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The economics of clean energy resource development and grid interconnection in Africa

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ABSTRACT

This paper analyzes the optimal options for supplying electricity to national economies from both domestic and distant energy resources using high voltage lines to transmit the substantial renewable energy resources of Africa. To meet the growing demand, Africa will need to provide 5.2 GW of new generation per year through 2025. This figure represents an increase of 65% from the 2010 level and will assist in connecting more than 11 million new customers per year through the development of a transmission network. The total discounted system cost is approximately 8% of the continent's GDP. Approximately two-thirds of the discounted system cost is associated with new generation, and the remaining one-third is associated with the development of the transmission network. From 2010 to 2025, trade expansion reduces the total system cost by 21% relative to the business as usual (BAU).

1. Introduction

The African continent has experienced a decline in both private and public expenditures in the power sector during the last decade. To address the short-term growth in demand, most countries have chosen to install small but expensive emergency thermal power generation units which are affected by fuel price fluctuations on the world market. Although this strategy may lead to an increase in electrification rates and assist in meeting the Millennium Development Goals (MDGs), it does not resolve the underlying lack of financing, profitability, and cost-effectiveness. The lack of investment in generation, transmission, and distribution is the greatest challenge encountered by electric utilities in this region. Therefore, there is a need for new policies and institutions that can foster new investments in generation and cross-country transmission capacities to produce the energy that is necessary for development.

Even though its energy consumption in general and electricity consumption in particular remains low[1] (approximately 8% of global electricity consumption), Africa possesses immense energy potential [1,2]. The geographic and technical potential for renewable electricity generation are much greater than the current total consumption in Africa. While hydro and geothermal resources are already highly cost-competitive, grid-connected PV and wind power could generate electricity at production costs that are competitive with those of current fossil fuel plants in the long term.[2] Every country in Africa has surplus energy resources; but financing difficulties have prevented the vast majority of countries from being able to exploit their energy potential.

The provision of low-cost electricity will be critical to the industrial development of the continent. Empirical evidence shows that historical electrification has followed an s-shaped curve and thus suggests that a massive investment is necessary to increase household connections (Fig. 1). Therefore, electrification would not differ for the remaining countries in Africa with low grid coverage. The limited amount of available financial resources should be allocated to technological options that will have the greatest effect on both access rates and prices. The uncertainties surrounding increasing and fluctuating crude oil prices lead us to argue that identifying 30–50 of the greatest large-scale utility solar, geothermal, wind, and hydro generation schemes offers a viable and competitive option for investment.

Rather than engaging in a country-by-country planning of generation and transmission, a continent-wide model is developed

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[1] In 2000, only 22.6% of the population in sub-Saharan Africa had access to electricity, compared with 40.8% in Asia, 86.6% in Latin America and 91.1% in the Middle East.

[2] The continent has one of the highest average annual solar radiations; 95% of the daily global sunshine above 6.5 kWh/m^2 falls on Africa during the winter.

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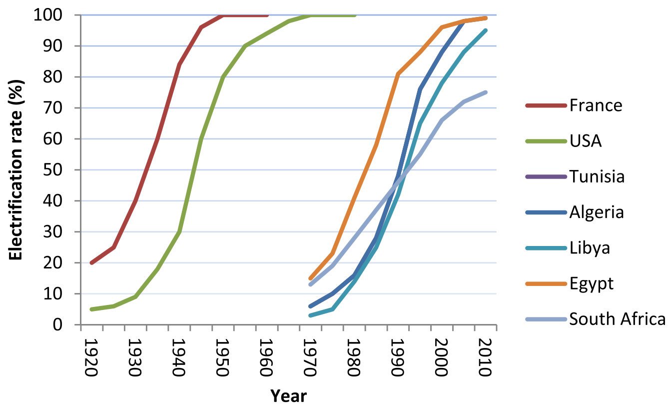

Fig. 1. Historical electrification rates in selected countries.

by considering the dynamic interactions among new projects in different locations. It analyzes electricity integration costs across the continent through 2025. Building on early studies of least-cost electricity access expansion in Kenya, Senegal, and various Millennium Village sites [3–5], the main purpose of this study is to provide necessary and valuable estimates of the least-cost grid expansion strategy for the energy-constrained countries of Africa to determine the extent of possible cost reductions resulting from sourcing less costly electricity sources across neighboring countries.

Numerous studies have analyzed the benefits of regional energy trade in Africa, but few studies have examined cost advantages on a continental scale. For example, Hammons [6] showed that the centralized operation of electric power systems can greatly improve economic efficiencies through economies of scale in hydro exploitation. Bowen et al. [7] found that the centralized and competitive dispatching of the SAPP (Southern African Power Pool) could save US$ 100 million annually. A more recent study by Graeba et al. [8] demonstrated that the benefit from trade expansion in Southern Africa could save US$ 110 million per year (5% of the total system cost) over a period of 20 years. Gnansounou et al. [9] found that a strategy of integrated electricity market in West Africa could reduce total system costs by 38%, which is similar to the 27% reduction that was found in a study that was conducted by Sparrow et al. [10] at Purdue University.

This study differs from its predecessors in the following ways: first, it includes the entire continent of Africa rather than a particular region. Second, it covers renewable expansion alone as well as in combination with fossil fuels attempting to show that clean energy sources have the technical, geographic and economic potential to supply both the short- and long-term energy needs of the continent. Third, it specifically considers the costs that are associated with the intermittency of renewable resources. Fourth, it introduces a more pragmatic approach to modeling demand projection. Fifth, it uses transmission costs, which are a function of both distance and quality of energy sources.

The remainder of this paper is organized as follows. Section 2 develops an electricity demand model that accounts for the specificity of population growth, economic growth, and income elasticity of electricity consumption in African countries. Section 3 explores the economic potential and cost of a renewable electricity supply. In Section 4, transmission costs are evaluated. In Section 5 covers the design of a continent-wide grid expansion based on differences in generation and transmission costs. Finally, discussions and policy implications are provided in Section 6.

2. Demand modeling

Africa produces 7% of the world's total energy, but consumes only 3% of the total at a level of energy intensity that is twice the world average [11]. Within the context of this contradictory situation, the identification of the drivers of aggregate electricity demand is important for forecasting and estimating necessary investments. In the electricity literature [12], several empirical studies have found that the gross domestic product (GDP), actual and relative prices, urbanization, and climate factors are the main drivers of electricity consumption growth. These relationships have been analyzed at the macroeconomic (country-wide, economy-wide, or sectoral) and microeconomic (household and firm) levels. For example, Al-Faris [13] as well as Narayan and Smyth [14] have modeled electricity demand as a function of actual price, the price of a substitute and real income. Nasr et al. [15] modeled electricity demand in Lebanon as a function of GDP proxied by total imports and temperature. Demand studies that have focused on the specific driving effect of GDP alone are reviewed by Jumbe [16] and Chen et al. [17]. In this paper, electricity demand is modeled by considering economic growth, population growth, income elasticity of electricity consumption, and access rate. The foundation of this study is the recognition that demand modeling in Africa suffers from the facts that both supply and demand are typically constrained. The paper uses both an econometric approach to model past income elasticity of electricity consumption and a pragmatic approach to consider projected economic growth, population growth, and electricity access policy goals.

