Investigating the water-energy nexus in African Power Pools by soft-linking the Dispa-SET, LISFLOOD and TEMBA models.

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ABSTRACT

The operation and economic profitability of modern energy systems is constrained by the availability of renewable energy and water resources. Thermal power plants need water for cooling purposes while hydropower plants are fuelled by the water to generate electricity. Furthermore, extremely high shares of renewables impact the stability of the power system and increase the operational and flexibility needs. Water shortages and increased water temperatures in rivers across the globe have regularly occurred in the last years. This has led to temporary shutdowns, activation of load shedding procedures, financial losses, increased wear and tear of the power plants and ultimately less reliable and more costly systems. The operation of power systems directly impacts the quantity and quality of water resources. The combined effect of lower water availability due to climate change, higher demand and increased water consumption for non-energy and energy needs may cause problems in Africa. In most African power systems hydropower is a dominant renewable energy resource, and interconnection capacities are usually limited ppr unreliable. This paper describes the modelling framework for analysing the water-power nexus in the Northern, Eastern and Central Africa Power Pools. The proposed modelling framework includes soft linking between three models. The LISFLOOD model is used to generate hydrological inputs, the TEMBA model is used for assessing the long-term expansion planning and the Dispa-SET model is used for mid-term hydrothermal coordination and optimal unit commitment and power dispatch of the system. The results show that the proposed modelling framework yields simulation results comparable to historical values, despite the data-related limitations, replicating the available statistics to great extent. Furthermore. The simulation was able to provide hourly time series of electricity generation at plant level in a robust way. We show that all analysed African power pools heavily rely on the availability of water resources. As a consequence, in the long term, the dependence of the power system on water resources could become even more important to meet the increasing electricity demand in the analysed power pools.

KEYWORDS

Water-Energy Nexus, African power pools, Dispa-SET, LISFLOOD, TEMBA

1. INTRODUCTION

Access to a stable and secure supply of energy is a fundamental driver of economic growth. More than two-thirds of the population, approximately 600 million people, in Sub-Saharan Africa lacked access to electricity in 2016 and 850 million people had no access to clean cooking facilities such as natural gas, liquefied petroleum gas, electricity and biogas, or improved biomass cook stoves [1]. Africa's gross economic activity is expected to continue its rapid growth. In Sub-Saharan Africa, economic growth is estimated at 2.4% in 2018 compared to 2.5% in 2017 and is set to reach 3.5% in 2019[1]. In order to meet this growing demand, and take advantage of trade opportunities, five regional power pools have been developed. This study analyses three power pools, namely the Central African Power Pool (CAPP)[2], the East African Power Pool (EAPP)[3] and the North African Power Pool (NAPP)[4].

Water-energy nexus is refers to the complex interactions between the water sector and the energy sector. The combined effect of increased water consumption, for energy and non-energy purposes, with lower availability of water resources due to climate change is, according to Fernández-Blanco et al. [2], expected to lead to monetary losses, power curtailments, temporary shutdowns and demand restrictions in power grids across the wrold. According to The World Bank, electricity and water demands in Africa are projected to grow by 700% and 500% by 2050 with respect to 2012. In most African energy systems, hydropower is the dominant renewable energy source [3]. Other salient characteristics of these systems are their small sizes, the low electrification rates, the high shares of oil in the power generation mix, and the lack of significant power and gas interconnections.

The United Nation's Sustainable Energy for All and Power Africa whose focus is explicitly set on Africa. Their aim is to electrify some 60 million homes and support the investment of 30 GW of clean power generation in the near future. Despite this, however, there is no coherent 'by country' and 'by region' set of concrete scenarios besides ones proposed by Taliotis et al. [4], nor an open energy system analysis platform that may be used to carry out a more detailed investigation of the proposed long term generation expansion scenarios.

The purpose of this study is to examine the potential for and relationship between current and future electricity situation and power trade between countries in selected power pools, making use of a higher temporal resolution than what has been done previously with TEMBA – OSeMOSYS (The Electricity Model Base for Africa) [5]. A second objective is the investigation of synergies between the water and energy sectors by assessing the hydro potential in the proposed region through several what if scenarios in regard to the availability of water for energy purposes in dry and wet seasons. This paper also identifies areas where grid extensions would be beneficial, so as to unlock part of this potential, thus leading to a cost-optimal growth of the African electricity supply system. Cross border interconnections with Europe and other African power pools, despite their important potential [6], are out of the scope of this paper.

This paper is structured as follows: the methodology section of the paper briefly presents the methodology and the adopted modelling framework. The main results from the selected scenarios are presented in Results and discussion section. The paper concludes with a summary of the key outcomes in Conclusions and suggests future steps and model enhancements to build on existing research efforts.

2. METHODS

2.1. Model structure

This section focuses on different tools, techniques and methods used within this paper. Figure 1 highlights all possible links and data flows within the modelling framework. It consists of the

[1] The World Bank: https://data.worldbank.org/indicator/NY.GDP.MKTP.KD.ZG?locations=ZG
[2] CAPP Geographic Information System: https://www.peac-sig.org/en/
[3] East African Power Pool: http://eappool.org/
[4] Comité Maghrébin de l'Electricité (COMELEC): https://comelec-net.org/index-en.php

following five elements: Sources, Inputs, Pre-processing, Simulation and Outputs. The usual measured historical or simulated input data, such as hourly timeseries, is complemented with the TEMBA Reference scenario outputs. These inputs include costs, demand projections and capacities (aggregated only per fuel type) as well as some net cross border interconnection capacities (NTC). It also provides yearly energy generation from which timeseries are generated for unit availabilities, demand profiles and energy flow limits between zones. High emphasis is put on the pre-processing of the input data. The framework consists of four models, LISFLOOD is used for generation of multiannual hydro profiles, TEMBA is used for long term generation expansion planning, third is the transitioning model between the LISFLOOD and TEMBA outputs formatted into the Dispa-SET readable format while the fourth and final one is the Dispa-SET mid term scheduling (MTS) module used for pre-allocation of large storage units such as hydro dams (HDAM) and pumped storage units (HPHS). Reservoir levels computed by the Dispa-SET MTS module are then used as minimum level constraints in the main Dispa-SET unit commitment (UCM) model. Results obtained from the Dispa-SET UCM model are used as main outputs of this study. In the following chapters pre-processing, simulation and outputs are discussed in more detail.

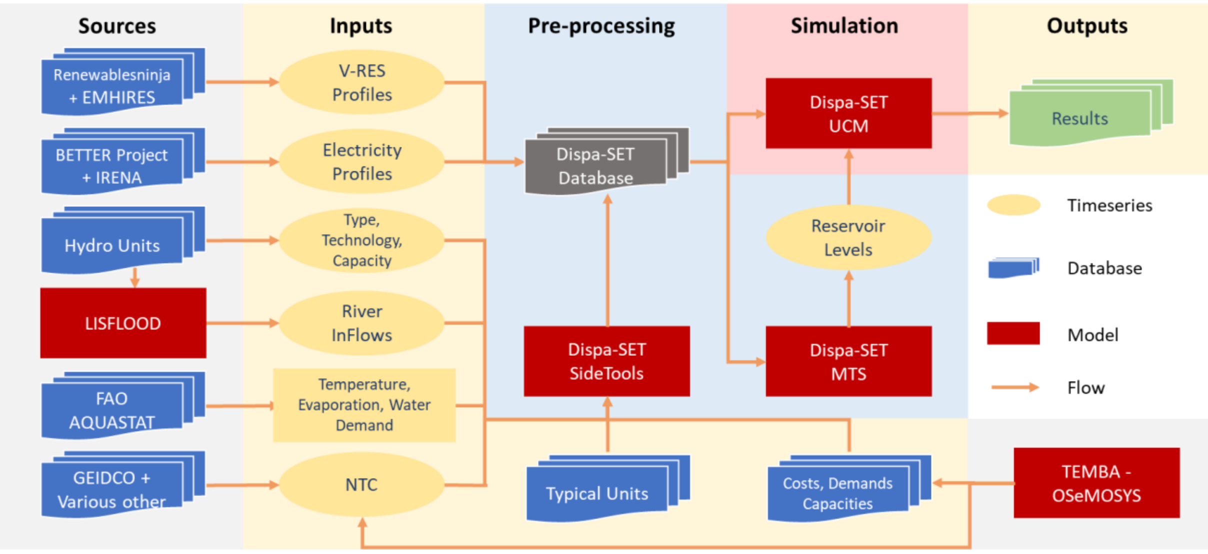

Figure 1 Relational block-diagram between models and various data sources used within this study. TEMBA - OSeMOSYS inputs are complemented with historical (where applicable) and computed hourly timeseries profiles. Unit commitment and power dispatch is solved with Dispa-SET.

2.2. Models used within this study

LISFLOOD

LISFLOOD [7] is a rainfall-runoff hydrological model capable of simulating the hydrological processes that occur in a particular catchment area. It was developed by the Joint Research Centre (JRC) of the European Commission, with the specific objective to produce a tool that can be used in large and trans-national catchments for a variety of applications, including: flood forecasting, assessing the effects of river regulation measures, the effects of land-use change and the effects of climate change. With in this study, LISFLOOD was used as a simulation tool for predicting historical discharge rates in river basins on which hydro units are located.

TEMBA – OSeMOSYS

The Electricity Model Base for Africa (TEMBA) was initially developed with the United Nations Economic Commission for Africa (UNECA) to provide a foundation for the analysis of the continental-scale African energy system [4]. For the purpose of this analysis, the results from the TEMBA model are used as inputs for assessing the future scenario in the three African power pools. The input data and modelling framework used within the TEMBA - OSeMOSYS model are described in more detail by Pappis et al. [8]. Main outputs of the study are as follows: capacity data (as investment in energy supply in Africa has been growing), cost and performance data, fuel price projections, new energy demand projections.

