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# Energy projections for African countries

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# Contents

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# Abstract

This report provides insights on energy supply and demand, power generation, investments and total system costs, water consumption and withdrawal by the energy sector as well as carbon dioxide emissions for the African continent.

The energy supply systems of forty-seven African countries are modelled individually and connected via gas and electricity trade links to identify the cost-optimal solution to satisfy each country's total final energy demand for the period 2015-2065. In this analysis, The Electricity Model Base for Africa (TEMBA) was extended to include a simple representation of the full energy system. It was also updated to include new data. Simulations were run using the medium- to long-term Open Source Energy Modelling System tool (OSeMOSYS). The TEMBA model produces aggregate results for the whole continental energy system and more detailed ones for the power system of each African country.

The scenarios examined in this study consider different emission trajectories and technology availability. The Reference scenario considers the national energy policies that were in place until 2017, whereas the 2.0°C and 1.5°C scenarios examine emission levels aligned with the climate targets agreed under the United Nations Framework Convention on Climate Change (UNFCCC) Paris Agreement. The scenarios have been aligned with the "Global Energy and Climate Outlook 2018: Greenhouse gas emissions and energy balances" report of the Joint Research Centre (Keramidas et al., 2018). The results demonstrate that power generation capacity will need to increase 10-fold from 2015 to 2065 to meet projected electricity demands. A significant proportion of this capacity will likely consist of renewable energy sources, particularly under the 2.0°C and 1.5°C scenarios, as technology costs fall. On the contrary, there will only be little investment for new coal generation. In addition, a number of African countries will invest in nuclear power plants and CCS technologies (biomass, coal, gas) in the future in order to achieve the emission targets set in the 2.0°C and 1.5°C scenarios.

The results also indicate how water demand from the energy sector could evolve. Under the Reference scenario, it is estimated that by 2065 the African energy system will contribute to a water withdrawal of approximately 4% of the total renewable water resources (TRWR) in Africa (3,950 bcm) (FAO - Food and Agriculture Organization of the United Nations, n.d.). On the one hand, this share appears meagre, but in reality, this number must be analysed in the perspective of the nexus between water for food, energy, household and productive uses. Most of the thermal power infrastructure is not located in remote places and is rather near to population centres. This creates an added complexity to future infrastructure planning. On the other hand, water withdrawals are expected to decrease to 1.2% and 1.6% of TRWR in the 2.0°C and 1.5°C scenarios respectively by 2065 owing to deep decarbonisation of the energy sector.

## Key conclusions

This report summarises results from three scenarios for the African countries at a national, regional and continental level. The scenarios consider the development of energy technologies, the role of existing policies as well as the emission reduction targets to achieve temperature targets agreed under the United Nations Framework Convention on Climate Change (UNFCCC) Paris Agreement. These scenarios are then analysed using an extended and updated version of the TEMBA model. Such scenarios present plausible future evolutions of the African energy systems. The results and conclusions are descriptive rather than prescriptive. The selected scenarios on a continental level are shown in Annex 1. The main messages from the scenarios are the following:

- To meet the projected increase in final electricity demand, a 10-fold increase in generation capacity is required to 2065
- Renewables play a significant role in electricity generation in the scenarios, with solar PV, wind, large hydro plants and geothermal particularly evident in the results
- There is low or no role for coal-fired power stations under the 2.0°C and 1.5°C scenarios, which is consistent with meeting agreed international targets
- In order to achieve the emission limits under the 2.0°C and 1.5°C scenarios a number of African countries will invest in nuclear power plants during the upcoming decades as well as in CCS technologies (biomass, coal, gas)
- In total, approximately 5.9 trillion USD of capital investments will be required in Africa during the period 2015-2065 (Reference scenario) to cover the projected energy needs
- Under the 2.0°C and 1.5°C scenarios, approximately 1000 GW of solar PV will be installed in African countries by 2065. These would require around 1 million hectares of land or 0.03% of the African continent
- The use of large quantities of solar PV creates opportunities for reducing energy-related water consumption
- In the Reference scenario, the total primary energy supply (TPES) will increase from approximately 810 Mtoe in 2015 to 1920 Mtoe in 2065. On the supply side, biomass remains the most important fuel until 2050, followed by oil and coal. However, afterwards, oil products constitute most of Africa's TPES followed by coal and biomass
- Under the 2.0°C scenario, biomass is the main fuel throughout the modelling period, followed by renewables (solar, wind, geothermal) and nuclear for the period 2050-2065. The 1.5°C scenario follows a similar trend in the primary energy supply. The main difference with respect to the 2.0°C scenario is the increased penetration of nuclear which is expected to overpass renewables' supply (solar, wind, geothermal) in the period 2060-2065
- here are strategic electricity trade implications under the 2.0°C and 1.5°C scenarios for the different countries, particularly those with large renewable resources, or those that border a large generator and a demand country. For example, the Grand Inga project could enable imports of low carbon electricity to displace local generation for the surrounding countries
- Overall water consumption in the fossil fuel-intensive Reference scenario is twice that of the 2.0°C and 1.5°C scenarios due to the water-intensive nature of the cooling systems of thermal station. In the Reference scenario by 2065, the African energy system alone will contribute to a water withdrawal of ~4% of the total renewable water resource (TRWR) in Africa which amounts to in 3,950 bcm every year (FAO - Food and Agriculture Organization of the United Nations, n.d.). This share is significantly lower, 1.2% and 1.6%, respectively, under the 2.0°C and 1.5°C scenarios due to the radical decarbonisation of the energy sector
- There are important trade-offs between technologies, competing objectives and countries. Indicatively:
    - Nuclear power provides low carbon baseload capacity, yet it increases water consumption
    - Investment in large-scale low-carbon renewable generation affects geopolitics:
        - Relatively large hydro investments require energy trade, as domestic demand is often low. For importing countries, that implies access to large quantities of low-cost energy

supplies. However, that will be at the expense of being able to meet their demands independently by utilising indigenous energy sources

  - While there is a high potential for exports of natural gas and electricity to Europe (and worldwide), the combination of relatively low international prices used in this study and high African demand limits potential trade options
  - Investment in renewable energy technologies (RET) will change the financial structure of energy investment in Africa to one that will require more capital and lower operation (fuel) costs. That has implications for securing finance and the repayment thereof

- Electricity trade from interconnection projects allows African countries to bring forward or delay investments in capacity additions, through the provision of new markets for the electricity
- Similarly, gas trade in hubs around reserves appears to play an important role in the energy development of neighbouring countries
- Carbon capture and storage (CCS) plays a critical role in deep decarbonisation if fuel switching to electricity for transport is not possible

## Quick guide

The report is organized as follows:

- Chapter 1 presents the socio-economic and energy situation of Africa
- Chapter 2 describes the OSeMOSYS-TEMBA energy model and the methodology used in the study
- Chapter 3 describes the three scenarios
- Chapter 4 provides the results of the analysis
- Chapter 5 draws conclusions on the analysis, including limitations and possible future work

# 1 Introduction

## 1.1 Overview of the African energy system

Access to a stable and secure supply of energy is a fundamental driver of economic growth. Several Sub-Saharan African countries are amongst the least developed economies in the world. A large proportion of the population in the region lack access to electricity and other modern energy services, while those who have access face frequent outages. 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 (LPG), electricity and biogas, or improved biomass cook stoves (ICS) (Table 1) (International Energy Agency, 2017a). While not analysed here, limited access to electricity will hinder water pumping potential especially in dry times when groundwater levels are lower, reducing and agricultural production and disrupting drinking water supply[1].

In the past years, improvements in electricity access have been made. The proportion of the population with access to electricity increased from 43% in 2010 to 51% in 2016. However, during the same period, the total number of people without access to clean cooking remained stable (72%). Lack of access to clean cooking facilities means that in many countries women need to spend, on average, an hour per day to collect fuelwood and several hours to cook with inefficient stoves. Indoor air pollution has health implications and increases the number of premature deaths. Poor access to electricity increases the vulnerability of water supply in various settings (Fuso Nerini et al., 2018)[2] and can increase deforestation (Kambiré et al., 2016). Other aspects of life affected by the lack of electricity access include: limited educational options, no cooling for vaccines, stunted telecoms and thus limited communication and commerce (Fuso Nerini et al., 2018).

However, meeting the energy demand required for Africa's transformation is difficult. Infrastructure is limited, the population is rapidly growing, historically fossil fuels and biomass have been the easiest energy sources to harness and climate change is exacerbating development challenges. The options to meet future energy needs include investing in trade and adopting new technologies to exploit the continent's abundant energy resources. This work sketches least cost, low carbon technology investment scenarios.

Africa is endowed with a wide range of energy resources, both fossil fuels and renewable energy. Nevertheless, the installed capacity of electricity in the continent was almost 165 GW in 2015, considerably less when compared to the systems of India (308 GW), China (1,519 GW) (Central Intelligence Agency, 2018) and (Europe 1,030 GW)[3] (ENTSO-E, 2015). South Africa's installed electricity generation capacity makes up approximately one quarter (47 GW, 2015) of the continent's total. Many African countries have not yet exploited their significant rich renewable energy resources with the share of renewables in the power generation mix being only 19%. Further, among all continents, Africa has the highest percentage of untapped technical hydropower potential, with only 11% developed so far (International Hydropower Association, 2019).

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 (The World Bank, 2019b). Ethiopia, Democratic Republic of the Congo (DRC), Côte d'Ivoire, Mozambique, Tanzania and Rwanda are some of the fastest-growing economies in the African continent (International Monetary Fund, 2019). Indicatively, Ethiopia's economic growth in 2017/18 was 7.7% (The World Bank, 2019b). Growth is fuelled by mineral extraction, commerce and agricultural development.

[1] Future analyses and follow up activities could assess the link between electricity and water access in a more detailed way.

[2] Access to reliable water supplies is not reported here, but would be of interest to correlate.

[3] This figure refers to the area covered by the Transmission System Operators of ENTSO-E that include 41 members covering 34 countries.

**Table 1.** Share of population with electricity access and without access to clean cooking

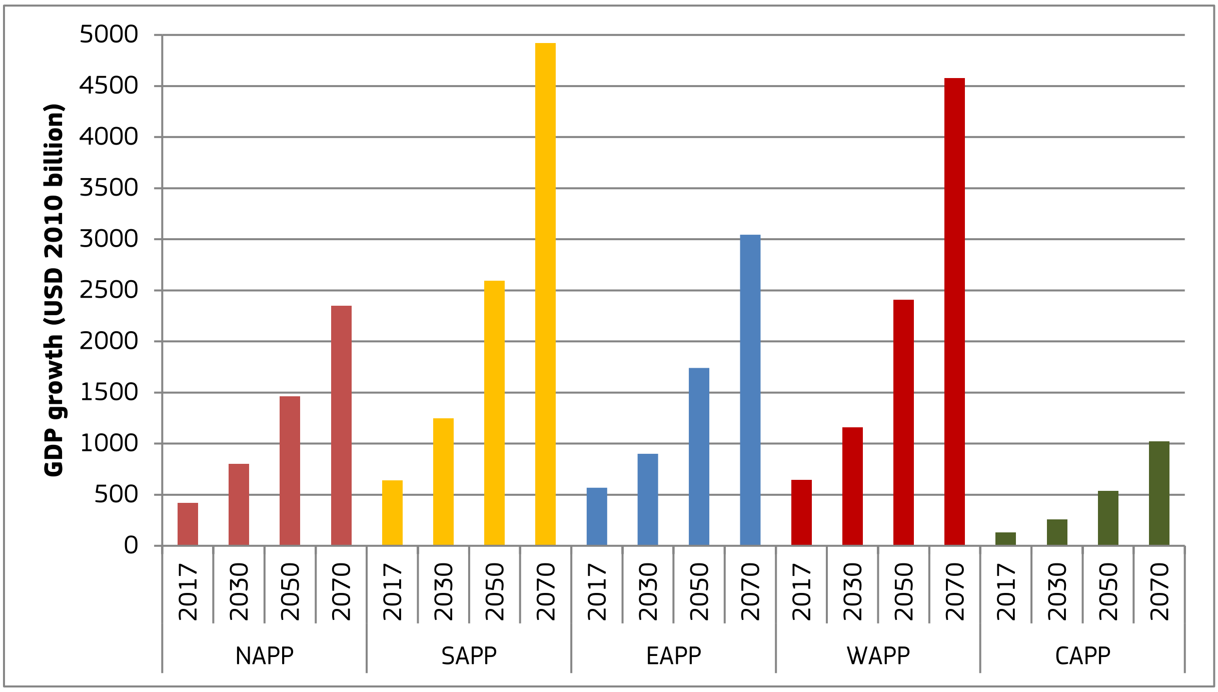
| Power pool/country | % with access to electricity | | % without access to clean cooking | |
|---|---|---|---|---|
| | 2010 | 2016 | 2010 | 2015 |
| **North Africa power pool (NAPP)** | **96%** | **97%** | **7%** | **6%** |
| Algeria | 99% | 100% | 1% | - |
| Libya | 100% | 100% | 1% | - |
| Mauritania | 19% | 31% | 68% | 66% |
| Morocco | 99% | 99% | 4% | 3% |
| Tunisia | 100% | 100% | 2% | 2% |
| **Central Africa power pool (CAPP)** | **21%** | **25%** | **92%** | **91%** |
| Cameroon | 49% | 63% | 79% | 77% |
| Central African Republic | 2% | 3% | 95% | 95% |
| Chad | 4% | 9% | 95% | 95% |
| Congo | 37% | 43% | 86% | 84% |
| Democratic Republic of the Congo | 15% | 15% | 95% | 95% |
| Equatorial Guinea | 27% | 68% | 78% | 77% |
| Gabon | 60% | 90% | 25% | 15% |
| **East Africa power pool (EAPP)** | **40%** | **54%** | **65%** | **67%** |
| Burundi | 5% | 10% | 95% | 95% |
| Djibouti | 50% | 42% | 94% | 94% |
| Egypt | 100% | 100% | 1% | 1% |
| Eritrea | 32% | 33% | 92% | 90% |
| Ethiopia | 23% | 40% | 84% | 95% |
| Kenya | 18% | 65% | 93% | 86% |
| Rwanda | 10% | 30% | 95% | 95% |
| Somalia | 14% | 16% | 95% | 95% |
| South Sudan | 0% | 1% | 95% | 95% |
| Sudan | 36% | 46% | 65% | 65% |
| Uganda | 9% | 19% | 95% | 95% |
| **West Africa power pool (WAPP)** | **42%** | **52%** | **92%** | **87%** |
| Nigeria | 50% | 61% | 95% | 94% |
| Benin | 27% | 32% | 94% | 90% |
| Cote d'Ivoire | 59% | 63% | 80% | 77% |
| Ghana | 61% | 84% | 88% | 71% |
| Senegal | 54% | 64% | 69% | 71% |
| Togo | 28% | 35% | 95% | 91% |
| Burkina Faso | 15% | 20% | 92% | 87% |
| Cape Verde | 70% | 97% | 26% | 25% |
| Gambia | 35% | 48% | 95% | 90% |
| Guinea | 20% | 20% | 95% | 95% |
| Guinea-Bissau | 12% | 13% | 95% | 95% |
| Liberia | 2% | 12% | 95% | 95% |
| Mali | 17% | 41% | 92% | 50% |
| Niger | 9% | 11% | 95% | 95% |
| Sao Tome and Principe | 57% | 59% | 62% | 40% |
| Sierra Leone | 12% | 9% | 95% | 95% |
| **South Africa power pool (SAPP)** | **83%** | **86%** | **87%** | **86%** |
| South Africa | 83% | 86% | 24% | 18% |
| Angola | 40% | 35% | 61% | 61% |
| Botswana | 45% | 55% | 44% | 43% |
| Comoros | 40% | 71% | 95% | 93% |
| Lesotho | 17% | 34% | 67% | 63% |
| Madagascar | 17% | 23% | 95% | 95% |
| Malawi | 9% | 11% | 95% | 95% |
| Mauritius | 99% | 100% | 3% | 2% |
| Mozambique | 15% | 29% | 95% | 95% |
| Namibia | 44% | 56% | 57% | 55% |
| Seychelles | 58% | 99% | 2% | 2% |
| Swaziland | 35% | 84% | 72% | 50% |
| Tanzania | 15% | 33% | 95% | 95% |
| Zambia | 19% | 34% | 83% | 87% |
| Zimbabwe | 37% | 34% | 71% | 71% |

Source: (International Energy Agency, 2017a)

In order to meet this growing demand, and take advantage of trade opportunities, regional power pools have been developed. The East African Power Pool (EAPP) includes: Burundi, DRC, Egypt, Ethiopia, Kenya, Rwanda and Sudan, Tanzania, Libya, Uganda, Djibouti and South Sudan[4]. The West African Power Pool (WAPP) includes Benin, Burkina Faso, Côte d'Ivoire, Gambia, Ghana, Guinea, Guinea Bissau, Liberia, Mali, Niger, Nigeria, Senegal, Sierra Leone and Togo. The Southern African Power Pool (SAPP) includes Angola, Botswana, DRC, Lesotho, Malawi, Mozambique, Namibia, South Africa, Swaziland, Tanzania, Zambia, Zimbabwe[5]. The North African Power Pool (NAPP), as it is reported here, is officially called the Maghreb Electricity Committee, or COMELEC. It includes Algeria, Libya, Mauritania, Morocco and Tunisia.

Nevertheless, economic growth will be uneven across countries and power pools. The Central African power pool is estimated to have the highest economic growth in the continent during the upcoming decades, around 7.8 times higher in 2070 compared to 2015 values followed by the Southern African power pool (7.7 times) (Figure 1).

**Figure 1.** GDP projections per power pool in Africa




Source: (The World Bank, 2019b)

[4] The DRC is also included in the Central African Power Pool, wherein it is reported. Also, Libya is included in the North African Power Pool, wherein it is reported.

[5] There the DRC is also included and reported in the Central African Power Pool and Tanzania in the EAPP

## 1.2 Energy resource potentials

African fossil and renewable potentials are varied, and often relatively high. Detailed country-by-country estimates can be found in Annex 3. Regional exploitation of those resources differs as well. Renewables capacity varies from 10% in the NAPP to over 60% in the EAPP. Table 2 summarises selected attributes of those power pools and shows that the continent and its power pools are diverse.

**Table 2.** Socio-economic data per power pool in Africa in 2015.

| Power pool | Population [million] | GDP [billion USD] | Installed capacity [GW] (% renewable) |
|---|---|---|---|
| **NAPP** | 96 | 395 | 3.2 (10%) |
| **SAPP** | 169 | 628 | 10.7 19%) |
| **EAPP** | 415 | 515 | 11.9 (63%) |
| **WAPP** | 348 | 625 | 5.1 (24%) |
| **CAPP** | 126 | 129 | 2.9 (24%) |

Sources: (S&P Global Platts, 2019; The World Bank, 2019b; United Nations, 2017)

The West African power pool (WAPP) is likely to play a significant role in shaping the continent's future energy mix. UN population projections expect an increase of its population from approximately 388 million in 2019 to 1.583 billion people in 2070 (International Energy Agency, 2017a; United Nations, 2017). The WAPP region will represent around one-third of the continent´s total population in 2070 (United Nations, 2017). Countries such as Nigeria, Ivory Coast and Ghana are lower- to middle-income economies. They are home to around 90% of the power pool´s installed capacity. It is anticipated that it will experience gradual economic growth in the following decades (International Monetary Fund, 2019; United Nations, 2014). Their future socio-economic development will be closely linked with their energy development. The high availability of natural gas reserves both onshore and offshore in Nigeria, Ivory Coast and Ghana as well as the existing West African Gas Pipeline will transform the region into an energy hub. The high solar potential (average yearly sum of global irradiation <1,800 kWh/m$^2$) and wind (average speed <3.75 m/s) is relatively low compared to other African regions[6] (IRENA, 2018).

The Northern African power pool (NAPP), is the only region in Africa that is almost fully electrified (97% in 2016). Mauritania has the lowest electricity access (31% in 2016) compared to the rest of the northern African countries (99.8% in 2016). It is a region quite rich in both fossil fuel reserves and renewable potential specifically wind and solar. The renewable share in the power generation mix was almost 9% in 2015 (International Energy Agency, 2017b). This is likely to increase sharply, however, as the northern African countries have indicated in their future energy policies that they aim to invest in renewable energy technologies. Morocco has set a target to increase the share of renewables of its total installed capacity from 34% in 2015 to 52% by 2030. The Noor power plant in Morocco, the largest concentrated solar plant in the world upon completion (580 MW), is one of those investments under the renewable energy portfolio (The World Bank, 2019c). Algeria and Libya have proven oil and gas reserves which are exported to Europe, the Middle East and other African countries and play a significant role in the global energy supply. Lastly, the North–South Power Transmission Corridor which links Africa with Europe will improve the security of energy supply in the region.

The Southern and Northern African power pools are the dominant electricity markets in Africa. The share of their renewable capacity is almost 19% and 10% respectively, significantly lower than that in the Central (24%) and East African (63%) power pools. Approximately 185 million people live in the Southern African power pool in 2019 with that number expected to increase to 632 million people by 2070 (United Nations, 2014). Electricity access was almost 52% in 2016, increased from 38% in 2010 (International Energy Agency, 2017a). South Africa is estimated to present the highest economic growth, 8 times by 2070 compared to 2017, in the region followed by Angola, Zambia and Botswana. The high fossil fuel reserves (coal, gas) in Angola, Botswana, Mozambique, South Africa and Zimbabwe can play a significant role in boosting the countries' economies mainly due to fuel exports and security of energy supply. Also, the solar (average yearly sum potential 2,150 – 2,752 kWh/m$^2$) energy potential, as well as the hydro energy potential (specifically in Zambia the potential exceeds 6 GW) can provide lower-cost electricity generation options in the region. In addition, the planned Zizabona power transmission trade link across Botswana, Namibia, Zambia and

[6] By comparison, most of Europe has solar irradiance of less than 1800 kWh/m$^2$ (European Commission - Joint Research Centre, 2017).

Zimbabwe will improve the security of energy supply in the region (Ndhlukula, Radojicic, Mangwengwende, Radojičić, & Mangwengwende, 2015).

The East African power pool (EAPP) is expected to be the second most populated region in the continent by 2065 (United Nations, 2014). However, the expected population growth will not be matched with proportionate economic growth since its gross domestic product will increase by approximately five times during the period 2015-2065, lower than any other power pool. Electricity access in the region was almost 54% in 2016. Kenya and Ethiopia achieved 65% and 40% electricity access, respectively and are on track to reach universal electricity access by 2030. The region has significant potential for renewable energy resources (hydro, geothermal, solar, wind). The main energy source is hydropower with a technical potential of more than 55 GW, ≈80% of which is located in Ethiopia. In addition, EAPP has the highest geothermal potential in the continent (>15 GW), mainly located in Kenya (10 GW). Lastly, the region also contains a relatively small amount of fossil fuel reserves mainly in Sudan, Ethiopia, Tanzania and Uganda for domestic uses or exports (Ndhlukula et al., 2015). Nevertheless, Egypt has a significant amount of proven oil and gas reserves exported mainly to Europe, the Middle East and other African countries and could play a significant role in the global energy supply. In addition, a recent new offshore gas discovery in Egypt could further improve the country's economy and role in the region (World Oil, 2019).

The Central African power pool has the lowest electrification rate in the continent, 25% in 2016. This is mainly due to the fact that electricity access in the Democratic Republic of the Congo, which represents around 65% of the region's total population, was as low as 15%. The power generation mix in the region is mainly based on renewable energy resources and specifically hydro, 2.8 GW out of 4.4 GW in 2015, providing low-cost electricity. The Democratic Republic of the Congo has the highest hydro energy potential in the continent. It has more than 100 GW and only approximately 5% has been exploited so far. The proposed Grand Inga project is a series of potential hydroelectric dams that could reach a cumulative installed capacity of 42 GW. If completed, it would be the largest hydro-electric power generating facility in the world. It would have the potential to transform aspects of the continent's power mix, by providing low-cost electricity to neighbouring countries (Taliotis et al., 2016). Other renewable energy sources such as wind (average speed <3.75 m/s) and solar (average potential <1,800 kWh/m$^2$) have lower energy potential.

## 1.3 Policy context

In recent years, a lot of progress has been made in improving the socio-economic and energy situation of Africa. The African Union's Agenda 2063 (African Union, 2014a), the UN 2030 Agenda for Sustainable Development (United Nations, 2015c) and the Common African Position on the post-2015 Development Agenda (African Union, 2014b) indicate the socio-economic transformation framework, the challenges posed by climate change as well as the goals for the African countries. The objectives of the aforementioned agendas are to achieve economic growth and sustainable development in the coming decades. Those frameworks indicate the importance and urgent need for energy planning. It is envisioned that the outcomes of the planning process will assist in selecting investments in energy production and services in the continent's energy infrastructure so as to ensure access to affordable, reliable, sustainable and modern energy for all by 2030 (Sustainable Development Goal 7) and 2063. The Sustainable Development Goals (SDGs) recognise the integrated nature of development. For example, a number of key factors that influence the energy system and the achievement of Goal 7, including the declining costs of renewables, development of new energy technology and the new business models can both support and hinder the achievement of the other SDGs (Fuso Nerini et al., 2018).

This report develops consistent scenarios of energy supply to meet energy demand projections. Those scenarios explicitly report simplified energy balances, gas trade, electricity trade and granular power system information for the medium to long term. Further regional and national water consumption and withdrawal by the energy system are provided. All of the tools and data underpinning this report are open source so as to allow their retrieval as well as reproduction of the analysis.

# 2 Description of the energy model – Overview of the methodology

The analysis of this report was conducted by extending and updating The Electricity Model Base for Africa (TEMBA). The extension includes a simple representation of other energy sources, while the update refers to the inclusion of the latest information for infrastructure, technology and fuel parameters. In this section, we provide an overview of OSeMOSYS and TEMBA and then present the structure of the TEMBA model and key assumptions.

## 2.1 Open Source Energy Modelling System

The open-source energy modelling system (OSeMOSYS) is a freely available energy system optimisation modelling framework originally developed at KTH Royal Institute of Technology and released under a permissive open license (Howells et al., 2011). OSeMOSYS provides analysts with an optimisation modelling framework which can be populated with data to create an optimisation model of a national energy system. The model can include representations of demands for energy or energy services, conversion technologies, which transform energy from one form to another, and energy resources, such as coal, natural gas or solar energy. In addition, the environmental impacts of energy consumption and production, such as the production of emissions can be quantified, and the evolution of technology over time can also be explored.

OSeMOSYS works using an optimisation paradigm. This is rather different from the more commonly understood simulation approach. Therein a "model" calculates the performance or operation of a system given a set of input assumptions and a characterisation of the system under examination. Instead, OSeMOSYS minimises an objective function by finding values for a large number of decision variables. The objective function is an equation which expresses the cost of operating and expanding the energy system as a linear function of the discounted sum of the generation capacity and activity over time. Decision variables relate to both capacity expansion and activity. Capacity expansion considerations include, among others: investment decisions to build new power plants, expand transmission and distribution systems or build new mines to exploit new energy resources. Activity considerations include: the dispatch of power plants to meet electricity demand, the production of oil and gas from reserves, the conversion of crude oil into petrol and diesel in refineries and the trade of energy commodities between countries and so on. In this way, models generated using OSeMOSYS provide insights into how national energy systems can transition from the current to a future state. In so doing they can include representations of the operational constraints while including environmental and economic considerations.

The types of insights provided by optimisation models can be characterised as "target in - policy out". By using energy demands, emission constraints and technology costs to develop scenarios of the future, the model outputs depict the portfolio of technologies and operational behaviour required to meet the objective of minimising the costs of expanding and operating the energy system. The parameters entered in the modelling framework are time-dependent and can be adjusted over the study horizon to represent a variety of potential futures.

## 2.2 TEMBA model

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 (Taliotis et al., 2016). For the purpose of this analysis, the TEMBA model is extended to include:

- Non-electricity demands for oil products (light and heavy), coal, biomass and natural gas
- Simple energy supply systems for non-electricity demands were developed including extraction, import, trade, refining and internal transport
- The operational production data for wind and solar was updated to include finer granularity
- New power plant options to include CCS and different cooling types were added
- Further, accounting for water was included; to do so, water factors were added to the model representation

The data used by the TEMBA model were updated to include the latest:

- Capacity data (as investment in energy supply in Africa has been growing)
- Cost and performance data
- Fuel price projections
- New energy demand projections

### 2.2.1 Model structure

TEMBA consists of final energy demands (electricity, coal, oil, natural gas, biofuel and waste) of forty-seven African countries. Each production, import, export and domestic transmission/transport option (both current and future) is modelled. The objective is to identify the "least cost" arrangement of current and future investment and operation of the system. This is undertaken simultaneously for all countries over the whole modelling period. Cross-border electricity trade links, as well as gas pipelines, are specified on a country-by-country basis, thus taking into account an energy-trading scheme among African countries. The model includes country-specific fuel availability, energy resource prices categorized in domestic, inland and coastal, transmission and distribution losses on a national level as well as techno-economic parameters of the fuel extraction, import, power generation technologies, pipelines, transmission-interconnectors and refineries. In addition, we represent the different cooling technologies used by each type of power plant in each country as well as the water factors associated with water use (withdrawal and consumption). That was done for the production of energy (production of biomass, coal, oil, gas and uranium) and energy transformations (in oil refineries and power plants).

The list of countries considered per power pool for the purposes of this analysis is presented in Table 3. It should be noted that isolated systems such as the islands of Sao Tome and Principe, Madagascar, Mauritius, Seychelles and Cape Verde were not included in the analysis due to either the relatively small size of those systems that will have a lower overall impact in the continent´s energy system or their limited overall trade potential and/or limited available data. In addition, the energy system of Western Sahara is excluded from the analysis due to limited data (energy balance) to forecast the energy demand.

**Table 3.** List of countries per power pool considered in the analysis (with ISO 3166-1 alpha-2 country code in brackets)

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

Source: (Medinilla, Byiers, & Karaki, 2019)

*The country belongs to more than one power pool so it is reported where it does not have an asterisk superscript.

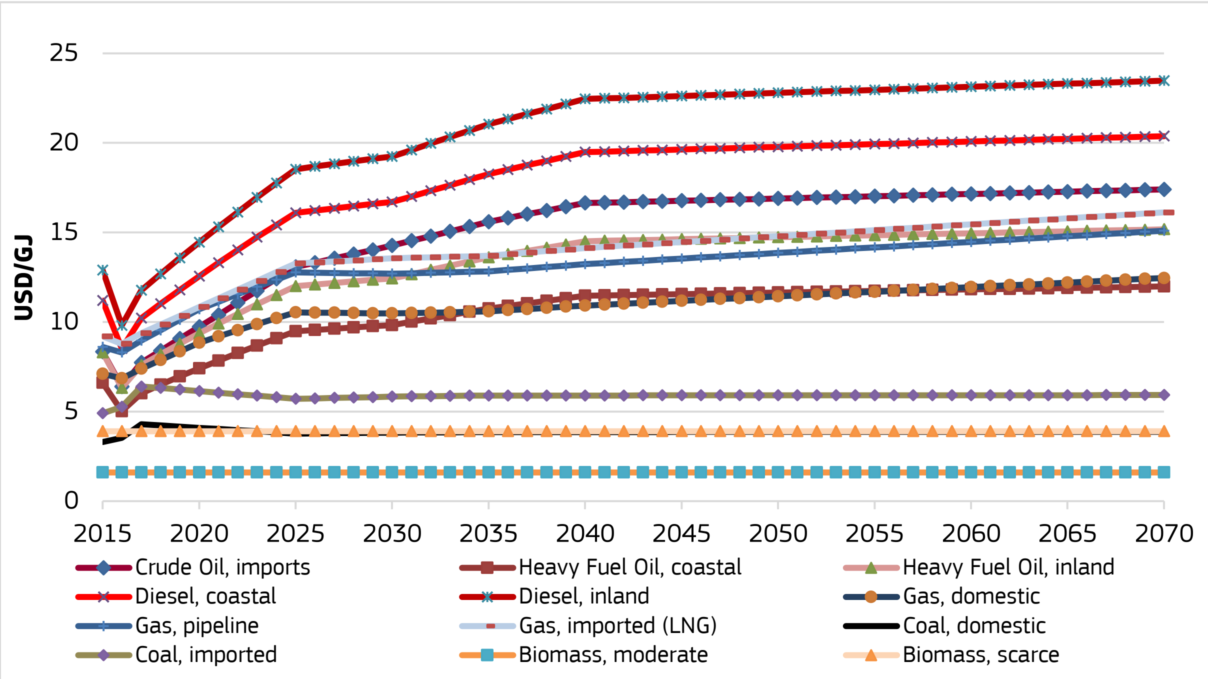
### 2.2.2 The energy system

#### *2.2.2.1 Primary fuel supply*

2.2.2.1.1 Extraction of primary energy

Primary fuels are either imported or extracted locally. Local extraction limits are set with country-specific reserves. Assumptions on average cost values are based on international projections and are summarised in Figure 2. Biomass is an important fuel in the African context as it provides most of the thermal energy required for cooking and heating in African homes. Biomass is made available for harvesting within national limits. Two types of biomass considered in the analysis: i) "moderate" assigned to countries with sufficient agriculture to potentially produce biomass for the power sector and ii) "scarce" where the agriculture potential is relatively low. Fossil fuel reserves (EIA, 2019; The World Bank, 2019a) and renewable energy potential (Annex 3) (Hermann, Miketa, & Fichaux, 2014; IRENA, 2018; Ndhlukula et al., 2015; United Nations, 2016) were derived from various sources.

**Figure 2.** Fuel price projections




Source: (International Energy Agency, 2017c)

2.2.2.1.2 Imports and exports

TEMBA assumes the following for representing energy imports:

— Electricity and gas interconnectors between African countries (and Europe) (detailed in Annex 4)

— Re-gasification and liquefaction for coastal imports (re-gasification's capital and fixed costs: 855,000 USD/PJ, liquefaction's capital and fixed cost: 1,520,000 USD/PJ (Energy-Economy-Environment Modelling Laboratory E3MLab, n.d.).

— Different fossil fuel prices for inland and coastal countries are considered in the analysis (Figure 2) based on the "World Energy Outlook" (2015-2017) by the International Energy Agency (International Energy Agency, 2017c). Country specific distance factors (estimated by KTH-dESA) are considered for fuel imports into inland countries. The price evolution (2018-2070) is based on (International Energy Agency, 2017c).

— The inland countries with identified gas reserves or existing/future gas pipelines projects can use natural gas as a fuel input, otherwise, not

— Only the coastal countries can invest in an LNG terminal and a regasification plant with an LNG storage facility

#### *2.2.2.2 Summary of cross-border electricity and gas interconnection projects*

Annex 4 presents over 100 electricity and gas interconnector projects. The lines transmit electricity in both ways, from one country to the other, and vice versa. The existing and the committed/under-construction projects are included in the model while the planned ones are given as an option to the model to invest.

In the Northern African power pool, there are quite a few export pipeline systems in Algeria (Medgaz, Maghreb, Trans-Mediterranean), Egypt and Libya (Green Stream). In the Western African power pool, the West African Gas Pipeline (WAGP) that transport gas from Nigeria to Benin, Togo and Ghana is the most significant regional pipeline system. In the Southern African region, Mozambique is planning to export natural gas through a pipeline into South Africa. whereas in the Eastern African power pool, it stands out the proposed gas pipeline system between Ethiopia-Djibouti and Tanzania-Uganda.

Electricity can be exported from Africa to Europe. That is limited by the planned interconnector size and by the value of the power exported. The electricity export price for trade to non-African countries, in the case of Egypt and Morocco, is assumed to be 0.31 USD/kWh during the period 2015-2029, 0.36 USD/kWh for 2030-2040, 0.41 USD/kWh for 2040-2050 and 0.47 USD/kWh for the period 2050-2065 (CEIC, 2019).

Natural gas can also be exported through pipelines from Algeria, Egypt and Libya to non-African countries (Italy, Portugal, Spain, Turkey). The natural gas export price for trade outside of Africa is assumed to be similar to the one for trade through a pipeline to African countries: 5.4 USD/Mbtu in 2015, 8 USD/Mbtu in 2030, 8.7 USD/Mbtu in 2050 and 9.5 USD/Mbtu in 2070 (International Energy Agency, 2017c).

#### *2.2.2.3 Oil refining*

Oil refining is represented in a simplified way in TEMBA. The model considers existing refineries, which are calibrated to produce either heavy or lighter oils (including kerosene, diesel, gasoline, LPG, etc.). Existing refineries produce those in a ratio that matches data national energy balances. In case there is an existing refinery in the country another option is given to the model as an alternative to invest in, consisting of 10% lower share of LFO and 10% higher share of HFO compared to the share in the existing refinery. On the other hand, if there is no existing refinery in the country then a new refinery is assumed to have a standard split of 90% LFO and 10% heavy fuel oil while the alternative option has a split of 80% LFO and 20% HFO.

Refineries can use either locally extracted or imported oil. The choice is based on the relative costs of the resulting energy system. All the countries have the possibility to invest in a crude oil refinery. The fuel output ratios of the existing refineries are based on historical data (International Energy Agency, 2017c; United Nations, 2015a). The availability and refining capacity in each country is considered.

#### *2.2.2.4 Power system*

The model takes into account for each type of power generation technology, its existing capacity as well as future investments that may occur throughout the modelling period. Under this study, only the committed projects (where the contract has been signed or the construction has started) are considered, while the planned ones are provided as an option for the model to invest. The list of the power generation capacities is compiled using online data sources as well as the "World Electric Power Plants Database (December 2015)" (S&P Global Platts, 2019). The existing power generation capacity aggregated by type of technology and per power pool is shown in Table 4.

**Table 4.** Power generation capacity by power pool in 2015

| Region (MW) | Coal | Diesel/HFO | Gas | Hydro | Solar | Wind | Geothermal | Biomass |
|---|---|---|---|---|---|---|---|---|
| **NAPP** | 2585 | 1866 | 25532 | 1851 | 411 | 952 | 0 | 0 |
| **CAPP** | 0 | 658 | 873 | 2886 | 5 | 0 | 0 | 9 |
| **SAPP** | 41289 | 2963 | 1,375 | 7624 | 1585 | 1,010 | 0 | 451 |
| **WAPP** | 68 | 3242 | 13,292 | 5025 | 55 | 12 | 0 | 50 |
| **EAPP** | 26 | 6130 | 31,564 | 8622 | 33 | 793 | 691 | 1727 |

Source: (S&P Global Platts, 2019)

The power generation technologies considered in this study are separated between centralised and decentralised options. The specific technologies (17 in all) are summarized in Table 5. In addition, for modelling purposes, these are categorized as old and new (old power plants are considered those added up to 2014 and their efficiencies are calibrated to meet national energy balance data, while newer technologies are characterised based on international data).

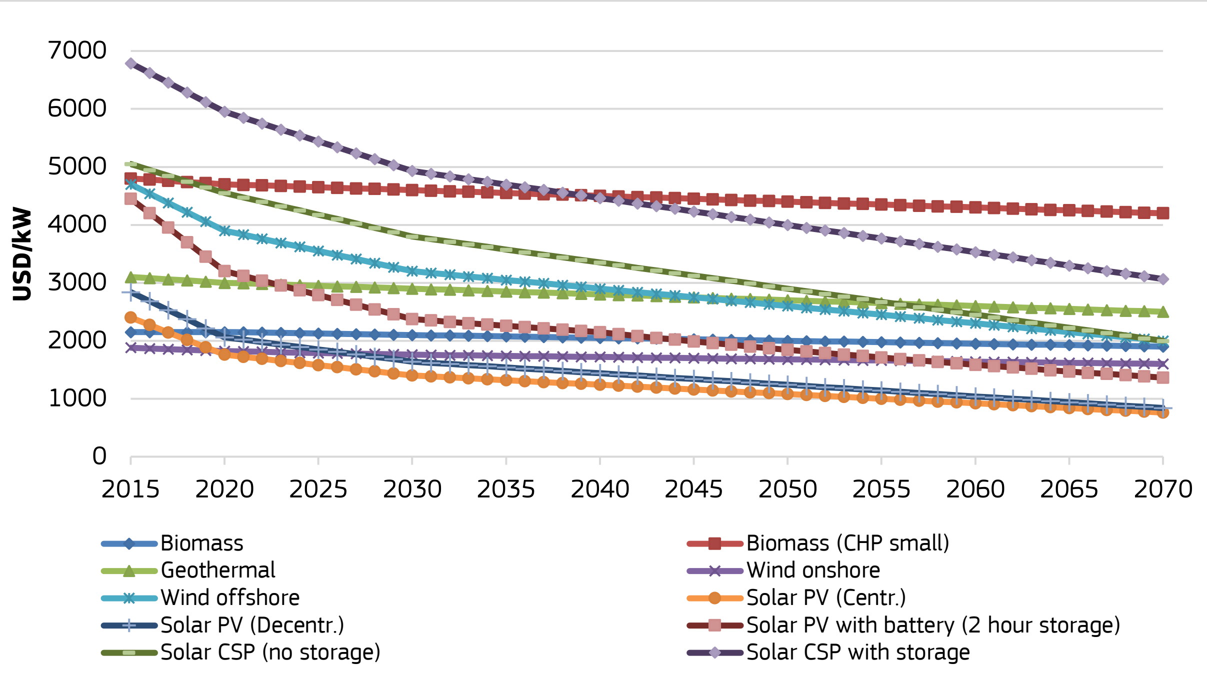
**Table 5.** Available power generation and conversion technologies.

| | Fossil and nuclear | Renewable | CCS |
|---|---|---|---|
| **Centralized** | Diesel<br>Heavy fuel oil<br>Natural Gas: OCGT, CCGT*<br>Supercritical coal<br>Nuclear | Geothermal<br>Biomass and waste CHP<br>Hydro: small, medium, large*<br>Wind: onshore, offshore<br>Solar PV (utility scale)<br>CSP with storage<br>CSP without storage | Biomass<br>Coal<br>Natural gas |
| **Decentralised** | Diesel 1 kW | Solar PV (roof top)<br>Solar PV with battery | |

*OCGT: Open Cycle Gas Turbine, CCGT: Combined Cycle Gas Turbine, Small Hydro (<10MW), Medium Hydro (10-100MW), Large Hydro (>100MW)

The techno-economic parameters of the power generation and conversion technologies are provided in Annex 2. Their values are assumed to change over time. Either the cost is reduced or performance improved, or both (Energy-Economy-Environment Modelling Laboratory E3MLab, n.d.; IEA-ETSAP, 2019; International Energy Agency, 2017c; IRENA, 2018). The estimated investment costs of renewable energy technologies are presented in Figure 3.

**Figure 3.** Renewable energy cost development assumptions (overnight investment costs)




Source: (Energy-Economy-Environment Modelling Laboratory E3MLab, n.d.; IEA-ETSAP, 2019; International Energy Agency, 2017c; IRENA, 2018)

### *2.2.2.5 Assumptions on cooling systems*

A special feature of this model update is the inclusion of selected water tracking. To that purpose, four cooling types are modelled in historic and committed power plants: dry cooling systems (AIR), natural and mechanical draft towers (NDT/MDT), once-through the cooling tower with freshwater (OTF), and once through the cooling tower with salt water (OTS). In order to identify the cooling types for the different type of technologies in each of the African countries, online sources were used, including “Google Earth” and “World Electric Power Plants Database (December 2015)” (Luo, Krishnaswami, & Li, 2018). In cases where the cooling type of a power plant could not be identified, it is assumed that the plant will have the same cooling type as the majority of the plants in the country. However, in cases without available data related to the cooling system, weighted averages were used.

### 2.2.2.5.1 Water factors

The water withdrawal and consumption factors for the power generation and conversion technologies by type of fuel considered in the analysis are presented in Table 6. The same water factors developed by the Joint Research Centre for the present energy situation in Africa have been used. As indicated in the table below, water factors associated with the extraction/process of biomass are not considered.

**Table 6.** Water factors per fuel-process and technology type

| Fuel | Processes | Technology Type | Withdrawal ($Mm^3/MWh$*) | Consumption ($Mm^3/MWh$*) |
|---|---|---|---|---|
| **Coal** | Extraction and processing | - | 0.0529 | 0.0523 |
| **Crude oil** | Extraction (first and secondary recovery) | - | 0.2011 | 0.2011 |
| | Refining | - | 0.171 | 0.171 |
| **Natural gas** | Extraction and processing | - | 0.0019 | 0.0019 |
| **Uranium** | Surface mining and milling | - | 0.0059 | 0.0059 |
| | Underground mining and milling | - | 0.0028 | 0.0028 |
| **Biomass-fired power plants** | AIR | | 0.000 | 0 |
| | MDT/NDT | Cooling tower - SUBCR | 3.326 | 2.095 |
| | OTF/OTS | Once-through - SUBCR | 132.576 | 1.136 |
| **Coal-fired power plants** | AIR | Dry cooling - SUBCR | 0.322 | 0.322 |
| | MDT/NDT | Cooling tower - SUBCR | 2.5 | 2.008 |
| | OTF/OTS | Once-through - SUBCR | 102.54 | 0.43 |
| **Coal-fired power plants with CCS** | MDT/NDT | Cooling tower - SUBCR | 4.92 | 3.56 |
| **LFO and HFO-fired power plants** | AIR | Dry cooling - CC | 0.015 | 0.015 |
| | MDT/NDT | Cooling Tower - CC | 0.947 | 0.795 |
| | OTF/OTS | Once-through - CC | 34.091 | 0.379 |
| | AIR | Dry cooling - SUBCR | 0.367 | 0.367 |
| | MDT/NDT | Cooling tower - SUBCR | 4.545 | 2.765 |
| | OTF/OTS | Once through - SUBCR | 136.364 | 1.098 |
| **Natural gas-fired power plants** | AIR | Dry cooling - CC | 0.015 | 0.015 |
| | MDT/NDT | Cooling tower - CC | 0.947 | 0.795 |
| | OTF/OTS | Once-through - CC | 34.091 | 0.379 |
| | AIR | Dry cooling - SUBCR | 0.367 | 0.367 |
| | MDT/NDT | Cooling tower - SUBCR | 4.545 | 2.765 |
| | OTF/OTS | Once through - SUBCR | 136.364 | 1.098 |
| **Natural gas-fired power plants with CCS** | MDT/NDT | Cooling tower - CC | 1.93 | 1.44 |
| **Wind power plant** | | Wind turbine | 0.004 | 0.001 |
| **Nuclear power plants** | | Once through - SUBCR | 178.03 | 1.515 |
| **Geothermal** | AIR | Dry cooling - SUBCR | 0 | 0.000 |
| | MDT/NDT | Cooling tower - SUBCR | 0.068 | 0.042 |
| | OTF/OTS | | 1.134 | 1.134 |
| **Biofuel-fired power plants** | | | 9 | 7.200 |
| **Solar power plants** | N/A | PV | 0.023 | 0.023 |
| | AIR | CSP | 0.098 | 0.098 |
| | N/A | PV (utility-scale) | 0.023 | 0.023 |

Source: (Medarac, Magagna, & Hidalgo González, 2018)

*Note: The units for fuel extraction and processing are $Mm^3/MWhf$ while for plant operation is $Mm^3/MWhe$.

#### 2.2.2.6 Losses

It is assumed that there are losses in the transport, transmission and distribution of the energy sent to the final consumer. Although the model is structured so as all losses are individually specified for all fuels in each country, generic indicative values are used in this analysis for all but electrical transmission losses. Consistent national fuel-specific information was not available. In addition, the model considers light fuel oil stand-alone (1kW) generators providing electricity to the final consumer without using the transmission and distribution system.

Transmission and distribution losses are defined at the national level and consider future efficiency improvements in Annex 4 (African Energy Commision, 2018; International Energy Agency, 2017c, 2017b; IRENA, 2018; Miketa & Merven, 2013; United Nations, 2015a). Losses from auto production are accounted for in the power plant or refinery efficiency.

#### 2.2.2.7 Other total primary energy supply

In this version of the model, transfers, statistical differences, autoproducer electricity plants, main activity producer CHP plants, autoproducer CHP plants, main activity producer heat plants, autoproducer heat plants, heat pumps, electric boilers, chemical heat for electricity production, gas works, coal transformation, liquefaction plants, non-specified (transformation) and energy industry own use are not considered.

#### 2.2.2.8 Final energy demand

Final energy demands are included and exogenously entered into the model. Industrial "heat" and "peat" demands are not included. Other energy carriers considered are as per the IEA energy aggregate energy balance format and include: coal; oil products; natural gas; biofuels and waste; and electricity. Note that in the biofuels and waste category, only fuel wood is modelled. Further demands are not disaggregated by sector.

