IRENA

International Renewable Energy Agency

Planning and prospects for renewable power

CENTRAL AFRICA

ISBN: 978-92-9260-650-3

CITATION

IRENA (2024), *Planning and prospects for renewable power: Central Africa*, International Renewable Energy Agency, Abu Dhabi.

Available for download: www.irena.org/publications.

For further information or to provide feedback, please contact IRENA at publications@irena.org.

ABOUT IRENA

The International Renewable Energy Agency (IRENA) is an intergovernmental organisation that supports countries in their transition to a sustainable energy future, and serves as the principal platform for international co-operation, a centre of excellence, and a repository of policy, technology, resource and financial knowledge on renewable energy. IRENA promotes the widespread adoption and sustainable use of all forms of renewable energy, including bioenergy, geothermal, hydropower, ocean, solar and wind energy in the pursuit of sustainable development, energy access, energy security and low-carbon economic growth and prosperity. **www.irena.org**

ACKNOWLEDGEMENTS

The report draws upon discussions and inputs developed as part of a capacity development programme between 2021-23 organised by IRENA and the Central African Power Pool (CAPP), in collaboration with the International Atomic Energy Agency (IAEA). The programme included participation by over 70 experts from planning offices in ministries, electric utilities and specialised agencies from Angola, Burundi, Cameroon, Central African Republic, Chad, Democratic Republic of the Congo, Equatorial Guinea, Gabon, Republic of the Congo, Rwanda, and São Tomé & Príncipe.

IRENA is grateful to those experts for permitting the use of their national models in this regional analysis and for their review of this report. The national models have been altered to some extent by IRENA, so that the results presented here do not necessarily reflect the national experts' original analysis.

This report was prepared by Daniel Russo (IRENA) under the guidance of Roland Roesch (Director, IRENA Innovation and Technology Centre), Asami Miketa (IRENA) and Larissa Pinheiro Pupo Nogueira (IRENA).

This report benefited from valuable contributions by Mohamed Bassam Ben Ticha (IAEA), Himalaya Bir Shrestha (IRENA), Bilal Hussain (IRENA), Bruno Merven (IRENA consultant), Tatyana Davydenko (IRENA), and Christoph Mehler (IRENA).

The report benefited from the reviews and comments provided by Sebastian Sterl (World Resource Institute); George Giannakidis (IEA-ETSAP); Thyrsos Hadjicostas (EU GTAF); Tonderayi Gumunyu (AUDA-NEPAD); Martin Lugmayr (UNIDO); Mamadou Goundiam (IRENA); Kamlesh Dookayka (IRENA); Nolwazi Khumalo (IRENA); Thierry Odou (IRENA); and Rebecca Bisangwa (IRENA).

Publications and editorial support were provided by Francis Field and Stephanie Clarke. The report was edited by Jonathan Gorvett, with design by Phoenix Design Aid.

IRENA is grateful for the generous support of the Walloon Government of Belgium which made this report possible.

DISCLAIMER

CONTENTS

FIGURES

TABLES

BOXES

ABBREVIATIONS

AC	alternating current
AfREP	African Renewable Energy Profiles for Energy Modelling
AU	African Union
AUDA-NEPAD	African Union Development Agency-New Partnership for Africa's Development
CAPEX	capital expenditure
CAPP	Central African Power Pool
CCGT	combined-cycle gas turbine
CMP	Continental Power Systems Master Plan
CO_2	carbon dioxide
CSP	concentrated solar power
DC	direct current
DNI	direct normal irradiation
DR Congo	Democratic Republic of the Congo
EAPP	East African Power Pool
ECCAS	Economic Community of Central African States
ECOWAS	Economic Community of West African States
EEZ	exclusive economic zone
EU	European Union
GDP	gross domestic product
GHI	global horizontal irradiation
GW	gigawatt
GWh	gigawatt hour
HFO	heavy fuel oil
HVDC	high voltage direct current
IAEA	International Atomic Energy Agency
IIASA	International Institute of Applied System Analysis
IRENA	International Renewable Energy Agency
$kTCO_2$	kilotonnes of carbon dioxide
kV	kilovolt
kW	kilowatt
kWh	kilowatt hour
MESSAGE	Model for Energy Supply Strategy Alternatives and their General Environmental Impact
MSR	model supply region
MW	megawatt
MWh	megawatt hour
OCGT	open-cycle gas turbine
OECD	Organisation for Economic Co-operation and Development
O&M	operation and maintenance
LCOE	levelised cost of electricity
LT	low tension
LTES	long-term energy scenarios
PP	power plant
PV	photovoltaic
ROR	run-of-river
SAPP	South African Power Pool
SPLAT	System Planning Test model
UN	United Nations
USD	United States dollar
VRE	variable renewable energy
WAPP	West African Power Pool

EXECUTIVE SUMMARY

REPORT BACKGROUND

Between 2020 and 2023, IRENA implemented the Regional Africa Modelling Analysis & Planning Support Programme for Central Africa, in partnership with the Central African Power Pool (CAPP).[1] The programme gave practical training and insight into how to develop national and regional generation capacity expansion scenarios that can inform the energy planning process. It was delivered to over 70 key staff from the region's national energy institutions.

This report aims to build on that work by performing a consolidated regional analysis of potential scenarios for regional long-term power sector development. In doing so, it provides a foundation of transparent power sector data, as well as providing scenarios for long-term infrastructure development to local stakeholders. As the region embarks on the development of its first official regional power sector masterplan, the capacity built by the IRENA-CAPP programme and this report are both seen as essential inputs.

KEY CHARACTERISTICS OF THE REGIONAL POWER SECTOR LANDSCAPE:

Electricity demand may expand significantly from a very low baseline.

Despite pockets of progress in recent decades for certain CAPP countries, Central Africa continues to be a region with one of the lowest levels of electricity access in the world. As of 2023, four CAPP countries had overall electricity access of less than 20%, while 7 out of the region's 11 countries had access levels below 50%. Except for Gabon, all of the region's countries were below the global average. As a result, there is enormous scope for electricity demand growth. While reference projections largely track historical trends, these would still indicate a doubling of regional electricity demand by 2040. A more ambitious level of development, such as that necessary to meet the aspirations of the African Union (AU) Agenda 2063, would indicate a nearly 350% increase in regional electricity demand by 2040. In such a scenario, peak load is projected to exceed existing and committed capacity by about 10 gigawatts (GW) – a nearly 50% gap – by 2040. This shows the clear need to plan and commit further investments in new generation projects.

Hydropower dominates existing and planned regional power supply.

At the start of 2023, installed power generation capacity in the CAPP region was just over 11 GW, of which hydropower made up roughly 75%. Hydropower continues to be the main category of new capacity being planned in the region, making up over 85% of committed and candidate projects, including the major Grand Inga hydropower project in the Democratic Republic of the Congo (DR Congo). With over 20 GW of hydropower potential at the Grand Inga site reflected in the modelling horizon – nearly two times more than the total current installed capacity in all of Central Africa – this project's potential development is emblematic of the region's ambitions to become an electricity exporter to the continent. It is also indicative of the region's rich renewable resources.

[1] *IRENA is grateful for the generous support of the Walloon Government of Belgium, which made the programme and this report possible.*

- **There is a major ambition to develop cross-border trade beyond its current, limited, scope.**

  As of 2023, existing cross-border transmission capacity within the CAPP region was mainly limited to infrastructure between DR Congo, Rwanda and Burundi. That year, this infrastructure accounted for around 515 megawatts (MW) of the 601 MW of total intra-CAPP capacity. Indeed, in 2023 there was more capacity between bordering countries/regions and the CAPP, with just over 1 GW of cross-border infrastructure connecting DR Congo, Rwanda and Angola to the Eastern African Power Pool (EAPP) and Southern African Power Pool (SAPP) countries.

  Planned projects reflect a strong ambition to change this picture, however. These projects aim to develop a more comprehensive cross-border transmission infrastructure within the CAPP, along with more export capacity to other regions. If all planned projects were to be developed, this infrastructure expansion would represent a more than ten-fold increase in current transmission capacity to other regions. It would also represent a twenty-fold increase in intra-CAPP transmission capacity.

KEY INSIGHTS FROM THE RESULTS:

- In all the scenarios covered by this report, renewables are central to meeting demand and trade expansion in Central Africa. In every scenario, out to the modelling horizon of 2040, **hydropower remains the largest renewable energy source in the region**, supplying nearly 70% of its electricity.

- **Reductions in the cost of solar photovoltaic (PV) and wind are driving their expansion in the regional capacity mix**. In all scenarios, the share of these two technologies rise from nearly zero today to at least 7% of regional production by 2040. Due to regional climate conditions, solar PV is set to grow faster. In scenarios with high demand, solar and wind reach 14%-20% of total production by 2040, while their role is even more important in scenarios with challenging future hydropower conditions, such as project delays and dry years.

- Although certain countries have gas capacity in the planning pipeline, **in all scenarios, the share of fossil fuels in regional electricity production falls from today's already low level**. In the majority of scenarios, it falls to below 5% of production by 2040. Interestingly, across almost all scenarios, the overall gas capacity begins to decrease by 2040 as the costs of renewable technologies and batteries continue to decline. This implies that these plants do not have a promising long-term outlook in the region.

- **There is large, untapped potential for cross-border electricity trade inside and outside the CAPP region**. More cross-border infrastructure would allow lower-cost renewable resources to be used more extensively, displacing more costly fossil fuel use. Consistently, exports from the CAPP to other regions also lower costs and emissions for Africa as a whole, particularly in western and southern Africa.

  For this reason, **by the mid-2030s, in all scenarios, cross-border interconnection capacity in the CAPP region grows over ten-fold to a total of at least 10 GW. This would result in lower power sector costs**. In scenarios where all physically possible interconnectors in the CAPP region are allowed, the highest total interconnector capacity reaches around 40 GW by the early 2030s and nearly 50 GW by 2040.

The Grand Inga hydropower project has a major influence on the evolution of inter-regional trade and the regional power system in Central Africa. Compared to the scenario with the most trade in 2040, regional results without the Grand Inga expansion contain 73% less interconnector capacity, or around 13 GW of capacity versus around 48 GW. Without Grand Inga, there are also 81% fewer net exports from the region.

Without the expansion of Grand Inga, other CAPP countries will need to plan for different capacity and production mixes. Angola, Cameroon, the Republic of the Congo and Gabon are the most affected in terms of capacity, but different variations of renewable and battery storage capacity could be cost-competitive in filling the gap in the 2030s.

In all scenarios, significant investment must be planned to meet the expected expansion of demand. Even in the scenario with the lowest investment needs, the overall amount implies costs, in US dollar (USD) terms, of over USD 5 billion per year, on average, for the regional power system. About two-thirds of this would be dedicated to capacity investment.

Cumulative system costs and investment in the CAPP region vary significantly depending on future assumptions in the areas of demand and cross-border trade. The highest-cost scenario reaches just over USD 145 billion between 2022 and 2040. This figure is around 48% – or USD 47 billion – higher than the lowest cost scenario for the region, which is around USD 97 billion over the same period.[2] The most significant driver of the difference is the level of investment in capacity to meet higher or lower regional demand and export demand.

These results highlight how important the planning of interconnector and export capacity development (and thus the role of the CAPP in leading such discussions) will be in the future overall costs and investment needs of the region, as well as of the continent as a whole. This is particularly the case for any large-scale hydropower projects, such as Grand Inga, which are to some extent linked to cross-border infrastructure.

[2] *For reference, IRENA estimates that the whole of Africa saw about USD 60 billion of investment in renewable energy between 2000-2020 (IRENA, 2023a).*

INTRODUCTION

1

1.1 BACKGROUND: THE IRENA REGIONAL MODELLING ANALYSIS & PLANNING SUPPORT PROGRAMME

In Central Africa, IRENA has implemented a wide range of programmes to support the development of renewable energy. Since 2013, IRENA member states in this region have also registered particular interest in strengthening energy planning capacity. This is to allow regional governments to develop robust energy sector objectives, plans and climate targets. The Regional Renewable Energy Roadmap of the Economic Community of Central African States (ECCAS), endorsed in 2021, aimed to identify key activities in addressing energy transformation among its members. The roadmap had two main recommendations: first, to strengthen the capacity for long-term energy planning processes with the tools to link the assessment of renewable potential to actual development; and second, to prepare national and regional master plans for the power or energy sectors that accounted for an increased share of variable renewables.

In partnership with the Central African Power Pool (CAPP), between 2020 and 2023, IRENA followed through on these recommendations by implementing the Regional Modelling Analysis & Planning Support Programme for Central Africa.[3] This programme delivered both methodological and practical training to official experts from the region's national energy institutions. It focused on how to develop national and regional generation capacity expansion scenarios, in order to inform the energy planning process. Over the course of two, six-month training phases, roughly 70 technical planning experts from all CAPP member states participated. Activities included: an e-learning course for the Model for Energy Supply Strategy Alternatives and their General Environmental Impact (MESSAGE) capacity expansion software, implemented with the support of the International Atomic Energy Agency (IAEA); four training workshops on long-term planning with renewables and the IRENA System Planning Test (SPLAT)-MESSAGE modelling framework; and on-request tutoring support for modelling and preparation of national summary reports.

The programme was closely integrated with the African Continental Power Systems Master Plan (CMP) development, led by the African Union Development Agency-New Partnership for Africa's Development (AUDA-NEPAD). Key financial support was provided for this by the European Union (EU), with IRENA's support as a modelling partner.

The outcome of this programme has been enhanced energy planning capacity for CAPP member-state planning authorities. A foundation of transparent power sector data and scenarios for long-term infrastructure development, owned by local stakeholders, has also been established. Both of these developments are seen as essential inputs as the region embarks on the development of its first, official, regional power sector masterplan.

---

[3] *IRENA is grateful for the generous support of the Walloon Government of Belgium, which made the programme and this report possible.*

1.2 THE REPORT IN CONTEXT

This report is part of the IRENA series, *Planning and Prospects for Renewable Energy*, which focuses on renewable electricity generation in African power pools. It aims to build on the work of the IRENA-CAPP Regional Modelling Analysis & Planning Support Programme by performing a consolidated regional analysis of potential scenarios for long-term power sector development in the region. In doing so, it partially documents the inputs and outputs of the SPLAT-Africa model that were elaborated by participants in the IRENA-CAPP programme. Based on the additional feedback from regional stakeholders given at a high-level review workshop in July 2023, this report also presents scenarios that have been further elaborated by IRENA for power system expansion in Central Africa through to 2040. These scenarios include the potential for interconnections within and outside the region.

While the work of this report is firmly based on regional engagement, it does not necessarily reflect countries' official positions, nor does it intend to prescribe a path of power sector development.[4] The assessment is based on certain assumptions surrounding power sector development, which stakeholders in the region may regard differently. Local experts are advised to continue exploring different assumptions in order to develop their own scenarios for comparison. The results from the analysis presented here are intended to support that effort and contribute to the forthcoming national and regional dialogue, as CAPP member states prepare to meet ambitious renewable energy targets and develop the region's first official power sector masterplan. The results also highlight the utility of the SPLAT-Africa model as a freely available tool to develop and explore national and regional power sector scenarios.

Chapter 2 of the report presents an overview of the methodology used in the analysis, including a description of the SPLAT-Africa model and its structure. More detailed elaboration of the modelling exercise's inputs is provided throughout Chapter 3, which also provides insight into the region's electricity sector landscape. Chapter 4 presents a detailed overview of the results for the different scenarios explored in the modelling exercise, while Chapter 5 offers high-level conclusions from the analysis. The data appendix that will be made available on the report homepage on the IRENA website, presents more detailed data used in the study and country-level results.

Box 1 Scenarios for the energy transition: The African power pool experience

As of the date of this report's publication, the Central African region does not have an official regional power sector masterplan. It is hoped that the analysis presented here – and the IRENA-CAPP Regional Africa Modelling Analysis & Planning Support Programme that has informed this report – will be valuable inputs in the development of such a plan.

To further support improved development and use of long-term scenarios, IRENA has also investigated the experience of existing African power pool plan development in the publication *Scenarios for the energy transition: Experience and good practices in Africa* (IRENA, 2023b). This was undertaken as part of the agency's Long-Term Energy Scenarios (LTES) network.

In that report, several best practices from the experience of the Eastern African Power Pool (EAPP) and the West Africa Power Pool (WAPP) were highlighted and are summarised below:

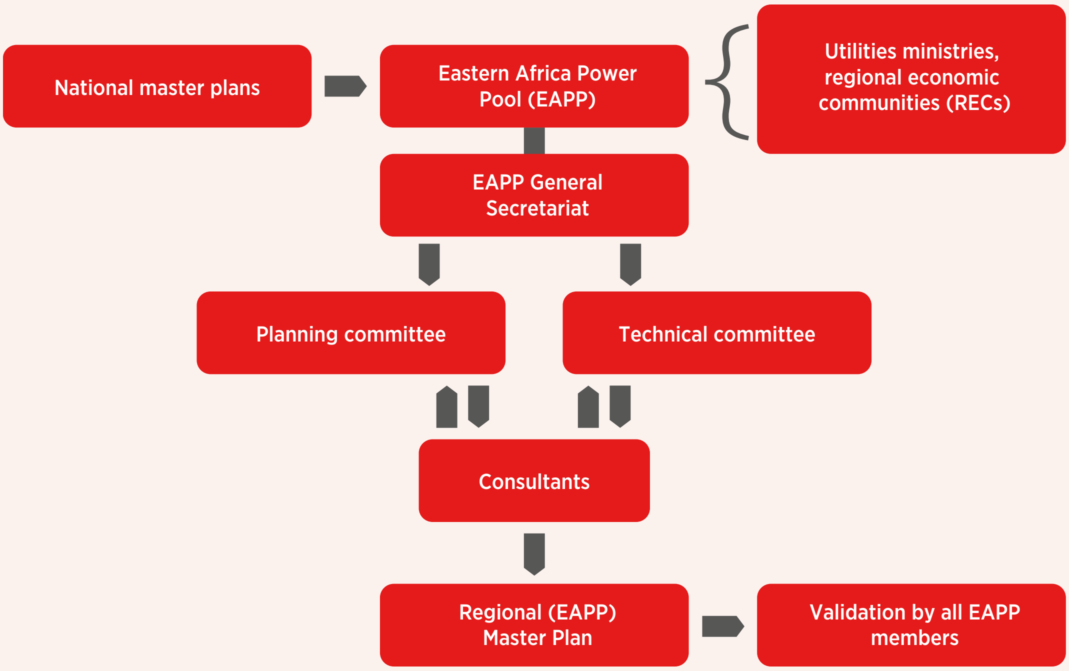
[4] *The CAPP member country teams that attended the SPLAT-MESSAGE training sessions are not responsible for the final specific results presented in this report, which are a product of IRENA's modelling and analysis.*

Box 1 Continued

- **A bottom-up approach in developing regional master plans**

  Energy scenario development by the EAPP and WAPP is a collaborative process between member state ministries, utilities and regional organisations. As illustrated in the figure below, a bottom-up approach is used in the EAPP, where master plans are developed at the national level and then used as the basis for the regional master plan.

Figure 1 Governance structure of the development of the EAPP Master Plan



In the WAPP, the master plan was validated by a committee within the power pool, endorsed by the Executive Board and sent to the General Assembly for its approval. The region's heads of state were then presented with the plan for their agreement.

- **Broad stakeholder participation in long-term energy scenario (LTES) development:** In both EAPP and WAPP, the scope of the LTES is defined, validated and agreed upon by all members. The modelling of LTES and identification of energy planning strategies is also participated by government institutions, the private sector, academia and other research institutions. This broad participation by stakeholders with different priorities serves to build consensus around scenarios and policy development.

- **Scenario update and use beyond development is well-defined**: There is an expectation that the WAPP Regional Master Plan is to be updated frequently enough to account for changing factors. These could include the continued development of renewable energies, as well as emerging technologies or strategies at the country level. In the EAPP, regional energy scenarios that are devised are used to support technical discussions at the national level. This aims to ensure that targets and decisions at the national level are aligned with regional strategy.

- **Capacity building is conducted through continuous training**: To reinforce energy planning capacity, the EAPP prepares annual training sessions for member states and incorporates these into the EAPP Short-Term Action Plan.

OVERVIEW OF METHODOLOGY 2

The SPLAT-Africa model used in this report was developed using the MESSAGE software – a dynamic, bottom-up, multi-year energy system modelling platform that applies linear and mixed-integer optimisation techniques. MESSAGE was originally developed at the International Institute of Applied System Analysis (IIASA), but has been enhanced by the IAEA. The modelling platform is a flexible framework within which the actual SPLAT-Africa model has been developed.

The SPLAT-Africa model consists of demand projections, a database of cross-border transmission infrastructure, power generation technologies characterised by economic and technical parameters, and information regarding existing infrastructure and its remaining life span. Starting with the existing power infrastructure in the region, the model calculates an evolution of technically feasible technology mixes that achieve a least-cost objective over the planning period (*i.e.* minimal total discounted system costs, including investment, operation and maintenance [O&M], fuel and any other user-defined costs), while meeting various system requirements (*e.g.* supply matching demand at a given time; sufficient resources and capacity in place to supply desired production) and user-defined constraints (*e.g.* reserve margin, speed of technology deployment, emission limits, policy targets).

The model inputs described above can be varied according to the user's preference to explore different scenarios of system evolution under particular sets of assumptions. The model's "solution" includes, *inter alia*, investment in new technologies, production, fuel use and trade. Economic and environmental implications associated with the identified least-cost systems can also be calculated with the model.

The SPLAT-Africa model used for this analysis covers all 11 CAPP member countries: Angola, Burundi, Cameroon, the Central African Republic, Chad, the Democratic Republic of the Congo (DR Congo), Equatorial Guinea, Gabon, the Republic of Congo, Rwanda and São Tomé & Príncipe. São Tomé & Príncipe is considered as a separate entity in the modelling, as it is not connected to the mainland electricity grid.[5]

The modelling of Central African countries is part of the broader SPLAT-Africa framework, which has been entirely developed and is regularly updated by IRENA. As such, the Central African countries that constitute the CAPP can be modelled individually, as part of an isolated Central Africa region, or modelled to reflect all the cross-border interconnections with countries outside of that region. The scenarios developed over the course of this modelling exercise utilise this range of structures to explore the impacts of various interconnection possibilities on power sector development. More information on assumptions and definitions in the scenarios developed can be found in the following chapters.

[5] *The particular geographical situation of Equatorial Guinea should also be well-noted, as its capital is on an island, while part of the country is on the mainland with direct land borders to neighbouring countries.*

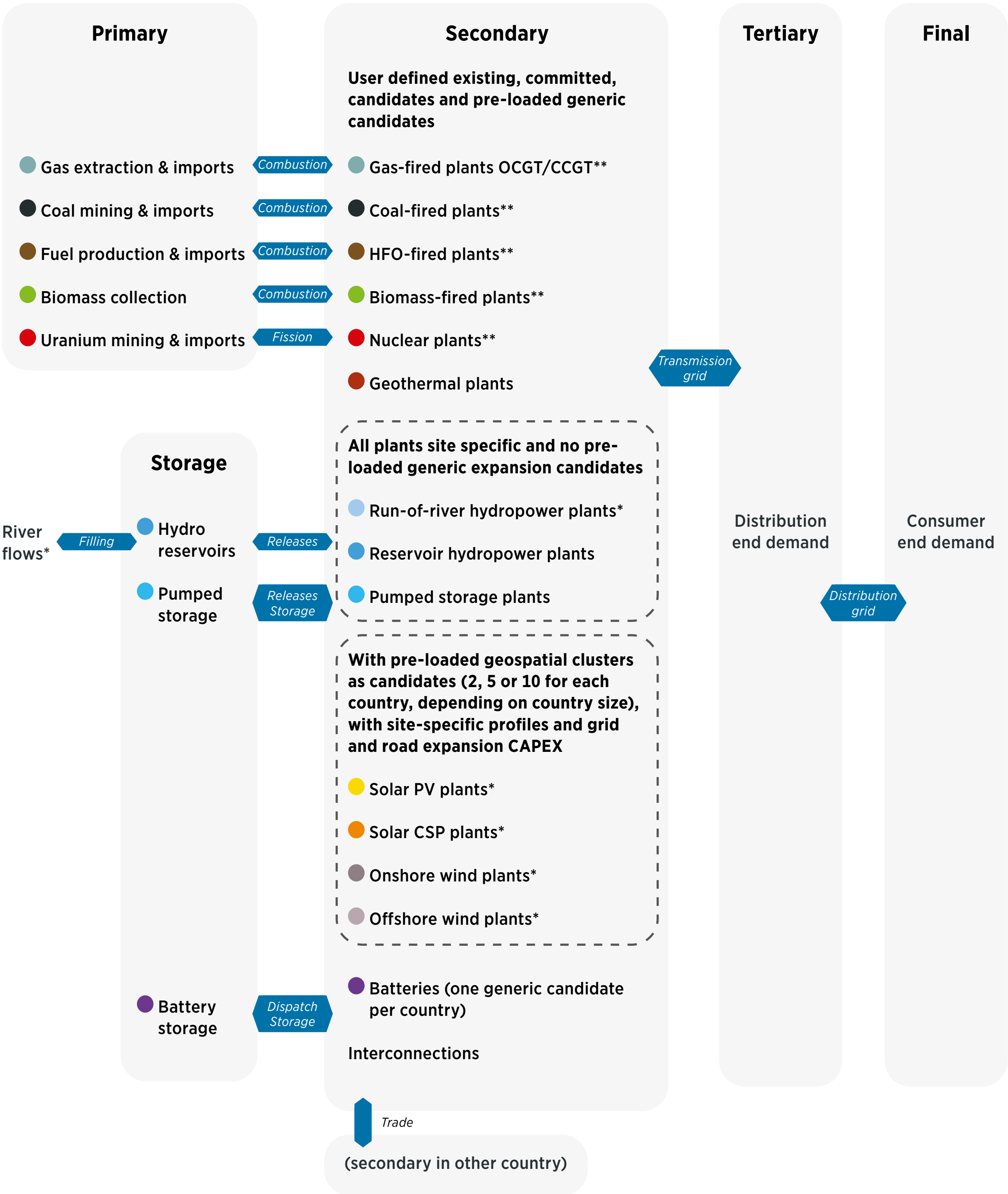
The key characteristics of the SPLAT-Africa model used in this report are:

- Countries are modelled as separate nodes, interlinked by transmission lines. Each node, representing the power system of a single country, is characterised as shown in Figure 2 below.
- Demand for electricity is defined at the "sent-out" level, *i.e.* before transmission and distribution. See point 1 on electricity demand in chapter 3 below for more detail.
- Computation is made of a least-cost power supply system that meets the given demand while satisfying all user-defined constraints. "Least-cost" is defined for the continental region as a whole, over the entire modelling period.
- There is explicit modelling of four categories of power generation options for all existing and known generation technologies, and cross-border transmission. The four categories are: existing capacity; committed site-specific projects that are expected to be commissioned; candidate site-specific projects that are under consideration; and non-site specific (generic) options. See section A.3, *Electricity generation options*, and point 3 of Chapter 3, for more details.
- Reliability of supply is addressed by assigning a 10% reserve margin above peak load. Different technologies are also assigned different levels of "firm" capacity to satisfy that margin, based on the nature of the resource. See Section A.5, *Constraints related to system and unit operation*, for more detail.

The implementation of the IRENA-CAPP Regional Modelling Analysis & Planning Support Programme was closely integrated with the development of the CMP, led by AUDA-NEPAD, with key financial support from the EU, which IRENA supports as a modelling partner. As such, a wide range of model inputs outlined in this report draw upon the work completed in the CMP project, which also had the full participation of the CAPP.

Further methodological details for the SPLAT-Africa model used for the Central Africa region can be found in the methodological appendix at the end of this report.

Figure 2 Schematic overview of the reference energy system of each country node in the SPLAT-Africa model



Notes: All technologies with an asterisk (*) are provided with a specific temporal availability profile (see chapter 3 below); technologies with two asterisks (**) allow for generic capacity expansion subject to stakeholder's preference. HFO = Heavy Fuel Oil; OCGT = Open-Cycle Gas Turbine; CCGT = Closed-Cycle Gas Turbine; ROR = run-of-river; PV = photovoltaic; CSP = concentrating solar power.

3 REGIONAL POWER SECTOR OVERVIEW AND KEY SCENARIO ASSUMPTIONS

This report takes into account the below characteristics of the regional power sector and makes the following assumptions when considering its development:

1 ELECTRICITY DEMAND MAY EXPAND SIGNIFICANTLY FROM A VERY LOW BASELINE

Despite pockets of progress for certain CAPP countries in recent decades, the CAPP region continues to have some of the lowest levels of electricity access and generation per capita in the world.

As shown in the figures below, in 2022, four CAPP countries had overall electricity access of less than 20%, while 7 out of 11 countries had access rates below 50%. All except Gabon were below the global average, and a number of countries have shown little progress in recent years. Levels of electricity generation per capita - an inexact proxy for electricity demand per capita, but one that is statistically available for all CAPP countries - were also far below the global average. As of 2022, electricity generation per capita in the CAPP countries ranged from 0.5% to 28% of the global average.

As a result, there is enormous scope for electricity demand growth in the region. Electricity demand assumptions in this report take this into account and are based on secondary, or sent-out electricity demand projections (*i.e.* at the utility level, before transmission) developed as part of the CMP project. Econometric modelling was performed for the CMP using forecast values for country-level demand drivers. These included gross domestic product (GDP) per capita, population, the urbanisation rate, electricity consumption per capita and the electricity access rate.[6] Modelled projections were then cross-referenced with available projections in official regional power pool and national masterplan documents. In some cases, reference demand projections were adjusted as necessary to align with official projections through consultations held within IRENA and CMP training sessions. Alternative scenarios for demand forecasts were also created using alternative projections and assumptions for the key driving parameters. These parameters included GDP per capita, the electricity access rate and electricity consumption per capita.

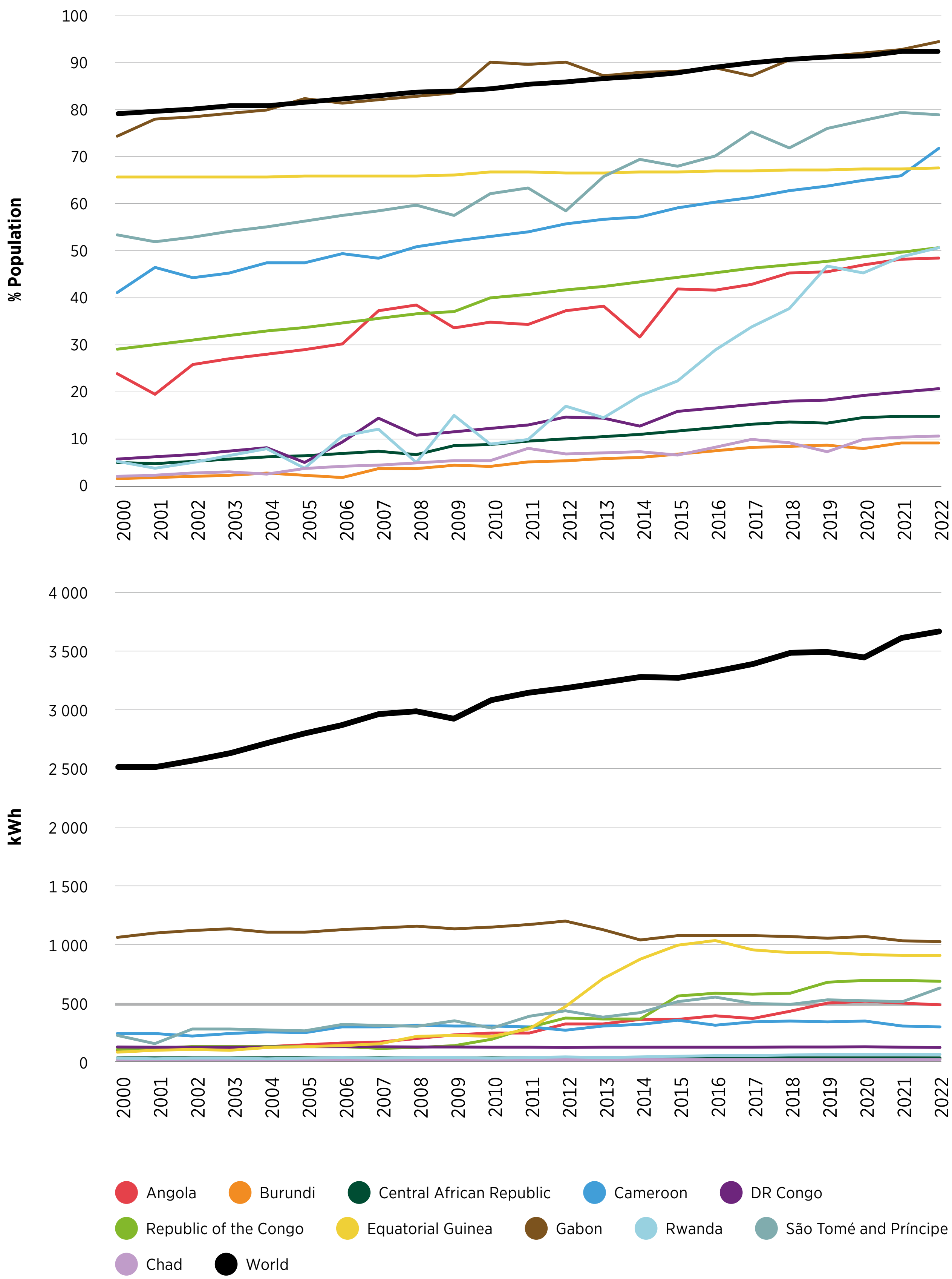
While reference projections largely track historical trends, these still show a doubling of regional electricity demand by 2040. A high alternative demand scenario reflects a more ambitious level of development, made to meet the aspirations of the African Union (AU) Agenda 2063. This includes the achievement of 100% electricity access and an increase in each country's per capita electricity consumption over the modelling horizon to align with the next highest income level category (*e.g.* a moving from lower-middle income to middle income). Such a scenario would represent a nearly 350% increase in regional electricity demand by 2040.

Figure 4 presents the projection of secondary electricity demand utilised for this analysis. Detailed country-level data can be found in the data appendix that will be made available from the report download page on the IRENA website.

---

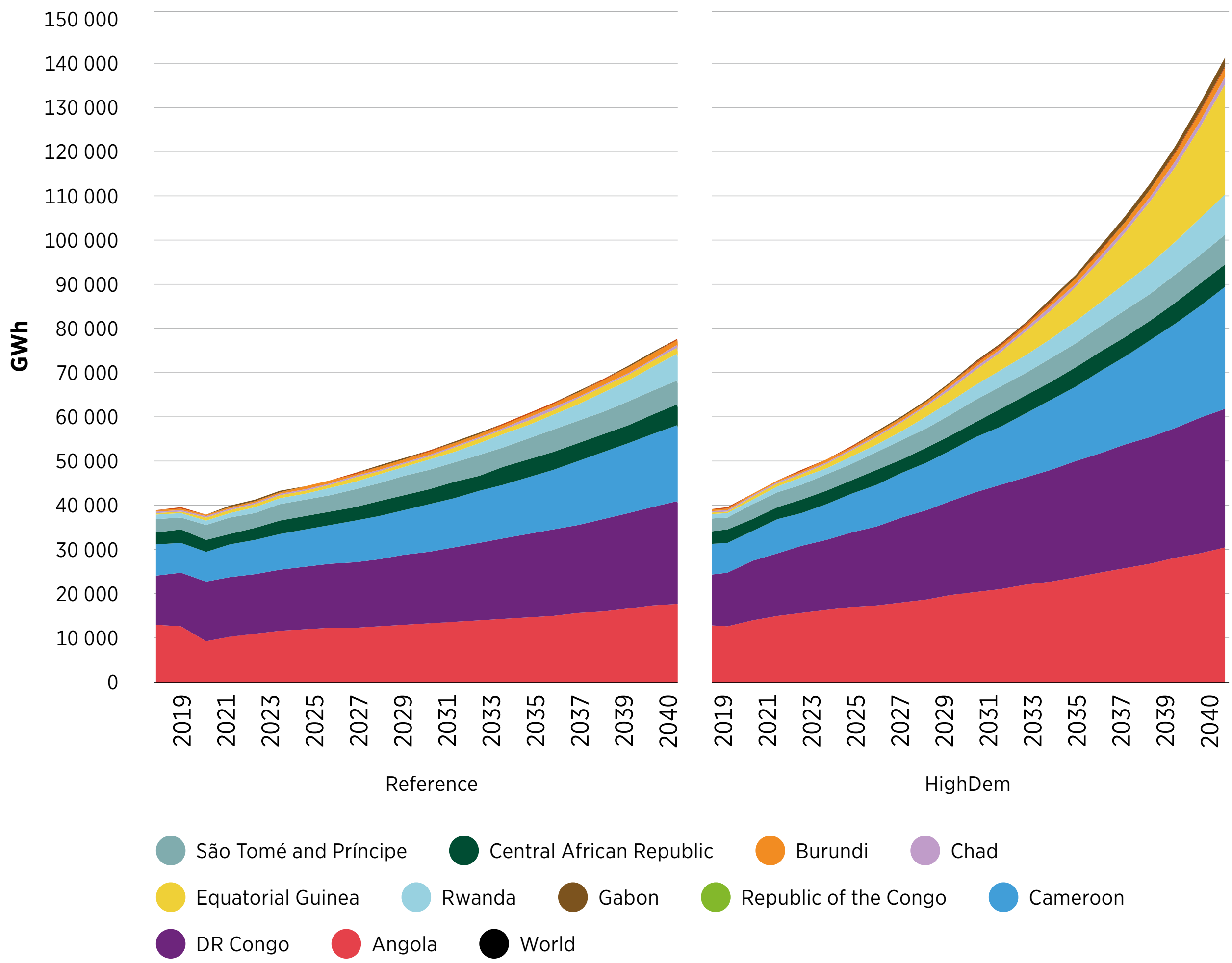
[6] *Sources for these values include IIASA, the United Nations (UN), the African Energy Commission and the IEA. Full detail behind any values and methodologies used in the CMP programme can be found in the CMP programme documentation: https://cmpmwanga.nepad.org/publications*

Figure 3 Electricity access (top) and electricity generation per capita (bottom) in CAPP countries, 2000-2022



Source: (Ember and Energy Institute, 2023; IEA et al., 2023).
Note: kWh = kilowatt hour.

Figure 4 Secondary (sent-out) electricity demand projections, 2019-2040, by country



Note: GWh = gigawatt hours.

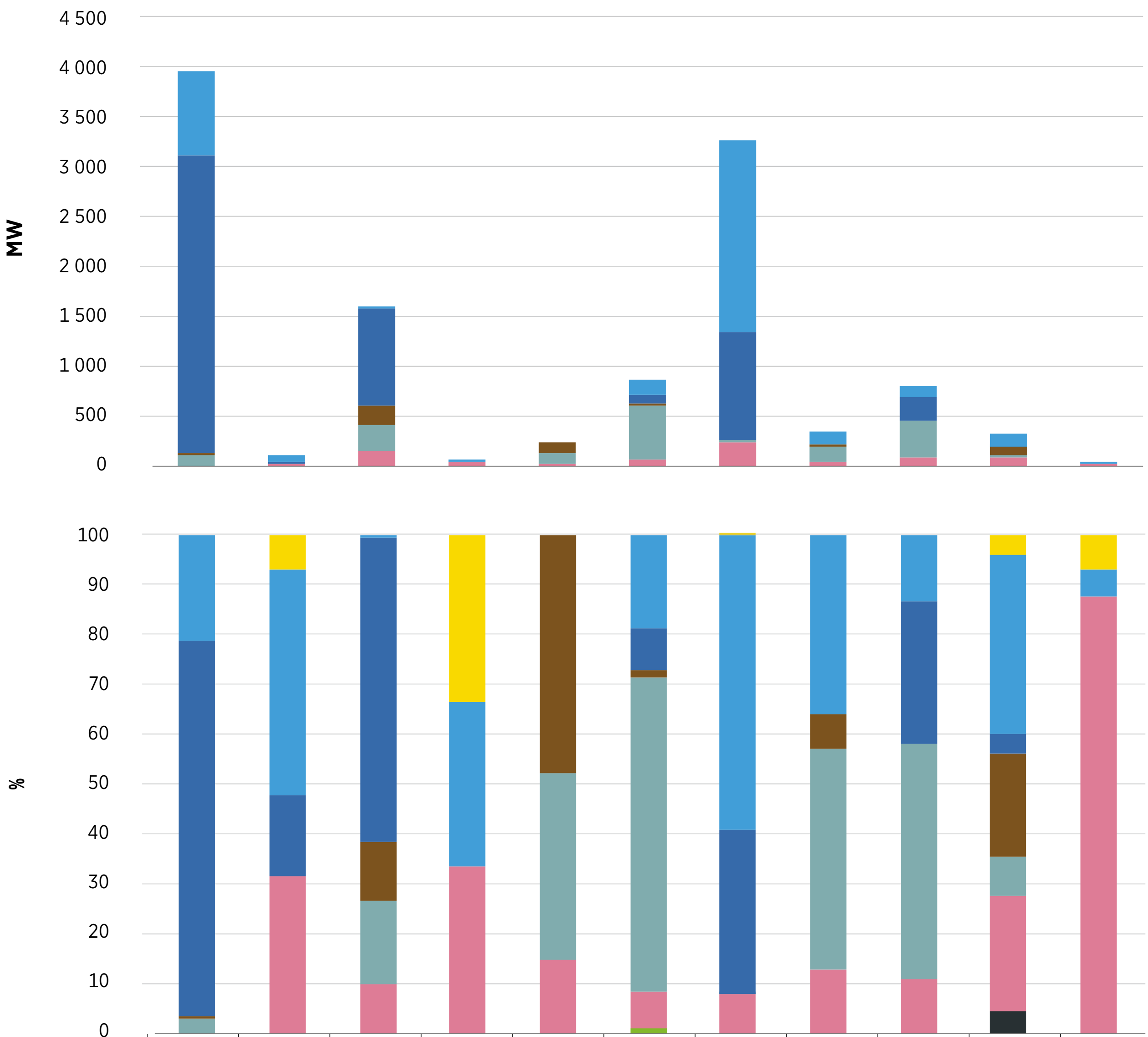
2 EXISTING AND PLANNED REGIONAL POWER SUPPLY IS MAINLY RENEWABLE DUE TO HYDROPOWER

Existing power generation in the CAPP region has been integrated into the SPLAT-Africa model based on the latest available data provided and reviewed by official regional and national planning representatives in the IRENA-CAPP Regional Modelling Analysis & Planning Support Programme and the CMP programme. An overview of existing generation capacity is presented in Figure 5 below.

