EASTERN AFRICA POWER POOL (EAPP)

EAPP REGIONAL POWER SYSTEM MASTER PLAN

VOLUME II: DATA REPORT

Ea Energy Analyses

ENERGINET.DK
Energy Consultancy A/S

February 2014

Published by:

EAPP, Eastern Africa Power Pool
Kirkos sub city, House No.513
P.O Box 100644
Addis Ababa, Ethiopia

Ea Energy Analyses
Frederiksholms Kanal 4, 3. th.
1220 Copenhagen K, Denmark

Energinet.dk
Tonne Kjærsvej 65
7000 Fredericia, Denmark

Contents

1 Introduction and background

This data report is part of the Eastern Africa Power Pool (EAPP) 2014 Master Plan. This report contains detailed information on the data used for modelling of the power systems of the EAPP member countries in BALMOREL in relation to the process of EAPP Master Plan as of 2014.

Approach

In order to identify and quantify the potential benefits of regional cooperation in terms of transmission and generation within the EAPP member (and relevant adjacent) countries, modelling of the power systems of the EAPP member countries is being carried out based on the concept of 'least-cost development planning'. A number of scenarios is set up in consultation with the EAPP and the member countries' utilities in order to illustrate the economic consequences of different possible future strategies.

The BALMOREL model is used to simulate the scenarios of the EAPP Master Plan. The model area includes all of the EAPP member countries (Burundi, Djibouti, DRC, Egypt, Ethiopia, Kenya, Libya, Rwanda, Sudan, South Sudan, Tanzania and Uganda).

Data from the 2011 Master Plan has been used as a starting point. Thorough data updating and verification process in association with the EAPP and the local utilities has been carried out prior to data input into BALMOREL. This process includes data collection tours as well as midway workshops to all EAPP member countries except Libya.

All cost data in this report are USD 2012 real terms. The results are presented in USD 2013 real terms using a conversion rate of 1.015.

2 The BALMOREL model

The power system analyses are carried out with the BALMOREL model, which is a least-cost dispatch power system model. The model is based on a detailed technical representation of the existing power system; all power generation plants are represented on a unit basis as well as the interconnected transmission grid.

The output is a least-cost optimisation of all the production and transmission units represented in the model. In addition to simulating least-cost dispatch of generation units, the model simultaneously allows investments to be made in different new generation units (hydro, coal, gas, wind, biomass etc.) as well as in new interconnectors.

2.1 Investment approach

The BALMOREL model is myopic in its investment approach, in the sense that it does not explicitly consider revenues beyond the year of installation. This means that investments are undertaken in a given year if the annual revenue requirement (ARR) in that year is satisfied by the market.

A balanced risk and reward characteristic of the market are assumed, which means that the same ARR is applied to most technologies, specifically 0.1175, which is equivalent to 10 % internal rate of return for 20 years. This rate should reflect an investor's perspective. Hydro and nuclear projects, due to their longer economic and technical lifetime, have been assigned an ARR of 0.1009 equivalent to 10% internal rate for 50 years. Sensitivity analyses are carried out for this parameter with parameter variations on 8% and 12 %.

In practice, this rate is contingent on the risks and rewards of the market, which may be different from technology to technology. For instance, unless there is a possibility to hedge the risk without too high risk premium, capital intensive investments such as hydro or nuclear power investments may be considered more risky by the potential investor (and higher return required as a result).

It should be stressed that the recommended socio-economic discount rate in many countries is significantly lower than the 10 % rate applied in the present study (Germany: 2.2 %, Sweden and Norway: 4 %, Denmark and Finland: 5 %, UK: 1.0-3.5 %, EU: 3.5-5.5 %[1]). Applying a lower discount rate would favour capital intensive technologies like wind power, nuclear power and solar power as opposed to for example gas power plants. It is considered relevant to apply a relatively high discount rate in this study due to the challenge of securing capital in East Africa.

2.2 Time resolution

The model is set up to analyse 2015 and the period 2020-2040 in five year intervals.

To limit the computing time not all hours of the year are included in the simulation. The yearly time resolution is set to 168x5 time steps, which is a total of 840 time steps. The 168 steps represent all hours of a week and the 5 are the number of selected weeks. The following weeks are chosen to represent a year in the model: week 1, 11, 21, 31 and 41. The chosen weeks are important in relation to the data profiles included in the model. This relates to electricity demand, hydro inflow, wind and solar profiles. Only the profile data of the above weeks are included in the simulation and it is important to carefully select the weeks so they represent e.g. the different hydro inflow and electricity demand situations of the year.

2.3 Geographical scope

The model contains data of the electricity systems of the 10 EAPP countries as well South Sudan and Djibouti. The map below illustrates the existing interconnected power system of the EAPP region.

[1] European Commission (2008): Guide to Cost-Benefit Analysis of investment Projects; Concito (2011): Den samfundsøkonomiske kalkulationsrente – fakta og etik

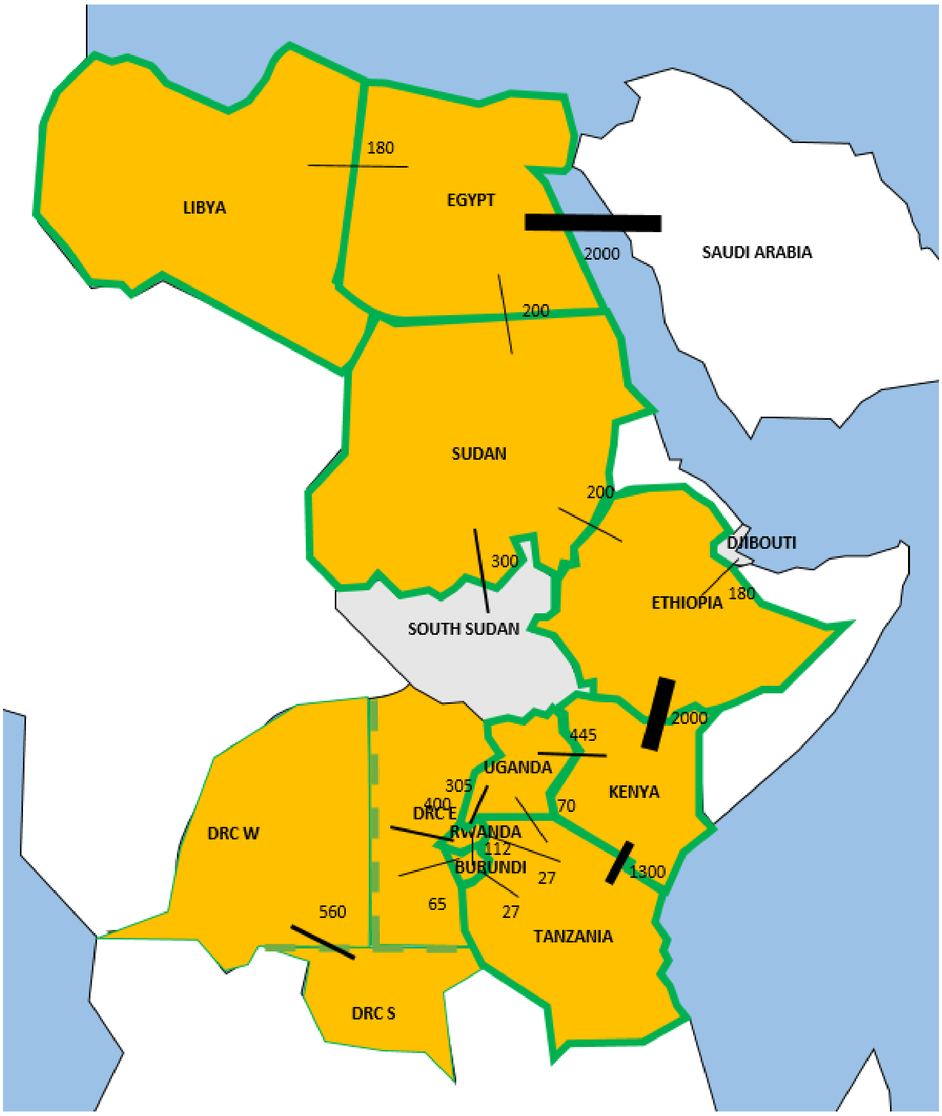


Figure 1. Current and committed (before 2020) interconnectors in EAPP (MW). Note that an additional 1000 MW line will connect the Western and Southern DRC by 2025 and a 500 MW will connect DRC South and East in 2025.

Each country is constituted of one or more regions while each region contains one or more areas. Any area must be included in exactly one region, and any region must be included in exactly one country. The areas are the building blocks with respect to the geographical dimension. Thus, for instance all generation and generation capacities are described at the level of areas, and so are all aspects of hydro inflow and resources.

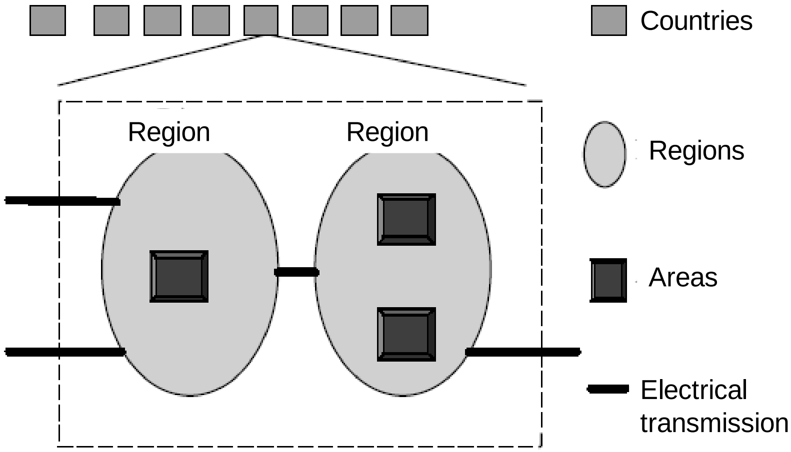


Figure 2: The geographical entities of the BALMOREL model.

Electricity balances are given on a regional basis. Hence, for each region an electricity balance must be fulfilled but electricity may be exchanged between regions. Hence the transmission, and its constraints, losses and costs, are the motivation for the concept of regions. A country is comprised of one or more regions.

The country does not have any generation or consumption apart from that which follows as the sum over the regions in the country. However, a number of characteristics may be identical for all entities (e.g. fuel prices) in a country. A country is constituted of more than one region when needed to represent bottlenecks in the electricity transmission system within the country. In the model only DRC is divided into several regions. This is done to reflect that the Western, Southern and Eastern DRC centralised power systems are not yet connected.

2.4 Hydro

Hydropower production potential is denoted as average yearly energy output (defined in the model in full-load hours), and each hydro plant has its own geographic entity with its own set of full load hours. This is the same for existing, committed and candidate hydro plants. There are two types of hydro power plants – hydro run-of-river plants and hydro reservoir plants. Run-of-river plants do not have any reservoir capacity, and therefore have to generate according to the water inflow to the plant. Reservoir plants can store the water and the model will use this functionality to maximise the value of the water. Both run-of-river and reservoir hydro plants are assigned with a hydro inflow profile in the model. This profile will correspond to the generation profile of a run-of-river plant, since the water has to be used when available for this technology type. For a reservoir plant this profile will tell the model how water inflow to the reservoir is throughout the year.

The hydro profiles in the model are from the EAPP 2011 Master Plan except for Ethiopia that has provided updated profiles for their entire system. The Ethiopian profiles are from the study “Ethiopian Power System Expansion Master Plan Study - Interim Report - Volume 3 - Generation Planning, 2013”.

3 General assumptions

The general assumptions such as technology catalogue, fuel prices and assumptions regarding electricity demand forecast are presented in this chapter.

3.1 Technology catalogue

The BALMOREL model has a technology catalogue with a set of power generation technologies that it can invest in according to the input data. The investment module allows the model to invest in a range of different technologies including (among others) coal power, gas power (combined cycle plants and gas engines), solar PV and wind power.

International Energy Agency

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 the 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 learning curves are applied depending on the development stage of the technology. Solar PV is e.g. expected to develop more in efficiency and investment costs than e.g. gas or steam turbines.

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.

Technology catalogue

Technical and economic data for the power generation technologies that the model may invest in can be viewed in the table below. The technology assumptions develop from now to 2035, which means that the costs and efficiencies are assumed to develop depending on the learning curves of the specific technologies. This development can be seen in the table below. Generally the technologies develop to have higher efficiencies and lower investments costs.

Technology type	Available (Year)	CAPEX incl. IDC (M$/MWel.)	Fixed O&M ($1000/MWel.)	Variable O&M ($/MWhel.)	Efficiency (%)	Technical lifetime (Years)
Steam Coal - Subcritical	2020-2034	1.8	45	3.8	35%	30
Steam Coal - Subcritical	2035-	1.8	45	3.8	35%	30
Steam Coal - Supercritical	2020-2034	2.2	63	5.3	40%	30
Steam Coal - Supercritical	2035-	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 1: Power generation technology catalogue. Efficiency is net lower heating value. For nuclear power all O&M costs are assumed to be fixed. (Costs in USD 2012 real terms).
** 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.*
**** Solar PV investment cost projections follow IEA WEO 2013 (and 2014). Alternative perspectives exist suggesting significantly higher cost reductions in the future.*

The opportunities to invest in the different technologies are not uniform across the region, for example because there are differences in the availability of resources in the different countries, e.g. access to natural gas. Political opinions about certain technologies like nuclear power and coal power also influence their future role in some countries.

The capital costs (CAPEX) include engineering and other pre-construction costs such as environmental assessments. The CAPEX together with the fixed annual and variable costs cover the operation of the plant in its technical lifetime, which e.g. for a CCGT is 30 years. Regarding grid connection costs these are considered on a project basis for candidate plants, which is the case for all hydro plants etc. This generic technology catalogue also includes grid connection costs, but assumes that power generation is built close to the existing grid.

The load factor is specifically defined for each single hydro power plant. In BALMOREL this is given by yearly full load hours. For candidate plants this data will come from the feasibility studies while for the existing plants it will be based on the average yearly energy for a historic period. Thermal power plants are considered to have a yearly availability of 90 %.

Interest paid during construction

Interests during construction (IDC) are of importance when evaluating the capital costs of one technology option to another. Units with a short construction phase pay less IDC's than plants with longer construction time.
Most capital cost data on power generation, also in the IEA catalogue, are given in overnight costs, meaning that no IDC are considered. To ensure that the technologies are equally considered by the model the IDC costs are therefore added to the capital costs.

In this study an IDC calculation approach is used which assumes that all costs are distributed equally during the construction phase. The distribution of costs will be different from one project to another, so as a generic assumption this method is considered valid. The following formula is applied when calculating IDC.

$$IDC = a \times \frac{(1+i)^t - 1}{\mathrm{i} \times \mathrm{t}} \times \left(1 + \frac{i}{2}\right) - a$$

Figure 3: IDC formula. i = interest rate, t = construction time (years), a = invested capital

To calculate the above for the different technologies the construction time must be estimated. The following table shows the estimated construction time as well as the calculated IDC. Note that the construction time for large hydro plants is project-specific. It is assumed that the IDC is accounted for in the cost data of each candidate hydro plant individually. An interest rate of 10% and 20 years payback time is assumed in the below.

Generation type	Construction time *(years)*	IDC *(%)*
Steam Coal - Subcritical	4	22%
Steam Coal - Supercritical	4	22%
CCGT	2	10%
Gas turbine	2	10%
MSD	2	10%
LSD	2	10%
Nuclear	7	42%
Geothermal	3 *	16%
Hydro - large	Project-specific	**
Hydro - small	4	22%
PV - large	1	5%
CSP	1	5%
Wind - onshore	1	5%

Table 2: Estimated construction time and calculated IDC for the technology catalogue. Interest rate is set to 10% and payback time assumed is 20 years.
** Geothermal plant construction time is based on estimate from "Republic of Kenya Updated LCPDP 2013-2033" (May 2013).*
*** Assumed to be incorporated in the project-specific investment cost estimates*

O&M for existing and committed units

Generic assumptions for fixed and variable operation and maintenance costs are applied for existing and committed power plants and are uniform across the region. The costs can be seen in the table below and are also based on the International Energy Agency (IEA) and their World Energy Outlook 2013.

Generation type	Fixed O&M *($1000/MWel)*	Variable O&M *($/MWhel)*
MSD	22	1.8
HYDRO	46	3.3
Steam Thermal Power Plant (STPP)	45	3.7
Open Cycle Gas Turbine (OCGT)	20	1.7
CCGT	26	2.1
Wind Power Plant (WPP)	22	3.7
Geothermal (Geo)	43	3.1
Cogeneration (Cogen)	45	3.7
LSD	10	0.8
Nuclear	125	0.0
Solar PV (PV)	29	0.2
Waste-to-Energy	45	3.7

Table 3: Generic fixed and variable O&M for existing and committed power plants. (Costs in USD 2012 real terms)

Outages

Forced and planned outages are assumed for both existing, committed and candidate power plants. All thermal units are set to have their net electricity capacity derated by 10 % yearly due to planned and unplanned outages. Wind, solar, and hydro are not set to be derated due to planned outages, since this is assumed to take place when there is no generation on the unit. Unplanned outages on these units are considered in their yearly energy output (full load hours).

Wind and solar capacity factors and production profiles

The wind power generation units are assigned a capacity factor to account for their yearly generation. This is set to 2200 full-load hours and is also based on the International Energy Agency (IEA) and their World Energy Outlook 2013. Solar power capacity factors are region-specific (see Table 4 below) and have been obtained from the Photovoltaic Geographical Information System of the European Commission Joint Research Centre[2].

Country	Balmorel region	Solar full-load hours
Burundi	BU_A_Thermal	1400
Djibouti	DB_A_Committed	1750
DRC	DRC_E_NewGen	1370
	DRC_S_NewGen	1550
	DRC_W_NewGen	1400
Egypt	EG_A_CAIRO	1780
	EG_A_EAST_DELTA	1800
	EG_A_UPPER_EGYPT	1820
Ethiopia	ET_A_ExiThe	1600
Kenya	KY_A_ExiThe	1600
	KY_A_FutThe	1600
Libya	LY_A_ExiThe	1700
Rwanda	RW_A_ExiThe	1400
	RW_A_FutThe	1400
Sudan	SD_A_ExiThe	1700
	SD_A_FutThe	1700
South Sudan	SS_A_ExiThe	1500
Tanzania	TZ_A_FutThe	1500
Uganda	UG_A_NewThe	1600

Table 4: Solar PV full-load hours. Source: PGIS of the European Commission JRC

Due to limited data availability, the hourly wind power production profile from the Karoo site in South Africa has been used across the EAPP region.

[2] Website: http://re.jrc.ec.europa.eu/pvgis/apps4/pvest.php?lang=en&map=africa

The hourly solar profiles have been obtained from the "SoDa. Integration and exploitation of networked Solar radiation Databases for environment monitoring", supported by the European Commission[3]. The profiles are based on the calendar year 2005, and where the data has been missing, it has been populated with the data of the previous day (i.e. past 24 hours of hourly data). The location of the observations has been the approximate geographical center of each country. The exceptions are Djibouti (using Ethiopia's profile), and Burundi (using Rwanda's profile). DRC East and South both use the same profile, for the approximate geographical centre of both areas combined. DRC West has an individual profile. The profiles of Libya and DRC West are each shifted by 1 hour to accommodate for the de facto time zone difference (with respect to daylight occurrence).

3.2 Fuel prices

The fuel prices of coal and oil in this study are based on the IEA *New Policies Scenario* as presented in IEA World Energy Outlook, November 2013. The New Policies Scenario, dealing with the period 2012-2035, assumes that current G20 low carbon agreements are implemented. A linear projection is assumed for the period 2035-2040 for fuel prices.
The cost of methane gas in Rwanda (deposits in Lake Kivu) is estimated at 6.75 USD/GJ (2012 USD values), constant in real terms throughout the modelling period.

The global efforts to combat climate change will reduce the demand for fossil fuels at the global level compared to a development with no low-carbon regulations. Therefore, according to the International Energy Agency (IEA), increases in prices of coal, oil and natural gas will be relatively moderate. In 2035 the price of crude oil is projected to reach $128 per barrel in real terms (in 2012 dollars).

