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Prospects for grid-connected solar PV in Kenya: A systems approach

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HIGHLIGHTS

- We evaluate the technical and economic feasibility of solar PV in Kenya using a systems approach.
- Unit commitment models of the 2012 and possible 2017 systems are used.
- In 2012, the economic value of PV exceeds potential project costs.
- In 2017, delays in planned plant investments extend the feasibility of PV.
- Conditions favorable to PV in Kenya are present in many other African countries.

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ABSTRACT

Capacity planners in developing countries frequently use screening curves and other system-independent metrics such as levelized cost of energy to guide investment decisions. This can lead to spurious conclusions about intermittent power sources such as solar and wind whose value may depend strongly on the characteristics of the system in which they are installed, including the overall generation mix and consumption patterns. We use a system-level optimization model for Kenya to evaluate the potential to use grid-connected solar PV in combination with existing reservoir hydropower to displace diesel generation. Different generation mixes in the years 2012 and 2017 are tested with a unit commitment model. Our results show that the value of high penetrations of solar in 2012 exceeds expected payments from the national feed-in-tariff. Under two 2017 generation mix and demand scenarios, the value of solar remains high if planned investments in low-cost geothermal, imported hydro, and wind power are delayed. Our system-scale methodology can be used to estimate the potential for intermittent renewable generation in other African countries with large reservoir hydro capacities or where there is a significant opportunity to displace costly diesel generation.

1. Introduction

Kenya has the potential to generate orders of magnitude more electricity from solar PV than is consumed each year from its national grid [1,2]. At the same time, electricity consumption has been growing at rapid rate, averaging 6% annually, and investments in new generation capacity have not come online fast enough to meet growing demand. As a short-term solution, diesel capacity, much of it leased, provides as much as 38% of all grid connected generation [3].

Spurred by rapid demand growth, and faced with a mandate to increase electricity access rates from less than 25% in 2010 [4] to 40% by 2030 [5], system planners must significantly and rapidly increase generating capacity in the coming years. The current national plan focuses on achieving this through expanded public and private investment in large geothermal, coal and gas projects [6]. In light of the large upfront investment costs for these projects and historically poor overall record of power sector investment throughout sub-Saharan Africa, we have investigated an alternative strategy emphasizing incremental investment in utility scale solar PV.

We believe that such a strategy is potentially attractive in Kenya and many other sub-Saharan African countries for several reasons.

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1. Short construction times for solar PV installations would enable smaller scale investments to be made continuously, thereby providing a hedge for system planners against load growth uncertainty and helping to lower investment risk.
2. Despite the nominally higher nameplate cost of utility scale PV relative to an equivalent amount of conventional fossil generating capacity, PV plants can be built close to load centers, eliminating the need for costly investments in transmission infrastructure associated with distant mine-head or coastal fossil fueled plants.
3. PV would tend to displace more expensive diesel generation and reduce total production costs, so long as other flexible generators, such as reservoir hydro plants, could compensate for PV's intermittency.

In this paper, we use a system-level model of the Kenyan generation system to examine how significant penetrations of solar PV affect system operations and production costs. Using these results, we calculate the economic value of PV in Kenya. We do this for the 2012 reference case and two possible future generation mixes in 2017. Significantly, we model a realistic representation of Kenya's hydro system, which includes both run-of-river and reservoir facilities. This enables us to treat hydro plants both as generators and energy storage devices, curtailing output when the sun shines and increasing output in the evening when PV output falls. With this model we derive the value per Watt of PV capacity added to the system over a wide range of penetration levels and compare our results with estimated renewable support payments in Kenya. This paper contributes to the growing literature on capacity expansion planning with intermittent renewables by offering an alternative method to estimate the value of a candidate technology for a future generation mix and evaluate current feed-in-tariff policies.

2. Background

There is a growing body of literature on the impacts of intermittent renewable generation, such as solar PV, on both short-term system operations and long-term capacity expansion planning. In the short-term, variability and uncertainty in PV output present a number of challenges to solar integration. [7,8]. Previous authors have examined the detailed aspects of how intermittent renewables may impact system stability [9,10], operating reserves [10], cycling of thermal power plants [11] and market prices [12,13]. At low penetration levels, solar generation can displace the most expensive generators and reduce average production costs but, as penetration levels increase, these savings could be countered by higher costs of cycling conventional thermal plant. Added storage, in the form of pumped hydro or batteries, has been suggested to smooth ramping rates and improve the response to power system disturbances [13]. For systems that already have reservoir hydropower capacity, jointly coordinating hydro and solar production can reduce net peak loads and cycling of thermal generators [12].