Dispa-SET

The Dispa-SET model is an open-source unit commitment and optimal dispatch model focused on the balancing and flexibility problems in smart energy systems with high shares of variable renewable energy sources (VRES). It is mainly developed within the JRC of the EU Commission and in close collaboration with the University of Liège and the KU Leuven. The core formulation of the model is an efficient MILP formulation of the UCM problem [9]. As mentioned before, a simplified hydro-thermal allocation (MTS), is a linear programming approximation (i.e. integer variables are relaxed) of the UCM modelling approach, used to pre-allocate reservoir levels of seasonal storage units. The main purpose of using the Dispa-SET model is the possibility of analysing large interconnected power systems with a high level of detail. Dispa-SET is the main modelling framework used within this study. The demands are assumed to be inelastic to the price signal. The MILP objective function is, therefore, the total generation cost over the optimization period and can be summarized in the following equation:

$$\text{Min}\, TotalSystemCost = \sum_{\forall u,i} \left(\begin{array}{c} CostStartUp_{i,u} + CostShutDown_{i,u} + \\ CostFixed_{u} \cdot Committed_{i,u} + \\ CostVariable_{i,u} \cdot Power_{i,u} + \\ CostRampUp_{i,u} + CostRampDown_{i,u} + \\ PriceTransmission_{i,l} \cdot Flow_{i,l} + \\ \sum_{n} \left(CostLoadShedding_{i,n} \cdot ShedLoad_{i,n} \right) + \\ VOLL_{Power} \cdot \left(LL_{MaxPower,i,n} + LL_{MinPower,i,n} \right) + \\ VOLL_{Reserve} \cdot \left(LL_{2U,i,n} + LL_{2D,i,n} + LL_{3U,i,n} \right) + \\ VOLL_{Ramp} \cdot \left(LL_{RampUp,u,i} + LL_{RampDown,u,i} \right) \end{array} \right) \tag{1}$$

The main constraint to be met is the power supply-demand balance, for each period and each zone, in the day-ahead market as proposed in the following equation:

$$\begin{aligned} \sum_{u} \left(\text{Power}_{u,i} \cdot Location_{u,n} \right) + \sum_{l} \left(\text{Flow}_{l,i} \cdot LineNode_{l,n} \right) &= Demand_{DA,n,h} \\ &+ \sum_{r} \left(\text{StorageInput}_{s,h} \cdot Location_{s,n} \right) - ShedLoad_{n,i} - LL_{MaxPower_{n,i}} \\ &+ LL_{MinPower_{n,i}} \end{aligned} \tag{2}$$

According to this restriction, the sum of the power generated by all the units present in the node (including the power generated by the storage units), the power injected from neighbouring nodes, and the curtailed power from intermittent sources is equal to the day ahead load in that node

2.3. River In-Flows

Outputs from the LISFLOOD model are given for a particular basin and geographical location. This usually results in rather excessive water availability for the particular location. In order to assess actual water availability for hydro generation, technological features, such as nominal head, maximum power capacity, volume and surface area of the reservoirs (for hydro dams (HDAM) or pumped storage (HPHS) units), as well as satellite based data such as average, minimal and maximal daily air temperatures and daily solar irradiation, need to be assessed. Evapotranspiration is calculated for each unit individually as proposed by Hargreaves et al. [10] and subtracted from the LISFLOOD outputs. For some hydro units, the computed inflows are orders of magnitude higher than the historical generation. This is due to inaccuracies in the definition of the catchment basins for these units and in the limited quality of the input data. In order to correct this, parameters such as hourly availability factors for hydro run-of-river (HROR) units and capacity factors for HDAM and HPHS units need to be adjusted to realistic values. To that aim, an iterative two stage calibration method is introduced as presented in Figure 2.

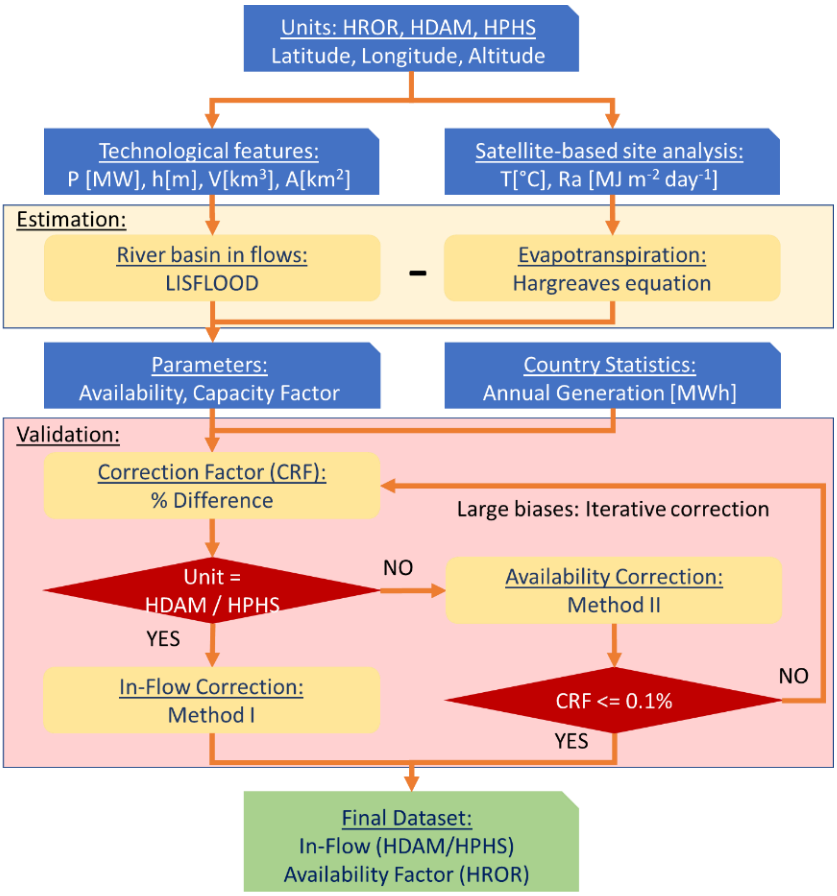

Figure 2 Flowchart for generating availability factors timeseries for HROR and scaled inflows timeseries for HDAM units.

In a first iteration, the difference between annual generation and the computed inflows is computed. Based on the unit type, one of the two scaling methods is selected. For HDAM and HPHS units, inflows are scaled based on the correction factor. As such units are usually built on large storage reservoirs, each containing several hundreds of hours of storage, no additional adjustments are necessary. In case of HROR units, a second method is applied. Since power output of these units is directly related to the inflows, the higher the inflow more power is generated and vice versa, in some instances spillage may occur (i.e. when inflows are higher than the design parameters of the turbine allow). Due to potential spillage, first method is not valid anymore and further adjustments are necessary. In order for spillage to be considered a following five step iteration is introduced:

$$\begin{aligned} &\text{I)} \quad InFlow_{u,i} = InFlow_{u,i} \cdot (1 + Correction) \\ &\text{II)} \quad Spill_{u,i} = InFlow_{u,i} - PowerCapacity_u \end{aligned} \tag{3}$$

III) $Spill_{u,i}(Spill_{u,i} < 0) = 0$

IV) $InFlow_{u,i} = InFlow_{u,i} - Spill_{u,i}$

V) $Correction = \frac{HistoricGeneration_u - \sum_{i=1}^{i=n} InFlow_{u,i}}{\sum_{i=1}^{i=n} InFlow_{u,i}}$

After spillage is assigned new inflows and correction factors are computed. If newly computed inflows are within desired values, iteration stops, otherwise new correction factor and newly computed inflows are used as new inputs for the next loop.

2.4. Wind and Solar AF

Wind and solar AF are estimated as weighted average shares of potential and feasible wind and solar PV sites. Capacity factors for renewable technologies are computed as follows:

$$CF_{tr,z} = \frac{PR_{tr} \cdot \bar{x}_{tr,z}}{8760} \quad (4)$$

where $CF_{tr,z}$ is the capacity factor of VRES technologies in each zone, in MWh/MW$_{el}$; PR_{tr} is performance ratio of renewable technologies, in %; and $\acute{x}_{tr,z}$ is weighted average number of peak load hours in each zone, in h.

$$\bar{x}_{tr,z} = \frac{\sum_{i=1}^{n} A_{tr,i,z}\, x_{tr,i,z}}{\sum_{i=1}^{n} A_{tr,i,z}} \quad (5)$$

where $A_{tr,i,z}$ is available area with particular VRES intensity for specific renewable technology and zone, in km^2; $x_{tr,i,z}$ are peak load hours for specific VRES intensity, renewable technology and zone, in h. Similar method is also applied when generation from individual hydro units is unknown, but the total annual hydro generation for the whole country to which these units belong to is available and reported in various annual energy reports and statistical databases.

2.5. Fuel Prices

Variability of fuel prices is estimated based on a fingerprints methodology[5]. For each fuel type, one fingerprint per category can be used for the increase or decrease of the final fuel price, as proposed within the ECOWAS study [11]. Each country is assigned one fingerprint for geographical location, local fuel production, import and/or transportation, and fuel availability. Fuel prices generated through this method are given in MWh of electrical energy. A summary of the fingerprint method is presented in Figure 3.

