Essays on Infrastructure Development and Public Finance

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Abstract

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This dissertation focuses on the economics of infrastructure development and public finance. The dissertation is composed of three papers: The first analyzes the optimal solutions for supplying electricity to national economies from both domestic as well as distant energy resources using transmission systems that can connect the huge renewable energy resources of Africa. The results point to options for achieving substantial increases in the sustainable energy supply and for improving access to energy across the continent. The second paper models a comparative local and national electricity distribution planning in Senegal by examining the trade-off between access and costs. The third paper uses exogenous variations in rainfall across municipalities in Mali to estimate the causal effect of household income shocks on municipal-level tax revenues. It also exploits a national tax collection incentive policy to measure the impacts of rainfall variation on intergovernmental transfers.

Table of Contents

List of Figures

List of Tables

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Chapter 1

Energy, Climate, and Sustainable Development

1.1. Abstract

This dissertation focuses on the economics of infrastructure development and public finance. The dissertation is composed of three papers[1]: The first analyzes the optimal solutions for supplying electricity to national economies from both domestic as well as distant energy resources using transmission systems that can connect the huge renewable energy resources of Africa. The results point to options for achieving substantial increases in the sustainable energy supply and for improving access to energy across the continent. The second paper models a comparative local and national electricity distribution planning in Senegal by examining the trade-off between access and costs. The third paper uses exogenous variations in rainfall across municipalities in Mali to estimate the causal effect of household income shocks on municipal-level tax revenues. It also exploits a national tax collection incentive policy to measure the impacts of rainfall variation on intergovernmental transfers.

[1] Each of the papers represents an independent study.

1.2. Energy and Sustainable Development

Cheap and abundant energy has been both the fuel of and the catalyst for rapid growth in today's economically advanced nations. These countries, which largely comprise the Organization for Economic Cooperation and Development (OECD), have historically had access to vast resources of oil, natural gas, and coal, and these fossil fuels were used to build the capital necessary for these countries' economic development. Achieving rapid development in the rest of the world would require the nations in that category to start consuming energy highly intensively and to face potentially exponential rates of increase in that consumption. However, current awareness of how anthropogenic activities (especially fossil fuel consumption) lead to environmental degradation makes it clear that new approach for energy sourcing and new strategies for processing and distribution would be needed to achieve sustainable outcomes for such a scenario. The problems of poverty, shortage of potable water, environmental degradation, energy supply, and economic development are interrelated and global; therefore, their solution can only come through a coordinated effort by the concerned countries.

There is no doubt about how critical energy is to economic and social development, but, depending on how it is generated, transported, and used, energy can contribute to many environmental problems[2]. Conventional energy sources will not be sufficient in the long run both to meet the growth needs of the developing countries and to maintain the material growth of the economically developed nations. If innovative and affordable energy solutions are not found, the increase in energy demand from developing countries would, by process of logical progression,

[2] Winkler, H. (2005). Renewable energy policy in South Africa: policy options for renewable electricity. Energy Policy, 33(1), 27-38

hasten the exhaustion of existing fossil fuel sources. Possible solutions to the energy and development dilemma include the extension of the life of existing fossil fuels by increasing the efficiency of their use, an increase in the production and availability of renewable sources of energy, or a combination of the two approaches. Efficiency measures would be very effective, particularly in the transition period, but the final solution resides in expanding the share and availability of renewables. The first part of this dissertation deals with the development of renewable energy resources.

Among the 1.6 billion people who have no access to electricity, 99% of them live in developing countries, four out of five live in rural areas, and 32% live in the sub-Saharan African (SSA) region. If current policies and patterns continue without change, 1.4 billion people will still lack electricity by 2030[3]. The contradictions in African power generation include the continued use of costly diesel generators while low-cost hydro power remains unexploited and, second, the suboptimal regional trade in electricity amplified by the fact that, while some countries have unmet demand, others have cheap unexploited potential. Another important feature of the African power sector is its inability to supply large populations in addition to the industrial and mining sectors which are somehow adequately better served. These situations in many African countries lead to the following conclusion: one of the key bottlenecks preventing the development of the power sector turns out to be the economy. This suggests that the profitability of power utilities will be affected when the macro-economic situation deteriorates, and, indeed, that proves to be the case. And inversely macro-economic conditions cannot be improved without enough supply of energy

[3] IEA. (November 2002). International Energy Administration. World Energy Outlook (Second Edition ed.). Paris: International Energy Administration

Presently, with the exception of oil exporting countries, most African nations import petroleum which can cost them the equivalent of 50% of their export earnings, making it difficult to implement sound economic and environmental policies. In addition to the environmental cost of burning these fossil fuels in mostly inefficient plants, spending on petroleum corresponds to an opportunity cost of less spending on education, health, and infrastructure building among other critical activities. The issue of sustainable energy provision in Africa needs to take into consideration all of the above aspects which is done in the first and second paper of this dissertation (chapter 2 and 3 respectively).

1.3. Climate Change and Sustainable Development

All past reports of the Intergovernmental Panel on Climate Change (IPCC) have projected that, in the absence of emission control policies, global temperatures will increase by 2.8ºC on average over the next century, with best-guess estimates ranging from increases of 1.8ºC to 4ºC. As a result, the frequency and intensity of extreme weather events will increase in the twenty-first century (IPCC, 2007).

It is now widely accepted in the scientific and policy communities that an anthropogenic global warming and climate change is taking place due to the accumulation of greenhouse gas in the earth's atmosphere. The most expected consequence of global warming and climate change is the increase in frequency and intensity of extremes weather patterns. While all countries are expected to be affected in some ways, developing countries are seen to be the most vulnerable, because these are countries with warmer, tropical climates; worse initial macroeconomic conditions; higher income inequality; and lower governmental effectiveness. At local levels in sub-Saharan Africa, the change in the climate will be reflected in variations in rainfall patterns.

These rainfall variations will also directly affect infrastructures, human capital, and food production capacities.

The interest in the implications of climate change among governments and policymakers is thus increasing rapidly. Although research on climate change has gained in importance over the last few decades, most studies have focused on the aspects of direct effects, mitigation, and adaptation, and few have looked at the economy-wide fiscal impact of climate change. The second part of this dissertation fills this gap by examining the effect of climate change through its various transmission channels in the economy. Chapter 4 specifically looks at the effect of climate change on agricultural income and output, its effect on tax revenues, and its effect on intergovernmental transfers. Few studies look at the chain of effects that can develop under a climate-change scenario.

There is an enhanced need to reconsider the potential effect of existing public policies in the context of climate change, given that the latter is expected to increase the variation in local rainfall. From a public policy standpoint it is important to know the magnitude and implications of the varying effects that climate change may have. To achieve a sustainable level of social service funding in sub-Saharan Africa (SSA), countries, regions, districts, and municipalities need to be able to increase tax revenues from an expanding tax base. Focusing on the ultimate fiscal situations of the local authorities is important for future sustainable social service financing and public goods provision. The fourth chapter provides insight into agricultural income, taxes, and intergovernmental transfers all within a framework of climate change.

1.4. Chapter Summaries

Chapter 2[4]: The Economics of Clean Energy Resource Development and Grid Interconnection in Africa

This chapter models a continent-wide generation and transmission of renewable electricity. Renewable sources can meet the energy demands of African countries in the near- and long-term future. Generation and transmission costs are relatively lower for a continental trade scenario in comparison with the national Business as Usual (BAU) scenario. Coal and natural gas are feasible generation options, but they increase CO_2 emissions. There are strong economies of scale in continental High Voltage (HV) expansion.

The emerging picture of a short-term energy system in Africa relies on the development of hydro-power. In particular, the vast hydro potential of central Africa can be transferred or distributed to any place on the continent at a maximum cost of US$0.20 per kWh. The geothermal potential in East Africa is inexpensive and can serve as a base load, but it is limited in quantity and in its ability to meet the needs of countries outside this region. Hydro resources from Central Africa are competitive in West Africa, but, when the availability of inexpensive natural gas from Nigeria is considered, the connection of these two regions is less optimal in the long term. Although a high potential to develop power from wind is available on the coasts of Somalia, Morocco, and Tanzania, the relatively low capacity factors for these sites triple the transmission costs. However, wind energy represents a competitive, long-term energy source for

[4] This chapter is in review in the *Renewable Energy Journal* with the title "The Economics of Clean Energy Resource Development and Grid Interconnection in Africa". The listed authors in order are Aly Sanoh, Ayse Selin Kocaman, Selcuk Kocal, Shaky Sherpa, and Vijay Modi.

East Africa. Although good solar energy is available throughout most of Africa, transmission from the desert and Sahelian areas to other parts of the continent becomes feasible only in the long term, when solar investment costs decrease by more than 50% to compensate for the high transmission costs. In terms of strategic interconnection, it is more sensible in the short term to invest in transmission lines that distribute hydro power from Central Africa to Southern Africa and from East to North Africa.

Chapter 3[5]: Local and National Electricity Planning in Senegal: Scenarios and Policies

This chapter models a comparative local and national electricity distribution planning in Senegal. We found that at both the local and national levels, a high percentage (20-50%) of the currently non-electrified population lives in areas where grid expansion is more cost favorable than decentralized energy supply technologies. Expansion outcomes (costs and access) are very sensitive to demand levels and to the capital cost of medium voltage lines and transformers. The local level analysis reveals that, in the case of rural electrification, policies related to demand and grid-related costs are likely to have the greatest impact on increasing grid coverage. An examination at the national level reveals some economies of scale in terms of the average connection cost per household for grid extension. Outcomes are more sensitive to variability at the national scale than at the local scale. These sensitivities are observed in terms of both coverage and connection costs for grid expansion.

[5] A version of this chapter is published in *Energy for Sustainable Development 16 (2012) 13–25* with the title "Local and National Electricity Planning in Senegal: Scenarios and Policies". The listed authors in order are: Aly Sanoh, Lily Parshall, Ousmane Fall Sarr, Susan Kum, and Vijay Modi.

Chapter 4[6]: Climate change, tax revenue, and intergovernmental transfer in Mali

In this chapter I examined the effect of climate factors on households' contributions to tax revenues for the provision of public goods. I specifically looked at the effect of rainfall variations on municipal tax revenues in farming areas in Mali. I found that negative rainfall shocks reduce municipal level tax revenues; the effects are heterogeneous and the impact of these shocks falls principally on rural rather than urban areas. In comparison with nomadic and commercial areas, the agricultural zones are the most affected by these shocks; the poorest municipalities are also affected the most. In the context of intergovernmental transfers, I found that high tax revenue is rewarded with more government transfers; in these transfers, there is no political party targeting but an election cycle; here, election cycles have a greater impact than the attitudes and policies of specific political parties. Transfers have a lagging effect on future tax revenue. These results call attention to the importance of the policy context in which climate adaptation policies are designed. If climate change is expected to increase the variability of temperature and precipitation, it is important to know its unintended and indirect consequences that may occur. In this case rainfall not only directly impacts tax revenues through its direct effect on agricultural production, but it also goes a long way to affect the allocation of central government resources available for investment in public goods.

[6] This chapter is in review in the *Journal of Development studies* with the title "Climate change, tax revenue, and intergovernmental transfer in Mali".

Chapter 2

The Economics of Clean Energy Resource Development and Grid Interconnection in Africa

Abstract[7]

This paper analyzes the optimal options for supplying electricity to national economies from both domestic and distant energy resources using HV lines to transmit the substantial renewable energy resources of Africa. The questions that are addressed are as follows: How can the electricity demand of per capita economic growth be satisfied? How can electricity access be expanded beyond urban centers? Where are the resources with the highest quality and the lowest cost? What are the most appropriate technologies for optimal generation and transmission expansion? We found that, to meet the growing demand, Africa will need to provide 5.2 GW of new generation per year through 2025. This figure represents an increase of 65% from the 2010 level and will assist in connecting more than 11 million new customers per year through the development of a transmission network. The total discounted system cost is approximately 8% of the continent's GDP. Approximately two-thirds of the discounted system cost is associated with new generation, and the remaining one-third is associated with the development of the transmission network. From 2010 to 2025, trade expansion reduces the total system cost by 21% relative to the business as usual (BAU).

Keywords: Electricity, Planning, Economic Modeling, Africa

[7] This chapter is in review in the *Renewable Energy Journal* with the title "The Economics of Clean Energy Resource Development and Grid Interconnection in Africa". The listed authors in order are: Aly Sanoh, Ayse Selin Kocaman, Selcuk Kocal, Shaky Sherpa, and Vijay Modi

1. Introduction

The African continent has experienced a decline in both private and public expenditures in the power sector during the last decade. To address the short-term growth in demand, most countries have chosen to install small but expensive emergency thermal power generation units. These units are petroleum-driven plants that are affected by price variations in the world fuel market. Although this strategy may lead to an increase in electrification rates and assist in meeting the Millennium Development Goals (MDGs), this approach does not resolve the underlying lack of financing, profitability, and cost-effectiveness. The lack of investment in all three sub-sectors of generation, transmission, and distribution is the greatest challenge encountered by electric utilities in this region. The under-investment in the electricity sector is primarily a result of the low returns in the power industry, high debt costs, and weak financial performance. The low returns are further exacerbated by increasing fuel costs. Therefore, there is a need for new policies and institutions that can foster new investments in generation capacities and cross-country transmission lines to produce the energy that is necessary for development.

Although its energy consumption in general and electricity consumption in particular remain low (approximately 8% of global electricity consumption), Africa possesses immense energy potential [25]. The geographic and technical potential for renewable electricity generation are much greater than the current total consumption in Africa. Although hydro and geothermal resources are already highly cost-competitive, grid-connected PV and wind power could generate electricity at production costs that are competitive with those of current fossil fuel plants in the long term[8].

[8] In 2000, only 22.6% of the population in sub-Saharan Africa had access to electricity, compared with 40.8% in Asia, 86.6% in Latin America and 91.1% in the Middle East (Karekezi and Kimani, 2002). However, on the supply front,

The provision of low-cost electricity will be critical to the industrial development of the continent. Although every country in Africa has surplus energy resources, financing difficulties have prevented the vast majority of countries from being able to exploit this energy potential. Empirical evidence shows that historical electrification has followed an s-shaped curve and thus suggests that a massive investment is necessary to increase household connections (Figure. 2.1). Therefore, electrification would not differ for the remaining countries in Africa with low grid coverage. Continental grid expansion offers a cost-effective option for achieving universal electrification during the next 40 years.

This study builds on early studies of least-cost electricity access expansion in Kenya, Senegal, and various Millennium Village sites [15, 16]. The main purpose of this study is to provide necessary and valuable estimates of the least-cost grid expansion strategy for the energy-constrained countries of Africa to determine the extent of possible cost reductions resulting from sourcing less costly electricity sources across neighboring countries.

Electricity shortages or blackouts represent bottlenecks that constrain economic growth in most African countries. This situation is continuously aggravated by increasing price fluctuations for fuel, which is the primary energy for electricity source of many African countries. Therefore, the limited amount of available financial resources should be allocated to technological options that will have the greatest effect on both access rates and prices. The uncertainties surrounding increasing and fluctuating crude oil prices lead us to argue that identifying 30 to 50 of the greatest large-scale utility solar, geothermal, wind, and hydro generation schemes offers a viable

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Africa has vast untapped potential. The continent has one of the highest average annual solar radiations; 95% of the daily global sunshine above 6.5 kWh/m^2 falls on Africa during the winter.

and competitive option for investment. Solving the energy issue will require additional generation and transmission lines across the continent.

Rather than engaging in the country-by-country planning of generation and transmission, we develop a continent-wide model that considers the dynamic interactions among new projects in different locations. We develop a model that analyzes electricity integration costs across the continent through 2025. Modeling these generation and transmission possibilities will provide valuable information on how to improve the quantity and quality of supply in Africa and how to reduce total supply costs. The optimal grid network will present the most cost-effective interconnection system for the continent.

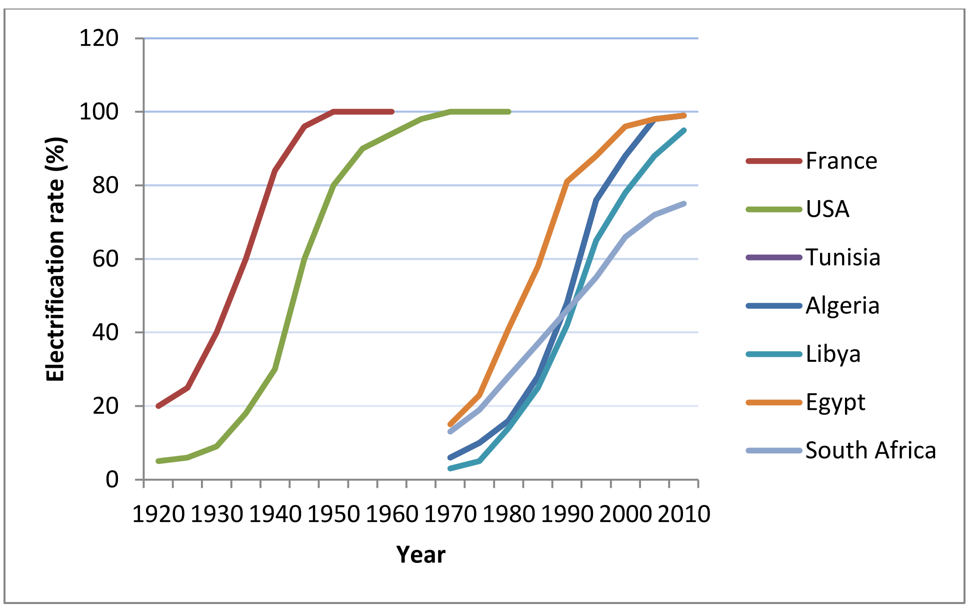


Figure 2.1: Historical electrification rates in selected countries

Numerous studies have analyzed the benefits of regional energy trade in Africa, but few studies have examined cost advantages on a continental scale. For example, Hammons [26] showed that the centralized operation of electric power systems can greatly improve economic efficiencies through economies of scale in hydro exploitation. Bowen et al. [27] found that the centralized and competitive dispatching of the SAPP (Southern African Power Pool) could save US$100 million annually. A more recent study by Graeba et al. [28] demonstrated that the benefit from trade expansion in Southern Africa could save US$110 million per year (5% of the total system cost) over a period of 20 years. Gnansounou et al. [29] found that a strategy of integrated electricity market in West Africa could reduce total system costs by 38%, which is similar to the 27% reduction that was found in a study that was conducted by Sparrow et al. [30] at Purdue University.

This study differs from its predecessors in the following ways. First, this research includes the entire continent of Africa rather than a particular region. Second, the study covers renewable expansion alone as well as in combination with fossil fuels attempting to show that clean energy sources have the technical, geographic and economic potential to supply both the short- and long-term energy needs of the continent. Third, this research specifically considers the costs that are associated with the intermittency of renewable resources. Fourth, this study introduces a more pragmatic approach to modeling demand projection. Fifth, this research uses transmission costs, which are a function of both distance and quantity transported.

The remainder of this chapter is organized as follows. Section 2 describes the methodological approach and develops an electricity demand model that accounts for the specificity of population growth, economic growth, and income elasticity in African countries. Section 3 explores the economic potential and cost of a renewable electricity supply, including solar, wind, hydro, and geothermal sources. In Section 4, we evaluate transmission costs. In Section 5, we design a continent-wide grid expansion based on differences in generation and transmission costs. Finally, we provide discussions and policy recommendations in Section 6.

2. Methodological Approach

The model begins by projecting demand growth through 2015, 2020 and 2025, as detailed in the demand model in *Appendix 2A*. We developed a model that accounts for economic and population growth, income elasticity, and current and target access rates to electricity across countries. Using GIS analysis, we identified the most exploitable sites based on the available potential of hydro, geothermal, solar, and wind energy sources. We identified the 30 to 50 largest and highest-quality energy resources (hydro, solar, geothermal, and wind) that can resolve the short- and long-term energy supply issue for the continent.

The current and projected differences in generation costs are computed based on resource quality as characterized by its capacity factor, and we compute transmission costs as a function of the energy source (capacity factor) and the distance to load centers. This computation is performed using GIS analysis to determine the distance between every potential energy site and demand centers. The transmission characteristics and related costs are solely dependent on the distance and the capacity factor of the energy source.

Finally, the model reveals the most cost-effective way of meeting the projected demand requirement based on various available potential resources and costs. Other local generation sources which are introduced later include thermal (coal, natural gas, diesel and heavy fuel oil). The model links demand points to the least expensive and closest (in terms of transportation) energy resources.

2.1 Demand Modeling

Africa contains approximately 14% of the world's population but accounts for only 2% of its gross domestic product (GDP). Although the continent produces 7% of the world's total energy, it consumes only 3% of the total at a level of energy intensity that is twice the world average [13]. Within the context of this contradictory situation, the identification of the drivers of aggregate electricity demand is important for forecasting and estimating necessary investments. In the electricity literature [1], several empirical studies have found that the gross domestic product (GDP), actual and relative prices, urbanization, and climate factors are the main drivers of electricity consumption growth. These relationships have been analyzed at the macroeconomic (country-wide, economy-wide, or sectoral) and microeconomic (household and firm) levels. Al-Faris [2] and Narayan and Smyth [3] have modeled electricity demand as a function of actual price, the price of a substitute and real income. Nasr et al. [4] model electricity demand in Lebanon as a function of GDP proxied by total imports and temperature. Demand studies that have focused on the specific driving effect of GDP alone are reviewed by Jumbe [5] and Chen et al. [6]. In this paper, we aim to model electricity demand by considering economic growth, population growth, income elasticity, and access rate. The foundation of this study is the recognition that demand modeling in Africa suffers from the facts that both supply and demand are typically constrained. We use both an econometric approach to model past income elasticity and a pragmatic approach to consider projected economic growth, population, growth, and electricity access policy goals.

2.2 Income Elasticity of Demand

We first examine past trends regarding the relationship between electricity consumption and economic growth for Africa as a whole for the period from 1970 to 2009. For comparison purposes, we add other large, medium-income countries, such as Brazil, China, India, Indonesia and Malaysia, whose path of development is likely to be mirrored by Africa.

Figures 2.2a and 2.2b present several well-documented and accepted relationships in the energy literature [23]: the positive correlation between growth in per capita electricity consumption and growth in per capita income, the negative correlation between population growth and per capita income levels, and the negative correlation between income elasticity and per capita income levels.

Economic growth is expected to be positively correlated with growth in electricity consumption, whereas the direction of the causation is under contention [5]. In Africa, the difficulty of measuring the sensitivity of power consumption to income growth is related to the structural particularities of the diverse countries and the nature of the constrained supplies. We use a simple method of estimating income and price elasticity that is widely used in the literature, the log-log regression:

$$\log E_t = a + b*\log GDP_t + c*\log P_t \qquad (1)$$

$$\log E_t = a + b*\log GDP_t + c*\log P_t + d*\log GDP_{t-1} \qquad (2)$$

where b and c are the income and price elasticity, respectively; E_t and GDP_t are the per capita electricity consumption and per capita income level, respectively; and P_t is the price of electricity. Because of the lack of data, we estimate only the income elasticity using different measures of per capita GDP, but the results are for per capita GDP in PPP (Purchasing Power Parity) terms. We use the long-run elasticity from equation (2)[9].

To estimate elasticity for specific countries, we perform a time series analysis of 22 countries for the period from 1970 to 2009 using the World Bank World Development Indicators database. In equation (2), without prices, the dependent variable is electricity consumption per capita (in kWh), and the independent variable is GDP per capita in PPP terms (constant US$, 2005). In this analysis, we additionally control for the production shares of agriculture, manufacturing, industries and services (in % of GDP).

[9] Long-run elasticity=b/(1-d). The elasticities b and c that are specified in (1) represent the short-run; In equation (2), d indicates the speed of adjustment towards the long-run equilibrium.

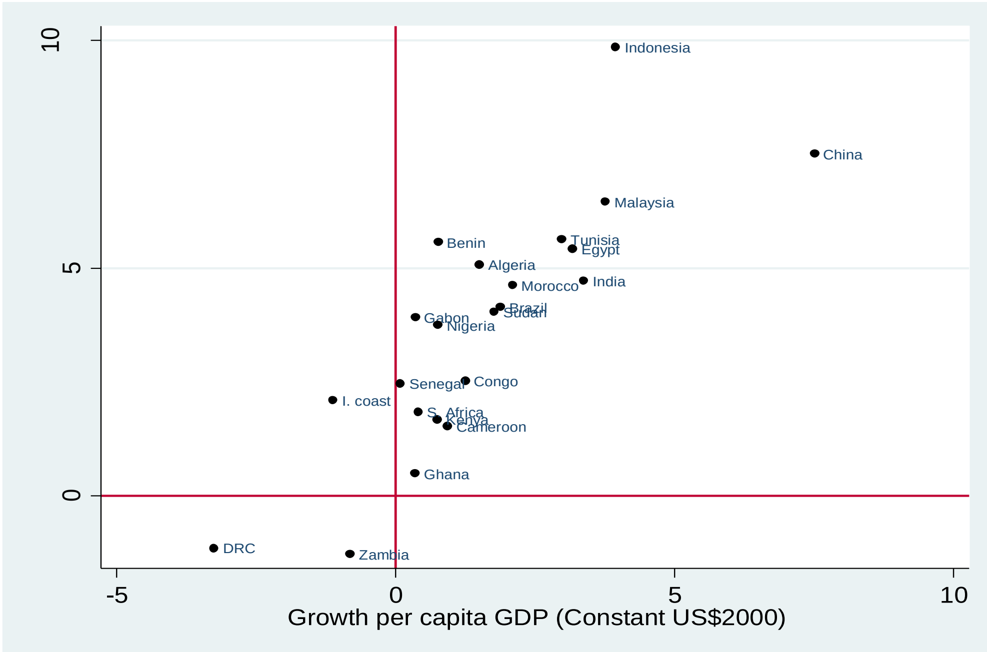


Figure 2.2a: Growth of per capita electricity consumption and growth of per capita GDP for selected countries

The results for income elasticity from both the short- and long-run equations (1) and (2) are above unity for all countries and comparable to other international findings [24]. This variation within African countries may be due to the small and heterogeneous nature of economies in this region. However, the variation across the countries is large and ranges from values greater than 4 for countries that include Ethiopia, DRC, and Mozambique to values of approximately 1.10 for countries that include Tunisia, South Africa, and Botswana. Demand for electric service is highly income-elastic in Africa. Countries at different levels of income differ in electricity consumption. Brazil, China, India, Indonesia, and Malaysia have elasticity between 1.5 and 2.

