EASTERN AFRICA POWER POOL (EAPP)

EAPP REGIONAL POWER SYSTEM MASTER PLAN

EXECUTIVE SUMMARY

Ea Energy Analyses

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Foreword

The current report is an executive summary of the second Master Plan published by the EAPP, the Eastern Africa Power Pool. The first Master Plan, published in 2011, has been updated and extended in scope to include Libya, the entire DRC and South Sudan.

The update is part of a *Twinning project* (June 2013 to December 2014), where the EAPP General Secretariat, member utilities and consultants have been working together to update the Master Plan. Intensive dialogue with the member utilities and Ministries has been part of the process. The EAPP Technical Subcommittee for Planning (TSC-P) has played an active role in the development of the Master Plan.

The EAPP Master Plan 2014 consists of the following documents:

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

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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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. The analysis is based on a model study of regional least-cost planning using the Balmorel model[1], taking into account e.g. electricity demand growth, and a large number of supply alternatives. The Master plan recommends six new transmission lines with a total capacity of 3,400 MW to be in place by 2020.

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[2] are now included, as illustrated by Figure 1.

The recommendations of the 2014 Master Plan are based on analyses of regional least-cost investments in generation and transmission. A Main scenario and 20 alternative scenarios have been used to analyse the potential development of the electricity system. The scenarios have been used to analyse the sensitivity of the results with respect to the central parameters.

In the executive summary, the focus is on decisions that can be taken in the short term. Therefore, the current report discusses the possible development of the electricity system towards 2020 and 2025, with the long-term perspectives (towards 2040) provided in other volumes of the Master Plan (e.g. Volume I: Main Report).

Electricity demand

The development of the EAPP power system is driven by strong growth in electricity demand, which is expected to double in the next ten years (see Table 1). This trend is a continuation of the development over the previous ten years.[3] Several countries have political focus on increasing electrification rates, which will, together with economic growth, increase electricity demand.

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[1] Balmorel is an open source economic and technical partial equilibrium model that simulates the power system and least-cost dispatch, as well as optimises investments in generation and dispatch. 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.
[2] The analysis is limited to the 12 countries, however information about the future Egypt – Saudi Arabia interconnector and possible export from Tanzania to Zambia has also been included.
[3] Historical demand and the expected demand until 2040 is described in the Main report.

Demand prognoses are supplied by national utilities. The current prognoses typically indicate a much higher demand compared to what was used in the 2011 Master plan. To study the consequences of different demand levels, a parameter variation of +/-10 % demand is used.

	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 1. Yearly electricity demand (TWh) and peak demand (GW) prognoses.[4]

With electricity demand as input, along with information about the existing, committed and candidate generation and transmission system components, the least-cost investments in generation and transmission are found.

Generation

The projected growth in electricity demand in the region requires large investments in new generation. Significant investments in renewable energy in the form of hydro and geothermal power are projected to take place from 2015 to 2020. The hydro capacity nearly doubles from 2015 to 2020, while the geothermal capacity triples by 2020. In addition, large investments in fossil fuel-based generation also take place towards 2020, as presented in Table 2.

[4] *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%.*

Fuel	By 2015 (GW)	By 2020 – before model based investments (GW)	2020 Model-based invest-ments (GW)	By 2020 (GW)
Natural gas	33	33	31	64
Hydro	11	21	3	24
Coal	0.1	3	2	5
Oil	6	5	0.3	5
Geothermal	0.7	2	0.2	3
Wind	2	4	-	4
Other	0.5	0.5	-	0.5
Total	**53**	**68**	**36**	**104**

Table 2. Existing and new generation capacity, 2015-2020. Main scenario.

In Table 3 the expected generation capacity is shown per country in 2025, where natural gas and hydro dominate. The large natural gas capacity is in Egypt and Libya, while Ethiopia and DRC have the largest hydro power capacities.