[5] Fingerprinting algorithm maps large data (in this case geography, local production and transportation and resource availability) to a much shorter sequence of bytes (in this case fuel price). Such a sequence is called the fingerprint. While fingerprints may identify the original data, the original data cannot be derived from its fingerprint. https://devopedia.org/fingerprinting-algorithms

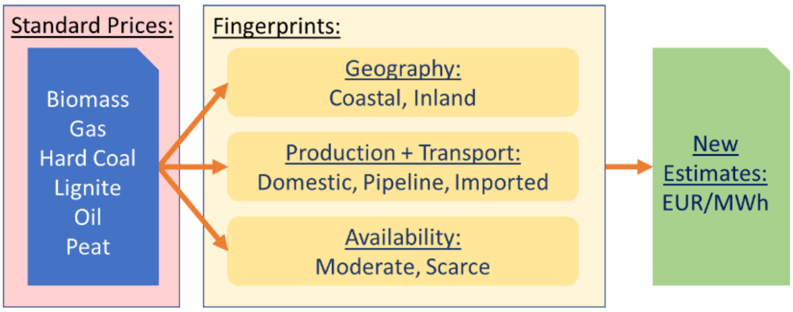

Figure 3 Fuel price estimation based on three fingerprint types: Geography, Fuel production and Availability.

2.6. RES Curtailment

In the context of this work, RES curtailment refers to the reduction of renewable generation due to grid constraints. The total curtailed energy and the maximum hourly curtailed energy are computed within this study to assess the flexibility of the proposed system. Excessive curtailed power is an indication of poorly optimized system with excess generation capacity and a lack of flexibility.

2.7. Shed load and Lost load

The amount of shed load highlights the adequacy of the system. It is defined as the demand of the system that must be reduced to match the available generation supply. Load shedding is used to prevent an imbalance and subsequent blackout of the system. A maximum value of the load shedding capacity is defined for each simulated country. This value might correspond to the load-shedding plans of the Transmission System Operator (TSO) or to the contracted sheddable load in large industries. In case load shedding does not allow to match generation and demand, an additional Lost Load (LL) relaxing variable is added to the market clearing equation. LL is given a very high price and ensures that no infeasibility occurs in the optimization problem. It should however never be activated (optimizations with LL > 0 are discarded). The total count of time intervals with non-null LL is recorded and compared between the different scenarios.

2.8. Shadow price

Shadow prices, expressed as EUR/MWh, are computed for each time step i, and for each zone n. The shadow price of electricity is the dual value of the energy balance equation. Similarly, the shadow price of heat is the dual value of heat balance equation.

2.9. Congestion

Congestion in the interconnection lines is computed as the number of congestion hours in each line and in each direction. For the sake of comparison, the normalized difference in number of hours is computed with respect to the baseline scenario.

2.10. Carbon emissions

In this study, carbon footprint is computed with standard emission factors of different fuel-types. It relates to emissions from power generation and operation of thermal units only (life cycle emissions are not considered) and is disaggregated per country.

3. SCENARIOS

In order to evaluate the potential flexibility originating from the water-energy nexus in the proposed African power pools, extreme scenarios are defined: a historic one representing the current state of the system and various 10 years-ahead scenarios corresponding to additional

NTC and capacity additions . In addition, special attention is paid to the capacity of the system to accommodate increased shares of VRES from the NAPP and hydro generation from CAPP and EAPP. In total, there are four scenarios, each including three subcases. One representing historical flows for the year 2015 and two alternative ones representing flows in the years closest to the 10 and 90 percentiles in terms of historical hydro generation. A summary of the proposed scenario definitions is presented in Table 1. A more detailed scenario descriptions are provided in the upcoming chapters.

Table 1 Scenario definitions and demand, infrastructure, and technology availability hypothesis.

Scenario definition										
Definitions		Demand		Infrastructure		Supply				
Scenarios	Cases	Electricity	Water Consumption	NTC	Pipelines	Hydro	Solar	Wind	Biofuels	Fosilfuels
REF (R)	H	+	++	+	+	+	+	+	+	+++
	W	+	+	+	+	+	+	+	+	+++
	D	+	++	+	+	+++	+	+	+	+
REF + NTC (RN)	H	+	++	+++	+	+	+	+	+	+++
	W	+	+	+++	+	+++	+	+	+	+++
	D	+	++	+++	+	+	+	+	+	+
TEMBA (T)	H	+++	++	+	++	+	++	++	++	+++
	W	+++	+	+	++	+	++	++	++	+++
	D	+++	+++	+	++	+++	++	++	++	+
TEMBA + NTC (TN)	H	+++	+++	+++	++	+	++	++	++	+++
	W	+++	+	+++	++	+	++	++	++	+++
	D	+++	+++	+++	++	+++	++	++	++	+
+ Low ++ Medium +++ High										

3.1. REF (R)

The REF scenario is the starting point of this analysis and is used for the calibration of the models. LISFLOOD river discharge rates used for power generation purposes are adjusted to match the historical capacity factors and generation, NTC availability is either limited to match historical cross border flows (where applicable) or allowed at full interconnector capacity. OF are also adjusted to limit the generation of certain technology-fuel pairs which would otherwise results in unrealistic over-generation, such as cheap GEO and BIO units. Furthermore, two additional subcases representing unusual years with either excessive rainfalls or prolonged droughts are investigated. A more detailed representation of the historical CF in each of the three power pools as computed by LISFLOOD model are presented in Figure 4.

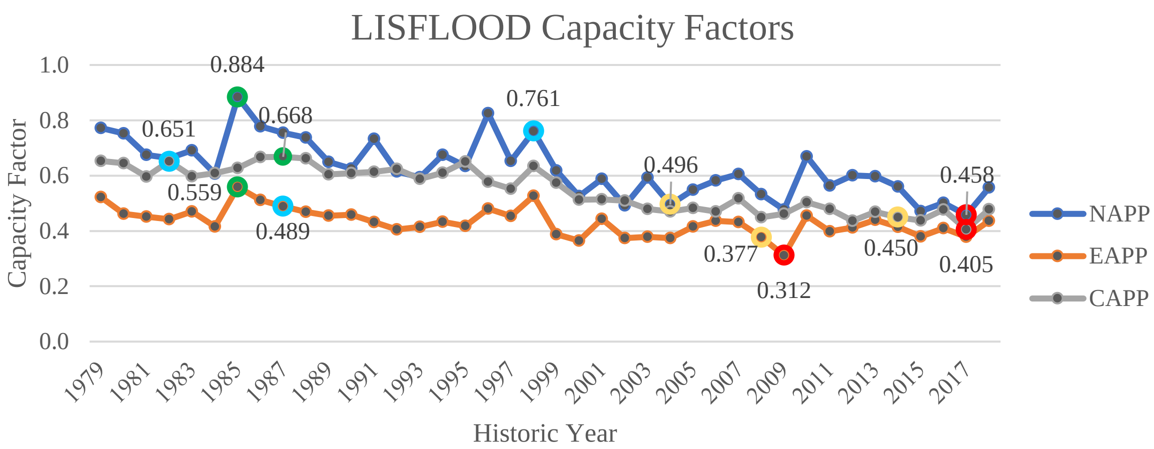

Figure 4 Historical CF for each power pool as computed by LISFLOOD model. Largest CF are computed in the 1980's while lowest from 2010 onward. Green circles stand for extremely wet and red circles stand for extremely dry years.

3.2. REF + NTC (RN)

In the REF + NTC scenario, all parameters from the REF scenario stay the same except NTC capacities. This scenario is a hypothetical scenario where, instead of investing in new generation capacities, all power pools are well interconnected (as proposed by multiple interconnection studies). In this scenario, cross-border flows are increased and the prices of electricity across the whole analysed area decrease and present a lower spread. Again, three cases representing historic year 2015, and two alternative ones are analysed.

3.3. TEMBA (T)

TEMBA scenario is the starting point of the technically more advanced systems, taking place ten years in the future from the previous two scenarios. Here, total demand and new capacity additions increase based on the projections by Taliotis et al. [4]. NTC capacities remain the same as in the REF scenario. The purpose of this analysis is to check what might happen if the energy systems are developed locally, without considering any new cross-border exchanges.

3.4. TEMBA + NTC (TN)

In the TEMBA + NTC scenario, capacities stay the same as in previous one, but cross-border infrastructure is well developed. This scenario is expected to be the most efficient, least carbon intensive and least costly from all four scenarios.

4. INPUTS

4.1. African Power Pools

There are five power pools in African continent. The major aim of these associations is to interconnect the electricity grids of the member countries in order to facilitate the trading of electric power between the members and take advantage of excess capacity within the network. This paper focuses on three of them: Central African Power Pool (CAPP), East African Power Pool (EAPP) and North African Power Pool (NAPP), also known as Comité Maghrébin de l'Electricité (COMELEC). A list of participating member states in each power pool is listed in Table 2. Since several countries are members of two or more power pools, and this study is carried out for all three power pools simultaneously, we decided that one country can only be member of one power pool. This way double counting of electricity generation is avoided and aggregate results for individual power pools are more intuitive.

Table 2 African power pools and participating member states.

Power Pool	Number of states	Member states (ISO-2 country code)
CAPP	8	Angola (AO)[6], Cameroon (CM), Central African Republic (CF), Republic of the Congo (CG), Chad (TD), Gabon (GA), Equatorial Guinea (GQ), Democratic Republic of the Congo (CD)[7]
EAPP	12	Burundi (BI), Djibouti (DJ), Ethiopia (ET), Eritrea (ER), Kenya (KE), Rwanda (RW), Somalia (SO), Sudan (SD), South Sudan (SS), Tanzania (TZ)[8], Uganda (UG)
NAPP	5	Algeria (DZ), Libya (LY), Egypt (EG) [9], Morocco (MA), Mauritania (MR), Tunisia (TN)

4.2. Fuel prices

A summary of fuel prices is presented in Figure 5. Variability of prices across zones and regions is based on the different fingerprints. Each variable increases or decreases default fuel price based on geographic location, local availability, and local fuel supply. Due to specific nature of VRES, geothermal and hydro units their marginal price is assumed to be zero.

