Strategic siting and regional grid interconnections key to low-carbon futures in African countries

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Recent forecasts suggest that African countries must triple their current electricity generation by 2030. Our multicriteria assessment of wind and solar potential for large regions of Africa shows how economically competitive and low-environmental–impact renewable resources can significantly contribute to meeting this demand. We created the Multicriteria Analysis for Planning Renewable Energy (MapRE) framework to map and characterize solar and wind energy zones in 21 countries in the Southern African Power Pool (SAPP) and the Eastern Africa Power Pool (EAPP) and find that potential is several times greater than demand in many countries. Significant fractions of demand can be quickly served with "no-regrets" options—or zones that are low-cost, low-environmental impact, and highly accessible. Because no-regrets options are spatially heterogeneous, international interconnections are necessary to help achieve low-carbon development for the region as a whole, and interconnections that support the best renewable options may differ from those planned for hydropower expansion. Additionally, interconnections and selecting wind sites to match demand reduce the need for SAPP-wide conventional generation capacity by 9.5% in a high-wind scenario, resulting in a 6–20% cost savings, depending on the avoided conventional technology. Strategic selection of low-impact and accessible zones is more cost effective with interconnections compared with solutions without interconnections. Overall results are robust to multiple load growth scenarios. Together, results show that multicriteria site selection and deliberate planning of interconnections may significantly increase the economic and environmental competitiveness of renewable alternatives relative to conventional generation.

Africa | energy policy | interconnections | renewable energy | siting

As a region, Africa has the lowest per capita electricity consumption in the world, due in large part to lack of generation and transmission infrastructure development at both the national and regional levels (1). However, the average cost of electricity in most African countries is at least twice that of other developing countries (1). For the region to successfully meet goals to increase affordable electricity access and reduce demand curtailment, electricity generation will need to grow exponentially. By some estimates, demand in the Eastern Africa Power Pool (EAPP) and Southern African Power Pool (SAPP), which encompass more than 50% of the continent's population, may collectively exceed 1,000 TWh by 2030, nearly triple their electricity consumption in 2010 (2, 3).

To meet energy goals, decision makers are looking to fossil fuel and hydropower as familiar and undertapped resources (1–3). With the insecurity and high costs of fossil fuels, the planning paradigm has become increasingly hydropower centric (1–3). Yet climate vulnerability (4), international cooperation barriers and transboundary water rights issues, large cost overruns (5), and high socio-environmental impacts (6) plague this paradigm and perpetuate risks of hydro-dependence. Among the alternatives, geothermal is considered underdeveloped but geographically limited with long lead times, and wind and solar have historically been dismissed as too expensive and temporally variable (1, 7).

However, costs of utility-scale wind and solar generation are rapidly declining (8). Levelized cost of wind energy is competitive with that of hydropower in Kenya and Ghana (9). Wind and solar photovoltaics (PV) are now South Africa's cheapest and third-cheapest form of generation, respectively (10). As a result of these competitive costs, renewable energy deployment is growing in a handful of African countries (11–13). However, the contribution of wind and solar in each power pool remains below 1%, likely due to multiple perceived risks of uncertain resource quality, interconnection unavailability, and high investment costs.

Multicriteria resource mapping can minimize risk by enabling strategic site selection. To identify "no-regrets" siting options—or those that are low cost, low impact, and highly accessible and thus can be justified from multiple-stakeholder perspectives of risk—large amounts of data across large spatial scales must be synthesized (14) and incorporated in a multicriteria framework. Comprehensive wind and solar energy assessments and integration analyses have highlighted their potential to contribute to energy transitions in many countries (15, 16), yet roughly half of the EAPP and SAPP countries lack even the most basic

Significance

This study identifies, characterizes, and values wind and solar electricity resources for 21 countries in the Eastern and Southern Africa Power Pools. We find that many countries possess potential many times their projected demand. However, because the most competitive wind and solar resources are spatially uneven, international transmission could allow the region as a whole to benefit from "no-regrets" or low-cost, low-impact, and highly accessible resources. International energy trade also lowers system costs by reducing the need for conventional power plants and allows lower impact, more accessible renewable energy sites to be cost competitive. Regional interconnections planned around strategic siting opportunities are crucial for realizing no-regrets wind and solar energy development that can be competitive with conventional generation in African countries.

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spatially explicit wind and solar assessments. Existing studies typically omit critical cost, interconnection, and socio-environmental impact information (17).

To address this gap, we developed a large-scale multicriteria resource assessment of grid-connected wind, solar PV, and concentrating solar power (CSP) and integrated it into a suite of tools—Multicriteria Analysis for Planning Renewable Energy (MapRE). The resource mapping approach is based on techno-economic criteria, generation profiles (for wind), and socio-environmental constraints. The suite of MapRE spatial models and tools (mapre.lbl.gov) gives any stakeholder the ability to weigh multiple siting criteria—e.g., generation cost, distance to transmission lines and load centers, and possible conservation impact—and examine their trade-offs. Considering these criteria in site selection could avoid difficult-to-monetize barriers, such as ecological impacts or challenging transmission extensions and upgrades, which often stall projects (18).

In addition to these factors, strategic siting of wind and solar power plants can help manage the temporal variability of generation, which can be a major challenge for grid integration, particularly in countries without strong institutional capacity and infrastructure. Technological solutions for balancing variability—such as excess reserve generation capacity, fast generators, and battery storage—are expensive (19) and are significant barriers to economies with limited access to capital. Strategic spatial diversification of sites is an alternative, potentially more cost-effective strategy for managing variability (20–24); however, no study has examined the grid value of geographic diversification in large regions of Africa.

Studies in other parts of the world suggest that extensive interconnections can strengthen the value of renewable energy spatial diversification (25), and other studies have found that it is significantly cost effective to support energy trade in Africa (26–30). However, those studies that examined renewable energy trade in Africa (29, 30) lacked the spatial and temporal resolutions necessary for modeling integration of highly temporally and spatially variable renewable energy. The EAPP and SAPP are considering new interconnections, but to exchange future conventional and hydroelectric generation (2, 3). Those required to support renewables may be substantially different.

