Specific Support Study on Solar Power Plants

Specific Support Study in support of the Continental Power System Masterplan (CMP) through the EU's Technical Assistance Facility (TAF) for African Union in the sustainable energy sector – Lot 12b

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Executive Summary

Solar power now ranks as the lowest cost electricity in history, and Africa is blessed with some of the world's best solar resources. Opening the floodgates to abundant, affordable solar can unleash a wave of clean energy investment and improve electricity access for all. Solar's potential in Africa is nearly limitless, enough to meeting over 17,000 times Africa's current electricity needs.

The Levelized Cost of Electricity (LCOE) generated by photovoltaic (PV) power plants now ranges between USD 2 and 5 cents/kWh, with an average of USD 3.6 cents/kWh. Though the cost of capital in Africa has a significant impact on the LCOE of solar, policy and regulatory de-risking have made it possible to achieve prices for solar power in the USD 2.5 cents/kWh range in some countries. Average installed cost now stands at USD 880/kW, though some projects report installation costs in the range of USD 550/kW. In addition to being cheap, solar PV is also exceptionally fast, with far shorter lead times (6-12 months) than virtually all other power generation projects.

Solar PV is a mature, proven technology, one that is modular, scalable, and usable everywhere in Africa, on households, on businesses, and at larger scales. Even in regions with comparatively lower solar resource potential, solar power can generate electricity at a fraction of the cost of modular alternatives (such as diesel and gasoline gensets), and more cheaply and rapidly than large-scale projects (such as large hydropower dams).

SOLAR MARKET HIGHLIGHTS

Solar is becoming unstoppable. In early 2022, the global installed capacity of solar PV surpassed the 1,000 GW mark. If the rate of growth of 40% per year since 1976 can be sustained, solar power output is on track to match total global electricity demand by the mid-2030s.

Africa is the world's sunniest continent. However, realities on the ground in many countries have hindered progress in harnessing this abundance. Solar resources in Africa are excellent, with large areas receiving 7 kWh/m² per day. If combined with bankable policy and regulatory frameworks, and supported with storage, solar can provide nearly limitless power for all.

Although solar PV is cheap and abundant, deployment on the continent remains modest, supplying less than 1% of total power generation; moreover, this deployment is heavily concentrated in a few countries. As can be seen in the map below, although large-scale solar projects have emerged in many parts of the continent, most projects are concentrated in a few jurisdictions.

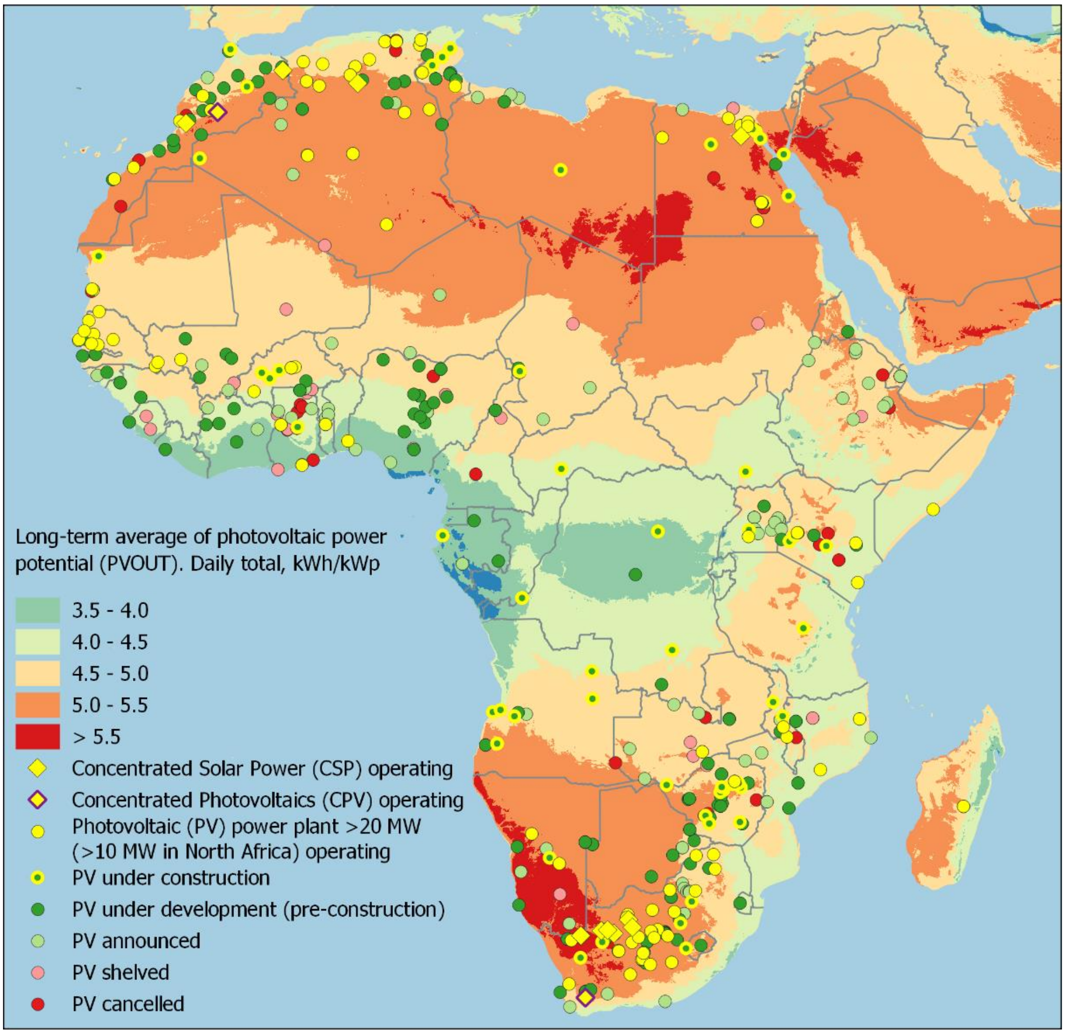

Figure 1: Solar power plants in Africa as of January 2023 (dataset), mapped alongside solar resource quality. Source: [1] [2]

Currently, there is approximately 8 GW of utility-scale solar photovoltaic (PV) projects in operation across the continent. Globally, this makes Africa home to less than 1% of total installed solar power capacity. This notwithstanding solar is growing at a rate of 14% year-on-year (9% in 2021).

In contrast to solar PV, growth is CSP has effectively stalled. There is approximately 1 GW of Concentrating Solar Power (CSP) plants in operation across Africa and growth is all but stagnant.

While governments, donor organizations, and lenders have focused mainly on utility-scale projects, the Commercial and Industrial (C&I) market segment currently shows greater signs of dynamism. Corporate & industrial projects continent-wide stand at an estimated 1,200 MW, with recent estimates from the Africa Solar Industries Association indicate the continent is adding 100 new such projects every day. The Continental Master Plan needs to take the rapid growth of this market segment into account, as it will have important implications for load growth, capacity planning as well as grid development in the years ahead.

Agrivoltaics (or Agri-PV) can significantly increase the benefits of solar deployment and can help deliver on other social and economic development objectives simultaneously. The shading provided by solar panels can help expand the range of crops that can be grown while reducing water loss, and cooling ground temperatures, which in turn increases solar panel efficiencies. The potential of Agri-PV has only begun to be tapped, and Africa is uniquely positioned to take the lead in this burgeoning new sector.

Floating photovoltaics in Africa have a technical potential of 300-1,000 GW. Thus far, this potential remains largely untapped. Floating solar can help reduce water loss at existing hydropower dams, as well as in irrigation canals and other applications. Though installation and operating costs are slightly higher than ground-mounted installations, floating solar can contribute to the continent's abundant renewable energy supply.

TECHNICAL AND GRID HIGHLIGHTS

Building on the stunning improvements in cost and performance in recent decades, solar PV performance continues to improve, breaking new records. Maximum cell efficiencies have recently surpassed 26%, and further improvements in solar cell technology (bi-facial, tandem cells, tracking, inverter loading ratio, and concentrating photovoltaics) are making it possible to increase output while further reducing the surface area required for each kilowatt hour produced.

The solar industry is making significant progress in addressing the twin concerns of e-waste and the recycling of solar PV panels and associated components. The issue is now rising up to the political agenda both in Africa and around the world. Meanwhile, recycling facilities for e-waste now exist on all continents, including in Africa. In 2014, the EU introduced an obligation for manufacturers to take back and recycle panels at their end-of-life, and similar efforts are under way elsewhere. Research aims to increase the lifetime of PV panels to 50 years.

To enable solar PV to live up to its full potential, stakeholders across Africa need to plan for a rapid expansion of storage and transmission infrastructure. Storage helps ease solar integration, while larger balancing areas help shift power quickly and efficiently from where it is generated to where it is consumed. Despite progress made since the establishment of Africa's Power Pools, many power grids across the continent remain effectively isolated, and most electricity is kept within national borders. For solar power to truly reach scale, this will need to change.

At low penetrations, solar PV can be integrated relatively easily. As the share of solar PV grows, strategies need to adapt, with improved forecasting, balancing, storage, modern inverters, and interconnections with neighboring regions playing an increasingly important role.

Although solar PV produces power during the daytime, the expansion of grid interconnections combined with the greater use of storage can enable solar to contribute directly to meeting evening loads across the continent. By combining solar with storage, it can produce power when utilities need it most, alleviating pressure on other peaking power plants, reducing load shedding, while improving overall system reliability.

FINANCING HIGHLIGHTS

Differences in the cost of capital can outweigh the differences in solar resource quality. Although it is common to focus on the installation cost of solar projects, growing evidence underscores the critical importance of the cost of capital in determining the actual cost of solar generation. Lower financing costs help unlock lower cost solar. In practice, jurisdictions with slightly weaker solar resources can compensate for this by reducing policy and regulatory risks, unlocking lower cost capital and lower cost solar.

Policy and regulatory stability often ranks more highly in investors' and developers' decision-making than resource quality. Investments in the renewable energy sector tend to flow to countries where policy and regulatory frameworks are stable. Efforts to reduce the cost of capital (in short, policy and financial de-risking measures) including streamlined permitting and project approvals are therefore vital to unlocking solar at the lowest possible cost for utilities and ratepayers. This applies equally to the critical issue of currency risk, which affects virtually all solar projects on the continent.

The weak financial position of many utilities in Africa is a direct barrier to the scale-up of utility-scale solar power. According to Africa-wide analyses, more than a third of the utilities in Africa are in precarious financial health. Indeed, a total of 35 utilities across Africa are not cost-covering even after subsidies.

The fact that land is abundant does not mean that siting solar power projects is easy. Several layers of negotiation are frequently required between local officials, local landowners and the central government before a suitable site (or sites) can be agreed upon. Governments can improve this situation by clarifying rules around land access and title, or by designating special zones, in concert with local and indigenous communities, for renewable energy development. Combining solar PV with agriculture (Agri-PV), as well as rooftop or industrial deployment can allow for symbiotic land use.

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1 Solar Power Generation in Africa

1.1 Introduction

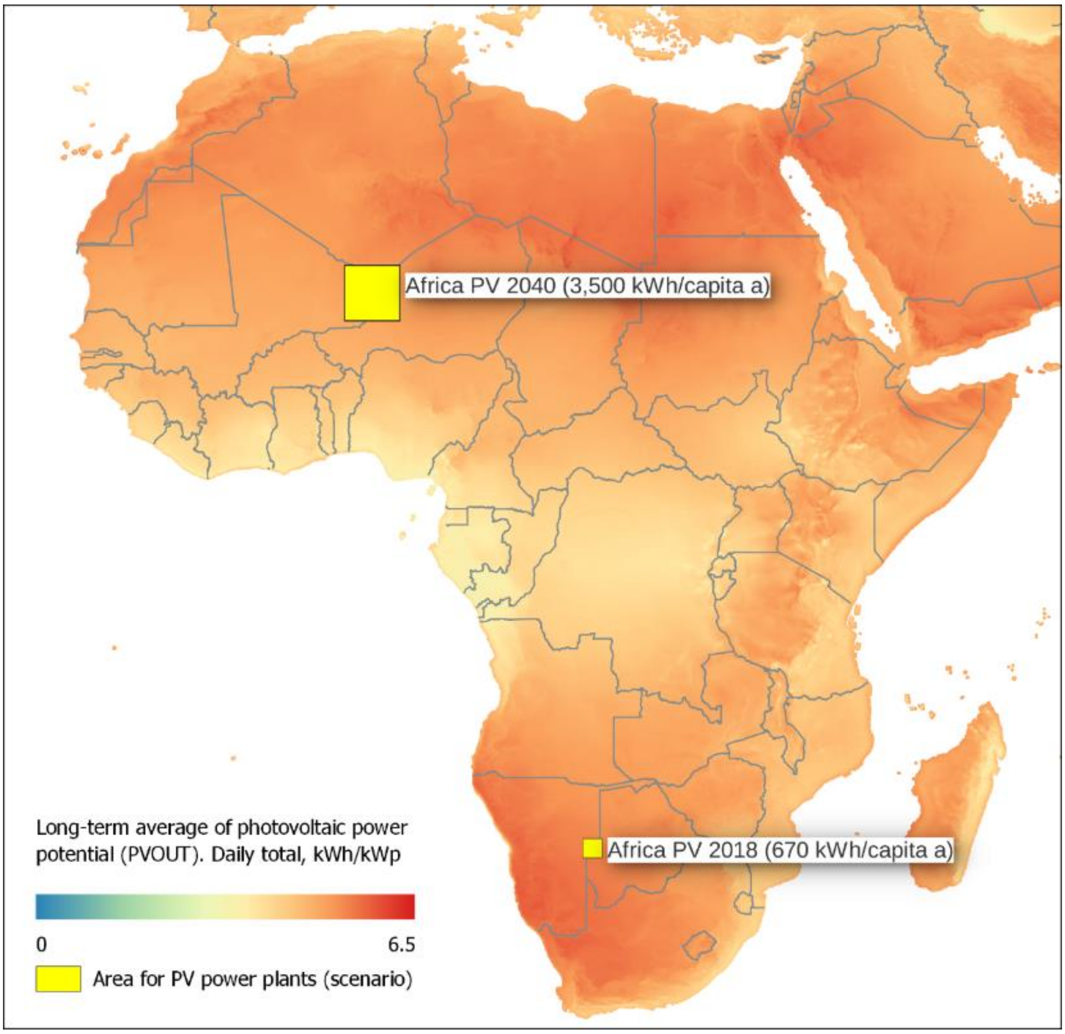


Figure 2: Solar resources in Africa; squares represent area required for photovoltaic generation of 100% of electricity, 2018 with actual power consumption per capita (0.08% of African area), 2040 with power consumption at current world average (0.66% of African area). Solar data [3], electricity consumption [4]

Africa has vast solar resources. The electricity demand of the continent can be satisfied to 100% by solar power generation, based on currently available technology, for a rapidly growing population, and a dramatic increase in the per capita consumption of electric energy.

For the results in Figure 2, standard photovoltaic power plant technology is used, local battery storage is employed. The African population will grow from 1.29 billion in 2018 to 2.10 billion in 2040. The annual consumption of electricity should reach at least current world average, increasing from 670 kWh/a in 2018 to 3,500 kWh/a by 2040 (data points from [4]). The total area of the PV power plants would be 24,000 km², and 200,000 km² for the 2018, and the 2040 generators, respectively. These calculate to 0.08%, and 0.66%, respectively, of the area of the African continent, the world's second largest.

Employing Concentrated Solar Power (CSP) would reduce the required land area further, as its efficiency (and its capacity factor) tends to be higher than those of PV. This report will describe terms and technologies.

Interconnecting the solar power plants through a power grid will also reduce the area required, as the grid may connect areas where power is available. This applies also to areas where the sun is still before the night (or already again in the morning) shining, reducing the need for local storage, and hence for collector field area used to charge the storage units.

Africa can power herself by the power of the sun; the resource is abundant. Solar electricity is the cheapest form of electricity there is, photovoltaic energy is sold for a record 1.04 $c/kWh [5].

1.2 Technology case studies

Seven solar power plants (the *Cases*) are examined in some detail, in order to extract parameters that can help explaining the success of these cases, and potentially other power plant projects like them.

Lists of solar power plants can be found for Concentrated Solar Power (CSP) plants [6], and for Photovoltaic (PV) power plants with a nameplate capacity greater than 20 MW (10 MW in Arabic-speaking countries) [1]. The African Solar Industry Association maintains a Projects Database [7] with more information for its members.

All lists are striving to be complete and up to date. Note that it can be cumbersome to obtain data on projects, which may be announced, but never close financing, or be hampered by difficulties for many years before commissioning, affecting the completeness of our Technology Cases and all available lists. That is the reason why numbers vary between databases, but even between years.

1.2.1 Selection of cases

The selection process is based on several criteria:

- Solar technology: CSP (power tower, or parabolic trough), PV. Emerging technologies, such as storage-assisted PV, and floating PV are to be considered
- Solar radiation: in regimes of extreme and lower DNI
- Storage technology: Thermal Energy Storage (TES) of various duration, battery storage
- Power Pool: Distributed over the five Power Pools of Africa

- Grid availability and dimension
- Financing: The three IEA-affiliated countries Egypt, Morocco, and South Africa are home to the majority of solar projects, and have developed financing mechanisms, such as REIPPPP in South Africa
- Politics: Stability and affiliation to geopolitical blocks
- Socio-economic indicators: poverty, and electrification ratio
- Availability of recent and complete data

The Cases are selected in a brainstorming session by the team. Selections are not final, nor is the number of included projects limited.

1.2.2 Technology cases

All Technology Cases are listed in Table 1, and shown in Figure 3. A brief description follows below.

Table 1: Technology Cases detailed in this study, Power Pools are described in section 8.2

Power plant	**Noor II**	**Redstone**	**Jasper**	**Danzi**	**Black Volta (BUI)**	**Kesses I**	**Cuamba**
Type	CSP trough	CSP tower	PV (next to CSP)	PV/battery storage	Floating PV (next to hydropower)	PV	PV/battery storage
Country	Morocco	South Africa	South Africa	Central African Republic	Ghana	Kenia	Mozambique
Power Pool	NAPP	SAPP	SAPP	CAPP	WAPP	EAPP	SAPP
Capacity	200	100	96	25	5	55	19
Unit	MWe	MWe	MWp dc	MWp dc	MWp dc	MWp dc	MWp dc
Storage capacity	1,200	1,200		25			7
Unit	MWh	MWh		MWh			MWh
Start up	2018	2023	2014	2022	2022	2022	2022
Latitude	31.04	-28.29	-28.31	4.50	8.28	0.43	-14.80
Longitude	-6.87	23.35	23.39	18.48	-2.24	35.40	36.51
Notes			75 MW ac		1 MW installed 2022		15 MW ac 2 MW storage

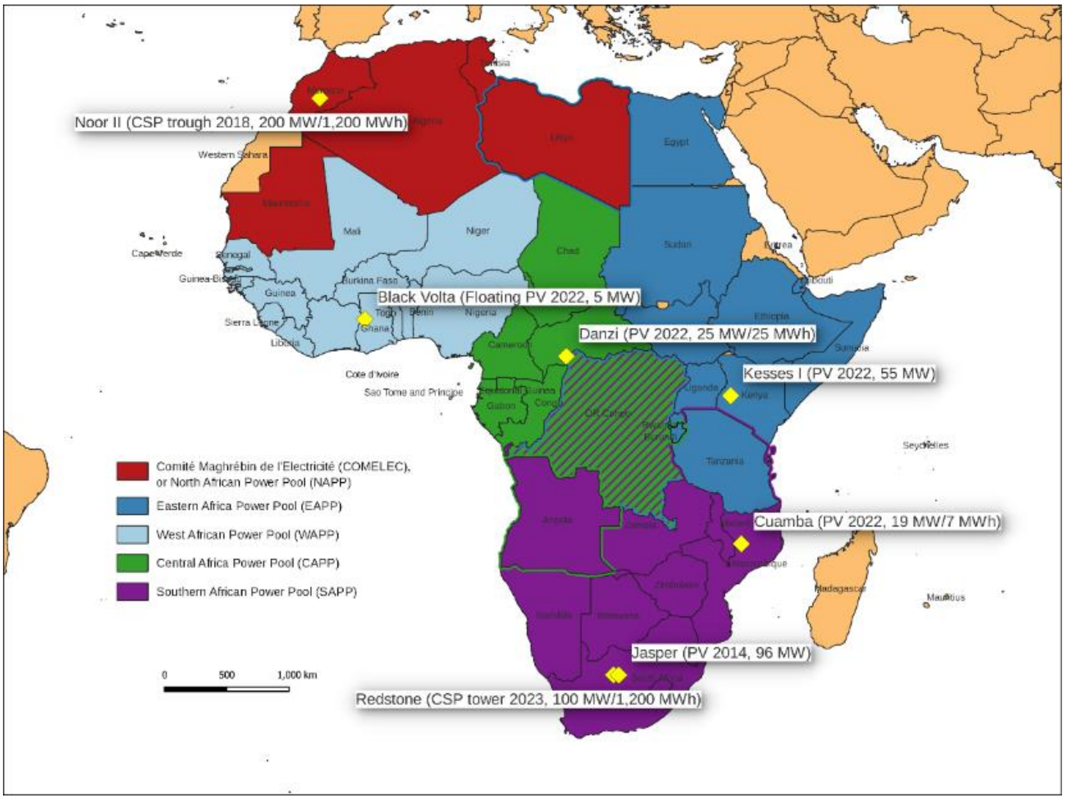


Figure 3: Cases detailed in this study, with their locations in the Power Pools, characterized by name, technology type, rated power and storage capacity (where applicable)

1.2.2.1 Noor II

200 MW CSP parabolic trough solar power plant with 7h of molten-salt storage. Located near Ouarzazate, Morocco. In operation since 2018. Mirrors are oriented in North-South direction tracking the sun azimuthally in one axis.

Figure 4: Aerial photograph of the Noor II power plant with mirror lines; in the centre the power block with air cooled condensers and hot/cold storage tanks is seen. Source: Google

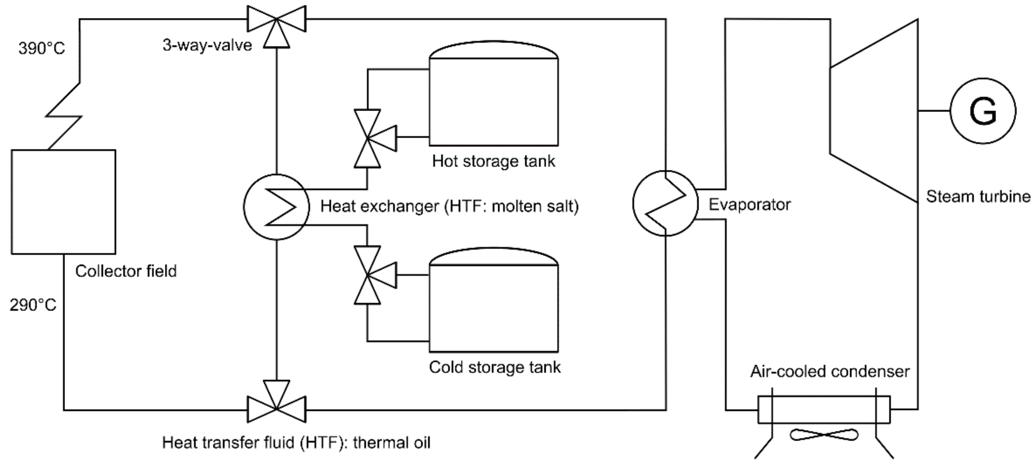


Figure 5: Schematic of the Noor II CSP power cycle. Note the 2-tank indirect storage configuration. 'Steam turbine' is a simplification of the power block running a Rankine steam cycle. Sources: [8] [9]

The schematic of the power cycle is shown in Figure 5. Noor II is a typical modern CSP plant with a field of parabolic trough collectors [8]. The collectors generate heat in a thermal oil from incident solar radiation. The overall efficiency of a solar power plant like the Noor II plant is 37.4% [9].

Noor II is owned by the Moroccan Agency for Sustainable Energy (MASEN), a limited company owned by Moroccan ministries, a fund and the utility ONEE (which is also the offtaker of the electricity). Saudi Arabia based ACWA Power Holding has been the developer, just as in the Redstone CSP plant.

1.2.2.2 Redstone

100 MW CSP power tower solar power plant with 12h of storage. Located in the Northern Cape province in South Africa. Currently under construction after several years of delay, the plant is due to be commissioned in 2023.

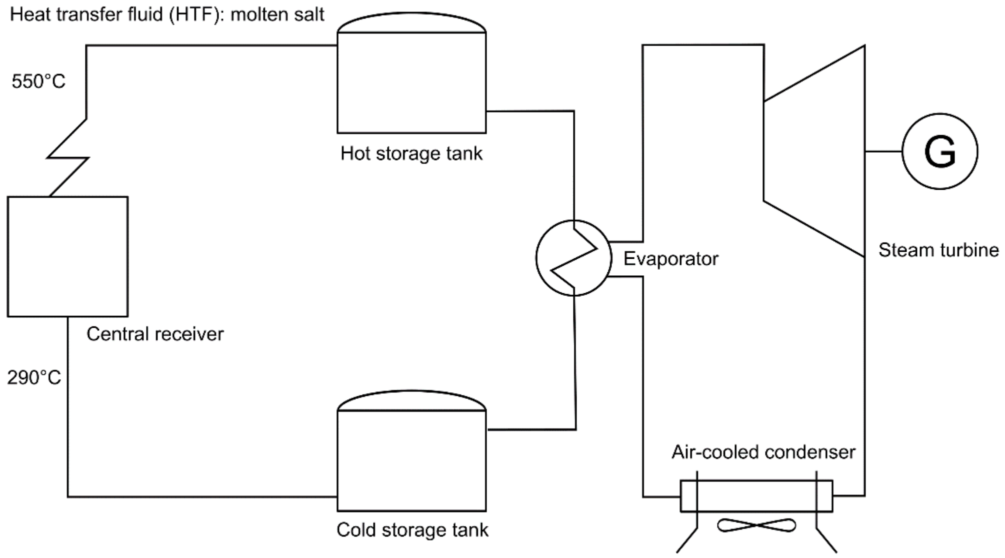


Figure 6: Schematic of the Redstone CSP plant. The storage tanks are positioned directly in the molten salt loop. 'Steam turbine' is a simplification of the power block, running a Rankine steam cycle. Sources [10] [11] [9]

The Redstone CSP plant is equipped with a state-of-the-art two-tank direct storage loop, shown in Figure 6. Due to the high operating temperature of up to 550°C, the power plant efficiency is 42.8% [9].

The Redstone plant is financed by private equity and loan investment [12], notably loans by the African Development Bank (AfDB), and the US Overseas Private Investment (OPIC). The main shareholder is ACWA Power (49%) [13]. The local community holds a share of 12.5% [12], which is remarkable for large-scale power projects.

The power generated is sold to South African utility Escom under a 20-year Build-Own-Operate-Transfer (BOOT) Power Purchase Agreement (PPA) [13].

Figure 7 shows the environmental impact assessment map of the Redstone CSP plant, giving an idea of the planning process of the site.

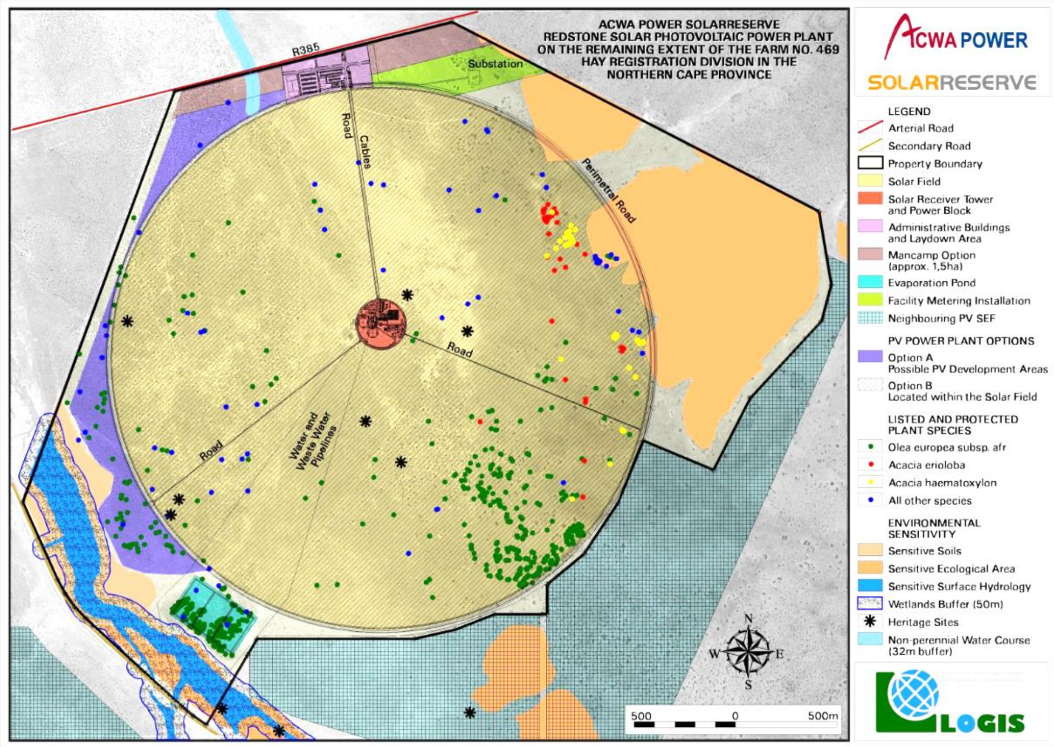


Figure 7: Environmental Management of the Redstone CSP plant: Sensitivity map of the power plant development footprint. Source: [14]

1.2.2.3 Jasper

96 MW dc (75 MW ac) PV plant next door to the Redstone CSP power plant in South Africa. Built under the REIPPPP incentive programme, and operational since 2014. Electricity is sold under a 20-year Power Purchasing Agreement (PPA) to utility Eskom.

Figure 8: Aerial photograph of the Jasper PV power plant. Source: Google

The Jasper power plant is owned by the Jasper Power Company (RF) Pty Ltd, which in turn is owned by several private enterprises (Figure 9).

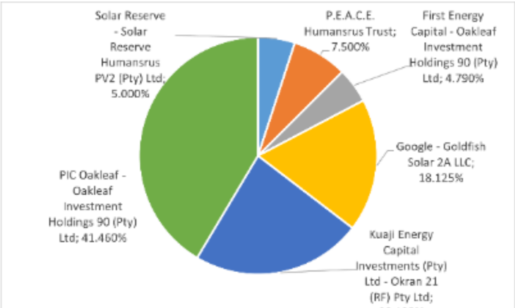


Figure 9: Ownership structure of Jasper Power Company (RF) Pty Ltd, owner of the Jasper PV power plant. Source [15]

The annual turnover of Jasper Power was ZAR 485 million (EUR 27 million) in 2020. The company is 'mandated' [15] to spend 1.5% of turnover (ZAR 9.7 million (EUR 540,000)) for Socio-Economic Development Initiatives, such as Healthcare, Social Welfare, Education, etc., and 0.6% of turnover (ZAR 3.3 million (EUR 183,000)) for Enterprise Development Initiatives, such as Pitch Your Business, Agricultural Projects, ECD Practitioner Training, Learn To Drive, etc.

1.2.2.4 Danzi

25 MW PV power plant with 25 MWh battery storage in Danzi, 18 km from Bangui, the capital of the Central African Republic. Start-up is in 2022 [16]. A power line connecting the three Boali hydroelectric power stations with Bangui passes close to the PV plant, see the map in Figure 10. There is a dam and reservoir just north of the Boali hydropower plants. The dam regulates stores water available in the wet season Dec-Mar for the dry season Apr-Nov. It has been opened in 1991, and successfully improved the capacity factor of the Boali I and Boali II plants (8.75 and 9.9 MW) roughly from 47% to 57% [17]. Boali III (10 MW, in the dry season 5 MW) opened in 2021 after a break in construction due to an armed conflict in 2013 [18].

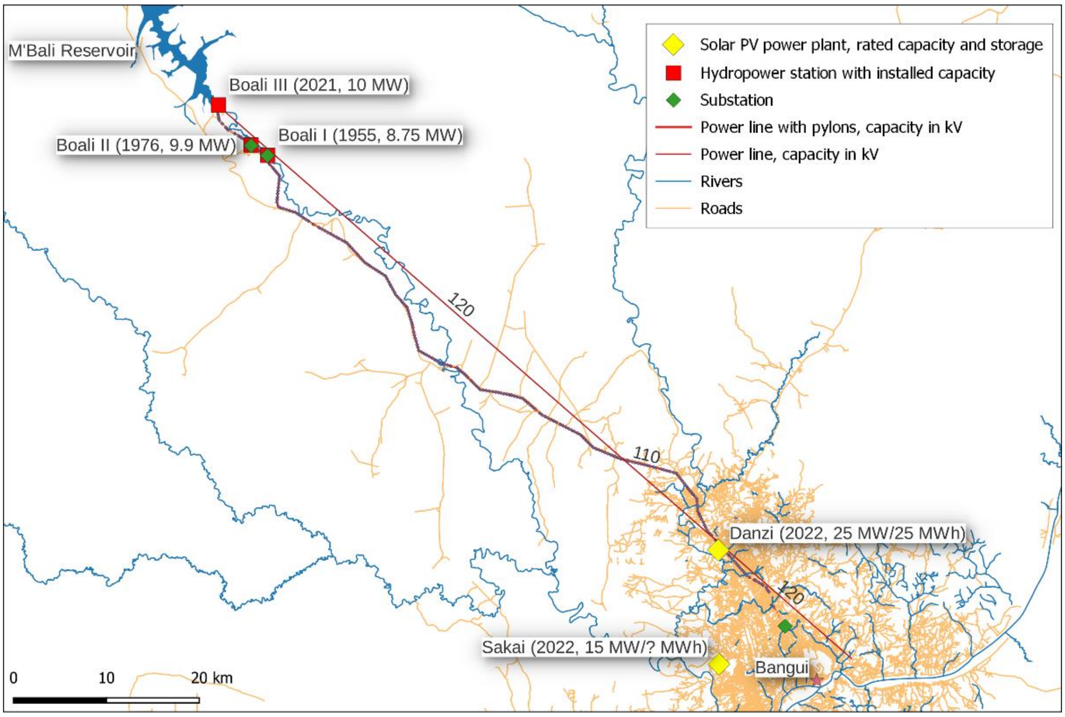


Figure 10: Danzi PV power plant north-west of Bangui, capital of the Central African Republic. The Danzi PV power plant connects to an existing power line between the Boali I-III hydroelectric power stations and Bangui. The map illustrates two paths of the power line, an approximated straight line [19] and the actual path [20] along the RN 1 road

The PV power plant will be using conventional polycrystalline or monocrystalline panels on a fixed steel structure.

The power line has been upgraded to a 80-km-long 110 kV line in 1995, from the older two lines of 60 kV.

The installation of the PV power plant will double the grid-connected power generation capacity in the country. It is entirely financed by the World Band through its International Development Association (IDA) [21], at 2018 USD 48 million, plus 17 million for transmission. Electricity will be fed into ENERCA's grid, though the utility does not qualify as offtaker in the sense of being able to sign a long-term Power Purchasing Agreement (PPA), due to its absence of creditworthiness. The country is 'not ready', in the regulations of the World Bank, to act as guarantor.

The Danzi project is under construction at the time of writing, and the capital's press takes interest also in the events that hamper progress [22].

There is another PV power plant about 10 km south of the Danzi solar plant, called Sakai, with a capacity of 15 MW plus 5 MW for battery storage operation, fixed-tilt installation, built by Tianjin Electric Power Construction, financed bilaterally, and commissioned in June 2022 [23] [24].

1.2.2.5 Black Volta (Bui)

The Bui Generating Station, a hydropower station of 404 MW, is located on the upper Black Volta River in Ghana, commissioned in 2013. The dam forms the Black Volta Lake. The ownership and the responsibility for the implementation of the hydropower dam was handed over by the Ministry of Energy to the Bui Power Authority.

The Bui Power Authority (BPA) engages in installing and operating solar photovoltaic power plants, among them a 1 MW system of Floating PV (FPV) installed on Black Volta Lake, directly behind the dam. This 1 MW FPV system is now part of a 50 MW PV power plant, commissioned in Nov 2020, later to be developed into a 5 MW/250 MW plant [25].

The goals for installing FPV are twofold, reserving land area for agricultural use, and reduce the evaporation of water, thus increasing the capacity of the hydropower dam. The Black Volta FPV project is a test project, but it is part of a large hybrid PV-hydro installation. Though the dam cannot be used for pumped hydro storage, the two generation plants may be used to balance their respective outputs and stabilize Ghana's National Interconnected Transmission System (NITS).

It is remarkable that the Black Volta power plant, unlike many other solar power plants, is owned by a government agency.

1.2.2.6 Kesses I

Finalized in September 2022, built by French company Voltalia and Chinese company Trina Solar, and developed by Spanish company Alten Energías Renovables through its subsidiary Alten Kenya Solarfarms BV. Development had started in 2013 [26].

Rated capacity is 55.6 MWp, the panels are one-axis tracking. There is no storage. The PV plant is located under a 230 kV transmission line.

Electricity will be sold on a 20-year take-or-pay Power Purchase Agreement (PPA) with Kenya Power and Lighting Company (KPLC) [27].

The plant has used bank financing [26], USD 41 million from Standard Bank through CIB Bank and Stanbic Bank Kenya, and USD 35 million from the Emerging Africa Infrastructure Fund (EAIF), which in turn is funded by the governments of the United Kingdom, The Netherlands, Switzerland, and Sweden, and raises debt capital from public and private sources.

1.2.2.7 Cuamba

The Cuamba photovoltaic power plant of 18 MW capacity in Mozambique includes a storage component of 1.86 MW (7.42 MWh) [28]. The electricity generated will be sold to the national utility EDM under a 25-year PPA.

Financing of the total construction cost of USD 36 million has been closed in Dec 2021, with a USD 19 million grant from Emerging Africa Infrastructure Fund (EAIF) through Private Infrastructure Development Group (PIDG) as the sole lender, to Central Electrica de Tetereane SA (CET), a company held to 15% by EDM [29].

The PV plant requires a 400 m power line of 33 kV to an existing substation of 110 kV to be rehabilitated under the grant [30].

1.2.3 Cases summary

Locations, and identifying technical parameters of the Technology Cases described can be found in Figure 3, and Table 1, respectively. More detailed parameters can be found in Table 21 towards the end of this report.

Parameters that should be considered in energy modelling, energy infrastructural planning, and decision making in energy system will be discussed in the sections on modelling and recommendations.

2 Solar technologies

2.1 Solar power plant technologies

Figure 11: Concentrating solar technologies: Solar Tower, CSP, linear Fresnel, CPV (from left to right); Ouarzazate, Morocco 2019

The current assignment Lot 12b discusses solar electricity generation technologies, PV and CSP. Both technologies are intended for large-scale power generation in power plants exceeding a capacity of 10 MW. CSP power plants usually have integrated storage lasting several hours.

Flat-plate photovoltaic (PV) energy conversion has become the dominant renewable energy generation technology worldwide. Light impinging on the panel is directly converted into electricity in a doped Silicon (Si) material. Electricity can be stored in batteries and fed into a grid. PV is a very modular technology, with plant sizes varying from a few Watts for small off-grid applications to over 1 GW in large, ground-mounted solar parks. PV power plants in Africa are currently not larger than 90 MW each, but announcements for more can be found (though chances are that projects will not reach construction phase, just like anywhere else).

Concentrated Solar Power (CSP, Figure 11) encompasses the solar thermal energy conversion technologies Solar Tower, Parabolic Troughs, and Linear Fresnel, where impinging sunlight is concentrated by parabolic mirrors, or mirror segments onto a tubular receiver, and by heliostat mirrors directed onto a central receiver on a tower, respectively. CSP power plants have a minimum size due to the efficient operation of the turbine, typically 50 MW.

The annually installed capacity of CSP power plants is given in Figure 13, for Africa and Rest-of-World, for three concentration modes Parabolic Trough, Solar Tower, and Linear Fresnel.

Table 2: Installations of solar concentration in Africa. Concentrated Solar Power (CSP) and Concentrating Photovoltaic (CPV). Source [2] [author]

Solar power plant	Country	Type	Year operational	Rated capacity MW	Storage duration h	Total capacity factor	Solar Multiple
ISCC Ain Beni Mathar	Morocco	CSP, Hybrid, Parabolic Trough	2011	20	0.0	0.31	0.00
ISCC Hassi R'mel	Algeria	CSP, Hybrid, Parabolic Trough	2011	20	0.0		0.00
ISCC Kuraymat	Egypt	CSP, Hybrid, Parabolic Trough	2011	20	0.0	0.19	0.00
Airlight Energy Ait-Baha Pilot Plant	Morocco	CSP, Parabolic Trough	2014	3	5.0	0.30	3.34
NOOR I	Morocco	CSP, Parabolic Trough	2015	160	3.0	0.39	1.48
Bokpoort	South Africa	CSP, Parabolic Trough	2016	50	9.3	0.91	1.75
Khi Solar One	South Africa	CSP, Power Tower	2016	50	2.0	0.49	1.21
Ilanga I	South Africa	CSP, Parabolic Trough	2018	100	4.5	0.55	1.52
NOOR II	Morocco	CSP, Parabolic Trough	2018	200	7.0	0.63	1.87
NOOR III	Morocco	CSP, Power Tower	2018	150	7.0	0.67	1.78
Xina Solar One	South Africa	CSP, Parabolic Trough	2018	100	5.5	0.66	1.54
Kathu Solar Park	South Africa	CSP, Parabolic Trough	2019	100	5.0	0.78	1.37
Redstone	South Africa	CSP, Power Tower	2023	100	12.0	1.05	1.93
Touwsrivier	South Africa	CPV	2014	44	0.0	0.19	1.00
Ouarzazate	Morocco	CPV	2016	1	0.0		1.00

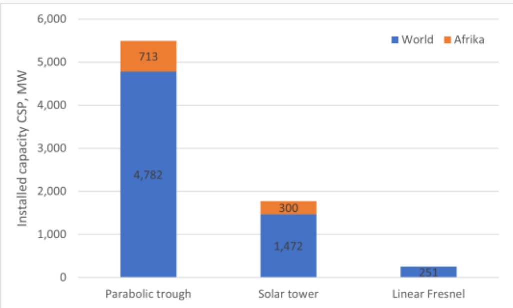


Figure 12: Cumulative installed capacity of Concentrated Solar Power (CSP) plants in Africa and the World. Source [31]

Installations of solar concentration power plants in Africa are listed in Table 2. The Redstone plant is under construction. Aggregated installation numbers for the three concentration technologies parabolic trough, solar tower, and linear Fresnel are given in Figure 12.

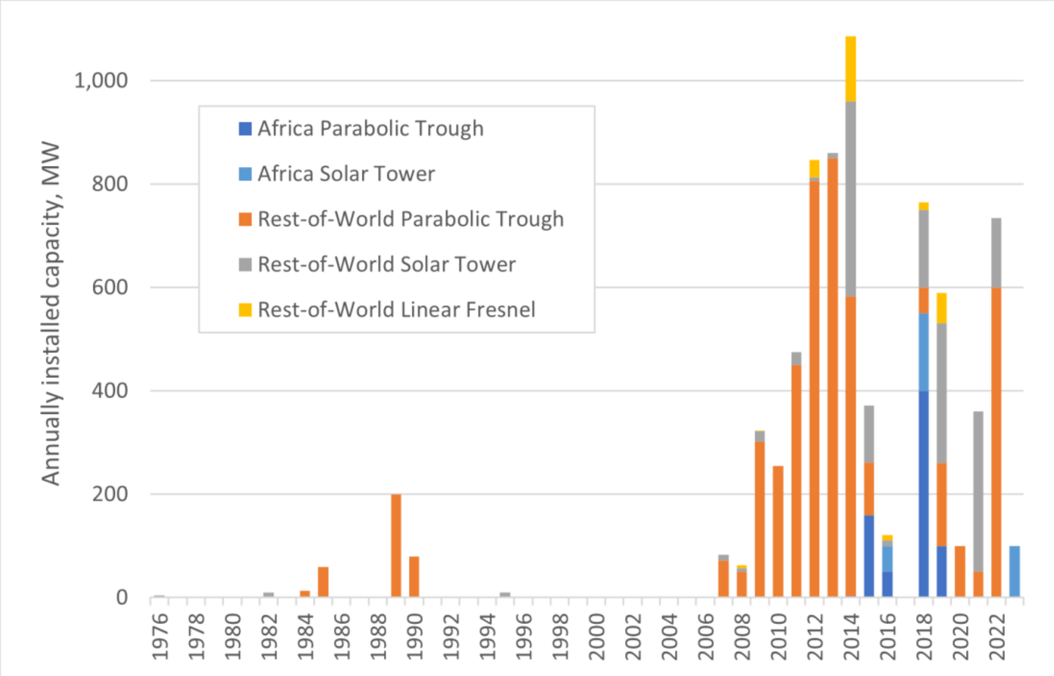


Figure 13: Annually installed CSP capacity for Africa and Rest-of-World, for three technologies, Parabolic Trough, Solar Tower, and Linear Fresnel concentration modes. Source [2]

A related solar technology is Concentrating Photovoltaic (CPV, Figure 11) power conversion, a technology where concentrated sunlight is directly converted into electricity by highly efficient photovoltaic multi-junction cells.

In contrast to solar PV technologies, which can make use of diffuse and direct sunlight to produce electricity, CSP and CPV plants have a narrower operating range, requiring direct sunlight under clear skies to generate at capacity.

2.2 Power efficiencies

The efficiency of solar power plants is to be understood as the ratio of electric power output to solar irradiance input. Both parameters are measured in Watts (W).

The upper efficiency limit of solar thermal power plants is the Carnot efficiency $\eta_\mathrm{C} = 1 - T_\mathrm{cold}/T_\mathrm{hot}$, where T_cold is the absolute temperature of the cold side of the power cycle in Kelvin, and T_hot is the absolute temperature of the hot side of the power cycle.

The cold side of the power cycle is defined by the temperature of the condensate, the hot side of the power cycle is the temperature of the steam entering the turbine. A typical power cycle is the Rankine cycle, which is the basis of the power cycles used in CSP [10].

The upper efficiency limit of photovoltaic power plants, in the thermodynamic limit, is equal to the Carnot efficiency with the temperature of the sun $T_\mathrm{sun} = T_\mathrm{hot}$, for the bandgap of the semiconductor material of the photovoltaic cell. Standard silicon photovoltaic cells convert photons with a wavelength shorter than 1,100 nm, all at the energy corresponding to that bandgap wavelength. Thus, stacking several semiconductor materials with bandgaps matching the solar spectrum will increase the efficiency of the photovoltaic device.

The concentration ratio of the optics of the power plant defines the apparent temperature of the sun, which can reach 5,777 K for the ideal geometrical concentration ratio of 42,000 X. We note that solar power conversion technologies have different geometrical concentration ratios (Table 3), a fundamental reason for their potential efficiencies to vary. For broad discussions on solar optics, see [32], for a theoretical treatment of solar energy conversion, see [33].

