Review Assessment of current electrification programs prepared by REG / EDCL and confirmation on institutional, technical and financial aspects

TASK 2 Report. Design of the National Electrification Plan in Rwanda

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Prepared by consortium of TATA POWER DDL, MIT–COMILLAS UEA Lab & EcoSecure Holding and REG

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Abstract

The government of Rwanda recognizes the vital role that electricity access plays in accelerating economic development through improving health and standards of living. Energy and particularly access to electricity is Government's key priority. This is why significant investments have been made and progress registered led to over 40.5% of households getting access to electricity by August 2017 and why the government has set the target of Universal Electrification for the year 2024.

The aforementioned initiative to extend access to electricity involves a coordinated effort across all power sector participants to connect new customers, focusing also on powering productive activities.

This document focuses on the definition of the "Grid Service Area", incumbent to EUCL. According to the institutional design established by REG – EDCL in the project, this Grid Service Area comprises (a) the customers selected for a connection to the Rwandan Central Distribution Network and (b) the customers that will receive their electricity supply through an isolated grid-compatible microgrid, as REG–EUCL will also take responsibility for the investment, implementation and maintenance of the microgrid networks, as well as for the electricity retail business with the customers base (bill collection, quality assurance and customer management), taking care of the appropriate remuneration of the Independent Power Providers (IPPs) that will supply electricity to each microgrid.

The least-cost achievement of Universal Access in Rwanda will also require the supply of DC Solar Kits for low-demand residential customers (below 50 Wp as defined by EDCL). It will also determine where a full-fledged stand-alone AC solar system should be provided to larger customers who are too isolated from the network and from other customers to techno-economically justify an individual connection to the central grid or an off-grid microgrid.

This Task 2 Report will serve as a base for discussion of the institutional arrangements, grid and off-grid tariff calculation, remuneration of IPPs, financial implementation and other regulatory and energy policy mechanisms with all the involved stakeholders, that will be finally specified along with the detailed description for the Implementation of the National Electrification Strategy NES (Task 3) and the detailed Preparation of the National Electrification Plan NEP (Task 4).

Keywords: Universal Access to Electricity, least-cost planning, grid extension, off-grid electrification, grid-compatible micro-grids, solar kits.

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1 Least-cost planning using the Reference Electrification Model

1.1 Lessons learned from past electrification plans and strategies in Rwanda

In 1991 the first electrification master plan for Rwanda was drafted by Hydro Québec International with a planning horizon reaching to 2010 (Fichtner and Republic of Rwanda EWSA, May 2011). The electrification plans, policies, and programs which followed in the years leading up to present day Rwanda will be discussed in further detail in *ANNEX 1: Detailed analysis of past electrification plans and strategies in Rwanda* of this report, but as the references are many, a timeline has been provided to assist the reader in following the narrative. Items referenced in this report are shown in blue text in Figure 1, with the two reports which constitute the main focus of the discussion displayed in bold font. Any items shown in grey have been included for context only and do not figure materially into the report.

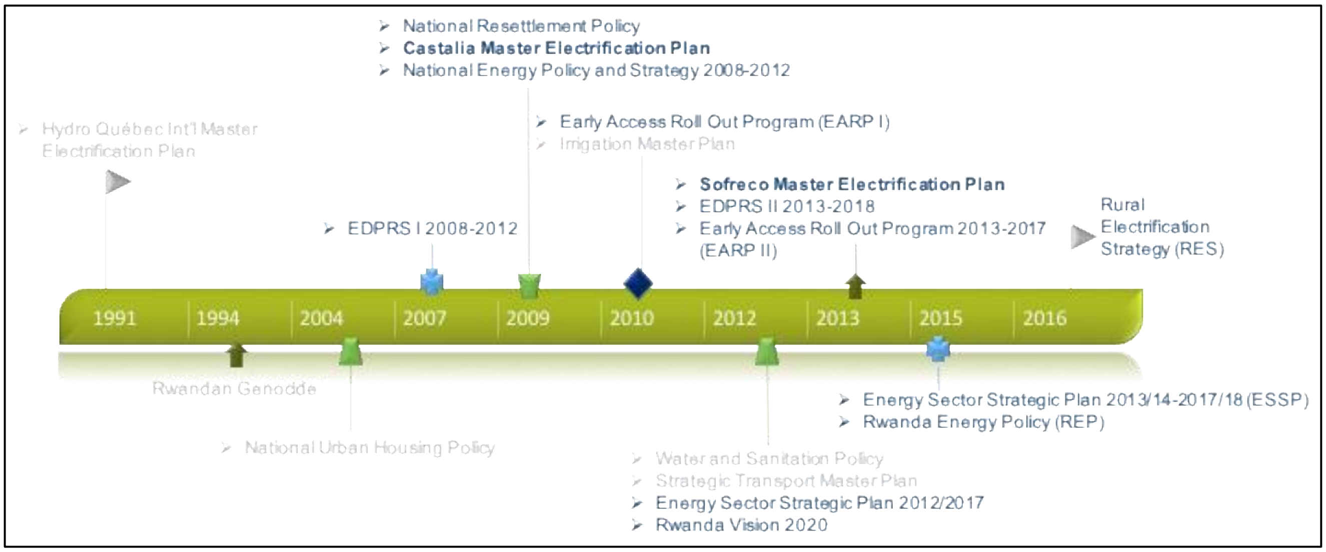


Figure 1: Timeline of Electrification Plans, Policies, and Programs in Rwanda

For this project, the two master electrification plan reports identified, those written by the consultants Castalia and Sofreco, respectively, have been reviewed along with their supporting documents for the purposes of identifying the methodology followed by each in the creation of a national electrification plan for Rwanda. The two methodologies will then be compared in order to identify common elements, unique attributes, strengths, and weaknesses. These findings, as detailed in ANNEX 1, have been used to form the basis of a critique of the capabilities of the Reference Electrification Model, so that recommendations may be formed concerning both the future use and development of this techno-economic planning tool.

1.2 The Reference Electrification Model: A decision support tool for the development of the Rwandan National Electrification Plan

1.2.1 Context

The **Reference Electrification Model** (REM) developed jointly by the Massachusetts Institute of Technology (MIT) and Universidad Pontifical Comillas Institute for Research in Technology (IIT) addresses the need for a tool that supports decision making on which technology to use to electrify any given area (cell, village or group of individual customers), through application of techno-economic modelling. It allows decision makers and planners to apply policy objectives and given assumptions to the physical landscape and existing infrastructure, using scientific data to calculate the most viable solutions.

The outputs provided by REM rely on a combination of **ground data**, **calculated assumptions** and **strategic decision-making**, and as such, the tool should be used in close interaction with the lead agency and departments for planning.

1.2.2 Objectives and methodology: REM Techno-Economic Procedure for Least-Cost electrification planning

The REM consists of two major steps: (1) clustering using a bottom-up approach and (2) final decision on the best electrification mode for each cluster.

Prior to step 1, in order to avoid multiple detailed evaluations of the optimal generation mix for each one of the many cluster combinations that REM has to try, REM calculates optimal generation designs for representative off-grid systems and stores the corresponding data in a look-up table.

In order to find these generation designs REM minimizes costs (both investment and operation cost plus a penalty for the amount of demand that is not met) using an optimization strategy with a master/slave strategy. The master part makes decisions about the design variables, using a direct pattern search approach, and the slave part performs a simulation with a load following dispatch strategy for each representative microgrid (other dispatch strategies have been included in other versions of REM).

If in the clustering or in the final designs algorithms REM needs information related to a generation design that is not in the look-up table, it interpolates using the closest designs. The generation technologies that REM presently considers are solar, batteries and diesel generation. The cost of the charge controllers and inverters is also included (if needed).

1.2.2.1 STEP 1. Clustering.

REM groups a large number of buildings into potential electrical sub-systems. This step is very important, because it will condition the spatial distribution of off-grid and on-grid systems. Since the number of possibilities for this is unmanageable in an exhaustive way, REM implements the following strategy:

a. A systematic bottom-up greedy algorithm, based in local decisions, to build clusters at two hierarchical layers, as shown in Figure 1. The first layer is built with off-grid assumptions, and the second layer with grid-extension assumptions.
b. Local decisions depend on the balance between savings (size-related economies of scale) and extra costs (network investments to connect buildings).
c. Economies of scale may derive from administrative or business models, network components/designs and generation components/designs. The results depend critically on accurate inputs or estimations of these size-related factors.
d. Since the number of possible local decisions may be huge in real-life problems, some simplifications are applied:
    i. Connectivity options are limited to the sub-set of most promising grouping solutions identified through graph theoretical results.
    ii. Extra network costs are estimated by simplified representations of the networks.
    iii. Generation costs are obtained interpolating in the look-up table calculated in the generation sizing block of REM.

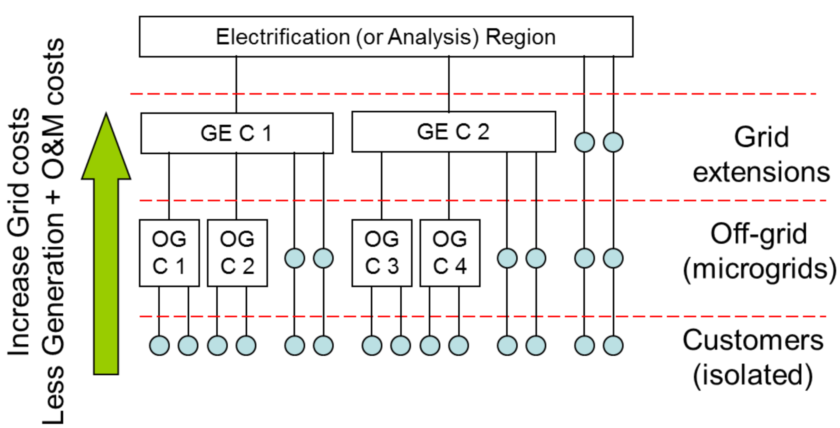


Figure 2: Example of structure of clusters (results from the clustering process)

For the Rwanda NEP, the minimum size of any Grid Extension cluster (GE) has been set by EDCL to the level of an administrative village. Therefore, either the whole village is connected to the grid, or it will all be electrified off-grid (with a combination of microgrids and stand-alone solar kits).

1.2.2.2 STEP 2. Final decision on the best electrification mode for each cluster.

After the clusters have been identified, the cost of the electrification options at different layers are calculated for each cluster as follows:

a. For the grid-extension option:
   i. Find the nearest viable connection points to the existing grid
   ii. Design the lowest cost distribution network to connect the buildings to the grid. This is done using the Reference Network Model [1].
   iii. Calculate the final cost, considering
      1. Cost of energy purchased from the grid
      2. Network costs (investment, maintenance and losses)
      3. Cost of non-served energy because of imperfect grid reliability
      4. Administrative and connection costs.

b. For the microgrid option:
   i. Calculate the cost of generation. This cost is either obtained interpolating in the look-up table calculated in the generation sizing block of REM, or performing a full optimization process for this particular cluster, considering the hourly dispatch for the total consumption of the customers within a specific microgrid.
   ii. Calculate the network cost as in 3.a.ii (RNM tool, but adapted to a microgrid case)
   iii. Calculate the final cost, considering:
      1. Generation costs (investment, operation, maintenance, and non-served energy).
      2. Network costs (investment, maintenance and losses).
      3. Administrative and connection costs.

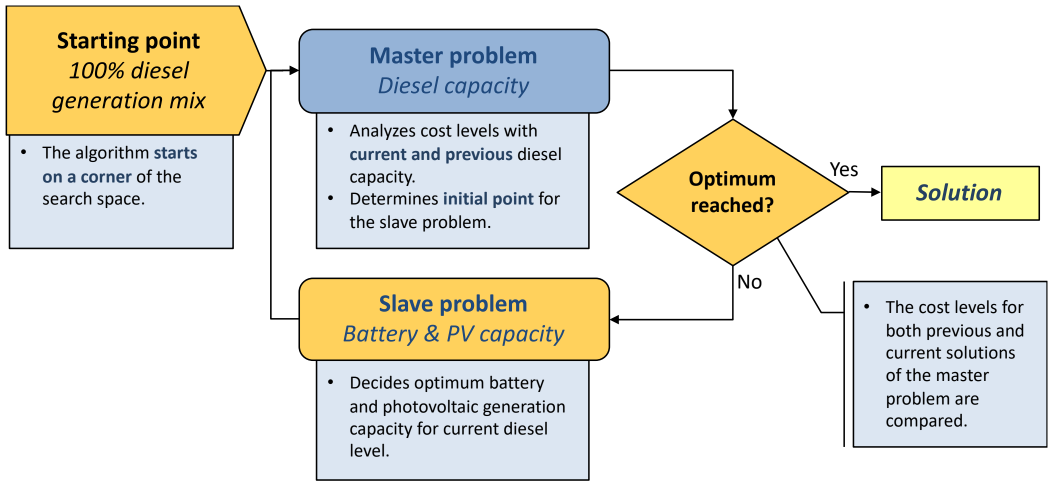


Figure 3: Master-Slave decomposition for the optimization of microgrid generation

c. For the single-building option: If the peak load of the customer is less than 50Wp, then this cost corresponds to that of the Solar Kit specified by EDCL for those consumers. If the consumption is higher (isolated productive or community loads), proceed as in the microgrid case, except for the network design and cost steps (no network present).
d. After the cost of the three electrification modes is calculated, the lowest-cost combination of clusters and their electrification modes is picked. Figure 2 shows a case in which the optimum solution is made of one grid-extension (groups “A” and “B” of customers), one microgrid (group “C”), and a set of isolated systems (group “D”). There is also the possibility of biasing solutions to be of particular types, by overriding the minimum-cost criteria to some extent.

Therefore it is important to notice that no heuristic rule is applied for the determination of the electrification mode (grid or off-grid), either based on the distance to the grid or density of load, but instead a thorough calculation of the actual implementation cost for each mode (grid extension, microgrid or solar kit/stand-alone system) is performed before the final decision is taken, based on pure techno-economic and social criteria.

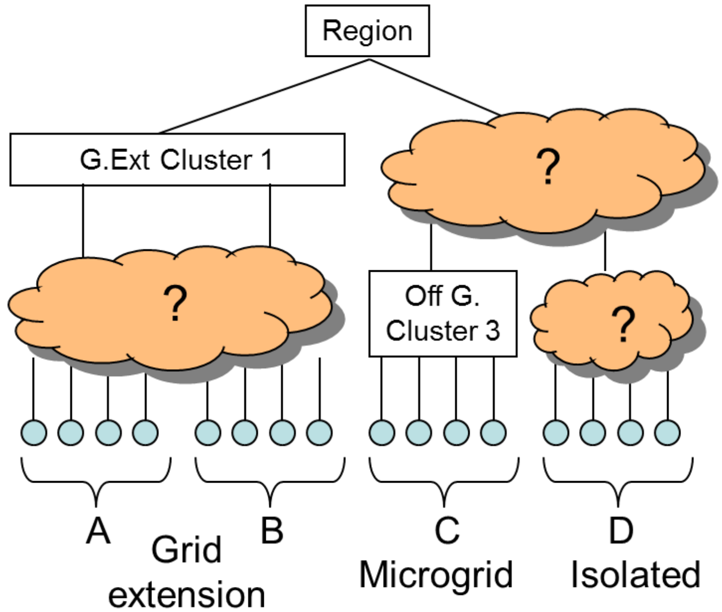


Figure 4: Example of minimum-cost electrification solution

1.2.3 Different types of input data

As said before, the outputs provided by REM rely on a combination of **ground data**, **calculated assumptions** and **strategic decision-making**. The classification of inputs into these three groups is not always clear, so the following is just a reasonable example.

1. Ground data. Inputs that are considered fixed data (although they may represent future plans or states of the system)
    a. Location of buildings (and therefore also the population density). It is necessary to know the latitude and longitude of all buildings in the study area, as well as the type of building if different types of demand profiles are used.
    b. Existing distribution feeders (MV), and therefore the distances from buildings to the existing grid. The location of the existing distribution feeders and transformers must be obtained for the study area. In the absence of this data, it is possible to estimate it with the RNM tool (greenfield mode), provided that the already electrified customers are given.
    c. Energy resources (solar power availability, diesel cost if available and allowed, micro-hydro sites). The availability of different energy resources in a given area is necessary in order to determine the suitability of different types of generation.
    d. Topography data (altitude map and penalized areas). RNM and REM use these data to design networks and incorporate restrictions in the clustering step.

2. Calculated assumptions. Inputs that are adjustable to different scenarios.
    a. Grid energy cost. Cost of energy estimated at MV feeders.
    b. Grid reliability. Reliability of the supply of electricity from the existing grid. This value can be expressed either as a single overall percentage, or broken up into hourly-related percentages (off-peak reliability, peak reliability and so on). Reliability is important to the concept of CNSE. It could also be linked to grid-energy cost figures, in case of evaluating generation and grid reinforcements in future scenarios.
    c. Demand profiles (critical and non-critical, demand growth rate). Following the classification of buildings, the demand for each building needs to be characterized. To design electrification solutions for un-electrified buildings it is necessary to estimate how much electricity each building might consume if it had access to electricity. Since the model will try to meet specified demand at the lowest techno-economic cost, more detail about demand at each individual load point is likely to have an influence on the results. Once the demand profile is constructed, it must be classified into one of two tiers: 1) essential or critical load (e.g., lighting) or 2) non-critical load (e.g., television).
    d. Network components (catalogue of lines and transformers). Power capacity and cost characteristics are the most relevant parameters.
    e. Microgrid generation components (catalogue of PV panels, batteries, diesel generators, and power conversion equipment)

3. Strategic decision-making. Inputs that are related to social and business models.
    a. Administrative costs. They account for the general management cost of the system and they may have different values for different electrification modes, and economies of scale depending on the size of the systems. These costs are calculated differently for off-grid and grid extension systems. In REM, the administrative cost of a system only depends on its number of consumers. The input parameters that REM requires to calculate this cost are the administrative cost of a small, medium-size and large microgrid as well as the number of consumers of a small and a medium-size microgrid (REM assumes that the number of consumers of a large microgrid is equal to the total numbers of consumers of the case study).

       In an off-grid system the administrative cost is approximated with an analytic expression, which is calculated with these input parameters. Specifically, the model uses an exponential function in order to ensure that the per-consumer administrative costs is a decreasing function of the number of consumers.
       The administrative cost of a grid extension is calculated with a constant per-consumer cost (it does not depend on size of the system) equal to the input parameter assigned to a large

microgrid. This ensures that the administrative cost of a grid extension is always lower than the administrative cost of a microgrid.

b. Cost of Non-Served Energy (CNSE). REM is basically a cost-driven tool, so the lack of quality/reliability of power supply must be translated to cost (it may also be imposed as a constraint in the case of microgrids). CNSE is the cost, to consumers, of energy that is not served. This concept is actually quite subjective, but is intended to represent the cost (i.e., the loss of utility) incurred by consumers when there is no electricity at a time when they were planning to use it. REM requires two values for CNSE, one for essential load and another for nonessential load. There could be multiple ways of arriving at a value for CNSE, but one way of calculating CNSE value is to adopt -as a proxy- the cost of an alternative energy solution (e.g., kerosene) that might be used when electricity is not available.
   When it comes to calculating the cost of non-served energy, REM applies different procedures with off-grid systems and grid extension designs. In off-grid systems REM multiplies each amount of demand (essential and nonessential) that is not met by the dispatch algorithm by the corresponding penalty. On the other hand, with grid extension designs REM assumes that the non-served energy is split homogenously between essential demand and nonessential demand before multiplying these numbers by the corresponding penalties. For example, if the grid has a 90% reliability and the essential and nonessential demands in an hour are 5 kWh and 1 kWh then REM assumes that there are 0.5 kWh and 0.1 kWh of non-served essential and nonessential demand in that hour, respectively.
c. Minimum microgrid quality/reliability of power supply. In addition to CNSE, this constraint may also imposed in the case of microgrids, in terms of percentage of energy served.
d. Discount rate, needed to translate upfront investments to annuities. It is related to the business/investment models. Different values may be set for different electrification modes
e. Grid connection criteria. Some practical criteria may be applied to bias grid connection of customers that are not too far from the grid (and not far from other customers). This may be not consistent with cost minimization, but related to social or political strategies.

