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Authors
Carvallo, Juan-Pablo
Shaw, Brittany J
Avila, Nkiruka I
et al.

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Sustainable Low-Carbon Expansion for the Power Sector of an Emerging Economy: The Case of Kenya

Juan-Pablo Carvallo,[†,‡] Brittany J. Shaw,[†,‡] Nkiruka I. Avila,[†,‡] and Daniel M. Kammen*[,†,‡,§]

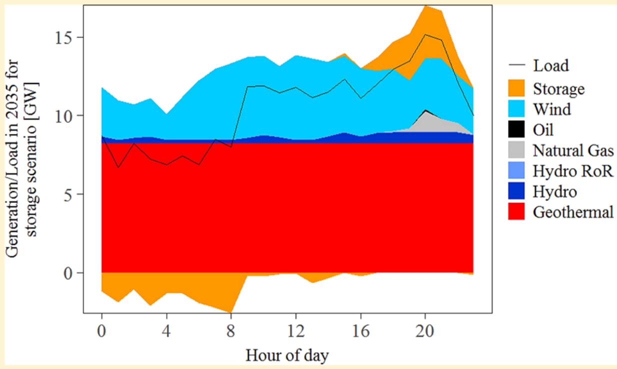
[†]Renewable and Appropriate Energy Laboratory, University of California, Berkeley, California 94720 United States

[‡]Energy and Resources Group, University of California, Berkeley, California 94720 United States

[§]Goldman School of Public Policy, University of California, Berkeley, California 94720 United States

Supporting Information

ABSTRACT: Fast growing and emerging economies face the dual challenge of sustainably expanding and improving their energy supply and reliability while at the same time reducing poverty. Critical to such transformation is to provide affordable and sustainable access to electricity. We use the capacity expansion model SWITCH to explore low carbon development pathways for the Kenyan power sector under a set of plausible scenarios for fast growing economies that include uncertainty in load projections, capital costs, operational performance, and technology and environmental policies. In addition to an aggressive and needed expansion of overall supply, the Kenyan power system presents a unique transition from one basal renewable resource—hydropower—to another based on geothermal and wind power for ~90% of total capacity. We find geothermal resource adoption is more sensitive to operational degradation than high capital costs, which suggests an emphasis on ongoing maintenance subsidies rather than upfront capital cost subsidies. We also find that a cost-effective and viable suite of solutions includes availability of storage, diesel engines, and transmission expansion to provide flexibility to enable up to 50% of wind power penetration. In an already low-carbon system, typical externality pricing for CO_2 has little to no effect on technology choice. Consequently, a "zero carbon emissions" by 2030 scenario is possible with only moderate levelized cost increases of between \$3 and \$7/MWh with a number of social and reliability benefits. Our results suggest that fast growing and emerging economies could benefit by incentivizing anticipated strategic transmission expansion. Existing and new diesel and natural gas capacity can play an important role to provide flexibility and meet peak demand in specific hours without a significant increase in carbon emissions, although more research is required for other pollutant's impacts.



■ INTRODUCTION

There are over 1.1 billion people without access to electricity, a large majority of these in countries with very high levels of poverty.[1] Sub-Saharan Africa (SSA) is the most electrically disadvantaged region in the world with over 600 million people lacking access to electricity, and hundreds of millions more connected to an unreliable grid that does not meet their daily energy service needs.[1] There is an established relationship between electricity and/or energy consumption per capita and a host of well-being indicators such as the Human Development Index, infant mortality, and life expectancy.[2,3] Mechanisms through which electricity access benefit the population are not clear, but there is a shared agreement that expansion in the capacity of consumers to use electricity will be key to lift populations out of poverty.[4]

Developing sustainable power systems requires a set of institutional, regulatory, economic, financial, technological, and social conditions. One constraint in the implementation of these conditions is imposed by climate change and the need to stay below the 2 C threshold as agreed in the UNFCC Paris Agreement by mitigating and avoiding future greenhouse (GHG) emissions. Many fast growing and emerging economies have expressed concern that imposing restrictions on their future GHG emissions by forcing adoption of mitigation technologies would create a burden to their economic development.[5] There are also concerns about the fairness of intertemporal emission allocation between wealthier and poorer economies and metrics that should be employed to achieve such allocations.[6,7] Despite of these concerns, the stringency of climate change targets will require that economies in general cooperate to grow more sustainably as a whole[8]

In this paper we explore sustainable growth paths for power systems in emerging economies through a case study of Kenya. The country is one of the fastest growing and most stables economies in Africa. To fuel this growth, the administration of

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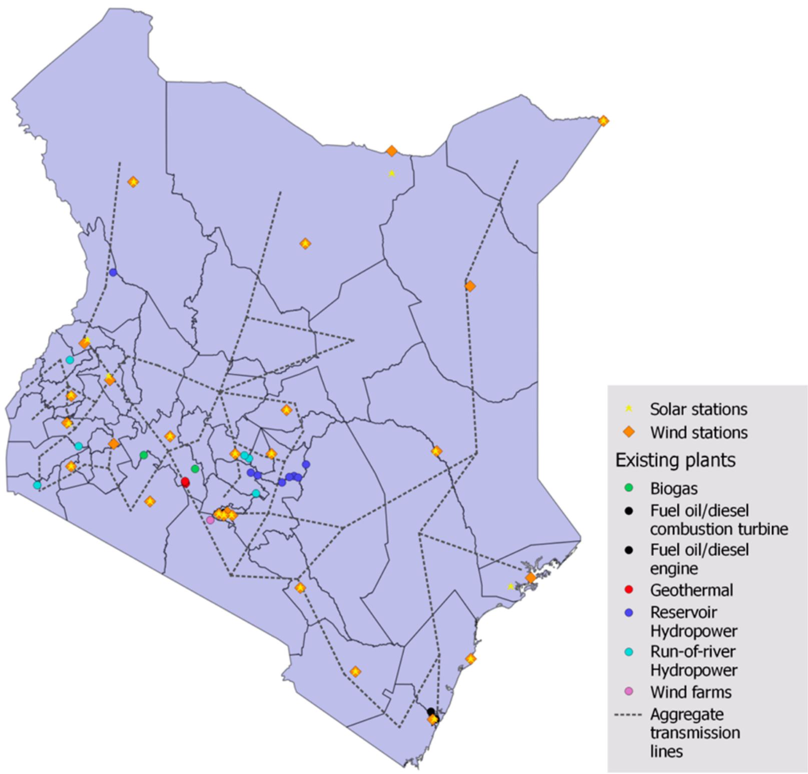

Figure 1. Modeled Kenya transmission system with location of existing and prospective projects and load zones represented by counties.