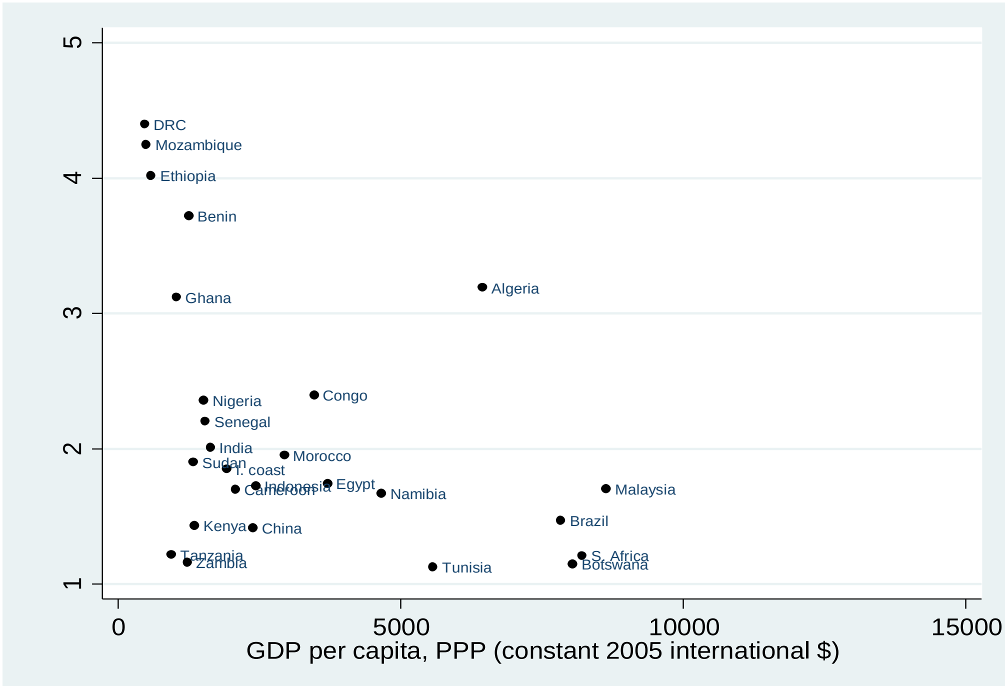


Figure 2.2b: Income elasticity of electricity consumption and per capita GDP for selected countries

2.3 Demand Projections

The unique characteristics of African countries make demand forecasting particularly challenging. As a pragmatic approach, in this paper, we assume that universal (100%) electrification can be achieved by 2050 by countries with at least 60% current electrification and that countries below this level can achieve at least 80% electrification[10]. Assuming that supply will not be a limiting factor and that universal electrification is possible, we estimate a value of per-country demand growth that is higher than what is typically reported in the literature.

A general expression of the annual electricity consumption growth (%) is given by equation (3):

[10] Although universal electrification is the ultimate goal, we assume that 10 years will not be sufficient to achieve such a goal for countries with a current electrification rate of less than 60%. However, for a longer planning horizon, such as 40 to 50 years, the achievement of this goal is possible.

$$ACG = e^{ln(TPC/CC)/T} \qquad (3)$$

where TPC (in MW) is the total projected consumption at year T (2015, 2020 and 2025), CC (in MW) is the current electricity consumption at year zero (2010), and T (number of years) is the time horizon. For large, inter-country energy projects, longer time horizons may be justified. Nevertheless, we use two time horizons: the short-term horizon (2010-2015) and the long-term horizon (2015-2025). For the projected country population growth rates, we use the estimates of the UN Population Division medium variant projection (Figure 2.3a); for the projected country economic growth rates, we specified a convergence economic growth model that relates the GDP growth path of every African country to that of the United States (Figure 2.3b). This procedure produces an annual GDP growth that reflects the fact that the growth of low-income countries is more rapid than that of high-income countries. See *appendix 2A* for further details pertaining to the demand model.

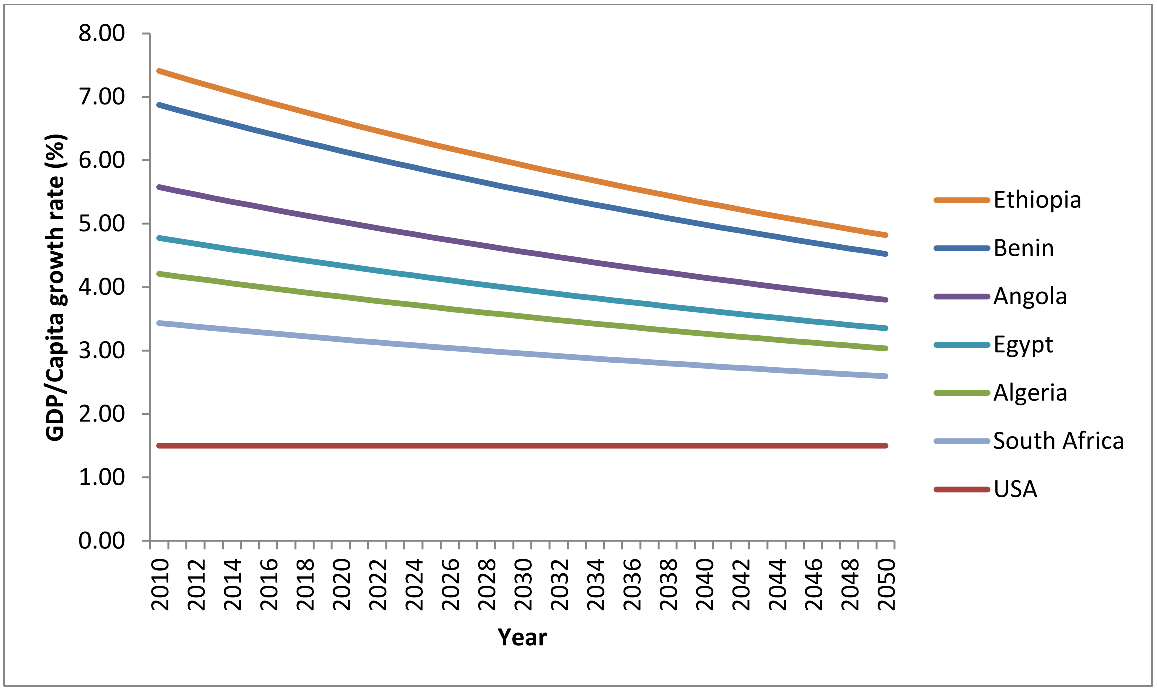


Figure 2.3a: Projected annual per capita GDP growth rate for selected countries from 2010 to 2050

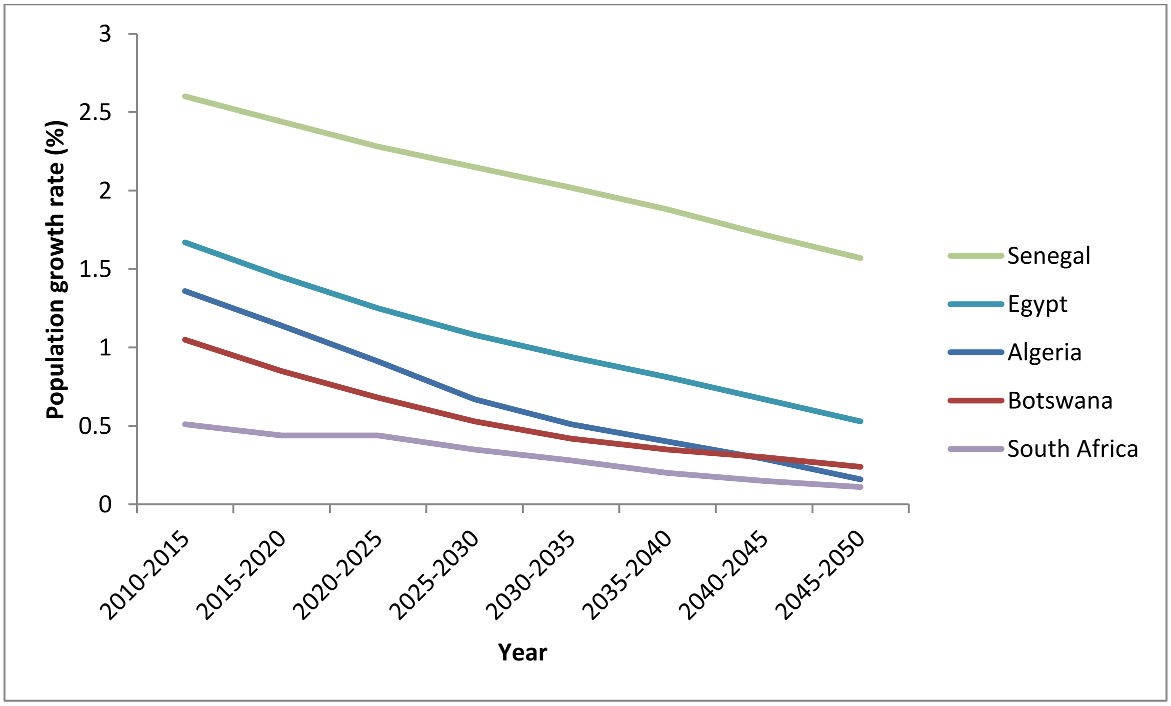


Figure 2.3b: Projected annual population growth rate for selected countries from 2010 to 2050

Our results show that the regional electricity consumption is expected to grow more rapidly than conventional estimates due to the following key drivers. First, the current low level of per capita GDP provides significant room for growth in per capita GDP, which falls in the range of 3 to 8% annually. This high economic growth is expected to drive per capita electricity consumption. Second, the best projections of population growth and urbanization rates are estimated at approximately 1-4% and 60%, respectively. High population growth combined with high urbanization will cause electricity consumption to increase, particularly in the residential and commercial sectors. Third, with less than 40% of the population connected to the grid, there is vast potential to expand grid access to all rural areas. Existing industrial customers that generate their own energy or customers with unmet demand could also be brought back into the grid. Fourth, with rapid economic growth, customers are expected to increase electricity consumption to a certain point as a result of the use of appliances, but the estimation of this household income elasticity of electricity consumption for developing countries poses many challenges because electricity demand is supply-constrained with severe rationing and constant blackouts. In this study, at the country level, we use an income elasticity value of 1 for all other countries except for those in our 22-country time series data analysis, which showed that the electricity consumption of most African countries has grown at a rate that is close to or greater than the rate of GDP growth.

Africa’s installed capacity is only 117 GW, which is supplied with 64% thermal and 36% hydro power. This installed capacity is insufficient, and the transmission and distribution capacities are also limited. In addition, there is a large amount of unmet demand because of the low electrification rate. In the absence of a supply constraint, Africa’s current population of 1.030

billion and electrification rate of approximately 40% translate into an expected average per capita GDP growth of 5%, an average population growth of 2% and an average electricity consumption growth of 7.8%. The total installed capacity in 2050 is projected to be 1,017 GW (or 6.7 million GWh). This demand will be driven by countries with low per capita GDP and low electrification rates, such as Burkina Faso, Burundi, Malawi, Tanzania, and Uganda, all of which will experience annual consumption growth of more than 10%. In contrast, high-income countries with high electrification rates, such as South Africa, Egypt, Algeria, Libya, Ghana, Morocco, Mauritius, and Tunisia, will experience less than 4% annual growth in consumption. In this variety of trends, South Africa and Egypt will remain the largest drivers of electricity integration across the continent. These two countries represent 30% of the projected 2050 capacities.

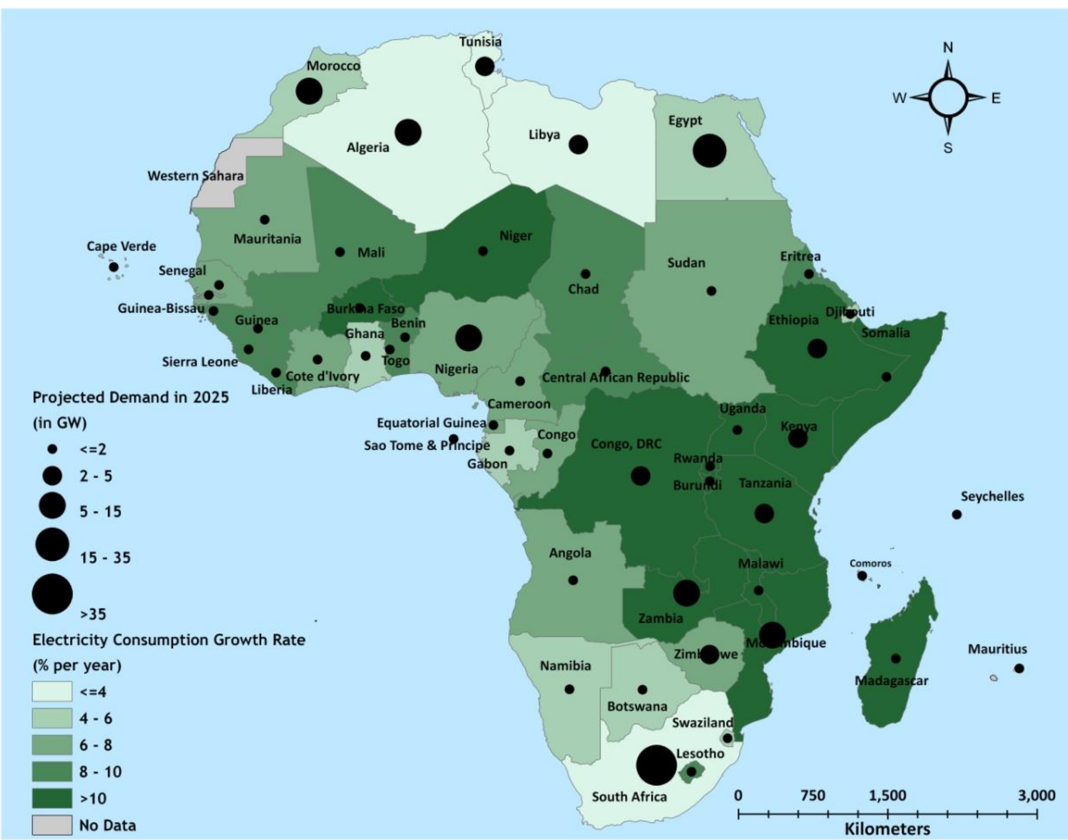


Figure 2.4: Annual electricity consumption growth rates and projected demand in 2025

3. Supply

3.1 Supply Potential

Africa is known for its abundant resources, which include energy resources (Figure 2.5). Although solar energy is almost uniformly available, other resources are highly uneven across the continent. For example, oil and gas potential tend to be concentrated in northern and western Africa. Hydro potential is found in central and eastern Africa, whereas exploitable coal is primarily located in the southern region [7]. Geothermal energy potential is found in the eastern region. Because every country has some solar, hydro, and wind potential, the question of interest concerns how many of these resources are technically and economically available for exploitation. In this paper, we estimate the available economic potential for solar, wind, geothermal, and hydro power for each country.

We use estimates from Piet et al. [11] (*see Appendix 1B* for their methodology and data sources). Many countries are already dependent on their hydro resources. An enormous amount of economically exploitable, inexpensive hydro resources are distributed across the continent: more than 50% of these resources are found in central, eastern and southern Africa, and 25% of these resources are found in northern and western Africa each. The hydro potential at Inga Falls is the greatest and the least expensive. With an average solar irradiation of 5-6 kWh/m2/day, solar energy is uniformly used but limited to small-scale applications. The countries with the greatest solar potential are Libya, Algeria, Niger, Mali, Chad, Ethiopia, Sudan, Tanzania, Angola, DRC, and Nigeria. The highest available intensities are found in the desert and Sahel areas. Wind energy has not been traditionally pursued on the continent, with the exception of its application for small-scale water pumping, but Egypt and Morocco have installed capacities of 68 MW and 54 MW, respectively [12]. Somalia, Sudan, Libya, Egypt, Mauritania and Madagascar have high potential for on-shore wind power. Although the overall potential for geothermal energy is smaller than that of other resources, this resource can be used in some countries, such as Kenya, Tanzania, and Morocco, where 1-5 GW are exploitable.

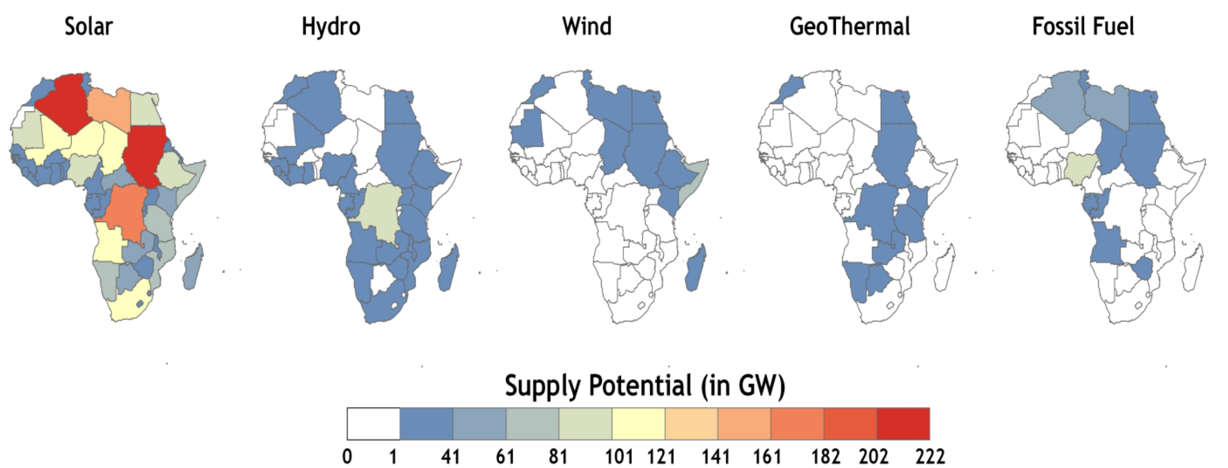


Figure 2.5: Countries' supply potential per resource (in GW)

3.2 Supply Costs

Several generation technologies can be used to supply electricity in Africa. Among the thermal options (coal, natural gas, and diesel), the choice of an optimal generation plant will depend on a plant's size, characteristics, and cost in addition to its fuel availability and price. A critical issue to address when developing these thermal options will be their cost-effectiveness compared with hydro or geothermal options, which can be easily used for base load generation.

We acknowledge that the assessment of the relative costs of various energy technologies is more complicated than our simplified methodology below. First, with respect to a continental grid connection, it is difficult to compare technology costs across various countries with different currencies and policy contexts. Second, although the cost of renewable energy is heavily influenced by site characteristics, thermal options are also strongly influenced by fuel prices both of which are hard to predict. For the thermal option, the fuel cost is likely to be the largest component of the kilo-watt-hour cost.

Supply is first modeled by quantifying the role of renewable energy, particularly geothermal, solar, wind, and hydro power. The cost of renewable resources is expected to decrease significantly in the medium term. In this study, we will not consider domestic or offshore applications of solar and wind, although both potential applications may be relevant in the African context. Rather, we focus on onshore, centralized, grid-connected solar and wind power[11]. Because of the intermittent nature of these two energy sources, they may require

[11] These systems are medium- to large-scale systems (from 100 kWp to many MWp) that are installed on the ground in areas with few competing land use issues.

additional storage[12] or back-up capacities. Therefore, we assume a storage cost of approximately 0.02-0.04 US$/kWh for the use of these sources as base load providers [13, 14]. We assume a module cost of 3-6 US$/Wp for solar power and a US$1915/kW investment cost for on-shore wind turbines [18]. The annual operation and maintenance cost is 3%. The annuity factor (0.11) is calculated based on a 10% interest rate and a 20-year equipment lifetime. Most of the pre-feasibility studies of hydro costs in Africa are outdated; therefore, we assumed an investment cost of 1000 to 4000 US$/kW for capacities greater than 250 MW [17]. We compute the levelized cost of electricity (LCOE[13]) production at each site by annuitizing the investment and O&M costs and dividing it by the annual energy output[14]. We also assume the possibility of scaling up power production with the current fuel mix of countries, considering the cost of the weighted averaged generation cost per technology. All costs remain constant during the planning horizon, although future trends are downward and may change during the roll-out phase. Hence, our figures could be considered upper-bound estimates.

[12] For these technologies to contribute as baseload, they will require storage capacities of up to 12 to 15 hours.

[13] The LCOE is the present value of expected costs (capital, operating, maintenance, and fuel) over the lifetime of a power plant divided by the discounted stream of power that is generated during the same period. The generated power is determined by the capacity factor.

[14] The annuity factor is calculated as follows: $a = \frac{r}{1-(1+r)^{-LT}}$, where r is the interest rate and LT denotes the lifetime. The investment cost is upfront, and we maintain a constant O&M cost over the lifetime of the project and thus neglect to consider that this cost may increase over time.

Technology	Investment Cost ($/kW)
Solar thermal	3,407
On-shore Wind	1,915
Photovoltaic	5,266
Geothermal	4,097
Hydroelectric (~10 MW)	2,400 – 5,760
Hydroelectric (~75 MW)	1,476 – 4,380
Hydroelectric (>250 MW)	1,080 – 3,720

Source: EIA (2009), EU (2008). Author adjusted.

4. Transmission

4.1 Energy Sources (Sites)

The best renewable energy sites in Africa are often located far from demand centers; thus, their exploitation feasibility is conditional on the construction of expensive new transmission networks. There is a tradeoff between expanding current fuel-based production and exploiting these distant, inexpensive resources. However, the estimation of these transmissions costs is difficult. These costs are important because they ultimately determine whether a continent-wide grid connection is economically efficient. Country A will import from country B only if the generation and transmission costs from country B are less than the generation cost in country A.

Potential supply sites are connected by HV transmission lines using length estimates of the shortest, most direct distance between them[15]. We do not model the expansion from current existing inter-country HV lines because of the lack of reliable detailed geographic information and difficulty of modeling the engineering aspects. To compute transmission costs, we first identify the best sites for solar and wind, to which we add the best sites for hydro and geothermal (Figure 2.6). For solar, we consider only sites that have irradiation figures that are equal or greater than 5 kWh/day. For wind, we consider only class 4 wind and above. These preferred sites are based solely on the quality of available resources. We select solar and hydro sites that are suitable for large-scale and year-round operation but do not consider those that are located in unsuitable areas, such as agricultural lands, residential land (population centers), or water and protected areas.

[15] Only HV lines are considered in this study, although some MV lines may be needed in certain countries. We model only between-country transmission lines over long distances.

Figure 2.6: Selected best sites for renewable production

4.2 Transmission Costs

The costs of transmission from the generation sites to demand centers depend on the capacity, distance and related power losses in the lines. We choose transmission in ways that minimize both the costs and the system unreliability (voltage drops). The characteristics of the transmission line (AC or DC and voltage level) are established as a function of capacity and distance. In our cost calculations, for a typical underground DC cable transporting 1 GW, we assume investment costs of US$ 1.2 million per km, an energy loss of 3.5% per 1000 km, a cost of US$120,000 for two stations at both end of the line, a 40-year transmission line lifetime, and a 10% interest rate [17,18,19,20,21]. These assumptions yield a transmission cost of US$ 0.027 /kWh/1000 km for transporting 1 GW without losses. Table 2.1 presents transmission characteristics as a function of distance and the quantity to be transported. HVAC technology is optimal for low capacities over short distances, whereas HVDC technology is optimal for large capacities over long distances. Estimates of transmission line and station investment costs with losses are presented in Table 2.2. For both AC and DC transmission, the annual operation and maintenance costs are set at 2% of the total capital cost [22]. For all possible transmissions, we compute the levelized cost of electricity delivery as a function of distance and a capacity utilization factor that is equal to the capacity factor of each source.

	10 MW	**50 MW**	**100 MW**	**500 MW**	**1000 MW**	**2000 MW**	**3000 MW**
10 km	33 kV AC	138 kV AC	138 kV AC	345 kV AC	500 kV AC	765 kV AC	200 kV DC
100 km	66 kV AC	138 kVAC	230 kV AC	345 kV AC	500 kV AC	765 kV AC	400 kV DC
250 km	230 kV AC	138 kVAC	230 kV AC	345 kV AC	500 kV AC	765 kV AC	500 kV DC
500 km	200 kV DC	138 kVAC	230 kV AC	500 kV AC	500 kV AC	765 kV AC	600 kV DC
750 km	200 kV DC	230 kVAC	230 kV AC	500 kV AC	500 kV AC	765 kV AC	600 kV DC
1000 km	200 kV DC	200 kV DC	300 kV DC	500k V AC	765 kV AC	765 kV AC	600 kV DC
2000 km	200 kV-DC	300 kV DC	400 kV DC	500 kV DC	500 kV DC	765 kV AC	800 kV DC

Table 2.1: Transmission characteristics (AC or DC and voltage level) as a function of distance and capacity

Transmission Type	Investment Cost (thousand US$/km)	Line Losses (%/1000 km)	2 Stations (thousand US$/MW)	Station Losses (%/station)
HVAC				
132 kV	90	17	40	0.2
220 kV	192	14	40	0.2
400 kV	200	12	40	0.2
600 kV	350	10	40	0.2
HVDC				
800 kV-OHL	384	3	120	0.7
600 kV-OHL	324	4.5	120	0.7
500 kV-OHL	300	5	120	0.7
400 kV-OHL	276	5.5	120	0.7

300 kV-OHL	252	6	120	0.7
200 kV-OHL	228	6.5	120	0.7
600 kV-UCL	1,200	3.5	120	0.7
500 kV-UCL	1,100	4.5	120	0.7
400 kV-UCL	1,000	5	120	0.7
300 kV-UCL	800	5.5	120	0.7
200 kV-UCL	680	7	120	0.7

Table 2.2: Investment costs Source: DLR (2009), DRL (2006), and Uwe et al. (2010)

5. Optimal Generation and Transmission Expansion

The rationale for grid interconnection in Africa is twofold: high-consumption countries do not have the highest supply potential, and an excessive number of small countries have small markets for which high investment is unfeasible. Therefore, integration enables high-consumption countries to have access to cheap resources outside of their borders and small countries to develop resources that they would not otherwise be able to exploit. Few studies have proposed grid interconnection options for Africa [7, 8]; other studies have focused on regional interconnection [9, 10]. In this study, we propose an interconnection that specifically accounts for countries' differences in generation costs and transmission costs.

The question of interest is as follows: given the projected demand, supply options and their respective generation costs, and transmission costs, what are the most viable interconnections, and what resources (hydro, geothermal, solar, and wind) can be moved around in the short and long term?

