How reliability and carbon prices impact pathways to universal electricity access in Africa

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ABSTRACT

Off-grid PV systems have been proposed as a panacea for economies with poor electricity access, offering a lower-cost “leapfrog” over grid infrastructure used in higher-income economies. However, reliability and carbon pricing impacts have been omitted from work that examines pathways to electricity access, underplaying the potential of off-grid PV. We perform high-resolution geospatial analysis on universal household electricity access in Sub-Saharan Africa that includes these aspects via least-cost pathways at different electricity demand levels. Under our "Tier 3" demand reference scenario, 24% of our study’s 470 million people obtaining electricity access by 2030 do so via off-grid PV. A penalty for unmet demand (0.50 $/kWh) increases this share to 41% and applying a carbon price (around $80/tonne CO_2-eq) increases it to 38%. We identify thresholds for policy effectiveness in different regions and highlight the high degree of spatial heterogeneity and the areas where policy intervention may be most effective.

Introduction

Access to electricity remains a significant global challenge. Around 700 million people remain without access to any electricity supply, most of whom reside in Sub-Saharan Africa (SSA). Progress in reducing this number has slowed in recent years due to hardship from Covid-19 and the conflict in Ukraine[1,2]. Additionally, many with a connection experience a poor service level: globally, as many as 3.5 billion may live with unreliable power[3], causing a significant drag on economic growth[4]. Achieving universal household electricity access, a key component of UN Sustainable Development Goal (SDG) 7[5], requires a focus on SSA, and is an uphill challenge given the anticipated population growth and the number of people still without power in the region[2]. An urgent acceleration in progress is needed to retain any chance of achieving universal household access by 2030.

Failing to do so will limit progress on several other SDGs[6], including improved healthcare (SDG3)[7], educational outcomes (SDG4)[8] and economic opportunities (SDGs 1, 8)[9].

The most appropriate technology to enable electricity access - grid extension, standalone systems, or mini-grids serving clusters of customers - varies with the context. Demand, population density, and distance to existing grid infrastructure are crucial factors influencing the cost competitiveness of different solutions. An argument for the use of solar photovoltaics- (PV) based off-grid systems, can be made on cost, system reliability and environmental grounds[10,11]. Off-grid PV systems have become markedly cheaper, benefiting from the increased deployment of PV globally and the mass production of batteries for electric vehicles; capital costs for PV mini-grids fell by 65-85% in the decade up to 2019, and are expected to fall further by 2030[12]. Off-grid systems may offer consumers higher reliability and more predictable power than current grid infrastructure in some contexts, which may encourage consumer preferences towards such systems[11,13]. Finally, PV-based off-grid systems can provide equivalent energy services with lower greenhouse gas (GHG) emissions relative to fossil-based alternatives[19]. Despite these advantages, in many low-access countries, renewables-based off-grid solutions are secondary in or omitted from electrification strategies[15].

Exploring different approaches for universal electricity access - e.g., centralised grid versus decentralised and fossil- versus renewables-based energy infrastructure - has been done at a national and regional level using integrated assessment models (IAMs)[16] and at a more granular level using geospatial analysis[17–21]. Factors influencing which solution is cost-optimal (e.g., population density, distance from the grid) vary greatly at the sub-national level and therefore high-resolution geospatial analysis can provide useful guidance for planning cost-effective electricity access. Previous geospatial analyses have demonstrated the importance of electricity demand[18], climate-impacted cooling electricity demand[19], financing rates[21], and diesel pricing and subsidies[17] for least-cost pathways to electricity access. Geospatial analysis has been used to inform approaches to electricity supply beyond households, such as for healthcare facilities[22] and refugee camps[23].

Reliability of supply is an additional factor that should be taken into account when considering electrification approaches[24]. Reliability is a key consideration impacting the costs of off-grid systems[25] and critical when comparing with national grids that often deliver poor service levels and associated negative impacts such as reduced security, reduced household income and additional expenditure on backup alternatives[26–28]. The reliability offered by access solutions has not been factored into previous geospatial work examining least-cost pathways to electricity access. This work seeks to address this research gap.

Further, as countries and corporations seek to mitigate their GHG emissions, and carbon pricing becomes more widespread[29], it is important to consider how it could impact pathways to electricity access. Voluntary carbon markets have the potential to provide significant amounts of climate finance for African countries, allowing them to sell carbon credits and spend money on clean energy access infrastructure. Presently, Africa only produces a fraction of the carbon credits it could issue[30]. Existing schemes such as the D-REC Initiative financial incentives for off-grid PV systems, increasing their uptake[31]. Understanding how carbon pricing could influence the relative cost and shares of different access technologies is important for forward planning and has not been well explored.

Here, we examine universal household electricity access in 43 SSA countries. Acknowledging the importance of considering country heterogeneity in the region's energy future[32], this paper combines detailed country-level data and electricity demand growth trajectories with open-source energy system modelling and high-resolution geospatial analysis to explore pathways to universal electricity access. Using a scenario-based approach and a new modelling framework that considers electricity demand growth by country (see Figure 1, Methods), we examine both reliability of supply and carbon pricing impacts on the shares of off-grid and grid provision of electricity at different demand levels. We explore the spatial heterogeneity with regard to the use of different technologies between and within countries and explore how electricity demand levels impact uptake of off-grid technologies. We also explore the impact of reliability and carbon price policy interventions, including regionally disaggregated sensitivity analysis indicates areas where policy interventions may be most effective.