Natural gas price

The natural gas price is dependent on infrastructure bottlenecks and availability as well as local resource availability and extraction costs. In the World Energy Outlook 2013 this is illustrated by the regional price differences of natural gas. In 2012 the US gas price was 2.7 $/MBtu while the European and Japanese price was 11.7 and 16.7 $/MBtu respectively. These regional price differences are caused by bottlenecks in the distribution system and costs of liquefying natural gas for transport by ship (LNG). The costs of liquefying and shipping gas is in the range of 4-7 $/MBtu depending on shipping distance and gas

[3] Website: http://www.soda-is.com/eng/services/service_invoke/gui.php?xml_descript=hc3v4_invoke_hour_demo.xml&Submit=HC3v4hour

price, which is a very significant cost element compared to the fuel price alone.

In the EAPP region there are known reserves of natural gas in Libya, Egypt, Tanzania, Ethiopia, western DRC and Rwanda. In Egypt the price of natural gas is subsidised, which also has the only LNG terminal in the EAPP region.

In this study a natural gas price starting at production costs in 2013 converging to the EU prices in 2030 will be used as the reference assumption. The EU price is based on IEA's World Energy Outlook, November, 2013. The production costs of natural gas is estimated to approx. 8.5 $/GJ[4]. Sensitivity analysis with the European gas price for the entire period is also conducted.

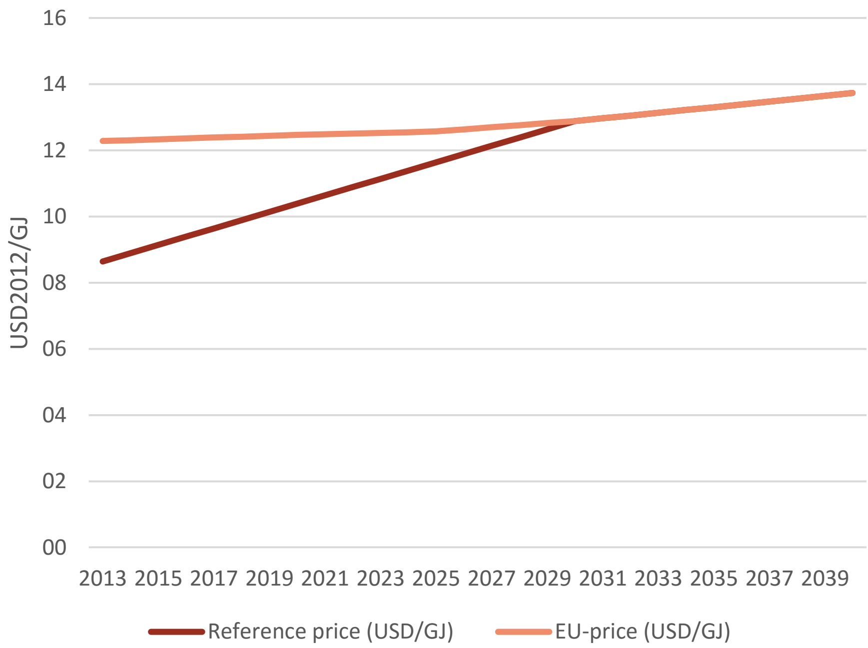


Figure 4: Natural gas price. The "Reference price" is used as the main assumption.

Transport costs and availability

Transport costs are considered for coal, natural gas and oil. Natural gas and oil transport and distribution costs are estimated to 0.5 and 0.4 $/GJ respectively. Oil for electricity generation is available in the entire region while natural gas is only assumed to be available in countries with their own domestic resource or if the country has plans of importing LNG. A domestic resource is available in Libya, Egypt, Tanzania, Ethiopia, DRC west and Rwanda while Kenya has plans of building a LNG terminal for gas imports.

[4] http://www.eia.gov/tools/faqs/faq.cfm?id=367&t=6

If there is no domestic coal resource, the costs of transport depends on if it is possible to locate the power plant by the sea enabling transport by ship. If coal has to be transported by truck this will significantly increase the transport costs. The assumptions on coal transport costs are presented on a country by country basis in the table below.

Country	Port	Destination	Port distance	Trucking cost	Total	Total
			(km)	*($/tonne)*	*($/tonne)*	*($/GJ)*
Burundi	Dar es-Salaam	Bujumbura	1560	90	90	4.50
Djibouti	Djibouti	Djibouti	0	0	0	1.00
DRC	Matadi	Kinshasa	360	21	21	1.65
Egypt	Cairo	Cairo	0	0	0	1.00
Ethiopia	Djibouti	D. Dawa	310	18	18	1.53
Kenya	Mombasa	Mombasa	0	0	0	1.00
Libya	Tripoli	Tripoli	0	0	0	1.00
Rwanda	Mombasa	Kigali	1460	85	85	4.26
South Sudan	Mombasa	Juba	1620	94	94	4.64
Sudan	Port Sudan	Port Sudan	0	0	0	1.00
Tanzania	Dar es-Salaam	Dar es-Salaam	0	0	0	1.00
Uganda	Mombasa	Kampala	1150	67	67	3.52

Table 5: Transport cost estimates for coal in the EAPP region. Trucking costs are set to 0.06 $/tonne/km while shipping and port charges are set to 0.8 $/GJ.

3.3 Levelized cost of energy overview

In the BALMOREL model, the dispatch of power generation takes place on a merit-order basis, with short-run marginal costs (SRMC) of generation setting the market price in every hour simulated. The short-run marginal costs are comprised of the fuel costs (accounted for the efficiency of each generation unit) and the variable O&M costs. For the model to invest in additional generation, however, Capital costs and Fixed O&M costs need to be covered by the prevailing power market prices over the respective year modelled. For this reason the Levelized Cost of Energy (LCOE) is a useful metric to evaluate in order to understand the relative standing of the different power generation technologies with regard to their cost-competitiveness.

BALMOREL operates under ‘perfect foresight’ within any given year, which means that the investment decisions the model makes will be based on the optimal dispatch (in other words, the realized full-load hours) of each potential plant. As such, the relative cost competitiveness (as expressed by the

LCOE) of the different technologies will vary depending on the obtainable dispatch of the respective plants.

Table 6 provides an illustration of the LCOE of different technologies for year 2020, using technology-representative cost data from the technology catalogue and typical Full-Load Hours (FLHs).

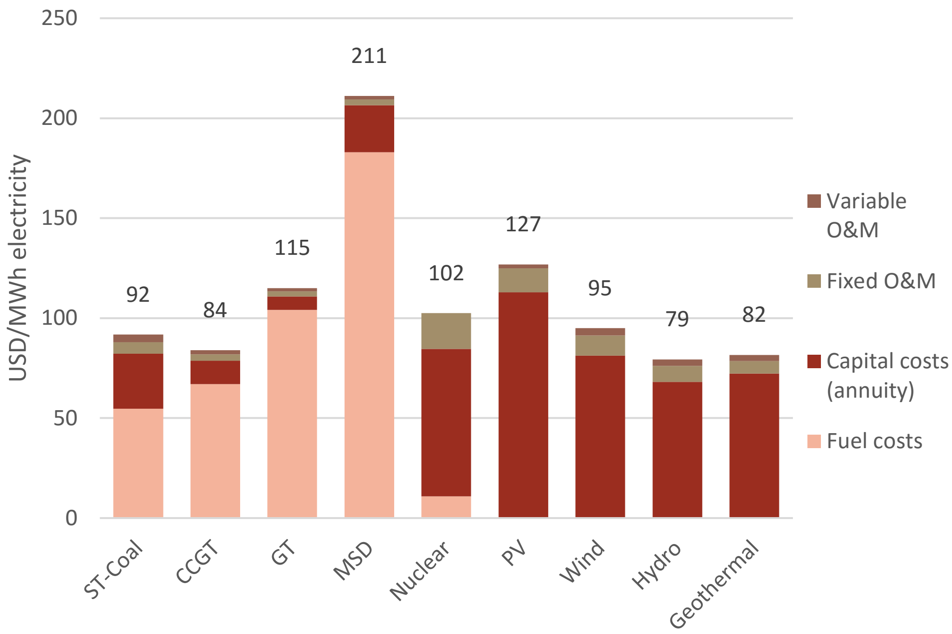


Table 6: Representative Levelized Cost of Energy comparison across different technologies for year 2020, assuming typical Full-Load Hours (FLHs). The Capital costs are converted into annuity payments based on 10% interest rate and 20 year economic lifetime (hydro and nuclear assumed 50 years)

Table 7 provides an overview of the technology-representative assumptions used in order to derive the representative LCOE estimates for year 2020. It should be noted that LCOE is sensitive to the realized FLHs, hence the relative cost-competitiveness of the different technologies will vary accordingly. Another important observation is that of the relatively little difference between the LCOE of coal-fired and gas-fired (CCGT) technologies. A relatively minor increase in the natural gas price can change the relative standing of the two technologies, making coal the least-cost generation technology.

Fuel type		ST-Coal	CCGT	GT	MSD	Nu-clear	PV	Wind	Hydro	Geo
Efficiency	(%)	35%	59%	38%	45%	33%	*	*	*	*
Capital costs	(mUSD/MWelectricity)	1.8	0.8	0.4	1.6	5.7	1.9	1.5	3.9	4.3
Fixed O&M	(USD/MWelectricity)	45	25	20	21.8	140	24	22	45.5	43.2
Variable O&M	(USD/MWhelectricity)	3.8	2.1	1.7	1.8	0.0	2.0	3.7	3.3	3.1
Fuel costs	(USD/GJ fuel input)	5.3	11.0	11.0	22.9	1.0	0.0	0.0	0.0	0.0
FLH	(Hours)	7800	7800	7800	7800	7800	2000	2200	5730	7000

Table 7: Assumptions used to derive the representative LCOE estimates for year 2020.
** The efficiency (capacity factor) of these technologies is reflected in their respective Full-Load Hour (FLH) metrics*

Figure 5 illustrates the LCOE of each technology in year 2020 depending on the realized Full-Load Hours of operation. As it can be observed in the graph, the relative cost-competitiveness of the different technologies changes depending on the realized power production, making gas turbines and CCGTs most economic for fewer operating hours (i.e. peaking units), and geothermal and hydro – for base load, respectively. It should, however, be noted, that technology-representative LCOE estimated are hereby presented – whereas the LCOEs of e.g. each individual hydro project could vary substantially based on its respective Capital costs.

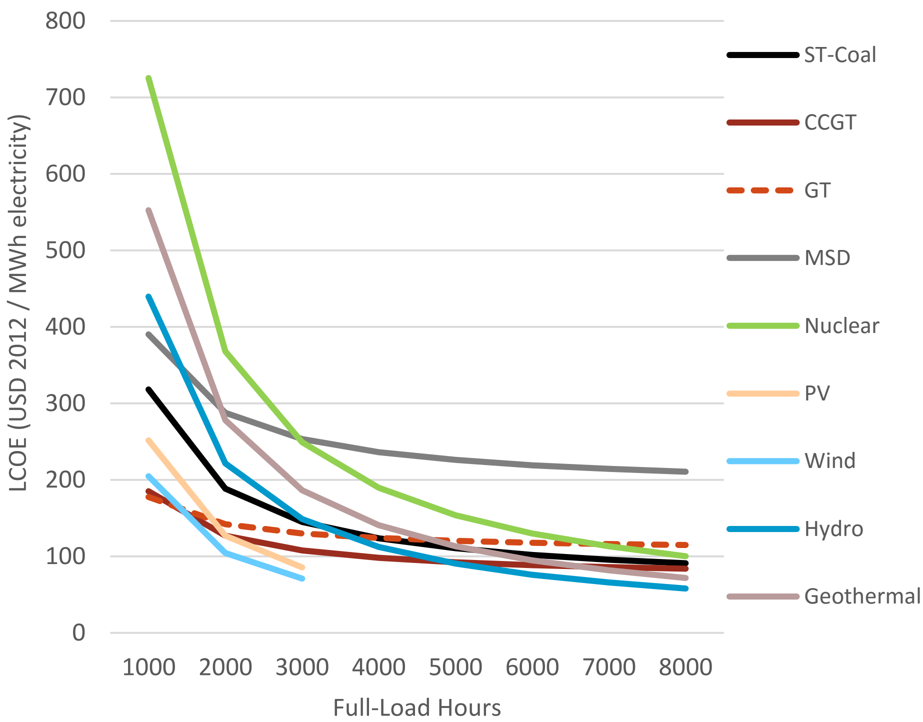


Figure 5: Representative LCOE across different technologies for year 2020, depending on the realized FLHs. The FLHs of wind and solar PV is site dependent, but is assumed not to exceed 3000 hours.

The LCOE of the different technologies – and the relative standing thereof - will also evolve in line with the projected developments in Capital, Fuel and O&M costs throughout the projection period (2025 – 2040) as laid out in the technology catalogue and fuel price descriptions earlier.

A cost can be added for technologies emitting CO_2, however this is not included here.

3.4 Electricity demand forecasts

The electricity demand forecasts applied in this study are based on the reference forecasts of the national utilities. These forecasts very much depend on the national policies for expansion of electricity access, infrastructure, and industry development etc. and hence the expectations to demand growth are different from country to country. The table below lists the references as well as the period covered by the individual forecasts country by country.

Country	Forecast period end year	Reference
Burundi	2025	Economic's study for Ruzizi 3 project (ANANDA)
Djibouti	2038	EAPP Master Plan, 2011
DRC	2030	Projections d'Offre & de Demande d'Energie Electrique en RDC et dans les Pools Africains: Volume 1, 2011.
Egypt	2026	EEHC forecast for EAPP Master Plan, 2013
Ethiopia	2037	Ethiopian Power System Expansion Master Plan Study - Interim Report - Volume 3 - Generation Planning, 2013
Kenya	2033	Republic of Kenya - updated least-cost power development plan - 2013-2033, 2013, 'High' forecast
Libya	2026*	International Energy Agency, 2011 country statistics
Rwanda	2022	SOFRECO Report, Revised 2014
South Sudan	2025	AFDB, INFRASTRUCTURE PLAN FOR SOUTH SUDAN CHAPTER 8 PROVISION OF ELECTRIC POWER AND RURAL ENERGY, 2013
Sudan	2031	Demand Forecast Report FINAL – Revision, 2013
Tanzania	2035	POWER SYSTEM MASTER PLAN, 2012 UPDATE
Uganda	2028	Grid Development Plan, 2012

Table 8: Country by country demand forecast period and literature references.
** No forecast for Libya has been available and the demand growth for Egypt has therefore been applied to the 2011 historical demand of Libya.*

As it can be seen in the above table, the national forecasts cover different periods that do not always span across 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 (if final year of forecast is before 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 region.

The demand forecasts are presented in Chapter 5 with country-specific data.

Demand profiles

All countries in the EAPP region are assigned their own hourly electricity demand profiles when available. This reflects the differences across the region regarding weekly and yearly demand variations. This is e.g. seasonal temperature variations which lead to yearly variations in electricity demand for cooling. Time zone differences are also captured as well as the differences in weekdays and weekends in the region. The table below illustrates the different time zones and weekday-weekend relations in EAPP. Eastern Africa Time (EAT) is set as the reference time, meaning that the yearly count of hours will start in this time zone.

EAT	EAT minus 1 hour	EAT minus 2 hours
Ethiopia	Egypt	**DRC West**
Burundi	Libya	
Djibouti	**DRC East**	
Kenya	DRC South	
Rwanda		
South Sudan		
Sudan		
Tanzania		
Uganda		

Table 9: Different time zones across the EAPP. The countries in red bold font have their weekend on Saturday-Sunday while the rest have their weekends on Friday-Saturdays.

The demand profiles used in this study are all from 2011.

3.5 Emission factors

The level of SO_2 and CO_2 emissions reported in the EAPP Master Plan 2014 is determined by the fuel use in the power production modelled in each time period by the individual generation units represented and the corresponding emission factors. An overview regarding the emission factors employed in the current analysis is provided in Table 10.

Fuel	CO_2 content (kg/GJ fuel)	SO_2 content (kg/GJ fuel)
Natural gas	56.8	0
Coal	95	0.07
Fuel oil	78	0.446
Light oil	74	0.023
Peat	107	0.24
Municipal waste	32.5	0.156
Wood	0*	0.025
Coke	95	0.07
Methane	49.28	0

Table 10: Assumptions regarding the SO_2 and CO_2 content in different fuels per GJ of fuel energy content. Only fuels emitting SO_2 and/or CO_2 have been listed.
** Wood and bagasse are assumed to be carbon-neutral fuels.*

The SO_2 emission coefficient for coal (0.07 kg/GJ) has been based on the World Bank guidelines, 2008 edition[5] corresponding to the emission limit for large (600 MW+) boiler type of 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.

The emission limit applicable to SO_2 content in flue gas of 200 mg/Nm^3 stated in the World Bank guidelines has been converted to kg/GJ by using the coal flue gas emission volume assumption[6] of 350 Nm^3/.

The 200 mg/Nm^3 emission level (and the corresponding 0.07 kg/GJ, respectively) represents 90% reduction in SO_2 emissions relative to the average non-desulphurised emission level of ca. 2000 mg/Nm^3. This level of desulphurisation has been deemed attainable both from technological and financial standpoints for the prospective power plant projects in the EAPP member countries.

[5] IFC World Bank Group, 2008: "Environmental Health and Safety Guidelines – Thermal Power Plants"
[6] Coal flue gas: dry, 6% excess oxygen. Source: World Bank Group, 1998: "Pollution Prevention and Abatement Handbook"

4 Interconnectors

The starting point of the interconnected grid within the EAPP region is all existing and committed interconnectors. In the BALMOREL model this is defined as the net transfer capacity between the countries. The DRC is divided into three geographical entities (the West, South, and the East), and the only existing connection is the DRC West – DRC South DC line. This grid of the existing and committed interconnectors will serve as a starting point for the BALMOREL model to make investments in interconnectors on top of the existing grid for the period beyond 2020. It is therefore of importance to define the existing and committed interconnectors as well as the costs for the development of the grid for the period 2020 to 2040.

4.1 Existing and committed interconnectors

Committed interconnectors are projects that are under construction or projects that are decided and financed. The table below shows a list of existing and committed interconnectors. These committed interconnection projects and their net transfer capacities will be considered as firm capacity just as existing interconnectors.

As mentioned above DRC is divided into three region to reflect that not all of the grids are currently not connected. The Western and Southern grids will be further connected in 2025 by a 1000 MW AC line. Construction of this line will continue to the Eastern grid of the DRC (DRC South – DRC East) with a capacity of 500 MW, which is also expected to be finalised by 2025. The construction of this approx. 2500 km line will result in the Western and Southern regions of the DRC also being interconnected with the EAPP region.

To/From	From/To	Existing (MW)	Committed (MW)	Online (Year)
DRC	Burundi	15.5	49	2018**
DRC	Rwanda	100	300	2015
DRC	Tanzania	-	-	
DRC	Uganda	-	-	
DRC South	DRC East	-	500	2025
DRC West	DRC East	-	-	
DRC West	DRC South	560	1000	2025
Egypt	Sudan	-	200	2016
Ethiopia	Djibouti	180	-	
Ethiopia	Kenya	-	2000	2017
Kenya	Tanzania	-	1300	2018***
Libya	Egypt	180	-	
Libya	Sudan	-	-	
Rwanda	Burundi	12	100	2018**
Rwanda	Tanzania	-	27	2018
South Sudan	DRC	-	-	
South Sudan	Ethiopia	-	-	
South Sudan	Kenya	-	-	
South Sudan	Uganda	-	-	
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 11: Existing and committed interconnectors (MW). "Online" is the year when the committed projects are expected to be operational.
** 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*

The figure below shows a map of the EAPP region with all existing and committed interconnectors as of 2020. Note that DRC is as the only country divided into three regions to represent that the Western, Southern and Eastern grid are not fully interconnected until 2025 as described in Table 7.

