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Declining cost of renewables and climate change curb the need for African hydropower expansion

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In continental Africa, more than 300 new hydropower projects are under consideration to meet the future energy demand resulting from the growing population and increasing energy access. Yet, large uncertainties associated with hydroclimatic and socioeconomic changes challenge hydropower planning. Here, we show that only 40-68% of the candidate hydropower capacity in Africa is economically attractive. By analyzing the African energy systems' development from 2020 to 2050 for different scenarios of energy demand, land-use change, and climate impacts on water availability, we find that wind and solar out-compete hydropower by 2030. An additional 1.8-4% increase in annual continental investment ensures reliability against future hydroclimatic vari-

ability. However, cooperation between countries is needed to overcome the divergent spatial distribution of investment costs and potential energy deficits.

One Sentence Summary:

The window for economically competitive African hydropower development over the next three decades might be rapidly closing.

Over the next few decades, the African energy systems are expected to undergo profound changes. The total electricity demand is predicted to increase by 5-6% per year over the next ten years and until 2050 (*1–3*) driven by the sustained population growth, mainly in Sub-Saharan Africa (*4*), and the continuous infrastructural investments aimed at improving energy access and living standards, especially in the least developed areas (*5, 6*). This increasing demand, together with the need to mitigate and adapt to anthropogenic climate change (*7*), will shape the future development of the African energy systems. The use of low-carbon energy sources (*3, 8, 9*) will gradually lessen the historical dependency on fossil fuels, which are abundant in the continent (*10*). In the short-term, annual investments of 190 billion USD are required to ensure such a successful energy transition, with more than two-thirds of this financial investment allocated to clean energy sources (*3*). Among these, hydropower has historically been favored as a low-cost source of baseload power (*11*) and current policies imply a substantial infrastructural expansion (*12*). Moreover, hydropower is an attractive component of the future African power system owing to its ability to balance grid load in support of intermittent renewable electricity sources (*13–15*), and because the remaining untapped potential in the continent is relatively large (*11*). According to plans of national and regional agencies, more than 300 new hydropower projects are currently committed, planned, or under consideration over the African continent (*16*). These projects amount to a total of around 100 GW of additional hydropower capacity, with 168 large ($\geq$ 100 MW) projects accounting for almost 90 GW (*16*).

Nevertheless, climate change makes future hydropower generation uncertain (*17*) and increases the risk of cascading power system failures across countries and power pools (*18*), likely jeopardizing its potential to foster resilience (*19*). Moreover, capacity expansion projections are linked to future energy demand, technology costs, and climate policy, which are fundamentally uncertain factors (*20, 21*). The excessive reliance on hydropower in many Sub-Saharan countries is currently a source of concern and a reason for caution in additional hydropower investment (*22*). Further doubts are cast on hydropower capacity expansion (*23*) when socioeconomic and environmental impacts of hydropower are analyzed, such as population displacement (*24*), reduced sediment connectivity (*25*), loss of biodiversity (*26*), and competition with other water uses, most importantly with agriculture (*21*).

Given the scale of future infrastructure development, the socioeconomic and environmental impacts of hydropower expansion, and the need to bridge continental as well as regional power system development, it is crucial to identify the hydropower projects that should be prioritized and the ones that should be discarded based on the cost-optimal power system capacity expansion. In fact, the selection and sequencing of the hydropower infrastructure required in light of energy, socio-economic, and technological development is a critical first step. Further research should evaluate the ensuing social, climatic, and environmental impacts on the alternatives of interest to support final planning decisions. To what extent do the planned hydropower expansion and its spatial distribution over the main river basins change depending on socioeconomic, land-use, and climatic uncertainties? What are the costs of climate-proofing the energy system, and how are these costs spatially distributed compared to power deficits driven by hydroclimatic variability?

Here, we build an integrated modeling framework to examine the role of hydropower in a sustainable energy transition that is cognizant of hydroclimatic and land-use change, socioeconomic projections, and climate policy options. While previous studies on strategic dam planning (*27–30*) rarely include the power system and rarely go beyond the basin scale (*31, 32*), our analysis examines the full energy portfolio at the continental scale. Specifically, we consider cross-basin interactions over the power grid (*33*), hydropower projects proposed at the river basin and national scale, as well as socioeconomic and land-use projections. By doing so, we limit undesirable outcomes resulting from the integration of national, regional, and continental policies across multiple sectors and scales (*34*).

Our results show that hydropower will have lost its dominant role in Africa's renewable electricity mix by 2050, with solar and wind representing at least 29-38% and 8-12% of generation, respectively, while hydropower's share shrinks to 7-14% under all considered scenarios. Between 40% and 68% of the proposed new hydropower capacity, or, in other words, between 120 and 251 of the 367 proposed projects could potentially be cost-optimal, and nearly no new hydropower plants are recommended after 2030. While the viability of hydropower expansion in the Zambezi River basin is dependent on the scenario, many of the proposed projects for the Nile, Congo, and Niger remain economically viable under all considered scenarios. Finally, guaranteeing the reliability of the energy system against hydroclimatic risks only requires reallocating some of the investments in hydropower towards other sources, especially solar and firming technologies, with a small increase in annual capital investments. Yet, the need for additional investment and the risk of shortages are often located in different regions. As a consequence, we highlight the importance of transnational governance measures to guarantee climate-resilient energy systems.

Sequencing hydropower projects within power capacity expansion To obtain plans for hydropower project sequencing and associated power capacity expansion, we set up a multi-scale, multi-sector modeling approach (Fig. S1). We combine input data from three main datasets. First, we use the Shared Socioeconomic Pathways (SSPs) database (*35*) to obtain projected energy demands. Second, we rely on the African Hydropower Atlas (*16*) to characterize each hydropower project in the OSeMOSYS-TEMBA model (*36*). Third, to coherently account for the co-evolution of the climatic and the socioeconomic system, we use the Inter-Sectoral Impact Model Intercomparison Project (ISIMIP2b) scenarios (*37*) to represent the future hydrological regime resulting from changes in the climate system and in the land-use sector. Natural climate variability is considered using a median and a very dry hydrological scenario. These correspond to the 50^{th} and 5^{th} percentile of the distribution of simulated annual average generation which is obtained by simulating a distributed hydrological model under an ensemble of climate projections from 2020 to 2050 (see Methods).

We use the model to study the expansion trajectory of the African energy systems over the period 2020-2050 at the continental scale assuming centralized decision-making. We consider three socioeconomic scenarios aggregating socioeconomic, land-use, and climatic assumptions: (i) a sustainable development scenario, using a carbon emission constraint compatible with a 2 °C long-term warming, according to SSP1-2.6; (ii) a scenario designed to focus on heterogeneous economic development among regions not associated with climate policy efforts, according to SSP4-6.0; and (iii) a fossil-fueled economic growth scenario associated with high greenhouse gas emissions, according to SSP5-8.5. For each socioeconomic scenario, we consider the median (MED) and very dry (DRY) hydrological scenario. We use the first to represent traditional hydropower planning and the second to stress-test the power system under worst-case hydroclimatic conditions. Indeed, these two scenarios can be seen as describing different risk-preparedness targets (risk-neutral and risk-averse, respectively) with respect to the uncertainty associated with hydroclimatic variability. For each considered scenario, we optimize the power capacity expansion for each energy source and the sequencing of the proposed (i.e., planned, committed, and candidate) hydropower projects collected in the African Hydropower Atlas. Moreover, we examine the cost-reliability trade-off at different spatial scales, which would otherwise remain hidden behind the large-scale formulation of the least-cost capacity expansion problem.

Cost-effectiveness of solar energy avoids the need for long-term hydropower expansion

Our model results show that at least one-third of the new hydropower capacity proposed at the regional and country level is not cost-optimal across continental Africa, and this result holds under all considered scenarios (Fig. 1). Under ensemble median hydrologic change (i.e., under the MED scenarios), new hydropower installed capacity ranges between 52 GW under SSP4-6.0 and 66 GW under SSP1-2.6, while these values drop to between 39 GW (SSP4-6.0) and 47 GW (SSP1-2.6) when considering dry hydrology conditions under the risk-averse robust approach (i.e., under the DRY scenarios), meaning that more than half of the proposed capacity is not economically viable at the continental scale. In all these plans, two large projects are responsible for more than 17 GW of viable capacity: the soon to be completed 6.4 GW Grand Ethiopian Renaissance Dam and the 11.0 GW Inga 3 candidate project in the Democratic Republic of the Congo. In general, the SSP1-2.6 scenario consistent with a warming of 2 °C at the global level requires more hydropower than other scenarios due to the reduced reliance on fossil fuels. To isolate the impact of climate change on hydropower expansion, we examine capacity expansion strategies considering hydropower generation based on observations from 1986 to 2005. We see that climate change is particularly affecting the scenarios with the largest hydropower expansion and it is responsible for a reduction of 9 GW (SSP1-2.6) and 8 GW (SSP5-8.5) (Fig. S2).As we consider the salvage value of infrastructure at the end of the planning horizon corresponding with the remaining operational life, our results remain consistent when we extend the horizon until 2070 (Fig. S3).

