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RWANDA RESOURCE STUDY FOR ELECTRICITY GENERATION SOURCES PHASE 3 REPORT

May 2022

East Africa Energy Program (EAEP)

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ABBREVIATIONS

ABBREVIATION	EXPLANATION
$	United States dollar
$B	Billions of United States dollar
$M	Millions of United States dollar
ARN.3	All Renewables by 2050 scenario
APV	Agri-voltaics
BES	Battery energy storage
CCS	Center for Climate Strategies
CH_4	Methane
CO_2	Carbon dioxide equivalent
CRF	Capital recovery factor
EAEP	East Africa Energy Program
EDCL	Energy Development Corporation Limited
EEI.7	Energy Efficiency Improvements scenario
EUCL	Energy Utility Corporation Limited
FiT	Feed-in Tariffs
FPV	Floatovoltaics
GCR	Ground coverage ratio
GDP	Gross domestic product
GEF	Gas extraction facility
GHG	Greenhouse gas
GHI	Global horizontal irradiance
GIS	Geographic information system

GOR	Government of Rwanda
GRASS	Geographic Resources Analysis Support System
GW	Gigawatt
GWh	Gigawatt-hour
Ha	Hectare
HAWT	Horizontal axis wind turbine
ICP	World Bank International Comparison Program
IPP	independent power producer
IRENA	International Renewable Energy Agency
JICA	Japanese International Cooperation Agency
kW	Kilowatt
kWh	Kilowatt-hour
kWp	Kilowatt-peak
kWh/m^2	Kilowatt-hour per square meter
LCOE	Levelized cost of energy (or levelized cost of electricity)
LCP	Light compensation point
LCPDP	Least Cost Power Development Plan
LEAP	Low Emissions Analysis Platform
LFG	Landfill gas
LHY.2	Limited Hydro scenario
LKM	Lake Kivu Methane
LMG.6	Lake Methane Displacing Natural Gas scenario
LSP	Light saturation point
LULC	Land use/land cover

m^2	Square meter
MININFRA	Ministry of Infrastructure (Rwanda)
MSW	Municipal solid waste
MTCO2e	Millions ton of CO2e
MV	Medium voltage
MW	Megawatt
MWh	Megawatt-hour
NISR	National Institute of Statistics Rwanda
NREL ATB	NREL Annual Technology Baseline
NTZ.5	"Net Zero" Rwanda scenario
O&M	Operations and maintenance
PLI	Price level indices
PPA	Power purchase agreement
PPPs	Purchasing power parities
PV	Photovoltaic
PVOUT	Photovoltaic electricity output
RCMRD	Regional Centre for Mapping of Resources for Development
REG	Rwanda Energy Group
REF.1	New Reference/Business-as-Usual scenario
RURA	Rwanda Utilities Regulatory Authority
RWI.4	Renewables with Interconnection scenario
SAS	Seasonal Agricultural Survey
SEI	Stockholm Environment institute
SHS	Solar home system

STP	Standard temperature and pressure
SRTM	Shuttle Radar Topology Mission
T&D	Transmission and distribution
TJ	Terajoule
TRI	Terrain Ruggedness Index
W	Watt
WACC	Weighted Average Cost of Capital
WtE	Waste-to-energy

1. EXECUTIVE SUMMARY

1.A. INTRODUCTION

This report is part of the Rwanda Resource Study for Electricity Generation Sources project (the Project) implemented under the Power Africa East Africa Energy Program (EAEP) with the technical expert assistance of the Center for Climate Strategies (CCS) in collaboration with the State-owned Rwanda Energy Group (REG).

Electricity demand has been growing rapidly in Rwanda as the economy expands and as more households and businesses, both rural and urban, are connected to the electricity grid or obtain electricity from mini-grids or solar home systems. At the same time, Rwanda is blessed with a variety of attractive resources for current and future electricity generation. Some of these resources, however, offer limits to the degree to which their use can contribute to meeting future electricity demand in Rwanda. The **purpose of the Project** is to identify the potential for a full suite of priority electricity resources in Rwanda to meet the growing demand while also addressing other priorities, such as environmental impacts, and to provide methods that promote continuous future updates by REG and stakeholders.

To this end, the EAEP Team conducted the following assessment of priority electricity generation resources and technologies in Rwanda (the **Assessment**):

- Estimation of potential capacity in megawatt (MW) based on resource **physical availability, technical potential, and economic and market potential.**
- Development of **seven alternative supply scenarios through 2050** to meet Rwanda growing electricity demand needs, namely alternative combinations of different supply resources to meet demand.

The Assessment covers the following **key electricity generation resources** that based on the most recent Least-Cost Power Development Plan (LCPDP)[1] assessment conducted by REG appear to have the greatest potential in Rwanda, and within each, the following priority technologies identified by REG[2]:

- *Solar*, with a focus on
  - Utility-scale photovoltaic (PV) power plants with a size range greater than 1 MW.
  - Co-developed agriculture and solar photovoltaic power systems (agri-voltaics or APVs).
  - Photovoltaic panels mounted on platforms in the water (“floatovoltaics” or FPVs).
  - All size ranges for urban-located buildings across residential, commercial/institutional, and industrial sectors (distributed solar).
- *Wind*, and more specifically Horizontal Axis Wind Turbine (HAWT);
- *Hydro*

[1] The December 2020 version of the LCPDP referred into this report was shared by REG.

[2] Although *nuclear energy* is used in many places around the world and is in theory a potential future source of electricity generation for Rwanda, it was not considered as a potential future generation resource in this Assessment for several reasons, including its high cost and the mismatch between the size of most commercial reactors and the size of the Rwandan grid. More detail son of what is known about the Rwandan uranium resource, and a more in-depth discussion of considerations related to the use of nuclear power in Rwanda are provided in Annex A.

- *Waste-to energy*, with a focus on crop residues (and principally rice husk produced at rice mills) and municipal solid waste (MSW)
- *Methane*
- *Geothermal*
- *Peat*

The Assessment was conducted with the support of an **integrated analytical system** that was delivered to REG as part of the Assessment to allow for future updates. The system includes:

- Open-source QGIS software (version 3.18) and associated tools[3] for the geographic information system (GIS) analysis.
- MS Excel spreadsheets for assessment of technical, economic and market potential; and
- The Low Emissions Analysis Platform (LEAP)[4] software model to develop alternative supply scenarios to meet Rwanda growing electricity demand.

The Assessment was coupled with a series of webinars to review and discuss the methodology and results, as well as build capacity within REG on the Rwanda LEAP model for future applications.

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[3] QGIS, https://www.qgis.org/en/site/

[4] The LEAP model was identified as part of the integrated analysis system to be used to conduct the electricity generation resource assessment for Rwanda. For more information on LEAP, please see the Phase 2 report or visit the following website https://leap.sei.org/default.asp?action=introduction

1.B. ESTIMATED POTENTIAL CAPACITY

Tables 1.B-1 below summarizes the estimated potential capacity for the priority electricity generation resources considered for this Assessment.

TABLE 1.B-1. ESTIMATED POTENTIAL CAPACITY (2030 AND 2050), THRESHOLD OF $130/MWH

RESOURCE	LCPDP AND EAEP: EXPLOITED TECHNICAL AVAILABLE CAPACITY (MW)	EAEP: UNEXPLOITED **TECHNICAL AVAILABLE CAPACITY** (MW)	EAEP: TOTAL EXPLOITED + UNEXPLOITED **TECHNICAL AVAILABLE CAPACITY** (MW)	**ECONOMIC POTENTIAL** AT 5% INTEREST RATE BASED ON UNEXPLOITED CAPACITY *(MW)*	**MARKET POTENTIAL AT 10% INTEREST RATE** BASED ON UNEXPLOITED CAPACITY *(MW)*	**MARKET POTENTIAL AT 15% INTEREST RATE** BASED ON UNEXPLOITED CAPACITY *(MW)*
Solar (2030 LCOE)[5]	2.1	168,699	168,701	165,471	38,866	6,025
Solar (2050 LCOE)	2.1	168,699	168,701	165,471	165,471	36,785
Hydro	164[6]	822	986	629	629	-
Wind (100m hub height)	-	225	225	203	203	203
Waste (2030)[7]	0.07	55	55	55	55	55
Waste (2050)	0.07	116	116	116	116	116
Geothermal	-	-	-	-	-	-
Lake Kivu Methane	116	102	218	218	-	-
Peat[8]	86	166	246	166	166	166
Total Capacity 2030	**368**	**170,069**	**170,431**	**166,742**	**39,919**	**6,449**
Total Capacity 2050	**368**	**170,130**	**170,492**	**166,803**	**166,585**	**37,270**
Electricity Demand Forecast 2030						**313 MW**
Electricity Demand Forecast 2050						**2,152 MW**

[5] Solar is the only resource for which economic and market potential estimates change between 2030 and 2050 since solar costs are expected to decrease significantly.

[6] Hydro "Available capacity" for existing and planned hydro come from Tables 2, 4 and 5 of the LCPDP (values for "available" or "firm" capacity). Additional planned sites in Table 3 that were not also in either Table 4 or 5 were also added (with an assumed 51% CF). LCPDP Total includes planned installed capacity from LCPDP (with available capacity estimated using average capacity factor).

[7] Waste-to-energy is the only resource for which the technical potential estimate changes over time since it is dependent on population growth.

[8] Peat: LCPDP Total is the milled peat estimate (121) plus remaining peat in Hakan concession area not allocated to the 80 MW plant.

The first three data columns of in the table above show the exploited, unexploited, and total capacity (MW) estimated for each resource based on **technical potential**, namely the amount of electricity that can be produced from the physical resource available through a specific technology. The capacity indicated is the "**available" capacity**[9] that takes into account the fraction of the time that a resource is not available to drive a generator at its full output and, as such, it is taken as the average capacity factor for the resource multiplied by the nameplate capacity (that is, the total maximum output of a resources/technology). **The results show an estimated total unexploited capacity in Rwanda of 170,069 MW in 2030 and 170,130 MW in 2050, in both cases with a very significant share of that covered by solar (168,699 MW), followed by hydro (822 MW) and wind (225 MW). The difference of technical potential estimates between 2030 and 2050 is due to the changes in the waste-to-energy resource estimates over time since this is the only resource dependent on population growth.**

The fourth data column of the table above shows unexploited capacity (MW) for each resource based on **economic potential**, that refers to the amount of electricity for which generation costs are competitive compared with costs of generating or purchasing electricity through other means at a 5% interest rate. This interest rate (5%) reflects a social interest rate that is consistent with the low rate of interest that might be used by a government for its own investments, or rates that might be offered to a government by a bilateral or multilateral development bank lender. **The results show a lower estimated unexploited total capacity in Rwanda (166,742 MW in 2030 and 166,803 MW in 2050) with hydro decreasing to 629 MW, wind to 203 MW and peat to 166 MW as a resulting of taking into account generation costs (that is, grid connection costs, and installation, equipment and O&M costs) at a social interest rate. The difference of economic potential estimates between 2030 and 2050 is due to the change in solar economic potential estimates since solar costs are expected to decrease significantly over time.**

The last two data columns of the table above shows unexploited capacity (MW) for each resource based on **market potential**, that refers to the amount of electricity that can feasibly be brought to market, under the prevailing conditions for power sales and investment, at a price that is competitive with other possible resources and technologies based on an higher interest (a 10% interest rate in the fifth data column, and a 15% interest rate in the last data column). These higher interest rates take into account financing, profit, taxes, and risk, and thus estimate the potential of market penetration of each generation resource. **The results show an estimated unexploited total capacity in Rwanda in 2030 of 39,919 MW at an interest rate of 10% and 6,449 MW at an interest rate of 15%, and in 2050 an estimated unexploited total capacity of 166,803 MW at an interest rate of 10% and 37,270 MW at an interest rate of 15%. Solar and hydro estimated unexploited capacity decrease significantly when market conditions are taken into account through higher (and more realistic) interest rates. The difference of market potential estimates between 2030 and 2050 is due to the change in solar market potential estimates since solar costs are expected to decrease significantly over time.**

The estimated economic and market potential above are assessed based on a threshold of $130/MWh that is equal or similar to the Feed-in Tariffs (FiTs) agreed to by REG for the purchase of electricity from a number of different independent power producers for both existing plants and some plants due to be commissioned in the coming years. Table 1.B-2 below shows the estimated **economic and market**

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[9] In the LCPDP, REG reports generation resource capacity estimates as "available" capacity in MW. Thus, to support REG in the updates of the LCPDP, Table 1.B-1 refers to available capacity rather than nameplate capacity.

potential (last three data columns) **relative to a lower threshold of $70/MWh that was agreed with REG to conduct sensitivity analysis**. **The results show:**

- **In 2030 an estimated unexploited total capacity in Rwanda of 6,912 MW based on economic potential and 6,025 MW based on market potential at 10% interest rate. No resource potential is estimated at an interest rate of 15%/yr.** The estimated potential for solar decreases significantly compared to the 2030 estimates at the $130/MWh threshold and seems to exist only at a 10%/yr interest because only distributed solar technologies can offer levelized costs of energy (LCOE) that are under the $70/MWh threshold in 2030 (for details on market potential estimates of each technology, please refer to section 4.D of this report).
- **In 2050 an estimated unexploited total capacity in Rwanda of 6,025 MW based on market potential at 15% interest rate covered entirely by solar (distributed solar)**, since no other resources can offer LCOE that are under the $70/MWh in 2050.

Although there are many uncertainties that go into the calculations of future LCOEs and into consideration of evaluation thresholds to be used to establish market potential, **it seems likely that REG tariffs will, overall, need to remain above $70/MWh to attract investment in generation in Rwanda. Consideration of the specific circumstances of an individual project, of course, may result in different findings about appropriate FiTs that REG could offer.**

For each priority electricity generation resource, and within them for each selected technology, Section 3 and 4 of this report provide the detailed assessment (data, methodology and assumptions) of the estimated physical availability, technical potential, generation costs, and economic and market potential that are the basis of the results shown below

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TABLE 1.B-2 2030 AND 2050 ECONOMIC AND MARKET POTENTIAL RESULTS FOR SENSITIVITY ANALYSIS USING A $70/MWH FiT THRESHOLD

RESOURCE	LCPDP AND EAEP: EXPLOITED TECHNICAL AVAILABLE CAPACITY (MW)	EAEP: UNEXPLOITED TECHNICAL AVAILABLE CAPACITY (MW)	EAEP: TOTAL EXPLOITED + UNEXPLOITED TECHNICAL AVAILABLE CAPACITY (MW)	**ECONOMIC POTENTIAL AT 5%** INTEREST RATE BASED ON UNEXPLOITED CAPACITY *(MW)*	**MARKET POTENTIAL** AT **10%** INTEREST RATE BASED ON UNEXPLOITED CAPACITY *(MW)*	**MARKET POTENTIAL AT 15%** INTEREST RATE BASED ON UNEXPLOITED CAPACITY *(MW)*
Solar (2030 LCOE)	2.1	168,699	168,701	6,025	6,025	-
Solar (2050 LCOE)	2.1	168,699	168,701	152,652	6,025	6,025
Hydro	164[10]	822	986	629	-	-
Wind (100m hub height, 2030)	0	225	225	203	-	-
Wind (100m hub height, 2050)	0	225	225	203	177	-
Waste 2030	0.07	55	55	55	-	-
Waste 2050	0.07	116	116	116	-	-
Geothermal	-	-	-	-	-	-
Lake Kivu Methane	116	102	218	-	-	-
Peat[11]	86	166	246	-	-	-
Total Capacity 2030	**368**	**170,069**	**170,431**	**6,912**	**6,025**	-
Total Capacity 2050	**368**	**170,130**	**170,492**	**153,600**	**6,203**	**6,025**
Electricity Demand Forecast 2030						**313 MW**
Electricity Demand Forecast 2050						**2,152 MW**

[10] Hydro "Available capacity" for existing and planned hydro come from Tables 2, 4 and 5 of the LCPDP (values for "available" or "firm" capacity). Additional planned sites in Table 3 that were not also in either Table 4 or 5 were also added (with an assumed 51% CF). LCPDP Total includes planned installed capacity from LCPDP (with available capacity estimated using average capacity factor).

[11] Peat: LCPDP Total is the milled peat estimate (121) plus remaining peat in Hakan concession area not allocated to the 80 MW plant.

I.C. ESTIMATED ELECTRITY DEMAND FORECAST

Figure I.C-I below shows the reference case demand forecast for grid electricity demand by sector in Rwanda. The assumption as to national GDP growth is shown as well, in billion 2020 US dollars (right axis). Despite population growth in Rwanda slowing over time, from about 2.2 percent annually through 2035 to 1.4% annually by 2045-2050, electricity demand grows rapidly throughout the forecast period. **From 2022 through 2050, demand for grid electricity grows by nearly a factor of 20, with an average annual growth rate of over 11 percent. By 2050, a grid electricity demand of 18,854.23 GWh (equal to 2,152.31 MW) is estimated.**

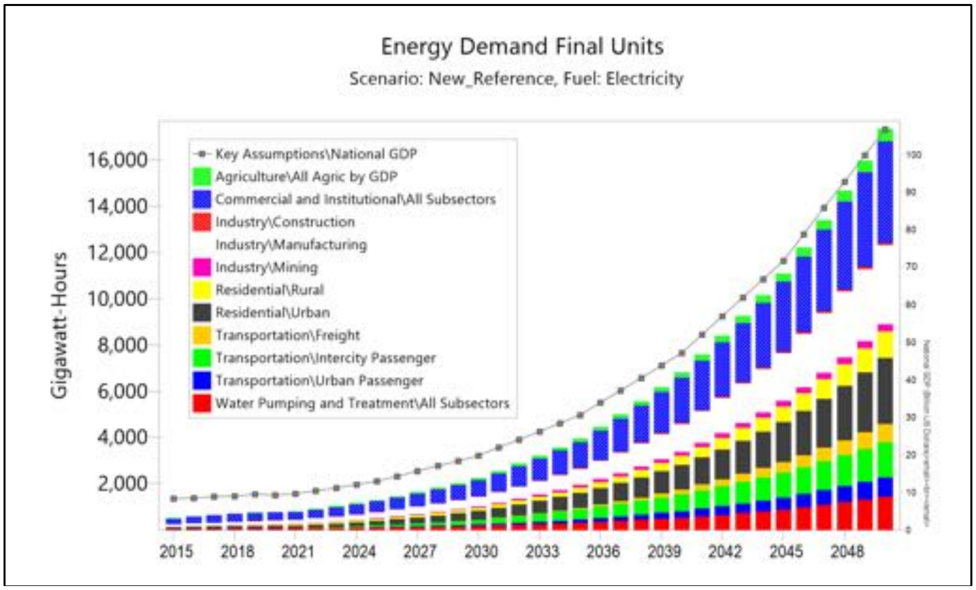

Figure 1.C-1 Reference Case Demand Forecast for Grid Electricity Use in Rwanda

Figure I.C-2 below shows the reference case demand forecast for electricity demand by solar home systems (also SHS—mostly small household photovoltaic panels providing electricity for lighting and small devices). **Much smaller amounts of electricity are provided by SHS and are substantially phased out by 2050 as these consumers shift to grid power supplies.**[12]

Figure I.C-3 below shows the reference case demand forecast for electricity demand by mini-grids powered by solar PVs or mini- or micro-hydroelectric generators. **Likewise, much smaller amounts of electricity are provided by these systems and the electricity is substantially phased out by 2050 as these consumers shift to grid power supplies.**

[12] The assumption in the supply scenarios below is that mini-grid generators are placed onto the main grid as their consumes are connected to the main grid. SHS are either retired, used to power back-up systems, or used in small off-grid applications, as their owners are connected to the central grid or to mini-grids.

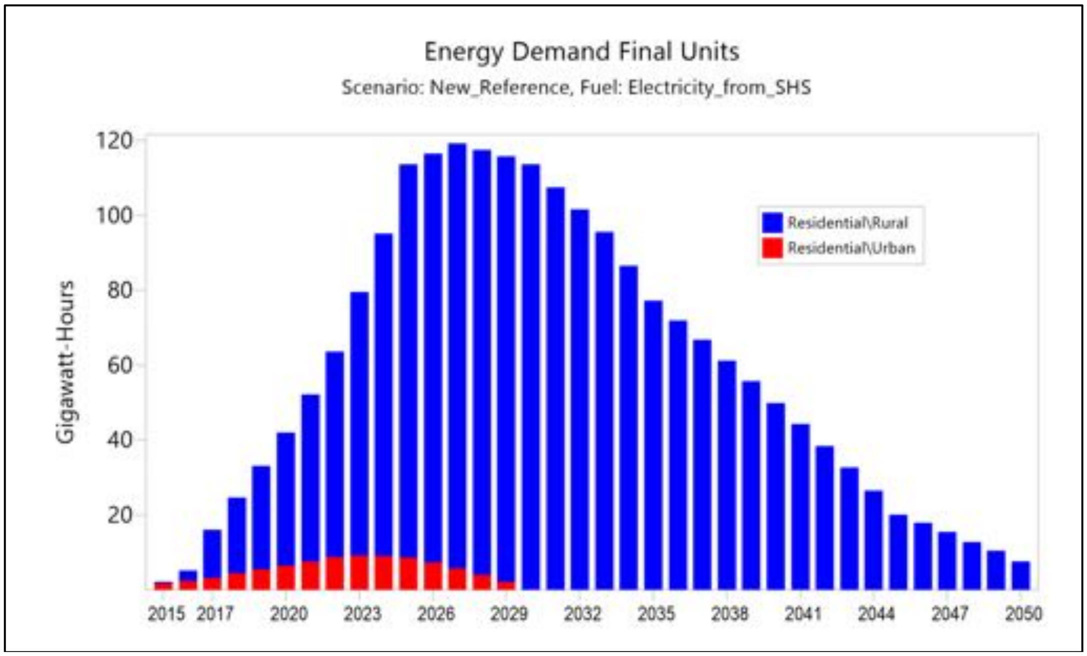

Figure 1.C-2 Reference Case Demand Forecast for Electricity from Solar Home System Use in Rwanda

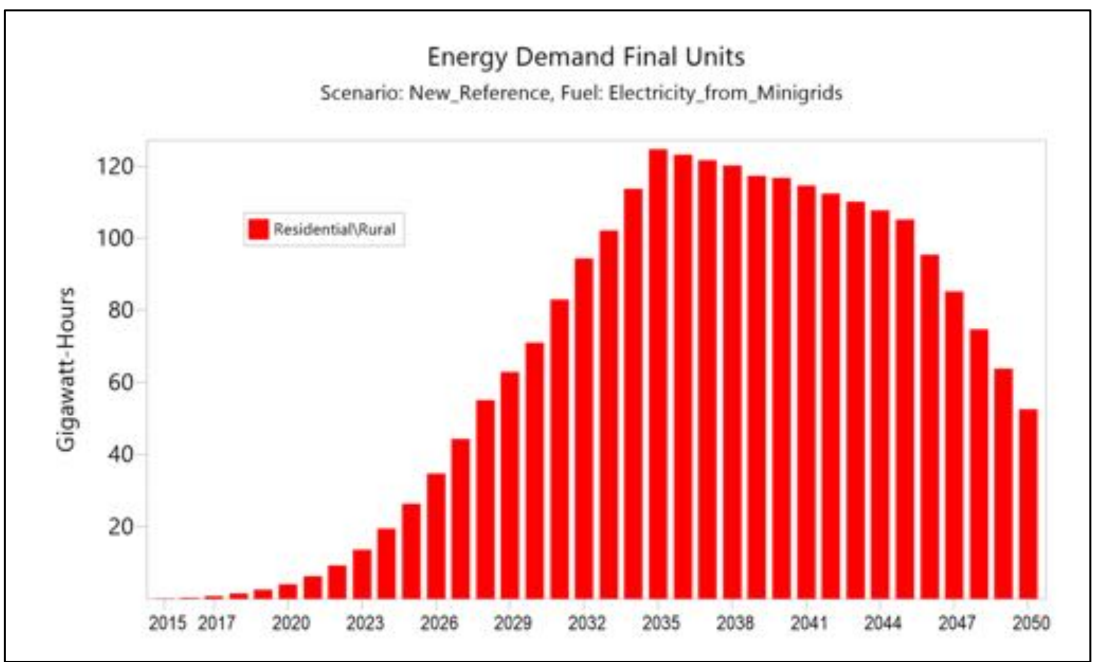

Figure 1.C-3 Reference Case Demand Forecast for Electricity from Mini-grids in Rwanda

Double-digit rates of growth in electricity use sustained for three decades are rare internationally, and perhaps unprecedented, as growth in electricity use tends to slow as economies mature and as population growth slows. The **main drivers of electricity demand growth in the Rwanda forecast** shown above are:

- Population growth, with Rwanda's population increasing from about 13 million in 2021 to over 22 million by 2050.[13]
- Continued strong growth in GDP, based on national and regional projections estimates from the African Development Bank, and extrapolations of the same, that correspond to 8 to 9 percent increases in real GDP growth annually from 2022 through 2050.[14]
- Growth in commercial and institutional floorspace from an estimated 1.1 square meters per capita in 2022 to 5 square meters per capita in 2050, representing a large increase in such buildings.
- The migration of population to urban areas, with the population in urban areas representing 43 percent of the total population by 2050, up from about 23 percent in 2022.
- Growth in electricity use per household
- Extension of grid electricity to almost all rural households by 2050.
- Some electrification of the transportation sector.

The high growth in this demand projection drives the need for large supply additions after about the 2030s when the combination of urbanization, partial electrification of transportation, rural electrification, and continued high GDP growth leading to higher industrial sector demand yields electricity demand growth that remains quite high, even while population growth falls.

Section 5.B of this report provides the detailed assessment (data, methodology and assumptions) of the estimated electricity demand forecast that is the basis of the results shown above.

1.D. ALTERNATIVE ELECTRICITY SUPPLY SCENARIOS

The estimated electricity supply in Rwanda assembled in LEAP tracks electricity generation for the central grid as well as by mini-grids, solar home systems (SHSs) and on-storage systems based on the estimated capacity indicated in section 1.B above. Considerations of changing loads (that is, how demand for electricity varies over time) and resource variation were also included to ensure that as demand for electricity varies, often literally from second to second, electricity output varies as well.

Sections 5.C and 5.D of this report provide the detailed assessment (data, methodology and assumptions) of the estimated electricity supply and the treatment of load curves.

To meet the forecasted electricity demand growth, **seven alternative long-range (through 2050) supply scenarios were developed to present substantially different ways of meeting the**

[13] Based on projections from the older Rwanda MAED model, which are only slightly lower, by 2050, than the United Nations "Medium Variant" projections for Rwanda.

[14] This trend in GDP growth was selected for the Reference Case forecast at the request of REG colleagues. The EAEP team notes that GDP growth at this level by a nation has rarely been sustained in the past for three consecutive decades, in part because some ups and downs in an economy are inevitable over such a long period, and in part because GDP growth tends to decline as economies mature.

demand for electricity and the services it provides in Rwanda. The goal of these scenarios is to inform planners and policymakers as to the benefits, costs, and risks associated with different electricity supply paths in Rwanda.

The seven scenarios that were considered on REG's request are:

- New Reference/Business-as-Usual ("REF.1")
- Limited Hydro ("LHY.2")
- All Renewables by 2050 ("ARN.3")
- Renewables with Interconnection ("RWI.4")
- "Net Zero" Rwanda ("NTZ.5")
- Lake Methane Displacing Natural Gas ("LMG.6")
- Energy Efficiency Improvements ("EEI.7")

Table 1.D-1 below summarizes the **requirements and assumptions of each scenario**. These scenarios reflect and extend electricity generation and related supply infrastructure (such as for natural gas imports) starting with the additions to generation considered in the latest LCPDP but adding new generation to meet the substantial growth in Rwandan electricity demand (as described above in the later years of the modeling period.

TABLE 1.D-1. SUMMARY DESCRIPTIONS OF SUPPLY SCENARIOS MODELED

SCENARIO NAME	SCENARIO CODE	KEY SUPPLY SOURCES AFTER MID-2030S	OTHER FEATURES
New Reference/ Business-as-Usual	REF.1	Diesel and natural gas	Adds some solar, hydro, wind, imports
Limited Hydro	LHY.2	Diesel and natural gas	Limits hydro deployment to plants planned by 2024
All Renewables by 2050	ARN.3	Solar PV, different technologies	Pumped-storage hydro used to meet timing of load, with solar power for pumping
Renewables with Inter-connection	RWI.4 (and RWI.4HE)	Solar PV plus imports from interconnection	Imports play a key role in meeting changing demand; some electricity exports also included
"Net Zero" Rwanda	NTZ.5	As in ARN.3, but expanded	Higher demand, supply due to additional electric end uses
Lake Methane Displacing Natural Gas	LMG.6	Diesel and Lake Kivu methane	Lake methane instead of natural gas, other as in REF.1
Energy Efficiency Improvements	EEI.7	Solar PV, different technologies	As in ARN.3, but lower electricity demand due to efficiency efforts, thus lower supply needs

Table 1.D-2 below provides a **summary of scenarios results**. The results for each scenario are reported - compared to the *business-as-usual* case, against a series of metrics such as estimated 2050 overall capacity (MW) generated, percentage of renewable supply needed, imports and exports levels (GWh), GHG emissions for the electricity sector and economy-wide, total social costs and total production costs. Other risks (such as fuel price, import dependence, additional pollution) and other benefits (such as reduced competition for water, use of domestic resources, reduced fuel price) are highlighted as well. **Policymakers can look at the different scenarios based on the metric or metrics of interest to identify the most appropriate electricity supply paths in Rwanda.**

Some key takeaways from the results below could be summarized as follow:

- From the perspective of increasing renewable electricity generation, the "All Renewables", the "Renewables with Interconnection" and "Net Zero Rwanda" scenarios offer the greater potential.
- From a GHG emissions perspective, the *All Renewables* scenario will drive power sector emissions down to nearly zero by 2050.
- From the perspective of 2050 electricity demand needs, the "Net Zero Rwanda" scenario drives a much higher demand for electricity by 2050 to the extent that most fossil-fueled end-uses move to electricity by 2050.
- From a production costs perspective, the *All Renewables* scenario shows much less costs because fuel costs for diesel and natural gas are high and won't expose Rwandan generators and electricity consumers to the risk that fuel prices will rise even higher than forecasted (as it might be the case under other scenarios).
- From the perspective of increasing domestic production, the "Renewables with Interconnection" scenario implies that Rwanda will have much more import dependence in its electricity sector and will thus be at risk if imported electricity prices rise substantially. This scenario does, however, offer the opportunity for—and in fact, requires—enhanced economic integration with the nations of the East Africa Region.
- In terms of other co-benefits, for instance, the "Limited Hydro" scenario would reduce competition for the water that the avoided hydroelectric plants would have at least partially diverted, including water relied upon by agriculture, cities, and downstream ecosystems.

TABLE I.D-2. SUMMARY RESULTS FROM SUPPLY SCENARIOS CONSIDERED

	NEW REFERENCE/ BUSINESS-AS-USUAL	LIMITED HYDRO	ALL RENEWABLES BY 2050	RENEWABLES WITH INTER-CONNECTION	"NET ZERO" RWANDA	LAKE METHANE DISPLACING NATURAL GAS	ENERGY EFF. IMPROVE-MENTS
Scenario Code	REF.1	LHY.2	ARN.3	RWI.4 (and RWI.4HE)	NTZ.5	LMG.6	EEI.7
2050 Electricity Demand	17,350 GWh	As in REF.1	As in REF.1	As in REF.1	29,640 GWh	As in REF.1	14,520 GWh
Capacity in 2050	4,540 MW	4,550 MW	8,810 MW	6,110 MW 7130 MW	17,400 MW	4,540 MW	3,850 MW
Additional Solar for Pumping	None	None	4,200 MW	90 MW 230 MW	5,400 MW	None	None
2050 Renewable Supply[15]	31%	20%	100%	100%	100%	29%	36%
2050 GWh Imports	2,000 GWh	2,030 GWh	2,140 GWh	11,300 GWh 11,600 GWh	1,800 GWh	1,770 GWh	1,930 GWh
2050 GWh Exports	None	None	None	1020 GWh 2500 GWh	None	6 GWh	None
Electricity Sector 2050 GHG Emissions	7.45 $MTCO_2e$	8.55 $MTCO_2e$	0.006 $MTCO_2e$	0.006 MTCO2e	0.005 $MTCO_2e$	7.77 $MTCO_2e$	6.40 $MTCO_2e$
Economy-wide 2050 GHG Emissions	19.1 $MTCO_2e$	20.3 $MTCO_2e$	10.9 $MTCO_2e$	10.9 MTCO2e	1.86 $MTCO_2e$	19.5 $MTCO_2e$	17.3 $MTCO_2e$
Total Social Cost Rel. to REF.1[16]	N/A	1.7 $B *1.6 $B*	-5.3 $B *-2.1 $B*	-6.0 $B /-5.7 $B *-5.7 $B /-4.8 $B*	-11.7 $B *-5.5 $B*	0.1 $B *1.4 $B*	-2.1 $B/*2.2 $B*
Total 2050 Electricity Prod. Cost Rel. to REF.1[17]	N/A	110 $M, *110 $M*	-690 $M, *-610 $M*	-560 $M /-520 $M *-550 $M /-490 $M*	-360 $M *200 $M*	-7.4 $M/*18.4 $M*	-280 $M, *-250 $M*
Other Risks[18]	Heavy fuel price risk, additional pollution	Heavy fuel price risk, additional pollution	More difficult load balancing vs. REF.1	Import dependence, import price risk	Load balancing, meeting additional demand	Additional diesel price risk	Performance risks for efficiency policies, programs
Other Benefits	Proven technologies	Reduced competition for water	Use of domestic resources, less fuel price risk, more energy sector employment	Enhanced economic integration with Region	Domestic resources use, less fuel price risk, more energy sector employment	Reduced gas import needs, emissions	Somewhat reduced fuel price risks, more energy sector employment

[15] Calculations of the fraction of electricity supplies as renewable assume that electricity imported into Rwanda is from renewable sources.
[16] Total economy-wide costs summed through 2050 relative to REF.1 Case. Costs are in 2020 US dollars calculated using real interest rates of 5%/yr and 15% yr, the latter in *italics*, and a real discount rate of 5%/yr.
[17] Costs of electricity generation in 2050 relative to REF.1 Case are in 2020 US dollars calculated using real interest rates of 5%/yr and 15% yr, the latter in *italics*, and a real discount rate of 5%/yr.
[18] The "Other Risks" and "Other Benefits" describe selected major additional attributes of the supply scenarios but are not exhaustive

Section 5.E of this report provides more detail on the assessment and results of each supply scenario.

Figure 1.D-1 below presents a comparison of total discounted social costs over the full modeling period for scenarios LHY.2 through EEI.7 relative to the New Reference case. **Savings in fuel imports (dark blue bar), for generation, as well as for the transportation sector, in NTZ.5, are the most important drivers of net cost savings for scenarios using substantial renewable generation relative to those that do not.** The results in this Figure reflect the use of a discount rate of 5%/yr, and an interest rate for the initial costs of generation of 5%/yr. Raising the interest rate used to model the annualization of initial costs reduces the net benefits that renewable energy-focused scenarios show relative to the REF.1 case (ARN.3 and NTZ.5, in particular), but those benefits remain substantial, as shown in Figure 1.D-2 that follows.

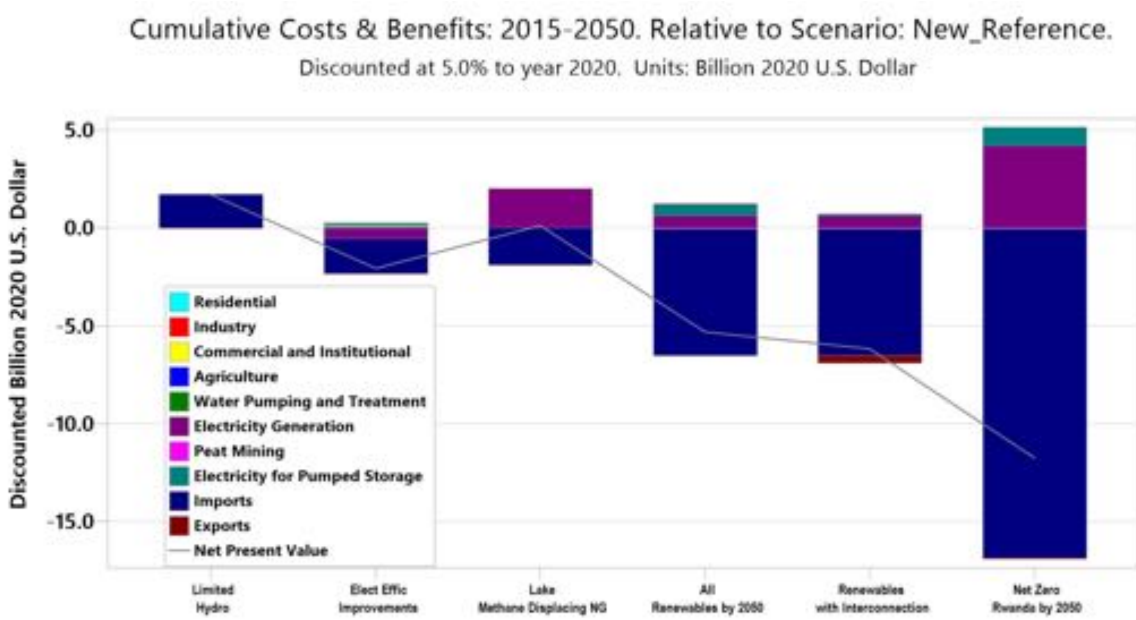

Figure 1.D-1 Social Costs Comparison Across Scenarios Relative to the New Reference Case (Using an interest rate of 5%/yr)

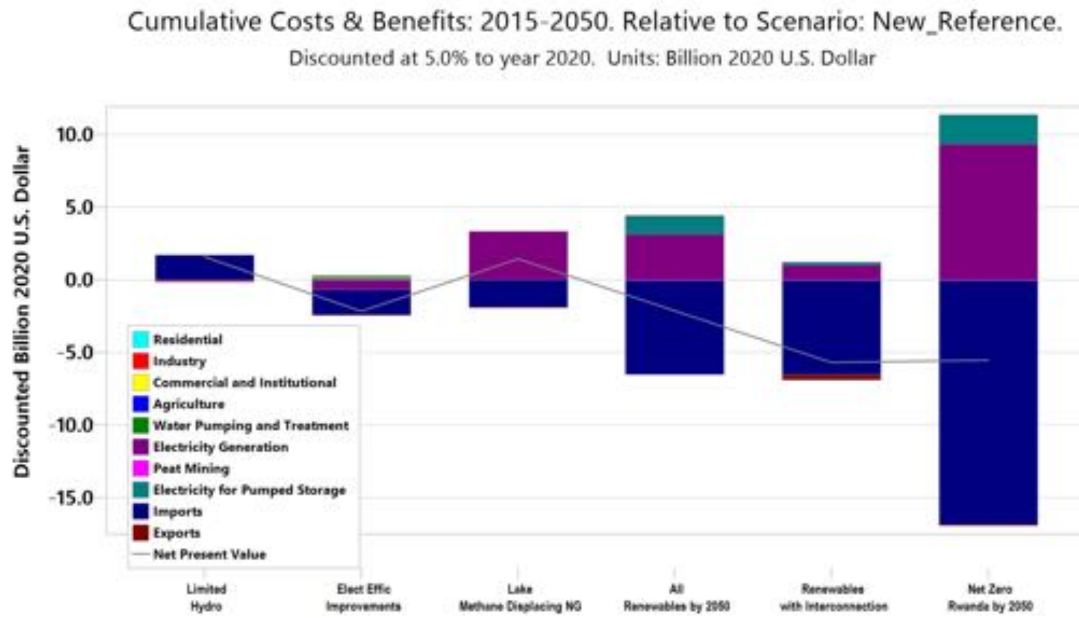

Figure 1.D-2 Social Costs Comparison Across Scenarios Relative to the New Reference Case (Using an interest rate of 15%/yr)

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Methods and results of the Assessment summarized above are presented in this report as follows:

- *Section 3* covers the assessment of *physical availability and technical potential* for the selected resources and technologies, as well as provides related *generation costs inputs* (that is initial installed costs, fixed operating, and maintenance (O&M) costs, and variable O&M costs.
- *Section 4* covers the assessment of *economic and market potential* for the above resources and technologies
- *Section 5* provides details, results, and comparison among the *seven alternative supply scenarios*
- *Section 6* provides *conclusions*

The following Annexes provides additional technical details on the Assessment:

- Annex A – Nuclear Power in Rwanda
- Annex B – Rwanda LEAP Model: Details

2. INTRODUCTION

This report is part of the Rwanda Resource Study for Electricity Generation Sources project (the Project) implemented under the Power Africa East Africa Energy Program (EAEP) with the technical expert assistance of the Center for Climate Strategies (CCS) in collaboration with the State-owned Rwanda Energy Group (REG).

Electricity demand has been growing rapidly in Rwanda as the economy expands and as more households and businesses, both rural and urban, are connected to the electricity grid or obtain electricity from mini-grids or solar home systems. At the same time, Rwanda is blessed with a variety of attractive resources for current and future electricity generation. Some of these resources, however, offer limits to the degree to which their use can contribute to meeting future electricity demand in Rwanda. The **purpose of the Project** is to identify the potential for a full suite of priority electricity resources in Rwanda to meet the growing demand while also addressing other priorities, such as environmental impacts, and to provide methods and training that promote continuous future updates by REG and stakeholders.

REG was incorporated by the Government of Rwanda (GOR) in 2014 to expand, maintain and operate the energy infrastructure in Rwanda through its two subsidiaries – the Energy Utility Corporation (EUCL) and the Energy Development Corporation (EDCL). Within this framework, planning of generation and transmission as well as electrification projects is under the joint responsibility of the Ministry of Infrastructure (MININFRA) and REG. As part of its planning mandate, REG leads the development of the Rwanda Least-Cost Power Development Plan (LCPDP) that covers the electricity generation expansion plan for the country through 2040. The LCPDP is updated by REG every six months and this Project aims at supporting these continuous future updates by REG

The **present report** covers the last phase of the Project (Phase 3) during which the EAEP Team conducted the **full assessment of physical availability, technical potential, and economic and market potential for priority electricity generation resources and technologies in Rwanda and developed seven alternative supply scenarios through 2050 to meet Rwanda growing electricity demand needs, namely alternative combinations of different supply resources to meet demand (the Assessment).**

The Phase 3 of the Project built on the Phase 1 gap analysis of studies, tools, and data sets for Rwanda generation resources, and on the Phase 2 recommended technical approach and integrated analytical system to conduct the Rwanda generation resource assessment. The Assessment covers the following **key electricity generation resources** that based on most recent LCPDP assessment appear to have the greatest potential in Rwanda, and within each, the following priority technologies identified by REG:

- *Solar*, with a focus on
    - On grid/ground/non-urban (that is, utility-scale PV power plants with a size range greater than 1 MW).
    - On grid/rooftop/urban (that is, all size ranges for urban-located buildings across residential, commercial/institutional, and industrial sector).
    - On grid/ground/agriculture (that is, co-developed agriculture and solar photovoltaic power systems or APVs).
    - On grid or off-grid/floating/surface water (that is, photovoltaic panels mounted on platforms in the water or “floatovoltaics”); floating photovoltaic systems are referred to here as FPVs.
    - Non-central grid options [such as PVs used in small scale mini-grids and solar home systems (SHS).

- *Wind*, and more specifically Horizontal Axis Wind Turbine (HAWT)
- *Hydro*
- *Waste-to energy*, with a focus on crop residues (and principally rice husk produced at rice mills) and municipal solid waste (MSW)
- *Methane*
- *Geothermal*
- *Peat*

Although *nuclear energy* is used in many places around the world and is in theory a potential future source of electricity generation for Rwanda, it was not considered as a potential future generation resource in this Assessment for several reasons, including its high cost and the mismatch between the size of most commercial reactors and the size of the Rwandan grid. Indeed, the cost of uranium is a minor portion relative to the combined costs of conversion, enrichment and fuel fabrication, services that for Rwanda would highly likely have to be imported, even if using Rwandan uranium, and the installed costs of nuclear power plants are typically quite high. Moreover, the size of typical commercial reactors (1000 MW or larger) is large relative to the Rwandan grid, which is currently several hundred megawatts, and even with substantial growth in electricity demand (see the Supply Scenarios section in this report) may not require more than 2000 average MW by 2050. Large reactors are unsafe to operate on grids that small, because if the plant is damaged, it will be difficult both to maintain grid operations and to assure that enough emergency backup power is available for the nuclear unit's coolant pumps to prevent the plant from overheating and damaging the reactor core.[19] Annex A provides more details on what is known about the Rwandan uranium resource, and a more in-depth discussion of considerations related to the use of nuclear power in Rwanda.

For each of the above resources and technologies covered under this Assessment, the **following levels of generation capacity** measured in MW were estimated:

- *Physical availability*, that is the total amount of primary energy available within a specified geographic boundary annually and over a period of years.
- *Technical Potential,* that refers to the amount of electricity that can be produced from the physical resource available through a specific technology.
- *Economic Potential*, that refers to the amount of electricity for which generation costs are competitive compared with costs of generating or purchasing electricity through other means at an interest rate that an interest rate that reflects a social interest rate (consistent with the low rate of interest that might be used by a government for its own investments, or rates that might be offered to a government by a bilateral or multilateral development bank lender).
- *Market Potential*, that refers to the amount of electricity that can feasibly be brought to market, under the prevailing conditions for power sales and investment, at a price that is competitive with other possible resources and technologies based on an higher interest rate that takes into account financing, profit, taxes, and risk, and thus estimate the potential of market penetration of each generation resource.

[19] This is a simplistic explanation of a complex issue. See, for example, IAEA (2012), *Electric Grid Reliability and Interface with Nuclear Power Plants*, IAEA Report # NG-T-3.8, available as https://www-pub.iaea.org/MTCD/Publications/PDF/Pub1542_web.pdf.

Figure 2-1. below summarizes these areas of assessment.

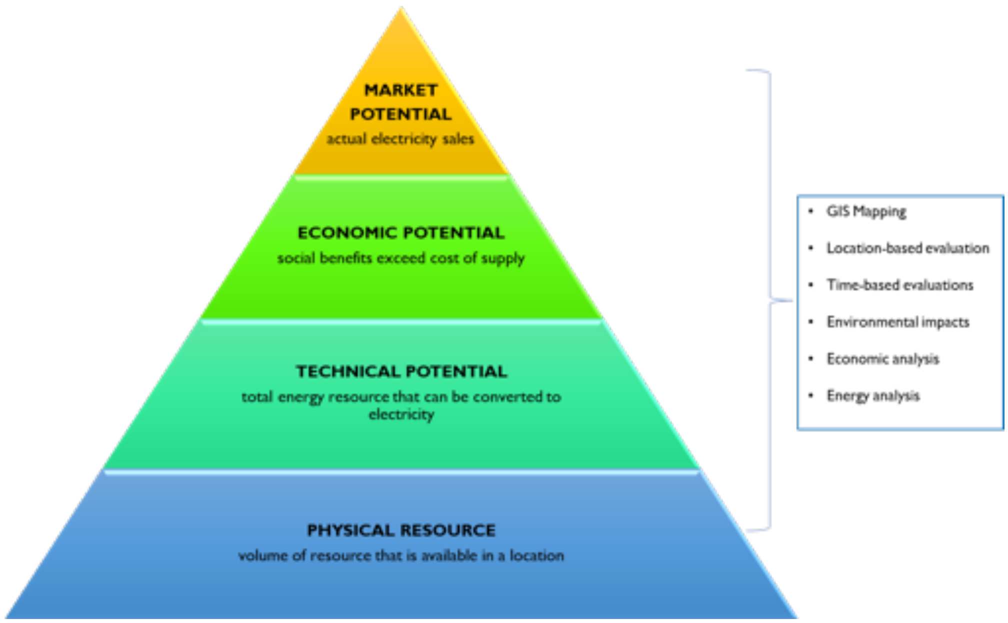

Figure 1-1. Level of generation capacity estimated

Based on these results, the EAEP Team developed and explored **long-range (through 2050) scenarios** for both electricity demand and for the use of different supply resources to inform and guide the path of supply expansion in Rwanda over time. The following seven scenarios were developed to present substantially different ways of meeting the demand for electricity through different combinations of supply resources and based on different metrics such as GHG emission impact, import/export, capacity, electricity output, costs (the Alternative Scenarios):

- New Reference/Business-as-Usual (“REF.1”)
- Limited Hydro (“LHY.2”)
- All Renewables by 2050 (“ARN.3”)
- Renewables with Interconnection (“RWI.4”)
- “Net Zero” Rwanda (“NTZ.5”)
- Lake Methane Displacing Natural Gas (“LMG.6”)
- Energy Efficiency Improvements (“EEI.7”)

Sections 5 of this report provides details on the requirements, assumptions, and results of each scenario.

Methods and results of the Assessment are presented in this report as follows:

- *Section 3* covers the assessment of physical availability and technical potential for the indicated resources and technologies, as well as provides related generation costs inputs (that is initial installed costs, fixed and variable operating and maintenance costs).
- *Section 4* covers the assessment of economic and market potential for the above resources and technologies.

- *Section 5* provides details and results on, as well as comparison among, the seven Alterative Scenarios.
- Section 6 provides *conclusions and recommendations* to REG.

The following Annexes provides additional technical details on the Assessment:

- Annex A – Nuclear Power in Rwanda
- Annex B – Rwanda LEAP Model: Details

3. RESOURCE ASSESSMENTS: PHYSICAL AVAILABILITY, TECHNICAL POTENTIAL AND COST INPUTS

3.A. INTRODUCTION

This section describes data, methods, assumptions, and results of the assessment of physical availability and technical potential for each resource and priority technology identified by REG. As indicated in the previous section, **physical availability** refers to the total amount of primary energy available within a specified geographic boundary annually and over a period of years; and **technical potential** refers to the amount of electricity that can actually be produced from the physical resource available through a specific technology. Additionally, this section provides for each resource and technology **cost information** (that is grid integration costs, and as installation, equipment, and O&M costs) that are used for the economic and market potential assessments that follow.

Technical potential is estimated based on '**nameplate" capacity** that denotes the total maximum output of a resources/technology. "Nameplate" capacity differs from "**available" capacity** that considers the fraction of the time that a resource is not available to drive a generator at its full output and, as such, it is taken as the average capacity factor for the resource multiplied by the nameplate capacity. That is, for example, a hydroelectric plant with a peak output of 5 MW would be rated at 5 MW as nameplate capacity, but less as "available" capacity.

In the LCPDP, REG reports generation resource capacity estimates as "available" capacity in MW. Thus, to support REG in the updates of the LCPDP, Table 3.A-1 below summarizes_**estimated results of technical potential** for each generation resource as "available" capacity (MW). **Total estimated technical capacity is reported for 2030 and 2050 since waste-to energy estimate changes over time because this resource is dependent on population growth.**

More specifically, for comparison purposes, the table reports for each generation resource:

- Exploited available capacity (that is, installed capacity) as indicated in the latest version of the LCPDP and that has been used by the EAEP Team as starting point of this Assessment.
- Total exploited and unexploited capacity as estimated in the latest version of the LCPDP.
- Unexploited available capacity as estimated under this Project.
- Total exploited and unexploited capacity as estimated under this Project.

The sub-sections that follow provide the details of the Assessment for each generation resource and the **breakdown by priority technology** within each resource, including a comparison between "nameplate capacity" estimates and "available" capacity estimates.

TABLE 3.A-1. SUMMARY ESTIMATED RESULTS OF AVAILABLE TECHNICAL POTENTIAL (2030 AND 2050)				
RESOURCE	LCPDP AND EAEP: EXPLOITED AVAILABLE CAPACITY (MW)	LCPDP: TOTAL EXPLOITED + UNEXPLOITED AVAILABLE CAPACITY (MW)	EAEP: UNEXPLOITED AVAILABLE CAPACITY (MW)	EAEP: TOTAL EXPLOITED + UNEXPLOITED AVAILABLE CAPACITY (MW)
Solar	2.1	2.1	168,699	168,701
Hydro	164[20]	262	822	986
Wind (100m hub height)	0	N/A	225	225
Waste (2030)	0.07	N/A	55	55
Waste (2050)	0.07	N/A	116	116
Geothermal	0	N/A	0	0
Lake Kivu Methane	116	250	102	218
Peat[21]	86	250	166	246
Total Capacity 2030	**368**	**764**	**170,069**	**170,431**
Total Capacity 2050	**368**	**764**	**170,130**	**170,492**

3.B. GENERAL GIS DATA SOURCES AND METHODS

This section describes general data sources and methods used for the GIS analysis across generation resources for the following components of the analysis:

- Administrative Boundaries
- Land Cover
- Digital Elevation Model
- Protected Areas
- Transmission Lines, Substations and Roads
- Building Footprints

[20] Hydro "Available capacity" for existing and planned hydro come from Tables 2, 4 and 5 of the LCPDP (values for "available" or "firm" capacity). Additional planned sites in Table 3 that were not also in either Table 4 or 5 were also added (with an assumed 51% CF). LCPDP Total includes planned installed capacity from LCPDP (with available capacity estimated using average capacity factor).

[21] Peat: LCPDP Total is the milled peat estimate (121) plus remaining peat in Hakan concession area not allocated to the 80 MW plant.

As agreed with REG during Phase 2 of this project, the EAEP Team conducted all GIS analysis using open-source QGIS software (version 3.18) and associated tools.[22]

Administrative Boundaries. Shapefiles for boundaries for administrative units within the country, including provinces, districts, sectors, cells, and villages, were provided by REG.

Land Cover. Land Cover layers were derived from the Rwanda Land Cover 2015 Scheme II raster file, which has a resolution of 1 arcsecond (approximately 30 meters), obtained from the Regional Centre for Mapping of Resources for Development (RCMRD).[23] Figure 3.B-1 shows the land cover types included in this data. The Scheme II land cover maps for 1990 and 2000 were also used for streamflow modeling, as described in the Hydropower section.

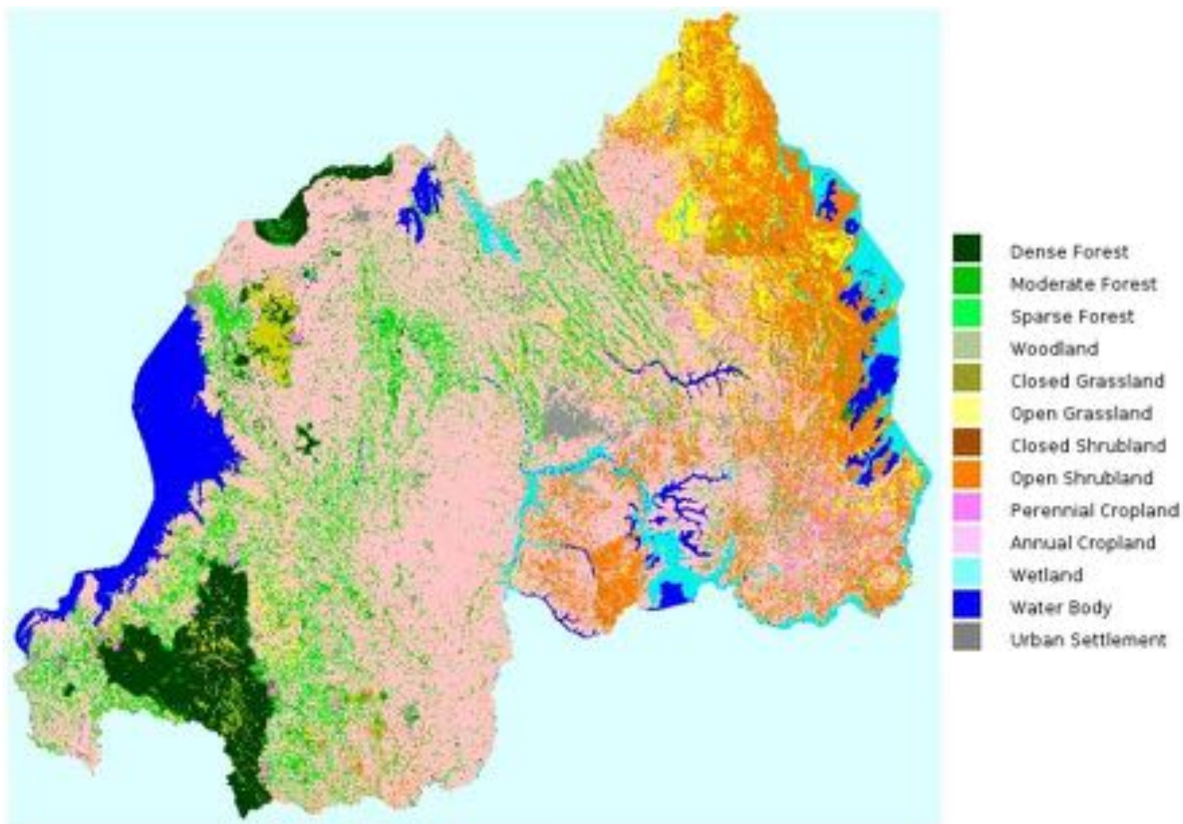

Figure 3.B-1. 2015 Land Cover Map

For exclusion analyses, individual land cover types were pulled from the raster file using the QGIS raster calculator tool. The resulting raster layers were then converted to polygon vector shapefiles, which could be merged or subtracted from one another, as needed. The specific land cover types included in exclusion analyses for each resource are discussed in more detail in the individual resource sections.

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22 QGIS, https://www.qgis.org/en/site/

23 RCMRD Geoportal, http://geoportal.rcmrd.org/layers/servir%3Arwanda_landcover_2015_scheme_ii

Digital elevation model (DEM). The EAEP Team used QGIS tools to develop slope, terrain ruggedness index (TRI), and hydrology raster layers using digital elevation model (DEM) data. The DEM layer used was the Shuttle Radar Topology Mission (SRTM) 1 Arc-Second Global dataset downloaded from USGS EarthExplorer.[24] The data was downloaded for latitudes 0 to -4 and longitudes of 28 to 32, to capture all of Rwanda's area as well as border regions where water may drain into Rwanda streams and rivers. The 9 separate files for this area were then merged into a single DEM raster file.

Slope and TRI layers were created using the QGIS raster terrain analysis tools. Hydrology layers were created using Geographic Resources Analysis Support System (GRASS)[25] tools included in the QGIS software, including the *r.stream.extract* and *r.watershed* tools. The *r.stream.extract* tool creates a raster layer for all delineated streams. The *r.watershed* tool creates a raster file for the upstream drainage area at each point.

Protected Areas. Protected areas used in the GIS analysis and referred to in the individual resource assessments are shown in Figure 3.B-2 below. These areas include:

- Akagera National Park boundaries and buffer
- Cyamudongo Forest Reserve
- Gisakura Forest
- Gishwati-Mukura National Park boundaries and buffer zones
- Nyungwe National Park
- Volcano National Park boundaries and park extension
- All Fully Protected Wetlands

Shapefiles for current protected areas were provided by the Rwanda Environmental Management Authority (REMA).

Transmission Infrastructure and Roads. Transmission infrastructures referred to in the individual resource assessments are shown in Figure 3.B-3 below. Shapefiles for high-voltage transmission lines and substations were provided directly by REG, including current lines and substations, and substations planned through 2027. Shapefiles for the network of principal and secondary roads were also provided by REG.

Building Footprints. Shapefiles for footprints for all buildings in Rwanda, developed from orthophoto, were provided directly by the Rwanda Land Management and Use Authority. The footprint data included attributes for building area, settlement name, and settlement type (i.e., rural settlement, district city, etc.). Statistics on building area (mean, minimum, maximum) were developed using the Group Stats plugin tool for QGIS.[26]

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[24] USGS EarthExplorer, https://earthexplorer.usgs.gov/

[25] Geographic Resources Analysis Support System, https://grass.osgeo.org/grass80/manuals/raster.html

[26] Group Stats, https://plugins.qgis.org/plugins/GroupStats/

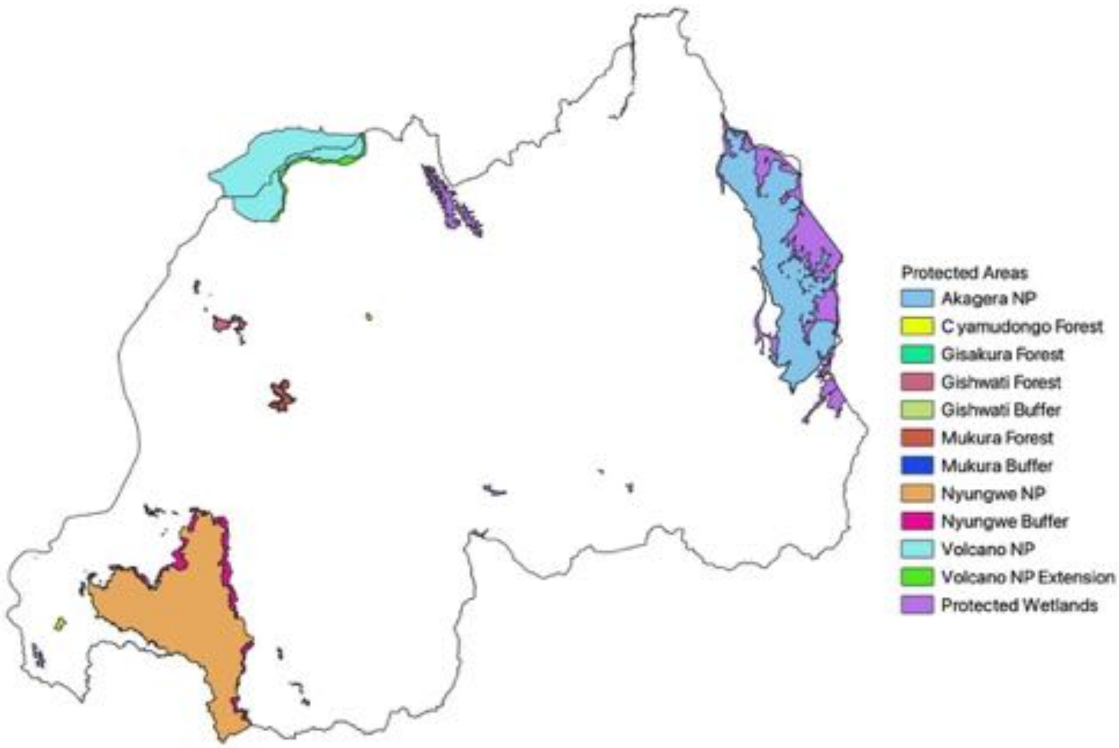

Figure 3.B- 2 Rwanda Protected Areas

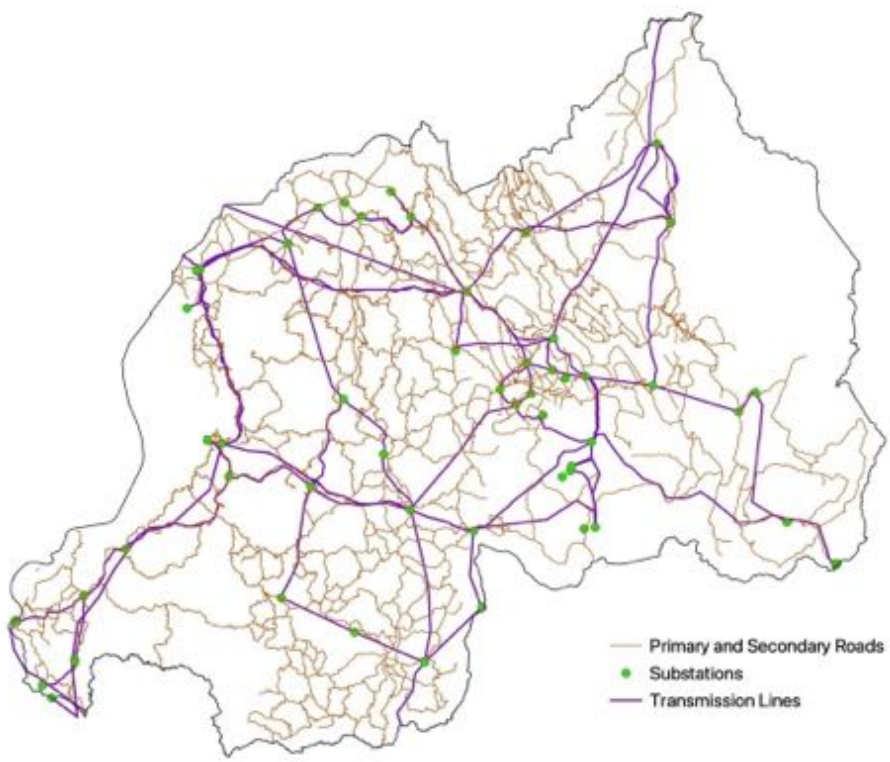

Figure 3.B-3 Transmission infrastructure

3.C. SOLAR RESOURCE ASSESSMENT

8.5 MW Solar Farm at Agahozo Shalom Youth Village east of Kilgali, Rwanda
SAMEER HALAI/SUNFUNDER/GIGAWATT GLOBAL

3.C.1. PHYSICAL RESOURCE AVAILABILITY

Rwanda's **physical solar resource** was characterized and documented in the Phase 2 report. Rwanda has a very good solar resource across much of the country, as indicated in Figure 3.C-1.1 below and reported in the Global Solar Atlas produced by Solargis.[27] The highest-intensity solar resources are found in the south-central and along the entire eastern border region. The physical solar resource shown in Figure 3.C.1-1 below is the average daily global horizontal irradiance (GHI) in units of kilowatt-hours/square meter (kWh/m^2) for each cell, that is an official administrative division in Rwanda, an intermediate spatial division between the larger sector cells and the much smaller village cells. There are 2,148 such administrative divisions in Rwanda, hereafter referred to simply as "Cells".

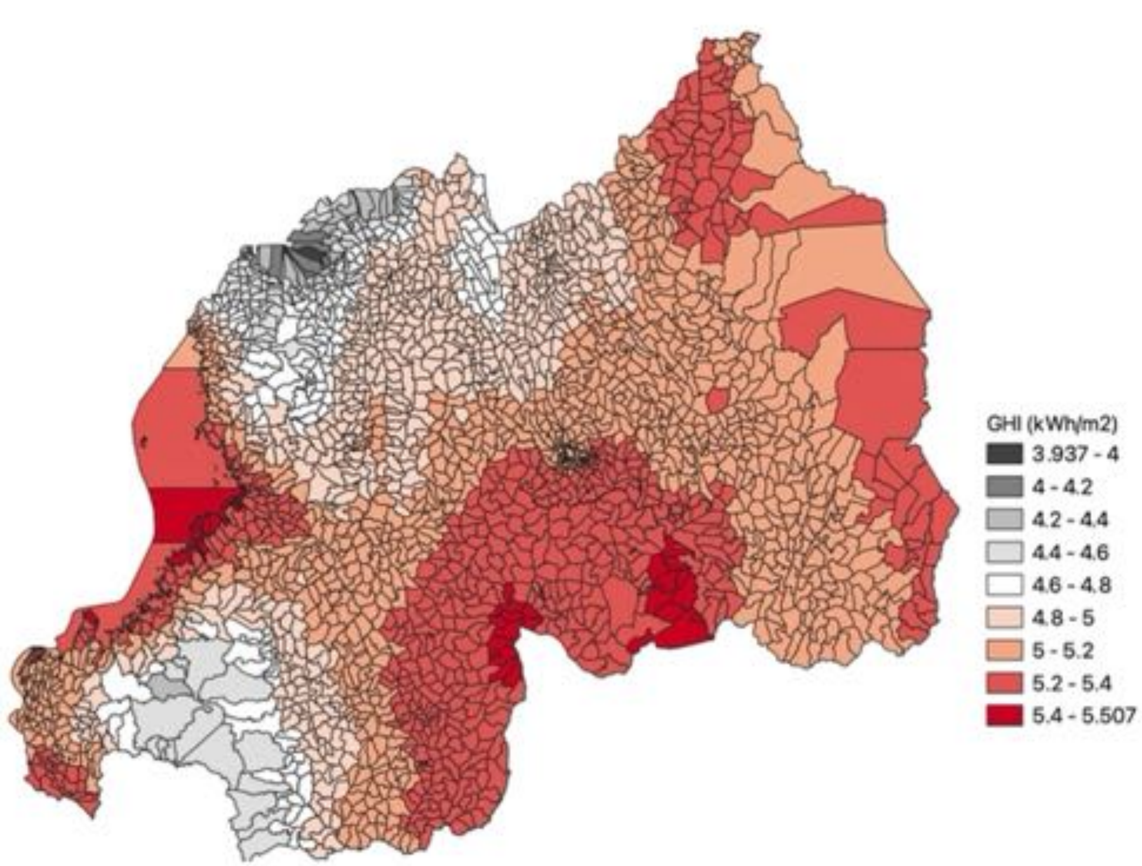

Figure 3.C.1-1. Average daily GHI for Rwanda at the Cell Level

[27] https://solargis.com. Solargis represents the most comprehensive and rigorous solar resource database that is publicly available and is a suitable basis upon which to define Rwanda's solar resource potential, as discussed in the Phase 1 report.

3.C.2. TECHNICAL POTENTIAL

REG selected the following **solar photovoltaic (PV) technologies** for the assessment of solar technical potential for Rwanda:

- On grid/ground/non-urban (that is, utility-scale PV power plants with a size range greater than 1 MW)
- On grid/rooftop/urban (that is, all size ranges for urban-located buildings across residential, commercial/institutional, and industrial sector)
- On grid/ground/agriculture (that is, co-developed agriculture and solar photovoltaic power systems or APVs)
- On grid or off-grid/floating/surface water (that is, photovoltaic panels mounted on platforms in the water or "floatovoltaics"); floating photovoltaic systems are referred to here as FPVs
- Non-central grid options [such as PVs used in small scale mini-grids and solar home systems (SHS)]

More specialized and targeted assessments will also likely be of interest for hybrid technologies involving solar PV. These would include solar PV combined with pumped storage. For example, the use of solar PV to pump water downstream of a hydro-power plant back into the reservoir behind the dam for later use in generating more hydropower. These types of targeted assessments will be defined later with input from REG and added into the available mix of generating technologies available for consideration in the LCPDP.

The **methods and data sources** used to characterize the technical potential for each of the solar technology applications bulleted above are provided in the following sections, and the **estimated results** of total (exploited/installed and unexploited) "nameplate" capacity and "available" capacity (GW) and related annual generation (GWh) are summarized in the table below. **A total technical potential (exploited and unexploited) of 169 GW of "available" capacity was estimated for solar in Rwanda (equal to 992 GW of "nameplate" capacity).**

TABLE 3.C.2-1. SOLAR TECHNICAL POTENTIAL ESTIMATES (EXPLOITED AND UNEXPLOITED)

TECHNOLOGY APPLICATION	NAMEPLATE CAPACITY (GW)	AVAILABLE CAPACITY (GW)	ANNUAL GENERATION (GWh)
Utility-Scale PV	200	34	300,030
Agri-PV	753	128	1,121,117
Floating PV	4	0.68	6,224
Rooftop PV – Non-residential	2.2	0.38	3,295
Rooftop PV - Residential	33	5.6	49,633
Total Solar (Exploited and Unexploited)	**992**	**169**	**1,480,299**
Total Solar Currently Exploited Available Capacity	**0.015**	**0.0035**	

3.C.2.a. Utility-scale PV power plant

Estimate of Country-Wide Technical Potential. In addition to the physical resource values mentioned above, Solargis also provides a measure of technical potential of solar PV expressed in photovoltaic electricity output (PVOUT)[28] as indicated in Figure 3.C.2.a-1 below.

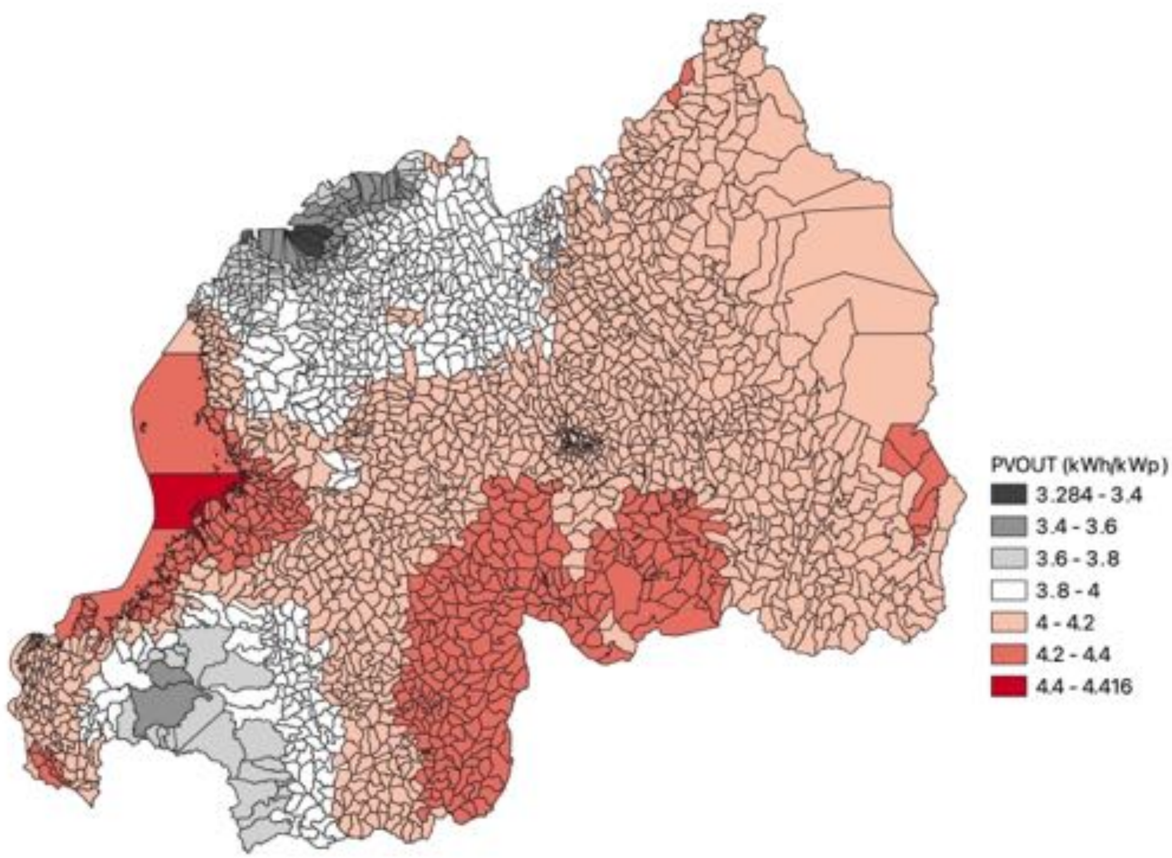

Figure 3.C.2.a-1 Solargis PVOUT for Rwanda[29]

[28] PVOUT or photovoltaic power potential, is simply the kilowatt-hours produced over a given time period (typically a day or a year) per peak kilowatt of installed capacity. The units in the figure are kWh-day/kWp and are calculated relative to Standard Test Conditions.
[29] Data source: https://solargis.com/. See the Phase 1 report for this project for a description of GHI and other metrics for characterizing the solar physical resource.

The technical parameters used by Solargis to model PV output are:[30]

- Installed power: 1.0 kWp (1 kW at peak solar input)
- PV field self-shading: 2.0%
- Module type: crystalline silicon
- Nominal operating cell temperature: 46.2 degrees C
- Inverter efficiency: 98%
- Other DC losses: 5.8%
- AC losses: 1.4%
- Availability: 100%

An exclusion analysis was then performed within QGIS to remove areas that are not amenable to utility-scale solar PV plants for varying reasons.

The following types of land were excluded:

- Land use and land cover: urban, water, wetlands, cropland (note: except for wetlands the other land cover categories are being addressed by other solar PV technologies described in subsequent sections below).
- Ruggedness: land areas with a Terrain Ruggedness Index (TRI) > 25. TRI expresses the difference in elevation between a cell and the eight cells directly surrounding it.[31] The higher the TRI, the greater the variation in elevation from adjacent areas. These steeply sloping areas make PV system installation difficult and/or are more likely to be in shade part of the time.
- Protected areas.

For the details of QGIS data sources used for the exclusion analysis, please refer to Section 3.B of this report. The exclusion analysis identified the available technical area for utility-scale solar PV plants as viable from a technical potential perspective. The total area comes to around 2.6 million hectares (Ha), or 18% of Rwanda's total land area.

The total country-wide technical potential capacity estimated for utility-scale solar PV (exploited and unexploited) is 200 GW of "nameplate" capacity. This potential capacity is capable of producing over 300,000 GWh of electricity annually.

Following the exclusion analysis within QGIS, the polygons larger than 2.35 million m2 (the approximate size of a 100 MW plant) were intersected with a layer of grid squares of approximately this size to break them down into polygons of this size or smaller. These polygons were then merged back into a single layer with the smaller polygons. Polygons smaller than 2,348 m2 (the approximate size of a 1 MW plant) were deleted from this layer. The mean PVOUT value for each polygon was then calculated using the QGIS zonal statistics tool, Then, to calculate the total technical PV capacity available for each polygon, the area of each polygon with technical potential was multiplied by a factor that accounts for the ground coverage ratio (GCR) for utility-scale solar power plants. GCR accounts for the fact that less than 100% of a plant's area will be covered by panels, as well as the areas for ancillary equipment and for site

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[30] These parameters are based on theoretical site data as documented here: https://globalsolaratlas.info/support/methodology. CCS confirmed with Solargis that these are the values applied for modeling PVOUT (S. Roe, CCS, email communication with M.P. Ojer, Solargis, 6/22/2021).

[31] Riley, S.J., De Gloria, S.D., Elliot, R. (1999): A Terrain Ruggedness that Quantifies Topographic Heterogeneity. https://download.osgeo.org/qgis/doc/reference-docs/Terrain_Ruggedness_Index.pdf.

access, such as for access roads, that are also needed).[32] For common PV power plants (e.g. crystalline silicon panels), values from the literature tend to range from around 0.03 kWp to about 0.08 kWp/m^2.[33] When expressed with units of capacity in the numerator, GCR also accounts for the efficiencies with which the solar panels convert incoming sunlight to electricity, as well as any power conversion losses. For this assessment, a value was calculated based on the 8.5 MW Rwamagana plant (the only utility-scale plant operating in Rwanda). Figure 3.C-2.a.2 shows the estimated total area for the plant based on the apparent site boundaries using Google Earth. The GCR value calculated was 0.043 kWp/m^2. This value was applied to the area of each polygon to estimate the total technical potential of each polygon.

Figure 3.C.2.a-2 Perimeter and Area of the Rwamagana Power Plant

Figure 3.C.2.a-2 shows the areas within Rwanda that have technical potential for utility-scale solar PV. These areas are widely distributed across the country with significant potential located in the eastern and south-central regions.

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32 Another term for the PV panels fit into a given area is the "packing factor". Some authors will use this term synonymously with GCR; others will use it to refer to only the area immediately below the PV panels. For this report, to avoid confusion, CCS has adopted the GCR term. It can be expressed as the % of ground area covered by panels and ancillary equipment or in units of generation capacity per unit area.

33 See for example, estimates from the US National Renewable Energy Lab (NREL) in Table ES-1 in the report at the following link: http://www.nrel.gov/docs/fy13osti/56290.pdf. An upper estimate, including an example from Tanzania at 0.08 kWp/m^2, can be found in solar training materials from IRENA, "Session 2a: Solar power spatial planning techniques", (page 24) available at: https://www.irena.org/-/media/Files/IRENA/Agency/Events/2014/Jul/15/9_Solar_power_spatial_planning_techniques_Arusha_Tanzania.pdf?la=en&hash=F98313D5ADB4702FC910B94586C73AD60FA45FDE.

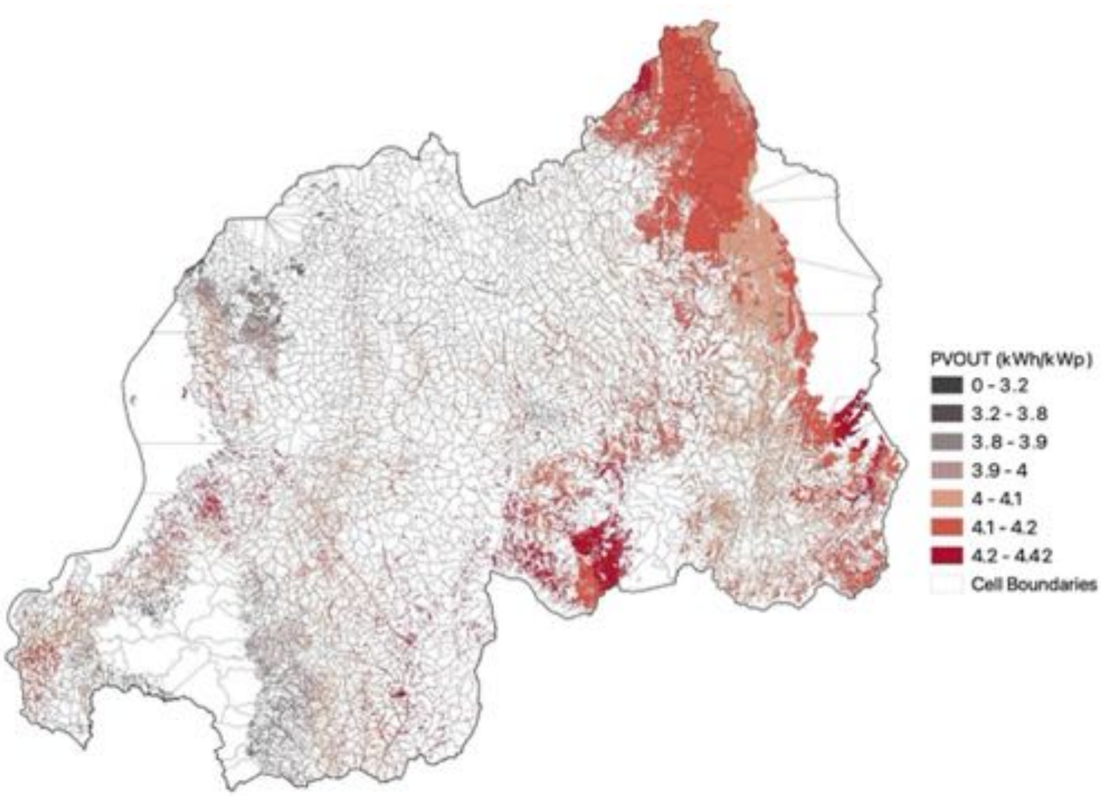

Figure 3.C.2.a-2. Areas of Rwanda Indicating Technical Potential for Utility-Scale Solar PV

Figure 3.C.2.a-3 below shows the resulting technical potential for utility-scale solar PV in Rwanda.[34] Technical potential capacity was calculated for each cell based on the cell area that remained after the exclusion analysis and the GCR value indicated above (0.043 kWp/m^2). As mentioned above, the total country-wide technical potential capacity estimated for utility-scale solar PV is 200 GW. Note that there are some building structures located within these areas that have technical potential;[35] however, collectively, these buildings represent only a small area. The total area taken up by these buildings is about 0.5% of the area with technical potential. Application of a 10-meter buffer around these buildings countrywide yields an area that total less than 4.0% of the total area with technical potential. Given the small amount of area involved and no indication of whether some of these buildings are or are not permanent structures, additional spatial analysis to remove these building areas was not conducted.

[34] The underlying data are being provided to REG both as GIS data and the MS Excel workbooks used to calculate technical potential and economic potential.
[35] GIS data on building footprints was provided by the Rwanda Land Management and Use Authority.

