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Review

An indicative analysis of investment opportunities in the African electricity supply sector — Using TEMBA (The Electricity Model Base for Africa)

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ABSTRACT

Africa is a resource-rich continent but lacks the required power infrastructure. Efforts such as the United Nations Sustainable Energy for All and U.S. President Obama's Power Africa initiatives aim to facilitate much needed investment. However, no systematic national and regional investment outlook is available to analysts. This paper examines indicative scenarios of power plant investments based on potential for electricity trade. OSeMOSYS, a cost-optimization tool for long-term energy planning, is used to develop least cost system configurations. The electricity supply systems of forty-seven countries are modelled individually and linked via trade links to form TEMBA (The Electricity Model Base for Africa). A scenario comparison up to 2040 shows that an enhanced grid network can alter Africa's generation mix and reduce electricity generation cost. The insights have important investment, trade and policy implications, as specific projects can be identified as of major significance, and thus receive political support and funding.

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Introduction

Access to modern energy services is extremely low in a number of African countries, particularly in Sub-Saharan Africa. National electrification rates vary greatly from country to country; for instance, this figure is at 85% in South Africa, while it only reaches 3% and 4% in Central African Republic and Chad respectively. Even within countries, there is great disparity between urban and rural communities; electrification rate in Cameroon ranges from 88% for urban and 17% for rural communities. At the same time, demand of electricity on the whole continent is projected to grow from 385 TWh in 2012 to about 1250 TWh in 2030 and 1870 TWh in 2040. This corresponds to an average annual growth rate of 4.6% in Sub-Saharan Africa, while it reaches 7.6% and 7.1% in East and West Africa respectively (IEA, 2014).

The electricity supply sector in Africa faces two major challenges; (a) to improve access rates and (b) to cope with the rapidly increasing demand for electricity. Extensive investments in generation, transmission, and distribution are needed to address these two challenges. There are a large number of publications that examine the issue of the underdeveloped African power sector. Some provide an overview of the current status of the system and recognize the problem (Eberhard et al., 2008), others argue for action and call for the necessary investments (Eberhard et al., 2011; Foster and Briceño-Garmendia, 2010), while others focus on the required measures and investigate scenarios that will enable universal access to modern energy services (Bazilian et al., 2012; Brew-Hammond, 2010). Relevant to this latter point, a comprehensive review of African energy policies pertaining to sustainable energy development has been conducted to examine whether existing policy making is heading in the right direction (Mandelli et al., 2014). Long-term explorative scenarios have been used by the World Energy Council to conclude that besides introduction of appropriate energy policies, an environment that can attract internal and external capital and innovation is important (Panos et al., 2015). The International Renewable Energy Agency argues that renewable energy integration can reduce the continent's generation cost (IRENA, 2012), while smart-grids are also suggested as way of leapfrogging traditional power system design and accelerating the achievement of electrification targets (Welsch et al., 2013).

The United Nation's Sustainable Energy for All and U.S. President Obama's Power Africa Initiatives offer important impetus. The former has the goals of increasing energy access, improving energy efficiency and doubling Renewable Energy Technology (RET) investment (SE4All, 2015). The latter has similar goals. It focuses explicitly on Africa. It aims to electrify some 60 million homes and support the investment of 30 GW of clean power generation (Power Africa | U.S. Agency for International Development, 2015). As of yet, however, there is no coherent 'by country' and 'by region' set of investment scenarios, nor an open long-term energy planning toolkit that may be used to investigate detailed scenarios.

The purpose of this paper is to examine the potential for and relationship between electricity investments and power trade between countries in Africa, making use of a higher geographical resolution than what has been developed previously (Taliotis et al., 2014a). An open source long-term cost-optimization tool is used to estimate the most economic generation technology mix on a national scale. Two key scenarios, in which the transmission system is either limited to existing and committed projects or expanded, allow the identification of countries with the greatest export potential, as well as those with the largest expected demand for cost-competitive electricity. Beyond the substantial fossil fuel reserves present in specific regions of the continent, there is considerable renewable energy potential (IRENA, 2014), which largely remains unexploited due, in part, to the lack of required infrastructure. This paper identifies areas where extensions would be required in the grid network, so as to unlock part of this potential, thus leading to a cost-optimal growth of the African electricity supply system. Despite the potential for electricity exports from North Africa to Europe (Trieb et al., 2012), the paper's scope does not consider this aspect and only focuses on intra-continental electricity exchanges.

Methodology section of the paper briefly presents the methodology and the adopted model structure. The main results from the selected scenarios are presented in Results and discussion section, where there is also a discussion on the main energy-planning insights offered by the analysis. The paper concludes with a summary of the key outcomes in Conclusions and suggests future steps and model enhancements to build on existing research efforts.

Methodology

The work presented in this paper builds on previous efforts in terms of research scope and model structure (Taliotis et al., 2014a). The following sub-sections describe the methodology followed to develop and apply TEMBA, a model of the African electricity system. The methodology includes details on the model structure, the modelling tool used, and the key assumptions. Further, the model from source code to data is open source to ensure repeatability and access.

OSeMOSYS

The model discussed in this paper, TEMBA, is developed using the Open Source energy MOdelling SYstem (OSeMOSYS) (Howells et al., 2011). OSeMOSYS is a dynamic, bottom-up, multi-year energy system model applying linear optimization techniques. It determines the optimal investment strategy and production mix of technologies and fuels required to satisfy an exogenously defined energy demand. While this is a simplification in the model in that it does not consider demand side management or energy efficiency measures, the aim of the model is to show the cost-optimum supply profile for a specified volume of electricity. Alternative demand scenarios can then be investigated so as to address this issue; this is a planned task for future enhancements of the present study. Technical, economic and environmental implications associated with the identified least-cost energy systems can be easily extracted from the model results. Like other optimisation models, OSeMOSYS assumes a perfect market with perfect competition and foresight. OSeMOSYS has been used to investigate climate resilience of proposed power infrastructure on the African continent (Cervigni et al., 2015), and thus its functionality has been tested in large models in the past.

Model structure

Similar to the model used by Taliotis et al. (2014a), the model structure developed in this paper consists of demand projections and a database of power supply technologies that are characterised by economic, technical and environmental parameters, and information regarding the existing capital stock and its remaining life span. Energy resource prices and quantities are defined by the model user. Furthermore, the model is restricted by so-called "constraints" used to reflect, amongst others, operational requirements, governmental policies, or socio-economic realities. All parameters entered in the modelling framework are time dependent and can be adjusted over the study horizon to represent a variety of potential futures.

Once the country level values have been derived, other past and projected national statistics – including population share between urban and rural populations, electrification rates, share of industrial activity in total GDP, market penetration of certain key technologies and their corresponding energy intensities on a household basis – can be used to split the country level value into the three components under review in this study:

- Heavy industry (e.g. mining), which connects to generation at a high voltage level and generally requires less transmission and no distribution infrastructure;
- Urban residential, commercial, and small industries, which are connected to generation via a more extensive transmission and distribution system with associated higher losses;

• Rural residential, which require even more transmission and distribution infrastructure.

As a driving element of this energy system optimisation framework, the volume of delivered electricity, which accounts for losses between the point of generation and the point of use, as well as the profile of each individual sectorial demand, has a high impact on the final results. Existing demand projections (Sofreco, 2011; IRENA, 2013a, 2013b) are used and calibrated to recorded electricity demands for 2010. Further, considering the uncertainties associated with the projections for national and international macroeconomic parameters, it is important to realise that final values of demand calculation within this study are merely indicative. While using best available data, they should not be considered forecasts. In cases of new industrial sector growth in developing countries for example, the introduction of high energy intensive activities could be responsible for stepwise increases in energy demand from one year to the next. Such changes cannot be captured by demand forecasting methodologies that are simply based on regressions — and assume a smooth evolution of GDP or population.

As shown in Table 1, in order to be able to reach constructive conclusions regarding electricity trade potential across the continent, an improved system resolution is used, where the continent is divided in 45 individual country-level system models; as opposed to the five-region model used by Taliotis et al. (2014a). It should be noted that systems of island countries (i.e. Sao Tome and Principe, Madagascar, Mauritius, Seychelles and Cape Verde) were not included in the analysis as they have no foreseeable trade potential, due to a lack of existing or future grid interconnections. Furthermore, due to lack of data and the relatively small impact of such a small system on the overall trade in Africa, the system of Western Sahara is excluded from the analysis. Similarly, South Sudan is included in the Sudanese system.

Key assumptions

A certain number of assumptions are fundamental in defining the structure and general context of the modelling effort. The following parameters are maintained constant throughout the analysis:

• The real discount rate applied is 5%.
• The monetary unit is 2010 US$.
• The reporting horizon of this study spans from 2010 to 2040. Simulations are undertaken on a yearly basis for the entire model period.
• The modelling framework is extended between 2040 and 2050 in order to avoid so called 'edge-effect' considerations from affecting the reported results.
• The year is represented by 4 characteristic time periods (2 seasons with day and night distinction) per year.
• As mentioned above, OSeMOSYS assumes a perfect market with perfect competition and foresight.
• Transmission and distribution losses are defined on a national level based on historical data. Different efficiency improvements are assumed to be achieved during the model horizon based on each country's current status (Appendix C).

Generation technologies

The model takes into account existing generation capacity, which is incorporated in the model to form the baseline. Additionally, committed future projects are added, while planned uncommitted projects can only be chosen if they are deemed to be part of the cost-optimal solution. A number of centralized and decentralized generation options are considered in the analysis. Specifically these are:

• Distributed diesel internal combustion engines that can serve industrial, urban or rural demand.
• Centralized diesel systems connected to the transmission network.
• Heavy fuel oil-fired power plants connected to the transmission network.
• Open cycle gas turbines connected to the transmission network.
• Combined cycle gas turbines connected to the transmission network.
• Large hydro (dam or run-of-river) connected to the transmission network.
• Small or mini-hydro facilities (<10 MW) that can only supply rural demand for electricity.
• Onshore wind facilities connected to the transmission network. Two options are included here; one with an average capacity factor of 25% and one with 30%.
• Biomass-fired plants connected to the transmission network.
• Large scale solar PV facilities connected to the transmission network.
• Rooftop solar PV facilities that can serve either urban or rural demand. Three options are modelled here; without storage, with 1 kWh battery or with 2 kWh battery.
• Large scale solar CSP connected to the transmission network. This is modelled as three alternatives; without storage, with thermal storage or with gas co-firing.

It should be noted that a learning curve is assumed for renewable energy technologies. This results in decreasing investment costs (See Fig. 1), for which values are taken up from existing literature (IRENA, 2013b).

Scenarios

Currently, grid interconnections between African countries are limited, which limits the possibility for electricity trade. However, this is changing and investments in major infrastructure projects through bilateral power purchase agreements, such as in the case of the Grand

Table 1
Countries included in the model and power pool grouping used by Taliotis et al. (2014a).