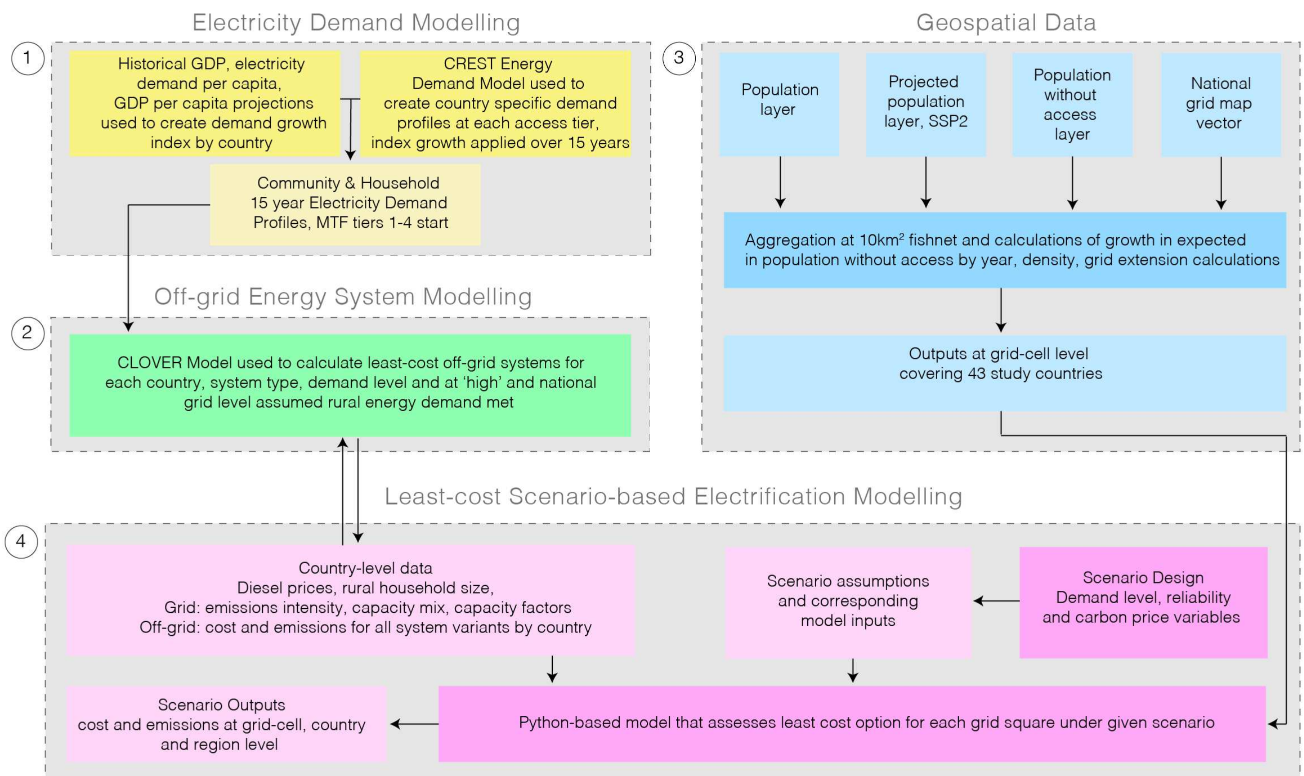

Figure 1. Flow diagram explaining the methodological components for the analysis in this paper. The first step was to model household and community level demand at different Tiers of access with a growth rate applied by country linked to projected GDP per-capita growth. The second step was to model off-grid systems types at different demand levels for each country; this was done at different levels of energy demand met. The third part of the methods involved processing geospatial data covering the 43 study countries. The final step used the outputs from the first three steps in an open-source scenario-based least-cost electricity access model.

Scenarios for universal household electricity access

To examine the least-cost pathways to universal household electricity access, we explore a range of scenarios that consider electricity demand, reliability of supply and carbon pricing (Table 1). We use population and electricity demand growth assumptions based on the shared-socioeconomic pathway (SSP) 2[33] (Methods). In our baseline assessment of the population requiring access, some countries are expected to reach universal household access (Results, Methods). Our least-cost scenarios include only the additional population above what we expect to occur in the baseline scenarios.

We use the Energy Sector Management Assistance Program (ESMAP) Multi-Tier framework (MTF)[34] to guide demand levels, similar to other studies[18,21,35], and due to the fact that many countries have electricity access targets aligning with the MTF. The MTF has Tiers 1 to 5, with household demand per year for each Tier of 4.5, 73, 365, 1241 and 2993 kWh, respectively. This paper examines only Tiers 1 to 4, with a focus on Tiers 2 to 4 for households that requiring electricity access. Tier 1 represents access only for phone charging or basic lighting and Tier 5 is largely unobtainable for newly-connected households in SSA that have low incomes. In our scenarios, the MTF Tiers are used as the starting point for household annual demand. However, household demand trajectories vary depending on expected GDP per-capita growth by country (Methods). Additionally, the estimated values represent electricity demand, rather than demand met, which varies based on the reliability of different technology options. We do not use the MTF for blackouts or hours of service since we perform our own analysis on service reliability.

Our scenarios explore reference cases and reliability and carbon pricing variations (Table 1). Additionally, we perform spatially disaggregated sensitivity analysis on carbon prices and reliability penalty levels. Including sensitivity analyses, this work presents results from 110 scenarios.

Results

Progress to universal household access and baseline scenario

In our baseline scenario, while some countries reach or make significant progress towards universal access by 2030, others see an increase in the number of people without access to electricity. Increases are driven by a combination of population growth and low levels of progress in specific regions (Methods). The total number of people lacking electricity access in 2030 in the Baseline scenario for the 43 study countries is just over 470 million (from 505 million in 2020), with almost no further reduction by 2035 (Table S1). This is in the context of a total population growth of 340 million between 2020 and 2030 and a further 240 million between 2030 and 2035. Higher-income countries such as Ghana, Kenya, South Africa, and Côte d'Ivoire are expected to reach universal access by 2030. By 2035, Senegal, Benin and Togo are also expected to reach universal household access. East African countries such as Ethiopia and Uganda are expected to see considerable increases in population without access due to their high anticipated population growth that exceeds expected progress in connections (Supplementary materials, Table S1 & Figure S1)

Electricity demand impacts technology choices for pathways to universal household access

Our results in the reference scenarios (*Ref_central*) imply that the electricity demand level is key in determining the most cost-effective technologies. Specifically, at the lowest demand level (Tier 1), off-grid PV-based technologies are the least-cost option for 78% of the population requiring access. At Tiers 2 and 3 (Figures 2a & 2b), grid connections, as well as off-grid

Table 1. The main scenarios modelled in this paper. The baseline scenarios attempt to understand the expected outcomes given recent trends in connections and expected population growth. The Reference scenarios are variants of a least-cost pathway to universal household electricity access with no policy intervention. The reliability scenarios explore how the least-cost pathways may be different when sizing off-grid systems at lower levels, or applying a financial penalty for unmet demand (Methods). The carbon pricing scenario details the least-cost pathways to universal access when a dynamic carbon price is applied across all access technologies (Methods).

Scenario	Demand Tier	Description	Target Year
Baseline	N/A	Scenario that uses historical trends in improvements in access and projected population growth to estimate the population remaining without access by the target year.	2020/2035
Reference			
Ref_central	Tiers 1-4	Central reference scenario where all unmet population above the baseline gain access via calculated least-cost electrification technology by 2030.	2030
Ref_single_modes	Tiers 3 & 4	Reference scenarios where all unmet population above the baseline gain access via single access technologies e.g., all via grid/diesel etc., for emissions and investment comparisons.	2030
Ref_late	Tiers 2-4	Central reference scenario where all unmet population above the baseline gain access via calculated least-cost access technology with a later target date.	2035
Reliability			
Rel_grid_all	Tiers 2-4	Reliability scenario where all unmet population above the baseline gain access via calculated least-cost mode with the off-grid technologies sized at the assumed reliability of the rural grid in for each respective country.	2030
Rel_penalty_0.50	Tiers 2-4	Reliability scenario where all unmet population above the baseline gain access via calculated least-cost technology with a $0.5/kWh penalty for unmet demand applied across all (Methods).	2030
Carbon Pricing			
Ctax_median	Tiers 2-4	Carbon price scenario where all unmet population above the baseline gain access via calculated least-cost technology, with a carbon price scheme representing the median values from the IPCC AR6 database[36] (C1 and C2 scenarios) is applied across all technologies (Methods).	2030

diesel become cost competitive. Diesel mini-grids are used in parts of Central Africa where the annual solar insolation is lower and there are few existing grid lines, as well as in parts of East and West Africa that have lower fuel prices (see Table S6). At Tier 3 demand, the grid is the least-cost option for 49% of the population and at Tier 4 demand (Figure 2c), the grid share increases to 63%. The share of off-grid PV installations falls from over a third at Tier 2, to 25% and 20% at Tiers 3 and 4, respectively. A delay in achieving the universal access target by five years (scenario *Ref_late*) increases the share of off-grid PV compared to a 2030 target. For detailed results of this scenario, see Supplementary Materials (S2.2).