#### 2.2.2.9 Overarching assumptions

This section details overarching assumptions that drive the modelling. Note that all assumptions can be changed in future work, and all aspects of the model, including: input data, OSeMOSYS model formulation, mathematical programming language, and solver are open, versioned and available for download. Thus, the assumptions below (as well as other inputs) can be updated for future analysis. The assumptions are summarised as follows:

- The exchange rate of 1.14 was used to convert EURO (€) to USD ($) (XE, 2019)
- The variability of renewable energy generation is represented using hourly wind and solar generation The model is run on a yearly basis for the period 2015 to 2070 to ensure potential milestones of the African Union Development Agenda 2063 (African Union, 2014a) are captured. The last reported year is 2065 (the last 5 years are not reported as they are distorted by the model considering 2070 as the 'end-of-time').
- Within each year an aggregate resolution has been adopted. Four seasons and two-day parts for each season are defined. The year split is defined in a continental level so that the countries cannot have a corresponding day split (e.g. day and night). The "*daypart 1*" starts at 09:00, finishes at 18:00 (when most of the commercial and public services are supposed to operate), and the "*daypart 2*" starts at 18:00, and finishes at 09:00. The duration of the seasons is such that "*Season 1*" corresponds to (March – May), "*Season 2*" (June – August), "*Season 3*" (September – November) and "*Season 4*" (December – February).
- Country specific hourly electricity demand profiles were used to develop average profiles for electricity demand for the models' temporal split.
- A discount rate of 10% is used. This is consistent with similar studies (Taliotis, Bazilian, Welsch, Gielen, & Howells, 2014).
- The monetary unit used is the 2015 United States Dollars (USD). Accordingly, the USD gross domestic product (GDP) deflator from the World Bank Group is used (The World Bank, 2019b) to adjust the fuel prices reported in different years to the base year (2015) considered in the analysis.
- Profiles for each one of the African countries (Pfenninger & Staffell, 2019). In the case of hydro, generic capacity factors were considered rather than country-specific ones, based on the seasonality of the region due to lack of data (IEA-ETSAP, 2010). In addition, for the old thermal power plants (commissioned

until 2014) it was not possible to use country-specific capacity factors due to inconsistencies between the available sources as far as installed capacity and generation are concerned for each country. Lower generic capacity factors were used 5% lower than the corresponding capacity factors of the new thermal power plants. The model will decide the load of operation based on the installed capacity of each power plant and the corresponding electricity demand in the country. In the earlier years, because electricity demand is much lower than the actual operation of the plant, the power plant will reflect the actual generation.

— A carbon tax is applied only in South Africa: 7.06 USD/ton. (2019), 9.69 USD/ton. (2025) and 21.14 USD/ton. (2040) (International Energy Agency, 2017c). It has been assumed that the carbon price will change over time at a decreasing annual rate (1% per year)[7].

[7] This is due to the fact that projections cover the period until 2040. After that year, it is assumed that the carbon price will change over time at a decreasing annual rate of 1% per year. Since the period 2035-2040 the annual growth rate of the carbon tax was decreasing by 2%.

# 3 Scenarios

In this section, we describe the three scenarios developed to project plausible future developments of the African energy system. The scenarios are not predictions of the future and as a consequence, the results, later presented in section 4, should not be taken literally. Each scenario is internally consistent, but they differ across a number of dimensions. These dimensions form part of the scenario space and are exogenous assumptions provided to the model as a set of scenario data. All other assumptions presented earlier remain constant across the scenarios. It is only the change in these scenario dimensions which induce a change in the results. The dimensions along which the scenarios differ include:

- Fuel demand, where both the absolute magnitude and mix of fuels demanded differ;
- The $CO_2$ mitigation level, ranging from no mitigation target to caps that are consistent with the 2.0°C and the more stringent 1.5°C targets;
- The development of technology, which includes the availability of CCS.
- The adoption of energy policies

In the Reference scenario, the aim is to extrapolate the current situation into the future to project a plausible African energy system where energy policies do not evolve. Two mitigation scenarios (2.0°C and 1.5°C) are developed to compare the future energy mix, power generation investments, water withdrawal and system costs with the Reference scenario. The scenarios are summarized below with some observations on their key attributes.

## 3.1 Fuel demand projections

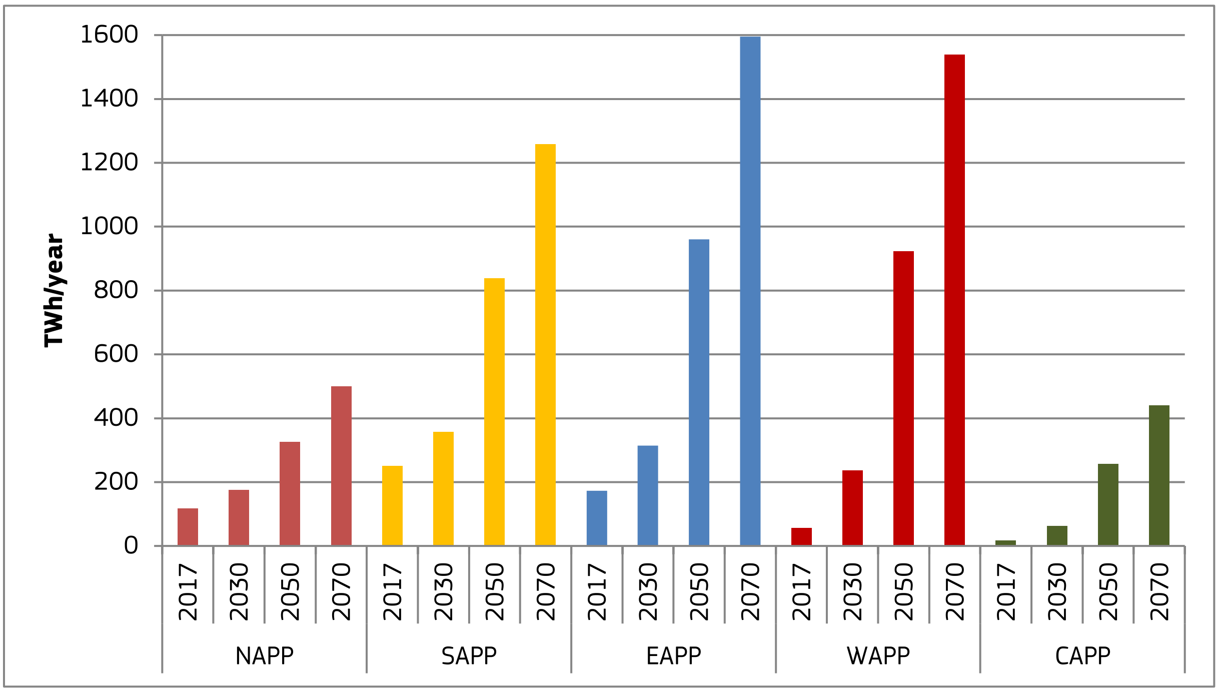
The final fuel demands considered among the scenarios are presented in this section. The objective of the model is to meet the final fuel demands using a number of primary sources (e.g. coal, oil, biomass, natural gas) at the minimum possible cost. The final fuel demands are inputs into the model and the model does not calculate them internally.

### 3.1.1 Reference scenario

The final energy demands by country are based on historical energy balances (International Energy Agency, 2017b; United Nations, 2015a) and projected national statistics including population (United Nations, 2017) and GDP projections (Keramidas et al., 2018). The energy demands are exogenous input parameters to the model. They are not disaggregated by sector but are accounted by type of fuel. Existing demand projections are used and calibrated to match the historical energy demands (International Energy Agency, 2017c; Keramidas et al., 2018; United Nations, 2015a). Efficiency improvements, penetration of energy-intensive industries as well as fuel switching in different sectors are analysed outside of the model and considered among the scenarios developed under this study. It should be noted that energy demand projections are subject to a number of uncertainties such as the transformation of energy markets as well as future developments in technologies, demographics and economic growth. Thus, they should not be considered predictions of what will happen, but rather modelled projections based on the given assumptions and methodologies.

The total electricity demand on the continent was 613 TWh in 2015. With the aforementioned projections, they are estimated to increase by approximately three times (2030 TWh) by 2040 and nine times (5331 TWh) by 2065. The Western African power pool represents the highest increase in electricity demand, with an average annual growth rate of 6.9% followed by the Central and Eastern African power pools with 6.7% and 4.6%, respectively. WAPP demand is driven by Nigeria. Similarly in EAPP continued growth in Egypt, Ethiopia and Kenya will drive demand, while in CAPP the Democratic Republic of Congo is expected to grow, though from a low base. In all cases, these countries are responsible for over 50% of their respective power pool demands. Demand increase is driven by population growth, increases in electrification rates and economic growth. The estimated electricity demand projections per power pool considered in the Reference scenario are presented in Figure 4 below. The electricity demand in the Northern and Southern African power pools is estimated to increase with an average growth rate of 2.9% and 3.3% respectively.

**Figure 4.** Electricity demand projections per power pool in the reference scenario




The final demand for fossil fuels in the non-power sector will increase from 214 Mtoe in 2015 to 565 Mtoe in 2065. The Northern African power pool region accounted for most of the continent's fossil fuel consumption in the non-power sector in 2015 (59.26 Mtoe). In 2065, the Western African power pool region is expected to be the leading consumer (164 Mtoe). This is driven by the shift in South Africa's energy mix, the largest single consumer on the continent at present. However, coal and oil consumption are expected to decrease with an annual average growth rate of -2% and -0.5% where natural gas is projected to increase by 3% per annum. This is due to the assumed penetration of more efficient technologies as well as natural gas consumption gradually replacing the relatively high coal and oil consumption. The Northern African Power Pool region is currently responsible for the use of 43% of the continent's natural gas followed by the Eastern African power pool (35%). The share in the Northern African power pool is expected to decrease to 18% as demand and production in the Western and Southern Africa increase. In Nigeria alone, economic and population growth would lead to an increase in its natural gas consumption from 4 Mtoe in 2015 to 38 Mtoe in 2065. Biomass demand in the non-power sector represented around 52% of the continent's total final fuel demand in 2015. The Western Africa power pool accounted for almost 43% of the continent's biomass demand in 2015 with that share to decrease to 41% in 2065. Nigeria is the largest consumer of biomass in the continent accounting for 30% of the total biomass demand. Aggregate demand projections by fuel and region are given in Table 7.

**Table 7.** Fuel demand projections (Mtoe) per power pool in the Reference scenario

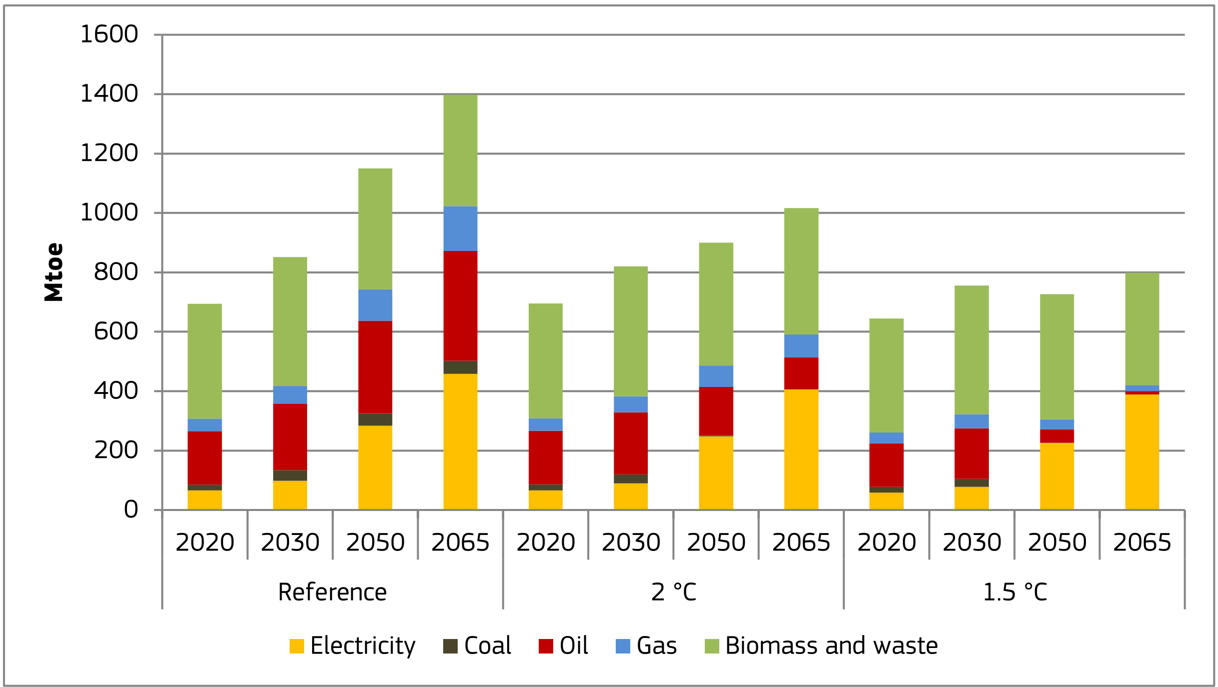
| Demand | 2015 | 2030 | 2050 | 2065 |
|---|---|---|---|---|
| **NAPP** | 71.97 | 96.09 | 121.88 | 151.43 |
| **Electricity** | 10.08 | 14.99 | 28.03 | 42.99 |
| **Coal** | 0.18 | 0.76 | 3.76 | 9.30 |
| **Oil** | 43.29 | 54.28 | 54.36 | 52.40 |
| **Natural gas** | 15.79 | 20.31 | 28.68 | 38.16 |
| **Biomass** | 2.63 | 5.75 | 7.05 | 8.58 |
| **SAPP** | 120.48 | 179.13 | 233.37 | 274.64 |
| **Electricity** | 21.47 | 30.64 | 72.11 | 108.15 |
| **Coal** | 17.38 | 26.32 | 24.61 | 20.32 |
| **Oil** | 36.05 | 45.20 | 56.28 | 63.10 |
| **Natural gas** | 3.97 | 8.24 | 17.16 | 25.82 |
| **Biomass** | 41.61 | 68.73 | 63.21 | 57.25 |
| **EAPP** | 162.5 | 243.53 | 331.29 | 403.03 |
| **Electricity** | 14.85 | 27.02 | 82.53 | 137.19 |
| **Coal** | 0.94 | 6.29 | 9.95 | 10.74 |
| **Oil** | 44.06 | 61.12 | 87.26 | 103.93 |
| **Natural gas** | 12.64 | 19.62 | 30.33 | 39.90 |
| **Biomass** | 90.01 | 129.48 | 121.22 | 111.27 |
| **WAPP** | 165.78 | 263.16 | 365.98 | 448.39 |
| **Electricity** | 4.85 | 20.24 | 79.27 | 132.29 |
| **Coal** | 0.36 | 2.23 | 3.48 | 3.53 |
| **Oil** | 30.74 | 49.68 | 87.66 | 115.94 |
| **Natural gas** | 4.02 | 10.96 | 28.43 | 44.40 |
| **Biomass** | 125.81 | 180.05 | 167.14 | 152.23 |
| **CAPP** | 38.22 | 69.3 | 97.18 | 120.52 |
| **Electricity** | 1.49 | 5.42 | 22.03 | 37.77 |
| **Coal** | 0 | 0 | 0 | 0 |
| **Oil** | 4.95 | 13.80 | 25.36 | 34.64 |
| **Natural gas** | 0.00 | 0.59 | 1.54 | 2.42 |
| **Biomass** | 31.78 | 49.49 | 48.25 | 45.69 |

### 3.1.2 Other scenarios

In order to meet the emission targets assumed in the 1.5°C and 2.0°C scenarios, the African countries will need to reduce their overall electricity consumption by approximately 11% and 27% respectively compared to the Reference scenario. In addition, fossil fuel consumption should be decreased overall by 39% and 71%.

In the two alternative scenarios, there is a significant shift away from coal, oil and gas towards electricity, with biomass and waste demand remaining at a similar level with respect to the Reference scenario. Such fuel switching is consistent with the high level of ambition required to meet stringent decarbonisation targets.

**Figure 5.** Fuel demand projections (Mtoe) across the scenarios



## 3.2 Carbon dioxide emissions and renewable energy policies

In Figure 6, the carbon dioxide emission constraints imposed in the 1.5°C and 2.0°C scenarios in comparison to the results from the Reference scenario are presented. The emission caps in the 1.5°C and 2.0°C scenarios start from 2020 onwards.

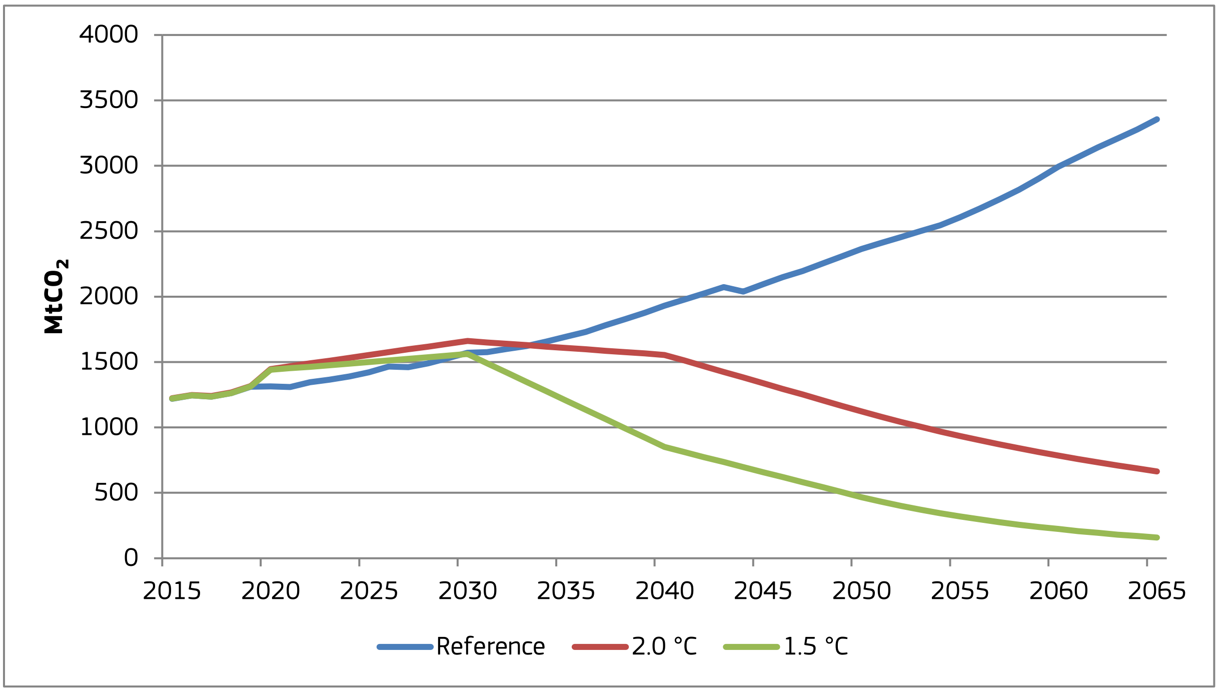
- The 2.0°C scenario takes into account emission targets that consistent with a likely chance of meeting the long-term goal of a mean global temperature increase over pre-industrial levels below 2.0°C (United Nations, 2015b). The 2.0°C warming scenario aims at a global mean temperature increase of 2.0°C with a 67% probability, used in the JRC-GECO report (Keramidas et al., 2018) and it was developed using the online MAGICC 6 model (van Vuuren et al., 2011). In the Reference scenario, the effects of an increase in global mean temperature are not considered
- The 1.5°C scenario assumes a stronger climate objective pursuing a reduction in carbon dioxide emissions to levels lower than in the Reference and 2.0°C scenarios with a 50% probability of reaching 1.5°C warming by 2100.

Carbon removal technologies such as carbon capture with storage (CCS) and bioenergy with carbon capture and storage (BECCS) technologies are considered only in the 1.5°C and 2.0°C scenarios.

The reference scenario takes into consideration the national renewable policies, which are in force until 2017, without considering new policies. Annex 5 includes a detailed review of the renewable energy generation targets by country.

The 1.5°C and 2.0°C scenarios consider the national renewable policies that were set in the Reference scenario as well as emission targets that will reduce the overall emissions in the continent to meet future climate goals.

**Figure 6.** Carbon dioxide emission limits ($MtCO_2$) in the 2.0°C and 1.5°C scenarios



# 4 Results

## 4.1 Overall energy patterns

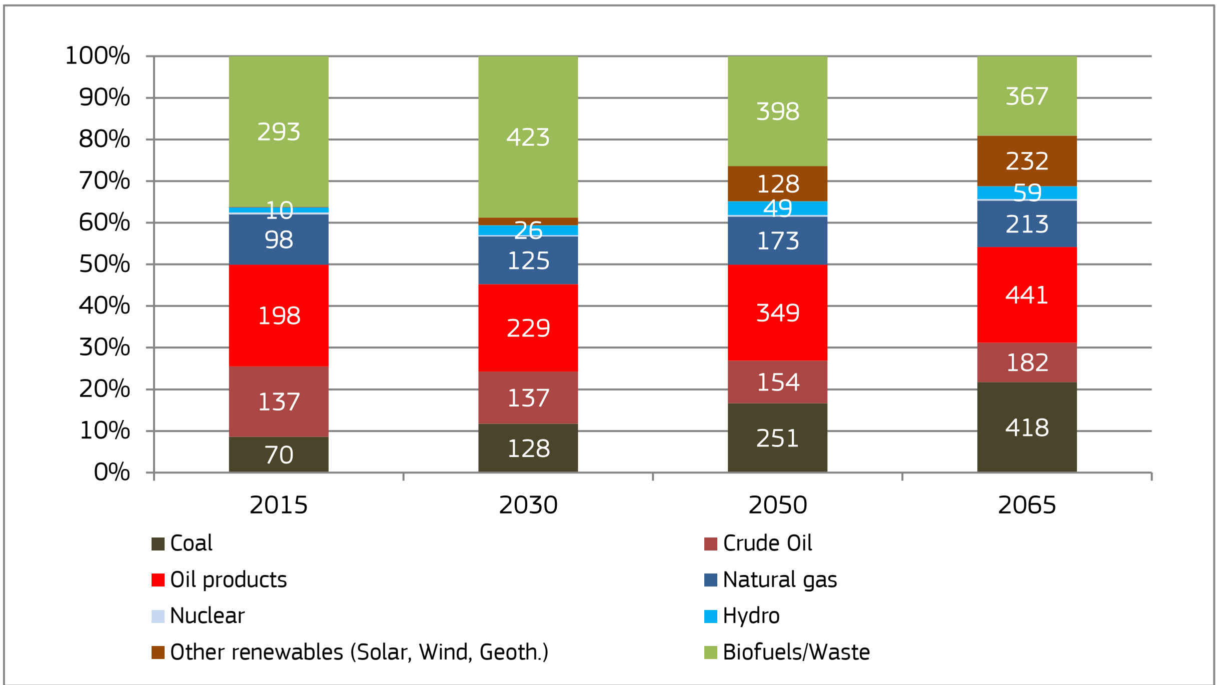
The aggregate energy balances (International Energy Agency, 2017b) for Africa under the different scenarios are reported in Annex 1. The total primary energy supply (TPES) and total final consumption (TFC) for the years 2015, 2030, 2050 and 2065 are reported there (based on each country´s energy balance) in order to discuss overarching trends below. Note that these figures show gross trade within the region (and thus add to imports to each country from within and without the region). The same implies for exports. Gross imports minus exports provide the net into (or out of) the region. The reason for including gross trade is to get a sense of its importance, which would otherwise be hidden. Further, not all losses are reported (which is consistent with the energy balance, for example, heat losses in power generation (or exergy) flows are neither calculated nor reported.

Each region is discussed in the remainder of this section, starting with Africa as a whole. First, the evolution of the Reference scenario over time is analysed, followed by the comparison with the 2.0°C and the 1.5°C scenarios.

### 4.1.1 All Africa

Total primary energy supply (TPES) grows 35% during the period 2015-2030, 38% during 2030-2050, and approximately 27% from 2050 to 2065. In 2065 it amounts to 1,920 Mtoe which is close to a 2.3-fold increase over the period. On the supply side, biomass is the most important fuel, followed by oil and gas. While biomass supply does not change significantly in absolute terms, its relative share decreases as other renewables including solar, wind, geothermal and hydro increase their contribution to total primary energy. Important increases in the use of renewables and coal are seen to fuel electricity production. As a result, African TPES diversifies significantly.

**Figure 7.** Total primary energy supply in Africa in the Reference scenario[8]




On the demand side, the general trend is an increase in the absolute use of oil and gas, and a large absolute and proportional increase in the use of electricity, which displaces biomass.

In comparison with lower carbon alternatives, Figure 9 shows that the general trend is a decrease in the use of fossil fuels. Initially, this affects the use of coal, and then oil and finally gas. Those are replaced by

[8] In this and subsequent graphs the white figures show the absolute value of the primary energy supply in Mtoe.

renewable energy carriers and thereafter with nuclear. In the Reference scenario, the TPES in 2065 is 1,920 Mtoe while in the 2.0°C and 1.5°C is 1,265 Mtoe and 1,050 Mtoe. While coal and crude exports are kept constant over the modelling period, flexibility is allowed in the export of electricity and gas to Europe..

**Figure 8.** Total final consumption in Africa in the Reference scenario

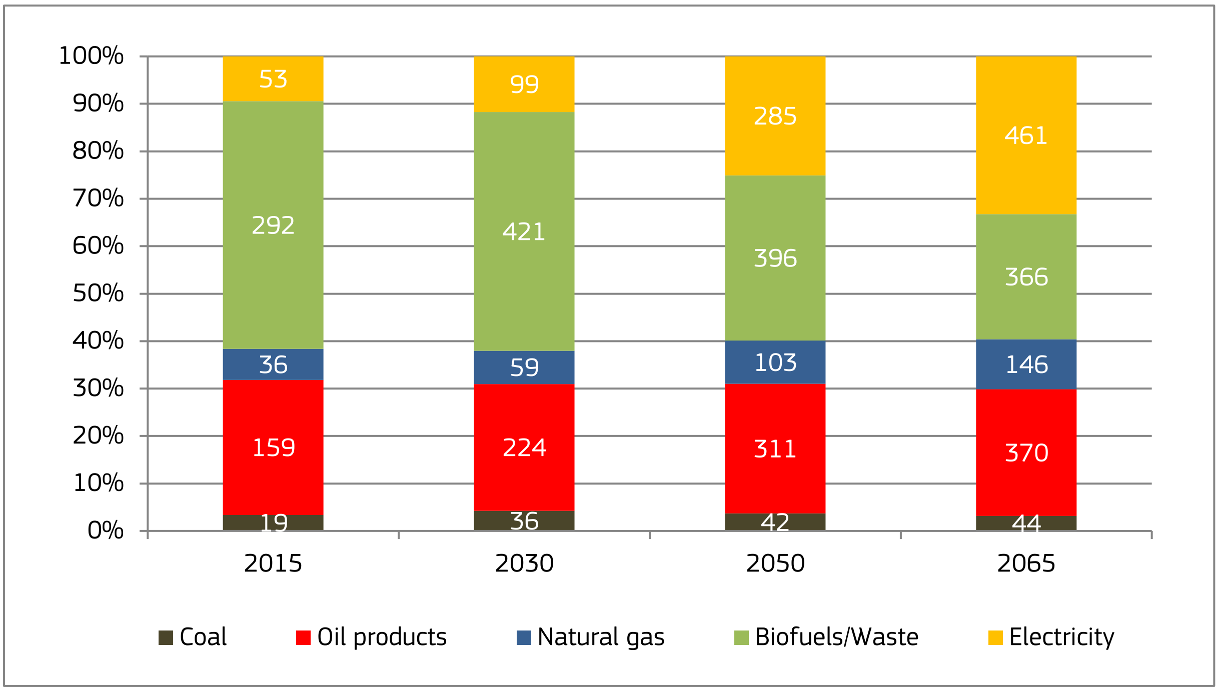
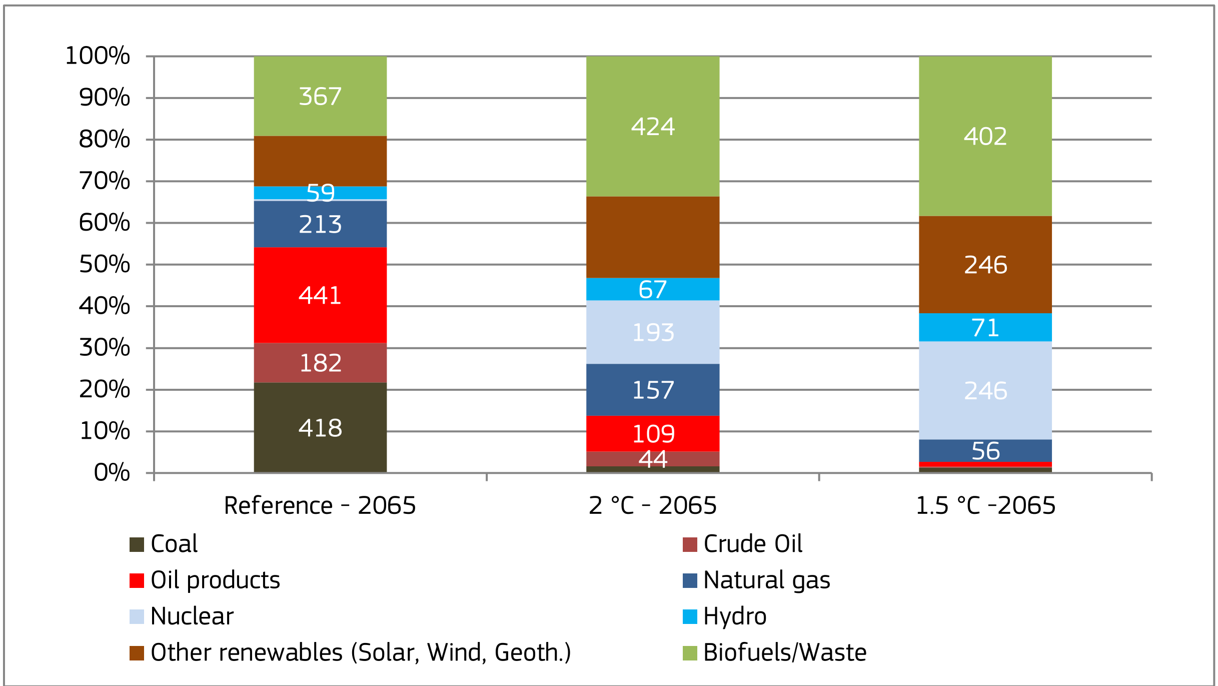



**Figure 9**. Total primary energy supply in Africa in the Reference, 2.0°C and 1.5°C scenarios



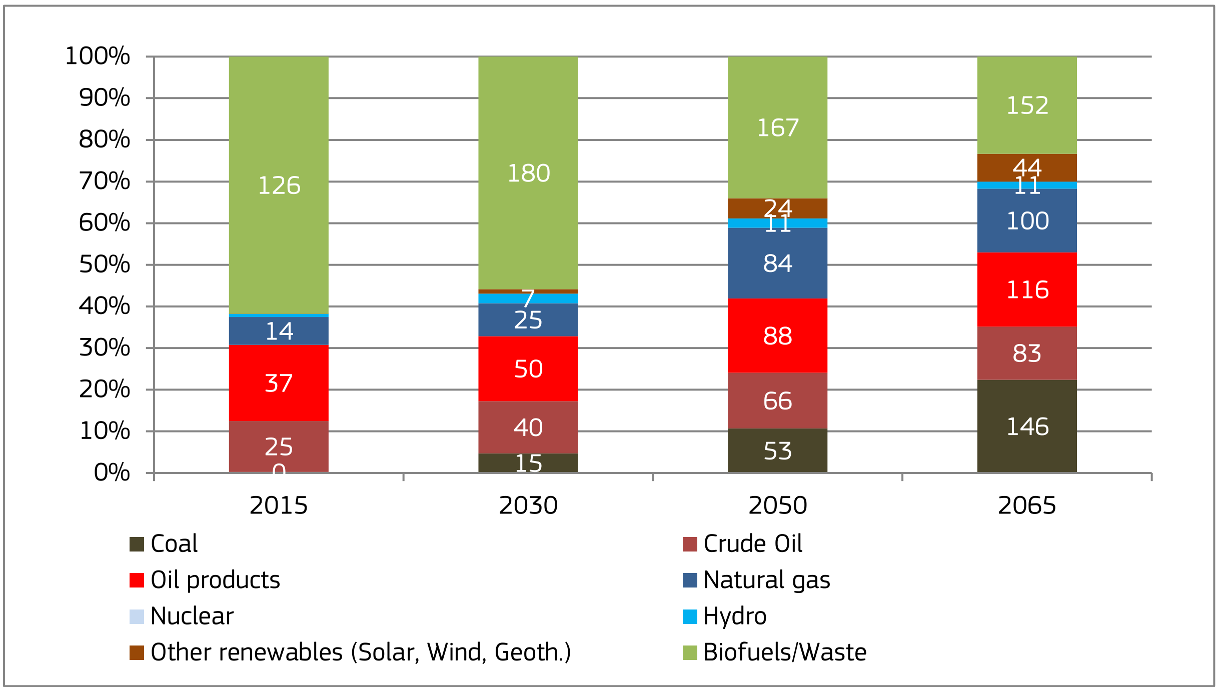

Africa is well endowed with energy resources. The results indicate that relatively high levels of trade are needed to fully exploit them Trade with Europe appears to be driven by relative demands. When supplies of gas, for example, are abundant in the medium term, exports are high. However, as gas is needed as a low carbon alternative - and to balance variable renewables - domestic demand increases. That, in turn, decreases sales to Europe. The analysis considers an exhaustive set of existing and planned interconnectors in the region. It is entirely feasible that more power could be traded from low-cost resource countries to others in Africa if new interconnectors (not yet planned) were considered. This may also increase the export potential out of Africa. Oil and coal trade was not specifically analysed (and trade levels were kept constant throughout the study).

### 4.1.2 Western Africa

In the Western African region, rapid energy supply growth is foreseen. TPES grows by 58% during 2015-2030, 52% during 2030-2050 and from 2050 to 2065 around 32%. In 2065, it is 653 Mtoe which is close to a 3.2 fold increase over the period.

Of all the regions in the model - together with Central Africa - it undergoes the most radical transformation. On the supply side, growing gas and coal supplies replace biomass. In the medium to long term their share, increase significantly. While in the short-term hydro starts to play a more prominent role, other renewables such as wind, solar, hydro and geothermal become significant.

**Figure 10.** Total primary energy supply in the WAPP region in the Reference scenario




The demand side somehow reflects the supply side. Initially, the dominant fuel is by far biomass, which is then replaced by increasing shares of electricity and gas consumption.

As the region is exposed to carbon constraints there is large increase in the use of nuclear. This is at the expense of coal initially and later, natural gas. On the continent, West Africa has relatively lower RET potential than other regions. In the Reference scenario, the TPES is 653 Mtoe while in the 2.0°C and 1.5°C is 493 Mtoe and 469 Mtoe correspondingly in 2065.

**Figure 11.** Total final consumption in the WAPP region in the Reference scenario

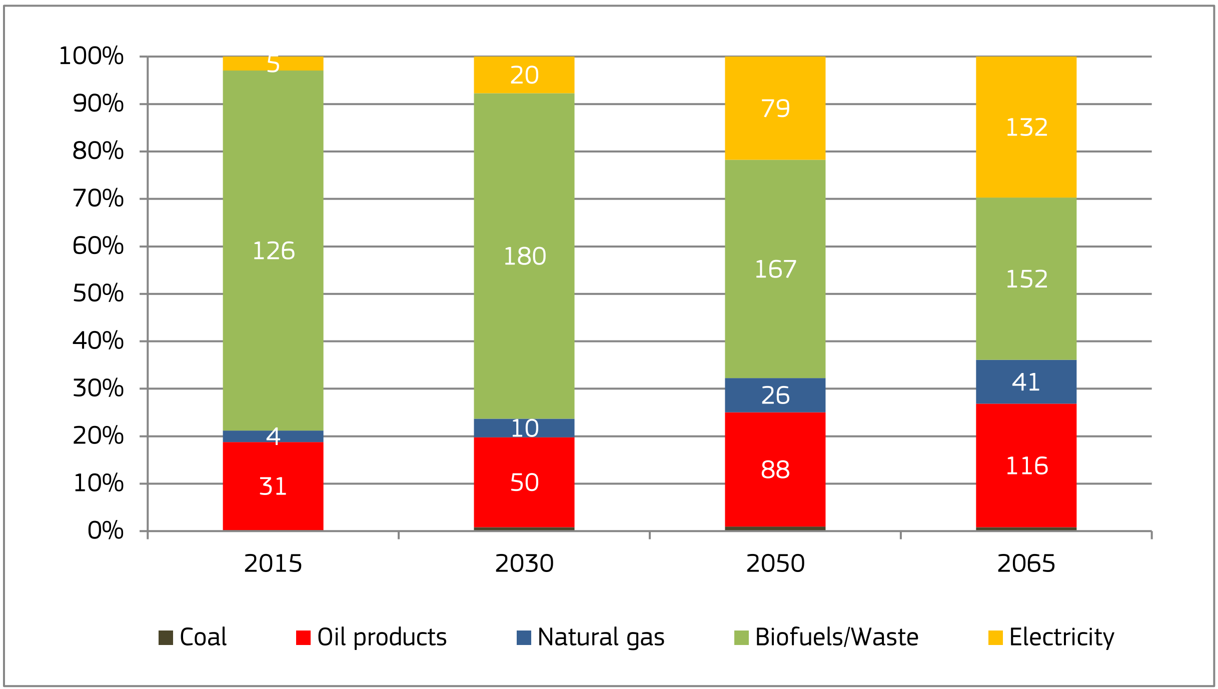
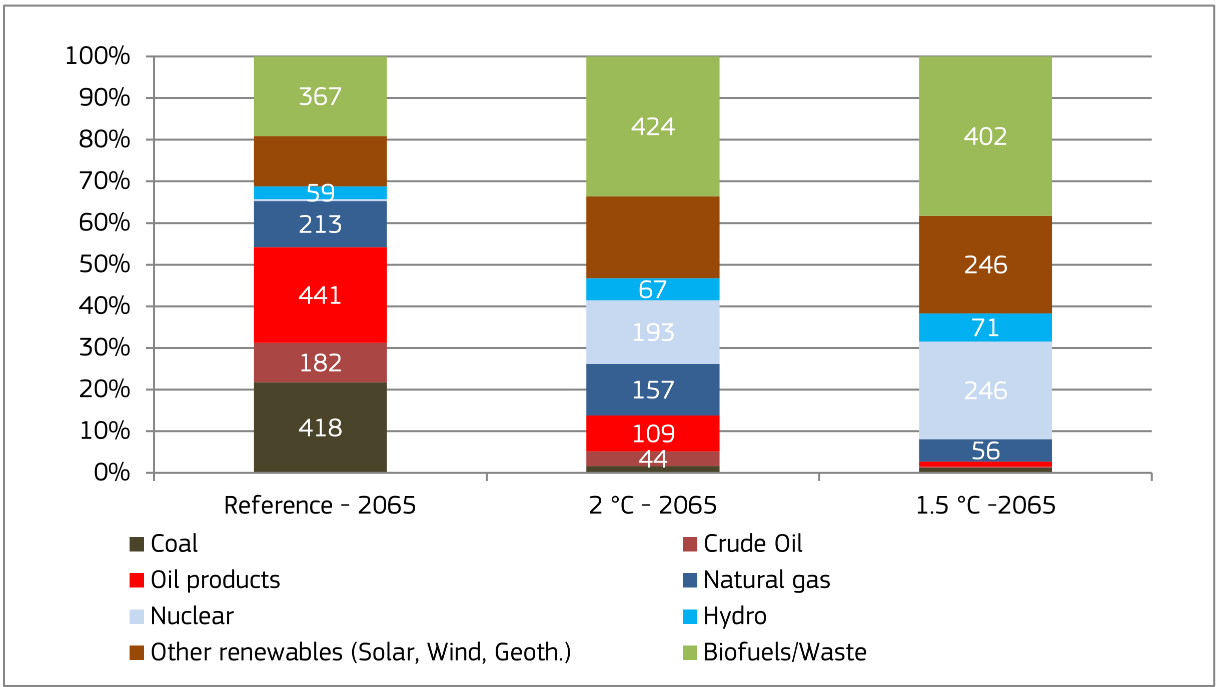


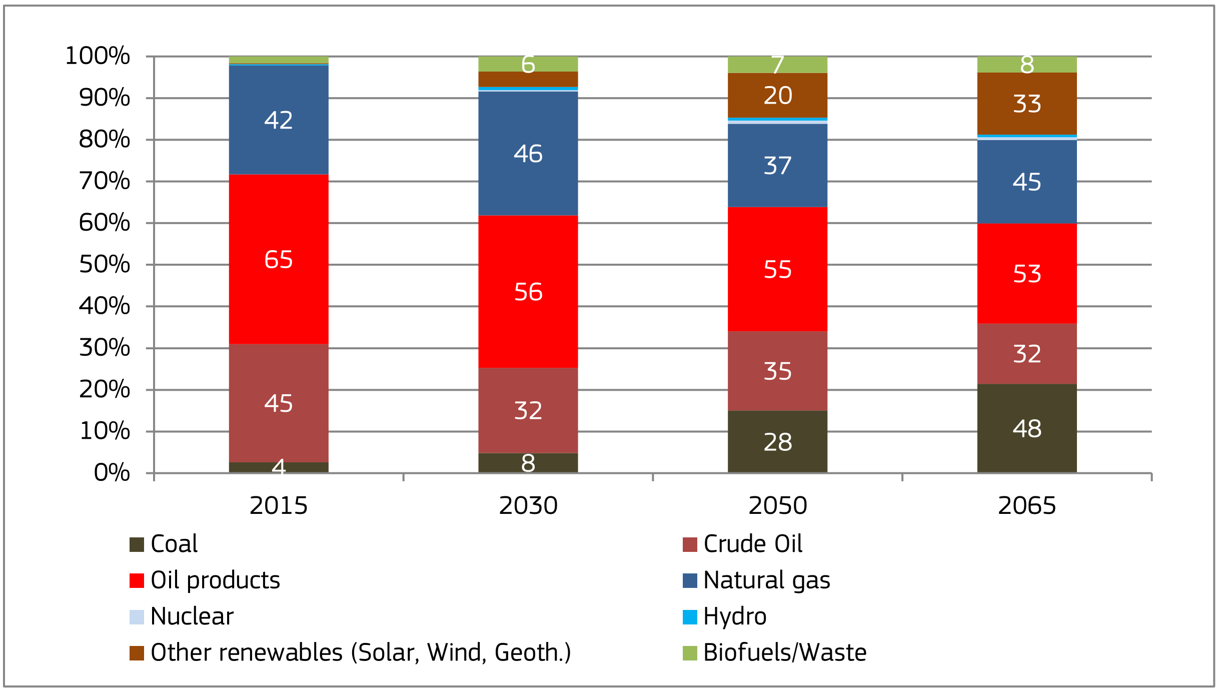

**Figure 12.** Total primary energy supply in Africa in the Reference, 2.0°C and 1.5°C scenarios



### 4.1.3 Northern Africa

TPES decreases by approximately 3% in 2015-2030. Later on and during the period 2030-2050 increases by 19% and finally the period 2050-2065 by 21%. In 2065, it reaches 223 Mtoe which is close to a 1.4 fold increase over the whole period.

**Figure 13.** Total primary energy supply in the NAPP region in the Reference scenario




On the supply side, gas and oil dominate but decrease in share over time. Important increases in the use of renewables and coal are seen to fuel electricity production towards the end of the period. In the medium term, large exports to Europe, in particular of natural gas, are expected.

On the demand side, the general trend is an increase in the absolute use of gas and a moderate (absolute and proportional) increase in the use of electricity. Moreover, the relative use of oil decreases.

Moving from the reference to lower carbon futures, there are initially large increases in the use of renewables. That is followed by baseload nuclear. Gas remains an important local fuel and a particularly important means to balance the large-scale deployment of variable renewables. Towards the end of the period, oil use is reduced. In the Reference scenario, the 2065 TPES is 223 Mtoe while in the 2.0°C and 1.5°C is significantly lower, at 113 Mtoe and 74 Mtoe, respectively.

**Figure 14.** Total final consumption in the NAPP region in the Reference scenario

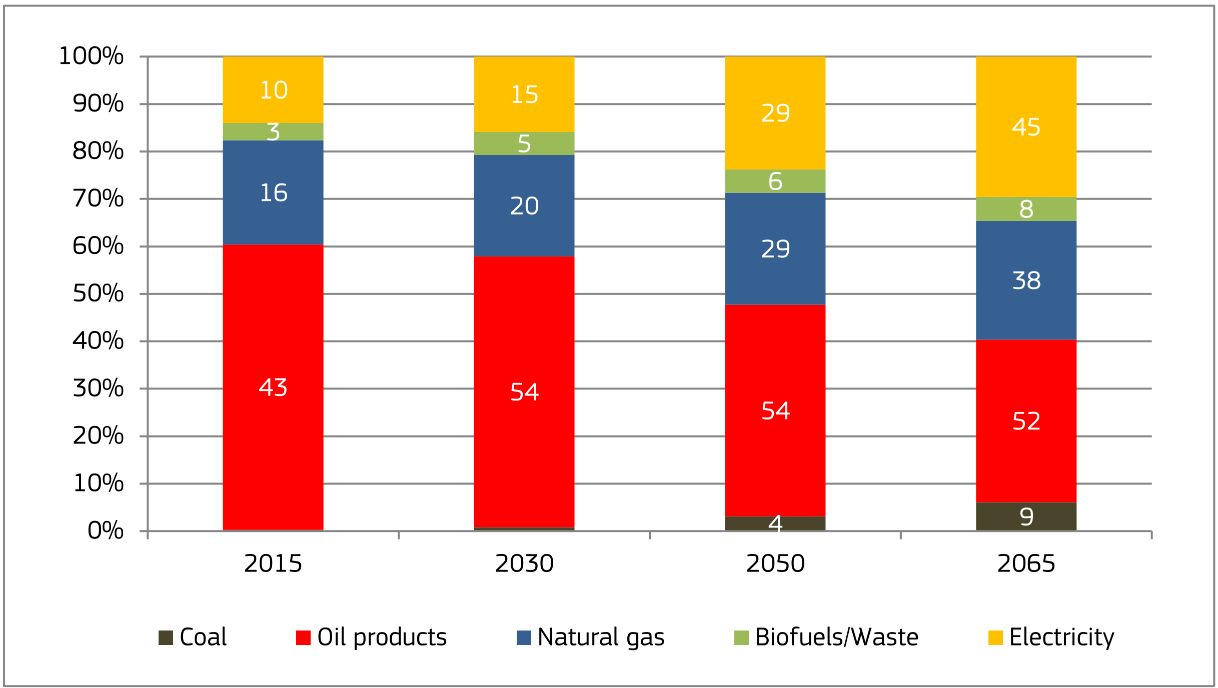
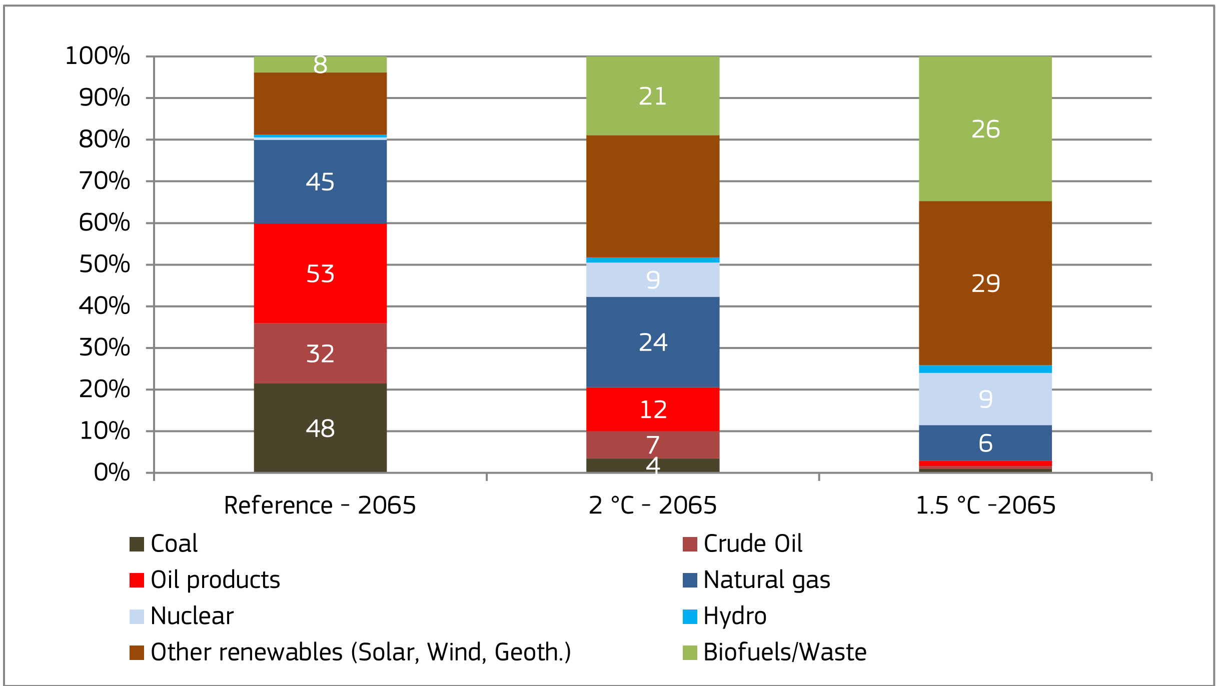



**Figure 15.** Total primary energy supply in the NAPP region in the Reference, 2.0°C and 1.5°C scenarios

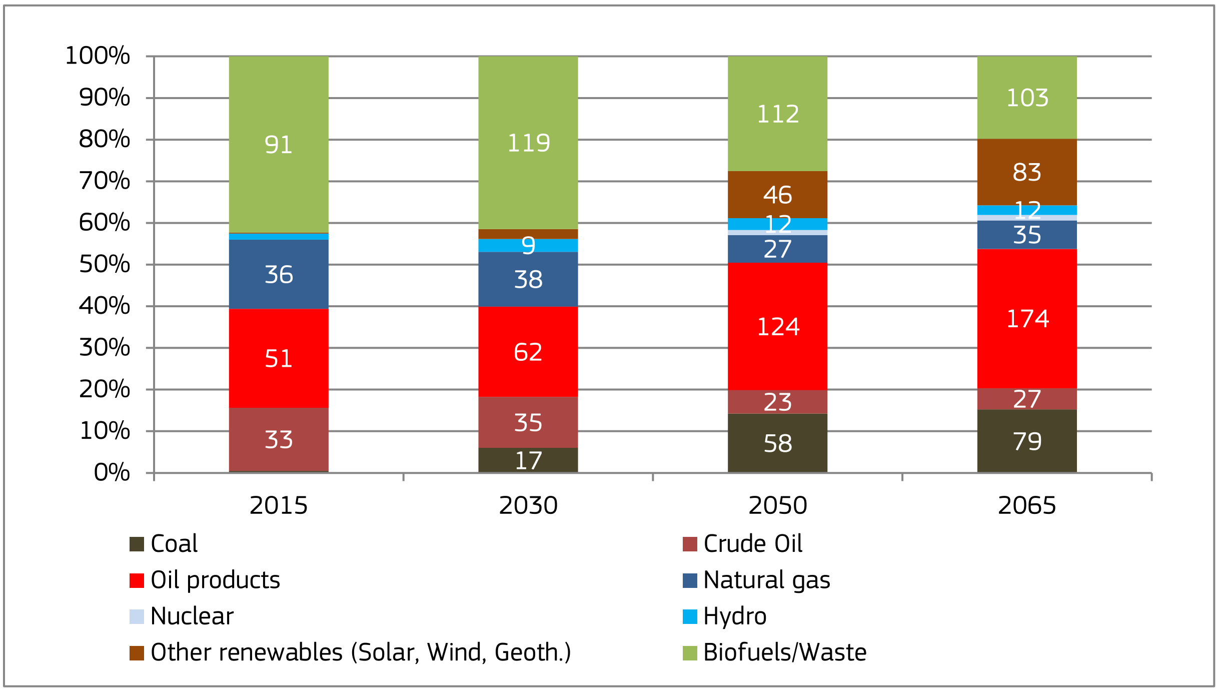


### 4.1.4 Eastern Africa

In the Eastern African region, TPES grows by 33% during the period 2015-2030, 42% during 2030-2050 and from 2050 to 2065 by approximately 28%. In 2065, it is 520 Mtoe, which is close to a 2.4 fold increase over the period.