Central Africa	Eastern Africa	Northern Africa	Southern Africa	Western Africa
Cameroon (CM)	Burundi (BI)	Algeria (DZ)	Angola (AO)	Benin (BJ)
Central African Rep. (CF)	Djibouti (DJ)	Egypt (EG)	Botswana (BW)	Burkina Faso (BF)
Chad (TD)	Eritrea (ER)	Libya (LY)	Lesotho (LS)	Cote d'Ivoire (CI)
Congo (CG)	Ethiopia (ET)	Mauritania (MR)	Malawi (MW)	Gambia (GM)
Democratic Rep. of Congo (CD)	Kenya (KE)	Morocco (MA)	Mozambique (MZ)	Ghana (GH)
Equatorial Guinea (GQ)	Rwanda (RW)	Tunisia (TN)	Namibia (NA)	Guinea (GN)
Gabon (GA)	Somalia (SO)		South Africa (ZA)	Guinea Bissau (GW)
	Sudan (SD)		Swaziland (SZ)	Liberia (LR)
	Tanzania (TZ)		Zambia (ZM)	Mali (ML)
	Uganda (UG)		Zimbabwe (ZW)	Niger (NE)
				Nigeria (NG)
				Senegal (SN)
				Sierra Leone (SL)
				Togo (TG)

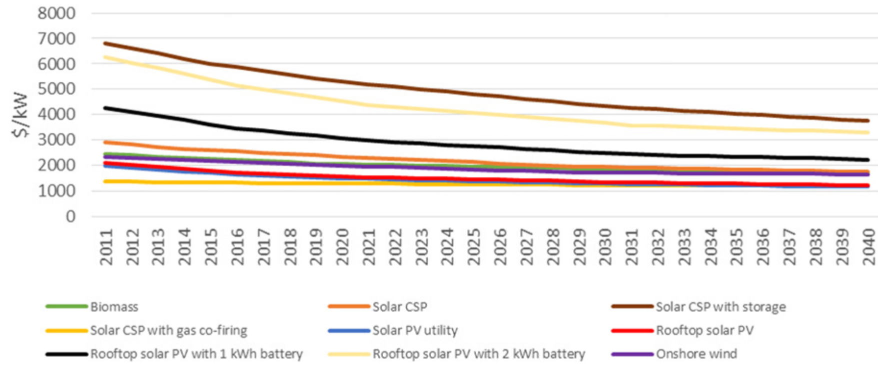

Fig. 1. Renewable energy technology investment cost projections (IRENA, 2013b).

Inga hydropower project (Democratic Republic of the Congo, 2013), can facilitate extensions of existing networks. In order to investigate to what extent grid interconnections affect investments on power generation infrastructure, the following scenarios are developed within the developed modelling framework:

a) *Reference Trade scenario* — In this scenario, existing and committed grid interconnector projects are included in the model. As such, results from this scenario can show what the trade potential will be if no further extensions are promoted on the continental grid network. This provides an indication of future financially-viable power generation infrastructure.
b) *Enhanced Trade scenario* — Additional to existing and committed grid interconnections, planned uncommitted projects are also included, while constraints on trade links are further relaxed from 2025 onwards, thus allowing grid expansion investments and trade to occur between neighbouring countries at cost-optimal levels, as calculated by the model. A comparison with the Reference Trade scenario can identify which additional grid interconnection projects that should be considered across the continent so as to allow further exploitation of cost-competitive energy resources. A detailed breakdown of the transmission capacity differences between the two scenarios is provided in Table C.2 of Appendix C.

Results and discussion

Generation capacity

As a result of the underdeveloped power supply on the continent and the rapidly increasing demand in electricity, investments in power generation capacity are needed. As shown in Fig. 2, total installed capacity in Africa grows from 177 GW in 2015 to 520 and 527 GW by 2030 and 772 and 773 GW by 2040 in the Reference Trade and Enhanced Trade scenarios respectively.

Significant additions are made in all power pools but, comparatively, the most substantial expansion is achieved in Central Africa, where capacity grows by tenfold from 5.2 GW in 2015 to 35 GW and 51 GW by 2040 in the Reference Trade and Enhanced Trade scenarios respectively. Furthermore, in absolute terms, the North African Power Pool experiences the largest extent of capacity additions, reaching 407 GW and 394 GW of total installed capacity by 2040 in the two scenarios. These additions relate primarily to renewable energy technologies; 142 GW of wind, 94 GW of solar thermal and 67 GW of solar PV in the Reference Trade scenario, while in the Enhanced trade scenario, a deployment of 147 GW of wind, 87 GW of solar thermal and 66 GW of solar PV occurs. This large expansion of the North African power infrastructure relates to the much faster energy demand growth projected for the region, as compared to Sub-Saharan African countries (see Appendix A). A quite diverse technology mix can be observed as investments occur in various technologies in both scenarios; namely hydro, geothermal, biomass, solar thermal, wind, as well as small amounts of coal. In the case of West Africa, there are significant investments in solar thermal, while installed capacities of hydro, gas facilities and solar PV increase by 2040 in the two scenarios.

Electricity generation mix

In the case of the Reference Trade scenario (Fig. 3), it is interesting to observe that, as mentioned in previous papers (Taliotis et al., 2014a, 2014b), the Central African Power Pool exports a significant volume of its electricity. Of the 111 TWh and 158 TWh that are generated in 2030 and 2040 in the power pool, 42 and 50 TWh are exported respectively beyond CAPP to other regions. In the case of East Africa, even though the power pool exports 2 TWh in 2020, it imports 4 TWh and 6 TWh in 2030 and 2040 respectively. During the model period, countries in EAPP continue to rely to a large extent on hydropower generation. However, they also increase share of generation from non-hydro renewable sources, with geothermal, solar thermal and solar PV being the most significant renewable energy technologies. Similarly, reflecting the large capacity investments mentioned above, in North Africa the contribution of fossil fuels decreases as variable renewables are used to cover the increasing demand in electricity. At the same time, nuclear energy generation in Egypt corresponds to approximately 9% of the generation in North Africa by 2040. In Southern Africa, electricity demand is met primarily through coal-fired generation and hydro for the majority of the model period, while in the decade 2031–2040 nuclear power, wind and solar thermal increase their contribution. Finally, in the case of Western Africa gas-fired generation continues to hold a significant share, while hydropower and solar thermal expand quite considerably.

When comparing the Reference Trade to the Expanded Trade scenario (Figs. 3–4), there are some noticeable differences, across all power pools. Perhaps the most significant difference is that by 2040, Central African power pool produces up to 80 TWh more in the latter scenario, of which 70 TWh are from hydropower. This added volume of electricity is exported and relates to hydropower generation from the Grand Inga project, and is a clear indication that in the absence of certain grid interconnections, such as the Westcor and ZiZaBoNa projects, this low-cost electricity supply cannot be exploited to its full potential.

A similar observation applies for East Africa, where total generation in 2040 amounts to 26 TWh higher in the Expanded Trade scenario. What's more interesting is that with a larger potential for electricity exchange, the generation mix in the power pool shifts to a certain degree. Particularly, solar thermal, centralized solar PV, gas and coal in the Reference Trade scenario, to a degree become substituted by geothermal, biomass and distributed rooftop PV generation in the Expanded Trade scenario. In North Africa, part of the solar thermal, coal and gas-fired generation is displaced by wind and imports, while in Southern Africa a share from solar thermal, wind and coal-fired generation is replaced

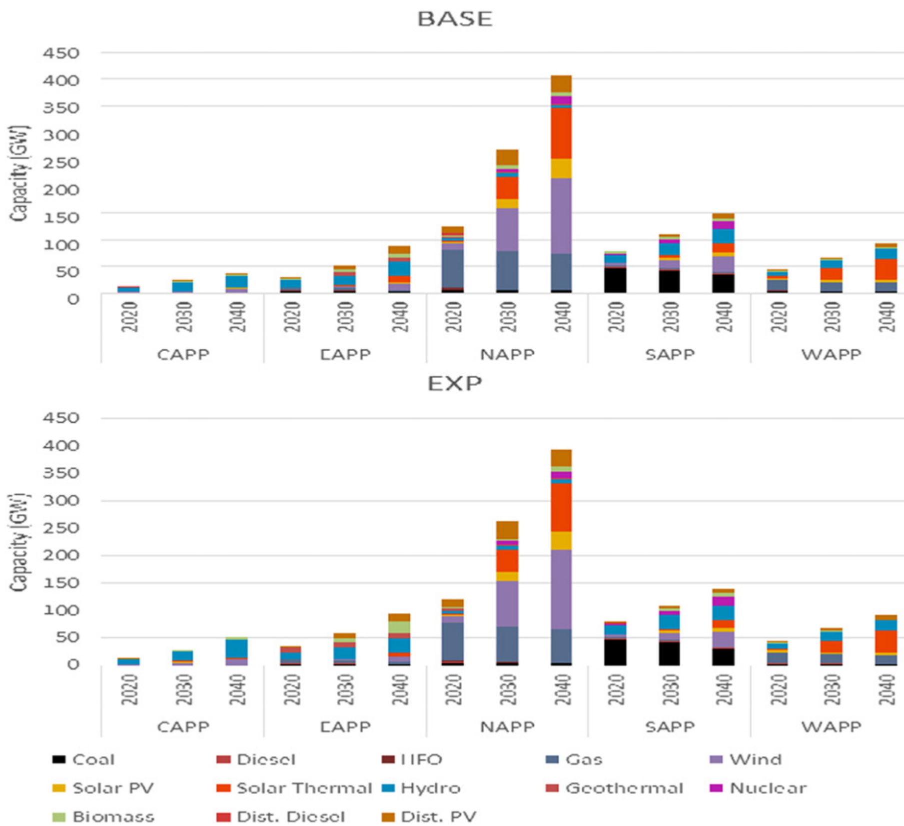

Fig. 2. Evolution of total installed capacity in each power pool in the Reference Trade (top) and Enhanced Trade (bottom) scenarios.

with increased shares of biomass, hydro and imports. In addition, gas-fired generation in West Africa is reduced in the Expanded Trade scenario and is replaced with imported electricity and a small volume of additional solar thermal and biomass-fired generation.