At lower demand Tiers, off-grid PV systems are relatively cheaper compared to other technologies as their modular nature permits sizing for low levels of demand. The cost of grid extension remains high regardless of the demand level, with only added grid capacity changing according to the demand Tier. Diesel systems are more economical above Tier 1 due to the minimum sizes and output capacity factors (Methods).

Variation in the reliability of electricity supply

National grids have poor reliability in many countries, such as Nigeria and Zambia[37] (See Figure 3b). Treating electricity access technologies equally regarding the levels of demand they meet may lead to poor outcomes for energy planning. We

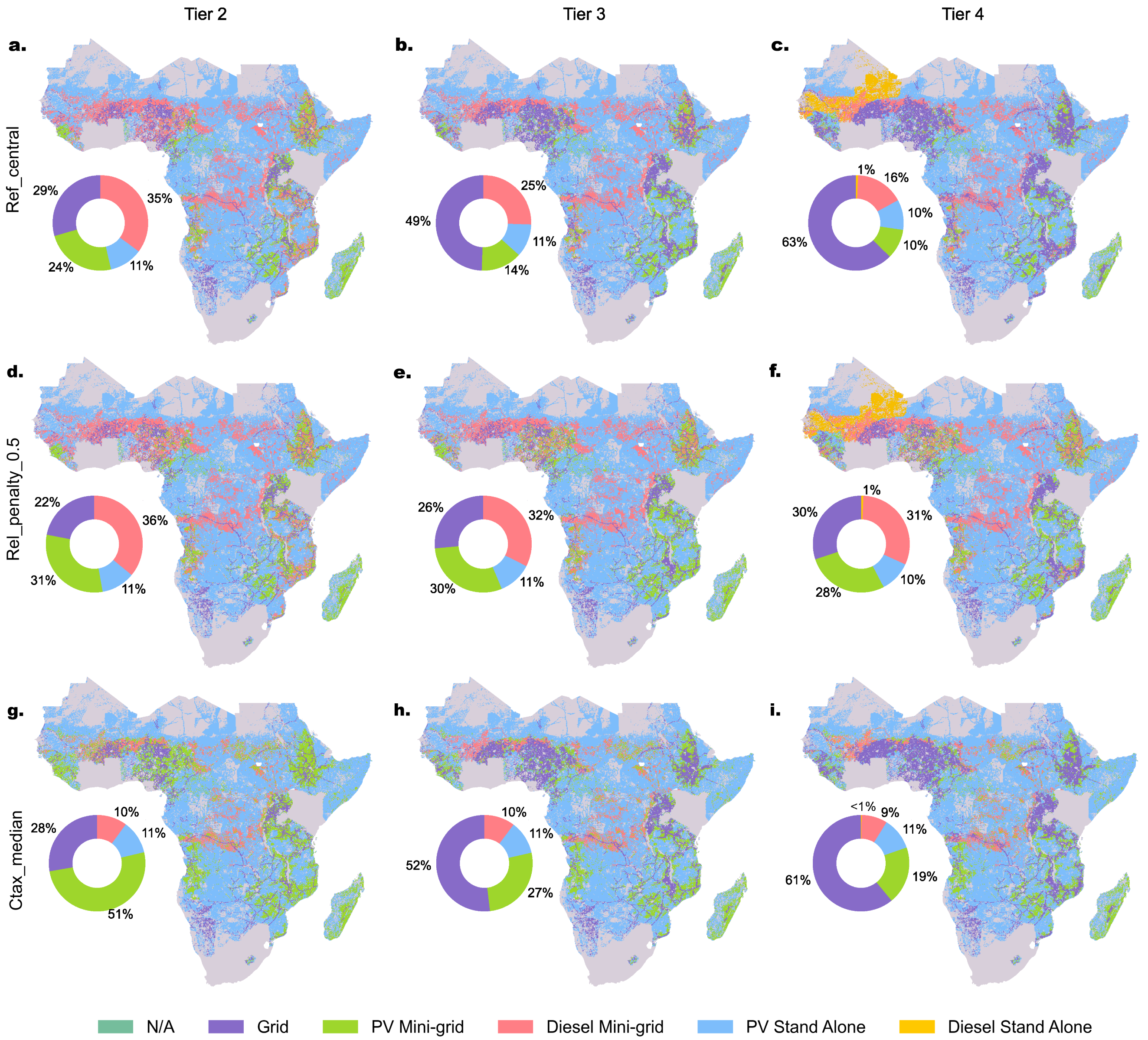

Figure 2. Spatially distributed least-cost electrification method for the Ref_central, Rel_penalty_0.5 and Ctax_median scenarios at demand Tiers 2-4. Panels a-c represent the Ref_central results, with no carbon price or unmet demand penalty applied, they show a declining role for off-grid technologies as demand increases. Panels d-f represent the Rel_penalty_0.5 scenario applying a 0.5$/kWh of unmet demand penalty universally across all technologies, this reduces the share of the grid at all demand Tiers, with the largest difference at the highest demand Tier. Panels g-i represent the Ctax_median scenario, equating to a carbon price scheme of around $4 (2022 USD) in 2020, rising to $146 by 2030, here diesel usage is reduced in all three Tiers, with the largest difference with Ref_central seen at Tier 2.

assess the impacts of the reliability of supply (% electricity demand met) on the technology shares and their spatial distribution. We first sized the off-grid systems in each country to match the assumed rural grid reliability in each country (*Rel_grid_all* scenario). Off-grid systems cost more at higher levels of electricity demand met[25], and so matching with unreliable grids sees substantially improved cost competitiveness. Detailed results of this scenario are provided in Supplementary Materials S2.3.

Unreliable electricity supplies result in costs to households in SSA[27,28]. To represent this, we add a financial penalty ($/kWh unmet) across all technology (Table 1, Methods). First, considering the scenario in which we implemented a 0.5 $/kWh penalty (*Rel_penalty_0.5*), the results (Figure 2d-f & Figure 3 d-f) show that, at all Tiers, there is more usage of off-grid technologies compared to in the *Ref_central* scenario, with the largest change being at Tier 4 demand. At a Tier-2 level of demand (Figure 3d), the impact is small, with the majority of the change, 7% of the population, shifting away from the grid towards off-grid PV. This occurs in parts of East and West Africa where the grid is deployed at this Tier under the *Ref_central* scenario. A marginal shift from grid- to diesel-based systems is seen in parts of the Western Sahel, where diesel is the cost-optimal option at all access Tiers under the *Ref_central* scenario.