Biomass initially dominates primary supplies together with oil and then gas. However, over time, renewable energy and coal take on increasing shares, as they become more competitive. This is primarily done at the expense of biomass and results in a more diversified energy supply mix for the region.

**Figure 16.** Total primary energy supply in the EAPP region in the Reference scenario




On the demand side, the relative proportion of biomass reduces significantly. This is replaced primarily by electricity and some coal.

As climate constraints are applied on the model, coal is replaced by renewables and natural gas. Tighter emissions constraints result in an increasing share of renewable and a relatively small quantity of nuclear reduce the use of oil in the region. In the Reference scenario, the 2065 TPES is 520 Mtoe while in the 2.0°C and 1.5°C is 309 Mtoe and 254 Mtoe, respectively.

**Figure 17.** Total final consumption in the EAPP region in the Reference scenario

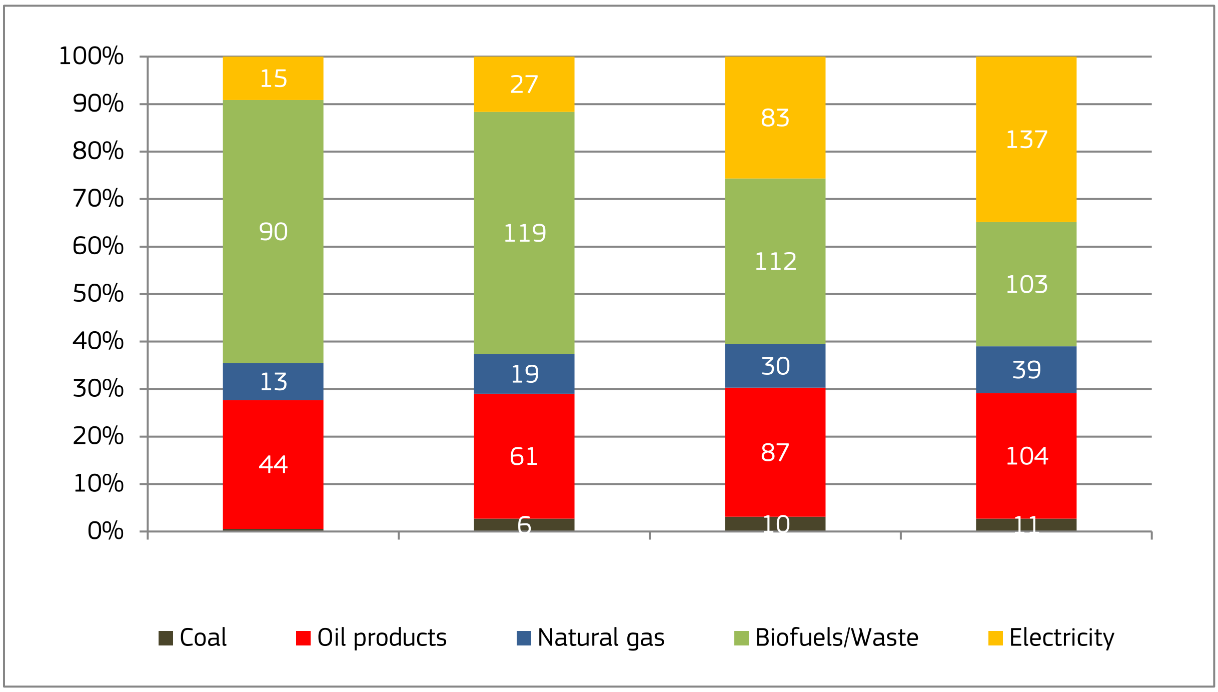
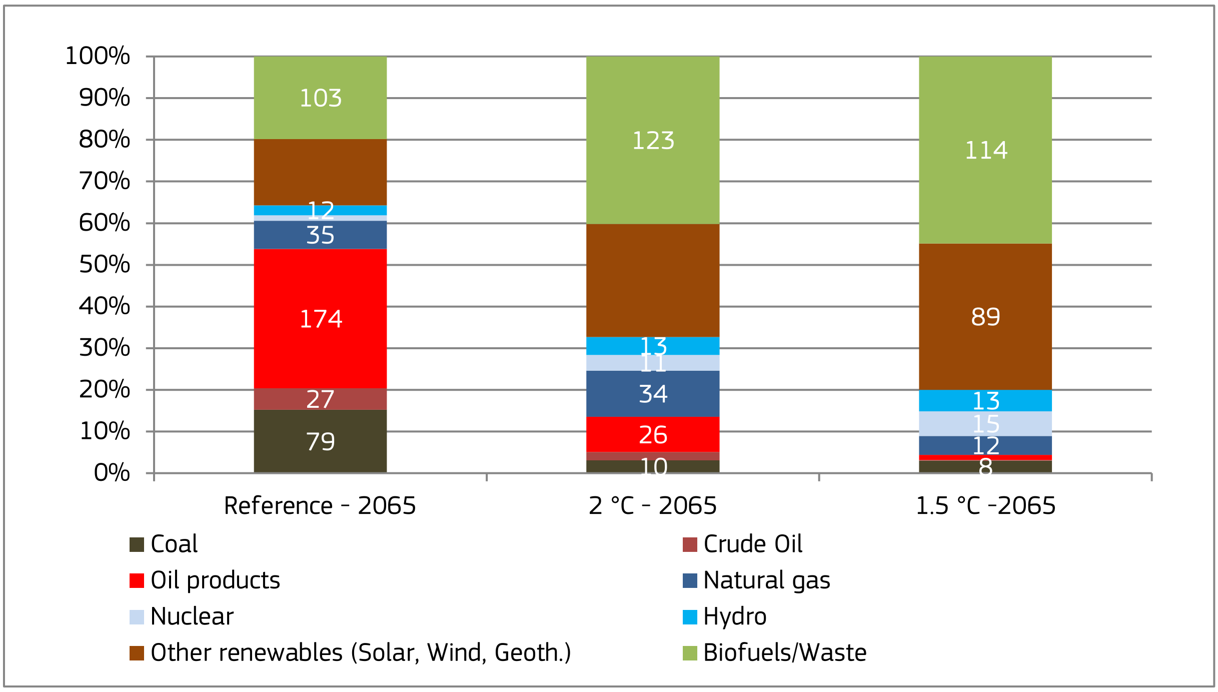



**Figure 18.** Total primary energy supply in the EAPP pool in the Reference, 2.0°C and 1.5°C scenarios

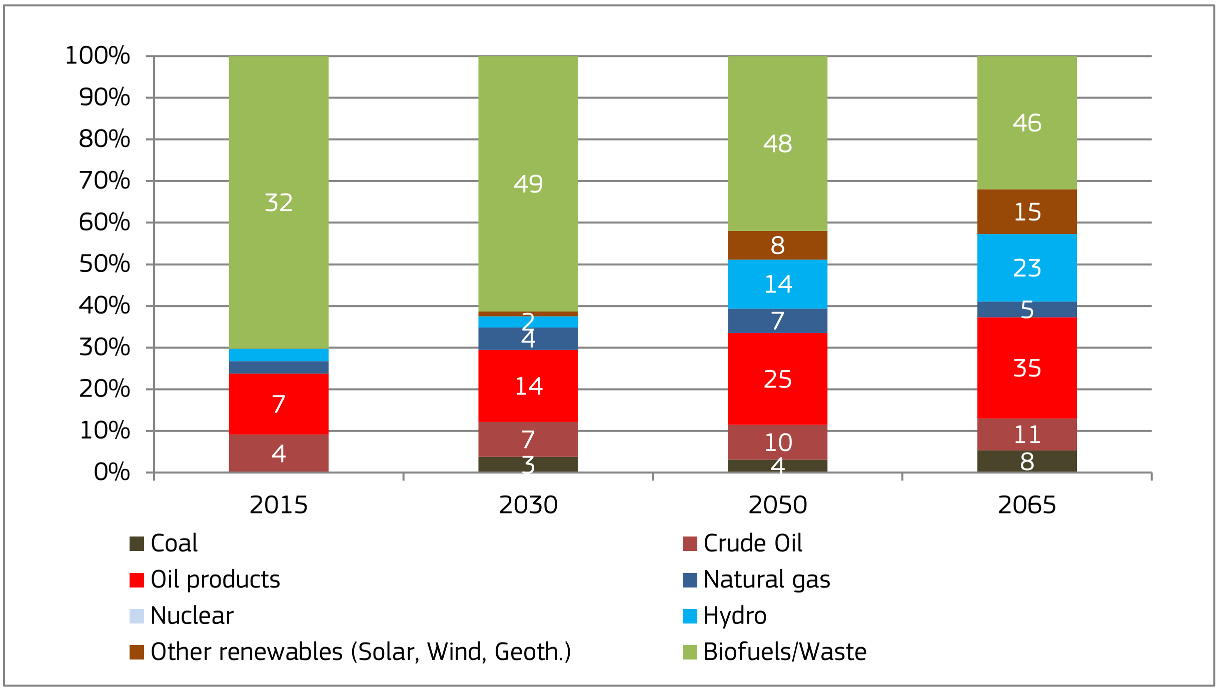


### 4.1.5 Central Africa

In the Central African region, TPES grows by 80% during the period 2015-2030, 41% the period 2030-2050 and from 2050 to 2065 around 24%. In 2065, it is 143 Mtoe, which is close to a 3.2 fold increase over the period.

Its transformation is radical. On the supply side, biomass is replaced by hydro, other renewables and gas. At the end of the period, hydro and other RET combined form the largest supplier of energy in the region. The uptake of hydro is associated with increased gross trade between countries. That is needed as hydro sites have large potentials, and local as well as neighbouring country demands are needed to exploit the associated resource.

**Figure 19.** Total primary energy supply in the CAPP region in the Reference scenario




The demand side reflects the supply side to some extent. By far the dominant fuel is initially biomass. This is replaced by increasing shares of electricity and a moderate increase in gas consumption.

As emissions reductions are applied in the region, its rich hydro resource is exploited further. It initially displaced coal and then oil. Towards the end of the period, small quantities of nuclear are used. In the Reference scenario, the TPES is 143 Mtoe while in the 2.0°C and 1.5°C is 104 Mtoe and 95 Mtoe correspondingly in 2065.

**Figure 20.** Total final consumption in the CAPP region in the Reference scenario

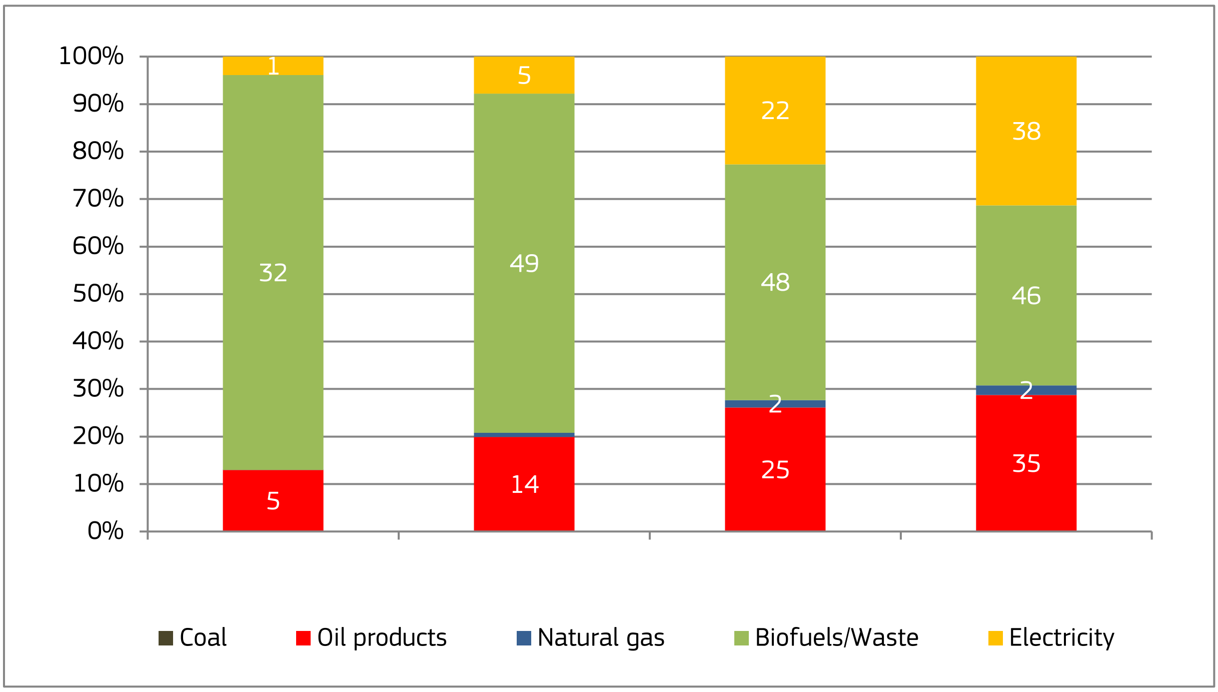
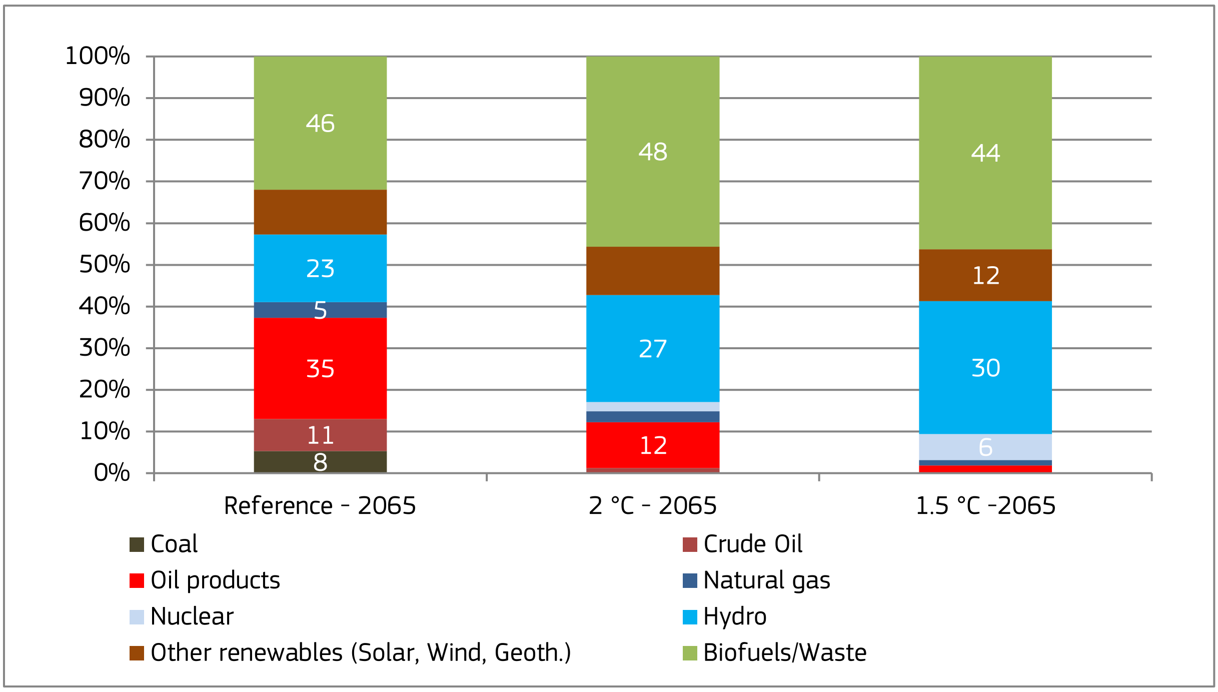



**Figure 21.** Total primary energy supply in the CAPP region in the Reference, 2.0°C and 1.5°C scenarios

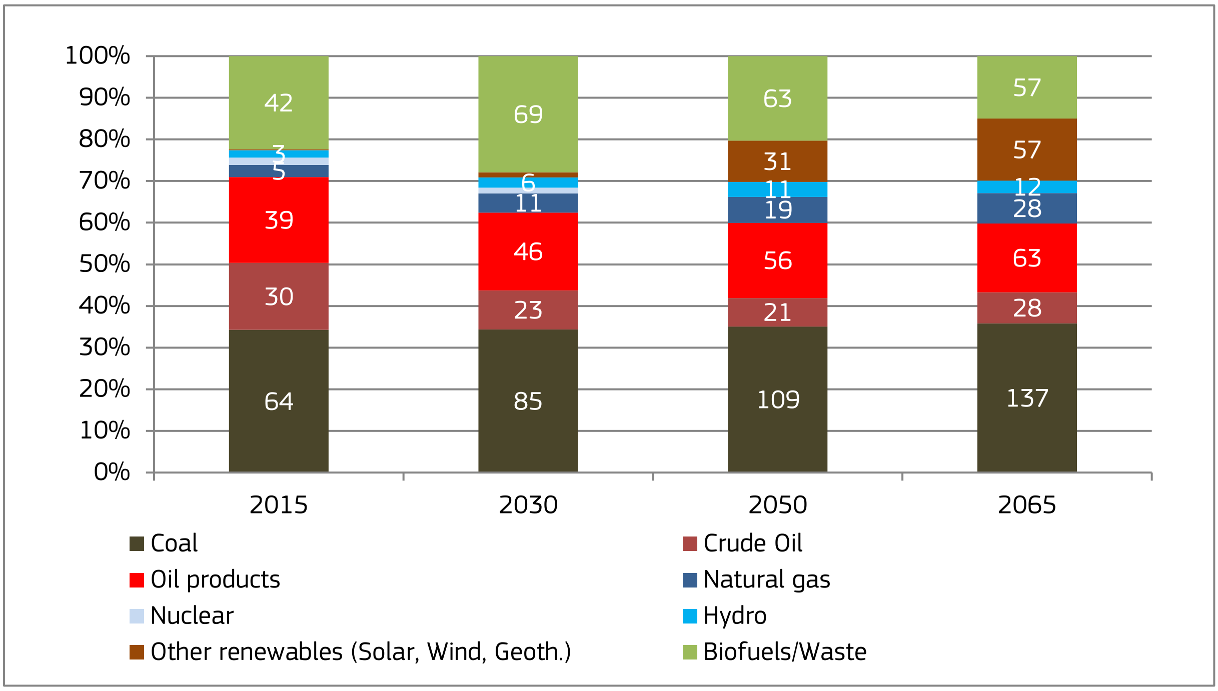


### 4.1.6 Southern Africa

TPES grows by 32% during the period 2015-2030, 27% during 2030-2050 and from 2050 to 2065 22%. In 2065, it is 382 Mtoe, which is close to a 2-fold increase over the period.

On the supply side, coal, oil and biomass are the most important fuels. Over time, oil reduces in importance and is replaced by renewable energy including solar, wind and geothermal. Coal remains the dominant energy supply option. As coal mining is an important source of employment for the region a move away from it when it becomes relatively expensive will require careful planning. Across scenarios, it is assumed that exports remain constant for crude and coal, generating important local income. However, the feasibility thereof given global shifts away from fossils predicted in these scenarios is questionable.

**Figure 22.** Total primary energy supply in the SAPP region in the Reference scenario




Compared to other regions the relative proportion of demand does not change drastically. While oil keeps a similar share over time, biomass and coal uses are replaced by increasing gas and electricity consumption.

As climate constraints are applied, a significant shift from coal and uptake of renewables takes place, followed by nuclear and natural gas. In particular, all renewable options are taken up, including the exploitation of hydro. As constraints tighten the use of oil decreases and is replaced by increasing shares of nuclear and renewables. In the Reference scenario, the 2065 TPES is 382 Mtoe while in the 2.0°C and 1.5°C is 247 Mtoe and 158 Mtoe, respectively.

**Figure 23.** Total final consumption in the SAPP region in the reference scenario

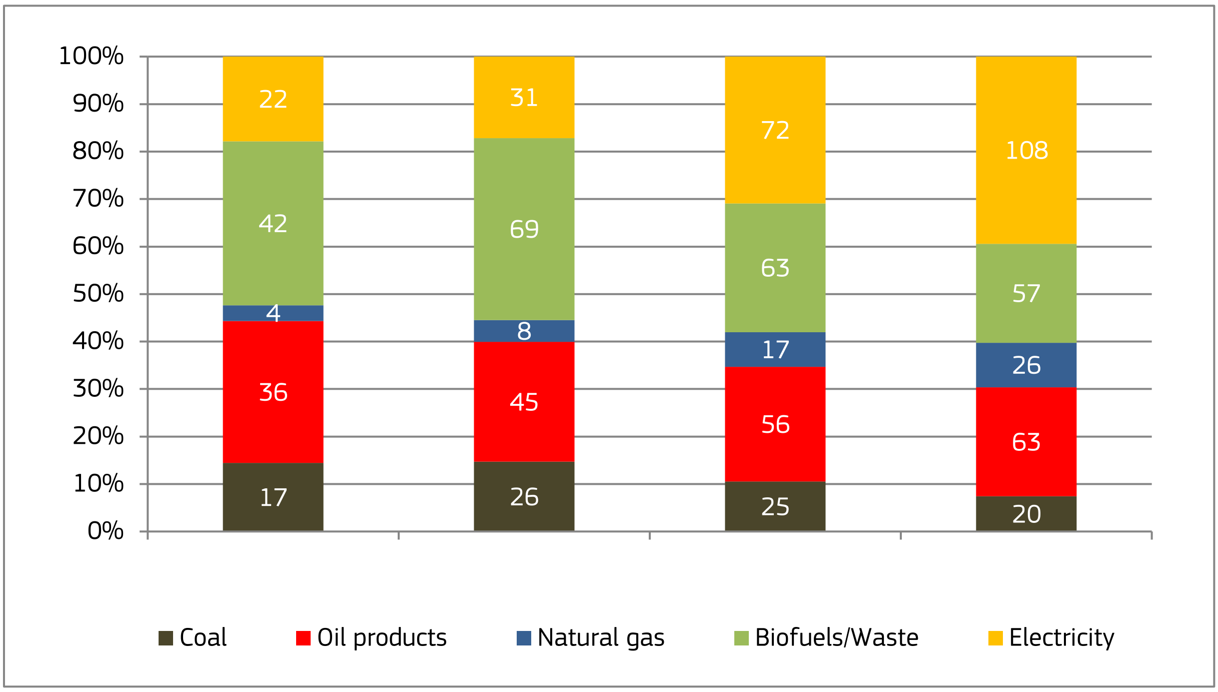
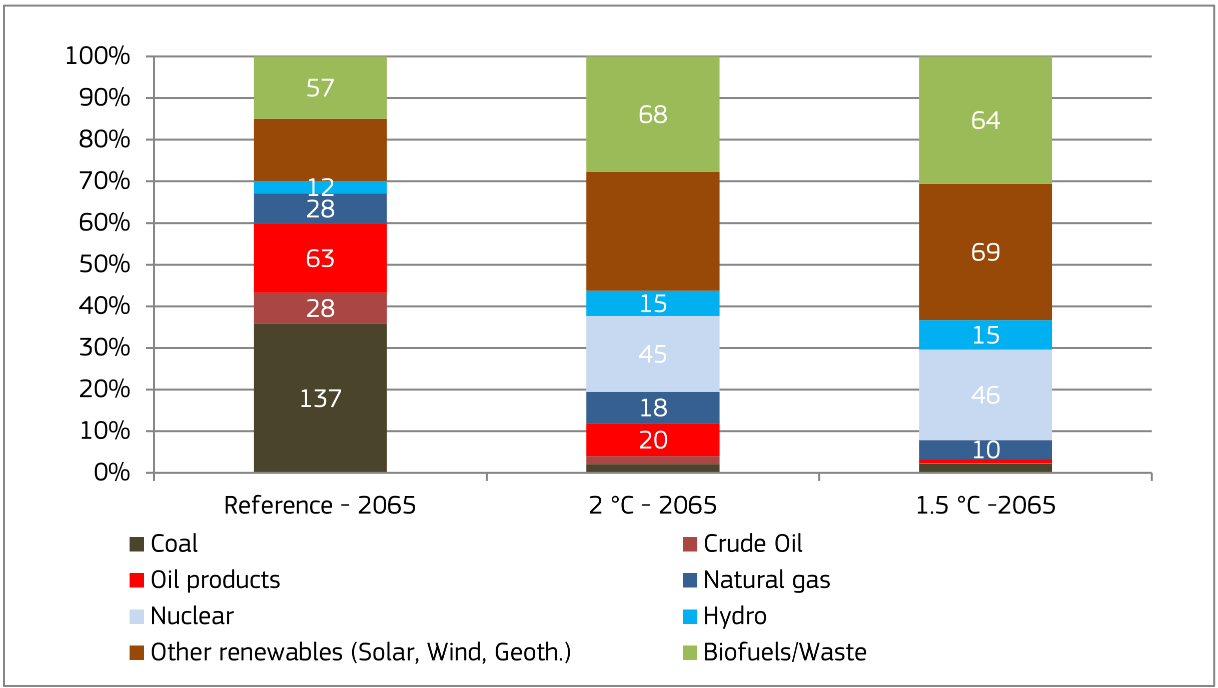



**Figure 24.** Total primary energy supply in the SAPP region in the Reference, 2.0°C and 1.5°C scenarios



## 4.2 Power sector: generation capacity

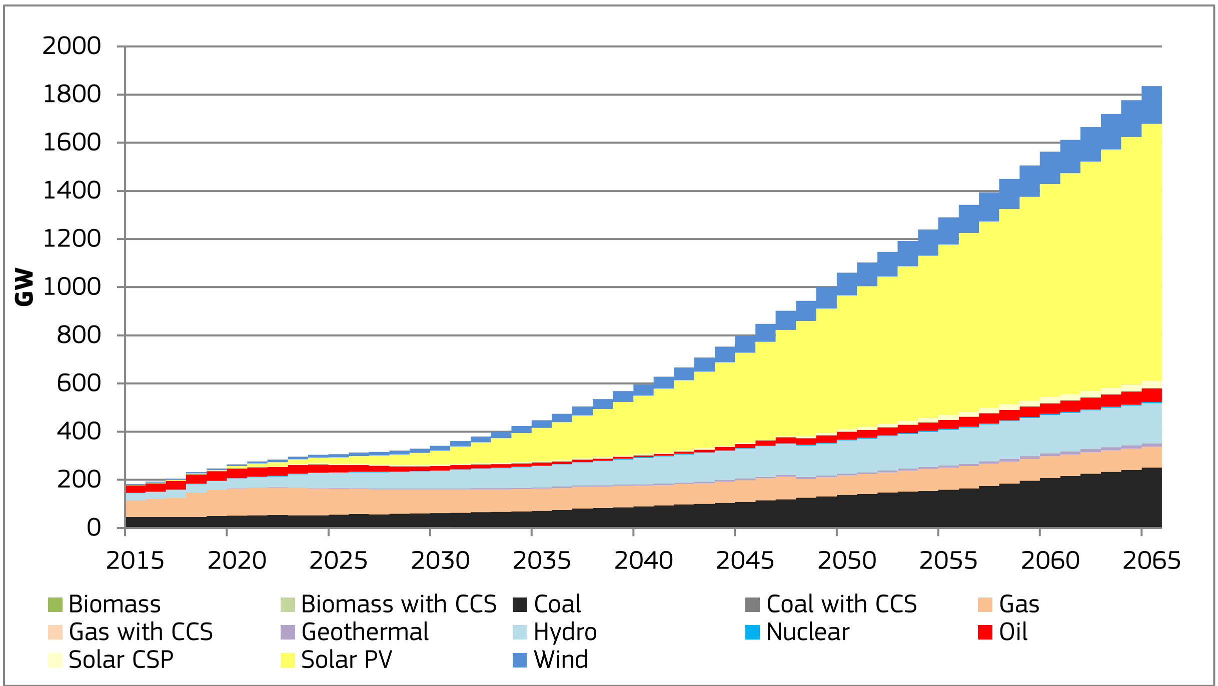
This section discusses the capacity and generation mix of the power system in the entire African continent and the individual power pools.

### 4.2.1 All Africa

Across the power pools, some patterns emerge in the Reference scenario results. Installed generation capacity increases dramatically to meet surging electricity demand. Deployments of renewable energy technologies (RET), particularly in solar PV, but also hydro and some wind, increase rapidly from 2020. They become increasingly competitive as the technology costs decline, even for the countries which have large fossil resources. However, fossil fuels do remain a key component of each of the power pools. What is noticeable from the results below is how the composition of each of the power pools is very different, and this reflects the unique nature of each of the constituent countries, their available resources, existing power systems and how their future demands evolve in the scenario.

In the Reference scenario, the total installed capacity will increase from 183 GW in 2015 to 596 GW in 2040 and 1835 GW in 2065 Figure 25. The Renewable share will gradually increase from 20% in 2015 to 78% in 2065. Specifically, the renewable capacity in the continent will reach to 164 GW (48% of the total) in 2030 mainly due to the fact that a number of African countries have set renewable energy targets that year. Hydropower constituted most of the continent's renewable capacity 28 GW (15% of the total) in 2015, followed by wind (3 GW), solar PV (2 GW), biomass (2 GW), solar CSP (0.31 GW) and geothermal (0.18 GW). In the future, the decreasing investment costs mainly in solar PV technologies will cause an increase in PV installed capacity from approximately 2 GW in 2015 to 1067 GW in 2065. However, it should be noted that the relatively low capacity factors of solar technology compared to other power generation technologies require a lot of capacity to be installed to generate the same amount of electricity. The fossil fuel capacity in the continent will increase from 147 GW in 2015 to 398 GW in 2065. In the upcoming years, the installed capacity of gas power plants will gradually be replaced by coal power plants as a result mainly of lower coal price projections. In addition, the nuclear capacity will approximately double between 2015 and 2065.

**Figure 25.** Power generation capacity in Africa in the Reference scenario




In the 2.0°C scenario, the total installed capacity will decrease by 72 GW (in total 524 GW) in 2040 and by 25 GW (1809 GW) in 2065 compared to the Reference scenario. The lower installed capacity in the 2.0°C scenario is mainly due to the lower estimated electricity demand projections (4723 PJ in 2065) compared to the Reference scenario (5331 PJ in 20165) consistent with policies to increase end-use efficiency and manage demand. In the 2.0°C scenario, the renewable energy share will be higher by 2% (71% in total) in 2040 and 7% (78% in total) by 2065 compared to the Reference scenario. Future investments mainly in wind technologies, solar CSP and hydropower plants will increase their respective capacity to 226 GW, 48 GW and

193 GW by 2065. Under the 2.0°C scenario, in order for the continent to achieve the annual carbon dioxide emission limits in the future, it will need to reduce its overall fossil fuel capacity by 128 GW by 2065 mainly by phasing out coal and oil power plants. Those investments will be replaced by increasing the natural gas capacity by 47 GW (134 GW in total) by 2065 compared to the Reference scenario. In addition, nuclear investments will be made in the following decades to provide reliable electricity supply, increasing the nuclear capacity to 104 GW, approximately 25 times more than in the Reference scenario. It should be highlighted that mainly the Western African power pool followed by the Southern African power pool will be responsible for approximately 63% and 24% of the continent's overall nuclear capacity in 2065. The following countries Nigeria (23 GW), Ghana (14 GW), Mali (14 GW), Côte d'Ivoire (6 GW) as well as Angola (12.5 GW) and Zambia (11.5 GW) are the ones responsible for most of the nuclear capacity in the respective power pools by 2065. A key investment that is also highlighted in the 2.0°C scenario is the commissioning of Phase III & IV of the Grand Inga hydropower project in the Democratic Republic of Congo in the upcoming decades. The power generation capacity for the whole of Africa in the 2.0°C scenario is presented in Figure 26.

In the 1.5°C scenario, the installed capacity in the continent will be approximately lower by 15% (503 GW) in 2040 and less than 1% (1827 GW) in 2065 compared to the Reference scenario. The renewable energy technologies will represent approximately 75% of the total capacity in 2040 while by 2065 that share will increase to 85%. As shown in Figure 27, the continent will need to relatively increase its capacity by 18 GW in the 1.5°C compared to the 2.0°C by 2065 since the lower capacity factors of renewable energy technologies would require larger investments on those technologies. In this scenario, in order to achieve the high emission reduction targets, the installed capacity of gas-fired power plants will need to reach to 87 GW in 2065 followed by 13 GW of coal and almost 1 GW of oil power plants. The continent will need to increase its hydro capacity by approximately 38 GW (205 GW in total) by 2065 between the Reference and the 1.5°C scenario with the Central African power pool to play a significant role on that as in the 2.0°C scenario. In addition, it should be highlighted the increase of the nuclear capacity by 168 GW in 2065 between the Reference and the 1.5°C scenario and by 68 GW compared to the 2.0°C scenario. The penetration of carbon capture with storage technologies the upcoming decades is also one of the reasons for the overall decrease of the carbon dioxide emissions in the continent.

**Figure 26** Power generation capacity in Africa in the 2.0°C scenario

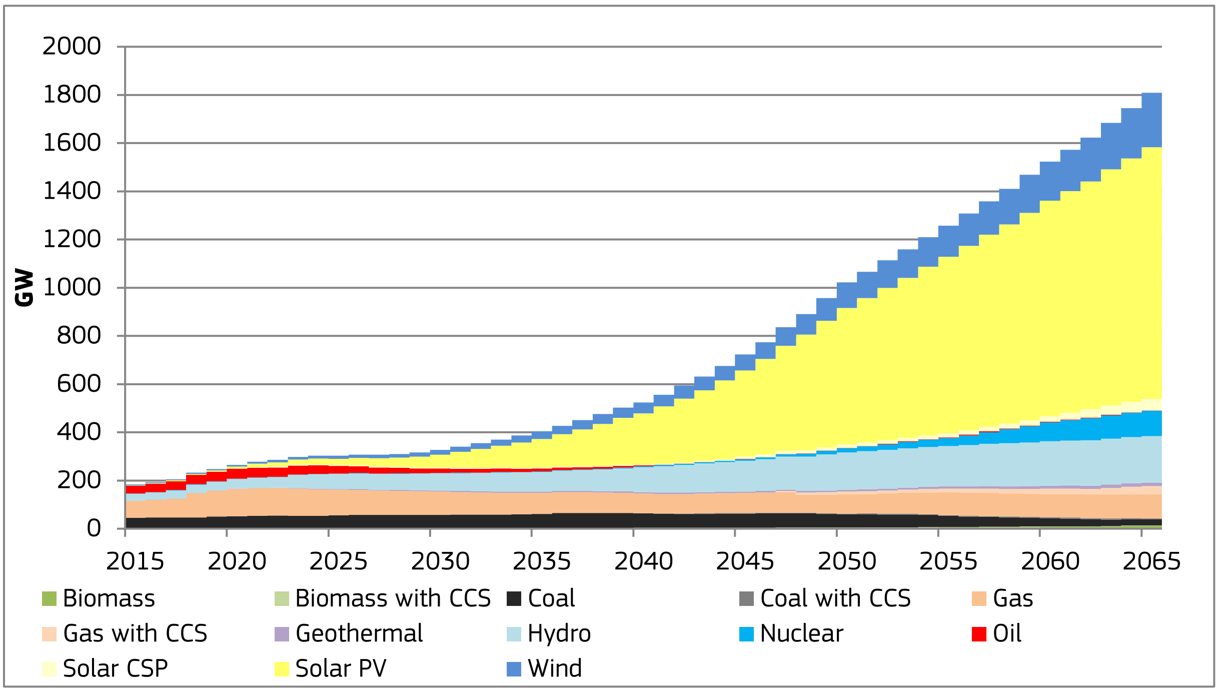
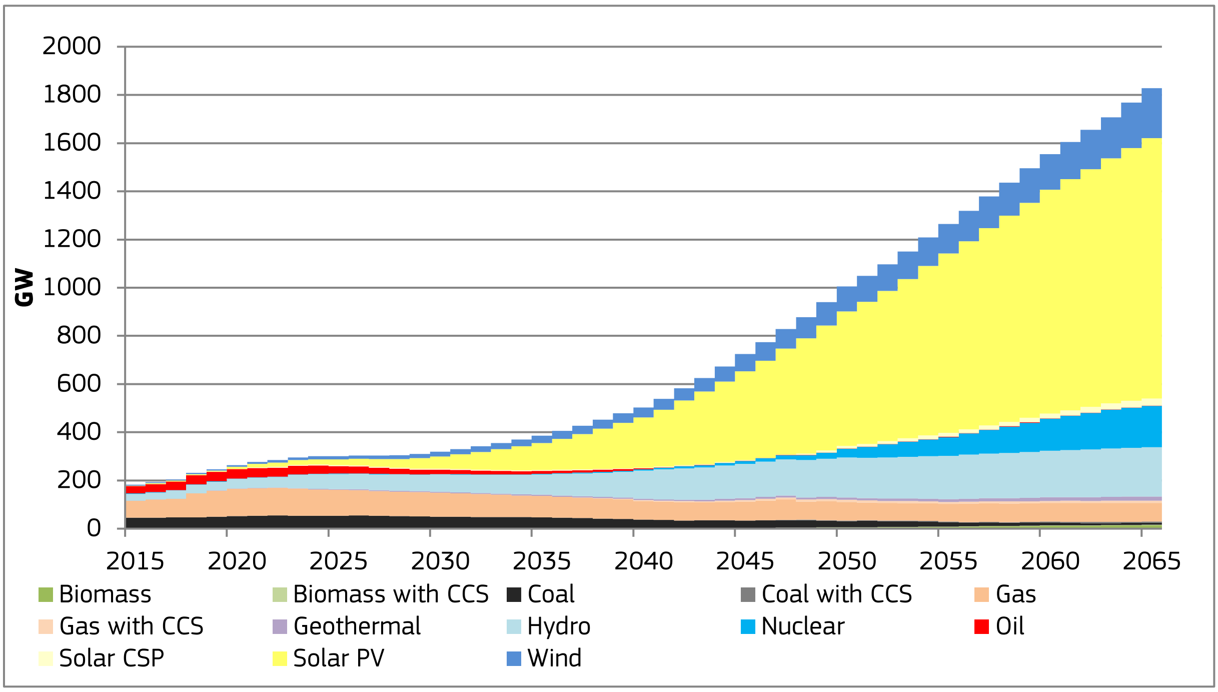


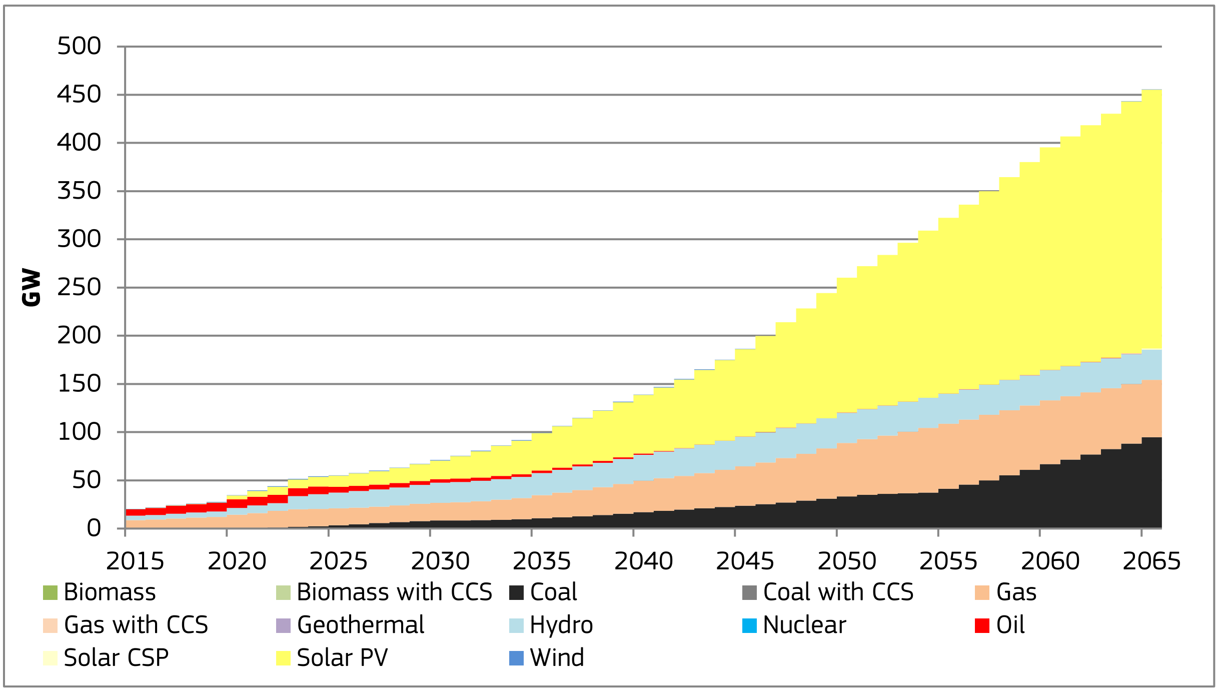
**Figure 27.** Power generation capacity in Africa in the 1.5°C scenario



### 4.2.2 Western Africa

The total installed capacity in the Western African power pool will increase by approximately 23 times the upcoming decades from 20 GW in 2015 to 455 GW in 2065 (Figure 28). Most of the continent's installed capacity in the future will be located in the WAPP region. The high increase in the capacity of the power system in the region is mainly due to the high increase of the electricity demand in the upcoming decades (low electricity access, high estimated population increase). Specifically, Nigeria's installed capacity will increase from approximately 10 GW in 2015 to 242 GW in 2065, representing around 53% of the power pool's total capacity. The RES share was relatively low in 2015, almost 24%, however, in the future it increases to 64% in 2040 and 66% in 2065. One of the main reasons is the high future renewable energy targets in most of the countries (Annex 5). The low wind energy potential in the region justifies the low installed capacity of wind technology throughout the modelling period, which is less than 1 GW. The solar energy potential is also relatively low in the region; nevertheless, the estimated future decreasing investment costs of solar technologies lead the countries to increase their solar PV capacity from less than 100 MW in 2015 to 268 GW in 2065. In addition, the relatively high hydropower potential in the region lead Benin, Guinea, Niger, Nigeria and Senegal to exploit part of it having future investments of 1 GW, 4 GW, 0.6 GW, 13 GW, 1 GW respectively, increasing the overall hydro capacity from almost 5 GW in 2015 to 31 GW in 2065. The installed capacity of natural gas will increase from around 9 GW in 2015 to 60 GW in 2065 with approximately 85% of the capacity to be allocated in Nigeria. The planned "Trans-Saharan" gas pipeline project that will export gas to Algeria and Niger as well as the existing "West African" gas pipeline through Benin, Togo and Ghana are some of the key projects that will transform Nigeria's energy mix. Most of the countries will invest in coal power plants in the future increasing the power pool's capacity from less than 100 MW in 2015 to 95 GW in 2065.

**Figure 28.** Power generation capacity in WAPP in the Reference scenario




In the 2.0°C scenario, the total installed capacity in the Western African power pool will decrease by approximately 16 GW (in total 440 GW) by 2065 compared to the Reference scenario. The renewable energy share will be higher by 5% (71% in total) by 2065 compared to the Reference scenario. Future investments mainly in wind technologies (29 GW), solar CSP (15 GW) and biomass (8.8 GW) power plants by 2065 justify that. It should be highlighted that a number of African countries in order to achieve the annual emission limits under this scenario will invest in nuclear power plants in the future increasing the overall nuclear capacity to almost 66 GW by 2065 while in the Reference scenario was zero. Furthermore, the coal and oil power capacity will decrease to 7 GW and less than 1 GW respectively in 2065 while the gas capacity to 55 GW. Nigeria will be mainly responsible for approximately 85% of the power pool s gas capacity in the future.