Other studies have focused on adopting long-term planning models to determine the optimal penetration level of intermittent renewables [14,15]. In US power systems, [16,17] conclude that solar PV penetration is limited by the ramping constraints of existing generators and the need to match intermittent generation and demand. To account for this in expansion planning models, some authors have introduced a *flexibility* constraint, based on the level of intermittent renewable energy penetration, to the conventional planning processes [17–19]. [20] use the concept of "system states" instead of load levels to maintain important chronological information and more accurately represent market outcomes and system costs. In cases where the system has sufficient flexible generation, other studies have used a net load duration curve to subtract the expected intermittent generation from the load first, then plan the remaining generation mix second [21,22].

The Kenyan government has cited "high capital costs" of solar PV as a barrier to PV deployment and does not include PV as a candidate technology in the most recent long-term power system plan which covers the period from 2011 to 2031 [23,24]. However, these findings appear to rely on outdated cost information from two 2005 reports based on costs in the US and Europe [24–26]. Given the recent changes in solar module prices, several authors have shown that economic assessments based on outdated data will overestimate the costs of solar PV [25,27,28]. In Kenya, [24] used country specific data on solar resources and existing generation technologies to estimate the levelized cost of electricity (LCOE) for grid-connected solar PV and found that PV is already competitive with some traditional fossil fuel plants currently in use. This is consistent with the other results based on comparisons of global prices [29].

A shortcoming of LCOE comparisons is that they fail to account for synergies between solar generation and demand or the impacts of introducing a new technology on the operational modes of existing plants. One proposed solution is the introduction of a "system LCOE" that accounts for variability and integration costs of intermittent renewables [28]. Another alternative is to avoid LCOE comparisons altogether and instead estimate the avoided costs from increased renewable generation. [30] use site-specific solar data and current tariff rates to calculate the avoided energy costs for rooftop solar PV systems in Kenya.

In this paper we also use the avoided cost metric to determine the value of different levels of solar PV deployment. However, instead of focusing on the avoided tariff payments, which are subject to policy in addition to technical influences, we calculate the avoided production costs for the system as a whole. Additionally, instead of looking at small rooftop PV system in specific locations, we model the operation of a generic large-scale solar PV plant alongside the existing generation fleet. In order to retain chronological information, we avoid load duration curves and time blocks and use an hourly unit commitment model.

The study is thus designed to address four key questions:

(i) What are the impacts on system operations and production costs of adding solar PV to the Kenyan system?
(ii) Given these impacts, what is the economic value per W installed of the solar PV investment?
(iii) How does this economic value compare with expected payments a solar generator could earn based on Kenya's feed-in-tariff (FIT)? And
(iv) How do these results change under different 2017 growth scenarios?

This paper contributes to previous work in three ways. First, our valuation extends previous work to estimate the value of solar PV in Kenya by capturing the cost of operational impacts that PV may have on other power plants. Second, this work contributes more broadly to the growing literature on the primary impacts of high penetrations of solar PV, particularly in systems with the potential to coordinate hydro and solar generation. Finally, we apply the results to gain insights as to whether or not the current FIT is cost effective.

3. Materials and methods

3.1. Model formulation

Two hydrothermal unit commitment models were developed for the representative years 2012 and 2017. These models contain the following characteristics:

- *Single node:* For the primary question of how solar generation impacts system operations and costs, the network was not modeled. Given the significant solar resource across the country, this simplification may underestimate the value of solar compared to other technologies that must be located far from existing load centers.
- *Partially stochastic:* Variation in hydro inflows, the largest source of uncertainty in the system, was modeled using scenario analysis. Solar insolation, wind speeds, demand, and fuel prices were modeled deterministically and sensitivity analyses were conducted for demand and fuel prices.
- *Hourly periods:* Hourly periods were used for both model years in order to capture the correlation between solar production and electricity consumption.

The objective function of the unit commitment model is the minimization of costs – variable, fixed, and penalties for non-served energy – over all periods. Following the method presented by [31], this model includes constraints pertaining to meeting demand and spinning reserve requirements, operating requirements and ramp rates of each generating unit, and minimum monthly reservoir levels that must be maintained.

Further information on the model formulation can be found in [32]. This work was done with the General Algebraic Modeling System (GAMS) and solved as a mixed integer linear problem using the CPLEX interior point method.