We provide a comprehensive multicriteria assessment of wind and solar resources in EAPP and SAPP and identify no-regrets options. We also examine the importance of strategic siting for managing temporal variability of generation by increasing hourly correlation between aggregate wind production and electricity demand, specifically whether international interconnections enable cost-effective deployment of wind capacity in the SAPP. The power pools include the following 21 countries: Angola, Botswana, Burundi, Djibouti, Democratic Republic of Congo, Egypt, Ethiopia, Kenya, Lesotho, Libya, Malawi, Mozambique, Namibia, Rwanda, South Africa, Sudan, Swaziland, Tanzania, Uganda, Zambia, and Zimbabwe.

We apply the MapRE approach to examine trade-offs between wind and solar resource quality and multiple-siting criteria, including transmission connectivity, distance to the nearest load center, and ecological intactness of potential project areas. Using a unique dataset of hourly demand profiles for nine SAPP countries and hourly wind profiles, we optimally select wind sites to minimize conventional capacity, with and without interconnections and with and without consideration of multiple-siting criteria. We examine wind specifically because it is currently more cost competitive than solar in Africa and exhibits more spatiotemporal variability. We compare this approach with the prevailing practice of selecting sites to minimize the levelized cost of wind electricity.

Results and Discussion

Wind and Solar Resources Are Heterogeneous in Quality and Quantity, but Sufficient No-Regrets Potential Exists in Each Power Pool. After excluding areas on the basis of physical, technical, and socio-economic suitability for large-scale renewable energy development (*SI Appendix*, Table S2), the resulting quantities (TWh) of wind, solar PV, and CSP resources that exist within the EAPP and SAPP collectively exceed the projected 2030 demand two- to fivefold (Fig. 1 and *SI Appendix*, Fig. S1 for power pool supply curves). However, these resources, particularly high-quality resources (e.g., high insolation or wind speed) that meet multiple-siting criteria, are unevenly distributed between and within countries.

Examining just resource quality and quantity alone, results show that high-quality resources in a majority of countries are one or two orders of magnitude greater than their projected 2030 demand (Fig. 1*B*). Although about one-fifth of all countries in the study region (Angola, Democratic Republic of Congo, Rwanda, and Burundi) lack sufficient high-quality wind resources, their neighboring countries have wind resources that exceed their projected demand (Tanzania, Zambia, and Namibia). Nearly all countries have large and high-quality solar PV potential (Fig. 1*B*). CSP is the most spatially limited of the three technologies, with potential significantly less than the projected 2030 demand in at least six countries. The distribution of resource availability and quality supports the need for resource sharing to cost-effectively achieve low-impact electricity development regionally.

To examine trade-offs between economic costs and other siting barriers, we selected resource areas across the entirety of each power pool that are in the top 20% and 50% of areas closest to transmission infrastructure, closest to load centers, and that have the highest human footprint score. The multiple dimensions to consider in prioritizing energy projects—resource sufficiency, cost, and other siting barriers—are represented in the shape of each supply curve (Fig. 2 and *SI Appendix*, Fig. S1).

Distances to load centers and transmission infrastructure account for the institutional, financing, and time barriers associated with connecting multiple distributed generation projects, barriers that are often not fully captured in the transmission component of the levelized cost of electricity (LCOE). Transmission availability is often cited as the greatest challenge to scaling-up wind energy (18), with some studies showing that it is often more cost and time effective to develop lower wind-speed projects closer to transmission than attempt to interconnect high-quality sites far from existing lines and load centers (31). The distance to load center is a proxy for investments in transmission infrastructure required to deliver electricity from generators to load centers. Finally, we used the human footprint score as a proxy for the degree of human "disturbance" from natural, unaltered states (32).

For solar PV, numerous countries have sufficient potential for no-regrets—low-cost, low-impact, easily accessible—development, but a subset of these countries would require additional domestic or international transmission infrastructure to achieve 2030 targets. Specifically, Tanzania, Zimbabwe, Botswana, and Lesotho can meet 30% of their projected 2030 demand with low-impact solar PV (thick lines in Fig. 2 represent the top 20% of all sites), with Tanzania able to export up to 20 TWh of inexpensive and low-impact solar electricity to neighboring countries (Fig. 2*A*). In the EAPP, Ethiopia, Sudan, Uganda, and Tanzania can most favorably achieve 30% solar PV generation targets domestically (Fig. 2*B*). For these countries, high resource quality sites have the lowest impact and are closest to load centers and existing infrastructure. This is not the case for all countries. Democratic Republic of Congo, Zambia,