At a Tier 3 demand, bigger changes occur (16% more off-grid PV, 7% more off-grid diesel) than for Tier 2 demand when compared to the *Ref_central* scenario (Figure 3e). Countries such as Nigeria and Senegal with low-grid reliability (Figures 3b) see more use of off-grid PV. The results show a marginal impact for the reliability penalty in other countries with poor grid reliability e.g., Zambia and the Central African Republic that already have higher levels of off-grid PV and lower levels of grid in the *Ref_central* scenario (Figure 2b). Countries with higher grid reliability, e.g., Ethiopia and Tanzania, see differences in their pathways under *Rel_penalty_50*, with these countries having a higher share of the grid under the *Ref_central* scenario. At Tier-4 (Figure 3f), a large increase (18% of the population) in usage off-grid PV systems is seen in all parts of the continent deploying grid connections under the *Ref_central* scenario. Increased use of off-grid diesel under the *Rel_penalty_50* scenario is the reason that we also see higher overall emissions, a 22% and a 4% increase for Tiers 3 and 4, respectively when compared to the *Ref_central* scenario (Table 2).

We tested the sensitivity to different penalties between $0.05 and $1.00 at 5-cent increments (Figure 3c). At Tier 2, the share of the grid drops from an already low level and plateaus after a threshold of 20 cents. Tiers 3 and 4 require higher penalties (20 and 50 cents) for meaningful changes. There is less impact after thresholds of 40 cents and 50 cents at Tiers 3 and 4, respectively. The level at which adding an unmet demand penalty influences the cost competitiveness between off-grid and grid technologies varies geographically at each Tier (Figure 3 g-h). For demand Tiers 3 and 4, lower levels of penalty (below 0.4 $/kWh) see differences in technology shares (when compared to *Ref_central* scenario) in certain countries including Nigeria, Angola and Ethiopia. Changes do not occur until higher penalty levels (above 0.6 $/kWh) in other areas, including parts of Mozambique, Rwanda and Uganda. This suggests that whilst national grid reliability contributes to geographical differences, (Figure 3b), other factors, e.g., the relative cost differentials between technologies in different regions, are important.

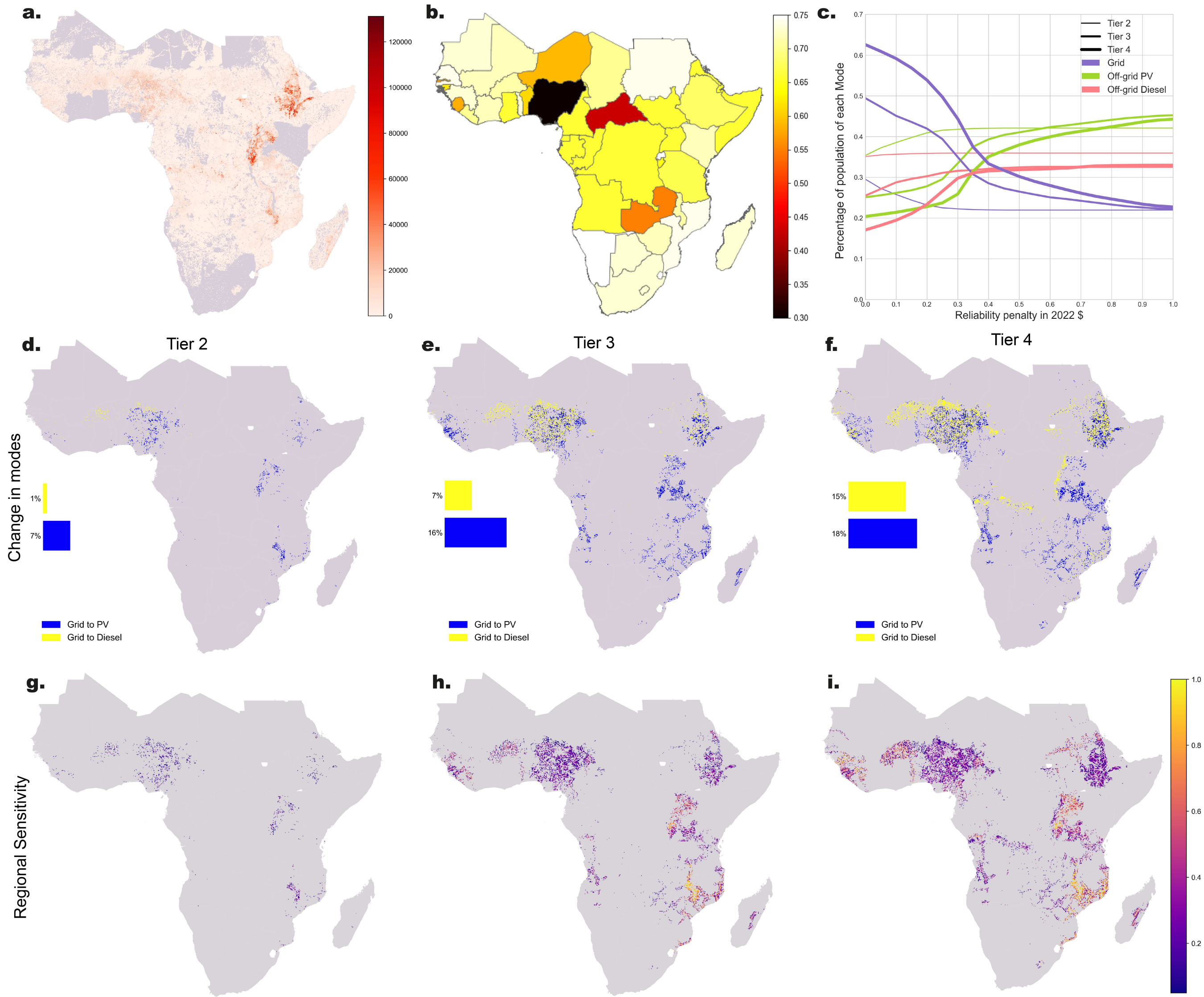

Figure 3. Panel a details the population requiring access to 2030. Panel b shows the rural grid reliability by country, in percentage energy demand met (data given the Supplementary Information). Panel c describes the sensitivity to different unmet energy penalties ($/kWh unmet) that grid, PV and diesel shares have at each Tier of access. The plateaus that can be observed are due to the shares of the population without access that live in close enough proximity to the grid that the cost advantage at a given Tier of access in terms of connection cost per household even with a high unmet demand penalty, off-grid modes remain uncompetitive (Methods). Panels d to f describe shifts in the mode of access at Tiers 2-4 from the reference scenario (Ref_central) to the scenario applying a $0.50/kWh penalty. Panels g to i show the different unmet energy demand penalty levels at which a change in electricity access technology occurs, Tiers 2 to 4. Increasing areas of shading can be seen as tiers increase due to increased shares of the grid used at higher tiers in the Ref_central scenario.

Inclusion of carbon pricing

The implementation of a carbon pricing scheme (*Ctax_median*) sees notable changes in the technology shares and geographical distribution (Figures 2 g-i and 4 d-f) when compared to the *Ref_central* scenario. The most significant change at all access Tiers is the reduction of off-grid diesel, predominantly supplanted by off-grid PV, but also by the grid in some regions. The total share of the population changing least cost technology option in the *Ctax_median* scenario compared to *Ref_central* scenario, reduces as electricity demand Tiers increase.