Under all socioeconomic and hydrological scenarios, at least half of the additional hydropower capacity is installed in the period 2020-2030 (Fig. 1a-c), with the window in which hydropower can still compete economically with solar PV rapidly closing. Beyond 2030, the share of new investments in solar power increases substantially, and further development of hydropower in Africa is unlikely to be cost-effective (Fig. 2). While hydropower could still be competitive with solar PV until the end of the current decade, the often-witnessed build time and cost overruns for hydropower projects (*38*) may even preclude large-scale hydropower expansion before that time, paving the way for further solar PV deployment. In addition, all capacity investments are growing rapidly in the decades following 2030, thus further diminishing the role of hydropower in the future energy portfolio (*39*). Similarly, given the large expansion of the power system in the next decades, the decline of hydropower is substantial also in the total capacity share (Fig. S4). The gap is even more pronounced for the DRY scenarios where more than half of the proposed capacity is not economically optimal resulting in higher investments in solar power (bottom row in Fig. 2). Solar power becomes a more competitive option displacing more impacted hydropower projects. In SSP1-2.6, an important role is played by nuclear power by mid-century, which is used to further reduce investment in fossil fuel power sources and represents an important share of generation in 2050 (Fig. S5). Contrary to SSP1-2.6, where coal becomes almost absent, under SSP4-6.0 and SSP5-8.5 it still contributes around 40% of the generation mix by mid-century with more than 2000 TWh under SSP5-8.5 (Fig. S5). For what concerns the flexibility required in the power system to balance the reduced output of solar plants at night, hydropower comes after biomass and fossil fuels, and wind has a complementary diurnal profile to solar as well (Fig. S6). As a consequence, our results do not suggest hydropower still being a major provider of firm generation and flexibility by mid-century.

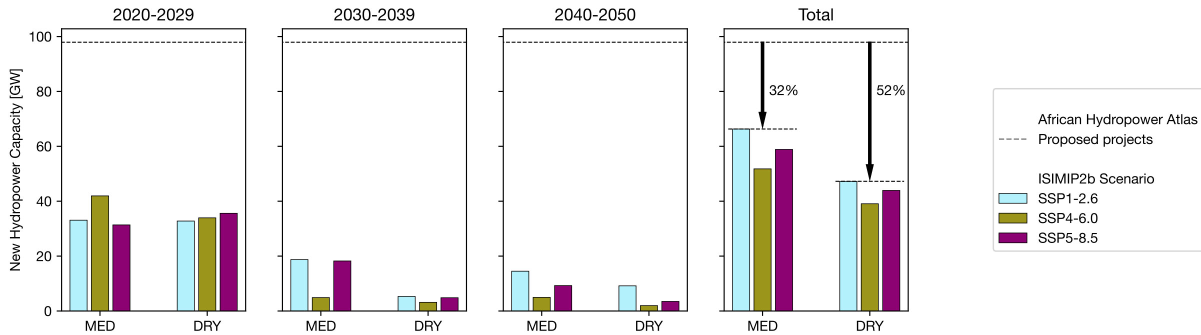

Fig. 1. Decadal and total hydropower capacity expansion under the considered scenarios. The dashed line indicates the capacity of proposed projects reported in the African Hydropower Atlas. The color of the bars is associated with the considered SSP scenarios, which coherently capture socioeconomic, land-use, and hydroclimatic change. For each decade and for the total, the left bars report the capacity expansion plan designed under ensemble median hydrology (MED), while the right bars correspond to the one designed under dry hydrology (DRY). The arrows indicate the fraction of proposed capacity which is not cost-optimal under the two different risk-preparedness targets.

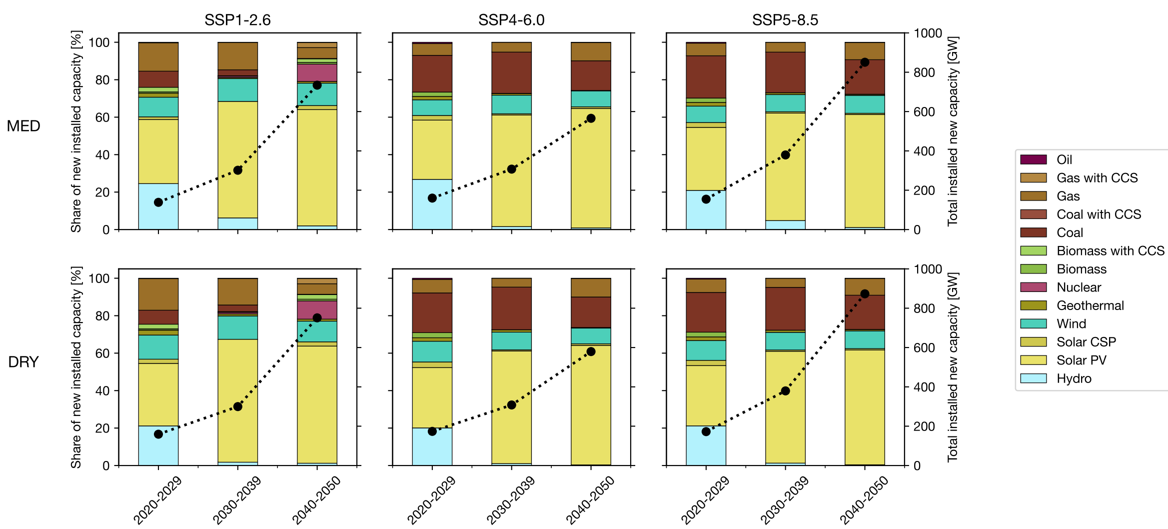

Fig. 2. Power capacity expansion at the continental level. The share of new installed capacity for each power source (on the left y-axis) and the new installed capacity (right y-axis) are reported against the three decades examined. While the top row reports the share of each power source in new capacity under median hydrology (MED scenarios), the lower panel reports the capacity expansion plans designed under dry hydrology (DRY scenarios). Each columns represents the different SSP scenarios. Each power source is described in the legend which whose order from bottom to top follows the order of the stacked bars.

Location and drivers of hydropower expansion Most of the planned African Hydropower projects concentrate in four major river basins, i.e., Nile, Congo, Zambezi, and Niger, which account for around 66% of the total potential (*16*). Across the socioeconomic and risk-preparedness scenarios, the cost-optimal dam portfolio varies substantially, even though some projects are consistently selected (Fig. S7). A robust finding over the considered scenarios and river basins is that less hydropower is installed in the DRY capacity expansion scenarios, and under SSP4-6.0 and SSP5-8.5 (Fig. 3). The Congo River basin is consistently cost-optimal for around half of its potential through the Inga 3 Dam, accounting for 11 GW in the Democratic Republic of Congo and built in all the scenarios. Half of the proposed potential for the Nile River basin is always cost-optimal, mainly in Ethiopia and Uganda, up to 80% in SSP5-8.5 with MED capacity expansion. The hydropower expansion in the Zambezi River basin is instead very uncertain and strongly dependent upon the considered scenario, ranging from 30% (SSP5-8.5) to 70% (SSP1-2.6) of the proposed capacity in the MED scenarios and between 13% (SSP4-6.0, SSP5-8.5) and 39% (SSP1-2.6) in the DRY scenarios. Finally, the cost-optimal hydropower potential in the Niger River basin is between 86% (SSP4-6.0) and 91% (SSP1-2.6) of the proposed capacity for the MED scenarios, and it is reduced to between 53% (SSP4-6.0) and 83% (SSP5-8.5)in the DRY scenarios. These projects are located mainly in Nigeria, a potential hotspot of hydropower development. For what concerns the remaining smaller basins, the development of projects varies significantly from 38% (SSP4-6.0) to 71% (SSP1-2.6) of their total capacity in the MED capacity expansion scenarios, and between 24% (SSP4-6.0) and 32% (SSP1-2.6) for the DRY capacity expansion scenarios.

Given these results, we can partially trace back the cost-optimal power expansion decisions to the characteristics of the proposed hydropower projects. High average capacity factors and high capacity are usually good indicators of cost-optimality (Fig. 4). Indeed, the higher the capacity, the lower the capital cost of new hydropower (*40*), even though the probabilities of delays and cost overruns increase too (*41*). Furthermore, the higher the average capacity factor, the higher the annual generation of a power plant. The construction of new hydropower projects is not sensitive to the inter-annual variability in the capacity factor. On the other hand, spatial and energy system constraints, such as transmission line capacity and proximity to more economically favorable hydropower projects, enable a full understanding of the cost-optimal power system development. This is, for example, the case of projects in the Zambezi basin in Zambia, a region well connected to the Democratic Republic of the Congo. The development of the Inga 3 Dam in the latter allows for substantial cheap electricity exports to neighboring countries, reducing the viability of domestic hydropower expansion in Zambia.