The model begins by projecting demand growth through 2015, 2020 and 2025, as detailed in Appendix A. Then using GIS analysis, the most exploitable sites based on the available potential of hydro, geothermal, solar, and wind energy sources are identified. The 30–50 largest and highest-quality energy resources (hydro, solar, geothermal, and wind) that can resolve the short- and long-term energy supply issue for the continent are selected. Then projected differences in generation costs are computed based on resource quality as characterized by the capacity factor, and follow the computation of transmission costs as a function of the energy source (capacity factor) and the distance to load centers. This calculation is performed using GIS analysis to determine the distance between every potential energy site and demand centers. Finally, the model reveals the most cost-effective way of meeting the projected demand requirement based on various available energy resources and their costs. Other local generation options which are introduced later include thermal sources such as coal, natural gas, diesel and heavy fuel oil. The model links demand points to the least expensive and closest (in terms of transportation) energy resources.

2.1. Income elasticity of electricity consumption

The first exercise examines past trends regarding the relationship between electricity consumption and economic growth for Africa as a whole for the period from 1970 to 2009. For comparison purposes, other large and medium-income countries such as Brazil, China, India, Indonesia and Malaysia whose path of development is likely to be mirrored by Africa are added. Figs. 2a and b present two well-documented and accepted relationships in the energy literature [18]: the positive correlation between growth in per capita electricity consumption and growth in per capita income, and the negative correlation between income elasticity of electricity consumption and per capita income levels. Economic growth is expected to be positively correlated with growth in electricity consumption; however the direction of the causation remains under contention [16].

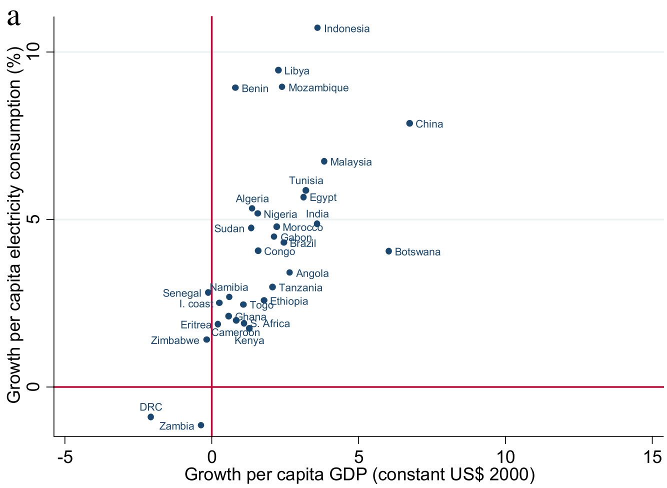

Fig. 2a. Growth of per capita electricity consumption and growth of per capita GDP for selected countries.

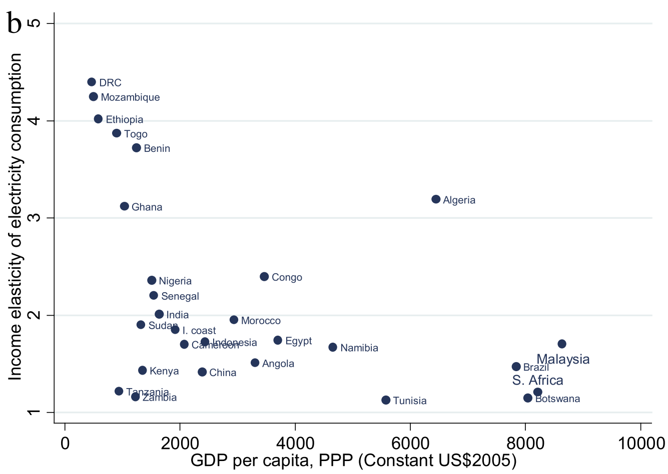

Fig. 2b. Income elasticity of electricity consumption and per capita GDP for selected countries.

In Africa, the difficulty of measuring the sensitivity of power consumption to income growth is related to the structural particularities of the diverse countries and the nature of the constrained supplies. A simple method (the log–log regression) of estimating income and price elasticity that is widely used in the literature is the following:

$$\log E_t = a + b^*\log \mathrm{GDP}_t + c^*\log P_t \qquad (1)$$

$$\log E_t = a + b^*\log \mathrm{GDP}_t + c^*\log P_t + d^*\log \mathrm{GDP}_{t-1} \qquad (2)$$

where b and c are the income and price elasticities, respectively; E_t and GDP_t are the per capita electricity consumption and per capita income level, respectively; and P is the price of electricity. Because of the lack of data, only the income elasticity using different measures of per capita (GDP in purchasing power parity) is estimated. Only the long-run elasticity from Eq. (2).[3] will be reported. Specific countries' elasticities are estimated by performing a time series analysis of 22 countries for the period from 1970 to 2009 using the World Bank World Development Indicators database [19]. In Eq. (2), without prices, the dependent variable is electricity consumption per capita (in kWh), and the independent variable is GDP per capita in PPP terms (constant US$, 2005). In this analysis, control for the production shares of agriculture, manufacturing, industries and services (in % of GDP) are added to the model.

The results for income elasticity from both the short- and long-run equations (1) and (2) are above unity for all countries and comparable to other international findings [20]. This variation within Africa may be due to the small and heterogeneous nature of its economies. However, the variation across the countries is large and ranges from values greater than 4 for countries that include Ethiopia, DRC, and Mozambique to values of approximately 1.10 for countries that include Tunisia, South Africa, and Botswana. Demand for electric service is highly income-elastic in Africa. Countries at different levels of income differ in electricity consumption. Brazil, China, India, Indonesia, and Malaysia have elasticity between 1.5 and 2 (Fig. 2b).

2.2. Demand projections

The unique characteristics of African countries make demand forecasting particularly challenging. As a pragmatic approach, in this paper, it is assumed that universal (100%) electrification can be achieved by 2050 by countries with at least 60% current electrification and that countries below this level can achieve at least 80% electrification.[4] Assuming that supply will not be a limiting factor and that universal electrification is possible, the results yield a value of per-country demand growth that is higher than what is typically reported in the literature.

The general expression of the annual electricity consumption growth (%) is given by Eq. (3):

$$Y = e^{\ln(X/Z)/T} \qquad (3)$$

where X (in MW) is the total projected consumption, Z (in MW) is the current electricity consumption at year zero (2010), and T (number of years) is the time horizon. For large, inter-country energy projects, longer time horizons may be justified. Nevertheless, two time horizons are applied: the short-term horizon (2010–2015) and the long-term horizon (2015–2025). For the projected country economic growth rates, a convergence economic growth model that relates the GDP growth path of every African country to that of the United States is specified (Fig 3a). This procedure produces an annual GDP growth that reflects the fact that the growth of low-income countries is more rapid than that of high-income countries (see Appendix A). For the projected country population growth rates, the estimates of the UN Population Division medium variant projection are used (Fig. 3b).

The results show that the regional electricity consumption is expected to grow more rapidly than conventional estimates due to the following key drivers. First, the current low level of per capita GDP provides significant room for growth in per capita GDP, which falls in the range of 3–8% annually. This high economic growth is expected to drive per capita electricity consumption. Second, high population growth (estimated at 1–4%) combined with high urbanization (estimated at 60%) will cause electricity consumption to

[3] Long-run elasticity = $b/(1-d)$. The elasticities b and c that are specified in (1) represent the short-run; in Eq. (2), d indicates the speed of adjustment towards the long-run equilibrium.

[4] Although universal electrification is the ultimate goal, it is assumed that 10 years will not be sufficient to achieve such a goal for countries with a current electrification rate of less than 60%. However, for a longer planning horizon, such as 40–50 years, the achievement of this goal is possible.