Table 3: Geometrical concentration ratios and typical system efficiencies of existing solar power conversion technologies

Solar power plant	Optics type	Geometrical concentration ratio	Typical solar-to-electricity efficiency, %	Sources
PV	none	1	18	[34]
CPV – Fresnel lens	Fresnel lens	1,000	33	[35]
CSP – Linear Fresnel	Linear Fresnel mirror	100	15	
CSP – Parabolic trough	Parabolic trough, linear	200	15	[36]
CSP – Solar tower	Heliostats, central receiver	1,000	20	[10]

The steam temperature can be higher in Solar Tower than in Parabolic Trough CSP plants, e.g. 371°C and 535°C, respectively, increasing the efficiency of the Solar Tower plant in line with Carnot's equation given above.

2.3 Storage technologies

2.3.1 Thermal Energy Storage (TES) for Concentrating Solar Power (CSP)

Concentrating Solar Power (CSP) plants are almost always operated with a significant amount of storage, as shown in Figure 14. Storage enables the extension of generation of solar electricity into the night when demand is highest. The CSP plant can be operated in a way utilities know from combined cycle plants, flexible rather than base load, and high availability for most of 24 hours.

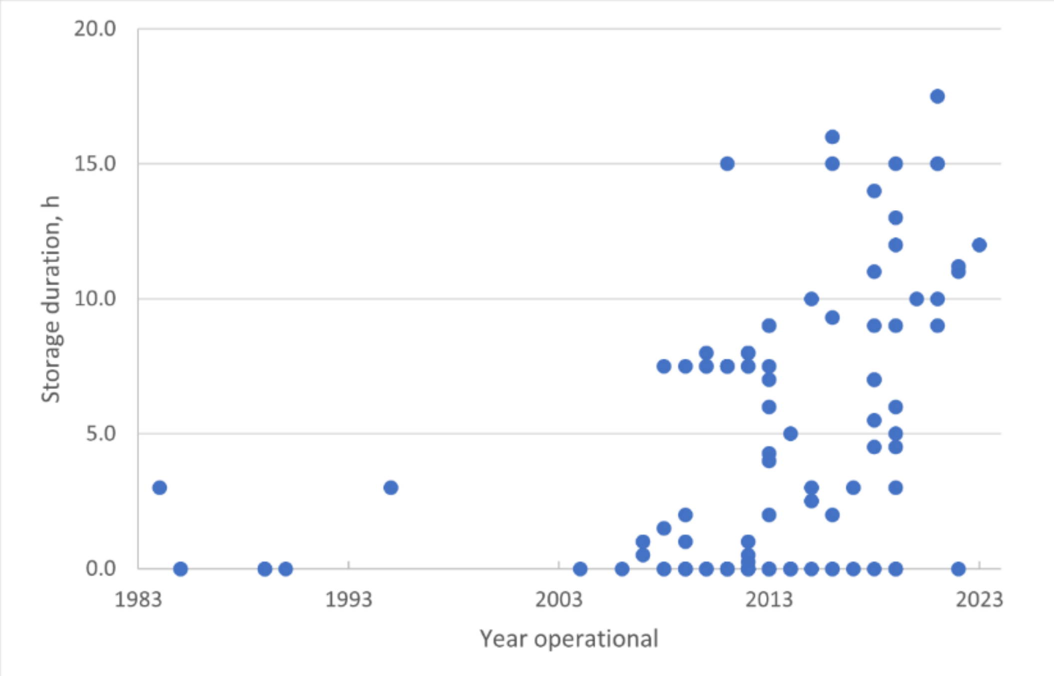


Figure 14: Storage duration in hours at rated capacity, for CSP plants listed in [2]

Current state-of-the-art storage is the two-tank molten salt type, as shown in Figure 6. One hot and one cold tank are placed directly into the collector loop. The storage medium is liquid, it works with sensible heat. Operators avoid cooling down of the tanks below solidification of the salt. Being able to use the latent heat of the phase change between solid and fluid (or fluid and gaseous) would increase the enthalpy of the heat transfer medium, and developments are under way [37].

The heat transfer fluid is a molten salt [10], composed of 60% $NaNO_3$ + 40% KNO_3. Its specific heat capacity is 1,493 kJ/(kg K), and its operating temperature range is 260-585°C.

2.3.2 Battery storage for photovoltaic (PV) power plants

Many photovoltaic (PV) power plants include battery storage. There are many ways to design the power plant architecture, in particular the integration of the battery storage. The preferred way [38] is called *DC-coupling*, shown in Figure 15.

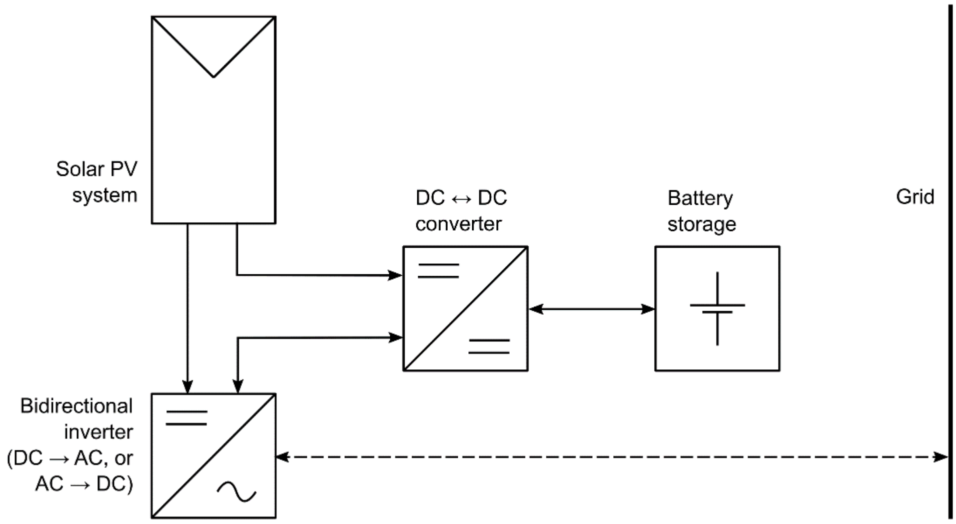


Figure 15: Solar PV system with battery storage, DC-coupled to the grid, analogous [39] [38]

DC-coupled PV power plants often have distributed batteries, increasing system complexity, and potentially increasing system control needs and cost.

Distributed batteries in the DC-coupled plant allow a high Round-Trip Efficiency (RTE). Since the battery is located before the inverter (as seen from the solar PV system), generated electricity may be stored before it may be curtailed by the Inverter Loading Ratio (ILR, section 2.4).

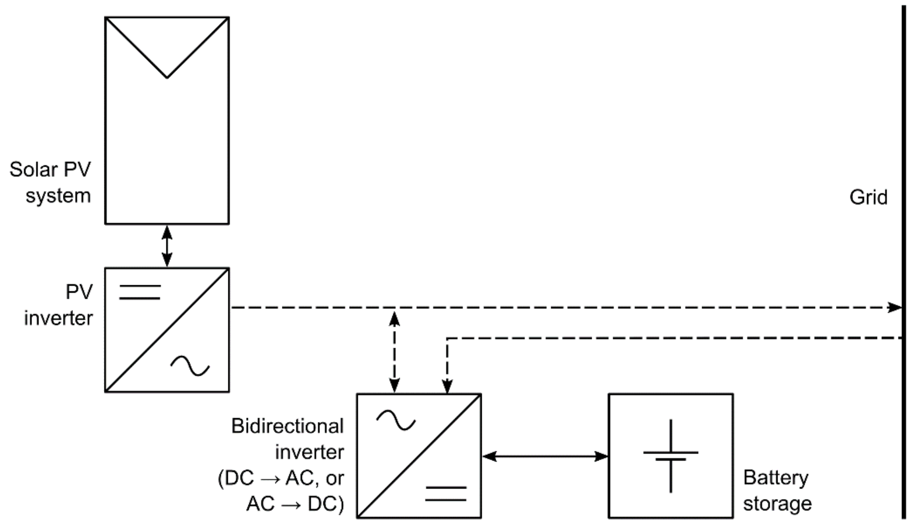


Figure 16: Solar PV system with battery storage, AC-coupled to the grid, following [38]

Battery storage can also be *AC-coupled* to the grid (Figure 16). The AC-coupled system has advantages over the DC-coupled system as it enables the battery storage to be operated independently of the PV system. AC-coupling is well suited for retrofitting battery storage to existing PV power plants.

2.3.3 Capacity factors of solar power plants

Capacity Factors (CF) describe any power generation technology by the ratio of generated energy over the energy that could be generated in the same timeframe (usually one year, or 8,760 hours, but also over the course of a day).

Fossil-fuel based energy generation tends to have Capacity Factors significantly higher (but not unity due to planned and unexpected downtimes) than VREs, simply put, since the sun shines for only half a day, on average. However, the sun does shine, whereas fossil fuel-based generation may be hampered by supply shortages, or may be endangered by coolant disruption, or other issues brought by disasters caused by war or Climate Change.

Capacity Credit [40] is the contribution that a given generator makes to overall system adequacy [41]. System adequacy [42] refers to the existence within a system of sufficient generation and transmission capacity to meet the load, whether under normal or unusual conditions, such as unavailability of facilities, unexpected high demand, low availability of renewable resources, etc.

For a working supply with electricity in a network, power capacity needs to be reserved for changes of demand. Load curves can change in minutes; therefore, flexible capacity reserves are required. Capacity may be provided by fast-adapting power generation technology like gas turbines, and by fast-accessible storage capacity like battery storage and molten salt storage of CSP, which can provide power in minutes.

Seasonal changes of supply or demand represent additional power capacity needs. Climate parameters, such as solar resources and temperatures also influences the capacity factors of power generation technologies. It can be useful to moderate the capacity factors by increasing the area where generation is bundled, such as a national grid, an intra-continental, or an inter-continental grid.

Storage capacity can be assigned a capacity factor, just like a generator. In a hybrid solar+storage PV plant [43] [44] [39], the storage unit and the solar plant can be treated independent of each other, if the storage unit can be charged by other generators on the grid, and inverter capacity remains available. This gives an additional degree of freedom. Increasing the battery duration tends to increase the capacity factor and the capacity credit available for the battery alone and for the hybrid solar photovoltaic plant.

Storage increases the capacity factor of a CSP plant [45]. Adding the capacity factor of the storage (calculated as storage duration as fraction of the day) and the capacity factor of the solar field results in a stacked capacity factor solar+storage. Analysing the CSP data collected and published under the name of CSP guru [46] [2] offers the capacity factors of most CPV plants operational and under construction (Figure 17). A few CSP plants are excluded from the list of capacity factors, due to incomplete, or inconsistent data.

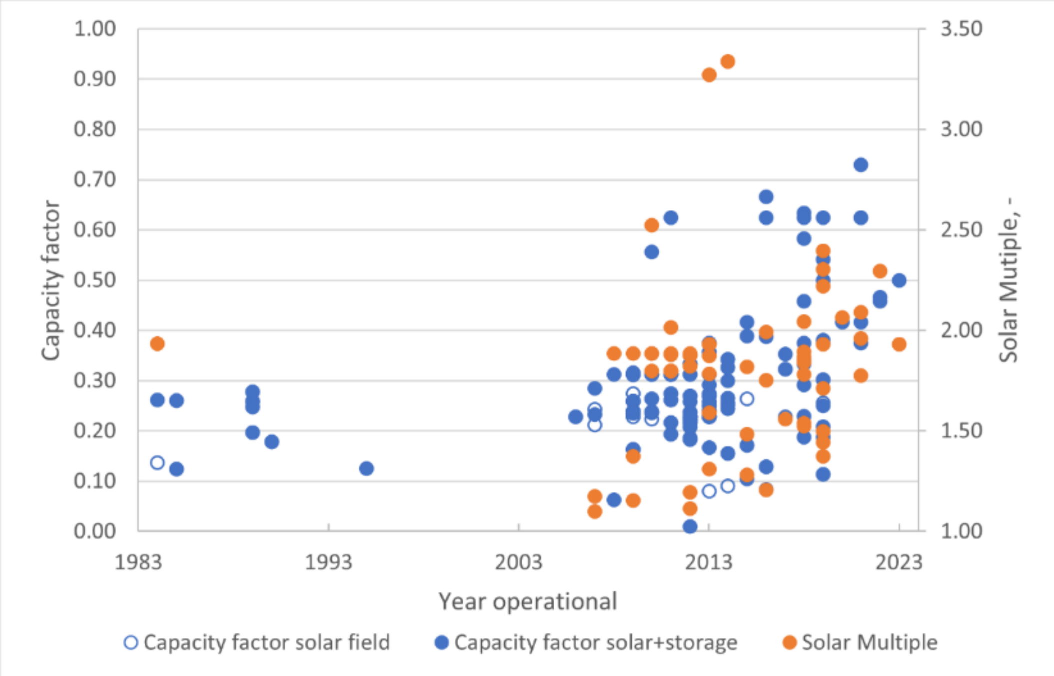


Figure 17: Capacity factors and Solar Multiple of most operational CSP plants (excluded are experimental plants, and plants where data has been found to be incomplete or incoherent). Source [authors] [2]

2.3.4 Calculating capacity factors of storage-assisted solar power plants

Concentrating Solar Power (CSP) and photovoltaics (PV) are different sides of the solar medal. One of the main differences is the way how storage options are integrated into the power plant:

- CSP – Thermal Energy Storage (TES) has developed into being the dominant part of the CSP plant. Storage duration tends to be long, and the solar field is currently the only means to charge the TES. The fraction of the solar field charging the TES is often much larger than the part of the solar field used for nameplate operations. The ratio of the two fields is termed Solar Multiple (SM).

- PV – Battery storage has only recently become common in photovoltaic power plants. Battery capacities have usually been smaller than solar field capacities. Batteries are charged from within the capacity of the PV plant. There is a fraction Y (%) describing how much of the power generation is directed by the operator into the battery.

The ways to design and operate CSP and PV power plants are very different; hence the mathematics for calculating the capacity factors CF of CSP+TES and PV+battery storage differ. We follow [39] in calculating the CF of utility-scale PV plus battery,

$$CF_{\mathrm{PV+battery}} = CF_{\mathrm{PV}} + CF_{\mathrm{battery}} \frac{P_{\mathrm{battery}}}{P_{\mathrm{inverter}}} \left(1 - \frac{Y}{\eta_{\mathrm{RTE}}}\right),$$

where P_{battery} and P_{inverter} are the nameplate powers of the battery, and the inverter, respectively. RTE is the Round-Trip Efficiency of charging and discharging the battery using power generated by the PV power plant. Y is the fraction of the power generated by the modules directed into the battery. CF_{battery} is the nominal capacity factor of the battery.

In the case of CSP+TES, the two capacity factors add up, to

$$CF_{\text{CSP+TES}} = CF_{\text{CSP}} + CF_{\text{TES}}\,,$$

assuming that the capacity factors are including the relevant efficiencies for heat transfer and storage. If the RTE efficiency for TES is required, 14% loss is a conservative value [47] for state-of-the-art two tank molten salt system. Advanced storage round-trip efficiencies have been demonstrated to exceed 98% [45].

2.4 Solar Multiple and Inverter Loading Ratio

The Solar Multiple (SM) of a CSP plant is defined as the ratio of the rated power capacity of the solar collector field to power block capacity [48],

$$SM = \frac{P_{\text{solar}}}{P_{\text{cycle}}}\,.$$

The solar field must be oversized to charge storage units (see 2.3).

There is a trend towards longer storage duration and higher solar multiples in CSP plants, along with the total capacity factor of CSP plants. The capacity of CSP plants with added storage approaches unity, as in Figure 17. For CSP plants with high-capacity storage, up to three quarters of the solar field are heating the storage medium in the storage tank. As a result, the CSP plant can operate 24h per day under rated irradiance. In Figure 14, output hours from solar-only operation need to be added to the storage duration.

There isn’t any solar multiple defined for PV/battery systems yet, as the battery storage duration is often short. In the case of Danzi the storage duration is one hour, the battery is charged by power within the nameplate field size. We expect the solar multiple to become a design parameter for photovoltaic power plants as soon as reducing storage costs are allowing storage durations comparable to CSP.

The solar multiple may be greater than one even for plants without storage capacity, as part-load operation is reduced. Reducing partial loading is equivalent to increasing operation time at rated power when all components operate at highest efficiency. Turbine efficiency in CSP plants benefits from full load operation, as does the efficiency of the inverter in a PV power plant.

The inverter in a PV plant converts direct current (DC) generated by the photovoltaic modules into alternating current (AC) required by the grid. The Inverter Loading Ratio (ILR), or DC/AC Ratio, defines the ratio of direct current power produced by the photovoltaic modules over the alternating current power fed into the grid

$$ILR = \frac{P_{\text{solar DC}}}{P_{\text{AC}}}\,.$$

In 2021, the ILR has reached 1.35 in the United States, where the number is documented well [49]. While a high ILR increases the cost of the inverter, and clips peak power coming from the modules (about -0.5% of annual energy generation), it increases the capacity factor of the PV plant by increasing the number of full-load hours, by about three percentage points. The same data [49] shows that tracking increases the capacity factor of US photovoltaic plants by another four percentage points, when compared to fixed-tilt installations. Capacity factors of PV plants in the US are at 25%, with the top installations reaching 32%.

Increasing ILR and the prevalence of tracking have been the sources of improving the capacity factors of PV power plants over the last decade, offsetting a decline in the quality of solar resources as installations have moved to less favourable locations.

As battery costs have been almost halved (US data, [49]) from USD 442 in 2018 to USD 264 in 2021, battery installations in PV/battery plants have increased dramatically from 232 MWh to 3350 MWh over the same three years.

3 Concentrated Solar Power (CSP)

3.1 CSP ramp-up

The World Bank [50] points out that in a grid of high VRE penetration, reserves are required to keep the fluctuations of grid frequency (as a measure of stability) at a minimum. These balances can be storage capacities in CSP plants, as long as their ramp-up and downturn are fast: *CSP and frame-type CTs* [Combined cycle gas Turbine power plants] *are very similar in terms of their ramping capability (roughly 10% of full capacity per minute)*, states Mark Mehos [51], Manager of Thermal Sciences R&D and CSP at NREL.

3.2 CSP operation

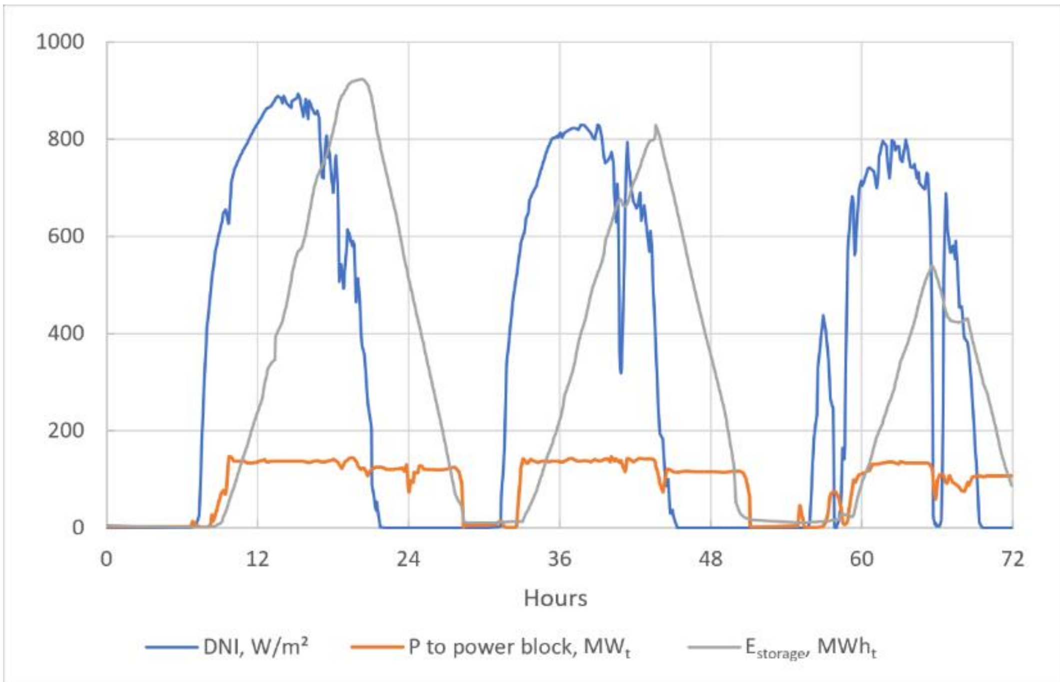


Figure 18: Actual operational data of the 50-MW$_e$-Concentrated Solar Power (CSP) plant *Andasol 2* (Spain) with parabolic trough collector field and 2-tank indirect storage configuration (see Figure 5) on June 26-28, 2010. Capacity of the molten-salt storage is 7.5 hours. The subscripts 't' and 'e' refer to 'thermal' and 'electric', respectively. From [52]

Operational data of a CSP plant with storage is shown in Figure 18 [52], for the 50-MW *Andasol 2* plant in Spain, for three consecutive summer days. The plant's configuration is very similar to the layout of the parabolic trough CSP plant Noor II shown in Figure 5. Imperative in operations at *Andasol 2* was the generation of power, as the power sent to the power block has a higher priority than filling the storage capacity. From the figure, when storage supplies thermal energy to the power block in the evenings, the power level is lower than during the day when the solar field supplies power. There is a small efficiency gap, and a small power drop when operations switch from field to storage.

Direct Normal Irradiance (DNI) reduces, and the collector field cannot fully load the storage on days two and three, resulting in a shorter operation time in the evenings of days two and (possibly) three. On day three in the afternoon, there might have been a decision by the operator to divert power from the field into the storage rather than into the power block. The storage capacity of the plant is 7.5 hours at 1,010 MWh capacity, and its Solar Multiple can be calculated to 2.0 (the collector field area is 510,120 m², and the DNI 2,260 kWh/(m² a) [2]). The capacity factor of the *Andasol 2* CSP plant is 0.36, not counting the capacity of the storage. Adding both capacity factors for solar field and storage yields a total capacity factor of 0.67, the Solar Multiple being 1.8.

3.3 Technical advances in CSP

There have been numerous proposals to advance the overall power conversion efficiency of Concentrated Solar Power (CSP) plants. Most approaches follow classical thermodynamics and relate to the Carnot efficiency via operating temperature increase, or the reduction of heat transfer losses. The operating temperature of power plants in general is limited by material properties. For example, the pressure limit of the core vessel sets the operating temperature of the primary power loop to some 330°C.

In a CSP plant with parabolic trough collectors, the heat transfer fluid is a synthetic thermal oil, limiting the operating temperature to 390°C before the oil dissipates. The molten salt [Ders21] used as heat transfer fluid in the central receiver of a solar tower CSP plant withstands temperatures of 550°C (which are set by the stability of austenitic steel tubes), but it needs to be warmer than 260°C before freezing. Keeping temperatures above ambient in the collector loop of the parabolic troughs is not possible, hence molten salts are used in solar towers, giving them a higher Carnot efficiency.

Pushing the operating temperature yet higher, above 700°C, requires other materials. A liquid metal, Sodium (Na) [37], which melts at 98°C, and evaporates at 890°C at ambient pressure, could be used in the storage loop at high temperatures. Sodium is very reactive and needs to be hermetically sealed, but experiences exist in nuclear reactors.

Another option of the heat transfer medium is gas, Carbon Dioxide (CO_2) [39] which is not reactive nor dangerous (on the plant level). It could be used in a volumetric receiver, in combination with sodium in the storage loop. Figure 19 schematically shows these improvements.

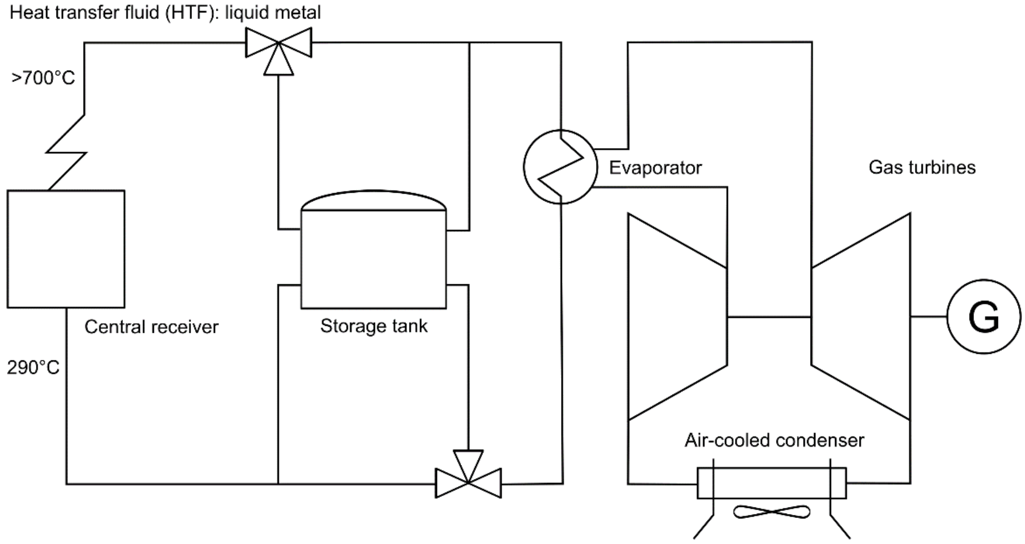


Figure 19: Proposed layout of a future high efficiency Concentrated Solar Power (CSP) plant based on current solar tower central receiver technology. Improvements include high-temperature heat transfer fluids in receiver and storage loop. The power block runs a Brayton cycle. Following [37] [39]

The tertiary loop of this future CSP plant is designed as Brayton cycle, usually used in gas-fired power plants (or jet engines), where temperatures of the gaseous fluid exceed the Rankine cycle's steam temperature.

3.4 High-temperature process heat

High temperature heat >600°C for industrial processes may offer further applications for Concentrating Solar Power (CSP) spillover technologies. Rather than generating steam for power generation, high-grade heat can be used directly for industrial processes, such as [53]:

- Calcination processes in the cement industry (Figure 20)
- Copper ore upgrading
- Industrial burners
- Manganese roasting
- Solar gasification

Figure 20: Kiln in the cement industry, as an example for future application of high-temperature solar process heat

The direct use of industrial process heat is efficient and offers chances to replace fossil fuels in domains where combustion is often deemed essential [54].

4 Solar Photovoltaics (PV)

4.1 Hybridization of PV and CSP

Hybridization of CSP and PV may be an option of the near future. Midelt, the Moroccan solar site east of the Atlas Mountains, will be built with CSP and PV integration. The reason for the hybridization of the two solar technologies is the storage capacity of the CSP plant. While PV as the least cost option may produce electricity during the day, the large storage option of the CSP plant can fulfil peak demand in the early evening and provide power throughout the night [50]. Excess power generate by the PV plant can be used to heat the working fluid of the CSP solar field [55].

4.2 Floating PV (FPV) and FPV hybridization with hydropower

Floating Photovoltaics (FPV) are PV power plants floating on water bodies. FPV can be installed on natural lakes and artificial reservoirs, as well as offshore on oceans.

Photovoltaic power plants can be operated in conjunction with hydropower stations. There are two options, firstly the integration of PV with pumped-storage hydropower, and the installation of floating PV on existing reservoir water surfaces behind the dams of impoundment hydropower stations. The difference between the two options is the chance to utilize surplus solar electricity to add water to the pumped-storage lake in the former.

There is a further option, the combination of PV with tidal power plants. As there is no tidal power plant in Africa, currently floating PV is mostly installed on reservoirs.

The modelled potential power generation capacity of FPV situated on artificial reservoirs is given in Table 4. The Table gives an indication of the assumptions set in the models. Two studies cited are concerned with the hybridization of FPV and hydropower. One study includes reservoirs which are used for industrial or irrigation purposes.

Table 4: Potentials of Floating Photovoltaics (FPV) and hybrid hydro-PV

Study with main assumptions	Region/Power Pool (where available)	Potential capacity in Africa, GW	Source
Hybrid hydro-FPV solar capacity • on man-made reservoirs with hydropower installations • median scenario (minimum 50 m, maximum 1,000 m) • 14% of surface area • regions by UN Geoscheme	Northern Africa	93	[56]
	Eastern Africa	135	
	Western Africa	189	
	Middle Africa	78	
	Southern Africa	17	
	Total Africa	512	
Potential capacity of FPV on existing hydropower reservoirs • detailed model • points out additional hydroelectric potential due to water evaporation savings • largest 146 reservoirs considered • 10% of surface area • FPV capacity equals 5 times existing hydropower capacity	NAPP	5	[57]
	EAPP	88	
	WAPP	105	
	CAPP	11	
	SAPP	83	
	Total Africa	292	
Total installable capacity of FPV on human-made reservoirs, including hydropower dams and industrial or irrigation reservoirs • based on Global Solar Atlas and GrandD database Version 1.1 of 2011 [58] • 724 water bodies assessed • 10% of surface area	Africa	1,011	[59] [60]

Advantages of Floating Photovoltaics (FPV) include:

- storage nearby in the reservoir possible,
- cooling through shading,
- reduction of evaporation (water savings by reduced evaporation 6.3% [61], 6-20% for 10% reservoir coverage, depending on floater type [57]),
- business integration of FPV with dams possible (often reservoirs and dams are owned by national entities).

Challenges are related to insurance coverage, ownership of the water body, and technical risks (mooring, float durability).

First projects in offshore FPV [62] are undertaken on an experimental stage. Offshore FPV would increase the potential area and power of floating technologies, possibly in an analogy to offshore wind power, where the experiences of the offshore industry were vital to the development of offshore wind power plants.

Land-based photovoltaic power plants may be built next to existing hydropower stations to take advantage of the existing infrastructure, in particular the existing transmission grid. One example of such a plant can be found in Ghana (Technology Case Black Volta, section 1.2.2.5).

4.3 Agrivoltaics

Agrivoltaics brings together agriculture and solar energy. Agrivoltaics is defined as *land use configuration where solar energy generation and sunlight-dependent agricultural activities are directly integrated and there is a layer of agricultural productivity within the boundaries of the solar infrastructure* [63]. The mutual benefits between agricultural productivity and solar energy generation are found to be protection crops from climatic elements [64] [65] and having developed lands accessible for solar power installations. In African especially, Climate Change might make arid lands unsuitable for cultivation. Hence, shading could be essential for preserving water in irrigation [66].

Figure 21: Early example for agrivoltaics: Sheep living under La Ola Solar Farm on Lanai Hawaii. They keep the weeds and grass trimmed down in the hard-to-reach places between and under the solar panels. 7 Mar 2011. Credit: Merril Smith. Wikimedia Commons

The first agrivoltaic system of East Africa having been launched in Kenya in Feb 2022 [67], there is little experience on the continent yet. The solar industry association in Europe and NREL in the USA have compiled reports with experiences and guidelines [68] [63].

Agricultural lands make up for 43% of the land surface of the contiguous United States, and only 1% of the surface of the USA are required for solar power to provide nearly all electricity needs of the country in 2050 [69].

Bifacial modules on single-axis trackers might be especially useful, as energy reflected by the crops/soil can be collected, while shading can be generated in line with the plants' needs.

4.4 Technical advances in photovoltaics

There are numerous technical advances in the field of photovoltaics. We will discuss the technology basics, and new products like bifacial photovoltaic modules, and tandem (perovskite) cells.

4.4.1 PV Technology components and evolution

The PV cell is the element for the direct conversion of solar radiation into electricity. There are different kind of PV cells depending on the materials involved in their fabrication and technology applied. The world record efficiency of sun-to-electricity conversion at laboratory level is 47,6% for a multijunction (4-junction) cell, with 665 suns concentration (announced 30 May 2022 by Fraunhofer ISE [70]). However, these are laboratory cells, and even non-record cells of that multijunction III-V technology have a limited production capacity, high cost and are mostly dedicated to spatial applications. The largest solar power plant operating on Concentrating Photovoltaic (CPV) technology using multijunction devices has a capacity of 44 MW and is located in Touwsrivier, South Africa, since 2014.

The majority of production corresponds to wafer based crystalline Silicon cells with different manufacturing technologies (BSF, PERC, TOPCON, IBC, Heterojunction, see below) and thin film technologies (CdTe, CIGS, or a-silicon). In recent years a new type of cell based on materials with the structure of perovskites has created interest, for its fast increase of efficiency and potentially low manufacturing costs. Also, perovskite materials allow modification of their spectral response making them a good candidate to be part of tandem structures for optimum spectrum absorption (perovskite onto crystalline silicon or onto CIGS) and resulting efficiency increase of the final cell. The drawbacks of perovskite cells include their lower than required time of life at this moment, the latest developments report a loss of efficiency close to 10% after 1,000 hours under the sun.

Cell efficiencies are thermodynamically limited to 29% for single-junction cells [71], while tandem cells (2-terminal), and multi-junction cells for CPV currently reach 35.9%, and 47.6%, respectively (Figure 22). As crystalline and thin film technologies are close to their theoretical maxima in efficiencies, technological development focuses incremental reduction in manufacturing cost, and performance increase employing tracking and other means, as discussed below.

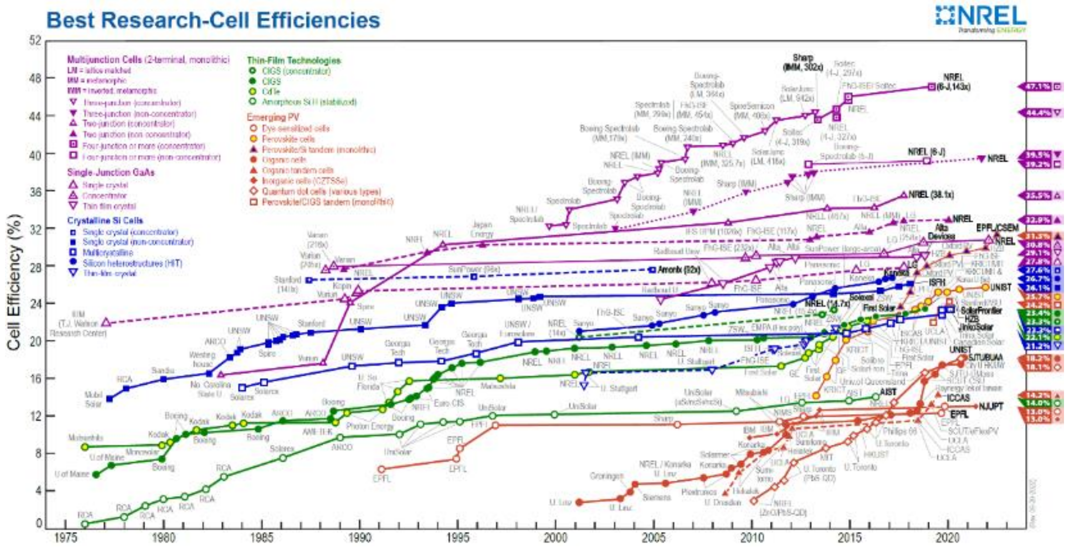


Figure 22: Best research-cell efficiencies. Sun-to-electricity efficiency of laboratory scale cells. Source: [72]

Out of the 2021 total world production of approximately 190 GWp (Figure 23), 95% correspond to wafer based crystalline silicon technology. The ratio of mono/multi on the crystalline silicon varies depending on evolution of cell technology. While cheaper multi-crystalline silicon was leading since 2000, from 2016 on, mono-crystalline silicon appears the winner as more efficient technologies require mono-crystalline substrates.

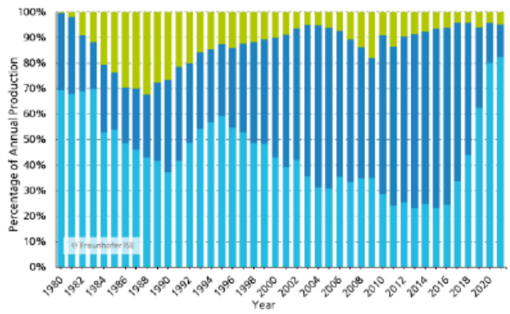


Figure 23: Breakdown of photovoltaic production according to cell technology. Source: [34]]

The thin film products are dominated by the CdTe technology (2/3), together with CIGS from and a few MWs of amorphous silicon. Although their lower production, some characteristics of thin film technologies (lower temperature coefficients or immunity to cracks, among others) make them recommended for specific applications or geographical locations.

4.4.2 Crystalline silicon wafer-based PV technology

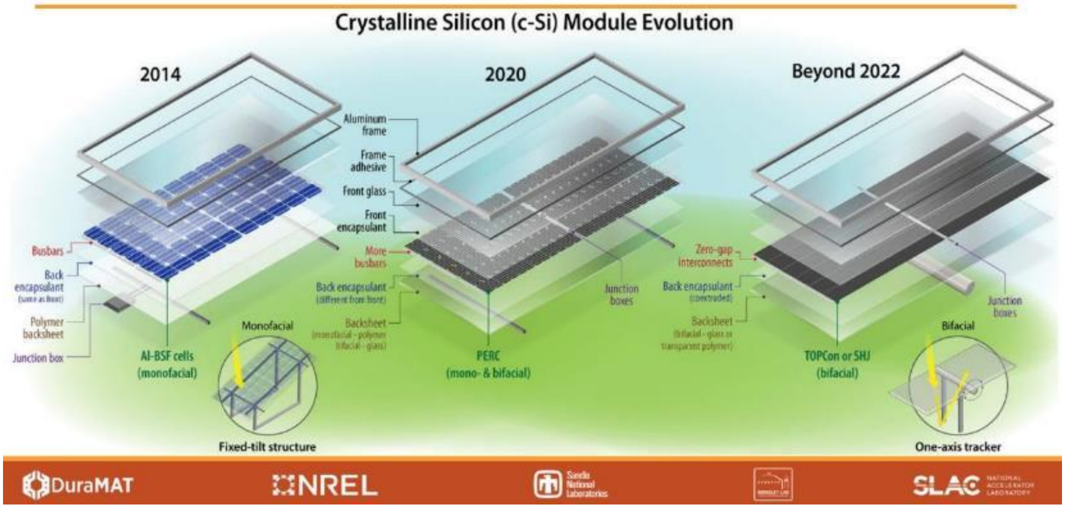


Figure 24: Photovoltaic crystalline silicon (c-Si) module trends. Source: [73]

The Durable Module Materials (DuraMAT) Consortium classifies technology evolution in three large steps (Figure 24). There are no drastic changes between technologies, as alternatives coexist for a while, but is a good representation of modifications introduced:

- Aluminum- BSF cell technology, mono-facial at around 2014,
- PERC, mono and bifacial technologies, with improved encapsulation materials and interconnection in the 2020s,
- TOPCon or HTJ technologies, both bifacial with optimized interconnections, encapsulants and materials for bifaciality beyond 2022.

This classification was done by the consortium members lead by US Department of Energy’s National Renewable Energy Laboratory (NREL) and university research capabilities taking into consideration the forecasts with respect to individual process steps of the technology evolution (starting material, cell and module) by ITRPV association of equipment manufacturers [74].

4.4.3 Wafers

Silicon has the highest material cost in the solar cell. New ingot slicing techniques have allowed the reduction in thickness of the wafers, from the 160 microns, standard now, down to 140 microns next years (depending on the dopant) [74].

Also, ingot growth technology allows the increase in size of the wafers (multi or mono) from 156 mm semi-squared (M2) wafers up to 186 mm (M10) semi-squared or even 210 mm squared (G12); the ‘semi’ stands for rounded corners. That evolution implies more efficient manufacturing (more watts per unit) and has influence on the final size and optimized characteristics of the modules. 700-W-modules have been announced with such cell sizes [Source]. Current modules are rated at 400 W.

On the technological side, bigger size of cells allows new module interconnection configurations (half-cell or even third-cell) and the improvement in performance associated with that.

4.4.4 Cell technology

Common PV cell technologies entering volume production in chronological order are:

- BSF (Back Surface Field),
- IBC (Interdigitated Back Contact),
- PERC (Passivated Emitter Real Cell),
- TOPCon (Thin Oxide Passivated Contact),
- HJT (Heterojunction cells)
- and in the future, tandem cells (perovskite on c-Si).

Stabilized efficiency of leading mass production cells of these technologies, actual values and forecast, are shown in Figure 25.

Figure 25: Average stabilized efficiencies for Si solar cells in mass production. Source: [74]

The lowest efficiency (21%) corresponds to the only multi-crystalline silicon PERC technology. The same PERC technology applied to p-type mono-crystalline substrates is at 23%. Technology evolution will go up to 26% by 2030 and expected tandem cells will allow 2% more [74].

Cost reduction drove the change from mono- to multi-crystalline silicon substrates with BSF technology. Newer technologies like PERC or recent efficiency improvements (change from p-type to n-type substrates), the use of TOPCon or Heterojunction, have driven the need of mono-crystalline versus multi-crystalline substrates. The improvement in efficiency implied, makes them more profitable as generation capacity increases and the final cost per kWh decreases.

Figure 25 shows the efficiencies of PV cells of various technologies out of mass production, and their expected evolution. The expected introduction of tandem cells will raise efficiency significantly.

Tandem cells, or perovskite-silcon dual junction devices [75], are currently in their industrialization phase [76]. While perovskites (which occur naturally) are water-soluble, the issue seems to be contained in all-glass photovoltaic modules. The perovskite top cell converts blue and green, high-energy photons (wavelength 250-750 nm) into electrons; silicon transforms red and infrared, lower-energy photons (wavelength 600-1,200 nm) into electrons. The splitting of the solar spectrum and the conversion at two distinct bandgaps increases the External Quantum Efficiency (EQE), hence the conversion efficiency of sunlight to electricity [77]. The world record for perovskites is at 32.5% (2022, Helmholtz-Center [78]).

4.4.5 Photovoltaic modules

Modules processing evolution has gone in parallel with the PV cell improvements. Manufacturing costs have also been reduced from both the materials and the fabrication aspects as optimization and dimensioning of new fabs (see above).

Materials like glass, Aluminum or encapsulants have their own R&D. Interconnections, as a key process in module manufacturing, has developed various alternatives, including the use of 'shingled' cells, that do not need ribbons or multi-busbars. A novelty coming out of bigger size cells have been the half-cut or third-cut cells. This variety of cell sizes allows the improvement of PV module characteristics and give versatility on manufacturing of PV modules for applications as rooftop or other kind of PV integration.

Modules for power plants are over 3 m^2 in surface area and up to 40 kg in weight.

4.4.6 Bifacial cells and modules

An important improvement in cell technology evolution has been the bifaciality, inherent to some technologies as TOPCon or Heterojunction, but also manufactured as PERCs. The increase in final electricity generation due to the capacity of those cells of absorbing radiation in the front and the back, pays for the cost of needing a glass/glass or glass/transparent encapsulant. Bifacial cells manufacturing volumes amounted to half of the production in 2021 and are expected to reach 85% by 2032 [74].

Figure 26: Bifaciality factor of various PV technologies. Source: [74]

Bifacial modules are intrinsically heavier due to their encapsulation (glass/glass usually) and require specific design of the installation and radiation management (as some radiation should enter the backside of the module). Bifacial modules were already accounting for 27% of the total photovoltaic module production in 2021 and expected to be at 62% by 2032 [74]. The bifaciality factor, calculated as the ratio between rear side and front side efficiency (at STC) depends on cell technology and is shown in Figure 26. STC stands for Standard Test Conditions (1,000 W/m² irradiance, AM 1.5 spectrum and 25ºC). Final influence in the PV plant's energy production will be affected by the design of the plant (albedo, ground coverage, module elevation) and even operation in case of tracking and could achieve up to 30% increase in electricity generation.

4.4.7 Advances in PV system components and operations

There have been technology developments of all components of the PV plants, such as

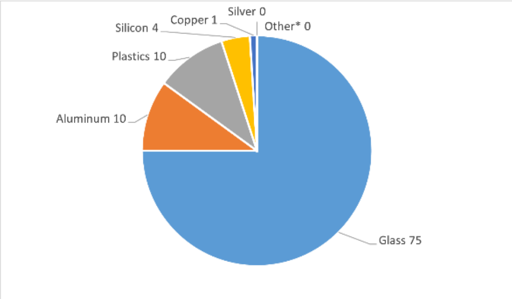
- with supporting structures, with the general installation trend of single-axis sun tracking in high-insolation regions,
- improvements in electronic equipment such as string or central inverters with DC/AC conversion ratio higher than 98% and 1,500 V maximum system voltage,
- control of the daily plant operation, with new capacities of digitalization for data management coming from the intelligence added to all components and aerial plant inspection (IR or EL) allow for the optimum production of solar power.

There are continuous and incremental improvements introduced into the design and manufacturing of cells and modules, and there are qualitative changes like tandem cells ahead. Power plant components see similar developments towards higher efficiencies.

The world record for the efficiency of a tandem device is 46.7%. Do not expect standard photovoltaic cells to reach this value anytime soon, but do expect the technology to continuously and steadily improve beyond 25% and towards 32% module efficiency.

4.4.8 Solar PV in the circular economy

Photovoltaic modules are decommissioned after a lifetime of 25 years or more. Modules must be collected, recycled and reintroduced into the circular economy, the process of manufacturing new panels [79]. The European Union (EU) sets targets for fractions to be recovered and recycled in the EU. The manufacturers and importers must provide panel data and are responsible for take-back and recycling since 2014 [80]. There are first recycling plants in Africa [81].



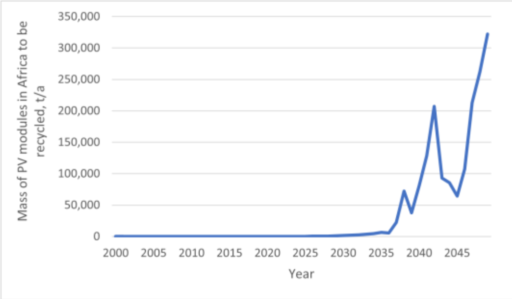


Figure 27: Material composition of a typical silicon PV module. Other* refers to electronics in junction box, anti-reflective coating, etc. Adopted from [82]

Figure 28: Mass of PV modules to be recycled in Africa, based on a lifetime of 25 years, and cost scenario in section 7

Material composition of PV modules changes over time and technology. Glass is by far the heaviest component; the metals silver and copper are the most valuable. The silicon wafer accounts for only 4% of the weight (Figure 52). Plastics, which are often laminated, tend to behave more difficult in the separation processes central to recycling and reintroduction into the circular economy.

Modules today have a specific power of 14 W/kg [82], which (with lifetime and nameplate capacity) allows for the calculation of the mass to be recycled now and in the future (Figure 28). There are efforts under way to increase the lifetime of solar panels to 50 years [73].

5 Estimation of the technical potential for PV and CSP

5.1 Solar power installations in Africa

There is a total of 7.9 GW of photovoltaic (PV) solar power plants, and of 1.1 GW of Concentrated Solar Power (CSP) plants installed in Africa in close to 4,000 projects, as of 2020, growing to 8.7 GW in 2021 [7]. The numbers in Figure 29 represent only large-scale, mini-grid, and C&I (Commercial & Industrial) installations, but do not include Solar Home Systems (SHS), nor residential units. Data does not include power plants under construction, only in operation.