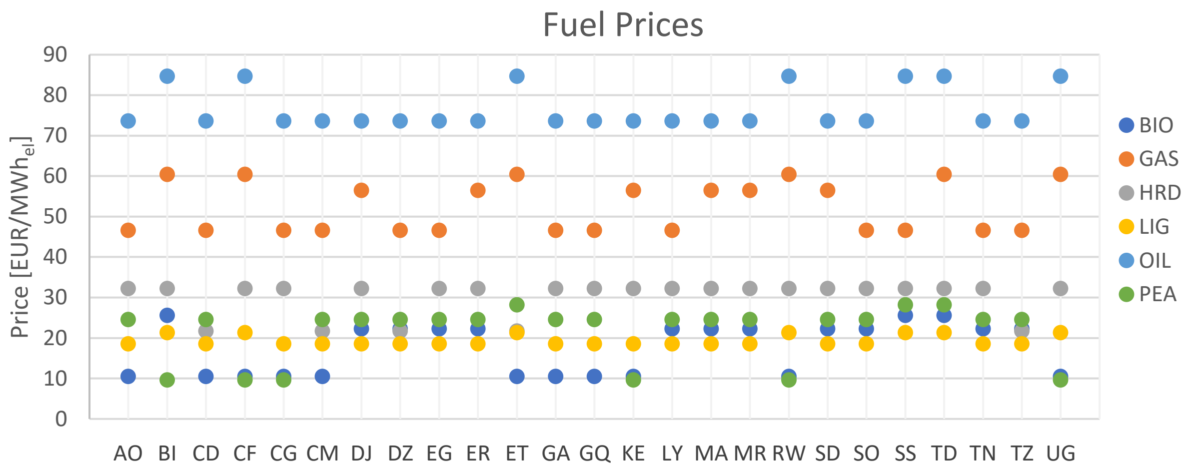

Figure 5 Fuel prices in different zones. Variability is based on the proposed price modification fingerprints. Fuel prices are estimated based on methodology used within the ECOWAS study [11].

4.3. Demands

Due to lack of data for most African countries, hourly demand profiles are estimated based on available historic data, as proposed by De Felice et al [3] . It is worthwhile to note that demand profiles in most CAPP and EAPP member states are based on energy profile of Ghana (provided by IRENA), while the demand profiles of NAPP member states are modelled individual, as provided inthe BETTER[10] project.

[6] Angola is participating in two power pools, namely CAPP and South African Power Pool (SAPP). In this study AO is member of CAPP.
[7] Due to its huge size, Democratic Republic of the Congo is member of three power pools, namely CAPP and EAPP as well as SAPP, which is not part of this study. In this study CD is only member of CAPP.
[8] Tanzania is transitioning country between EAPP and SAPP. In this study TZ is member state of EAPP
[9] Egypt belongs to NAPP and EAPP. In this study EG is part of NAPP.
[10] Deliverable 3.2.1 “Demand Development Scenarios”: https://www.ec-better.eu/pages/better-project

4.4. Supply

Capacity mix on the supply side varies significantly between the power pools, as shown in Figure 6. Capacity wise, NAPP is the largest of the three power pools. It is mostly dominated by fossil fuels, especially oil and gas, whose combined capacity sums up to more than 90%. CAPP on the other hand is the smallest power pool and it mostly relies on hydro and oil. EAPP is particularly interesting due to the most diversified capacity mix. Both EAPP and CAPP heavily rely on RES whose total capacity sums up to more than 60%. A detailed table of installed capacities by country and by power pools is presented in

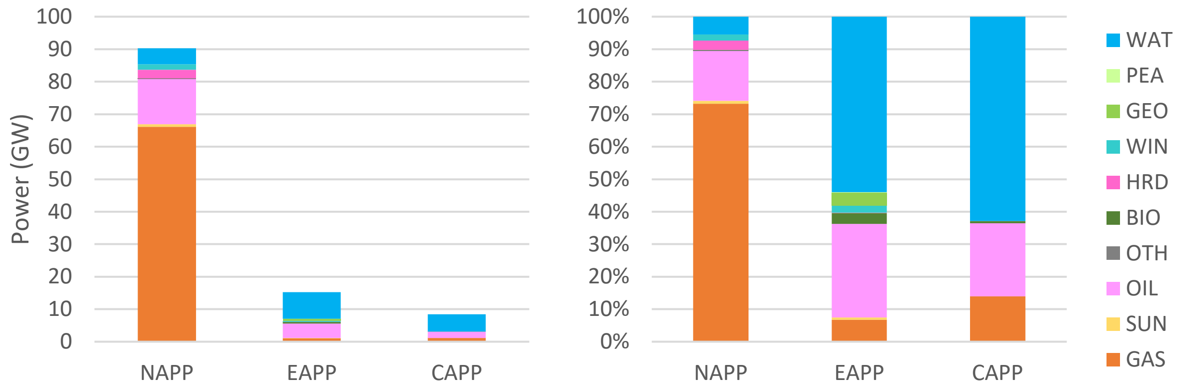

Figure 6 Capacity mix in all three power pools according to S&P Global PLATTS database[11]. Total installed capacity used in RES and RES + NTC scenarios is presented on the left. Share of individual fuel types is shown on the right.

Hydro units

Hydro units are dominant technology in the equatorial region. The main reason for such a high hydro availability comes from the Congo river (second largest river in the world with average annual discharge rate of 41 200 m^3/s) and the Nile river (longest African river with average annual discharge rate of 2 830 m^3/s) basins as well as the great lakes (total hydro potential is estimated to 549 218 GWh[12]). A visual summary of the three main HDAM parameters, such as nominal head, storage capacity and installed power, are presented in Figure 7. Five of seven largest units are located in EAPP, while rest of units are scattered across all three power pools. Hydro is rather scarce resource in the NAPP. Total installed hydro capacity sums up to 4 904 MW, of which more than 75% is located in Egypt. The total available hydro capacity in countries Tunis and Algeria is limited to only several MW, mainly due to water shortages and reservoir leakages in multi-purpose (drinking water, power generation and irrigation) reservoirs. Technical parameters of hydro units are presented in Table 3.

Table 3 Technical and cost parameters of hydro units [12–14].

Fuel	Technology	Efficiency	Min Up Time	Min Down Time	Ramp Rate	Start Up Cost	No Load Cost	Ramping Cost	Part Load Min	Start Up Time	CO_2 Intensity
WAT	HDAM	0.80	0	0	0.067	0	0	0	0	0	0

[11] https://www.spglobal.com/platts/en/products-services/electric-power/world-electric-power-plants-database
[12] Estimated by the World Bank, IEA, World Energy Outlook, Hydropower & Dams World Atlas 2016: https://www.andritz.com/hydro-en/hydronews/hydropower-africa/east-africa

WAT	**HROR**	1	0	0	0.067	0	0	0	0	0	0

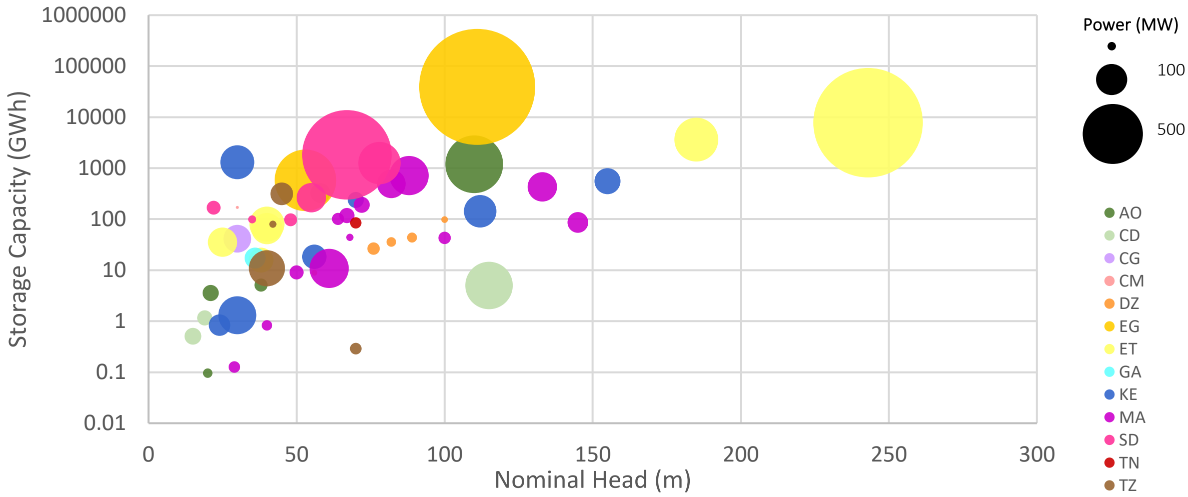

Figure 7 Semi logarithmic three parameter diagram of HDAM units in the proposed power pools. Bubble size indicates the installed capacities, while colour code indicates the location.

Thermal units

Total installed capacity of thermal units in all three power pools combined amounts to more than 80% of total installed capacity. Gas, with total of 68 GW, is the dominant technology, it is followed by 20 GW of oil derivates such as (LFO, diesel, crude oil, gasoline etc.) and 3 GW of hard coal units. Combined capacity of other thermal units amounts to les then 2 GW. Due to lack of data, each technology – fuel pair was assigned same typical values as proposed in the Dispa-SET Balkans study [12]. Shor summary of technical and economical parameters of typical units is presented in
Table 4.