Carbon pricing has the greatest impact on the uptake of off-grid PV systems at Tier 2. The share of population that switches from off-grid diesel to off-grid PV systems is around 25% in the *Ctax_median* scenario compared to the *Ref_central* scenario. This occurs in all regions where diesel is deployed under the *Ref_central* scenario (Figures 2a and 4d). A small change (2% of population) is also observed from the grid to PV in parts of East Africa, including in areas of a relatively high density of population requiring connectivity (Figure 4b). Movement from diesel to grid connectivity (1% of population) occurs in West Africa where grid emissions intensity of electricity is moderate (around 0.6 kgCO_2-eq/kWh) and grid lines already exist. The cost of grid extension with a carbon price becomes viable in these regions.

At Tier 3 demand (Figure 4e), under the *Ctax_median* scenario there is less displacement of diesel by PV systems than at Tier 2 (10% of population) when compared to the *Ref_central* scenario. Shifts from the grid to PV systems occur at the same total level as Tier 2 (2% of population); however, distributed over a more diverse area, particularly in countries with higher relative grid emissions intensity, e.g., Angola, Mozambique and Zimbabwe (Figure 4b). There is a change (5% of population) from diesel to the grid in parts of Ethiopia and Sudan that have a high density of population requiring access and lower grid emissions intensity. The results highlight that national grid emissions intensity influences the role of off-grid PV in achieving universal household electricity access when including a carbon price. For Tier 4 electricity demand, trends remain fairly similar to the Tier-3 results. However, there is both a smaller change from diesel to PV systems (7% of population) and from diesel to the grid (1% of population) in densely populated parts of East Africa (Figure 4e).

Carbon pricing (*Ctax_median*) leads to reduced total emissions (2020-30) when compared to the *Ref_central* scenario: 37 to 16 MtCO_2-eq at Tier 2, 105 to 63 MtCO_2-eq at Tier 3, and 174 to 121 MtCO_2-eq at Tier 4. These numbers are small when compared to global totals. Reductions are concentrated in areas with a higher population density requiring access that see changes in electricity access technology (Figure 4 a and g-h) and where the difference in emissions intensity between technologies is highest. This can be seen in central Africa where there are pockets of high population density and changes from diesel to PV.

We explored sensitivity in carbon prices (Figure 4c) from the IPCC AR6 scenario database[36] (Methods) between 10th and 90th percentiles at 10% increments (Table S5 for values). For Tier 2 and 3 electricity demand, carbon prices have more impact at lower levels than for Tier 4 demand which sees virtually no change in total shares until the 40th percentile, after which, there are reductions in both off-grid diesel and grid, with off-grid PV filling the gap. The results suggest that generally, at higher levels of demand, a higher carbon price would be required to see changes. Looking at sensitivity to carbon pricing spatially

(Figures 4 j-l), significant diversity can be seen regarding the effectiveness of carbon prices. Notably, at all Tiers of access, there are regions where a shift to different access technologies occurs at lower carbon prices (10^{th}-30^{th} percentile values), As the Tiers of access increase, the areas only sensitive to the highest carbon prices become more prevalent.

Additional investment and emissions for universal household access by 2030

Although our modelling does not capture all aspects of investment (Methods), it implies that taking a cost-optimal approach over one heavily dependent on certain technologies is advantageous (Table 2). Emissions contributions, even from the most polluting single-mode pathway are low when compared to global emissions and are occurring in regions with virtually no historical emissions contributions. However, there may be technology 'lock-in' from initial access technologies and emissions growth in future as electricity demand grows. Therefore, the choice of electricity access mode may still be important for future emissions[38].

Table 2. The discounted investment costs (in 2022 USD) resulting in emissions and reliability metrics for selected scenarios. See methods for detail on what is included and omitted from investment and emissions.

Scenario	Investment 2020-30 (billion $)*	Emissions (MtCO_2-eq) 2020-30	Demand-weighted Mean Reliability
Tier 3			
Ref_central	36	105	0.73
Ref_single_mode (PV MG)	51	14	0.90
Ref_single_mode (Diesel MG)	52	247	0.90
Ref_single_mode (Grid)	235	98	0.62
Rel_Penalty_0.5	52	109	0.81
Ctax_median	42	63	0.73
Tier 4			
Ref_central	52	174	0.71
Ref_single_mode (PV MG)	78	24	0.90
Ref_single_mode (Diesel MG)	82	459	0.90
Ref_single_mode (Grid)	244	158	0.63
Rel_Penalty_0.5	81	212	0.81
Ctax_median	62	121	0.71

*Investment includes reliability penalties/carbon prices incurred in each scenario.

Geographically, the investment requirements broadly follow the population density requiring access at all Tiers (Figures 4a and Extended Data Figure 1a). Under the *Ref_central* scenario (Tier-3 access) areas of the highest total investment requirement are in densely populated parts of central and eastern DRC, Ethiopia and northwestern parts of South Sudan. Other countries with significant areas of high investment needs are Malawi, Burundi and Uganda (Extended Data Figure 1a). Per-household investment requirements (Extended Data Figure 1b) at Tier 3 are more uniform, with higher values seen in areas with lower population density deploying standalone systems (Figure 2b).