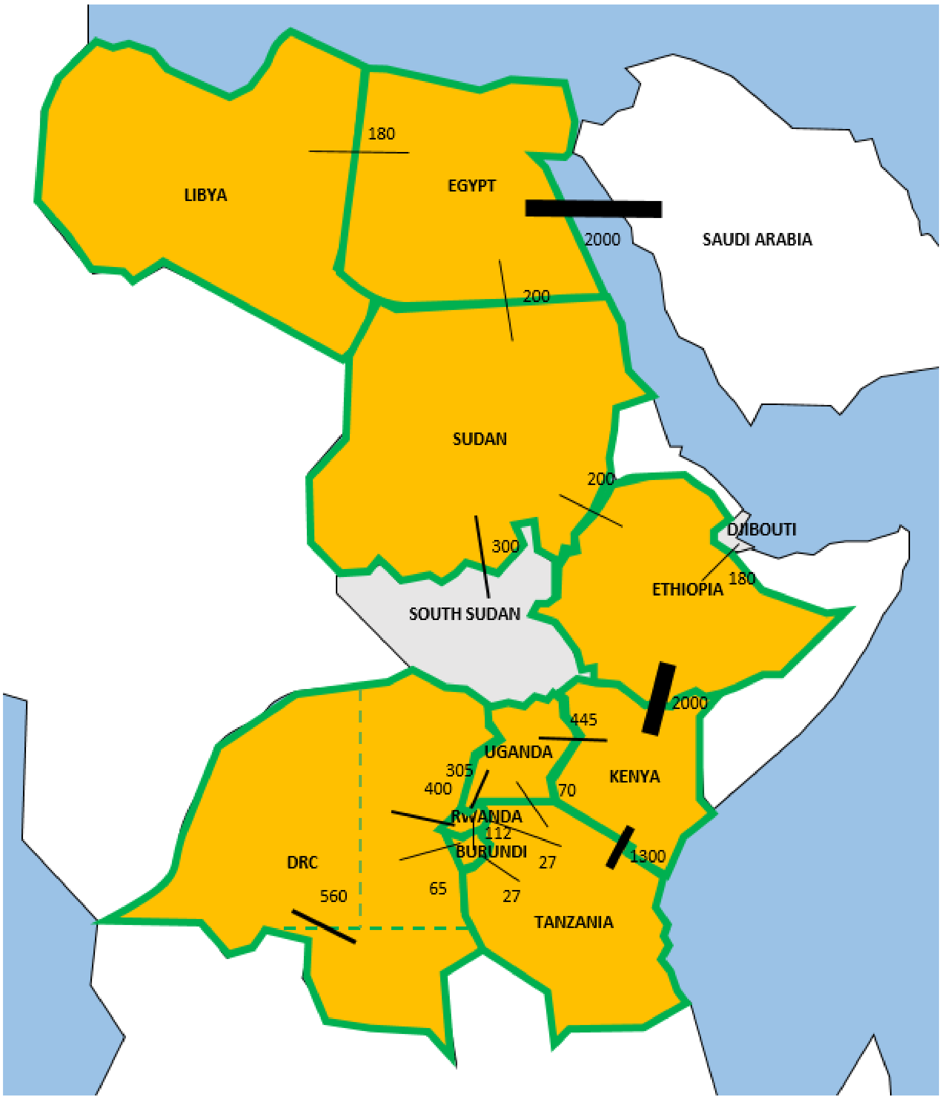


Figure 6. Current and committed (before 2020) interconnectors in EAPP (MW). Note that an additional 1000 MW line will connect the Western and Southern DRC by 2025 and a 500 MW will connect DRC South and East in 2025.

The net transfer capacity of all interconnectors in the model are derated by 10 % on a yearly basis to account for planned and unplanned outages of the lines.

Egypt-Saudi Arabia interconnector

An interconnector between Saudi Arabia and Egypt is also considered as committed. This is a 3000 MW HVDC line that is estimated to come online in 2018. The line is set to export from Egypt to Saudi Arabia during the mid-day peak in Saudi Arabia and from Saudi Arabia to Egypt during their evening peak. It is assumed that the export of 3000 MW to Saudi Arabia takes place every day all year from 7 AM to 4 PM. Hereafter the line is used for import to Egypt from 4

PM to 12 PM, also at 3000 MW per hour. This is a 9 hours flow in each direction every day all year, corresponding to a yearly flow in each direction of 9.83 TWh, hence the yearly net balance is zero.The power system of Saudi Arabia is not modelled, but the aforementioned import and export flows are imposed on Egypt to simulate the planned effect of the interconnector.

4.2 Interconnector investment costs

To analyse the development of the future interconnected EAPP power system beyond 2020 the investment costs of interconnectors is an important element. It is preferable to use cost data from actual feasibility studies, and this is done for all projects where the data has been available. In the absence of cost data from feasibility studies, the investment costs need to be estimated.

Estimating interconnector costs

The cost estimates presented in Table 8 are based on the EAPP 2011 Master Plan. These costs are considered to still be accurate. To account for inflation, the cost data have been converted to correspond to 2012 USD in real terms. The inflation-adjusted interconnector costs are presented in the table below:

Technology	Voltage level *(kV)*	Configuration	Line cost *(k$/km)*	Converter cost *(k$/MW/terminal)*	Fixed cost for additional AC requirements *(M$)*
HVDC	500	Bipolar	301	130.8	14.2
HVDC	600	Bipolar	316	136.3	17.4
AC	220	Double-circuit	262	-	10.9
AC	400	Double-circuit	436	-	14.2
AC	500	Double-circuit	480	-	17.4

Table 12: Assumptions for estimating interconnector capital costs (Costs in USD 2012 real terms)

Interest paid during construction (IDC) is added to the above costs based on an estimate of the duration of the construction phase. This estimated construction time can be found in the table below. As with power plants an approach calculating IDC assuming that all costs are distributed equally during the construction phase is applied in this study.

The costs of all possible interconnectors and their technical characteristics are presented in the table below. In BALMOREL the costs of interconnectors are defined as costs per MW net transfer capacity and are given line by line. The model can invest in an interconnector of any size using this input. When the costs are estimated using the cost estimates from Table 8 above "Estimated" is written under source in Table 9. Only the costs of 9 out of 26 possible lines are estimated whereas the rest are based on actual project cost data or feasibility studies.

In the table below an AC and a HVDC option for the Egypt-Sudan interconnector is listed. Due to grid stability issues this AC option is limited to 1000 MW. The AC line has significantly lower costs than the HVDC alternative, which means that the model will choose the AC option before the HVDC. If the model increase the capacity on this border above 1000 MW it has to invest in the HVDC technology for all capacity above 1000 MW.

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	Tanzania	AC	220	678	300	4	229	0.34	**0.76**	Estimated
DRC East	Uganda	AC	220	352.2	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 east	AC	400	1710	1000	9	1204	0.70	**1.20**	Estimated
DRC west	DRC south	AC	400	1700	1000	9	1110	0.65	**1.11**	DRC
DRC west	*Egypt**	*HVDC*	*600*	*5351*	*3500*	*10*	*7521*	*1.41*	***2.15***	*AECOM & EDF*
Egypt	Sudan**	AC	500	775	1000	4	444	0.57	**0.44**	Sudan
Egypt	Sudan	HVDC	600	1665	2000	4	1385	0.83	**0.69**	NBI
Ethiopia	Djibuti	AC	220	283	300	3	98	0.35	**0.33**	Estimated
Ethiopia	Kenya	HVDC	500	1068	2000	4	1260	1.18	**0.63**	AFDB
Kenya	Tanzania	AC	400	508	1300	3	214	0.42	**0.16**	NBI & Tanzania
Libya	Egypt	AC	220	163	300	3	62	0.38	**0.21**	Estimated
Libya	Sudan	HVDC	500	1400	1000	4	849	0.61	**0.85**	Estimated
Rwanda	Burundi	AC	220	131	300	3	55	0.42	**0.18**	Rwanda
Rwanda	Tanzania	AC	220	115	320	3	47	0.41	**0.15**	Estimated
South Sudan	DRC east	HVDC	500	583	1000	4	550	0.94	**0.55**	Estimated
South Sudan	Ethiopia	AC	220	300	300	3	101	0.34	**0.34**	EAPP and AFDB
South Sudan	Kenya	HVDC	500	540	1000	4	534	0.99	**0.53**	Estimated
South Sudan	Uganda	AC	400	200	1000	3	117	0.59	**0.12**	NBI
Sudan	Ethiopia	AC	500	550	1200	4	267	0.49	**0.22**	NBI***
Sudan	South Sudan	AC	220	400	300	4	141	0.35	**0.47**	Estimated
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 13: All possible new interconnectors in the EAPP region and assumptions regarding their type, length and capital costs. (Costs in USD 2012 real terms). Nile Basin Initiative (NBI) and African Development Bank (AFDB)

** 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*

5 Country-specific data

This section presents the BALMOREL data input for each of the countries in the EAPP region, including data on the existing power plants, the candidate plants, hydro data as well as the electricity demand forecasts.

The existing and candidate power plants are described by their technology type, net fuel efficiency, installed net capacity and fixed and variable operation and maintenance costs.

Committed generation units are plants that are certain to come online within the short-term. These are plants that are either under construction or contracted units that are financed.

5.1 Burundi

Existing, committed and candidate plants

The existing Burundian power system consist of smaller diesel engines and hydro plants, which are aggregated into two groups in the table below. Four hydro plants are committed, which will more than double the power capacity before 2020.

	BALMOREL area	Name	Type	Nominal capacity (MW el.)	Fuel	Effici-ency (net %)	CAPEX (M$/MW el.)	Fixed costs (1000$/MW el.)	Variable costs ($/MWh el.)	On power (Year incl.)	Retire-ment (Year incl.)
Existing	BU_A_Thermal	Burundi_exi_the	MSD	17 (*10.5*)*	Diesel	27%		21.80	1.82	1998	2027
	BU_A_ExiHydro	Burundi_exi_hy	HYDRO	39 (*33*)*	Water - ROR			45.53	3.25	2010	2050
Committed	BU_A_Mpanda	Mpanda	HYDRO	10	Water - RESER			45.53	3.25	2018	2050
	BU_A_Kabu_16	Kabu_16	HYDRO	21 (*20*)*	Water - ROR			45.53	3.25	2018	2050
	BU_A_JIJI	JIJI	HYDRO	33	Water - ROR			45.53	3.25	2017	2050
	BU_A_Mulembwe	Mulembwe	HYDRO	17	Water - ROR			45.53	3.25	2019	2050
	BU_A_Thermal	BU_PV	PV	20	Sunlight			29.38	0.24	2015	2039
	BU_A_RUSUMO_FALLS	RUSUMO_FALLS	HYDRO	26.7	Water - ROR			45.53	3.25	2018	2050
Candidates	BU_A_KAYONGOZI	KAGUNUZI_06	HYDRO	8	Water - RESER		3.75	45.53	3.25	2019	2050
	BU_A_RUZIZI_3	RUZIZI_3	HYDRO	48	Water - ROR		3.47	45.53	3.25	2017	2050
	BU_A_Ruzibazi	Ruzibazi	HYDRO	17	Water - ROR		4.52	45.53	3.25	2019	2050
	BU_A_KabuDiversion	Kabu 23	HYDRO	14.6	Water - ROR		4.52	45.53	3.25	2019**	2050
	BU_A_RUZIZI_4	RUZIZI_4	HYDRO	95.7	Water - ROR		3.00	45.53	3.25	2019**	2050

Table 14: Existing, committed and candidate power plants as represented in the model for Burundi

** The capacities indicated in parentheses (in italics) correspond to the latest data updates received from Burundi. These are provided for reference only (not included in the model simulation due to data being received after the closure of the data collection period).*

*** Based on the latest data updates received from Burundi, both Kabu 23 and Ruzizi 4 should be available for investment 2025 and onwards. The updates are not included in the model simulation due to data being received after the closure of the data collection period.*

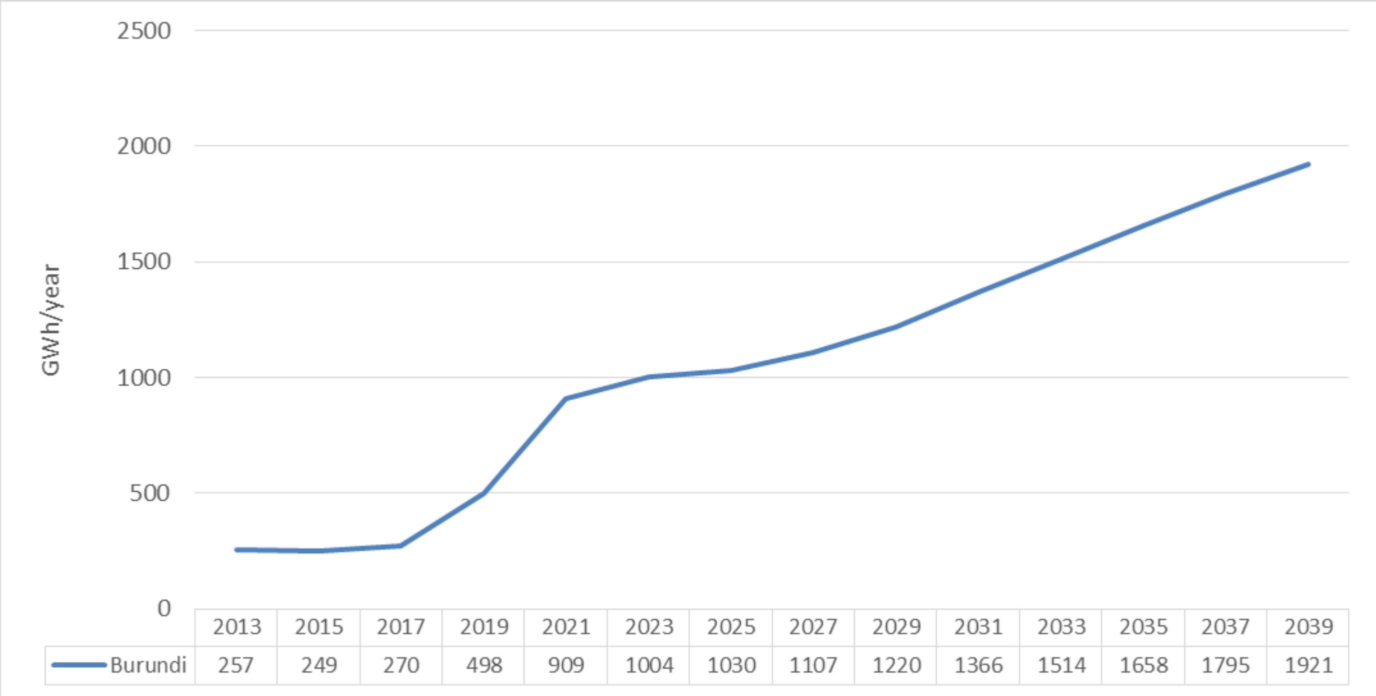
Hydro

BALMOREL area	Name	Type	Capacity (MW)	Avg hydro gen (GWh/year)	Avg hydro gen (FLH/year)	Storage size (GWh)
BU_A_ExiHydro	Burundi_exi_hy	Water - ROR	39	215	5515	
BU_A_ JIJI	JIJI	Water - ROR	33	147	4480	
BU_A_Kabu_16	Kabu_16	Water - ROR	21 (*20*)*	105	5097	
BU_A_KAYONGOZI_6	KAYONGOZI_6	Water - RESER	8	44	5500	9
BU_A_Mpanda	Mpanda	Water - RESER	10	30	2885	27
BU_A_Mulembwe	Mulembwe	Water - ROR	17	91	5292	
BU_A_RUSUMO_FALLS	RUSUMO_FALLS	Water - ROR	27	149	5576	
BU_A_RUZIZI_3	RUZIZI_3	Water - ROR	48	219	4892	
BU_A_Ruzibazi	Ruzibazi	Water - ROR	17	70	4118	
BU_A_KabuDiversion	Kabu 23	Water - ROR	15	70	4777	
BU_A_RUZIZI_4	RUZIZI_4	Water - ROR	95.7	583	4892	

Table 15: Average yearly energy output for existing, committed and candidate hydro plants in Burundi.
** The capacities indicated in parentheses (in italics) correspond to the latest data updates received from Burundi. These are provided for reference only (not included in the model simulation due to data being received after the closure of the data collection period).*

Demand forecast

The demand forecast, which is presented in the figure below, is from “Economic's study for Ruzizi 3 project (ANANDA)” and covers the period until 2025. The method for prolonging the forecast until 2040 is described in Chapter 3.3.



	2013	2015	2017	2019	2021	2023	2025	2027	2029	2031	2033	2035	2037	2039
Burundi	257	249	270	498	909	1004	1030	1107	1220	1366	1514	1658	1795	1921

Figure 7: Demand forecast for Burundi (GWh/year)

5.2 DRC

DRC is divided into the Eastern, Western and Southern grid to reflect that these are currently not fully connected. This division is also reflected in the representation of the data, as shown below. It should also be noted that 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. This is done to account for the challenging infrastructural and investment environment domestically within the DRC.

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, for similar reasons as stated earlier. This would be a very ambitious and challenging infrastructural project involving, among other things, regional coordination among several countries, hence its potential implications, if / when materialized, are explored in a separate scenario, as opposed to it being included as a part of the base assumptions in the Main scenario.

Existing, committed and candidate plants

All hydropower generation plants in the DRC (both existing, committed and candidate) have been modelled as run-of-river units, with the exception of Nseke and Nzilo plants. These 2 units have been modelled with reservoir storage capacity equivalent to 30% on annual power production. The Grand Inga site has been provided as a set of candidate projects, made available for investment in a step-wise manner by 2040. The candidate project investment stages follow the suggested development pathway laid out in the pre-feasibility study of the Grand Inga site (AECOM & EDF 2011). It should be noted that the Inga 3 candidate project has a recommended capacity of 4800 MW, yet a Joint Development Agreement has been signed with South Africa along with a commitment of purchase of 2500 MW of the Inga 3 produced power. South Africa is beyond the scope and modelled area of the current EAPP Master Plan.

As such, should the Inga 3 project materialize in the foreseeable future, only the remaining 2300 MW of its capacity would be available for local demand in the DRC and / or power exchanges with other EAPP member countries. As such, only the 2300 MW capacity is hereby modelled for the Inga 3 candidate project.

In addition, due to significant data availability limitations, the majority of the DRC hydro projects are assigned the inflow profile of the Ruzizi River. Grand Inga site projects, however, follow the Grand Inga recorded hydro inflow[7].

For the committed Kakobola 10 MW hydro project, due to lacking data, the Zongo 2 full-load hours have been applied based on the project similarities.