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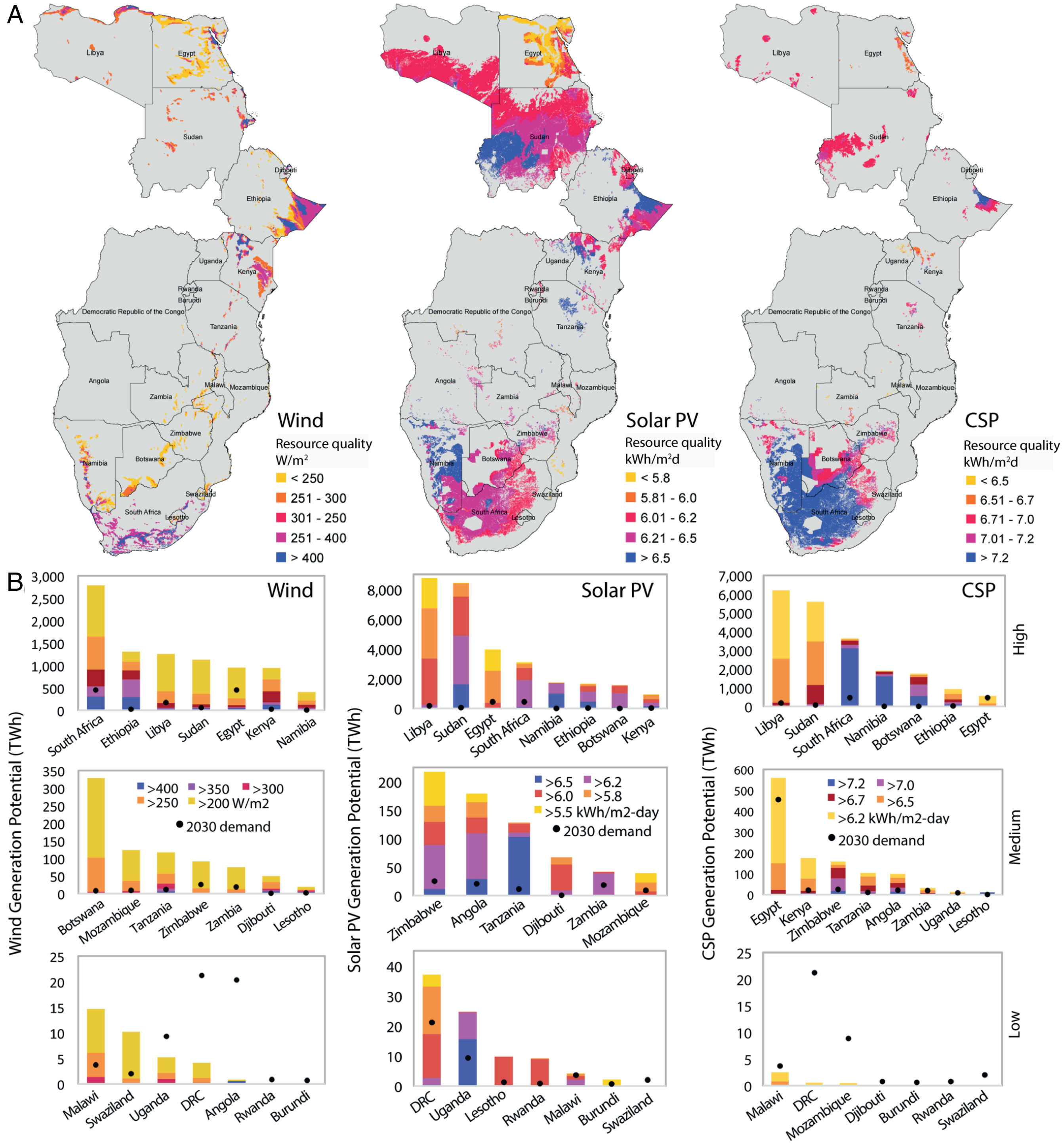

Fig. 1. Location and potential (TWh) of each country's renewable resources within the SAPP and EAPP. (*A*) Maps show the location and quality of renewable energy potential. (*B*) Corresponding bar charts for each technology show the generation potential (TWh) of each resource quality range (in kWh·m^{-2}·d^{-1} for insolation and m/s for wind speed) for each country. Countries are sorted by generation potential (high, medium, low). The 2030 demand for each country, as projected by the EAPP and SAPP Master Plans, is provided as a reference point (2, 3).

Angola, South Africa, Egypt, Kenya, and Libya possess some cost-effective sites that should receive high prioritization, but are not in the top 20% primarily due to limited transmission access. For these countries, meeting an ambitious 2030 target would require investing in transmission extensions to access lower-cost PV resources or importing from neighbors. For CSP, the pattern of project prioritization is very similar to that of solar PV, but with fewer countries meeting all sufficiency, low-cost, and other siting criteria dimensions.

Wind resource supply curves are generally steeper and more divergent than those for solar technologies, indicating more variation in cost and quality of sites within a country (Fig. 2). The least-cost wind resource areas are distributed across several countries, including Malawi, Lesotho, Zambia,

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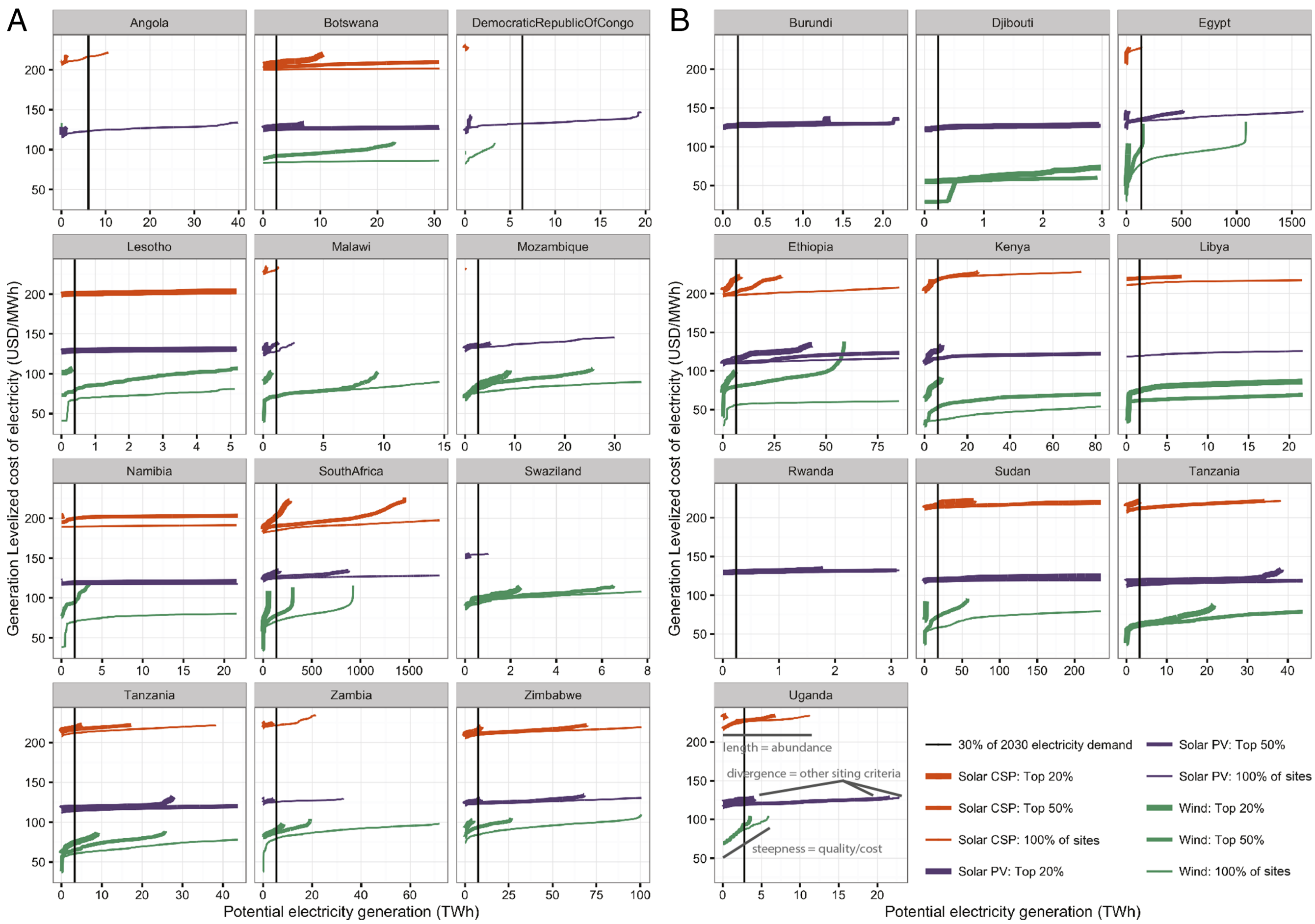