President Mwai Kibaki launched in 2008 the Vision 2030 initiative. The Vision 2030 is a long-term economic, social, and political development program whose objective is to make Kenya a middle income industrialized economy with high living standards for its population. One of the core components of this program is the Least Cost Power Development Plan (LCPDP), which lays out the investment needs for the electricity sector in Kenya. Currently, roughly 40% of the population has access to electricity, but only 15% of rural inhabitants do. Even in urban areas, power quality is low, supply is unreliable, and the system well-being is volatile due to its high dependence on hydropower.[9] Emergency investments in diesel and fuel oil based capacity have rendered the country with one of the highest power costs in the region. However, Kenya is richly endowed with renewable and conventional resources that can be tapped to fulfill its development vision in an affordable and sustainable manner.[10]

Existing analyses of power system expansion at the pan-African level suggest capacity expansions between 50 and 200 GW by 2025 at around 8−13% annual rates.[11−14] However, there is little research in the literature for national level sustainable power system expansion for individual SSA economies. Some examples are found for Ghana[15] and Nigeria.[11,16,17] Unfortunately, the methods used in these few studies lack the temporal and spatial resolution required to properly characterize variable resources such as wind and solar. These studies also use a very coarse representation of the power system, missing key elements such as transmission capacity and dispatch, geographical diversity, decrease in capital costs due to learning curves, and operational restrictions such as spinning and quickstart reserve margins. They also tend to focus on a narrow set of future scenarios, whereas in most of these growing economies there is important uncertainty on how their energy transition will be shaped. The system-level modeling and analytical approach employed in this paper produce novel results not available in the current literature and that challenge current conceptions on technological choices in fast growing power systems. Specific features of emerging economies' systems like load uncertainty and growth rate, capacity constraints, and large endowment of renewable resources have not been studied integrally like we do in this case study for Kenya.

This paper answers the following questions about cost-effective expansion pathways for the Kenyan power sector:

- What are least cost capacity expansion routes for Kenya to meet its future load?
- What is the generation and transmission costs and operational and environmental impacts on this expansion pathway of:
  - Uncertainty in load projections and future load shape, including the adoption of energy efficiency and of residential air conditioning.
  - Uncertainty in capital expenditures and operational performance of geothermal units.
  - Uncertainty in coal generation unit capital costs.
  - The adoption of battery storage technologies.
  - Very high levels of renewable energy penetration.
  - The adoption of environmental policies such as a carbon tax or a zero-emissions target.

In this paper we do not explicitly model the challenges of providing electricity to unconnected or underserved population—particularly through off-grid solutions—a topic we will address in future work. The Kenya government has trusted the Rural Electrification Authority (REA) with the task of providing universal access to critical facilities and trade centers across Kenya. The Kenya Power and Lighting Company (KPLC)—

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the sole electricity distributor and retailer—reports increase in connections from 37% in 2014 to 47% in 2015.[18]

However, it is still challenging to translate these progress results into load forecasts because not all inhabitants with access get connections and not all connected users can consume power due to affordability and reliability issues. We do not capture the latter because SWITCH-Kenya enforces perfect reliability at the generation-transmission level. We also use a coarse estimation for load projections, as there is much we do not know about the levels and spatial/temporal patterns of consumption and pace of growth that different customer classes will develop under different economic conditions. We do include an analysis of the effect of air conditioning adoption in the residential sector. A detailed load forecast tool for economies with low electricity access applied to Kenya will be developed as part of another paper.

Methods and Data. This analysis employs the SWITCH long-term planning model, which has been used to simulate a wide variation of power systems including North America, China, Chile, and Nicaragua.[19−24] SWITCH is a mixed integer linear program that estimates the least cost investment decisions to expand a power system subject to meeting load forecast and a host of operational constraints. The model concurrently optimizes installation and operation of generation units, transmission lines, storage, and the distribution system while meeting a realistic set of operational and policy constraints (see Table S−Y1 for values of operational constraints). SWITCH employs unprecedented spatial and temporal resolution for each region analyzed, allowing for an improved representation of variable resources like wind, solar, and storage. More information on the model can be found in the Supporting Information (SI).

The SWITCH model implemented for Kenya is based on using the existing 47 counties as load zones or nodes (Figure 1). We assign existing generation units to each node based on their location and sum up individual existing transmission line capacity to reflect aggregate existing internodal (i.e., inter-county) transmission capacities. We extract existing generation capacity from the latest LCPDP report, totaling 1960 MW as of 2015 (approximately 25% geothermal, 35% hydro, 35% fuel oil, and 5% other resources) and transmission line data obtained from the Kenya Transmission Company (KETRACO) totaling 65 GW of transport capacity. Technologies considered for expansion include solar PV with one axis tracking, wind turbines, geothermal flash units, pulverized coal units, gas combustion turbines, gas combined cycle units, and diesel/fuel oil engines. We do include chemical battery storage as an expansion option in specific scenarios to understand its impacts on the power system and on the environment. We do not include new hydropower expansion in this study because we lack the high resolution temporal data required to appropriately model reservoir stocks and flows and run-of-river production. We also include neither technologies that are still in demonstration phase−carbon capture and sequestration or wave/tidal generation−nor technologies for which there are no proposed projects in Kenya, such as nuclear reactors and pumped hydropower. Also, the model does not currently consider imports or exports with Ethiopia, Tanzania, and/or Uganda due to absence of appropriate data to model these exchanges.

Temporally, the model base year is 2015 and runs from 2020 to 2035 in 5 year increments or "investment periods". This time frame matches the latest expansion master plan issued by the Ministry of Energy and Petroleum.[25] The model makes investment decisions for each of these four periods (2020, 2025, 2030, and 2035) and determines optimal dispatch for the operation of power plants in each hour of those periods. Each period is composed of 12 representative months that roughly reflect an average month on a given year. Each month is represented by its peak day (the day when peak monthly demand occurs) and a median demand day. Each day is simulated with its full 24 h. The model then makes hourly generation, transmission, and storage dispatch decisions for 576 h per investment period, or 2304 total hours. This sampling method captures adequately peak demand requirements, but may fail to fully account for all the energy required for a continuous period of months or years. This is particularly relevant for energy constrained power systems that rely on hydropower or that deploy large energy storage capacity. This is not the case for most of the scenarios we simulate, but still further testing in high temporal resolution production cost models is necessary to ensure that energy consumption is met over extended periods of time.