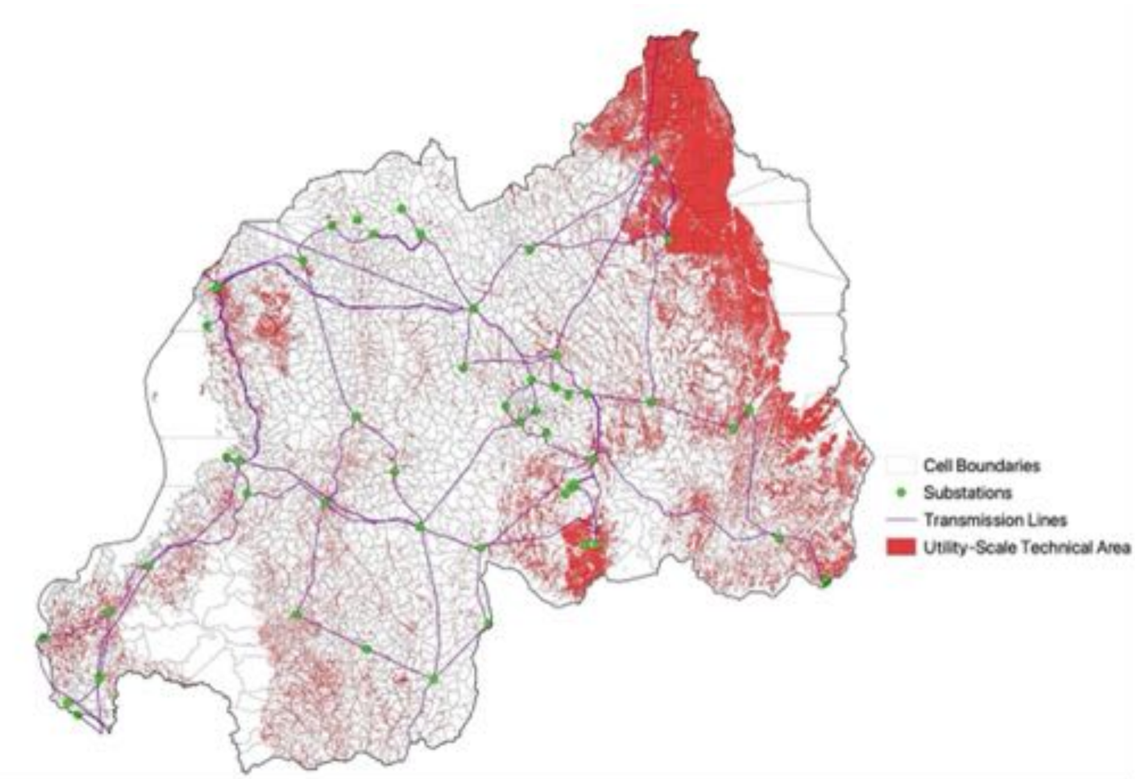

Figure 3.C.2.a-3 Spatial Analysis Results for Utility-Scale Solar PV Technical Potential (Technical Area)

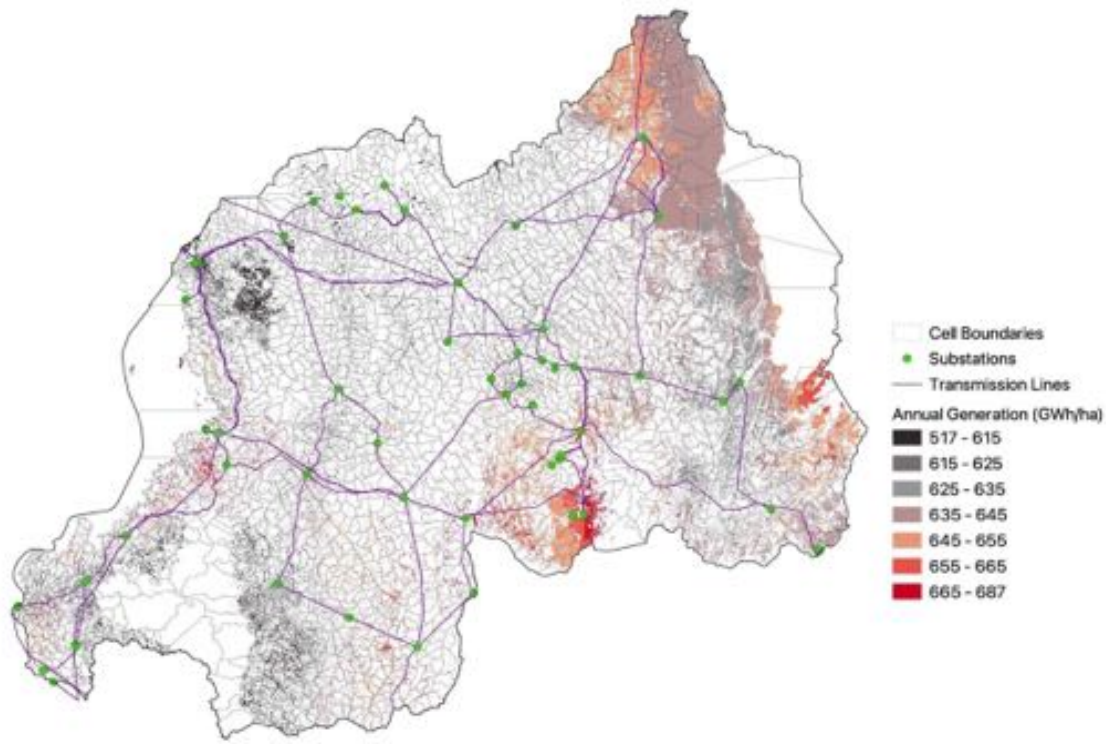

Figure 3.C.2.a-4 Spatial Analysis Results for Utility-Scale Solar PV Technical Potential (Annual GWh per Hectare)

Annual production was also calculated for each polygon based on its value for PVOUT (daily kWh/kWp), the technical potential capacity described above, and operations for 365 days/yr. Total country-wide annual production was estimated to be 300,030 gigawatt-hours (GWh). The units for the map are for PV generation potential per unit area (MW/ha)). Also shown are the locations of transmission lines and substations. Note that these represent the locations of all substations expected to be installed by 2027. Also note that, as per the exclusion analysis described above, agricultural lands are excluded (they are separately considered within the agri-voltaics technology application described in the next section), as are urbanized areas. Therefore, much of the central portion of the country shows little technical potential (as agricultural lands dominate in the central portion of the country).

3.C.2.b Agri-voltaic PV Plants

As described in the subsections below, the assessment of agri-voltaic PV (APV) technical potential required: 1. gathering data on land use/land cover (LULC) data; crop data; and data from the literature (on crop light requirements and application of APV technologies); and, 2. developing a method for applying these data in order to estimate the technical potential for APV across the country. As described further below, it is necessary to account for the light requirements of different crops when APV systems are in the planning stage. This accounting dictates the amount of surface area that can be covered by PV panels, which in turn, limits the output capacity of APV plants (as compared to similar commercial or utility-scale ground-mount systems).

Land Use/Land cover Data. As with the utility-scale PV power plants addressed above, the starting point for assessing APV technical potential is the Solargis data for PVOUT as indicated in Figure 3.C.1-1 above. For APV, however, only agricultural lands are addressed. Figure 3.C.2.b-1 below provide the LULC for Rwanda, including available details for agricultural land uses. As indicated in these maps, agricultural land use is spread throughout the country and only a small proportion of total cropland is devoted to perennial crops.

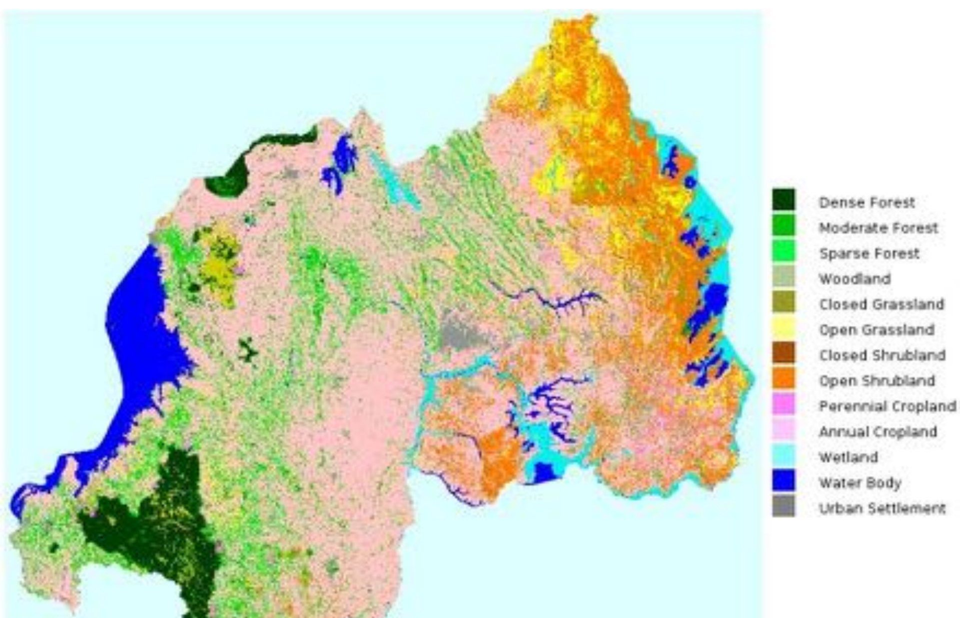

Figure 3.C.2.b-1 Land Use/Landcover for Rwanda[36]

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[36] Rwanda Land Cover 2015 Scheme II, RCMRD Geoportal, http://geoportal.rcmrd.org/layers/servir%3Arwanda_landcover_2015_scheme_ii

Rwanda Crop Data. Table 3.C.2.b-1 provides a summary of land use/land cover and crop area data from the latest (2020) Seasonal Agricultural Survey (SAS) by the National Institute of Statistics, Rwanda (NISR).[37] Among the agricultural land uses, hillside agricultural lands dominate. Including rangelands, total agricultural land use totaled around 1.5 million hectares (Ha) in 2020.

TABLE 3.C.2.b-1. 2020 LULC STATISTICS FOR RWANDA

LULC CODE	CATEGORY NAME	AREA (HA)	% SHARE
1.0	Consolidated tea plantations	17,821	0.7
1.1	Hillside agricultural land	1,343,933	53
2.1	Non-rice agricultural wetlands	55,807	2.2
2.2	Paddy rice wetlands	21,848	0.9
2.3	Non cropped wetlands	37,743	1.5
3.0	Rangeland	144,490	5.7
4.1	Urban settlements	31,612	1.2
4.2	Rural settlements	78,928	3.1
5.0	Bare land/rocks	15,404	0.6
6.0	Water bodies	135,295	5.3
7.0	National parks	241,455	9.5
8.0	Protected wetlands	12,201	0.5
9.0	Forest plantations	395,001	16
	Total	**2,531,538**	**100**

In theory, APV could be applicable to any crop; however, due to current uncertainties about its potential (for example, the level of existing shading for already shade-grown crops) and implementation costs for certain crop types (e.g., high supporting structures to get above the crop canopy), some

[37] Upgraded Seasonal Agricultural Survey Report located at: https://www.statistics.gov.rw/datasource/seasonal-agricultural-survey-2020.

perennial crop types have been excluded from current consideration. Based on the NISR SAS, these crop types are:

- Bananas: no information in the literature was identified regarding APV application to bananas.
- Fruits: some low growing crops are likely amenable to APV (as shown in European berry production); but tree orchards may not be amenable for technical or economic reasons, including height of the required APV array. Different fruit types are not broken out separately in the NISR SAS data.
- "Other crops": it isn't clear what other crop types are included in this category; however, coffee and tea would be among them. No information on APV application for coffee has been identified, although its application to tea cultivation seems promising. Regardless, this "other crops" category from the NISR SAS does not provide breakouts of specific crops, so it has been excluded from current consideration.

TABLE 3.C.2.b-2. LSP VALUES FOR VARIOUS CROP TYPES[38]

CROP	LSP (kLX)
Corn	80-90
Watermelon	80-90
Tomato	80
Taro	80
Cucumber	55
Pumpkin	45
Blueberry	45
Cabbage	45
Rice	40-45
Carrot	40
Turnip	40
Sweet potato	30
Lettuce	25
Green pepper	20-30
Spring onion	25

Crop Light Requirements and APV Technology Configurations. Each type of plant has its own light saturation point (LSP). Above that level, additional light is not needed to meet the daily photosynthetic requirements of the plant; and in some cases, the additional heat and dryness that comes along with the higher light exposure can stress the plant. Table 3.C.2.b-2 provides some examples of LSP for different crops (units are in thousand lux, kLX).[39] For perspective, depending on time of year, geographic location and atmospheric conditions, direct sunlight can provide a light intensity up to 100 kLX. High LSP values indicate a crop that is less tolerant to shading.

Another concept related to LSP is the light compensation point (LCP) for a crop. LCP is the intensity of light where the rate of carbon dioxide (CO_2) uptake by a plant (through photosynthesis) is equal to the rate of CO_2 loss through respiration back to the atmosphere. Figure 3.C-2.b.3 illustrates the relationship between LSP and LCP. As indicated in the chart, when light intensity increases above the LCP value, a plant's uptake of CO_2 will be greater than zero (meaning a gain in biomass via photosynthesis). The gains in CO_2 uptake will continue up to the point where the LSP value is reached. Available light at an intensity above the LSP value can be considered available for PV electricity production without affecting plant growth.

[38] D Sekiyama, Takashi & Nagashima, Akira. (2019), Solar Sharing for Both Food and Clean Energy Production: Performance of Agrivoltaic Systems for Corn, A Typical Shade-Intolerant Crop. Environments. 6. 65. 10.3390/environments6060065, https://www.researchgate.net/publication/333638552_Solar_Sharing_for_Both_Food_and_Clean_Energy_Production_Performance_of_Agrivoltaic_Systems_for_Corn_A_Typical_Shade-Intolerant_Crop.

[39] Another set of common units for LSP is 1 unit of photosynthetic photon flux density or PPFD (micro-mol/m^2-s). For sunlight, 1 PPFD = 54 lux.

Crops identified in the SAS were categorized into two different groups based on light requirements:

- High LSP: fodder crops; grains (mainly corn and sorghum); rice is also added here based on experimental work in Japan[40] which indicates that lighting requirements might be closer to other grains.
- Low to Moderate LSP: legumes and pulses (beans, including soybeans, and peas); vegetables (tomatoes may be included here but are not broken out separately); tuber and root crops (taro is one of these but is not a dominant component).

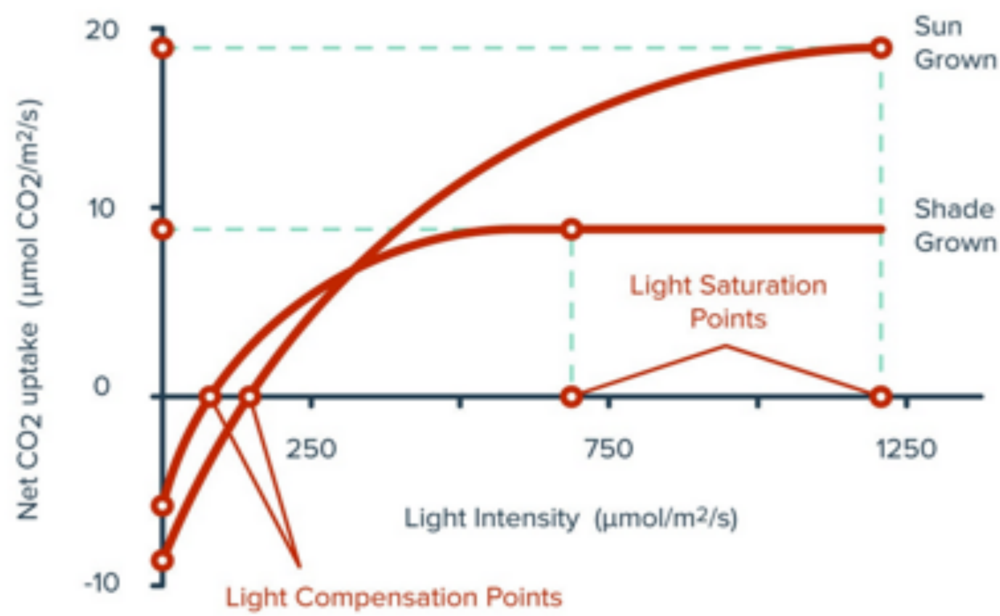

Figure 3.C.2.b-3. Relationship between LSP and LCP[41]

Larger "pore-spacing" is needed for crops with high LSP than for crops with low/moderate LSP. Each "pore" refers to the ground area that is not directly underneath the solar array (hence, pore spacing size is often dictated by the distance between rows; although panels could also be placed in a checkerboard pattern to also adjust pore size. Limited references from the literature (cited previously above) suggest the following assignments for pore-spacing for each of these crop categories:

- High: 30% GCR (70% pore-spacing); experimental studies from Japan referenced above for corn and rice indicate a range of 28 - 59% is possible. Since these results are based on fairly small plots in only one experimental location, a value at the lower end of the range is recommended to be conservative.
- Low to Moderate: 50% GCR (50% pore spacing); studies for APV application on these crops generally don't exceed 50%. It is possible that some crops with low light requirements could be grown without significant yield or quality impacts at GCR levels above 50%; however, this value is assumed to be the upper end of the range for this analysis.

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[40] Gonocruz, R.A.; Nakamura, R.; Yoshino, K.; Homma, M.; Doi, T.; Yoshida, Y.; Tani, A., "Analysis of the Rice Yield under an Agrivoltaic System: A Case Study in Japan," *Environments,* 2021, 8, 65. https://doi.org/10.3390/environments8070065.
[41] https://phenterminecombinationhvm.blogspot.com/2020/02/top-85-of-light-compensation-point-and.html.

Assuming conventional monocrystalline solar PV panels are used for the APV array, covering 100% of the crop area would yield a capacity per unit area value of about 0.191 kWp/m^2.[42] An additional 20% was added to the spacing to account for additional space needed for panel access and any auxiliary equipment. At 30% GCR recommended for high LSP crops, this value becomes 0.046kWp/m^2. At 50% GCR for low/moderate LSP crops, the value becomes 0.077 kWp/m^2. For reference, the distance between rows at the Rwamagana plant mentioned in Section 1.1 indicates a pore-spacing of about 44% (56% GCR).[43]

In addition to the consideration of light requirements for plants, APV planning is further complicated by the fact that there are many emerging technologies and configurations for the PV panels. Figure 3.C.2.b-4 provides illustrations of the two most common configurations for open-field APV technologies. Whether ground- or stilt-mounted, a key consideration is the pore-spacing of panels.

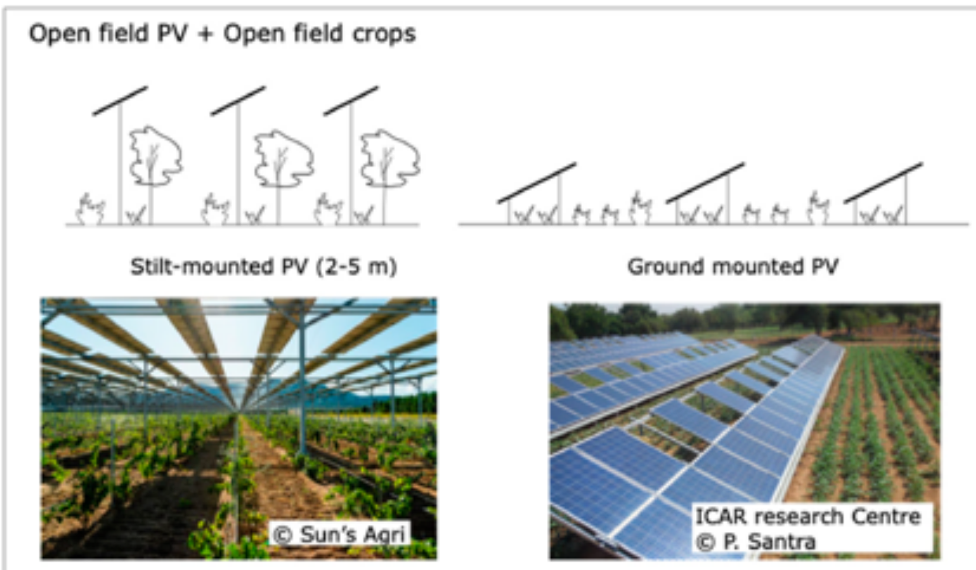

Figure 3.C.2.b-4. Typical APV Configurations[44]

APV systems may require panels to be mounted at varying heights to accommodate different crops or mechanical equipment. The height of panel placement also affects the amount of light reaching the crop. Typical ground-mounted systems will often have a ground surface directly beneath the panels where little if any light reaches it over the course of a day.

Emerging technologies and configurations include:

- Transparent PV panels: manufacturers are beginning to produce panels with varying degrees of transparency to photochemically-active radiation (PAR; light at the wavelengths required for

[42] Derived from specifications for a 320-watt Renogy monocrystalline panel which measures 1.67 m^2. https://www.renogy.com/320-watt-monocrystalline-solar-panel/.
[43] Derived from measurements of solar panel area and open area between panel rows using Google Earth.
[44] Toledo, C.; Scognamiglio, A., "Agrivoltaic Systems Design and Assessment: A Critical Review, and a Descriptive Model towards a Sustainable Landscape Vision (Three-Dimensional Agrivoltaic Patterns)". *Sustainability,* 2021, 13, 6871. https://doi.org/10.3390/su13126871.

photosynthesis, generally between 400 and 700 nanometers). In the near future, these types of panels will allow for smaller pore sizes (greater panel densities) for APV systems while still providing crops with sufficient daily PAR requirements.

- Bi-facial vertically-mounted solar panels: as shown in Figure 3.C-2.b.5 panels with solar PV cells on both sides can be mounted vertically along a north-south axis. This leaves no overhead panels and eliminates the potential need for elevated racking systems. This type of configuration also makes it easier to navigate cultivation equipment.

For this initial assessment of APV application in Rwanda, these emerging technologies and configurations are not considered in the approach for estimating technical potential. Not only is this because they have not yet been as widely applied as the more typical options shown in Figure 3.C.2.b-4 above, but also because the assumption of the typical arrays provides for a more conservative approach (one that likely underestimates the technical potential, rather than overestimates it).

Figure 3.C.2.b-5. Vertical Solar PV Arrays[45]

Crop Production Statistics. Crop production statistics are available from the NISR SAS as referenced above. As introduced above, there are three growing seasons; however, Season A is the season when most of the crop area is under cultivation (see Figure 3.C.2.b-6). Although it is not completely clear from the NISR, it appears that most of the Season B crop represents the second crop of double-cropped systems. Season C crops seem to represent a small set of crops that are cultivated in areas that are too wet during the other two seasons.

[45] These are Next2Sun systems installed in Austria and Germany. Taken from: Toledo, C.; Scognamiglio, A. "Agrivoltaic Systems Design and Assessment: A Critical Review, and a Descriptive Model towards a Sustainable Landscape Vision (Three-Dimensional Agrivoltaic Patterns)." *Sustainability,* 2021, 13, 6871. https://doi.org/10.3390/su13126871.

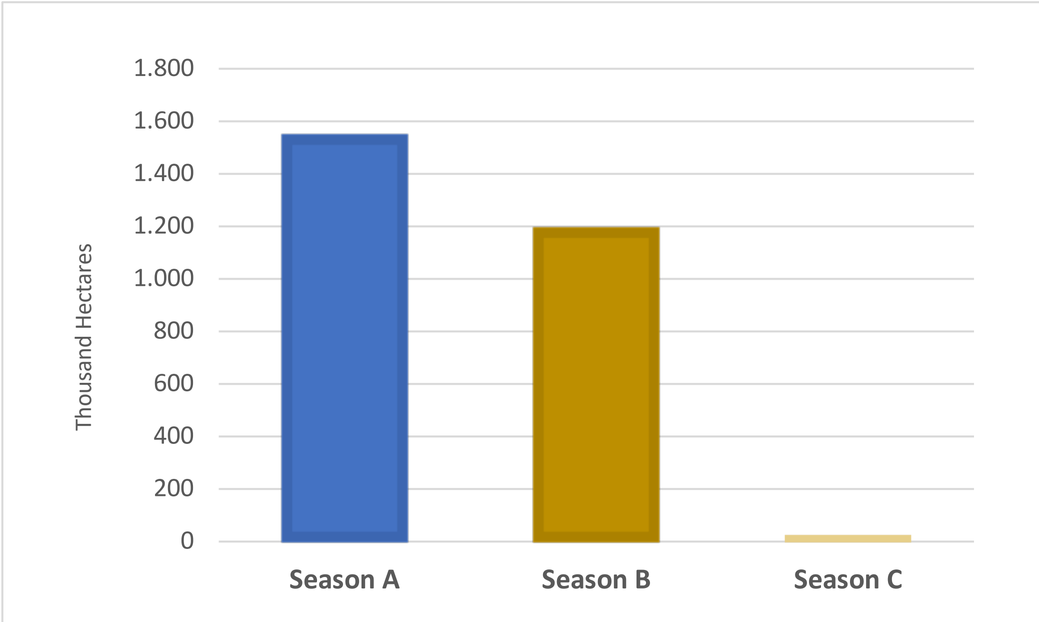

Figure 3.C.2.b-6 2020 Crop Area in Development by Season

To assign the total crop area into two categories representing either high LSP or low/moderate LSP, it was necessary to determine whether the crop types grown varied significantly between at least Season A and B.[46] If there aren't significant differences, then the crops grown during Season A should provide a good understanding of the light requirements for the cropland in each District across the seasons. For each Season, the 2020 NISR crop data were aggregated into the two different LSP categories and then compared. These comparisons are shown for each district in Figure 3.C.2.b-7 below.

[46] Due to the small amount of area for Season C, and that it is unclear whether it represents a third cropping season for the same agricultural areas in Season A and B or is totally separate, the area and crops grown in Season C are not considered.

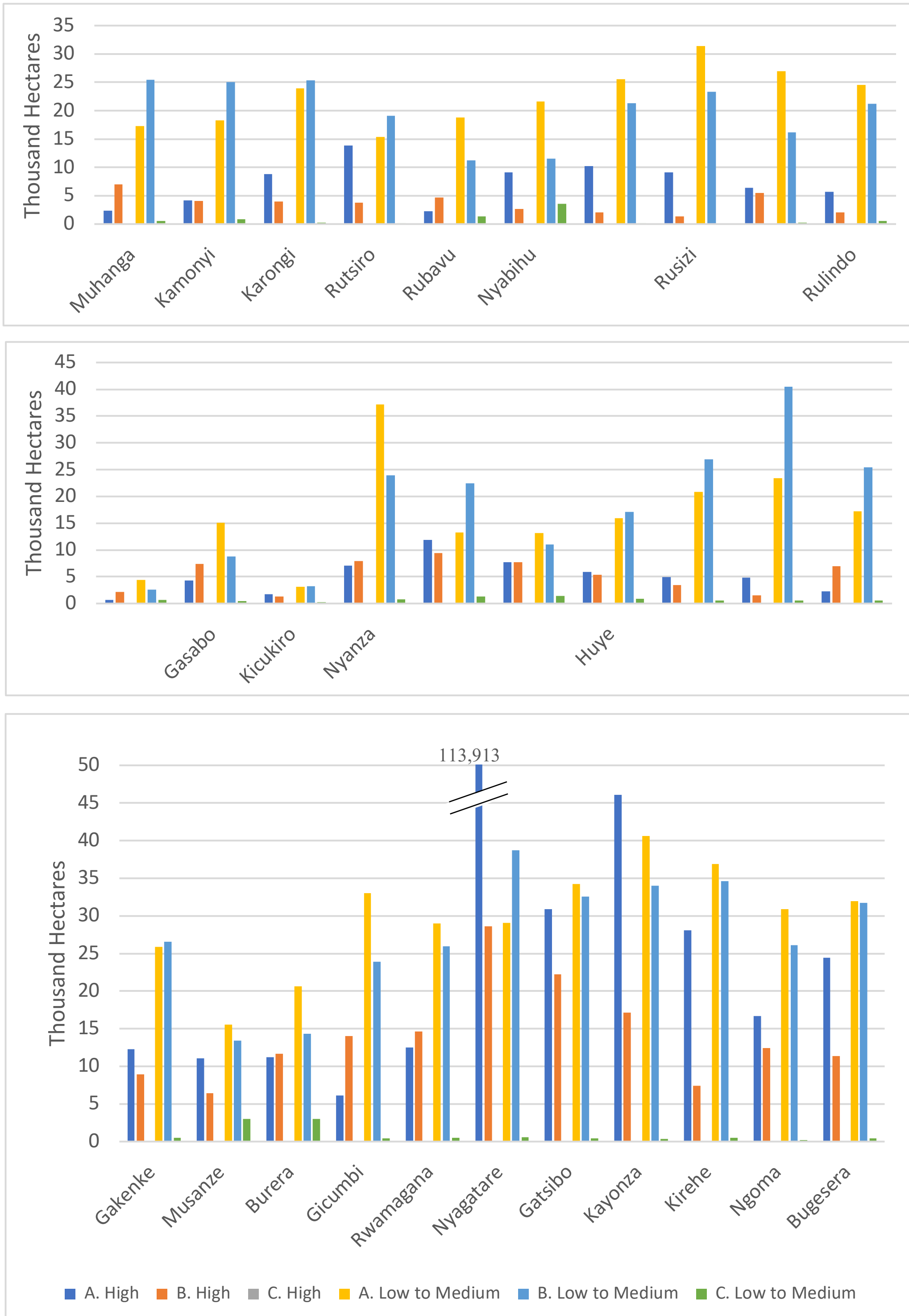

Figure 3.C.2.b-7. Comparison of High and Low/Moderate Crop Lighting Requirements by District, Crop Area Grouped by Light Requirements

As indicated in the district-level data in Figure 3.C.2.b-7 above, Season A crop area tends to be higher than Season B, although there are some exceptions. For example, Season B crop area for high LSP crops is greater than Season A in Nyarugenge, Gasabo, and Nyanza districts; however, the differences are small, and the crop areas involved are also small. Similarly, Season A area for low/moderate LSP crops is also higher than Season B with some exceptions (such as Gisagara, Huye, Nyamagabe, Ruhango, and a few others). Overall, Season A appears to be the best season to use to characterize the light requirements for crops grown within each district, since the largest areas of high LSP crops tend to be grown during this season (and it is most important to identify these areas to avoid over-estimates of available area for higher density APV systems).

Figure 3.C.2.b-8 provides a district-level summary of Season A crop areas divided into high and low/medium light requirements. As indicated in these results, there is significant variation among the districts. Nyagatare district, for example, is dominated by crops with high LSP. A fair number of districts are dominated by crop types with low/moderate LSP, while others are about evenly divided among high and low/moderate LSP.

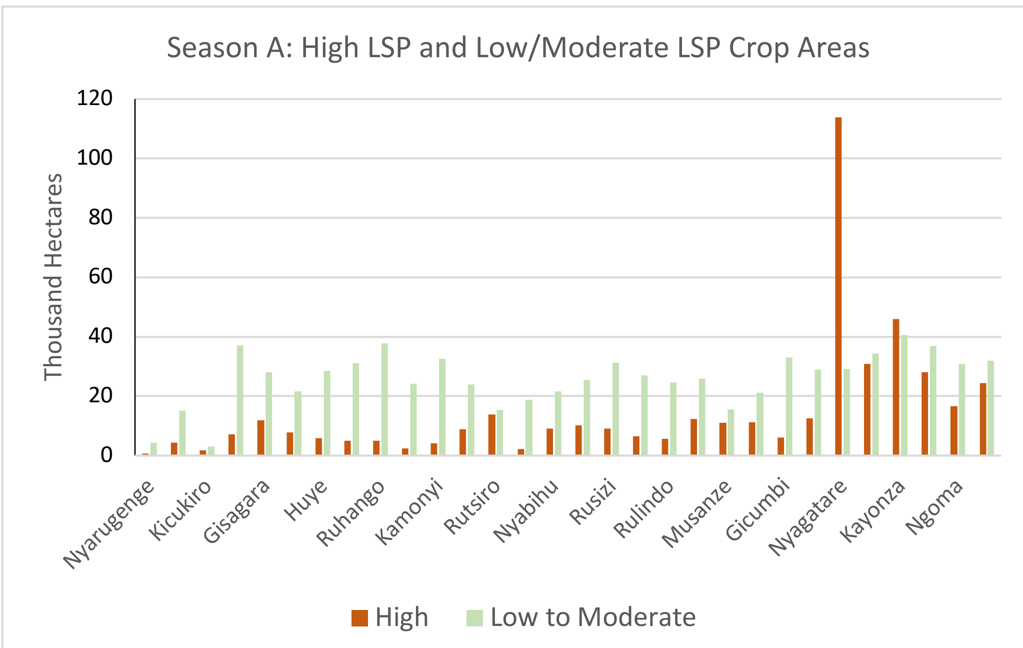

Figure 3.C.2.b-8. Season A District-Level Crop Areas by Lighting Requirements

Estimate of Country-Wide Technical Potential. The annual and perennial cropland area was pulled from the Scheme II land cover raster layer (see Figure 3.C.2.b-1) and converted to vector format. From this area, the area of greater than 45% slope was subtracted to remove the most highly sloping areas that would be the most difficult for installing solar systems. The area of land greater than 45% slope was developed from the DEM layer as described in the General GIS Methods section. Resulting polygons were divided using the QGIS subdivide tool. Subdivide tool splits polygons based on the number of nodes, so the subdivide tool was run on larger polygons, with the number of nodes decreased, until all polygons were below 200 ha in size. To determine the district for each polygon, a layer with the centroid of each polygon was intersected with the district map, this data was then linked back to the polygon layer based on polygon ID number. The resulting APV polygon layer includes information on type of cropland (annual or perennial) and district.

The district-level data breakdowns of crop area by lighting requirements represented in Figure 3.C.2.b-8 above were then allocated to each polygon. Some uncertainty occurs at this step, since the district-level characterization might not be representative of the crops grown in certain polygons; however, much more detailed crop data than the district-level data available in the NISR SAS would be needed to develop polygon-specific estimates. At the polygon level, the technical potential PV capacity is calculated as follows for crops with high LSP:

Polygon A Technical Potential PV Capacity for High LSP Cropland (peak kWp) =

Total Crop Area for Polygon A (m^2) x High LSP Crop (%) x High LSP Capacity/unit area (kWp/m^2)

For capacity per unit area, CCS selected a value of 0.046 kWp/m^2 (30% GCR; as described above). The value selected for low/moderate LSP was 0.077 kWp/m^2 (50% GCR). For each polygon, the total capacity was calculated by adding the capacity calculated for high LSP crops to the capacity calculated for low/moderate LSP crops.

To calculate the technical potential for APV generation, the polygon level PVOUT values from Solargis (documented in Section 1.1 above) were used along with the capacity values calculated above:

Polygon A Technical Potential PV Generation (kWh/yr) =

Polygon A TP Capacity (kWp) x PVOUT (daily kWh/kWp) x 365 days/yr

Figures 3.C.2.b-9 and 3.C.2b-10 are maps showing technical potential APV capacity (annual MWh/Ha peak MW/Ha). **A total technical potential (exploited and unexploited) of 753 GW of "nameplate" capacity was estimated for APV in Rwanda. This peak capacity could produce almost 957,000 GWh of electricity annually.**

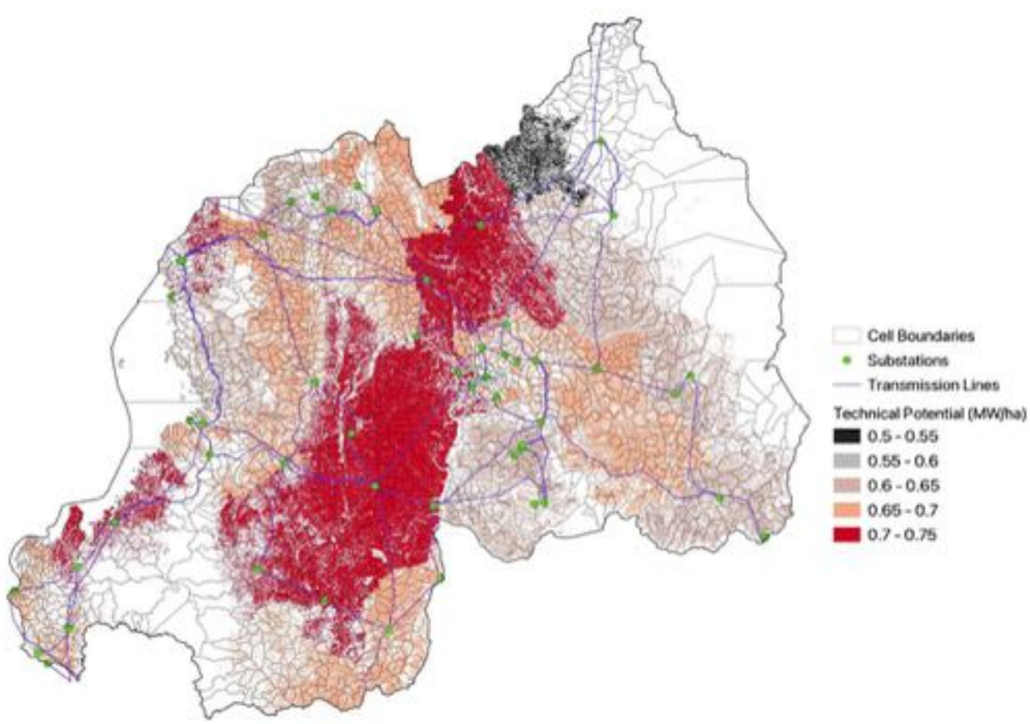

Figure 3.C.2.b-9 APV Technical Potential (Annual MWh/Ha)

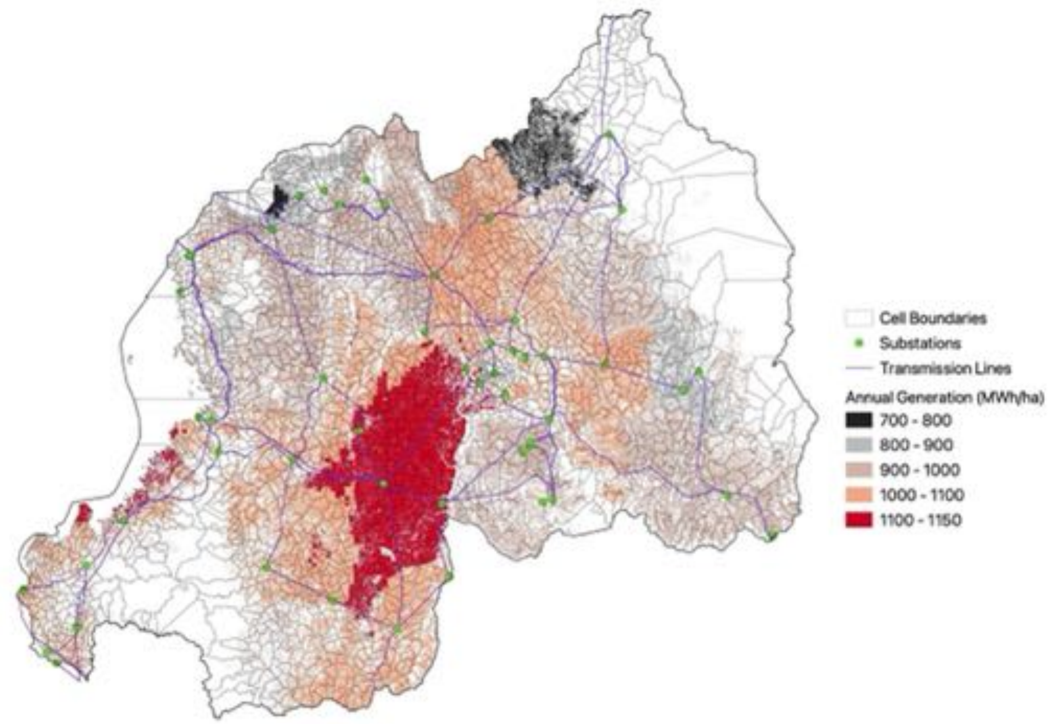

Figure 3.C.2.b-10 APV Technical Potential (peak MW/Ha)

3.C.2.c. Floating PV Systems

Floating PV systems (FPVs) are applied directly to water surfaces, most often those such as ponds, lakes, or impoundments that do not have flowing water or are significantly affected by tidal movements. Figure 3.C.2.c-1 provides a typical example. PV panels are attached to a floating structure which in turn is connected to an onshore distribution system or T&D substation.

Figure 3.C.2.c-1. Example FPV System being Installed in the US[47]

[47] Source: US DOE NREL: https://www.nrel.gov/state-local-tribal/blog/posts/floating-solar-photovoltaics-could-make-a-big-splash-in-the-usa.html.

In a recent assessment of technical potential for FPV application in the US, NREL limited its assessment to only man-made bodies of water.[48] This limitation was put in place to avoid complications associated with natural bodies of water, including recreational activities, fishing, and transportation. Still, the assessment indicated that there were over 24,000 water bodies with technical potential in the 48 contiguous states with a total surface area of 2.2 million Ha. Additional benefits for FPV systems include reduced evaporation of water (important especially in arid regions), and that the cooling effects of water provide a boost to electricity production (gains have been cited to range from 1.5 - 22%).

Since the application of FPV is still relatively new with significant global installations occurring only since around 2018, there are still some key unknowns about their impacts. A key one for Rwanda and other countries with lots of natural water bodies is to what extent FPV systems can negatively impact the aquatic ecosystem to which they are applied (for example, by limiting PAR to aquatic plant life).[49] Sufficient background information on this issue was not identified in on-line data searches. As a result of this issue, as well as the need to avoid impacts to fishing areas, recreation, transport, and other activities, the available surface areas for Rwanda's lakes were significantly restricted to derive some initial estimates of technical potential. For all lakes and impoundments other than Lake Kivu, the assumed upper limit of surface water availability for FPV systems was set at 5%. For Lake Kivu, the assumed upper limit was set at 2.5%. Lake surfaces within or abutting protected areas were removed from consideration of technical potential. These assumptions are based only on experts' judgment and can be further refined with input from REG.

After the available water surface areas were characterized, a value of 0.10 kWp/m^2 was applied to estimate the capacity of FPV that could be installed. This value was taken from the same NREL study cited above addressing the technical potential of FPV in the US. Then, the same PVOUT data from Solargis described above for utility-scale solar PV were applied to calculate daily generation for each polygon. To develop conservatively low estimates of electricity production, no assumed increase in electricity production was applied to the PVOUT data to account for the potential cooling of panels mentioned above.

Figure 3.C.2.c-2 is a map of water surfaces in Rwanda and the corresponding technical potential. **Note that the locations of each marker on the map indicate an amount of capacity available for that water body; they do not indicate optimal or proposed locations for FPV facilities (FPV locations should be considered along the shorelines of large water bodies, such as Lake Kivu).**

[48] https://pubs.acs.org/doi/10.1021/acs.est.8b04735.
[49] Note that, depending on where they are applied, FPV systems could have either positive or negative ecosystem impacts. Negative impacts could include reduced ecosystem productivity, and positive impacts could include reduced warming of the water body, reduced evaporation, reduced algal growth and potential for eutrophication. See for example: https://www.sciencedirect.com/science/article/pii/S0038092X2100116X and https://repositorio.uchile.cl/bitstream/handle/2250/174830/Floating-photovoltaic-plants.pdf?sequence=1.

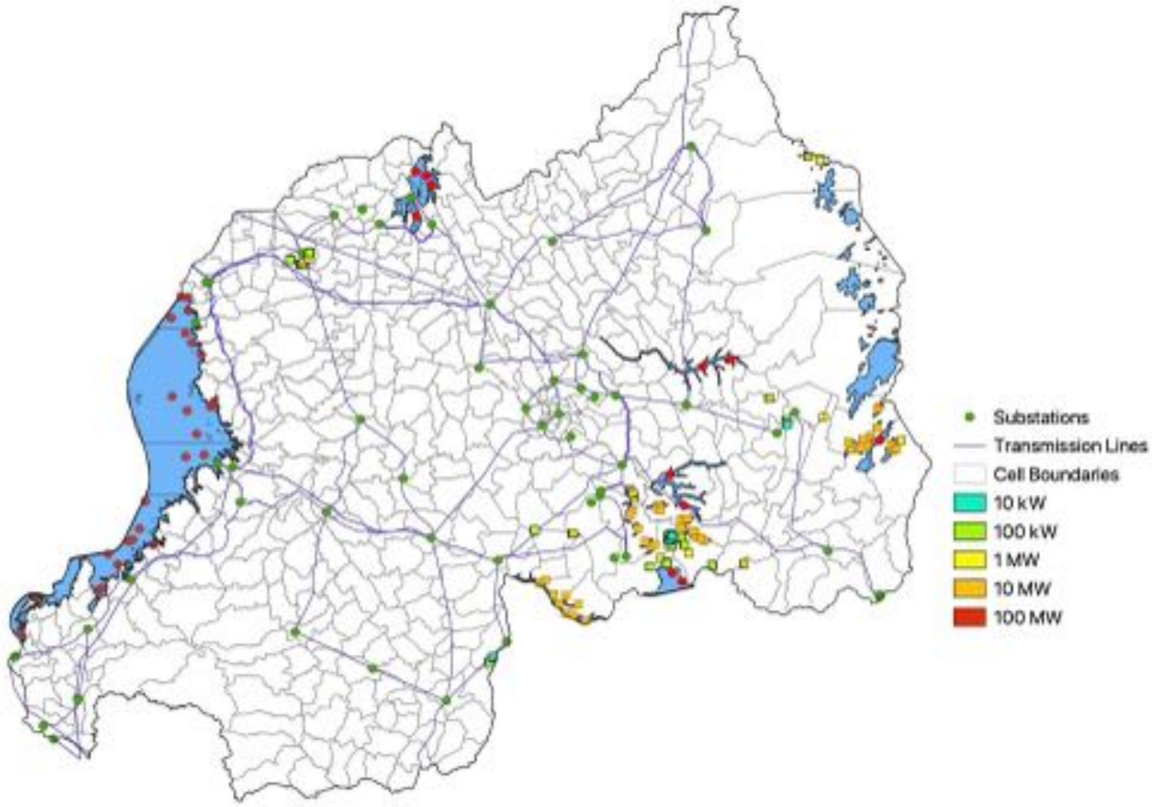

Figure 3.C.2.c-2. Geographic Distribution of FPV Technical Potential

The total technical potential estimated for FPV in Rwanda (exploited and unexploited) is 4.0 GW of "nameplate" capacity. The area represented is 2.7% of the total surface water area of the country. **This capacity could produce over 6,224 GWh of electricity annually.** A key need for future assessments of FPV potential are GIS data that include not just the mostly natural bodies of water shown in Figure 3.C.2.c-2 above but also the potentially numerous smaller man-made bodies of water used for irrigation or flood control, aquaculture, industrial/mining operations, etc. Since those water bodies generally don't have similar issues in regard to competing needs for the water surface, a large fraction of the available surface could be considered available for FPV systems. Figure 3.C.2.c-3 shows an example FPV system mounted over an irrigation pond at a winery in California, USA that covers a large portion of the surface offering additional benefits in reduced evaporation. Rwanda data on the location and sizes of man-made water bodies would allow for the characterization of additional FPV technical potential for the country.

Figure 3.C.2.c-3. FPV System over a Man-Made Water Body Surface

3.C.2.d. Distributed PV Programs

Distributed PV programs refer to rooftop programs meant to stimulate uptake of new solar PV rooftop systems on buildings in the following sectors: public service (institutional); industrial; commercial; and residential. Results for the first 3 building sectors are presented first below, and then the residential sector is addressed. However, for all building types, the first steps and data sources are as follows:

1. Determine which buildings are likely to already be tied into the electrical grid or could be based on their proximity.
    a. Within QGIS, the "buildings database"[50] and medium voltage (MV) transmission lines data were loaded. Note that this step could also be done with a spatial coverage of the distribution system; however, no distribution system GIS layer has been obtained by the project.
    b. Another database showing the locations of electrical meters[51] was then loaded into QGIS.
    c. Determine a reasonable buffer around the MV lines to identify meters that are likely to be grid-tied. Review of the meter and MV line locations within QGIS indicated that a 5 km buffer was adequate for capturing the locations of most customer meters.
2. Within QGIS characterize each building by customer sector (residential, public service, commercial, large and small industrial) by assigning each building to the nearest meter.
3. Remove buildings that are outside of the MV line buffer. This step removed 18,723 buildings of the total 2,385,710 buildings in the database. Buildings outside of the MV line buffer may be considered later in the project to identify locations for future mini-grid or SHS programs.

[50] Jean Claude NTIRENGANYA, Spatial Data Infrastructure Specialist, Rwanda Land Management and Use Authority.
[51] The electricity meter data was in a set of transmission infrastructure files provided to CCS by REG.

4. The results of this step were then used to calculate the technical potential for each building type as summarized below. During this step, there were approximately 2,700 large buildings with > 750 m^2 of rooftop area and ranging up to almost 13,000 m^2 of roof area that were initially coded as residential buildings based on the nearest meter. While it is possible that some of these buildings really are very large homes, it seems more likely that they are a nonresidential building type. The most likely appropriate building sector is commercial since these make up more than half of the non-residential buildings. So, these buildings were re-coded as commercial buildings.

Commercial, Public Service, and Industrial Buildings. For each of these sectors, the TECHNICAL POTENTIAL for PV capacity was calculated for each rooftop by applying a scaling factor of 0.7 and a rooftop PV packing factor of 8.5 m^2/kWp. The scaling factor accounts for portions of a rooftop that are already taken up by other equipment (such as heating, ventilation, and air conditioning equipment). The packing factor addresses the rooftop area required by the PV panels themselves. These values were taken from a resource assessment conducted by CCS in southern China.[52] Similar inputs were not identified for these building types in Rwanda or elsewhere in eastern Africa. Considering a rooftop with an area of 1,000 m^2, the TECHNICAL POTENTIAL of PV system capacity would be:

technical potential peak capacity (MW) = 1,000 m^2 x 0.7 x kWp/8.5 m^2 x 1 MWp/1,000 kWp = 0.082 MWp

From the capacity values estimated above for each building, an annual system output in MWh was then calculated using the daily PVOUT (daily kWh/kWp) introduced previously. For example, using the same 1,000 m^2 building area TP capacity value estimated above:

technical potential generation (MWh/yr) = 0.082 MWp x 4.17 kWh/day/kWp x 365 days/year = 125 MWh

To support the work to follow that assesses the economic potential (EP) of different solar PV programs, it is useful at this stage to summarize the results by rooftop size. This is because the technology costs addressed in Section 1.6 are expected to vary by system size, because of the economies of scale for such large systems (for example, as compared to smaller residential systems). Based on recent US data, NREL estimated 2020 installed costs for a typical residential rooftop PV system were $3.12 watt of alternating current (Wac), while a 200 kW rooftop system in the commercial sector was estimated to cost $1.96 Wac to install in 2020.[53] Meaningful differences in installed costs will likely occur as system sizes increase by orders of magnitude, so the following size ranges were applied to characterize each rooftop system as either large (L), medium (M), or small (S):

- S: <100 kW direct current (kWdc)
- M: 100 kWdc to 1,000 kWdc
- L: > 1,000 kWdc

[52] See the link to the final report for this project on this web page: https://www.climatestrategies.us/projects-all/south-china-renewable-energy-implementation-project. These inputs were reviewed and revised based on input from the local solar energy industry association.
[53] https://www.nrel.gov/news/program/2021/documenting-a-decade-of-cost-declines-for-pv-systems.html.

The TECHNICAL POTENTIAL estimates summarized in Tables 3.C.2.d-1 through 3.C.2.d-5 below should be understood to be upper-level estimates for the following reasons:

- It was assumed that all rooftops are structurally sound enough to accommodate solar PV systems.
- No factors have been applied to account for possible shading effects on rooftops (e.g., due to adjacent structures or vegetation).
- No factors have been applied to account for roof orientation or pitch. These should be less of a factor in areas like Rwanda near the equator and where pitched roofs are uncommon.
- Any existing rooftop PV systems have not been included in the assessment.

Also, there are uncertainties at the building sector level, since the GIS methods applied to assign building types (i.e., nearest meter type to a building) may have resulted in miss-matches. As indicated in Table 1.4-5, there are over 240,000 non-residential buildings in the country with an estimated total **technical potential (exploited and unexploited) of 3.6 GW "nameplate" capacity for non-residential distributed PV, which could produce almost 5,400 GWh/year**. There are only a dozen buildings that are large enough to support the largest sized rooftop systems greater than 1 MW in size and most of these are large industrial buildings outside of the Kigali region. There are hundreds of buildings, both within and outside of Kigali, that could host medium-sized systems in the 100 kW to 1 MW range.

TABLE 3.C.2.d-1. ROOFTOP SOLAR PV TECHNICAL POTENTIAL FOR COMMERCIAL BUILDINGS

AREA	SYSTEM SIZE (S,M,L)	NUMBER OF BUILDINGS	CAPACITY (MW)	ANNUAL GENERATION (MWH)
Kigali	L	1	1	1,728
	M	487	88	133,495
	S	12.050	197	298,190
Other Areas	L	2	2	3,136
	M	442	70	104,316
	S	98,949	853	1,270,557
Total		**11,931**	**1,212**	**1,811,422**

TABLE 3.C.2.d-2. ROOFTOP SOLAR PV TECHNICAL POTENTIAL FOR PUBLIC SERVICE BUILDINGS				
AREA	SYSTEM SIZE (S,M,L)	NUMBER OF BUILDINGS	CAPACITY (MW)	ANNUAL GENERATION (MWH)
Kigali	L	0	0	0
	M	117	19	28,076
	S	5,920	98	148,591
Other Areas	L	0	0	0
	M	202	31	45,882
	S	76,839	722	1,076,576
Total		**83,078**	**870**	**1,299,125**

TABLE 3.C.2.d-3. ROOFTOP SOLAR PV TECHNICAL POTENTIAL FOR LARGE INDUSTRIAL BUILDINGS				
AREA	SYSTEM SIZE (S,M,L)	NUMBER OF BUILDINGS	CAPACITY (MW)	ANNUAL GENERATION (MWH)
Kigali	L	0	0	0
	M	88	18	27,831
	S	388	9	13,037
Other Areas	L	9	27	40,363
	M	31	9	12,737
	S	2,315	16	23,434
Total		**2,831**	**78**	**117,402**

TABLE 3.C.2.d-4. ROOFTOP SOLAR PV TECHNICAL POTENTIAL FOR SMALL INDUSTRIAL BUILDINGS				
AREA	SYSTEM SIZE (S,M,L)	NUMBER OF BUILDINGS	CAPACITY (MW)	ANNUAL GENERATION (MWH)
Kigali	L	0	0	0
	M	26	5	7,674
	S	547	10	14,434
Other Areas	L	0	0	0
	M	8	2	2,363
	S	3,591	29	42,838
Total		**4,172**	**45**	**67,308**

TABLE 3.C.2.d-5. ROOFTOP SOLAR PV TECHNICAL POTENTIAL FOR ALL NON-RESIDENTIAL BUILDINGS				
AREA	SYSTEM SIZE (S,M,L)	NUMBER OF BUILDINGS	CAPACITY (MW)	ANNUAL GENERATION (MWH)
Kigali	L	1	1	1,728
	M	718	130	197,075
	S	18,905	314	474,252
Other Areas	L	11	29	43,500
	M	683	111	165,297
	S	181,694	1,620	2,413,406
Total		**202,012**	**2,205**	**3,295,258**

Figure 3.C.2.d-1 provides a map showing the distribution of technical potential throughout the country for non-residential buildings. As indicated in this map, much of the technical potential is located in the Kigali region; however, good resources are also spread all around the country.

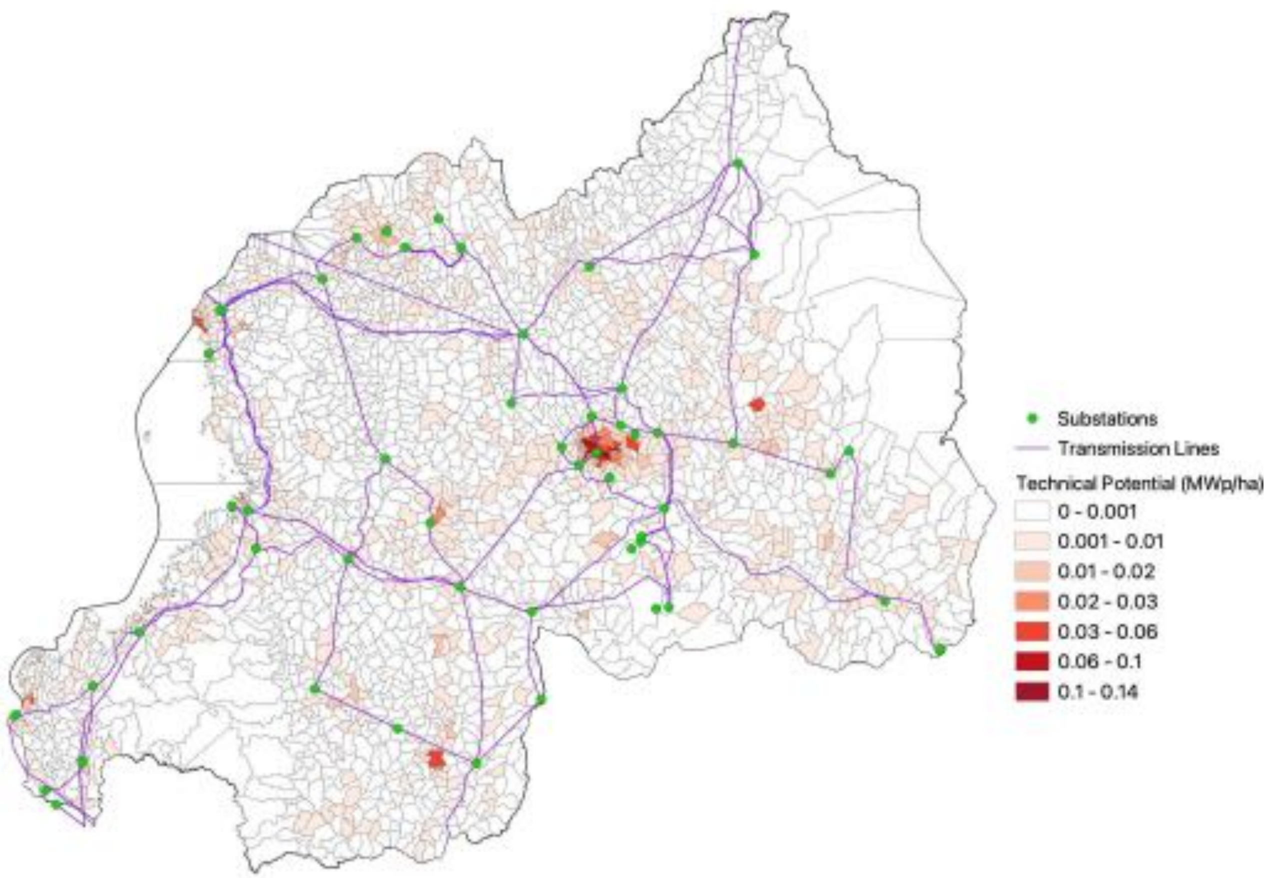

Figure 3.C.2.d-1. Map of Commercial, Public Service and Industrial Rooftop PV Technical Potential

Residential buildings. Table 3.C.2.d-6 provides a summary of the technical potential calculations for on-grid residential rooftop PV programs at the District level. The same data and methods applied above for non-residential buildings were applied with only one exception. The rooftop scaling factor of 0.7 applied to non-residential buildings to account for portions of a typical rooftop not available for PV panels was not applied. Additional survey work using high resolution imagery in QGIS could be employed to determine whether a scaling factor is necessary, as well as an appropriate value; however, the application of such a factor is not expected to have a substantial impact on these initial results.

As indicated in the table below, **a total of over 33 GW of "nameplate" capacity (exploited and unexploited) for residential distributed PV is available.** This capacity could generate almost 50,000 GWh of electricity each year. The same uncertainties as indicated above for non-residential buildings apply, including that these initial estimates do not address existing residential rooftop systems in areas where they could be considered part of the electrical grid.

Figure 3.C.2.d-2 below provides a map showing the distribution of technical potential throughout the country for residential buildings. There is a total technical potential of over 33 GW of peak capacity throughout the country. Similar to the non-residential buildings sector above, as indicated in this map, much of the technical potential is located in the Kigali region; however, good resources are spread all through the country.

TABLE 3.C.2.d-6. ROOFTOP SOLAR PV TECHNICAL POTENITAL FOR ALL RESIDENTIAL BUILDINGS

DISTRICT	ROOFTOP AREA (M^2)			TECHNICAL POTENTIAL	
	BUILDINGS <300 M^2	BUILDINGS 300-750 M^2	TOTAL	NAMEPLATE CAPACITY (MW)	GENERATION (MWH/YR)
Bugesera	12,130,931	551,883	12,682,814	1,492	2,304,288
Burera	5,309,130	187,505	5,496,635	647	919,632
Gakenke	7,280,908	295,585	7,576,493	891	1,289,390
Gasabo	20,361,600	3,085,360	23,446,960	2,758	4,158,692
Gatsibo	10,242,829	336,182	10,579,011	1,245	1,870,408
Gicumbi	6,971,748	253,860	7,225,609	850	1,257,836
Gisagara	5,049,117	196,369	5,245,486	617	956,928
Huye	7,856,389	714,644	8,571,033	1,008	1,545,651
Kamonyi	8,540,116	453,833	8,993,949	1,058	1,611,957
Karongi	8,133,159	493,313	8,626,471	1,015	1,569,820
Kayonza	8,655,050	327,767	8,982,817	1,057	1,573,125
Kicukiro	16,177,598	2,175,985	18,353,583	2,159	3,290,016
Kirehe	10,007,764	437,063	10,444,827	1,229	1,845,276
Muhanga	9,762,091	498,252	10,260,343	1,207	1,799,286
Musanze	12,145,929	680,440	12,826,369	1,509	2,049,794
Ngoma	7,597,339	312,645	7,909,983	931	1,396,537
Ngororero	4,847,103	301,273	5,148,376	606	876,519
Nyabihu	4,738,604	315,099	5,053,703	595	815,461

TABLE 3.C.2.d-6. ROOFTOP SOLAR PV TECHNICAL POTENITAL FOR ALL RESIDENTIAL BUILDINGS					
	ROOFTOP AREA (M2)			TECHNICAL POTENTIAL	
DISTRICT	BUILDINGS <300 M2	BUILDINGS 300-750 M2	TOTAL	NAMEPLATE CAPACITY (MW)	GENERATION (MWH/YR)
Nyagatare	12,177,522	531,872	12,709,393	1,495	2,249,624
Nyamagabe	6,266,633	342,416	6,609,049	778	1,134,366
Nyamasheke	9,222,933	424,791	9,647,724	1,135	1,702,065
Nyanza	5,620,162	296,314	5,916,477	696	1,079,433
Nyarugenge	9,998,323	857,034	10,855,357	1,277	1,929,945
Nyaruguru	4,081,129	163,136	4,244,266	499	731,001
Rubavu	9,723,846	695,771	10,419,617	1,226	1,766,329
Ruhango	7,755,803	309,738	8,065,540	949	1,457,846
Rulindo	6,233,650	267,836	6,501,486	765	1,121,722
Rusizi	]12,222,789	746,143	12,968,932	1,526	2,286,503
Rutsiro	5,269,122	232,825	5,501,947	647	972,081
Rwamagana	11,199,676	464,816	11,664,492	1,372	2,071,261
Total	**265,578,992**	**16,949,749**	**282,528,741**	**33,239**	**49,632,791**

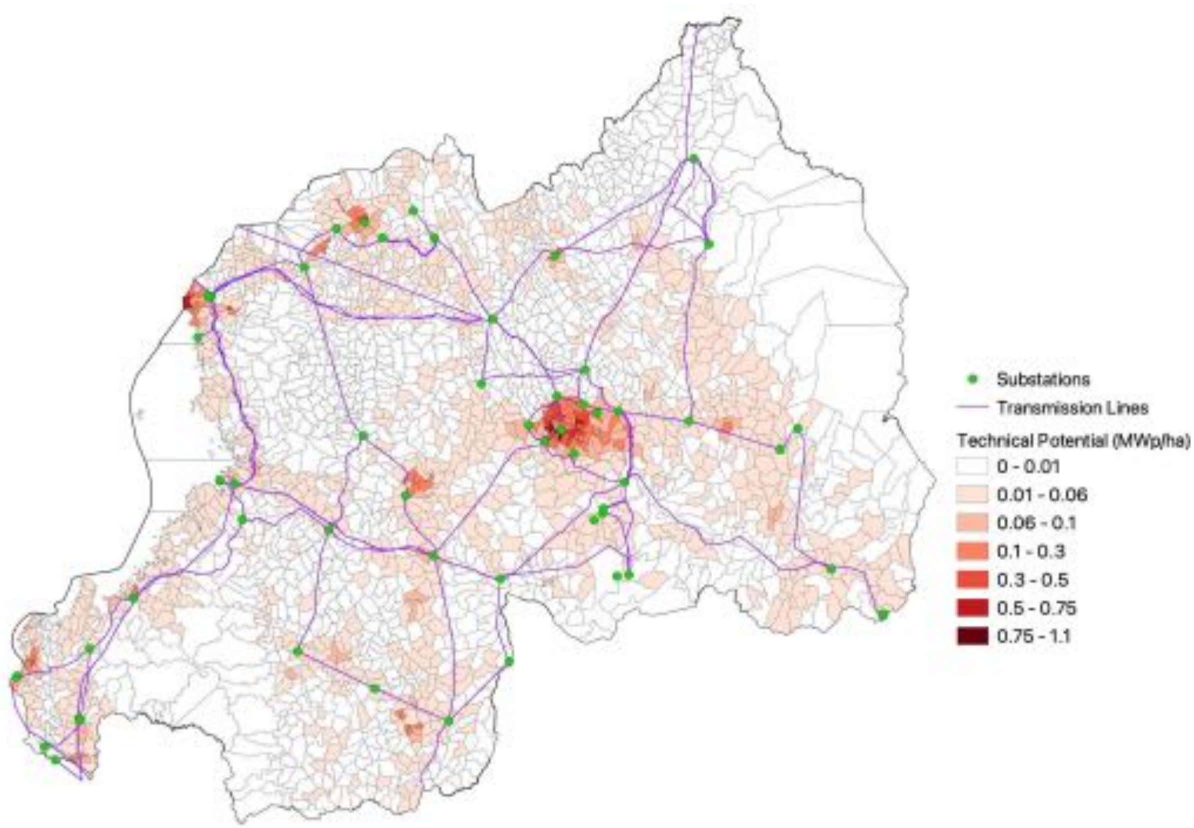

Figure 3.C.2.d-2. Map of Residential Rooftop PV Technical Potential

3.C.3. GRID-INTEGRATION COSTS

For each of the **non-distributed solar PV** applications above, the costs for grid integration were calculated for each of the polygons indicated to have some amount of technical potential (see the sections above for each solar technology application on the spatial analysis methods used to construct these polygons). For **distributed solar PV applications,** the costs to integrate the rooftop system into the electrical grid will be captured within the installation costs provided in Section 1.6 (i.e., there are no additional costs to run transmission lines, etc. for these programs). Grid integration costs were estimated based on the position of the centroid of each polygon.

Grid integration costs include those estimated for new medium voltage (MV; <110 kV) transmission lines (to connect a PV project to a substation), substations or substation upgrades, access roads and site land acquisition. These grid integration costs are just a portion of the total implementation cost for a solar technology. The remaining costs for purchase, installation and operations and maintenance of the technologies themselves are added during energy modeling in LEAP.

QGIS was used to calculate the distance to the nearest road, nearest high voltage (HV) line, and nearest substation. In the case of substations, distances to substations that will exist on the grid in 2027 were used for this assessment.

Table 3.C.3-1 below provides a summary for each of the integration cost components used to estimate total integration costs for each polygon with solar PV technical potential. Some of this information was available from REG in data gathered during Phases 1 and 2 of the project. However, in other cases, data gaps were filled using information from the literature. The same costing routine will be used for other new generation resources based on their location.

For any project, there will be a cost for a new road to the site and land acquisition. The values applied are indicated in Table 3.C.3-1. Notably, for land use, it was assumed that for all solar PV projects, a project developer would acquire the land needed, rather than leasing it. If REG believes that the land is more likely to be leased in some cases (e.g., for agricultural land or for surface waters), then the analysis can be adjusted with appropriate assumptions about land lease rates.[54] The current value in Table 1.5-1 is a placeholder based on sales of agricultural land.[55] Other options for payments for the lands required to host PV projects are also possible. For example, on agricultural land, a project developer and landowner could enter into an agreement whereby the project developer pays a royalty fee to the landowner based on electricity sales.

[54] If modeled as land lease rates, the cost of land acquisition would be removed from the grid integration costs, and the land costs would be modeled as part of the annual operating costs within LEAP.

[55] Future improvements to this analysis should include better representations of land acquisition costs. The value currently used is probably best applied to agri-voltaic projects where a land purchase is required by the project developer. So, a better value here for utility-scale projects would be representative of non-urban and non-agricultural lands (i.e., those lands included in the technical potential assessment). Land acquisition costs likely also vary spatially within a land use; for example, land costs are likely greater near urban centers.

TABLE 3.C.3-1. GRID INTEGRATION COST INPUTS

ITEM	VALUE	UNITS	NOTES AND CITATIONS
MV Transmission Line cost	70,000	$/km	REG provided the following values (<66 kV lines): Steel poles Distribution lines=140K USD/km; Distribution lines with Concrete poles cost is 70K USD/km; Distribution lines with Wooden poles cost is 54K USD/km. The value associated with concrete poles was selected.
New Substation cost	300,000	$/MW	Value from the Rilima Substation (Industrial Park) from REG Transmission Projects Database. This was the only substation cost value broken out separately in the REG database. This compares to a median value of ~$205k/MW or MVA for substations less than 50 MVA provided in this study of unit costs for sub-Saharan Africa. (https://www.eu-africa-infrastructure-tf.net/attachments/library/aicd-background-paper-11-unit-costs-summary-en.pdf). It is assumed that these costs include the costs for any land required.
Substation Upgrade cost	115,000	$/MW	Cost for a small (<10 MVA) transformer (https://peguru.com/2019/08/power-transformer/) is $600,000 ($60k/MVA). This compares to an average of $115k/MVA for installed costs for distribution transformers in the 1 - 2.5 MVA size range from NREL's Equipment Cost Database (https://data.nrel.gov/submissions/101). The NREL value was selected since it addresses installed costs. The costs for addition of a step-up transformer at the nearest substation is assumed to represent the bulk of substation upgrade costs required to integrate a new utility-scale solar PV system into the electrical grid.
Width of required road access	4.0	m	Assumed
Road Construction Cost	15,000	$/km	Values for African locations for unpaved roads range from around $8 - 20k/km based on this UK data, which is around 20 years old (https://assets.publishing.service.gov.uk/media/57a08bd7e5274a27b2000dc3/TI_UP_HD_Feb2007_Cost_of_Roads_in_Africa.pdf). Value selected is the value shown for Uganda. Site access roads are assumed to be unpaved. By contrast, AFDB Study provided a range of $150-400k/lane-km for construction/rehab of paved roadways in East Africa. (https://www.afdb.org/fileadmin/uploads/afdb/Documents/Publications/Study_on_Road_Infrastructure_Costs-_Analysis_of_Unit_Costs_and_Cost_Overruns_of_Road_Infrastructure_Projects_in_Africa.pdf.) This study did not provide any construction for simple unpaved access roads. However, the costs per lane-km for re-graveling/periodic maintenance were on the order of $10k/lane-km (Table 5-1).
Land acquisition per m^2	4.45	$/$m^2$	Placeholder. Average sales price of agricultural land in RW from this 2016 paper: https://openknowledge.worldbank.org/bitstream/handle/10986/24707/Sustaining0the0gistration0in0Rwanda.pdf?sequence=1&isAllowed=y. Used for technologies where land is expected to be purchased for installation of a technology application.
Land acquisition per MW	104,500	$/MW	Calculated from per-area land acquisition cost and MW capacity per unit site area.

After assessing land requirements, for each polygon centroid, two different cost options for grid integration were evaluated, and the lower cost option was selected to represent the grid integration costs for that polygon (each of these options includes the costs for building a road to access the site and the cost of associated land for the road):

1. Integration via an existing substation, includes the costs for an MV line to the nearest substation and the required upgrades to the substation to accommodate the project. For the latter cost component, based on available data, it was assumed that the addition of a step-up transformer represents the majority of costs.
2. Integration via a new substation, includes the costs for an MV line to a new substation and the new substation costs. The location of the new substation is assumed to be adjacent to the nearest HV line to the polygon centroid.

These two different options are shown graphically in Figure 3.C.3-1 below.

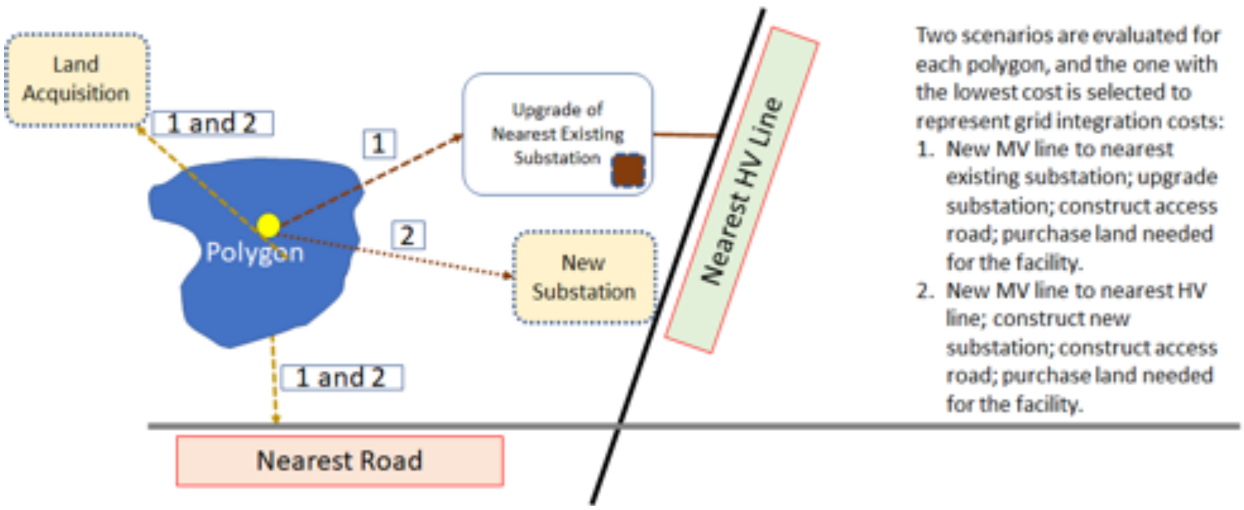

Figure 3.C.3-1. Grid Integration Cost Scenarios

For each polygon, total grid integration costs ($/MW) were estimated using the following equation:

Polygon Grid Integration Cost ($/MW) = Cost for Access Road + Cost for Land Acquisition + Cost for MV line + Cost for Substation (or substation upgrade)

Again, as mentioned above, the lowest of the two integration cost options was selected to represent the cost for that polygon.

3.C.3.a. Utility-Scale Solar PV

For utility-scale solar PV, there were 22,483 polygons that could support projects above 1 MW in size (the lower size threshold selected for utility-scale projects). Summary statistics for grid integration costs ($/MW) were calculated and are provided below:

- Mean: $525,340
- Median: $462,907
- Standard deviation (SD): $281,479
- Range: $220,102 - $3,045,599

Grid integration costs computed for all polygons were then divided into four Grid Integration Cost Classes by quartile:

- Cost Class I: lowest 25% of integration costs
- Cost Class II: next lowest 25% of total integration costs (25th to 50th percentile)
- Cost Class III: 50th to 75th percentile
- Cost Class IV: 75th to 100th percentile.

Table 3.C.3.a-1 provides a summary of the values computed for each Grid Integration Cost Class. The number of polygons per quartile do not match completely, since some small polygons were removed due to their small size (i.e., did not meet the lower size threshold to support at least a 1 MW plant). As indicated in these results, there is a technical potential of over 157 peak GW available within Grid Integration Cost Class I. The total for all cost classes is over 200 peak GW. These values represent maximum output (or nameplate capacity). Technical potential on a generation basis is just over 300,000 GWh.

TABLE 3.C.3.a-1. UTILITY-SCALE SOLAR PV GRID INTEGRATION COST CLASSES

CLASS	NUMBER OF POLYGONS	INTEGRATION COST ($/MW)			TECHNICAL POTENTIAL (MW)	ANNUAL GENERATION (MWH)	AREA (HA)
		LOW	HIGH	MEAN			
I	5520	$0	$323,183	$264,478	157,351	236,071,655	369,509
II	5555	$323,183	$462,907	$397,721	21,850	32,505,824	51,311
III	5650	$462,907	$629,936	$536,092	12,243	18,225,045	28,750
IV	5758	$629,936	$3,045,599	$902,655	8,941	13,228,305	20,995
				Total	**200,385**	**300,030,829**	**470,565**

Figure 3.C.3.a-1 is a map indicating the locations of the polygons by integration cost class. Although opportunities for utility-scale plants are broadly dispersed around the country, the best locations in terms of integration costs are concentrated in the east, south-central, and northwest of the country. The total area associated with this technical potential represents around 18% of Rwanda's total land area.

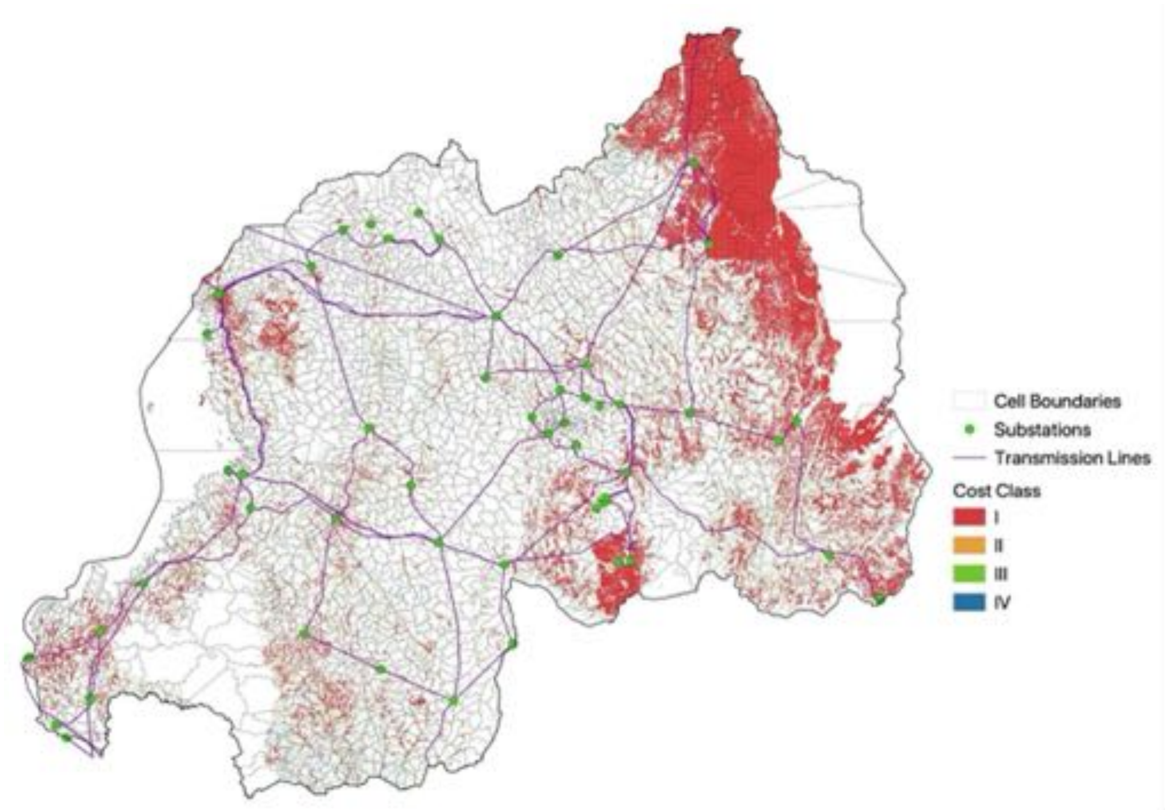

Figure 3.C.3.a-1. Utility-Scale Solar PV Technical Potential by Grid Integration Cost Class

3.C.3.b Agri-Voltaic PV Plants.

The same approach for assessing grid integration costs described above for utility-scale solar projects was applied to the APV polygons derived from the technical potential assessment above. Summary statistics for grid integration costs ($/MW) were calculated and are provided below:

- Mean: $936,765
- Median:
- Standard deviation (SD): $1,214,683
- Range: $175,492-$15,909,437

Table 3.C.3.b-1 provides a summary of the grid integration cost classes for APV. As shown in the table below, the peak TECHNICAL POTENTIAL capacity is 941 GW, and that capacity would be capable of producing about 1.4 million GWh of electricity annually.

TABLE 3.C.3.b-1. APV GRID INTEGRATION COST CLASSES							
CLASS	NUMBER OF POLY-GONS	INTEGRATION COST ($/MW)			TECH. POTENTIAL (MW)	ANNUAL GENERATION (MWH)	AREA (HA)
		LOW	HIGH	MEAN			
I	7,787	$0	$231,726	$199,077	667,902	995,501,928	979,752
II	10,391	$231,726	$499,587	$360,770	66,465	98,765,045	103,636
III	11,150	$499,587	$1,071,618	$728,176	12,900	19,121,809	19,585
IV	11,244	$1,071,618	$15,909,437	$2,457,858	5,238	7,728,379	8,020
				Total	**752,507**	**1,121,117,161**	**1,110,993**

Figure 3.C.3.b-1 provides a map of technical potential for APV which displays the locations of potential locations for APV projects by integration cost class. As shown in Table 3.C.3.b-1, the map indicates that most of the APV technical area is in Cost Class I. Areas of Cost Classes II-IV are those that are farther from the transmission infrastructure and/or have smaller contiguous area for installation.