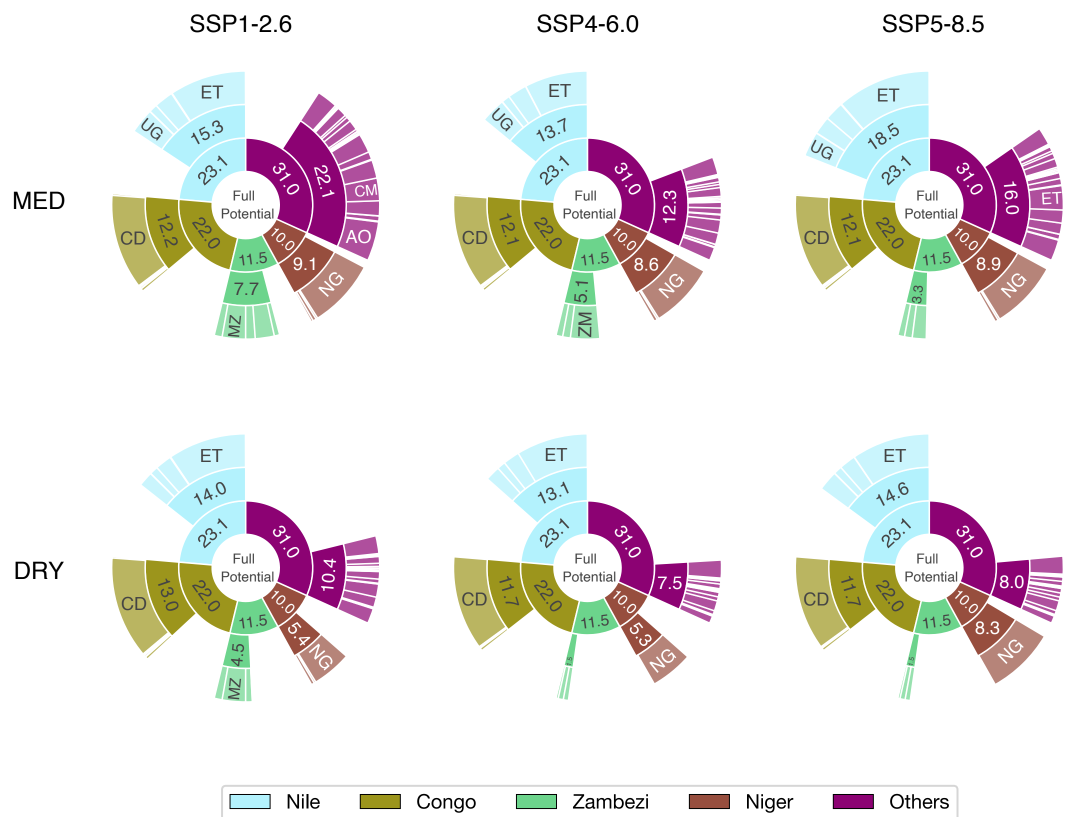

Fig. 3. Basin and country level hydropower capacity expansion. The full capacity of proposed projects is reported by river basin in the inner circle. The cost-optimal capacity in each river basin is reported in the middle circle and assigned to the corresponding countries in the outer circle. All values are reported in GW units. The columns correspond to the SSP scenarios examined. The top and the bottom row reports results from the MED and DRY capacity expansion scenarios, respectively. For each scenario, only countries building more than 2.5 GW of new hydropower are labeled, namely Angola (AO), Democratic Republic of the Congo (CD), Cameroon (CM), Ethiopia (ET), Mozambique (MZ), Nigeria (NG), Uganda (UG), Zambia (ZM).

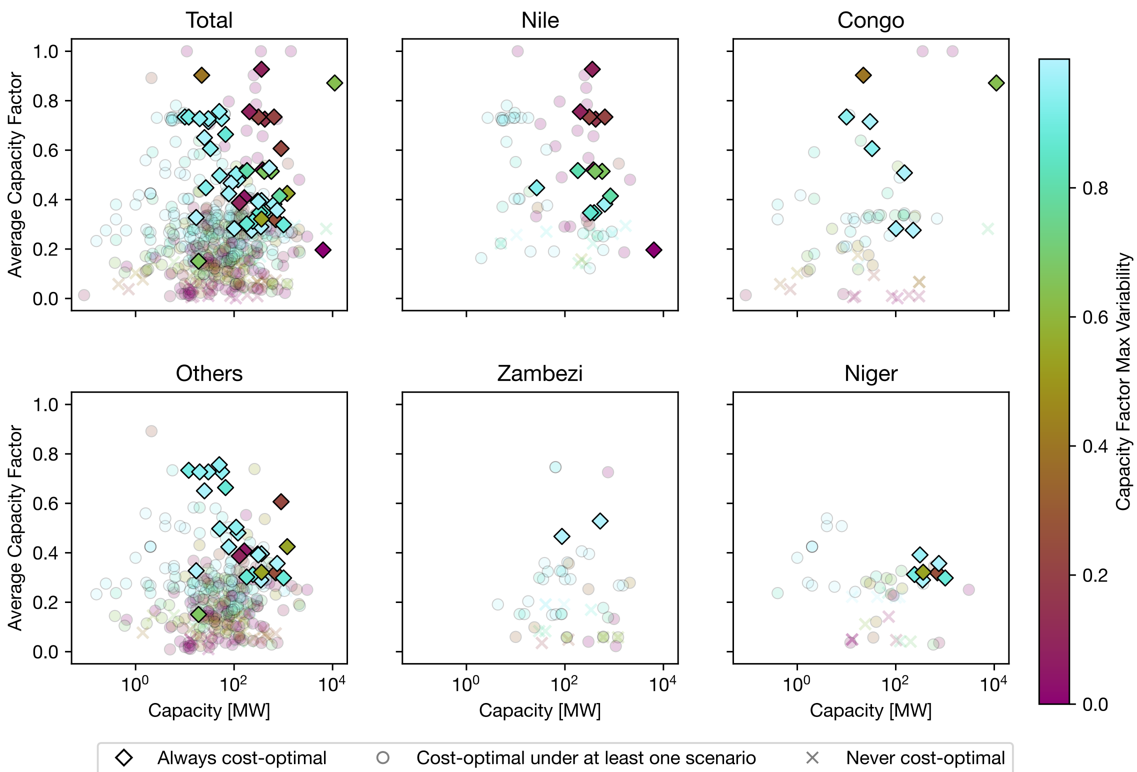

Fig. 4. Main characteristics of projects and their role in least-cost capacity expansion. Capacity, average capacity factor, and maximum inter-annual capacity factor variability under very dry hydrology of the examined hydropower projects are reported on the x-axis, y-axis, and using color, respectively. The black-edged diamond marker indicates a project which is always cost-optimal. The transparent circles correspond to projects that are at least once cost-optimal, while the transparent crosses to the projects that are never built. The always cost-optimal projects correlate with the average capacity factor under very dry hydrology (point bi-serial correlation coefficient: 0.37, p-value: 2e-19) and capacity (point bi-serial correlation coefficient: 0.18, p-value: 3e-5). Yet, they are less correlated by the variability of the capacity factor (point bi-serial correlation coefficient: 0.09, p-value: 0.03).

The regional distribution of costs and deficits requires cooperation It is currently unclear how the magnitude of drought-induced power deficits compares with the size of additional investment costs required to climate-proof the energy system (i.e., to guarantee demand satisfaction under dry hydrological conditions). For this reason, we stress-test the capacity expansion plans MED, obtained under median hydrology, by simulating it under dry hydrology to estimate the potential deficit that can occur. The observed generation deficits should be understood as the result of planning the power capacity expansions for each source, not only for hydropower, without explicitly accounting for hydroclimatic variability. The reported deficits present a worst-case scenario since safety mechanisms such as reserve margins are supposed to be in place to reduce the probability of occurrence of these events. The DRY capacity expansion plans can remove this risk with a capital cost increase between 1.8% (SSP5-8.5) and 4% (SSP1-2.6) in annual capital investments at the continental level under all the socioeconomic scenarios. Yet, at the country level, the cost increase and potential deficit are unevenly distributed and vary widely across the scenarios (Fig. 5).

Generally, reduced hydropower generation requires backing up with existing, mainly fossil-based technologies, or with additional capacity. This additional capacity is typically solar PV under cost-optimal expansion scenarios, especially under SSP1-2.6 in which the reliance on fossil fuels for power generation is constrained. Consequently, spatial planning of renewable power plants' deployment will be affected as well.

For many regions not dependent on hydropower, there is no difference between the two plans as they are not affected by deficits or additional costs induced by hydrological variability (Northern Africa and South Africa). Nonetheless, power pools strongly dependent on hydropower, such as the Southern, the Eastern, and the Western African Power Pools, are more subject to cost increase and deficit. Under SSP1-2.6, West Africa is affected by generation deficit events that require substantial capital investments to ensure reliability (e.g., Senegal, Guinea-Bissau, Ghana, and Togo). On the other hand, the power deficits in Nigeria and Burkina Faso require a modest increase in annual capital cost. In the other scenarios, the power deficit affects mostly Mali, Niger, and Benin, but the costs to achieve reliability remain low in all the power pool. For what concerns the Eastern African Power Pool, Ethiopia, Tanzania, Uganda, Rwanda, and South Sudan are most at risk of power outages induced by hydroclimatic variability. All these countries require significant investments to reduce this risk, while additional economic efforts will be required from Egypt, Sudan, and Kenya, especially in the case of SSP1-2.6. Concerning the Southern African Power Pool and scenario SSP1-2.6, Zambia, Namibia, and Mozambique remain most vulnerable to droughts. Zambia is particularly at risk as the power deficit would be around 13%, which could be mitigated with an 11% increase in annual capital investment. In addition to the above-mentioned countries, also Angola, Zimbabwe, and the neighboring Democratic Republic of the Congo, in the Central African Power Pool are required to increase their investments to climate-proof their energy system to a substantial extent. Under the other scenarios, Zambia remains always exposed to drought-related power outage risk, together with Namibia, whose cost to ensure reliability remains lower. In all scenarios, a generation deficit is observed if power trade is not allowed between countries, underscoring the importance of cooperation and political stability in the region (Fig. S8).

