EASTERN AFRICA POWER POOL (EAPP)

EAPP REGIONAL POWER SYSTEM MASTER PLAN

VOLUME I: MAIN REPORT

Ea Energy Analyses

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List of Abbreviations

CC – Coordination Centre

DAM – Day-ahead Market

EAPP – Eastern Africa Power Pool

EC – European Commission

ENTSO-E - The European Network of Transmission System Operators for Electricity. It represents all electric TSOs in the EU and others connected to their networks, for all regions, and for all their technical and market issues

EU – European Union

IRR – Internal Rate of Return

GTC – Grid Transfer Capability

LOLP – Loss-of-load Probability

MP – Master Plan

PS – Permanent Secretariat

PSS/E – Power System Simulator for Engineering. It is an integrated, inter-active program for simulating, analysing, and optimizing power system performance

RES – Renewable Energy Sources

SAPP – Southern African Power Pool

SCADA – Supervisory Control and Data Acquisition, and industrial control system

SRMC – Short-Run Marginal Costs

TOR – Terms of Reference

TSC-P – Technical Sub-Committee for Planning

TSO – Transmission System Operator

TYNDP - Ten-Years-Network-Development-Plan

WAPP – Western African Power Pool

Foreword

This is the second Master Plan published by the EAPP, the Eastern Africa Power Pool. The first Master Plan, published in 2011, is now updated and extended in scope to include Libya, the entire DRC and South Sudan.

The update is part of a *Twinning project* where the EAPP General Secretariat, the member utilities and the consultants have been working together. Intensive dialogue with the member utilities and Ministries has been a key input in the process. The EAPP Technical Subcommittee for Planning (TSC-P) has played an active role in the final development of the Master Plan.

This Main Report is a concentrated description of the methods and the overall results. This report serves to provide the reader with a high-level overview and insight in the main results, with more detailed data and results descriptions being presented in the other volumes of the EAPP Master Plan 2014.

The EAPP Master Plan 2014 consists of the following documents:

- Executive summary
- Volume I: Main Report (current document)
- Volume II: Data Report
- Volume III: Results Report

The Data Report details the data input both on an overall, and on a country-specific level. The Results Report presents the modelling results on an overall and country-specific level for each of the modelled scenarios throughout the projection period.

The following supporting documents supplement the EAPP Master Plan 2014's main three volumes:

- African regional transmission projects: status memo
- Planning gap analysis
- Environmental analysis
- Risk analysis
- Network analysis

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1 Introduction

The purpose of the EAPP Master plan is to analyse the benefit of regional co-operation and to recommend a package of new cross-border transmission lines.

This EAPP Master Plan 2014 updates the Master Plan 2011 for expansion of the Eastern Africa electricity system. The 2011 Master Plan included Burundi, Djibouti, East DRC, Egypt, Ethiopia, Kenya, Rwanda, Sudan, Tanzania and Uganda. The 2014 Master Plan has been extended in scope to include Libya, the entire DRC and South Sudan. In total, 12 countries are now included.

The Master Plan update process has contributed to the capacity-building of the EAPP staff, as it has been a part of a *Twinning project* where the EAPP General Secretariat, the member utilities and the consultants have been working together. Intensive dialogue with the member utilities and Ministries has been a key input in the process. The EAPP Technical Subcommittee for Planning (TSC-P) has played an active role in the final development of the Master Plan 2014. The ambition of the *Twinning* project has been to enable the EAPP and the TSC-P to carry out the subsequent activities, including continuous updating of the EAPP Master Plan.

The methods used in the EAPP Master 2014 plan are similar to the ones used in the 2011 Master plan, as well as in the preparation of national Master Plans. The key element of the study is least-cost analysis of potential investments in generation and transmission. However, the current study is different from traditional Master Plan studies in a number of ways:

- As a part of the *Twinning* project, all necessary hardware and model software have been provided to the EAPP staff, installed in the EAPP headquarters in Addis Ababa, Ethiopia. Training in the use of the Balmorel model has been provided to relevant EAPP staff, as well as EAPP member utility representatives.
- The large area and long time horizon covered. 12 countries are analysed in a single model, from 2015 to 2040 in five-year time steps.
- 21 scenarios are analysed. These include a Main scenario and 20 scenarios where typically only a single parameter is varied. This gives a detailed insight in the interactions and dynamics in the regional electricity system. Examples of parameters varied are: Electricity demand, fuel prices, delay of projects, interest rate, cost of transmission and generation, CO_2 price and targets for the share of renewable energy.

The scenarios are used to analyse the robustness of different investments. This is important because of the uncertainty regarding the future development of many important parameters.

- In many studies investment in generation and transmission is analysed separately, e.g. what transmission is needed given a certain portfolio of generation. In this study, the model is investing simultaneously in generation and transmission. All scenarios find optimal solutions, and when a parameter is changed, the optimal investment in both generation and transmission will change.
- Only secure investments in plants and transmission lines have been included as “existing” and “committed”. This gives more flexibility to the model to identify least-cost investments. Predictably, this (together with the regional as opposed to national focus of the study), may result in different regional power system planning projections compared to the ones prescribed in the national Master plans of the individual countries.

Data uncertainty

Significant effort has been made during the Master Plan update process to obtain the best possible data for the modelling and scenario analyses. Demand forecasts are uncertain and have significant impact on the modelling results. A number of assumptions and projections regarding the development path of key parameters has been made in this analysis, and the accuracy of the results is subject to the materialisation of the said assumptions.

Structure of report

The current report is Volume I: Main Report of the EAPP Master Plan 2014. Additional information on data input and detailed results are provided in Volume II: Data Report and Volume III: Results Report, respectively.

The analysis is based on a model study of regional least-cost planning using the Balmorel model, taking into account e.g. electricity demand growth, and a large number of supply alternatives. The current situation and recent national Master plans are described in chapter 2. The model is presented in chapter 3. Key assumptions are described in chapter 4.

The recommendations of the 2014 Master Plan are based on analyses of regional least-cost investments in generation and transmission. The Main scenario (and the alternative scenarios used to analyse the sensitivity of the results with respect to the central parameters) are described in chapter 3.

Model results are described in chapter 5 and 6 and conclusions and recommendations in chapter 7.

2 EAPP energy landscape

The Eastern Africa Power Pool (EAPP) is a regional organisation established in 2005 following the signature on an Inter-Governmental MOU (IGMOU) and an Inter-Utility MOU (IUMOU). Similar to the other power pools in Africa, the EAPP has been adopted by COMESA as a special arm responsible for power issues. Its headquarters are located in Addis Ababa, Ethiopia.

EAPP's objectives include ensuring security of supply, optimal use of resources, affordable prices through interconnection, as well as creation of a conducive investment environment and development of a competitive electricity market.

Ten countries are members of the EAPP (see Table 1). The member countries are expected to experience significant economic growth. The International Energy Agency expects an average economic growth in Sub-Saharan East Africa of 5.4% from 2012 to 2040, with a higher growth rate of 6.4% from 2012 to 2020 (IEA, 2014).

	Population (million)	Area ('000 km^2)	GDP (current USD/capita)
Burundi	10	28	251
DRC	66	2,345	418
Egypt	81	1,002	3,256
Ethiopia	92	1,104	467
Kenya	43	581	933*
Libya	6	1,760	13,303
Rwanda	11	26	623
Sudan	37	1,886	1,695
Tanzania	48	945	609
Uganda	36	241	551
Total (Average)	430	9,920	(2,210)

Table 1. Statistical information about EAPP countries in 2012. Source: World Bank Development Indicators (http://databank.worldbank.org/).
** Kenya National Bureau of Statistics cites 1,246 USD/capita due to re-basing of Kenya's GDP per capita*

Electrification and greater economic activity will result in increased electricity demand in the region. The demand is expected to increase from 315 TWh in 2015, to 675 TWh in 2025, corresponding to an annual growth rate of 7.6%. This annual growth rate is expected to continue over the longer term as well, as the International Energy Agency expects 7.6% annual growth in electricity demand in Sub-Saharan Africa from 2012 to 2040 (IEA, 2014).

(TWh)	2000	2010	2015	2020	2025
Burundi	0.02	0.1	0.2	0.6	1.0
Djibouti	-	0.3	0.8	0.9	1.0
DRC	-	-	18.3	31.0	40.7
Egypt	78	146	201.5	279.6	377.8
Ethiopia	1.6	5.6	14.7	35.0	53.2
Kenya	4.7	9.0	13.3	41.6	61.3
Libya	-	-	33.9	47.1	63.6
Rwanda	0.2	0.33	0.8	1.5	1.9
South Sudan	-	-	0.7	2.0	3.2
Sudan	2.4	7.2	14.7	24.5	32.0
Tanzania	2.5	5.3	11.2	19.6	27.1
Uganda	1.3	3.0	4.8	7.8	12.1
Total	**91**	**177**	**315**	**492**	**675**
Growth, % p.a.		7%	8%	9%	7%

Table 2. Electricity demand in TWh (including losses). Data from 2011 Master Plan and recent national prognoses. The yearly growth has been calculated for 2000 to 2015 without Djibouti, DRC and Libya.

As a result, large investments in new generation are necessary. Further investments in transmission capacity between the countries can significantly reduce the fuel costs and improve the security of supply in the system. The expected electricity generation by fuel type is 2015 is shown in Figure 1. Natural gas is the dominating fuel (70%) on a regional basis. Natural gas is used in Egypt, Libya and Tanzania. Hydro is 16%. A portion of the demand is indicated as unserved (4%). This is mainly in DRC and illustrate that the existing and committed plant are not able to meet the expected demand by 2015.

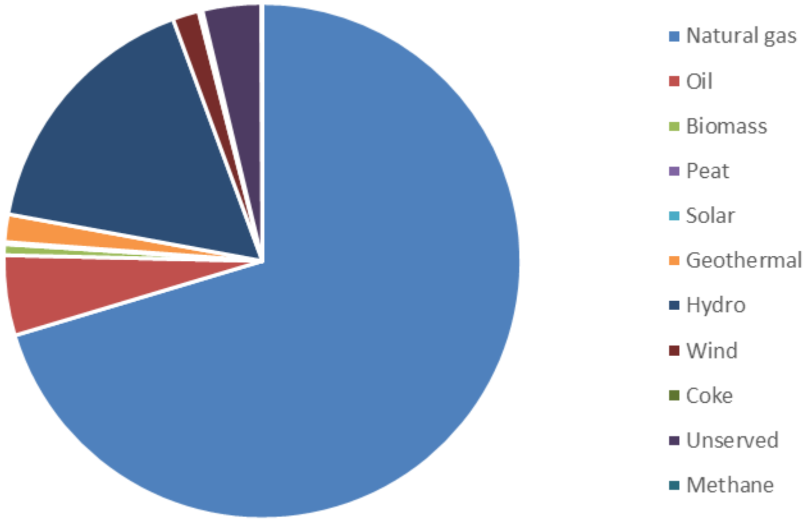

Figure 1. Expected electricity generation in 2015 by fuel type.

Starting point

Electricity systems in Eastern Africa have been developed almost exclusively according to a local and/or national focus. Today, only small interconnectors exist between the countries (in most cases below 200 MW). Therefore, exchange of power has been limited, as have other benefits from cooperation, such as sharing of reserves and balancing dry and wet years. From 2017, strong interconnectors will connect Ethiopia, Kenya and Tanzania, and several other projects will make regional trade possible. Realisation of the committed transmission projects will secure that each EAPP member country will have cross-border power exchange capabilities towards 2020.

In recent years, several countries have been experiencing low security of supply. This can be due to supply problems with natural gas (Egypt), dry years (Tanzania) or inadequate distribution systems (Ethiopia). Lost sales due to electric outages have been above 5% in Uganda, DRC, Tanzania and Kenya (IEA, 2014). In addition, unexpected power cuts can seriously hinder economic growth.

In many EAPP countries, the access to electricity is in the range of 10-30% of the population, and numerous countries have programmes to increase this. The UN has called for a universal access to modern energy services by 2030[1],

[1] See: www.unfoundation.org/what-we-do/issues/energy-and-climate/clean-energy-development.html and: (Bazilian, 2012).

and countries are striving to reach this goal. E.g., Ethiopia aspires to accelerate reaching an electrification rate of over 80% by 2030 (as opposed to the earlier target of 2035).

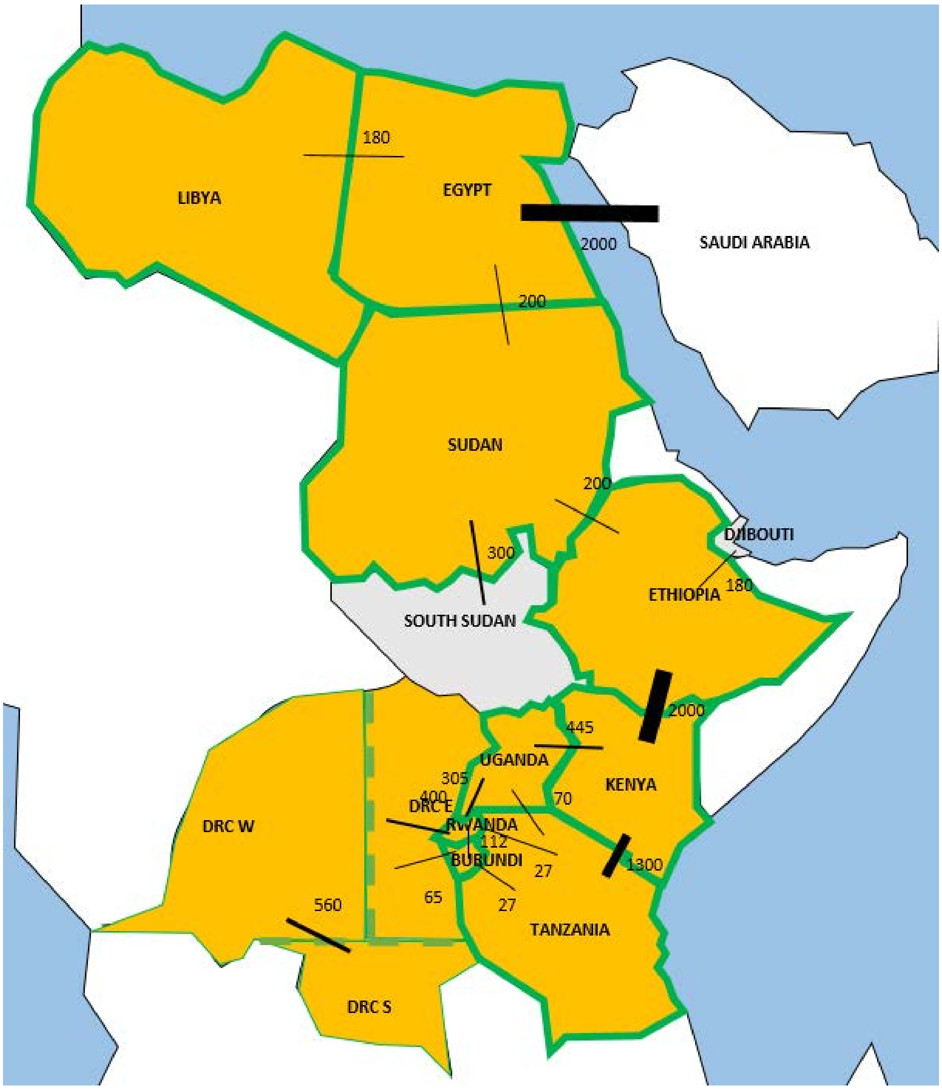

Figure 2. Current and committed (before 2020) interconnectors in Eastern Africa (MW). Note that an additional 1,000 MW line will connect the Western and Southern DRC by 2025 and a 500 MW line will connect DRC South and East in 2025.

As indicated in Figure 2 and Table 3, the EAPP power system will soon undergo significant changes, and will no longer be characterised as a region largely lacking in interconnectors. Realisation of the committed transmission projects will secure that each EAPP member country will have cross-border power exchange capabilities towards 2020. The construction of a strong interconnector from Ethiopia via Kenya to Tanzania will open up new possibilities for large-scale trade of electricity, sharing of hydro, balancing wet and dry years, as well as balancing other situations such as delays in generation expansion.

From	To	Existing (MW)	Committed (MW)	Online (Year)
DRC	Burundi	16	49	2018**
DRC	Rwanda	100	300	2015
DRC South	DRC East	-	500	2025
DRC West	DRC South	560	1,000	2025
Egypt	Sudan	-	200	2016
Ethiopia	Djibouti	180	-	
Ethiopia	Kenya	-	2,000	2017
Kenya	Tanzania	-	1,300	2018***
Libya	Egypt	180	-	
Rwanda	Burundi	12	100	2018**
Rwanda	Tanzania	-	27	2018
Sudan	Ethiopia	200	-	
Sudan	South Sudan	300*	-	
Tanzania	Burundi	-	27	2018
Uganda	Kenya	145	300	2015
Uganda	Rwanda	5	300	2015
Uganda	Tanzania	70	-	

Table 3: Existing and committed interconnectors (MW). "Online" is the year when the committed projects are expected to be operational. Ethiopia – Kenya is a DC line. All others AC.
** The 220 kV line is currently operated at 12 MW.*
*** According to data updates received from Burundi.*
**** The project is awaiting financial close at the time of writing this report; 2018 has been indicated as a realistic commissioning year*

Energy resources

Hydro

The region has abundant energy resources that are not yet exploited. Hydro potential is large in e.g. Ethiopia, the DRC, Uganda and South Sudan (in the order of 45,000 MW, 45,000 MW, 3,000 MW and 1,500-3,000 MW, respectively[2]). However, it can be difficult to exploit these potentials because hydro is capital intensive and has environmental consequences, such as flooding of land and change of downstream flow. The hydro potential far exceeds the current (and short to medium term) local electricity demand forecasts, and hence there would be a clear benefit in linking investments in hydro to corresponding investments in transmission. Many hydro projects are economically attractive, even when the transmission investments required also are taken into account.

[2] See: (Bates, 2013) and (Kumba, Lokudu, & Athorbei, 2011)

Grand Inga

The Grand Inga project in the western part of the DRC has a potential of 42,000 MW hydropower from the large Congo River. Cost estimates indicate that the cost of electricity can be as low as USD 12/MWh for the later stages. The combination of large volume and low costs means that it is economically attractive to transport the electricity to regional load centres. The pre-feasibility study identifies South Africa (3,500 km), Nigeria (1,700 km) and Egypt (5,300 km) as potential demand centres for Grand Inga power exports.[3] In these load centres, the hydro-based electricity could replace fossil-based electricity. Egypt is the only EAPP member country analysed in detail in the pre-feasibility study as a potential power export destination (yet interconnections with all the DRC EAPP-member neighbour countries have been considered in the scenario analysis in the current Master Plan). A balanced future development vision could involve a gradual expansion of the Grand Inga capacity until 2040 or 2050 in order to supply both national demand, and transmission to other load centres, e.g. South Africa and Nigeria.

Geothermal

Countries along the Great Rift Valley (Ethiopia, Kenya, the DRC and Tanzania) have significant potential for using geothermal energy for electricity generation. Kenya will have 572 MW geothermal power in 2015, and the resource is economically attractive. Further expansion is planned, and the total capacity is expected to reach 4,000 MW by 2025. The geothermal plants generate a steady flow of electricity and are hence used as base load.

Natural gas

Natural gas has been extracted in Egypt and Libya since the 1990s, and recently significant offshore natural gas resources have been discovered in Egypt and Tanzania. At present, Tanzania produces small volumes of natural gas for domestic consumption, but the country has the potential to become a liquefied natural gas (LNG) exporter in the future.

Oil

Oil is being extracted in e.g. Libya and South Sudan. Libya's oil production recovered in 2012 after the civil war, but remained lower than levels prior to the war. Libya is believed to hold large amounts of untapped hydrocarbon resources as it shares similar hydrocarbon-bearing geological structures with its neighbouring countries. The unified Sudan has been producing oil since the 1990s. Most of the production assets are near or extend across the border to South Sudan.

[3] See: “Hydropower development of Inga site and associated transmission lines - Executive Summary of the pre-feasability study” (AECOM & EDF, 2011)

Coal

Coal deposits have been discovered in Egypt and Tanzania, but large-scale use of coal (as planned in Sudan and Egypt) must be based on import.

National Master Plans

Recent national Master Plans exist for several countries, e.g. Kenya (draft, 2013), Ethiopia (2014), Uganda (2011), Tanzania (2012) and Sudan (2013). The following section briefly describes these master plans and the energy situation they seek to address, specifically focusing on generation.

Egypt

Egypt is among the largest oil and natural gas produces in Africa. Egypt is also the largest oil and natural gas consumer on the continent, with its fuel consumption outpacing its fuel production since 2010. Government subsidies have contributed to rising energy demand.

More than 99% of the Egyptian population has access to electricity, however Egypt experiences frequent electricity blackouts because of rising demand, natural gas supply shortages, aging infrastructure, and inadequate generation and transmission capacity.

