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Impact of political and economic barriers for concentrating solar power in Sub-Saharan Africa

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ABSTRACT

Sub-Saharan Africa (SSA) needs additional affordable and reliable electricity to fuel its social and economic development. Ideally, all of this new supply is carbon-neutral. The potentials for renewables in SSA suffice for any conceivable demand, but the wind power and photovoltaic resources are intermittent and difficult to integrate in the weak electricity grids. Here, we investigate the potential for supplying SSA demand centers with dispatchable electricity from concentrating solar power (CSP) stations equipped with thermal storage. We show that, given anticipated cost reductions from technological improvements, power from CSP could be competitive with coal power in Southern Africa by 2025; but in most SSA countries, power from CSP may not be competitive. We also show that variations in risk across countries influences the cost of power from CSP more than variations in solar resources. If policies to de-risk CSP investment to financing cost levels found in industrialized countries were successfully implemented, power from CSP could become cheaper than coal power by 2025 in all SSA countries. Policies to increase institutional capacity and cooperation among SSA countries could reduce costs further. With dedicated policy measures, therefore, CSP could become an economically attractive electricity option for all SSA countries.

1. Introduction

The electricity systems of Sub-Saharan Africa (SSA) face a number of serious challenges. Electricity demand is increasing rapidly, and is likely to at least double in the next 25 years (EIA, 2013; IRENA, 2015a). Simultaneously, only one-third of the population has electricity access, and current progress on electrification is merely keeping up with the population growth (IEA and World Bank, 2015). There is thus a need to expand the electricity generation faster than today: need estimates range from 7000 MW/year to 14000 MW/year, corresponding to 5–10% of the currently installed capacity; presently, some 4000 MW/year are installed in SSA (EIA, 2015). Blackouts are common because of capacity shortages and unreliable infrastructure, forcing consumers to rely on expensive and inefficient diesel-fueled backup generators. In some countries, diesel generators represent half the installed capacity, despite their very high cost of 50 US¢/kWh or more, greatly exceeding the cost of grid power (Briceño-Garmendia and Shkaratan, 2011; Eberhard et al., 2011; Eberhard and Shkaratan, 2012; Gallup, 2010; Mukasa et al., 2015).

The electricity production must be completely decarbonized by the second half of this century, also in SSA (IPCC et al., 2014; UNFCCC, 2015a). This means that all new long-lived infrastructure must be based on carbon-neutral technologies (IPCC, 2011; Rogelj et al., 2015). To meet the objectives of sustainable development and poverty eradication defined under the Millennium Development Goals (MDGs) and the Paris Agreement (UN, 2016; UNFCCC, 2015a), however, new electricity generation in SSA also needs to be affordable, not increasing costs beyond what consumers can afford. Currently, three-quarters of the sub-Saharan countries have average power generation costs exceeding 10 US¢/kWh, and one third exceed 15 US ¢/kWh (Eberhard et al., 2011). Hence, if new carbon-neutral electricity is to be considered "affordable", it must be at least competitive with the existing power mix and have generation costs of less than 10–15 US ¢/kWh. If it is to be competitive with the largest electricity system carbon emitter – coal power – then it must have generation costs of less than about 8 US¢/kWh (IRENA, 2013c).

In the sub-Saharan context, the search for additional generation is further complicated, as the weak electricity grids south of the Sahara would struggle to integrate large-scale additions of new intermittent power (Mukasa et al., 2015). Hence, either the grids must be reinforced to integrate fluctuating renewables, or ways could be sought to smooth the renewable electricity on the generation site and make the feed-in

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predictable and controllable so as to minimize the added strain on the grid. Dispatchable and economical renewable power would therefore be particularly valuable for the electricity supply of SSA.

These multiple policy objectives of carbon-neutrality, dispatchability and affordability are not easily compatible, for several reasons. Current costs of renewable power still exceed those of most fossil technologies, although this gap has closed substantially through substantial technological development: the cost of solar photovoltaic (PV), for example, has decreased by 50% over the last four years (IPCC, 2011; IPCC et al., 2014; Rogelj et al., 2015). Solar PV and wind turbines are the least-cost renewable technologies, and both could be competitive on a levelized cost basis in many SSA countries: today, wind power costs some 6–9 US¢/kWh, on par with new fossil generation, while PV costs some 10–12 US¢/kWh in America and Europe, depending on solar resource and market situation, down to 6 US¢/kWh in the United Arab Emirates with very good solar resources (IRENA, 2015b). On the other hand, there are not many options for supplying dispatchable renewable power at large scale. Dam hydropower and biomass power have limited potentials and are questionable for a very large-scale expansion because of their environmental impact (IRENA, 2012b, 2014). Wind power would need bulk storage for large amounts of power, such as pressurized air storage, to smooth the wind farm output on-site, and such storages are currently not commercially available at scale (Budt et al., 2016). Solar PV, which is modular and easy to quickly install also in remote places, can be equipped with batteries in a decentralized setting, making the supply to the grid more – or even fully – predictable, or enabling consumers to be fully autarkic (Baurzhan and Jenkins, 2016). The last option – the one we investigate here – is concentrating solar power (CSP) with thermal storage, which offers the potential to provide fully predictable renewable bulk power (Pfenninger et al., 2014). The potential for CSP in SSA is vast, and would in principle suffice to cover any conceivable future SSA demand (Hermann et al., 2014; Trieb et al., 2009b). However, CSP is lagging behind and is not expanded as fast as PV – there are 5 GW of CSP world-wide, compared to 230 GW PV (NREL, 2016; SolarPowerEurope, 2014) – also because of PV's rapid cost development. Indeed, several projects have seen a shift in technology, from CSP to PV, because of the lower costs of PV. For example, this happened at the 250 MW Beacon project in the US (CSP World, 2013) and the 10–30 MW Erfoud, Zagora and Missour projects in Morocco (World Bank, 2014): in these cases, the CSP plants were planned without storage, so that the CSP power would have been similarly fluctuating as that of the final PV projects. Today, most recent CSP projects and those under construction are equipped with thermal storage to leverage this advantage, including all CSP stations built or under construction in Africa (Morocco and South Africa) (NREL, 2016). When comparing CSP with thermal storage and PV with lithium-ion (Li-ion) batteries on a levelized cost of electricity (LCOE) basis, CSP with storage emerges as the lower-cost alternative: using current and projected costs (2020), the LCOE of CSP is lower than of PV with the same hours of storage for peak and intermediate power coverage (Feldman et al., 2016). When comparing CSP with thermal storage and PV with Li-ion batteries on a net system cost basis, the projected costs (2020) of both technologies are similar but with high uncertainties especially for PV with batteries (Mehos et al., 2016).

Here, therefore, we examine the competitiveness of CSP with thermal storage as one possible policy option for supplying dispatchable renewable power to SSA and compare it with typical cost of coal power, which in most cases is the currently cheapest dispatchable electricity supply option. In this article, we investigate the potential for and cost of CSP with thermal storage in SSA. In particular, we explore how dispatchable solar power could be traded, and investigate how the current political, institutional and economic situation in SSA with its far-reaching effects on financing costs, technological capacity, and international cooperation on infrastructure development affect the prospects of this technology, and what it would take in terms of policy to solve key problems and make CSP with thermal storage a viable electricity option in SSA.

2. Background

2.1. Concentrating solar power

Concentrating solar power collects the heat of the sun through large mirrors, which focus the light on a focal line (parabolic trough, Fresnel) or a focal point (solar towers), to generate steam and drive a turbine. The aspect that sets CSP off from other renewables is the option of equipping it with thermal storage. The thermal storage is charged during the sunny hours of the day and allows the power station to operate after sundown, at night, or during periods of adverse weather. Recent analyses suggest that with the proper system coordination, CSP with thermal storage can be operated in the Northern and Southern African deserts to provide both a constant and a dispatchable power supply (Pfenninger et al., 2014; Trieb et al., 2014).

Today, there are almost 5 GW of CSP in the world, mainly in Spain and in the US, and further CSP stations stand in another 8 countries, including South Africa, Morocco, China and India. This is less than expected during the CSP hype a decade ago, but CSP continues to develop and expand, albeit at a much lower pace than wind and solar PV. Some 2 GW of CSP are currently under construction, almost all of which outside the industrialized world, mainly in Morocco, South Africa, Chile, China and India (NREL, 2016).

One reason for the slow expansion pace is that optimal conditions for CSP are found in areas with high direct normal solar irradiance (DNI). Such areas are typically found in deserts and arid regions, and most deserts are not in the industrialized countries traditionally driving renewables development and expansion (IRENA, 2012a; Lilliestam et al., 2012). Even in countries with good CSP sites, such as the US or South Africa, large cities and densely populated areas are often located far away from such dry places, so that long power lines are needed for CSP to reach the main grid and the consumers. This makes CSP projects more complicated than other renewables to be expanded near demand, but CSP projects can be cost-effectively connected to demand-centers with high-voltage power lines (Trieb et al., 2015).

2.2. Renewable energy investments and finance in Sub-Saharan Africa

Renewable power technologies have high upfront investment costs but low operation costs compared to fossil alternatives, as they have no fuel costs (except biomass power). The investment and the financing costs[1] are therefore the dominant drivers of the LCOE for renewables, making them very different investment cases than, for example, gas and coal power stations.

Investment costs are commonly higher in developing than in developed countries due to factors such as poorly trained labor forces, a need to bring engineers from abroad, and weak transportation infrastructure (IRENA, 2015a; Ondraczek et al., 2015). The financing costs are also commonly much higher in developing than in developed countries, as they represent the extra reward required by investors and lenders to compensate them for the high risks. These risks arise because of perceived or factual political, regulatory, financial and administrative barriers, long and uncertain permission processes, and other general investment risks (Backhaus et al., 2015; Ondraczek et al., 2015; UNDP, 2013). Given that renewables are capital-intense investments, renewable energy projects are especially sensitive to financing risks driving up the cost of capital (Williges et al., 2010). To address

[1] Throughout the article, we use the terms weighted average cost of capital (WACC), financing cost and discount rate interchangeably, as they refer to practically the same financial concept in the context of our study.

this, international efforts are underway to lower such barriers and help improving legal, policy and regulatory environments to decrease such risks and facilitate renewable energy investments, for example in the US-led Power Africa initiative but also within the frame of the Paris Climate Agreement (UNFCCC, 2015a; US Government-led Partnership, 2015).

To our knowledge, only few renewable energy studies consider differences in financing risk and use country-specific financing costs. In the cases where this is done, for example for solar PV in Peters et al. (2011) and PV and wind power in Schmidt et al. (2012), the importance of contextualization by taking country risk into account is a key finding. For example, Schinko and Komendantova (2016) show that the actual weighted average cost of capital (WACC) in North Africa is more than twice as high as in Europe, and policies bringing the North African WACC down to European levels could decrease CSP costs by 40%. Even more striking, Ondraczek et al. (2015) show by applying a country-specific WACC to solar PV in all countries globally that the WACC is a stronger determinant for the PV cost than the solar resource quality: counter-intuitively, they show that it is cheaper to build PV in a low-sun and low-risk country such as Germany than in a high-sun, higher-risk one such as many SSA countries.

Despite its importance for renewable LCOE and its large variance across countries, most studies assume uniform financing costs for all assessed countries. The International Renewable Energy Agency (IRENA) uses, for example, a uniform 10% discount rate when examining the prospects for renewable energy in the Southern and Western African power pools (IRENA, 2013c, 2013d), and also globally (IRENA, 2013b). This standardization allows for direct comparison between projects and technologies, but also means that the risk profile of all countries is assumed to be the same, which is obviously an incorrect assumption. Here, we assume country-specific WACCs (see Section 3).