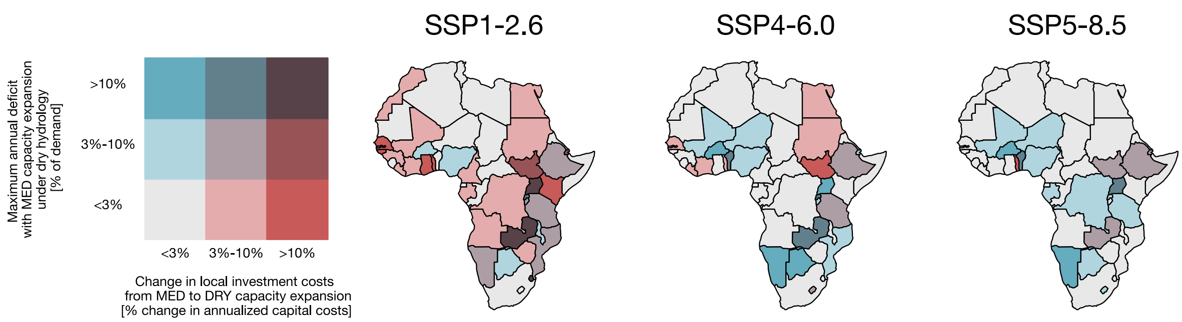

Fig. 5. Country-level cost-deficit trade-offs. Maximum annual power deficit as a percentage of demand over the period 2020-2050 obtained from simulation of the MED capacity expansion plan under dry hydrology. The additional cost of eliminating the power deficits is derived as the percentage increase derived from the annualized capital costs of the MED and the DRY capacity expansion plan. Their joint value is reported for each country in the maps using the bi-dimensional color scale visible in the legend, with the columns that correspond to SSP scenarios examined.

Discussion As African power demand grows, especially in Sub-Saharan Africa, the remaining untapped hydropower potential represents a cheap, clean energy source, which explains the large number of infrastructural projects currently under consideration. However, as costs associated with solar and wind power generation continue to decline, the historical reliance on hydropower of many Sub-Saharan African countries might come to an end. Solar and wind power are expected to become the primary power sources in 2050 representing 50% of the electricity mix of the continent in the sustainable development scenario compatible with a 2°C long term warming (SSP1-2.6) and always representing at least 50% of new installed capacity in the next three decades under all scenarios considered. Even under the SSP1-2.6 scenario which pushes for extensive renewable capacity expansion, no more than 67% of proposed hydropower capacity is cost-optimal with this percentage shrinking to 48% under the assumption of aversion to hydroclimatic risk. Project delays and cost overruns might further favor solar and wind projects making hydropower development even less competitive from an economic perspective (*42*). Yet, in the short term, especially in the transition to a final net zero configuration, hydropower represents a cheap alternative to avoid the high costs of installing solar and wind at the current level of technological maturity and to displace fossil fuels, mainly coal. The Nile, Congo, and Niger River basins provide reliable hydropower generation. Yet, the development of projects in these regions needs to be accompanied by investment in grid capacity in order to reap all the benefits of large hydropower. Climate-proofing the energy system against hydroclimatic variability requires reducing investment in hydropower and investing in additional solar, wind, and firming capacity, in particular in the scenarios where emissions are constrained. These additional costs are not necessarily distributed uniformly or fairly across the countries, highlighting the need for coordination and incentives mechanisms to support capacity expansion plans which are robust to climate change impacts.

Through the reduction in economically viable hydropower capacity associated with the declining cost of wind and solar, technological innovation helps reduce pressure on riverine ecosystems and small communities in proximity of proposed impoundments and further downstream as far as the impacts of these changes propagate (*43*).

Indeed, previous research on the hydropower's social and environmental trade-offs (*25, 27, 30*) and the effects of environmental risks on the financial performance of this infrastructure (*44*) has suggested caution in construction of new projects. Introducing these factors in our modeling framework is likely to further reduce the space for hydropower in future energy systems. Analyses at the river basin level remain complementary to our analysis and might be better tailored to address such concerns. However, additional research and development of new methods are needed to connect local, regional, and continental scales for a robust planning of water and energy systems (*34*). Similarly, greenhouse gas emissions from reservoirs (*30, 45–47*) are a deterrent for hydropower capacity expansion, in particular in tropical areaswhere life cycle emissions associated with new dams might be comparable to the ones of fossil fuel power sources (*48, 49*). Accounting for this factor will likely further promote the expansion of wind, solar, and other carbon-neutral technologies.

On the other hand, we are not able to fully capture the contribution of hydropower projects to ancillary services such as frequency regulation and improved renewable integration associated with the rapid ramp-up of power output. While these services are rarely considered in hydropower planning, their importance will rise as more wind and solar power are added to the grid, potentially affecting our results. Moreover, electricity generation is not always the main purpose for which water reservoirs are built. If some of the reservoir hydropower projects were to be associated with other needs (e.g., agriculture, flood control, drinking water supply), cross-sectoral interactions could improve their economic performance and make them attractive investments. In this case, reservoir greenhouse gas emissions should not be attributed to electricity generation only, but the exact attribution of greenhouse gas emissions to the different sectors remains a complex issue.

Governance and political stability are key in ensuring sustainable exploitation of the economically viable hydropower potential, particularly in transboundary river basins (*50*). The Nile and the Niger River basins, identified as hotspots of hydropower development, are high-risk areas due to their transboundary nature in regions of political instability and presence of armed conflict (*51*). Implementation of cooperation schemes is crucial to reduce tensions and provide water and energy security in these areas (*13, 15, 52–54*).

In a broader sense, cooperation and governance are fundamental to allow all African countries to switch their focus from energy independence to energy security (*55*). In this regard, establishing power pools and the African Clean Energy Corridor has been crucial for energy governance. These mechanisms and investments paved the way for increased energy security in the continent (*56*). To prepare for the impacts of dry years, investment in alternative power sources is required, even in locations that might not be directly impacted by generation deficits. Understanding the consequences of interconnected power systems can therefore promote the design of agreements and policy interventions fostering energy security and resilience in the face of hydroclimatic change. Growing evidence motivates concerns about the increased risk of conflict and instability associated with the growing impacts of climate change (*57*). Governments and power pools must prepare for stressful contexts where local strategies do not match large-scale cost-optimal development. To confront the friction between coordinated and decentralized decision-making levels, mechanisms building on incentive schemes and side payments need to be designed. In this conundrum, our results can inform future research to ensure multi-scale coordination for energy security and sustainable hydropower development in the African continent.

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Supplementary materials

Materials and Methods

Supplementary Notes

References *(59-82)*

Figs. S1 to S8

Table S1

Materials and Methods

Overview Our analysis is based on an open-source energy system model, which we extend with publicly available datasets compiling projections of socioeconomic development, land-use, climate change and natural variability impacts, and hydropower generation. A schematic overview of the model used to obtain the results discussed in the article is reported in Figure S1. The modeling framework is used to study the least-cost African power capacity expansion to meet future energy demand and the implications for the hydropower sector from 2020 to 2050. Scenarios available through phase 2b of the Inter-Sectoral Impact Model Intercomparison Project 2b (ISIMIP2b) (*37*) are used to coherently consider future final energy demands, land-use changes, and future climate impacts on the hydrological cycle. These inputs inform the OSeMOSYS-TEMBA model (*59*) modified to account for each existing and future hydropower project in continental Africa. As model output, we obtain the least-cost capacity expansion and generation mix to meet the demand for each of the scenarios considered, including the sequencing of new hydropower projects. These power capacity expansion plans are evaluated based on different metrics such as costs and generation deficit, that are obtained by simulations over different hydrological scenarios.

OSeMOSYS-TEMBA model The OSeMOSYS-TEMBA model (*59*), (*2, 36*) is an energy system model for long-term planning in continental Africa, i.e., Cape Verde, Comoros, Madagascar, Sao Tome and Principe, and Seychelles are not considered. It is developed using the OSeMOSYS (Open Source energy MOdelling SYStem) framework (*60*). It is an optimization model that finds the least-cost capacity expansion and associated generation needed to satisfy given trajectories of energy demands for 47 countries over time by solving a linear programming problem assuming cooperative centralized decision-making, i.e., minimizing costs at the continental level. The plan determines the investment in new capacity, new transmission lines, and the activity for each considered technology.

The data and the model are publicly available online (*61*). The data include: (i) projections of final energy demands for each country based on population data (*62*), energy balances (*63, 64*) and Gross Domestic Product (GDP) projections (*65*); (ii) fossil fuel reserves and renewable energy potential, combined from different sources (*66–71*); (iii) the installed capacity and cooling system technology in place in each country derived from the Global Platts database (*72*); (iv) projections of techno-economic parameters (such as variable, fixed and capital costs) of the power generation and conversion technologies, based on different sources (*69, 73–75*); (v) water factors for the different technologies and fuel processes (*76*). The original OSeMOSYS-TEMBA model is available with three scenarios reporting assumptions on climate policy and associated final energy demand: (i) a reference scenario (Refer) where no emissions limit is imposed (but emission penalties related to carbon taxes already in place are anyway considered); (ii) a scenario compatible with a 2°C temperature increase (2.0); (iii) a 1.5°C compatible scenario (1.5). These are obtained by constraining the annual emissions of the African energy systems to a cap obtained using the MAGICC 6 model (*77*) and information from the JRC GECO report (*65*). For the climate policy scenarios (ii) and (iii), also final energy demands are reduced in the OSeMOSYS-TEMBA model, with electricity consumption reduced by 11% and 27% and fossil fuel consumption reduced by 39% and 71% in scenarios 2.0 and 1.5, respectively (*2*). The renewable energy potential and the capacity factors associated with renewable power plants do not consider the impact of climate change.