3.2. Economic analysis

The economic value of adding solar PV is based on changes in the total annual production costs, including operating and annual fixed costs. The annual savings from added solar PV in each scenario is the difference in the total system production cost with respect to the base case with no PV in each tested year. Here we are taking the perspective of the system operator, not a particular investor or generation utility. When computing costs, a 20-year lifetime and 5% discount rate have been assumed and we did not account for PV degradation over the project lifetime or the operation and maintenance costs of the solar plant. The economic value (\$/W) of added solar is calculated ex-post as the net present value of avoided costs spread over the lifetime of the plant divided by the size of the plant. Eq. (1) contains the mathematical formulation to calculate the value of solar in each scenario. C_{Base} is the total annual cost for the base case, C_{PV} is the total annual cost in each PV scenario, r is the discount rate and y is the year of operation ranging from 1 to 20.

$$Value\ of\ solar = \frac{\sum_y \frac{C_{Base}-C_{PV}}{(1+r)^y}}{Size\ of\ PV\ plant\ [W]} \tag{1}$$

We compare these results with expected payments that a solar generator would receive from the Kenyan FIT of \$0.12 per kW h [33]. Again, the discounted payments over the life of the plant are divided by the size of the plant to derive a comparable value of \$ per W. This value provides a benchmark for policy-makers keen to promote solar power by providing insight as to whether the FIT is reasonable and, if so, over what range of PV capacities it is economically justified. If the payments from the FIT exceed the expected system-wide savings, investment in solar PV at that penetration level is not economical for the consumers, as they must pay the cost of the support scheme. If, however, the expected savings exceed the cost of the FIT, the consumers benefit from the corresponding solar penetration. In this method, we assume the cost savings from solar remain the same over the lifetime of the plant. This provides a baseline for the value of solar if no further cost-savings measures are pursued and allows us to avoid hypothesizing how the demand and generation mix may evolve over the next 20 years.

There are currently no major grid-connected solar projects being developed in Kenya. It is left open as to whether the Kenyan FIT is high enough to attract investment but, as a comparison, national renewable energy bids in similar developing markets in South Africa and India have achieved project bid prices of \$0.10 and \$0.15 per kW h, respectively [34,35].

3.3. Data and case studies

We used three data sets to represent the generation units available in 2012 and two possible generation mixes in 2017 (Table 1). The 2012 system is composed of seven hydropower plants, three geothermal plants, eight diesel and emergency power plants, and one cogeneration plant. National plans to expand and diversify the generation mix are based on ambitious goals to more than double current generating capacity by 2017. These efforts are focused on significant expansions of geothermal, coal, wind capacity as well as increased imports. With the exception of four new wind plants, new additions in 2017 are modeled as one plant per technology type. Given the high degree of uncertainty that all of these investments will be completed as scheduled, we used an alternative 2017 scenario to reflect the case where projects are delayed and demand growth is slower than anticipated.

These scenarios are:

1. *2012:* all plant and demand data reflect conditions as reported in 2012 by the system operator;
2. *2017 National Plan (NP):* generation mix and demand projections based on the government's Least Cost Power Development Plan (LCPDP) [6];
3. *2017 Slow Growth (SG):* demand based on historic annual growth rate, investments in hydro expansion are completed, half of planned geothermal investments are completed and the remaining demand is met through increased diesel capacity.

When possible, all technical and cost data for existing and planned projects are based on published information in the LCPDP [23]. Input parameters for the cogeneration plant were not available from the plant owner and, therefore, are based on data available for South Africa. Wärtsila 18V46 engines are used in five of the heavy fuel oil plants and General Electric PG6541B engines are used in the kerosene gas turbines [34]. Manufacturer's data on fuel consumption during start up and shut down and ramping rates were not available for the PG6541B engine. In this case, and for new diesel capacity in 2017, values for the 18V46 engine were used. Kenya's grid code mandates that operating reserves must be sufficient to meet demand if the two

Table 1
Total installed generation capacity in 2012 and 2017 simulated years (MW) [6].

Generator type	2012	2017	
		National plan	Slow growth
Hydro	733.2	765.2	765.2
Geothermal	202.0	1060.3	631.2
Gas turbine (Kerosene)	60.0	0	–
Diesel	455.8	796.8	885.0
Cogeneration (Bagasse)	26.0	26.0	26.0
Emergency power (Diesel)	120.0	–	–
Coal	–	600.0	–
Wind	–	435.5	–
Imports	–	600.0	–
Total capacity	1597.0	4283.8	2307.4

largest units are unavailable [35]. Due to insufficient data on the size of individual units for each plant, the spinning reserve requirement in the model was simplified to equal the capacity of the largest dispatched plant in each period.

