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Local and national electricity planning in Senegal: Scenarios and policies

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ABSTRACT

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 km^2 in northern Senegal) and national case studies of Senegal yield the following key results. For both case studies, a high percentage (20–50%) of the currently non-electrified population lives 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.

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 varies 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,

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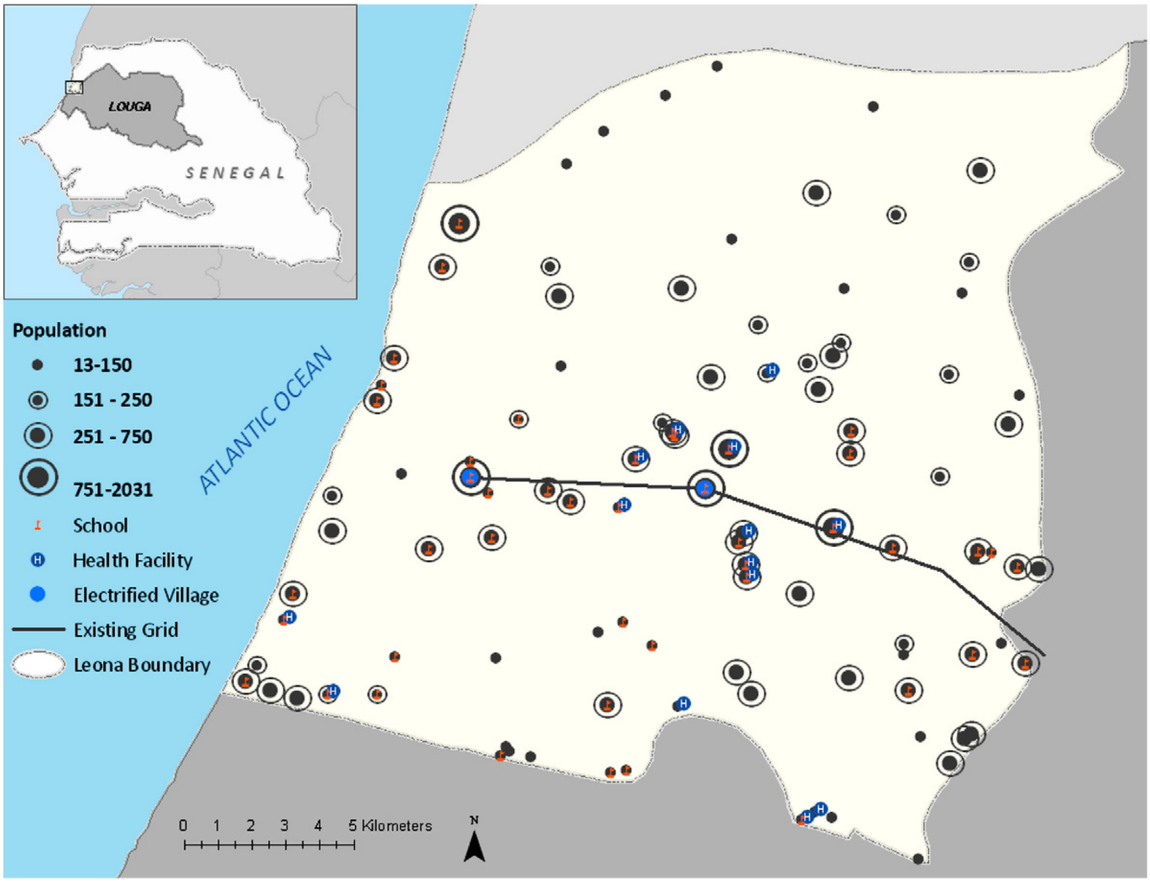

Fig. 1. Map of Leona that shows the location of population centers and existing infrastructure (schools, health centers, and electricity grid) as of 2007.

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).[1] 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?

Table 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.

Table 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%)

[1] 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.

Table 3
Sensitivity analysis for Leona: Varying demand, electricity purchase price, diesel fuel price, grid, and solar equipment 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)	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
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 refers to domestic (household), productive, and institutional (schools and health centers) energy consumptions.