SSP-driven final energy demands The Shared Socioeconomic Pathways (*35*) are a set of five plausible socioeconomic narratives used to project into the future - up to 2500 (*78*) - population, economy, social and energy trends in the different regions of the world. Each of these narratives corresponds to a set of specific assumptions on technological growth, economic relationships between the countries, and challenges to climate mitigation and adaptation. The dataset is publicly available online and it consists of several components: (i) projections of basic components such as GDP and the population at the country level; (ii) projections of key variables for energy, technology, economic, population, land cover, emission, and agricultural sectors from integrated assessment modeling scenarios at the regional level (five regions are considered: OECD, Reforming Economies, Middle East and Africa, Asia and Latin America); (iii) emissions for the different pollutants considered for the Coupled Model Intercomparison Project 6 (CMIP6) project.

In this work, we are interested in the energy consumption derived from the integrated assessment models run under the different scenarios as they will be used to describe uncertainty in future final energy demands. This step provides final energy demands scenarios that are coherent at the energy system level. We consider the scenarios which have been considered in ISIMIP2b (*37*): SSP1-2.6, SSP4-6.0, and SSP5-8.5. While we rely on data from the baseline scenario Refer of the TEMBA energy system model for scenarios SSP4-6.0 and SSP5-8.5, we use final energy demands and emissions cap from the 2.0 scenario to configure the optimization and simulation of the SSP1-2.6 scenario (Table S1). The SSP-driven final energy demands are computed by combining the OSeMOSYS-TEMBA projections, more reliable in the short term, and the SSP scenarios, which are given more importance in the long term as follows

$$D_{r,t}^{SSP,ene} = \alpha_t D_{r,t}^{\mathrm{TEMBA},ene} + (1-\alpha_t) D_{\mathrm{MAF},t}^{SSP,ene} \quad \frac{GDP_{r,t}^{SSP}}{GDP_{\mathrm{MAF},t}^{SSP}} \tag{1}$$

with $\alpha_t = \alpha_{2020} - (t-2020)/80$, $\alpha_{2020} = 1$, and $\alpha_{2100} = 0$, and where $D_{r,t}^{SSP,ene}$ is the demand for energy carrier ene, in scenario SSP, for country r, in year t. The energy carriers considered in the model are the following: coal, charcoal, biomass, firewood, electricity, heat, gas, crude oil, heavy fuel oil, and light fuel oil. The demand is computed as a convex combination of the OSeMOSYS-TEMBA original demand ($D_{r,t}^{\mathrm{TEMBA},ene}$) and the SSP projection at the regional level ($D^{SSP,ene}_{\mathrm{MAF},t}$, MAF stays for Middle East and Africa) downscaled using the GDP of the country as a proxy variable. After downscaling, the data from the SSP scenarios, which are obtained with 10-year time steps are interpolated to produce final energy demand trajectories at the annual time step to match the resolution of OSeMOSYS-TEMBA model data.

African Hydropower Atlas The African Hydropower Atlas (*16*) is a dataset collecting information on existing and future hydropower projects in Africa. Its main purpose is to provide information and data to improve hydropower representation in power and energy system models in order to better assess the role of hydropower in the energy transition. It supports the quantification of the ability of hydropower to balance variable renewable energy sources by providing seasonal availability curves under normal, wet, and dry scenarios. It is the largest publicly available dataset collecting information on the hydropower sector in Africa and it describes both storage and run of the river power plants: 266 existing, 60 committed, 44 planned, and 263 candidate projects for a total of 633 hydropower plants. Here, we group the committed, planned, and candidate projects and we refer to them as proposed hydropower projects. It combines technical information such as the power plant's nominal capacity, the reservoir volume, and the geographical location, as well as some crucial information such as inflow to the reservoirs, and an estimation of the monthly capacity factor. The capacity factor is a parameter often used in power and energy system modeling to describe the power output of hydroelectric power plants as a ratio of their nominal capacity. In the African Hydropower Atlas, this parameter is estimated for every month of the year using a hydrological model (SWAT+) simulated with meteorological data over the time period 1980-2016. Additionally, projections of the capacity factors are available for all the hydropower projects for the three ISIMIP2b scenarios, over the period 2020-2050 using as input meteorological variables of interest derived from bias-adjusted projections of four global climate models (GFDL-ESM2M, HadGEM2-ES, ISPL-CM5A-LR, and MIROC5) forced with the concentration described in the Representative Concentration Pathways (RCPs) associated to each of the SSP scenarios part of the ISIMIP2b project (*79, 80*). The capacity factors are based on inflow profiles for each month under normal, wet, and dry conditions. Normal capacity factors are derived as monthly median, while wet and dry are obtained by multiplying the monthly median profiles by the ratio of 5^th and 95^th percentile of annual generation to multi-annual average generation. The difference in quantiles between control and projection are averaged across the ensemble of global climate models and applied to the SWAT+ model forced with EWEMBI. The percentiles are derived from the distribution of annual average generation which is obtained via simulation of the SWAT+ hydrological model forced by the bias-adjusted projections for the four global climate models considered. In order to consider the ability of reservoir hydropower to dispatch power flexibly over the year, the inflow profile is divided into a storable and a non-storable component. The storable component is equal to the live storage (assumed to be 70% of total reservoir volume) and can be turbined all over the year, while the remaining is non-storable and is assumed to be directly turbined (*16*).

Hydropower representation in the OSeMOSYS-TEMBA-AHA energy system model In the OSeMOSYS-TEMBA model, hydropower is described by aggregating all hydropower plants at the country level with a common capacity factor for each of the three technologies considered (micro-hydro, run-of-the-river, reservoir). To improve the level of detail, we substitute the run-of-the-river and reservoir plants in each country with the existing and future hydropower projects reported in the African Hydropower Atlas. We update the installed capacity of country-level aggregate hydropower to consider potential mismatches when hydropower capacity is larger than the sum of projects reported in the African Hydropower Atlas for a specific country. We also ensure that no new hydropower can be built, except for the candidate, planned, and committed power plants in the African Hydropower Atlas. To enforce the constraint that the full nominal capacity of a hydropower project has to be built at once, the optimization problem needs to be formulated as a mixed integer linear program. Indeed, the decision variable of whether to build or not a new hydropower plant is a binary variable for each year. Further details on these are given in the Supplementary Material. Depending on the considered SSP and hydrological scenarios, capacity factors from the African Hydropower Atlas are used for the specific hydropower projects, aggregated from monthly to seasonal time-step to match the time resolution of OSeMOSYS-TEMBA. The capacity factor is assumed to remain constant across the day and night time slices of the energy system model, i.e., hydropower is only used for seasonal balancing, not for diurnal-scale balancing of VRE, especially solar PV. For the remaining aggregate hydropower OSeMOSYS-TEMBA, less than 5% of existing capacity and not contributing to new capacity, capacity factors are left unchanged. When information about the capacity factors for a specific power plant is not available in the African Hydropower Atlas, these are set to be equal to the ones associated with hydropower in that specific country in the OSeMOSYS-TEMBA model. Since no specific information is available in the African Hydropower Atlas, hydropower projects' capital costs are based on the most recent data (*40*). With respect to capital costs we take the average capital cost for small (i.e. below 10 MW) and large (i.e. above 10 MW) hydropower projects in Africa from (*40*). We then assign (i) the average capital cost between small and large hydropower projects to the capacity of 10 MW (i.e. 2836.5 USD/kW); (ii) the average capital cost for small hydropower projects to the capacity of 1 MW (i.e. 3256 USD/kW); (iii) the average capital cost for large hydropower projects to the capacity of 500 MW (i.e. 2446 USD/kW); (iv) we set two additional points by assuming the capital cost of 0.1 MW and 11 GW plants to be 3744.4 USD/kW and 2054.5 USD/kW, respectively. Between the points defined above, we adopt linear interpolation. Out of these points, we adopt the same linear function used in the preceding interval. It should also be noted that hydropower projects in the African Hydropower Atlas have a capacity in the range between 0.09 MW and 11050 MW. Such representation of capital cost is not only useful to represent more realistic information on hydropower construction costs. It also ensures a reduction of symmetry in the mixed integer linear problem. When the effect of many alternative decisions is similar, the solver's ability to find a gradient among the alternative decisions is slowed down impacting computational time (*81*).

Most of the remaining hydropower parameters are left unchanged with respect to traditional hydropower in OSeMOSYS-TEMBA since additional information is not available.

Hydrological scenarios In order to represent different risk preferences with respect to the uncertainty associated with climate variability, we develop two hydrological scenarios for each considered SSP scenario. In the MED scenarios, the capacity factors from the median year are used in the energy system model over the whole horizon for all the hydroelectric power plants individually modeled. This scenario represents a neutral risk aversion and it is a traditional approach in water-energy system modeling. In the DRY scenarios, the hydroelectric power plants' capacity factors of the energy system model are updated with the ones from the very dry conditions from the African Hydropower Atlas. With the aim of modeling a risk-averse decision-maker, we use these capacity factors for every year considered over the horizon, consistently with a robust optimization approach focused on optimizing with respect to the worst case. In this case, the decision-maker is focusing on averting the consequences of a very dry year (representative of a 1 in a 20 years event) and in the absence of any information about the spatial correlation of droughts in the continent.

Estimating power demand deficit and costs for the robust capacity expansion plan To estimate the maximum annual power demand deficit associated with the capacity expansion designed under median hydrology, we constrain the new capacity to be installed in the model to be equal to the one derived from the optimization under median hydrology. We optimize the generation from each source for each scenario under the very dry hydrology and we consider as generation deficit the demand satisfied by the backstop technology. Since we don't know when the very dry year might occur, we simply use the maximum annual deficit as a percentage of demand in each year as a risk metric. Conversely, when assessing the costs of the robust capacity expansion plan we constrain the capacity to the one found via optimization under very dry hydrology. Consequently, we let the generation of each technology be optimized under median hydrology and we compute the associated costs that can now be compared with the ones of the capacity expansion under median hydrology.