Fig. 2. Multicriteria project opportunity area supply curves for countries in the SAPP and EAPP. Supply curves show the cumulative potential of all wind, solar PV, and CSP sites and those that meet the top 20% and 50% of criteria values within the SAPP (*A*) and EAPP (*B*). Project opportunity areas are sorted by generation LCOE. Vertical lines show 30% of each country's projected electricity demand in 2030. Criteria values include transmission distance, distance to nearest load center, and human footprint score. For example, the quantities of CSP potential in the top 50% and all sites in Uganda meet 2030 targets, and the difference between solar PV supply curves shows that although the top 20% of sites are limited in Uganda, they are sufficient to meet 2030 targets. Note that the *x* axis varies between countries whereas the *y* axis is fixed. For countries with large potential, the maximum value of the *x* axis is six times the anticipated 2030 demand. Tanzania is a member of both power pools. The top 20% or 50% of sites are selected relative to other sites within the power pool. Assumptions for LCOE, including discount rate, are consistent across countries.

Djibouti, Ethiopia, Kenya, Libya, South Africa, Egypt, and Tanzania. However, these low-cost, high-quality wind sites generally score low in other siting criteria, as is seen in the large divergence between the supply curves within these countries. Tanzania, Swaziland, Djibouti, and Libya are exceptions in being able to meet 30% of their demand with accessible, low-impact, and cost-effective wind sites. Although trade-offs between cost and other siting factors appear to be greater for wind power, leaving fewer no-regrets areas, generation cost is not the only important determinant of wind resource quality. Selecting sites with wind-speed regimes that generate most during the highest demand hours will increase their value (20), a consideration we address in the following section.

International Transmission Interconnections Enable Least-Cost Wind Deployment and Greater Displacement of Conventional Generation by Wind. With hourly electricity demand data for nine countries in the SAPP (*SI Appendix*, section S1.3.1), we selected wind zones using four approaches: (*i*) "Min-Net-Demand," minimizing the maximum hourly net electricity demand (i.e., demand remaining after accounting for wind generation) across an entire year using all zones (*SI Appendix*, section S1.3.2); (*ii*) "Min-LCOE," minimizing the annual average generation LCOE of wind using all zones; and (*iii* and *iv*) "Top-50%," performing approaches *i* and *ii* using a subset of zones that meet the top 50% of other siting criteria within a power pool, as described in the previous section. For a given investment or installed capacity target, the Min-LCOE approach maximizes wind generation, which reduces the need for conventional energy, whereas the Min-Net-Demand approach reduces integration costs by minimizing need for nonwind, typically conventional generation capacity. We selected wind zones with and without international interconnections, referred to as "Interconnected" and "Isolated" scenarios, respectively. Each scenario installs a total of 61 GW of wind capacity, the amount needed to meet a 30–33% wind energy target by 2030 across the SAPP (*SI Appendix*, Table S7).

We compared the distribution of selected wind zones and found that the Min-Net-Demand, Interconnected, Top-50% scenario results in the most even distribution of capacity across countries (Fig. 3*A*). Instead of meeting South Africa's large demand domestically, a fully interconnected SAPP allows for a large portion of its demand to be met internationally, in areas where wind generation profiles are better matched to SAPP's demand profile. In the Top-50%, Interconnected scenario, many countries—Swaziland, South Africa, Malawi, Zambia, and Zimbabwe—see an increase in their share of wind