We create load forecasts from annual peak demand and energy country-level sales forecast data by customer class extracted from Kenya Power and Light Company's (KPLC) 2013 Distribution Master Plan. While there are more recent load forecasts in LCPDP documents, the KPLC forecast is the only one specified by customer class. We estimate a daily hourly profile for each customer class that matches their expected load factor. We estimate average daily energy use from the annual consumption and modulate it by these daily hourly profiles to create hourly loads (see SI Figure S1). This method omits intra-annual heterogeneity, but seasonality in Kenya demand is relatively low and we believe it adequately represents an expected load duration curve (see SI Figure S2). To assign this country-level load geographically to SWITCH load zones, we use a specific method depending on the customer class. Residential and streetlight demand is distributed based on county population and urban/rural share as reported in the Kenya 2009 census. Industrial and commercial demand is allocated to each county based on their regional secondary and tertiary GDP as estimated by the World Bank.[26] Hourly profiles are conservatively maintained through the projected forecast. However, we do estimate future air conditioning adoption at the residential level, its effect on hourly consumption, and its impact on capacity expansion decisions. Details of the method can be found in the SI.

Finally, "flagship" projects are specific industrial and technological initiatives supported by the Government of Kenya as part of their Vision 2030 program. We treat these as industrial loads for our forecasting purposes and allocate them by total county population, assuming that counties with larger population will have the human capital to host these projects. The KPLC forecast implicit growth rate is roughly 10% per year and starts from 2012. We compare the first few years of the forecast against actual energy and peak demand and find that actual growth is closer to 8%. We then adjust the base load forecast projection for all load zones to this level.

Fuel price forecast can have an important impact on the choice of future resources. We use the most recent World Bank commodity price forecasts for coal, oil (for diesel and fuel oil), and liquefied natural gas (LNG).[27] On average, coal price is \$50/ton, oil is \$50/bbl and natural gas is 9−12 \$/MMBTu (see SI Figure S3). For natural gas we develop a supply curve that reflects the incremental investment costs in expanding the

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gasification terminal for LNG imports. These costs are estimated in 1.5 \$/MMBTu for each additional 3 MMm^3/day of maximum gasifying capacity. We use a diesel premium of 0.002 \$/MMBTu-km to reflect intracountry transportation costs to each different county, as calculated from the 2013 LCPDP. This version of the study does not include the use of biomass as a fuel to produce electricity, largely due to the absence of a proper market price for this fuel. Biomass share of generation capacity is currently about 1.5%.[28]

Capital cost for nonconventional technologies such as PV and wind may decrease in the future. We extract PV cost forecasts from a 2015 study developed by the German Fraunhofer Institute.[28] Wind, combined cycle, gas turbine, combustion turbine, and coal unit costs come from a 2013 report by the U.S. Energy Information Administration.[29] The costs for fossil-fuel based generation are fairly stable given the maturity of these technologies. For wind we assume a linear trend in capital cost reduction of 2% per year, in line with empirical results.[31] Geothermal unit costs depend importantly on their location. We use a list of prospective projects with their expected capital expenditure as reported in the 2013 LCPDP to assign a different cost to each geothermal project depending on its location. This essentially produces a supply curve for geothermal plants that recognizes the higher cost of prospecting, exploring, deploying, and operating geothermal units in certain locations (see SI Figure S4). We derive costs for battery storage from the midscenario in Cole et al. (2016), with estimates at 0.7 \$/W and 488 \$/kWh in the current year decreasing to 0.5 \$/W and 192 \$/kWh by 2035.[32] Capital, variable nonfuel, and fixed costs for all technologies are shown in SI Table S2. Costs are discounted with a 7% rate, which corresponds to the median historical central bank rate as reported by the Kenya Central Bank. We test 3% and 11% discount rates and find no changes in our results due to the short time span of the simulations.

Wind and solar PV technologies require hourly capacity factors for at least a year for SWITCH's dispatch module. We use NOAA meteorological data for 26 stations in Kenya that record global horizontal and direct normal radiation, wind speed and direction measured at 10 m, dry bulb temperature, and atmospheric pressure (for location see Figure 1). We employ NREL's System Advisor Model to simulate the hourly production of a PV module with tilt equal to the latitude of the station. Wind turbine power curves are used to determine average production for each hour based on 15 years of hourly wind speed at an adjusted hub height of 100 m and meteorological data. We finally translate production for both solar PV and wind turbines into capacity factors ranging from 0 to 1. We select 18 wind locations to site 600 MW projects and 23 solar locations to site 800 MW projects for a total technical potential of 10.8 GW of wind and 18.4 GW of solar PV, respectively.

Scenarios. Forward looking models like SWITCH-Kenya have little to no empirical evidence to be calibrated against. Therefore, their proper use is for within-model comparisons through scenario based analysis. The assumptions described in the preceding section produce a base case scenario or *business-as-usual (BAU)*. The outcome of this scenario should not be interpreted as the most likely pathway for future power system development, but as a benchmark given the assumptions that we are making about the different variables and their projections. The remaining scenarios are created to provide answers to the research questions presented in the introduction. A list of scenarios and brief description is shown in Table 1 and detailed key parameters are shown in SI Table S4.

Table 1. Scenarios Used in the Simulation

scenario name	definition (expressed as variation from the BAU scenario)
BAU	none
LowLF	same energy consumption but lower load factor across all customer classes
LowLoad	reduced energy consumption, from implementation of energy efficiency policies across all customer classes
HVAC	alternative load forecast that includes adoption and use of air conditioning by urban residential customers
HighGeoCost	higher geothermal investment costs by 30%
LowGeoCF	lower and decreasing capacity factor from new geothermal plants
RedGeo	halve the technical potential of new geothermal
RedGeoSto	halve the technical potential of new geothermal, include storage as "storage" scenario
Storage	allows up to 1 GW storage projects in each of the 8 largest load zones
LowCoal	lower investment cost for coal generation, 70% of base cost
CarbonTax-30	apply a \$30/tonCO_2 carbon tax to fossil fuel based generation
CarbonTax-10	\$10/tonCO_2 carbon tax to fossil fuel based generation
ZeroCO2	zero emissions from 2030, include storage as "Storage" scenario
ZeroCO2Sp	zero emissions from 2030, include storage as "Storage" scenario and also constraint spilled energy to 5% maximum

Geothermal Energy. Geothermal energy is the largest energy source technically available in Kenya and may be the most relevant resource for domestic power system expansion.[10] The SWITCH-Kenya model includes over 8 GW of potential new geothermal capacity. While the technology is relatively mature, the risks involved in the exploration and operation of specific wells make final capital costs and capacity factors uncertain.[33] We test the impact of higher than expected capital costs by shifting up in 30% the base supply curve. Separately, we test the impact of reduced and declining capacity factors due to lack of maintenance. The base capacity factor assumption for new geothermal is 94%, consistent with current flash steam technologies.[34] The sensitivity is run with a base capacity factor of 85% that declines 0.5% per year from the start of operation of a given project. We test two additional scenarios with half of the base case technical potential (4 GW instead of 8 GW). In one of these two scenarios we also allow the deployment of storage.