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 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.

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 – 190 km of 90 kV and 48 km 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 is underground and 6849 km is aerial) and low voltage network (6761 km) brings 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.[2] By 2007, the total national installed capacity 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.[3]

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 by 2.6% in 2007 to 1786 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.[4] In fact, a review of the evolution of SENELEC reveals two important trends: increasing vulnerability to fuel cost volatility and high cost

Table 4
Effect of double demand on the per household length of MV line for Leona.

	Number of households (HH)	Total MV line ength 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

[2] Estimates put Senegal's electricity demand growth at 10% annually.
[3] These private producers are imports from Manantali hydro dam in Mali and the IPP Agreko in Dakar.
[4] 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.

Table 5
Effect of half grid costs on the per household length of MV line for Leona.

Scenarios 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
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.

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.[5]

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 US$373/ton in 2006 to US$429/ton in 2007. Similarly over the same time period, diesel oil (DO) cost increased from US$696/ton to US$726/ton. 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 goal 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 this goal 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 5000 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.

[5] 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.

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.[6] 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 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.[7] 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. 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.

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).

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 input prices established from local expertise and trends are still the

[6] 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.

[7] 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.

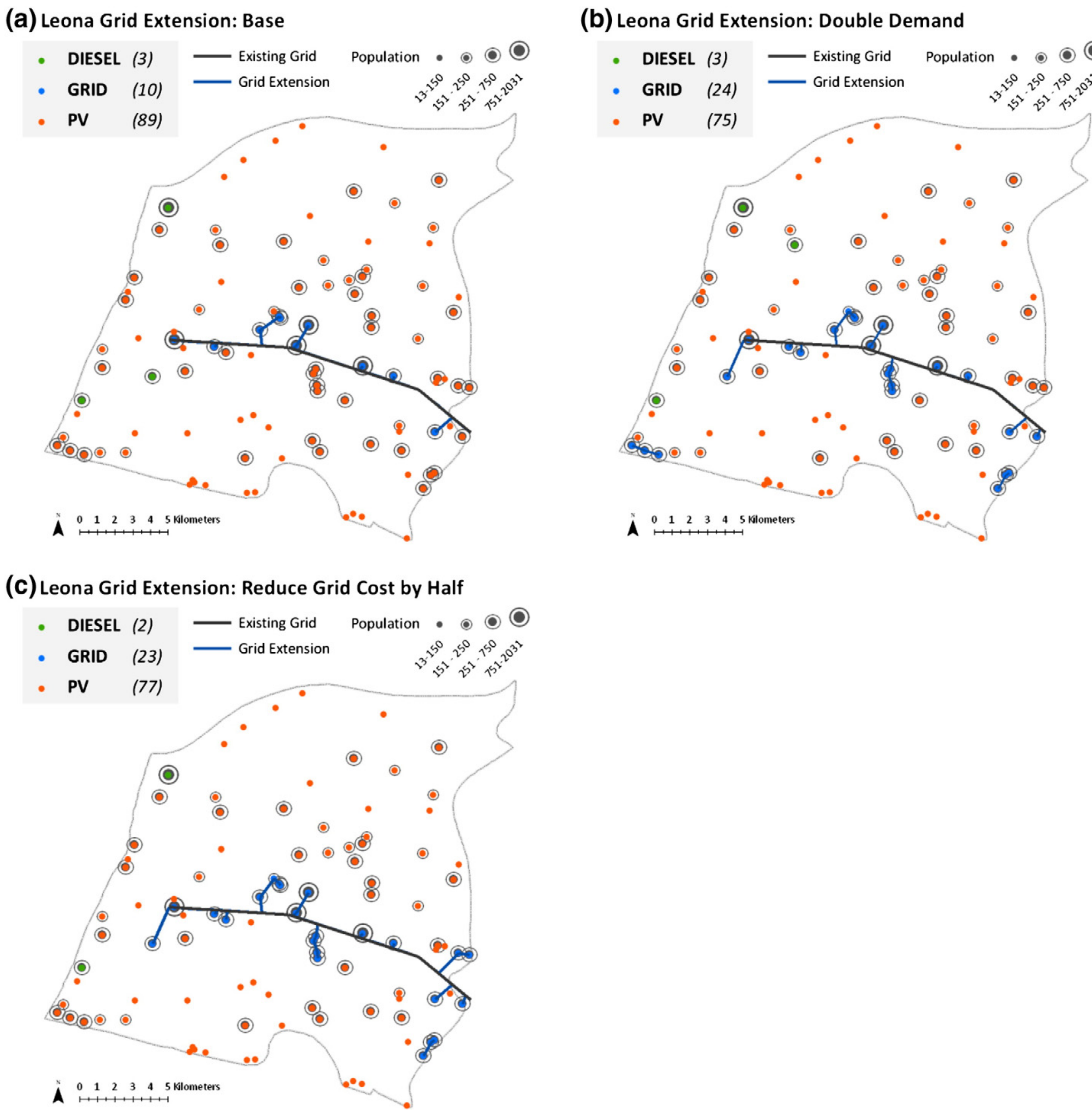

Fig. 2. Scenarios of grid expansion for Leona: (a) Base represents the best estimates of all input demand and cost parameters; (b) double demand represents the case in which future domestic demands, productive demands, and social infrastructure (i.e. schools and health facilities) demands are doubled; all other input parameters are the same as base scenario; and (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.

most important factors in ensuring both cost recovery for the utility and reasonably-priced electricity services for consumers.

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.[8] As shown in Fig. 1, Leona has 102 population centers that vary in population size with household counts ranging from 10 households to 237 households.

[8] 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 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.

Table 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 (thousand kWh/year)	303	765	372
Approximate generation capacity[a] (KW)	860	218	106
Grid investment (US$/kWh)	1.47	1.13	1.83
(includes capital cost of MV line, LV line, transformer, and HH equipment)			
Grid investment (US$/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$)	806 (100%)	1056 (100%)	830 (100%)
LV line and HH equipment	490 (60%)	522 (49%)	510 (62%)
MV line and transformers	316 (40%)	534 (51%)	320 (38%)

[a] Lifetimes considered because some equipment have lifetimes shorter than the project planning horizon.