Table 4 Technical and costs parameters for typical power generation units [12–14]

Fuel	Technology	Efficiency	Min Up Time	Min Down Time	Ramp Rate	Start Up Cost	No Load Cost	Ramping Cost	Part Load Min	Start Up Time	CO_2 Intensity
BIO	**STUR**	0.40	4	6	0.020	120	12.5	1.30	0.4	1	0.42
BIO	**GTUR**	0.33	1	1	0.167	25	2.9	0.25	0.2	0.167	0.32
BIO	**COMC**	0.51	3	3	0.070	55	2.9	0.25	0.06	1	0.22
BIO	**ICEN**	0.36	1	1	0.040	24	0	0.63	0.25	1	0.27
GAS	**COMC**	0.51	3	3	0.070	55	2.9	0.25	0.06	1	0.36
GAS	**GTUR**	0.33	1	1	0.167	25	2.9	0.25	0.2	0.167	0.68
GAS	**STUR**	0.37	1	1	0.020	25	2.9	0.25	0.4	0.167	0.53
GAS	**ICEN**	0.36	0	0	1	0	0	0	0.3	0	0.01
GEO	**STUR**	0.10	2	2	0.020	0	0	0	0	0	0
HRD	**STUR**	0.42	6	6	0.040	65	12.5	1.80	0.18	2	0.47
LIG	**STUR**	0.40	8	8	0.008	65	8	2.20	0.43	7	1.15
OIL	**STUR**	0.33	5	5	0.020	120	0	1.80	0.4	1	0.73
OIL	**GTUR**	0.33	0	0	0.167	0	0	0	0.2	0.167	1.08

OTH	**STUR**	0.33	0	0	0.167	0	0	0	0.2	0.167	0.80

RES units

Although, VRES potential across Africa is one of the largest in the world, the current deployment remains limited. Total installed VRES (excluding hydro) capacity is insignificant. Across all three power pools, it amounts to 4 GW, which is only 3.68% of total installed capacity. A graphical summary of the overall potential is presented in Figure 8. Supplementary tables containing detailed data about the total usable VRES potential is provided in Table 7 and Table 8 located in the annex of this paper. Wind CF is based on the normalized power curves as proposed by King et al. [15], while PV and CSP are estimated according to IEA method [16].

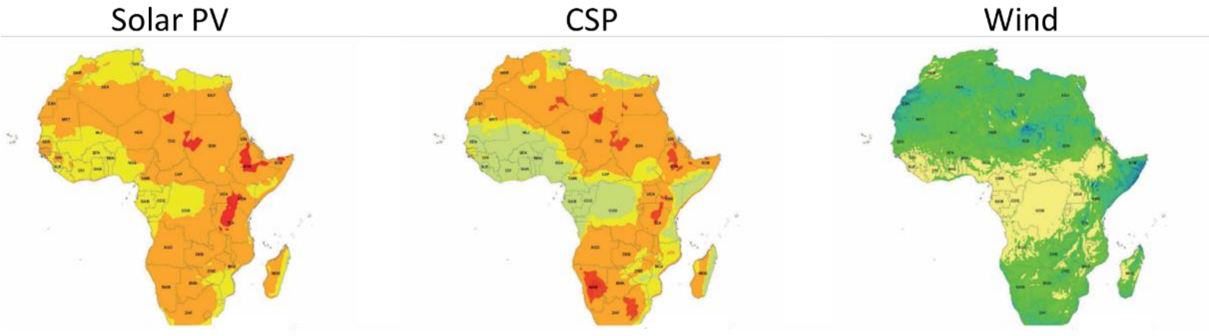

Figure 8 Overall resource potential for PV, CSP and wind technologies (figure taken from [17]).

4.5. Cross-border interconnections

A summary of existing and planned additions of NTC capacities in the analysed power pools is presented in Figure 9. In this analysis, the availability of NTC capacities stays the same throughout the year (seasonal variabilities are, due to the lack of data, out of the scope of this paper). Historic NTC from 2017 are rather small compared to the planned ones. Thus this analysis investigates both options as the two boundary conditions.

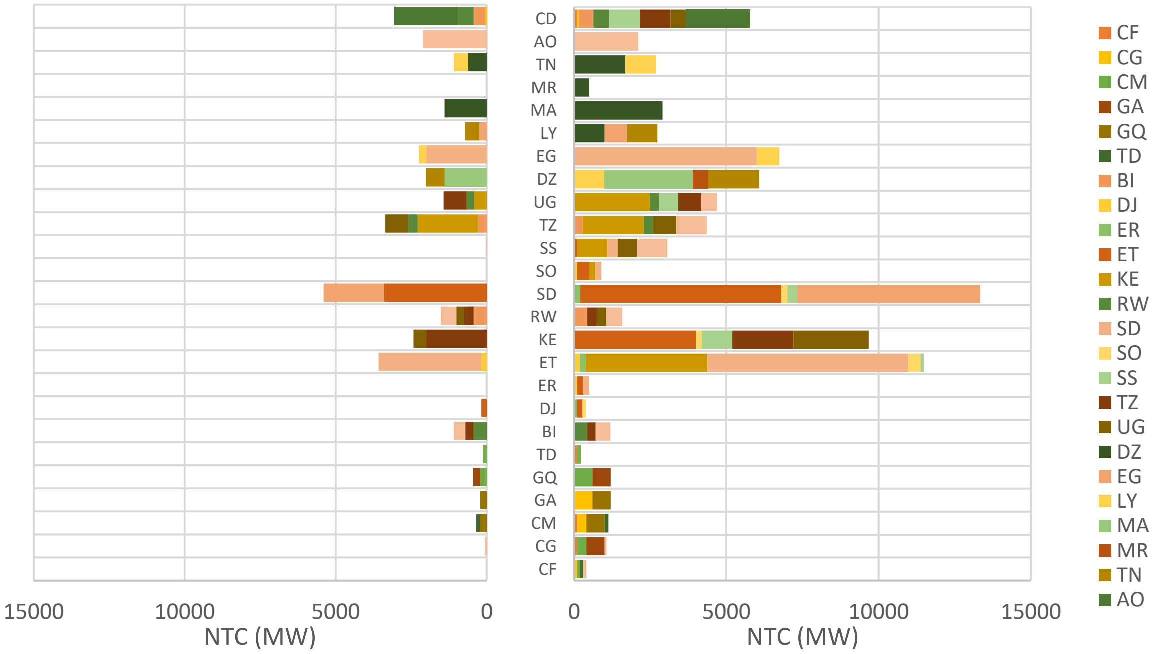

Figure 9 Cross border transfer capacities. Left diagram represents historical NTC's from 2017. Right diagram represents all projects planned for the near future.

4.6. Soft linking with TEMBA

One goal of this work is to assess the flexibility potential in future energy system characterized by relatively high penetration of variable renewable energy. To that aim, a long term planning model (TEMBA) is firstly run until year 2025 and beyond with a certain target for CO2 emissions (Reference scenario). The simulated 2025 energy system is then used as input for the low spatial and high time-resolution Dispa-SET model.

The selected long-term objectives include an energy related CO2 emission reduction target. More details regarding the inputs and constraints of the simulated TEMBA-Reference scenario are available in [8]. Uni-directional soft-linking between TEMBA model and the Dispa-SET model is done through several intersecting variables:

- Total annual demands per country: power and water
- Total installed capacities per country: RES, Conventional, hydro and CSP units

These variables are used within a "Translation model" to generate realistic Dispa-SET inputs, such as scaled time series for all types of demands or realistic power plant fleet according to the projected capacities. Other parameters such as renewable availability factors (AF) (a non-dimensional timeseries), river inflows are assumed unchanged from their historically computed values from LISFLOOD model. Re-forecasting of AF due to technological advancements, climate change, wake effects etc. are out of the scope of this paper. Total installed capacities as computed by TEMBA are presented in Figure 10.

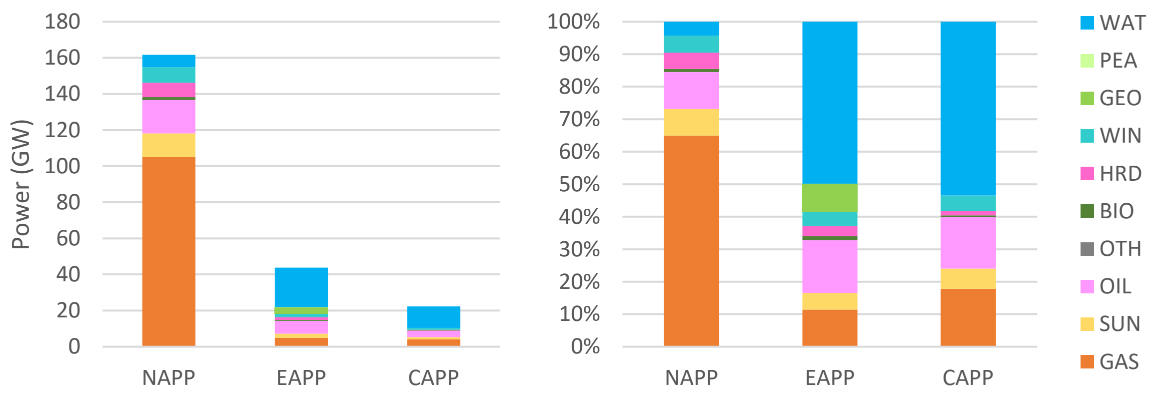

Figure 10 Total installed capacity used in TEMBA and TEMBA + NTC scenarios is presented on the left. Share of individual fuel types is shown on the right.