[7] Grand Inga site inflow profile: based on the The Grand Inga Power Plant Project presentation by Mr Vika di Panzu, SNEL CEO

	BALMOREL area	Name	Type	Nominal capacity (MW el.)	Fuel	Efficiency (net %)	CAPEX (M$/MW el.)	Fixed costs (1000$/Mwel.)	Variable costs ($/MWh el.)	On power (Year incl.)	Retirement (Year incl.)
Existing	DRC_E_ExiThe	DRC_Exi_Ther	MSD	18	Diesel	27%		21.80	1.82	2009	2038
	DRC_E_Tshopo1	Tshopo1	HYDRO	19	Water - ROR			45.53	3.25	2010	2050
	DRC_E_Ruzizi1	Ruzizi1	HYDRO	28	Water - ROR			45.53	3.25	2010	2050
	DRC_E_Ruzizi2	Ruzizi2	HYDRO	36	Water - ROR			45.53	3.25	2010	2050
	DRC_S_Bendera	Bendera	HYDRO	43	Water - ROR			45.53	3.25	2010	2050
	DRC_S_Nseke	Nseke	HYDRO	240	Water - RESER			45.53	3.25	1957	2050
	DRC_S_Nzilo	Nzilo	HYDRO	110	Water - RESER			45.53	3.25	1954	2050
	DRC_S_Mwadingusha	Mwadingusha	HYDRO	66	Water - ROR			45.53	3.25	1954	2050
	DRC_S_Koni	Koni	HYDRO	42	Water - ROR			45.53	3.25	1950	2050
	DRC_W_Inga1	Inga1	HYDRO	351	Water - ROR			45.53	3.25	1971	2050
	DRC_W_Inga2	Inga2	HYDRO	1424	Water - ROR			45.53	3.25	1982	2050
	DRC_W_Zongo	Zongo	HYDRO	75	Water - ROR			45.53	3.25	1965	2050
	DRC_W_Sanga	Sanga	HYDRO	12	Water - ROR			45.53	3.25	1949	2050
Committed	DRC_S_Katende	Katende	HYDRO	64	Water - ROR			45.53	3.25	2017	2050
	DRC_W_Kakobola	Kakobola	HYDRO	10	Water - ROR			45.53	3.25	2016	2050
	DRC_W_Zongo2	Zongo2	HYDRO	150	Water - ROR			45.53	3.25	2015	2050
Candidates	DRC_E_WanieRukula	WanieRukula	HYDRO	688	Water - ROR		2.50	45.53	3.25	2021	2050
	DRC_E_RuziziIV	RuziziIV	HYDRO	95.7	Water - ROR		3.00	45.53	3.25	2019	2050
	DRC_E_RuziziIII	RuziziIII	HYDRO	48	Water - ROR		3.47	45.53	3.25	2017	2050
	DRC_E_Bengamisa	Bengamisa	HYDRO	50	Water - ROR		3.50	45.53	3.25	2018	2050
	DRC_E_Babebal	Babebal	HYDRO	50	Water - ROR		3.50	45.53	3.25	2019	2050
	DRC_E_Semliki	Semliki	HYDRO	14	Water - ROR		3.50	45.53	3.25	2018	2050
	DRC_E_Mugomba	Mugomba	HYDRO	40	Water - ROR		3.50	45.53	3.25	2019	2050
	DRC_S_Nzilo2	Nzilo2	HYDRO	120	Water - ROR		3.00	45.53	3.25	2018	2050
	DRC_S_PianaMwanga	PianaMwanga	HYDRO	29.5	Water - ROR		3.49	45.53	3.25	2018	2050
	DRC_S_Bendera2	Bendera2	HYDRO	43	Water - ROR		3.50	45.53	3.25	2017	2050
	DRC_S_Luapula	Luapula	HYDRO	800	Water - ROR		2.50	45.53	3.25	2022	2050
	DRC_W_Inga3	Inga3	HYDRO	2300	Water - ROR		2.00	45.53	3.25	2022	2050
	DRC_W_Inga4	Inga4	HYDRO	7424	Water - ROR		2.50	45.53	3.25	2030	2050
	DRC_W_Inga5	Inga5	HYDRO	7424	Water - ROR		2.50	45.53	3.25	2035	2050
	DRC_W_Inga6	Inga6	HYDRO	7424	Water - ROR		2.50	45.53	3.25	2035	2050
	DRC_W_Inga7	Inga7	HYDRO	7424	Water - ROR		2.50	45.53	3.25	2040	2050
	DRC_W_Inga8	Inga8	HYDRO	7424	Water - ROR		2.50	45.53	3.25	2040	2050
	DRC_S_Busanga	Busanga	HYDRO	240	Water - ROR		2.5	45.53	3.25	2022	2050

Table 16: Existing, committed and candidate power plants as represented in the model for DRC

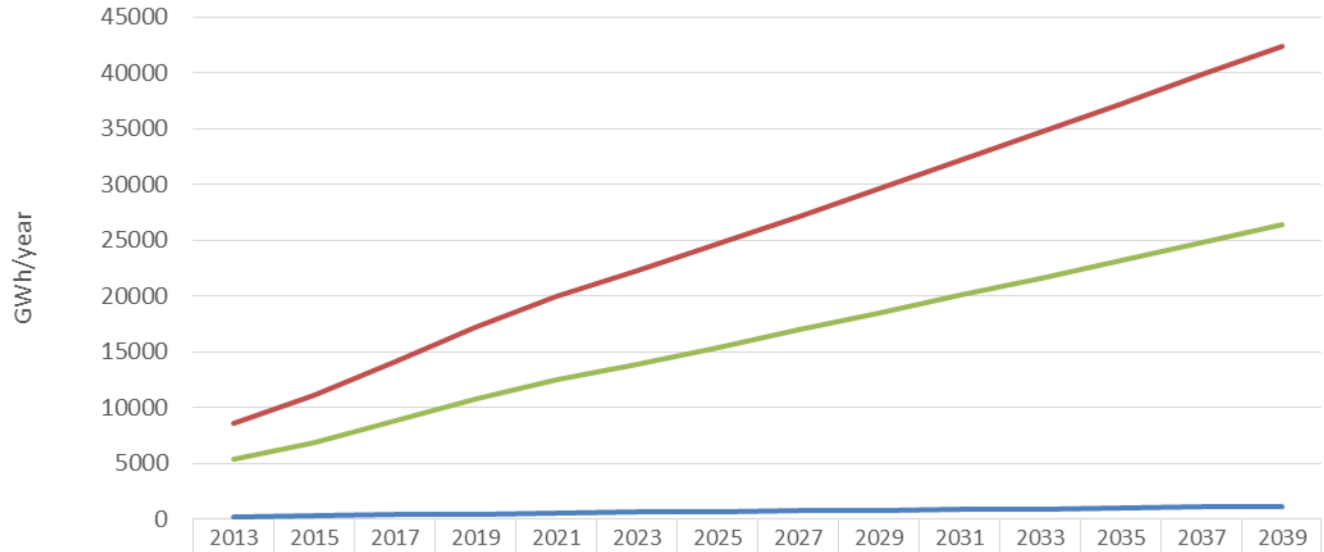
Hydro

BALMOREL area	Name	Type	Capacity (MW)	Avg hydro gen (GWh/year)	Avg hydro gen (FLH/year)	Storage size (GWh)
DRC_E_Babebal	Babebal	Water - ROR	50	280	5600	
DRC_E_Bengamisa	Bengamisa	Water - ROR	50	280	5600	
DRC_E_Mugomba	Mugomba	Water - ROR	40	210	5250	
DRC_E_Ruzizi1	Ruzizi1	Water - ROR	28	159	5674	
DRC_E_Ruzizi2	Ruzizi2	Water - ROR	36	247	6867	
DRC_E_RuziziIII	RuziziIII	Water - ROR	48	235	4892	
DRC_E_RuziziIV	RuziziIV	Water - ROR	95.7	468	4892	
DRC_E_Semliki	Semliki	Water - ROR	14	84	6000	
DRC_E_Tshopo1	Tshopo1	Water - ROR	19	106	5585	
DRC_E_WanieRukula	WanieRukula	Water - ROR	688	6000	8721	
DRC_S_Bendera	Bendera	Water - ROR	43	143	3327	
DRC_S_Bendera2	Bendera2	Water - ROR	43	231	5372	
DRC_S_Busanga	Busanga	Water - ROR	240	1540	6417	
DRC_S_Katende	Katende	Water - ROR	64	364	5693	
DRC_S_Koni	Koni	Water - ROR	42	224	5333	
DRC_S_Luapula	Luapula	Water - ROR	800	4900	6125	
DRC_S_Mwadingusha	Mwadingusha	Water - ROR	66	392	5939	
DRC_S_Nzilo2	Nzilo2	Water - ROR	120	770	6417	
DRC_S_PianaMwanga	PianaMwanga	Water - ROR	29.5	182	6169	
DRC_W_Inga1	Inga1	Water - ROR	351	1115	3177	
DRC_W_Inga2	Inga2	Water - ROR	1424	5601	3933	
DRC_W_Inga3	Inga3	Water - ROR	2300	16100	7000	
DRC_W_Inga4	Inga4	Water - ROR	7424	50728	6833	
DRC_W_Inga5	Inga5	Water - ROR	7424	50728	6833	
DRC_W_Inga6	Inga6	Water - ROR	7424	50728	6833	
DRC_W_Inga7	Inga7	Water - ROR	7424	50728	6833	
DRC_W_Inga8	Inga8	Water - ROR	7424	50728	6833	
DRC_W_Kakobola	Kakobola	Water - ROR	10	65	6533	
DRC_W_Sanga	Sanga	Water - ROR	12	28	2333	
DRC_W_Zongo	Zongo	Water - ROR	75	104	1380	
DRC_W_Zongo2	Zongo2	Water - ROR	150	980	6533	
DRC_S_Nseke	Nseke	Water - RESER	240	1149	4787	345
DRC_S_Nzilo	Nzilo	Water - RESER	110	630	5727	189

Table 17: Average yearly energy output for existing, committed and candidate hydro plants in DRC

Demand forecast

The demand forecast, which is presented in the figure below, is from “Projections d’Offre & de Demande d’Energie Electrique en RDC et dans les Pools Africains: Volume 1, 2011” and covers the period until 2025. The method for prolonging the forecast until 2030 is described in Chapter 3.3.



	2013	2015	2017	2019	2021	2023	2025	2027	2029	2031	2033	2035	2037	2039
DRC East	230	298	381	464	538	601	664	731	797	864	933	1002	1072	1141
DRC West	8529	11057	14147	17237	19955	22302	24649	27123	29596	32085	34625	37198	39780	42348
DRC South	5321	6898	8826	10754	12450	13914	15378	16921	18465	20017	21602	23207	24818	26420

Figure 8: Demand forecast for DRC (GWh/year)

5.3 Egypt

Existing, committed and candidate plants

The maximum nuclear development is delimited to the expansion plan as set out in the “Generation Expansion Plan During the Period 2012/2013 – 2026 / 2027”, i.e. 1650 MW nuclear capacity added every 2 years starting 2022/2023. The total (cumulative) installed nuclear capacity in Egypt cannot exceed 3 300 MW by 2025, 7 300 MW by 2030, 11 300 MW by 2035 and 15 300 MW by 2040, respectively.

	BALMOREL area	Name	Type	Nominal capacity (MW el.)	Fuel	Efficiency (net %)	CAPEX (M$/MW el.)	Fixed costs (1000$/MW el.)	Variable costs ($/MWh el.)	On power (Year incl.)	Retirement (Year incl.)
Existing	EG_A_CAIRO	Shouba_El_Kheima	STPP	1260	NG/HFO	37%		44.9	3.7	1988	2017
	EG_A_CAIRO	Shouba_GT	OCGT	35	NG/LFO	26%		20.4	1.7	1986	2015
	EG_A_CAIRO	Cairo_West	STPP	175	NG/HFO	26%		44.9	3.7	1979	2013
	EG_A_CAIRO	Cairo_West_Ext	STPP	660	NG/HFO	41%		44.9	3.7	1995	2024
	EG_A_CAIRO	Cairo_South_1	CCGT	450	NG/HFO	38%		25.5	2.1	1989	2018
	EG_A_CAIRO	Cairo_South_2	CCGT	165	NG	34%		25.5	2.1	1995	2024
	EG_A_CAIRO	Cairo_North	CCGT	1500	NG/LFO	55%		25.5	2.1	2006	2035
	EG_A_CAIRO	6_October_CC	CCGT	450	NG/LFO	45%		25.5	2.1	2012	2041
	EG_A_CAIRO	Wadi_Hof	OCGT	100	NG/LFO	23%		20.4	1.7	1985	2014
	EG_A_CAIRO	Tebbin	STPP	700	HFO	44%		44.9	3.7	2010	2039
	EG_A_CAIRO	Cairo_West_New	STPP	700	NG/HFO	41%		44.9	3.7	2011	2040
	EG_A_EAST_DELTA	Ataka	STPP	900	NG/HFO	34%		44.9	3.7	1987	2016
	EG_A_EAST_DELTA	Abu_Sultan	STPP	600	NG/HFO	33%		44.9	3.7	1986	2015
	EG_A_EAST_DELTA	Shabab	OCGT	100	NG/LFO	24%		20.4	1.7	1982	2013
	EG_A_EAST_DELTA	Shabab_New_GT	OCGT	1000	NG/LFO	32%		20.4	1.7	2011	2040
	EG_A_EAST_DELTA	Port_Said	OCGT	73	NG/LFO	23%		20.4	1.7	1984	2013
	EG_A_EAST_DELTA	Arish	STPP	66	NG/HFO	34%		44.9	3.7	2000	2029
	EG_A_EAST_DELTA	Oyoun_Moussa	STPP	640	NG/HFO	41%		44.9	3.7	2000	2029
	EG_A_EAST_DELTA	DamiettaCC	CCGT	1200	NG/LFO	45%		25.5	2.1	1993	2022
	EG_A_EAST_DELTA	Damitta_West_Gt	CCGT	500	NG/LFO	45%		25.5	2.1	2012	2041
	EG_A_EAST_DELTA	DamiettaGT	CCGT	750	NG/LFO	34%		25.5	2.1	2016	2045
	EG_A_EAST_DELTA	Sharm_el_Sheikh	OCGT	178	LFO	39%		20.4	1.7	2000	2029
	EG_A_EAST_DELTA	Hurghada	OCGT	143	LFO	39%		20.4	1.7	2000	2029
	EG_A_EAST_DELTA	Suez_Gulf	STPP	683	NG/HFO	38%		44.9	3.7	2002	2031
	EG_A_EAST_DELTA	Port_Said_East	STPP	683	NG/HFO	38%		44.9	3.7	2003	2032
	EG_A_EAST_DELTA	Zafarana_Wind	WPP	547	Wind			22.5	3.7	2010	2029
	EG_A_MIDDLE_DELTA	Talkha	CCGT	290	NG/LFO	37%		25.5	2.1	1989	2018
	EG_A_MIDDLE_DELTA	Talkha_210	STPP	420	NG/HFO	35%		44.9	3.7	1995	2024
	EG_A_MIDDLE_DELTA	Talkha_750	CCGT	750	NG/LFO	38%		25.5	2.1	2006	2035
	EG_A_MIDDLE_DELTA	Nubaria_1_2	CCGT	1500	NG/LFO	53%		25.5	2.1	2006	2035
	EG_A_MIDDLE_DELTA	Nubaria_3	OCGT	750	NG/LFO	54%		20.4	1.7	2009	2038
	EG_A_MIDDLE_DELTA	Mahmoudia_1	CCGT	316	NG/LFO	37%		25.5	2.1	2009	2038

	EG_A_MIDDLE_DELTA	El_Atf	CCGT	750	NG/LFO	55%	25.5	2.1	2010	2039
	EG_A_WEST_DELTA	Kafr_Dawar	STPP	440	NG/HFO	31%	44.9	3.7	1986	2015
	EG_A_WEST_DELTA	Damhour_Ext	STPP	300	NG/HFO	36%	44.9	3.7	1991	2020
	EG_A_WEST_DELTA	Damanhour_1	STPP	195	NG/HFO	31%	44.9	3.7	1969	2013
	EG_A_WEST_DELTA	Damanhour_2	CCGT	157	NG/LFO	40%	25.5	2.1	1995	2024
	EG_A_WEST_DELTA	Abu_Kir	STPP	911	NG/HFO	39%	44.9	3.7	1991	2020
	EG_A_WEST_DELTA	Abu_Kir_2	OCGT	24	NG/LFO	36%	20.4	1.7	1983	2013
	EG_A_WEST_DELTA	Sidi_Krir_3_4	STPP	683	NG/HFO	42%	44.9	3.7	2001	2030
	EG_A_WEST_DELTA	El_Seiuf	OCGT	200	NG/LFO	23%	20.4	1.7	1984	2013
	EG_A_WEST_DELTA	Karmouz	OCGT	23	LFO	22%	20.4	1.7	1980	2013
	EG_A_WEST_DELTA	Sidi_Krir_1_2	STPP	640	NG/HFO	42%	44.9	3.7	2000	2029
	EG_A_WEST_DELTA	Sidi_Krir_New	CCGT	750	NG/HFO	56%	25.5	2.1	2010	2039
	EG_A_WEST_DELTA	Matrouh	STPP	60	NG/HFO	30%	44.9	3.7	1990	2019
	EG_A_UPPER_EGYPT	Walidia	STPP	624	HFO	27%	44.9	3.7	1997	2026
	EG_A_UPPER_EGYPT	Kuriemat_1	STPP	1254	NG/HFO	41%	44.9	3.7	1999	2028
	EG_A_UPPER_EGYPT	Kuriemat_2	CCGT	750	NG/LFO	56%	25.5	2.1	2009	2038
	EG_A_UPPER_EGYPT	Kuriemat_3	OCGT	750	NG/HFO	50%	20.4	1.7	2011	2040
	EG_A_UPPER_EGYPT	Assiut	STPP	90	HFO	29%	44.9	3.7	1967	2013
	EG_A_UPPER_EGYPT	Kuriemat_solar-thermal	STPP	140	Sunlight	37%	44.9	3.7	2011	2035
	EG_A_High_Aswan_Dam	High_Aswan_Dam	HYDRO	2100	Water - RESER		45.5	3.3	2010	2050
	EG_A_Aswan_1	Aswan_1	HYDRO	280	Water - ROR		45.5	3.3	2010	2050
	EG_A_Aswan_2	Aswan_2	HYDRO	270	Water - ROR		45.5	3.3	2010	2050
	EG_A_Esna	Esna	HYDRO	86	Water - ROR		45.5	3.3	2010	2050
	EG_A_Naga_Hamadi	Naga_Hamadi	HYDRO	64	Water - ROR		45.5	3.3	2010	2050
Committed	EG_A_CAIRO	Suez_Gulf_Wind1	WPP	500	Wind		22.5	3.7	2015	2034
	EG_A_CAIRO	Suez_Gulf_Wind2	WPP	200	Wind		22.5	3.7	2017	2036
	EG_A_CAIRO	Nile_Wind_EW_1	WPP	910	Wind		22.5	3.7	2015	2034
	EG_A_CAIRO	Nile_Wind_EW_2	WPP	600	Wind		22.5	3.7	2017	2036
	EG_A_CAIRO	Solar_EG	PV	425	Sunlight		29.4	0.2	2016	2040
	EG_A_CAIRO	6_October_CC_New	CCGT	600	NG	57%	25.5	2.1	2015	2044
	EG_A_EAST_DELTA	Ain_SokhnaST	STPP	1300	NG	40%	44.9	3.7	2015	2044
	EG_A_MIDDLE_DELTA	BanhaCC	CCGT	750	NG	57%	25.5	2.1	2015	2044
	EG_A_UPPER_EGYPT	Giza_NorthCC	CCGT	1750	NG	57%	25.5	2.1	2015	2044
	EG_A_UPPER_EGYPT	Giza_NorthCC_2	CCGT	500	NG	57%	25.5	2.1	2016	2045
	EG_A_CAIRO	DairoutCC	CCGT	0	NG	57%	25.5	2.1	2016	2045
	EG_A_CAIRO	DairoutCC_2	CCGT	0	NG	57%	25.5	2.1	2017	2046
	EG_A_EAST_DELTA	SuezST	STPP	650	NG	40%	44.9	3.7	2016	2045
	EG_A_MIDDLE_DELTA	DamanhourCC	CCGT	0	NG	57%	25.5	2.1	2014	2043
	EG_A_MIDDLE_DELTA	DamanhourCC_2	CCGT	0	NG	57%	25.5	2.1	2015	2044
	EG_A_MIDDLE_DELTA	DamanhourCC_3	CCGT	0	NG	57%	25.5	2.1	2017	2046
	EG_A_CAIRO	El_SuiefCC	CCGT	0	NG	57%	25.5	2.1	2014	2043
	EG_A_CAIRO	El_SuiefCC2	CCGT	0	NG	57%	25.5	2.1	2015	2044
	EG_A_CAIRO	El_SuiefCC3	CCGT	0	NG	57%	25.5	2.1	2017	2046

	EG_A_MIDDLE_DELTA	MahmoudiaCC	CCGT	0	NG	57%		25.5	2.1	2014	2043
	EG_A_MIDDLE_DELTA	MahmoudiaCC2	CCGT	0	NG	57%		25.5	2.1	2016	2045
	EG_A_EAST_DELTA	El_ShababCC	CCGT	500	NG	57%		25.5	2.1	2017	2046
	EG_A_SmallHydro	MiniHydro	HYDRO	0	Water - ROR			45.5	3.3	2015	2050
	EG_A_UPPER_EGYPT	HelwanSouthST	STPP	1950	NG	40%		44.9	3.7	2018	2047
	EG_A_UPPER_EGYPT	Assuit_New	STPP	650	HFO	29%		44.9	3.7	2018	2047
	EG_A_EAST_DELTA	Damitta_West_Gt_New	CCGT	250	NG	45%		25.5	2.1	2017	2046
	EG_A_WEST_DELTA	Abu_Kir_NewST	STPP	1300	NG/HFO	39%		44.9	3.7	2013	2042
Candidates	EG_A_Nuclear	EG_Nuclear	Nuclear	4950	Nuclear	33%	5.56	125.5	0.0	2019	2078

Table 18: Existing, committed and candidate power plants as represented in the model for Egypt

Hydro

BALMOREL area	Name	Type	Capacity (MW)	Avg hydro gen (GWh/year)	Avg hydro gen (FLH/year)	Storage size (GWh)
EG_A_High_Aswan_Dam	High_Aswan_Dam	Water - RESER	2100	9921	4724	19516
EG_A_Aswan_1	Aswan_1	Water - ROR	280	1512	5401	
EG_A_Aswan_2	Aswan_2	Water - ROR	270	1770	6556	
EG_A_Esna	Esna	Water - ROR	86	411	4776	
EG_A_Naga_Hamadi	Naga_Hamadi	Water - ROR	64	19	304	
EG_A_SmallHydro	MiniHydro	Water - ROR	32	139	4352	

Table 19: Average yearly energy output for existing, committed and candidate hydro plants in Egypt

Demand forecast

The demand forecast, which is presented in the figure below, is from "EEHC forecast for EAPP Master Plan, 2013" and covers the period until 2026. The method for prolonging the forecast until 2040 is described in Chapter 3.3.