Load forecast. Load growth is the most impactful variable for power system planning.[35] There is high uncertainty for load growth in fast growing and emerging economies that have large portions of their population without access to electricity and whose commercial and industrial activities are incipient and much more sensitive to economic performance. As mentioned, we already adjusted downward the original load forecasts developed in the 2013 KPLC Master Distribution Study report. We then test three possible scenarios for deviations in load (see SI Figure S5):

- First, we assess a case with similar energy consumption but lower load factors for all customer classes. The original load factors are 42% for urban and 36% for rural residential consumers and 83% for commercial/industrial and flagship projects. The resulting system level load

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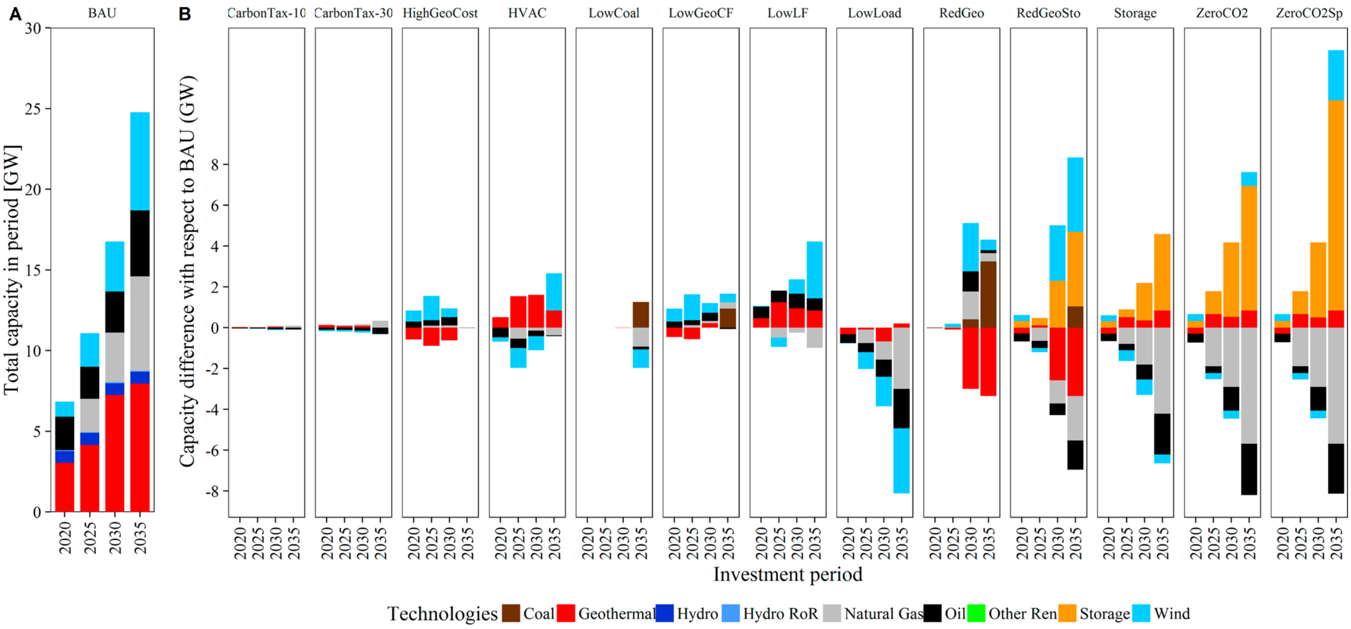

Figure 2. Cumulative generation capacity expansion for BAU scenario (A) and difference in cumulative generation capacity expansion for all scenarios when compared to BAU (B).

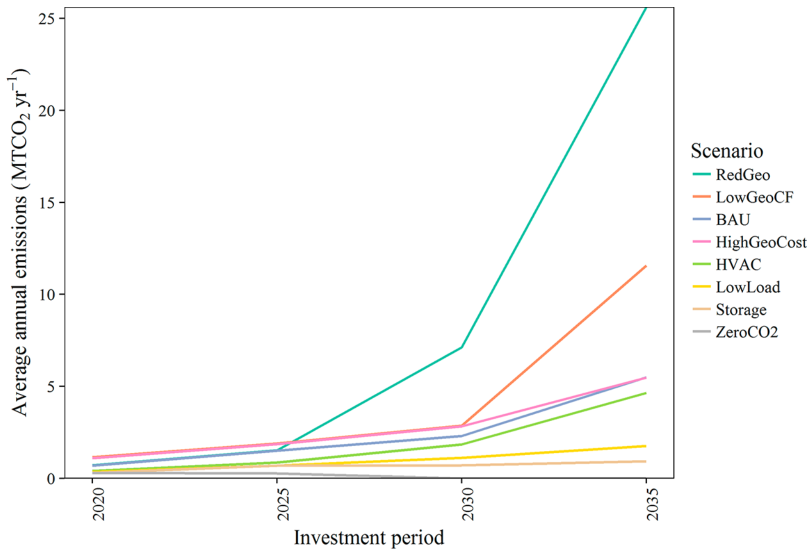

Figure 3. Average annual CO_2 emissions for selected scenarios by investment period.

factor is 64%. The sensitivity is run with 30% and 20% load factor for urban and rural residential load, respectively, and 66% for commercial/industrial, for a system load factor of 55%. This translates into ∼10−15% higher peak demand for the sensitivity scenario compared to the base case scenario.