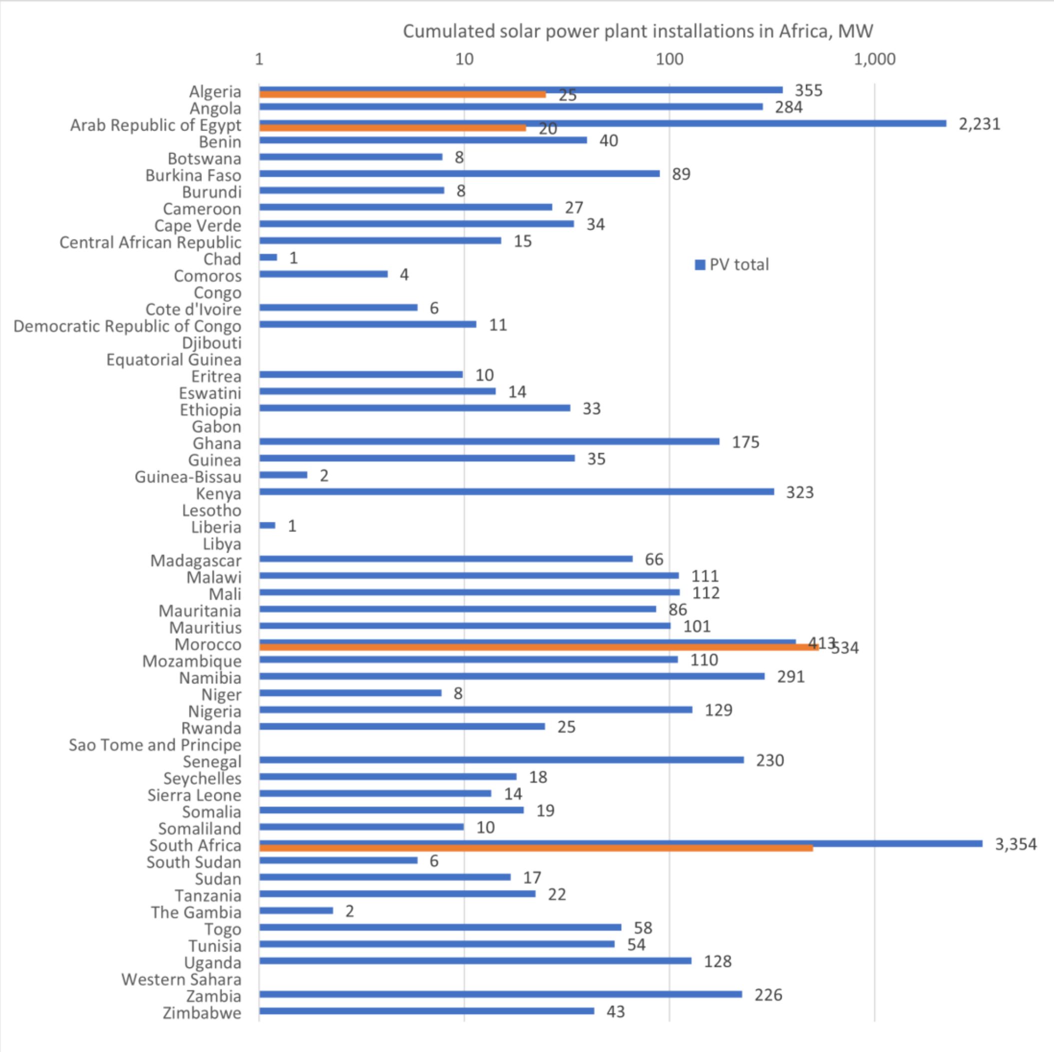


Figure 29: Total installed power of photovoltaic (PV) and Concentrated Solar Thermal (CSP) power plants installed in countries and regions of Africa, as of 2022. Figures represent large-scale, mini-grid, and C&I (Commercial & Industrial) installations. Logarithmic scale. Source: [83]

While the numbers are encouraging, nearly half (42%) of all solar power installations in Africa are located in South Africa. South Africa, Egypt, and Morocco together comprise 76% of all installations. In other words, 95% of all African countries share less than a quarter of all African solar power installations. Which is a very imbalanced distribution of solar energy generation on the continent.

With the world's total installation having passed 1,000 GW, total solar installations in Africa represent less than one percent of the global solar power installations.

5.2 Corporate and industrial PV installations (C&I)

Subject of this report are large-scale, concessional photovoltaic (PV) power plants. In recent years, Corporate and Industrial (C&I) PV installations (which are not concessional, but privately financed, and operate outside national grids) have driven the growth of installations in Africa.

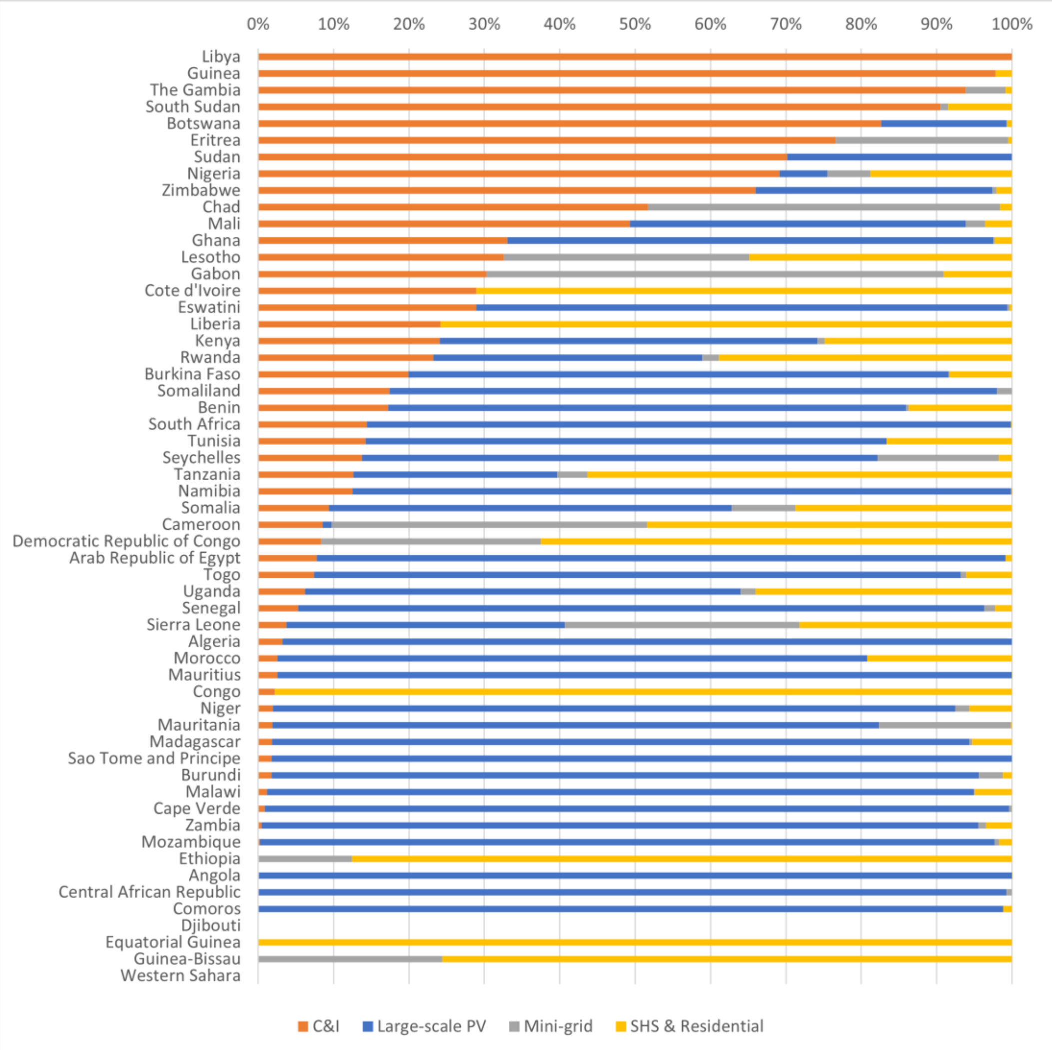


Figure 30: Percentage of Corporate and Industrial (C&I) PV installations in countries and regions of Africa, in 2022. Data: [83]

Total C&I installations in 2022 amounted to 1,181 MW (2021: 717 MW). C&I PV makes up for 26% of all commissioned PV installations in 2022, the average size per installation was 1.15 MW in 2021 [84]. C&I grows at an annual rate of 61.5% (2021: 23.8%), when PV in general in Africa grows only at 13.8% (2021: 9.0%) [84]. C&I grows at the speed of global PV and is the main driver in African solar growth.

In several countries and regions in Africa, C&I installations dominate the market, as shown in Figure 30. There are no timeseries of this data available, but it will be interesting to track the C&I installations to indices like grid status, industrial development, and Gross Domestic Product (GDP) in order to derive dependencies.

5.3 Africa's solar resources

Solar radiation consists of two fractions, the direct (beam) fraction, and the diffuse fraction. Direct radiation creates shade, diffuse radiation is isotropic, appearing equally strong from any direction. The direct and diffuse fractions are measured by satellite instruments, calculated, and collected in databases like PVGIS [85] [86] and SolarGIS [3]. The fractions are stored as Direct Normal Irradiance (DNI), and Diffuse Horizontal Irradiance (DIF). The unit typically is kWh/(m² day), for the long-term daily average.

Concentration requires solar beams to be redirected and focussed, only DNI can be concentrated, and Concentrated Solar Power (CSP) can utilize DNI only. The parabolic troughs and heliostat mirrors of CSP plants track the sun.

Photovoltaic (PV) power generation converts both the direct and diffuse fractions of solar irradiance into electricity. Tracking helps in collecting the beam fraction, increasing the energy yield. If PV modules are installed in fixed-tilt mode (not tracking), they should be oriented towards the sun in the optimum way, again collecting as much of the beam fraction as possible by having the optimum tilt angle.

The optimum tilt angle is near zero for PV installations at the equator, whereas further south panels look north, and at latitudes further north, panels are oriented towards the south. The sun appears in a band set by the declination ±23.45°, and the optimum tilt angle will consider these positions and climate conditions at the location.

Combining DNI and DIF fractions, for an optimum tilt angle, results in the Global Tilted Irradiance (GTI, kWh/(m² day)).

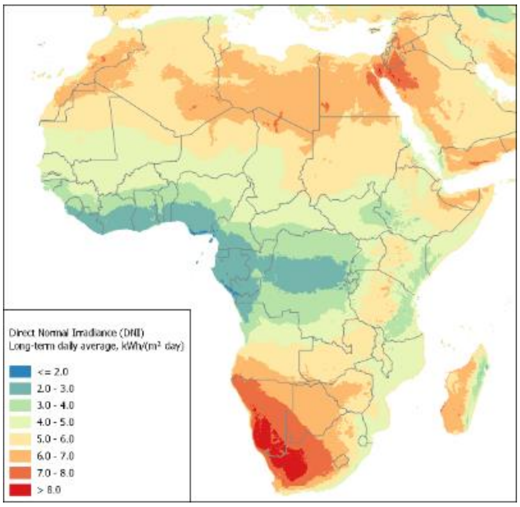


Figure 31: Direct Normal Irradiance (DNI), resource for Concentrated Solar Power (CSP). Data: [3]

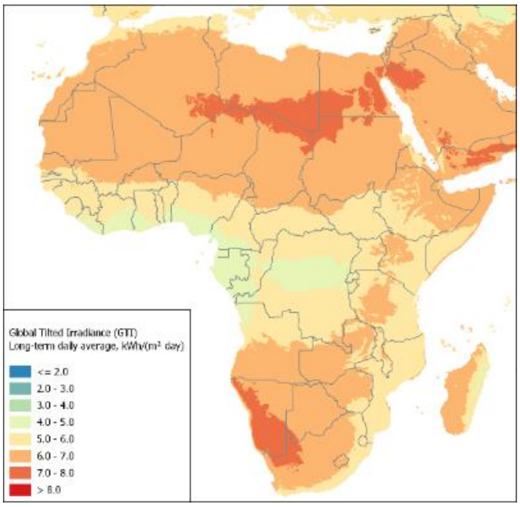


Figure 32: Global Tilted Irradiance (GTI), resource for Photovoltaic (PV) power plants. Data: [3]

The distribution of the direct irradiance DNI over Africa allows preselecting suitable sites for CSP plants. The distribution of global irradiance on a tilted surface GTI allows preselecting the best sites for the installation of PV power plants.

Most locations in Africa outside the tropical rainforest areas are blessed with excellent irradiance conditions. From the maps in Figure 31 and Figure 32, the best areas for solar power installation are the Sahara and Namib deserts, as well as the higher elevations along Rift Valley and the Horn of Africa. It should be noted that local conditions could be far from the long-term average. Every power plant needs to have its own design.

Africa’s solar power potential is practically unlimited, as we have shown in Figure 2. Serving the energy needs of the continent, and even of the world, is possible – there are no restrictions regarding area or resource. Solar is the perfect path to power.

5.4 Resource variability (solar radiation)

Solar irradiance data can change in a matter of seconds when a cloud moves between the module/mirror and the sun. In the case of PV, electricity production of the shaded module will drop by up to 90%. The drop in local performance is equivalent to the fraction of direct radiation to total radiation; after the cloud moves in, only diffuse radiation reaches the panel. Only direct radiation can be concentrated.

In the case of CSP, the mirrors cease to see any direct light, concentration will be off. The CSP plant is inert, as the working fluid stays hot and keeps the power cycle operating. With storage integrated, changes of irradiance on the scale of seconds or minutes should not be changing the output power of the system.

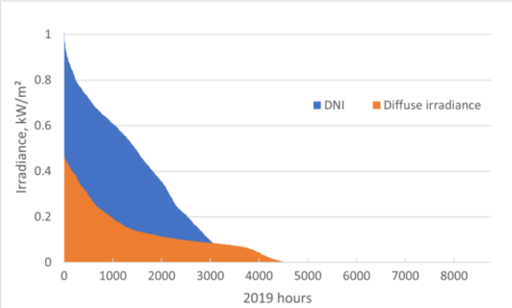


Figure 33: Histogram of hourly Direct Normal Irradiance (DNI) and Diffuse Irradiance on a tilted plane, for Cuamba. Source: [87]

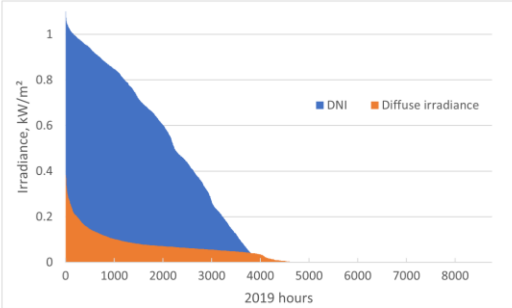


Figure 34: Histogram of hourly Direct Normal Irradiance (DNI) and Diffuse Irradiance on a tilted plane, for Noor II. Source: [87]

Table 5: Solar irradiance values for Cuamba and Noor II. Irradiance on an optimum tilted fixed plane

	Cuamba	Noor II
Latitude, degree	-14.80	31.01
Direct Normal Irradiance (DNI), kWh/(m² a)	1,470	2,230
Diffuse irradiance, kWh/(m² a)	630	370
Total irradiance, kWh/(m² a)	2,100	2,600
Direct fraction on total irradiance	70%	85%

The fraction of direct irradiance on total radiance differs for location. Figure 33 and Figure 34 compare the hourly Direct Normal Irradiance (DNI) and the Diffuse irradiance for Cuamba, Mozambique, and Noor II in Morocco. Clearly, Noor II receives more DNI than Cuamba, the fractions of DNI on total irradiance are 70% and 85%, for Cuamba and Noor, respectively. The total irradiance in Noor is 1/4 higher than in Cuamba, as shown in Table 5.

Clouds scatter incoming radiation, increasing the fraction of diffuse irradiance. Clouds also reflect some of the incoming radiation back into space, reducing the total irradiance that reaches the ground. Thus, arid climates have higher direct and total irradiance numbers, while subtropical and tropical climates are characterized by high diffuse fractions. Noor II and Redstone are located in the so-called sun belts of the globe, which are known for their deserts.

We should also note that the number of solar hours (half a year, 4,380 hours) is the same for any location on Earth. The seasonal distribution of the solar hours over the year can be very different, but Africa does not reach high latitudes. Seasonal variations are less extreme than on any other continent.

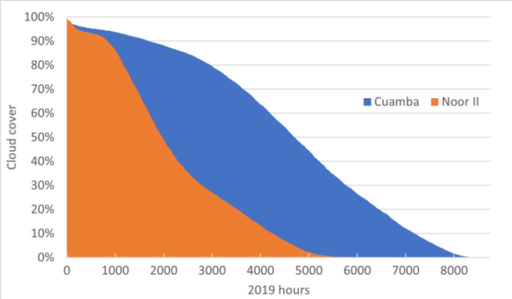


Figure 35: Cloud cover for 2019 in Cuamba and Noor. Data sources: [87] [88]

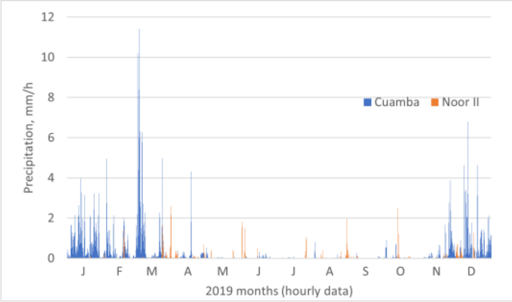


Figure 36: Hourly precipitation for 2019 in Cuamba and Noor. Data sources: [87] [88]

Some modules or mirrors of large power plants may see some clear sky, even on a cloudy day. However, there are overcast days, even in the best solar locations, as shown in Figure 35 for the site of the PV plant in Cuamba, Mozambique and the CSP Noor II plant in Morocco. Data [87] [88] has been simulated, note that it includes night hours. Data collected at Ouarzazate Airport, about 5 km from the Noor plant, shows an average of two days of precipitation per month year-round [89], though total precipitation is only 140 mm per year. The precipitation in Cuamba is ten times as high, though concentrated in a distinctive wet season from November to April (Figure 36).

5.5 Advancing solar installations

Modelling might continue beyond the current capabilities towards the choice of location and design parameters of solar power plants. Will it make sense to install CSP or PV? How much storage is required? What are the technical parameters (such as tracking)?

The choices in installing power plants are complex, as non-technical decision parameters need to be incorporated in public power plants.

The Continental Power System (Transmission and Generation) Masterplan (CMP)

will indicate a roadmap to ultimately integrate the continent through the creation of an integrated and sustainable continental transmission network within the context of AU Agenda 2063. The subsequent infrastructure development will link all the power utilities within each regional power pool, interconnect the regional power pools and ultimately connect the continent to Europe, the Middle East and Asia through existing and planned interconnectors. [90]

Developments in the power will need to be 100% renewable to meet climate goals and attract foreign assistance. With only 28% of healthcare facilities in Sub-Saharan Africa having access to reliably electricity [91], rural electrification is a priority. A map of healthcare facilities and grid in western Zambia is shown in Figure 37. An example of how the community is integrated is the Jasper PV plant, described in the section of Technology Cases.

Development goals may work best if a sustainable industry base is built providing the demand for sizable solar power plants. Industrial clusters can be the nuclei of growth and wealth, providing the basis for sustainable development. Carbon-intensive industries like cement can be retrofitted with solar power. Mines are occasionally equipped with private solar power plants (Figure 38). Corporate & Industrial (C&I) solar power plants are proving a way to add electricity infrastructure beyond the existing utility structure, which is burdened by inefficient generation assets and uncreditworthiness.

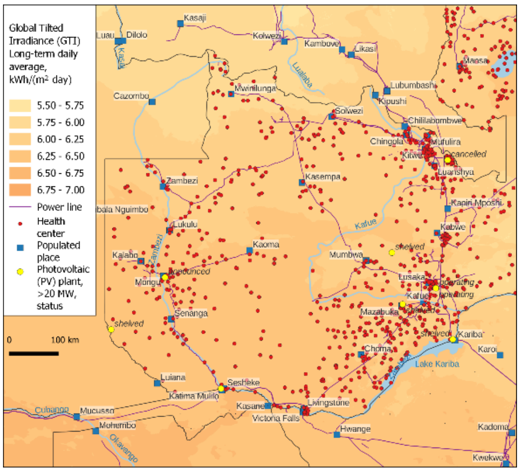


Figure 37: Healthcare facilities and grid in western Zambia. Source: [92]

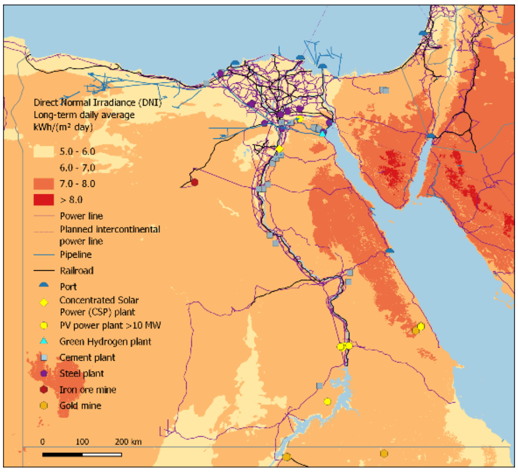


Figure 38: Industrial base and infrastructure of Egypt. Source: [20]

Socio-economic layers integrated into the modelling may provide additional parameters for informed and strategic decision-making. The Geographical Information System (GIS) can provide visualization and calculation tools. A concise effort to generate the data required should be undertaken.

Africa is blessed with an abundance of solar irradiance, which can be employed through modular PV in an entrepreneurial power generation infrastructure, potentially with local access, and also large-scale provision of carbon-free renewable power in an industrial setting. Solar electricity can be exported directly or be converted in value-added products.

Dependence on fossil fuels disappears. Photovoltaics power is the cheapest source of electricity, costs are continuing to fall. PV will be combined with battery storage, and with the grid to provide reliable electricity around the clock, all year, every year.

6 Performance of solar power plants

6.1 Capacity factors

6.1.1 Definition and assumptions

The capacity factor CF of a generator is a dimensionless number giving the ratio of energy actually generated E_g in a time period t over the fictious energy E_f that could be generated in the same time period:

$$CF = \frac{E_\mathrm{g}(t)}{E_\mathrm{f}(t)} = \frac{E_\mathrm{g}(t)}{P_\mathrm{inst}\ t},$$

where P_inst is the installed (nameplate) capacity of the generator. Time periods can be anything, typically seconds, hours, or one year. A generator must be understood as power plant, or as a group of power plants in a region. The region defines the model sizes.

The energy generated by a solar power plant depends on the irradiance and the efficiency of the conversion technology. Hence, comparisons of CFs can show technological advances in history or comparative advantages between conversion technologies.

In Table 6, components and parameters influencing the calculation of capacity factors are listed.

Table 6: Components and parameters in the calculation of capacity factors

Capacity Factor component	Parameter
Irradiance	Weather – Climate
Region (model size)	Case – Country – Power Pool – Africa
Generator technology	PV – CSP – VRE (other Lots)
Integration	Hybridization – Storage – Grid
Technology road map	Efficiency – O&M – Cost
Granularity (time period t)	Hour – Day – Month – Year (season)

Solar energy is an intermittent energy source, the irradiance varies significantly over any period of time. While we understand intuitively that the irradiance can change rapidly due to clouds, recent climate changes cause monthly values of irradiance for whole countries to differ by 40-50% from the long-term average (see section 5.1).

Assumptions in the following analysis include the following:

- Data used is freely available [87]. The simulations follow the approach of [93]. Numbers are based on long-term satellite observations and the global reanalysis model MERRA-2 [87] [94] [89].
- Data does not include scheduled or unscheduled downtime, e.g., for maintenance of the plant;

- Data does include an across-the-board 10% system loss, but does not account for system parasitics, i.e., energy generated and later used by the plant itself.

Simulation results are based purely on solar irradiance data. They are normalized for power plant nameplate capacity.

6.1.2 Granularity (time slices)

The capacity factors of solar power generation depend on the amount of aggregating and averaging done during the preparation of data. Solar irradiance data is collected by satellite observations in minute intervals. Hourly data is summarized from the minute data. This data is made available to users. Hourly data is then summarized to create daily data, which can be averaged to monthly average daily data, and even yearly data.

We illustrate hourly capacity factors for the PV plant Cuamba, Mozambique in their distribution over the year 2019, in Figure 39. Though the data gives a clear indication of the yearly distribution, ordering the same data in a histogram as in Figure 40, gives a frequency distribution of the hourly capacity factors. Capacity factors can be compared in the histogram representation.

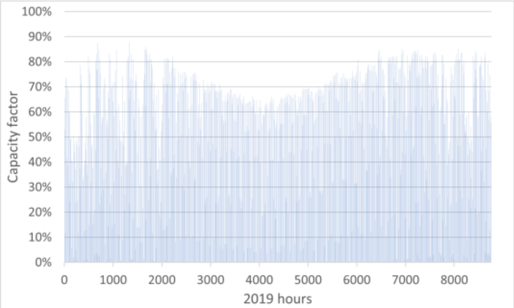


Figure 39: Simulated capacity factors for PV power plant in Cuamba, Mozambique; hourly distribution for 2019. Data source: [87]

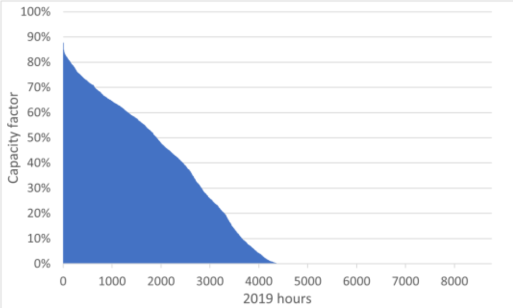


Figure 40: Simulated capacity factors for PV power plant in Cuamba, Mozambique; hourly distribution histogram 2019. Data source: [87]

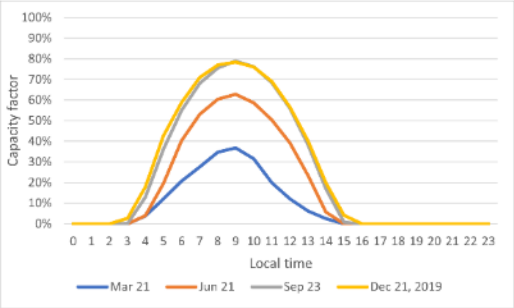


Figure 41: Simulated capacity factors for PV power plant in Cuamba, Mozambique; hourly distribution during four days in 2019. Data source: [87]

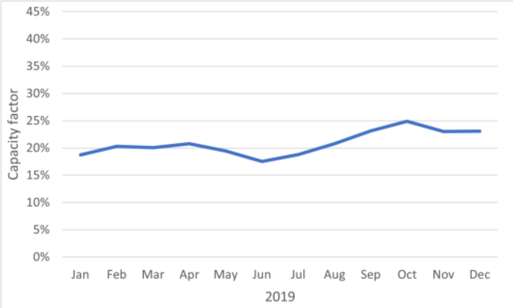


Figure 42: Simulated capacity factors for PV power plant in Cuamba, Mozambique; monthly averages for 2019. Data source: [87]

In the histogram, the actual distribution over the day gets lost. Selecting daily profiles of capacity factors can help understand seasonal variations, and extreme days, without having to look at all 365 days in the year and year-on-year variations (as an automated model will do).

The capacity factors for the solstice days (Jun-21, Dec-21) and for the equinox days (Mar-21, Sep-23) in Figure 41 show the capacity factor for Mar-21 to be well below the other three, hinting at a day in the rainy season. Celestial mechanics will not be the reason for the low CF of Mar-21, as Dec-21 and Sep-23 stand in the same relation of solstice/equinox and do have very similar CF profiles.

Looking at the monthly capacity factors in Figure 42 implies a uniform capacity of solar power production in Cuamba. From the indications in Figure 41, and the details from the data in Figure 39, we can deduct significant daily variations, which may well correlate with the precipitation shown on Figure 36. The yearly capacity factor for Cuamba is 17.9% (2019) [87]; this number is void of all details on irradiance variations. It does not suit itself for in-depth planning of the power infrastructure in the region.

Assuming that solar power generation should be uniform in the face of demand, there are two options, firstly employing storage options to moderate the variations in irradiance, and, secondly enlarging the model size, increasing the number and geographic divergence of generators. The second option is equivalent to grid connection.

Hence, we find that the installation of storage and the connection of generators to a common grid follow the same goal, which is moderating power fluctuations.

6.1.3 Regions and model size

Connecting solar power plants over long distances in East-West direction extends the daily availability of the group of power plants by one hour per each 15° in longitude. As Earth rotates by 360° in 24 hours, 15° equals one hour. The African continent stretches over the equivalent of five hours of longitude.

Connecting solar power plants over long distances in North-South direction moderates seasonal variations of the combined capacity factors and combined energy generation.

Any bundling of VRE power plants over any area can homogenize the energy output of the power plants, reducing the effects of the local weather conditions.

6.1.3.1 East-West grouping: extension daily availability

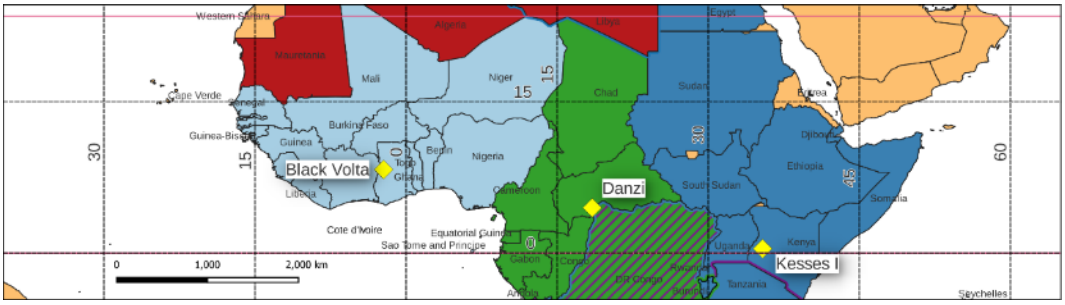


Figure 43: Africa between the Equator and the Tropic of Cancer at 23.45°N, with 15-degree latitude and longitude lines, and the three solar PV plants Black Volta, Danzi, and Kesses I

The locations of the cases Black Volta, Danzi, and Kesses I stretches over 37°. The PV plant at Kesses generates power approximately three hours before the PV plant Black Volta sees the dawn approaching. Looking into the simulation data (Figure 44 and Figure 45) reveals possible 15 hours of solar energy production, three hours longer than the 12 hours to be expected for Sep 23, one of the equinox days.

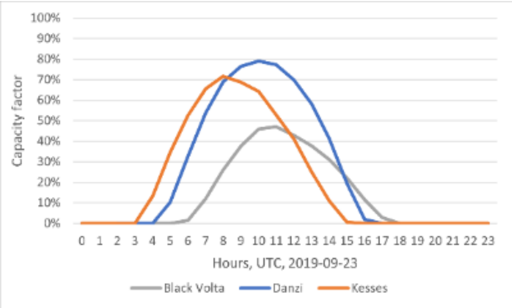


Figure 44: Hourly capacity factors for 23 Sep 2019, simulated, for the PV plants Black Volta, Danzi, and Kesses I, UTC time. Source: [87]

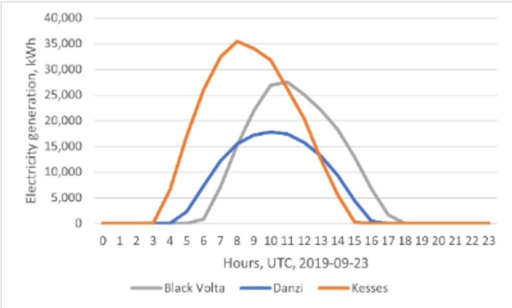


Figure 45: Hourly energy generation for 23 Sep 2019, simulated for the PV plants Black Volta (65 MW), Danzi (25 MW), and Kesses I (55 MW), UTC time. Source: [87]

6.1.3.2 North-South grouping: complimenting seasonal fluctuations

Africa extends to both sides of the equator, so seasonal effects on solar capacity factors are expected. A high-level comparison of the monthly capacity factors for the CSP power plants Noor II in Morocco (at latitude 31°N) and Redstone in South Africa (at 28°S) reveals a complimentary match of the two curves in Figure 46. The figures consider the solar fields of the plants, not the efficiencies of the turbines.

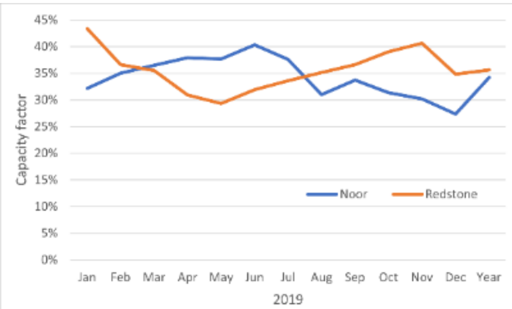


Figure 46: Monthly capacity factors for the CSP power plants' solar fields Noor II and Redstone. Source: [87]

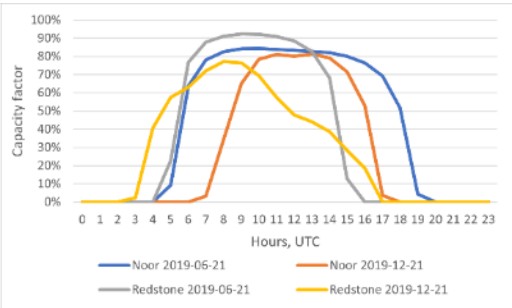


Figure 47: Hourly capacity factors for the solstice days of 2019, for the CSP power plants' solar fields Noor II and Redstone. Source: [87]

The seasonal match can also be observed on the daily level. Figure 47 shows the hourly capacity factors of the CSP plants Noor II and Redstone for the solstice days. The December solstice day in Redstone must have had bad weather, reminding us that variations are real, but otherwise, seasonal performances are mirrored at the equator, so to speak.

The East-West distance between Noor and Redstone is almost 30° in longitudinal difference, amounting to two hours of additional operational availability, if the two plants were connected by a grid (Section 6.1.3.1).

6.1.3.3 National capacity factors

Data on installed power capacity, and on energy generated is available for African nations for a period of twenty years [95]. National energy systems can be dominated by a single source of electricity generation (Central African Republic, Figure 48) or can have a full range of generation technologies (South Africa, Figure 49). Yearly capacity factors aggregate information, and cannot show any diurnal, or seasonal information. We conclude that hourly capacity factors must be used for a meaningful analysis involving regional groupings, such as Power Pools, or the African continent.

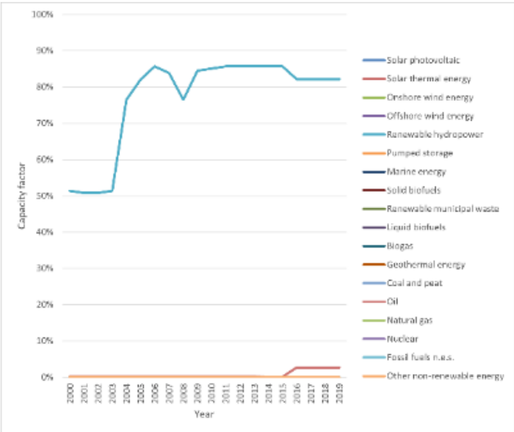


Figure 48: Annual capacity factors 2000-2019 for power generation in the Central African Republic. Source: [95]

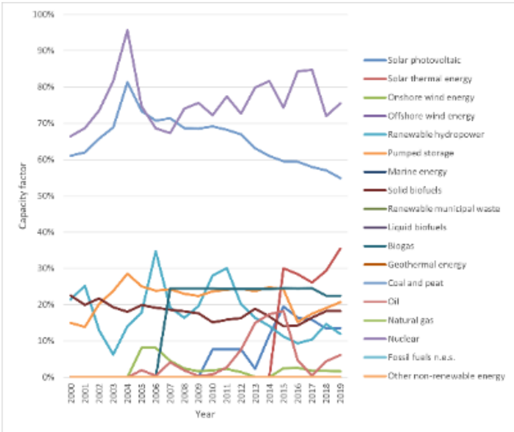


Figure 49: Annual capacity factors 2000-2019 for power generation in South Africa. Source: [95]

6.1.4 Technology advances

Technology advances will improve the capacity factors of the solar power plants. Technology advances will reduce the required size of the solar field to generate a given amount of energy, when compared to the current state of the technology. An increase of the efficiency of a photovoltaic module does not change the capacity factor itself, but when seen in a comparison to an existing plant of the same area, the energy generated increases, and with it the capacity factor. It is important to set a base value when setting out to show the impact of advances in technology on capacity factors.

The increase of capacity factors together with technology advances shall be described using the examples of the Inverter Loading Ratio (ILR, section 2.4), and single-axis tracking. The following numbers are not from actual plant designs, but are meant to illustrate the design parameter options.

6.1.4.1 Capacity factors and Inverter Loading Ratio

The photovoltaic field is often oversized in relation to the inverter. The rationale is to operate the power plant at the rated power of the inverter for extended periods of time, instead of only occasionally loading the inverter with power near its capacity. The efficiency of the inverter is highest near its capacity. The risk of this design is that the output power of the field will be curtailed by the capacity of the inverter during periods of exceptional high solar radiation regimes.

A typical ILR value is 1.25, meaning that the solar field will have a nameplate capacity of 1,250 W/m² at Standard Testing Conditions (STC) facing the inverter's capacity of 1,000 W. Solar irradiance at STC corresponds to 1,000 W/m², a value rarely reached.

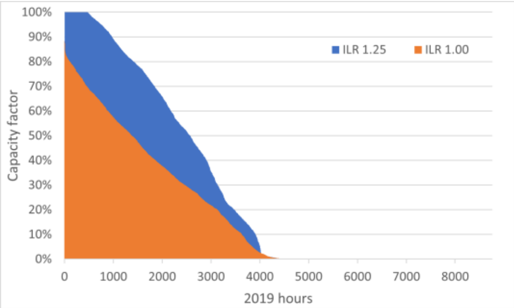


Figure 50: Hourly capacity factors 2019 for two Inverter Loading Ratios (ILR), for the solar irradiance at Kesses I

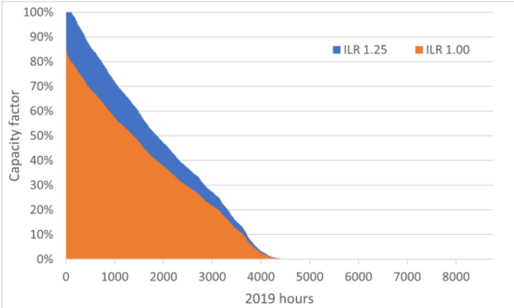


Figure 51: Hourly capacity factors 2019 for two Inverter Loading Ratios (ILR), for the solar irradiance at Jasper

The ILR improves the capacity factor of the power plant independently of the irradiance regime, as shown in Table 7, for the Kesses I and the Jasper PV plants. Curtailment of radiation by the limit of the inverter eliminates 1.3%, and 0.1% of the potential energy generation in the case of Kesses I, and Jasper, respectively.

6.1.4.2 Capacity factors and tracking

Tracking the sun increases the capacity factor, shown in Figure 52 and Figure 53, for the cases Kesses I and Jasper. If a photovoltaic module, or a mirror/heliostat of a CSP plant at all times remains oriented normal to the sun, achieved by two-axes tracking, it collects the maximum possible irradiance. In solar locations characterized by a high fraction of direct irradiance (Jasper), the angular orientation of the panel towards the sun makes a greater difference than in locations where the diffuse fraction of sunlight is notable (Kesses I).

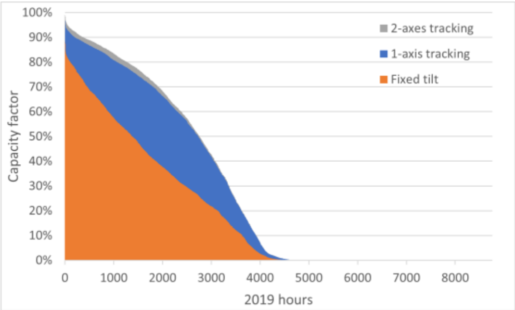


Figure 52: Hourly capacity factors 2019 for the Kesses I PV plant (1-axis tracking installation), and hypothetical power plants with fixed tilt and 2-axes tracking at the same location

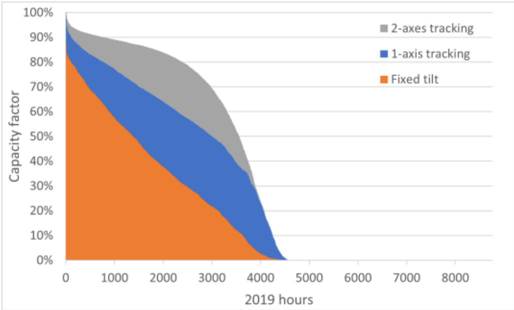


Figure 53: Hourly capacity factors 2019 for the Jasper PV plant (fixed tilt installation), and hypothetical power plants with 1-axis and 2-axes tracking at the same location

Table 7: Improvements of annual capacity factors for solar irradiance regimes for the PV power plant cases Kesses I, Kenya, and Jasper, South Africa. Note that the increase of the Inverter Loading Ratio (ILR) can increase the plant's capacity factor independently of DNI, whereas tracking increases the capacity factor over proportionally when DNI is exceptional (as in the case of Jasper), solar data [87]

Kesses I		**fixed tilt 0°**	**ILR 1.25**	**1-axis**	**2-axes**
Annual direct normal irradiance (DNI)	kWh/(m² a)	1,598	1,598	2,122	2,205
Annual diffuse irradiance	kWh/(m² a)	667	667	649	649
Annual capacity factor	-	22.8%	28.1%	27.6%	28.3%
Jasper		**fixed tilt 23°**	**ILR 1.25**	**1-axis**	**2-axes**
Annual direct normal irradiance (DNI)	kWh/(m² a)	1,462	1,462	2,570	3,303
Annual diffuse irradiance	kWh/(m² a)	366	366	375	395
Annual capacity factor	-	18.2%	22.7%	29.1%	35.6%

A 'normal' orientation to the sun, where the panel faces the sun at an angle of zero degrees, is most efficient. Once the panel is tilted in respect to a direct line to the sun, it intercepts the beam of sunlight at an angle, making the sunlight less dense by a factor of the cosine of this angle. This is termed the cosine-effect. If the panel is tilted by 45°, the density of sunlight cannot exceed 70.7%; and if the incidence is grazing, i.e., panel surface and line to the sun form a right angle, only very little sunlight reaches the panel.

On top of the cosine-effect, there is an angular dependency of the absorption of direct sunlight on the panel. Light impinging at angles greater than 60° are increasingly being reflected away from the panel surface.

Furthermore, it makes a difference for tracking, if the panel rows are installed in North-South, or East-West direction. For one-axis tracking, N-S orientation requires azimuthal (daily) tracking between -90 and +90 degrees. In the case of E-W orientation and one-axis tracking, the elevational tracking is between -23.45 and +23.45 degrees, compensating the ecliptic in celestial mechanics (which is responsible for the seasons, of course).

Two-axes tracking compensates both azimuthal and elevational angles, the panel is always oriented normal to the sun. The cosine-effect is zero for two-axes tracking. Mechanical solutions are most complex for two-axes tracking (compare the heliostats in the case of the Redstone CSP plant versus the parabolic troughs in the Noor II case). For PV plants, one-axis tracking is a good compromise between complexity and additional energy collection.

Tracking can improve the capacity factor of the solar power plant significantly (Table 7). The positive effects of tracking are particularly noticeable in solar regimes characterized by a very high direct fraction of radiation, as in South Africa.

90% of new PV power plants in the United States were installed with one-axis tracking (2021, [49]), with minuscule higher cost that fixed-tilt installations.

6.1.4.3 Capacity factors and further technical improvements

Optimization of the Inverter Loading Ratio (ILR) and the introduction of one-axis tracking has happened over last two decades. There are several other technologies making inroads from the laboratory into the field, including bifacial cells, and tandem devices (devices made of two stacked cells, with perovskite technology being the leading candidate). Multi-junction devices (several stacked cells improving the coverage and conversion of the solar spectrum) appear feasible in the mid-term future, as they have been tested in Concentrating Photovoltaics (CPV).

Concentrated Solar Power (CSP) is marked by increasing capacity factors (Figure 54) over the decade 2010-2020, based on technological advances of a limited number of installations in only the best locations on earth. From Figure 12 and Figure 63, respectively, there are 1,013 MW of CSP, and 13,000 MW of PV installed in Africa.

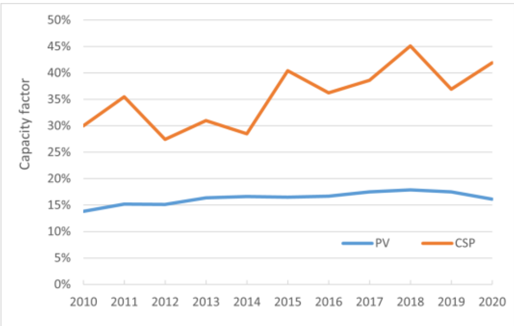


Figure 54: Capacity factors of PV and CSP power plants installed worldwide. Source: [31]

The picture for PV is more complex: over the last years, the capacity factor is decreasing in the world's PV installations. This can be explained by the large number of PV installations in regions of less favourable irradiance. See [49] for the explanation in the American case. The effects of radiation regime on capacity factor are also implied by the Technology Cases presented in this report.

A road map summarizing technology and cost trends in PV and CSP follows the discussion of capacity credits.

6.2 Capacity credit analysis

6.2.1 Introduction

This section evaluates some of the methodologies that are used to calculate the capacity credit of different power generation facilities with a focus on their applicability to solar PV. Strictly speaking, the term *capacity credit* refers to the degree to which a generator can contribute to resource adequacy. Mathematically, the capacity credit of a given generator is measured in terms of its physical capacity relative to its nameplate capacity and can be denoted as a whole number or a percentage. For instance, a generator with a nameplate capacity of 100 MW could have a capacity credit of 80 MW or 80% [96]. In practice, the calculation of capacity credits is often conducted to estimate how effectively and reliably (i.e., predictably) a given generator can contribute to meeting a given power system's peak demand.

Every power system needs to have sufficient generation capacity to meet demand, including during times of high demand, or of low solar or wind availability; failure to do so results in power outages or in a loss in power quality for electricity customers. Since both the magnitude and the shape of power demand is influenced by multiple variables including weather, the level of industrialization, the underlying rate of economic growth, as well as idiosyncratic factors such as public holidays, power system planners need to ensure that there is always a sufficient reserve margin to meet power demand reliably 24-hours per day, 365 days per year. As the share of variable renewable energy resources like wind and solar power has grown over the last three decades, many utilities and power system planners have therefore sought out ways to assess the impact of these technologies on their generation capacity needs [97]. One of the tools that utilities and power system planners use to ensure this is the calculation of a generation technology's capacity credit.

This analysis provides an overview of the various methodologies used to calculate capacity credits, starting with an overview of their benefits and shortcomings.

6.2.2 Capacity credits: Benefits and shortcomings

Capacity credits can provide a number of benefits:

- They provide a comparable metric that can be applied across different generation technologies despite the latter's different operating characteristics.
- Capacity credits can be used across various power systems, climate zones, seasons, and locations.
- Capacity credits serve as an important metric for market participants to demonstrate compliance and to ensure that generators are adequately compensated for the capacity they provide.

- Furthermore, depending on the power market, capacity credits can provide an additional payment to different generation technologies, adding to the revenues earned in energy-only markets.

- However, there are several important issues with capacity credits:

- Capacity credits are based on the operating characteristics of conventional thermal power plants: as such, they do not apply as well to weather-dependent renewable energy technologies like solar, wind, or even certain forms of hydropower (due to its seasonality).

- Capacity credit methodologies frequently overstate the reliability of conventional power plants such as coal, gas, and nuclear. As France has recently seen, with over half of its nuclear fleet offline [98] [99], and Texas where much of the natural gas plants in the state went offline due to unusually cold weather causing damages in excess of USD 100 billion [100], the costs of the unreliability of conventional power plants can be substantial. Also, as low water levels caused by drought undermine the ability of conventional generation plants to operate in many parts of the world [101] [102], the ability of conventional generation plants to meet system adequacy needs is arguably below what is commonly assumed in capacity credit calculations.