MW	Natural gas	Hydro	Geo-thermal	Coal	Oil	Wind	Solar	Other
BURUNDI	-	180	-	-	17	-	20	-
DJIBOUTI	-	-	50	24	122	-	-	-
DRC	3,284	6,891	-	1,046	18	-	-	-
EGYPT	61,407	2,800	-	-	1,645	2,756	565	-
ETHIOPIA	-	15,475	75	-	78	324	-	614
KENYA	3,440	934	4,000	1,920	391	636	-	44
LIBYA	11,092	-	-	-	-	-	-	-
RWANDA	50	76	-	-	55	-	28	297
SOUTH SUDAN	-	1,937	-	-	346	-	-	-
SUDAN	-	2,665	-	2,121	1,525	20	10	100
TANZANIA	2,901	3,299	-	700	65	100	120	19
UGANDA	-	2,226	250	-	150	-	20	107
Total	**82,173**	**36,483**	**4,375**	**5,811**	**2,981**	**3,836**	**763**	**1,181**

Table 3. Total installed capacity by 2025. Other includes Wood, Coke, Bagasse and Methane

Hydro-dominated countries (without strong interconnectors to other countries) may experience difficulties in supplying electricity in dry years. However, model simulations indicate that even in the driest hydro year experienced thus far, no demand is unserved.[5] By using other power plants and the available transmission capacity through optimal regional least-cost dispatch, it is possible to supply the entire demand.

Transmission

Realisation of the committed transmission projects will secure that each EAPP member country will have cross-border power exchange capabilities towards 2020. 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 the formation of a strong regional backbone. See Figure 1.