- Second, we assess the impact of more efficiency growth. The base case of 8% average annual load growth is tested against a more efficient annual growth of 5%.
- Lastly, we use a simple model of air conditioning adoption and use at the residential level to assess its impact on system expansion and operation (see SI for the methodology)

Coal Power. Kenya is considering the use of domestic or imported coal to install and operate new generation units in Lamu and Kitui counties. There is strong resistance from environmental groups and local stakeholders to the adoption of this technology due to environmental and economic concerns. We run a sensitivity analysis on capital cost for coal plants to test how it impacts adoption. The base capital cost for a single unit advanced pulverized coal plant is \$3246/kW and the lower sensitivity cost is \$2435/kW, 70% of the base cost. This value is the average of an alternative capital cost included in NREL's study of \$2890/kW[36] and the expected cost for these coal projects as reported in the 2013 LCPDP of \$2000/kW. We do not use this reported cost directly for several reasons. First, the reported cost at \$2000/kW is much lower than any other international benchmark. Second, the country has no experience with coal plant deployment and the expected cost may be optimiztically lower than the actual cost. Finally, the reported cost does not account for the additional infrastructure required to install the coal plant, which includes a railway, a port, and a dedicated transmission line to connect to the Kenya power system.

Storage. We run a scenario with battery storage units to be deployed in the main load centers. For this, we select the 20% of load zones with higher peak demand in the base load forecast scenario and allow the model to install up to 1 GW of storage on each site. We test whether the model chooses to deploy storage technologies and, if so, its capacity (GWh), discharge rate (GW), how it is operated, and what its economic impact is. Storage operation is simulated using a "circular" approach. This means that the charge at the end of the day matches the one at the beginning of the same day. This conservative approach does not require a prespecified initial storage level, but does require further testing in more detailed models than SWITCH-Kenya to verify adequate system operation.

Climate Policies. We finally test two sustainable growth scenarios based on climate policy constraints. In the first, we run the model twice with a \$10/ton and a \$30/ton of CO_2 carbon tax respectively, passed as a fuel adder based on carbon content for fossil fuels. In the second we use a carbon cap to test the impact of a zero-emissions policy by 2030. The design of the tax policy is based on average social costs of carbon as found in the literature.[37,38] The carbon cap does not have empirical support, but we want to stress-test the power system by forcing zero direct CO_2 emissions by 2030.

■ RESULTS

The BAU expansion relies heavily in geothermal, natural gas, and wind technologies, which in total comprise over 70% of installed capacity and 90% of energy generation (Figures 2 and 3). In this scenario geothermal reaches 3 GW of installed capacity by 2020 and 8 GW by 2035, using almost all the available technical potential. Wind power shows a steady progression from around 1 GW in 2020 to 6 GW in 2035. Diesel capacity remains relatively high and grows from 2 to 4 GW in the period analyzed. The base expansion is relatively low on emissions, totaling ∼50 MT/CO_2 in the analysis period or ∼2.5 MT/CO_2-yr. The average levelized cost of generation and transmission for the BAU scenario is ∼82 \$/MWh. Our BAU results are consistent with similar projection efforts developed in Kenya (see SI).

Scenarios that perform geothermal generation sensitivities are very relevant to gauge the future of the Kenyan power sector given its important role in the base case and overall abundant potential. Higher than anticipated geothermal costs would lead to delayed adoption of this technology, but would still reach the same 8 GW as in the base case by 2035. Wind power is the preferred least cost resource to replace the delayed geothermal capacity, with an expansion 20% higher than the base case (Figure 2). Higher geothermal investment costs translate to approximately 4 \$/MWh additional average levelized cost, or a ∼ 6% increment (SI Figure S7).

The effect of degradation in the capacity factor for new geothermal plants is different than the impact of higher investment costs. The energy mix for this scenario is essentially the same as the scenario with higher costs (SI Figure S10). However, the cumulative effect of reduced production requires the adoption of around 1 GW of coal capacity by 2035. Consequentially, this scenario has ∼50% more CO_2 emissions (Figure 3). The cost impact is similar on average, but as production degradation is higher in older plants, these costs tend to rise toward the end of the analysis period.

Our base assumption for portfolio availability is that there are ∼8 GW of technically feasible capacity in Kenya. We test the impact of developing only half of this capacity or ∼4 GW, which we implement by halving the maximum capacity of each of the 23 geothermal projects that the model can develop. We find little to no change in the capacity installed during the first two investment periods (Figure 2). However, once the available capacity is exhausted the expansion relies importantly in wind and natural gas in 2030 (about 4 GW) and coal in 2035 (about 3.5 GW). The levelized cost of these alternative pathways are on average 10 \$/MWh higher than the base case in the two latter periods (SI Figure S7). Transmission costs are particularly relevant in 2030, as transmission capacity is required to enable the adoption of over 2.5 GW of wind in that period.

We simulate a variation of the above scenario by adding battery storage units to the portfolio of eligible projects, but still maintaining the restricted geothermal portfolio at half its base capacity. We want to test whether the availability of storage could delay or reduce the adoption of coal based generation. The hypothesis is that battery storage may enable higher cost-effective wind adoption by providing flexibility to the system. Indeed, the adoption of ∼13 GWh of storage capacity at ∼3.7 GW average discharge rate is correlated with a reduction of coal generation capacity to less than a third the original value and an increase of wind capacity of 80%. Diesel capacity additions are also reduced as a result of a systemic interaction between storage and diesel generation that will be discussed later.

Load forecasting is very challenging for fast growing economies because there are many uncertainties on the types of energy services that the economy will demand, how they will be used in time, and who will have access to them. We test the impact of an "energy efficient" scenario in which electricity demand grows slower for all customer classes. The impact of 3 percentage points reduced growth (from 8% in the base case to 5%) is to install roughly 8 GW less of total capacity by 2035, as much as a third of the total capacity installed in the base case. Geothermal energy continues to be the least cost preferred resource and produces on average 75% of the generation during the analysis period. In contrast to the energy efficiency scenario, the impact of a lower than expected load factor is reflected in larger capacity expansion requirements for up to 4 GW or 20% of the base case. The expansion is in line with the 15% higher peak demand that lower load factor produces (SI Figure S5). Our analysis of urban residential HVAC adoption reveals no significant impact on peak demand (SI Figure S6). We estimate about 5% increase in midday demand by 2035 due to residential HVAC use compared to the BAU scenario. Interestingly, the improvement in system load factor due to the additional energy results in earlier geothermal power adoption, delayed wind capacity adoption, and reduced oil and natural gas capacity at the generation level.