- For renewable energy technologies like solar PV, the capacity credits change dynamically over time as the share of solar PV in the power system grows. Calculations run in Oman (total installed generation capacity of 6.372 MW, predominantly gas-fired) resulted in a capacity credit for the first 500MW of new solar PV added to the grid of roughly 24% (or 120 MW). By contrast, the addition of subsequent 500 MW tranches of solar PV gave declining capacity credits of 20%, 15%, 10%, and 5% [103]. Similar results were found in a collection of earlier studies [104] as well as in a detailed analysis conducted for California [105].

- Capacity credits understate (or ignore altogether) the potential for demand-side flexibility as well as the growing importance of storage. If a given power system in Africa were to increase the flexibility of its load and shift more cooling load to the daytime (for instance), it could counteract the decline in the capacity credit value of solar PV by enabling solar to make a greater contribution to serving load, and hence to meeting resource adequacy requirements. In practice, this means that the capacity credit awarded to technologies like solar is not fixed in time, or universal across power systems: it is location-specific and changes as a function of the demand curve and overall power system flexibility. The more utilities, customers, and other stakeholders increase the flexibility of grid-connected loads, the higher the capacity credit technologies like solar PV can achieve.

- A further challenge with capacity credits is that improperly applied capacity credit calculations can lead to market distortions and may result in under- or over-investment in certain power generation technologies, as well as higher costs to utilities and their customers, as well as distortions in terms of the locations where investments occur.

- Capacity credit calculation methodologies are applied inconsistently across different jurisdictions, frequently leading to misunderstanding and to disagreements among stakeholders [106].

Improving the Capacity Credit of Solar PV in Evening-Peaking Power Systems
One additional challenge faced by many jurisdictions in parts of Africa, and in particular in sub-Saharan Africa, is that due to the relatively low level of industrial power demand drawn from the grid (many mines and other large industries like cement factories self-supply), the power demand peak occurs in the early evening hours when the sun is setting and solar output is declining (from 18:00 – 21:00). In such power systems, solar PV's ability to contribute to peak demand (and hence, to be awarded a high capacity credit) is limited, making many utilities reluctant to substantially scale-up solar, at least in the absence of storage. This reluctance is one reason why many utilities and power system operators throughout Africa are keen to develop CSP projects, as such projects are often coupled with storage that can help meet electricity demand when supply is needed most. A number of CSP projects have been built in Morocco and in South Africa (see Figure 3), and a number of new projects are being planned. Compounding this challenge is that many power systems throughout Africa experience significant load shedding in the early evening hours due to a complex range of factors including rapid urbanization, sustained population growth, insufficient generation capacity, limited interconnectedness, low appliance efficiency, and insufficient demand-side flexibility. In such contexts, the capacity credit attributed to technologies like solar PV is therefore artificially low, as solar frequently contributes only minimally to meeting peak system demand. Overcoming this mismatch is arguably critical to a sustained scale-up of solar PV on the African continent. Against this backdrop, utilities and system operators have several options: they can take measures to increase the flexibility of demand, shifting more power demand to the daytime hours, such as via variable electricity tariffs that feature lower tariffs during the daytime; they can add storage of any of a variety of forms including thermal, battery, mechanical, or other; and they can expand interconnections with neighbouring jurisdictions, among others.

The next section provides a more detailed overview of the main methodologies for calculating capacity credits. Further details including various formulae are provided in the Appendix.

6.2.3 Capacity credit: Calculation methods

There are multiple methodologies that can be used to estimate the capacity credit of different generation technologies. The methods used will differ based on one's specific needs, the availability of key input data, as well as the available computational resources. These methodologies can be broken down to two broad categories:

1. Methods to estimate the capacity credit *ex-ante* (i.e., before the fact) – ex-ante methods include two variations, the reliability-based approach as well as the approximation-based approach; and

2. Methods used to estimate the capacity credit *ex-post* (i.e., after the fact) – also referred to as the chronological method [107].

The analysis below provides an overview of these different methodologies as well as their respective strengths and weaknesses.

6.2.3.1 Ex-ante calculations methods

6.2.3.1.1 Reliability-based methods

Reliability-based methods use probabilistic resource adequacy tools to quantify the risk of being unable to serve demand at all times. These methods use power system reliability techniques based on metrics such as loss of load probability (LOLP), which refers to the probability of a loss of load event in which demand on the system exceeds generating capacity during a given time period; loss of load expectation (LOLE), which is the number of hours during a planning period (e.g. one year) that load will not be met; and expected unserved energy (EUE), which is the expected amount of energy that a generator is unable to supply due to a capacity deficiency [107] [108]. These metrics are based on inputs such as generator information, hourly demand and transmission grid data. Many reliability models rely on Monte Carlo analysis, in which random states of the conventional generation (i.e., maintenance, failure, and normal operation) and random external factors (such as grid conditions and weather) are sampled repeatedly to determine the probabilities of different outcomes.

There are three main reliability-based methods for estimating capacity credit which are based on calculating the following metrics:

1. Equivalent Conventional Power (ECP) – this metric refers to the amount of a new generating technology (e.g., solar PV) that can replace an existing generator of a different technology (e.g. gas-fired power plant) while maintaining the same level of system reliability. The capacity value for the new generator is measured in terms of a conventional dispatchable generator.

2. Effective Load-Carrying Capability (ELCC) – this metric refers to the amount a given power system's load can increase while maintaining the same level of reliability following the addition of a new generator. (Both California and the Midcontinent Independent System Operator (MISO) use ELCC and PJM, Southwest Power Pool (SPP) and Northwest Power Pool (NWPP) are currently exploring it as part of their calculations of capacity credit [109].

3. Equivalent Firm Capacity (EFC) – this method refers to the amount of a theoretical, fully-reliable generation technology that can replace an existing/new generator (e.g., solar PV) while maintaining the same level of reliability in the system [96].

The formulas and calculation steps for each of these three metrics are listed in the Appendix.

6.2.3.1.2 Load duration curve method

An additional method that is used that relies on probabilistic analysis is the load duration curve (LDC) method: this approach estimates a resource's capacity credit based on the difference between the average highest peak load hours and the average highest peak *net* load hours after adding the generation resource. This can be visualized as the difference between an LDC, which charts the load from the highest to the lowest point over a given period (i.e., one year) and a net LDC during the peak load hours. Note that the load and net duration load curves are sorted independently. The difference between the curves represents the decrease in the highest net load hours regardless of when they occur. The LDC method is thus able to capture any effects where the deployment of a resource causes shifts in the time of day or season in which net load peaks occur [44]. Figure 73 below provides a visual representation.

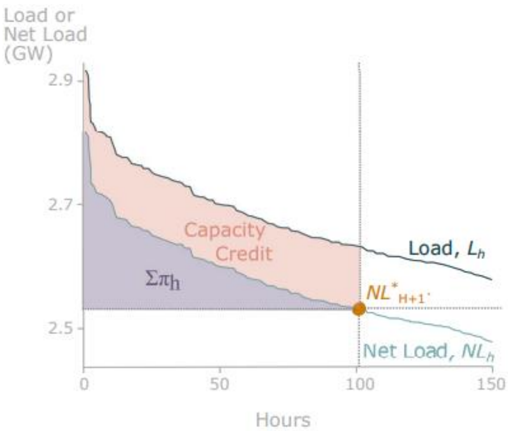


Figure 55: Load and Net Load Duration Curves for Peak Hours (Top 100 peak hours) of the Year. Source: [44]

The main benefits of the reliability-based and probabilistic methods are that they are well-known, computationally straight-forward, fast to calculate (can be completed in seconds) and they are reasonably accurate [110]. Additionally, these methods can factor in elements such as transmission constraints using Monte Carlo simulations and the interactive effects of various non-firm resources together [107] [109]. Additionally, such methods can still be useful when there is a lack of chronological data [41]. Furthermore, the LDC method has even been used previously in studies when there was a lack of load profiles for the power system [41].

However, the underlying models are more complex than those used in approximation-based methods, and they require significant data and computational power. Additionally, these methods may incorrectly assume that load and generation outages are independent random variables. This problem can be addressed by running separate simulations for different seasons.

6.2.3.1.3 Approximation-based methods

Approximation techniques offer simpler, less precise alternatives for estimating the capacity credit for a generation technology. These methods are based on using a generator's capacity factor during a given time period chosen to represent system stress, such as peak load hours. Some of the approximation methods include:

1. Capacity Factor-Approximated Capacity Credit – This method estimates capacity credit based on a generator's capacity factor during periods when the grid is at high risk of an outage event. The periods used are typically the top 1, 10, 100, and

1000 net load hours each year [107]. According to NREL, using the top ten or 100 hours yields the closest approximations for PV capacity credit with this method [96]. There are three different techniques that are often used which differ based on the hours used. One technique uses the average capacity factor during peak load hours. Another uses the capacity factor during the peak-LOLP hours. The third technique uses the highest load hours but normalizes the capacity factor by the LOLPs [107]. (See Appendix for more details on the calculation).

2. Garver's Approximation Method – This method offers a way to estimate the ELCC without needing to recalculate LOLEs when adding the new generator to the system. This method uses a linearized risk function to relate the system's LOLE to the system's excess generation capacity when plotted on a logarithmic basis. The slope of the risk function, *m*, represents the necessary capacity for an annual LOLE that is *e* times larger than the original system LOLE [107]. (See Appendix for more details).

3. Garver's Approximation Method for Multi-State Units – This method is a generalization of Garver's approximation method so that it can model generators that operate at different capacities due to outages or resource availability (referred to as multi-state generators). The methodology assumes that probability distribution for renewable availability remains the same at different time periods [107]. (See Appendix for more details on the calculation).

4. Z Method – This method calculates the ELCC based on a z statistic – the mean divided by the standard deviation – for a random variable *S*, which is the difference between available generating capacity and peak hours and has a Gaussian distribution. Essentially, the ELCC of a new generator here is the amount of incremental load that keeps the z statistic constant following the addition of the new generator to the system. The Z method assumes that while the mean and variance may change when adding a new generation to the system, the shape of the probability distribution does not. Under higher PV penetration, the shape of the distribution is subject to change and thus the method would no longer be valid [107]. (See Appendix for more details on the calculation).

For the following approximation methods, the capacity credit is estimated by computing the average capacity factor of a given generation unit during key time periods which represent times of system stress (i.e., peak load hours). Such methods typically rely on the following four steps:

- Evaluate the impact of transmission on the capacity credit by calculating a capacity factor approximation with *regional* criteria (for all regions in question) and separately with overall *system* criteria.

- Evaluate the impact of adding variable renewable generation by comparing the capacity credit calculated for the averages of the top load hours and of the top net load hours.

- Examine the impact of the time period included in the capacity factor approximation by evaluating the capacity credit by again taking the mean of the capacity factor during the top 1, 10, 100, and 1000 hours with the highest level of system stress each year.

- Evaluate the impact of seasonality by calculating the capacity factor approximated capacity credit for each individual season rather than the annual average.

5. Capacity Credit Computed with Weighted Expected Unserved Energy – This method is based on a weighted capacity factor approximation, which weights each hour by the expected unserved energy (EUE) experienced each hour [107].

6. Capacity Credit Estimated by Measures of Load – Rather than calculate the EUE as in the method above, this method estimates CC by calculating an average capacity factor over a given number of hours per step c. listed above that can represent gross or net peak system load [107].

7. Capacity Credit Computed on a Seasonal Basis – This approximation method estimates capacity credit by calculating the system EUE-weighted capacity factor for each of the four seasons of the year.

The primary benefit of approximation-based methods for calculating the capacity credit is that they provide an alternative to reliability-based approaches for utilities and system operators when the data and computational capabilities are lacking. Furthermore, approximation-based methods offer a relatively simple way to calculate the capacity credit. They can also estimate the impact of seasonality and use larger number averages to smooth out the data as a way of managing potential outliers.

However, approximation-based methods might miss factors such as the impact of incremental resources, inter-temporal constraints and transmission constraints [107] [96]. Moreover, extensive calculations may still be required for iterative estimation of LOLE, ELCC and ECP methods [96].

Reliability-based methods are typically preferred over approximation methods when the data and computational capabilities are available. However, the approximation-based method is typically preferred in contexts where data availability is limited. Approximation-based methods can typically provide sufficiently reliable values for conducting resource adequacy assessments and are used by utilities in both developed and developing countries.

6.2.3.2 Ex-post chronological method for calculating capacity credits

The chronological method for estimating the capacity credit is based on a computation of the capacity factor for a generator over a fixed period of time using historical time-series data. For this approach, one must carefully select average timescales from time intervals such as 10-minute, half-hour, hour, daily, or monthly [111]. Using data from peak load hours leads to a closer approximation of the capacity credit awarded.

The chronological method provides an accurate estimation of the generator output and of the capacity credit based on actual recorded data which is useful for renewable generation owners and system operators [111]. However, it is less useful to system planners as it the method is retrospective and does not account for future system changes which can be better incorporated in probabilistic models. The chronological method also falls short when it comes to capturing the impacts of extreme weather events (as seen in the case of Texas above), or of other unexpected developments such as fuel shortages (e.g., pipeline gas being shut off).

6.2.4 Strategies to increase the capacity credit of solar PV

By complementing solar PV plants with other renewables such as wind, geothermal, or with storage technologies, the overall capacity credit of renewable energy technologies can be increased.

Also, as highlighted above, another important way in which the capacity credit of variable renewables like solar PV can be increased is by increasing the flexibility of demand: In years prior, power system planners and system operators simply forecast load based on historically known values, assuming a certain level of load growth, and corrected the load forecast in light of key variables such as weather, public holidays, and other aspects that can and do significantly impact electricity demand. Load was thus taken as given.

With the rise of heat pumps, electric vehicles, programmable thermostats and water heaters, controllable air conditioners and other flexible loads, the hourly and daily load curve of the power system can be shaped to better align with the availability of supply on the system. In short, although the transformation will occur over decades, the paradigm used to operate the power system is evolving from one in which we forecast demand and schedule supply to one in which we forecast supply, and schedule demand. This has several implications for power system operation as well as for the capacity credit that can be awarded to variable renewables like solar PV.

If load is completely inflexible (i.e., given), then the capacity credit of technologies like solar PV will always be less than 1 (and often substantially less than 1), as solar supply may not correspond to moments of peak load in the system. In short, demand flexibility and storage technologies can either reduce or shift demand from peak hours or to extend the hours in which solar PV is able to meet demand [112]. Figure 56 below illustrates the interactive effects of solar+storage to show how the two technologies can reduce peak load and in turn reduce metrics such as LOLP.

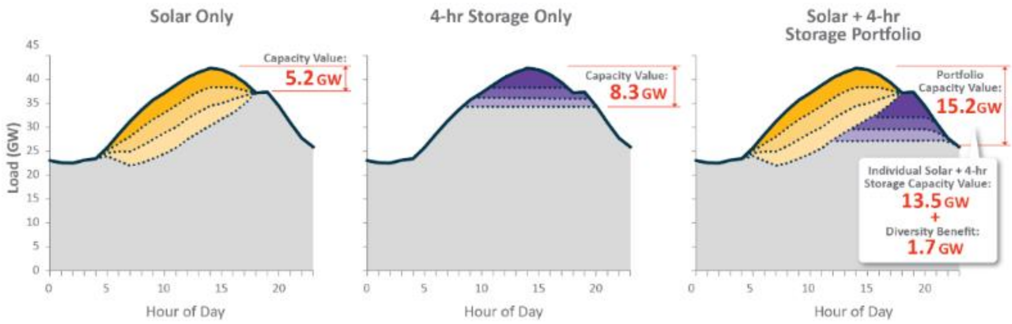


Figure 56: Interactive effects of complementary resources - solar PV and storage. Source: [109]

Based on analyses conducted in Australia’s National Electricity Market, a further factor that has been shown to increase the capacity credit of renewables (including that of solar PV) is improving the capacity and availability of grid interconnections [113]. By expanding interconnections between different regions, the contribution of each individual solar plant (for instance) to meeting resource adequacy requirements of the system grows accordingly.

Whether taken together, or individually, these various interventions can help increase the capacity credit value attributed to solar PV.

7 Cost development of solar power technologies, including storage

7.1 Costs and markets

Large-scale solar photovoltaic installations have closed Power Purchasing Agreements (PPA) for as low as 0.0104 USD/kWh [5], so that *for projects with low-cost financing that tap high quality resources, solar PV is now the cheapest source of electricity in history* [114].

In Concentrated Solar Power (CSP), PPA are higher priced than PV, but still very comparable to fossil fuel-based generation costs. Dubai signed a PPA for 0.073 USD/kWh [115].

Table 8: Installations of Concentrated Solar Power (CSP) and photovoltaic (PV) utility-scale (>10 MW) power plants

	Cumulative utility-scale installations, GW	
	Concentrated Solar Power (CSP)	Photovoltaic (PV)
Africa 2021 [84] [2]	1	9
Africa 2050 [authors]	34	4,200
World 2022 [116] [117]	7	1,130
World 2050 [authors]	260	222,000

Current and future installed solar power capacities are listed in Table 8. As we will see in this chapter, solar photovoltaic energy generation has increased with an average of 42% in worldwide year-on-year production between 1976 and 2022. Costs have decreased 11% every year.

By 2050, the expected installed PV capacity of 222 TW will have surpassed global primary power generation, which is expected to be 107 TW [118], already having considered a capacity factor of 25% for PV. Primary power includes all sources of energy transformed into usable secondary forms of energy, such as electricity, heating & cooling, mobility & transport, for all sectors of the economy. In 2050, most energy will be supplied as electricity, except for some niche applications, such as long-range shipping and certain industrial processes.

The share of Concentrated Solar Power (CSP) on globally installed solar power generation now is 0.7%. This value might further decrease to 0.1% in 2050, if the scenarios summarized in Table 8 are materializing.

Despite Africa being the sunniest continent, the capacity of solar installations in Africa will reach only 2% of the global solar installation by 2050, for the business-as-usual scenarios. Africa’s annual rate of photovoltaic installations over the last decade has exceeded the World’s rate of photovoltaic installations on average by 11.4% (authors’ calculations on data by [84]). There is hope that this trend will continue and possibly reinforce itself.

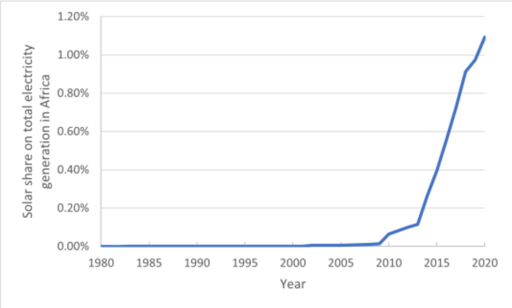


Figure 57: Solar share on total electricity generation in Africa. Source: [119]

1.2% of Africa's electricity in 2020 were generated by solar power plants (Figure 57). The number is growing fast, from a very low base.

7.1.1 Developments in Concentrating Solar Power (CSP)

Costs for installed Concentrating Solar Power (CSP) plants vary due to technology differences (parabolic trough, solar tower, linear Fresnel), and the limited number of installations worldwide. A typical number across all technologies and locations is 5,000 EUR/kW, for 2020 [31] [39].

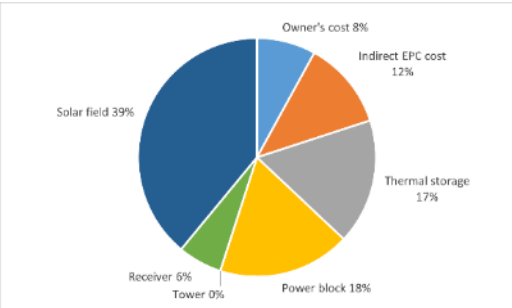


Figure 58: Cost breakdown of a CSP plant based on parabolic trough technology. Source: [31]

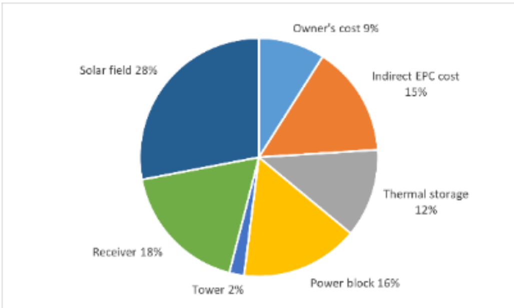


Figure 59: Cost breakdown of a CSP plant based on solar power technology. Source: [31]

The cost breakdown of two CSP technologies is shown in Figure 58 for a typical plant based on parabolic trough collectors and in Figure 59 for a typical plant based on a solar tower central receiver. The solar field for a one-axis tracking collector field (parabolic troughs) must be larger than the field of heliostats to collect the same amount of solar energy (see the section on capacity factors and tracking).

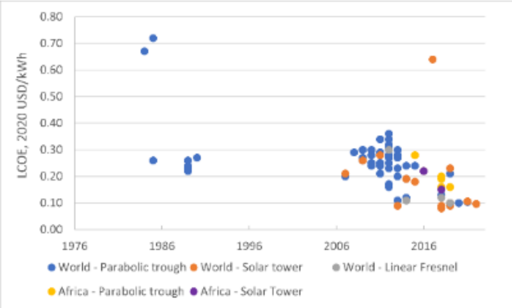


Figure 60: Levelized Cost of Electricity (LCOE) of energy generated by Concentrated Solar Power (CSP) plants in Africa and the World. Source: [2]

The Levelized Cost of Electricity (LCOE) generated by the CSP plants is shown in Figure 61 for all plants where numbers are known, distinguished for location and technology. LCOE has dropped below USD 0.10 per kWh. There are no obvious cost differences depending on location in Africa, or the Rest of the World, nor for technologies.

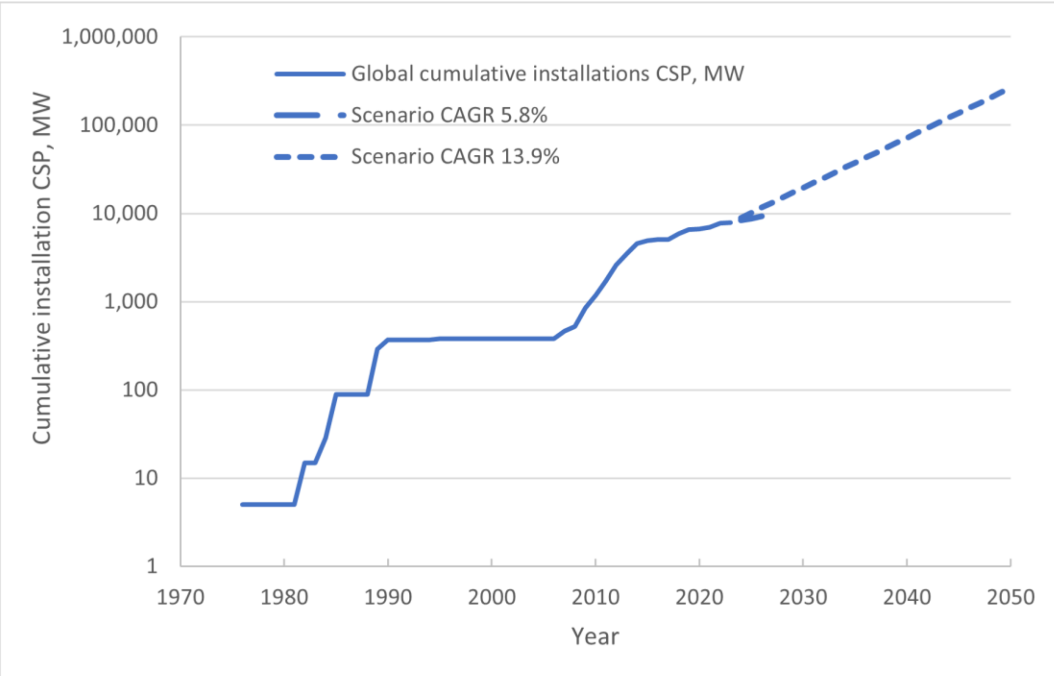


Figure 61: Cumulative global installations of Concentrated Solar Power (CSP) 1976-2050. Sources: [authors] [120] [121] [2]

Figure 61 shows that the global installations in CSP have grown in two steps, first in 1980's with the Luz Plants in the Mojave Desert in the United States, and then in the 2010's with the boom of CSP in Spain and Africa.

7.1.2 Developments in photovoltaics (PV)

7.1.2.1 Cost of PV modules

In 2021 and 2022, PV prices have been increasing (Figure 62). The increase has been significant but starting at a low level. It must be noted that the price of a turn-key photovoltaic system is a factor 4-6 higher than the module price, softening the impact of the module cost on system cost.

Increasing demand has caused some of the increase, intensifying with the energy insecurity caused by the Russian attack on Ukraine, and the subsequent stop of gas and oil deliveries from Russia. Weakening supply chains in China due to Covid-19 lead to shortages of smaller components, increasing delivery times [122]. Rising transportation costs, and rising inflation in 2022 cause volatility on the PV module market.

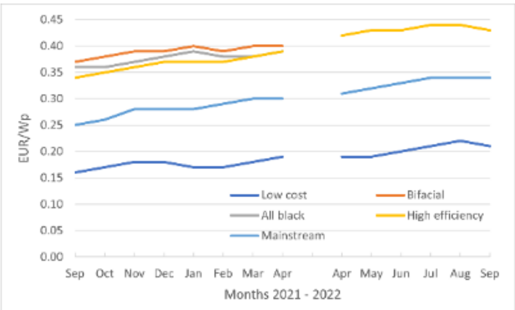


Figure 62: European spot market prices of PV modules 2021-22, module-only, Chinese goods, custom-cleared. Updated classification from May 2022. Source: [123]

The good news is that while the PV markets have been affected by various crises over the last forty years, most notably the shortage of silicon in 2006, the long-term stability of the markets have shown extraordinary strength, both in increasing production volumes and decreasing real costs.

Cell and module production capacity in 2022 will reach 600 GW, up from 360 GW in 2021 [124]. This shows that the volatilities of the current times are little more than minor disruptions in the continuous roll-out and expansion of PV.

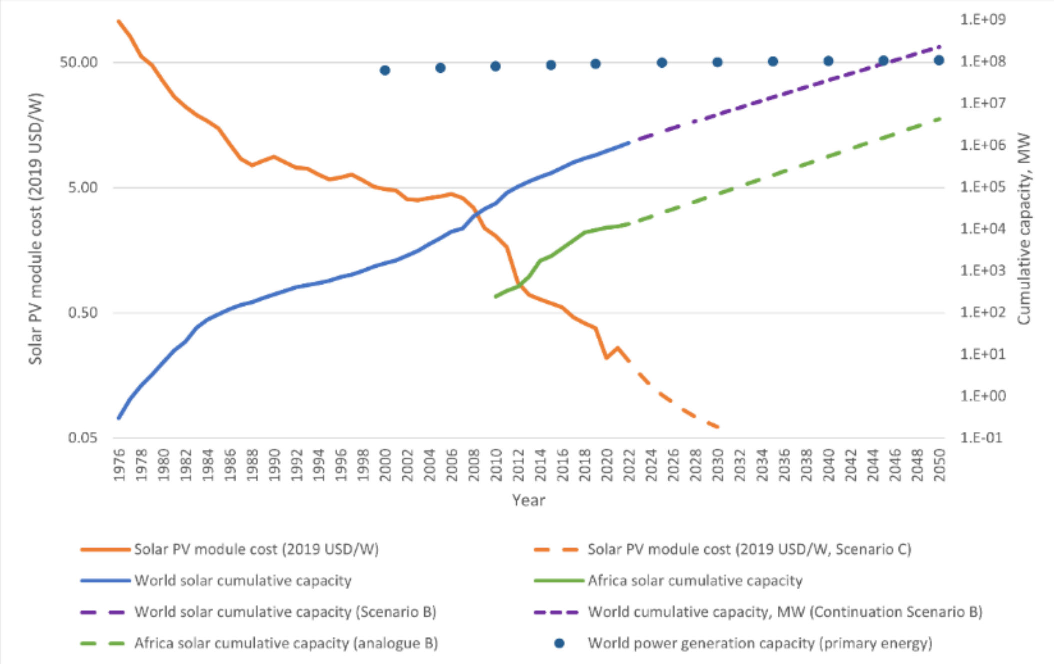


Figure 63: Solar PV module cost in 2019 USD/W; African and World cumulative PV capacity in MW, with forecasts until 2030. Note the logarithmic scale. Sources: [84] [120] [116] [117] [125] [118]

The price of PV modules has dropped since 1976 by three orders of magnitude and is predicted at 0.21 USD/W for 2022, with the cumulative capacity of PV reaching 1 TW, as shown in Figure 63. PV module costs are expected to further decrease, until they reach the barrier of material cost. The module cost increase around 2005 was caused by a shortage of silicon raw material, but markets moved back to an exponential cost decrease.

Year-on-year PV manufacturing volumes increase 42%, and costs decreased 11.7% in real terms, for the full period of 1976-2022 (Figure 64). Analysts are expecting further manufacturing volume increases and cost decreases, as given in the scenarios (Figure 63):

- A – PV module manufacturing values increase by up to 20% annually until 2030 [116].
- B – PV module manufacturing increase with CAGR of 20.1% until 2028 [120]. The forecast for Africa is not explicitly given in the source, but we expect the developments in Africa to follow world developments in the mid-term to 2028.
- C – PV cost reduction by an annual 10% for, assuming the production increase of Scenario A, with a yearly inflation of 5% [authors]. In manufacturing, a rule of thumb states that doubling the production volume leads to cost reductions of 20%. In the production of worldwide PV, the average cost reductions for any (hypothetical) doubling of manufacturing volume is 32% (Figure 65).

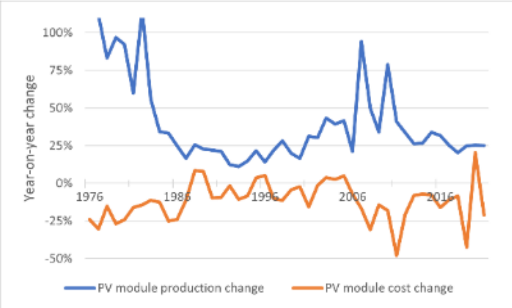


Figure 64: Year-on-year changes of PV module production, and PV module cost. Sources: [116] [117] [125]

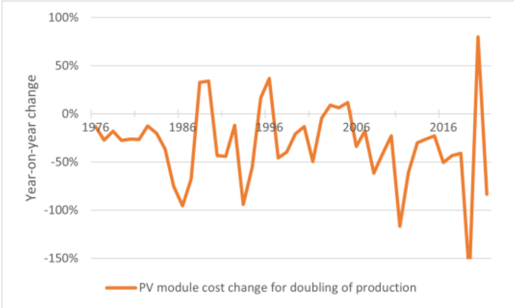


Figure 65: Year-on-year hypothetical changes of PV module cost assuming doubling of production volume; yearly average is -32%. Sources: [116] [117] [125]

As there is a lower cost barrier, there is a limit of a maximum output. We set this at the electricity generation capacity equal to the global primary (not: electricity) energy demand. For a 100% renewable world, all energy (not only electric energy) must be generated by solar power plants. In 2050, the yearly consumption of primary energy will reach 760 EJ [118], corresponding to a global solar electricity generation capacity capable of satisfying this complete demand of 107 TW. The number is calculated by assuming that electricity can be converted in any other form of (primary) energy with an efficiency of 90%; the capacity factor of solar power plants is taken to be 25%.

We are building our scenarios on meta data, looking at the past and credible assumptions of future developments. If in doubt, we stay with continuity rather than disruption. When looking at the past developments of production changes and cost changes for PV (Figure 64 and Figure 65), one may appreciate how constant production increases and cost reductions have been over the last forty years. There are single exceptions in yearly values, but the trends have been very constant. Therefore, rather than assuming massive changes, our scenarios use extrapolated data, where it makes sense. That way, we don't get lost in discussions on marginal issues, or issues that cannot be solved within the scope of this report.

Other scenarios are built in a bottom-up approach [126][Papp19], with all assumptions and values scrutinized and simulated with confidence levels. They can deliver scenario values on the level of country or Power Pool, we would think that all countries know where they stand in the African comparison, at least after having learned about their solar options. We can only assure everybody that photovoltaic power plants and rich sunshine are available to the whole continent. This view will solidify with the African Single Electricity Market (AfSEM) becoming reality.

7.1.2.2 Cost of solar photovoltaic power plants

The cost of installed PV power plants is no longer dominated by the cost of the module. Though the semiconductor part remains the costliest single item, many other components contribute to the cost of photovoltaic power plants. Installation costs of PV plants around the world are shown in Figure 66.

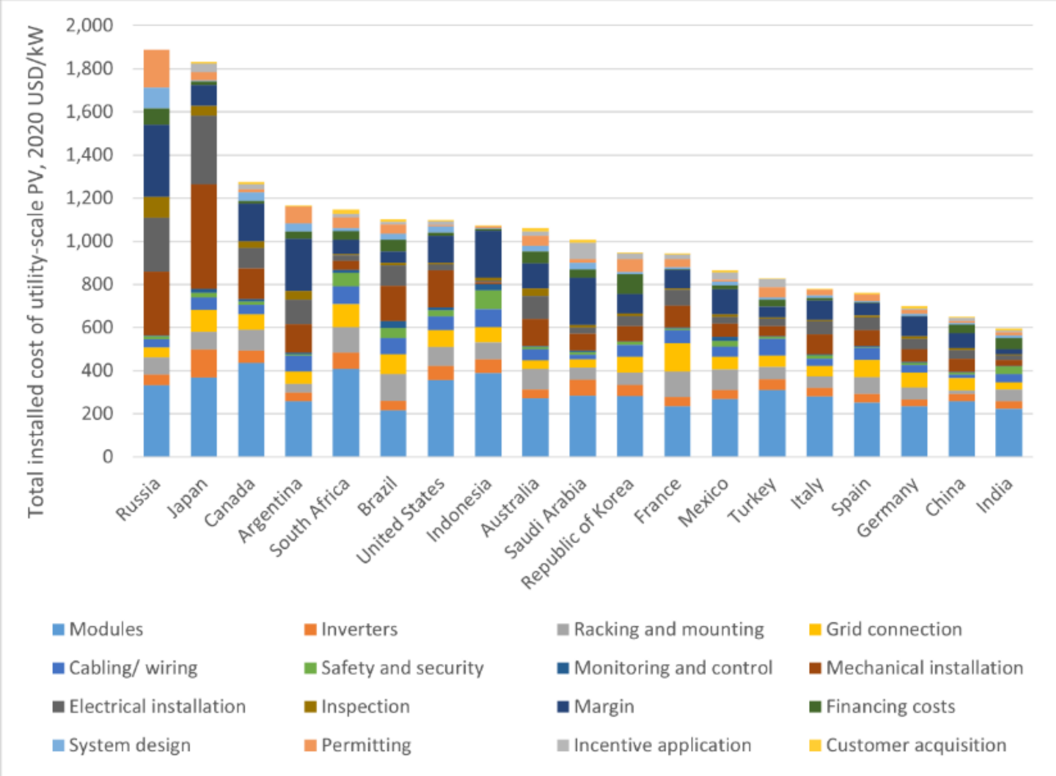


Figure 66: Installation cost of utility-scale PV, for various countries, and including a breakdown of components. Source: [31]

The module remains the single most costly item in the installed photovoltaic power plant, but there are other cost items to be closely watched. In Figure 67 and Figure 68, the lists of cost breakdown for PV power plants in countries throughout the World and in South Africa are compared. While mechanical and electrical installation works are major factors in the World, in Africa major factors are racking and mounting and grid connection.

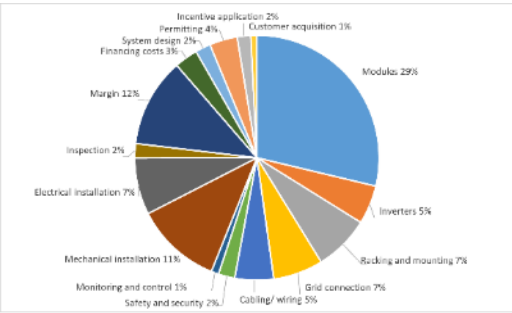


Figure 67: Average cost breakdown for PV power plant installations in nineteen countries throughout the World. Sources: [31]

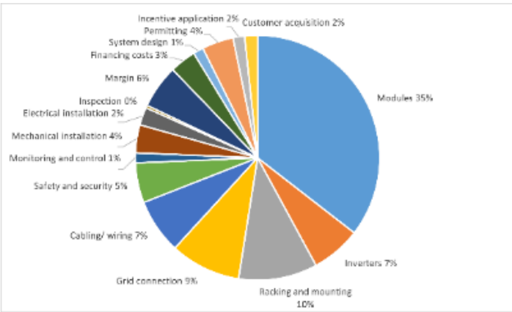


Figure 68: Cost breakdown for PV power plant installations in South Africa. Source: [31]

Costs of PV installations in South Africa are 11% higher than the average of PV installations in the nineteen countries listed in Figure 66.

7.1.3 Comparison of costs in PV and CSP

7.1.3.1 Capex and Opex

All costs occurring in PV and CSP can be distinguished into Capital Expenditures (Capex), also termed capital cost, and Operating Expenditures (Opex), termed cost for Operation & Maintenance (O&M). The categories and items related to Capex and Opex are listed in Table 9 and Table 10, respectively.

Table 9: Capital Expenditure (Capex) categories and items for all power plants, with costs specific to photovoltaic (PV), PV+battery storage power plants and Concentrating Solar Power (CSP) plants. Source: [39]

Category of Capital Expenditure (CAPEX)	Item	PV *PV+battery storage*	CSP
Balance of system/balance of plant	All other major plant components within the facility fence line needed to deliver electricity to the bulk power system.		
Electrical infrastructure and interconnection (electrical interconnection, electronic, electrical infrastructure, electrical)	Internal and control connections	AC wiring and installation *(also for batteries)*	Switchgear
	On-site electrical equipment (e.g., switchyard)*	DC wiring and installation *(also for batteries)*	
	Power electronics	Distance-based spur line cost (GCC) *(also for batteries)*	
	Transmission substation upgrades*	Inverters *(also for batteries)*	
	Plant construction	*Switch gear*	
	Power plant equipment	*Transformers*	
		Energy Management System	
		Monitors, Controls and Communications	
Generation equipment and infrastructure (civil works, generation equipment, other equipment, support structure)	Plant construction	Foundation *(also for batteries and inverters)*	Piping and heat-transfer fluid system
	Power plant equipment	Hardware	Power block (heat exchangers, power turbine, generator, cooling system)
		Module supply	Solar collectors
		Racking *(also for batteries)*	Solar receiver
		Battery pack	Thermal energy storage system
		Battery container	
		Battery Management	
		Thermal management	

		Fire suppression	
Installation and indirect	Distributable labor and materials		Installation
	Engineering		
	Start-up and commissioning		
Owners' costs	Development costs		
	Environmental studies and permitting		
	Insurance		
	Legal fees		
	Preliminary feasibility and engineering studies		
Site costs	Property taxes during construction*		
	Access roads*		
	Buildings for operation and maintenance*		
	Fencing*		
	Land acquisition*		
	Site preparation*		
	Transformers*		
	Underground utilities*		
*not included in distributed technologies (residential or commercial)			

Table 10: Operating Expenditure (Opex) categories and items for all power plants, with costs specific to photovoltaic (PV), PV+battery storage power plants and Concentrating Solar Power (CSP) plants. Source: [39]

Category of Operating Expenditures (OPEX)	**Item**	**PV** ***PV+battery storage***	**CSP**
Fixed costs	Administrative fees		
	Administrative labor		
	Insurance		
	Land lease payments*		
	Legal fees		
	Operating labor		
	Other		
	Property taxes		
	Site security		
	Taxes		
Fixed costs components	Project management		
Large components		Inverters at 15 years	
		Battery-related inverters 15 years	
Maintenance costs	General maintenance	Cleaning	Mirror washing
	Scheduled maintenance over technical life	Vegetation removal	
	Unscheduled maintenance over technical life		
Variable cost components	Consumables (e.g., water, chemicals, and catalysts)		
	Waste disposal (e.g., ash, slag, process wastes, and process byproducts that are not otherwise sold)		
Maintenance components	Transformers*	Solar PV plants	Power block
			Solar field
Replacement costs	Annualized present value of large component		

	replacement over technical life		
Utilities	Parasitics		Water, power, natural gas
*not included in distributed technologies (residential or commercial)			

Variable cost components in Opex are relatively small in comparison to fixed components. In CSP, the variable components amount to 20% of the total Opex, for the reference solar tower plant Crescent Dunes in Nevada, USA. The values are 0.012 USD/kWh, and 0.003 USD/kWh for the fixed and the variable components, respectively [39].

7.1.3.2 Capital costs (CAPEX) in power plants

Capex of photovoltaic (PV) solar power plants is lower than the Capex required for Concentrating Solar Power (CSP) plants. CSP plants, as compared in Figure 69, include storage. Past developments, and future projections of Capex for PV and CSP are plotted in Figure 70. Capex projections for PV+storage systems are added. Capex values from the USA [39] historically have been on the high side [127], so we recommend to also consider Capex values [128] compiled in Europe.

Nuclear or fossil fuel-based power plants incur higher Capex than PV power plants. Installation costs do not include the capacity factor of the power plant.

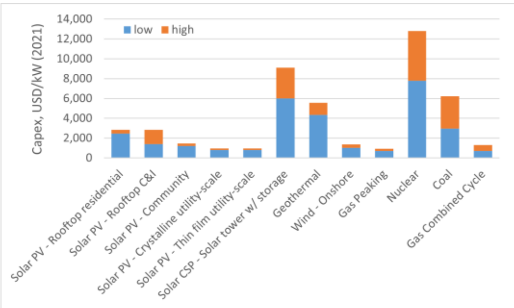


Figure 69: Capital costs of solar and fossil fuel-based energy generation technologies. Source: [129]

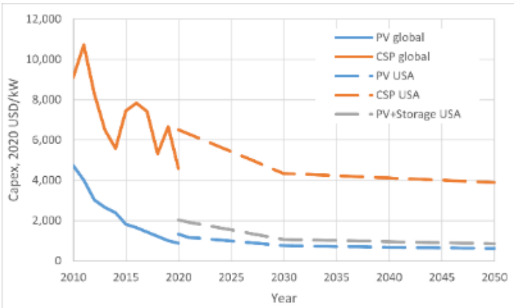


Figure 70: Installation cost (Capex) of utility-scale PV, CSP, and PV+Storage installations worldwide and forecast for the United States. Source: [31] [39]

7.1.3.3 Operation & Maintenance costs (OPEX) in power plants

The costs for Operations and Maintenance (O&M), or OPEX, are given in Figure 71 for a fixed-tilt, and in Figure 72, for a single-axis tracking PV power plant. Single-axis tracking is about 10% more expensive to operate and maintain than fixed-tilt. As single-axis tracking increases the energy generation yield significantly (Table 7), the Capex of single-axis tracking photovoltaic power plants is very much equal to the Capex of fixed-tilt PV power plants [49]; hence the higher operating costs of a single-axis tracking PV plant will be more than offset by its higher energy yield.

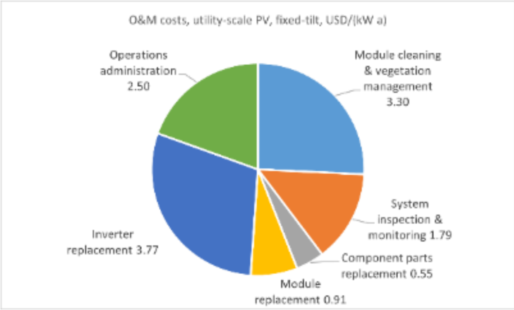


Figure 71: Operation & Maintenance (Opex) costs for a fixed-tilt PV power plant in the USA. Source: [130]

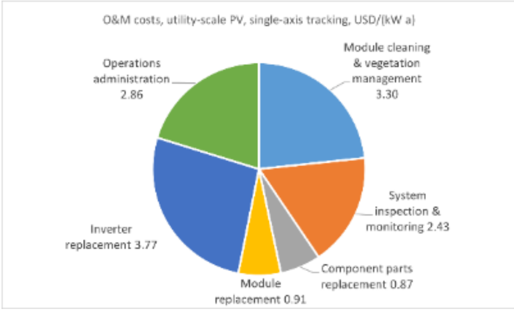


Figure 72: Operation & Maintenance (Opex) costs for a single-axis tracking PV power plant in the USA. Source: [130]

The O&M costs for Concentrating Solar Power (CSP) plants in Africa are given as 0.012 USD/kWh and 0.013 USD/kWh, for the solar tower plants in Morocco and South Africa, and for the parabolic trough plants in the same countries, respectively [31]. These values are thought to be 60% of the values in the USA and Spain, while being on par with the Opex in Saudi Arabia [31].

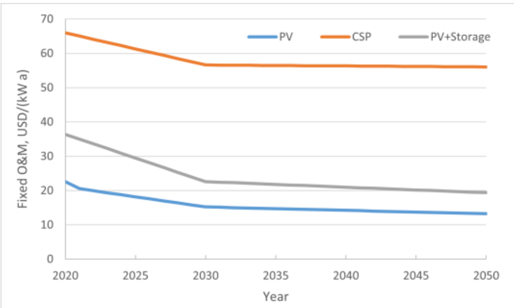


Figure 73: Fixed O&M cost for PV, CSP, and PV+Storage plants in the USA, forecast to 2050. Source: [39]

Opex of photovoltaic power plants is expected to be about one quarter of what Opex for CSP is, as shown in Figure 73. As CSP includes a Thermal Energy Storage (TES) system, it is fair to compare CSP with PV+battery storage. Though the reference plants [39] are far from identical, PV+Storage O&M costs remain at about one third of the O&M costs of CSP.

7.1.3.4 Levelized cost of electricity (LCOE)

Costs contributing to the Levelized Cost of Electricity (LCOE) are Capex, Opex (fixed and variable costs of Operation & Maintenance), as well as fuel cost. The ‘fuel’ of solar power plants, the solar irradiance, is free. This cost advantage leads to utility scale PV having the lowest LCOE of all energy generation technologies (Figure 74). The variation in cost between high and low is smaller than with any other technology.

Interesting is that the cost of residential rooftop PV installations is not higher than Gas Peaking or Nuclear power generation. Even at small size, the high modularity of PV leads to competitive systems. PV installations are very democratic, as market entry barriers are low.

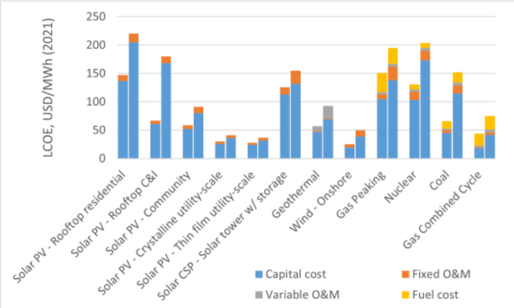


Figure 74: Breakdown of Levelized Cost of Electricity (LCOE) of solar and fossil fuel-based energy generation technologies, paired as low and high values. Source: [129]

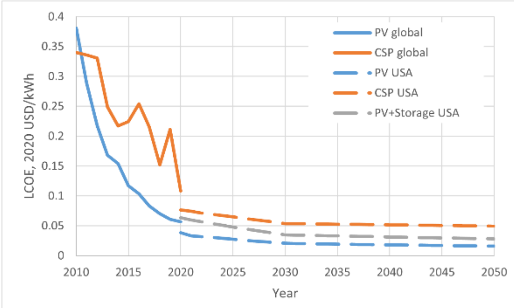


Figure 75: Levelized cost of electricity (LCOE) of utility-scale PV, CSP, and PV+storage installations worldwide and forecast for the United States. Source: [31] [39]

The LCOE of solar power generation has been declining, for both PV and CSP. Expectations are seeing the downward trend continue, though at a slower pace. Cost reductions are also forecasted for PV+battery storage systems, as shown in Figure 75.