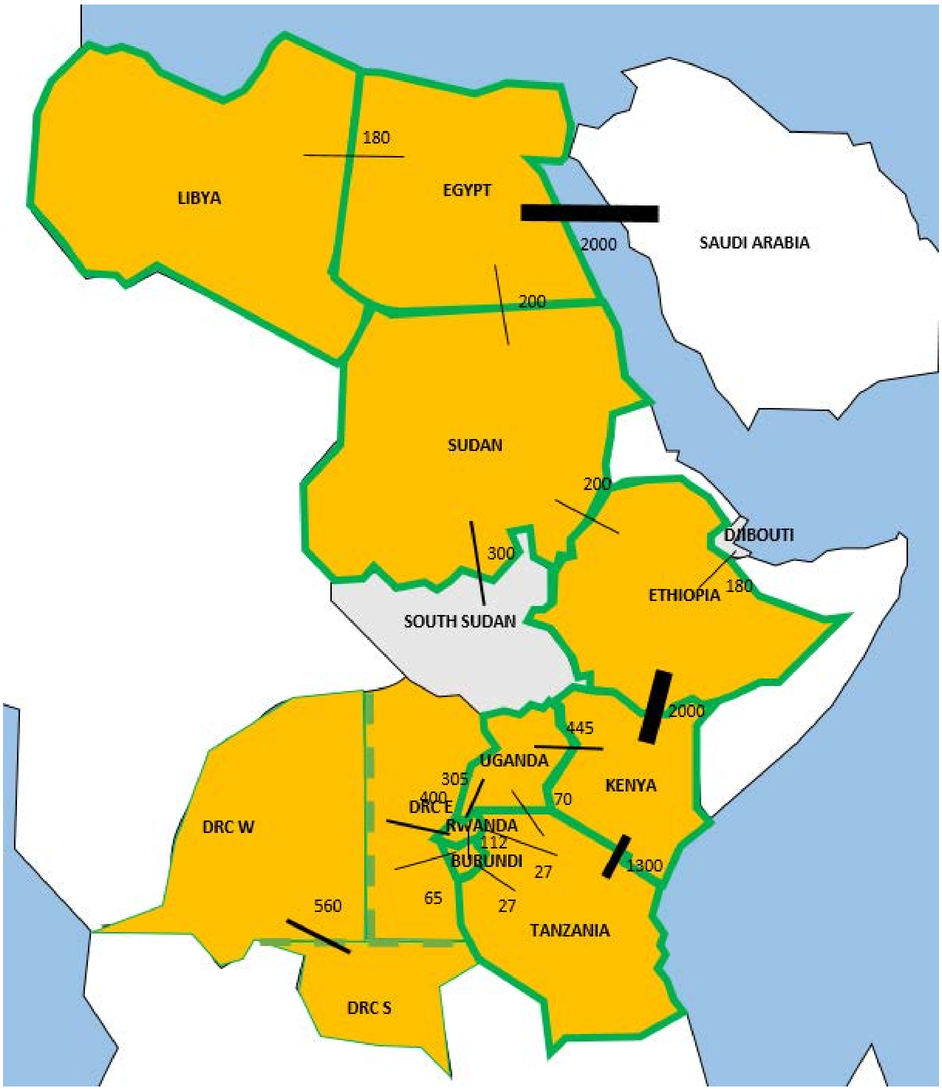

Figure 1. Current and committed (before 2020) interconnectors in Eastern Africa. Numbers indicate capacity in MW.

[5] Based on hydro inflow data from 1972 to 2006. The results for the modelled year 2040 feature unserved demand, though the amount is negligible.

The 2014 Master Plan recommends extending the Ethiopia – Kenya – Tanzania backbone (expected to be completed in 2018) with two new corridors (see Figure 2):

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

Part of the lines are recommended for 2020, with more recommended to follow in 2025.

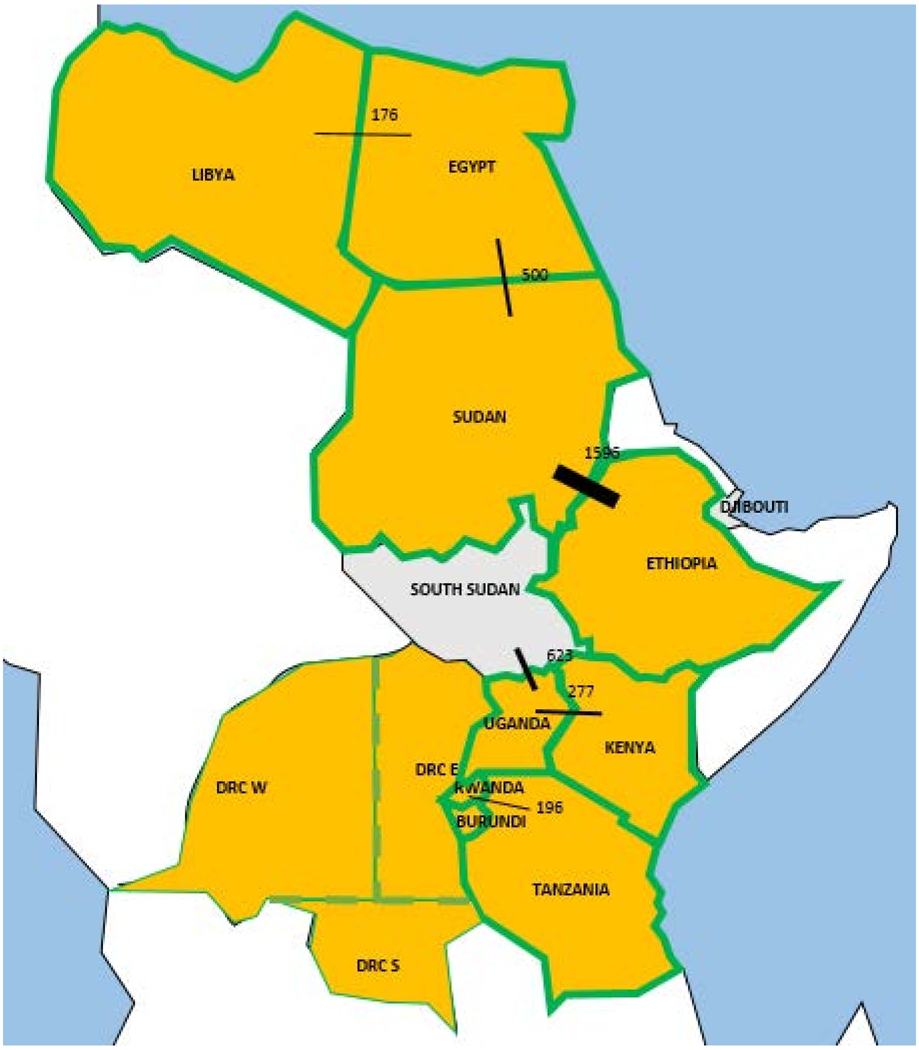

Figure 2. Recommended new lines by 2020. Numbers indicate capacity in MW.