The BAU scenario results do not include coal power expansion as a preferred least cost resource. Coal power has only been deployed so far in scenarios with rather extreme conditions, such as halving the technically available geothermal capacity or degrading geothermal performance. We test further the role of coal by testing a scenario with low capital costs for this technology. We find that a cost 30% lower than the base case has a modest impact on the adoption of 1 GW of coal generation by 2035 only. The largest systemic impact of adoption of coal is reduced need in transmission construction due to the displacement of more remote wind projects. In none of the scenarios analyzed in this paper coal generation was adopted before 2030.

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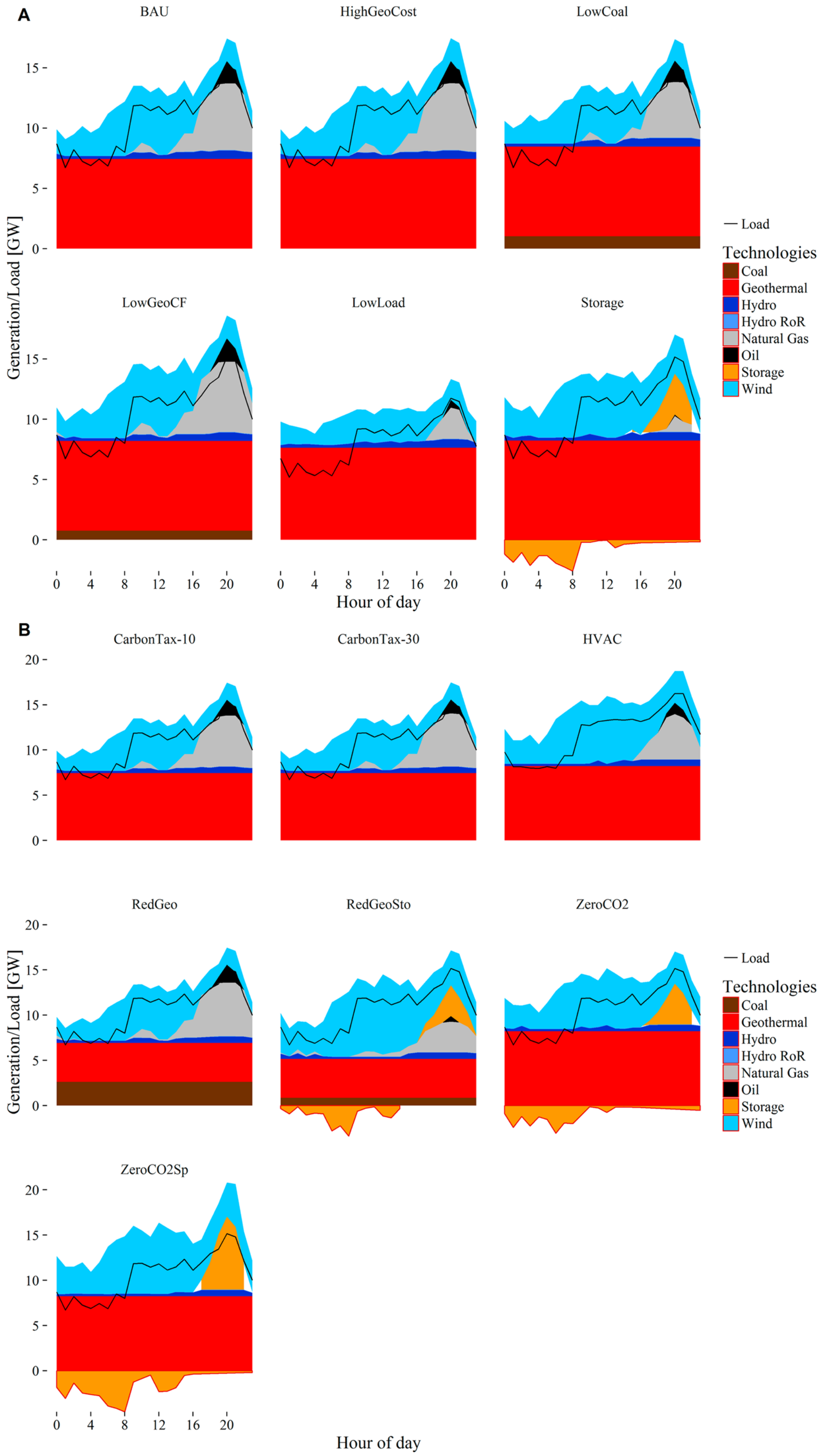

Figure 4. (A,B) Hourly dispatch for a representative day in May 2035 for all scenarios (panels A and B). Load is the same for all scenarios with the exception of the "LowLoad" and "HVAC" scenarios. The negative orange areas in some scenarios represent storage charging, which also appears as positive when it is discharging into the grid.

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Battery storage has important cost reduction impacts due to the displacement of oil and natural gas generation and providing flexibility for the adoption of additional relatively inexpensive geothermal baseload. We estimate savings of around 15 \$/MWh or 15% of average levelized system costs (SI Figure S7). 13.5 GWh of storage capacity at 3.8 GW discharge rate are installed by 2035−for an average of 3.5 h of storage, about 15% of the total installed capacity of 22.6 GW for the "Storage" scenario (Figure 2). Geographically, this storage is initially installed close to the major load centers in Nairobi and Kiambu counties, but by 2035 there is storage capacity installed in all possible load zones.

We find that both levels of carbon tax at \$10 and \$30/tonCO_2 have a negligible effect in the resource expansion choices. An interesting outcome is that in both cases there are minimal reductions in wind power adoption compared to the BAU scenario. This is possibly due to the reductions in oil based generation triggered by the carbon tax and subsequently with the reduced flexibility in the system to absorb variable wind generation. In addition, we verify that these tax levels have no impact in emissions reductions compared to the BAU scenario (Figure 3). More interesting results appear in the "zero emission" set of scenarios, in which we require the Kenyan power system to have zero emissions by 2030. The first implementation of this restriction—that did not allow storage—had no feasible solutions because without oil or natural gas generation the system did not have a large enough source of spinning reserve to operate reliably. To address this, we implement the "ZeroCO_2" scenario with the same storage options as in the "Storage" scenario. We find that the power system substitutes natural gas and oil based generation with storage, geothermal, and wind power to achieve zero emissions in 2030. 470 MWh of storage is installed in 2020, increasing to over 21 GWh by 2035 with a discharge capacity of 6.1 GW for 3.5 h of average storage.