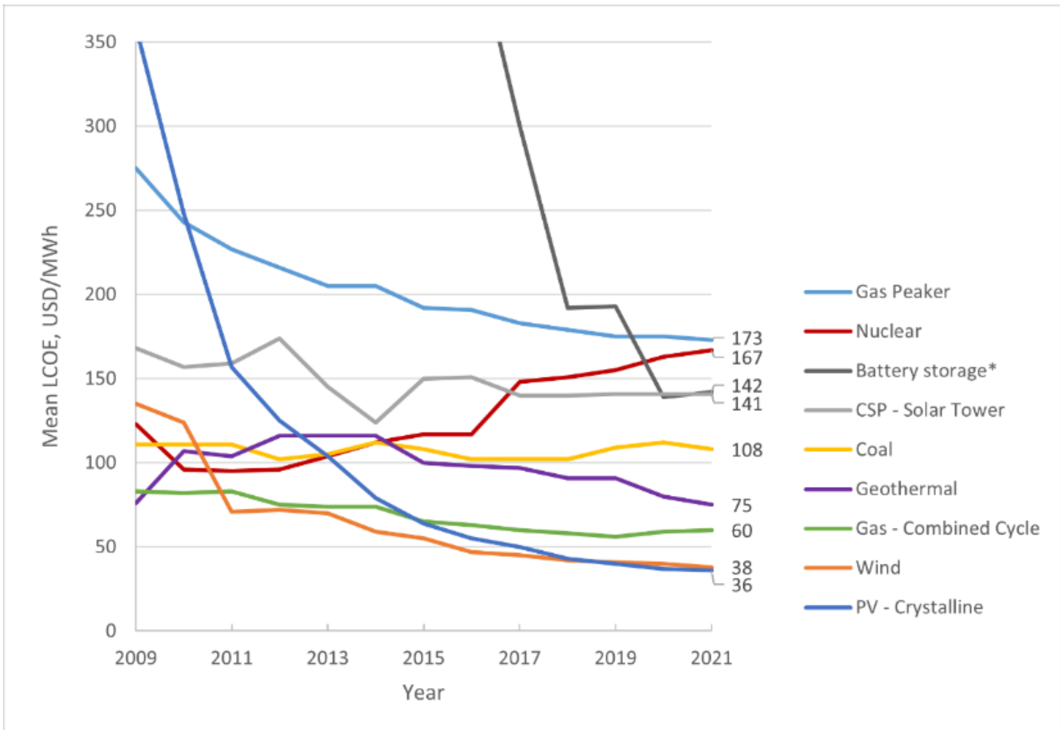


Figure 76: Levelized Cost of Electricity (LCOE) for utility-scale power generation technologies, as average of high and low values. *Note: battery storage is utility-scale Li-ion, daily cycle, includes charging cost. Sources: [129] [131] (for battery storage)]

The current state of LCOE for various energy generation technologies is given in Figure 76. Most technologies have bottomed out, showing that their cost reduction potential has largely been exhausted. Drastic cost reductions can be observed for PV and for battery storage.

7.1.3.5 Storage in CSP and PV

Though solar power plants deliver electricity at the lowest Levelized Cost of Electricity (LCOE) of all generators, solar is a Variable Renewable Energy (VRE). Overcoming diurnal changes in the resource requires storage capacity.

The cost of storage depends on its rated capacity in hours. Modelling (Figure 77) shows that the large capacities of the Thermal Energy Storage (TES) linked to Concentrated Solar Power (CSP) plants can be more cost-effective than the modular battery storage attached to photovoltaic (PV) power plants.

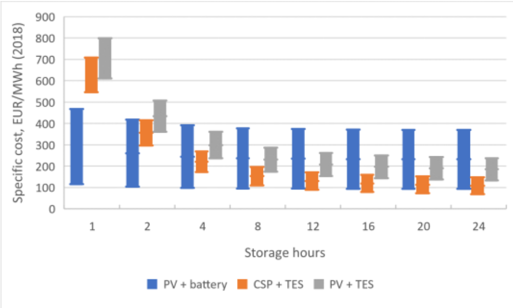


Figure 77: Specific cost of electricity generated by PV+battery, CSP+TES (Thermal Energy Storage), and PV+TES for storage durations up to 24 hours. Source: [132]

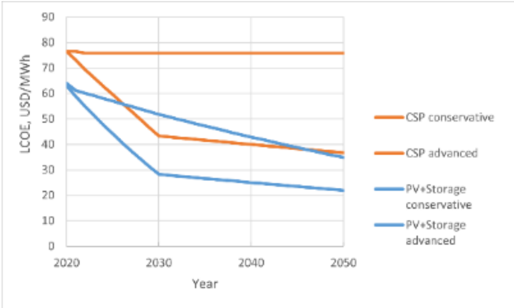


Figure 78: Storage scenarios for CSP (including TES) and PV plus battery storage. Source: [39]

Even now, and surely in the next decades, PV+battery storage LCOE beat the LCOE of CSP+TES, predicted in Figure 78. It seems that PV+battery will follow the path of PV, record low Capex, Opex, and LCOE.

7.1.4 Solar market opportunities

The global Concentrating Solar Power market size is projected to reach USD 7,208 million by 2026, from USD 4,823 million in 2019, at a CAGR of 5.8% during 2021-2026 [120].

Storage will increase its share in CSP markets: at a CAGR of 6.3% (2022-2028) the global Thermal Energy Storage (TES) market will grow from USD 3,817 million in 2021 to 6,020 million by 2028 [120].

The global Photovoltaic market size is estimated to be worth USD 62,970 million in 2022 and is forecast to be a readjusted size of USD 188,980 million by 2028 with a CAGR of 20.1% during the review period [120].

7.2 Life Cycle Analysis (LCA)

Cost is not the only important decision-making factor. Climate change dictates to consider the Carbon Footprint of energy generation technologies. For every kilowatt hour of generated electricity, a certain mass of carbon dioxide (CO_2) is emitted. CO_2 is a greenhouse gas responsible for two thirds of the global temperature increase (Figure 79).

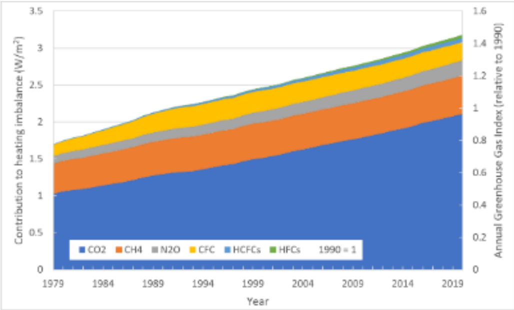


Figure 79: Heating imbalance caused by the major human-produced greenhouse gases, and Annual Greenhouse Gas Index (1990 = 1), graph by NOAA Climate.gov based on [133]

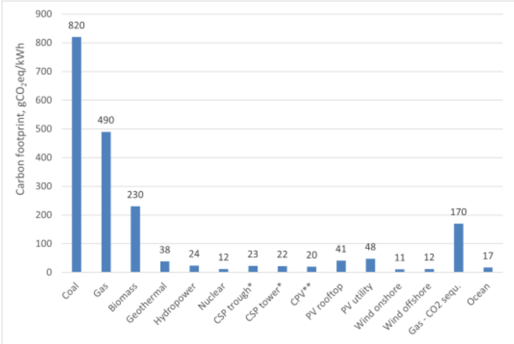


Figure 80: Carbon footprint in CO_2-equivalent for several energy conversion technologies [134] * [135] ** [136]

The carbon footprint of fossil fuel-based energy generation technologies can be 50-100 times larger than the carbon footprint of renewable energy generation (Figure 80).

8 Grid Integration of Solar Power

8.1 The power grid in Africa

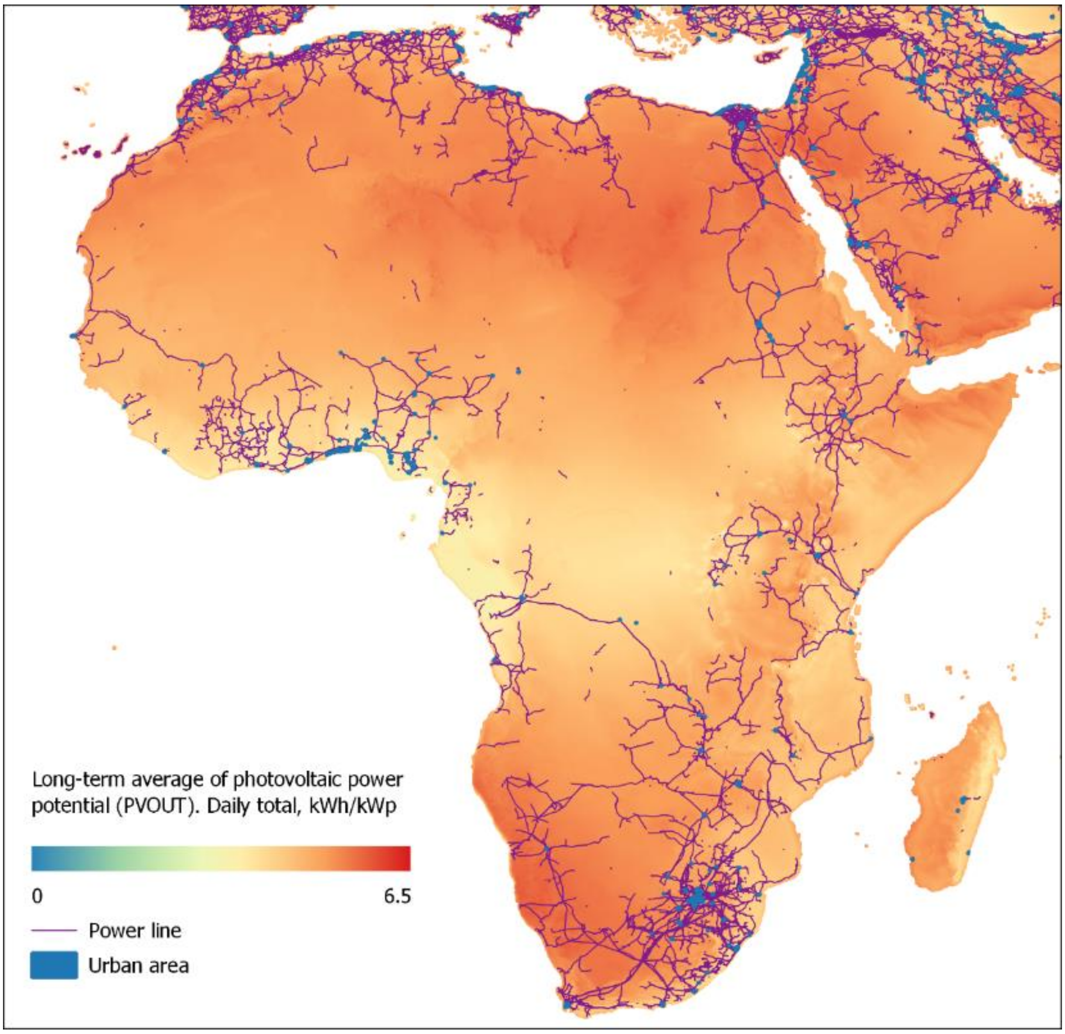


Figure 81: The African transmission grid [20], urban areas, with a map of the long-term average of photovoltaic power potential (PVOUT) [3]; note the large areas without transmission grid, and the gaps between regional grids

The African grid (Figure 81) is characterized by regional clusters extending over several countries, but few inter-connectors between these regional networks. None of the transmission lines extends over the entire continent.

Grid data is available [19] [20], with the latter showing actual locations (Figure 10). Some transmission lines have been planned but were never executed on, see a transcontinental connector in [137]. Observers [138] think that efforts are required to enlarge and strengthen the grid.

8.2 Power Pools

Table 11: Power Pools in Africa, and countries home to Case Studies

Power Pool with member countries, or home countries of member utilities	Jurisdiction of Case Study
Comité Maghrébin de l'Electricité (COMELEC), or North African Power Pool (NAPP) Algeria, Libya, Mauritania, Morocco, Tunisia	Morocco
Eastern Africa Power Pool (EAPP) Burundi, Democratic Republic of the Congo, Djibouti, Egypt, Ethiopia, Kenya, Libya, Rwanda, Somalia, South Sudan, Sudan, Tanzania, Uganda	Kenya
West African Power Pool (WAPP) Benin, Burkina Faso, Côte d'Ivoire, Gambia, Ghana, Guinea, Guinea-Bissau, Liberia, Mali, Niger, Nigeria, Senegal, Sierra Leone, Togo	Ghana
Central Africa Power Pool (CAPP) Angola, Burundi, Cameroon, Central African Republic, Chad, Republic of the Congo, Democratic Republic of the Congo, Equatorial Guinea, Gabon, Rwanda, São Tomé and Príncipe	Central African Republic
Southern African Power Pool (SAPP) Angola, Botswana, Democratic Republic of the Congo, Eswatini, Lesotho, Malawi, Mozambique, Namibia, South Africa, Tanzania, Zambia, Zimbabwe	South Africa Mozambique

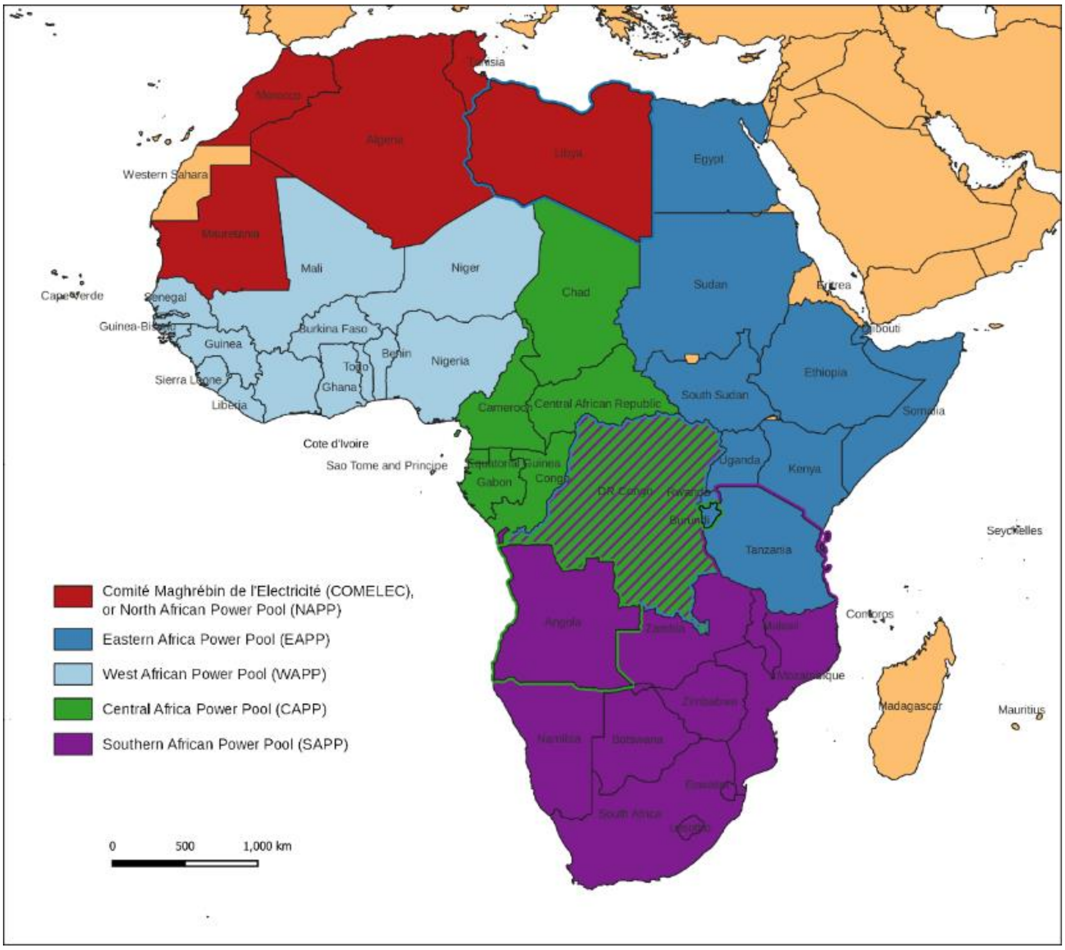


Figure 82: The five Power Pools of Africa (1:50,000,000); Angola, Burundi, Libya, and Tanzania are members of two Power Pools; the Democratic Republic of Congo is member of three Power Pools, see also Table 11

There are five Power Pools in Africa. These are multi-national organizations consisting of national utilities. A list of the Power Pools with their member countries is given in Table 11 and Figure 82.

8.3 Intercontinental energy exchange

Africa is beginning to connect to surrounding Europe and Asia. The first two interconnectors between Fardioua/Morocco and Tarifa/Spain have been commissioned in 1997, and 2006, respectively. The first power line between Bard/Egypt and Medina and Tabuk/Saudi Arabia has been contracted and is due for commissioning in 2025.

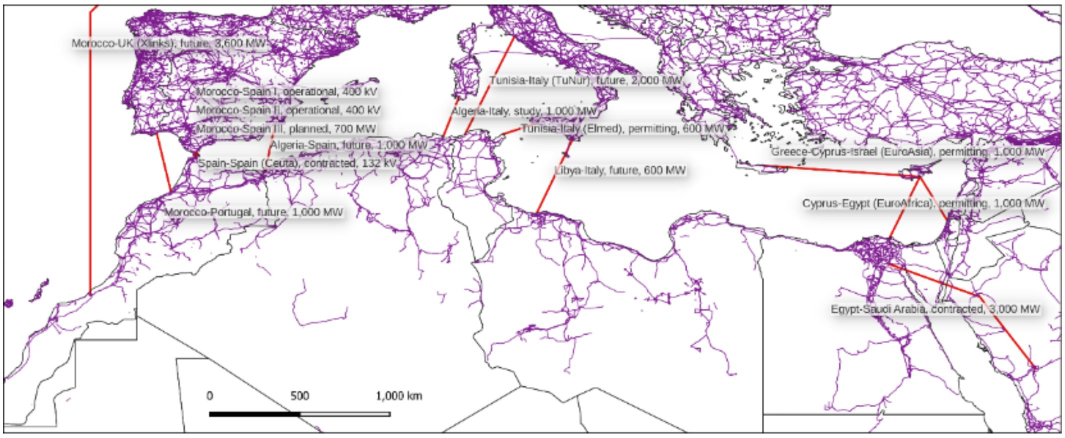


Figure 83: Undersea cables between Africa and Europa, as well as between Africa and Arabia, with status, voltage, or power capacity where available. Sources: [139] [140] [141] [142], for details see Table 12

A map of the interconnectors between Africa and Europa and between Africa and Asia is shown in Figure 83. All interconnectors have at least a short undersea section. Details of the interconnector projects are listed in Table 12.

Table 12: Interconnectors around the Mediterranean. Sources: [139] [140] [141] [142], for map see Figure 83

Name	Place	Place	Voltage, kV	Power, MW	Technology	Status	Due	Source
Xlinks	Morocco, Tantan	UK, Devon, Plymouth		3,600	HVDC	future		[143]
	Morocco, Fardioua	Spain, Tarifa	400			operational	1997	[144] [145]
	Morocco, Fardioua	Spain, Tarifa	400			operational	2006	
	Morocco, Fardioua	Spain, Tarifa	400	700		planned	2026	
	Morocco, Beni Harchane	Portugal, Tavira		1,000		future		
	Spain, Ceuta	Spain, Tarifa	132		HVAC, double-circuit, three-core	contracted		[146]
	Algeria, Ain Fatah	Spain, El Carril/ Mazarron	400	1,000	HVDC	future		
	Algeria, El Hadjar	Italy, Porto Vesme (Sardinia)		1,000	HVDC	study		
TuNur	Tunisia, Tunur Solar Power Project	Italy, Montalto di Castro	500	2,000	HVDC, two independent cables	future		[147]
Elmed	Tunisia, El Haouaria	Italy, Partanna (Sicily)		600	HVDC	permitting	2027	[140]
	Libya, Az-Zawiya	Italy, Chiaramonte Gulfi (Sicily)		600	HVDC	future		
EuroAsia	Greece, Paralia Fodele (Crete), Korakia	Cyprus, Alaminos, Kofinou	500	1,000	HVDC	permitting	2026	[148]
EuroAsia	Israel, Hadera	Cyprus, Alaminos, Kofinou	500	1,000	HVDC	permitting	2026	[149] [150] [148]
EuroAfrica	Egypt, Damietta	Cyprus, Alaminos, Kofinou				future		[151] [148]
	Egypt, Badr	Saudi, Medina & Tabuk	500	3,000	HVDC, multi-terminal	contracted	2025	[152] [153]
	Greece, Peloponnese, Neapoli Voion	Greece, Crete, Chania	150	400	HVAC, two cables	operational	2022	[154] [155]

As explained above, larger grid-connected areas mean higher capacity factors for intermittent renewable power sources like solar and wind. Reaching 100% renewable energy supply 24/7 over all seasons requires a grid extending across the whole globe.

Storage options reduce the required dimension of the grid. Initial studies [156] [157] support the need to add work in this field.

8.4 Desertec

Desertec is a foundation created in 2009 promoting the generation of renewable electricity. Desertec is the successor of the Trans-Mediterranean Energy Cooperation (TREC), which was created in 2003 by the Club of Rome, the Hamburg Fonds for Climate Protection, and the Jordanian National Energy Research Centre. As of 2013, Desertec became partner in the Dii GmbH (Desertec Industrial Initiative).

The core concept of Desertec (Figure 84) was the generation of electricity in Concentrated Solar Power (CSP) plants in the Middle East and North Africa (MENA), and the transmission of the solar energy to Europe [158]. Desertec proposed optimum point-to-point High-Voltage Direct Current (HVDC) power lines for CSP [159].

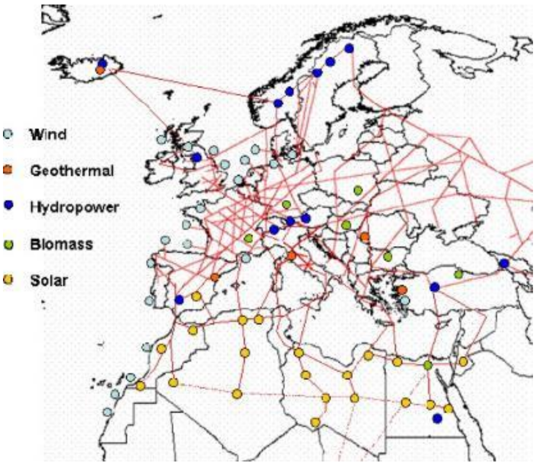


Figure 84: Vision of an EUMENA backbone grid using HVDC power transmission, from [158] 2006

The idea behind the concept can be traced to solar energy research in the 1980's in Germany, for the generation of hydrogen by means of solar power [32]. History duplicates itself, as we can see with the announcement of green hydrogen projects in Egypt [160].

Desertec’s concept has not been implemented outside of Morocco. Reasons for the failure of Desertec are including:

- Timeframe and scope: too long, and too broad for consistently following a project involving over 40 countries with national grids (Scheer, MP Germany, [161]).
- Industry practice: ‘the energy sector doesn't work by building 'special cables [...], or some such nonsense', to transmit electricity between the continents of Africa and Europe. Europe is said to possess excess capacities, and will use them, unless the production of power in Africa is cheaper, and big quantities are available’ (van Son, chairman Dii GmbH, Mar/2015, cited in [161]).
- Political instability: unstable political situation in MENA after the winter 2010/11 'Arabellion'.

- Technological developments: the lower cost of photovoltaics led to an increase in local installations in Europe, particularly in Germany, where most Desertec supporters were located [161]. Germany's Energiewende and the high feed-in tariff for locally produced renewable electricity produced locally (but not for solar power produced internationally) counteracted the Desertec path of working only with CSP, Desertec's exclusive technology.

- Neo-colonialism, and paternalism was interpreted into the Desertec plans, though the self-portrait was partnership, and the presentation of a win-win-situation. [162] uses case studies of local discontent with the distribution of wealth, pollution, and intransparency to illustrate negative effects of the multinational energy industries in Algeria, Tunisia, and Morocco.

- Internal differences: founding of Dii GmbH (Desertec Industrial Initiative, with Desertec Foundation as member) in 2009, and subsequent change of business model into consultation, following a 'step-by-step' approach [163]. The Desertec Foundation left Dii GmbH in 2013 [161].

- External pressure: the influence of leading energy companies in the fossil fuel business cannot be ruled out. In 2022, in response to questioning from Chairwoman Maloney [of the United States House Committee on Oversight and Reform] on an internal memorandum showing Exxon and Chevron worked behind the scenes to water down industry climate commitments, Ms. Salter [Founder and Executive Director of the Energy Justice Law and Policy Center and Member of the New York State Climate Action Council] stated: 'Unfortunately, the fossil fuel company commitments are just frankly disingenuous. The fossil fuel lobby combats climate action on every single level – global, national, state, and regional.' [164].

Diversions from the initial concept of point-to-point interconnectors into a 'supergrid' led to failure of Desertec, according to one of its founders [165]. The high complexity of a multi-national long-term project could have been stressing the commitments of the Desertec members and the countries in favour of the concept. Political stability would have been essential for financing and might have been compromised by the 'Arabellion' 2010/11. The kingdom of Morocco passes the unrest unscathed and emerged as a location for CSP.

Business practises of the (then constituting) solar energy industry were probably not up to the task. The experience and strength of multinational companies was lacking. The global fossil fuel industry showed no interest in Desertec. We may assume that Desertec was considered a threat to the fossil fuel industry's business model. The contribution of carbon emissions on global warming was known to and could be accurately modelled by the fossil fuel industry [166].

The perceptions of neo-colonialism and underselling of African resources as reasons for the failure of Desertec cannot be supported by literature. It seems that Desertec failed in earlier stages.

Europe may have focussed on local resources at the time of Desertec, reducing the chances for the success of the project, but the setting has changed, Europe is in need of renewable electricity, which can be produced cheaper in Africa than in Europe due to favourable solar resources. Solar photovoltaics, rather than CSP, has emerged as the least costly option of all energy generation technologies.

Lessons can be learned from the Desertec failure: any project needs ample planning and financial resources. Coupled with commercial interest and demand for carbon-free solar energy, a successor project for Desertec may have a chance, as solar energy has a chance in Morocco.

One may argue that there is no need for electricity from another continent, but it will be difficult to overcome the logic of intra-continental grids. Additional interconnectors in the European grid are seen as promoting 'energy transition, integration of renewables, security of supply as well as regional and local socio-economic welfare, economic cooperation, peace and solidarity' [167].

8.5 Grid Connection and Reinforcement Costs

8.5.1 Abstract

This research describes the cost components of grid connection and reinforcement costs and aims to estimate price ranges based on real world implementations and academic studies where available. The data collection includes 30 reference studies with a strong focus on the reporting of the respective power pools, ministries and development funds in Africa. Furthermore, recent studies from across the globe were included to provide additional support for price benchmarking and fill in the knowledge gaps that could not be acquired based on the available studies for the African continent.

Power systems of the 54 countries in Africa exhibit a wide range of voltage levels, substation configurations, line designs and ratings at transmission, sub-transmission and distribution level. The immense geographic heterogeneity in system needs and costs makes it difficult to generalize costs obtained from a relatively small sample of different projects, and in addition it is not always straightforward to distinguish costs for system level assets from costs for individual generation resources. Therefore, this research should be seen as a first approximation for cost estimation and a general guide for contingency assessment. It is recommended that the data be updated and validated by the local resources and authorities.

8.5.2 Introduction

New utility-scale generation sites have to be connected to the existing grid; most of the time this requires additional infrastructural investment for grid expansion. Connectivity associated costs can be decisive for the feasibility of the new capacity installment. The locations with largest resource potential are not necessarily the best candidates as new generation sites, because the distance from the existing grid, any existing network congestion points, road accessibility, and the temporal variability of power generation must be considered [168]. The lack of adequate infrastructure can be a limiting factor for the deployment or utilization of renewables. This lack of adequate infrastructure is illustrated by the fact that according to the World Bank, Africa has the largest electricity access deficit in the world. Less than one third of the African countries were evaluated to have support mechanisms in place to enable electrification by establishing and extending public distribution and transmission systems [169]. Therefore the expected compromises between resource quality and grid proximity for capacity expansion may be different in African power systems than on other continents.

The cost analysis presented here starts with an introduction of the grid connection of a renewable power generation asset and its cost structure to lay out the cost elements considered. This is followed by an extensive explanation of the collection and aggregation of a component-based price benchmarking, as material and manufacturing costs can be considered valuable references.

From an engineering, installation and commissioning perspective, the reference costs should be expected to differ significantly between projects. To capture this, the subsequent sections discuss the most important cost drivers and common project risks that can lead to cost overruns.

The existing T&D infrastructure may need to be replaced and upgraded to accommodate new generation capacity. Furthermore, with changes of the generation and consumption profiles specifically driven by the increase in economic activities and VRE penetration, the existing infrastructure might fall inadequate and necessitate upgrade investment sooner than the original lifetime projections foresaw. The IEA predicts that worldwide until 2030, around 16 million km of existing distribution lines and 1.5 million km of transmission lines would need to be replaced, refurbished and digitalized, together with all the associated grid components. Therefore, the last two sections are dedicated to refurbishment costs and operational costs.

8.5.3 Grid Connection Costs

The main components of a grid connection are the multiple network elements required to physically connect a new generator to the existing grid – such as transformers, substations (circuit breakers, busbars for management of line connections), synchronous condensers (for system strength remediation), T&D lines, steel towers, and secondary equipment. Battery storage facilities usually incur lower connection costs due to higher flexibility in their location, as well as the option of leveraging the connection assets used for variable renewables when collocated.

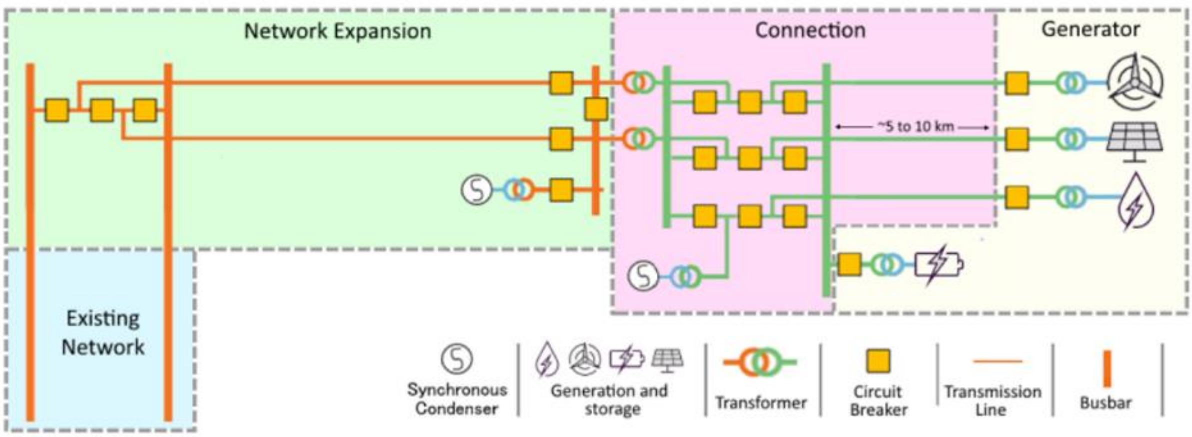


Figure 85 Connection cost representation [170]

Power systems of the 54 countries on the African continent exhibit a wide range of voltage levels, substation configurations, line construction designs and ratings at transmission, sub-transmission and distribution level. Different voltage levels per country in a simplified grouping can be found in an AICD study [171]. The immense geographic heterogeneity in system needs and costs makes it difficult to generalize costs obtained from a relatively small sample of different projects, and in addition it is not always straightforward to distinguish costs for system level assets from costs for individual generation resources [172].

Figure 86 provides a detailed cost breakdown structure for the estimation of project budgets. In the literature review conducted, only the *"building blocks"* have been considered. The other fundamental cost items (please see Figure 86) are always project specific and cannot be estimated based on a literature review; they need to be taken into account during project development based on the specific projects conditions.

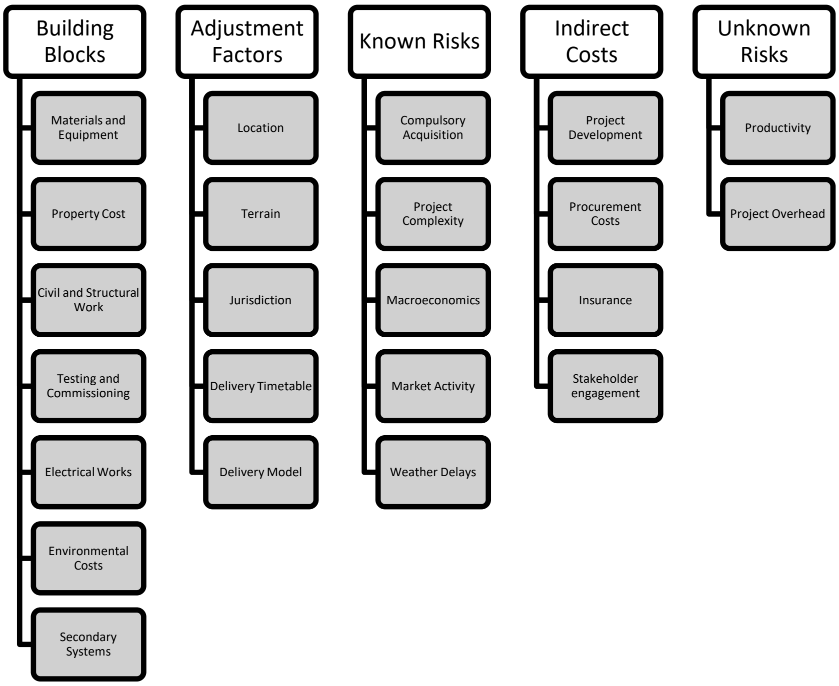


Figure 86 Cost breakdown structure for grid development and reinforcement projects, based on [170]

The building blocks can be seen as reference points, as the grid development design choices and the country-specific regulations can drastically change the selection of the components, leading to different end costs. The proximity to the transmission infrastructure, and the operating voltage level of the existing network are decisive for the available options to integrate new generation capacity, including the choices of voltage level and transfer capacity of new connection lines. Transformers, substations and transmission lines or cables are the most expensive equipment for network expansion when unit costs are considered. The World Bank study states that the largest cost component for grid connectivity is the material acquisition [169]. From the engineering, installation and commissioning perspectives the reference costs are expected to differ significantly within Africa. In contrast, materials and manufacturing costs can be considered a valuable reference across continents.

The data collected for this study included 30 reference studies with a strong focus on the respective power pools, ministries and development funds in Africa. Voltage levels and system current (AC/DC) were chosen as the most important differentiation factors in the analysis.

Some of the cost information obtained in the literature review is explicitly based on data collected from real-world project implementations. This refers in particular to the data from Australia provided by AEMO and from the EU provided by ACER.

8.5.3.1 Transmission and Distribution Lines

Table 13 summarizes the costs by averaging according to different layout types (overhead lines versus underground/subsea cables), AC/DC and voltage levels for different locations.

Table 13 Reference cable prices are expressed in USD/km, and average values are provided based on aggregation levels (costs normalized to 2022)

	EAPP	SAPP	WAPP	Africa-Mixed	EU	Australia	USA	Africa-Average	Total-Average
Overheadlines	*249,162*	*291,850*	*1,156,087*	*731,928*	*610,188*	*432,973*	*1,628,435*	*506,910*	*749,514*
AC	188,554	291,850	1,156,087	550,004	610,188	432,973	1,089,214	475,810	614,505
<=132kV	78,759	185,385	1,522,590	550,004			258,975	502,998	472,495
220kV	252,922		423,080		482,795	311,806	431,625	408,669	419,290
330kV		325,167			1,151,219	393,547	1,164,352	325,167	627,689
400kV		365,000				593,565		550,004	950,814
>=500kV	563,362						1,795,560		1,795,560
DC	370,380			913,853			2,976,486	587,769	1,270,260
<=132kV	222,228							222,228	222,228
220kV	296,304							296,304	296,304
400kV	592,608			913,853				592,608	592,608
>=500kV							2,976,486	913,853	1,945,169
Subsea					*1,139,437*		*3,453,000*		*2,030,625*
220kV					1,587,507				1,587,507
>=500kV					1,051,367				1,051,367
DC							3,453,000		3,453,000
Underground					*3,511,466*				*3,511,466*
<=132kV					1,531,733				1,531,733
220kV					3,843,072				3,843,072
400kV					6,807,721				6,807,721

The figures obtained from the literature review and presented in Table 13 shows significant variance between the regions. It remains unclear to which extent this variance represents realistic differences between the conditions in the considered regions, and to which extent it should instead be attributed to simple artifacts of different methodologies and scopes used in the reference studies.

The literature review and follow-up analysis provided some insights and remarks to be considered:

- Material cost component: Depending on the line layout type, between 47% and 57% of the total project cost was constituted by the materials and manufacturing according to the report from ACER [173].
- Voltage level: Unit costs of transmission lines in USD/km decrease with decreasing voltage level. (It should be noted that this does not consider the power transmission capacity. Higher voltage levels are cheaper for higher

capacity needs. Therefore unit costs for transmission capacity are also often specified in USD/MW/km [174].) Voltage levels and number of circuits were identified as the most important cost drivers (95%) for overhead AC lines.

- Distance: Mills [175] could not find a direct correlation between the per-kilometer unit cost of transmission with the distance; on the other hand AfDB estimations for interconnection lines clearly demonstrates the expectation of decreasing unit cost with increasing length. It can be impactful whether the transmission additions are single, long-distance lines, or several short-distance transmission lines [175].
- Reactive power: Reactive power compensation costs were estimated to amount roughly to 1% of the specific cost for transmission lines per kilometer [176].
- Current rating: In addition to the voltage levels and number of circuits, line costs also depend on the line rating. The higher the rating, the larger the cost, as more conductor material is needed.

Interconnectors

High-voltage level interconnection between countries, or interconnectors, can play a fundamental role for electricity access and its affordability. They are also particularly relevant when considering intercontinental connections. Therefore, interconnector costs have been analyzed separately to capture their specific impact.

Table 14 Interconnector costs in USD/km based on the literature review conducted (costs normalized to 2022)

	EAPP	SAPP	WAPP	CAPP	NAPP	Africa-Mixed	Total-Average
AC	*491,501*		*676,172*				*565,369*
220kV	327,945						327,945
225kV			551,844				551,844
330kV			800,500				800,500
400kV	545,741						845,741
500kV	600,816						600,816
DC	*386,149*						*386,149*
500kV	376,762						376,762
600kV	395,537						395,537
Undefined	*344,014*	*326,376*		*3,566,132*	*573,600*	*967,950*	*1,155,614*
300kV							326,376
400kV	344,014	326,376					344,014
Undefined				3,566,132	573,600	967,950	1,702,561

PIDA [177] estimates the investment needs for continental interconnectivity to meet the forecast demand in 2040 would amount to $5.4 billion per year.

There are scholar tools developed for estimating cost of interconnectors. For example, DLR [178] suggests using the IDRISI-tool, which identifies the least cost HVDC line based on cost-distance images. HVDC lines are mostly preferred for long-distance interconnectors, such as the recent Norway-Netherlands 580 km subsea HVDC cable. The study does not recommend HVDC applications in industrial areas, areas with sea-depth of over two kilometers, protected areas, and sand dunes areas. Specifically, the exclusion of sand dunes might be a concern for connecting large amounts of solar PV that could be built in desertic areas.

In another example, Neuhoff points out that the cost estimations of the interconnectors significantly depend on how to share the costs and benefits of the transmission infrastructure among the different countries involved. As these are cross-border transmission lines, there may be mismatched incentives for the different parties [179].

There are a number of efforts for developing a common convention to facilitate cross-border trade and interconnector capacity development. For instance, there is a working group for regional grid code development for SAPP, including 17 countries, driven by the Southern African Development Community. The result of these efforts will be crucial for achieving the necessary levels of harmonization of technical requirements and estimating the corresponding costs [180].

8.5.3.2 Substations

Substations host the grid equipment for the interconnection of the different voltage levels used in transmission and distribution grids, and at the grid intersections. The number of components of a substation depends on its configuration and on the grid intersection requirements. The most important components of the substations are the transformers, the switchgear, the capacitors and the busbars. The switchgear and the transformers constitute more than 60% of the total cost of a substation.

The total substation rating determines 99% of its cost. Busbar voltage, the number of bays and insulation type are the cost differentiating factors. Gas insulated switchgear is more costly than normal (air insulated) switchgear as it requires more components to ensure its security, yet it is more favorable for severe environmental conditions. Furthermore, gas insulated switchgear enables the installment of substations of up to 550 kV in the middle of load centers with space restrictions, as they have a much more compact design [181].

Table 15 Average substation costs (USD per unit, costs normalized to 2022)

	EAPP	SAPP	WAPP	Africa-Mixed	EU	Australia	USA	Africa-Average	Total-Average
AC	*16,626,216*	*45,934,400*	*5,137,400*	*75,970*	*17,750,943*	*6,537,803*	*48,342,000*	*15,348,754*	*16,160,523*
90-33kV			7,252,800						7,252,800
110kV					969,680				969,680
132-33kV	7,407,600							7,407,600	7,407,600
220-30kV						4,329,637			4,329,637
220-132kV	13,457,140							13,457,140	13,457,140
225-33kV			3,022,000					3,022,000	3,022,000
330-30kV						5,861,042			5,861,042
330-66kV		45,934,400						45,934,400	45,934,400
400-220kV	22,820,062							22,820,062	22,820,062
500-220kV						9,422,729			9,422,729
Undefined				75,970	34,532,206		48,342,000	75,970	27,650,059
DC							*517,950,000*		*517,950,000*
Undefined							517,950,000		517,950,000

8.5.3.3 HVDC Converter Stations

The most important components of HVDC stations are the converters and the converter transformers. Significant factors in determining the costs of an HVDC station are the rating of the station (MVA), the number of converter transformers [173], and the choice of power electronics in the HVDC converters, as IGBT-based systems are significantly more expensive than thyristor-based systems (more information on the technical characteristics of HVDC systems is provided in section 8.6.1).

Table 16 Transformer and converter costs USD/MVA based on the literature survey (costs normalized to 2022)

	EAPP	EU	Australia	Total-Average
AC/AC Transformer	*13,173*	*13,743*	*11,322*	*12,746*
HVDC Converters	*167,165*	*168,526*		*167,845*
1-4 Transformers		*120,972*		
4-8 Transformers		*216,081*		
Undefined	*167,165*			

8.5.3.4 Labor costs

There is a significant variation in costs between countries due to the different labor costs and commodity pricing. The size, maturity and openness of the local markets have an impact on the competitiveness of the supply and of the service chains. IRENA's latest study on the mapping of utility-scale solar project costs around the globe provides an insight about the cost composition differences among several countries [182]. Although from the African continent only South Africa's data is included, it can be seen that the engineering and project management costs are around 15% lower compared to the mean value of the other 20 analyzed countries.

According to AICD, it was expected that the lack of grid expansion expertise in Africa would cause that all countries, except for South Africa, contract foreign parties for construction and engineering. In 2009, there was no knowledge of the existence of local manufacture of materials and neither equipment nor construction contractors in CAPP, EAPP and WAPP [171].

8.5.3.5 Data on the Overall Connection Costs

Newly built and reinforced transmission infrastructure for new power generation facilities can consist of two categories – new connection infrastructure belonging specifically to the facility, and network expansion of the existing power system (see Figure 85). Depending on the renewable energy and transmission system regulation, the transmission element costs that have to be borne by the generators varies. For example, in the USA, generators usually have to bear the network expansion cost [172]. In other countries these costs are borne by the transmission owner, who may recover them through some legal or regulatory mechanism.

There are studies that estimate the transmission costs of VRE projects based on the connection cost. However, utility-scale new capacities most of the time rely on access to the bulk transmission system to move power from resource areas to load centers, therefore region wide transmission investments are needed most of the time.

USA-based studies found median wind transmission costs to be in the range of 33 to 762 USD per kilowatt, which amounts to roughly 15%–25% of a wind project's cost. These costs tend to go beyond 300 USD per kilowatt when the integration into the Bulk is considered [175]. Gorman's study [172] analyzes the transmission investment costs for different generation types based on a pool of over 6000 US-based projects. Solar projects turned out to incur higher transmission investment costs per kilowatt in general compared to other generation sources, including a larger bulk cost component of the projects. This result was driven by the most decisive cost component: preexisting transmission structure and the load levels. There are several studies highlighting the importance of economies of scale in transmission investments, which indicate that it is more efficient to proactively build larger transmission ahead of new generation capacity rather than make smaller transmission investments for individual projects.

According to IRENA, for the specific case of South Africa, the grid connection cost is 56% higher than the world average of 68 USD per kilowatt. However, there is a global trend of decreasing grid connection costs (13 USD per kilowatt over the past decade), which can be due to the learning curve, as well as due to economies of scale [180]. Another IRENA study focused on Eastern and Southern Africa assumes that transmission and infrastructure related expenses amount to only 2% of the capital cost of new capacities for large-scale renewables deployment in ideal zones (areas with large resources and good connections) [183].

Table 17 Connection costs per USD/MW based on the literature survey (costs normalized to 2022)

	SAPP	World	Total-Average
Transmission	*156,000*	*154,000*	*155,000*
Material	106,000	68,000	87,000
Engineering and PM	206,000	240,000	223,000

8.5.3.6 Treatment of factors influencing the reference data

Taxes, inflation, and exchange rates and outliers are the most important factors influencing reference costs in this study. Since the collected cost data considers projects realized at different times across different countries, these factors vary considerably.

Tax information is difficult to obtain considering the extent of the study. One example found, was of Tanzania electric supply company (TANESCO), who provided the tax information for new consumer connection charges in 2012. This amounted to 18% of value-added rate on top of the material and 10% contingency [184]. Collected data was segregated in regions and technical sub-groupings during the analysis which might have partially helped to capture different tax brackets.

The costs were adjusted for inflation based on the reporting date of the research, as well as to the respective country when applicable. USD_{2022} was used as a base rate, and the data provided in other currencies was converted taking currency inflation rates.

8.5.4 Cost Drivers

A working paper by IRENA provides a modelling approach to identify optimum locations for new solar and wind capacity development in Africa that embeds the features of resource potential, population density, grid and road infrastructure, land use and topography for different regions, while also considering network costs [168]. The following subsections discuss the cost drivers identified in the aforementioned study as well as in the other reports analyzed.

8.5.4.1 Economies of scale vs. Supply curve effect

In case a large volume of new capacity is developed in a certain region, this volume may enable higher voltage transmission lines that would be used for a series of individual connections. In this way, economies of scale can lead to lower unit costs of transmission. However, the supply curve effect can counter-balance this, such that as more new capacity is added to the system, lower-cost development prospects get exhausted.