Table 2 contains the operating parameters for each generator type. The maximum capacity of each plant is reduced to reflect power consumed for the plant's own use, *auxiliary load factor*, as well as periods when the plants are unavailable due to planned or unplanned outages, *outage rate*.

Table 3 contains the assumed costs of fuel, operation and maintenance, leasing, and annualized capital cost for each technology. Leasing costs are only applied to the diesel capacity provided by emergency power producers in the 2012 system and investment costs are only applied to new plants included in the 2017 scenarios. The cost of leased power is based on financial information provided in [2]. The cost of non-served energy for both 2012 and 2017 is based on the Kenyan Government's estimate of \$0.84/kW h used for planning to 2031 [6].

Hourly demand values in 2012 are based on actual loads experienced during the period July 2011–June 2012. The system operator provided these data for the purposes of this study. Kenya experiences a fairly stable load during the year with minimal seasonal variation and peak demand in the evenings. Based on end-use electricity forecasts in the LCPDP, peak demand in 2017 will reach 3230 MW, reflecting a very high annual growth rate [6]. Projected demand in the Slow Growth scenario, by contrast, is based on the continued historic growth rate of 6% annually, resulting in lower projected peak demand of 1743 MW in 2017. The hourly load for 2017 was estimated by increasing each 2012 value by a linear multiple equal to the ratio of 2017 and 2012 peak demands. This method has two shortcomings. First, as with any demand forecast, demand may not grow as expected, resulting in over- or under-estimates of peak demand. Second, this approach does not account for future shifts in consumption patterns that may change the shape of the load profile. For both 2012 and 2017 scenarios, hourly load values were increased to account for estimated transmission and distribution losses reported in the LCPDP, totaling 14.5% in 2012 and 12% in 2017.

The seven hydropower plants included in the 2012 and 2017 models consists of one run-of-river plant along the Sondu River, one reservoir hydro plant along the Turkwel River and five cascading reservoir plants along the Tana River. The plant owners provided data on the monthly minimum reservoir requirements, historic inflows, historic generation and maximum reservoir capacities. These data were used to validate the model results and ensure the simulated hydro plant operations are technically feasible and reflect actual historic operations. More information on the plant and reservoir characteristics and model validation is available in [32]. We used historic inflow data provided by the plant owners over the period of 1948–1994 to estimate the variations in annual inflows and the effects of inter-annual inflow relationship (e.g., a dry year followed by a dry year). In order to keep the model deterministic, the 2012 and 2017 models were run using each of the 47 annual data sets in sequence. We obtained an *average* hydrological year by averaging the solutions obtained for each individually simulated year. Representative *dry* and *wet* hydrological years correspond to solutions from the years with annual inflows in the lowest and highest 20th percentile, respectively.

Ground-based hourly measurements of global horizontal insolation (GHI) from 23 measuring stations collected over 2000–2002 were used to represent the solar resource in Kenya [1]. From these, we estimated the expected generation from a generic solar PV plant without specifying a particular location. A shortcoming of this method is that values averaged over multiple years and multiple locations tend to mask variability and uncertainty in estimated solar generation [32]. Similarly, hourly wind generation is modeled deterministically based on project design documents [41–43]. For both cases, we assume that existing hydro storage capability renders intermittency insignificant for the objectives of this study. As interest in solar and wind generation in Kenya grows, additional resource data may become available, providing greater accuracy in future studies.

Table 2
Operating parameter assumptions for each generation technology [6,36–38].

Generator type	Outage rate	Aux. load factor	Ramp rate (GW/h)	Fuel consumption		
				Variable (MJ/kW h)	Fixed (MJ/h)	Start Up (J)
Diesel	0.098	0.94	0.12	7.66	0.008	0.084
Kerosene GT	0.078	0.94	0.12	11.47	0.004	0.084
Geothermal	0.068	1	0.005	–	–	–
Cogeneration	0	0.98	0.13	41.83	0.042	0.042
Hydro	0.097	1	–	–	–	–
Coal	0.267	0.9	0.6	9.92	0.008	0.017
Wind	0	1	–	–	–	–
Imports	0.15	1	–	–	–	–

Table 3
Variable and fixed cost assumptions for each generation technology [6,39,40].