Power production relies mainly on natural gas and a small amount of hydro power, wind power and solar energy.

Whilst the Egyptian generation expansion plan (2013/14 to 2026/27) indicates continued use of natural gas, it also presents an important shift with significant investments in coal and nuclear – both being new fuels in the electricity mix of the country. In addition, as indicated in Table 4, significant development of wind and solar power are planned.

MW	“2015”	“2020”	“2025”	Total
Natural gas	6,300	24,150	9,750	40,200
Coal	0	7,000	6,000	13,000
Nuclear	0	1,650	3,300	4,950
Wind, solar, & small hydro	2,685	7,782	4,150	14,617
Total	8,985	40,582	23,200	72,767

Table 4. Summary of the planned investments in new generation in Egypt until 2026/27. “2015” = 2013/14-2016/17, “2020” = 2018/19-2022/23, “2025” = 2023/24-2026/27

Sudan

At present, hydroelectricity is Sudan's largest source of power, accounting for up to 75% of generation, followed by oil and some biomass and waste. In 2011, 29% of Sudan's population had access to electricity.

According to the "Long and Medium Term System Plans Sudan", the need for new dependable power capacity is estimated to exceed 4,000 MW by 2031.[4] The System Plan concludes the least-cost and technically suitable generation technology for the Sudanese power system is coal-fired steam power plants located by the Red Sea. At least 2,000 MW of such base load will be needed from 2019 onwards. Together with existing and committed generation, and three candidate hydro power plants on the River Nile, this expansion is considered sufficient to meet demand.

In the long term, the Plan envisions a total expansion of coal-fired power capacity of 3,300 MW (by 2031), with the first two 300 MW units each coming online in 2017.

Development in the country has been impacted by international trade boycotts since 1997.

Ethiopia

In Ethiopia, 23% of the population had access to electricity as of 2011. The Ethiopian Power System relies almost exclusively on hydro power, with minor contributions from fossil fuels and geothermal energy.

Thus far only limited oil and gas reserves have been located, but geology indicates that development of oil production might be possible in the future. However, hydro potential is substantial and only a fraction of this potential is exploited today. In recent years, new hydro capacity has been commissioned, thus enabling substantial future power export from Ethiopia to its neighbours when these projects are completed.

In addition, Ethiopia has a large potential for geothermal energy, as well as some biomass (bagasse form sugar cane and sorghum stalks).

Expansion Master Plan Study of 2013[5] recommends a plan comprising a combined hydro – renewable – thermal system. In the short term, the plan recommends construction of hydro power capacity (adding approximately 9,000 MW by 2030 to the 5,434 MW currently under construction), as well as construction of wind (900 MW by 2030), solar (300 MW in 2016) and some diesel-fired capacity (the latter to be subsequently converted to gas).

[4] See (Lahmeyer International, 2013)
[5] See: (Ethiopian Electric Power Corporation, 2013)

The Master Plan also recommends development of geothermal power; particularly in the medium and long term (2025 and onwards) when expansion of hydro power ceases. Roughly 5,000 MW geothermal power is foreseen by 2037. In 2013, an agreement was reached with an Icelandic company to develop up to 1,000 MW geothermal power.

Kenya

The total installed electricity generation capacity in Kenya is approximately 1,680 MW (as of 2014) of which roughly half is hydropower, and 34% is based on fossil fuels, relying heavily on imports.

Kenya is the largest producer of geothermal power in Africa. In 2013, geothermal accounted for 20% of Kenya's total net electricity generation, and geothermal installed capacity was 260 MW (15 % of total capacity). According to Kenya's state-owned Geothermal Development Company, the country has the potential to produce 10,000 MW of geothermal-powered electricity.

Kenya currently does not produce any crude oil or natural gas, however the country is a prospective oil producer as exploration has accelerated recently following successful discoveries. In addition, some coal reserves have been discovered, and Kenya aims to promote further intensive coal exploration.

In 2011, around 25% of Kenya's population had access to electricity, and this was estimated to have reached 30 – 37% in the fiscal year 2013/2014. The goal is to reach 70% electrification by 2020. The majority of the population relies on traditional biomass and waste for household heating and cooking.

More than 400,000 additional customers were connected to the power system in the fiscal year 2013/2014, and another million new customers are expected to be connected in 2014/2015. This, together with economic growth, is expected to increase the peak power demand to 18,000 MW by 2030 – more than a factor 10 higher than today's peak.

Kenya's draft National Energy Policy[6] anticipates an increase in coal plants (2 x 1,000 MW), geothermal energy (1,600 MW) and LNG (1,000 MW) in the short term, bringing the total capacity up to app. 7,000 MW by 2016.

In the long term, the policy relies on nuclear energy with the commissioning of 1,000 MW by 2024 and 4,000 MW by 2030, respectively.

[6]See: (Ministry of Energy and Petroleum, 2014)

Uganda

Uganda has substantial hydropower and biomass resources as well as fossil fuel potential in the forms of oil, natural gas and peat. Uganda does not currently produce any hydrocarbons, but crude oil production is expected to start within the next five years from resources in the Lake Albert region.

As of 2014, the Ugandan power system had a total installed capacity of 850 MW, of which the three largest hydropower plants contributed 630 MW. The share of hydro generation in the overall generation mix exceeds 80%, whilst thermal and industrial co-generation account for 12% and 7%, respectively.

In the past, Uganda has suffered from power supply shortages, which have been exacerbated by reductions in the water level of Lake Victoria. However, with the completion of the Bujagali 250 MW power plant, introduction of thermal power in the energy mix, enhancing power generation from bagasse as well as mini hydro generation, the situation has been improved.

As of 2011, around 14% of the population had access to electricity. The majority of the population relies on traditional biomass and waste (typically wood, charcoal, manure, and crop residues) for household heating and cooking.

Uganda's Power Sector Investment Plan[7] expects peak electricity demand to rise to more than 1,800 MW by 2030, i.e. an average annual growth of 5.9% from 2011 to 2030.

The plan primarily foresees the development of hydro energy to supply the growing demand, as the plan considers hydro generation to be the least-cost future solution. According to the plan, the total capacity is to increase to 2,400 MW by 2030.

Tanzania

Tanzania produces small volumes of natural gas for domestic consumption, but the country has the potential to become a liquefied natural gas (LNG) producer in the future. Tanzania also has hydro power potential, and it produces coal for domestic consumption. Tanzania does not produce crude oil, and there have not been any recent commercial oil discoveries in the country.

[7] See: (Uganda Ministry of Energy and Mineral Development, 2011)

The current power generation capacity is roughly 1,500 MW, of which 565 MW is hydro power, and the remainder predominantly gas or oil-fired. A few plants are also based on biomass.

The dependence on hydro power has created supply security problems both historically and in recent years with frequent seasons of drought. This has caused load curtailment and power outages, as well as leading to high generation costs from oil-fired plants.

Approximately 15% of the population had access to electricity as of 2011. The majority of the population uses biomass and waste for heating and cooking. According to Tanzania's Power System Master Plan[8], the Government is committed to an accelerated electrification strategy, aimed at adding 250,000 new customers annually during the period 2013 – 2017. Currently, the rate is 200,000 per year. The target is 30% connectivity by 2015.

The Master Plan stipulates that the country will need a total of 3,400 MW in the short term (2013-17) and 8,990 MW by 2035. The “base case” plan suggests an installed capacity of 8,960 MW by 2035 consisting of 3,300 MW hydro, 1,000 MW natural gas and 3,800 MW coal-fired generation and 240 MW solar, wind and biomass generation.

The plan recommends a hydro/thermal ratio of 40:60 in order to ensure diversification and reduce the risk of power shortages during drought periods.

Libya

Libya is the holder of Africa's largest proved crude oil reserves, and an important contributor to the global oil supply. Libya also has the fourth largest amount of proved natural gas reserves on the African continent.

Electricity generation relies exclusively on oil and natural gas, and as of 2011, nearly 100% of the Libyan population had access to electricity.

Despite the high electrification rate, the country suffers from power outages due to electricity shortfalls, which also occurred before the 2011 civil war. Libya's oil sector has in some instances been affected by power supply issues, which has compromised production at some of the oil fields. As a result of the war, a major task lies in rebuilding infrastructure and power plants.

[8]See: (Ministry of Energy and Minerals, 2012)

Power System Studies conducted by the General electricity Company of Libya[9] estimates that Libyan power generation capacity should be extended to 14,280 MW in 2015, rising to 23,580 MW in 2030. The planned and new generation capacity is expected to be a mix of gas and steam turbines.

South Sudan

The South Sudanese economy relies heavily on oil production, which currently contributes with 98% of the national budget. [10] In addition to oil resources, South Sudan has unexploited hydro power potential.

Power generation is based on diesel generation and limited to a few towns (24 MW in total). In addition to the low level of generation capacity, a weak distribution network contributes to shortages of supply with frequent blackouts and load shedding. Only 4% of the population has access to electricity.

The majority of the population uses biomass such as fuel-wood, charcoal and grass for cooking (99%) and lighting (50%). Biomass will continue to be a dominant source of energy for some time to come, particularly in rural areas.

Plans are being developed to set up a number of small reliable diesel plants and strengthen the power infrastructure in order to improve security of supply and promote socio-economic development. Furthermore, South Sudan envisions starting the development of its hydropower potential.

According to the Infrastructure Plan for South Sudan, 336 MW of diesel power (sets of up to 5 MW) and 40 MW of hydropower is to be installed during 2015-2020, and an additional 115 MW of diesel power and 300 MW of hydropower is to be established during 2021-2025.

DRC

In the DRC, access to electricity is planned to increase from 9% today to 14% in 2015, and 26% in 2020 (IEA, 2014). The DRC has large hydro potentials, as described in one of the sub-reports (EAPP Master Plan 2014: African regional transmission projects: status memo), which contains the status for interconnectors in Africa, and a description of the Grand Inga project.

Rwanda and Burundi

No recent master plans exist for Rwanda and Burundi. In Rwanda, access to electricity is planned to increase from 17% today to at least 60% in 2020 (IEA, 2014).

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[9] See (General Electric Company of Libya, 2010). Only limited interaction with representatives from Libya took place during the development of this Master Plan. Data for Libya may not all be up to date.
[10] See (African Development bank and African Development Fund, 2011)

Overview

An overview of the various national Master Plans is shown below:

Country	Future priorities in resent master plans
Egypt	Coal and nuclear
Ethiopia	Hydro, natural gas, renewables + exports
Sudan	Coal
Kenya	Coal, geothermal, LNG, nuclear
Tanzania	Coal, hydro, natural gas
Uganda	Hydro
Libya	Natural gas, oil
South Sudan	Hydro, small diesel

Table 5. National Master Plans

EAPP 2011 Master Plan

The first EAPP Master Plan was published in 2011.[11] The objective of the study was "to identify power generation and interconnection projects, at Master Plan level, to interconnect the power systems of the EAPP countries in the short-to-long term". The study covered Burundi, Djibouti, the Eastern part of the Democratic Republic of the Congo (DRC), Egypt, Ethiopia, Kenya, Rwanda, Sudan, Tanzania and Uganda. Libya was not covered, as the country first became a member in 2011.

The 2011 Master Plan project was comprehensive and included analyses of demand forecasts, tariffs, environmental impact assessment, description of generation supply study and planning criteria, identification of candidate generation projects, transmission network and interconnection study. Many of the analyses are still up-to-date and will not be worked with in the current project.

The EAPP 2011 Master Plan recommended six interconnectors, connecting the countries from Egypt to Tanzania. Two of the projects, Ethiopia – Kenya, and Kenya - Uganda are now underway and are expected to come online in 2017 and 2015, respectively. The Kenya – Tanzania line is awaiting financial close at the time of writing this report. The 2011 Master Plan acted as a part of the documentation that supported the relevance of these two interconnectors.

[11]See: (SNC Lavalin International, 2011). In 2005 the East African Power Master Plan Study was published. In covered Tanzania, Uganda and Kenya (BKS Acres, 2005).

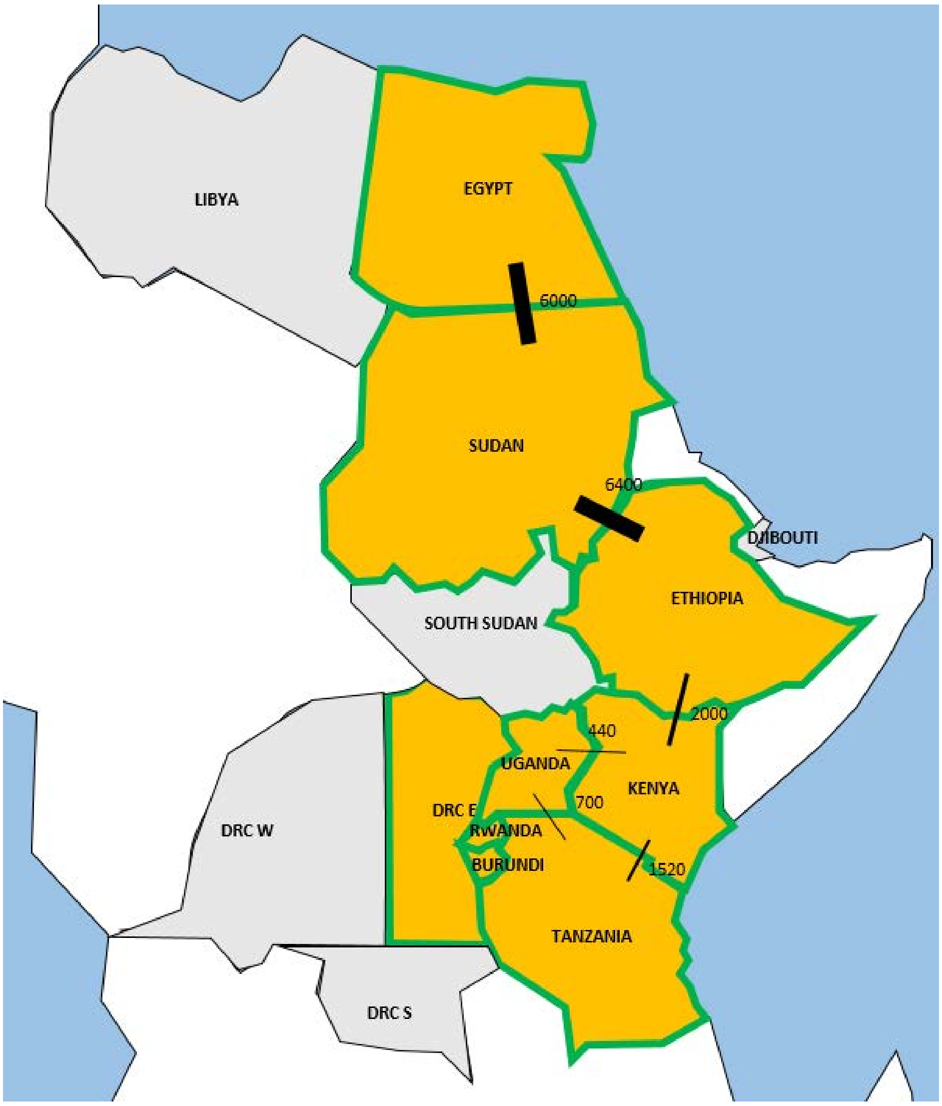


Figure 3. The recommended interconnectors in the 2011 Master plan for the period 2015-2025. Two projects come in stages: The Egypt-Sudan line is in three stages to come online in 2016, 2020 and 2025, respectively, and the Sudan-Ethiopia line in 2016 and 2020, respectively. The Egypt-Sudan and the Ethiopia-Kenya lines are DC lines.

Comparison with the EAPP Master Plan 2014

In broad terms, the methods used in the 2011 Master Plan are also applied in the 2014 update. The methods for least-cost planning are similar, despite the fact that different planning models are used. One notable difference is the approach to analyse the benefit of interconnectors. The 2011 Master Plan used the national master plans for transmission and generation as a reference scenario, and analysed the benefit of adding coordinated transmission planning (called first level of cooperation). In the 2014 update of the Master Plan, a slightly different approach has been chosen. In the 2014 update, the scenario "Only G" acts as a reference without investments in transmission. When comparing this with a scenario with investments in both generation and transmission, the benefits of coordinated transmission planning can be highlighted. In this way, the results are separated from the impact of national priorities, and a truly regional least-cost power system design is outlined.

Several aspects analysed in the 2011 Master plan are not updated in this round, e.g.:

- The detailed system studies per country (PSS/E analyses of load flow, short circuit analyses and stability)
- Description of methods for electricity demand prognoses
- Environmental analysis for hydro, nuclear and transmission
- Institutional and tariff aspects
- Project funding

Input data updated

The fuels prices used in this Master Plan update are based on IEA's World Energy Outlook 2013 and are significantly higher than the prices used in 2011. Demand prognoses for the different countries are in general much higher today, compared with the values used in the 2011 Master plan. Such changes illustrate the uncertainty regarding input values. The increase in demand will significantly affect the results.

Connections to Non-EAPP countries

A 3,000 MW multiple terminal DC line (1,500 km) from Egypt to Saudi Arabia is planned to come online in 2018. The purpose of this interconnection is to provide Egypt and the Kingdom of Saudi Arabia with necessary flexibility to share their capacity and trade energy in a commercial manner during normal operation, and to provide mutual back-up assistance during emergency operating conditions.[12] The line is expected to be used in both directions to reduce peak load costs, as peak load in Egypt is in the evening and in Saudi Arabia it is during mid-day. Both Egypt and Saudi Arabia primarily generate electricity from natural gas. The yearly net flow is modelled to be zero, and the daily flow is modelled with a fixed profile with import during Egyptian peak load, and export during off-peak mid-day hours.

Tanzania is connected to Zambia via low voltage lines and there are plans for an upgrade to a high voltage connection, scheduled to enter into operation in 2016. A scenario has been created that investigates the impact of a constant flow of power export to Zambia.

[12] See: (Rahman, 2012)

Ethiopia has a 180 MW connection to Djibouti, and is considering increasing the capacity to allow for export to Yemen (across the 20 km strait connecting the Red Sea with the Gulf of Aden).

South Sudan has very limited infrastructure. A 220 kV connection exists between Sudan and South Sudan with potential capacity of 300 MW, though it is currently only operated at 12 MW. The two non-EAPP members, Djibouti and South Sudan, are included in the model.

EAPP Planning code

The update of the Master Plan is carried out in line with the draft EAPP Planning Code (SNC Lavalin International, 2011). The purpose of the planning code is to develop a secure system that will supply electricity at the lowest cost.

The focus is on minimising the regional cost of supplying electricity. Any contrast between national and regional least costs is expected to be negotiated in a form of cost sharing, so the regional benefits are shared between all relevant stakeholders.

The mutual cooperation among EAPP countries should also include any cross border impact of projects, e.g. on grid stability, pollution, or water usage. Regional benefit should be balanced with national benefit for all countries.

Power Balance Statement

As part of the planning code, EAPP has the task of delivering a yearly Power Balance Statement. The statement has a focus on the next 10 years, including:

- A projection of the seasonal maximum and minimum demand, and yearly electricity demand in each country.
- The generation capacity currently available.
- The amount of generation capacity required to ensure that operating margins are achieved.
- Plans for building additional generation.
- The amount of electricity imported or exported from/to other EAPP or non EAPP member countries.

In order to create a Power Balance Statement, the EAPP member utilities will need to share planning data concerning demand, existing and planned generation and capacity of transmission lines. At the time of writing this report, a Power Balance Statement has not yet been issued.

Environment

The planning code highlights the fact that environmental and other considerations must be taken into account. All types of electricity generation have environmental impacts. Fossil fuel-based plants emit pollutants, e.g. sulphur, nitrogen and carbon dioxide. Sulphur and nitrogen can effectively be removed from fuel gasses if adequate systems are installed. Hydropower plants have other environmental and social consequences, e.g. loss of land, people affected, relocation of people, interruption of access routes, impact on culture and fauna, downstream impacts and consequences on aquatic systems.[13] Meanwhile, wind and solar power have other consequences mainly associated with land use.

There are currently no regional principles and procedures in place outlining how these environmental considerations shall be included in the least-cost planning. In e.g. the EU and South Africa, CO_2 quota systems exist and a price on CO_2 can be used to prioritise different supply solutions. For sulphur and nitrogen, the EU has strict emission norms that are applied to existing and new power plants.

The EAPP could have a role in developing a system that could help find least-cost environmental improvements. In view of the expected growth in electricity demand, and the prospect of increased use of fuels with high sulphur and CO_2 emissions such as coal, this may prove to be an important endeavour.

Main challenges

Rise in demand, security of supply

The rapid growth of the electricity demand, combined with the fact that several countries are experiencing low security of supply, poses a significant challenge for the electricity sector in the region. This can be due to supply problems with natural gas (Egypt), dry years (Tanzania) or inadequate distribution systems (Ethiopia). Unexpected power cuts can seriously hinder economic progress.