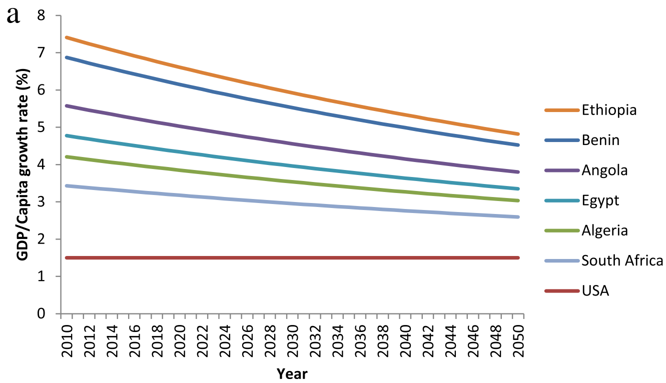

Fig. 3a. Projected annual per capita GDP growth rate for selected countries from 2010 to 2050.

increase, particularly in the residential and commercial sectors. Third, with less than 40% of the population connected to the grid, there is vast potential to expand grid access to all rural areas. Existing industrial customers that generate their own energy or customers with unmet demand could also be brought back into the grid. Fourth, with rapid economic growth, customers are expected to increase electricity consumption to a certain point as a result of the use of appliances, but the estimation of this household income elasticity of electricity consumption for developing countries poses many challenges because electricity demand is supply-constrained with severe rationing and constant blackouts. In this study, at the country level, an income elasticity value of 1 is used for all other countries except for those in the 22-country time series data analysis, which showed that the electricity consumption of most African countries has grown at a rate that is close to or greater than the rate of GDP growth.

Africa's current installed capacity is only 117 GW,which is supplied with 64% thermal and 36% hydro power. In the absence of a supply constraint, Africa's current population of 1.030 billion and electrification rate of approximately 40% translate into an expected average per capita GDP growth of 5%, an average population growth of 2% and an average electricity consumption growth of 7.8%. The total installed capacity in 2050 is projected to be 1017 GW (or 6.7 million GWh). This demand will be driven by countries with low per capita GDP and low electrification rates, such as Burkina Faso, Burundi, Malawi, Tanzania, and Uganda, all of which will experience annual consumption growth of more than 10%. In contrast, high-income countries with high electrification rates, such as South Africa, Egypt, Algeria, Libya, Ghana, Morocco, Mauritius, and Tunisia, will experience less than 4% annual growth in consumption (Fig. 4). In this variety of trends, South Africa and Egypt will remain the largest drivers of electricity integration across the continent. These two countries represent 30% of the projected 2050 capacities (Fig. 4).

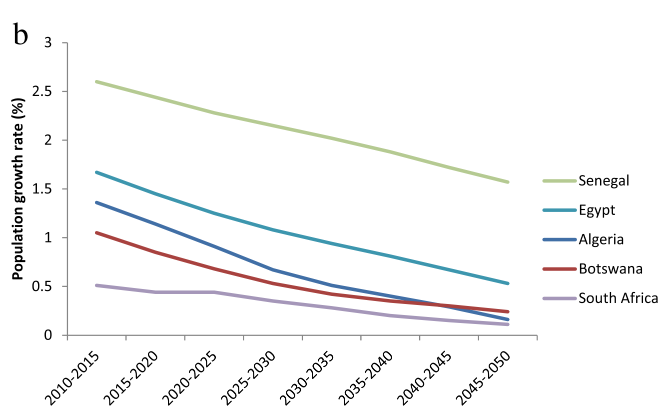

Fig. 3b. Projected annual population growth rate for selected countries from 2010 to 2050.

3. Supply and costs

Africa is known for its abundant resources, which include energy resources. Although solar energy is almost uniformly available, other resources are highly uneven across the region. For example, oil and gas potential tend to be concentrated in northern and western Africa. Hydro potential is found in central and eastern Africa, whereas exploitable coal is primarily located in the southern region [21]. Geothermal energy potential is found in the eastern region. Because every country has some solar, hydro, and wind potential, the question of interest concerns how many of these resources are technically and economically available for exploitation. This paper uses estimates of the available economic potential for solar, wind, geothermal, and hydro power for each country from Piet et al. [22].[5]

An enormous amount of economically exploitable, inexpensive hydro resources are distributed across the continent: more than 50% of these resources are found in central, eastern and southern Africa, and 25% of these resources are found in northern and western Africa each. The hydro potential at Inga Falls is the greatest and the least expensive. With an average solar irradiation of 5–6 kWh/m^2/day, solar energy is uniformly used but limited to small-scale applications. The countries with the greatest solar potential are Libya, Algeria, Niger, Mali, Chad, Ethiopia, Sudan, Tanzania, Angola, DRC, and Nigeria. The highest available intensities are found in the desert and Sahel areas. Wind energy has not been traditionally pursued on the continent, with the exception of its application for small-scale water pumping, but Egypt and Morocco have installed capacities of 68 MW and 54 MW, respectively [23]. Somalia, Sudan, Libya, Egypt, Mauritania and Madagascar have high potential for on-shore wind power. Although the overall potential for geothermal energy is smaller than that of other resources, this resource can be used in some countries, such as Kenya, Tanzania, and Morocco, where 1–5 GW are exploitable (Fig. 5).

It has to be acknowledged that the assessment of the relative costs of various energy technologies is more complicated than the simplified methodology below. First, with respect to a continental grid connection, it is difficult to compare technology costs across various countries with different currencies and policy contexts. Second, although the cost of renewable energy is heavily influenced by site characteristics, thermal options[6] are also strongly influenced by fuel prices both of which are hard to predict. For the thermal option, the fuel cost is likely to be the largest component of the kilowatt-hour cost.

Supply is first modeled by quantifying the role of renewable energy, particularly geothermal, solar, wind, and hydro power. The cost of renewable resources is expected to decrease significantly in

[5] Assumptions used in the estimation of country energy potential by source. For solar, a conversion efficiency of 15% is assumed with an available amount of land per country of 1 in 1000 (0.001). For wind energy, hub height is 80 m hub, offshore (0–15 km), and wind speed > 7 m/s, and 60% sitting density taken based on figures for Germany. Hydro refers to the technically exploitable resource (not economic) based on country-level studies. Finally, for geothermal energy, the assumed heat conversion potential is 5%; the country-level specific capacity factor value, except for Egypt and Ethiopia, is 48%.

[6] A critical issue to address when developing these thermal options will be their cost-effectiveness compared with hydro or geothermal options, which can be easily used for base load generation.