5.1 Methodology

We develop a simple regional investment optimization model that identifies the regional energy projects that are needed to balance the electricity supply and demand at the continental level. We use a linear programming model to determine the most cost-effective approach for the expansion of generation capacity at the lowest unit cost for the supply of regional power pools through cross-border trade. We use the general algebraic modeling system (GAMS) as the language in a linear programming model for optimization. We simply minimized the total discounted generation and transmission costs that are subject to demand and supply constraints. The main equations in the models are presented below:

The objective function to minimize

$$\sum_{i=0}^{105} . \sum_{j=0}^{46} . \sum_{t=1}^{15} \mathrm{GitXijt} + \mathrm{TijtXijt} \quad (4)$$

Subject to

$$\sum_{j=0}^{46} . \sum_{t=1}^{15} \mathrm{Xijt} \le \sum_{t=1}^{15} \mathrm{Hit} \ \forall i, \ i = 0,1,2, \dots \dots 105$$

$$\sum_{i=0}^{105} . \sum_{t=1}^{15} \mathrm{Xijt} \ge \sum_{t=1}^{15} \mathrm{Djt} \ \forall j, \mathrm{j} = 0,1,2,3, \dots \dots ..46$$

where $\mathbf{i}$ denote generation units and $\mathbf{j}$ denote demand nodes, $\mathbf{H_{it}}$ is the supply potential at generation unit $\mathbf{i}$ (MW) at time $\mathbf{t}$, $\mathbf{D_{jt}}$ is the demand to be satisfied at node $\mathbf{j}$ (MW) at time $\mathbf{t}$, $\mathbf{G_{it}}$ is the generation cost at unit $\mathbf{i}$ at time $\mathbf{t}$, and $\mathbf{T_{ijt}}$ is the cost of moving electricity from generation unit $\mathbf{i}$ to demand node $\mathbf{j}$ (\$/MW) at time $\mathbf{t}$. $\mathbf{X_{ij}}$ is the decision variable, which is the quantity of electricity to be shipped from generation unit $\mathbf{i}$ to demand node $\mathbf{j}$ (MW) at time $\mathbf{t}$. Despite its simplicity, this model has some advantages in terms of flexibility. First, the model enables the simultaneous minimization of both generation and transmission costs. Second, this model is sufficiently flexible to include numerous regulatory and institutional policies related to trade, such as national restrictions on import for energy security or tariffs on imports for revenue generation.

The levelized generation and transmission costs account for annualized investment costs, annualized variable and fixed operation costs, and the annualized maintenance cost for both generation and transmission. We use a real discount rate of 10% in all computations. Generation costs are characterized solely by the capacity factor of a source, whereas transmission costs are characterized by the distance between a source and a demand node. For the both the short-term (2015) and long-term (2025) horizons, the objective function in equation (4) is minimized to balance the electricity supply and demand at the continental level.

Transmission is modeled as a basic transport problem without considering all of the dynamics of load flows. This method of modeling allows for the simultaneous optimization of transmission and generation in the GAMS. The model is optimized for 3 periods of 5 years each between 2010 and 2025, but the cost results are aggregated for the 2025 horizon.

Further restrictions that are imposed on the model include the following:

1- Demand: We are concerned only with meeting new demand that results from population and economic growth and access policy goals. Thus, there is no replacement of existing capacities, even those that may be more expensive than the new available sources. Therefore, our cost results do not include the refurbishment of existing capacities, which are considered sunk costs. New electricity demand must be met in every period and at every location, but we do not allow for excess generation.

2- Supply: No country can develop more than 25% of its total potential (which is equally distributed among its sources) over a 20-year period. This restriction leads to more realistic results because it reflects the extra time that may be necessary to ramp up generation and transmission in Africa because of the continent's weak institutional and political environment.

3- Export and Import: Although there is no limit on the export potential of each country, high-income countries, such as Egypt or South Africa, cannot import more than 40% of their total demand, and low-income countries, such as Benin, cannot import more than 80% of their demand.

5.2 Results

5.2.1 Optimal Generation

The optimal generation result is displayed in Figure 2.7, and the associated regional distribution is presented in Table 2.3. The optimization adds a total of 77 GW by 2025. We found that, to meet the growing demand, Africa will need to provide 5.2 GW of new generation per year through 2025. This figure represents an increase of 65% from the 2010 level, which will assist in connecting more than 11 million new customers per year through the development of an extensive transmission network. West Africa will add 5.7 GW in new generation (or 7.5% of the total), with primarily hydro in Guinea, Nigeria, the Ivory Coast and Ghana, whereas solar will be in Niger. New generation in central Africa represents 23% of the total energy generation and will be exclusively derived from hydro in DRC, Congo, Cameroon, and Gabon. East Africa equally contributes 23% of the total energy generation, specifically hydro in Ethiopia and Sudan, wind in Somalia, and geothermal in Kenya and Tanzania. North Africa will add 12 GW, including 30% solar in Morocco and Egypt. In contrast, the contribution of solar energy is far greater in southern Africa, with 60% of the total addition of new generation from Zambia, Namibia, Botswana and South Africa.

	West Africa	Central Africa	East Africa	North Africa	Southern Africa	Total
Capacity (GW)	**10.82**	**3.95**	**5.06**	**45.57**	**51.61**	**117.01**
Consumption (Billion kWh)	34.42	12.96	18.63	187.36	260.47	
Thermal (%)	75.48	66.68	59.61	91.67	47.12	
Hydro (%)	23.28	32.47	46.95	8.33	37.08	
Gen. Cost (US$ cents/kWh)	0.31	0.22	0.20	0.37	0.13	0.246
New Generation 2015 (GW)	**1.199**	**4.805**	**5.085**	**2.803**	**4.376**	**18.267**
Hydro	1.199	4.805	3.593	0	2.329	11.925
Geothermal	0	0	0.378	0.816	0.219	1.414
Wind	0	0	1.114	1.689	0	2.803
Solar	0	0	0	0.297	1.828	2.125
New Generation 2020 (GW)	**1.705**	**6.205**	**5.982**	**3.761**	**7.068**	**24.721**
Hydro	1.267	6.205	3.889	0	2.566	13.926
Geothermal	0	0	0.504	1.089	0.292	1.885
Wind	0.000	0	1.589	1.807	0	3.396
Solar	0.438	0	0	0.865	4.210	5.513
New Generation 2025 (GW)	**2.814**	**6.655**	**7.233**	**5.567**	**11.902**	**34.171**
Hydro	1.334	6.655	4.185	0	2.740	14.914
Geothermal	0	0	0.504	1.089	0.292	1.885
Wind	0.000	0	2.544	1.925	0	4.469
Solar	1.479	0	0	2.553	8.870	12.903
Total	**5.717**	**17.665**	**18.300**	**12.130**	**23.347**	**77.159**

Table 2.3: New generation by region, planning period and source

5.2.2 Optimal Trade (Transmission)

The cost-optimal HV transmission expansion is depicted in Figure 2.8 (net quantity traded in MW and line voltages). A large electricity trade is made possible by countries that include DRC, Ethiopia, Cameroon, Angola, Guinea, Mauritania, and Morocco. Half of the total electricity that is traded is provided by these hydro sites, whereas solar accounts for a quarter of the total electricity from sites in Morocco, Egypt, Niger, Zambia, Namibia, Botswana and South Africa (Table 2.4). Substantial wind energy is offered for trade by Somalia and Libya. The small geothermal capacity in Kenya and Tanzania is cost-effective for trade in southern Africa. Among the regions, only central and East Africa can export to other regions. North Africa, West Africa, and Southern Africa trade only within regions.

5.2.3 Costs and Financing

The total discounted system cost is approximately 8% of the continental GDP. Approximately two-thirds of the overall discounted system costs are associated with new generation, and the remaining one-third is associated with the development of the extensive transmission network. From 2010 to 2025, trade expansion will reduce the total system cost by 21% relative to the business as usual (BAU) scenario, which is based on the projection of current historical average costs. The annual cost of 8 billion through 2025 is 21% less than the current energy spending (US$11.6 billion) on expensive thermal generation by individual African countries.

		2025		
		US$ in billions	Share of Total (%)	Share of GDP (%)
Trade Expansion	Total System Cost	**131.9**	**100**	**7.63**
	Generation	**82.9**	**63**	**4.80**
	Hydro	12.56	15	
	Geothermal	3.4	4.1	
	Wind	8.8	10.6	
	Solar	58.2	70.2	
	Transmission	**48.9**	**37.1**	**2.83**
	Hydro	21.5	43.8	
	Geothermal	1.9	4.05	
	Wind	11.5	23.5	
	Solar	14	28.6	
BAU	Total System Cost	**166.3**	**100**	**9.61**

Table 2.4: Trade expansion cost by the end of the planning horizon in 2025

5.2.4 Oil, Natural Gas, and Coal Scenario

The first part of this paper has been solely concerned with the supply of clean energy from hydro, geothermal, solar, and wind sources, whereas we now consider the development of thermal technologies given the abundance of some fossil fuels in some countries. Based on oil, natural gas, and coal reserves that existed at the end of 2005, according to Piet et al., and following conversion methods using current country production ratios, we estimate an oil potential of

47GW in Libya, 5GW in Egypt, 15 GW in Algeria, 45 GW in Nigeria, 11 GW in Angola, 8GW in Sudan and 3GW in Gabon. For natural gas, we estimate a potential of 44 GW in Nigeria, 38 GW in Algeria, 16GW in Egypt and 12GW in Libya. For coal, we estimate a potential of 255GW in South Africa and 3 GW in Zimbabwe. These annual energy potential values are based on 50 years of exploitation. We assumed a supply cost for natural gas at 11 cents/kWh, coal at 7.7 cents/kWh, and oil at 20 cents/kWh. We also add the restriction that no country can develop more than 25% of its total potential over 20 years, and we do not allow thermal electricity production to be exported.

In this scenario, the results indicate that Nigeria, South Africa, Algeria, and Zimbabwe can rely on total domestic electricity production. Nigeria has a mix of hydro and natural gas, whereas the total annual new electricity demand in South Africa and Zimbabwe is met with coal generation. Although solar is not more cost-effective in Egypt, the country remains dependent on hydro from Ethiopia in addition to its own natural gas electricity generation.

The total discounted system cost to meet total demand in 2025 is reduced from US$131.93 to US$94.47 billion or a 28% reduction relative to the clean energy scenario. This reduction primarily results from the replacement of the expensive solar option in the desert regions with cheap domestic fossil fuel electricity generation in Northern and Southern Africa.

Although the addition of fossil fuel technologies reduces the discounted financial cost by 28%, this addition increases total CO_2 emissions over the planning horizon by 1.099 billion tons. The cost difference of US$37 billion represents the implicit subsidy that would be needed to bring clean technology into parity with fossil fuels, with a cost of US$142 per ton of CO_2 avoided[16]. Equivalently it would require a tax carbon of US$ 142 per ton of CO2 to bring clean technology in parity with fossil fuels.

	Clean Energy Only		Clean energy + Fossil Fuels	
	Net Generation (GW)	Share of Total (%)	Net Generation (GW)	Share of Total (%)
New Generation by 2025	**77.159**	**100**	**77.159**	**100**
Hydro	40.765	52.8	27.899	36.2
Wind	10.667	13.8	11.785	15.3
Geothermal	5.184	6.7	1.909	2.5
Solar	20.541	26.6	3.596	4.7
Coal			20.393	26.4
Natural Gas			11.023	14.3
Oil			0.553	0.7
Total Cost in billion US$	**131.93**	**100**	**94.47**	**100**
Generation	82.97	62.9	53.70	56.85
Transmission	48.96	37.1	40.77	43.15

Table 2.5: Generation (GW), Technology Share (%), and Total cost for clean energy alone and in combination with fossil fuels

[16] This value is computed by taking the difference between the NPV of the total cost for the two scenarios divided by the discounted emission difference over 15 years.

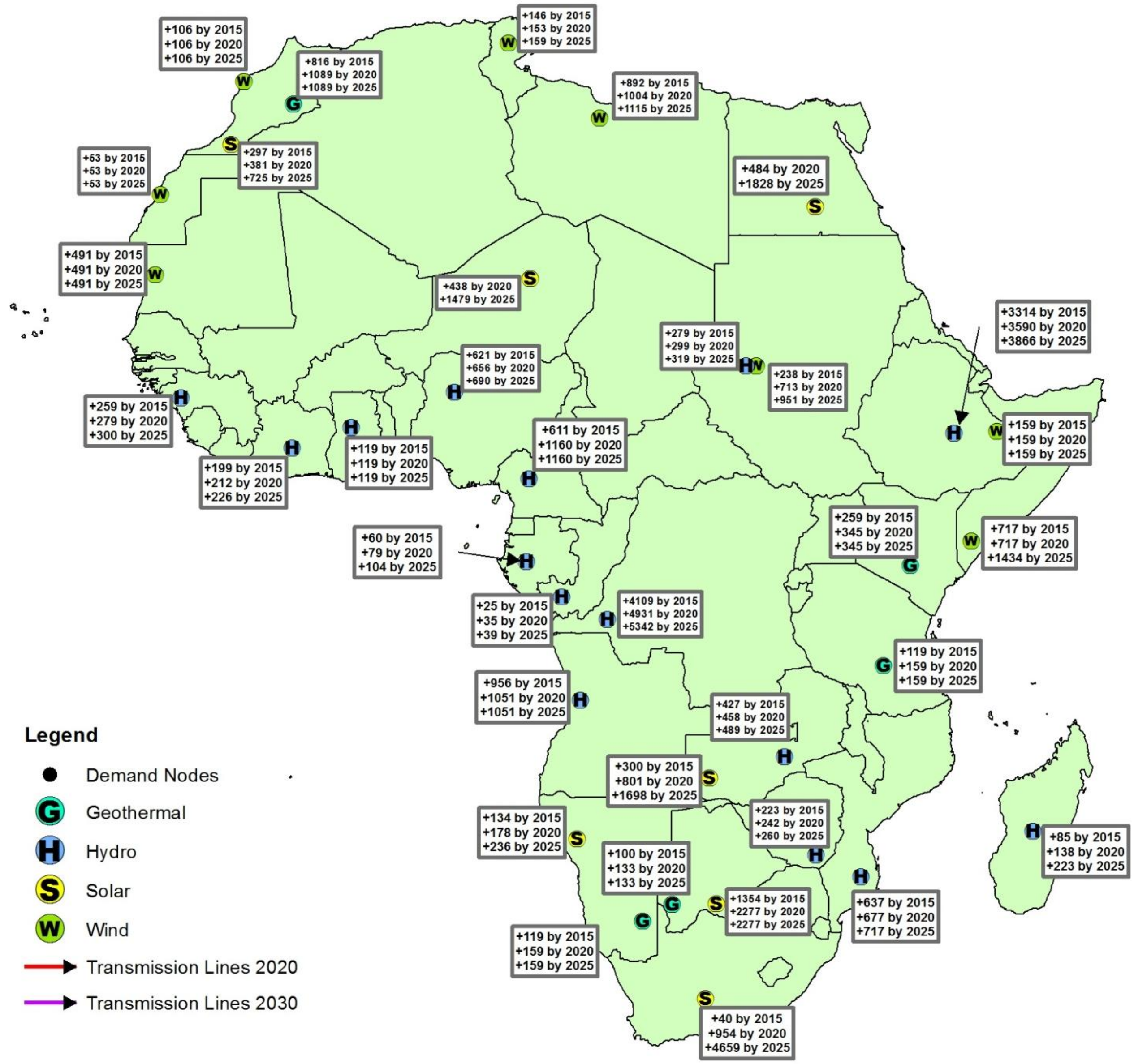


Figure 2.7: Optimal new generation expansion in MW to meet demand from 2010 to 2025

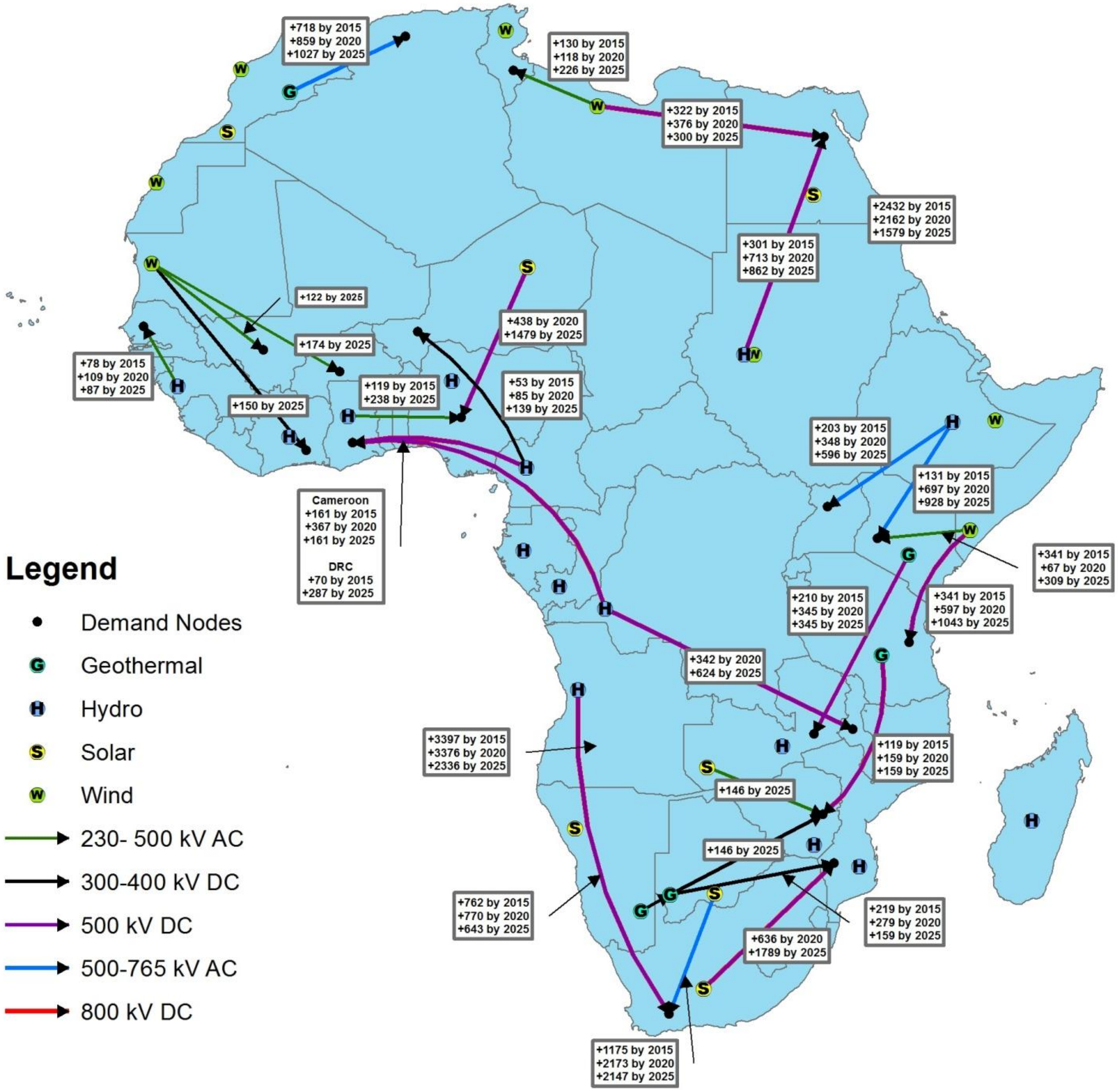


Figure 2.8: Optimal new dominant transmission and trade expansion in MW to meet demand from 2010 to 2025. The full optimal transmission with all the lines is provided in *Appendix 2C*.

6- Discussion

Our analysis of the various generation and transmission cost possibilities leads to the following general conclusions:

1- The emerging picture of a short-term energy system in Africa relies on the development of hydro-power. In particular, the vast hydro potential of central Africa can be shipped to any place on the continent at a maximum cost of US$0.20. For example, for the two largest energy consumers, the Inga Hydro cost is approximately US$0.13 in Egypt and US$ 0.09 in South Africa.

2- The geothermal potential in East Africa is inexpensive and can serve as a base load but is limited in its quantity and ability to meet the needs of countries outside of this region. For example, geothermal energy from Kenya has a cost of approximately US$0.19 in North Africa and is competitive with domestic sources.

3- Hydro resources from central Africa are competitive in West Africa, but when the availability of inexpensive natural gas from Nigeria is considered, the connection of these two regions is less optimal in the long term.

4- Although high wind potential is available on the coasts of Somalia, Morocco, and Tanzania, the relatively low capacity factors for these sites triple the transmission costs. Wind energy that is produced at US$0.085 in southern Morocco has a cost of approximately US$ 0.25 in nearby Egypt. However, wind energy represents a competitive long-term energy source for East Africa.

5- Although good solar energy is available throughout most of Africa, transmission from the desert and Sahelian areas to other parts of the continent becomes feasible only in the long term when solar investment costs decrease more than 50% to compensate for the high transmission costs.

6- In terms of strategic interconnection, it is more sensible in the short term to invest in transmission lines that ship hydro power from Central Africa to Southern Africa and from Eastern to North Africa.

Appendix 2A: Demand Model

This section presents the derivation of equation (3), which estimates the country-level projected annual consumption growth.

Variables:

ACG: Annual Consumption Growth (%/year)

CC: Current Consumption in 2010 (MW)

TPC: Total Projected Consumption in 2025 (MW)

T: Number of years

ECG: Existing Customer Growth (%/year)

NCG: New Customer Growth (%/year)

NCPR: New Customer Power Requirement (MW)

PCPR: Per capita Customer Power Requirement (MW)

P: Current Population

NC: New Connection (/year)

CER: Current Electrification Rate (%)

TER: Target Electrification Rate (%)

CGR: Combined projected economic and population growth rate (%/year)

IE: Income Elasticity

$$ACG = e^{ln(TPC/CC)/T} \quad (3)$$

$$TPC= CIC*ECG^{T} + \sum_{n=0}^{T} NCPR * NCG^{T-n} \qquad (5)$$

NCPR= PCPR*NC

NC= P (TER-CER)/T

ECG=NCG= [CGR]*IE_k

CGR= $PEG_K + PPG_K$

To compute PEG_K, we specified a convergence economic growth model that compares the growth path of each African country to the GDP growth path of the United States. This procedure produces an annual GDP growth that reflects that the low-income countries will experience higher future growth relative to the high-income countries. We use the 2010 purchasing power parity GDP per capita data (in $USD constant 2010 prices). We begin with a per capita GDP of $46,000 in 2010 in the US, which grows hereafter at 1.5 percent per annum. Any African country k begins at GDP_k (PPP adjusted country GDP in 2010 $USD).

To compute the per capita GDP growth for a given African country k, we define the following:

$logGDP_k(t) = ln[GDP_k(t)]$

$$logGDP_{USA}(t) = \ln[GDP_{USA}(t)]$$

Thus, the gap between country k and the USA is as follows:

$$logGAP_{USA\text{-}K}(t) = logGDP_{USA}(t) - logGDP_{k}(t)$$

The annual growth rate of country k is then defined as follows:

$$logGDP_{k}(t+1) = logGDP_{k}(t) + PGDPG_{USA} + .014^{*}\ logGAP_{USA\text{-}K}(t)$$

$$PEG_{K} = Exp[logGDP_{k}(t+1) - logGDP_{k}(t)]-1 = Exp[\ PGDPG_{USA}+.014^{*}\ logGAP_{USA\text{-}K}(t)]-1$$

where

$PGDP_{USA}$ is the projected per capita GDP growth in the USA (%),

PEG_{K} is the projected per capita economic growth (%/year) in country k, and

PPG_{K} is the projected population growth (%/year) in country k.

	Current Estimates						Projection					
Country	Pop. 2010 (millions)	Elec. Rate (%)	Thermal (%)	Hydro (%)	Installed Cap. 2010 (GW)	Cons. 2010 (GWh)	Annual pc GDP growth (%)	Annual pop. growth (%)	Installed Cap. 2050 (GW)	Cons. 2050 (GWh)	Annual new customer added	Aver. Elc. Cons growth (%)
Algeria	35.42	99.3	95.4	4.6	8.95	32099	3.57	0.70	37.3	134302	6199	3.64
Angola	18.99	26.2	33.2	66.8	1.00	3749	4.60	2.01	11.6	74268	255456	7.75
Benin	9.21	24.8	100	0	0.07	734	5.59	2.26	1.2	23225	127126	9.02
Botswana	1.98	45.4	100	0	0.15	2940	3.05	0.56	0.7	17408	17110	4.55
Burkina Faso	16.29	10	61.5	38.5	0.31	697	5.49	2.62	9.5	52872	285023	11.43
Burundi	8.52	7	25.6	74.4	0.04	158	6.11	1.25	1.9	21557	155472	13.08
Cameroon	19.96	29.4	15.5	84.5	1.04	5705	4.77	1.70	11.8	107371	252469	7.61
Cape Verde	0.51	81			0.08	265	3.68	0.62	0.4	1424	2437	4.29
CAR	4.51	25	48.8	51.2	0.05	131	5.56	1.62	0.8	4026	61958	8.94
Chad	11.51	18	100	0	0.04	113	5.30	2.23	0.7	4362	178343	9.56
Comoros	0.69	33	80	20	0.01	24	5.20	2.11	0.1	487	8119	7.80
Congo	3.76	30	24.6	75.4	0.14	548	4.23	1.95	1.3	8127	46988	6.97
DRC	67.83	11.1	1.8	98.2	3.06	7522	6.10	1.82	101.0	654422	1168320	11.81
I. Coast	21.57	47.3	23.7	76.3	1.32	3912	5.24	2.05	13.7	55908	176343	6.87
Djibouti	0.88	59	100	0	0.14	311	4.95	1.51	1.2	3125	4615	5.94
Egypt	84.47	99.4	83.7	16.3	26.02	119930	4.00	1.07	129.9	600608	12671	4.11
E. Guinea	0.69	18	80	20	0.01	28	2.65	1.91	0.1	368	10742	6.61
Eritrea	5.22	32	0	0	0.21	282	5.77	2.00	3.2	7430	62688	8.52
Ethiopia	84.98	15.3	16	77.8	1.02	3907	5.99	1.42	25.6	232862	1374487	10.76
Gabon	1.50	36.7	46.5	53.5	0.47	1639	3.58	1.55	3.1	15090	16248	5.71
Gambia	1.75	45	100	0	0.04	179	4.98	2.13	0.4	2421	15321	6.73
Ghana	24.33	54	9.7	80.3	2.04	6743	4.65	1.76	15.9	65759	158165	5.86
Guinea	10.32	21	76.9	23.1	0.32	948	4.97	2.10	4.8	27298	152279	8.76
Guinea-Bissau	1.65	29	100	0	0.03	75	6.12	1.86	0.3	2521	20999	9.18
Kenya	40.86	15	19.8	74.7	1.60	6664	5.35	2.19	34.3	315959	664024	10.13
Lesotho	2.08	16	0	0	0.09	617	4.92	0.64	1.6	22264	33344	9.38
Liberia	4.10	30	75.6	24.4	0.23	403	5.77	2.22	3.7	11370	51275	8.71
Libya	6.55	99.8	100	0	6.95	24513	2.93	0.81	22.3	78886	327	2.97
Madagascar	20.15	19	51.8	48.2	0.31	1207	5.88	2.39	6.6	56622	307227	10.10
Malawi	15.69	9	21.1	78.9	0.40	1993	6.36	3.02	16.8	244766	278533	12.78
Mali	13.32	22	56.1	43.9	0.34	589	5.61	2.53	6.2	21320	193184	9.39