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, 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.

The capacities of the recommended transmission projects in the short-term, i.e. towards 2020, are presented in Table 4.

	Capacity (MW)	Type	Length (km)	Cost (Mio. USD)
Sudan – Ethiopia	1,600	AC, 500 kV	550	373
Egypt – Sudan	500	AC, 500 kV	775	233
Rwanda – Tanzania	200	AC, 220 kV	115	30
Uganda – South Sudan	600	AC, 400 kV	200	77
Libya – Egypt	200	AC, 220 kV	163	38
Kenya - Uganda	300	AC, 400/220 kV	254	44
Total by 2020	**3,400**		**2,057**	**795**

Table 4: Recommended transmission projects and their capacities in 2020. The capacities are rounded to 100 MW for simplicity. Costs expressed in millions USD 2013 real values.

The capacity of the Northern corridor (Ethiopia – Sudan – Egypt) is less than recommended in the 2011 Master plan. This is mainly because of a much higher projected electricity demand growth in Ethiopia, Kenya and other countries. Increased demand results in a higher share of the cheap electricity being used to cover domestic demand.

Looking at 2025, three additional transmission lines are recommended, and additional capacity is added to three of the lines recommend for 2020. Increasing demand and new hydro power plants motivate the additional capacity. See Table 5 and Figure 3.

	Capacity (MW)	Type	Length (km)	Cost (Mio. USD)
Sudan – Ethiopia *	1,600	AC, 500 kV	550	373
Egypt – Sudan	1,000	AC, 500 kV	775	466
Rwanda – Tanzania	1,000	AC, 220 kV	115	149
Uganda – South Sudan *	600	AC, 400 kV	200	77
Libya – Egypt *	200	AC, 220 kV	163	38
Kenya – Uganda	600	AC, 400/220 kV	254	100
Rwanda – DRC	300	AC, 220 kV	46	99
DRC – Uganda	500	AC, 220 kV	352	115
Sudan – South Sudan	300	AC, 220 kV	400	163
Total by 2025	**6,100**		**2,855**	**1,580**

Table 5: Recommended transmission projects and their capacities in 2025. The capacities include recommendation for both 2020 and 2025. The capacities are rounded up to 100 MW for simplicity. Costs expressed in millions USD 2013 real values.
** These lines have the same capacity as in Table 4 (2020).*