2.3. Electricity cooperation in Sub-Saharan Africa

Sub-Saharan Africa has four regional power pools – the Central, Eastern, Western and Southern African power pools – that trade electricity among the participating countries to foster economies of scale and improve reliability of the electricity system. Some of the electricity trade is accompanied by long-distance transmission, such as the 1400 km high-voltage direct current (HVDC) link connecting the Cahora-Bassa dam in Mozambique to Johannesburg, South Africa. Two more HVDC lines connect remote generation points in Namibia (Caprivi Link, 950 km) and Democratic Republic of the Congo (DRC) (Inga-Shaba, 1700 km). Yet the experience with substantial international power trade and long-distance transmission remains limited: only 16% of all electricity in SSA is traded between countries, and more than 90% of this is in the Southern power pool (Eberhard et al., 2011).

Previous studies have identified insufficient institutional capacity, especially for the coordination and execution of multi-national projects, as an important barrier to CSP expansion in cooperation between North Africa and Europe (Lilliestam et al., 2012; Lilliestam and Patt, 2015; Williges et al., 2010), along with the fact that many potential exporter countries struggle already with satisfying their own electricity needs and have difficulties to raise finance to fund large-scale generation and transmission assets for their own needs (Beneking et al., 2016; Frieden et al., 2016; Lilliestam et al., 2016). Multi-national CSP and transmission projects may be even more challenging in the SSA context, where most countries lack the institutional capacity present in Europe and the Maghreb, putting up additional barriers compared to similar projects in other regions. Such problems vary between countries and their domestic political and economic situation, but may include administrative inefficiency, political instability, corruption, low political and institutional capacity and weak administration. None of these barriers are CSP-specific, and may also be encountered in other multi-national projects, such as gas pipelines or highways (Kaufmann and Kraay, 2016; Transparency international, 2016).

Large-scale, multi-national electricity projects will be particularly difficult to realize in countries with particularly weak or even failed institutions, in so-called *fragile states* (FFP, 2014). Fragile states are those where the governance systems have collapsed and the government is unable to maintain core functions, including having lost the state monopoly of violence or control over parts of the territory, and a failure to supply most or all of the public services. State fragility thus leads to an erosion of government legitimacy and its capacity to make and enforce decisions (DFID, 2005), so that fragile states will have great difficulties in enacting large-scale cooperation projects with other countries. For example, the Inga 3 hydropower project in DR Congo, a fragile state, exemplifies how insufficient institutional capacity and political instability may make infeasible an economically attractive project. There are several occasions in which the DRC closed a deal to build the Inga 3 dam – most recently to South Africa, via an HVDC line through Angola and Namibia. Economically it could be attractive: the power could be cheap, and South Africa needs firm capacity; yet, just as on several other occasions since the 1950s investors have withdrawn, and there is no activity on the ground, no financing deals have been settled, and there are no plans for how or where to build the transmission line, as administration is slow and the uncertainty and risks, including financing risk, are vast (International Rivers, 2016). Currently, 10 of 49 SSA countries are classified as fragile: South Sudan, Sudan, Somalia, Central African Republic (CAR), DRC (very high alert); and Chad, Zimbabwe, Guinea, Côte d'Ivoire and Guinea Bissau (high alert) (FFP, 2014).

3. Method

3.1. Model structure

To estimate the cost of CSP stations and transmission lines and the cost for delivery to SSA demand centers, we developed a model to identify the best sites to install CSP stations and the optimal power line routes from the generation sites to selected demand centers, and calculate the total cost of CSP generation at these sites and the HVDC or HVAC transmission to the different demand centers. We describe each step of the modeling here, and a detailed description of the model, including equations, data, assumptions and sources is found in sections A1–A4 in Appendix A.

We select the demand centers among metropolitan areas with more than one million inhabitants (UN-Habitat, 2014) or among national economic centers (World Bank 2015a). This is where the need for power is the largest today, and these are likely areas for the fastest demand growth in the future. We consider these demand centers as representatives for the country, as anchoring points for the power lines, and hence limit the selection to one city per country while seeking geographic spread between the cities. We exclude fragile states from being demand centers, and from being supply and transit countries in the base case and selected scenarios (see Sections 3.2 and 3.3).

To give a sense of magnitude, we compare our results with the typical cost of coal power, which is the currently cheapest dispatchable power option. For this benchmark, we assume that the costs of coal power are the same across the continent, which is of course not exactly correct: the costs will vary across countries, for example depending on the country-specific financing risk or the availability of domestic coal resources. Hence, the comparison is to be understood as a tool to help quickly see whether CSP with thermal storage is, under the scenario conditions, an economically attractive option for SSA countries. It is not intended as a precise statement or forecast of the cost of coal power, but as a help to the reader. We take the cost for coal power from studies of IRENA for the Southern and Eastern African power pools (IRENA, 2013c, 2013d).

We model the cost of supplying electricity from CSP in three consecutive steps. We first identify the most suitable sites to deploy CSP stations for DNI levels exceeding 2000 kWh/m^2/year, a level to which typically project developers restrict the potential sites (IRENA, 2012a). We classify the generation sites according to their DNI, in steps of 100 kWh/m^2/year. Within this large set of potential sites, we exclude areas where CSP cannot be built (e.g. too steep terrain, water bodies, protected areas, settlements, shifting sand) as detailed in Table A1 in Appendix A. This gives a set of possible generation sites, at different resource levels.

Second, we identify the transmission corridors from the demand centers to the generation sites, by seeking the least-cost corridor between the demand center and the closest generation site at each DNI level. We do this by assigning weights – so-called friction costs – to different types of land, defining grassland as the base (friction cost 1) and assign equal or higher friction costs to other terrain types, for example mountains or forest. For data on this, see Table A2 in Appendix A. For distances exceeding 800 km, we simulate the construction of HVDC overhead lines, as these are more cost-effective than AC for such long-distance transmission (SNC-Lavalin and Brinckerhoff, 2011; Trieb et al., 2015).

Third, we estimate the cost of the electricity supplied to the demand center by calculating and adding the generation and the transmission costs. We calculate the LCOE from a dry-cooled solar tower station with 10 h of thermal storage at each site. This configuration will not produce baseload power, especially not during winter, but it will produce dispatchable, fully predictable and controllable renewable electricity (Mehos et al., 2016; Pfenninger et al., 2014). We assume dry cooling for all stations, as wet cooling is rarely a viable option in deserts, and as the costs of dry cooling are relatively low (Damerau et al., 2011). We choose solar tower over parabolic trough technology, as it achieves higher temperatures and hence a higher thermodynamic efficiency. Further, the flat mirrors and single receiver is more low-tech than troughs, enabling (at least in principle) the manufacturing of more components locally, thus potentially contributing to the local industrial and economic development (IRENA, 2013a). The power station costs are for a 100 MW, 10 h-storage, molten-salt solar tower station similar to the US Crescent Dunes station, with total costs of 7910 US$/kW (Turchi and Heath, 2013). Following continued learning and cost reduction, we assume a 10% learning rate and the global CSP expansion scenario of the International Energy Agency technology roadmap (IEA, 2014). This implies that the CSP investment costs in 2025 are about 30% lower than in 2012. Detailed descriptions of the equations, the data and all sources are found in section A4 in Appendix A.

We then calculate the levelized transmission cost for a power line in the friction cost-minimized corridor, and add it to the generation cost. The transmission cost data is taken from the regional power system master plan for the Eastern African Power Pool and the East African Community. The cost for a 600 kV-HVDC bi-pole line is 150 US$/MW per km, for the converters stations (of which two – on at each line end – are needed) is 130,000 US$/MW, and for a 500 kV-AC double-circuit line is 290 US$/MW per km (SNC-Lavalin and Brinckerhoff, 2011). Cost for transmission components remain as 2012 costs, as these costs are for projects planned by the regional power system master plan to start operation in 2025, same base year as our base case and scenarios (see Sections 3.2 and 3.3). The transmission line capacity factor follows that of the CSP station(s) connected to it, following the solar multiple-capacity factor equation of Trieb et al. (2012) (see Eq. (A11) in Appendix A).

To account for the financing risk of each generation-transmission project, we follow the *Investment Analysis* methodological tool developed by the Clean Development Mechanism's (CDM) Executive Board, which recommends using a country-specific WACC as financing cost when the project-specific financing cost is missing (UNFCCC, 2015b). We calculate country-specific WACCs as the weighted combination of equity and debt costs of each country (see Table 1). For the real equity rate of return K_{E_n} we use default values recommended by the CDM Executive Board for investment analyses in the energy industry for Non-Annex 1 countries (UNFCCC, 2015b). For the nominal prime-lending rate K_{D_n} we use the average lending rates for the period 2010–2014 (World Bank, 2015b). If this data is not available for a country for a specific year, we apply data from the last available year. For countries where K_{D_n} values are missing we replace missing values with data from neighbor countries as suggested by Ondraczek et al. (2015). We thus calculate the $WACC_n$ for country n as:

Table 1
Country-specific $WACC_n$ for the relevant SSA countries.

Country, demand center	K_{En} (%)	K_{Dn} (%)	$WACC_n$ (%) 30_{En}:70_{Dn}
Angola, Luanda	12.3	18.0	16.3
Benin, Porto Nuovo	14.6	16.8	16.1
Botswana, Gaborone	9.1	10.5	10.1
Burkina Faso, Ouagadougou	17.6	16.8	17.0
Cameroon, Douala	16.1	15.0	15.3
Ethiopia, Addis Ababa	14.6	8.0	10.0
Gabon, Libreville	13.2	15.0	14.5
Ghana, Accra	16.1	25.6	22.7
Mali, Bamako	16.1	16.8	16.6
Mozambique, Maputo	14.6	16.5	15.9
Namibia, Windhoek	11.1	8.8	9.5
Niger, Niamey	16.1	16.8	16.6
Nigeria, Lagos	13.2	16.7	15.7
Republic of the Congo, Brazzaville	13.2	15.0	14.5
Senegal, Dakar	14.6	16.8	16.1
Republic of South Africa, Johannesburg	10.7	9.0	9.5
Tanzania, Dar es Salaam	17.6	15.4	16.1
Uganda, Kampala	14.6	22.6	20.2
Kenya, Nairobi	14.6	16.6	16.0
Zambia, Lusaka	14.6	14.6	14.6
Transit or exporter country	**K_{En} (%)**	**K_{Dn} (%)**	**$WACC_n$ (%) 30_{En}:70_{Dn}**
Chad	16.1	15.2	15.5
Democratic Republic of Congo	17.6	33.4	28.6
Malawi	17.6	34.2	29.2
Sudan	14.6	17.0	16.3

$$WACC_n = \frac{E}{E + D} \times K_{En} + \frac{D}{E + D} \times K_{Dn} \tag{1}$$

where E and D are the equity and debt shares of the project; throughout, we use a 30:70 equity: debt share, which is common in renewable electricity projects (UNDP, 2013). For generation, we use the WACC of the country where the CSP station stands, whereas we apply the highest WACC along the corridor for the entire transmission project.

3.2. Base case

In our base case, we calculate the cost of supplying CSP from the sites at the highest DNI level available within each power pool[2] to the twenty demand centers representing the feed-in point of electricity supplied by CSP in each country, while taking into account current country-specific risks and constraining trade to within the existing power pools. We apply projected costs for 2025, as it is unlikely – given that no project is even in planning today – that large CSP or CSP with transmission projects will materialize anywhere outside the southern-most countries before then. Results with 2012 costs are found in Table B1 in Appendix B.