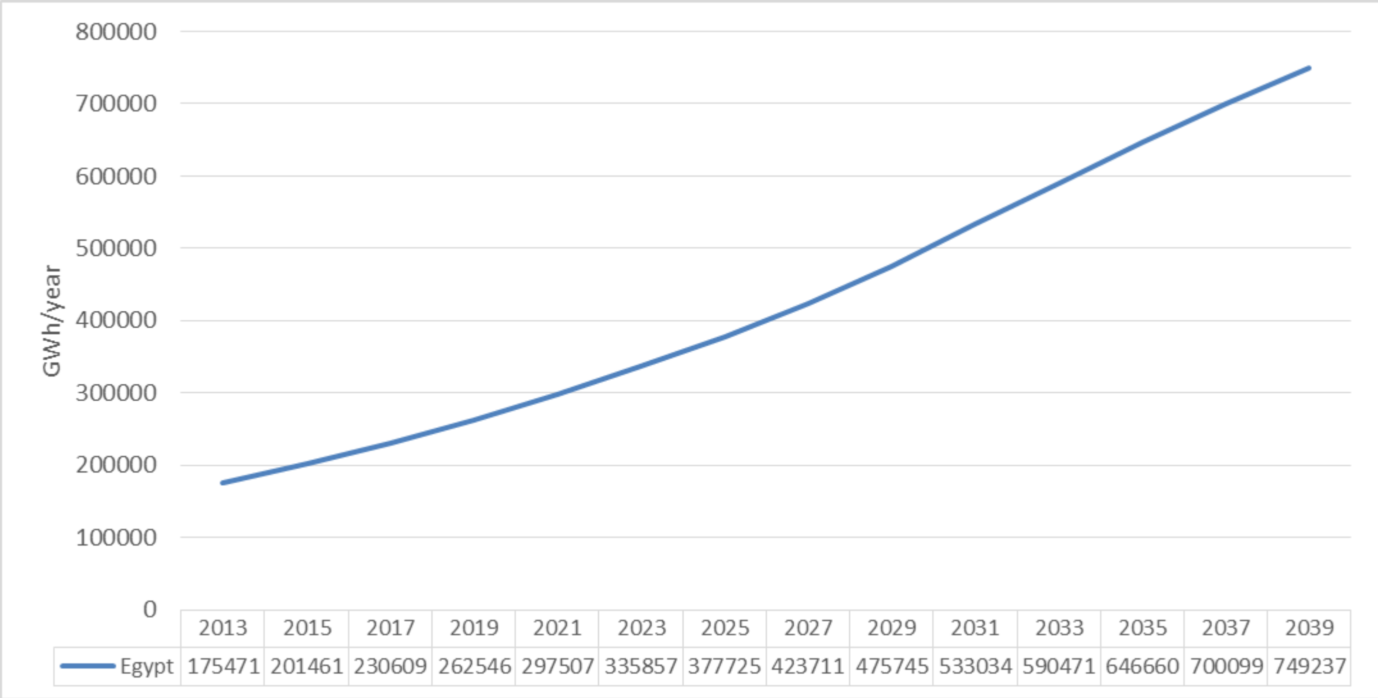


Figure 9: Demand forecast for Egypt (GWh/year)

5.4 Ethiopia

Existing, committed and candidate plants

The potential for geothermal power in Ethiopia is 5,000 MW. In this study this potential is bound to the development pathway presented in the latest Ethiopian generation plan starting at 500 MW in 2020 and reaching the maximum of 5,000 MW in 2037.

The CAPEX for the long-term hydro potential of Ethiopia has been estimated based on the overall average CAPEX of all hydro candidate projects in Ethiopia, resulting in a CAPEX estimate for the ET_HY_LongTerm of ca. 4 M$/MW. It should be noted that this estimate is relatively high compared to the investment costs of some of the best hydro candidates (e.g. Beko Abo or Gibe). In the 'Long-Term Hydro' scenario (see Volume III: Results Report), an assumption of more cost-competitive long-term hydro resource in Ethiopia has been used at a CAPEX of 2.5 M$/MW. This estimate is the approximated capacity-weighted investment cost average across all known candidate projects in Ethiopia, excluding Tams and WabiShebele (indications of significantly lower updated investment costs per MW based on reconnaissance studies at the time of writing this report).

	BALMOREL area	Name	Type	Nominal capacity (MW el.)	Fuel	Efficiency (net %)	CAPEX (M$/MW el.)	Fixed costs (1000$/MWel.)	Variable costs ($/MWh el.)	On power (Year incl.)	Retirement (Year incl.)
Existing	ET_A_ExiThe	DirDawa	MSD	38	Diesel	27%		21.80	1.82	2004	2033
	ET_A_ExiThe	Awash7	MSD	30	Diesel	27%		21.80	1.82	2003	2032
	ET_A_ExiThe	Kaliti	MSD	10	Diesel	27%		21.80	1.82	2003	2032
	ET_A_ExiThe	Aluto	Geo	5	Heat	33%		43.25	3.09	2007	2036
	ET_A_ExiThe	Ashegoda1_2	WPP	120	Wind			22.49	3.75	2013	2032
	ET_A_ExiThe	Adama_I	WPP	51	Wind			22.49	3.75	2012	2031
	ET_A_Tis_Abbay_1	Tis_Abbay_1	HYDRO	11	Water - ROR			45.53	3.25	2000	2050
	ET_A_Tis_Abbay_2	Tis_Abbay_2	HYDRO	68	Water - ROR			45.53	3.25	2010	2050
	ET_A_Finchaa	Finchaa	HYDRO	128	Water - RESER			45.53	3.25	1973	2050
	ET_A_Gilgel_Gibe_I	Gilgel_Gibe_I	HYDRO	184	Water - RESER			45.53	3.25	2004	2050
	ET_A_Gilgel_Gibe_II	Gilgel_Gibe_II	HYDRO	420	Water - ROR			45.53	3.25	2010	2050
	ET_A_Malka_Wakana	Maleka_Wakana	HYDRO	153	Water - RESER			45.53	3.25	2014	2050
	ET_A_Koka	Koka	HYDRO	43	Water - RESER			45.53	3.25	1960	2050
	ET_A_Awash_2	Awash_2	HYDRO	32	Water - ROR			45.53	3.25	1966	2050
	ET_A_Awash_3	Awash_3	HYDRO	32	Water - ROR			45.53	3.25	1971	2050
	ET_A_Beles	Beles	HYDRO	460	Water - RESER			45.53	3.25	2010	2050

	ET_A_Tekeze_I	Tekeze_I	HYDRO	300	Water - RESER			45.53	3.25	2010	2050
	ET_A_AmartiNeshe	AmartiNeshe	HYDRO	98	Water - RESER			45.53	3.25	2013	2050
	ET_A_Sor	Sor	HYDRO	5	Water - RESER			45.53	3.25	2014	2050
Committed	ET_A_Committed	Adama_II	WPP	153	Wind			22.49	3.75	2015	2034
	ET_A_Committed	Reppi-EFW-50	Waste-to-Energy	20	Waste	23%		44.88	3.74	2016	2040
	ET_A_Committed	TendaueEnde	STPP	70	Bagasse	17%		44.88	3.74	2015	2039
	ET_A_Committed	Wenji	STPP	16	Bagasse	17%		44.88	3.74	2014	2038
	ET_A_Committed	FinchaaBagasde	STPP	10	Bagasse	17%		44.88	3.74	2014	2038
	ET_A_Committed	Beles1	STPP	20	Bagasse	17%		44.88	3.74	2016	2040
	ET_A_Committed	Beles2	STPP	20	Bagasse	17%		44.88	3.74	2016	2040
	ET_A_Committed	Beles3	STPP	20	Bagasse	17%		44.88	3.74	2016	2040
	ET_A_Committed	Wolkayit	STPP	82	Bagasse	17%		44.88	3.74	2016	2040
	ET_A_Committed	OmoKuraz1	STPP	20	Bagasse	17%		44.88	3.74	2016	2040
	ET_A_Committed	OmoKuraz2	STPP	40	Bagasse	17%		44.88	3.74	2016	2040
	ET_A_Committed	OmoKuraz3	STPP	40	Bagasse	17%		44.88	3.74	2016	2040
	ET_A_Committed	OmoKuraz4	STPP	40	Bagasse	17%		44.88	3.74	2017	2041
	ET_A_Committed	OmoKuraz5	STPP	40	Bagasse	17%		44.88	3.74	2017	2041
	ET_A_Committed	OmoKuraz6	STPP	40	Bagasse	17%		44.88	3.74	2019	2043
	ET_A_Committed	Kessem	STPP	16	Bagasse	17%		44.88	3.74	2015	2039
	ET_A_Committed	Bamza-120	STPP	60	Wood	25%		44.88	3.74	2013	2037
	ET_A_Committed	Melkasedi-137	STPP	60	Wood	25%		44.88	3.74	2016	2040
	ET_A_Committed	AlutoLangano	Geo	70	Heat			43.25	3.09	2018	2047
	ET_A_Gilgel_Gibe_III	Gilgel_Gibe_III	HYDRO	1870	Water - RESER			45.53	3.25	2016	2050
	ET_A_Genale3	Genale3	HYDRO	254	Water - RESER			45.53	3.25	2016	2050
	ET_A_Renaissance	Renaissance	HYDRO	6000	Water - RESER			45.53	3.25	2019	2050
Candidates	ET_A_GibeIV	GibeIV	HYDRO	1472	Water - ROR		2.29	45.53	3.25	2020	2050
	ET_A_HaleleWerabessa	HaleleWerabessa	HYDRO	436	Water - RESER		2.74	45.53	3.25	2020	2050
	ET_A_ChemogaYeda1_2	ChemogaYeda1_2	HYDRO	280	Water - RESER		2.60	45.53	3.25	2020	2050
	ET_A_Geba1_2	Geba1_2	HYDRO	372	Water - RESER		2.08	45.53	3.25	2020	2050
	* ET_A_Baro1_2	Baro1_2	HYDRO	645	Water - RESER		3.34	45.53	3.25	2020	2050
	* ET_A_Genji	Genji	HYDRO	214	Water - RESER		1.25	45.53	3.25	2040	2050
	ET_A_UpperMandaya	UpperMandaya	HYDRO	1700	Water - RESER		1.93	45.53	3.25	2023	2050
	ET_A_GibeV	GibeV	HYDRO	660	Water - ROR		2.04	45.53	3.25	2020	2050
	ET_A_BekoAbo	BekoAbo	HYDRO	935	Water - RESER		1.82	45.53	3.25	2022	2050
	ET_A_Karadobi	Karadobi	HYDRO	1600	Water - RESER		2.17	45.53	3.25	2021	2050
	ET_A_Genale6D	Genale6D	HYDRO	246	Water - RESER		3.23	45.53	3.25	2020	2050
	ET_A_Gojeb	Gojeb	HYDRO	150	Water - RESER		4.74	45.53	3.25	2020	2050
	ET_A_Tekeze2	Tekeze2	HYDRO	450	Water - RESER		5.07	45.53	3.25	2020	2050
	ET_A_BirbirR	BirbirR	HYDRO	467	Water - RESER		3.43	45.53	3.25	2020	2050
	ET_A_Tams	Tams	HYDRO	1000	Water - RESER		7.85	45.53	3.25	2020	2050
	ET_A_UpperDabus	UpperDabus	HYDRO	326	Water - RESER		2.60	45.53	3.25	2020	2050
	ET_A_LowerDabus	LowerDabus	HYDRO	250	Water - RESER		4.50	45.53	3.25	2020	2050

ET_A_LowerDedessa	LowerDedessa	HYDRO	550	Water - RESER	1.46	45.53	3.25	2020	2050
ET_A_Genale5	Genale5	HYDRO	100	Water - RESER	3.87	45.53	3.25	2020	2050
ET_A_WabiShebele	WabiShebele	HYDRO	88	Water - RESER	12.61	45.53	3.25	2020	2050
ET_A_Sor2	Sor2	HYDRO	5	Water - ROR	4.46	45.53	3.25	2017	2050
ET_A_AbaSamuel	AbaSamuel	HYDRO	6	Water - ROR	3.53	45.53	3.25	2020	2050
ET_A_AleltuEast	AleltuEast	HYDRO	189	Water - RESER	5.43	45.53	3.25	2020	2050
ET_A_AleltuWest	AleltuWest	HYDRO	265	Water - RESER	6.01	45.53	3.25	2020	2050
ET_A_NewGeo	ET_GEO	Geo	4925	Heat	3.72	43.25	3.09	2020	2049
ET_HY_LongTerm	HY_LongTerm_ET	HYDRO	22536	Water - ROR	4 **	45.53	3.25	2030	2050

Table 20: Existing, committed and candidate power plants as represented in the model for Ethiopia.
** Genji candidate project is only possible upon completion of the Baro1_2 candidate project. In the modelling analysis this has been represented by allowing investment in Baro1_2 as of 2020, and Genji as of 2040. However, the interdependence of the 2 projects has not been enforced in the model due to this information being received after the closure of the data collection period.*
*** The CAPEX assumption used in the Main scenario for the long-term Ethiopian hydro potential (based on the approximated simple average of M$/MW cost of all known candidate projects in Ethiopia).*
In the 'Long-Term Hydro' scenario (see Volume III: Results Report), an assumption of more cost-competitive long-term hydro resource in Ethiopia has been used at a CAPEX of 2.5 M$/MW. This estimate is the approximated capacity-weighted investment cost average across all known candidate projects in Ethiopia, excluding Tams and WabiShebele (indications of significantly lower updated investment costs per MW based on reconnaissance studies at the time of writing this report).

Hydro

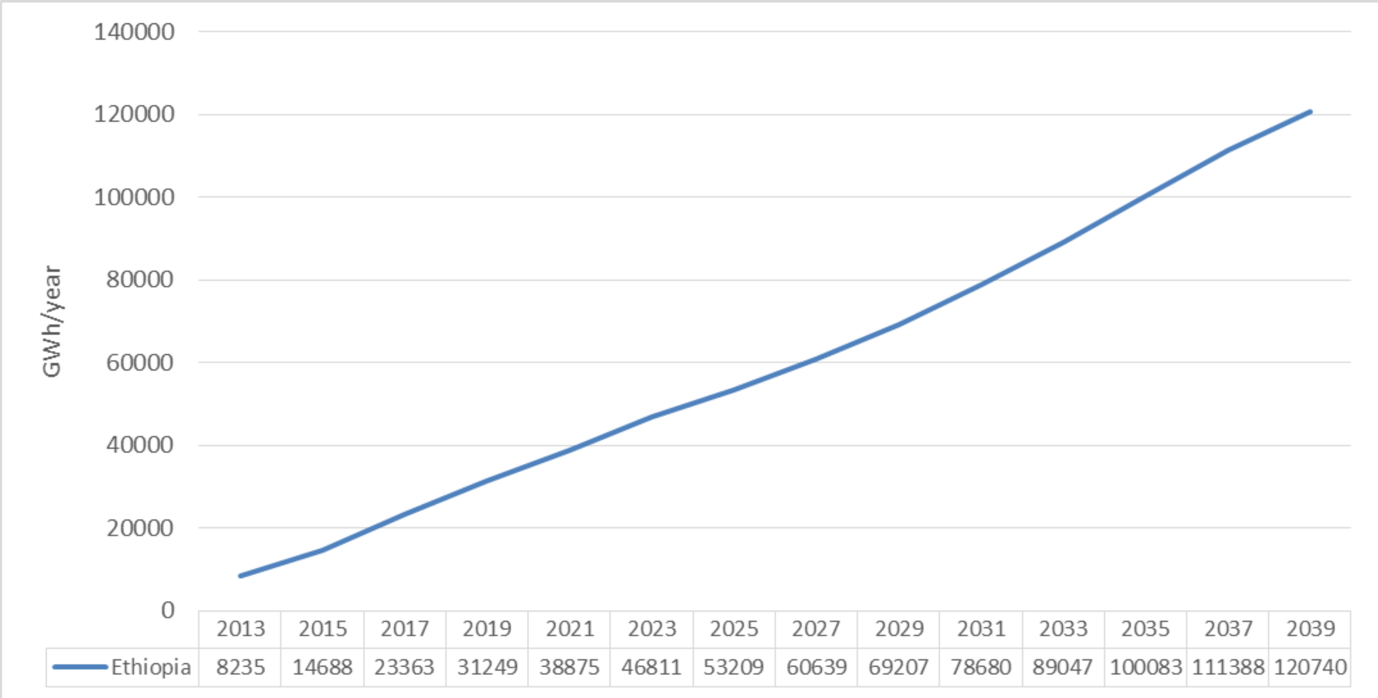
BALMOREL area	Name	Type	Capacity (MW)	Avg hydro gen (GWh/year)	Avg hydro gen (FLH/year)	Storage size (GWh)
ET_A_Tis_Abbay_1	Tis_Abbay_1	Water - ROR	11	2	148	
ET_A_Tis_Abbay_2	Tis_Abbay_2	Water - ROR	68	10	148	
ET_A_Finchaa	Finchaa	Water - RESER	128	615	4802	1008
ET_A_Gilgel_Gibe_I	Gilgel_Gibe_I	Water - RESER	184	882	4794	378
ET_A_Gilgel_Gibe_II	Gilgel_Gibe_II	Water - ROR	420	2030	4834	
ET_A_Malka_Wakana	Maleka_Wakana	Water - RESER	153	555	3631	343
ET_A_Koka	Koka	Water - RESER	43	133	3111	14
ET_A_Awash_2	Awash_2	Water - ROR	32	183	5734	
ET_A_Awash_3	Awash_3	Water - ROR	32	184	5757	
ET_A_Beles	Beles	Water - RESER	460	2749	5976	7291
ET_A_Tekeze_I	Tekeze_I	Water - RESER	300	1399	4665	2634
ET_A_AmartiNeshe	AmartiNeshe	Water - RESER	98	245	2500	281
ET_A_Sor	Sor	Water - RESER	5	30	5978	24
ET_A_Gilgel_Gibe_III	Gilgel_Gibe_III	Water - RESER	1870	5348	2860	5517
ET_A_Genale3	Genale3	Water - RESER	254	1691	6656	732
ET_A_Renaissance	Renaissance	Water - RESER	6000	14684	2447	18282

ET_A_GibeIV	GibeIV	Water - ROR	1472	6127	4162	
ET_A_HaleleWerabessa	HaleleWerabessa	Water - RESER	436	1966	4509	2739
ET_A_ChemogaYeda1_2	ChemogaYeda1_2	Water - RESER	280	1088	3884	798
ET_A_Geba1_2	Geba1_2	Water - RESER	372	1705	4585	2458
ET_A_Baro1_2	Baro1_2	Water - RESER	645	2607	4042	801
ET_A_Genji	Genji	Water - RESER	214	909	4248	9
ET_A_UpperMandaya	UpperMandaya	Water - RESER	1700	8554	5032	3800
ET_A_GibeV	GibeV	Water - ROR	660	1899	2877	
ET_A_BekoAbo	BekoAbo	Water - RESER	935	6617	7077	353
ET_A_Karadobi	Karadobi	Water - RESER	1600	7831	4894	10406
ET_A_Genale6D	Genale6D	Water - RESER	246	1528	6213	120
ET_A_Gojeb	Gojeb	Water - RESER	150	559	3729	273
ET_A_Tekeze2	Tekeze2	Water - RESER	450	2713	6029	2986
ET_A_BirbirR	BirbirR	Water - RESER	467	2717	5817	2019
ET_A_Tams	Tams	Water - RESER	1000	6044	6044	2437
ET_A_UpperDabus	UpperDabus	Water - RESER	326	1455	4463	1300
ET_A_LowerDabus	LowerDabus	Water - RESER	250	635	2540	516
ET_A_LowerDedessa	LowerDedessa	Water - RESER	550	974	1771	1987
ET_A_Genale5	Genale5	Water - RESER	100	573	5730	23
ET_A_WabiShebele	WabiShebele	Water - RESER	88	690	7835	818
ET_A_Sor2	Sor2	Water - ROR	5	39	7700	
ET_A_AbaSamuel	AbaSamuel	Water - ROR	6	16	2608	
ET_A_AleltuEast	AleltuEast	Water - RESER	189	801	4239	1206
ET_HY_LongTerm	HY_LongTerm_ET	Water - ROR	22536	112679	5000	
ET_A_AleltuWest	AleltuWest	Water - RESER	265	1066	4024	1491

Table 21: Average yearly energy output for existing, committed and candidate hydro plants in Ethiopia

Demand forecast

The demand forecast, which is presented in the figure below, is from “Ethiopian Power System Expansion Master Plan Study - Interim Report - Volume 3 - Generation Planning, 2013” and covers the period until 2037. The method for prolonging the forecast until 2040 is described in Chapter 3.3.