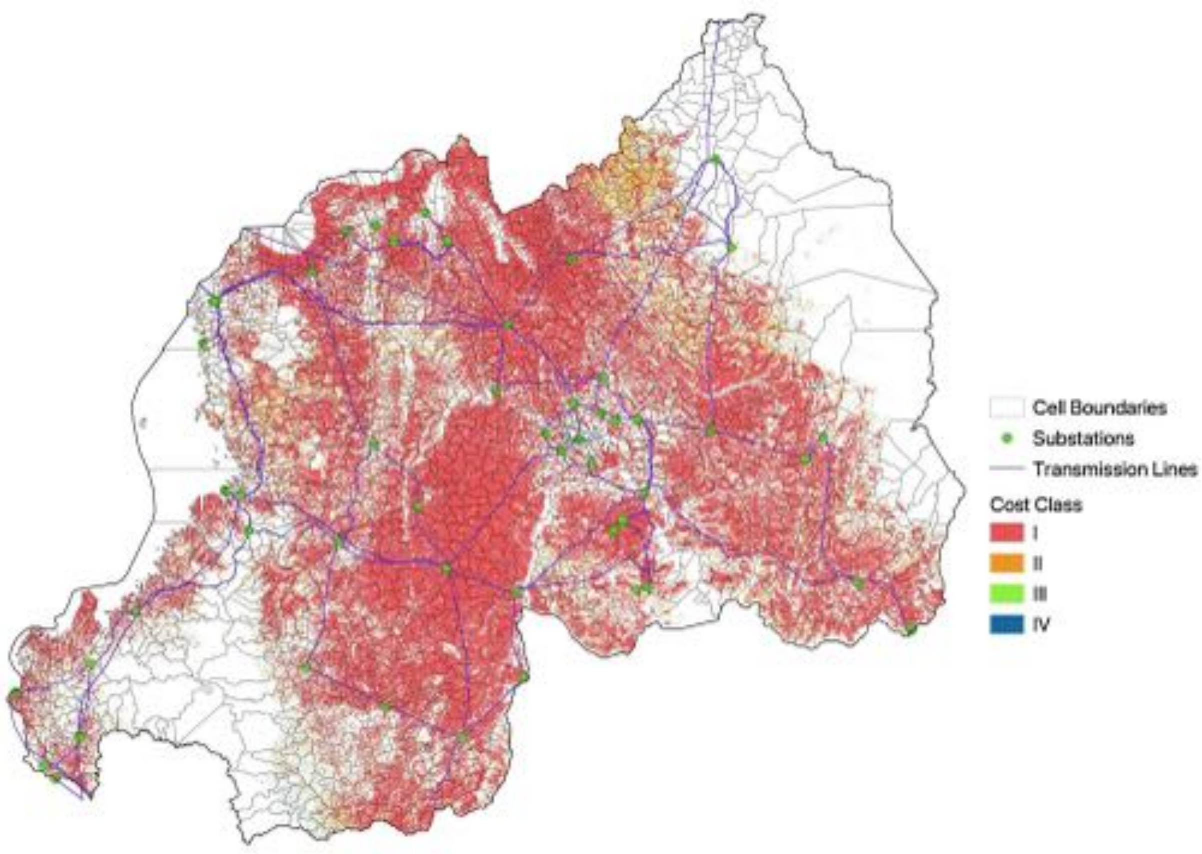

Figure 3.C.3.b-1APV Technical Potential by Grid Integration Cost Class

3.C.3.c. Floating PV Plants

The methodology for calculating grid integration costs mirrored the approach taken for utility-scale PV plants and APV above. Summary statistics for grid integration costs ($/MW) were calculated and are provided below:

- Mean: $3,587,565
- Median: $458,959
- Standard deviation (SD): $13,003,457
- Range: $165,693 - $198,481,465

As shown in Table 3.C.3.c-1 a significant fraction of the TECHNICAL POTENTIAL (79%) is in the first two cost classes. Note that because of the value selected for the density of capacity additions (0.10 kWp/m^2), the values of technical potential capacity and area are the same. As shown in the table below, that capacity would be capable of producing over 6,000 GWh of electricity annually.

TABLE 3.C.3.c-1. FPV GRID INTEGRATION COST CLASSES

CLASS	NUMBER OF POLY-GONS	INTEGRATION COST ($/MW)			TECH. POTENTIAL (MW)	ANNUAL GENERATION (MWH)	AREA (HA)
		LOW	HIGH	MEAN			
I	317	$0	$333,984	$266,057	1,737	2,671,394	1,737
II	316	$333,984	$458,959	$396,447	1,428	2,237,332	1,428
III	317	$458,959	$1,034,737	$648,831	766	1,192,492	766
IV	316	$1,034,737	$198,481,465	$12,441,984	79	122,365	79
				Total	**4,009**	**6,223,582**	**4,009**

Figure 3.C.3.c-1 provides a map of TECHNICAL POTENTIAL for FPV which displays the locations of potential locations for FPV projects by integration cost class. As in Table 1.5-4, the map indicates that most lake area falls within cost classes I or II.

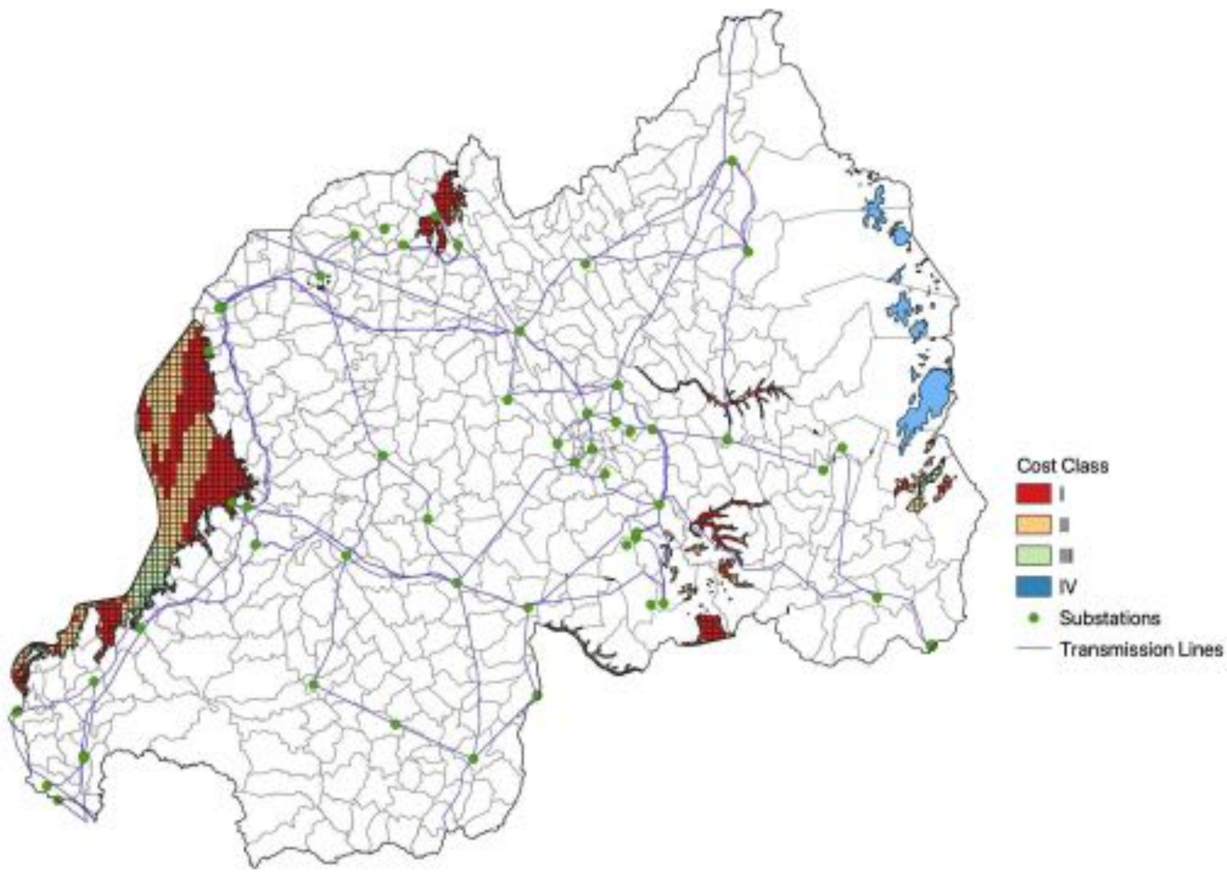

Figure 3.C.3.c-1. FPV Technical Potential by Grid Integration Cost Class

3.C.4. EQUIPMENT, INSTALLATION AND O&M COSTS

This section summarizes the selection of equipment cost information for the four solar PV technology applications covered above to support assessment of the economic potential (EP). These costs include for each technology, at least the following 3 components:

- Equipment costs: for example, total costs for PV panels, racking, inverters, cabling.
- Installation labor costs.
- Ongoing O&M costs: for example, total annual costs to cover cleaning of panels, replacement of parts, etc.

These costs exclude the costs for grid integration which were assessed separately in the previous section. When available, more detailed cost information was also included. For example, for equipment, these would include the individual costs of panels, racking, inverters, etc. This detailed information could be applied to develop more refined estimates for a technology application (e.g., switching out one type of PV panel or racking system for another).

Given the rapidly changing nature of PV implementation costs, cost information that is no more than five years old was preferred, and in some cases, information no more than 2 to 3 years old. The following order of geographic preference for cost information was also considered for each technology:

1. Rwanda-specific
2. East Africa region
3. African continent
4. Other regions

In some cases, there was a need to adjust cost information to assure that it best represents the Rwandan context. For example, cost information from projects in the US or Europe needed to be adjusted to account for the differences in equipment and labor costs for Rwanda. In such cases, indices from the World Bank International Comparison Program (ICP), 2017 (the most recent data set) were applied.[56] According to the World Bank: "price level indices (PLI) are obtained by dividing purchasing power parities (PPPs) (US$=1) by market exchange rates (US$=1) and further normalizing the ratios to a world average set equal to 100 ((World = 100). A PLI for a given expenditure component or category above 100 indicates that the economy's price level is higher than the world average; a value below 100 indicates that the economy's price level is lower than the world average."

There are two PLIs used to adjust non-regional cost data found in the literature:

- **For equipment costs:** Rwanda Machinery and Equipment ICP 2017 index = 138; the Machinery and Equipment ICP classification heading covers expenditures for fabricated metal products, except machinery and equipment; electrical and optical equipment; general purpose machinery; special purpose machinery; road transport equipment; other transport equipment.
- **For installation labor and ongoing O&M:** Rwanda Construction ICP 2017 index = 81; this ICP classification heading covers expenditures for residential buildings; non-residential buildings; civil engineering works. The construction and civil engineering survey is based on a list of common resources for construction work, including materials, equipment hire rates, and labor costs.[57]

For example, consider a case where the total installed equipment costs for a technology application in the US are $1,000/kW of nameplate capacity and that the equipment costs are attributed 50% to equipment and 50% to installation. The US ICP 2017 index for equipment costs is 91, while the index for installation labor is 264. The total installed costs for Rwanda would be:

Rwanda installed costs ($/kW) = ($500/kW x 138/91) + ($500/kW x 81/264) = $913/kW

All cost values taken from the literature were adjusted to 2021 US dollars (USD), when needed. This was done using the latest consumer price index values from the World Bank.[58]

The costs for each technology application are documented below. For each technology application, available cost information is presented to represent: (i) a case with just the generation technology; as well as (ii) a case with the generation technology plus battery storage. Note that other types of electricity storage are emerging and will certainly be available during the forecast period. i.e., through

[56] World Bank International Comparison Program, 2017: https://databank.worldbank.org/source/icp-2017.
[57] The ICP survey collects prices for inputs to construction work, including materials, equipment hire, and labor. The prices provided are those paid by construction contractors to their suppliers. For materials, these are typically the prices paid, after discounts, to manufacturers or intermediaries (agents or merchants), including all nonrecoverable taxes and excluding all recoverable taxes such as a value added tax. For equipment, prices are the rental charges paid to hire companies or internal hire rates. For labor, these reflect the cost to the contractor of employing workers. In addition, resource weights for each input component (materials, equipment hire, labor) for typical residential, nonresidential, and civil engineering projects are collected.
[58] World Bank, World Development Indicators: https://databank.worldbank.org/source/world-development-indicators.

2050 (e.g., flow batteries, kinetic, thermal, compressed air storage, among others). However, this initial assessment for Rwanda focuses on current commercially available lithium-ion battery storage.

3.C.4.a. Utility-Scale PV

Table 3.C.4.a-1 provides a summary of cost information identified in the literature that was considered in the selection of cost inputs for the economic potential modeling. As described above, values reported for outside of the east African region have been adjusted to better reflect local costs. Total installed costs include both equipment and installation labor costs.

For Rwanda, the detailed Kenyan cost study was selected as the most representative based on geographic specificity and age. Installed costs per MW are substantially lower than the Rwamagana plant; however, these are expected based on the substantial reductions in utility-scale PV implementation costs in recent years. The values presented for the Kenyan case study are also in good agreement with values from IRENA and NREL, which suggest that PV projects at this scale may not vary substantially between the east Africa region and more developed economies. From the IRENA reported values, none were available for Rwanda or east Africa. Of the countries reported, Indonesia seemed the most representative based on its geography, latitude, and level of development (those values are shown in the table below).

Note that the available data correspond to plants that are larger than those expected for Rwanda (generally in the 1 - 10 MW range). Because of the economies of scale for these larger plants, the values in Table 1.6-1 could underestimate the installation costs in Rwanda. A recent analysis of utility-scale installation costs in the U.S. indicates a unit cost savings of 8% when comparing the average installed costs of a 100 MW plant to a 10 MW plant.[59] Based on that, the installed cost value from the Kenya study was increased by 8% to represent expected system sizes in Rwanda. As a result, a value of $1,225/kW was selected to represent total installed costs for utility-scale PV installations in Rwanda as of 2021.

[59] https://www.greentechmedia.com/articles/read/key-2020-us-solar-pv-cost-trends-and-a-look-ahead.

TABLE 3.C.4.a-1. ECONOMIC POTENTIAL MODELING COSTS INPUTS CONSIDERED AND SELECTED FOR ULITILTY-SCALE SOLAR PV INSTALLATIONS			
TECHNOLOGY DESCRIPTION	TOTAL INSTALLED COST ($2021/KW)	ANNUAL O&M ($2021/KW-YR)	NOTES AND CITATIONS
Kenya Utility-Scale PV Case Study, 2021; 42.5 MW	$1,134	$23	https://www.treasury.go.ke/wp-content/uploads/2021/08/Case-Study-for-CBA-42.5-MW-SOLAR-PROJECT.pdf
Rwamagana, RW, 2015; 8.5 MW	$3,168	N/A	https://openaccess.nhh.no/nhh-xmlui/handle/11250/2432146
NREL Q1 2020 PV Benchmark, 2020; 100 MW	$1,210	$11	https://www.nrel.gov/docs/fy21osti/77324.pdf
IRENA 2020 Power Generation Costs; 2019[60]	$1,387	$9.3	https://www.irena.org/publications/2021/Jun/Renewable-Power-Costs-in-2020
NREL Q1 2020 PV + Energy Storage Benchmark, 2020; 100 MW PV + 60 MW/240MWh battery	$2,125	$17	https://www.nrel.gov/docs/fy21osti/77324.pdf
Selected Value for only Utility-scale PV Installation: 1 - 10 MW PV System	**$1,225**	**$23**	Adjusted Kenya Case Study; unit installed costs adjusted up by 8% to account for higher economies of scale for the Kenyan study.
Selected Value for Utility-scale PV Installation + Battery Storage: 1 - 10 MW PV System	**$2,295**	**$36**	Equipment: NREL Q1 2020 PV + Energy Storage Benchmark with a +8% adjustment to account for smaller plant sizes in Rwanda. O&M: Kenya case study adjusted for additional battery storage.

For annual O&M costs, the value from the Kenyan case study provided a good accounting of these costs and was adopted as input to the economic potential modeling without any adjustments. It is not clear from the available documentation why this value is more than double the costs reported by IRENA and NREL; however, in addition to system inspection and cleanings, the costs include general administration and security of the 42.5 MW power plant, as well as annualized inverter replacement costs. Note that the size of this plant is larger than the typical size of plants expected in Rwanda (+/- 10 MW), which may produce slightly lower unit costs than may be achieved by the smaller systems expected for Rwanda. Still, this appears to be a good current representation of utility-scale system installed costs for the east African region.

For systems that include battery storage, an incremental cost to account for the battery storage system was calculated using the results of the 2020 NREL benchmark study. The total cost was calculated by multiplying the PV system cost by a factor of 1.76. That value was derived by dividing the NREL PV + Storage value by the value for just PV (i.e., $2,125/$1,210). To account for the higher O&M costs for

[60] Figure 3.5 for total installed costs: value selected is for Indonesia which seems to be the best representation for Rwanda conditions. No specific system size was indicated. O&M value is based on IRENA's 2020 assumption for non-OECD countries. Assumes a 5% decline from 2019.

systems that include battery storage, the O&M value from the Kenya case study was adjusted by a factor of 1.56 which was derived from the NREL annual technology database values for O&M costs for utility-scale PV systems only ($23/kW-yr) and similar systems that include battery storage ($36/kW-yr). Although these values correspond to systems in the 100 MW size range, no adjustments were made to the O&M costs to reflect potentially higher costs for systems in the size range expected in Rwanda (there was no basis for such adjustments found in the literature).

As detailed in the sections below, additional considerations were then made to account for changes in equipment costs during the forecast period.

Utility-scale PV Installation. Both the IRENA and NREL studies cited above provide recent historic estimates in the reductions of installed system costs for utility-scale solar PV. IRENA's estimates are based on global installations, while NREL's are based on US installations. No similar data were found for other regions of the world, in particular, the east Africa region. Both IRENA and NREL have reported significant cost declines over the past 10-15 years. However, those high rates of reduction are not likely to continue into the future given the maturation of the industry. Figure 3.C.4.a-1 provides a sense of this issue. If one looks back to 2015 or earlier, it is apparent that the annual rates of declining costs were much greater during that period and earlier (as compared to the most recent 3 years).

Figure 3.C.4.a-1 NREL Historical US Benchmark Costs for Utility-Scale Solar PV

Figure 3.C.4.a-2 provides NREL's US forecast of installed costs using three different scenarios and compared to the median forecast of industry analysts ["Med (US)"]. The conservative scenario is based on lower levels of research and development (R&D) investment, minimal technology advancement and current global module pricing. The moderate scenario is based on moderate R&D investment, industry technology roadmaps being achieved, but no substantial innovations or new technologies introduced into the market. The advanced scenario is based on higher levels of R&D spending that generates substantial innovation, which allows for historical rates of development to continue.[61] The conservative

[61] See the NREL Annual Technology Database documentation for utility-scale solar PV at: https://atb.nrel.gov/electricity/2021.

scenario represents lower expected declines in costs than both the other scenarios as well as analyst forecasts.

Regionally specific estimates were not identified for the expected declines in equipment installation costs. For economic potential modeling purposes, the conservative forecast from NREL was adopted. This assumes that continued innovation and R&D spending that further drives down installation costs will drive substantial reductions through 2030. That resulted in the annual rates of decline indicated in Table 3.C.4.a-2 below. The NREL database also provides the expected rate of decline for O&M costs for utility-scale PV systems. The conservative forecasts were also adopted for use in economic potential modeling and are shown in the table below.

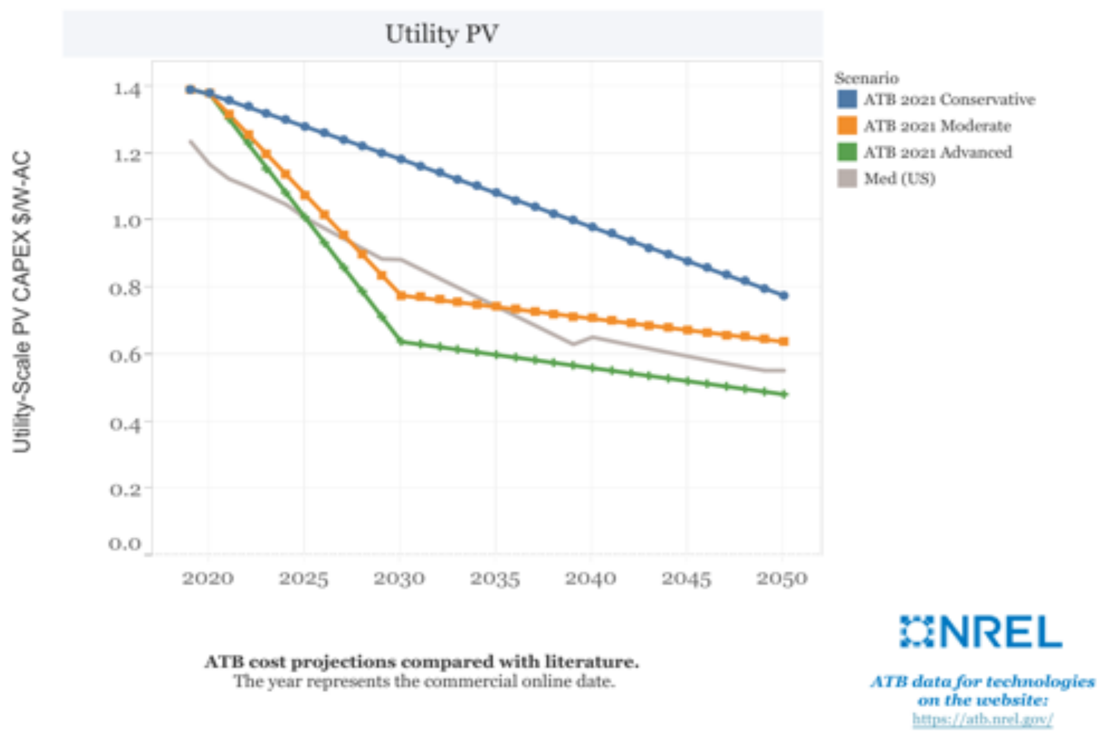

Figure 13.C.4.a-2. NREL Annual Technology Database Equipment Cost Forecast for Utility-Scale Solar PV

TABLE 3.C.4.a-2. ECONOMIC POTENTIAL MODELING FORECAST ASSUMPTIONS FOR UTILITY-SCALE PV SYSTEMS

MODELING INPUT DESCRIPTION	2021-2030 CHANGE (%/YR)	2031-2050 CHANGE (%/YR)
Annual decline in installed equipment costs: PV only	-1.5%	-2.1%
Annual decline in fixed O&M costs: PV only	-1.0%	-1.1%
Annual decline in installed equipment costs: PV + Battery Storage	-2.9%	-1.9%
Annual decline in fixed O&M costs: PV + Battery Storage	-2.4%	-1.2%

Source: https://atb.nrel.gov/electricity/2021.

Utility-Scale PV + Battery Storage. Some additional information is provided in this section for the current and expected future costs of utility-scale battery storage. NREL provided recent cost projections for utility-scale PV with battery storage.[62] Forecasted costs for 4-hour duration battery storage for a 100 MW PV plant are summarized in Table 3.C.4.a-3 below. The values associated with NREL's mid-level cost forecast were selected for EP modeling. For comparison, the incremental cost of battery storage shown in Table 1.6-1 from a separate NREL study translates to $394/MWh of storage. The values selected from the high-range forecast (most conservative) indicate annual rates of decline of -2.6% from 2021 - 2030 and -1.4% from 2031 - 2050. These values are very close to those selected and shown in Table 3.C.4.a-2 above for modeling the cost decline in PV+battery storage (from the NREL Annual Technology Database).

TABLE 3.C.4.a-3. UTILITY-SCALE WITH 4-HOUR PV BATTERY STORAGE COST FORECAST

	2021$/MWH		
YEAR	LOW	MID	HIGH
2020	317	383	396
2021	296	363	385
2030	149	215	303
2040	120	188	265
2050	91	161	227

In the same NREL technology database cited above, a fixed O&M cost of $39/kW-yr was provided. After converting to Rwandan conditions, the value is $24/kW-yr. This value has been adopted for EP modeling. NREL anticipates significant cost declines through 2030 (4.6%/yr) and continued declines of 0.8%/yr through 2050.

3.C.4.b. Agri-voltaics

A summary of cost inputs for economic potential modeling of APV identified in the recent literature are shown in Table 3.C.4.b-1 below. The APV system descriptions are taken from the conventions put forth by NREL in their study cited in the table below. NREL characterizes APV systems by application to the landscape (crops, pastures, or pollinator habitat) and by mounting structure (ground-mount, reinforced regular mount, stilt-mount, and vertical mount). The APV technical potential estimates documented above address annual croplands, so either of the latter two elevated mounting systems could be considered (see Figure 3.C.4.b-1 for an illustration). Stilt-mounted systems are generally applied to tall crops or in cases where it is required by cultivation machinery. Reinforced regular mounting systems allow for greater panel densities.

[62] Cost Projections for Utility-Scale Battery Storage: 2020 Update; https://www.nrel.gov/docs/fy20osti/75385.pdf.

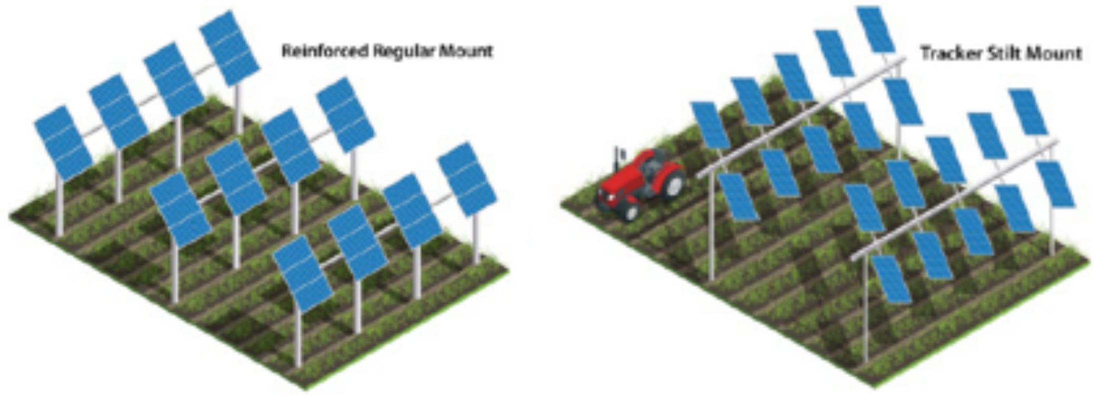

Figure 3.C.4.b-1 Reinforced Regular Mount Versus Stilt-Mounting for APV Systems[63]

TABLE 3.C.4.b-1. ECONOMIC MODELING COST INPUTS IDENTIFIED AND SELECTED FOR APV SYSTEMS

TECHNOLOGY DESCRIPTION	TOTAL INSTALLED COST ($2021/KW)	ANNUAL O&M ($2021/KW-YR)	NOTES AND CITATIONS
Agri-Voltaic on Crop Systems: 35 kW Reinforced Regular Mount. China, 2021 Demonstration Project.	$847	$7.7	https://journals.plos.org/plosone/article?id=10.1371/journal.pone.0254482
Agri-Voltaic on Crop Systems: 500 kW Reinforced Regular Mount. NREL, 2020 (built from US cost data)	$2,207	N/A	https://www.nrel.gov/docs/fy21osti/77811.pdf
Agri-Voltaic on Crop Systems: 500 kW Stilt Mount. NREL, 2020 (built from US cost data)	$1,978	N/A	https://www.nrel.gov/docs/fy21osti/77811.pdf
Agri-Voltaic on Crop Systems: 500 kW Vertical Mount. NREL, 2020 (built from US cost data)	$1,732	N/A	https://www.nrel.gov/docs/fy21osti/77811.pdf
Agri-Voltaic on Crop Systems: 50 kW Reinforced Regular Mount (assumed). Niger 2021 Case Study	$1,450	$29	https://www.mdpi.com/2073-4395/11/10/1906
Agri-Voltaic on Crop Systems: 1.04 MW Reinforced Regular Mount. Germany 2021 Case Study.	$1,643	$12	https://www.sciencedirect.com/science/article/pii/S030626192030249X
Selected 2021 Value: 500 kW APV system	**$1,978**	**$22**	NREL value for stilt mounted APV and German estimates for annual O&M costs.

[63] Source: NREL, 2020. https://www.nrel.gov/docs/fy21osti/77811.pdf.

The value from the recent Chinese demonstration is a clear outlier in terms of installed costs being much lower than any other value identified. It is not clear why this cost estimate is so low; however, it is not clear from the documentation whether a full accounting of costs was provided, including installation labor. As a result, given the uncertainty around cost accounting, the difference from other values, and the fact that it represented just a demonstration-scale project (35 kW), that value was not considered for use in the economic potential modeling.

Similar to the China case study, the costs shown for the Niger case study are also based on a very small system size (50 kW); however, the installed cost values are closer to those from the US and Germany. The estimated O&M costs are over twice those estimated for German APV systems which may be due to a combination of its small system size and that the conditions in the dry and dusty Sahel region would require higher levels of maintenance. Because of these concerns around its representativeness to APV systems for Rwandan grid connection (0.1 - 1.0 MW in size), the values for the Niger case study were excluded from the economic potential modeling.

NREL built system-level costs based on component costs in the US. Regardless of mounting type, these are all quite a bit higher than the recent case studies identified in Niger and Germany. At 1 MW, the German case study represents the higher end of the size range currently considered for Rwanda. The value from NREL for US installations is based on a 500-kW system size and was selected as a conservative value for EP modeling for Rwanda ($1,978/kW). The NREL study did not provide estimates for O&M costs. Therefore, the value from the German case study was selected ($12/kW-yr after adjusting to Rwandan conditions).

Information in the literature on battery storage applications to APV systems is currently lacking. For the economic potential modeling purposes, the same incremental costs to add battery storage to utility-scale systems described above were adopted for APV systems (see Table 1.6-3). Economies of scale differences may also apply here for storage as they do for different PV system capacities. However, since no supporting data were identified to derive a scaling factor, no adjustment was made to the storage costs. The same value for fixed O&M costs was also selected for the economic potential modeling.

No information was found in the literature to support APV-specific installed equipment or fixed O&M cost forecasts. Therefore, the same assumptions for utility-scale PV shown in Table 1.6-2 are applied for the economic potential modeling. Given that APV technology has not yet reached the same level of maturity as ground-mount utility-scale systems, the selected rates of decline for installed costs may underestimate the rate of decline under real-world conditions, especially in the near-term (e.g., next 10 years).

3.C.4.c. Floating Systems

Recent information on the costs of FPV implementation indicate that the up-front equipment costs remain slightly above those for utility-scale PV.[64] However, the combination of lower O&M costs and slightly higher power output make the overall costs for implementing FPV systems on par or slightly lower than utility-scale PV over the lifetime of the project. NREL[65] recently stated that "*FPV system costs are site-specific and can vary widely across countries based on a range of factors, including: the type of water body, water depth and distance to shore (which impact the type of floating, mooring, and anchoring systems needed), geography (which could impact soft costs such as labor and logistics), size of project, and differences in floating, mooring, and anchoring systems used*". Further, NREL noted a wide range of installed FPV costs

[64] See, for example, this industry news article for US-based systems: https://www.pv-magazine.com/2020/10/07/floating-solar-nearing-price-parity-with-land-based-us-solar/.

[65] https://www.nrel.gov/docs/fy21osti/76867.pdf.

depending on the location and size of the system. Installed costs as low as $520/kW for large-scale projects in India in the 20-80 MW range represent one end of the spectrum while costs as high as $3,020/kW for projects in Japan in the 1-5 MW range represent the other.

Figure 3.C.4.c-1 provides a schematic representation of a typical large FPV system. As indicated in the figure, when the system is not located adjacent to the shore, both the panel arrays and one or more central inverters are installed on floating structures which need to be anchored to the bottom of the water body.

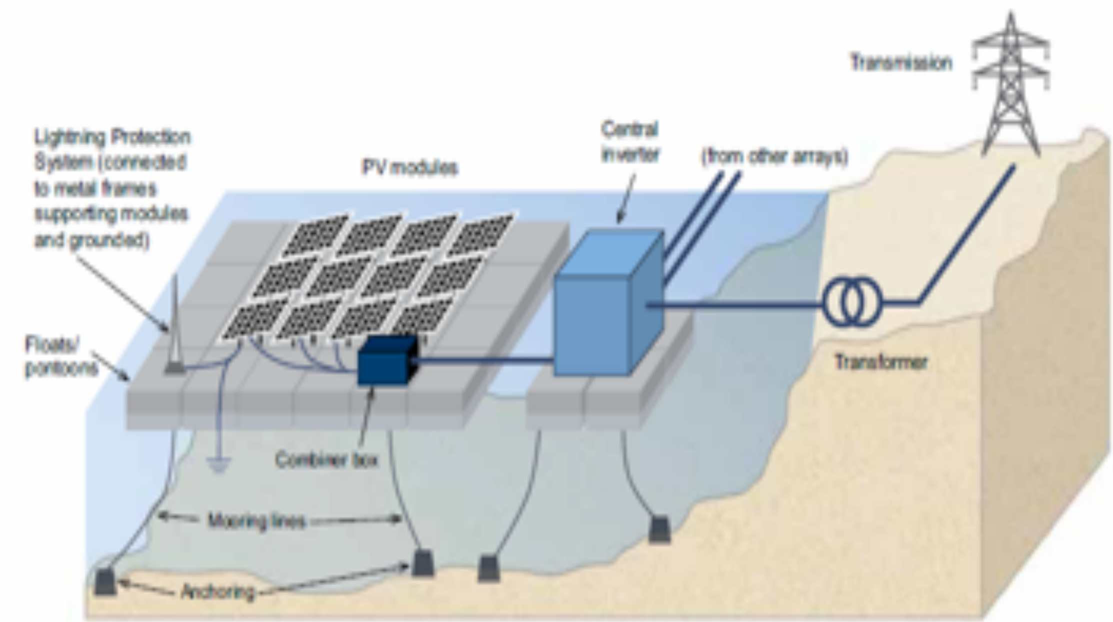

Figure 3.C.4.c-1 Typical Large-Scale FPV System[66]

Table 3.C.4.c-1 provides a summary of the economic potential modeling cost data inputs found in the literature. None of the data sources provided any breakdown of installed costs (for example, equipment, labor, etc.). As well, it is unclear whether these costs also include those for integration into the electrical grid (such as costs for medium voltage lines, substations, extensions of high voltage lines). The conversion of costs from the site country to Rwanda used the same breakdown of equipment (70%) to construction (30%) costs applied to the utility-scale PV plants. Again, this is because no breakdown of total installed costs specific to FPV systems was available.

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66 Source: https://documents1.worldbank.org/curated/en/579941540407455831/pdf/Floating-Solar-Market-Report-Executive-Summary.pdf.

TABLE 3.C.4.c-1. ECONOMIC MODELING COST INPUTS IDENTIFIED AND SELECTED FOR FPV SYSTEMS

TECHNOLOGY DESCRIPTION	TOTAL INSTALLED COST ($2021/KW)	ANNUAL O&M ($2021/KW-YR)	NOTES AND CITATIONS
2014 Sheeplands, United Kingdom: 0.2 MW	$1,515	N/A	https://documents1.worldbank.org/curated/en/579941540407455831/pdf/Floating-Solar-Market-Report-Executive-Summary.pdf.
2015 Japan: 2 MW	$3,399	N/A	
2016 Portugal: 0.2 MW	$2,972	N/A	
2016 United Kingdom: 6.3 MW	$1,621	N/A	
2016 Anhui, Xinyi China: 20 MW	$1,539	N/A	
2017 Noma Ike, Japan: 2.4 MW	$3,192	N/A	
2017 Anhui Sungrow, China: 40 MW	$1,175	N/A	
2017 Kerala, India: 0.5 MW	$4,809	N/A	
2017 Mita Kannabe, Japan: 1.5 MW	$3,192	N/A	
2018 Yamakura Dam, Japan: 13.7 MW	$1,057	N/A	
2018 Andhra Pradesh, India: 2 MW	$1,558	N/A	
2018 Three Gorges, China: 150 MW	$1,029	N/A	
2018 West Bengal, India Avg. Auction Price: 5 MW	$1,930	N/A	
2018 Ramgiri, Andhra Pradesh India Case Study: 10 MW	$2,034	$21	https://www.climateinvestmentfunds.org/sites/cif_enc/files/meeting-documents/note_on_financial_and_economic_analysis_for_storage_and_floating_solar_applications_07202017.pdf
2021 Near shore (Yellow Sea) mega FPV system in South Korea: 2,100 MW	$3,174	N/A	https://www.power-technology.com/features/worlds-biggest-floating-solar-farms/
2021 Omkareshwar dam, India: 600 MW	$1,150	N/A	
2021 FPV in a reservoir at Alappuzha, Kerala, India: 105 MW	$774	N/A	
2021 FPV in a reservoir at Telangana, India: 100 MW	$956	N/A	
Selected Value: FPV systems <100 MW as of 2021	**$1,645**	**$21**	Installed costs estimate is the average of four recent values (no earlier than 2018) for systems no larger than 100 MW. Fixed O&M is based on the only value identified for FPV systems.

As indicated in the summary shown in Table 3.C.4.c-1, the values for installed costs vary substantially both over time and site location. Generally speaking, the costs prior to 2018 for the earliest systems have higher unit costs; however, these are also relatively small. Some of the latest values for projects currently under construction represent large-scale systems of at least tens of megawatts, if not hundreds or thousands. So, project scale is also a key consideration for assigning installed cost values. Finally, the type of water body involved might also be a factor in driving installed costs. For example, the mega FPV project listed for South Korea (2.1 GW) is being built near shore on the Yellow Sea, which could be one reason its costs are generally higher than for projects sited on potentially less technically challenging bodies of water such as inland reservoirs. The examples of reservoir applications could in some cases be associated with existing hydro-electric generation facilities, which should offer lowered integration costs to the extent that those costs were included in the reported cost values.

In Rwanda, FPV systems would most likely be sized in the scale of tens of MW based on the size of available water bodies other than Lake Kivu. While one or more large-scale systems (> 100 MW) could be built on Lake Kivu, it remains uncertain that the electrical grid and the associated demand could accommodate systems of this size. Therefore, the 2021 FPV installed costs value selected for EP modeling was calculated as the average of recent (2018 and later) projects shown in Table 3.C.4.c-1 above that were less than 100 MW in size. That value is $1,645/MW and is about 34% higher than the value selected for utility-scale PV shown in Table 3.C.4.a-1.

The fixed O&M cost value selected for FPV comes from the only literature source that specified these costs. This cost is about 9% lower than the value selected for utility-scale PV plants. Based on solar PV industry reporting,[67] these cost inputs seem reasonable based on the available information. In 2020 in the US, FPV systems were thought to be 10-15% more expensive than ground-mounted systems. For fixed O&M, the same industry article mentions that FPV systems have lower costs, although how much lower was not specified.

As with APV, no information was found in the literature to support FPV-specific installed equipment or fixed O&M cost forecasts. Therefore, the same values selected for utility-scale PV shown in Table 3.C.4.a-1 are applied for EP modeling. As with APV systems, FPV technology has not yet reached the same level of maturity as ground-mount utility-scale systems, Hence, the selected rates of decline for installed costs may underestimate real-world conditions, especially in the near-term (e.g., next 10 years).

FPV + Battery Storage. Information in the literature on battery storage applications to FPV systems is currently lacking. For EP modeling purposes, the same incremental costs to add battery storage to utility-scale systems described above were adopted for FPV systems (see Table C.4.a-3). Economies of scale differences may also apply here for storage as they do for different PV system capacities. However, since no supporting data were identified to derive a scaling factor, no adjustment was made to the storage costs. The same value for fixed O&M costs was also selected for the economic potential modeling.

3.C.4.d. Distributed PV

Distributed PV technology applications include rooftop solar PV applied to buildings in the residential sector as well as the commercial/institutional/industrial sectors.

Residential Rooftop Solar PV. Table 3.C.4.d-1 provides a summary of the information from the literature considered for establishing cost inputs for the economic potential modeling.

[67] https://www.pv-magazine.com/2020/10/07/floating-solar-nearing-price-parity-with-land-based-us-solar/.

TABLE 3.C.4.d-1. ECONOMIC POTENTIAL MODELING COST INPUTS IDENTIFIED AND SELECTED FOR RESIDENTIAL PV SYSTEMS			
TECHNOLOGY DESCRIPTION	TOTAL INSTALLED COST ($2021/KW)	ANNUAL O&M ($2021/KW-YR)	NOTES AND CITATIONS
Residential Rooftop Solar PV	$2,262	$9.2	https://www.nrel.gov/docs/fy21osti/77324.pdf
Residential Solar PV	$2,021	$9.3	https://www.irena.org/publications/2021/Jun/Renewable-Power-Costs-in-2020
Selected value: Residential Rooftop Solar PV	**$2,142**	**$9.3**	Average of the NREL and IRENA values.
Residential Rooftop + Battery Storage	$3,559	$12	https://www.nrel.gov/docs/fy21osti/77324.pdf
Selected value: Residential Rooftop Solar PV + Battery Storage in 2021	**$3,559**	**$12**	Value provided by the NREL study.

Aside from some dated information from IRENA on solar PV application in African countries, no other data sources were found covering the costs for residential rooftop PV systems. Note that here, residential rooftop PV systems being considered are in the range of 1 - 10 kW, and they do not include the much smaller systems associated with SHS programs, nor do they include PV systems that support micro-grids. After adjusting the costs for Rwandan conditions, the NREL and IRENA values shown in the table are fairly close. While the IRENA value does not specify that it specifically addresses rooftop systems, that is assumed to be the case for this assessment. An average of NREL and IRENA values was selected for use in the economic potential modeling.

To adjust the installed costs to Rwandan conditions, the breakdown of installed costs from NREL was used to estimate the fraction of costs for equipment (42%) versus installation (58%). This same breakdown was applied to the total installed cost value from the IRENA study. For NREL, the costs were adjusted from US conditions, while for IRENA, the costs were adjusted from the value cited for South Africa (the nearest country to Rwanda included in the IRENA study).

Table 3.C.4.d-1 also provides the value selected to represent the case of solar rooftop PV + battery storage systems. These costs are indicative of a 7 kW PV system coupled with battery storage of 3 kW/6 kWh. These values were taken from the NREL study cited in the table and adjusted to Rwandan conditions (about 40% are equipment costs with the remainder made up of installation and other soft costs).

Institutional/Commercial/Industrial (ICI) Rooftop Solar PV. Table 3.C.4.d-2 summarizes the information assessed to establish the EP modeling costs inputs for ICI rooftop solar PV. These are the same two reference sources used to establish the inputs for residential rooftop solar PV above. A cost estimate was found in the literature for an industrial solar PV installation in Rwanda[68]; however, details

[68] https://renewables.org/projects/edible-oil-refinery-in-kigali-rwanda/.

were lacking, and the resulting unit installation cost of $555/kW is well below what would be expected for this technology.

TABLE 3.C.4.d-2. ECONOMIC POTENTIAL MODELING COST INPUTS IDENTIFIED AND SELECTED FOR ICI PV SYSTEMS			
TECHNOLOGY DESCRIPTION	TOTAL INSTALLED COST ($2021/KW)	ANNUAL O&M ($2021/KW-YR)	NOTES AND CITATIONS
ICI Rooftop Solar PV	$1,555	$6.0	https://www.nrel.gov/docs/fy21osti/77324.pdf
ICI Solar PV	$1,141	$9.3	https://www.irena.org/publications/2021/Jun/Renewable-Power-Costs-in-2020
Selected value: ICI Rooftop Solar PV	**$1,348**	**$7.7**	Average of the NREL and IRENA values.
ICI Rooftop + Battery Storage	$2,316	$8.9	https://www.nrel.gov/docs/fy21osti/77324.pdf
Selected value: ICIRooftop Solar PV + Battery Storage in 2021	**$2,316**	**$8.9**	Value provided by the NREL study.

As with the other technologies, the US based costs from NREL were adjusted to Rwandan conditions as documented at the beginning of this section. NREL provided cost estimates for systems ranging from 0.1 MW to 2 MW. There was less than an 8% reduction in unit installation costs for systems sized at 200 kW versus 2 MW. For the IRENA installation cost value, no values for Africa were provided. There is a substantial range in installed costs reported by IRENA. At the low end, costs in India were reported at $651/kW, while several costs in US states were all above $2,600/kW. The value indicated in the table is the value reported for Germany and has been adjusted to Rwandan conditions. It represents about the middle of the range of global values reported by IRENA.

Table 1.6-7 also provides the value selected to represent the case of ICI rooftop PV + battery storage systems. These costs are indicative of a 1 MW PV system coupled with battery storage of 600 kW/2.4 MWh. These values were taken from the NREL study cited in the table and adjusted to Rwandan conditions (about 65% are equipment costs with the remainder made up of installation and other soft costs).

The selected forecast in decline of installed equipment costs and fixed O&M costs for distributed generation systems is provided in Table 3.C.4.d-3 below. In all cases, the information was taken from NREL's Annual Technology Database, since no other information sources reviewed provided such estimates at the level of detail needed for EP modeling (that is. technology application specific values).

TABLE 3.C.4.d-3. ECONOMIC POTENTIAL MODELING FORECAST ASSUMPTIONS FOR DISTRIBUTED PV SYSTEMS			
MODELING INPUT DESCRIPTION	2021-2030 CHANGE (%/YR)	2031-2050 CHANGE (%/YR)	NOTES AND CITATIONS
Annual decline in installed equipment costs: Residential rooftop PV systems	-9.8%	-1.3%	NREL 2021 Annual Technology Baseline: https://atb.nrel.gov/electricity/2021.
Annual decline in installed equipment costs: ICI rooftop PV systems	-6.5%	-1.3%	https://www.irena.org/publications/2021/Jun/Renewable-Power-Costs-in-2020
Annual decline in fixed O&M costs: Residential rooftop PV	-7.8%	-0.9%	Average of the NREL and IRENA values.
Annual decline in fixed O&M costs: ICI rooftop PV	-4.4%	-1.0%	https://www.nrel.gov/docs/fy21osti/77324.pdf
Annual decline in installed equipment costs: Residential PV + battery storage	-6.7%	-1.4%	Derived from NREL technology baseline installed costs for a 7 kW PV system and 3 kW/6 kWh battery.
Annual decline in installed equipment costs: ICI PV + battery storage	-5.9%	-1.4%	Derived from NREL technology baseline installed costs for a 1 MW PV system and 600 kW/2.4 MWh battery.

3.D. HYDRO RESOURCE ASSESSMENT

Nyabarongo Hydropower Project
RWANDA ENERGY GROUP

In 2008, SHER Ingénieurs published the Rwanda hydropower atlas, a comprehensive identification of pico (≤ 5kW), micro (5-100 kW), and mini (100 kW-1 MW) sites of exploitable hydropower potential. Its aim was to assess exploitable hydropower potential in Rwanda with focus on small hydropower sites (i.e., less than 5 MW). Phase 1 of the SHER study inventoried and analyzed the available bibliography and carried out 100 site visits which were documented in a database. Phase 2 of the SHER study included 228 more site visits and an analysis of hydro capacity in MW. The final database identified 330 micro hydro sites and an additional 3 border sites with medium hydro exploitable potential (i.e., 15-100 MW). This information was encoded into a GIS platform that is known as the Rwanda Hydropower Atlas that continued spatial and power potential for all 333 sites totaling 82.598 MW of exploitable hydropower capacity. The estimated potential for pico, micro, and mini hydropower from the Hydropower Atlas, along with the existing and planned small (1-30 MW) and large (>30 MW) hydropower, was the operative existing estimate of total hydropower potential for Rwanda.

Based on the feedback received from REG had of concerns with the SHER 2008 estimates of hydro potential, the EAEP Team undertook a independent small hydro physical resource assessment. Based on the scope and resources of this Project, this assessment is based on desk-based analysis that uses peer-reviewed methods, state-of-the-art digital elevation models, GIS tools, and Rwandan hydrographic data to assess the power potential of every stream segment within the country for potential small hydropower project development. The methodological approach for the desk-based portion of the assessment aims to take advantage in the development and refinement since 2008 of analytical techniques and methods for estimating streamflow and power potential in ungauged catchments in the peer-reviewed engineering literature. These techniques were applied to Rwandan conditions as defined by available local hydrographic and other data of suitable quality.

3.D.1 PHYSICAL RESOURCE AVAILABILITY

Based on the above, hydropower **physical resource** is determined by the amount of flow in Rwanda's streams and rivers and the available head, the height that the water falls.[69]

Head can be determined using digital elevation model (DEM) data. For streamflow, there is some data available from stream monitors and field measurements. However, there are many streams that are ungauged, in addition to segments along gauged streams where the flow may vary significantly due to additional tributaries joining the flow. The following steps were used to estimate streamflow across all rivers and streams in Rwanda based on literature search for methods and tools to estimate streamflow in ungauged catchments, with a particular focus on available studies undertaken in Rwanda.

- Use GIS methods to delineate streams and determine the upstream drainage area for each point along these streams.
- Use available streamflow data for stream segments to develop a suitable regression model relating streamflow to drainage area, rainfall, catchment slope, catchment landcover.
- Apply the regression model to all stream segments to estimate streamflow for each segment.
- Summarize the results of the assessment into a detailed, stream segment-based estimate of physical resource availability of hydropower in Rwanda which can be used as the new operative existing estimate of total hydropower potential for Rwanda.

These methods are explained in more detail below.

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[69] Head and flow detailed review, Renewables First, https://www.renewablesfirst.co.uk/hydropower/hydropower-learning-centre/head-and-flow-detailed-review/.

Stream Delineation and Drainage Area. The first step for estimation of hydropower physical power resource was to use GIS tools to delineate streams within Rwanda's borders. Several hydrology tools from Geographic Resources Analysis Support System (GRASS)[70] are included in the QGIS software. Two of these tools were used along with elevation data to create a stream raster layer, using the *r.stream.extract* tool, and a drainage area raster layer, using the *r.watershed* tool. The elevation layer used was the SRTM 30-meter digital elevation model (DEM) raster data obtained from USGS EarthExplorer,[71] explained in more detail in the GIS section.

Additional GRASS tools, *r.thin* and *r.to.vect* were used to convert the stream raster to a line vector. This generated stream layer was compared to satellite images and a stream layer developed from surveys and digitization of orthophotos.[72] Streams that were incorrectly generated, such as across lakes and wetlands, were manually deleted. Stream segments within Protected Areas were also deleted. More information on GIS methods and data sources is provided in Section 3.B.

Streamflow Observed Data. Streamflow data was obtained from three sources to include the most data points possible for the streamflow model. First, streamflow data was compiled from Rwanda Water Resource Portal website maintained by the Rwanda Water Board, along with the location of each monitor or field measurement site.[73] Three types of flow data were compiled:

- Continuous flow monitoring for a complete or near-complete year (1987 or later).
- 4 or more field measurements in different months in recent years.
- Several field measurements that were part of the record (i.e., no new field measurements were taken during the hydro assessment) could be used to establish a relationship between flow rate and water level; the annual average flow could then be estimated based on available continuous water level monitoring data.

Table 3.D.1-1 below lists the sites, type of data, dates of monitoring or sampling, and estimated annual average flow.

Second, five additional data points were added based on data compiled from hydropower feasibility studies and location data provided by REG. These studies included annual average stream flow, proposed plant location, and upstream drainage area, as shown in Table 3.D.1-2.

Third, streamflow data estimates from site visit records accompanying the 2008 SHER Hydropower Atlas were added to capture stream flow for small streams of flow rate less than 1 m^3/s. The number of samples and dates of measurement were not available; however, these data were included because it was the only source of flow rates for very small streams.

[70] Geographic Resources Analysis Support System, https://grass.osgeo.org/grass80/manuals/raster.html.
[71] USGS EarthExplorer, https://earthexplorer.usgs.gov/.
[72] Rwanda Water Bodies, https://rwanda.africageoportal.com/maps/africageoportal::rwanda-water-bodies/about.
[73] Rwanda Water Portal, https://waterportal.rwb.rw/data/surface_water.

TABLE 3.D.1-1 STREAMFLOW DATA FROM RWANDA WATER BOARD MONITORING SITES				
LEVEL 1 CATCHMENT	STATION	INTEGRATION COST ($/MW)	DATE RANGE OF DATA	AVERAGE FLOW RATE (M3/S)
Kivu	Nyundo	continuous monitoring	1/1987-12/1987	4.91
Kivu	Nyundo	continuous monitoring	1/2012-12/2012	6.27
Mukungwa	Ngaru(Mukungwa)	continuous monitoring	3/2016-2/2017 (missing June-Sept)	51.42
Mukungwa	Nyakinama(Mukungwa)	continuous monitoring	3/2016-2/2017	9.26
Mukungwa	Rusumo(Rugezi)	continuous monitoring	3/2016-1/2017	2.80
Muvumba	Kagitumba	continuous monitoring	1/1987-12/1987	15.93
Muvumba	Kagitumba	continuous monitoring	1/2012-12/2012	17.09
Nyabarongo lower	Ruliba(Nyabarongo)	continuous monitoring	1/1987-12/1987	100.22
Nyabarongo lower	Ruliba(Nyabarongo)	continuous monitoring	1/1990-12/1990	118.22
Nyabarongo lower	Ruliba(Nyabarongo)	continuous monitoring	1/2000-12/2000	98.38
Nyabarongo lower	Ruliba(Nyabarongo)	continuous monitoring	1/2013-12/2013	150.18
Nyabarongo lower	Yanze	continuous monitoring	3/2016-2/2017	1.23
Nyabarongo upper	Mudasomwa	continuous monitoring	3/2016-2/2017	3.87
Rusizi	Akanyaru-upper	continuous monitoring	3/2016-2/2017	11.52
Rusizi	Kanzenze	continuous monitoring	3/2016-2/2017	93.16
Akagera upper	Kamanyola	4 field measurements	2018-2020	143.55
Akanyaru	Ururumanza	4 field measurements	2018-2020	0.34
Akanyaru	Rte Butare/Ngozi	5 field measurements	2018-2020	27.22
Nyabarongo lower	Mbirurume outlet	5 field measurements	2018-2020	10.99
Nyabarongo upper	Ngaru(Nyabarongo)	5 field measurements	2018-2020	86.76
Nyabarongo upper	Nyagisozi	5 field measurements	2018-2020	23.59
Rusizi	Bugarama-Ruhwa	6 field measurements	2018-2020	13.25
Rusizi	Bugarama(Rubyiro)	6 field measurements	2018-2020	3.19
Akanyaru	Kibeho	estimated from water level	1/1990-12/1990	4.11
Akanyaru	Kibeho	estimated from water level	1/2000-12/2000	3.37
Akanyaru	Kibeho	estimated from water level	1/2012-12/2012	4.49

TABLE 3.D.1-1 STREAMFLOW DATA FROM RWANDA WATER BOARD MONITORING SITES				
LEVEL 1 CATCHMENT	STATION	INTEGRATION COST ($/MW)	DATE RANGE OF DATA	AVERAGE FLOW RATE (M^3/S)
Kivu	Bihongora	estimated from water level	8/2020-7/2021	5.66
Nyabarongo lower	Muhazi Outlet	estimated from water level	2018-2019	4.42
Nyabarongo Lower	Nemba	estimated from water level	3/2016-2/2017	3.99
Rusizi	Kivu Outlet	estimated from water level	2018-2020	132.77

The locations for each measurement site, determined using coordinates in the Hydropower Atlas documentation,[74] were matched to streams in GIS to determine the upstream drainage area and the catchment. In some cases, the coordinates placed a site near multiple streams, so the location was placed on the nearest stream. The measured flow rates for these sites were compared to an initial version of the regression model (described below), and where the difference between the observed and predicted flow produced a z-score greater than 3 or less than -3, the sites were assumed to not be matched correctly and excluded. The final model includes 254 of these data points between 0.001 and 51 m^3/s, with 230 of these between under 1 m^3/s.

TABLE 3.D.1-2. STREAMFLOW DATA FROM HYDROPOWER FEASIBILITY STUDIES			
HYDROPOWER SITE	YEAR OF STUDY	DRAINAGE AREA (KM^2)	ANNUAL AVERAGE FLOW RATE (M^3/S)
Janja[75]	1990	36.1	0.8
Gashashi[76]	1990	11.2	0.22
Nyirabubhombohombo[77]	1990	68.8	2
Nyirantaruko[78]	1990	51.1	1
Rusumo[79]	1971-2009	30,700	233

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[74] SHER Ingenieurs-Conseils, "Rwanda Hydropower Atlas Database" Rwanda Ministry of Infrastructure, 2008. https://www.getinvest.eu/market-information/rwanda/renewable-energy-potential/
[75] Final Design Report, Janja Hydro Power Plant, Annexure, 2, provided by REG.
[76] Final Design Report, Gashashi Hydro Power Plant, Annexure, 2, provided by REG.
[77] Final Design Report, Nyirabuhombohombo Hydro Power Plant, Annexure, 2, provided by REG.
[78] Detailed Study Report – Update 22nd of July 2020, HPP Nyirantaruko, provided by REG.
[79] Rusumo Falls Hydroelectric Power Development Project, Power Generation Plant Final Feasibility Study, January 2012, https://rusumoproject.org/index.php/en/publications/feasibility-studies.

Streamflow Regression Model. Several studies have modeled streamflow for ungauged streams based on a product of powers form of equation, including in Kentucky[80] and at the national level in the US.[81,] The Kentucky study related streamflow to drainage area, mean catchment elevation, latitude, and a coefficient accounting for annual precipitation and temperature. The national US study related streamflow to drainage area, annual precipitation, and temperature.

For this assessment, multiple iterations considered different variables, including drainage area, elevation, rainfall, temperature, elevation, slope, and landcover and considered these variables at different catchment levels. The nonlinear regression formula below was chosen and applied to the observed streamflow data, because it had the simplest form and displayed the best fit with observed data as subsequent statistical tests revealed.

$$Q = k \cdot \left(\frac{A}{1000}\right)^{w} \cdot \left(\frac{S}{10}\right)^{x} \cdot \left(\frac{R}{1000}\right)^{y}$$

Where:

Q = annual average flow rate (m^3/s);

A = drainage area for stream segment (km^2);

S = average slope of Level 3 catchment (%);

R = average annual rainfall of Level 2 catchment (mm).

For each of the streamflow data points described above, the location for each was used to determine the values for each regression model parameter noted below. For rainfall and landcover factor, data specific to the years of streamflow sampling were used for the model.

- *Drainage area* was extracted for each point from the drainage raster layer created from the elevation raster as described above.
- *Slope* values were generated for Level 3 catchments from the SRTM DEM data. The slope terrain analysis tool in QGIS was used to generate a slope raster layer, then the zonal statistics tool was used to calculate the mean slope for each catchment.
- *Annual average rainfall* values for Level 2 catchments taken from CHIRPS raster files for each year of observed streamflow.[82] The zonal statistics tool in QGIS was used to calculate the mean rainfall for each catchment for each year.

The best-fit values for each parameter were calculated using NCSS statistical software.[83] Values of the parameters k, w, x, and y are shown in Table 3.D.1-3 along with the standard error found for each. For all parameters, the standard error is less than 12%.

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80 US Geological Survey, 2002. Martin, G.R. Estimating Mean Annual Streamflow of Rural Streams in Kentucky, https://pubs.usgs.gov/wri/2002/4206/report.pdf.

81 INEEL, 2004. https://www1.eere.energy.gov/wind/pdfs/doewater-11111.pdf.

82 CHIRPS, https://www.chc.ucsb.edu/data/chirps.

83 Regression Analysis in NCSS, https://www.ncss.com/software/ncss/regression-analysis-in-ncss/.

TABLE 3.D.1-3 PARAMETER VALUES AND STARDARD ERRORS FOR STREAMFLOW REGRESSION MODEL					
PARAMETER	VALUE	AYMPTOTIC STANDARD ERROR	STANDARD ERROR PERCENT	LOWER 95% CONFIDENCE LEVEL	UPPER 95% CONFIDENCE LEVEL
k	11.9658	0.6723	5.6%	10.6426	13.2891
w	1.0008	0.0223	2.2%	0.9569	1.0446
x	0.4412	0.0473	10.7%	0.3482	0.5431
y	0.8431	0.0998	11.8%	0.6466	1.0395

Figure 3.D.1-1 shows a scatter plot of the estimated streamflow versus the observed streamflow values. The model could likely be improved with better streamflow measurements, especially at low flow rates. As noted above, the streamflow data for streams that do not have continuous monitoring may not accurately represent annual average flow rates, in particular, those taken from the Hydro Atlas, where information on date of measurement was not available. Also, the precision for the Hydro Atlas data is low (1-2 significant figures), so multiple measurement locations with differing parameters have the same observed streamflow value.

The nonlinear regression model can also be expressed in a linear regression form by taking the natural log of each term, as shown below.

$$lnQ = lnk + w \cdot ln(A/1000) + x \cdot ln(S/10) + y \cdot ln(R/1000)$$

Converting the nonlinear form of the regression model into its equivalent linear form facilitated an analysis of the validity of the model relative to its fit with observed data and the distribution of its residuals. The residuals of the linear form of the model were tested for normality, an assumption for linear regression.

The residuals were then calculated as the difference between the natural logs of the predicted and observed flow rates:

$$Residual = lnQ_{predicted} - lnQ_{observed}$$

The chi-squared goodness of fit test was applied to the linearized version of the regression model to test whether the hypothesis that the residuals are normally distributed, a key requirement for a valid predictive model. If true, the test statistic (i.e., square root of the sum of the square of the residuals for the linearized model) should be less than the computed chi-squared statistic. With 292 observations, the degrees of freedom are one fewer for the goodness of fit test, or 291. For this number of degrees of freedom and assuming a significance level of 0.05, the calculated chi-squared value is 332. This was compared to the test statistic of 251. Since the test statistic is less than the calculated chi-squared value, the values predicted by the regression model will fall within the 95% confidence interval. Hence the form of the regression model is valid and useful for establishing hydropower potential of individual stream segment in Rwanda. A frequency histogram of the residuals is shown in Figure 3.D.1-2 below.

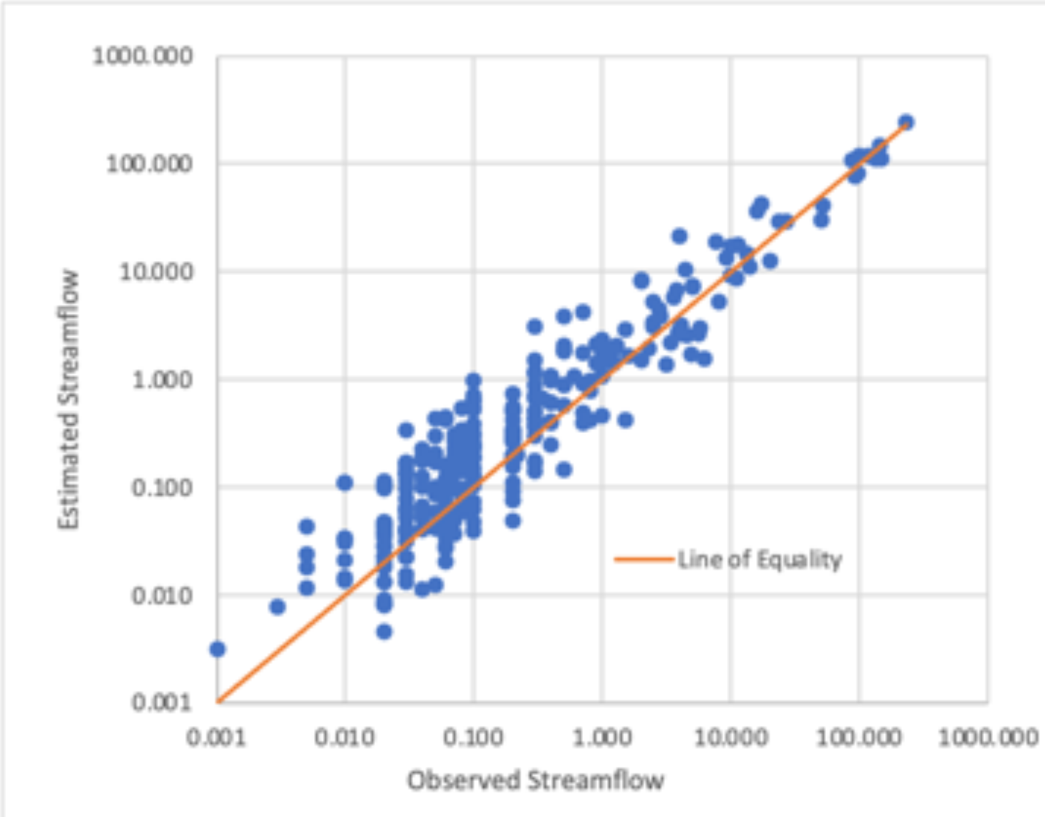


Figure 3.D.1-1 Streamflow Estimated by Model versus Observed Streamflow

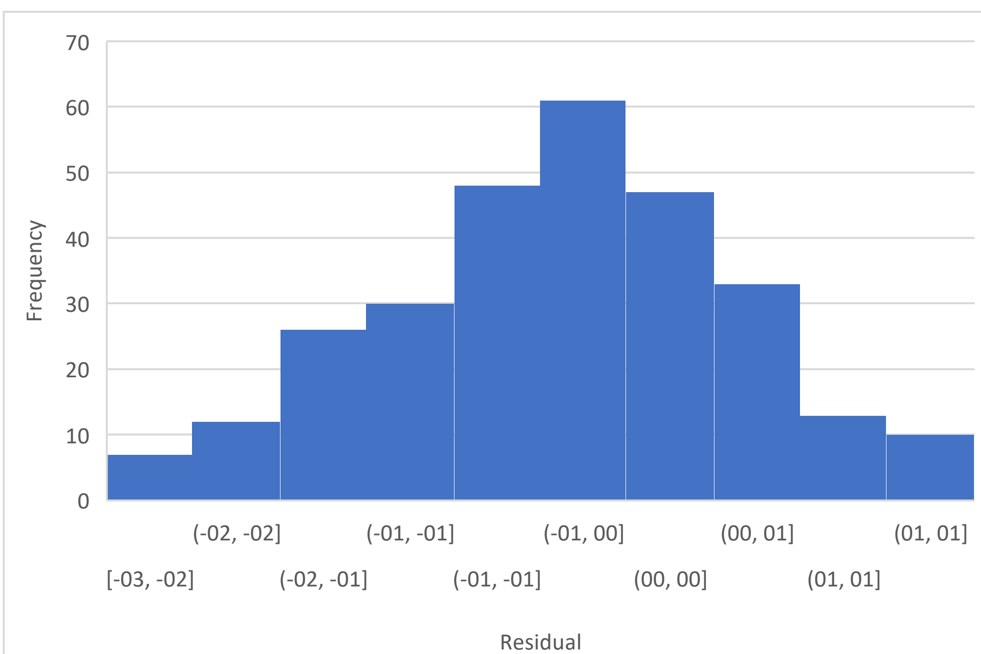


Figure 3.D.1-2 Frequency Histogram of Streamflow Regression Model Residuals

Streamflow Estimates. To estimate streamflow along all streams, the generated streams developed under the first step were split into 150-meter segments, with segments shorter than 150 meters deleted. The regression model was applied to each of the 150-meter stream segments to estimate the annual average streamflow. Average annual rainfall for 2018-2020 period, and the land cover factor for 2020 was used for estimating current streamflow. The elevation layer was used to determine the head for each segment, estimated as the difference in elevation between each segment endpoint.

The resulting map of stream flow estimates, in Figure 3.D.1-3 below, shows that there are a few major rivers with flow rates above 10 m^3/s (10-100 m3/s shown in orange and >100 m3/s shown in red), but most stream segments fall below 10 m^3/s (shown in blue, green, and yellow).

Physical Resource Estimates. The physical resource from each stream segment in watts was estimated using the streamflow and head estimates based on the formula below (1 watt = 1 kg-m^2/s^3).[84]

$$\textit{Physical Resource watts} = \rho \cdot g \cdot h \cdot Q$$

Where:

ρ = density of water (1000 kg/m^3)

g = acceleration due to gravity (9.81 m/s^2)

h = head (m)

Q = annual average flow rate (m^3/s)

Head was determined for each stream segment based on the DEM layer. The elevation was determined at the upstream and downstream endpoints of each segment and the difference taken. Figure 3.D.1-4 is a map of stream head, showing that there are a few segments in the southwest corner of the country with head over 100 meters, but most segments are below 100 meters.

The physical resource estimate for each 150-meter segment is shown in Figure 3.D.1-5. Summing the physical resource for all stream segments gives a value of 27,656 MW hydro physical resource available in Rwanda.

[84] Hydropower, The Engineering Toolbox, https://www.engineeringtoolbox.com/hydropower-d_1359.html.

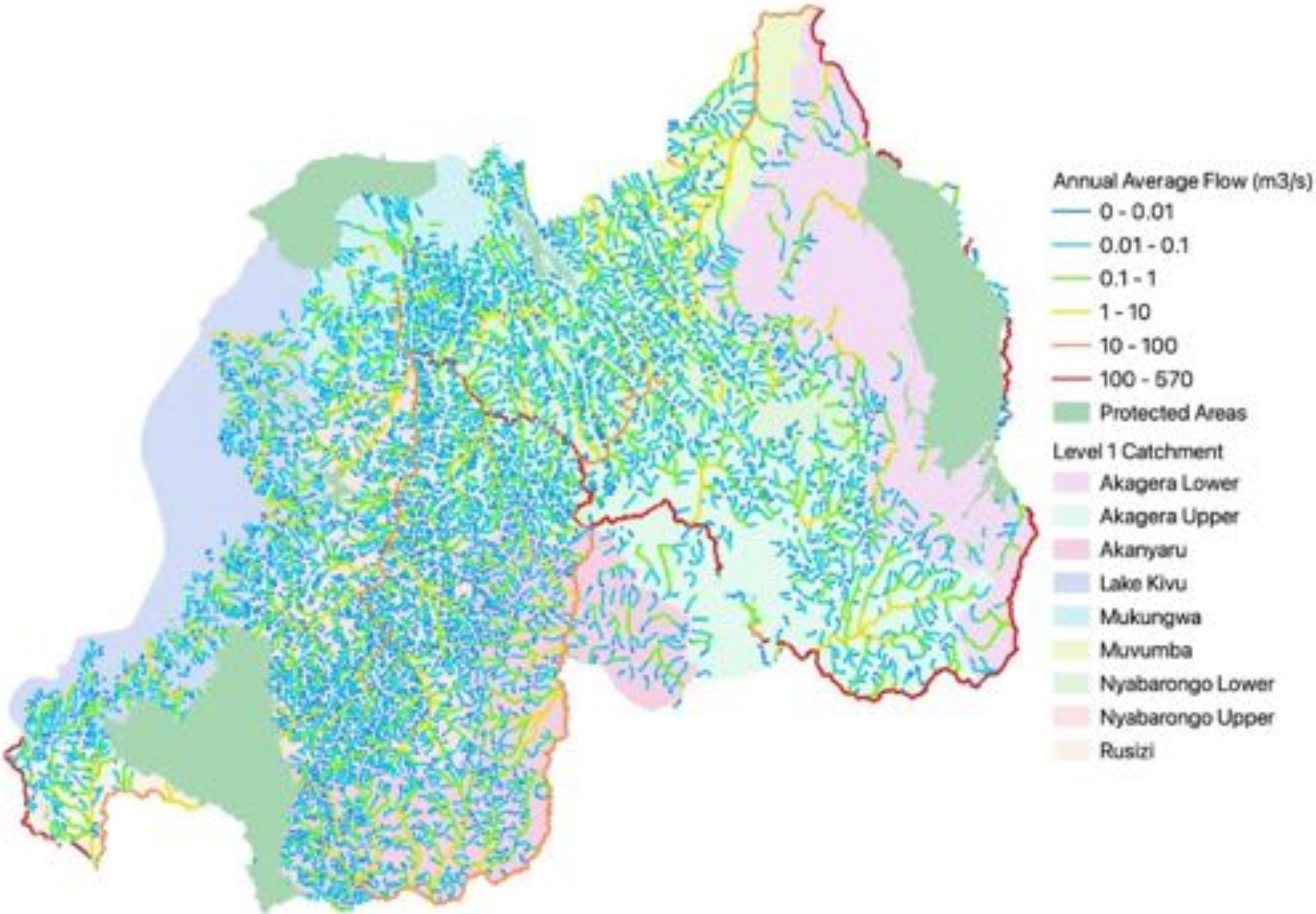


Figure 3.D.1-3 Annual Average Stream Flow Estimates for Stream Segments Outside of Protected Areas

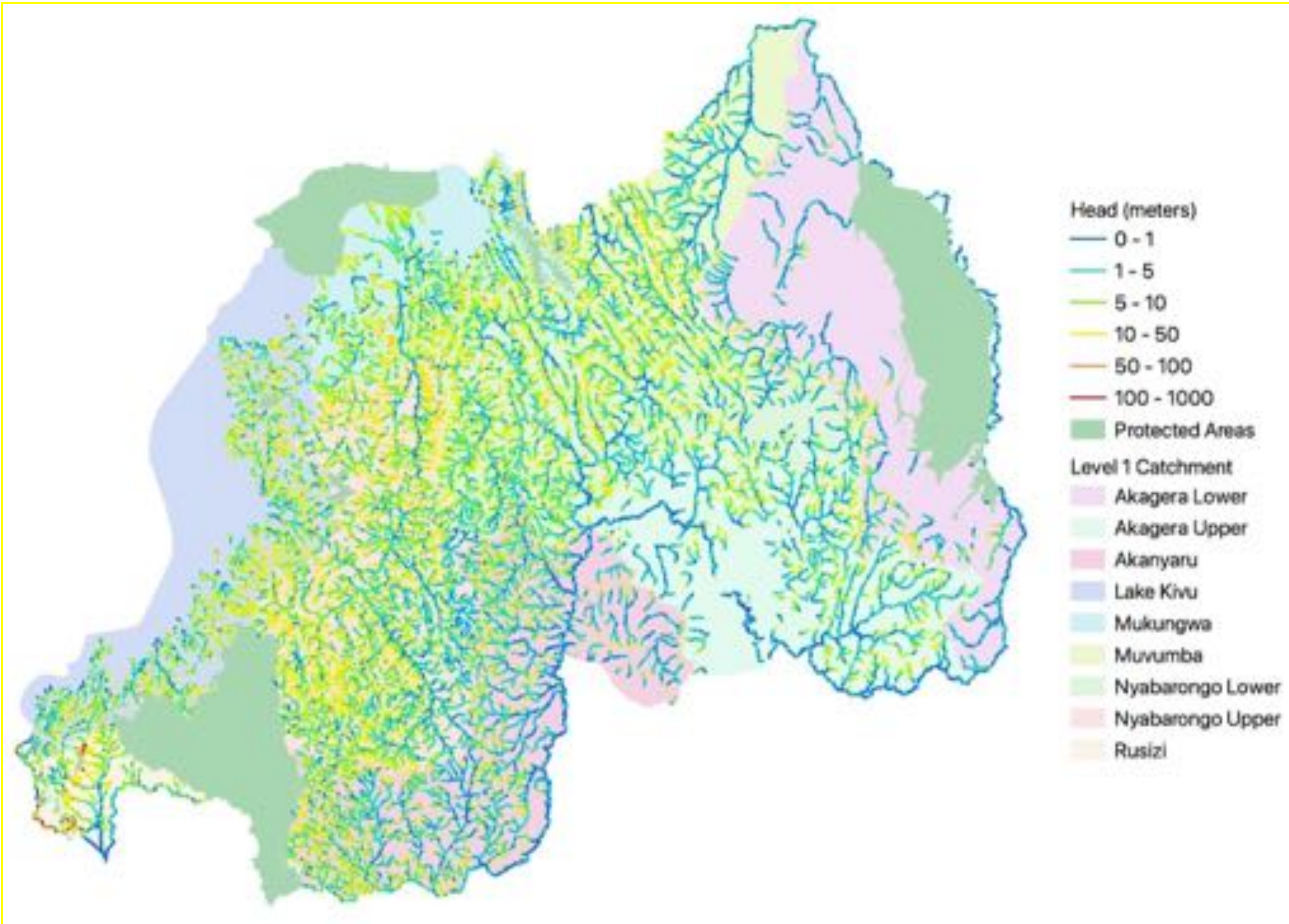


Figure 3.D.1-4 Head (meters) of 150-meter String Segments

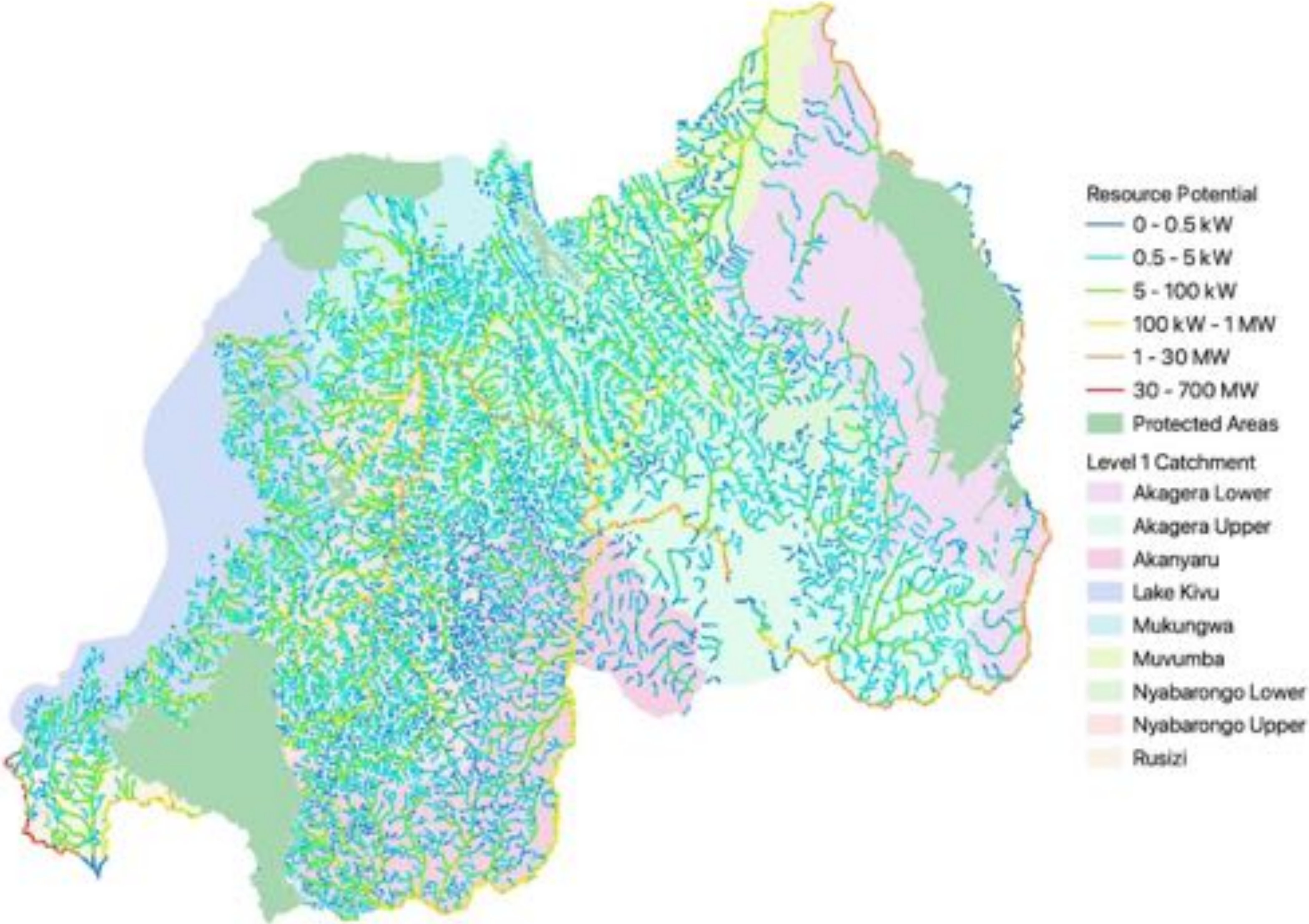


Figure 3.D.1-5 Physical Resource of 150-meter Stream Segments

3.D.2. TECHNICAL POTENTIAL

The **methods and data sources** used to characterize the technical potential for hydropower are provided in the following sections, and the **estimated results** of total (exploited and unexploited) "nameplate" capacity and "available" capacity (MW) and related annual generation (MWh) are summarized in the table below. **A total technical potential of 1,363 MW of "nameplate" capacity (exploited and unexploited) is estimated for hydro. If no new capacity beyond currently planned capacity can be added to the Rusizi, the technical potential would be approximately 900 MW of "nameplate" capacity (assuming 156 MW of "nameplate" capacity for Rusizi I-IV).**

TABLE 3.D.2-1 HYDROPOWER TECHNICAL POTENTIAL ESTIMATES (EXPLOITED AND UNEXPLOITED)

	ALL STREAM SEGMENTS >0.5 KW POTENTIAL	SEGMENTS WITH >5% SLOPE	RWANDA PORTION ONLY		INCLUDING ONLY 2 NEW PLANTS ON RUSIZI	
RIVER	AVAILABLE MW	AVAILABLE MW	NAMEPLATE MW	AVAILABLE MW	NAMEPLATE MW	AVAILABLE MW
Total	**13,476**	**9,860**	**5,019**	**3,631**	**1,363**	**986**
Akagera	2,141	95	44	32	44	32
Akanyaru	204	38	32	23	32	23
Mukungwa	39	13	18	13	18	13
Nyabarongo	797	135	187	135	187	135
Ruhwa	65	34	24	17	24	17
Rusizi	9,382	9,226	4,276	3,093	620	448
Satinsyi	21.5	11.7	16	11.7	16	11.7
Sebeya	9.0	5.7	8	5.7	8	5.7
All Others	817	300	415	300	415	300

The technical potential of each segment in watts was estimated based on a similar formula as the physical resource, with the addition of an efficiency factor for electrical generation and a factor reflecting the fraction of annual flow used for generation, as shown in the formula below (1 watt = 1 $kg\text{-}m^2/s^3$). The assumed turbine-drive-generator efficiency was set at 75%, a typical value for modern hydropower plants, and the percent of streamflow available for generation was assumed to be 65% to allow for minimum environmental flow.[85]

$$\textit{Technical Potential watts} = \eta \cdot \rho \cdot g \cdot h \cdot Q \cdot p$$

Where:

η = combined efficiency of turbine, drive, and generator (assumed to be 75%)

ρ = density of water (1000 kg/m^3)

g = acceleration due to gravity (9.81 m/s^2)

h = head (m)

Q = annual average flow rate (m^3/s)

p = percent of annual streamflow available for generation (assumed to be 65%)

Applying the streamflow model with these conservative estimates of efficiency and flow availability was assumed to provide a reasonable estimate of total available capacity on all streams across the country. To narrow down the total capacity to the stream segments that are most technically feasible for hydropower exploitation, the segments were filtered by potential capacity (only those greater than 0.5 kW, the smallest size for micro hydro) and slope (only those greater than 5%). Rivers on borders were divided by 3 (Akagera, Akanyaru, Rusizi) or 2 (Ruwha) to estimate the potential available to Rwanda. Table 6 shows a total estimated hydro technical potential for Rwanda of 3,631 MW along with estimated technical potential by river. The installed capacity was estimated based on the weighted average capacity factor of 72.3%, based on the existing and committed capacity.

As shown in Table 3.D.2-1, most of the total potential capacity is on the Rusizi River. More detailed study, including field studies, will be needed to determine how much of this capacity can be exploited, and where potential new power plants can be sited considering potential environmental effects and displacement of residents. For the purposes of estimating an upper limit on potential for the LEAP modelling, only 2 new power plants on this river were assumed, one between Rusizi I and II, and one between Rusizi II and III, as shown in Figure 3.D.2-1 below which results in a **total technical potential estimate of 1,363 MW of "nameplate" capacity and 986 MW of "available capacity" (exploited and unexploited). If no new capacity beyond currently planned capacity can be added to the Rusizi, the technical potential would be approximately 653 MW of available capacity (assuming 115 MW of available capacity for Rusizi I-IV).**

[85] Pastor, A.V., et al. (2013). Accounting for environmental flow requirements in global water assessments. Hydrology and Earth System Sciences Discussions. 10. 14987-15032. 10.5194/hessd-10-14987-2013. https://www.researchgate.net/publication/260724522_Accounting_for_environmental_flow_requirements_in_global_water_assessments.