Investment costs on renewable infrastructure are usually higher in

[2] Tanzania is member of both the Eastern and the Southern power pool; we assign it to the Southern Power Pool, so as to be coherent with IRENA's SSA power system reports.

countries without active policy programs to support renewables, without local manufacturing capacity, and/or a lack of adequate logistic infrastructure, such as well-developed highway or railway systems (IRENA, 2015a). The CSP station investment costs apply for a new station constructed in the US (see Section 3.1), where none of the above-mentioned difficulties exist. Thus, we assume a cost mark-up factor of 6% for stations constructed in Southern Africa, and of 26% for stations constructed in the remaining SSA, reflecting the cost-difference between SSA countries and more developed regions as described in IRENA (2015a). For the financing costs, we take country-specific risks into account by using country-specific WACCs, see Table 1.

We assume that no generators or transmission lines can be built in states currently classified as fragile (see Section 2.3), as the investment risks and barriers are too large. Further, we assume that CSP projects with transmission can only take place within existing power pools, as the development of projects crossing power pool border would require the negotiation of new modalities for international electricity trade, but the political and administrative capacity for this may be limited.

3.3. Scenario variations

In a second step, we analyze the implications on costs and the location of transmission lines for five alternative scenarios, in which we relax the constraints on cooperation, reduce the financing costs compared to the base case, and remove the cost mark-up factor on the cost of components for stations constructed in SSA. As in the base case, we use projected CSP investment costs for 2025.

In the first scenario (2a), we relax the trade limitation and allow trade of electricity supplied by CSP between all countries, including currently fragile states. This variation represents an improvement in political stability and international cooperation capacity among SSA countries, resulting from successful policies to increase institutional capacities. This could enable some countries to access generation sites with higher DNI and, with other conditions remaining the same, lower generation costs.

The second scenario (2b) considers an improvement in project finance, so that financing cost decrease from the country-specific WACC, which in SSA is often 15% or higher, to a uniform 5%, which can currently apply in particularly low-risk OECD countries (Schinko and Komendantova, 2016). This variation represents de-risking policies to reduce the perceived or actual investment risks and barriers, for example programs for concessional finance or loan guarantees.

In the third scenario (2c), we remove the cost mark-up factor for CSP components in SSA, assuming the same investment costs for SSA as for industrialized regions. This variation represents successful policies for technology transfer, improving the logistic infrastructure, and expanding local technical resources and expertise.

The fourth scenario (2d) considers a relaxation of all three assumptions simultaneously. This variation represents the most optimistic outlook for CSP, when all policy efforts for providing cheap finance, technology transfer, infrastructure improvements and measures to enable and enhance regional cooperation have been successful.

In the fifth scenario (2e), we limit electricity from CSP to be generated, transmitted and consumed domestically. This variation represents a situation where low institutional capacity hinders countries to cooperate at all, restricting CSP generation to the solar sites available domestically.

4. Results

4.1. Base case

Our results show that under current economic and political conditions, electricity from CSP is competitive with coal power in the Southern power pool, except in Tanzania, when using 2025 technology costs. It is uncompetitive in all other parts of SSA, and in all countries if 2012 costs are used (see Table B1 and Fig. B1 in Appendix B). Fig. 1 shows the costs in the demand centers, and the location of the CSP stations and associated transmission lines using 2025 costs. The cost figures described in the sections below represent 2025 costs, except as otherwise stated.

In Southern Africa, the CSP supply from 2900 kWh/m^2/year solar resources costs from 6.7 US¢/kWh for Namibia, with excellent solar resources close to the capital Windhoek, to 9.8 US¢/kWh for Tanzania, which also gets its electricity from CSP from Namibia through more than 3000 km long transmission lines. This emphasizes that the transmission cost is not a main cost driver, but adds roughly 1–2 US ¢/kWh per 1000 km line, depending on the country-specific WACC for the levelized cost of transmission. Tanzania, however, belongs not only to the Southern but also to the Eastern power pool. If Tanzania were considered to get power from the Eastern power pool, the cost of the electricity from CSP from Kenya, a neighbor country, would be more expensive (20.2 US¢/kWh at 2600 kWh/m^2/year, WACC 16%) than allocating Tanzania to the Southern power pool and hence getting the electricity from Namibia (9.8 US¢/kWh at 2900 kWh/m^2/year, WACC 9.5%), despite the length of the transmission line. In all Southern power pool cases, except Tanzania, the solar resource is domestic or in a neighbor country, and CSP supply to all countries could be competitive with coal power. Especially Namibia, South Africa and Botswana are countries that are politically stable and have more efficient institutions than other Southern African countries. These countries are also among the countries with the highest average income and the lowest perceived level of corruption in all of Africa (Kaufmann and Kraay, 2016; Transparency international, 2016; World Bank, 2016): it is no coincidence that South Africa is the one SSA country already expanding CSP. The generation areas we identify in Southern Africa are identical or similar to existing, under construction and planned CSP installations; for example KaXu (existing, 100 MW) or Xina Solar One (under construction, 100 MW) in South Africa, or Khorixas (planned, 22 MW) in Namibia (CSP Today, 2016).

In Western Africa, the CSP supply from 2900 kWh/m^2/year solar resources from Niger costs about 14 US¢/kWh, and – as in the Eastern and Central power pools – it is not competitive with coal power. The solar resources in Western Africa are comparable to those in Southern Africa, but the financing costs are much higher due to higher country risk levels: whereas the WACC in Namibia, South Africa and Botswana is about 10%, the WACCs in Western African countries range from 15.7% for Nigeria up to 22.7% for Ghana (see Table 1).

In Eastern Africa, the CSP supply costs are about 13 US¢/kWh. The maximum solar resources in Eastern Africa are 2600 kWh/m^2/year, comparable to those in the southwestern of the US where CSP stations are in operation. As the financing costs are too high, CSP is not competitive with coal power anywhere in Eastern Africa.

In Central Africa, the CSP supply costs are about 15 US¢/kWh, although the best available solar resource is only 2300 kWh/m^2/year, but the WACC of Cameroon is lower than in Eastern and Western African source countries. This resource level is the lowest of the four sub-Saharan power pools, yet it is higher than the solar resource in southern Spain, where CSP stations are in operation.

4.2. Scenario variations

4.2.1. Scenario a: unrestricted trade

Fig. 2a shows the costs (2025) in the demand centers when electricity trade between all countries is allowed. In Eastern and Western Africa, the cost reductions of allowing electricity trade between all countries compared to the trade-constrained base case are up to 0.7 US¢/kWh, whereas in Central Africa they are up to 5.7 US ¢/kWh (see Table 2). This makes the electricity from CSP roughly competitive with coal power in some countries in Central Africa, mainly

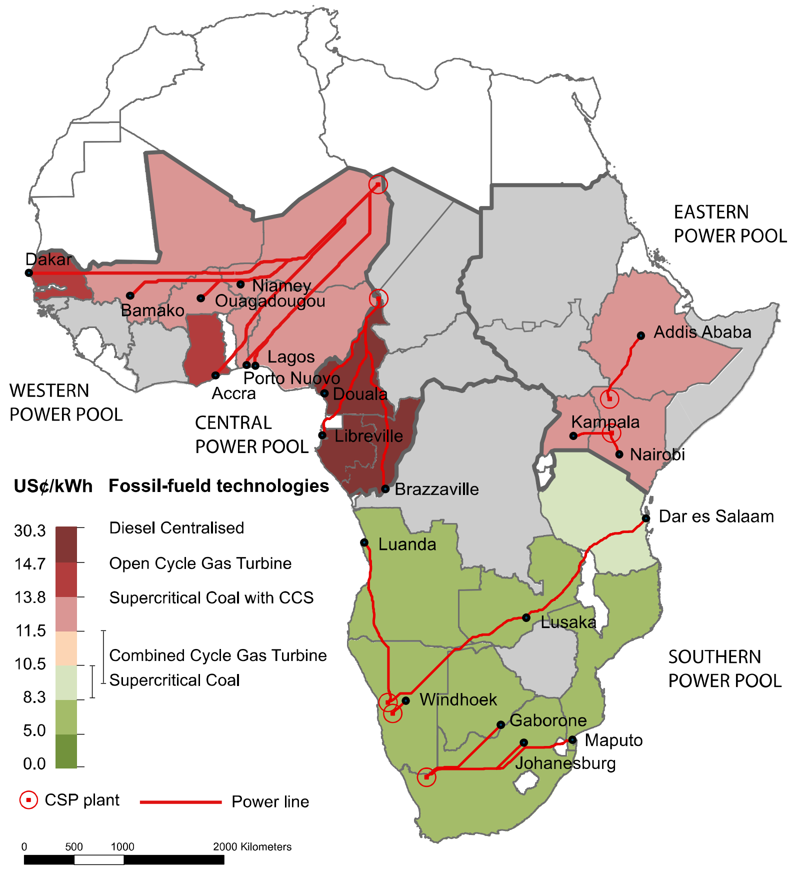

Fig. 1. Levelized electricity costs (US¢/kWh) for the power supplied by CSP to demand centers in sub-Saharan countries, and locations of associated generation sites and transmission lines under base case assumptions; using projected 2025 technology costs. Countries in grey are fragile states. The colors show the supply costs and compare them to typical costs of fossil fuel power plants in Africa (IRENA, 2013c, 2013d).

because of the lower WACC in Namibia compared to the base case source country Cameroon. In Southern Africa there is no change, as these countries already access excellent, relatively low-risk resources in the base case. When electricity trade is allowed between all countries, Western and Eastern African countries receive its electricity from CSP from the very good solar sites in Niger, Chad and Sudan, whereas the Central African countries generate their electricity from CSP in Chad and Namibia. In some cases the power station are built domestically (e.g. Namibia and South Africa) or in a neighbor country (e.g. Botswana), but for some demand centers up to 5 countries must be involved to access the highest resources. When electricity trade between all countries is allowed, all countries except Southern and some Western African countries involve more countries than compared to the base case, but get lower costs in return.

4.2.2. Scenario b: improved financing conditions

Fig. 2b shows the costs (2025) in the demand centers using a uniform 5% WACC for all countries. The impact of decreasing the financing risk is strong in Western, Central and Eastern African countries where the financing risks are currently high: there, a uniform WACC of 5% halves CSP costs compared to the base case. For Southern African countries this effect is smaller, as the WACCs there are lower, but the cost reduction is still 2–3 US¢/kWh (see Table B3 in Appendix B). The costs in Southern Africa are lowest, as the cost mark-up is lower than in the other countries, as the solar resource is higher, and the power lines are often shorter than in Western Africa with same solar resource. Under the assumption of uniformly improved financing conditions, electricity from CSP is competitive with coal power in all countries, with total LCOEs in all cases below 7.3 US¢/kWh, indicating that policies to reduce financing costs are key to making electricity from CSP an attractive option in SSA.

4.2.3. Scenario c: no investment cost mark-up

Fig. 2c shows the costs (2025) when the costs of the CSP stations are the same as for industrialized countries, without the cost mark-up. For Western, Central and Eastern African countries, this reduces costs (compared to the base case) by about 3 US¢/kWh, whereas it is some 0.4 US¢/kWh in Southern Africa where the mark-up factor is lower (see Table B3 in Appendix B). In this scenario, the competitive/non-competitive status of the power supplied by CSP is the same as in the base case. This scenario thus indicates that issues such as a lack of skilled labor or weak infrastructure are important aspects, but they are not game-changers for the competitiveness of CSP, especially not in Southern Africa.