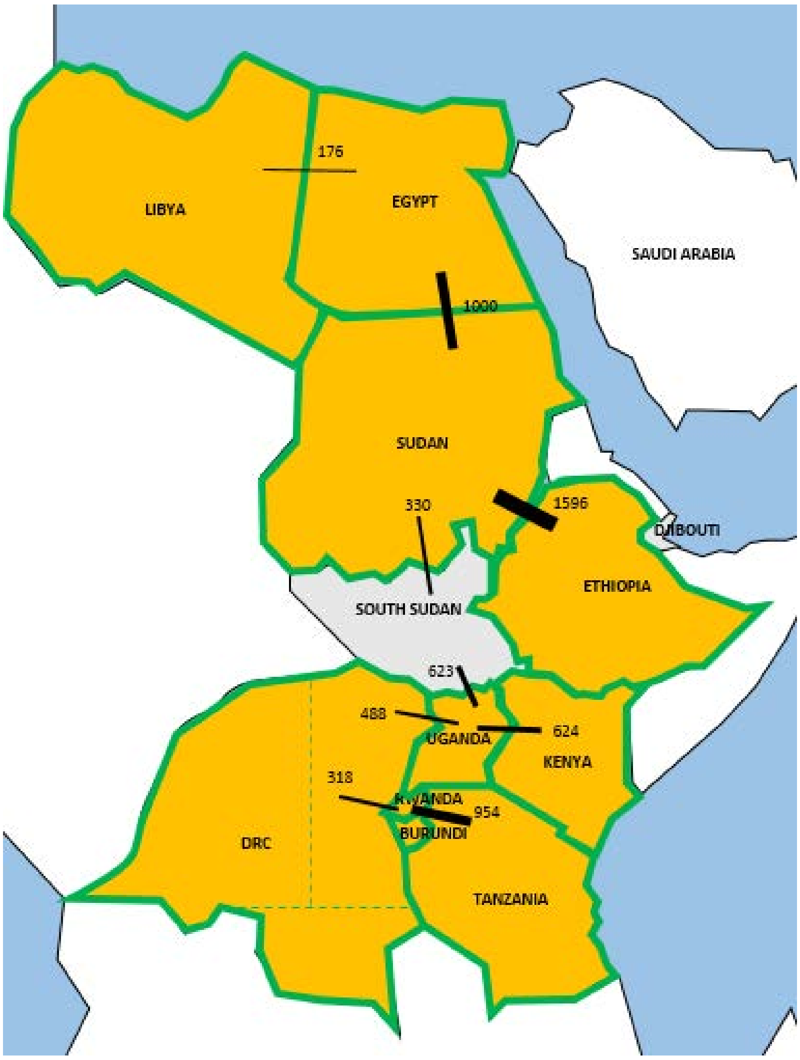

Figure 3. Recommended new lines by 2020 and 2025 (accumulated). Numbers indicate capacity in MW.

With the two new corridors in place towards 2025, the EAPP countries would be connected with a strong backbone from the DRC in the West, via Tanzania in the South, and to Egypt in the North. The difference in generation technologies would make supply more robust against hydrological variation and fuel supply challenges. A more interconnected would also be more robust against outages of key system elements.

The flow on the interconnectors will typically flow from West to East and from central to North, as illustrated in Table 6. Many minor changes take place from 2020 to 2025, but in general the results are robust: The flow on the interconnectors are maintained in 2025. From 2025 all of DRC is connected and this motivates the increased flow, e.g. on the DRC – Burundi line and on the DRC – Rwanda line.

		2020		2025	
		->	<-	->	<-
BURUNDI	DRC	3%	1%	0%	43%
	RWANDA	6%	2%	6%	1%
	TANZANIA	52%	2%	37%	0%
DJIBOUTI	ETHIOPIA	0%	31%	0%	28%
DRC	RWANDA	2%	1%	68%	0%
	UGANDA	-	-	26%	0%
EGYPT	LIBYA	22%	39%	7%	57%
	SUDAN	1%	74%	0%	83%
ETHIOPIA	KENYA	7%	20%	34%	14%
	SUDAN	54%	1%	45%	3%
KENYA	TANZANIA	3%	0%	10%	2%
	UGANDA	0%	74%	0%	63%
RWANDA	TANZANIA	52%	0%	58%	0%
	UGANDA	0%	6%	1%	15%
SOUTH_SUDAN	SUDAN	68%	0%	85%	0%
	UGANDA	0%	68%	17%	2%
TANZANIA	UGANDA	0%	70%	0%	52%

Table 6. Expected flow on interconnectors. The value is relative to the transmission capacity.

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, along with less investment in coal-fired generation
- 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.

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 7). 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 7. 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 7, the savings considerably exceed the costs.

Natural gas vs. coal

Generation based on hydropower and natural gas dominates until 2025. The cost competitiveness balance between natural gas and coal is tight, however. In a parameter variation case assuming natural gas price in the EAPP region matching the European price level (as forecasted by the IEA WEO 2013), a shift from natural gas to coal takes place in 2020. Alternatively, in a case where the interest rate is lowered to 8%, (while maintaining the natural gas price assumptions of the Main scenario), the investment in natural gas-based generation shifts to coal and nuclear. These shifts in supply primarily take place in Egypt, and show the tight economical balance between different competing supply technologies. The planned expansion in Egypt until 2027 contains three technologies: natural gas, coal and nuclear.