When we look at individual country results (Fig. 5), there are some important dissimilarities between the two scenarios. In the case of the two major consumers of the continent, Egypt and South Africa, a greater reliance on electricity imports occurs in the Expanded Trade scenario. In

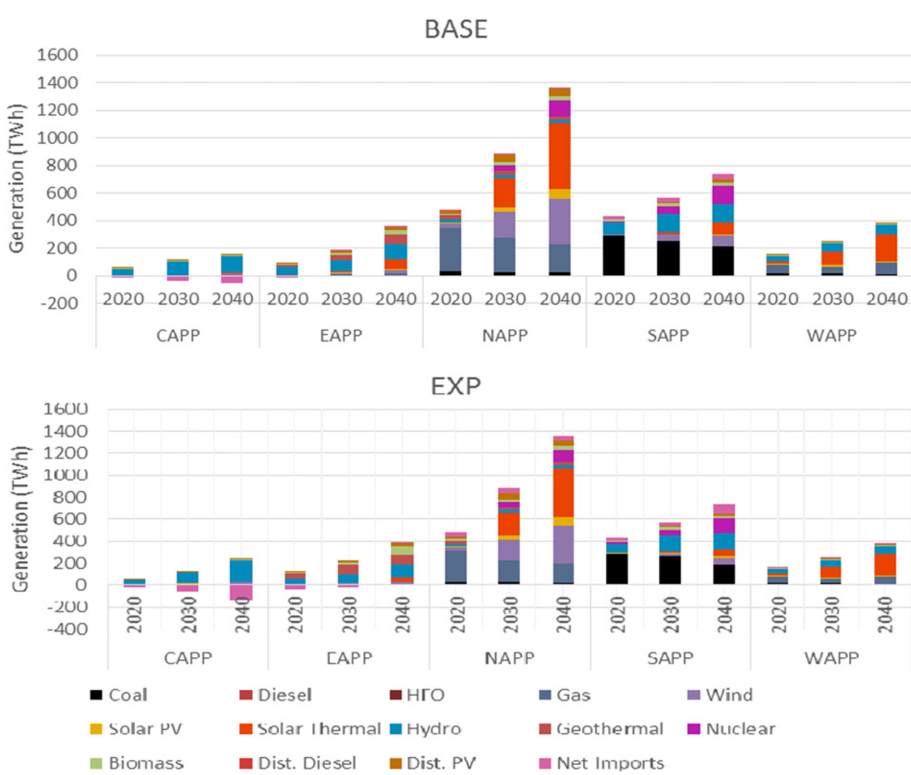

Fig. 3. Evolution of generation mix in each power pool in the Reference Trade (top) and Enhanced Trade (bottom) scenarios.

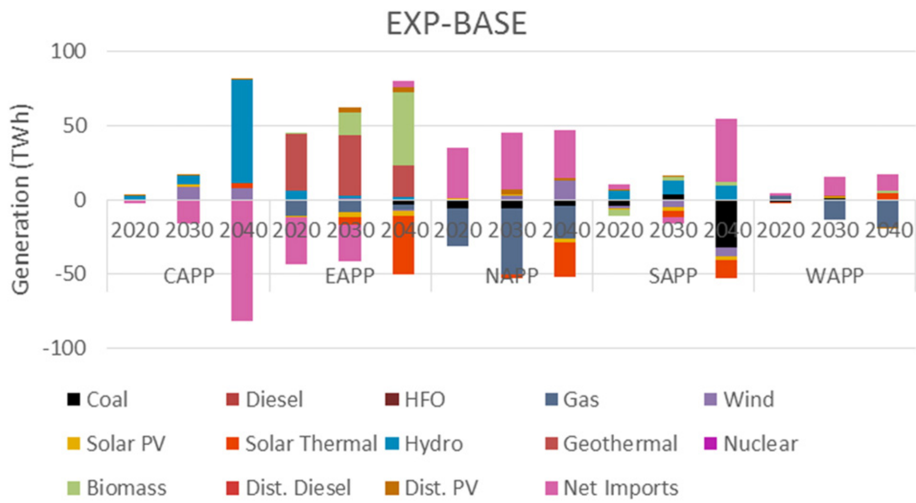

Fig. 4. Differences in generation mix for each power pool in the two scenarios (Expanded minus Reference Trade).

the case of Egypt, minimal imports take place in the Reference Trade scenario, while when trade limitations are relaxed, the country imports about 5% of its demand in 2040. Similarly, South Africa imports an additional 42 TWh in 2040 in the latter scenario, which correspond to roughly 7% of the country's final electricity demand for the same year. Furthermore, a more enhanced grid network also affects smaller nations quite considerably. For instance, Chad, Equatorial Guinea and Eritrea do not trade electricity in the reference case, but once trade links become established they export up to about 33% of their generated electricity by 2040. Such trade opportunities can allow developing countries to improve their power infrastructure and can provide an additional revenue for their economy. Table 2 summarizes the contribution of each technology to the continent's generation mix, while the respective information for each power pool is provided in Appendix D.

Cross-border electricity trade

As shown in Fig. 5, the majority of countries on the continent become divided into net importers or net exporters of electricity, as very few countries do not rely on electricity imports or exports (e.g. Gabon and Somalia). An expansion of the current grid network can help in the reduction of expensive fossil-fired generation, as countries with unexploited renewable energy potential in different sources can actively trade with their neighbours. In this way, foreign investments can be attracted to finance such projects as part of power purchase agreements.

Fig. 6 illustrates electricity trade flows between countries in the Enhance Trade Scenario in 2040; 42 of the 47 modelled countries are involved in exchanges of electricity by 2040. As indicated by the figure, the largest net exporter of electricity on the continent in 2040 is

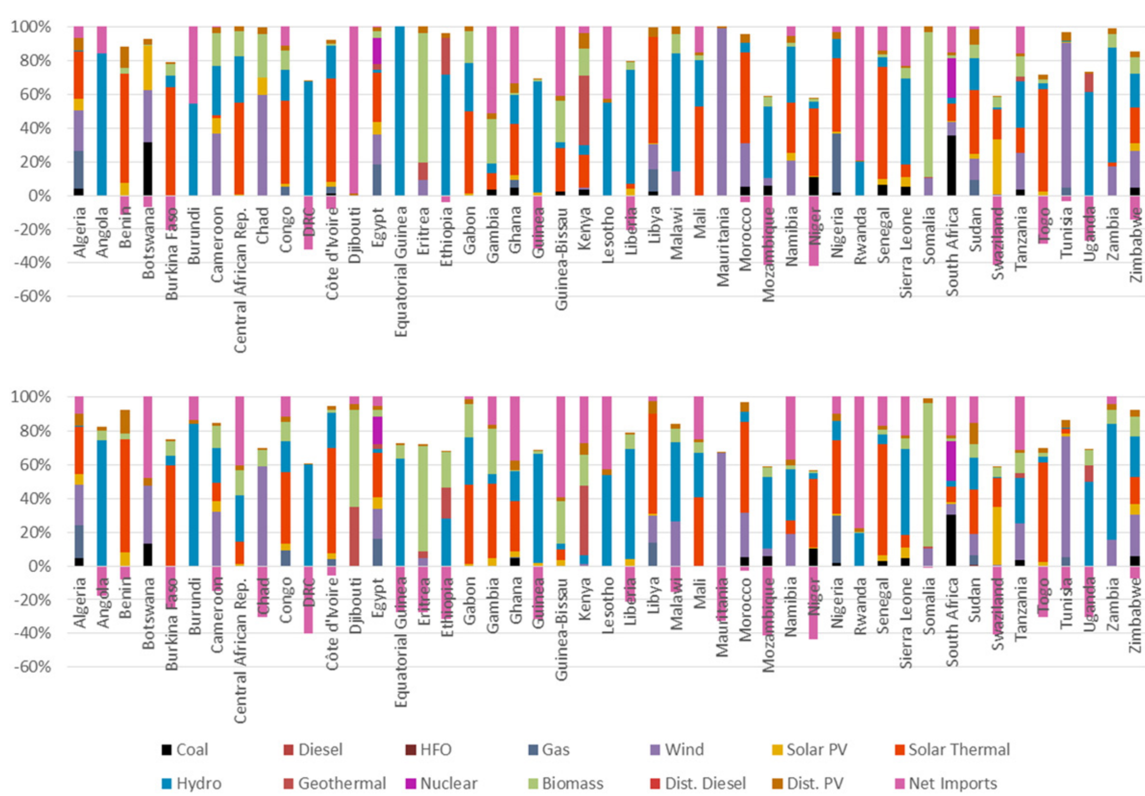

Fig. 5. Evolution of generation mix by country in 2040 for the Reference Trade (top) and Enhanced Trade (bottom) scenarios.

Table 2
Continental generation mix (TWh).

		Biomass	Coal	Solar thermal	Diesel	Dist. diesel	Dist. solar	Gas
Reference	2020	152	1234	83	0	0	102	1404
	2030	280	1090	1180	0	0	301	1141
	2040	385	913	2946	0	0	411	1089
Enhanced	2020	137	1188	81	0	0	103	1282
	2030	342	1084	1135	0	0	333	904
	2040	577	769	2709	0	0	431	931
		Geothermal	HFO	Hydro	Nuclear	Solar	Wind	
Reference	2020	141	0	880	57	72	129	
	2030	234	0	1434	356	211	829	
	2040	314	0	1701	910	376	1603	
Enhanced	2020	281	0	934	57	70	123	
	2030	381	0	1497	356	201	853	
	2040	388	1	1993	910	343	1654	

the Democratic Republic of Congo, with a total export volume of 115 TWh, due to the assumed development of the Grand Inga project (total addition of 29 GW). Additionally, the largest importer is South Africa, which has net imports of 129 TWh in 2040; this corresponds to about 23% of the country's final electricity demand.

Another important aspect to note is that of transit countries. As indicated by Fig. 6, Sudan plays a significant role in this regard. In 2040, 49 TWh are imported by Sudan from Ethiopia, of which 40 TWh are further exported to Egypt; this corresponds to about 5% of Egyptian final electricity demand in that year. A similar situation occurs with electricity from DRC, which exports significant volumes of electricity to a number of countries that channel electricity to South Africa; this includes Angola, Botswana, Namibia, Zambia and Zimbabwe and proves the significance of the proposed power corridors. It should be noted that Egypt and South Africa currently are and projected to remain the biggest electricity consumers on the African continent, accounting for 26% and 19% of the total electricity consumption in Africa in 2040 respectively. This highlights the importance of an enhanced role taken up by the African Power Pools. Even though currently bilateral purchase agreements seem to be the norm (Democratic Republic of the Congo, 2013), if such large volumes of electricity are to be traded across the continent, the existing power pool framework will have to be improved.