4.2.4. Scenario d: unrestricted trade, improved financing conditions, no investment cost mark-up

Fig. 2d shows the costs (2025) in the demand centers after simultaneously relaxing all three non-technical assumptions of the three preceding cases. This makes electricity from CSP competitive with coal power in all countries, with costs around and below 5 US ¢/kWh (see Table B3 in Appendix B). In this very optimistic scenario, electricity from CSP is most likely the cheapest dispatchable electricity option of all, showing that policies to remove current barriers to CSP expansion have the potential to put SSA on track to a sustainable, reliable and highly affordable electricity supply.

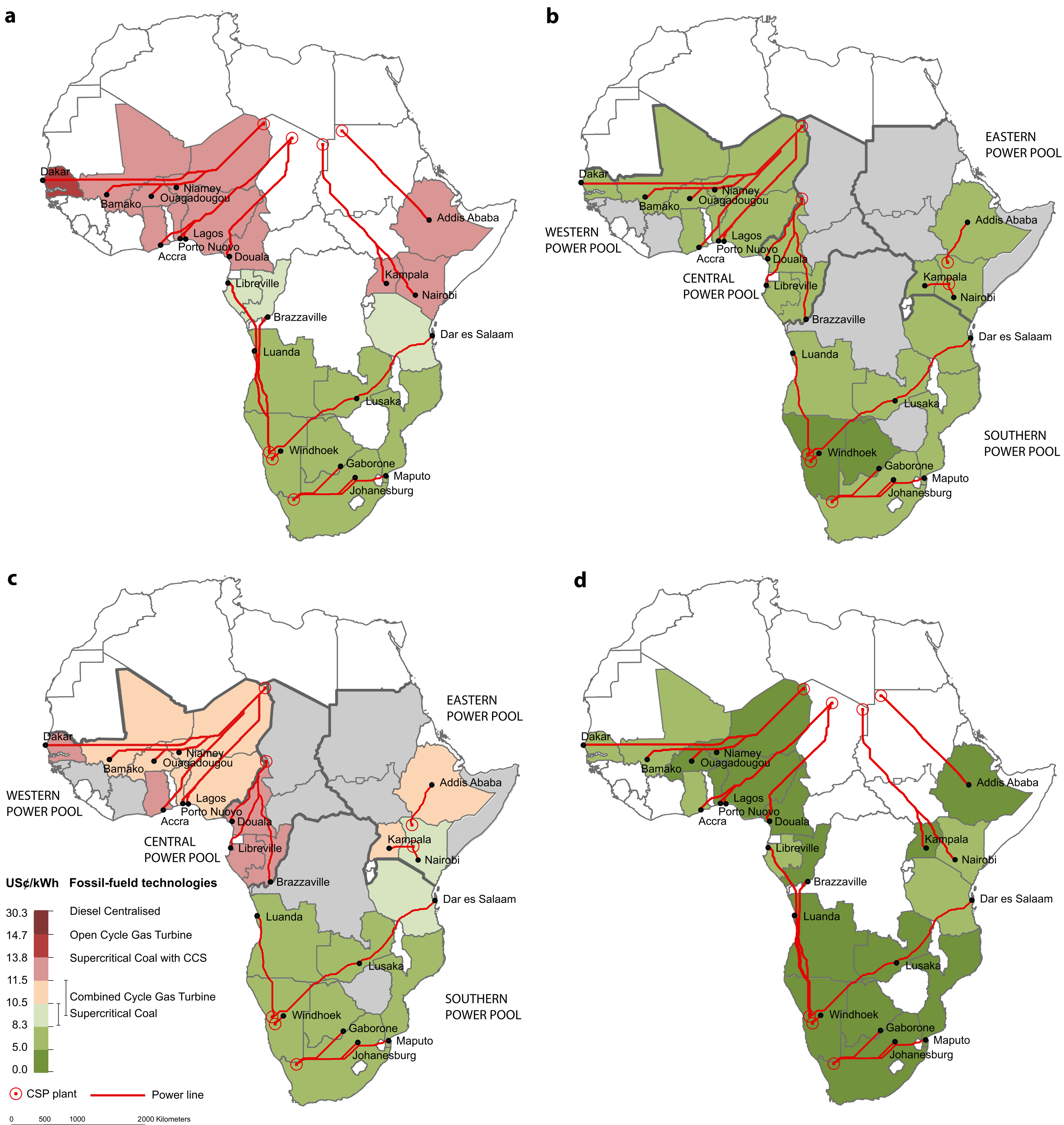

Fig. 2. Levelized electricity costs (US¢/kWh) for the power supplied by CSP to demand centers in sub-Saharan countries, and locations of associated generation sites and transmission lines using 2025 technology costs; (a) under unrestricted trade; (b) WACC 5%; (c) investment cost from industrialized countries; (d) considers all assumptions from previous scenarios. In (b) and (c) electricity trade is limited within each of the sub-Saharan power pools. Countries in grey are fragile states. The colors show the supply costs and compare them to typical costs of fossil fuel power plants in Africa (IRENA, 2013c, 2013d).

4.2.5. Scenario e: domestic solar resources

Similarly, countries may face a decision between exploiting the best possible solar sites, which are in some far away place and are thus cheap but complicated to access, and the best solar sites available within the country, which may be more expensive in generation but easier to access. Countries such as Niger, South Africa, Namibia, Cameroon and Kenya have no reason to import power supplied by CSP as they have good solar resources available domestically. Imports are beneficial from a cost perspective in all other cases. Table 3 shows that for twelve countries is more economical to import power from other countries of the power pool than use domestic solar resources, and for other two is not even possible to use domestic resources as these are below 2000 kWh/m^2/year, and they necessarily should import power. Accra (Ghana) could even save 9 US¢/kWh, as it has

Table 2
Transmission distances (km) from cities to CSP plants at the highest solar resources in Africa when electricity trade between all countries is allowed, number of countries borders crossed and associated cost saving (US¢/kWh) for the year 2025 compared to plants at the highest solar resources within each power pool (base case). *np* means not possible.

	Distance (km)	Borders crossed	Cost saving (US¢/kWh)		Distance (km)	Borders crossed	Cost saving (US¢/kWh)
Western Power Pool				Luanda, Angola	1626	1	0.0
Accra, Ghana	2658	5	−0.6	Lusaka, Zambia	1628	3	0.0
Bamako, Mali	2840	2	0.0	Maputo, Mozambique	1498	2	0.0
Dakar, Senegal	3731	3	0.0	Windhoek, Namibia	151	0	0.0
Lagos, Nigeria	2304	2	−0.7	**Central Power Pool**			
Niamey, Niger	1743	0	0.0	Brazzaville, RC	2149	3	−5.1
Ouagadougou, Burkina Faso	2175	1	0.0	Douala, Cameroon	2236	2	−2.2
Porto Nuovo, Benin	2333	3	−0.7	Libreville, Gabon	2837	4	−5.7
Southern Power Pool				**Eastern Power Pool**			
Dar es Salaam, Tanzania	3243	5	0.0	Addis Ababa, Ethiopia	1886	1	−0.3
Gaborone, Botswana	869	1	0.0	Kampala, Uganda	2490	3	−0.1
Johannesburg, RSA	1014	0	0.0	Nairobi, Kenya	2852	4	0.3

Table 3
Transmission distances (km) from cities to CSP plants at the highest solar resources within each power pool (base case), number of countries borders crossed and associated cost saving (US¢/kWh) for the year 2025 compared to plants at the highest domestic solar resources. *np* means not possible.

	Distance (km)	Borders crossed	Cost saving (US¢/kWh)		Distance (km)	Borders crossed	Cost saving (US¢/kWh)
Western Power Pool				Luanda, Angola	1626	1	3.8
Accra, Ghana	2495	4	9.0	Lusaka, Zambia	1628	3	3.2
Bamako, Mali	2840	2	0.6	Maputo, Mozambique	1498	2	5.0
Dakar, Senegal	3731	3	0.5	Windhoek, Namibia	151	0	0.0
Lagos, Nigeria	2251	1	1.6	**Central Power Pool**			
Niamey, Niger	1743	0	0.0	Brazzaville, RC	2022	1	np
Ouagadougou, Burkina Faso	2175	1	2.0	Douala, Cameroon	1131	0	0.0
Porto Nuovo, Benin	2281	2	2.8	Libreville, Gabon	1551	2	np
Southern Power Pool				**Eastern Power Pool**			
Dar es Salaam, Tanzania	3243	5	1.5	Addis Ababa, Ethiopia	742	1	−4.0
Gaborone, Botswana	869	1	0.4	Kampala, Uganda	362	1	4.7
Johannesburg, RSA	1014	0	0.0	Nairobi, Kenya	220	0	0.0

both sub-par solar resources and high financing costs (WACC: 22.7%), but to access the best resources within the power pool (and hence lower costs), a transmission line of 2500 km crossing 4 borders from Niger to Accra is needed. Hence, many countries have a choice to make, between cheap but complicated or simpler but more expensive power from CSP.

In the scenario variations a-d, the costs are lower than in the base case Fig. 1, making electricity from CSP competitive with coal power in a larger number of countries. The largest single cost-reduction comes with improvements in project finance as shown in Fig. 2b. Indeed, we confirm the finding for PV of Ondraczek et al. (2015), that the WACC is a stronger determinant of the cost of the power supplied by CSP in SSA than the solar resource quality. For example, consider the case of Cameroon: in the base case (Fig. 1) the power is domestic (WACC: 15%, DNI: 2300 kWh/m^2/year) and costs 14.9 US¢/kWh, whereas it is only 7.1 US¢/kWh in case 2b (same as base case, but 5% WACC). However, in case 2a, with unrestricted trade, the power comes from the high-irradiance Chad (WACC: 15%, DNI 2900 kWh/m^2/year) at 12.7 US¢/kWh. Hence, improving the solar resource in this case to the best possible reduces costs by 2.2 US¢/kWh, whereas lowering the WACC can reduce costs by up to 7.8 US¢/kWh. Hence, Cameroon can import electricity from CSP from high-risk, high-irradiance Chad at high cost, or take policies (also in cooperation with the international community) to improve the financing conditions for its domestic solar resources and access much cheaper electricity (see Tables B3-B4 for precise values for scenarios a-e).

5. Conclusions and policy implications

We have shown that electricity from CSP is generally not competitive with coal power in SSA, even considering expected cost reductions up to 2025; except in Southern Africa, where solar resources are excellent and financing costs comparatively low. From a cost perspective, policy-makers may already view CSP as a viable supply option in these countries, even if the best resources are in another country. Here, the main challenge is not cost, but the institutional capacity for electricity cooperation. For the other countries in SSA, electricity from CSP is not competitive and cost reductions induced by technological learning alone will not change that.

Development along the three policy axes to improve institutional capacity and enhance multinational cooperation, de-risk finance, and improve technology transfer and domestic logistic infrastructure can however improve the cost outlook for CSP in SSA to the point of being competitive with coal power.

In most cases, importing electricity from CSP is cheaper than generating it domestically. Improving the capacity for international cooperation beyond the power pools could improve costs slightly, but at the cost of highly complex trading schemes between many countries and across existing administrative borders (e.g. outside existing free-trade areas, which also define the power pools). Similarly, removing the cost mark-up for CSP projects in SSA through policies for technology transfer and domestic infrastructure improvements would improve costs, but it would not on its own make power from CSP competitive with coal power.