1.2.4 Sensitivity analysis (qualitative)

The different inputs described in the previous section are analyzed here with respect to their influence on the expected results. The proposed classification and terms is respected, but two intermediate results are also used in the explanations, i.e., economies of scale and size.

- Economies of scale, as said before, are the basis for local clustering decisions. They are also critical in the "detailed design" step. Since they may derive from different sources or inputs, they will be mentioned explicitly along the explanations

- Size of clusters (or sub-systems), in terms of number of buildings connected to each other. It is an intermediate result from clustering that may affect a lot the final solutions. Size is affected in different ways by different inputs, and therefore it will be used in the cause-effect reasoning processes

Obviously, economies of scale are closely related to size by definition (savings due to size), but we will try to identify the two effects individually when possible.

The expected results of REM are affected by the different input data elements in the following way:

1.2.4.1 Ground data.

a. Location of buildings (in terms of population density). Higher population density produces larger sizes of systems. They will result in larger microgrids (if far from the grid) and more grid-extensions (if not far from the grid). The influence of size in grid extensions is closely related to network catalogues components (the right power capacity and the right economy of scale may lead to relevant savings).
b. Existing distribution feeders (in terms of distances to buildings). Part of the connection costs are proportional to distance, so systems next to the grid will obviously tend to become grid extensions (here the availability of small network components is critical).
c. Energy resources (solar power availability, diesel cost if available and allowed). High solar power availability and low diesel prices favor microgrids.
d. Topography data (altitude map and penalized areas). Adverse terrain characteristics produce smaller systems and even isolated solutions.

1.2.4.2 Calculated assumptions.

a. Grid energy cost. Obviously, higher energy costs produce more microgrids and less grid-extensions (small influence in isolated systems, except when they are special high-demand customers). The effect of this parameter on the solution is smooth if buildings-to-grid distances are relevant. In case of short distances, changes may be dramatic (connection cost thresholds depend mainly on transformers, instead of lines).
b. Grid reliability. This parameter affects dramatically the presence of grid extensions if CNSE is significant, since non-served energy is directly penalized by CNSE (critical and non-critical). In contrast with microgrids, grid reliability is a user input that cannot be mitigated by extra investments.
c. Demand profiles (critical and non-critical, demand growth rate). Critical energy is important since its CNSE value is usually high. More critical energy means higher cost in grid

extensions (if reliability is not 100%). In microgrids it may just impose more reliability to the solutions, but the cost is not that much affected, since non-served energy costs are replaced by generation costs. The effect of demand growth rate is similar to the effect of smaller components in the catalogues (network and generation). Higher demands produce bigger sizes and better economies of scale in the system, and therefore they favor bigger microgrids and more grid-extensions. The p.u. cost ($/kWh) usually decreases as demand increases.

d. Network components (catalogues of lines and transformers). Smaller and less expensive components tend to produce bigger microgrids and more grid-extensions, since they allow more connections with the same savings.
e. Microgrid generation components. Smaller and less expensive components tend to produce bigger microgrids and more grid-extensions, due to the bottom-up clustering strategy (initial decisions are possible). Beyond that, what is relevant is the presence of economies of scale in generation components. Diesel generators usually provide these economies of scale, both in investment costs and in operational costs (efficiency). In the case of batteries and PV panels, in which big systems are made of many small components, economies of scale should be modelled explicitly in realistic terms. Economies of scale produce bigger microgrids, and indirectly they even may produce more grid-extensions (since large systems are more likely to be connected to the grid). The specific micro-hydro sites will be analyzed in Task 4 for the detailed implementation of the NEP in a second phase. Whereas most hydro sites will be connected to the central grid, those who are far from the grid will provide a lower cost alternative for microgrid clusters nearby, so a case by case analysis will be developed for either alternative (grid or microgrid) for each microgrid site.

1.2.4.3 Strategic decision-making.

a. Administrative costs. They may have different fixed values for different electrification modes (grid extension or microgrids) or also include p.u. costs as a decreasing function of size, to reflect economies of scale in the administration of larger systems, as for instance in fee collection tasks. The influence of economies of scale is quite relevant; as it has been already stated, they favor big microgrids and more grid-extensions in the final solution. As these costs are estimated, they are reflected separately in the final solution.
b. Cost of Non-Served Energy (CNSE). CNSE should be set to a value bigger than the typical energy cost in the system. CNSE is closely related to grid reliability in the case of grid-extensions, since non-served energy is directly penalized by CNSE (critical and non-critical). In the case of microgrids, the effect is not so dramatic, since non-served energy costs are replaced by generation costs. Also in microgrids, the use of CNSE as a reliability driver may

be replace (or coordinated) with the use of minimum reliability constraints (next input described)

c. Minimum microgrid quality/reliability of power supply. This constraint may be imposed in the case of microgrids, in terms of percentage of energy served. The effect is to guarantee a minimum reliability level for every off-grid solution, despite the cost.
d. Discount rate, needed to translate upfront investments to annuities. The effect is obviously to change the annual costs, imposing a shorter or longer recovery of the investment. Since different values may be set for different electrification modes, it may bias the final solution one way or another (grid-extensions, microgrids or isolated systems).
e. Grid connection criteria. They may bias grid connection of priority customers that are not too far from the grid (and not far from other customers), so that the effect on the final solution is directly predictable in qualitative terms. The quantitative effects are quite interesting, since they may be used to estimate the actual cost of the particular criteria applied.

2 Setting the main design features for the NEP

2.1 Input data, inferences and main assumptions

Most of the effort by the Consortium with EDCL in the first Phase of this study has been devoted to gathering the existing data described in the previous section, considering the different sources available, any inference processes that could be derived from them, and where information was not directly available the determination and validation by the technical team at EDCL of the different assumptions proposed by the consortium.

2.1.1 Location and characterization of expected demand

The detailed design of network and generation infrastructure developed by REM for the National Electrification Plan requires to determine, as exactly as possible, the location and characteristics of the different loads that will be supplied either by the central network, microgrids or isolated systems.

2.1.1.1 Residential customers

The location of residential customers was determined considering (a) the existing database of customers developed for the 2013 Sofreco Report, (b) the 2017 High Resolution Settlement Layer HRSL for Rwanda (Columbia University Center for International Earth Science Information Network)[1] and (c) the expected growth in Urban and Rural Areas for 2024.

This information about location of buildings did not include whether these customers were electrified (connected to the grid) or not. To determine the location of the customers actually supplied (or about to be) by LV network, a 37.5m buffer around the existing and already planned LV lines was calculated, as specified by EDCL, considering those customers inside the buffer as already electrified (as they were within reach of the existing network using side drop lines). The customers located inside forbidden areas (high-risk wetlands and other areas non suitable for residential settlements) are not considered for a permanent electrification with grid standard extension or microgrids, as they are expected to move to villages according to the villalization program, but will be provided with solar kits as a transitory pre-electrification solution.

[1] www.ciesin.columnia.edu/data/hrsl

EDCL provided statistical information, classifying, for each cell in the country, the households in two customer types according to their demand. Type 1 households are expected by EDCL to demand initially only a very low level of supply (below 10Wp in 2017 for two lights, a phone charger and may be a high-efficiency radio). Type 2 customers will demand less than 50Wp. Larger domestic customers, well above those two essential levels, are a rare minority (below 5 customers per thousand).

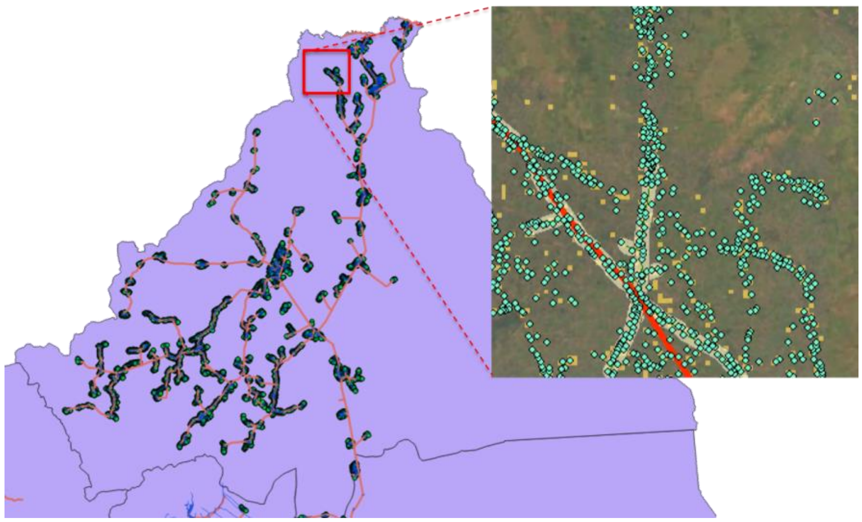


Figure 5: Sample image of different data sources:
Sofreco (green dots), HRSL (yellow squares), MV (red lines) and LV (green lines) and 37.5 m buffer (light yellow) combined for the determination of location of non-electrified residential customers in Nyagatare district

Residential customers connected to minigrids are assumed to have an equivalent profile as those connected to the central grid, with equivalent supply and technical standards. The hourly profile of consumption expected from them has been extrapolated from average feeder data provided by EDCL and from the field study developed by MIT-IIT Universal Energy Access Lab in 2015 for the village of Karambi, Mutete Sector, Gicumbi district[2] for the purpose of inferring the consumption profiles every hour of the day by lower and higher demand households. In case these customers are assigned a Solar Kit, all Type 1 and 2 residential customers (below 50Wp in 2017) are assigned by default a 10 Wp DC Solar Kit (2 lamps and a phone charger) as per EDCL characterization.

An average demand growth of 8.40% per year and customer has been sanctioned by EDCL according to historical data of connected customers in Rwanda.

[2] Santos, Javier, “Metodología de ayuda a la decisión para la electrificación rural apropiada en países en vías de desarrollo” Universidad Pontificia Comillas, 2015.
Li, Vivian, “The Local Reference Electrification Model: comprehensive decision-making tool for the design of rural microgrids” Massachusetts Institute of Technology, 2016.

A larger relocation of population is expected to happen in the long term, after 2024, as the villalization program develops. Different hypotheses will be considered for the long term scenarios for 2030, agreed to be analyzed during Phase 2 of the project, including also higher demand growth hypotheses.

2.1.1.2 Productive and community customers

For the present plan, a total number of 20 different types of productive and community customers and two residential customers have been considered, according to EDCL specifications.

REM type	Customer type	Power (kWp) (year 0)	Power (kWp) year 7
Customer_type1	Airport	6,000.00	10,552.52
Customer_type2	Cell office	2.00	3.52
Customer_type3	Coffee washing station	1.50	2.64
Customer_type4	Health center	1.80	3.17
Customer_type5	Health post	1.00	1.76
Customer_type6	IDP Model Village (avg.)	13.00	22.86
Customer_type7	Irrigation pumping	3,000.00	5,276.26
Customer_type8	Markets	8.00	14.07
Customer_type9	Milk collection center	1.40	2.46
Customer_type10	Mining	25.00	43.97
Customer_type11	Preprimary school	0.40	0.70
Customer_type12	Primary school	0.40	0.70
Customer_type13	Secondary school	1.30	2.29
Customer_type14	Sector Office	1.40	2.46
Customer_type15	Tea Factory	3,800.00	6,683.26
Customer_type16	Technical Schools	26.00	45.73
Customer_type17	Telecom Tower	280.00	492.45
Customer_type18	Universities and Institutes	130.00	228.64
Customer_type19	VTC	280.00	492.45
Customer_type20	Water pumping stations	40.00	70.35
Customer_type21	Residential 10W	0.010	0.018
Customer_type22	Residential 50W	0.050	0.088

Table 1 Classification of Customers and their peak consumption for the REM Reference Case Scenario

EDCL provided a GIS file including the location of productive and community customers, their present electrification status (yes/no) and their expected peak and average yearly demand in 2019.

Figure 6 shows a sample of hourly profiles obtained from the field study in Karambi village, Gicumbi district, which has been taken into account to estimate the shape of the hourly demand curve for each individual customer, each one subject to the peak and average demand data provided by EDCL.

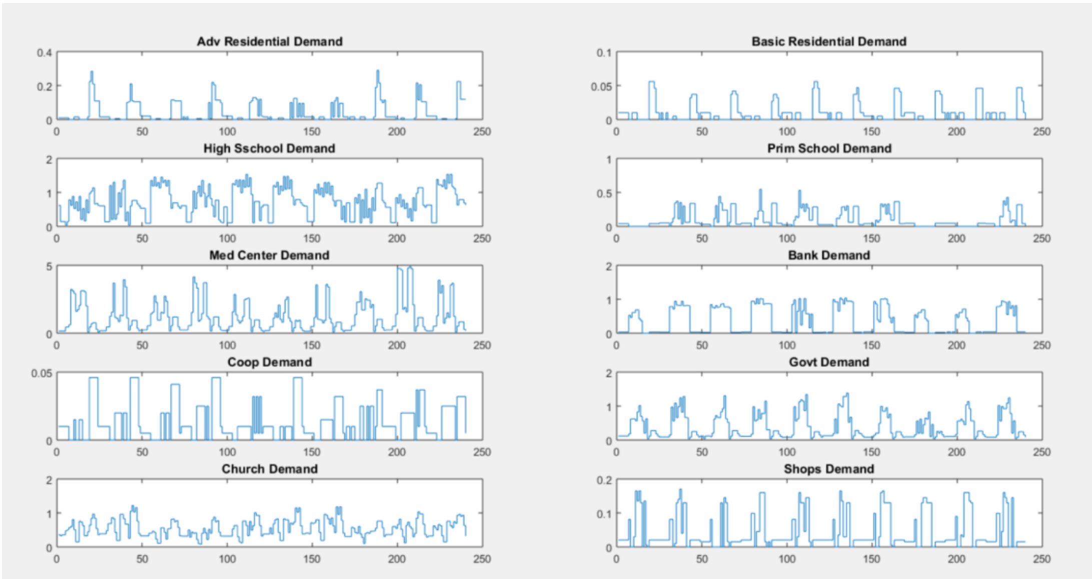


Figure 6: Sample demand profiles for domestic, community and productive loads in Karambi village (Santos J. 2015, Li, V. 2015)

All community and industrial customers are supplied in AC, disregarding whether they are connected to the central grid, a microgrid or are supplied with an individual stand-alone system.

2.1.1.3 Quality of Service

As described in Section 1.2, REM considers both the reliability of the central network (for the grid connected customers) as well as the performance of microgrids and isolated systems (for the off-grid customers).

Different scenarios can be calculated using REM, according to different reliability hypotheses. For the central network we have analyzed scenarios ranging from a 100% reliable network (considering that the country will improve from the present status through the necessary investments in central generation and transmission and distribution reinforcements) down to 85% considering that the scenario in 2024 will be similar to the one today.

For the purpose of this report, in order to determine which villages should be on and off-grid, we are providing the 100% reliable network scenario so the final status of a customer in the long term is determined by this ideal solution. Another high-demand scenario has been developed to determine the outer boundaries of grid extension in case household demand rises above the essential levels described above, above Tier 3 for low income households and aboveTier 4 for high income ones.

As for the microgrid generation, the expected system reliability is very high (above 97% in the scenario described in this document) and even better than in many places serviced by the main network. REM determines this reliability level according to the inferred cost of non-served energy for critical and non-critical loads (0.75 $/kWh and 0.30 $/kWh respectively), and a hard low-end reliability constraint (which in this case is set to at least 80%). The value of the critical cost of non-served energy (in $/kWh) was estimated considering the present expenditure of firms in diesel backup systems that supply around 15% of their energy consumption in a year as backup for blackouts. This cost per kWh is high because the customers are required to size their diesel generators according to their peak demand power, even if the diesel only produces 15% of their total energy consumption in a year. The non-critical cost of non-served energy was assigned a value in the order of the average cost of generation of a small AC Solar Home System.

Finally, for very small residential customers below 50Wp, REM will consider the social cost of grid connection or microgrids against the supply with a small 35$ DC Solar Kit, that will repaired and upgraded as needed in the future. The overnight cost of purchase of these systems is very low, but they can only supply a fraction of the customer demand for a limited amount of hours. Therefore, loss of utility of these systems, as compared to grid and microgrid connections, is high. This value of non-served energy for DC systems is different to the one considered for critical and non-critical connected demand, as described above, and has been estimated in the order of the cost of other alternatives (in $/kWh) as kerosene lamps, candles or disposable battery lights (0.9 $/kWh).

Failure rates of equipment and technical characteristics (e.g. voltage drop at the connection point) are built into the techno-economic catalogue, and therefore comply with the specifications established by EDCL.

2.1.2 Existing infrastructure

2.1.2.1 Existing distribution network (MV and LV)

REM computes millions of alternatives to find the optimal least-cost design for grid connection systems, as well as for microgrids and stand-alone systems, comparing them and determining, for each household, the solution that minimizes the social cost (including cost of non-served energy).

Regarding grid connection, each network extension system designed by REM must be connected to the existing (or already projected) MV network layout. A detailed GIS layout of all existing and already planned MV and LV lines has been taken into account to optimize the connection of newly designed grid extension to the existing infrastructure.

Upstream reinforcements are estimated by the cost of energy purchased from the grid for distribution, and are not included in the scope of the present study, but could be the subject of a subsequent analysis.

The cost of the energy supplied by the main grid at bulk MV distribution level has been set to 0.12 $/kWh for the Reference Case Scenario. This is indeed significantly lower than Rwanda's 2017 energy cost; however, we note that it is many times larger than the global level, and close to double that of the neighboring land locked country of Uganda. Indeed, it will be necessary for Rwanda to move away (as it plans to do) from excessive diesel generation and seek to achieve to be economically competitive energy costs by adopting a lower cost generation mix. Sensitivities have been analyzed to assess the impact of higher energy costs, up to 0.20 $/kWh.

2.1.2.2 Least-cost network planning, catalogue and quality standards

EDCL established the MV and LV catalogue to be considered for new grid extensions and off-grid electrification in this NEP for 2024 (please refer to ANNEX 2: RCS REM input catalogue tables for further details on catalogue components and characteristics). Components selected for the Reference Case Scenario, either MV or LV lines as well as transformers, had been specified bestowing the best practices and experience of EDCL according to the following considerations:

- Given this target and that the coverage of the existing MV network is already high in every district of Rwanda, new grid extensions and MV lines do not need to be spread over very large distances to reach different customers.
- In this RCS only highly populated and priority industrial and community loads (the least-cost connections) are expected to get coupled to the central grid.
- These priority loads and high density areas need, according to the experience of REG, the promotion of high quality of service standards, already in place in the country. The purpose of this strategic approach is to guarantee the necessary quality to foster economic growth.