At the start of 2023, installed power generation capacity in the CAPP region stood at just over 11 gigawatts (GW), of which Angola and DR Congo accounted for more than half. As hydropower makes up over 90% of the capacity mix of each of these countries, the region-wide supply mix is also majority hydropower (75%), followed by gas (14%) and diesel (7%). Heavy fuel oil (HFO) contributed 4%, with the remainder made up of other small capacities. Although fossil fuel capacity is relatively less prominent at the regional level, several countries in the region, such as Chad, Republic of the Congo, Equatorial Guinea, Gabon, Rwanda, and São Tomé and Príncipe, currently rely heavily on such capacity.

Country-level detail of existing capacity are given in the data appendix accompanying this report.

Figure 5 Total existing capacity per CAPP country per technology (as of start of 2023)



	Angola	Burundi	Cameroon	Central African Republic	Chad	Republic of the Congo	DR Congo	Equatorial Guinea	Gabon	Rwanda	São Tomé and Príncipe
Solar PV		8		40			1			12	2
Hydro ROR	827	50	1	40		158	1 906	127	102	123	2
Hydro dam	2 958	18	958			74	1 080		228	12	
HFO	20		186		114	13		25		70	
Gas	120		267		90	545	5	157	372	27	
Diesel		35	150	40	35	62	249	45	85	78	29
Coal										15	
Biomass						9					

Notes: Capacity values are meant to reflect total installed capacity. They therefore may not reflect differences in effective capacity due to operational issues. ROR = run of river, MW = megawatt.

Future site-specific project information was originally developed by IRENA based on official national and regional masterplan documents and desk research to cross-check international databases. The final information used in this report also reflects a full review and revision by national and regional stakeholders in both IRENA and CMP trainings.

An overview of site-specific project capacity beyond 2022 in CAPP countries in the SPLAT-Africa model is presented in the figures below, which show the capacities of committed and candidate projects. Committed projects are those which are considered certain to come online in a known future year, while candidate projects reflect known sites in the planning process that do not yet have a determined construction date.

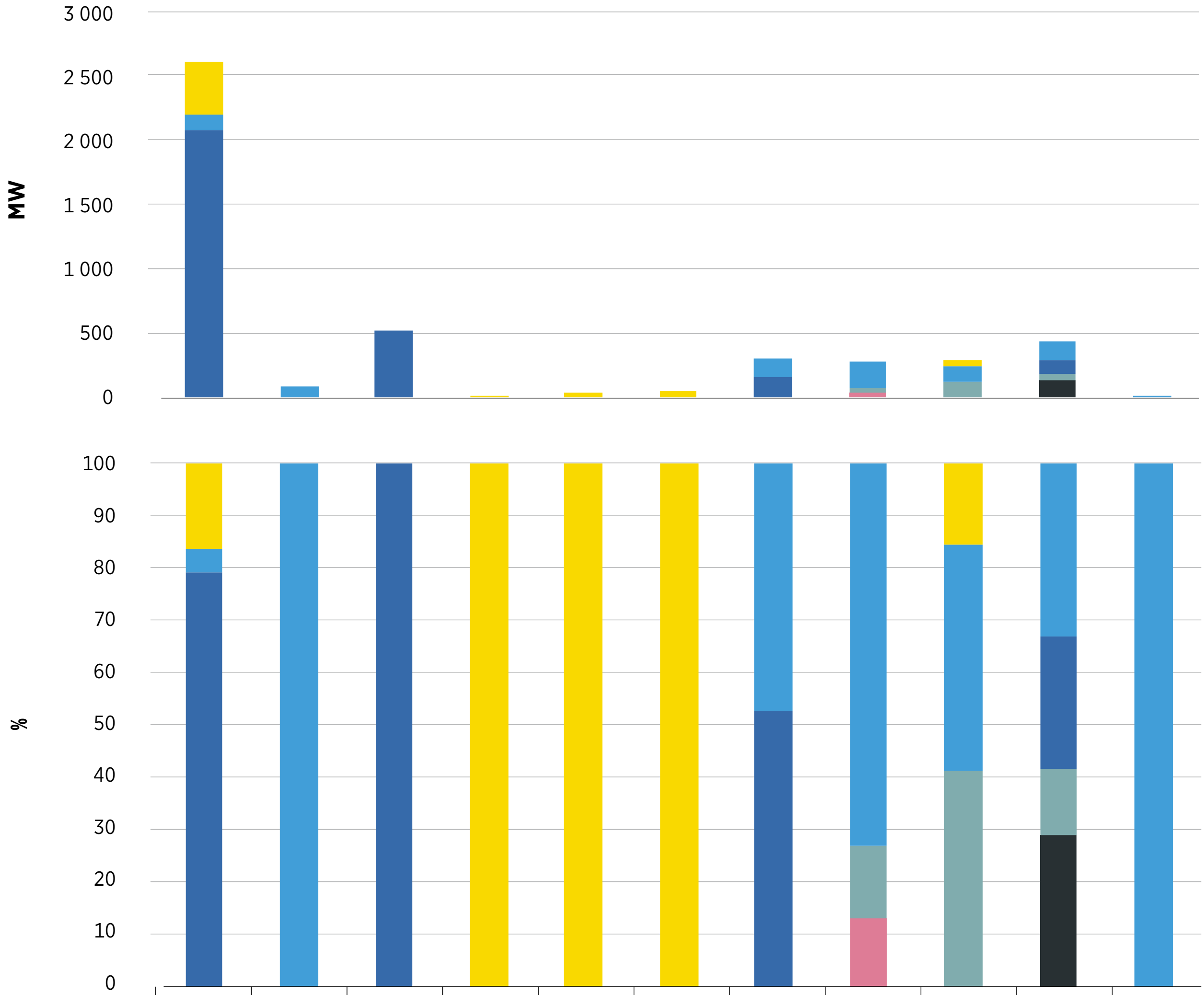
Although certain countries have nationally-significant amounts of gas capacity in the planning process, hydropower continues to be the main category of new capacity being planned in the region. This is particularly the case for candidate projects, which also include the major Grand Inga hydropower project in DR Congo. With the modelling horizon reflecting over 20 GW of hydropower potential at the Inga site – a figure that is nearly twice the total current installed capacity in all of Central Africa – Grand Inga's envisaged development is both emblematic of the region's rich renewable resources and its ambitions to become an electricity exporter for the continent.[7]

Beyond these site-specific capacities, additional future capacity options are included in the model. The section below, *Renewable generation options*, provides details of the region's wider renewable potential.[8] Detailed technical parameters for these technologies (*e.g.* costs, efficiency, construction duration, lifetime) are summarised in the data appendix accompanying this report.

[7] *Note that the site has up to 40 GW of potential capacity, but not all of which is included for potential construction by 2040 under the analysis assumptions. In addition, challenges in the development of the Grand Inga project cannot be ignored in a prudent planning process. For this reason, although the project is officially a candidate for development, the modelling for this report also explores the impact of delays or alternatives to the Grand Inga project on regional power sector development.*

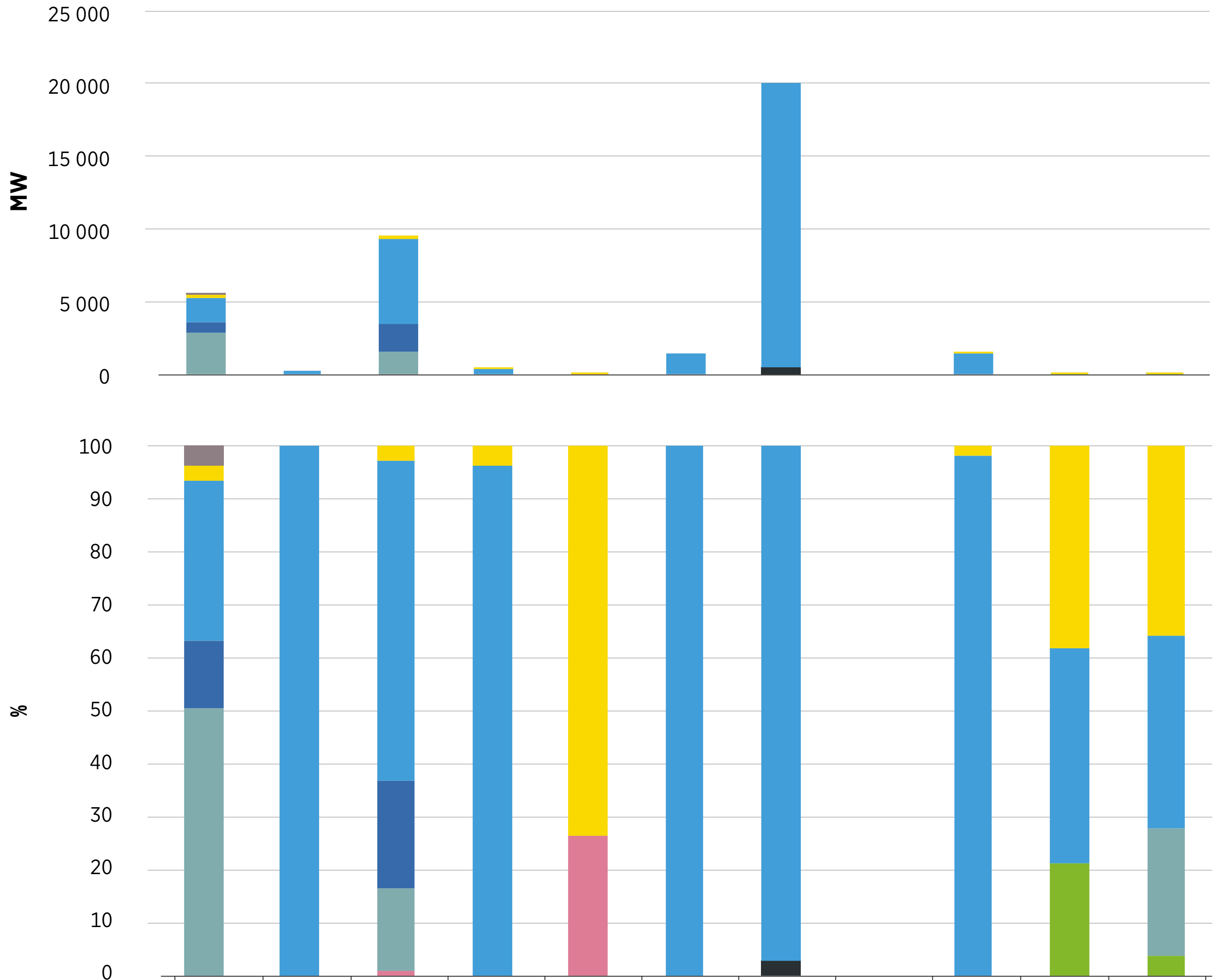
[8] *This section focuses on hydro, solar and wind power; more detail on the modelling methodology for all future capacity options can also be found in Section A.3, Electricity generation options.*

Figure 6 Total committed site-specific capacity per CAPP country per technology (as of start of 2023)



	Angola	Burundi	Cameroon	Central African Republic	Chad	Republic of the Congo	DR Congo	Equatorial Guinea	Gabon	Rwanda	São Tomé and Príncipe
Solar PV	424			12	37	50			45		
Hydro ROR	121	87					143	200	124	146	7
Hydro dam	2 100		525				160			112	
Gas								38	120	56	
Diesel								36			
Coal										130	

Figure 7 Total candidate site-specific capacity per CAPP country per technology (as of start of 2023)

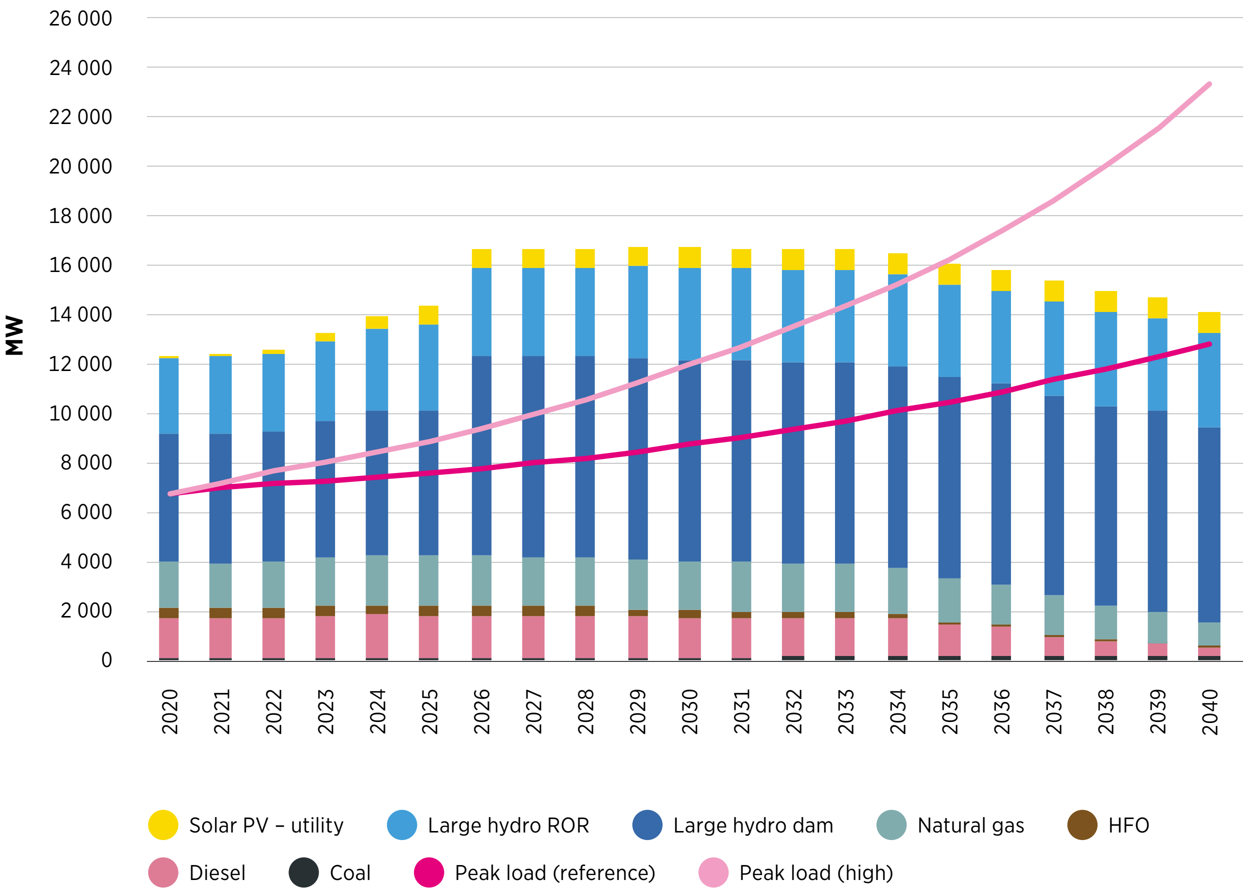


	Angola	Burundi	Cameroon	Central African Republic	Chad	Republic of the Congo	DR Congo	Equatorial Guinea	Gabon	Rwanda	São Tomé and Príncipe
Wind Onshore	204										
Solar PV	168		273	15	63				30	40	45
Hydro ROR	1 717	288	5 742	406		1 461	19 369		1 440	43	45
Hydro dam	715		1 927								
Gas	2 850		1 464								30
Diesel			73		23						
Coal							500				
Biomass										22	5

Notes: Data presented here reflects site-specific candidate project capacity included in the model horizon – *i.e.* up to 2040. This is an important distinction for the Grand Inga hydropower project, which has up to 40 GW of potential capacity, but not all of which is included for potential construction by 2040 under the analysis assumptions.

The figure below presents a projection of the lifetime of existing power plants and committed projects, compared to the projected peak load under the reference and high demand scenarios used in this study. Although current total installed capacity figures appear in excess of peak load, one must consider that the capacity factor of hydropower plants – *i.e.* the availability of capacity to meet peak load – is typically below 100%. This is due to dependence on hydrological conditions to various extents, while installed capacity values for all technologies may also not reflect differences in effective capacity due to operational issues.[9] For these reasons, new power generation projects must be planned and investments committed to meet future electricity demand under both scenarios. This is particularly the case in the high-demand scenario, in which peak load is projected to exceed existing and committed capacity by nearly 10 GW by 2040. Before that point, existing and committed total capacities in the region above the peak demand projections going into the 2030s reflect the regional ambition to become an important centre for electricity exports in the continent, as discussed in point 3 below in this chapter.

Figure 8 Existing and committed capacity in Central Africa by technology, compared with projected peak load, 2020-2040



[9] *These factors are taken into consideration in the modelling for this study. For more details, see Appendix: Methodological details.*

RENEWABLE GENERATION OPTIONS

Large hydropower

With hydropower as the largest source of current and planned regional power supply, it is important to ensure it is well-represented in regional planning and modelling processes. Due to the variability in climate zones within and across African countries and corresponding patterns of rainfall and river flow, it is critical to model the following aspects of hydropower generation:[10]

- The seasonality in power generation caused by river inflow, constrained by possible discrepancies between maximum river discharge and maximum turbine flow, and mitigating effects that the presence of reservoirs can have on this seasonality.
- The flexibility that reservoir hydropower plants can provide to support VRE integration on a sub-daily basis, modulated by their seasonal availability.

These aspects were modelled at the plant level for existing, committed and candidate plants, using the African Renewable Energy Profiles for Energy Modelling (AfREP)-Hydro database published by IRENA for the benefit of the modelling community (See IRENA, 2021a and Sterl *et al.*, 2021 for methodological information). This database uses a continental-level river flow dataset in combination with technical information at the hydropower plant level to estimate seasonal capacity factor profiles.

In the modelling for this report, two alternative scenarios related to large hydropower were also considered, based on guidance from participants in the IRENA-CAPP Regional Modelling Analysis & Planning Support Programme. These were: a scenario where all hydro production is subject to dry year assumptions; and a scenario where all candidate hydropower greater than 1 GW is delayed by five years. Dry year assumptions are based on the range of river flow simulations underpinning the AfREP-Hydro database (for more detail, see (Sterl *et al.*, 2021)). Large hydropower capacity in CAPP countries in the SPLAT-Africa model is summarised in Table 1. Detailed parameters for existing and planned hydropower projects are given in the data appendix accompanying this report.

[10] *For more detail on the links between renewable energy resources and weather and climate conditions, see WMO and IRENA, 2023.*

Table 1 Existing and identified hydropower projects, as of start of 2023 (MW)

MW	EXISTING		EXISTING TOTAL	COMMITTED		COMMITTED TOTAL	CANDIDATE		CANDIDATE TOTAL	GRAND TOTAL
	Hydro reservoir	Hydro ROR		Hydro reservoir	Hydro ROR		Hydro reservoir	Hydro ROR		
Angola	2 958	706	3 664	2 100	121	2 221	715	1 717	2 432	8 317
Burundi	18	50	68		87	87		288	288	443
Cameroon	958	1	960	525		525	1 927	5 742	7 669	9 154
Central African Republic		40	40					406	406	446
Republic of the Congo	74	158	232					1 461	1 461	1 693
DR Congo	1 080	1 906	2 986	160	143	303		19 369	19 369	22 658
Equatorial Guinea		127	127		200	200				327
Gabon	228	102	331		124	124		1 440	1 440	1 895
Rwanda	12	123	135	112	146	258		43	43	435
São Tomé & Príncipe		2	2		7	7		45	45	54
Grand total	**5 329**	**3 215**	**8 543**	**2 897**	**827**	**3 724**	**2 642**	**30 510**	**33 152**	**45420**

Notes: Official national documents reviewed and updated as part of the IRENA-CAPP Regional Modelling Analysis & Planning Support Programme and CMP programme. ROR = run-of-river.

Variable renewable power generation: Solar and wind

While the SPLAT-Africa model includes project-specific solar and wind supply options, this resource pool is limited in size, covering only a small portion of the extensive resource base in the region. To sufficiently cover the resource potential beyond the current project pipeline, geographic clusters of high-potential sites have been included in the model (IRENA, 2024). The clusters are based on IRENA's concept of model supply regions (MSRs), which are model-ready candidate regions with specific capacity potential, infrastructure costs and generation profiles at the country-level.

For the majority of countries in Africa, even after excluding unsuitable or protected areas, the potential of variable renewable energy (VRE) covers large portions of the country's surface area. In SPLAT-Africa, expansion of VRE technologies is limited to 5% of a country's surface area. This has been done in order to maintain sufficient potential resource options for future system expansion, while also keeping the model size reasonable. To do this, exploitable potential in a country (available as MSRs) was screened for the areas representing the 5% most attractive regions of a country's surface area.[11,12] "Most attractive" is defined as those areas where power plants would have the lowest expected levelised cost of electricity (LCOE). This LCOE has been calculated after considering the effects of resource quality (*i.e.* the level of solar irradiation and wind speed), as well as the distance from existing grid infrastructure that would lead to additional expense

[11] *Or of a country's Exclusive Economic Zone, in the case of offshore wind.*

[12] *This is the case as long as the 5% are within the range of potential deemed commercially exploitable (Sterl et al., 2022). This was the case for most countries.*

for grid and road network build-out.[13] The resulting set of geospatially referenced regions thus represents a realistic selection of the most promising locations in each country for constructing power plants, while covering possible spatial resource divergences within that country.

Significant solar PV potential is present in every country. The SPLAT-Africa model can therefore invest in solar PV clusters in any CAPP country. This is not the case for onshore wind, for which no high-quality potential MSRs were identified within the CAPP region for Burundi, Equatorial Guinea, Gabon and Rwanda.[14] There were therefore no interesting options for the SPLAT-Africa model to invest in regarding onshore clusters in these countries.

Solar CSP was taken to be able to compete economically with solar PV only if it had thermal storage included. Therefore, solar CSP with a typical amount of storage (six hours) was included in the model as technology, but solar CSP without storage was excluded. Candidate clusters for solar CSP were developed in a comparable way as for solar PV, but using normalised direct normal irradiation (DNI) as a proxy for capacity factor profiles instead of global horizontal irradiation (GHI). To reduce computational burden in the modelling, a maximum of two clusters per country were used. Due to the geographic disparity in DNI (as opposed to GHI, which is relatively uniformly distributed), not all countries boast realistically exploitable solar CSP potential. In the CAPP region, no solar CSP MSRs were identified for Rwanda, Equatorial Guinea, Gabon or the Republic of the Congo.

The development of wind production profiles used in the model is described in (Sterl *et al*., 2022). For offshore wind, three specific considerations were made. First, two types of offshore wind power plants – floating and fixed – were considered, based on seabed depth. Floating MSRs were those at an average depth of 50 meters to 800 metres (beyond which regions were excluded from consideration), while fixed plants were those in shallower MSRs. Floating wind farms have a higher level of capital expenditure (CAPEX). Second, the cost of grid connection was differentiated by the offshore portion and the onshore portion, with offshore transmission infrastructure assumed to cost more per kilometre than onshore infrastructure. Third, the area considered for offshore wind MSRs was limited to the Exclusive Economic Zone (EEZ) of any applicable country. Similarly to solar CSP, to reduce computational burden the offshore wind MSRs were grouped into two clusters for each country.[15] Based on this analysis, the set of countries with offshore wind potential in Africa was relatively limited. Indeed, among non-landlocked countries in Central Africa, clusters of offshore wind potential were only available for Angola.[16]

The figures below provide an example of the VRE potential included in the modelling as future investment options in Angola (the full set of country views can be found in the data appendix accompanying this report).

---

[13] *For all other parameters (e.g. exclusion criteria, expected losses, etc.) for solar PV and wind clusters, the reader is referred to (Sterl et al., 2022).*

[14] *Based on the various assumed exclusion criteria for any site to qualify as commercially exploitable. These criteria included a minimum threshold for resource quality of 6 metres per second (m/s) annual average wind speed at 100 metres in height.*

[15] *In clustering offshore wind MSRs, individual clusters might include both areas suitable for fixed turbines and areas suitable for floating turbines. The "majority rule" was adopted to allocate the structure type (fixed/floating) to a cluster and thus the costs.*

[16] *No MSRs were identified for the rest of the countries after assuming the various exclusion criteria. These included a minimum threshold for resource quality of 7.5 m/s annual average wind speed at 100 metres in height for any site to qualify as commercially exploitable.*

Table 2 Total solar and wind capacity potential included in CAPP countries in the SPLAT-Africa model (MW)

MW	SOLAR PV	SOLAR CSP	WIND OFFSHORE	WIND ONSHORE	TOTAL
Angola	206 252	111 758	12 562	61 435	392 006
Burundi	3 327	83			3 410
Cameroon	76 376	41 257		21 188	138 822
Central African Republic	102 748	55 197		752	158 698
Chad	208 678	112 798		186 751	508 227
Republic of the Congo	55 786			23	55 810
DR Congo	385 439	41 868		1 840	429 146
Equatorial Guinea	4 202				4 202
Gabon	43 058				43 058
Rwanda	4 054				4 054
Total	**1 089 921**	**362 961**	**12 562**	**271 990**	**1 737 433**

Source: (IRENA, 2024).

Figure 9 Country-level detail on technical VRE potential (MW) in the SPLAT-Africa model: Example of Angola

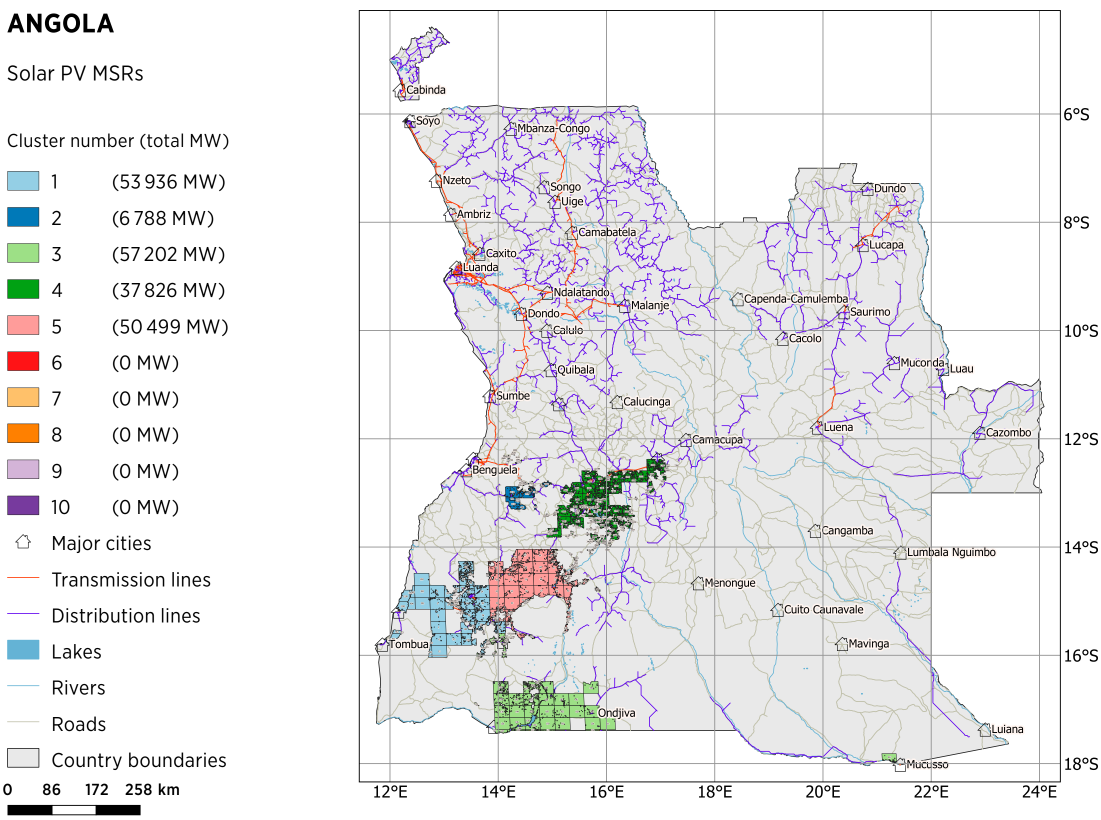
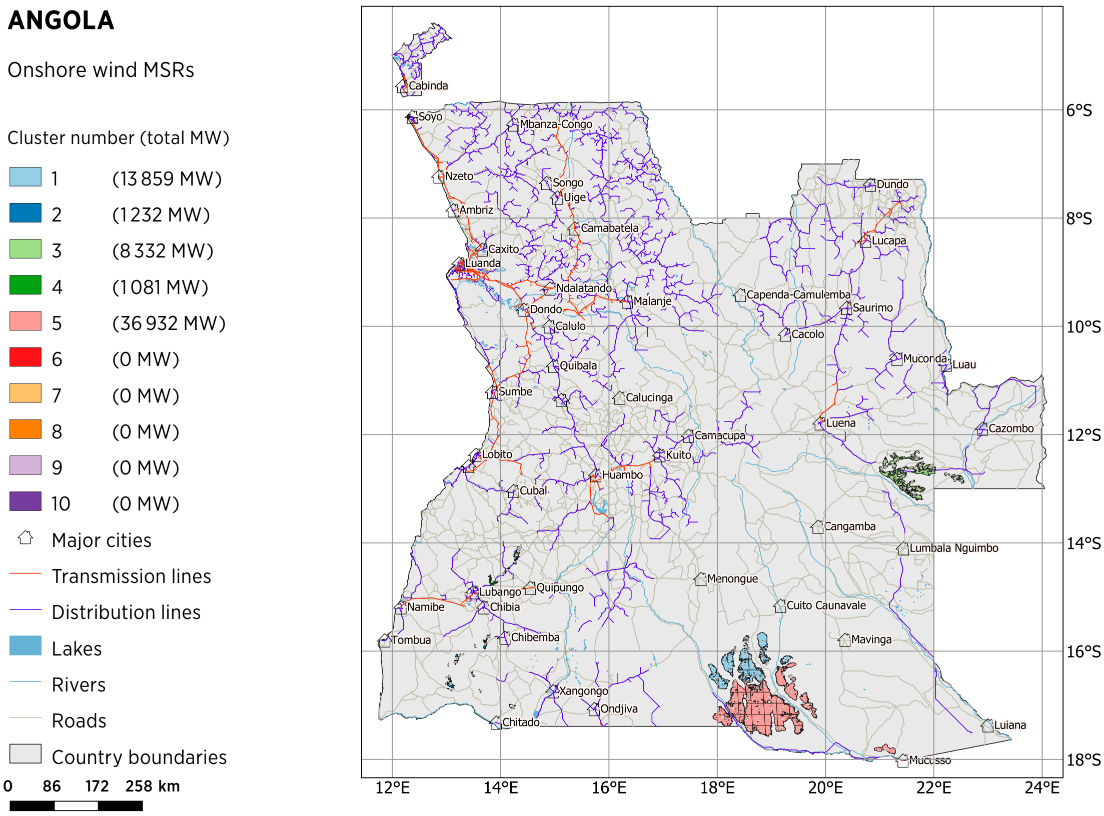


Figure 9 Continued



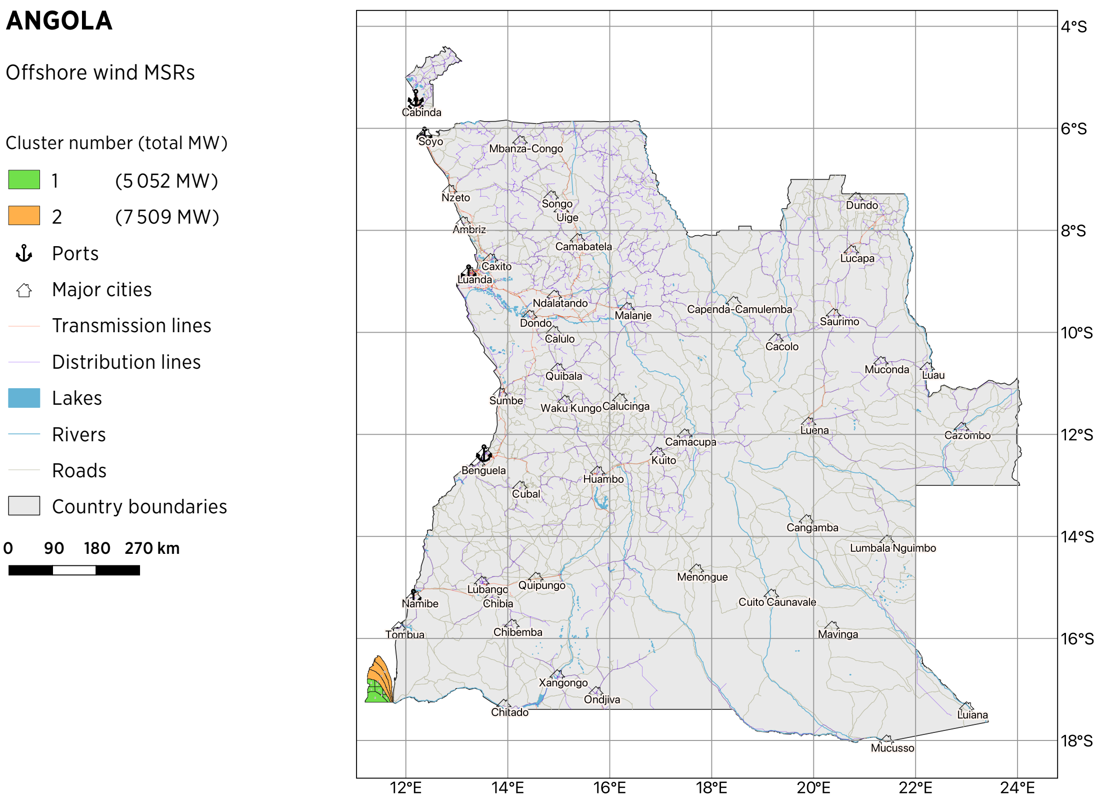
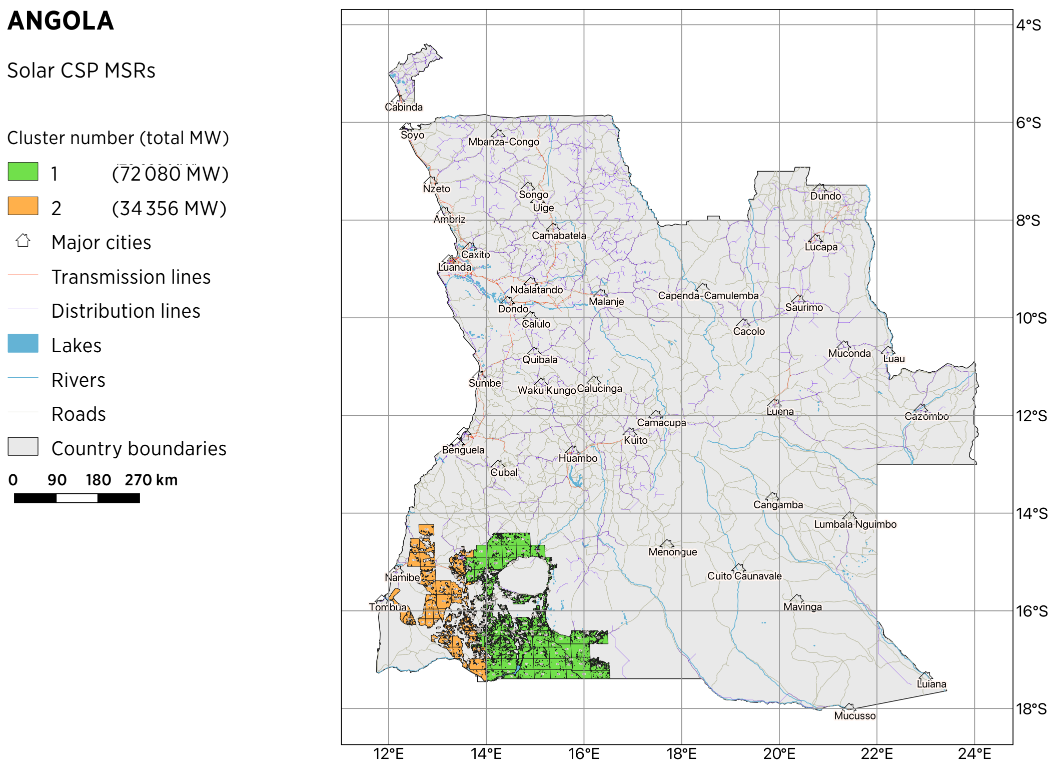


Figure 9 Continued



Disclaimer: These maps are provided for illustration purposes only. Boundaries and names shown on these maps do not imply the expression of any opinion on the part of IRENA concerning the status of any region, country, territory, city or area or of its authorities, or concerning the delimitation of frontiers or boundaries.

3 THERE IS A MAJOR AMBITION TO DEVELOP CROSS-BORDER TRADE BEYOND ITS CURRENT LIMITED SCOPE

The information used here regarding existing cross-border transmission infrastructure and planned projects is based on official national and regional planning documents collected and reviewed by CAPP members as part of the IRENA and CMP capacity building programmes. The capacities and first years of possible construction of all regional interconnectors for CAPP are summarised in Table 4, with further details and cost parameters for all continental options in the data appendix accompanying this report.

As of 2023, existing cross-border transmission capacity within the CAPP region was mainly limited to infrastructure between DR Congo, Rwanda and Burundi (around 515 MW of the total 601 MW of intra-CAPP capacity). At that time, however, greater capacity had been installed between the CAPP countries and bordering countries and regions. Just over 1 GW of cross-border infrastructure existed connecting DR Congo, Rwanda and Angola to the Eastern African Power Pool (EAPP) and Southern African Power Pool (SAPP) countries.

Committed and candidate projects reflect a strong ambition to change this picture, however, by developing more comprehensive cross-border transmission infrastructure within CAPP, along with more export capacity to other regions. As the table below shows, committed projects would represent a three-fold increase in the current transmission capacity to other regions, and a seven-fold increase in intra-CAPP transmission capacity (all planned before 2030). If all candidate projects were also developed, this would represent a more than ten-fold increase in current transmission capacity to other regions, and a twenty-fold increase in intra-CAPP transmission capacity.

Table 3 Existing, committed and candidate cross-border transmission infrastructure (MW)

	INTRA-CAPP	EXTRA-CAPP
Existing	601	1 022
Committed	3 646	2 114
Candidate	7 793	8 778

Given the importance of this infrastructure development in the region, this study explores two possible cross-border trade conditions: "Reference" and "Full Continental". It also explores the impact of interconnector project delays. Under Reference scenario conditions, trade between countries is limited by existing infrastructure and planned cross-border transmission projects. Any hypothetical projects that are not currently identified are only included under Full Continental scenario conditions. In interconnector delay scenarios, the delays implemented are as follows: a four-year delay for any project planned for 2024; a three-year delay for any project planned for between 2025 and 2030; and a two-year delay for any project planned between 2030 and 2040. This assumes a gradual improvement in mitigating delays as experience in the construction of cross-border transmission infrastructure improves. This was deemed more reasonable than a standard delay over the course of the modelling period.

Importantly, cross-border interconnections with all other regions have also been considered in the modelling exercise. Although the focus of this report and analysis is on the Central African region, the SPLAT-Africa model allows all countries to be included in the modelling simultaneously. It is especially important to have a more realistic picture of any imports or exports that may be taking place from and to the Central African region's neighbours, given its central location on the continent, both geographically and in terms of renewable energy resources.