In many countries, the access to electricity is in the range of 10-30% of the population, and many countries have programmes in place to increase this by investing in new power production as well as new electricity distribution networks.

The current update of the Master Plan 2011 focuses on preparation and scheduling of reinforcements and extensions to the existing interconnector grid. The scenarios aim to identify the priority investments in new transmission projects during the next 10-25 years.

[13] (Ethiopian Electric Power Corporation, 2013)

Market and trade

A key challenge that exists today is the establishment of an electricity market in the region in order to initiate cross-border trade. A market-based system for power exchange is an important basis for realising the full economic benefits associated with new power transmission lines.

In 2014, the EAPP and its member countries carried out a pilot project of short-term trade on two selected lines (Uganda-Kenya and Ethiopia-Sudan). This simulated trade was based on marginal generation cost bids on each side, and took place on the newly developed market platform, ADAM, the Eastern African Power Pool Day Ahead Market. The next envisioned step following the successful completion of the pilot project is the commencement of real day-ahead trading on the available capacity of the lines.

National vs. regional planning

A move towards a regional power pool in Eastern Africa will result in more interdependent power flows across national borders. Transmission planning and system design must, therefore, look beyond national boundaries and move towards integrated regional solutions. This is a challenge that requires cooperation between the EAPP member countries. However, a closer cooperation will provide a basis for coherent and coordinated planning necessary for the development of a successful regional power pool.

The main objective of transmission system planning is to ensure the development of an adequate transmission system, which, with respect to mid and long term time horizons, ensures safe system operation, enables an increased level of security of supply, contributes to a sustainable energy supply and contributes to the efficiency of the system. In order to achieve this, some key issues must be addressed in the planning process, such as economic efficiency, national legislation and regulation, national policies and targets, environmental concerns and transparency in the procedures applied.

The planning criteria upon which transmission systems are designed are generally specified in transmission planning documents developed for application on the national level, taking into account the specific needs and conditions of the network to which they relate. If a regional concept is to be implemented successfully, it is important that common guidelines for grid development describe how future cross-border projects shall be implemented, and how common investment assessments are developed.

This requires identification of the gaps between the system planning procedures of the member utilities and the planning code in the proposed EAPP Inter-connection Code. A central part of the EAPP planning code is the publication of a power balance statement with a 10-year perspective. For more on this, please see the supporting document: Planning gap analysis.

Risks

The purpose of the 2014 Master Plan is to point out the transmission projects that should be prioritised, and the model-based study estimates the value of the candidate projects. Undoubtedly, there are considerable risks associated with such large international infrastructure projects, and the Risk Analysis deals with assessment of these risks, which can be broadly classified into two categories:

1. Planning risk
2. Investment risk

The *planning risk* primarily deals with the risk involved in accurately planning and coordinating the large number of investments as recommended by the Master Plan. Sub-categories of planning risk include sequencing risk (associated with timing and sequence of the interconnector development, with regard to both further transmission development, and relevant generation project development), input variable accuracy and modelling risk (arising from the uncertainty associated with the materialisation of future projections and model assumptions), as well as risks associated with international coordination, collaboration and benefit sharing (institutional, cultural and financial risks, respectively).

The *investment risk* comprises the risks following the investment decision relating to the realisation of the return on the financial commitments to be made. Sub-categories of investment risk include political risk (associated with potentially unsustainable macro-economic situations, possibility of devaluation, expropriation, civil disturbances, policy reforms etc.), business risk (associated with exchange rate volatility and availability of short-term credit), construction and commercial risk (associated with potential deviations from the expected cost, quality and timeline of the construction, as well as operational risks of the project), as well as regulatory and legal risks (associated with potential critical regulation reforms or breach of contract), and social and environmental risks (commonly covered by application of the Equatorial Principles).

The specific risk of the transmission projects recommended by the Master Plan is assessed within the framework of the major potential risk sub-categories identified, followed by a list of mitigation measures proposed. Please see the supporting document: Risk analyses.

In addition, a number of sensitivity analyses have been undertaken in this study in order to estimate the impact of potential variations in, e.g. electricity demand, fuel prices, CO_2 costs, construction times, interest rates and impact of national expansion strategies (in relation to nuclear and renewable energy).

3 Least-cost planning

The EAPP Master Plan should be understood as a supplement to other analyses. The least-cost analyses described below have a regional perspective and only include the national aspects to a limited degree. Such analyses must be supplemented with national analyses, e.g. the national Master Plans of the member countries. Together such analyses can form the basis for deciding *a package of prioritised transmission projects*.

The regional perspective can be illustrated by the fact that any change in demand, generation or transmission in an interconnected system will affect all stakeholders. The network design of the transmission system also means that any new interconnector will not only benefit the countries it connects – but will also influence the electricity flow in the entire region.

By defining *a package of prioritised transmission projects,* a balanced solution can be set up and the cost and benefits of these projects can be distributed across all countries.

The Balmorel model has been used in this study to simulate the entire power system of the EAPP. The task of the model is simple: *Based on a set of inputs including future electricity demand, cost of any possible generation technology, and the costs of possible transmission projects, to compute a least-cost expansion plan for the region.*

A large number of scenarios are simulated – and each has one least-cost solution. By comparing the results, a detailed understanding of the system can be achieved and it is possible to point out robust candidates for the *package of prioritised transmission projects*.

The Balmorel model

The Balmorel power system model is an economic and technical partial equilibrium model that simulates the power system and least-cost dispatch.[14] The model optimises the production at the existing and planned production units and simultaneously simulates investments in new generation and transmission. Investments are also made on a cost-minimising basis and they can include constraints on availability of fuels, cap on transmission investments, etc.

[14] See: www.balmorel.com. For this study a special version of Balmorel is used, where for example all equations related to district heating have been removed for clarity.

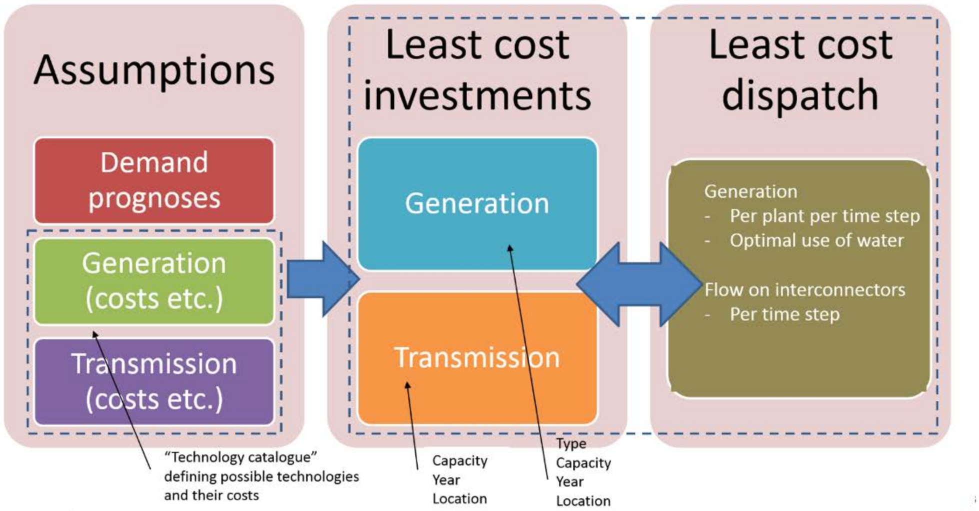


Figure 4. Output of Balmorel model is least cost investment in generation and transmission infrastructure with an optimal dispatch.

Balmorel is a deterministic model that finds optimal solutions based on given inputs. All information is used in the form of "perfect foresight" within a given year. This simplification gives two important benefits:

- It is easy to compare alternative scenarios. All solutions are least-cost, and any difference in the results is a result of the change in input.
- Computation time is significantly decreased.

Model-based investments

The model invests in generation if the value of the generated electricity exceeds the annualised cost of the investment plus fuel and O&M costs. An example could be a renewable energy technology with an investment cost of US $1.5 per MW and no fuel or O&M costs. With an interest rate of 10% p.a., and an economic horizon of 20 years, the annualised investment cost is 11.7% of the initial investment cost, or US $0.175 per MW. The value of the generated electricity is computed as the marginal generation costs in each hour, similar to the most expensive plant supplying electricity. For each time step the electricity generated is multiplied with the value. If the value of the electricity produced during the year is higher than the annualised investment costs, the model will invest.

The same principle applies to transmission investments. The model will invest in transmission if the reduction in total regional cost is reduced more than the annualised investment costs for the line (including losses and O&M costs).

Note that all investments and the least-cost dispatch take place simultaneously. Since the investment is based on a single year, it must afterwards be verified that the investments continue to be profitable. With the strong growth in electricity demand in the EAPP region this would often be the case.

In hydro-dominated power systems, such as the Eastern Africa system, the stochastic nature of the hydro inflow is a very important feature, and scenarios with dry, normal and wet years are therefore computed. The value of e.g. an interconnector may be very high in dry and wet years, where large quantities of electricity will be transported.

Simplification

The representation of the transmission grid and the dependency between different hydro generators is simplified. Transmission lines are represented by the total capacity between countries. Other models are more detailed, but will then have neighbouring countries represented in a simplified way or will only simulate selected operational mode, e.g. peak load. Such models are typically used in relation to the national master plans.

The Balmorel model can include unit commitment (allowing for setting a cost for start and stop of power plants). This feature is not used in the current work, but could be relevant in more detailed studies.

The strength of the model is its ability to find least-cost solutions in a large system, like the Eastern Africa system where 12 countries are modelled. Computing time for solving the model for 2020 to 2040 for a single scenario is around 10 to 40 minutes.

Modelling risk

The sequencing risk may be significant. If investment in generation or transmission is delayed, this will influence the economy of the new lines (and vice versa). In addition, a number of assumptions (e.g. optimal power dispatch, investment coordination possibility regionally between generation and investments etc.) and projections regarding the development path of key parameters (e.g. power demand growth, fuel prices etc.) have been made in this analysis, and the accuracy of the results is subject to the materialisation of the said assumptions.

Scenarios

Scenario analysis approach is chosen for this study, whereby 21 scenario has been modelled and explored. These include a Main scenario and 20 scenarios where typically only a single parameter is varied. This approach gives a detailed insight in the interactions and dynamics in the regional electricity system. Examples of parameters varied are: Electricity demand, fuel prices, delay of projects, interest rate, cost of transmission and generation, CO_2 price and targets for the share of renewable energy. The scenarios are used to analyse the robustness of different investments. This is important because of the uncertainty regarding the future development of many important parameters. Table 6 shows three of these scenarios. In the scenario entitled 'Only G' the model is only allowed to invest in generation. Existing (and committed) transmission is included. The results from this scenario can be compared to the Main scenario where the model can invest in both generation and transmission.

Scenario	Least/cost investment in new generation	Least/cost investment in new transmission	Requirement of 110% national capacity
Main	X	X	X
Only Generation	X	-	X
Benchmark	X	X	-

Table 6. Comparison of the key parameters across the Main, Only Generation and Benchmark scenarios.

In the first two scenarios, each country is required to have domestic generation capacity corresponding to 110% of the yearly peak demand.[15] The benchmark scenario (not 110%) is similar to the Main scenario, except that the 110% requirement is not included. This scenario illustrates the consequences of the requirement of local capacity – not only on investment in generation, but also in transmission and on dispatch of generation. In this scenario, some countries will be dependent on import to cover peak load.

Sensitivity analysis

The Main scenario is also tested in four variants with different assumptions regarding transmission:

- With maximum new transmission capacity limited to 1,500 MW per border and per simulated year (2020, 2025,..), ceteris paribus. Large cross-border transmission projects might be delayed by many challenges (financing, political priorities, right of way, enforcement of local grid). This scenario illustrates the consequences of such delays.

[15] Technologies encompassed by the domestic capacity requirement: natural gas, coal, lignite, fuel oil, light oil, peat, municipal waste, straw, wood, hydro, geothermal, bagasse, nuclear, methane. Wind and solar PV power are considered 'intermittent' power sources, and hence not counted towards the national security of supply requirement.
All thermal generation across all scenarios is furthermore reduced by 10% to reflect the need for maintenance.

- With no extra capacity allowed to be added between Sudan and Egypt/Libya before 2030, ceteris paribus. The Ethiopia – Sudan – Egypt line was one of the recommended lines in the 2011 Master Plan. However, the line is politically controversial, and this scenario illustrates the consequences of a delay of the northern part of the line, e.g. how this will affect the optimal expansion of hydropower capacity in Ethiopia, and the expansion of transmission capacity in other directions.
- With 50% higher capital costs on all new transmission lines, ceteris paribus. This is a simple sensitivity analysis of the price for new lines. The result can also be used to understand the impact of lower costs for transmission.
- With a direct transmission line from Grand Inga (DRC) to Cairo (Egypt) added as a candidate project from 2030.

The following scenarios illustrate the sensitivity to inputs such as interest rates, electricity demand, fuel prices and availability of hydro inflow.

- Variation of the interest rate. As an alternative to the standard 10% p.a., 8% and 12% p.a. are tested.
- Variation of demand. A 10% decrease/increase in demand is tested.
- High natural gas price. By default (in the Main and most other scenarios), the natural gas prices converge linearly from local production costs today, to international (European) gas prices towards 2030. As an alternative, the price is set to the European price already from 2020.
- Regional dry and wet hydro years. Based on the regional inflow of water in a time series covering 35 years, the years with the 10 years dry and wet (the dry and wet year that has a 10% probability) and absolute driest year has been found. The time series with inflow is weighted with the hydro generation capacity in the Main scenario. Because of the expansion of hydro power capacity the weighting and the resulting dry years change: E.g. 1978 in 2020 and 1996 for 2025.[16] For the dry years' scenarios, investments in generation and transmission are set to be the same as in the Main scenario. The simulations test the ability of the regional interconnected system to cope with dry years and also indicate the change in dispatch and operational costs.

[16] E.g. the development with expansion of hydro capacity in Ethiopia and DRC means that these countries should have a higher weight in 2025 than in 2020. Note that since the method find a *regional* dry year, some countries have an above average inflow the selected dry year. In the long time series no year exist where all countries have a below average inflow! This is a result of the large geographical area studied.

Finally, the Main scenario is tested with different assumptions regarding generation:

- A scenario with nuclear development in Kenya (300 MW) and Egypt (3,300 MW), corresponding to the national plans in these two countries in 2025. This scenario illustrates the impact of the proposed expansion of nuclear on least-cost transmission investments.
- A scenario with an increased share of renewable energy in the region: a requirement of 30% in 2020 and 35% in 2025 (compared with 29% and 32% in the Main scenario), increasing to 50% by 2040. The model decides on technology (hydro, wind, solar) and the location.[17] The results also indicate the need for additional transmission capacity in this renewable energy context.
- A scenario where CO_2 is priced at \$20/ton CO_2 in 2025.[18] In the other scenarios, the price of CO_2 is set to zero. The scenario illustrates the consequences of a moderately high CO_2 price. The actual implementation does not need to be a tax (or a quota system) – it can also be that CO_2 is weighted in all decisions.
- Delay of hydro investments. In this scenario, a cap is put on investments in hydro capacity. The cap reduces the model-based investments in hydropower across all countries by 33% compared to the investments made in the Main scenario and exists in all years.
- Export to Southern Africa Power Pool, SAPP. This scenario involves a fixed flat export to Zambia from Tanzania all year, with 500 MW in 2020 and 2025 and 1000 MW in 2030, 2035, and 2040.
- Lower costs for long-term hydro. Many candidate hydro plants are used in the model, so some uncertainty exists regarding the cost of new hydro at the end of the simulation period (2030-2040). In this scenario, the investment cost for hydro in Ethiopia is reduced by ca. 40% in 2030 to 2040.

[17] The required values in 2030 and 2035 are: 40% and 45%

[18] Values in 2020, 2025, 2030, 2035 and 2040 are: US \$/ton 10, 20, 30, 40 and 50. The values are above the current planned South African CO_2 price for 2020, 2030 and 2035: US \$/ton 8, 15 and 20. Low CO_2 scenarios (450 ppm) uses prices between US \$/ton 100 and 125 for 2035. See IEA World Energy Outlook, 2013.

4 Key assumptions

Electricity demand

Within the EAPP region, growth in electricity demand has doubled in the last 10 years, corresponding to an average growth of 7-8% p.a. The EAPP member countries expect a similar growth during the next ten years (8% p.a.). This is a significant driver for investment in generation capacity. The regional demand[19] is expected to increase from 315 TWh in 2015, to 674 TWh in 2025. Kenya has the highest growth rates, while Djibouti has the lowest.

Demand projections reflect the national projections for each country. Table 7 displays the forecasted yearly demand and peak demand for each country.

	2015		2020		2025	
	TWh	GW	TWh	GW	TWh	GW
BURUNDI	0.2	0.04	0.6	0.1	1.0	0.2
DJIBOUTI	0.8	0.1	0.9	0.2	1.0	0.2
DRC	18	3	31	5	41	7
EGYPT	201	32	280	44	378	60
ETHIOPIA	15	3	35	6	53	9
KENYA	13	2	42	7	61	10
LIBYA	34	5	47	7	64	10
RWANDA	0.9	0.1	2.0	0.3	2.5	0.4
SOUTH SUDAN	0.7	0.1	2.0	0.4	3.2	0.6
SUDAN	15	3	24	4	32	6
TANZANIA	11	2	20	3	27	4
UGANDA	5	1	8	1	12	2
Total	**315**	**51**	**492**	**80**	**675**	**110**

Table 7. Yearly electricity demand (TWh) and peak demand (GW) prognoses.[20]

The national forecasts cover different periods that do not always cover the entire projection period of the current study, i.e. until 2040. To extrapolate the forecast to 2040, the individual country forecasts have been linearly adjusted from their last year of projection to exhibit a 6% annual demand growth rate towards 2030, and a 3% annual growth rate in between 2030 and 2040. This assumption reflects the assumed decrease in demand growth rate as electricity access is provided to a larger share of the population of the EAPP

[19] The 10 EAPP countries plus South Sudan and Djibouti.

[20] *The load factor (Yearly demand/Peak demand*8760) is individual per country and is assumed to be constant in the studied period. Average load factor across all countries is 70%.*

region. Figure 5 illustrates the ambitious average annual growth rates projected in each respective countries' electricity demand forecast for the period 2015 - 2025.

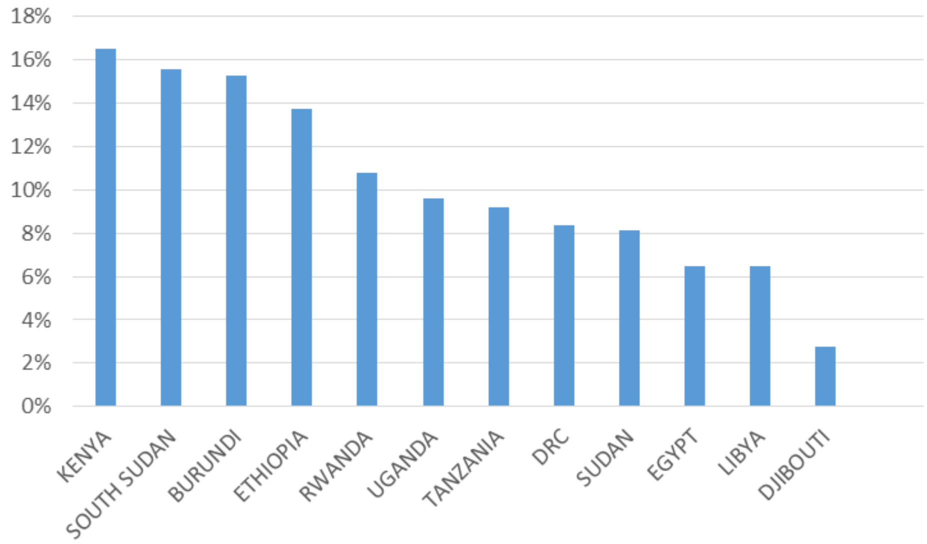


Figure 5. Average growth in electricity demand, 2015 to 2025. % p.a.

The total electricity demand projections for the EAPP (and adjoining countries) region modelled in this study is presented in Figure 6.