Supplementary Text

OSeMOSYS-TEMBA nomenclature

Below tables are provided reporting the nomenclature adopted in the equations of the OSeMOSYS-TEMBA model.

Symbol	Set
r	country E
t	technology T
f	fuel F
m	mode of operation M
y	year Y (initial year y^0 and terminal time y^{end})
l	time-slice L
e	emission E

Symbol	Variable
AFC	Annual Fixed Cost
AVC	Annual Variable Cost
ACC	Annual Capital Cost
DSV	Discounted Salvage Value
$DTEP$	Discounted Technology Emissions Penalty
NC	New Capacity
ROA	Rate of Activity
SV	Salvage Value

Symbol	Parameter
ρ	Discount Rate
FC	Fixed Cost
OL	Operational Life
RC	Residual Capacity
VC	Variable Cost
YS	Year Split
CC	Capital Cost
CF	Capacity Factor
$CTAU$	Capacity to Activity unit
AF	Availability Factor
OAR	Output Activity Ratio
SAD	Specified Annual Demand
SDP	Specified Demand Profile
IAR	Input Activity Ratio
AAD	Accumulated Annual Demand
$TAMaC$	Total Annual Max Capacity
$TAMiC$	Total Annual Min Capacity
$TTAAUL$	Total Technology Annual Activity Upper Limit
$TTAALL$	Total Technology Annual Activity Lower Limit
$TTMPAUL$	Total Technology Model Period Activity Upper Limit
$TTMPALL$	Total Technology Model Period Activity Lower Limit
EAR	Emission Activity Ratio
EP	Emissions Penalty
AEE	Annual Exogenous Emission
AEL	Annual Emission Limit
$MPEL$	Model Period Emission Limit

The optional variables and parameters used to include the African Hydropower Atlas in the OSeMOSYS-TEMBA model, and for the robust scenario analysis, are listed here.

Symbol	Description
$COTU$	Capacity of One Technology Unit (parameter)
$NNTU$	Number of New Technology Units (integer variable)

OSeMOSYS-TEMBA model equations

OSeMOSYS-TEMBA defines a cost minimization problem formulated as a linear program whose objective function is the sum of various annual components of cost summed over time, the considered technologies, and regions. The cost minimization problem can be written as

$$\min_{u} \sum_{r,t,y} \left(\frac{AFC_{r,t,y} + AVC_{r,t,y}}{(1+\rho)^{(y-y^0+0.5)}} + \frac{ACC_{r,t,y}}{(1+\rho)^{(y-y^0)}} - DSV_{r,t,y} + DTEP_{r,t,y} \right) \tag{2}$$

$$s.t. \qquad AFC_{r,t,y} = FC_{r,t,y} \cdot \left(\sum_{yy \leq y} \left(NC_{r,t,yy} \left[y - yy < OL_{r,t} \right] \right) + RC_{r,t,y} \right) \tag{3}$$

$$AVC_{r,t,y} = \sum_{m} \sum_{l} VC_{r,t,m,y} \cdot ROA_{r,l,t,m,y} \cdot YS_{l,y} \tag{4}$$

$$ACC_{r,t,y} = CC_{r,t,y} \cdot NC_{r,t,y} \tag{5}$$

$$DSV_{r,t,y} = \frac{SV_{r,t,y}}{(1+\rho)^{y^{\text{end}}-y^0}} \tag{6}$$

$$SV_{r,t,y} = \begin{cases} 0, & y + OL_{r,t} - 1 \leq y^{\text{end}} \\ CC_{r,t,y} \cdot NC_{r,t,y} \cdot \frac{(1+\rho)^{(y^{\text{end}}-y)}}{(1+\rho)^{(OL_{r,t}-1)}}, & \text{else} \end{cases} \tag{7}$$

$$DTEP_{r,t,y} = \sum_{e} \sum_{l} \sum_{m} \frac{1}{(1+\rho)^{(y-y^0+0.5)}} \cdot EAR_{r,t,e,m,y} \cdot ROA_{r,l,t,m,y} \cdot YS_{l,y} \cdot EP_{r,e,y} \tag{8}$$

where the sets, variables, and parameters are reported in the nomenclature. The total cost is minimized with respect to the decision variables $u = \{NC_{r,t,y}, ROA_{r,l,t,m,y}\}$. These are the new capacity $NC_{r,t,y}$ to be installed in year y for technology t in the region r and the rate of activity $ROA_{r,l,t,m,y}$ in time-slice l (i.e., time step associated with season and day night conditions) during the year y for technology t in the region r with the mode of operation m (for technologies that operate in multiple directions such as transmission lines, pumped-storage hydro). The new capacity of all technologies also considers the expansion of transmission lines, extraction, and refining processes, in addition to generation capacity for all the power sources considered. As reported in (2), the total costs consist of annual fixed costs, described in (3), and annual variable costs, described in (4), discounted at mid-year as these costs occur over the entire year; additionally we have also annual capital costs, discounted at the beginning of each year and described in (5), discounted salvage value, described by (6) and (7), and discounted emissions penalty by technology, whose computation is described in (8).

Additional constraints are imposed so that generation from each technology is constrained by the installed capacity of the technology in a specific year, its capacity factor, and its availability factor, that take into account for planned maintenance of technologies. This is described in (9) and (10). For what concerns the fixed costs in (3), we used the Iverson notation to sum the new capacities installed in year yy, if the associated operational life is not already finished in year y.

$$\begin{gathered}\sum_{m} ROA_{r,l,t,m,y} \leq \\ \left(\sum_{yy \leq y} \left(NC_{r,t,yy} \left[y - yy < OL_{r,t}\right]\right) + RC_{r,t,y}\right) \cdot CF_{r,t,l,y} \cdot CTAU_{r,t}\end{gathered} \tag{9}$$

$$\begin{gathered}\sum_{m}\sum_{l} ROA_{r,l,t,m,y} \cdot YS_{l,y} \leq \\ \sum_{l}\left(\sum_{yy \leq y} \left(NC_{r,t,yy} \left[y - yy < OL_{r,t}\right]\right) + RC_{r,t,y}\right) \cdot CF_{r,t,l,y} \cdot AF_{r,t,y} \cdot CTAU_{r,t}\end{gathered} \tag{10}$$

Energy balances are formulated at the time-slice level in (11) and at the annual level (12). In their simplest terms, these equations ensure that enough energy is generated to meet demand from other technologies and pre-specified final energy demands, defined at the annual or time-slice level.

$$\begin{gathered}\sum_{m}\sum_{t} ROA_{r,l,t,m,y} \cdot OAR_{r,t,f,m,y} \cdot YS_{l,y} \geq \\ SAD_{r,f,y} \cdot SDP_{r,f,l,y} + \sum_{m}\sum_{t} ROA_{r,l,t,m,y} \cdot IAR_{r,t,f,m,y} \cdot YS_{l,y}\end{gathered} \tag{11}$$

$$\begin{gathered}\sum_{m}\sum_{t}\sum_{l} ROA_{r,l,t,m,y} \cdot OAR_{r,t,f,m,y} \cdot YS_{l,y} \geq \\ \sum_{m}\sum_{t}\sum_{l} ROA_{r,l,t,m,y} \cdot IAR_{r,t,f,m,y} \cdot YS_{l,y} + AAD_{r,f,y}\end{gathered} \tag{12}$$

The constraints (13)-(16) ensure that the capacity and the newly installed capacity remain between predefined minimum and maximum capacity and capacity investment.

$$\sum_{yy \leq y} \left(NC_{r,t,yy} \left[y - yy < OL_{r,t} \right] \right) + RC_{r,t,y} \leq TAMaC_{r,t,y} \tag{13}$$

$$\sum_{yy \leq y} \left(NC_{r,t,yy} \left[y - yy < OL_{r,t} \right] \right) + RC_{r,t,y} \geq TAMiC_{r,t,y} \tag{14}$$

$$NC_{r,t,y} \leq TAMaCI_{r,t,y} \tag{15}$$

$$NC_{r,t,y} \geq TAMiCI_{r,t,y} \tag{16}$$

Annual and whole horizon (or model period) activity limits are enforced for each technology in the constraints (17)-(20).

$$\sum_{l} ROA_{r,l,t,m,y} \cdot YS_{l,y} \leq TTAAUL_{r,t,y} \tag{17}$$

$$\sum_{l} ROA_{r,l,t,m,y} \cdot YS_{l,y} \geq TTAALL_{r,t,y} \tag{18}$$

$$\sum_{y} \sum_{l} ROA_{r,l,t,m,y} \cdot YS_{l,y} \leq TTMPAUL_{r,t,y} \tag{19}$$

$$\sum_{y} \sum_{l} ROA_{r,l,t,m,y} \cdot YS_{l,y} \geq TTMPALL_{r,t,y} \tag{20}$$

The annual and model period emission limits are expressed in constraints (21) and (22).

$$\sum_{l} \sum_{m} \sum_{t} EAR_{r,t,e,m,y} \cdot ROA_{r,l,t,m,y} \cdot YS_{l,y} + AEE_{r,e,y} \leq AEL_{r,e,y} \tag{21}$$

$$\sum_{l} \sum_{m} \sum_{t} \sum_{y} EAR_{r,t,e,m,y} \cdot ROA_{r,l,t,m,y} \cdot YS_{l,y} + AEE_{r,e,y} \leq MPEL_{r,e,y} \tag{22}$$

Additional constraints to include data from the African Hydropower Atlas in OSeMOSYS-TEMBA

To ensure that the new capacity built for a specific hydropower project is aligned with the nominal capacity reported in the African Hydropower Atlas, we adopt a set of built-in variables, parameters, and constraints available in the standard OSeMOSYS model framework. We use the optional variable $NNTU_{r,t,y}$, defining how many new units of technology t are built in year y in the region r, the optional parameter $COTU_{r,t,y}$, describing the minimum amount of capacity that has to be added when building technology t in year y in the region r, and we add the additional constraint that relates these to the decision variable $NC_{r,t,y}$ using (23).

$$COTU_{r,t,y} \cdot NNTU_{r,t,y} = NC_{r,t,y} \tag{23}$$

It should be noted that the variable $NNTU_{r,t,y}$ is defined as an integer variable and constrained to be 0 or 1, as building one technology unit for the hydropower project examined would result in its realization. Furthermore, the parameter $TAMaC$, set equal to the hydropower plant nominal capacity for each hydropower project, ensures that the project is built only once during the model period considered. As a result, the optimization problem is a mixed-integer linear program, whose computational complexity is notoriously higher than the one of a linear program.