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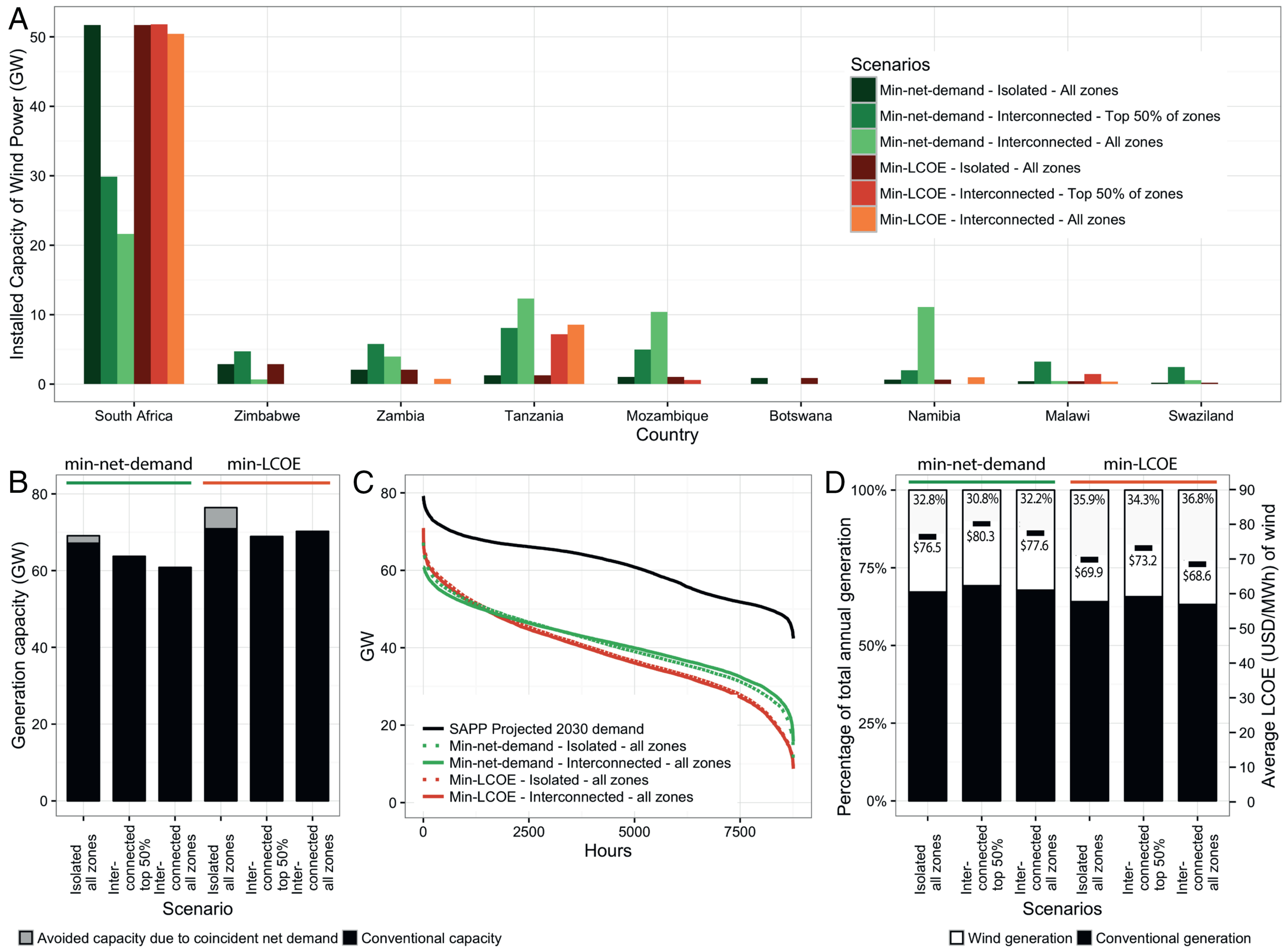

Fig. 3. Impacts of wind build-out scenarios for the SAPP in 2030. (*A*) Distribution of installed wind capacity among countries in the SAPP. (*B*) Conventional installed capacity needed to meet the highest hourly net demand within 2030. (*C*) The hourly net electricity demand in gigawatts (GW) sorted from highest to lowest compared with the projected 2030 electricity demand. (*D*) The percentage of annual electricity from wind and nonwind generation (primary *y* axis and bar plot) compared with the average LCOE of wind generation (secondary *y* axis and horizontal lines).

capacity because of their more favorable sites, whereas others—Namibia, Mozambique, and Tanzania—reduce their share relative to the "All-Zones" approach (Fig. 3*A*). With interconnections, both Min-Net-Demand and Min-LCOE approaches significantly increase capacity in Tanzania at the expense of capacity in other countries with lower capacity factors (Fig. 3*A*).

Results show a trade-off between selecting sites to maximize wind generation (Min-LCOE) and minimize additional conventional capacity (Min-Net-Demand; Fig. 3*B*), although system costs are on the whole lower for the Min-Net-Demand approach (Fig. 4*A*). With interconnections, the Min-LCOE, All-Zones approach generates 12% (24.5 TWh) more wind energy than the Min-Net-Demand, All-Zones approach, resulting in 11% reduction in average wind LCOE (Fig. 3*D*), yet it requires 15% more, or 9.4 GW, conventional capacity (Fig. 3*B*). We estimated system costs assuming the extra conventional capacity needed would be met by natural gas combustion turbine (CT), scrubbed coal, or hydropower, as these are the technologies that have high-priority status in the SAPP (*SI Appendix*, section S1.3.3). Costs show that the Min-Net-Demand, Interconnected, All-Zones scenario leads to 0.4–2.5 billion USD/y in cost savings over the Min-LCOE, Interconnected, All-Zones approach, depending on the technology assumption (Figs. 4*A* and 5). These cost savings account for 3.5–19% of the total annual costs of wind capacity. Assuming hydropower or coal capacity would be avoided, selecting sites to minimize peak net demand is more cost effective from the systems perspective than selecting sites to minimize wind LCOE.

Other, nonmonetized system benefits of the Min-Net-Demand approach include reduction in the temporal variability of hourly wind capacity factors and net demand (20–30% reduction in the coefficients of variation; Table 1). In contrast, there are few or no differences in the coefficient of variation between Interconnected and Isolated scenarios when selecting sites to minimize LCOE (Table 1). That is, the main factor determining temporal variability of wind generation is the site selection approach, not the presence or absence of interconnections. For example, two countries with existing wind farms sited based on minimizing LCOE that later interconnect may not see reductions in the variability of generation or net demand. Interconnections, however, do increase the diversity of available sites, allowing a Min-Net-Demand siting approach to further reduce variability. This finding that increasing the geographic diversity of wind sites decreases the coefficient of variation is consistent with empirical studies examining interconnection scenarios of wind plants (33).