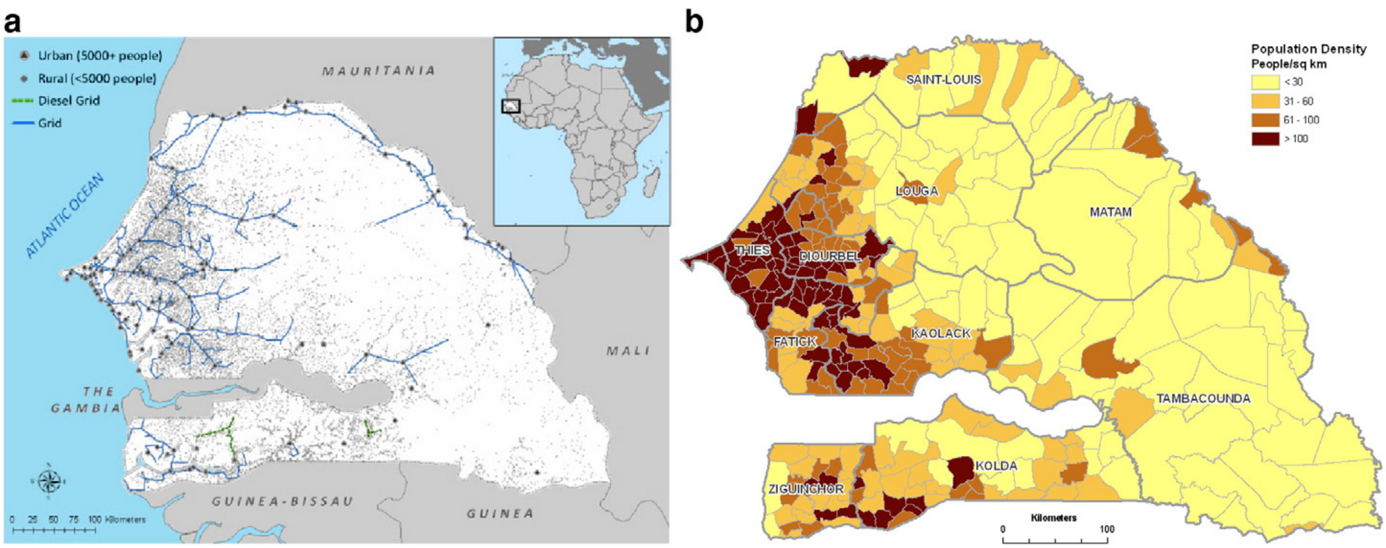

Fig. 3. a. Senegal existing grid map. b. Senegal population density map.

The social infrastructures are extremely limited. The community has only one health center and 19 cases de santé (health posts), 43 unelectrified primary schools, and one college. A power line, a 30 kVA 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.

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 is 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

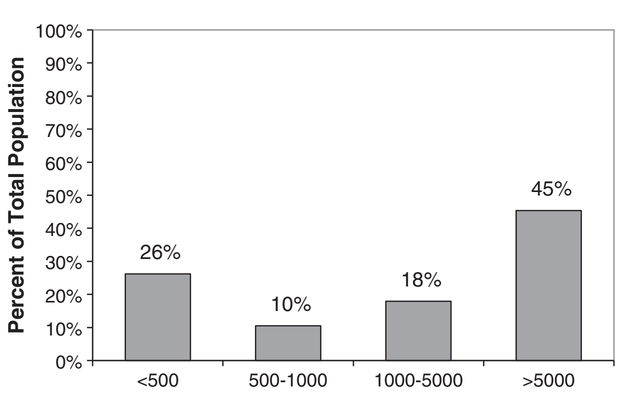

Fig. 4. Senegal population distribution.

Table 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.

Table 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 9
Percentage population electrified by region and supply technology.

	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%

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 l 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.

accurate measure of the inter-household distance which is critical for determining the cost of LV lines.[9] Additional modeling assumptions are outlined in the Appendix.

Results

Table 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 to the fact that the household demand for smaller population centers is assumed to be lower, as observed by the utility.[10]

The finance and cost performance indicators of grid extension for the base scenario, which can be found in Table 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.[11] 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.

The grid extension requires on average per household, 13 m of MV line and 25 m 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.

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, indicate that outcomes are indeed sensitive to variability in level of demand, fuel price, and grid-related costs.

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 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%.

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

[9] 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 m was taken for population centers less than 500 people, 24 m for population centers with 500 to 5000 people, and 8 m for population centers with more than 5000 people.

[10] 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.

[11] 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 a demand 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.

Table 10
Sensitivity analysis for Senegal: Varying demand, electricity purchase price, diesel fuel price, grid, and solar equipment 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

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 m to 16 m, 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 Scenario 10). Moreover, as shown in Table 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 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	3694	27.5
Double demand			
Total connections	206,659	6920	33.5
New additional connections	72,211	3764	52.1
Base scenario connections	134,448	3155	23.5

Table 12
Effect of grid cost (reducing the costs of MV line and transformers by half).

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	3694	27.5
Half grid cost			
Total connections	226,256	8322	36.7
New additional connections	91,808	5229	57
Base scenario connections	134,448	3092	23

Table 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) [a]	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%)

[a] Cost includes transport, civil engineering, fuel tank, and installation.

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 Fig. 2 and Table 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.

Model application national scale: Senegal

In Senegal, the grid is currently established along the high population density corridors (see Figs. 3a and b).

Given that almost half of the national population lives in these corridors, the challenge is in bringing access to villages of less than 5000 people, in particular the nearly quarter of the population that lives in villages of less than 500 people (see Fig. 4).

All cost data were obtained through discussion with experts from ASER and SENELEC.[12] 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.[13] Additional modeling assumptions are outlined in the Appendix. 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.

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 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 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 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.

Finance and cost performance indicators of grid extension for the base scenario at the national level, which can be found in Table 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 m 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 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 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 in 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

[12] 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.

[13] 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.