Therefore the Reference Case Scenario for REM has been specified by EDCL to select the least-cost electrification design, but according to initial high quality standards. Where the grid will not reach, customers will be supplied either with grid-standard microgrids (that may eventually get connected to the grid in the future) or, because of budget constraints, with only a transitory DC solar kit or stand-alone AC system, expressing EDCL purpose of electrifying the whole the country with grid-equivalent service in the future.

Therefore, for this Reference Case Scenario, the use of low-cost distribution technologies (e.g. SWER lines or two phase wires that could lower the cost of long distance distribution lines) has not been considered, but could be analyzed in the future to connect the more distant clusters of customers, specially where there is local generation installed already (e.g. microgrids or large AC stand-alone loads), that contributes to enhance the quality of service for these remote customers.

The use of lower rural electrification standards has also been discussed, but these standards have also been set to high quality levels of service as per specification of EDCL (e.g. 4% maximum voltage drop at the end LV customer). The useful life of the network has been set to 25 years and the financial discount rate is 8%.

2.1.3 Off-grid generation techno-economical catalogue

This concentrated effort for grid extension in high density of load areas results in a Base Case Scenario that shows a large share of off-grid electrification in Rwanda (both microgrids and solar kits). This will result in an increase in the market size for PV panels, batteries and other off-grid equipment. Therefore we expect that with higher volumes of purchases, the prices will become similar to those of other international markets. Per system costs such as infrastructure investment (e.g. small control buildings or fuel tanks) are also taken into account, as well as installation and maintenance labor costs.

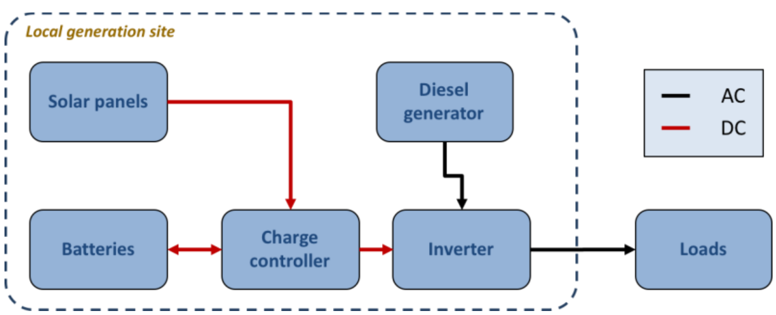


Figure 7: REM standard Microgrid Generation scheme

REM assumes that each off-grid system has a single centralized generation system. The architecture is flexible, as not all components are always required. There are alternative architectures, but this one was selected because it can be supported with available off-the-self components, and it provides AC service, allowing a more straightforward comparison with grid extension designs.

The sizing of each micro-grid is optimized considering the hourly solar performance profile, the aggregated customer profiles and the existing solar, storage and diesel hybrid generation alternatives. For each point in the search space, REM performs a simulation using the load following dispatch strategy. This strategy tries to meet the demand using solar energy first, batteries in the second place, and diesel as the last resource. The battery is only charged with solar energy.

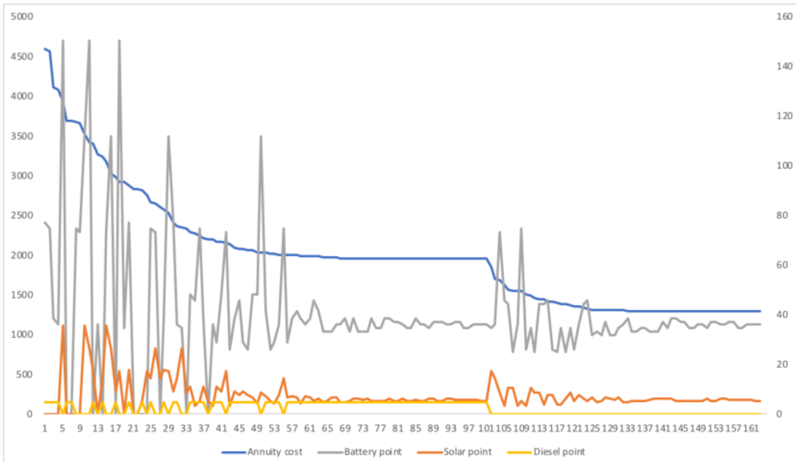


Figure 8: REM optimization pathway for a 1kWp microgrid

There optimization of each generation design includes the examination of the different diesel / solar / storage choices to minimize the annuity cost of generation (as shown in Figure 8). This design considers the aggregated demand profile and also the cost of lack of reliability, taking into account that some designs will not be able to meet all the expected demand at certain hours of the year.

2.1.4 Topographical restrictions

There are a number of features that are taken into account at different moments in our methodology. First for the definition of our beneficiary population (outside any forbidden areas) and then to determine the cost of generation (solar map of Rwanda) and network: slope of the terrain, areas of special difficulty (wet lands, rainforest areas) or even forbidden.

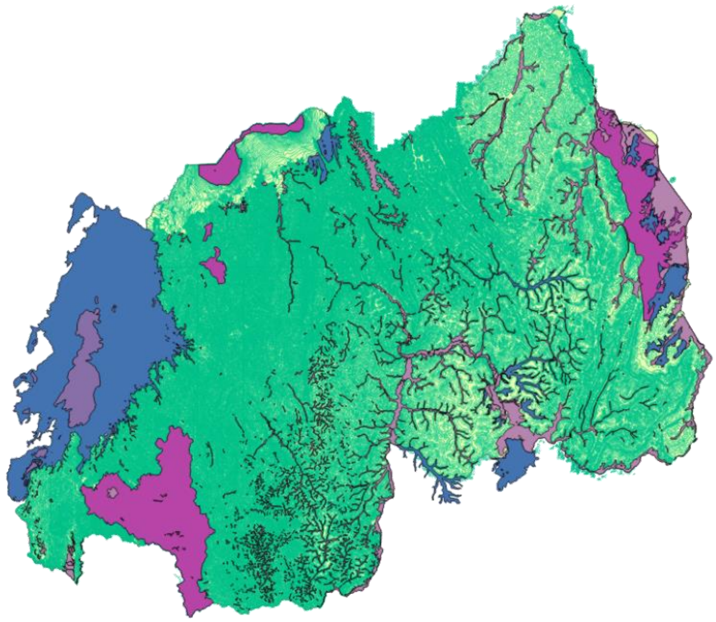


Figure 9: Example of Rwanda topographical features:
Water bodies and wet lands, protected areas, national parks and altitude lines

2.2 REM algorithmic configuration

2.2.1.1 Free clustering vs. cell and village level grid-extension constraints

The decision-making algorithms of the REM model have been adapted to meet the requirements specified by EDCL for Rwanda.

A first comparison was developed to analyze the impact of making decisions for grid connection at a whole cell level (every customer within the cell boundary would be either grid connected or off-grid), and comparing those with the results at village level (smaller boundaries) or with the general REM free clustering algorithm (that only considers optimal groups of customers according to their layout and their demand, not restricted by administrative boundaries).

Though algorithms restricted by cell or village boundaries were slightly less optimal (within a -2% margin), EDCL considers that not discriminating anyone within an on-grid village (that could be left off-grid in the free clustering configuration) is essential for the success of the implementation electrification plan, counterweighing the loss of optimality according to the preferences of the final customers.

2.2.1.2 Village level REM Exhaustive vs. Non-Exhaustive algorithms

Another issue to be considered is how to consider productive loads inside villages which are better off-grid as a whole. Even if the village is off-grid, the connection of high-demand productive loads (e.g. Telecom towers) to the grid can result in a lower electrification cost, and can also benefit other nearby customers with a grid connection (though not the whole village in these cases). REM allows to evaluate individually the connection to the grid of any load (or group of loads) inside an off-grid clusters (called the Exhaustive Algorithm configuration in REM). EDCL determined that connection of customers around productive loads, excluding others within the same village, could be considered as inequitable by those other citizens not so near the productive facility.

For this reason, the NEP plan has been configured to not consider the choice of individual grid connections inside off-grid village (Non-Exhaustive algorithm) to determine the choice of electrification modes for each village. But in the implementation phase, any load can always be connected to the grid if it is considered a priority, even if the cost of connection is higher than the cost of the stand-alone solution.

2.3 Selection of Reference Case Scenario for the NEP

After the different previous analyses were discussed in detail with EDCL, the following Reference Case Scenario (RCS) for the initial proposal of Grid and Off-Grid areas for the National Electrification Strategy is:

- Algorithm: Grid extension decision taken at administrative village level, non-exhaustive.
- Cost of energy from the central grid: 0.12 $/kWh
- Reliability of the central grid: 100%
- National catalogue and network standards: equal for grid extension and grid-compatible microgrids.
- International catalogue for off-grid generation.
- Smallest microgrid size: 50 customers or 3 kWp.
- Discount rate 8%
- Administrative charges per grid-connected customer: 9 $/year
- Administrative charges per microgrid customers
    - Medium size microgrid (100 customers): 16 $/year
    - Large size microgrid: Asymptote at 9$/year
- Per customer costs (as per EDCL specifications)
    - Grid extension and microgrids connection cost: 65 $/customer (meter and connections)

- Solar kits: 35 $/solar kit (retail price specified by EDCL of a basic SE4all Tier 1 system)

- Average cost of diesel: 1.2 $/l
- Average cost of labor: 1.6 $/hour
- Already electrified customers (2017): 721 512
- Non-electrified customers (2017): 1 612 432
- Number of cells: 2 148
- Number of villages: 14 816
- Forbidden areas: Excluded from the National Electrification Plan

3 Techno-economic least-cost plan for Universal Access in 2024

3.1 Techno-economic optimum for the Reference Case Scenario: Global results for Rwanda

The least-cost balance for this Reference Case Scenario (RCS) is defined by the cost of service of grid extension vs. the alternative cost of microgrids and, where appropriate, solar kits or stand-alone systems. As detailed in Section 1.2, REM calculates the Cost of Service for any given alternative (evaluated as an annuity in USD/year) considering:

- Grid Extension:
  - Cost of energy purchased from the grid, in our case at a cost of 0.12$/kWh, and supplied to the customers, according to their demand, including network losses,
  - Cost of network investment, operation, preventive and corrective maintenance, according to the catalogue and standards defined by EDCL for Rwanda NEP.
  - Other supply costs: Connection, protections and meters, administrative, billing, fee collection overhead costs incurred by the distribution company (EUCL).
  - Social cost of non-served energy. In this RCS this cost will be zero, as the scenario considers as a hypothesis that the reliability of supply in 2024 will be 100%.
- Microgrids:
  - Cost of distributed generation: According to the hourly demand profile of the customers connected to the microgrid, the associated network losses and the solar profile, considering hourly variations, and to the generation catalogue established for the RCS. See Figure 10: for a sample of this scenario for the district of Nyagatare.
  - Cost of microgrid network, including also investment, operation, preventive and corrective maintenance.
  - Other supply costs, also incurred by the incumbent microgrid company (in this scenario, according to REG specifications, also EUCL).
  - Social cost of non-served energy, according to the specific reliability of the microgrid every hour of the year, considering the different costs of Non Served Energy for Critical and Non Critical loads / hours.
- Solar Kits and Stand Alone Systems
  - Cost of distributed generation, according to the choice of supply:
    - DC Solar Kits for isolated residential loads under 50 Wp

- AC Stand-Alone Solar Systems for other eventually isolated high-consumption community and productive customers.
- Administrative costs:
  - Solar Kits: No other administrative costs are included in this case, as every guarantee or commercial insurance is considered as included in the retail price.
  - AC Stand-Alone Solar Systems. Due to the higher cost and maintenance of these larger systems, a pay per service fee is considered, equivalent to that of very small microgrids.
- Social cost of non-served energy, according to the loss of load in each specific case.

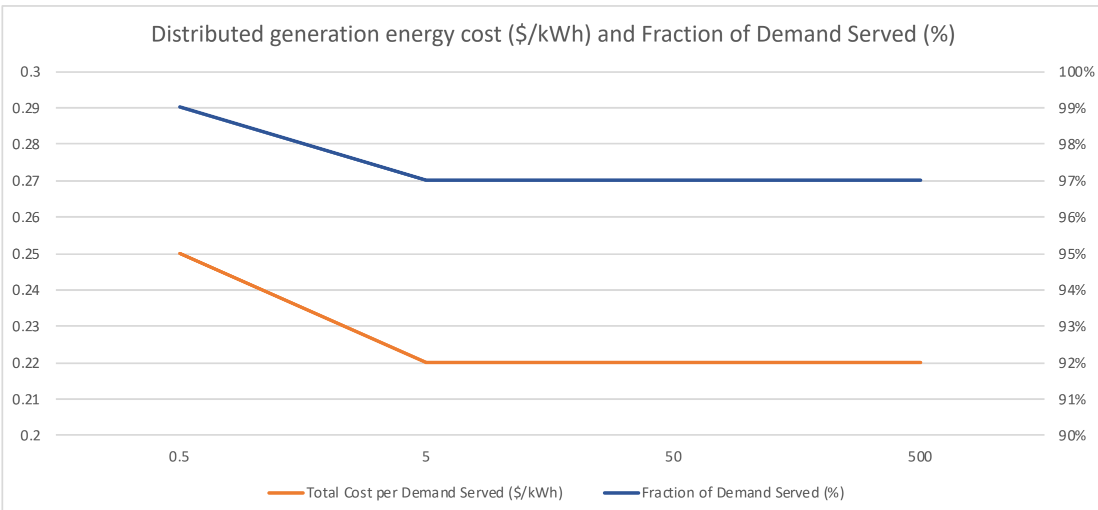


Figure 10: Optimal generation cost ($/kWh secondary axis) and average reliability (% energy demand served) of a hybrid solar-diesel microgrid in Nyagatare, for microgrids between 500 Wp (50 type 1 households equivalent) up to 500 kWp

The minimum microgrid size allowed was equivalent to a village of 50 type 1 households (less than 500Wp demand). The cost of generation per kWh for these very small microgrids is a 15% higher than the cost for larger microgrids.

kWp	0.5	5	50	500
Total Cost per Demand Served ($/kWh)	0.25	0.22	0.22	0.22
Fraction of Demand Served (%)	99%	97%	97%	97%
Peak Demand 2017 (kWp)	0.50	5.00	50.00	500.00
Peak Demand 2024 (kWp)	0.81	8.11	81.12	811.23
Average Demand 2024 (kW)	0.311	3.107	31.072	310.724
Yearly Energy Demand 2024 (MWh/yr)	2.72	27.22	272.19	2,721.94
Solar Capacity (kWp)	3	29	288	2832
Battery Capacity (kWh)	19.32	182.16	1854.72	17951.04
Generator Capacity (kW)	0	0	0	60
Financial Cost per Demand Served ($/kWh)	0.25	0.21	0.21	0.21
Percentage of diesel used (%)	0	0	0	0
Total Cost ($/year)	680	5,948	58,940	588,129
Total Cost per user ($/year)	13.61	11.9	11.79	11.76

Table 2 Optimal reference designs for solar microgrids generation in Nyagatare,
for systems between 500 Wp (smaller microgrid size allowed 50 type 1 households) up to 500 kWp

The generation for each actual microgrid designed by REM will be sized according to the actual users connected to that microgrid clusters, considering their customer types and the demand expected in 2024. PV panels, batteries and, where applicable, diesel generation is optimized to establish the reference cost that can be used to evaluate tender proposals for IPPs in microgrids, as will be furtherly detailed in Task 3 and Task 4 reports.

Diesel penetration in the optimal designs, considering the average cost of fuel is 1.2$/l, is insignificant and only appears as small backup power in systems over 500 kWp. This cost is much higher in isolated rural areas and highly volatile, therefore the conclusion is that diesel, if allowed, will be reserved for backup and mainly in very large systems.

3.1.1 Rwanda National Electrification Plan system map

Figure 11 below shows the map of systems designed by REM for the Reference Case Scenario. Blue and red lines correspond to medium voltage (MV) and low voltage (LV) connections to the central grid. Green LV lines define connect customers to off-grid microgrid generations and, eventually, orange lines would represent MV networks for very large minigrids (not present in this scenario). Purple points represent stand-alone solar kits and SHS.

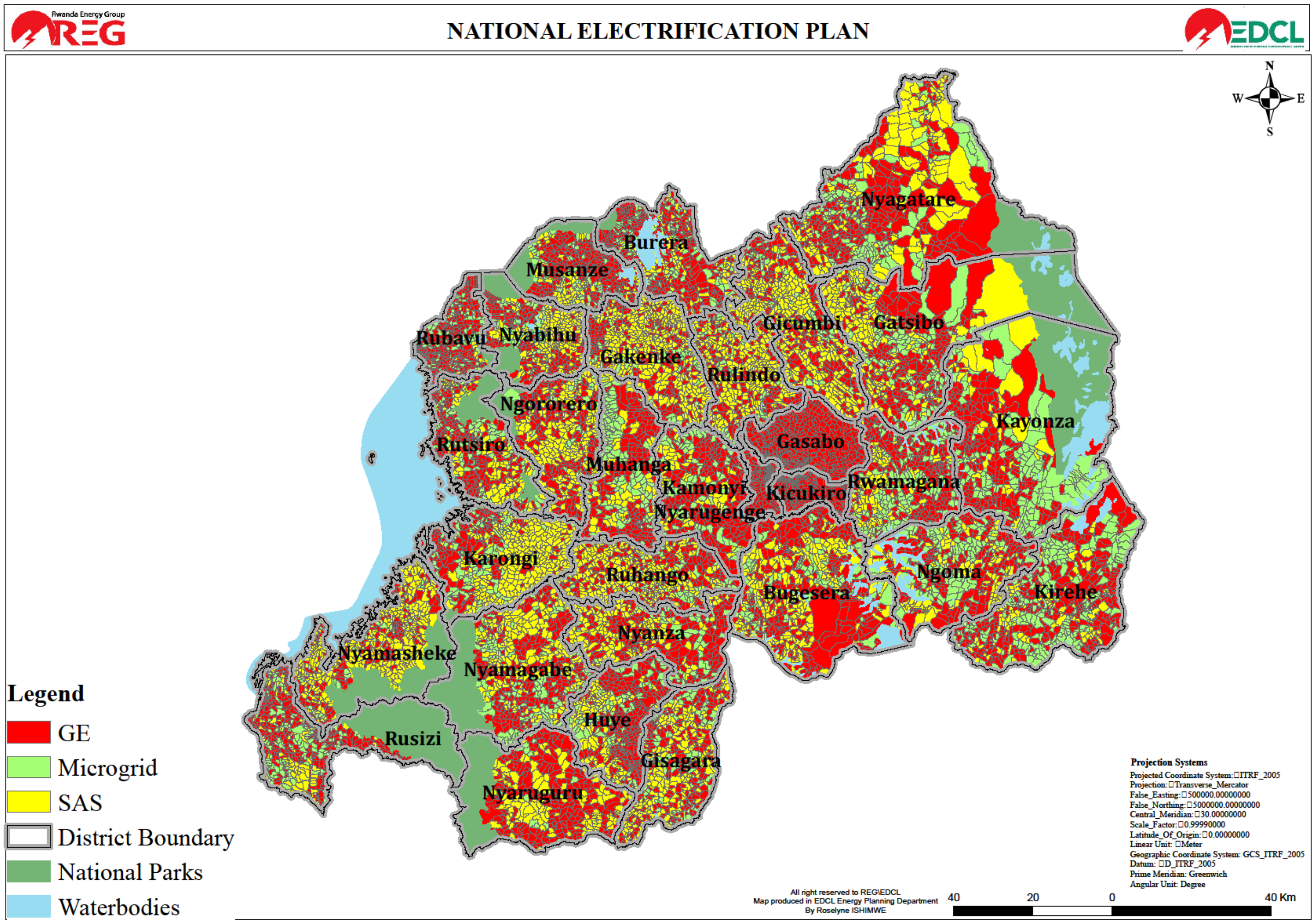
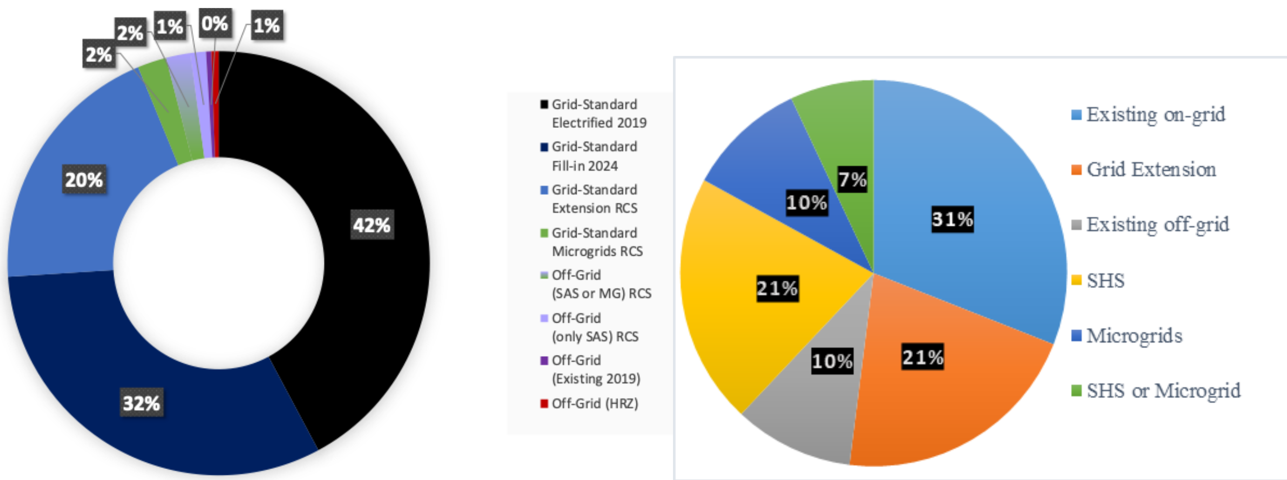


Figure 11 Systems map for the Rwandan National Electrification Plan – Reference Case Scenario

For the whole of Rwanda, Figure 12 shows the share of the different electrification modes, both in terms of number of customers supplied by grid extension, microgrids and solar kits (a), and regarding the amount of energy supplied to the whole population electrified by the NEP 2017-2024 (b) under the Reference Case Scenario.