Financial requirements

In order to achieve a greater grid integration on the continent, investments are required. This would mean a slightly higher investment level than in a Reference Trade scenario, of which the majority would

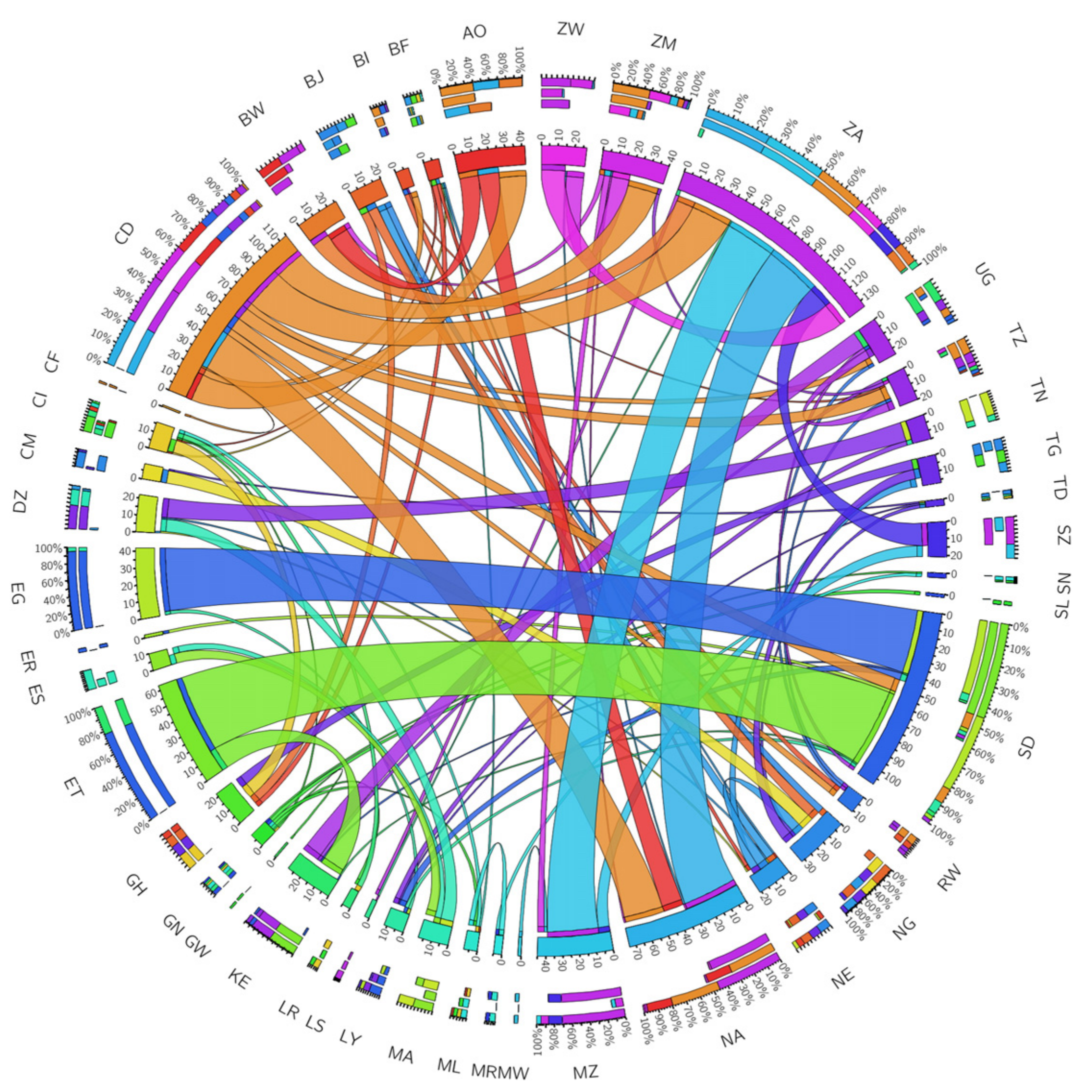

Fig. 6. Exchange of electricity across the continent in 2040 (TWh) in the Enhanced Trade scenario (country code is given in Table A.1 of Appendix A). Corresponding figures for each scenario for years 2020, 2030 and 2040 are provided in Appendix E.

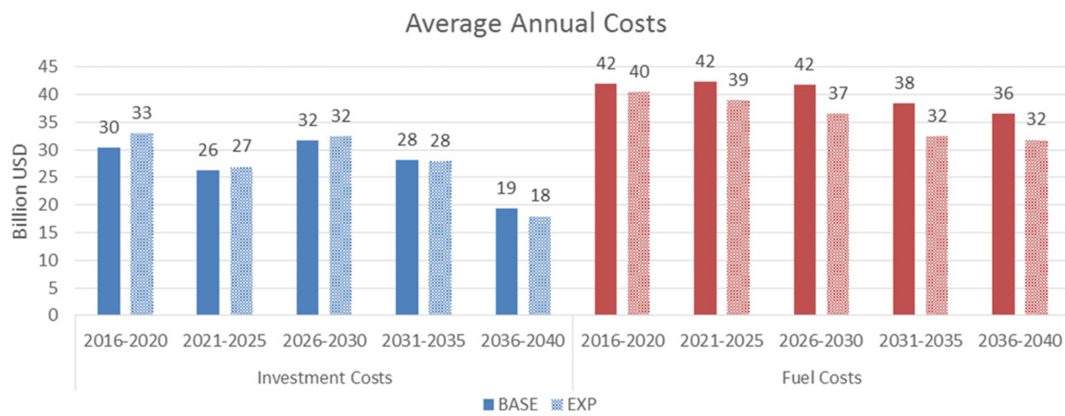

Fig. 7. Comparison of total investment cost and fuel costs in the two scenarios.

be on generation infrastructure, but this has the potential of lowering total system costs due to the reduction of fuel consumption. As shown in Fig. 7, even though the first few years would be more capital intensive, fuel savings early on in the period and even more so later on, would surpass investment requirements. During 2021–2040, annual total system cost savings would range between 2–6 billion USD. This figure is even more promising than the annual savings of 2 billion USD that were estimated to be achieved through a pan-African grid as reported in the literature (Foster and Briceño-Garmendia, 2010). The previous estimate mentioned here was based on a model that had lower technological detail and only considered four options for thermal generation (natural gas, coal, heavy fuel oil and diesel) and four renewable energy technology options (large hydro, mini-hydro, solar photovoltaics and geothermal) (Vennemo and Rosnes, 2009). The greater detail provided in the TEMBA model, along with updated renewable energy technology cost projections, may explain this difference in expected savings.

Conclusions

The work presents indicative coherent national, regional and continental investment and trade scenarios for Africa. Continuing current trends and assuming an efficient market, RET investments (including large hydro) of between 573–589 GW are anticipated. Significant efficiency gains can be achieved by increasing trade and transmission investments. Comparative RET investments are anticipated to account for 77% and 79% of new investment in the Reference and Expanded Trade scenarios respectively. This depends strongly on assumptions relating to fossil fuel price, the speed at which RET technology will develop and the degree of interconnection allowed.

With this in mind there are key investment, trade and policy recommendations. From an investment point of view there would appear to be potential for both coordinated trade and power plant investments as well as nationally focused investment (with limited trade). Trade is affected at two levels. Firstly, increased transmission has the potential to unlock power generation resources in one region and lower system costs across the continent. Secondly, as fuel costs decrease with increased RET penetration, there is potential to free up domestic fossil fuel resources for other uses or export. The latter has geopolitical and revenue raising implications. From a policy point of view this work identifies indicative investments by country, timing and average operation. Such information is useful to target specific support mechanisms. These might include power purchase agreements, joint infrastructure development to the development of specific sets of projects.

The model from source code of the programming language to the data input is open source.[1] This is important as it provides for repeatability and open access. It is potentially helpful not only from an academic point of view, but also helpful in terms of providing a starting point for national, regional, investment and policy focused scenario generation. We have investigated a very narrow set of scenarios, with the intention of demonstrating the TEMBA toolkit. However, a series of investigations, extensions and revisions will now be possible that the structure of the model has been created and initial input data have been gathered.

Investigations required to provide this support may include: explicit analysis of security and trade by country; developing regional integrated GHG mitigation cost curves and emissions trade; calculating power supply costs by country and region; understanding the impact of local or technology specific constraints, such as hydro generation under a changing climate, developing deep analysis of potential intermittency[2] and transmission constraints associated with increased RET deployment, as well as many others.

The model itself is limited. We deliberately present only part of the picture. The article investigates how an optimal supply scenario might develop to meet exogenously defined growing demand. However, future analysis may focus on important aspects such as: how much electricity demand is suppressed; how price elasticities might evolve as a function of industrial split; evaluating impacts of higher or lower electrification levels; amongst many other drivers. These analyses may add pieces to the puzzle that illustrate how to analyse the energy system in its entirety. As such, future iterations of TEMBA will be pursued. An important enhancement would be a greater temporal resolution, where a larger number of time-slices could be used. This would allow a more accurate estimation of potential for electricity exchanges between countries, as periods of low and high demand would be better represented. This will lead to significantly higher model calculation times, which was a limitation in the present study.

This paper illustrates the importance of carrying out such analytical exercises when assessing cost-competitiveness of power infrastructure projects across the African continent. However, this competence needs strengthening within national governments in many of the involved countries, in trading partners and in international agencies. Since TEMBA is an open-source tool, it could (in selected instances) form the basis upon which active engagement of pan-African initiatives, regional power pools, national authorities and other relevant stakeholders can be sought. The open approach might also help provide a means by which contributions by pan-African regional and national experts are gathered and assimilated.

The openness and removal of barriers to entry implies that scenarios reflecting an inclusive African Energy development agenda can be explored autonomously or within partnerships — with little upfront cost. International organizations might facilitate this by supporting training on the use of such tools and open data initiatives, thus ensuring proper knowledge building and transfer. Eventually, self-sustaining expertise might be developed within relevant authorities and centres.

[1] OSeMOSYS code and TEMBA data file are available at www.osemosys.org.

[2] See for example: Welsch (2013), Welsch et al. (2014).

Acknowledgements

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Appendix A. Final electricity demand projections

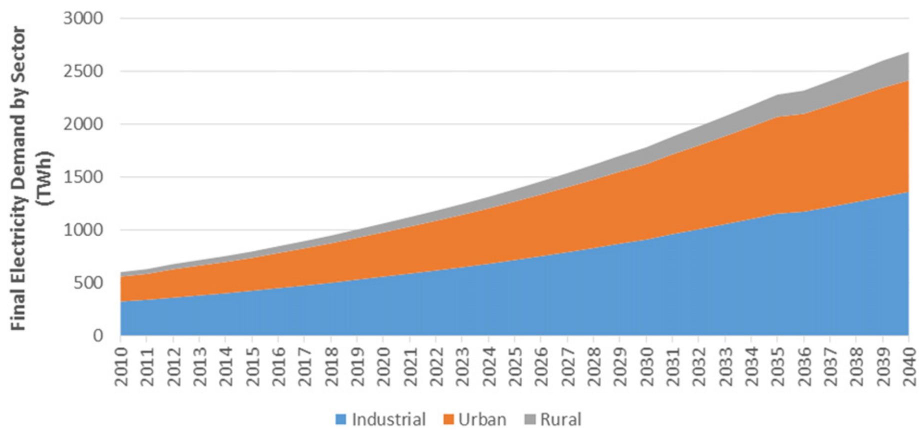


Fig. A.1. Final electricity demand across Africa by sector.

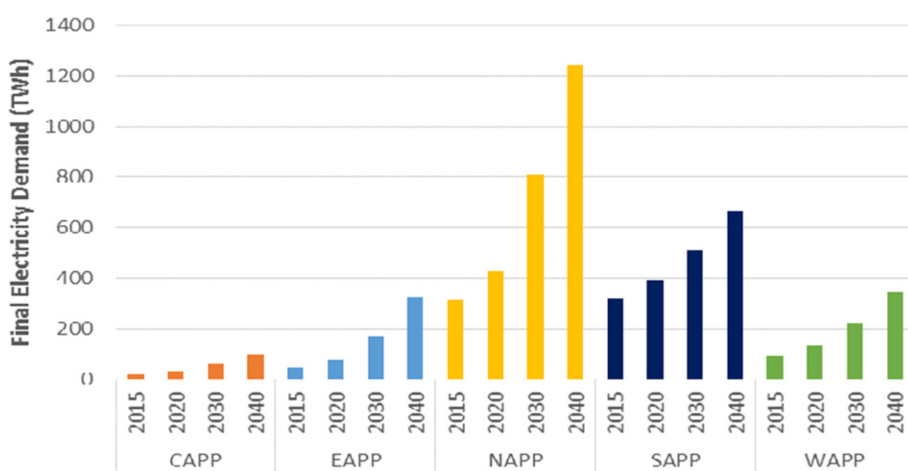


Fig. A.2. Final electricity demand across power pools.