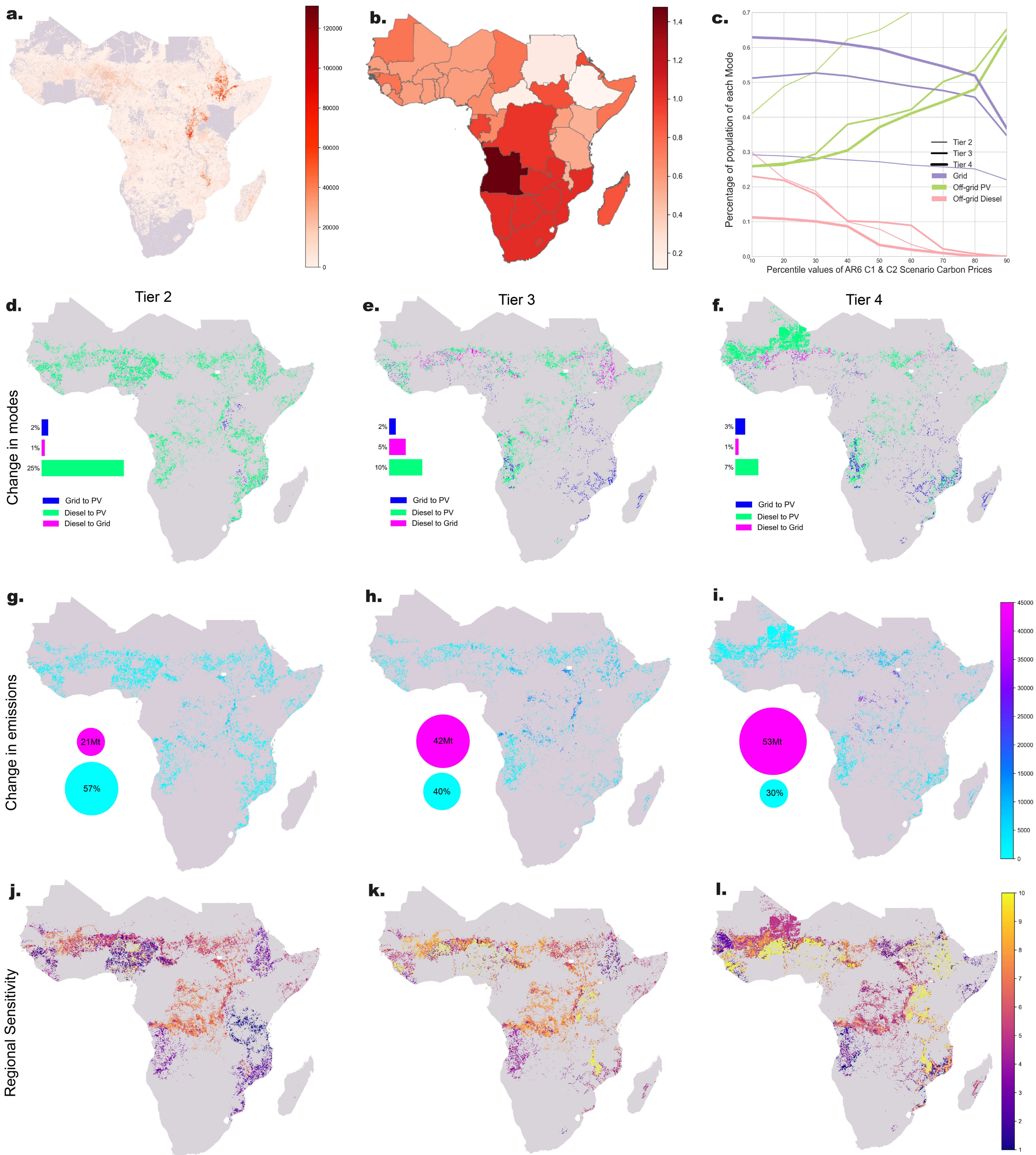

Figure 4. Panel a details the population requiring access to 2030. Panel b shows the assumed grid emission intensity of electricity (kgCO2e/kWh), detailed by country in the Supplementary Information. Panel c describes the sensitivity to different carbon prices that shares of grid, PV and diesel have at each Tier of access. Panels d to f describe shifts in mode of access at Tiers 2-4 from the reference scenario (Ref_central) to the carbon price scenario with median AR6 C1 and C2 values (Ctax_median). Panels g to i describe the geographical distribution of the corresponding change in GHG emissions resulting from the carbon price scenarios at Tiers 2-4 (given in kgCO2e, 1e7 on scale). Panels j-l give mapped sensitivity showing at what carbon price (AR6 value deciles) mode shifting occurs, Tiers 2-4.

Diversity in demand, reliability and emissions matter for pathways to SDG7

Population growth and the pace of progress in new household connections in SSA suggest limited progress toward universal household access to electricity by 2030 or 2035. The strength of action and investment over the remaining decade will determine how close individual countries get to achieving SDG7. Following a least-cost pathway, where a range of electricity access options including PV mini-grids and standalone systems are built into electrification plans, can provide significant investment savings relative to plans that rely on incumbent technology options such as grid expansion or diesel generation. Following previous work[18], our results reiterate the importance of considering least-cost pathways in the context of electricity demand levels. For example, far greater emphasis is needed on off-grid PV at lower access Tiers. This point has salience for national electricity access plans that are centred around Tiers of access: policymakers should consider possible technology lock-ins and how they may influence costs for increasing access Tiers for households in future. Our results highlight significant regional diversity. Country-specific factors are crucial in assessing the role decentralised technologies will play in achieving the goal of universal household electricity access. High-resolution country-level studies can further elucidate the most appropriate pathways to inform national electricity access plans and the most appropriate associated policy support to achieve them.

SDG7 highlights the importance of reliable energy. Treating technology options that have diverse levels of reliability as equal is shortsighted. An urgent focus on the reliability of supply received by newly connected consumers is needed so they can move up the energy ladder and experience the economic benefits of electricity. Accounting for the financial costs to households of poor service levels, extending a highly unreliable grid at a lower infrastructure cost than an off-grid solution with higher reliability may actually result in higher overall costs. Alternatively, sizing off-grid systems to meet the same service levels as rural national grids makes them more cost competitive with grid extension in some regions. When a cost for units of unmet demand is included in least-cost pathways, shares of access modes deployed change: at Tier 3, for example, applying a $0.50/kWh unmet penalty sees almost 80 million more people gaining access from off-grid PV. The impacts of such a policy intervention vary greatly depending on the electricity demand level and the level of penalty applied. There is also a high degree of spatial heterogeneity when observing whether there are changes in access technologies. A crucial observation is that there are areas with a high density of population needing access where applying a very low penalty for unmet demand sees uptake of off-grid technologies instead of grid connections. Policymakers and electricity access planners should seek to further quantify the negative economic impacts of poor reliability and factor them into cost pathways to ensure the best outcomes for households.

As carbon pricing becomes more prevalent, particularly with the expansion of the voluntary carbon market, carbon price signals will have an increased influence on electricity access pathways. Whilst not exploring practical implementation, we present the first high-resolution geospatial analysis that explores carbon pricing impacts on pathways to universal household electricity access. Our modelling suggests that depending on demand and carbon price levels, increased uptake of lower-carbon technologies of access occurs. At Tier 2, 140 million people switch to off-grid PV under the central carbon price scenario considered here, with a 50 million increase at Tier 3 demand levels. Whilst there is broadly a decline in the effectiveness of carbon price signals as electricity demand levels increase, there is significant variation in impacts spatially. Crucially, there are regions where very low carbon price signals lead to a movement to lower-emissions alternatives. This quantification of the spatial variation in the effectiveness of carbon price signals has implications for policymakers and stakeholders wishing to tailor policy interventions to specific countries or regions.

The results in this paper emphasise the need for further regional and national-level studies. Addressing the lack of high-resolution spatial data regarding both reliability of the grid and off-grid technologies would allow a more detailed comparison of supply options. In addition, expansion to non-residential demands would strengthen the analysis as electricity demand goes beyond households. Nevertheless, this study highlights the importance of considering reliability and carbon pricing when considering the role off-grid PV may play in developing pathways to SDG7.

Methods

This study combines electricity demand modelling, energy system modelling, and geospatial modelling to investigate the impact of reliability of supply and carbon pricing on the shares of each technology used in scenarios aimed at achieving universal household electricity access (see Figure 1).

Electricity demand Household electricity demand levels are guided by the ESMAP MTF Tiers of Access[34]. However, we assume demand growth, underpinned by expected increases in GDP per capita growth, and the historical relationship between GDP per capita growth and electricity per capita growth, by country. For this, we use SSP2 'Middle of the Road' population and GDP growth projections. We reindexed long-range GDP per capita growth projections from SSP2[39] using 2020 figures of recorded GDP per capita (PPP)[21], combined with IMF economic growth forecasts[41] that take into account the economic impact of Covid-19. From 2025 onwards, we applied the SSP2 growth rates to the adjusted data for the immediate future. We used historical GDP per capita (PPP) and electricity demand per capita data[21], available in varying quantities from 1970 to 2014, to derive a linear relationship between both variables by country. For countries without adequate data availability, a country with a similar socioeconomic profile in the same region was selected as a proxy (Table S7).

We used the historical relationship calculated for each country as the income elasticity of demand. We assume households do not begin to reach a satiation point for their demand for electricity and therefore this value is held constant. Using the elasticity of the GDP per capita projections we calculated an electricity demand growth index up to 2050, with 2020 as 1; to guide the increases used for the demand profiles. A range of other factors that may influence demand are not captured here; however, this approach rests on existing evidence suggesting income growth can lead to growth in electricity demand[42] including in low and middle-income countries (LMICs)[43].