The "ZeroCO_2" scenario results in significant levels of spilled energy of 8% to 13% per year. Spills may be socially optimal under highly constrained conditions as the ones we are simulating. However, in many power systems with functioning markets, operators and project developers would not tolerate those levels of curtailment. We test a scenario in which curtailment is constrained at a 5% maximum—a reasonable threshold based on BAU curtailment—to assess its effects on the resulting expansion. The effect of this constraint is largely to promote earlier and more aggressive adoption of storage. This larger adoption of storage does not have a tangible effect in the choice of investments for other technologies, but does affect the system operation (Figure 4). The hourly dispatch shown in Figure 4 reflects how storage is charged in the night using baseload geothermal and available wind capacity, and then entirely discharged to meet the evening peak. The levelized costs of this alternative are 10%−15% higher than the scenario with socially optimal spills, in the range of 3−7 \$/MWh (SI Figure S7). We also find an increase in the number of hours with zero short-term marginal costs in high renewable energy penetration scenarios compared to BAU (SI Figure S11).

We measure the environmental impact of different selected scenarios through their CO_2 emissions. The BAU scenario for Kenya shows an 8-fold increase in emissions from 0.7 to 5.5 MTCO_2/yr (Figure 3), although the carbon intensity only increases from 20 kgCO_2/MWh to 50 kgCO_2/MWh (SI Table S3). The increase in emissions in the power system is led by adoption of natural gas units. Scenarios in which geothermal power is not fully available are the most polluting due to coal generation adoption: lower geothermal capacity factor due to lack of maintenance can lead to double the BAU emissions by 2035 and a restricted geothermal portfolio to four times BAU emissions by 2035. In contrast, energy efficiency and storage adoption can lead to three to four times less emissions than BAU. In both these cases the implicit carbon price is negative: these scenarios are more cost-effective and also less polluting. The stringent "ZeroCO_2" scenario with restricted spills achieves zero emissions from 2030 at an average implicit cost of \$60 to \$140/tCO_2.

We put these results in perspective by estimating per capita emissions for the Kenya power system using population projections from the United Nations Department of Economic and Social Affairs.[39] Climate stabilization targets suggest average per capita emissions between 1 and 2 tCO_2/yr.[40,41] Based on data from the World Bank, we estimate that the electricity sector was responsible of 25% to 50% of total direct country level emissions in 2008. The lower range corresponds to low income economies and the upper range to OECD economies, although there is large variance within each income group. Then, a rough approximation for climate stabilizing per capita emissions from the electricity sector should be in the range of 0.25 to 1 tCO_2/yr. In almost all scenarios the Kenya power system is well below this range, with BAU emissions per capita of 0.08 tCO_2/yr by 2035 (SI Table S3). The restricted geothermal portfolio scenario produces the largest value of emissions per capita of 0.35 tCO_2/yr, still within the acceptable range. These results do not contemplate a potential massive electrification of end uses due to new technology diffusion and adoption, which may increase the pressure for low carbon system development.

DISCUSSION

The Kenyan power system expansion reflects critical interactions between technologies and across input variables that apply to several fast growing and emerging economies in SSA and possibly elsewhere. In this section we highlight these interactions and how policy making could foster and enhance system level planning in Kenya to achieve sustainable growth. Our recommendations cover geothermal operation subsidies, integration of variable renewable resources, the role of storage and flexible generation such as diesel and natural gas, and the importance of forward looking transmission expansion.

A Kenya-specific result is related to geothermal plant investment cost levels and the importance of appropriate maintenance routines and standards. Higher investment cost does substitute geothermal, mostly for wind power. There are several phases in geothermal investment, starting with prospective exploration and test well drilling up to plant construction and operation. Higher cost for geothermal may then arise from unexpected exploration expenses as well as additional construction costs. Our results suggest that subsidies for geothermal investments may not be completely justified from a sustainability perspective, as the alternative pathway has equally low carbon intensity. However, subsidies and state involvement in the initial phases would probably still be relevant from a risk management perspective.

We show that even a small annual degradation in geothermal production performance has relevant long-term impacts in terms of resource choices. Performance of geothermal plants may have a larger effect than initial capital cost outlays, particularly from a sustainability perspective due to coal

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substitution in Kenya. Well casings and reservoir management are two critical sources of potential decrease in performance when not developed adequately. Higher standards for both processes and adoption of world-class practices may raise upfront costs. However, we show that these increases in cost have a lesser effect when compared to performance degradation in the long run.

A system level analysis is important to capture dynamics that otherwise are missed, particularly if they are not intuitive. We find that when geothermal potential is halved, over 75% of the gap can be filled with a nonbaseload resource such as wind when storage is available. While the model employs battery storage and diesel peakers in other scenarios, it is very possible that the same flexibility services could be provided with new reservoir hydropower if it was available. Restrictions in dispatch on hydropower would probably require larger installed capacity to provide equivalent performance as dedicated battery storage. However, we find that the large amounts of variable resources can be integrated with relatively modest amounts of storage capacity. Then, even in the absence of battery storage, Kenya should be able to integrate large amounts of variable renewable resources using existing and potentially new reservoir hydropower in addition to the transmission expansion required to mobilize this power.

Storage can play a very important role in the future Kenyan power system by reducing the use of fossil fuels, particularly natural gas and diesel. This has an important impact on costs, with savings of 10 to 15 $/MWh, as storage enables the adoption of cost-effective resources that would otherwise would not be adopted due to operational restrictions in power systems. In scenarios with very tight emissions constraints, battery storage was indispensable for the system to operate within feasible regimes. The adoption of battery storage has also important distributional consequences: it enables the adoption of higher capital intensive nondispatchable technologies such as wind and geothermal in lieu of dispatchable ones like diesel and natural gas generation. In these cases up to 90% of the system cost will be in capital, compared to 60% in the base case. This can have important implications for the trade balance of countries that import liquid fuels and also makes the power system and the economy more resilient to shocks and volatility in liquid fuel prices.