(a) Share of energy Suplied (b) Share of energy supplied

Figure 12 Share of total customers and of energy supplied per electrification mode in the Reference Case Scenario 2024

The share of **grid extension in 2024 will reach 52% of on-grid connections in 2024 of all Rwanda** in the National Electrification Plan, including 31% of already existing connections in April, The remaining 21% will be both fill-in connections in already electrified villages and extension of the grid to new villages in 2024. **Off-grid connections will represent 48%** of the universal electrification target, of which Grid Standard Microgrids serving a whole village would represent 10%, and DC Solar Kits or AC Stand-Alone Systems would account for 38%, of which 7 % are villages where coexistence of solar kits and microgrids could be a choice to consider at the implementation phase, 21% are in villages where only SAS is the recommended option, 10%% are off-grid customers already electrified in as of April, 2019. Households in High risk zones are not included in this Plan as they will rather be re-located to modern settlements as per the GoR policy.

Out of a total of nearly 3.9 million connections, including residential, community and productive customers, 2 million (62%) would be high-quality grid standard solutions (1.7 million connected to the central network and 326 thousand clustered in village microgrids), while almost 1.2 million would receive a DC solar kit, or a fully fledge AC stand-alone-system for large isolated loads, as a transitory solution.

It is important to notice that the total amount of energy demanded by the 52% of grid connected customers' accounts in fact for 93.8% of the total energy consumption of the electrified customers (see Figure 12 b and **Error! Reference source not found.**). 8.2% Micrograds would supply 2.2% of the energy whereas 35.8% stand-alone systems would represent 4% of the energy demand, as most of the productive and community loads, with a higher weight in the energy mix, are connected by REM to the central grid or to micrograds.

The total energy consumption estimated for the Reference Case Scenario reaches 2.36 TWh/year in 2024. This figure reflects on one side that the number of new customers connected through this NEP will be 2.2 times the present number of grid connections, including many significant high-consumption industrial and productive customers. The expected per customer demand growth per year in the RCS is 8.4%, a high figure that results in the design of a robust network that can accommodate future growth and will not become a bottle neck for economic activities in the country.

The cost of fill-in connections in already electrified villages has been estimated according to an average cost of connection of 600 $/customer as per EDCL indications. A more indepth study, though is beyond the scope of this NEP, could be developed but would require a very thorough analysis of the status of the present MV and LV network components and their load. As for the new grid standard extension, the average investment cost is 732 $/customer and averages many different connection types and circumstances. Considering the load and distance to the existing MV grid, some large systems show an average of 301$/customer, whereas others climb up to 5,901 $/customer, nearly twenty times more, in the Reference Case Scenario (depending not only on the distance of the village to the grid, but also on the loads in the grid extension piece). Grid standard Microgrids have an average overnight cost of 630 $/customer, which in this case includes network (67%) and generation (33%) investment costs. In this case the cost per customer ranges from 449 $/customer to 3,684 $/customer for those microgrids where large anchor loads increase the cost of generation (74% in this case) in relation to the network (26%).

Table 3 shows how the average investment cost of connection to the grid is split according to the relative weight of the different customer types. The network cost per customer is calculated according to their peak load in 2024, according to the NEP timeline, with an average cost of 364.15 $/kWp. Therefore, while large industrial connections would cost several millions of dollars, residential connections, with a subsistence peak load in the range of tens of watts will individually represent a very small amount of the total share of the grid cost.

REM type	Customer type	Power (kWp) (year 0)	Power (kWp) year 7	Grid Standard Extension Investment cost per customer	Grid Standard Extension Investment cost per kWp (year 7)
Customer_type1	Airport	6,000.00	10,552.52	23,891,900	2,264.09
Customer_type2	Cell ofice	2.00	3.52	7,964	2,264.09
Customer_type3	Coffee washing station	1.50	2.64	5,973	2,264.09
Customer_type4	Health center	1.80	3.17	7,168	2,264.09
Customer_type5	Health post	1.00	1.76	3,982	2,264.09
Customer_type6	IDP Model Village (avg.)	13.00	22.86	51,766	2,264.09
Customer_type7	Irrigation pumping	3,000.00	5,276.26	11,945,950	2,264.09
Customer_type8	Markets	8.00	14.07	31,856	2,264.09
Customer_type9	Milk collection center	1.40	2.46	5,575	2,264.09
Customer_type10	Mining	25.00	43.97	99,550	2,264.09
Customer_type11	Preprimary school	0.40	0.70	1,593	2,264.09
Customer_type12	Primary school	0.40	0.70	1,593	2,264.09
Customer_type13	Secondary school	1.30	2.29	5,177	2,264.09
Customer_type14	Sector Office	1.40	2.46	5,575	2,264.09
Customer_type15	Tea Factory	3,800.00	6,683.26	15,131,536	2,264.09
Customer_type16	Technical Schools	26.00	45.73	103,532	2,264.09
Customer_type17	Telecom Tower	280.00	492.45	1,114,955	2,264.09
Customer_type18	Universities and Institutes	130.00	228.64	517,658	2,264.09
Customer_type19	VTC	280.00	492.45	1,114,955	2,264.09
Customer_type20	Water pumping stations	40.00	70.35	159,279	2,264.09
Customer_type21	Residential 10W	0.010	0.018	39.82	2,264.09
Customer_type22	Residential 50W	0.050	0.088	199.10	2,264.09

Table 3 Breakdown of average network cost per customer in the Reference Case Scenario

The energy consumption is higher for grid-connected customers (1,129 kWh/yr-customer) than the one of microgrids customers (172 kWh/yr-customer). This is due to the fact that large industrial and productive customers are mainly connected to the grid, therefore their energy demand is enormous (with peak consumptions up to 6 MW) in comparison with the very small demand of the average residential customer (from 10 to 50 W).

The average total per unit cost of energy for the system is high (0.255 $/kWh), especially if we compare it with the cost of purchasing energy from the upstream network (0.12 $/kWh). The level of consumption is small compared to the capacity of the network components used in the catalogue, meaning than in average the cost of new distribution, both grid and off-grid, multiplies in more than twice the cost of centralized energy from the grid in the Rwandan System. The average cost for grid standard extension is 0.199 $/kWh, while for grid standard microgrids it climbs up to 0.593 $/kWh. This is due not only to the higher cost of off-grid generation, in comparison to the cost of energy from the grid, but also because of the better use of the grid made by high-consuming grid connected customers.

3.1.2 Costs breakdown of individual grid extension and microgrids.

It is also important to realize that the cost of supply for grid standard extension customers is not homogeneous for all the 931 individual grid extension projects summarized in Figure 13. The average size of 463 customers per grid extension section and 0.199 $/kWh do not reflect the diversity of situations shown in the Figure. Starting with those sections in downtown areas or nearby very high-end industrial loads, the cost of service for those customers will be around 0.13 cents actually. When the weight of these large energy consumers diminishes, the cost of service rapidly starts to increase for the connection of disperse loads, even if they are cheaper than off-grid alternatives (microgrids or solar kits / SHS) rapidly reaching over 0.40 $/kWh for still large size grid extension sections, and then growing up to 0.80 $/kWh for large grid sections far from the existing MV grid and with a very low energy consumption (shown in the figure as the generation cost, as compared to the annual network cost).

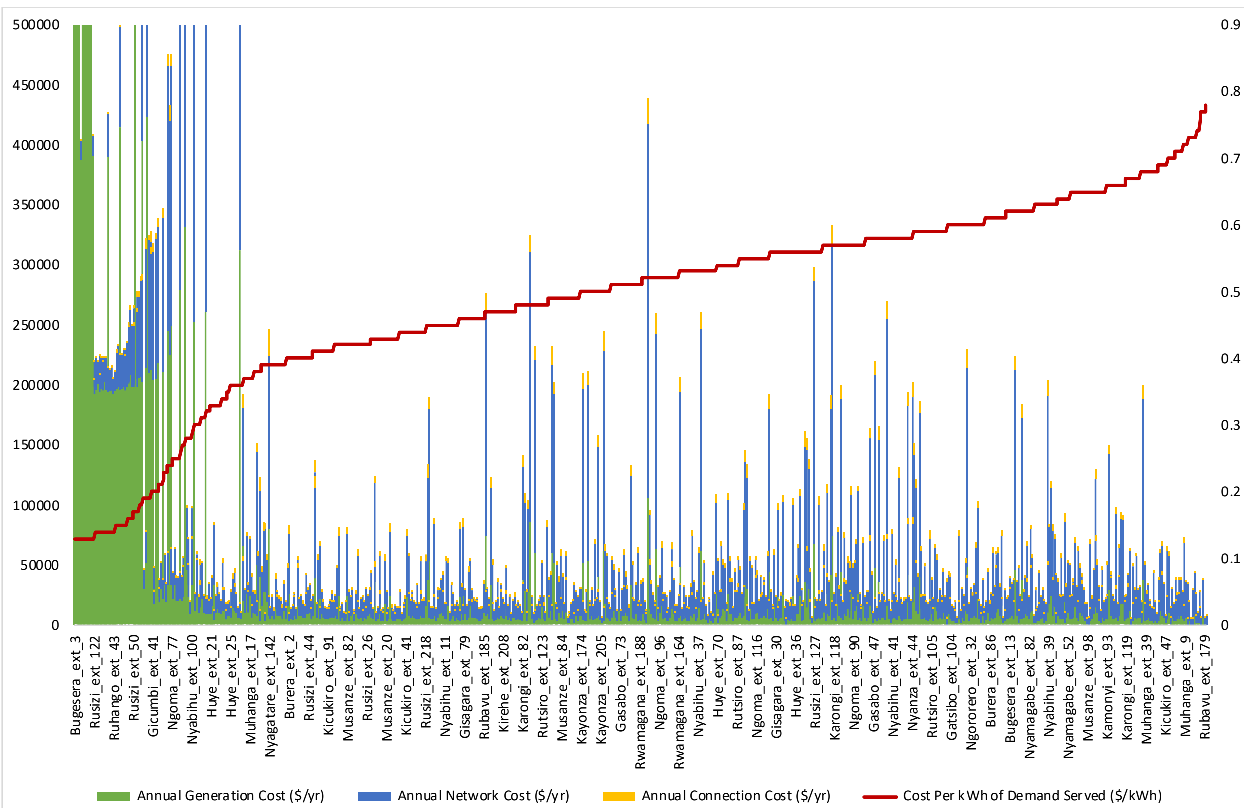


Figure 13 Breakdown of selected individual grid standard extension costs annuities ($/yr) and per unit costs ($/kWh). Rwandan National Electrification Plan – Reference Case Scenario

A similar breakdown can be shown for the 2843 microgrids, which are much smaller in average size (152 customers per microgrid) as shown in Figure 14. Most of the microgrids are in the final trench over 0.50 $/kWh, but very dense microgrids shown in the Figure, that include mid-size productive loads far from the grid can get their costs down to 0.23 $/kWh, very competitive with the cost of the grid. Therefore it is individual balance between the costs shown in Figures 24 and 25 the one that determines the frontier between the grid the microgrids, a qualitatively different approach to the use of heuristics like the distance to the grid or the density of loads, which do not resemble correctly the actual complexity of grid and off-grid system design calculated by REM.

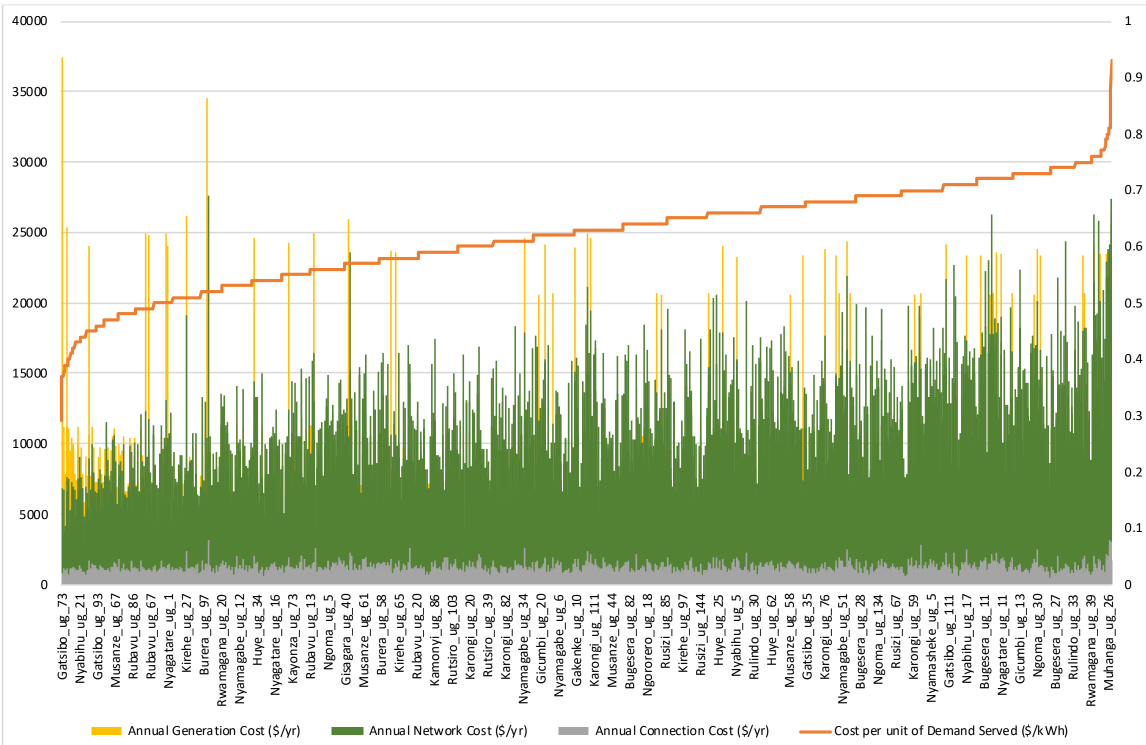


Figure 14 Breakdown of selected individual microgrids costs.
Rwandan National Electrification Plan – Reference Case Scenario

3.1.3 Solar Kits and Stand-Alone Systems in the Reference Case Scenario

Finally, REM also will include the design of those isolated loads that are being served (from a least cost perspective) by an isolated system, instead of connected to the grid or a microgrid.

Customer type	PV Array Size (kWp)	Battery Bank Size (kWh)	Annual Demand (kWh)	Fraction of Demand Served (p.u.)	Cost Per kWh ($/kWh)	NPV per Customer ($)
Pre-primary	2	14	2,178	0.93	0.26	5,572
Primary School	2	14	2,178	0.93	0.26	5,572
Secondary School	7	46	7,077	0.95	0.22	16,157
Sector Office	8	50	7,621	0.95	0.22	17,330
Technical Schools	145	925	141,541	0.96	0.21	304,880
Telecom Tower	1,584	9,853	1,524,289	0.96	0.21	3,317,780
VTC	1,584	9,853	1,524,289	0.96	0.21	3,317,780
Cell Office	11	71	10,888	0.95	0.22	24,368
Water pumping	223	1,422	217,756	0.96	0.21	468,608
Residential 10W	0	0	54	0.45	0.36	94
Residential 50W	0	0	272	0.09	0.36	94
Coffee Washing	8	53	8,166	0.95	0.22	18,503
Health Center	10	64	9,799	0.95	0.22	22,022
Health Post	6	36	5,444	0.95	0.23	12,638
IDP Model Village	73	463	70,771	0.96	0.21	152,848
Markets	45	285	43,551	0.96	0.21	94,422
Milk Collection	8	50	7,621	0.95	0.22	17,330
	53	**333**	**51,392**	**0.80**	**0.26**	**111,846**

Table 4. Solar Kits and Stand-Alone Systems design and average cost breakdown for the Reference Case Scenario (Solar Kits Villages)

In the Reference Case Scenario we find that the majority of these loads are low-consumption residential customers of Types 1 and 2 (consuming less than 10 W and 50 W) provided with a DC Solar Kit. In these cases the reliability resembles the share of their grid connected demand that would be served by the selected Kit, not the reliability of the Kit itself, which should provide the service according to those essential needs it is covering. There are also other loads that at each district are in off-grid villages and do not get connected to nearby customers. This is the case for more than 300 schools in the country, almost the same amount of cell Offices. The cost of supply of an AC Stand-Alone System for those demands is very competitive (in between 0.21 $/kWh and 0.26 $/kWh), making them a possible suitable solution for community and productive loads far from the grid and below the minimum threshold established for a microgrid (i.e. 50 customers or at least 3 kWp demand). The proposed IDP model village sites under development have been modelled as a single load for the purpose of REM, but naturally they will be recieve microgrid supply as they are built.