The largest cost savings come not from accessing better solar resources – these are distributed across the continent, with every power pool having good and very good resources – but from accessing very good solar resources in lower risk countries. This will also increase the overall feasibility of CSP expansion: the same risks that increase costs may also make a project fully unfeasible, so that deviating to lower risk countries both reduces cost and improves the likelihood of a project being realized at all. Or, conversely, non-technical barriers such as political instability, weak institutions or corruption of many countries are particularly serious barriers for a CSP expansion in SSA.

The most important aspect to tackle for making CSP competitive across SSA is finance: policies to de-risk CSP finance to OECD levels could make power from CSP competitive with coal power in every country in SSA. Hence, the one measure that would support CSP the most is one of providing low-risk finance: through dedicated de-risking policies, such as long-term power purchase agreements, concessional loans, and/or loan guarantees, CSP could become competitive in all SSA countries, also without technology transfer or cooperation across power pools. In many cases, however, this also hinges on the capacity to cooperate among several countries, because not all countries have good domestic solar sites, and that political-administrative capacity is often lacking today. The issues of financing renewables and improving institutional capacity in developing countries are key issues in the Paris Agreement, and concrete policies to these ends are likely to be implemented as UNFCCC process continues in the next few years (UNFCCC, 2015a). Success on these issues could be immediately beneficial also for the industrialized countries: reducing the WACC of SSA CSP investments to OECD levels, and scaling CSP supply to the level of power consumption anticipated for SSA (IRENA, 2015a), over $10 billion could be saved annually, equivalent to about one fourth the current official development aid for SSA (OECD, 2016).

We also showed, somewhat counter-intuitively, that financing risk is a more important determinant for the cost of CSP supply in SSA than the solar resource quality. This confirms previous findings for PV: also for PV, country risk is a stronger cost determinant than the solar resource quality (Ondraczek et al., 2015). Whereas it would intuitively be beneficial to utilize better solar resources even if they are further away (as the transmission costs are much lower than the generation costs), we have shown that is generally cheaper to utilize lower solar resources in a low-risk country than to exploit better solar resources in a high-risk country.

Whereas we have shown that CSP with thermal storage can, if accompanying policies are implemented, be an affordable option for dispatchable renewable power, it is not the only possible option. In particular, solar PV coupled with batteries may also become an option to provide electricity of a similar quality. Current projections suggest that this will remain more expensive for large-scale dispatchable renewable power than CSP with thermal storage, but given the enormous pace of both PV and battery development, there is reason to believe that this combination may make huge technological strides in the next few years, possibly overtaking CSP as the cheapest dispatchable renewable option: projections of PV and battery costs have repeatedly been far too pessimistic, and this could apply in this case too. Thus, we suggest further research on the technical, economic and political requirements, including technology scenario analysis, for making solar PV with battery storage a viable solution for large-scale dispatchable supply in Africa and other developing regions.

In this article, we have shown that the future of CSP in SSA hinges critically on improvements of the political-administrative aspects leading to increased project feasibility and reduced financing costs: without that, electricity from CSP will be economically viable only in a few Southern African countries, but with successful policy efforts, CSP with thermal storage could become competitive across the continent.

Acknowledgements

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Appendix A. Model description

A1. Model structure

Fig. A1 shows the model structure. The detailed methodology description for the identification of potential generation sites and transmission corridors is described in section A2, the extensive breakdown of the data used as input is provided in section A3, whereas the methodology for the calculations of the levelized electricity cost at the points of demand is described in section A4.

A2. Identification of optimal generation sites and transmission corridors

We use a geographic information system (GIS) platform to identify the optimal CSP generation sites and the transmission corridors. Current literature does not denote a specific method to assess site suitability of a CSP plant and the associated transmission corridors. Most existing studies use an exclusion criteria approach (Broesamle et al., 2001; Fluri, 2009; Gastli et al., 2010; Mehos and Kearney, 2007; Trieb et al., 2009a). This results in an exclusion mask of non-suitable areas for CSP location, which is subsequently overlaid on a map of all areas with sufficient direct normal irradiance (DNI). Other studies have employed a weighting criterion for the different variables that determine CSP location (Clifton and Boruff, 2010; Dawson and Schlyter, 2012; Figueira and Roy, 2002). This weighting criterion results in a ranking of the variables (e.g. type of land cover, type of land protection, slope of the terrain, proximity to infrastructure, degree of visibility, etc.) in terms of importance to assess the suitability of the land. Thus, these studies use different methods and assumptions depending on the scope of the investigation. Yet, sufficiently strong classification certainty to identify common criteria for suitability mapping was not found. To decrease the uncertainty given by the variability of weighting criteria for CSP site location, we rely on an excluding and non-excluding criteria approach to identify suited and unsuited CSP generation sites (see Table A1).

The identification of the transmission corridors relies on a weighting approach. Weights, here measured in terms of incremental installation costs over a base case of flat grassland, are assigned to the land to identify the least cost interconnection between the demand and the generation

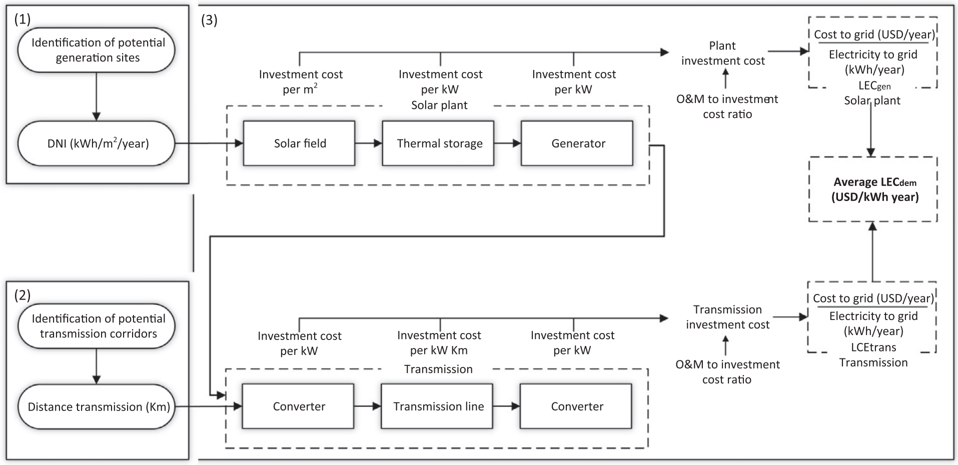

Fig. A1. Model structure. The model is composed by three main sets of tools for: (1) identification of potential generation sites, (2) identification of potential transmission corridors and, (3) estimation of the solar electricity cost at the point of demand. Each of the solid boxes represents a specific subset of infrastructure. Final outputs are total investment costs, total electricity to grid and annual average levelized electricity cost.

Table A1
Selected and excluded criteria for identification of CSP sites.

	Selected	Excluded	Considerations
Direct Normal Irradiance			
DNI ≥ 2000 kWh/m^2/year	x		
Slope			
Slope > 3%		x	
Land cover			
Cropland, rain fed: Herbaceous cover	x		
Cropland, rain fed: Tree or shrub cover	x		
Cropland, irrigated or post-flooding	x		
Mosaic cropland (> 50%) / natural vegetation (tree, shrub, herbaceous cover) (< 50%)	x		
Mosaic natural vegetation (tree, shrub, herbaceous cover) (> 50%) / cropland (< 50%)	x		
Tree cover, broadleaved, evergreen, closed to open (> 15%)	x		
Tree cover, broadleaved, deciduous, closed (> 40%)	x		
Tree cover, broadleaved, deciduous, open (15–40%)	x		
Tree cover, needle leaved, evergreen, closed (> 40%)	x		
Tree cover, needle leaved, evergreen, open (15–40%)	x		
Tree cover, needle leaved, deciduous, closed (> 40%)	x		
Tree cover, needle leaved, deciduous, open (15–40%)	x		
Tree cover, mixed leaf type (broadleaved and needle leaved)	x		
Mosaic tree and shrub (> 50%) / herbaceous cover (< 50%)	x		
Mosaic herbaceous cover (> 50%) / tree and shrub (< 50%)	x		
Shrub land: Evergreen shrub land	x		
Shrub land: Deciduous shrub land	x		
Grassland	x		
Lichens and mosses	x		
Sparse shrub (< 15%)	x		
Sparse herbaceous cover (< 15%)	x		
Tree cover, flooded, fresh or brackish water		x	
Tree cover, flooded, saline water		x	
Shrub or herbaceous cover, flooded, fresh/saline/brackish water		x	
Bare areas: Consolidated bare areas	x		
Bare areas: Unconsolidated bare areas	x		
Bare areas: Sandy desert and dunes		x	Buffer 3 km around shifting sands
Water bodies		x	
Permanent snow and ice		x	
Protected areas		x	Buffer 2 km around protected areas
Industrial locations and population			
Airports		x	Buffer 3 km around airports
Urban areas		x	

Table A2
Weighting criteria for the evaluation of land for transmission corridors.

Land cover	Weight
Cropland, rain fed: Herbaceous cover	1.0
Cropland, rain fed: Tree or shrub cover	1.0
Cropland, irrigated or post-flooding	1.0
Mosaic cropland (> 50%) / natural vegetation (tree, shrub, herbaceous cover) (< 50%)	1.0
Mosaic natural vegetation (tree, shrub, herbaceous cover) (> 50%) / cropland (< 50%)	1.0
Tree cover, broadleaved, evergreen, closed to open (> 15%)	5.0
Tree cover, broadleaved, deciduous, closed (> 40%)	5.0
Tree cover, broadleaved, deciduous, open (15–40%)	5.0
Tree cover, needle leaved, evergreen, closed (> 40%)	5.0
Tree cover, needle leaved, evergreen, open (15–40%)	5.0
Tree cover, needle leaved, deciduous, closed (> 40%)	5.0
Tree cover, needle leaved, deciduous, open (15–40%)	5.0
Tree cover, mixed leaf type (broadleaved and needle leaved)	5.0
Mosaic tree and shrub (> 50%) / herbaceous cover (< 50%)	1.0
Mosaic herbaceous cover (> 50%) / tree and shrub (< 50%)	1.0
Shrub land: Evergreen shrub land	1.0
Shrub land: Deciduous shrub land	1.0
Grassland	1.0
Lichens and mosses	1.0
Sparse shrub (< 15%)	1.0
Sparse herbaceous cover (< 15%)	1.0
Tree cover, flooded, fresh or brackish water	7.0
Tree cover, flooded, saline water	10,000
Shrub or herbaceous cover, flooded, fresh/saline/brackish water	10,000
Bare areas: Consolidated bare areas	1.0
Bare areas: Unconsolidated bare areas	3.0
Water bodies	7.0
Permanent snow and ice	10,000
Slope (%)	**Weight**
0–20	1.0
20–65	3.0
65–110	5.0
110–155	7.0
155–200	10.0
> 200	10.0

sites (see Table A2). Incremental costs on land to deploy a transmission line vary widely depending on land cover typology. In the case of transmission lines crossing unstable ground, such as sandy ground, requires larger and deeper tower foundations to avoid subsidence during operation foundation. In this case, costs may increase by 24–48%, compared to drained arable land. For large river crossings, associated structures are needed, and the costs increase by 60–100% (Parsons Brinckerhoff, 2012). Incremental costs on land also vary widely depending on the slope of the terrain. When the transmission line crosses rolling hills and thus 3 m extra of tower height is typically required, costs typically increase by 5% compared to the base case of flat ground (Parsons Brinckerhoff, 2012). Extra additional expenditures are required to install transmission lines and associated pylons in slopes higher than 20% (Trieb et al., 2009a). The range of slope values in degrees in GIS is 0–90 degrees. Whereas a flat surface corresponds to 0%, a 45-degree surface corresponds to 100%; as the surface becomes more vertical, the incline increases beyond 100%. Trieb et al. (2009a) assume that above 200%, the magnitude of the slope is irrelevant for the additional costs. Thus, here we keep the weight constant for slopes above this value.