5. RESULTS AND DISCUSSION

A summary of important results such as simulation time, memory usage, total system costs and average generation costs is presented in Table 5. A more detailed description regarding the model formulations in the Dispa-SET model is available in [18]. For this study, a "per typical unit" formulation was used. The resulting total number of units in reference scenarios was reduced from 816 historic units to 156 typical units and from 206 historical plus TEMBA additions to 206 typical units with same characteristics. From computational point of view, scenarios with more interconnection capacities took on average 5.1% longer to solve in reference and 11.9% in the TEMBA scenarios. Average total system costs in scenarios with fully interlinked grids are lower than in the historical networks. The total system costs in the TEMBA scenarios is 47.7% lower with historical grids and 51.8% lower with more interlinked network.

Table 5 Summary of simulation results

Average Results from all three cases				
Scenarios	Simulation time [hh:mm:ss]	Total system cost [10^9 EUR]	Average generation cost [EUR/MWh]	Total number of units
R	01:27:59	44.51	105.39	156 (816)
RN	01:32:44	44.01	104.22	156 (816)
T	02:24:02	26.67	55.08	206 (941)
TN	02:43:35	24.33	50.24	206 (941)

5.1. Total System Costs and Shadow Prices

A more detailed cost breakdown is presented in Figure 11. As expected, increased share of zero marginal cost units (units powered by VRES, HDAM's and CSP) positively impacts the total system costs. Main reason for this is the increased share of zero marginal cost units. Furthermore, well interlinked electricity grid does enable even higher integration of VRES, which significantly increases the energy flows from VRES abundant to VRES scarce regions where lack of total installed capacity also causes implementation of load shedding. This is also visible in hourly shadow prices across the power pools. A summary of hourly shadow prices in all zones is presented in Figure 12.

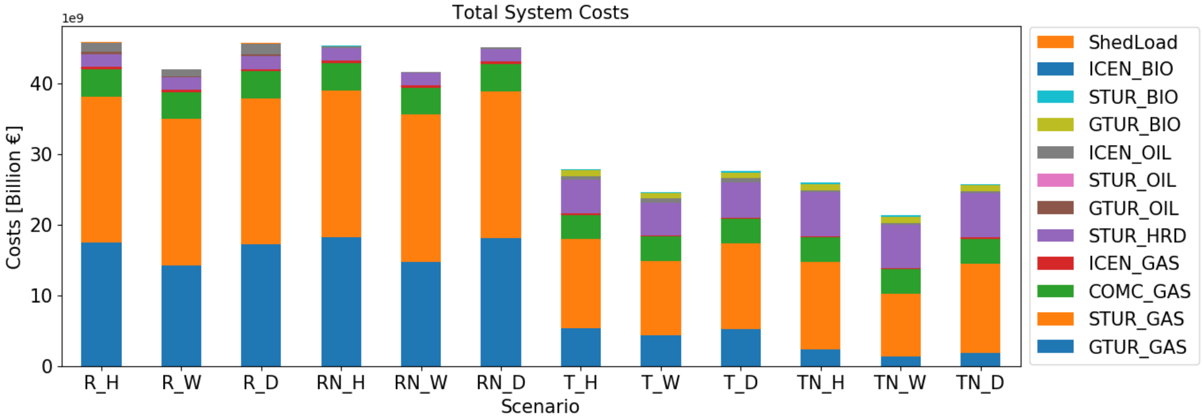

Figure 11 Costs breakdown in all twelve cases and scenarios. Variable fuel costs are presented per fuel and per technology type and other costs represent shed load.

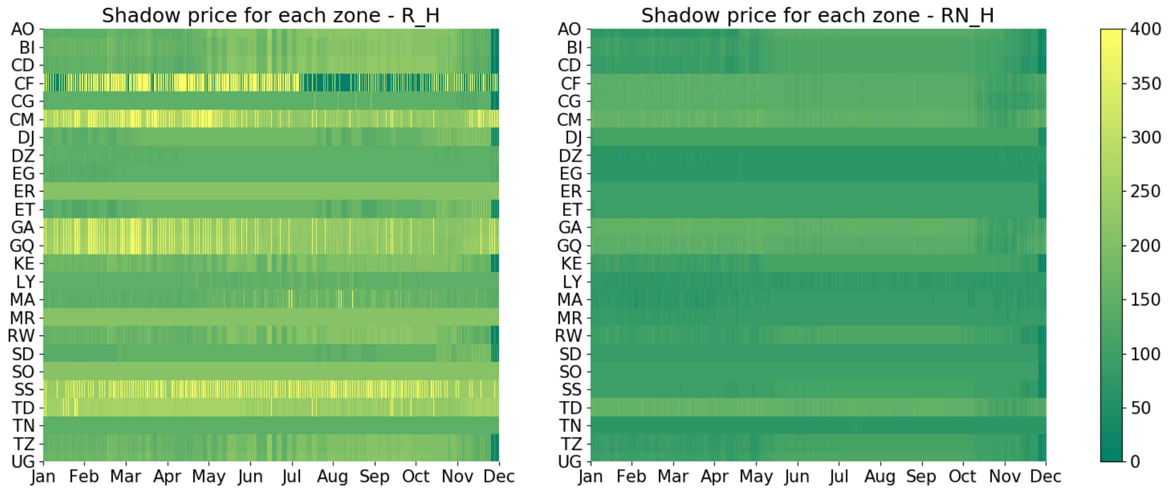

Figure 12 Heat map of computed shadow prices on hourly scale in each of the 25 countries. Values on the legend indicate shadow prices in EUR/MWh, green colours represent variable dispatch costs, yellow stands for shed load.

5.2. Generation

Energy output of hydro units is presented in Figure 13. Due to data availability, the model was calibrated to match historical outputs for the year 2015. That particular year was extremely dry year across all five power pools, resulting in relatively low hydro generation when compared to the average hydro potential. Despite that, model was successfully calibrated and hydro generation in all countries was within the acceptable error margin. It is important to note that hydro generation can vary significantly between different years and power pools. Overall, EAPP has the most stable hydro generation.

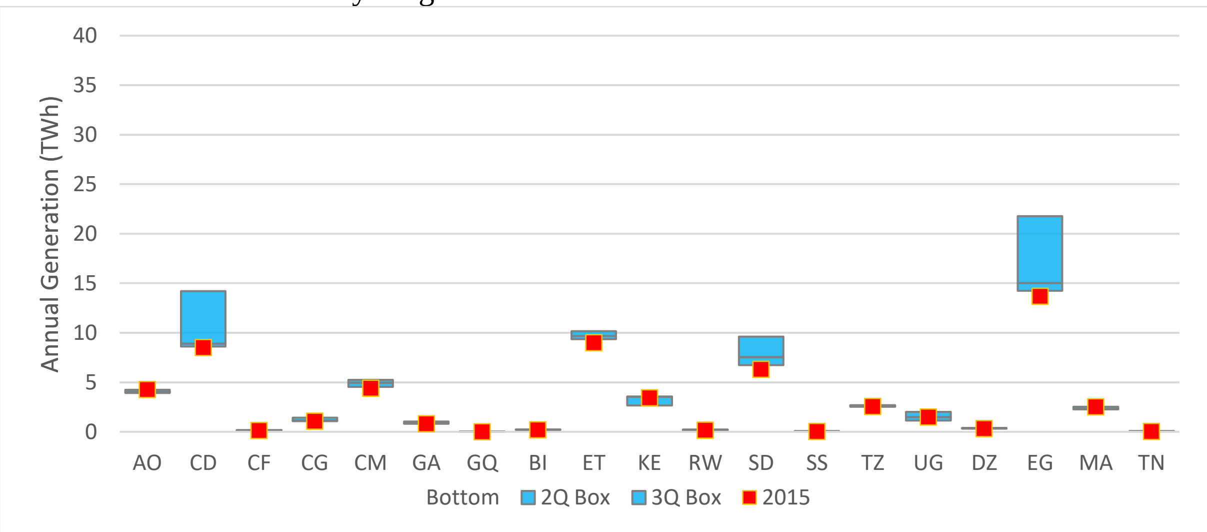

Figure 13 Simulated annual hydro-power generation in the three power pools. Red cross indicates the historical flows for the year 2015 as reported in IHA annual report 2016 [19]. In this analysis only R scenarios are included.

The energy output of thermal units is presented in Figure 14. Because of the limited data availability, deviations between historical and simulated thermal generation are present, especially in countries belonging to the EAPP. the main reason for this is a sub-optimal dispatch of local generation fleet and limited usage of the NTCs. In reality, local dispatch is influenced by power plants and interconnection lines outages (e.g. due to political decisions, extreme weather conditions or inappropríoate infrastructure), which could not be taken into account. The present analysis demonstrates that the historical dispatch is sub-optimal, especially in the countries with the lowest GDP per capita.