3.1.4 Rwanda National Electrification Plan: villages map

The basic block for grid/off-grid electrification choice in Rwanda is the administrative village boundary. REM calculates the least-cost option for the whole customers (productive, community or residential) inside the village, so they will all get either connected to the central network or provided an off-grid solution.

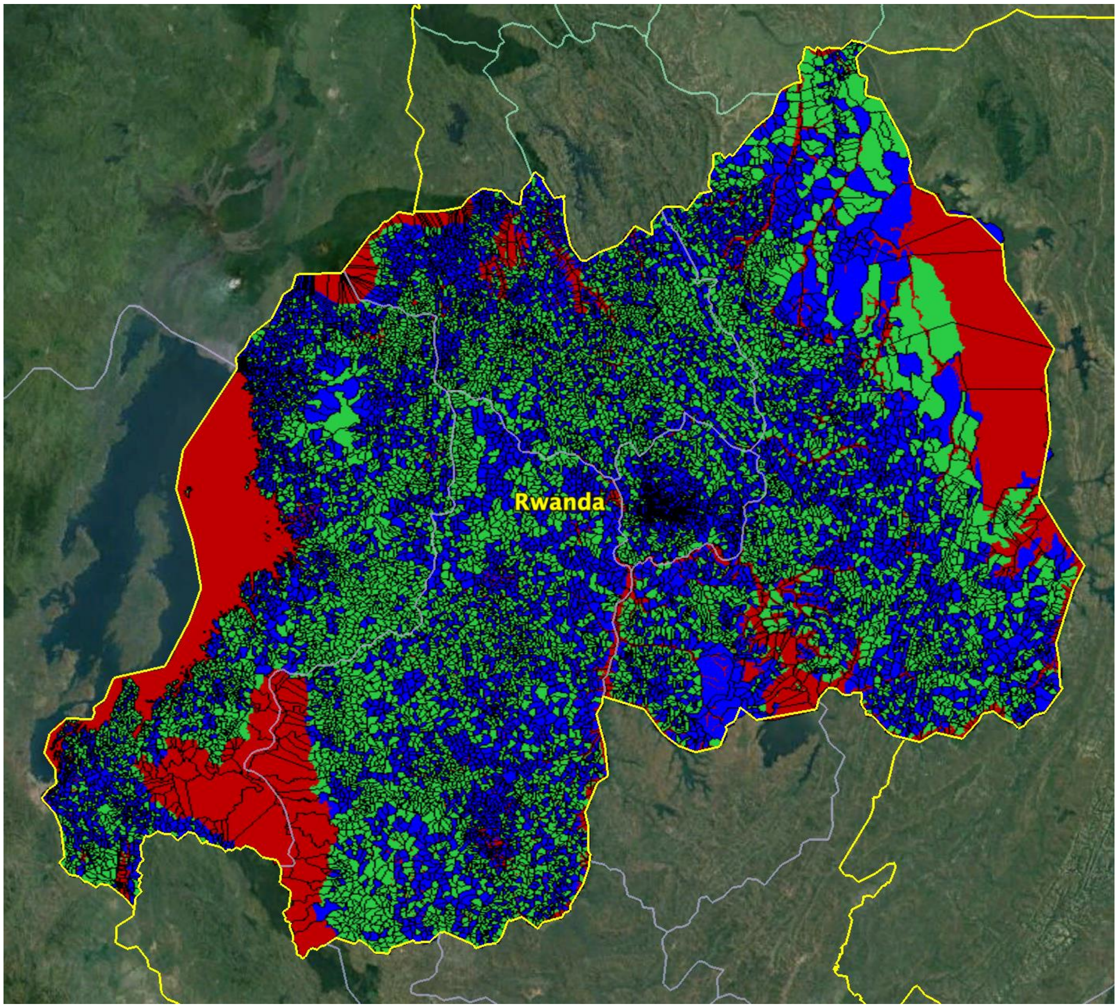


Figure 15 Satellite projection of grid extension villages (blue), off-grid villages (green) and High-Risk Zones (red) for the Reference Case Scenario

Figure 15 shows the map of the grid connected and off-grid villages for the National Electrification Plan of Rwanda. The National Electrification Plan has classified all the cells in the country according to the following electrification modes:

- Grid Extension Villages. These include:
  - Grid Standard Extension RCS Villages: Out of 14,816 villages in Rwanda, 2,476 shall be connected to the grid in the Reference Case Scenario. They will require the development of new infrastructure (MV transformers, MV and LV lines)..
  - Grid Standard Fill-In Villages: 4,662 villages have already got a MV line and transformer providing electricity service. From 2019 to 2024 the challenge for these villages is to connect any facility or household not yet connected or built anew in the area.

- Off-Grid Villages:
    - Grid Standard Microgrid RCS Villages: Additionally, the basic block in off-grid villages to decide whether microgrids or solar kits are the least-cost solution is the village boundary. 2,568 Villages have been classified for microgrid electrification when the least cost option is to electrify the customers in the village with a microgrid.
    - DC Solar Kits or AC Stand-Alone Systems RCS Villages. All these 5,110 villages are selected for electrification with isolated systems, either DC solar kits for small customers (low-income households) or full-fledged systems which provide 24 hours service for larger customers (isolated productive and community loads). In some of these villages, smaller clusters could still be suitable for microgrid electrification, as shown in **Error! Reference source not found.**, but the villages where the whole population could be electrified with one or several Microgrid Systems have been prioritized and in all the remaining off-grid villages, solar kits and stand-alone systems will be promoted.
    - NEP High Risk Zones: The households in these areas, regardless of the village they belong to, will be electrified with Solar Kits as required by MININFRA, and they have not been considered for grid standard electrification (either grid extension or microgrid). Some villages are completely inside these high-rish zones shown in red in Figure 15 above, while others villages may have some areas inside HRZ, whose customers have not been considered for the RCS and will be electrified only with solar kits.

It is **important to notice** that this NEP for Rwanda does only focus on the new infrastructure that is required to connect additional customers so that Universal Access can be achieved in 2024. Reinforcements and densification of the existing MV and LV distribution network are not within the scope of this report. Consequently, the classification of off-grid villages therefore only answers to a techno-economic optimization criteria where new infrastructure is required. Some of the off-grid villages are nearby existing MV and LV lines, which could still retain some extra capacity to accommodate new connections without additional MV lines or transformers. To fully ascertain the possibility of connecting these undergrid NEP off-grid villages to the existing grid, an additional individual field study will be required for each one of them, to accurately establish the existence and the amount of idle capacity in these lines and transformers, and to determine the cost of connecting these new customers to the already existing grid.

ANNEX 1: Detailed analysis of past electrification plans and strategies in Rwanda

The first electrification master plan which appears to have been developed for Rwanda was drafted by Hydro Québec International in August of 1991, with a planning horizon reaching to 2010 (Fichtner and Republic of Rwanda EWSA, May 2011). Implementation of this plan was interrupted by the genocide in 1994, a massive upheaval of the country's social, political, and economic systems from which it would spend the following decades trying to recover. A series of national infrastructure development legislation was issued starting with the National Urban Housing Policy in 2004 followed by the Economic Development & Poverty Reduction Strategy published in 2007, which appears to have been the first national proclamation in recent decades expressing the intention of the administration to prioritize electrification. The electrification plans, policies, and programs which followed in the years leading up to present day Rwanda will be discussed in further detail in the following sections of this report, but as the references are many, a timeline has been provided to assist the reader in following the narrative. Items referenced in this report are shown in blue text in Figure 16, with the two reports which constitute the main focus of the discussion displayed in bold font. Any items shown in grey have been included for context only and do not figure materially into the report.

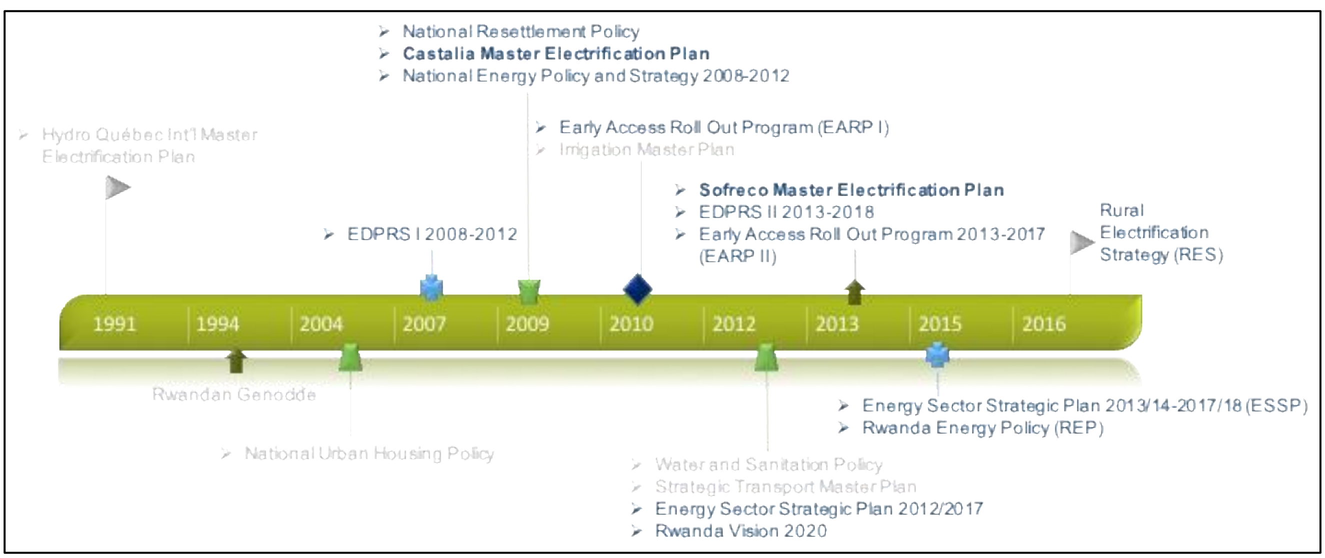


Figure 16: Timeline of Electrification Plans, Policies, and Programs in Rwanda

For this project, the two master electrification plan reports identified, those written by the consultants Castalia and Sofreco, respectively, have been reviewed along with their supporting documents for the purposes of identifying the methodology followed by each in the creation of a national electrification plan for Rwanda. The two methodologies will then be compared in order to identify common elements, unique attributes, strengths, and weaknesses. These findings will then be used to form the basis of a critique of the capabilities of the Reference Electrification Model, so that recommendations may be formed concerning both the future use and development of this techno-economic planning tool.

Castalia Master Plan Study (2009)

The Castalia report is comprised of two documents: the Prospectus and the Technical Annex. Both were consulted for the purposes of this review.

Context

The Castalia study was published in 2009, two years after the release of the Economic Development & Poverty Reduction Plan (EDPRS I), which called for an increase in the total number of electricity connections from 100,000 in 2008 to 350,000 in 2012 (~16% of households (Castalia Strategic Advisors, March 2009)) and the prioritization of establishing connections for social infrastructure (i.e. health facilities, schools, and administrative offices) with the objective of electrifying 100% of both health facilities and administrative offices and 50% of schools by 2012. A memorandum of understanding (MOU) had been signed the year before, in 2008, between the Ministers of Finance and active development partners agreeing to facilitate an increased level of coordination and cooperation among actors belonging to government institutions, utilities, development agencies, and development partners in what was being called a sector-wide approach, or SWAP. The Castalia report describes this as a "move away from implementing one-off energy projects towards a systematic and coherent approach to planning, financing, and making new electricity connections".

The Castalia report also makes reference to the government having recently enacted multiple pieces of legislation geared toward reorganization of the energy sector and refinement of related development plans. Among these laws were those calling for the creation of a new electricity utility 'RECO' and the establishment of a National Energy Development Agency 'NEDA'. The independent regulator RURA was also purportedly given additional powers and responsibilities. In general, it indicated that the new legislation sought to transition away from government-managed energy provision toward a system involving a greater degree of private-sector investment and participation, specifically inviting private investment in generation. Exclusive control over the transmission system was given to Electrogaz. The new energy policy, National Energy Policy and National Energy Strategy 2008-2012 (Republic of

Rwanda Ministry of Infrastructure, January 2009), called for cost-reflective tariffs and required RURA to consult MININFRA before setting tariffs in order to be clear about the level of subsidies which could be expected from the government.

Objectives

The Castalia Prospectus states that the intention of its planning exercise was to develop a five-year least-cost technical plan satisfying the electrification goals set forth by the EDPRS, which it referred to as "set[ting] the medium-term framework to 2012 for achieving the long-term aspirations embodied in Vision 2020". The reference being made in this instance is to the original version of Rwanda's Vision 2020 which was published in the year 2000 and which established the goal of reaching 35% countrywide electrification by 2020. In addition to developing a plan that would demonstrate how the 35% electrification goals could be met from a technical standpoint, Castalia was tasked with the complementary objective of providing a phased investment plan to instill confidence in would-be investors, whom it calls out as its primary audience: "The Prospectus seeks to raise US$250 million from development partners to fund access programme investments. The Prospectus aims to ease the analytical burden on development partners by providing credible information on Rwanda's electrification plans and presenting all relevant information and analysis on the access programme in one document".

Assumptions

There was no section in the report dedicated to the enumeration of all assumptions used by Castalia in the development of its plan, but an effort was made to formulate a list of assumed values as they became apparent over the course of reviewing the Prospectus and Technical Annex. This is not, therefore, to be taken as a necessarily comprehensive list but, may be considered at least as a suggestion of the types of values assumed.

Assumptions appearing in the Technical Annex include those pertaining to the technology selection process (e.g. discount rate, population growth rate, average number of people per household), those pertaining directly to the off-grid technologies considered (e.g. costs of generator models of varying capacities, annual maintenance costs, installation costs), and those employed in what the report refers to as the "operations and financing model".

Assumptions appearing in the Prospectus:

- Technology costs: Investment lifetime was considered to be ten years for all energy sources; the costs each technology configuration was expected to incur over a ten-year period were discounted into present value terms assuming a discount rate of 10%.

- ECIV2 survey responses were used to estimate the percentage of households per district with different demand levels. *Minimum Consumption* was assumed to be 20kWh per month (the equivalent of 2-3 energy efficient light bulbs and a radio) and approximate average energy expenditures were considered as follows:

Area	Max. Energy Expenditures (%)	Expenditures on Min. Consumption (%)
Urban	10	2-3
Peri-urban	15	4-5
Rural	20	8-10
Deep rural	25	10-14

Table 5: Consumer Energy Expenditure Estimates by Location Type

- The study assumed that economic growth would translate into an average annual household income increase of 5%. It was not, however, made clear why a 10-year planning horizon was used, as Castalia states its objective as developing a plan that can achieve the EDPRS 5-year goals and that it is considering 20 years as the long-term planning horizon.
- It is assumed that the following system sizes will be sufficient to meet the demand (nature of demand unspecified) for social institutions receiving standalone solar PV systems in lieu of grid connection: health centers – 3kW, schools – 1.5kW, administrative offices – 1kW.
- 100% grid reliability and sufficient generation supply were assumed to be available for the duration of the planning period.
- For the purposes of microhydro minigrid cost estimation, an average ADMD (defined as After Diversity Maximum Demand) of 300W is assumed along with a power factor of 0.99.
- New grid extension will be funded as follows: 10% of the capital cost will be covered by connections fees (although consumers are purportedly only expected to contribute 10% of this value, or ~$100USD), 10% will be paid for by the utilities through surplus tariff revenues, with the remaining 80% being covered by the government and development partners.
- The government was planning to complete a full tariff study the year this master plan was studied.

Inputs

Type of Characteristic	Variable	Source	Figure Reference
Demographic	Population data and growth[11]	National ID Survey	Figure 4.2
Political	Country and administrative boundaries	National Institute of Statistics and MINALOC	Figure 4.2
Political	Presidential priorities	Electrogaz	Not shown
Social	Administrative offices	MINALOC	Figure 4.3
Social	Health centres	MINISANTE	Figure 4.3
Social	Schools	MINEDUC	Not shown
Natural features	Roads, rivers, national parks etc	MININFRA and MINIRENA	Not shown
Electricity infrastructure	Location of power lines (HV, MV and LV)	Electrogaz	Figure 4.4
Electricity infrastructure	Location of micro-hydro sites	BTC micro-hydro atlas	Figure 4.4
Demographic	Income levels and poverty data	NIS EICV2 Survey	Figure 4.5

Table 6: Table of Inputs as Provided in the Castalia Prospectus

- Per-cell population density values were calculated from data collected by the Rwanda National Institute of Statistics (NIS) during the 2008 National ID Project and entered as cell attributes in ArcGis.
- The geographical location of all prioritized social facilities, including health clinics, administrative offices, and schools were obtained from NUR-CGIS (the Rwanda Centre for Geographic Information Systems and Remote Sensing), and the MINEDUC and MINISANTE ministries, and were incorporated into the GIS database.
- Existing and planned electrical network information was obtained from NUR-CGIS and MININFRA and a subset of potential microhydro sites were taken from the "Hydropower Atlas", which was made available through a study conducted by BTC in 2008. It should be noted that the microhydro sites selected from the atlas for consideration in this study were only those having a potential installed capacity of 1 MW or less.
- 'Typical' Conductor Sizes, as shown in Table 7, were provided by the utility for use in assessment of the existing network, as the Prospectus indicates that "Distribution network information on line and cable types for distribution feeders in Rwanda is currently very limited”.

kV	Conductor	Current (A) Normal	Capacity (MVA)
110	240 / 40	610	117
70	132 / 24	420	51
30	120 / 20	410	22
15	70 / 12	300	8
6.6	35	190	3

Table 7: Rwandan Standard Conductor Size Chart as Provided by RECO/Electrogaz for the Castalia Report

- The Prospectus indicates that network loading data was obtained from the National Dispatch Center, but no further details as to the nature of this data, the form in which it was provided, or how exactly it was used, were provided.

Methodology

Castalia states that the planning horizon used was 20 years, with a 'directed focus' on the first five years in order to address the EDPRS electrification targets. The software used included Microsoft Office Excel and ArcGis version 9.2. The figure below was provided in the Prospectus for the purpose of illustrating the steps followed in the planning process. The titles from the planning blocks shown in this illustration will be used herein as the framework for the description of the methodology employed.