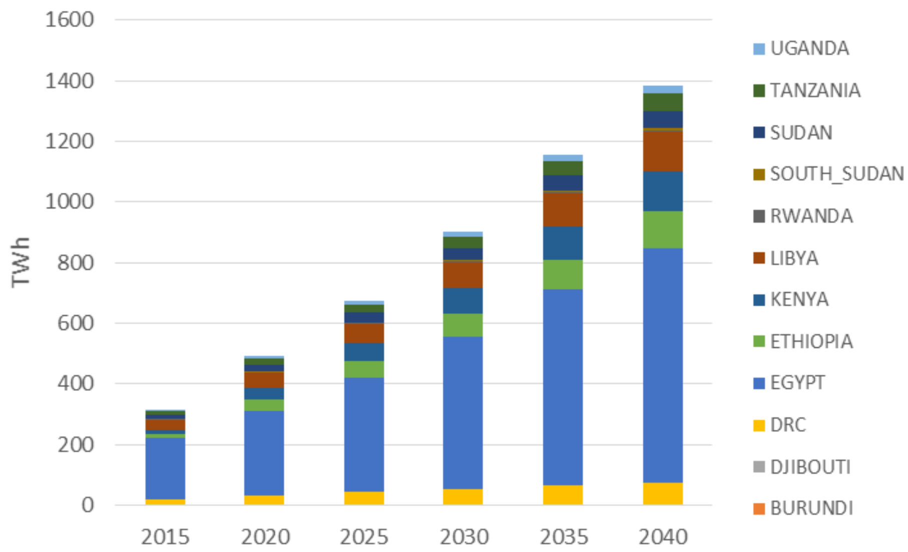


Figure 6. Projections of electricity demand developments from 2015 to 2040.

Challenges associated with power demand forecasting

The current prognoses for the electricity demand are much higher than previous prognoses. As an example, past prognoses for the year 2025 made in 2005, and 2011, along with that from 2014 are shown in Table 8. In several cases the current prognosis for 2025 demand are more than double that of earlier estimates.

Meanwhile, Sudan and South Sudan (seen together) have reduced their prognoses by 52% from 2011 to 2014.

TWh	Seen from 2005	Seen from 2011	Seen from 2014
Egypt	-	343	378
Ethiopia	-	23	53
Kenya	16	33	61
Sudan	-	69	32
South Sudan	-	-	3
Tanzania	9	9	27
Uganda	7	7	12

Table 8: Prognoses for the year 2025 for selected countries. From Master plans from 2005 (BKS Acres, 2005), 2011 and the current prognoses. The value from 2005 is the medium forecast.

Several countries have political focus on increasing electrification rates (see chapter 2). This will, together with economic growth, increase electricity demand.

In the model studies a cost of 1.2 $/kWh has been allocated to unserved demand.

Data uncertainty

Significant effort has been made during the Master Plan update process to obtain the best possible data for the modelling and scenario analyses. Demand forecasts are uncertain and have significant impact on the modelling results. Sensitivity analyses with higher and lower demand growth projections as compared to the Main scenario have been tested.

Fuel prices

In terms of the fuel prices utilised in the study, for oil and coal prices, the assumptions used are those from the IEA World Energy Outlook 2013. Due to the varying transportation costs for coal, the coal prices used in the project are country-specific.

With respect to natural gas prices, the difficulty lies in the fact that there currently is no transparent gas market in East Africa and the price is subsidised. As such, it was elected to use a price starting at the 2013 gas production cost, and having this converge to the 2030 EU price for natural gas as per the IEA World Energy Outlook 2013.

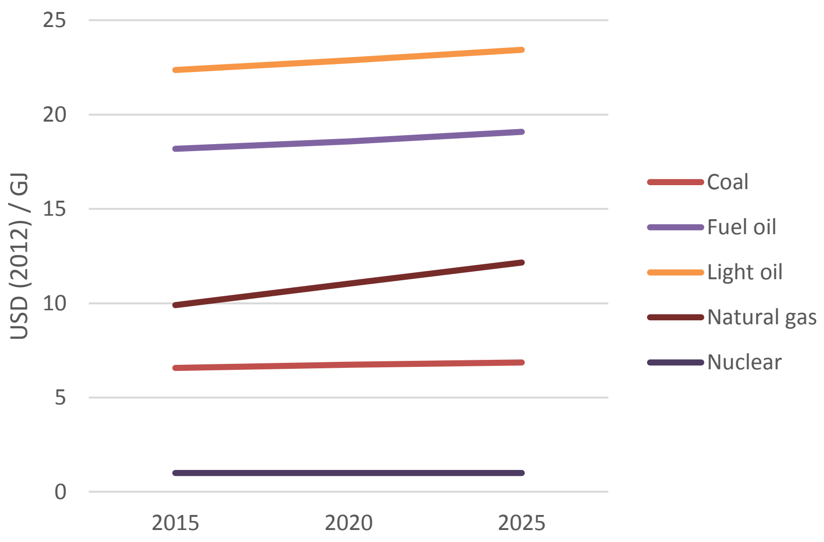


Figure 7. Fuel prices utilised (USD/GJ in 2012 USD real terms) for the years 2015-2025.

These fuel prices are in the order of 50% higher that the prices used in the 2011 Master plan. The source behind the 2011 data is not known.

Interest rate

A real interest rate of 10% p.a. (real) is used with a 20 year investment horizon. For investment in hydro and nuclear, a 50 year time horizon is used. The relatively high interest rate reflects the generally high demand for capital in the region, as well as the higher than average risk. A high interest rate makes the capital-intensive technologies such as hydro, geothermal and transmission relatively more expensive. This is illustrated by the sensitivity analyses.

The 2011 Master plan also used an interest rate of 10% p.a.

In the context of the current analysis, this can be interpreted as all model-based investments, both in generation and transmission, achieving an Internal Rate of Return (IRR) of 10% or higher.

Cost of generating technologies

The technology catalogue applied in this study is based on data from the International Energy Agency (IEA) and their World Energy Outlook 2013. The IEA catalogue is regional, which means that cost data is based on a review of the latest country data available for the African continent. The IEA also has an evolution in assumptions in the projection period towards 2035. This means that they apply learning curves depending on the development stage of the technology. E.g., solar PV is expected to develop more in terms of efficiency and capital costs than e.g. gas or steam turbines.

All technologies are described with the current and future values of efficiencies and costs, e.g. the cost of PV and wind power is expected to decrease 25% and 4% from 2020 to 2035, respectively.

It should be noted that the investment cost projections for solar PV technology of IEA WEO 2013 (maintained in WEO 2014) used in the current study represent medium cost reduction perspective. Alternative sources (e.g. OECD / IEA Technology Roadmap: Solar Photovoltaic Energy, 2014 edition) project significantly higher cost reduction pathways.

The opportunities to invest in the different technologies are not uniform across the region, e.g. because of differences in availability of resources in the different countries, e.g. access to natural gas. Policies regarding certain technologies such as nuclear and coal power also influence their future role in some countries.

Capital costs and resource availability for hydro and geothermal candidate plants are on a unit-by-unit basis based on feasibility studies, if available.

Table 9 presents an overview of the cost and performance data of the generic technologies available for model-based investments (i.e. above and beyond the existing and committed generation units) in the scenario simulations. In addition to the represented 184 existing plants, 140 committed plants are included in the model. Each existing and committed power plant is represented with name, capacity, fuel, efficiency and last year of expected operation

Technology type	Available (Year)	CAPEX incl. IDC ($M\$/MW_{el.}$)	Fixed O&M ($\$1,000/MW_{el}$)	Variable O&M ($\$/MWh_{el.}$)	Efficiency (%)	Technical lifetime (Years)
Steam Coal - Subcritical	2020	1.8	45	3.8	35%	30
Steam Coal - Supercritical	2020	2.2	63	5.3	40%	30
CCGT	2020-2034	0.8	25	2.1	59%	30
CCGT	2035	0.8	25	2.1	61%	30
Gas turbine	2020-2034	0.4	20	1.7	38%	30
Gas turbine	2035	0.4	20	1.7	40%	30
Geothermal*	2020	4.3	43	3.1		30
Medium Speed Diesel (MSD) Engine	2020	1.6	22	1.8	45%	30
Low Speed Diesel (LSD) Engine	2020	2.4	10	0.8	46%	30
Nuclear**	2020	5.7	140	0.0	33%	60
Solar PV	2020-2034	1.9	24	2.0		25
Solar PV	2035	1.5	23	1.9		25
Wind - onshore	2020-2034	1.5	22	3.7		20
Wind - onshore	2035	1.4	21	3.5		20

Table 9: Power generation technology catalogue. Efficiency is net lower heating value. For nuclear power all O&M costs are assumed to be fixed. Costs expressed in millions USD 2012 real values.
**Geothermal only available as an investment option for Ethiopia and Kenya, limited by the resource availability. Capital costs derived from "Republic of Kenya Updated LCPDP 2013-2033" (May 2013).*
***Nuclear only available as an investment option for Egypt and Kenya, constrained by the development limits set by the respective National Master Plans*

Table 10 provides an overview of the characteristics of the largest (400 MW and larger) *committed* projects modelled in the EAPP Master Plan 2014. Since 'committed' projects in the context of this study are almost exclusively denoted as projects with secured financing and/or on-going construction, the investment is considered to have already taken place. As such, the capital costs of the committed projects are not considered in the modelling process. Please see the Data Report (EAPP Master Plan 2014 Volume II: Data Report) for a comprehensive overview of all committed projects modelled in the EAPP Master Plan 2014.

Table 11, in turn, provides an overview of the characteristics of the largest (400 MW and larger) *candidate* projects modelled in the EAPP Master Plan 2014. These are the projects that are not considered 'committed' in the model, and hence the investment decision is being made by the model. Model-based investment in a given generation unit takes place if the addition of the unit would yield the lowest regional system costs, i.e. the least-cost solution. Since Balmorel is a linear optimisation model, investment in the exact optimal capacity level can be made, as long as it is lower or equal to the nominal capacity limit. Please see the Data Report (EAPP Master Plan 2014 Volume II: Data Report) for a comprehensive overview of all candidate projects modelled in the EAPP Master Plan 2014.

Generation profiles for solar power are taken from international databases with individual profiles per country. Full load hours for solar are estimated with individual values per country.[21]

For wind power a standardised profile is used and 2,200 full load hours are assumed. Some sites will have better wind resources, but more detailed data has not been available.

Please see the Data Report (EAPP Master Plan 2014 Volume II: Data Report) for a detailed overview of generation technology input data, as well as representative Levelised Cost of Energy estimates.

[21] Profiles with hourly values from: www.soda-is.com/eng/index.html
Full load hours: re.jrc.ec.europa.eu/pvgis/apps4/pvest.php?lang=en&map=africa

Status	BALMOREL area	Name	Type	Nominal capacity (MW_{el})	Fuel	Efficiency (net %)	Fixed costs ($1,000/ MW_{el})	Variable costs ($/$MWh_{el}$)	On power (Year incl.)	Technical lifetime (Years)
Committed	ET_A_Renaissance	Renaissance	HYDRO	6,000	Water - RESER		45.53	3.25	2019	50
Committed	EG_A_UPPER_EGYPT	HelwanSouthST	STPP	1,950	NG	40%	44.88	3.74	2018	30
Committed	ET_A_Gilgel_Gibe_III	Gilgel_Gibe_III	HYDRO	1,870	Water - RESER		45.53	3.25	2016	50
Committed	EG_A_UPPER_EGYPT	Giza_NorthCC	CCGT	1,750	NG	57%	25.50	2.13	2015	30
Committed	EG_A_EAST_DELTA	Ain_SokhnaST	STPP	1,300	NG	40%	44.88	3.74	2015	30
Committed	EG_A_WEST_DELTA	Abu_Kir_NewST	STPP	1,300	NG/HFO	39%	44.88	3.74	2013	30
Committed	KY_A_FutThe	KY_Coal	STPP	960	Coal	40%	44.88	3.74	2016	30
Committed	KY_A_FutThe	KY_Coal2	STPP	960	Coal	40%	44.88	3.74	2018	30
Committed	EG_A_CAIRO	Nile_Wind_EW_1	WPP	910	Wind		22.49	3.75	2015	20
Committed	EG_A_MIDDLE_DELTA	BanhaCC	CCGT	750	NG	57%	25.50	2.13	2015	30
Committed	KY_A_FutThe	KY_LNG	CCGT	700	NG	57%	25.50	2.13	2017	30
Committed	EG_A_EAST_DELTA	SuezST	STPP	650	NG	40%	44.88	3.74	2016	30
Committed	EG_A_UPPER_EGYPT	Assuit_New	STPP	650	HFO	29%	44.88	3.74	2018	30
Committed	EG_A_CAIRO	Nile_Wind_EW_2	WPP	600	Wind		22.49	3.75	2017	20
Committed	EG_A_CAIRO	6_October_CC_New	CCGT	600	NG	57%	25.50	2.13	2015	30
Committed	UG_A_Karuma_High	Karuma_High	HYDRO	600	Water - ROR		45.53	3.25	2019	50
Committed	UG_A_Ayago	Ayago	HYDRO	600	Water - ROR		45.53	3.25	2020	50
Committed	SD_A_FutThe	RedSea	STPP	534	Coal	41%	44.88	3.74	2017	30
Committed	EG_A_CAIRO	Suez_Gulf_Wind1	WPP	500	Wind		22.49	3.75	2015	20
Committed	EG_A_UPPER_EGYPT	Giza_NorthCC_2	CCGT	500	NG	57%	25.50	2.13	2016	30
Committed	EG_A_EAST_DELTA	El_ShababCC	CCGT	500	NG	57%	25.50	2.13	2017	30
Committed	SD_A_FutThe	Kosti	STPP	470	HFO	34%	44.88	3.74	2013	30
Committed	KY_A_FutThe	Menengai_2	Geo	460	Heat		43.25	3.09	2018	30
Committed	EG_A_CAIRO	Solar_EG	PV	425	Sunlight		29.38	0.24	2016	25
Committed	TZ_A_FutThe	Mtwara	CCGT	400	NG	57%	25.50	2.13	2017	30

Table 10: Overview of the characteristics of the largest (400 MW and larger) committed projects modelled in the EAPP Master Plan 2014. Costs expressed in millions USD 2012 real values.

Status	BALMOREL area	Name	Type	Nominal capacity (MW_{el})	Fuel	Efficiency (net %)	CAPEX ($M\$/MW_{el}$)	Fixed costs ($\$1000/MW_{el}$)	Variable costs ($\$/MWh_{el}$)	Available earliest (Year incl.)	Technical lifetime (Years)
Candidate	ET_HY_LongTerm	HY_LongTerm_ET	HYDRO	22,536*	Water - ROR		4.00	45.53	3.25	2030	50
Candidate	KY_A_NewGeo	KY_New_Geo	Geo	7,660*	Heat		4.31	43.25	3.09	2024	30
Candidate	DRC_W_Inga4	Inga4	HYDRO	7,424	Water - ROR		2.50	45.53	3.25	2030	50
Candidate	DRC_W_Inga5	Inga5	HYDRO	7,424	Water - ROR		2.50	45.53	3.25	2035	50
Candidate	DRC_W_Inga6	Inga6	HYDRO	7,424	Water - ROR		2.50	45.53	3.25	2035	50
Candidate	DRC_W_Inga7	Inga7	HYDRO	7,424	Water - ROR		2.50	45.53	3.25	2040	50
Candidate	DRC_W_Inga8	Inga8	HYDRO	7,424	Water - ROR		2.50	45.53	3.25	2040	50
Candidate	EG_A_Nuclear	EG_Nuclear	Nuclear	4,950	Nuclear	33%	5.56	125.46	0.00	2019	60
Candidate	ET_A_NewGeo	ET_GEO	Geo	4,925*	Heat		4.31	43.25	3.09	2020	30
Candidate	DRC_W_Inga3	Inga3	HYDRO	2,300	Water - ROR		2.00	45.53	3.25	2022	50
Candidate	ET_A_UpperMandaya	UpperMandaya	HYDRO	1,700	Water - RESER		1.93	45.53	3.25	2023	50
Candidate	ET_A_Karadobi	Karadobi	HYDRO	1,600	Water - RESER		2.17	45.53	3.25	2021	50
Candidate	ET_A_GibeIV	GibeIV	HYDRO	1,472	Water - ROR		2.29	45.53	3.25	2020	50
Candidate	ET_A_Tams	Tams	HYDRO	1,000	Water - RESER		7.85	45.53	3.25	2020	50
Candidate	ET_A_BekoAbo	BekoAbo	HYDRO	935	Water - RESER		1.82	45.53	3.25	2022	50
Candidate	KY_A_Nuclear	KY_Nuclear	Nuclear	900	Nuclear	33%	5.56	125.46	0.00	2019	60
Candidate	SS_A_Fula	Fula	HYDRO	890	Water - ROR		1.78	45.53	3.25	2024	50
Candidate	DRC_S_Luapula	Luapula	HYDRO	800	Water - ROR		2.50	45.53	3.25	2022	50
Candidate	DRC_E_WanieRukula	WanieRukula	HYDRO	688	Water - ROR		2.50	45.53	3.25	2021	50
Candidate	ET_A_GibeV	GibeV	HYDRO	660	Water - ROR		2.04	45.53	3.25	2020	50
Candidate	SD_A_Dal	Dal	HYDRO	648	Water - ROR		2.31	45.53	3.25	2030	50
Candidate	UG_A_Murchisson_F_High	Murchisson_F_High	HYDRO	648	Water - ROR		1.91	45.53	3.25	2025	50
Candidate	ET_A_Baro1_2	Baro1_2	HYDRO	645	Water - RESER		3.34	45.53	3.25	2020	50
Candidate	TZ_A_Steiglers_Gorge2	Steiglers_Gorge2	HYDRO	600	Water - RESER		0.72	45.53	3.25	2024	50
Candidate	SS_A_Bedden	Bedden	HYDRO	570	Water - ROR		2.30	45.53	3.25	2024	50
Candidate	ET_A_LowerDedessa	LowerDedessa	HYDRO	550	Water - RESER		1.46	45.53	3.25	2020	50
Candidate	TZ_A_Aumakali	Rumakali	HYDRO	520	Water - RESER		1.38	45.53	3.25	2025	50
Candidate	ET_A_BirbirR	BirbirR	HYDRO	467	Water - RESER		3.43	45.53	3.25	2020	50
Candidate	ET_A_Tekeze2	Tekeze2	HYDRO	450	Water - RESER		5.07	45.53	3.25	2020	50
Candidate	ET_A_HaleleWerabessa	HaleleWerabessa	HYDRO	436	Water - RESER		2.74	45.53	3.25	2020	50
Candidate	SD_A_Shereik	Shereik	HYDRO	420	Water - ROR		3.25	45.53	3.25	2020	50
Candidate	SS_A_Lakki	Lakki	HYDRO	410	Water - ROR		1.62	45.53	3.25	2024	50

Table 11: Overview of the characteristics of the largest (400 MW and larger) candidate projects modelled in the EAPP Master Plan 2014. Costs expressed in millions USD 2012 real values.
** Cumulative potential capacity indicated, gradual investments over time possible (as for all other candidate projects). Constraints implemented on the development rate of geothermal potential (2,000 MW per 5 years in Kenya, 1,500 MW per 5 years in Ethiopia, increasing to 1,800 MW toward the end of the projection period).*

Cost of transmission

Where feasibility studies exist for transmission projects, costs from these studies are used (see Table 12). If no such cost estimates exist, costs are estimated with the method also used in the 2011 Master Plan (see Table 13). The technology catalogue for model-based transmission investments in the current study consists of 27 different transmission projects (characteristics of 18 of them is based on feasibility or similar studies, whereas the data on the remaining 9 has been estimated). Please see Volume I: Data Report for more information.

The Balmorel model can freely invest in any of the transmission projects options[22] based on least-cost optimisation principle for the entire modelled region. The Balmorel model uses the specific cost (USD/MW), and can invest in any size of line. Practical aspects related to the selecting of appropriate capacities is not included at this stage.

[22] Special limitations apply to the internal DRC transmission investments. See Grand Inga section in the Long-term perspectives, 2030 – 2040, Generation chapter. A direct DC connection from the Grand Inga site (DRC West) to Egypt is only made available as an investment option in the 'Inga North East' scenario, and not before 2030.