**Figure 29.** Power generation capacity in WAPP in the 2.0°C scenario

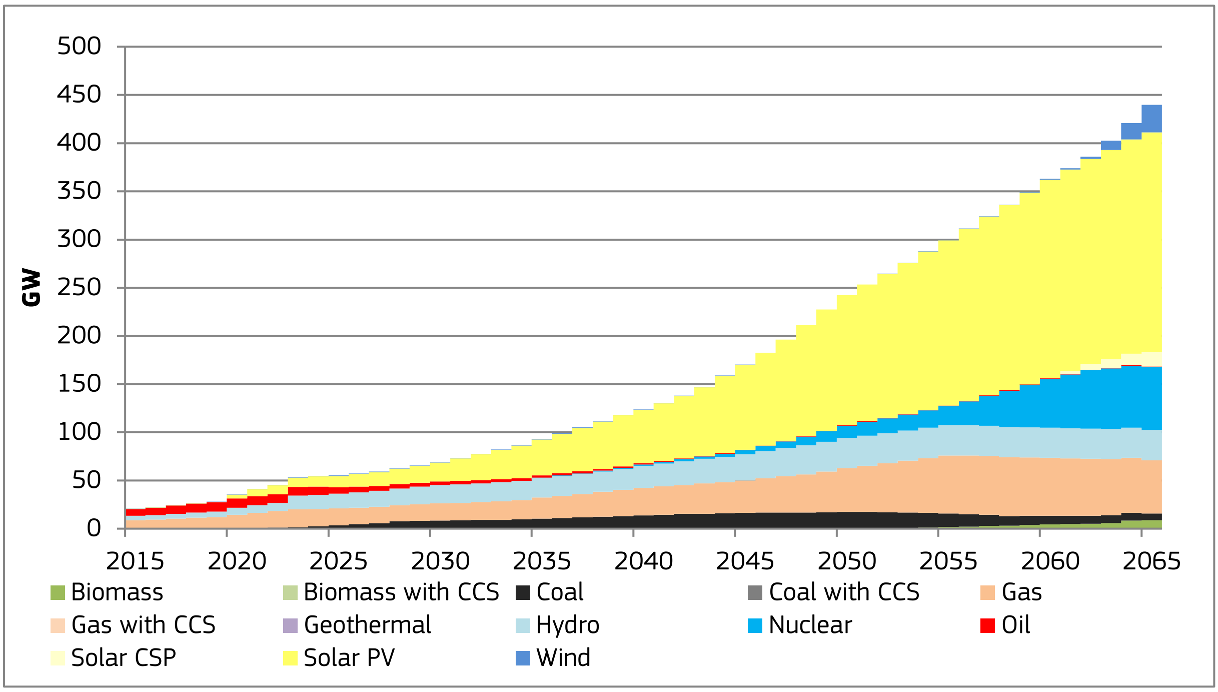
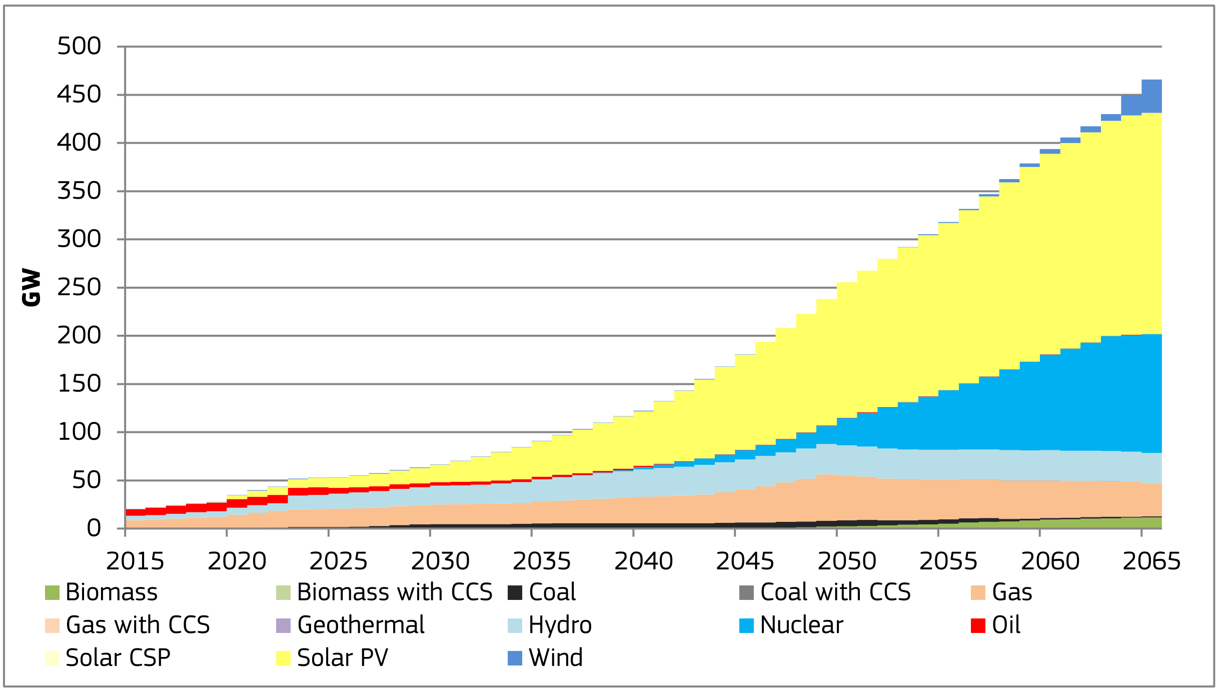



**Figure 30.** Power generation capacity in WAPP in the 1.5°C scenario

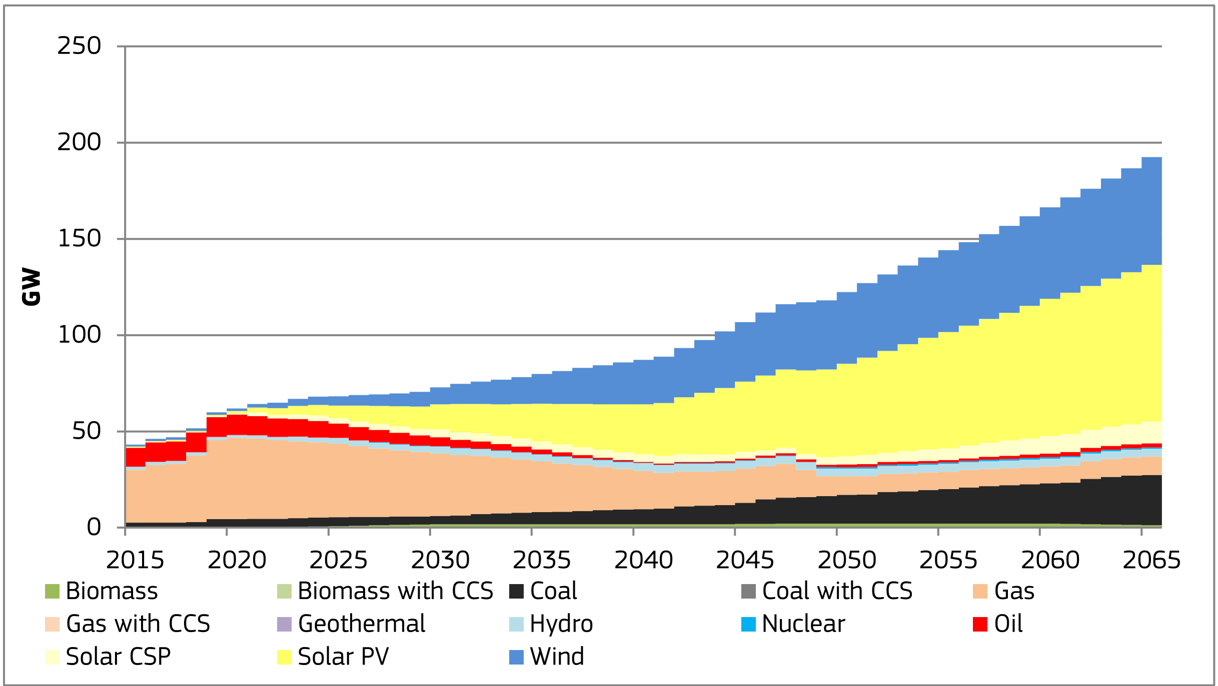



In the 1.5°C scenario, the installed capacity in the power pool will be approximately lower by 13% (122 GW) in 2040 compared to the Reference scenario while after 2063 it will be higher 2% (465 GW) in 2065. This is mainly due to the increase in the installed capacity of wind technologies the period 2053-2065. In addition, the installed capacity of biomass will increase to 12 GW by 2065 compared to 0 GW in the Reference scenario. It should be highlighted that the installed capacity of coal in the Reference scenario, 95 GW in 2065, will be decreased to almost 1 GW in the 1.5°C scenario and be substituted mainly by nuclear investments. The nuclear capacity in this scenario it will increase to 123 GW in 2065 compared to zero levels in the Reference scenario.

### 4.2.3 Northern Africa

The generation capacity in the Northern African power pool is expected to increase from approximately 41 GW in 2015, to 85 GW in 2040 and 192 GW in 2065 (Figure 31). Extensive investments will be required, as the electricity demand in the region will increase by approximately four times in 2065, in comparison to 2015. It should be noted that the share of renewables (including hydro) will increase from 7% in 2015 to 67% in 2040 and 79% in 2065. The relatively high renewable electricity generation targets in countries such as Morocco (52% by 2030) and Algeria (27% by 2030) will drive that trajectory.

**Figure 31.** Power generation capacity in NAPP in the Reference scenario




Solar PV technology accounts for most of the renewable capacity in the region, ~80 GW by 2065, followed by wind (~56 GW). The high wind and solar potential in the region along with the decreasing cost of renewables and each country's RET targets are some of the factors that favour the increase of renewable energy technologies in the future. Specifically, in Tunisia where the fossil fuel reserves are low, the RET investments are relatively higher than in other countries. Future investments in solar CSP technologies are expected mainly in Morocco. In the upcoming years, the natural gas investments will be made in Algeria where the installed capacity is expected to increase to about 29 GW in the period 2015-2020. The new natural gas power plants will gradually replace the old inefficient ones. The Reference scenario shows that in the future, a gas dominated region in 2015 (63%) will switch its generation capacity to one based on renewables (~80%) in 2065; the share of gas-based power plants is expected to drop to 5%. In the NAPP, Morocco is expected to have the largest share (36%) in totalled installed capacity by 2065. In addition to the investments in renewable sources of electricity generation, Morocco is also expected to invest in coal power plants, as per their national expansion strategy. The investment in hydropower plants is capped by the low potential in the region (~4 GW). Investments in nuclear power plants are expected to amount to ~700 MW—with most of the capacity expected in Tunisia.

In the 2.0°C scenario, the total installed capacity in the Northern African power pool will decrease by approximately 20 GW (in total 173 GW) by 2065 compared to the Reference scenario. The renewable energy share will be higher by 7% (87% in total) by 2065 compared to the Reference scenario. Future investments in solar CSP technologies in Egypt and Morocco will increase the overall installed capacity of those technologies in the region to 14 GW, 21% higher than in the Reference scenario. In addition, the wind capacity in the region will increase by 2 GW (57 GW in total) while hydropower capacity (4 GW) will relatively be similar between the two scenarios. It should be noted, in this scenario the overall nuclear capacity will increase to 5 GW in 2065 compared to 700 MW in the Reference scenario, starting in 2051, consisting mainly by nuclear investments of 1.6 GW in Tunisia and 3.5 GW in Morocco. Those investments in the aforementioned countries will shift the region's energy mix decreasing the coal and oil capacity to 4 GW and 200 MW by 2065 respectively, approximately 7 times less than in the Reference scenario. Also, Morocco will invest to approximately 200 MW of biomass CCS technologies in the future.

In the 1.5°C scenario, the installed capacity in the power pool will be approximately lower by 22% (149 GW) in 2065 compared to the Reference scenario. The renewable energy technologies will represent approximately 89% of the total installed capacity in 2065 compared to 80% in the Reference scenario, constituting mainly by solar PV (64 GW), followed by wind (54 GW), solar CSP (9 GW) and hydropower (4 GW) technologies. In this scenario, the installed capacity of coal and oil power plants will decrease to 700 MW and 2 MW in 2065 while the gas capacity to 10.5 GW. Similar to the 2.0°C scenario, nuclear investments will increase to 5 GW by 2065 replacing carbon-emitting power plants. In addition, it should be noted the penetration of biomass CCS technologies into the power pool's power system such as in Morocco where the installed capacity of biomass CCS technologies will be approximately 200 MW.

**Figure 32.** Power generation capacity in NAPP in the 2.0°C scenario

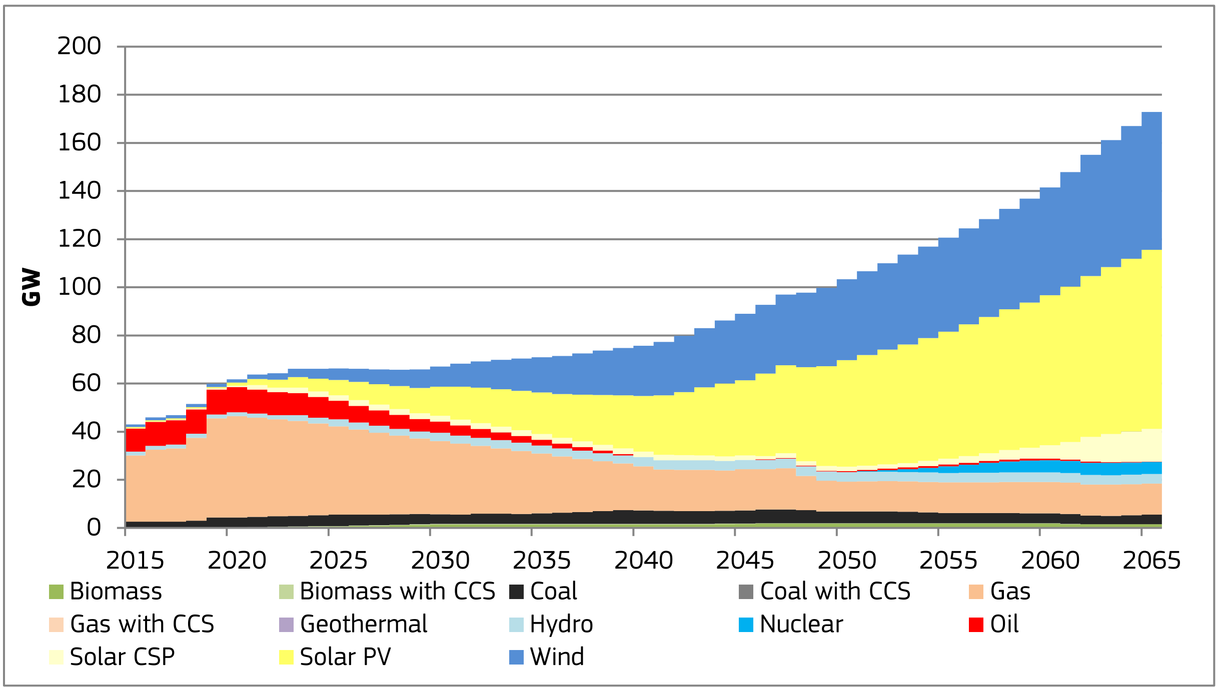
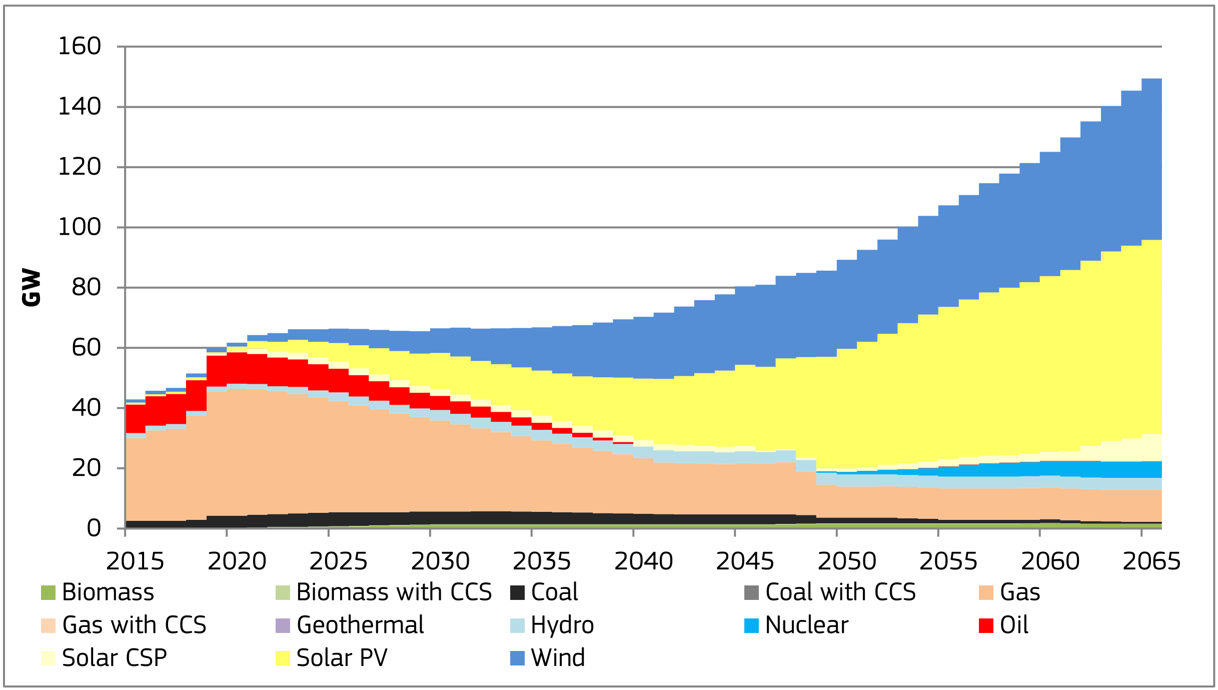


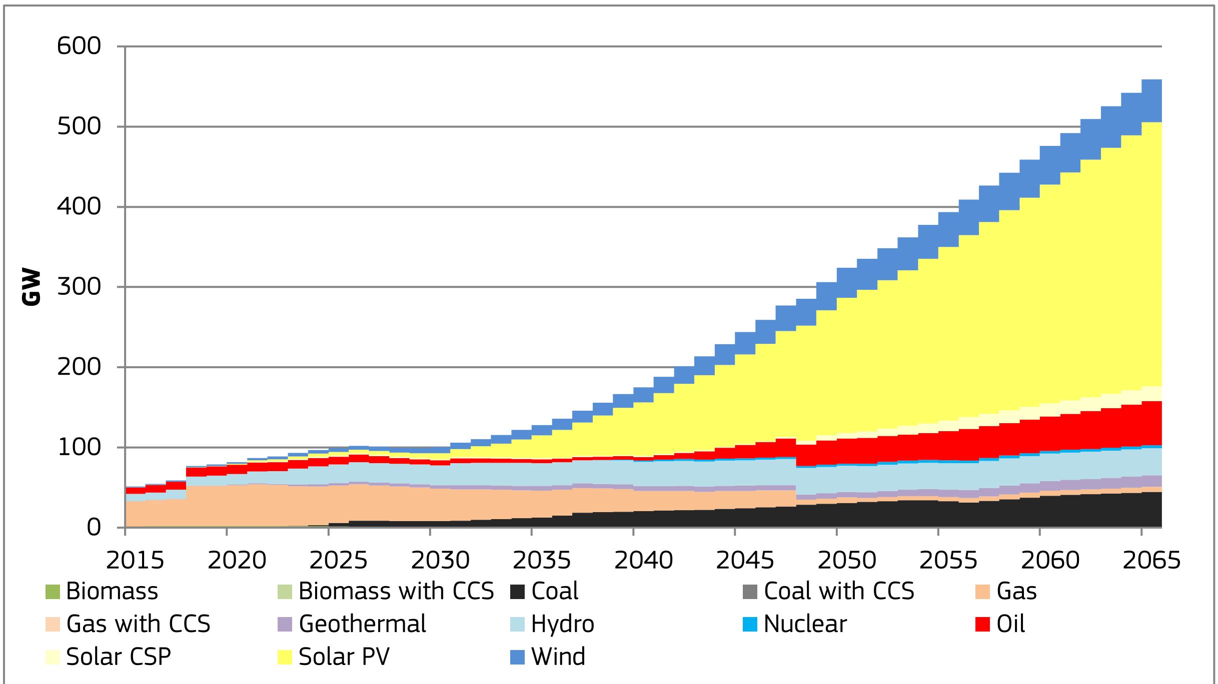

**Figure 33**. Power generation capacity in NAPP in the 1.5°C scenario



### 4.2.4 Eastern Africa

The installed capacity in the Eastern African power pool will increase from 51 GW in 2015 to 175 GW in 2040 and 559 GW in 2065. The renewable technologies will represent approximately 23% out of the total installed capacity in 2015 and increase to 71% in 2040 and 80% in 2065. In the region, only Egypt, Rwanda and Sudan have specific RET targets for the future, 60% and 20% correspondingly. The relatively high hydro potential in the region, mainly in Burundi, Egypt, Ethiopia, Kenya, Tanzania and Uganda will increase the hydro capacity in the region from 9 GW in 2015 to 34 GW in 2065. The future hydropower plant investments in Ethiopia mainly the Grand Renaissance Dam (6 GW, 2020-2023), the Gilgel Gibe III (1.9 GW, 2017) and Koysha (2.2 GW, 2021) could provide low domestic electricity prices and transform the country to an electricity hub exporter. The hydro potential along with the geothermal potential in the region could play an important role in shaping the power pool's energy mix. The high potential of geothermal energy will increase the geothermal capacity from 0.18 GW in 2015 to 14 GW in 2065. Kenya will mainly invest to geothermal of 9.6 GW by 2065, followed by Ethiopia 7.36 GW, Rwanda 1.4 GW and Tanzania 1.3 GW. Solar PV could potentially play an important role in many of the EAPP countries (Djibouti, Egypt, Ethiopia, Kenya, Rwanda, Tanzania, Uganda). Solar PV capacity will increase from less than 100 MW in 2015 to 329 GW in 2065, followed by wind investments 54 GW in 2065. In addition, investments on solar CSP technologies will mainly be held in Egypt in the future of approximately 18 GW by 2065. Furthermore, the overall investments in fossil fuel power plants in the region will be considerably lower than the renewables ones. This happens even without an upper bound on emissions since renewable energy costs are gradually decreasing in the future in comparison to fossil fuel technologies. The installed capacity of coal will increase from 0.04 GW in 2015 to 44 GW in 2065, followed by an increase in oil and gas capacity from 7.8 GW and 31.5 GW in 2015 to 55 GW and 6 GW in 2065 respectively. One of the main reasons of that shift in the power pool's capacity is the change in the energy mix of Egypt from gas to oil and coal the upcoming decades, 0 GW, 55 GW and 26 GW in 2065, respectively. The installed capacity of the natural gas power plants in the country will be gradually phased out and be replaced by nuclear investments reaching 3.5 GW in 2065.

**Figure 34**. Power generation capacity in EAPP in the reference scenario




In the 2.0°C scenario, the total installed capacity in the Eastern African power pool will increase to 156 GW in 2040 and 551 GW in 2065. In this scenario, the installed capacities are approximately 24% higher than in the Reference scenario. This is mainly due to the higher share of renewables in the power system, 88% compared to 80% (Reference scenario), since more capacity is required to produce the same amount of electricity from thermal plants. Specifically, the solar PV capacity will increase to 363 GW in 2065 followed by wind 47 GW and hydropower 40 GW. The geothermal capacity remains constant between the scenarios, 14 GW in 2065. In the 2.0°C scenario, hydropower will increase by approximately 6 GW between the two scenarios mainly through expansions in Egypt, Sudan, South Sudan and Uganda. The 2065 coal and oil capacities will decrease by 33 GW and 55 GW, respectively between the two scenarios, while gas capacity will increase by 41 GW in the same year. This is mainly due to the shift in the energy mix of Egypt, from coal and oil to natural gas.

However, Egypt will need to invest mainly in CCS technologies; 1.5 GW of biomass CCS, 4.5 GW of coal CCS and 35 GW of gas CCS by 2065 to reduce its overall carbon dioxide emissions.

In the 1.5°C scenario, the installed capacity in the power pool will be approximately 10 GW lower (549 GW in total) in 2065 compared to the Reference scenario. The renewable technologies will constitute 93% of the region's total installed capacity in 2065, 13% more than in the Reference scenario at the same year. Specifically, the solar PV capacity will increase by 56 GW (385 GW in total) in 2065, followed by hydropower expansion of 7 GW (41 GW in total), a geothermal increase of 2 GW (17 GW in total) and biomass increase of 1.5 GW between the two scenarios. It should be highlighted the penetration of biomass, gas and coal CCS technologies mainly in Egypt´s power system´s constituting approximately 1.5 GW, 10 GW and 4.5 GW respectively by 2065. Furthermore, the coal capacity will decrease from 44 GW in the Reference scenario to 5 GW in this scenario in 2065, and oil capacity from 55 GW to 20 MW respectively at the same year. This energy transformation will lead the countries located in the power pool to increase the power pool's installed capacity of gas to 24 GW and nuclear to 9 GW, compared to 6 GW and 3.5 GW in the Reference scenario, respectively in 2065.

**Figure 35.** Power generation capacity in EAPP in the 2.0°C scenario

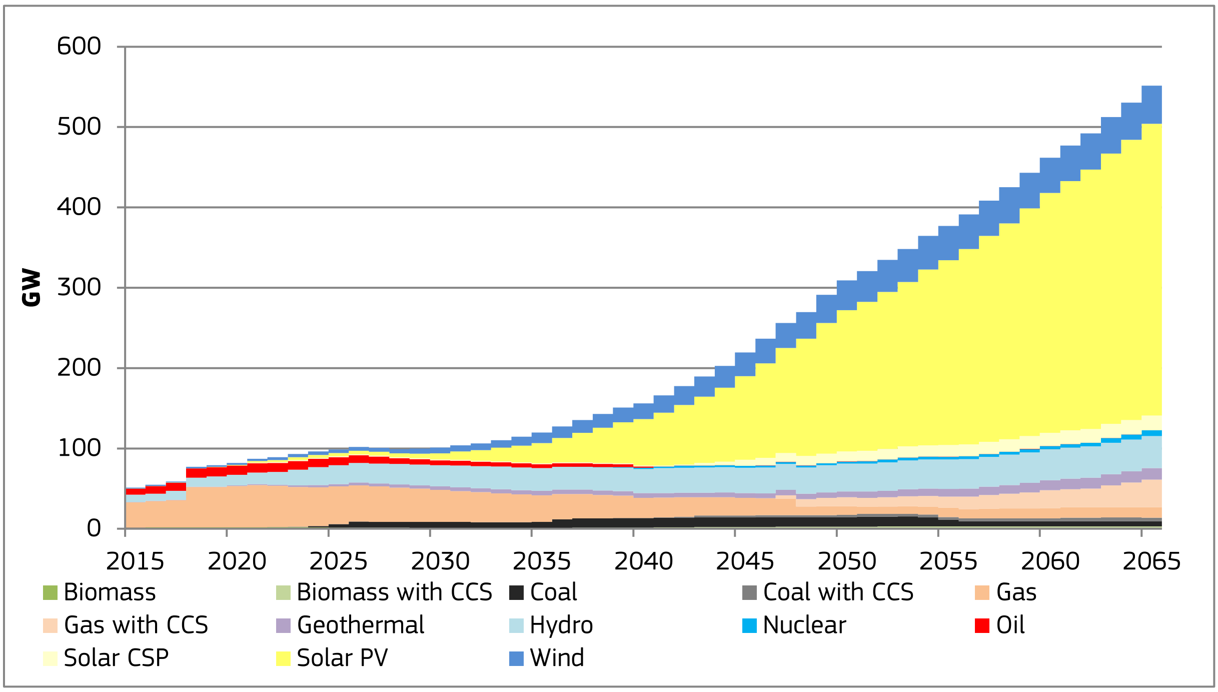
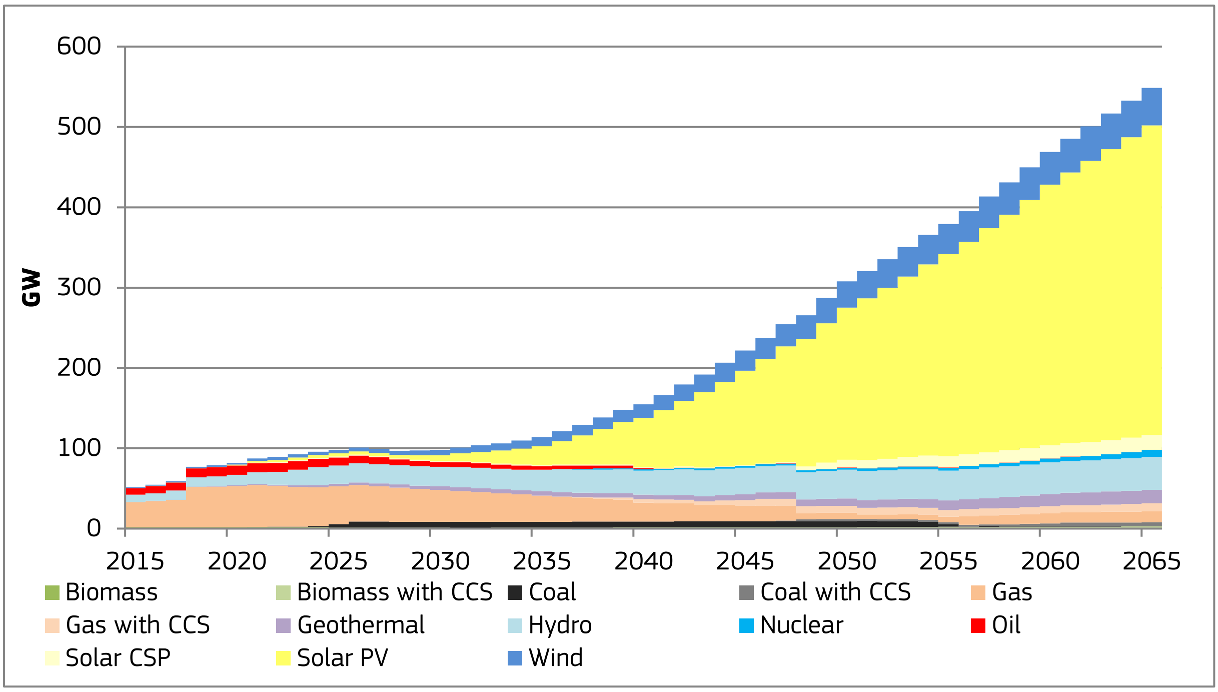


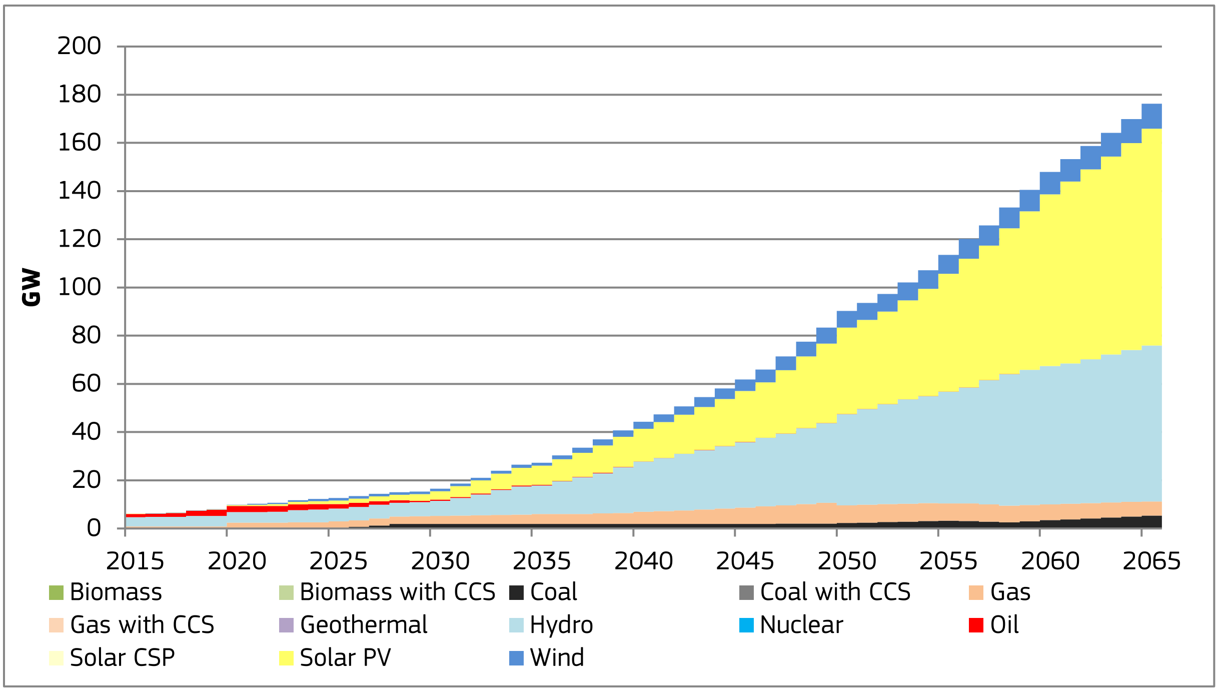

**Figure 36**. Power generation capacity in EAPP in the 1.5°C scenario



### 4.2.5 Central Africa

Installed capacity in CAPP will increase from 6 GW in 2015 to 44 GW in 2040 and 176 GW by 2065. The renewable energy share in the CAPP region is the highest one in the continent, 64% in 2015, with the aim to increase to 84% in 2040 and 94% in 2065. Hydropower represented almost all of the renewable installed capacity in the power pool (3.8 GW), 99% in 2015, with that share to decreases to 39% in 2065 (64.7 GW). The installed capacity of solar PV will increase to 90 GW by 2065, starting from less than 100 MW in 2015, followed by wind capacity of 10 GW by 2065. The relatively low potential of fossil fuel reserves in the region, apart from coal reserves in the Democratic Republic of Congo, is one of the reasons that the region will invest in renewable energy technologies. Coal capacity will increase to 5 GW in 2065, including 1.3 GW in Equatorial Guinea and 1 GW in Gabon by 2065. On the other hand, oil (1.4 GW in 2015) will gradually be replaced by natural gas power plants (6 GW in 2065). One of the future key investments that will transform the region's energy mix is the expected expansion phases of the Grand Inga hydropower project in the Democratic Republic of Congo. In this scenario, Phases III (4.75 GW) and IV (37.3 GW) of the project become operational and produce low price electricity that could be exported to the entire African continent.

**Figure 37**. Power generation capacity in CAPP in the Reference scenario




In the 2.0°C scenario, the total installed capacity will decrease by 5 GW (39 GW) in 2040 and by 25 GW (152 GW) in 2065 compared to the 44 GW and 176 GW foreseen in the Reference scenario. The 2065 renewable energy share will increase from 94% in the Reference scenario to 96% in this scenario, due to further increases of hydropower and solar PV capacities by 10 GW (75 GW in total) and 33 GW (59 GW), respectively. On the other hand, 2065 coal capacity will only be about 70 MW compared to the 5 GW in the reference scenario. The 2065 gas capacity will be approximately 3 GW. In addition, under this scenario nuclear investments will be held mainly in Gabon after 2060, increasing the power pool's nuclear capacity to 1.2 GW in 2065.

In the 1.5°C scenario, the total installed capacity will increase to 40 GW in 2040 and to 162 GW in 2065. The renewable energy share will increase with even higher rates than the 2.0°C scenario. The total capacity will be higher by 10 GW due to the higher penetration of renewables into the power system. Specifically, hydropower capacity will be 85 GW and the solar PV capacity 61 GW in 2065. In this scenario, coal (80 MW), oil (1 GW) and gas (2 GW) 2065 capacities will be lower than under the other scenarios. However, nuclear capacity will reach 4 GW in the same year with investments held in Gabon and Equatorial Guinea after 2052.

**Figure 38.** Power generation capacity in CAPP in the 2.0°C scenario

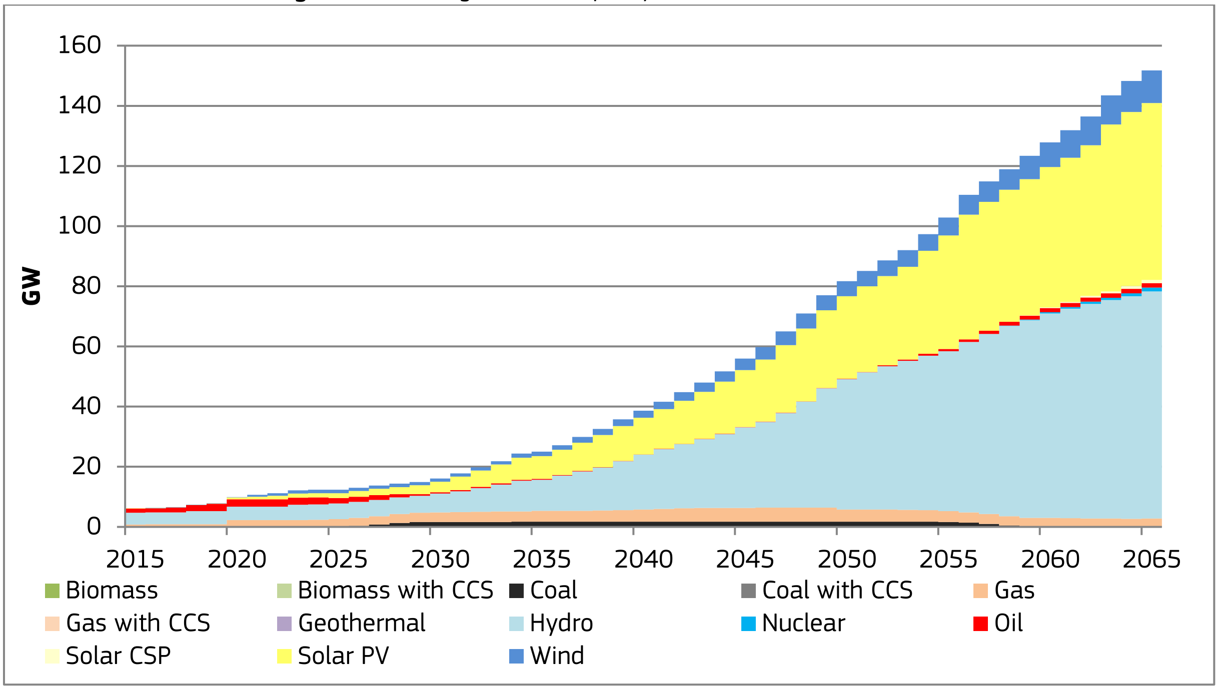
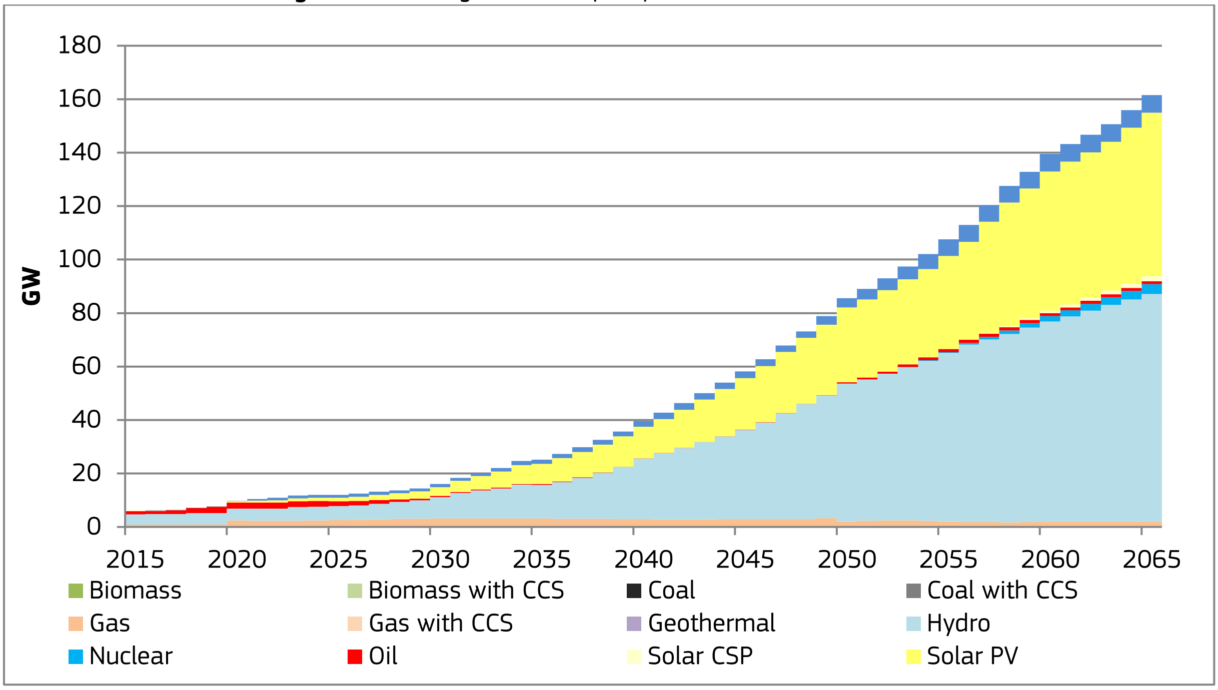


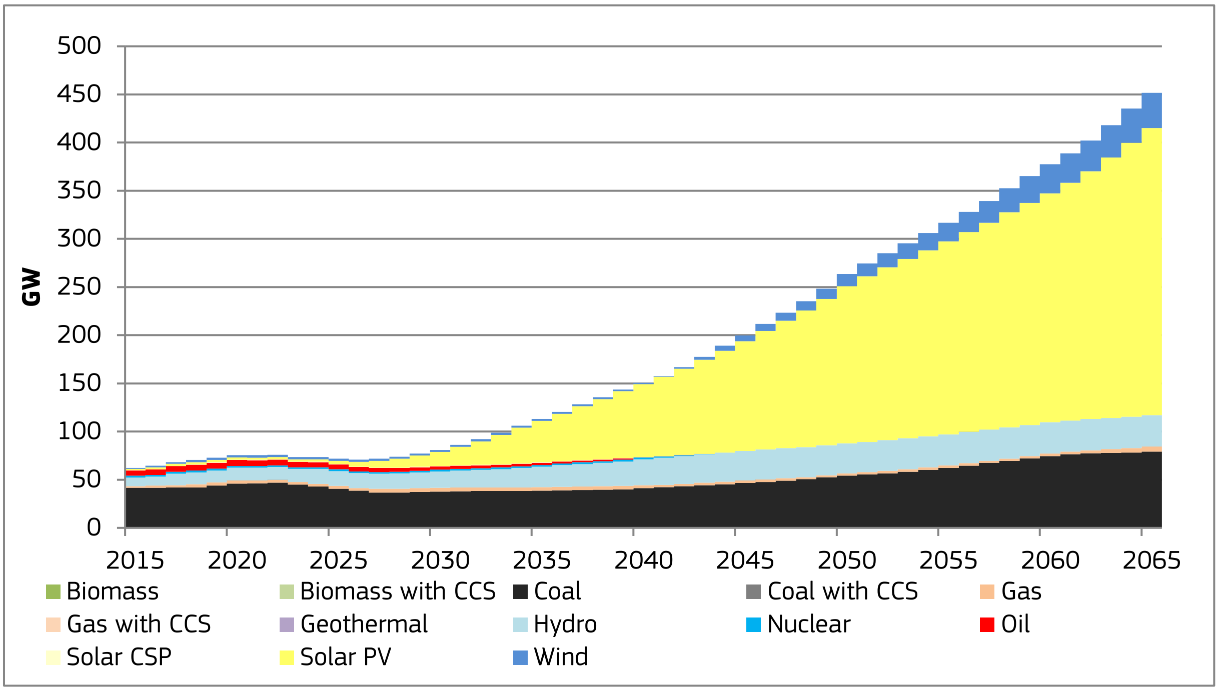

**Figure 39.** Power generation capacity in CAPP in the 1.5°C scenario



### 4.2.6 Southern Africa

In the Southern African power pool, the installed capacity increases from 62 GW in 2015 to 451 GW in 2065. It will be the region with the second-largest total installed capacity in the continent, only after WAPP (year 2065). This is mainly due to increases in South Africa's and Angola's future electricity demand by approximately 2 times and 25 times, respectively. Renewable capacities' share increases from 20% in 2015, to 69% in 2040 and 81% in 2065. Most of the RET investments are in solar PV, increasing the capacity in the region from 1.3 GW in 2015 to 298 GW in 2065. Wind increases to 36 GW and hydro reaches 33 GW in 2065. Most of the future hydro investments are located in Angola (17 GW in 2065), specifically with the operation of Lauca (2 GW) and Caculo Cabaca (2.2 GW) hydropower plants in 2017 and 2024, respectively. The high quantities of coal reserves in the region along with the relatively low coal prices favour future coal investments. This results in increases in the power pool's installed coal power capacity from 41 GW in 2015 to 79 GW in 2065. In addition, the installed capacity of natural gas will increase from nearly 1.6 GW in 2015 to approximately 5 GW in 2065. The proposed gas pipeline "African Renaissance" between Mozambique and South Africa (2021) would potentially affect South Africa's future energy mix. The installed capacity of oil power plants is gradually phased out by 2043 and is replaced by coal investments. The largest share of coal capacity is in South Africa (approximately 95% in 2015) where in the future Angola will also increase its capacity to 14 GW by 2065. The nuclear capacity in South Africa (1.83 GW, 2015) will be phased out in 2044 and no new nuclear investments will be held until 2065.

**Figure 40.** Power generation capacity in SAPP in the Reference scenario




In the 2.0°C scenario, the total installed capacity in the Southern African power pool will increase to 130 GW by 2040 and to 493 GW by 2065. In this scenario, the total installed capacity will be higher than in the Reference scenario starting from 2048 onwards. This is mainly due to the increase of solar PV, hydropower and wind capacities reaching to 320 GW, 43 GW and 82 GW respectively in 2065. Investments in renewables along with the increase of the biomass capacity (150 MW in 2065) will lead to an increase of the share of renewable energy technologies in the power pool to 90% compared to 81% in the Reference scenario. In the 2.0°C scenario, the capacities of coal and oil power plants will gradually phase out reaching 8 GW and 190 MW, respectively in 2065. On the contrary, gas capacity will increase to 15 GW in 2065. It should be highlighted that nuclear investments will only occur from 2049 onwards, mainly in Angola, Zambia and Zimbabwe reaching 1 GW, 0.5GW and 22 GW respectively in 2065. In addition, South Africa will need to invest to develop 150 MW of biomass CCS technologies by 2065 in order to reach the annual emission limits.

In the 1.5°C scenario, the total installed capacity in the power pool will reach 116 GW in 2040 and 502 GW in 2065. Under this scenario, the 2065 installed capacity will be 50 GW higher than in the Reference scenario (452 GW). This is mainly due to increases of the solar PV, hydropower and wind capacities that will reach a total of 339 GW, 43 GW and 66 GW, respectively. Such investments create an 8% difference of the RES share between the two scenarios. RES share in the 1.5°C scenario will be 89% in 2065. Furthermore, biomass capacity will reach 400 MW in 2065. Lastly, coal capacity will decrease by 73 GW (6 GW in total) in 2065 compared to the Reference scenario, while gas capacity will increase by 11 GW (16 GW in total) in the same year. The transformation of the energy mix in South Africa the upcoming decades, mainly the substitution of its coal power plants by renewable technologies (solar PV, wind), is the main reason for that shift in the power pool's total capacity. In addition, South Africa will invest to approximately 430 MW of biomass CCS technologies by 2065.