Generator type	Fuel cost (\$/GJ)		Variable O&M (\$/MW h)	Annual fixed O&M (\$/kW)	Annual capital cost (\$/kW)	Lease (\$/kW)
	2012	2017				
Diesel	16.9	14.6	9.0	62.5	176.6	40.8
Kerosene GT	19.4	–	12.0	11.8	–	–
Geothermal	–	–	5.57	56.0	461	–
Cogeneration	5.3	5.3	9.0	11.8	–	–
Hydro	–	–	0.0	21.3	533.8	–
Coal	–	3.4	4.3	69.0	359.7	–
Wind	–	–	0.0	28.1	288.3	–
Imports	–	–	5.0	29.6	60.3	–
Non-served energy			840			

For each simulated year, we ran eleven scenarios: one base case with no solar, referred to as the 0 PV case, and ten solar scenarios with installed PV capacity ranging from 100 to 1000 MW.

4. Results

4.1. Effect of solar PV in the 2012 power system

4.1.1. System operations

In the 2012 system the majority of demand is met through reservoir and run-of-river hydropower ("Hydro Res" and "Hydro RoR") and fuel oil plants. As solar capacity is added to the system, the optimal hourly schedule of conventional thermal plants is shifted to reduce total production from the most expensive plants and minimize additional ramping and start up costs.

Fig. 1 compares the generation profiles for a sample week under the 0 PV and 500 MW PV scenarios. Generation from fuel oil plants is displaced during the day by solar generation and during the evening by increased hydro generation. Unlike fuel oil plants, hydro plants can vary their output without increased costs from ramping or additional start ups and shut downs. Therefore, during the day output from reservoir hydro plants is reduced to avoid shutting down fuel oil plants only to restart them a few hours later to meet evening peak demand.

Notably, unmet demand (represented as "energy non-served", ENS) persists for a small number of peak hours, around 250 in the 0 PV scenario, consistent with the 238 load shedding events recorded during the same period by the Kenyan system operator. Because Kenya's evening peak demand does not coincide with periods of solar generation and all plants are already operating at maximum levels during peak hours, PV penetration does not reduce instances of unmet demand during these periods.

4.1.2. Total system costs

In 2012, reduced fuel consumption in fuel oil plants leads to reductions in system production costs. The discounted total savings over the lifetime of the solar plant (Fig. 2), are equivalent to the amount the system operator would be justified in paying a solar plant owner for each Watt maintained on the system. The first trend that emerges from this analysis is that solar PV displaces the most expensive generation technologies first, thus the investment value falls as the installed capacity increases. Second, the value of solar PV is highest in dry hydrological conditions when more production from fuel oil plants is required to compensate for reduced hydropower generation.

As installed solar capacity increases from 0 to 1000 MW, the economic value of solar PV based on avoided costs falls from $5.1 to $3.6 per W. For all hydrological scenarios, these values are higher than the total estimated payments the system operator would pay the solar generator based on the current FIT of $0.12 per kW h for grid-connected solar PV, indicating that the investment is economical for Kenyan consumers if the FIT can successfully attract investment.

4.2. Effect of solar PV in the 2017 power system

4.2.1. System operations

Under the **2017 National Plan** scenario (Fig. 3a), as solar is added to the system, daytime production from fuel oil plants is reduced as compared to the 0 PV case. However, production from these units is

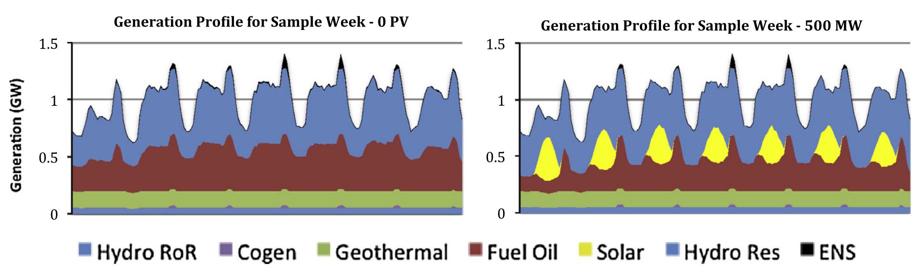

Fig. 1. Changes in system operations as a result of 500 MW solar penetration over a sample 1 week period in the 2012 scenario. Generation from diesel is displaced by solar generation during the day and by shifted hydropower generation during the evenings and night.