The analysis of Mills on wind connection projects in the USA showed that projects with over 10 GW incremental generation capacity have connection costs of less than 500 USD per kilowatt, whereas projects that add between 1.1 GW to 4 GW of incremental generation capacity have costs over 1000 USD per kilowatt most of the time [175]. However, the study emphasizes that the unit cost of transmission does not experience a strong increase at higher levels of new capacity deployment in the case of large utility-scale projects in larger areas with consistently high resources. Once dedicated transmission is built to connect generation in the area, the high resource availability enables more transmission to be built at approximately the same cost to realize more generation capacity.

This observation was also made in the IRENA theoretical study for Africa; in which a “remoteness premium” for wind resources was identified: There is an economic sense in exploiting excellent remote resources that makes additional infrastructural investment worthy [168]. The same conclusion was not made for solar resources, due to the significantly lower resource differences between regions in comparison to wind. For example, Namibia and Somalia were identified as the optimum regions for PV generation in Africa. Nevertheless, Namibia reaches substantially lower LCOE levels than Somalia once the grid integration costs are embedded. The reason is that the remoteness premium of Namibia is lower due to a more adequate existing grid infrastructure, whereas the resource potential in Somalia was not large enough to cover for the remoteness premium.

8.5.4.2 Population spread

The Kenya National Electrification Strategy highlights another point of attention for grid connection cost parameters [185]: Regarding universal electricity access, the government estimates grid intensification costs (connection to the medium voltage grid within a 2 km perimeter) to be five times higher (1.9 billion USD) than those of grid expansion (connection to the medium voltage grid in a perimeter of more than 15 km). Most of the population and economic activity is concentrated in the south-west of the country. Consequently, the grid is far more developed there than in the rest of the country [185]. Further electrification of the sparsely populated areas through off-grid systems is more economically feasible than connecting them to the national grid. Remoteness premium can become particularly high when different grid systems are considered. Similarly, the study of Deichmann for Sub-Saharan Africa points out that as the centralized grid expands into more sparsely populated areas, the marginal cost of network provision is likely to be higher than the marginal cost of decentralized provision at some point [186].

8.5.4.3 Site specific needs

VRE resources have site-specific features and variability. Therefore, high VRE penetrations require a more flexible and resilient power system. The study of Hess shows the impact of fluctuating energy supply on grid expansion costs, as the generation peaks increase grid expansion needs [187]. Therefore, site-specific generation profiles should be considered when the transmission system is designed. The adequacy of the grid has a direct impact on the Return of Investment (ROI) of VRE projects. The World Energy Outlook 2020 reported that the Weighted Average Cost of Capital (WACC) of solar PV investments declined over the last 5 years and curtailment volumes were reduced from 15% to 3% thanks to improvements in grid structure. For example, due to its low network density, California experienced significant wind and solar curtailment due to grid congestion. 70% of the curtailments were driven by congestions in the first half of 2020 [188].

8.5.4.4 Technology couplings

Complementary technologies to VRE generation can also have an impact on the site-specific grid connection costs. For example, the study of Kennedy highlights that when Concentrated Solar Power installations are complemented with Thermal Energy Storage, this can help with reducing the grid expansion and maintenance costs [189].

The study of Klonari proves that hybrid power plants can reduce infrastructure investment costs, as only a single grid connection point needs to be set up in most cases (the substation and coupling point are shared), and they facilitate optimal utilization of the total grid connection capacity. In case a PV installation is made within the power converter specs of the turbine, it is even technically possible to eliminate solar inverters by connecting PV and wind on the DC level. The shared infrastructure can be used more effectively in particular when wind and solar generation profiles are complementary [190].

8.5.5 Cost Overruns and Risks

According to the AEMO 2021 Transmission Cost Report, the project costs can vary up to 50% from the initial estimation due to several risks [170]. The Kenya Energy Ministry considers 5% of the EPC price as a contingency margin for the grid development plan [176].

The research of Sovacool [191] covers 50 international transmission projects and provides a statistical insight about their cost overruns. An average overrun of 30 million USD per project was calculated. HVDC projects had the largest budget overruns, and the single project with the largest overrun (1 billion USD) was the Inga-Kolwezi HVDC line in Democratic Republic of Congo. Nevertheless, the reason behind it is that this project was realized in extremely hard conditions in 1982. Other transmission investments were found to be relatively safe from overruns due to the mature technology and the relatively short construction times.

According to the World Bank, setting up a grid-connected renewable energy project such as a wind farm takes 17 months on average, but the observed range extends from one month in Ukraine to 60 months in Honduras. Short time frames protect cost estimations from fluctuations in the market due to changes in material and component costs [169]. Furthermore, transmission projects have large siting issues due to crossing through land with many different owners, which usually introduces large delays.

The policy and regulatory settings also play a role in increasing the overrun costs. They can impact grid connection costs, project development lead times, obtaining permits, environmental impact assessment costs, etc.

The prices for the fundamental materials of connection equipment are subject to macroeconomic conditions and the global supply and demand dynamics. Common conductor materials used for transmission and distribution systems are copper, aluminum, steel-cored aluminum, galvanized steel and cadmium-copper alloys. Although copper has better physical and chemical properties, aluminum is widely preferred as a replacement material with lower cost and lighter density. The supporting towers for the over-headlines can be wooden, steel, reinforced cement concrete or lattice steel. The choice of supporting structure depends on the necessities of the individual projects (weight, wind loads, humidity etc.).

Forecasting material prices is very difficult; nevertheless, the trend of the previous 20 years shows that the prices are increasing, and they have constant volatility. For example, in 2022 the copper price averages 9500 USD per ton, which corresponds to an increase of over 400% compared to 2000.

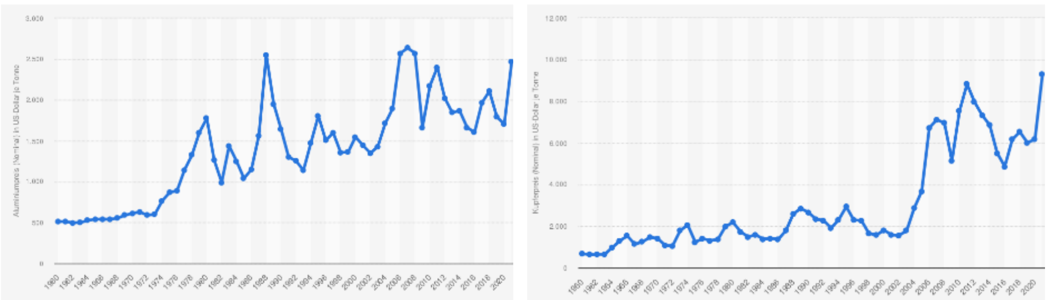


Figure 87 Development of Aluminum (left) and Copper (right) prices 1960-2020 [192]

8.5.6 Refurbishment Costs

In older power systems, such as the European, 20% of the current network needs to be replaced. However, most of the global line replacements are expected to take place in emerging and developing economies [188].

A study focused on sub-Saharan Africa developed by Africa Infrastructure Country Diagnostics (AICD) used the assumption that the refurbishment unit cost amounts to 60% of the replacement cost for lines older than 30 years. The transmission systems in some countries are considerably old with high shares of equipment being above the 30 years threshold, e.g. Niger with 96%, Zimbabwe with 85% and Zambia with 80%. The following table lists the average transmission (>66 kV) and distribution (<66 kV) system features and corresponding refurbishment costs per power pool based on [171].

Table 18 Refurbishment cost estimation by power pool based on AICD study [171]

Power Pool	Line Type	Line (km)	Unit Value (USD/km)	% Assets >30 years	Refurbishment Cost (million USD)
SAPP	Transmission	11086	139,000	48	600
EAPP	Transmission	6078	105,000	49	299
WAPP	Transmission	2157	134,000	46	120
CAPP	Transmission	935	132,000	49	24
SAPP	Distribution	54576	50,000	45	747
EAPP	Distribution	15932	44,000	34	212
WAPP	Distribution	46969	47,000	38	303
CAPP	Distribution	4454	24,000	44	24

8.5.7 Operational Costs and Losses

Transmission and distribution losses in 2016 were estimated by the AfDB as shown in the table below [193]. Further upgrades and investments in the grid are expected to reduce these losses. The AfDB assumed that losses would be reduced by 0.5% per year until they level out at 10%.

A study [194] shows that between 2006 and 2016, 20.1% of the total electricity supply in Ghana was lost due to transmission and distribution issues, which is aligned with the AfDB estimations, and the corresponding annual price of such losses was estimated to 100 million USD. Nevertheless, it was also underlined that transmission system losses alone only amounted to around 4% of electricity supply.

Without infrastructural development, grid congestion can become more frequent and impactful, resulting in power outages and supply shortages. The economic consequences of outdated and inadequate grid infrastructure are usually of a much larger scale than those of grid specific costs. According to estimations by the Finance Ministry of Ghana in 2019, Ghana had to bear costs exceeding 2.5 billion Ghana-Cedi (approximately 450 million USD) annually due to the inadequacy of the power transmission infrastructure [194].

In Asia, a study focused on ASEAN countries by ERIA assumes the OPEX to be 2% per year of the CAPEX for transmission infrastructure cost estimations [174]. In Australia, AEMO approximated the projects' OPEX as 1% per year of the CAPEX. Some sources in the USA estimate that the average annual transmission O&M costs are 5%–10% of a project's original CAPEX [195]. A rough figure of 2 million USD per country was estimated by the AfDB as the minimal level of necessary investment in existing grids for upgrades and maintenance [193]. Specifically for Africa, Rosnes assumed that the original asset depreciates at 3% per year in Sub-Saharan Africa. Together with the OPEX costs, the relevant annual investment to maintain the grid capacity and functionality over a 10-year period was determined as 5% of the original CAPEX [171].

Transmission infrastructure with poor maintenance conditions is more prone to failure and under-performance with high system losses, and likely to reach the end of its lifetime prematurely. Hence, the age and fitness of the existing T&D infrastructure is crucial for estimating costs for new grid connections. A paper [196] provides the failure rates of different network components and corresponding costs based on German network data. For example, the failures of steel towers, overhead lines and power transformers amount to 83% of the outage costs of the whole German power system.

Table 19 Failure rates and costs per grid component [196]

Equipment	Major failure /year	Major costs/year (€)	Minor failure/year	Minor cost/year (€)
Substation	0.00218	48066	-	18508
Circuit-breaker	0.00067	17127	0.00407	12983
Transformer	0.00569	106352	0.01138	40469
Disconnector	0.00035	11464	-	5801
Secondary equipment	-	20166	0.00228	4696
Shunt inductor	-	85082	-	119336
Instrument transformer	0.00025	30939	-	7182
Transmission route	-	-	-	-
Steel tower	0.00013	103590	0.00478	26242
Overhead line	0.00051	0	0.01913	4143

8.6 Grid Integration: New Technologies and Future Aspects

Grid technology is developing rapidly and new technologies will play an important role in the future development of any power system in the world, including Africa. In the following subsections some technical developments are presented in more detail, using case studies from around the world. For each technology, a brief summary of relevant aspects is provided.

8.6.1 High Voltage Direct Current - HVDC

High voltage direct current (HVDC) is frequently used for bulk power long distance transmission. Its main advantage, the lack of need for reactive power compensation, makes it an economically attractive option for this application case, such as interconnecting remote large-scale PV. Furthermore, HVDC links allow connection between asynchronous systems either with different frequencies or phase angles [197]. This is particularly relevant when interconnecting different power systems and/or countries for increasing the transnational interconnection capacity. HVDC interconnections provide full controllability of the power flows and can therefore be used to help avoid congestions in the AC grids they are connected to.

HVDC systems have various applications useful for integrating variable renewable energy, such as PV, to the grid. Due to the power electronics used in HVDC converters, the active and the reactive power flows can be controlled independently. Controllability of active power facilitates efficient utilization of grid infrastructure [198]. Furthermore, due to its fast controllability, the system's stability and security can be enhanced by the ability to support during blackstart, by damping power oscillations, by providing AC voltage control, and sometimes by contributing synthetic inertia [199]. Independent controllability of reactive power is of great interest particularly for weak or passive systems.

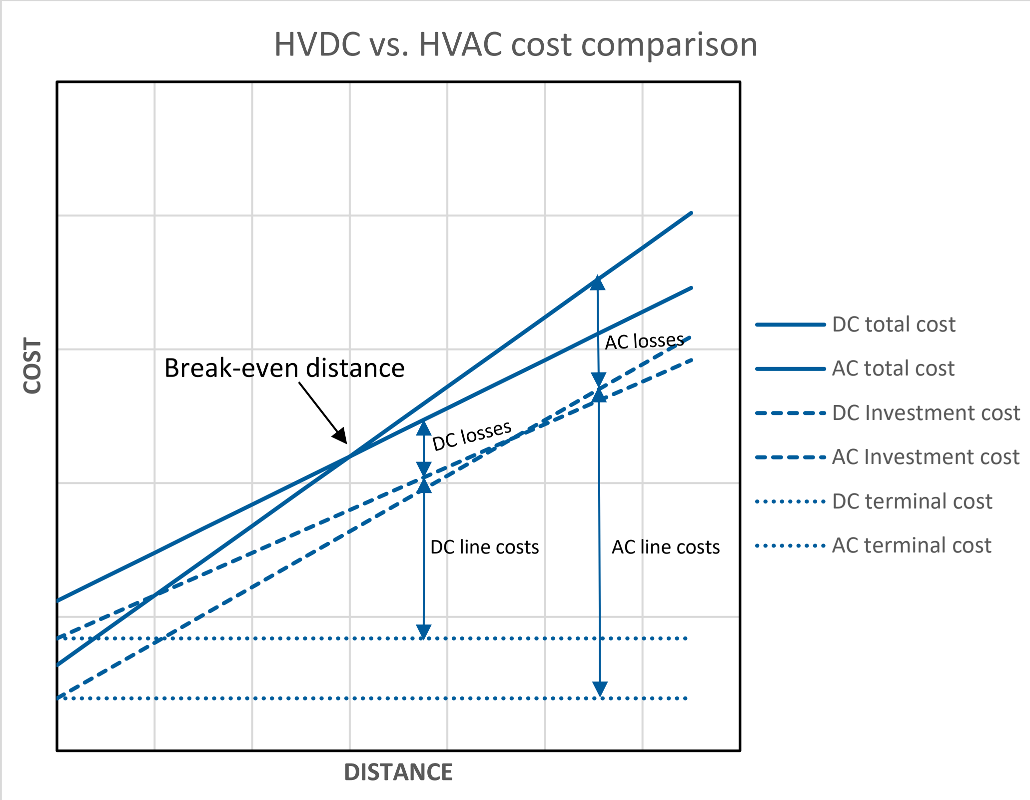


Figure 88. HVDC vs. HVAC costs [200]

The advantages of direct current transmission are [201]:

- Lack of need for reactive power compensation
- Possibility of power flow control
- Fewer losses in DC lines than in AC lines due to lack of skin effect
- Longer lifetime due to the absence of dielectric losses
- Adaptation to different systems frequencies and voltages
- Greater transmission capacity with less materials and cable requirements
- Narrow rights-of-way and lower visual impact than HVAC [201]

HVDC technology comes with a high capital expenditure due to the high cost of the converter stations [201]. However, transmission costs in DC are lower than in AC; this is why after a break-even distance of around 500-800 km for overhead lines or 50 km for offshore transmission, HVDC technology is a better option, as shown in Figure 88 [200].

Some of the disadvantages of HVDC compared to AC systems are the complexity of its arc extinguishing devices, the need for faster grid control and grid protection, lower efficiency for short-distance transmission due to higher converter losses, additional infrastructure needed such as AC filters to eliminate harmonics, DC filters to eliminate ripples, and cooling to dissipate the heat produced by switching losses [201]. Furthermore, there may be challenges regarding multivendor interoperability.

Regarding the direct current converters, AC/DC rectifiers and DC/AC inverters are required. There are two HVDC converter technologies: Current Source Converters (CSC) also called line commutated converters (LCC) based on thyristors, and Voltage Source Converters (VSC) based on IGBT transistors (Figure 89) [197].

CSC works with constant current direction; the power reversal is done by changing voltage polarity [197]. This technology is more mature than VSC because it has been in the market for a longer time. This has the advantage of having low operational losses ~0,7% [202], but the harmonics are more predominant than in VSC. A CSC consists of converters, converter transformers, reactive power compensators, smoothing reactors, AC and DC filters, and DC connections [197].

In VSC the current direction changes with the power, while the voltage polarity remains the same. This technology has fewer harmonics than CSC, because the switching frequency of the IGBTs is higher; however, this implies higher losses of ~1%. The VSC systems are usually formed by: converters, converter transformers, inductances, DC capacitors, control systems, AC and DC filters, and DC connections [197].

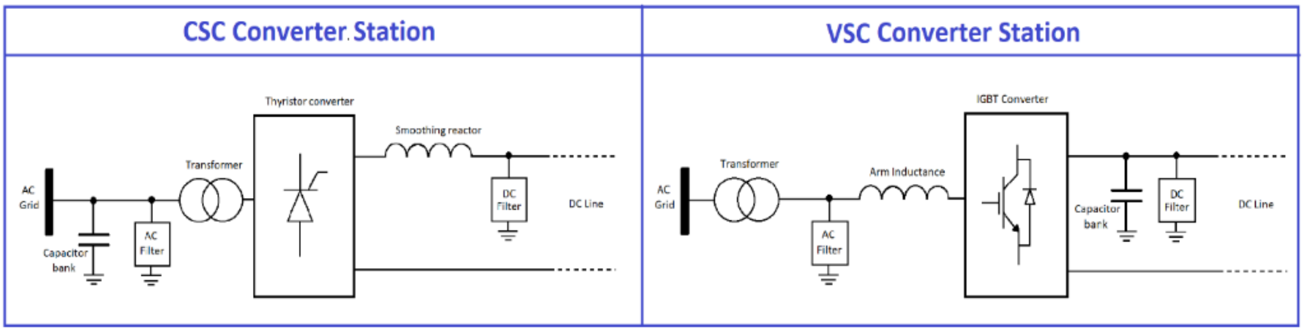


Figure 89. HVDC Technologies: CSC Converter and VSC Converter [197]

Additionally, HVDC can be connected in a point-to-point configuration, in which the rectification and inversion are located in the same area. This topology is mainly used to control power transfer between two asynchronous AC systems [203].

According to the global innovation report from 2020 to 2025 [204], the HVDC market is expected to grow at a rate of around 11%, which is more than three times faster than the projected growth in the global gross domestic product (GDP). In particular, VSC HVDC systems that can operate from several hundred MW to approximately one GW have increased their cumulative capacity exceeding 30 GW during 2020 [204].

Selected HVDC application examples (worldwide)

1) In 2020, the Nordlink HVDC link between Norway and Germany was established. It enables grid interconnection and exchange of power from renewables such as wind, solar, and hydropower with a power transmission of 1,400 MW in ±500 kV. The converter stations are of VSC technology with a bipolar configuration. The total length is 623 km, with 83% being submarine cable [205].

2) The Melo HVDC station in Uruguay is a back-to-back HVDC connection between Uruguay's power grid operating at 50 Hz and Brazil's power grid at 60 Hz. The converter can provide up to a third of Uruguay's power needs [206].
3) By 2027, the world's largest offshore wind farm on the east coast of the UK is expected to have two HVDC systems capable of transmitting at least 2.85 GW of renewable electricity to power more than 3 million UK homes. This project contributes significantly to the goal of the British Energy Security Strategy of obtaining up to 50 GW of offshore wind capacity by 2030 [207].
4) According to a techno-economic comparison between HVDC and HVAC for a proposed system in Afghanistan of 1,000 MW and 640 km in 500 kV, the implementation cost of a VSC HVDC technology system is approximately 28% lower than the cost of its AC alternative; considering losses and maintenance The higher capital expenditure for the AC system is due to a required STATCOM for voltage stability, which is not needed in the HVDC variant [201].
5) The Cahora-Bassa HVDC connects the Songo converter station in the North of Mozambique near the Cahora Bassa hydropower plant to the Apollo substation in Johannesburg, South Africa. This link consists of two parallel monopolar lines transmitting 1,920 MW in a 1,420 km long route. This project was commissioned in three stages between 1977 and 1979. Since this transmission system is an important source of imported power to the South African grid, in the year 2006, the Apollo station was updated to increase the capacity of the transmission to 2.500 MW and enhance the availability and reliability of the station as well as to reduce required maintenance. In 2013-2014, the Songo station was refurbished to increase system reliability by replacing high voltage equipment such as transformers, DC smoothing reactors, arresters and measuring equipment [208].

8.6.2 Virtual Power Plant (VPP)

A VPP is a system that integrates various types of distributed energy resources (DERs) into a small or medium-scale decentralized power network to increase flexibility and enable trading of products such as energy and reserve power in different electrical markets. VPPs can consist of wind turbines, distributed solar PV, heat and power units, flexible energy consumers, and storage systems, among others [209]. The aggregation of several small assets into a VPP make the net generation profile a more stable one, that can be better forecasted, optimized, and marketed [209].

An important characteristic of VPPs is their ability to participate directly in the electricity markets as a manager of controllable loads and as a provider of energy and other products, in order to obtain greater economic and technical benefits. A diagram of a VPP and its interaction with the electricity network and market is shown in Figure 90 [210].

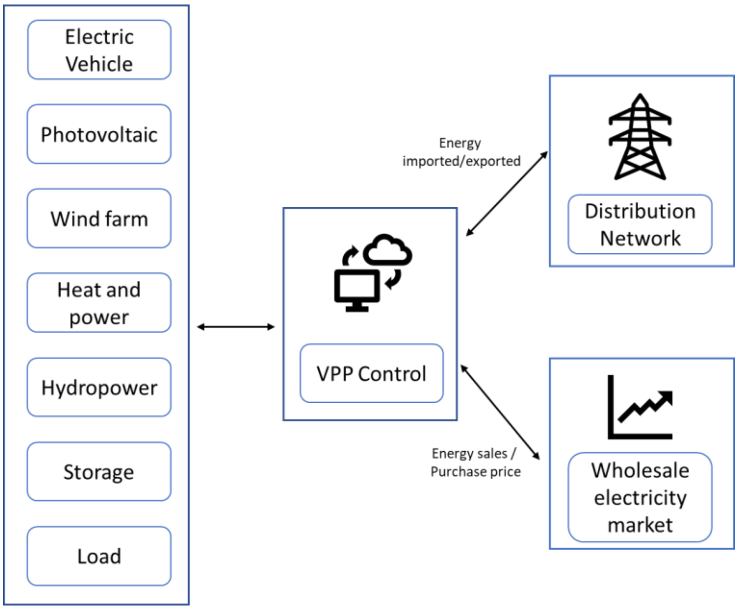


Figure 90. Diagram of a VPP and interaction with electricity network and market [210]

The main applications of VPPs for integration of renewables are:

- Renewable capacity firming: The aggregation of several small generators reduces variations and forecast errors, allowing for the generation to be kept at committed levels. This is further enhanced by other DER such as storage and flexible loads.
- Load shifting and emissions reduction: It offers demand management services to network operators to make real-time shifting in residential, commercial and industrial loads based on prices. This could reduce the demand for power plants that produce high carbon emissions [211].
- Grid support: With VPP software and other optimization platforms, intermittent renewable energy resources such as solar and wind power can also provide voltage, frequency, and reactive power control [211]. This includes providing system wide flexibility, as well as local flexibility for DSOs [212].
- Improve forecasting: by taking advantage of the aggregation of generating resources, its distributed nature and the historical data, VPP may provide a forecast to operators who not always have visibility of the generation at a distribution level [212].

VPPs are becoming attractive because, through providing the aforementioned services, they can offer savings for the utilities by optimizing the system operation. In 2020, Europe led the VPPs market share with a value of 0.28 billion USD, and according to the Market Research Report by Fortune Business Insight, the Compound Annual Growth Rate (CAGR) of the global VPP market is expected to grow at 32.89 % during the 2021-2028 period [213]. VPPs are becoming popular in systems with high penetrations of DER and established wholesale markets such as the Netherlands, Norway, the United Kingdom, California, New York, South Australia and Japan [212]. However, VPPs still have some barriers ranging from customer access and acquisition costs to data flow, privacy and cybersecurity to fulfill technical requirements and to participate in the different markets [211].

Selected VPP application examples (worldwide)

1) The South Australian Virtual Power Plant (SA VPP) is a network of 50,000 solar-battery systems. This VPP operator uses Wi-Fi technology and sophisticated software to charge or discharge energy from batteries and trade it in the national energy market. SA VPP leases the solar-battery systems from the customers, offering them a reduction in their electricity bills of up to 423 AUD per year. This VPP is able to provide support to stabilize the grid frequency, which can help to ensure the availability of power during trips, disconnections, high and low frequency events, as was needed for instance during the bushfires in 2019. The project began in 2018 and it is currently supported by the government and the Australian Renewable Technology Fund [214].
2) TenneT, the TSO from the Netherlands, uses a grid service called automatic Frequency Restoration Reserve (aFRR) to provide support for balancing the system. Traditionally, this service is provided by utility-scale power plants. However, with the decentralization of the system, the availability of this service will decrease. With this in mind, TenneT launched a pilot project to investigate the feasibility of the aFRR delivery with new flexibility sources such as aggregated DER. The results show that aggregated DER are technically capable of providing aFRR and they adopted some measures to make the bidding and settlement processes easier for these assets. Particularly, one of the seven pilot partners provided aFRR through the aggregation of electric vehicles through a virtual power plant. The electric vehicles can provide balancing for both deficits and excess of electricity [215] [215].

8.6.3 Hybrid Power Plants (HPPs)

HPPs are the combination of multiple generation assets in a power plant with a single interconnection point [216]. It may include two or more technologies such as wind turbines, solar PV, Concentrated Solar Power (CSP), storage, geothermal power, hydropower, biomass, natural gas, oil, coal, or nuclear power [216]. The main objective of an HPP is to be capable of providing well-controlled generation instead of arbitrarily variable generation, thus ensuring a stable and efficient supply, considering variable renewables. HPPs can also have lower electricity costs, fuel consumptions and CO2 emissions compared to power plants of only one technology [217] [218] [219]. HPPs were developed to compensate the variable nature of wind and solar, and so the most usual combinations are: Phovoltaic+Wind, Photovoltaic+Hydro, Hydro+Wind, Wind+Diesel, Solar PV+Diesel, Solar PV+Battery storage, and CSP+Biomass [219].

HPPs are becoming popular as they can increase the system reliability and push for increasing shares of variable renewable sources by:

- Allowing capacity firming, similar to VPP, the complementarity of different generation sources and storage can keep the generation at committed levels.
- Provide reliability as the generating technologies can provide energy uninterruptible.
- Provision of flexibility and other grid services by variable renewable energy
- Increasing capacity factor of the overall plant, as the technologies complement each other during their generating times.
- Improve profitability of projects as it can stack different revenue streams and generate more hours during the year.

Further advantages of HPPs are the possibility of lowering costs for final consumers, as one single connection point normally has lower needs of grid infrastructure investments and thus lower grid tariffs [220].

The biggest challenges in HPP are:

- Location: having an optimal location for more than one source of generation.
- Complexity of their design: Due to the interaction of the different technologies more considerations must be taken. For example, precautions for shadows on PV panels or using only one converter for wind and solar.
- Potential resources: Its characterization as well as the potential revenue streams available based on local market conditions [221].
- Scarce regulations: Since the individual technologies of HPP are mostly established and mature, the concept of enabling HPPs in a system is a regulatory and market design issue, as for example, the connection and metering processes are quite new and therefore are not standardized and/or streamlined

Selected HPP application examples (worldwide)

1) In 2022, in Haring Vliet, Netherlands, an HPP was inaugurated. It will be able to produce energy at a lower cost than individual power plants, and enhance the use of available grid capacity. This project consists of six wind turbines, 11,500 solar panels, and a large battery. All three technologies share the same grid connection. The HPP will produce around 140 GWh of electricity per year, the equivalent of the electricity consumption of 40,000 Dutch households. This project leverages the complementarity of wind and solar during different seasons and within a day, while the battery ensures that the grid remains balanced. The sharing of the substation, cables, grid connection, and the maintenance of roads reduced the initial investment and time required [222].
2) Isolated electrical systems have challenges regarding stable and affordable energy system due to variability in weather conditions , fluctuations in demand, and high costs of energy and imported fuels. In this scenario a hybrid solution could improve the reliability of the system and reduce energy costs, compared to having several power plants. MAN Energy Solutions conducted an analysis on an island system with a peak demand of 80 MW and a reserve requirement of 20%. The traditional solution considers the addition of three heavy fuel oil engines. However, an HPP consisting of an energy storage system and 30 MW

photovoltaic panels could replace one of the engines, reducing the Levelized Cost of Electricity (LCOE) by 10%, and achieving a payback period of less than 4 years, and a Return of Investment (ROI) of up to 30% [217].

3) In Ghana, a 50 MW hybrid solar-hydro plant was commissioned in 2022. This project consists of the generation of electricity from solar power during the day to complement the existing hydroelectric production; it also has a floating solar component of 1 MW. This takes advantage of the vast solar resource and enables the operators to use the hydro resource only during the evenings, which can been affected by low water levels during dry seasons and droughts. This project is expected to reduce greenhouse gas emissions by more than 47,000 tons per year. The plant is built in instalments of 50 MW up to a total of 250 MW [223].

8.6.4 Smart Grids

The transformation of primary energy use worldwide aimed at replacing fossil fuels with renewable resources, especially solar PV and wind, changes power system planning and operation in fundamental ways. Where previously generation was designed to cope with the variability of the demand, there is now significant uncontrolled variability on both the demand and generation sides, and new sources of flexibility become needed to balance the system. All available sources of flexibility will be needed, including demand flexibility through Demand-Side-Response (DSR), inter-regional power exchange through enhanced transmission and distribution infrastructure, application of energy storage, and electrification and digitalization of flexible demand sectors such as heating and mobility. Intelligent planning and operational management is required to keep the system efficient under these conditions. The corresponding introduction of new intelligent operation and control mechanisms is transforming the traditional power systems into Smart Grids.

A smart grid should have at least communication, measurement, control and automation infrastructure that allows for real time visualization of and reaction to the grid conditions [224] [225]. This can serve different purposes such as automation of processes, engagement of customers/users, transformation of the distribution grid to a more active role, and more efficient integration of renewables.

All kinds of grid users are relevant as potential providers of flexibility in the smart grid. This is illustrated in Figure 91 [226].

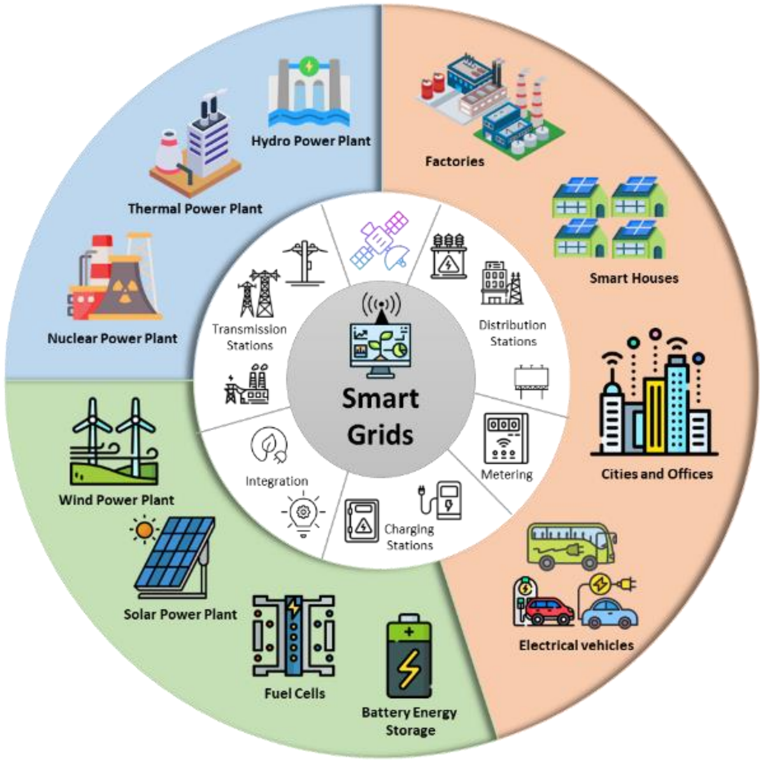


Figure 91. The Smart Grid concept involves all grid users [226].

For the purposes of the present discussion of new grid-related technologies, three smart grid applications will be described in more detail: SCADA, demand side response and sector coupling. These are well established and proven applications in multiple systems worldwide and have aided in the integration of renewables.

8.6.4.1 SCADA

A supervisory control and data acquisition (SCADA) system refers to a collection of hardware and software that provides an operator (from a power plant, TSO, DSO or ISO) with enough data regarding the current conditions of their equipment and/or processes. It can also involve remote control reactions to a specific set of conditions, i.e. automation. Traditionally, SCADA systems are used in power systems to monitor and control generation assets and transmission network elements in voltages of 110 kV or above [226].

SCADA systems consist of:

- Remote Transmission Units (RTU) in traditional SCADA systems, or Intelligent Electronic Devices (IED) in Smart SCADA systems, which will collect, convert, and bundle data;
- A communication system transmitting the data from the RTU or IED to the master station;
- A Master Station and a Human-machine interface that decode the data and allow the operator to monitor and control the system.

With further modernization developments, advanced metering infrastructure (AMI) and smart SCADA systems can be used for communication between the utility, distributed generators, substations and loads, enabling increased integration of renewables. A SCADA system serves the system operators to monitor and control trackers, meters and inverters and increase observability of the network state. This can serve the integration of renewables by:

- Detecting and communicating disturbances in the power plants,
- Control specific power plants or storage units in terms of their (active and/or reactive) power output,
- Coordinating different components of the power system to improve operations and efficiency,
- Predictability/forecasting of renewable generation,
- Enable other technologies such as FACTS, HVDC, DLR.

Figure 92 shows an example of a power plant SCADA system used for renewable energy management in an HPP that combines solar photovoltaic, fuel cells and wind power [227]. The system components of the HPP are connected to the SCADA through Programmable Logic Controllers (PLC) and remote terminal units (RTUs) for real time supervision and control. The PLC collects all the data and connects to the control room through a communication link. Another PLC is connected to the energy management unit to carry out the control actions according to the grid needs.

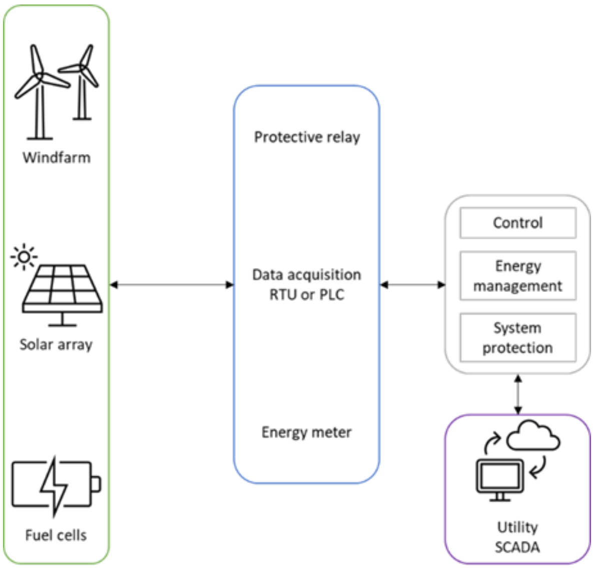


Figure 92. SCADA systems for renewable energy management based hybrid power system [227]

An example use case of a modern SCADA application is the Ingesys smart SCADA platform based on big data and IoT by the company Ingeteam [228], developed for the integration of renewable energy systems in transmission and distribution systems. With the implementation of this platform, it has been possible for a client to detect anomalies within the power plant, as well as changes in the behavior of the network. This allowed the client to detect underperformance in one of the wind farms, prevent failure of equipment such as transformers based on abnormal thermal behavior, and calculate the curtailment losses in a solar plant. As a result, after the first year of operation, the client generated estimated savings of over $500.000 [228].

8.6.4.2 Demand side response (DSR)

DSR is a strategy to optimize electricity consumption to increase the flexibility of the system, by shifting consumption in time (Figure 93). Traditionally, DSR has been done by large consumers that get a preferential tariff under the condition of disconnecting their consumption if the operator sent a signal. Through modern technologies and electricity tariff schemes, the active participation of small consumers is possible as well. For providing flexibility to increase or decrease the load and follow the generation profile, it is necessary to have load forecasting, smart devices that allow load switching, and if possible energy storage [229]. The implementation of these options represents an investment cost that must be weighed against the potential savings for the consumer and greater availability of the service by avoiding blackouts during peak hours [230]. This can be particularly relevant for PV integration, as DSR allows shifting the consumption into the time periods when the panels are producing their maximum power. This can be done in a distributed scale to match generation and consumption locally, or at a large scale where industrial and commercial loads provide flexibility to balance the system.

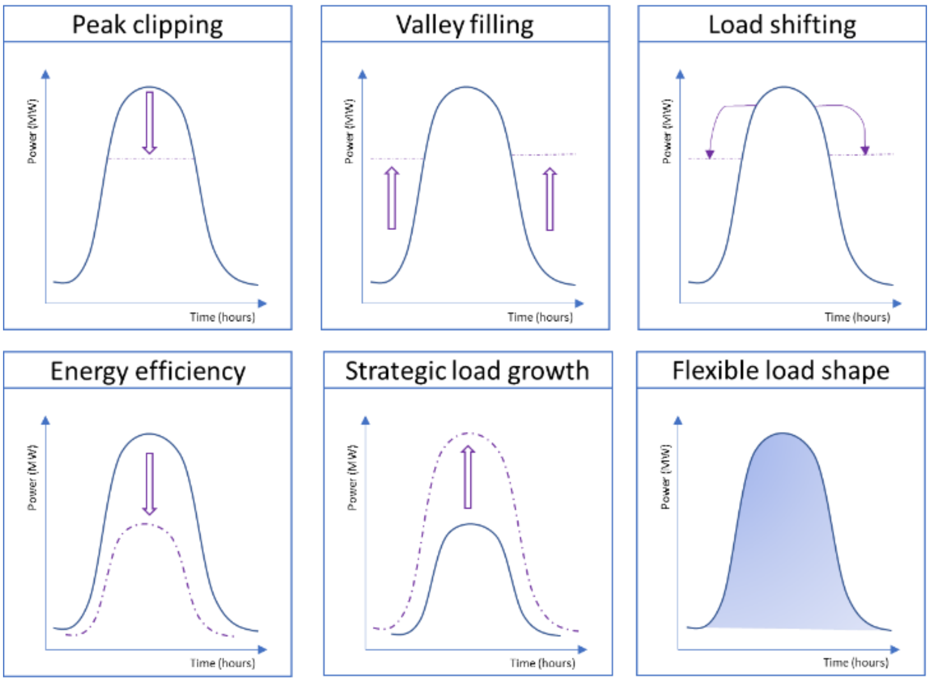


Figure 93. Demand Management Strategies [229]

A study performed in Turkey found that the adoption of a DSR system with consumption measures such as flexibility in heating and domestic hot water, air conditioning, and smart charging of more than 2.5 million electric vehicles has the potential of reducing the net peaks of the system by more than 6 GW by the year 2030, as it is shown in Figure 94 [230].

It was also observed that flexibility in the electricity-intensive production processes of cement, paper and steel could have an impact of 900 GWh per year. In this case, the CAPEX (Capital Expenses) of the DSR system has an approximate cost of 72 million euros/year. However, with these initiatives a net saving of 550 million euros/year is expected, representing a significant saving in electricity costs [230].

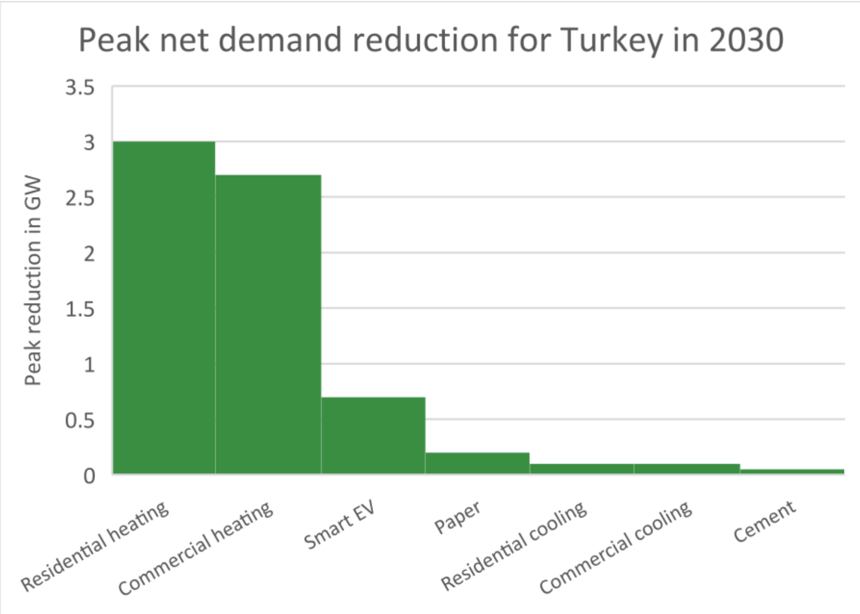


Figure 94. Contribution of DSR sector via reduced peak net demand in Turkey study [230]

8.6.4.3 Sector coupling

The electrification of other sectors is considered one of the most important strategies for achieving energy decarbonization [231]. Sector coupling seeks to increase the use of electricity from renewable sources in areas such as heating, cooling, mobility and transportation, thus contributing to the energy transition of all sectors [232].

Figure 95 shows the sectors aimed to be coupled with the power system [233]. All sectors benefit from this coupling: The heating, gas, and mobility sectors can be decarbonized from a renewables-based electricity system, which in turn benefits from the flexibility available from these sectors, enabling significantly more efficient integration of variable renewable resources. Many applications in the coupled sectors are able to respond quickly to variations in the availability of power [231]. For example, heating and cooling applications have an intrinsic thermal inertia. This allows for switching on and off the supply to follow variations in generation, without significantly impacting the thermal use case. In the same manner, electromobility allows for load shifting, as long as the batteries have enough energy at departure time.

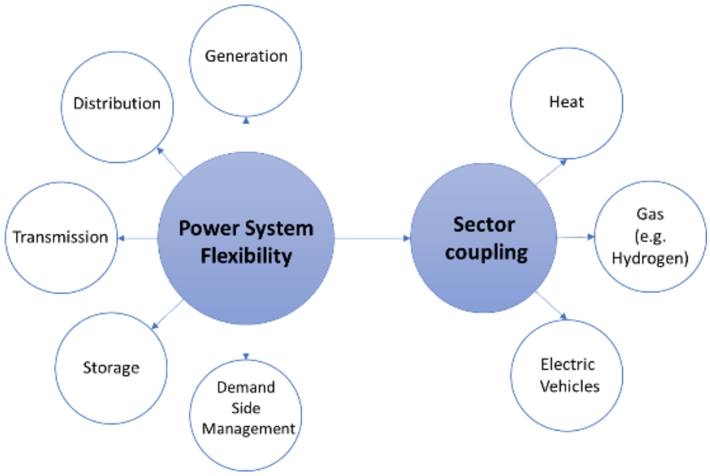


Figure 95. Flexibility in Power system and sector coupling [233]

Technologies for sector coupling must be developed in such a way as to help increase the stability of the energy system and reduce energy costs. This increases the complexity of the entire coupled system, which also comes with challenges. For example, estimating risks and costs becomes more complex [232]. Plenty of data, monitoring and controlling capabilities are needed to tap into the full potential of sector coupling.

Selected sector coupling application example (worldwide)

1) The pilot project Rosa Zukunft implemented in Austria combined smart electrical, thermal and gas networks with thermal storage to take advantage of synergies between the different sectors for 129 houses. The integration of the sectors was satisfactorily achieved, reaching great reliability in residential heat supply. However, due to the complexity of the project, considerable effort was required for the dimensioning and energy calculations, which meant a suboptimal economic efficiency because of the oversizing in some of the units for energy production and storage [232].

8.6.5 Grid Codes

A Grid Code, also known as network code or interconnection code, is the set of conditions for accessing the electricity grid [234] to ensure the safety, quality, security and reliability of the power system. With the increased integration of renewable energy resources and new technological development, grid codes have evolved to enable connection of new resources according to their capabilities and limitations [235]. Grid codes may have different scopes, covering for example utility-scale generators, distributed energy resources of various types and sizes, transmission and distribution infrastructure, and/or loads; they may also include market guidelines, operational and planning guidelines, and metering [236]. The technical requirements included in the grid codes shape the current and future power systems.

Current grid codes usually include the following technical topics with regard to connection requirements [235]:

- To ensure power quality, limits on harmonics, flickering and voltage dips are included.
- Specification of frequency and voltage ranges during normal operation and contingencies prevent inadvertent disconnection of generators due to unavoidable variations. Active and reactive power capability curves facilitate voltage management. Some grid codes are including limits on the rate of change of frequency, and/or an inertia floor, to address further stability issues.
- The required behavior of generators during faults must be specified. This includes fault withstanding capabilities, and may also include anti-islanding protection and black start capabilities.
- Specification of required protection devices, and their default configuration and permissible ranges of settings, also makes behavior during faults predictable for system operators.
- Cybersecurity standards to be complied with.

The technical requirements in grid codes apply to all grid users, including distributed generators, storage systems and adjustable loads. Besides mandatory requirements for connection, grid codes can also specify requirements to be eligible to provide certain ancillary services.

A relevant topic in the context of grid codes is that in order to maintain system stability, it might sometimes be required to retrofit legacy installations to meet new requirements. Such retrofitting schemes are expensive, and the cost cannot be borne by the facility owners, because that would create uncertainty and prevent investment in future projects.

While interconnecting different systems, harmonized requirements between the systems are desirable for higher system reliability and improved market integration. Regional stakeholder consultations should be held as early as possible to work towards harmonizing the requirements when there is an interest in interconnecting the systems.

Grid codes play an important role in the successful integration of variable renewable energy. Depending on the shares of these inverter-based resources on the system, technical requirements need to be adapted to reflect the needs of the system as well as the technological state of the art.

Figure 96 shows the interrelated grid code and innovation trends according to [236].