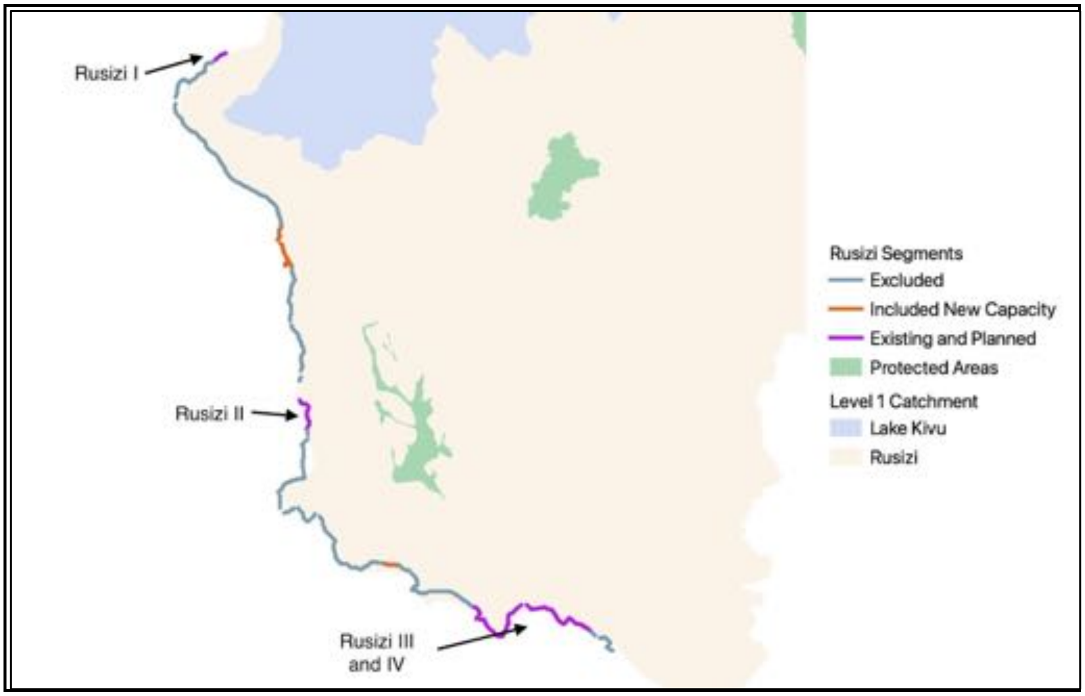


Figure 3.D.2-1 Hypothetical Future Exploitation of Rusizi River Capacity

Comparison to Existing and Planned Capacity provided by REG

The estimated technical capacity values were compared to capacity values provided by REG for existing and planned generation plants. To this end, the estimated 150-meter stream segments were matched to existing and planned these plants based on a combination of location coordinates, satellite imagery, and other available information, such as capacity and head. The estimated available capacity for all planned and existing plants (262 MW) was estimated based on the total available capacity and a capacity factor of 72.3%, the weighted average capacity for the existing and committed plants in the LCPDP. While the modeled estimates do not accurately predict the available capacity for each individual hydropower plant, the overall estimate of available capacity for these stream segments (258 MW) is close to the estimated available capacity from all planned and existing plants provided by REG.

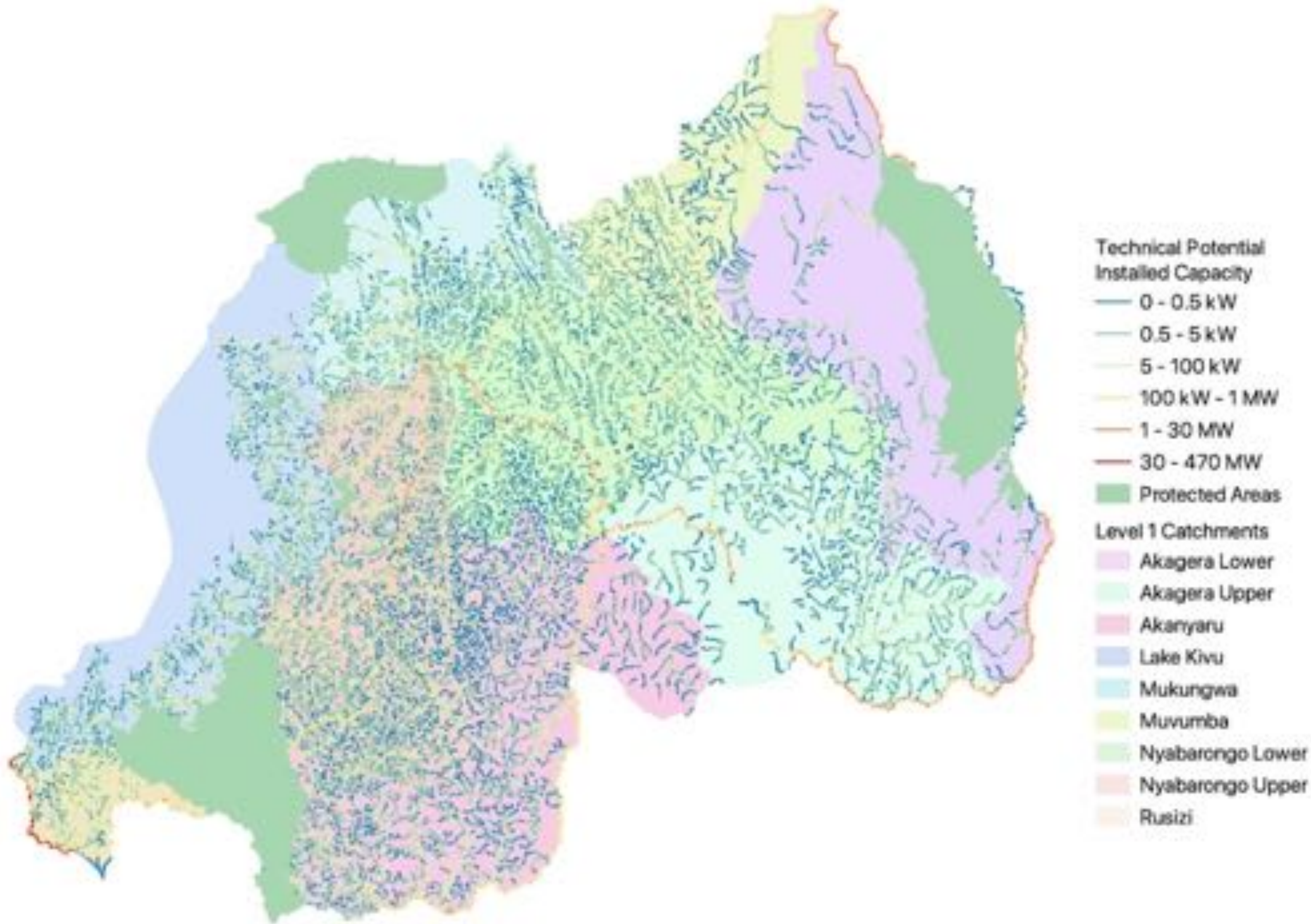


Figure 3.D.2-2 Technical Potential of 150-meter Stream Segments

TABLE 3.D.2-2 EXISTING AND PLANNED HYDROPOWER CAPAITY PROVIDED BY REG COMPARED TO MODELED CAPACITY ESTIMATES FOR MATCHED STREAM SEGMENTS

	DATA SUPPLIED BY REG					ESTIMATED FROM STREAMFLOW MODEL		
PLANT NAME[86]	STATUS	NAME-PLATE MW	AVAILABLE MW	DESIGN FLOW (M^3/S)	HEAD (M)	EST. AVAIL-ABLE MW	ESTIMATED ANNUAL FLOW (M^3/S)	HEAD (M)
Agatobwe	Existing	0.39	0.07	1.9	24	0.37	2.83	27.45
Base I	Planned	2.9	NA	4.1	78.6	5.29	7.92	142.51
Base II	Planned	2.9	NA	4.1	79.5	2.88	7.83	79.85
Bihongora	Planned	4.22	NA	1.1	470.59	1.13	1.30	382.12
Cyimbili	Existing	0.3	0.15	0.22	165	0.08	0.12	152.45
Gaseke	Existing	0.582	0.5238	2.3	38	0.27	1.47	39.45
Gashashi	Existing	0.28	0.112	0.35	96	0.08	0.13	125.34
Giciye I	Existing	4	1.6	4	120.5	1.77	2.69	140.51
Giciye II	Existing	4	1.6	4	121.3	1.62	2.88	115.39
Giciye III	Planned	9.8	9.6	4	278.4	4.66	3.43	280.99
Gihira	Existing	1.8	1.26	3.2	62.4	1.23	3.97	68.84
Gisenyi	Existing	1.7	1.105	2.5	77.88	1.78	4.27	102.67
Janja	Existing	0.2	0.16	0.336	78	0.33	0.64	111.38
Kavumu	Planned	0.334	NA	N/A	N/A	0.32	0.67	98.24
Keya	Existing	2.2	1.1	3	85.5	0.35	0.87	90.81
Kigasa	Existing	0.272	0.1	0.4	80	0.08	0.24	84.19
Kore	Planned	0.74	NA	0.45	186.8	0.27	0.16	379.26
Mazimeru	Existing	0.5	0.245	0.3	N/A	0.21	0.14	339.10
Muhembe	Planned	0.3	0.2	N/A	N/A	0.39	2.25	34.58
Mukungwa I	Existing	12	6	14	114	8.55	13.59	130.65
Mukungwa II	Existing	3.6	2.628	13.6	30.27	0.04	0.18	47.12
Murunda	Existing	0.1	0.045	0.2	69	0.05	0.16	71.44
Musarara	Existing	0.4	0.2205	0.1	N/A	0.43	1.79	48.11
Mutobo	Existing	0.2	0.09	0.22	123	1.13	1.75	130.05
Ngororero	Planned	2.4	NA	2.6	111.5	1.90	3.54	112.91
Nkora	Existing	0.68	0.34	0.7	110.8	0.23	0.41	123.57
Nshili	Existing	0.4	0.24	N/A	N/A	0.21	0.74	58.87

[86] Ntaruka (11.25 MW) was not included in this table because it uses a tunnel between lakes and is not on a stream segment.

TABLE 3.D.2-2 EXISTING AND PLANNED HYDROPOWER CAPAITY PROVIDED BY REG COMPARED TO MODELED CAPACITY ESTIMATES FOR MATCHED STREAM SEGMENTS

	DATA SUPPLIED BY REG					ESTIMATED FROM STREAMFLOW MODEL		
PLANT NAME[86]	STATUS	NAME-PLATE MW	AVAILABLE MW	DESIGN FLOW (M^3/S)	HEAD (M)	EST. AVAIL-ABLE MW	ESTIMATED ANNUAL FLOW (M^3/S)	HEAD (M)
Ntaruka A	Planned	2	1.6	12.6	19.8	1.24	11.63	22.28
Nyabahanga I	Existing	0.2	0.11	N/A	N/A	0.16	0.72	47.91
Nyabarongo I	Existing	28	13.44	54	59	28.22	44.85	131.84
Nyabarongo II	Planned	43.5	28.3	99.9	49	23.88	100.21	49.12
Nyamyotsi I	Existing	0.1	0.06	0.104	123	0.37	0.57	124.54
Nyamyotsi II	Existing	0.1	0.06	0.104	N/A	0.31	0.61	111.70
Nyirabuhombo-hombo	Existing	0.5	0.175	0.9	81	0.42	1.26	80.08
Nyirahindwe I	Planned	1.2	NA	N/A	N/A	1.26	0.78	332.19
Nyirahindwe II	Planned	1.2	NA	N/A	N/A	0.81	1.06	159.10
Nyirantaruko	Existing	1.84	1.2	1.087	189.9	0.65	0.93	153.91
Nyundo	Planned	4.5	NA	14	42.3	3.03	15.80	43.78
Rubagabaga	Existing	0.45	0.2	1.8	153.5	0.83	1.11	168.72
Rucanzogera	Planned	1.9	NA	1.05	N/A	0.02	0.04	90.53
Rugezi	Existing	2.6	1.3	2.2	135	2.22	3.01	154.38
Rukarara I	Existing	9	3.6	8	137	3.03	4.94	123.91
Rukarara II	Existing	2.2	1.155	5.6	42.37	1.02	4.34	48.16
Rukarara V	Existing	2.3	2	N/A	N/A	2.72	7.01	80.15
Rukarara VI	Planned	9.5	NA	5	110	3.63	6.82	112.02
Rukore	Planned	2	NA	N/A	N/A	0.99	1.15	207.44
Rusizi I	Unavail.	4.1	NA	85.6	24	4.53	117.95	23.97
Rusizi II	Existing	12	10.68	172.5	28.5	9.22	134.53	48.06
Rusizi III	Planned	48.33	45.9	150	107.5	29.29	142.05	127.54
Rusizi IV	Planned	95	NA	N/A	N/A	78.64	116.54	503.37
Rusumo	Planned	26.7	25.4	250	37	23.71	315.87	47.47
Rwaza Muko	Existing	2.6	1.56	12	26.46	1.22	10.40	25.04
Rwondo	Planned	2.6	NA	1.7	163	1.08	1.44	167.03
	Total	**362**	**262**[87]	**946**[88]		**258**	**980**	

[87] Available capacity estimated based on weighted average capacity factor of 72.3%.

[88] This value does not include design flow for planned plants, where the data was not available.

3.D.3. GRID-INTEGRATION COSTS

To estimate grid-integration costs for hydropower installations, 150-meter segments were grouped into longer segments based on the original delineated stream layer into hypothetical plants. The lengths vary based on the number of contiguous stream segments in the generated layer. These segment groupings are not optimized in terms of capacity or connection costs, as this would require more detailed information, including field studies. However, these random groupings can provide estimates of the distribution of costs in different locations.

Grid-integration costs were estimated based on distances to transmission infrastructure (substations and high-voltage lines) and roads using the same methods as used for solar resources. A detailed description of the methods and cost values used for these estimates can be found in Section 3.C.3.

Costs and associated capacity were divided into 4 cost classes as shown below in Table 3.D.3-1 Grid integration costs computed for all stream segments were then divided into four Grid Integration Cost Classes as follows:

- Cost Class I: lowest 0.5% of integration costs
- Cost Class II: next 1 % of costs (0.5%-1.5%)
- Cost Class III: next 3.5% (1.5%-5%)
- Cost Class IV: over 5%.

The potential capacity is shown including the total capacity and when assuming only the 3 hypothetical new plants on the Rusizi.

TABLE 3.D.3-1. GRID INTEGRATION COST CLASSES FOR POTENTIAL HYDROPOWER NOT INCLUDING CURRENT EXISTING AND PLANNED GENERATION

CLASS	INTEGRATION COST ($/MW)			TECHNICAL POTENTIAL (AVAILABLE MW)	POTENTIAL WITH LIMITED NEW RUSIZI (AVAILABLE MW)
	LOW	HIGH	MEAN		
I	$115,180	$222,323	$140,050	3,021	411
II	$222,323	$448,498	$357,706	122	119
III	$448,498	$1,343,006	$855,436	84	84
IV	$1,343,006	$4,204,685,316	$177,838,817	146	146
			Total	3,373	761

All Class I segments are along the Rusizi, where all segments have high capacity and are near transmission infrastructure. One section of Rusizi is in the Class II category. Most of the Class II segments are along the Nyabarongo River. As noted above, the selection of segment groups was not optimized for capacity and costs, so grid connection costs could possibly be lowered with careful siting of plants. Class III segments can be seen near transmission lines. Class IV segments are those with low capacity (many in the 0.5-1 kW range) and greater distance from transmission infrastructure. Class III and IV segments could be exploited in mini-grids along with other nearby micro hydropower plants or generation from other sources, and possibly connected to the national grid in the future as transmission infrastructure expands to accommodate other generation.

3.D.4. EQUIPMENT, INSTALLATION AND O&M COSTS

This section summarizes the selection of equipment cost information for hydropower technology applications covered above to support assessment of the economic potential (EP). These costs include for each technology, at least the following 3 components:

- Equipment and other materials costs: for example, pipes, hydraulic turbine, and generator, as well as dams and buildings.
- Land acquisition.
- Installation labor costs.
- Ongoing O&M costs: replacement of parts, land lease costs, insurance, etc.

Detailed costs data was available for several hydropower projects in Rwanda, as shown in Table 3.D.4-1. Cost values were converted to 2021 US dollars (USD) using the latest consumer price index values from the World Bank. These costs exclude the costs for grid integration which were assessed separately in the previous section. When available, more detailed cost information was also included. Land acquisition costs were broken out from other project costs for only two of the projects shown in Table 3.D.4-1, Nyirantaruko (1.6% of total investment) and Rusumo (0.3% of total investment). Therefore, land acquisition was included as part of installed costs. There was no apparent trend in installed costs between project sizes. Cost values considered for EP modeling were estimated as the average of all projects shown.

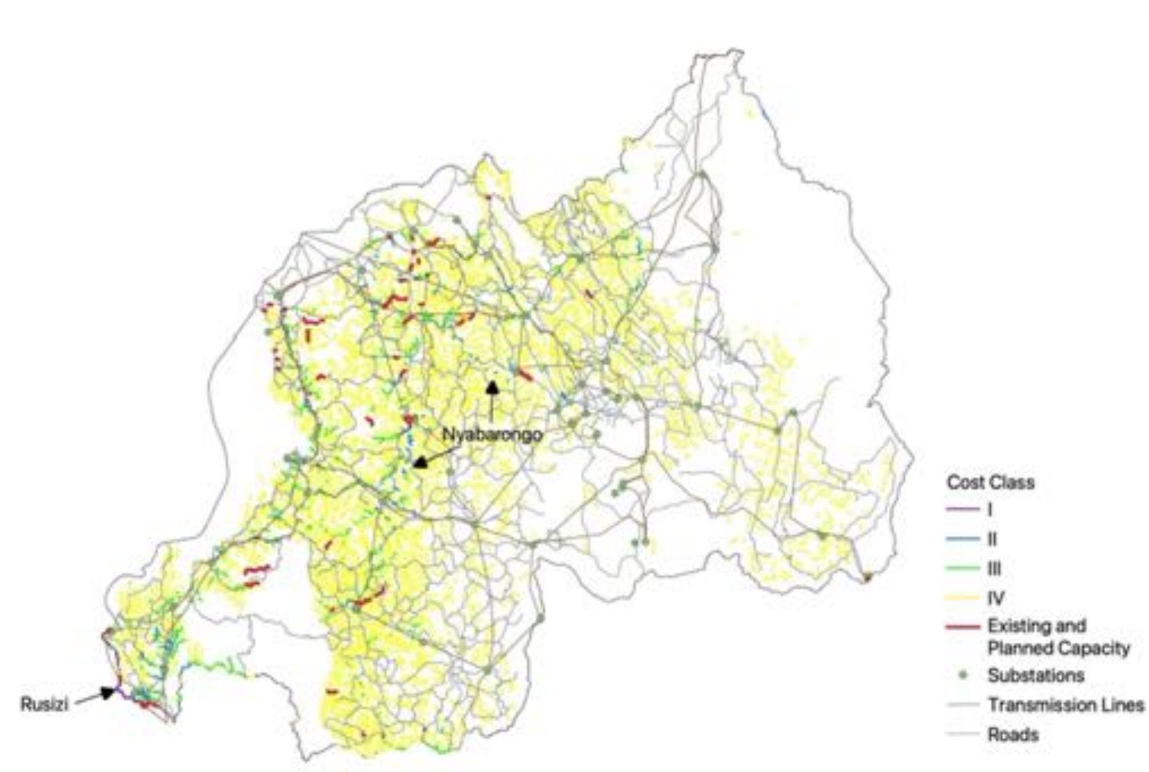
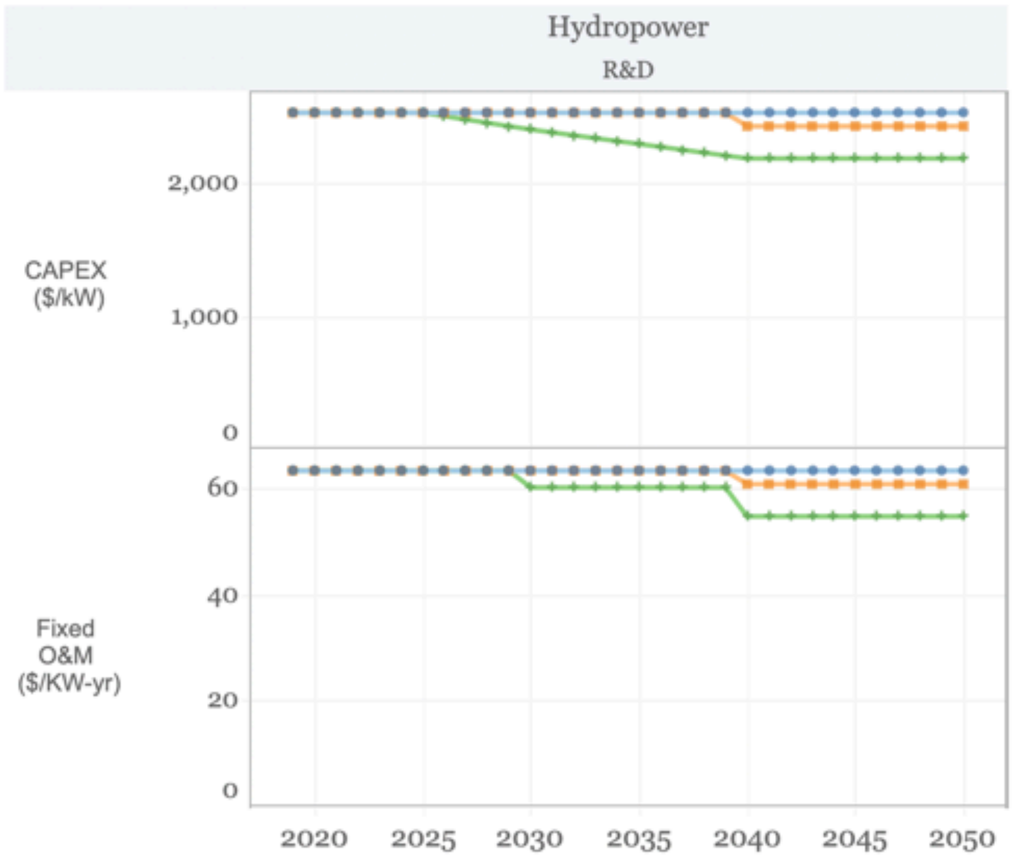


Figure 3.D.3-1 Grid Integration Costs

TABLE 3.D.4-1 ECONOMIC POTENTIAL MODELING COST INPUTS CONSIDERED AND SELECTED FOR HYDROPOWER INSTALLATIONS			
TECHNOLOGY DESCRIPTION	TOTAL INSTALLED COST ($2021/KW)	ANNUAL O&M ($2021/KW-YR)	NOTES AND CITATIONS
Janja, 2006, 200 kW	$3,991	$162	Grid integration costs excluded. Source: Feasibility study provided by REG
Gashashi, 2006, 200 kW	$3,296	$214	
Nyirabuhombohombo, 2006, 500 kW	$3,303	$244	
Nyirantaruko, 2020, 1.84 MW	$3,923	$167	
Mukungwa II, 2006, 2.5 MW	$2,045	$92	
Rusumo, 2014, 90 MW	$3,648	$109	Grid integration costs excluded. Source: Feasibility study provided by REG, available at: https://rusumoproject.org/index.php/en/publications/feasibility-studies
Selected Value for Hydropower Projects	**$3,727**	**$142**	Average of project values shown above.

Hydropower is a well-developed technology and costs are not expected to change significantly over the forecast period. Figure 3.D.4-1 provides NREL's US forecast of installed costs and O&M using three different scenarios and compared to the median forecast of industry analysts ["Med (US)"]. The conservative scenario is based on lower levels of research and development (R&D) investment, minimal technology advancement and current global module pricing. The moderate scenario is based on moderate R&D investment, industry technology roadmaps being achieved, but no substantial innovations or new technologies introduced into the market. The advanced scenario is based on higher levels of R&D spending that generates substantial innovation, which allows for historical rates of development to continue. The conservative scenario represents lower expected declines in costs than both the other scenarios as well as analyst forecasts. Regionally specific estimates were not identified for the expected declines in equipment installation costs. For the economic potential modeling purposes, the conservative forecast from NREL was adopted, which assumes that costs will remain flat.



Blue = conservative forecast, orange = moderate, green = advanced.

Figure 3.D.4-1 NREL Annual Technology Database CAPEX and O&M Forecasts for Hydropower

3.E. WIND RESOURCE ASSESSMENT

Lake Turkana Wind Farm, Kenya
KENYA ELECTRICITY TRANSMISSION CO.

3.E.1. PHYSICAL RESOURCE AVAILABILITY

The EAEP Team characterized Rwanda's wind **physical resource** was characterized based on data from the Global Wind Atlas (version 3.0),[89] which provides GIS data on wind resources at 250-meter resolution. Wind resource is often expressed as power density, a quantitative measure of the energy available in the wind at a particular location and height, in terms of mean annual power per unit of swept area of turbine blades. Power density is calculated based on wind speed and air density and can vary with turbine hub height. As shown in the map below for power density at 100-meter hub height, most of the country has a very low wind resource. However, there are some areas at high elevation, especially on the mountains east of Lake Kivu, that have power densities in the 200-400 W/m^2 range, typically considered as being marginal to fair wind resource.

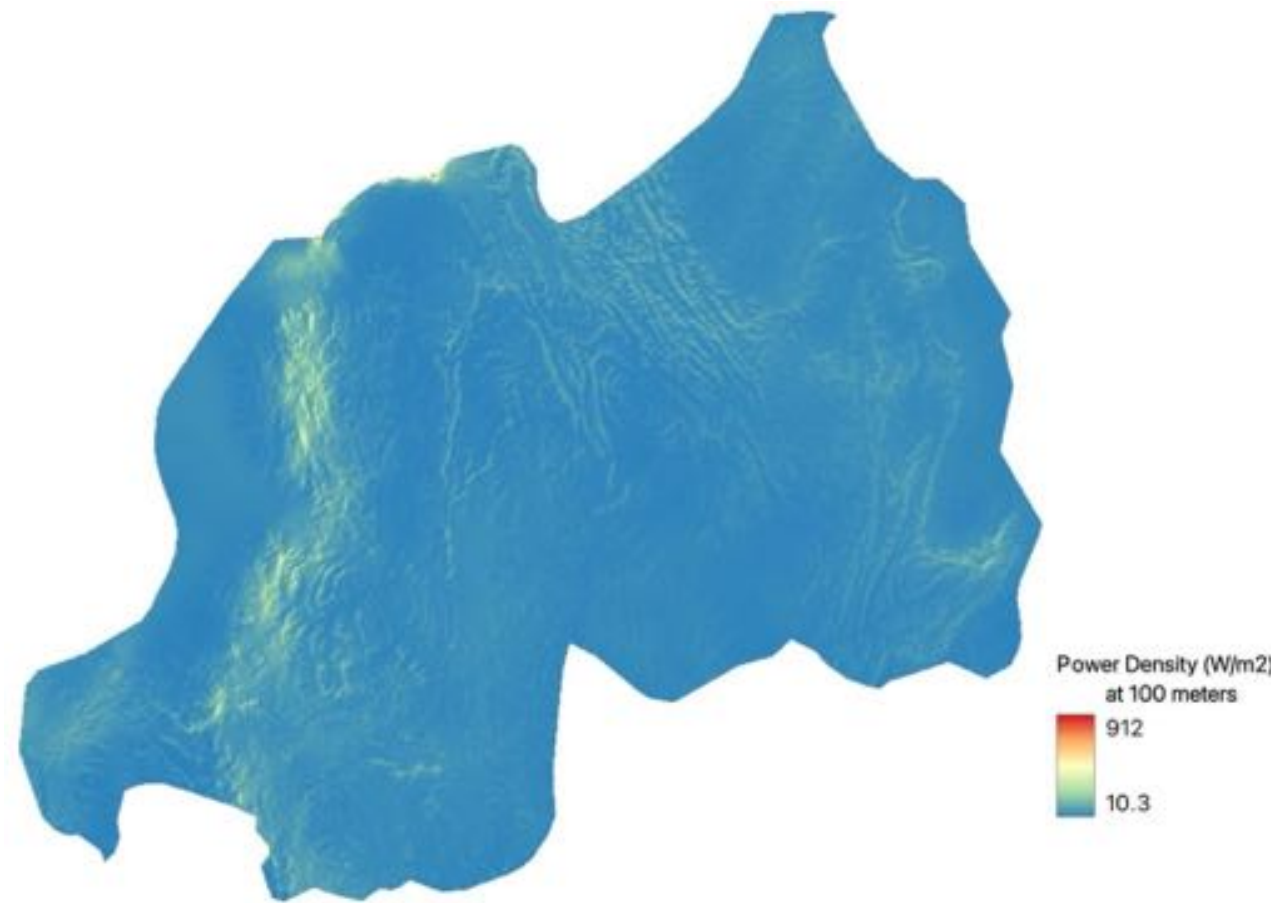


Figure 3.E.1-1 Wind Power Density (W/m2) at 100 Meters Hub Height[90]

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[89] Global Wind Atlas, https://globalwindatlas.info/.
[90] Source: Power density raster data downloaded from GWA 3.0

3.E.2. TECHNICAL POTENTIAL

The wind **technical potential** for Rwanda was assessed for the following wind priority technologies selected by REG for the assessment of technical potential:

- Horizontal axis wind turbine (HAWT), upwind facing system
- Horizontal axis wind turbine (HAWT), downwind trailing system

The **methods and data sources** used to characterize the technical potential for the above technology applications are provided in the following sections, and the **estimated results** of total (exploited and unexploited) "nameplate" capacity and "available" capacity (MW) and related annual generation (MWh) are summarized in the table below. **A total technical potential of 715 MW of "nameplate" capacity (exploited and unexploited) was estimated for wind at a hub height of 100 meters in Rwanda.**

TABLE 3.E.2-1 WIND TECHNICAL POTENTIAL ESTIMATES (EXPLOITED AND UNEXPLOITED)

HUB HEIGHT	NUMBER OF TURBINES	AVERAGE CAPACITY FACTOR OF TURBINE SITES	TOTAL POTENTIAL NAMEPLATE CAPACITY (EXPLOITED AND UNEXPLOITED MW)	TOTAL AVAILABLE CAPACITY (EXPLOITED AND UNEXPLOITED MW)	TOTAL GENERATION (MWH)
50 meters	412	30%	185	50	435,776
100 meters	227	28%	715	225	1,968,801
150 meters	208	31%	1,098	309	2,710,568

Please note that these potential for the different hub heights are not additive but indicate the total potential if all wind installations used this size turbine.

In particular, the EAEP Team followed the major steps below to determine the wind technical potential in Rwanda:

1. Define total area with technical potential as well as sub-areas where wind farms could be potentially located.
2. Estimate rotor diameter and swept areas for hub heights of 50, 100, and 150 meters.
3. Determine turbine count for each sub-area with technical potential.

Definition of Technical Area. As shown in the table below, power density below 200 W/m^2 is considered to have poor resource potential. Therefore, as a first step in defining the technical area, all areas within Rwanda's boundaries with average wind power densities greater than 200 W/m^2 were extracted from the Global Wind Atlas power density raster file for each available hub height (50, 100, 150 m) to create the overall initial wind resource areas for each hub height. Data for 200-meter hub height is also available; however, at this time, turbines this tall are only used for offshore installations.

TABLE 3.E.2-2. WIND POWER CLASSES[91]		
WIND POWER CLASS	WIND POWER DENSITY (W/M^2)	RESOURCE POTENTIAL RATING
1	0-200	Poor
2	200-300	Marginal
3	300-400	Fair
4	400-500	Good
5	500-600	Excellent
6	600-800	Outstanding
7	>800	Superb

The technical area was then narrowed down by subtracting:

- Protected areas.
- Areas with terrain ruggedness index (TRI) greater than 25, where development would require land leveling making it more difficult and expensive; and
- Areas around buildings, roads, and transmission lines, where a falling turbine could damage infrastructure.

Protected areas, terrain ruggedness, and infrastructure data sources and GIS analyses are described in more detail in the GIS section of this report.

To delineate areas around infrastructure, buffers of 110% of the tip height of the turbines for each hub height, based on calculations explained in the section below, were placed around building footprints, roads, and nearby transmission lines.[92,93]

[91] Introduction to Wind Power, http://web.mit.edu/wepa/teaching/MIT.2015.IntroductionWindPower.pdf.
[92] US DOE, 2021. https://windexchange.energy.gov/files/u/publication/document_upload/6872/78591.pdf.
[93] ENA, 2012.
https://www.spenergynetworks.co.uk/userfiles/file/Energy_Networks_Association_Separation_Wind_Turbines_Overhead.pdf.

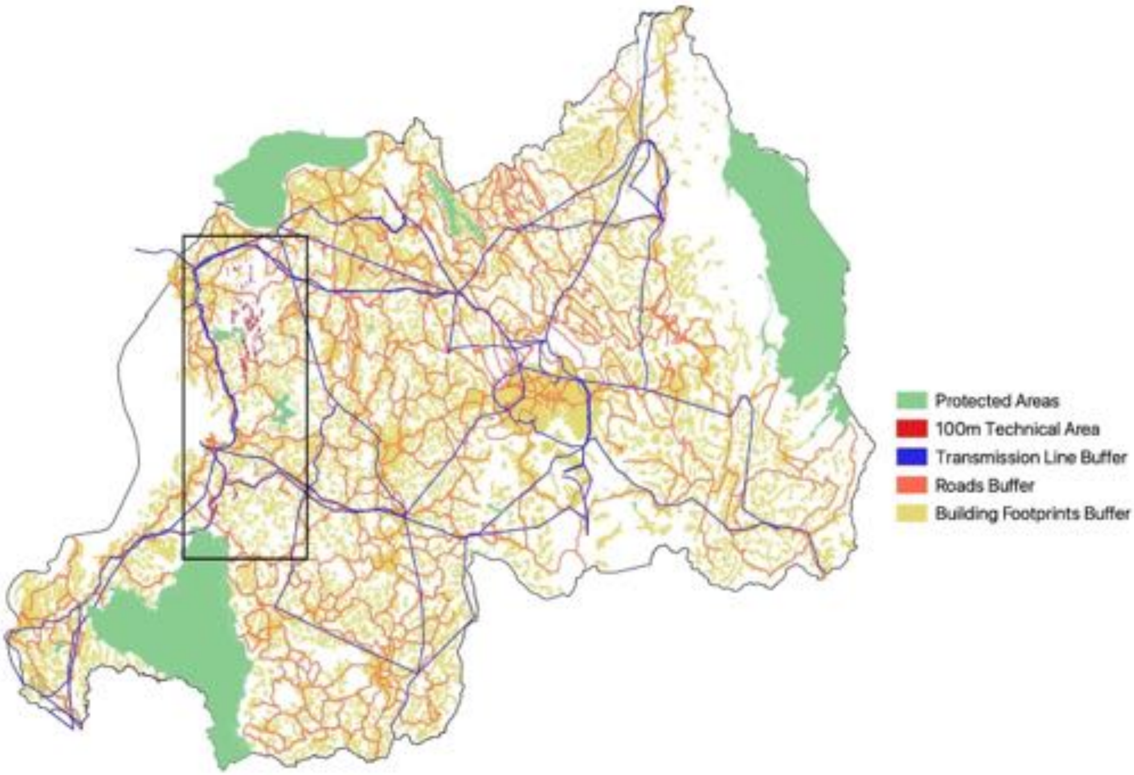
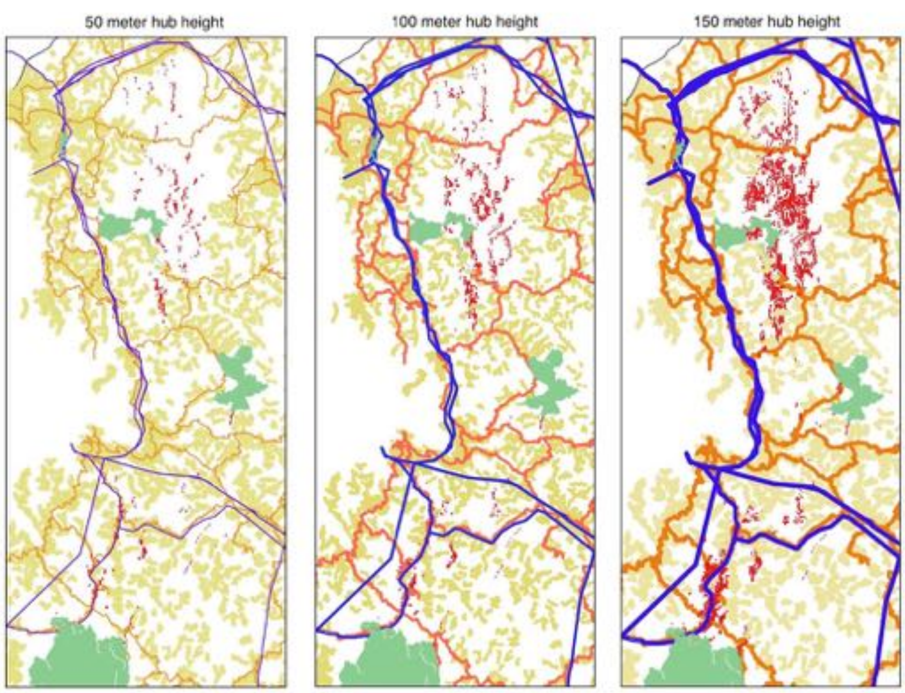


Figure 3.E.2-1. Map of Technical Area



Note: There are additional areas with very small technical areas in the north and southeast of the country.

Figure 3.E.2-2. Map of Technical Area with Enlarged Area for Each Hub Height

TABLE 3.E.2-3 WIND TECHNICAL AREA SUMMARY BY HUB HEIGHT (SOURCE: EXTRACTED FROM GWA 3.0 AND FILTERED AS DESCRIBED)		
HUB HEIGHT	TOTAL TECHNICAL AREA (KM^2)	AVERAGE POWER DENSITY (W/M^2)
50 meters	12.8	250
100 meters	24.4	240
150 meters	72.1	248

Estimation of Rotor Diameter, Tip Height, and Swept Areas. The EAEP Team estimated rotor diameters for 50- and 100-meter hub heights were estimated for each hub height based on data from the USGS wind turbine database.[94] Data for turbines installed from 2010 to the present were plotted to find the relationship between hub height and rotor diameter, as shown in the figure below.

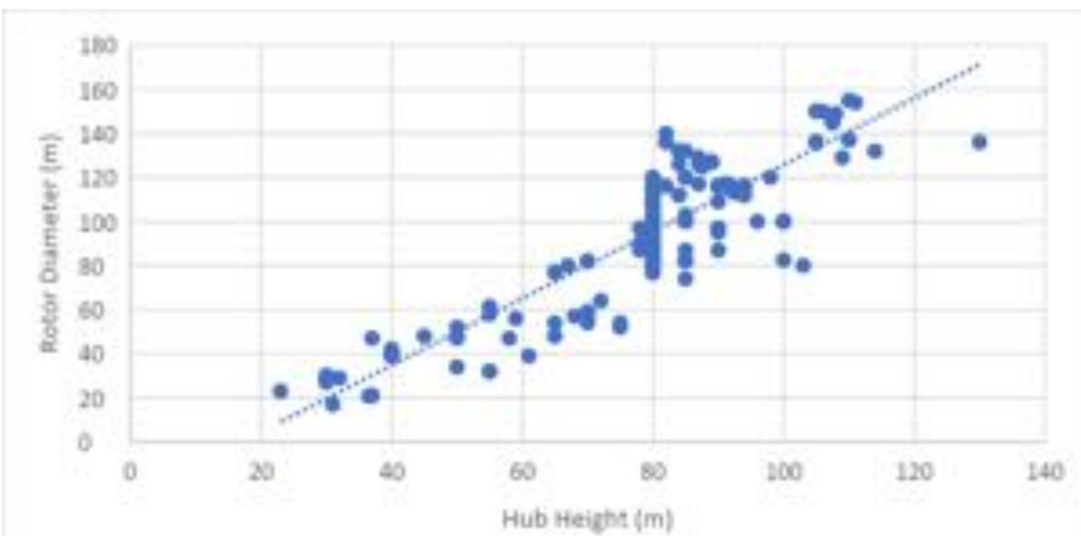


Figure 3.E.2-.4 Hub Height Versus Rotor Diameter from USGS Turbine Database

The trend line formula was then applied to the hub heights considered for this assessment. The tallest turbine in the database is 130 meters, and while this relationship could be extrapolated to 150 meters, this would result in a rotor diameter larger than the current technology for onshore turbines. Therefore, a rotor diameter of 164 meters, the current largest diameter for onshore turbines[95] was assumed for the 150-meter hub height.

[94] USGS, The U.S. Wind Turbine Database, https://eerscmap.usgs.gov/uswtdb/.

[95] https://en.wikipedia.org/wiki/List_of_most_powerful_wind_turbines.

Tip height was then calculated as:

$$tip\ height = hub\ height + 1/2\ rotor\ diameter$$

Swept area was calculated as:

$$swept\ area = 3.1415 * (1/2\ rotor\ diameter)^2$$

These values are shown in Table 3.E.2-4 below.

TABLE 3.E.2-4. TURBINE SPECIFICATIONS FOR EACH HUB HEIGHT

HUB HEIGHT (M)	ROTOR DIAMETER (M)	110% TIP HEIGHT (M)	SWEPT AREA (M^2)
50 meters	48	81	1,798
100 meters	127	180	12,598
150 meters	164	255	21,123

Determination of Turbine Counts and Power Potential. To estimate the number of turbines that could be placed within the technical resource area, the EAEP Team assumed a spacing of at least 5 by 7 rotor diameters was assumed, based on IRENA guidance, as shown in the figure below.

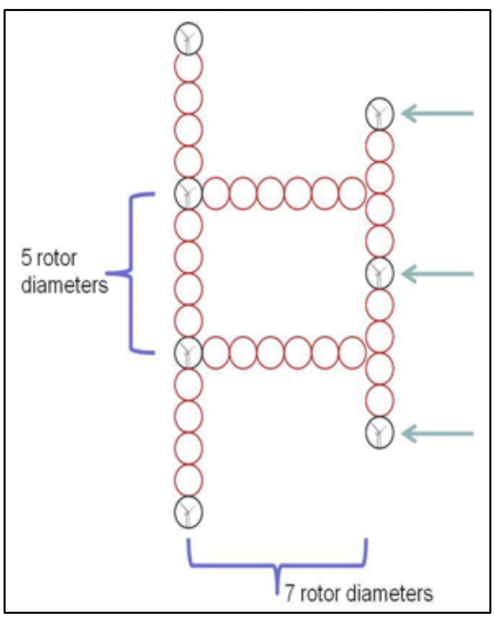


Figure 3.E.2-5 Turbine Spacing[96]

Turbine points were added to the technical area for each hub height by overlaying a diamond-shaped grid with dimensions of 5 by 7 rotor diameters. This arrangement assumes an east-west direction for prevailing winds, but it was assumed that a rotated grid would result in a similar number of turbines. A centroid layer for each grid was created and intersected with the technical area layer for each hub height. There were some areas that were identified by visual inspection to be far away enough from other turbine sites to host a turbine but were not assigned a turbine by the automated method of applying grids to the GIS technical area map because they did not overlap with a centroid. For these areas, turbine points were added manually, as shown in Figure 3.E.2-6 below.

[96] IRENA, https://www.irena.org/-/media/Files/IRENA/Agency/Events/2014/Jul/15/13_Wind_power_spatial_planning_techniques_Cairo_Egypt.pdf?la=en&hash=6CA1BE407AD7E4905EE13356EF069E364E9FED09.

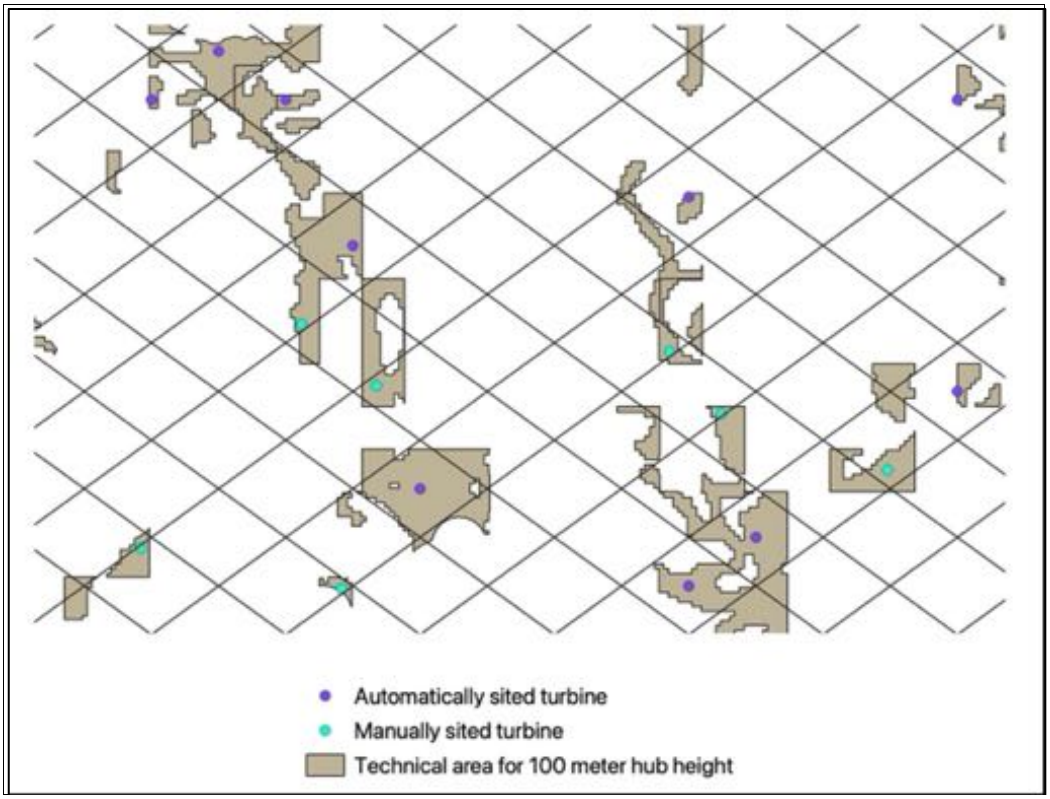


Figure 3.E.2-6 Example of Placement of Turbines in Technical Resource Area, 100-meter hub height

The EAEP Team estimated the power potential for each turbine based on typical generator capacities and with the swept area (shown in Table 3.E.2-4) at each hub height. Class III turbines (please refer to Table 1 above for the list of classes) are generally associated with power densities in the 200-300 W/m^2 range, and an installed capacity of 250 W/m2 was assumed. Annual generation was estimated based on the installed capacity for each site, capacity factor values from the Global Wind Atlas raster layers for each point at which a turbine site is located, and a loss factor to account for losses. The capacity factors for Class III turbines were only available as a country-wide downloadable layer for 100-meter hub height, so the capacity factors were estimated for 50 and 150 meter hub heights based on the relationship in capacity factors between hub heights from selected sites determined using the Global Wind Atlas online tool. A loss factor of 10% was assumed to account for availability, wake effects, turbine performance, curtailment, electrical losses, and environmental losses.[97] **A total technical potential of 715 MW of "nameplate" capacity (exploited and unexploited) was estimated for wind at a hub height of 100 meters in Rwanda.**

[97] NREL, https://www.nrel.gov/docs/fy16osti/64735.pdf.

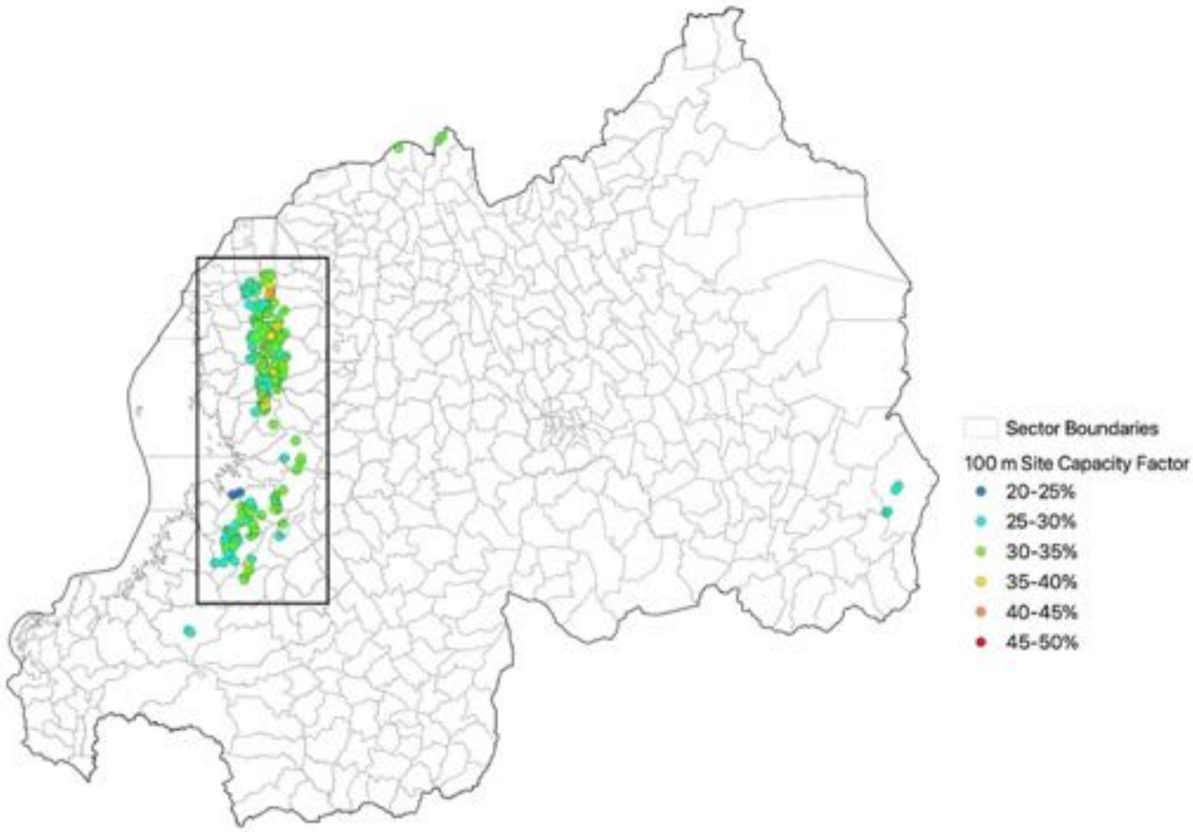


Figure 3.E.2-7 Turbines Sited in 100 meter Hub Height Technical Resource Area

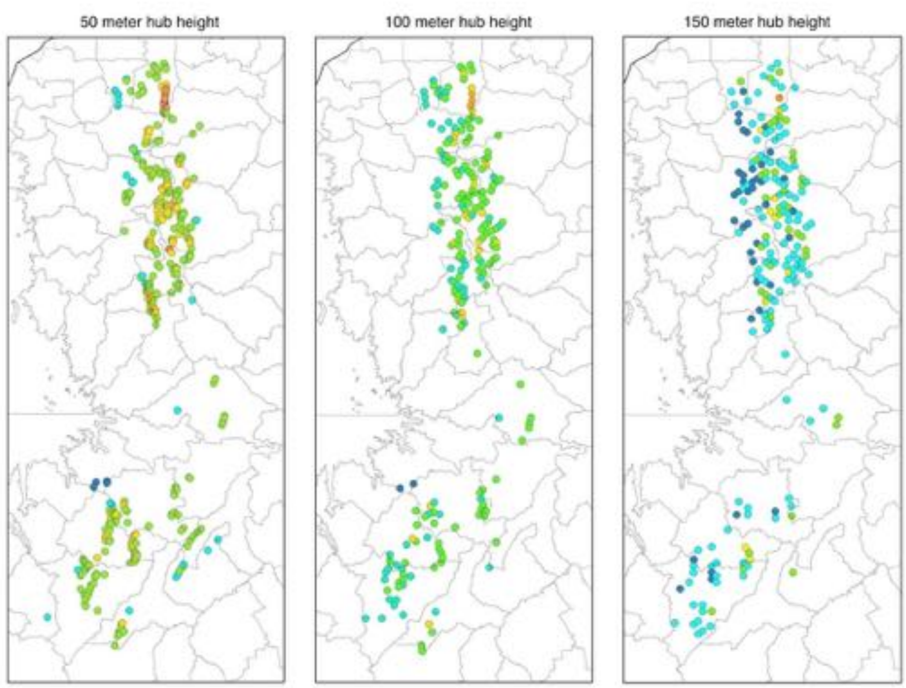


Figure 3.E.2-8 Enlarged Area for Each Hub Height

TABLE 3.E.2-5 TECHNICAL POTENTIAL FOR EACH HUB HEIGHT

HUB HEIGHT	POTENTIAL NUMBER OF TURBINES	AVERAGE CAPACITY FACTOR OF TURBINE SITES	TOTAL POTENTIAL NAMEPLATE CAPACITY (EXPLOITED AND UNEXPLOITED MW)	TOTAL AVAILABLE CAPACITY (EXPLOITED AND UNEXPLOITED MW)	TOTAL GENERATION (MWH)
50 meters	412	30%	185	50	435,776
100 meters	227	28%	715	225	1,968,801
150 meters	208	31%	1,098	309	2,710,568

Note that the potentials for each hub height are not additive, since they are based on overlapping technical areas, but show the total potential if all wind installations used this size turbine.

TABLE 3.E.2-6 SUMMARY OF SECTOR-LEVEL LOCATIONS OF MODELED TURBINE SITES

		5O METER HUB HEIGHT		100 METER HUB HEIGHT		15O METER HUB HEIGHT	
DISTRICT	SECTOR	NUMBER OF TURBINE S	AVERAGE CAPACITY FACTOR OF TURBINE SITES	NUMBER OF TURBINES	AVERAGE CAPACITY FACTOR OF TURBINE SITES	NUMBER OF TURBINES	AVERAGE CAPACITY FACTOR OF TURBINE SITES
Burera	Kinyababa	2	29%	2	32%	0	NA
Burera	Cyanika	2	26%	1	30%	3	29%
Nyamagabe	Musebeya	2	25%	0	NA	0	NA
Nyamagabe	Nkomane	1	29%	2	31%	0	NA
Nyamagabe	Kaduha	3	25%	0	NA	0	NA
Kirehe	Nyarubuye	2	23%	2	27%	2	31%
Kirehe	Mpanga	2	21%	2	26%	0	NA
Karongi	Bwishyura	3	17%	1	22%	0	NA
Karongi	Rugabano	6	28%	4	31%	1	35%
Karongi	Ruganda	7	25%	1	29%	1	36%
Karongi	Rwankuba	49	31%	14	32%	8	33%
Karongi	Twumba	23	28%	19	30%	23	30%
Karongi	Gashari	4	26%	1	32%	0	NA
Karongi	Gitesi	25	28%	14	31%	8	31%
Karongi	Mutuntu	10	29%	3	32%	0	NA
Ngororero	Kavumu	0	NA	0	NA	1	29%
Ngororero	Muhanda	76	31%	39	33%	37	33%
Nyabihu	Bigogwe	30	34%	15	35%	11	34%
Nyabihu	Karago	0	NA	0	NA	1	32%

TABLE 3.E.2-6 SUMMARY OF SECTOR-LEVEL LOCATIONS OF MODELED TURBINE SITES							
		5O METER HUB HEIGHT		100 METER HUB HEIGHT		15O METER HUB HEIGHT	
DISTRICT	SECTOR	NUMBER OF TURBINES	AVERAGE CAPACITY FACTOR OF TURBINE SITES	NUMBER OF TURBINES	AVERAGE CAPACITY FACTOR OF TURBINE SITES	NUMBER OF TURBINES	AVERAGE CAPACITY FACTOR OF TURBINE SITES
Nyabihu	Muringa	6	31%	5	32%	5	32%
Nyabihu	Rambura	10	32%	6	34%	7	32%
Nyamasheke	Mahembe	1	21%	0	NA	0	NA
Nyamasheke	Cyato	0	NA	2	26%	0	NA
Rubavu	Kanama	13	30%	15	32%	13	30%
Rubavu	Kanzenze	9	24%	6	28%	4	29%
Rutsiro	Nyabirasi	37	29%	22	31%	32	30%
Rutsiro	Ruhango	15	31%	10	31%	10	31%
Rutsiro	Rusebeya	2	27%	1	34%	1	31%
Rutsiro	Gihango	4	30%	4	32%	6	30%
Rutsiro	Manihira	18	33%	5	33%	5	34%
Rutsiro	Mukura	8	28%	6	32%	5	33%
Rutsiro	Murunda	42	30%	25	31%	24	31%

3.E.3. GRID-INTEGRATION COSTS

To estimate grid-integration costs for wind installations, the EAEP Team grouped turbines were grouped into potential plants (arrays of turbines in nearby locations). Turbines were grouped based on natural breaks in spacing. In general, for 50-meter hub height, turbines more than 3 grid squares away from the next nearest turbine were assumed to be part of a separate group. Because of the larger grid sizes, the spacing between plants for 100 meters and 150 meters, was 1-2 grid squares. For each plant, the EAEP Team calculated the total generation potential and average distances to the nearest substation, transmission line, and road were calculated.

Please refer to section 3.C.3 on solar resource for more details on what grid integration costs include and how they were estimated.

For wind, summary statistics for grid integration costs ($/MW) were calculated and are provided below.

50-meter hub height:

- Mean: $649,088
- Median: $419,584
- Standard deviation (SD): $483,835
- Range: $124,560 - $2,012,208

100-meter hub height:

- Mean: $266,839
- Median: $278,169
- Standard deviation (SD): $109,532
- Range: $121,939 - $481,811

150-meter hub height:

- Mean: $197,631
- Median: $165,284
- Standard deviation (SD): $79,395
- Range: $117,218 - $344,436

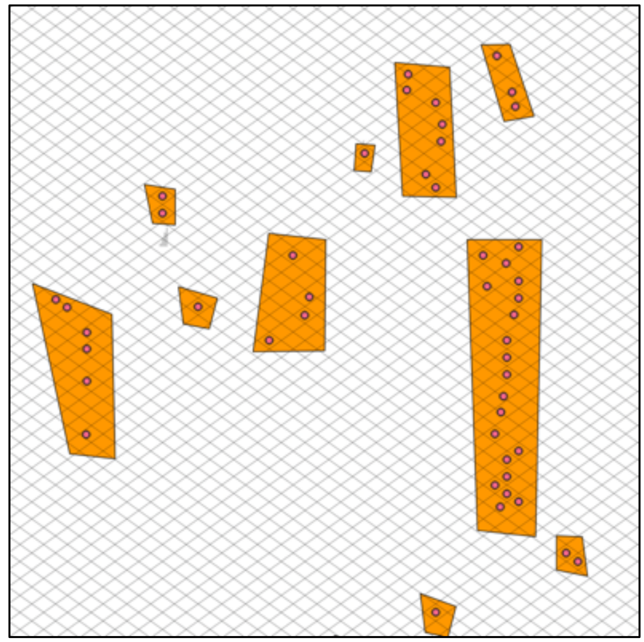


Figure 3.E.3-1 Example of Turbine Grouping into Plants

Grid integration costs computed for all polygons were then divided into four Grid Integration Cost Classes by quartile:

- Class I: lowest 25% of integration costs
- Class II: next lowest 25% of total integration costs (25th to 50th percentile)
- Class III: 50th to 75th percentile
- Class IV: 75th to 100th percentile.

Table 3.E.2-7 provides a summary of the values computed for each Grid Integration Cost Class. As indicated in these results, there is a technical potential of over 139, 554, and 882 GW available within Grid Integration Cost Class I for 50-, 100-, and 150-meter hub height, respectively.

Figure 3.E.3-2 is a map indicating the locations of the wind plants by integration cost class. The lowest grid integration costs are in locations where the greatest numbers of turbines can be installed near one another.

TABLE 3.E.3-1. WIND GRID INTEGRATION COST CLASSES

COST CLASS	INTEGRATION COST ($/MW)			TECHNICAL POTENTIAL (AVAILABLE MW)	ANNUAL GENERATION (MWH)	IMPLIED WEIGHTED AVERAGE CAPACITY FACTOR
	LOW	HIGH	MEAN			
50 METER HUB HEIGHT						
I	$124,560	$320,280	$209,481	139	336,381	28%
II	$320,280	$419,584	$363,456	26	57,645	25%
III	$419,584	$989,992	$612,339	12	24,312	24%
IV	$989,992	$2,012,208	$1,352,463	8.5	17,438	23%
			Total	185	435,776	27%
100 METER HUB HEIGHT						
I	$121,939	$166,814	$ 132,209	554	1,555,592	32%
II	$166,814	$278,169	$ 194,985	85	220,158	30%
III	$278,169	$347,208	$327,418	41	105,730	29%
IV	347,208	$481,811	$400,507	34.6	87,321	29%
			Total	715	1,968,801	31%
150 METER HUB HEIGHT						
I	$117,218	$126,989	$ 122,516	882	2,187,967	28%
II	$126,989	$165,284	$142,074	127	304,589	27%
III	$165,284	$267,580	$214,960	63	154,405	28%
IV	267,580	$344,436	310,973	26.4	63,606	27%
			Total	1,098	2,710,568	28%

Note: the implied capacity factors shown here do not match those in Table 4 because these are weighted by the power density at each site and include the 10% losses, explained above.

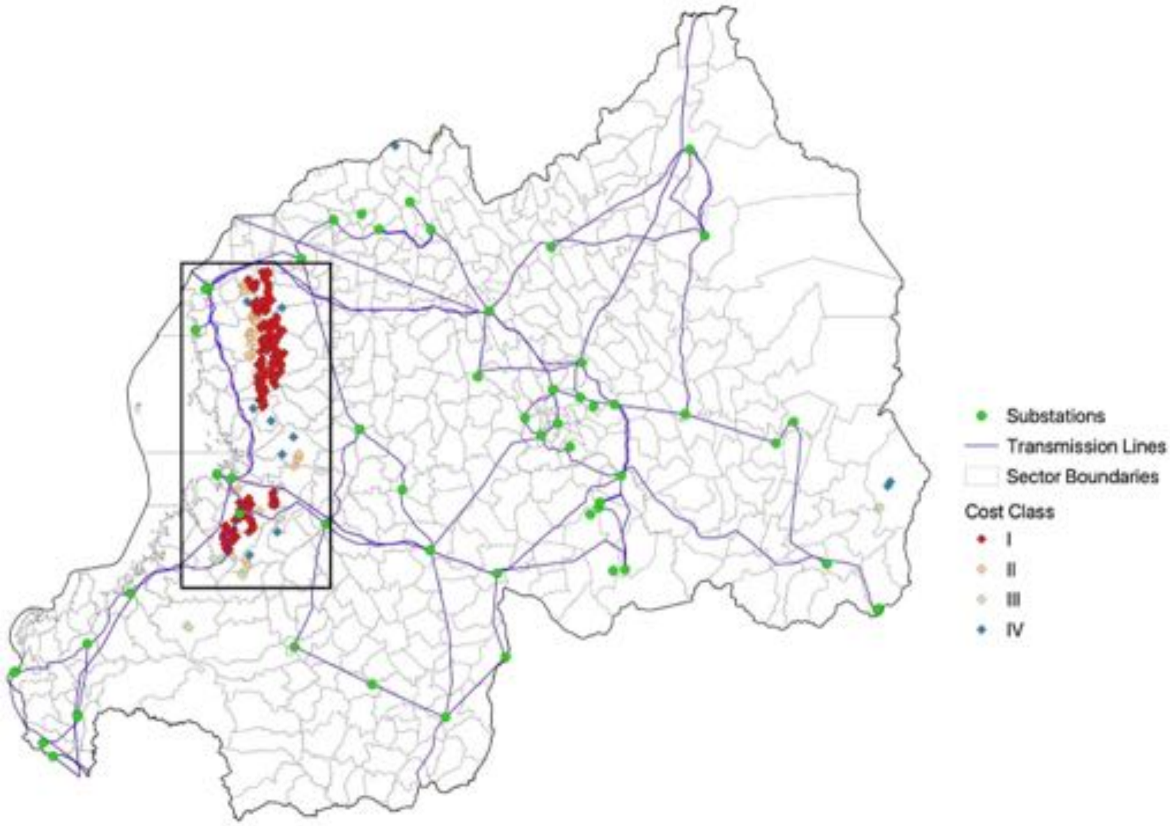


Figure 3.E.3-2 Grid Integration Cost Classes for 100 m Hub Height

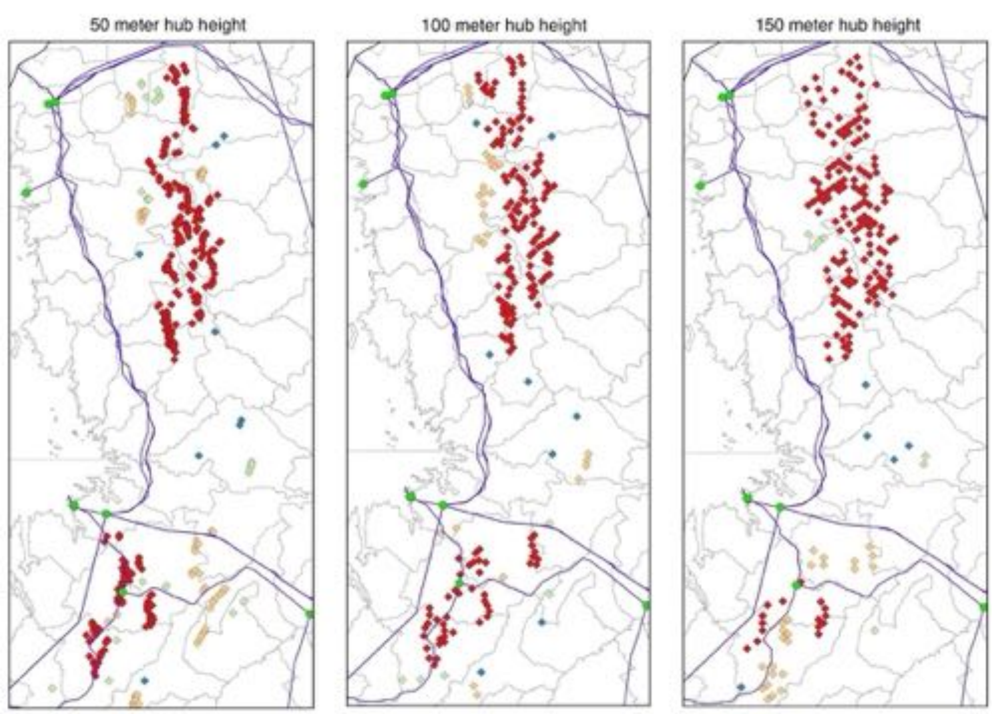


Figure 3.E.3-3 Grid Integration Cost Classes for All Height Hubs

3.E.4. EQUIPMENT, INSTALLATION AND O&M COSTS

This section summarizes the selection of equipment cost information for wind technology applications covered above to support assessment of the economic potential. These costs include for each technology, at least the following 3 components:

- Equipment costs.
- Installation labor costs.
- Ongoing O&M costs: replacement of parts, land lease costs, insurance, etc.

These costs exclude the costs for grid integration which were assessed separately in the previous section. When available, more detailed cost information was also included.

There are currently no wind installations in Rwanda, so there is no local cost data available. Detailed cost data was not available for most wind projects identified in Africa, with only total project costs available. One project with some publicly available detailed cost data is a 2012 project in Kenya. In addition, a feasibility study on several potential wind projects in Mali estimated detailed project costs based on local cost factors and similar projects in South Africa. Cost values were adjusted to consider the falling price of wind turbines in the last decade using annual costs in the US taken from a US Department of Energy report (see Table 7 below) and were adjusted to 2021 US dollars (USD) using the latest consumer price index values from the World Bank. Cost values considered for EP modeling are shown in Table 8.

O&M costs vary, with maintenance often provided through a contract with the original manufacturer or project developer. Data for IEA reference projects in several countries show that for most projects O&M costs are between 1 and 4% of investment costs.[98] The Mali modeling study estimated maintenance costs as 5% for the first 10 years and 6% for the next 10 years plus 0.5% for insurance. For EP modelling, a value of 4% of investment costs was used plus land costs, as described below.

Wind farms require a large area of land; however, only a small portion of the land is taken up by the footprint of turbines and other equipment. Most of the land around turbines can still be used for other purposes, such as cropland or grazing land. Instead of acquiring land, wind projects often lease land or pay royalties to landowners. In the US, land lease agreements vary widely, but are typically in the range of $2,000-$6,000/MW or 1-4% of gross revenue from generated power.[99] The Kipeto Wind Project in Kenya is structured to give 5% equity in the project to the local Masaai community, with this percentage of the annual returns given to the local community trust and used for community projects.[100] This type of land lease was assumed to be used in Rwandan projects and a cost of $3/kW was included in the estimated O&M costs.

[98] IEA, 2020. https://www.iea.org/reports/projected-costs-of-generating-electricity-2020.

[99] Winikoff and Parker, Farm Size, Spatial Externalities, and Wind Energy Development. 2021. https://aae.wisc.edu/dparker/wp-content/uploads/sites/12/2021/02/wind_land_tex.pdf.

[100] Social Impact Assessment Study for a Proposed 100MW Wind Energy Project, Kajiado District, Kenya, Appendix H. https://www3.dfc.gov/environment/eia/kipeto/SEIA%20site/appendices/Appendix%20H%20Merged.pdf.

TABLE 3.E.4-1 2010-2020 TURBINE AND TOTAL CAPEX COSTS FOR US PROJECTS[101]

YEAR	US CAPACITY-WEIGHTED AVERAGE CAPEX (2020$/KW)	VESTAS GLOBAL AVERAGE TURBINE COSTS
2010	$2,535	1,555
2011	$2,430	1,592
2012	$2,193	1,485
2013	$2,063	1,442
2014	$1,904	1,292
2015	$1,735	1,105
2016	$1,774	1,077
2017	$1,693	949
2018	$1,491	908
2019	$1,430	875
2020	$1,462	840

[101] US Department of Energy Land-Based Wind Market Report, 2021. https://emp.lbl.gov/wind-technologies-market-report.

TABLE 3.E.4-2 ECONOMIC POTENTIAL MODELING COST INPUTS CONSIDERED AND SELECTED FOR WINDINSTALLATIONS

TECHNOLOGY DESCRIPTION	TOTAL INSTALLED COST ($2021/KW)	ANNUAL O&M ($2021/KW-YR)	NOTES AND CITATIONS
Kenya, Kipeto Wind Farm, 2011; 107.2 MW	$1,473	NA	1.6 MW turbines, 80 meter hub height. Grid integration costs excluded. Project costs adjusted turbine costs by turbine price index, and total costs adjusted to 2021$ by consumer price index. https://www3.dfc.gov/environment/eia/kipeto/SEIA%20site/appendices/Appendix%20H%20Merged.pdf
Senegal, Taiba N'Diaye Wind Farm; 2018, 158.7 MW	$2,045	NA	Costs details not available, so grid integration costs could not be excluded. Costs were adjusted based on total CAPEX costs index for US.
Mali, Feasibility Modelling Study, 2012, 170 MW	$1,919	6% of investment costs	850 kW turbines, 55 meter hub height, Grid integration costs excluded. Turbine costs were adjusted turbine costs by turbine price index. Project costs were converted from EURO to USD using exchange the 2012 rate of $1.286 USD/EURO, and total costs adjusted to 2021$ by consumer price index. https://www.aimspress.com/article/doi/10.3934/energy.2017.3.557?viewType=HTML
Mali, Feasibility Modelling Study, 2012, 8.5 MW	$2,249	6% of investment costs	850 kW turbines, 60 meter hub height, Costs adjusted as described above. https://www.aimspress.com/article/doi/10.3934/energy.2017.3.557?viewType=HTML
Mali, Feasibility Modelling Study, 2012, 0.825 MW	$2,802	6% of investment costs	275 kW turbines, 55 meter hub height, Costs adjusted as described above. https://www.aimspress.com/article/doi/10.3934/energy.2017.3.557?viewType=HTML
NREL Land-based Wind Reference Turbine, 2019; 2.6 MW	$1,436	$43	Based on average installation. Costs not adjusted. O&M includes annual costs, such as maintenance, insurance, administration, and land leasing. https://www.nrel.gov/docs/fy21osti/78471.pdf
Selected Value for Small Projects	$2,249	$93	Mali 8.5 MW estimate, O&M estimated as 4% of installed costs plu $3/kW for land lease
Selected Value for Larger Projects	$1,473	$62	Kenya Kipeto Wind Farm installed costs, O&M estimated as 4% of installed costs plu $3/kW for land lease

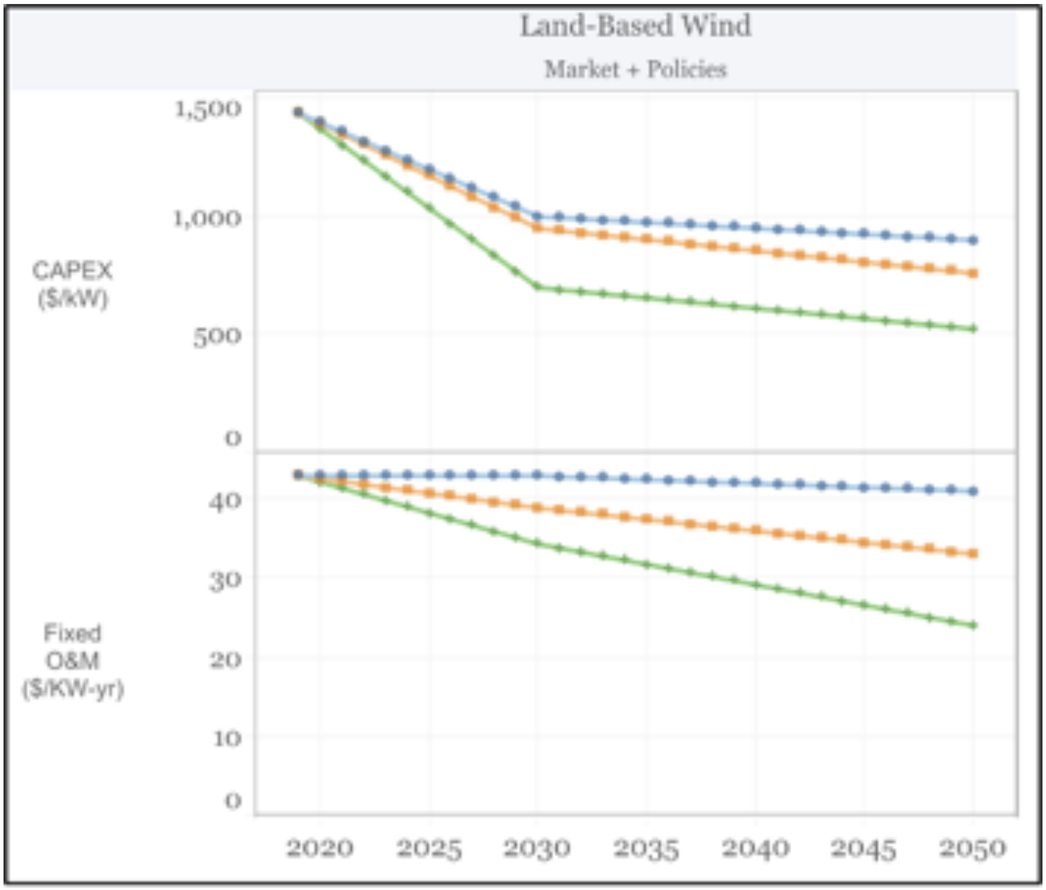
When selecting values, for each hub height, several factors were considered. The power density and capacity factors were not found to be significantly different between the different hub heights, so these were assumed to not have significant impact on costs. However, the smaller technical area at lower hub height results in smaller modeled wind farm sizes. Smaller wind farms have higher costs on a $/kW basis, because they do not have the economies of scale that a larger installation would have. Table 3.E.4-3 below shows costs by size for wind projects in the US in 2019 and 2020. The largest difference in costs is for small projects below 5 MW. There was no data for projects in the 5-20 MW range, so a cut-off between small and larger projects was set at 10 MW, since the value selected for small projects is based on estimates for a 8.5 MW modeled project. These costs were assigned based on the grid-integration cost classes discussed in the previous section, as shown in Table 3.E.4-4.

TABLE 3.E.4-3 TURBINE SPECIFICATIONS FOR EACH HUB HEIGHT

PROJECT SIZE BIN	SAMPLE PROJECTS	SAMPLE MW	AVERAGE COST 2020$/KW
≤5 MW	5 projects	21 MW	$2,395
5-20 MW	none	0 MW	NA
20-50 MW	4 projects	145 MW	$1,556
50-100 MW	14 projects	1,007 MW	$1,671
100-200 MW	45 projects	6,954 MW	$1,501
>200 MW	46 projects	12,664 MW	$1,400

Wind installation costs are expected to continue decreasing in the near future. Figure 10 provides NREL's US forecast of installed costs and O&M using three different scenarios and compared to the median forecast of industry analysts ["Med (US)"]. The conservative scenario is based on lower levels of research and development (R&D) investment, minimal technology advancement and current global module pricing. The moderate scenario is based on moderate R&D investment, industry technology roadmaps being achieved, but no substantial innovations or new technologies introduced into the market. The advanced scenario is based on higher levels of R&D spending that generates substantial innovation, which allows for historical rates of development to continue. The conservative scenario represents lower expected declines in costs than both the other scenarios as well as analyst forecasts.

TABLE 3.E.4-4. SELECTED TOTAL INSTALLED COSTS AND O&M BY GRID INTEGRATION COST CLASS FOR WIND				
GRID INTEGRATION COST CLASS	AVERAGE MODELED PLANT SIZE	ASSIGNED INSTALLED COST CLASS SIZE	ASSIGNED TECHNOLOGY INSTALLED COST ($/KW)	ASSIGNED O&M COST ($/KW-YR)
		50 METER HUB HEIGHT		
I	11.6	Large	$1,473	$66
II	2.2	Small	$2,249	$101
III	1.0	Small	$2,249	$101
IV	0.7	Small	$2,249	$101
Total	3.8			
		100 METER HUB HEIGHT		
I	61.6	Large	$1,473	$66
II	9.4	Large	$1,473	$66
III	4.5	Small	$2,249	$101
IV	3.5	Small	$2,249	$101
Total	19.3			
		150 METER HUB HEIGHT		
I	176.4	Large	$1,473	$66
II	25.3	Large	$1,473	$66
III	12.7	Large	$1,473	$66
IV	5.3	Small	$2,249	$101
Total	54.9			



Blue = conservative forecast, orange = moderate, green = advanced.

Figure 3.E.4-1 NREL Annual Technology Database CAPEX and O&M Forecasts for Land-based Wind

Regionally specific estimates were not identified for the expected declines in equipment installation costs. For EP modeling purposes, the conservative forecast from NREL was adopted. This assumes that continued innovation and R&D spending that further drives down installation costs will drive substantial reductions through 2030. That resulted in the annual rates of decline indicated in Table 11 below. The NREL database also provides the expected rate of decline for O&M costs for utility-scale PV systems. The conservative forecasts for O&M were also adopted for use in EP modeling and are shown in the table below.

TABLE 3.E.4-5 MODELING FORECAST ASSUMPTIONS FOR WIND INSTALLATIONS[102]

MODELING INPUT DESCRIPTION	2021-2030 CHANGE (%/YR)	2031-2050 CHANGE (%/YR)
Annual decline in installed costs	-3.3%	-1.0%
Annual decline in fixed O&M costs	-0.0%	-0.5%

[102] NREL, https://atb.nrel.gov/electricity/2021.

3.F. WASTE-TO-ENERGY RESOURCE ASSESSMENT

Reppie Waste-to-Energy Project in Ethiopia
BUSINESS INSIDER

3.F.1. PHYSICAL RESOURCE AVAILABILITY

Waste to energy (WtE) resources can include a wide range of possible fuels/feedstocks, including:

- *Livestock manure* from cattle or other animals (best opportunities come from confined animal operations, like dairies, feedlots, large poultry operations).
- *Other animal waste*, including waste from slaughterhouses or waste from aquaculture.
- *Agricultural crop residues* (corn stover, rice straw, other residue left on the field) or crop processing residues at the mill or other processing facility (rice husk, coffee husk/peel/pulp).
- *Wood waste* from logging, sawmills, and industrial facilities.
- Other industrial organic wastes, such as used cooking oil or other food waste from food processing plants.
- *Municipal solid waste (MSW),* either as feedstock for fuel or electricity generation or deposited in landfills from which landfill gas (LFG) can be collected.
- *Wastewater solids* from wastewater treatment plants.

Based on the inputs received by REG and data availability, the EAEP Team limited this assessment of WtE resource potential for Rwanda to crop residues (and principally rice husk produced at rice mills) and municipal solid waste (MSW). Rice husk generation can be sited at or near rice mills, reducing the need for transportation of the resource. Similarly, MSW generation could be sited at or near waste collection sites, such as landfills or transfer stations.

3.F.1.a. Crop Residue Resource Potential

TABLE 3.F.1.A-1 ANNUAL CROP RESIDUE AVAILABILITY IN RWANDA[103]

CROP RESIDUE	2020 ANNUAL AMOUNT (DRY TONS)
Cereal crop straws	400,000
Corn stover	390,000
Sorghum stover	150,000
Rice straw	100,000
Rice husk	23,000
Coffee husk	15,000
Total	**1,088,000**

Essentially, any crop that produces biomass residue could serve as an energy resource for electricity production. Crop residue includes straw or stalks that are generally left on the field or burned, as well as the outer shell or husk that is left over when the crop is processed at a processing facility. Annual estimates of several crop residues produced in Rwanda that might be considered for electricity production are provided in Table 3.F.1.a-1 at left. Other crop types including tubers, legumes, vegetables, and tea also produce some crop residue; however, these have been left out of this current assessment of technical potential, since they have not been targeted in other countries for energy production. This is likely due to the cost of gathering the material from the field, processing it, and transporting it to a conversion facility.

[103] Sources of information are the annual NISR survey report for crop production values: https://www.statistics.gov.rw/publication/upgraded-seasonal-agricultural-survey-annual-report-2020; and the Intergovernmental Panel on Climate Change emissions guidelines for crop residue fractions: http://www.ipcc-nggip.iges.or.jp/public/2006gl/vol4.html.

3.F.1.b Municipal Solid Waste Resource Potential

Opportunities for MSW WtE in Rwanda should be assessed within the broader context of a national strategy for solid waste management. This is because opportunities for utilizing MSW for energy use need to consider other waste management goals. Those goals may include source reduction (reducing waste generation rates), increasing the rates of composting of organic materials, recycling (including plastic waste), and reducing the use of landfills (and their associated environmental, health and safety problems).

MSW WtE opportunities will differ regionally. In Kigali, a significant and growing population produces MSW in a concentrated region at volumes that could support one or more modern large-scale energy recovery facilities. This assumes that no substantial progress is made in the future for source reduction and landfill diversion programs (e.g., re-use, recycling, composting). Ongoing MSW planning in Kigali[104] recognizes the importance of MSW reduction programs, landfill gas utilization, WtE, and composting.

Other large urban areas may also reach MSW generation rates that support a large-scale energy recovery plant (such as the large mass burn plants converting mixed MSW to steam for electricity production in the US, EU, and other countries). However, depending on future MSW generation growth rates, and the success of re-use, recycling and composting programs, those rates might not be achieved. In such cases, other approaches to waste management, including energy recovery options, should be investigated. These could include:

- Smaller waste combustion and energy recovery facilities.
- Biomass gasification projects (as applied to crop residues in the previous section).
- Well designed and managed landfills with landfill gas (LFG) to energy recovery; and
- Biodigesters. A biodigester is a device or structure in which the digestion of organic waste matter by bacteria takes place with the production of a burnable biogas (typically at least 50% methane by volume). A biodigester may be a purpose-built (organics management) stand-alone facility, or it may be an existing anaerobic digester located at a wastewater treatment plant. For example, the state of California, USA currently has over 30 biodigester projects that accept organic waste materials from the municipal waste stream.[105]

The starting point for assessing MSW WtE is a forecast of MSW generation in Rwanda. This begins with a population forecast which is shown in Figure 3.F.1.b-1 below.[106] As indicated in this chart, the total population is expected to reach nearly 25 million by 2050. Growth rates are expected to be much higher in the urban areas (4.3%/yr) versus rural areas (0.8%/yr) which leads to roughly a 50:50 distribution of the population between urban and rural areas by 2050.