	2013	2015	2017	2019	2021	2023	2025	2027	2029	2031	2033	2035	2037	2039
Ethiopia	8235	14688	23363	31249	38875	46811	53209	60639	69207	78680	89047	100083	111388	120740

Figure 10: Demand forecast for Ethiopia (GWh/year)

5.5 Kenya

Existing, committed and candidate plants

The candidate geothermal potential in Kenya is set to 7,660 MW. This is calculated by subtracting the capacity of existing and committed geothermal projects from the total potential of 10,000 MW. The maximum geothermal development is delimited to 2,100 MW per 5 year period (in line with the power system development plan “Republic of Kenya - updated least-cost power development plan - 2013-2033 Draft” as of May 2013). The maximum nuclear development is also delimited to the expansion plan as set out in the LCPDP 2013-2033. The total (cumulative) installed nuclear capacity in Kenya cannot exceed 300 MW by 2025, 1800 MW by 2030 and 3900 MW by 2035 and beyond, respectively.

	BALMOREL area	Name	Type	Nominal capacity (MW el.)	Fuel	Efficiency (net %)	CAPEX (M$/MW el.)	Fixed costs (1000$/Mwel.)	Variable costs ($/MWh el.)	On power (Year incl.)	Retirement (Year incl.)
Existing	KY_A_ExiThe	Kipevu_1_Diesel	MSD	60	HFO	40%		21.80	1.82	1999	2017
	KY_A_ExiThe	Emabakasi	OCGT	0	LFO	26%		20.40	1.70	1999	2028
	KY_A_ExiThe	Olkaria_1	Geo	44	Heat	36%		43.25	3.09	1981	2013
	KY_A_ExiThe	Olkaria_2	Geo	101	Heat	36%		43.25	3.09	2003	2032
	KY_A_ExiThe	OrPower_4a	Geo	13	Heat	36%		43.25	3.09	2000	2029
	KY_A_ExiThe	OrPower_4b	Geo	35	Heat	33%		43.25	3.09	2008	2037
	KY_A_ExiThe	Iberafrica_IPP	MSD	56	HFO	39%		21.80	1.82	1997	2026
	KY_A_ExiThe	Tsavo_IPP	MSD	74	HFO	41%		21.80	1.82	2001	2017
	KY_A_ExiThe	Mumias	STPP	26	Bagasse	39%		44.88	3.74	2008	2032
	KY_A_ExiThe	Aggreko_IPP	MSD	120	Diesel	40%		21.80	1.82	2008	2037
	KY_A_ExiThe	Olkaria_Well_Head	Geo	4	Heat	33%		43.25	3.09	2012	2041
	KY_A_ExiThe	Rabai_diesel_IPP	MSD	90	HFO	40%		21.80	1.82	2009	2017
	KY_A_ExiThe	Iberafrica_3_IPP	MSD	52	HFO	39%		21.80	1.82	2004	2033
	KY_A_ExiThe	Kipevu_III_Diesel	MSD	115	HFO	40%		21.80	1.82	2011	2017
	KY_A_ExiThe	Ngong	WPP	5	Wind			22.49	3.75	2010	2029
	KY_A_ExiThe	Eburru	Geo	2	Heat			43.25	3.09	2012	2041
	KY_A_Tana	Tana	HYDRO	20	Water - ROR			45.53	3.25	1955	2050
	KY_A_Small_hydro	KY_Small_hydro	HYDRO	11	Water - ROR			45.53	3.25	2010	2050
	KY_A_Kamburu	Kamburu	HYDRO	90	Water - RESER			45.53	3.25	1974	2050
	KY_A_Gitaru	Gitaru	HYDRO	216	Water - ROR			45.53	3.25	1998	2050
	KY_A_Kindaruma	Kindaruma	HYDRO	44	Water - ROR			45.53	3.25	1968	2050
	KY_A_Masinga	Masinga	HYDRO	40	Water - RESER			45.53	3.25	1981	2050
	KY_A_Kiambere	Kiambere	HYDRO	164	Water - RESER			45.53	3.25	1988	2050
	KY_A_Sondu_Miriu	Sondu_Miriu	HYDRO	60	Water - ROR			45.53	3.25	2008	2050
	KY_A_Turkwell	Turkwell	HYDRO	105	Water - RESER			45.53	3.25	1991	2050
	KY_A_Sangoro	Sangoro	HYDRO	20	Water - ROR			45.53	3.25	2012	2050
Committed	KY_A_FutThe	THIKA	MSD	0	HFO	45%		21.80	1.82	2043	2072
	KY_A_FutThe	GULF	MSD	80	HFO	41%		21.80	1.82	2014	2043
	KY_A_FutThe	Triumph	MSD	83	HFO	44%		21.80	1.82	2014	2043
	KY_A_Kindaruma_opt	Kindaruma_opt	HYDRO	24	Water - ROR			45.53	3.25	2015	2050
	KY_A_FutThe	ORP4	Geo	17.6	Heat			43.25	3.09	2014	2043
	KY_A_FutThe	OLK1B	Geo	140	Heat			43.25	3.09	2014	2043
	KY_A_FutThe	OLK4	Geo	140	Heat			43.25	3.09	2014	2043
	KY_A_FutThe	OLKWH1	Geo	45.6	Heat			43.25	3.09	2014	2043
	KY_A_FutThe	MENW	Geo	70	Heat			43.25	3.09	2017	2046
	KY_A_FutThe	MENWH	Geo	0	Heat			43.25	3.09	2017	2046
	KY_A_FutThe	OLK1B_2	Geo	70	Heat			43.25	3.09	2016	2045
	KY_A_FutThe	OLKWH2	Geo	30	Heat			43.25	3.09	2015	2044
	KY_A_FutThe	Ngong2	WPP	14	Wind			22.49	3.75	2014	2033
	KY_A_FutThe	NgongI2	WPP	7	Wind			22.49	3.75	2014	2033

	KY_A_FutThe	Kwala	Cogen	18	Bagasse	17%		44.88	3.74	2015	2039
	KY_A_FutThe	KY_LNG	CCGT	700	NG	57%		25.50	2.13	2017	2046
	KY_A_FutThe	Aelous	WPP	60	Wind			22.49	3.75	2015	2034
	KY_A_FutThe	Menengai_I	Geo	107	Heat			43.25	3.09	2015	2044
	KY_A_FutThe	Silali	Geo	100	Heat			43.25	3.09	2018	2047
	KY_A_FutThe	Isiolo	WPP	100	Wind			22.49	3.75	2016	2035
	KY_A_FutThe	KY_Coal	STPP	960	Coal	40%		44.88	3.74	2016	2045
	KY_A_FutThe	LTWP	WPP	150	Wind			22.49	3.75	2016	2035
	KY_A_FutThe	LTWP2	WPP	150	Wind			22.49	3.75	2016	2035
	KY_A_FutThe	Kipeto	WPP	100	Wind			22.49	3.75	2016	2035
	KY_A_FutThe	Prunus	WPP	50	Wind			22.49	3.75	2016	2035
	KY_A_FutThe	Suswa	Geo	150	Heat			43.25	3.09	2016	2045
	KY_A_FutThe	OLK1B_3	Geo	140	Heat			43.25	3.09	2017	2046
	KY_A_FutThe	Menengai_2	Geo	460	Heat			43.25	3.09	2018	2047
	KY_A_FutThe	OLK_V	Geo	140	Heat			43.25	3.09	2017	2046
	KY_A_FutThe	Baringo	Geo	200	Heat			43.25	3.09	2017	2046
	KY_A_FutThe	Suswa2	Geo	50	Heat			43.25	3.09	2018	2047
	KY_A_FutThe	Silali2	Geo	0	Heat			43.25	3.09	2018	2047
	KY_A_FutThe	KY_Coal2	STPP	960	Coal	40%		44.88	3.74	2018	2047
	KY_A_FutThe	Silali3	Geo	0	Heat			43.25	3.09	2019	2048
	KY_A_FutThe	AGIL	Geo	140	Heat			43.25	3.09	2018	2047
	KY_A_FutThe	OLK_VI	Geo	140	Heat			43.25	3.09	2017	2046
	KY_A_FutThe	Kipevu_GT_I_III	OCGT	194	NG	26%		20.40	1.70	2017	2046
	KY_A_FutThe	Tsavo_NG	OCGT	74	NG	26%		20.40	1.70	2017	2046
	KY_A_FutThe	Rabai_NG	OCGT	90	NG	26%		20.40	1.70	2017	2046
	KY_A_FutThe	Eburru_New	Geo	25	Heat			43.25	3.09	2018	2047
Candidates	KY_A_NewGeo	KY_New_Geo	Geo	7660	Heat		4.31	43.25	3.09	2024	2053
	KY_A_Nuclear	KY_Nuclear	Nuclear	900	Nuclear	33%	5.56	125.46	0.00	2019	2050
	KY_A_Karura	Karura	HYDRO	90	Water - ROR		3.70	45.53	3.25	2020	2050
	KY_A_LowerGrand	LowerGrand	HYDRO	140	Water - RESER		3.62	45.53	3.25	2020	2050

Table 22: Existing, committed and candidate power plants as represented in the model for Kenya

Hydro

BALMOREL area	Name	Type	Capacity (MW)	Avg hydro gen (GWh/year)	Avg hydro gen (FLH/year)	Storage size (GWh)
KY_A_Tana	Tana	Water - ROR	20	63	3170	
KY_A_Small_hydro	KY_Small_hydro	Water - ROR	11	59	5388	
KY_A_Kamburu	Kamburu	Water - RESER	90	460	5107	20
KY_A_Gitaru	Gitaru	Water - ROR	216	892	4130	
KY_A_Kindaruma	Kindaruma	Water - ROR	44	273	6201	
KY_A_Masinga	Masinga	Water - RESER	40	191	4774	133
KY_A_Kiambere	Kiambere	Water - RESER	164	916	5586	166
KY_A_Sondu_Miriu	Sondu_Miriu	Water - ROR	60	404	6729	
KY_A_Turkwell	Turkwell	Water - RESER	105	437	4162	1391
KY_A_Sangoro	Sangoro	Water - ROR	20	143	7131	
KY_A_Kindaruma_opt	Kindaruma_opt	Water - ROR	24	149	6201	
KY_A_Karura	Karura	Water - ROR	90	235	2615	
KY_A_LowerGrand	LowerGrand	Water - RESER	140	707	5050	170

Table 23: Average yearly energy output for existing, committed and candidate hydro plants in Kenya

Demand forecast

The demand forecast, which is presented in the figure below, is the ‘High’ demand forecast from “Republic of Kenya – 10 Year Power Sector Expansion Plan 2014-2024” as of June 2014 and covers the period until 2024. The method for prolonging the forecast until 2040 is described in Chapter 3.3. The ‘High’ demand forecast has been chosen due to the political commitment expressed by the government of Kenya.

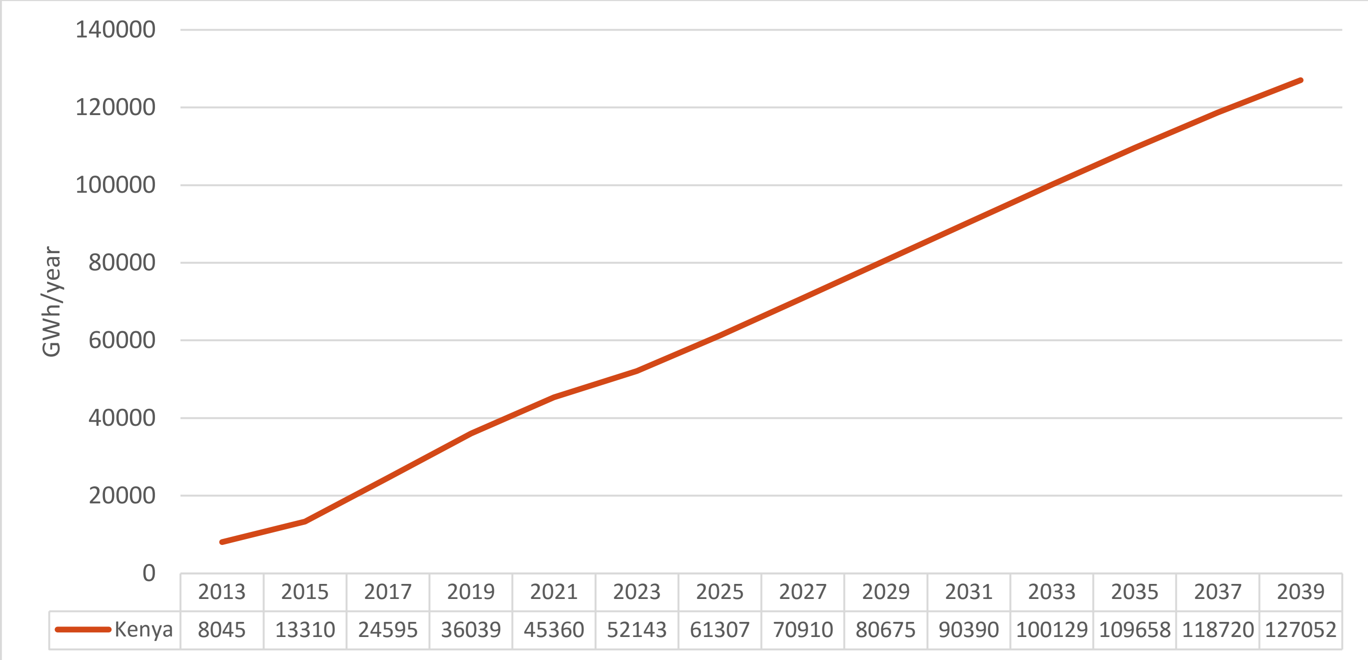


Figure 11: Demand forecast for Kenya (GWh/year)

5.6 Rwanda

Existing, committed and candidate plants

	BALMOREL area	Name	Type	Nominal capacity (MW el.)	Fuel	Efficiency (net %)	CAPEX (M$/MW el.)	Fixed costs (1000$/Mwel.)	Variable costs ($/MWh el.)	On power (Year incl.)	Retirement (Year incl.)
Existing	RW_A_ExiThe	Jabana1	MSD	7.2	Diesel	27%		21.80	1.82	2004	2033
	RW_A_ExiThe	Jabana2	MSD	20.0	HFO	27%		21.80	1.82	2009	2038
	RW_A_ExiThe	Gikondo	MSD	10.0	Diesel	27%		21.80	1.82	2005	2015
	RW_A_ExiThe	Mukungwa	MSD	10.0	Diesel	27%		21.80	1.82	2010	2015
	RW_A_ExiThe	KP1_Gisenyi_Methan	STPP	1.8	Methane	44.3%		44.88	3.74	2009	2038

	RW_A_ExiThe	JaliSolar	PV	0.25	Sunlight			29.38	0.24	2007	2031
	RW_A_ExiHy	Rwanda_Exi_Hy	HYDRO	49	Water - ROR			45.53	3.25	1990	2050
Committed	RW_A_FutThe	KivuWattGT_1	STPP	25	Methane	44.3%		44.88	3.74	2015	2044
	RW_A_FutThe	KivuWattGT_2	STPP	75	Methane	44.3%		44.88	3.74	2019	2048
	RW_A_FutThe	Gisenyi_Methane	STPP	50	Methane	44.3%		44.88	3.74	2018	2047
	RW_A_FutThe	Gishoma_Peat	STPP	15	Peat	28%		44.88	3.74	2015	2039
	RW_A_FutThe	HakanPeat	STPP	80	Peat	28%		44.88	3.74	2017	2041
	RW_A_FutThe	Akanyaru_Peat	STPP	50	Peat	28%		44.88	3.74	2020	2044
	RW_A_FutThe	RW_PV	PV	18.5	Sunlight			29.38	0.24	2015	2039
	RW_A_FutThe	Nyagatare_PV	PV	10	Sunlight			29.38	0.24	2016	2040
	RW_A_FutThe	RW_Diesel	MSD	50	Diesel	40%		21.80	1.82	2014	2043
	RW_A_Rusumo	Rusumo_RW	HYDRO	26.7	Water - ROR			45.53	3.25	2019	2050
	RW_A_FutThe	KSEZ_LNG	OCGT	50	NG	42%		20.40	1.70	2017	2046
Candidates	RW_A_Nyabarongo1	Nyabarongo1	HYDRO	28	Water - ROR		4.32	45.53	3.25	2014	2050
	RW_A_Nyabarongo2	Nyabarongo2	HYDRO	18	Water - ROR		4.32	45.53	3.25	2017	2050
	RW_A_Rusizi_3	Rusizi_3	HYDRO	45	Water - ROR		3.47	45.53	3.25	2020	2050
	RW_A_Rusizi_4	Rusizi_4	HYDRO	95.7	Water - ROR		3.00	45.53	3.25	2019	2050

Table 24: Existing, committed and candidate power plants as represented in the model for Rwanda

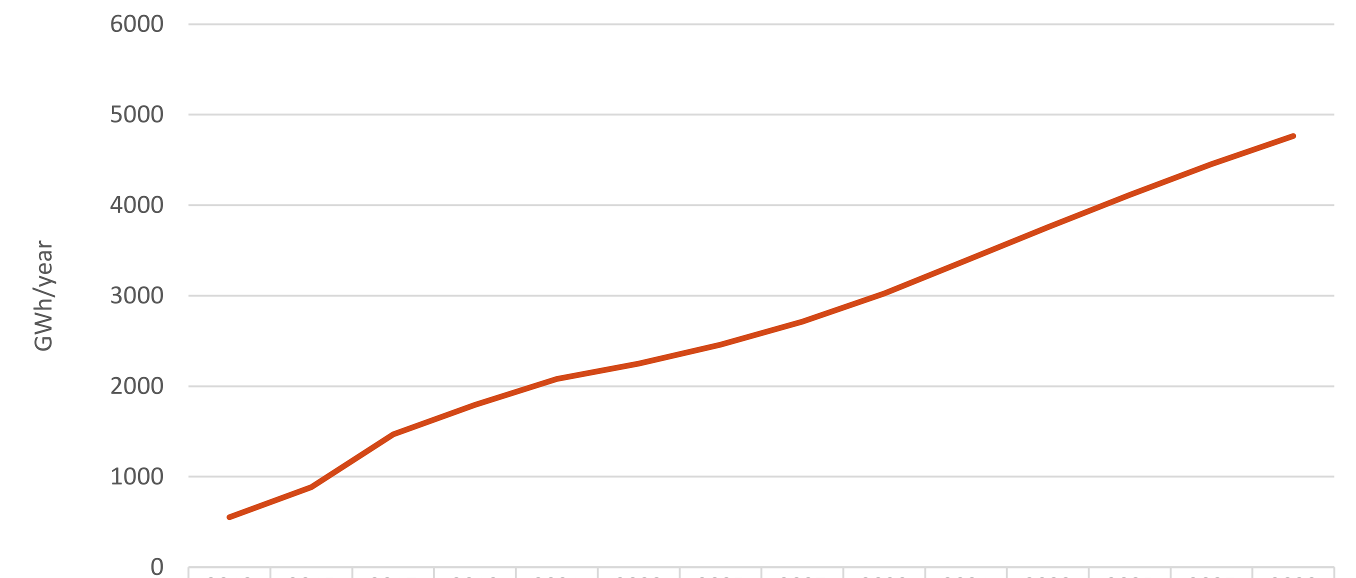
Hydro

BALMOREL area	Name	Type	Capacity (MW)	Avg hydro gen (GWh/year)	Avg hydro gen (FLH/year)
RW_A_ExiHy	Rwanda_Exi_Hy	Water - ROR	49	333	6786
RW_A_Nyabarongo1	Nyabarongo1	Water - ROR	28	140	5036
RW_A_Nyabarongo2	Nyabarongo2	Water - ROR	18	91	5036
RW_A_Rusumo	Rusumo	Water - ROR	26	139	5353
RW_A_Rusizi_3	Rusizi_3	Water - ROR	45	245	4892
RW_A_Rusizi_4	Rusizi_4	Water - ROR	95.7	468	4892

Table 25: Average yearly energy output for existing, committed and candidate hydro plants in Rwanda

Demand forecast

The demand forecast, which is presented in the figure below, is based on the load forecast from the “SOFRECO Report, Revision 2014” and covers the period until 2022 (the growth rates of the load forecast have been applied to the historic power demand). The method for prolonging the forecast until 2040 is described in Chapter 3.3.