Table A.1
Final electricity demands in each country (TWh).

	Code	2010	2015	2020	2025	2030	2035	2040
Angola	AO	5.1	7.9	10.8	14.3	18.2	20.7	23.9
Burkina Faso	BF	0.7	1.0	1.5	2.1	3.0	4.3	5.8
Burundi	BI	0.1	0.2	0.4	0.6	1.0	1.4	1.9
Benin	BJ	1.1	1.7	2.6	3.7	5.0	7.1	9.3
Botswana	BW	3.7	4.7	6.2	6.7	7.1	7.3	7.5
Congo, the Democratic Republic of the	CD	7.6	11.9	18.2	26.8	36.2	42.9	48.7
Central African Republic	CF	0.1	0.2	0.4	0.8	1.3	1.8	2.5
Congo	CG	0.5	0.6	0.9	1.4	2.1	3.0	4.2
Côte d'Ivoire	CI	4.7	6.4	9.0	11.8	15.0	19.5	24.1
Cameroon	CM	4.9	6.6	9.2	12.8	17.7	24.3	33.1
Djibouti	DJ	0.4	0.7	0.9	1.0	1.1	1.2	1.3
Algeria	DZ	33.8	43.4	61.6	91.1	130.1	179.0	187.7
Egypt	EG	137.1	185.4	246.7	324.7	423.9	547.5	691.3
Eritrea	ER	0.3	0.4	0.6	0.9	1.3	1.7	2.3
Ethiopia	ET	4.8	8.9	14.5	21.6	31.8	46.9	65.2

Table A.1 (*continued*)

	Code	2010	2015	2020	2025	2030	2035	2040
Gabon	GA	1.4	1.6	2.1	2.7	3.5	4.4	5.6
Ghana	GH	8.7	12.0	16.5	22.0	29.5	41.0	53.1
Gambia	GM	0.2	0.5	0.7	0.9	1.1	1.3	1.6
Guinea	GN	0.4	1.2	6.2	7.0	7.6	8.3	9.0
Equatorial Guinea	GQ	0.1	0.1	0.1	0.2	0.2	0.3	0.3
Guinea-Bissau	GW	0.1	0.1	1.0	1.1	1.3	1.4	1.6
Kenya	KE	8.1	13.8	20.8	30.8	45.3	65.3	89.3
Liberia	LR	0.0	1.3	2.0	2.1	2.3	2.5	2.7
Lesotho	LS	0.5	0.6	0.8	0.9	1.2	1.5	1.8
Libya	LY	26.5	33.8	47.7	70.4	100.4	137.9	144.6
Morocco	MA	23.4	31.3	46.6	70.5	102.6	143.6	150.4
Mali	ML	0.9	1.9	3.0	3.8	4.7	5.8	6.9
Mauritania	MR	0.8	1.0	1.4	1.9	2.5	3.3	4.5
Malawi	MW	1.3	2.0	2.6	3.4	4.4	5.7	7.1
Mozambique	MZ	3.2	4.2	5.2	6.4	7.9	9.8	11.8
Namibia	NA	3.2	3.7	4.4	5.2	6.1	7.2	8.3
Niger	NE	0.7	1.1	1.4	1.8	2.2	2.8	3.3
Nigeria	NG	32.9	59.4	80.6	110.2	136.0	169.2	203.7
Rwanda	RW	0.3	0.6	1.0	1.5	2.2	3.1	4.1
Sudan	SD	6.1	12.2	21.4	34.9	54.3	80.0	110.7
Sierra Leone	SL	0.5	1.3	5.6	5.9	6.1	6.3	6.6
Senegal	SN	2.1	3.1	4.6	6.2	8.1	10.7	13.4
Somalia	SO	0.3	0.5	0.8	1.1	1.6	2.1	2.8
Swaziland	SZ	1.1	1.3	1.5	1.6	1.7	1.9	2.0
Chad	TD	0.2	0.3	0.5	0.8	1.6	2.8	4.3
Togo	TG	0.8	1.3	2.0	2.8	3.8	5.4	7.1
Tunisia	TN	13.3	18.1	26.2	37.7	52.1	69.4	69.3
Tanzania, United Republic of	TZ	4.0	6.3	9.6	14.0	20.7	27.4	33.8
Uganda	UG	2.9	3.8	5.1	6.9	8.9	11.2	13.7
South Africa	ZA	232.1	271.9	324.6	369.3	415.0	474.5	520.5
Zambia	ZM	11.3	14.8	19.4	25.1	32.5	42.6	53.2
Zimbabwe	ZW	8.7	10.9	13.4	16.5	20.3	25.1	30.1

Appendix B. Techno-economic parameters

Table B.1
Technical parameters for power generating technologies.

Technology	Variable O&M	Investment cost	Life	Load factor	Efficiency	Construction time
	$/MWh	$/kW	Yrs			Yrs
Diesel centralized	17	1070	25	80%	35%	2
Diesel 100 kW system (industry)	55	659	20	80%	35%	0
Diesel/Gasoline 1 kW system (residential/commercial)	33	692	10	72%	21%	0
HFO	15	1350	25	80%	35%	2
OCGT	20	603	25	85%	30%	2
CCGT	3	1069	30	85%	48%	3
Supercritical coal	14	2403	35	85%	37%	4
Small hydro	5	4000	50	17%	N/A	2
Biomass	20	2500	30	50%	38%	4
Wind onshore	16	2000	25	Varies	N/A	1
Solar PV (utility)	20	2000	25	25%	N/A	1
Solar PV (roof top)	24	2100	25	20%	N/A	1
PV with 1 h battery	24	4258	25	22.5%	N/A	1
PV with 2 h battery	24	6275	25	25%	N/A	1
Solar thermal no storage	22	2910	25	35%	N/A	1
Solar thermal with storage	19	5238	25	63%	N/A	1
Solar thermal with gas co-firing	19	1374	25	85%	53%	2

Table B.2
Fuel costs.

USD/GJ	2015	2020	2030	2040
Biomass	1.50	1.50	1.50	1.50
Coal (domestic)	2.50	3.00	4.00	4.00
Coal (imported)	3.75	4.50	6.00	6.00
Crude oil	18.77	20.47	23.03	23.03
Diesel (coastal)	24.10	26.30	29.60	29.60
Diesel (inland)	27.70	30.20	34.00	34.00
Gas (domestic)	9.00	9.50	11.00	11.00
Gas (imported)	11.65	12.30	14.20	14.20
Heavy fuel oil (coastal)	14.20	15.50	17.40	17.40
Heavy fuel oil (inland)	17.90	19.50	22.00	22.00

Appendix C. Transmission and distribution

Table C.1
Losses in national transmission and distribution networks.

	Transmission	Distribution								
		Industry			Urban			Rural		
		2010	2020	2040	2010	2020	2040	2010	2020	2040
Angola	5.0%	2.0%	2.0%	1.0%	20.0%	15.0%	8.0%	30.0%	20.0%	20.0%
Burkina Faso	5.0%	1.0%	1.0%	1.0%	17.0%	10.0%	8.0%	25.0%	20.0%	20.0%
Burundi	1.4%	1.1%	1.1%	1.1%	1.6%	1.6%	1.6%	12.0%	12.0%	12.0%
Benin	5.0%	1.0%	1.0%	1.0%	17.0%	10.0%	8.0%	25.0%	20.0%	20.0%
Botswana	5.0%	3.0%	2.0%	1.0%	15.0%	10.0%	8.0%	20.0%	20.0%	20.0%
Congo, the Democratic Republic of the	5.0%	3.0%	2.0%	1.0%	25.0%	10.0%	8.0%	20.0%	20.0%	20.0%
Central African Republic	1.4%	1.1%	1.1%	1.1%	1.6%	1.6%	1.6%	12.0%	12.0%	12.0%
Congo	1.4%	1.1%	1.1%	1.1%	1.6%	1.6%	1.6%	12.0%	12.0%	12.0%
Côte d'Ivoire	5.0%	1.0%	1.0%	1.0%	17.0%	10.0%	8.0%	25.0%	20.0%	20.0%
Cameroon	1.4%	1.1%	1.1%	1.1%	1.6%	1.6%	1.6%	12.0%	12.0%	12.0%
Djibouti	2.3%	0.4%	0.4%	0.4%	3.6%	3.6%	3.6%	12.0%	12.0%	12.0%
Algeria	5.0%	2.0%	2.0%	1.0%	20.0%	15.0%	8.0%	30.0%	20.0%	20.0%
Egypt	3.6%	3.1%	3.1%	3.1%	1.3%	1.3%	1.3%	12.0%	12.0%	12.0%
Eritrea	5.0%	2.0%	2.0%	1.0%	20.0%	15.0%	8.0%	30.0%	20.0%	20.0%
Ethiopia	3.4%	0.1%	0.1%	0.1%	4.4%	4.4%	4.4%	12.0%	12.0%	12.0%
Gabon	1.4%	1.1%	1.1%	1.1%	1.6%	1.6%	1.6%	12.0%	12.0%	12.0%
Ghana	5.0%	1.0%	1.0%	1.0%	17.0%	10.0%	8.0%	25.0%	20.0%	20.0%
Gambia	5.0%	1.0%	1.0%	1.0%	17.0%	10.0%	8.0%	25.0%	20.0%	20.0%
Guinea	5.0%	1.0%	1.0%	1.0%	17.0%	10.0%	8.0%	25.0%	20.0%	20.0%
Equatorial Guinea	1.4%	1.1%	1.1%	1.1%	1.6%	1.6%	1.6%	12.0%	12.0%	12.0%
Guinea-Bissau	5.0%	1.0%	1.0%	1.0%	17.0%	10.0%	8.0%	25.0%	20.0%	20.0%
Kenya	5.3%	0.7%	0.7%	0.7%	9.6%	9.6%	9.6%	12.0%	12.0%	12.0%
Liberia	5.0%	1.0%	1.0%	1.0%	17.0%	10.0%	8.0%	25.0%	20.0%	20.0%
Lesotho	5.0%	2.0%	2.0%	1.0%	12.0%	10.0%	8.0%	25.0%	20.0%	20.0%
Libya	5.0%	2.0%	2.0%	1.0%	20.0%	15.0%	8.0%	30.0%	20.0%	20.0%
Morocco	5.0%	2.0%	2.0%	1.0%	20.0%	15.0%	8.0%	30.0%	20.0%	20.0%
Mali	5.0%	1.0%	1.0%	1.0%	17.0%	10.0%	8.0%	25.0%	20.0%	20.0%
Mauritania	5.0%	2.0%	2.0%	1.0%	20.0%	15.0%	8.0%	30.0%	20.0%	20.0%
Malawi	5.0%	2.0%	2.0%	1.0%	20.0%	10.0%	8.0%	30.0%	20.0%	20.0%
Mozambique	5.0%	5.0%	4.0%	2.0%	30.0%	15.0%	8.0%	30.0%	20.0%	20.0%
Namibia	5.0%	2.0%	2.0%	1.0%	20.0%	10.0%	8.0%	25.0%	20.0%	20.0%
Niger	5.0%	1.0%	1.0%	1.0%	17.0%	10.0%	8.0%	25.0%	20.0%	20.0%
Nigeria	5.0%	1.0%	1.0%	1.0%	17.0%	10.0%	8.0%	25.0%	20.0%	20.0%
Rwanda	1.8%	0.1%	0.1%	0.1%	0.7%	0.7%	0.7%	12.0%	12.0%	12.0%
Sudan	7.0%	2.4%	2.4%	2.4%	10.5%	10.5%	10.5%	12.0%	12.0%	12.0%
Sierra Leone	5.0%	1.0%	1.0%	1.0%	17.0%	10.0%	8.0%	25.0%	20.0%	20.0%
Senegal	5.0%	1.0%	1.0%	1.0%	17.0%	10.0%	8.0%	25.0%	20.0%	20.0%
Somalia	5.0%	2.0%	2.0%	1.0%	20.0%	15.0%	8.0%	30.0%	20.0%	20.0%
Swaziland	5.0%	2.0%	2.0%	1.0%	15.0%	10.0%	8.0%	20.0%	20.0%	20.0%
Chad	1.4%	1.1%	1.1%	1.1%	1.6%	1.6%	1.6%	12.0%	12.0%	12.0%
Togo	5.0%	1.0%	1.0%	1.0%	17.0%	10.0%	8.0%	25.0%	20.0%	20.0%
Tunisia	5.0%	2.0%	2.0%	1.0%	20.0%	15.0%	8.0%	30.0%	20.0%	20.0%
Tanzania, United Republic of	5.0%	2.0%	2.0%	1.0%	17.0%	10.0%	8.0%	25.0%	20.0%	20.0%
Uganda	2.3%	0.4%	0.4%	0.4%	3.5%	3.5%	3.5%	12.0%	12.0%	12.0%
South Africa	5.0%	1.0%	1.0%	1.0%	17.0%	10.0%	8.0%	25.0%	20.0%	20.0%
Zambia	5.0%	4.0%	3.0%	1.0%	25.0%	15.0%	8.0%	30.0%	20.0%	20.0%
Zimbabwe	5.0%	2.0%	2.0%	1.0%	17.0%	12.0%	8.0%	20.0%	20.0%	20.0%