Table 4 Site-specific cross-border transmission infrastructure summary

COUNTRY 1	COUNTRY 2	DESCRIPTION	STATUS	INSTALLATION/ FIRST YEAR	TOTAL CAPACITY (MW)
Angola	Namibia	Existing Angola-Namibia (LT 132 kV Ondjiva (Angola) – Efunja (Namibia))	Existing	2012	10
Angola	DR Congo	Committed Angola-DR Congo (220 kV Maquela do Zombo-Kuilo)	Committed	2026	318
Angola	Republic of the Congo	Committed Angola-Republic of the Congo-DR Congo 400 kV (Inga-Cabinda-Pointe Noire)	Committed	2028	1 514
Angola	Namibia	Committed Angola-Namibia (LT 400 kV Cahama (Angola)-Kunene (Namibia))	Committed	2027	1 514
Angola	DR Congo	Candidate Inga N`Zeto Phase 1 DR Congo-Angola (Matadi-Nzeto) 400 AC	Candidate	2030	1 663
Burundi	Rwanda	Burundi-Rwanda 110 kV	Existing	1987	12
Burundi	Rwanda	Committed Burundi-Rwanda (Gitega-Gisagara) 220 kV	Committed	2025	100

Table 4 Continued

COUNTRY 1	COUNTRY 2	DESCRIPTION	STATUS	INSTALLATION/ FIRST YEAR	TOTAL CAPACITY (MW)
Burundi	Rwanda	Candidate Burundi-Rwanda (Gitega-Kigoma) 220 kV	Candidate	2023	184
Burundi	DR Congo	Candidate DR Congo-Burundi 400 AC	Candidate	2022	748
Burundi	Rwanda	Candidate Rwanda-Burundi (Ruzuzi-Bujumbura) 220 AC	Candidate	2029	610
Cameroon	Chad	Committed Cameroon-Chad 220 kV (Maroua-Ndjamena)	Committed	2025	200
Cameroon	Central African Republic	Candidate Cameroon-Central African Republic 220 kV (Dimoli)	Candidate	2035	185
Cameroon	Chad	Candidate Cameroon-Chad 400 kV	Candidate	2030	1 900
Cameroon	Gabon	Candidate Cameroon-Gabon (Memve'ele-Bata-Ntoum)	Candidate	2030	210
Cameroon	Nigeria	Candidate WAPP (Nigeria)-CAPP (Inga-Cameroun)	Candidate	2033	814
Central African Republic	DR Congo	Bangui-Zongo	Existing	2021	5
Republic of the Congo	Central African Republic	Candidate Congo-Central African Republic 220 kV (Dimoli)	Candidate	2027	185
Republic of the Congo	Gabon	Candidate Congo-Gabon 400 kV (Grand Poubara)	Candidate	2024	400
DR Congo	Burundi	DR Congo-Burundi 70 kV	Existing	2010	65
DR Congo	Republic of the Congo	DR Congo-Republic of the Congo 200 kV (Inga-Brazzaville)	Existing	2010	80
DR Congo	Rwanda	DRC-Rwanda (Goma-Rubavu) 220 kV	Existing	2023	400
DR Congo	Rwanda	DRC-Rwanda 30 kV	Existing	2010	39
DR Congo	Uganda	DRC-Uganda (Beni- Nkenda)	Existing	2023	26
DR Congo	Zambia	DRC-Zambia (3 x Lumumbashi-Luano 220 AC)	Existing	2010	230
DR Congo	Central African Republic	Mobayi-Mobaye	Existing	2003	1
DR Congo	Angola	Committed DRC-Angola-Republic of the Congo 400 kV (Inga-Cabinda-Pointe Noire) 400 kV	Committed	2026	1 514
DR Congo	Nigeria	Candidate DR Congo-South Africa Grand Inga HVDC Phase 1 (Inga-Calabar) 600 HVDC	Candidate	2030	1 030

Table 4 Continued

COUNTRY 1	COUNTRY 2	DESCRIPTION	STATUS	INSTALLATION/ FIRST YEAR	TOTAL CAPACITY (MW)
DR Congo	South Africa	Candidate DR Congo-South Africa Grand Inga HVDC Phase 1 (Inga-Merensky) 600 HVDC	Candidate	2030	1 130
DR Congo	Egypt	Candidate DR Congo-South Africa Grand Inga HVDC Phase 1 (Inga-Region Caire) 600 HVDC	Candidate	2030	2 514
DR Congo	Zambia	Candidate DR Congo-Zambia (Matadi/Kolwezi-Lumwana/Solwezi) 500 DC	Candidate	2031	2 000
Equatorial Guinea	Cameroon	Candidate Cameroon-Equatorial Guinea (Memve'ele-Bata-Ntoum)	Candidate	2030	210
Gabon	Equatorial Guinea	Candidate Gabon-Equatorial Guinea (Memve'ele-Bata-Ntoum)	Candidate	2030	210
Gabon	Equatorial Guinea	Candidate Gabon-Equatorial Guinea (Mongomo-Oyem)	Candidate	2029	300
Namibia	Angola	Committed [ANNA] Namibia-Angola (Omatando-Xangongo/ Baynes-Cahama) 400 AC/400 AC	Committed	2025	600
Rwanda	Uganda	Existing Rwanda-Uganda (Birembo-Mirama) 220 kV	Existing	2019	300
Rwanda	United Republic of Tanzania	Rwanda-Tanzania (Rilima-Rusumo) 220 kV	Existing	2023	43
Rwanda	Uganda	Rwanda-Uganda (Shango-Mirama) 220 kV	Existing	2019	50
Rwanda	DR Congo	Candidate DR Congo-Rwanda (Kamanyola-Rusizi) 220 kV	Candidate	2029	600
Rwanda	DR Congo	Candidate DR Congo-Rwanda (Poids-Bukari) 220 AC	Candidate	2030	388
United Republic of Tanzania	Rwanda	Candidate Rwanda-Tanzania (Gasogi-Rusumo) 220 AC	Candidate	2022	181
United Republic of Tanzania	Burundi	Candidate Tanzania-Burundi (Kigoma-Musimba) 400 AC	Candidate	2022	1 109

Notes: Official national documents reviewed and updated as part of the IRENA-CAPP Regional Modelling Analysis & Planning Support Programme and CMP programme. Capacity values are meant to reflect total installed capacity and therefore may not reflect differences in effective capacity due to operational issues. LT = low tension, kV = kilovolt, AC = alternating current, HVDC = high voltage direct current, DC = direct current.

3.1 GENERAL DEFINITION OF SCENARIOS

The table below shows the main scenarios developed for this report. These were based on the work and feedback from all the participants in the IRENA-CAPP Regional Africa Modelling Analysis & Planning Support Programme. Six scenarios were explored under the two conditions regarding cross-border interconnection outlined above – "Reference" and "Full Continental" – giving a total of 12 scenarios.

The basic Reference scenario reflects power system development in the absence of any major constraints, based on the detailed capacity statistics and assumptions outlined previously in this chapter. In this scenario, cost-competitiveness acts as the key driver for the deployment of technologies. In terms of technology costs, the scenario reflects reductions in renewable energy costs consistent with global observations and trends. Alternate scenarios are based on key priority areas identified by regional stakeholders for exploration, as discussed in previous sections of this chapter. These include more ambitious demand projections, major project delays, hydropower availability and interconnector development.

Table 5 Capacity expansion scenarios

	NAME	
1	Reference	Reference demand projections from the modelling performed in the CMP programme.[17] All committed and planned projects considered.
2	RefHydroDelay	Reference scenario with all candidate hydro projects larger than 1 GW delayed by 5 years.[18]
3	RefHydroDry	Reference scenario with all hydro production subject to dry year assumptions.
4	RefInterconDelay	Reference scenario with all candidate interconnectors delayed.[19]
5	RefHighDem	Reference scenario with high demand projections from the modelling performed in the CMP programme.
6	RefDelayDryHigh	Reference scenario with a combination of all constraints imposed in the previous four alternate scenarios (numbers 2 to 5).
7	FullContinental	Reference scenario with all physically possible interconnectors allowed, as of 2030.
8	FullConHydroDelay	RefHydroDelay scenario with all physically possible interconnectors allowed, as of 2030.
9	FullConHydroDry	RefHydroDry scenario with all physically possible interconnectors allowed, as of 2030.
10	FullConInterconDelay	RefInterconDelay scenario with all physically possible interconnectors allowed, as of 2030.
11	FullConHighDem	RefHighDem scenario with all physically possible interconnectors allowed, as of 2030.
12	FullConDelayDryHigh	RefDelayDryHigh scenario with all physically possible interconnectors allowed, as of 2030.

[17] *For more detail on any demand related assumptions see point 1 above in this chapter on electricity demand.*

[18] *For more detail on any hydropower related assumptions see point 2 above in this chapter on electricity generation options.*

[19] *For more detail, see point 3 above in this chapter on cross-border trade.*

MODELLING RESULTS

4

4.1 CAPACITY AND GENERATION

Figure 10 and Figure 11 below show the high-level capacity results obtained across all scenarios in the modelling, as well as the difference between the Reference and alternative scenarios in those results. General insights from these results are discussed below, with **more specific and country-level insights related to hydropower, solar, wind, batteries, fossil fuels and cross-border trade in the sections that follow**.

In all scenarios with reference demand projections, renewable sources – hydropower and solar PV, plus (in certain countries) onshore wind – meet the vast majority of projected demand until 2040 at the regional level. This is also the case for scenarios with larger exports to other regions (the Full Continental scenarios). Only in the scenarios where demand becomes much higher, around two times the reference demand, do we see new fossil fuel infrastructure being built in significant capacities in the results.

Overall, even though the type of capacity mix is broadly similar across scenarios, it is clear that the total capacity required to be built in the region is quite sensitive to different future conditions. All scenarios need to at least double today's regional capacity by 2040 to meet projected demand. In the scenarios with the lowest overall capacity needs (Reference scenarios with interconnector or hydropower delays), total capacity grows from around 12 GW currently to around 30 GW in 2040. In all but one scenario where all physically possible interconnections are allowed in the model after 2030 (the Full Continental scenarios), total capacity in the region grows to over 40 GW. In the scenario with the highest overall capacity in the region – the Full Continental scenario with high demand and no challenging conditions (FullConHighDem) – nearly 65 GW of capacity is built by 2040. This is more than two times the capacity required in the basic Reference scenario, and would imply a 500% increase from today's capacity in the region.

Figure 10 Capacity results in all scenarios

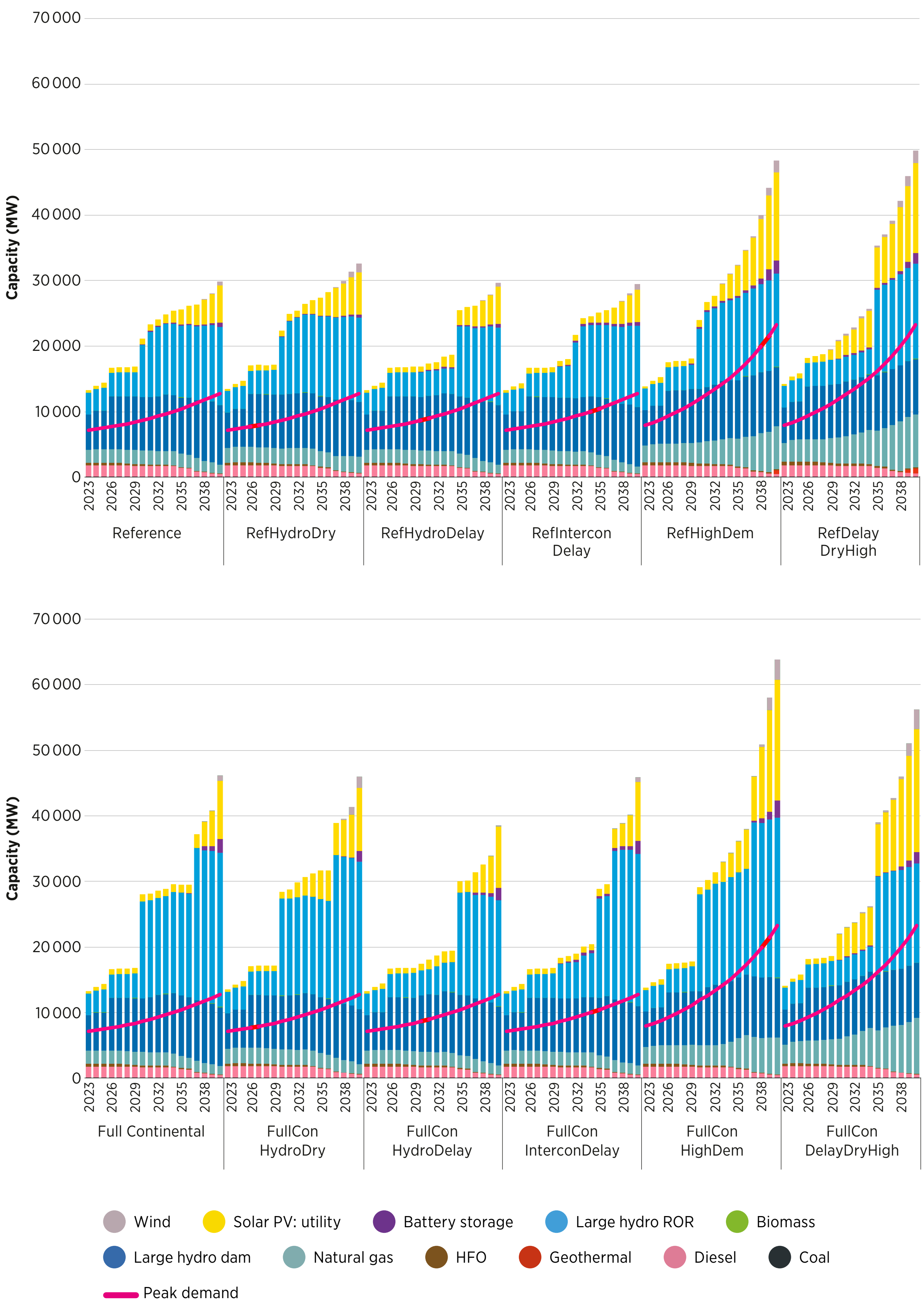


Figure 11 Difference in capacity results relative to Reference and Full Continental scenarios

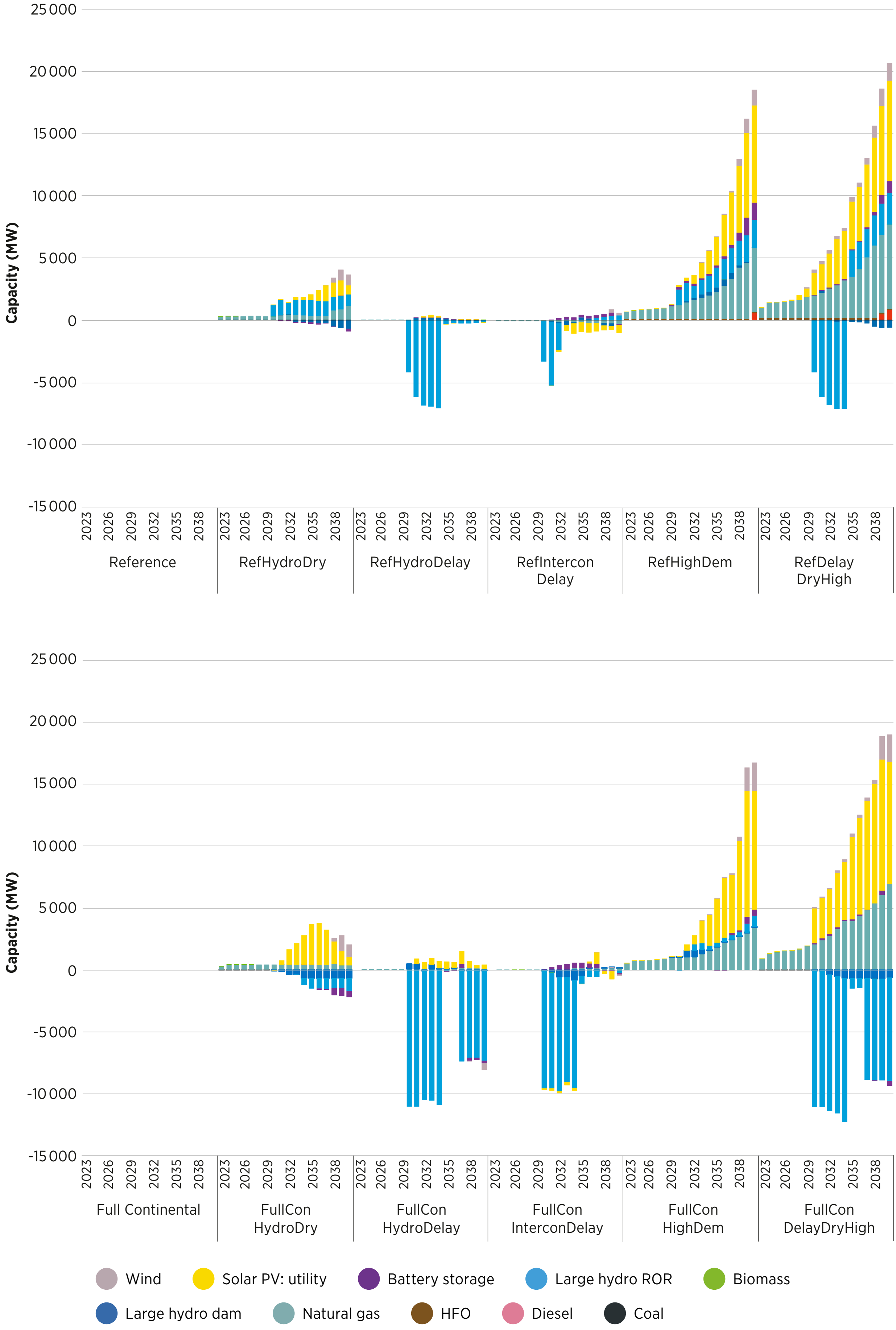


Figure 12 and Figure 13 show production results across all scenarios, as well as the difference between the Reference and alternative scenarios in those results. As shown in Figure 12 below, in all scenarios, the CAPP region exports to other regions, making use of its low-cost renewable resources and hydropower in particular. The amount the region exports by 2040 is largely the same across all reference scenarios that do not allow for generic interconnection options. This is the case even in the scenario with the most challenging export conditions, which include delays to interconnector projects and large hydropower projects, dry year conditions, and high demand across the continent.

In scenarios in which the construction of new interconnector capacity beyond the current project pipeline is allowed, however, we see nearly double the amount of exports to other regions. By 2040, the amount exported rises from around 60 gigawatt hours (GWh) in Reference scenarios to around 140 GWh, except in the scenario with the most challenging export conditions (FullConDelayDryHigh). Before 2040, the other major difference across scenarios is due to delays in large hydropower projects and interconnectors, which both contribute to reduced exports in the 2030s, relative to scenarios without delays.

Figure 12 Production results in all scenarios

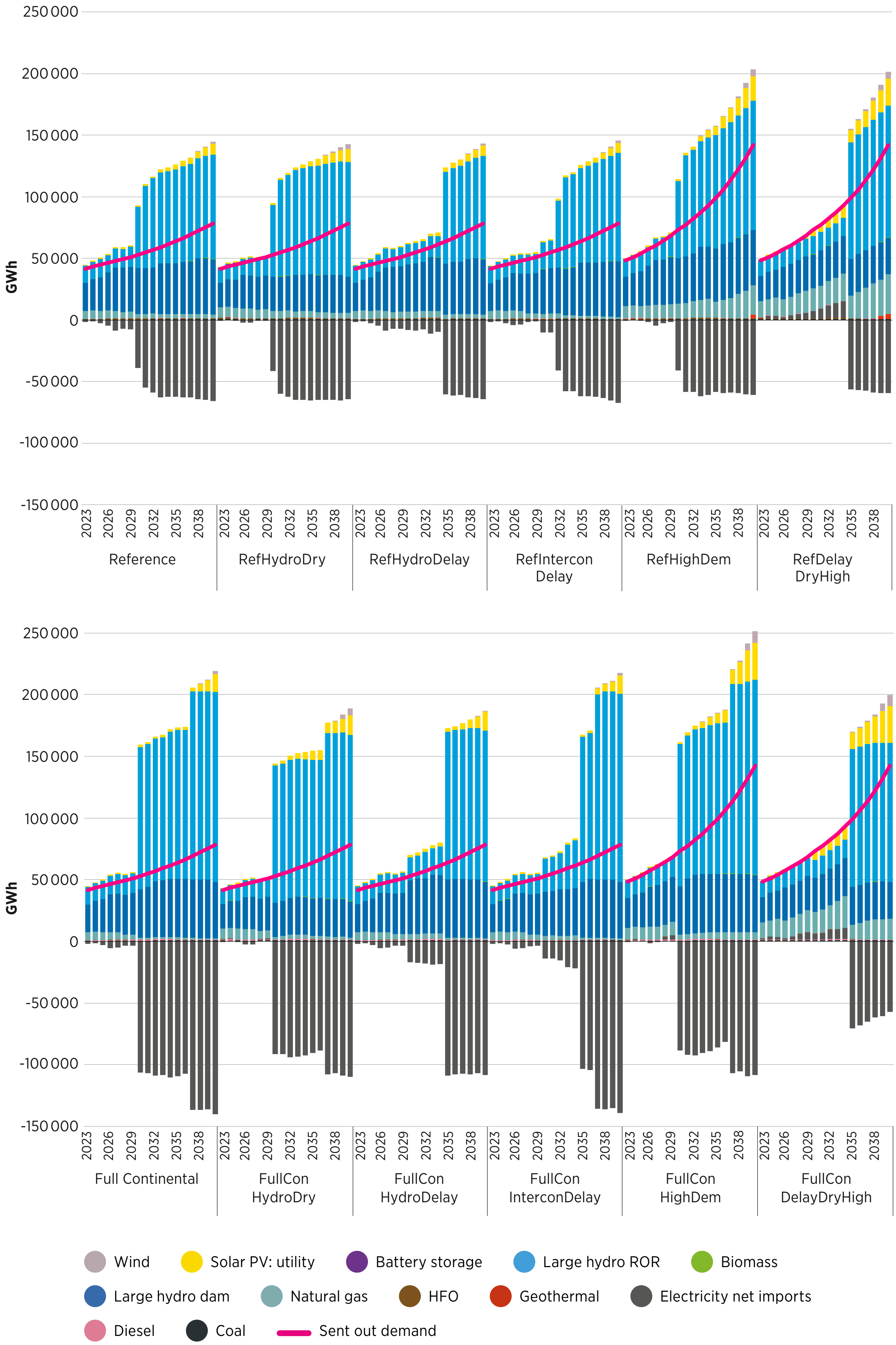
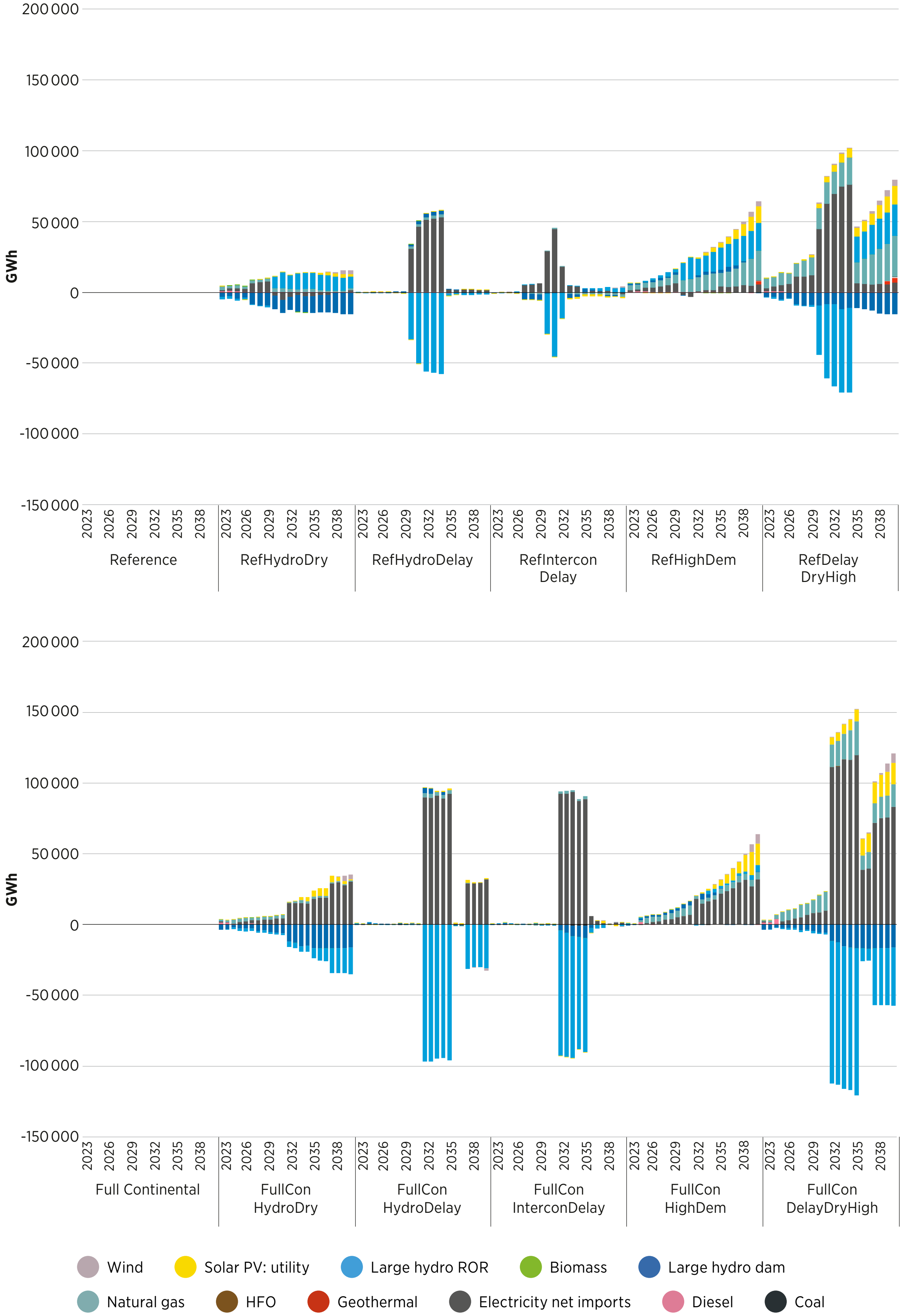


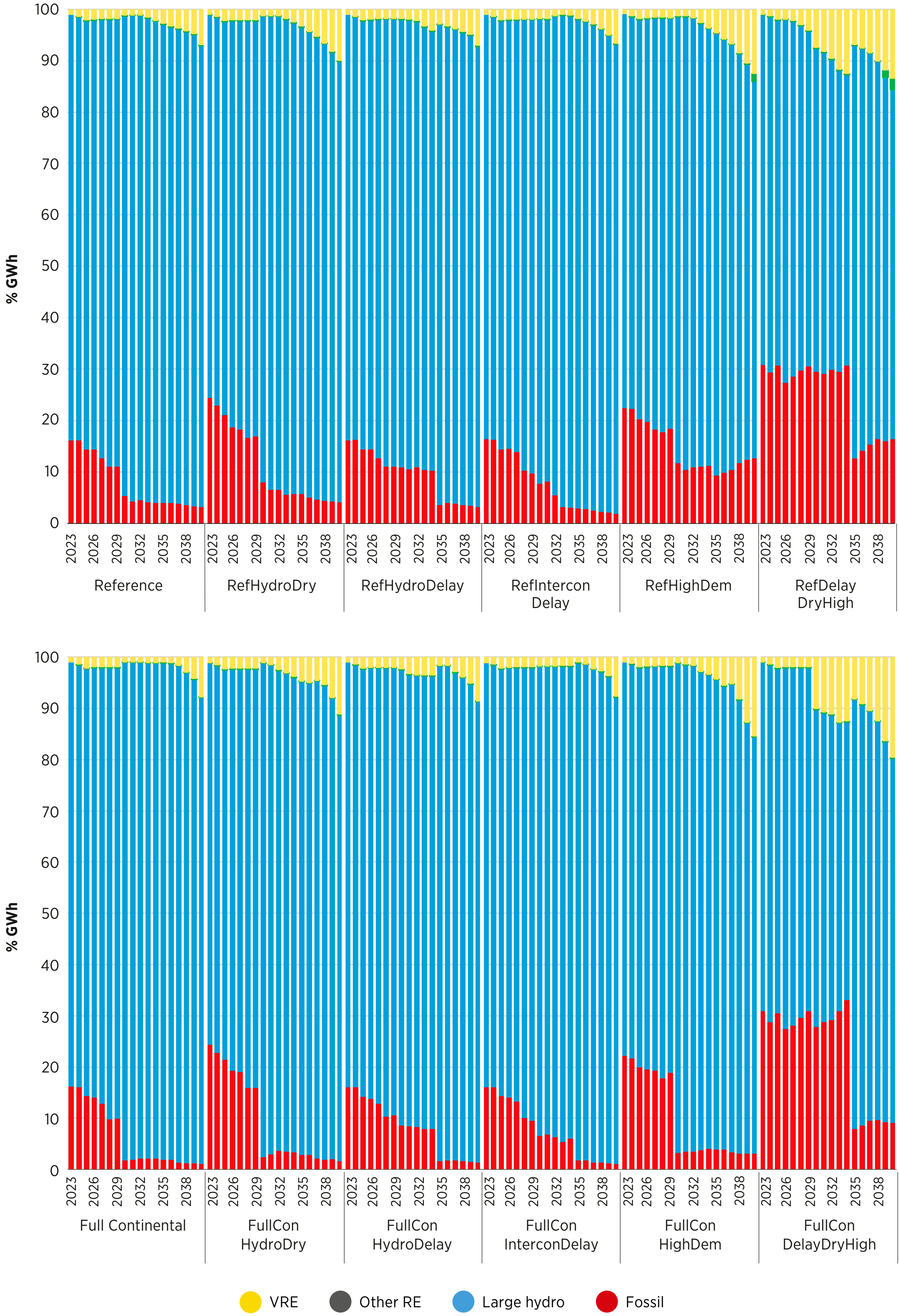
Figure 13 Difference in production results relative to Reference and Full Continental scenarios



In terms of production share, Figure 14 shows that the share of fossil fuels in electricity production falls from today's already low level to below 5% of production by 2040 in the majority of scenarios.

In all reference demand scenarios, the share of hydropower in production grows from its current level, supplying at least 80% of the electricity in the region over the modelling horizon. This is the case even in scenarios with delays to large hydropower and dry year conditions. The share of solar and wind goes from nearly zero to at least 7% of regional production by 2040 in all scenarios. In scenarios with high demand, solar and wind reach 13%-20% of production by 2040, with the highest values in the scenarios with challenging hydropower conditions (delays and dry years) and strong exports to other regions.

Figure 14 Production share across scenarios



Note: RE = renewable energy.

Figure 15 and Figure 16 display the country-level results for capacity and generation mix in 2040. In many countries, the results show a strong presence of both hydropower and solar PV. Across all scenarios, these two sources making up more than 75% of the capacity mix for Angola, Burundi, the Central African Republic, DR Congo and Rwanda. Onshore wind appears across all but one scenario where there is good potential in Cameroon and Chad, particularly in high-demand cases in Chad. While natural gas and diesel capacities still make up between 20% and 50% of the mix in most scenarios for Chad, Republic of the Congo, Equatorial Guinea and Gabon, they constitute a much smaller share of production in those countries by 2040, as they are used more to meet model reserve margin requirements (along with more battery capacity) in those countries. This is especially the case in the Full Continental interconnection scenarios with a greater amount of cross-border trade. More detail on the country-specific trade results is discussed in Section 4.3 below, *Cross-border electricity trade*.

Figure 15 Country-level breakdown of the power capacity mix by 2040, by scenario

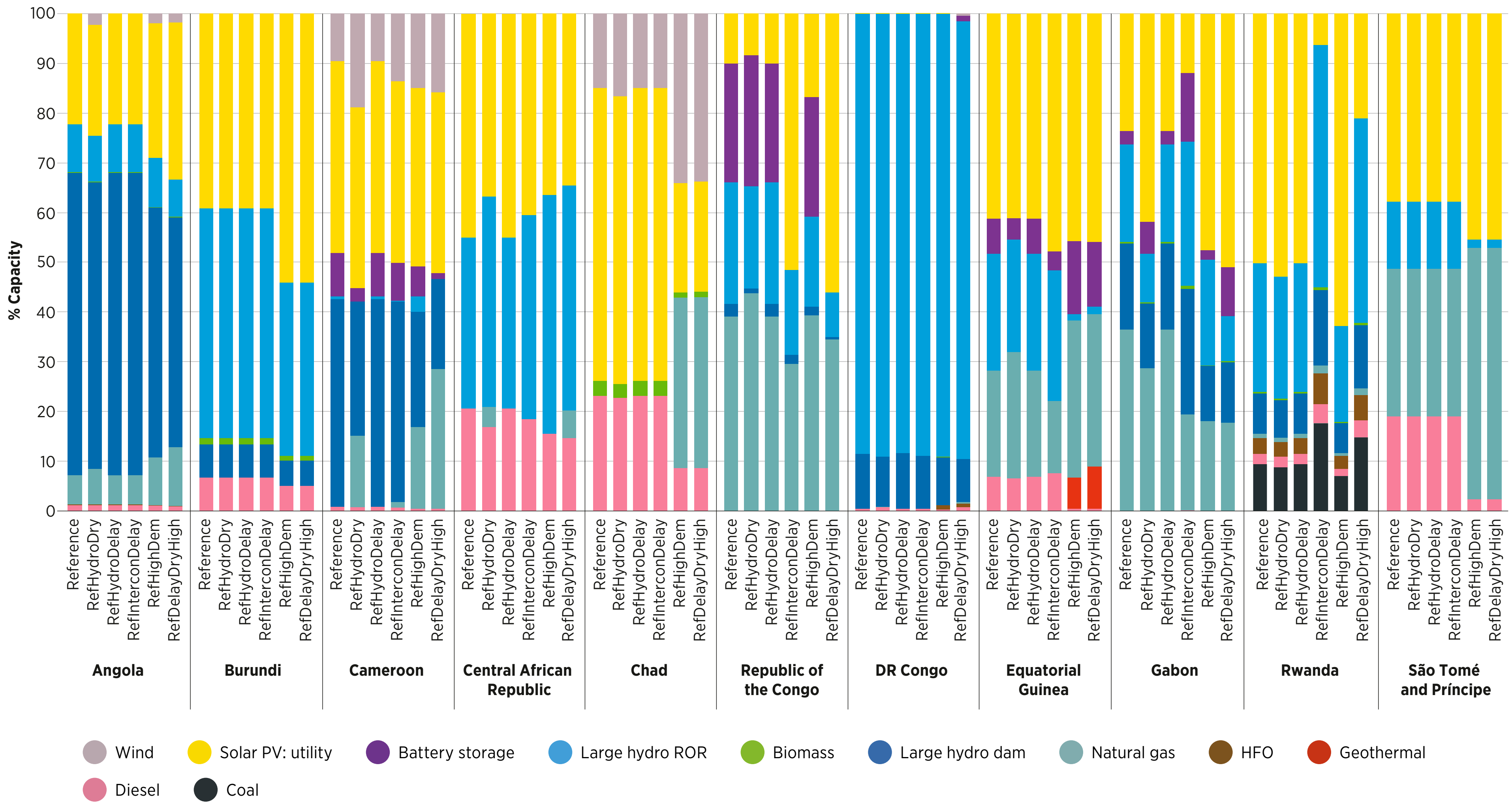


Figure 15 Continued

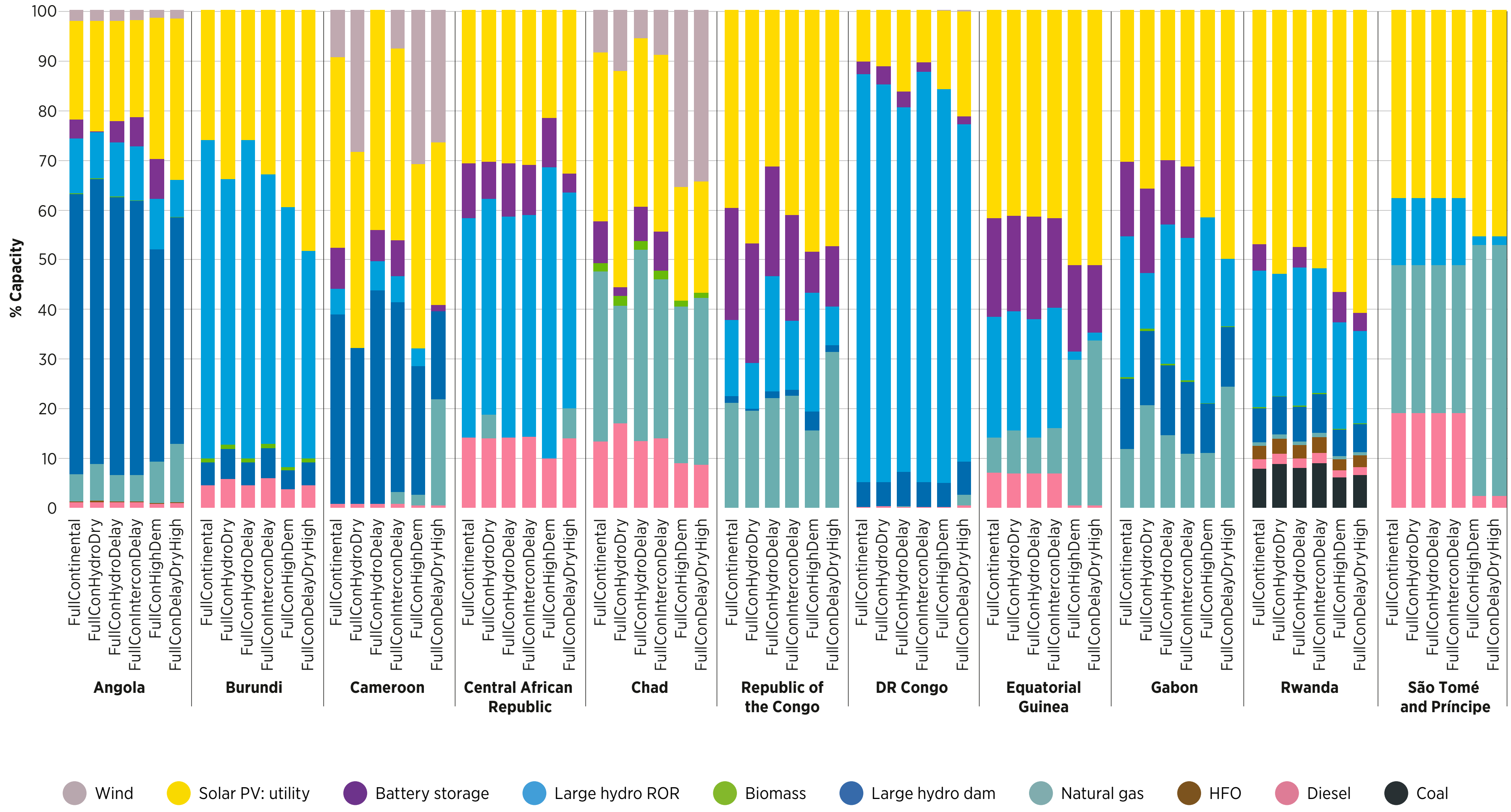


Figure 16 Country-level breakdown of the power generation mix by 2040, by scenario

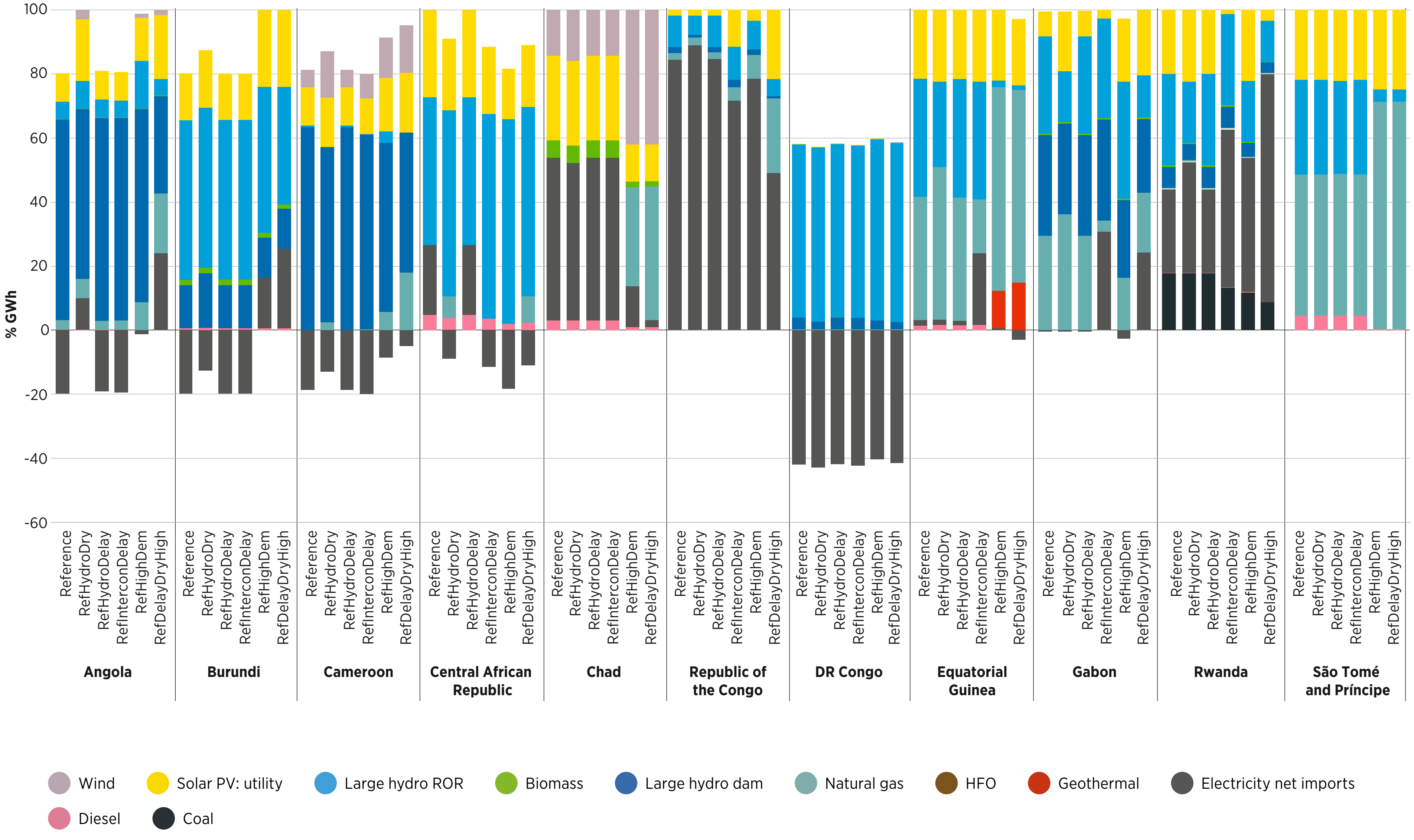
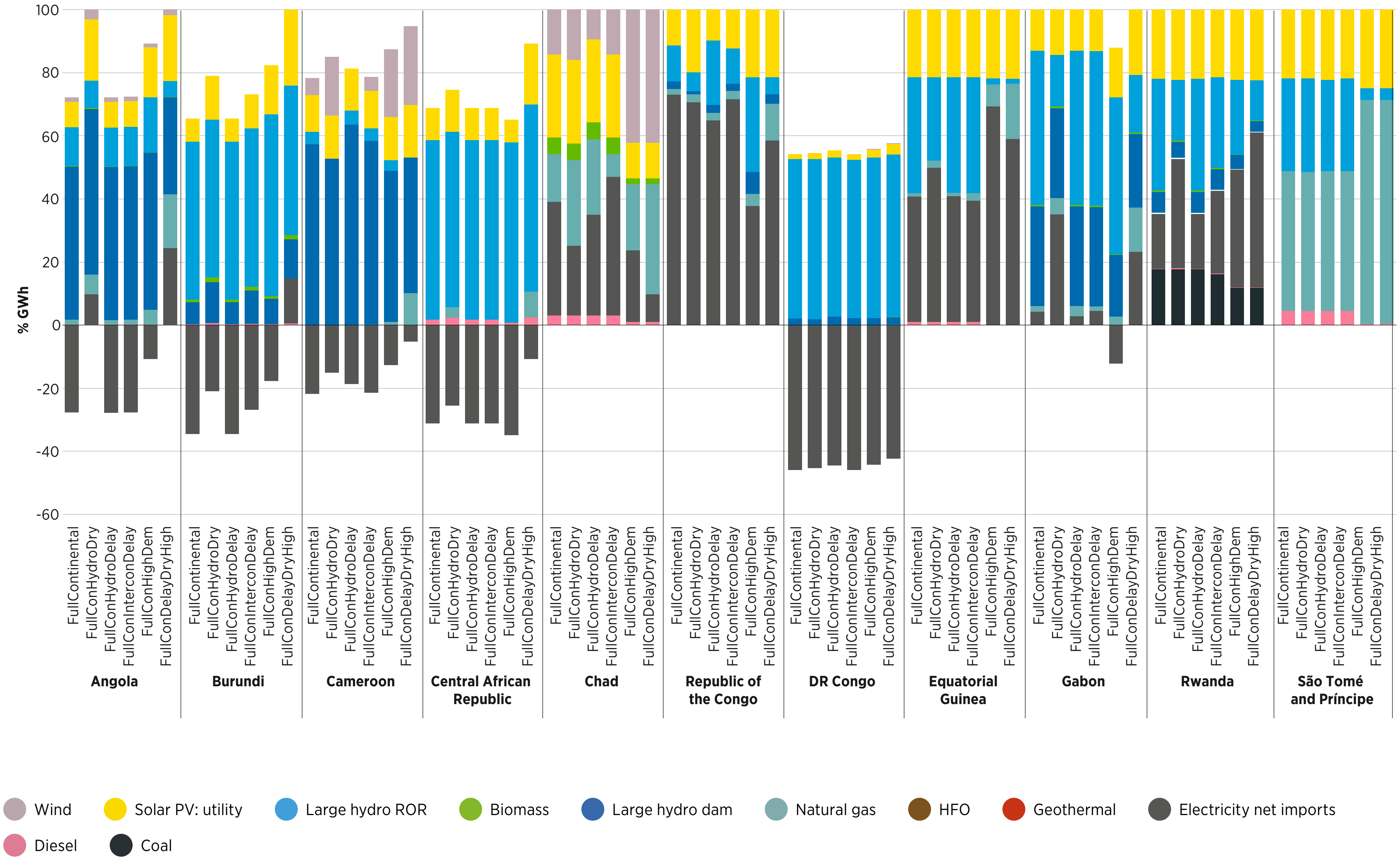


Figure 16 Continued



Hydropower

Hydropower accounts for over 80% of production across all reference demand scenarios and over 65% of production in high demand scenarios. It is therefore important to understand the potential development of this resource in the CAPP region and its impacts on the regional system. This section discusses key insights regarding hydropower evident in this report's results.