Lower aggregate net demand variability reduces the need to ramp up or down conventional generators to balance the variability (see *SI Appendix*, Fig. S2 for hourly ramp rate distributions),

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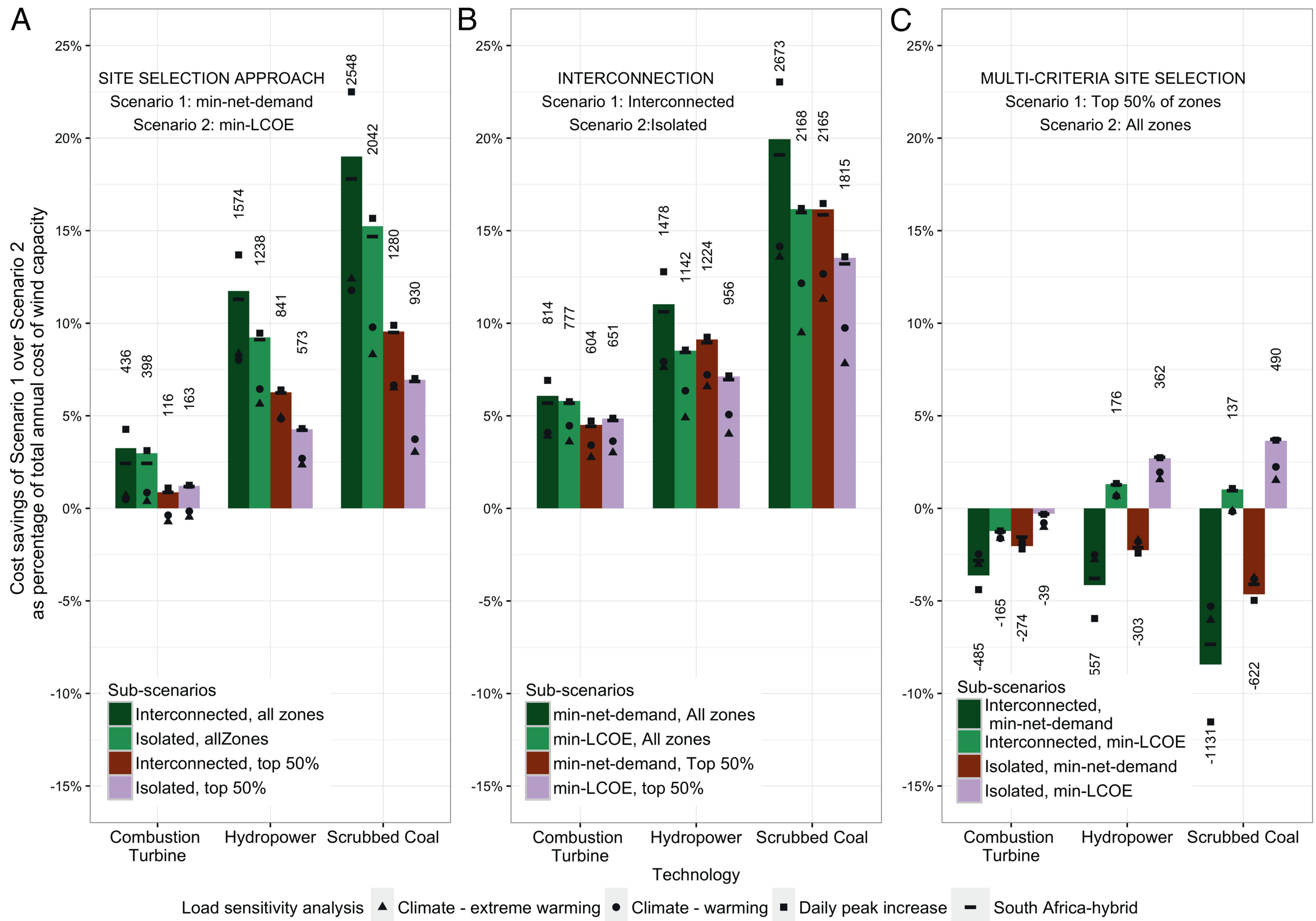

Fig. 4. Cost differences between wind build-out scenarios. Cost differences are expressed as percentage of total annual wind capacity cost, which is constant across scenarios. Actual cost differences in millions of USD/y are labeled above each bar for the base-load sensitivity case. Positive percentage and cost values indicate cost savings of scenario 1 compared with scenario 2, and negative values indicate additional costs of scenario 1 compared with scenario 2 in each panel. Costs were estimated assuming three different possible conventional capacity technologies—natural gas combustion turbine (CT), hydropower, and scrubbed coal (*x* axis). (*A*) The cost savings of the Min-Net-Demand over the Min-LCOE site selection approach. Positive values indicate that Min-Net-Demand is more cost effective. (*B*) The cost savings of the Interconnected over the Isolated scenario. Positive values indicate that the Interconnected scenario is more cost effective. (*C*) The cost savings of the Top-50% over the All-Zones site selection approach. Positive values indicate that the Top-50% scenario is more cost effective. The set of points for each bar (defined at bottom) shows results from load sensitivity analyses of four plausible future load growth scenarios: "Climate - extreme warming," "Climate - warming," "Daily peak increase," and "South Africa - hybrid." See *SI Appendix*, section S1.3.4 and Figs. S10 and S11 for descriptions of the load growth scenarios.

and a flatter load curve allows for more efficient use of base-load generators (Fig. 3*C*). Therefore, a site selection process based only on minimizing wind LCOE may not minimize system-wide costs and may not maximize the cost savings of interconnections compared with a site selection approach that best matches wind generation with electricity demand.

Comparisons between Interconnected and Isolated scenarios show that interconnections reduce system costs regardless of site selection approach or assumptions about the conventional generation technology wind may displace (Fig. 4*B*). Compared to the Isolated scenario, the Interconnected scenario using the Min-Net-Demand, All-Zones approach results in avoiding close to 10% or 6.3 GW of conventional generation capacity in the SAPP (Fig. 3 *B* and *C*). The annual cost savings of interconnections combined with the Min-Net-Demand approach are particularly large when assuming additional coal (2.2–2.7 billion USD or 14–20% of annual wind capacity costs) or hydropower capacity (1.2–1.5 billion USD or 9–12%; ranges represent Top-50% and All-Zones approaches, respectively; Fig. 4*B*).