This initial assessment for MSW addresses waste collected in urban areas. No information was found on rural MSW generation rates in Rwanda, so this should be an area of future study. Figure 3.F.1.b-2 provides a summary of urban MSW generation (units are metric tons, t). As indicated in the figure, the Kigali urban area currently appears to produce most of the MSW in the country; however, this is due to

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104 Global Green Growth Initiative, "Waste to Resources: Improving Municipal Solid Waste (MSW) and Hazardous Waste Management in Rwanda", https://gggi.org/rwanda-launches-new-project-waste-to-resources-improving-municipal-solid-waste-msw-and-hazardous-waste-management-in-rwanda/

105 CalRecycle, https://www.google.com/url?sa=t&rct=j&q=&esrc=s&source=web&cd=&ved=2ahUKEwjHzYLukr70AhUFrHIEHbbrDLAQFnoECBQQAQ&url=https%3A%2F%2Fwww2.calrecycle.ca.gov%2FDocs%2FWeb%2F115971&usg=AOvVaw30N9WRz3ZQvmVrLCGoizX_.

106 This forecast came from REG from the population forecast in the MAED model. It is consistent with the forecast used in the LEAP model for this project.

the much lower rates of collection in other urbanized areas. About 88% of the MSW generated in Kigali is collected with much of that landfilled,[107] and that rate of collection was assumed to remain constant through 2050. In other urbanized areas, less than 10% of waste generated is collected for formal management. However, since the country has a goal to collect 80% of waste generated for management by 2030, it was assumed that that rate would be achieved on time and maintained through 2050. The other input required to estimate annual waste generation was the MSW generation rate. A value of 0.59 kg/capita-day was selected for both Kigali and other urban areas.[108]

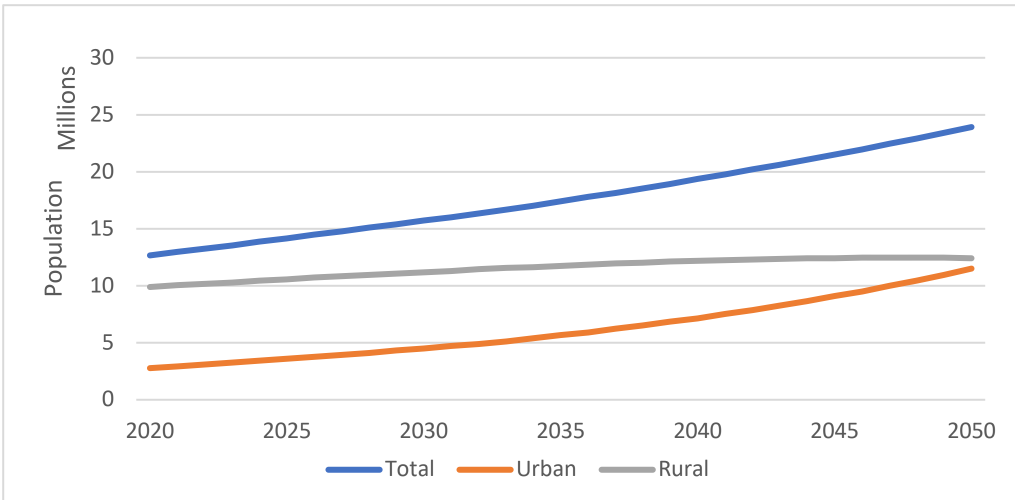

Figure 3.F.1.b-1. Population Forecast

In addition to understanding the annual rates of total MSW collection, an understanding is also needed of the characteristics of the waste including heat content to inform the selection of conversion technologies and the amount of electricity generation possible; and the environmental outcomes of conversion technology selection (including greenhouse gas emissions). A basic level of waste characterization is a breakdown of waste into organic and inorganic fractions. The organic fraction is made up of food, garden, and wood waste; paper and cardboard; and textiles, rubber, and leather. The inorganic fraction is made up of metals and other noncombustible materials (e.g., cement, brick, glass, etc.). For the organic fraction, it can be further broken down into biogenic and fossil fractions (important for understanding GHG impacts). Although waste characteristics may be different between

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[107] "Benchmarking performance of solid waste management and recycling systems in East Africa: Comparing Kigali Rwanda with other major cities," Telesphore, Kabera, et al., Waste Management & Research, 2019. https://pubmed.ncbi.nlm.nih.gov/30761955/.

[108] A range of values for MSW generation in Rwanda have been reported from 0.49 to 0.70 kg/capita-day, average across studies used. Note that solid waste generation rates tend to increase with rising personal income rates. To the extent that will happen in Rwanda, these initial estimates of waste generation will be underestimated.
"Benchmarking performance of solid waste management and recycling systems in East Africa: Comparing Kigali Rwanda with other major cities," Telesphore, Kabera, et al., Waste Management & Research, 2019. https://pubmed.ncbi.nlm.nih.gov/30761955/.
"Assessing Waste Management Services in Kigali," Rajashekar, Anirudh, et al., *International Growth Center*, 2019. https://www.theigc.org/wp-content/uploads/2019/11/Rajashekar-et-al-2019-paper.pdf
"Solid Waste Management in Secondary Cities of Rwanda - Muhanga & Huye," *Global Green Growth Institute*, 2019. https://gggi.org/report/solid-waste-management-in-secondary-cities-of-rwanda-muhanga-huye/

Kigali and other urban areas, the following breakdown in Table 3.F.1.b-1 was the only one identified,[109] and it was applied to the waste generated for all urban areas and held constant through 2050.

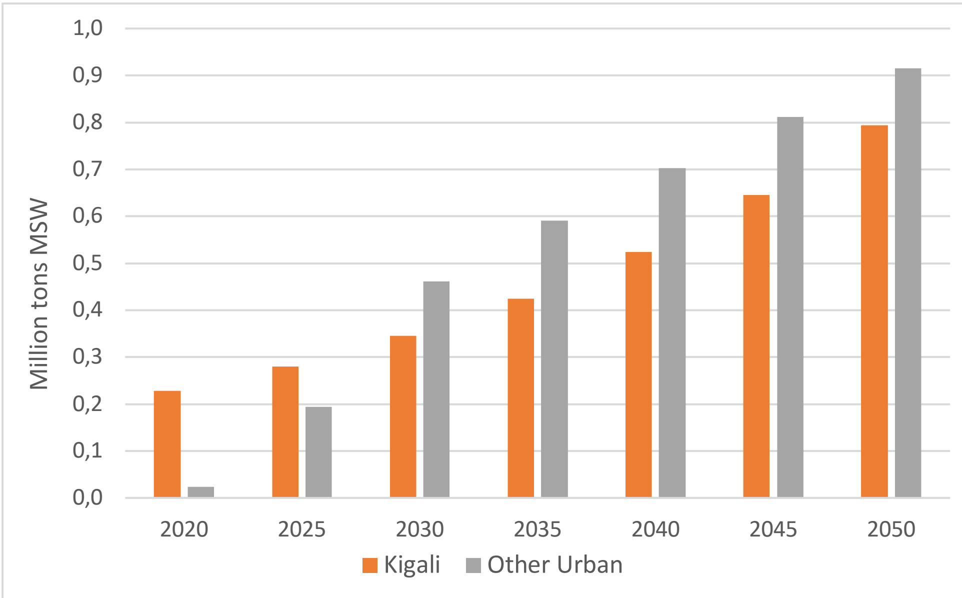

Figure 3.F.1.b-2 Urban MSW Waste Collection

TABLE 3.F.1.B-1 URBAN MSW BREAKDOWN		
MSW FRACTION	MSW COMPONENT	WEIGHT %
Organic - biogenic	Food, garden wood	70%
	Paper and Cardboard	6%
Organic - fossil	Plastic	5%
Non-Organic	Metal	3%
	Glass	1%
Combination	Other (incl. textiles, rubber/ leather)	15%

[109] "Assessing Waste Management Services in Kigali," Rajashekar, Anirudh, et al., International Growth Center, 2019. https://www.theigc.org/wp-content/uploads/2019/11/Rajashekar-et-al-2019-paper.pdf. Waste characteristics may well differ substantially in different urban areas based on the make-up of commercial and industrial enterprises that contribute to the MSW stream. This is another area of future work that should be undertaken to improve these initial TP estimates for MSW WtE.

For the MSW combination fraction in the table above, it was assumed to be 100% organic and that 25% of it was biogenic (e.g., natural rubber, leather, plant/animal derived textiles). To the extent that some non-organic materials are included in this fraction (e.g., cement, glass), then there will be slight over-estimates of the energy content of MSW described below. The breakdown of the MSW collection forecast into its organic fractions is summarized in Figure 3.F.1.b-3 below. As shown, the collection forecast is dominated by biogenic organic materials (food, yard waste, wood, paper and cardboard, natural textiles and rubber, and leather).[110]

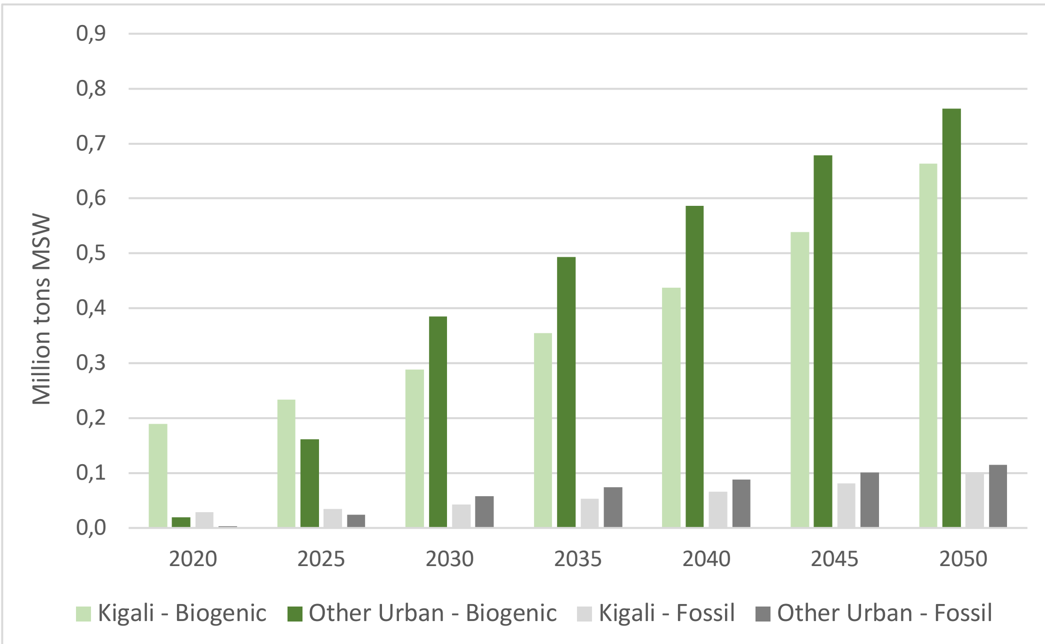

Figure 3.F.1.b-3 Forecasted Collection of MSW Organic Fractions

Next, the energy (heat) content of MSW was estimated. The heat contents shown in Table 3.F.1.b-2 below[111] were applied to estimate the amount of energy available in each year from the collected MSW. The units for the table are megajoules per ton (MJ/t). There are values shown for each MSW component. For biogenic organics, the weighted value is 8,381 MJ/t. As mentioned above, the combination component is assumed to be 100% organic and 25% of that is assumed to be biogenic.

Figure 3.F.1.b-4 provides the estimated heat content for urban MSW waste collection. This can be considered as an estimate of the **physical resource** available for electricity production. The units are gigawatt-hours (GWh) of energy per year. As indicated in these results, current MSW collection produces a physical resource of around 650 GWh of energy. By 2050, the physical resource is expected to reach nearly 4,500 GWh of energy.

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[110] A key question for future research is to what extent will the urban waste generation profile change over time. For example, it is possible that with rising incomes, more packaging waste is generated with much greater contributions by plastics in the MSW stream.

[111] "Methodology for Allocating Municipal Solid Waste to Biogenic and Non-Biogenic Energy," *US Energy Information Administration,* 2007. https://www.eia.gov/totalenergy/data/monthly/pdf/historical/msw.pdf.

TABLE 3.F.1.B-2 HEAT CONTENTS FOR MSW COMPONENTS	
MSW COMPONENT	HEAT CONTENT (MJ/TON)
Biogenic Organics	
Food, garden, wood	7,655
Paper and Cardboard	11,100
Fossil Organics	
Plastic	19,616
Combination	
Other (incl. textiles, rubber/ leather)	17,575

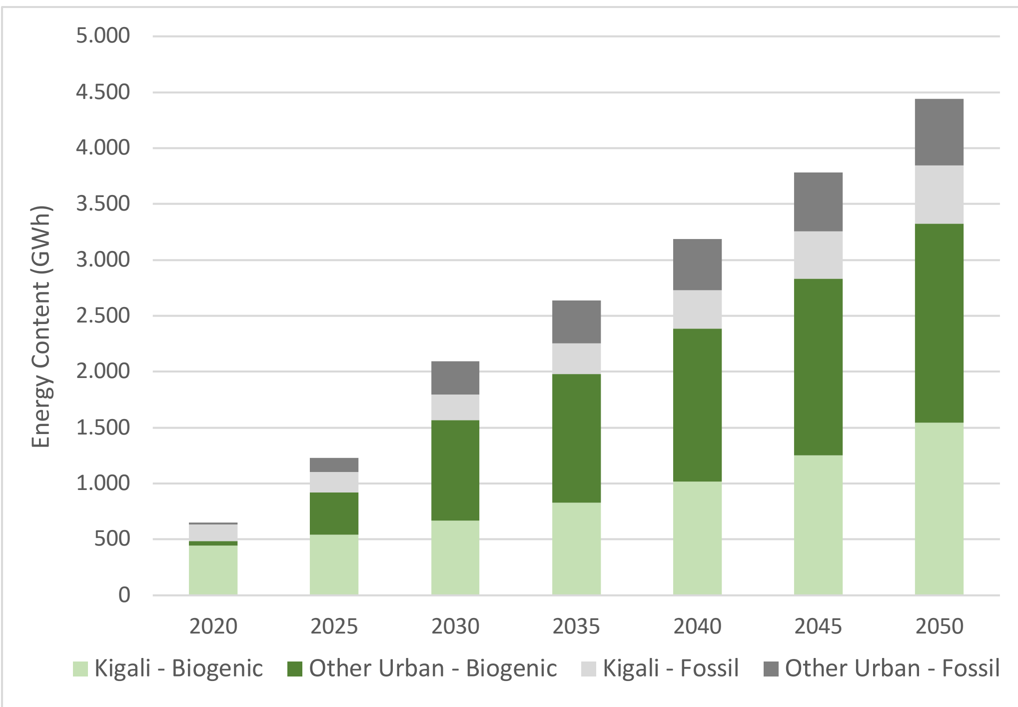

Figure 3.F.1.b-4 Heat Content of Collected Urban MSW

3.F.2. TECHNICAL POTENTIAL

The **methods and data sources** used to characterize the **technical potential** are provided in the following sections, and the **estimated results** of total (exploited and unexploited) "nameplate" capacity and "available" capacity (MW) and related annual generation (MWh) are summarized in the table below. **The estimated total technical potential (exploited and unexploited) for WtE in 2030 is about 70 MW of "nameplate" capacity**.

TABLE 3.F.2-1 WTE TECHNICAL POTENTIAL ESTIMATES (EXPLOITED AND UNEXPLOITED)				
RESOURCE	FEEDSTOCK AVAILABILITY (TON/YEAR)	TECHNICAL POTENTIAL NAMEPLATE CAPACITY (MW)	TECHNICAL POTENTIAL AVAILABLE CAPACITY (MW)	ANNUAL GENERATION (MWH)
MSW 2020	240,311	21	17	148,493
MSW 2030	774,516	68	55	478,591
Rice Husk 2020	23,300	2.5	2.0	17,592

3.F.2.a. Crop Residue

This technical potential assessment is limited to rice husk, which has been used in Rwanda and other locations for electricity production and is in a readily available form for conversion. Rice husk resources are located at a single location (the rice mill) in a form that requires no additional processing for energy conversion. The other crop residues listed in the table would require additional evaluation beyond the scope of the current assessment, including detailed spatial information on crop locations in order to identify where different crop residue feedstocks are available within a reasonable radius of possible conversion facilities, and assessment of technical or cost barriers to remove the material from the field, transport it to a conversion facility, and convert it into a physical form needed by a conversion facility (e.g., through chipping or shredding). In 2020, rice production in Rwanda totaled around 116,500 metric tons (t). Based on information provided by REG, as shown in Table 3.F.2.a-1 below, Rwanda has 27 rice mills with processing capacities ranging from 1.5 to 6.0 t rice/hour. This capacity was down by approximately 11% from 2019. [112]

TABLE 3.F.2.a-1 RICE MILLS IN RWANDA		
NAME OF MILL	DISTRICT	PROCESSING CAPACITY (TONS OF RICE/HOUR)
MAYANGE RICE	Bugesera	5.0
KUNDUMURIMO Ruhuha	Bugesera	4.0
GATSIBO RICE	Gatsibo	5.0
GIKONKO RICE	Gisagara	4.5
MINETORIE DE HUYE	Huye	3.5
KARUBANDA RICE MILL	Huye	2.5

[112] National Institute of Statistics of Rwanda, https://www.statistics.gov.rw/publication/upgraded-seasonal-agricultural-survey-annual-report-2020.

TABLE 3.F.2.a-1 RICE MILLS IN RWANDA		
NAME OF MILL	DISTRICT	PROCESSING CAPACITY (TONS OF RICE/HOUR)
RWABUYE RICE MILL	Huye	2.5
KINAZI RICE M LTD	Huye	4.0
MAMBA RICE	Huye	5.0
MRPIC	Kamonyi	2.5
IZIMANO INDUSTRY	Kayonza	3.5
KIREHE RICE MILL	Kirehe	5.0
CORIMI NGOMA	Ngoma	1.5
NYAGATARE RICE	Nyagatare	5.0
NAVR	Nyagatare	5.0
NYAGATARE RICE	Nyagatare	2.5
HIGH PRODUCTIVE GRAIN MILL	Nyamasheke	5.0
ALPHA NYANZA	Nyanza	3.0
RUHUKA/BUSORO	Nyanza	2.5
GAFUNZO RICE MILL	Ruhango	2.5
MASHYUZA RICE MILL	Rusizi	2.5
COTCORI	Rusizi	2.5
MUGANZA AGRI BUSINESS LTD	Rusizi	2.5
BUGARAMA RICE	Rusizi	4.5
RWAMAGANA RICE	Rwamagana	4.5
BRITH GENERAL CO LTD	Location not provided	6.0
RT CO LTD	Location not provided	2.5
Total Capacity (note does not include micro-mills) =	**99**	

When rice is milled about 20% of the total weight is removed as rice husk. Therefore, the total annual available rice husk feedstock for electricity production is around 23,300 t/yr. This total available feedstock value (23,300 t husk/yr) presumes that all rice is processed at rice mills that are large enough to host a small power plant, such as those represented in the table above. It is unknown how much of current rice production is still processed at much smaller micro-mills in the country; however, information provided by REG indicates that in some Districts more than half of rice production might still be processed in these smaller mills. Conceivably, this is due to either the cost of transport to the larger mills or the lower prices offered to farmers by those mills. For the purposes of this technical potential assessment, it is assumed that over time all production will be processed at rice mills in the size range indicated by those in the table above. The current milling capacity indicated in Table 3.F.2.a-1 appears to be more than sufficient to process existing rice production and additional growth. For example, this level of capacity running at 40 hours/week for 50 weeks per year could process almost 200,000 tons of rice.

Commercially available technologies for conversion of rice husk to electricity include direct combustion of the husk to produce steam in a boiler and then a steam turbine to produce electricity; and biomass gasification[113] to produce a combustible gas which can then also be used to produce steam in a boiler for a steam turbine or supplied directly to a gas turbine or engine to produce electricity. Small rice husk gasification plants have gained in popularity over the past 10 years, primarily in southern Asia.[114] Other small-scale biomass gasification projects have also become increasingly economically viable over the last 10 years as a result of small, packaged units produced in Europe and China.

In Rwanda, the Nyagatare Rice Company milling facility has a rice husk gasification to electricity plant sized at 70 kW of electricity. It converts about 600 t husk to 453 MWh of electricity each year (1.33 kg/kWh).[115] This value is more efficient than some other values in the literature, including a conversion value of 1.43 kg/kWh for the south Asia study cited above, as well as a larger but much older rice husk gasification facility in operation in China (1.8 kg/kWh).[116] While details of plant design are lacking in the studies reviewed, it appears that all of them are based on a biomass gasifier feeding a standard engine/generator set.

For this initial assessment of technical potential for rice husk to electricity production, it is assumed that conversion will occur at mills with processing capacity of <10 t rice/hour) using biomass gasification and an engine/generator set. As mentioned above, it is assumed that all rice produced is directed to rice mills of sufficient size to utilize the rice husk produced. Finally, it is assumed that the conversion rate cited for the Nyagatare facility is representative for any rice husk to electricity projects in Rwanda (as cited above, this is also equal to 1.33 t husk/MWh). **The estimated annual generation potential for Rwanda's rice production is 17,592 MWh** as shown below:

Annual Electricity Generation (MWh) = 116,500 t rice x (0.20 t husk/t rice) x (1 MWh/1.325 t husk)

= 17,592 MWh

[113] Gasification is a process of converting a solid feedstock into a combustible gas by heating the material at high temperatures (typically > 700 degrees Celsius) and in a controlled air environment.
[114] Capital costs estimated for this study addressing south Asia were $1,300/kW (annual operating costs were estimated as 4% of capital costs). These are higher than the $800/kW mentioned for projects carried out by Indian companies using locally produced equipment. https://www.sciencedirect.com/science/article/pii/S0961953414003043.
[115] Rice Husk, to Power Project, Nyagatare District. http://www.fonerwa.org/rice-husk-power-project-nyagatare-district.
[116] Design and operation of CFB gasification and power generation system for rice husk. https://www.sciencedirect.com/science/article/abs/pii/S0961953402000429?via%3Dihub.

Based on engineering judgment and assuming that these plants are run around the clock as base load plants with an average capacity factor of 80% (about 7,000 hours/yr), **the estimated total technical potential (exploited and unexploited) associated with the annual generation calculated above would be 2.5 MW of "nameplate" capacity**, as shown below:

$$\text{Capacity (80\% CF)} = 17{,}592 \text{ MWh} \times (1/7{,}000 \text{ hours}) = 2.5 \text{ MW}$$

If instead, these plants are run primarily to address shoulder and peak loads (e.g., with a CF of 40%), then the estimated associated capacity would be:

$$\text{Capacity (40\% CF)} = 17{,}519 \text{ MWh} \times (1/3{,}500 \text{ hours}) = 5.0 \text{ MW}$$

There may be opportunities to increase the technical potential for crop residues if projects can be sited to take advantage of multiple feedstocks. In these cases, the design of the gasifier will need to account for the different characteristics of these different fuels, including heating value and moisture content. For example, there is around 15,000 t of coffee husk available annually in Rwanda. Rice straw is another potential feedstock; however, as with any potential feedstock that is not already present at a milling/processing facility, the material needs to be baled/packaged and transported to the energy conversion site. Depending on the feedstock, some additional processing might be needed in order to use it at an energy conversion facility (e.g., chopping, shredding). Detailed spatial information is needed to conduct an analysis of where different yet compatible feedstocks overlap in order to estimate the additional technical potential for these crop residues. As part of such assessments, some project level analysis would also be needed to determine whether the feedstock transport costs are low enough to make the project financially viable.

Assuming the same gasification conversion technology and 80% CF and a similar heat content for all crop residues, an upper limit of the technical potential for all of the crop residues listed in Table 3.F.2.a-1 is roughly 120 MW. This was derived by multiplying the 2.5 MW for rice husk above by 1,088,000 t residue/23,000 t rice husk. In reality though, not all of that biomass will be available for conversion to electricity for varying reasons. These include the need for some crops to leave some residue on the field to promote soil health. In some areas, there may not be enough biomass to justify the construction of a conversion facility; or the costs for gathering/transporting/processing are prohibitively high for economic conversion to electricity.

3.F.2.b. Municipal Solid Waste

For this initial technical potential assessment for MSW, the conversion technology considered for urban MSW to electricity projects is direct (mass) combustion of MSW to electricity (via a steam turbine).[117] The conversion efficiency selected for these plants is 15.7 MJ/kWh (about 23%).[118] As indicated in the figure below, over 1 million GWh of technical potential is forecasted to be available for collected urban

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[117] As previously mentioned, information on rural solid waste generation is currently lacking but it is another waste resource that should be investigated in the future. There are potential geographic overlaps with other rural energy resources, such as agricultural residues. Also, especially in the Kigali region, landfill gas to energy power production should be analyzed for addition to this initial TP assessment.

[118] This value was derived from information for a 95 MW WtE plant in Florida: http://wpca.info/pdf/Newsletters/2016_WPCA_Winter_NL.pdf. It is very close to a more general value provided by NREL for direct combustion biomass to electricity production (15.8 MJ/kWh): https://www.nrel.gov/docs/fy13osti/52829.pdf.

MSW in Rwanda (both Kigali and other urban areas). Note that these are net GWh available for the electrical grid; these types of plants have fairly high electrical energy requirements themselves to support advanced air emissions control systems.

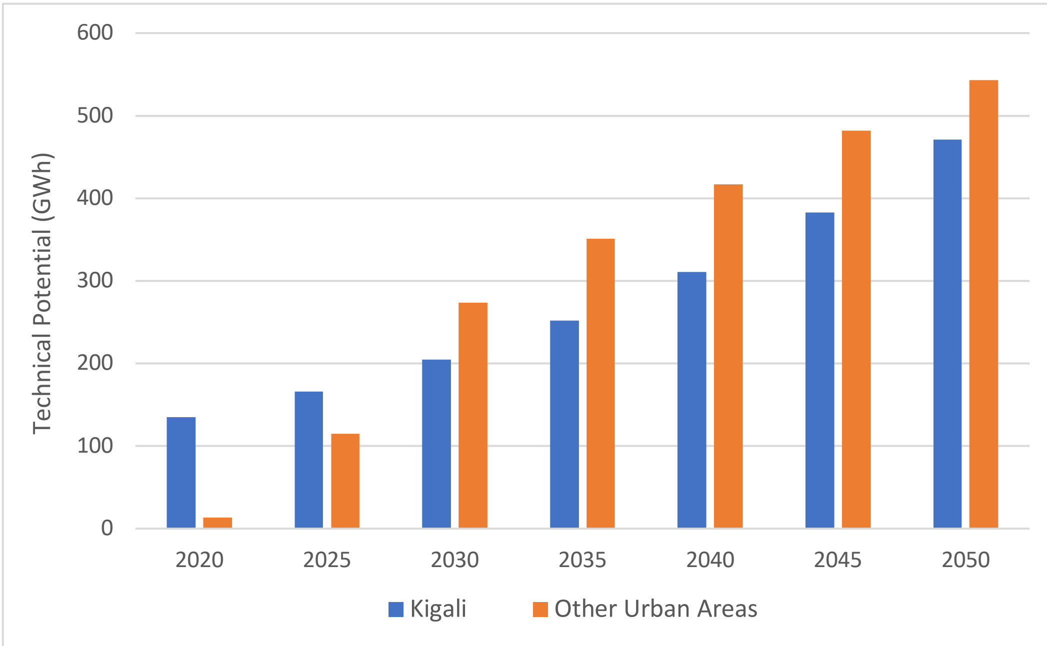

Figure 3.F.2.b-1 Technical Potential for Collected Urban MSW: Generation

Figure 3.F.2.b-2 below provides the technical potential for collected urban MSW on a capacity basis. These estimates were derived from the generation values above and an assumed capacity factor of 80%. **By 2030, it is estimated a total technical potential (exploited and unexploited) of almost 70 MW of "nameplate" capacity from collected urban MSW. By 2050, it is estimated that about 145 MW of technical potential will be available.**

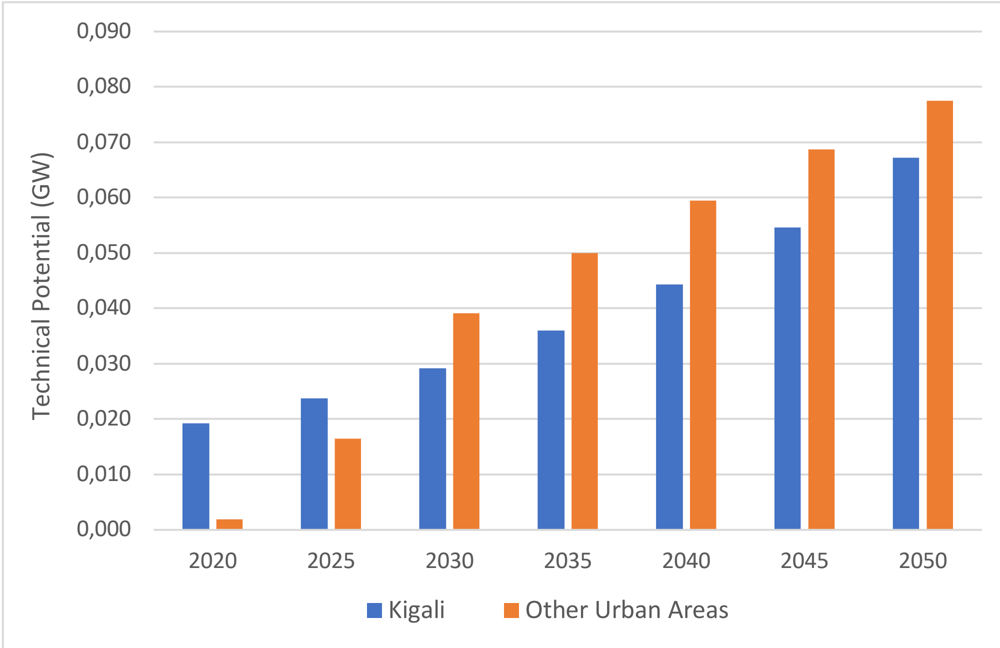

Figure 3.F.2.b-2 Technical Potential for Collected Urban MSW: Capacity

3.F.3 GRID-INTEGRATION COSTS

3.F.3.a. Crop Residue

A simplified approach was used to assess grid integration costs. The approach uses consistent cost inputs as those used for the other resources; however, the following steps were taken, and assumptions made:

1. Each mill was assumed to be able to process a fraction of national rice production equal to its contribution of total mill capacity. This assumes that all national rice production is directed for processing at those mills listed in Table 3.F.2.a-1 above and that each one processes an amount equivalent to its maximum capacity. For example, the Muyange mill in Table X.1-1 has 5.1% of the processing capacity listed, and therefore is assumed to process that fraction of national rice production.
2. For 12 of the mills, the village location was available; for 13 sites, the district location was available. For these 25 sites, the centroid of the polygon was used as the site location in order to estimate distances to the nearest substation or HV line. For the remaining two, the distances were assigned as the average of the other 25.
3. It is assumed that no road access or site acquisition costs are pertinent to grid integration (i.e., the mill owner is providing the space needed for equipment).
4. The lowest cost was selected for grid integration either via a new or existing substation, whichever cost was estimated to be lower (consistent with the costing approach to other resources).
5. For the last two mills listed in Table X.1-2, no district location was provided. Therefore, the integration costs were estimated using the average distances to the nearest existing substation or high voltage line.

Please refer to section 3.C.3 on solar resource for more details on what Grid integration costs include and how they were estimated.

For rice husk to electricity projects, grid integration costs were estimated to have a large range from \$0.47 - \$13.5 million/MW. For the purposes of assessing the economic potential, the median value of \$2.2 million/MW was selected to represent grid integration costs inputs for rice husk to electricity projects. Since biomass gasification plants for electricity production are likely to be very small and costly to integrate into the grid, better opportunities for their use may be as electricity generators for micro-grids. Also, as indicated earlier, additional investigation to address the potential for other feedstocks should be undertaken to determine whether there are opportunities for supporting larger biomass gasification facilities.

3.F.3.b. Municipal Solid Waste

The best locations for siting MSW WtE facilities will be at existing material recovery facilities or landfill locations. This is because the collected MSW is already being routed to these facilities, so no additional costs for transport are needed. Future work to improve upon this assessment should include some survey work to identify candidate locations within each of the urbanized areas of the country. For each candidate location, the size of the land parcel should be evaluated to determine if sufficient size exists to site the plant. Based on the site locations, a standard assessment of integration costs could then be performed (e.g. as shown for solar PV and other energy resources).

Since no information was identified on likely locations for WtE facilities, a simple approach was used to construct a generic grid integration cost value. The steps and associated assumptions are described below:

1. No existing substations are assumed to be located nearby.
2. An existing HV line is assumed to be located within 1 kilometer of the WtE plant.
3. A new substation is assumed to be constructed.
4. No land purchase costs are assumed (new plants are built on the site of existing waste management facilities).
5. No road construction costs are assumed.
6. A plant with a capacity of 25 MW is assumed.

Please refer to section 3.C.3 on solar resource for more details on what grid integration costs include and on cost inputs values. Based on those cost input values and the assumptions above, the grid integration costs for MSW WtE plants are as follows, based on the cost inputs indicated in Section 1.5:

Grid Integration for 25 MW Plant (\$2021/MW) = MV Line to New Substation + New Substation =

(\$70,000/km x 1 km) + (\$300,000/MW x 25 MW) = \$7,570,000

Cost/MW = \$302,800/MW

3.F.4 EQUIPMENT, INSTALLATION AND O&M COSTS

3.F.4.a Crop Residue

Given the size of rice mills in Rwanda and other applications of rice husk to energy conversion, the assumed conversion process is to use a biomass gasifier to generate synthesis gas which is then fed to an engine/generator set. Direct combustion waste to energy plants tend to be >1 MW in size,[119] and this is much too large to be supported by the amount of husk available at Rwandan rice mills. Table 3.F.4.a-1 provides a summary of values from the literature on the costs to implement this technology. Except for the Uganda value, the values shown in the table have been adjusted to Rwandan conditions (see Section 1.6 of the Solar assessment for a description of the general methods and data sources used to make these cost adjustments). For biomass gasification, it was assumed that half of the costs were associated with equipment and the other half associated with construction costs (e.g., for structures to house the equipment and feedstock storage). Gasifiers can often be locally fabricated; but the engine/generator set will likely need to be imported.

TABLE 3.F.4.A-1 INSTALLED COST INPUTS FOR RICE HUSK GASIFICATION AND ELECTRICITY PRODUCTION FOR ECONOMIC POTENTIAL MODELING

TECHNOLOGY DESCRIPTION	TOTAL INSTALLED COST ($2021/KW)	NOTES	CITATIONS
60 kW Biomass Gasification	$3,290	U.S. value of $3,522/kW adjusted to RW conditions (Machinery and Equipment Ratio of 0.66 applied); using biomass or MSW as feedstock	Energies 2020, 13, 3703; doi:10.3390/en13143703; https://www.google.com/url?sa=t&rct=j&q=&esrc=s&source=web&cd=&ved=2ahUKEwj21_ijnrH0AhWgSDABHZI-A_oQFnoECAUQAQ&url=https%3A%2F%2Fwww.mdpi.com%2F1996-1073%2F13%2F14%2F3703%2Fpdf&usg=AOvVaw3XoxXJqZrSIBIkESyCuimi.
250 kW Biomass Gasification	$1,808	Uganda project	
75 kW Biomass Gasification	$4,927	Poland project	
500 kW Biomass Gasification	$640	Indonesian project	https://www.google.com/url?sa=t&rct=j&q=&esrc=s&source=web&cd=&cad=rja&uact=8&ved=2ahUKEwj21_ijnrH0AhWgSDABHZI-A_oQFnoECCQQAQ&url=http%3A%2F%2Fiopscience.iop.org%2Farticle%2F10.1088%2F1757-899X%2F334%2F1%2F012012%2Fpdf&usg=AOvVaw0JeXFRJQSfCiAm14vDhPI1.
Value Selected	**$2,549**	**Average of U.S. and Uganda project values**	

[119] Cost Analysis for Combustion of Rice Husk in a Fluidized Bed Combustion, https://ris.utwente.nl/ws/portalfiles/portal/160144185/During2019cost.pdf.

It is not clear why the Indonesian project costs are so low as compared to the others; nor is it clear why the project in Poland had much higher costs. Assessing the two middle values, at least some of the lower costs for the Ugandan project could be explained via economies of scale. For the purposes of EP cost modeling, a mid-point of the U.S. and Ugandan values was selected ($2,549/kW). A total O&M cost of $0.196/kWh from the same U.S. study was also selected. This value was adjusted to RW conditions using the construction price indices for RW and the U.S., which resulted in a total O&M value of $0.136/kWh. Only about 6% of these were for variable costs, the rest were for fixed O&M.

3.F.4.b Municipal Solid Waste

The costs for installing and operating WtE plants are relatively high as compared to other types of power plants. One of the key factors involved is the need for air pollution controls to reduce emissions of particulate matter and toxic air pollutants. The latter group includes toxic metals, including mercury, as well as toxic organic compounds, such as chlorinated dioxins and furans.

Table 3.F.4.b-1 below provides a summary of installation cost information identified in the literature that was considered in the selection of cost inputs for the economic potential modeling for MSW WtE. The Florida, USA plant cited is a relatively new facility (constructed in 2014) which includes all air pollution controls. It had a construction cost of $7,929/kW (adjusted to 2021 USD). Expression of these US costs to Rwanda conditions is difficult since a breakdown of costs was not available. Given the complex nature of such a state-of-the-art WtE plant, it seems likely that the equipment costs would be a larger contributor to total installed costs than the local construction costs. So, it was assumed that equipment costs make up two-thirds of total installed costs. Using the methods described in Section 3.C.3 for the solar assessment to adjust costs to Rwanda conditions, the total installed cost estimate from the Florida plant was estimated to be $8,886/kW as shown in Table 3.F.4.b-1 below.

For the economic potential modeling, the installation cost value from the Ethiopia plant was selected. Since only the NREL citation provided O&M values, these were selected (after adjusting to Rwandan conditions).

TABLE 3.F.4.B-1 COST INPUTS FOR ECONOMIC POTENTIAL MODELING OF MSW WTE

TECHNOLOGY DESCRIPTION	TOTAL INSTALLED COST ($2021/KW)	FIXED & VARIALBE O&M ($2021/KWH)	NOTES AND CITATIONS
Florida, USA WtE; 95 MWe	$8,886	Not provided	2,700 tons MSW/day; $7,929/kW total installed costs adjusted to Rwanda conditions; http://wpca.info/pdf/Newsletters/2016_WPCA_Winter_NL.pdf.
USA Installed Costs; Dedicated Biomass Power	$4,500	$46/kW-yr $0.008/kWh	NREL Annual Technology Database; overnight capital costs and O&M costs adjusted to Rwanda conditions; https://atb.nrel.gov/electricity/2021/data.
Ethiopia WtE; 25 MWe	$5,318	Not provided	Engineering, Procurement and Construction (EPC) Cost, Cambridge Industries, https://static1.squarespace.com/static/57c7f80620099eafefefe77a/t/5b31caeff950b7cb65f7437d/1529989903242/Reppi+Brochure+%28technical+detail%29.pdf.
Selected Values	**$5,318**	**$46/kW-yr** **$0.008/kWh**	**Ethiopia installed costs; NREL O&M costs.**

3.G. GEOTHERMAL RESOURCE ASSESSMENT

Olkaria II Geothermal Power Station in Kenya
NICHOLA SOBECKI, NATIONAL GEOGRAPHIC

3.G.1. PHYSICAL RESOURCE AVAILABILITY

Geothermal energy is a type of energy that is generated from heat resources beneath the surface of the earth, capturing heat from hot rock, water, and steam to generate electricity. Given its position along the Great Rift Valley, Rwanda has been considered a site of potential development of geothermal energy. However, **geothermal exploration has yet to identify a geothermal resource suitable for the generation of electricity in Rwanda, and there are no operational geothermal power plants in the country.** A geothermal **physical resource** assessment would require significant exploration drilling and modeling activities that are outside of the scope of this project. As such, for the purpose of supporting the modeling of technical and economic potential of geothermal resources as part of this project, **the EAEP Team used the estimation of physical resource availability and technical potential from previous work carried out on this topic**.

A national geothermal study was conducted by the Japanese International Cooperation Agency (JICA) in 2016, as a baseline for geothermal resources in Rwanda. The assessment of generation of electricity from geothermal resources is limited to large, centralized generation for transmission on the national grid. In this assessment, applications of geothermal energy technologies focus on standard (widely applied systems), rather than enhanced geothermal systems (EGS or engineered geothermal systems). Current exploratory activities in Rwanda have estimated that Rwanda is likely to have low-to-medium temperature geothermal resources, and therefore future projects are expected to apply binary plant generation technologies. That will be the technology used for this analysis.

The physical geothermal resource assessment was documented in the Phase 2 report. Rwanda has no known geothermal resources, however there are five sites in four geothermal fields (Kinigi, Karisimbi, Gisenyi and Bugarama) which have been identified in prior analysis as having potential for development of electricity generation projects (Figure 3.G.I-1).

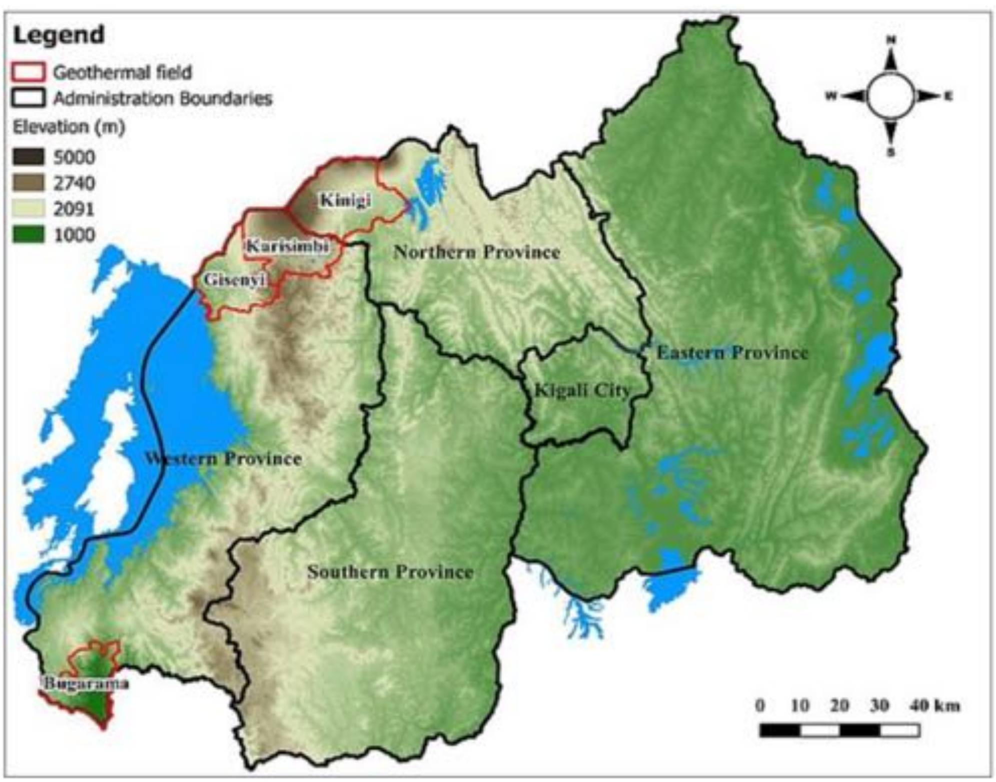

Figure 3.G.I-1 Geothermal resource map REG

3.G.2. TECHNICAL POTENTIAL

There is currently no proven geothermal resource in Rwanda. Estimated figures below are hypothetical values for geothermal development based on current understanding of geothermal fields resulting from site surveys and conceptual modeling, and are as such, they are developed for illustrative purposes only.

The geothermal resource potential of the detailed geoscientific survey conducted by JICA was estimated by the volumetric method from some parameters necessary for the calculation. The volumetric method is a method for calculating the heat energy stored underground, then calculating the energy available for power generation and finally converting that energy into power output. For the fields, technical potential was calculated using assumed minimum and maximum conversion efficiency values of 5.0% and 10.0% for a binary-type installation, a plant capacity factor of 85%, and plant operational life of 30 years. The results of this assessment are presented in Table 3.G.2-2 below at both the 50% and 80% confidence levels.

TABLE 3.G.2-1 HYPOTHETICAL GEOTHERMAL DEVELOPMENT

FIELD NAME	RESOURCE POTENTIAL P80 (MWE)	PLANT CAPACITY (MWE)	POWER UNIT	NUMBER OF PRODUCTION WELLS	NUMBER OF REINJECTION WELLS
Kinigi	32.6	20	5MW x 4	5	3
Bugarama	6.6	5	5MW x 1	2	1
Total	**39.2**	**25**			

The 2016 JICA study selected prospective areas for geothermal power development in Rwanda on the basis of temperatures expected from the chemistry of thermal water, geological and geophysical information, and the present state of exploration of each field.

TABLE 3.G.2-2 SUMMARY OF RESOURCE EVALUATION FOR 5 FIELDS

FIELD NAME	RESOURCE POTENTIAL AT 80% CONFIDENCE LEVEL (MWE)	RESOURCE POTENTIAL AT 50% CONFIDENCE LEVEL (MWE)
Kinigi	32.6	58.6
Bugarama	6.6	15.1
Gisenyi	1.9	3.7
Karago	2.5	4.9
Iriba	3.7	7.2

Given the characterization of the five geothermal fields, it was determined that the Kinigi and Bugarama fields are the most likely to contain significant enough geothermal resources for generation of electricity. Due to the extremely high cost of geothermal exploration and development, as well as technology implementation, the threshold of siting of geothermal projects is typically 5 MW. **Only Kinigi and Bugarama were assessed to have a technical potential meeting this criterion and were considered for further assessment.** These sites were confirmed by REG staff to be of primary concern and were focused on for further analysis for this Phase 3 assessment. **It should again be noted that the presence of a geothermal reservoir adequate for power generation has not yet been confirmed for either site and will require further exploration activity. All technical potential figures provided in this Phase 3 assessment are illustrative only to provide data for the modeling of varying energy system configurations in LEAP in conjunction with other resources.**

As discussed above, the conversion technology selected for conducting the geothermal resource assessment for Phase 3 are binary cycle plants due to the low-to-medium temperature geothermal resources expected to be present in Rwanda. Operationally, in binary cycle plants, water/steam from the geothermal resource never comes into contact with the turbine, but instead heats a secondary working fluid via a heat exchanger. The working fluid will have a much lower boiling and condensation point than water and will be matched to the specific geothermal resource temperature to improve efficiency.

The JICA study assessed both the Kinigi and Bugarama fields for potential for electricity generation using the figures obtained at a 80% confidence level. The proposed development of these two fields were analyzed for development using the following specifications (Table 3.G.2-2), which resulted in an **estimated technical potential of 25 MWe available for development**, taking a conservative estimate of the available resource at each field for generation of electricity.

TABLE 3.G.2-3 MAIN SPECIFICATIONS FOR POSSIBLE POWER DEVELOPMENT AT KINIGI AND BUGARAMA

FIELD NAME	RESOURCE POTENTIAL P80 (MWE)	PLANT CAPACITY (MWE)	POWER UNIT	NUMBER OF PRODUCTION WELLS	NUMBER OF REINJECTION WELLS
Kinigi	32.6	20	5MW x 4	5	3
Bugarama	6.6	5	5MW x 1	2	1
Total	**39.2**	**25**			

3.G.3. GRID-INTEGRATION COSTS

A simplified approach was used to assess grid integration costs. Grid integration costs include those estimated for new high voltage transmission lines, substations or substation upgrades, access roads and site land acquisition. An overview of all associated grid integration cost assumptions can be found in Section 3.C 1.5-1 of this report. The approach uses consistent cost inputs as those used for the other resources; however, the following steps were taken and assumptions made:

1. For the two geothermal fields, a representative plant site was established based upon the results of the JICA resource assessment and locations of proposed wells. It is assumed that geothermal plants will be developed directly at the geothermal field, with HV transmission connecting to the national grid (Figure 2) . These proposed sites are only a hypothetical location of the geothermal plants using best available data; the exact location would be determined after further exploration and development activities are conducted. These points were plotted using QGIS

and used as the site location to estimate the distances to the nearest substation, HV line and existing road infrastructure.

2. It is assumed that no existing road access is available at the site and will need to be constructed to connect the geothermal project site with existing infrastructure.
3. It is assumed that land will need to be acquired for project implementation. There may be costs associated with relocation of populations due to project development, however these costs have not been incorporated into this analysis.

Grid integration costs were estimated to be $509,390/MW for the Kinigi geothermal site and $535,544/MW for the Bugarama geothermal site, or an average of $491,155/MW between the two fields, which is the figure that will be used for the modeling of economic potential.

As an example, for Kinigi, the geospatial analysis that for the hypothetical project site determined that the location was 8,061 m from the closest HV transmission line and 1,385 m from the closest road infrastructure. Rwanda specific values for infrastructure costs were applied (an explanation of this criteria can be found in the solar resource assessment), a land acquisition cost of $4.45/m2 which for geothermal included a high voltage transmission line cost of $200,000/km, a new substation cost of $300,000/MW, and a road construction cost of $15,000/km. This provided cost of $4.70 M for land acquisition, $1.61 M for new HV line construction, $7.50 M for new substation construction and $.02 M for construction of new road infrastructure, totaling $12.73 M. This equates to a total grid integration cost of $509,390/MW.

Figure 3.G.3-1 Hypothetical Sites for Geothermal Development at Kinigi and Bugarama

3.G.4. EXPLORATION AND DEVELOPMENT COSTS

Unlike other renewable energy resources, geothermal resources require allocation of time and financial resources to prove out the viability of a given geothermal site. These development costs can be in the tens of millions of dollars and require five years or more of development. This variable significantly increases the cost and risk for the development of geothermal energy projects in comparison to other resources.

In 2017, IRENA estimated that exploration costs are expected to be approximately 4% of total geothermal project costs,[120] and ISOR/ESMAP estimated that exploration drilling and testing would account for approximately 6% of project costs.[121] For a typical geothermal plant, this can result in costs of $5 million to over $20 million depending on project size, and the exploration may prove unsuccessful, as occurred with the Karisimbi exploration program in Rwanda in 2013.

In the 2016 JICA assessment, the estimated cost for the resource feasibility study in Kinigi was estimated to be $26 million USD over approximately 3 years, which included the exploration program and drilling of three exploration wells to confirm presence of a geothermal reservoir. For Bugarama, this activity was estimated for a duration of 2.5 years, at a cost of approximately $18 million USD, which included drilling of two test wells.[122] For the Kinigi project, this represents over 14% of estimated total project costs, and for Bugarama this represents over 25% of estimated project costs. This is due to the high cost of exploration in comparison to the small resource potential of the two sites.

3.G.5. INSTALLATION, EQUIPMENT AND O&M COSTS

Due to the low-to-medium temperature geothermal resources expected to be present in Rwanda, it is assumed that binary cycle technology will be employed for any project in the country. Binary cycle plants are more expensive than flash or dry steam plants, as they are closed-loop systems which requires the use of a high-pressure working fluid to serve as a heat exchange medium, which is used to transfer heat and produce steam which run through a turbine to produce electricity, rather than using geologic steam or superheated water directly.

According to the NREL Annual Technology Baseline (NREL ATB) 2021, the estimated capital cost for the binary cycle geothermal plant is $8,832/kW, while the estimated cost of a typical flash steam geothermal plant is $6,662/kW. Size ranges for geothermal installations range from a minimum size of 5 MW to hundreds of megawatts. Potential geothermal projects in Rwanda are therefore considered to be very small at 5 MW and 20 MW, which does not afford the economies of scale that benefit the largest projects.

Given the extreme variation in size and cost for exploration, the cost ranges for geothermal development vary greatly. On the low end of the spectrum are those projects which are expansions of existing geothermal projects, which tend to be large in scale and provide low-risk exploration and development and utilize existing infrastructure. On the high end of costs are new unproven geothermal field development with high-risk exploration, as is the case for potential geothermal projects in Rwanda.

Table 3.G.5-1 provides a summary of values from the literature on the costs of recently developed small geothermal projects globally, including cost estimates from the 2016 JICA report for the Kinigi and Bugarama fields. The cost estimates for development of these two fields are on the very high end of the cost spectrum. For the JICA and NREL cost estimates, the values shown in the table have been adjusted to Rwandan conditions (see Section 3.C.3 of the Solar assessment for a description of the general methods and data sources used to make these cost adjustments).

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[120] Geothermal Technology Brief, IRENA 2017, https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2017/Aug/IRENA_Geothermal_Power_2017.pdf.
[121] Phases of Geothermal Development, https://esmap.org/sites/default/files/esmap-files/Flovenz%20Day%201%20-WB-2-phases-final.pdf.
[122] JICA, https://openjicareport.jica.go.jp/pdf/12260238_03.pdf.

TABLE 3.G.5-1 INSTALLED COST INPUTS FOR GEOTHERMAL ECONOMIC POTENTIAL MODELING			
TECHNOLOGY DESCRIPTION	TOTAL INSTALLED COST ($2021/KW)	NOTES	CITATIONS
Italy – 40 MW	4,150	2021, 3% discount rate	https://www.iea.org/reports/projected-costs-of-generating-electricity-2020
Italy – 15 MW	7,686	2021, 3% discount rate	
Italy – 10 MW	10,560	2021, 3% discount rate	
Italy – 5 MW	11,810	2021, 3% discount rate	
US – 30 MW	4,440	2021, 3% discount rate	
US – 25 MW	5,968	2021, 3% discount rate	
NREL ATB Binary Cycle	9,141	2019, adjusted for inflation,	https://atb.nrel.gov/
Kinigi	10,295	JICA 2015 cost estimate, adjusted for inflation	https://openjicareport.jica.go.jp/pdf/12260238_03.pdf
Bugarama	14,661	JICA 2015 cost estimate, adjusted for inflation	https://openjicareport.jica.go.jp/pdf/12260238_03.pdf
Value Selected	**9,418**		

It is not known what technology is being employed at the US and Italian installations reviewed in the chart above. The NREL ATB cost estimate for new binary cycle geothermal projects is the most up to date cost metric available, is similar in range to the cost estimate for the larger Kinigi geothermal estimate provided by JICA and falls within the midrange of global geothermal energy projects. Given the wide range of variables associated with geothermal development, the NREL ATB cost estimate for binary cycle power plants has been selected as the reference project cost for this analysis. The cost includes capital costs for plant construction, $9,141/kW. This does not include fixed O&M costs for geothermal plant operation, which are estimated to be $277/kW/yr.

Given the high capital cost of geothermal development related to the drilling program, the following cost assessment developed by JICA for the potential Kinigi plant has been provided to show the allocation of costs for exploratory drilling, construction, and grid integration. Phase 1 exploration survey work was completed during the 2016 assessment.

TABLE 3.G.5-2 COST ASSESSMENT DEVELOPED BY JICA FOR THE POTENTIAL KINIGI PLANT	
RESOURCE EXPLORATION SURVEY IN KINIGI (PHASE 2)	
Details	To carry out supplemental surface geoscientific surveying to update the geothermal conceptual model and select drilling targets in the Kinigi field.
Project Period	Approx. 1 year Approx.
Activities	• Supplemental geological geochemical study • Gravity survey (200 stations) • Supplemental MT/TEM survey • Resource Assessment/Planning (Integrated analysis) • Study of multi-purpose utilization
Total Cost	$.8 million USD
RESOURCE EXPLORATION SURVEY IN KINIGI (PHASE 3)	
Details	To carry out an exploration survey including drilling three (3) exploration wells in the Kinigi field to confirm presence of a geothermal reservoir and to evaluate the geothermal resource.
Project Period	Approximately 3 years
Activities	• Exploratory Well Drilling & Testing (3,000m x 2 wells, 1,500m x 1 well) • Production testing • Resource Assessment/Planning/basic Design etc. • Study of multi-purpose utilization
Total Cost	$26.0 million USD
KINIGI GEOTHERMAL PROJECT CONSTRUCTION	
Details	Upon completion of EISA and project appraisal, c, activities to bring the geothermal plant to operation.
Project Period	Approximately 6 years
Activities	• Engineering Services by Consultant • Steam Field Development • Fluid Collection and Reinjection System Construction • Power Plant Construction • Transmission Line and Switchyard Construction
Construction Cost	$124.03 million USD
Total Cost including Labor, O&M and Financing)	$184.47 million USD

3.H. LAKE KIVU METHANE RESOURCE ASSESSMENT

Methane gas extraction facility on Lake Kivu
THE NEW TIMES, RWANDA

3.H.1. PHYSICAL RESOURCE AVAILABILITY

The Lake Kivu methane (LKM) **physical resource** has been well characterized, most recently in the 2019 Intercalibration study,[123] which estimated a methane volume of approximately 40.9 km^3 at standard temperature and pressure (STP) within the *resource zone* (i.e. 260 and 480 meter depth), and another 8.4 km^3 in the potential resource zone (200-260 m depth). Methane has a lower heating value of 35.8 MJ/m^3; therefore, the above volumes of methane are equivalent to approximately 1.5 million terajoules (TJ) of energy in the resource zone and 0.3 million TJ in the potential resource zone for a total of 1.8 million TJ. The resource in Lake Kivu is shared 50/50 with the Democratic Republic of the Congo (DRC), so Rwanda's share of this resource would be approximately 0.7 million TJ of energy in the resource zone and almost 0.9 million TJ total.

Table 3.H.1-1 below lists current and planned generation from LKM. The 3.6 MW KP1 plant was previously in operation but has been recently out of service. Magma Energies Ltd has been contracted to rehabilitate and operating this plant. There are plans to increase the capacity from the 3.6 MW phase I pilot plant to 25 MW. This plant uses a single floating gas extraction facility (GEF).

KivuWatt started operation in 2015 with 26.19 MW as part of Phase 1 in a plan to expand to 100 MW. The timeline on expansion is unknown. The current plant uses 3 GEFs, with a plan for 9 additional GEFs for the full 100 MW of capacity. The Kivu56 plant will begin operating 14 MW and a single GEF in 2022, with plans to increase capacity top 56 MW using a total of 4 GEFs.

In addition to electricity generation, Rwanda signed a concession agreement with Gasmeth Energy in 2020 to extract methane from the lake and directly bottle the methane gas for direct use by consumers. Extracting methane for direct use by consumers reduces the amount available for electricity generation, but the impact is assumed to be insignificant compared to consumption by power plants.

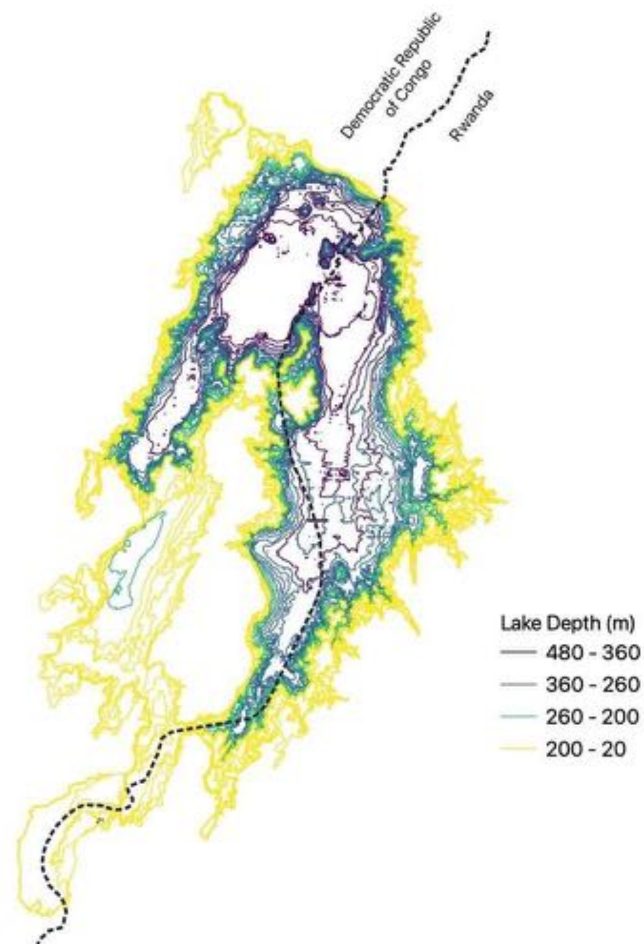

Figure 3.H.1-1 Bathymetry Map for Lake Kivu

[123] Intercalibration Campaign for Gas Concentration Measurements in Lake Kivu, Swiss Federal Institute of Aquatic Science and Technology, Helmholtz-Centre for Environmental Research, UFZ, Germany, 2019. https://www.dora.lib4ri.ch/eawag/islandora/object/eawag%3A18541/datastream/PDF/Schmid-2019-Intercalibration_campaign_for_gas_concentration-%28published_version%29.pdf.

TABLE 3.H.1-1 CURRENT AND PLANNED RWANDAN GENERATION FOR LAKE KIVU METHANE					
PLANT NAME	COMPANY	NAMEPLATE CAPACITY (MW)	TOTAL PLANNED CAPACITY (MW)	NUMBER OF GEFS (INSTALLED)	NUMBER OF GEFS (PLANNED)
KP1	Magma Energies Ltd	3.6	25	1	NA
KivuWatt	Contour Global	26.19	100	3	12
Kivu56	Shema Power Lake Kivu Ltd (formerly Symbion Energy)	14[a]	56	1	4
Total	43.79	181	5	NA	

[a]Beginning in 2022

3.H.2. TECHNICAL POTENTIAL

Table 3.H.2-1 below summarizes the **estimated technical potential for LKM** in terms of “nameplate” capacity and “available” capacity (GW) and related annual generation (GWh). **A total technical potential (exploited and unexploited) of 237 MW of “nameplate” capacity for 50 years of exploitation of Rwanda’s share of the lake methane, using single-cycle power plants was estimated**

TABLE 3.H.2. -1. LKM TECHNICAL POTENTIAL (EXPLOITED AND UNEXPLOITED)						
	TOTAL LAKE			RWANDA SHARE		
PLANT TYPE, TIMEFRAME	GENERATION (MWH/YEAR)	NAMEPLATE CAPACITY (MW)	AVAILABLE CAPACITY (MW)	GENERATION (MWH/YEAR)	NAMEPLATE CAPACITY (MW)	AVAILABLE CAPACITY (MW)
Single-cycle, 25 years	3,815,137	473	436	1,907,569	237	218
Combined-cycle, 25 years	6,540,235	812	747	3,270,117	406	373
Single-cycle, 50 years	1,907,569	237	218	953,784	118	109
Combined-cycle, 50 years	3,270,117	406	373	1,635,059	203	187
Current Exploited				213,369	29.8	24.4

The estimation of technical potential, as well as the other estimates indicated in the table above, are limited based on the following considerations and assumptions:

- *Physical Resource*. As indicated above the total physical resource in the resource zone is estimated to be 40.9 km^3 of methane, with Rwanda's portion at 20.45 km^3. The lower heating value of methane is 35.8 MJ/m^3, to Rwanda's portion of the physical resource is equivalent to 732,110 TJ of energy. The methane outside the main resource zone was not included in this assessment since it is more technically difficult to extract. There may be some methane recharge in the lake, but the amount is quite small and uncertain, so it was assumed to be zero for this assessment.
- *Efficiency of methane recovery from degassing of siphoned water*. Current technology can efficiently and economically extract methane down to a concentration of 5 mol/m^3. The current concentration at 350-meter depth is 15 mol/m^3, so it was assumed that 67% of the total methane could be extracted from the resource zone (10 mol/m^3 out of 15 mol/m^3 extracted).[124] Newer technology may be able to increase this recovery rate to as high as 90%; however, this technology has not been applied.[125] Therefore, the current value of 67% was assumed for this assessment. Applying this efficiency to the Rwanda's physical resource results in an energy content of 490,514 TJ.
- *Timing of resource extraction*. The length of the concessions granted for the KivuWatt and Kivu56 plants are 25 years,[126] but the Government of Rwanda has set a target of 50 years operational time. Timeframes of both 25 and 50 years were considered. The resource of 490,514 TJ of energy over 25 years equals 19,621 TJ/year, or 9,810 TJ/year for 50 years.
- *Efficiency of conversion to electricity*. Single-cycle power plants, as currently installed at the existing plants, have an electrical conversion efficiency of approximately 35% (heat rate of 10,286 kJ/kWh). Replacing these engines with combined cycle engines could boost efficiency up to 60% (6,000 kJ/kWh).[127] Potential was estimated at both efficiencies. The available capacities estimated based on these potential levels of generation. The installed capacities were also estimated based on 92% availability. The most recent LCPDP shows an availability factor of 100% for KivuWatt, and the feasibility study for the KP1 estimates an availability of 86%.

One other consideration for the assessment of technical potential is the rate at which gas can be extracted annually, given the constraints on the space needed for gas extraction facilities over the resource zone. GEFs need to have enough vertical distance between intake in the lower resource zone and re-injection into the upper resource zone to prevent short-circuiting between these two water flows. Therefore, they must be sited over deep water and be light enough to float above the relatively shallow upper resource zone.

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[124] EAWAG, 2009. Modelling the reinjection of deep-water after extraction in Lake Kivu, https://www.eawag.ch/fileadmin/Domain1/Abteilungen/surf/projekte/kivu/kivu_simulation_report_eawag_2009.pdf.

[125] Energy efficiency and sustainability assessment for methane harvesting from Lake Kivu, https://www.sciencedirect.com/science/article/pii/S0360544221004643#bib31.

[126] Kivuwatt, https://www.afdb.org/sites/default/files/documents/environmental-and-social-assessments/kivuwatt_abbrev_rap_exec_summary_-_en_final.pdf.

Shema, formerly Symbion, https://www.reg.rw/what-we-do/projects/project-details/view/shema-power-lake-kivu/category/generation/

[127] Energy efficiency and sustainability assessment for methane harvesting from Lake Kivu, https://www.sciencedirect.com/science/article/pii/S0360544221004643#bib31.

Based on the Kivu56 plant, GEFs can be at least large enough to supply enough gas to power 14 MW capacity at single-cycle efficiency of 35%. Each Kivu56 GEF will be sited with a 1 km exclusion zone, and the 4 GEFs will occupy a lake surface area of 5 km by 2 km.[128] Both KP1 and KivuWatt both draw water from 350-meter depth, so this was assumed to be the optimum depth.

Referring to the bathymetry map for Lake Kivu, if theoretical GEFs were placed approximately 1.25 km apart (4 GEFs for 5 km of distance), extending from the national border at the north to the near the border at the south, as shown in Figure 2, there would be approximately 35 GEFs. If each GEF extracted enough methane for 14 MW, this would result in enough gas for 490 MW of capacity. This value is greater than the 218 MW of capacity available to Rwanda for single-cycle power plants over 25 years.

Therefore, the EAEP Team assumed that the technical potential is not limited by the space for GEFs on the lake surface, and any new capacity could be placed in locations that have favorable conditions regarding distance to shore for the GEF and distance to transmission infrastructure for the onshore facilities.

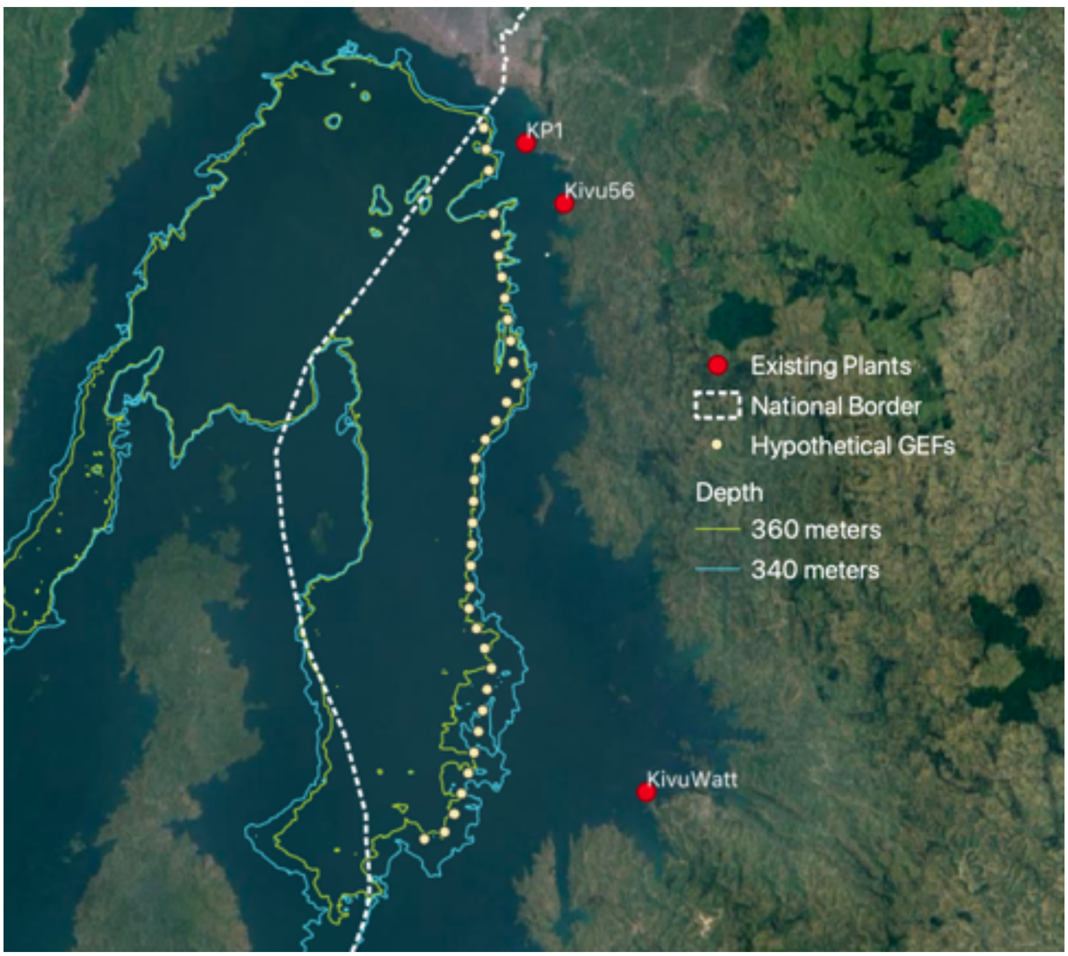

Figure 3.H.1-2 Lake Kivu Existing Generation and Hypothetical GEF Spacing

[128] Symbion Power Lake Kivu Ltd. Kivu 56, Addendum to the Environmental and Social Impact Assessment, 2018, https://www.miga.org/sites/default/files/2018-12/10669-20181015-ESIA%20Addendum_final_signed.pdf.

3.H.3. GRID-INTEGRATION COSTS

Costs for connecting new generation to the grid was not estimated as a separate cost for Lake Kivu methane for several reasons. First, most new generation will likely come from expansion of existing power plant sites, and any new sites would likely have similar grid connection costs to the existing plants. Second, the available cost information for current generation does not have grid connection or land acquisition broken out as separate cost estimates, so these are included in the project costs discussed below.

3.H.4. EQUIPMENT, INSTALLATION AND O&M COSTS

This section summarizes the selection of cost information for Lake Kivu methane electricity generation power plants for the modelling of economic potential. This costs information includes the following components:

- Land acquisition costs.
- Grid connection costs: costs for access roads, transmission line and substation upgrades.
- Equipment costs: for example, total costs for the GEF equipment, pipeline from GEF to power plant, gas turbines.
- Installation labor costs.
- Ongoing O&M costs: total annual costs to operate and maintain the gas extraction and generation equipment.

All cost values taken from the literature were adjusted to 2021 US dollars (USD), when needed, using the latest consumer price index values from the World Bank, and are listed in Table 3.H.4-1 below.

Estimated total capital expenditure costs were available for existing LKM power plants. Various cost estimates were seen for each plant, so an effort was made to choose the most recent in each case. For several plants, cost estimates went up over time due to delays and cost over-runs. O&M estimates were available for 2 plants. In addition, costs for several selected natural gas plant projects were provided as comparison. The natural gas plants costs are lower, in part, due to LKM plants having the added gas extraction equipment. These costs for each technology application are documented below.

For the economic potential modelling in this assessment, the Kivu56 installed costs were chosen as representative since it is the most recent plant. Costs could come down further in the future due to developments in knowledge and technology, but these developments are uncertain. For annual O&M, the KP1 rehabilitation cost value was chosen since this value seems more in-line with O&M practice for typical power plants.

TABLE 3.H.4-1 ECONOMIC MODELING COST INPUTS CONSIDERED AND SELECTED FOR LAKE KIVU METHANE ELECTRICITY GENERATION

TECHNOLOGY DESCRIPTION	TOTAL INSTALLED COST ($2021/KW)	FIXED & VARIALBE O&M ($2021/KWH)	NOTES AND CITATIONS
KP1, 2005; 4.5 MW	$28,050	NA	https://ppi.worldbank.org/en/snapshots/project/Kibuye-Power-1-3745
KP1 rehabilitation, 2020; 3.6 MW	$1,504	$288	Magma Energies Ltd feasibility study documents and financial model, provided by REG. Mid-point between best-case and worst-case scenarios.
KivuWatt Phase 1, 2015; 26.2 MW	$8,050[129]	$2,688[130]	The project was 3 years late in coming online and costs escalated from USD 127.1 M (May 2010) to USD 198.9 M (Nov 2015); https://www.government.nl/documents/reports/2018/05/01/evaluation-of-the-infrastructure-development-fund-–-volume-1-–-main-report O&M data taken from costs estimates provided by REG. Includes $460 for the power plant and $2,227 for the gas plant. 45% of estimated gas plant O&M costs are for insurance.
Kivu56, 2022; 56 MW	$7,846	NA	https://www.reg.rw/media-center/news-details/news/rubavu-shema-gas-methane-power-plant-nears-completion/
Natural gas combined cycle, Mexico; 503 MW	$669	$235	Shown for comparison only, note these are much larger plants and do not include GEFs. Installed costs are overnight costs not including investment costs. O&M values include fuel costs https://iea.blob.core.windows.net/assets/ae17da3d-e8a5-4163-a3ec-2e6fb0b5677d/Projected-Costs-of-Generating-Electricity-2020.pdf
Natural gas open-cycle, Brazil; 980 MW	$739	$363	
Internal combustion engine, US; 21 MW	$1,813	$36	https://www.eia.gov/outlooks/aeo/assumptions/pdf/table_8.2.pdf
Selected Value for Lake Kivu Methane Gas and Power Plants	**$7,846**	**$288**	Kivu56 installed cost estimate, KP1 rehabilitation project annual O&M cost estimate

129 The $127.1 million cost was used here, since the added costs were assumed to be due to the project delays.
130 It is unclear why this cost estimate is so high. According to the data provided, 45% of the gas plant annual costs are due to insurance.

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3.1. PEAT RESOURCE ASSESSMENT

Gishoma peat power plant
THE NEW TIMES

3.I.1. PHYSICAL RESOURCE AVAILABILITY

There are significant peat resources in Rwanda, with the largest resources concentrated in the Akanyaru Valley on the border with Burundi. Peat resources in Rwanda have been well characterized in the 2016 National Peat Resource Assessment, which was conducted by SWECO AB under contract from the Government of Rwanda. This assessment identified and sampled 18 peat bogs across the country, covering a total 13,571 hectares (Ha), which were all peat bogs of adequate size to be considered as a fuel source. As a result of the assessment, 16 peat bogs were identified as being suitable for extraction of peat resources for the purposes of energy generation.

The **physical availability** of peat resource in Rwanda was documented in the Phase 2 report. The SWECO AB study will serve as the baseline for this Phase 3 assessment of peat resources in Rwanda, supported by data regarding currently existing peat power plants in Rwanda provided by REG. The location of the 16 peat bogs that were characterized as being suitable for power generation in the SWCO AB report are shown in Figure 3.I.1-1 below.

Figure 3.I.1-1 Location of 16 identified Peat Bogs in Rwanda suitable for energy development

Figure 3.I.1-2 Hakan Concession Area Peat Bogs

Prior to the peat resource characterized in the SWECO study, a separate study by Hakan Power and HICE Consulting of peat resources was conducted in 2013 to develop three 35 MW peat plants, referred to as the "Hakan Concession Area." This resource is located in the Akanyaru Valley between the Akanyaru North and South Peat Bogs in Figure 3.1.1-1 and is shown in Figure 3.1.1-2 above. This resource was not included in the SWECO study and includes an additional 3,520 ha of peat resources. The 70 MW Hakan plant is expected to require 2500 ha of this resource to be harvested and used as a fuel for operation.

Table 3.1.1-1 below shows an updated assessment of the physical availability of peat resource in Rwanda identified in the two studies, providing an estimated exploitable peat resource of 7,579 ha.

TABLE 3.1.1-1 UPDATED ASSESSMENT OF THE PHYSICAL AVAILABILITY OF PEAT RESOURCE IN RWANDA

STUDY	ESTIMATED EXPLOITABLE RESOURCE (HA)
Hakan Project Study (2013)	4,056
SWECO AB National Assessment (2016)	3,520

This assessment of generation of electricity from peat resources is limited to large, centralized generation for transmission to the national grid using widely available thermal generation technologies, in this case combustion, such as implementation of a bubbling fluidized bed boiler at planned Hakan peat power plant.

There are currently two peat power plants in Rwanda. The 15 MW Gishoma Thermal Power Station was brought online in April 2016 and is operated by EUCL. While the plant began operation in 2016, it has been marked by technical and supply chain issues. According to generation statistics provided by REG, the plant has not been operational for more than six total months any year since its opening, with the highest total output occurring in 2018 with a total of 31,218,055 kWh over the course of six months. The Gishoma plant has on-site peat storage of up to 3000 tons, enough to provide fuel for 7-10 days before stocks are replenished. As identified in the Phase 2 report, fuel procurement has been problematic at the Gishoma site, particularly during the rainy season when peat resources are difficult to harvest.

According to EUCL, an agreement was reached in October 2021 to turn the Gishoma plant over to a private operator, who will convert the plant to run both on peat and gas. No exact timetable or operational details of this agreement have been identified; however, it is expected that the ability for fuel switching at the Gishoma plant will occur within the next five years. A PPA was approved by the Cabinet for the Government of Rwanda on July 14, 2021, for the Gishoma plant. It is unclear what proportion of peat versus gas will be used at this plant moving forward.

The second plant is the 70 MW Hakan Quantum Power Project, which began construction in 2016 and was slated to commence operations in March of 2021 but has been delayed due to supply chain issues resulting from the COVID-19 pandemic. The 70 MW plant is owned and operated by Hakan Quantum Power, and power sold through a PPA with the Government of Rwanda for a period of 26 years, at which point it will be turned over to GoR. The plant is currently under testing and commissioning and full operation is expected to begin in March 2022. The Hakan facility has two covered receiving halls with a combined storage of 1428 tons, or 14 hours of fuel. Peat to be used during the rainy season will be stored near the peat bog and covered to allow for continued drying. According to the PPA, there is an option to expand the Hakan plant by an additional 40 MW, but this expansion is not under development currently.

Table 3.1.1-2 below shows the current and planned generation from peat resources in Rwanda. Note that the Gishoma plant has not operated at capacity at any point since its commissioning and is expected to enable fuel flexibility for use of gas as a feedstock. The Hakan plant is expected to come online in March 2022, however this date may change given the operational delays to date.

There is currently no additional peat generation planned for Rwanda, and expectation would be that the Hakan plant expansion would be the primary mechanism for future additions due to the existing infrastructure that will be present. However, in the SWECO AB study, seven locations were identified for potential capacity additions based on resource concentration. These are the sampled sites that contain peat with a low (<50%) average ash content on a dry basis and are therefore most advantageous for power generation. These are presented in Table 3.1.1-3, however there are no known plans to develop these resources for power generation at this time.

TABLE 3.1.1-2 CURRENT AND PLANNED GENERATION FROM PEAT RESOURCES IN RWANDA

PLANT NAME	COMMISSIONED	INSTALLED CAPACITY (MW)	AVAILABLE CAPACITY (MW)
Gishoma	2016	15	14.25
Hakan	2022	70	63

TABLE 3.1.1-3 SAMPLED SITES THAT CONTAIN PEAT WITH A LOW (<50%) AVERAGE ASH CONTENT ON A DRY BASIS

PEAT BOG	POWER OUTPUT FROM EXPLOITABLE RESOURCES, 30 YEAR OPERATION (MW)	AVERAGE ASH CONTENT IN IN-SITU PEAT, DRY BASIS (% WEIGHT)
Murago	≤ 3.6	42
Rucyahabi	≤ 4	48
Akanyaru North, middle	13-22	49
Akanyaru North, south	54-71	35
Akanyaru South	36-41	30
Mukido	≤ 6	20

3.1.2. TECHNICAL POTENTIAL

The peat resource technical potential in Rwanda was estimated using the outputs of the detailed national peat assessment conducted by SWECO in 2016 and the results of the 2013 Hakan project peat assessment conducted by HICE consulting. To develop the technical potential estimate, it is assumed that peat will be extracted using the milled method, as opposed to block sod extraction. As discussed in the Phase 2 report, block sod extraction results in a higher amount of available resources; however it is more time consuming and labor intensive and is generally not applied to large-scale peat generation projects.

The sixteen peat bogs identified in the SWECO study characterized as suitable for power generation, and the peat bogs assessed in the Hakan study are presented in Table 3.1.2-1 below. These figures are assuming the technical potential of the resource as a fuel to power a plant for 30 years, an estimation of plant operational life. Power capacities are calculated using an assumed fuel to electric efficiency of 30% based upon the fuel Net Calorific Value (NCV), which is similar to US averages for coal-fired plants of 32%.[131] Dry peat typically has an energy content of 20-23 MJ/kg, which is lower than that of coal, which ranges 20-33 MJ/kg.

Table 3.1.2-1 below summarizes the **estimated results** of total (exploited and unexploited) peat capacity (MW) and related annual generation (MWh). **The estimated technical potential (exploited and unexploited) for generation of electricity from peat is 246 MW, which includes all resources in the Hakan Concession Area.**

It should be noted that as peat requires a drying period and harvesting primarily occurs during the dry season when peat bogs are more accessible. This requires significant stockpiling of resources, which is currently done by covering the milled peat stocks in polyethene to protect them from wind, water contamination, heating, or other material degradation. It has been described that the Hakan plant is situated to host necessary stockpiles of peat resources to enable continuous operation. However, the Gishoma plant has not been able to maintain a steady supply of fuel peat due to extraction issues at the peat bog located in proximity of the plant.

TABLE 3.1.2-1 TECHNICAL POTENTIAL FOR GENERATION OF ELECTRICITY FROM PEAT RESOURCES

NAME OF PEAT BOG	EXPLOITABLE AREA (HA)	POWER OUTPUT RESERVES, 30 YEARS OF OPERATION, MILLED PEAT APPLICATION (MW)	ANNUAL GENERATION POTENTIAL (MWH, 90% CAPACITY FACTOR)
Cyato	67	0.8	7,008
Murago	167	2.7	23,652
Rucyahabi	182	3.6	31,536
Akanyaru North (Others), middle part	118	0.37	3,241

[131] EIA, Average Operating Heat Rate, https://www.eia.gov/electricity/annual/html/epa_08_01.html.