To create relevant country-specific demand profiles to be employed in our off-grid modelling, we used the CREST open-source thermal-electrical demand model, which employs stochastic programming techniques to represent dwelling diversity and creates location-specific profiles that vary depending on temperature and daylight[44,45]. We generated 25 household electricity demand profiles for each country and for Tiers 1-4 of electricity access[?], as defined by the ESMAP MTF[34].

The household profiles were used to construct hourly, multi-year demand profiles that fit our annual future electricity demand estimates, derived from the GDP per capita projections for each country as explained above. For the mini-grid demand profiles, we assumed a community size of 100, and for each year took a proportional mix of demand profiles from the electricity access Tier above and below the annual household consumption value, A, (in kWh) for a given year, n; with the annual household energy values (in kWh) represented by T^U and T^{Lo} for the upper and lower Tiers, respectively. We calculated the relevant percentages of the upper T^U_{Sh} and lower Tier profiles T^{Lo}_{Sh}, with the upper given by:

$$T^U_{Sh} = \frac{100(A_n - T^{Lo})}{T^U - T^{Lo}} \tag{1}$$

and the lower Tier percentage T^L_{Sh} the corresponding value that totals 100%. Using these shares, we added the respective proportion of household demand profiles for each Tier. We selected households (1-25) at random for each Tier profile added during this process. We used the one-year profiles for each country for relevant years to form 15-year demand profiles for each location that track the predicted demand growth with start years for every year between 2020 and 2035.

For modelling the standalone systems, we used a demand profile of 1% of the demand of the relevant mini-grid profiles. Our modelling considers energy demand on an hourly basis (see below) and therefore does not consider sub-hourly spikes in power demand. Consequently, the diversity benefits from the mini-grid demand profile passed to the single household profile are assumed to be minimal with the daytime/nighttime shares of demand salient for system sizing.

Off-grid energy system modelling We used the CLOVER open-source energy system model[46] to estimate the cost and emissions of delivering electricity via different off-grid systems. The CLOVER model runs simulations of energy systems within specifications predetermined by the user. It has an hourly temporal resolution and is designed to simulate systems over a multi-year time horizon with dynamic demand, component health and renewable resource. CLOVER interacts with the Renewables.ninja API to provide estimates of hourly solar generation for given coordinates, tilt and azimuth. Using these inputs, the Renewables.ninja model estimates solar output for a given system size based on reanalysis data from the MERRA-2 data set[47] (Section S1 in Supplementary Materials).

The model has an 'exhaustive search' optimisation feature that tests numerous configurations to find the best-performing system for the optimisation criterion selected (see Equation 2). The model explores different system capacities in steps relevant to each technology type: for diesel, PV and battery technologies it explores capacities in units that these technologies are sold in. Diesel generators, for example, are not typically sold in units with capacities below 1 kW and so are less favourable to the smallest system types. Additionally, the model has a sufficiency criterion, typically a reliability level, and systems that do not meet this are not considered. The model can break down the system life into multiple periods to reflect the need to add capacity when demand increases and components degrade.

We used the model to find the cost-optimal standalone systems for single households and mini-grid systems powering 100 households, at each of our locations using solar PV and battery systems, as well as diesel-powered systems. We assumed a 15-year project length, but re-optimising systems every five years to take into account the growing demand profiles and degrading components. For our reference scenarios, we set our sufficiency criterion as 90% of energy demand met. For simplicity, we assume consistency in the type of components used across system sizes, with them scaled as necessary by the model for the demand level (technical inputs used are given in Table S2 in Supplementary Materials).

We optimised systems for cost, given this is most representative of how systems are designed in reality. We use the levelised cost of *used* electricity (LCUE) as our metric of unit cost. This metric is similar to the more commonly used levelised cost of electricity (LCOE); however, it considers only electricity used rather than generated and is, therefore, more appropriate for off-grid systems that have significant dumped energy[48]. The LCUE is calculated by dividing the discounted sum of the total costs (capital investment I, operation and maintenance M, and fuel F) in each year, by the electrical energy *used* E^U (also discounted) in each year:

$$LCUE = \frac{\sum_{n=1}^{N} \frac{I_n+M_n+F_n}{(1+r)^n}}{\sum_{n=1}^{N} \frac{E_n^U}{(1+r)^n}} \tag{2}$$

For a full breakdown of the cost and emissions inputs used see Table S3 in the supplementary materials. Associated total and unit emissions for the system are given as outputs for each system.

For each of our countries, we used the model to find the cost-optimal mini-grid and standalone systems with starting electricity demand Tiers (1-4), 15-year system lifetimes and start years of 2020, 2025, 2030 and 2035 to reflect growing demand and reduced component costs. Further, systems were modelled at 'high' reliability (90%) of electricity demand met, and 'grid' reliability; which equates to the estimated rural grid reliability in each country (Table S6 in Supplementary Material). The emissions and cost outputs of this process are used in the following stage.

Geospatial data For our analysis, we used geospatial data sets covering Sub-Saharan Africa (43 countries) for population, projected population growth, population without access to electricity and national grid infrastructure. Population gridded datasets for the years 2014 and 2020 were taken from the LandScan Global data sets[49,50]. Downscaled population projections (SSP2) at ten-year intervals were used (2020, 2030 and 2040) for spatially disaggregated population trajectories[51,52]. We used a gridded data set providing estimates for the population without access to electricity across Sub-Saharan Africa based on remote sensing night-light data from Falchetta (2019)[53]. We used the data from both the years 2014 and 2020[54]. We used vector maps of the African grid available from Moner-Girona & Georgia (2021)[55]. We aggregated these data and performed relevant calculations for our own gridded map at a 10km^2 resolution to be used in our modelling.

Estimation of baseline population without access To calculate estimates of the population for the years 2020-35 we first used the historical geospatial electricity access population data (2014 and 2020) to produce estimated annual changes at the grid-cell level. In our forward projections, we assume that population growth in each cell is divided by the 2020 share of access in each cell; so, population growth occurring in partially electrified cells is divided on this basis. We calculated annual estimations of the population without access at the map cell level up to 2035. This calculation considers assumed population growth amongst the population without access and any expected change in access, as per the trend. Given that in any given cell, improvements in access may mean a cell would reach universal access; any surplus trend improvement that may exist is calculated annually and aggregated at the national level. This amount is then used and allocated to 'electrify' households within cells without access, starting with cells with the highest number of people without access first. This process is recorded by year for use in the next section. This logic rests on the assumption that an investor or government agency would seek to provide access to the areas with the highest population density required first. We assume that trend gains in electricity access stay within national borders and once a country reaches universal access it is removed from the process.