Figure 17 and Figure 18 present the hydropower capacity results across all scenarios, as well as the differences between scenarios relative to the Reference and Full Continental scenarios. Even in the scenario with the lowest hydropower buildout (the Reference scenario with hydro delays), current hydropower capacity in the region more than doubles, growing from around 8 GW to just over 20 GW by 2040. There is no major difference in the range of hydropower capacity built by 2040 in all scenarios with reference interconnector conditions – *i.e.* only interconnector projects in the current pipeline. Although capacity is lower in the mid-2030s in scenarios with delays to hydropower plants and interconnectors, the model still gives a result of at least 20 GW in those conditions. This implies that this capacity is worthwhile across a range of future conditions, if the interconnectors that are in the pipeline can be built.

Dry year conditions and project delays to interconnectors also have an effect on the amount and timing of hydropower built across the model horizon. This is the case in both the Reference and Full Continental interconnection conditions. In terms of lower final hydropower capacity values in 2040, only hydropower project delay scenarios reduce capacity substantially in comparison with the Reference scenario. In scenarios with those conditions, other regions build their own additional capacity to fill the gap left by fewer hydropower exports from CAPP in the 2030s. Between 7 GW and 8 GW less hydropower is developed in CAPP by 2040 as a result. The shortfall is mainly from the Grand Inga project, for which further details are provided below.

Figure 17 Hydropower capacity in all scenarios

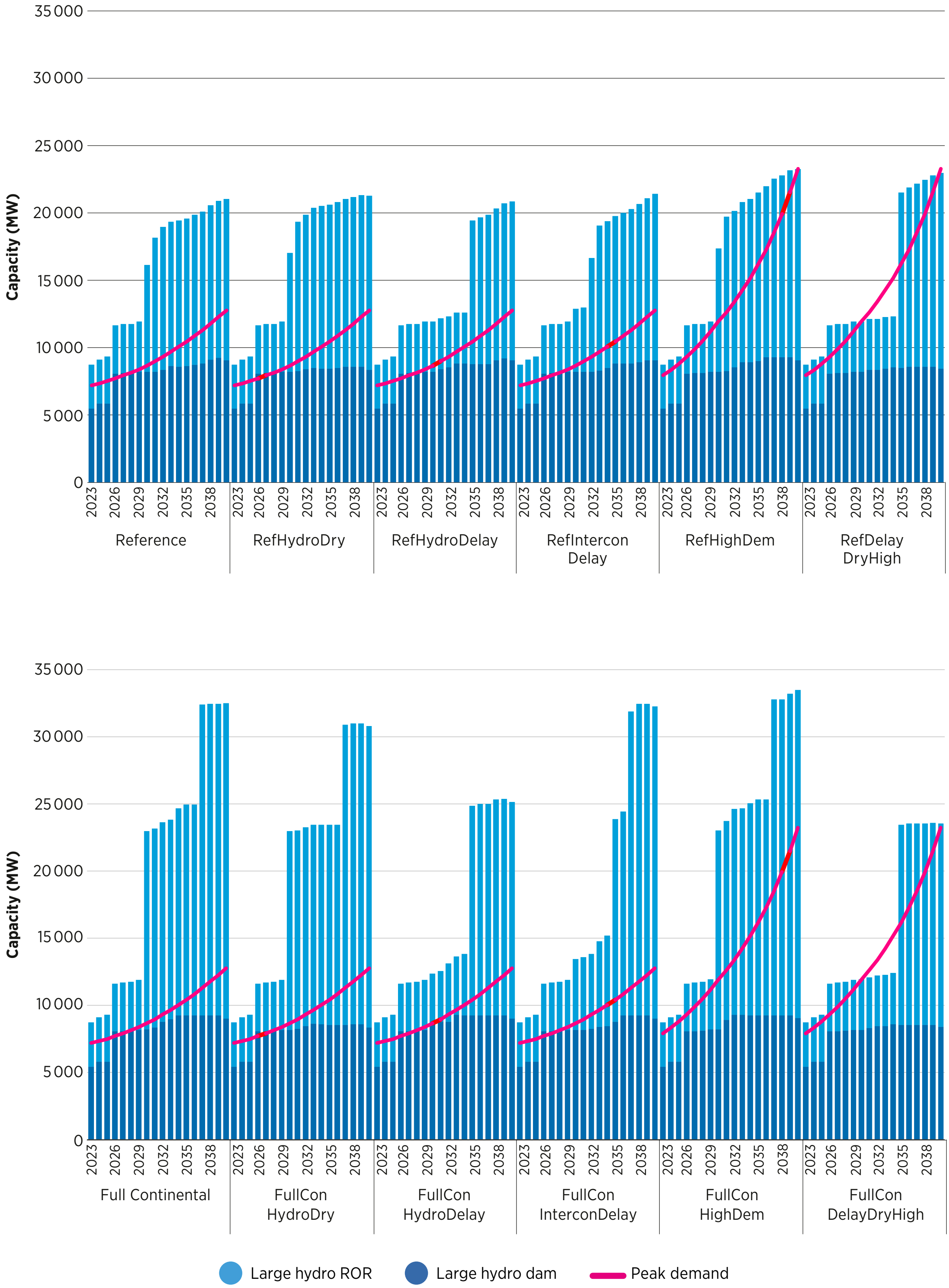
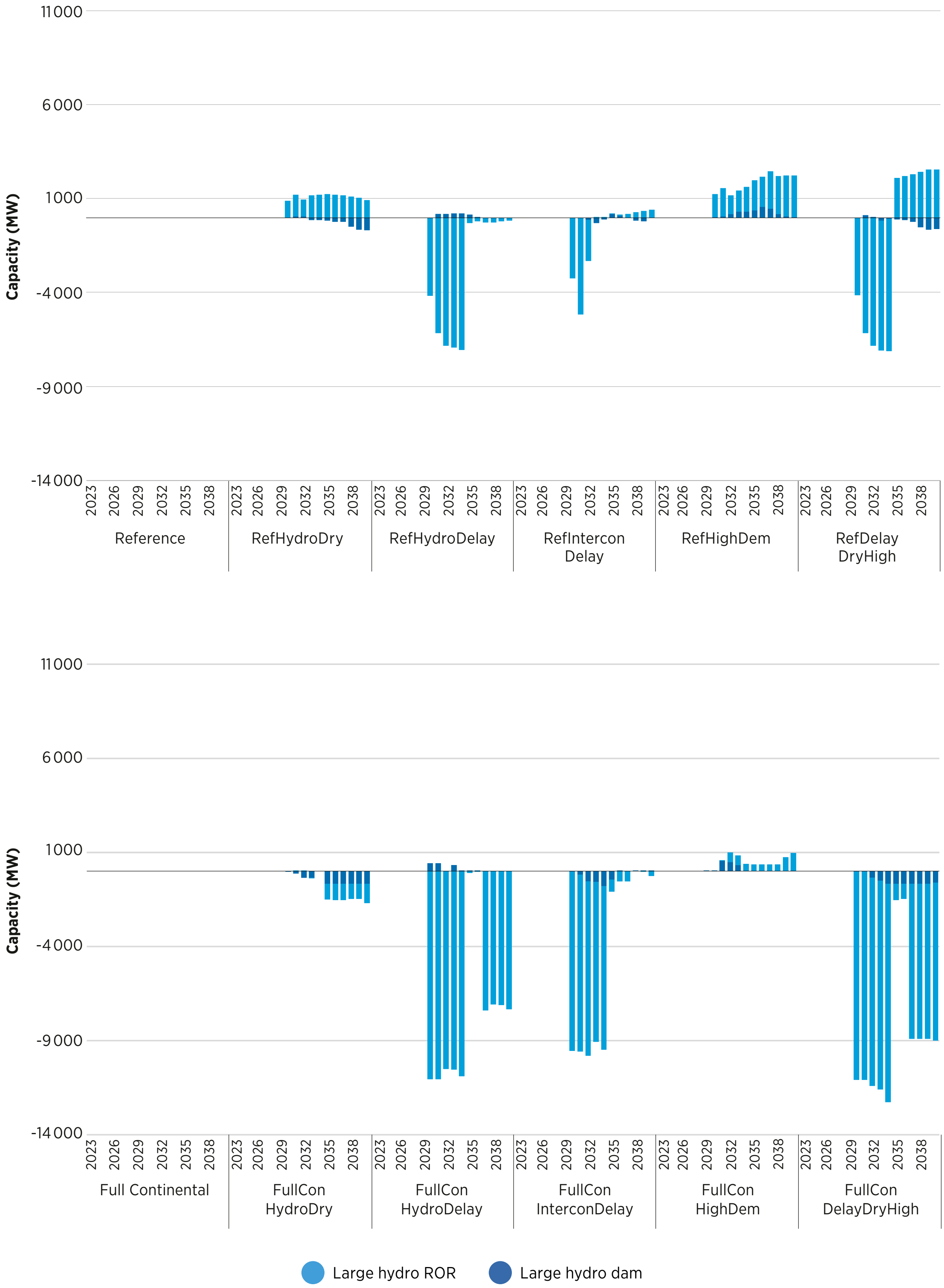


Figure 18 Difference in hydropower capacity results relative to Reference and Full Continental scenarios



The single largest driver of the regional-level results described above is the development of the Grand Inga hydropower project in DR Congo. As shown in Figure 19, this project is chosen for development in every scenario, while for a view of the impact on results without Grand Inga see Box 4: *Grand Inga: Implications on model results*.

In the scenario with the lowest amount of Grand Inga development – the Reference scenario with five-year hydro delays – 7.8 GW of additional capacity is added between 2035 and 2040. In scenarios with the highest amount of development – four scenarios from the Full Continental interconnection conditions – all 11 GW of the third phase of Inga is built by 2030, while 7.4 GW of the fourth phase is built by 2037. This gives a total of over 20 GW of Inga capacity.

Hydropower production from this build-out alone is enough to meet the region's total demand beyond 2030 in non-delay scenarios. A substantial driver of hydropower capacity build out, however (and especially Grand Inga buildout) is for export to other regions. This can be seen in the mirrored patterns of hydropower production and net exports in the results in Figure 20, as well as in the much higher capacity in scenario results where the model allows interconnections beyond the current project pipeline. The main destination for these exports is southern and western Africa, as discussed in more detail in Section 4.3, *Cross-border electricity trade*. The Full Continental scenario with high demand sees the most hydropower capacity development, with capacity quadrupling to over 33 GW (10 GW more than the Reference scenario).

In all scenarios the overall composition of hydropower shifts to ROR hydropower over the time horizon as more ROR capacity is built, particularly since the expansion phases of Grand Inga are included in the model as ROR. By 2040, in all the scenarios, ROR hydropower accounts for at least 55% of hydropower production, rising to 73% in the Full Continental scenario with dry hydro conditions. It should also be noted that to some extent, complementarity between production profiles and types of hydropower projects across different countries in the region also drives the construction of plants, as well as cross-border interconnection (see Box 3: *SPLAT-Africa dispatch results* for more detail).

Figure 19 Grand Inga development across all scenarios

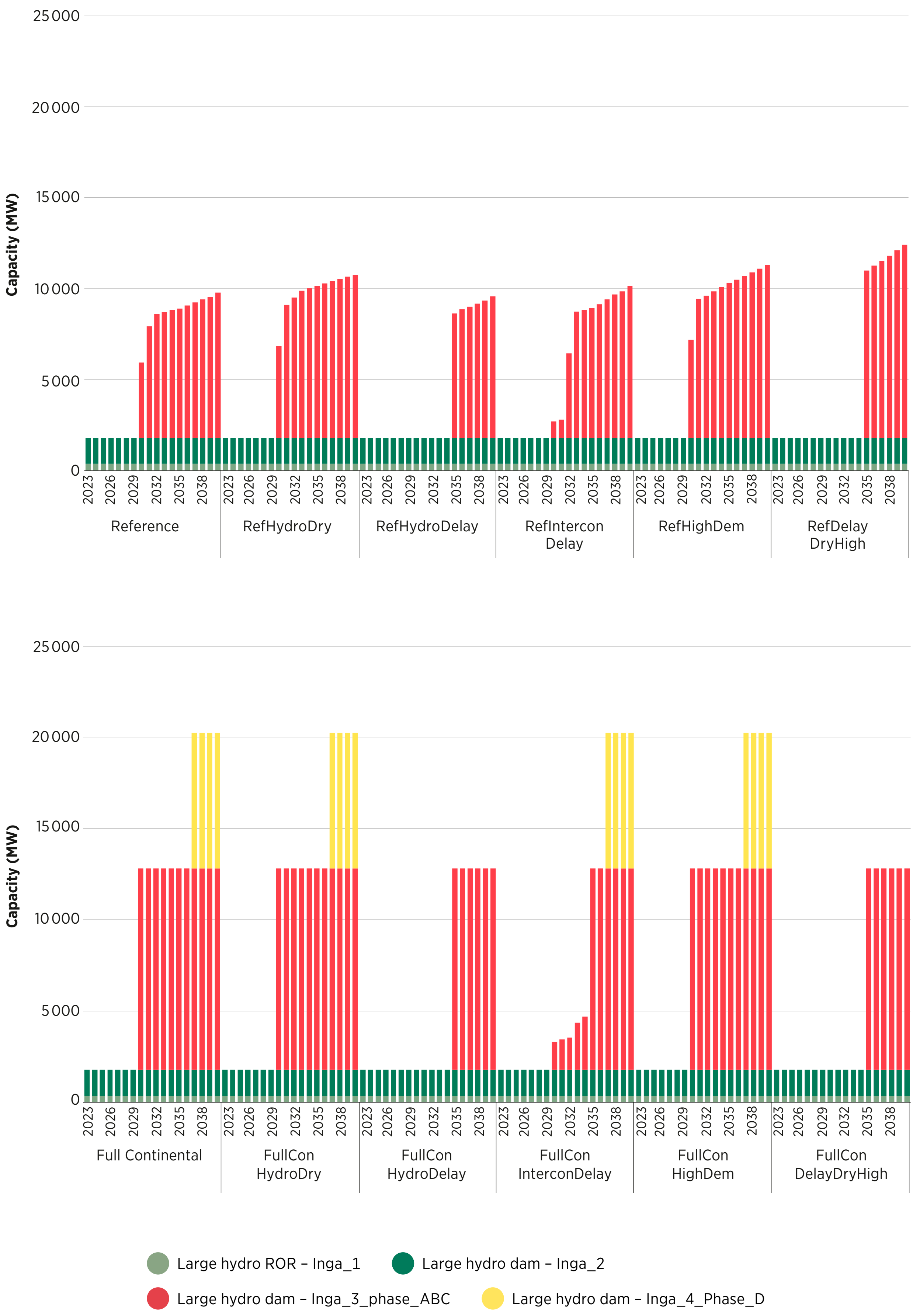
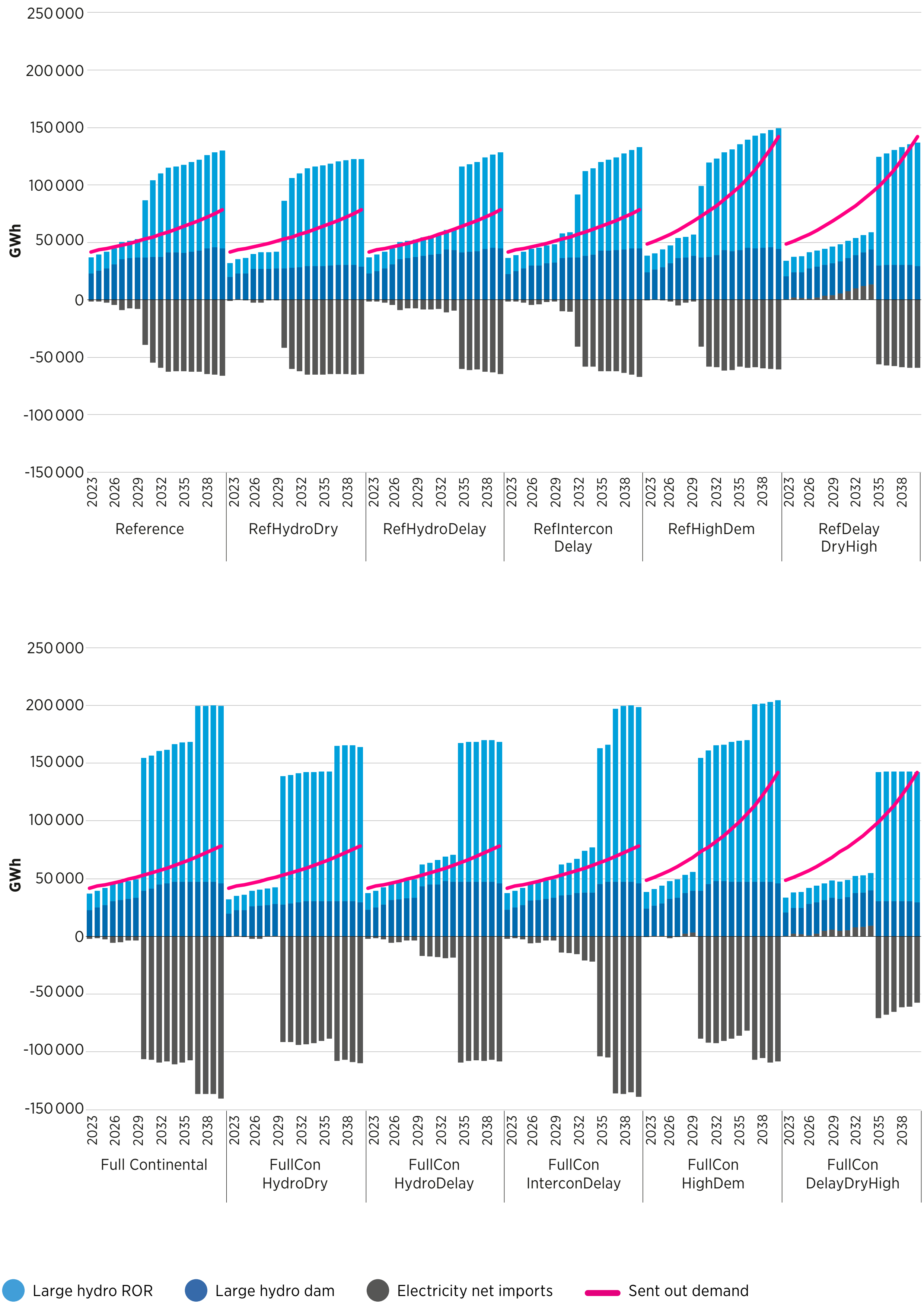


Figure 20 Hydropower production in all scenarios



As shown in Figure 21 below, country-wise, DR Congo is driving regional development and scenario differences, due to Grand Inga. The development of hydropower is also strong in Angola, Cameroon, Gabon and Rwanda, but differs only slightly across scenarios for these countries. The Grand Eweng dam in Cameroon is the only other large plant where development differs across scenarios to a material degree (between zero and 500 MW in dry versus reference conditions, suggesting this project is sensitive to future climate conditions).

Figure 21 Results by country for hydropower capacity in scenarios with the lowest (RefHydroDelay), top, and the highest (FullConHighDem), bottom (DR Congo separated)

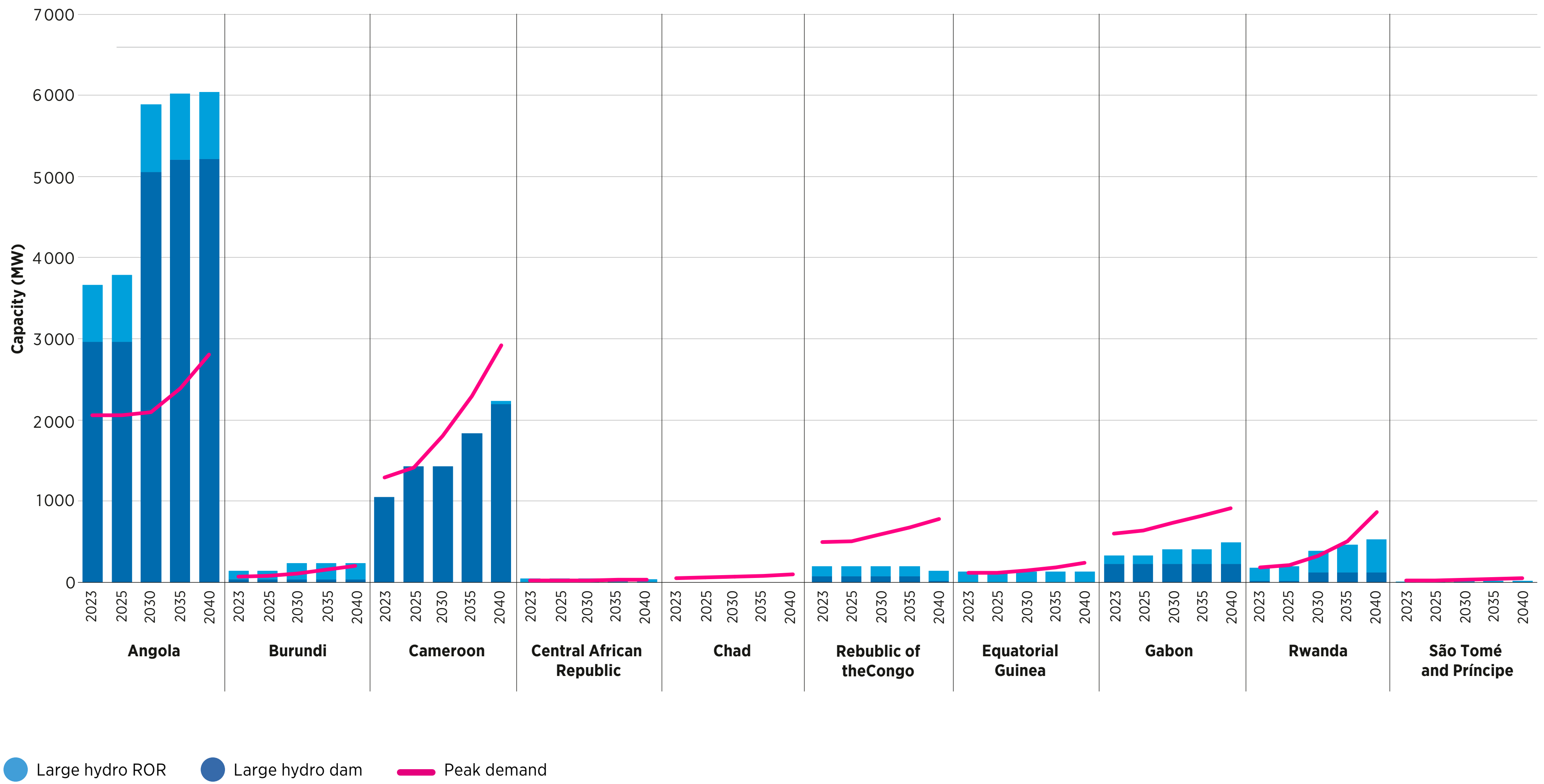


Figure 21 Continued

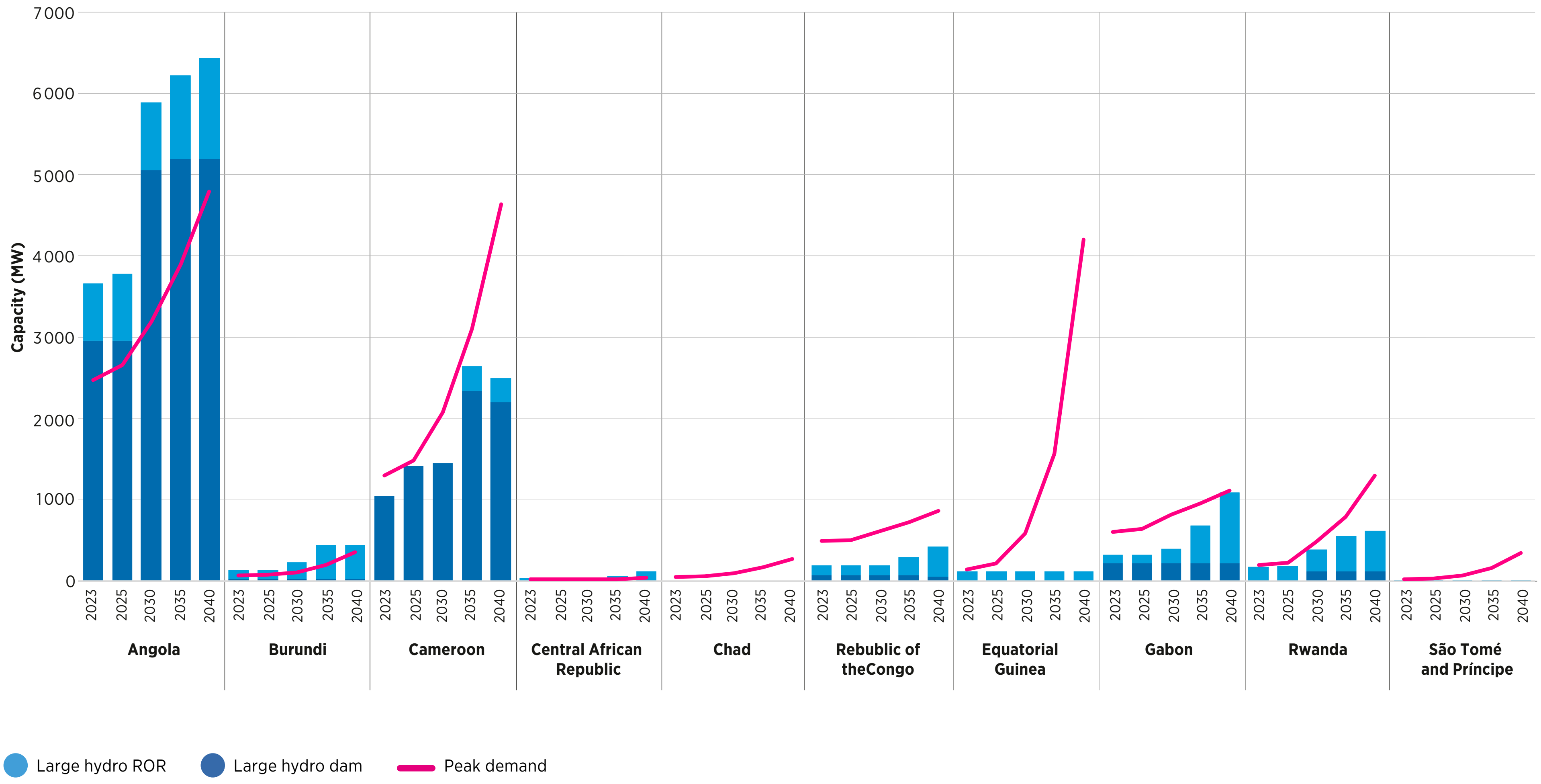
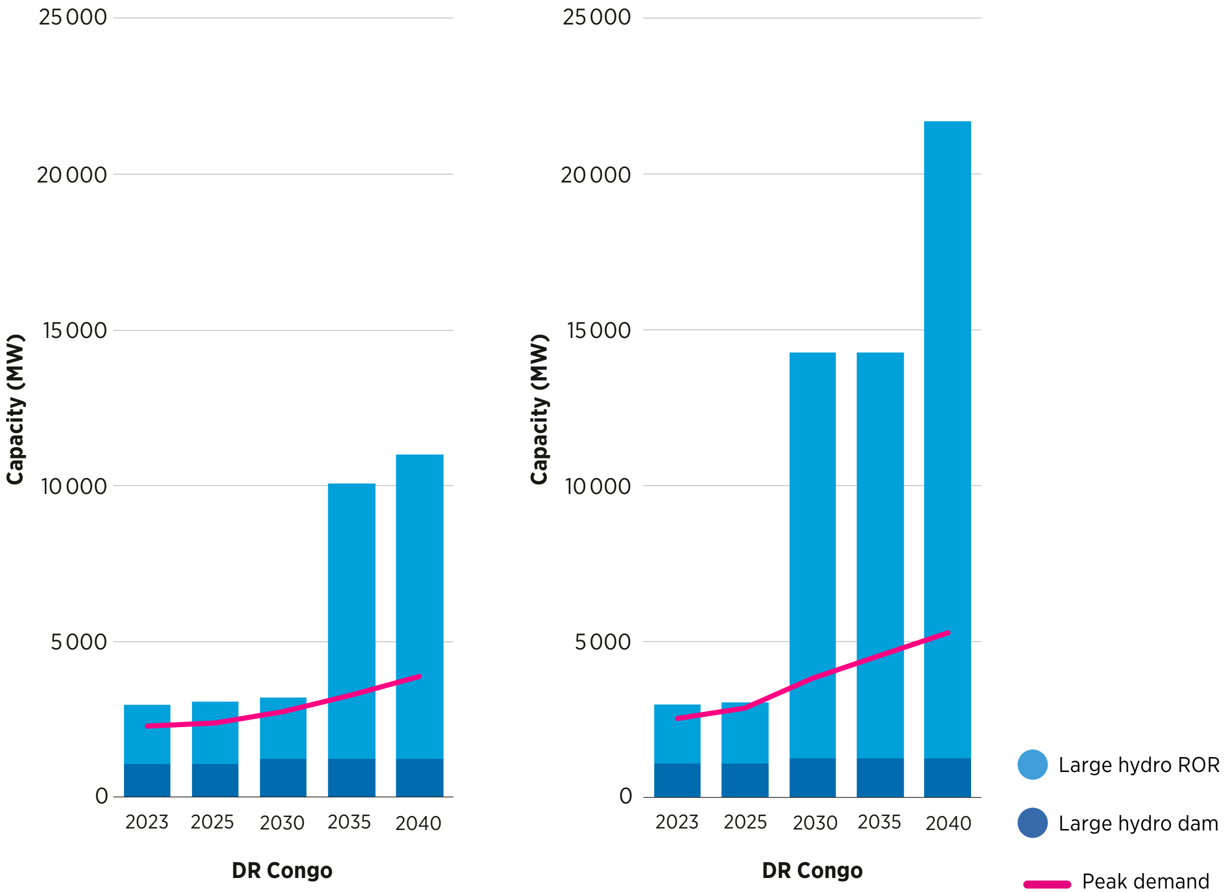


Figure 21 Continued : Democratic Republic of Congo results for hydropower capacity in scenarios with the lowest (RefHydroDelay), left, and the highest (FullConHighDem), right.



Solar, wind and batteries

In the modelling results, solar power makes up the next largest source of electricity production in the region after hydropower. Wind also plays an important role in countries such as Cameroon and Chad. This section discusses key insights in the results regarding solar and wind, as well as their complementary technology: batteries.

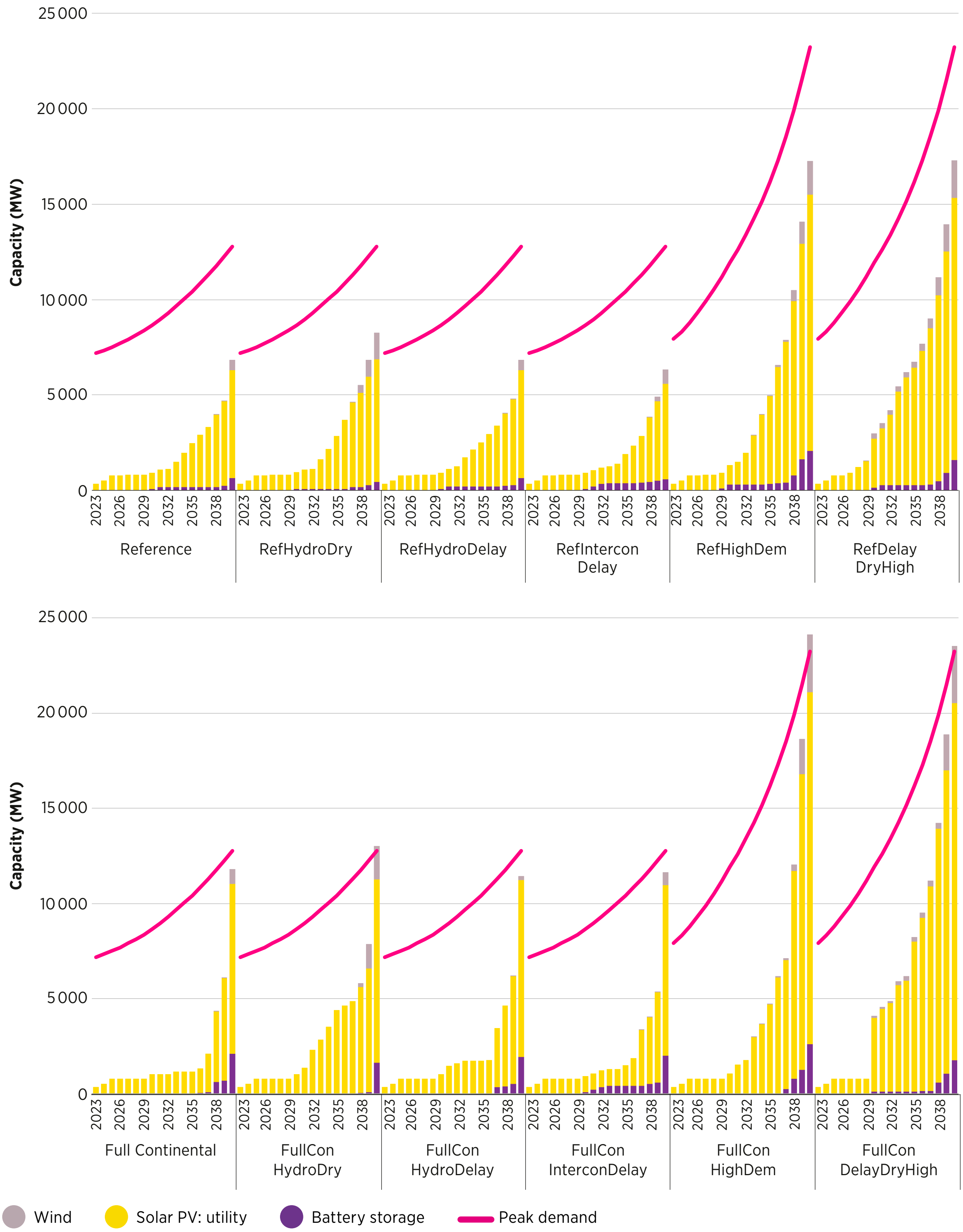
As mentioned previously, the share of solar and wind goes from virtually zero to at least 7% of production by 2040 in all scenarios. In scenarios with high demand, solar and wind reach nearly 15% of production by 2040, while reaching around 20% of production in scenarios with challenging hydropower conditions (*i.e.* delays and dry years).

Figure 22 and Figure 23 present the capacity of these sources across scenarios, as well as differences in alternate scenarios in comparison to the Reference and Full Continental scenarios. In the model results, the amount of solar PV and wind built varies widely between scenarios. For solar, for example, by 2040, we see a minimum of nearly 5 GW in the Reference scenario with interconnector delays, while there is a maximum of nearly 19 GW in the Full Continental scenario with high demand, project delays and dry year conditions. For wind, we see a minimum of just over 0.5 GW in the Reference scenario and a maximum of just over 3 GW in the Full Continental scenarios with high demand.

Interestingly, batteries appear more strongly in the mid-2020s and early 2030s in scenarios with the more constrained Reference interconnection conditions. This implies that in scenarios where more possible interconnections are available, the flexibility required in the regional CAPP system is met by imports and/or exports in those years, rather than batteries.[20] Both interconnector delay scenarios have the highest amount of battery capacity installed in the early 2030s, at around 400 MW. By 2040, however, battery capacity difference under the various interconnector scenario conditions is not as strong, as battery capacity is built across all scenarios to match the strong VRE capacity additions in late model years.

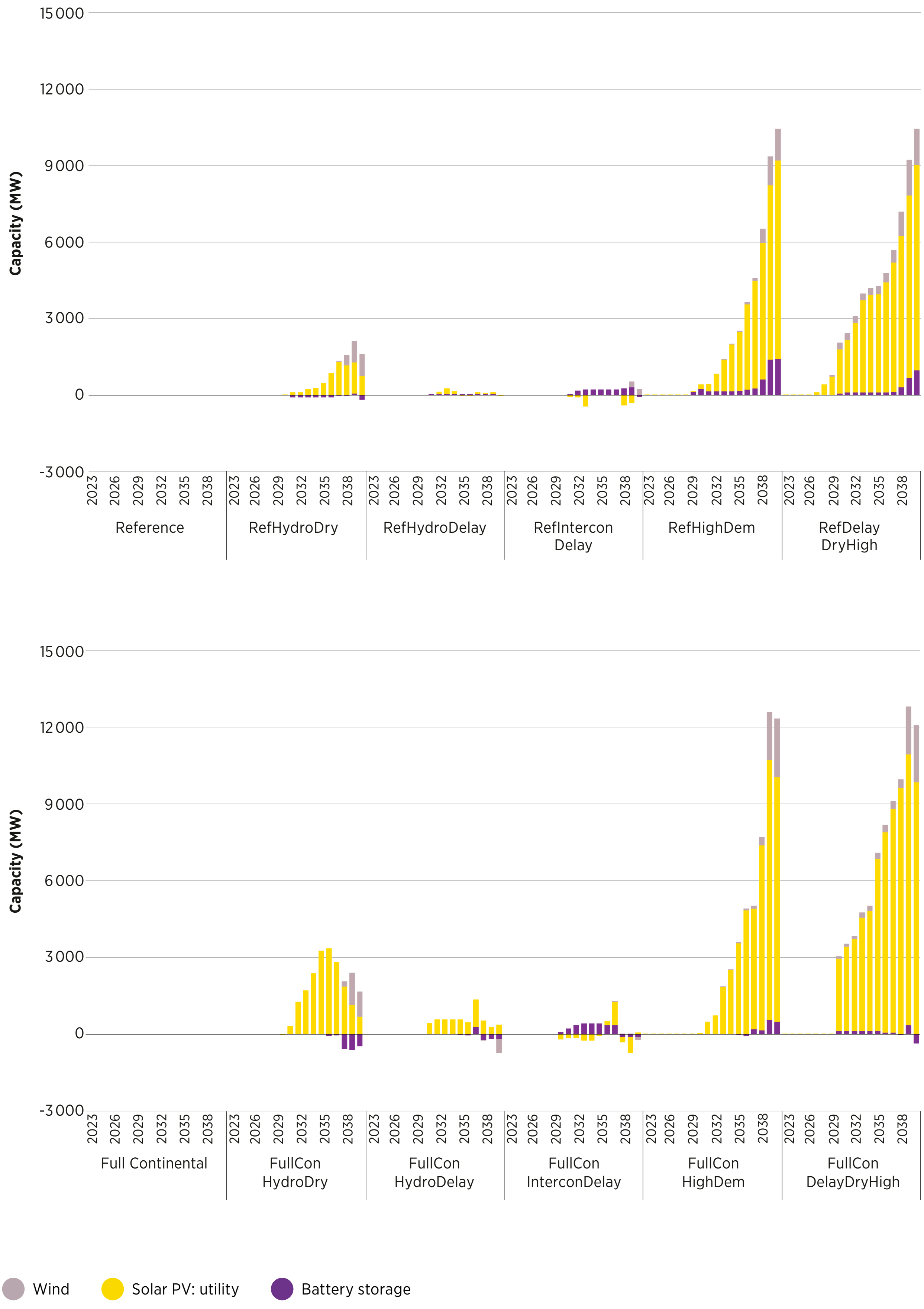
[20] *For more detail on flexibility in the model dispatch results, see Box 3, SPLAT-Africa dispatch results.*

Figure 22 Solar PV, onshore wind and battery capacity across all scenarios



The largest driver of differences in scenarios for these technologies is higher demand than expected in the reference projections. In high demand cases, between 18 GW and 24 GW of combined solar, wind and battery capacity are built, showing that these technologies are typically being chosen by the model as complements to low-cost hydropower options, or as those options run out in the model horizon. Dry year conditions also have a modest impact on the deployment of these three technologies, as more capacity is built in the mid-2030s to make up for lower hydropower production.