**Figure 41.** Power generation capacity in SAPP in the 2.0°C scenario

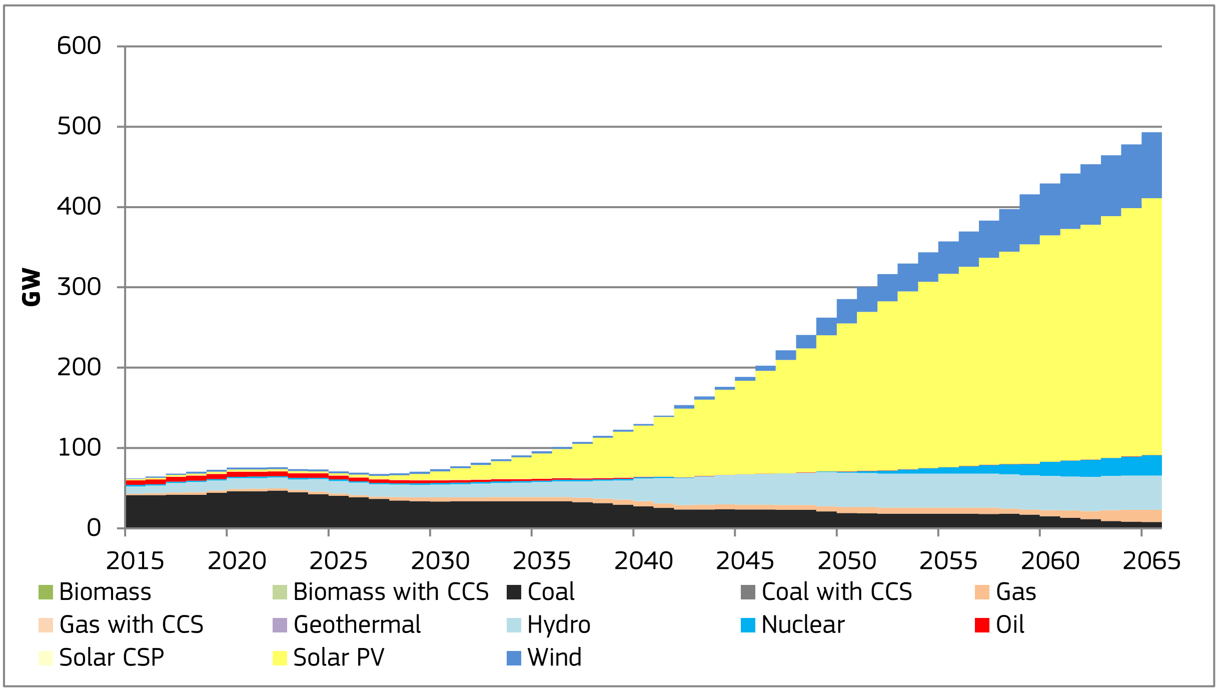
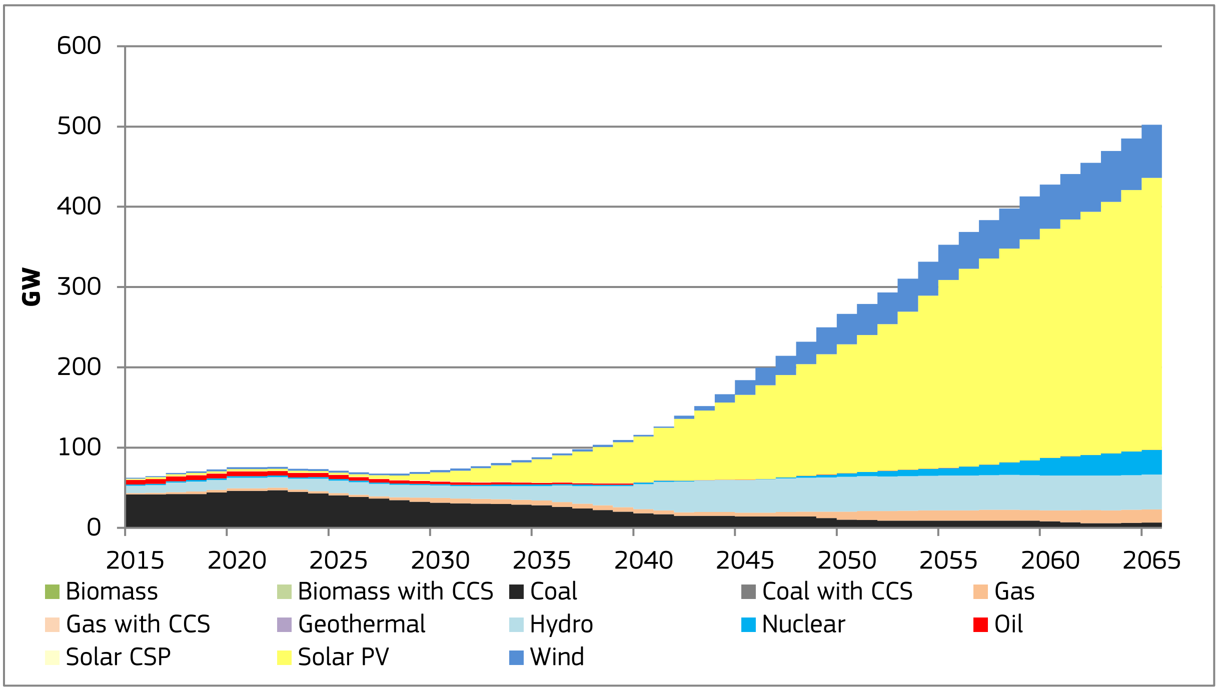



**Figure 42.** Power generation capacity in SAPP in the 1.5°C scenario



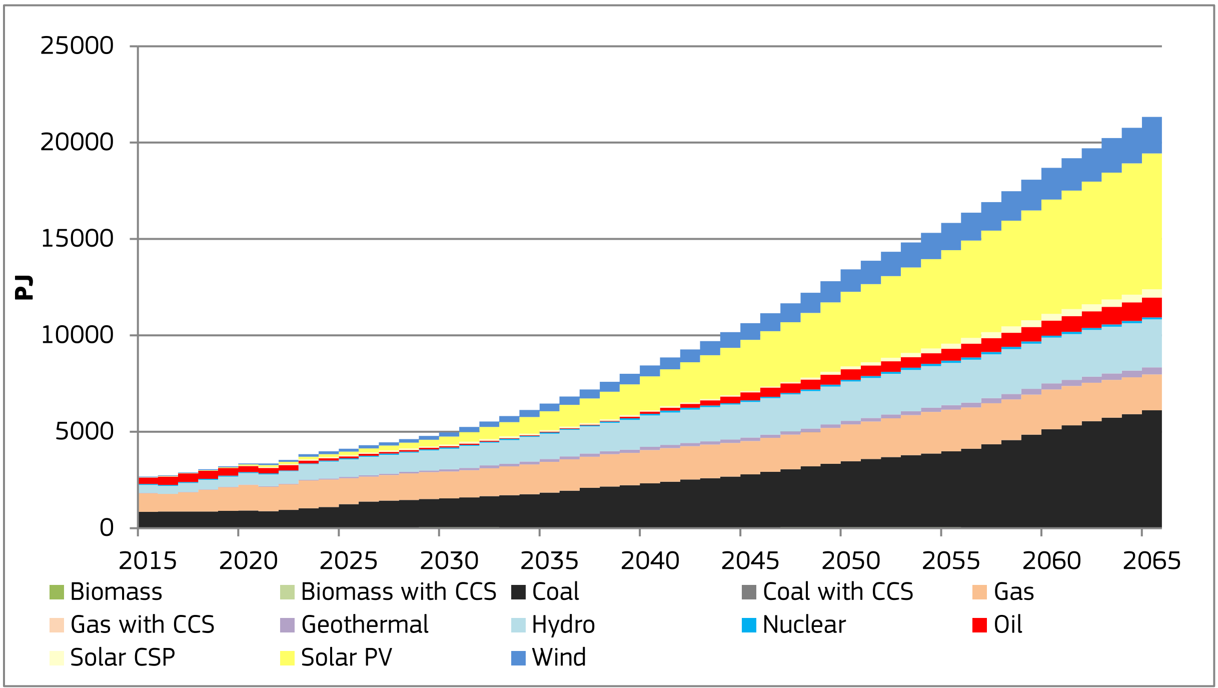
## 4.3 Power sector: electricity production

In this section, the power sector generation mix, including the trade of electricity, is analysed. The power generation mix, as well as the energy supply mix by country, can be found in Annex 1 (energy balances, greenhouse gas emissions and costs). The results in this section are driven by the power sector capacity discussed in the previous section; therefore these results are only discussed briefly.

### 4.3.1 All Africa

The energy supply mix results describe a grand transition from the relatively small quantities of electricity consumed today, to levels that are the result of an increase of 5 to 100 times over the base year. Total generation reaches around 13 EJ in 2050, up from ~2.5 EJ in 2015. The evolution of the supply mix of electricity reflects the very different energy supply systems that were revealed in the generation capacity results. However, the key characteristics of the technologies involved explain the differences between capacity and generation graphs. In all power pools, we see a transition to energy supply systems which are more diverse and include a larger proportion of renewable generation capacity. However, due to the lower capacity factors of modern renewables, the actual electricity generated is lower than the equivalent fossil fuel nameplate capacity. Taken another way, this means that in the Reference scenario, a lot of the electricity is still generated from coal, oil and natural gas, although the exact blend of fuels is a function of the characteristics of the different countries within the power pools. These are discussed in detail in the following sections.

**Figure 43.** Power generation in Africa in the Reference scenario




In aggregate, electricity production is shared across coal, gas, hydro, and solar, with smaller proportions of oil, wind and geothermal generation, particularly after 2050. Very little electricity is derived from nuclear power or from biomass, given the cheaper fossil and renewable alternatives. Given the lack of emissions constraint in the Reference scenario, there is no cost implication of using coal to generate electricity. Besides, it is a cheap and abundant resource and it accordingly forms the largest single share of generation. However, as a proportion of the total, electricity from coal is squeezed by the rapid growth of solar and wind power and the steady increase in hydroelectricity.

Under the 2.0°C and 1.5°C scenarios, the electricity generation mix transitions from one largely based on coal to one dominated by a mix of low-carbon generation sources including solar, hydro, nuclear, wind, natural gas and geothermal.

Total electricity consumption is much lower in the 1.5°C scenario than both reference and 2.0°C scenarios, and this is matched in the supply sector.

Under the 2.0°C scenario, electricity from coal remains in the system through the model horizon, peaking at around 1500PJ in 2035 and then decreasing steadily. In the 1.5°C scenario, electricity from coal reaches a peak of 1000PJ in 2020 which is then sustained until the early 2030s before being squeezed out by large quantities of low-carbon generation sources.

Electricity from variable renewables, including solar and wind, play a large role in both scenarios making up almost 50% of the total generation in 2050 and more than 50% in 2065.

Nuclear power plays a proportionally larger role in the 1.5°C scenario, squeezing out the residual emissions from gas generation.

**Figure 44.** Power generation in Africa in the 2.0°C scenario

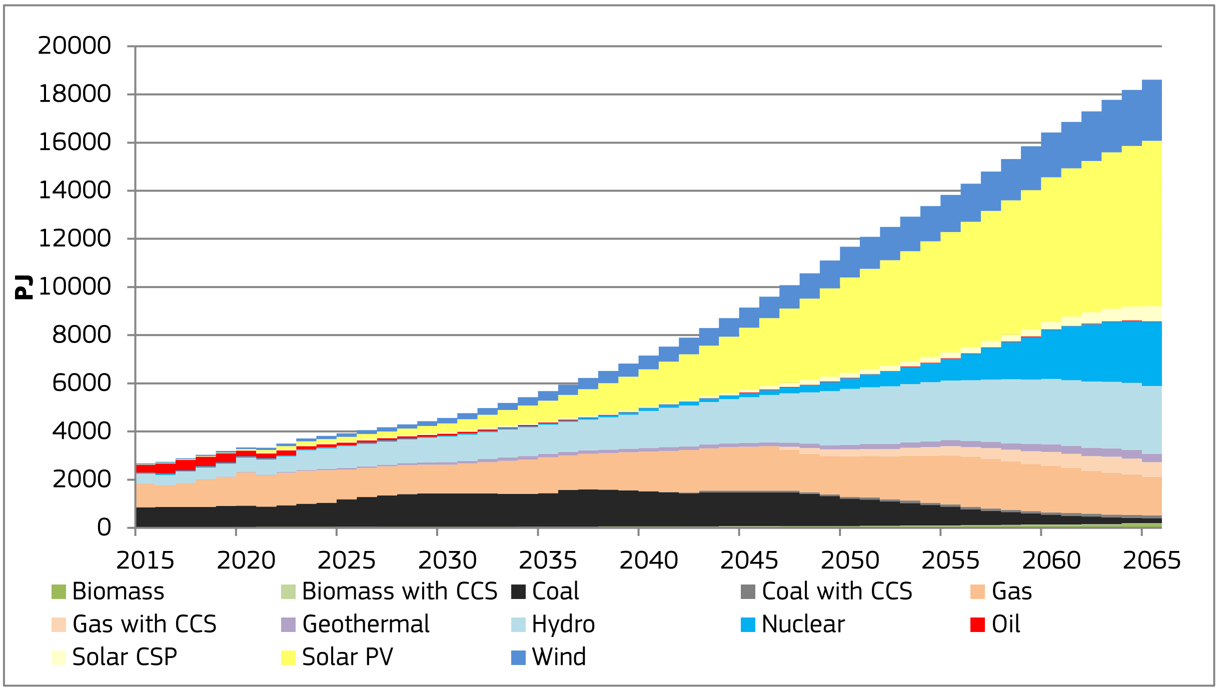
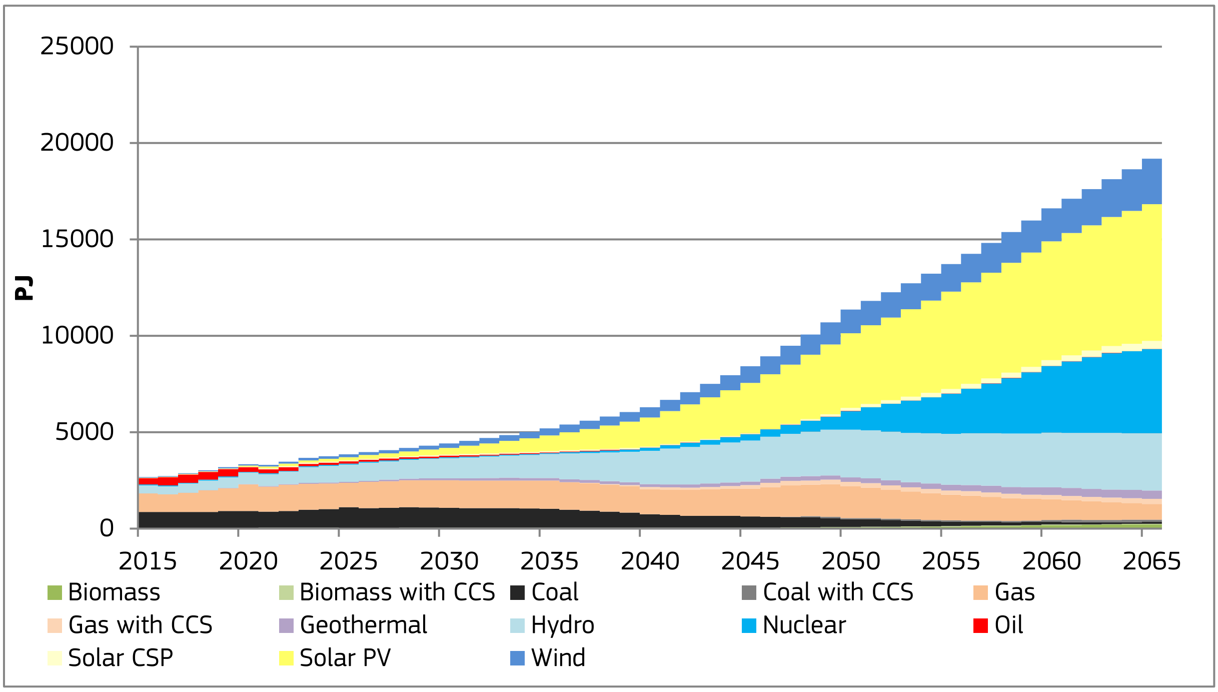



**Figure 45.** Power generation in Africa in the 1.5°C scenario

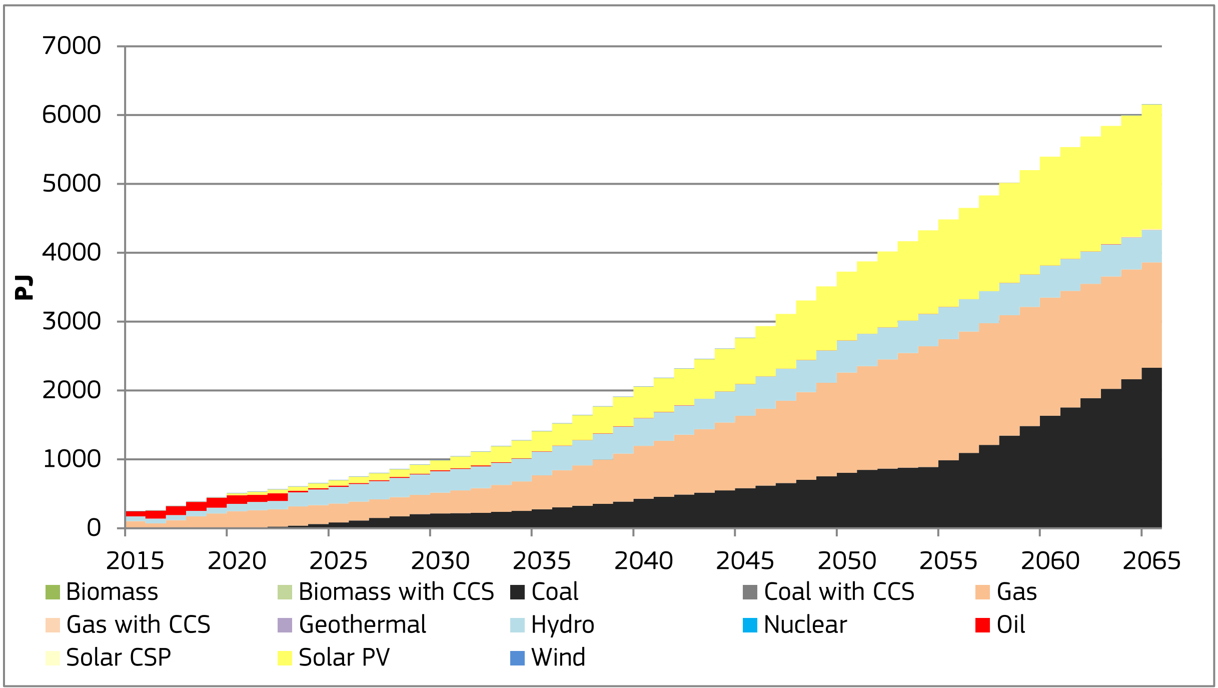


### 4.3.2 Western Africa

The Western African power pool increases electricity generation by approximately 27 times, from 232 PJ in 2015 to 6193 PJ in 2065. The high losses in the power system, as well as the rapid increase of the region's electricity demand in the region the upcoming decades, cause an urgent need for investments in the power sector. In Nigeria alone, electricity demand will increase from 25 PJ in 2015 to approximately 920 PJ in 2065.

The Western African region has the highest electricity generation on the continent. Although the share of renewable energy generation technologies will increase, corresponding to an electricity generation of a total ~2000 PJ in 2065, in the Reference scenario the majority of generation is from fossil sources. Solar PV technologies will represent approximately one-third of the total electricity supply by 2065 followed by hydropower (6%). Natural gas was the main source of electricity production in 2015 representing around 44% of the total electricity mix followed by oil (26%) however; the corresponding share will decrease to 25% by 2065 and gradually be replaced by coal-fired power plants (42%). Natural gas will still be the dominant fuel in the region but it will be used for domestic uses in the non-power sector and exports. Specifically, in the case of Nigeria, the natural gas final demand in the non-power sector will increase from approximately 4 PJ in 2015 to 38 PJ in 2065. The region will export electricity to neighbouring countries of less than 1% of its total electricity generation mainly through Cote D'Ivoire, Gambia, Ghana, Guinea Bissau and Liberia by exploiting their hydro potential. In some cases, countries such as Senegal, which are currently net exporters, will become net importers in the future.

**Figure 46.** Power generation in WAPP in the Reference scenario




Under the two-decarbonisation scenarios, there are dramatic changes in the composition of the electricity mix. The key differences include an overall reduction in electricity production, a significant reduction in electricity from coal, and increase in nuclear production. In the 1.5°C scenario, natural gas is displaced from 2050 onwards by a further tranche of nuclear power, producing more than half of the total electricity from 2060 onwards.

**Figure 47.** Power generation in WAPP in the 2.0°C scenario

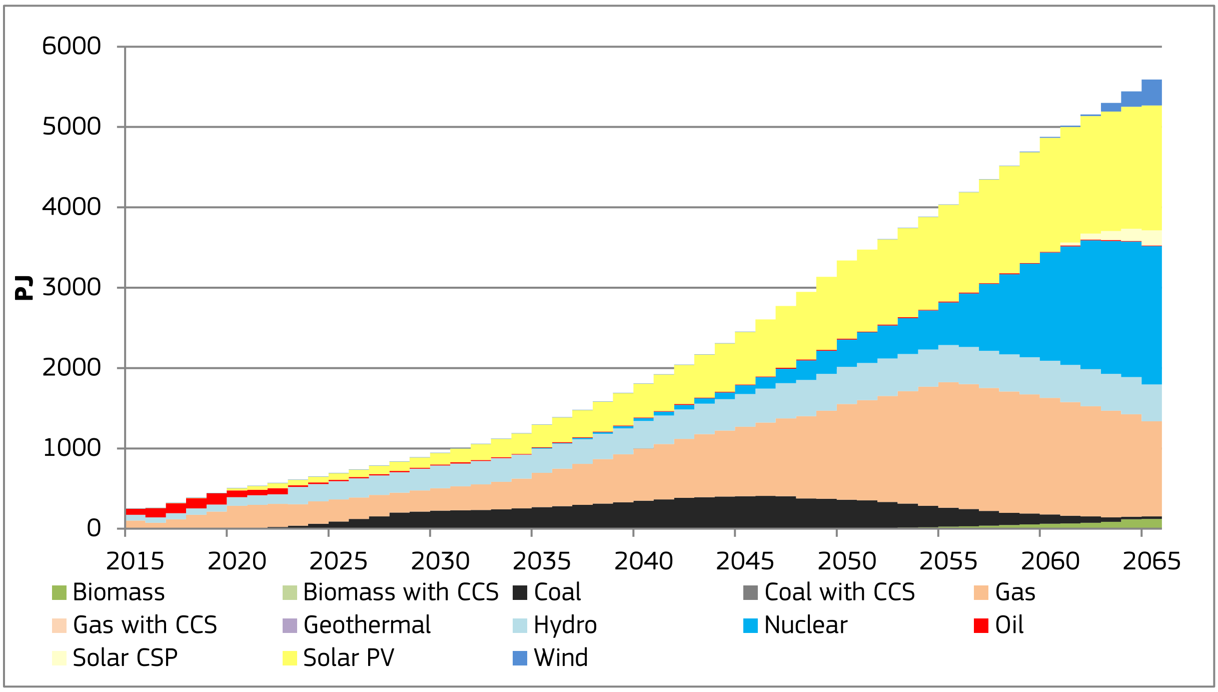
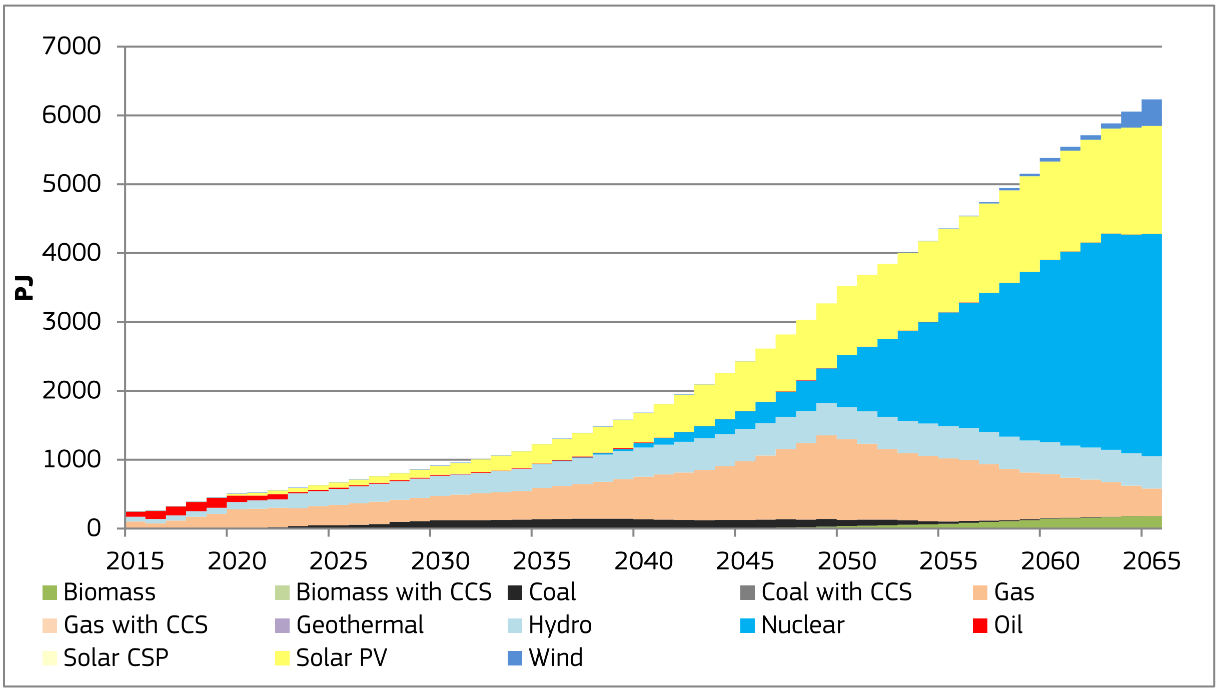


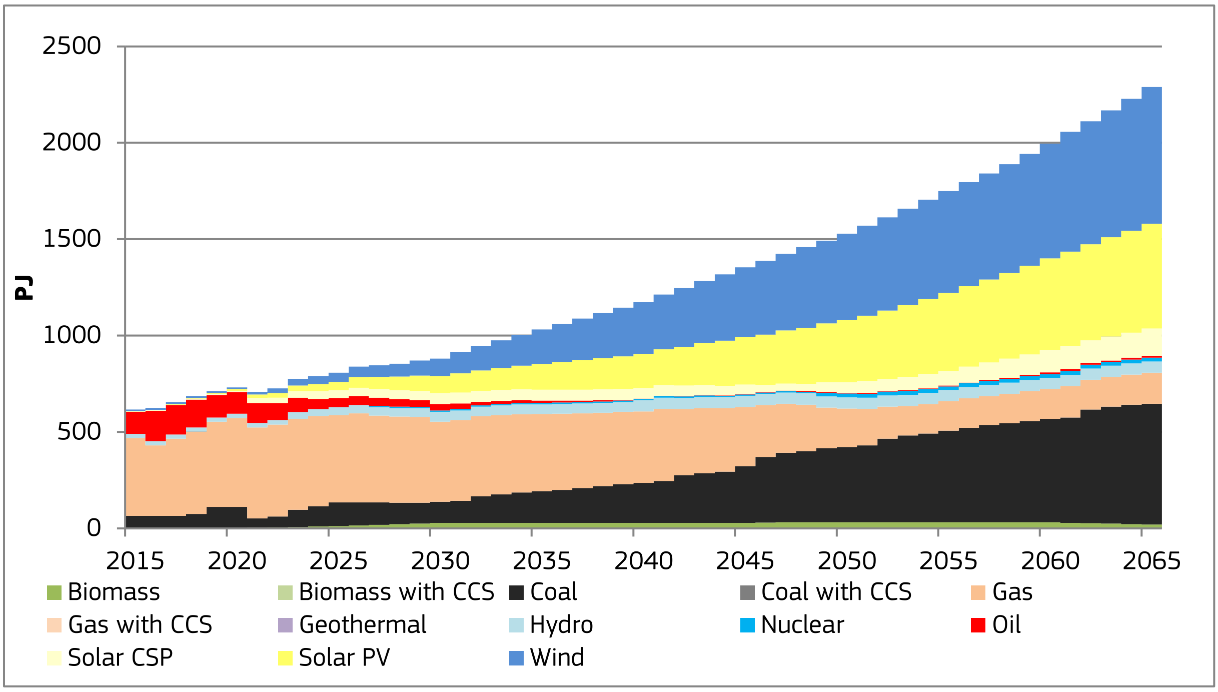

**Figure 48.** Power generation in WAPP in the 1.5°C scenario



### 4.3.3 Northern Africa

Under the Reference scenario, electricity generation grows from just over 500 PJ in 2015 to ~2100PJ in 2065. In contrast to the other regions, the northern African region sees a complex transition from a mix dominated by natural gas with some coal and oil in 2020, to one containing a mix of coal, natural gas, solar and wind as well as a small proportion of hydro in 2040. By 2065, the shares of coal, wind and solar into the power system will further increase.

**Figure 49.** Power generation in NAPP in the Reference scenario




Under the mitigation scenarios, the 3-stage transition of the Reference scenario is replaced by a simpler process, where electricity from natural gas is slowly dominated by the rapid increase in electricity from wind and solar (PV and CSP), with nuclear electricity introduced from 2050. Electricity from coal is never established under these mitigation scenarios, making up at most 15% of generation in the 2020s.

**Figure 50.** Power generation in NAPP in the 2.0°C scenario

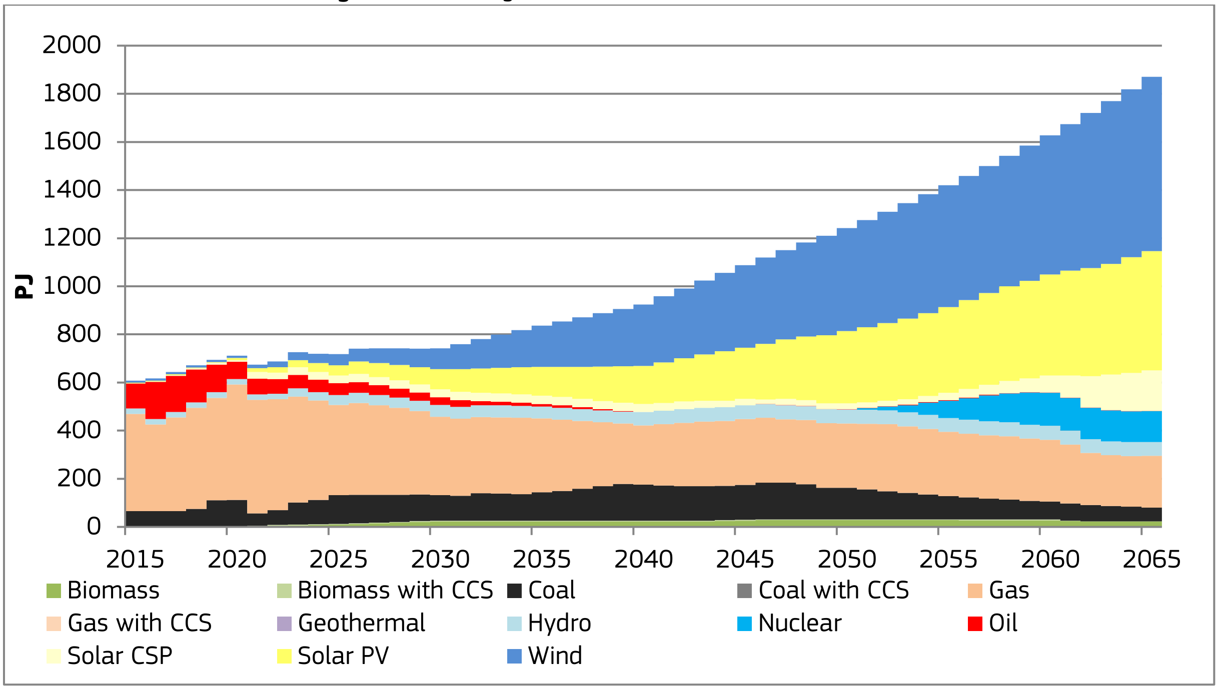
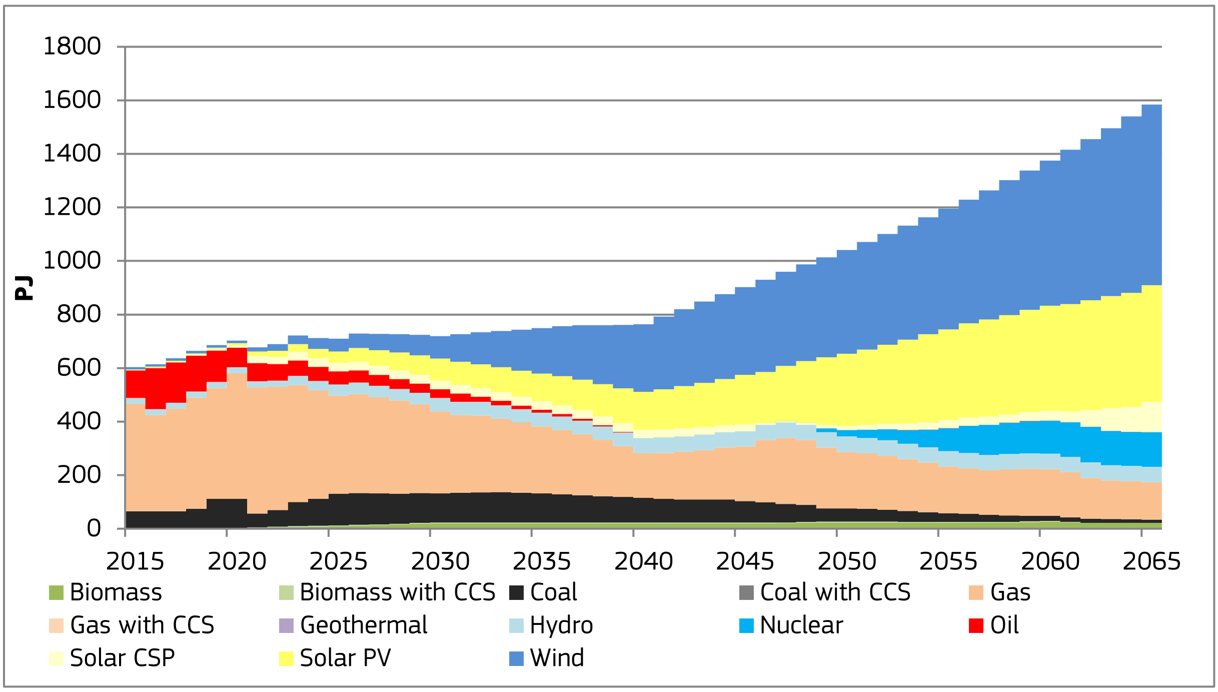


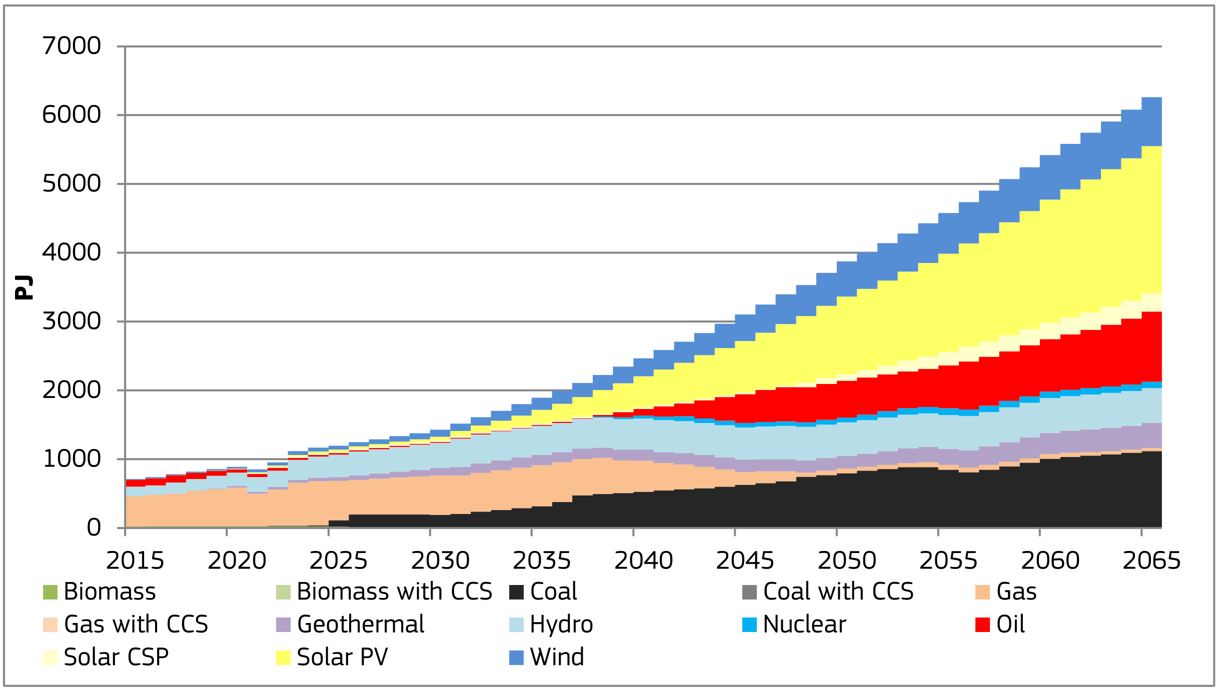

**Figure 51.** Power generation in NAPP in the 1.5°C scenario



### 4.3.4 Eastern Africa

Under the reference scenario, electricity generation in the Eastern African power pool increases from ~800 PJ in 2015 to ~6000 PJ by 2065 (Figure 52). Renewable technologies including hydro make up at least 50% of the electricity supply mix from 2035 onwards. In the latter half of the time horizon, we see a strong switch from natural gas to oil and a gradual increase in coal generation. In 2065, the electricity mix is comprised of around 50% coal, oil and hydro and 50% solar, wind and geothermal sources.

**Figure 52.** Power generation in EAPP in the Reference scenario




Under the mitigation scenarios, the evolution of the electricity supply mix looks quite different. Total demand is almost 20% lower than the reference, reaching ~5000 PJ in 2065. The switch from gas to oil no longer occurs, coal is not established as a dominant generation source and there is a far greater role for solar PV with wind and hydro taking a smaller role.

**Figure 53.** Power generation in EAPP in the 2.0°C scenario

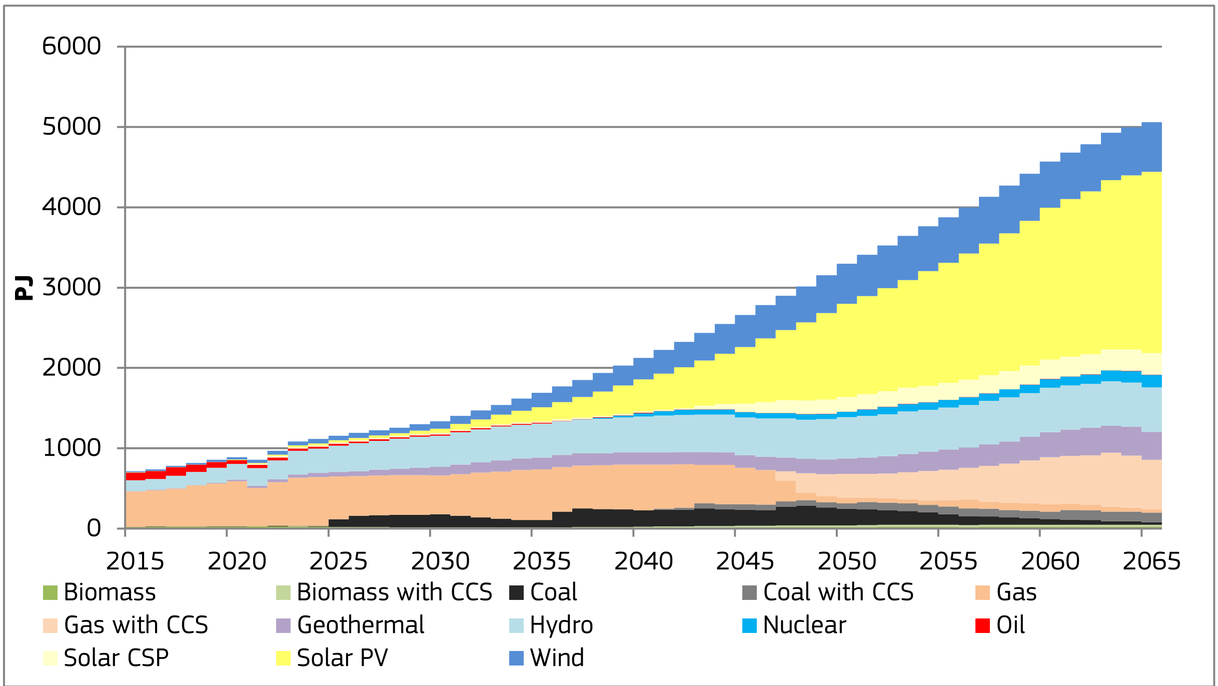
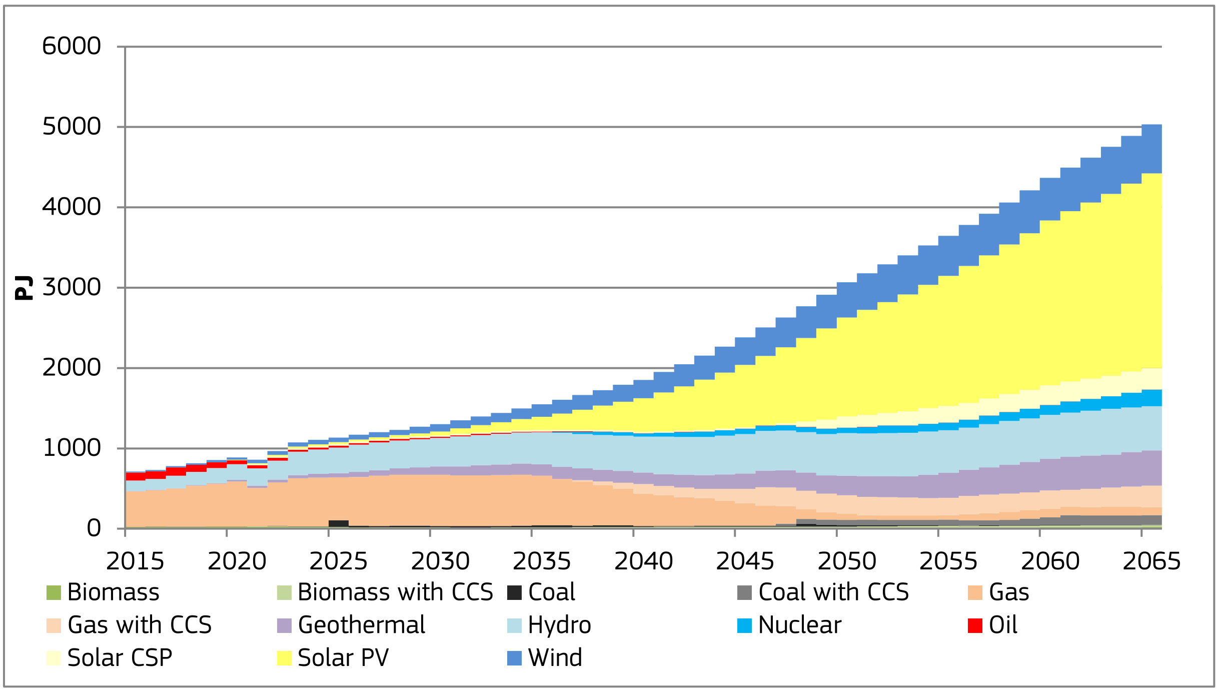


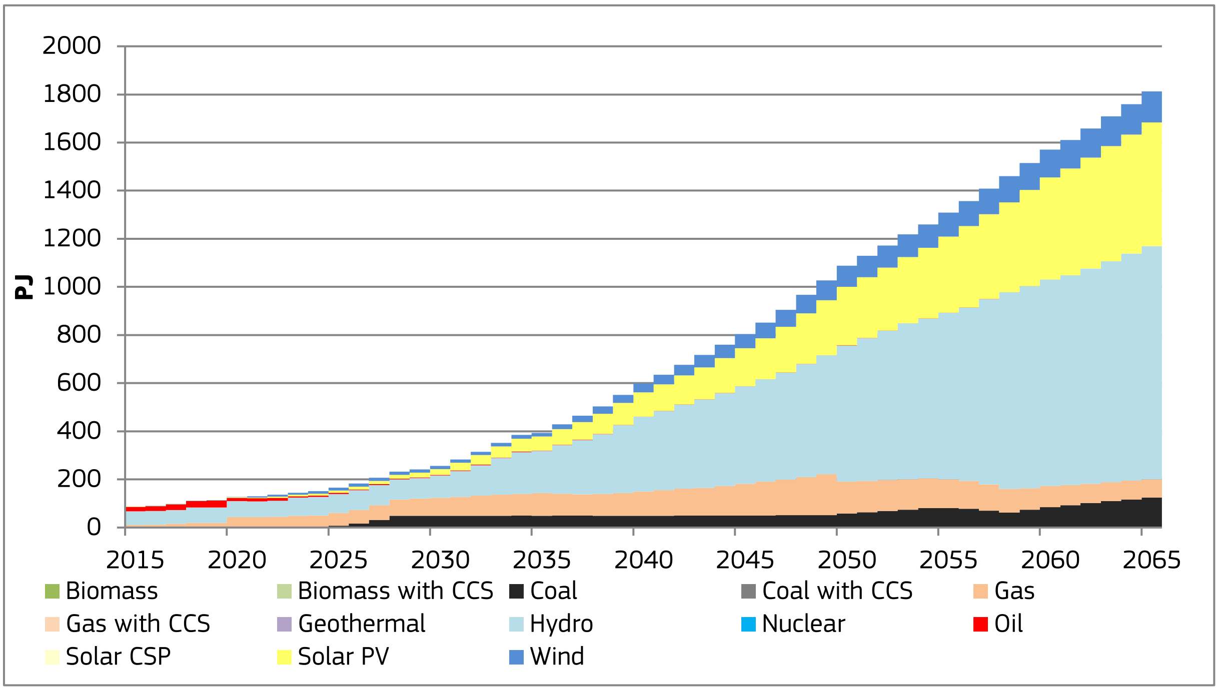
**Figure 54.** Power generation in EAPP in the 1.5°C scenario



### 4.3.5 Central Africa

The electricity generation in the Central African power pool increases from ~90 PJ in 2015 to ~1800 PJ. Hydropower represents most of the region's electricity supply in 2065 (650 PJ) although with a significant contribution from solar, and small contributions from natural gas, coal and wind. Specifically, the Democratic Republic of Congo will constitute most of the hydropower electricity generated in the region, 96% in 2065. Solar PV will account for approximately 28% of the electricity generation by 2065 increasing its share from less than 1% in 2015. The region overall will be a net importer in the upcoming decades importing electricity between 2 to 38 PJ.

**Figure 55.** Power generation in CAPP in the Reference scenario




Due to the huge proportion of hydro in the Central African region, the change in the electricity supply mix between reference and mitigation scenarios is relatively small. The small quantity of electricity generated from fossil fuel sources reduces proportionally to the ambition of the mitigation scenario, and a small tranche of nuclear electricity is evident from 2055 onwards.

Under the mitigation scenarios, the huge quantity of hydroelectricity becomes an invaluable source of low carbon electricity to neighbouring regions and there is some trade in electricity. The flexibility to trade electricity enables countries to sequence investments to meet their requirements. Either by importing electricity to meet a shortfall due to plants reaching the end of their life, or exporting excess electricity to increase the returns on investment until the local market is sufficiently established.

