.

[24] External financing will be forthcoming only if, first, the future sector cash flow is strong enough to contribute to sector investment and service commercial loans directly or indirectly through power purchase agreement.

In the case of **Manantali,** the early designation of OMVS as project developer was instrumental in maintaining the momentum for project development. When an established ad hoc regional institution does not exist, the countries involved need to agree to designate a credible coordinator for project development at an early stage, to be superseded later by an ad hoc organization. This approach was instrumental in the successful development of the **Nangbeto** project.

Assessing and Managing Commercial Risk

Utilities in financial distress cannot be expected to enter into commercial agreements with a regional project company, even with back-up from the Government. When there are several off-takers, host or transit utilities/countries, each one of them should be equally creditworthy. Regional projects can operate only between countries where the sector is financially sound, and with credible indication that sector creditworthiness will be maintained in the long-run.

Government commitments to address sector financial issues need to be backed by up-front actions. In the case of **SINELAC**, all three off-takers were in financial distress and were unable to operate without Government subsidies. The same pattern occurred, although less severely, with **Manantali** and occasionally, with **Nangbeto.** Conversely, for **Cahora Bassa**, where the off-taker was ESKOM, there were no payment concerns.

Importance of a Sound Contractual framework

Even when a regional project is not structured as a PPP, its contractual framework needs to be similar to that of a PPP project in order to guarantee its financial and commercial viability. The lack of sound, long term contractual frameworks, with clear provisions for future tariff increases, led to (a) an unequal renegotiation of the export terms for Cahora Bassa: and (b) the financial distress of SINELAC; and, to a lesser extent, Manantali, as there are no well-structured, long term power purchase agreement, take or pay arrangements, or dispute resolution mechanisms. The quality of power purchase agreements is also essential and should be the subject of careful review as key project parameters change over time.

Importance of Assuring Sustained Commercial Viability

Sustained commercial viability of regional projects requires specific project structuring and mechanisms need to be put in place to ensure the commercial viability of the project. In the case of **SINELAC, Manantali** and **Nangbeto** regional projects, a strong political consensus was considered sufficient to replace the need for long term contracts and payment/performance securities. Experience has demonstrated that such a consensus is not sufficient and needs to be complemented by long term tariff setting mechanisms and payment guarantees, with credible international arbitration arrangements independent of the participating Governments.

Governance of regional projects

The Governments of the countries sharing the benefits from a regional project need to be kept fully informed of the project's performance. The need for accountability, however, does not require that government is present in the project management structure, as the project should operate exclusively on the basis of commercial contracts and compliance with national laws. Specific information disclosure agreements between the Governments/regulators and the project companies can ensure adequate information sharing. Alternatively, a minority participation in the equity without veto right may ensure suitable information sharing. The limited involvement of the Togolese and Beninese governments in the **Nangbeto** project management has enabled the company to run the **Nangbeto** scheme fairly effectively while keeping the Governments well informed of the project's performance. Conversely, in the case of **SINELAC**, the heavy involvement of Governments in the management of the project company has not allowed them to be fully informed of the impact of their decisions on the sustainability of the assets and the company.

Integration into a Regional Plan

Regional projects need to be integrated into a broader long-term vision of the regional system. Existing regional projects, with the exception of **Manantali,** were not designed and implemented as part of a complete regional development plan. Rather, they were developed based on local interests and priorities (**Nangbeto, SINELAC, Cahora Bassa**) of the countries concerned. The cost-saving potential of more extensive regional interconnection and trans-border trade in the regional context needs to be explicitly taken into account.

12.2.5 Risk Mitigation Steps for Regional Energy Investments

In order to mitigate the different risks highlighted above, the following policies and actions will need to be adopted and implemented.

- *Coordinate planning and development of national and regional energy investments* by allocating responsibilities between countries, RECs/Pools for project development;
- *Achieve, with support from donors, effective coordination between (i) national and regional planning priorities* through an increased planning role granted to the Pools; and (ii)*energy, water and telecom regional planning through cooperation between the Pools, Water Basin Agencies and Telecom Regulators*.
- *Develop specific mechanisms for facilitating the development and financing of large regional projects: a specific political risk management instrument and a continental project development financing facility.*
- *Establish a continental or regional project development financing facility to allow faster preparation of projects for regional integration, avoiding delays between the successive phases of preparation and ens*uring that the full preparation of selected projects is adequately funded from the start.
- *Establish a continent-wide risk guarantee facility funded by donors (as an alternative to direct financing of regional projects).*
- *Limit the development of large gas pipeline networks for regional and continental consumption in recognition of their (i) high capital investment costs; and (ii) the priority granted to large scale hydro for power generation in the Energy Outlook 2040.* However, selected gas pipelines may still be considered as important trans-African infrastructure, given the shorter development time of pipelines and thermal plants in comparison to hydro.
- *Consider investment in new petroleum refineries only if financed with private sector participation and/or a strategic partner- and in the perspective of the global international petroleum product market.*

13. Conclusions

The preparation of an Energy Sector Outlook to the year 2040 has helped clarify the magnitude of the investment challenge if Africa is to meet its stated objective of providing energy access to a majority of the population.

The main conclusions emerging from this analysis are the following:

- 1 *Investment Requirements:* The investment implications of meeting forecast energy demand for Africa to the year 2040 are enormous. The average annual investment needs for the power sector are estimated at $43.6 billion, with the largest proportion for power generation ($33.1 billion), and $3.7 billion in transmission and a relatively modest annual investment of $2.5 billion in access. An estimated $1.3 billion per year will also be needed for gas and petroleum product pipelines.
- 2. *Two* aspects of the investment requirements need particular emphasis:
  - *Investment in Interconnection* is now urgent and needs to be undertaken upfront in order to meet the projected energy demand of 2020;
  - *Investment in Access* is affordable and could enable a dramatic change in the current access levels of only 31% (in SSA countries) to average access levels close to 70%, with no country having an access rate below 60% by 2040;
- 3. *Financing and Implementation Challenges* The financing and implementation implications of these investment needs are equally formidable. The financing challenge will require significant improvements in the finances of national utilities to generate increased cash flow while financing from private sector sources is also essential. Both sources of finance currently make a negligible contribution to energy investment.
- 4. The following aspects of the Energy Sector Outlook need to be highlighted:
  - Africa's hydro resources are large but will be insufficient to meet long term demand, based on currently identified hydro sites; after 2030, Africa would revert to an increasingly dominated conventional thermal based system for its power generation unless new technologies have become more competitive than at present.
  - The Outlook projects a large increase in demand for petroleum products, which in turn will require further investment in pipeline networks. The proposed investments in the Outlook reflect a minimum investment scenario;
- 5. In regard to *energy security*, the Outlook indicates that the development of large cost hydro sources will reduce the need for imported oil products in the period to 2030. However, unless new indigenous resources or new energy technologies are developed in the meantime, Africa would become once again dependent on oil products.
- 6. The Outlook indicates that the *average cost of energy* will decrease slightly over the first 20 years and then increase slightly. Current average tariff levels are therefore adequate to meet increased energy demand. However, major improvements must take place to break the present culture of non-payment in order to generate the needed financial resources for future investment

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