To/From	From/To	Type (AC/HVDC)	Voltage (kV)	Distance (km)	Capacity (MW)	Construction time (years)	Total costs (incl. IDC) (M$)	Costs per km (M$/km)	Costs per MW (M$/MW)	Source
DRC East	Burundi	AC	220	78	49	2	41	0.53	**0.83**	Burundi
DRC East	Rwanda	AC	220	46	300	2	89	1.93	**0.30**	Rwanda
DRC East	Uganda	AC	220	352	600	4	134	0.38	**0.22**	Uganda
DRC south	DRC east	AC	220	841	500	5	227	0.27	**0.45**	DRC
DRC west	DRC south	AC	400	1,700	1,000	9	1,110	0.65	**1.11**	DRC
DRC west	*Egypt**	*HVDC*	*600*	*5351*	*3500*	*10*	*7,521*	*1.41*	*2.15*	*AECOM & EDF*
Egypt	Sudan**	AC	500	775	1,000	4	444	0.57	**0.44**	Sudan
Egypt	Sudan	HVDC	600	1,665	2,000	4	1,385	0.83	**0.69**	NBI
Ethiopia	Kenya	HVDC	500	1,068	2,000	4	1,260	1.18	**0.63**	AFDB
Kenya	Tanzania	AC	400	508	1,300	3	214	0.42	**0.16**	NBI & Tanzania
Rwanda	Burundi	AC	220	131	300	3	55	0.42	**0.18**	Rwanda
South Sudan	Ethiopia	AC	220	300	300	3	101	0.34	**0.34**	EAPP and AFDB
South Sudan	Uganda	AC	400	200	1,000	3	117	0.59	**0.12**	NBI
Sudan	Ethiopia	AC	500	550	1,200	4	267	0.49	**0.22**	NBI***
Tanzania	Burundi	AC	220	161	27	3	44	0.27	**1.66**	Burundi
Uganda	Kenya	AC	400/220	254	600	3	92	0.36	**0.15**	Uganda&Kenya
Uganda	Rwanda	AC	220	172	600	3	61	0.35	**0.10**	Uganda&Rwanda
Uganda	Tanzania	AC	220	271****	400	4	172	0.63	**0.43**	Uganda&Tanzania

Table 12. Cost of candidate transmission projects. Based on feasibility studies or national plans. Costs expressed in millions USD 2012 real values.
** A direct DC connection from the Grand Inga site (DRC West) to Egypt is only made available as an investment option in the 'Inga North East' scenario, and not before 2030.*
*** The Egypt-Sudan AC line is limited to a maximum of 1000 MW, hereafter the model will need to invest in HVDC.to increase the capacity on this border.*
**** The NBI cost estimate for the Ethiopia-Sudan line has been updated to reflect the pre-existing 500 kV substation as well as closer expected geographical location*
***** The length of the Uganda – Tanzania line has been reduced from 640 km to 271 km to reflect the currently on-going line developments. The costs per MW have been adjusted accordingly*

To/From	From/To	Type (AC/HVDC)	Voltage (kV)	Distance (km)	Capacity (MW)	Construction time (years)	Total costs (incl. IDC) (M$)	Costs per km (M$/km)	Costs per MW (M$/MW)	Source
DRC East	Tanzania	AC	220	678	300	4	229	0.34	**0.76**	Estimated
DRC west	DRC east	AC	400	1,710	1,000	9	1,204	0.70	**1.20**	Estimated
Ethiopia	Djibuti	AC	220	283	300	3	98	0.35	**0.33**	Estimated
Libya	Egypt	AC	220	163	300	3	62	0.38	**0.21**	Estimated
Libya	Sudan	HVDC	500	1,400	1,000	4	849	0.61	**0.85**	Estimated
Rwanda	Tanzania	AC	220	115	320	3	47	0.41	**0.15**	Estimated
South Sudan	DRC east	HVDC	500	583	1,000	4	550	0.94	**0.55**	Estimated
South Sudan	Kenya	HVDC	500	540	1,000	4	534	0.99	**0.53**	Estimated
Sudan	South Sudan	AC	220	400	300	4	141	0.35	**0.47**	Estimated

Table 13. Estimated cost of additional candidate transmission projects. Costs expressed in millions USD 2012 real values.

5 Model results, 2020 – 2025

This chapter presents the key results from the model. In Volume III: Results Report, the results are presented in more detail: For 20 scenarios, all years (2020 – 2040 in five-year steps) and for all 12 individual countries.

For the sake of simplicity, it is primarily detailed results for the Main scenario that are presented here – and often aggregated for 2020 and 2025. Insights from specific years and scenarios are included where relevant. In next chapter the results from 2030 to 2040 are presented.

A key feature in least-cost dispatch and least-cost investment in generation and transmission is the marginal cost of generating electricity in each time step.[23] Figure 8 displays the average price in the Main scenario based on the marginal cost of generation. The three northern countries (Libya, Egypt and Sudan) have the highest price and the western and central countries (DRC, Uganda, Burundi and Rwanda) have the lowest prices (in 2025). This pattern is relevant for the flow of electricity: From west/central to North and South. The same order of costs exists in practically all scenarios (except the scenario without investment in transmission and in the dry and wet year scenarios).

[23] The marginal cost, i.e. the most expensive generator delivering electricity, is a price referred to in market studies. However, the computed price does not depend on the existence of a free market. With technical least-cost dispatch the same price can also be computed. The price for a certain time step can be the same in several countries – depending on the available transmission capacity between the countries. When there is a lack of sufficient transmission capacity the price will be the different in different countries (for a specific time step). The line will then be fully loaded in the direction from the low price area to the high price area. The dispatch (and the modelled power price) is based on Short-Run Marginal Cost (SRMC) whenever possible; however, if additional investments are needed for a least-cost solution, and SRMC pricing would not cover the investment costs, the investment costs are then distributed across the hours when the newly invested plant is activated. In these instances the modelled power price would still be the marginal cost of generation, yet not SRMC.

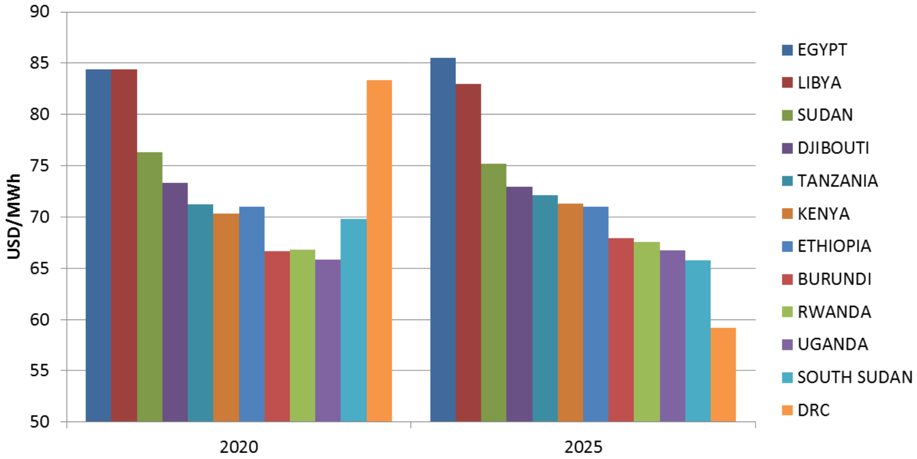


Figure 8. Average marginal cost of generation in the Main scenario. Note, the Y-axis starts at 50 USD/MWh. Countries are sorted according to the price in 2025. Represented in 2013 USD values, real terms.

Generation

Main scenario

Based on all the inputs, the model invests in generation and transmission using a least-cost approach. Table 14 displays the investment in generation in the Main scenario. In Libya and Egypt, the preferred technology is natural gas, while hydro and geothermal are exploited where such potentials exist. Investment in coal takes place in Sudan. It should be noted that coal is only marginally more expensive than natural gas in Egypt. Given the current natural gas shortages in Egypt, a more balanced mix in coal and natural gas could be considered.

A requirement has been included in the model that stipulates all countries must have domestic capacity corresponding to 110% of the yearly peak demand. The oil capacity invested in South Sudan is primarily undertaken in order to fulfil this requirement. These oil-based plants will only have very limited generation.

Investments in hydropower capacity in the DRC are higher than seen in the 2011 Master Plan, where only East DRC was included. Significant investment takes place in hydro in South Sudan (1,895 MW in 2025).

Please see Volume III: Results Report for the specific results on individual project level for each country.

Year	Country	Existing and Committed (MW)								Model-based investments (MW)					Total (MW)
		Natural gas	Coal	Hydro	Geothermal	Oil	Wind	Solar PV	Other*	Natural gas	Coal	Hydro	Geothermal	Oil	
2015	Burundi			39		17		20							76
	Djibouti				50	122									172
	DRC			2,596		18									2,614
	Egypt	27,359		2,800		1,645	1,956	140							33,900
	Ethiopia			1,934	5	78	324		172						2,513
	Kenya			794	636	730	86		44						2,290
	Libya	4,530				1,770									6,300
	Rwanda			49		97		18	42						206
	South Sudan					33									33
	Sudan			1,565		1,172		10	100						2,847
	Tanzania	861		565		65			19						1,510
	Uganda			691		100			44						835
	2015 Total	**32,750**		**11,033**	**691**	**5,847**	**2,366**	**188**	**421**						**53,296**
2020	Burundi			147		17		20							184
	Djibouti				50	122					7				179
	DRC			2,670		18				3,284	1,046	193			7,210
	Egypt	25,724		2,800		1,645	2,756	565		21,696					55,186
	Ethiopia			10,058	75	78	324		614			858			12,007
	Kenya	1,058	1,920	794	2,321	391	636		44	609		140			7,913
	Libya	2,872				740				5,449					9,061
	Rwanda	50		76		55		28	297						506
	South Sudan			42		33								313	388
	Sudan		534	1,885		1,525	20	10	100		468	420			4,962
	Tanzania	2,901	700	592		65	100	120	19			987			5,484
	Uganda			2,226	50	150		20	107				200		2,753
	2020 Total	**32,605**	**3,154**	**21,290**	**2,496**	**4,839**	**3,836**	**763**	**1,181**	**31,038**	**1,521**	**2,598**	**200**	**313**	**105,833**
2025	Burundi			147		17		20				33			217
	Djibouti				50	122					24				196
	DRC			2,670		18				3,284	1,046	4,221			11,238
	Egypt	21,912		2,800		1,645	2,756	565		39,495					69,173
	Ethiopia			10,058	75	78	324		614			5,417			16,566
	Kenya	1,058	1,920	794	2,321	391	636		44	2,382		140	1,679		11,365
	Libya	2,100								8,992					11,092
	Rwanda	50		76		55		28	297						506
	South Sudan			42		33						1,895		313	2,283
	Sudan		534	1,885		1,525	20	10	100		1,587	780			6,441
	Tanzania	2,901	700	592		65	100	120	19			2,707			7,204
	Uganda			2,226	50	150		20	107				200		2,753
	2025 Total	**28,021**	**3,154**	**21,290**	**2,496**	**4,099**	**3,836**	**763**	**1,181**	**54,152**	**2,657**	**15,193**	**1,879**	**313**	**139,034**

Table 14: Existing and committed, and model-based (cumulative) investments in new generation capacity in MW in the Main scenario in modelled years 2015, 2020 and 2025.
** 'Other' includes bagasse-, coke-, methane-, municipal waste-, peat- and wood-based generation.*

Egypt and Libya

In the Main scenario, model-based investments in Egypt exceed 39,000 MW of natural gas-based generation towards 2025. Given the current natural gas supply crisis in Egypt, this is a critical issue. It should be noted that natural gas is cheaper than coal under the applied assumptions, but that the difference is marginal. Note that that the plans for Egypt (see Table 4) also have investment in natural gas-based generation, and in addition to this, significant investments in nuclear, coal and wind power.

If the interest rate is reduced from 10% to 8%, investment in Egypt and Libya will shift to coal in 2025. Coal power plants are more capital-intensive than natural gas plants, so the natural gas solution has a competitive advantage in a situation with higher interest rates. In addition, if the European natural gas price forecast is used, coal will be most economic – already in 2020. The results are similar for Libya.

Kenya

In Kenya, the model only invests in geothermal power. This is mainly caused by the large amount of committed generation capacity (960 MW coal, 1,050 MW LNG, 581 MW wind, and 740 MW geothermal added as committed). In 2025, geothermal is 35% of the total capacity in Kenya.

Renewable energy

No model-based investments in nuclear, solar or wind power take place in the Main scenario. This is due to the fact that these technologies are more expensive than the alternatives. In the context of the current study, renewable energy sources (RESs) are defined as follows: generation based on hydro (also large hydro), wind, solar, geothermal, biomass (bagasse and wood), municipal waste and methane (only relevant for Rwanda, and considered renewable because of its origin of Lake Kivu deposits).

In the Renewable scenario, the required renewable capacity in 2025 is delivered by hydro (1,720 MW) and geothermal (1,414 MW), with wind power only playing a marginal role (19 MW).

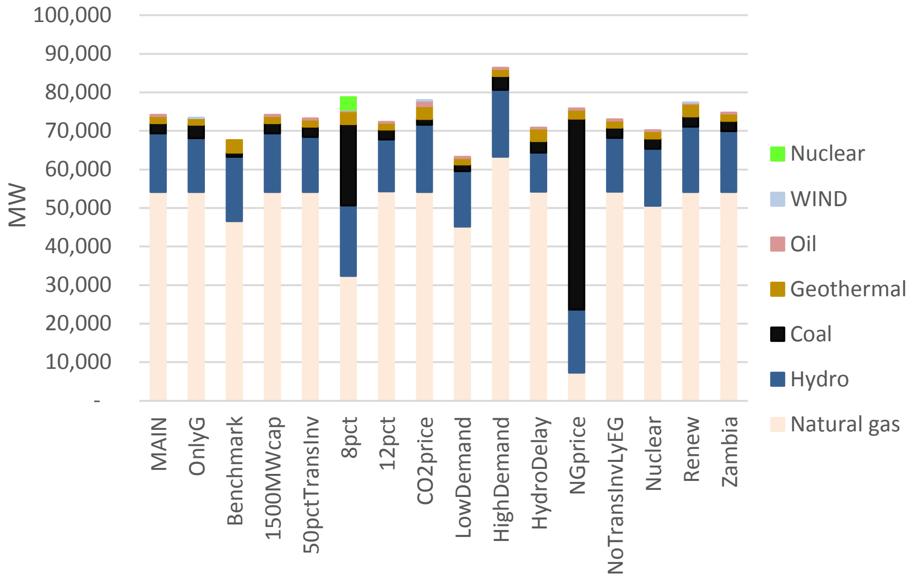


Figure 9. Model-based investments in generation in MW, 2020-2025, across all scenarios[24].

Other scenarios

Figure 9 shows the investment in generation across all scenarios. The general patterns are very robust against the many changes in assumptions. The largest difference is in the scenario with an international market price for natural gas ('NG price'). Due to the higher natural gas price in this scenario, large investments in coal-fired generation take place.

The results in the Main scenario can be compared to the scenario where only investments in generation are allowed ('Only G'). In this scenario, the total new capacity is practically unchanged (1% lower capacity), but the distribution of technologies invested in is different, i.e. less hydro (300 MW in the DRC and 900 MW in South Sudan) and geothermal, and more coal (mostly in Sudan). These results highlight the interdependence of generation and transmission project development (sequencing risk) in South Sudan and the DRC in particular. I.e., in the absence of possibility to construct additional regional transmission lines, less hydro generation capacity is being developed there.

If the requirement that each country must have 110% domestic generation capacity is lifted, total capacity invested in would be reduced by 9% (-6,500 MW), however investment in hydro and geothermal would be increased. The capacity invested in to fulfil the 110% requirement undermines the business case for additional hydro and geothermal.

[24] Four scenarios are not shown because then are similar to the Main scenario in 2020 and 2025: The Grand Inga North West (the connection is allowed from 2030) and the Long term hydro (with lower hydro cost after 2030).

Hydro variability implications

Three separate scenarios have been created to assess the implications of possible hydrological variability on the projected regional power system set-up based on the Main scenario: Dry, Wet (modelling the conditions of 1-in-10 years' dry and wet year, respectively), and Driest (modelling the conditions of the driest year over the available 1972 – 2006 observation period)[25]. The projections of both Dry and Driest scenarios over the projection period of 2020 to 2040 indicate that the regionally integrated system based on the Main scenario would be fully capable of accommodating both the specific hydrological conditions of 1-in-10 historic dry year, and 1-in-34 historic dry year[26].

Transmission

Main scenario

Results for the model-based least-cost transmission investments are presented in Table 15. The table shows the nine specific model-based interconnections (and their respective capacities) established in the Main scenario in 2020 and 2025, respectively. For six of the projects, capacity is feasible already by 2020, whereas three of the projects become feasible in 2025. Three of the projects that are recommended for 2020 have extra capacity in 2025.

The largest projects are the interconnections from Ethiopia via Sudan to Egypt. In addition, West – East interconnections are feasible.

Another major project of importance is the Rwanda – Tanzania line, where a capacity of 954 MW becomes feasible by 2025. It should be noted that the Rwanda – Tanzania line is used to transport hydropower from the DRC and Uganda to Tanzania. The model chooses to go through Rwanda because this line, under the applied assumptions, has the lowest costs. A feasibility study should analyse if this is the case, as a line e.g. going directly from the DRC to Tanzania might be more economic.

[25] See more information on the scenarios and the results in Volume III: Results Report.
[26] It should be noted that Main scenario includes 110% capacity as a fraction of national peak load requirement. Minor instances of unserved demand (under 0.1% of the total power generation in the respective area) are observed in DRC South area.

MW	2020	Cumulative 2020+2025	Utilization rate ->	Utilization rate <-	Robustness
Sudan – Ethiopia	1,596	1,596	3%	45%	82-250%
Egypt – Sudan	500	1,000	0%	83%	41-201%
Rwanda – Tanzania	196	954	58%	0%	59-112%
Rwanda – DRC	-	318	0%	68%	0-132%
Uganda – South Sudan	623	623	2%	17%	95-107%
Libya – Egypt	176	176	57%	7%	0-402%
Kenya - Uganda	277	624	0%	63%	100-140%
DRC - Uganda	-	488	26%	0%	78-167%
Sudan – South Sudan	-	330	0%	85%	0-187
Total	3,369	6,110			

Table 15: Investment in new transmission capacity (2020 and cumulative for 2020+2025) in the Main scenario. The electricity transported in 2025 is indicated as utilization rate in both directions. The robustness is measured by the change in capacity when comparing the Main scenario with the five other scenarios: 'Benchmark (removal of 110% of peak demand requirement)',' Higher Transmission Cost', 'Hydro Delay', 'High Demand' and 'Low Demand' scenarios. See chapter 3 for definition of scenarios.

The model-based least-cost transmission investments are relatively robust across the different scenarios. The risk for investing in a too high capacity is limited, however in several scenarios the optimal size is larger than in the Main scenarios. See Table 16 for the impact of different scenarios on the Ethiopia – Sudan line. The Main scenario is in the middle of the range.

Scenario	Recommended capacity (MW)
8% rate	4,258
Benchmark *	3,985
NG price	3,810
Renewable	3,661
CO2 price	3,577
Low Demand *	2,439
Main	1,596
Nuclear	1,596
Delay Ly & Eg	1,567
Zambia	1,554
1,500 MW	1,500
12% rate	1,387
Hydro Delay *	1,376
50 % increase *	1,324
High Demand *	1,315

Table 16. Optimal size of Ethiopia – Sudan transmission line (in 2025) across all scenarios[27]. Please see Volume III: Results Report for full overview across all transmission lines and scenarios.
** Indicates scenarios that are used in the robustness test.*

Compared to the 2011 Master Plan, the main difference is that the connection between Sudan and Egypt is reduced significantly. A 200 MW AC connection is included as committed in the model. The demand (e.g. in Ethiopia) is much higher in the current prognosis compared to the one used in the 2011 Master plan. This means that a larger share of the hydro is used locally. If on the other hand electricity demand is reduced by 10% (as is the case in the "Low Demand" scenario as outlined in the table above), then the Ethiopia – Sudan line is increased by 50%. The capacity also increases if the natural gas price is increased, or a CO_2 price is introduced. In both cases the marginal electricity price in Egypt and Sudan will increase – making in more attractive to transport electricity in this direction. More hydro and geothermal (as in the renewable scenario) also increases the capacity. In the scenario without the requirement of 110% local capacity (the benchmark scenario), the capacity is more than doubled. In this scenario less generation capacity exist in e.g. Egypt and Sudan and more in Ethiopia. This motivates more transmission capacity.

[27] Six scenarios are excluded. In the Only G scenario no investment take place – by definition. The Grand Inga North West and the Long term hydro are similar to the Main scenario in 2025. The Dry, Wet and Driest years' scenarios have same investments as the Main scenario. See Volume III: Results Report for more information.

Higher model-based transmission investment take place in the Tanzania – Uganda and Rwanda – Tanzania lines compared to the 2011 Master Plan recommendations. This is caused by higher hydropower investments in the DRC and Uganda.

Moreover, a number of additional lines are analysed in this study, e.g. three lines to South Sudan and two lines to Libya. Libya and South Sudan were not included in the 2011 Master Plan.

The least-cost model-based transmission investments are not affected by the exogenous (forced) investment in nuclear in Egypt and Kenya in the Nuclear scenario. Nuclear-based generation will always operate as base load, and will never be the marginal generation. Therefore, the transmission capacity and the flow on the lines will not change in this scenario because the Kenyan and Egyptian demand at this time is high enough for the nuclear plants to operate as domestic base load only.

Delay of the Sudan – Egypt line (-1,000 MW) until after 2025 calls for a reduction in the Sudan – South Sudan connection (-330 MW), and a reduction in investment in hydro power (-1,200 MW). The impact on the other transmission and generation investments are limited.

Sensitivity analysis

Table 17 and Table 18 show the sensitivity to respective changes in interest rates and electricity demand. The impact of altering the interest rate by just 2 percent points is very significant. Higher interest rates result in less transmission due to the capital intensive nature of these investments. For electricity demand, the results indicate that higher demand results in lower transmission – simply because generation from low cost sources is used to cover local demand. Note that of the various scenarios undertaken, variations of the interest rate or electricity demand had the largest impact on the results.