	2013	2015	2017	2019	2021	2023	2025	2027	2029	2031	2033	2035	2037	2039
Rwanda	551	883	1469	1795	2081	2250	2458	2714	3026	3390	3756	4113	4453	4765

Figure 12: Demand forecast for Rwanda (GWh/year)

5.7 Sudan

Existing, committed and candidate plants

	BALMOREL area	Name	Type	Nominal capacity (MW el.)	Fuel	Effici-ency (net %)	CAPEX (M$/MW el.)	Fixed costs (1000$/Mwel.)	Variable costs ($/MWh el.)	On po-wer (Year incl.)	Retire-ment (Year incl.)
Existing	SD_A_ExiThe	Dr_Sherif_1	STPP	28	HFO	29%		44.88	3.74	1984	2015
	SD_A_ExiThe	Dr_Sherif_2	STPP	110	HFO	29%		44.88	3.74	1994	2031
	SD_A_ExiThe	Dr_Sherif_3	STPP	190	HFO	29%		44.88	3.74	2011	2041
	SD_A_ExiThe	Dr_Sherif_GT	OCGT	34	Gasoil	29%		20.40	1.70	2001	2030
	SD_A_ExiThe	GarriCC_1	CCGT	170	Gasoil	36%		25.50	2.13	2003	2028
	SD_A_ExiThe	GarriCC_2	CCGT	170	Gasoil	36%		25.50	2.13	2003	2028
	SD_A_ExiThe	GarriST_4	STPP	100	Coke	31%		44.88	3.74	2010	2035
	SD_A_Roseires	Roseires	HYDRO	270	Water - ROR			45.53	3.25	1966	2050
	SD_A_Sennar	Sennar	HYDRO	26	Water - ROR			45.53	3.25	1962	2050
	SD_A_Kashm_El_Girba	Kashm_El_Girba	HYDRO	10	Water - ROR			45.53	3.25	1964	2050
	SD_A_Merowe	Merowe	HYDRO	1240	Water - ROR			45.53	3.25	2009	2050
	SD_A_Jebel_Aulia	Jebel_Aulia	HYDRO	19	Water - ROR			45.53	3.25	2003	2050
Committed	SD_A_UpperAtbara	UpperAtbara	HYDRO	320	Water - ROR			45.53	3.25	2016	2050
	SD_A_FutThe	RedSea	STPP	534	Coal	41%		44.88	3.74	2017	2046
	SD_A_FutThe	AlFula	STPP	381	HFO	34%		44.88	3.74	2016	2045
	SD_A_FutThe	Kosti	STPP	470	HFO	34%		44.88	3.74	2013	2042
	SD_A_FutThe	SU_PV	PV	10	Sunlight			29.38	0.24	2015	2039
	SD_A_FutThe	SU_WND	WPP	20	Wind			22.49	3.75	2017	2036
		*Port Sudan CCGT	CCGT	900	NG	59%		25.50	2.13	2017	2046
Candidates	SD_A_Shereik	Shereik	HYDRO	420	Water - ROR		3.25	45.53	3.25	2020	2050
	SD_A_Kajbar	Kajbar	HYDRO	360	Water - ROR		3.38	45.53	3.25	2024	2050
	SD_A_Dagash	Dagash	HYDRO	312	Water - ROR		3.33	45.53	3.25	2028	2050
	SD_A_Mograt	Mograt	HYDRO	312	Water - ROR		1.68	45.53	3.25	2030	2050
	SD_A_Dal	Dal	HYDRO	648	Water - ROR		2.31	45.53	3.25	2030	2050
	SD_A_Sabaloka	Sabaloka	HYDRO	205	Water - ROR		2.26	45.53	3.25	2030	2050

Table 26: Existing, committed and candidate power plants as represented in the model for Sudan.
** Not included in the model simulation due to data being received after the closure of the data collection period.*

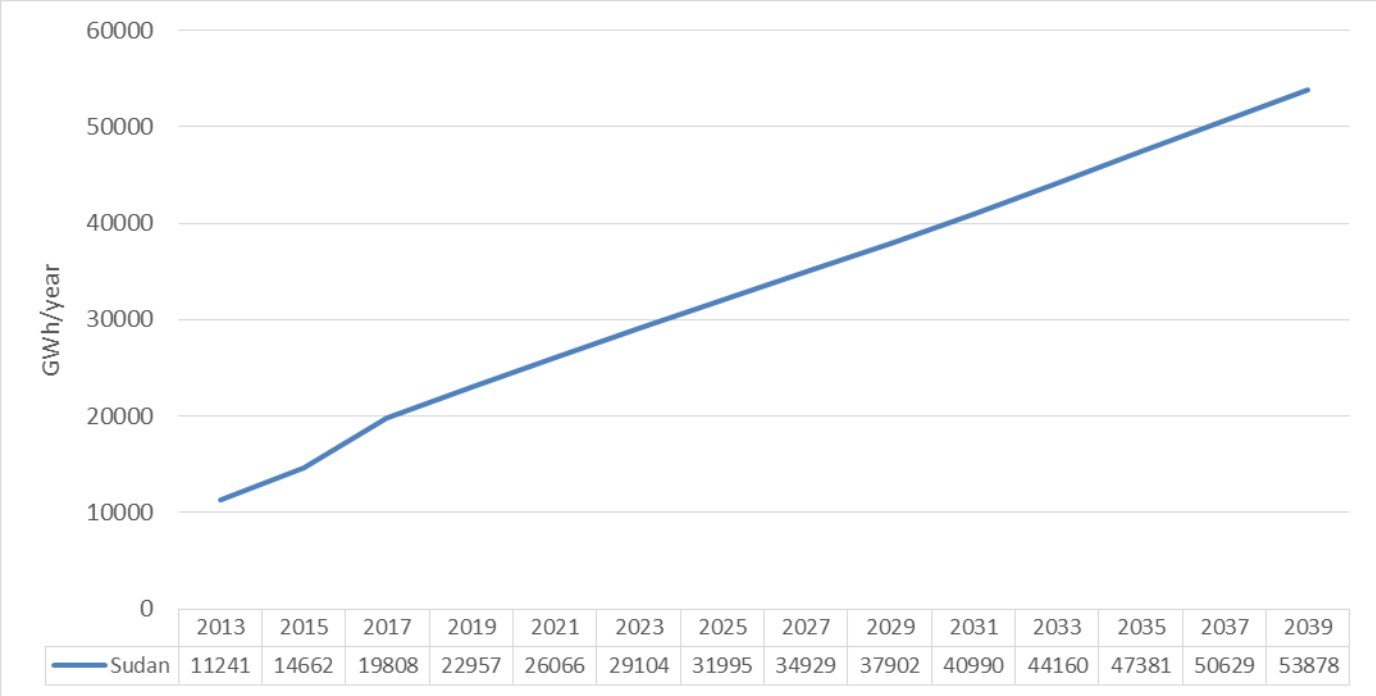
Hydro

BALMOREL area	Name	Type	Capacity *(MW)*	Avg hydro gen *(GWh/year)*	Avg hydro gen *(FLH/year)*
SD_A_Roseires	Roseires	Water - ROR	270	1613	5974
SD_A_Sennar	Sennar	Water - ROR	26	105	4049
SD_A_Kashm_El_Girba	Kashm_El_Girba	Water - ROR	10	45	4464
SD_A_Merowe	Merowe	Water - ROR	1240	5658	4563
SD_A_Jebel_Aulia	Jebel_Aulia	Water - ROR	19	83	4373
SD_A_UpperAtbara	UpperAtbara	Water - ROR	320	795	2485
SD_A_Shereik	Shereik	Water - ROR	420	2179	5188
SD_A_Kajbar	Kajbar	Water - ROR	360	1878	5217
SD_A_Dagash	Dagash	Water - ROR	312	1337	4285
SD_A_Mograt	Mograt	Water - ROR	312	1314	4212
SD_A_Dal	Dal	Water - ROR	648	2185	3372
SD_A_Sabaloka	Sabaloka	Water - ROR	205	866	4224

Table 27: Average yearly energy output for existing, committed and candidate hydro plants in Sudan

Demand forecast

The demand forecast, which is presented in the figure below, is from "Demand Forecast Report FINAL – Revision, 2013" and covers the period until 2031. The method for prolonging the forecast until 2040 is described in Chapter 3.3.



	2013	2015	2017	2019	2021	2023	2025	2027	2029	2031	2033	2035	2037	2039
Sudan	11241	14662	19808	22957	26066	29104	31995	34929	37902	40990	44160	47381	50629	53878

Figure 13: Demand forecast for Sudan (GWh/year)

5.8 South Sudan

Existing, committed and candidate plants

	BALMOREL area	Name	Type	Nominal capacity (MW el.)	Fuel	Efficiency (net %)	CAPEX (M$/MWel.)	Fixed costs (1000$/MWel.)	Variable costs ($/MWh el.)	On power Year (incl)	Retire-ment Year (incl)
Existing	SS_A_ExiThe	South_Sudan_Exi_The	MSD	33	Diesel	27%		21.8	1.82	2009	2038
Committed	SS_A_FulaSmall	FulaSmall	HYDRO	42	Water - ROR			45.53	3.25	2017	2050
Candidates	SS_A_Bedden	Bedden	HYDRO	570	Water - ROR		2.30	45.53	3.25	2024	2050
	SS_A_Fula	Fula	HYDRO	890	Water - ROR		1.78	45.53	3.25	2024	2050
	SS_A_Lakki	Lakki	HYDRO	410	Water - ROR		1.62	45.53	3.25	2024	2050
	SS_A_Shukoli	Shukoli	HYDRO	235	Water - ROR		3.42	45.53	3.25	2024	2050
	SS_A_Small_hydro	Small_hydro	HYDRO	25	Water - ROR		2.28	45.53	3.25	2024	2050

Table 28: Existing, committed and candidate power plants as represented in the model for South Sudan

Hydro

BALMOREL area	Name	Type	Capacity (MW)	Avg hydro gen (GWh/year)	Avg hydro gen (FLH/year)
SS_A_FulaSmall	FulaSmall	Water - ROR	42	189	4489
SS_A_Bedden	Bedden	Water - ROR	570	2595	4553
SS_A_Fula	Fula	Water - ROR	890	3946	4434
SS_A_Lakki	Lakki	Water - ROR	410	1848	4507
SS_A_Shukoli	Shukoli	Water - ROR	235	1049	4464
SS_A_Small_hydro	Small_hydro	Water - ROR	25	112	4489

Table 29: Average yearly energy output for existing, committed and candidate hydro plants in South Sudan

Demand forecast

The demand forecast, which is presented in the figure below, is from “AFDB, INFRASTRUCTURE PLAN FOR SOUTH SUDAN CHAPTER 8 PROVISION OF ELECTRIC POWER AND RURAL ENERGY, 2013” and covers the period until 2025. The method for prolonging the forecast until 2040 is described in Chapter 3.3.

	2013	2015	2017	2019	2021	2023	2025	2027	2029	2031	2033	2035	2037	2039
South Sudan	524	747	1277	1729	2208	2717	3173	3581	4031	4517	5003	5479	5932	6348

Figure 14: Demand forecast for South Sudan (GWh/year)

5.9 Tanzania

Existing, committed and candidate plants

	BALMOREL area	Name	Type	Nom. cap. *(MWel.)*	Fuel	Efficiency *(net %)*	CAPEX *(M$/MWel.)*	Fixed costs *(1000$/MWel.)*	Variable costs *($/MWh el.)*	On power *Year (incl)*	Retirement *Year (incl)*
Existing	TZ_A_ExiThe	Songas_1	OCGT	38	NG	36%		20.40	1.70	2004	2033
	TZ_A_ExiThe	Songas_2	OCGT	108	NG	36%		20.40	1.70	2005	2034
	TZ_A_ExiThe	Songas_3	OCGT	36	NG	36%		20.40	1.70	2006	2035
	TZ_A_ExiThe	Ubungo_1	OCGT	98	NG	43%		20.40	1.70	2007	2036
	TZ_A_ExiThe	Tegeta_IPTL	OCGT	98	NG	39%		20.40	1.70	2002	2031
	TZ_A_ExiThe	Tegeta_GT	OCGT	42	NG	43%		20.40	1.70	2009	2038
	TZ_A_ExiThe	Ubungo_2	OCGT	98	NG	43%		20.40	1.70	2012	2041
	TZ_A_ExiThe	TANWAT	STPP	2	Wood	25%		44.88	3.74	2010	2034
	TZ_A_ExiThe	TPC	STPP	17	Wood	25%		44.88	3.74	2011	2035
	TZ_A_ExiThe	Zuzu	MSD	5	HFO	38%		21.80	1.82	2010	2039
	TZ_A_ExiThe	Nyakato	MSD	60	HFO	38%		21.80	1.82	2013	2042
	TZ_A_Mtera	Mtera	HYDRO	80	Water - RESER			45.53	3.25	1988	2050
	TZ_A_Kidatu	Kidatu	HYDRO	204	Water - RESER			45.53	3.25	1975	2050
	TZ_A_Hale	Hale	HYDRO	21	Water - ROR			45.53	3.25	1967	2050
	TZ_A_Kihansi	Kihansi	HYDRO	180	Water - ROR			45.53	3.25	2000	2050
	TZ_A_NewPanganiFalls	NewPanganiFalls	HYDRO	68	Water - ROR			45.53	3.25	1995	2050
	TZ_A_NyumbaYaMungu	NyumbaYaMungu	HYDRO	8	Water - RESER			45.53	3.25	1968	2050
	TZ_A_Mwenga	Mwenga	HYDRO	4	Water - ROR			45.53	3.25	2012	2050
Committed	TZ_A_FutThe	Kinyerezi_1	OCGT	335	NG	38%		20.40	1.70	2015	2044
	TZ_A_FutThe	Kinyerezi_2	CCGT	240	NG	57%		25.50	2.13	2016	2045
	TZ_A_FutThe	Kinyerezi_3	CCGT	300	NG	57%		25.50	2.13	2016	2045
	TZ_A_FutThe	Mtwara	CCGT	400	NG	57%		25.50	2.13	2017	2046
	TZ_A_FutThe	Kinyerezi_4	CCGT	330	NG	57%		25.50	2.13	2016	2045
	TZ_A_FutThe	Mkuranga_PPP	CCGT	250	NG	57%		25.50	2.13	2017	2046
	TZ_A_FutThe	Kiwira_1	STPP	200	Coal	40%		44.88	3.74	2016	2045
	TZ_A_FutThe	Kiwira_2	STPP	200	Coal	40%		44.88	3.74	2018	2047
	TZ_A_FutThe	Mchuchuma_1	STPP	300	Coal	40%		44.88	3.74	2018	2047
	TZ_A_FutThe	Wind_1	WPP	50	Wind			22.49	3.75	2016	2035
	TZ_A_FutThe	Wind_2	WPP	50	Wind			22.49	3.75	2017	2036
	TZ_A_FutThe	Solar_1	PV	60	Sunlight			29.38	0.24	2016	2040
	TZ_A_FutThe	Solar_2	PV	60	Sunlight			29.38	0.24	2017	2041
	TZ_A_FutThe	Somanga_Fungu	CCGT	320	NG	57%		25.50	2.13	2016	2045
	TZ_A_FutThe	Somanga_TANESCO	OCGT	8	NG	42%		20.40	1.70	2015	2044
	TZ_A_Ausumo	Rusumo	HYDRO	26.7	Water - ROR			45.53	3.25	2018	2050
	TZ_A_FutThe	Zinga	OCGT	200	NG	38%		20.40	1.70	2017	2046
Candidates	TZ_A_Kakono	Kakono	HYDRO	70	Water - RESER		2.17	45.53	3.25	2020	2050
	TZ_A_Kihansi_II	Kihansi_II	HYDRO	120	Water - ROR		1.20	45.53	3.25	2020	2050
	TZ_A_Mpanga	Mpanga	HYDRO	144	Water - RESER		2.16	45.53	3.25	2020	2050
	TZ_A_Masigira	Masigira	HYDRO	118	Water - ROR		2.27	45.53	3.25	2020	2050
	TZ_A_Auhudji	Ruhudji	HYDRO	358	Water - RESER		3.89	45.53	3.25	2020	2050
	TZ_A_Aumakali	Rumakali	HYDRO	520	Water - RESER		1.38	45.53	3.25	2025	2050

TZ_A_Songwe	Songwe	HYDRO	170	Water - RESER	1.90	45.53	3.25	2020	2050
TZ_A_Steiglers_Gorge1	Steiglers_Gorge1	HYDRO	300	Water - RESER	2.73	45.53	3.25	2024	2050
TZ_A_Steiglers_Gorge2	Steiglers_Gorge2	HYDRO	600	Water - RESER	0.72	45.53	3.25	2024	2050
TZ_A_Steiglers_Gorge3	Steiglers_Gorge3	HYDRO	300	Water - RESER	1.21	45.53	3.25	2024	2050
TZ_A_Ikondo	Ikondo	HYDRO	340	Water - RESER	2.33	45.53	3.25	2020	2050
TZ_A_Taveta	Taveta	HYDRO	145	Water - ROR	1.93	45.53	3.25	2020	2050
TZ_A_Malagarasi_Stage	Malagarasi_Stage	HYDRO	44.8	Water - RESER	4.06	45.53	3.25	2020	2050

Table 30: Existing, committed and candidate power plants as represented in the model for Tanzania

Hydro

BALMOREL area	Name	Type	Capacity *(MW)*	Avg hydro gen *(GWh/year)*	Avg hydro gen *(FLH/year)*	Storage size *(GWh)*
TZ_A_Mtera	Mtera	Water - RESER	80	429	5363	726
TZ_A_Kidatu	Kidatu	Water - RESER	204	1111	5446	55
TZ_A_Hale	Hale	Water - ROR	21	93	4429	
TZ_A_Kihansi	Kihansi	Water - ROR	180	694	3856	
TZ_A_NewPanganiFalls	NewPanganiFalls	Water - ROR	68	341	5015	
TZ_A_NyumbaYaMungu	NyumbaYaMungu	Water - RESER	8	36	4500	46
TZ_A_Mwenga	Mwenga	Water - ROR	4	24	6000	
TZ_A_Kakono	Kakono	Water - RESER	70	404	7623	2
TZ_A_Kihansi_II	Kihansi_II	Water - ROR	120	69	575	
TZ_A_Mpanga	Mpanga	Water - RESER	144	955	6632	60
TZ_A_Masigira	Masigira	Water - ROR	118	664	5627	1
TZ_A_Auhudji	Ruhudji	Water - RESER	358	1928	5385	492
TZ_A_Aumakali	Rumakali	Water - RESER	520	1475	2837	1936
TZ_A_Ausumo	Rusumo	Water - ROR	27	148	5576	
TZ_A_Songwe	Songwe	Water - RESER	170	835	4909	290
TZ_A_Steiglers_Gorge1	Steiglers_Gorge1	Water - RESER	300	2230	7433	236
TZ_A_Steiglers_Gorge2	Steiglers_Gorge2	Water - RESER	600	1506	2510	236
TZ_A_Steiglers_Gorge3	Steiglers_Gorge3	Water - RESER	300	1523	5077	6619
TZ_A_Ikondo	Ikondo	Water - RESER	340	1832	5388	737
TZ_A_Taveta	Taveta	Water - ROR	145	850	5862	2
TZ_A_Malagarasi_Stage	Malagarasi_Stage	Water - RESER	45	187	4167	4167

Table 31: Average yearly energy output for existing, committed and candidate hydro plants in Tanzania

Demand forecast

The demand forecast, which is presented in the figure below, is from “POWER SYSTEM MASTER PLAN, 2012 UDATE” and covers the period until 2035. The method for prolonging the forecast until 2040 is described in Chapter 3.3.