Figure 23 Difference in solar PV, onshore wind and battery capacity results relative to Reference and Full Continental scenarios



Country-wise, as shown in Figure 24 below, Cameroon and Angola have the two largest amounts of solar, wind and battery in most scenarios. With the exception of DR Congo, solar plays a significant role in all other countries in the Reference scenarios. In higher-demand scenarios, however, all countries across the board make significant use of these technologies. In Full Continental high demand scenarios, even DR Congo builds over 4 GW of solar PV by 2040, to complement their larger exports of hydropower to other regions. While wind power appears in all scenarios in the region-wide results, it should be highlighted that it is concentrated in most scenarios in Cameroon and Chad, the two countries with the best wind resources.[21]

[21] *For more detail on the geographical locations of VRE options chosen by the model, see Box 2, Geographic location of potential VRE projects: Example of IRENA Model Supply Regions in Angola.*

Figure 24 Results by country for the lowest solar PV, onshore wind and battery capacity (RefInterconDelay), top, and the highest (FullConHighDem), bottom

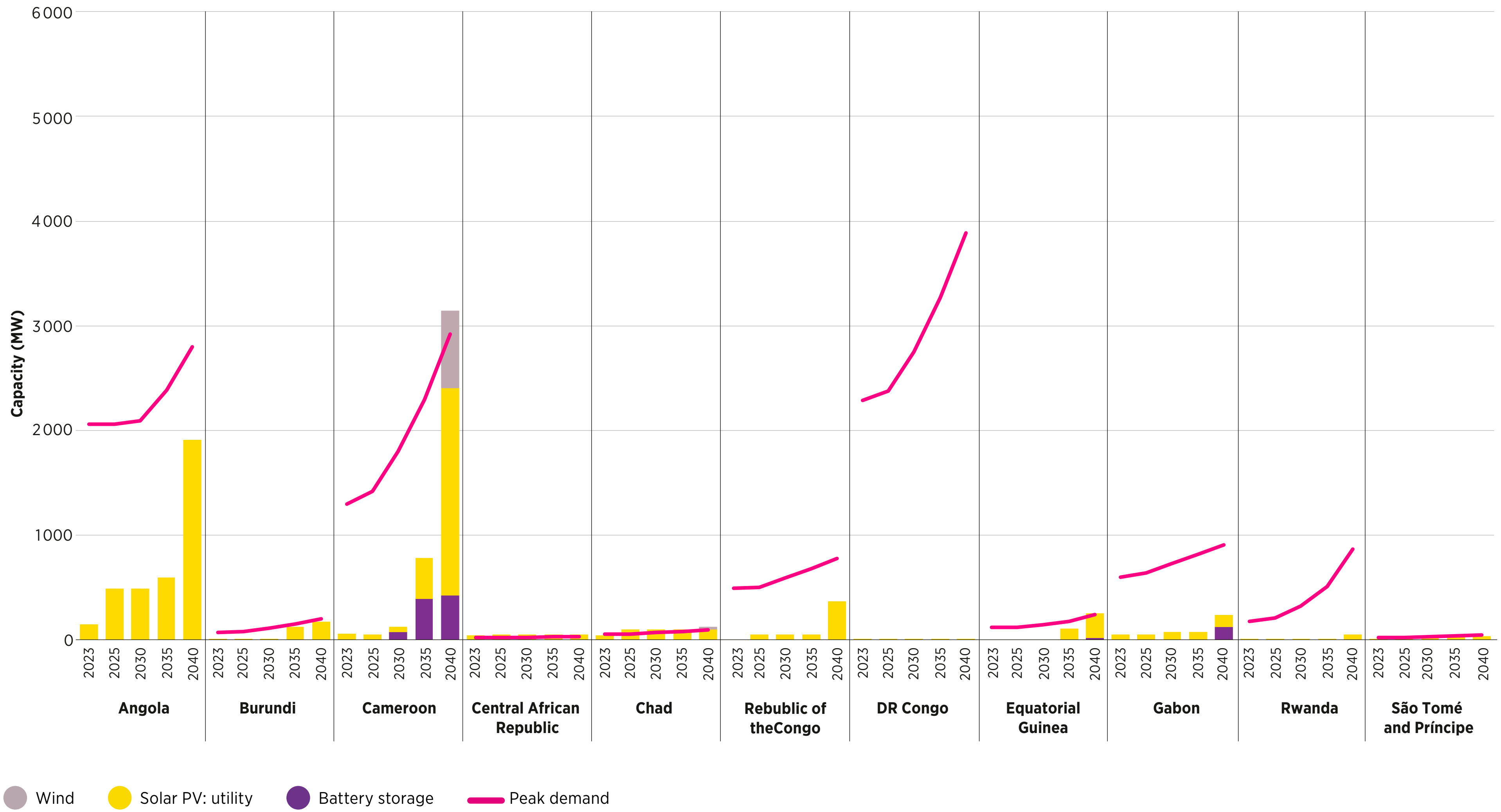
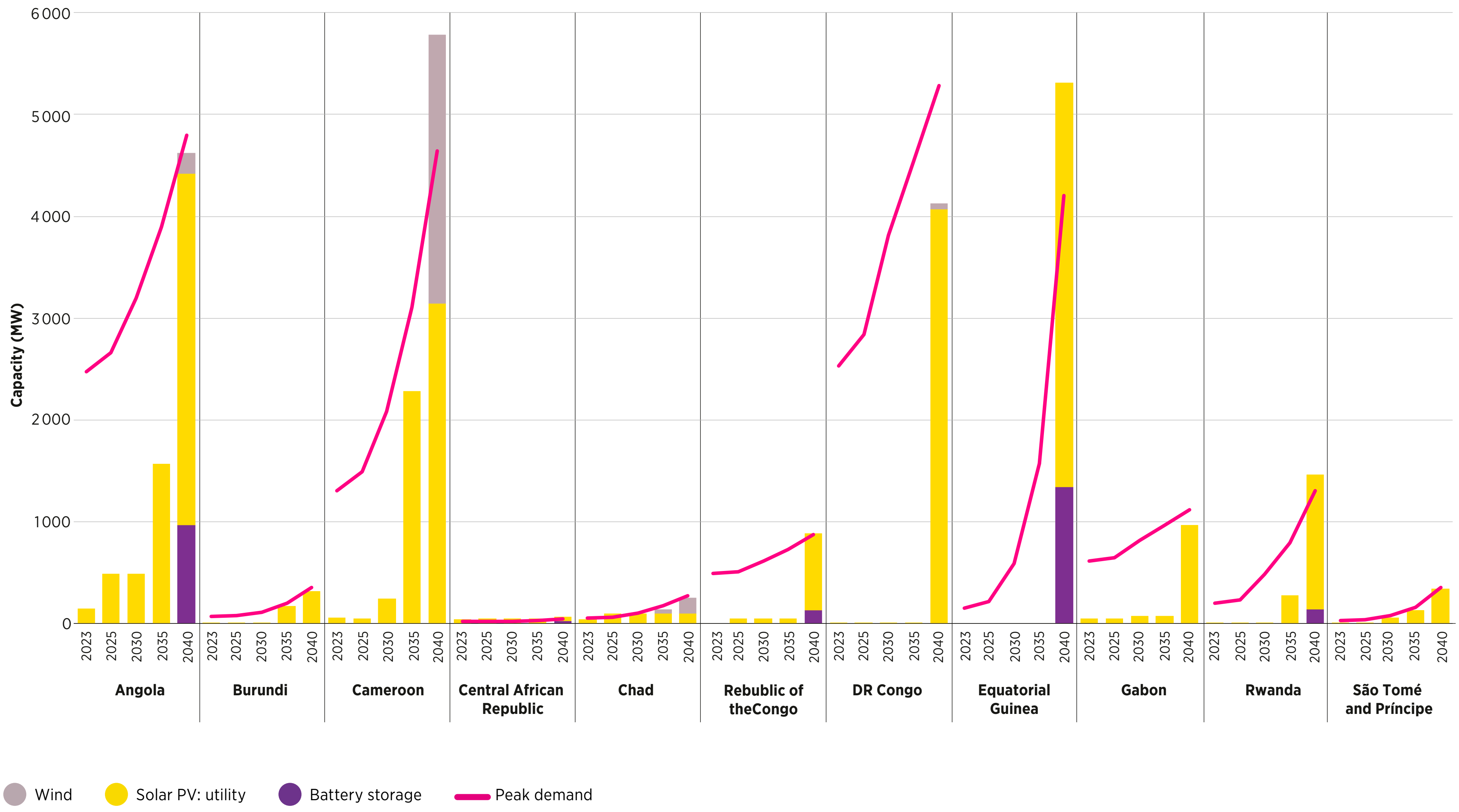


Figure 24 Continued



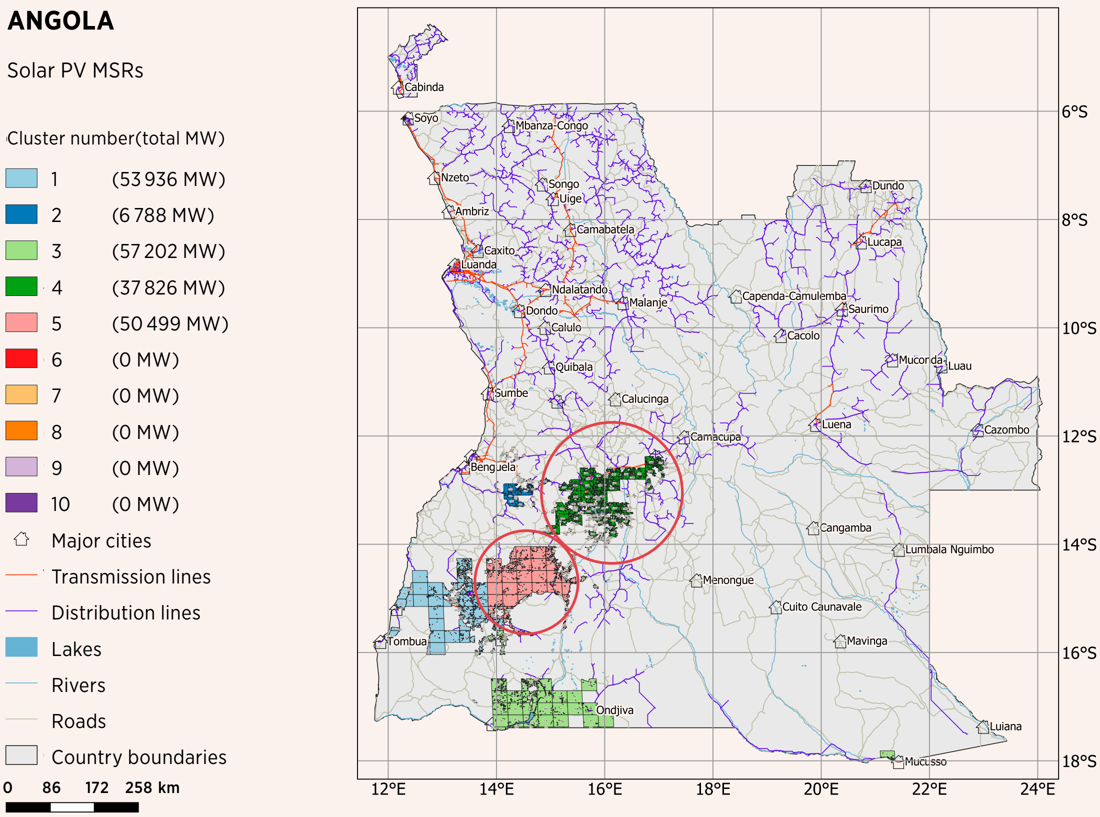
Box 2 Location of potential VRE projects in results: Example of IRENA Model Supply Regions in Angola

As outlined in detail in Chapter 3, the SPLAT-MESSAGE Central Africa model includes regional clusters of high potential solar and wind supply options, based on IRENA's MSR work. These MSRs act as model-ready "candidate regions" with specific capacity potential, infrastructure costs, and generation profiles at the country-level. This set of regions provides a realistic selection of the most interesting locations in each country to construct renewable power plants, while covering spatial resource divergences within that country.

Inclusion of the MSR data in the SPLAT-MESSAGE modelling framework allows countries to explore which specific geographical areas may be of interest for further studies or policies related to procurement and project development. The figure below displays an example of these results from the modelling performed in this report, showing which solar PV zones feature in Angola results and to what extent across all of the scenarios. This can provide planners with a range of potential capacity that could be of interest for further exploration, depending on future conditions. Specific capacity results for renewable MSRs across scenarios, along with the MSR maps for each country, can be found in the data appendix accompanying this report.

Figure 25 Location and amount of Solar PV MSR capacity (MW) in Angola across scenarios (selected MSRs circled in red)

	NUMBER OF SCENARIOS IN WHICH ZONE CHOSEN	CAPACITY IN SCENARIOS (MW)		
		MIN.	AVERAGE	MAX.
Solar PV Zone 004	1/12	0	27	322
Solar PV Zone 005	12/12	1317	1862	4060



Disclaimer: These maps are provided for illustration purposes only. Boundaries and names shown on these maps do not imply the expression of any opinion on the part of IRENA concerning the status of any region, country, territory, city or area or of its authorities, or concerning the delimitation of frontiers or boundaries.

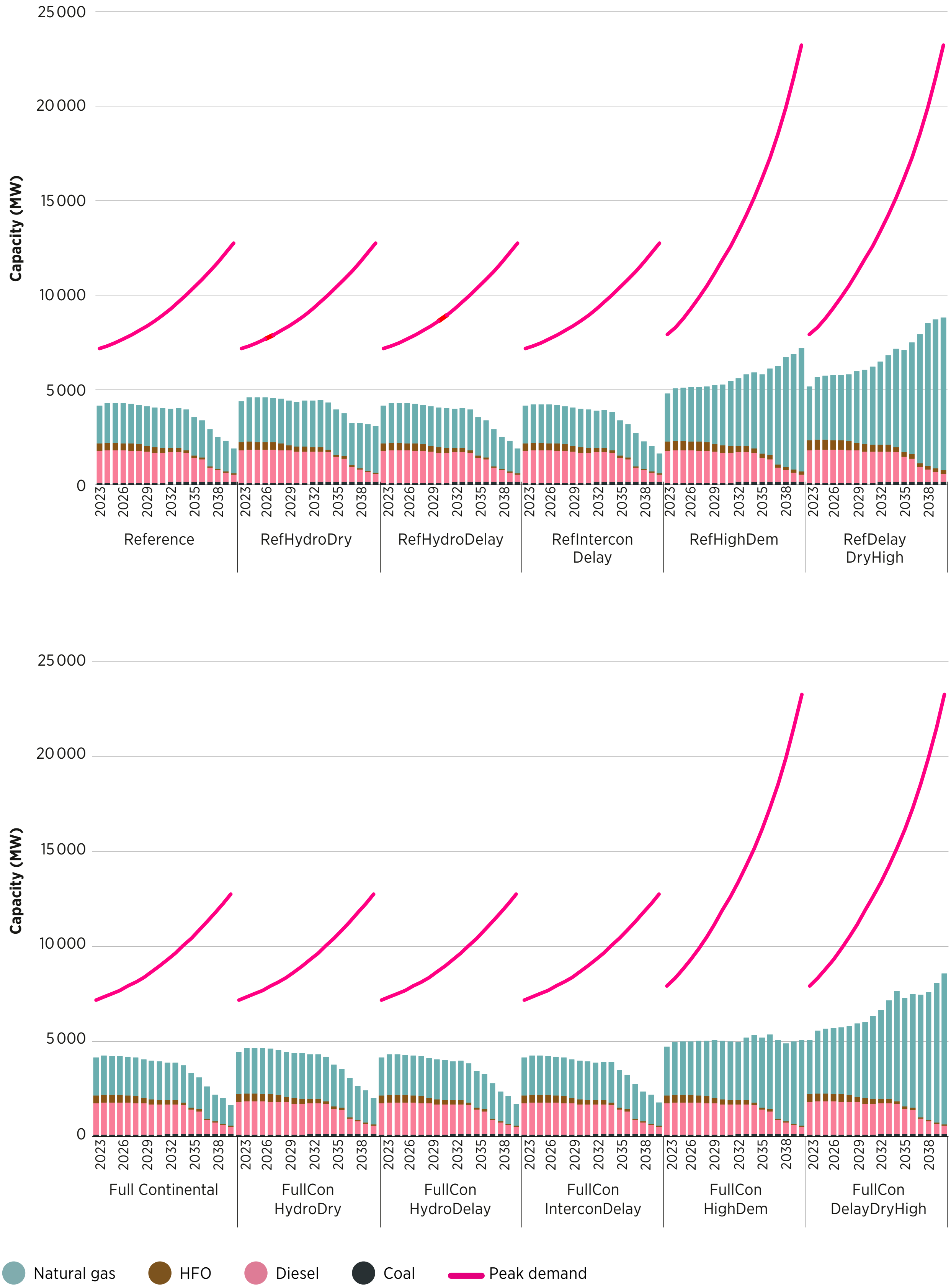
Fossil fuels

Although fossil fuels, including coal, gas, and oil, currently account for nearly 20% of production in the CAPP region – and more than that in many individual countries – their future development is unclear. This is due to the region's vast renewable resource potential and increasing climate ambitions.

This section discusses key insights regarding fossil fuel capacity given by the results.[22] Figure 26 and Figure 27 show the fossil fuel capacity outcomes across the scenarios, as well as the differences in those results across alternate scenarios.

[22] *For more detail on certain aspects of fossil fuel production in the model dispatch results, see Box 3, SPLAT-Africa dispatch results.*

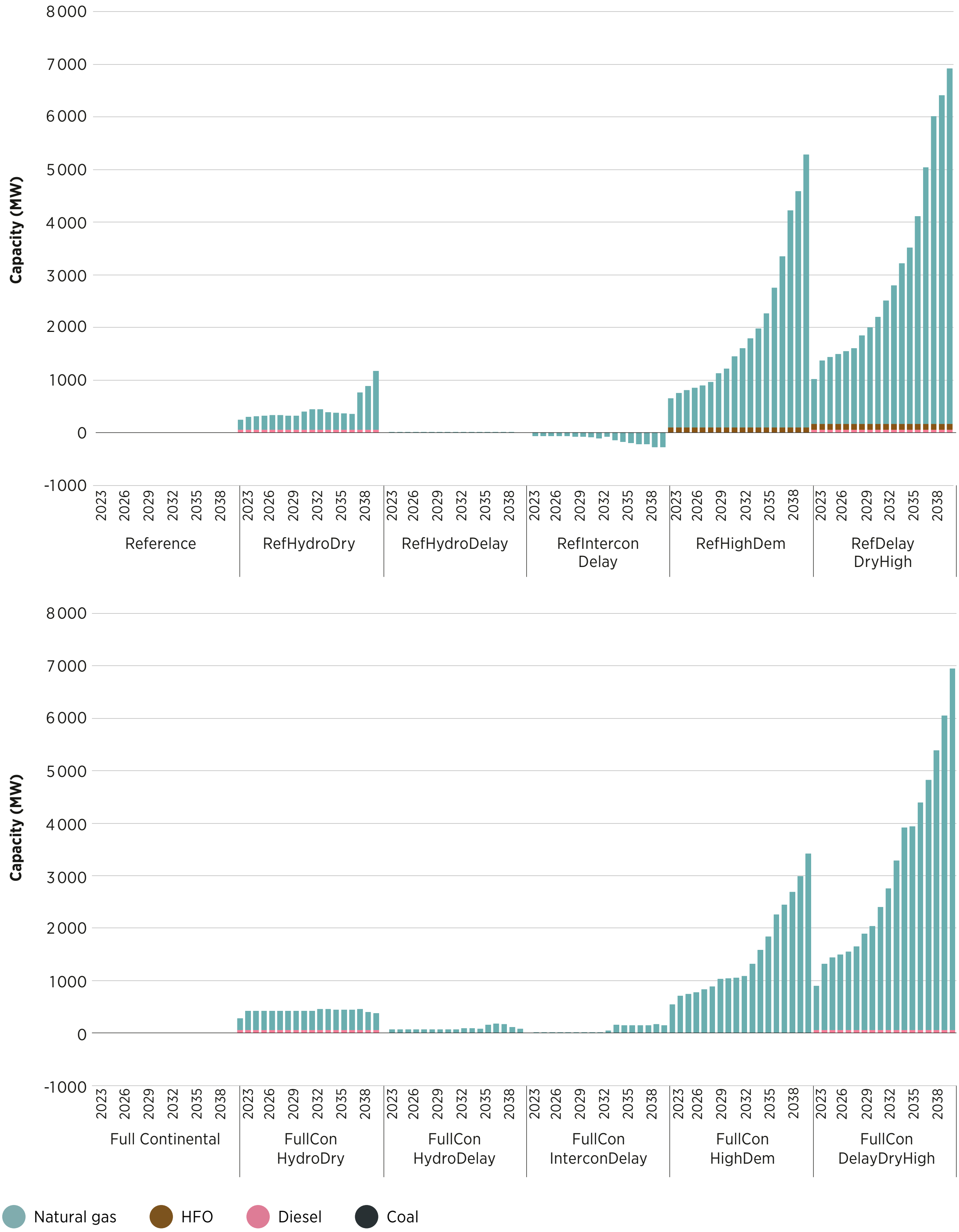
Figure 26 Fossil fuel capacity across all scenarios



In all scenarios with Reference demand projections, fossil fuel capacities decrease significantly from their current level in the modelling results, even in scenarios with hydropower delays and dry year conditions. By 2040, in Reference demand scenarios, HFO and diesel capacities are nearly phased out. Gas capacities are, at most, close to today's levels of around 1.5 GW to 2 GW. This is due to remaining capacity, largely located in Angola, Republic of the Congo, Gabon and Equatorial Guinea. This can be seen in the country-level results in Figure 28. Coal capacity is only present in Rwanda, due to capacity in the pipeline that has been designated as "Committed" by the national team – although, more specifically, these are peat-fired plants.

In scenarios with higher demand forecasts, there is some expansion of fossil fuel capacity, although in these cases, only gas capacity is expanded. New gas capacity is a particular feature of high-demand scenarios in which hydropower experiences delays and dry year conditions. To fill the gap, by 2040, gas capacity increases to 8.5 GW in the FullConDelayDryHigh scenario, up from a current level of around 2 GW. Dry year conditions also have an effect on gas capacity, but to a lesser extent than demand drivers. There is 1 GW more gas in a dry year scenario with reference interconnector conditions, but only 300 MW more in a dry year scenario, if the model also allows for generic interconnection capacity.

Figure 27 Difference in fossil fuel capacity results relative to Reference and Full Continental scenarios



Country-wise, in scenarios where gas capacity is expanded, additional gas capacity relative to the Reference scenario is built in Cameroon, Republic of the Congo, DR Republic of the Congo, Equatorial Guinea and São Tomé & Príncipe. Interestingly, however, across almost all scenarios that do see new gas capacity built in these countries, the overall gas capacity begins to decrease by 2040, as costs of renewable technologies and batteries continue to decline. This implies that these plants do not have a promising long-term outlook beyond the modelling horizon.

Figure 28 Results by country for scenarios with the lowest fossil fuel capacity (RefInterconnDelay), top, and the highest (FullConDelayDryHigh), bottom

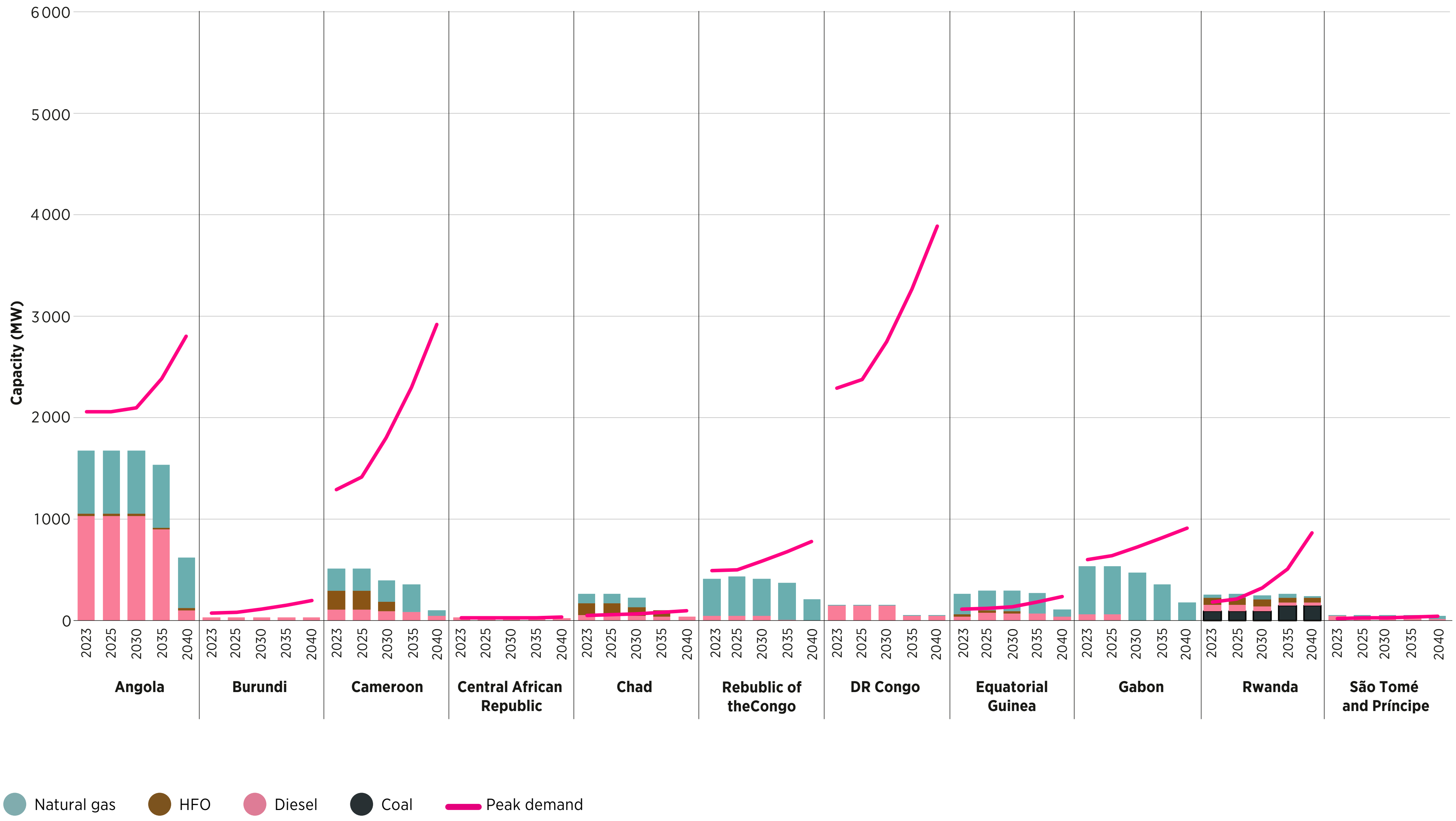
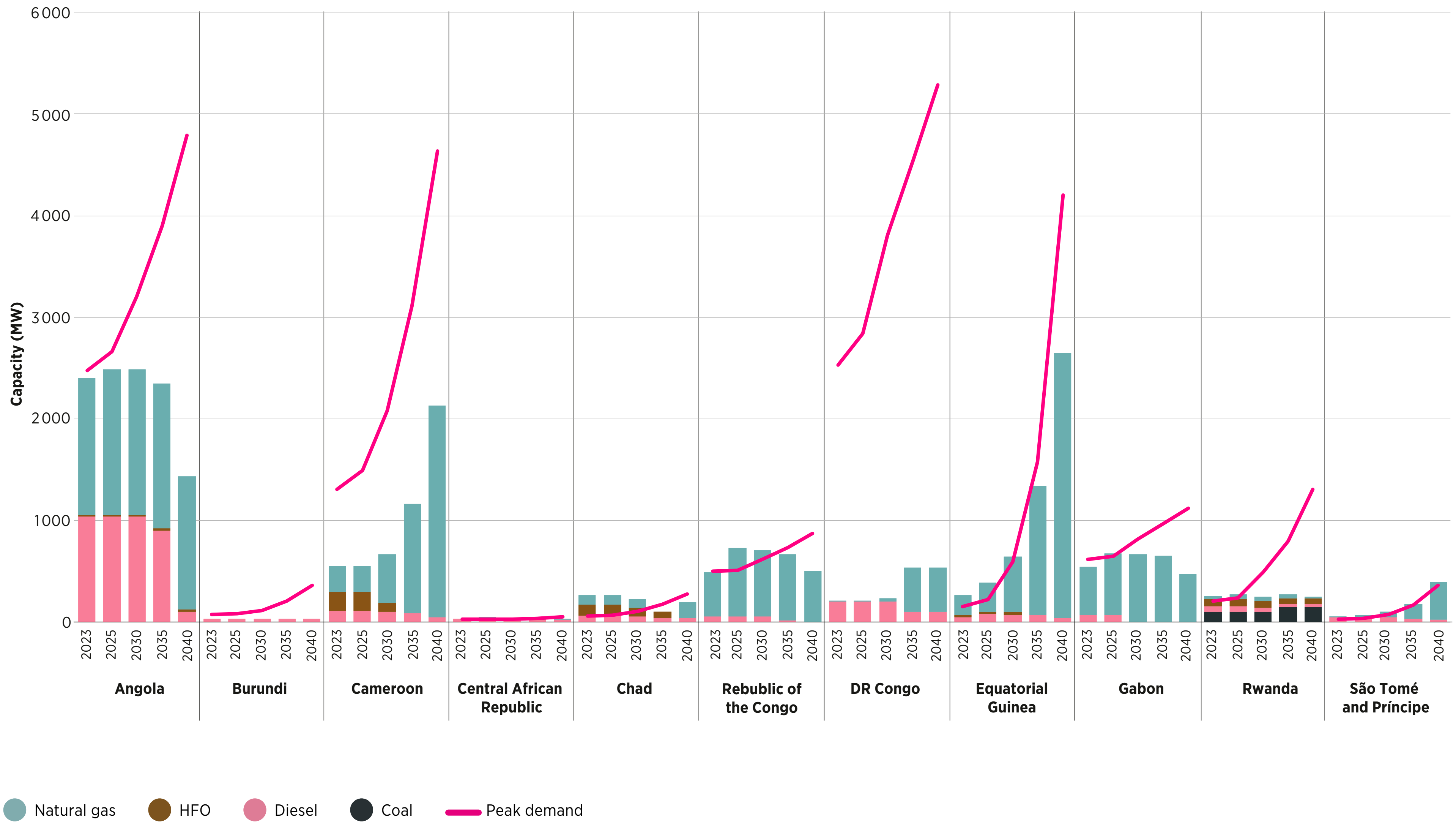


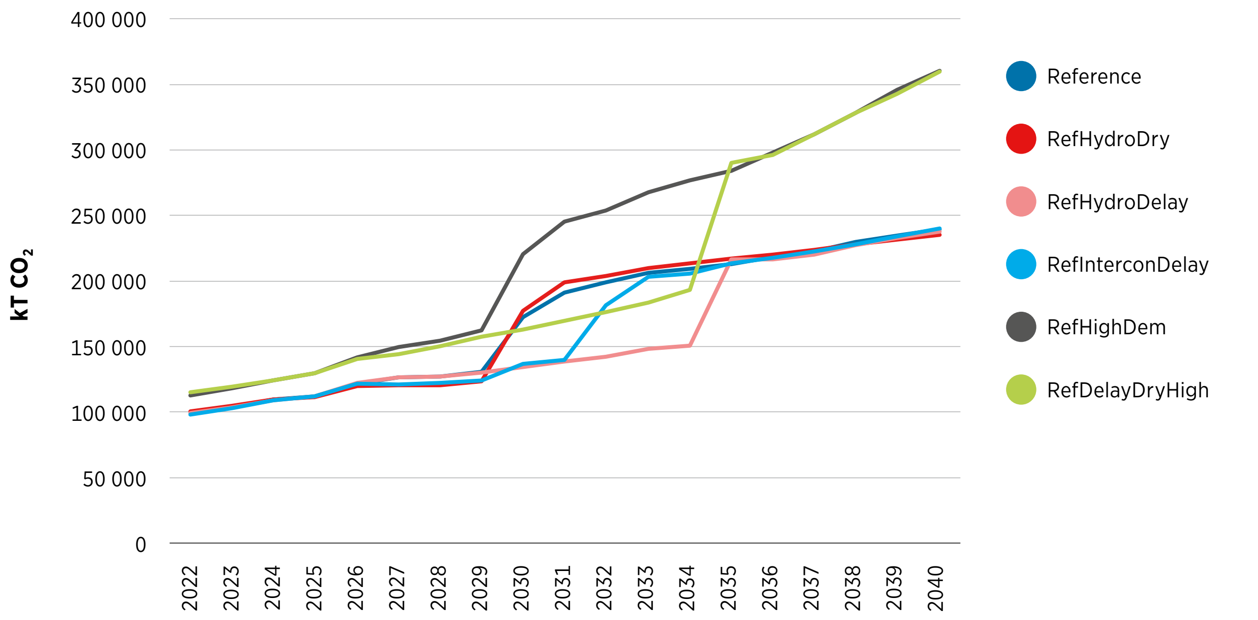
Figure 28 Continued

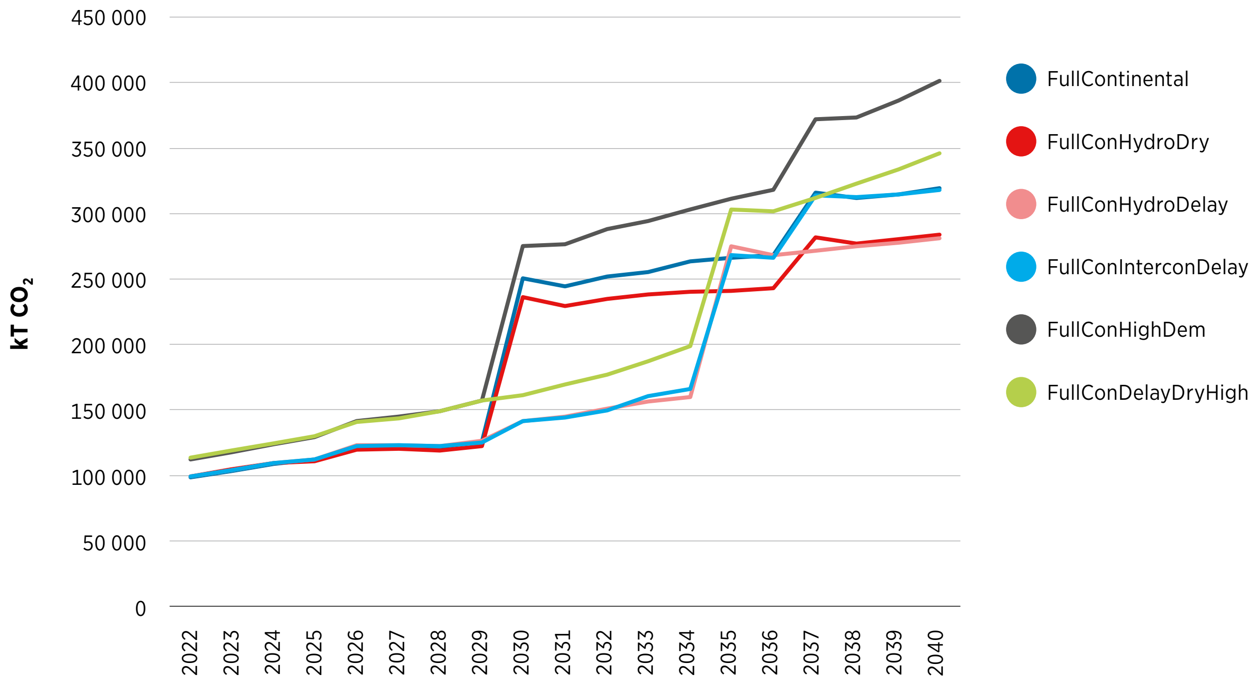


4.2 CO_2 EMISSIONS

Figure 29 provides an overview of emissions in kilotonnes of carbon dioxide (kT CO_2) across all of the scenarios explored in this report. The clearest distinction between overall emissions levels in scenarios is due to demand differences, with high demand projections resulting in much higher emissions levels. This is directly related to the expansion of more fossil fuel production in those scenarios, as discussed in the previous section.

Figure 29 CO_2 emissions from CAPP region generation across scenarios



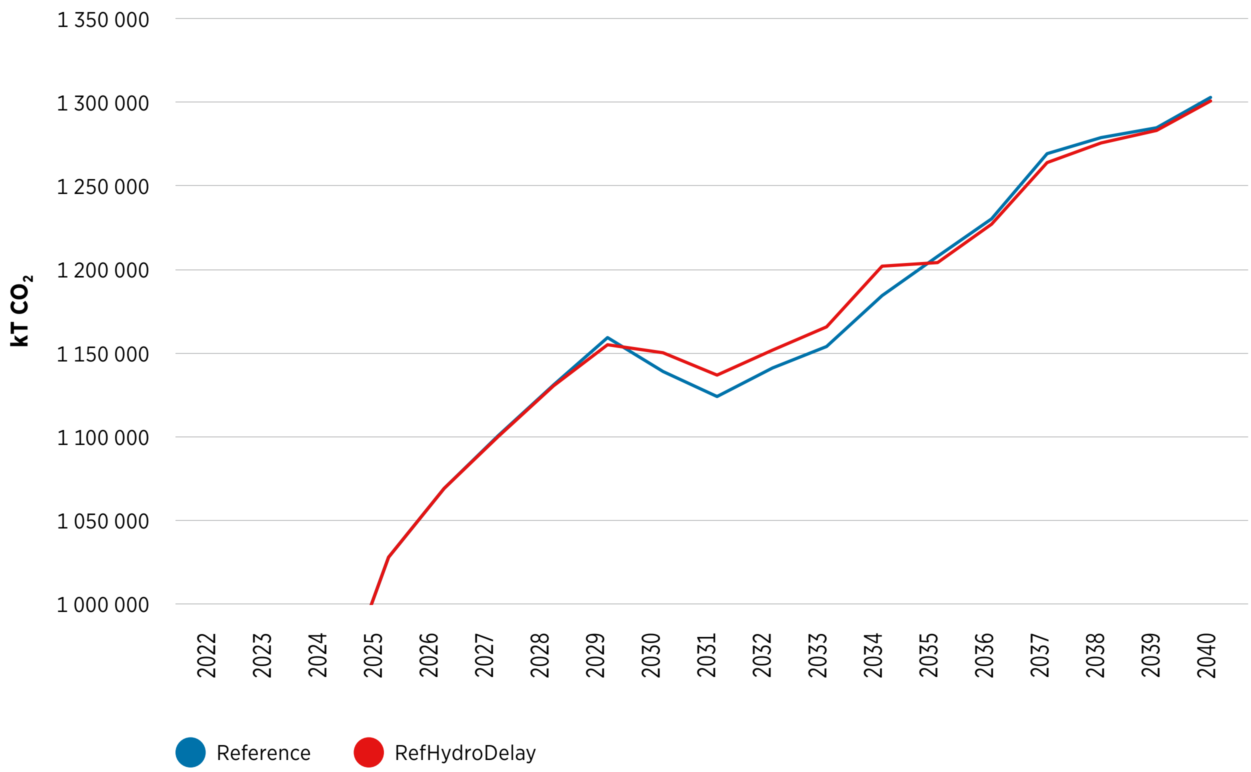


By 2040, in scenarios with Reference demand and interconnector assumptions there is little distinction between emissions. This is because a similar amount of fossil fuel production exists in each scenario. However, there is a clear jump in CAPP regional emissions when large interconnection projects come online to export hydropower in "delay" scenarios. This implies that once large interconnection capacity is available for export to other regions, relatively more hydropower is exported to displace costly fuels in other regions, or to provide flexibility that would reduce costs more in other regions than it would in CAPP. Once this happens, relatively more fossil fuel generation occurs in the CAPP region in place of the hydropower.

The same dynamic can be seen in Full Continental scenarios with all interconnections allowed, where dry and delay conditions counterintuitively keep CAPP emissions lower. These scenarios have relatively lower net exports by 2040 due to those challenging conditions, meaning relatively more hydropower is used for consumption within CAPP.

However, it is critical to note that even though emissions from CAPP production alone may increase, if it exports more hydropower, Figure 30 below shows that these exports would reduce emissions in the two major economies importing from CAPP – South Africa and Nigeria. This is because these exports reduce the overall use of coal and natural gas and serve as a valuable source of flexibility. These results stress the importance of inter-regional perspectives in long-term energy planning by African stakeholders.

Figure 30 CO_2 emissions from generation in Nigeria and South Africa (combined) in Reference and RefHydroDelay scenarios



4.3 CROSS-BORDER ELECTRICITY TRADE

In all of the scenarios explored, the results show that interconnector projects are implemented as soon as they are available, with significant trade between CAPP countries. The tables and figures in this section show the baseline of existing trade in the model between DR Congo, the Central African Republic, the Republic of the Congo, Burundi and Rwanda. They also show examples of flows within and beyond the region by 2040 in all the Reference and Full Continental scenarios.