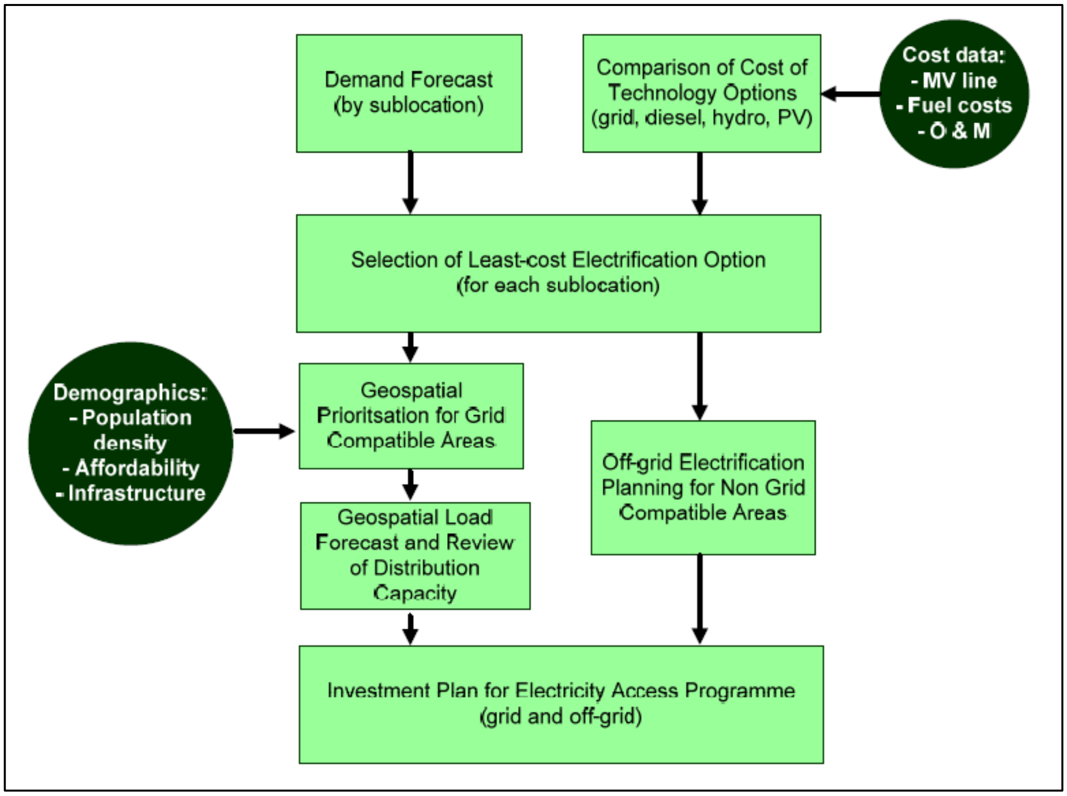


Figure 17: Planning Process Steps as Defied by Castalia

Demand Forecast (by sublocation)

Sublocations used for the purposes of this study were administrative divisions referred to as cells, defined by the Rwanda National Institute of Statistics (NIS) to support its 2002 census data gathering activities. It is indicated on pg. 23 of the Prospectus that "The technology selection model first conducts a simple load forecast for each planning cell, using variables on population growth, affordability and load growth for new connections (using an S-curve growth rate)". Details regarding the load forecast calculation are not provided, but average estimated annual per customer demand values are furnished in the Technical Annex and are shown in Table 8. A load forecast, for which the source listed is "Electrogaz Reports and Government Estimates", was provided on pg. 4 of the Prospectus to accompany a brief discussion regarding utility-scale generation expansion planning, but there was no indication that this load forecast information was used in the Castalia study itself.

General Category	Customer Type	2009	2010	2011	2012	2013
Residential and Institutional	Existing	1224	1260	1296	1332	1368
	Urban	993	1031	1074	1125	1155
	Peri-urban	649	679	720	774	795
	Rural	443	460	481	505	519
	Deep Rural	354	368	385	404	415
Commercial	Existing	80016	82016	84888	87432	87432
	New Connections	40008	41208	42444	43716	43716

Table 8: Estimated Average Consumer Demand per Customer
*All values shown are in units of kWh.

Comparison of Cost of Technology Options (grid, diesel, hydro, PV)

The off-grid technology options considered include diesel generator set microgrid, microhydro generator microgrid (where resources are conducive), and solar photovoltaic (PV) coupled with batteries for standalone systems only. Microgrids consisting of technology combinations (e.g. microhydro or solar PV combined with diesel backup) do not appear to have been considered. The selection of electricity provision technology was performed on a per-cell basis, which means that all inhabitants of a given cell will receive power from the same technology. The cost (both fixed and variable) of each off-grid energy provision option was considered and the least cost option selected. This analysis was performed in a spreadsheet-based model that is referred to in the Prospectus as the "Technology Selection Model". Images of spreadsheet model results are provided in the Technical Annex but the calculation details used to obtain those results and the actual spreadsheet were not made available for review.

Selection of Least-cost Electrification Option (for each sublocation)

This analysis was also performed using the Technology Selection Model. Now that the least cost off-grid option has been selected, it is compared with the cost of grid extension, and the least cost of these two options is assigned as the electrification mode for the cell. The analysis is performed as follows: the cost of the selected off-grid option is divided by the cost per kilometer of medium voltage (MV) line and the resulting length is considered to be the maximum theoretical conductor length for which grid connection would be economical for the cell in question. The value used as a proxy for the actual grid extension distance the cell would require is the distance from the center of the cell to the edge of the nearest adjacent cell. If this distance is less than the max theoretical conductor distance, the cell is considered to be 'grid compatible', or best suited to grid connection. Otherwise, the cell is slated for electrification with the least-cost off-grid source.

It should be noted that it is not disclosed the capacity of the MV conductor or what cost per kilometer value was used in this procedure. Presumably the conductor size was not the same for every cell but was a function of the projected demand of that cell, but this information was not included. In addition, if the cost of the off-grid option used here is the same as that used for the off-grid technology selection, then it includes both fixed and variable costs. This would imply that the cost per kilometer of the MV conductor would also need to include variable costs, such as operations and maintenance costs. According to an entry on pg.23 of the Prospectus, a section of the report other than that in which this process is initially presented, the procedure is described as follows: "The model then compares the best decentralized electrification option with the capital and operating costs of a "generalized grid" supply, initially disregarding the location of the existing electricity network”. This would seem to imply that the cost per kilometer does in fact include some manner of operating costs, although this value too remains unspecified.

Geospatial Prioritization for Grid-compatible Areas

Cells deemed 'grid compatible' are then weighted in order to determine the priority order for connection to the grid. Weights are based on the following attributes of a cell: proximity to the existing medium-voltage network, number of unelectrified households, inter-household distance (determined from population density values), number of unelectrified social facilities, access to road networks, consumer ability to pay, existence of economic development centers/markets, and presidential priorities for electrification. The methodology employed for evaluating these inputs and using them to assign weighted values to cells is extremely vague and appears to be based on a purely subjective visual assessment of the data as imported into and portrayed in ArcGis. The extent of the information provided in the Prospectus regarding this weighting assessment process is as follows: "Each attribute receives a weight according to its relative significance in determining the likely costs and benefits of electrification. The total score for each sublocation is then used to rank the planning cells relative to each other. Cells that receive the highest scores are prioritized for electrification in the access programme, according to a realistic assessment of the number of new connections that can be achieved in each year”. It then goes on to say that "This approach captures many of the elements that would form part of a project cost-benefit analysis – higher population densities, proximity to the network and access to roads will all tend to lower the costs of the programme. Prioritizing cells with more unelectrified households, social institutions, and economic activity will tend to increase the economic benefits of the programme”.

Based on this cell prioritization, a least-cost annual grid extension approach was outlined for the next five years, 2009 through 2013, as was a final plan for the year 2020 claiming to achieve the Vision 2020 goal of 35% national electrification. Results are discussed in the following section. It is indicated in the Prospectus that an additional non-least-cost scenario was considered at the behest of the government which "provides grid coverage in ever sector by 2012". However, the corresponding plan illustration is for "100 Percent Grid Coverage of Administrative Sectors" and the legend indicates that the connections shown are through planning year 2013. In either case, it is not clear if 'providing grid coverage' to a 'sector' consists of electrifying all inhabitants, or extending MV line to that cell and connecting only certain consumers. Due to lack of details, the methodology by which the plan for this scenario was developed cannot be elaborated upon further for the purposes of this paper.

Geospatial Load Forecast and Review of Distribution Capacity

Although the Prospectus makes claim to development of a 'geospatial load forecast', neither the method by which this load forecast is developed nor are the assumptions used in its development discussed. With regard to the process of reviewing the distribution capacity, the Prospectus indicates only that the "typical conductor sizes have been compared with network loading data received from the National Dispatch Centre", but supporting information was not provided.

Off-grid Electrification Planning for Non-Grid-Compatible Areas

Microhydro: As described in the Castalia inputs section, section 4.2 of the Prospectus reiterates that of the potential hydro sites identified in the Hydropower Atlas, only those with a capacity equal to or less than 1MW were considered as potential mini-grid microhydro sites and entered into the GIS input file. However, the Prospectus then indicates in section 4.5 that only those sites having a potential capacity of less than 750kW were considered. Based on the microhydro generator sizes listed in the Technical Annex, combinations of the following generator sizes were considered in determination of system cost: 5, 25, 50,100, and 250kW. It is indicated that sites with higher expected net present values, as well as those which are not expected to be capacity-constrained within the following ten years, were prioritized. Based on this information, the top 25 sites were selected to factor into the five-year development plan (without indication as to why the number 25 was used). Of these 25 microhydro sites, it was then determined which should be recommended for interconnection to the grid based on whether or not the sum of the costs to develop and interconnect the site were less than the estimated long-term marginal grid supply cost estimation of $0.12/kWh.

Solar PV: Social institutions which lay outside of cells selected for grid connection in the 5-year plan were identified and included in the 5-year plan as recipients of solar PV units.

The results of the technology selection model are shown in Figure 18. Distribution lines shown represent the existing network. A total of 95% of the cells were identified as being grid compatible, with microhydro mini-grids representing the least-cost option for about 4.5% of the cells, and diesel mini-grids and standalone solar PV being considered the least-cost option in fewer than 1% of the cells. It was further concluded in the report that while microhydro facilities may or may not be connected to the grid, depending upon when the hydro resource is developed and when the grid arrives, the diesel mini-grid cells (shown in brown) identified by the process were close enough to the existing grid that these cells would most likely be interconnected instead of electrified with diesel, although based on their relatively low demand they were nevertheless considered as not justifying prioritization under the access program. A note to the reader to be aware that substations and grid-compatible cells were assigned the same color (bright green) in the figure below, as were microhydro cells and water bodies (light blue), and while there do not appear to be any solar PV cells, the color chosen for solar PV (yellow) is so similar to that of substations and grid-compatible cells that it may be effectively dissimulating any that are displayed.

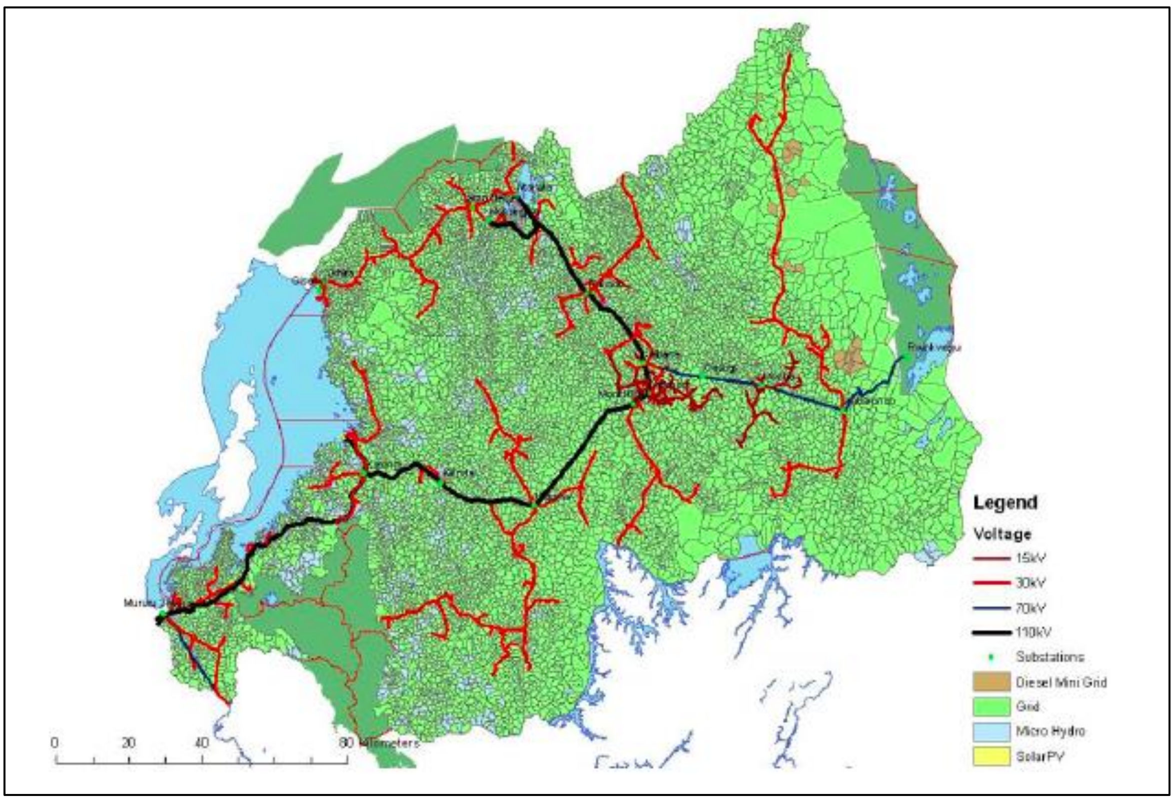


Figure 18: Technology Selection Results

Figures were also provided to illustrate the proposed network expansion. Based on these figures, proximity to the grid would appear to have been the attribute of greatest importance in cell prioritization. The relative contributions to cell weight made by other attributes is not readily apparent. The study concludes that >60% of the population were at that time living within 5 km of the existing grid, and that over 95% of the connections planned to be made through 2012 lay within this buffer, indicating that "the government's targets can be achieved without a massive extension of the medium voltage (MV) network". It goes on to say that a non-insignificant number of the new connections are infills, meaning that they are slated to be made in areas which already have an existing low voltage (LV) network and are concentrated in urban and peri-urban areas, which the report contends will also help to minimize program costs.

A figure illustrating the existing network and the corresponding 5km buffer is available in Appendix I, along with figures portraying the annual recommended grid connection scenarios for the ensuing 5 years, the plan for achieving 100% Grid Coverage of Administrative Sectors, and a plan which achieves the Vision 2020 goal of electrifying 35% of the population by the year 2020. An annual planning approach for progressing from the plan in 2013 to that of 2020 was not provided.

Other results provided in the Prospectus and Technical Annex include:

- Medium and low voltage (MV/LV) annual investment totals, although no mention was made in the Prospectus or Technical Annex as to how LV costs were estimated (no LV-level distribution designs having been shown or discussed at any point in the report). The Technical Annex does provide annual lump sum totals for the following items:
    - MV Lines: Wires & Accessories, Poles, Transport, Labor
    - MV/LV Transformers: Transformers & Accessories, Transport, Labor
    - LV Lines: Wires & Accessories, Poles, Transport, Labor
    - Service Connections: Service Cable & Meter, Transport, Labor
- The following conclusions were drawn with regard to network upgrades: 'An initial high-level assessment of current loading indicates that adequate capacity will be generally available to support the new connections during the initial years of the access program. However, detailed network modelling and load flow analysis will be necessary in the implementation stage of the access program to identify potential capacity constraints in specific areas". It goes on to say that a cost estimate for network upgrades has been provided with the report but that it is based only on expected demand growth.
- Sample results of the technology selection process are provided in the Technical Annex for 20 out of the 9300 cells evaluated. Included in these sample results are the technology types and sizes considered for each cell, the corresponding total system costs that were calculated for each technology, the max MV length, distance to the nearest cell, and least cost technology selected.

- The following are titles and subcomponent descriptions of additional results figures not discussed above (all values listed are provided on an annual basis for the years 2009-2013, some through the year 2020):
    - Capital Cost Components of Electricity Access Programme – per km costs for network extensions, per connections costs for low voltage connections separated into infill, expansion, and CFLs(?), network strengthening ($USD/MWh), off-grid technology connection costs for both solar PV and microhydro ($/kW), solar hot water and technical assistance.
    - Estimated System Operating Costs – Costs associated with current connections including generation, transmission and distribution, and administrative costs; the same breakdown of costs but for new grid connections; Off-grid connections; Operating contingencies.
    - Summary of Annual Capital Costs Associated with Sector Investment Plans (excluding generation under PPAs) – Generation, HV Transmission, Distribution Rehabilitation, Access Program.

Sofreco Master Plan Study (2013)

The Sofreco study is comprised of eleven reports, one planning and one load flow report for each of the five planning regions and a combined report summarizing the methodology used and findings at the national level. Several supporting spreadsheet models were provided along with the report as well, in addition to a full suite of GIS shapefiles. All documents were consulted for the purposes of this review.

Context

The Sofreco report was published in 2013, the same year that the second Rwandan Economic Development & Poverty Reduction Strategy (EDPRS II 2013-2018) was published, the Early Access Roll Out Program was updated (EARP II), and the year after the revised version of Rwanda Vision 2020 and the Energy Sector Strategic Plan 2012/2017 were published. The Vision 2020 document indicates that the government had set a goal of increasing the electrification rate to 1.5 million (or ~70% of the population) by 2017. EDPRS II called for 45% of households to receive grid connection by 2017 through EARP, with the remainder of the population to be connected through off-grid installations.

The Energy Sector Strategic Plan also indicated that the "government will support programs to ensure that 100% of households get access to electricity through grid and off-grid solutions by 2017". There is also a continuation of the initiative discussed in the Castalia Prospectus to electrify social institutions which are not slated to receive grid connection in the subsequent five years via solar PV, although goals have at this point been increased with respect to the desired electrification rate of schools, from

50% to 100%. The goal for health facilities and administrative offices remains at 100%. By this time, MININFRA has been appointed responsible for managing the off-grid electrification efforts, while EWSA has been placed in charge of the grid component. According to Figure 19: Rwanda Electrification Rate (grid access only) 2009-2016 Figure 19, the national electrification rate in Rwanda had grown to approximately 17%.

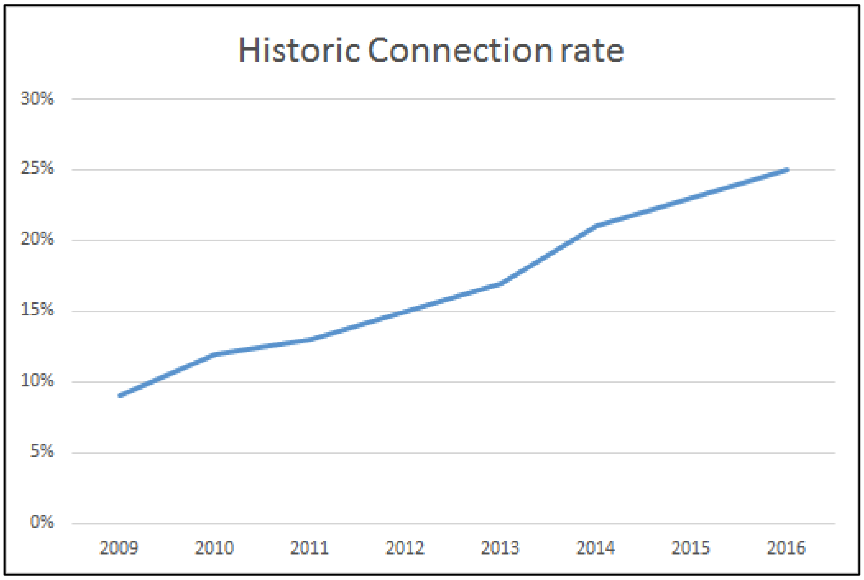


Figure 19: Rwanda Electrification Rate (grid access only) 2009-2016
(Republic of Rwanda, Ministry of Infrastructure, 2016)

Objectives

The stated objectives of Sofreco are to A) develop a plan to support the Early Access Rollout Program to achieve the goal set forth by the government to increase the national electrification rate to 70% by 2017, and B) provide the government with an estimate of how many people would need to be relocated to the Imidugudu settlements in order to achieve this goal. Sofreco describes its role as follows: "SOFRECO was appointed as a Planning Consulting Firm with its mission's main objective to assist the newly formed Planning & Design Unit to meet the electrification targets through the following: GIS, Electricity network design & planning, capacity building, and training activities".