TABLE 3.1.2-1 TECHNICAL POTENTIAL FOR GENERATION OF ELECTRICITY FROM PEAT RESOURCES

NAME OF PEAT BOG	EXPLOITABLE AREA (HA)	POWER OUTPUT RESERVES, 30 YEARS OF OPERATION, MILLED PEAT APPLICATION (MW)	ANNUAL GENERATION POTENTIAL (MWH, 90% CAPACITY FACTOR)
Akanyaru North (Others), middle part	564	14	122,640
Akanyaru North (Others), south part	1,533	55	481,800
Akanyaru South (Others)	922	36	315,360
Mukindo	185	3.4	29,784
Gishoma	54	0.46	4,029
Gihitasi	6	0.07	613
Mashya	23	0.47	4,117
Kaguhu	14	0.36	3,153
Bahimba	17	0.09	788
Kageyo	20	0.22	1,927
Ndongozi	50	0.67	5,869
Nyirabirande	120	2.9	25,404
Hakan Concession Area	3,520	125	1,095,000
Total	**7,576**	**246**	**2,155,924**
Peat Demand for 70 MW Hakan Plant	2,500	63	551,880
Total Remaining Peat Fuel	**5,076**	**176**	**1,603,080**
Total Exploited Capacity Potential (Gishoma & Hakan)		**77***	**674,520***
Total Exploited & Unexploited		**246**	**2,155,924**

*The Gishoma plant has not been fully operational at any time since its inception and is slated for conversion to dual firing with natural gas. In addition, it is unclear what peat resource locations have been used to harvest peat to date for fuel. As such, total peat consumed for operation of 15 MW Gishoma plant has not been included as a separate total for exploited resources in calculations.

3.1.3. GRID-INTEGRATION COSTS

Costs for connecting new generation to the grid was not estimated as a separate cost for new peat generation. New generation will likely come from expansion of existing power plant sites, most notably the Hakan plant, which currently has an option for expansion by an additional 40 MW under the current PPA. Any new sites would likely have similar grid connection costs to the existing plants.

3.1.4. INSTALLATION, EQUIPMENT AND O&M COSTS

This section summarizes the selection of cost information for peat generation electricity generation power plants for the modeling of economic potential. This costs information includes the following components:

- Land acquisition costs.
- Grid connection costs: costs for access roads, transmission line and substation upgrades up to the point of interconnection with HV transmission lines.
- Equipment costs: for example, total costs for the circulating fluidized bed (CFB) boiler, turbines, electrical systems, buildings, and civil works, etc.
- Installation and construction labor costs.
- Ongoing O&M costs: total annual costs for peat fuel and handling, labor, environmental controls, etc.

All cost values taken from the literature were adjusted to 2021 US dollars (USD), when needed, using the latest consumer price index values from the World Bank, and are listed in Table 3.1.4-1 below.

As the Hakan plant is currently under construction (in the testing phase), detailed capital expenditure and O&M costs were taken from the Hakan plant from the 2013 feasibility study conducted by SWECO AB. In addition, the World Bank has published data for estimated costs for the original 120 MW Hakan plant, of which only 70 MW are currently being constructed. Gishoma plant costs were estimated based on data provided directly from EUCL, however a detailed cost estimate for the project was not made available or otherwise obtained. As Rwanda has the only peat generation in Africa and there are few recently constructed peat generation projects globally, estimates specific to Rwanda were used in this assessment. The estimated project costs are provided in Table 3.1.4-1 below.

For the economic potential modelling in this assessment, the World Bank total project costs was selected as representative as it is the most recent cost data available and includes a potential 40 MW expansion at the project site. As this expansion is already included in the PPA signed for the Hakan project, it is expected to be the most likely new additional peat generation constructed in Rwanda. For annual O&M, the 71 MW SWECO feasibility study figure was selected as it is the most similar in scale to future project development. As thermal generation from peat uses a well understood and widely deployed technology, a CFB boiler and turbine, there are no cost efficiency improvements in the coming year.

TABLE 3.1.4-1 PEAT INSTALLED COST INPUTS FOR FOR ECONOMIC POTENTIAL MODELING			
TECHNOLOGY DESCRIPTION	TOTAL INSTALLED COST ($2021/KW)	FIXED & VARIALBE O&M ($2021/KW-YR)	NOTES AND CITATIONS
Gishoma 15 MW Plant	3,676	NA	Cost data direct from EUCL, includes $24 M for Design and $19 M for civil works.
Hakan Feasibility Study Estimate - 100 MW Single Plant (100 MW)	3,391	251	SWECO AB 2013, includes all costs up to main HV switchgear.
Hakan Feasibility Study Estimate - 100 MW Dual Plant (2 x 50 MW)	3,639	273	SWECO AB 2013, includes all costs up to main HV switchgear.
Hakan Feasibility Study - 71 MW (2 x 35.5 MW)	4,387	287	SWECO AB 2013, includes all costs up to main HV switchgear.
Hakan Project Cost - 120 MW	3,523	N/A	World Bank 2017, https://ppi.worldbank.org/en/snapshots/project/HQ-Peat-fired-Power-Plant-9036

4. ECONOMIC AND MARKET POTENTIAL ASSESSMENT

4.A INTRODUCTION AND METHODOLOGY

The evaluation of the economic potential of resources and technologies for generating electricity requires that the costs of generating electricity from a resource using a particular type of generator be compared with costs of generating or purchasing electricity through other means. Whether a resource/technology pair is "economic" or not therefore depends on whether benefits outweigh costs regardless of other resource and technologies and thus in large part on whether other resources are available to generate electricity at a particular time, and at what cost. The concept of market potential goes one step further and asks whether a particular resource/technology pair can feasibly be brought to market, under the prevailing conditions for power sales and investment, at a price that is competitive with other possible resources and technologies.

A tool that is frequently used to compare the costs of resources and technologies is the computation of levelized costs of energy, or LCOE. LCOE computation allows the costs of electricity generation options with different characteristics—including, for example, plant lifetimes and capacity factors—to be compared with each other and with other economic indicators, such as existing costs of electricity.

LCOE computation requires the following types of data, to the extent they are applicable, for each resource/technology being investigated:

- Initial installed costs (capital costs)
- Fixed operating and maintenance (O&M) costs
- Variable O&M costs
- Fuel costs
- Efficiency or its inverse, the heat rate
- Plant lifetime
- Capacity factor
- Interest rate
- Capital recovery factor

The full levelized cost, incorporating the factors above, is then calculated as follows:

$$LCOE = \{(\text{initial cost} * CRF + \text{fixed O\&M cost})/(8760 * \text{capacity factor})\}$$
$$+ (\text{fuel cost} * \text{heat rate}) + \text{variable O\&M cost}.$$

The LCOE of different generation technologies can be compared with each other or with other cost indicators to determine cost-effectiveness in particular situations.

DATA FOR LCOE COMPUTATION

- **Initial installed costs** of generation facilities, frequently referred to as "capital costs". These costs describe the amount of investment required to purchase the equipment for a power plant and fully install it at a project site, including any construction of on-site facilities such as buildings, support structures, or dams. These costs also sometimes, particularly for plants that take a long time to build, include the costs of financing plant investments while the plant is under construction and not yet producing electricity. Initial costs are typically expressed in cost (here, United States Dollars or USD) per unit of capacity, such as $/kW or MW (kilowatt or megawatt)
- **Fixed operating and maintenance (O&M) costs**, which describe costs that must be incurred independent of how much electricity a plant generates. Examples may be administrative costs or certain types of maintenance, such as cleaning intake screens in hydroelectric plants or cleaning dirt from solar panels. Fixed O&M costs are typically expressed in cost per kilowatt-year ($/kW-yr).
- **Variable O&M costs** are costs that vary with the amount of power produced. Examples might include the cost of ash removal and disposal for coal- or peat-fired plants, or of lubrication for diesel power plants. Variable O&M costs are typically expressed in costs per megawatt hour of production ($/MWh). As a rule of thumb (that is, typically), variable O&M costs will be very low or effectively zero for many renewable energy systems, including solar photovoltaic and wind power systems, also low for hydroelectric generation, and highest for combustion plants fired with fossil fuels.
- **Fuel costs** specify the cost, in $ per gigajoule (GJ) or some other energy-related unit (such as tonnes or liters of fuel) of the fuel used in a power plant, if any. Liquid and gaseous fuels typically have the highest costs, with coal, peat, and biomass fuels being typically much less expensive per unit of energy content.
- Relatedly, for fuel-fired power plants, the **efficiency** (the fraction of fuel input energy that is output as electricity, or its inverse, the **heat rate**, in units of input energy per unit of output energy) with which fuel is converted into electricity is an input to the LCOE calculation.
- A **capacity factor**, or the equivalent fraction of the hours in a year that a plant is expected, on average, to run at full capacity, determines the relationship between the capacity of the plant and its annual output.
- The plant **lifetime**, in years, is used to distribute initial costs over the period in which the plant is expected to be in service. Note that for LCOE calculations an "economic lifetime" is typically used, as it reflects the period over which a plant investment would be financed, as opposed to the physical lifetime, which for some assets—most notably hydroelectric dams—can be considerably longer.
- The **interest rate**, in percent per year (%/yr) used to amortize the investment in the plant, is set to reflect a rate of return needed to justify the investment based on exogenous and endogenous factors. The interest rate and the plant lifetime are used to calculate a capital recovery factor (CRF) as follows CRF = {i *(1 + i)^n} / {[(1 + i)^n]-1}, where **i** is the interest rate, and **n** is the economic lifetime in years.

The LCOE calculations described below were denominated in constant 2021 US dollars, meaning that inflation is not considered in the calculation. As a result, the interest rates used in the calculation are real interest rates, that is, net of inflation. In addition, some of the parameters in the calculation can vary over time. In particular, solar photovoltaic technologies have shown steep declines in initial costs in recent years, as have wind power technologies. As these cost trends are expected to continue, LCOE values for these technologies will be lower for a plant commissioned in, for example, 2020, than for a plant commissioned in 2040 or 2050.

The EAEP Team has used LCOE estimates prepared as above to estimate the **economic potential** of resource and technologies for electricity generation in Rwanda using a 5%/yr interest rate to calculate LCOE for each resource, then compared the resulting LCOE with a threshold electricity price of $130 per MWh and a threshold price of $70 per MWh for sensitivity analysis. In particular:

- A 5%/yr interest rate reflects a social interest rate, consistent with the low rate of interest that might be used by a government for its own investments, or rates that might be offered to a government by a bilateral or multilateral development bank lender.
- $130/MWh was chosen as a threshold because it is equal or similar to the Feed-in Tariffs (FiTs) agreed to by REG) for the purchase of electricity from a number of different independent power producers for both existing plants and some plants due to be commissioned in the coming years. FiTs are price guarantees designed to stimulate market investment and implementation. As a result, FiTs are relevant to levelized costs that are calculated for suppliers and investors with interest rates that include financing, profit, taxes, and risk, often referred to as a Weighted Average Cost of Capital (WACC) interest rate. In practice, under different conditions (for example, if a plant is relied on primarily to provide peak energy, or baseload energy), or at different periods in the planning horizon, different threshold values can be used.
- $70/MWh was chosen as a threshold for sensitivity analysis based on conversation with REG that is in the process of considering using lower FiTs in the future, including possibly differentiating FiTs by type of resource and/or technology.

For the calculation of **market potential,** the EAEP Team used the same approach as above, but in this case applied interest rates of 10%/yr and 15%/yr. These higher interest rates can be considered to consider financing, profit, taxes, and risk, and thus estimate the potential market penetration of each generation resource. That is, the use of these higher interest rates is intended to reflect conditions that private or largely private developers of generation assets would be considering in deciding whether it was worthwhile to develop projects to sell electricity into the Rwandan grid.

For the calculation of the amount, for example, in MW, of economic or market potential, the EAEP Team identified which resources and technologies had costs that fell above and below the comparison threshold ($130/MWh or $70/MWh, as the case may be) in each of the years 2030, 2040, and 2050. The total MW of potential, based on the technical resource potential estimates described in section 2 of this Report, with LCOE falling at or under the threshold value was summed for each of the three analysis years. Results of this calculation using LCOE for each resource/technology determined as above with a 5%/yr interest rate were taken to reflect total economic potential for that type of power plant. Results of the calculation using LCOEs determined at 10%/yr and 15%/yr were taken to reflect total market potential. the

The generation resources covered in this analysis focused on those described in section 3 along with the related key costs. Four additional generic types of generation were added to the LCOE analysis as points of comparison with the resources/technologies above:

- Pumped-storage hydro power plants (typically used to provide peak power and using electricity from the grid for pumping water uphill).
- New diesel power plants fueled with imported diesel.
- Natural gas combined cycle plants using natural gas assumed to be imported from a neighboring country by pipeline.
- Natural gas plants using simple cycle turbine, which have both lower initial costs and lower efficiencies than combined-cycle plants.

Table 4.A-1 presents the key input assumptions to the LCOE analysis used for each of the types of power plants considered.

TABLE 4.A-1 INPUT ASSUMPTIONS FOR LCOE ANALYSIS

PLANT / PLANT TYPE	CAPITAL (INITIAL) COSTS (2021$/KW) 2020	2030	2040	2050	FIXED O&M ($/KW-YR) 2020	2030	2040	2050	VARIABLE O&M ($/MWH)	FUEL ($/GJ)	EFFICIENCY	LIFETIME (YR)	CAPACITY FACTOR
New Diesel	1,325	1,325	1,325	1,325	67	67	67	67	13.00	17.40	35%	20	60%
Peat-Fired	3,100	3,100	3,100	3,100	95	95	95	95	17.70	1.10	33%	30	70%
Lake Methane-fired	7,846	7,846	7,846	7,846	288	288	288	288	-	-	45%	50	92%
Natural Gas Combined Cycle	1,200	1,200	1,200	1,200	15	15	15	15	3.50	28.97	52.5%	20	60%
Natural Gas Simple Cycle	600	600	600	600	15	15	15	15	5.00	28.97	35.0%	20	10%
New Hydro. Class I	3,867	3,867	3,867	3,867	142	142	142	142	-	-	100%	50	60%
New Hydro. Class II	4,085	4,085	4,085	4,085	142	142	142	142	-	-	100%	50	60%
Pumped Storage Hydro	3,500	3,500	3,500	3,500	52	52	52	52	-	19.44	77.5%	50	13.0%
Utility Solar PV Class I	1,489	1,318	1,116	953	23	21	19	17	-	-	100%	30	17.1%
Utility Solar PV Class II	1,623	1,451	1,249	1,087	23	21	19	17	-	-	100%	30	17.0%
Utility Solar PV Class III	1,761	1,589	1,388	1,225	23	21	19	17	-	-	100%	30	17.0%
Utility Solar PV Class IV	2,128	1,956	1,754	1,592	23	21	19	17	-	-	100%	30	16.9%
Utility Solar (I) with BES	2,559	1,974	1,676	1,430	36	28	25	22	-	-	100%	30	17.1%
Utility Solar (II) with BES	2,693	2,108	1,809	1,563	36	28	25	22	-	-	100%	30	17.0%
Agri-PV Class I	2,160	1,883	1,558	1,295	22	20	18	16	-	-	100%	30	17.0%
Agri-PV Class II	2,298	2,021	1,696	1,433	22	20	18	16	-	-	100%	30	17.0%
Floating Solar PV Class I	1,911	1,680	1,410	1,191	21	19	17	15	-	-	100%	30	17.6%
Floating Solar PV Class II	2,041	1,811	1,540	1,322	21	19	17	15	-	-	100%	30	17.9%
Residential Dist PV	2,142	764	670	588	9	4	4	3	-	-	100%	30	17.0%
Residential Dist PV with BES	3,559	1,779	1,545	1,342	12	6	5	5	-	-	100%	30	17.0%
ICI Dist PV	1,348	688	604	530	8	5	4	4	-	-	100%	30	17.1%
ICI Dist PV with BES	2,316	1,261	1,095	951	9	5	4	4	-	-	100%	30	17.1%
ICI Dist PV	5,621	5,284	4,968	4,672	46	46	46	46	8.00	-	100%	30	17.1%
ICI Dist PV with BES	2,549	2,387	2,236	2,094	97	97	97	97	1.18	-	100%	30	17.1%
Waste to Energy	9,650	9,203	8,778	8,374	277	277	277	277	-	-	30%	30	80%
Biomass-fired	2,458	1,817	1,664	1,525	93	93	88	84	-	-	30%	30	60%
Geothermal	2,612	1,971	1,818	1,679	93	93	88	84	-	-	100%	30	80%
Wind Power 50 m Cost Class I	1,605	1,185	1,085	994	62	62	59	56	-	-	100%	20	28%
Wind Power 50 m Cost Class II	1,668	1,248	1,147	1,056	62	62	59	56	-	-	100%	20	25%
Wind Power 100 m Cost Class I	1,596	1,176	1,075	984	62	62	59	56	-	-	100%	20	32%
Wind Power 100 m Cost Class II	1,615	1,195	1,094	1,003	62	62	59	56	-	-	100%	20	30%
Wind Power 150 m Cost Class I	1,325	1,325	1,325	1,325	67	67	67	67	13.00	17.40	100%	20	28%
Wind Power 150 m Cost Class II	3,100	3,100	3,100	3,100	95	95	95	95	17.70	1.10	100%	20	27%

4.B ECONOMIC POTENTIAL: LCOE RESULTS AT BASE INTEREST RATES

As indicated above, to estimate the economic potential for each resource/technology, LCOE results for a range of generation options were calculated at a 5%/yr interest rate and compared with the $130/MWh threshold. Table 4.B-1 below shows the estimated unexploited capacity (MW) for each resource based on **economic potential compared to the estimated technical potential. The results show a lower estimated unexploited total capacity in Rwanda (166,742 MW in 2030 and 166,803 MW in 2050) with hydro decreasing to 629 MW, wind to 203 MW and peat to 166 MW as a resulting of taking into account generation costs (that is, grid connection costs, and installation, equipment and O&M costs) at a social interest rate. The difference of economic potential estimates between 2030 and 2050 is due to the change in the solar estimates since solar costs are expected to decrease significantly over time.**

TABLE 4.B-1. ESTIMATED ECONOMIC POTENTIAL (2030 AND 2050), THRESHOLD OF $130/MWH

RESOURCE	LCPDP AND EAEP: EXPLOITED TECHNICAL AVAILABLE CAPACITY (MW)	EAEP: UNEXPLOITED TECHNICAL AVAILABLE CAPACITY (MW)	EAEP: TOTAL EXPLOITED + UNEXPLOITED TECHNICAL AVAILABLE CAPACITY (MW)	**ECONOMIC POTENTIAL AT 5% INTEREST RATE** (2030 LCOE) BASED ON UNEXPLOITED CAPACITY *(MW)*
Solar	2.1	168,699	168,699	165,471
Hydro	164[132]	822	986	629
Wind (100m hub height)	0	225	225	203
Waste (2030)	0.07	55	55	55
Waste (2050)	0.07	116	116	116
Lake Kivu Methane	116	102	218	218
Peat[133]	86	166	246	166
Total Capacity 2030	**368**	**170,069**	**170,429**	**166,742**
Total Capacity 2050	**368**	**170,130**	**170,490**	**166,803**

[132] Hydro "Available capacity" for existing and planned hydro come from Tables 2, 4 and 5 of the LCPDP (values for "available" or "firm" capacity). Additional planned sites in Table 3 that were not also in either Table 4 or 5 were also added (with an assumed 51% CF). LCPDP Total includes planned installed capacity from LCPDP (with available capacity estimated using average capacity factor).

[133] Peat: LCPDP Total is the milled peat estimate (121) plus remaining peat in Hakan concession area not allocated to the 80 MW plant.

Table 4.B-2 presents intermediate levelized capital/initial costs, O&M costs, fuel costs, and total LCOE for each technology at 5%/yr interest rate.

TABLE 4.B-2 RESULTS FOR LCOE ANALYSIS 5% ANNUAL INTEREST RATE

PLANT/PLANT TYPE	LEVELIZED COSTS (2021$/MWH)				LEVELIZED O&M FIXED + VARIABLE ($/MHW)					TOTAL LEVELIZED COST OF ENERGY (2021$/MWH)			
	2020	2030	2040	2050	2020	2030	2040	2050	FUEL $/MWH	2020	2030	2040	2050
New Diesel	40.27	40.27	40.27	40.27	25.65	25.65	25.65	25.65	178.97	244.90	244.90	244.90	244.90
Peat-Fired	76.99	76.99	76.99	76.99	33.19	33.19	33.19	33.19	12.00	122.19	122.19	122.19	122.19
Lake Methane-fired	146.17	146.17	146.17	146.17	35.74	35.74	35.74	35.74	-	181.90	181.90	181.90	181.90
Natural Gas Combined Cycle	36.48	36.48	36.48	36.48	6.29	6.29	6.29	6.29	198.67	241.43	241.43	241.43	241.43
Natural Gas Simple Cycle	109.43	109.43	109.43	109.43	21.75	21.75	21.75	21.75	298.00	429.17	429.17	429.17	429.17
New Hydro. Class I	110.46	110.46	110.46	110.46	27.02	27.02	27.02	27.02	-	137.48	137.48	137.48	137.48
New Hydro. Class II	116.68	116.68	116.68	116.68	27.02	27.02	27.02	27.02	-	143.70	143.70	143.70	143.70
Pumped Storage Hydro	461.44	461.44	461.44	461.44	45.66	45.66	45.66	45.66	90.32	597.42	597.42	597.42	597.42
Utility Solar PV Class I	151.20	133.76	113.32	96.78	15.33	13.86	12.41	11.11	-	166.53	147.62	125.73	107.89
Utility Solar PV Class II	166.13	148.54	127.92	111.24	15.46	13.98	12.52	11.21	-	181.59	162.52	140.44	122.45
Utility Solar PV Class III	180.17	162.59	141.99	125.33	15.45	13.97	12.51	11.20	-	195.62	176.57	154.50	136.53
Utility Solar PV Class IV	219.01	201.32	180.59	163.83	15.55	14.06	12.59	11.27	-	234.56	215.38	193.18	175.10
Utility Solar (I) with BES	259.82	200.43	170.13	145.12	24.00	18.82	16.68	14.78	-	283.82	219.25	186.81	159.90
Utility Solar (II) with BES	275.67	215.77	185.22	159.99	24.20	18.98	16.82	14.91	-	299.87	234.75	202.04	174.90
Agri-PV Class I	220.74	192.39	159.16	132.29	14.76	13.35	11.95	10.70	-	235.50	205.74	171.11	142.99
Agri-PV Class II	235.57	207.13	173.80	146.84	14.81	13.39	11.99	10.73	-	250.37	220.52	185.78	157.57
Floating Solar PV Class I	189.23	166.38	139.60	117.94	13.65	12.35	11.05	9.90	-	202.88	178.73	150.66	127.84
Floating Solar PV Class II	198.41	175.98	149.70	128.44	13.40	12.12	10.85	9.71	-	211.81	188.10	160.55	138.15
Residential Dist PV	218.47	77.89	68.33	59.95	6.23	2.76	2.53	2.22	-	224.70	80.65	70.86	62.17
Residential Dist PV with BES	363.00	181.43	157.58	136.85	8.04	4.02	3.49	3.03	-	371.03	185.45	161.06	139.88
ICI Dist PV	137.38	70.15	61.55	54.00	5.15	3.29	2.97	2.69	-	142.53	73.44	64.52	56.69
ICI Dist PV with BES	236.04	128.49	111.59	96.92	5.96	3.24	2.82	2.45	-	241.99	131.73	114.41	99.37
ICI Dist PV	122.15	114.82	107.96	101.53	14.56	14.56	14.56	14.56	-	136.72	129.39	122.52	116.09
ICI Dist PV with BES	363.00	181.43	157.58	136.85	8.04	4.02	3.49	3.03	-	371.03	185.45	161.06	139.88
ICI Dist PV	137.38	70.15	61.55	54.00	5.15	3.29	2.97	2.69	-	142.53	73.44	64.52	56.69
ICI Dist PV with BES	236.04	128.49	111.59	96.92	5.96	3.24	2.82	2.45	-	241.99	131.73	114.41	99.37
Waste to Energy	122.15	114.82	107.96	101.53	14.56	14.56	14.56	14.56	-	136.72	129.39	122.52	116.09
Biomass-fired	73.86	69.18	64.79	60.68	19.60	19.60	19.60	19.60	-	93.46	88.78	84.39	80.28
Geothermal	209.73	200.01	190.78	181.99	39.53	39.53	39.53	39.53	-	249.25	239.54	230.30	221.52
Wind Power 50 m Cost Class I	160.13	118.37	108.36	99.30	37.92	37.92	36.06	34.30	-	198.05	156.29	146.27	137.22
Wind Power 50 m Cost Class II	190.58	143.81	132.59	122.45	42.47	42.47	40.39	38.41	-	233.05	186.28	175.06	164.92
Wind Power 100 m Cost Class I	91.48	67.55	61.81	56.62	22.12	22.12	21.04	20.01	-	113.60	89.67	83.93	78.74
Wind Power 100 m Cost Class II	101.40	75.87	69.75	64.22	23.59	23.59	22.44	21.34	-	124.99	99.47	93.34	87.81
Wind Power 150 m Cost Class I	103.92	76.57	70.01	64.08	25.28	25.28	24.04	22.87	-	129.20	101.85	95.29	89.36
Wind Power 150 m Cost Class II	109.09	80.73	73.93	67.78	26.21	26.21	24.93	23.71	-	135.31	106.94	100.14	93.99

Figure 4.B-1 shows LCOE results for each of the years evaluated (2020, 2030, 2040, and 2050), for a selected group of options. LCOEs for the power plant types/resources evaluated range from under $26 to over $370 per MWh, depending on the year of analysis.

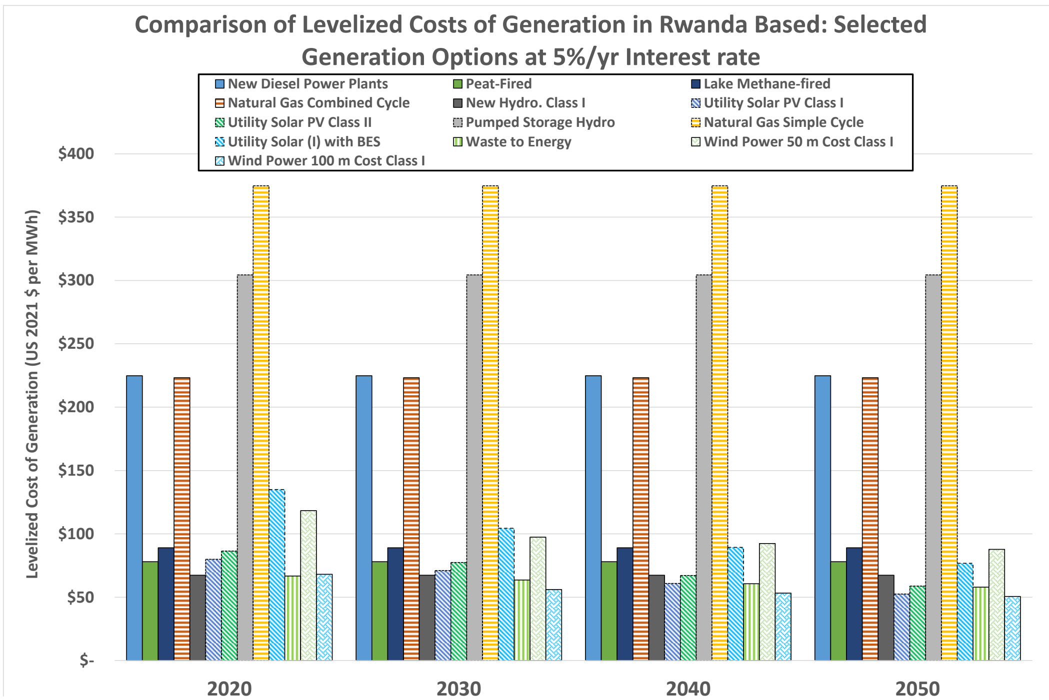


Figure 4.B-1 LCOE Results for in Different Years for Selected Generation Options, Interest Rate of 5%/yr

Costs for solar generation, and particularly distributed solar generation (for which panel support costs are smaller than for utility and other types of PVs, because distributed PVs are roof-mounted), decline over time. The costs of waste-to-energy and biomass-fired plants are relatively low due to high-capacity factors and the assumption of zero fuel costs (as these plants provide a disposal service). The highest cost plants are diesel generators and natural gas generators, with costs primarily driven by the high cost of imported fuel. The LCOE of pumped-storage hydro generation is also quite high but depends (about 30 percent of the total cost shown above) on the assumption used for the cost of electricity for pumping—here about $70 per MWh of electricity input - and to the assumption of an average annual pumped storage capacity factor, for which the value used in the figure and tables above is 13 percent, similar to the historical average experienced at facilities in the United States. If, however, pumped storage hydro in Rwanda is ultimately used mostly to balance load in a system dominated by solar generation, it may be used at a much higher effective capacity factor. Increasing the capacity factor to 40%, which would be near a maximum for pumped storage hydro, reduces the installed cost per unit output, and thus reduces the LCOE of pumped storage hydro to just over half of the value shown in Figure 1, to about $160/MWh.

Figure 4.B-2 below presents LCOE results for all of the generation options evaluated using costs for the year 2030. At the 5% per year interest rate (an assumed weighted average cost of capital, or WACC) used, all of the options except diesels, natural gas-fired plants, and pumped storage hydro (shown in red) yield LCOE values that are less than the threshold value of $130 per MWh. As a result, **each of the options shown in blue would be cost-effective relative to the threshold value, and all of**

those technology/resource pairs are thus considered to have economic potential as of 2030.

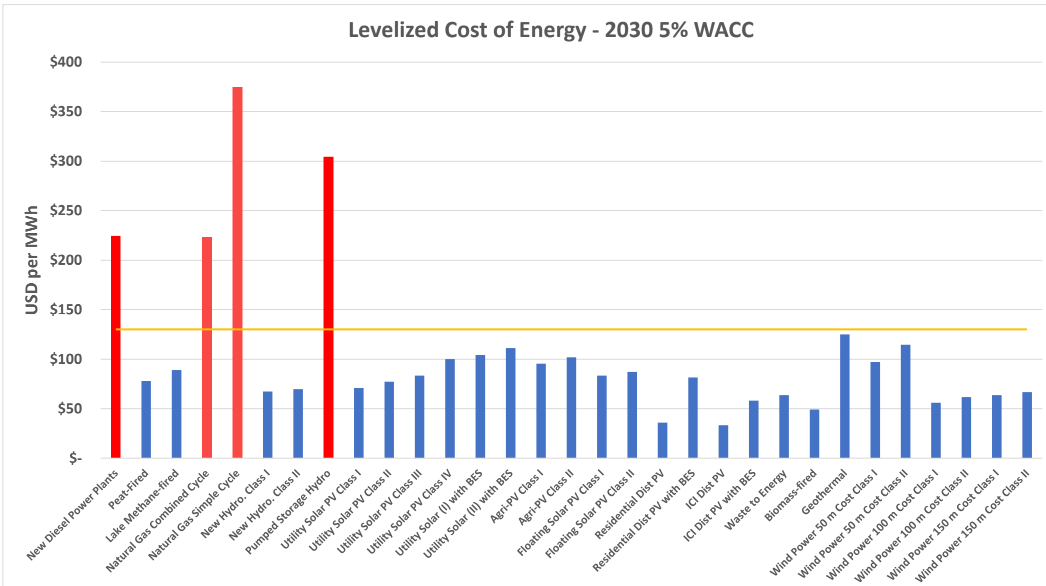


Figure 4.B-2 LCOE Results for All Generation Options Evaluated for 2030, Interest Rate of 5%/yr

Based on the results above, Table 4.B-3 shows – in addition to the technical potential covered in Section 3 - the estimated economic potential in MW by electricity generation technology and resource (rightmost column of the table). Only technologies and resources for which LCOEs calculated as above fall at or below the $130/MWh threshold, using year 2030 costs and a 5% annual real interest rate, are included in the rightmost column of the table, and those with calculated LCOEs above that threshold do not. Diesel and natural-gas-fired power plants, and pumped-storage hydro, show zero values for economic potential due to their high cost. Diesel and natural gas plants also rely on imported resources, so technical and economic potential values for these types of plants are not readily comparable to the other types of plants, which use Rwandan resources.

TABLE 4.B-3 ECONOMIC POTENTIAL RESULTS BY RESOURCE/TECHNOLOGY			
PLANT/PLANT TYPE	TECHNICAL POTENTIAL (NAMEPLATE MW 2030)	TECHNICAL POTENTIAL (AVAILABLE MW)	ECONOMIC POTENTIAL AT 5% ANNUAL INTEREST RATE, $130 MWH THRESHOLD (AVAILABLE MW)
New Diesel Power Plants			
Peat-Fired	184	166	166
Lake Methane-fired	237	218	218
Natural Gas Combined Cycle			-
Natural Gas Simple Cycle			-
New Hydro. Class I	569	411	411
New Hydro. Class II	165	119	119
Pumped Storage Hydro			-
Utility Solar PV Class I	157,351	26,750	26,750
Utility Solar PV Class II	21,850	3,715	3,715
Utility Solar PV Class III	12,243	2,081	2,081
Utility Solar PV Class IV	8,941	1,520	1,520
Utility Solar (I) with BES	157,351	26,750	26,750
Utility Solar (II) with BES	21,850	3,715	3,715
Agri-PV Class I	667,902	113,543	113,543
Agri-PV Class II	66,465	11,299	11,299
Floating Solar PV Class I	1,737	295	295
Floating Solar PV Class II	1,428	243	243
Residential Dist PV	33,239	5,651	5,651
Residential Dist PV with BES	33,239	5,651	5,651
ICI Dist PV	2,205	375	375
ICI Dist PV with BES	2,205	375	375
Waste to Energy	76	68	68
Wind Power 50 m Cost Class I	139	39	39
Wind Power 50 m Cost Class II	26	7	7
Wind Power 100 m Cost Class I	554	177	177
Wind Power 100 m Cost Class II	85	26	26
Wind Power 150 m Cost Class I	882	247	247
Wind Power 150 m Cost Class II	127	34	34

Two additional notes about Table 4.B-3 follow. First, the table includes generation capacity denominated as "nameplate" capacity and "available" capacity, as described in Section 1 of this report. **It should be noted that the values in this table are not additive across technologies**, because:

- Capacities for the various categories of solar plants that include BES are assumed to be the same as those without BES, because with few exceptions, places that can support a solar PV installation can also support a solar-PV-with-BES installation, and the capacities of the two types of systems, because they depend on the same solar resource, are the same. Thus, the potential estimates for solar PV with BES overlap entirely with solar without BES. Note that there are, however, some solar PV technology categories that do not have counterparts with BES in this table, such as the floating solar and agri-solar categories, although in practice either could also be built with a BES component.
- The resource potential estimates for three wind power hub heights, in most instances, are for the same sites in Rwanda that have higher average wind speeds, and since wind turbines are unlikely to be built on the same sites with different hub heights, the estimates potential capacities at the different hub heights overlap. In particular, as there are likely to be significant logistical difficulties involved in trying to transport the components of turbines, particularly with 150 m hub heights, to attractive wind power sites in Rwanda, it is the estimates for 50 m and 100 m hub height wind power that are most likely to be relevant in the Rwandan context.

4.C. MARKET POTENTIAL: LCOE RESULTS AT HIGHER INTEREST RATES

Table 4.C-1 below shows the estimated unexploited capacity (MW) for each resource based on **market potential** (last two data columns) compared to estimated technical and economic potential. **The results show an estimated unexploited total capacity in Rwanda in 2030 of 39,919 MW at an interest rate of 10% and 6,449 MW at an interest rate of 15%, and in 2050 an estimated unexploited total capacity of 166,585 MW at an interest rate of 10% and 37,270 MW at an interest rate of 15%. Solar and hydro estimated unexploited capacity decrease significantly when market conditions are taken into account through higher (and more realistic) interest rates. The difference of market potential estimates between 2030 and 2050 is due to the change in solar market potential estimates since solar costs are expected to decrease significantly over time.** Details on the market potential estimates for each technology are presented below.

TABLE 1.B-1. ESTIMATED MARKET POTENTIAL (2030 AND 2050), THRESHOLD OF $130/MWH						
RESOURCE	LCPDP AND EAEP: EXPLOITED TECHNICAL AVAILABLE CAPACITY (MW)	EAEP: UNEXPLOITED TECHNICAL AVAILABLE CAPACITY (MW)	EAEP: TOTAL EXPLOITED + UNEXPLOITED TECHNICAL AVAILABLE CAPACITY (MW)	ECONOMIC POTENTIAL AT 5% INTEREST RATE (2030 LCOE) BASED ON UNEXPLOITED CAPACITY (MW)	**MARKET POTENTIAL** AT 10% INTEREST RATE (2030 LCOE) BASED ON UNEXPLOITED CAPACITY (MW)	**MARKET POTENTIAL** AT 15% INTEREST RATE (2030 LCOE) BASED ON UNEXPLOITED CAPACITY (MW)
Solar (2030 LCOE)	2.1	168,699	168,699	165,471	38,866	6,025
Solar (2050 LCOE)	2.1	168,699	168,699	165,471	165,471	36,785
Hydro	164[134]	822	986	629	629	0
Wind (100m hub height)	0	225	225	203	203	203
Waste (2030)	0.07	55	55	55	55	55
Waste (2050)	0.07	116	116	116	116	116
Geothermal	0	0	0	0	0	0
Lake Kivu Methane	116	102	218	218	0	0
Peat[135]	86	166	246	166	166	166
Total Capacity 2030	**368**	**170,069**	**170,429**	**166,742**	**39,919**	**6,449**
Total Capacity 2050	**368**	**170,130**	**170,490**	**166,803**	**166,585**	**37,270**

[134] Hydro "Available capacity" for existing and planned hydro come from Tables 2, 4 and 5 of the LCPDP (values for "available" or "firm" capacity). Additional planned sites in Table 3 that were not also in either Table 4 or 5 were also added (with an assumed 51% CF). LCPDP Total includes planned installed capacity from LCPDP (with available capacity estimated using average capacity factor).
[135] Peat: LCPDP Total is the milled peat estimate (121) plus remaining peat in Hakan concession area not allocated to the 80 MW plant.

As indicated above, to estimate the market potential for the different resource/technology pairs relevant to Rwanda, the EAEP Team used the list of technologies described above, together with the technical and cost assumptions by technology provided in Table 4.A-1 but applied higher interest rates reflecting the levels of return that an investor in a commercial power supply project might require in order to move forward with the development of generation capacity. As mentioned, the use of 10% or 15% annual interest rates, or weighted average costs of capital, is consistent with the level of risk that a private investor/developer of electricity generation facilities in Rwanda might face, particularly if their projects were unable to secure loan guarantees from, for example, international financial or aid institutions.

The application of higher interest rates affects a technology's LCOE by raising the annualized cost of the initial investment in plant equipment and installation. As such, technology/resource pairs for which initial investment costs represent a higher fraction of overall LCOE face a greater impact on costs than do technologies where other cost components dominate. For example, the LCOEs of solar, wind, and hydro power, which have low operating costs and no fuel costs, but relatively high capital costs (per unit output), are affected by higher interest rates more than the LCOEs for facilities like natural gas-fired power plants, for which fuel costs are the main driver of overall costs.

Table 4.C-2 show the results of the LCOE analysis of the candidate technologies and resources calculated at interest rates of 10 % and 15% per year for facilities to be installed in 2030, 2040, or 2050. Cells with bold numbers indicate those technologies for which the calculated LCOE exceeds the threshold used for cost-effectiveness, which is the same $130/ MWh as used in the economic potential analysis above. With that threshold assumption, in addition to the diesel, natural gas, and pumped storage hydroelectric plants that are not cost-effective under the economic potential test (at a 5%/yr interest rate), a number of solar technologies, geothermal, and wind power at 50 m hub height and at with higher interconnection costs rise above the cost threshold at a 10% interest/WACC rate for at least year 2030 and 2040 installations. At a 15% interest WACC rate, more solar and wind technologies in more years fail the market potential cost-effectiveness tests, although some technologies, particularly distributed PV systems, waste-to-energy, and larger wind power systems continue to show market potential at an interest rate of 15%/yr. Also passing the market potential threshold are some other solar technologies (utility and floating) in 2040 and 2050, as solar installed costs continue to decline.

TABLE 4.C-2 RESULTS FOR LCOE ANALYSIS FOR 10% AND 15% ANNUAL INTEREST RATE						
PLANT / PLANT TYPE	TOTAL LEVELIZED COST OF ENERGY 10% INTEREST RATE (2021$/MWH)			TOTAL LEVELIZED COST OF ENERGY 15% INTEREST RATE (2021$/MWH)		
	2030	2040	2050	2030	2040	2050
New Diesel	234.23	234.23	234.23	244.90	244.90	244.90
Peat-Fired	**98.82**	**98.82**	**98.82**	**122.19**	**122.19**	**122.19**
Lake Methane-fired	133.93	133.93	133.93	181.90	181.90	181.90
Natural Gas Combined Cycle	231.78	231.78	231.78	241.43	241.43	241.43
Natural Gas Simple Cycle	400.20	400.20	400.20	429.17	429.17	429.17
New Hydro. Class I	**101.22**	**101.22**	**101.22**	137.48	137.48	137.48
New Hydro. Class II	**105.40**	**105.40**	**105.40**	143.70	143.70	143.70
Pumped Storage Hydro	445.97	445.97	445.97	597.42	597.42	597.42
Utility Solar PV Class I	**107.03**	**91.34**	**78.52**	147.62	**125.73**	**107.89**
Utility Solar PV Class II	**117.44**	**101.62**	**88.69**	162.52	140.44	**122.45**
Utility Solar PV Class III	**127.22**	**111.41**	**98.49**	176.57	154.50	136.53
Utility Solar PV Class IV	154.28	138.37	**125.38**	215.38	193.18	175.10
Utility Solar (I) with BES	158.42	135.18	**115.86**	219.25	186.81	159.90
Utility Solar (II) with BES	169.27	145.83	**126.35**	234.75	202.04	174.90
Agri-PV Class I	148.55	**124.00**	**104.04**	207.45	172.83	144.70
Agri-PV Class II	160.54	135.93	**115.89**	224.66	189.93	161.72
Floating Solar PV Class I	**128.23**	**108.29**	**92.05**	178.73	150.66	**127.84**
Floating Solar PV Class II	134.69	**115.12**	**99.17**	188.10	160.55	138.15
Residential Dist PV	**57.01**	**50.12**	**43.97**	**80.65**	**70.86**	**62.17**
Residential Dist PV with BES	130.39	**113.24**	**98.35**	185.45	161.06	139.88
ICI Dist PV	**52.15**	**45.84**	**40.30**	**73.44**	**64.52**	**56.69**
ICI Dist PV with BES	**92.74**	**80.54**	**69.95**	131.73	**114.41**	**99.37**
ICI Dist PV	**94.54**	**89.76**	**85.28**	**129.39**	**122.52**	**116.09**
ICI Dist PV with BES	**67.78**	**64.73**	**61.87**	**88.78**	**84.39**	**80.28**
ICI Dist PV	178.84	172.40	166.28	239.54	230.30	221.52
ICI Dist PV with BES	**124.95**	**117.58**	**110.92**	156.29	146.27	137.22
Waste to Energy	148.20	139.95	132.49	186.28	175.06	164.92
Biomass-fired	**71.78**	**67.56**	**63.75**	**89.67**	**83.93**	**78.74**
Geothermal	**79.38**	**74.87**	**70.80**	**99.47**	**93.34**	**87.81**
Wind Power 50 m Cost Class I	**81.57**	**76.75**	**72.39**	**101.85**	**95.29**	**89.36**
Wind Power 50 m Cost Class II	**85.57**	**80.57**	**76.04**	**106.94**	**100.14**	**93.99**
Wind Power 100 m Cost Class I	234.23	234.23	234.23	244.90	244.90	244.90
Wind Power 100 m Cost Class II	**98.82**	**98.82**	**98.82**	**122.19**	**122.19**	**122.19**
Wind Power 150 m Cost Class I	133.93	133.93	133.93	181.90	181.90	181.90
Wind Power 150 m Cost Class II	231.78	231.78	231.78	241.43	241.43	241.43

Figure 4.C-1 through Figure 4.C-3 show comparative results for the years 2030, 2040 and 2050 at the three different annual interest rates.

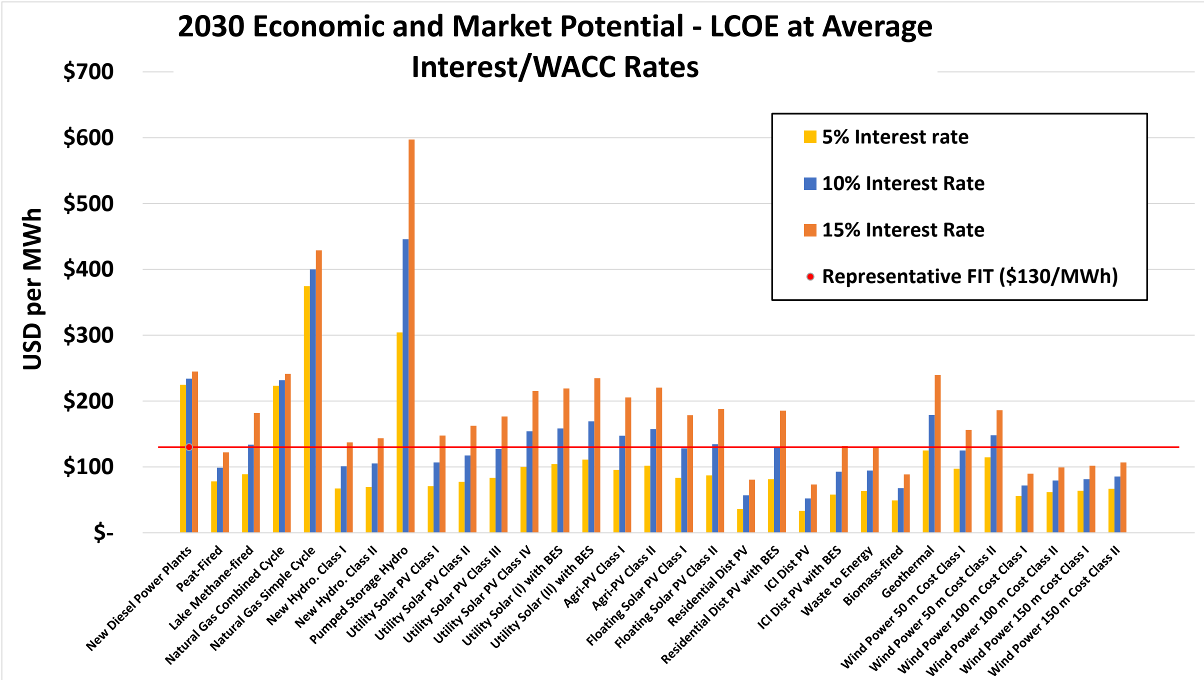


Figure 4.C-1 LCOE Results for All Generation Options Evaluated for 2030 at Interest/WACC Rates of 5%/yr to 15%/yr

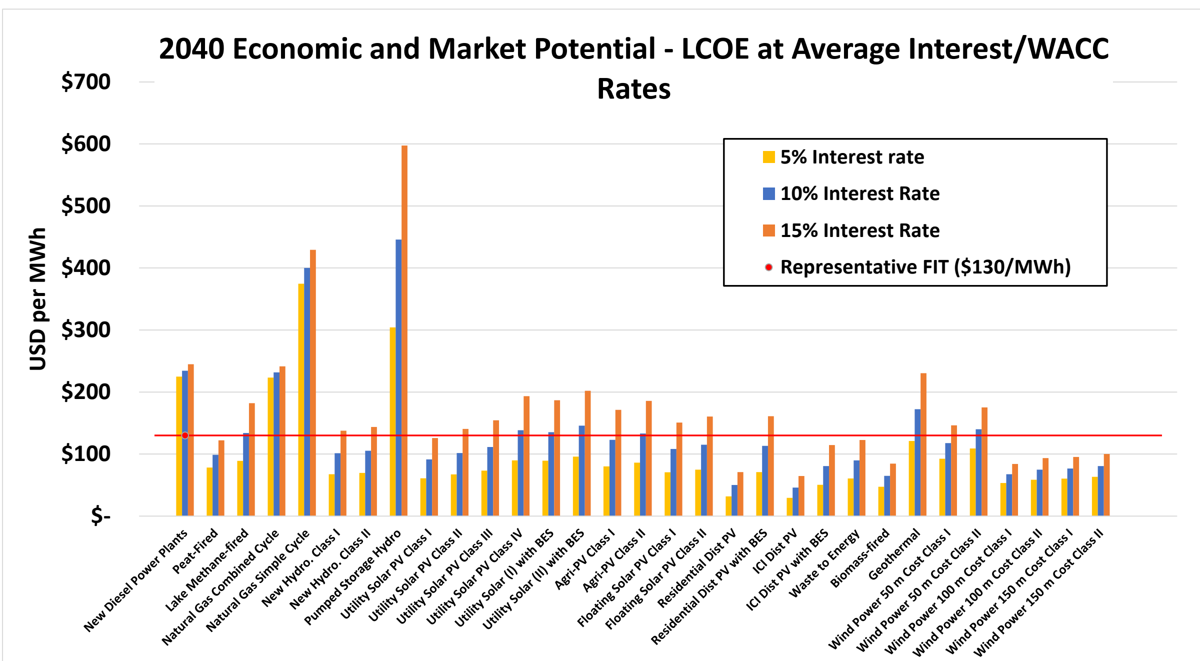


Figure 4.C-2 LCOE Results for All Generation Options Evaluated for 2040 at Interest/WACC Rates of 5%/yr to 15%/yr

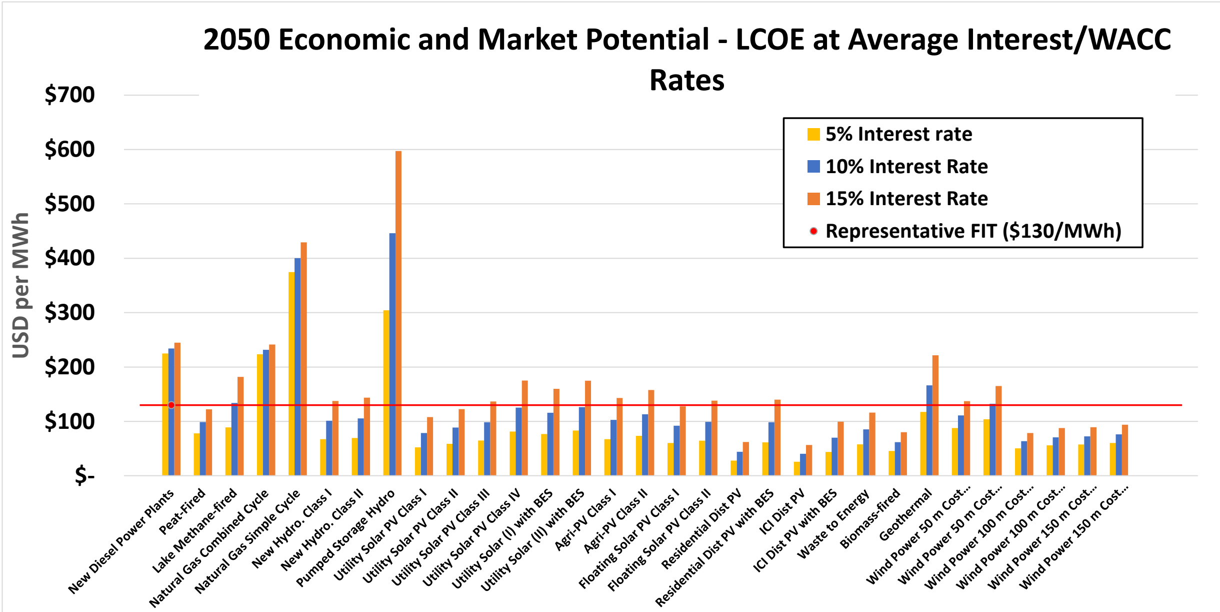


Figure 4.C-3 LCOE Results for All Generation Options Evaluated for 2050 at Interest/WACC Rates of 5%/yr to 15%/yr

Based on the results above, Table 4.C-3 shows the estimated market potential of resources/technologies in MW for electricity generation in Rwanda at interest/WACC rates of 10 and 15% per year (the two rightmost columns of the table). 2030 is the year of analysis, and is significant because, based on the electricity demand and supply scenarios modeled as shown in section 4 of this report, the Rwandan power grid will begin to need new generation beyond what is now in REG plans in the early to mid-2030s. Similar to the economic potential discussion above, whether a resource/technology passes the market cost-effectiveness test in this analysis depends on whether its LCOE evaluated at market interest rates falls at or below the assumed threshold for competitiveness in the Rwanda electricity market, here taken to be $130 per MWh. Here, the market potential of renewable resources falls considerably relative to the technical and economic potential at higher interest rates. When interest rates are set at 15%/yr, only distributed solar PV, larger wind turbines, lake methane, and waste-to-energy plants appear as resources/technologies with market potential. By 2040 and 2050, as initial costs for solar PV and wind systems are assumed to keep declining in real terms, the market potential for more of these technologies rise above the threshold value.

TABLE 4.C-3. MARKET POTENTIAL RESULTS BY RESOURCE/TECHNOLOGY					
PLANT NAME	TECHNICAL POTENTIAL (NAMEPLATE MW) 2030	TECHNICAL POTENTIAL AS AVAILABLE CAPACITY (MW)	ECONOMIC POTENTIAL AT 5%/YR INTEREST RATE, $130/MWH THRESHOLD (MW)	MARKET POTENTIAL AT 10%/YR INTEREST RATE, $130/MWH THRESHOLD	MARKET POTENTIAL AT 15%/YR INTEREST RATE, $130/MWH THRESHOLD
New Diesel Power Plants					
Peat-Fired	184	166	166	166	166
Lake Methane-fired	237	218	218	-	-
Natural Gas Combined Cycle			-	-	-
Natural Gas Simple Cycle			-	-	-
New Hydro. Class I	569	411	411	411	-
New Hydro. Class II	165	119	119	119	-
Pumped Storage Hydro			-	-	-
Utility Solar PV Class I	157,351	26,75	26,750	26,750	-
Utility Solar PV Class II	21,850	3,715	3,715	3,715	-
Utility Solar PV Class III	12,243	2,081	2,081	2,081	-
Utility Solar PV Class IV	8,941	1,520	1,520	-	-
Utility Solar (I) with BES	157,351	26,750	26,750	-	-
Utility Solar (II) with BES	21,850	3,715	3,715	-	-
Agri-PV Class I	667,902	113,543	113,543	-	-
Agri-PV Class II	66,465	11,299	11,299	-	-
Floating Solar PV Class I	1,737	295	295	295	-
Floating Solar PV Class II	1,428	243	243	-	-
Residential Dist PV	33,239	5,651	5,651	5,651	5,651
Residential Dist PV with BES	33,239	5,651	5,651	-	-
ICI Dist PV	2,205	375	375	375	375
ICI Dist PV with BES	2,205	375	375	375	-

TABLE 4.C-3. MARKET POTENTIAL RESULTS BY RESOURCE/TECHNOLOGY					
PLANT NAME	TECHNICAL POTENTIAL (NAMEPLATE MW) 2030	TECHNICAL POTENTIAL AS AVAILABLE CAPACITY (MW)	ECONOMIC POTENTIAL AT 5%/YR INTEREST RATE, $130/MWH THRESHOLD (MW)	MARKET POTENTIAL AT 10%/YR INTEREST RATE, $130/MWH THRESHOLD	MARKET POTENTIAL AT 15%/YR INTEREST RATE, $130/MWH THRESHOLD
Waste to Energy	76	68	68	68	68
Wind Power 50 m Cost Class I	139	39	39	39	-
Wind Power 50 m Cost Class II	26	7	7	-	-
Wind Power 100 m Cost Class I	554	177	177	177	177
Wind Power 100 m Cost Class II	85	26	26	26	26
Wind Power 150 m Cost Class I	882	247	247	247	247
Wind Power 150 m Cost Class II	127	34	34	34	34

In considering these results it is important to recognize some of the uncertainties associated with these analyses of market potential. Key considerations in this regard are described in Section 4.E. below.

4.D. SENSITIVITY OF ECONOMIC AND MARKET POTENTIAL TO LOWER THRESHOLD ASSUMPTION ($70/MWh)

Conversations with REG indicated that although the $130/MWh threshold used above or a similar value has been used in the recent past as a Feed-in-Tariff in contracting with electricity suppliers, REG was considering using lower FiTs in the future, including possibly differentiating FiTs by type of resource and/or technology. The EAEP Team was provided with a set of estimates of FiTs, based on levelized cost analyses, performed by REG in 2020 for a range of different technologies and a range of installed cost and interest rates for each technology.[136] It is the EAEP Team's understanding that these estimates were to be used as inputs to REG negotiations with potential power suppliers, and thus do not represent existing contracts. Based on a review with REG of the wide range of estimates provided in

[136] The document received by the EAEP team is a REG presentation entitled "AFFORDABLE TARIFF EVOLUTION", dated November 11, 2020. Note that the EAEP team has not had an opportunity to fully review the underlying methods used to prepare the LCOE/FiT estimates presented in the presentation.

the document, **it was decided that a $70/MWh threshold would be used to test the sensitivity of the market potential estimates described above to possible lower FiTs.**

Table 4.D-1 below shows the estimated unexploited capacity (MW) for each resource based on **economic and market potential** (last three data columns) **relative to the sensitivity-level FiT of $70/MWh and compared to estimated technical potential. The results show:**

- **In 2030 an estimated unexploited total capacity in Rwanda of 6,925 MW based on economic potential and 6,025 MW based on market potential at 10% interest rate. No respire potential is estimated at an interest rate of 15%/yr.** The estimated potential for solar decreases significantly compared to the 2030 estimates at the $130/MWh threshold and seems exist only at a 10%/yr interest because only distributed solar technologies can offer levelized costs of energy (LCOE) that are under the $70/MWh in 2030 (please refer to Table 4.D-2 for details on the market potential estimates for each technology).
- **In 2050 only an estimated unexploited total capacity in Rwanda of 6,025 MW based on market potential at 15% interest rate covered entirely by solar (distributed solar)**, since no other resources can offer LCOE that are under the $70/MWh in 2050.

Although there are many uncertainties that go into the calculations of future LCOEs and into consideration of evaluation thresholds to be used to establish market potential, **it seems likely that REG tariffs will, overall, need to remain above $70/MWh to attract investment in generation in Rwanda. Consideration of the specific circumstances of an individual project, of course, may result in different findings about appropriate FiTs that REG could offer**

Tables 4.D-2 and 4.D-3, as well as Figures 4.D-1 through 4.D-3 present the LCOEs of the resource/technology options for Rwanda evaluated relative to the sensitivity-level FiT of $70/MWh. Relative to the use of the current practice FiT of $130/MWh, many fewer technologies/resources offer an LCOE that is under the threshold value. **At an interest rate of 10%/yr, only distributed solar technologies, biomass-fired power, and some wind power offer LCOEs less than $70/MWh (numbers in bold in the table below). At an interest rate of 15 percent/yr, only distributed solar technologies can offer LCOEs less than $70/MWh, and then only after 2030 (numbers in bold in the table below).**

TABLE 4.D-1 ECONOMIC AND MARKET POTENTIAL RESULTS FOR SENSITIVITY ANALYSIS USING A $70/MWH FiT THRESHOLD (2030 AND 2050)

RESOURCE	LCPDP AND EAEP: EXPLOITED TECHNICAL AVAILABLE CAPACITY (MW)	EAEP: UNEXPLOITED TECHNICAL AVAILABLE CAPACITY (MW)	EAEP: TOTAL EXPLOITED + UNEXPLOITED TECHNICAL AVAILABLE CAPACITY (MW)	ECONOMIC POTENTIAL AT 5% INTEREST RATE (2030 LCOE) BASED ON UNEXPLOITED CAPACITY *(MW)*	**MARKET POTENTIAL** AT 10% INTEREST RATE (2030 LCOE) BASED ON UNEXPLOITED CAPACITY *(MW)*	**MARKET POTENTIAL** AT 15% INTEREST RATE (2030 LCOE) BASED ON UNEXPLOITED CAPACITY *(MW)*
Solar (2030 LCOE)	2.1	168,699	168,699	6,025	6,025	-
Solar (2050 LCOE)	2.1	168,699	168,699	152,652	6,025	6,025
Hydro	164[137]	822	986	629	-	-
Wind (100m hub height)	0	225	225	203	177	-
Waste 2030	0.07	55	55	55	-	-
Waste 2050	0.07	116	116	116	-	-
Geothermal	-	-	-	-	-	-
Lake Kivu Methane	116	102	218	-	-	-
Peat[138]	86	166	246	-	-	-
Total Capacity 2030	**409**	**170,123**	**170,487**	**6,925**	**6,025**	**-**
Total Capacity 2050	**409**	**409**	**170,200**	**153,629**	**6,203**	**6,025**

[137] Hydro "Available capacity" for existing and planned hydro come from Tables 2, 4 and 5 of the LCPDP (values for "available" or "firm" capacity). Additional planned sites in Table 3 that were not also in either Table 4 or 5 were also added (with an assumed 51% CF). LCPDP Total includes planned installed capacity from LCPDP (with available capacity estimated using average capacity factor).

[138] Peat: LCPDP Total is the milled peat estimate (121) plus remaining peat in Hakan concession area not allocated to the 80 MW plant.

TABLE 4.D-2 RESULTS FOR LCOE ANALYSIS OF INTEREST RATES OF 10 AND 15%/YR WITH THRESHOLD OF $70/MWH

PLANT / PLANT TYPE	TOTAL LEVELIZED COST OF ENERGY $/KWH AT 10%				TOTAL LEVELIZED COST OF ENERGY $/KWH AT 15%			
	2020	2030	2040	2050	2020	2030	2040	2050
New Diesel	234.23	234.23	234.23	234.23	244.90	244.90	244.90	244.90
Peat-Fired	98.82	98.82	98.82	98.82	122.19	122.19	122.19	122.19
Lake Methane-fired	133.93	133.93	133.93	133.93	181.90	181.90	181.90	181.90
Natural Gas Combined Cycle	231.78	231.78	231.78	231.78	241.43	241.43	241.43	241.43
Natural Gas Simple Cycle	400.20	400.20	400.20	400.20	429.17	429.17	429.17	429.17
New Hydro. Class I	101.22	101.22	101.22	101.22	137.48	137.48	137.48	137.48
New Hydro. Class II	105.40	105.40	105.40	105.40	143.70	143.70	143.70	143.70
Pumped Storage Hydro	445.97	445.97	445.97	445.97	597.42	597.42	597.42	597.42
Utility Solar PV Class I	120.65	107.03	91.34	78.52	166.53	147.62	125.73	107.89
Utility Solar PV Class II	131.17	117.44	101.62	88.69	181.59	162.52	140.44	122.45
Utility Solar PV Class III	140.94	127.22	111.41	98.49	195.62	176.57	154.50	136.53
Utility Solar PV Class IV	168.09	154.28	138.37	125.38	234.56	215.38	193.18	175.10
Utility Solar (I) with BES	204.97	158.42	135.18	115.86	283.82	219.25	186.81	159.90
Utility Solar (II) with BES	216.21	169.27	145.83	126.35	299.87	234.75	202.04	174.90
Agri-PV Class I	169.70	148.55	124.00	104.04	237.22	207.45	172.83	144.70
Agri-PV Class II	181.76	160.54	135.93	115.89	254.51	224.66	189.93	161.72
Floating Solar PV Class I	145.45	128.23	108.29	92.05	202.88	178.73	150.66	127.84
Floating Solar PV Class II	151.59	134.69	115.12	99.17	211.81	188.10	160.55	138.15
Residential Dist PV	158.40	**57.01**	**50.12**	**43.97**	224.70	80.65	70.86	**62.17**
Residential Dist PV with BES	260.87	130.39	113.24	98.35	371.03	185.45	161.06	139.88
ICI Dist PV	100.84	**52.15**	**45.84**	**40.30**	142.53	73.44	**64.52**	**56.69**
ICI Dist PV with BES	170.36	92.74	80.54	69.95	241.99	131.73	114.41	99.37
ICI Dist PV	99.65	94.54	89.76	85.28	136.72	129.39	122.52	116.09
ICI Dist PV with BES	71.05	**67.78**	**64.73**	**61.87**	93.46	88.78	84.39	80.28
Waste to Energy	185.60	178.84	172.40	166.28	249.25	239.54	230.30	221.52
Biomass-fired	155.65	124.95	117.58	110.92	198.05	156.29	146.27	137.22
Geothermal	182.58	148.20	139.95	132.49	233.05	186.28	175.06	164.92
Wind Power 50 m Cost Class I	89.38	71.78	**67.56**	**63.75**	113.60	89.67	83.93	78.74
Wind Power 50 m Cost Class II	98.14	79.38	74.87	70.80	124.99	99.47	93.34	87.81
Wind Power 100 m Cost Class I	101.68	81.57	76.75	72.39	129.20	101.85	95.29	89.36
Wind Power 100 m Cost Class II	106.42	85.57	80.57	76.04	135.31	106.94	100.14	93.99
Wind Power 150 m Cost Class I	234.23	234.23	234.23	234.23	244.90	244.90	244.90	244.90
Wind Power 150 m Cost Class II	98.82	98.82	98.82	98.82	122.19	122.19	122.19	122.19

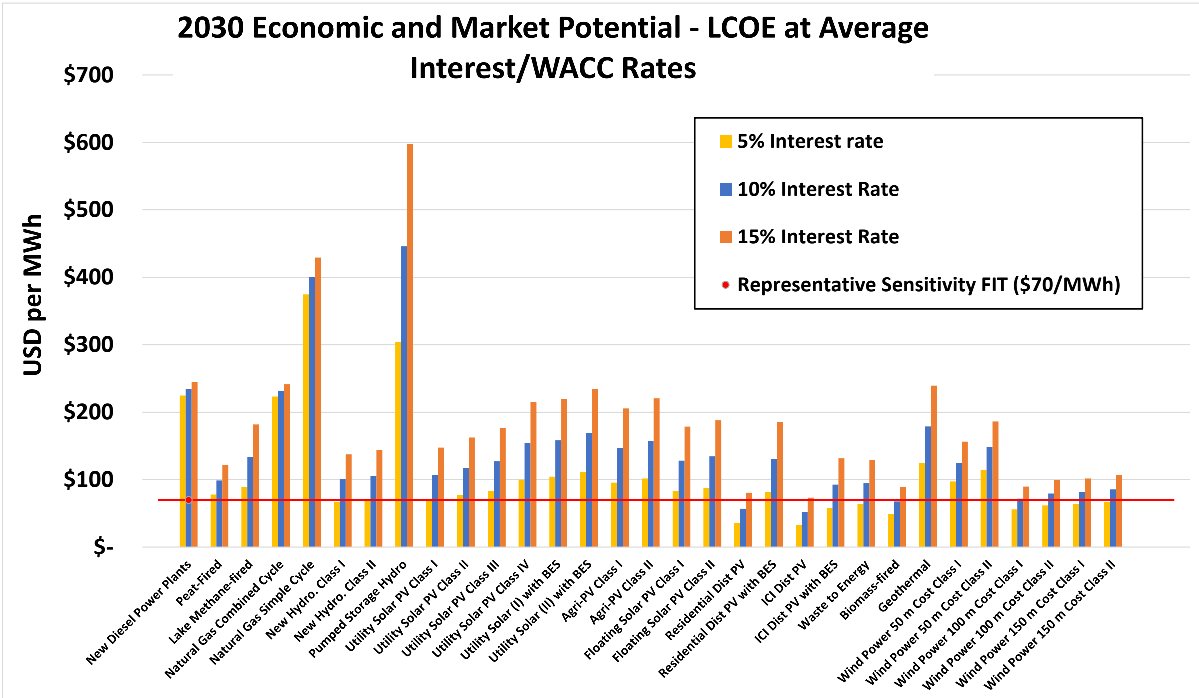


Figure 4.D.-1: LCOE Results for All Generation Options Evaluated for 2030 at Interest/WACC Rates of 5%/yr to 15%/yr and Relative to a $70/MWh FiT Threshold

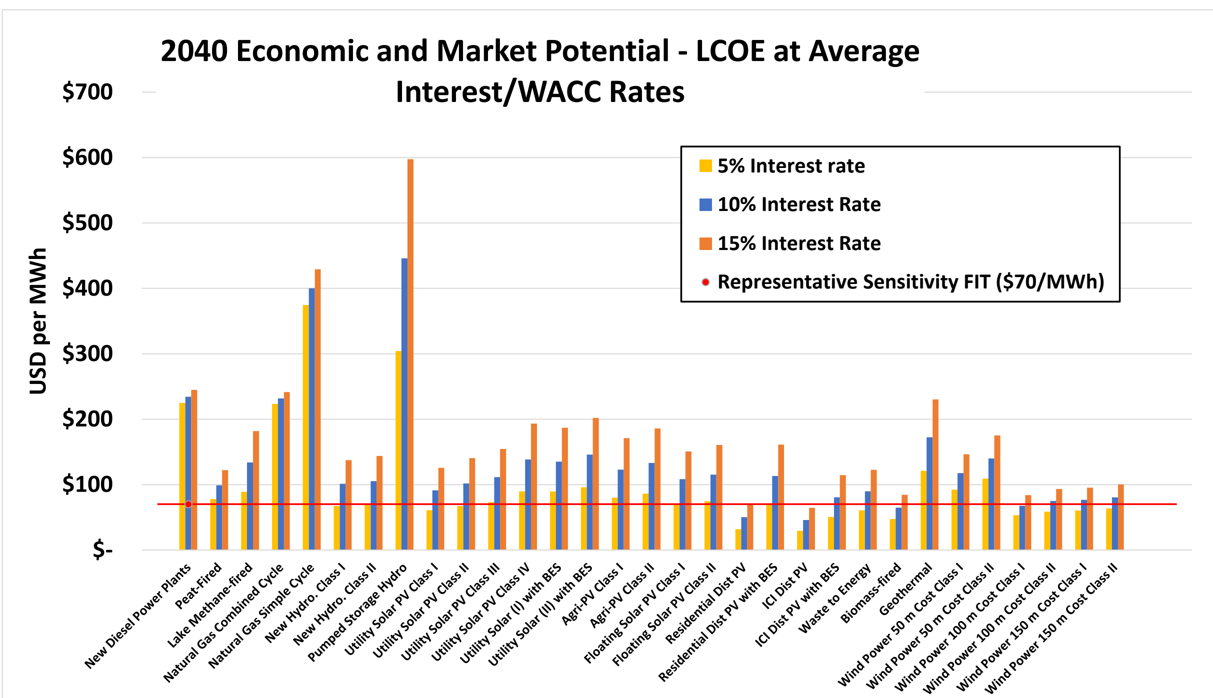


Figure 4.D.-2: LCOE Results for All Generation Options Evaluated for 2040 at Interest/WACC Rates of 5%/yr to 15%/yr and Relative to a $70/MWh FiT Threshold

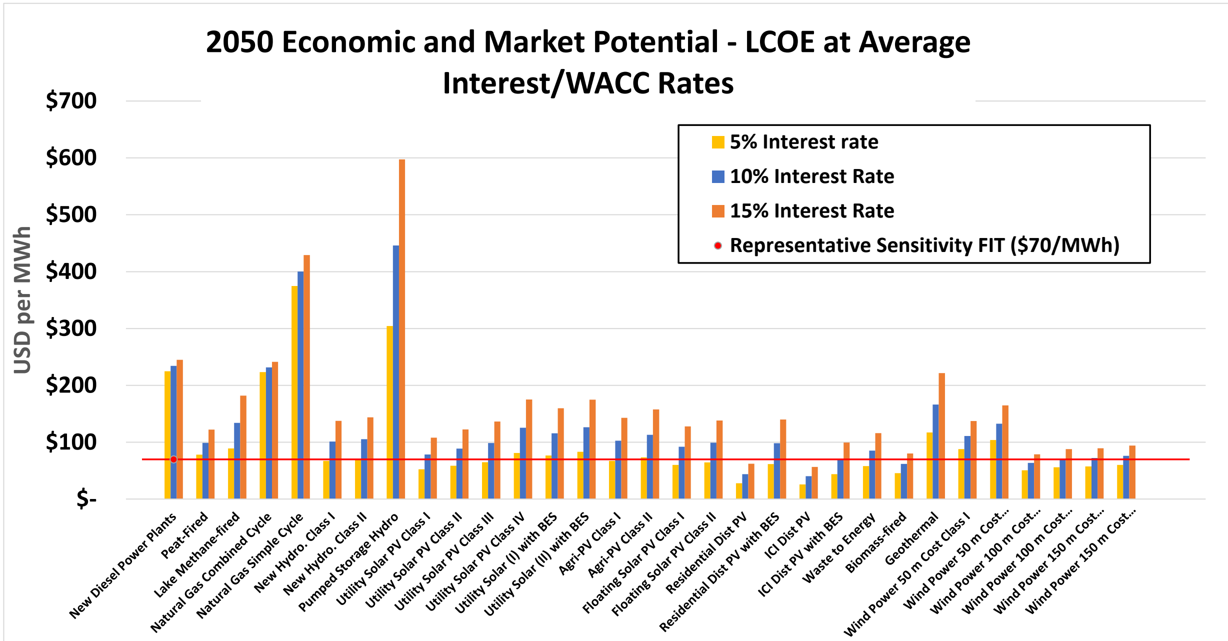


Figure 4.D.-3: LCOE Results for All Generation Options Evaluated for 2050 at Interest/WACC Rates of 5%/yr to 15%/yr and Relative to a $70/MWh FiT Threshold

Table 4.D-3 below presents the MW of market potential for each technology in 2030 using the $70/MWh threshold and different interest rates. **Only residential and ICI distributed solar technologies can offer LCOEs that are under this threshold in 2030, and then only at a 10 percent/yr interest rate**.

TABLE 4.D-3. MARKET POTENTIAL RESULTS BY RESOURCE/TECHNOLOGY, SENSITIVITY ANALYSIS USING A $70/MWH FiT THRESHOLD					
PLANT NAME	TECHNICAL POTENTIAL (NAMEPLATE MW) 2030	TECHNICAL POTENTIAL AS AVAILABLE CAPACITY (MW)	ECONOMIC POTENTIAL AT 5%/YR INTEREST RATE, $70/MWH THRESHOLD	MARKET POTENTIAL AT 10%/YR INTEREST RATE, $70/MWH THRESHOLD	MARKET POTENTIAL AT 15%/YR INTEREST RATE, $70/MWH THRESHOLD
New Diesel Power Plants					
Peat-Fired	184	166	-	-	-
Lake Methane-fired	237	218	-	-	-
Natural Gas Combined Cycle			-	-	-
Natural Gas Simple Cycle			-	-	-
New Hydro. Class I	569	411	411	-	-
New Hydro. Class II	165	119	119	-	-
Pumped Storage Hydro			-	-	-
Utility Solar PV Class I	157,351	26,750	-	-	-
Utility Solar PV Class II	21,850	3,715	-	-	-
Utility Solar PV Class III	12,243	2,081	-	-	-
Utility Solar PV Class IV	8,941	1,520	-	-	-
Utility Solar (I) with BES	157,351	26,750	-	-	-
Utility Solar (II) with BES	21,850	3,715	-	-	-
Agri-PV Class I	667,902	113,543	-	-	-
Agri-PV Class II	66,465	11,299	-	-	-
Floating Solar PV Class I	1,737	295	-	-	-
Floating Solar PV Class II	1,428	243	-	-	-
Residential Dist PV	33,239	5,651	5,651	5,651	-
Residential Dist PV with BES	33,239	5,651	-	-	-
ICI Dist PV	2,205	375	375	375	-

TABLE 4.D-3. MARKET POTENTIAL RESULTS BY RESOURCE/TECHNOLOGY, SENSITIVITY ANALYSIS USING A $70/MWH FiT THRESHOLD					
PLANT NAME	TECHNICAL POTENTIAL (NAMEPLATE MW) 2030	TECHNICAL POTENTIAL AS AVAILABLE CAPACITY (MW)	ECONOMIC POTENTIAL AT 5%/YR INTEREST RATE, $70/MWH THRESHOLD	MARKET POTENTIAL AT 10%/YR INTEREST RATE, $70/MWH THRESHOLD	MARKET POTENTIAL AT 15%/YR INTEREST RATE, $70/MWH THRESHOLD
ICI Dist PV with BES	2,205	375	375	-	-
Waste to Energy	76	68	68	-	-
Wind Power 50 m Cost Class I	139	39	-	-	-
Wind Power 50 m Cost Class II	26	7	-	-	-
Wind Power 100 m Cost Class I	554	177	177	-	-
Wind Power 100 m Cost Class II	85	26	26	-	-
Wind Power 150 m Cost Class I	882	247	247	-	-
Wind Power 150 m Cost Class II	127	34	34	-	-

4.E. UNCERTAINTIES IN CALCULATIONS OF LCOES AND IN ESTIMATION OF ECONOMIC AND MARKET POTENTIAL

Consideration of the LCOE results described above, and of the economic and market potential findings shown, should take into account a number of uncertainties. These include the following:

- Although the different types of costs (initial, O&M, and fuel costs) for each of the resource/technology pairs considered here has been modeled at values that are best estimates from consideration of the literature and/or from recent experience in Rwanda, in fact, **a range of costs will inevitably apply to each individual installation of generation**. For some technologies, which use fairly standard equipment and for which installation costs likely will not vary much by location, costs may not vary much across installations. Examples here may be solar PV (especially utility and floating solar), diesel, or natural gas power plants. Other types of resources by their nature have highly variable costs of installation. Hydroelectric plants, and pumped-storage hydro, are key examples here, as each site may require a different approach in terms of engineering and construction. Variations in costs, and particularly installed costs, for this latter category of plants in particular will have significant effects on the calculated LCOEs, and whether those resources prove cost-effective from an economic or market perspective. **Thus, even if a particular class of technologies shows costs above that are greater than the cost-effectiveness threshold, there still may well be variants/applications of that technology that would be cost-effective.**

- Relatedly costs for technologies as a whole **can change over time**. Although some of the technologies considered here, such as hydro and fossil-fueled generation, are relatively mature, and unlikely to see substantial changes in installed costs, others, particularly solar PV, battery energy storage, and to a lesser extent wind technologies, have been and likely will continue to be undergoing profound reductions in cost per unit capacity over time. The EAEP Team has included estimates of reduction in solar and wind costs in the analyses described above, based on estimates from the US National Renewable Energy Laboratory, but even those estimates may prove inaccurate as the future unfolds. For example, a number of battery technologies are under development that could show huge cost reductions relative to the lithium-ion batteries that now dominate the market. Similarly, solar technologies that are much easier to produce than today's silicon-based PVs will come to market before 2050, with potentially disruptive but un-knowable impacts on cost. **Changes in cost over time are particularly important in the Rwandan context, as Rwanda's needs for generation are projected to grow substantially in the future.**
- For solar technologies, **increases in efficiency of solar PV modules will affect both the cost and, in fact, the technical potential for solar**. If the average efficiencies with which PVs convert light to electricity rise, as they in fact have been over the past decades, then technical, economic, and market potential will rise as well, because more electricity can be produced per unit of panel area, and per unit area of sites for solar PVs.
- Just as key technology costs will change over time and can vary by installation, **the cost threshold against which LCOEs have been measured to determine cost-effectiveness may change too**. The EAEP Team has used $130/MWh as the threshold for cost-effectiveness in the analyses described above, based on recent FiT policies by REG, but in fact this "yardstick" is itself subject to revision. One reason for this is that over time, the default generation technology to meet Rwanda's incremental needs will likely change as Rwanda's needs for electricity grow with its economy. So if, for example, Rwanda's growth in electricity needs is such that new demand can only be met by deployment of additional diesel generation, the threshold cost for other types of new generation to be competitive will be much higher than if, say, the availability of electricity from imports expands greatly at $100 per MWh. In addition, **place and timing can play significant roles in whether a given resource has economic or market potential**.

  In particular places in Rwanda, and for meeting particular types of loads, it may well be that more expensive options are just fine—examples might be remote mines, or villages where loads are small, but electricity displaces expensive fossil fuels for lighting or battery charging. These more expensive options may be acceptable even if the area to be served is on the central Rwandan grid. For example, if the area to be served is sufficiently remote that increasing supplies to the area will require a significant investment in new transmission resources, adding local generation, even if it costs more, may be cost-effective due to the avoided costs of new power lines.

  Generation resources that can produce power at times when electricity is most needed may also be worth more, and thus should be compared to a higher cost threshold. For example, solar PV systems with battery energy storage that allows the PV output to effectively be shifted from the daytime, when power may be plentiful, into the evening to cover peak demand, is more valuable to the power system. Whether such systems are actually paid for the peak-serving benefits they provide will depend on how feed-in-tariffs are set and/or how markets for electricity in Rwanda are organized in the future. In a number of locations around the world, electricity markets determine what the price paid for generation will be at any given moment. Although this type of system is not fool-proof, and must be implemented carefully, as certain situations can result in exorbitant market prices that consumers may not be able to afford, electricity markets provide indicators to potential developers as to whether the power they plan to sell will be competitive in a market where prices, that, like electricity demand, fluctuate over time.

These uncertainties suggest that although the physical and technical resources for electricity generation in Rwanda may be largely static, **economic and market potential are much more dynamic, and may depend on many factors that can change depending on where and when a resource is evaluated. As such, an agile, flexible approach to utility management is needed that works with the private sector to create opportunities for creativity in project design, implementation, and interconnection and in project finance, including setting up a well-administered, independently regulated market for future generation options, with coordination in planning to keep supply and demand growth in balance.**

5. SUPPLY SCENARIOS FOR RWANDA

The most recent LCPDPs include projections for electricity supply sources to be added through the early 2030s, as well as a set of electricity demand projections based on a range of growth rates through 2040. Working with REG staff, and using **the LEAP (Low Emissions Analysis Platform)**[139] software tool, **the EAEP Team assembled a range of electricity supply scenarios for Rwanda through the year 2050, with different scenarios tapping different types and amounts of the resources for which assessments are provided in section 3 of this report.** The remainder of this section provides a summary of the process of defining and modeling those supply scenarios, as well as a summary of scenario relative results. Additional details on the implementation of the LEAP model for Rwanda are provided in Annex B to this report.

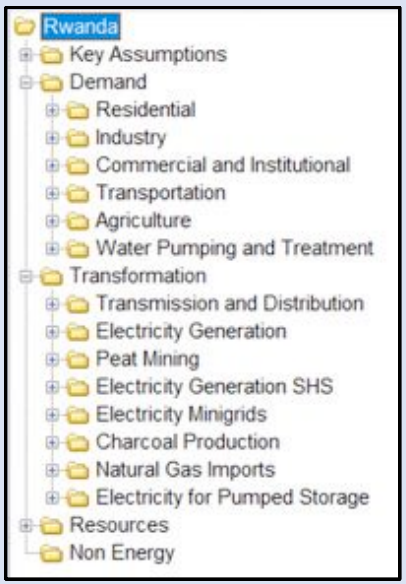
The LEAP model prepared to run the supply scenarios described focuses on electricity demand and supply, but in fact provides a complete reflection of all of the main fuels used in Rwanda, as well as information on the supplies of fuels and resources used to generate electricity. As such, the tool prepared by the EAEP Team is capable of modeling, for example, the impact of policies that affect multiple types of fuel use. Most importantly for the electricity sector, the dataset can be used to model the switching from non-electric fuels to electricity. These fuel-switching process include, for example, switching from the use of kerosene and candles to electricity for lighting, or from wood to electricity for cooking, in some households, or, most notably, the growth of the use of electric vehicles in the Rwandan transport fleet.