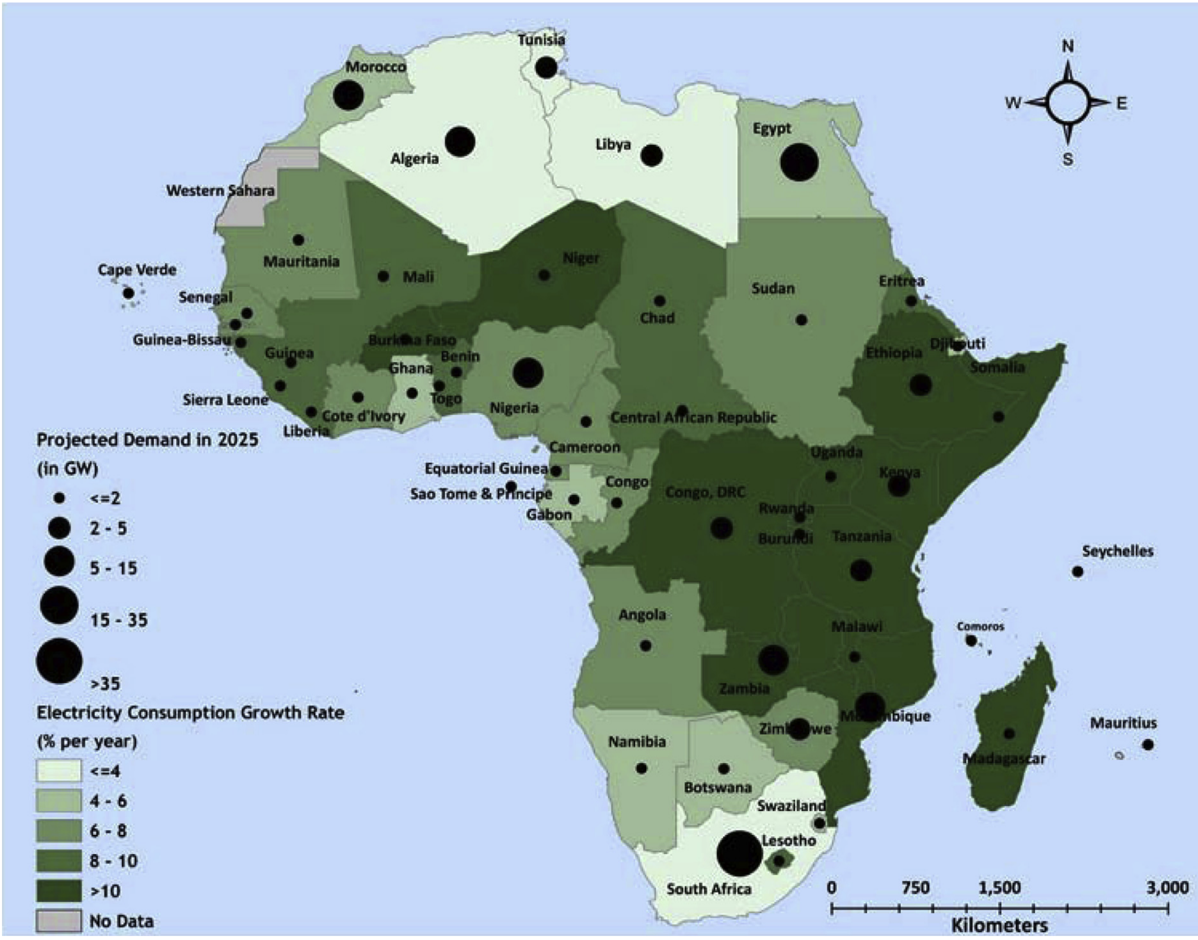

Fig. 4. Annual electricity consumption growth rates and projected demand in 2025.

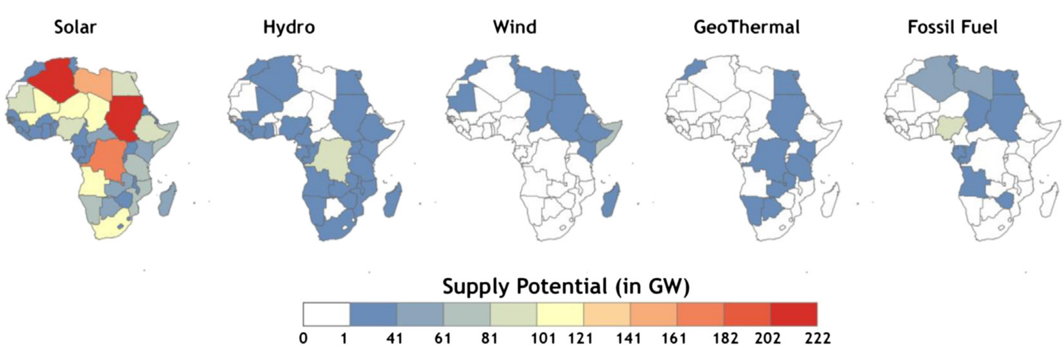

Fig. 5. Countries' supply potential per resource (in GW).

the medium term. This study does not consider domestic or offshore applications of solar and wind, although both potential applications may be relevant in the African context. Rather, it focuses on onshore, centralized, grid-connected solar and wind power.[7] Because of the intermittent nature of these two energy sources, theyrequire additional storage[8] or back-up capacities. Therefore, the storage cost is assumed to be approximately 0.02–0.047US$/kWh for the use of these sources as base load providers [11,24]. Other assumptions include a module cost of 3–67US$/Wp for solar power and a US$ 1915/kW investment cost for on-shore wind turbines [25]. The annual operation and maintenance cost is 3%. The annuity factor (0.11) is calculated based on a 10% interest rate and a 20-year equipment lifetime. Most of the pre-feasibility studies of hydro costs in Africa are outdated; therefore, an investment cost of 1000–4000 US$/kW is adopted for capacities greater than 250 MW [26]. The levelized cost of electricity (LCOE[9])

[7] These systems are medium- to large-scale systems (from 100 kWp to many MWp) that are installed on the ground in areas with few competing land use issues.

[8] For these technologies to contribute as baseload, they will require storage capacities of up to 12–15 h.

[9] The LCOE is the present value of expected costs (capital, operating, maintenance, and fuel) over the lifetime of a power plant divided by the discounted stream of power that is generated during the same period. The generated power is determined by the capacity factor.

Table 1
Transmission characteristics (AC or DC and voltage level) as a function of distance and capacity.

	10 MW	50 MW	100 MW	500 MW	1000 MW	2000 MW	3000 MW
10 km	33 kV AC	138 kV AC	138 kV AC	345 kV AC	500 kV AC	765 kV AC	200 kV DC
100 km	66 kV AC	138 kV AC	230 kV AC	345 kV AC	500 kV AC	765 kV AC	400 kV DC
250 km	230 kV AC	138 kV AC	230 kV AC	345 kV AC	500 kV AC	765 kV AC	500 kV DC
500 km	200 kV DC	138 kV AC	230 kV AC	500 kV AC	500 kV AC	765 kV AC	600 kV DC
750 km	200 kV DC	230 kV AC	230 kV AC	500 kV AC	500 kV AC	765 kV AC	600 kV DC
1000 km	200 kV DC	200 kV DC	300 kV DC	500k V AC	765 kV AC	765 kV AC	600 kV DC
2000 km	200 kV DC	300 kV DC	400 kV DC	500 kV DC	500 kV DC	765 kV AC	800 kV DC

production at each site is computed by annuitizing the investment and O&M costs and dividing it by the annual energy output.[10] The study allows the possibility of scaling up power production with the current fuel mix of countries, considering the cost of the weighted averaged generation cost per technology. All costs remain constant during the planning horizon, although future trends are downward and may change during the roll-out phase. Hence, the figures in this paper could be considered upper-bound estimates.

4. Transmission and costs

The best renewable energy sites in Africa are often located far from demand centers; thus, their exploitation feasibility is conditional on the construction of expensive new transmission networks. There is a tradeoff between expanding current fuel-based production and exploiting these distant, inexpensive resources. However, the estimation of these transmissions costs is difficult. These costs are important because they ultimately determine whether a continent-wide grid connection is economically efficient. Country A will import from country B only if the generation and transmission costs from country B are less than the generation cost in country A.