Regarding the incremental costs on land cover, we assign a value of 1.0 for the base case of flat grassland up to a value of 7.0 depending on the typology of land (a value of 10,000 means non-suitable and thus excluded). Regarding the incremental costs on the incline of the terrain, we assign a value of 1.0 for slopes up to 20% and increase it linearly in steps of 45% up to a value of 10 for slopes of 200%. Then, we sum the weights on the land cover and on the slope of the terrain and identify the land representing the least cost interconnection.

A3. Data

Direct normal irradiance

Direct sunlight, as measured by the direct normal irradiance (DNI), is the fundamental resource for CSP technologies. It refers to the "radiation flux (irradiance) normal to the direction of the sun in the 0.2–4 μm wavelength region", at the ground surface (CM SAF, 2015). We use 31 years (1983–2013) of Climate Monitoring Satellite Application Facilities (CM-SAF) DNI data at a resolution of 0.05°x0.05° (CM SAF, 2015). This dataset accurately represents the general structure of the spatial distribution of the surface solar radiation. The temporally averaged CM SAF DNI dataset is shown in Fig. A2.

Ground slope

CSP plants such as solar tower plants are limited by ground inclination and should be built on relatively flat land to minimize the cost of land flattering. We use the digital elevation model (DEM) obtained from the NASA Shuttle Radar Topography Mission (Jarvis et al., 2008) at a resolution of 300×300 m to calculate slope values in terms of percentage.

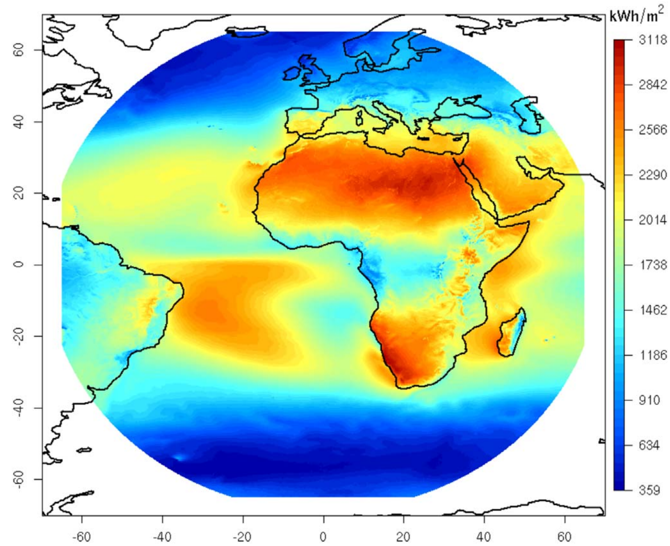

Fig. A2. Temporally averaged DNI (kWh/m^2/year) for Africa for the period 1983–2013.

Land cover

We use land cover data from the Land Cover (2008–2012) project of the Climate Change Initiative (CCI) led by the European Space Agency at a resolution of 300×300 m (ESA Climate Change Initiative, 2014). This dataset includes information regarding forest coverage, woodlands, shrub lands and grasslands, agriculture, bare soil and salt hardpans, water bodies and settlements, among other land cover typologies. Information regarding shifting sands is from the Global Land Cover 2000 by the European Joint Research Center (Mayaux et al., 2003) at a resolution of 1×1 km.

Land cover: shifting sands

Dunes may incur high costs for earth removal and the creation of a suitably stable foundation for both solar plant construction and erection of transmission pylons (Trieb et al., 2009a). Shifting dunes may, although they move slowly, bury an installation in its path, so that areas within the trajectories of existing shifting dunes must be excluded (Trieb et al., 2009a).

Concerning shifting sands, the available data – from the geographic information layer *sandy desert and dunes* of the Global Land Cover 2000 dataset or from literature such as (Ashkenazy et al., 2012; Sharaky et al., 2002) – is not of sufficiently high spatial resolution or sufficiently strong classification certainty to clearly identify shifting sands in the Sahara Desert. Given the lack of reliable data, our exclusion mask may have a slight error concerning shifting sands and should be treated with caution. In some areas of the Sahara, dune mobility in some particular areas of the desert may achieve up to 100 m/year and is mainly directed to the south (Embabi, 1982). However, in the Namib Desert dune mobility is only some 0.1 m/year (Bristow et al., 2007), and in the Kalahari Desert dunes are stable dunes fixed by vegetation (Ashkenazy et al., 2012; Sharaky et al., 2002). Considering an average CSP life plant of 30 years (Turchi and Heath, 2013), we have created a protecting buffer of 3 km around Sahara moving dunes to ensure the integrity of the facility during the operation lifetime. We do not consider dune mobility in the other deserts of Africa, as these dunes move too slowly.

Further, sandstorms are sometimes mentioned as a potential problem due to mirror abrasion. We do not consider sandstorms in our exclusion mask, both as they can – in principle – happen anywhere in sandy deserts and as there is no evidence of this being a serious problem for CSP stations (Patt et al., 2013).

Land cover: salt hardpans

Salt hardpans are dry, saline deserts, forming a highly corrosive environment unsuited for CSP or transmission installation (Trieb et al., 2009a). The main hardpans are Etosha and Magadikgadi Pans in Southern Africa, the Natron Lake in East Africa, and the Chotts in Northern Africa. We exclude all salt hardpans from consideration in this analysis.

Land cover: water bodies

All water bodies are unsuitable for CSP plants and we exclude them in this study. However, we classify narrow water bodies (i.e. rivers) as complicated, and hence more expensive, but possible for the installation of transmission infrastructure, thus allowing transmission lines to cross rivers.

Land cover: settlements and commercial industrial areas

We exclude all areas currently used for settlements. We also exclude a 3 km buffer zone around airports (OurAirports, 2011) to avoid the collisions of airplanes with power lines or solar towers.

Protected areas

The World Database on Protected Areas (WDPA) is the most extensive dataset on protected areas worldwide, which is why we use it here (UNEP-WCMC and IUCN, 2010). The WDPA is a collaborative project between the United Nations Environment Programme-World Conservation Monitoring Center and the International Union for Nature Conservation World Commission on Protected Areas. In this, a protected area is defined as “a clearly defined geographical space, recognized, dedicated and managed through legal or other effective means, to achieve the long term

Table A3
Categories of protected areas unsuitable for CSP plant location.

Categories	
I	Strict protection [a) Strict nature reserve and b) Wildness area]
II	Ecosystem conservation and protection (i.e., National Park)
III	Conservation of natural features (i.e. Natural Monuments)
IV	Conservation through active management (i.e. Habitat/Species management area)
V	Landscape/seascape conservation and recreation (i.e. Protected landscape/Seascape)
VI	Sustainable use of natural resources (i.e. Managed resource protected areas)

Table A4
Technical and economic parameters describing the solar plant and transmission system.

Variable	Description	Value	Unit	Source
DNI	Annual direct normal irradiance	≥2000	$kWh/m^2/year$	See A3. Data
P_{gen}	Plant capacity	100,000	kW_e	See Table A5
h_{stor}	Storage time	10	hours	See Table A5
T	Plant life time	30	years	Assumption
C_{stor}	Thermal storage cost	27	$US\$/kWh_t$	See Table A5
C_{sf}	Solar field cost	180	$US\$/m^2$	See Table A5
C_{pb}	Power block cost	1200	$US\$/kW_e$	See Table A5
C_{sg}	Steam generation cost	350	$US\$/kW_e$	See Table A5
C_{rec}	Receiver cost	173	$US\$/kW_t$	See Table A5
C_{om}	O & M costs plant	65	US$/kW/year	See Table A5
$C_{om\ var}$	Variable O & M costs plant	0.004	US$/kWh	See Table A5
η	Annual solar-to-electric efficiency	14.8	%	See Table A5
CF	Annual capacity factor	See Equation A11	–	See Table A5
SM	Solar Multiple	2.4	–	See Table A5
r	Country-specific WACC	Variable	%	See Table 1
T_{dist}	Transmission distance	Variable	Km	–
	Voltage level (HVDC and HVAC)	± 600 and ± 500	kV	See Table A5
P_{trans}	Transmission capacity	2,000,000	kW	See Table A5
T	Transmission infrastructure life time	40	years	Assumption
C_{trans}	Transmission cost (HVDC and HVAC)	0.151 and 0.286	US$/kW/km	See Table A5
C_{con}	Converter cost for HVDC (x2)	130	US$/kW	See Table A5
$T_{loss\ line}$	Transmission losses (HVDC and HVAC)	4.5 and 6.8	%/1000 km	See Table A5
$T_{loss\ con}$	Converter station losses (x2)	0.7	%	See Table A5
$T_{om\ line}$	O & M costs line (HVDC and HVAC)	2	%	See Table A5
$T_{om\ con}$	O & M costs converter	1	%	See Table A5
r	Country-specific WACC	Variable	%	See Table 1

Table A5
Data types and sources used in the model.

Type	Source (s)	Comments
Solar tower plant	(Turchi and Heath, 2013)	Plant capacity, storage capacity, thermal storage, mirror field, power block, steam generation system, receiver, O & M costs, efficiency
	(Trieb et al., 2012)	Capacity factor
Transmission	(SNC-Lavalin and Brinckerhoff, 2011)	Transmission line costs and converter station costs
	(Trieb et al., 2012)	Transmission line losses and converter station losses

conservation of nature with associated ecosystem services and cultural values" (Dudley, 2009). We exclude all protected areas described in WDPA, see Table A3, as well as a 2 km buffer around them to provide a safety region for nature conservation.

Availability of land

A utility-scale CSP plant requires substantial amounts of land: typically, a solar tower plant at a good site (2600 $kWh/m^2/year$) requires up to some 17000 m^2/MW for the land directly occupied by solar arrays, access roads, substations, and other infrastructure. When including all the land enclosed within the site boundary, land requirements increase up to some 40500 m^2/MW (Ong et al., 2013). Land, however, is often abundant and available at relatively low cost in the areas where CSP is suitable, such as deserts. After applying the exclusion criteria, the remaining land with a continuous area of less than 2 km^2 is also excluded for CSP plant location, as this would be too small to accommodate the 100 MW solar tower plants we assume here (see Table A4).

A4. Calculation of electricity cost at the point of demand

The third set of tools refers to the calculation of the solar electricity cost at the point of demand. The levelized electricity cost (LCOE) is a useful metric when analyzing investment opportunities for renewable energy technologies. As defined by the Energy Information Administration, "levelized cost represents the present value of the total cost of building and operating a generating plant over an assumed financial life and duty cycle, converted to equal annual payments and expressed in terms of real dollars to remove the impact of inflation" (EIA, 2011). A LCOE approach allows for a like-for-like comparison of the generation costs of different technologies for the expected life of the facilities, as well as it provides a measure of a renewable technology's competitiveness and is valuable in determining the need for publicly funded financial incentives. A levelized cost approach does not, however, factor in the cost of intermittency balancing and the different value of peak/off peak generation costs, or portfolio and merit-order effects of renewable energy technologies.