[139] As indicated in the Introduction Section of this report, during Phase 2 of the Project, the LEAP model was identified as part of the integrated analysis system to be used to conduct the electricity generation resource assessment for Rwanda. For more information on LEAP, please see the Phase 2 report or visit the following website https://leap.sei.org/default.asp?action=introduction

Structure of the EAEP Rwanda LEAP Model

The EAEP Rwanda LEAP dataset covers each of the main sectors of electricity use in Rwanda, namely the residential (household), industrial, commercial, and institutional (including services), transportation, agriculture, and water pumping and treatment sectors.

The conversion of resources and intermediate fuels (such as oil products) to fuels and energy forms that meet final demand is accomplished in the "transformation" portion the model. Transformation "modules" include transmission and distribution (of electricity and natural gas, although natural gas does not currently appear as a fuel in demand sectors in the scenarios modeled), electricity generation, peat mining, electricity generation using solar home systems and mini-grids, charcoal production, natural gas imports, and electricity generation for pumped-storage hydro.



All of the major fuels used in the Rwandan economy are covered in the dataset. Direct uses of biomass fuels are described as just "wood" or "charcoal", although in practice it is understood that a number of types of biomass fuels are used in the country. If needed, use of different biomass fuels can be differentiated in the model in the future by REG or other model users. The "Resource" portion of the model specifies the total reserves (for non-renewable resources) or yields (for renewable resources) of key resources included in the dataset, as well as the import costs for fuels such as petroleum products, all of which are imported to Rwanda at present. All of the fuels and resources covered by the model appear as either "primary" or "secondary" resources.

A number of "Key Assumptions" were used across the model in different demand sectors and subsectors and in electricity generation. Examples of key assumptions include growth in population, changes in rural/urban household fractions, growth in gross domestic product (GDP), and demand for transport services.

Sources of Data for Rwanda LEAP Dataset

A variety of data sources and inputs and outputs from previous modeling efforts were used to prepare the Rwanda LEAP dataset. Key sources of information have included (but were not limited to) the following:

- Data on historical changes in population, households, GDP, and other activities that "drive" energy use from the National Institute of Statistics of Rwanda;
- Data and projections of the end use of electricity and other fuels across the economy from the inputs and outputs of a previous modeling effort using the MAED (Model for Analysis of Energy Demand) software tool;[i]
- Electricity usage and supply data from the Rwanda Utilities Regulatory Authority (RURA),[i] which were in many cases used to "true up" MAED parameters to match historical electricity use;
- Electricity supply and capacity data by plant provided by REG;
- Data from REG *Annual Reports* and other information provided on the REG website;
- Projections for capacity additions by plant provided by REG for the period through the 2020s;
- Electricity output data and loads by hour over the years 2017 through 2020 provided by REG and used to estimate seasonal and daily load curves for use in LEAP, as well as the variation of hydroelectric and solar output seasonally and daily/seasonally, respectively;
- Projections of GDP for Rwanda and for the East Africa region by the African Development Bank, the World Bank, and others;
- News articles, academic papers, and reports on the Rwandan energy sector as available from the international literature; and
- The results of the assessment of potential generation resources prepared under this project by the EAEP team and summarized in Section 3 of this report.

5.A. GOALS OF SUPPLY SCENARIO DEVELOPMENT

As described in sections 3 and 4 of this report, Rwanda is blessed with a variety of attractive resources for current and future electricity generation. Some of these resources, however, offer limits to the degree to which their use can contribute to meeting future electricity demand in Rwanda. Examples here are hydroelectric resources, which form the backbone of the current Rwanda power system, but for which other uses of water must be taken into account in planning future capacity expansions; Lake Kivu methane, which is a limited resource; and peat, which is used for power generation in Rwanda but may have environmental limitations. Other resources for generation are available, and solar power is particularly attractive and ubiquitous as a resource, but new technology and business models may be needed to spur the widespread use of solar for electricity generation.

The overall goal of the supply scenario development and modeling process described here is to contribute to the LCPDP development process by developing and exploring longer-range (through 2050) scenarios for both electricity demand and for the use of different supply resources to meet demand. The EAEP Team developed seven alternative scenarios designed to present substantially different ways of meeting the demand for electricity and the services it provides in Rwanda, so as to **provide different policy**-relevant points of reference to inform and guide the path of supply expansion in Rwanda over time.

Each of the supply scenarios, with one exception, are based on the same electricity demand forecast. The general directions taken in several of the scenarios were suggested by REG; others were based on goals commonly being explored in many nations in response to climate change, namely a "100% renewables" approach to generation, and a scenario working toward "Next Zero" GHG emissions economy-wide.[140] The seven scenarios modeled have been compared with respect to physical parameters such as output and capacity by type of generator, environmental parameters focusing on greenhouse gas emissions, and overall social costs and costs of electricity production, as well as other, qualitative considerations such as impacts on energy supply security.

It is anticipated that REG will use these scenarios, as well as additional scenarios that REG may assemble in the future using and further updating the LEAP model that has been developed under this Project, to identify and compare different ways forward in providing Rwanda with the electricity needed for economic development at an affordable cost and with acceptable levels of risk. The scenarios shown here, in addition, have implications for how REG and other stakeholders may need to build capacity and develop regulatory and market procedures in order to be able to efficiently and cost-effectively build and manage the electricity sector going forward.

[140] See, for example, Khanyi Mlaba (2021), "Why Is It Essential for Rwanda to Race to Zero Carbon Emissions?", *Global Citizen*, dated August 26, 2021, and available as https://www.globalcitizen.org/en/content/rwanda-race-to-zero-carbon-emissions/.

5.B ELECTRICITY DEMAND FORECAST

Electricity demand has been growing rapidly in Rwanda as the economy expands and as more households and businesses, both rural and urban, are connected to the electricity grid or obtain electricity from mini-grids or solar home systems. Based on RURA data, yearly sales of electricity (or electricity billed to consumers), rose an average of 8.5 percent year-on-year between 2014 and 2020. Annual recorded growth ranged from 15.2 percent in 2016 to 1.6 percent in the pandemic year of 2020, with other years being between 7 and 10 percent. Note that these figures do not capture demand provided from mini-grids or solar home systems, or, more importantly, consumption of electricity not billed or paid for, that is, "non-technical losses". Base year (2020) demand in the model, however, has been adjusted to take into account the estimated fraction of losses that are non-technical, with an amount of electricity demand equal to those estimated losses apportioned between the residential and commercial sectors.

The business as usual case forecasts for electricity demand by sector are shown in Figures 5.B-1, 5.B-2 and 5.B-3below (the Reference Case Demand Forecast). In particular,

- Figure 5.B-1 shows the Reference Case Demand Forecast for grid electricity demand by sector. The assumption as to national GDP growth is shown as well, in billion 2020 US dollars (right axis). Despite population growth in Rwanda slowing over time, from about 2.2 percent annually through 2035 to 1.4% annually by 2045-2050, electricity demand grows rapidly throughout the forecast period**. From 2022 through 2050, demand for grid electricity grows by nearly a factor of 20, with an average annual growth rate of over 11 percent.**
- Figure 5.B-2 shows the Reference Case Demand Forecast for electricity demand by solar home systems (also SHS—mostly small household photovoltaic panels providing electricity for lighting and a small devices). **Much smaller amounts of electricity are provided by SHS and is substantially phased out by 2050 as these consumers shift to grid power supplies.**[141]
- Figure 5.B-3 shows the Reference Case Demand Forecast for electricity demand by mini-grids powered by solar PVs or mini- or micro-hydroelectric generators. **Likewise, much smaller amounts of electricity are provided by these systems and the electricity is substantially phased out by 2050 as these consumers shift to grid power supplies.**

[141] The assumption in the supply scenarios below is that mini-grid generators are placed onto the main grid as their consumes are connected to the main grid. SHS are either retired, used to power back-up systems, or used in small off-grid applications, as their owners are connected to the central grid or to mini-grids.

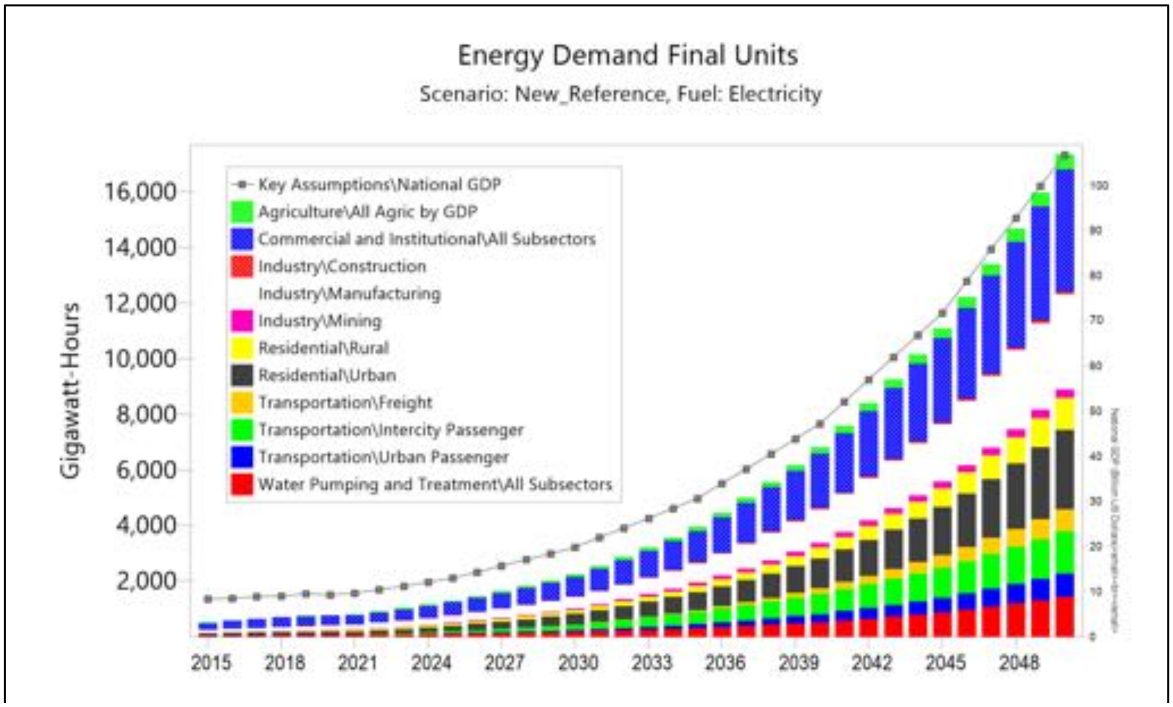


Figure 5.B-1 Reference Case Demand Forecast for Grid Electricity Use in Rwanda

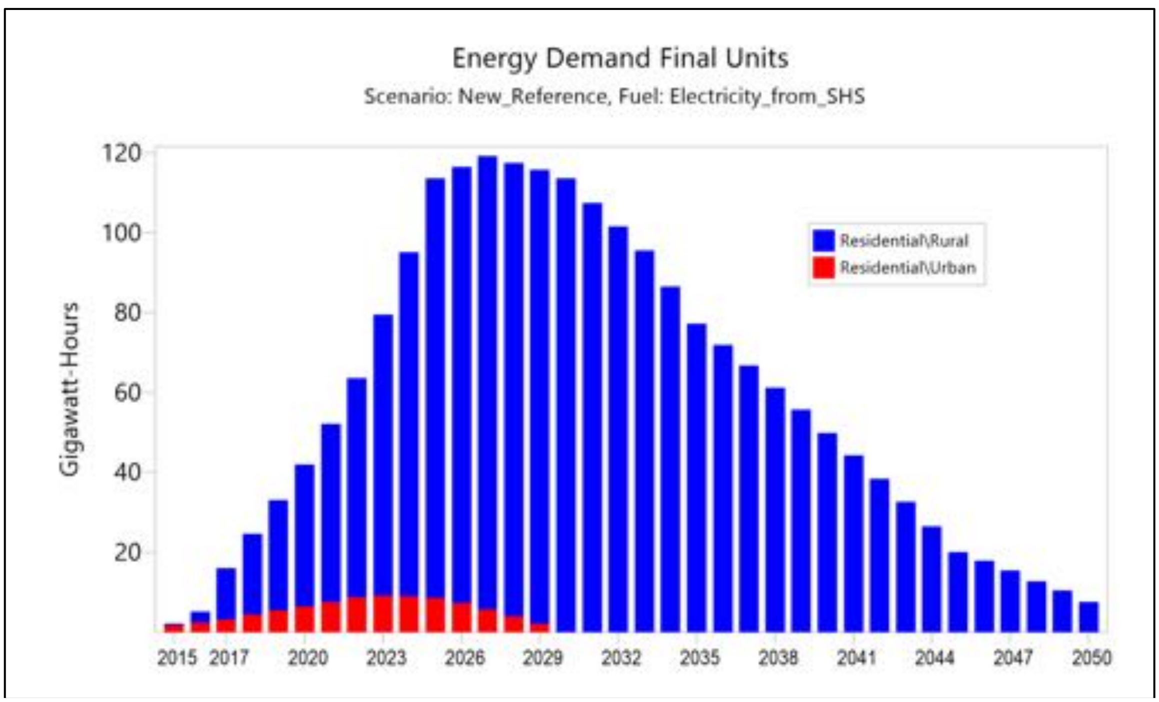


Figure 5.B-2 Reference Case Demand Forecast for Electricity from Solar Home System Use in Rwanda

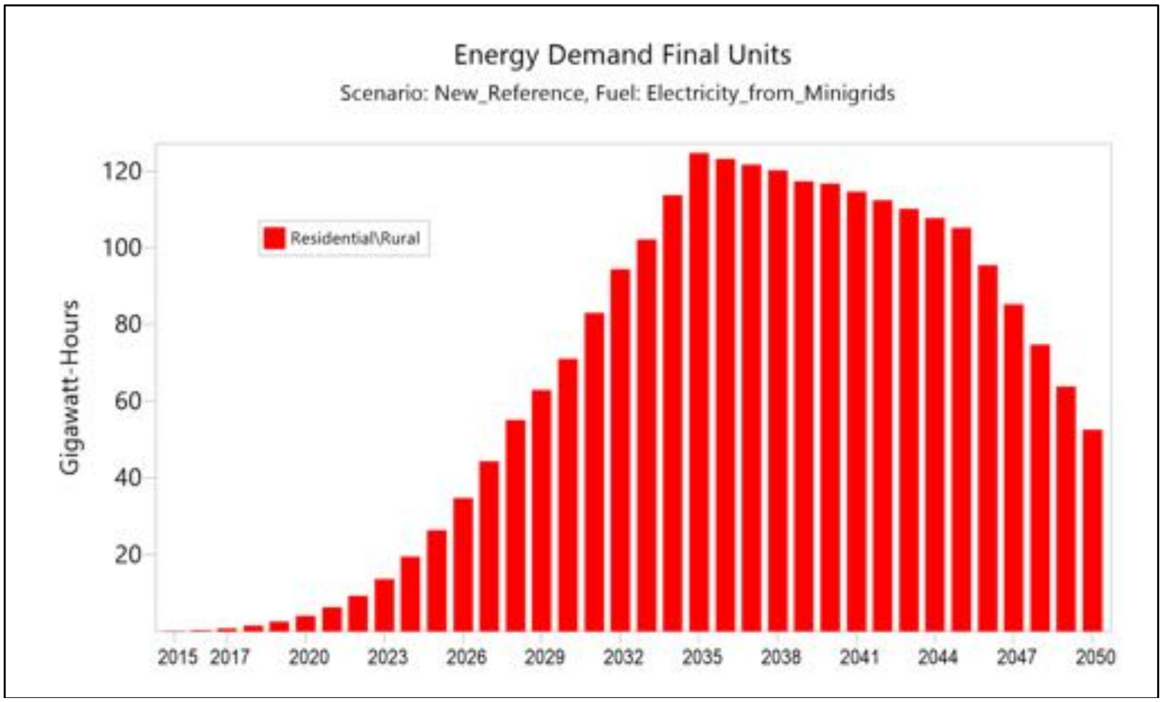


Figure 5.B-3 Reference Case Demand Forecast for Electricity from Mini-grids in Rwanda

Double-digit rates of growth in electricity use sustained for three decades are rare internationally, and perhaps unprecedented, as growth in electricity use tends to slow as economies mature and as population growth slows.[142] Even China's phenomenal economic performance over 1990 through 2020 yielded less than 10 percent annual average growth in electricity use.[143] As such the growth included in this forecast of electricity demand for Rwanda may not, ultimately, be sustained. There may, however, be factors, such as electrification of the transport sector, that may push future rates of growth in electricity demand in Rwanda and countries at similar levels of economic development higher than would have been expected due to past trends in other nations. **The forecast shown in Figure 5.B-1, however, is the result of assumptions about driving activities, such as growth in GDP, and energy intensities, such as electricity use per unit of GDP in industrial sectors, that have been discussed with and requested by REG.**

The **main drivers of electricity demand growth in the Rwanda forecast** shown above are:

- *Population growth*, with Rwanda's population increasing from about 13 million in 2021 to over 22 million by 2050.[144]
- *Continued strong growth in GDP*, based on national and regional projections estimates from the African Development Bank, and extrapolations of same, that correspond to 8 to 9 percent

[142] Further, population growth in some nations has tended to slow as per-capita incomes rise, due to factors such as parents delaying having children as they pursue careers and the growing expense of raising children, particularly in more urban environments. The relationship between population growth and economic development, and vice versa, is, however, complicated and often nation-specific. See, for example, E. Wesley F. Peterson (2017), "The Role of Population in Economic Growth", *SAGE Open*, October-December 2017: 1–15, available as https://journals.sagepub.com/doi/pdf/10.1177/2158244017736094.
[143] See, for example, Enerdata (2021), "China Energy Information", available as https://www.enerdata.net/estore/energy-market/china/.
[144] Based on projections from the older Rwanda MAED model, which are only slightly lower, by 2050, than the United Nations "Medium Variant" projections for Rwanda.

increases in real GDP growth annually from 2022 through 2050.[145] GDP growth in the Rwanda model shown here is only directly used as a driving activity in the industrial subsectors, though growth in the drivers of demand in some other sectors, such as commercial/institutional and transport, are set so as to be consistent with this growth in the industrial sector.

- *Growth in commercial and institutional floorspace* from an estimated 1.1 square meters per capita in 2022 to 5 square meters per capita in 2050, representing a large increase such buildings.
- *The migration of population to urban areas,* with the population in urban areas representing 43 percent of the total population by 2050, up from about 23 percent in 2022. This change has an impact on electricity use because urban populations use more electricity per household than rural populations (on average).
- *Growth in electricity use per household*, although the per-household use of electricity under this forecast is considerably less than that included in the MAED modeling done previously.
- *Extension of grid electricity* to almost all rural households by 2050.
- *Some electrification of the transportation sector.*

The combined impact of these assumptions, combined with other drivers of electricity use such as increased use of air conditioning, electric water heat, and water use and treatment, result in the rapid and continued growth in electricity use shown in Figure 5.B-1.

This Reference Case Demand Forecast is used in all but one of the supply scenarios detailed below. The high growth in this demand projection drives the need for large supply additions after about 2030s. This is particularly true in the years after the late 2030s when the combination of urbanization, partial electrification of transportation, rural electrification, and continued high GDP growth leading to higher industrial sector demand yield electricity demand growth that remains quite high, even while population growth falls. A lower Reference Case Demand Forecast would result in lower need for capacity additions in the future, and perhaps more flexibility in selecting from electricity resources and technologies during the coming decades.[146]

5.C. ELECTRICITY SUPPLY

Electricity supply in the Rwanda LEAP model assembled by the EAEP team with REG staff input **tracks electricity generation for the central grid as well as by mini-grids and SHSs**. In the several scenarios where pumped-storage hydro is used, electricity generated to provide pumping energy is also included. The model elements relating to electricity supply as described briefly below, and in additional detail in Annex B.

[145] This trend in GDP growth was selected for the Reference Case forecast at the request of REG colleagues. The EAEP team notes that GDP growth at this level by a nation has rarely been sustained in the past for three consecutive decades, in part because some ups and downs in an economy are inevitable over such a long period, and in part because GDP growth tends to decline as economies mature.

[146] As an example, the 2018 LEAP model prepared by Stockholm Environment Institute (SEI) for the Rwanda Water Resources Board, which the EAEP team and REG learned about in late 2021, includes a 2050 electricity demand projection that is less than a quarter of the over 16,000 GWh. There are significant differences between the two models, including that the SEI model starts from a base such that the 2020 electricity demand calculated is significantly less than real 2020 demand, and uses a lower rate of GDP growth, less industrial demand, a much lower rate of growth of per-household growth in electricity use than in the EAEP team's Reference Case forecast shown above, in addition to including no transport sector electricity use.

5.C.1 TRANSMISSION AND DISTRIBUTION

Transmission and distribution (T&D) of electricity models losses as decreasing over time as investments in T&D continue and as the Rwandan grid is built out. Technical (as opposed to non-technical) transmission and distribution losses in all scenarios are assumed to decline from about 15 percent of generation in 2020 to 8 percent in 2050.

5.C.2 GENERATION OF GRID ELECTRICITY

Grid electricity generation models the production of electricity to meet load in each model year, as well as by hour for an average weekday and weekend day in each of four seasons (see section 0, below). In historical years and through most of the 2020s, electricity is produced by plants already on the Rwandan grid, currently under construction, or scheduled to come online, with the designation of plants to be added to the grid derived from the most recent REG LCPDP and/or other projections provided by REG staff. These existing and planned facilities include hydroelectric plants, peat- and Lake Kivu methane-fired plants, diesel power plants, a waste-to-energy plant, two small solar power plants, and imports of power. For existing and planned power plants, each plant is listed individually in the model, except for hydroelectric plants with capacities less than 1.0 MW, which are grouped for convenience. In some cases, existing power plants are "decommissioned" in a future year by setting their capacity to zero. For most existing and planned power plants, costs were modeled based on scheduled Feed-in-Tariffs for each plant, a listing of which was provided to the EAEP Team by REG staff.

In addition to existing and planned power plants, a number of new generation types are defined. These include hydro, Lake methane, peat, solar PV, wind, and waste-to-energy plants, as described in section 2 of this report, as well as additional imports from planned interconnections of the electricity grids of the countries of East Africa. Diesel, natural gas, and pumped-storage hydroelectric plants are also included in the list of plants for possible future generation. The cost and other assumptions used to model the inclusion of new power plants are for the most part as described in section 3 of this report.

Future additions to generation are modeled in LEAP as either "exogeneous" or "endogenous" capacity. Exogeneous additions are designated directly as the addition of a particular amount of a particular type of capacity in a given year. Endogenous additions are added automatically by the model as the amount and timing of loads grow over time. Most of the supply scenarios described below use exogenous additions, and capacity additions consistent with the design of each scenario are added until unmet demand is zero or near-zero. In some of the supply scenarios described below, including the reference case, fuel-fired generation capacity—diesel, natural gas, and/or Lake methane—are added endogenously by the model to augment exogeneous additions and meet electricity demand.

5.C.3 GENERATION OF MINI-GRID ELECTRICITY

As in many countries, mini-grids are being deployed in Rwanda to bring the benefits of electrification to communities that the central grid is not scheduled to reach in the near-term and/or that it would be difficult or cost-prohibitive for the central grid to serve. In the Rwanda LEAP model, the deployment of mini-grids accelerates bringing electricity to rural areas. Mini-grids are deployed to meet demand for energy defined as "electricity from minigrids". In addition to the mini-grids already deployed by 2020, new mini-grids based on solar PV power or mini- or micro-hydro are added as needed to meet demand, with about 4 MW of solar PV added for each MW of hydro, but with hydro's average maximum availability (capacity factor) being higher (40 percent versus 17 percent) than for solar PV.

Starting in 2035, as shown in Figure 5.B-3 demand for mini-grid electricity decreases as more households are added to the central grid. At that point, excess generation from mini-grids is modeled as being provided to the main grid, as the areas electrified by mini-grids are added to the main grid.[147]

5.C.4 GENERATION OF SOLAR HOME SYSTEM ELECTRICITY

Solar home systems are deployed, particularly in the next decade, to rapidly provide electricity benefits, albeit with relatively small amounts of power, to households that do not have access to grid electricity. About 70 total MW of capacity are added by 2040, with 46.5 MW added by 2030. Over time, the need for SHS electricity falls, as shown in Figure 5.B-2, as homes are connected to either mini-grids or the central grid. As the deployment of SHS and thus costs of SHS are the same in each of the supply scenarios below, those costs are not currently included in the model.

5.C.5. GENERATION OF ELECTRICITY FOR ON-GRID STORAGE

In several of the supply scenarios developed for Rwanda and described below, solar PV power of different types become the dominant types of capacity additions after the mid 2030s. Solar resources in Rwanda are abundant, but solar power without storage can only provide electricity when the sun shines. As a result, scenarios with a significant amount of solar PV capacity must also include significant electricity storage. Some of the types of solar PV added in the scenarios below include battery energy storage, which is modeled assuming four kWh or storage per kW of capacity--about an average day of solar generation. In the solar-dominated scenarios below, however, there is a need for storage that will go beyond what batteries are typically able to provide today. As such, pumped-storage hydroelectric capacity is included in several supply scenarios, and electricity inputs for pumping are therefore required.[148] In the Rwanda LEAP model, electricity for pumped-storage hydro (and/or perhaps other technologies) is provided by utility-scale solar PV systems, deployed to produce sufficient "electricity for pumping" from the "Electricity for Pumped Storage" module in LEAP to meet demand in each supply scenario.[149] Electricity for pumping is then used as an input by pumped storage hydro plants in the electricity generation module.

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[147] Note that at present costs for mini-grid generation are not include in the model, because all of the supply scenarios modeled include the same amount of mini-grid generation. In the future, REG might choose to explore supply cases where more communities are served by mini-grids, and in that case, it will be necessary to add costs. Solar PV initial costs for mini-grids should be roughly consistent with costs for larger distributed generation with battery energy storage (or perhaps small pumped-storage hydro, depending on the location), with some additional costs for distribution lines and equipment.

[148] Although pumped-storage hydro is included here as the technology of choice for longer-term energy storage in Rwanda, a wide variety of different storage methods are under development, and may well be commercialized to and cost-competitive with pumped-storage hydro by the time that Rwanda needs substantial bulk electricity storage. See, for example, Julian Spector (2020), "The 5 Most Promising Long-Duration Storage Technologies Left Standing: Low-carbon grids need longer-duration storage, but few technologies have succeeded at scale. Here's the current roster of best bets.", GTM, dated March 31, 2020, and available as https://www.greentechmedia.com/articles/read/most-promising-long-duration-storage-technologies-left-standing.

[149] Historically, energy for pumped storage hydro in most countries has typically been supplied by baseload power sources such as coal-fired and nuclear plants, which run more efficiently when they are operated at a high-capacity factor. As more renewables are added to grids worldwide, this situation is changing, and pumped storage systems more often use wind and solar energy for pumping. In Rwanda, there are relatively other good candidates to provide energy for pumping, as the output of methane plants can be varied to follow load, as can hydro. Although peat-fired plants, similar to coal-fired plants, likely run more efficiently at high-capacity factors and thus would be a candidate to provide pumping energy, the peat resource in Rwanda is limited, and peat extraction and electricity generation from peat have significant environmental impacts.

5.D. TREATMENT OF LOAD CURVES AND ELECTRICITY SUPPLY CURVES

Even if large-capacity facilities for storing electricity are available on a grid, electricity must be produced or retrieved from storage to meet demand. As demand for electricity varies, often literally from second to second, electricity output must be varied as well. The matching of electricity supply and demand requires assumptions about how demand for electricity varies over time, which can be described by "load curves", and how the output of a generator varies over time if its output cannot be easily adjusted. The two most important future resources for electricity generation in Rwanda, solar energy and hydro, each show variation over the course of the year, with available solar output varying primarily over the course of each day, but also seasonally, and the availability of hydro power varying by season. To incorporate considerations of changing loads and resource variation while keeping the LEAP model as simple as possible, the EAEP Team divided each year into 192 "time slices" representing weekday and weekend days divided into 24 hours in each of four seasons (2 x 24 x 4 = 192). The months of the year were mapped into four seasons in consultation with REG staff, with the result as follows:

- "Middle": January and February
- "Early Wet": March through May
- "Dry": June through August
- "Late Wet": September through December

5.D.1. LOAD CURVES FOR RWANDA

Starting with hourly production data, provided by REG staff, for all the generators (plus imports) used in Rwanda during 2017 through 2020, the EAEP Team developed a set of load curves charting the variation of load by hour. Figure 5.D.1-1 presents the summary results of the analysis. This load curve shows a broad plateau of demand from morning through late afternoon, then a pronounced peak starting from about 18:00 hours through 22:00 hours, as households use electricity for lighting, cooking, water heating, and entertainment during the evening. Baseload demand occurs from about midnight though 7:00. The EAEP Team has derived for use in LEAP separate curves for each of weekday and weekend demand, and for each of the seasons (see Annex B). These load curves are not markedly different, however.

Note that load curves derived from 2017 through 2020 data are used for the entire projection period through 2050. In practice, the load curve for Rwanda can be expected to evolve in future years. The development of the industrial sector, for example, can be expected to increase use late at night and during the day, and a larger commercial sector would raise daytime and perhaps some evening use. A significant feature of the Reference Case Demand Forecast described above, however, is increasing connections of households to the grid, which would tend to raise the evening peak. An uncertain factor regarding the future load curve is the transportation sector, as vehicle charging could in theory happen at any hour of the day, but could also be guided, through markets and policy, to times of day when electricity is plentiful and produced at low cost. As such, the EAEP Team has opted not to modify the load curve over time, although the LEAP model has the capability to do so, and future users of the Rwanda LEAP model are encouraged to explore this option.

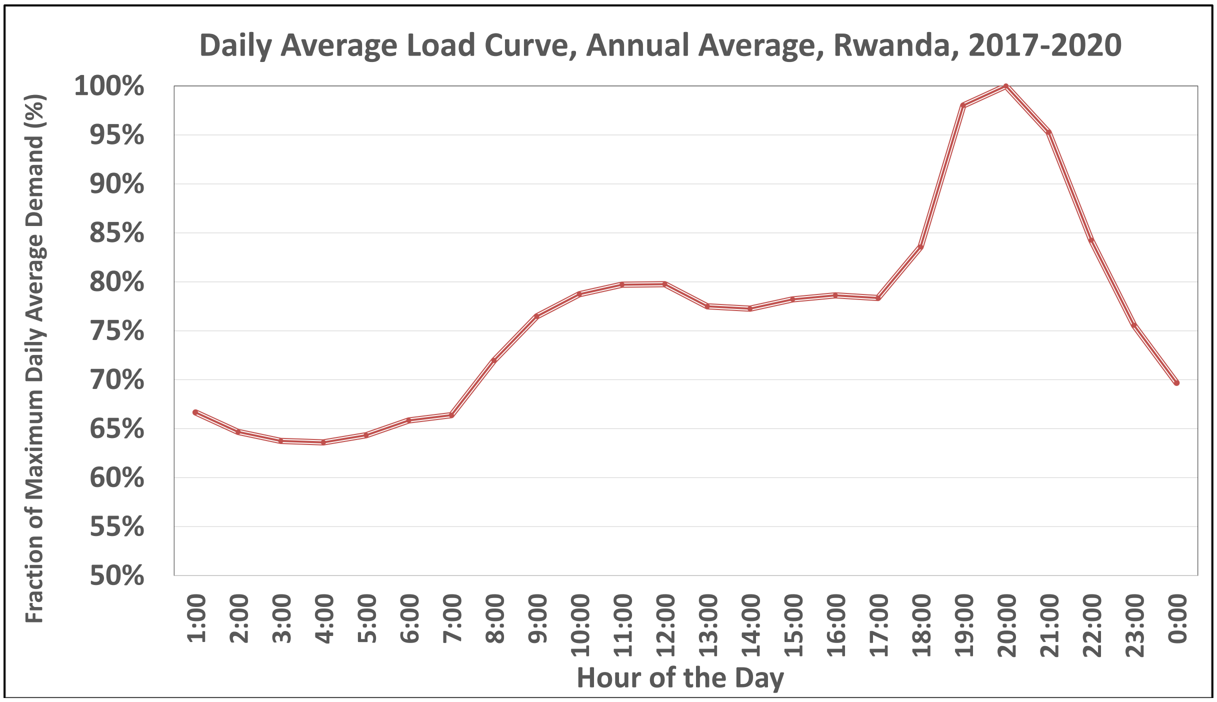

Figure 5.D.1-1 Daily Average Load Curve in Rwanda, 2017-2020

5.D.2. SUPPLY CURVES FOR SOLAR POWER

Starting with records of solar output for each hour of the year for 2017 through 2020 for the existing Gigawatt and Nasho Solar generation facilities in Rwanda, as provided by REG staff, the EAEP Team derived average supply curves for solar generation by hour for each of the seasons. These curves were normalized to an average annual output of 1500 kWh per peak kW of solar capacity, which is similar to the average value used in estimating the solar resource in Section 3.C of this report. As might be expected, and as shown in Figure 5.D.1-1, solar output peaks around the middle of the day, and although dry season output is somewhat greater than in the other seasons, Rwanda's position near the equator means that seasonal variation of solar output is modest. Figure 5.D.2-1 shows results for a weekday, but weekday and weekend-supply curves as entered in LEAP are identical.

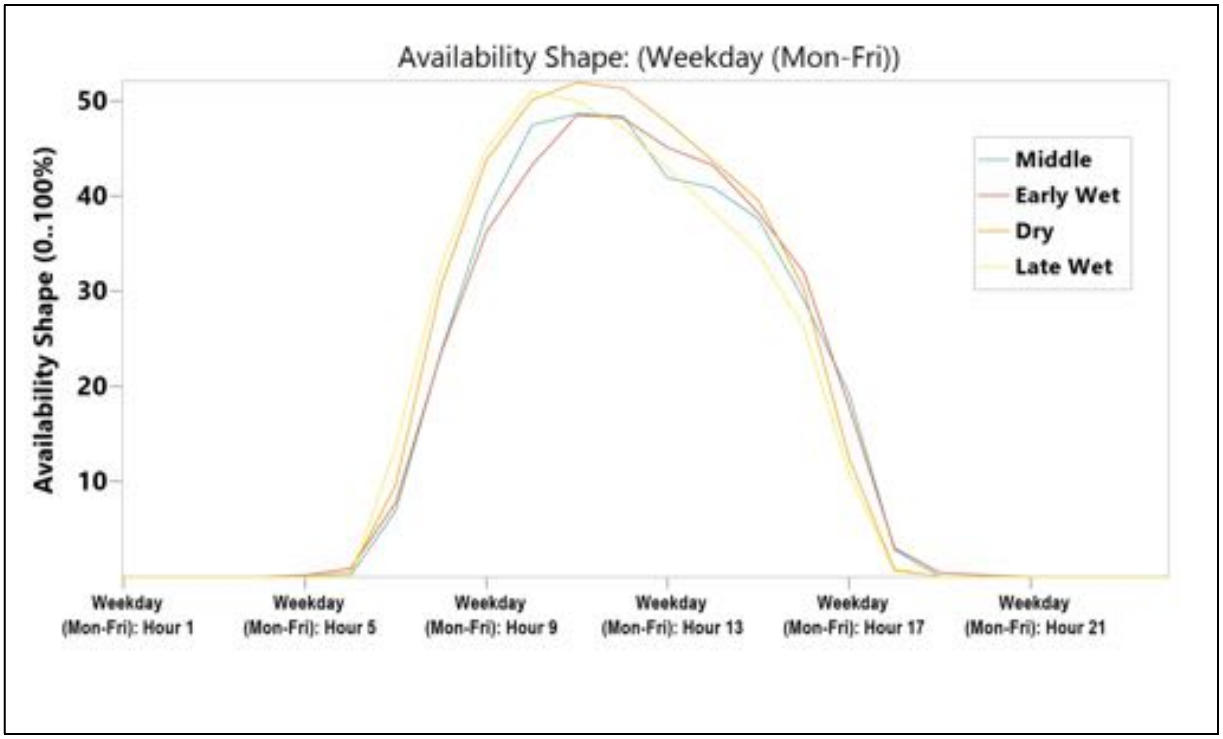

Figure 5.D.2-1 Daily Solar Supply Curves in Rwanda, 2017-2020

5.D.3. SUPPLY CURVES FOR HYDROELECTRIC POWER

Unlike solar power, the output of hydroelectric power plants can be varied to meet load without simply curtailing output. As such, it is not meaningful to attempt to chart hydro availability over the course of a day or a week for a long-term modeling effort. Hydro availability does, however, vary seasonally, with more availability in wet seasons and less in dry seasons. Even the sensitivity to seasonal variations, however, can vary between hydro installations based on individual plant designs. For the Rwanda LEAP model, the EAEP Team developed, again based on 2017 through 2020 output data provided by REG staff, separate hydroelectric availability estimates by plant and by season for the larger Ntaruka, Nyabarongo, and Mukungwa I plants, as well as a composite set of seasonal values for the smaller existing plants hydro plants. Ultimately, however, the EAEP Team decided to use alternative availability factors for the three larger plants based on data in the LEAP dataset prepared by SEI for the Rwanda Water Resources Board.[150] The EAEP Team did so because the values in the SEI LEAP dataset were somewhat higher, and thus may better reflect the actual maximum availability of those plants by season, whereas the values derived from the dataset provided by REG may be somewhat understated for use as maximum availability factors because they are based on actual load data, and thus likely include some periods where output for those plants was reduced due to the need to follow load. The variations of the maximum availability factor for smaller plants by season, which are based on the REG dataset, are shown in Figure 5.D.3-1. These are similar, overall, to the values in the SEI LEAP dataset.

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[150] Data from the SEI LEAP dataset were shared by REG

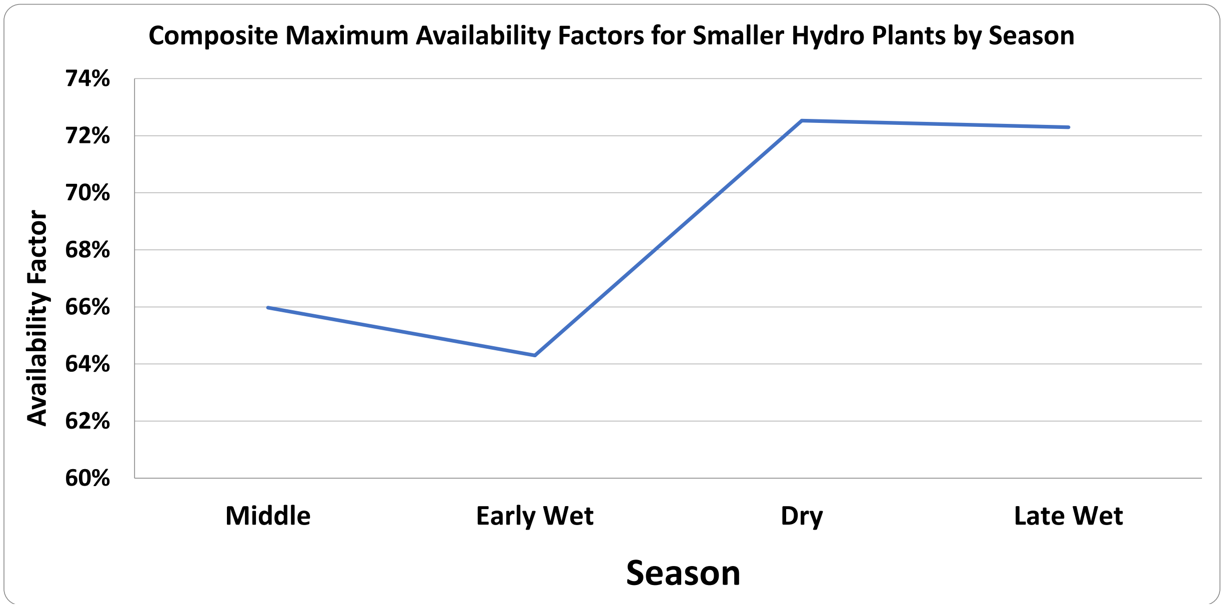

Figure 5.D.3-1 Daily Average Hydro Availability Factors for Smaller Hydro Plants

5.E. ALTERATIVE SUPPLY SCENARIOS

As noted earlier in this section, the EAEP Team modeled a set of seven electricity supply scenarios for Rwanda. These scenarios reflect and extend electricity generation and related supply infrastructure (such as for natural gas imports) starting with the additions to generation considered in the December 2020 LCPDP but adding new generation to meet the substantial growth in Rwandan electricity demand (as described in section 5.B) in the later years of the modeling period. **The scenarios compiled represent quite different ways that Rwanda might go about meeting its future electricity needs.** Overviews of each scenario are provided below, together with results that compare physical outputs, costs, emissions, other attributes of the scenarios. **In practice, REG and other Rwandan stakeholders will likely explore and choose a way forward for the electricity sector that includes elements of many, or all of the scenarios explored here, thus the goal of the work reported on below is to inform planners and policymakers as to the benefits, costs, and risks associated with different electricity supply paths.**

The **key requirements and assumptions** of the seven supply scenarios considered are described in Table 5.E-1.

TABLE 5.E-1. SUMMARY DESCRIPTIONS OF SUPPLY SCENARIOS MODELED			
SCENARIO NAME	SCENARIO CODE	KEY SUPPLY SOURCES AFTER MID-2030S	OTHER FEATURES
New Reference/ Business-as-Usual	REF.1	Diesel and natural gas	Adds some solar, hydro, wind, imports
Limited Hydro	LHY.2	Diesel and natural gas	Limits hydro deployment to plants planned by 2024
All Renewables by 2050	ARN.3	Solar PV, different technologies	Pumped-storage hydro used to meet timing of load, with solar power for pumping
Renewables with Inter-connection	RWI.4 (and RWI.4HE)	Solar PV plus imports from interconnection	Imports play a key role in meeting changing demand; some electricity exports also included
"Net Zero" Rwanda	NTZ.5	As in ARN.3, but expanded	Higher demand, supply due to additional electric end uses
Lake Methane Displacing Natural Gas	LMG.6	Diesel and Lake Kivu methane	Lake methane instead of natural gas, other as in REF.1
Energy Efficiency Improvements	EEI.7	Solar PV, different technologies	As in ARN.3, but lower electricity demand due to efficiency efforts, thus lower supply needs

Table 5.E-2 provides **a summary of scenario results.** Sections that follow, provide additional details of the supply scenarios and selected scenario results. Annex B provides additional detailed results.

The results for each scenario are reported - compared to the *business-as-usual* case - against a series of metrics such as estimated 2050 overall capacity (MW) generated, percentage of renewable supply needed, imports and exports levels (GWh), GHG emissions for the electricity sector and economy-wide, total social costs and total production costs. Other risks (such as fuel price, import dependence, additional pollution) and other benefits (such as reduced competition for water, use of domestic resources, reduced fuel price) are highlighted as well. **Policymakers can look at the different scenarios based on the metric or metrics of interest to identify the most appropriate electricity supply paths in Rwanda.** Considering the expected progress in technologies and decrease in costs, the "all Renewable by 2050" scenario appears one important option for REG to consider. This scenario will offer REG the possibility to contribute to the country's decarbonization targets and leverage its significant renewable resource potential. Adjustments to the scenario could be considered such as increased space for electricity trade if the Regional Power Pool is place by 2050; additional pumped storage hydro; and possible revisions to the demand forecast to reflect a paraphs more realistic growth rate.

TABLE 5.E-2. SUMMARY RESULTS FROM SUPPLY SCENARIOS CONSIDERED

	NEW REFERENCE/ BUSINESS-AS-USUAL	LIMITED HYDRO	ALL RENEWABLES BY 2050	RENEWABLES WITH INTER-CONNECTION	"NET ZERO" RWANDA	LAKE METHANE DISPLACING NATURAL GAS	ENERGY EFF. IMPROVE-MENTS
Scenario Code	REF.1	LHY.2	ARN.3	RWI.4 (and RWI.4HE)	NTZ.5	LMG.6	EEI.7
2050 Electricity Demand	17,350 GWh	As in REF.1	As in REF.1	As in REF.1	29,640 GWh	As in REF.1	14,520 GWh
Capacity in 2050	4,540 MW	4,550 MW	8,810 MW	6,110 MW 7130 MW	17,400 MW	4,540 MW	3,850 MW
Additional Solar for Pumping	None	None	4,200 MW	90 MW 230 MW	5,400 MW	None	None
2050 Renewable Supply[151]	31%	20%	100%	100%	100%	29%	36%
2050 GWh Imports	2,000 GWh	2,030 GWh	2,140 GWh	11,300 GWh 11,600 GWh	1,800 GWh	1,770 GWh	1,930 GWh
2050 GWh Exports	None	None	None	1020 GWh 2500 GWh	None	6 GWh	None
Electricity Sector 2050 GHG Emissions	7.45 $MTCO_2e$	8.55 $MTCO_2e$	0.006 $MTCO_2e$	0.006 MTCO2e	0.005 $MTCO_2e$	7.77 $MTCO_2e$	6.40 $MTCO_2e$
Economy-wide 2050 GHG Emissions	19.1 $MTCO_2e$	20.3 $MTCO_2e$	10.9 $MTCO_2e$	10.9 MTCO2e	1.86 $MTCO_2e$	19.5 $MTCO_2e$	17.3 $MTCO_2e$
Total Social Cost Rel. to REF.1[152]	N/A	1.7 $B *1.6 $B*	-5.3 $B *-2.1 $B*	-6.0 $B /-5.7 $B *-5.7 $B /-4.8 $B*	-11.7 $B *-5.5 $B*	0.1 $B *1.4 $B*	-2.1 $B/*2.2 $B*
Total 2050 Electricity Prod. Cost Rel. to REF.1[153]	N/A	110 $M, *110 $M*	-690 $M, *-610 $M*	-560 $M /-520 $M *-550 $M /-490 $M*	-360 $M *200 $M*	-7.4 $M/*18.4 $M*	-280 $M,*-250 $M*
Other Risks[154]	Heavy fuel price risk, additional pollution	Heavy fuel price risk, additional pollution	More difficult load balancing vs. REF.1	Import dependence, import price risk	Load balancing, meeting additional demand	Additional diesel price risk	Performance risks for efficiency policies, programs
Other Benefits	Proven technologies	Reduced competition for water	Use of domestic resources, less fuel price risk, more energy sector employment	Enhanced economic integration with Region	Domestic resources use, less fuel price risk, more energy sector employment	Reduced gas import needs, emissions	Somewhat reduced fuel price risks, more energy sector employment

[151] Calculations of the fraction of electricity supplies as renewable assume that electricity imported into Rwanda is from renewable sources.
[152] Total economy-wide costs summed through 2050 relative to REF.1 Case. Costs are in 2020 US dollars calculated using real interest rates of 5%/yr and 15% yr, the latter in *italics*, and a real discount rate of 5%/yr.
[153] Costs of electricity generation in 2050 relative to REF.1 Case are in 2020 US dollars calculated using real interest rates of 5%/yr and 15% yr, the latter in *italics*, and a real discount rate of 5%/yr.
[154] The "Other Risks" and "Other Benefits" rows here describe selected major additional attributes of the supply scenarios but are not intended to provide an exhaustive listing of those attributes.

Some key takeaways from the table above could be summarized as follow:

- From the perspective of increasing renewable electricity generation, the "All Renewables", the "Renewables with Interconnection" and "Net Zero Rwanda" scenarios offer the greater potential.
- From a GHG emissions perspective, the *All Renewabl*es scenario allow to drive power sector emissions down to nearly zero by 2050.
- From the perspective of 2050 electricity demand needs, the "Net Zero Rwanda" scenario drives a much higher demand for electricity by 2050 to the extent that that most fossil-fueled end-uses move to electricity by 2050.
- From a production costs perspective, the *All Renewables* scenario show much less costs because fuel costs for diesel and natural gas are high and won't expose Rwandan generators and electricity consumers to the risk that fuel prices will rise even higher than forecast (as it might be the case under other scenarios).
- From the perspective of increasing domestic production, the "Renewables with Interconnection" scenario implies that Rwanda will have much more import dependence in its electricity sector and will thus be at risk if imported electricity prices rise substantially. This scenario does, however, offer the opportunity for—and in fact, requires—enhanced economic integration with the nations of the East Africa Region.
- In terms of other co-benefits, for instance, the "Limited Hydro" scenario would reduce competition for the water that the avoided hydroelectric plants would have at least partially diverted, including water relied upon by agriculture, cities, and downstream ecosystems.

5.E.1. NEW REFERENCE/BUSINESS-AS-USUAL ("REF.1")

The "New Reference" (so named to distinguish it from earlier reference cases developed by the EAEP Team) or "Business-as-Usual" electricity supply scenario uses capacity additions provided in latest LCPDP, mostly for hydroelectric generation, but for some other technologies as well, and extends those additions through 2050 by adding capacity by type at about the same pace as provided in the LCPDP, to the extent that resources allow. Specific additions to capacity include:

- 320 MW of hydro by 2050 starting in 2028;
- Imports from the regional interconnection expand to 320 MW by 2050 (imports are assumed to generated from carbon-free resources, subject to confirmation);
- 25 MW of lake methane capacity are added every 5 years starting in 2034, in addition to plants already listed in the LCPDP;
- No new peat-fired plants are added;
- 10 MW of solar (utility class I) are added annually from 2028 to 2040, with 20 MW added annually thereafter; and
- The gap in power needs is filled with diesel-fired plants and with plants fired with imported natural gas after 2032, in an overall ration of 50%/50% diesel/gas, with one third of gas capacity being of the simple cycle type, and two-thirds using combined-cycle technology

As shown in Figure 5.E.1-1, **diesel and natural gas capacity increase rapidly from the mid-2030s through 2050 to meet demand. The total of all nameplate capacity in the REF.1 case is about 4600 MW by 2050.** Electricity output in this case by 2050 (see is approximately 19,000

GWh/yr, with diesel and gas-fired capacity contributing nearly two-thirds of the total by 2050. **By 2050, greenhouse gas emissions in the REF.1 case are about 8 million tonnes of CO_2e/yr from the electricity sector alone.** Most GHG emissions are from diesel and natural gas plants, but some are from peat- and lake methane-fired plants, as both peat and lake methane, having been produced over a time period of thousands or millions of years, are not considered to be renewable resources.

The *New Reference* case, as it relies heavily on imported diesel fuel and natural gas for generation, would leave the Rwandan electricity system at significant risk of fuel price increases, as well as markedly increasing the emissions of GHGs and other air pollutants relative to the current situation. REF.1, however, does rely on proven technologies that are easily controlled to meet loads by operators.

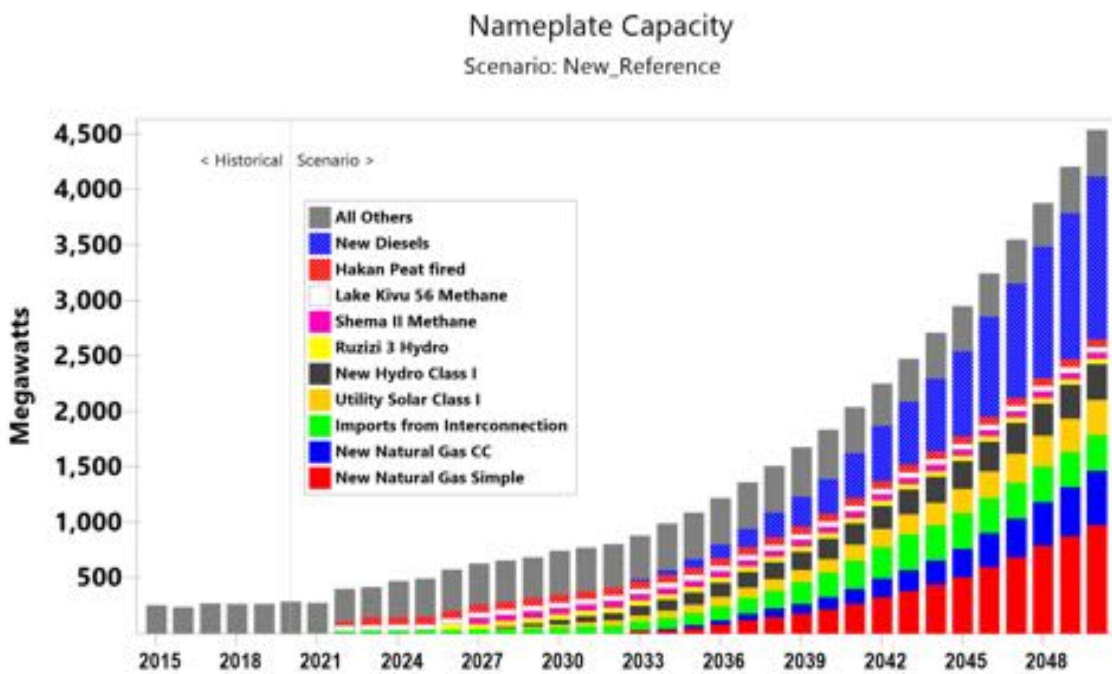

Figure 5.E.1-1 Nameplate Capacity by Year for REF.1 Supply Scenario

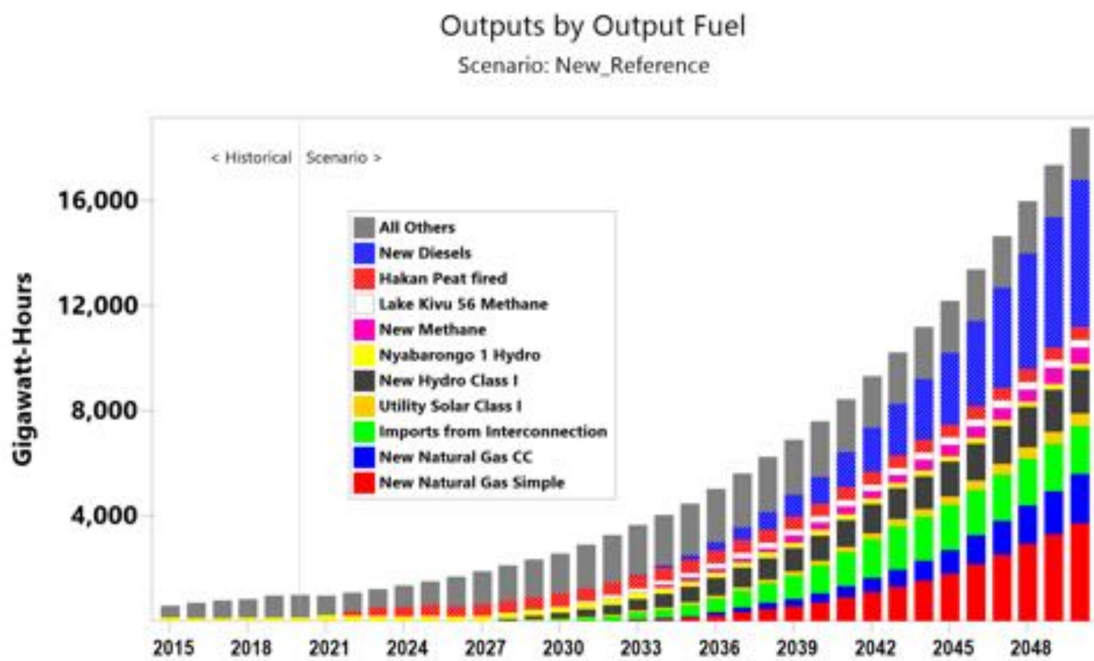

Figure 5.E.1-2 Output by Capacity Type by Year for REF.1 Supply Scenario

5.E.2. LIMITED HYDRO ("LHY.2")

The *Limited Hydro* scenario includes capacity additions and electricity demand largely as described in the New Reference case but reduces added hydro capacity to roughly match the levels used in the LEAP model prepared by SEI for the Rwanda Water Board.[155] Reasons for reducing hydroelectric deployment include concerns about having enough water for downstream uses, such as agriculture, use by cities, and maintenance of aquatic life, as well as concerns about how climate change may affect water resources. As such, in the LHY.2 case, hydroelectric development is largely curtailed after 2024, leaving hydro capacity at about 200 MW (a bit more than in the SEI model), with no subsequent additions through 2050. This case also includes, based on a suggestion by REG, about double the capacity of new Lake methane power plants relative to the REF.1 case, otherwise planned additions as in REF.1.

The differences between REF.1 and LHY.2 capacity by year are shown in Figure 5.E.2-1. **There is additional need for diesel and natural gas capacity in the LHY.2 case to 2050 relative to REF.1, due to the decrease in hydropower deployment**. Bars shown in the bottom half of the figure show hydro types and individual plants displaced in LHY.2. The blue and red bars at the top of the figure show generators that need to be added to make up for the hydro reduction.

Error! Reference source not found. Figure 5.E.2-2 shows a production cost comparison, discounted a t a rate of 5%/yr, between the REF.1 and LHY.2 supply scenarios. Bars at the top of the figure show the added cost of new generation needed to make up for the reduced hydroelectric deployment in LHY.2, while the bars at the bottom show the hydro costs avoided. **Additional fuel costs for diesels and natural gas plants under LHY.2 dominate the comparison, which uses an interest rate of 5%/yr for new additions.**

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155 Note that, as indicated earlier in this section, electricity demand in the SEI LEAP Model is much lower than in REF.1 and the other scenarios described in this report.

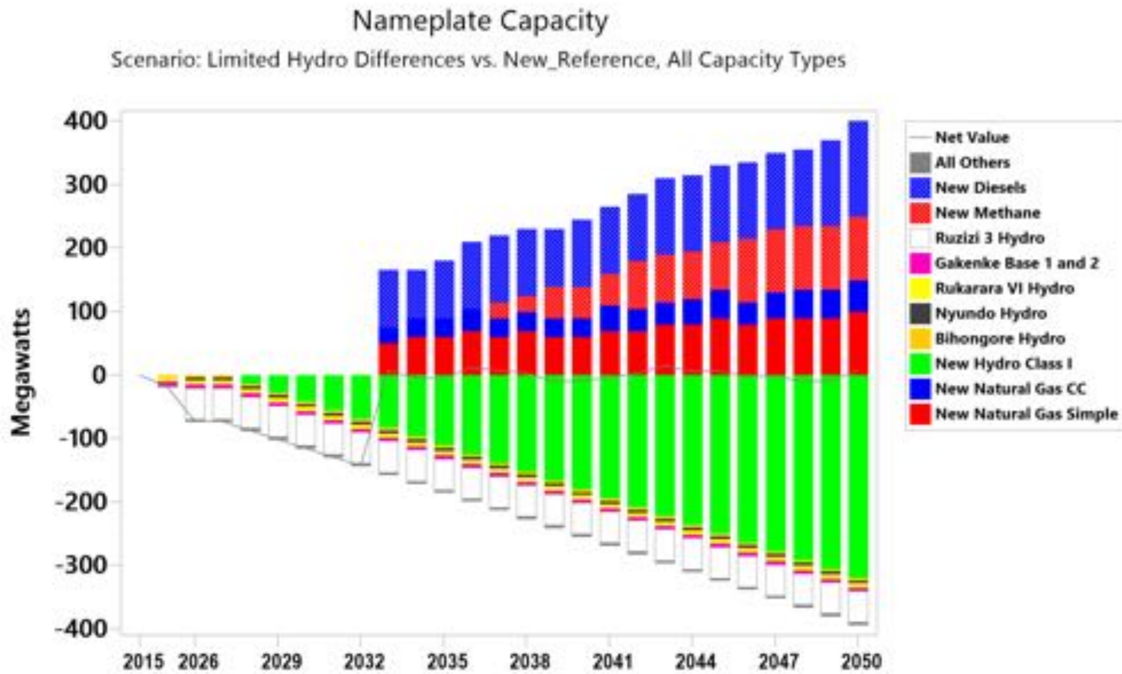

Figure 5.E.2-1 Capacity Differences by Type by Year for the LHY.2 versus the REF.1 Supply Scenario

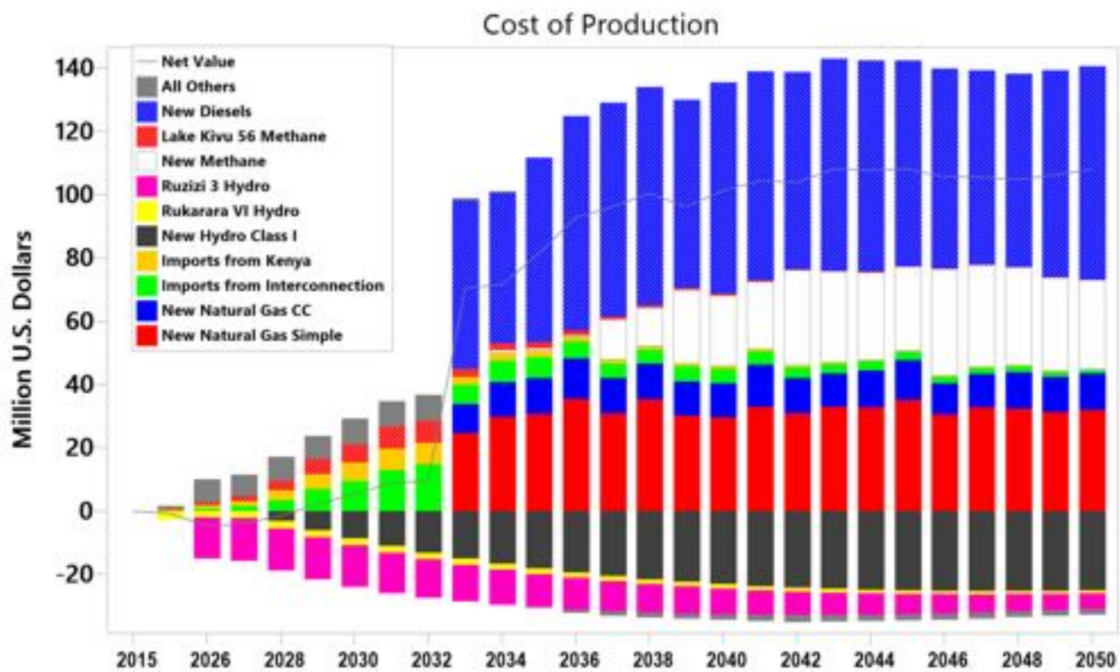

Figure 5.E.2-2 Production Cost Differences by Capacity Type by Year for the LHY.2 versus the REF.1 Supply Scenario

To a slightly greater extent than the REF.1 case, **LHY.2 scenario exposes Rwandan generators and electricity consumers to the risk that fuel prices will rise even higher than forecast, with additional GHG and other air pollutant emissions even beyond those of the New Reference case. The LHY.2 case would, however, reduce competition for the water** that the avoided hydroelectric plants would have at least partially diverted, including water relied upon by agriculture, cities, and downstream ecosystems.

5.E.3. ALL RENEWABLES BY 2050 ("ARN.3")

The *All Renewables* by 2050 scenario modifies the *New Reference* scenario by assuming that all electricity generation will be renewable by 2050. This means that most additions beyond Reference-level hydro will be solar to meet demand. All of the types of solar PV generation described in Section 2, above, are included in this scenario. This includes distributed generation, with distributed generation (residential and industrial/commercial/institutional) modeled on the supply side.[156] **Wind power is also added, in modest amounts,** including 50 MW of 50 m hub height turbines, and 200 MW of larger 100 m hub height turbines, by 2050. **25 MW of biomass-fired capacity is added by 2050, but no more waste-to-energy capacity is added than is included in REF.1. Battery energy and pumped storage hydro capacity (and/or a future electricity storage technology of similar capability) are added to balance loads.** Peat and Lake methane plants phased out by the scheduled end of life of existing and new facilities or 2050, whichever comes first.

Considerable solar capacity is added in the ARN.3 case, including utility-scale (up to grid integration cost Class II), agrivoltaics, floating systems and distributed solar with and without battery energy storage (BES), as well as utility-scale and distributed solar with BES. The split between BES and non-BES solar systems is assumed to be about 60-40 by 2050. In addition, the energy required for pumped-storage hydro is assumed generated by solar PV systems at the utility scale, with pumped-storage hydro assumed to be 77.5% efficient in converting pumping energy to electricity output when needed to the grid. **The result of these additions is a requirement for overall nameplate capacity that much higher than in REF.1 due to the low capacity factors of solar (and to a lesser extent, wind) generation**. A total of nearly 9000 MW of on-grid capacity is required under the ARN.3 case by 2050, plus an additional 5400 MW of solar PV capacity needed by 2050 to power pumped-storage hydro.

From a GHG emissions perspective, **the ARN.3 case drives power sector emissions down to nearly zero by 2050** mostly due to peat and methane power plants phased out, with solar additions making up the difference, and no use of fossil fuels for generation by 2050. Figure 5.E.3-1 shows GHG emissions going nearly to zero in 2050 in the *All Renewables* case.

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156 Another way to model distributed generation is to include it on the demand side, as, effectively, negative electricity consumption. This modeling method allows needs for transmission and distribution to be offset, which is one important impact of distributed generation, but the EAEP Team has chosen in this instance to model distributed generation on the supply side to make modeling results easier to interpret.

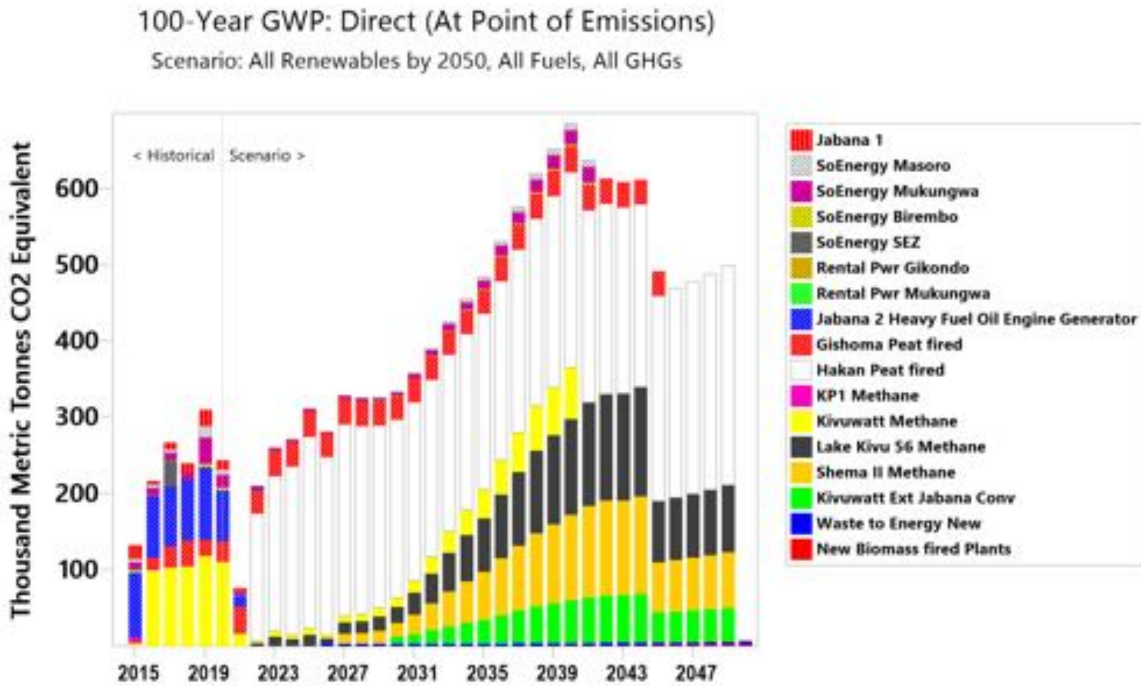

Figure 5.E.3-1 GHG Emissions by Generator/Type in ARN.3

A comparison of production costs between the ARN.3 scenario and the REF.1 case, discounted at 5%/yr and using an interest rate for initial costs of 5%/yr, is shown in Figure 5.E.3-2. **The production costs shown under the ARN.3 scenario are much less because fuel costs for diesel and natural gas are high.** Note that this figure does not include the costs of providing solar power for pumped storage, but even including those costs, which add about $100 million annually (discounted) annually to ARN.3 costs in 2050, still leaves the *All Renewables* case much less expensive than REF.1. The cost difference is mostly driven by the costs for diesel and natural gas avoided by moving to the ARN.3 case. The comparison of production costs can be done using a higher interest rate of 15%/yr for installed costs, which might be more indicative of the rates of return that unsubsidized private investors in renewable generation in Rwanda might require. The use of higher interest rates erodes, but do not fully offset the cost differences shown in the figure below, even when including costs of solar for pumping, which increase about 2-fold at a 15% versus a 5%/yr interest rate.

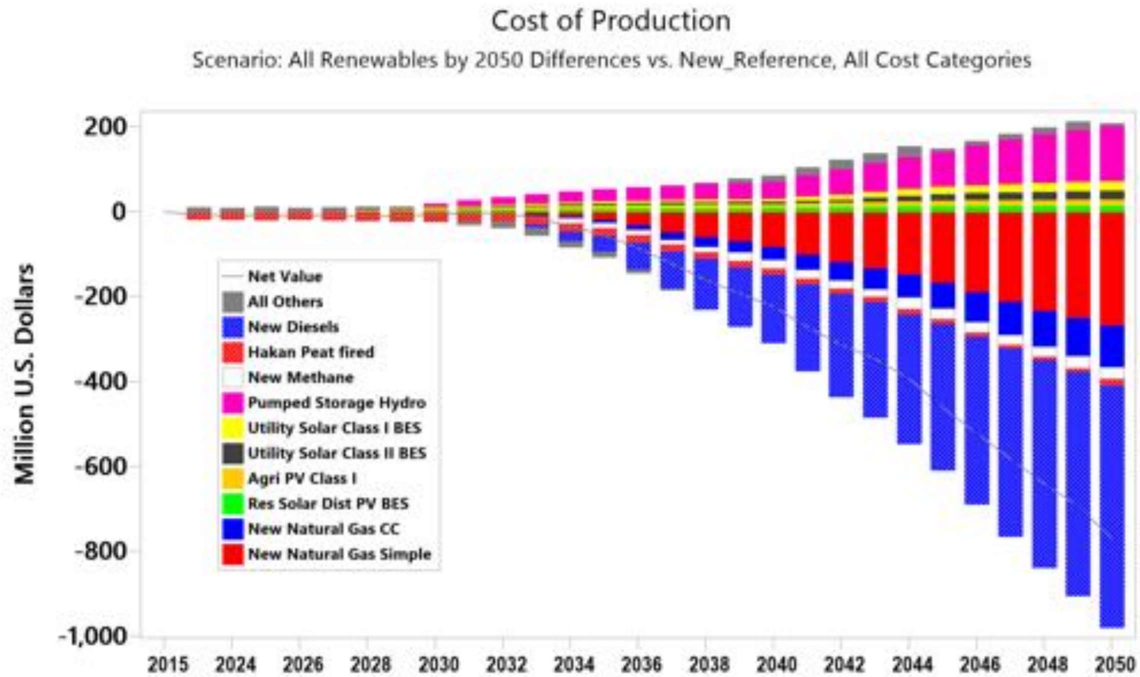

Figure 5.E.3-2 Costs of Electricity Production by Generator/Type in ARN.3 Relative to REF.1

With regard to other criteria for comparison, **the ARN.3 scenario would make for more difficult balancing of electricity supply and demand relative to REF.1, as it includes much more capacity whose output is intermittent.** On the other hand, the ARN.3 scenario provides much greater use of domestic resources for generation, offers less of fuel price shocks, and will likely provide much more energy sector employment than the New Reference case.

5.E.4. RENEWABLES WITH INTERCONNECTION ("RWI.4")

The Renewables with Interconnection scenario modifies ARN.3 by displacing renewables with electricity imports from grid interconnections between Rwanda and its neighbors. This scenario includes additional exports from Rwanda to its neighbors, presumably of excess solar production when available, although exports are assumed to be about one tenth of imports by 2050. The RWI.4 scenario starts with the assumption that solar generating capacity (in all technology types) will grow only half as fast as in the ARN.3 scenario and adds carbon-free imports from the interconnection in equal amounts as needed by the model to avoid unmet demand. As such, the RWI.4 scenario adds to the 320 MW of import capacity from an assumed regional interconnection that is already in ARN.3 and REF.1, with import (and export) transmission capacity rising to 2100 MW by 2050.

The analysis of imported electricity in the Rwanda LEAP model assumes an average real purchase cost of $100 per MWh is sustained through 2050. This is the same as REG indicates as current cost for imports from Kenya. The model does not independently estimate the installed costs of transmission lines, rather the $100/MWh cost assumption is assumed to be inclusive of both the cost of transmission lines and the value of generation to the exporting country.

Figure 5.E.4-1 shows **the decrease in overall capacity in the *Renewables with Interconnection* Scenario relative to ARN.3 that occurs because imports have a higher capacity factor than do solar technologies.** The RWI.4 case also provides a 96% decrease in the solar capacity required

for pumping relative to the ARN.3 case, because imports are available to balance loads, so much less pumped storage is needed. As noted above, **it is assumed for the sake of GHG emissions comparisons that that electricity imports from neighbors are carbon-free,** likely, by the 2030s and beyond, based on hydro and solar, but that may not prove to be the case if the plentiful fossil fuels available to some of Rwanda's neighbors end up being used to generate electricity for exports.

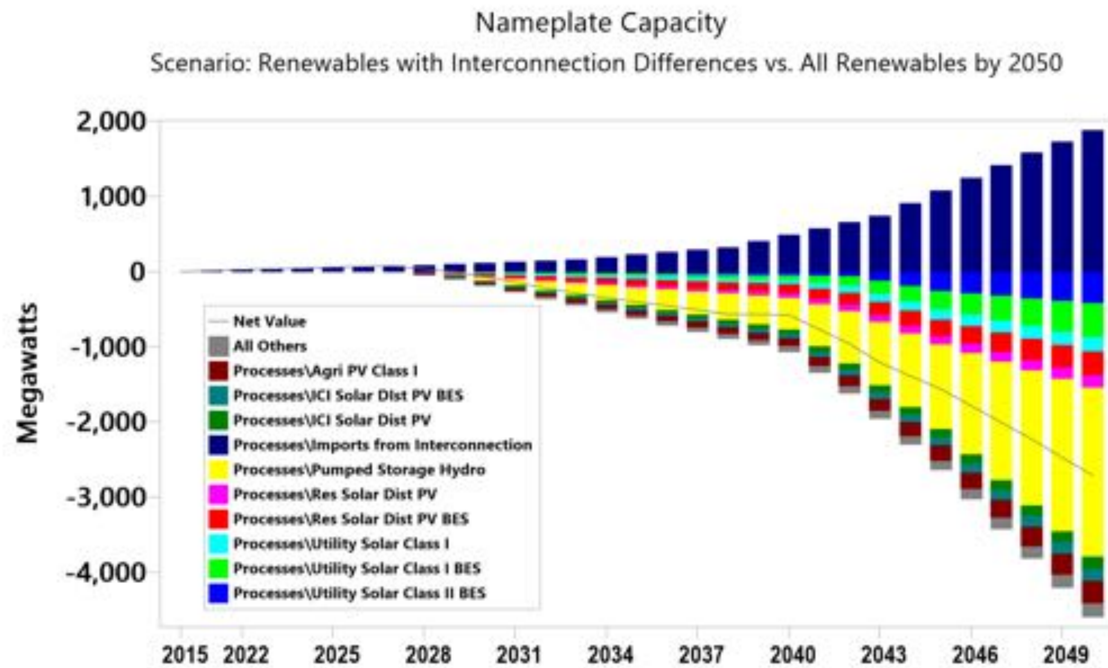

Figure 5.E.4-1 Nameplate Capacity Differences by Type by Year for the RWI.4 versus the ARN.3 Supply Scenario

Figure 5.E.4-2 presents a comparison of the costs of electricity production between the Renewables with Interconnection case and ARN.3, using real discount and interest rates 5%/yr. Here **imports displace the costs of renewable additions and pumped storage.** Although the costs of RWI.4 are shown as higher here, the additional displacement of solar costs due to avoidance of the capacity need to power pumped storage, which amounts to over $70 million per year by 2050 (discounted), and the value of electricity exported under this case, at about $23 million per year by 2050 (again discounted) tip the costs, in a discounted comparison, to the RWI.4 scenario, with the costs of the RWI.4 case being about $50 million per year lower than costs in the ARN.3 case by 2050. Note, however that realizing these net cost benefits of the RWI.4 case depends on Rwanda being able to consistently purchase imports and sell exports at on the order of $100/MWh. If a higher interest rate (15%/yr) were used to estimate the annualized initial costs of power plants, it would tip the balance (discounted) further toward imports, and the avoided costs of solar capacity for pumping makes the benefits of the RWI.4 case still larger relative to the ARN.3 scenario.

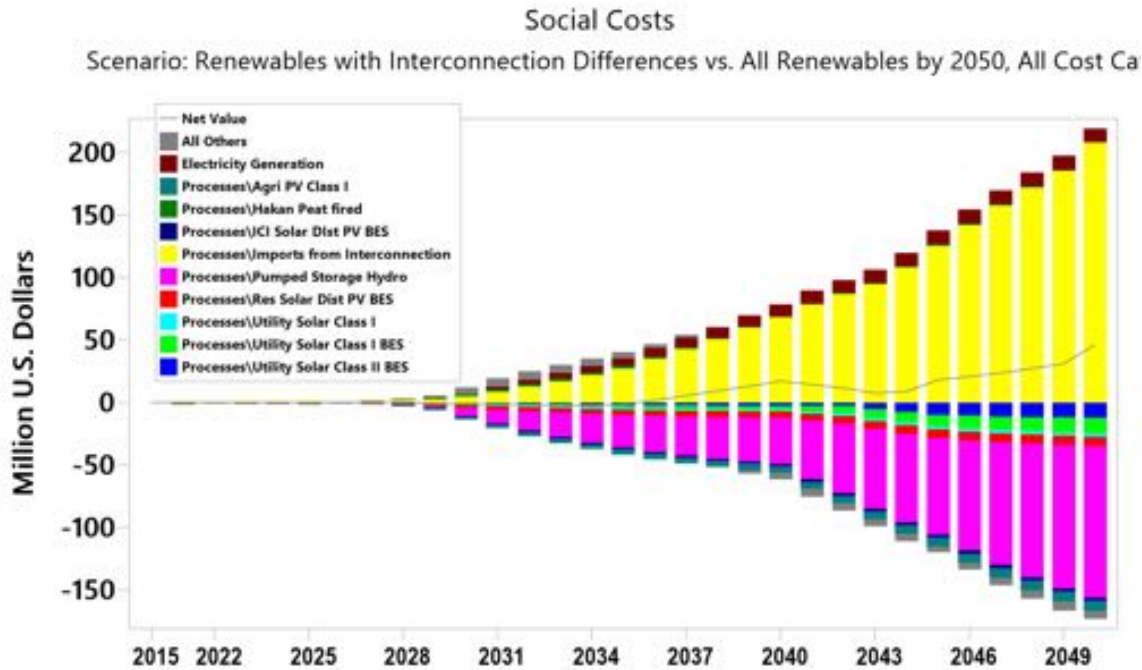

Figure 5.E.4-2 Social Costs of Electricity Production by Generator/Type in RWI.4 Relative to ARN.3 (Using an interest rate of 5%/yr)

Although it avoids the need for substantial generation capacity, relative to ARN.3, **the RWI.4 scenario means that Rwanda will have much more import dependence in its electricity sector and will thus be at risk if imported electricity prices rise substantially**. The RWI.4 scenario does, however, offer the opportunity for—and in fact, requires—enhanced economic integration with the nations of the East Africa Region.

At the request of REG, the EAEP Team prepared a variant of the RWI.4 scenario to test its sensitivity to increasing the ratio of electricity exports from Rwanda to electricity imports to Rwanda. **In this variant, named "RWI.4HE", denoting higher exports, it was assumed that exports will be 2.5 times the level in RWI.4, or about 22 percent of imports.**

The higher exports variant of RWI.4 requires that Rwanda develops more solar capacity, in this case assumed to be a mix of different types, and particularly additional solar capacity with battery energy storage and pumped storage hydro, in order to balance loads (Figure 5.E.4-3).[157] About 1000 MW of additional domestic capacity is needed by 2050. **This is because**

[157] This sensitivity case could, alternatively, have been modeled simply by increasing imports to cover the additional assumed exports. This approach would require additional interconnection capacity, which is not costed separately from the bulk power cost assumption in this analysis and would have resulted in no changes in required domestic generation relative to the RWI.4 case. The net cost difference between the RWI.4HE case and the RWI.4 case would in this modeling approach (increasing gross imports) have been near zero, as additional costs for imported electricity would be made up by additional revenue for exports. If the assumption that both imports and exports are valued at $100/MWh were independently varied, cost results would be different. In practice, assuming the eventual development of an East Africa Power Pool or similar, the cost of imports to Rwanda and the value of exports from Rwanda may well vary markedly even from hour to hour, depending on what types of generation are developed in Rwanda and by its neighbors to feed power into the interconnection.

additional exports mean that imports cannot provide as much power, on a net basis, to balance domestic Rwandan loads. The social costs of the variant with greater exports are about $50 million per year more expensive in 2050 than the RWI.4 case with exports set at about 10 percent, but those additional outlays are about 75 percent offset by the combination of a reduction in the need for solar PV power for pumped storage plus sales of exported power. On a net basis, there is therefore not much difference in cost between the RWI.4 case and its higher-exports variant.

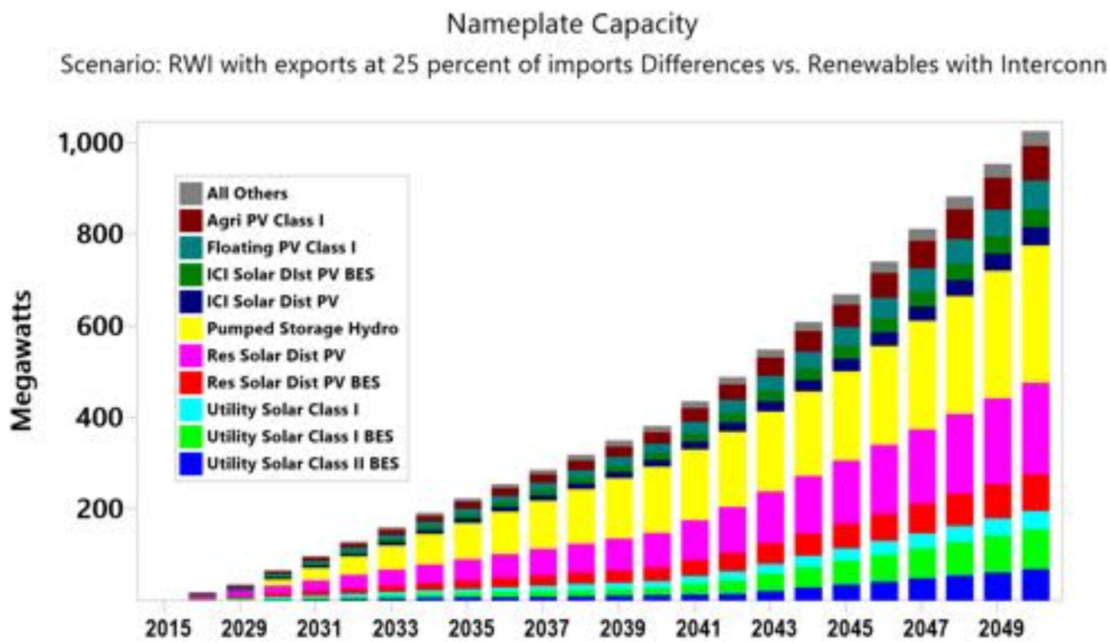

Figure 5.E.4-3 Nameplate Capacity Differences by Type by Year for the RWI.4HE variant Versus the RWI.4 Supply Scenario

5.E.5. “NET ZERO” RWANDA (“NTZ.5”)

The *“New Zero” Rwanda* scenario modifies the *All Renewables* electricity supply scenario by further assuming that most fossil-fueled end-uses move to electricity by 2050. As such, the NTZ.5 case adds renewable generation (largely solar) to ARN.3 to meet new load that is primarily in the transport sector, but also in the industrial, commercial/institutional, and household sectors, where fossil fuel use is substituted for by electricity. In evaluating the relative costs of this case, the EAEP Team did not include demand-side costs for switching to electricity, as many of these are or may become negative in the next two decades anyway, particularly if maintenance savings for electric versus fossil-fueled devices are factored in. In practice, some fossil fueled end uses may be converted to fossil-free status by converting devices to use renewable-derived “green” fuels such as hydrogen or ammonia over time. This approach for some end uses can be added by later users of the EAEP Rwanda LEAP model. Note that this scenario does not actually provide a complete picture of a “Net Zero” carbon emissions economy for Rwanda, because this modeling covers only energy sector, focusing on electricity, but it could be used as a tool for Rwandan stakeholders to explore more comprehensive GHG emissions reduction scenarios in the future.