Potential supply sites are connected by HV transmission lines using length estimates of the shortest, most direct distance between them[11] but this study does not model the expansion from current existing inter-country HV lines because of the lack of reliable detailed geographic information and difficulty of modeling the engineering aspects. To compute transmission costs, the analysis starts by identifying the best sites for solar and wind, to which are added the best sites for hydro and geothermal. For solar, only sites that have irradiation figures equal or greater than 5 kWh/day are considered. For wind, only class 4 wind and above are considered. These preferred sites are based solely on the quality of available resources. The analysis is limited to solar and hydro sites that are suitable for large-scale and year-round operation but do not consider those that are located in unsuitable areas, such as agricultural lands, residential land (population centers), or water and protected areas.

The costs of transmission from the generation sites to demand centers depend on the capacity, distance and related power losses in the lines. Transmission lines are chosen in ways that minimize both the costs and the system unreliability (voltage drops). In the cost calculations, for a typical underground DC cable transporting 1 GW,this study assumes an investment cost of US$ 1.2 million per km, an energy loss of 3.5% per 1000 km, a cost of US$ 120,000 for two stations at both end of the line, a 40-year transmission line lifetime, and a 10% interest rate [25–29]. These assumptions yield a transmission cost of US$ 0.027/kWh/1000 km for transporting 1GW without losses. Table 1 presents transmission characteristics as a function of distance and the quantity to be transported. HVAC technology is optimal for low capacities over short distances, whereas HVDC technology is optimal for large capacities over long distances. For both AC and DC transmission, the annual operation and maintenance costs are set at 2% of the total capital cost [30]. For all possible transmissions, the levelized cost of electricity delivery is computed as a function of distance and a capacity utilization factor that is equal to the capacity factor of each source.

5. Optimal generation and transmission expansion

The rationale for grid interconnection in Africa is twofold: high-consumption countries do not have the highest supply potential, and an excessive number of small countries have small markets for which high investment is unfeasible. Therefore, integration enables high-consumption countries to have access to cheap resources outside of their borders and small countries to develop resources that they would not otherwise be able to exploit. Few studies have proposed grid interconnection options for Africa [21,31]; other studies have focused on regional interconnection [7,32]. In this study proposes an interconnection that specifically accounts for countries' differences in generation and transmission costs. The question of interest is as follows: given the projected demand, supply options and their respective generation costs, and transmission costs, what are the most viable interconnections, and what resources (hydro, geothermal, solar, and wind) can be moved around in the short and long term?

The investment optimization model uses a linear programming to determine the most cost-effective approach for the expansion of generation capacity at the lowest unit cost for the supply of regional power pools through cross-border trade. The model uses the general algebraic modeling system (GAMS) as the language in a linear programming model for optimization. It simply minimized the total discounted generation and transmission costs that are subject to demand and supply constraints. The main equations in the models are presented below:

The objective function to minimize

$$\sum_{i=0}^{105} \cdot \sum_{j=0}^{46} \cdot \sum_{t=1}^{15} G_{it}X_{ijt} + T_{ijt}X_{ijt} \tag{4}$$

Subject to

$$\sum_{j=0}^{46} \sum_{t=1}^{15} X_{ijt} = \sum_{t=1}^{15} H_{it} \quad \forall i, \quad i = 0, 1, 2, \ldots, 105$$

$$\sum_{i=0}^{105} \sum_{t=1}^{15} X_{ijt} \geq \sum_{t=1}^{15} D_{jt} \quad \forall j, \; j = 0, 1, 2, 3, \ldots, 46$$

where i denote generation units and j denote demand nodes, H_{it} is the supply potential at generation unit i (MW) at time t, D_{jt} is the

[10] The annuity factor is calculated as follows: $a = r/[1 - (1+r)^{-LT}]$, where r is the interest rate and LT denotes the lifetime. The investment cost is upfront, and a constant O&M cost is maintained over the lifetime of the project and thus neglect to consider that this cost may increase over time.

[11] Only HV lines are considered in this study, although some MV lines may be needed in certain countries. Only between-country transmission lines over long distances are modeled.

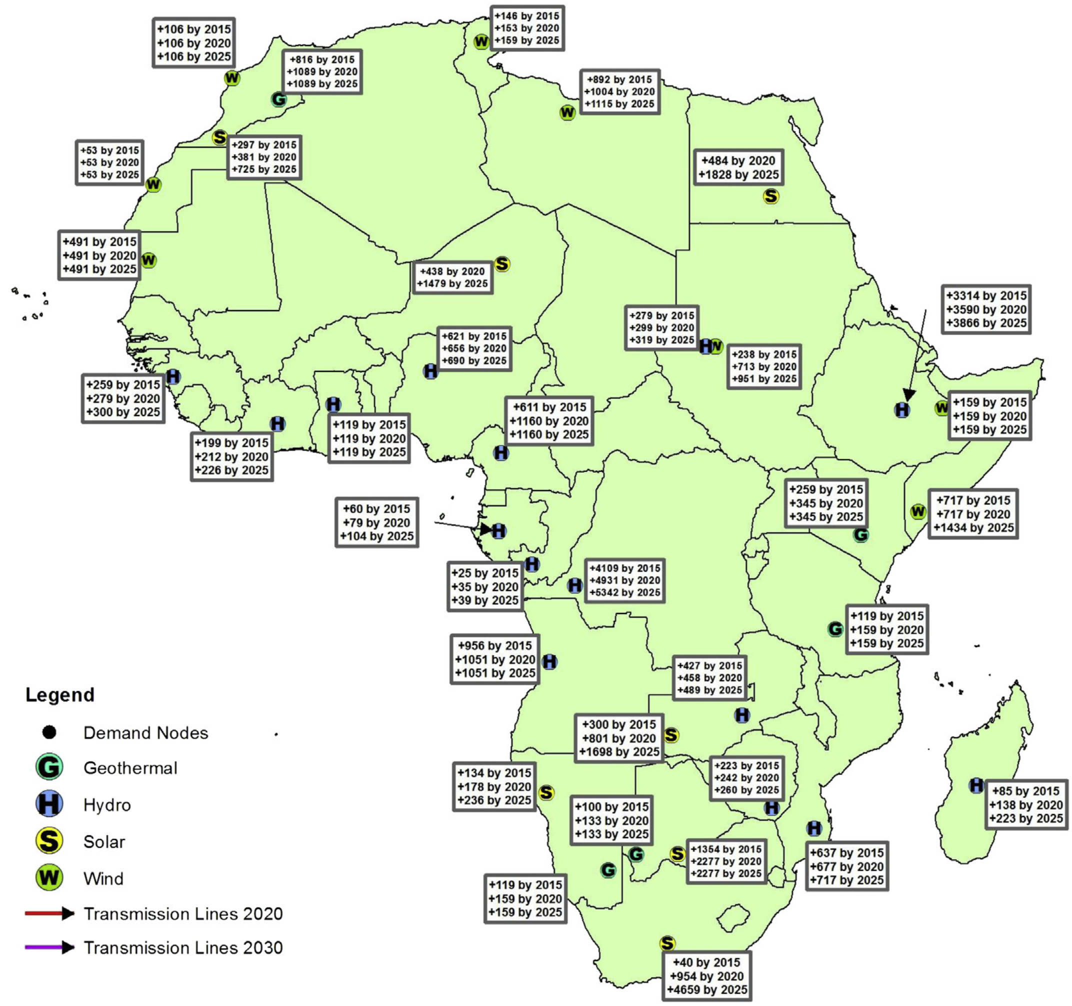

Fig. 6. Optimal new generation expansion in MW to meet demand from 2010 to 2025.

demand to be satisfied at node j (MW) at time t, G_{it} is the generation cost at unit i at time t, and T_{ijt} is the cost of moving electricity from generation unit i to demand node j ($/MW) at time t. X_{ijt} is the decision variable, which is the quantity of electricity to be shipped from generation unit i to demand node j (MW) at time t. Despite its simplicity, this model has some advantages in terms of flexibility. First, the model enables the simultaneous minimization of both generation and transmission costs. Second, this model is sufficiently flexible to include numerous regulatory and institutional policies related to trade, such as national restrictions on import for energy security or tariffs on imports for revenue generation.