The LCOE at the point of demand LCOEdem(i) is the sum of the levelized generation cost LCOEgen(i) and the levelized transmission cost LCOEtrans(i) (see Equation A1-Equation A3). We use the depreciation rate to calculate the annuity at which capital expenditures (i.e. investments for power plant and transmission line components) are included in the system cost (see Equation A10). To reflect varying political and legal risks for investors we apply country-specific WACCs in the calculation of country-specific LCOEgen and LCOEtrans (see Table 1 for country-specific WACCs). Table A4 shows the technical and economic parameters used to calculate LCOEdem(i). We express all costs in US$$_{2012}$. Costs for the solar tower plant were already in US$$_{2012}$. Costs for the transmission projects and costs of typical fossil fuel power generation in Africa used as benchmark were in US$$_{2011}$ and US$$_{2010}$, respectively, and adjusted to US$$_{2012}$ using the US GDP deflator from the Bureau of Economic Analysis U.S. Department of Commerce.

$$LCOE_{dem}(\mathbf{i}) = LCOE_{gen}(\mathbf{i}) + LCOE_{trans}(i) \tag{A1}$$

$$LCOE_{gen}(\mathbf{i}) = \frac{C_{cons}(i) \times dep(i) + C_{om\ gen}(i)}{E_{gen}(i)} \tag{A2}$$

$$LCOE_{trans}(\mathbf{i}) = \frac{C_{trans}(i) \times dep(i) + C_{om\ trans}(i)}{E_{trans}(i)} \tag{A3}$$

The levelized generation cost $LCOE_{gen}(i)$ for each plant is given by the construction cost $C_{cons}(i)$ and the operations and maintenance cost $C_{om\ gen}(i)$.

$$C_{cons}(i) = (P_{gen} \times h_{stor} \times C_{stor}) + \left(\frac{P_{gen} \times 8760 \times CF}{DNI \times \eta} \times C_{sf}\right) + (P_{gen} \times C_{pb}) + (P_{gen} \times C_{sg}) + (P_{gen} \times C_{rec}) \tag{A4}$$

$$C_{om\ gen}(\mathbf{i}) = (P_{gen} \times C_{om}) + (E_{gen} \times C_{om\ var}) \tag{A5}$$

$$E_{gen}(i) = P_{gen} \times 8760 \times CF \tag{A6}$$

The levelized transmission cost LCOEtrans(i) for each transmission line is given by the construction cost $C_{trans}(i)$ and the operations and maintenance cost $C_{om\ trans}(i)$.

$$C_{trans}(i) = (T_{dist} \times C_{trans} \times P_{trans}) + (C_{con} \times P_{trans} \times 2) \tag{A7}$$

$$C_{om\ trans}(\mathbf{i}) = (T_{dist} \times C_{trans} \times P_{trans} \times T_{omline}) + (C_{con} \times P_{trans} \times T_{om\ con} \times 2) \tag{A8}$$

$$E_{trans}(i) = (P_{trans} \times 8760) - ((T_{loss\ line} \times T_{dist} \times P_{trans} \times 8760) + (T_{loss\ con} \times P_{trans} \times 8760 \times 2)) \tag{A9}$$

The depreciation rate is given by

$$dep(\mathbf{i}) = \frac{r_n \times (1 + r_n)^{\mathrm{T}}}{(1 + r_n)^{\mathrm{T}} - 1} \tag{A10}$$

As we use a levelized cost approach, the size of the power plant does not matter. In reality, larger power stations generally have lower levelized costs due to economies of scale, leading to lower specific investment costs. We use data for a 100 MW CSP station with 10 h of storage, and although the effect of varying the size of the station to achieve a net output capacity equal than the capacity of the transmission line would be limited, our cost calculations refer to this configuration only.

The equation to estimate the capacity factor of the CSP plant was derived by Trieb et al. (2012) from hourly time series of the performance of parabolic trough plants. The same equation can be used to describe the capacity factor of solar tower plants.

$$CF = (2.5717 \times DNI + 694) \times (-0.0371 \times SM^2 + 0.4171 \times SM - 0.0744) \tag{A11}$$

Transmission costs were derived from the regional power system master plan for the Eastern Africa Power Pool and the East African Community (SNC-Lavalin and Brinckerhoff, 2011). Costs of the HVDC and HVAC transmission lines and converter stations are from projects planned by the regional power system master plan for a transmission line Egypt-Sudan 600 kV-HVDC bi-pole and 2000 MW, and a Ethiopia-Sudan line 500 kV-AC double-circuit and 1600 MW, to start operation in 2025 (Table A1).

Appendix B. Results

Base case. Table B1 and Fig. B1
Scenario variations: Scenarios a, b, c, and d. Table B2 and B3 and Fig. B2
Scenario variation: Scenario e. Table B4

Table B1
Levelized electricity costs (US¢/kWh) for the power supplied by CSP to demand centers in sub-Saharan countries under base case assumptions, with 2012 technology costs and projected 2025 costs. Electricity trade is limited to the power pools; financing costs are country-specific, technology costs have a cost penalty, fragile countries are excluded from being a generation, transit or importing country. An asterisk (*) represents projects with HVDC transmission, the remaining represent projects with HVAC. The color code is the same as in Fig. 1 in the main article.

	Base case 2012	Base case 2025
	US¢/kWh	US¢/kWh
Western Power Pool	**2900 kWh/m^2**	**2900 kWh/m^2**
Accra, Ghana	20.0*	14.1*
Bamako, Mali	19.7*	13.8*
Dakar, Senegal	20.1*	14.2*
Lagos, Nigeria	19.4*	13.5*
Niamey, Niger	19.2*	13.3*
Ouagadougou, Burkina Faso	19.4*	13.5*
Porto Novo, Benin	19.4*	13.5*
Southern Power Pool	**2900 kWh/m^2**	**2900 kWh/m^2**
Dar es Salaam, Tanzania	12.9*	9.8*
Gaborone, Botswana	10.4*	7.3*
Johannesburg, RSA	10.4*	7.3*
Luanda, Angola	11.0*	7.8*
Lusaka, Zambia	11.0*	7.8*
Maputo, Mozambique	10.9*	7.7*
Windhoek, Namibia	9.9	6.7
Central Power Pool	**2300 kWh/m^2**	**2300 kWh/m^2**
Brazzaville, RC	22.0*	15.2*
Douala, Cameroon	21.7*	14.9*
Libreville, Gabon	21.9*	15.0*
Eastern Power Pool	**2600 kWh/m^2**	**2600 kWh/m^2**
Addis Ababa, Ethiopia	19.8	13.4
Kampala, Uganda	19.6	13.2
Nairobi, Kenya	19.4	13.1

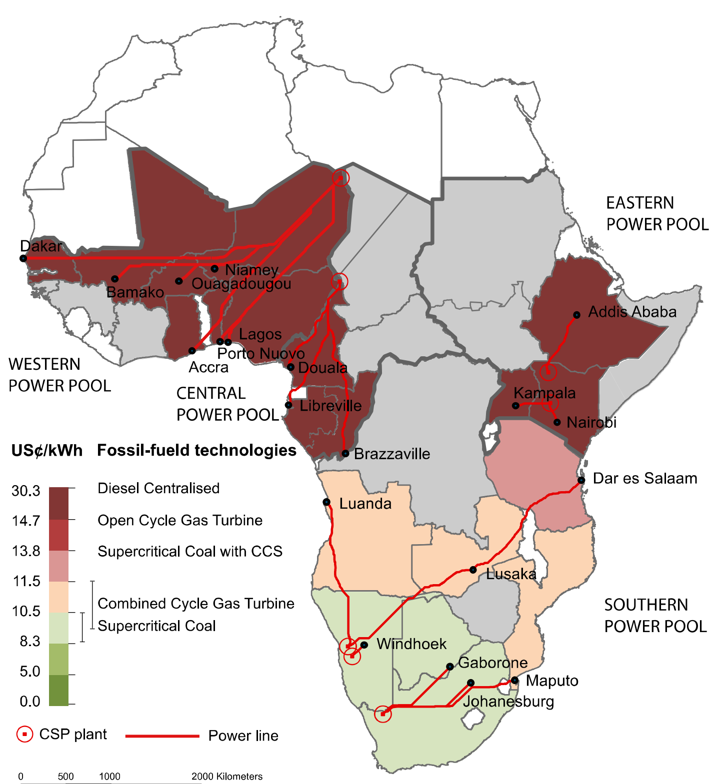

Fig. B1. Levelized electricity costs (US¢/kWh) for the power supplied by CSP to demand centers in sub-Saharan countries, and locations of associated generation sites and transmission lines under base case assumptions; using 2012 technology costs. Countries in grey are fragile states.

Table B2
Levelized electricity cost (US¢/kWh) for the power supplied by CSP to demand centers in sub-Saharan countries under the assumptions from the different scenarios, with 2012 technology costs. An asterisk (*) represents projects with HVDC transmission, the remaining represent projects with HVAC. The color code is the same as in Fig. 1 in the main article.

	Scenario a	Scenario b	Scenario c	Scenario d
	Unrestricted trade	WACC 5%	Investment industrialized countries	With variations a, b and c
	US¢/kWh	US¢/kWh	US¢/kWh	US¢/kWh
Western Power Pool	**2900 kWh/m^2**	**2900 kWh/m^2**	**2900 kWh/m^2**	**2900 kWh/m^2**
Accra, Ghana	19.0*	8.7*	16.3*	7.1*
Bamako, Mali	19.7*	8.8*	16.0*	7.1*
Dakar, Senegal	20.1*	8.9*	16.4*	7.3*
Lagos, Nigeria	18.4*	8.7*	15.7*	7.0*
Niamey, Niger	19.2*	8.6*	15.5*	7.0*
Ouagadougou, Burkina Faso	19.4*	8.6*	15.7*	7.0*
Porto Novo, Benin	18.4*	8.7*	15.7*	7.1*
Southern Power Pool	**2900 kWh/m^2**	**2900 kWh/m^2**	**2900 kWh/m^2**	**2900 kWh/m^2**
Dar es Salaam, Tanzania	12.9*	7.6*	12.4*	7.2*
Gaborone, Botswana	10.4*	7.2*	9.8*	6.8*
Johannesburg, RSA	10.4*	7.2*	9.9*	6.8*
Luanda, Angola	11.0*	7.3*	10.4*	6.9*
Lusaka, Zambia	11.0*	7.3*	10.4*	6.9*
Maputo, Mozambique	10.9*	7.3*	10.3*	6.9*
Windhoek, Namibia	9.9	6.9	9.3	6.5
Central Power Pool	**2900 kWh/m^2**	**2300 kWh/m^2**	**2300 kWh/m^2**	**2900 kWh/m^2**
Brazzaville, RC	13.9*	10.5*	17.7*	7.0*
Douala, Cameroon	18.3*	10.4*	17.4*	7.0*
Libreville, Gabon	13.1*	10.4*	17.6*	7.1*
Eastern Power Pool	**2900 kWh/m^2**	**2600 kWh/m^2**	**2600 kWh/m^2**	**2900 kWh/m^2**
Addis Ababa, Ethiopia	18.9*	9.1	15.8	7.0*
Kampala, Uganda	18.7*	9.0	15.6	7.1*
Nairobi, Kenya	18.9*	9.0	15.5	7.2*

Table B3
Levelized electricity costs (US¢/kWh) for the power supplied by CSP to demand centers in sub-Saharan countries under the assumptions from the different scenarios, with projected 2025 technology costs. An asterisk (*) represents projects with HVDC transmission, the remaining represent projects with HVAC. The color code is the same as in Fig. 1 in the main article.