Mauritania	3.37	36	75.6	24.4	0.23	459	4.78	1.80	2.3	7092	37026	7.08
Mauritius	1.30	99.4	83.8	16.2	0.78	2376	2.84	0.14	2.4	7367	195	2.87
Morocco	32.38	97	74.6	25.4	6.26	23973	4.05	0.52	32.0	124793	24286	4.21
Mozambique	23.41	11.7	12.8	87.2	2.90	12372	5.40	1.92	75.6	761809	399657	10.85
Namibia	2.21	34	0	0	0.30	3591	3.51	1.15	2.0	34558	25438	5.82
Niger	15.89	19	100	0	0.18	736	5.92	3.19	4.0	35826	242338	10.20
Nigeria	158.26	46.8	41.9	58.1	7.23	23562	5.57	2.26	86.2	393292	1313550	7.29
Rwanda	10.28	13	11.8	88.2	0.05	284	5.47	2.26	1.2	16338	172140	10.66
Sao Tome	0.17	61	66.7	33.3	0.01	22	5.50	1.49	0.1	336	1609	7.05
Senegal	12.86	42	100	0	0.56	1669	5.13	2.10	5.9	25718	122180	7.08
Seychelles	0.09	99			0.11	258	3.01	0.00	0.3	856	21	3.04
Sierra Leone	5.84	25	98.4	1.6	0.06	92	5.88	1.60	1.1	3224	80245	9.30
Somalia	9.36	24	100	0	0.08	329	6.35	2.76	1.7	15033	131026	10.02
South Africa	50.49	75	93	1.7	47.27	237954	2.97	0.31	181.9	1032971	315575	3.74
Sudan	43.19	31.4	55	45	1.26	4078	4.73	1.86	13.5	70708	524783	7.39
Swaziland	1.20	49	61.3	38.7	0.15	1453	3.91	0.88	0.9	11350	9316	5.27
Tanzania	45.04	11.5	39.4	60.6	1.20	3999	6.14	2.82	39.6	348627	771310	11.82
Togo	6.78	20	88.2	1.8	0.10	773	5.17	1.55	1.7	25132	101700	9.09
Tunisia	10.37	99.5	96.3	3.7	3.72	13357	3.33	0.48	14.1	50585	1297	3.39
Uganda	33.80	9	4.3	95.7	0.49	2502	5.17	2.60	14.8	184655	599879	11.35
Zambia	13.26	18.8	7.8	92.2	2.09	10971	5.85	3.09	45.3	521501	202832	10.14
Zimbabwe	12.64	41.5	67.8	32.2	2.49	12896	4.69	1.26	22.3	164807	121699	6.58

Table 2.6: Projected Consumption through 2050. Sources: UN 2010 Population; electrification rates are from the WEO/IEA 2008 estimates completed with some estimates from the websites of national agencies; projected population growth rates are estimates of the UN Population Division medium variant projection; economic growth rates are estimated from a demand convergence model

Appendix 2B: Solar, Wind, Hydro, and Geothermal: Data Sources and Assumptions

Table 2.7: Annual Potential of Renewable Resources by Country (GW)

Country	Solar			On-shore wind			Hydro	Geothermal		
	Low	Medium	High	Low	Medium	High		Low	Medium	High
Angola	21.6	62.5	104.1	0.0	0.0	0.0	9.6	0.0	0.0	0.0
Burundi	0.4	1.1	1.7	0.0	0.0	0.0	0.1	0.0	0.0	0.0
Cameroon	8.0	23.1	38.5	0.0	0.0	0.0	12.2	0.0	0.0	0.0
CAR	10.9	31.3	52.3	0.0	0.0	0.0	0.3	0.0	0.0	0.0
Congo	5.3	15.3	25.5	0.0	0.0	0.0	5.3	0.0	0.0	0.0
Congo, Dem Rep	37.6	108.3	180.4	0.0	0.0	0.0	82.2	0.8	1.6	2.4
Gabon	3.7	10.6	17.7	0.0	0.0	0.0	8.5	0.0	0.0	0.0
Rwanda	0.4	1.1	1.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Zambia	12.5	35.8	59.7	0.0	0.0	0.0	3.1	0.1	0.4	0.5
Benin	2.0	5.7	9.6	0.0	0.0	0.0	0.1	0.0	0.0	0.0
Cape Verde	0.1	0.3	0.4	0.4	0.7	0.8	0.0	0.0	0.0	0.0
Ivory Coast	5.4	15.7	26.0	0.0	0.0	0.0	1.3	0.0	0.0	0.0
Equa. Guinea	0.4	1.2	1.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gambia	0.1	0.5	0.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Ghana	3.9	11.3	18.7	0.0	0.0	0.0	1.2	0.0	0.0	0.0
Guinea	4.2	12.1	20.2	0.0	0.0	0.0	2.0	0.0	0.0	0.0
Guinea-Bis	0.5	1.3	2.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Liberia	1.6	4.5	7.4	0.0	0.0	0.0	1.2	0.0	0.0	0.0
Nigeria	17.7	50.8	84.8	0.0	0.0	0.0	3.5	0.0	0.1	0.1
Sao Tome	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Senegal	3.6	10.2	17.0	0.0	0.0	0.0	0.4	0.0	0.0	0.0
Sierra Leone	1.2	3.5	5.7	0.0	0.0	0.0	0.8	0.0	0.0	0.0
Togo	0.9	2.7	4.5	0.0	0.0	0.0	0.3	0.0	0.0	0.0
Djibouti	0.4	1.2	2.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Eritrea	2.0	5.7	9.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Ethiopia	18.6	53.4	89.0	0.4	0.7	0.8	27.6	0.0	0.0	0.0
Kenya	10.6	30.7	51.2	3.6	4.9	6.1	0.9	0.5	1.1	1.7
Malawi	1.6	4.5	7.6	0.0	0.0	0.0	0.7	0.0	0.0	0.0
Somalia	12.7	36.8	61.3	43.0	57.4	71.7	0.1	0.1	0.1	0.3

Sudan	46.2	133.0	221.7	14.2	19.0	23.8	2.0	0.3	0.4	0.7
Tanzania	16.1	46.5	77.4	0.0	0.0	0.0	2.1	0.3	0.5	0.8
Uganda	3.5	10.1	16.9	0.0	0.0	0.0	0.8	0.0	0.0	0.0
Comoros	0.0	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mauritius	0.0	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Seychelles	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Madagascar	10.6	30.7	51.1	3.9	5.2	6.4	19.1	0.0	0.0	0.0
Burkina Faso	5.2	15.0	25.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Chad	24.7	71.2	118.7	0.8	1.2	1.5	0.0	0.0	0.0	0.0
Mali	23.6	68.2	113.6	0.0	0.0	0.0	0.5	0.0	0.0	0.0
Mauritania	18.9	54.4	90.7	5.8	7.8	9.8	0.0	0.0	0.0	0.0
Niger	25.2	72.5	120.8	0.0	0.0	0.0	0.1	0.0	0.0	0.0
Botswana	9.6	27.3	45.5	0.0	0.0	0.0	0.0	0.3	0.4	0.7
Lesotho	0.4	1.3	2.1	0.0	0.0	0.0	0.3	0.0	0.0	0.0
Mozambique	14.1	40.5	67.6	0.0	0.0	0.0	4.0	0.0	0.0	0.0
Namibia	14.9	42.9	71.6	0.0	0.0	0.0	0.9	0.3	0.5	0.8
South Africa	21.0	60.4	100.8	0.1	0.1	0.1	1.2	0.1	0.3	0.4
Swaziland	0.3	0.7	1.2	0.0	0.0	0.0	0.1	0.0	0.0	0.0
Zimbabwe	6.4	18.3	30.5	0.0	0.0	0.0	1.9	0.0	0.1	0.1
Algeria	46.1	132.8	221.2	0.0	0.0	0.0	0.5	0.0	0.0	0.0
Egypt	19.4	55.8	92.8	4.5	6.0	7.6	5.3	0.5	1.3	2.0
Libya	32.9	94.8	158.0	6.6	8.9	11.2	0.0	0.0	0.0	0.0
Morocco	7.4	21.2	35.4	0.4	0.4	0.5	0.5	1.9	3.6	5.4
Tunisia	2.7	7.7	12.9	0.4	0.5	0.7	0.0	0.0	0.0	0.0

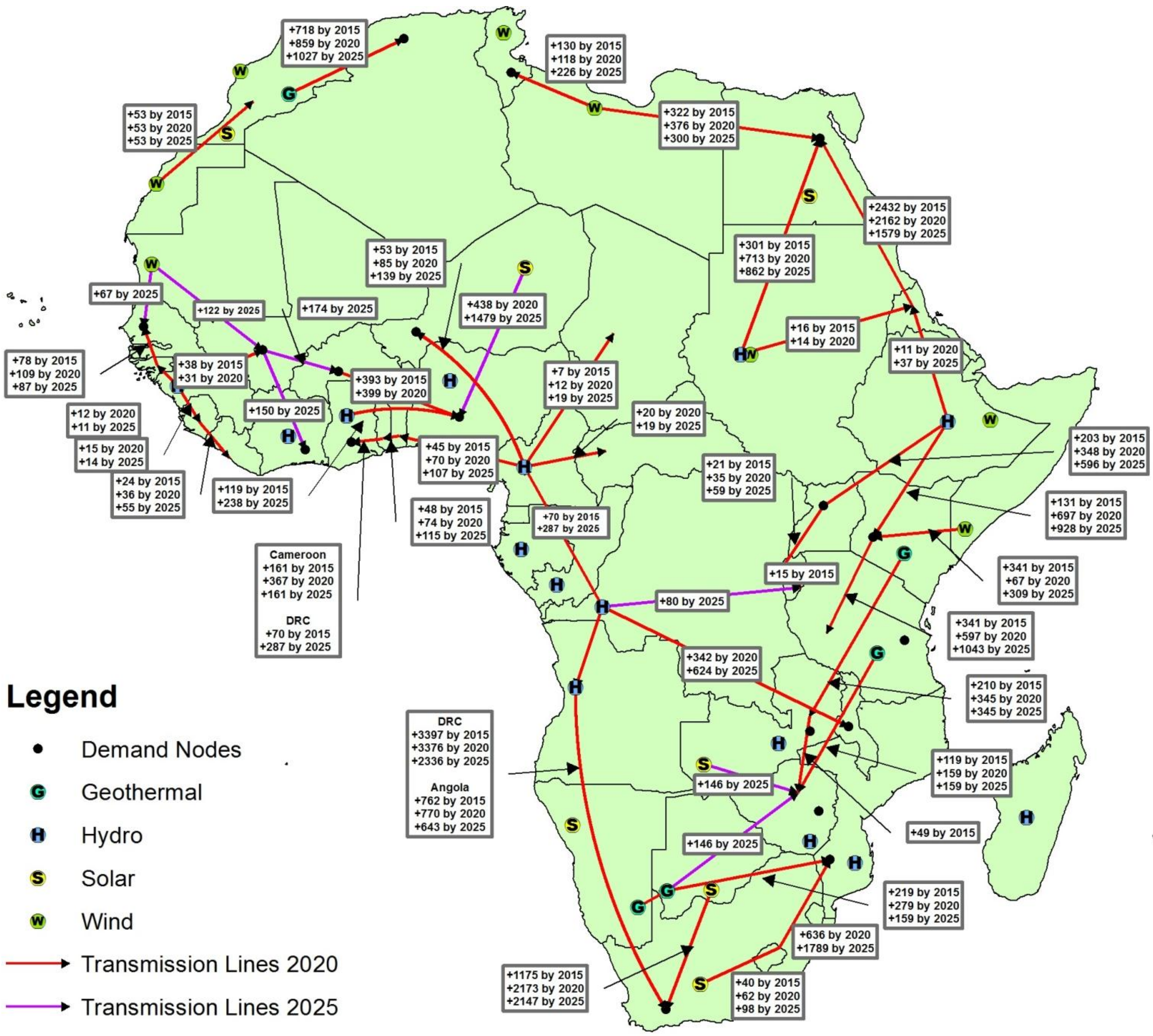
Source: Piet et al. 2007

Assumptions:

The following assumptions of Piet et al. are used in the estimation of country energy potential by source. For solar, a conversion efficiency of 15% is assumed with an available amount of land per country of one in one thousand (0.001). For wind energy, hub height is 80 m hub, offshore (0-15 km), wind speed>7 m/s, and 60% sitting density taken based on figures for Germany. Hydro refers to the technically exploitable resource (not economic) based on country-level studies. Finally, for geothermal energy, the assumed heat conversion potential is 5%; the country-level specific capacity factor value, except for Egypt and Ethiopia, is 48%.

Appendix 2C

Figure 2.9: Full optimal new transmission and trade expansion in MW to meet demand from 2010 to 2025



Contributions

Aly Sanoh and Vijay Modi conceived the research ideas and questions. Selin Kocaman contributed to the optimization design. Shaky Sherpa and Aly Sanoh produced the maps. Selcuk Kocal developed the transmission model. Aly Sanoh developed the overall integrated model. Aly Sanoh conducted the analysis and wrote the paper.

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Chapter 3

Local and National Electricity Planning in Senegal: Scenarios and Policies

Abstract[17]

To achieve the Millennium Development Goals (MDG), all households in sub-Saharan Africa will need to have access to basic infrastructure services. The challenge in meeting this goal is in bringing this access while simultaneously driving down the costs. With an understanding of cost drivers and the implications of achieving scale it becomes possible to plan a pathway to successful infrastructure services access expansion. The analysis presented in this paper addresses the issue of local and national electricity distribution planning in Senegal using a model that identifies cost drivers of targeted electrification, providing useful policy guidance to both national and local planners. A sensitivity analysis was conducted to capture connection cost and coverage (access) variations as a function of demand, fuel, and policy uncertainties. The local (an area of 400 sq km in northern Senegal) and national case studies of Senegal yields the following key results. For both case studies, a high percentage (20-50%) of the currently non-electrified population live in areas where grid expansion is more cost favorable than the decentralized energy supply technologies. Expansion outcomes (costs and access) are very sensitive to demand levels and capital cost of Medium Voltage lines and transformers.

Keywords: Electricity, Planning, Sub-Saharan Africa

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1. Introduction

Over the next decade, countries in sub-Saharan Africa are expected to increase their share of energy production and consumption to meet economic growth. Despite the existence of enormous energy sources in this region, electrification rates remain low. Rural electrification rates of around 15% and national rates in the 30-40% range have become one of the most restrictive bottlenecks to development. In addition, population growth is surpassing connection rates in most countries, which does not bode well for raising electrification rates (Haanyika, 2006). Given current conditions and financial constraints, energy planning in sub-Saharan Africa should focus on self-sufficient and environmentally sound energy policies that maximize the impact of investment and support economic growth (Weisser, 2004). Strategies that lower electrification costs, particularly household connection costs, are crucial to the economic future of the region.

Electric utilities currently focus their expansion planning primarily in areas already covered by the existing network or at best, areas that are reasonably close to the network. If current planning strategies for electrification remain the only approaches, expansion of access to new areas will be very slow. Rural areas in particular are falling behind in electrification because of the high cost of investment, low load factors, and sparse demand. Even when rural households are directly under the network line, they often do not get electrified because they promise only very low demand which may be due either to limited incomes or to the simple facts of their life-style (Haanyika, 2006). If planners take into account only the short-term characteristics of villages such as low income, low domestic and productive demand, enclosed areas (i.e. limited road access), and large dispersion of households, rural electrification may never be achieved.

The cost of electrification of new households in both electrified and non-electrified areas vary depending on customer mix and density, technology, level of development, geography and other location specific factors. Therefore, cost effective electricity planning should identify where costs are relatively high, differentiating the relative costs between rural and urban areas. Detection of areas where grid distribution is expensive is especially important in quantifying where decentralized/off-grid power offers the greatest potential for cost savings (Knapp et al., 2000). Accordingly, we apply a methodology for electricity expansion that aims to produce cost estimates of targeted electrification – within a specific time horizon and geo-spatial scale – that captures the dynamic evolution of demand.

Most energy planning exercises are carried out with aggregate data at the national level with only a few efforts for energy planning at regional levels (Zvoleff et al., 2009). In contrast, depending on the availability of data, our electricity planning model can be adjusted to generate results for any geographic scale (i.e. national, regional, or local level) and therefore, can address either main interconnected national expansion or local level planning issues. It is acknowledged that electrification has the greatest impact on development only when it integrates all sectors – education, health, and agriculture (Modi et al., 2006). By explicitly modeling schools, health facilities, and productive capacity, our planning methodology takes into account the needs and growth in demand from various sectors. Since demand and energy sources are by nature spatially distributed, we make extensive use of geographical information systems (GIS).[18] Moreover, in distribution network planning, upfront investment in the power distribution systems constitute the most significant part of the utilities' expenses. For this reason, efficient planning tools are needed to assist planners reduce costs (Miguez et al., 2002). Our planning methodology, which is based on discounted cash flow analysis and augmented by a sensitivity analysis, aims to estimate the investment needed and the household connection cost to extend electricity coverage in the most cost-effective way.

The two questions underpinning this study are:

1) Given fixed available financial resources, what electricity expansion planning approach will achieve the greatest number of customer connections at the lowest cost while factoring in some reliability constraints and delivering accurate analyses for both national and local situations? Specifically, what are the investment and connection costs for targeted electricity distribution expansion?
2) How do uncertainties in demand, prices, and policy choices affect the total and per connection costs and the subsequent length of the grid distribution network?

To address the study questions, which have been addressed in other recent studies (Parshall et al., 2009; Zvoleff et al., 2009; Deichmann et al., 2010), we apply the electricity planning methodology mentioned above to a local case study of Leona and a national case study of Senegal. For the analyses that are discussed in this paper, we first computed the cost of

[18] GIS methods have been used to process geographic information. ESRI ArcGIS/Arc Info software has been used to visualize geographic information. All the maps that appear in this paper have been produced with Arc Map.

implementing technologies to meet projected demands. We then compared different scenarios based on net present costs. Finally, we analyzed the sensitivity of our results to changes in demand, economic conditions such as fuel prices, and policy decisions such as the purchase price of grid electricity. Our contribution in this paper is in comparing local and national electricity distribution planning and sensitivity of results to changes in demand, fuel prices, and subsidies. Our electricity planning model allows energy policy makers, especially network planners, to evaluate different electrification scenarios by comparing projections of both investment and recurrent costs classified by supply technology and year in the planning time horizon.

2. Background to the Power Sector

The power sector in Senegal is dominated by the national utility, “Société National d'Éléctricité” (SENELEC). The high voltage transmission network – 190km of 90kV and 48km of 225 kV design used as 90 kV – provides energy to major distribution centers, interconnecting the power production sources and distribution stations. A combination of medium voltage network (7553 km total of which 704 km are underground and 6849km are aerial) and low voltage network (6761 km) bring electricity to the final consumers. Besides the two failed attempts at privatization in the 1990s, SENELEC has held a monopoly over the generation, transmission, and distribution of electricity. In 2003, however, the government reorganized the power sector, allowing private sector participation in generation of electricity to cope with the decrease of service quality and growing electricity demand.[19] By 2007, the total national installed capacity

[19] Estimates put Senegal’s electricity demand growth at 10% annually.

was 641 MW with SENELEC contributing 63% of total installed capacity at 416.2 MW, and the independent private producers contributing 37% of total installed capacity at 243 MW.[20]

In 2007, SENELEC experienced a 9.2% increase in customers, adding 60,000 new subscribers to serve a total of 712,000 customers as compared to 652,000 customers in 2006. The total energy billed to the customers increased 2.6% in 2007 to 1,786 GWh, an additional 45.6 GWh compared to the previous year. The total turnover on these sales, excluding taxes, was US$361 million. The overall average price per kWh increased 22.2% to US$0.22 from US$0.18 in 2006 (SENELEC, 2007). With the exceptional surge in oil prices, variable costs of production for SENELEC represented 80% of gross revenue. Therefore, despite the increase in rates, the revenues made by SENELEC were still insufficient to cover the cost of its operations.[21] In fact, a review of the evolution of SENELEC reveals two important trends: increasing vulnerability to fuel cost volatility and high cost of production per kWh. Since more than 90% of its production is of thermal origin, SENELEC continues to experience revenue losses due to soaring oil prices.[22]

During the past five years, fuel prices in the country have generally followed the global trend of rise in crude oil prices. A barrel of oil reached a then-historic price of US$140 in August 2008. The annual average for the year was US$75, a nearly three-fold increase from 2002 annual average of US$25. Furthermore, the average price for fuel oil (FO) in Dakar rose from

[20] These private producers are imports from Manantali hydro dam in Mali and the IPP Agreko in Dakar.
[21] Inflation of fuel prices has not been adequately reflected in SENELEC pricing. Therefore, despite the payment of compensation by the state, this has still resulted in liquidity deterioration.
[22] The recent drop in world fuel prices will be beneficial only if prices remain low since utilities are usually involved in long term purchase contracts.

US$373/tonne in 2006 to US$429/tonne in 2007. Similarly over the same time period, diesel oil (DO) cost increased from US$696/tonne to US$726/tonne. As for cost of production, the cost per kWh was estimated at US$0.12 for the entire interconnected system (including purchases) in 2007. While SENELEC's own units were producing at US$0.11/kWh, the independent producers generated power at approximately US$0.17/kWh. The Manantali hydro dam in Mali provided its contribution at $US0.03/kWh (SENELEC, 2007).

While SENELEC focuses on urban electrification, rural electrification has been the responsibility of "Agence Sénégalaise d'Électrification Rurale" (ASER) since its creation by the government on 14 April 1998. The mandate of ASER is to implement a rural electrification strategy that not only increases access to electricity but also contributes to the reduction of poverty. The goals of the agency as stated in the Senegalese Plan of Action for Rural Electrification (PASER) is to reach 30% of the potential population in 2015 and 60% by 2022. Staying on track to reach these goals has required ASER to increase private participation in its activities. The leading program under implementation by ASER is the rural electrification priority program (PPER) which focuses on establishing concessions via private sector participation. This approach of electrification by concession led to the division of the country into 18 concessions available for competitive bidding. Each concessionaire is expected to develop local electrification plans (LEP) that take into account the uncertainty of demand and distinct geographic variations within and among the concessions. These concessions, which can span 10 to 25 years and cover 5,000 to 10,000 customers, are well suited for the application of our model since our model identifies appropriate electrification technologies and processes levels of investment required to meet electrification needs based on user-specified targets, and in so doing, maximizing resources for a more significant impact on poverty reduction.

3. Methodological concept

Extending the grid network to remote and low demand areas will not be economical even after a ten year planning horizon. Hence, our model considers two decentralized technology options – solar photovoltaic power (PV) and diesel generators.[23] The cost function to be minimized consists of both fixed and variable factors. Fixed factors include investments in medium-voltage (MV) and low-voltage (LV) lines and related equipment for grid extension, engines for diesel mini-grid, and solar panels for solar photovoltaic technologies. Variable factors include resources and equipment required for the operation and maintenance of the technologies. The cost minimization underlies the choice of technology for electrification in the model.

We first establish the electrification status of populations. This information needs to come from existing utility, government surveys or censuses. Furthermore, knowing where the people live – i.e., exact and precise location and size of all population centers – is essential to minimize costs and calculate needed investments. Therefore, the more detailed the population, geographic, and cost data are, the more accurate the estimates will be. To determine the optimal technology

[23] The limited choice to these two technologies is based on discussions with experts from the rural electrification agency (ASER). These two technologies are proven and widely in use in the country. Although hybrid solutions such as wind-diesel could be included in the model, the lack of knowledge about the cost structure of this later technology did not allow for that.

solution for populations that are not electrified, the discounted costs of each of the technologies are calculated and compared. The lowest cost decentralized technology option, diesel mini-grid or PV-diesel system, is the optimal technology solution unless the cost of grid expansion reduces the cost even further.[24] The decision variable for connecting to the grid is the maximum length of medium voltage line that can be built to connect a population to the grid before the lowest cost decentralized option becomes more cost-effective. A modified minimum spanning tree algorithm is run on the results from the cost comparison of technologies and geo-referenced population data to simulate the extension of the grid. Further details on this methodology are described in the *Appendix 2A*. The three technologies – MV grid extension, diesel mini-grid, and PV-diesel system – are compared solely based on the kWh delivered and their ten-year capital and discounted recurrent costs.

4. Sensitivity Analyses

Sensitivity analysis shows possible design alternatives when predicted conditions change. Electricity planning intrinsically aims to avoid an under-designed or over-designed system. Both cases can prove to be costly because an under-designed system places limitations on the growth through a lack of capacity, while an over-designed system presents a lost opportunity for investment elsewhere (Haynes and Krmenec, 1989).

[24] The diesel mini-grid refers to a diesel generator with low-voltage (LV) distribution network. PV-diesel system refers to stand-alone solar photovoltaic (PV) systems to meet domestic and institutional (e.g. health facilities and schools) needs and a diesel engine to meet productive needs.

To improve on the disadvantages of using a deterministic method, we carry out a sensitivity analysis on certain model inputs that may have a critical effect on the cost outcomes. Due to the inherent uncertainties surrounding the projection of demand levels, fuel prices, and policy variables such as penetration rates and electricity sale prices, this study concerns itself not only with planning for infrastructure expansion but also how sensitive our results are with respect to these uncertainties. For instance, over-forecasting demand affects fixed costs, while under-forecasting demand requires purchase of more expensive units of power.

Despite the usefulness of sensitivity analysis, such an analysis has limits that should not be overlooked. Its addition does not in itself resolve the challenges of effective planning. Predictions of demand and inputs prices established from local expertise and trends are still the most important factors in ensuring both cost recovery for the utility and reasonably-priced electricity services for consumers.

5. Model Application Local Scale: "Communité Rurale de Leona"

We applied our model to the rural community of Leona, which is located in the Louga region, to identify potential factors that may affect electrification at the local level. Leona is the site of the Millennium Village Project (MVP) intervention and is a fast-growing community in need of long-term energy planning that accounts for the community's specific geographic, demographic, and infrastructural characteristics.[25] As shown in Figure 3.1, Leona has 102 population centers

[25] MVP is the proof of concept of the African Millennium Villages Initiative. The objective of MVP is to establish the feasibility of achieving the Millennium Development Goals (MDGs) in rural Africa through advanced design and implementation of community-led, practical investments in food production, health, education, access to clean

that vary in population size with household counts ranging from 10 households to 237 households. The social infrastructures are extremely limited. The community has only one health center and 19 cases de santé (health posts), 43 un-electrified primary schools, and one college. A power line, a 30kVA medium voltage line connected to the national network, runs along the road between Louga and Potou. With only two transformers, grid electricity is available in two population centers, Leona center and Potou. Since the implementation of the MVP, there has been a burst in commercial activities, such as dressmaking, carpentry, welding, and commerce, which require electricity.