Table 6 Electricity trade between CAPP countries, 2019 (GWh)

	CENTRAL AFRICAN REPUBLIC	REPUBLIC OF THE CONGO	BURUNDI	RWANDA	DR CONGO	GRAND TOTAL
Burundi				90	1	91
Rwanda			15		47	62
DR Congo	6	701	189	290		1 185
Grand total	**6**	**701**	**203**	**381**	**48**	**1 338**

Notes: Row = exporting country; column = importing country

Even in the Reference scenario with the least amount of trade – with hydro delays – substantial trade still occurs between the CAPP countries. This shows how complementary resources can reduce overall regional costs and provide flexibility.[23] As can be seen in the figure below, in all scenarios, net imports in Chad, the Republic of the Congo and Rwanda are important in meeting demand. At the same time, the status of Central African Republic and Equatorial Guinea as net importers or exporters changes depending on whether the model allows for more interconnection projects beyond the current pipeline. With all the possible interconnection projects allowed in the model, the Central African Republic develops more hydro resources and becomes a net exporter to the Republic of the Congo and Chad, while Equatorial Guinea uses more lower-cost imports of hydro-generated electricity from Cameroon and Gabon in place of natural gas.

[23] *For some examples of this flexibility in the model dispatch results, see Box 3, SPLAT-Africa dispatch results.*

Figure 31 Country-level breakdown of imports and exports in the power generation mix by 2040 (GWh, by scenario)

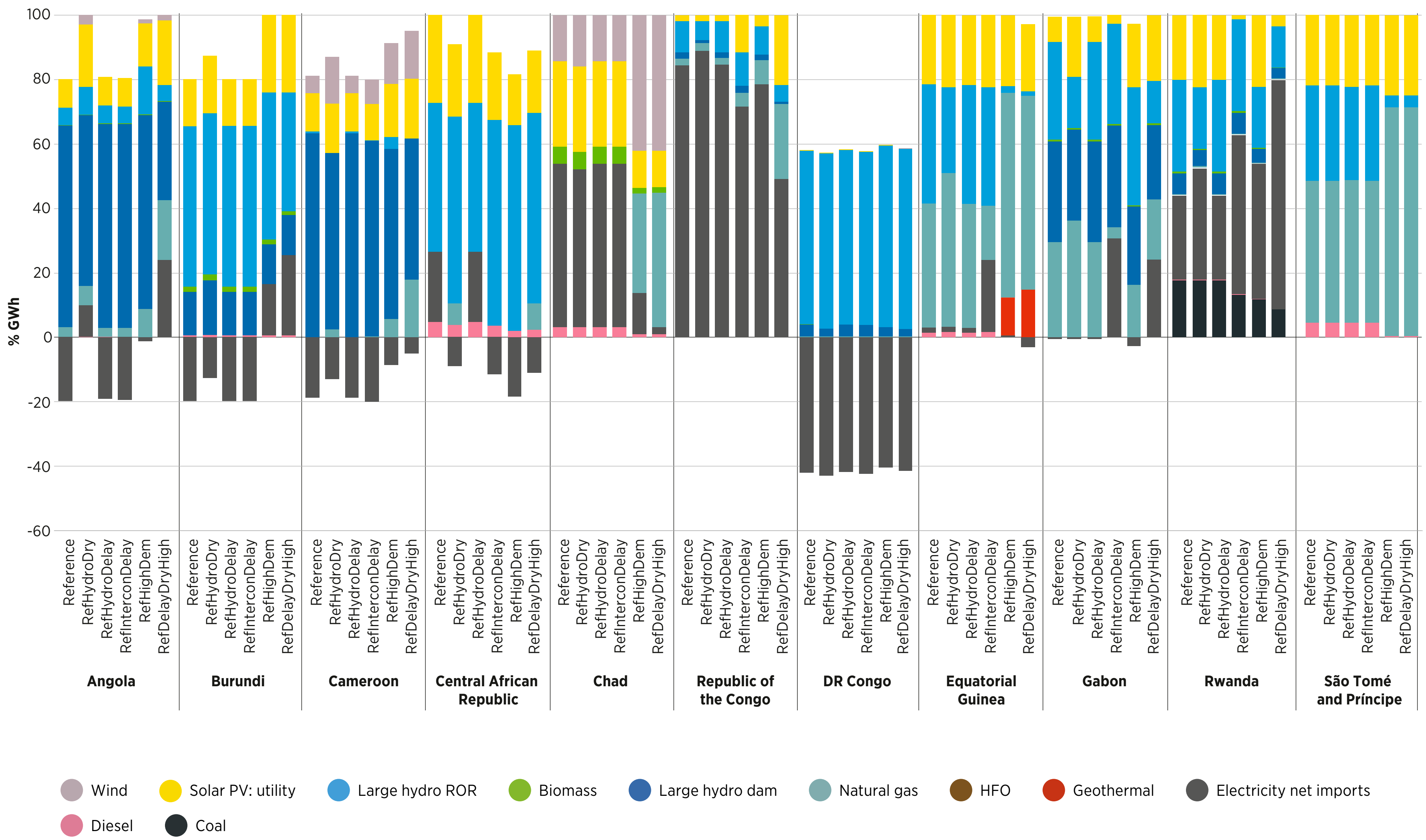
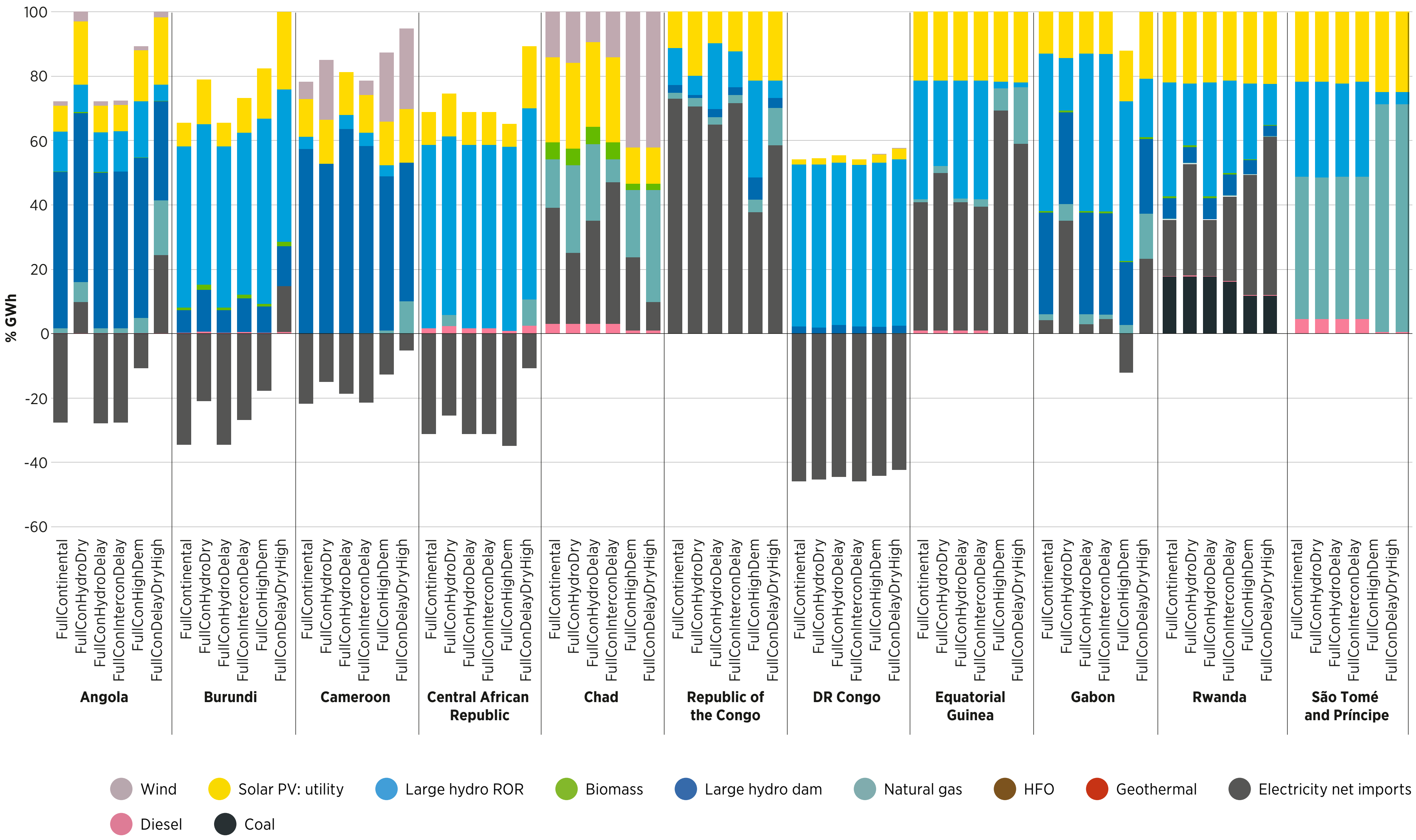


Figure 31 Continued



All scenarios also show substantial exports to other regions, particularly from DR Congo to SAPP and WAPP in parallel with the Grand Inga development. As can be seen in the figures below, some of the Full Continental scenarios in which more interconnectors are allowed to be built beyond the current pipeline of projects have around double the amount of exports from DR Congo. These flow mainly to the major demand centres of South Africa and Nigeria.

With a greater expansion of interconnection and trade in the Full Continental scenarios, we also see other countries take on major roles as transit hubs for wheeling electricity – specifically, the Republic of the Congo, Gabon and Cameroon – facilitating trade with WAPP. These countries maintain their overall position as net importers or exporters in 2040, but the amount of trade flowing through these hubs increases substantially. Cameroon, for example, exports some of its own hydropower to WAPP across all scenarios. At the same time, although Rwanda and Burundi continue to see exchange with EAPP countries beyond the horizon, the amount of electricity trade sent through them to the rest of EAPP is relatively lower, especially if interconnection within the EAPP itself increases.

In terms of capacity to support this trade, cross-border interconnection grows more than ten-fold in all Reference scenarios to a total of around 10 GW by the mid-2030s. The largest projects chosen across all Reference scenarios include DR Congo-Zambia (2 GW), Angola-Namibia (1.5 GW), DR Congo-South Africa and DR Congo-Nigeria (1 GW each). In scenarios where all physically possible interconnectors are allowed, the amount of capacity chosen by the model increases significantly. In one of the scenarios with the highest interconnector capacity (Full Continental), the model chooses to build over 40 GW in the CAPP region by the early 2030s and nearly 50 GW by 2040.[24] Even in the Full Continental scenario with the most challenging trade conditions (with delays, dry year conditions and high demand), the model reaches over 20 GW of cross-border interconnection by 2040. The main driver of this increase is new interconnector capacity to facilitate export to the WAPP and SAPP regions. This starts in the 2030s and is mainly driven by the development of low-cost hydropower resource potential in DR Congo and Cameroon.

[24] *By comparison, this is about half of the current interconnection capacity in Europe.*

Figure 32 CAPP electricity imports and exports across all scenarios, 2040 (only countries with >5% of regional gross imports/exports, GWh)

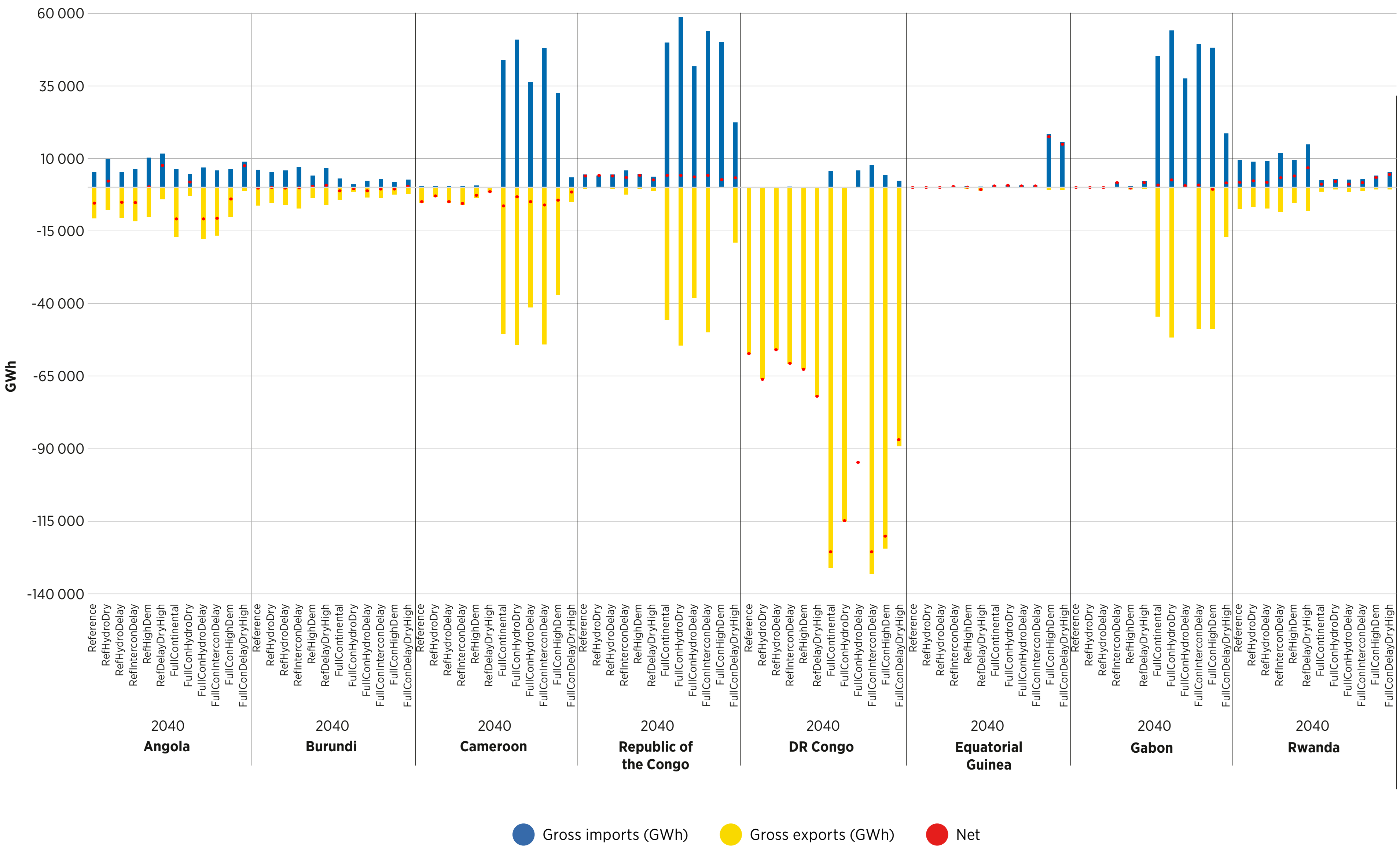
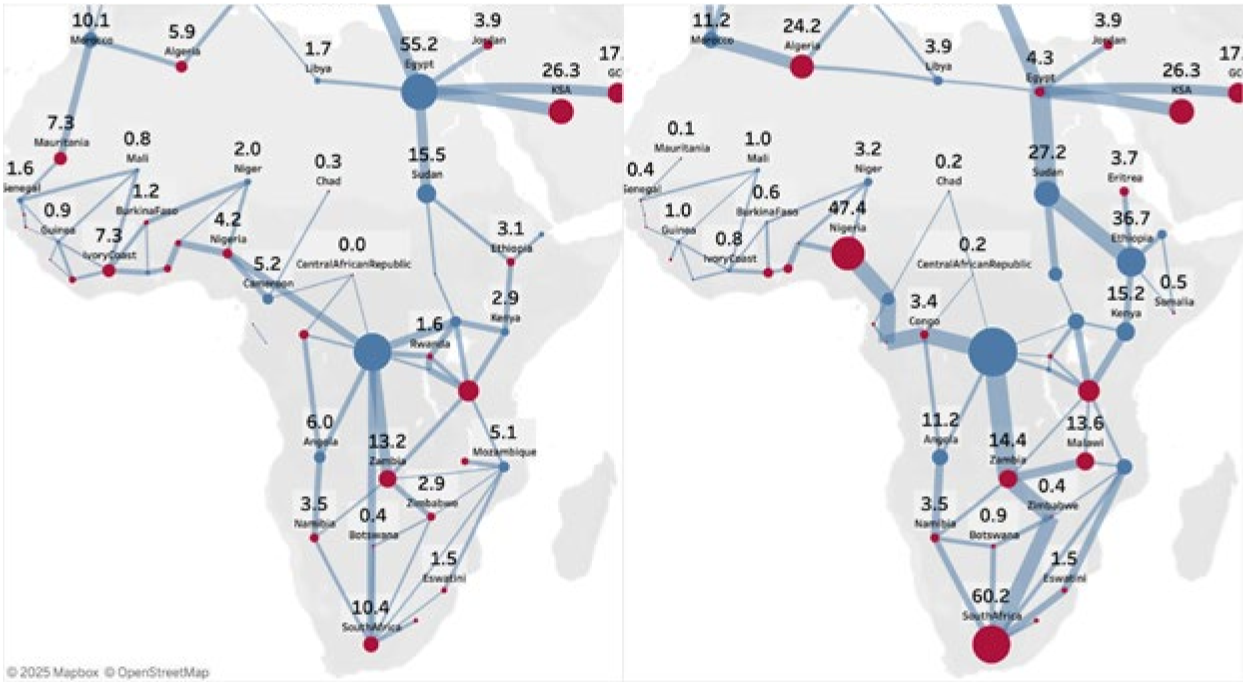


Figure 33 CAPP electricity imports and exports, 2040 (GWh): Reference scenario (left) and Full Continental scenario (right)

Reference **Full Continental**



Notes: Basemap ©Mapbox/OpenStreetMap; red = net importer; blue = net exporter; KSA = Kingdom of Saudi Arabia; GCC = Gulf Co-operation Council (excluding KSA)

Disclaimer: This map is provided for illustration purposes only. Boundaries and names shown on this map do not imply any endorsement or acceptance by IRENA.

Figure 34 Interconnector capacity results (MW): Lowest (top, RefHydroDry) and highest (bottom, Full Continental)

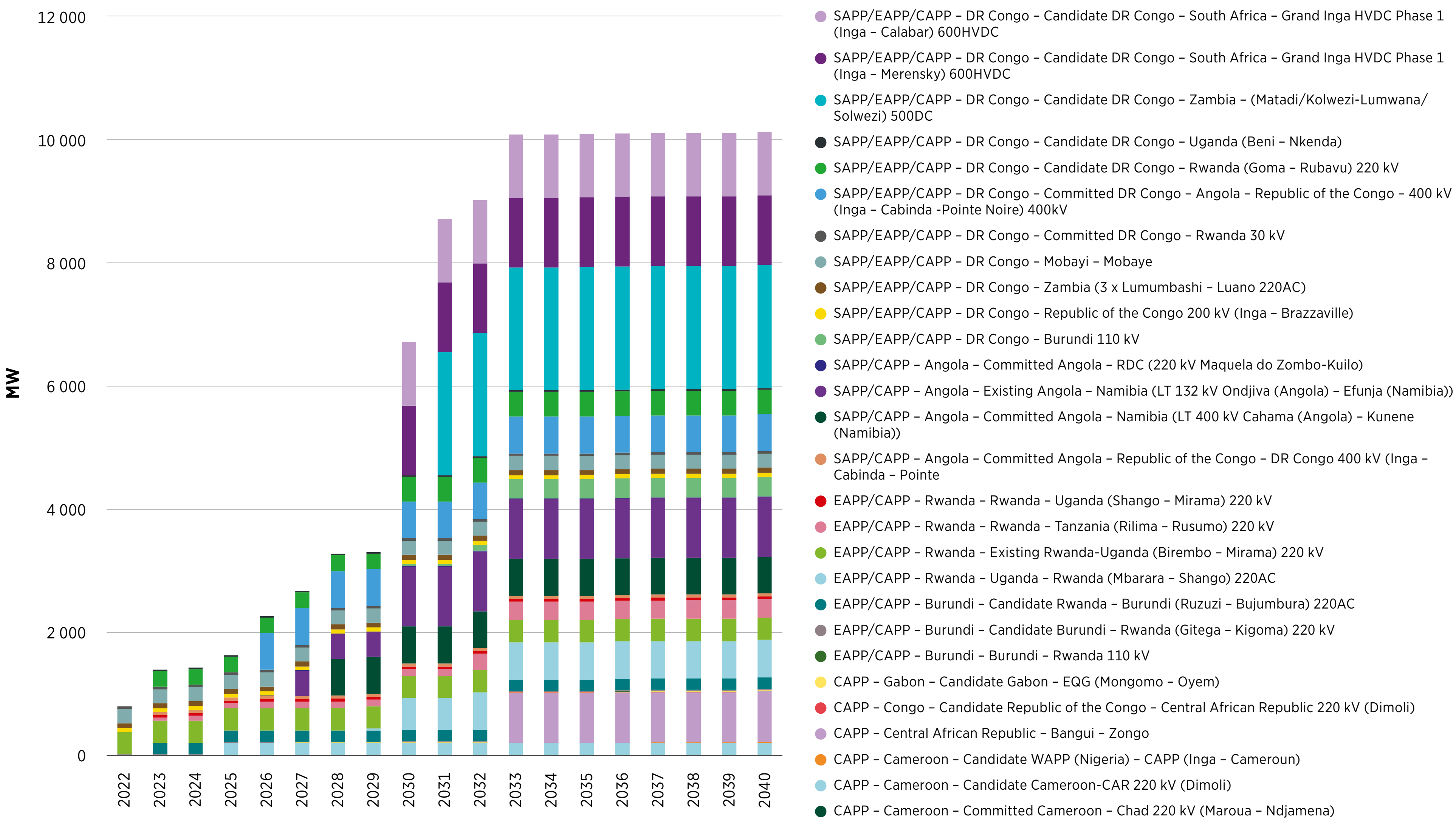
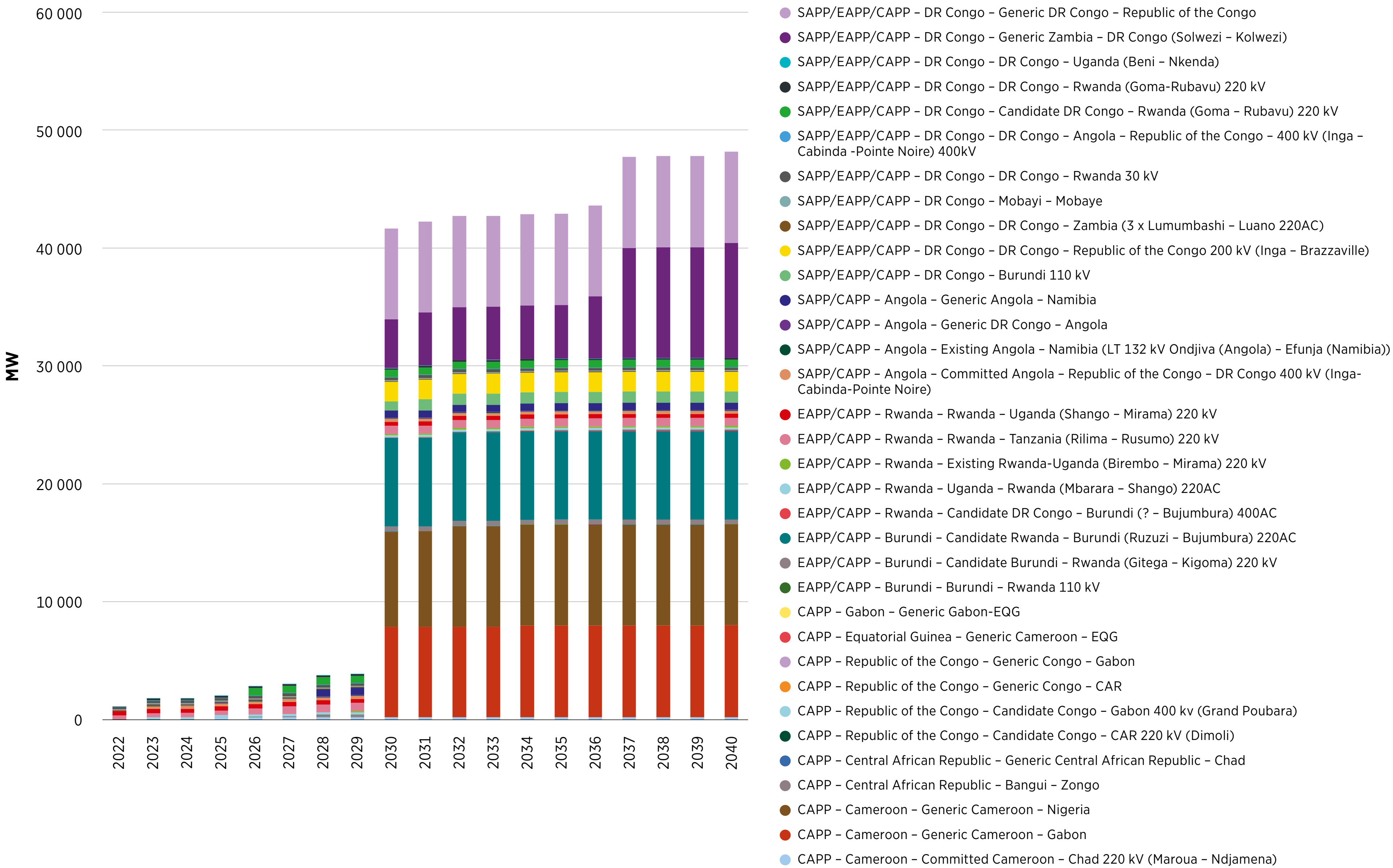


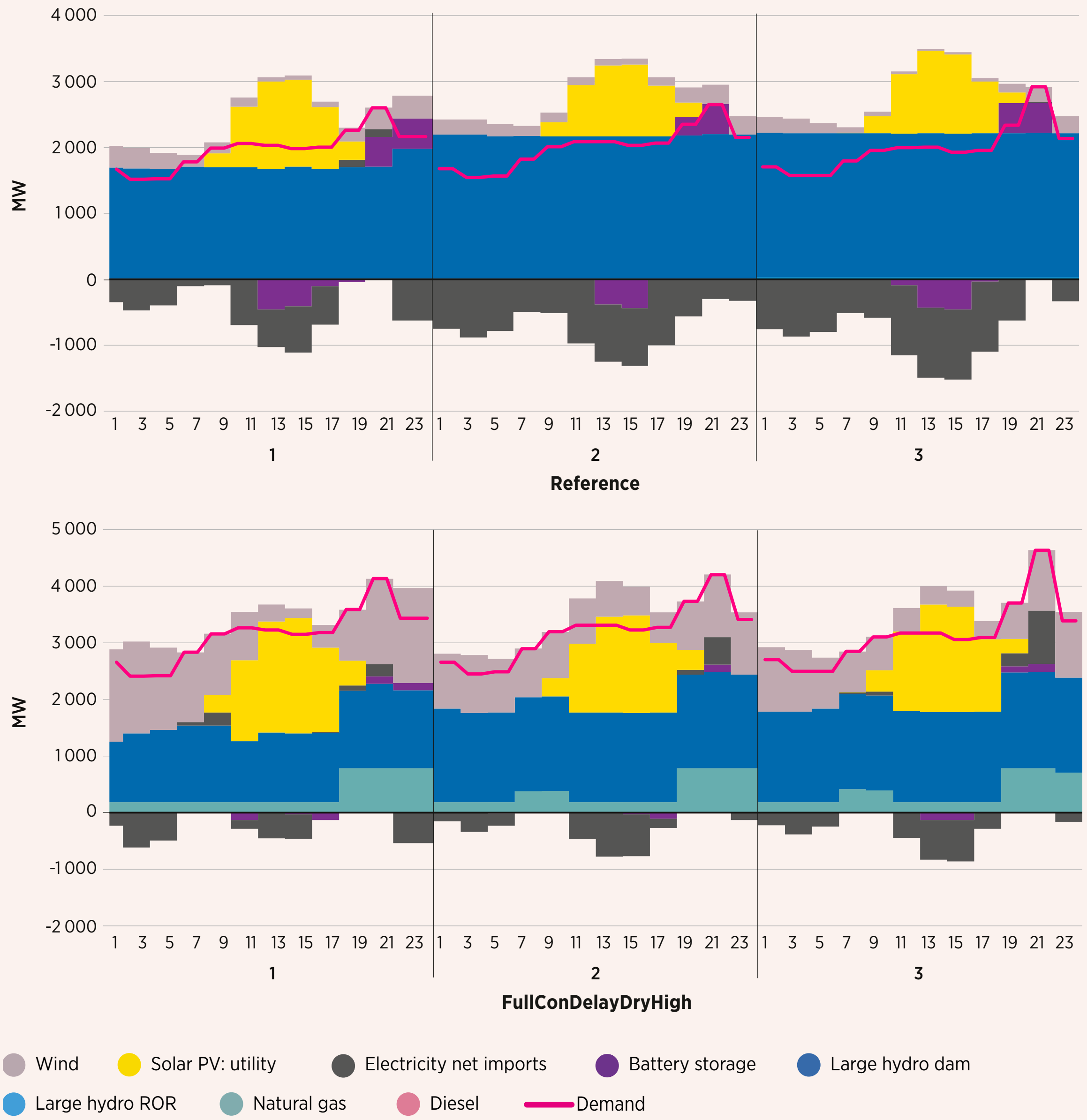
Figure 34 Continued



Box 3 SPLAT-Africa dispatch results

To better understand how electricity systems may evolve in the Central Africa region, it is important to also view the sub-annual dynamics of generation at the country level. As described in the methodological appendix of this report, every year of the SPLAT-Africa model for this analysis contains three seasons, namely: January-April, May-August and September-December. For each season, days are characterised by twelve blocks, resulting in a total of 36 model "time slices". While it is possible to increase the model's granularity, this parameterisation sufficiently represents behaviours of generation that will be critical to understand in future systems, particularly with the strong VRE penetration expected in many scenarios. These variables include the daily and seasonal variation of major renewable sources like solar PV, wind, and hydropower, as well as the flexibility solutions that will be deployed to complement such variation, including batteries and imports. Viewing more detailed sub-annual results can also provide insight into the behaviour of the little remaining fossil fuel capacity in many countries, to understand its role and plan for possible alternatives.

Figure 35 Cameroon sub-annual generation mix, 2040 (MW): Reference and FullConDelayDryHigh scenarios

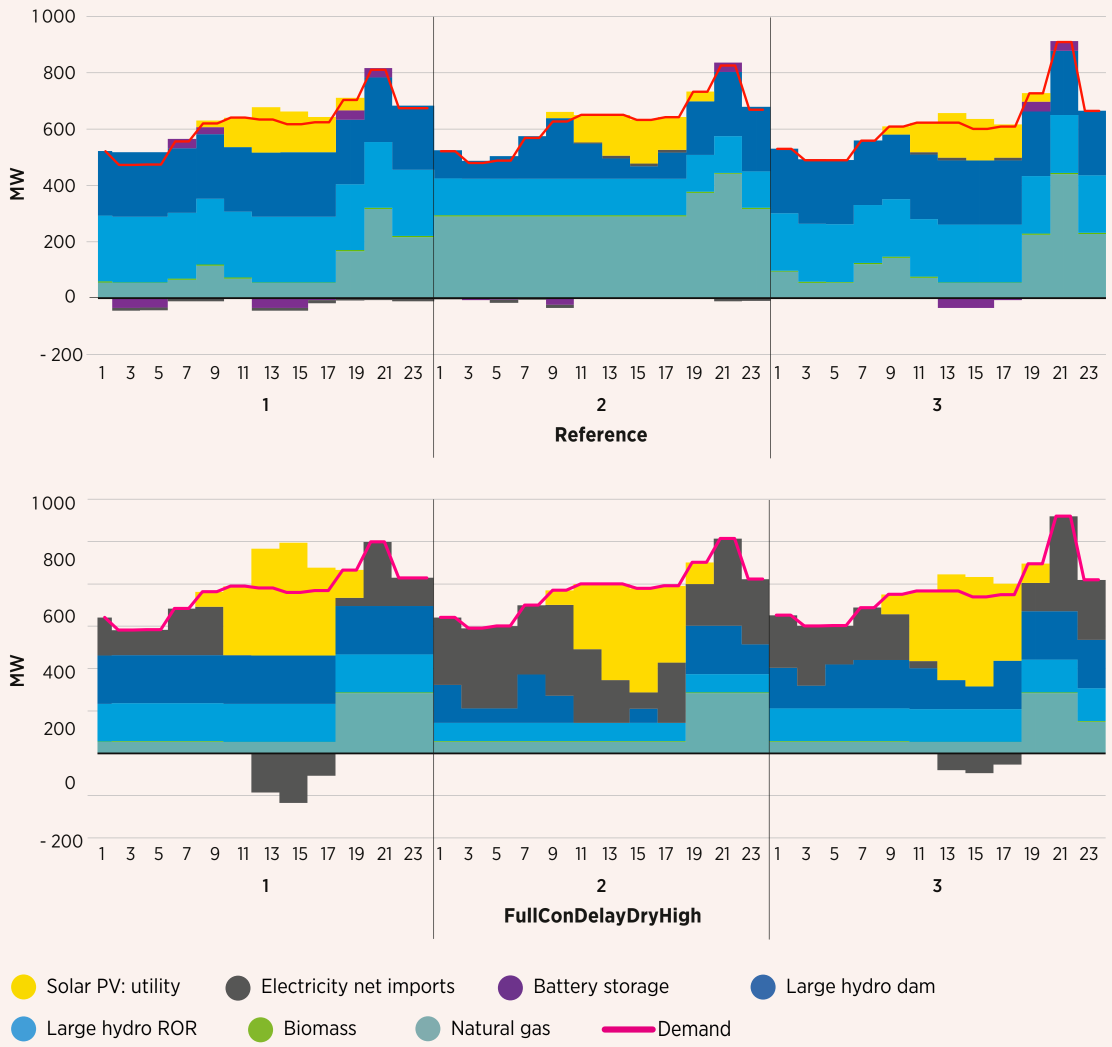


Box 3 Continued

The figures above and below show examples of sub-annual results for Cameroon and Gabon in 2040. They do this for the Reference scenario and the Full Continental scenario in which all interconnectors are possible, there is high demand, delays to interconnector and hydropower projects, and dry year conditions. The latter is therefore a scenario that includes a large amount of VRE capacity. In the case of Cameroon, in both scenarios we see the temporal complementarity of solar and wind resources through day and night-time production. In the Reference scenario, batteries play a role in further utilising solar power by shifting output to meet peak demand. Interestingly, we can also see one of the effects of greater interconnection discussed in the results section of this report: the use in the FullConDelayDryHigh scenario of more readily available imports, along with batteries, to meet peak demand. We also see what dry year conditions can do to the generation mix in that scenario, noting the reduced hydropower production and the retention of some gas capacity to meet peak demand.

In Gabon, we see similar dynamics at play, but also a clearer example of why temporal profiles on a daily and seasonal basis are especially important in representing hydropower. The availability of more interconnections and imports has a key role in the generation differences between both scenarios, but we also see that seasonal differences in hydropower availability have an influence on whether Gabon is exporting or importing power from one season to another. These types of insights are very important for long-term planners, enabling them to take informed decisions and account for various risks and possibilities. Such insights cannot be inferred only by viewing annual model results or net annual import/export values.

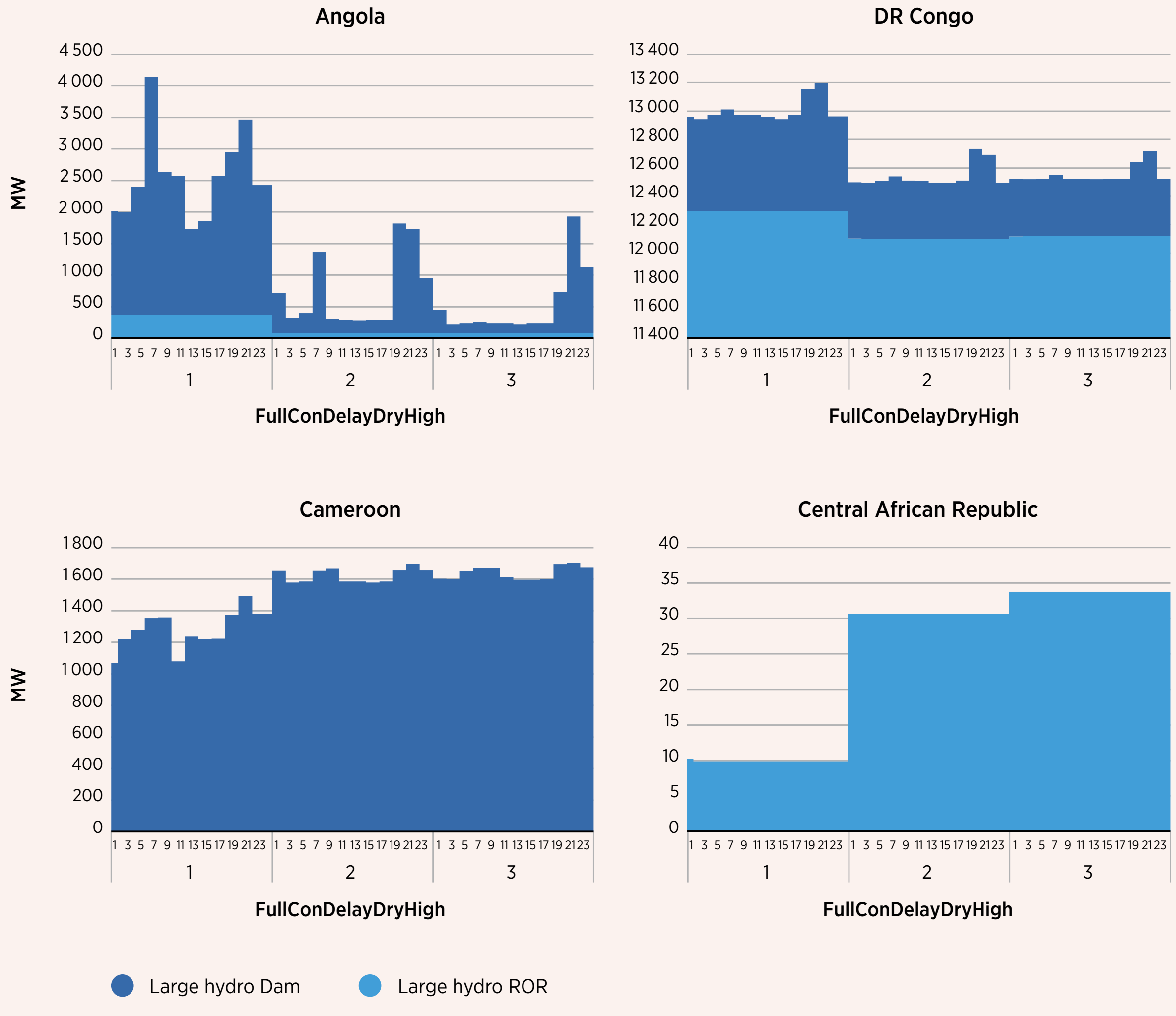
Figure 36 Gabon sub-annual generation mix, 2040 (MW): Reference and FullConDelayDryHigh scenarios



Box 3 Continued

Delving further into sub-annual results also shows the complementarity of renewable resources – strengthening the case for cross-border interconnection. The figures for 2040 shown below, for example, show hydropower reservoir and ROR plant production for countries in different river basins – Cameroon and the Central African Republic, and Angola and DR Congo. Even in the FullConDelayDryHigh scenarios shown here – the most challenging for hydropower and cross-border trade – we see seasonal complementarity in production profiles, as well as complementarity between types of hydropower plants in the construction pipeline.

Figure 37 Sub-annual hydropower generation, 2040 (MW): FullConDelayDryHigh scenarios



4.4 SYSTEM COSTS

The SPLAT-Africa model provides economic results for a given scenario in terms of investment cost, fuel costs and O&M costs. The sum of these elements constitutes the system costs that the model aims to minimise. The figures in this section show various views of the discounted system costs across all of the scenarios explored in this report. Investment costs are annualised over the lifetime of each technology. In addition, investment costs for the CAPP region include the cost of interconnection projects with countries outside the CAPP region, for comparison across scenarios. Importantly, the model optimises total costs at the African level, meaning it is possible to see higher investment costs in the CAPP region, if such investments would reduce the costs of the continental system as a whole.

As shown in Figure 38 below, the first notable result is a wide variation in total system costs for the CAPP region, across scenarios. Between 2022 and 2040, the cumulative cost of the highest-cost scenario (FullConHighDem) reaches around USD 145 billion. This is around 48% higher than the lowest cost scenario for the region (RefHydroDelay), which stands at around USD 97 billion for the same period.

Before investigating the drivers of these different scenario costs, it should be noted that, in general, the regional power system requires significant investment in the coming decades, regardless of scenario. Even in the RefHydroDelay scenario with the lowest regional investment, the overall amount implies a cost of around USD 5 billion per year on average for the region (see Figure 39), with about two-thirds dedicated to capacity investment.