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 different parameter variation cases tested (lower and higher power demand, higher transmission investment costs and removal of national security of supply requirement)[6] the recommended (optimal) capacity varies from 40% to 200% relative to the Main scenario.

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 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 transmission 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 (see Table 4) 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 Rwanda – Tanzania line, a feasibility study should be performed.
- 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.

[6] These cases have been tested in the Low demand, High demand, 50% increase and Benchmark scenarios, respectively. See Volume I: Main Report, and Volume III: Results Report for more detailed description and results.

- EAPP should continually monitor the development of the six lines. E.g. with half-year updates on status.

A further three lines are recommended for 2025 (see Figure 3). Similar steps should be planned for these lines.

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. 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 significant emissions. 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.

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[7]).

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).

Methods used

The EAPP Master Plan is a regional least-cost plan. The general methods used are similar to those used in many national Master Plans. Some unique features of the current study are however highlighted in this section.

[7] 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.

Input data regarding the future

The least-cost analysis is based on a number of assumption regarding the future, including:

- The future electricity demand in each country
- The characteristics of candidate power plants. In this study, 10 generic plant types (e.g. based on coal, natural gas, diesel, geothermal, nuclear, solar and wind), as well as 87 individual projects (typically hydro) comprise the generation investment technology catalogue[8]
- The characteristics of candidate transmission lines. In this study, 26 different transmission candidate projects comprise the transmission investment catalogue[9]

Simultaneous investment in generation and transmission

The analyses of the least-cost investment and dispatch are based on the model Balmorel. The Balmorel power system model is an economic and technical partial equilibrium model that simulates the power system and least-cost dispatch.[10] The model optimises production at the existing and planned production units and simultaneously simulates least-costs investments in new generation and transmission, thereby finding the regional least-cost way to supply the needed electricity. The investment projects (as well as the year of investment, location and capacity) are chosen by the model via an impartial and objective least-cost optimisation approach based on the input data provided.

Key assumptions

A number of assumptions are used in the calculation of the least-cost plan. These are typically similar to those used in the national Master Plans:

- A planning interest rate of 10% p.a. (real). This corresponds to a real IRR rate of at least 10% for all model-based investment projects. The economic lifetime for projects is assumed to be 20 years in most cases, but 50 years for hydro and nuclear. The investment decision is based on the assumption that the specific year of investment represents a 'typical' year of operation of the respective project throughout its economic lifetime.
- Cost of unserved electricity demand of 1.2 $/kWh

[8] The cost and efficiency of the generic plant types are taken from The International Energy Agency's World Energy Outlook 2014 for Africa. The site-specific candidate project characteristics have been provided by the respective national utilities

[9] The characteristics of 17 of these lines have been based on information from their respective feasibility studies, while the cost for the remaining 9 lines has been estimated based on their type, voltage and length

[10] See: www.balmorel.com. The model is open source and is installed in the EAPP office.
See www.eaea.dk/themes/111_theme_modelling_of_energy_systems.html for examples of the use of the model.

- A requirement that all countries have 110% capacity compared to the peak demand. In order to study the costs and impacts of this requirement, in one scenario it is not included.
- 10% of thermal power plant capacity is reserved for planned and unplanned maintenance.

Also, as in national Master Plans, the existing electricity system is represented in detail. Each existing power plant is represented with name, capacity, fuel, efficiency and last year of expected operation. 184 existing plants are included in the model, together with 140 committed plants.[11]

Existing transmission lines are described by their capacity.

Committed units

Committed power plants and transmission lines are included. However, only projects that have a high degree of certainty are included. The projects must be under construction or fully financed. The idea is that the model should be given highest possible (realistic) degree of freedom in terms of finding least-cost solutions.

The unique features of this study

This study is different from traditional Master Plan studies in a number of ways:

- The 2014 Master plan has been developed during a *twinning project* where the EAPP Permanent Secretariat, member utilities and consultants have been working together to complete the task. Model software and hardware have been installed at the EAPP office, and two rounds of training in its use have also been undertaken.
- 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

[11] In most cases this is individual power plants. In some cases small units are grouped together.

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.