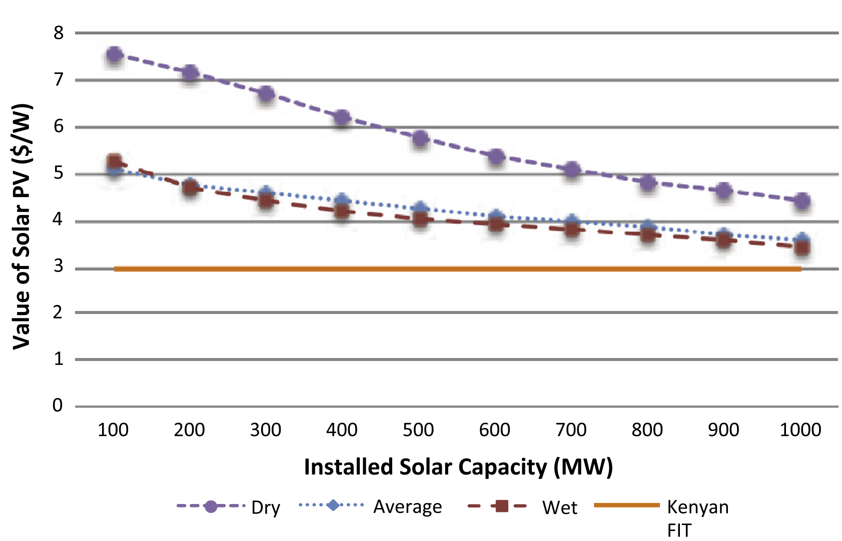

Fig. 2. Economic value of solar PV based different penetration levels in the 2012 simulated year. The value for dry years is higher the value for wet and average hydrological years for all penetration levels. The values for all penetration levels and hydrological conditions are higher than the expected payments from the Kenyan FIT.

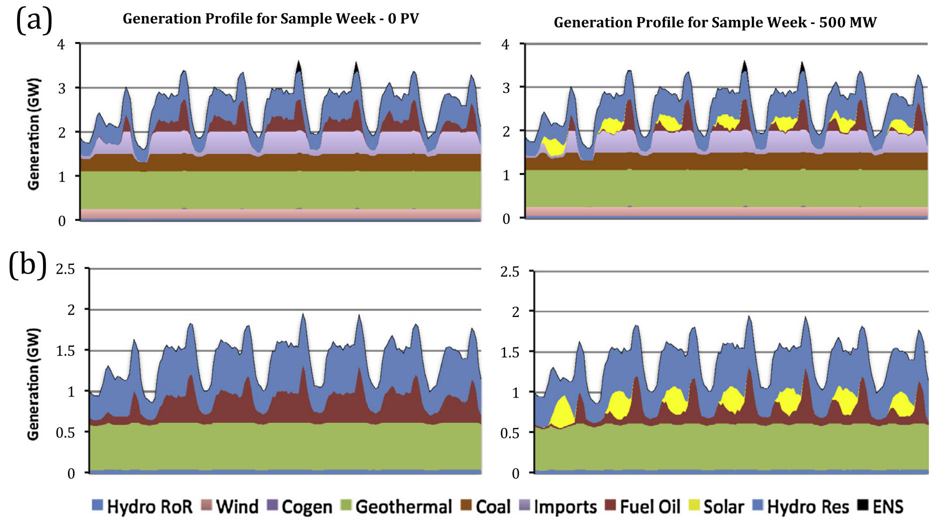

Fig. 3. Changes in system operations as a result of 500 MW solar penetration over a sample 1 week period in the 2017 (a) National Plan, (b) Slow Growth scenarios.

already reduced compared with the 2012 scenario, resulting in limited opportunities for solar to directly displace fuel oil generation. Since hydropower production is already maximized during peak demand periods, there is no possibility to shift hydro production from daytime to evening. As a result, higher levels of solar penetration now displace coal and imported sources during the day.

The **2017 Slow Growth** scenario (Fig. 3b) reflects the generation mix where many large-scale investments have not been completed and demand growth is compatible with historic growth rates. This generation mix may also be a more accurate reflection of what investments may be completed by 2017 since large-scale investments have historically faced significant delays and intermediate solutions in the form of increased diesel generation have been required to meet demand. As in 2012, added solar capacity displaces diesel output directly during the day and indirectly in the evenings through shifted reservoir hydropower production.