Table C.2
Cross-border electricity interconnections considered in the model. All of these are included in the Enhanced Trade scenario and indication is provided as regards to the Reference Trade scenario.

From	To	Capacity (MW)	Investment cost ($/kW)	Status	First year	Included in Reference Trade scenario	Comments
Angola	Botswana	1500	224	Planned	2020	No	Westcor project (IRENA, 2013a)
Angola	DRC	2100	137	Planned	2016	Partly — 600 MW	600 MW committed (2016) and 1500 MW of Westcor uncommitted (2020) (IRENA, 2013a)
Angola	Namibia	1900	240	Planned	2016	No	400 MW planned (2016) and 1500 MW of Westcor uncommitted (2020) (IRENA, 2013a)
Angola	Zambia	1000	1641	Assumed	2025	No	
Burkina Faso	Benin	300	746	Assumed	2025	No	
Burkina Faso	Mali	306	574	Planned	2015	No	Inter-zonal transmission hub (IRENA, 2013b)

Table C.2 (*continued*)

From	To	Capacity (MW)	Investment cost ($/kW)	Status	First year	Included in Reference Trade scenario	Comments
Burkina Faso	Togo	300	746	Assumed	2025	No	
Burundi	Rwanda	430	105	Existing		Partly — 100 MW	100 MW relate to an existing interconnection. 330 MW expansion in 2015 (EAPP and EAC, 2011)
Burundi	Tanzania	100	171	Assumed	2025	No	
Benin	Ghana	655	180	Assumed	2025	No	
Benin	Togo	300	142	Assumed	2025	No	
Botswana	Namibia	2100	75	Planned	2018	Partly — 1500 MW	300 MW (committed in 2018), planned ZiZaBoNa project (1500 MW in 2020) and 300 MW in 2028 (IRENA, 2013a; SAPP, 2014)
Botswana	South Africa	1300	205	Existing		Partly — 800 MW	800 MW relate to an existing interconnection. 500 MW of planned interconnection in 2012 (IRENA, 2013a; SAPP, 2014)
Botswana	Zambia	600	1044	Assumed	2025	No	
Botswana	Zimbabwe	1250	75	Existing		Partly — 650 MW	650 MW relate to an existing interconnection. 600 MW of ZiZaBoNa project (300 MW in 2018 and 300 MW in 2028) (SAPP, 2014)
DRC	Burundi	475	107	Existing		Yes	145 MW of an existing interconnection plus an addition of 330 MW in 2014 (EAPP and EAC, 2011)
DRC	Central Af. Rep.	100	203	Assumed	2025	No	
DRC	Congo	60		Existing		Yes	
DRC	Namibia	3000	203	Planned	2020	Partly — 1500 MW	Westcor project (IRENA, 2013a)
DRC	Rwanda	527	71	Existing		Yes	157 MW relate to an existing interconnection. 370 MW addition in 2014 (EAPP and EAC, 2011; IRENA, 2015)
DRC	Sudan	1000	2238	Assumed	2025	No	
DRC	Tanzania	1000	603	Assumed	2025	No	
DRC	Uganda	500	603	Assumed	2025	No	
DRC	South Africa	3000	1405	Planned	2023	Partly — 2500 MW	Refers to interconnector that will take Grand Inga's electricity to South Africa
DRC	Zambia	2310	603	Existing		Partly — 810 MW	310 MW relate to an existing interconnection. 500 MW committed in 2017 and 1500 MW planned addition in 2020 relating to 765 kV project (IRENA, 2013a; 2015)
Central Af. Rep.	Congo	100	746	Assumed	2025	No	
Central Af. Rep.	Cameroon	100	746	Assumed	2025	No	
Central Af. Rep.	Sudan	100	2089	Assumed	2025	No	
Central Af. Rep.	Chad	100	821	Assumed	2025	No	
Congo	Cameroon	300	1268	Assumed	2025	No	
Congo	Gabon	600	725	Planned	2020	No	African Energy Corridor
Ivory Coast	Burkina Faso	327		Existing		Yes	IRENA (2013b)
Ivory Coast	Ghana	982	137	Existing		Yes	327 MW of an existing interconnection plus an undergoing addition of 655 MW in 2015 (Coastal Transmission Backbone Subprogram) (IRENA, 2013b)
Ivory Coast	Guinea	500	895	Assumed	2025	No	
Ivory Coast	Liberia	338	177	Committed	2014	Yes	IRENA (2013b)
Cameroon	Gabon	500	522	Assumed	2025	No	
Cameroon	Nigeria	1000	709	Assumed	2025	No	
Cameroon	Chad	125	926	Planned	2020	Yes	Part of Central African Power Interconnection project (PIDA, 2014a)
Djibouti	Eritrea	100	597	Assumed	2025	No	
Djibouti	Somalia	100	1194	Assumed	2025	No	
Algeria	Libya	1000	895	Assumed	2025	No	
Algeria	Morocco	1440	671	Assumed	2025	No	
Algeria	Mali	500	2014	Assumed	2025	No	
Algeria	Mauritania	500	2462	Assumed	2025	No	
Algeria	Niger	300	1865	Assumed	2025	No	
Egypt	Sudan	6000	517	Planned	2016	No	Additions of 2 GW in 2016, 2020 and 2025. Part of North–South Power Transmission corridor (IRENA, 2015)
Spain	Morocco	1400		Existing		Yes	
Ethiopia	Djibouti	180		Existing		Yes	
Ethiopia	Eritrea	200	746	Assumed	2025	No	
Ethiopia	Kenya	2000	423	Planned	2018	No	Part of North–South Power Transmission corridor (IRENA, 2015)
Ethiopia	Sudan	6600	190	Existing		Partly — 200 MW	200 MW relate to an existing interconnection (EAPP and EAC, 2011). Part of North–South Power Transmission corridor. Planned additions of 3.2 GW in 2016, 1.6 GW in 2020 and 1.6 GW in 2025 (IRENA, 2015).
Ethiopia	Somalia	400	1044	Assumed	2025	No	
Gabon	Equatorial Guinea	600	494	Planned	2020	No	Part of Central African corridor and connected to Grand Inga project (PIDA, 2014b)
Ghana	Burkina Faso	332	202	Planned	2017	No	Financing required. Connected to Grand Inga project (IRENA, 2013b)
Ghana	Benin	963	137	Existing		Yes	IRENA (2013b)
Ghana	Togo	963	137	Existing		Yes	IRENA (2013b)
Gambia	Guinea-Bissau	329	275	Planned	2022	Yes	OMVG interconnector (The World Bank, 2015)
Guinea	Mali	321	366	Committed	2020	Yes	Inter-zonal transmission hub (PIDA, 2014b)
Equatorial Guinea	Cameroon	600	244	Planned	2020	No	Part of Central African corridor and connected to Grand Inga project (PIDA, 2014b)
Guinea-Bissau	Guinea	310	585	Planned	2022	Yes	OMVG interconnector (IRENA, 2013b)
Guinea-Bissau	Senegal	100	373	Assumed	2025	No	IRENA (2013b)
Kenya	Sudan	1000	1492	Assumed	2025	No	
Kenya	Somalia	200	865	Assumed	2025	No	

(continued on next page)

Table C.2 (*continued*)