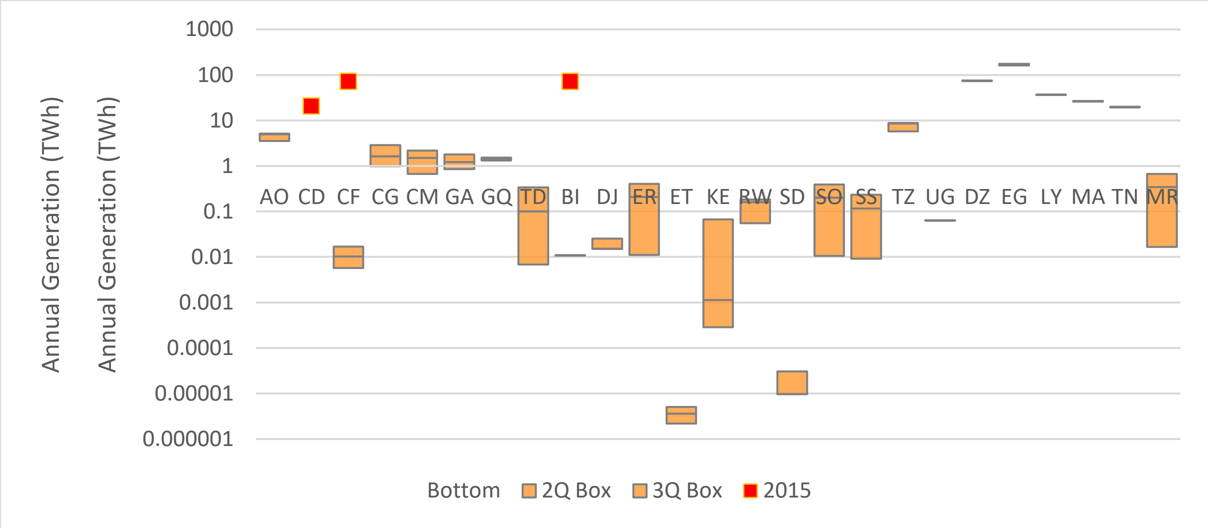

Figure 14 Simulated annual thermal-power generation in the three power pools. Red cross indicates the historical generation for the year 2015 as reported by AFREC-Energy [20]. In this analysis only R scenarios are included.

5.3. Curtailment

This analysis points out that, in current system configuration, a small fraction of the total VRES production needs to be curtailed. Maximum curtailment in R scenarios is around 6.68%, mostly in isolated countries with no cross border interconnections such Central African Republic. In both TEMBA scenarios, the maximum curtailment stays on the same level as in R scenario, despite significant increase of additional VRES capacities. Total annual and peaking curtailment in terms of total installed VRES capacity across all three power pools are presented in Figure 15.

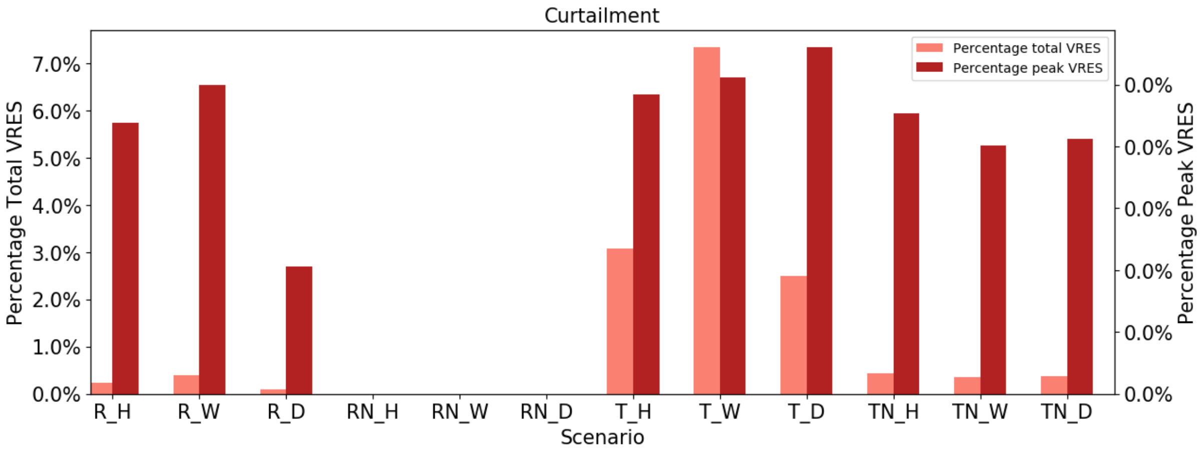

Figure 15 Total annual and maximum aggregated hourly curtailment as percentage of total and peak generation from VRES in all scenarios

5.4. Load shedding

Lack of adequate power infrastructure, both on supply and demand side lead to unreliable grid operation in several African countries. Central African Republic and South Sudan, two isolated countries still recovering from the ongoing civil unrests and recent wars, experience system outages on average for more than 10 hours per day [21]. Similar problems occur throughout the continent. In this analysis, highest load shedding was observed in the CAPP and EAPP. No outages were recorded in NAPP, mostly due to relatively stable overall energy system. Total annual and peaking load shedding in terms of total demand across all power pools is shown in Figure 16. Two such examples where the mismatch between available generation capacity and local demand are clearly visible, especially throughout the evening hours is presented in Figure 17.

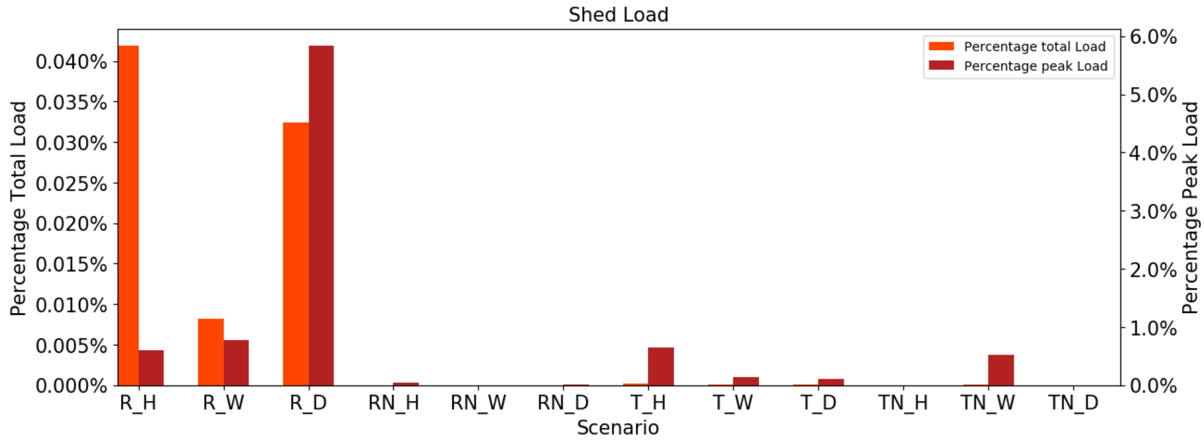

Figure 16 Total annual and maximum hourly shed load in all scenarios as a percentage of total and peak load.

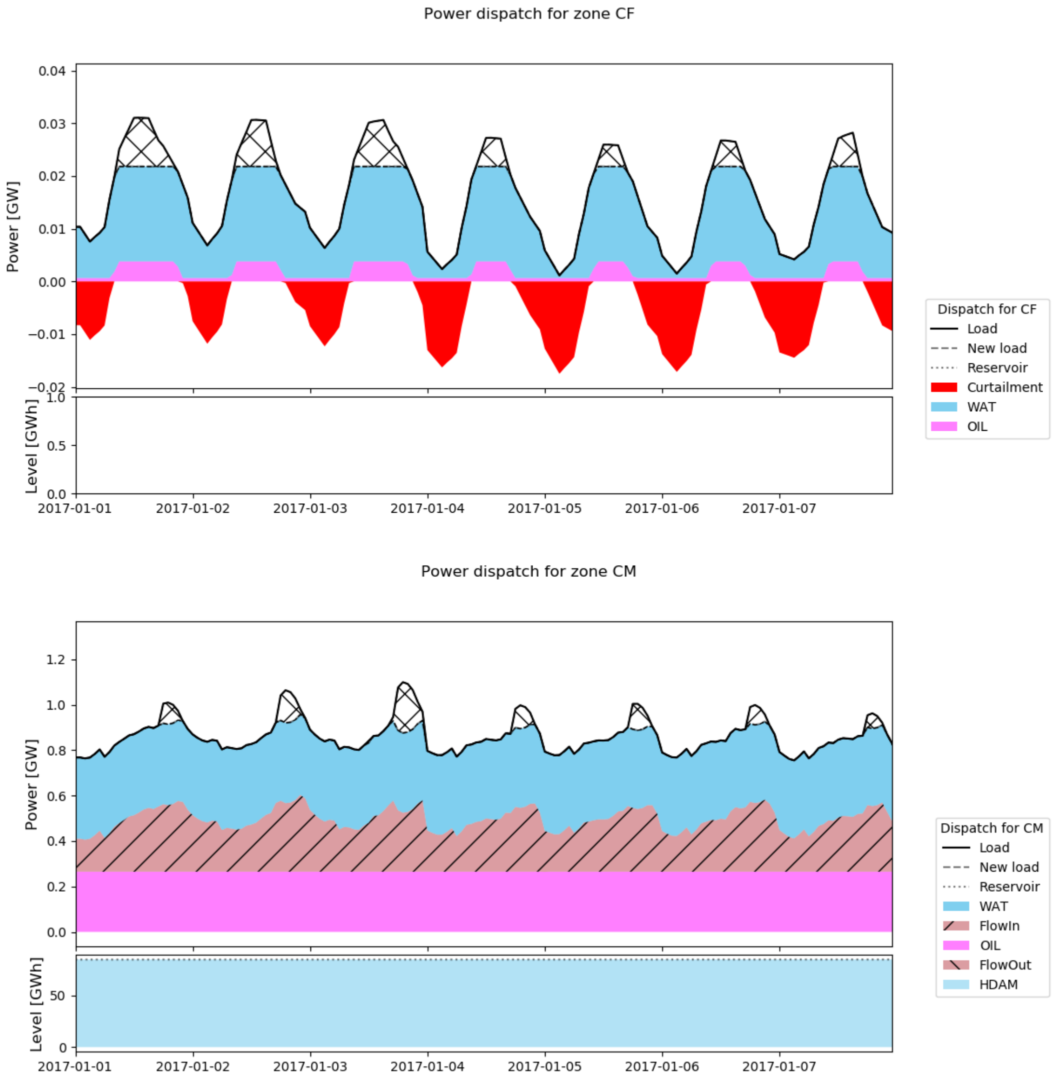

Figure 17 Dispatch plot for Central African Republic and Cameroon for the first week of January. On top diagram mismatch between available generation capacity and local demand is clearly visible, especially throughout the night hours. On the bottom diagram lack of total installed capacity does not allow covering of the peek demands, despite full utilization of the NTC.