	Scenario a	Scenario b	Scenario c	Scenario d
	Unrestricted trade	WACC 5%	Investment industrialized countries	With variations a, b and c
	US¢/kWh	US¢/kWh	US¢/kWh	US¢/kWh
Western Power Pool	**2900 kWh/m^2**	**2900 kWh/m^2**	**2900 kWh/m^2**	**2900 kWh/m^2**
Accra, Ghana	13.5*	6.1*	11.6*	5.1*
Bamako, Mali	13.8*	6.2*	11.3*	5.1*
Dakar, Senegal	14.2*	6.4*	11.8*	5.3*
Lagos, Nigeria	12.8*	6.1*	11.0*	5.0*
Niamey, Niger	13.3*	6.0*	10.8*	4.9*
Ouagadougou, Burkina Faso	13.5*	6.1*	11.0*	5.0*
Porto Novo, Benin	12.8*	6.1*	11.0*	5.0*
Southern Power Pool	**2900 kWh/m^2**	**2900 kWh/m^2**	**2900 kWh/m^2**	**2900 kWh/m^2**
Dar es Salaam, Tanzania	9.8*	5.5*	9.4*	5.2*
Gaborone, Botswana	7.3*	5.0*	6.9*	4.8*
Johannesburg, RSA	7.3*	5.1*	6.9*	4.8*
Luanda, Angola	7.8*	5.2*	7.4*	4.9*
Lusaka, Zambia	7.8*	5.2*	7.4*	4.9*
Maputo, Mozambique	7.7*	5.1*	7.4*	4.9*
Windhoek, Namibia	6.7	4.7	6.4	4.5
Central Power Pool	**2900 kWh/m^2**	**2300 kWh/m^2**	**2300 kWh/m^2**	**2900 kWh/m^2**
Brazzaville, RC	10.1*	7.3*	12.3*	5.0*
Douala, Cameroon	12.7*	7.1*	12.0*	5.0*
Libreville, Gabon	9.3*	7.2*	12.2*	5.1*
Eastern Power Pool	**2900 kWh/m^2**	**2600 kWh/m^2**	**2600 kWh/m^2**	**2900 kWh/m^2**
Addis Ababa, Ethiopia	13.1*	6.3	10.8	4.9*
Kampala, Uganda	13.2*	6.2	10.6	5.0*
Nairobi, Kenya	13.4*	6.1	10.5	5.1*

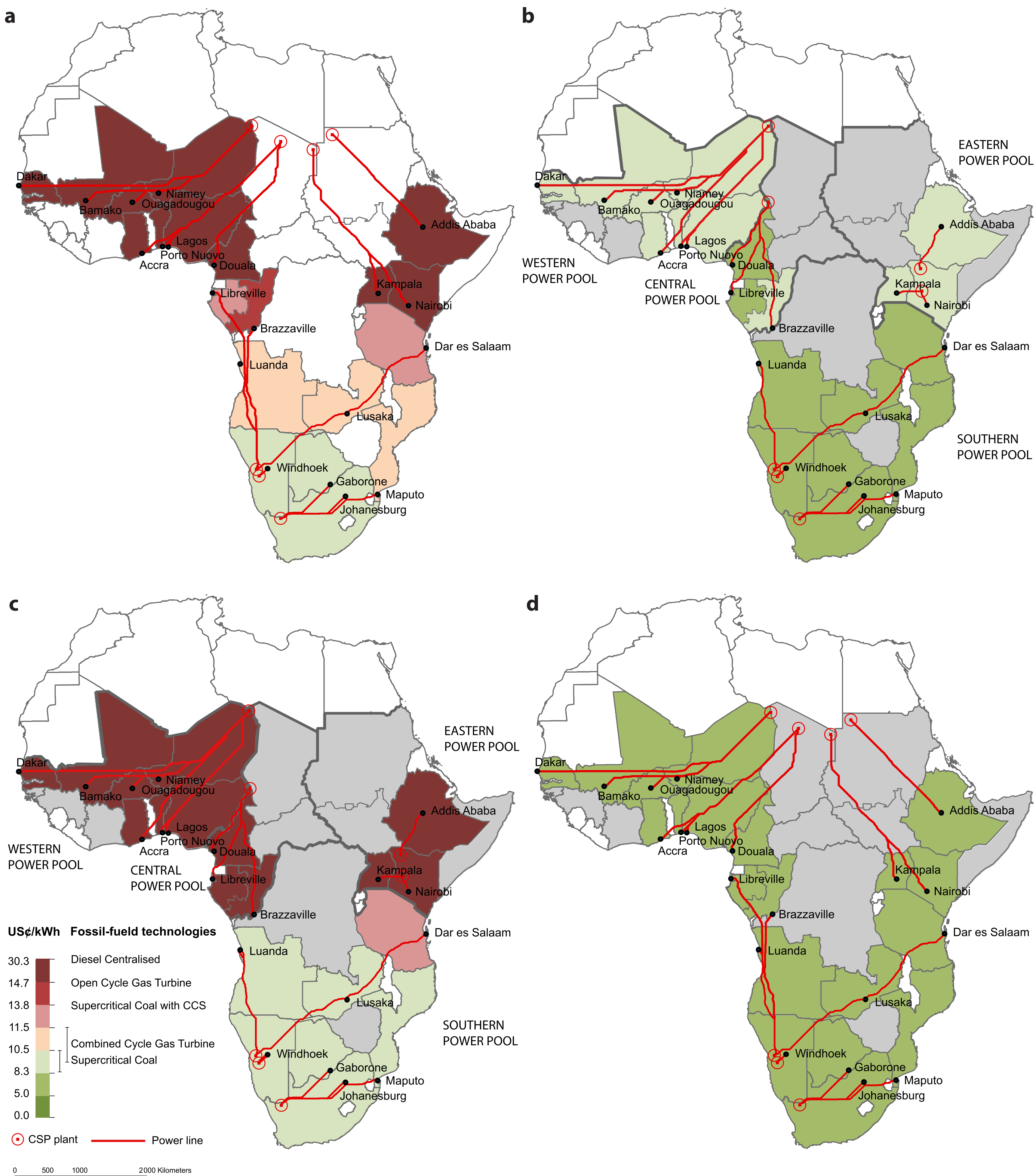

Fig. B2. Levelized electricity costs (US¢/kWh) for the power supplied by CSP to demand centers in sub-Saharan countries, and location of associated transmission lines using 2012 technology costs; (a) under unrestricted trade; (b) WACC 5%; (c) investment cost from industrialized countries; (d) considers all assumptions from previous scenarios. Countries in grey are fragile states.

Table B4
Levelized electricity costs (US¢/kWh) for the power supplied by CSP to demand centers in sub-Saharan countries, from sites with the highest domestic irradiance. Base case is under base case assumptions; scenarios *b*, *c*, and *d* are under the assumptions from the different scenarios, all with projected 2025 technology costs. An asterisk (*) represents projects with HVDC transmission, the remaining represent projects with HVAC. The color code is the same as in Fig. 1 in the main article. *np* means not possible.

	Base case	Scenario b	Scenario c	Scenario d
		WACC 5%	Investment industrialized countries	With variations b and c
	US¢/kWh	US¢/kWh	US¢/kWh	US¢/kWh
Western Power Pool	**2000 kWh/m^2**	**2000 kWh/m^2**	**2000 kWh/m^2**	**2000 kWh/m^2**
Accra, Ghana	23.1	7.8	18.4	6.3
	2600 kWh/m^2	**2600 kWh/m^2**	**2600 kWh/m^2**	**2600 kWh/m^2**
Bamako, Mali	14.4*	6.5*	11.7*	5.3*
	2300 kWh/m^2	**2300 kWh/m^2**	**2300 kWh/m^2**	**2300 kWh/m^2**
Dakar, Senegal	14.7	6.8	11.8	5.5
	2300 kWh/m^2	**2300 kWh/m^2**	**2300 kWh/m^2**	**2300 kWh/m^2**
Lagos, Nigeria	15.1*	7.1*	12.2*	5.8*
	2900 kWh/m^2	**2900 kWh/m^2**	**2900 kWh/m^2**	**2900 kWh/m^2**
Niamey, Niger	13.3*	6.0*	10.8*	4.9*
	2300 kWh/m^2	**2300 kWh/m^2**	**2300 kWh/m^2**	**2300 kWh/m^2**
Ouagadougou, Burkina Faso	15.4	6.8	12.3	5.5
	2100 kWh/m^2	**2100 kWh/m^2**	**2100 kWh/m^2**	**2100 kWh/m^2**
Porto Novo, Benin	16.3	7.5	13.0	6.1
Southern Power Pool	**2600 kWh/m^2**	**2600 kWh/m^2**	**2600 kWh/m^2**	**2600 kWh/m^2**
Dar es Salaam, Tanzania	11.2	5.3	10.6	5.0
	2700 kWh/m^2	**2700 kWh/m^2**	**2700 kWh/m^2**	**2700 kWh/m^2**
Gaborone, Botswana	7.7	5.2	7.2	4.9
	2900 kWh/m^2	**2900 kWh/m^2**	**2900 kWh/m^2**	**2900 kWh/m^2**
Johannesburg, RSA	7.3*	5.1*	6.9*	4.8*
	2700 kWh/m^2	**2700 kWh/m^2**	**2700 kWh/m^2**	**2700 kWh/m^2**
Luanda, Angola	11.6*	5.4*	11.0*	5.1*
	2400 kWh/m^2	**2400 kWh/m^2**	**2400 kWh/m^2**	**2400 kWh/m^2**
Lusaka, Zambia	11.0	5.6	10.4	5.3
	2400 kWh/m^2	**2400 kWh/m^2**	**2400 kWh/m^2**	**2400 kWh/m^2**
Maputo, Mozambique	12.7*	6.0*	12.0*	5.6*
	2900 kWh/m^2	**2900 kWh/m^2**	**2900 kWh/m^2**	**2900 kWh/m^2**
Windhoek, Namibia	6.7	4.7	6.4	4.5
Central Power Pool	**< 2000 kWh/m^2**	**< 2000 kWh/m^2**	**< 2000 kWh/m^2**	**< 2000 kWh/m^2**
Brazzaville, RC	np	np	np	np
	2300 kWh/m^2	**2300 kWh/m^2**	**2300 kWh/m^2**	**2300 kWh/m^2**
Douala, Cameroon	14.9*	7.2*	12.0*	5.8*
	< 2000 kWh/m^2	**< 2000 kWh/m^2**	**< 2000 kWh/m^2**	**< 2000 kWh/m^2**
Libreville, Gabon	np	np	np	np
Eastern Power Pool	**2500 kWh/m^2**	**2500 kWh/m^2**	**2500 kWh/m^2**	**2500 kWh/m^2**
Addis Ababa, Ethiopia	9.4	6.4	7.6	5.1
	2300 kWh/m^2	**2300 kWh/m^2**	**2300 kWh/m^2**	**2300 kWh/m^2**
Kampala, Uganda	17.9	6.8	14.3	5.5
	2600 kWh/m^2	**2600 kWh/m^2**	**2600 kWh/m^2**	**2600 kWh/m^2**
Nairobi, Kenya	13.1	6.1	10.5	4.9

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