From / To (MW)	8%	Main (10%)	12%
DRC			
RWANDA	262	318	301
UGANDA	689	488	505
EGYPT			
LIBYA	237	176	58
SUDAN	3,877	1,000	268
ETHIOPIA			
SUDAN	4,258	1,596	1,387
KENYA			
UGANDA	984	624	518
LIBYA			
EGYPT	237	176	58
RWANDA			
DRC	262	318	301
TANZANIA	919	954	823
SUDAN			
EGYPT	3,877	1,000	268
ETHIOPIA	4,258	1,596	1,387
SOUTH_SUDAN	502	330	
SOUTH SUDAN			
SUDAN	502	330	
UGANDA	627	623	647
TANZANIA			
RWANDA	919	954	823
UGANDA			
DRC	689	488	505
KENYA	984	624	518
SOUTH_SUDAN	627	623	647

Table 17. Recommended new transmission capacity in MW by 2020 and 2025 dependent on the interest rate utilised.

From / To (MW)	Low Demand (-10%)	Main	High demand (+10%)
RWANDA		318	419
UGANDA	813	488	383
EGYPT			
LIBYA	205	176	185
SUDAN	2,009	1,000	711
ETHIOPIA			
SUDAN	2,439	1,596	1,315
KENYA			
UGANDA	705	624	874
LIBYA			
EGYPT	205	176	185
RWANDA			
DRC		318	419
TANZANIA	563	954	1,068
SUDAN			
EGYPT	2,009	1,000	711
ETHIOPIA	2,439	1,596	1,315
SOUTH_SUDAN	617	330	
SOUTH SUDAN			
SUDAN	617	330	
UGANDA	593	623	656
TANZANIA			
RWANDA	563	954	1,068
UGANDA			
DRC	813	488	383
KENYA	705	624	874
SOUTH_SUDAN	593	623	656

Table 18. Recommended new transmission capacity in MW by 2020 and 2025 dependent on the electricity demand prognoses.

Economic analyses

The approach to economic analysis employed in this study is based on the concept of 'Total System costs' derived in the Balmorel modelling process. In the Balmorel modelling framework, the system costs consist of:

- Investment costs - annualised[28] (for new model-based investments in generation and transmission)
- Fixed O&M costs (for all of the operating units)
- Variable O&M costs (for all of the operating units)

[28] A real interest rate of 10% p.a. (real) is used with a 20 year investment horizon assumption. For investment in hydro and nuclear, a 50 year time horizon is used. In the context of the current analysis, this can be interpreted as all model-based investments, both in generation and transmission, achieving an IRR of 10% or higher.

- Fuel costs (for all fuel used in power generation)

The system costs <u>do not</u> include the capital costs of the existing and committed plants.

The system costs are calculated for each of the scenarios modelled, and comparisons across different scenarios can then be carried out to establish the additional cost/benefit of the respective parameter variation introduced (the majority of the scenarios have been constructed in such a way that only a single parameter variation vis-à-vis the Main scenario has been made, thereby making such comparisons possible).

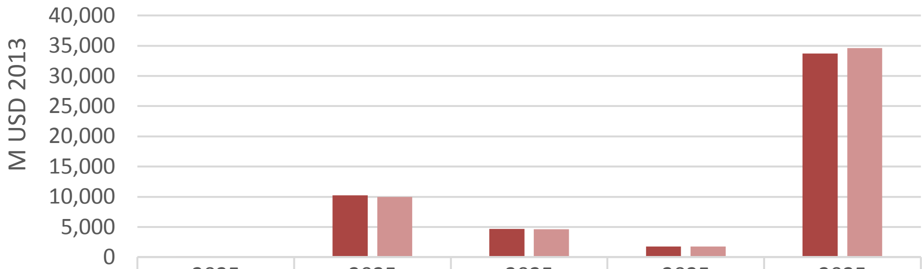
Value of regional transmission

Scenario analysis allows for an estimation of the value of regional transmission. In order to arrive at this estimate, the following two scenarios need to be compared:

- Main scenario (simultaneous optimisation of generation and transmission investments and dispatch allowed);
- Only G scenario (only optimisation of generation investments and dispatch allowed, ceteris paribus).

The possibility to construct additional regional transmission projects is the only difference between the 2 scenarios. Hence, the difference in the system costs of the 2 scenarios will indicate the benefit (or cost) of 'regional transmission'.

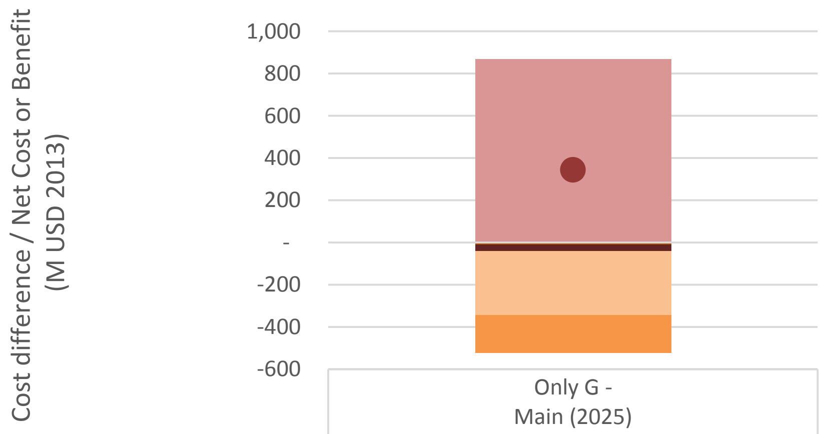
Figure 10 provides a comparison of the components constituting the total system costs across the two scenarios for the modelled year 2025. As one can see from the graph, the Main scenario results in higher capital costs, as well as expenditure related to investments in electricity transmission. The Only G scenario on the other hand, results in considerably higher total fuel costs (and no costs related to transmission investments – in accordance with the scenario definition).



	2025 Annualised Investment in transmission (M$/year)	2025 Annualised Investment in generation (M$/year)	2025 Annual Fixed O&M (M$/year)	2025 Annual Variable O&M (M$/year)	2025 Annual Fuel Cost (M$/year)
Main	178	10,266	4,671	1,769	33,738
Only G		9,962	4,639	1,759	34,606

Figure 10: System cost comparison by cost component between the Main and Only G scenarios for the modelled year 2025 in millions of USD, expressed in 2013 real values.

Once the respective total system costs are stacked against each other, as illustrated in Figure 11 (the costs of the Main scenario are subtracted from the costs of the Only G scenario), the net difference between the Only G and Main scenarios can be calculated.



	Only G - Main (2025)
Annualised Investment in transmission	-178
Annualised Investment in generation	-303
Annual Fixed O&M	-32
Annual Variable O&M	-10
Annual Fuel Cost	867
TOTAL (Net Cost / Benefit)	344

Figure 11: System cost comparison by cost component (and the total net cost / benefit) between the Main and Only G scenarios for the modelled year 2025 in millions of USD, expressed in 2013 real values (Only G – Main).

The resulting 344 million USD cost difference (costs of Only G – costs of Main) indicates that Only G results in higher total system costs, and that the cost reduction potential (i.e. the value) of introducing additional regional transmission possibility (based on the set of inputs and assumption used in the current analysis) amounts to 344 million USD in 2025.

The total cost of supplying electricity in the region is 50.6 billion USD in 2025 (in the Main scenario). 66.6% of the total cost is fuel costs, 13% operation and maintenance costs, 20% investment in generation (annual costs) and 0.4% investment in transmission (annual costs).[29] When comparing the scenario without transmission investments (Only G) with the Main scenario in 2025, the difference between the two scenarios is almost exclusively the extra investment in transmission, which also makes way for an alternative mix of investment in generation. Together, the investment in transmission and the new generation mix result in a reduction of the annual fuel costs of 867 million USD. For each dollar invested in transmission and generation (total additional expenditure in the Main scenario of 481 million USD), the total benefit (net difference of 344 million USD) is increased by 0.7 USD (344 / 481 = 0.7).

Cost of national security of supply

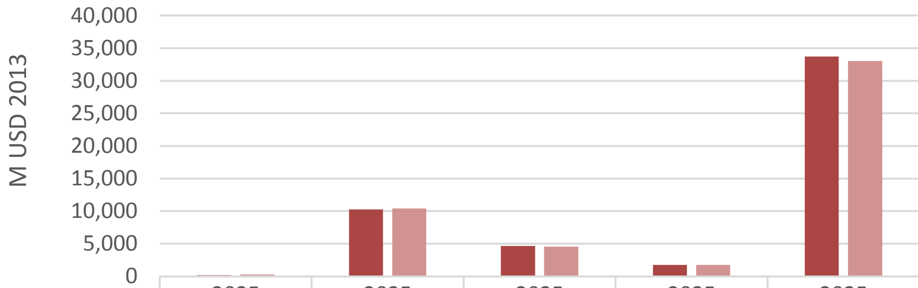
Using the same approach, the cost of fulfilling the national security of supply requirements (as represented by the 110% national capacity requirement), can be calculated. The system costs of the following two scenarios will be compared:

- Main scenario (requirement for national generating capacity to match 110% of national peak load);
- Benchmark scenario (no requirement for national generating capacity to match 110% of national peak load, ceteris paribus).

The introduction of the 110% capacity requirement in the Main scenario is the only difference vis-à-vis the Benchmark scenario. Hence, the difference in the system costs of the 2 scenarios will indicate the cost of the national security of supply requirement.

Figure 12 provides a comparison of the components constituting the total system costs across the two scenarios for the modelled year 2025. As outlined in the graph, the Main scenario results in slightly lower capital costs, as well as lower expenditure related to investments in electricity transmission. The Benchmark scenario, in turn, results in considerably lower fuel costs.

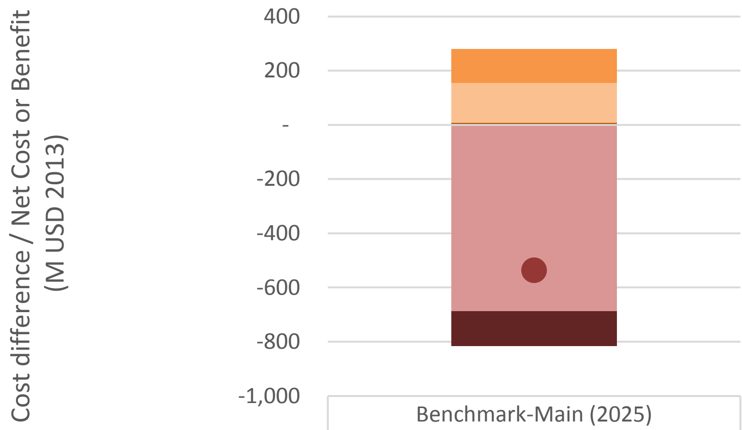
[29] Capital costs of existing and committed generation and transmission lines are not included in these numbers and considered sunk costs.



	2025 Annualised Investment in transmission (M$/year)	2025 Annualised Investment in generation (M$/year)	2025 Annual Fixed O&M (M$/year)	2025 Annual Variable O&M (M$/year)	2025 Annual Fuel Cost (M$/year)
Main	178	10,266	4,671	1,769	33,738
Benchmark	302	10,413	4,543	1,777	33,051

Figure 12: System cost comparison by cost component between the Main and Benchmark scenarios for the modelled year 2025 in millions of USD, expressed in 2013 real values.

Once the respective total system costs are stacked against each other, as illustrated in Figure 13 (the costs of the Main scenario are subtracted from the costs of the Benchmark scenario), the net difference between the Benchmark and Main scenarios can be calculated.



	Benchmark-Main (2025)
Annualised Investment in transmission	123
Annualised Investment in generation	148
Annual Fixed O&M	-128
Annual Variable O&M	8
Annual Fuel Cost	-687
TOTAL (Net Cost / Benefit)	-536

Figure 13: System cost comparison by cost component (and the total net cost / benefit) between the Main and Benchmark scenarios for the modelled year 2025 in millions of USD, expressed in 2013 real values (Benchmark – Main).

The resulting -536 million USD cost difference (costs of Benchmark – costs of Main) indicates that Benchmark results in lower total system costs, and that the additional cost required to comply with the national security of supply requirement in the EAPP region in 2025 (based on the set of inputs and assumption used in the current analysis) amounts to 536 million USD.

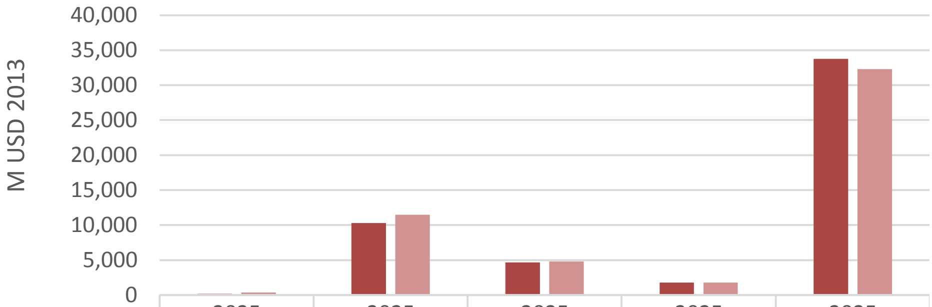
Cost of higher RES share

Lastly, the same approach is utilised to arrive at an estimate of the additional cost required for the EAPP region to achieve a higher share of RES generation. The following two scenarios are compared:

- Main scenario (no requirement for RES share);
- Renewable scenario (35% RES requirement by 2025, ceteris paribus).

The introduction of the 35% RES generation requirement in the Renewable scenario is the only difference vis-à-vis the Main scenario. Hence, the difference in the system costs of the 2 scenarios will indicate the additional cost of meeting the 35% RES generation requirement. It should be noted that generation from RES reaches 32% in 2025 in the Main scenario.

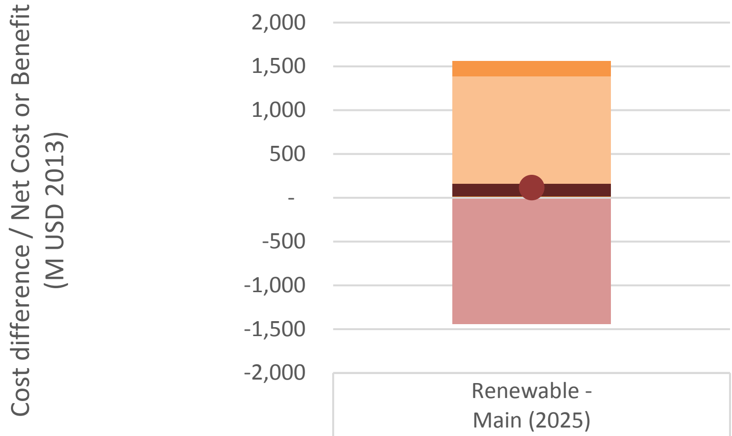
Figure 14 provides a comparison of the components constituting the total system costs across the two scenarios for the modelled year 2025. As depicted in the graph, the Renewable scenario results in significantly higher capital costs, as well as slightly higher expenditure related to investments in electricity transmission. On the other hand, it yields considerably lower fuel costs relative to the Main scenario.



	2025 Annualised Investment in transmission (M$/year)	2025 Annualised Investment in generation (M$/year)	2025 Annual Fixed O&M (M$/year)	2025 Annual Variable O&M (M$/year)	2025 Annual Fuel Cost (M$/year)
Main	178	10,266	4,671	1,769	33,738
Renewable	349	11,494	4,812	1,787	32,295

Figure 14: System cost comparison by cost component between the Main and Renewable scenarios for the modelled year 2025 in millions of USD, expressed in 2013 real values.

Once the respective total system costs are stacked against each other, as illustrated in Figure 15 (the costs of the Main scenario are subtracted from the costs of the Renewable scenario), the net difference between the Renewable and Main scenarios can be calculated. The resulting 116 million USD cost difference (costs of Renewable – costs of Main) indicates that Renewable results in higher total system costs, and that the additional cost required to meet the 35% of RES generation share requirement in the EAPP region in 2025 (based on the set of inputs and assumption used in the current analysis) amounts to 116 million USD.



	Renewable - Main (2025)
Annualised Investment in transmission	171
Annualised Investment in generation	1,229
Annual Fixed O&M	141
Annual Variable O&M	18
Annual Fuel Cost	-1,443
TOTAL (Net Cost / Benefit)	116

Figure 15: System cost comparison by cost component (and the total net cost / benefit) between the Main and Renewable scenarios for the modelled year 2025 in millions of USD, expressed in 2013 real values (Renewable – Main).

Table 19 provides a summary of the economic analyses described above.

Scenarios compared	Δ Annualised Investment in transmission (M$/year)	Δ Annualised Investment in generation (M$/year)	Δ Annual Fixed O&M (M$/year)	Δ Annual Variable O&M (M$/year)	Δ Annual Fuel Cost (M$/year)	Total Annual System Cost Difference (M$/year)
Only G - Main	-178	-303	-32	-10	867	344
Benchmark - Main	123	148	-128	8	-687	-536
Renewable - Main	171	1,229	141	18	-1,443	116

Table 19. Total system cost difference overview across the scenario combinations for the modelled year 2025 in millions of USD expressed in 2013 real values expressed in 2013 real values.

Environment

In the Main scenario, the CO_2 emissions from electricity generation in the region are 187 Mt CO_2 per year in 2025. In two scenarios the use of coal is increased, and this has significant consequences on CO_2 emissions. In the low interest rate scenario (8% rate scenario) emissions increase by 53%, and in the high natural gas price scenario (NG price), emissions more than double in 2025 compared to the Main scenario. As can be seen in Figure 16, the CO_2 price (CO_2 price scenario) has little impact (a 6% reduction) in 2025. This is due to the fact that the CO_2 price by 2025 has not yet reached a level that would affect the generation investments considerably (the emission levels decrease substantially in the CO_2 price scenario after 2030, in line with further CO_2 price increases assumed in the scenario).

Similarly, the level of emissions is not drastically different in the Renewable scenario as compared to the Main scenario, where the required level of RES in the total power generation is set to 35% in 2025, a relatively modest requirement vis-à-vis the RES share of over 30% in the Main scenario in 2025.

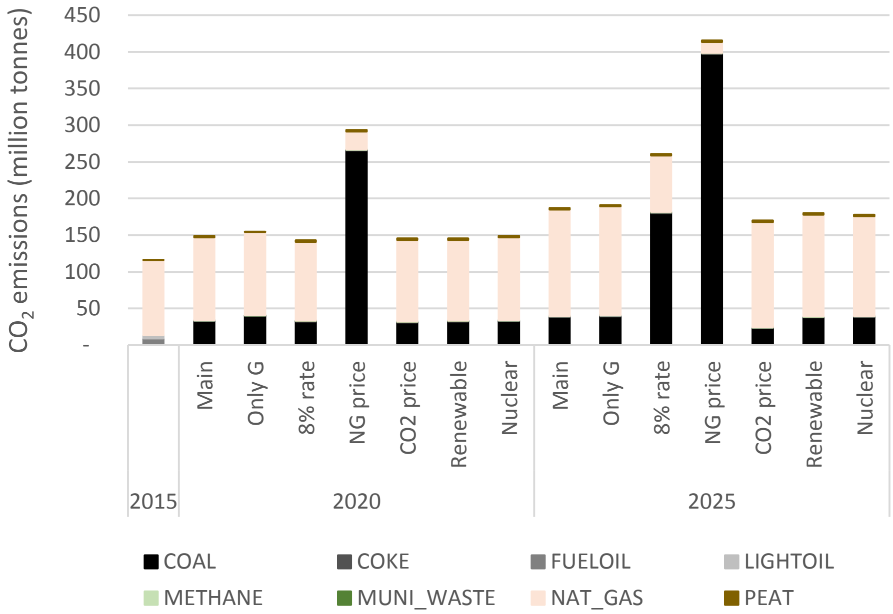


Figure 16. Annual CO_2 emission level in millions of tonnes in the EAPP region over the 2015-2025 period based on the modelling results of the selected scenarios.

6 Long-term perspectives, 2030 – 2040

Results are also computed for the years 2030, 2035 and 2040. This long-term perspective is important to give an understanding of the expected use of the investments planned in 2020 and 2025, e.g. the full-load hours for new generation and transmission projects.

Significant uncertainty exists regarding all the important parameters for these years (i.e. electricity demand prognoses, fuel prices, etc.). As such, the results should be interpreted with care.

Special focus should be on improving the information about candidate hydro plants for the long term, since these tend to have a short-term focus. Many of the attractive candidate hydro plants have been developed before 2030 – and without information from feasibility studies, it is difficult to describe the long-term hydro potential.

Generation

More coal-fired generation

In 2030 and forward, the natural gas price is assumed to be at the level of the European gas price, and this results in coal being the most attractive type of generation after all hydro power potential is exhausted. Therefore countries such as Egypt, Libya, Sudan and Kenya increase their coal use in 2030, while Tanzania starts utilising coal in 2035 (as displayed in the following figures).