Flexibility is and will be an even more critical feature of future power systems with high penetration of variable resources and high load forecast uncertainty.[39] We inspect the role that oil based capacity may have in future of fast growing and emerging economies power systems by comparing its installed capacity against that of wind (SI Figure S9). When storage is not available, there is very high correlation between higher levels of wind capacity and higher levels of oil based generation capacity. The role of oil based generation as a key ancillary service and flexibility provider has been largely neglected both in the literature and electricity regulatory frameworks, with many countries making important efforts to decommission their existing oil based generation capacity as a sign of "progress". Our results suggest that market mechanisms should be designed to encourage diesel, fuel oil, and potentially natural gas generation capacity to be available to system operators to provide these services as well as meeting peak load. While availability of storage will reduce the need for oil based generation, in the short and medium term this will continue to be a key source for flexibility. These results are not advocating for *increase* in oil based electricity *production*. Oil based generation used for ancillary services and resource adequacy supplies only between 0.5% and 1% of total energy in any scenario. This translates to 40−80 h of annual operation, roughly 500 times less than current diesel operation hours in Kenya.

We believe the proposed operational strategy for diesel based generation has low environmental impacts compared to system-level benefits. However, additional research using air quality and pollution dispersion models is required to assess the potential local and regional impacts of oil based generation. We design a set of additional scenarios in which we remove diesel generation from the portfolio to assess the economic impact of its moratorium in Kenya. This economic impact is an upper bound for willingness to pay for no diesel generation. We find that in the absence of storage, coal generation is adopted in 2035 to meet peak demand, with significant spilled energy, increased CO_2 emissions, and an additional system cost of 9−10 $/MWh. If storage is available, there is a 2−4 $/MWh increase in cost compared to a storage scenario that allows diesel generation. A no-diesel expansion path would be reasonable if Kenyan authorities determined that the marginal damage of diesel generation is above the 10 $/MWh level. More details of these simulations are available in the SI.

Another key provision of flexibility in power systems is transmission capacity expansion. Our results suggest that the Kenyan transmission system needs to grow 3 to 4 times in capacity by 2035 in all scenarios. However, the transmission expansion depends on the assumptions and conditions that affect the whole system (SI Figure S8). A lower load factor than expected would require additional transmission capacity in excess of 40% to 50% of the base case expansion to meet the new higher peak load. In contrast, the energy efficiency scenario produces capacity savings in transmission expansion of over 25% compared to the BAU scenario. These large fluctuations in transmission capacity do not necessarily translate into significant costs, largely because of the low cost of expanding the transmission system in Kenya. We identify critical specific transmission corridors like the Nyeri-Kiringaya-Embu connector running through the center of the country to evacuate geothermal power to the load centers. Our results suggest that specific corridors should be prioritized through anticipated construction to allow the development of least cost generation. These interactions between transmission and generation should be a central component of least cost planning activities lead by the Kenyan Government.

The load uncertainty analysis reveals the potential effect of demand response (DR) and other policies that shape hourly profiles through automation and consumer behavior. Energy efficiency policies would save up to $30/MWh by 2035 or almost a third of the original average cost. This average cost of saved energy suggests there may exist plenty of cost-effective opportunities for the Kenyan system to use energy efficiency as an effective tool to meet load needs in the future. The "LowLF" scenario provides insights on the potential effects of DR. The shape of the hourly profile in the alternative load factor scenario is created by increasing the peak demand and decreasing the shoulder−middle of the day−and off peak demands. This has an interesting effect in the case of Kenya, where there is high wind availability in the shoulder hours. Higher demand in shoulder hours is met by existing wind capacity, saving about 15% of costs compared to the BAU scenario in the form of reduced natural gas generation that was originally dispatched in the late afternoon. This is a very specific result that depends

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largely on our assumptions for the shape of the alternative low load factor hourly profile. However, it does suggest how displacing demand to match generation profiles for non-dispatchable resources that are already committed may create cost reductions. It also shows that DR programs may not necessarily be aimed to reduce peak demand, but also to match load profiles with generation profiles from nondispatchable resources. The balance of these two dissimilar objectives is an open area of research.

An unexpected result is the absence of solar power investment on any of the resource expansion scenarios. This is unexpected because solar power has been a widely adopted off grid solution through solar home systems.[43] In the case of Kenya, we believe the absence of utility scale solar may be justified by (i) the large potential of geothermal energy with lower levelized costs, (ii) the relatively better quality of the wind resource as a zero carbon source, and (iii) the low capacity value of solar photovoltaic in an economy with an evening peak throughout the year. These conditions are specific to Kenya and other SSA countries could still find solar PV cost-effective in the absence of other low carbon alternatives. Widespread adoption of air conditioning may shift the peak demand toward midday and enhance the capacity value of solar PV, making it a more cost-effective resource. Our results, however, suggest that by 2035 adoption will not be high enough to significantly increase the capacity value of solar PV.

Several shortcomings that stem from uncertainties and simplifications of the model and data could be addressed in future research to strengthen these conclusions. Among them, we find a need for better load forecasting tools, improved transmission representation to assess congestion conditions, intrahourly assessments for variable resources—particularly wind power—and incorporation of demand response and other demand side resources. A deeper assessment of locational environmental impacts of each technology, particularly diesel and natural gas, is required.

Technological developments are expected to continue lowering the costs of low and zero carbon emission technologies. As our expansion modeling exercise shows, most of these technologies will be the basis for expansion in emerging economy's power systems. Critical environmental impacts will be related to the ability of these economies to cost-effectively and efficiently tap and integrate into these resources. Our results show that for Kenya delays or cost overruns in geothermal development lead to increases in both costs and carbon emissions due to adoption of coal generation. In contrast, adoption of storage and energy efficiency reduces emissions and costs through less use of natural gas and diesel. In a low carbon system, reaching the zero-carbon milestone by 2030 with technical feasibility will still be relatively expensive at \$60−140/tonCO_2. This suggests two strategies. First, the burden of mitigation should be borne by regions and jurisdictions with existing carbon intensive systems, possibly through environmental policies. Second, fast growing and emerging economies should focus on cost-effective development of their renewable resources, possibly through targeted technology subsidies, market design, and capacity building. Refs 30 and 42.

■ ASSOCIATED CONTENT

Ⓢ Supporting Information

The Supporting Information is available free of charge on the ACS Publications website at DOI: 10.1021/acs.est.7b00345.

The SWITCH-Kenya model and inputs; comparison of SWITCH-Kenya results against existing modeling efforts in Kenya; analysis of air conditioning adoption in the residential sector; discount rate sensitivity analysis; no-diesel expansion simulations; additional result figures and tables (PDF)

■ AUTHOR INFORMATION

Corresponding Author

*Phone: (510) 642-1640; fax: (510) 642-1085; e-mail: kammen@berkeley.edu.

Notes

The authors declare no competing financial interest.

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