**Figure 56.** Power generation in CAPP in the 2.0°C scenario

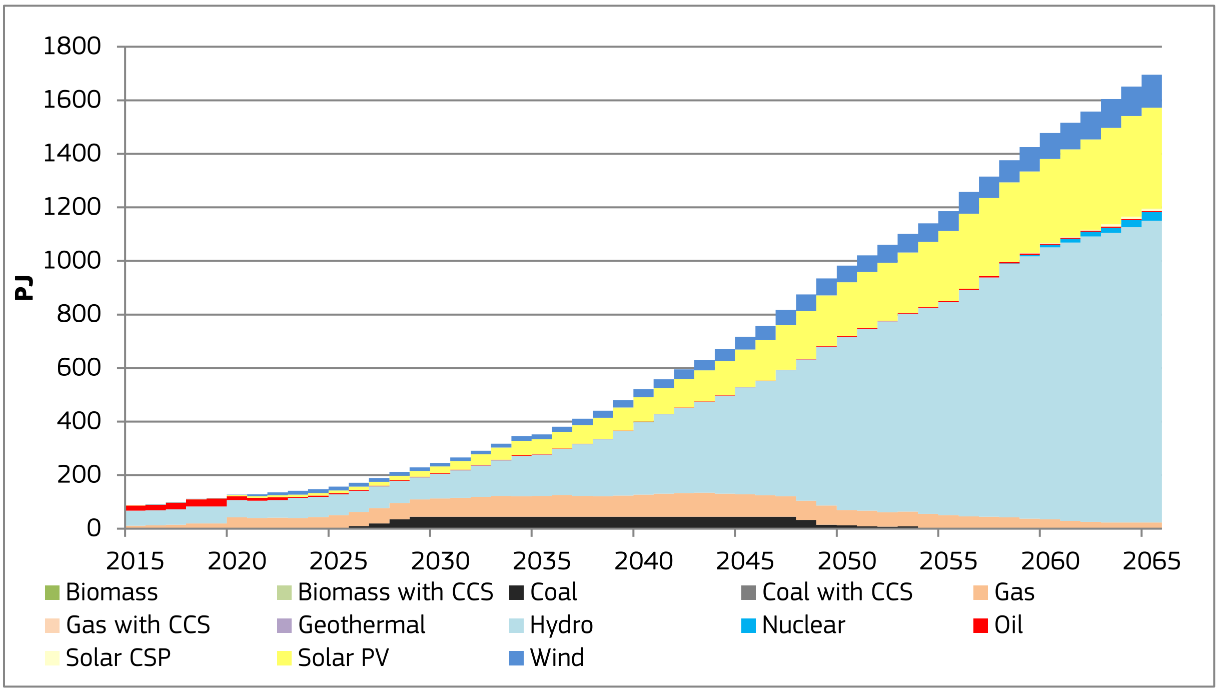
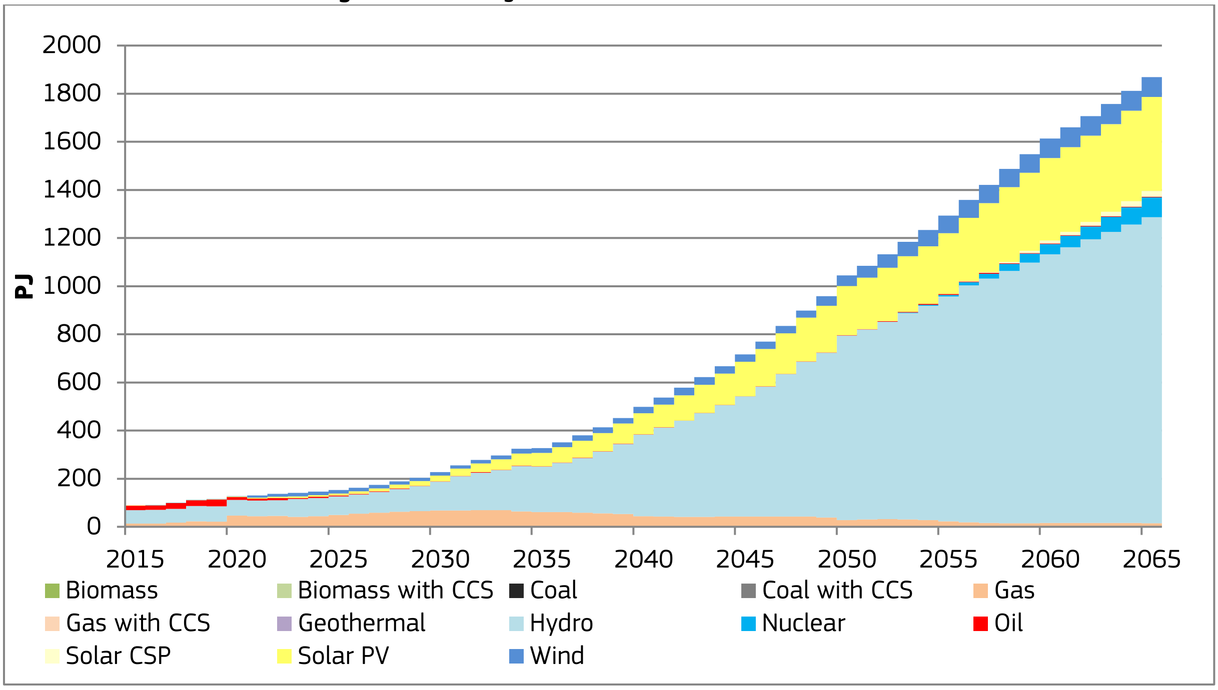


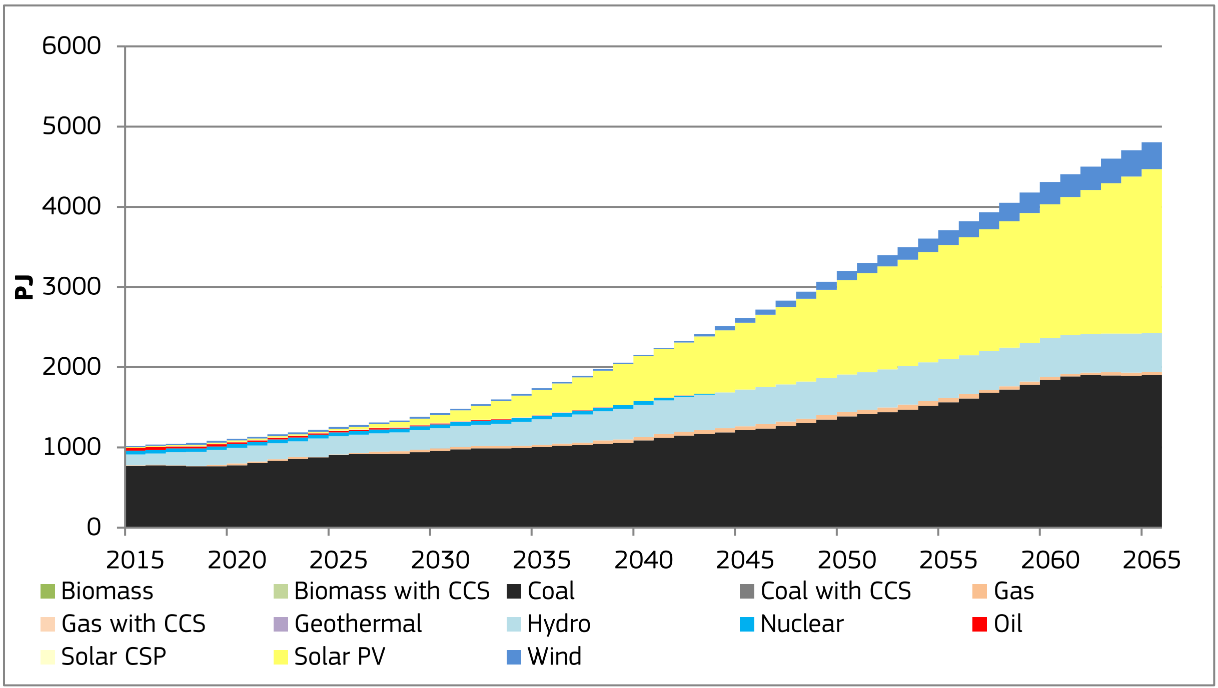

**Figure 57.** Power generation in CAPP in the 1.5°C scenario



### 4.3.6 Southern Africa

In the Reference scenario for the Southern African power pool, the electricity supply will increase by approximately five times between 2015 and 2065 (Figure 58). The electricity generation from 1015 PJ in 2015 will increase to 4800 PJ in 2065. Around 15% of the total electricity supply was met with renewable technologies in 2015 with that share to increase to over 60% by 2065. The solar PV technologies will present the highest increase in the renewable energy generation supply mix, increasing their share from 5% in 2015 to 85% in 2065. Hydropower electricity generation will increase by approximately three times the period 2015-2065 where other renewables will account for only 2% of the regional renewable electricity generation. In general, renewables will contribute to a big margin to the regional electricity supply mix, however, those will need to be backed -up by fossil fuel-based generation technologies. Coal will be the dominant fossil fuel generation technology in the region in the future representing approximately 40% of the total electricity supply in 2065. The small nuclear generation in South Africa will gradually be phased out from 46 PJ in 2015 to 0 PJ in 2044. The power trade in the region will be relatively low, less than 1%. Botswana, Malawi, Namibia and Zambia will be net importers by 2065, comprising between 15% and 25% of their electricity supply, while South Africa, Swaziland and Zimbabwe will be net exporters mainly take advantage of their domestic coal reserves.

**Figure 58.** Power generation in SAPP in the Reference scenario




Total electricity supply decreases from around 4800 PJ in 2065 in the Reference scenario to around 4100 PJ in the two mitigation scenarios. Instead of the increase in coal visible in the reference scenario, from 2050 onwards, we see a large tranche of nuclear enter the supply mix along with an earlier increase in generation from wind and solar. Some natural gas generation enters the supply mix, and there is a larger role for hydroelectricity too.

**Figure 59**. Power generation in SAPP in the 2.0°C scenario

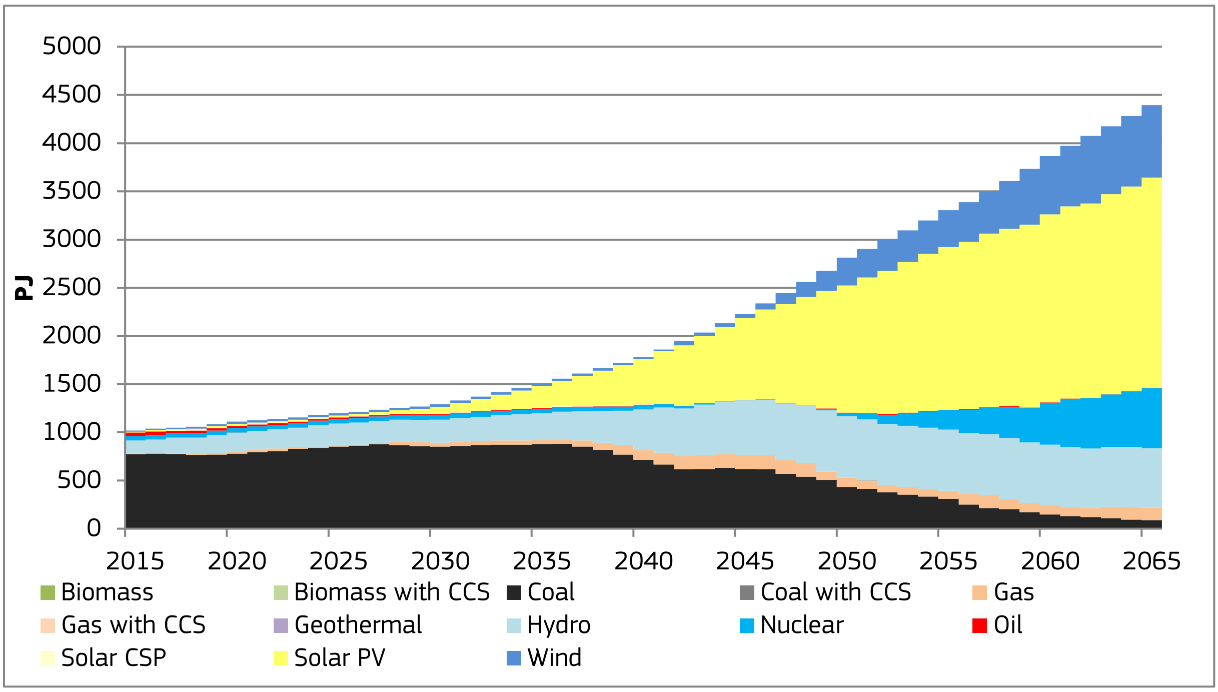
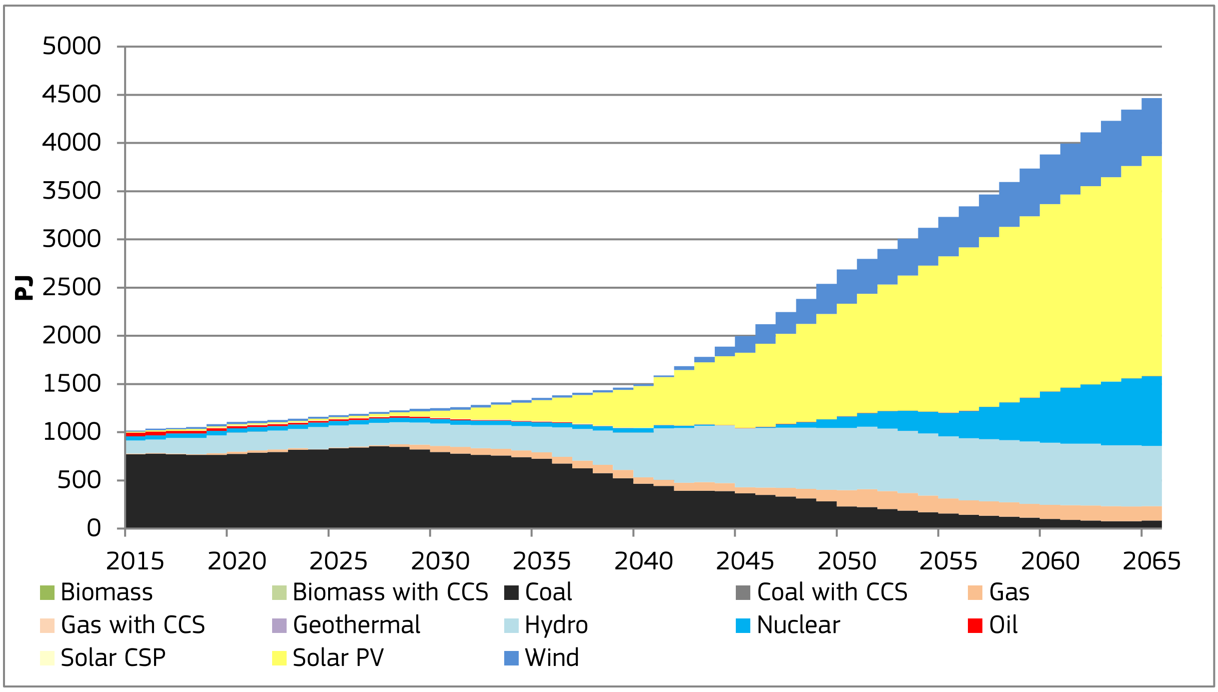



**Figure 60**. Power generation in SAPP in the 1.5°C scenario



## 4.4 Water consumption and withdrawal

### 4.4.1 All Africa

With a high share of electricity generation from thermal power plants (International Energy Agency, 2017b) the amount of water[9] withdrawn and consumed by this infrastructure is important in the African continent—especially when there is high uncertainty in climate change-induced water availability. In this section, we explore the trends in water withdrawal and consumption in the continent under different ambitious low carbon strategies.

In the Reference scenario, the water withdrawal will increase from approximately 17,000 million cubic meters (MCM) in 2015 to 142,000 MCM in 2065 in the continent, with an annual average growth rate of 4%. Most of the withdrawal is supposed to be used for cooling of oil and natural gas power plants in the SAPP and the NAPP. The ratio of water consumption to withdrawal drops from 7% in 2015 to ~2%. One potential reason for this being the usage of weighted consumption/withdrawal factors for new power plants in comparison to old power plants where there was a differentiation based on the actual installed cooling system. It must be taken into consideration that biomass has the largest share in terms of TPES in the countries. However, in this analysis, water consumption in biomass production has not been considered.

In the 2.0°C and 1.5°C scenarios, the water withdrawal is expected to be lower than in the reference scenario. The withdrawal in the reference scenario is expected to be 49% and 37% more than in the 1.5°C and 2.0°C scenarios respectively. In the power sector, the replacement of coal power plants by the less water-consuming natural gas power plants as well as the increase of renewable energy technologies could lead to lower future water withdrawals in the 2.0°C scenario. The choice of cooling type is another angle that needs to be explored in detail to arrive at the exact contribution of each of the factors to the total water withdrawal and consumption. The overall decrease of coal consumption in the continent between the 2.0°C scenario and the reference, 866 PJ compared to ~17,500 PJ respectively in 2065 could also be a contributing factor. In the case of the 2.0°C scenario, the withdrawal is relatively flat compared to the Reference scenario. Towards the end of the modelling period, there is some nuclear penetration in the 2.0°C scenario. However, it is expected that most of the nuclear infrastructure, in the coastal countries, will be based close to the sea near the load centres, and therefore using seawater for cooling.

On the other hand, in the 1.5°C scenario, the water withdrawal will be lower than in the Reference scenario until the end of the modelling period. The withdrawal in the 1.5°C scenario is expected to go beyond the 2.0°C scenario in the last decade, owing to larger nuclear power plant usage in inland countries.

[9] Including both fresh and seawater.

**Figure 61.** Water withdrawal in Africa in the Reference scenario

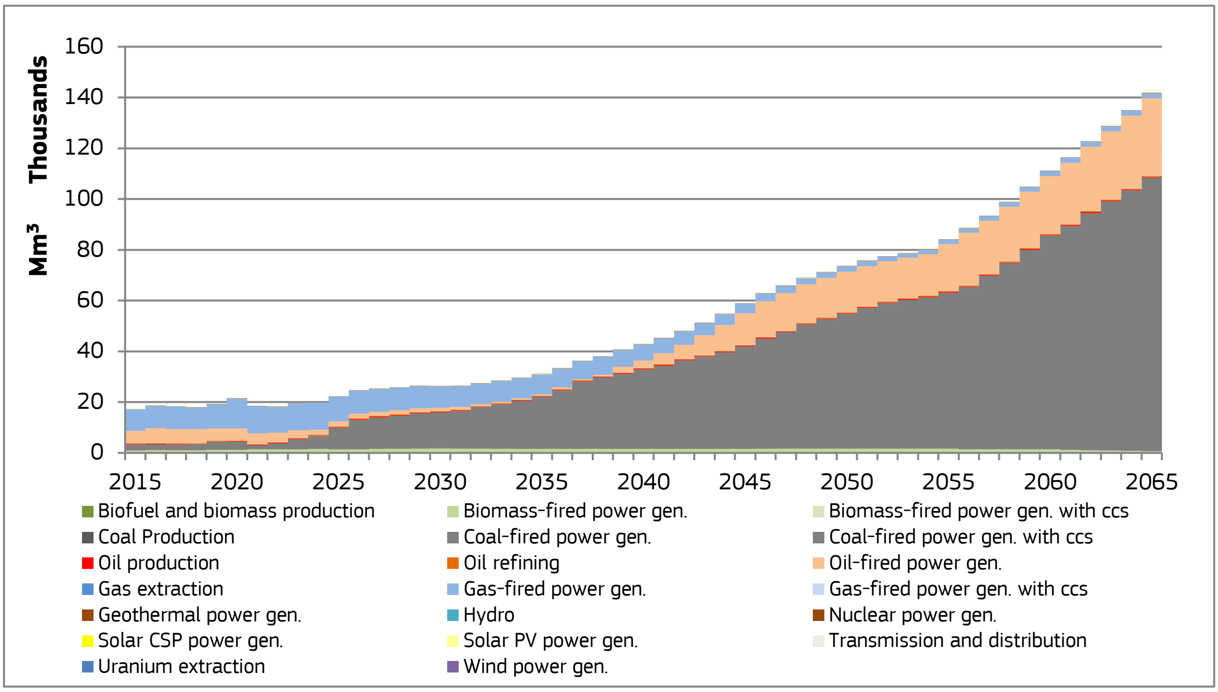



**Figure 62**. Water consumption in Africa in the Reference scenario

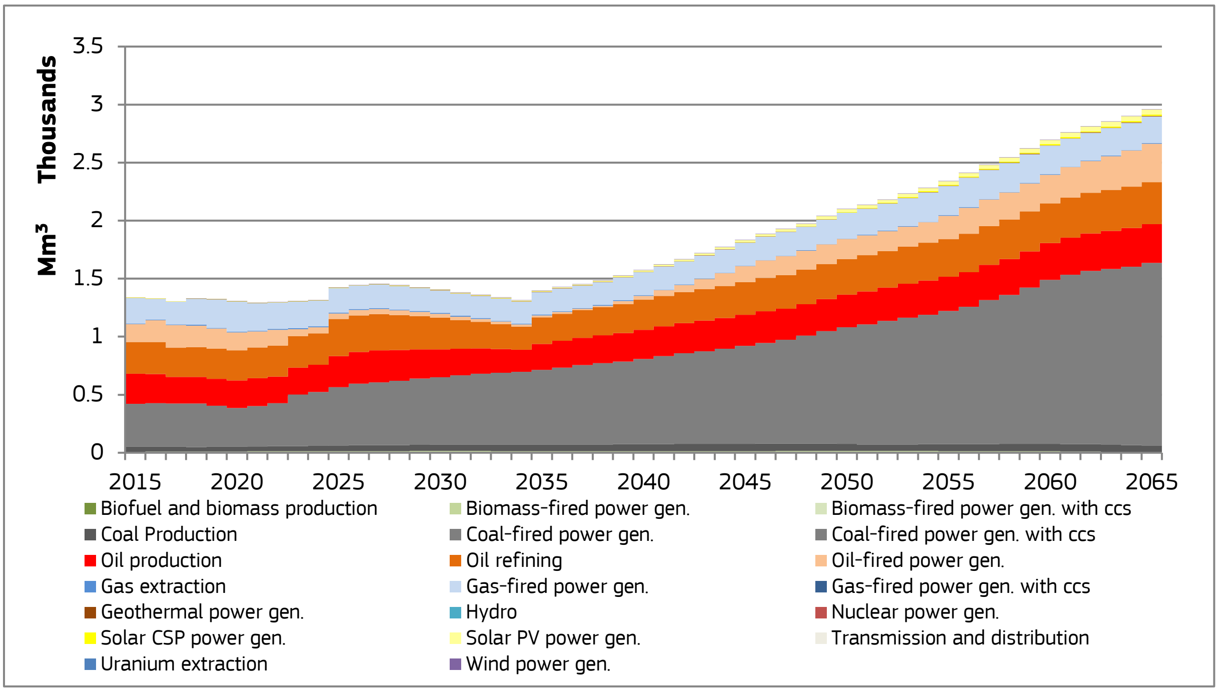


**Figure 63.** Water withdrawal in Africa in the Reference, 2.0°C and 1.5°C scenarios

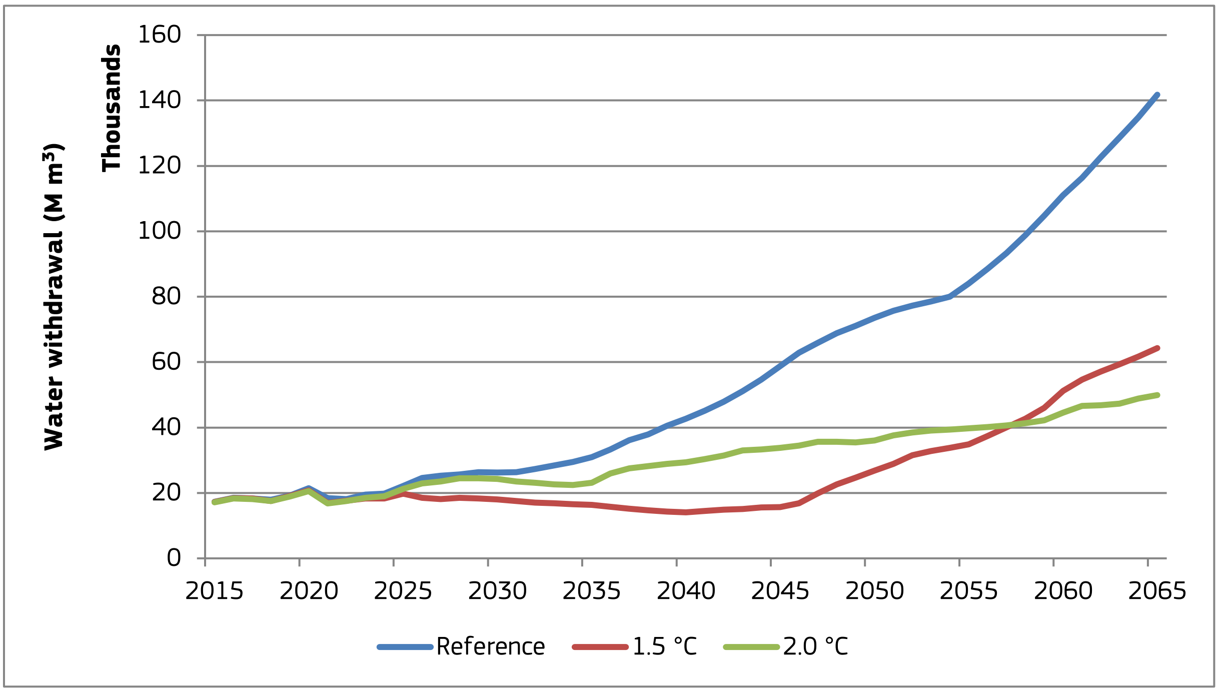
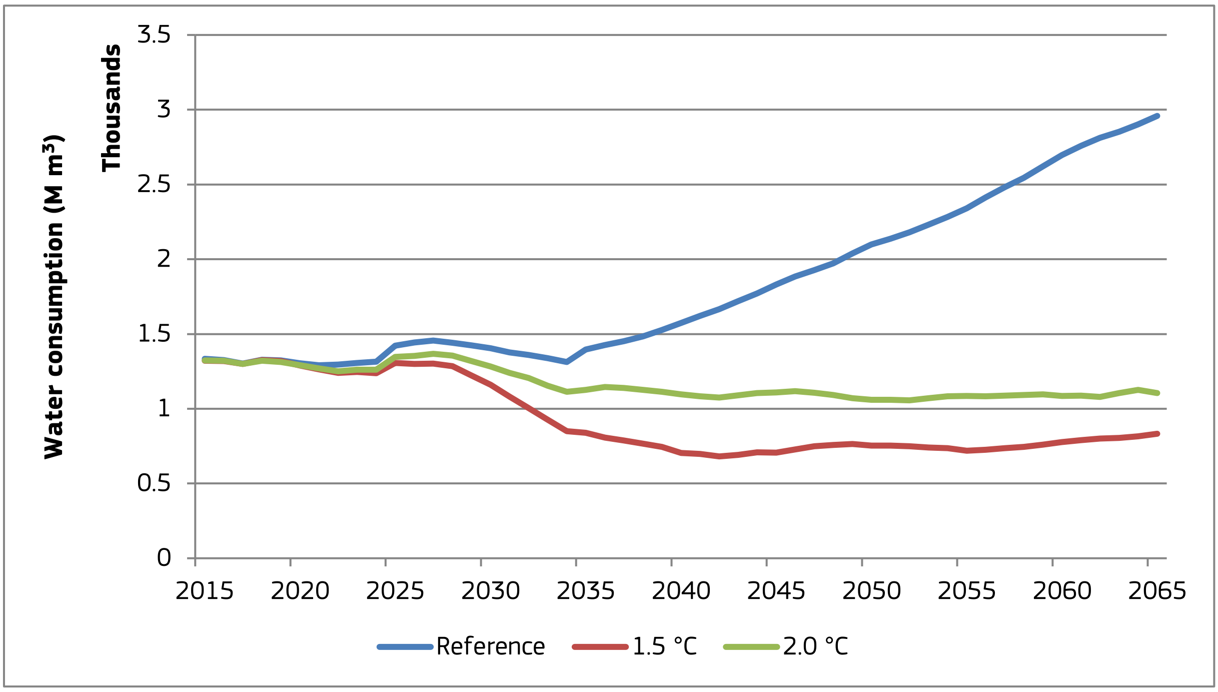



**Figure 64.** Water consumption in Africa in the Reference, 2.0°C and 1.5°C scenarios




The water consumption graphics show a slightly different trend. The reference scenario has a high consumption owing to the relatively higher use of coal and oil-based electricity generation (towards the end of the modelling period). It must be taken into consideration that the use of oil for the non-power generation (primarily transport) is high as well.

For the entire modelling period, the overall water consumption in the 1.5°C and 2.0°C scenario is 53% and 44% less than in the reference scenario.

In the following sections, water consumption and expansion for the different power pools are explored to identify the reasons, which support the continental trends, discussed above.

### 4.4.2 Western Africa

WAPP is one of the largest contributors to water withdrawal in the Reference scenario. The increase in coal-based power generation in Nigeria, towards the end of the modelling period results in this increase. This is partly due to the once through cooling systems that are installed along with the air and MDT/NDT systems. That being said, the cooling system types, in future work, should take into consideration the proximity of mines to the thermal power plants. Some calculative assumptions on cooling system types have to be made if the resource is mined inland or imported and if the country is land-locked or coastal. The withdrawal curves for the Reference and the 2.0°C diverge around 2045. Nuclear power plants in Mali and inland biomass-based generation in other countries replaces coal in the power sector. In the 1.5°C scenario, increased nuclear and biomass usage contributes to the bump in the last five years.

Towards the end of the modelling period, the consumption in the Reference scenario constitutes about 1/4 of the continental water consumption. Countries like Nigeria, with their future heavy gas and oil usage are the reason behind the upward trend of water consumption lines in both the WAPP and TEMBA in the Reference scenario. In the 2.0°C and 1.5°C scenarios, WAPP contributes roughly 50% and 30% of the continental water consumption respectively. Overall, the consumption decreases in the 2.0°C and 1.5°C scenario compared to the Reference.

**Figure 65.** Water withdrawal in WAPP in the Reference, 2.0°C and 1.5°C scenarios

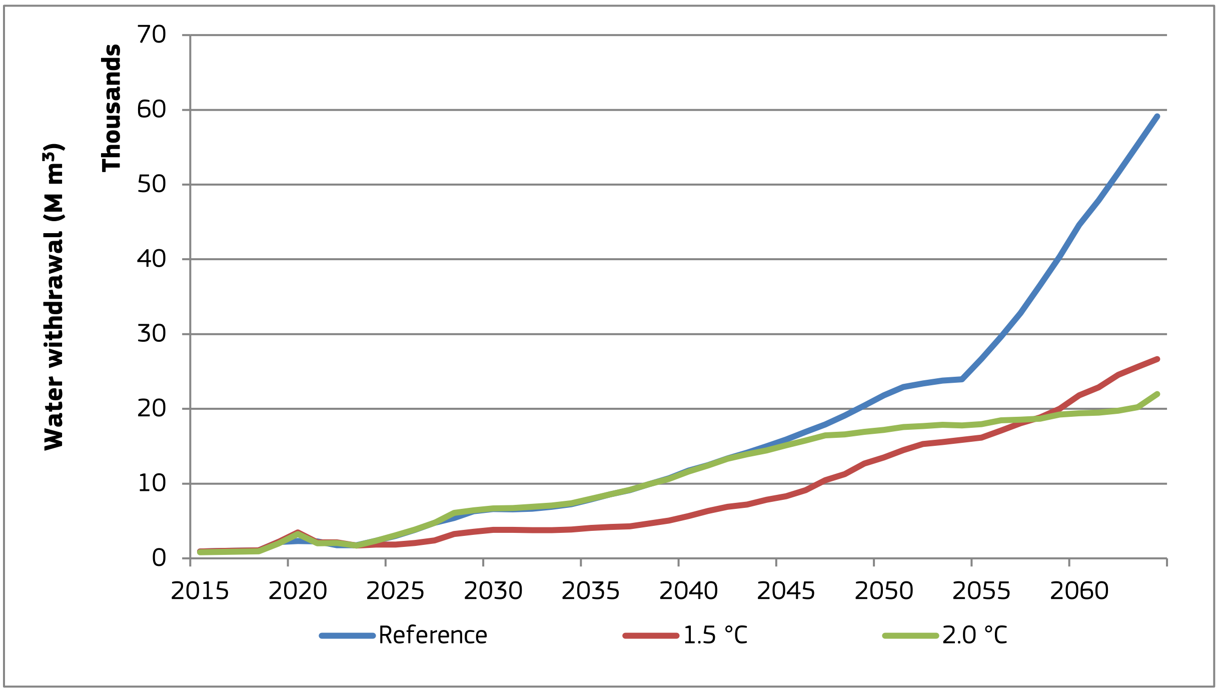
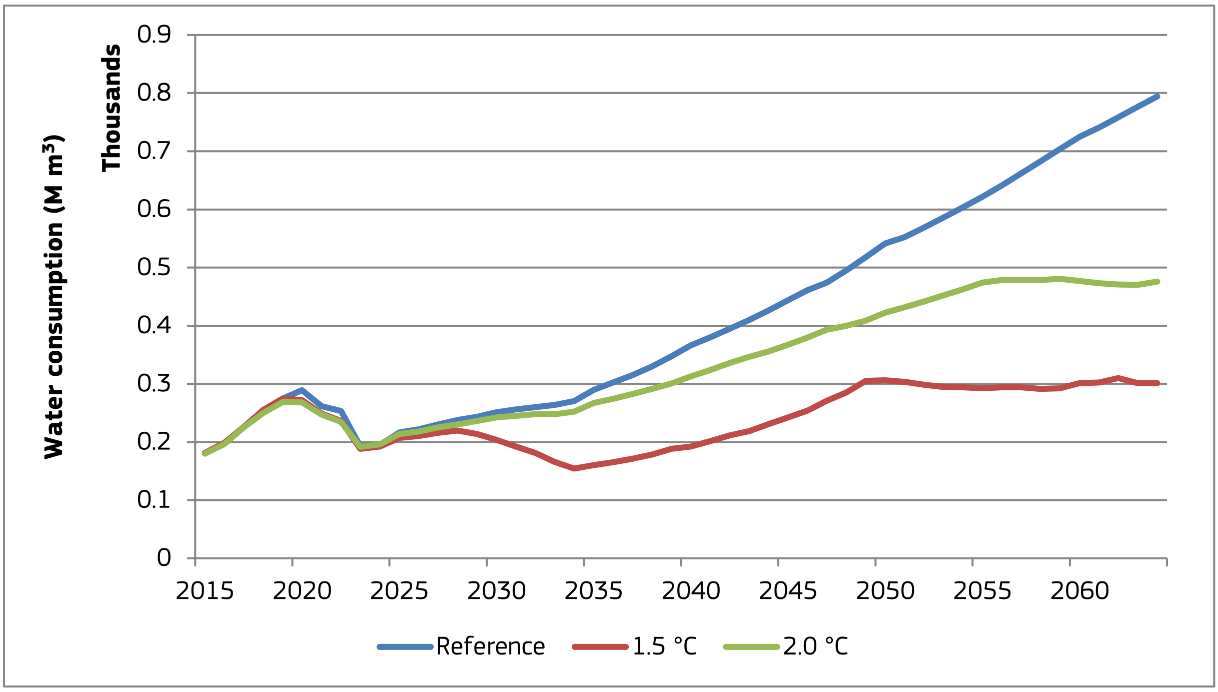



**Figure 66.** Water consumption in WAPP in the reference 2.0°C and 1.5°C scenarios



### 4.4.3 Northern Africa

Water withdrawal in the NAPP is quite high in the first years—about 46% of continental withdrawal—but drops to 14% in 2065 owing to the higher share in other regions and higher RE penetration. Within the NAPP, for the Reference scenario, the increase is due to the growth in coal-based electricity generation in Morocco. Almost all the future coal and open cycle gas turbines in Morocco are assumed to be of once through type. The withdrawal in the 1.5°C scenario shows a decreasing trend until the very end. In the 2.0°C and 1.5°C scenarios, the share of RE based power generation (solar and wind) is high, hence the decline in total system emissions.

Regarding water consumption in the reference scenario, the trend is quite flat This could be due to the use of coal-based power plants with once through type cooling systems in the system along with the MDT/NDT cooling systems in open and closed cycles gas turbines and HFO power plants. In the other scenarios, the consumption decreases because of the reduced use of coal in power generation and higher penetration of biofuels and electric vehicles in the transport sector.

**Figure 67.** Water consumption in NAPP in the Reference, 2.0°C and 1.5°C scenarios

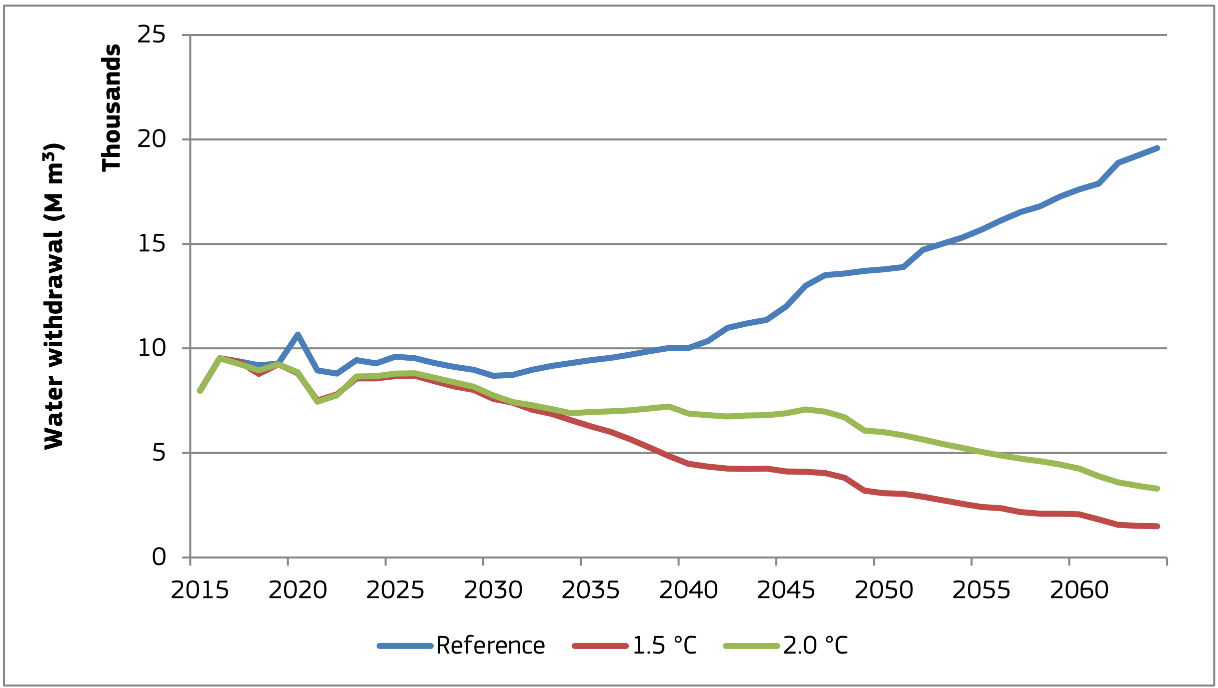
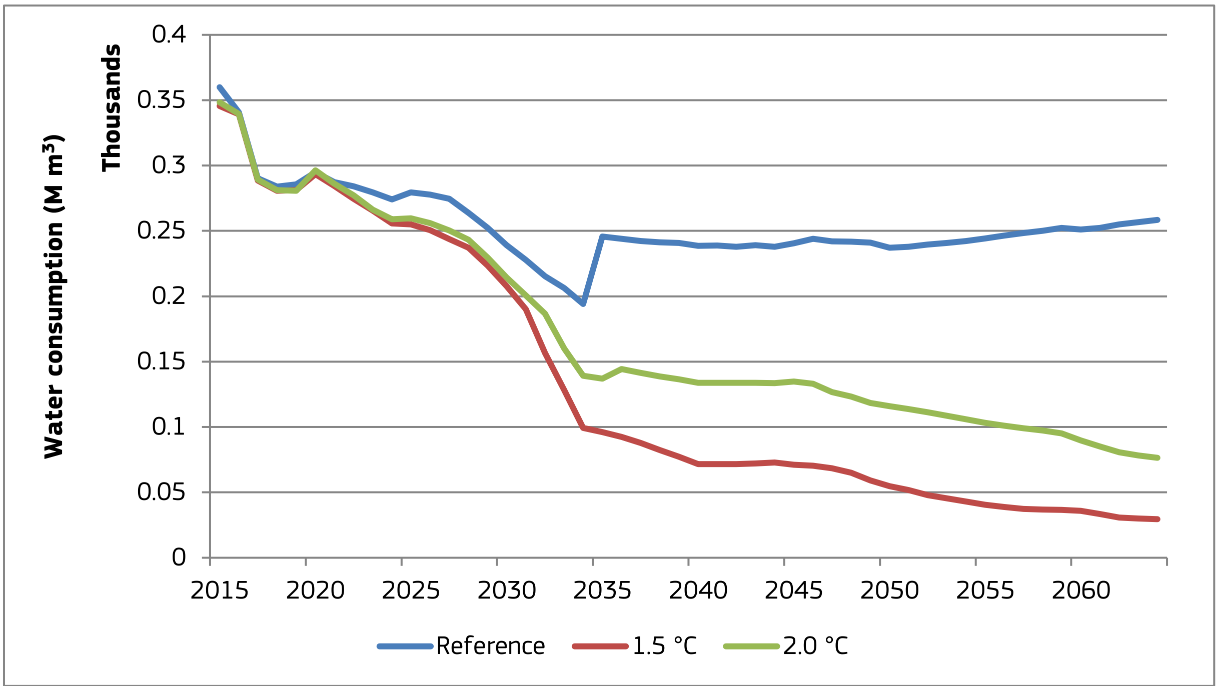



**Figure 68.** Water consumption in NAPP in the reference, 2.0°C and 1.5°C scenarios



### 4.4.4 Eastern Africa

The EAPP has the highest water withdrawal numbers amongst the power pools, owing to its high consumption of oil and coal in the power sector. Most of the oil and coal used in the energy systems is expected to be imported. Hence, this is not reflected in the water withdrawal or consumption projections. In the 2.0°C scenario, there is a significant reduction in the usage of coal and gas in the power sector. It is also interesting to notice the effect f introducing CCS in gas, coal and biomass-based power plants.

The water consumption graphs display similar trends to water withdrawal. There is significant reduction in water consumed in the 1.5°C and 2.0°C scenarios compared to the reference. In the 1.5°C and 2.0°C scenarios, the power plants equipped with CCS contribute a lion's share to the consumption.

**Figure 69.** Water withdrawal in EAPP in the reference, 2.0°C and 1.5°C scenarios

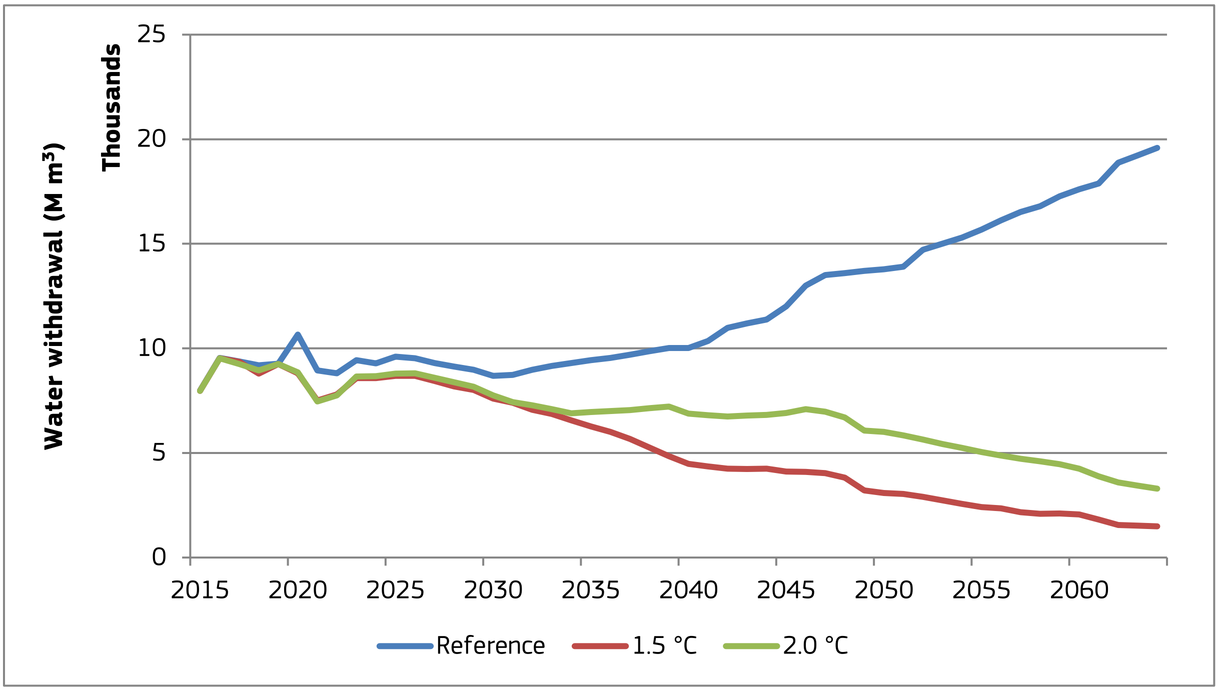
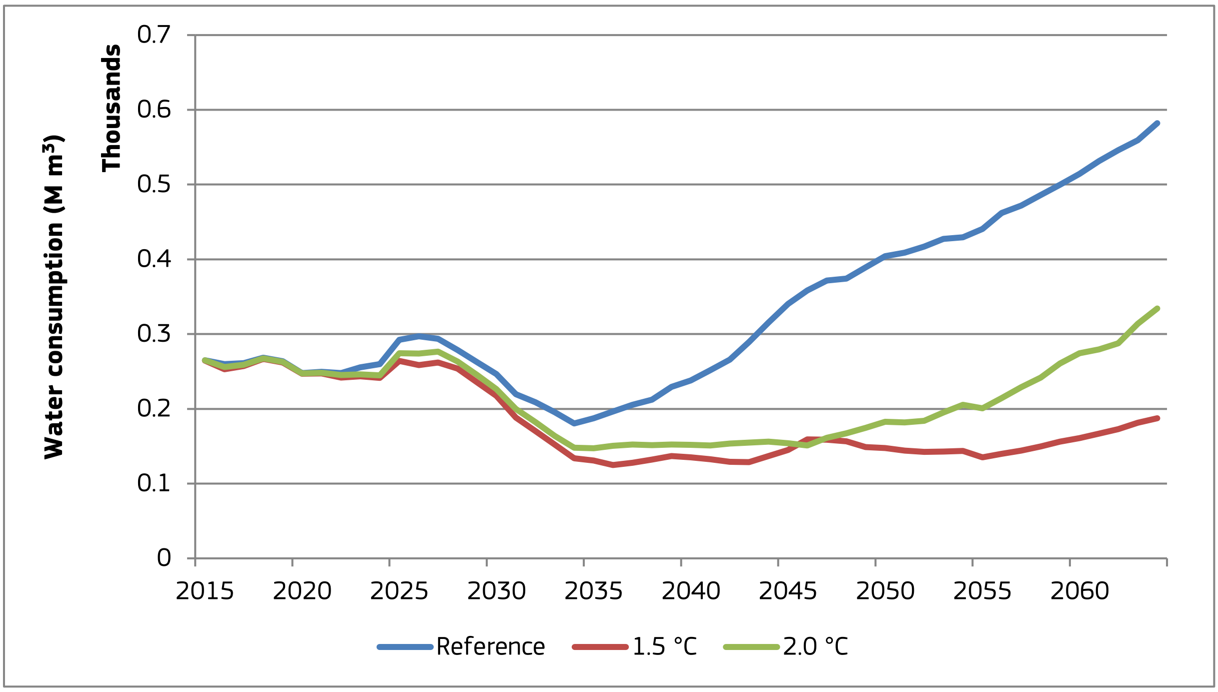



**Figure 70.** Water consumption in EAPP in the reference, 2.0°C and 1.5°C scenarios



### 4.4.5 Central Africa

For the Reference scenario, the CAPP has a high share of RE penetration in the power sector. Fossil fuels contribute to less than 20% of the power pool's electricity generation. Hence, the water withdrawal and consumption figures are the lowest amongst the power pool's consumption (2-3% on average) and withdrawal (less than 1% on average). However, in the 1.5°C and 2.0°C scenarios, due to expected nuclear power generation in Chad (especially in the 1.5°C scenario), the water withdrawal factors are high; that is the reason behind the skewed graphics.

Crude oil extraction and refining are the main contributors to water consumption in the CAPP. In the 1.5°C and 2.0°C scenario, periodic decarbonisation results in lower oil usage in the system, which contributes to lower water consumption. In the 1.5°C scenario, towards the end of the modelling period, nuclear power plant operation results in an increase in water consumption.