From	To	Capacity (MW)	Investment cost ($/kW)	Status	First year	Included in Reference Trade scenario	Comments
Liberia	Guinea	338	177	Planned	2020	Yes	Part of CLSG interconnector project (WAPP, 2014)
Liberia	Sierra Leone	303	816	Planned	2017	Yes	Construction should have started in 2014 and project is scheduled to be commissioned by 2017 (PIDA, 2014b)
Lesotho	South Africa	360	50	Existing		Partly — 230 MW	230 MW relate to an existing interconnection. Planned addition of 130 MW in 2015 (IRENA, 2013a)
Libya	Egypt	740	1514	Assumed	2025	No	
Libya	Niger	300	2238	Assumed	2025	No	
Libya	Sudan	1000	1492	Assumed	2025	No	
Libya	Chad	200	1492	Assumed	2025	No	
Libya	Tunisia	1000	536	Assumed	2025	No	
Morocco	Algeria	1680	597	Assumed	2025	No	
Mali	Ivory Coast	320	428	Planned	2016	Yes	Inter-zonal transmission hub (IRENA, 2013b). Project is under construction
Mali	Mauritania	500	1044	Assumed	2025	No	
Mali	Niger	500	1015	Assumed	2025	No	
Mali	Senegal	429	288	Existing		Yes	100 MW relate to an existing interconnection (IRENA, 2013b). 329 MW expansion in 2020 (Manantali transmission lines)
Mauritania	Senegal	250	380	Assumed	2025	No	
Malawi	Mozambique	900	117	Planned	2015	No	300 MW addition in 2015 and 600 MW addition in 2017 (PIDA, 2014b)
Malawi	Tanzania	500	895	Assumed	2025	No	
Malawi	Zambia	200	416	Planned	2018	No	IRENA (2013a)
Mozambique	Swaziland	1450		Existing		Yes	SAPP (2014)
Mozambique	Tanzania	1000	1194	Assumed	2025	No	
Mozambique	South Africa	3850	123	Existing		Yes	SAPP (2014)
Mozambique	Zambia	600	1268	Assumed	2025	No	
Mozambique	Zimbabwe	1200	98	Existing		Partly — 700 MW	700 MW relate to an existing interconnection (IRENA, 2015). 500 MW addition planned in 2017 (IRENA, 2013a).
Namibia	South Africa	4050	227	Existing		Partly — 2550 MW	750 MW relate to an existing interconnection (SAPP, 2014). 300 MW addition in 2018 and 3 GW addition in 2020 (1.5 GW for Westcor and 1.5 GW for 765 kV projects) (IRENA, 2013a).
Namibia	Zambia	3800	75	Existing		Partly — 2900 MW	200 MW relate to an existing interconnection (IRENA, 2015). 300 MW addition in 2018 (ZiZaBoNa) (Horvei, 2012) and 3 GW addition in 2020 (1.5 GW for Westcor and 1.5 GW for 765 kV projects) (IRENA, 2013a).
Namibia	Zimbabwe	2100	220	Planned	2018	Partly — 1500 MW	Planned addition of 300 MW in 2018, 1.5 GW in 2020 (765 kV project) and 300 MW in 2028 (IRENA, 2013a)
Niger	Burkina Faso	638	393	Planned	2014	No	North-Core Transmission project (IRENA, 2013b)
Niger	Benin	650	256	Planned	2014	No	North-Core Transmission project (IRENA, 2013b)
Niger	Chad	200	1268	Assumed	2025	No	
Niger	Togo	650	256	Planned	2014	Yes	North-Core Transmission project (IRENA, 2013b)
Nigeria	Benin	1333	255	Existing		Partly — 686 MW	686 MW relate to an existing interconnection. Planned expansion of 647 MW in 2020 (IRENA, 2013b)
Nigeria	Niger	832	219	Existing		Yes	169 MW relate to an existing interconnection. Addition of 663 MW in 2014 (North-Core Transmission) (IRENA, 2013b)
Nigeria	Chad	200	813	Assumed	2025	No	
Nigeria	Togo	1333	255	Existing		Partly — 686 MW	686 MW relate to an existing interconnection. Planned expansion of 647 MW in 2020 (IRENA, 2013b).
Rwanda	Tanzania	200	118	Assumed	2025	No	
Sudan	Eritrea	200	671	Assumed	2025	No	
Sudan	Chad	200	1768	Assumed	2025	No	
Sudan	Uganda	500	1858	Assumed	2025	No	
Sierra Leone	Guinea	334	243	Planned	2014	Yes	Construction should have started in 2014 and project is scheduled to be commissioned by 2017 (IRENA, 2013b)
Senegal	Gambia	341	106	Planned	2017	Yes	OMVG interconnector (IRENA, 2013b; The World Bank, 2015)
Senegal	Guinea	286	1012	Planned	2017	Yes	OMVG interconnector (IRENA, 2013b; The World Bank, 2015)
Togo	Ghana	655	180	Planned	2020	Yes	Part of Coastal Transmission Backbone Subprogram (IRENA, 2013b)
Tunisia	Algeria	1680	597	Assumed	2025	No	
Tanzania	Kenya	1920	77	Planned	2016	Partly — 1520 MW	1520 MW in 2016 and 400 MW in 2017 (ZTK interconnector) (PIDA, 2014b)
Tanzania	Uganda	759	43	Existing		Yes	59 MW relate to an existing interconnection. 700 MW planned addition in 2023 (EAPP and EAC, 2011)
Tanzania	Zambia	400	204	Planned	2017	No	ZTK interconnector (PIDA, 2014b)
Uganda	Kenya	858	161	Existing		Partly — 418 MW	418 MW relate to) an existing interconnection. 440 MW planned expansion in 2023 (IRENA, 2015)
Uganda	Kenya	500	161	Assumed	2025	No	
Uganda	Rwanda	250		Existing		Yes	EAPP and EAC (2011)
South Africa	Swaziland	1900	16	Existing		Partly — 1450 MW	1450 MW relate to an existing interconnection (SAPP, 2014). 450 MW planned expansion in 2018.
South Africa	Zimbabwe	2750	220	Existing		Partly — 1250 MW	600 MW relate to an existing interconnection. 650 MW addition in 2017 and 1.5 GW in 2020 (765 kV line) (IRENA, 2013a).
Zambia	Zimbabwe	2800	440	Existing		Partly — 2200 MW	700 MW relate to an existing interconnection (IRENA, 2015). 300 MW addition planned in 2018, 1.5 GW in 2020 and 300 MW in 2028 (ZiZaBoNa project) (Horvei, 2012).

Appendix D. Generation mix results

Table D.1
Generation mix evolution in each power pool (TWh).

			Biomass	Coal	Solar thermal	Diesel	Dist. diesel	Dist. solar	Gas	Geothermal	HFO	Hydro	Nuclear	Solar	Wind	Net Imports
CAPP	Reference	2020	11	0	0	0	0	2	2	0	0	175	0	2	2	−68
		2030	22	0	5	0	0	4	0	0	0	351	0	5	11	−150
		2040	35	0	25	0	0	7	1	0	0	431	0	13	55	−179
	Enhanced	2020	11	0	0	0	0	2	1	0	0	185	0	2	2	−76
		2030	22	0	2	0	0	5	1	0	0	373	0	13	39	−206
		2040	36	0	37	0	0	7	2	0	0	682	0	13	83	−471
EAPP	Reference	2020	16	7	0	0	0	4	38	53	0	189	0	2	5	−6
		2030	60	7	18	0	0	53	44	146	0	298	0	13	25	13
		2040	126	19	263	0	0	87	40	226	0	418	0	13	94	20
	Enhanced	2020	16	4	0	0	0	3	1	193	0	210	0	0	6	−119
		2030	115	6	0	0	0	65	16	293	0	304	0	0	28	−77
		2040	305	6	122	0	0	98	27	300	1	424	0	0	92	35
NAPP	Reference	2020	46	124	17	0	0	82	1128	88	0	94	0	27	96	14
		2030	86	104	759	0	0	192	894	88	0	94	158	130	664	19
		2040	107	85	1703	0	0	204	747	88	0	94	427	261	1183	10
	Enhanced	2020	46	101	17	0	0	82	1036	88	0	94	0	29	96	136
		2030	86	83	749	0	0	204	734	88	0	94	158	134	674	157
		2040	107	70	1622	0	0	211	668	88	0	94	427	250	1229	126
SAPP	Reference	2020	56	1046	0	0	0	6	0	0	0	277	57	17	27	74
		2030	87	926	53	0	0	26	0	0	0	460	199	34	129	137
		2040	95	767	270	0	0	55	0	0	0	492	483	59	271	159
	Enhanced	2020	41	1032	0	0	0	7	0	0	0	300	57	13	20	86
		2030	94	937	37	0	0	30	0	0	0	496	199	24	112	122
		2040	104	650	228	0	0	57	0	0	0	526	483	50	250	311
WAPP	Reference	2020	23	56	66	0	0	8	236	0	0	145	0	25	0	0
		2030	26	54	345	0	0	26	202	0	0	230	0	29	0	0
		2040	21	42	686	0	0	58	301	0	0	266	0	29	0	0
	Enhanced	2020	23	50	64	0	0	8	244	0	0	145	0	26	0	5
		2030	26	58	346	0	0	28	153	0	0	230	0	30	0	46
		2040	26	42	700	0	0	58	234	0	0	266	0	30	0	41
Africa	Reference	2020	152	1234	83	0	0	102	1404	141	0	880	57	72	129	
		2030	280	1090	1180	0	0	301	1141	234	0	1434	356	211	829	
		2040	385	913	2946	0	0	411	1089	314	0	1701	910	376	1603	
	Enhanced	2020	137	1188	81	0	0	103	1282	281	0	934	57	70	123	
		2030	342	1084	1135	0	0	333	904	381	0	1497	356	201	853	
		2040	577	769	2709	0	0	431	931	388	1	1993	910	343	1654	

Appendix E. Cross-border electricity trade

Table E.1
Exchange of electricity across the continent in 2020 (TWh) in the Reference Trade scenario.

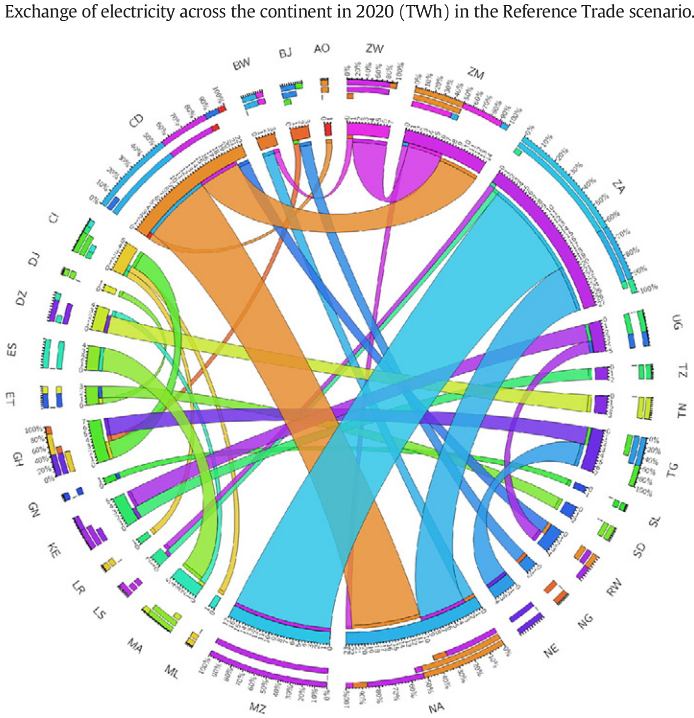


Table E.2
Exchange of electricity across the continent in 2030 (TWh) in the Reference Trade scenario.