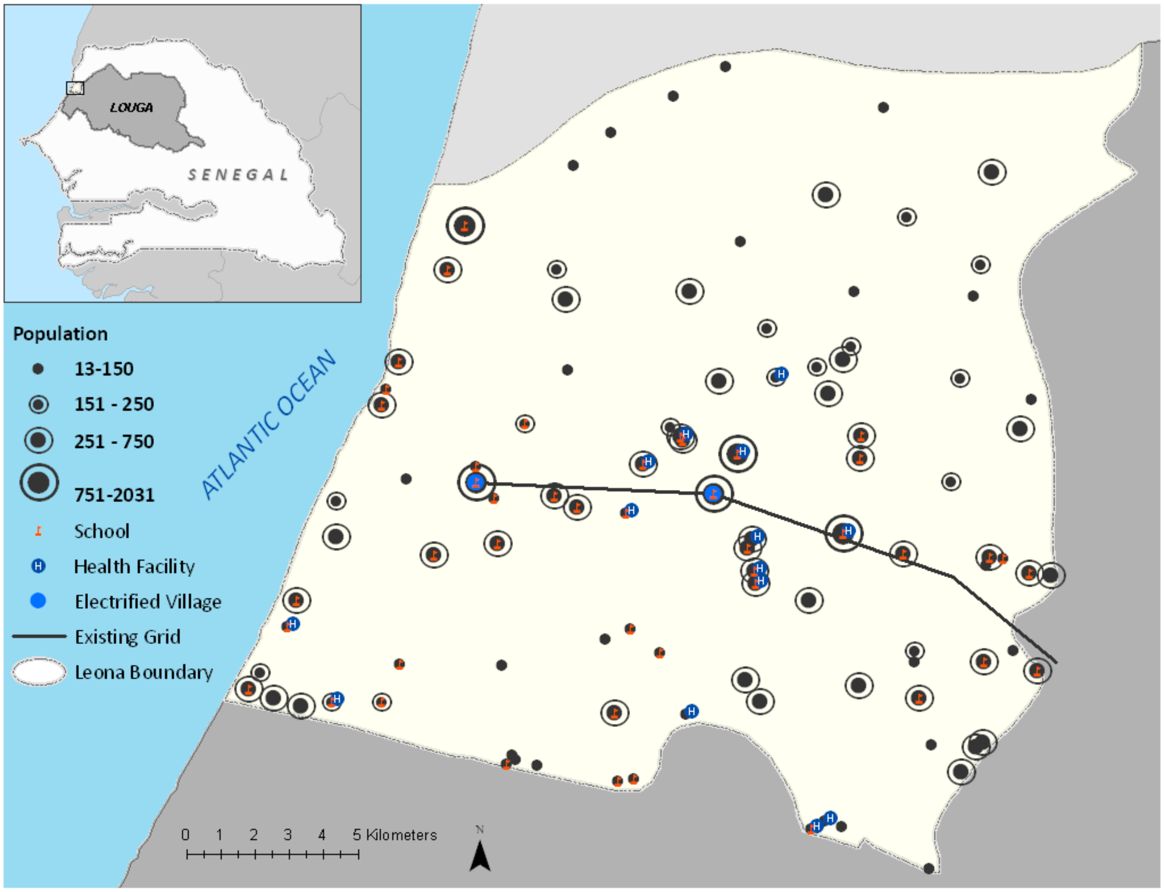

Figure 3.1. Map of Leona that shows the location of population centers and existing infrastructure (schools, health centers, and electricity grid) as of 2007

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water, and essential infrastructure over a five year time-frame. The Millennium Villages initiative is supported by Millennium Promise, the UN Development Programme (UNDP), and the Earth Institute, Columbia University.

Whereas conventional rural electrification planning in sub-Saharan Africa is often based on demand modeling criteria that do not consider the specifics of local areas, we specifically model future demand for each of the population centers in Leona. A population growth rate is applied to current population estimates to determine the population and number of households at the end of the planning horizon. Based on population projections, the social infrastructure – schools and health facilities – needed to serve each population center by the end of the planning horizon are computed. When estimating future demand, special consideration has been made for the growth of businesses. Businesses in Leona have always proven to connect to electricity whenever it is available. Our model also takes into account a more accurate measure of the inter-household distance which is critical for determining the cost of LV lines.[26] Additional modeling assumptions are outlined in the *Appendix 2A.*

5.1 Results

Table 3.1 shows the model results for the base scenario, which represents our best estimates of parameters and projections. For the rural community of Leona, the least cost technology option is grid electricity for 27% of the households at an average connection cost of US$806 per household; solar PV-diesel systems for 63% of the households at US$719 per household; and diesel mini-grids for the remaining 10% of the households at US$936 per household. Here it is critical to recognize that the lower average connection cost of solar PV-diesel option is likely due

[26] The assumed inter-household distances were derived from a study on rural electrification in Togo but adjusted with experts from the rural electrification agency ASER. For Senegal, 30 meters was taken for population centers less than 500 people, 24 meters for population centers with 500 to 5000 people, and 8 meters for population centers with more than 5000 people.

to the fact that the household demand for smaller population centers is assumed to be lower, as observed by the utility.[27]

Table 3.1. Average Connection Cost by Supply Technology for Leona			
Base Scenario	**Grid**	**Diesel**	**PV**
Number of new households connected	446	162	1064
Average connection cost per household (US$)	806	936	719
For each supply technology, the average connection cost per household is the total ten-year capital investment of the supply technology divided by the number of new households that are connected by the supply technology over the ten-year horizon, independent of the year in which the households were actually connected.			

The finance and cost performance indicators of grid extension for the base scenario, which can be found in Table 3.2, indicate that for Leona, 303,000 kWh of grid electricity will need to be supplied annually and the approximate generation capacity required will be 86 kW.[28] The financial viability measured in terms of annual capital investment (costs of MV line, LV line, transformers, and household equipment) per kWh deliver annually stands at US$1.47. Annual capital investment reduces to US$0.46 if capital costs are limited to MV line and transformers. This suggests that if customers and government were to come to an agreement on paying or financing the capital costs of the low voltage extension to households and internal household equipment, grid extension would be commercially viable for the utility.

[27] It is important to be aware that average household connection cost may not be used as an indication of the cheapest technology, because costs are affected by the number of households for each technology.

[28] The approximate generation capacity needed to meet the scale-up in distribution will depend on the type of power plant in the grid-supply mix. Here we assume a generation capacity factor of 40% for the grid-supply mix in Senegal. In reality, economic growth may require a much higher increase in generation capacity. If demand a estimate which accounted, for example, for an elasticity of electricity demand growth of 1.5% and an economic growth rate increasing at an annual rate of 5%, is assumed to be decoupled from the demand estimated in this study, the generation capacity required may be up to five times higher than the figures reported here.

The grid extension requires on average per household, 13 meters of MV line and 25 meters of LV line. The average household connection cost broken down by cost components is US$490 for the low voltage infrastructure (LV line and HH equipment) and US$316 for the medium voltage infrastructure (MV line and transformers), which suggests that the medium voltage infrastructure costs are higher than the low voltage infrastructure costs. It is worth noting that MV costs assumed per km are only 25% higher than those in large markets such as India, but LV costs are as much as 50% higher, so there is considerable opportunity for reducing the cost of LV lines.

Table 3.2. Grid Extension Financial and Cost Performances for Leona

New Households Connected Grid	446
Additional Grid electricity Supplied (thousand kWh/year)	303
Approximate Generation Capacity(KW)	86
Grid Investment (US$/kWh) (includes capital cost of MV line, LV line, transformer, and HH equipment)	1.47
Grid Investment (US$/kWh) for MV line and transformer only	0.46
MV line length per household (MV/HH)	13
LV line length per household (LV/HH)	25
Average Cost per HH (US$)	806 (100%)
LV line and HH Equipment	490 (60%)
MV line and Transformers	316 (40%)

5.2 Sensitivity Analysis

We conducted a sensitivity analysis to observe how outcomes change with different assumptions of demand and prices. We specifically evaluated the effects of grid electricity purchase price and solar equipment cost-variability on electrification plans in order to assess the potential impact of government subsidies for either of the conditions. The model results, which are summarized in Table 3.3, indicate that outcomes are indeed sensitive to variability in level of demand, fuel price, and grid-related costs.

Table 3.3. Sensitivity Analysis for Leona: Varying demand, electricity purchase price, diesel fuel price, grid, and solar equipments cost with respect to the base scenario[29]

Scenario Description	# new HH connected via grid extension	Population covered by new grid extension	Population coverage new grid extension (%)	Average grid connection cost per household ($/HH)	MV line length per household (MV/HH)	Total population coverage by technology (%)		
						Grid	Diesel	PV
Base (best estimates of all input parameters)	446	4284	12.7	806	13	18	5	39
Scenario 1: Reduce all demands by 25%	196	1884	5.6	1210	30	6.4	1.4	54
Scenario 2: Increase all demands by 25%	489	4697	14	868	17	19	3.4	40
Scenario 3: Double all demands	796	7652	23	958	18	28	4.3	29.4
Scenario 4: Reduce electricity purchase price by 25%	446	4284	12.7	806	13	18	5	39
Scenario 5: Increase electricity purchase price by 25%	446	4284	12.7	806	13	18	5	39
Scenario 6: Double electricity purchase price	422	4053	12	797	13	18	5	39

[29] Demand refers to domestic (household), productive, and institutional (schools and health centers) energy consumptions.

Scenario 7: Reduce diesel fuel price by 25%	446	4284	12.7	806	13	18	5.5	38
Scenario 8: Increase diesel fuel price by 25%	489	4697	14	860	16	19	3.4	39
Scenario 9: Double diesel fuel price	489	4697	14	860	16	19	0	42
Scenario 10: Halve all grid-related costs	772	7421	22	771	22	27	3.4	31
Scenario 11: Double all grid-related costs	259	2487	7	857	7.5	12	8.5	40
Scenario 12: Halve PV equipment costs (panels and batteries)	446	4284	12.7	806	13	17	4.6	40

Demand. A doubling of all future demand would make the grid the least-cost option, grid-compatible, for about 23% of the population but at a much higher average cost at US$958 as compared to US$806 in the base scenario. When demand increases, scenarios 2 and 3, it becomes more cost effective to connect a greater proportion of the population to the grid, but the additional population centers that become grid-compatible are not as clustered as the population centers which were grid-compatible in the base scenario. The increase in MV line length when demand is doubled is due solely to the addition of new population centers (Table 3.4). When demand doubles, total MV line length increases from 5.9 km to 14.3 km (13.2 m/HH to 17.9 m/HH), but interestingly 9.3 km of the 14.3 km can be attributed to the addition of new population centers. Moreover, the double demand scenario leads to a more cost effective configuration of population center connections than the base scenario. Population centers that were grid-compatible in the base scenario get connected more efficiently, requiring only 4.9 km of MV line as compared to 5.9 km (10.9 m/HH to 13.2 m/HH). While greater electricity demand may promote connections to remote population centers, which increases access, the cost increases as well, though not proportionately. Reducing demand results in a shift away from both grid and diesel mini-grid to PV-diesel systems. When all future demands are reduced by 25%, scenario 1, the population covered by grid falls from 18% in the base scenario to 6.4%.

Table 3.4. Effect of double demand on the per household length of MV line for Leona

	Number of Households (HH)	Total MV line length for grid extension (km)	MV line length per household (m/HH)
Base Scenario			
Total Connections	446	5.9	13.2
Doubled Demand Scenario			
Total Connections	796	14.3	17.9
New Additional Connections	350	9.3	26
Base Scenario Connections	446	4.9	10.9

Grid electricity purchase price. Increasing or reducing grid electricity purchase price by 25%, scenarios 4 and 5, has no affect on the outcomes. Grid remains the least-cost option for only those population centers that were found to be grid-compatible in the base scenario. When grid electricity purchase price is doubled, only 3 population centers shift from grid to diesel mini-grid. In terms of average cost and grid coverage, a change in grid electricity price has only a very minor effect.

Diesel fuel price. Reducing diesel fuel prices, scenario 7, results in a minor shift in population covered by PV-diesel system in the base scenario to diesel mini-grid. Increasing diesel fuel prices, scenario 8 and 9, causes a shift from diesel mini-grid to grid; when diesel fuel prices are doubled, there is also a shift to PV-diesel systems. Nevertheless, even if diesel fuel prices were to rise and populations shift to grid, average cost of connection remains high. In fact, when diesel fuel price doubles, average connection cost per household for grid extension increases from US$806 in the base scenario to US$860. The meters of MV line required increases from 13 meters to 16 meters, which suggests that the population centers that shift to grid require more MV line. It is important to keep in mind that the average connection cost refers to the capital investment for connection, but fuel cost variability affects recurrent costs more so than capital costs.

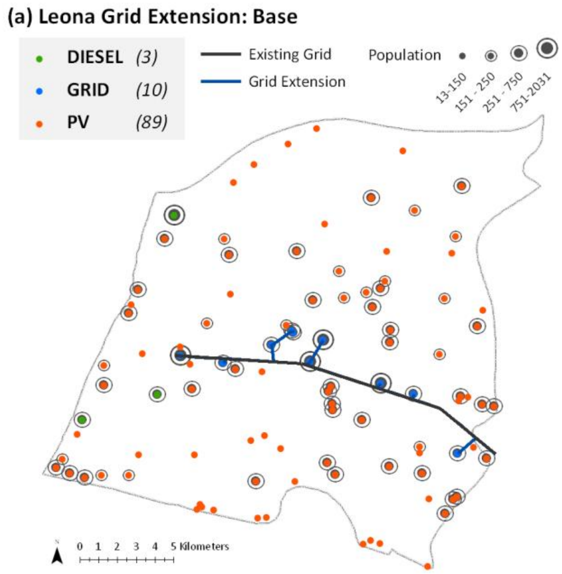
Capital costs. In terms of policy instruments, government actions that target the capital cost of grid or PV-diesel systems may not have the desired impact because of the tradeoff between cost and coverage as indicated in the outcomes for scenarios 10, 11, and 12. For example, a government subsidy that bears half the cost of PV equipment is not enough to dramatically change the share of PV which remains around 40% of total population coverage. Populations that were connected by grid or diesel mini-grid in the base scenario do not shift to PV-diesel because their demands still remain high for PV-diesel to be relatively cost effective. A subsidy that reduces the investment cost of MV and transformers by half, however, could boost new grid coverage up to 22% and reduce the average connection cost per household from US$806 in the base scenario to US$771 (Table 3.3 Scenario 10). Moreover, as shown in Table 3.5, the increase in MV line length can be attributed to new additional connections, 12.3 km of the 17.3 km of MV line length and population centers that were grid-compatible in the base scenario get connected more efficiently, requiring 5.0 km of MV line as compared to 5.9 km (11.2 m/HH to 13.2 m/HH).

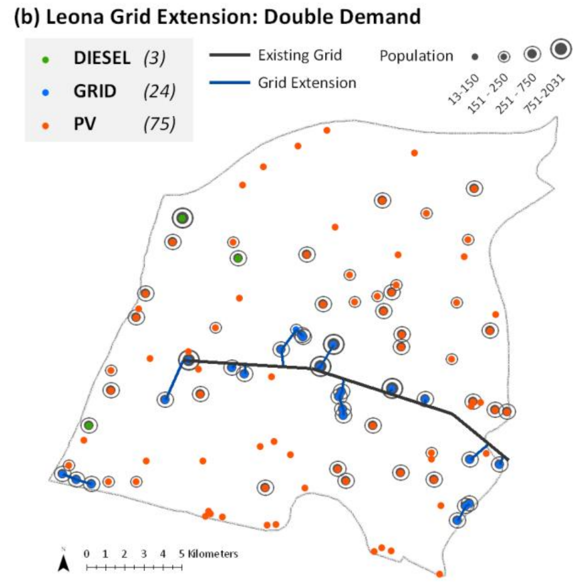
Table 3.5. Effect of half grid costs on the per household length of MV line for Leona

Scenarios Leona	Number of Households (HH)	Total MV line length for grid extension (km)	MV line length per household (m/HH)
Base Scenario			
Total Connections	446	5.9	13.2
Half Grid Costs			
Total Connections	772	17.3	22.4
New Additional Connections	326	12.3	37.7
Base Scenario Connections	446	5.0	11.2

This table allows comparison between the base scenario and the half grid cost scenario in two dimensions: number of household (column 1) and Length of MW grid (column 2). In the base scenario 446 Households are connected with 5.9 km of MV line. In the half grid scenario 772 Households are connected with 17.3 km of MV line. Within these 772 households, 326 households are new and the 446 correspond to the ones in the base scenario but at the difference that they are connected with 5 km of line instead of 5.9 which indicates a better efficiency.

The local level analysis reveals that for rural electrification, policies related to demand and grid-related costs are likely to have the greatest impact on increasing grid coverage (See Figure 3.2 and Table 3.6). And though variability in grid electricity purchase price and diesel fuel price may not affect grid coverage, they may affect average cost per connection.





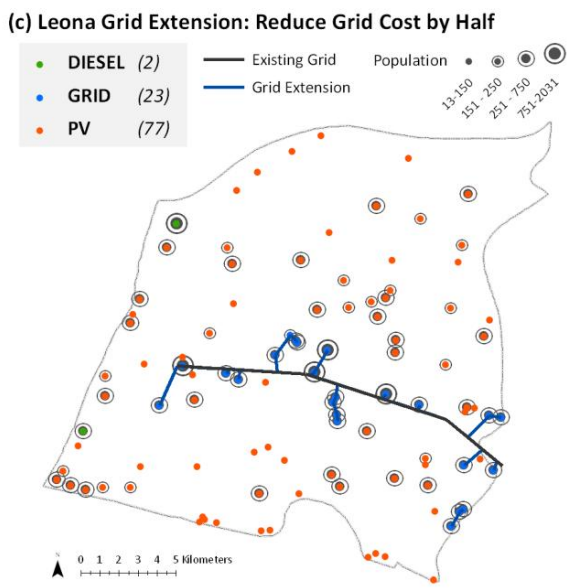


Figure 3.2. Scenarios of grid expansion for Leona:

(a) Base represents the best estimates of all input demand and cost parameters

(b) Double demand represents the case in which future domestic demands, productive demands, and social infrastructure (i.e. schools and health facilities) demands are doubled; all other input parameters are the same as base scenario

(c) Reduce grid cost by half represents the case in which capital costs for MV infrastructure (MV lines and transformers only) are reduced by half; all other input parameters are the same as base scenario

Table 3.6. Financial and Cost Performances Indicators for Leona			
	Base Case	Double Demand (household, productive, and social Infrastructure)	Reduce grid extension cost by half (MV line and transformers)
New Households Connected Grid	446	796	772
Additional Grid electricity Supplied (MWh/year)	303	765	372
Approximate Generation Capacity[30] (kW)	860	218	106
Grid Investment (US$/kWh) (includes capital cost of MV line, LV line, transformer, and HH equipment)	1.47	1.13	1.83
Grid Investment (US$/kWh) for MV line and transformer only	0.46	0.44	0.54
MV line length per household (MV/HH)	13	18	22
LV line length per household (LV/HH)	25	25	27
Average Cost per HH (US$) LV line and HH Equipment MV line and Transformers	806 (100%) 490 (60%) 316 (40%)	1056 (100%) 522 (49%) 534 (51%)	830 (100%) 510 (62%) 320 (38%)

[30] The approximate generation capacity needed to meet the scale-up in distribution will depend on the type of power plant in the grid-supply mix. Here we assume a generation capacity factor of 40% for the grid-supply mix in Senegal. In reality, economic growth may require a much higher increase in generation capacity. If demand a estimate which accounted, for example, for an elasticity of electricity demand growth of 1.5% and an economic growth rate increasing at an annual rate of 5%, is assumed to be decoupled from the demand estimated in this study, the generation capacity required may be up to five times higher than the figures reported here.

6. Model Application National Scale: Senegal

In Senegal, the grid is currently established along the high population density corridors (See Figure 3.3a and Figure 3.3b). Given that almost half of the national population lives in these corridors, the challenge is in bringing access to villages of less than 5,000 people, in particular the nearly quarter of the population that lives in villages of less than 500 people (See Figure 3.4).

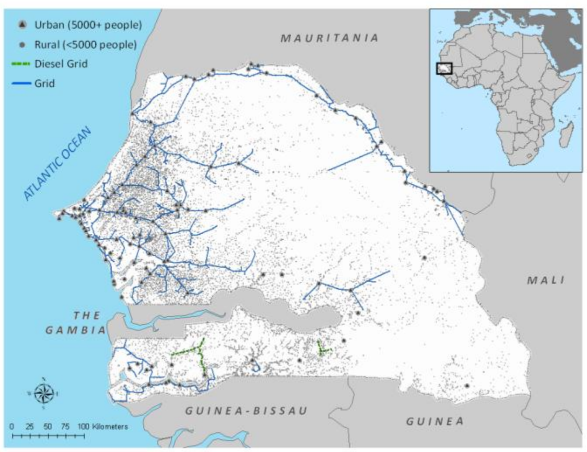


Figure 3.3a. Senegal Existing Grid Map

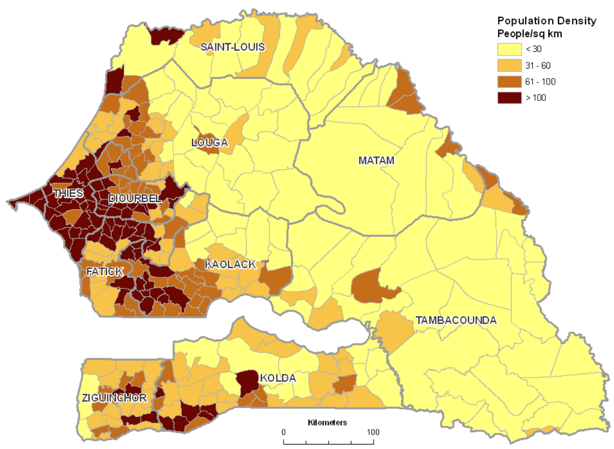


Figure 3.3b. Senegal Population Density Map

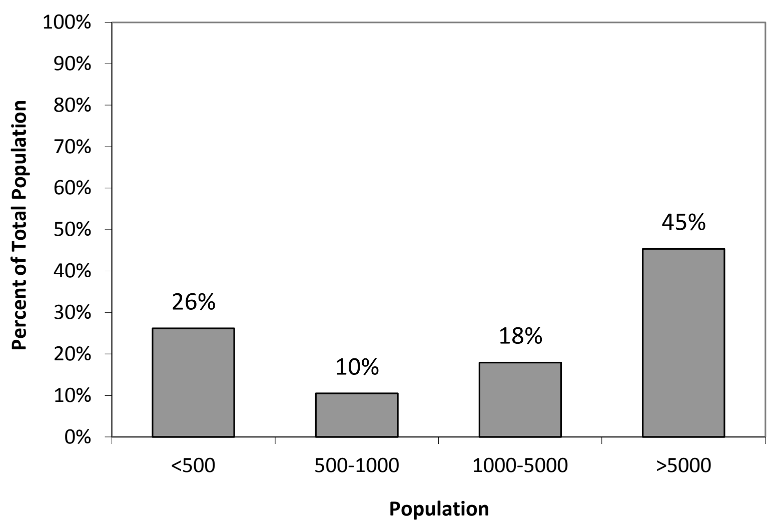


Figure 3.4. Senegal population distribution

All cost data were obtained through discussion with experts from ASER and SENELEC.[31] In the model for the national level analysis, population centers with less than 5000 people were classified as being rural. In addition, all urban population centers were assumed to already be electrified. Therefore for urban population centers, the target was to meet a 100% electrification rate. In other words, within the planning horizon, the target was to add household connections via LV extension until all households were electrified.[32] Additional modeling assumptions are outlined in the *Appendix 2A.* In the national case study, we report and emphasize the cost related specifically to rural electrification because this is the area in which considerable progress is needed.

6.1 Results

As in the local level analysis, results for the base scenario, which represents the best estimates of parameters and projections, are reported first. Note that Table 3.7 shows model results for only rural population centers in Senegal. By the end of the ten-year planning horizon, grid electricity can be provided to an additional 134,448 rural households at an average connection cost per household of US$1048 and to an additional 288,000 urban households at an average connection

[31] The cost of technologies and assumptions regarding discount rate, penetration rates, and demand levels were finalized in collaboration with experts from ASER and SENELEC during the Electrification Workshop organized by the Earth Institute in June 2007. The raw grid data was obtained from ASER in November 2006 and a subsequent clean version was created by the Earth Institute in February 2007. The village geographic data with population estimates from the 2002 census was acquired from ASER and DPS in 2006.

[32] One weakness of the model is that we do not take into account the additional internal MV line cost that may be needed in certain urban areas. In terms of GIS data, the centroid locations of population centers were the greatest level of detail we were able to obtain. We were unable to obtain GIS data of social infrastructures (i.e. location of health, education, commercial facilities), which makes it difficult to make assumptions about internal MV.

cost per household of US$409. The average connection cost at the national level for a rural household is US$242 more than the average connection cost for a household found at the local level – the rural community of Leona. If all newly connected households are considered, the overall national average connection cost is US$728 which is US$78 less than the average connection cost at the local level. This implies that from the standpoint of grid electricity distribution expansion, concurrent national expansion to rural and urban areas has the advantage of economies of scale because customers in urban areas can be connected at much lower costs than customers in rural areas, bringing down the overall average connection cost per household. The average connection cost for the decentralized technology options, PV-diesel and mini-grid diesel, for rural households at the national level are US$723 and US$850 respectively (Table 3.7). The average connection cost for rural households through off-grid electrification, PV-diesel, does not differ whether planned at the national level, US$723, or the local level, US$719. The average connection cost for a rural HH through diesel mini-grid is US$850 at the national level compared to US$936 at the local level.

Table 3.7: Average Household Connection Cost by Supply Technology for rural households in Senegal

Base Scenario	**Grid**	**Diesel**	**PV**
Number of additional rural households connected	134,448	37,170	102,206
Connection cost per household (USD$)	1048	850	723

For each supply technology, the average connection cost per household is the total ten-year capital investment of the supply technology divided by the number of new households that are connected by the supply technology over the ten-year horizon, independent of the year in which the households were actually connected.

Finance and cost performance indicators of grid extension for the base scenario at the national level, which can be found in Table 3.8, indicate that a total of 111 million kWh (GWh) of grid electricity will need to be supplied annually to rural households. The financial viability measured in terms of annual capital investment (costs of MV line, LV line, transformers, and household equipment) for every kWh delivered annually is estimated to be US$1.68. If the capital cost components are limited to the medium voltage infrastructure (MV line and transformers only), capital investment decreases to US$1.19. The annual capital investment for grid extension at the national level, US$1.68, is higher than at the local level, US$1.47.

At the national level, the increase in number of households connected to the grid reduces the average cost per household, but the average number of meters of MV line required is much higher, more than double. While 13 meters of MV line per household was sufficient for grid extension to population centers at the local level, the MV line per household increases to 27.5 at the national level. So, at the national level, the reach of the grid is greater due to higher demand, but the grid configuration is less efficient.

The average rural household connection cost, broken down by cost components, is US$500 for LV line and HH equipment, and US$548 for the MV line and transformer costs (Table 3.6). About half of the investment required to deliver a kWh of electricity annually is attributed to investments in the low voltage infrastructure (LV line and household equipment), while the other half goes to the medium voltage infrastructure. In other words, the cost related to delivering services to the households is almost equal to the cost related to grid expansion to the population centers.