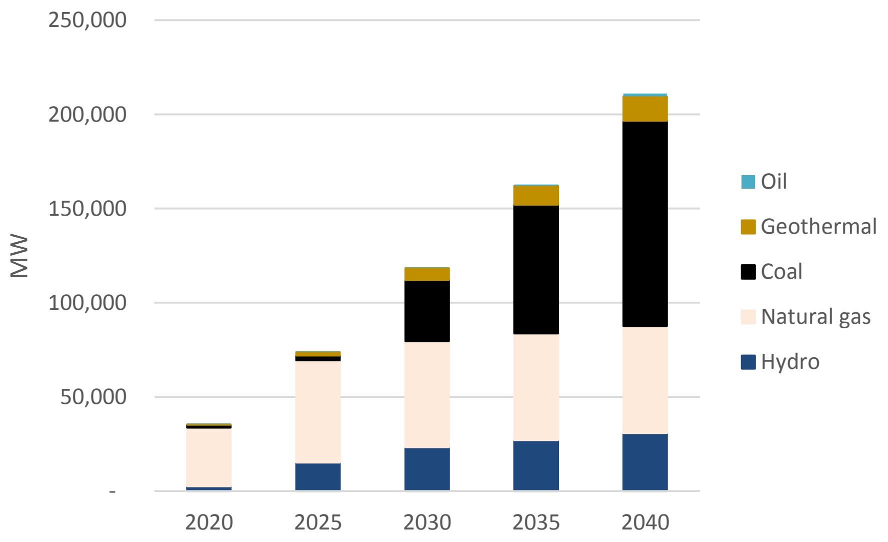


Figure 17. Accumulated investments in generation capacity in MW. All countries, Main scenario.

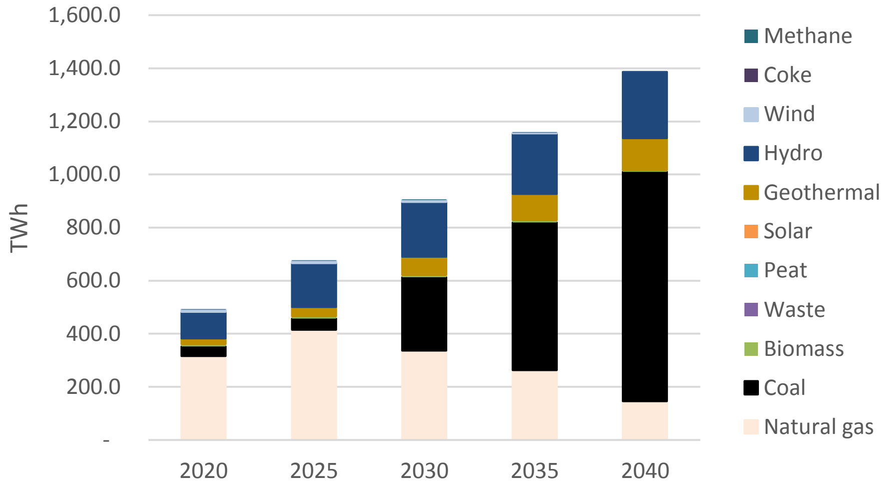


Figure 18. Annual electricity generation in TWh. All countries, Main scenario.

Grand Inga

The Grand Inga site at the Congo River in the Western part of the DRC holds a potential of 42,000 MW hydro power with more than 6,800 full load hours. In the Main scenario, the model invests in 13,400 MW of hydro in the DRC, including 11,300 MW at the Grand Inga site (see Table 20). The potential export to non-EAPP countries such as South Africa and Nigeria is not included in the study. South Africa is likely to receive electricity from Inga 3. The generation capacity needed for this and other export to non-EAPP countries should be added to the capacity in Table 20.

It should be noted that the projected development of the Grand Inga site would also require construction of additional internal transmission lines within the DRC[30], most notably from DRC West to DRC East. In the Main scenario, 1,000 MW capacity is being invested in at each 5-year period modelled 2030 onwards (reaching 3,000 MW total capacity by 2040). Model-based investments are also observed between DRC West and DRC South (550 MW by 2040) and DRC East to DRC South (400 MW, respectively).

Egypt is the main load centre within the EAPP, but export to Cairo would require a 5,400 km transmission line with an estimated cost of US$ 7,500 million[31]. If electricity from Grand Inga can displace natural gas or coal-based generation in Egypt, it would in a narrow economic sense be attractive to construct the line. This would also increase hydro capacity within DRC to 23,500

[30] Model-based investments from/to DRC West and from/to DRC South (above and beyond the committed lines added in 2025, respectively) are only allowed starting from 2030 and limited to 1000 MW addition per line per 5-year period.
[31] A direct DC connection from the Grand Inga site (DRC West) to Egypt is only made available as an investment option in the 'Inga North East' scenario, and not before 2030.

MW in 2040 (Inga North East scenario). The projected additional internal transmission lines within the DRC in this scenario are almost identical to those projected in the Main scenario.

The line would be more than twice as long as the longest currently existing DC line in the world[32]. However, many alternatives exist, including a slower development of the Grand Inga site adapted to the development in electricity demand close to the site. For example, the DRC and neighbouring countries are, as the rest of the region, experiencing electricity demand growth rates in the order of 7% p.a., and therefore waiting for this local demand to develop, and then meeting it with later development of the Grand Inga could be a viable course of action.

	2020	2025	2030	2035	2040
Babebal					28
Bendera2	43	43	43	43	43
Busanga		240	240	240	240
Inga3		2,300	2,300	2,300	2,300
Inga4			3,781	3,781	6,622
Inga5				2,411	2,411
Luapula		800	800	800	800
Nzilo2	120	120	120	120	120
PianaMwanga	30	30	30	30	30
RuziziIV					96
Semliki			14	14	14
WanieRukula		688	688	688	688
Total	193	4,221	8,016	10,426	13,391

Table 20. Model-based investment in hydro in the DRC in MW. Main scenario. Additional 2,500 MW of Inga 3 is reserved for South Africa from 2025.

[32] The overhead length of the 600 kV HVDC Rio Madeira transmission link in Brazil, inaugurated in November 2013, is 2,385 km. The transmission capacity is 7,100 MW (Power Technology, 2014).

Transmission

Table 21 displays the recommended investment in transmission in the Main scenario.

From / To (MW)	2020	2025	2030	2035	2040
DRC					
RWANDA		318	1,198	1,830	1,861
UGANDA		488	950	1,266	2,270
EGYPT					
LIBYA	176	176	176	176	176
SUDAN	500	1,000	1,000	1,000	1,000
ETHIOPIA					
SOUTH_SUDAN					446
SUDAN	1,596	1,596	1,596	1,596	1,683
KENYA					
UGANDA	277	624	989	989	989
LIBYA					
EGYPT	176	176	176	176	176
RWANDA					
DRC		318	1,198	1,830	1,861
TANZANIA	196	954	1,724	2,274	2,274
SUDAN					
EGYPT	500	1,000	1,000	1,000	1,000
ETHIOPIA	1,596	1,596	1,596	1,596	1,683
SOUTH_SUDAN		330	330	330	330
SOUTH SUDAN					
ETHIOPIA					446
SUDAN		330	330	330	330
UGANDA	623	623	623	623	724
TANZANIA					
RWANDA	196	954	1,724	2,274	2,274
UGANDA					
DRC		488	950	1,266	2,270
KENYA	277	624	989	989	989
SOUTH_SUDAN	623	623	623	623	724

Table 21. Capacity of model-based cross-border interconnectors in MW. Main scenario. Values are accumulated. Internal DRC investments are not shown in the table. Connections are shown for both directions, e.g. DRC – Rwanda and Rwanda – DRC.

Changed use of interconnectors

The flow on some of the interconnectors is reduced towards the end of the simulation period. E.g. the lines between Ethiopia, Sudan and Egypt will have a reduced flow in 2035 and 2040 (see Table 22 and Figure 19).

Some other lines however show an increasing utilisation trend, e.g. the lines connecting the DRC. In addition, the Kenya – Ethiopia lines also sees an increasing utilisation rate up to 2040.

At the end of the period, demand in Ethiopia and other countries will have increased, whilst the development of additional hydro power sites is projected to slow down, and the relatively cheaper hydropower will now for the most part be used domestically. As a result, e.g. Ethiopia, a country with a projected net export corresponding to 20% of national demand in 2020 to 2030, ends up importing power (to a small extent) in 2040. It should be noted, however, that there is currently very limited information available on the cost data of ca. 22,000 MW long-term hydro potential in Ethiopia[33]. Better data on the long-term candidate plants is expected to refine this result.

Uganda meanwhile is a strong net exporter in 2020, is in balance in 2025 and finally is a net importer in 2040.

On the other side of the spectrum, net export from the DRC starts with a small amount in 2020, but increases to nearly 40% of national demand by 2040.

[33] A conservative investment cost estimate of 4 M USD / MW (2012 USD real terms) for the long-term hydro potential in Ethiopia has been used in the Main scenario. The implications of more cost-competitive long-term hydro potential in Ethiopia has been tested in the Long-term hydro scenario (assuming 2.5 M USD/ MW investment cost). Please see Volume III: Results Report for more information.

From Country	To Country	2020	2025	2030	2035	2040
BURUNDI	DRC	3%	0%	0%	0%	0%
	RWANDA	6%	6%	11%	10%	4%
	TANZANIA	52%	37%	55%	49%	30%
DJIBOUTI	ETHIOPIA	0%	0%	33%	32%	37%
DRC	BURUNDI	1%	43%	44%	45%	63%
	RWANDA	2%	68%	70%	71%	63%
	UGANDA		26%	64%	50%	63%
EGYPT	EGYPT	0%	0%	0%	0%	0%
	LIBYA	22%	7%	9%	6%	1%
	SUDAN	1%	0%	2%	1%	20%
ETHIOPIA	DJIBOUTI	31%	28%	1%	0%	0%
	KENYA	7%	34%	65%	49%	22%
	SOUTH_SUDAN					2%
	SUDAN	54%	45%	52%	20%	4%
KENYA	ETHIOPIA	20%	14%	8%	19%	31%
	TANZANIA	3%	10%	22%	22%	12%
	UGANDA	0%	0%	0%	1%	2%
LIBYA	EGYPT	39%	57%	10%	3%	3%
RWANDA	BURUNDI	2%	1%	1%	3%	12%
	DRC	1%	0%	0%	0%	0%
	TANZANIA	52%	58%	66%	66%	54%
	UGANDA	0%	1%	10%	8%	9%
SOUTH_SUDAN	ETHIOPIA					52%
	SUDAN	68%	85%	45%	37%	18%
	UGANDA	0%	17%	39%	26%	7%
SUDAN	EGYPT	74%	83%	76%	56%	21%
	ETHIOPIA	1%	3%	4%	12%	39%
	SOUTH_SUDAN	0%	0%	2%	3%	7%
TANZANIA	BURUNDI	2%	0%	0%	0%	0%
	KENYA	0%	2%	12%	8%	16%
	RWANDA	0%	0%	0%	0%	0%
	UGANDA	0%	0%	1%	1%	1%
UGANDA	DRC		0%	2%	3%	1%
	KENYA	74%	63%	64%	44%	51%
	RWANDA	6%	15%	11%	12%	12%
	SOUTH_SUDAN	68%	2%	1%	2%	14%
	TANZANIA	70%	52%	47%	38%	33%

Table 22. Flow of electricity on interconnectors (in terms of utilisation rate). Flow is presented is each direction. E.g. the first line shows the flow from Burundi to the DRC. The flow in the opposite direction can be found in line 5.

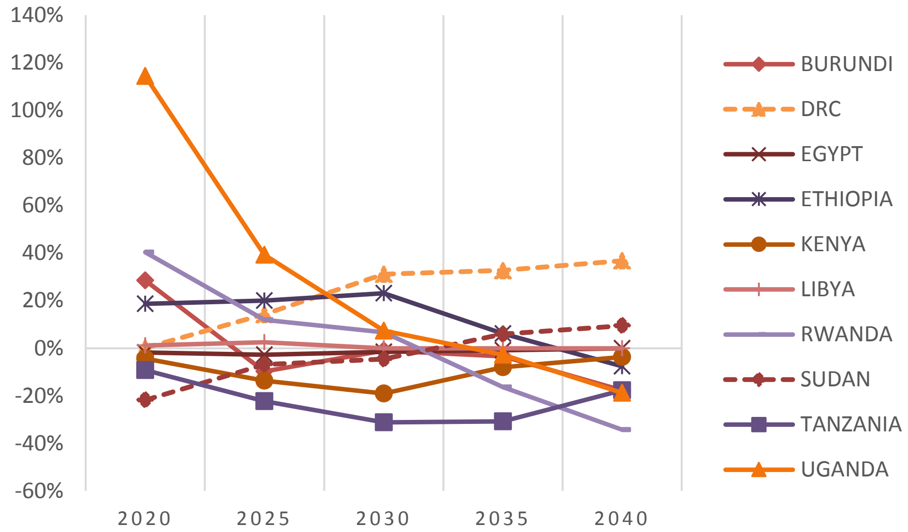


Figure 19. Net export compared to national demand. Positive values represent export.

Environment

The future development pathway as projected by the Main scenario features a manifold increase both in SO_2 and CO_2 emission levels across the EAPP region in the medium to long term, in line with projections of significant increase in coal-fired power capacity investments and generation. This projection is based on least-cost optimisation of generation and transmission investments, as well as dispatch – in the absence of any environmental requirements or constraints. No regional agreements as to the treatment of externalities exist at the time of writing this report (e.g. SO_2 emission standards or the planning value of SO_2 or CO_2). However, in order to illustrate examples of environmental policies (and the projected environmental and economic impacts thereof), two scenarios have specifically been developed.

The CO_2 price scenario introduces a modest CO_2 price of 10 USD/ton in 2020 (gradually increasing to 50 USD/ton in 2040). This brings about significant impacts after 2030, i.e. no investment in coal-fired generation takes place, wind power gains ground (86,000 MW in 2030, increasing to 170,000 MW in 2040). No investment in solar power take place in this scenario[34]. However, investments in nuclear[35] take place (8,200 MW in 2030 increasing to 16,200 MW in 2040).

[34] Solar PV investment cost projections follow IEA WEO 2013 (and 2014). Alternative perspectives exist suggesting significantly higher cost reductions in the future. See Volume II: Data Report for more information.
[35] Model-based investments in nuclear are only permitted in Egypt and Kenya, and limited by the development pathways as laid out in the respective National Master Plans.

The Renewable scenario imposes a requirement of renewable energy source[36] generation as a share of gross national demand (starting at 30% in 2020, and gradually increasing to reach 50% by 2040). It should be noted that generation from RES reaches 28% in 2020 in the Main scenario, and peaks at 32% in 2025/2030. In the Renewable scenario investment in hydropower is increased by 17% (+5,100 MW) relative to the Main scenario. In addition, massive investment in wind power takes place (132,300 MW of wind power capacity being invested in from 2025 to 2040 in the Renewable scenario). No investment in solar power take place in this scenario.

Figure 20 displays the projected CO_2 emission levels for the selected scenarios. The emissions levels in 2015 are very low, but increase drastically over the simulation period. The results of the Main and Nuclear scenarios exhibit a very similar pattern, i.e. the implementation of the nuclear power development plans in Egypt and Kenya would not yield significant CO_2 emission abatement on the regional level. With a higher natural gas price (NG price scenario) the CO_2 emission levels increase significantly in the medium term (2020-2030) due to the shift from natural gas- to coal-fired generation earlier on.

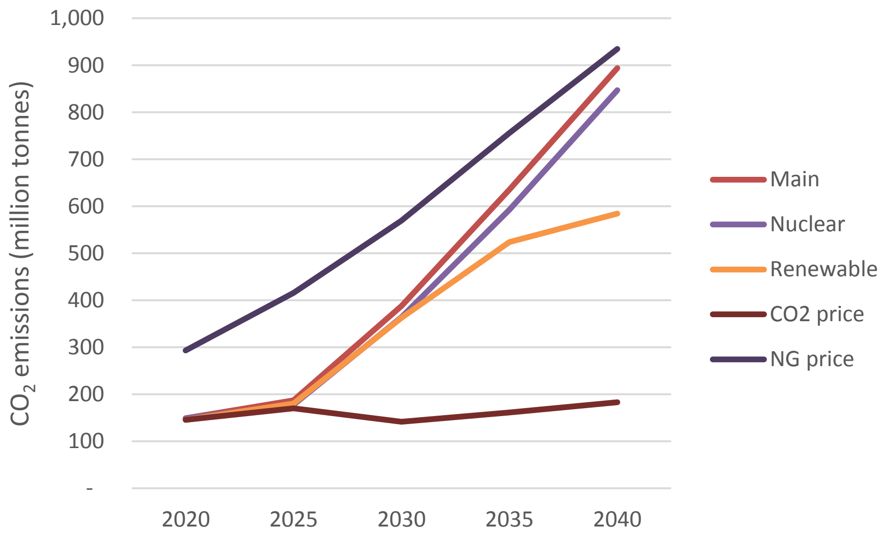


Figure 20. Annual CO_2 emission level in millions of tonnes in the EAPP region over the projection period based on the modelling results of the selected scenarios.

Figure 21 displays the projected SO_2 emission development pathways for the selected scenarios over the projection period[37]. In the period from 2015 to

[36] Renewable energy sources are defined as follows: generation based on hydro (also large hydro), wind, solar, geothermal, biomass (bagasse and wood), municipal waste and methane (only relevant for Rwanda, and considered renewable because of its origin of Lake Kivu deposits)
[37] The SO_2 emission coefficient for coal (0.07 kg/GJ) has been based on the World Bank guidelines, 2008 edition (IFC World Bank Group, 2008) corresponding to the emission limit for large (600 MW+) boiler type of

2020, a decrease in the SO_2 emission levels could be expected in the Main scenario if the commitment to phase out oil-based generation succeeds towards 2020. The emissions levels are, however, projected to increase drastically in the medium to long term. The sulphur dioxide emission pathways exhibit the same pattern as the CO_2 emissions across scenarios – Nuclear is follows Main very closely, whereas higher natural gas price, the emissions of both SO_2 and CO_2 increase significantly in the medium term.

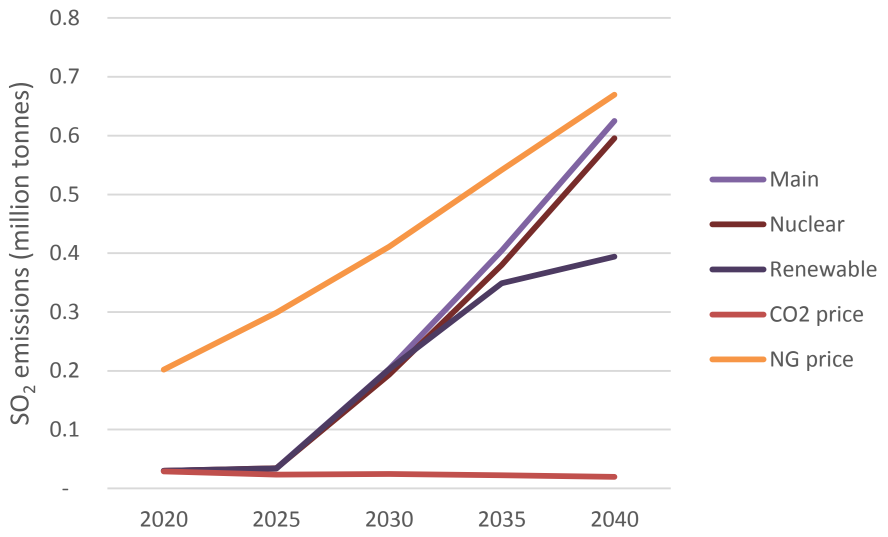


Figure 21. Annual SO_2 emission level in millions of tonnes in the EAPP region over the projection period based on the modelling results of the selected scenarios.

The projected significant increases in the emission levels can be avoided, as illustrated by the Renewable and the CO_2 price scenario results. The CO_2 price also has a very strong impact on the SO_2 emission levels as the use of coal is reduced.

The level of CO_2 price used in the CO_2 price scenario is considered moderate to high. The results indicate that even a lower CO_2 price would have a significant impact. It should be highlighted that the assumptions and projections underlying these specific scenarios should not be regarded as recommendations; rather, as an illustration of two different environmental policy instruments, and their respective impact.

plants, with solid fuels located in degraded airsheds. The World Bank guidelines have been explicitly stated as relevant for coal power plant projects in Kenya and Sudan by their respective utility representatives, and have been assumed representative of the EAPP region.

More in-depth analysis is provided in the EAPP Master Plan 2014 supporting document: Environmental Analyses.

7 Conclusions and recommendations

This Master plan represents least-cost planning based on detailed modelling of 12 countries in the EAPP region.