Using SAPP's recent wheeling charges as a proxy for transmission capital costs per MWh traded (*SI Appendix*, section S1.3.3), we find that transmission costs in the Interconnected scenario are 1.6–1.8% of the amortized annual cost of wind capacity for the Min-Net-Demand, All-Zones site selection approach and 0.40–0.44% for the Min-LCOE, All-Zones approach (*SI Appendix*, Table S1). These percentage cost ranges are less than the range of potential savings from avoided conventional capacity resulting from the availability of interconnections under these same scenarios (6–20% for Min-Net-Demand and 4–16% for Min-LCOE; Fig 4*B*). When international interconnection costs are included, interconnections would save 4.3% at worst (assuming CT capacity) and 18% at best (assuming scrubbed coal capacity) in avoided conventional capacity, represented as percentage of amortized annual wind capacity costs (Fig. 4*B*).

Multicriteria site selection is not significantly more costly and, for the Min-LCOE scenarios assuming hydropower or scrubbed coal capacity displacement, yield cost savings (Fig. 4*C*). This is because sites selected using multiple-siting criteria (Top-50%) and the Min-LCOE approach result in lower net peak demand compared with the All-Zones approach, reducing conventional capacity costs. Nearly all cost differences between the

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Top-50% and All-Zones site selection scenarios are <5% of the annual cost of wind capacity (Fig. 4*C*). When examining ranked cost differences across all scenarios, results show that the Min-Net-Demand, Interconnected, Top-50% scenario is the second-most cost-effective option by a large margin when the avoided conventional technology is hydropower or coal (∼1 billion/y USD; Fig. 5). Regardless of the conventional technology, interconnections reduce the system costs of multicriteria selection relative to all scenarios without interconnections (Fig. 5).

Load Sensitivity Analysis and Limitations. Because only one year of load data was available and load profiles in 2030 are highly uncertain, we performed a sensitivity analysis using four future load growth trajectories that represent load responsiveness to climate change, economic structural changes, and grid-connected electrification and reduced load curtailment (see *SI Appendix*, Figs. S10 and S11 and section S1.3.4 for detailed scenario descriptions). Results show that the cost effectiveness of Interconnected scenarios and the Min-Net-Demand site selection approaches is sensitive to different load growth trajectories, but the range of results suggests that the baseline load scenario is in the middle (Figs. 4 and 5). Despite the trajectories being fairly extreme scenarios of load shifting and growth, on the whole, they do not change the conclusion that interconnections are very likely to reduce system costs from avoided conventional capacity (Figs. 4*B* and 5).

The South Africa - hybrid scenario, which represents economic structural changes, is very similar to that of the baseline (unmodified) load growth profile. The two climate-warming scenarios increase the conventional generation capacity requirements for the Interconnected scenario, but decrease it for the Isolated scenario, with a smaller yet still positive avoided capacity difference between Interconnected and Isolated scenarios compared with baseline (*SI Appendix*, Fig. S4). For the "daily peak increase" load growth scenario, both the Interconnected and Isolated conventional capacity requirements increase, but the avoided capacity of the Interconnected scenario is larger relative to baseline

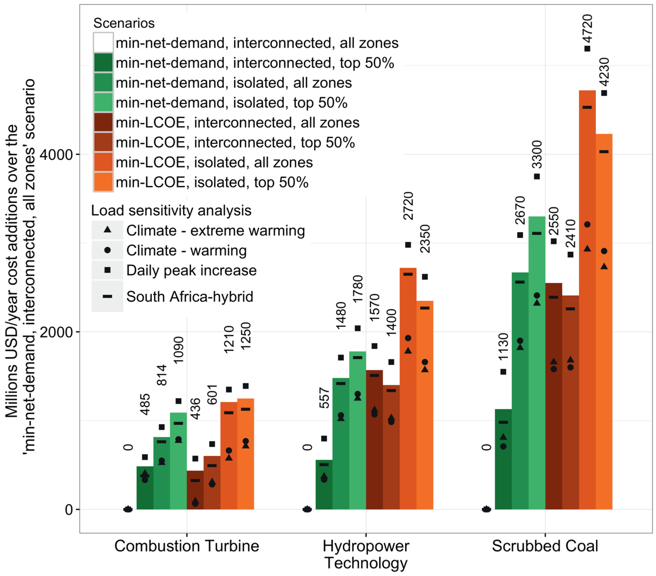

Fig. 5. System cost additions compared with the least-cost scenario. For each technology, the bars show the difference in system costs between each scenario and the least-cost scenario (Min-Net-Demand, Interconnected, All-Zones). System costs include the additional energy and/or conventional capacity required in each scenario. The set of four points for each bar shows results from load sensitivity analyses of four plausible future load growth scenarios (*SI Appendix*, Figs. S10 and S11).

Table 1. Coefficient of variation of hourly time series of net demand and site-averaged wind capacity factor for all site selection approaches (Min-Net-Demand and Min-LCOE) and interconnection scenarios

	Min-Net-Demand		Min-LCOE	
Interconnection scenario	Net demand	Wind capacity factor	Net demand	Wind capacity factor
Interconnected, All-Zones	0.197	0.320	0.283	0.426
Interconnected, Top-50%	0.199	0.334	0.258	0.426
Isolated, All-Zones	0.224	0.354	0.280	0.440
Isolated, Top-50%	0.223	0.357	0.256	0.442

(*SI Appendix*, Fig. S4). These results suggest that the cost effectiveness of the Interconnected scenario is highly dependent on the annual peak demand. We posit that the two climate load growth scenarios represent fairly extreme load responses to climate change such that the entire seasonal pattern disappears or inverts (*SI Appendix*, Fig. S10 *C* and *D*), without the counterbalancing likelihood of increased electrification or reduced curtailment, which has the effect of elevating demand during the daily peak hours. On the whole, the Interconnected scenario remains the more cost-effective choice, with load growth uncertainty reducing the confidence of this result only if natural gas CT were the avoided conventional technology under the climate-warming load growth scenario (Fig. 5). Otherwise, for hydropower and coal, the differences in additional costs of the Isolated scenario remain large even under climate-warming scenarios (1–3 billion USD/y; Fig. 5) and the differences would be very significant under the daily peak increase scenario (1.9–5.6 billion USD/y; Fig. 5). These costs would be adjusted downward by 0.04–0.24 billion USD/y (depending on site selection approach) due to transmission costs (*SI Appendix*, Table S1).