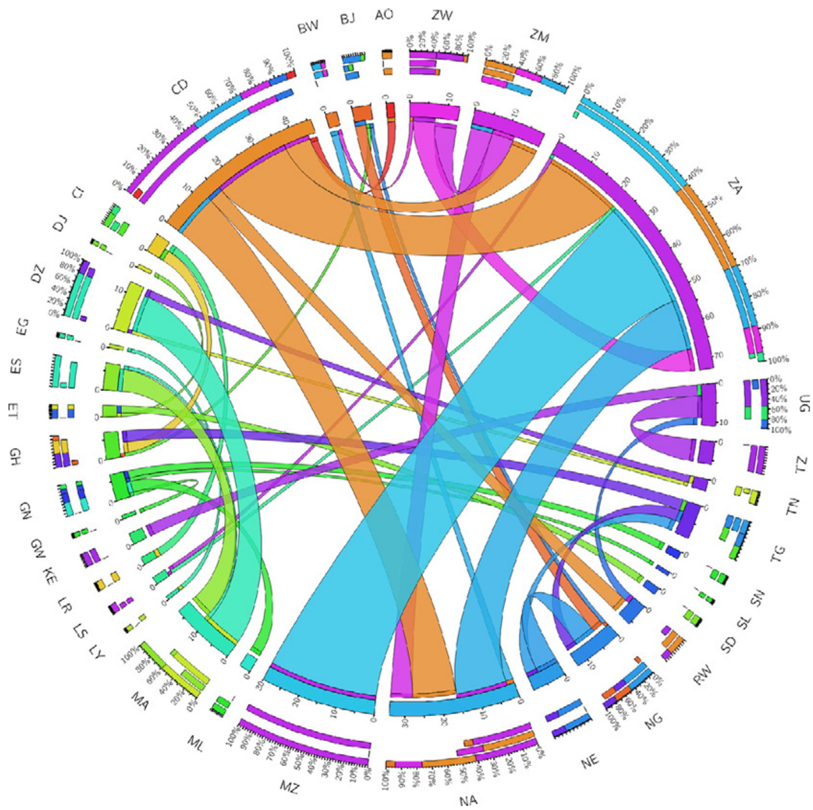


Table E.3
Exchange of electricity across the continent in 2040 (TWh) in the Reference Trade scenario.

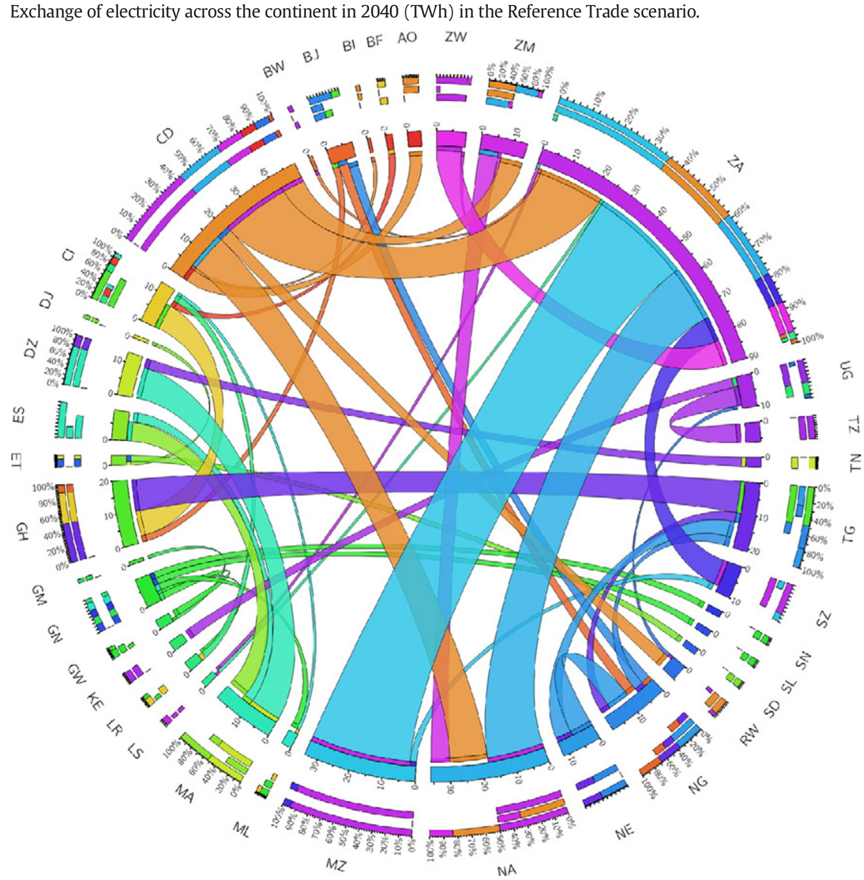


Table E.4
Exchange of electricity across the continent in 2020 (TWh) in the Enhanced Trade scenario.

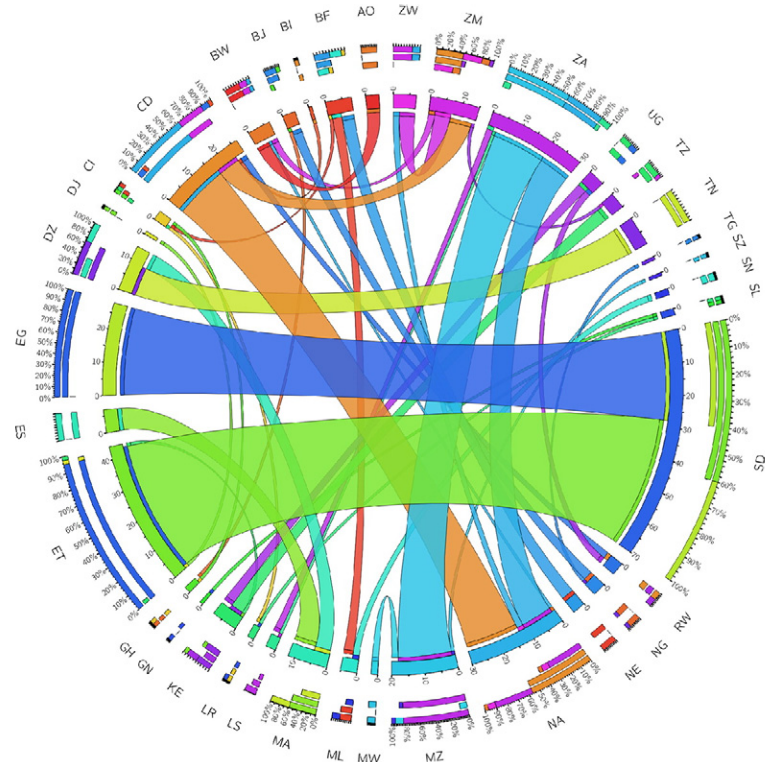


Table E.5
Exchange of electricity across the continent in 2030 (TWh) in the Enhanced Trade scenario.

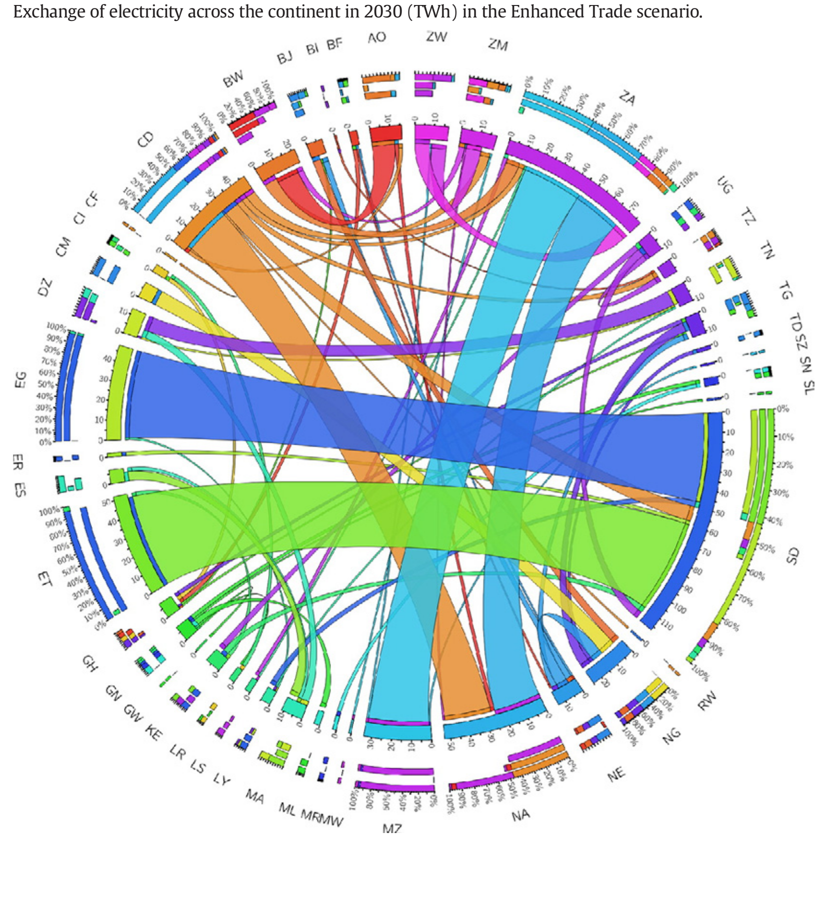
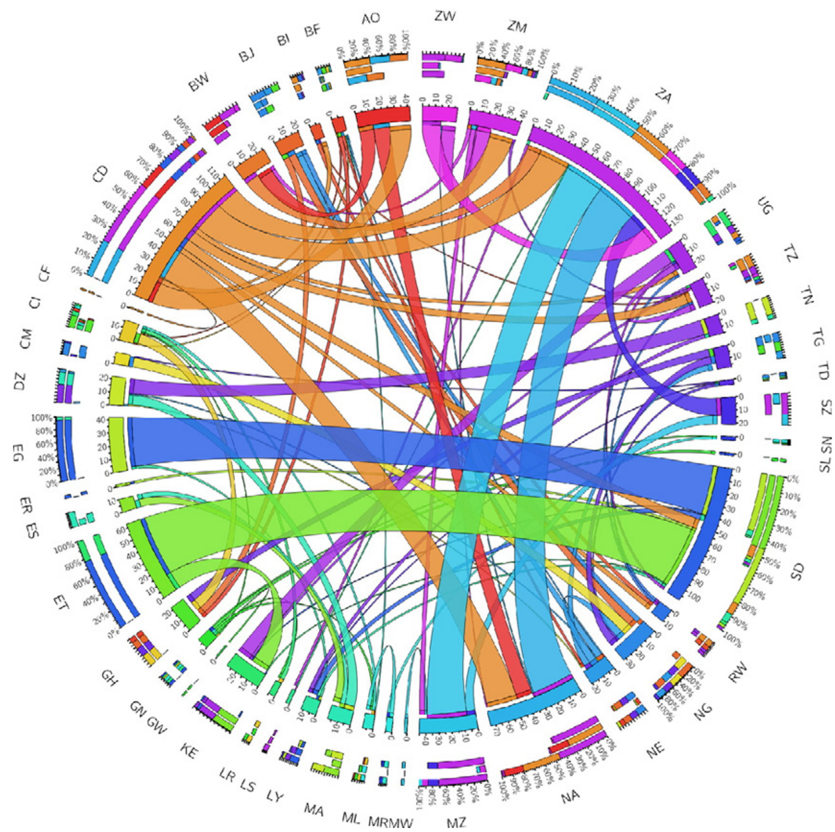


Table E.6
Exchange of electricity across the continent in 2040 (TWh) in the Enhanced Trade scenario.



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