The levelized generation and transmission costs account for annualized investment costs, annualized variable and fixed operation costs, and the annualized maintenance cost for both generation and transmission. A real discount rate of 10% is used in all computations. Generation costs are characterized solely by the capacity factor of a source, whereas transmission costs are characterized by the distance between a source and a demand node. For both the short-term (2015) and long-term (2025) horizons, the objective function in Eq. (4) is minimized to balance the electricity supply and demand at the continental level.

Transmission is modeled as a basic transport problem without considering all of the dynamics of load flows. This method of modeling allows for the simultaneous optimization of transmission and generation in the GAMS. The model is optimized for three periods of 5 years each between 2010 and 2025, but the cost results are aggregated for the 2025 horizon.

Further restrictions that are imposed on the model include the following:

1. *Demand*: the paper is concerned only with meeting new demand that results from population and economic growth and access policy goals. Thus, there is no replacement of existing capacities, even those that may be more expensive than the new available sources. Therefore, the cost results do not include the refurbishment of existing capacities, which are considered sunk costs. New electricity demand must be met in every period and at every location, but the model does not the possibility for excess generation.
2. *Supply*: no country can develop more than 25% of its total potential (which is equally distributed among its sources) over a 20-year period. This restriction leads to more realistic results because it reflects the extra time that may be necessary to ramp up generation and transmission in Africa because of the continent's weak institutional and political environment.
3. *Export and import*: although there is no limit on the export potential of each country, high-income countries, such as Egypt or South Africa, cannot import more than 40% of their total

Table 2
New generation by region, planning period and source.

	West Africa	Central Africa	East Africa	North Africa	Southern Africa	Total
Capacity (GW)	10.82	3.95	5.06	45.57	51.61	117.01
Consumption (billion kWh)	34.42	12.96	18.63	187.36	260.47	
Thermal (%)	75.48	66.68	59.61	91.67	47.12	
Hydro (%)	23.28	32.47	46.95	8.33	37.08	
Gen. cost (US$ cents/kWh)	0.31	0.22	0.20	0.37	0.13	0.246
New generation 2015 (GW)	1.199	4.805	5.085	2.803	4.376	18.267
Hydro	1.199	4.805	3.593	0	2.329	11.925
Geothermal	0	0	0.378	0.816	0.219	1.414
Wind	0	0	1.114	1.689	0	2.803
Solar	0	0	0	0.297	1.828	2.125
New generation 2020 (GW)	1.705	6.205	5.982	3.761	7.068	24.721
Hydro	1.267	6.205	3.889	0	2.566	13.926
Geothermal	0	0	0.504	1.089	0.292	1.885
Wind	0.000	0	1.589	1.807	0	3.396
Solar	0.438	0	0	0.865	4.210	5.513
New generation 2025 (GW)	2.814	6.655	7.233	5.567	11.902	34.171
Hydro	1.334	6.655	4.185	0	2.740	14.914
Geothermal	0	0	0.504	1.089	0.292	1.885
Wind	0.000	0	2.544	1.925	0	4.469
Solar	1.479	0	0	2.553	8.870	12.903
Total	5.717	17.665	18.300	12.130	23.347	77.159

demand, and low-income countries, such as Benin, cannot import more than 80% of their demand.

5.1. Results

5.1.1. Optimal generation

The optimal generation result is displayed in Fig. 6, and the associated regional distribution is presented in Table 2. The optimization adds a total of 77 GW by 2025. It is found that, to meet the growing demand, Africa will need to provide 5.2 GW of new generation per year through 2025. This figure represents an increase of 65% from the 2010 level, which will assist in connecting more than 11 million new customers per year through the development of an extensive transmission network. West Africa will add 5.7 GW in new generation (or 7.5% of the total), with primarily hydro in Guinea, Nigeria, Ivory Coast and Ghana, whereas solar will be in Niger. New generation in central Africa represents 23% of the total energy generation and will be exclusively derived from hydro in DRC, Congo, Cameroon, and Gabon. East Africa equally contributes 23% of the total energy generation, specifically hydro in Ethiopia and Sudan, wind in Somalia, and geothermal in Kenya and Tanzania. North Africa will add 12 GW, including 30% solar in Morocco and Egypt. In contrast, the contribution of solar energy is far greater in southern Africa, with 60% of the total addition of new generation from Zambia, Namibia, Botswana and South Africa.

5.1.2. Optimal trade (transmission), costs and financing

The cost-optimal HV transmission expansion is depicted in Fig. 7 and Appendix B (net quantity traded in MW and line voltages). A large electricity trade is made possible by countries that include DRC, Ethiopia, Cameroon, Angola, Guinea, Mauritania, and Morocco. Half of the total electricity that is traded is provided by these hydro sites, whereas solar accounts for a quarter of the total electricity from sites in Morocco, Egypt, Niger, Zambia, Namibia, Botswana and South Africa. Substantial wind energy is offered for trade by Somalia and Libya. The small geothermal capacity in Kenya and Tanzania is cost-effective for trade in southern Africa. Among the regions, only central and East Africa can export to other regions. North Africa, West Africa, and Southern Africa trade only within regions.

The total discounted system cost is approximately 8% of the continental GDP. Approximately two-thirds of the overall discounted system costs are associated with new generation, and the remaining one-third is associated with the development of the extensive transmission network. From 2010 to 2025, trade expansion will reduce the total system cost by 21% relative to the business as usual (BAU) scenario, which is based on the projection of current historical average costs. The annual cost of 8 billion through 2025 is 21% less than the current energy spending (US$ 11.6 billion) on expensive thermal generation by individual African countries (Table 3).