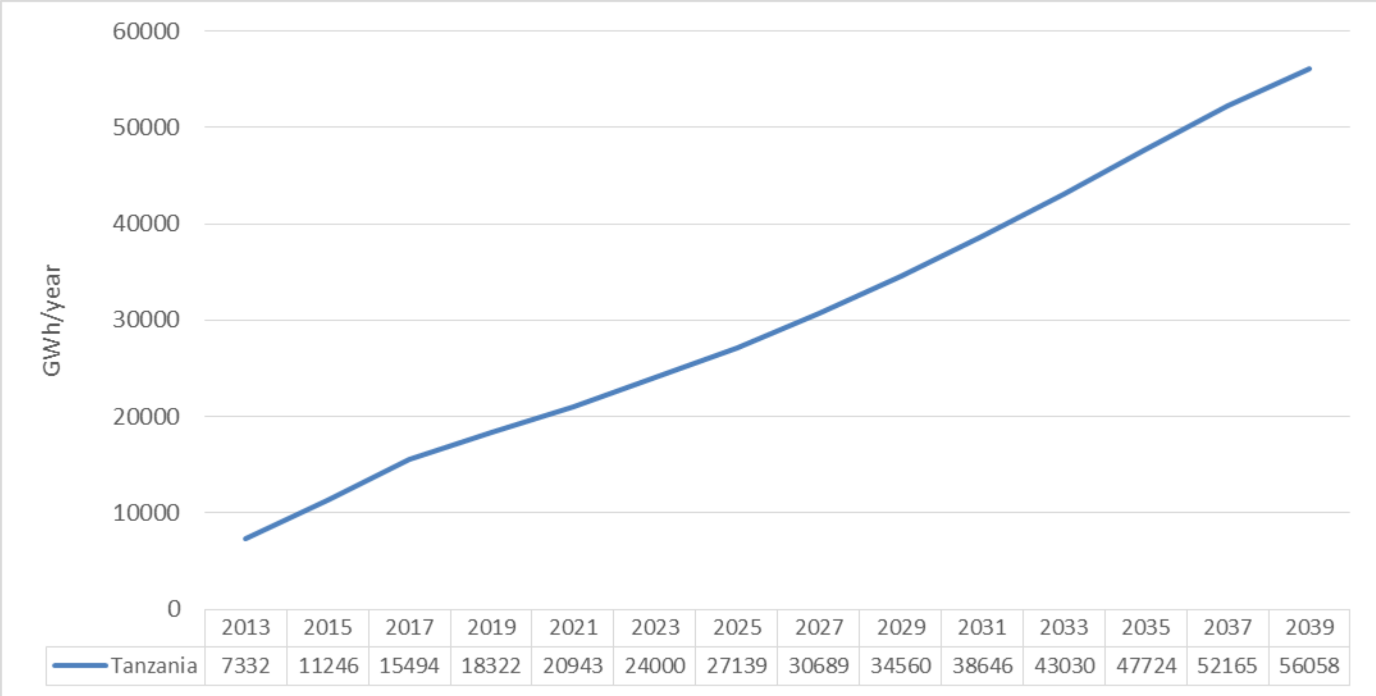


Figure 15: Demand forecast for Tanzania (GWh/year)

5.10 Uganda

Existing, committed and candidate plants

	BALMOREL area	Name	Type	Nom. cap. *(MWel.)*	Fuel	Effici-ency *(net %)*	CAPEX *(M$/MWel.)*	Fixed costs *(1000$/MWel.)*	Variable costs *($/MWh el.)*	On po-wer *Year (incl)*	Retire-ment *Year (incl)*
Existing	UG_A_ExiThe	Namanve	MSD	50	HFO	38%		21.80	1.82	2008	2037
	UG_A_ExiThe	Kakira	Cogen	30	Bagasse	17%		44.88	3.74	2008	2032
	UG_A_ExiThe	Kinyara	Cogen	1.5	Bagasse	17%		44.88	3.74	2009	2033
	UG_A_ExiThe	Electromaxx	MSD	50	HFO	38%		21.80	1.82	2012	2041
	UG_A_Nalubaale	Nalubaale	HYDRO	180	Water - ROR			45.53	3.25	2010	2050
	UG_A_Kira	Kira	HYDRO	200	Water - ROR			45.53	3.25	2010	2050
	UG_A_Bujagali	Bujagali	HYDRO	250	Water - ROR			45.53	3.25	2010	2050
	UG_A_Small_hydro	UG_Small_hydro	HYDRO	61	Water - ROR			45.53	3.25	2011	2050
Committed	UG_A_NewThe	Albatros	MSD	50	HFO	38%		21.80	1.82	2017	2046
	UG_A_Karuma_High	Karuma_High	HYDRO	600	Water - ROR			45.53	3.25	2019	2050
	UG_A_Isimba	Isimba	HYDRO	183	Water - ROR			45.53	3.25	2018	2050
	UG_A_NewThe	Kinyara2	Cogen	30	Bagasse	17%		44.88	3.74	2016	2040
	UG_A_NewThe	Sugar_Allied_Industries	Cogen	12	Bagasse	17%		44.88	3.74	2014	2038
	UG_A_NewThe	Kabale_Peat	STPP	33	Peat	17%		44.88	3.74	2016	2040
	UG_A_NewThe	Katwe1	Geo	50	Heat			43.25	3.09	2017	2046
	UG_A_Shydro_com	UG_Shydro_com	HYDRO	152	Water - ROR			45.53	3.25	2017	2050
	UG_A_NewThe	Solar_UG	PV	20	Sunlight			29.38	0.24	2017	2041
	UG_A_Ayago	Ayago	HYDRO	600	Water - ROR			45.53	3.25	2020	2050
Candidates	UG_A_NewThe	Katwe2	Geo	200	Heat		3.72	43.25	3.09	2016	2045
	UG_A_Kiba	Kiba	HYDRO	288	Water - ROR		8.57	45.53	3.25	2025	2050
	UG_A_Oriang	Oriang	HYDRO	392	Water - ROR		4.88	45.53	3.25	2025	2050
	UG_A_Murchisson_F_High	Murchisson_F_High	HYDRO	648	Water - ROR		1.91	45.53	3.25	2025	2050
	UG_A_SHydro_cand	UG_SHydro_cand	HYDRO	99	Water - ROR		4.05	45.53	3.25	2020	2050

Table 32: Existing, committed and candidate power plants as represented in the model for Uganda

Hydro

BALMOREL area	Name	Type	Capacity *(MW)*	Avg hydro gen *(GWh/year)*	Avg hydro gen *(FLH/year)*
UG_A_Nalubaale	Nalubaale	Water - ROR	180	767	4260
UG_A_Kira	Kira	Water - ROR	200	747	3737
UG_A_Bujagali	Bujagali	Water - ROR	250	1970	7882
UG_A_Karuma_High	Karuma_High	Water - ROR	600	4309	7182
UG_A_Isimba	Isimba	Water - ROR	183	1039	5678
UG_A_Small_hydro	UG_Small_hydro	Water - ROR	61	306	5019
UG_A_Kiba	Kiba	Water - ROR	288	2066	7174
UG_A_Oriang	Oriang	Water - ROR	392	2768	7061
UG_A_Ayago	Ayago	Water - ROR	600	4357	7262
UG_A_Murchisson_F_High	Murchisson_F_High	Water - ROR	648	2314	3571
UG_A_Shydro_cand	UG_SHydro_cand	Water - ROR	99	582	5882
UG_A_Shydro_com	UG_Shydro_com	Water - ROR	152	891	5882

Table 33: Average yearly energy output for existing, committed and candidate hydro plants in Uganda

Demand forecast

The demand forecast, which is presented in the figure below, is from “Grid Development Plan, 2012” and covers the period until 2028. The method for prolonging the forecast until 2040 is described in Chapter 3.3.

	2013	2015	2017	2019	2021	2023	2025	2027	2029	2031	2033	2035	2037	2039
Uganda	3682	4835	5621	6965	8541	10148	12057	14324	16786	18807	20833	22816	24701	26435

Figure 16: Demand forecast for Uganda (GWh/year)

5.11 Djibouti

Djibouti power system data are mainly derived from the EAPP 2011 Master Plan. Some minor updates are made to this, e.g. plans of geothermal power.

Existing, committed and candidate plants

	BALMOREL area	Name	Type	Nom. cap. *(MWel.)*	Fuel	Efficiency *(net %)*	CAPEX *(M$/MWel.)*	Fixed costs *(1000$/MWel.)*	Variable costs *($/MWh el.)*	On power *Year (incl)*	Retirement *Year (incl)*
Existing	DB_A_ExiThe	Boulaos	MSD	108	Diesel	27%		21.80	1.82	2000	2029
	DB_A_ExiThe	Marabout	MSD	14	Diesel	27%		21.80	1.82	2000	2029
Committed	DB_A_Committed	DBGeothermal	Geo	50	Heat			43.25	3.09	2015	2044

Table 34: Existing, committed and candidate power plants as represented in the model for Djibouti

Demand forecast

The demand forecast, which is presented in the figure below, is from "EAPP Master Plan, 2011" and covers the period until 2038. The method for prolonging the forecast until 2040 is described in Chapter 3.3.

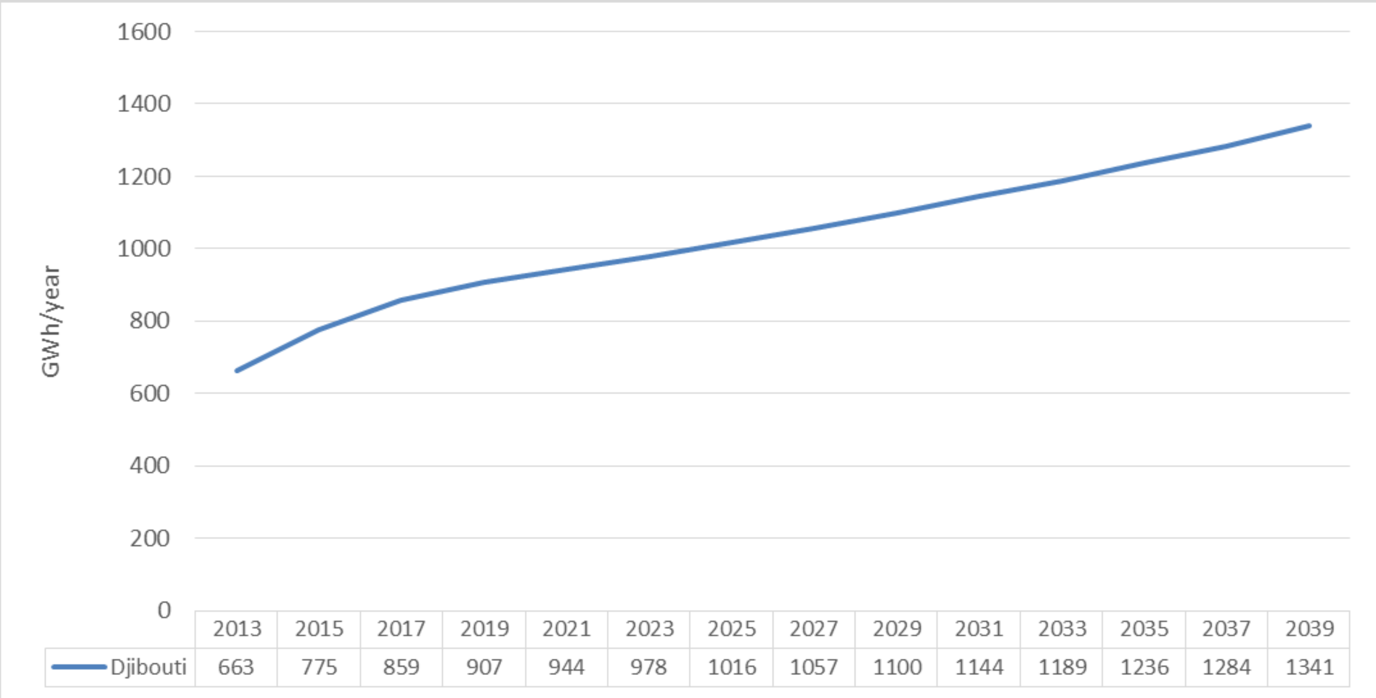


Figure 17: Demand forecast for Djibouti (GWh/year)

5.12 Libya

The data for the Libyan power system in mainly derived from the study titled "2010 Power System Studies" for the General Electric Company of Libya carried out by PB in 2010. It has not been possible to conduct data collection tours or workshops on Libya.

Existing, committed and candidate plants

	BALMOREL area	Name	Type	Nom. cap.	Fuel	Efficiency	CAPEX	Fixed costs	Variable costs	On power	Retirement
				(MWel.)		*(net %)*	*(M$/MWel.)*	*(1000$/MWel.)*	*($/MWh el.)*	*Year (incl)*	*Year (incl)*
Existing	LY_A_ExiThe	KufraGT	OCGT	30	HFO	35%		20.40	1.70	1990	2019
	LY_A_ExiThe	AbuKamashGT	OCGT	60	HFO	35%		20.40	1.70	1990	2019
	LY_A_ExiThe	TripoliWestGT	OCGT	200	HFO	35%		20.40	1.70	1981	2010
	LY_A_ExiThe	HomsPowerST	STPP	440	HFO	35%		44.88	3.74	1983	2012
	LY_A_ExiThe	HomsPowerGT	OCGT	480	LFO	35%		20.40	1.70	1995	2024
	LY_A_ExiThe	DernaST	STPP	100	LFO	35%		44.88	3.74	1986	2015
	LY_A_ExiThe	TobrukST	STPP	100	LFO	35%		44.88	3.74	1986	2015
	LY_A_ExiThe	MisurataST	STPP	350	LFO	35%		44.88	3.74	1990	2019
	LY_A_ExiThe	TripoliSouthGT1	OCGT	168	NG	35%		20.40	1.70	1990	2019
	LY_A_ExiThe	TripoliSouthGT2	OCGT	252	NG	35%		20.40	1.70	1995	2024
	LY_A_ExiThe	ZwitinaGT	OCGT	160	NG	35%		20.40	1.70	1990	2019
	LY_A_ExiThe	ElRowisGT	OCGT	520	NG	35%		20.40	1.70	1990	2019
	LY_A_ExiThe	ZawiaCC	CCGT	810	NG	45%		25.50	2.13	1990	2019
	LY_A_ExiThe	ZawiaST	STPP	390	LFO	35%		44.88	3.74	1990	2019
	LY_A_ExiThe	BenghaziPowerST	STPP	260	LFO	35%		44.88	3.74	1995	2024
	LY_A_ExiThe	BenghaziPowerGT	OCGT	520	NG	35%		20.40	1.70	1995	2024
	LY_A_ExiThe	MisurateCC	CCGT	460	NG	45%		25.50	2.13	2010	2039
	LY_A_ExiThe	BenghaziPowerCC	CCGT	460	NG	45%		25.50	2.13	2010	2039
	LY_A_ExiThe	SrirWestCC	CCGT	460	NG	45%		25.50	2.13	2010	2039
	LY_A_ExiThe	ElRowisCC	CCGT	260	NG	45%		25.50	2.13	2010	2039
	LY_A_ExiThe	ZwitinaCC	CCGT	460	NG	45%		25.50	2.13	2010	2039

Table 35: Existing, committed and candidate power plants as represented in the model for Libya

Demand forecast

The demand forecast, which is presented in the figure below, is from “International Energy Agency, 2011 country statistics” and covers the period until 2026*. The method for prolonging the forecast until 2040 is described in Chapter 3.3.

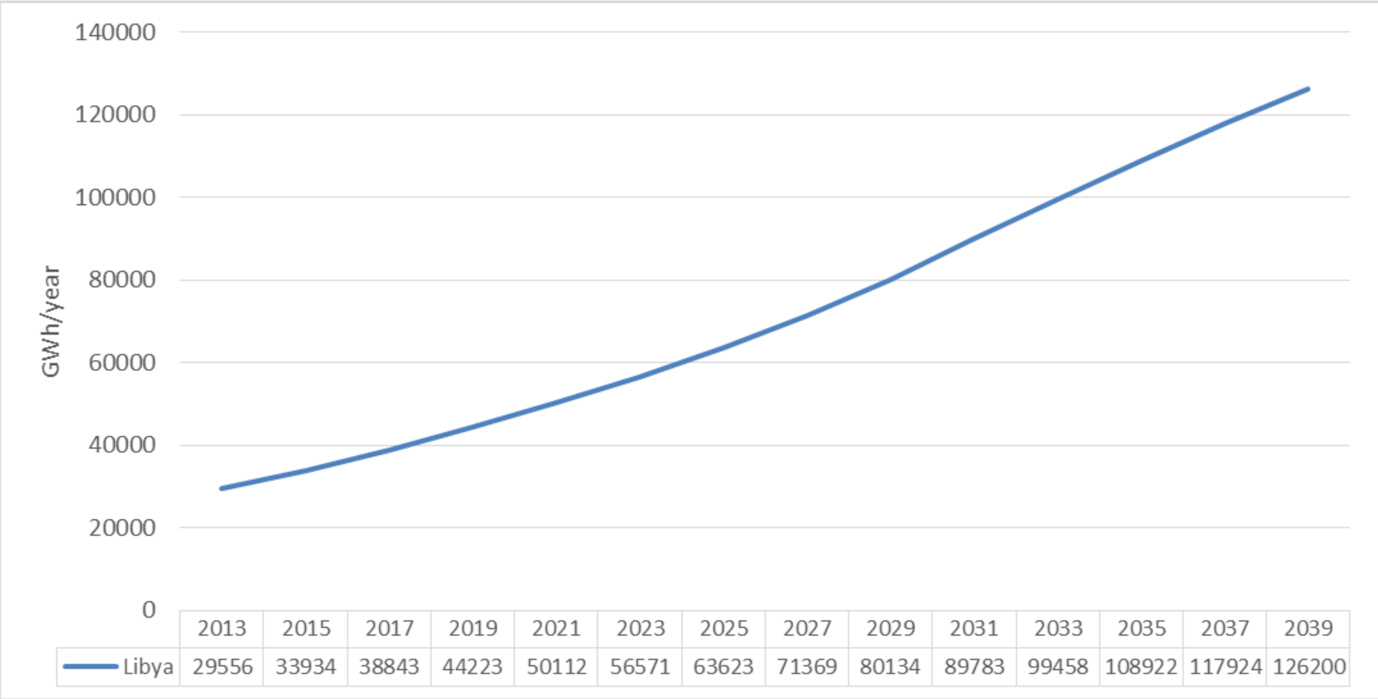


Figure 18: Demand forecast for Libya (GWh/year)

6 References

Eastern Africa Power Pool (EAPP) and East African Community (EAC) - Regional Power System Master Plan and Grid Code Study, SNC Lavalin International Inc in association with Parsons Brinckerhoff, 2010-2011

References to Parts of the study:
[1] Final Interim Report Module 1C Appendices part 1
- Hydro profiles p. 44
- Hydro Potential p. 92

[2] Final Interim Report Module 1C Appendices part 2
- Tech data p. 6
- Future Tech plan p. 36

[3] Final Interim Report Module 1C part 3
- Transmission p. 75

[4] Final Interim Report- Module 1A Demand Forecast Main
- Demand year

[5] Final Interim Report Module 1C part 2
- Fuel prices

Eastern Nile Power Trade Programs Study, EDF – Generation and Engineering Division and Scott Wilson, 2007

References to Parts of the study:
[6] Final main report – Energy Sector Profile & Projections Vol2 – Egypt
- Demand variation Egypt

[7] Final main report – Energy Sector Profile & Projections Vol3 – Ethiopia
- Demand variation Ethiopia

[8] Final main report – Energy Sector Profile & Projections Vol4 – Sudan
- Demand variation Sudan