Figure 38 CAPP cumulative total system costs (USD million) by scenario (top) and difference from Reference scenario (bottom)

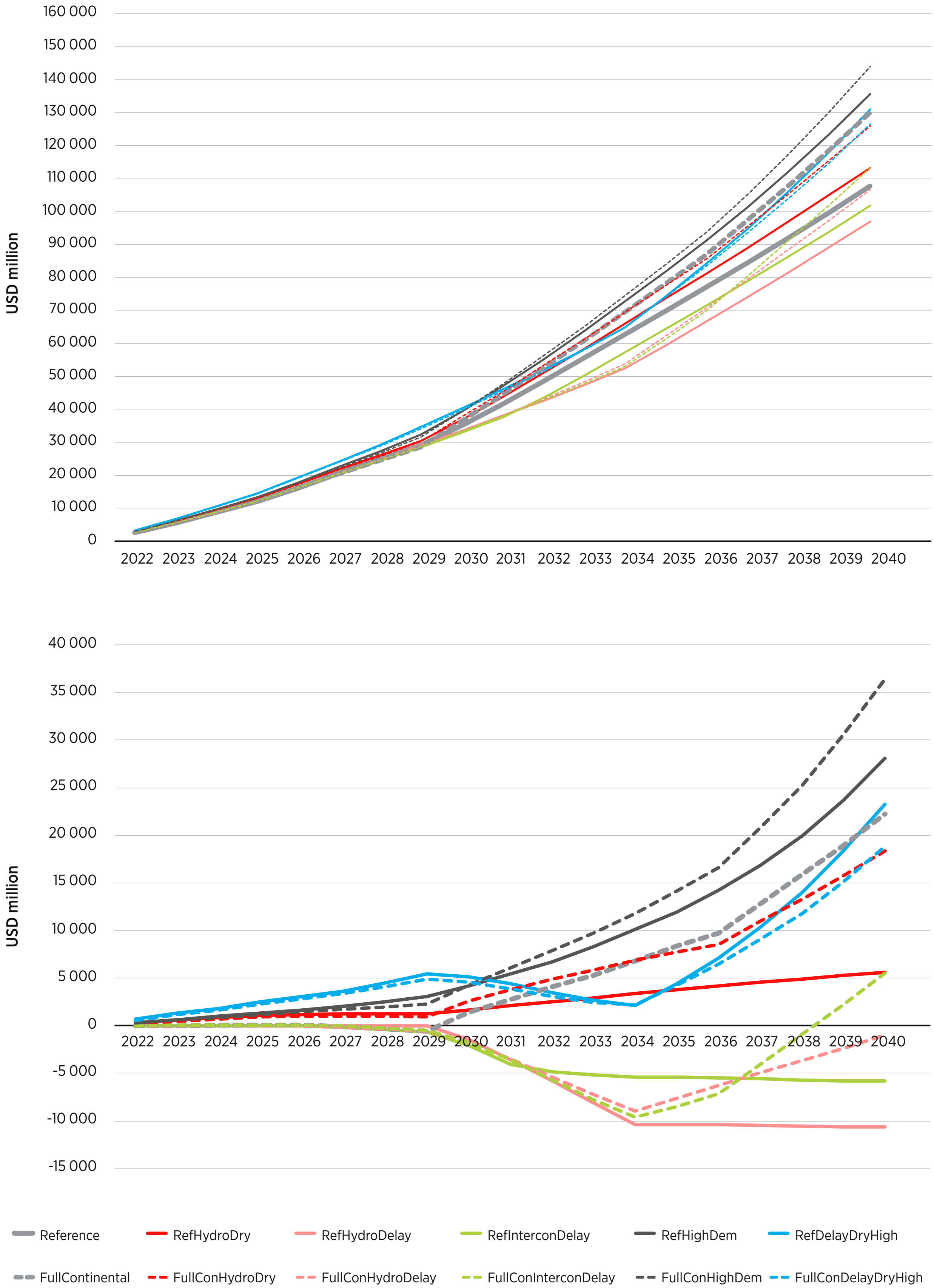


Figure 39 CAPP annual total system costs (USD million) by scenario

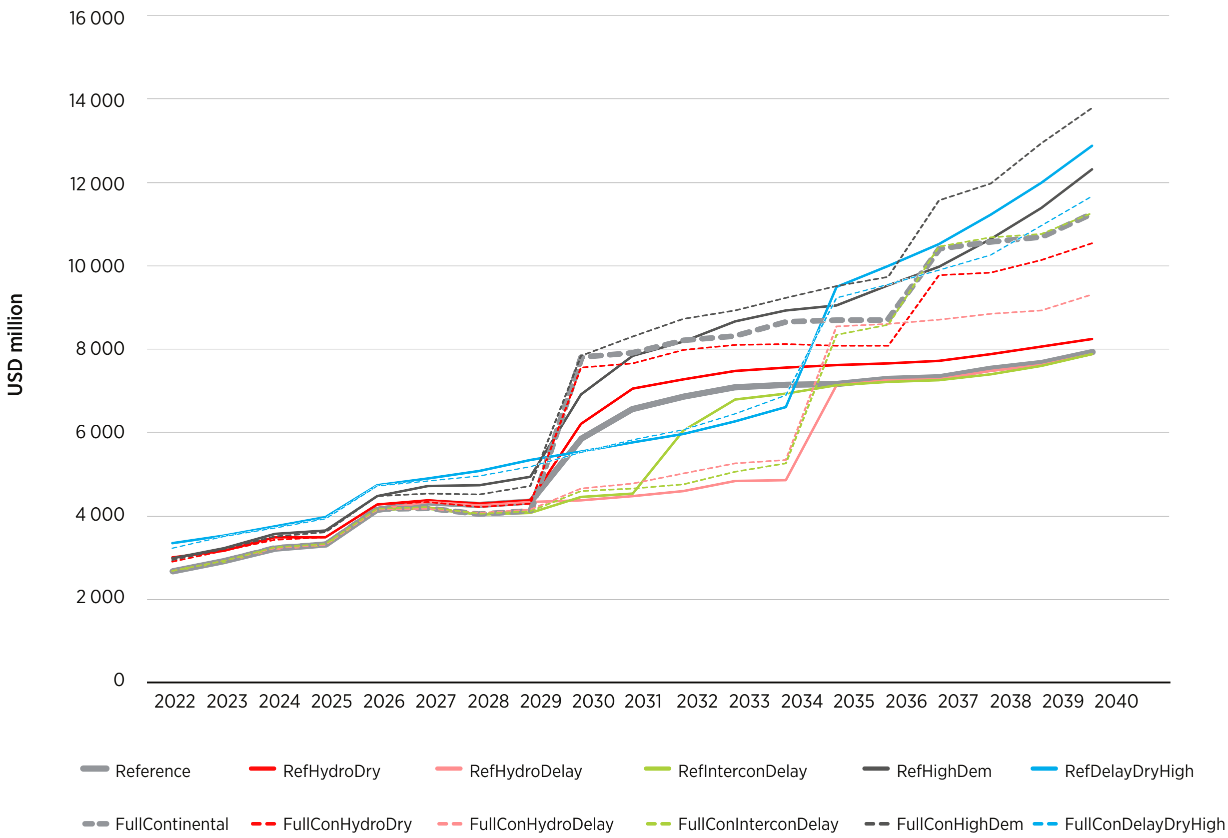


Figure 40 presents the annual system cost difference by category across all scenarios in comparison to the Reference scenario. The two main drivers behind the CAPP system cost are the level of demand growth and the level of interconnection between regions. High demand assumptions naturally lead to more investment needs in capacity. However, in high-demand scenarios with Reference scenario interconnection assumptions (*i.e.* fewer interconnections available to the model), the CAPP region also sees higher natural gas fuel costs, since fewer alternatives are available to meet higher demand from outside the region. For that reason, high future demand has a stronger effect on costs under Reference scenario interconnection conditions. The cumulative costs are 26% higher in the RefHighDem scenario than in the Reference scenario, while they are only 11% higher in the FullConHighDem scenario as opposed to the FullContinental scenario.

Figure 40 CAPP annual total system costs (USD million): Difference from Reference scenario by cost category (top) and technology (bottom)

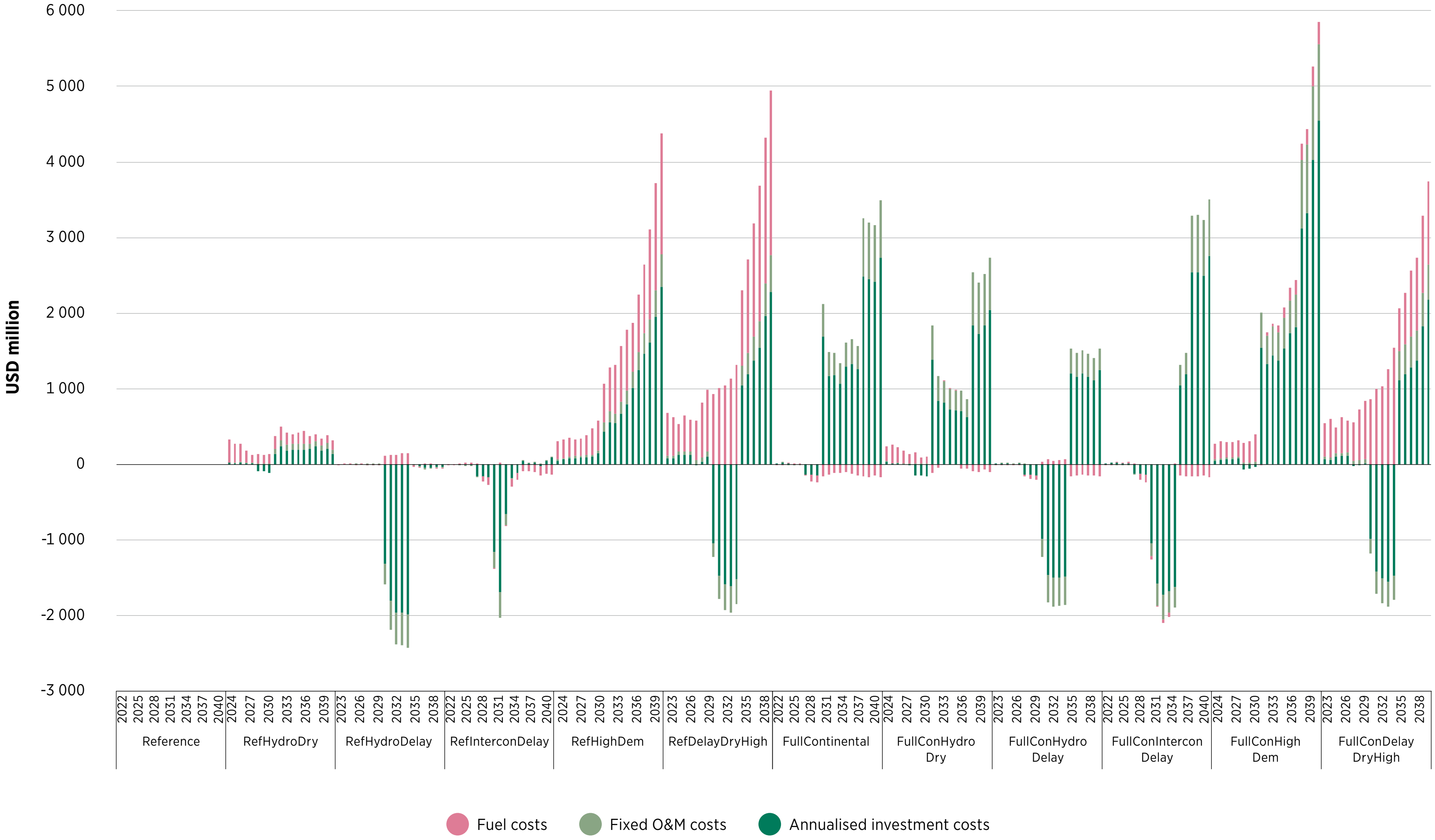
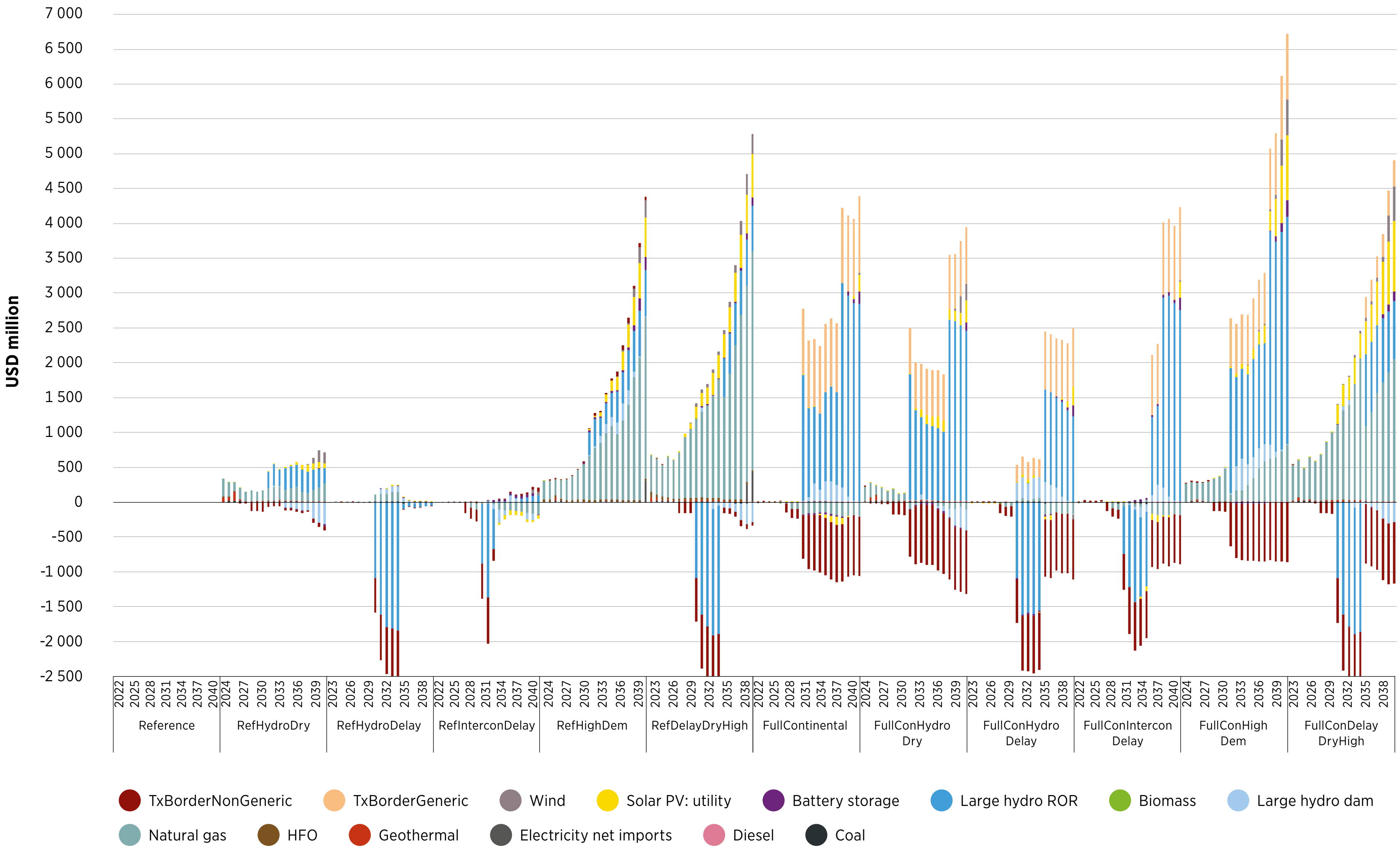


Figure 40 Continued



The other major determinant of CAPP regional system costs in the model is the level of interconnection that is eventually developed with other regions. As can be seen in Figure 41 and Figure 42 below, Full Continental scenarios are consistently less costly for Africa as a whole, since they allow lower cost – mainly renewable – resources to be used more extensively across borders. Interestingly, however, these results also show how important the CAPP region is for this outcome. Looking back at Figure 40, we see that Full Continental scenarios all include higher investment in hydropower capacity (especially related to large hydropower, *i.e.* the Grand Inga project) and associated cross-border transmission infrastructure, leading to higher cumulative "costs" for the CAPP region in scenarios with more inter-regional interconnection. For example, the scenario with lowest CAPP investment costs, RefHydroDelay, mainly reflects the fact that delays to large hydro in that scenario result in the least amount of investment in large hydropower and cross-border interconnection capacity.

These results highlight how important the planning of interconnector and export capacity development – and thus the role of CAPP in leading such discussions – is for future overall costs and investment needs in the region. They also highlight how important this planning is for the continent as a whole. As an example, we can see in Figure 43 – which shows the drivers of all-Africa system costs across scenarios – that higher investments in CAPP substantially reduce fuel costs in other regions of Africa. In particular, CAPP hydro exports displace the need for costly natural gas and coal fuel. We also know from Section 4.3 that several CAPP countries play a role in wheeling electricity through transmission to enable inter-regional exports. Thus, the amount of future overall investment cost in the CAPP region must always be viewed *vis-a-vis* any potential offsetting revenue, *e.g.* from inter-regional payments or cost-sharing agreements.

Figure 41 Cumulative total system costs (USD million) by scenario (top) and difference from Reference scenario (bottom), Africa

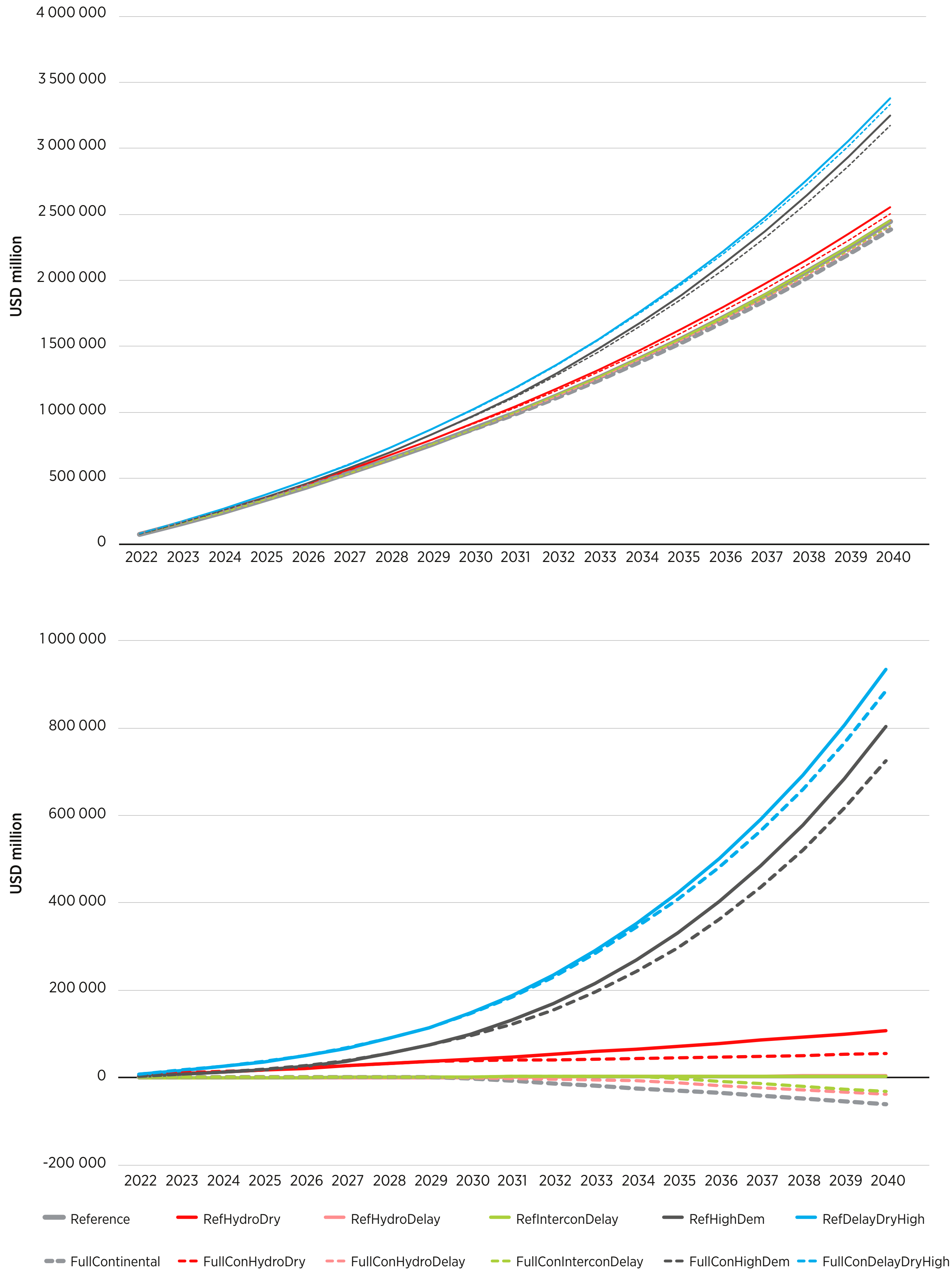


Figure 42 Annual total system costs (USD million) by scenario, Africa

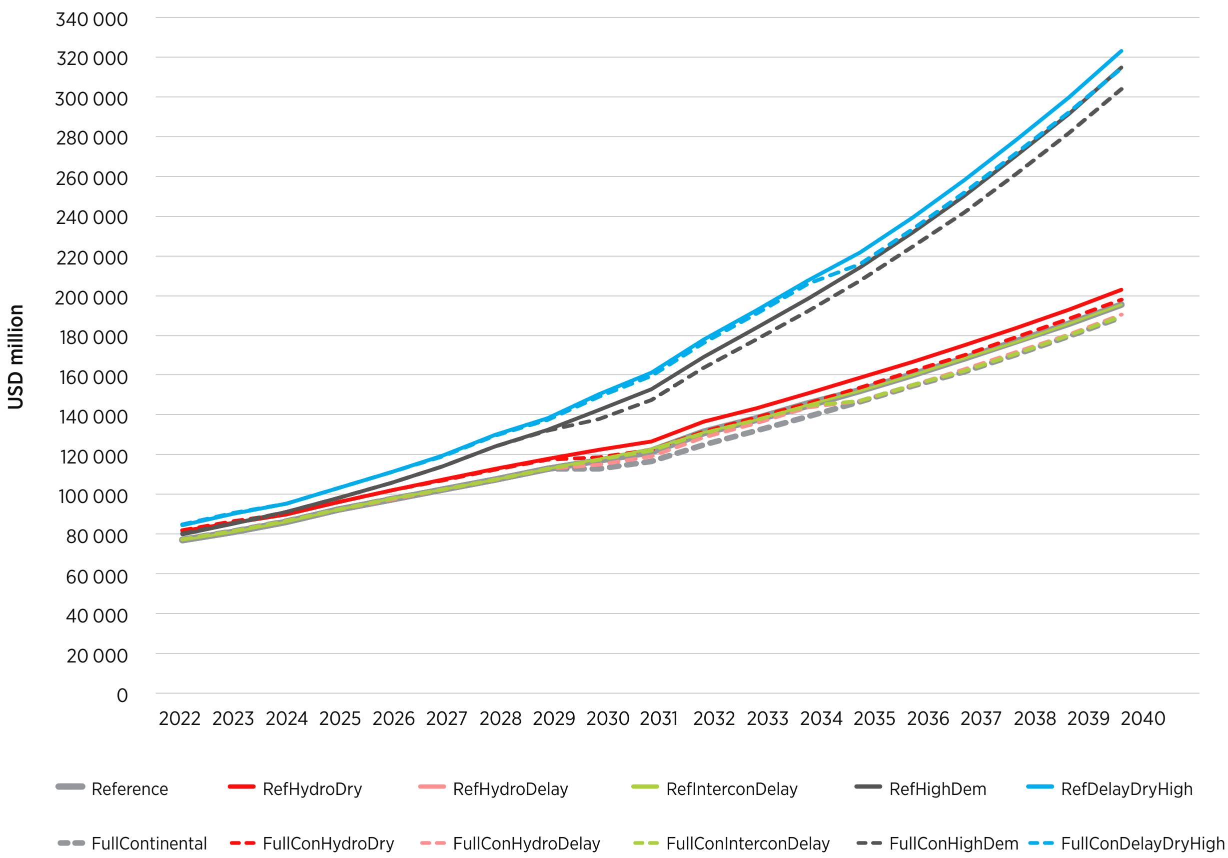


Figure 43 Annual Africa total system costs (USD million): Difference from Reference scenario by cost category (top) and technology (bottom)

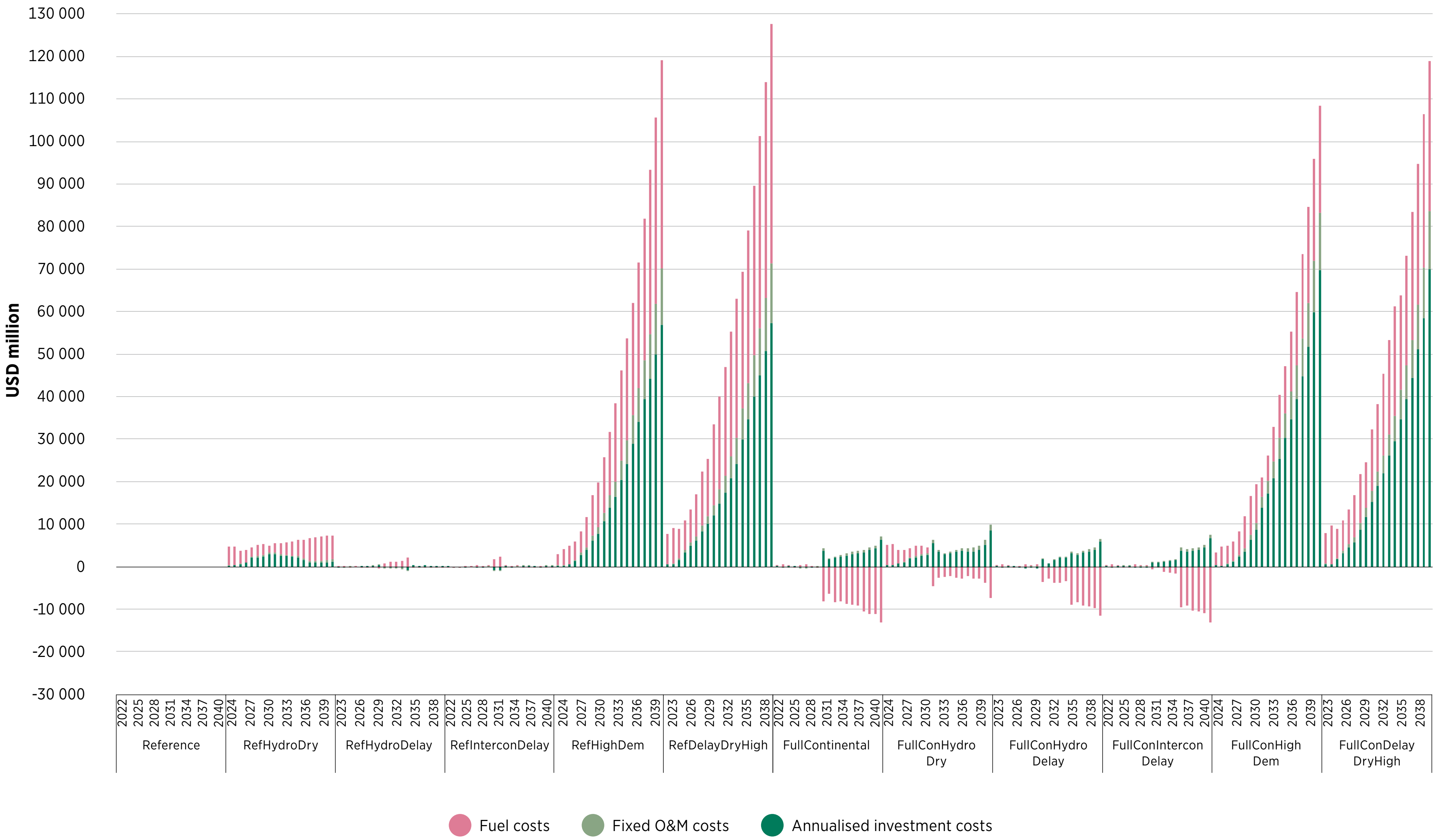
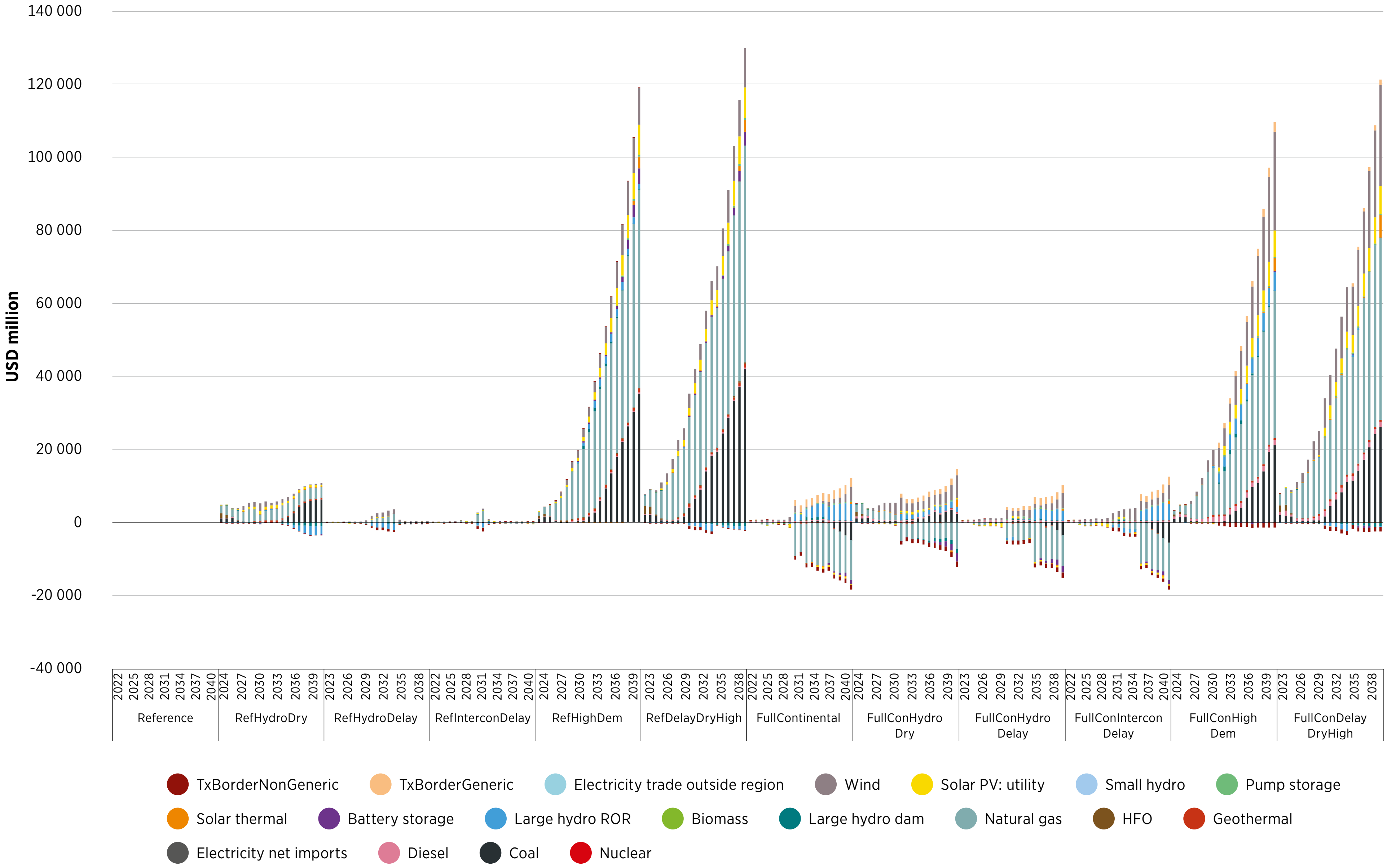


Figure 43 Continued



Box 4 Grand Inga: Implications on model results

In all the results, it is clear that the further development of the Grand Inga hydropower project would have a major influence on the broad evolution of the regional power system in Central Africa. With over 20 GW of hydropower potential reflected in the modelling – nearly twice the total current installed capacity in all of Central Africa – its development is emblematic of the region's ambitions to become an electricity exporter for the continent, and its rich renewable resources. However, given the project's outsize influence on model results, it is also prudent to explore future regional development, if Grand Inga is not further developed. The figures in this box provide a sample of the key difference in results with no new capacity from the project allowed under the Full Continental scenario conditions.

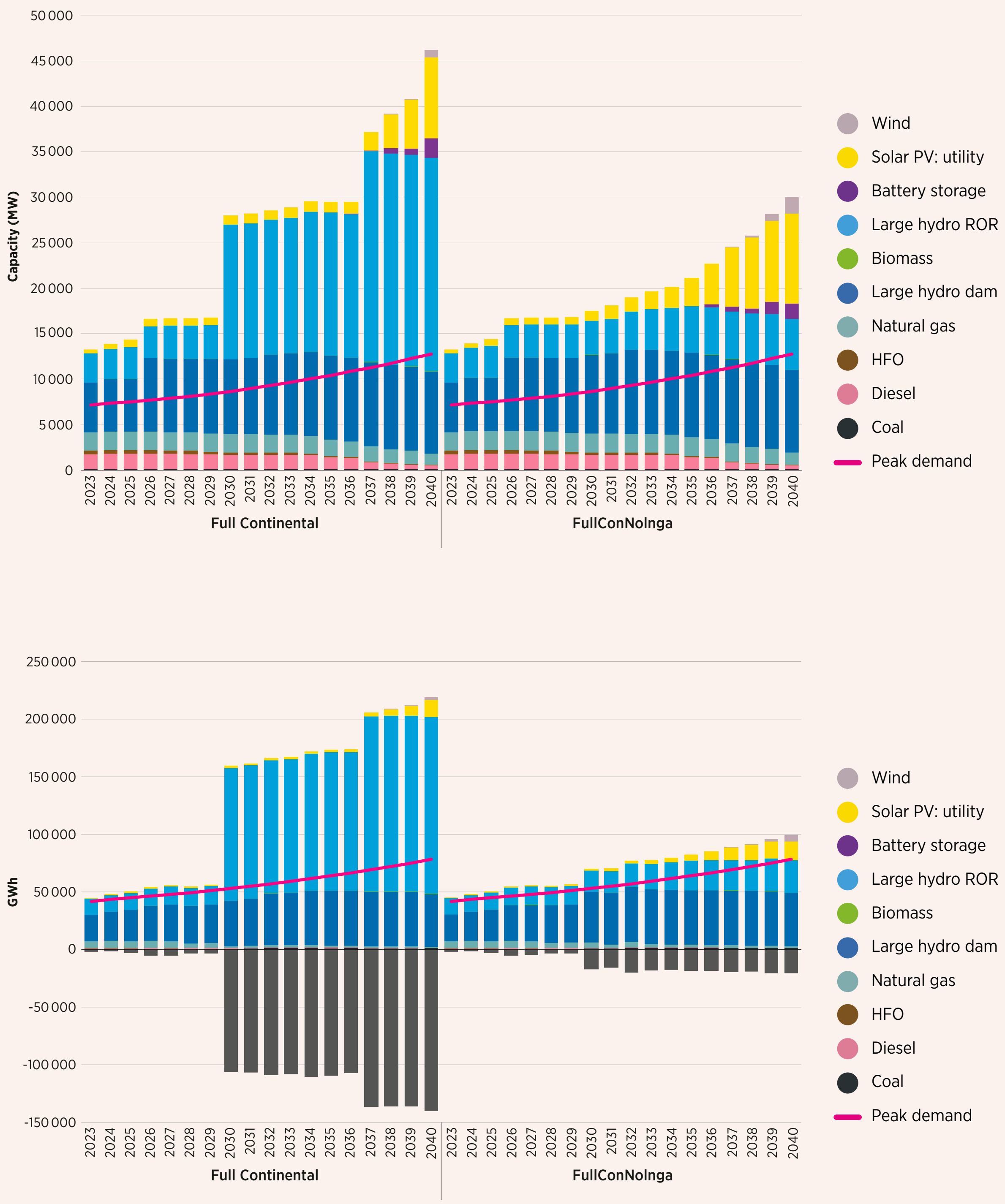
Removing Grand Inga expansion from the model also highlights some of the main findings from the results. First, the single project is a significant driver of regional capacity expansion and trade flows with other regions. Compared to the Full Continental scenario, regional results without Grand Inga contain 73% less interconnector capacity (around 13 GW as opposed to around 48 GW) and 81% fewer net exports from the region by 2040 (see Figure 39). Even though other types of capacity are built in the CAPP region that, to some extent, make up for Grand Inga, the removal of such a large project and its associated interconnector capacities reduces the investment costs in the region by a significant amount. Indeed, this results in cumulative costs (led by reduced investment) being nearly USD 40 billion lower in the CAPP region by 2040. As mentioned in previous sections of this report, however, such investment cost in CAPP for Grand Inga expansion are largely associated with exports to reduce costs in other regions, A scenario without Grand Inga expansion therefore increases continent-wide system costs, with cumulative costs for the continent by 2040 becoming about USD 45 billion higher.

As mentioned above, in terms of generation capacity, other sources are built in the region that partially take the place of Grand Inga, however. Interestingly, by the 2030s, when alternatives are required, renewables are cost-competitive enough to fill the gap in all countries, with just over 1 GW more solar PV and 1 GW of wind built in the CAPP region by 2040.

Figure 48 and Figure 49 show how other countries in the region shift their capacity and production without the presence of Grand Inga. It can be seen that Angola, Cameroon, the Republic of the Congo and Gabon are the most affected in terms of capacity, with these countries building different combinations of renewable and battery storage capacity for their own domestic systems. In terms of production, we see that Gabon shifts from being a net importer to a net exporter without the availability of Grand Inga, while without the project, the Republic of the Congo's share of imports in its production mix falls significantly by 2040.