**Figure 71.** Water withdrawal in CAPP in the reference, 2.0°C and 1.5°C scenarios

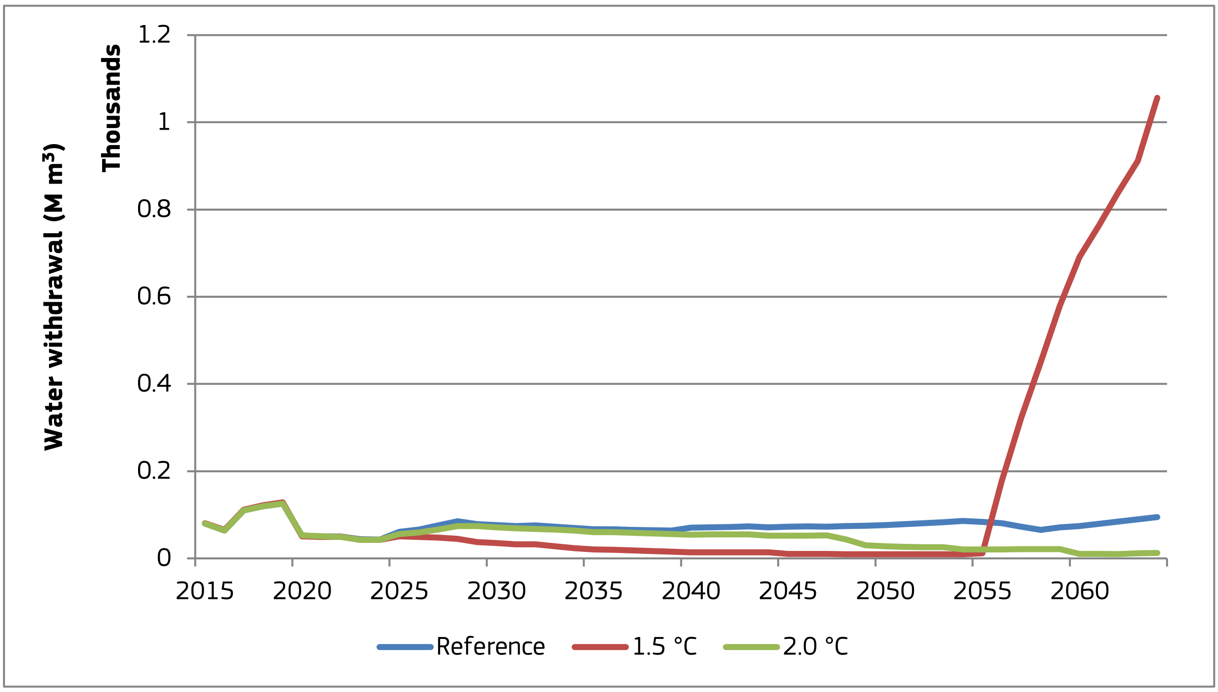
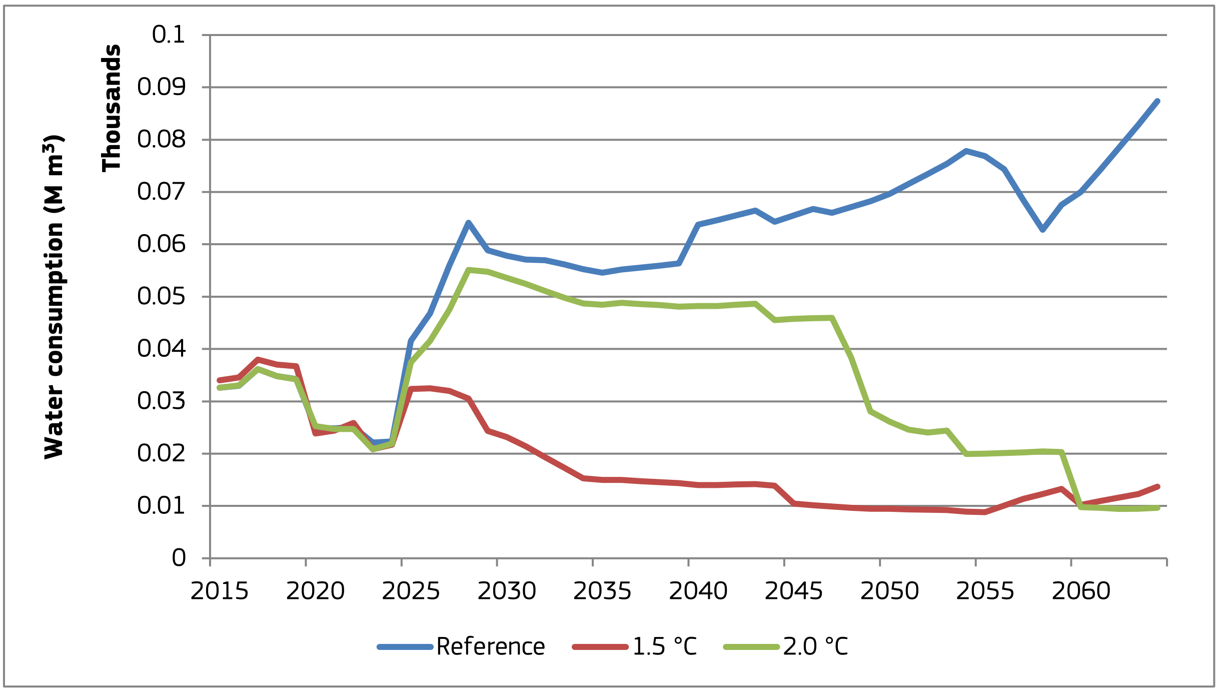



**Figure 72.** Water consumption in CAPP in the reference, 2.0°C and 1.5°C scenarios



### 4.4.6 Southern Africa

In the 1.5°C and 2.0°C scenarios, the power system shifts away from heavy coal dependence and turns to renewables (solar PV ad wind) and nuclear-based electricity generation. Nuclear power plants in the landlocked countries—Zimbabwe and Zambia—lead to a sharp increase in water withdrawal numbers. In comparison to the reference scenario, water consumption numbers decrease in the 1.5°C and 2.0°C scenarios as the share of coal usage in the power system reduces.

**Figure 73.** Water withdrawal in SAPP in the reference, 2.0°C and 1.5°C scenarios

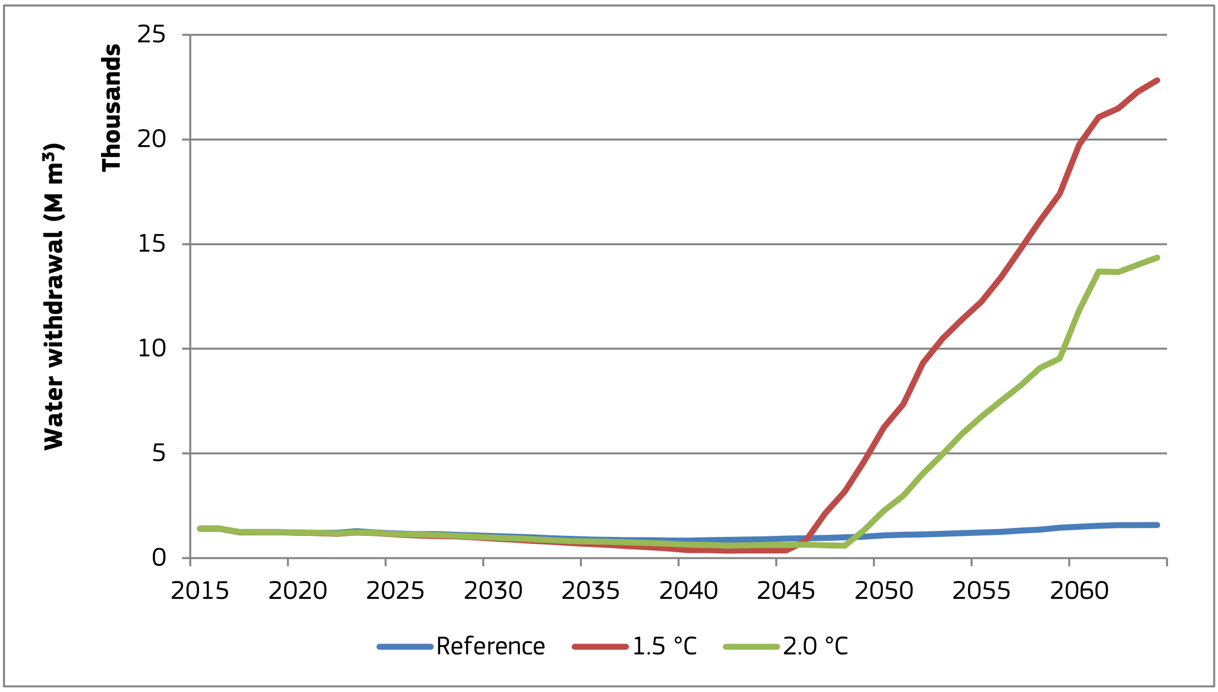
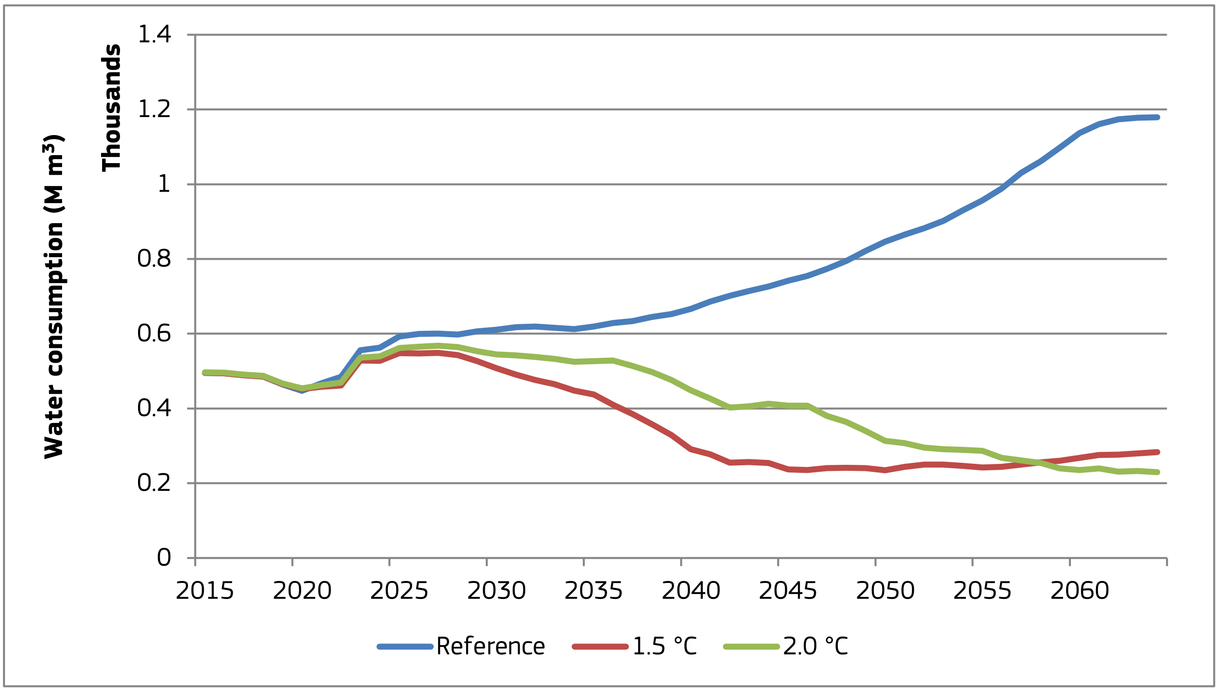



**Figure 74.** Water consumption in SAPP in the reference, 2.0°C and 1.5°C scenarios



## 4.5 Carbon dioxide emissions

With rapid economic development in many African countries and an improving trend in access to electricity and modern forms of energy, the demand for electricity in the continent is expected to increase. With increasing demand, cheap fossil fuel sources are expected to play a critical role similar to the development of most nations in the world. This section discusses the $CO_2$ emission trends in the continent for the Reference scenario and the two low-carbon development scenarios. It can be noticed that the $CO_2$ emission trends under the different scenarios start to differ in 2020 where the emission caps and the renewable targets are introduced in a number of African countries. The model has detailed fuel-specific emission representation in each of the countries; whereas the cap is introduced for the whole continent. The WAPP, SAPP, and EAPP are the highest emitters in the continent when compared to the CAPP and NAPP countries. This is evident in the figure below.

**Figure 75.** Total carbon dioxide emissions in Africa in the reference, 2.0°C and 1.5°C scenarios

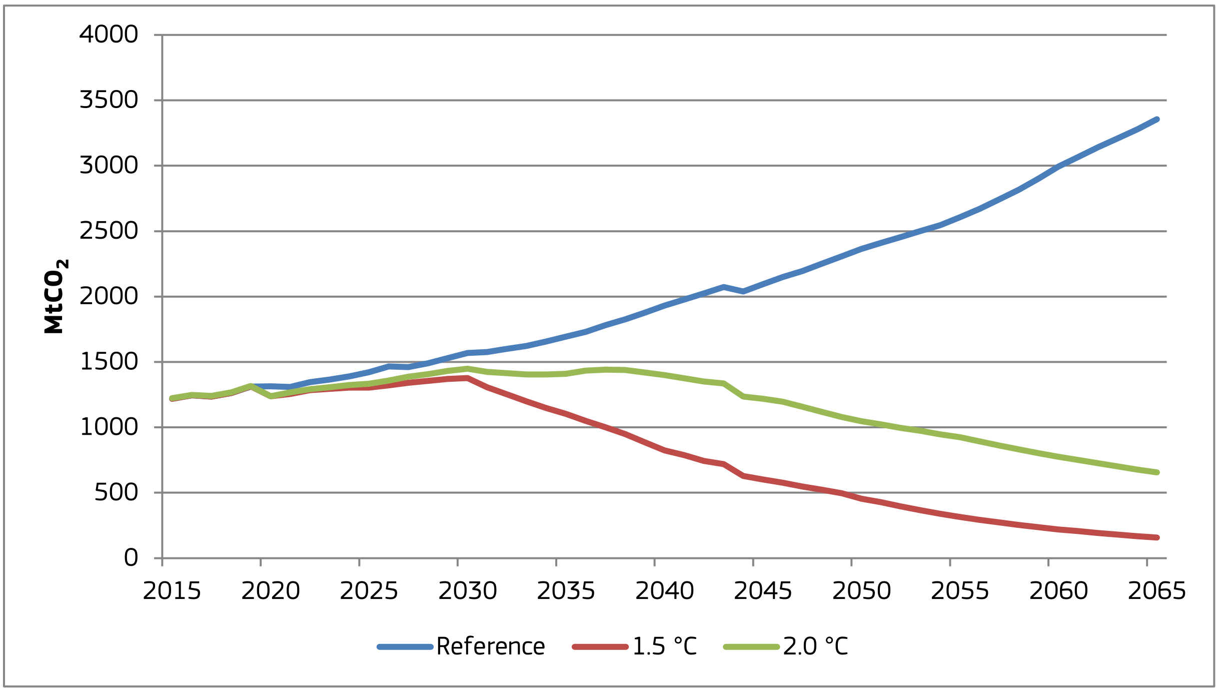
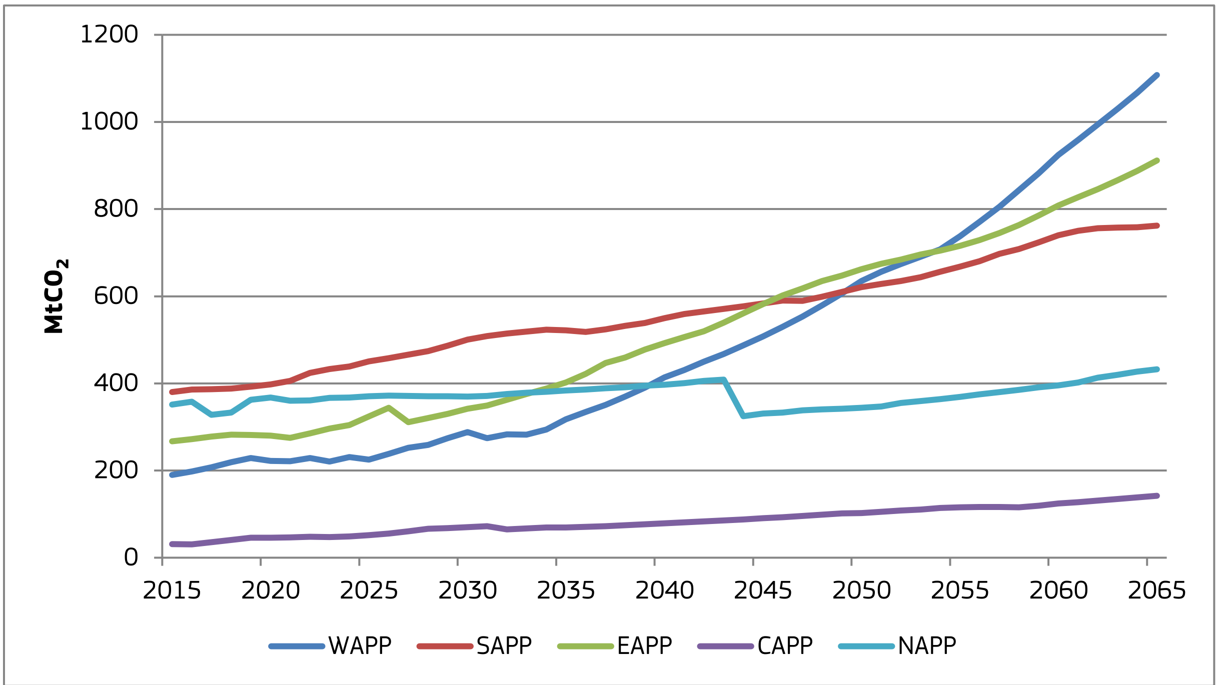
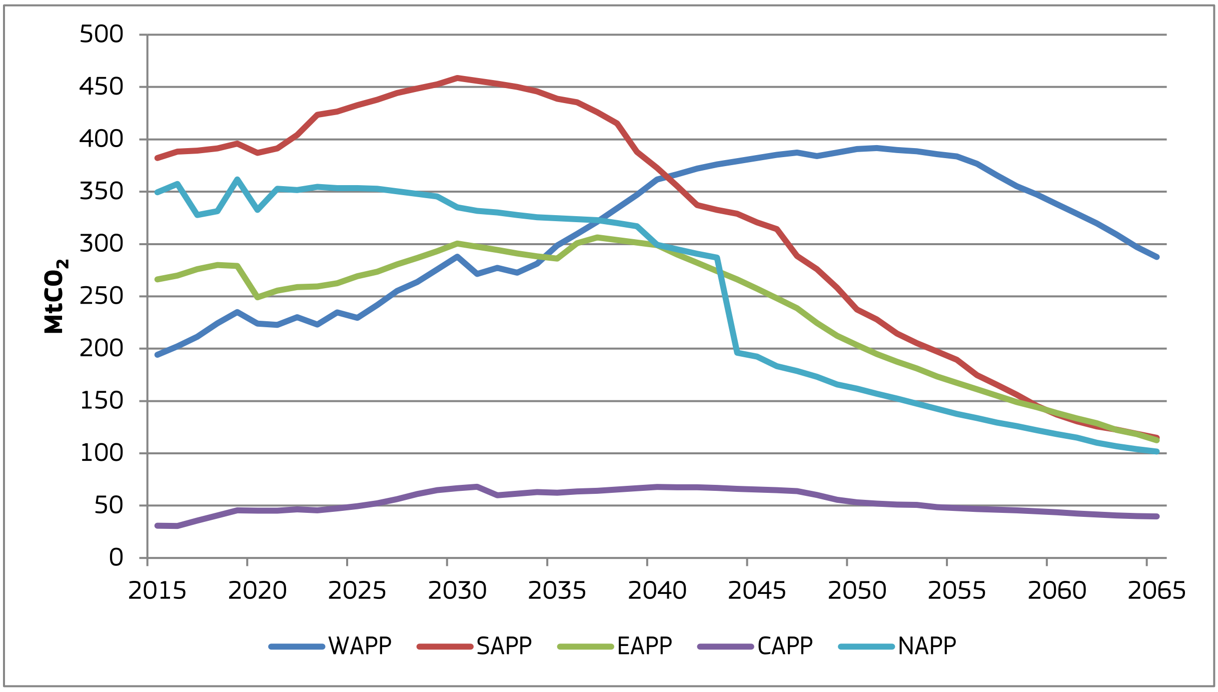



**Figure 76.** Comparison of the total carbon dioxide emissions per power pool in the reference scenario



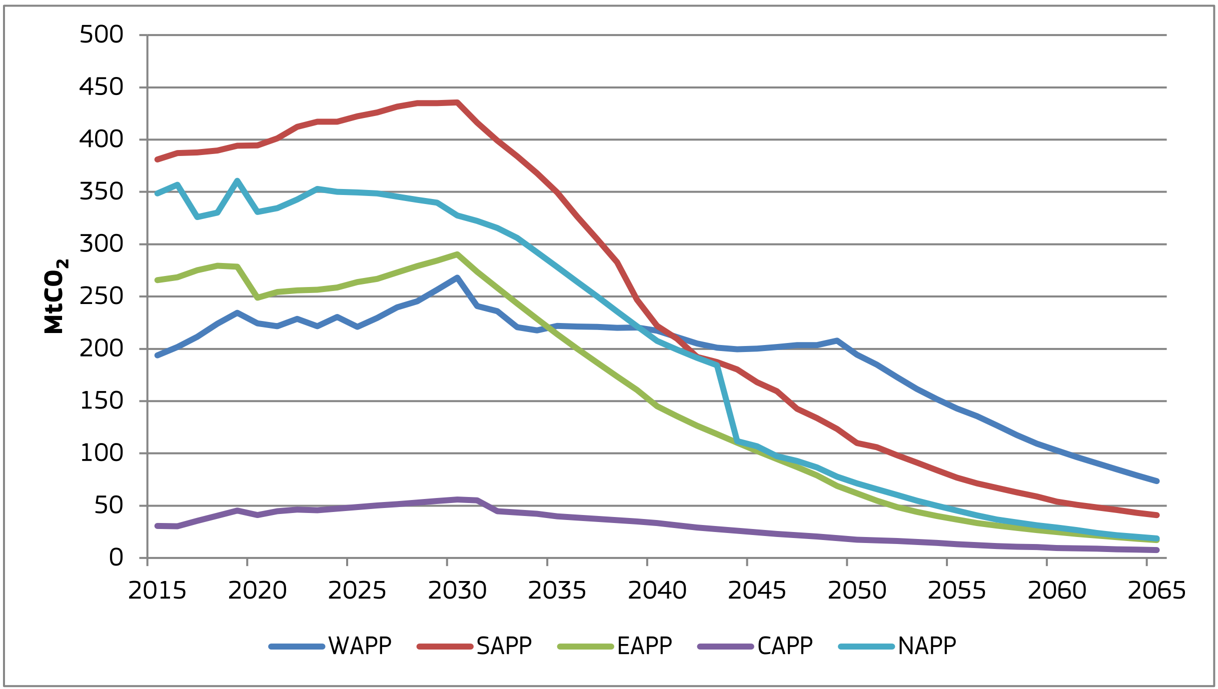
It can be noticed that, in the Reference scenario, WAPP emissions are low at the start of the modelling period owing to high shares of gas and hydropower in the energy system. However, close to the end of the modelling period, there is significant use of coal which propels the emissions. In the CAPP, the emissions are the lowest amongst the power pools owing to the high usage of Hydropower in the system (most of it in the DRC). Though the emissions from the NAPP countries are high at the beginning, their share in the total continental emissions is expected to fall towards the end. There is a shift in fossil fuel usage in between 2043-2044 in the Northern African countries and hence the dip, which is noticeable across all scenarios.

**Figure 77.** Total carbon dioxide emissions per power pool in the 2.0°C scenario




In the above figure, the emissions under the 2.0°C scenario are illustrated. We can notice that, despite an overall reduction in total emissions in the continent, there is an increase in emissions in the WAPP during 2037-2057. This is due to the higher coal usage in the power system in those years. Since the emission caps are on a continental level, the model optimizes the energy systems of the individual countries to achieve a low-cost expansion mix taking into consideration the low-carbon limitations.

**Figure 78.** Total carbon dioxide emissions per power pool in the 1.5°C scenario



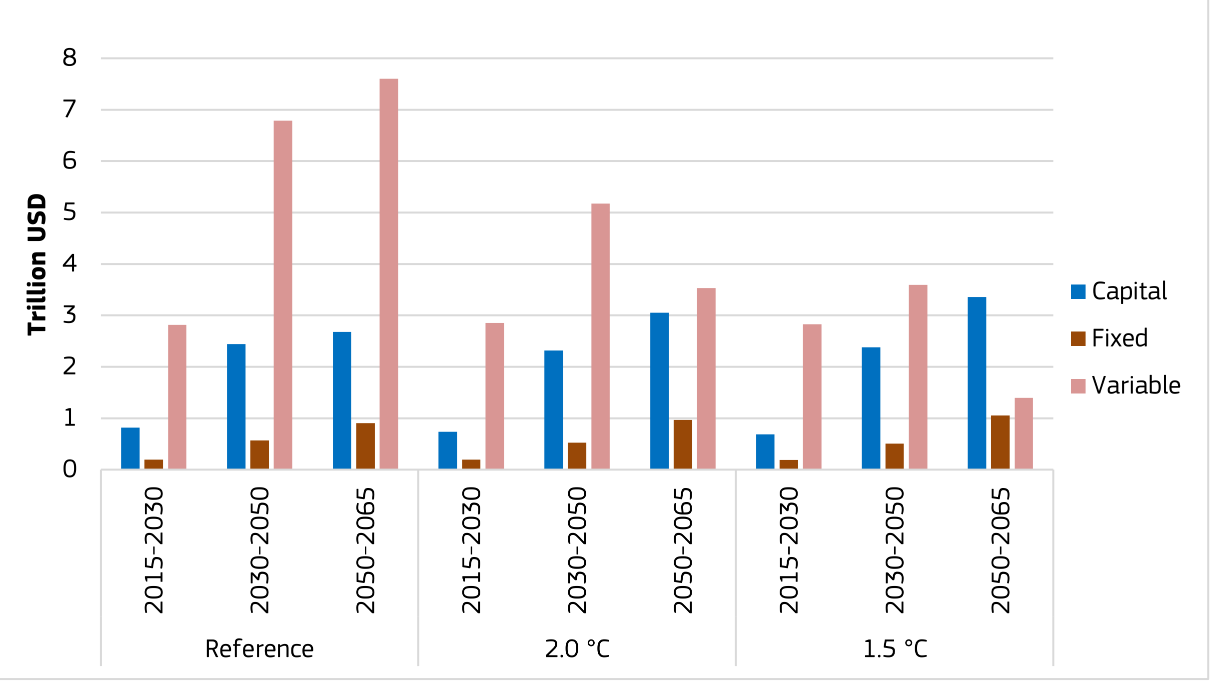

In the 1.5°C scenario, as illustrated above, there is a significant reduction in total emission in all the power pools. The share of SAPP's emission drops significantly as it shifts from a coal-based power pool to a combination of nuclear and renewable usage. The emissions do not drop to a zero level as the transport sector still depends on fossil fuels. Additionally, as the fuel usage in the non-power systems slowly transitions from fossil fuels to cleaner and sustainable alternative, it remains interesting to see how the capital will be sourced in many of the African countries to achieve the highly ambitious low-carbon goals.

## 4.6 Total system costs

Figure 79 shows the total system costs (split into capital, fixed and variable costs) required by each country to cover its future energy needs under the different scenarios.

In the Reference scenario, in total, approximately 5.9 trillion USD of capital investments, 1.7 trillion USD of fixed costs and 17.2 trillion USD of variable costs will be required to cover its energy needs during the period 2015-2065. In the 2.0°C and 1.5°C scenarios, the total system costs will be relatively higher than in the Reference scenario due to the higher share of renewable energy technologies and nuclear plants in the power generation mix. The changes in the generation mix require higher capital investments and fixed costs, but lower variable (fuel) costs.

**Figure 79.** Total system costs in Africa across the scenarios



# 5 Conclusions

This study presents three energy scenarios for Africa on a national and continental level. The scenarios describe in which type of power generation technology an African country should invest in to cover its future energy needs and what would be the associated expenses, carbon dioxide emissions and water requirements. It develops scenarios considering existing renewable energy targets (until 2017) as well as emission reduction targets to achieve temperature targets agreed under the United Nations Framework Convention on Climate Change (UNFCCC) Paris. These scenarios are then analysed using the TEMBA model. The scenarios present plausible futures and the results and conclusions should be read as descriptive rather than prescriptive.

The Reference scenario indicates the scale of the capital investments (~ 5.9 trillion USD) that would be required in the energy sector in the upcoming decades in order for the continent to cover its future energy needs. The results show that with no new policies to manage demand or supply mix, the total installed capacity in Africa will increase approximately three times by 2040 and ten times by 2065, to 1834 GW. The existing poor power infrastructure (an average of 40% of the electricity output is being lost through the distribution network) is one of the main reasons for this. As such, significant investments will be required to improve and extend the transmission and distribution networks on the continent.

Key assumptions for the TEMBA model which influence the mix of technologies include those relating to fossil fuel prices, the renewable energy cost development assumptions as well as the power system's reserve capacities margin. The high penetration of renewable technologies, particularly solar PV, hydro in SAPP, EAPP and WAPP regions, wind in NAPP and geothermal in EAPP will increase the continent's renewable capacity from 20% in 2015 to 78% in 2065. The share of renewable energy sources in the continent's electricity generation will be 57% by 2065.

In the Reference scenario, the total primary energy supply will increase from approximately 810 Mtoe in 2015 to 1920 Mtoe in 2065. On the supply side, biomass is the most important fuel followed by oil and coal until 2050, however, afterwards, oil products constitute most of the continent's TPES followed by coal and biomass. This is in contrast to the 2.0°C scenario where biomass is the main fuel throughout the modelling period, followed by renewables (solar, wind, geothermal) and nuclear the period 2050-2065. The 1.5°C scenario follows similar trends in the primary energy supply as the 2.0°C scenario with the main difference being that nuclear generation will be greater than renewable-based generation (solar, wind, geothermal) during the period 2060-2065.

The Reference scenario presents a future in which the African continent switches from a gas-based power generation region in 2015 to use coal as the main fossil fuel source. However, in the 2.0°C and 1.5°C scenarios, the continent's installed capacity will be relatively lower than in the Reference scenario, 1809 GW and 1827 GW in 2065 respectively, due to lower final energy demand. Nevertheless, for the African countries to achieve the emission targets in the 2.0°C and 1.5°C scenarios they will need to increase the share of their renewable capacity to 85% and 85% in 2065 respectively. To do so a number of African countries will increase their hydropower capacity, invest in gas-fired power plants instead of coal plants as in the Reference scenario and take advantage of the electricity trading schemes in the continent. Such countries are Angola, Cote D'Ivoire, Cameroon, Ghana, Morocco, Senegal and South Africa. A key investment highlighted in this study is the potential commission of the next phases of the Grand Inga hydropower project in the Democratic Republic of Congo in the upcoming decades where the country will mainly use the produced electricity for domestic use and export part of it to the neighbouring countries. In addition, Sudan will increase its hydropower generation to export electricity mainly to Egypt in order to assist Egypt to reduce its fossil-fuel dependency. The implementation of the Grand Renaissance dam in Ethiopia is also one of the mega-investments that will transform the continent's future energy mix. However, policy makers and investors should consider Africa's vulnerability to climate change. The commissioning of most of the cross-border electricity interconnector projects in the future proves to be beneficial across the scenarios. Nuclear power will also be one of the key power generation technologies in the continent as it is highlighted in the 2.0°C and 1.5°C scenarios.

It should be noted that in order to achieve the estimated emission limits under the two scenarios, the African countries should decrease their final fossil energy demand from 565 PJ in 2015 in the Reference scenario, to 185 PJ and 30 PJ in the 2.0°C and 1.5°C scenarios. In addition, energy policies that favour efficiency improvements are essential for the upcoming decades. The water supply and demand are one of the main challenges that the African countries are facing. FAO estimates the total renewable water resource (TRWR) which is the theoretical maximum annual volume of water resources available in a country, in the African continent to be 3,950 billion cubic meters every year (FAO, n.d.). Under this study, it is estimated that, in the

Reference scenario, by 2065, the African energy system alone will withdraw ~4% of the TRWR in Africa. At first glance, this share appears meagre, but in reality, this number must be analysed in the perspective of the nexus between water for food, energy, household uses, etc. Most of the thermal power infrastructure is not located in remote places and they are not far from population centres. This creates an added complexity to future infrastructure planning. Our analysis estimates that this share will reduce to 1.2% and 1.6% in the 2.0°C and 1.5°C scenarios respectively owing to deep decarbonisation of the energy sector. We also need to bear in mind that we do not take into consideration, the climate-induced changes in water availability, of which there has been only a downward trend projected for major parts of the African continent (Cervigni, Liden, Neumann, & Strzepek, 2015). These withdrawal estimations must be matched with crop calendars in the respective countries to get an actual idea of how much impact this will have on crop irrigation. With many countries battling to improve their food security, and irrigation being one of the key climate mitigation techniques to improve minimum dietary conditions, the water withdrawal and consumption for the energy system must be planned in a sustainable manner. From a policy point of view, it means that in order to achieve less carbon dioxide emissions in the future, a significantly higher amount of water withdrawal will be required. Lastly, the annual investments and operational costs, as well as conclusions on the energy supply of each African country, can found in Annex 1 (energy balances, greenhouse gas emissions and costs). One of those is the increase of the LNG exports in a number of African countries of approximately 53,080 PJ in the period 2015-2030 such as: Angola (3,680 PJ), Algeria (22,082 PJ), Djibouti, Egypt (8,546 PJ), Equatorial Guinea (2,619 PJ), Ghana (87 PJ), Mauritania (1105 PJ), Mozambique (1353 PJ), Nigeria (13,349 PJ), Namibia (257 PJ).

## 5.1 Limitations and options for future work

The model developed under this study could be further improved and enhanced on important aspects such as:

- Including an explicit representation of reserve margin into the power system,
- Considering hydropower with storage plants,
- Explicitly modelling storage technologies such as solar PV with batteries,
- Including country-specific hydro capacity factors,
- Increased temporal resolution,
- Disaggregate the final energy demand in sectors as well as on exogenous assumptions around fuel switching and efficiency improvements
- Incorporate demand technologies into the model to endogenise fuel switching
- include more detailed sub-annual time resolution,
- analysis of increased trade potential with increased trans-African as well as African-European interconnectors and super grid development
- Analysing in detail trade including regional gas hubs and pipelines such as those linking North Africa with Europe as well as West and East Africa.
- Understanding the dynamics and limitations associated with hydro exploitation, especially in central Africa where national demands are limited. Those limitations require interconnections, which are subject to risk and investment considerations.
- Undertaking large ensemble scenario runs to understand determinants of key outputs, such as investment risk.
- Coupling hydro production with runoff modelling to determine potential vulnerabilities associated with climate change.
- Including oil and coal export analysis (rather than assuming exogenous sales levels)
- Including synthetic fuel production (from coal and gas) currently excluded from this analysis
- Including separation of biomass and fuelwood production used in households as well as obtain the water requirements
- Including estimations of water losses from hydropower

— Developing a more accurate methodology to estimate and allocate the different cooling systems to the future power plants

— Developing a process for collaborative data updates and easier model use and transfer

A number of those factors were excluded from this study due to the significant increase in the model calculation time. However, the open source code of the model as well as the open access of the input dataset of this analysis, are helpful for reproducing the findings of this study. In addition, as part of this analysis, a number of scenarios could be investigated such as: an expanded energy trading scheme, a Sustainable Development Goal scenario, a Climate Change and a Shared Socio-economic Pathways scenario.

## 5.2 Reproducibility

All input data and a reproducible scientific workflow incorporating the use of the Apache Licenses OSeMOSYS model are available from https://github.com/KTH-dESA/jrc_temba.

The precise instance of the workflow which produced the figures and data that underpin this report can be found in release v0.1 downloadable from https://github.com/KTH-dESA/jrc_temba/releases.

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## List of abbreviations and definitions

| | |
|---|---|
| bcm | Billion cubic metres |
| BECCS | Bioenergy with carbon capture and storage |
| CAPP | Central Africa power pool |
| CCS | Carbon capture and sequestration |
| EAPP | East Africa power pool |
| FAO | Food and Agriculture Organization |
| GECO | Global Energy and Climate Outlook |
| ICS | Improved biomass cook stoves |
| Mbtu | Million British thermal units |
| Mtoe | Million tonnes of oil equivalent |
| NAPP | North Africa power pool |
| OSeMOSYS | Open Source Energy Modelling System |
| RET | Renewable energy technologies |
| SAPP | South Africa power pool |
| SDG | Sustainable Development Goals |
| TEMBA | The Electricity Model Base for Africa |
| TFC | Total final consumption |
| TPES | Total primary energy supply |
| TRWR | total renewable water resource |
| UNFCCC | United Nations Framework Convention on Climate Change |
| WAPP | West Africa power pool |

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# Annexes

## Annex 1. Energy balances, GHG emissions and costs

| **Africa – Reference scenario** | **2015** | **2030** | **2050** | **2065** |
|---|---|---|---|---|
| **Energy balance, by fuel (Mtoe)** | | | | |
| **Primary energy production** | **885.70** | **1117.46** | **1126.20** | **1281.60** |
| Coal | 68.31 | 90.14 | 102.65 | 95.18 |
| Crude oil | 111.08 | 102.70 | 119.77 | 143.85 |
| Oil products | 135.44 | 135.38 | 152.55 | 179.70 |
| Natural gas | 263.46 | 317.24 | 176.04 | 204.72 |
| Nuclear | 3.34 | 3.34 | 0.00 | 0.00 |
| Hydro | 9.96 | 25.67 | 48.87 | 59.39 |
| Other renewables (solar, wind, geothermal) | 1.26 | 19.82 | 128.16 | 232.22 |
| Biofuels/waste | 292.85 | 423.16 | 398.16 | 366.53 |
| Electricity | 0.00 | 0.00 | 0.00 | 0.00 |
| **Imports** | **96.59** | **192.71** | **456.92** | **719.25** |
| Coal | 1.44 | 37.70 | 148.72 | 322.38 |
| Crude oil | 25.73 | 34.04 | 34.32 | 37.67 |
| Oil products | 62.58 | 93.79 | 196.27 | 261.50 |
| Natural gas | 3.38 | 15.54 | 53.59 | 68.37 |
| Nuclear | 0.00 | 0.53 | 6.27 | 8.21 |
| Hydro | 0.00 | 0.00 | 0.00 | 0.00 |
| Other renewables (solar, wind, geothermal) | 0.00 | 0.00 | 0.00 | 0.00 |
| Biofuels/waste | 0.00 | 0.00 | 0.00 | 0.00 |
| Electricity | 3.46 | 11.11 | 17.75 | 21.12 |
| **Exports** | **-172.76** | **-219.12** | **-73.91** | **-81.19** |
| Coal | 0.00 | 0.00 | 0.00 | 0.00 |
| Crude oil | 0.00 | 0.00 | 0.00 | 0.00 |
| Oil products | 0.00 | 0.00 | 0.00 | 0.00 |
| Natural gas | -169.30 | -208.01 | -56.15 | -60.07 |
| Nuclear | 0.00 | 0.00 | 0.00 | 0.00 |
| Hydro | 0.00 | 0.00 | 0.00 | 0.00 |
| Other renewables (solar, wind, geothermal) | 0.00 | 0.00 | 0.00 | 0.00 |
| Biofuels/waste | 0.00 | 0.00 | 0.00 | 0.00 |
| Electricity | -3.46 | -11.11 | -17.75 | -21.12 |
| **Total primary energy supply** | **809.52** | **1091.04** | **1509.21** | **1919.66** |
| **Power generation (Mtoe)** | | | | |
| **Fuel inputs for thermal power generation** | **-123.75** | **-161.73** | **-328.86** | **-523.24** |
| Coal | -50.88 | -92.24 | -209.57 | -373.66 |
| Oil products | -21.84 | -5.01 | -36.30 | -69.12 |
| Natural gas | -46.68 | -58.81 | -75.03 | -71.53 |
| Nuclear | -3.34 | -3.87 | -6.27 | -8.21 |
| Hydro | 0.00 | 0.00 | 0.00 | 0.00 |
| Biofuels/waste | -1.01 | -1.79 | -1.69 | -0.73 |
| **Gross electricity generation** | **64.05** | **118.92** | **320.58** | **509.45** |
| Coal | 19.85 | 35.98 | 81.73 | 145.73 |
| of which CCS | 0.00 | 0.00 | 0.00 | 0.00 |
| Oil | 8.24 | 1.76 | 12.96 | 24.52 |
| Natural gas | 22.99 | 33.25 | 45.69 | 44.40 |
| of which CCS | 0.00 | 0.00 | 0.00 | 0.00 |
| Biofuels/waste | 0.66 | 1.17 | 1.10 | 0.47 |
| of which CCS | 0.00 | 0.00 | 0.00 | 0.00 |
| Nuclear | 1.10 | 1.28 | 2.07 | 2.71 |
| Hydro | 9.96 | 25.67 | 48.87 | 59.39 |
| Wind | 0.77 | 5.44 | 27.80 | 45.11 |
| Solar | 0.37 | 11.75 | 96.00 | 178.45 |
| Other | 0.12 | 2.63 | 4.36 | 8.66 |
| **Oil refineries (Mtoe)** | | | | |
| Crude oil | -136.81 | -136.75 | -154.09 | -181.52 |
| Oil products | 135.44 | 135.38 | 152.55 | 179.70 |
| **Losses (Mtoe)** | | | | |
| Power generation | -9.76 | -15.75 | -30.62 | -43.50 |
| **Total final consumption (Mtoe)** | | | | |
| **Total** | **559.04** | **838.21** | **1137.51** | **1386.86** |
| Coal | 18.87 | 35.60 | 41.81 | 43.90 |
| Oil products | 159.10 | 224.09 | 310.93 | 370.01 |
| Natural gas | 36.41 | 58.61 | 103.31 | 146.32 |
| Biofuels/waste | 291.83 | 421.37 | 396.47 | 365.80 |
| Electricity | 52.83 | 98.54 | 285.00 | 460.83 |
| **GHG emissions (Mt $CO_2$ eq.)** | | | | |
| Total $CO_2$ | 1219.14 | 1569.79 | 2364.93 | 3355.79 |
| **Total System Costs (Mil. USD)** | | | | |
| Investment | 26458.19 | 68262.56 | 178167.93 | 209275.39 |
| Fixed | 8095.67 | 15811.36 | 45015.41 | 74266.40 |
| Variable | 127501.89 | 238475.94 | 438482.31 | 583151.81 |

| Africa – 2.0°C scenario | 2015 | 2030 | 2050 | 2065 |
|---|---|---|---|---|
| **Energy balance, by fuel (Mtoe)** | | | | |
| **Primary energy production** | **886.79** | **970.36** | **944.36** | **1000.99** |
| Coal | 68.80 | 80.34 | 35.91 | 5.17 |
| Crude oil | 111.21 | 95.71 | 60.30 | 34.95 |
| Oil products | 135.59 | 126.43 | 79.74 | 43.65 |
| Natural gas | 263.79 | 192.80 | 167.11 | 147.61 |
| Nuclear | 3.34 | 3.34 | 2.53 | 30.04 |
| Hydro | 9.96 | 25.18 | 55.42 | 67.30 |
| Other renewables (solar, wind, geothermal) | 1.26 | 18.10 | 134.44 | 248.02 |
| Biofuels/waste | 292.85 | 428.45 | 408.91 | 424.27 |
| Electricity | 0.00 | 0.00 | 0.00 | 0.00 |
| **Imports** | **96.69** | **209.44** | **235.88** | **316.26** |
| Coal | 1.44 | 34.44 | 41.43 | 15.53 |
| Crude oil | 25.74 | 32.00 | 20.25 | 9.14 |
| Oil products | 62.78 | 88.75 | 84.84 | 65.58 |
| Natural gas | 3.41 | 42.87 | 42.47 | 37.88 |
| Nuclear | 0.00 | 0.00 | 29.42 | 162.61 |
| Hydro | 0.00 | 0.00 | 0.00 | 0.00 |
| Other renewables (solar, wind, geothermal) | 0.00 | 0.00 | 0.00 | 0.00 |
| Biofuels/waste | 0.00 | 0.00 | 0.00 | 0.00 |
| Electricity | 3.32 | 11.37 | 17.47 | 25.52 |
| **Exports** | **-172.62** | **-130.65** | **-81.68** | **-52.14** |
| Coal | 0.00 | 0.00 | 0.00 | 0.00 |
| Crude oil | 0.00 | 0.00 | 0.00 | 0.00 |
| Oil products | 0.00 | 0.00 | 0.00 | 0.00 |
| Natural gas | -169.30 | -119.28 | -64.20 | -28.98 |
| Nuclear | 0.00 | 0.00 | 0.00 | 0.00 |
| Hydro | 0.00 | 0.00 | 0.00 | 0.00 |
| Other renewables (solar, wind, geothermal) | 0.00 | 0.00 | 0.00 | 0.00 |
| Biofuels/waste | 0.00 | 0.00 | 0.00 | 0.00 |
| Electricity | -3.32 | -11.37 | -17.47 | -23.16 |
| **Total primary energy supply** | **810.85** | **1049.14** | **1098.56** | **1265.11** |
| **Power generation (Mtoe)** | | | | |
| **Fuel inputs for thermal power generation** | **-123.02** | **-145.88** | **-189.50** | **-307.98** |
| Coal | -50.99 | -84.61 | -73.94 | -20.20 |
| Oil products | -20.94 | -4.95 | -1.20 | -1.13 |
| Natural gas | -46.74 | -50.93 | -78.73 | -85.93 |
| Nuclear | -3.34 | -3.34 | -31.95 | -192.65 |
| Hydro | 0.00 | 0.00 | 0.00 | 0.00 |
| Biofuels/waste | -1.01 | -2.04 | -3.68 | -8.06 |
| **Gross electricity generation** | 63.85 | 108.90 | 278.80 | 444.54 |
| Coal | 19.89 | 33.00 | 28.75 | 7.84 |
| of which CCS | 0.00 | 0.00 | 1.59 | 2.87 |
| Oil | 7.97 | 1.74 | 0.47 | 0.41 |
| Natural gas | 23.02 | 28.61 | 47.35 | 52.80 |
| of which CCS | 0.00 | 0.00 | 7.17 | 14.76 |
| Biofuels/waste | 0.66 | 1.16 | 1.83 | 4.60 |
| of which CCS | 0.00 | 0.16 | 0.55 | 0.63 |
| Nuclear | 1.10 | 1.10 | 10.54 | 63.57 |
| Hydro | 9.96 | 25.18 | 55.42 | 67.30 |
| Wind | 0.77 | 5.24 | 30.54 | 60.69 |
| Solar | 0.37 | 10.32 | 99.35 | 179.12 |
| Other | 0.12 | 2.54 | 4.55 | 8.20 |
| **Oil refineries (Mtoe)** | | | | |
| Crude oil | -136.96 | -127.71 | -80.54 | -44.09 |
| Oil products | 135.59 | 126.43 | 79.74 | 43.65 |
| **Losses (Mtoe)** | | | | |
| Power generation | **-9.70** | **-14.32** | **-25.75** | **-37.81** |
| **Total final consumption (Mtoe)** | | | | |
| **Total** | **560.44** | **810.28** | **891.23** | **1006.73** |
| Coal | 19.25 | 30.17 | 3.40 | 0.50 |
| Oil products | 159.96 | 210.18 | 163.05 | 108.01 |
| Natural gas | 36.70 | 53.59 | 71.43 | 75.71 |
| Biofuels/waste | 291.84 | 426.40 | 405.24 | 416.20 |
| Electricity | 52.70 | 89.94 | 248.12 | 406.31 |
| **GHG emissions (Mt $CO_2$ eq.)** | | | | |
| Total $CO_2$ | 1222.57 | 1448.61 | 1046.45 | 656.20 |
| **Total System Costs (Mil. USD)** | | | | |
| Investment | 26345.90 | 56136.62 | 190548.37 | 239589.39 |
| Fixed | 8101.19 | 14794.69 | 44327.46 | 86058.37 |
| Variable | 128024.52 | 235822.88 | 250590.76 | 243605.88 |

| Africa - 1.5°C scenario | 2015 | 2030 | 2050 | 2065 |
|---|---|---|---|---|
| **Energy balance, by fuel (Mtoe)** | | | | |
| **Primary energy production** | **885.69** | **966.12** | **782.74** | **748.95** |
| Coal | 68.45 | 66.52 | 15.25 | 4.61 |
| Crude oil | 110.83 | 84.83 | 21.76 | 1.75 |
| Oil products | 135.19 | 111.07 | 27.36 | 2.44 |
| Natural gas | 263.59 | 227.25 | 103.47 | 53.74 |
| Nuclear | 3.34 | 3.34 | -6.93 | -32.17 |
| Hydro | 9.96 | 25.03 | 59.02 | 71.05 |
| Other renewables (solar, wind, geothermal) | 1.26 | 17.63 | 131.29 | 245.87 |
| Biofuels/waste | 293.07 | 430.44 | 431.53 | 401.66 |
| Electricity | 0.00 | 0.00 | 0.00 | 0.00 |
| **Imports** | **96.66** | **205.81** | **142.65** | **335.46** |
| Coal | 1.44 | 23.54 | 12.90 | 8.59 |
| Crude oil | 25.72 | 27.36 | 5.88 | 0.71 |
| Oil products | 62.75 | 99.92 | 25.58 | 10.18 |
| Natural gas | 3.40 | 42.39 | 20.32 | 14.23 |
| Nuclear | 0.00 | 0.00 | 59.46 | 278.65 |
| Hydro | 0.00 | 0.00 | 0.00 | 0.00 |
| Other renewables (solar, wind, geothermal) | 0.00 | 0.00 | 0.00 | 0.00 |
| Biofuels/waste | 0.00 | 0.00 | 0.00 | 0.00 |
| Electricity | 3.36 | 12.60 | 18.50 | 23.10 |
| **Exports** | **-172.66** | **-155.72** | **-36.02** | **-34.61** |
| Coal | 0.00 | 0.00 | 0.00 | 0.00 |
| Crude oil | 0.00 | 0.00 | 0.00 | 0.00 |
| Oil products | 0.00 | 0.00 | 0.00 | 0.00 |
| Natural gas | -169.30 | -143.12 | -17.51 | -11.50 |
| Nuclear | 0.00 | 0.00 | 0.00 | 0.00 |
| Hydro | 0.00 | 0.00 | 0.00 | 0.00 |
| Other renewables (solar, wind, geothermal) | 0.00 | 0.00 | 0.00 | 0.00 |
| Biofuels/waste | 0.00 | 0.00 | 0.00 | 0.00 |
| Electricity | -3.36 | -12.60 | -18.50 | -23.10 |
| **Total primary energy supply** | **809.70** | **1016.20** | **889.38** | **1049.81** |
| **Power generation (Mtoe)** | | | | |
| **Fuel inputs for thermal power generation** | **-123.04** | **-133.87** | **-176.94** | **-382.07** |
| Coal | -50.90 | -63.58 | -27.83 | -13.19 |
| Oil products | -21.10 | -4.89 | -0.49 | -0.21 |
| Natural gas | -46.70 | -60.18 | -74.51 | -41.70 |
| Nuclear | -3.34 | -3.34 | -69.91 | -316.53 |
| Hydro | 0.00 | 0.00 | 0.00 | 0.00 |
| Biofuels/waste | -1.01 | -1.87 | -4.20 | -10.44 |
| **Gross electricity generation** | 63.72 | 105.39 | 271.47 | 458.23 |
| Coal | 19.85 | 24.80 | 10.77 | 5.11 |
| of which CCS | 0.00 | 0.00 | 1.59 | 2.87 |
| Oil | 7.90 | 1.72 | 0.21 | 0.07 |
| Natural gas | 23.00 | 34.05 | 44.94 | 25.65 |
| of which CCS | 0.00 | 0.00 | 5.49 | 6.39 |
| Biofuels/waste | 0.66 | 1.06 | 2.17 | 6.04 |
| of which CCS | 0.00 | 0.15 | 0.55 | 0.73 |
| Nuclear | 1.10 | 1.10 | 23.07 | 104.45 |
| Hydro | 9.96 | 25.03 | 59.02 | 71.05 |
| Wind | 0.77 | 5.24 | 29.26 | 56.26 |
| Solar | 0.37 | 9.84 | 96.22 | 179.20 |
| Other | 0.12 | 2.54 | 5.82 | 10.42 |
| **Oil refineries (Mtoe)** | | | | |
| Crude oil | -136.55 | -112.19 | -27.64 | -2.46 |
| Oil products | 135.19 | 111.07 | 27.36 | 2.44 |
| **Losses (Mtoe)** | | | | |
| Power generation | **-9.71** | **-13.85** | **-25.48** | **-39.89** |
| **Total final consumption (Mtoe)** | | | | |
| **Total** | **560.13** | **801.02** | **757.84** | **836.82** |
| Coal | 18.99 | 26.48 | 0.32 | 0.01 |
| Oil products | 159.97 | 206.05 | 52.18 | 12.41 |
| Natural gas | 36.54 | 53.09 | 37.01 | 20.08 |
| Biofuels/waste | 292.06 | 428.57 | 427.33 | 391.22 |
| Electricity | 52.57 | 86.84 | 240.99 | 413.11 |
| **GHG emissions (Mt $CO_2$ eq.)** | | | | |
| Total $CO_2$ | 1219.60 | 1377.19 | 454.93 | 157.76 |
| **Total System Costs (Mil. USD)** | | | | |
| Investment | 25655.33 | 47249.74 | 263783.94 | 243991.12 |
| Fixed | 8086.98 | 14209.83 | 45223.97 | 94108.71 |
| Variable | 127656.66 | 230677.85 | 135176.64 | 77813.03 |