4.2.2. Total system costs

For the **2017 National Plan** (Fig. 4)**,** the discounted reduced cost analysis reveals a range of solar PV values of $2.7 to $1.9 per W. These values are significantly less than those found for the 2012 scenario due to expected changes in the generation mix between 2012 and 2017. The increased use of low variable cost technologies such as geothermal, coal, and wind and the low utilization of fuel oil plants eliminate the potential economic gains from displacing production from costly thermal generation with solar PV. The fraction of annual demand met by hydropower is reduced from over 45% in 2012 to 20% in 2017. As a result, there was little discernible difference in the economic value of solar between wet, average and dry years.

Finally, in the **2017 Slow Growth** scenario (Fig. 5), continued use of diesel generators provides an economic opportunity for solar PV to continue displacing output from these plants. The savings from reduced fuel consumption are lower than those seen in the 2012 simulated year because the most expensive kerosene-fueled plants have been decommissioned by this time. The resulting range of solar values is $3.4–$2.4 per W. Based on these values, up to 700 MW of solar PV would be economically justified based on expected payments from the Kenyan FIT. The expected payments decrease at high penetration levels because some solar production is curtailed in order to avoid curtailing production from hydropower plants.

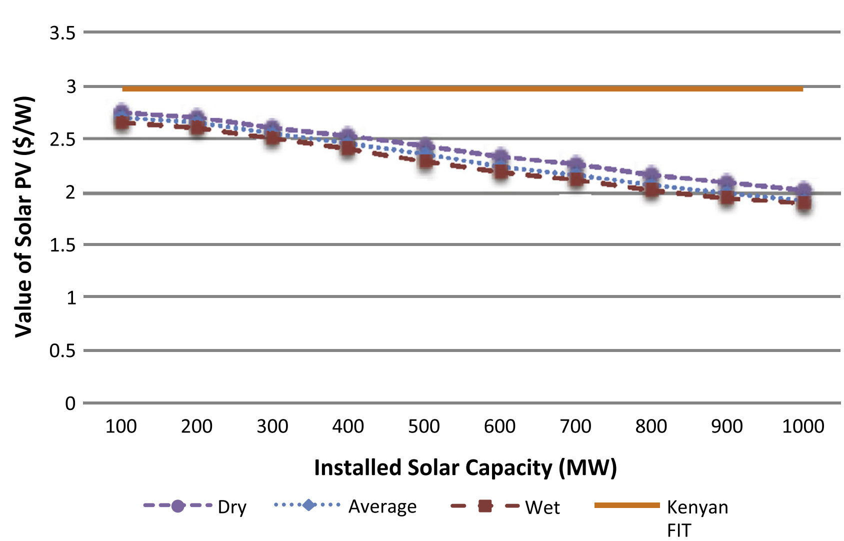

Fig. 4. Economic value of solar PV at different penetration levels in the 2017 National Plan scenario. For all penetration levels and hydrological conditions, the value of solar is below the expected payments from the Kenyan FIT.

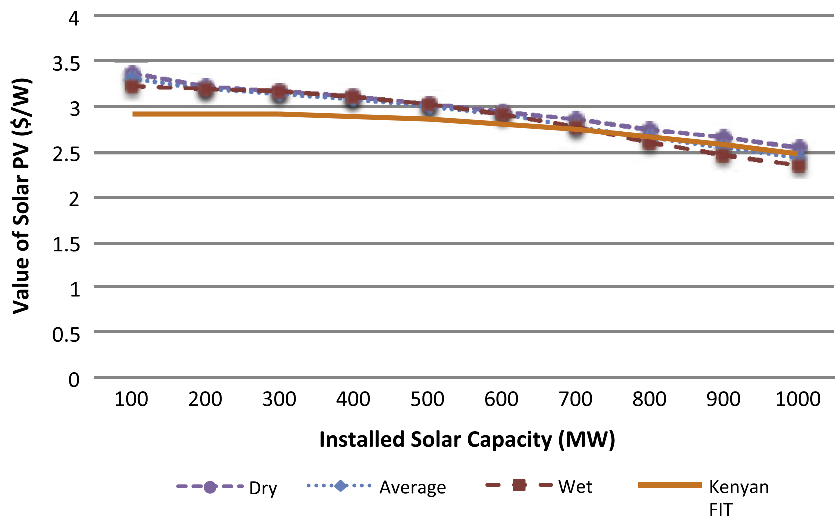

Fig. 5. Value of solar PV in the 2017 Slow Growth simulated year. The value of solar is above the expected payments from the Kenyan FIT up to 700 MW. At higher penetration levels, both the value of solar and expected FIT payments decline because solar is curtailed.