Currently, hydropower and coal appear to be the marginal generation technologies in the SAPP, although recent discoveries of natural gas in Mozambique may change this trend. However, transport of natural gas through a pipeline network would add significant capital costs that have not been considered in the cost estimates for CT capacity.

This study does not examine the effect of solar generation on system costs in the SAPP, but it is expected to alter net demand patterns. We relied on 1 y of modeled wind-speed data, which may have interannual variability. However, previous analysis using 10 y of mesoscale wind data shows that the wind regime during peak hours in the region is stable (34), although wind patterns may change in the future. Such potential changes underscore the importance of incorporating multicriteria analysis in siting decisions on an ongoing basis. Due to limited power systems data availability across multiple countries, our model examines only the extreme ends of SAPP's future—either complete grid isolation with no energy trade or complete interconnection such that the entire SAPP region operates like a coordinated, single balancing area without transmission constraints. Because generator-specific time series and constraint data needed for a production cost model and capacity expansion model could not be acquired across multiple countries, our model does not account for flexibility or responsiveness of other generators in the system. For the same data limitation reasons, we could use a capacity expansion model or a model that minimizes system costs to generate a scenario that balances conventional capacity and energy trade-offs.

Conclusions

Results demonstrate the large potential for utility-scale wind and solar energy development in many EAPP and SAPP countries,

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with particular countries possessing sufficient no-regrets–low-cost, accessible, and low-impact–potential sites that can rapidly provide low-carbon electricity. However, the most competitive resources are spatially heterogeneous, underpinning the need for regional coordination and transmission infrastructure to enable resource sharing. Our study demonstrates how spatiotemporal models can be used to assess opportunities and address barriers for renewable energy development in countries where data are limited and where the load growth trajectory is highly uncertain.

By providing the institutional structure for electricity trade, the power pools in Africa can lay the groundwork for power plant siting that minimizes regional system costs. Currently, the emphasis on large hydropower in a small handful of EAPP and SAPP countries could result in a set of interconnection plans that fail to support the development of plentiful no-regrets solar and wind options across multiple countries. Our results show that wind and solar electricity can be cost competitive and have a much larger role to play in Africa's energy transition, especially if the benefits of strategic siting and international interconnections are considered.

Materials and Methods

MapRE Model Overview. To estimate renewable resource potential and spatially specific criteria important for site selection, we developed the MapRE spatial model, using Python and R programming languages and the arcpy spatial analysis module (*SI Appendix*, Fig. S5). The framework is founded in previous resource assessment and zoning studies (14, 35, 36), but improved and adapted to account for data availabilities of the study region. We used a combination of global or continental data and country-provided datasets that can be broadly categorized into the following: physical (slope, elevation), socio-economic (population density, built areas), technical (resource quality), and environmental (land cover, protected areas) (*SI Appendix*, Table S2). We applied thresholds and buffer distances used in previous studies (14, 35, 36) (*SI Appendix*, Table S2), but adjusted within an economically viable range for each country, depending on the projected demand and the resource quality (*SI Appendix*, Table S3). We created maps of suitable areas for renewable energy development and further divided large areas into 5×5-km spatial units or project opportunity areas (POAs). For each POA, we estimated multiple-siting criteria values, including component and total LCOE. Using a statistical regionalization technique (Spatial Kluster Analysis by Tree Edge Removal), we spatially clustered POAs into "zones" (30–1,000 km^2 in size) based on the homogeneity of resource quality (W/m^2) of each POA. We then area weighted averaged POA siting criteria to generate zone criteria values.

Criteria Estimates. We estimated the following site selection criteria for each POA and zone: slope; elevation; population density; resource quality; distance to nearest major load center, transmission line, substation, road, surface water body, and existing and proposed wind, solar, and geothermal energy projects; land cover type; total land area; and human footprint score (*SI Appendix*, section S1.2.1 and Table S4). We collected country-specific transmission and substation spatial data and, where unavailable, we used the continental dataset from the African Infrastructure Country Diagnostic initiative (*SI Appendix*, Table S5). In addition, load center locations were collected from countries individually. These criteria values were then used to calculate the following additional criteria for each POA and zone: capacity factor (*SI Appendix*, section S1.2.2), annual electricity generation, transmission or substation LCOE, generation LCOE, road LCOE, and total LCOE. Cost estimates relied on various assumptions about fixed and variable costs specific to the technology and subtechnology (*SI Appendix*, section S1.2.3 and Table S6).

Wind Build-Out Scenarios for 2030. To understand the implications of different zone selection approaches and availability of interconnections, we modeled various wind energy build-out scenarios for SAPP in 2030 (*SI Appendix*, section S1.3). We acquired hourly wind-speed profiles from Vaisala Inc. for 233 wind locations and solicited at least one year (2013) of hourly electricity demand data from each country to create 2030 load forecasts (*SI Appendix*, section S1.3.1 and Table S7). Using these two datasets, we constructed a linear optimization problem to select wind zones that minimize the hourly peak net demand (Min-Net-Demand) with and without interconnections. We compared the results of this approach to a scenario that minimizes wind LCOE. For each scenario, we compared the maximum net demand (i.e., the installed capacity required in addition to wind power), total annual net demand (i.e., the generation required in addition to wind power), average wind LCOE, and approximate system costs (*SI Appendix*, section S1.3.3).

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