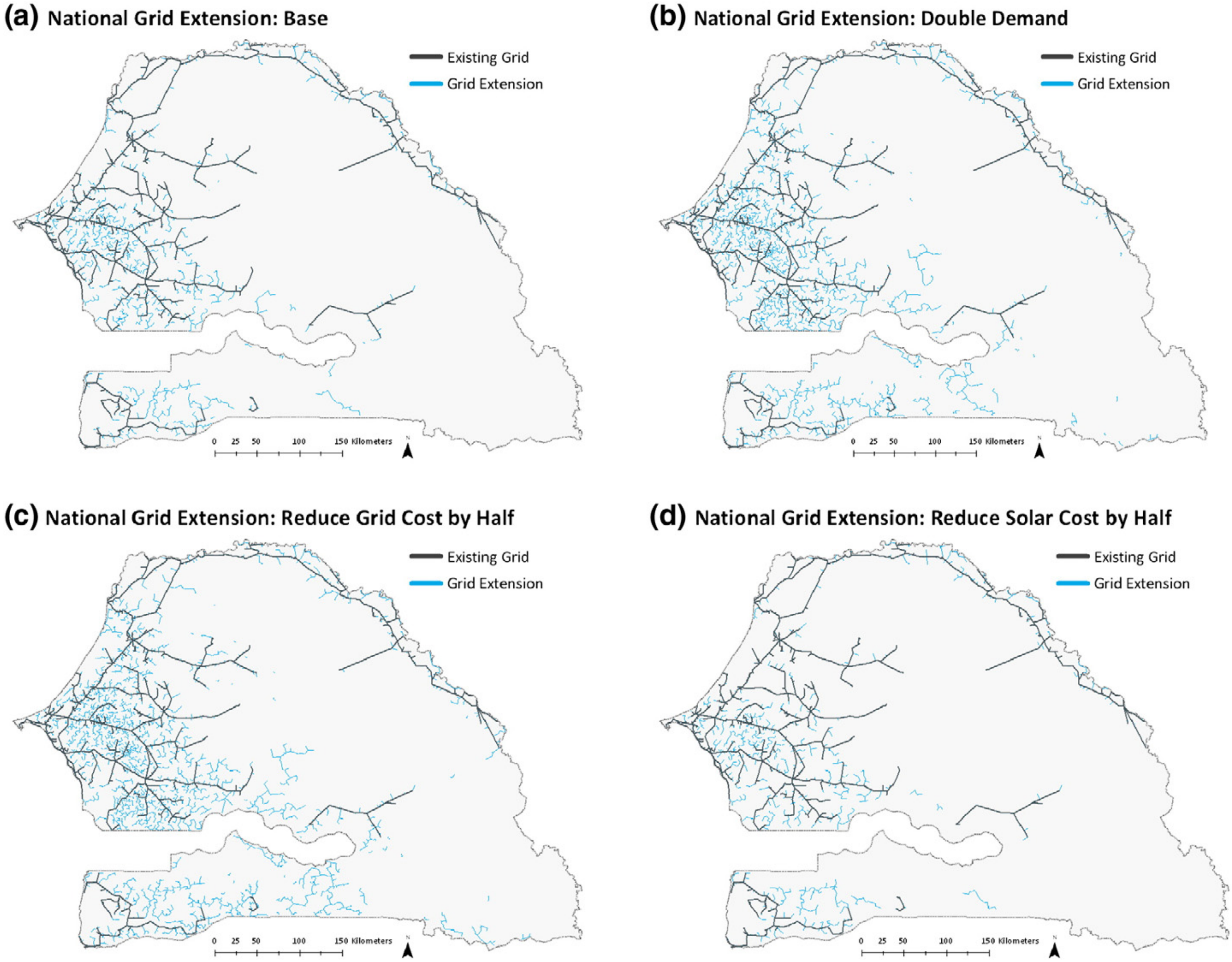

Fig. 5. Scenarios of grid expansion for Senegal: (a) Base represents the best estimates of all input demand and cost parameters; (b) double demand represents the case in which future domestic demands, productive demands, and social infrastructure (i.e. schools and health facilities) demands are doubled; 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; and (d) 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.