5.1.3. Oil, natural gas, and coal scenario

The first part of this paper has been solely concerned with the supply of clean energy from hydro, geothermal, solar, and wind sources, whereas now it considers the development of thermal technologies given the abundance of some fossil fuels in some countries. Based on oil, natural gas, and coal reserves that existed at the end of 2005, according to Piet et al., and following conversion methods using current country production ratios, the paper estimates an oil potential of 47 GW in Libya, 5 GW in Egypt, 15 GW in Algeria, 45 GW in Nigeria, 11 GW in Angola, 8 GW in Sudan and 3 GW in Gabon. For natural gas, the estimated potentials are 44 GW in Nigeria, 38 GW in Algeria, 16 GW in Egypt and 12 GW in Libya. For coal, the estimated potentials are 255 GW in South Africa and 3 GW in Zimbabwe. These annual energy potential values are based on 50 years of exploitation. Supply cost assumptions are 11 cents/kWh for natural gas, 7.7 cents/kWh for coal, and 20 cents/kWh for oil. An additional restriction in the model is that no country can develop more than 25% of its total

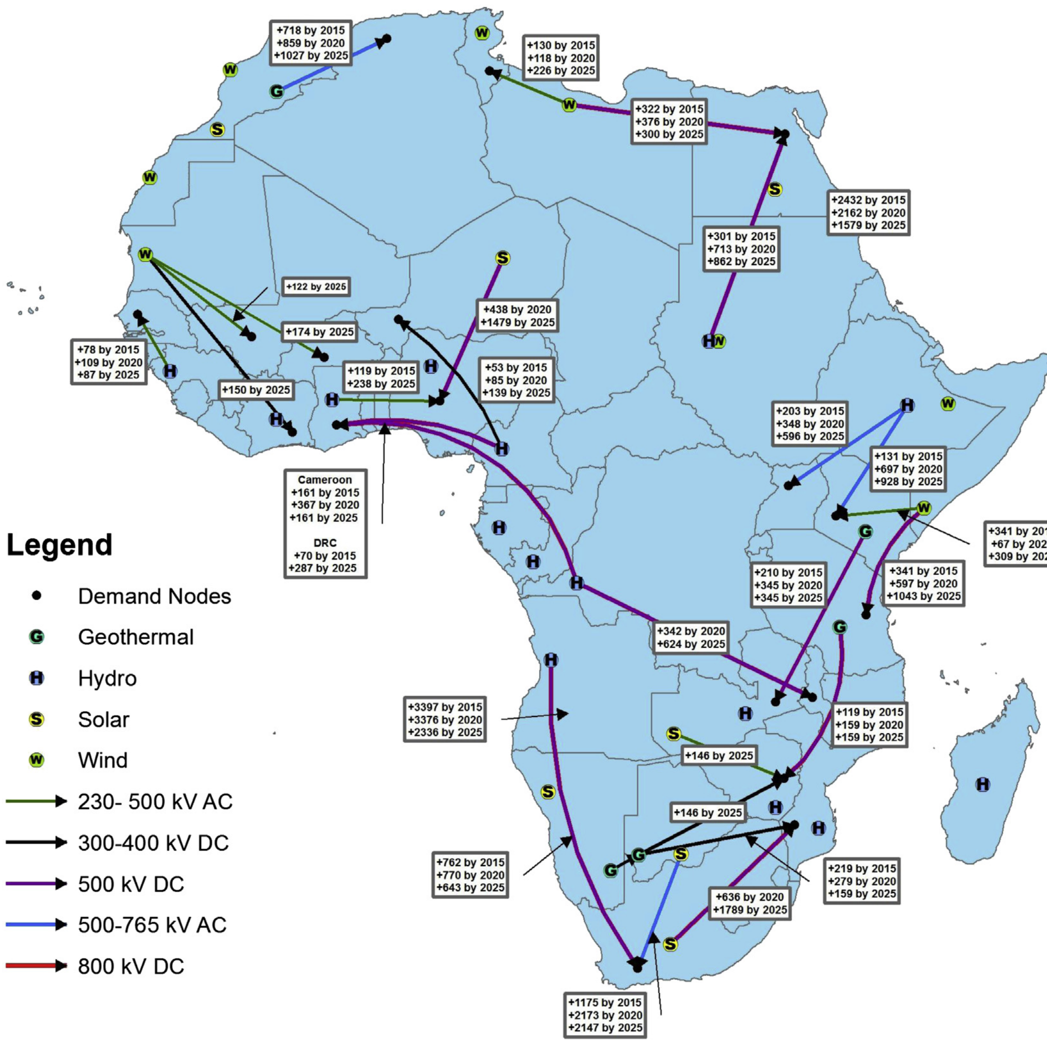

Fig. 7. Optimal new dominant transmission and trade expansion in MW to meet demand from 2010 to 2025. The full optimal transmission with all the lines is provided in Appendix B.

potential over 20 years, and there is no possibility for thermal electricity production to be exported.

In this scenario, the results indicate that Nigeria, South Africa, Algeria, and Zimbabwe can rely on total domestic electricity production. Nigeria has a mix of hydro and natural gas, whereas the total annual new electricity demand in South Africa and Zimbabwe is met with coal generation. Although solar is not more cost-effective in Egypt, the country remains dependent on hydro from Ethiopia in addition to its own natural gas electricity generation.

The total discounted system cost to meet total demand in 2025 is reduced from US$ 131.93 to US$ 94.47 billion or a 28% reduction relative to the clean energy scenario. This reduction primarily results from the replacement of the expensive solar option in the desert regions with cheap domestic fossil fuel electricity generation in Northern and Southern Africa (Table 4).

Although the addition of fossil fuel technologies reduces the discounted financial cost by 28%, this addition increases total CO_2 emissions over the planning horizon by 1.099 billion tons. The cost difference of US$ 37 billion represents the implicit subsidy that would be needed to bring clean technology into parity with fossil fuels, with a cost of US$ 142 per ton of CO_2 avoided.[12] Equivalently it would require a tax carbon of US$ 142 per ton of CO_2 to bring clean technology in parity with fossil fuels.

Table 3
Trade expansion cost by the end of the planning horizon in 2025.

		2025		
		US$ in billions	Share of total (%)	Share of GDP (%)
Trade expansion	Total system cost	131.9	100	7.63
	Generation	82.9	63	4.80
	Hydro	12.56	15	
	Geothermal	3.4	4.1	
	Wind	8.8	10.6	
	Solar	58.2	70.2	
	Transmission	48.9	37.1	2.83
	Hydro	21.5	43.8	
	Geothermal	1.9	4.05	
	Wind	11.5	23.5	
	Solar	14	28.6	
BAU	Total system cost	166.3	100	9.61

[12] This value is computed by taking the difference between the NPV of the total cost for the two scenarios divided by the discounted emission difference over 15 years.

Table 4
Generation (GW), technology share (%), and total cost for clean energy alone and in combination with fossil fuels.

	Clean energy only		Clean energy + fossil fuels	
	Net generation (GW)	Share of total (%)	Net generation (GW)	Share of total (%)
New generation by 2025	77.159	100	77.159	100
Hydro	40.765	52.8	27.899	36.2
Wind	10.667	13.8	11.785	15.3
Geothermal	5.184	6.7	1.909	2.5
Solar	20.541	26.6	3.596	4.7
Coal			20.393	26.4
Natural gas			11.023	14.3
Oil			0.553	0.7
Total cost in billion US$	131.93	100	94.47	100
Generation	82.97	62.9	53.70	56.85
Transmission	48.96	37.1	40.77	43.15

6. Discussion

The analysis of the various generation and transmission cost possibilities leads to the following general conclusions:

1. The emerging picture of a short-term energy system in Africa relies on the development of hydro-power. In particular, the vast hydro potential of central Africa can be shipped to any place on the continent at a maximum cost of US$ 0.20. For example, for the two largest energy consumers, the Inga Hydro cost is approximately US$ 0.13 in Egypt and US$ 0.09 in South Africa.
2. The geothermal potential in East Africa is inexpensive and can serve as a base load but is limited in its quantity and ability to meet the needs of countries outside of this region. For example, geothermal energy from Kenya has a cost of approximately US$ 0.19 in North Africa and is competitive with domestic sources.
3. Hydro resources from central Africa are competitive in West Africa, but when the availability of inexpensive natural gas from Nigeria is considered, the connection of these two regions is less optimal in the long term.
4. Although high wind potential is available on the coasts of Somalia, Morocco, and Tanzania, the relatively low capacity factors for these sites triple the transmission costs. Wind energy that is produced at US$ 0.085 in southern Morocco has a cost of approximately US$ 0.25 in nearby Egypt. However, wind energy represents a competitive long-term energy source for East Africa.
5. Although good solar energy is available throughout most of Africa, transmission from the desert and the Sahel areas to other parts of the continent becomes feasible only in the long term when solar investment costs decrease more than 50% to compensate for the high transmission costs.
6. In terms of strategic interconnection, it is more sensible in the short term to invest in transmission lines that ship hydro power from Central Africa to Southern Africa and from Eastern to North Africa.