## Annex 2. Techno-economic parameters

**Table 8**. Techno-economic parameters of the power generation technologies

| Technology | Overnight investment cost (USD/kW) | | | | O&M cost (USD/kW) | | | | Lead and life time | | Efficiency (%) | | | | Load factor |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2015 | 2030 | 2050 | 2070 | 2015 | 2030 | 2050 | 2070 | Years | | 2015 | 2030 | 2050 | 2070 | % |
| **Diesel (centralised)** | 1200 | 1200 | 1200 | 1200 | 35 | 35 | 35 | 35 | 2 | 25 | 35 | 35 | 35 | 35 | 80 |
| **Diesel 1 kW system (decentralised)** | 752 | 752 | 752 | 752 | 23 | 23 | 23 | 23 | <1 | 10 | 16 | 16 | 16 | 16 | 30 |
| **HFO** | 1467 | 1467 | 1467 | 1467 | 44 | 44 | 44 | 44 | 2 | 25 | 35 | 35 | 35 | 35 | 80 |
| **OCGT** | 400 | 400 | 400 | 400 | 20 | 20 | 20 | 20 | 2 | 25 | 38 | 39 | 43 | 47 | 85 |
| **CCGT** | 700 | 700 | 700 | 700 | 25 | 25 | 25 | 25 | 3 | 30 | 58 | 59 | 61 | 63 | 85 |
| **CCGT - CCS** | 2450 | 2200 | 2000 | 1800 | 80 | 70 | 70 | 70 | 3 | 30 | 51 | 52 | 56 | 60 | 85 |
| **Supercritical coal** | 1600 | 1600 | 1600 | 1600 | 65 | 65 | 65 | 65 | 4 | 30 | 39 | 39 | 39 | 39 | 85 |
| **Coal + CCS** | 4500 | 4100 | 3700 | 3300 | 160 | 150 | 130 | 110 | 4 | 30 | 32 | 35 | 37 | 39 | 85 |
| **Hydro (large scale)** | 2100 | 2100 | 2100 | 2100 | 55 | 55 | 55 | 55 | 4 | 50* | 100 | 100 | 100 | 100 | Varies |
| **Hydro (small scale)** | 3300 | 3300 | 3300 | 3300 | 65 | 65 | 65 | 65 | 4 | 30* | 100 | 100 | 100 | 100 | Varies |
| **Hydro (med. scale)** | 2100 | 2100 | 2100 | 2100 | 55 | 55 | 55 | 55 | 4 | 50* | 100 | 100 | 100 | 100 | Varies |
| **Biomass** | 2150 | 2100 | 2000 | 1900 | 75 | 75 | 65 | 55 | 3 | 40 | 35 | 35 | 35 | 35 | 50 |
| **Biomass (CHP small)** | 4800 | 4600 | 4400 | 4200 | 180 | 170 | 170 | 170 | 2 | 40 | 65 | 65 | 65 | 65 | 50 |
| **Biomass CCS** | 4256 | 3864 | 3360 | 3100 | 91.28 | 91.28 | 91.28 | 89.89 | 3 | 40 | 27 | 29 | 30 | 31 | 50 |
| **Nuclear** | 4000 | 4000 | 4000 | 4000 | 170 | 170 | 170 | 170 | 7 | 60 | 33 | 33 | 33 | 33 | 85 |
| **Geothermal** | 3100 | 2900 | 2700 | 2500 | 60 | 60 | 50 | 40 | 4 | 25 | 80 | 80 | 80 | 80 | 85 |
| **Wind onshore** | 1880 | 1760 | 1680 | 1600 | 48 | 44 | 44 | 44 | 1.5 | 25 | 100 | 100 | 100 | 100 | Varies |
| **Wind offshore** | 4700 | 3200 | 2600 | 2000 | 165 | 125 | 105 | 85 | 3 | 25 | 100 | 100 | 100 | 100 | Varies |
| **Solar PV (centr.)** | 2400 | 1400 | 1080 | 760 | 24 | 22 | 22 | 22 | 1 | 25 | 100 | 100 | 100 | 100 | Varies |
| **Solar PV (decentralised)** | 2840 | 1640 | 1240 | 840 | 28 | 26 | 26 | 26 | 1 | 20 | 100 | 100 | 100 | 100 | Varies |
| **Solar PV with battery** | 4449 | 2373 | 1845 | 1364 | 48 | 46 | 46 | 46 | 1 | 20 | 100 | 100 | 100 | 100 | Varies |
| **Solar CSP** | 5050 | 3800 | 2900 | 2000 | 200 | 150 | 110 | 70 | 3 | 25 | 100 | 100 | 100 | 100 | Varies |
| **Solar CSP with storage** | 6789 | 4929 | 3997 | 3065 | 228 | 178 | 138 | 90 | 3 | 25 | 100 | 100 | 100 | 100 | Varies |

Source: (Energy-Economy-Environment Modelling Laboratory E3MLab, n.d.; IEA-ETSAP, 2019; International Energy Agency, 2017c; IRENA, 2018)

**Table 9**. Techno-economic parameters of the energy conversion technologies

| Technology | Capital & fixed cost per unit of output (USD/PJ) | | Variable cost per unit of output (USD/GJ) | | Lead | Life | Efficiency | Load factor |
|---|---|---|---|---|---|---|---|---|
| | 2015 | 2030 | 2015 | 2030 | Years | Years | % | % |
| **LNG liquefaction plant** | 1520000 | 1520000 | 0.63 | 0.95 | 4 | 25 | 0.85 | Varies |
| **Regasification plant** | 855000 | 855000 | 0.63 | 0.63 | 4 | 25 | 0.98 | Varies |
| **Crude oil refinery** | 24.13 | 24.13 | 0.72 | 0.72 | 4 | 35 | Varies | Varies |

Source: (Energy-Economy-Environment Modelling Laboratory E3MLab, n.d.)

**Table 10**. Fuel price projections (USD/GJ)

| Technology | Capital & fixed cost per unit of output (USD/PJ) | | Variable cost per unit of output (USD/GJ) | | Lead | Life | Efficiency | Load factor |
|---|---|---|---|---|---|---|---|---|
| | 2015 | 2030 | 2015 | 2030 | Years | Years | % | % |
| **LNG liquefaction plant** | 1520000 | 1520000 | 0.63 | 0.95 | 4 | 25 | 0.85 | Varies |
| **Regasification plant** | 855000 | 855000 | 0.63 | 0.63 | 4 | 25 | 0.98 | Varies |
| **Crude oil refinery** | 24.13 | 24.13 | 0.72 | 0.72 | 4 | 35 | Varies | Varies |

Source: (International Energy Agency, 2017c)

## Annex 3. Fossil and renewable energy potentials

**Table 11**. Fossil fuel reserves in Africa

| Reserves | Total Recoverable Coal (mil.. short tons) in 2017 | Crude Oil proved reserves (billion barrels) in 2019 | Natural Gas proved reserves (trillion cubic feet) in 2019 | Uranium (tonnes) |
|---|---|---|---|---|
| **Algeria** | 65.04 | 12.2 | 159.05 | Exploratory |
| **Angola** | - | 8.38 | 14.91 | - |
| **Benin** | - | 0.01 | - | - |
| **Botswana** | 127.72 | - | - | 193500 |
| **Cameroon** | - | 0.2 | 4.77 | - |
| **Central African Republic** | 3.31 | - | - | 5700 |
| **Chad** | - | 1.5 | NA | - |
| **Congo (Brazzaville)** | - | 1.6 | 3.2 | - |
| **Congo (Kinshasa)** | 97.00 | 0.18 | 0.04 | 51776 |
| **Cote d'Ivoire** | - | 0.1 | 1 | - |
| **Egypt** | 17.67 | 3.3 | 63 | - |
| **Equatorial Guinea** | - | 1.1 | 5.12 | - |
| **Ethiopia** | - | 0.00043 | 0.88 | - |
| **Gabon** | - | 2 | - | Exploratory |
| **Ghana** | - | 0.66 | 0.8 | - |
| **Guinea** | - | - | - | 179000 |
| **Libya** | - | 48.36 | 53.14 | - |
| **Malawi** | 2.20 | - | - | Exploratory |
| **Mali** | - | - | - | Exploratory |
| **Mauritania** | - | 0.02 | 15 | Exploratory |
| **Morocco** | 15.43 | 0.00068 | 0.05 | Exploratory |
| **Mozambique** | 1975.34 | - | 100 | - |
| **Namibia** | - | - | 2.2 | 199068 |
| **Niger** | 6.61 | 0.15 | NA | 11661 |
| **Nigeria** | 379.19 | 36.18 | 198.71 | Exploratory |
| **Rwanda** | - | - | 2 | - |
| **South Africa** | 34722.77 | 0.02 | NA | 514421 |
| **Sudan** | - | 5 | 3 | - |
| **Swaziland** | 158.73 | - | - | |
| **Tanzania** | 296.52 | - | 0.23 | 23200 |
| **Tunisia** | - | 0.43 | 2.3 | - |
| **Uganda** | - | 2.5 | 0.5 | - |
| **Zambia** | 49.60 | - | - | 37296 |
| **Zimbabwe** | 553.36 | - | - | 1720 |

Source: (EIA, 2019; The World Bank, 2019a).

**Table 12**. Renewable energy potential in Africa

| Estimates of Renewable Energy Potential | Hydro (MW) | Small hydro (MW) | Solar thermal (TWh/y) | Solar PV (TWh/y) | Biomass (MW) | Wind (CF 20%) (TWh/y) | Wind (CF 30%) (TWh/y) | Wind (CF 40%) (TWh/y) | Geothermal (MW) |
|---|---|---|---|---|---|---|---|---|---|
| **Algeria** | n/a | n/a | 26530 | 27904 | n/a | 30155 | 2535.9 | 153.4 | n/a |
| **Angola** | n/a | 861 | 9786 | 13319 | 500 | 202 | - | - | - |
| **Benin** | n/a | 187 | - | 3898 | 761 | 405 | - | - | - |
| **Botswana** | n/a | 1 | 13070 | 13764 | 10 | 9,793 | 303 | - | - |
| **Burkina Faso** | - | 38 | - | 7742 | 1075 | 4154 | 7.5 | - | - |
| **Burundi** | 1700 | 61 | 786 | 888 | n/a | - | - | - | n/a |
| **Cameroon** | 23000 | 615 | 3706 | 10105 | n/a | 979 | 15.9 | - | - |
| **Central African Republic** | n/a | 41 | 3471 | 5284 | n/a | 79 | - | - | - |
| **Chad** | - | - | 10284 | 10506 | n/a | 9165 | 1519.4 | 578.3 | - |
| **Congo (Brazzaville)** | n/a | 50 | 2 | 6778 | n/a | - | - | - | - |
| **Congo (DRC, Kinshasa)** | 100000 | 101 | 12439 | 22862 | 500 | 2173 | 41.4 | - | n/a |
| **Cote d'Ivoire** | 1900 | 40.7 | 221 | 10325 | 3260 | 430 | - | - | - |
| **Djibouti** | n/a | - | 852 | 947 | n/a | 934 | 149.1 | 77.3 | 1000 |
| **Egypt** | 3664 | 52 | 26605 | 32218 | n/a | 36601 | 6185 | 529.9 | n/a |
| **Equatorial Guinea** | n/a | 7 | - | 706 | n/a | - | - | - | - |
| **Eritrea** | n/a | - | 4349 | 4775 | n/a | 3154 | 412.4 | 129.1 | n/a |
| **Ethiopia** | 45000 | 1500 | 22959 | 27154 | n/a | 14838 | 3002.1 | 1981 | 5000 |
| **Gabon** | n/a | 6 | 6 | 5402 | n/a | - | - | - | - |
| **Gambia** | n/a | 12 | 316 | 474 | 60 | 173 | 1.3 | - | - |
| **Ghana** | 2480 | 1245 | 229 | 7644 | 4449 | 606 | 2.4 | - | - |
| **Guinea** | n/a | 198 | 467 | 5204 | 1732 | 2 | - | - | - |
| **Guinea-Bissau** | 184 | - | 906 | 1493 | 205 | 124 | - | - | - |
| **Kenya** | 6000 | 3000 | 15399 | 23046 | n/a | 22476 | 4446.4 | 1739.6 | 10000 |
| **Lesotho** | n/a | 20 | 1122 | 938 | 10 | 599 | 40.1 | 3.7 | - |
| **Liberia** | 2300 | 65.9 | - | 667 | 1375 | - | - | - | - |
| **Libya** | n/a | - | 11823 | 13979 | n/a | 21649 | 5149.5 | 1079.5 | n/a |
| **Malawi** | n/a | 150 | 4474 | 5210 | 200 | 1986 | 262.1 | 42.4 | n/a |
| **Mali** | 1150 | 117 | - | 7906 | 447 | 1923 | - | - | - |
| **Mauritania** | n/a | - | 4988 | 7990 | n/a | 11822 | 2940.5 | 1337.8 | - |
| **Morocco** | n/a | 54 | 15127 | 15155 | n/a | 11297 | 1458.8 | 851 | n/a |
| **Mozambique** | n/a | 1000 | 16851 | 22024 | 1000 | 10805 | 395.9 | 5.2 | n/a |
| **Namibia** | n/a | 108 | 29716 | 26183 | 50 | 15196 | 497 | 4.9 | - |
| **Niger** | n/a | - | 8829 | 15669 | 266 | 14628 | 1262 | 55.8 | - |
| **Nigeria** | >14120 | 735 | 10045 | 32456 | 7291 | 12867 | 95.3 | - | n/a |
| **Rwanda** | 500 | 48 | 789 | 892 | n/a | - | - | - | 700 |
| **Senegal** | 1,200 | n/a | 1537 | 7519 | 466 | 5454 | 323.6 | 3 | - |
| **Sierra Leone** | - | 1513 | 197 | 1499 | 587 | - | - | - | - |
| **Somalia** | n/a | - | 13156 | 25687 | n/a | 43539 | 10616.4 | 8893.3 | - |
| **South Africa** | n/a | 247 | 43275 | 42243 | 3000 | 41195 | 6076.3 | 1559.1 | n/a |
| **Sudan and South Sudan** | 4920 | 27 | 77422 | 87817 | n/a | 61661 | 9837.8 | 2947.1 | 400 |
| **Swaziland** | n/a | 16 | 559 | 572 | 200 | 476 | 9.7 | - | - |
| **Tanzania** | 3800 | 400 | 31482 | 38804 | 1000 | 18456 | 2295.2 | 789.2 | 650 |
| **Togo** | - | 144 | - | 1257 | 378 | 79 | - | - | - |
| **Tunisia** | n/a | 56 | 2045 | 4645 | n/a | 6842 | 1244 | 226.5 | n/a |
| **Uganda** | >4500 | 200 | 8582 | 9470 | n/a | 815 | 100.7 | 23.8 | 450 |
| **Zambia** | 6000 | 42 | 15691 | 17894 | 1000 | 13229 | 1145 | 15.6 | n/a |
| **Zimbabwe** | n/a | 120 | 11874 | 15864 | 1000 | 12137 | 1000.3 | 47.3 | - |

Source: (Hermann et al., 2014; IRENA, 2018; Miketa & Merven, 2013; Ndhlukula et al., 2015; United Nations, 2016)

## Annex 4. Energy infrastructure

Table 13. Oil refineries in Africa

| Country | Name of the plant | Distillation capacity (tb/d) | Nameplate capacity (tb/d) | Earliest year | Status |
|---|---|---|---|---|---|
| **Algeria** | Adrar | 13 | | 2007 | Operational |
| **Algeria** | Algiers | 58 | | 1964 | Operational |
| **Algeria** | Arzew | 90 | | 1973 | Operational |
| **Algeria** | Skikda | 462 | | 1993 | Operational |
| **Algeria** | Hassi Messaoud | 27 | | 1979 | Operational |
| **Angola** | Luanda | 65 | | 1958 | Operational |
| **Angola** | Luanda expansion | | | 2021 | Planned |
| **Cameroon** | Cape Limboh Limbe | 70 | | 1981 | Operational |
| **Chad** | Ndajamena | 20 | | 2011 | Not operational |
| **Congo** | Pointe Noire | 21 | | 1982 | Operational |
| **Cote d Ivoire** | Abidjan | 84 | | 1962 | Operational |
| **Cote d Ivoire** | Société Multinationale des Bitumes (SMB) | | | | |
| **Egypt** | Ameriya (Alexandria) | 88 | 81 | 1972 | Operational |
| **Egypt** | El Mex (Alexandria) | 115 | | 1958 | Operational |
| **Egypt** | MIDOR (Alexandria) | 115 | | 1994 | Operational |
| **Egypt** | MIDOR (Alexandria) expansion | 45 | | 2020 | Under construction |
| **Egypt** | Assiut | 60 | 47 | 1987 | Operational |
| **Egypt** | El Suez | 68 | | 1963 | Operational |
| **Egypt** | Mostorod | 142 | | 1982 | Operational |
| **Egypt** | Nasr El Suez | 146 | 107.55 | 1913 | Operational |
| **Egypt** | Nasr Wadi Feran | 9 | | 1990 | Operational |
| **Egypt** | Tanta | 35 | | 1982 | Operational |
| **Eritrea** | Assab oil refinery | 17.5 | 0 | 1960 | Non-operated since 1997 |
| **Gabon** | Port Gentil | 24 | | 1967 | Operational |
| **GHANA** | TEMA | 45 | | 1963 | Operational |
| **Liberia** | Monrovia | 15 | | | Non-operated |
| **Libya** | Ras Lanuf plant | 220 | | 1984 | Operational |
| **Libya** | Azzawiya and Benghazi | 120 | | 1974 | Operational |
| **Libya** | Brega | 10 | | 1970 | Operational |
| **Libya** | Sarir | 10 | | 1989 | Operational |
| **Libya** | Tobruk | 20 | | 1985 | Operational |
| **Morocco** | Mohammedia | 200 | 0 | 1961 | Non operation since 2015 |
| **Niger** | Zinder, Ganaram | 20 | 12 to 16 | 2011 | Operational |
| **Nigeria** | Port Harcourt refinery I and II | 210 | 50% | 1965 (I), 1989 (II) | Operational |
| **Nigeria** | Kaduna | 110 | 50% | 1983 | Operational |
| **Nigeria** | Warri | 125 | 50% | 1978 | Operational |
| **Senegal** | M´ Bao (Dakar) | 25 | | 1963 | Operational |
| **Sierra Leone** | Freetown | 5 | | 1970 | Non operated since 1992 |
| **South Africa** | Caltex | 100 | | 1966 | Operational |
| **South Africa** | Durban | 135 | 120 | 1997 | Operational |
| **South Africa** | Sapref | 180 | | 1963 | Operational |
| **South Africa** | Sasolburg | 105 | | 1971 | Operational |
| **Sudan** | Khartoum | 100 | | 2006 | Operational |
| **Sudan** | Al-Obeid | 10 | | 1979 | Operational |
| **Sudan** | Concorp (Alshajara) | 10 | | 2000 | Operational |
| **Sudan** | Abu Gabra | 2 | | 1992 | Operational |
| **Sudan** | Port Sudan | 21.7 | | 1964 | Not operational |
| **Tunisia** | Bizerte | 34 | | 1963 | Operational |
| **Tunisia** | La Skhira | 150 | | | Planned |
| **Zambia** | Indeni-Ndola | 24 | | 1973 | Operational |

Source: (McKinsey, 2019)

Table 14. LNG terminals

| Country | Project name | Capacity | Year | Status |
|---|---|---|---|---|
| **Algeria** | Arzew - GL1Z T1-6 | 7.9 MTPA | 1978 | Operational |
| **Algeria** | Arzew - GL2Z T1-6 | 8.2 MTPA | 1981 | Operational |
| **Algeria** | Skikda - GL1K Rebuild | 4.5 MTPA | 2013 | Operational |
| **Algeria** | Arzew - GL3Z | 4.7 MTPA | 2014 | Operational |
| **Angola** | Angola LNG T1 | 5.2 MTPA | 2014 | Operational |
| **Benin** | Cotonou (connect to Ghana, Togo) | 1.6 bcm/y | | Planned |
| **Benin** | Cotonou extension | 1.1 bcm/y | | Planned |
| **Cameroon** | PFLNG Satu | 92 MTPA | | Under construction as of March 2018 |
| **Cameroon** | Cove Point LNG | 92 MTPA | | Under construction as of March 2018 |
| **Cameroon** | Kribi FLNG | 92 MTPA | | Under construction as of March 2018 |
| **Cameroon** | LNG1 | 12 MTPA | 2018 | Under construction |
| **Cameroon** | LNG2 | 8 MTPA | 2021 | Planned |
| **Cote d´Ivoire** | Grand Bassam | 5 MTPA | | Planned |
| **Djibouti** | Djibouti FLNG | 3 MTPA | 2021 | Under construction |
| **Egypt** | SEGAS LNG T1 | 5 MTPA | 2005 | Operational |
| **Egypt** | Egyptian LNG T1 | 3.6 MTPA | 2005 | Operational |
| **Egypt** | Egyptian LNG T2 | 3.6 MTPA | 2005 | Operational |
| **Egypt** | Ain Sokhna Hoegh (floating) | 4.2 MTPA | 2015 | Operational |
| **Egypt** | Sumed BW (floating) | 5.7 MTPA | 2017 | Operational |
| **Equatorial Guinea** | EG LNG T1 | 3.7 MTPA | 2007 | Operational |
| **Equatorial Guinea** | Fortuna FLNG 1-2 | 4.4 MTPA | 2020-2025 | Planned |
| **Ghana** | Tema (Golar Tundra) | 1.8 bcm/y | 2017 | Under construction |
| **Ghana** | Tema | 2.6 bcm/y | | Under construction |
| **Ghana** | Tema extension | 2 bcm/y | | Under construction |
| **Ghana** | Ghana 1000 | 3.7 bcm/y | | Under construction |
| **Kenya** | Mombasa | | | Planned |
| **Libya** | | | | Planned |
| **Mauritania** | Greater Tortue FLNG (shared with Senegal) | 2.5 MTPA | 2021 | Under construction |
| **Mozambique** | Coral South FLNG | 3.4 MTPA | 2022 | Under construction |
| **Mozambique** | Mamba LNG | 10 MTPA | 2020-2021 | Planned |
| **Mozambique** | Coral FLNG (Area 4) | 3.4 MTPA | 2022 | Planned |
| **Mozambique** | Mozambique LNG (Area 1) | 12 MTPA | 2023-2024 | Planned |
| **Morocco** | Jorf Lasfar | 2 bcm/y | 2021 | Planned |
| **Morocco** | Jorf Lasfar extension | 3 bcm/y | 2025 | Planned |
| **Namibia** | Walvis Bay | 0.6 bcm/y | | Operational |
| **Nigeria** | Nigeria LNG T1 | 3.3 MTPA | 2000 | Operational |
| **Nigeria** | Nigeria LNG T2 | 3.3 MTPA | 2000 | Operational |
| **Nigeria** | Nigeria LNG T3 | 3 MTPA | 2003 | Operational |
| **Nigeria** | Nigeria LNG T4 | 4.1 MTPA | 2006 | Operational |
| **Nigeria** | Nigeria LNG T5 | 4.1 MTPA | 2006 | Operational |
| **Nigeria** | Nigeria LNG T6 | 4.1 MTPA | 2008 | Operational |
| **Nigeria** | NLNG T7-8 | 8.6 MTPA | N/A | Planned |
| **Republic of Congo** | Congo-Brazzaville FLNG | 1.2 MTPA | 2020 | Planned |
| **Senegal** | Greater Tortue FLNG (shared with Mauritania) | 2.5 MTPA | 2021 | Under construction |
| **South Africa** | Saldanha Bay/Richards Bay | | | Planned |
| **Sudan** | | | | Planned |
| **Tanzania** | Tanzania LNG (T1-3) | 15 MTPA | 2026-2027 | Planned |
| **Tanzania** | Tanzania LNG (T4) | 5 MTPA | N/A | Planned |
| **Togo** | | | | Planned |

Source: (International Gas Union, 2018)

**Table 15**. Cross-border electricity interconnector projects in Africa.

| From | To | Capacity (MW) | Investment cost | Status | Earliest year | Comments |
|---|---|---|---|---|---|---|
| **Angola** | **DRC** | 600 | 191 mil. USD | Planned | 2019 | |
| **Algeria** | **Morocco** | 240 | | Operational | | North Africa Power Transmission Corridor |
| **Spain** | **Morocco** | 1400 | | Operational | | |
| **Spain** | **Morocco** | 700 | 150 mil. € | Planned | 2026 | Spain shouldering about half the cost. It is due to be commissioned before 2026. Planned addition to an existing interconnector project 1.4 GW. |
| **Benin** | **Niger** | 330 | 730 mil. USD | Planned | 2022 | Station: MALANVILLE-ZABORI. Part of the Northcore interconnector |
| **Benin** | **Ghana** | 654.6 | 117.6 mil. USD | Under construction | 2020 | Station: Kara/Bembereke/Parakou (TB)–Yendi (GH) |
| **Botswana** | **South Africa** | 800 | - | Operational | | |
| **Botswana** | **Zambia** | 300 | 223 mil. USD | Planned | 2021 | Part of the Zizabona project |
| **Botswana** | **Namibia** | 300 | 223 mil. USD | Planned | 2021 | Part of the Zizabona project |
| **Botswana** | **Zimbabwe** | 300 | 223 mil. USD | Planned | 2021 | Part of the Zizabona project |
| **Burkina Faso** | **Niger** | 330 | 730 mil. USD | Planned | 2022 | Stations: OUAGADOUGOU-NIYAMEY. Part of the Northcore interconnector |
| **Burundi** | **Rwanda** | 17 | | Operational | | There are plans to increase the capacity |
| **Cameroon** | **Chad** | 1900 | 1362 mi. USD | Planned | 2020 | As option to invest in the following years (2020: 0.475GW, 2021: 0.475GW, 2022: 0.475GW, 2023: 0.475GW) |
| **Cote d´Ivoire** | **Sierra Leone** | 110 | 500 mil. USD | Planned | 2020 | |
| **Cote d´Ivoire** | **Ghana** | 655.2 | 90 mil. USD | Operational | 2017 | Station: Riviera - Presea |
| **Cote d´Ivoire** | **Burkina Faso** | 327 | | Operational | | |
| **Cote d´Ivoire** | **Liberia** | 337.6 | 59.7 mil. USD | Under construction | 2018 | Station: Man (CI)–Yekepa (LI) |
| **DRC** | **Burundi** | 15.5 | | Operational | | |
| **DRC** | **Burundi** | 49 | | Under construction | 2018 | |
| **DRC** | **Congo** | 60 | | Operational | | |
| **DRC** | **Rwanda** | 100 | | Operational | | |
| **DRC** | **Rwanda** | 300 | | Under construction | 2015 | |
| **DRC** | **South Africa** | 3000 | | Planned | 2023 | Included partly-2500MW |
| **DRC** | **Zambia** | 260 | | Operational | | |
| **Egypt** | **Sudan** | 6600 | 6000 mil. USD | Under construction | | North–South Power Transmission Corridor |
| **Egypt** | **Jordan** | 300 | | Operational | | |
| **Egypt** | **Saudi Arabia** | 3000 | | Under construction | 2021 | |
| **Ethiopia** | **Kenya** | 2000 | 1,260 mil. USD | Under construction | 2019 | Wolayta-Sodo (ETH) and Suswa (KEN) substations; Over 95% of the construction of the Ethio-Kenya interconnection transmission line is completed and work on the project is executed by the respective countries. |
| **Ethiopia** | **Djibouti** | 180 | | Operational | | |
| **Ethiopia** | **Sudan** | 200 | | Operational | | |
| **Ghana** | **Burkina Faso** | 332.2 | 67 mil. USD | Under construction | 2017; 2019 | The line is operational but only used at 50% capacity due to the unfinished Kumasi –Bolgatanga line. Stations: Han (GH) - Bobo Dioulase (BU). Part of the Hub Intrazonal project. |
| **Ghana** | **Cote d´Ivoire** | 327 | | Operational | | |

| From | To | Capacity (MW) | Investment cost | Status | Earliest year | Comments |
|---|---|---|---|---|---|---|
| **Ghana** | **Togo** | 438 | | Operational | | |
| **Ghana** | **Togo** | 655.2 | 90 mil. USD | Under construction | 2017 | Station: VOLTA-DAVIÉ (LOMÉ); Part of the WAPP Coastal Transmission Backbone. The total cost for this project is divided between Ghana, Togo and Benin |
| **Ghana** | **Benin** | 655.2 | 90 mil. USD | Under construction | 2017 | Station: VOLTA-DAVIÉ(LOMÉ); Part of the WAPP Coastal Transmission Backbone |
| **Ghana** | **Mali** | 100 | 230 mil. USD | Planned | 2021/2022 | |
| **Gambia** | **Guinea Bissau** | 329.1 | 90.6 mil. USD | Under construction | 2019 | Station: Soma (GA)–Bissau (GB) .Part of the OMVG project |
| **Gambia** | **Senegal** | 340.7 | 36.2 mil. USD | Under construction | 2019 | Station: Birkelane (SE)–Soma (GA). Part of the OMVG project |
| **Guinea** | **Mali** | 321.3 | 117.6 mil. USD | Under construction | 2020 | Station: Fomi (GU)–Bamako (MA). Part of the Hub Intrazonal project. |
| **Guinea** | **Senegal** | 286.3 | 289.8 mil. USD | Under construction | 2019 | Station: Kaolack (SE)–Linsan (GU). Part of the OMVG project |
| **Kenya** | **Uganda** | 103 | | Operational | | |
| **Kenya** | **Uganda** | 440 | 380 mil. USD | Under construction | 2019 | |
| **Kenya** | **Tanzania** | 1 | | Operational | | |
| **Kenya** | **Tanzania** | 1300 | | Planned | 2018 | |
| **Libya** | **Egypt** | 170 | | Operational | 1998 | |
| **Lesotho** | **South Africa** | 230 | | Operational | | |
| **Morocco** | **Algeria** | 480 | | Operational | | North Africa Power Transmission Corridor |
| **Mali** | **Cote d´Ivoire** | 319.7 | 136.9 mil. USD | Under construction | 2017 | Station: Segou (MA)–Ferkessedougou (CI). Part of the Hub Intrazonal project. |
| **Malawi** | **Mozambique** | 2400 | 125 mil. USD | Planned | 2020 | |
| **Malawi** | **Tanzania** | 180 | 829 mil. USD | Planned | 2022 | |
| **Mozambique** | **South Africa** | 3850 | | Operational | | PLN-600 MW |
| **Mozambique** | **Swaziland** | 1450 | | Operational | | |
| **Mozambique** | **Zimbabwe** | 500 | | Operational | | PLN-500 MW |
| **Namibia** | **Botswana** | 300 | 223 mil. USD | Planned | 2021 | Part of the Zizabona project |
| **Namibia** | **South Africa** | 750 | | Operational | | |
| **Namibia** | **Zambia** | 300 | 223 mil. USD | Planned | 2021 | Part of the Zizabona project |
| **Namibia** | **Zimbabwe** | 300 | 223 mil. USD | Planned | 2021 | Part of the Zizabona project |
| **Niger** | **Burkina Faso** | 358 | 250.4 mil. USD | Planned | 2023-2029 (2023-137MW, 2024-11MW, 2026-59MW, 2027-21MW, 2028-31MW, 2029-53MW, 2030-46 MW) | Station: Niamey (NI)–Ouagadougou (BU). Part of the Corridor Nord interconnector |
| **Niger** | **Benin** | 30 | 166.6 mil. USD | Planned | 2030 | Station: Zabori (NI)–Bembereke (TB) |
| **Nigeria** | **Benin** | 686 | | Operational | | |
| **Nigeria** | **Benin** | 494 | 164.6 mil. USD | Planned | 2027-2030 (2027-65MW, | Station: Kaindhji (NG)–Kara/Bembereke/Parakou (TB). Part of Dorsale Mediane project |

| From | To | Capacity (MW) | Investment cost | Status | Earliest year | Comments |
|---|---|---|---|---|---|---|
| | | | | | 2028-126MW, 2029-173MW, 2030-130MW) | |
| **Nigeria** | **Niger** | 169 | | Operational | | |
| **Nigeria** | **Niger** | 653.1 | 143.1 mil. USD | Planned | 2020 | Station: Birnin Kebbi (NG)–Niamey (NI) |
| **Nigeria** | **Togo** | 646.7 | 164.6 mil. USD | Under construction | 2020 | Station: Kaindhji (NG)–Kara/Bembereke/Parakou (TB) |
| **Rwanda** | **Burundi** | 12 | | Operational | | |
| **Rwanda** | **Tanzania** | 400 | 33 mil. USD | Under construction | 2019 | |
| **Senegal** | **Mauritania** | 250 | 207 mil. USD | Planned | 2021 | |
| **South Africa** | **Swaziland** | 1450 | | Operational | | |
| **South Africa** | **Zimbabwe** | 600 | | Operational | | |
| **Togo** | **Benin** | 345 | | Operational | | |
| **Togo** | **Ghana** | 654.6 | 117.6 mil. USD | Under construction | 2020 | Station: Kara/Bembereke/Parakou (TB)–Yendi (GH) |
| **Tanzania** | **Burundi** | 27 | | Under construction | 2018 | |
| **Tanzania** | **Kenya** | 2000 | 310 mil. USD | Under construction | 2020 | Isinia-Singida substation; Part of the ZTK Transmission Interconnector |
| **Tanzania** | **Uganda** | 58 | | Operational | | |
| **Tanzania** | **Zambia** | 530 | 152.19 mil. USD | Under construction | 2020 | Part of the ZTK Transmission Interconnector. |
| **Tunisia** | **Algeria** | 480 | | Operational | | |
| **Uganda** | **Kenya** | 145 | | Operational | | |
| **Uganda** | **Kenya** | 300 | | Under construction | 2015 | |
| **Uganda** | **Tanzania** | 70 | | Operational | | |
| **Uganda** | **Tanzania** | 200 | - | Planned | 2022 | |
| **Uganda** | **Rwanda** | 145 | 58 mil. USD | Operational | | |
| **Uganda** | **Rwanda** | 300 | | Under construction | 2015 | |
| **Zambia** | **Zimbabwe** | 1400 | | Operational | | |
| **Zambia** | **Tanzania** | 458 | 172.6 mil. USD | Under construction | 2020 | Part of the ZTK Transmission Interconnector. 386 MW in 2020, based on the Zambia´s projected electricity generation and in 2025 will be 458MW (max. power transfer). |
| **Zambia** | **Botswana** | 300 | 223 mil. USD | Planned | 2021 | Part of the Zizabona project |
| **Zambia** | **Namibia** | 300 | 223 mil. USD | Planned | 2021 | Part of the Zizabona project |
| **Guinea Bissau** | **Guinea** | 309.6 | | Under construction | 2019 | |
| **Burkina Faso** | **Mali** | 305.8 | | Under construction | 2020 | |
| **Liberia** | **Guinea** | 337.6 | | Under construction | 2018 | |
| **Mali** | **Mauritania** | 250 | | Planned | 2021 | |
| **Mali** | **Sierra Leone** | 327 | | Planned | 2020 | |
| **Mali** | **Senegal** | 329.1 | | Under construction | 2020 | |
| **Niger** | **Togo** | 649.7 | | Planned | 2020 | |
| **Sierra Leone** | **Guinea** | 333.7 | | Under construction | 2018 | |
| **Senegal** | **Gambia** | 340.7 | | Under construction | 2019 | |
| **Senegal** | **Guinea** | 286.3 | | Under construction | 2019 | |
| **Senegal** | **Mali** | 100 | | Operational | | |

**Table 16**. Gas pipelines projects in Africa

| From | To | Capacity | Investment (bil. USD) | Status | Year | Gas pipelines projects |
|---|---|---|---|---|---|---|
| **Algeria** | **Italy** | 8 bcm/year | 2.5 | Operational | 2014 | GALSI |
| **Algeria** | **Italy** | 30.2 bcm/year increased to 33.5 bcm/year by 2012 | 6.25 | Operational | 1983 | Trans-Mediterranean |
| **Algeria** | **Portugal** | 12 bcm/year | 2.3 | Operational | 1996 | Maghreb-Europé (Pedro Duran Farell) (through Morocco, Spain) |
| **Algeria** | **Spain** | 8 bcm/year | 0.90 € | Operational | 2010 | Medgaz (offshore) |
| **Algeria** | **Spain** | 30 bil.cub.litres | 12 | 2015 commissioned. | 2021 | Trans-Saharan |
| **Algeria** | **Tunisia** | 30.2 bcm/year increased to 33.5 bcm/year by 2012 | 6.25 | Operational | 1983 | Trans-Mediterranean |
| **Egypt** | **Turkey** | 10.3 bcm/year | 1.2 | Out of order since 2012.<br>To re-open in 2019 | 2003 | Arab (through Israel-Jordan-Syria-Lebanon) |
| **Israel** | **Egypt** | 6 bcm/year | | Under construction | 2020 | EMG pipeline |
| **Cyprus** | **Egypt** | | | Planned | | |
| **Ethiopia** | **Djibouti** | 3 bil. cub. feet/y | 3.2 | Under construction (signed) | 2021 | Ethiopia - Djibouti |
| **Libya** | **Italy** | 11 bcm/year | | Operational | 2004 | Greenstream |
| **Mozambique** | **South Africa** | | 6 | Planned (not signed) | 2021 | African Renaissance |
| **Nigeria** | **Algeria** | 30 bil.cub.litres | 12 | 2015 commissioned | 2021 | Trans-Saharan |
| **Nigeria** | **Benin** | 0.2-0.6 mil.cub.feet a day | 0.9 | Operational | 2011 | West African |
| **Nigeria** | **Cote d´Ivoire** | 0.2-0.6 mil.cub.feet a day | | Planned | 2025 | West African |
| **Nigeria** | **Ghana** | 0.2-0.6 mil.cub.feet a day | 0.9 | Operational | 2011 | West African |
| **Nigeria** | **Niger** | 30 bil.cub.litres | 12 | 2015 commissioned | 2021 | Trans-Saharan |
| **Nigeria** | **Togo** | 0.2-0.6 mil.cub.feet a day | 0.9 | Operational | 2011 | West African |
| **Tanzania** | **Uganda** | 3 bil.cub.feet/ | 3.55 | Under construction (2018 the agreement signed) | 2026 | Tanzania - Uganda (LNG transport) |

Source: (Hydrocarbons Technology, 2019; NEPAD, 2019)

**Table 17**. Losses in national electricity transmission and distribution networks

| Country | Transmission | Distribution | | | |
|---|---|---|---|---|---|
| | | 2015 | 2030 | 2050 | 2070 |
| **Algeria** | 5% | 26.6% | 22.1% | 17.9% | 13.7% |
| **Angola** | 5% | 7.4% | 5.3% | 5.3% | 5.3% |
| **Benin** | 5% | 13.6% | 16.8% | 14.7% | 12.6% |
| **Botswana** | 4% | 16.6% | 13.5% | 11.5% | 9.4% |
| **Burkina Faso** | 5% | 46.1% | 46.3% | 42.1% | 37.9% |
| **Burundi** | 5% | 10.5% | 8.4% | 6.3% | 4.2% |
| **Cameroon** | 5% | 20.8% | 17.9% | 15.8% | 13.7% |
| **Central African Rep.** | 5% | 20.8% | 17.9% | 15.8% | 13.7% |
| **Chad** | 5% | 20.8% | 17.9% | 15.8% | 13.7% |
| **Congo** | 5% | 46.3% | 43.2% | 38.9% | 34.7% |
| **Congo, Dem. Rep.** | 5% | 10.5% | 8.4% | 6.3% | 5.3% |
| **Cote d´ Ivoire** | 5% | 17.9% | 13.7% | 11.6% | 9.5% |
| **Djibouti** | 5% | 18.9% | 16.8% | 14.7% | 12.6% |
| **Egypt** | 3.6% | 8.7% | 7.7% | 5.6% | 3.5% |
| **Equatorial Guinea** | 5% | 27.5% | 20.0% | 15.8% | 11.6% |
| **Eritrea** | 5% | 19.1% | 13.7% | 11.6% | 9.5% |
| **Ethiopia** | 5% | 13.7% | 11.6% | 9.5% | 7.4% |
| **Gabon** | 5% | 40.4% | 35.8% | 31.6% | 27.4% |
| **Gambia** | 5% (2015), 4%( 2040) | 17.9% | 15.8% | 13.5% | 11.5% |
| **Ghana** | 5% | 17.9% | 17.9% | 15.8% | 13.7% |
| **Guinea** | 5% (2015), 4%( 2040) | 6.3% | 5.3% | 4.2% | 4.2% |
| **Guinea-Bissau** | 5% | 47.7% | 51.6% | 47.4% | 43.2% |
| **Kenya** | 5% | 14.7% | 11.6% | 7.4% | 5.3% |
| **Lesotho** | 5% | 11.6% | 7.4% | 6.3% | 5.3% |
| **Liberia** | 5% | 32.4% | 30.5% | 26.3% | 22.1% |
| **Libya** | 5% | 28.4% | 27.4% | 23.2% | 18.9% |
| **Malawi** | 5% | 17.9% | 15.8% | 13.7% | 11.6% |
| **Mali** | 5% | 17.2% | 15.8% | 13.7% | 11.6% |
| **Mauritania** | 5% | 33.2% | 34.7% | 30.5% | 26.3% |
| **Morocco** | 5% | 11.6% | 8.4% | 6.3% | 4.2% |
| **Mozambique** | 5% | 11.6% | 10.5% | 6.3% | 4.2% |
| **Namibia** | 3% | 5.2% | 6.2% | 4.1% | 2.1% |
| **Niger** | 5% | 22.1% | 20.0% | 15.8% | 11.6% |
| **Nigeria** | 5% | 11.6% | 8.4% | 6.3% | 4.2% |
| **Rwanda** | 5% | 30.4% | 21.1% | 16.8% | 12.6% |
| **Senegal** | 5% | 10.5% | 8.4% | 6.3% | 4.2% |
| **Sierra Leone** | 5% | 43.2% | 41.1% | 32.6% | 24.2% |
| **Somalia** | 5% | 47.4% | 42.1% | 33.7% | 25.3% |
| **South Africa** | 4% | 5.2% | 4.2% | 4.2% | 4.2% |
| **South Sudan** | 5% (2015), 4%( 2040) | 5.3% | 5.3% | 4.0% | 4.0% |
| **Sudan** | 5% (2015), 4%( 2040) | 10% | 5.3% | 4.0% | 4.0% |
| **Swaziland** | 5% | 5.0% | 5.0% | 5.0% | 5.0% |
| **Tanzania** | 5% | 13.7% | 10.5% | 8.4% | 6.3% |
| **Togo** | 5% | 2.6% | 8.4% | 6.3% | 4.2% |
| **Tunisia** | 5% | 12.6% | 10.5% | 8.4% | 6.3% |
| **Uganda** | 5% | 13.7% | 11.6% | 9.5% | 7.4% |
| **Zambia** | 4% | 6.2% | 9.4% | 7.3% | 5.2% |
| **Zimbabwe** | 4% | 15.6% | 11.5% | 9.4% | 7.3% |

Source: (African Union-African Energy Commission, 2018; IEA, 2017c; International Renewable Energy Agency, 2013; OECD, n.d.; United Nations Department for Economic and Social Affairs Statistics Division, 2018

## Annex 5. Renewable energy generation targets

**Table 18**. National grid-connected renewable energy generation targets

| Country | 2020 | 2024 | 2030 |
|---|---|---|---|
| **Algeria** | | | 27% |
| **Egypt** | 20% | | |
| **Libya** | 10% | | |
| **Morocco** | 42% | | 52% |
| **Mauritania** | 20% | | 35% |
| **Tunisia** | | | 30% |
| **Botswana** | | | 35% |
| **Namibia** | | | 70% |
| **South Africa** | | | 10% |
| **Rwanda** | | 60% | 60% |
| **Sudan** | | | 20% |
| **Benin** | 20% | | 44% |
| **Burkina Faso** | 23% | | 50% |
| **Cote d` Ivoire** | | | 16% (excl. large hydro) |
| **Gambia** | 35% | | 48% |
| **Ghana** | 10% | | 20% (excl. large hydro) |
| **Guinea** | 25% | | 30% (excl. large hydro) |
| **Guinea – Bissau** | 30% | | 50% |
| **Liberia** | 25% | | 30% |
| **Mali** | | | 30% (excl. large hydro) |
| **Niger** | 40% | | 57% |
| **Nigeria** | 20% | | 30% |
| **Senegal** | 20% | | 30% (excl. large hydro) |
| **Sierra Leone** | 30% | | 50% |
| **Togo** | 17% | | 30% |

Source: (International Energy Agency, 2019; REN21, n.d.)

## Annex 6. Emission factors and units

**Table 19**. Emission factors considered in the input fuels

| Fuel | Emission factor (kg $CO_2$/MMtoe) |
|---|---|
| Crude Oil | 1.880 |
| Coal | 2.405 |
| Natural Gas | 1.338 |
| Heavy Fuel Oil | 1.987 |
| Diesel | 1.845 |

Source: (IEA-ETSAP, 2019)

Table 20. Units

| | | |
|---|---|---|
| **Energy** | | |
| PJ | Petajoule | $10^{15}$ J |
| GJ | Gigajoule | $10^{9}$ J |
| toe | Tonne of oil equivalent | |
| ktoe | Thousand tonnes of oil eq. | $10^{3}$ toe |
| Mtoe | Million tonnes of oil eq. | $10^{6}$ toe |
| Gtoe | Giga tonnes of oil eq. | $10^{9}$ toe |
| Mbl/d | Million barrels per day | $10^{6}$ bl/d |
| Mt | Million metric tonnes | $10^{6}$ t |
| MTPA | Million tonnes per annum | |
| tb/d | Thousand barrels per day | |
| bcm/y | billion cubic meter per year | |
| **Electricity** | | |
| GW | gigawatts | $10^{9}$ W |
| TWh | terawatt-hours | $10^{12}$ W |
| **Water** | | |
| $Mm^3$ | Million cubic meters | |
| MCM | Million cubic meters | |
| **Prices** | | |
| $/bbl | USD per barrel of oil | |
| $/boe | USD per barrel of oil eq. | |
| **Emissions and related** | | |
| $tCO_2$ | Tonne $CO_2$ | |
| $MtCO_2$ | Million tonne $CO_2$ | |
| **Monetary units** | | |
| M$ | Million USD | |
| Bn$ | Billion USD | |

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