Simulating scenarios of universal access To reach universal household access in all countries not expected to achieve universal access by the target year, a pathway must be defined. This is done on a country-by-country basis, with the annual number of people connected for each country, P_X^n, defined by:

$$P_X^n = P_R^n \left(\frac{n}{N}\right)^2 \tag{3}$$

where P_R^n is the remaining population for a given country in year n, and N is the total number of years. This produces an S-curve, leading to most connections made in the middle of the period[56]. The model then takes the approach of connecting cells by the year in each country up to the amount P_X^n. Any growth in the non-electrified population in already 'electrified' cells is also taken into account first, after which the next densest non-connected cells are added, as above. Cells that are registered as being connected under the baseline scenario are skipped, avoiding double counting. The trajectory of the population reaching universal access (by individual map cell) is then converted to the number of households using the rural household size by the country for the most recent year available from the Global Data Lab average household size database[23].

For national grid costs, the distance from the nearest grid line to the centroid of the selected cell, combined with an estimated cost per km of grid extension and a grid connection fee per household is applied for non-generating infrastructure costs. The installation of equipment such as transformers or substations is omitted. For additional capacity, we derived values for weighted average grid capacity factor G_y (%) and cost in 2022 USD G_I for units of capacity (kW/kWp) on the grid in each country κ using generation mixes per country[58,59], and country-relevant capacity factors and costs[24]. With these values, the model estimates additional grid capacity, G^{cap}, required in each cell, (ϕ, based on the average hourly electricity demand E^L (in kWh) in the final year N; taking into account the assumed reliability of the rural grid (estimated % of energy demand met) in each country $G^R(\kappa)$ and is given by:

$$G^{cap}(\phi) = \left(\frac{1}{G_y(\kappa)}\right) E_N^L \left(G^R(\kappa)\right) \tag{4}$$

The estimated additional grid capacity for each grid cell $G^{cap}(\phi)$ is then multiplied by the estimated cost per installed unit of capacity for the relevant country $C_G^I(\kappa)$. The generating and network costs are discounted according to the year of construction in the model, as guided by the above (see S4 in supplementary materials for further details).

Data on grid reliability in SSA is sparse. However, estimates of varying recentness for grid reliability by country are available from the World Bank Enterprise Survey[37] for business connections, typically in urban areas which are known to be considerably higher than those in rural locations[19,61]. Using the average number of outages and average length, we estimate the percentage of energy unmet annually (assuming a flat demand curve). We then assume a 25% further penalty to reflect that supply on national grids is poorer for rural connections and worse for households than nearby enterprises[62].

To calculate grid emissions, we use the demand estimations (described above) by country and by Tier. Grid emissions intensity figures are assumed to be constant (Table S6 in supplementary materials). The reliability factor, as above, is applied to the demand totals before calculating emissions resulting by multiplying by the relevant grid emissions factor. We do not include embedded emissions in the generating capacity due to poor data availability. We include embedded emissions in grid extension infrastructure, with the emissions split over the assumed infrastructure lifetime (Table S4 and S4 in supplementary materials).

For the off-grid systems, emissions and investment figures are calculated for system type and country, as described above. The outputs are used to calculate estimates of the cost and emissions of electrification via each mode, for each cell; to be used in the final stage. The number of households requiring connection is multiplied by the investment estimate (per household) for each given system: diesel and PV mini-grid and standalone systems, sized for each country, start Tier of access; and levels of reliability. These numbers are then discounted (at 8%) accordingly with the respective year of connection. Emissions for off-grid PV are split annually over the assumed system lifetime (Table S4 and S4 in supplementary materials).

In the final stage, estimations of the least investment cost approach are made for each cell covering all countries requiring electrification to reach universal access by 2030. Cells are first assessed for population density, to establish whether standalone or mini-grid systems are more appropriate (see S4 in supplementary materials). Next, the grid and the relevant off-grid PV and diesel systems investment requirements are each compared by cell covering the entire gridded map. Using the estimated investment required for access via each mode, the least cost approach for each is selected for the given scenario. For scenarios applying a carbon price or reliability penalty, these are applied uniformly across all modes to tonnes of CO2e and kWh of lost load respectively, and discounted, prior to finding the least-cost approach.

For scenarios accounting for the financial cost of unmet demand, a penalty is added across all technologies for each lost kWh, acknowledging that there is an economic cost for households in SSA when power outages occur[27,28]. Often referred to as a 'loss of load penalty', existing studies have focused on high-income countries, finding large variation but with higher costs for businesses than households and the methodology of calculating the value having a large impact[63]. For our study, this value is difficult to quantify consistently and will vary across countries, income groups and demand levels. To address this uncertainty we examine sensitivity to different penalty levels regionally, and at different electricity demand Tiers of access. The values we investigate (5 cents- $1) are considerably lower than those suggested for high-income countries[63]; however, they are in line with the cost of a unit of electricity, considering only households and that our study is focused on countries and households where incomes are typically very low. We use 50 cents as our main scenario as it is the threshold at which significant change in technologies is seen at Tiers 2, 3 and 4. The penalty amounts are included in the total investment costs, and would hypothetically be incurred by an electricity supply company when blackouts occur.

The carbon prices used are values for 2020, 2025 and 2030 from the IPCC AR6 C1 and C2 scenarios that correspond to a 50% chance of limiting warming to within 1.5 degrees by 2100 without, and with overshoot respectively. We use values converted into 2022 USD provided from the AR6 scenarios database[36], the values by percentile are given in the Supplementary Materials, Table S5.

Limitations Our methodology has several limitations that are outlined here, with the anticipated influence on our results. Firstly, for the grid emissions intensity, reliability and costs by country are assumed to be constant. In reality, they are likely to change over time. Broadly, we can expect grids to become less emissions-intensive over time as countries add more renewable-based generating capacity. However, this is less certain for lower-income countries in SSA. In addition, there is uncertainty around grid reliability and the cost of additional capacity over time. In some countries, grid reliability is likely to improve as the grid is strengthened; however, others may continue to see low reliability. Improvements or deterioration in values for the grid in each country are likely to make the grid more or less favourable depending on the variable and scenario.

In addition, our modelling framework has a simplistic consideration of grid extension. We use the distance from the grid combined with a single extension cost per km for each cell as a proxy for the cost of extending. We do not take into account substations, transformers or other grid infrastructure needed. This is a limitation to our work as we are likely misinterpreting the costs of the grid in certain regions. A grid-routing algorithm, as is used in other work[20], would likely lower the cost of grid extension for some cells, whereas including other grid extension equipment would increase it. Using a grid-routing algorithm is computationally intensive and would prohibit an annual temporal resolution with many scenarios and sensitivities as is required for this study.

Finally, our emissions accounting method does not capture the embedded emissions in the added national grid-generating infrastructure. This is largely due to the fact that it is highly complex to do so and the lack of data availability for plants installed in the region. This omission will give an emissions reduction for grid-generated electricity, and therefore create a bias towards the grid in carbon pricing scenarios.

Code availability and reproduction Codes and data used to produce the scenario outputs are available at github.com/hamishbeath/LEAF-geospatial-energy-africa; the CLOVER model code is available at github.com/CLOVER-energy/CLOVER and has documentation available at github.com/CLOVER-energy/CLOVER/wiki.

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Author contributions statement

H.B, S.M, S.F, P.S, J.N and A.G conceived and designed the study. H.B performed the experiments and analysed the data. H.B, S.M, S.F, B.W, P.S and C.M contributed materials or analysis tools for the study. H.B led the writing of the study, with writing contributions from all other authors. All authors reviewed the manuscript before submission.

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