Appendix A. Demand model

This section presents the derivation of Eq. (3), which estimates the country-level projected annual installed capacity growth.

Variables:

ACGannual consumption growth (%/year)
CCcurrent consumption in 2010 (MW)
TPCtotal projected consumption in 2020 (MW)
Tnumber of years
ECGexisting customer growth (%/year)
NCGnew customer growth (%/year)
NCPRnew customer power requirement (MW)
PCPRper capita customer power requirement (MW)
Pcurrent population
NCnew connection (/year)
CERcurrent electrification rate (%)
TERtarget electrification rate (%)
CGRcombined projected economic and population growth rate (%/year)
IEincome elasticity

$$\mathrm{ACG} = e^{\ln(\mathrm{TPC}/\mathrm{CC})/T} \tag{3a}$$

$$\mathrm{TPC} = \mathrm{CIC}^{*}\mathrm{ECG}^{T} + \sum_{n=0}^{T} \mathrm{NCPR}^{*}\mathrm{NCG}^{T-n} \tag{5}$$

$\mathrm{NCPR} = \mathrm{PCPR} * \mathrm{NC}$
$\mathrm{NC} = P(\mathrm{TER} - \mathrm{CER})/T$
$\mathrm{ECG} = \mathrm{NCG} = [\mathrm{CGR}] * \mathrm{IE}_k$
$\mathrm{CGR} = \mathrm{PEG}_K + \mathrm{PPG}_K$

To compute PEG_K, a convergence economic growth model compares the growth path of each African country to the GDP growth path of the United States. This procedure produces an annual GDP growth that reflects that the low-income countries will experience higher future growth relative to the high-income countries. The model uses the 2010 purchasing power parity GDP per capita data (in $USD constant 2010 prices). It begins with a per capita GDP of $46,000 in 2010 in the US, which grows hereafter at 1.5% per annum. Any African country k begins at GDP_k (PPP adjusted country GDP in 2010 $USD).

To compute the per capita GDP growth for a given African country k, the following formula are defined:

$$\log \mathrm{GDP}_k(t) = \ln[\mathrm{GDP}_k(t)]$$

$$\log \mathrm{GDP}_{\mathrm{USA}}(t) = \ln[\mathrm{GDP}_{\mathrm{USA}}(t)]$$

Thus, the gap between country k and the USA is as follows:

$$\log \mathrm{GAP}_{\mathrm{USA\text{-}K}}(t) = \log \mathrm{GDP}_{\mathrm{USA}}(t) - \log \mathrm{GDP}_k(t)$$

The annual growth rate of country k is then defined as follows:

$$\log \mathrm{GDP}_k(t+1) = \log \mathrm{GDP}_k(t) + \mathrm{PGDPG}_{\mathrm{USA}} + 0.014 * \log \mathrm{GAP}_{\mathrm{USA}\text{-}K}(t)$$

$$\mathrm{PEG}_K = \mathrm{Exp}[\log \mathrm{GDP}_k(t+1) - \log \mathrm{GDP}_k(t)] - 1 = \mathrm{Exp}[\mathrm{PGDPG}_{\mathrm{USA}} + 0.014 * \log\mathrm{GAP}_{\mathrm{USA}\text{-}K}(t)] - 1$$

where $PGDP_{USA}$ is the projected per capita GDP growth in the USA (%), PEG_K is the projected per capita economic growth (%/year) in country k, and PPG_K is the projected population growth (%/year) in country k.

Appendix B

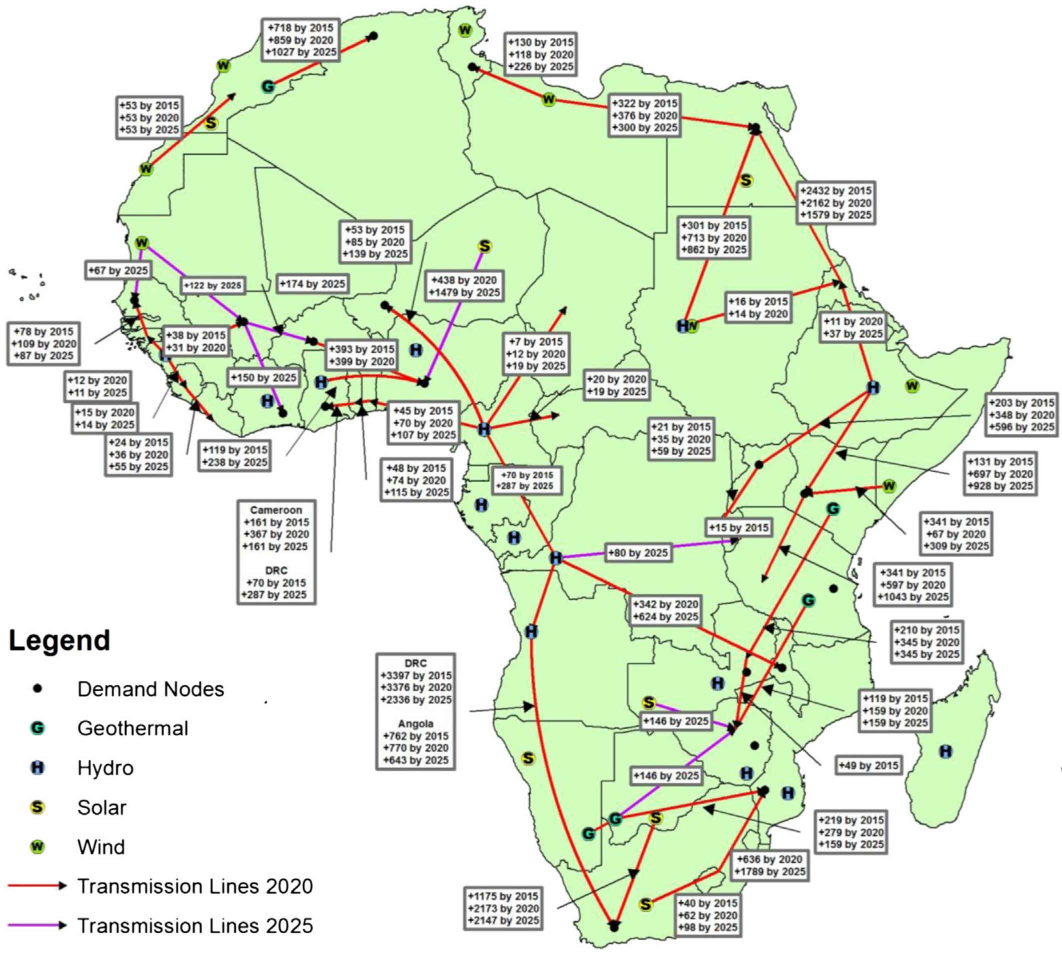

Fig. 8. Full optimal new transmission and trade expansion in MW to meet demand from 2010 to 2025.

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