Table 3.8. Senegal: Financial and Cost Performance by Scenarios	
	Base Case
New rural Households Connected Grid	134,448
Additional Grid electricity Supplied (million kWh/year)	111
Approximate Generation Capacity (MW)	32
Grid Initial Annual Investment (US$/kWh) (this includes capital cost of MV line, LV line, Transformer, and HH equipment)	1.68
Grid Investment (US$/kWh) for MV line and transformer only	1.19
Number of meters of MV line per HH	27.5
Number of meters of LV line per HH	24
Average Cost per rural HH (USD)	1048 (100%)
LV line and HH Equipment	500 (48%)
MV line and Transformers	548 (52%)

Table 3.9 shows the regional distribution of electrified population at the end of the ten year horizon national plan to achieve 70% electrification. As mentioned above, our model is especially well-suited for the concession approach of electrification. Within the context of the decentralization of electricity services which Senegal, the model results show which technologies the concessionaires may consider focusing on within a particular region. For example, regions with low potential for grid interconnection such as Tambacounda, Kolda, and Louga may start with PV technologies sooner than later. It is interesting to note that for the densely populated Dakar region in western Senegal, grid will meet the entire electrification target, while in the sparsely populated Tambacounda region in eastern Senegal, only 24% of the population will be electrified by grid.

Table 3.9: Percentage Population Electrified by Region and Supply Technology[33]			
	PV	**Diesel**	**Grid**
Saint Louis	6%	4%	60%
Matam	10%	3%	57%
Dakar	0%	0%	70%
Zinguinchor	7%	4%	59%
Diourbel	11%	2%	57%
Tambacounda	31%	15%	24%
Kaolack	21%	8%	40%
Thies	10%	1%	59%
Fatick	15%	9%	46%
Kolda	32%	8%	29%
Louga	38%	4%	28%

6.2 Sensitivity Analysis

The results of the sensitivity analysis for the national case study are summarized in Table 3.10. The same uncertainties in demand and costs applied at the local level have been applied at the national level. Note that scenario 13 will be discussed further in the following section.

[33] In the model, the national electrification goal at the end of the 10 year period is set at 70%. Therefore all cost figures of the scaling up reflect the cost of achieving this goal of 70% national electrification rate. In each village (location) the model target 70% of the new potential HH to be electrified in order to achieve this goal. The penetration rate could be interpreted here as the maximum number of HH (with the ability to pay for electricity) that can be added from each demand point.

Table 3.10. Sensitivity Analysis for Senegal: Varying demand, electricity purchase price, diesel fuel price, grid, and solar equipments cost with respect to the base scenario

Scenario Description	# new HH connected via grid extension	Population covered by new grid extension	Population coverage new grid extension (%)	Average grid connection cost per household ($/HH)	MV line length per household (MV/HH)	Total population coverage by technology (%)		
						Grid	Diesel	PV
Base (best estimates of all input parameters)	134,448	1,283,261	9.7	1048	27.5	52	4	13
Scenario 1: Reduce all demands by 25%	120,119	1,146,443	8.7	1003	25	51	2	16
Scenario 2: Increase all demands by 25%	138,745	1,324,535	10	1078	29	52	4	13
Scenario 3: Double all demands	206,659	1,977,817	15	1204	33.5	57	3	9
Scenario 4: Reduce electricity purchase price by 25%	140,998	1,346,229	10	1066	28	52	3.8	13
Scenario 5: Increase electricity purchase price by 25%	128,225	1,224,321	9	1036	26	52	4	13
Scenario 6: Double electricity purchase price	94,999	905,032	7	921	20	49	6	14
Scenario 7: Reduce diesel fuel price by 25%	121,528	1,159,987	8	1001	24	51	6	12
Scenario 8: Increase diesel fuel price by 25%	143,015	1,365,601	10	1081	29.5	53	3	13
Scenario 9: Double diesel fuel price	154,473	1,475,739	11	1125	32	54	2	14

Scenario 10: Halve all grid-related costs	226,256	2,166,315	16	881	36.7	59	2	8
Scenario 11: Double all grid-related costs	85,617	814,827	6	1278	20	48.5	6.5	14.5
Scenario 12: Halve PV equipment costs (panels and batteries)	84,679	810,242	6	1084	29	48.5	2	19
Scenario 13: Kenya demand levels and technology cost structure	337,423	3,236,359	24.64	983	19.82	67	2.6	0.005

Demand. A doubling of all future demand results in a grid expansion that could reach about 15% of the population but at a higher average cost than the base scenario, US$1204 as compared to US$1048. Increases in demand, scenarios 2 and 3, lead to greater grid access but do not result in a decrease in average cost because the additional population centers electrified by the grid require more MV lines. While in the base scenario, 3694 km of MV line is required to connect 134,448 rural households, 6920 km of MV line is required to connect 206,659 households when demand doubles (27.5 m/HH to 33.5 m/HH). Although the total MV length increases when demand is doubled, population centers that were also grid-compatible in the base scenario get connected with a better optimized network for the same population centers, at 3155 km instead of 3694 km, or 23.5 m/HH as compared to 27.5 m/HH (Table 3.11). The increase in overall MV line length per household from 27.5 to 33.5 meters is a result of additional population centers which now become cost-effective to connect, but are located much further away from the grid. Reducing all future demands by 25%, scenario 1, would likely lead to fewer new households being electrified by grid and mini-grid, and instead, more households being electrified by PV-diesel. The results at the national level for variable demand parallel the results found at the local level. Whether grid expansion is planned at the local level or the national level, higher demand increases the propensity for connecting more households.

Table 3.11. Effect of double demand on the per household length of MV

Scenarios for Senegal	Number of Households (HH)	Total MV line length for grid extension (km)	MV line length per household (m/HH)
Base Scenario			
Total Connections	134,448	3,694	27.5
Double Demand			
Total Connections	206,659	6,920	33.5
New Additional Connections	72,211	3,764	52.1
Base Scenario Connections	134,448	3,155	23.5

Grid electricity purchase price. Reducing or increasing electricity purchase price by 25%, scenario 4 and 5, is not as sensitive to outcomes, but doubling the electricity purchase price, scenario 6, will tremendously reduce expansion possibilities. When electricity purchase price is doubled, the percentage coverage of new households connected to the grid falls from 9.7% in the base scenario to 7%, and the average connection cost falls from US$1048 in the base scenario to US$921.

Diesel fuel price. The outcomes when fuel prices are reduced by 25%, scenario 7, remain almost unchanged in terms of supply technology population coverage. Increasing diesel fuel prices, scenario 8 and 9, lead to higher average connection cost US$1081 and US$1125 respectively compared to US$1048 in the base scenario. When diesel fuel prices increases there is a minor shift from diesel mini-grid to grid and to PV-diesel systems. This shift to grid lead to the increase average cost because of the fact that more distant households formerly suitable for diesel mini grid are added to the grid. When diesel fuel price doubles, MV line length per household rises to 32 m/HH from 27.5 m/HH in the base scenario.

Capital costs. In terms of policy instruments at the national level, government actions that target the capital cost of the grid and solar equipment would have an impact on average connection cost and coverage. Halving all grid-related capital cost, scenario 10, leads to the lowest connection cost, US$881, and the highest grid coverage of new households, 16%. Moreover, as shown in Table 3.12, the increase in MV line length can be attributed to new additional connections, and population centers that were grid-compatible in the base scenario get connected more efficiently. Doubling all grid-related capital costs, scenario 11, would lead to a decrease in coverage by grid, but an increase in coverage by PV-diesel, but more so, diesel mini-grid. Accordingly, there is an increase in average grid connection per household. A government subsidy for solar equipment, scenario 12, would result in an increase in percentage of the population electrified by PV-diesel systems as compared to the base scenario.

Table 3.12. Effect of grid cost (reducing the costs of MV line and transformers by half) on the per household length of MV

Scenarios for Senegal	**Number of Households (HH)**	**Total MV line length for grid extension (km)**	**MV line length per household (m/HH)**
Base Scenario			
Total Connections	134,448	3,694	27.5
Half Grid Cost			
Total Connections	226,256	8,322	36.7
New Additional Connections	91,808	5,229	57
Base Scenario Connections	134,448	3,092	23

The national scale analysis reveals that outcomes are more sensitive to variability at the national scale than at the local scale. These sensitivities are observed in terms of both coverage and connection cost for grid expansion. Moreover, policies related to demand and capital costs would have the most impact on rural electrification. Table 3.13 shows the analysis of finance and cost performance indicators at the national scale. Figure 3.5 shows grid extension for the base, double demand, reduce grid related costs by half, and reduce solar costs by half scenarios. Figure 3.6 displays the outcomes for PV and diesel for the base scenario only.

Table 3.13. Financial and Cost Performances Indicators for Senegal

	Base Case	Double Demand (household, productive, and social Infrastructure)	Reduce grid extension cost by half (MV line and transformers)
New rural Households Connected Grid	134,448	206,659	226,256
Additional Grid electricity Supplied (million kWh/year)	111	270	138.5
Approximate Generation Capacity (MW)[34]	32	77	40
Grid Initial Annual Investment (US$/kWh) (this includes capital cost of MV line, LV line, Transformer, and HH equipment)	1.68	0.97	1.70
Grid Investment (US$/kWh) for MV line and transformer only	1.19	0.93	1.16
Number of meters of MV line per HH	27.5	33.5	36
Number of Meters of LV line per HH	24	26	26
Average Cost per rural HH (USD)	1048 (100%)	1204 (100%)	881 (100%)
LV line and HH Equipment	500 (48%)	527 (44%)	510 (58%)
MV line and Transformers	548 (52%)	677 (56%)	371 (42%)

[34] The approximate generation capacity needed to meet the scale-up in distribution will depend on the type of power plant in the grid-supply mix. Here we assume a generation capacity factor of 40% for the grid-supply mix in Senegal. In reality, the economic growth may require a much higher increase in generation capacity. For example, if the elasticity of electricity demand growth is 1.5 and economic growth is increasing at an annual rate of 5% and if this demand is assumed to be decoupled from the demand estimated here, the true required generation capacity may be five times higher than the figures reported here.

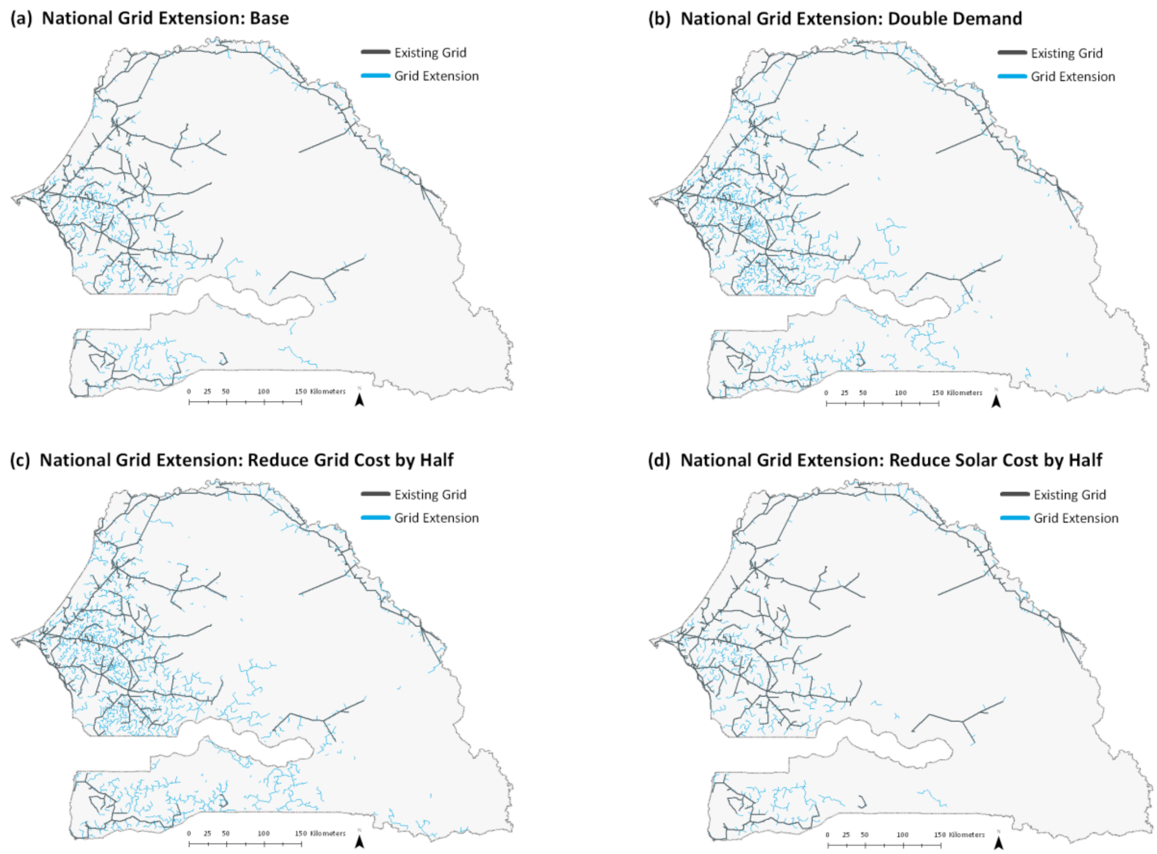


Figure 3.5. Scenarios of grid expansion for Senegal:
(a) Base represents the best estimates of all input demand and cost parameters
(b) Double demand represents the case in which future domestic demands, productive demands, and social infrastructure (i.e. schools and health facilities) demands are doubled; all other input parameters are the same as base scenario
(c) Reduce grid cost by half represents the case in which capital costs for MV infrastructure (MV lines and transformers only) are reduced by half; all other input parameters are the same as base scenario
(c) Reduce solar cost by half represents the case in which the capital costs for solar equipment are reduced by half; all other input parameters are the same as base scenario

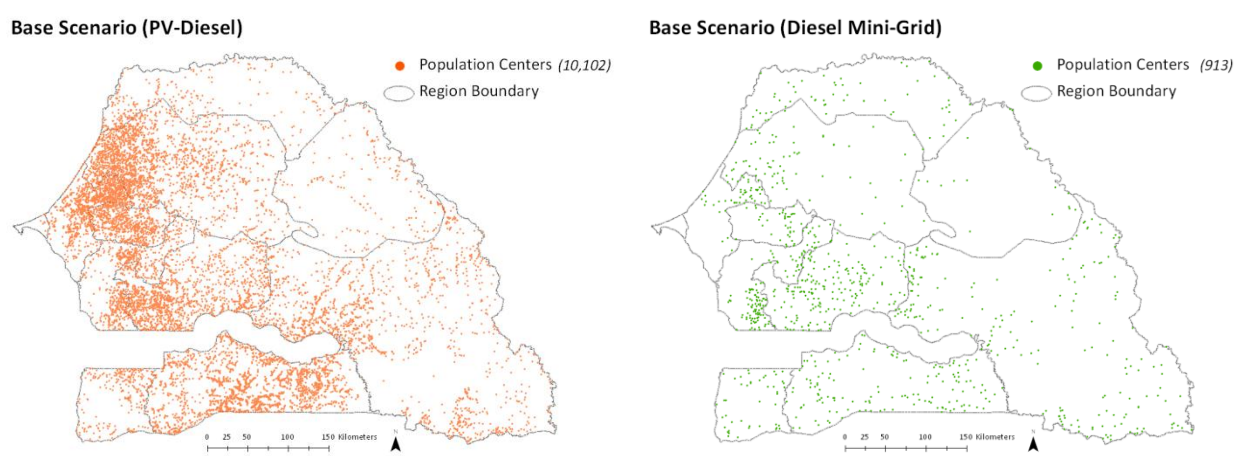


Figure 3.6: Localities compatible (favorable) to Diesel mini-grid and Solar Technologies

7. Comparison with Kenya

In our analysis of national grid expansion in Kenya, we found that households have very high energy demand levels [5]. Both productive and domestic demands are four to five times higher than in Senegal. Moreover, the equipment costs in Kenya are relatively low for all three technologies, about 15 to 20 percent lower than in Senegal. We hypothesized that if a cost regime similar to that in Kenya were applied to Senegal, results would likely yield higher grid coverage even though household connections costs for Kenya are much higher than for Senegal. When we modeled the Senegal data using the base scenario demands level and technology costing inputs for Kenya, a greater proportion of the population were indeed electrified by grid, but at a higher average connection cost (Table 3.14).

Because household demand in Kenya is up to five times higher than in Senegal, the average connection costs for households in Senegal are much higher, particularly for households electrified by the decentralized technologies, diesel mini-grid and PV-diesel. For households electrified by mini-grid diesel, the higher connection cost can be attributed to the increase in the amount of fuel required to meet higher demand levels. As for households electrified by PV-diesel, the higher connection cost can be explained by the higher capital investments in larger PV solar systems to meet the additional household demand. The model results indicate that PV-diesel technology may actually be implemented to meet electrification targets in higher demand areas despite the high costs in implementing the technology.

Table 3.14. Average Connection Cost by Supply Technology for Senegal using Kenya demand levels and technology cost structure			
Base Scenario	**Grid**	**Diesel**	**PV**
Number of additional households connected	337,423	14,265	20
Average connection cost per household (US$)	1375	1322	4216

Using Kenya parameters (demand levels and technology costs) and projections do not make grid expansion more effective as indicated by the finance and cost performance indicators in Table 3.15. Not only does the length of MV line required per household increase, from 27.5 to 34 meters, the length of LV line per household also increase, from 24 to 27 meters. The increase in MV line per household can be explained by grid extension to remote population centers with higher demand, and the increase in LV line per household is probably a result of grid extension to smaller population centers with higher inter-household distances.

Table 3.15. Financial and Cost Performance: Comparison of Senegal Base Scenario and Scenario using Kenya demand levels and technology costing structure		
	Base	**Kenya Inputs**
New Households Connected Grid	134,448	337,423
Additional Grid electricity Supplied (million kWh/year)	111	370
Approximate Generation Capacity (MW)	32	106
Grid Investment (US$/kWh) (this includes capital cost of MV line, LV line, Transformer, and HH equipment)	1.68	1.41
Grid Investment (US$/kWh) for MV line and transformer only	1.19	1.03
Number of meters of MV line per HH	27.5	34
Number of Meters of LV line per HH	24	27
Average Cost per HH (USD) LV line and HH Equipment MV line and Transformers	1048 (100%) 500 (48%) 548 (52%)	1375 (100%) 540 (39%) 835 (61%)

The geography of the two countries is very different. Our analysis of the Kenya electricity grid expansion showed that the population distribution and settlement pattern advance and contribute to rapid electrification. Kenya's population is concentrated in less than one-third of the country, around the western region, where high density population centers are clustered. Moreover, the current electricity grid has been established in this region. Hence, high population density around the current existing grid allowed a model of electrification called intensification, where the planning focus is in connecting additional households in already electrified areas, which in turn, lowers costs. In comparison, the population is much more dispersed in Senegal leading to higher costs because grid expansion will involve connections of greater distances between population centers, as well as, between households within a population center.[35]

8. Concluding remarks and policy recommendations

In the context of decentralization in Senegal, where decision-making power regarding health, education, and rural infrastructures is being transferred to local levels, we have developed and tested a planning model for electricity expansion that can be used at both local and national levels. In addition to the increased involvement of local authorities in energy provision, the development of concession contracts to private energy service providers presents another opportunity for the application of the model outlined in this paper. From either the perspective of public or private energy provision in Senegal, our tool can help planners analyze the issues of

[35] Another intrinsic difference between the two models is that in Kenya we use polygons for the districts while in Senegal we model directly the village points as nodes. In the case of Kenya, working with polygon requires additional internal MV lines.

electricity-distribution network planning at either national or local levels by identifying connection cost drivers of targeted electrification.

The local level analysis reveals that for rural electrification, policies related to demand and grid-related costs are likely to have the greatest impact on increasing grid coverage. And although variability in grid electricity purchase price and diesel fuel price may not affect grid coverage, they may affect average cost per connection. The national level reveals some economies of scale in terms of the average connection cost per household for grid extension. Outcomes are more sensitive to variability at the national scale than at the local scale. These sensitivities are observed in terms of both coverage and connection cost for grid expansion.

We found that at both the local level and the national level, a high percentage of the currently non-electrified population lives in areas where grid costs are more favorable than solar PV and diesel mini-grids if the current cost structure remains the same. An increase in electricity demand by a factor of two or reducing the cost of grid extension by a factor of half would lead to grid extension being a cost-effective technology for a much greater number of households than the base scenario. In either of these cases additional households connected would require nearly twice the length of wire per household, as one is reaching increasingly remote populations. Larger grid coverage, however, reduces the average wire lengths for population centers and households that were also grid-compatible at baseline.

Contributions

Aly Sanoh, Lily Parshall, and Vijay Modi conceived the research ideas and questions. Ousmane Fall Sarr provided the data and commented on the draft. Aly Sanoh and Susan Kum produced the maps. Aly Sanoh conducted the analysis and wrote the paper.

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Appendix 3A

Model Assumptions

The model is based on several assumptions related to demographics, demand and the specifications and unit costs of the three supply technologies. Although some of these assumptions do indeed point to the weaknesses of the model, they do not reduce the value of the model as a preliminary means to assess cost of different electrification scenarios.

First, some general assumptions that underlie the model:

1. Over the fixed time horizon of the planning, the discount rate and inflation are assumed to be constant.[36] The assigned costs of all equipments as well as the diesel fuel cost are fixed over the planning period.
2. Demand grows at the rate of the assumed population growth of the location. The kW peak demand size of any technology is chosen based on the projected demand of the location at the final year of the time horizon. The additional demand that may result from economic growth is not included.
3. The effect of topographical and geographical factors (elevation, rivers, roads, etc.) is negligible in the total cost.
4. There are no electrical engineering design requirements taken into account when generating the potential MV-grid.

[36] We take a fixed time horizon of planning of 10 years and discount rate (obtained after discussion with experts at the World Bank) of 10%. No inflation is applied to the cost of equipments over the time horizon.

Second, the demand assumptions are based on our categorization of village level population sizes. We define four populations categories (pop <500, 500-1000, 1000-5000, 5000-10,000). Demand for households, institutions (i.e. schools), and productive activities (i.e. grinding) are assigned with related assumptions about inter-household distance, household size, and penetration rate. The demand levels used by the model and shown in the table below are adjusted for 15% transmission losses.

Population size (number of people)	**Household (kWh/HH/yr)**	**School (kWh/school/yr)**	**Health Center (kWh/health center/yr)**	**Productive (kWh/HH/yr)**
< 500	73	438	223	20
500-1,000	110	657	335	60
1,000-5,000	450	986	502	70
> 5,000	1398	1478	753	100

Third, the supply technology assumptions are listed in the tables below.

Grid Cost Assumptions

Fixed Initial Cost		
	MV line (US$/km)	16,000
	LV line (US$/km)	12,000
	MV/LV Transformer[37] (US$/kW)	1,000
	Household Fees related to connection, regulator, lamps, installation (US$/HH)	263
Recurrent Cost		

[37] Transformer costs were collected for specific peak demand of 4, 8, 20, 40, and 80kW. The costs reflect a decreasing marginal cost per kW. For any location with peak demand outside of these specifications, the additional kW needed was computed by dividing the difference between the costs of transformers by the difference in their sizes. The cost assumptions reported here refer to the 4 kW peak demand only.

	MV line O&M (% of MV line cost/year)	2
	LV line O&M (% of LV line cost/year)	3
	Transformer O&M (% of transformer cost/year)	3
Lifetime[38]		
	Transformer	10
	Public light	5

Diesel Mini Grid Cost Assumptions

The diesel mini-grid cost structure includes a diesel generator and an LV distribution network (mini-grid). The mini-grid cost structure is the same as the LV portion of grid extension.[39] Studies commissioned by ASER in Senegal show that the cost of a generator is a linear function of its apparent power.

Cost of generator (USD) = 134 * Generator Apparent Power (kVA) + 8920

Using the above formula yields the following capital cost estimates:

Generator Power (kVA)	10	20	30	50
Cost[40] (US$)	12,842	14,535	16,227	19,612

PV-Diesel System Cost Assumptions

[38] Lifetimes considered because some equipment have lifetimes shorter than the project planning horizon.
[39] The mini-diesel LV network could be single-phase, three-phase, or both in a village. Generators are estimated to have a lifetime of five years and consume 0.4 liter of diesel fuel per kWh. The cost of fuel was US$1.08 per liter as of January 2007. The mini-grid technical losses are 5%. Annual maintenance of the system is 5% of the initial engine cost.
[40] Cost includes transport, civil engineering, fuel tank, and installation.

Power (Wp)	50	75	150
Capital			
Panel & Fixing	430	660	1320
Regulator	56	56	56
Batteries	140	150	250
Lamp and accessories	40	40	50
Installation	50	50	100
Total Initial Cost	716	956	1,776

Methodology

The overall methodology estimates the cost and effectiveness of grid extension and derives average connection cost by technology. We have applied this methodology to estimate the cost effectiveness of grid extension at both national and local levels under the same uncertainties scenarios and computation model assumptions.

The step-by-step process to arrive at our results:

First Step: Given all the input parameters and cost assumptions, we compute in an Excel worksheet, the total cost of electrification for every location (node) that is not already electrified. For each node, we calculate the total cost of each technology so that the projected demand at the end of the year of planning is met. Then we compare the costs of stand-alone technologies and grid extension in order to determine the optimal technology solution for each node. Next, we compute for every node, the maximum length of MV (MVmax) line required for the node to connect to the grid. This MVmax allow us to determine the grid compatible nodes.

Second Step: We determine which nodes should be connected to the grid by simulating a grid extension using a modified Kruskal's minimum spanning tree algorithm. For any node to be connected, the following condition has to be met:

MVmax (meters/person)*Pop >= Distance (meters), where Pop refers to the population at the location and Distance refers to the distance between the location and the nearest node (another location or a point on the existing grid).

The modified Kruskal's algorithm programmed in Java:

1. Generates all edges between every pair of points (within a set search radius);
2. Sorts edges by distances in ascending order;
3. Generates potential grid starting with the shortest edge by connecting 2 vertices if they are grid-compatible according to the MVmax (maximum length of MV-line per capita threshold) and the new connection is not creating a loop;
4. Loop on step 3 until all edges have been compared; and
5. Clean independent networks that are too small (eliminate networks that do not meet the specified minimum network size)

The investment needed to reach this optimized electricity coverage is calculated from the target grid extension coverage and unit costs for each technology. The average connection cost is computed based on the number of households connected by each technology.

Chapter 4

Climate change, tax revenue, and intergovernmental transfer in Mali

Abstract[41]

This paper explores the implications of climate change for tax revenues and intergovernmental transfer policies in Mali by addressing two unresolved questions in the literature of public finance and development. First, the study uses exogenous variation in rainfall in a panel data of municipalities to estimate the causal effect of household income shocks on municipal level tax revenue. Second, it measures the impacts of such rainfall variation on intergovernmental transfers. I found that negative rainfall shocks reduce municipal level tax revenues; that these effects are a rural but not an urban phenomenon; that the agricultural zones are the most affected (as compared to nomadic and commercial areas); and that the poorest municipalities are equivalently the most impacted. In the context of intergovernmental transfers, I found that high tax revenue is rewarded with more government transfers. There is no political party targeting, but there is an election cycle effect; the transfers have a lagging effect on future tax revenue.