The development of the power system is driven by strong growth in electricity demand, i.e. the doubling of demand in the next ten years. This trend is a continuation of the development over the previous ten years. With national electricity demand projections as input, along with information about the existing and committed generation and transmission system, the Balmorel model computes least-cost investment in generation and transmission.

The main focus of the work is on decisions that can be taken in the short term. Therefore, the electricity system and its possible development in 2020 and 2025 have been studied in detail, and the period until 2040 has been included to illustrate the long term perspectives.

Generation

The growth in electricity demand in the region requires large investments in new generation[38]. Significant investments in renewable energy in the form of hydro and geothermal are projected to take place. In addition, large investments in fossil fuel-based generation also are projected to take place, primarily natural gas-fired. See Table 23.

[38] Please see **Error! Reference source not found.** for model-based generation expansion overview per country towards 2025.
Please see the Results Report (EAPP Master Plan 2014 Volume III: Results Report) for country-specific generation results by generation technology (and specific projects) over the projection period.

Year		Natural gas	Coal	Hydro	Geo-thermal	Oil	Wind	Solar PV	Other*	Total
2020	Burundi			147		17		20		184
	Djibouti		7		50	122				179
	DRC	3,284	1,046	2,863		18				7,210
	Egypt	47,420		2,800		1,645	2,756	565		55,186
	Ethiopia			10,916	75	78	324		614	12,007
	Kenya	1,667	1,920	934	2,321	391	636		44	7,913
	Libya	8,321				740				9,061
	Rwanda	50		76		55		28	297	506
	South Sudan			42		346				388
	Sudan		1,002	2,305		1,525	20	10	100	4,962
	Tanzania	2,901	700	1,579		65	100	120	19	5,484
	Uganda			2,226	250	150		20	107	2,753
	2020 Total	**63,643**	**4,675**	**23,888**	**2,696**	**5,152**	**3,836**	**763**	**1,181**	**105,833**
2025	Burundi			180		17		20		217
	Djibouti		24		50	122				196
	DRC	3,284	1,046	6,891		18				11,238
	Egypt	61,407		2,800		1,645	2,756	565		69,173
	Ethiopia			15,475	75	78	324		614	16,566
	Kenya	3,440	1,920	934	4,000	391	636		44	11,365
	Libya	11,092								11,092
	Rwanda	50		76		55		28	297	506
	South Sudan			1,937		346				2,283
	Sudan		2,121	2,665		1,525	20	10	100	6,441
	Tanzania	2,901	700	3,299		65	100	120	19	7,204
	Uganda			2,226	250	150		20	107	2,753
	2025 Total	**82,173**	**5,811**	**36,483**	**4,375**	**4,412**	**3,836**	**763**	**1,181**	**139,034**

Table 23. Total generation capacity in MW in the Main scenario in modelled years 2020 and 2025.
** 'Other' includes bagasse-, coke-, methane-, municipal waste-, peat- and wood-based generation.*

A number of the EAPP countries have their own individual national plans outlining their projected electricity generation development. The regional model studies described within this report and these national master plans are overall well aligned. For example, natural gas is preferred in the first years, and then a shift to coal takes place. In the scenarios, this shift to coal takes place in 2020, 2025 or 2030 – depending on the different assumptions. With the assumptions used in the Main scenario, the shift takes place in 2030, however, under the assumption of higher natural gas prices (in line with the European natural gas price projections), the shift takes place in 2020 instead. There is a fine cost-competitiveness balance between natural gas- and coal-based generation. A lower interest rate (8% instead of the central assumption of 10% interest rate in the Main scenario) also results in an earlier introduction of coal.

All in all, the results are well in line with the plans of Egypt and Sudan to introduce coal in 2019/20 and 2017, respectively.

In most of the scenarios analysed, no price on the CO_2 emissions has been set, and there are no requirements for the use of renewable energy. However, the results indicate that a moderate CO_2 price, or a goal for expansion of renewable energy can dramatically change the composition of the generation capacity, especially in the long term. In both scenarios the use of coal and the level of CO_2 emissions are reduced with a factor of 4 to 5 (in 2040), and SO_2 emissions are reduced with a factor of 3 with the renewable energy goal (and are essentially eliminated with the CO_2 price).

Long term

Focus has been on the short to medium term (2020 – 2025) because this is important for the decisions that are to be made within the next few years. However, the study includes results until 2040. In 2040, the electricity demand is expected to exceed 1,400 TWh (compared to 313 TWh in 2015). Data and results for the long-term are clearly subject to great uncertainty, however it is relevant to study, e.g., the consequences of the continuing demand growth on the power flow on the transmission lines.

The model invests in the order of 4,000 MW of transmission capacity in each modelled 5-year period of 2020, 2025 and 2030. However, for 2035 and 2040 the rate of investments declines to 750 – 1,500 MW. This change is driven by the fact that hydropower expansion slows, whilst investment in coal generation takes place in several countries in parallel.

Based on the model's current projections and assumptions, a significant shift takes place in 2030. While Libya and Egypt invest in natural gas generation in 2020 and 2025 – this changes to coal from 2030. As a result, 2/3 of all electricity generation in the Main scenario is based on coal in 2040. This development is similar across the projections of most of the scenarios. Renewable and CO_2 price are the only scenarios, exhibiting much lower degree of reliance on coal-fired generation.

Nuclear investment is observed in two scenarios: The 8% interest scenario, and the CO_2 price scenario. The first time the model invests in nuclear is in 2020 in the 8% scenario, and in 2025 in the CO_2 price scenario[39].

In the scenario where the model can invest in the cross-continental transmission line from the Grand Inga site in the Western part of the DRC to the load

[39] Nuclear is assumed to have 7 years construction time. If construction starts in 2015 it could be completed in 2022. We are only simulating every fifth years, so "2020" should be understood as 2020 +/- 2.5 years.

centre in Cairo, Egypt (starting from 2030), the investment takes place indicating that this project is economically attractive. The model does not evaluate transmission to load centres outside the model area, such as South Africa and Nigeria.

Transmission

Realisation of the committed transmission projects will secure that each EAPP member country will have cross-border power exchange capabilities towards 2020. In several cases the capacity is limited. The committed connections with the largest capacities will be the Ethiopia – Kenya – Tanzania corridor with 2,000 MW and 1,300 MW capacities, respectively. This is the beginning of formation of a strong regional backbone. The 2014 Master Plan recommends extending the Ethiopia – Kenya – Tanzania backbone (expected to be completed in 2018) with two new corridors:

The Central – North corridor, with the flow going North

- From Ethiopia via Sudan to Egypt

The West – East corridor, with flow going East

- From DRC and Uganda via Uganda to Kenya, and
- From DRC via Rwanda to Tanzania

The results are relatively robust across a number of sensitivity analyses. The results arise from the fact that marginal electricity generation costs are highest in the fossil fuel-fired power dominated North (Libya, Egypt and Sudan), and lowest in the hydro-abundant West/Central region (the DRC, Ethiopia, South Sudan, Rwanda, Burundi and Uganda). Geothermal and hydro generation is relatively cheap, provided good site conditions, and expansion of these technologies can reduce the fuel use (and expenditure) for electricity generation.

Recommended lines and capacities are:

	Capacity (MW)	Cost* (M USD)	Length** (km)
Sudan – Ethiopia	1,600 MW in 2020	373	550
Egypt – Sudan	500 MW in 2020 1,000 MW in 2025	233 466	775
Rwanda – Tanzania	200 MW in 2020 1,000 MW in 2025	31 149	115
Rwanda – DRC	300 MW in 2025	99	46
Uganda – South Sudan	600 MW in 2020	77	200
Libya – Egypt	200 MW in 2020	38	163
Kenya - Uganda	300 MW in 2020 600 MW in 2025	44 100	254
DRC - Uganda	500 MW in 2025	115	352
Sudan – South Sudan	300 MW in 2025	163	400
Total by 2025	**6,100 MW**	**1,580 M USD**	**2,855 km**

Table 24: Recommended list of projects and their capacities (rounded up to 100 MW) in 2020 and 2025, respectively. Costs expressed in millions USD 2013 real values.
** The costs hereby stated are based on the costs of the candidate transmission projects as presented in the Cost of transmission section, capacity-weighted, and converted to 2013 USD currency terms (coefficient 1.05).*
*** The line lengths hereby stated are based on the line length data of the candidate transmission projects as presented in the Cost of transmission section.*

The capacity of the Northern corridor (Ethiopia – Sudan – Egypt) hereby recommended is smaller than recommended in the 2011 Master plan. This is mainly because of a higher projected electricity demand in the EAPP member countries, most notably Ethiopia and Kenya. At the same time, the recommended lines for the West - East corridors are new. Note that only the Eastern part of the DRC was included in the 2011 Master plan.

Analysis of the projected utilisation rates of the recommended transmission lines indicates that flow on some of the interconnectors would be reduced towards the end of the simulation period (most notably, the Northern Corridor towards 2035 and 2040), whereas an increasing utilisation trend towards 2040 could be observed on e.g. the Kenya – Ethiopia line, and lines connecting the DRC. These dynamics are driven by the balance between demand growth, and availability of cost-competitive hydro power projects. High degree of uncertainty is associated with assumptions and projections towards 2040, however, and the long-term results should be interpreted with care. More accurate data on the long-term hydro potential in Ethiopia would be a value-adding contribution to further analysis.

With the two new corridors in place, EAPP countries would be connected with a strong backbone from the DRC in the West via Tanzania in the South to Egypt in the North. The difference in generation technologies would make supply more robust against hydrological variation, fuel supply challenges and outages of key system elements.

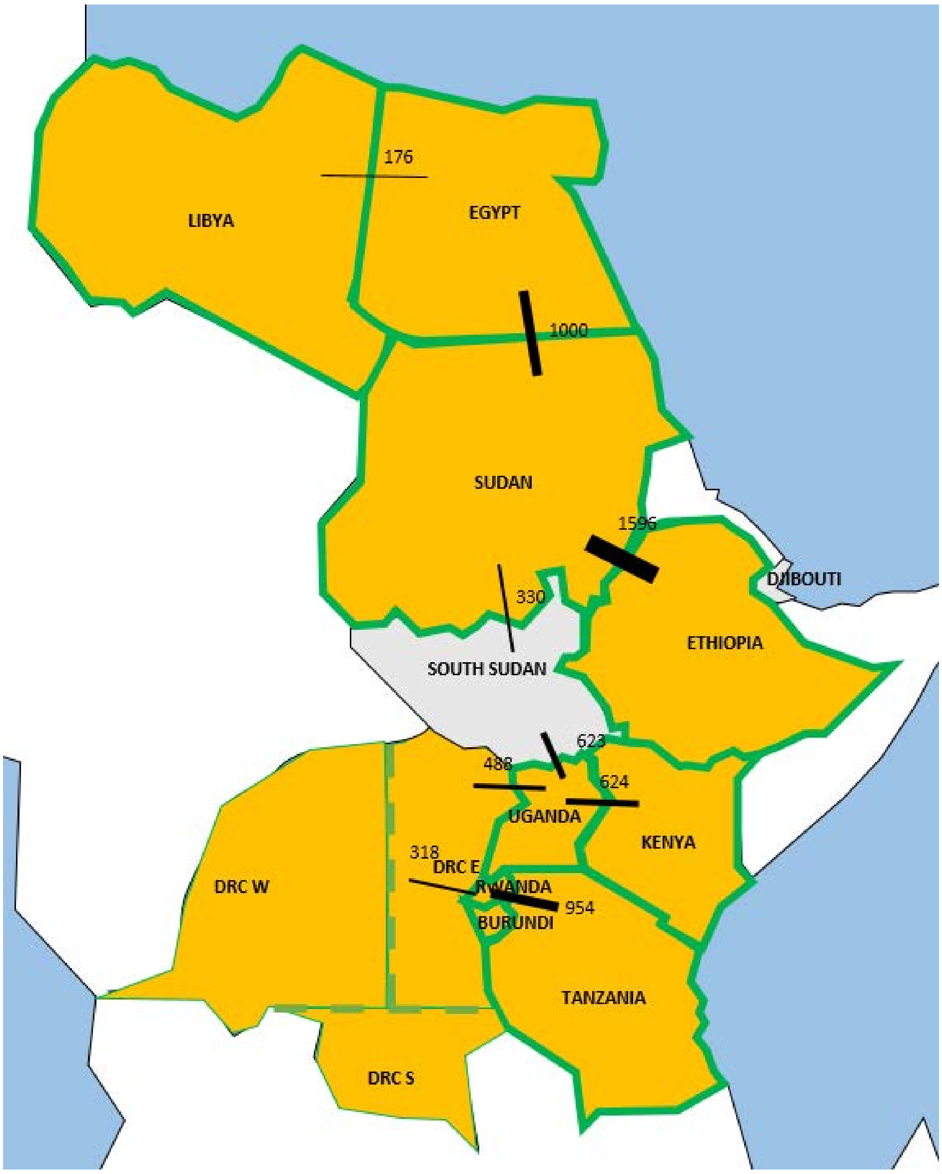


Figure 22. Recommended new lines by 2025. Numbers indicate capacity in MW, 2025.

Discussion

Impact of allowing investments in transmission

By comparing scenarios with and without investments in transmission, it becomes clear that the extra transmission has two important consequences:

- Investment in generation: More hydro and geothermal and less investment in coal.

- Savings in operational costs: Reduction of fuel costs by more efficient dispatch across countries and technologies.

Investment in hydro and geothermal generation increases by 9% when investment in transmission is allowed. Thus, the additional hydro and geothermal projects can be considered cost-competitive candidate projects of regional importance, realisation of which would only be made possible through increased regional transmission capability. The additional hydro generation investments consist of 300 MW in the DRC and 900 MW in South Sudan. These results provide an example of sequencing risk, i.e. interdependence between generation and transmission development.

Fuel	Generation and Transmission (MW)	Only Generation (MW)
Natural gas	54,152	54,152
Hydro	15,193	13,954
Coal	2,657	3,520
Oil	313	
Geothermal	1,879	1,679
Wind		75
Total	**74,419**	**73,380**

Table 25. Model-based generation investment (2020-2025) in MW for two scenarios: With investment in transmission (Main scenario), and without (Only G scenario).

Value of transmission

If investment in new transmission is not allowed in the model, the total system cost will increase. In the modelled year 2020, the total annual system cost is 412 million USD/year higher in the case without allowing additional regional transmission projects (Only G), as compared to the Main scenario, which allows optimal investment in both generation and transmission (see Table 26). As such, this difference corresponds to the value of regional transmission for the EAPP region in 2020.

Scenario	Annualised Investment in transmission (M$/year)	Annualised Investment in generation (M$/year)	Annual Fixed O&M (M$/year)	Annual Variable O&M (M$/year)	Annual Fuel Cost (M$/year)	Total Annual System Cost (M$/year)
Main	90	4,088	3,567	1,292	23,927	32,964
Only G		4,062	3,604	1,292	24,418	33,376
Difference	**90**	**26**	**-37**	**-1**	**-491**	**-412**

Table 26: Key economic results in scenarios with (Main) and without investment (Only G) in new transmission (expressed in millions USD in 2013 real terms). Note that investments are indicated as the annual cost to repay the investment. Costs of existing and committed generation and transmission are not included. An economic life time of 20 years is assumed for most investments, however 50 years is used for hydro generation. The interest rate is 10% p.a. in real terms.

The possibility to develop additional regional transmission lines (and implementation thereof) allows for development of additional cost-competitive candidate projects, such as hydro and geothermal. This, in turn, results in slightly higher annualised investments costs in the modelled year 2020 (both in generation and transmission), but also in significant fuel cost savings. As illustrated by the results in Table 26, the savings considerably exceed the costs.

Robustness

The recommended transmission projects are relatively robust to changes in assumptions. For example, for the Ethiopia – Sudan line, a case with 50% increase in transmission investment costs, as well as a case with 10% higher electricity demand in all countries, only reduces the optimal capacity of the line by ca. 20% (in each case). Alternatively, if demand is 10% lower than in the Main scenario, the recommended capacity of this line increases; less local demand in hydro resource-rich areas motivates longer transport of hydro-based generation. In addition, if the requirement of 110% of domestic generation capacity relative to the peak load is removed, the recommended interconnector capacity of the line will double. I.e., with less local generation capacity, transmission will play a greater role.

The Sudan - Egypt line is the project that is most sensitive to variation in input parameters. In four scenarios[40] the recommended (optimal) capacity varies from 40% to 200% relative to the Main scenario.

Environment

As illustrated in this Master Plan, a significant part of the future electricity demand is likely to be supplied by coal-fired power plants if the generation and transmission expansion planning is based on least-cost principle alone. Together with strong electricity demand growth, this will transform the EAPP to a region with significantly increasing emission levels. It is illustrated that a planning price of CO_2 of 10 $/ton in 2020 increasing to 30 $/ton in 2030 would minimise the use of coal in the region. These values have been used to illustrate the impact of introduction of a CO_2 planning value only, and should not be regarded as a recommendation. Even lower values could have a significant impact.

Data uncertainty

Significant effort has been made during the Master Plan update process to obtain the best possible data for the modelling and scenario analyses. Demand forecasts are uncertain and have significant impact on the modelling results. Sensitivity analyses with higher and lower demand growth projections as compared to the Main scenario have been tested.

The sequencing risk may be significant. If investment in generation or transmission is delayed, this will influence the economy of the new lines. E.g. the

[40] Benchmark, Higher transmission costs, Low and High demand scenarios. See Table 17. See (EAPP Master Plan 2014 Volume III: Results Report) for more details

Sudan – Egypt line is dependent on the Ethiopia – Sudan line, and several lines are dependent on the materialisation of the hydro investments in e.g. South Sudan and DRC.

A number of assumptions (e.g. optimal power dispatch, investment coordination possibility regionally between generation and investments etc.) and projections regarding the development path of key parameters (e.g. power demand growth, fuel prices etc.) have been made in this analysis, and the accuracy of the results is subject to the materialisation of the said assumptions.

Next steps

Six lines are recommended to be implemented by 2020. Because of construction time and the required preparation, concrete actions must start now. For the six projects the following steps should be initiated in 2015:

- Evaluate if existing feasibility studies need updating. For the line Rwanda – Tanzania a feasibility study should be performed.
- Consider coordinating the development of the recommended transmission projects with the relevant generation projects (e.g. in South Sudan and the DRC).
- Perform detailed design studies for the lines.
- Start negotiating cost sharing for the lines. As a first step this could include the two involved countries for the line. If needed, other countries, e.g. those sharing the corridor, could be included in the discussion.
- Prepare financing for the projects
- EAPP should continually monitor the development for the six lines. E.g. with half-year updates on status[41].

Further three lines are recommended for 2025. Similar steps should be planned for these lines.

Highest priority should be given to realising the Northern corridor. Feasibility studies already exist, and concrete decisions could be taken soon. Feasibility studies may need to be adjusted to the capacities recommended in this study.

National demand prognoses have been used in the current study. Since demand is one of the main uncertainties for the economy of new transmission lines, it could be relevant to make a detailed review and recommendations regarding demand expectations. Establishment of a regular Power Balance

[41] See www.entsoe.eu/fileadmin/user_upload/_library/publications/nordic/planning/Prioritised_cross-sections.pdf for an example of a short status report about prioritised transmission reports

Statement issuance process (described below) could facilitate this. In addition, more refined representation of the long-term hydro potential in Ethiopia would also benefit the regional planning process.

Power balance statement	It is recommended that EAPP should start publishing a Power Balance Statement each year in September. Sharing the needed data and assessing the power balance for the next 10 years can add a regional perspective to the national power balance evaluations. The EAPP Planning code exists in a draft version and could be adopted.
Environmental framework	In the current Master Plan, no planning value has been assigned to emissions of SO_2 and CO_2. It is recommended that EAPP Governments decide and agree on the importance of reducing these emissions. For SO_2, a regional agreement could be made to ensure that the maximum emission level for coal-based power plants should not exceed e.g. 200 mg/Nm^3 flue gas (see IFC World Bank Group 2008 guidelines[42]).
Update of Master plan	The region is very dynamic and it is recommended to regularly update the Master Plan, e.g. every second year. This is e.g. the same frequency as the European Ten-Years-Development-Plans (ENTSO-E's TYNDP).

[42] International Finance Corporation, World Bank Group: "Environmental Health and Safety Guidelines – Thermal Power Plants", 2008. The emission level limit cited is for large (600 MW+) boiler type of plants, with solid fuel located in degraded airsheds.

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List of Documents

EAPP Master Plan 2014:

- Executive summary
- Master Plan, Volume I: Main Report (current document)
- Master Plan, Volume II: Data Report
    - Demand forecasts, fuel prices, technology catalogue for generation and transmission
- Master Plan, Volume III: Results Report
    - Detailed model results: All countries, all years, all scenarios

Supporting documents of the EAPP Master Plan 2014:

- African regional transmission projects: status memo
- Planning gap analysis
- Environmental analysis
- Risk analysis
- Network analysis