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Supplementary Figures

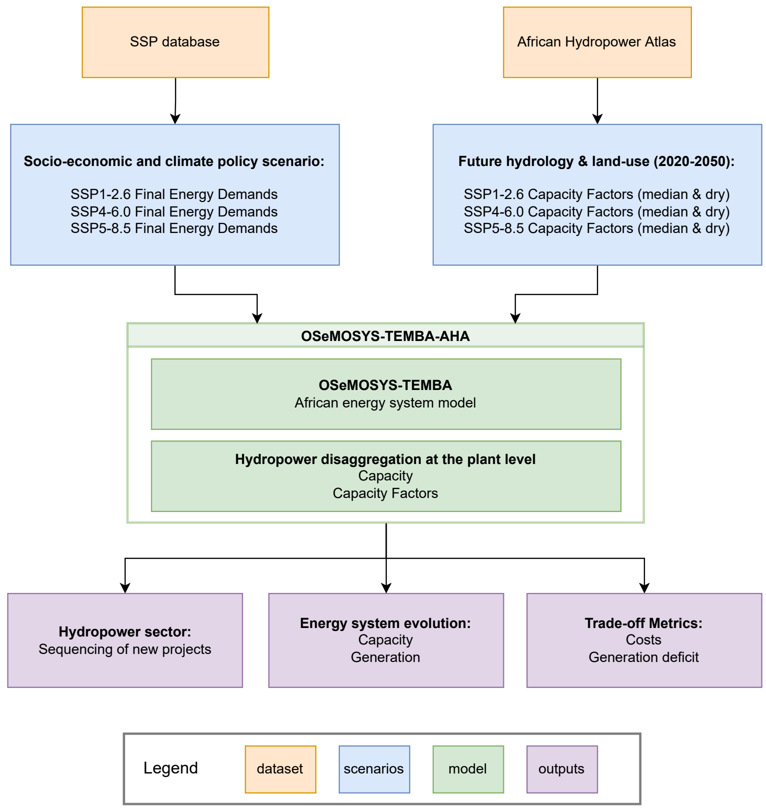

Fig. S1. Methodology. The OSeMOSYS-TEMBA model is updated with final energy demands derived from the SSP database and hydropower plant information from the African Hydropower Atlas to develop the OSeMOSYS-TEMBA-AHA model. A set of scenarios coherently exploring socioeconomic projections, agricultural expansion, climate change, and hydrological variability is used to examine the development of the hydropower sector disaggregated into individual existing and future power plants. The outputs of the model are trajectories of capacity and generation over time, including sequencing of hydropower projects. The capacity expansion plans are compared based on their costs and ability to meet the final electricity and energy demand.

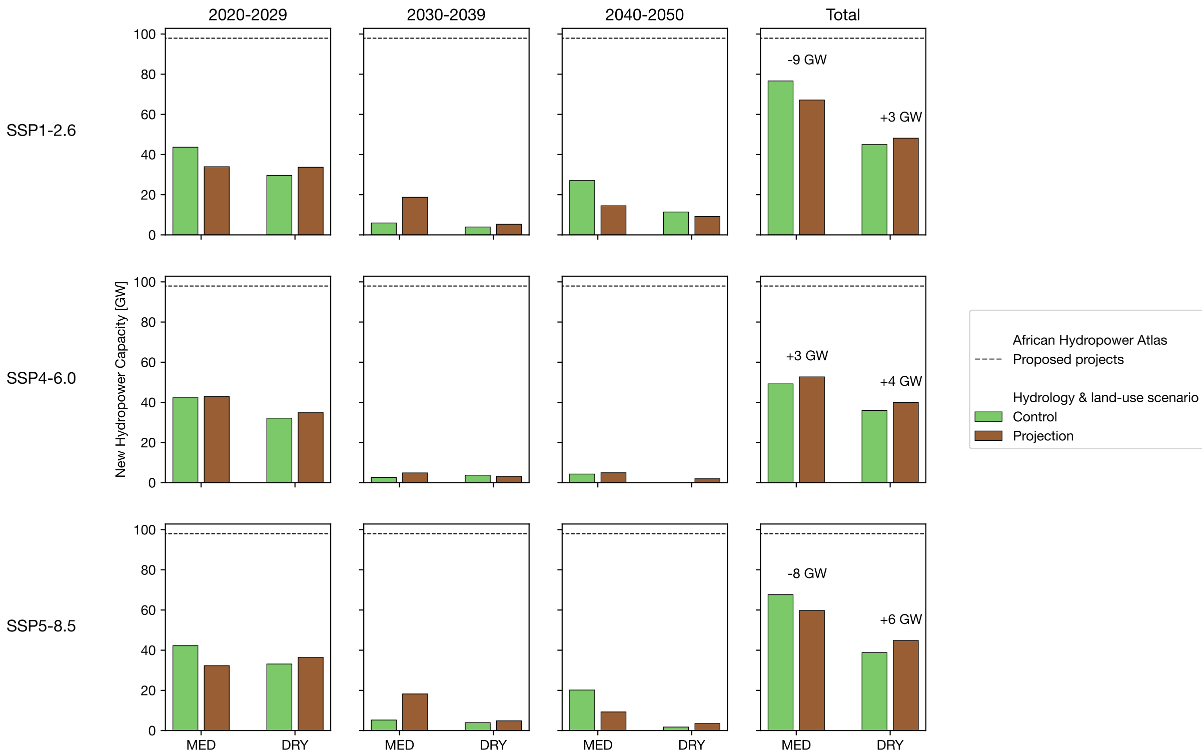

Fig. S2. Hydropower expansion under control and projection scenarios for hydrology and land-use. New installed hydropower capacity is reported for each decade and in total along the columns with rows corresponding to the considered SSP scenarios. For the total column, we report the difference in installed hydropower capacity between control and projection scenarios.

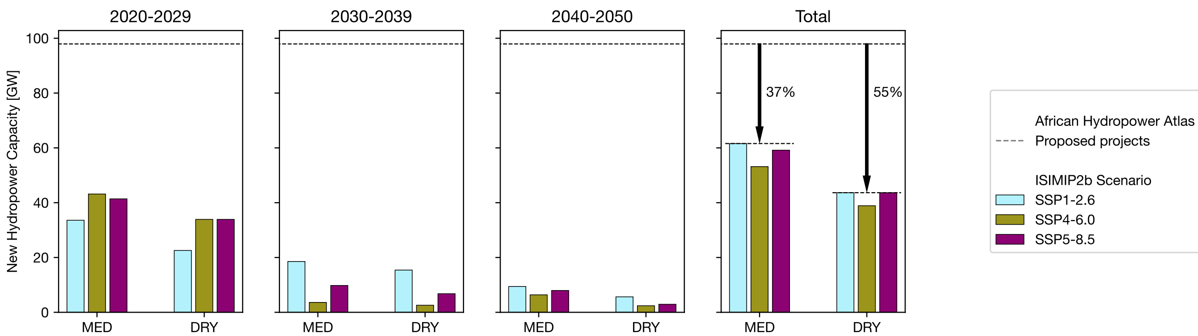

Fig. S3. Decadal and total hydropower capacity expansion under the considered scenarios with a planning horizon until 2070.

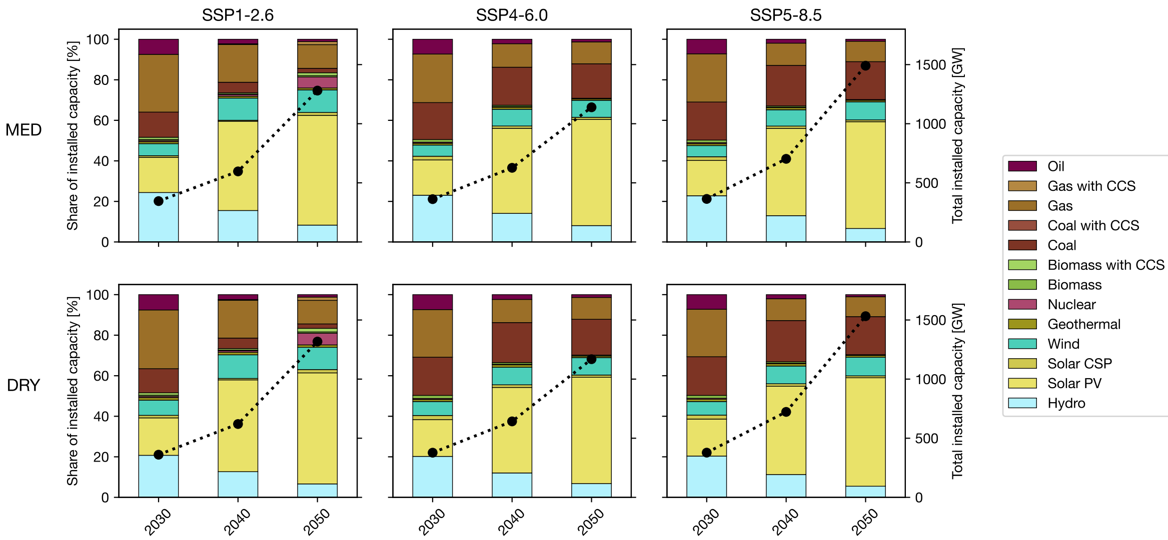

Fig. S4. Total capacity installed at the continental level under the different considered scenarios.