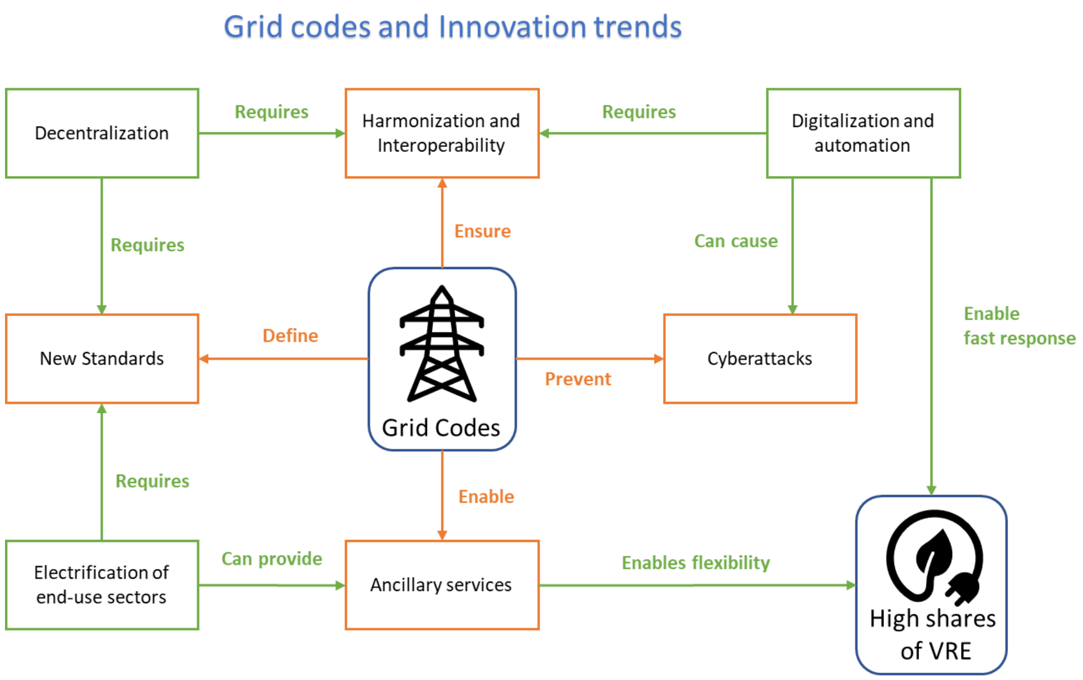


Figure 96. Grid codes and Innovation trends [236]

Selected grid code application example (worldwide)

1) The European Network of Transmission System Operators for Electricity (ENTSO-E) on behalf of the European Commission drafted a framework for the minimum set of requirements that member states' grid codes must have. Each country is required to follow these guidelines in their own grid codes. This effort seeks to facilitate the integration and efficiency of the European electricity market and the quality of the system [237], and can be seen as a step towards the harmonization of requirements. In this context it also contributes to facilitating technical requirements suitable for the integration of increased shares of renewable resources into the countries' power systems.

8.6.6 High-temperature conductors and dynamic overhead line monitoring

Since electrical current in an overhead line produces heat losses, the materials inside the line heat up and expand with increasing power transmission, which increases the sag of the line. When designing overhead lines, safety considerations are taken to ensure enough distance between the ground and the lines remains. This distance (sagging included) determines the maximum current that can go through the line considering its thermal expansion and the prevalent environmental conditions. If this distance is decreased too much, short circuits can arise; the poles or towers can fail, or surrounding vegetation can be ignited.

For this reason, overhead lines are normally operated only up to a temperature of 80 degrees Celsius. High-temperature and low sag conductors (HTLS) and dynamic overhead line monitoring are two strategies to increase the current limits of the existing network, and thus enabling transmission of more power without more substantial reinforcement and grid expansion measures.

HTLS conductors consist of materials that have a smaller thermal expansion coefficient, causing smaller expansion and therefore less sagging. Therefore, these conductors can be heated up beyond the usual 80°C temperature limit and can carry more current. While the exact increase in transmission capacity and the permitted conductor temperature depend on the technology used, it is typically about 50% to 100% more transmission capacity than that of conventional Aluminum Conductor Steel Reinforced. Some examples of these materials are Super Thermal Alloy Conductor Invar Reinforced (STACIR), Aluminum Conductor Composite Core (ACCC) and Gap-type Super Thermal Resistant Aluminum Alloy Conductor Steel Reinforced (GZTACSR).

Overhead line monitoring allows for having dynamic line rating (DLR). This is a technique to calculate the real-time rating of transmission lines instead of using static values. Since the expansion of the material depends on the temperature rise, the environmental conditions for heat dissipation play a significant role and are thus considered for determining the current limit. In this sense, normally there is a specific ambient temperature, radiation conditions and wind speed considered. For example, the German standard DIN EN50182.96, establishes the conditions considered should be 35°C, cloudless sky, 900 W/m2 and a wind speed of 0.6 m/s at a right angle with the conductor. This all translates into bad conditions for heat dissipation. Another possibility is to use historical average data or build a “worst-case scenario”. Although some seasonal differences can be considered (i.e., having different limits in the winter and the summer), this still translates into a large underutilization of the line capacity, as very rarely the environmental conditions will match the assumed ones. Overhead line monitoring can capture variables such as temperature and sag of the conductor, or the actual weather conditions. With these data, the actual capacity of the line can be adjusted and calculated in real time.

Since variable renewable energies tend to be far away from the consumption centers, the power flows can congest lines, causing curtailment and unit redispatch. By increasing the available transmission capacity, HTLS and DLR reduce congestion on power lines, optimize asset utilization, improve operation efficiency and defer more substantial grid reinforcement investments. With regard to the case of solar PV generation, the peak irradiation itself causes line heating and thermal expansion, resulting in reduced line capacity coinciding with peak generation. Thus, HTLS can help evacuate more generation. Also, cold ambient temperatures increase the capacity of the lines as well as the power output of PV panels, increasing efficiency. Overhead line monitoring can serve to evacuate the extra generation.

Selected HTLS application examples (worldwide)

1) In 2013, Power Line Africa installed ULS (Ultra Low Sag) ACCC conductors in Congo. This conductor transmits power to the Mumu mine in a double-circuit transmission line of 120 kV, which crossed Lake Nzilo. The conductor of CTC

Global was selected due to its high-strength, light-weight, high-capacity and self-damping characteristics. The transmission line has a length of 10 km, with 1.39 km over the lake between erected 108 m tall lattice structures [238].

2) A transmission line in Mozambique has been in operation since 2015. It uses an HTLS conductor to cross the Zambezi River in a section of at least 1.56 km .The main purpose of the 42 km double circuit 220 kV transmission line is to provide additional power supply to the Moatize mine in the province of Tete [239].

8.6.7 Load flow control based on power electronics

Load flow control is a concept to optimize the usage of the existing transmission infrastructure. Through different measures (other than adjustment of generation or load demand) the load on the transmission lines can be controlled to increase the use of underutilized lines and relieve those that are overloaded. This supports the integration of variable renewable energy by alleviating congestion and reducing losses caused by the transmission of power over long distances.

Controlling the power flow over individual power lines in a meshed network is complex, because the current in the network always adjusts itself according to the physical conditions of voltage and impedance. However, there is equipment (phase-shifting transformers, and new equipment based on power electronics) that allows to achieve more direct control by modifying these physical conditions. In a transmission path with a line with high impedance in parallel to a line with low impedance, the line with low impedance will carry the bulk of the power flow. Hence, the power flow can be adjusted by modifying the line impedances. The effective line impedance of a specific line can be adjusted by inserting controlled series compensation, or by inducing a voltage in series with the line impedance. In a similar manner the voltage angle at selected line endpoints can be adjusted, also resulting in a modified power flow.

These strategies make it possible to increase the power flow in underutilized lines and decrease it in overloaded lines, resulting in a more even utilization of transmission equipment and consequently in prevention of line overloading and reduction of losses. The power flow control equipment must be controllable and able to adapt to different situations, as the loading of the transmission lines depends on the varying consumption and generation conditions, including variable renewable generation, maintenance schedules, etc.

Some of the different technologies used to control power flows are:

- **Phase-shifting transformer (PST):** This type of transformer consists of two individual transformers, one of which takes the voltage from the grid while the other induces a voltage in series to the line conductors. The value of this induced voltage can be controlled. PSTs do not offer fast-responding power flow control and can only provide coarse control increments.
- **Flexible Alternate Current Transmission Systems (FACTS):** FACTS use power electronic components (i.e., very fast, controllable equipment) to influence the

power flow. FACTS are superior to phase-shifting transformers in terms of fast response times and more fine-grained controllability. Examples of FACTS are:

- **Thyristor Controlled Series Capacitor (TCSC):** It is essentially a controllable capacitance built into the line.
- **Unified Power Flow Controller (UPFC):** It is a flexible tool for inducing voltages in series to the line it is connected to. It can also provide voltage support.

Selected PST and FACTS application examples (worldwide)

1) The 330kV Nigerian National Grid has an installed power generation capacity of about 5500 MW; the transmission network consists of 5000 km of 330 kV lines and 6000 km of 132 kV lines. The power system is characterized by low voltage issues, frequent outages and high losses. For this reason, in [240] a simulation of the incorporation of a Phase Shifting Transformer (PST) was performed in MATLAB to evaluate the power flow performance using this technology. As a result, the insertion of PSTs in four of the nodes in the system showed improvement in the active power flow on the lines and also a reduction of the power losses in the system. This proves the efficiency of a PST inclusion in weak systems as the power system in Nigeria [240].

8.6.8 Reliability (n-1)

The so-called (n-1) rule describes a dimensioning criterion for robustness related to contingencies or disturbances. The idea is that in the event of failure or shutdown of any element in the power system, grid security should be retained without further countermeasures. This means that in case any element of the power system (generator, line, transformer) becomes unavailable, all voltages, currents, and short-circuit power will still be kept within their designated limits; no supply interruptions will occur, the disturbance will not spread, and the grid stability will not be endangered.

In order to ensure (n-1)-secure operation, redundant equipment must be kept available in the transmission grid. Furthermore, a contingency reserve must be kept available in case of an outage or disconnection. The contingency reserve must cover at least the largest generation unit or interconnector.

The redundant equipment will not be fully utilized under normal circumstances; the unutilized margin is only intended to take over the power of the failed equipment in the event of a fault. Therefore, the power transmission capacity is underutilized during normal operation. Considering this, there are proposals on how to allow higher utilization of the grid resources while keeping reliability and security.

One proposed concept is to establish an automated system management mechanism for post-fault response. With such a system, (n-1) secure operation is no longer maintained by building redundant operating equipment (preventively), but faults are automatically dealt with (curatively) only in case they occur. This concept has already been implemented in some countries to a limited extent in a system called system protection scheme.

Another proposed concept is a Risk Based Security Assessment (RBSA). In this case, the redundancy design criteria are determined through deterministic and probabilistic methods. The probabilities of occurrence of certain operating situations and equipment failures as well as their consequences are considered in the assessment. With this approach, not all failures are treated in the same way. Failures with cascade effects and high probability should be considered more relevant than simple failures with low probability, even if the failing element has a larger capacity. The ability to make this distinction may allow the system operators to accept higher utilization of some equipment compared to the rigid (n-1) criterion.

9 Technical and Non-technical Barriers

To scale-up solar technologies on a continent-wide scale throughout Africa, several key technical and non-technical barriers need to be overcome.

On the non-technical front, the issues are diverse and highly jurisdiction specific and include both policy and regulatory barriers as well as investment barriers. These country-specific barriers in turn depend on a range of risks, including political risk, economic risk, regulatory risk, and social acceptance risk (see Table 20 below). Country-specific factors such as the financial strength of the national utility, the prevailing generation mix, the current electricity tariffs (which are frequently subsidized), the strength of the national regulator, the degree of power market liberalization (for example, the presence of independent power producers, or IPPs), as well as the underlying currency risk all play an important role. To mobilize investment at scale to achieve the aims of the CMP, these barriers and institutional bottlenecks will need to be overcome.

As has been shown by dozens of researchers from across Africa [241], the continent of Africa is exceptionally diverse and cannot be accurately characterized as a single whole: there are significant country-to-country variations in terms of existing energy infrastructure, the levels of energy poverty [242], overall resource endowments [243], the current costs of capital [244], as well as in terms of existing human capital [245]. Moreover, there are significant disparities that persist between remote, rural, near-urban, and urban areas within individual countries that make even country-specific generalizations difficult. This can have substantial implications for the cost, feasibility, and development impact of different generation technologies.

Given the importance of the policy and regulatory conditions in influencing where renewable energy investment occurs, countries with more stable policy and regulatory conditions, including stronger, more financially stable off-takers, are likely to attract more investment than countries where these fundamentals do not exist. According to the interviews conducted with investors and developers over the course of this project, **policy and regulatory stability often ranks more highly in investors' and developers' decision-making than resource quality**.

As highlighted in the summary of Africa's solar resource (see Section 5), Africa has abundant solar power potential from coast, to coast, to coast, and it has even been dubbed the world's "sunniest continent." [246] The fact that Africa's solar resource quality is high throughout much of the continent makes solar development and investment fundamentally different than traditional resource extraction such as mining or oil and gas, where investment (when it occurs) is highly concentrated in specific geographic regions. The trend for solar development differs markedly in this respect:

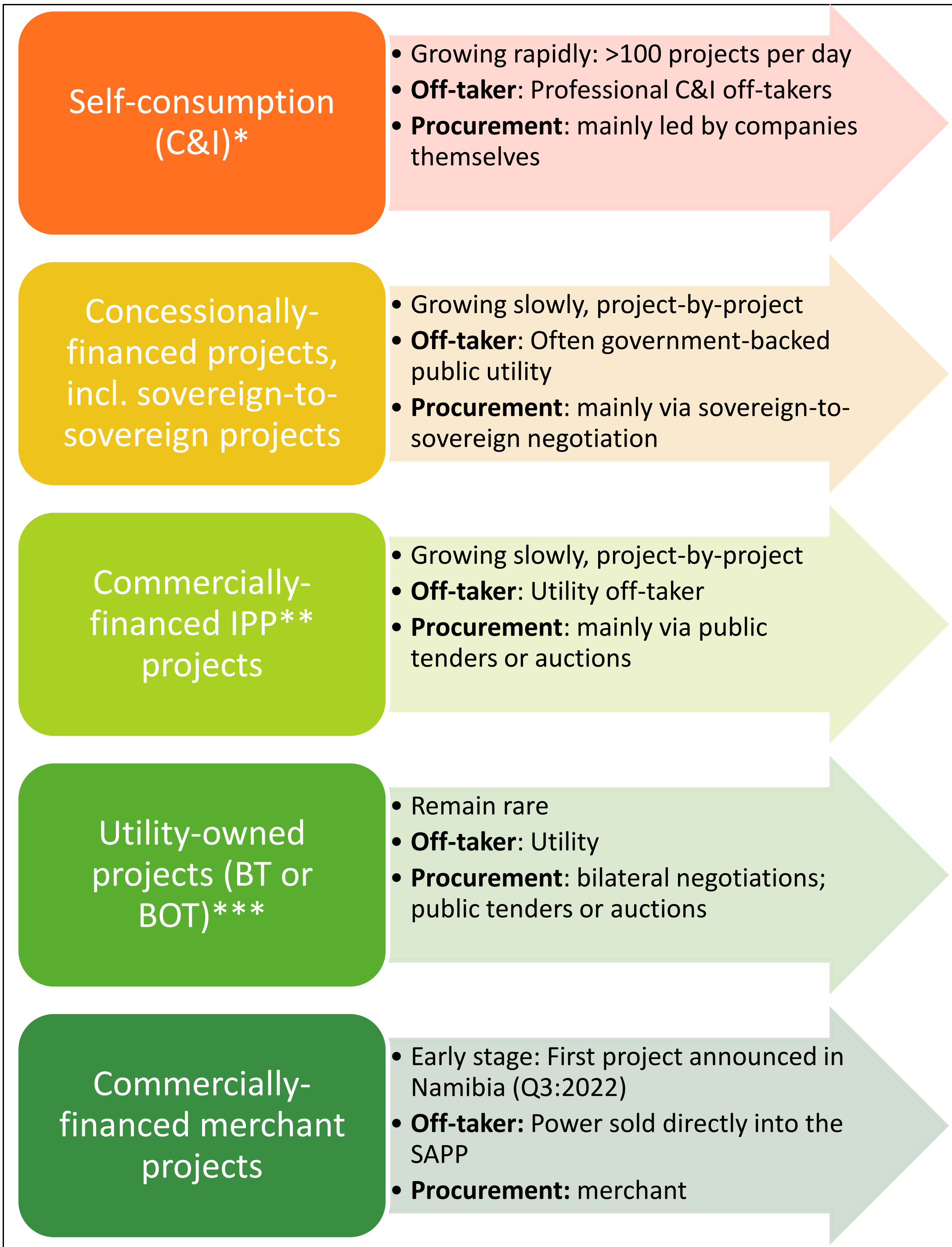
Africa has seen far less investment in solar than other parts of the world such as Germany or China where solar insolation is lower, and many of the regions in Africa with the best solar resources, such as Chad, have seen comparatively little solar power development to date[1] [247]. Rather than being concentrated where the resources are best, solar power projects have tended to be concentrated in markets with stable policy and regulatory conditions that support project bankability. This underscores the importance of policy and regulatory factors in shaping where investment occurs.

The next section examines the main market segments in Africa's solar power market before turning to the policy and regulatory barriers, as well as the technical barriers.

9.1 Five Main Market Segments in Africa's Solar Market

Investment in solar PV projects in Africa can be broken down into five basic categories.

[1] According to IRENA, Chad had 1MW of grid-connected solar PV capacity at the end of 2021. A major new project is planned to power a local refinery and the capital city of N'Djamena: if successful, the project will add 500MW of solar PV capacity to the country's power system, in addition to significant battery storage capacity. See: Max Hall (June 1 2022). Energy company plans 500MW of solar in Chad, PV Magazine, https://www.pv-magazine.com/2022/06/01/energy-company-plans-500-mw-of-solar-in-chad/



***C&I = Commercial and Industrial**

**** IPP = Independent Power Producer**

***** BT and BOT = Build-Transfer, and Build-Operate-Transfer**: a contracting mode where the ownership of the asset transfers to the government, or sovereign either immediately after construction (BT), or after a pre-determined period of operation (BOT).

Figure 97: Five main market categories of solar PV projects

Each of these five project categories has fundamentally different characteristics and drivers. One of the key differentiating factors is the nature of the off-taker: simply put, **who is buying the power?** The central importance of the off-taker is explored in greater depth below.

Out of these five market segments, the one that is currently growing the most rapidly (albeit from a small base) is the commercial and industrial market segment, with over 100 projects being installed Africa-wide every day [248]. The most active C&I market currently is South Africa, spurred on by several factors including rapidly rising power rates, persistent reliability issues, and recent regulatory changes that have increased the threshold for allowable project sizes from 1MW, to 100MW [249]. Most C&I projects are configured behind-the-meter, which means they are designed to supply onsite loads, and in most cases, such projects are not connected to the grid. In some cases, such as in South Africa, some projects are starting to make use of rules allowing the wheeling of power, paying fees to the grid operator for access to the grid [250].

One of the reasons that the C&I sector is growing so rapidly is that demand is strong, the economics are increasingly compelling, project sizes are often smaller, and developers can sign and close off-take agreements more quickly, reducing many of the risks and delays that frequently hamper negotiations with utilities and other government-backed off-takers. Larger transactions face higher non-completion risks and can take 3-4 years or more before construction begins. Projects procured by commercial and industrial clients, by contrast, can be signed, closed, and built within a matter of months, providing a decisive edge in terms of meeting burgeoning power demand on the continent.

This points to another important differentiator for solar power: when compared to other generation technologies such as geothermal, hydropower, or wind power, which are highly dependent on government/utility procurement procedures, solar PV has another pathway to market.

Key Insight for the CMP	**The C&I market segment is growing rapidly and dynamically in many parts of Africa and shows little sign of slowing down. The Continental Master Plan needs to take the rapid growth of this market segment into account, as it will have important implications for load growth, capacity planning as well as grid development in the years ahead.**

Since the main aims of the CMP and of the SPLAT modelling that supports it is on large-scale solar power development, the rest of the analysis that follows focuses primarily on the four other market segments.

9.2 Policy and Regulatory Gaps

This section provides an overview of the regulatory and policy barriers and bottlenecks that are currently inhibiting the deployment of Solar Power Plants (PV and CSP) in the African power system.

Throughout Africa, the policy and regulatory barriers often take the form of **policy gaps**, as the underlying policy and regulatory frameworks in many cases do not exist. These policy gaps, whether at the country level or at the regional level continue to hinder project identification and development. The main policy gaps can be broken down into four major categories:

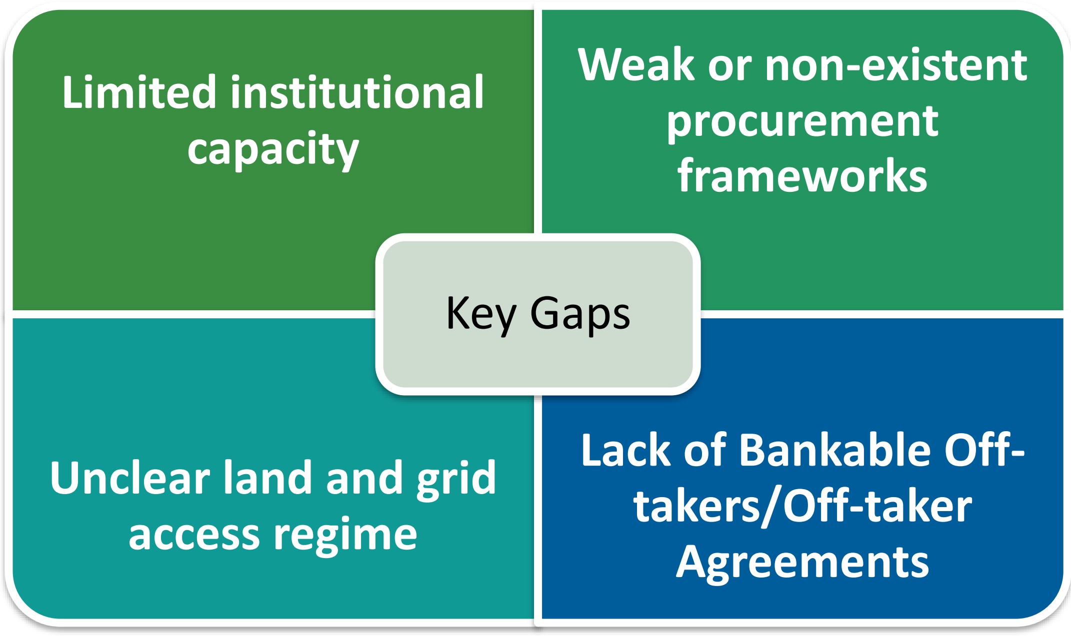


Figure 98: Four key policy gaps in scaling solar power in Africa

The following looks at each of these four gaps in turn.

9.2.1 Limited institutional capacity

Many countries throughout Africa face multiple urgent challenges simultaneously ranging from infrastructure, health care, education, waste collection, to public safety. Many public institutions and regulatory agencies are understaffed and must deliver on multiple objectives simultaneously. This makes it difficult to devote the resources required to power sector development, including to solar procurement.

9.2.2 Weak or non-existent procurement frameworks

One of the primary policy gaps relates to the fact that many countries in sub-Saharan Africa have not yet developed experience with competitive tendering or auctions for renewable energy projects. While competitive tenders have been held in certain countries such as South Africa, Zambia, Senegal, and Kenya, and certain countries have held competitive tenders for off-grid concessions as well as other forms of infrastructure such as bridges or airports, many countries in Africa have not yet held competitive solicitations for grid-connected renewables such as solar PV.

Due to this lack of prior experience, **many countries have not yet developed the underlying legal, policy and regulatory foundations required to procure privately financed renewable electricity generating capacity.** The result is that many countries in Africa continue to rely on unsolicited proposals and resort to bilateral negotiations to implement new power generation projects [251]. However, due to the lack of capacity, negotiations are frequently asymmetrical and tend to favour larger players.

Further gaps that are related to the lack of clear procurement mechanisms include the lack of clear procedures for conducting environmental and social impact assessments (particularly in the case of large-scale projects, including CSP projects). While some jurisdictions such as Kenya have adopted rules governing environmental and social impact assessments, this remains a gap in many countries and increases the operational and investment risks for developers [252].

9.2.3 Unclear land and grid access regime

Although it is commonly assumed that Africa has abundant land, obtaining access to dedicates sites with **clear legal title** can prove difficult in practice. Experience in developing solar projects in Senegal and Zambia has shown that finding suitable sites can be challenging, while experience in Madagascar has underscored that the lack of clarity over title can significantly hamper development [251]. The fact that land is abundant does not mean that siting solar power projects is easy. Several layers of negotiation are frequently required between local officials, local landowners and the central government before a suitable site (or sites) can be agreed upon.

A related challenge is the **lack of a clear framework for public and stakeholder consultations.** In many cases, local communities and landowners (including indigenous populations) are inadequately consulted as clear procedures and guidelines for public consultations, including for instance a duty to consult, frequently do not exist. This gap translates into additional risks, both for lenders and for project developers.

A related set of challenges and barriers emerges when considering **grid access**. Many countries in Africa have limited grid infrastructure, often concentrated in clusters around the capital, and occasionally linking large industrial sites such as mines, or linking the power output from hydropower projects. In addition, grid networks are frequently isolated from one another. According to the IEA, only 4.5% of electricity generated in Africa is traded across national borders[2] [114]. This means that despite progress made since the establishment of the major Power Pools, many power grids across the continent remain effectively isolated, and most electricity is kept within national borders.

It is important to note in this context that **the politics of electricity supply in many countries in Africa continue to favour exports over imports**. According to the interviews conducted as part of the project, a perception persists in many countries that relying on neighbours for electricity supply (including when part of the power pools) represents a threat to the security of supply rather than a way to boost security of supply. Overcoming these perceptions and concerns will prove essential to fostering wider pan-African and intra-pool electricity trade in the coming years.

The persistence of these policy gaps hinders project development and negatively impacts the willingness of investors to enter the market.

9.2.4 Lack of bankable off-takers/off-taker agreements

Central to the question of the investability of solar power is the **quality of the off-taker agreement**, which refers to the Power Purchase Agreement (PPA); this refers by extension to the quality and reliability of the off-taker.

According to Africa-wide analyses, more than a third of the utilities in Africa are in precarious financial health [253]. Indeed, a total of 35 utilities across Africa are not cost-covering even after subsidies [254]. There are many factors that contribute to the weak financial position of many utilities in Africa, including low payment collection rates, increases in operating costs that are not able to be offset by increases in customer tariffs, increasing cost of capital, high grid losses, as well as weak oversight [243] [4].

The weak financial position of many utilities in Africa is a direct barrier to the scale-up of utility-scale solar power. In addition, this financial weakness leads to challenges accessing financing; in turn, the difficulty accessing financing hinders the construction of vital grid infrastructure as well as the ability to sign new power purchase agreements, even when such projects would help reduce power generation costs and stabilize electricity rates (or reduce the need for annual government subsidies).

In turn, many solar power projects being developed in Africa rely on various forms of credit enhancements such as partial risk guarantees as well as political risk insurance [251]. While such credit enhancements are possible at modest scales, they are unlikely to be available at scale to support the development of hundreds of GW of solar power

[2] It is noteworthy, however, that this value is above the global average, which stands at roughly 3%. International Energy Agency (December 2020). Electricity Market Report: 2020 Global Overview, https://www.iea.org/reports/electricity-market-report-december-2020/2020-global-overview-trade

projects on the continent. Moreover, many governments across Africa are either reluctant, or unable, to issue such guarantees themselves due to financial and other constraints. In response, a few alternatives have emerged including guarantees issues by national banks, corporates, export credit agencies, or Development Finance Institutions (DFIs), but there can also be costly and time-consuming to obtain [255].

These factors, combined with the various project-level investment risks that exist (see Section 9.3. below), mean that many utility-scale solar power projects being built in Africa frequently rely on concessional financing that is often donor-led, or donor-sponsored, as pure commercial financing is either unavailable in many markets, or too expensive.

A related response to the high country-level risks is that financing occasionally takes the form of sovereign-to-sovereign agreements: in this case, projects are the result of bilateral negotiations between higher levels of government. Such projects are not financed on a commercial basis, and in most cases the terms of the agreements remain unclear.

9.3 Key Investment Risks and Barriers

There are several specific investment barriers that hinder solar PV development in Africa. Table 20 below provides an overview of the main categories of investment risk that project developers and investors face when investing in renewable energy projects like solar.

Table 20: Key investment risks facing solar projects. Source: based on Jacobs et al. (2016) [256]

Investment Risk	Description
Economic Risk	Risk that economic factors beyond the control of the project impact revenues, or profitability: e.g. recessions, macroeconomic shocks, etc.
Political Risk	Risk of political instability, change of government, etc.
Regulatory Risk	Risk that regulators change the rules, regulations, or tax provisions during the project’s operating life.
Off-taker Risk	Risk that the buyer (e.g. the utility) experiences financial difficulties, and can no longer honour the PPA, or other obligations.
Performance Risk	Risk that the wind or solar output will fluctuate beyond projections, or under-perform: particularly disruptive if this occurs in the early years
Technology Risk	Risk of technological malfunction, or higher-than-projected downtime, repairs, etc.
Construction Risk	Risk that construction faces local opposition, or delays due to operational or project management failures
Revenue Risk	Fluctuations in revenues due to fluctuating prices of electricity, or in the tariffs at which the project has been financed, or to the value of the revenue streams generated by the project (e.g. due to inflation); revenue risk can also be negatively impacted by other factors such as curtailment, or non-compensated electricity output
Currency Risk	Risk that the currency in which sales are denominated changes abruptly or significantly over time in relation to the currency in which the project was financed (e.g. EUR, USD)
Social Acceptance Risk	Risk that the project faces opposition from citizens, neighbouring communities, civil society groups, or others. Social acceptance is critical to financing long-term infrastructure investments.

Each of these risks represents a major investment barrier to the sustained scale-up of solar power in Africa.

9.3.1 Risk and the cost of capital

The various risks surrounding investments in a solar PV project directly impact the cost of capital used to finance the project [241]. The impact of these risks on a project's cost of capital can be visualized as follows:

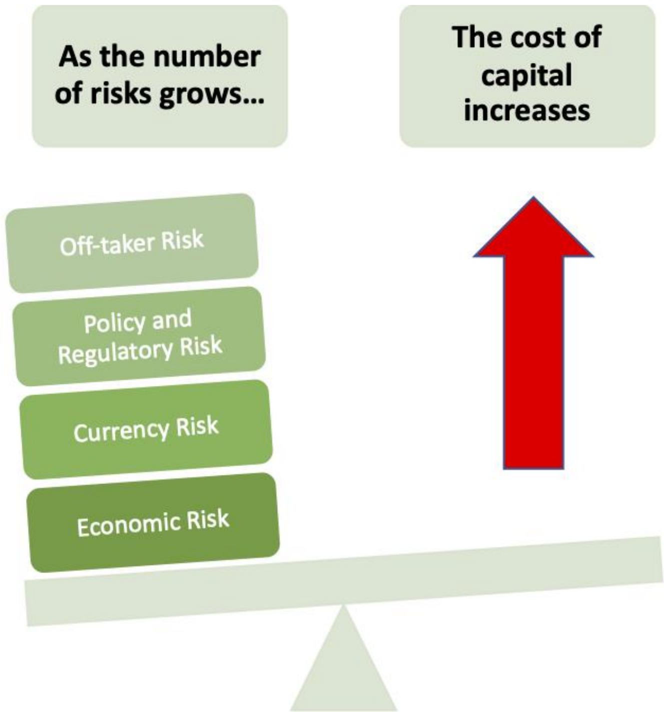


Figure 99: Relationship between risk and the cost of capital

The cost of solar is therefore intimately linked to the cost of capital [257]. While economists and engineers commonly think in terms of capital expenditures (CAPEX) and operating expenditures (OPEX), with capital intensive projects like solar PV, it is important to consider the impact of *financial* expenditures (or FINEX).

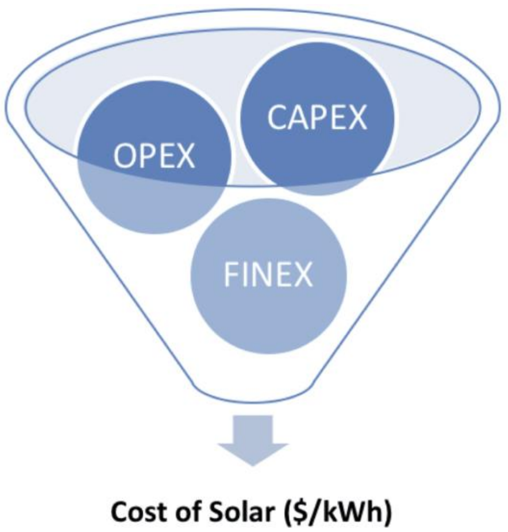


Figure 100: OPEX, CAPEX and FINEX as inputs into solar LCOE

The higher the cost of capital, the higher the overall financial expenditures over the course of the project's life.

FINEX costs are spread over the course of the project's life in the form of interest payments. Small differences in the cost of capital used to finance projects can have major impacts on how much interest needs to be paid (see Figure 101).

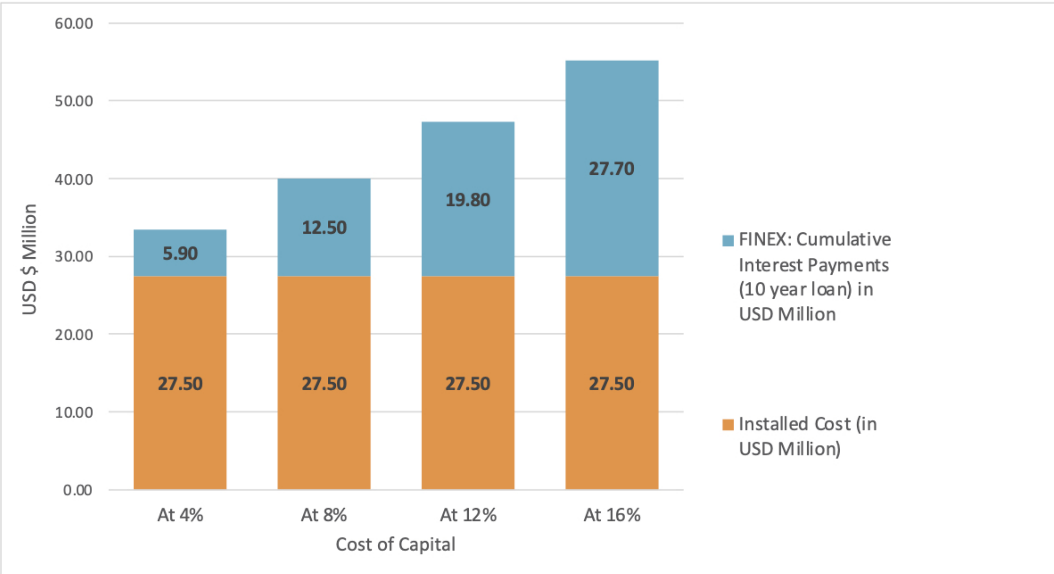


Figure 101: Increase in Total FINEX as the Cost of Capital Increases (Illustrative). Note: this depiction refers to a hypothetical 50MW solar project financed over a 10-year loan tenor at a fixed cost of capital.

As can be seen above, for a project financed with a 10-year loan tenor, *once the cost of capital surpasses 16%, the total interest costs exceed the initial CAPEX*. In absolute terms, the FINEX become greater than the initial CAPEX.

One consequence of this is that as the costs of solar continue to decline, and the efficiency of solar panels continues to improve (see section 4.4 above), **the importance of FINEX in determining the actual cost of electricity production from solar is poised to grow**. Efforts to reduce the cost of capital (in short, policy and financial de-risking measures) are therefore vital to unlocking solar at the lowest possible cost for utilities and ratepayers [258] [241].

9.3.2 Higher cost of capital translates into higher LCOE

Figure 102 below shows how this cost of capital translates into the levelized cost of electricity (LCOE) for solar PV projects financed at a weighted average cost of capital of 4%, 8%, 12% and 16%.

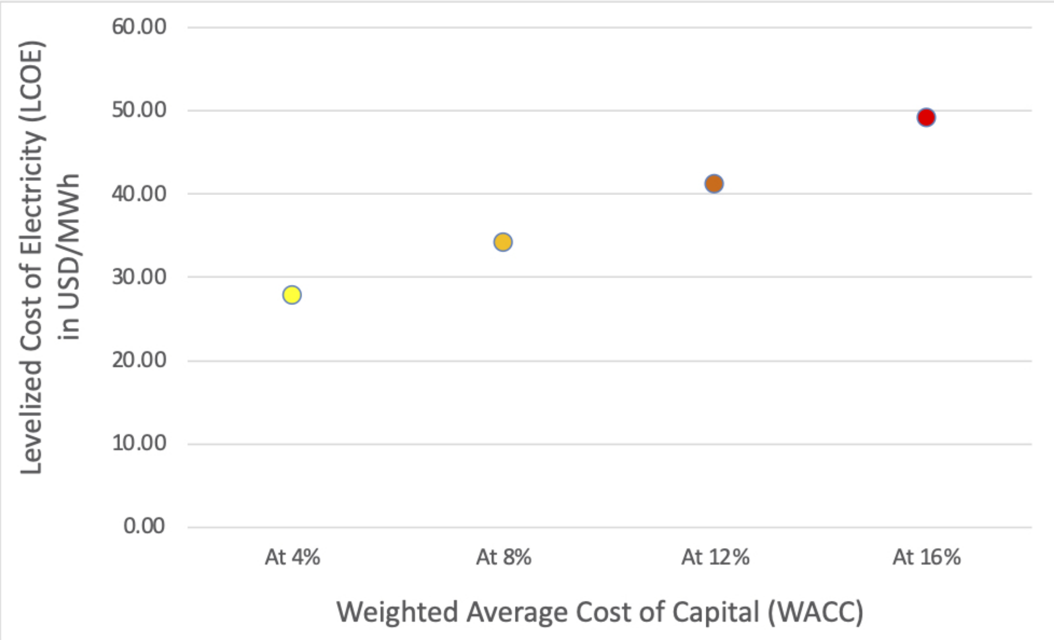


Figure 102: Levelized Cost of Electricity (LCOE) of Solar PV at Different Costs of Capital. Assumptions: Installed cost: USD 550/kW, Solar insolation 7kWh/m2/day, Cell efficiency 20%, Degradation 0.5%, O&M costs USD $12/kW/year

As can be seen above, the higher the cost of capital, the higher the LCOE. The cost of capital indicates the expected financial return, or the minimum rate of return required, to invest in a particular project. This expected return is closely related to the risks associated with the cash flows generated by the project. If projects face multiple complex risks, including operational, political, macro-economic, or otherwise, these risks are priced into the cost of capital that investors provide. This is confirmed in recent research: the levelized costs of solar PV are approximately 2.5 times higher in countries as Liberia, Sudan, and Sierra Leone than in countries such as Botswana, Namibia, South Africa and Morocco, due to a combination of resource quality and country risk profiles [241].

While concessional lenders such as development finance institutions (DFIs) typically offer loans at below-market rates, it is unlikely that every utility-scale solar PV project across

Africa can benefit from such favourable financing conditions through 2050 and beyond. Conversely, not all governments are prepared, or willing, to meet all the conditions associated with such DFI-backed loans.

9.3.3 Impact of monetary policy tightening

In the current investment environment (Q4:2022), a major related challenge is the fact that monetary policy is being tightened in much of the world, as seen in a flurry of recent increases in central bank lending rates.

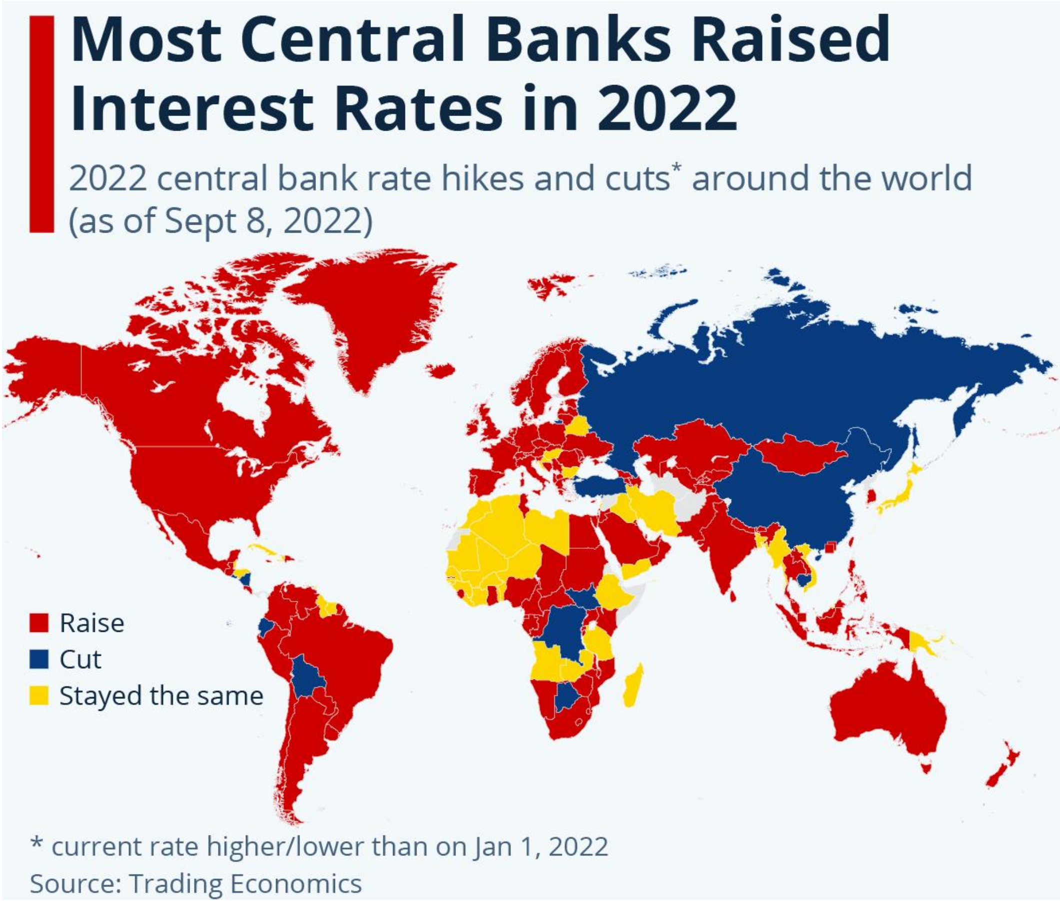


Figure 103: Central Bank Main Policy Interest Rate Changes in 2022. Source: [259]

The trend of monetary policy tightening is already having major knock-on effects throughout emerging markets, including throughout Africa [260]. One of the near-term consequences of this is that the spread between borrowing costs for governments and utilities in Africa and those in the rest of the world is growing: yields on government bonds in the secondary market in Africa have approximately doubled since the start of the year, increasing by 6% (600 basis points) on average [261].

At least for the time being, the era of loose monetary policy and low interest rates is over. Rising interest rates directly increase the cost of borrowing; these higher borrowing costs in turn impact the cost of capital available to finance solar projects.

Many solar projects in Africa are financed on a Euribor+ basis, at a premium above the benchmark Euribor lending rate. As can be seen below, the steady decline in the European overnight lending rate over the last decade, and a slide into negative territory around 2025, the rate has kicked into reverse and started to increase precipitously in recent months.

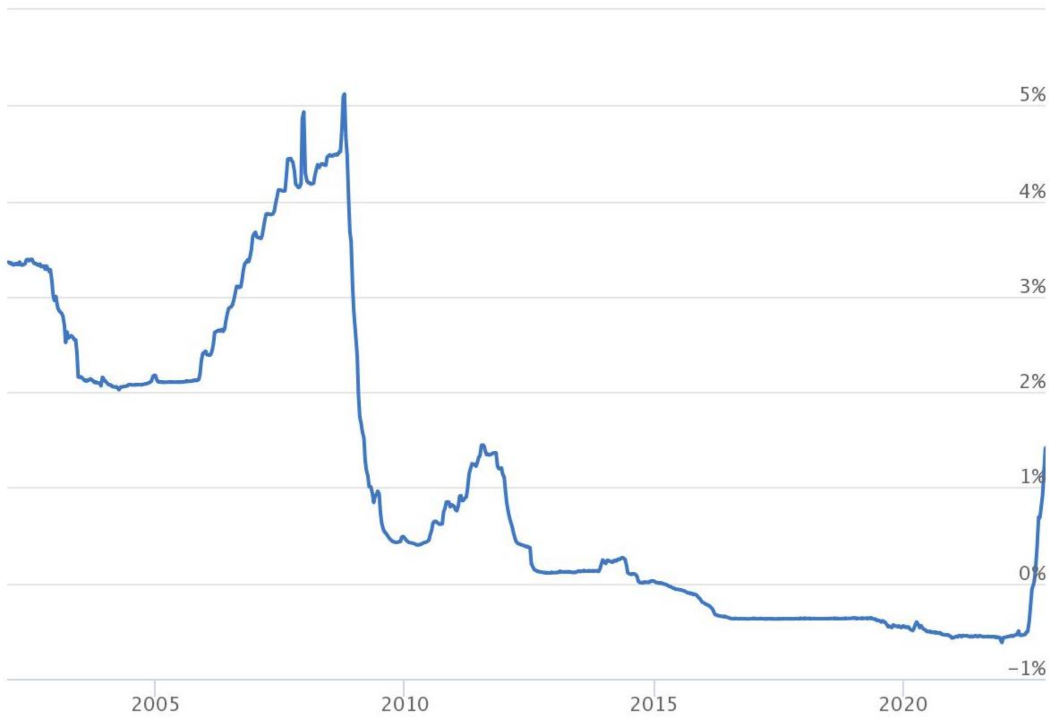


Figure 104: Euribor overnight lending rate 2002 – 2022. Source: [262]

This increase in benchmark lending rates is going to have significant implications for the scale-up of solar PV on the continent: the cost of capital is poised to go up, pushing PPA prices upward. In turn, the prospect of higher PPA prices could drive some governments and utilities to take a wait-and-see approach, deferring investments in new generation capacity at a critical time for power sector development on the continent.

9.3.4 Impact of rising commodity prices on governments' ability to borrow

Rising interest rates need to be considered against the backdrop of recent trends: Government borrowing in Africa doubled in the last decade from roughly 32% of GDP in 2010 to 65% in 2022 [261]. Countries' ability to repay these loans is being constrained by the surge in interest rates and the rapid rise in commodity prices triggered in part by the war in Ukraine, including specifically in oil, natural gas, and food.[3]

The Covid-19 pandemic has also had its toll: for commodity importers across Africa, the external debt servicing costs have increased from 4% of exports on average before the pandemic to 11% by mid-2022; partly as a result, seven countries in Sub-Saharan Africa have fallen into debt distress and a further 15 are at risk [261].

9.3.5 Financial strength of governments and utilities interlinked

What makes the worsening financial strength of many governments in Africa an issue for renewable energy projects is that many utilities in Africa are backed directly or indirectly by the national government, and many remain vertically integrated utilities that are owned, in full or in part, by the government [263].

The worsening financial position of many countries in the region introduces additional risk to the overall investment landscape for solar.

9.3.6 Limited fiscal capacity constrains ability to invest

A related factor is the low tax base in many countries in Africa, which significantly constrains fiscal capacity: in practice, this limited fiscal capacity means that many governments do not have the funds available to invest significantly in publicly financed infrastructure projects, or afford to offer wide-ranging tax incentives or reductions to import duties, as these revenues are essential to support government coffers [264]. This constraint also limits the ability of government-owned utilities to invest in new power generation as well as in key infrastructure such as power grids, leading to an increased preference for Public Private Partnerships, or PPPs.

9.3.7 Unclear tax and investment rules

A further barrier for many investors and developers, particularly in markets without a prior track record of renewable energy procurement, is that the applicable tax rules and regulations are unclear [265]. Investors and developers frequently do not know what tax rules apply when planning new investments, and this lack of clarity hinders investment.