Assumptions

- Consumer load values (see Table 9).
- Province-level load forecast assumptions (see Table 10).

* It was assumed that only 75% of potential consumers would connect during the planning period (although scenarios where 100% connection was achieved were also considered), and that population growth would remain at a steady 3% for the duration of the planning period.
* The cost for a fill-in connection occurring during the year 2012 was established by EWSA, independent of this report, to be $600USD (where a fill-in connection is defined as any connection made to a portion of the network in a year other than the year of its construction). The assumption was then made in this report that the connection costs in subsequent years would be based on this value but reduced by $50 each year "as more and more infrastructure will be installed, and less low voltage has to be constructed each year to cater for all the fill-in connections".
* The phased capital investment schedule (see the results section) assumes a 5% escalation rate.
* The Sofreco study assumes 100% grid reliability and that sufficient generation supply will be available to support the developed plans. It is stated in the report that the national target at that point in time was to achieve a total of 1000MW of installed generation capacity by 2017.

Inputs

* Orthophotos which were several years old at the time, but which presumably covered the entire country, were provided by EWSA.
* Consumer locations were derived from these orthophotos.
* Topographical data including roads, rivers, lakes, wetlands, and national parks was obtained from various institutions.
* The locations of *planned* 11,782 Imidugudu settlements were provided by MINALOC.
* The 2012 EWSA connection forecast.
* Locations of social infrastructure – initial dataset provided by Rwanda government and EWSA but data considered to be outdated so efforts were made by Sofreco to update this database.
* Existing electrical network – the initial dataset, presumably a vestige of the Castalia study, was found to be incomplete and incorrect so efforts were made by Sofreco to update this database.
* Loading of existing substations and feeders and 'normal open points on the network' were provided by the National Control Centre.

Methodology

The Sofreco combined report states initially that electrification via extension of LV and MV lines will be "implemented based on the prioritization methodology described in the project Prospectus", which presumably refers to the Sofreco Prospectus, as it then goes on to say that, "During the inception period, the revision of the order of prioritized zones for undertaking the design and planning activities was discussed with the Director of the Planning and Design Unit at EARP. Considering available information, on-going projects, recently completed projects and the overall state of network development in each zone, it was agreed that the activities would be carried out in the following revised order…". The report goes on to describe the reorganization of the electrification priorities by zone as follows (items taken directly from (Sofreco, 2013)):

1. South Zone: This zone has minimal activity in terms of new additional consumer connections. This has to be taken up in first priority.
2. North Zone: Three big EPC contractors are being awarded contracts to undertake approximately 14,000 connections. The MV extension is expected to be 150 km. The project completion period is 18 months and the work is likely to begin in early 2012. This zone is considered priority-2 and has to be started after the South Zone.
3. Western Zone and Eastern Zone: In the Western zone, about 150 km of MV line is under construction. The LV Line component will be built by EWSA. This zone is considered priority-3 and is to be started after the North Zone. A Tunisian Company, STEG, is currently adding 500 km of line in the Eastern Zone to achieve an expected additional 50,000 connections.
4. Central Zone, Kigali: The Central Zone is considered priority-4 and to be started after completion of the other zones indicated above.

All data available from EWSA was incorporated in the geodatabase and a suite of institutions, both governmental and non-governmental, were solicited for any further information which may have been available. Extensive efforts were then undertaken to update both the network infrastructure and social institution location portions of the database. Technicians were deployed by EARP and Sofreco to collect location data on social facilities in order to update the information provided by EWSA and the government. Additional infrastructure types were added over what had originally been provided, including factories, markets, and universities. Approximately 2,500 additional infrastructure points were added to the approximately 4,000 Sofreco had initially been provided.

The country was divided into five zones which bear some similarities to the administrative provinces, in terms of region naming convention and boundary, but differ in that "the location of the source determines the zone for study purposes", which presumably refers to the generation source(s) considered to be serving that area. Figure 20 shows the Sofreco planning zones (left) as compared with the Rwanda administrative boundaries (right).

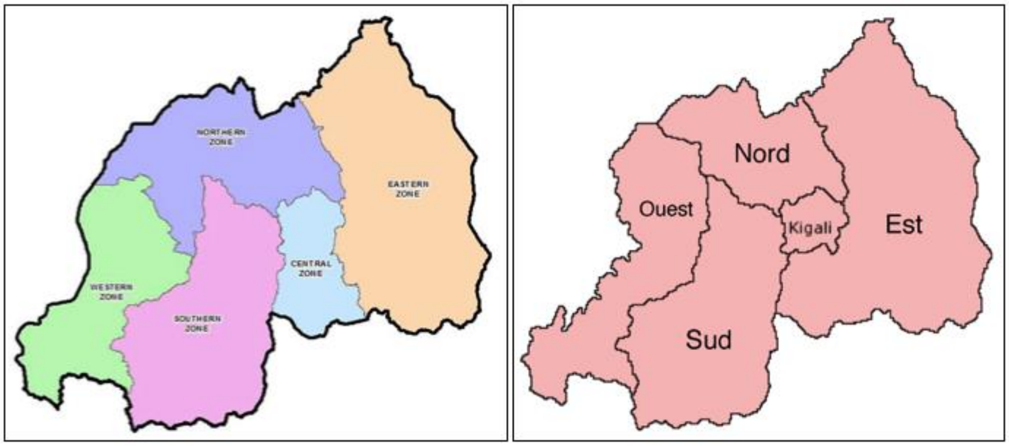


Figure 20: Sofreco Planning Zones (left), Rwanda Administrative Provinces (right)

Consumer locations were identified by placing a point on top of each dwelling as detected using the orthophotos provided by EWSA. These points were then compiled into shapefiles. It is presumed that this location exercise was performed manually, as the report contains no specification to the contrary. Just over 1.7 million households were identified.

Population 'concentrations' were identified manually through GIS map visualization of the consumer points identified from the orthophotography. An example of these clusters is shown in Figure 21. It is not evident that any maximum customer-to-customer distance or other numerical grouping criteria was employed in this process. These groupings are referred to in the report as planned MV/LV transformer zones and were made to encompass not only consumer concentrations but also to include all Imidugudu settlements and as many social facilities as possible. Zones were created covering a total of 482,854 *existing potential* consumers. That figure does not account for expected population growth due to Imidugudu resettlement but the report indicates on pg. 24 that expected growth due to resettlement *was* considered in the design phase for the purposes of determining network component capacity needs. It is worth noting here that it is not entirely clear from the order of planning operations described in the remainder of the report that this was the case.

Figure 21: Population Clusters or ‘Transformer Zones’ Identified by Sofreco

The number of customers lying within each transformer zone was then tallied and these values used to estimate both initial and forecasted load values for each zone. Distribution networks were designed for each cluster, an example of which can be seen in Figure 22 with LV conductors sized in order to accommodate expected long-term load growth. Locations of transformers and the routing of MV and LV lines appear to have been identified manually. LV lines were routed along roads with the working definition of electrification being that a potential consumer was located "within service connection length from a low voltage line".

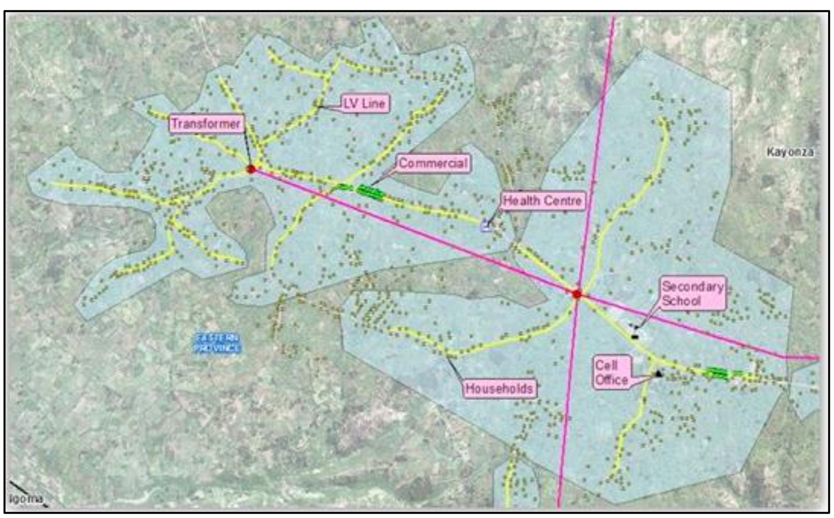


Figure 22: Illustration of Network Design for two Transformer Zones

The report was not explicit about what planning horizon was considered ‘long term’, but entries in the spreadsheet model would seem to suggest ten years (2013-2022). The report indicates that values estimated for initial demand, demand growth, and saturation for each transformer zone were "derived from statistics and with the assistance of EARP's planning department". These values can be seen in Table 9.

Load Category	Rating(kVA)	% Growth from 2012-2017	% Growth from 2017-2022
Household growth	100 watts	300 Watts saturation after 6 years	
Business Centre	10	3	2
Primary school	1	3	1
Secondary school	2	3	1
Health centers	10	4	2
Hospitals	20	2	1
Coffee wash station	2	1	1
Cell office	1	3	1
Sector office	2	3	1
District office	4	3	1
Factories	20	2	1
Market	8	4	2

Table 9: Consumer Load Assumptions (table taken from (Castalia Strategic Advisors, March 2009))

After the LV network was designed to accommodate the existing infrastructure and forecasted load for each transformer zone, the MV network ties required in order to connect these transformer zones to the existing MV network were planned. It should be noted that care was taken to route lines with respect to topographical features, avoiding traversing sensitive areas such as wetlands and crossing areas which may incur extra construction and maintenance costs such large bodies of water. It was stated in the report that “all existing and future sources of supply, such as existing and planned substations, planned hydro sites and potential hydro sites” were considered in the planning of new MV conductor sections. “Thicker backbone lines were planned to these sources or potential sources of supply. Also, proposed substation sites were used as future sources of supply and backbone lines were planned from here. New feeders were also created to relieve the load off existing long feeders”. Load flow studies were performed using a software called CYME to evaluate various buildout solutions during this line routing process. The CYME model files were purportedly provided to the Rwandan working group but only the regional load flow analysis results have been provided for MIT review.

The transformer zone designs were then grouped into what the report refers to as ‘lots’ for contract bidding purposes. This process resulted in a total of 146 lots which were then prioritized for construction over a period of five years, from 2013 -2017. Each lot was assigned a priority ranking based on the following attributes: the social infrastructure it contained, its distance from the existing network, government targets for the district where the lot was located, cost, and social demand, which was considered higher in areas with no pre-existing electrical connections. An example of lot prioritization in the southern planning region can be seen in Figure 23.

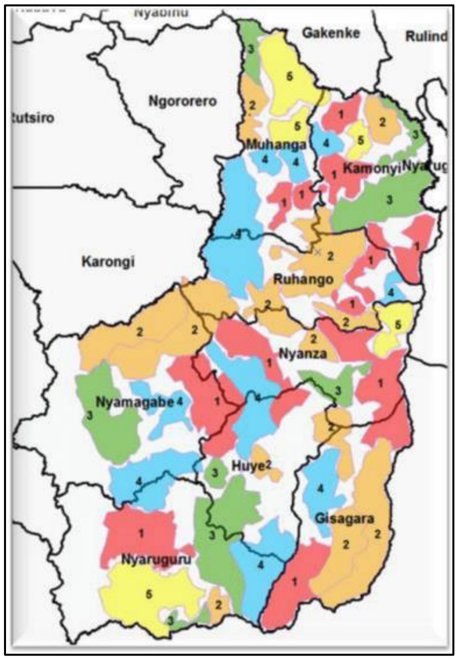


Figure 23: An Example of Lot Prioritization in the Southern Planning Region

A connection forecast was then created for the purposes of determining how many consumers would need to be successfully relocated and connected through the Imidugudu resettlement program in order for the government’s goal of reaching a 70% electrification rate by 2017 to be reached. The forecast developed covered the years 2012 through 2017. The forecast used for year one was a connection forecast developed by EWSA. For the years 2013 through 2017, the load was calculated based on the following:

- The timeline for construction based on the aforementioned lot prioritization.
- An assumed population growth rate of 3%.
- That only 75% of potential consumers will be connected to a new line during the year it is constructed (the remaining being calculated as fill-in connections in the following years, although the report is not explicit as to how these numbers were incorporated).

The sum of the existing connections as of the start of 2012 and total number of connections theoretically achievable by the end of 2017 was then subtracted from the total expected 2017 country population. This remainder was considered to be the number of consumers which must be relocated and connected over the span of the planning period in order to reach the goal of 70% electrification by 2017. It was assumed for cost assessment purposes that approximately 1/5 of this total number of relocated consumers would be connected annually between 2013 and 2017. The analysis was then repeated assuming a potential consumer connection rate of 100% instead of 75%. An updated load forecast was determined including population resettlement values. The load values provided in the spreadsheet model that accompanies the report have been aggregated at the planning province level. Table 10 shows the forecast assumptions used and the resulting start load value.

Load Forecast	South	North	East	West	Central	
ADMD start	0.06	0.06	0.06	0.06	0.3	kw
ADMD Saturat	0.3	0.3	0.3	0.3	0.7	kw
Duration for saturation	6	6	6	6	6	yr
Start Load	18	15.6	4.5	18	65	MVA
% Growth on Existing load	4%	3%	3%	4%	5%	

Table 10: Province Level Load Forecast Assumptions

ADMD, according to (Barteczko-Hibbert, 2015), stands for After Diversity Maximum Demand and is defined as follows: “After diversity maximum demand is used in the design of electricity distribution networks where demand is aggregated over a large number of customers. After diversity maximum demand (ADMD) accounts for the coincident peak load a network is likely to experience over its lifetime and as such is an overestimation of typical demand”.

The ADMD start values provided do not appear to be consistent with this definition, they would appear rather to be per customer average demand values (60 watts per customer in all planning zones except for the Central Zone, for which the ADMD start value is 30 watts). It should be noted that these values are hard-coded in the spreadsheet model provided and thus the more granular data from which these figures were purportedly conceived is not available, making them difficult to reproduce or update. In addition, if the ADMD start and saturation values are intended to represent consumer averages, then they would appear to be highly inconsistent with the table of consumer load values used in the estimation of loads for each transformer zone (see Table 9) whose values range from 100W to 20 kW. The long-term load forecast values, assuming relocation targets are met, are shown in Figure 24.

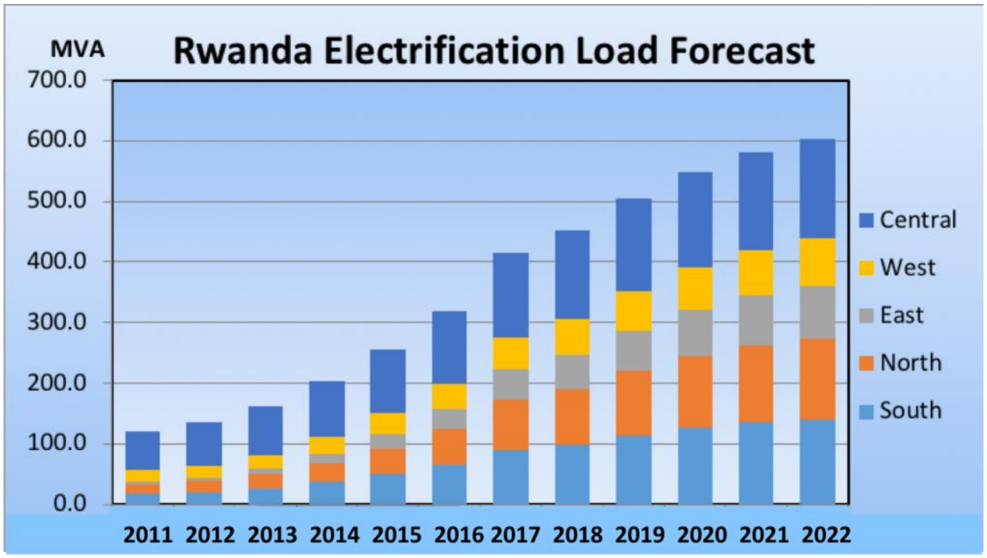


Figure 24: Long-term Load Forecast Assuming Relocation Targets Met

Following the load forecast adjustment, a detailed bill of quantities was developed based on quantity and length values calculated using the GIS software and a phased capital investment schedule was created. This was accomplished by first tallying the capital investment required in each region for new construction based on the lots identified and the year each was scheduled to be developed (it is not clear if this includes cost for suggested upgrades for the existing network). Then the annual costs for fill-in connections, as based on the 2012 value provided by EWSA (see the Sofreco Assumptions section for further details), were tallied. These two sets of values were then added.

Report Conclusions and Recommendations

It was concluded in the Sofreco report that the network update designs it had formulated left "very few places more than 2 or 3km away from a planned Medium Voltage line", the vast majority of Rwanda's population would eventually be grid connected. The final network design was comprised of 5,083 transformers, 6,594km of MV lines, and 10,058km of LV lines.

A load flow report was created for each region. Each load flow report contains two sections: 1) a detailed analysis of the network, as it existed at the time of publication, in each region on a per-substation basis, making specific recommendations for components which needed to be upgraded based on the existing level of loading and related severity of losses and voltage issues, 2) the same manner of analysis for a proposed network buildout design. Commentary was also provided as to whether or not EWSA already had plans in place to address any needed upgrades identified. It was pointed out in the load flow reports that the conditions on which the recommendations were made are to a certain extent ephemeral and should be reevaluated if buildout plans change or are delayed. “The proposed year of implementation must be carefully monitored by looking at voltage levels and loading. The connection rate of new consumers will determine the rate of load growth. The connection rate can be manipulated by outside factors such as economy, connection application cost, relocation of people, etc.” The main report also included a reminder of the importance of ongoing coordination with transmission planning efforts, as these analyses were conducted on the distribution network only.

All case files developed for use in the CYME load flow software, for both existing and proposed networks, were submitted in original format to the Rwanda EARP working group as a deliverable along with the reports so that the model may be rerun and the network upgrade plans reevaluated, should changes in forecast, load growth, and/or saturation values change.

		COST (USD Millions)					
COST SUMMARY		2012/13	2013/14	2014/15	2015/16	2016/17	2017/18
EPC Contracts		0.00	82.14	87.72	86.52	54.63	6.25
MV_LV Contracts		0.00	22.05	19.86	21.73	17.03	3.06
Fill In Projects		68.62	88.82	85.23	80.74	75.36	69.08
YEARLY TOTAL		68.62	193.01	192.81	188.99	147.02	78.39
ACCUM TOTAL ALL (PV)		68.62	261.63	454.44	643.43	790.45	868.84
Excalated	5%	68.62	202.66	212.57	218.78	178.70	100.05
Accum	5%	68.62	271.28	483.85	702.63	881.33	981.38

Table 11: Phased Capital Investment Program

For all new connections made from 2013 to 2017 other than fill-in connections (where ‘new connections’ here is defined as all connections made to newly constructed lines in the year they are constructed, including connections resulting from population growth and relocation), and assuming that only 75% of potential customers connect annually, the average connection cost was determined to be $1102USD, decreasing to $1065USD if 100% connection was assumed. The average cost for all customers connected over the roll-out period, including fill-in customers, was calculated to be $631USD.

Sofreco vs. Castalia

The purpose of this section is to use the information identified during review of the Castalia and Sofreco plans to compare the objectives, approaches, assumptions and any other aspects of the two reports which may help to inform the future use and or development of the Reference Electrification Model.