5.5. Environmental Impact

A summary of operational carbon emissions from thermal all units is finally presented in Figure 18 for each of the four scenarios and accompanying sensitivity cases. There is a clear downwards trend in carbon emissions in years with particularly long wet seasons (scenarios with xy_W extension) and full grid availability (scenarios with the extension xN_z). Nevertheless, water availability still contributes more to the total carbon emissions. NAPP is the most fossil relying among the three analysed power pools. The total emissions from NAPP sum up to more than 90% of total emissions from all three power pools. 87,2% of total emissions in reference scenarios come from gas units. In TEMBA runs, several countries are expected to build additional coal capacities. Thus, the total carbon emissions are divided between those two fuels. Despite oil abundance across all Saharan countries, relatively high oil price almost entirely prevents dispatch of oil units.

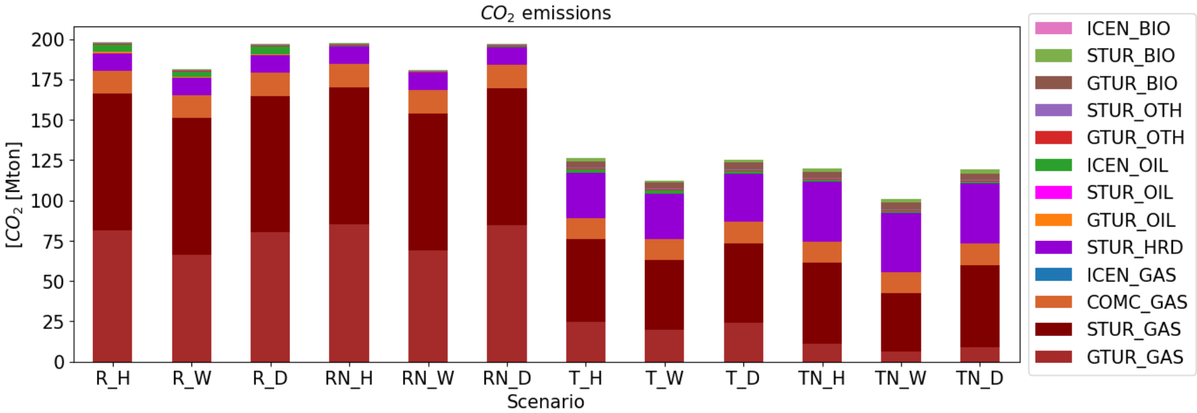

Figure 18 Summary of carbon emissions grouped per fuel and per technology type in all scenarios.

6. CONCLUSION

The work presents indicative coherent national, regional and sub-continental energy system analysis for several African scenarios, one historic and three alternatives. Continuing current trends and assuming perfect market conditions, capacity additions of between 573–589 GW are anticipated. Significant efficiency gains can be achieved by utilizing existing NTCs and increasing trade between the zones. This strongly depends on assumptions relating to fossil fuel prices, the degree of interconnection allowed and seasonal hydro availability.

It is important to note that the goal of this paper is to provide the upper and lower boundaries for the flexibility potential of hydro sector, and not to simulate an in-between and more realistic, but highly uncertain scenario. All the proposed models, methods, and data are released with an open license to ensures transparency and reproducibility of the work; they can be freely downloaded[13].

Simulation results indicate that power sector is strongly dependent on the availability of the water resources in the proposed region. The analysis further shows that simultaneous integration and new VRES capacity addition can reduce the potential carbon emissions by more than 30% compared to the reference scenario where flexibility provided by hydro units is limited. Furthermore, congestion in the proposed interconnection lines might cause serious VRES curtailment by limiting the energy flows from southern, hydro abundant, countries. Furthermore, variation between unusually wet and unusually dry years significantly impacts final energy mix and thus the total operational costs of the systems and carbon emissions.

[13] https://github.com/energy-modelling-toolkit/Dispa-SET

As the primary energy generation from thermal units in future low carbon scenarios is significantly lower, lack of flexibility and load shifting options can lead to curtailment in time periods with high availability and load shedding in time periods with low renewable availability. Despite this, excess capacity in the NAPP combined with the well developed transmission network is sufficient to cover all potential mismatches between the supply and demand side in the EAPP and CAPP and vice versa.

Finally, results suggest that long term planning models such as TEMBA - OSeMOSYS can be complemented by a more detailed dispatch model to ensure feasibility of the proposed scenarios. This uni-directional soft linking between long term planning and short term power dispatch models is the main limitation of this study. Further steps of this work would include a bi-directional soft linking between the Dispa-SET and TEMBA models, which would provide a more insightful and comprehensive projections for the analysed power pools.

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8. Annex A

Table 6 Installed capacity in each of the analysed countries within the three power pools.

Power Pool	Zone	SUN	BIO	GAS	GEO	HRD	OIL	PEA	WAT	WIN
CAPP	AO		51	591			1,087		1,374	
	CD								2,561	
	CF						5.1		18	
	CG		8.5	352			70		194	
	CM						302		743	
	GA			92			204		286	
	GQ			146			37		120	
	TD	0.0					185			
EAPP	BI						5.5		26	
	DJ						85			
	ER						175			
	ET	0.2	120		8.5		154		4,073	324
	KE	55	28	0.2	617		976		961	5.4
	RW	12		30			57	15	141	
	SD	0.1	244				2,137		1,731	
	SO		0.8				101			
	SS	18					32		5	
	TZ	0.0	48	997		16	402		566	
	UG	20	63				274		730	
NAPP	DZ	315		16,881			1,455		237	
	EG	52	67	40,955			2,659		2,842	883
	LY			4,364			5,161			
	MA	360		856		2,575	2,344		1,534	626
	MR	15					345			30
	TN			3,077			1,983		49	208

Table 7 Areas associated with different suitability classes (Wind). Areas restricted to 10-200 km around urban centres. Wind (Potential Categories): Yearly Wind Speed Average [m/s] as proposed by Hermann et al. [17].

$PR_{WIN} = 1$		Economically viable area [km^2]						
Power Pool	Zone	5-6 [m/s]	6-7 [m/s]	7-8 [m/s]	8-9 [m/s]	9-10 [m/s]	10-11 [m/s]	$\acute{x}_{WIN}$ [-]
CAPP	AO	5,163						0.149
	CM	23,424	1,133					0.153
	CF	2,013						0.149
	TD	79,055	66,968	23,846	5,407	1,107		0.237
	CG							0
	CD	51,402	2,943					0.154
	GQ							0
	GA							0
EAPP	BI							0
	DJ	8,656	5,108	4,140	98			0.235
	ER	38,524	20,155	6,641	392			0.207

	ET	72,442	72,662	99,912	7,294	321		0.286
	KE	120,110	192,618	78,964	7,375	4,490	1,202	0.261
	RW							0
	SO	27,493	122,616	264,747	153,725	29,664		0.413
	SD	571,245	490,354	154,814	6,242			0.222
	TZ	237,481	107,172	35,021	7,042			0.206
	UG	10,549	5,468	1,312				0.199
	SS							0.286
NAPP	DZ	512,395	169,539	8,449				0.177
	EG	303,703	399,362	31,552				0.215
	LY	26,913	289,631	58,446	836			0.266
	MR	1,551	114,047	66,306	5,994	135		0.309
	MA	139,847	43,254	28,348	13,887	1,363		0.227
	TN	47,780	72,403	12,475				0.227
	$x_{WIN,i}$ [-]	0.149	0.251	0.388	0.565	0.762	0.914	

Table 8 Areas associated with different suitability classes (PV). PV (Potential Categories) Global Horizontal Irradiation [kWh/m2/year) as proposed by Hermann et al. [17].

$PR_{SUN} = 0.75$		Economically viable area [km²]			
Power Pool	Zone	1500 – 2000 [kWh/m²/a]	2000 – 2500 [kWh/m²/a]	2500 – 3000 [kWh/m²/a]	$\acute{x}_{SUN}$ [-]
CAPP	AO	70,958	240,784		0.170
	CM	135,617	119,076		0.157
	CF	4,315	114,061		0.178
	TD		233,472		0.180
	CG	193,020	505		0.137
	CD	133,049	404,565		0.169
	GQ	20,159			0.137
	GA	153,793	419		0.137
EAPP	BI		19,737		0.180
	DJ		21,036		0.180
	ER		106,110		0.180
	ET	12,883	588,252	4,216	0.179
	KE	66,369	451,266	7,565	0.175
	RW		19,824		0.180
	SO	155,202	450,114		0.169
	SD	24,504	1,932,441		0.179
	TZ	5,501	845,122	10,570	0.180
	UG		210,450		0.180
NAPP	DZ	570,894	176,064		0.147
	EG	206,412	555,423		0.168
	LY	293,308	82,519		0.146
	MR	53,252	136,134		0.168
	MA	148,136	221,572		0.163
	TN	132,712			0.137