The policy conclusion drawn from the results points to the enhanced need for reconsidering the potential effects of existing public policies in the context of climate change given that the latter is expected to increase the variation in local rainfall. Because intergovernmental transfers—that is, revenue transfers from central to lower levels of government—are important sources of revenue for municipalities, the Malian government should have a lump-sum grant component that depends solely on municipal characteristics as related to specific shocks to insure municipalities against agricultural productivity shock and provide a better distribution of income. It is important that the government efficiently distribute resources for public investment, such as high quality schools and health clinics or improved roads and markets, because not only do these measures

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directly stimulate economic development—that is, contribute to higher household income—but they also help expand the local tax base.

Keywords: taxes, decentralization, inter-governmental transfers, rainfall, income shocks

1. Introduction

In recent years, the phenomenon of political and fiscal decentralization has gained increasing attention from development policy makers. Within this field, there has been an increasing focus on the possible linkages between fiscal variables and development outcomes. There is ample empirical evidence on the determinants of revenue generation and the allocation of intergovernmental funds. Much has also been written about the exogenous impact of weather shocks. Empirical papers have shed light on the mechanisms of household risk sharing, consumption smoothing, and allocation decisions within the context of random shocks. In this paper, I bridge these two strands of literature by addressing the following question: what is the effect of climate-driven income shocks on households' payment of tax revenues for local public goods provision? I specifically examine the effect of rainfall variations on the local tax revenue collection in farming municipalities in Mali and draw implications for intergovernmental transfers. The paper examines the dynamics of both revenue generation and intergovernmental transfer in the context of exogenous shocks.

The literature on taxation in public finance is vast, yet there is little known about taxes in the specific context of developing countries. Most papers have looked at the determinants of tax compliance in developed countries rather than in developing countries due to a lack of reliable data for developing countries. What we do know is that because of information and enforcement constraints, it is difficult for developing countries to levy taxes on **subsistence farmers and laborers in all cash economies.**[42] Therefore, it remains an empirical question of why widespread differences in tax revenue performances are observed among local authorities and what are the implications of these.

[42] There is also a wide scope for corruption in tax collection. It is, therefore, no surprise that taxation in developing countries is focused on sectors with high information, such as banking, commerce, mining, and manufacturing. Usually, corporations, industries, or enterprises are the target but not individuals.

This question of what determines local tax revenues is important for several reasons. First, rural agricultural districts are vulnerable to weather-induced crop or income losses with immediate and lagged effects on productions. From a public policy standpoint, it is important to clarify the magnitudes and implications of these losses. Focusing on the ultimate fiscal outcomes of the local authorities is important for future sustainable social service financing and public goods provision, and it can be safely argued that fiscal outcome is a good indicator of progress. To achieve a sustainable level of social service funding in Sub-Saharan Africa (SSA), countries, regions, districts, and municipalities must be able to increase tax revenues from an expanding tax base. Given that the agricultural sector is still the largest employer and contributor to the gross domestic product (GDP)[43], raising tax revenues will depend on the dynamism of that agricultural sector, which in turn means growth in agricultural revenues or income at the individual and community levels. Because a small tax base and low tax compliance limit the capacity of local government to provide sustainable financing for services, it is vital to know the effect of random weather fluctuations on fiscal outcome. Second, this research can help the government to incorporate weather into the design of policies aimed at directly stabilizing rural agricultural income or indirectly increasing local authorities' revenues or capacities to provide public goods.

In this paper, I use a unique, local-level panel dataset to primarily estimate the effect of municipal household income shock on tax revenues. I use variation in rainfall as an instrument for income to estimate the impact of income on tax revenues. Although randomized experiments would have been the perfect solution to omitted variable bias, the exogeneity of rainfall

[43] In Mali, agriculture as a value added percentage of GDP has decreased from 69% in 1970 to 36% in 2007. Cereal yields have increased from 707 to 1172 kg per hectare from 1960 to 2008. Total tax revenue as a percentage of GDP has only increased from 13 to 16% from 2000 to 2008.

overcomes this issue and identifies the true causal effect. Rainfall is a good instrument for income, particularly in rural areas that largely depend on rain-fed agriculture, assuming the relative absence of irrigation in a country such as Mali. Variations in rainfall allow me to identify both the causal effect of income shock on tax revenues and the effect as it is reflected in central government transfers from 2000 to 2008.

I find that rainfall has a significant effect on the level of tax revenues collected. For example, a 100mm negative rainfall shock leads to a decrease of 136,300 FCFA[44] (approximately 8% of the mean revenue). Equivalently, one standard deviation in annual rainfall corresponds to an approximately 10% decrease in annual tax revenues for farming municipalities. Furthermore, for every FCFA that the municipality fails to raise from taxes due to lack of rain, it loses approximately 5–7 FCFA from central government transfers. Using proxy income measures at district levels, I find that rainfall significantly affects the probability that a municipality is food-insecure and facing income difficulties. An annual rainfall 1% below the mean historical district rainfall increases the probability of the district encountering food or income difficulties by 0.3%. Among the crops grown in Mali, only the yield of millet (the main staple) is significantly related to rainfall. A 1% increase in annual rainfall relative to the mean historical district rainfall increases both millet production and yield by approximately 0.5%. This statistic is important because millet represents 40% of the total cereal production in Mali.

I also investigate whether the presence of physical infrastructure (paved roads, electricity) and the sizes of the municipalities affect government distribution amid rainfall uncertainty. I find that the presence of physical infrastructure does not significantly mediate the effect of rainfall

[44] The FCFA is the common currency used in Mali and many other African countries. It stands for Franc of the African financial community

through tax revenues on government transfers. I also find that the effect of rainfall is not mediated by the size of the municipalities.

Lastly, I find that there is a cyclical negative mechanism taking root meaning that decreased rainfall leads to decreased revenue for some municipalities. Consequently, the government bestows lower transfers on these affected municipalities, which again affects the level of tax revenues.

The outline of this paper is as follows. In section 2, I review the literature on the determinants of tax revenues. In section 3, I provide a background on taxation in Mali. In section 4, I describe the data. In section 5, I outline the empirical strategy used in this study. I present my results with interpretations and implications in section 6, and in section 7, I conclude with the policy implications of the results.

2. Literature

A wide array of literature has sought to link taxation to development. At the macro level, a number of empirical studies have examined the determinants of tax revenues in developing countries [1, 2]. More specifically, Saeid Mahdavi [3] has studied the level and composition of tax revenue in developing countries by using unbalanced panel data. Khattry and Rao [4] have investigated the tax revenue implications of trade liberalization, whereas Ghura [5] and Tanzi and Dawoodi [6] have focused on the effect of economic policies and corruption on tax revenues. For studies focusing mainly on Sub-Saharan Africa, Stotsky and Woldemariam [7] used a panel data of 43 countries from 1990 to 1995 to measure the determinants of tax shares and tax efforts. They found that countries with a relatively high tax share tend to have a relatively high index of tax effort. Ghura [5] studied 39 Sub-Saharan African countries from 1985 to 1996 and found that tax revenue performance is affected by economic policies and corruption. He demonstrated that revenue rises with declining inflation, the implementation of structural reforms, rising human capital, and declining corruption. Terence et al. [8], using a panel of 22 countries in Sub-Saharan Africa from 1980 to 1996, perform Generalized Method of Moment regressions to show that trade liberalization positively affects tax revenue, although the result is sensitive to the measure used to proxy for trade liberalization. Bird et al. [16] found that if taxpayers perceive that their interests are properly represented in political institutions and that the governance is good, then their willingness to contribute by paying taxes increases.

At the local level, empirical studies have examined the specific effects of political, fiscal, administrative, geographic, and socio-economic factors on revenue generation. Allers et al. [10] and Solé-Ollé [9] have analyzed the effect of partisan politics and electoral competition on tax revenue generation. De Mello [11] has measured the effect of local public spending in Brazil on local, per capita tax revenue growth. Tewodaj Mogues [12] evaluated the impact of government transfers on local tax revenues in Ghana. Odd-Helge Fjeldstad [13] found that differences in revenue performance among local authorities are due to variations in the degree of coercion involved in tax enforcement.

I examine tax revenue performance in the context of exogenous income shocks. Although different aspects of tax revenues have been analyzed both at the macro and micro levels, to the best of my knowledge, no empirical study has evaluated the effect of income shock on taxes and its implication for government transfers. Within the existing work, this study aims to provide additional insights, within the context of decentralization, into the functioning of local government, especially in relation to tax revenue performance, public goods delivery and the distribution incentive problems faced by central government.

3. Background

3.1 Local government and Taxation

Mali has been one of the most successful stories of democratization and decentralization in Africa. Starting in the late 1990s, the country established local, government-endowed municipalities with autonomy and distinct responsibilities, which they are authorized to enforce. In every municipality, council members are directly elected to the local government by a proportional vote. Mali is an ideal country in which to study the effect of rainfall variation on tax revenue outcomes for two reasons. First, the country is sufficiently large to encompass many geographic zones, ranging from desert to wet savannah. Second, since 1999, Mali has been working on and has now completed a decentralization process that led to the creation of 705 municipalities and the first elections of municipal council-members. For these reasons, Mali is an interesting country to analyze in the context of local taxation policy. Although these council-members are elected by a proportional vote, they themselves elect a mayor of the municipality. Because decentralization was intended to bring decision making closer to the concerned populations, municipalities were granted the responsibilities of raising revenues and providing public goods services in the areas of health, education, and rural infrastructures.

In Mali, as in many African countries, local governments tend to raise whatever taxes, fees, and charges they can levy without considering the economic distortions and distribution effects that these instruments may create. Malian municipalities can raise revenues through taxation on households, livestock, transport, and firearms or through other means such as commercial licenses and permits. The tax raised on households is the TDRL (Local and Regional Development Tax). This “head tax” is paid by every head of family, and it represents over 75% of the total revenues raised by municipalities [14]. The TDRL is a flat tax that varies by municipality and region. It varies from $1.5 to $6 per capita per year.[45]

Municipalities have the mandate to tap many sources of tax revenue, which represent their biggest financial resource, but the amount they can access is far below what is required to finance investment needs. Because of the lack of financial resources to adequately provide better access to basic social services, especially education, health, and drinking water, the Malian government supports municipalities through a matching grant system. A state agency called ANICT (Agence Nationale d'Investissements dans les Collectivités Territoriales) annually transfers funds to municipalities to carry out the public goods projects. These transfers represent 60–70% of the total local government spending on public goods.

[45] Although the tax is applied to anyone older than 14 years, it exempts veterans, women with more than 4 children, full-time students, and people over 60 years old.

3.2 Overview of the ANICT Common Fund

In 2004, ANICT was annually funded by the central government (10%) and foreign donors (90%). Ninety-five percent of the total funds received by ANICT were disbursed to municipalities, whereas 5% was retained for operations expenses. Equally, 97% of taxes collected by municipalities were disbursed back to them, and 3% was retained by ANICT for operational expenses. All financial transactions between municipalities and the agency go through the national treasury (Figure 4.1). The funds are allocated among municipalities based on their population, tax performance, remoteness, and wealth index. For every qualified public investment project, the municipalities contribute 20%, whereas ANICT finances 80% of the total cost [15]. Because taxes serve as one criterion with which to allocate these funds, any effect of rainfall on taxes is reflected in central government transfers.

The Malian central government framework for the allocation of donor funds to municipalities faces a dilemma of how to balance incentives, promote revenue generation and ensure equity across municipalities. Therefore, the allocation formula has built-in criteria that meet the goals of equity and incentivizing. Equal weights are given to the municipal population level and tax revenue generation performance as well as to infrastructure needs and remoteness. Based on the available budget from governments and donors, the state agency annually computes an index for each municipality. Specifically, the funds to be transferred to each municipality are equal to that municipality's index times the total budget ($Tranfer_{it} = I_{it}*Budget_{it}$). The index I_{it} is a weighted mean of 4 indices, population (30%), taxes (30%), remoteness (20%) and infrastructure need (20%). Population and revenue generation criteria favor rich and urban municipalities, whereas infrastructure level and remoteness criteria favor poor communities. This fund allocation formula has remained fixed since its inception in 2000.

It is worth noting that the remoteness measure, which is based on the sum of the distance between each municipality and its district capital as well as between each municipality and the country capital, is fixed. The population measure has been extrapolated with an annual fixed growth rate based on the 1998 census. The infrastructure needs (wealth index) are measured every 3 years. Therefore, the only discernible annual variance in the formula arises from annual changes in tax revenues. Tax revenues, which can be affected by rainfall, explain most of the variation in annual fund allocation. In this paper, I argue that the central government's revenue generation incentives penalize or reward municipalities based not only on effort but also on random rainfall shocks. Richer municipalities raise more taxes and therefore are rewarded more transfers while the poor municipalities mostly in rural farming zones raise less revenue due to random shock to their revenue from rainfall variation and are penalized with less transfer (See figure 4.4).

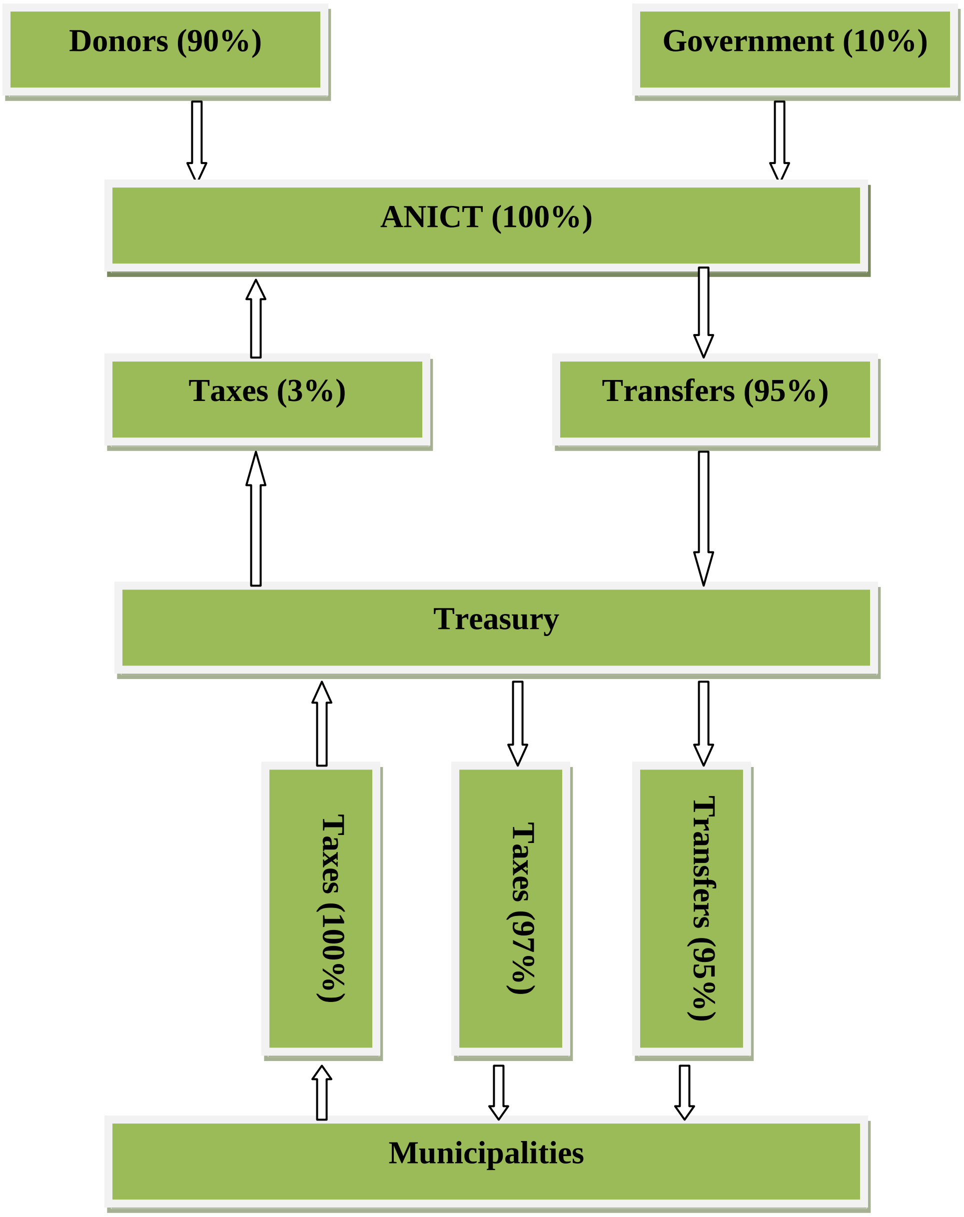

Figure 4.1: Intergovernmental transfers

4. Data

The research draws on multiple sources of data. The main tax data, which are not publicly available at present, were obtained from the office of the DNCT (Direction Nationale des Communautés Territoriales). These data cover the years 1999–2008, although there are many missing values for the latter years. The complement to these tax data was obtained from the ANICT for the years 2007 and 2008. The full panel data contains the amount of tax issued and collected by municipality and year as variables. The data on transfers to local government were separately obtained from ANICT. These transfers constitute a dataset of 10,256 projects that have been implemented through the municipal investment funds. The projects are categorized by objectives: economic, social, and environmental. The economic projects include the construction of banks, shops, administrative offices, and computer centers and providing mills, engines, and other materials. The social projects mainly involve building health centers and schools, including supplying the equipment for these institutions. The environmental projects include irrigation, agricultural equipment, storage, reforestation, and waste management. The total capital investment of every project is given and broken down by government and municipality contributions from 2000 to 2008.

The basic hypothesis of this paper is that climatic conditions affect revenue levels and central government transfers. I use only rainfall as a measure of this climatic condition because of the inability to acquire temperature data at the desired scale. The rainfall data are from the NASA TRMM (Tropical Rainfall Measuring Mission). It is a gridded data of 0.25 by 0.25 square km available for the globe from 1998 to present. I use historical annual rainfall values averaged over 705 Malian municipalities from 2000 to 2008. Additional data on yields of millet, sorghum, rice and maize were obtained from FAO (Food and Agricultural Organization), but only at district levels. Other welfare indicators, such as measures of food insecurity and income difficulty at district levels, were obtained from SAP (Système D'Alerte Precoce). Data on municipal socioeconomic and demographic variables were derived from the survey, "Enquête légère intégrée auprès des ménages" (ELIM 2006), and the measures of poverty were obtained from two publications of "Observatoire du développement humain durable et de la lutte contre la pauvreté" in 2003 and 2006.

In Mali, there are many anecdotal accounts of high variations in revenues collection, particularly in the cash crop cotton farming region, where the income earned from cotton is used to pay taxes. Many government reports point to a low contribution of taxes during years with dry conditions (inadequate rainfall). However, there is no study of the magnitude of this revenue-decreasing effect. In the data, there are indeed high variations in tax revenues among municipalities and from year to year. The tax compliance rate varies from 20 to 95%. Rainfall and government transfers present equally large between and within variations at the municipality level.

Summary statistics for the main variables are presented in Table 4.1. The average rainfall is 662 mm per municipality per year with a standard deviation of 250 mm. In general, rainfall increases from south to north with large variations from year to year. Total tax revenue ranges from 6000 to 0.710 billion FCFA, whereas government transfers average 0.144 billion FCFA per municipality per year.

Variable		Mean	Std. Dev.	Min	Max	Obs
Tax Revenue (FCFA)	overall	4,653,617	4,256,282	6000	$7.10*10^7$	N = 6246
	between		3,280,756	140553	$2.69*10^7$	n = 694
	within		2,714,104	$-1.79*10^7$	$6.28*10^7$	T = 9
Head Tax (FCFA/pers)	overall	1658.523	435.35	875	2600	N = 6246
	between		435.63	875	2600	n = 694
	within		0	1658.52	1658.52	T = 9
Revenue per capita (FCFA/pers)	overall	1042.165	3157.97	1.285971	73,662.13	N = 6237
	between		2956.12	19.08083	54,615.52	n = 693
	within		1115.93	−19,916.96	27,494.5	T = 9
Annual Rainfall (mm)	overall	662.1847	250	48.7	1466.4	N = 6228
	between		209.77	96.28	1053.41	n = 692
	within		136.21	242.01	1273.29	T = 9
Government Transfer (CFA)	overall	1.44e+07	$1.87*10^7$	0	2.66e+08	N = 6246
	between		7,322,201	0	$6.45*10^7$	n = 694
	within		$1.72*10^7$	−5.01e+07	$2.16*10^8$	T = 9
Population	overall	14,361.04	12526.52	0	174,327.5	N = 6238
	between		12,447.28	0	154,706.9	n = 694
	within		1497.67	−3906.894	33,981.65	T = 9

Table 4.1: Descriptive statistics

5. Empirical strategy

In general, estimating the impact of income shocks on the tax revenue performance is difficult because of omitted variable bias and endogeneity. To overcome this empirical challenge, I use exogenous variation in municipal income caused by rainfall over time to identify the causal effect of income shock on tax revenues. Given that 85% of the 705 municipalities are rural with a livelihood based on rain-fed agriculture, it is safe to use rainfall as a proxy for income shocks.

I acknowledge upfront that tax revenue performance in a developing country context is particularly difficult to explain given the many factors (social, political, economic, and structural) that are in play. Specifically, municipal households can pay higher or lower taxes for many other reasons than being richer or poorer. For example, we know that communication and enforcement can play a significant role; the capacity of the local authority to collect matters; the provision of public services and corruption are factors that count; and importantly, households can act strategically based on expected payoffs from tax compliance. However, in Mali, many anecdotal accounts point to income as the main mechanism that links the exogenous shock to tax outcome. Rainfall variations affect agricultural production, which affects household income, which in turns affects people's ability to meet tax obligations. In rural areas where **agriculture represents the main source of employment and income**, tax contributions can be dependent on rainfall. Figure 4.5 presents non parametric evidence of the positive relationship between rainfall and the main staple crop millet yield as well as between rainfall and tax revenue. In years of good rainfall, households have more financial resources than in years of inadequate rainfall. The goal of my study is to try to explain the inter-municipal and inter-annual variations in tax revenues that are partially due to random variations in rainfall patterns; I then seek to evaluate the effect of this variation on intergovernmental transfers.

The basic estimating equations for municipality i in year t are as follows:

Reduced Form

$$Y_{it} = a + \gamma^{*}R_{it1\text{-}2} + y_t + m_i + \varepsilon_{it}, \quad [1]$$

Two Stage Least Square

First Stage

$$T_{it\text{-}1} = b + \lambda^{*}R_{it\text{-}1} + y_t + m_i + \varepsilon_{it}, \quad [2]$$

Second Stage

$$Y_{it} = c + \beta^{*}T_{it\text{-}1} + y_t + m_i + \varepsilon_{it}, \quad [3]$$

where $\mathbf{Y_{it}}$ is the total amount of government transfer (which can also be a proxy for local government spending), $\mathbf{R_{it}}$ is rainfall in (mm) and $\mathbf{T_{it}}$ is the tax amount collected. The parameters of interest λ and β give the effect of rainfall on tax revenues and government transfers, respectively. y_t is included to capture the aggregate time effect in year t that is common to all municipalities. m_i is included to capture municipal-fixed effects in all stages of the regressions.

6. Empirical Results

6.1 Rainfall, agricultural production, and income

The rainfall pattern in Mali is characterized by two rainfall periods per year: a dry season and a rainy season. The intensity of the rain can vary widely across the country and from year to year. The main staple crop, millet, is rain-fed, whereas other important crops such as sorghum, rice, and cotton are mildly irrigated.[46] Other less important crops include maize, coffee, cassava, niebe, and fonio. The extremely drought-resistant sorghum is the second most important crop, followed by rice, which is heavily irrigated. In the Malian agricultural records, drought has been more of a problem than flooding, and one of the main sources of uncertainty in most of the agricultural communities is currently the variability of rainfall patterns. Although part of this variability can be anticipated to some degree, the geographic and year-to-year deviations are sufficiently large to greatly affect agricultural production and income.

There are no disaggregated agricultural data in Mali. However, at the district level, I find that rainfall has a significant impact on millet production and yield but not on other crops such as sorghum, maize, and rice. Therefore, years of unusually high rainfall are associated with high millet production and yield. For a district rainfall that is 1% higher than normal (the historical mean rainfall), millet production and yield each increase by approximately half a percentage point (Table 4.2). However, crop data are subject to numerous sources of measurement error, and

[46] Millet, rice, and sorghum remain the basic staple foods for the majority of the country. Millet, which has been traditionally the most widely consumed, is very sensitive to rainfall. In recent years, rice has become a popular substitute for millet in urban areas. Sorghum is generally more important for rural than for urban households.

I do not have direct measures of income levels; I therefore used two additional measures of agricultural income at the district level to estimate the effect of rainfall. Both food and income security indicators tend to vary seasonally, and the Malian government uses these indicators to assist different districts under shock conditions. Both measures are dummy indicators of whether in any given year a municipality is facing income or food difficulty in its population. I found that a 1% positive deviation in rainfall with respect to the mean normal in the district significantly increases the probability of encountering food or income difficulties by approximately a third of a percentage point (Table 4.3).

	Dependent Variable: Production and Yield (log)							
	Millet		Sorghum		Maize		Rice	
	Production	Yield	Production	Yield	Production	Yield	Production	Yield
Rainfall Dev. (log)	**0.54***	**0.55*****	−0.23	0.01	−.06	0.009	0.04	−0.05
Std. Err.	(0.26)	(0.14)	(0.30)	(0.14)	(0.37)	(0.13)	(0.23)	(0.12)
District FE	Y	Y	Y	Y	Y	Y	Y	Y
Year FE	Y	Y	Y	Y	Y	Y	Y	Y
N	371	371	346	346	320	320	362	362

legend: * p<0.05; ** p<0.01; *** p<0.001

Table 4.2: Effect of rainfall on agriculture

Notes: All specifications include district and year fixed effects. Rainfall deviation is exactly log annual rainfall minus log historical mean rainfall for the district.

Food and Income Severity			
	Food	Income	Food_income
Rainfall Deviation (log)	**−0.31*** **	**−0.32** **	**−0.39*** **
Std. Err.	(0.08)	(0.11)	(0.11)
District FE	Y	Y	Y
Year FE	Y	Y	Y
N	441	441	441

legend: * p<0.05; ** p<0.01; *** p<0.001

Table 4.3: Linear Probability

Notes: All specifications include district and year fixed effects. Rainfall deviation is exactly log annual rainfall minus log historical mean rainfall for the district.

6.2 Rainfall and Tax revenues

In equatorial countries such as Mali, rainfall is the most important climatic feature because temperature has a tendency to remain invariant both within and across years. Although the intensity of the wet and dry seasons varies heavily across the country, the length of seasons is the same throughout the region. I first look at the effect of rainfall on tax revenues in the full data and within different subsample categories: administrative (urban versus rural) and agricultural (farming versus non-farming) area classifications (Table 4.4) and quintile of income poverty groups (Table 4.5). The regressions in these tables correspond to the first stage in equation [2] above.