For both 2012 and 2017, a sensitivity analysis was conducted to determine the effects of changes in demand and fuel prices on the value of solar.[1] Since the 2012 system is already capacity constrained, the value of solar was found to be highly sensitive to demand, increasing significantly with increases in demand. In the 2017 scenarios, it is assumed that there is now sufficient capacity to meet demand without solar and the generation mix has only limited high cost fuel oil units remaining. Therefore, the value of solar was more sensitive to decreases in demand than increases. Since the value of solar is mostly based on avoided fuel costs, changes scaled almost linearly with changes in fuel prices. These results were also found to be sensitive to the performance of the solar plant over its lifetime and assumed discount rate. If output from the PV plant falls by 1% per year, the discounted value of solar decreased by as much as 8%. A 1% increase in the assumed discount rate results in a 6% decrease in the value of solar. However, the relative value of solar compared to estimated FIT payments would remain the same since we applied the same discount rate to both terms.

5. Discussion and conclusions

Solar PV may offer an economic alternative to the current use of fuel oil plants, which currently provide 38% of Kenya's electricity. Simulations of the 2012 and potential 2017 systems indicate that Kenya's reservoir hydro capacity could enable the integration of high penetrations of solar PV without the need for additional investments in storage. Proposed investments in geothermal, wind, and coal capacity drastically reduce the economic gains of solar PV capacity by 2017. However, the value of solar PV remains above expected payments from the FIT in 2017 if, as demonstrated in the 2017 Slow Growth scenario, plans for new plants are delayed and diesel plants are used to fill the capacity gap.

This study aims to provide high-level insights on the impacts and economic value of solar PV in the Kenyan system. The actual impacts will depend on the specific technical and economic characteristics of the project. The cost of required transmission infrastructure for proposed plants in the 2017 plans was not included in this analysis. If solar PV could be sited near major load centers, avoiding additional transmission investments, the economic competitiveness of solar in the future system would increase. The use of a multi-node model that includes transmission and distribution networks and stochastic representations of intermittent renewables in future work could increase the accuracy of calculated gains or costs of introducing solar PV in Kenya as well as provide insights on potential project locations. Changes in consumption patterns over time that result in a flattening of the load profile or daytime peaks that coincide with solar production would tend to favor the economics of solar PV over diesel. For investors and planners, uncertainty in demand growth would also favor solar PV over large-scale projects that require long lead times and supporting infrastructure. On the other hand, if long-term decreases in production due to degradation or higher discount rates are taken into account, the value of solar may decrease in $ per Watt terms compared to our estimates. Finally, further work on the value of storage in the Kenyan system may result in expansion planning scenarios that incrementally increase reservoir hydro and solar PV capacity in a coordinated fashion or favor concentrated solar power technologies.

While this analysis focused on the potential for solar PV in the Kenyan system, the results may be applicable to other sub-Saharan African countries, many of whom are faced with the same challenges: growing demand for electricity, insufficient generating capacity, and long lead times and extensive financial investments required for planned generation projects. As a result, many countries have turned to short-term expensive solutions such as diesel plants. Currently, all but 5 countries in Africa derive some portion of grid-connected capacity from these plants and over 28 countries have over 50% total capacity from oil plants, presenting a significant opportunity for solar PV [3]. Further, the other characteristics that may make solar PV a favorable option in Kenya – an abundant solar resource and large capacities of untapped reservoir hydropower – are also present across the continent. The same approach can be used to value investments in wind generation.

For policy-makers and international organizations eager to reduce carbon emissions and dependence on imported fuels, the deployment of hydro resources alongside intermittent renewables such as solar PV and wind may be a viable option for many sub-Saharan African countries. Solar PV may also be attractive in non-hydro based systems where diesel is the primary source of base load power. However, under current planning methodologies, where technologies are evaluated on an individual project-level, solar PV capital investment costs may appear too high to compete with those of coal, geothermal, hydro, and wind power. The

[1] Detailed results from the sensitivity analysis are available in [32].

system-level approach used in this study reveals that the economic value of a candidate technology is not a static metric but depends on the demand and generation assets of the particular system. As countries pursue higher levels of renewable energy deployment, continued development of new system-level approaches to planning will become increasingly valuable.

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