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.

Sensitivity analysis

The results of the sensitivity analysis for the national case study are summarized in Table 10. The same uncertainties in demand and costs applied at the local level have been applied at the national level.

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 11). The increase in overall MV line length per household from 27.5 to 33.5 m 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.

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

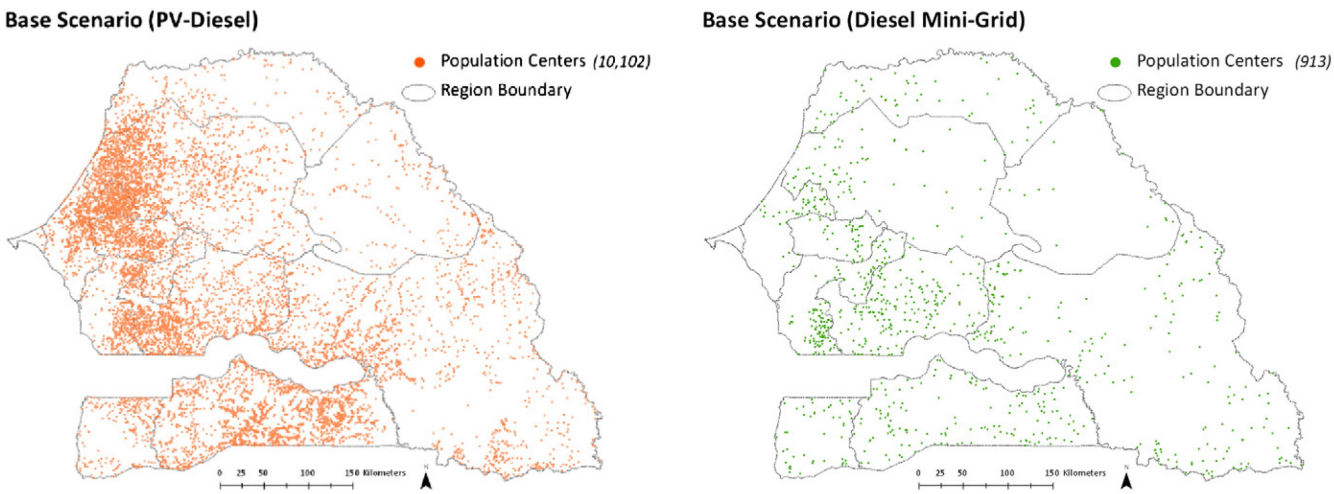

Fig. 6. Localities compatible (favorable) to diesel mini-grid and solar technologies.

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, scenarios 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 increase there is a minor shift from diesel mini-grid to grid and to PV-diesel systems. This shift to grid leads 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 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.

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 13 shows the analysis of finance and cost performance indicators at the national scale. Fig. 5 shows grid extension for the base, double demand, reduce grid related costs by half, and reduce solar costs by half scenarios. Fig. 6 displays the outcomes for PV and diesel for the base scenario only.

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 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.

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Appendix

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.[14] The assigned costs of all equipment 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.

Second, the demand assumptions are based on our categorization of village level population sizes. We define four population 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
500–1000	110	657	335	60
1000–5000	450	986	502	70
>5000	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[a] (US$/kW)	1000
	Household fees related to connection, regulator, lamps, installation (US$/HH)	263
Recurrent cost	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[b]	Transformer	10
	Public light	5

[a] Transformer costs were collected for specific peak demand of 4, 8, 20, 40, and 80 kW. 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.

[b] Lifetimes considered because some equipment have lifetimes shorter than the project planning horizon.

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.[15] 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[a] (US$)	12,842	14,535	16,227	19,612

[a] Cost includes transport, civil engineering, fuel tank, and installation.

PV-Diesel system cost assumptions

Power (Wp)	50	75	150
Capital			
Panel and 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	1776

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 allows 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 $\geq$ 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;

[14] 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.

[15] 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 l 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.

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. Loops on step 3 until all edges have been compared; and
5. Cleans 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.

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