I find evidence supporting the hypothesis that income shocks reduce tax revenues. This finding is significant for rural municipalities but not for urban municipalities. The finding is also significant for farming zones but not for non-farming zones. The negative effect on tax revenues of income shocks is also true for the first quintile group of poverty because it represents mostly rural areas. For example, a 100 mm negative rainfall shock leads to a drop of 136,300 FCFA (approximately 8% of the mean revenue). Equivalently, one standard deviation in annual rainfall corresponds to an approximately 10% decrease in annual tax revenues for farming municipalities. This rainfall effect is contemporaneous, and there are no lag effects. As a falsification test, I also look at the effect of future rainfalls by adding rainfall in years (t+1) and (t+2) while maintaining municipality and year fixed effects. For all of the regressions, future rainfall does not affect current tax revenues. Population appears to be a significant factor only in the rural sample of municipalities.

Variable	Tax Revenue (level this year)						
Sample	All	All	Rural	Urban	Farming	Nomadic	Trade and Mining
Rain (t)	1362*** (388)	1379*** (394)	1151** (384)	2000 (1268)	1392** (426)	1088 (1159)	1227 (3321)
Rain (t−1)		542 (471)	185 (424)	1143 (1780)	699 (513)	605 (1030)	−4005 (4336
Rain (t−2)		−562 (420)	−455 (358)	126 (1431)	−549 (454)	1355 (1579)	−4370 (4614)
Rain (t+1)		−309 (360)	−229 (377)	−821 (1050)	−257 (389)	534 (1166)	−5289 (2568)
Rain (t+2)		194 (431)	420 (386)	−550 (1568)	−5 (474)	1191 (1574)	927 (2732)
Pop (t)		179 (101)	484*** (125)	109 (239)	162 (105)	130 (392)	274 (188)
N	6228	6228	4779	1179	5652	441	135
R^2_a	56	56	57	52	55	47	49

legend: * p<0.05; ** p<0.01; *** p<0.001

Table 4.4: Effect of rainfall on tax revenues

Notes: Robust and clustered standard errors at the municipality level are given in parenthesis. All regressions include municipality and year fixed effects.

Variable	Tax Revenue (level this year)				
Sample	Q1	Q2	Q3	Q4	Q5
Rain (t)	1302***	−974	2454	786	2111
	(374)	(944)	(1452)	(1960)	(1610)
Rain (t−1)	727	−337	−1082	−2632	1878
	(450)	(1066)	(1760)	(2096)	(2203)
Rain (t−2)	−353	−1244	−472	−132	−2206
	(430)	(863)	(1381)	(1722)	(1888)
Rain (t+1)	14	−1387	1916	−283	−2713
	(400)	(1009)	(1337)	(1669)	(1783)
Rain (t+2)	444	239	1468	1325	−2829
	(422)	(852)	(1403)	(1439)	(1867)
Pop (t)	440*	842*	1208*	113	−23
	(213)	(362)	(380)	(292)	(103)
N	3429	702	666	495	936
R^2_a	49	62	52	47	51

legend: * p<0.05; ** p<0.01; *** p<0.001

Table 4.5: Effect of rainfall on tax revenues for different poverty groups

Notes: Robust and clustered standard errors at the municipality level are given in parenthesis. All regressions include municipality and year fixed effects.

Next, I look at whether rainfall shocks in the different agricultural seasons have differential impacts on tax revenues. In addition to the annual rainfall measure, I construct three seasonal measures. The first is rainfall during the sowing period, the second is rainfall during the rainy months from May to August, and the last measure is the total amount of rainfall during the growth stage of the crops (Figure 4.2). The results are presented in Table 4.6. Estimates of the effect of seasonal rainfall on tax revenues are similar to that of the yearly rainfall, but the results reveal that rainfall during the rainy season and the growth period of crops are particularly important. For example, a shock of 100 mm of negative rainfall during the growth stage of crops reduces tax revenues on average by 325,100 FCFA, which is almost three times the effect on revenues during the rainy season or the annual period. In comparison, rainfall during the sowing period, which corresponds to the first months of the rainy season, has little effect on tax revenues.

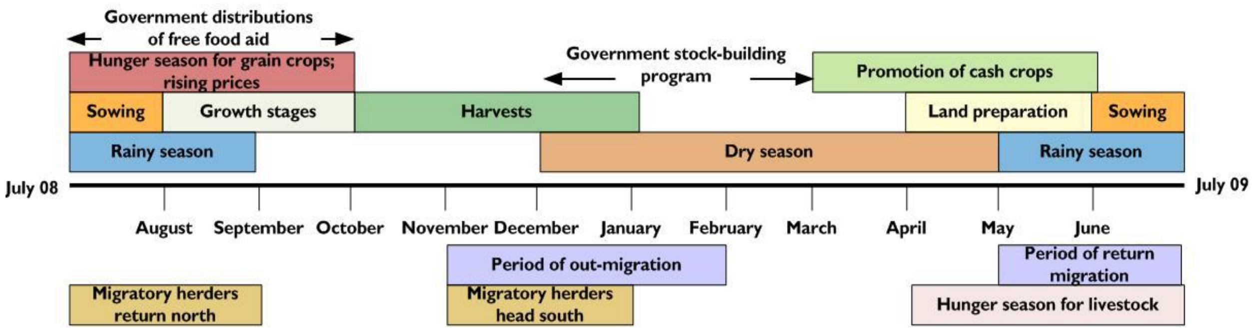

Figure 4.2: Seasonal calendar
Source: FEWS NET

Variable	Tax Revenue (level this year)		
Sowing (t)	925 (566)		
Sowing (t−1)	1102 (749)		
Sowing (t−2)	−1051 (570)		
Pop (t)	181 (102)	180 (101)	180 (101)
Growth (t)		3251** (1002)	
Growth (t−1)		−1168 (1115)	
Growth (t−2)		669 (1003)	
Rainy (t)			1179* (457)
Rainy (t−1)			840 (4910
Rainy (t−2)			−619 (454)
N	6228	6228	6228
R^2_a	56	56	56

legend: * p<0.05; ** p<0.01; *** p<0.001

Table 4.6: Seasonal effect of rainfall on tax revenues

Notes: Robust and clustered standard errors at the municipality level are given in parenthesis. All regressions include municipality and year fixed effects.

6.3 Tax revenues and intergovernmental transfers

After finding evidence supporting the hypothesis that income shocks reduce tax revenues, I turn to the ultimate effect on intergovernmental transfers for public goods provision. The reduced form and second stage regression results are presented in Tables 4.7 and 4.8. Using lagged rainfall for two periods, I found that rainfall has a prolonged, significant effect on government transfers to municipalities. For example, in Table 4.7, a 100 mm negative rainfall shock compared to the rainfall totals of the two previous years decreases government transfers by approximately 924,100 and 2,021,200 FCFA, respectively. These effects correspond to 7 and 15% decreases relative to the mean transfer, respectively. In terms of the elasticity of the transfers with respect to tax revenues (Table 4.8), I found that for every amount that the municipality fails to collect from taxes due to lack of rain, it loses approximately 5–7-fold as much from decreased central government transfers.

Variable	Government Transfer (level this year)		
Rain (t)	−2544 (2117)	−2594 (2117)	−2544 (2117)
Rain (t−1)	9241*** (1999)	9193*** (2001)	9241*** (1999)
Rain (t−2)	20,212*** (2238)	20,251*** (2237)	20,212*** (2238)
Pop (t)	2037*** (334)	2042*** (329)	2037*** (334)
Indicator State Party (t)		948,885 (763,764)	
Indicator election year (t)			28,021,077*** (1,711,395)
N	6228	6228	6228
R^2_a	39	39	39

legend: * p<0.05; ** p<0.01; *** p<0.001

Table 4.7: Effect of rainfall on government transfers

Notes: Robust and clustered standard errors at the municipality level are given in parenthesis. All regressions include municipality and year fixed effects.

Variable	Government Transfer (level in this year t)				
Revenue (t−1)	7.07**	6.99**	6.55*	5.99*	6.59*
	(2.64)	(2.71)	(2.84)	(3.02)	(2.90)
Pop (t)	1389	1393	993	773	1241
	(860)	(8600	(1353)	(1619)	(852)
electricity*revenue		0.0085			
		(0.0349)			
infrastructure*revenue			1.129		
			(3.558)		
counselors*revenue				0.114	
				(0.276)	
personnel*revenue					0.023
					(0.056)
N		5536	5536	5536	

legend: * p<0.05; ** p<0.01; *** p<0.001

Table 4.8: Effect of tax revenues on government transfers

Notes: Robust and clustered standard errors at the municipality level are given in parenthesis. All regressions include municipality and year fixed effects.

6.4 Political Economy Factors

Providing public goods, insuring against unexpected risks or shocks, and redistributing income are all basic functions of any government, but occasionally, politics may interfere with these functions. Therefore, I additionally examine whether intergovernmental transfers are affected by political alliances and election cycles. Some studies [17, 18] have found that a government's central distribution of investment for public goods is at times politically motivated. Banful [19], for example, found that in Ghana, there is tendency to allocate more funds to incumbents' districts and that there is an election cycle effect in the disbursement. The most important feature of intergovernmental transfers is that they aim to distribute more resources to poor communities than to rich communities, regardless of those communities' political affiliations. The results of the effect of political factors on intergovernmental transfers are reported in Table 4.7. I use two indicators of political influence: whether a municipality has a mayor belonging to the same party as the government party and whether it is an election year. There is no tendency to allocate more funds to municipalities represented by the incumbent political party. However, more funds are significantly disbursed during election years than in non-election years; therefore, there is an election cycle effect.

I also investigate whether the presence of physical infrastructure (e.g., paved roads, electricity) and the size of the municipalities affect government distribution amid rainfall uncertainty. I find that the presence of physical infrastructure does not significantly mediate the effect of rainfall through tax revenues on government transfers. I also find that the effect of rainfall is not mediated by the size of the municipalities (measured by the number of counselors and personnel).

Lastly, I find that there is a cyclical negative mechanism taking root in municipalities, meaning that decreased rainfall leads to decreased revenue for some municipalities. Consequently, the government bestows lower transfers on these affected municipalities, which again affects the level of tax revenues. Although the magnitude of this last effect is very small, it remains highly significant (Table 4.9).

Variable	Tax revenue (level this year)		
Rain (t)	1333***	1379***	1778***
	(387)	(394)	(423)
Pop (t)	180)	179	
	(100	(101)	
Rain (t−1)		542	
		(471)	
Rain (t−2)		−562	
		(420)	
Rain (t+1)		−309	
		(360)	
Rain (t+2)		194	
		(431)	
Gov. Transfer (t-1)			0.010***
			(0.003)
N	6228	6228	5536
R^2_a	56	56	56

legend: * p<0.05; ** p<0.01; *** p<0.001

Table 4.9: Effect of transfers on tax revenues

Notes: Robust and clustered standard errors at the municipality level are given in parenthesis. All regressions include municipality and year fixed effects.

7. Policy Conclusion

In this paper, I have investigated the role that climatic change has played in revenue collection in municipalities across Mali. I assembled a panel data set that allowed me to estimate the effect of rainfall on agricultural production and tax revenues. The results of the econometric analysis suggest that climatic change, as proxied by rainfall, has altered tax revenue collection. Income shocks from rainfall affect tax revenues and government transfers. The magnitudes of these effects are important and have the following implications:

a- Policies: The results call attention to the importance of the policy and economic context when designing climate adaptation policies. If climate change is expected to increase the variability of temperature and precipitation, it is important to know the unintended and indirect consequences that may occur as a result. In this case, rainfall not only directly affects tax revenues through its effect on agricultural production but also significantly indirectly affects the allocation of central government transfers for public goods provision. In this specific context, estimates of the benefit of climate change adaptation investments such as irrigation may be underestimated because such investment not only protect local revenues but it also ensure more transfers from government

b- Role of government

Establishing the link between tax revenues and transfers to local government highlights the tradeoff between efficiency and fairness in the interaction between the two levels of government. Whereas a government policy that uses taxes as a criterion for public funds allocation justly rewards municipalities that are good tax collectors, such a policy may not be efficient in this particular case. Municipalities that tend to have longer, successive droughts may fall behind in the provision of public goods not because of lack of revenue-collection effort but because of random shocks. Rural farming areas have had lower revenues because of continued decrease in rainfall and the government has been penalizing them with less transfer.

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Appendix: maps and graphs

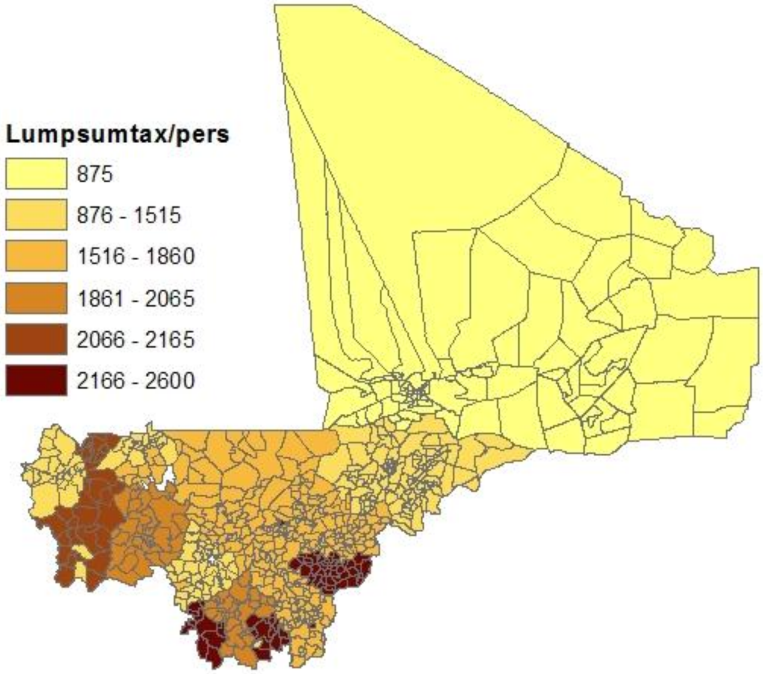

Figure 4.3a: Municipality level distribution of the lump sum head tax per person

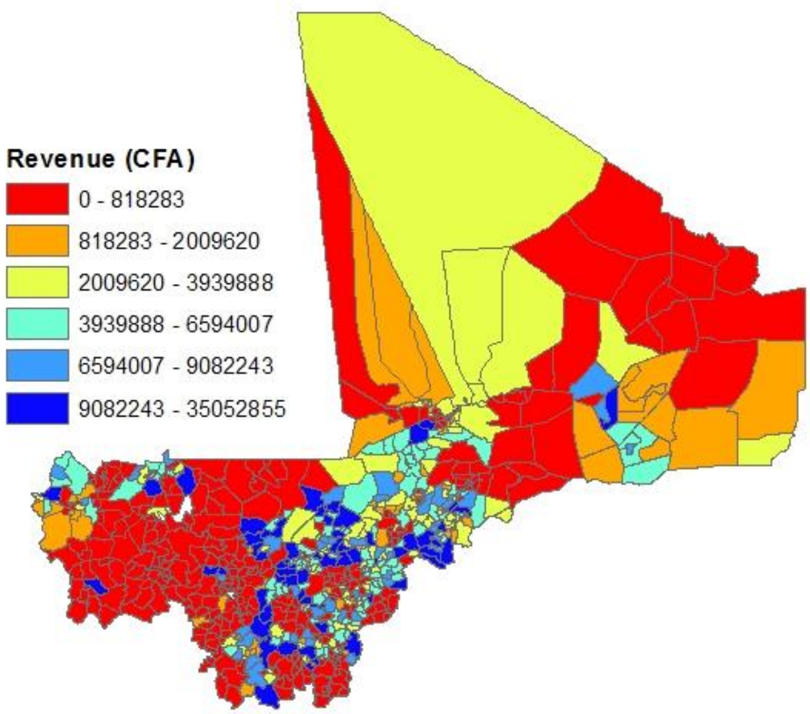

Figure 4.3b: Municipality level distribution of absolute tax amount raised in 2006

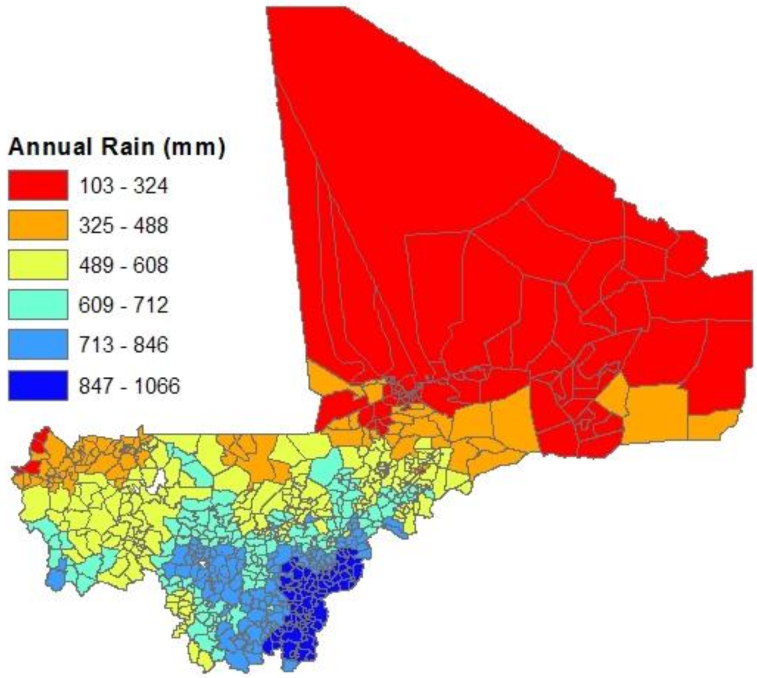

Figure 4.3c: municipality level distribution of annual rainfall

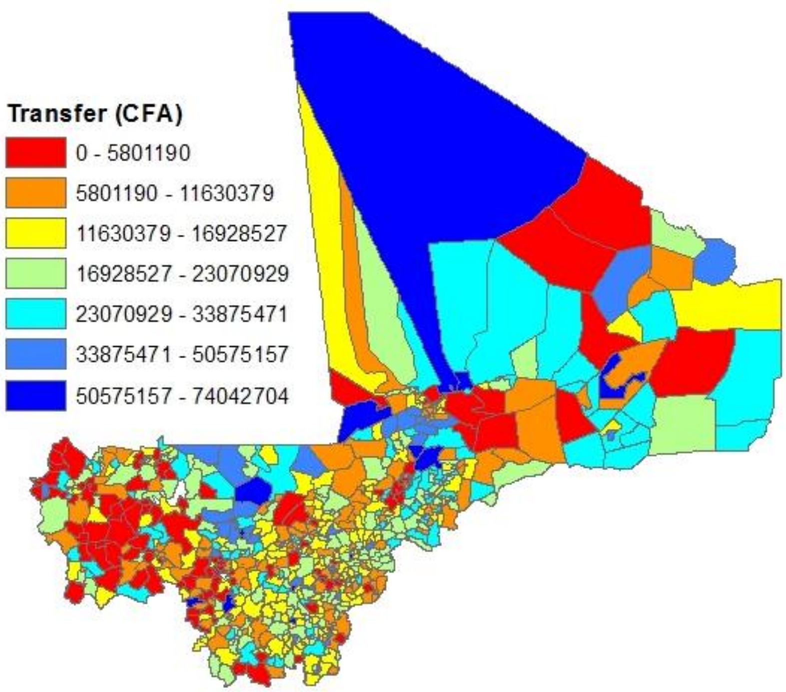

Figure 4.3d: Municipality level distribution of the central government transfers in 2006

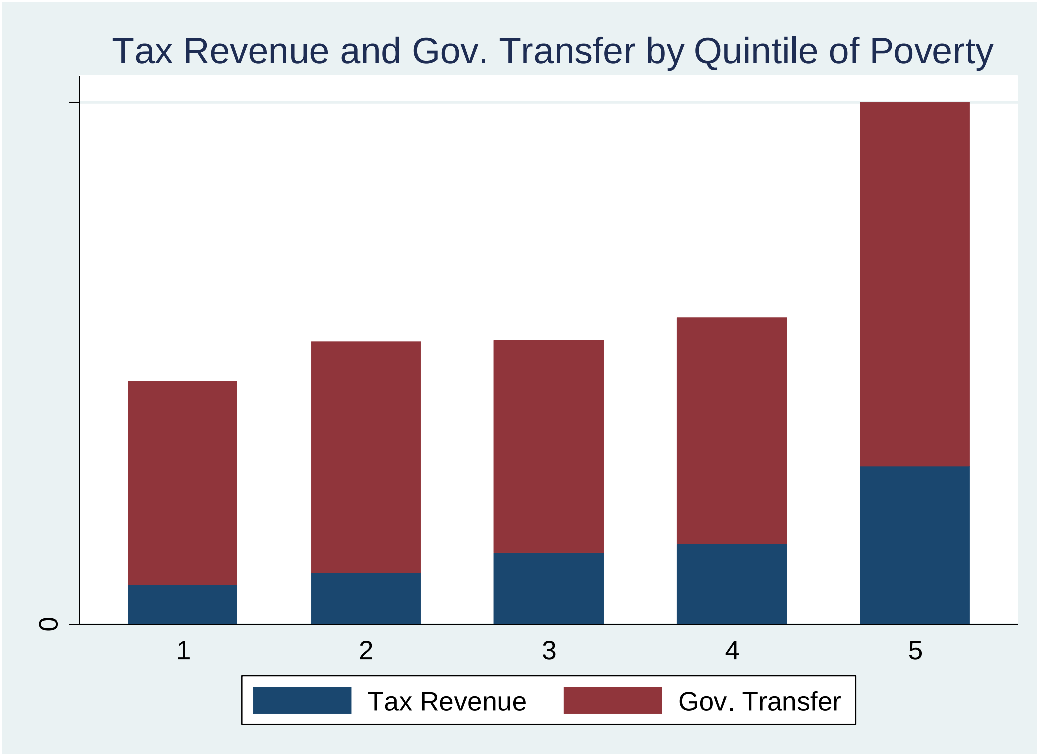

Figure 4.4: Tax revenue and government transfer by quintile of poverty

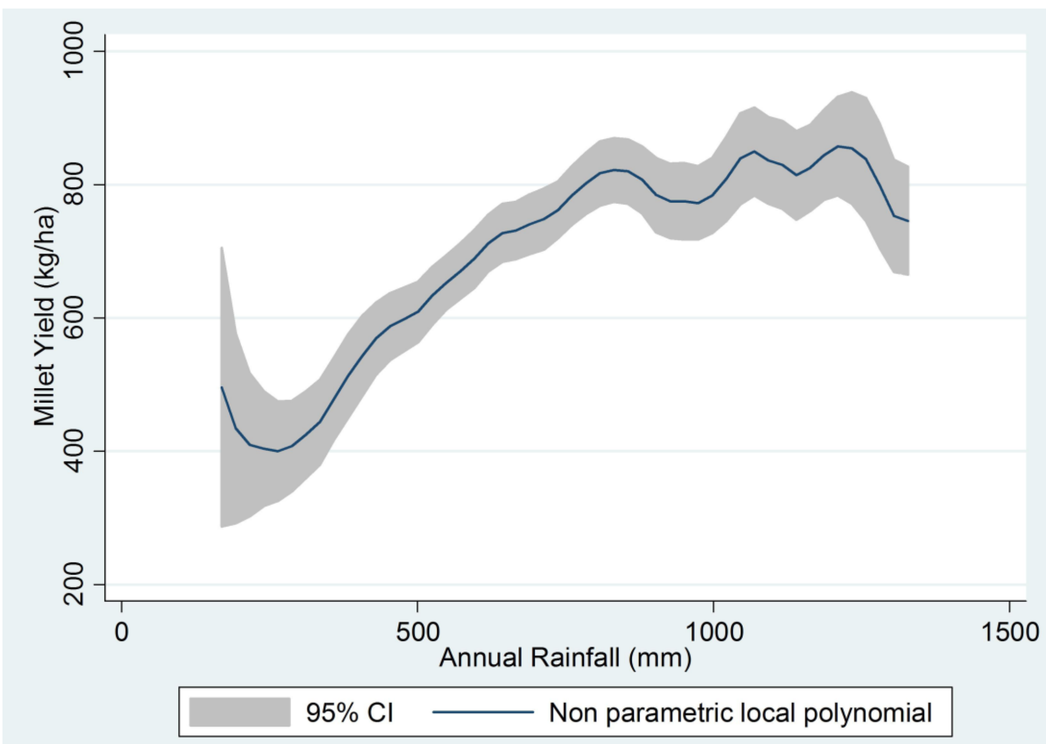

Figure 4.5a: Effect of rainfall on millet yield at district level

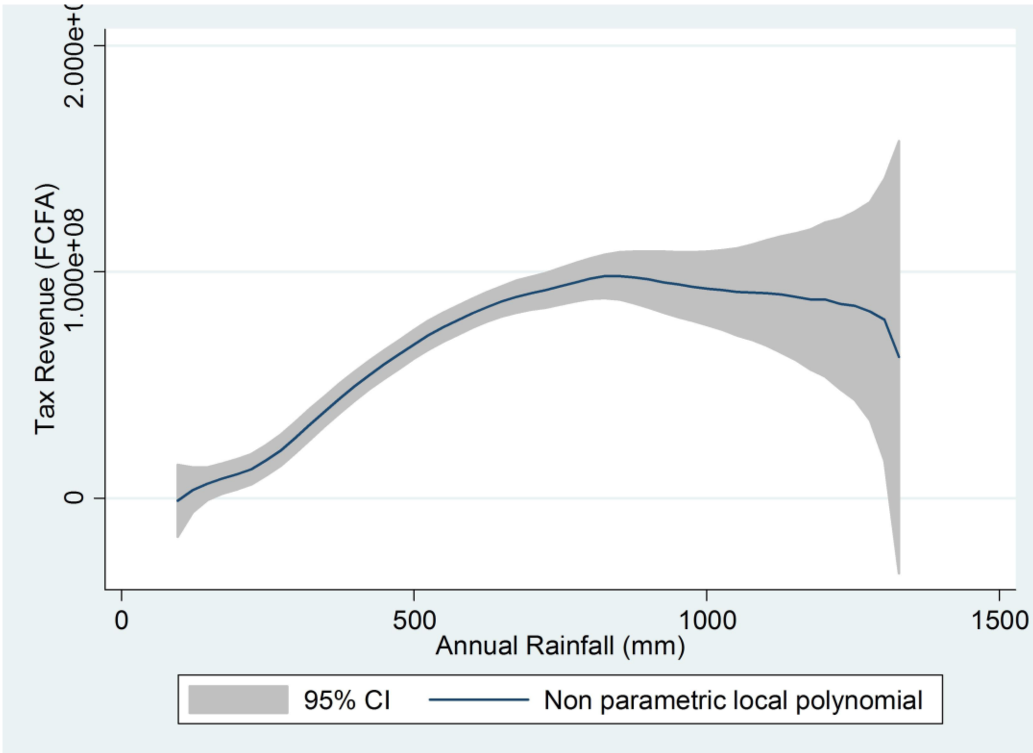

Figure 4.5b: Effect of rainfall on tax revenues at district level