Master Plan Comparison

Objectives/Priorities/Major Assumptions

Priorities appear to have been reversed from one report to the next, from A) an attempt by the Castalia plan to maximize the cost-benefit tradeoffs by prioritizing connection of those closest to population centers and the existing network, and targeting regions where the ability to pay appeared to be the highest, to B) the prioritization regime followed by the Sofreco study of making those areas which had seen the fewest connections in the electrification process up to that point top priority and relegating fill-in connections in the Kigali region to the back burner. Furthermore, the possible modes of electrification differed from one plan to the next. Castalia claimed to be formulating a least-cost plan, where off-grid vs. grid extension technology costs were compared for given demand level estimates. Sofreco, on the other hand, did not claim to be striving for a least-cost approach, only a thorough one which aimed to meet the stated national electrification goals. By the time of the Sofreco report, MININFRA had been put in charge of off-grid electrification and EWSA of grid extension. It is not clear if the EARP Planning & Design group was affiliated only with/or under the direction of EWSA, but Sofreco was only asked to look at grid extension. The only off-grid element mentioned in the Sofreco report was the government goal of electrifying social facilities not slated for grid connection in the subsequent five years with standalone solar PV, although the report makes no mention of this beyond the introduction section. The Sofreco plan was also created after the Resettlement Act had gained momentum, so included this information in its plan whereas it was not considered in the Castalia report.

Overall Structure and Organization of the Documents

One thing to note with regard to both reports is the lack of clarity regarding order of planning operations and the manner in which assumptions were used. The planning methodology followed by Castalia was particularly difficult to reconstruct for the purposes of reporting it in this paper. Elements of the planning process followed were discussed out of chronological order with assumptions provided in some locations but not in others and terminology that was often vague or descriptions which were seemingly conflicting. The Sofreco report was much easier to follow as it was, for the most part, laid out in chronological order, but it still required a relative amount of effort on the part of the reader to piece information together. For instance, it is unclear whether or not the load forecast including the resettled consumers was the one used to inform the creation of the network design. The way the report reads, the forecast including resettlement was determined after the network upgrades were designed. It is thus not evident upon which assumptions the transformer zone load forecasts, and thus ultimately the network design, were based.

Quality of the Input Data

It was the conclusion of both reports that a more comprehensive and up-to-date geodatabase than what was presented to them was ultimately required for the types of planning exercises they were attempting to carry out. Sofreco put a great deal of work into gathering data for and updating GIS files of the existing network, and commented in its report that it discovered during this process that the network files it was initially provided (presumably those created during the Castalia planning process) were not only outdated but also incorrect. The figure below was taken from the Sofreco report, and although no legend was included with the images, they nevertheless give an indication of the amount of work required of Sofreco in order to update the database for use in their planning process.

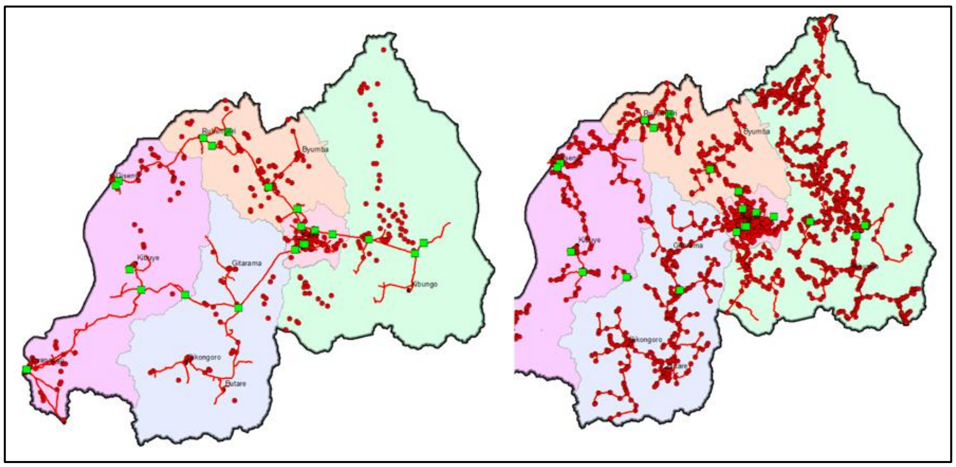


Figure 25: Sofreco Network Data as Received (left) and After Being Updated by Sofreco (right)

Methodologies

Several different areas of the methodologies employed by these two companies are worth commenting on, so the discussion has been itemized by subtopic below.

- Distribution Line Routing and Topographical Features: The Castalia report does not appear to have utilized any topographical information in the distribution line routing process, in fact the Prospectus makes no mention of this process at all, although LV and MV component cost estimates are provided. Lack of evidence that LV designs were actually created casts a certain level of doubt on the validity of these cost estimates. Sofreco, on the other hand, created very detailed MV and LV designs and in the process, made use of ArcGis files which included data on waterways, wetlands, national parks, and roads to ensure that networks were planned such that they circumnavigated undesirable zones and were accessible by road.

- Population Clustering: Both consultants used some manner of population grouping to establish clusters of consumers who would be evaluated as a group, although each did so for differing reasons. Castalia grouped the population by administrative cell boundary for generation technology selection purposes (i.e. every citizen belonging to a particular cell was destined, according to that planning methodology, to be assigned the same generation type). In the Sofreco study, population 'concentrations' were identified manually through GIS map visualization of the consumer points identified from the orthophotography. It is not evident that any maximum customer-to-customer distance or other numerical grouping criteria was employed in this process. Sofreco referred to these groupings as 'planned transformer zones' and included all of the Imidugudu resettlement areas as well as social institutions, wherever possible.
- Assigning consumers to off-grid vs grid extension: Sofreco did not consider off-grid modes of electrification as it appeared that group was tasked with developing a grid-extension-only plan. Castalia did consider both grid extension and off-grid options, but the off-grid technology configurations it considered were somewhat limited, at least by more recent standards, and the equivalent MV length methodology of selecting between grid extension and the least-cost off-grid technology was somewhat crude, using the closest adjacent cell as a proxy for the nearest network tap-off location.
- Developing a load forecast: The Castalia report indicated that the planning team developed both a load forecast for each cell (for the purposes of least-cost generation technology selection) and then later a 'geospatial load forecast' based on the resulting network development plan, but in neither case did it explain how exactly the forecast was developed. It is presumed that the cellular load forecasts were based on the estimations provided in the Technical Annex of average demand by consumer type, but it is not evident from any information provided in what way the ‘geospatial load forecast’ differed from the cellular forecast. Sofreco provided a greater level of assumption information than did Castalia, but the report failed to provide a holistic explanation of how the various assumptions were used and at which stages of the development process (with regard, in particular, to the Imidugudu resettlement back calculation and its influence on the network design), leaving the reader to question the results and detracting from the integrity of the claim that this model was readily repeatable.

- Assessing the existing network for needed upgrades: Castalia used a load forecast and existing network loading data to conclude that "adequate capacity will be generally available to support the new connections during the initial years of the access programme", but the assertion was vague and unsupported by numerical details. No load flow was performed. A cost estimate for future upgrades was provided based on expected load growth, although no methodology was described in support of this either, and 'load growth' was not defined (i.e. Did it include fill-in, new connections, and increase in average consumer demand?). Sofreco, on the other hand, did perform load flow analyses in order to identify upgrades required by the existing network, and to evaluate possible electrical infrastructure buildout solutions. Detailed load flow reports were provided for each planning region.

- Identification of Planning Stages: In the case of Sofreco, the Planning Director of the EARP design group dictated the order of planning zone priority, with those regions having received the fewest connections to that point taking top priority. From there, Sofreco created lots in each region, each including one or more transformer zones, for bidding purposes and ranked them 1 through 5 (according to somewhat subjective criteria), with these values corresponding to the year within the five-year planning period during which they were to be constructed. In the Castalia report, priority for electrical connection via grid extension was given to those consumers located within five kilometers of the existing network and which inhabited districts considered as having the highest demand. Social institutions were also included, even if located in areas not meeting these criteria. Once enough cells were selected to meet the 35% electrification target, they were assigned to one of each of the five years of the planning timeframe, with those closest to the existing network and closest to large population centers prioritized for the first years.

Study Replicability

It is not apparent that Castalia made the technology selection spreadsheet it used available to any particular Rwandan planning group for later use, making the results of this study static and difficult to replicate. Sofreco left both the spreadsheet model it used for demand and cost forecasting as well as the CYME software load flow files to the EARP planning group for to update and reuse as necessary. However, it is important to note that off-grid technologies were not considered in the Sofreco planning process so no tool was provided which can assist in making decisions involving off-grid generation options.

Usefulness of Report Results

The intention of the Castalia report was to elicit funding by instilling confidence in donors with what was intended to be a thorough analysis. But in an attempt to show that all possible costs had been considered, the report seems to have succeeded in providing a great deal of unsupported, static values, many of which have little practical use (for instance, Table 4.8 in the Technical Annex provides expected costs for each year from 2009 to 2013 for such things as "Lowering Programme Cost" and creating "Joint sector performance reports"). And this seems to have been done at the expense of providing procedural details for the planning process, which may have ultimately been of much greater use to Rwandan planners. Sofreco's study, on the other hand, left a substantial legacy of planning details, which were seemingly of considerably greater use from a planner's perspective, with specific upgrade recommendations, designs based on load flow reports, and exact locations for placement of infrastructure.

Evolution of the Rwandan Energy Sector Strategy

The Electrification goal as of the original Vision 2020 publication (ca. 2010) was 35% by 2020. The political agenda to increase the national electrification rate went from a relatively modest goal of adding 250,000 connections over the course of five years (from 100,000 in 2008 to 350,000 in 2012), when the Castalia plan was being drafted, to the more ambitious goal of achieving an electrification rate of either 70% (~1.5 million connections) or even 100% by 2017, by the time the Sofreco report was published. EDPRS II, published in 2013, stated that "approximately 48% of the total population will be within feasible range of the grid" and went on to specify that EARP "will target around 45% of households with direct connections by 2017, while for the remainder of the households off-grid solutions represent an attractive cost-effective option". The Energy Sector Strategic Plan 2013/14 – 2017/18, published in 2015, set as one of its 'high-level target objectives' to increase household electricity access by 70%: 48% grid connection, 22% off-grid.

Then in 2016, the Rural Electrification Strategy (RES) was published by MININFRA, recognizing that the consumption levels seen with the EARP connections which had been made by that point (totaling 226,000 households, representing an increase in the national electrification rate from just under 15% in 2012 to approximately 24% by June 2016) were too low to ensure cost recovery for the utility. Almost half of those connected under EARP were using less than 20 kWh per month when, according to the ESSP published in the same year, cost recovery was only possible if each consumer used no less than approximately 130 kWh per month. The report deduced from this that off-grid technologies needed to play a bigger role, pointing out that "Two emerging technologies, standalone solar systems and mini-grids, have recently started to be delivered at large scale across Africa, and there is significant scope for these technologies to be used in Rwanda to rapidly scale up electricity access". The document proposes a change in the working definition of energy access, suggesting that instead of continuing to measure energy access as the percentage of grid-connected households, the levels of access defined in the SE4All Multitier Framework should be incorporated into the national lexicon. These access levels can be seen in Table 12 below.

Level	Tier 1	Tier 2	Tier 3	Tier 4	Tier 5
Energy usage	Household lighting, radio and phone charging	Household lighting, radio, phone charging and basic appliances (TV or fan)	Tier 2 plus medium appliances such as low power refrigeration	Tier 3 plus high power appliances such as pumping	24/7 high power suited to commercial and industrial uses

Table 12: SE4All Consumption Tiers

It is suggested in the RES that the ESSP target of electrifying 48% of households through grid-connection by 2017/18 be revised to include any source (either on-grid or off-grid) which can provide access levels corresponding to the SE4All Tier 2 or higher. To put the descriptions provided in Table 12 in perspective, below is a figure showing monthly consumption of existing EARP consumers (as of 2013) by tier, including a suggested alternative form of energy supply for each tier.

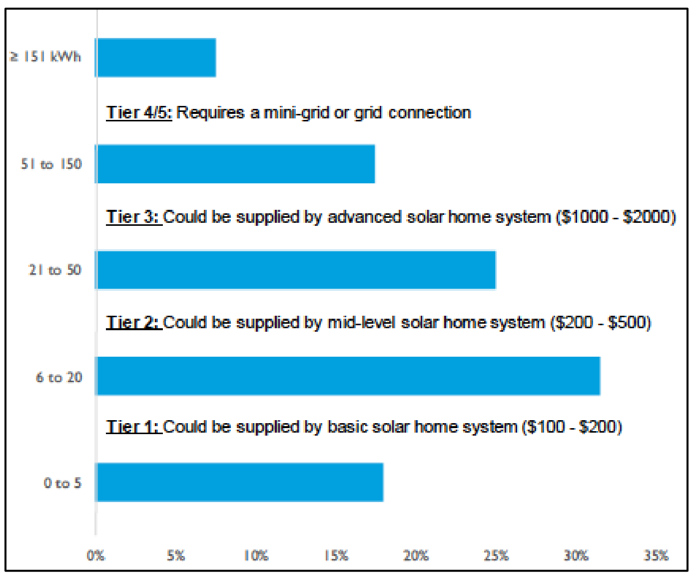


Figure 26: 2013 EARP Consumer Monthly Consumption Levels (kWh)

The document also asserts that "100% access to electricity is targeted by 2020", although it is not clear if this goal was declared prior its mention in this document. No mention is made in the 2015 National Energy Policy of any goal beyond the 70% to be achieved by the end of EDPRS II.

Of additional interest for the purposes of this report is that the Rural Electrification Strategy indicates that although mini-grids will be developed by the private sector, the government (REG in particular) will assume the role of identifying the sites most appropriate for microgrids, as it considers mini-grids to be on the order of 50% more expensive per consumer than for the average EARP grid connection, thus only representing an economical advantage when used for populations that have sufficient demand to justify the investment but are located in areas that are far from the grid or otherwise geographically constrained. It is noted in the RES that the notion that microgrid connection is 50% more expensive is based on an estimated average cost per customer connection for microgrids of $1500 taken from what was referred to as ‘an EU study for Rwanda’, but for which no author or title was provided. Also of interest is the recognition in the RES report that microgrids with generation provided by hydro or solar resources are “often in conjunction with either battery storage or diesel generation to handle the intermittency of power output presented by renewables”. This is a change from the time of the Castalia report when diesel and hydro were only considered separately as potential off-grid technologies, not in combination, and solar PV and battery combos were considered only as solar home system options, not for larger microgrid installations. It was also stated in the RES that microgrids had a better chance of being viable in locations where demand was “both high and spread across the day”, and thus selection of candidate locations by REG would prioritize locations with anchor loads such as water pumping stations and cell phone towers.

ANNEX 2: RCS REM input catalogue tables

Network catalogue

Name	Resistance [ohm/km]	Reactance [ohm/km]	Rated current [A]	Avg. failure rate [failures/ (km*yr)]	Investment cost [$/km]	Preventive maintenance cost [$/(year*km]	Corrective maintenance cost [$/failure]
Twistedcable 3x35+54.6	0.87	0.24	135.00	0.133	15000	2.8	427
Twistedcable 3x70+54.6	0.43	0.19	250.00	0.133	17931	2.8	427

Table 13. Low-voltage (LV) lines

Name	Resistance [ohm/km]	Reactance [ohm/km]	Rated current [A]	Avg. failure rate [failures/ (km*yr)]	Investment cost [$/km]	Preventive maintenance cost [$/(year*km]	Corrective maintenance cost [$/failure]
ACSRSteel 70	0.58	0.24	276	0.133	23510.26	700	900
ACSRSteel 120	0.39	0.23	357	0.133	24900.69	700	900

Table 14. Medium-voltage (MV) lines

Name	Installed power capacity [kVA]	MV Voltage [kV]	No-load lossess [kW]	Short-cirtuit resistance on the low-voltage side [ohms]	Avg. Failure rate [failures/year]	Investment cost [$]	Preventive maintenance cost [$/yr]	Corrective maintenance cost [$/failure]
CTI0_VUG	15	30	0.070	0.040	0.70	3600.0	80.20	25.80
CTI1_VUG	25	30	0.090	0.060	1.27	5653.9	80.20	25.80
CTI2_VUG	50	30	0.135	0.034	1.87	6876.5	80.20	25.80
CTI3_VUG	100	30	0.295	0.020	2.13	10442.3	80.20	25.80
CTI4_VUG	160	30	0.375	0.014	2.45	12012.2	80.20	25.80
CTI5_VUG	250	30	0.625	0.012	3.50	18555.0	80.20	25.80
CTI6_VUG	315	30	0.725	0.011	4.10	23222.0	80.20	25.80
CTI7_VUG	400	30	0.840	0.010	4.80	28455.0	80.20	25.80

Table 15. Medium-to-low voltage (MV/LV) transformers

Additional parameters :

- Cost of distribution energy RCS:0.12 $/kWh
- Discount rate: 8%
- Years of useful life for distribution network: 25 years
- Years of useful life for microgrids network: 25 years
- Maximum voltage drop at MV network: 4%
- Maximum voltage drop at end LV customer: 4%

Generation catalogue

Size [kW]	Cost [$]	Lifetime [years]	Installation costs, as a fraction of panel cost	Annual O&M, as a fraction of panel cost	Annual O&M man-hours	Annual capacity loss [p.u.]
0.02	20	25	0.1	0.01	5	0.007
0.25	125	25	0.1	0.01	5	0.007

Table 16. Solar (PV) panels

Battery Name	Cost [$]	Energy [kWh]	Lifetime throughput [kWh]	SOC (min)	Capacity at end of life (fraction of nameplate energy capacity)	Installation costs as a fraction of battery cost	Annual O&M as a fraction of battery cost	Annual O&M man-hours
TROJ_T105	150	1.38	1656	0.5	0.8	0.1	0.01	5
VIS_CP12240D	60	0.2844	426	0.4	0.8	0.1	0.01	5

Table 17. Batteries

Diesel generators:

- Not required for the NEP of Rwanda
- Sensitivities run as backup (max 15% total energy)
- Features:
  - 30 generator options *(listed in the external “gencatalog” file)* are included in the catalog
  - They range in size from 5 – 2,250 kW at a cost of $3,200 – 450,000, respectively
  - Assumptions used for each generator:
  - Installation cost as a fraction of generator cost: 0.8
  - Annual O&M as a fraction of generator cost: 0.05
  - Annual O&M man-hours: 25

Charge controllers:

- Lifetime [years]: 15
- Efficiency [p.u.]: 0.95
- Installation costs as a fraction of charge controller cost: 0.1
- Annual O&M as a fraction of charge controller cost: 0.01
- Annual O&M man-hours: 2

Costs [$/kW]	481	375	283	215	133
Sizes [kW]	0.054	0.12	0.24	1.44	3.84

Table 18. Charge controllers

Inverters:

- Lifetime [years]: 15
- Inverter efficiency [p.u.]: 0.95
- Rectifier efficiency [p.u.]: 0.9
- Installation costs as a fraction of charge controller cost: 0.1
- Annual O&M as a fraction of charge controller cost: 0.01
- Annual O&M man-hours: 2

Costs [$/kW]	927	740	600	543	364	319	260	220	190	190
Sizes [kW]	0.15	0.2	0.25	0.3	1	1.5	5	6	10	11.4

Table 19. Inverters