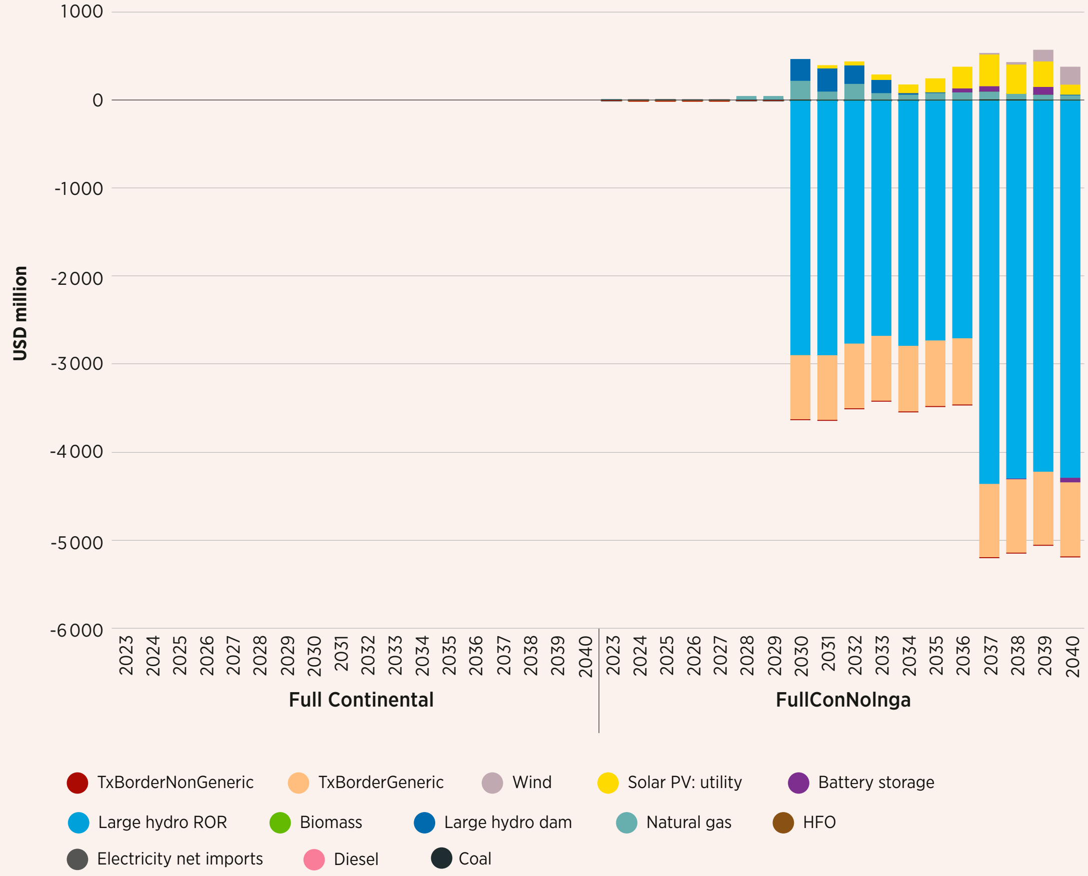
Box 4 Continued

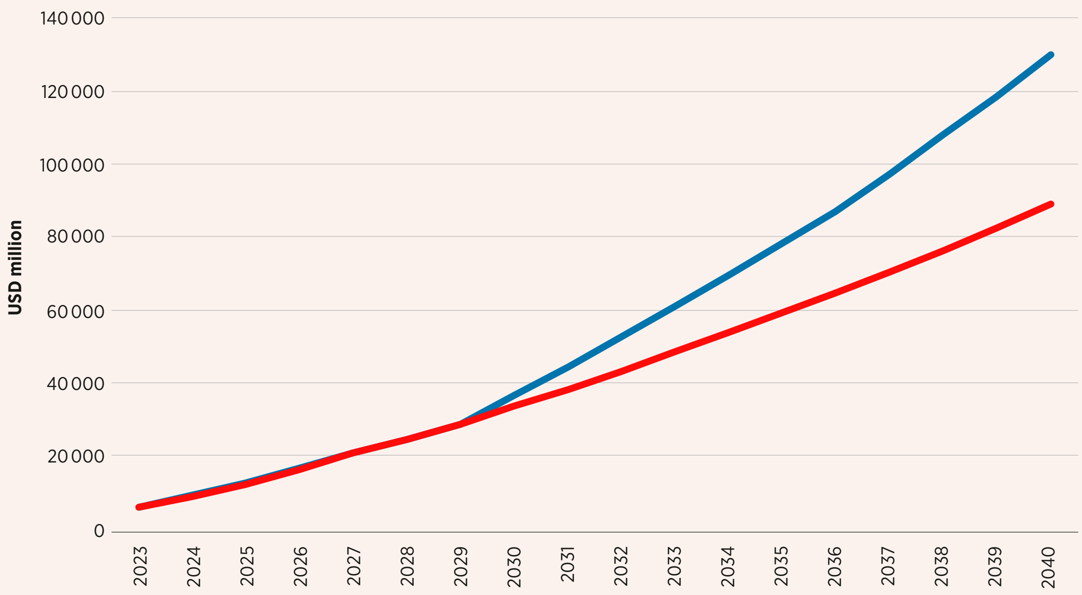
Figure 44 Capacity and production in the Full Continental scenario with and without Grand Inga



Box 4 Continued

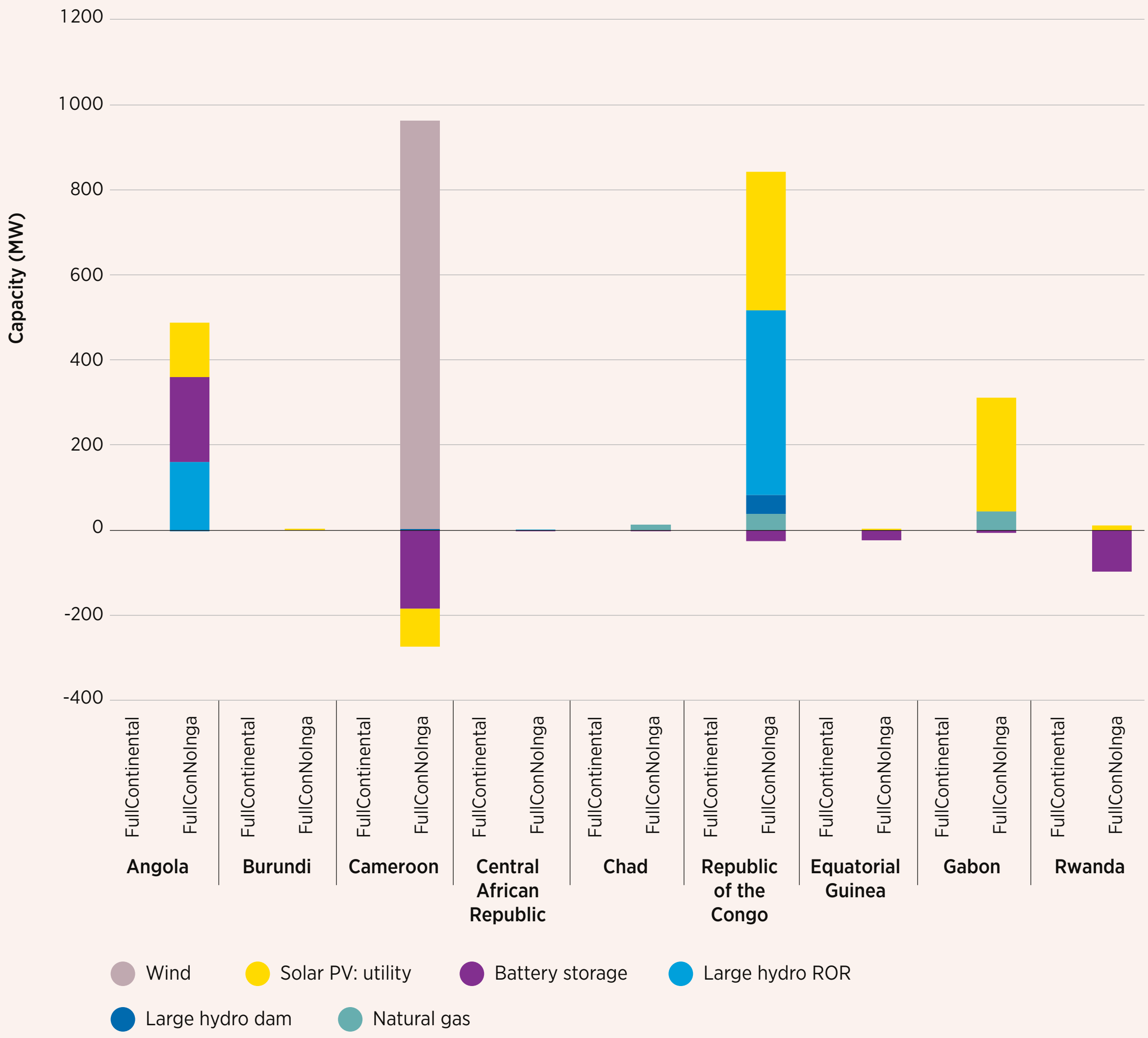
Figure 45 Total annual (top) and cumulative (bottom) CAPP system cost difference in the Full Continental scenario with and without Grand Inga





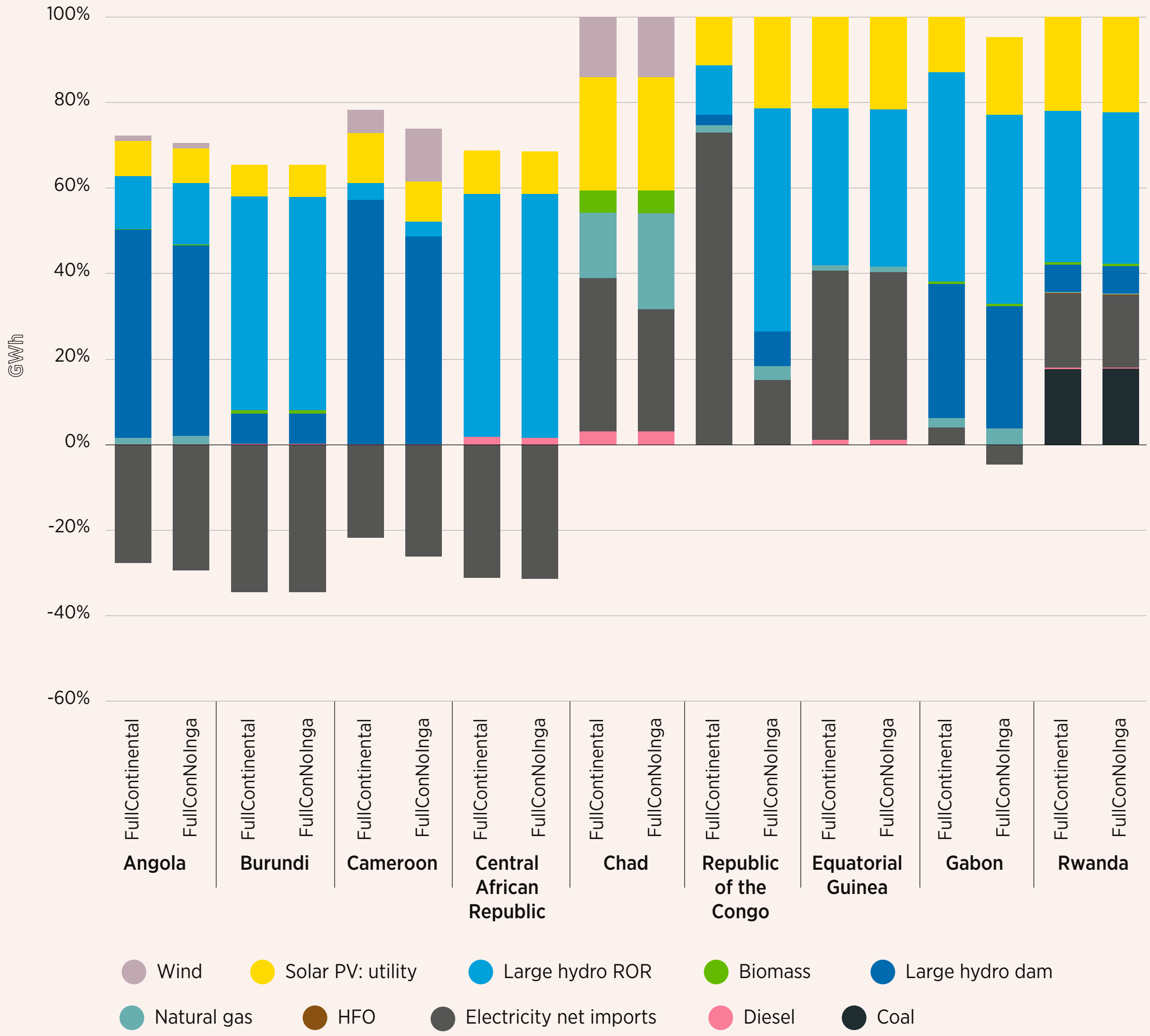
Box 4 Continued

Figure 46 Country-level capacity difference in the Full Continental scenario with and without Grand Inga by 2040 (not including DR Congo)



Box 4 Continued

Figure 47 Country-level breakdown of the power generation mix in the Full Continental scenario by 2040, with and without Grand Inga



CONCLUSIONS

5

IRENA's SPLAT-Africa model was developed to provide experts from IRENA member countries with a tool to plan power systems for the medium to long term, assess the economic implications of a given investment path, and prioritise investment options.

This report has aimed to build on the work of the IRENA-CAPP Regional Modelling Analysis & Planning Support Programme, by performing a consolidated regional analysis of potential scenarios for long-term power sector development in the region. In doing so, it documents the inputs and outputs of the SPLAT-Africa model that were developed by participants in the IRENA-CAPP programme.

Local experts are advised to continue exploring different assumptions in order to develop and compare their own scenarios. Such exercises will be needed to comprehensively analyse the benefits and challenges of accelerated deployment of renewables, especially in the light of recent ambitions. Amongst others, these ambitions are the COP28 pledge of tripling global renewables by 2030 and the Nairobi declaration, which aims to increase Africa's renewable generation capacity from a 2022 total of 56 GW to at least 300 GW by 2030.

The results of the analysis presented here are intended to support that effort and contribute to the national and regional dialogue to come, as CAPP member states prepare to meet ambitious renewable energy targets and develop the region's first official power sector masterplan. The results also serve to highlight the utility of the SPLAT-Africa model as a free and well-maintained tool to explore alternative national and regional power sector development scenarios.

The main findings from analysing the scenarios in this report include the following:

Renewables – especially hydro and solar PV – are central to capacity and trade expansion

- In all scenarios with reference demand projections, renewable sources (hydropower and solar PV, plus – in certain countries – onshore wind) meet the vast majority of projected demand up to 2040 at the regional level. This is without any targets imposed in the modelling. This is the case for scenarios with and without larger exports to other regions. In the majority of scenarios, the share of fossil fuels in electricity production falls from today's already low level in all scenarios to below 5% of production by 2040.

- Hydropower remains the largest renewable energy source in the region across all scenarios, supplying nearly 70% of the electricity in the region over the modelling horizon.

- The share of solar and wind goes from nearly zero to at least 7% of regional production by 2040 in all scenarios, with solar PV growing much more due to regional climate conditions. In scenarios with high demand, solar and wind reach between 14% and 20% of production by 2040. The highest values are observed in scenarios with challenging hydropower conditions (delays and dry years) and strong exports to other regions.

- In capacity terms, these results imply a large expansion of solar PV, wind and their complementary technology – batteries – relative to very low current levels. Depending on the scenario, the results show the potential for between 5 GW and 25 GW of solar PV, 0.5 GW and 3 GW of wind and 0.4 GW and 2.5 GW of batteries in the region by 2040.

Future developments in the region regarding demand, cross-border infrastructure, project delays, or hydropower conditions have a substantial influence on results; all should be considered in long-term plans

- In all scenarios, the CAPP region exports to other regions, making use of its low-cost renewable resources, particularly hydropower. In scenarios which allow the model to construct new interconnector capacity beyond the current project pipeline, however, we see over double the amount of exports to other regions. Indeed, the quantity exported rises from around 65 GWh in the Reference scenario in 2040 to around 140 GWh. This reflects the greater future export potential of large hydropower projects in the region, such as Grand Inga in DR Congo.

- Overall, the total amount of capacity required to be built in the region is quite sensitive to different future conditions. However, all scenarios need to at least double the amount of today's capacity in the region by 2040 to meet projected demand. In the scenario with the highest overall capacity in the region – the Full Continental interconnection scenario with high demand (FullConHighDem) – nearly 65 GW of capacity is built by 2040. This is more than twice the capacity required in the Reference scenario. It would also imply a 500% increase in today's total regional capacity in order to meet higher demand and exports outside the region.

- The type of capacity built to meet future demand at lowest cost is also sensitive to large project delays and dry year conditions. Dry year conditions and large hydropower project delays result in much more solar PV and more wind capacity built by 2040, while interconnector delays result in more battery capacity being built into the model to provide an alternative source of flexibility.

There is a large untapped potential for cross-border electricity trade

- In all Reference scenarios, cross-border interconnection capacity in the CAPP region grows over ten-fold to a total of around 10 GW by the mid 2030s. The largest projects chosen across all Reference scenarios include DR Congo-Zambia (2 GW), Angola-Namibia (1.5 GW), DR Congo-South Africa and DR Congo-Nigeria (around. 1 GW each). In scenarios where all physically possible interconnectors are allowed, the highest total interconnector capacity in the CAPP region reaches around 40 GW by the early 2030s and nearly 50 GW by 2040.

- The main driver of the overall increase in new interconnector capacity is to facilitate export to the WAPP and SAPP regions, starting in the 2030s. This is mainly driven by development of hydropower resource potential in DR Congo, and to some extent in Cameroon.

- However, there is also substantial trade between the countries of the CAPP in all scenarios. This demonstrates how they can take advantage of complementary resources to reduce overall regional costs and provide flexibility. For example, complementarity between hydropower production profiles and types of hydropower projects across different countries in the region improve the case for more interconnection.

- In scenarios with all potential interconnectors allowed, countries like the Republic of the Congo, Gabon and Cameroon also take on key new roles as transit hubs for wheeling electricity to major demand centres outside the region (*e.g.* Nigeria in the WAPP).

The Grand Inga hydropower project has a major influence on the evolution of inter-regional trade and the regional power system in Central Africa

- With over 20 GW of hydropower potential at the Grand Inga site reflected in the modelling (an amount nearly twice the total current installed capacity in all of Central Africa), the project's development is both emblematic of the region's ambitions to become an electricity exporter for the continent, and of its rich renewable resources.

- Removing the option of Grand Inga expansion from the model emphasises one of the main findings from the results. This is that this single project is a significant driver of regional capacity expansion and trade flows with other regions. Compared to the normal Full Continental scenario, regional results without Grand Inga contain 73% less interconnector capacity (around 13 GW as opposed to around 48 GW), and 81% fewer net exports from the region by 2040.
- These results highlight the fact that Grand Inga expansion is heavily connected – and in some ways dependent – on the expansion of cross-border interconnector capacity with other regions.
- In terms of generation capacity without Grand Inga expansion, other sources are built in the region that can take its place. Interestingly, by the 2030s – when alternatives are required – solar and wind are cost-competitive enough to substantially fill the gap in all countries. Without Grand Inga expansion, just over 1 GW more solar PV and 1 GW of wind is built in the CAPP region by 2040.
- Other CAPP countries also shift their capacity and production without Grand Inga expansion. The results show that Angola, Cameroon, the Republic of the Congo and Gabon are the most affected in terms of capacity, with the countries building different variations of renewable and battery storage capacity for their own domestic systems. In terms of production, we see that Gabon shifts from being a net importer to a net exporter without the availability of Grand Inga, and that the Republic of the Congo's share of imports in its production mix falls significantly by 2040 without the project.
- The future development of Grand Inga and CAPP interconnection capacity for export also has important continental implications. The results show that hydropower exports from CAPP largely displace coal and natural gas production in the two major importing countries of South Africa and Nigeria, thus reducing both emissions and costs from a continental perspective.

The results show that in all scenarios, the regional power system requires significant investment in the coming decades, although the overall amounts vary depending on future demand and cross-border interconnection

- Even in the scenario with the lowest investment needs, the overall amount implied is over USD 5 billion per year for the regional power system, with about two-thirds dedicated to capacity investment.
- Importantly, the model optimises total costs at the continental level, while higher investment costs in the CAPP region tend to reduce the costs of the African continental system as a whole. Higher investments in CAPP substantially reduce fuel costs in other regions of Africa, with CAPP hydro exports especially displacing the need for costly natural gas and coal fuel.
- The two main drivers behind the cost differentials in the CAPP region are the level of demand growth and the level of interconnection between regions, as these are associated with more capacity investment.
- Cumulative system costs for the CAPP region (including investment cost in generation and cross-border interconnection capacity, fuel costs and O&M costs) vary significantly depending on future assumptions in the areas of demand and cross-border trade. The highest-cost scenario (FullConHighDem) reaches just over USD 145 billion between 2022 and 2040. This is around USD 47 billion – or 48% higher – than the lowest cost scenario for the region (RefHydroDelay), which totals around USD 97 billion over the same period.[25]
- These results highlight how important the planning of interconnector and export capacity development – and thus the role of CAPP in leading such discussions – will be in determining the overall future costs and investment needs of the region – and of the continent as a whole.

[25] *For reference, IRENA estimates that all of Africa saw about USD 60 billion of investment in renewable energy between 2000 and 2020 (IRENA, 2023a).*

REFERENCES

Ember and Energy Institute (2023), "Total electricity generation per person", Our World in Data 2023, https://ourworldindata.org/grapher/per-capita-electricity-generation

IEA, *et al.* (2023), *Tracking SDG7: The energy progress report 2023*, International Energy Agency, International Renewable Energy Agency, United Nations Statistics Division, the World Bank and World Health Organization, Geneva, www.irena.org/Publications/2023/Jun/Tracking-SDG7-2023

IRENA (2019), *Sugarcane bioenergy in Southern Africa: Economic potential for sustainable scaleup*, International Renewable Energy Agency, Abu Dhabi, www.irena.org/Publications/2019/Mar/Sugarcane-bioenergy-in-Southern-Africa-Economic-potential-for-sustainable-scale-up

IRENA (2021a), *African renewable electricity profiles for energy modelling database: Hydropower*, International Renewable Energy Agency, Abu Dhabi, www.irena.org/publications/2021/Dec/African-Renewable-Electricity-Profiles-Hydropower

IRENA (2021b), *Planning and prospects for renewable power: Eastern and Southern Africa*, International Renewable Energy Agency, Abu Dhabi, www.irena.org/publications/2021/Apr/Planning-and-prospects-for-renewable-power-Eastern-and-Southern-Africa

IRENA (2023a), *World energy transitions outlook 2023: 1.5°C pathway*, International Renewable Energy Agency, Abu Dhabi, www.irena.org/Publications/2023/Jun/World-Energy-Transitions-Outlook-2023

IRENA (2023b), *Scenarios for the energy transition: Experience and good practices in Africa*, International Renewable Energy Agency, Abu Dhabi, www.irena.org/Publications/2023/Jan/Scenarios-for-the-energy-transition-Experience-and-good-practices-in-Africa

IRENA (2023c), *Planning and prospects for renewable power: North Africa*, International Renewable Energy Agency, Abu Dhabi, www.irena.org/Publications/2023/Jan/Planning-and-prospects-for-renewable-power-North-Africa

IRENA (2024), *Advancements in continental power system planning for Africa*, International Renewable Energy Agency, Abu Dhabi, www.irena.org/Publications/2024/Jul/Advancements-in-continental-power-system-planning-for-Africa

ISO (2020), *Sugar Yearbook*, International Sugar Organisation, www.isosugar.org/publications/1/sugar-yearbook

Sterl, S., *et al.* (2021), "A spatiotemporal atlas of hydropower in Africa for energy modelling purposes", *Open Research Europe*, vol. 1, pp. 29, https://doi.org/10.12688/openreseurope.13392.1

Sterl, S., *et al.* (2022), "An all-Africa dataset of energy model 'supply regions' for solar photovoltaic and wind power", vol. 9, pp. 664, https://doi.org/10.1038/s41597-022-01786-5

UN DESA (2022), "Revision of World Population Prospects", https://population.un.org/wpp/

World Bank (n.d.), "World Bank GDP statistics", http://data.worldbank.org/indicator/NY.GDP.MKTP.CD

APPENDIX: METHODOLOGICAL DETAILS

A.1 OVERALL ASSUMPTIONS

In all scenarios, the overall methodological assumptions were as follows:

- The real discount rate applied is 10%. This is consistent with assumptions in the CMP.
- The monetary unit used is the 2019 USD rate, and adjustments to any data in USD from other years are made using the US GDP deflator from the World Bank (World Bank, n.d.).
- The study horizon spans 2019 to 2040. The year 2019 is the base year from which optimisation begins, with model calibration performed to reflect the situation at the time of modelling.

As mentioned previously in this report, the implementation of the IRENA-CAPP Regional Modelling Analysis & Planning Support Programme was closely integrated with the development of the CMP, led by AUDA-NEPAD and with key financial support from the EU, with IRENA in a supporting role as a modelling partner. As such, a wide range of model inputs outlined in this report draw upon the work completed by the CMP project, which also had the full participation of the CAPP.

A.2 ELECTRICITY DEMAND PROFILES

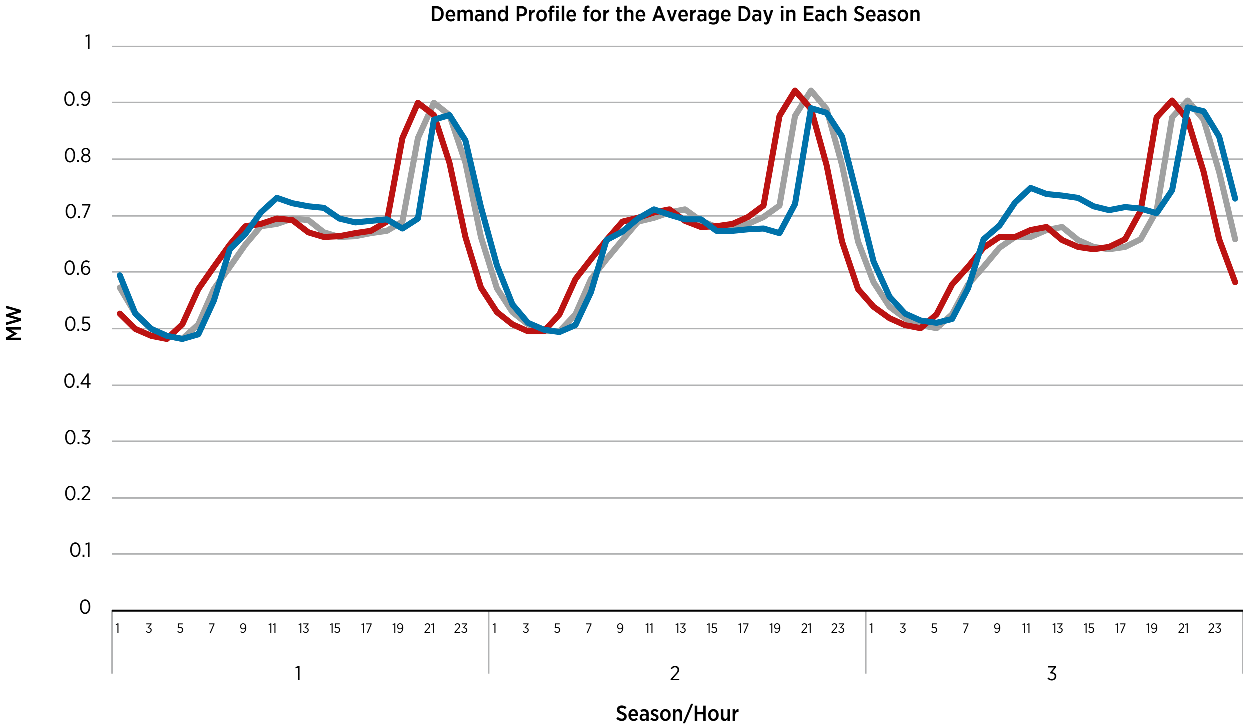
To capture electricity demand patterns, SPLAT model years are characterised by load profiles for different seasons and parts of the day. Hourly load profile data provided as part of the CMP programme were aggregated by time slice for modelling purposes with the SPLAT methodology using an algorithm to preserve hourly peak demands under the approach. Figure 49 shows a representative visualisation of the selected countries load profile data used in the analysis, post-aggregation.[26] The model for this analysis contains three seasons: pre-boreal summer (January-April), boreal summer (May-August) and post-boreal summer (September-December). For each season, days are characterised by twelve blocks, as presented in the figure below, resulting in a total of 36 model "time slices".

Figure 48 Daily time slice aggregation

HOUR	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
BLOCK	1	1	2	2	3	3	4	4	5	5	6	6	7	7	8	8	9	9	10	10	11	11	12	12

[26] Full detail behind load profile assumptions can be found in the CMP programme documentation at https://cmpmwanga.nepad.org/publications

Figure 49 Normalised load (MW) on an average day in each season, all years of the modelling period



Note: Figure shows example of load curves in the modelling of three countries in the region for illustrative purposes only.

A.3 ELECTRICITY GENERATION OPTIONS

The core of IRENA's SPLAT-MESSAGE modelling framework is its power system database. This consists of electricity generation investment options that can be optimised to meet future demand. The SPLAT-MESSAGE modelling framework not only contains existing power generation assets, but also committed assets. These are specific plants which are not online yet, but which are considered certain to come online in a known future year. The model also includes all candidate technologies, with the model able to choose a selection to cover any future supply-demand gap.

Candidate technologies in the SPLAT-MESSAGE modelling framework are modelled distinctly by type:

(i) Candidate power plants or gensets running on gas, coal, HFO, diesel and biomass, as well as candidate nuclear power plants, are modelled as "generic" technologies. "Generic" means that no technological, geographical, or economic distinction is made in the cost characteristics between different individual "candidate" plants. The generic candidate technology is a lumped category that covers all future possible power plants of that technology which do not fall under "committed".

(ii) Candidate hydropower plants are modelled as site-specific, given the importance of the resource in the region. Since it is not meaningful to speak of "generic" hydropower potential, given that every hydropower plant has very specific characteristics and output profiles (see *Renewable generation options* below), the potential for building new hydropower plants across Africa has been appraised at the level of individual plants. Each of these plants is separately included in the model, both for ROR and for reservoir hydropower plants. The latter requires including river flow dynamics and reservoir filling dynamics in the MESSAGE modelling framework.

(iii) Like hydropower, candidate geothermal plants are also modelled at the individual project level, according to an appraisal performed under one of the CMP support studies of possible future projects in Africa.[27]

(iv) A wider pool of candidate capacity in renewable technologies whose potential is spatially divergent, but less site-constrained than hydropower and geothermal, has been modelled as a set of regional "clusters" of high potential sites. These renewable technologies are solar PV, solar CSP, onshore wind, and offshore wind. The potential for these technologies can cover large swathes of a country's surface area, while hydropower, for example, is restricted to locations where rivers undergo altitude drops. As a result, the most attractive part of this renewable potential was screened out for each country and grouped into a number of clusters with comparable production profiles. Each of these serves as an individual "candidate" technology in the model with its own techno-economic parameters. The number of region-specific clusters thus obtained varies between 2 to 10, according to technology and country (see *Renewable generation options*). On top of this, the capacity of project-specific candidate solar PV, solar CSP and onshore wind is represented in the model, characterised according to stakeholder inputs from the IRENA and CMP training programmes.

(v) Certain technologies require a temporal profile to model their availability on diurnal and/or seasonal timescales. This includes all solar and wind technologies and ROR hydropower, as well as the river flow technologies feeding hydropower reservoirs. The profiles for site-specific technologies are therefore uniquely defined to reflect each site's meteorological and hydrological conditions.

The SPLAT-MESSAGE framework also contains storage technologies. These consist of regular hydropower reservoirs (see above), pumped-storage (off-river) hydropower and battery storage. Similar to the "river technology" classification used to model reservoir hydropower, battery storage technology is linked to a certain energy/power ratio to control the length of storage duration. Candidate battery storage schemes are modelled generically, with the same option per country.

A.4 EVOLUTION OF CAPITAL EXPENDITURE, OPERATING EXPENDITURE AND FUEL COSTS FOR POWER GENERATION

The capital expenditure of building new generating plants is an essential parameter in capacity expansion modelling. For site-specific committed and candidate projects, announced project costs are used where available. These were provided by, or reviewed as part of, the IRENA-CAPP Regional Modelling Analysis & Planning Support Programme and the CMP programme. If project costs were not available, generic values for the particular technology were applied. Detailed economic parameters for all technologies are summarised in the data appendix accompanying this report.

For generic thermal generation options, investment costs were taken from the support studies and modelling performed in the CMP programme. These were also informed by existing IRENA publications (IRENA, 2021b, 2023c). For each technology, the same capital costs were considered for all countries in Central Africa. The yearly fixed operating expenditure for these technologies was assigned a generic assumption of 3% of the capital expenditure (IRENA, 2021b, 2023c). These costs are taken to be constant throughout the study period as the technologies in question are assumed to have reached maturity.

For solar PV, onshore and offshore wind, and CSP there is a significant trend towards lower capital costs. In general, these technologies show a relatively steep decline in the early years of the study, followed by a less pronounced decline beyond 2030. This represents the gradual maturation of these technologies over the study horizon. Between 2020 and 2040, baseline onshore wind investment cost assumptions fall from

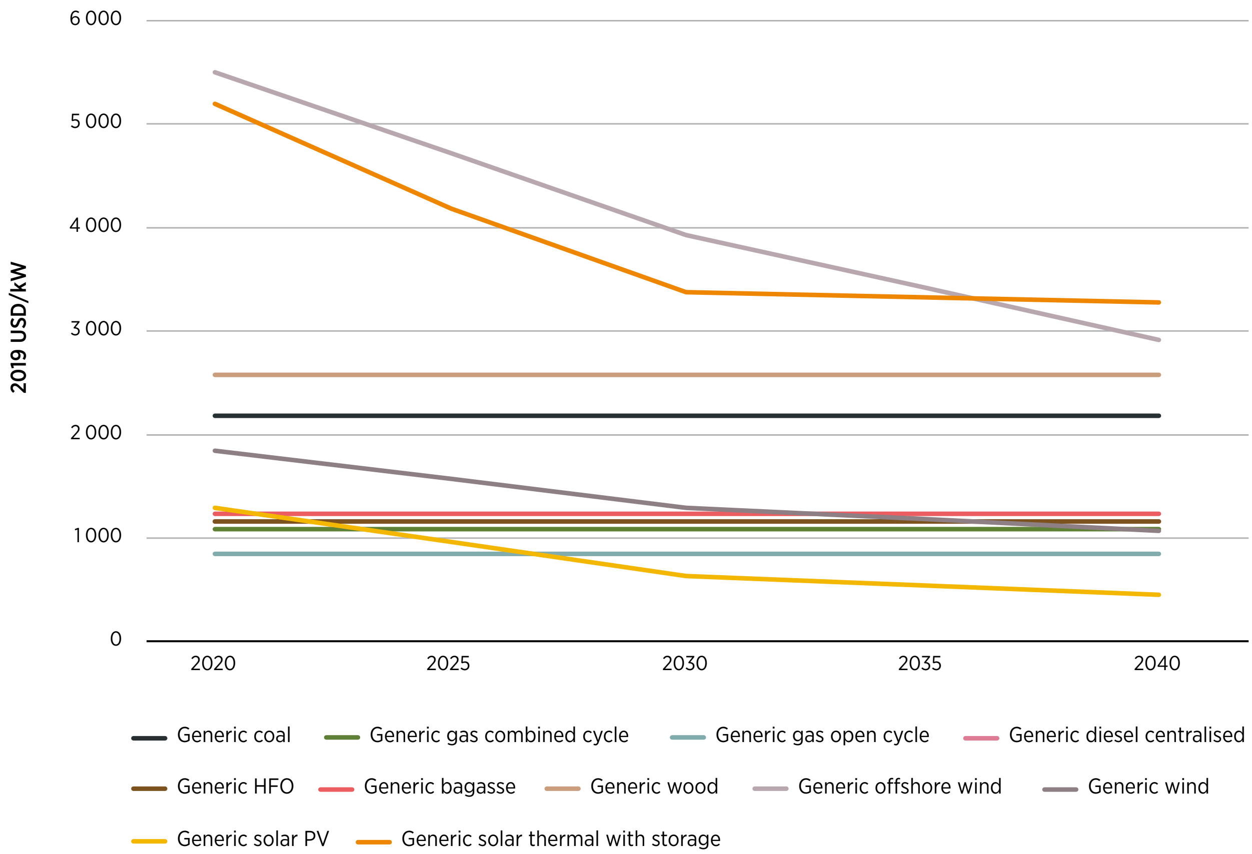
[27] *It should be noted that geothermal potential in CAPP countries is not very common and unexplored where present (e.g. mainly in Cameroon and possibly Equatorial Guinea).*

USD 1 850/kilowatt (kW) to USD 1 070/kW; for offshore wind they are expected to fall from USD 5 500/kW to USD 2 915/kW. Solar PV costs are projected to fall from USD 1 295/kW to USD 450/kW over the same period, while CSP (with six-hour storage) capital costs are projected to decline from USD 5 195/kW to USD 3 280/kW.[28]

These assumptions are based on the IRENA costing analysis for the World Energy Transition Outlook. They assume that Central African costs will gradually decline from the high end of current non-OECD ranges towards equivalence with global average costs by the end of the horizon. The O&M costs of wind and solar plants are taken from the non-Organisation for Economic Co-operation and Development (OECD) assumptions in the IRENA costing analysis and assumed to be constant over the horizon. These figures can be found in the data appendix accompanying this report.

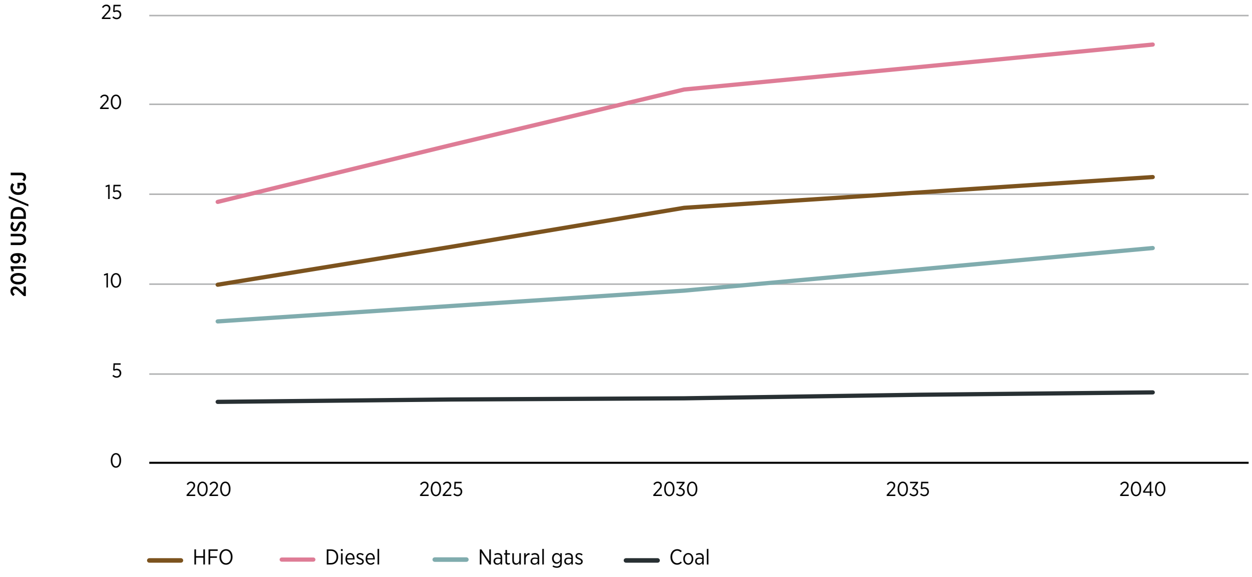
Fuel price projections were based on modelling performed in the CMP programme, which was informed by existing IRENA modelling of African power systems (IRENA, 2021b, 2023c). No differentiation was made between country-level fuel prices and those between producers and importers. The rationale for this is that subsidies are the main reason for inter-country differences in fuel prices. Not differentiating thus avoids skewing results on the basis of such subsidies. In other words, using the global fuel price allows the modelling to take into account the real cost of electricity generation and the real potential for exporting those fuels from oil and gas producing countries. As shown in Figure 51, an increase in fossil fuel prices is expected through the horizon, with a different rate of increase after 2030, as demand for these fuels is expected to shift over time.

Figure 50 Baseline overnight investment cost assumptions for generic technologies (USD/kW)



[28] *As noted in the previous section, these baseline investment costs are adjusted upwards for specific wind and solar MSRs in the model, depending on the particular characteristics of each MSR – e.g. on the need for additional transmission or road infrastructure.*

Figure 51 Fuel price projections



A.5 CONSTRAINTS RELATED TO SYSTEM AND UNIT OPERATION

In the SPLAT-Africa model, key system constraints are introduced to ensure realistic results and that generation of VREs, such as wind and solar power, is represented accurately.

Reserve margin

To ensure power system reliability, excess operational capacity needs to be installed over and above peak demand requirements. This is referred to as a reserve margin and is defined as the difference between operable capacity and the peak demand for a particular year, as a percentage of peak demand. In all scenarios, a minimum reserve margin constraint of 10% has been imposed on every country.[29] Only "firm" capacity, which is guaranteed to be available to meet demand, is considered to contribute to this requirement.

The "capacity credit", or the share of capacity that is considered firm, is set at 100% for dispatchable technologies such as thermal and large hydropower with dams.[30] For variable renewable generation technologies, however, the capacity credit values that can be applied in such a modelling exercise typically depend on a statistical analysis of the correlation between a country's variable resource and its demand profile. The capacity credit of these technologies is generally lower than their capacity factor, as no single site can be relied upon to generate power at any given time, considering the natural variability of wind and solar conditions. As reflected in the table below, the capacity credit of solar PV and wind is treated very conservatively in the SPLAT-Africa model, with no contribution to the reserve margin. This implies that the amounts of solar and wind capacity featured in the results of this report should also be considered conservative amounts for planning purposes, and to be further investigated. For full details on the rationale behind all reserve margin contributions by technology, the reader is referred to the IRENA report "Advancements in continental power system planning for Africa", which describes the methodology and design of the SPLAT-Africa model (IRENA, 2024).

[29] *While reserve margin is defined in the model, progress toward this target for countries currently below the 10% level is practically constrained by the combination of existing capacity and available future capacity options in a given year. This essentially results in a gradual approach to 10% reserve margins in certain contexts.*

[30] *Note that capacity credit values assigned to conventional generation can depend on the methodology behind the value calculation. Values less than 1.0 are reasonably applied to account for plant availability in certain approaches.*

The national-level reserve margin constraint is defined as follows:

$$\sum_{i=1}^{n} \alpha(i) C_P(i) \geq (1 + RM)D$$

Where:

- $\alpha(i)$ is the capacity credit given to plant/technology *(i)* or share of capacity that is accounted for as "firm" (fraction)
- $C_p(i)$ is the capacity of power plant/technology *(i)* in MW
- *D* is the peak demand in MW
- *RM* is the reserve margin (fraction).

Table 7 Overview of reserve margin contributions of the various technology types used in the SPLAT-Africa model (numbers represent the percentage of the technology's installed capacity that counts towards the installed reserves)

TECHNOLOGY	RM CONTRIBUTION
CONVENTIONAL GENERATION	
Gas	100%
Coal	100%
HFO/diesel	100%
Nuclear	100%
Biomass	100%
Hydropower (RoR)	100%
Hydropower (reservoir)	100%
VRE GENERATION	
Solar PV	0%
Onshore wind	0%
Offshore wind	0%
TECHNOLOGIES WITH STORAGE	
Pumped hydropower	75%
Solar CSP with 6 hours storage	75%
Batteries with 4 hours storage	75%
TRADE	
Interconnections to neighbours	50%

Instantaneous variable renewable penetration

The reserve margin constraint is applied at the annual level, without regard for the temporal dynamics of power mix penetration of sources with zero reserve margin contribution. Given concerns about the frequency and voltage stability of power grids with relatively low inertia – which characterises many (though not all) African countries – the SPLAT-Africa model contains the option to limit the instantaneous penetration of VRE generation in each model time slice for each country's power system.

Based on real-world examples and on stakeholder consultations in the CMP process, to simulate the effect that it may not be desirable for power systems across Africa to run on 100% VRE for extended periods of time in the near- and medium-term, a maximum value of 70% was used as a default across all countries in the CMP analysis.

Technology deployment speed for VRE and biomass technologies

The model contains maximum buildout rates for modern renewables currently undergoing fast cost reductions (solar PV, solar CSP, onshore wind and offshore wind). The rationale behind this is that the declining cost curves can make it attractive for the model to invest "in bulk" in these technologies in a given year, leading to spurious results in which the capacity of a country's power system could be doubled or tripled within a single year. To avoid this issue, and also to reflect real-world constraints related to financing and/or manufacturing resources, maximum deployment speeds for the VRE technologies (in MW/year) are modelled at the individual country level. These growth constraints are modelled to increase from year to year in line with the growing size of a country's power system. The default maximum VRE deployment speed used in SPLAT-Africa was 25% of the peak demand of the previous year. This default was corrected upwards in all cases where it would have otherwise contradicted the capacity coming online from large, already committed projects.

In addition to VRE, annual build limits are also imposed on the buildout of biomass-based plants. The approach for this was as follows. First, historical sugar production was assessed at a country-level (ISO, 2020) and the production per capita was calculated. Assuming this ratio to remain constant, sugar production was then extrapolated across the model period using the UN population projections (UN DESA, 2022). Sugar tonnage was then converted to the production potential of electricity from biomass (bagasse) based on a previous IRENA study (IRENA, 2019). Lastly, this yearly potential in megawatt hours per year (MWh/year) was converted to buildout potential in MW/year, assuming a 65% capacity factor (IRENA, 2021b). Non-bagasse-based electricity generation from biomass was not considered in the model.

Other constraints

Other generic specifications at the power plant level were implemented to account for certain operational dynamics not captured explicitly, given the level of detail used in the SPLAT-Africa model.

For example, a minimum utilisation rate was applied for all thermal plants. This was done in order to capture, in a simplified way, the fact that thermal plants have to run at a certain minimum level to ensure stable operation and avoid a lack of capacity in contingency situations. The standard values used for the minimum utilisation rate were 5% for diesel and OCGT plants, 15% for CCGT plants, 20% for coal plants and 70% for nuclear plants.[31] Certain dispatchable renewables, namely biomass and geothermal plants, were also assumed to operate with a 20% minimum utilisation rate. The higher values for CCGT, coal and biomass plants reflect the fact that these plants normally have higher minimum stable operational levels and slower ramp rates than OCGTs.

Unplanned outages in thermal plants were also modelled using a derating factor for each power plant's capacity. This essentially limits the output of the plant in the modelling dispatch. This factor was generically taken to be set as the average forced outage rate for each plant, where data was available. If this was not, this factor was set to a generic value of 10.5% for reciprocating engine plants and 8% for others. This de-rating was not applied for reserve margin purposes. While this approach does not explicitly model the temporal dynamics of power plant outages, it factors outages into the economic considerations of generation expansion.

[31] *State-of-the-art technology for gas, coal, nuclear and geothermal power plants may lead to lower minima becoming more standard in the near- and medium-term.*

IRENA

International Renewable Energy Agency

www.irena.org