[3] There are of course exceptions such as among commodity exporters, which have broadly benefitted from the higher prices. For instance, the credit rating of countries like Angola has even been upgraded over the last year. [148]

9.3.8 Local bank involvement remains limited, loan tenors too short

Another barrier relates to the involvement of local banks: **many local banks in Africa have little experience with financing renewable energy projects and remain risk averse** when lending to projects or technologies to which they have not lent before. When involved in transactions, the loan tenors are frequently significantly shorter than those provided by international lenders and development financial institutions (DFIs). It is not uncommon for local banks to decline offering loan tenors longer than 5-7 years. Considering that a solar project can operate for 25 years or more, such short loan tenors significantly increase the debt repayment costs for the project owner in the early years of the project, which means that higher PPA prices are required to get projects financed.

One result of the short loan tenors on offer by many local banks is for project developers to seek capital elsewhere, namely from non-African banks. While international lenders can provide debt over longer and better terms, they often require various forms of risk guarantees such as sovereign guarantees or partial risk guarantees in exchange. This can significantly increase negotiating time and make it harder to close deals. Moreover, this reliance on external financing, including from DFIs, arguably works against the emergence of an informed, self-determined, and Africa-led energy transition [241].

Some project developers and lenders have attempted to overcome these challenges by financing solar projects through syndicated transactions, involving a number of different lenders to spread the risk. This is the case for instance in Burkina Faso's recent 38MW solar PV project (see Case Study below).

Case Study: Syndicated Debt Financing for 38MW Solar PV Project in Burkina Faso
The 38MW solar PV project in Burkina Faso is being funded via a syndicated loan structure involving multiple lenders. The Dutch FMO is providing EUR 12 million of debt combined with a further EUR 8.1 million from the Interact Climate Change Facility (ICCF), both of which are structured over a 14½-year tenor; this debt funding is being combined to an additional 8.1 million from the Access to Energy Fund (AEF), which is structured over a 20-year tenor, bringing the total to just over EUR 40 million. Such syndicated transactions help spread the risk across different lenders and are often favoured by lenders, particularly in markets without a significant track record in prior renewable energy project development. However, while such approaches help ***spread*** the risk, they arguably do not reduce it.

9.3.9 Currency risk remains a major concern

One final barrier is the issue of **currency risk**. The equipment used to build solar PV projects is typically financed in international currencies such as USD, or EUR. Debt payments typically need to be made in the same currency in which the projects were financed; however, the revenues from electricity sales to end-users are typically collected in local currency. This arrangement leaves the utility or off-taker having to pay hard currency liabilities with local currency cash flows. This mismatch creates significant risks for projects financed with dollar- or Euro-denominated debt: if the local currency depreciates, or the dollar or euro strengthen, the burden of debt payment grows. This issue can be exacerbated if there are issues with currency convertibility.

Several mechanisms are available to mitigate currency risk, including various instruments such as pegs, swaps, forward contracts, and others, but these tend to be costly and are therefore mainly used in the context of larger transactions [255].

In response, picking up on the previous barrier highlighted above, there have been efforts to finance solar projects in Africa at least in part with local currency, typically by engaging with local banks [266]. One recent example in Kenya shows that involving local banks financing projects in local currency can be a viable pathway in certain cases [267]. As the track record of solar power in Africa grows, it is likely that local banks will start to play a bigger role as lenders in projects, putting vital local capital into the continent's emerging energy transition. Increasing the involvement of Africa's own financial sector in renewable energy project lending is one way to ensure that the scale-up of solar, and the energy transition more broadly, remains locally rooted, and Africa-led.

9.4 Technical Integration Barriers

There are many technical and grid integration barriers that hamper the scale-up of solar power in African power systems. Integrating large volumes of solar power into the power system can create a host of challenges for grid operators and for power system planners.

This section breaks down some of the main technical challenges for solar integration, organized by topic, while also providing an overview of some of the main solutions.

9.4.1 Temporal mismatch

Most power systems in Africa are evening peaking, which means that solar output (when unsupported by storage) declines when it is needed most. This remains one of the main reasons why many utilities across the continent remain reticent to procure large volumes of solar. In addition, daytime solar output can impact the scheduling of existing conventional generating units, which many utilities are hesitant to do. This temporal mismatch creates unique challenges scaling up solar power.

In order to solve this mismatch, there are broadly three options: 1) expand grid interconnections with neighbouring regions, 2) make demand (i.e. load) more flexible, or 3) add storage to extend the output of solar power into the evening hours.

Regarding the first, a specific example can help: when the sun sets in Dakar, Senegal, it is already 10PM in Addis Ababa, Nairobi, and Dar es Salaam: in practice, this means that increasing the capacity of east-west interconnections in the African power system would significantly improve the integration of solar power.

Second, there is an expanding universe of flexible sources of demand beyond electric vehicles: there are controllable thermostats, smart water heaters, heat pumps, and a range of other smart appliances that can react to grid signals like fans and refrigerators. Indeed, one of the fastest growing sources of power demand worldwide is air conditioning [268]; finding ways of shifting this cooling demand away from the evening peak and into the daytime (perhaps via the thermal storage of cooling energy) is poised to play an increasingly important role. In certain countries, air conditioning alone represents over half of total peak electricity demand [268].

A further way to encourage such demand side flexibility is to make daytime power cheap. This can be accomplished by introducing time-varying tariffs and aligning them to the near-zero marginal cost of daytime power. If power supply is over-abundant during the daytime, making it inexpensive can encourage households and businesses to shift more of their demand (to the extent they can) to the daytime. Offering lower electricity tariffs during the daytime could generate a range of win-wins, including fostering industrial development and supporting small and medium-sized businesses.

Third, the addition of storage can increase solar's ability to contribute to meeting evening peaks. Recent auctions in India for so-called "round the clock" power supply have resulted in competitively priced, round-the-clock power supply drawing on varying renewables like wind and solar combined with battery storage [269]. In one such auction conducted in India, the combination of solar PV with both wind and storage project has enabled the project to meet a combined annual plant load factor of 80%.

9.4.2 Intermittency and variability

As the penetration of grid-connected solar power increases, the intermittency or variability of plant output can create challenges for grid operators. When there are multiple solar projects connected to the grid, cloud cover and other factors are smoothened out to a certain extent, but when there is only one solar plant present, as was the case in Praia in Cabo Verde when the country's first solar PV project came online over a decade ago (a 5MW plant), the output variability needs to be managed and forecasting improved [270].

In fact, although variable renewables like solar power are weather dependent, solar output can be predicted relatively accurately, particularly when supported by forecasting, when aggregated over larger areas, and as the total number of solar projects increases [271]. For instance, while the individual output of a single solar PV project is quite erratic, the aggregate output of hundreds of solar projects becomes relatively smooth (see Figure 105).

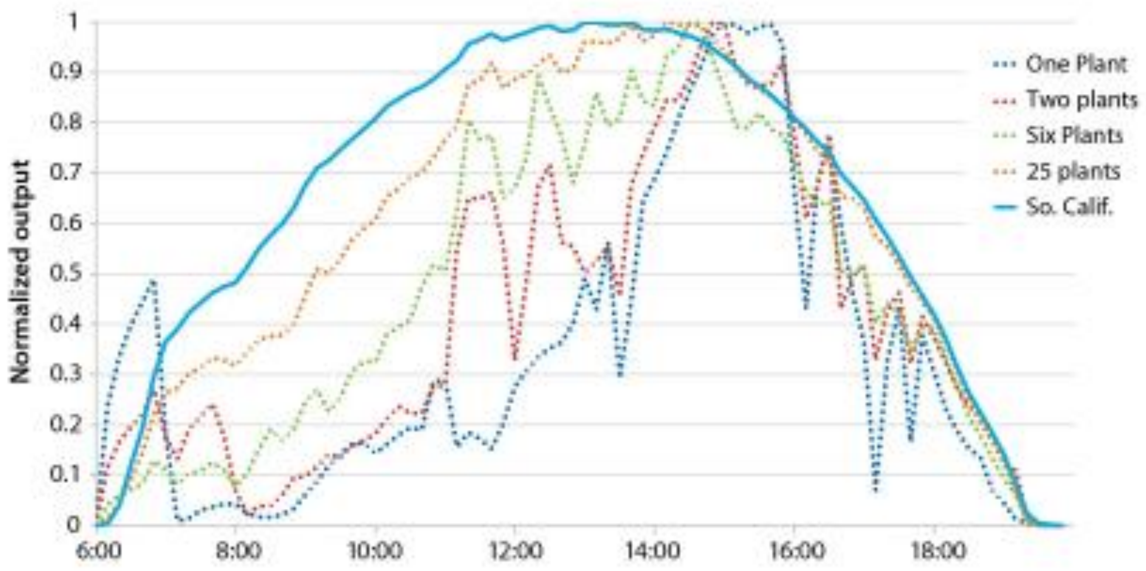


Figure 105: Output profile of different solar PV projects, including in all of Southern California. Source: L. Bird et al (2013). http://www.nrel.gov/docs/fy13osti/60451.pdf

As the share of solar PV grows, this variability needs to be modelled, planned, and adapted into power system planning. As highlighted above, since weather and temperature patterns (much like electricity load) can change quickly and unpredictably, reaching and sustaining high penetrations of solar requires a high degree of **power system flexibility**.

9.4.3 Increased uncertainty of net load

A related challenge facing variable renewables like solar PV is that they **increase the uncertainty of net load** (the ***net*** electricity demand that needs to be met ***<u>after</u>*** solar). As the share of solar power grows, the net daytime load that needs to be met by conventional generators starts to shrink.

In November 2021, South Australia achieved net negative electricity demand during the daytime for the first time, largely due to the high concentration of solar PV [272]. This pattern is repeating itself with increasing frequency as the share of solar in the state grows (including seven times in October 2022 alone): during these periods, all grid-connected loads on the system are being powered by solar PV [273].

While most power systems in Africa are far from such levels of solar penetration today, the sustained growth of solar translates into a reduced need for traditional "baseload" power generation. What is therefore needed is more operational flexibility on the supply side to adjust to periods of high or low solar output, as well as greater flexibility on the demand side to make use of the abundant solar power when it is available. This is particularly the case if interconnections with neighbouring jurisdictions are limited, as they are in many parts of Africa.

To maintain reliability, balancing supplies are frequently needed and support for frequency and voltage control can be required. New inverter technologies exist that are making it possible for solar projects to contribute actively to providing such services, while the addition of **storage** (see further below) enables solar to produce power into the evening hours, overcoming one of the main barriers to solar adoption among stakeholders in Africa [274].

9.4.4 The Duck Curve

In the early evening hours, the so-called "duck curve" illustrates the difficulties of balancing and controlling power systems with modest to high penetrations of solar PV. As daytime solar output increases, the belly of the duck dips, increasing the steepness of the ramp rate required when the sun sets.

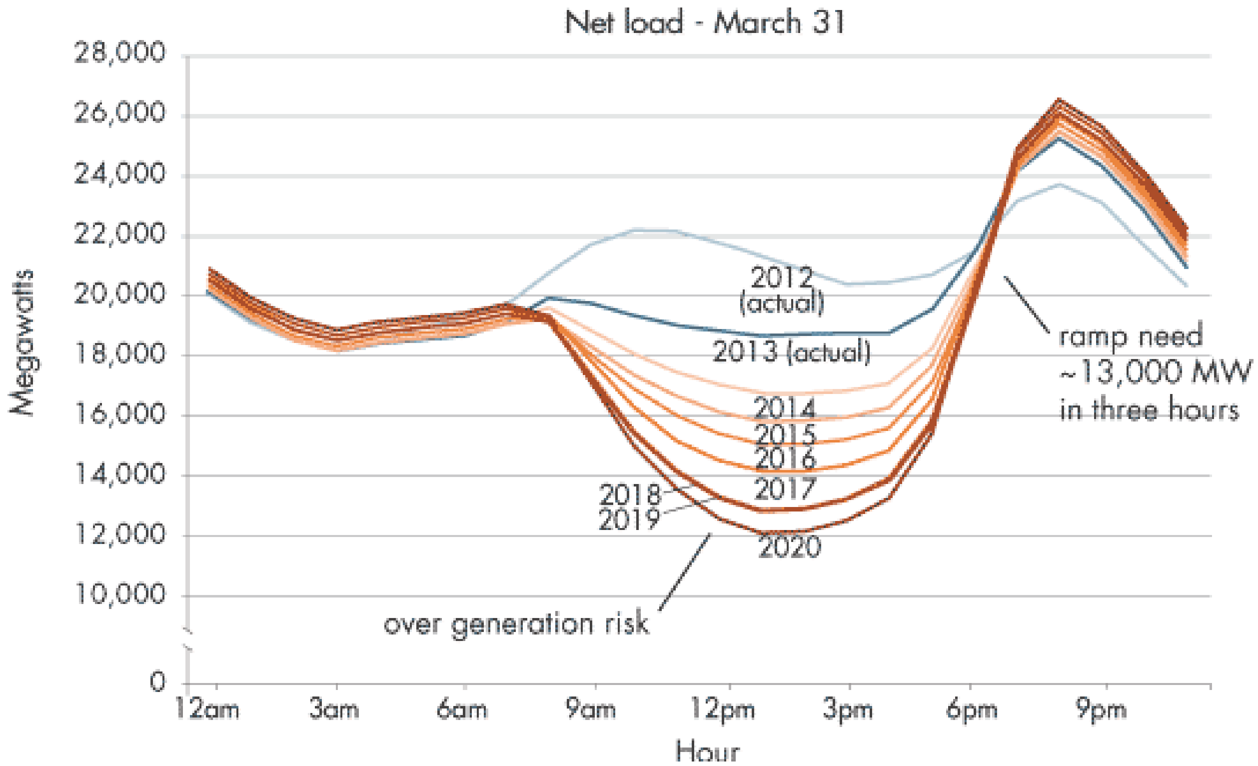


Figure 106: The duck curve. Source: CAISO 2016, https://www.caiso.com/Documents/FlexibleResourcesHelpRenewables_FastFacts.pdf [275]

There are several different strategies to help deal with the duck curve [276] [277]. These strategies include, among others, shifting more demand to the daytime to reduce evening peaks, increasing the efficiency of end-use appliances that contribute to the evening peak, orienting solar panels westward, increasing the number of loads that are "smart" (i.e. controllable) such as water heaters and heat pumps, expanding grid regional interconnections, and increasing the amount of storage in the system, among others.

9.4.5 Voltage fluctuation

Voltage fluctuation can be caused by sudden fluctuations in PV system output caused by ambient factors such as cloud cover. Such fluctuations can become more significant as solar PV penetration grows and in extreme cases, when left unchecked, such fluctuations can undermine power quality. The magnitude of the specific voltage fluctuations depends on the specific location of the solar project(s), the total installed PV capacity in that particular balancing area, and the overall configuration of the power grid. However, as with frequency regulation, modern inverter technologies are equipped with new capabilities to mitigate many of the issues stemming from the variability of solar output [278]. This is one reason why some jurisdictions such as Hawaii have started to require advanced inverters for all new solar installations in the state [279]. Such advanced inverters provide a range of advanced functionalities that older inverter technologies lack.

9.4.6 Inertia

Electricity generation has historically been dominated by hydropower, or by burning a fuel and creating steam, which spins a turbine and generates electricity. The motion of such generators produces power in the form of Alternating Current (AC) as the device rotates; this rotation sets the frequency, which refers to the number of times per second the sine wave repeats [278].

The overall power frequency is a key indicator for monitoring the health of the electrical grid. If a given grid system has too much load, more energy is being removed from the grid than is being generated. As a result, in a conventional power system dominated by turbines that feature inertia, the turbines slow down and the frequency in the grid decreases. Since turbines are large spinning objects, they resist and counteract sudden changes in the frequency. This inertia plays an important role in maintaining the right level of frequency in the power grid.

Solar PV, by contrast, does not have inertia as it has no turbines, and features no large spinning objects. In the case of solar PV, it is the inverter that regulates the frequency at which the power output enters the grid. This is one reason why solar PV and other technologies like batteries are called “inverter-based resources” [280]. As the share of solar and batteries in the power system grows, inverters become increasingly important in regulating the frequency of the grid, correcting and stabilizing disruptions. The ability of smart or advanced inverters to stabilize the grid in this way is critical to the large-scale adoption of solar PV.

Modern inverters are equipped with “fault ride through” capabilities, enabling them to continue operating despite small disruptions in voltage or frequency. In these and other ways, modern inverters can actively support grid reliability.

9.4.7 Frequency response

The frequency of a power system must be preserved within a narrow range of values (either 50Hz or 60Hz depending on the region). Most of Africa's power grid, like the EU's, operates at 50Hz. Frequency deviations arise when there is a mismatch between generation and load [278]. Frequency response is particularly important because any substantial drop in frequency is typically associated with one or more generation units going offline. In response to a change in frequency, modern inverters are configured to change their power output to help restore the overall power grid's operating frequency within the required parameters.

9.4.8 Black Start Capability and "Grid Forming"

Another key grid service that some inverters can supply is what is referred to as "grid forming". While grid-forming inverters have existed for some time, their use in larger power systems to support key grid functions is growing.

One of the functions that grid forming inverters can provide is that they can kick start a grid after black outs; this ability is known as black start capability. Traditional so-called "grid *following*" inverters require an external signal from the power grid to determine when to start generating a sine wave that can be fed into the power grid; grid-forming inverters can generate this signal themselves [281].

Grid-forming inverters are also able to operate stably in "weak" grid sections with low short circuit power, which grid-following inverters have difficulty with, and they can provide inertia in the same way as synchronous generators, contributing to improved frequency stability.

9.4.9 Reactive Power

Reactive power is one of the most important services that advanced inverters can provide to the grid [278]. On the grid, the voltage is constantly switching back and forth, along with the current. Electrical power is maximized when both voltage and current are tightly synchronized.

However, if voltage and current are out of sync, a portion of the current flowing through the circuit cannot be absorbed by loads, resulting in a loss of efficiency. In such a situation, more current is needed to create the same amount of "real" power to the grid. To counteract this loss in efficiency, utilities need to ensure an adequate supply of what is called "reactive power," which refers to power that can be used to bring the voltage and current back in sync.

Modern inverters can both provide and absorb reactive power and in so doing, they can help keep the power grid in balance. Moreover, since reactive power is difficult to transport over long distances, distributed resources like solar PV and battery storage technologies are particularly valuable sources of reactive power, as they can significantly reduce the reliance on distant, centralized (and often fossil-based) generation units [278].

9.4.10 Harmonics

Solar PV inverters convert DC power into AC, and in the process can lead to harmonics [282]. Such harmonics can jeopardize power quality by creating what are analogous to eddy currents in electric grids. Harmonics can generate heat in electrical equipment containing coils such as transformers and motors and in extreme cases can lead to equipment malfunction [283]. Modern inverters are also able to help regulate and minimize harmonics in the power grid [284].

10 Solar Identity Sheets

Solar Identity Sheets are meant to summarize the numbers and findings of the report above.

10.1 Solar Photovoltaic (PV) Power – Identity Sheet

Technology Name	**Solar Photovoltaic (PV) Power**				
Technology Description	Utility-scale photovoltaic power plants, MW-range				
Technology Characteristics	**Statistics**	***Projections***			
	2020	***2025***	***2030***	***2035***	***2040***
Total Installed Capacity in Africa in 2020 (MW)	10,600	*24,000*	*68,000*	*190,000*	*540,000*
Total Generation in Africa in 2020 (GWh)	14,900	*36,000*	*110,000*	*320,000*	*950,000*
Technical Potential (MW) *10% of land area*	3.34E+08	*3.64E+08*	*3.95E+08*	*4.25E+08*	*4.56E+08*
Electricity production at Technical Potential (GWh) *Global Tilted Irradiance (GTI)* *5.5 kWh/(m² day)*	1.34E+09	*1.46E+09*	*1.59E+09*	*1.71E+09*	*1.83E+09*
Weighted Average Capacity factor (%)	16	*17*	*18*	*19*	*20*
Technical Efficiency *Average sun-to-electricity (%)*	22	*24*	*26*	*28*	*30*
Unit investment costs (Euro/kW)	740	550	420	400	380
Annual O&M Costs (EUR/(kW a))	19	*15*	*12*	*12*	*12*
Lifetime (years)	25	*30*	*35*	*40*	*45*
LCOE Range (Euro/kWh) in Africa	0.035	*0.025*	*0.019*	*0.018*	*0.017*
Land Use (m²/kW)	9.09	*8.33*	*7.69*	*7.14*	*6.67*
Additional Information					
Flagship projects in Africa					
Locational priorities in Africa	PV can be installed anywhere in Africa, optionally floating PV, and agrivoltaics				
Related transmission / other integration issues	PV is modular; plant size can be adjusted to grid, generated power may be used locally				
Related regulatory issues					
Related financing issues					
Related environmental issues / considerations	none				
Applicability recommendations for Africa	highly applicable for all regions in Africa, will be the backbone of future power system				

10.2 Solar Photovoltaic (PV) Power + Battery Storage – Identity Sheet

Technology Name	Solar Photovoltaic (PV) Power + Battery Storage				
Technology Description	Utility-scale photovoltaic power plants with battery storage, MW-/MWh-range				
Technology Characteristics	**Statistics**		***Projections***		
	2020	***2025***	***2030***	***2035***	***2040***
Total Installed Capacity in Africa in 2020 (MW)					
Total Generation in Africa in 2020 (GWh)					
Technical Potential (MW) *10% of land area*	3.01E+08	*3.28E+08*	*3.55E+08*	*3.83E+08*	*4.10E+08*
Electricity production at Technical Potential (GWh) *Global Tilted Irradiance (GTI)* *5.5 kWh/(m² day)*	1.21E+09	*1.32E+09*	*1.43E+09*	*1.54E+09*	*1.65E+09*
Weighted Average Capacity factor (%)	22	*26*	*29*	*33*	*40*
Technical Efficiency *Average sun-to-electricity (%), including round-trip-efficiency for batteries*	20	*22*	*23*	*25*	*27*
Unit investment costs (Euro/kW)	1,800	*1,400*	*970*	*920*	*870*
Annual O&M Costs (EUR/(kW a))	30	*24*	*18*	*18*	*17*
Lifetime (years)	25	*28*	*30*	*35*	*40*
LCOE Range (Euro/kWh) in Africa	0.058	*0.044*	*0.032*	*0.030*	*0.029*
Land Use (m²/kW)	10.10	*9.26*	*8.55*	*7.94*	*7.41*
Additional Information					
Flagship projects in Africa					
Locational priorities in Africa	PV can be installed anywhere in Africa, optionally floating PV, and agrivoltaics				
Related transmission / other integration issues	PV is modular; plant size can be adjusted to grid, generated power may be used locally. Battery storage can be used to stabilize the grid				
Related regulatory issues					
Related financing issues	none particular to PV				
Related environmental issues / considerations	none				
Applicability recommendations for Africa	highly applicable for all regions in Africa, will be the backbone of future power system				

10.3 Concentrated Solar Power (CSP) – Identity Sheet

Technology Name	Concentrated Solar Power (CSP)				
Technology Description	Utility-scale solar thermal power plants, 100-MW-range				
Technology Characteristics	**Statistics**		***Projections***		
	2020	***2025***	***2030***	***2035***	***2040***
Total Installed Capacity in Africa in 2020 (MW)	1,010	*1,010*			
Total Generation in Africa in 2020 (GWh)	4,000	*4,000*			
Technical Potential (MW) *2% of land area*	7.59E+07	*7.90E+07*	*8.20E+07*	*8.50E+07*	*8.81E+07*
Electricity production at Technical Potential (GWh) *Direct Normal Irradiance (DNI)* *6.5 kWh/(m² day)*	7.78E+08	*7.21E+08*	*6.63E+08*	*6.63E+08*	*6.63E+08*
Weighted Average Capacity factor (%)	40	*40*	*45*	*50*	*55*
Technical Efficiency *Average sun-to-electricity (%)*	25	*26*	*27*	*28*	*29*
Unit investment costs (Euro/kW)	5,900	*4,900*	*3,900*	*3,800*	*3,700*
Annual O&M Costs (EUR/(kW a))	54	*50*	*46*	*46*	*46*
Lifetime (years)	25	*28*	*30*	*35*	*40*
LCOE Range (Euro/kWh) in Africa	0.070	*0.059*	*0.049*	*0.048*	*0.047*
Land Use (m²/kW)	8.00	*7.69*	*7.41*	*7.14*	*6.90*
Additional Information					
Flagship projects in Africa	Noor II (Morocco), Redstone (South Africa)				
Locational priorities in Africa	High DNI regions in northern Sahara and southern Namib deserts				
Related transmission / other integration issues	requires standard connection to grid				
Related regulatory issues					
Related financing issues					
Related environmental issues / considerations	power plants must be air-cooled to limit water consumption				
Applicability recommendations for Africa	CSP power pipeline seems to have dried up, future applications in high-temperature industrial heat				

11 Recommendations

As highlighted throughout this report, the potential of solar in Africa is tremendous, and remains largely untapped. To scale-up solar power, several changes need to occur at the strategy, planning, policy, regulatory and investment levels. While it is virtually impossible to formulate recommendations for all of Africa, as each country and region faces unique circumstances, this section attempts to establish a few core recommendations that apply regardless of the specific political, market or utility context.

The recommendations are structured into three main categories:

1. Technical recommendations
2. Grid-related recommendations
3. Policy and financing-related recommendations

11.1 Technical recommendations

11.1.1 Which solar technology to use

All solar technologies are reliable and efficient. Differences between c-Si and thin film, between fixed-tilt and single-axis tracking, bi-facial panels, inverter loading, and storage connection will be accounted for in project designs; they should not deter high-level decision making.

11.1.2 Expand the establishment of research facilities, test laboratories, and documentation centres to improve local knowledge and capacity

Such research facilities/innovation hubs can be established adjacent to universities and expand the understanding of key issues related to solar PV technology and adoption, including climate, semiconductor physics, and the mechanical/electrical engineering.

11.1.3 Increase research and adoption of solar PV applications such as agrivoltaics

Agrivoltaics holds great potential in many countries throughout Africa. Research on which crops grow best when combined with solar PV, under what conditions, in which geographic regions of Africa is urgently needed to expand the role of agrivoltaics across the continent.

11.1.4 Increase the adoption of floating solar where feasible

Floating solar can be adopted on existing hydro reservoirs and canals, reducing evaporation rates and PV land requirements while boosting distributed power supply.

11.1.5 Begin pilot production/assembly of modules, mounting structures, and trackers

Expanding the local production capacity of solar can start by supporting the local manufacture of mounting structures and trackers, while building capacity toward the manufacture of modules and other key supporting technologies.

11.1.6 Expand the training of local workforce for installation, plant operation and maintenance. Employ women. Let them take charge. Provide resources improving employability and career growth

Expanding the local workforce for solar deployment is at the heart of successful and sustained solar adoption continent-wide. This capacity needs to be fostered, and built, and opportunities for women in particular need to be expanded and diversified.

11.2 Grid-related recommendations

11.2.1 General recommendations for the grid

11.2.1.1 Accelerate the deployment of hybrid solar PV + storage installations

Given the greater difficulty of integrating solar PV in weaker grids and the frequent lack of capacity at the utility/system operator, utility-scale solar PV plants should be incentivized to integrate storage (e.g., battery storage) where necessary to mitigate output variability at the source. Such hybrids of generation and storage allow faster adoption of solar power while helping reduce grid expansion costs and enabling simpler grid integration – due to reduced variability in comparison to solar power plants without storage.

11.2.1.2 Improve national grid codes while improving regional harmonization

Grid codes are meant to enable fair participation between system users, and fair sharing of responsibilities between system users and operators. Stakeholders throughout Africa should accelerate discussions on establishing regional grid codes and harmonizing national grid codes where possible. This should be considered a foundational element of the African Single Electricity Market (AfSEM).

11.2.1.3 Adopt requirements for the use of modern inverters

A growing number of jurisdictions are requiring the use of modern inverters for all new grid-connected solar PV projects. While such inverters are marginally more expensive than older inverter types, they provide a wide range of capabilities that can be helpful to grid operators and to the integration of variable resources such as solar.

11.2.1.4 Expand grid interconnections with neighbouring regions

Cooperation and coordination between the countries within and beyond the African power pools is key to sustained progress. The larger the overall balancing area, the greater the ability of the grid to integrate variable renewables, as fluctuations in one region of the grid can be offset by fluctuations elsewhere, resulting in a smoother solar PV output profile across the system.

11.2.1.5 Improve forecasting capabilities

To scale-up solar in a sustained way, investments in local and regional weather forecasting are required.

11.2.2 Recommendations for more developed countries with high electrification rates

11.2.2.1 Adopt integrated power system planning

Adopting integrated planning processes can enable more efficient planning of generation, transmission, and demand. Planning processes should span all relevant time scales; planning should also explicitly consider the role of storage and flexible demand in meeting system needs.

11.2.2.2 Increase the flexibility of power system operations

Increasing a power system's operational flexibility is increasingly important as the share of variable renewables like solar PV grows. This includes a range of factors such as the implementation of real-time forecasting, faster unit scheduling, shorter gate closing times, and incorporating flexibility reserves into ancillary services, many of which can be done without the need for substantial investment.

With the right regulations and price incentives, such flexible sources of generation can be encouraged to respond more flexibly to power system needs, increasing the amount of flexibility that can be harnessed from a utility's existing assets.

11.2.2.3 Establish rules enabling Virtual Power Plants

In addition to integrating solar PV with storage, virtual power plants can help to make electricity supply more efficient and make it easier to integrate different renewable electricity supply into the system. As such, regulators should establish rules granting virtual power plants access to energy markets as well as to ancillary service markets.

11.2.3 Recommendations for less developed countries with lower electrification rates

11.2.3.1 Make solar power the workhorse of off-grid electrification

Solar PV is now the cheapest source of electricity not only on-grid, but also for off-grid supply. As such, solar PV should become the default power source for non-electrified regions. Developing more decentralized electricity supply can help complement centralized approaches (such as expanding transmission grids), improve reliability and reduce costs.

11.2.3.2 Ensure all solar PV market segments benefit from open access to the market

With the rise of decentralized renewable energy, power systems in Africa are becoming more decentralized. Policy makers should seek to establish regulatory conditions that foster open-ended solar PV market development and deployment, across all market segments including in utility-scale as well as customer-sited and off-grid applications.

11.3 Policy and financing-related recommendations

11.3.1 Expand efforts to reduce investment risks and lower the cost of capital

Efforts to reduce the cost of capital (in short, policy and financial de-risking measures) are vital to unlocking solar at the lowest possible cost for utilities and ratepayers. Governments can reduce the cost of capital by introducing a host of de-risking measures, and by increasing the stability and predictability of power sector development and planning.

11.3.2 Set out clear solar PV deployment targets

Solar is inexpensive and its potential is vast. Governments throughout Africa can benefit from low-cost and abundant solar power, reducing their reliance on imports, by adopting ambitious solar deployment targets, and an appropriate strategy for deployment.

11.3.3 Introduce streamlined procurement mechanisms, drawing on best practices from across Africa

Many countries throughout Africa have already held successful auctions for solar power. Draw on these experiences while also learning from failures, including from auctions with low project completion rates.

11.3.4 Expand demand-side flexibility

Demand-side flexibility is emerging as a powerful new tool in power system operation and can support with the integration of variable renewables such as solar PV; it involves encouraging consumers to adjust their demand in response to particular signals such as price signals or network constraints in a framework allowing flexibility.

Shifting more power consumption to the middle of the day reduces the need for storage capacity and drives down the required capital expenditure, reducing costs for ratepayers. In most cases, demand response can be done automatically, requiring no active involvement of the customer.

11.3.5 Establish a clear framework for securing land access, including improving ESIAs

In many cases the land access regime is unclear. This lack of clarity increases project risk, and with it, the cost of capital. The same applies to the required Environmental and Social Impact Assessments (ESIAs). Governments across the continent should start detailed zoning and land rights analysis to identify suitable zones for solar PV development, including for agri-PV development. This could take the form of special renewable energy development zones. This can involve providing pre-packaged, publicly-owned land, and leasing that land to private developers, or creating a clearer process and legal framework governing land access and title.

11.3.6 Expand the involvement of local banks in financing solar projects on the continent

To achieve an energy transition that is truly Africa-led, fostering the involvement of local banks and investors in providing capital is critical. The hesitation of many banks in Africa to invest in solar can be overcome through greater awareness, the organization of study tours, providing detailed case studies of project loan documents and power purchase agreements.

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13 Glossary

Description of acronyms and terms in tabular form.

Assignment	This project under the Continental Master Plan (CMP)
AUC	African Union Commission
AUDA-NEPAD	African Union Development Agency – New Partnership for Africa Development
BOO	Build Own Operate
BOOT	Build Own Operate Transfer
BOS	Balance Of System, all components other than the central part. In photovoltaics, BOS encompasses all parts other than the panel
C&I	Corporate and Industrial: renewable power plants financed by the private sector excluding utilities, but sometimes including electricity distribution to surrounding private consumers
CAGR	Compound Annual Growth Rate $PV = \frac{FV}{(1+r)^Y}$, $CAGR = \left(\frac{FV}{PV}\right)^{1/Y} - 1$, where PV is the present value (= starting principal), FV is the future value, r and CAGR are the annual interest rate, and Y is the number of years invested
Capacity Credit	Capacity credit (sometimes called capacity value) is the contribution that a given generator makes to overall system adequacy. Even the availability of conventional generation is not assured at all times because there is always a non-zero risk of mechanical or electrical failure. Because reliability is expensive it is common to adopt a reliability target for the system. The capacity value of any generator is the amount of additional load that can be served at the target reliability level with the addition of the generator in question [Enss08]
Capacity Factor	The ratio of the electrical energy produced by a generating unit for the period of time considered to the electrical energy that could have been produced at continuous full power operation during the same period (www.eia.gov)
CAR	Central African Republic

CMP	Continental power system (generation and transmission) Master Plan for Africa, base of the present Assignment
CPV	Concentrated Photovoltaic power: The direct fraction of sunlight is concentrated on highly efficient (>40%) multi-junction cells
CSP	Concentrated Solar Power: Solar thermal power. Solar trough, solar tower, linear Fresnel are the typical geometries concentrating the impinging direct fraction of sunlight
DNI	Direct Normal Irradiance, in W/m², on a plate oriented normal to the sun (always tracking the sun)
EPC	Engineering, Procurement and Construction; the main contractor in building a solar power plant
GHI	Global Horizontal Irradiance, in W/m², on a horizontal plate
GTI	Global Tilted Irradiance, in W/m², on a plate tilted towards the sun at an optimum (yet fixed) angle
GIS	Geographic Information System: Generation and mapping of geographic information, like boundaries and terrain, but also land use, or alphabetization rate
HTF	Heat Transfer Fluid (in the power cycle of the CSP plant), thermal oil, molten salt or water
IAEA	International Atomic Energy Agency
LCOE	Levelized Cost of Electricity, the depreciated cost of generated power, given in EUR/kWh, for any base year
LOLE	Loss of load expectation, used in calculations for capacity credits
Lot	Group of Experts contributing to the Continental master Plan (CMP)
MESSAGE	see SPLAT
MSR	Model Supply Regions: favourable locations for renewable power plants, selected by the algorithms of SPLAT
IEA	International Energy Agency
IRENA	International Renewable Energy Agency
Phase	Group of Tasks in the Assignment
PIDA-PAP	Programme for Infrastructure Development in Africa – Priority Action Plan
PIU	Project Implementation Unit
Power Pool	Five associations of power utilities across Africa (see section 8.2)

PPA	Power Purchase Agreement, where a buyer agrees to buy electrical energy at a price, and under certain conditions
PPA BOOT	Power Purchase Agreement (PPA) in Build Own Operate Transfer mode, see [285]
PSSE	Power System Simulator for Engineering, a software package designed to simulate large electricity grids, by Siemens AG.
PV	Photovoltaic generation of electricity by means of flat-plate panels capturing direct and diffuse fractions of sunlight with an efficiency of 20%
REIPPPP	Renewable Energy Independent Power Producer Procurement Programme, introduced 2011 in South Africa to promote renewable energies
RTE	Round-Trip Efficiency, used to characterize the losses of a charge-discharge cycle in a PV power plant with battery storage
SDR	Special Drawing Rights (of the World Bank)
Solar Multiple	Solar Multiple (SM) of a CSP plant is defined as the ratio of the rated power capacity by the solar collector field to power block capacity
SPLAT	models developed by IRENA. SPLAT uses the IAEA's Model for Energy Supply System Alternatives and their General Environmental Impacts (MESSAGE) tool, see https://www.irena.org/energytransition/Energy-System-Models-and-Data/System-Planning-Test-Model
SSS	Specific Support Study, for example the present Assignment for Lot 12b
Task	Activity, or work package of Phase in the Assignment
TES	Thermal Energy Storage (TES) in Concentrated Solar Power (CSP) plants
TOR	Terms of Reference, preceding the Inception Report. The TOR referred to in the Inception Report is *CW243_CMP_SSS_ Solar TOR final v2.docx* (as of 2022-02-26)
USD	United States Dollars
UTC	Coordinated Universal Time
VRE	Variable Renewable Energy sources like solar and wind, termed variable due to potentially intermittent power generation

14 Appendix

14.1 Summary of Technology Cases

A summary on the main characteristics of Technology Cases is given in Table 21.

Table 21: Main characteristics of the Technology Cases. Sources: see section 1.2.2

	Noor II	**Redstone**	**Jasper**	**Danzi**	**Black Volta**	**Kesses I**	**Cuamba**
Technology	CSP parabolic trough	CSP power tower	PV	PV/battery storage	Floating PV	PV	PV/battery storage
Power Pool	COMELEC	SAPP	SAPP	CAPP	WAPP	EAPP	SAPP
Country	Morocco	South Africa	South Africa	Central African Republic	Ghana	Kenya	Mozambique
City	Ouarzazate					Eldoret	Cuamba
Owners							
Nominal Power, MW	200	100	96	25	65	55.6	19
Status	Operational	Under construction	Operational	Under construction	LOI, 5 MW operational	Under construction	Under construction
Start Year	2018			2022	2023		2022
Background							
Break Ground Date	2015						
Expected Generation, GWh/a	600	480(?)	181	35		123	
Solar Resource, kWh/(m² a)	2,503	2,707		1,830			
Power Efficiency (turbine), %	37.4	42.8					
Annual capacity factor, % (2019)	34.2 no storage	54.8 35.6 no storage	18.2	17.7 no storage	17.9	22.8	20.9 no storage
Participants							
Developer	ACWA Power	ACWA Power			Bui Power Authority	Alten Energías Renovables	Globaleq Generation Limited
EPC	SENER			Shanxi Construction Investment Group Co., Ltd. (sxcig.com)			TSK (Spain)

Electricity Generation Offtaker	Moroccan Agency for Solar Energy (MASEN)	Eskom Holdings SOC Ltd	Eskom Holdings SOC Ltd	Energie Centrafriquaine (enerca-rca.com)	Ghana National Interconnected Transmission System (NITS)	Kenya Power and Lighting Company	Electricidade de Mocambique (EDM)
Costs							
Total Construction Cost, mUSD	1,119	789	210	48		76	36
Financing							
PPA or Tariff Period, years	25	20				20	25
Support Scheme Type	PPA-BOOT	PPA-BOO				PPA take-or-pay	PPA
Solar Field							
Tracking	2-axes	2-axes	fixed	fixed	fixed	1-axis	fixed(?)
Storage							
Storage Type	2-tank indirect, molten salt (sensible heat)	2-tank direct, molten salt (sensible heat)		Battery			Battery
Nominal Size, MWh	1,200	1,200		25			7
Storage Duration, hours	6	12					3.5 (at 2 MW)
Expected Storage Lifetime, years				5, increasing to 8, 10 years			
Storage Cost, mUSD				10.0			
Grid							
Power Line, kV				63 (to be rehabilitated)		230	33/110 (to be rehabilitated)
Power Line Distance, km				3		0	0.4

14.2 Capacity credit calculation details

14.2.1 Calculations for probabilistic methods

14.2.1.1 Equivalent Conventional Power (ECP) formula

The steps for calculating the ECP of a generator (i.e. solar) are listed below:

1. For a given set of conventional generators, the LOLE for a system prior to introducing the solar PV plant is calculated as follows:

$$\mathrm{LOLE} = \sum_{i=1}^{T} \mathrm{P}(\mathrm{G_i}<\mathrm{L}), \quad (1)$$

Where:

- T = the total number of hours of study,
- G_i = the available conventional capacity in hour i, and
- L_i = the amount of load.
- $P(G_i < L_i)$ refers to the probability of available generating capacity being less than demand, which is the LOLP in each hour.

Adding up these hourly LOLPs gives the LOLE. The calculated LOLE represents the system's original reliability level. In order to meet a planning target of no more than a single outage-day for every 10 years, one must adjust the loads in each hour so the LOLE of the base system, given by equation (1) is 0.1 days/year. This load adjustment is done by applying a fixed percentage change (0.1% - 5% between the different study years) to each hourly load.

2. After the solar PV plant is added, the new LOLE is calculated as

$$\mathrm{LOLE_{PV}} = \sum_{i=1}^{T} \mathrm{P}(\mathrm{G_i}+\mathrm{C_i}<\mathrm{L}), \quad (2)$$

Where:

- C_i = the output of the PV plant in hour i.

Since the PV plant has been added to the system, $LOLE_{PV}$ will be lower than the base system's LOLE (the base system is more reliable with lower LOLPs).

3. The PV plant is then "removed" from the system and replaced by a conventional generator. The LOLE of the new system, denoted as $\mathrm{LOLE_{Gen}}$, is computed with:

$$\mathrm{LOLE_{Gen}} = \sum_{i=1}^{T} P(G_i+X_i<L_i), \quad (3)$$

Where:

- X_i is the available generating capacity in hour i from the added conventional generator.

This added conventional generator is assumed to have a fixed EFOR, but the nameplate capacity of the conventional plant is adjusted until the LOLE of the system with the solar PV and the conventional generator are equal (i.e., until $LOLE_{PV} = LOLE_{Gen}$). The nameplate capacity of the conventional generator that achieves this equality is defined as the ECP of the solar PV. The benchmark generator to which the PV plant is compared to is assumed to be a natural gas-fired power plant. The PV plant's ECP will be sensitive to this assumption because different generation technologies against which it could be benchmarked will have different EFORs.

14.2.1.2 Effective Load Carrying Capacity (ELCC) Formula

The steps used to calculate the ELCC of a PV generator are as follows:

1. For a given conventional generator(s), the LOLE of the system without the PV plant is calculated using formula (1).

2. The PV plant is added to the system and the LOLE is recalculated. This is shown in formula (2). $LOLE_{PV}$ will be less than the LOLE of the base system because of the added generation to the system.

3. Keeping the PV plant in the system a constant load is added in each hour. The LOLE of the new system, which is denoted as $LOLE_{Load}$ is calculated with the following:

$$LOLE_{Load} = \sum_{i=1}^{T} P(G_i < L_i + D), \qquad (4)$$

Where:

- D is the load added in each hour.

The value of D is adjusted until the LOLEs calculated in steps 1 and 3 (representing the LOLE of the base system and the system with the added PV and load) equal each other. The value of D that achieves this equality is defined as the ELCC of the solar PV.

14.2.1.3 Equivalent Firm Capacity (EFC) calculation

The steps for calculating the EFC of a generator (i.e. solar) are listed below:

1. For a given set of conventional generators, the LOLE of the system without the PV plant is calculated using Eqn. (1).

2. The PV plant is added to the system and the system's LOLE, denoted as $LOLE_{PV}$, is calculated with Eqn. (2).

3. The PV plant is then "removed" from the system and is "replaced" by a fully reliable conventional generator (EFOR of 0%). The LOLE of the new system, denoted as $LOLE_{Gen}$, is computed according to formula (3) with the difference that X_i is the available generating capacity in hour i from the added fully reliable conventional generator.

4. The nameplate capacity of the plant is adjusted until the LOLE of the system with the PV plant and the conventional generator are equal (in other words, until $LOLE_{PV} = LOLE_{Gen}$). The nameplate capacity of the conventional generator that achieves this equality is defined as the EFC of the solar PV.

14.2.2 Calculations for approximation methods

14.2.2.1 Capacity factor approximation method calculation

The weights for the capacity factor approximation are obtained with the following formula:

$$w_i = \frac{LOLP_i}{\sum_{j=1}^{T} LOLP_j}, \tag{5}$$

Where:

- w_i is the weight in hour i, is the LOLP in hour i, and
- T is the number of hours in the study.

These weights are used to calculate the weighted average capacity factor of the PV plant in the highest-load hours as:

$$CV = \sum_{i=1}^{T'} w_i C_i , \tag{6}$$

Where:

- T' = the number of hours used for the estimation, and
- CV = the weighted generation of the solar PV during the high-load hours and is considered as an approximation for capacity value.

14.2.2.2 Garver's Approximation Method

Garver's method approximates the PV plant's ELCC by first estimating the LOLE of the system when the PV plant is added as:

$$\sum_{i=1}^{T} \exp\left(\frac{-(PL - L_i + C_i)}{m}\right), \tag{7}$$

Where:

- m = slope of the risk function, which represents the necessary capacity for an annual LOLE that is e times greater than the original LOLE.
- PL = annual peak load,
- L_i is the hourly load, and
- C_i is the hourly PV output.

By substituting the PV plant's output with a constant, denoted *ELCC*, the system LOLE would change to:

$$\sum_{i=1}^{T} \exp\left(\frac{-(PL - L_i + ELCC)}{m}\right), \tag{8}$$

The ELCC approximation is given by the value of *ELCC*, which yields equality between formulas (7) and (8). A closed-form solution for the *ELCC* is as follows:

$$ELCC = m \times Ln\left[\frac{\sum_{i=1}^{T} \exp\left(\frac{-(PL-L_i)}{m}\right)}{\sum_{i=1}^{T} \exp\left(\frac{-(PL-L_i+C_i)}{m}\right)}\right], \tag{9}$$

14.2.2.3 Garver's Approximation Method for multi-state units

The methodology relies on two main assumptions:

1. The probability distribution of renewable availability stays the same in different time periods.
2. The LOLE of a system can be approximated as Be^{md}, where
   - d = the annual peak load, and
   - B and m are parameters.

These parameters can be approximated by estimating the LOLE of the system using formula (1) with different system peaks (e.g., by increasing all loads proportionally) and fitting values for B and m to the LOLE values.

This method approximates the ELCC of a generator with the following formula:

$$ELCC = -\frac{1}{m} \times Ln\left[\sum_{i=1}^{T} \mathrm{p}_i \mathrm{e}^{-mC_i}\right], \tag{10}$$

Where:

- P_i is the probability of the PV plant to generate C_i.

The relevant empirical distribution assigns probabilities Pi to each generating state C_i by counting the number of occurrences of C_i divided by the total number of hours used in the analysis.

14.2.2.4 Z Method Calculation

Equation (11) is used to calculate the z-statistic (Z_0) for a random variable S. Variables μ_S and σ_S refer to the mean and standard deviation of S.

$$Z_0 = \frac{\mu_S}{\sigma_S}, \tag{11}$$

The Z method assumes that the shape of probability distribution of S (Gaussian distribution) would not change when a new generator is added to the system, although the mean and variance of the distribution could change.

Assuming that the above assumption holds concerning the shape of the probability distribution, the ELCC of a new generator can be defined as the amount of incremental load that keeps the z-statistic constant after adding that generator to the system. The closed form solution, which approximates ELCC based on the assumption above, is shown below in (12) where μ_{PV} and σ_{PV} are mean and standard deviation of PV availability.

$$ELCC = \bar{\mu}_{PV} - \frac{Z_0 \bar{\sigma}^2{}_{PV}}{2\sigma_S}\,. \qquad (12)$$

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