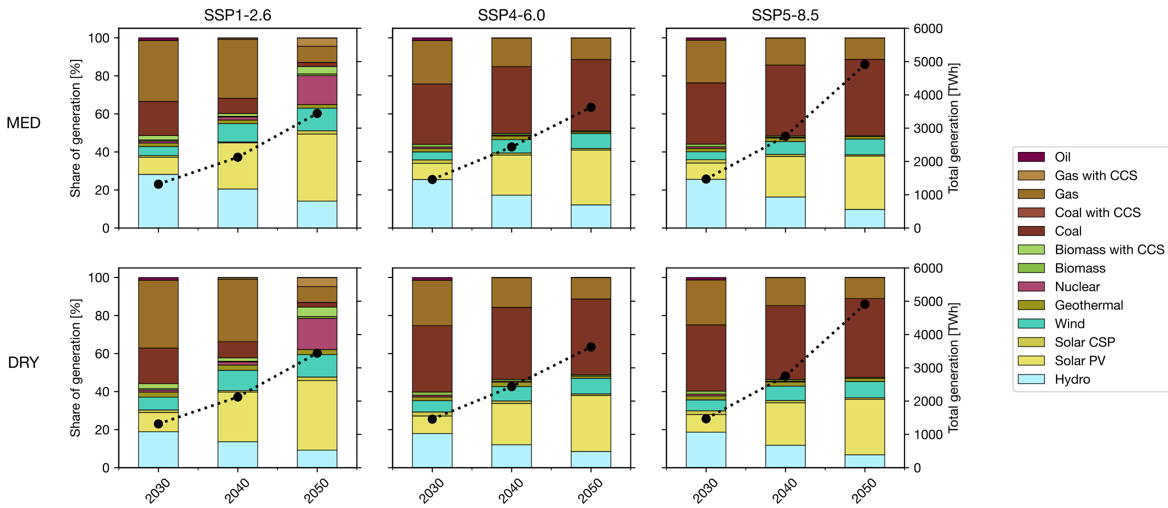

Fig. S5. Total generation at the continental level under the different considered scenarios.

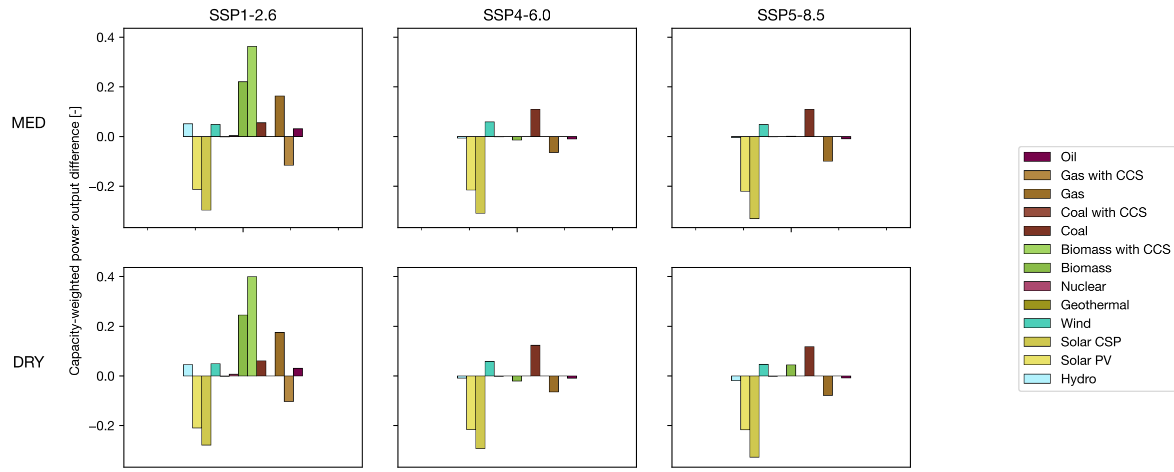

Fig. S6. Average capacity-weighted power output difference between the 18:00-09:00 and the 09:00-18:00 time periods across seasons for the year 2050 under the different considered scenarios.

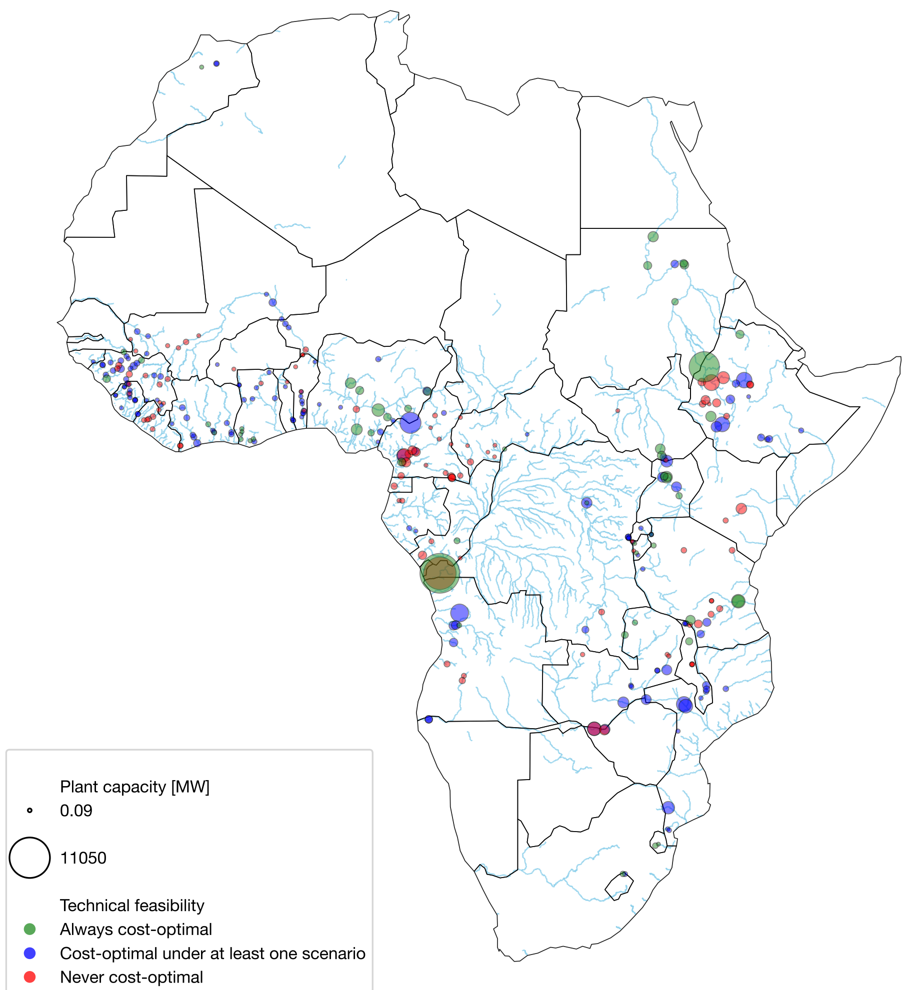

Fig. S7. Location of future hydropower projects: in green are reported the projects always built under all considered scenarios, in red the ones never built, and in blue the uncertain. The size of each marker increases with the capacity of the considered hydropower project. The river network is derived from the HydroRIVERS dataset, publicly available online at https://www.hydrosheds.org/products/hydrorivers (*82*).

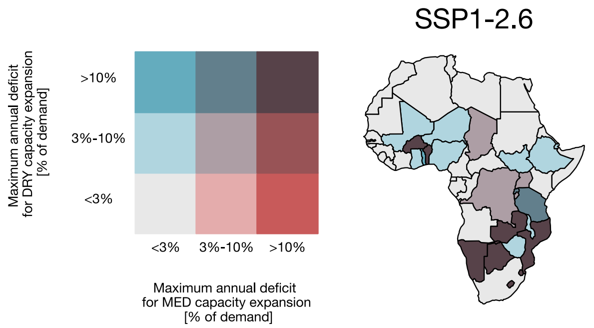

Fig. S8. Maximum annual generation deficit observed under dry hydrology and absence of power trade for the capacity expansion plans designed under median and dry hydrology. Many countries remain at risk of substantial generation deficit if power trade is not guaranteed, especially in Sub-Saharan Africa.

Supplementary Tables

SSP scenario	TEMBA Energy Demand	TEMBA Emission Cap
SSP1-2.6	2.0	2.0
SSP4-6.0	Refer	Refer
SSP5-8.5	Refer	Refer

Table S1. SSP scenarios considered and their mapping to OSeMOSYS-TEMBA model configurations