Figure 5.E.5-1 shows **the trend in total generation capacity under the NTZ.5 scenario, which is much higher than even the amount needed in the ARN.3 case due to the much higher**

demand for electricity by 2050. Solar capacity additions with and without BES dominate overall capacity by 2050, even though Figure 5.E.5-1 does not include the additional 5,400 MW of solar capacity needed to supply the energy to pumped storage hydro plants by 2050. **Outputs of electricity under this case are also higher than in any of the other cases,** as shown in Figure 5.E.5-2, with outputs from various types of solar technologies providing most of the additional generation relative to the ARN.3 case.[158]

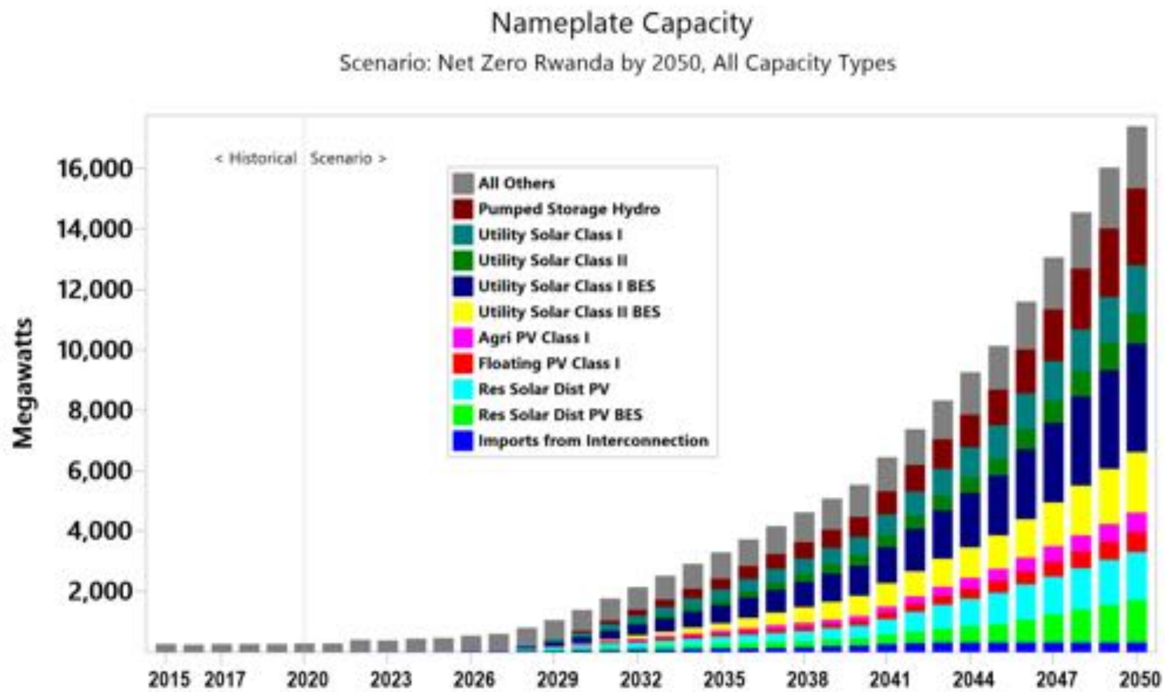

Figure 5.E.5-1 Nameplate Capacity by Type by Year for the NTZ.5 Supply (and Demand) Scenario

As shown in Figure 5.E.5-3 below, **the NTZ.5 scenario avoids 90 percent of REF.1 scenario GHG emissions in the Rwanda energy sector by 2050.** This is accomplished, as shown in Figure 5.E.5-4 at a net negative social cost over the entire energy sector, as fossil fuel costs avoided in the demand sectors (particularly transportation) and in electricity generation outweigh additional costs for solar and other generation in the electricity sector.

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158 The small amount of generation shown as displaced (values less than zero) correspond mostly to reduced hydro generation in the model due to the additional availability of solar generation. In a real-world implementation of this scenario in Rwanda, this would likely not occur (or be much less pronounced), as less solar generation would be added to allow hydro to run to capacity, or possibly some of the hydro output shown here as deferred could be directed serve power export markets, in an interconnected East Africa grid.

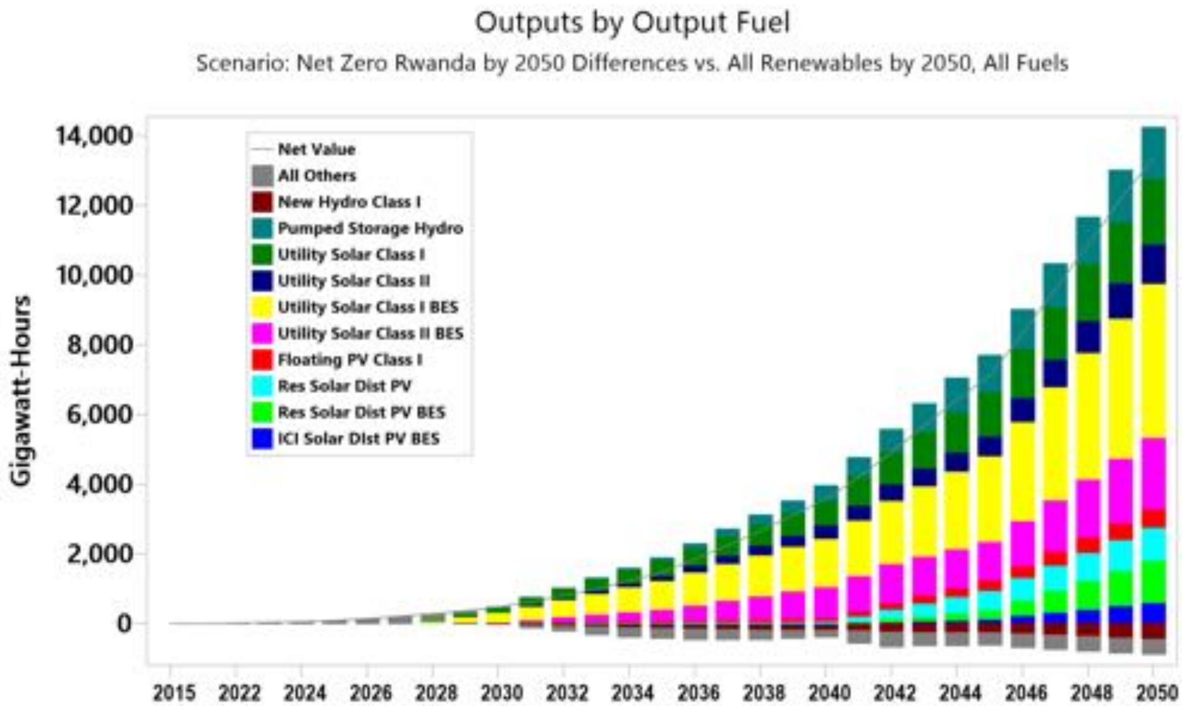

Figure 5.E.5-2 Output by Type of Capacity by Year for the NTZ.5 Supply Scenario Relative to the All Renewables Case

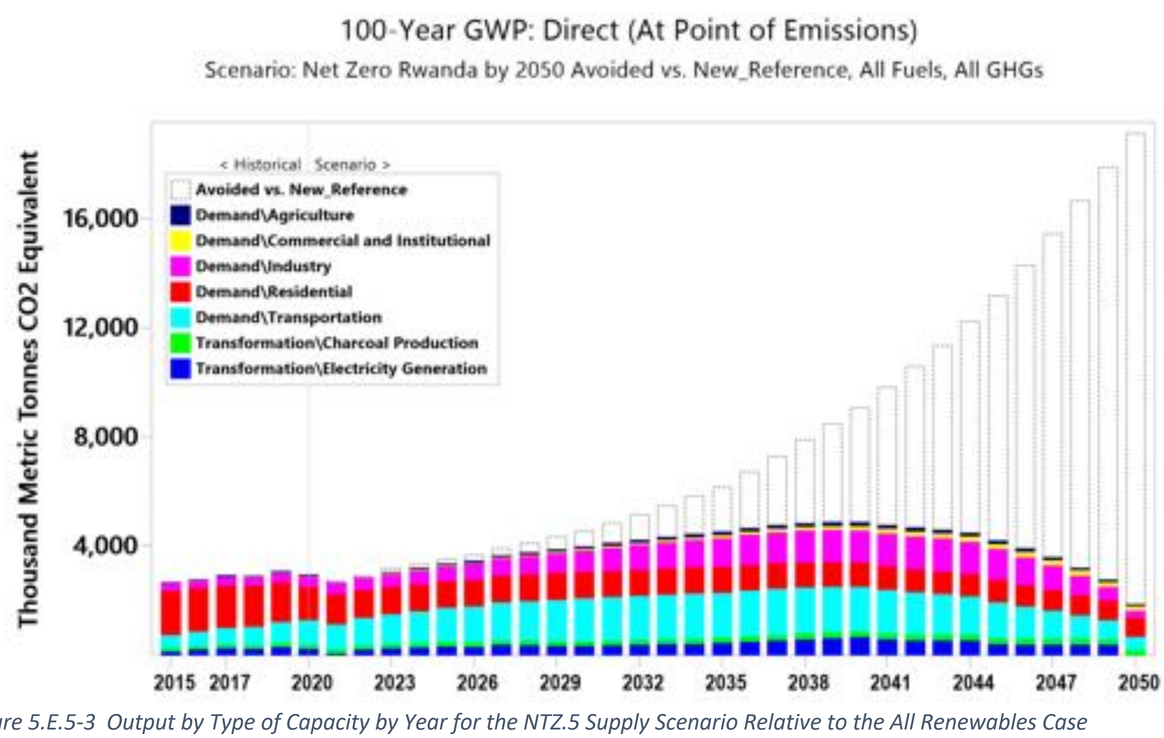

Figure 5.E.5-3 Output by Type of Capacity by Year for the NTZ.5 Supply Scenario Relative to the All Renewables Case

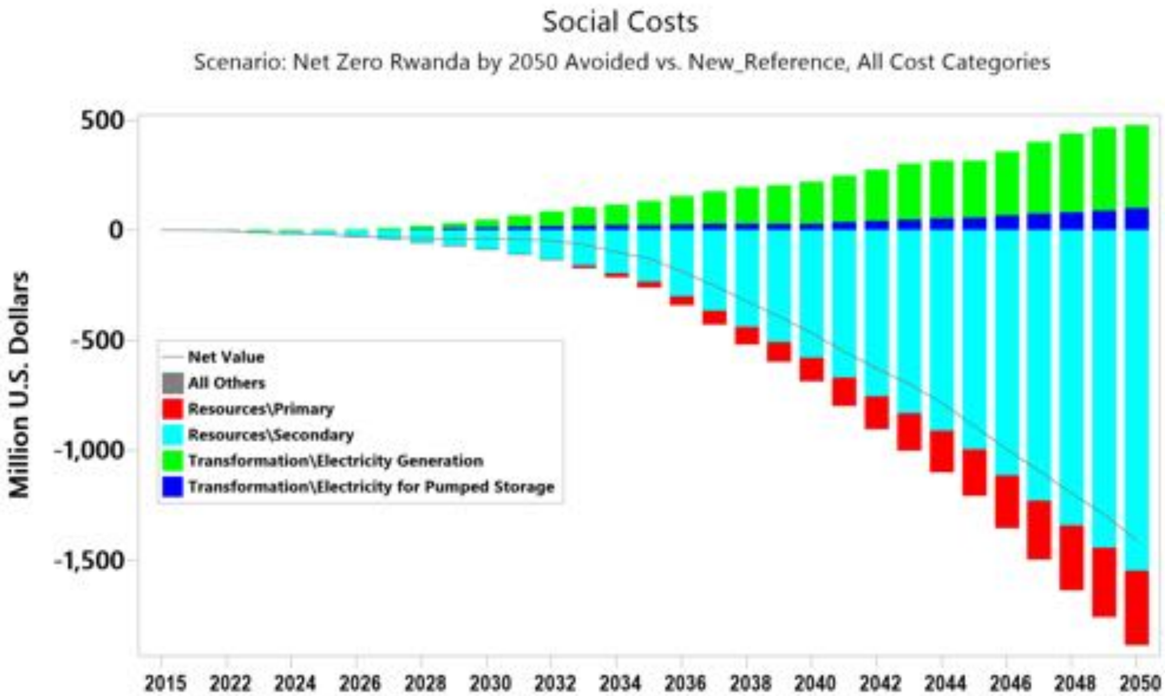

Figure 5.E.5-4 Social Costs of Energy Sector Activities in Rwanda in the NTZ.5 Scenario Relative to the New Reference Case (Using an interest rate of 5%/yr)

The NTZ.5 scenario, relative to other cases, requires **more effort and organization go into balancing of electricity supply and demand**, given the dominance of intermittent resources in meeting a much larger load than in REF.1. In return, it offers **much expanded use of domestic resources, much less fuel price risk** than scenarios relying on imported fuel or power, and **more energy sector employment**, in addition to its benefits for the global and local environment.

5.E.6. LAKE METHANE DISPLACING NATURAL GAS ("LMG.6")

The *Lake Methane Displacing Natural Gas* scenario modifies REF.1 by assuming that natural gas will not be available, or will not be used for generation, in Rwanda. As such, the gas-fired generation used in REF.1 is either replaced with Lake methane-fueled power, to the limit of the resource, or by diesel power plants. This scenario, added at the suggestion of REG staff, is designed partly to provide a public safety service by reducing the probability of a CO_2/methane limnic eruption in the Lake Kivu area, and partly to use domestic resources. In the LMG.6 case, Lake methane plants are added with diesel plants in a 1:2 capacity ratio as demand for electricity rises. Thus, **Lake methane displaces most of the natural gas used in REF.1, and diesel displaces the rest.** By 2050, in the LMG.6 case, approximately 60-70% of Rwanda's share of the Lake Kivu methane resource will have been used in new and planned/existing plants.

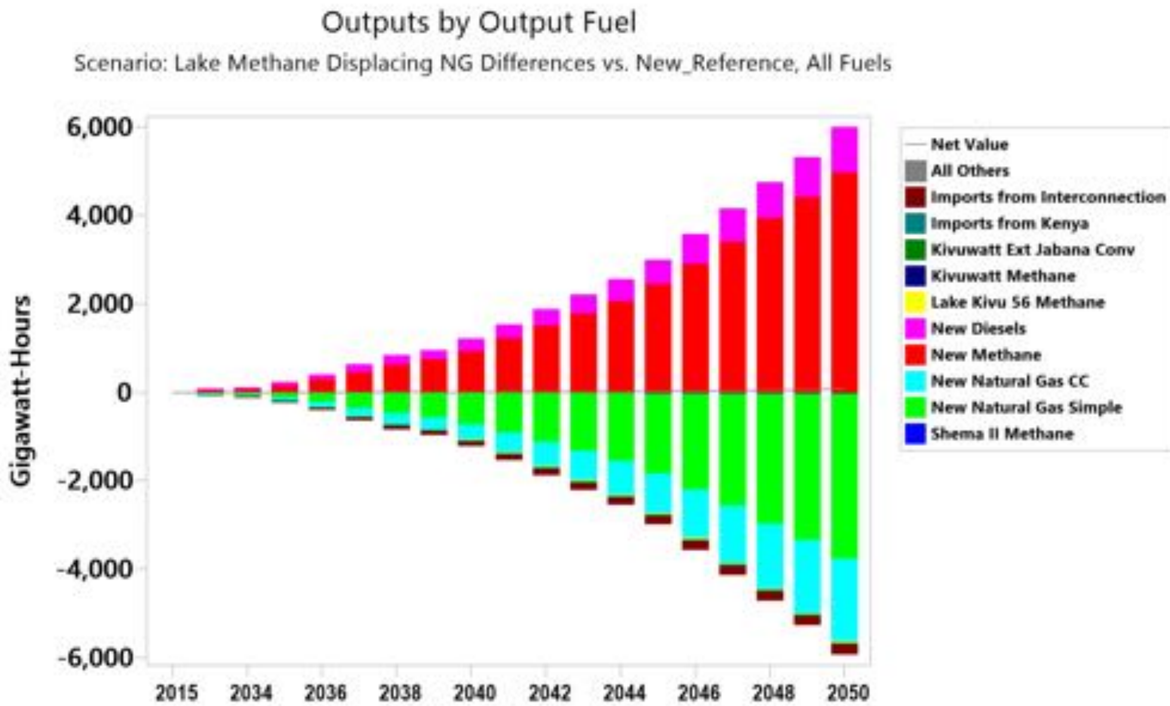

Figure 5.E.6-1 Output by Type of Capacity by Year for the LMG.6 Supply Scenario Relative to the New Reference Case

Additional costs for electricity generation (O&M, annualized initial costs, diesel) essentially in the Lake methane generation case essentially offset savings in natural gas imports relative to REF.1 (discounted at 5%/yr, and calculated at an interest rate at 5%/yr), as shown in Figure 5.E.6-2.

Additional considerations for the LMG.6 case relative to the REF.1 include additional diesel price risk, offset by reduced gas import needs (and reduced gas price risks). **Emissions of non-GHG pollutants would likely be slightly higher** in the LMG.6 case, although the use of additional Lake methane might reduce risks of an overturn of lake waters that would be catastrophic for the nearby population—although the effects of reduction of deep methane and carbon dioxide levels in Lake Kivu on the risk of such an event have yet, so far as the EAEP Team knows, to be fully investigated.

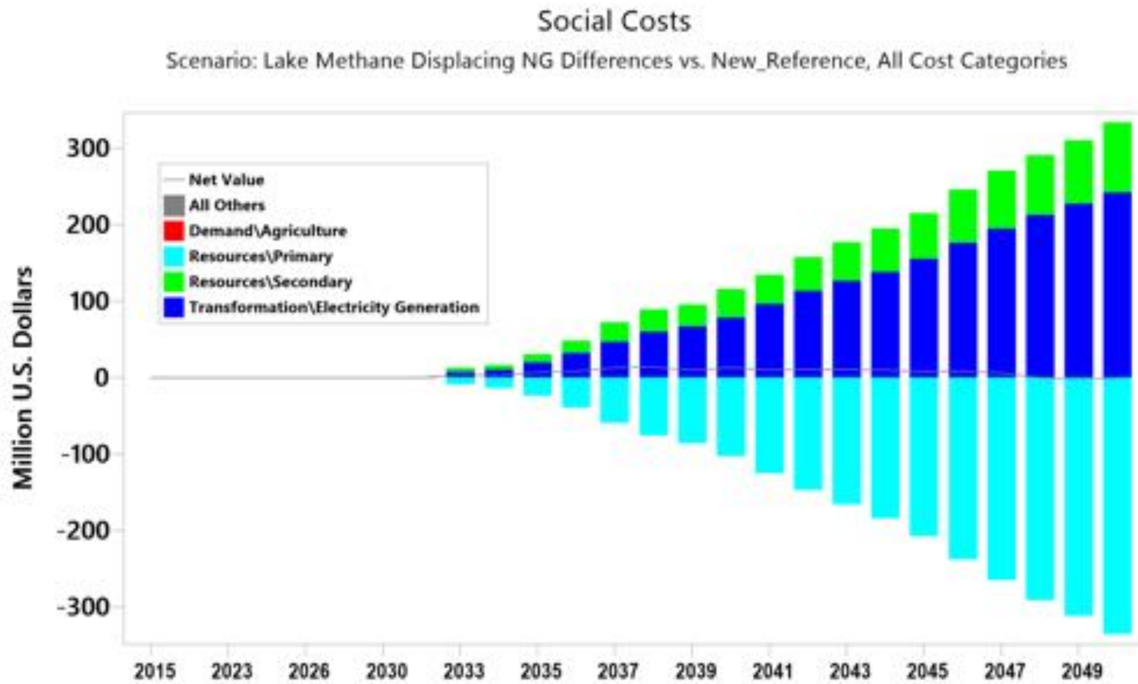

Figure 5.E.6-2 Social Costs of Energy Sector Activities in Rwanda in the LMG.6 Scenario Relative to the New Reference Case (Using an interest rate of 5%/yr)

5.E.7. ENERGY EFFICIENCY IMPROVEMENTS ("EEI.7")

The Energy Efficiency Improvements scenario modifies REF.1—and could also be applied to modify ARN.3 and NTZ.5 in future modeling—by employing electricity energy efficiency improvements throughout the demand sectors. Except when calculated directly from incremental device costs, the costs of energy efficiency improvements were assumed to be in the range of 20 to 40 USD/MWh, based on US and other utility experience. A central value of 31.7 USD/MWh (2020 USD) based on a 2015 study by the American Council for an Energy Efficient Economy (ACEEE) was used for most end-use energy efficiency applications modeled.[159] This scenario displaces the need for marginal generation in each case. In the REF.1, this means diesel and natural gas generation, but if applied to ARN.3 or NTZ.5, renewable generation would be offset. Results for differences with REF.1 only are presented here. Energy efficiency improvements by consumers, which can be subsidized and/or assisted by the utility, government, or hired contractors using a variety of different types of policies or programs, are routinely the least expensive way to provide energy services, allowing more consumers to be served by the same generation, transmission, and distribution infrastructure, or for infrastructure needs to be reduced.

As shown in Figure 5.E.7-1, the **Energy Efficiency Improvements scenario displaces generation from diesels, natural gas-fired power, Lake methane plants, and peat-fired power plants**.

Increases in costs for higher efficiency demand devices and other energy efficiency measures in the demand sectors is much more than offset by savings in electricity

[159] An approximately 2012 value (updated by the EAEP Team to 2020 dollars) from United States from the American Council for an Energy-Efficient Economy report summarized in Kevin Normandeau (2015), "The (Real) Cost and Value of Energy Efficiency", *Microgrid Knowledge*, dated March 15, 2015, and available as https://microgridknowledge.com/cost-and-value-of-energy-efficiency/.

generation infrastructure and in avoided purchases of resources for electricity generation (fuel imports), as shown in Figure 5.E.7-2. Costs in this figure were discounted at 5%/yr, and initial costs of generation equipment and installation were annualized at an interest rate of 5%/yr.

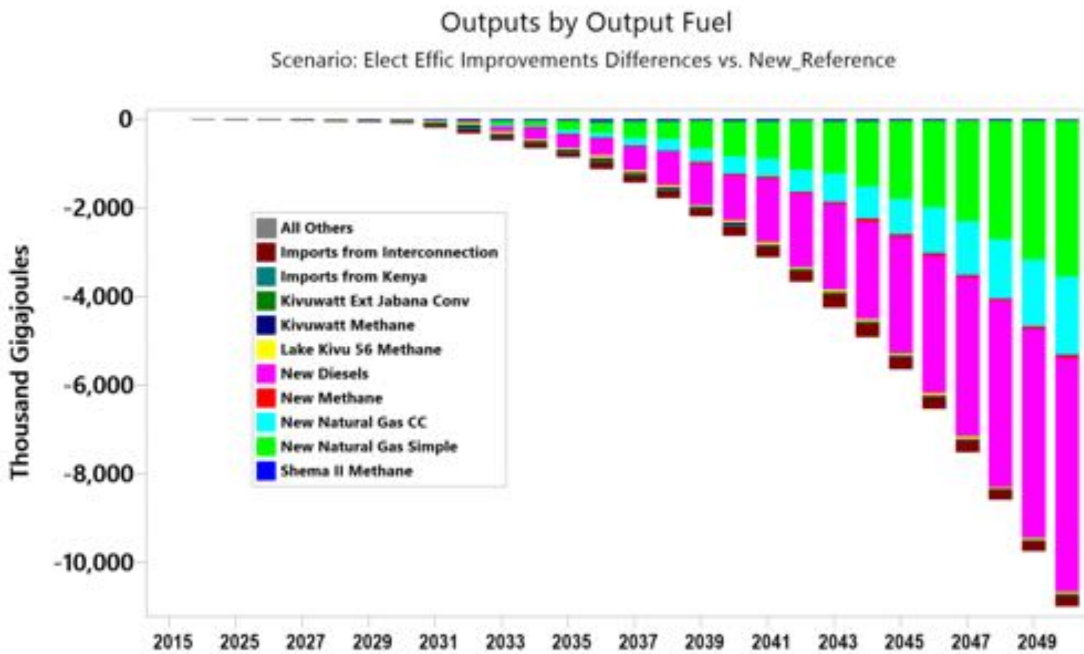

Figure 5.E.7-1 Output by Type of Capacity by Year for the EEI.7 Supply Scenario Relative to the New Reference Case

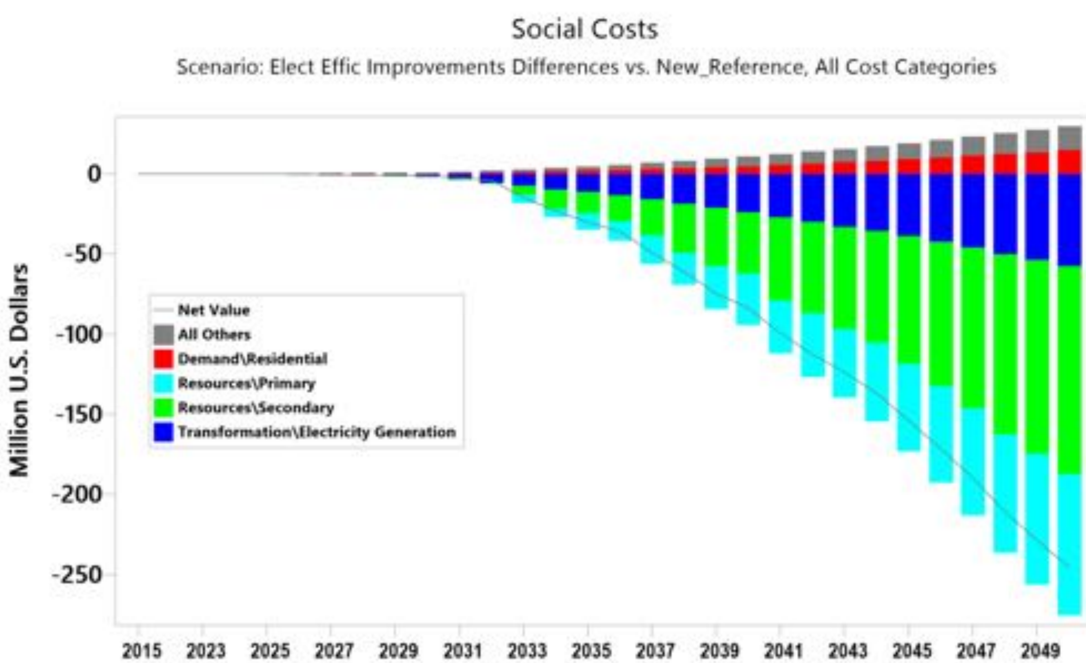

Figure 5.E.7-2. Social Costs of Energy Sector Activities in Rwanda in the LMG.6 Scenario Relative to the New Reference Case (Using an interest rate of 5%/yr)

Other considerations for the EEI.7 case include performance risks for the efficiency policies and programs that will be needed to drive energy efficiency reductions in Rwanda. As the Rwandan market for energy efficiency devices matures and expertise in energy efficiency in Rwanda grows, these risks will be reduced. Relative to the New Reference scenario, the EEI.7 scenario also offers somewhat reduced fuel price risks and additional energy sector employment, as the deployment of energy efficiency measures is typically more labor-intensive, per unit of electricity services delivered, than the operation of fossil-fueled power plants.

5.E.8. SOCIAL COST COMPARISON OF SCENARIOS

Figure 5.E.8-1 presents a comparison of total discounted social costs over the full modeling period for scenarios LHY.2 through EEI.7 relative to the New Reference case. **Savings in fuel imports (dark blue bar), for generation, as well as for the transportation sector, in NTZ.5, are the most important drivers of net cost savings for scenarios using substantial renewable generation relative to those that do not**. These and other cost results above, of course are sensitive to assumptions about future fuel prices. The results in Figure 5.E.8-1 reflect the use of a discount rate of 5%/yr, and an interest rate for the initial costs of generation of 5%/yr. Raising the interest rate used to model the annualization of initial costs reduces the net benefits that renewable energy-focused scenarios show relative to the REF.1 case (ARN.3 and NTZ.5, in particular), but those benefits remain substantial, as shown in Figure 5.E.8-2.

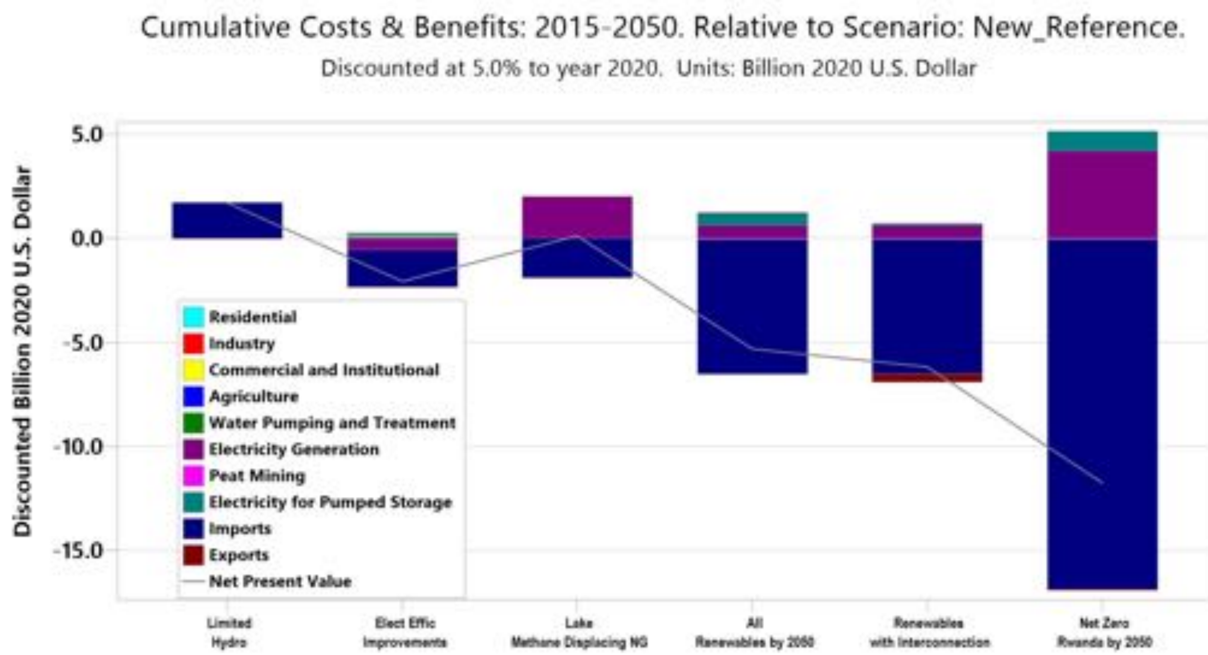

Figure 5.E.8-1 Social Costs Comparison Across Scenarios Relative to the New Reference Case (Using an interest rate of 5%/yr)

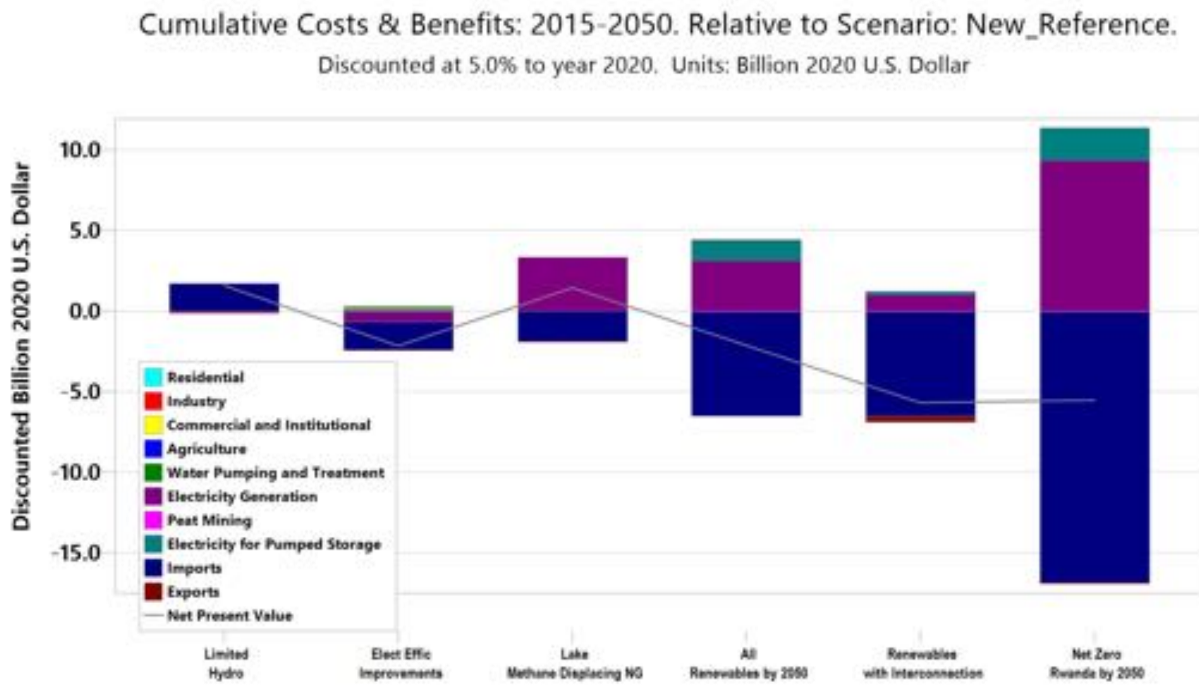

Figure 5.E.8-2 Social Costs Comparison Across Scenarios Relative to the New Reference Case (Using an interest rate of 15%/yr)

7. CONCLUSIONS

The results of this Assessment have demonstrated a new understanding of Rwanda's significant electricity generation capacity to meet its rapidly growing demand through 2050 as the economy expands. Substantial solar, wind and, to some extent, hydropower generation capacities were estimated that can feasibly be brought into the market based on current best estimates of costs and market requirements such as risks and profit.

Based on this potential capacity, very different combinations of priority resources and technologies are possible and the alternative electricity supply scenarios developed under this Assessment has shown the different benefits, costs, and risks associated with each. These scenarios can inform policymakers and sector planners in the definition of Rwanda future electricity supply path.

The integrated analytical system that supported this Assessment is a new critical tool that REG can use for future updates of the LCPDP as economic, market and technology conditions change.

Looking ahead, physical resource and technical potential for electricity generation in Rwanda could benefit from field investigations to validate and improve the results of this Assessment. Additionally, since economic and market potential may depend on many factors that can change depending on where and when a resource is evaluated, an agile, flexible approach to i electricity sector planning and management is needed that works with the private sector to create opportunities in project design, implementation, and interconnection, and in project finance.

ANNEX A – Nuclear Power in Rwanda

Nuclear power systems have provided baseload power in a number of countries around the world since the first commercial nuclear generating station was opened in 1958, in the United States.[160] As of 2022, almost all of the world's nuclear plants are located in North America, Europe, and Northeast Asia, with the vast majority of the growth in the global reactor fleet in recent years taking place in China.[161] Africa's only commercial nuclear reactors are located in South Africa, where the two reactors at the Koeberg station, completed in the mid-1980s, generate about five percent of the nation's total electricity needs.[162]

Over the years, nuclear power has periodically been of interest in Rwanda, as it has in many countries. Most recently, a 2019 agreement with a Russian company to develop a nuclear research center, including a small research reactor, in Rwanda has received both support and opposition from governmental agencies and others within Rwanda.[163] The Rwandan Atomic Energy Board was created by the government in late 2020, and tasked with playing a role in coordinating and "accelerating nuclear development in the key sectors of agriculture, health, electricity generation, pharmaceuticals and biotechnology, industry, environment, geology and mining".[164]

Several African nations, most notably Namibia and Niger, have major deposits of uranium (U) and are major international producers. Although uranium and thorium deposits have been identified in Rwanda, these deposits have to date not been well characterized. A 1985 report by the International Uranium Resources Evaluation Project, an initiative of the OECD Nuclear Energy Agency and the International Atomic Energy Agency (IAEA) reported "estimated speculative resources" of between 500 and 5000 tonnes of uranium in Rwanda.[165] Most of this total was identified in the Ruzizian geological unit in the West of the country, with two particular possible resource areas identified in Karago and Nshili, in the Northwest and Southwest, respectively.[166]

The existence of uranium (or thorium) resources in Rwanda does not guarantee an easy path to nuclear energy. A typical large commercial reactor—about 1000 MW—uses about 27 tonnes of enriched

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160 See, for example, American Society of Mechanical Engineers (2022), "#47 Shippingport Nuclear Power Station" https://www.asme.org/about-asme/engineering-history/landmarks/47-shippingport-nuclear-power-station.

161 See World Nuclear Association (2022), "Nuclear Power in China", dated January, 2022, and available as https://world-nuclear.org/information-library/country-profiles/countries-a-f/china-nuclear-power.aspx.

162 World Nuclear Organization (2021), "Nuclear Power in South Africa", dated August, 2021, and available as http://www.world-nuclear.org/information-library/country-profiles/countries-o-s/south-africa.aspx.

163 See, for example, Anadolu Agency (2020), "Rwanda: Opposition grows to Russian-backed nuclear plants; Lawmaker voices fears about safety of nuclear plants in densely populated Rwanda, but top official says nuclear is inevitable", dated November 29. 2020 and available as https://www.aa.com.tr/en/africa/rwanda-opposition-grows-to-russian-backed-nuclear-plants/2059467; and DW,com (2020), "Russia's nuclear play for power in Africa: Russia is pushing nuclear technology to African nations to both turn a profit and expand its political might on the continent", dated June 30, 2020, and available as https://www.dw.com/en/russias-nuclear-play-for-power-in-africa/a-54004039.

164 MINIFRA (2020), "Rwanda Atomic Energy Board to coordinate nuclear energy technologies, Minister Gatete", dated October 29, 2020, and available as https://www.mininfra.gov.rw/updates/news-details/rwanda-atomic-energy-board-to-coordinate-nuclear-energy-technologies-minister-gatete.

165 International Uranium Resources Evaluation Project (1985), *IUREP Orientation Phase Mission, Summary Report, Rwanda*, available as https://inis.iaea.org/collection/NCLCollectionStore/_Public/40/087/40087896.pdf.

166 The article "Lithium, Uranium minerals confirmed in Rwanda, research underway to start extraction", by By IGIHE, dated 9 December 2020 (available as https://en.igihe.com/news/article/lithium-uranium-minerals-confirmed-in-rwanda-research-underway-to-start), notes the common presence of uranium and thorium in ores of other frequently mined minerals, such as "Cassiterite, Colta [coltan] and Wolframite", which are extracted in Rwanda mainly for their tin, tantalum, and tungsten contents.

uranium fuel per year,[167] which at an enrichment of 4 percent of the fissile isotope uranium-235 (235U) from the 0.7 percent 235U in natural uranium means that about 150 tonnes of natural U are required per reactor year. At that rate, the “estimated speculative resource” identified in 1985 in Rwanda would fuel a large reactor for between 3 and 30 years. Moreover:

- Uranium ore typically contains on the order of 0.1 percent uranium by weight, meaning that producing 150 tonnes of uranium requires mining and processing 150,000 tonnes of ore.
- Uranium ore processing is quite water-intensive, and often creates wastes that are difficult to dispose of.
- Once processed, uranium must be converted to uranium hexafluoride gas and then enriched in 235U, which requires large array of centrifuges. Enrichment of uranium is done by a relatively small number of countries around the world, and, with a few exceptions for reactor types that use natural uranium, other countries are obliged to import enriched uranium.
- Once enriched and made into pellets of uranium oxide, nuclear reactor fuel is fabricated to high tolerances using special metals, a technology available in a relatively small number of countries, thus many countries import fuel rods and assemblies.

Further, the cost of nuclear fuel is typically a relatively small part (on the order of $10/MWh, though that can vary substantially with uranium and enrichment costs in the global market) of the cost of generating electricity with nuclear power, much smaller, for example, than the fraction of generating costs made up by fuel costs in coal or gas-fired power plants. Of nuclear fuel costs, the cost of uranium is a minor portion relative to the combined costs of conversion, enrichment and fuel fabrication, services that for Rwanda would highly likely have to be imported, even if using Rwandan uranium.

Moreover, the installed costs of nuclear power plants are typically quite high. The most recent nuclear plants installed in the United States cost on the order of $14 billion for each 1150 MW unit. The listed cost for the 5600 MW (four reactor units) Barakah nuclear power plant in the United Arab Emirates is listed at $24.4 billion, although construction is not yet complete and there have been suggestions that the full cost of the units is not entirely transparent.

For Rwanda, additional key considerations could include:

- The size of typical commercial reactors (1000 MW or larger, although Russia offers some smaller units, down to about 440 MW) relative to the Rwandan grid, which is currently several hundred megawatts, and even with substantial growth in electricity demand (see the Supply Scenarios section in this Report) may not require more than 2000 average MW by 2050. Large reactors are unsafe to operate on grids that small, because if the plant trips, it will be difficult both to maintain grid operations and to assure that enough emergency backup power is available for the nuclear unit’s coolant pumps to prevent the plant from overheating and damaging the reactor core.[168] It is possible that if eventually Rwanda’s grid is fully integrated with that of its regional neighbors, the combined interconnected grid may be large enough to support nuclear reactors, but that will depend on the design and interconnectedness of the regional grid, and grid interconnection on a large scale in the East Africa region at the approximately 0.5 or more GW line capacity scale seems unlikely to happen for 20 years or more.

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[167] See World Nuclear Association (2022), “How is uranium made into nuclear fuel?”, available as https://www.world-nuclear.org/nuclear-essentials/how-is-uranium-made-into-nuclear-fuel.aspx.
[168] This is a simplistic explanation of a complex issue. See, for example, IAEA (2012), *Electric Grid Reliability and Interface with Nuclear Power Plants*, IAEA Report # NG-T-3.8, available as https://www-pub.iaea.org/MTCD/Publications/PDF/Pub1542_web.pdf.

- Large reactor units require large amounts of water for cooling, which might make them difficult to site in areas of Rwanda where water use is already intensive and might make reactors using river water vulnerable to shut down in years where rainfall is low.[169]
- The availability of space to store or dispose of nuclear spent fuel in a small and populous country.
- The country's relatively active seismology.
- The reactor size consideration relative to the Rwanda grid may be possible to address by using a small modular reactor (SMR) design. SMR units have been under development for many years, but the first such commercial unit did not come online until December 2021, when a 200 MW Chinese unit reached commercial operation at Shidao Bay in Shandong Province.[170] As some point it may be possible for Rwanda to import SMR units that are of an appropriate size for the Rwandan grid and are "fail safe" such that the reactor cores will not be damaged and will not leak radiation even if cooling power is lost. It is likely, however, that even the SMR units, which are designed to be made in factories, will be very expensive on a per MW of capacity basis, likely requiring low-cost loans or concessional financing to make them affordable for Rwanda.

[169] Many nuclear reactors worldwide are located on or near seacoasts and use saltwater for cooling to avoid issues with cooling water scarcity and/or with too-high cooling water temperatures in hot and/or dry years. It is conceivable that Lake Kivu water could be used for reactor cooling, but Lake Kivu's unique nature, with its methane- and CO_2-rich stratified deep water, might present problems depending on how the intake and outfall for reactor cooling water were designed and implemented.
[170] Bloomberg News (2021), "China is Home to World's First Small Modular Nuclear Reactor", dated December 20, 2021, and available as https://www.bloomberg.com/news/articles/2021-12-21/new-reactor-spotlights-china-s-push-to-lead-way-in-nuclear-power.

ANNEX B – Rwanda LEAP Model: Details

B.1. CONTENTS

B.2. INTRODUCTION

As a part of the Rwanda Resource Assessment Project undertaken by the EAEP Team, a model of current and future (through 2050) energy demand and supply was prepared using the LEAP (the Low Emissions Analysis Platform tool, formerly called "Long-range Energy Alternatives Planning") software tool customized to Rwanda (the Rwanda LEAP Model). The Rwanda LEAP model was designed to help to place the assessment of Rwandan resources for electricity generation into to the context of potential scenarios of future electricity demand in Rwanda. As electricity demand in the future will in part depend on the interlinked changes in use of other fuels and of electricity, as, for example, the transportation and other sectors become "electrified" to reduce national greenhouse gas (GHG) emissions, the Rwanda LEAP model includes estimates of current and future demand not just for electricity, but also for other fuels, including both commercial (petroleum products, charcoal) and traditional (wood and biomass) fuels. **The Rwanda LEAP model therefore provides both the means to review nationwide energy supply and demand, including, in some detail, electricity supply and demand, and a platform for future analysis of measures and policies that might be implemented to address key national development, environmental, and other goals.** The LEAP Rwanda model is suited to providing estimates of energy needs and the supply systems needed to meet them, the environmental emissions associated with energy demand and supply, and the relative costs of different future energy scenarios.

This Annex is designed to complement Section 4 of this Report that describes electricity supply scenarios for Rwanda, as well as serving as a resource and guide for future users of the Rwanda LEAP model. In the remainder of this Annex, focusing on inputs to the New Reference Case (Business as Usual) scenario on which other scenarios as based, we:

- Offer a general description of the LEAP modeling tool
- Describe the overall structure of the Rwanda LEAP Model
- Present the structure, assumptions, and data used to project demand for electricity and other fuels in the Model
- Present the structure, assumptions, and data used to model electricity supply—both on- and off-grid—and to model other types of "energy transformation", such as production of peat and imports of natural gas
- Describe the treatment of load curves for electricity demand and for curves for electricity supply from intermittent or variable resources
- Present ideas for future development/updating/enhancement and use of the Rwanda LEAP model

B.3. GENERAL DESCRIPTION OF THE LEAP MODELING TOOL

The following general description of key elements of the LEAP modeling tool is provided by the Stockholm Environment Institute (SEI) the developer of LEAP (https://leap.sei.org/default.asp?action=introduction):

- "LEAP has been adopted by thousands of organizations in more than 190 countries worldwide. Its users include government agencies, academics, non-governmental organizations, consulting companies, and energy utilities. It has been used at many different scales ranging from cities and states to national, regional and global applications".
- "LEAP is fast becoming the de facto standard for countries undertaking integrated resource planning, greenhouse gas (GHG) mitigation assessments, and Low Emission Development Strategies (LEDS) especially in the developing world, and many countries have also chosen to

use LEAP as part of their commitment to report to the U.N. Framework Convention on Climate Change (UNFCCC). At least 32 countries used LEAP to create energy and emissions scenarios that were the basis for their Intended Nationally Determined Contributions on Climate Change (INDCs): the foundation of the historic Paris climate agreement intended to demonstrate the intent of countries to begin decarbonizing their economies and invest in climate-resilience."

- For **integrated planning**, "LEAP is an integrated, scenario-based modeling tool that can be used to track energy consumption, production and resource extraction in all sectors of an economy. It can be used to account for both energy sector and non-energy sector greenhouse gas (GHG) emission sources and sinks. In addition to tracking GHGs, LEAP can also be used to analyze emissions of local and regional air pollutants, and short-lived climate pollutants (SLCPs) making it well-suited to studies of the climate co-benefits of local air pollution reduction." **Error! Reference source not found.** shows the interaction of LEAP modeling elements."
- With regard to ***flexibility and ease-of-use***, "LEAP has developed a reputation among its users for presenting complex energy analysis concepts in a transparent and intuitive way. At the same time, LEAP is flexible enough for users with a wide range of expertise: from leading global experts who wish to design polices and demonstrate their benefits to decision makers to trainers who want to build capacity among young analysts who are embarking on the challenge of understanding the complexity of energy systems."
- In terms of its modeling **approach and methodologies**, "LEAP is not a model of a particular energy system, but rather a tool that can be used to create models of different energy systems, where each requires its own unique data structures. LEAP supports a wide range of different modeling methodologies: on the demand side these range from bottom-up, end-use accounting techniques to top-down macroeconomic modeling. LEAP also includes a range of optional specialized methodologies including stock-turnover modeling for areas such as transport planning. On the supply side, LEAP provides a range of accounting, simulation and optimization methodologies that are powerful enough for modeling electric sector generation and capacity expansion planning, and which are also sufficiently flexible and transparent to allow LEAP to easily incorporate data and results from other more specialized models".

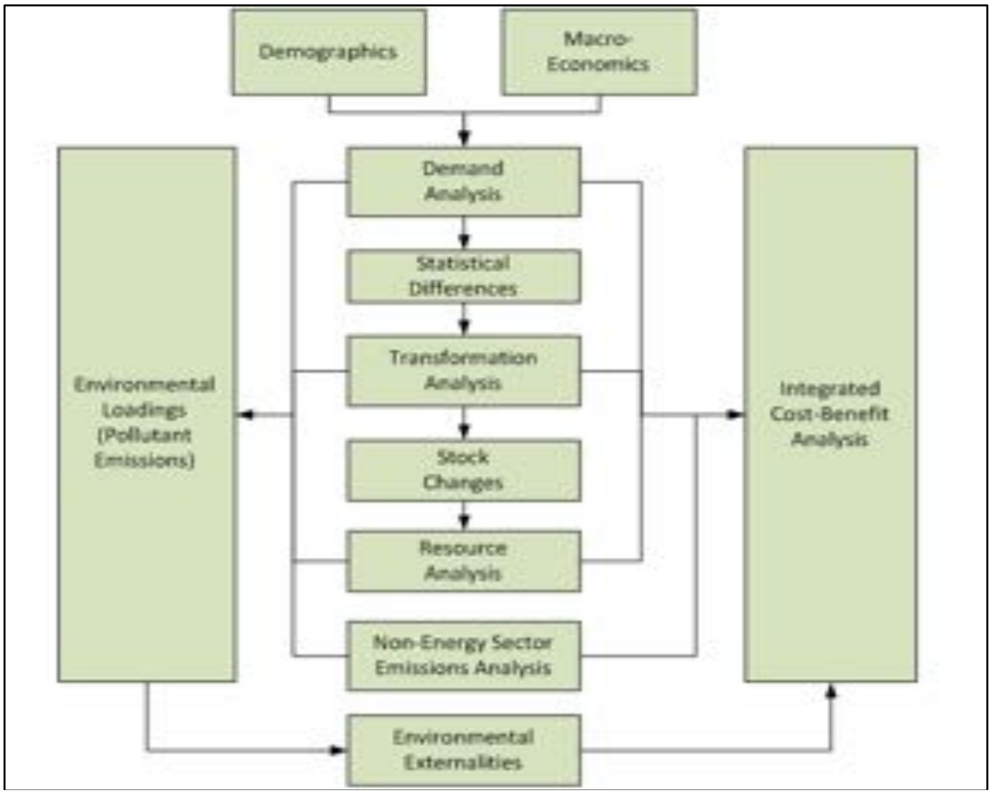

Figure B.3-A LEAP Elements and their Interactions for Integrated Modeling

- "LEAP's modeling capabilities operate at two basic conceptual levels. At one level, LEAP's built-in calculations handle all of the "non-controversial" energy, emissions and cost-benefit accounting calculations. At the second level, users enter spreadsheet-like expressions that can be used to specify time-varying data or to create a wide variety of sophisticated multi-variable models, thus enabling econometric and simulation approaches to be embedded within LEAP's overall accounting framework. The newest versions of LEAP also support optimization modeling: allowing for the construction of least cost models of electric system capacity expansion and dispatch, potentially under various constraints such as limits of CO_2 or local air pollution."
- **Time frame for LEAP analyses**, "LEAP is intended as a medium- to long-term modeling tool. Most of its calculations occur on an annual time-step, and the time horizon can extend for an unlimited number of years. Studies typically include both a historical period known as the Current Accounts, in which the model is run to test its ability to replicate known statistical data, as well as multiple forward-looking scenarios. Typically, most studies use a forecast period of between 20 and 50 years. Some results are calculated with a finer level of temporal detail. For example, for electric sector calculations the year can be split into different user-defined "time slices" to represent seasons, types of days or even representative times of the day. These slices can be used to examine how loads vary within the year and how electric power plants are dispatched differently in different seasons."
- **LEAP use for scenario analyses**, "LEAP is designed around the concept of scenario analysis. Scenarios are self-consistent storylines of how an energy system might evolve over time. Using LEAP, policy analysts can create and then evaluate alternative scenarios by comparing their energy requirements, their social costs and benefits and their environmental impacts. The LEAP Scenario Manager, shown the Figure below an be used to describe individual policy measures

which can then be combined in different combinations and permutations into alternative integrated scenarios. This approach allows policy makers to assess the impact of an individual policy as well as the interactions that occur when multiple policies and measures are combined. For example, the benefits of appliance efficiency standards combined with a renewable portfolio standard might be less than the sum of the benefits of the two measures considered separately. In the screen shown right, individual measures are combined into an overall GHG Mitigation scenario containing various measures for reducing greenhouse gas emissions."

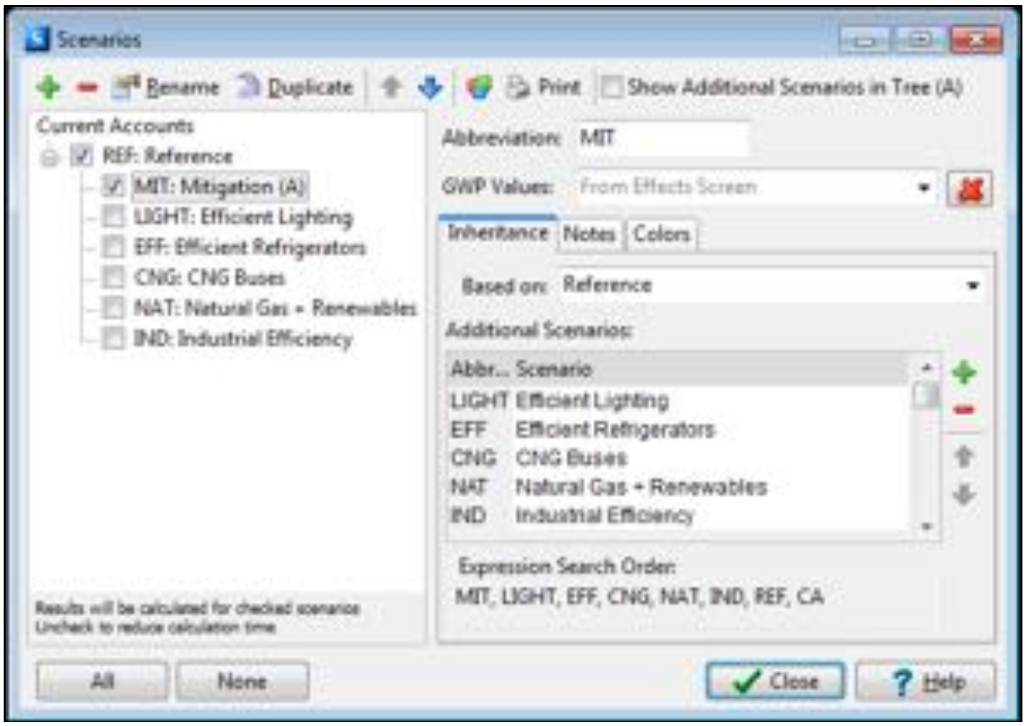

Figure B.3-B : LEAP Elements and their Interactions for Integrated Modeling

For those who have registered on and logged into the LEAP website, LEAP Users' Guide and exercises are available, along with a library featuring articles and reports by LEAP users and other information.

B.4. OVERALL STRUCTURE OF AND DATA SOURCES FOR THE RWANDA LEAP MODEL

The overall structure of the Rwanda LEAP model shown in the Figure below, include key assumptions that "drive" energy demand in Rwanda (and in some instances, provide parameters for energy transformation modules, the demand sectors, subsectors, and lower "branches" themselves, energy transformation, which describes how resources are converted into fuels used for demand end-uses (and in some cases, intermediate products used in other transformation processes), and the resources themselves. The Rwanda LEAP model includes the full range of fuels used in the country, from biomass and wood to petroleum products and electricity, and provides the option to include more detail, such as more Rwanda-specific biomass fuels, as needed.

Figure B.4-A: Overview of the Rwanda LEAP Model "Tree"

The Figure below shows a Sankey diagram for the Rwanda LEAP model for the year 2021. Overall, input data for the model have been derived from a number of sources, including the inputs and outputs of a previous Rwanda energy modeling effort using the MAED software tool[171], Rwanda Energy Group (REG) data both from published sources and provided by REG staff, information from the National Institute of Statistics Rwanda, Rwanda Utilities Regulatory Authority (RURA) data, and information derived from a range of national, regional, and international publications and literature sources. Much of the data that underly that Rwanda LEAP model are compiled and documented workbooks assembled by the EAEP Team and shared with REG. These include:

- A workbook used to compile and derive information for LEAP demand modeling
- A workbook used to assemble data on electricity generation sources
- Workbooks used for the derivation of load curves and of output curves for solar and hydroelectric power, with results derived from hourly data provided by REG staff
- A workbook for the calculation of Levelized Costs of Energy for different resources, which includes both the summary results of resource assessments and cost estimates for a number of electricity generation options

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[171] See, for example, International Atomic Energy Agency (IAEA, 2006), Model for Analysis of Energy Demand (MAED-2), User's Manual. IAEA Computer Manual Series No. 18, IAEA, Vienna, available as https://www-pub.iaea.org/MTCD/Publications/PDF/CMS-18_web.pdf.

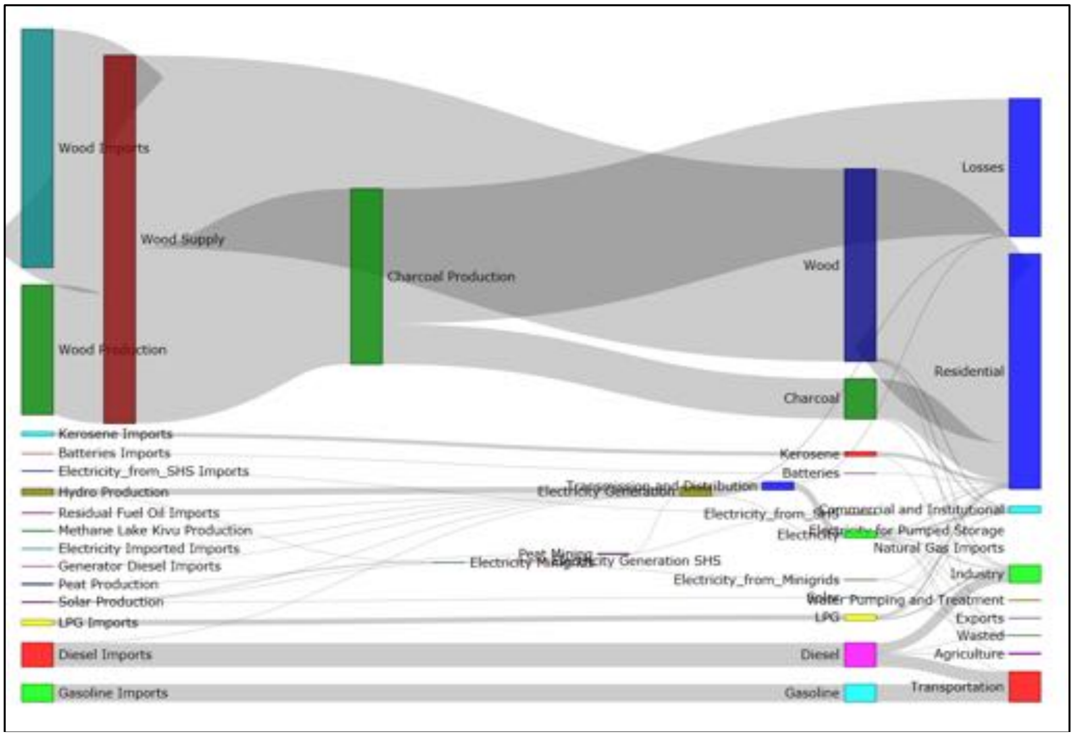

Figure B.4-B: Sankey Diagram for the Rwanda LEAP Model in 2021

B.5. KEY ASSUMPTIONS

Key Assumptions in the Rwanda model include assumptions about demographic and economic changes over time. A listing of the Key Assumptions included in the Rwanda LEAP module is provided in Figure B.5-A. In some cases, notably for demographic parameters, projections have been provided from two different sources, namely from the earlier MAED modeling prepared for Rwanda, and from the United Nations population. In practice, these projections are not very different, as shown in Figure B.5-B, with population growth slowly decreasing over time, and total national population in 2050 of 21 to 22 million. Figure B.5-C shows several different projections for GDP growth in Rwanda. The higher growth trend (green curve) was used in the New Reference case at the suggestion of REG colleagues, and reflects high and sustained GDP growth targets.

Several Key Assumptions, including those described above and shown below, are used across the Rwanda LEAP model. These include tariff assumptions and settings for interest rates. Other Key Assumptions are mostly used within specific sectors or for energy transformation modules, and those assumptions are described in the sections that follow.

Figure B.5-A: Rwanda LEAP Model "Tree" for Key Assumptions

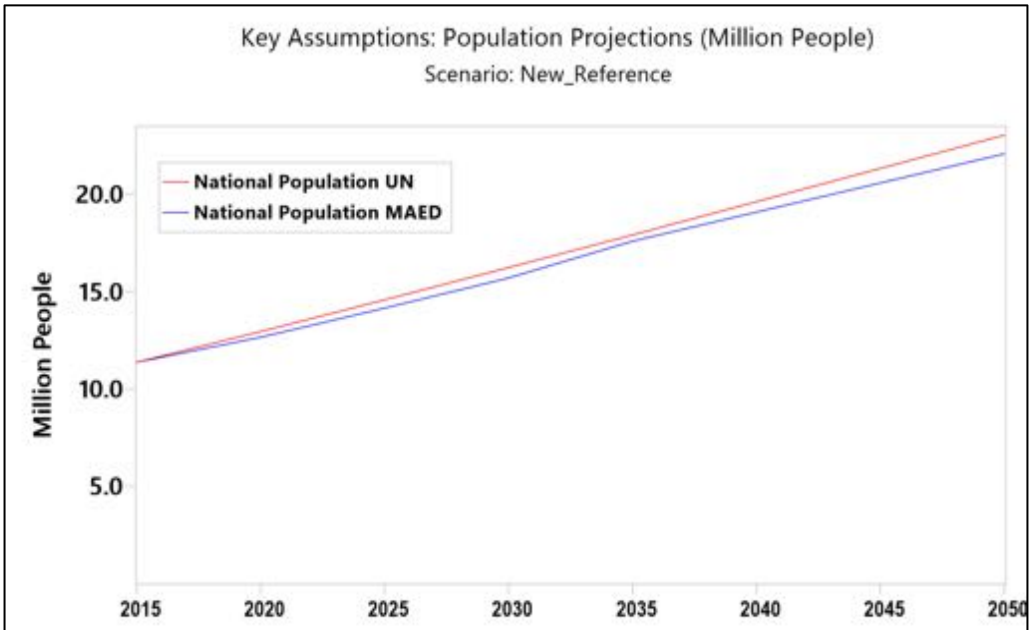

Figure B.5-B: Population Projections in Rwanda

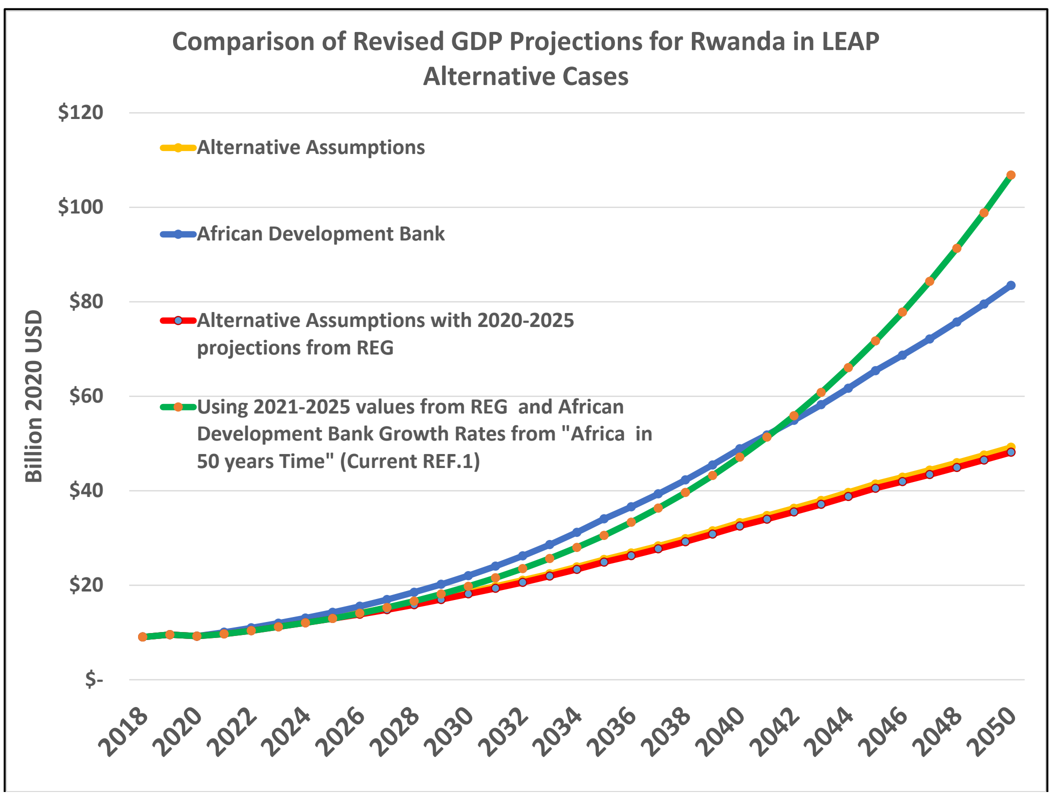

Figure B.5-C: GDP Projections in Rwanda

B.6. DEMAND FOR ELECTRICITY AND OTHER FUELS IN RWANDA LEAP MODEL

B.6.1 INTRODUCTION: OVERALL SCOPE OF RWANDA DEMAND MODEL

The Rwanda LEAP model covers all demand sectors for which data were available to the Project Team, including all types of fuel use, that is, although the model was meant primarily to inform electricity sector planning, its coverage was not restricted to electricity. The decision to cover all fuels was based on the prospects, that electricity could start to substitute for other fuels in some end uses in the near future and thus that understanding non-electric energy use was important to obtaining a full picture of what future electricity use could be. In addition, a scope that includes all fuels allows the study of important current and future impacts of energy sector activities, such as emissions of local and global air pollutants, and the societal costs of changes in the energy sector under different scenarios.

Figure B.6.1-A shows the six sectors used to model energy demand in Rwanda.

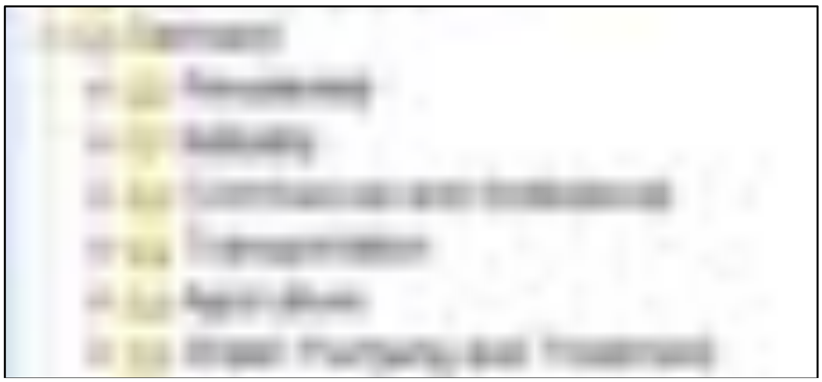

Figure B.6.1-A: Rwanda LEAP Model "Tree" for Demand Sectors

B.6.2 RESIDENTIAL SECTOR

A tree structure for the divisions used for the residential sector is shown in the Figure B.6.2-A below. The residential sector is broken into the urban and rural subsectors. Each of these is further broken down based on the sources of electricity used. In the urban subsector, these are the electrified, not electrified, and electrified using solar home systems (SHS) components. Each of these is further broken down into end-uses—water heating, cooking, air conditioning, and appliances and lighting. The water heating and cooking end-uses are further served by various energy sources—solar and electricity for water heating, and charcoal, wood, fossil, and electric stoves for cooking. (Note that the "Non Electric End Uses" categories are not currently used in the model—their energy intensities are set to zero.)

Figure B.6.2-B shows projections for the numbers of urban and rural households used through 2050. Although Rwanda has been primarily rural, the fraction of population living in urban areas is projected to rise to 43 percent by 2050.

Figure B.6.2-A: Rwanda LEAP Model "Tree" for Residential Sector and Subsectors

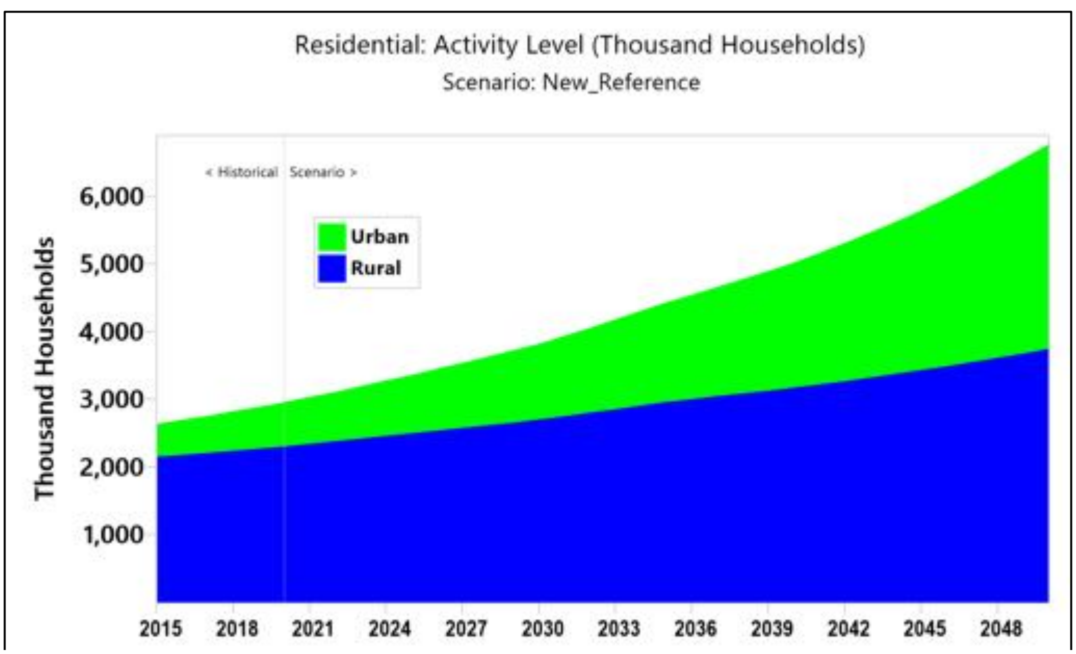

Figure B.6.2-B: Growth in Rural and Urban Households in Rwanda LEAP Model

Electrification of urban households is rapidly being completed in Rwanda. As shown in Figure B.6.2-C below Reference Case projections call for all urban household to be either on the central grid or using SHS by 2023, and for all of those households using solar home systems to be on the central grid by 2030.

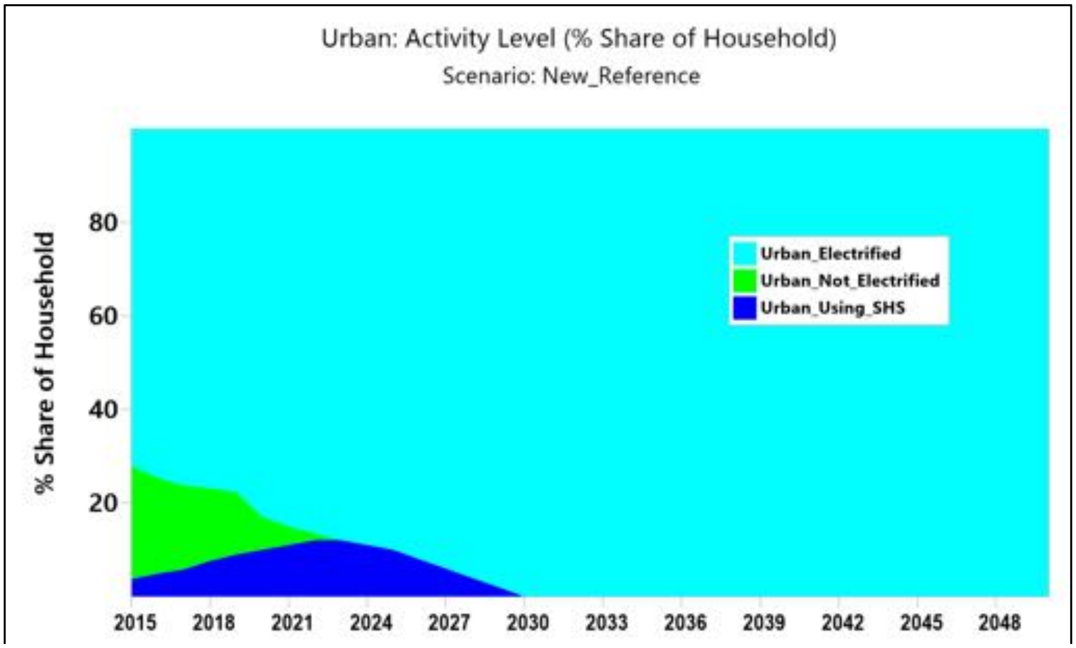

Figure B.6.2-C: Urban Households by Connection Status in Rwanda LEAP Model

Electrification in the Rural sector is essentially completed in 2034, with all rural households having access to electricity via central grid connections, solar home systems, or connections to mini-grids, and by 2050 90 percent of rural households are assumed to be connected to the central grid, with most of the rest on mini-grids (see Figure below). Over time, mini-grids are assumed to be absorbed into the central grid, as the latter is extended to new areas.

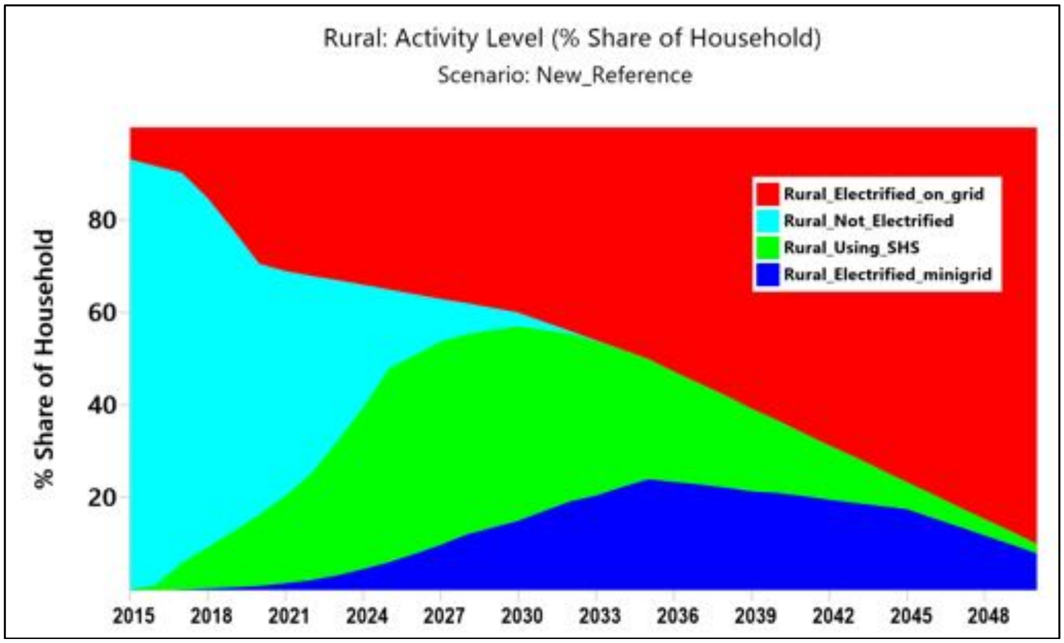

Figure B.6.2-D: Urban Households by Connection Status in Rwanda LEAP Model

In most households, the major use for electricity is in "lighting and appliances" (essentially, all uses except cooking, water heating, and air conditioning). Assumptions for changes in the energy intensity (annual electricity use per household) over time for the New Reference case for the urban subsector are shown in Figure B.6.2-E, and for the rural subsector—where usage per household is assumed to continue to be lower—in Figure B.6.2-F.

The use of air conditioning in urban households in the Reference case increases from about 1 percent of households in 2020 to 5 percent in 2050. The amount of electricity per household used for air conditioning decreases slightly over time as equipment and building efficiencies improve. Air conditioning in rural electrified households is assumed to remain effectively zero in the Reference case.

Figure B.6.2-G and Figure B.6.2-H show overall energy demand (all fuels) in the urban and rural electrified subsectors under the New Reference scenario. Urban demand increases overall,[172] but by 2050 electricity and liquefied petroleum gas (LPG, used largely for cooking) account for more than half of urban demand. In rural households, traditional fuels—mostly wood—continue to dominate overall energy use through 2050, although electricity and LPG become more important. Figure B.6.2-I shows demand by fuel in 2021, 2035, and 2050 for the entire residential sector, underscoring the importance of wood and charcoal (and related biomass) fuel use throughout the modeling period, but also the increasing use of electricity and fossil fuels.

[172] Note that the phase-out of kerosene for lighting in non-electrified households causes the rapid decrease in household kerosene use before 2023, although in fact the use of non-electric fuels (and batteries) for lighting in non-electrified urban households probably should be better characterized through further research.

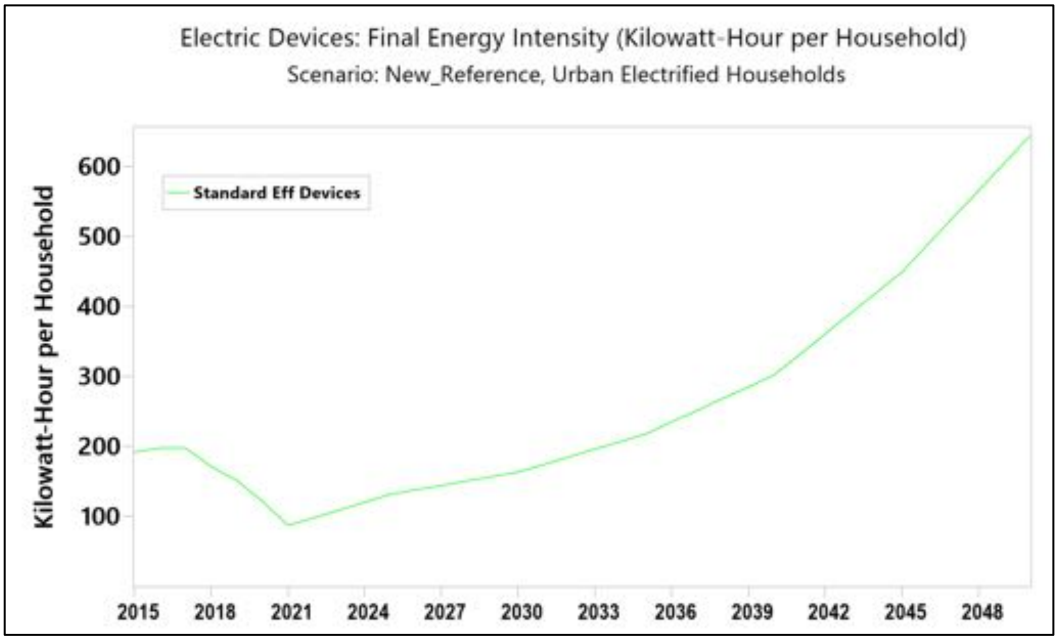

Figure B.6.2-E: Energy Intensity of Lighting and Appliances Electricity Uses in Urban Electrified Households in Rwanda LEAP Model (New Reference Case)

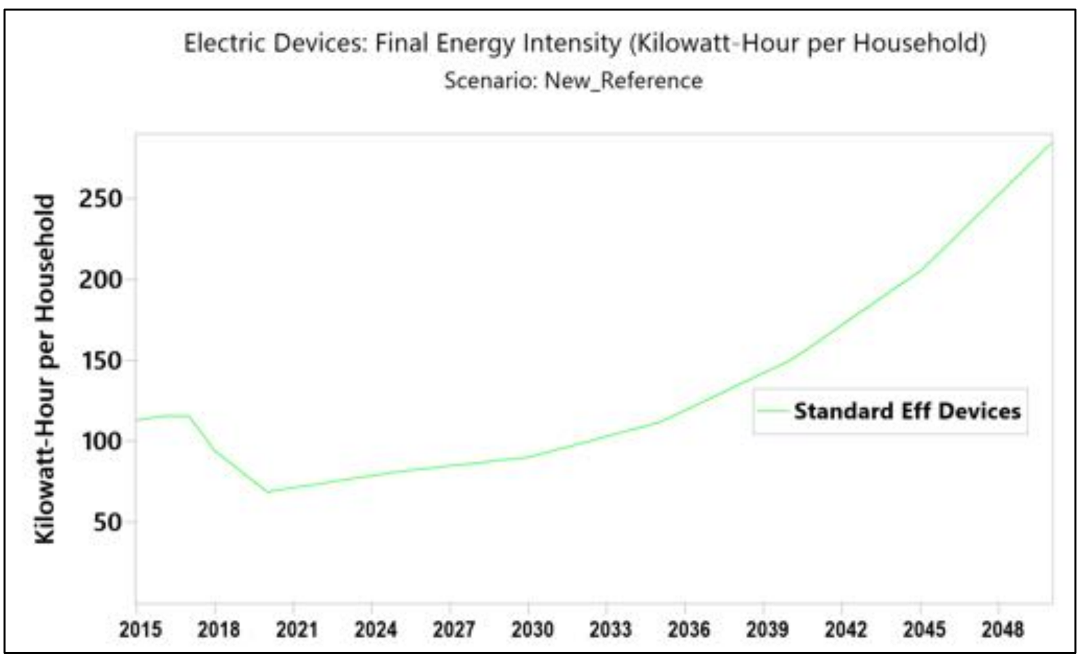

Figure B.6.2-F: Energy Intensity of Lighting and Appliances Electricity Uses in Urban Electrified Households in Rwanda LEAP Model (New Reference Case)

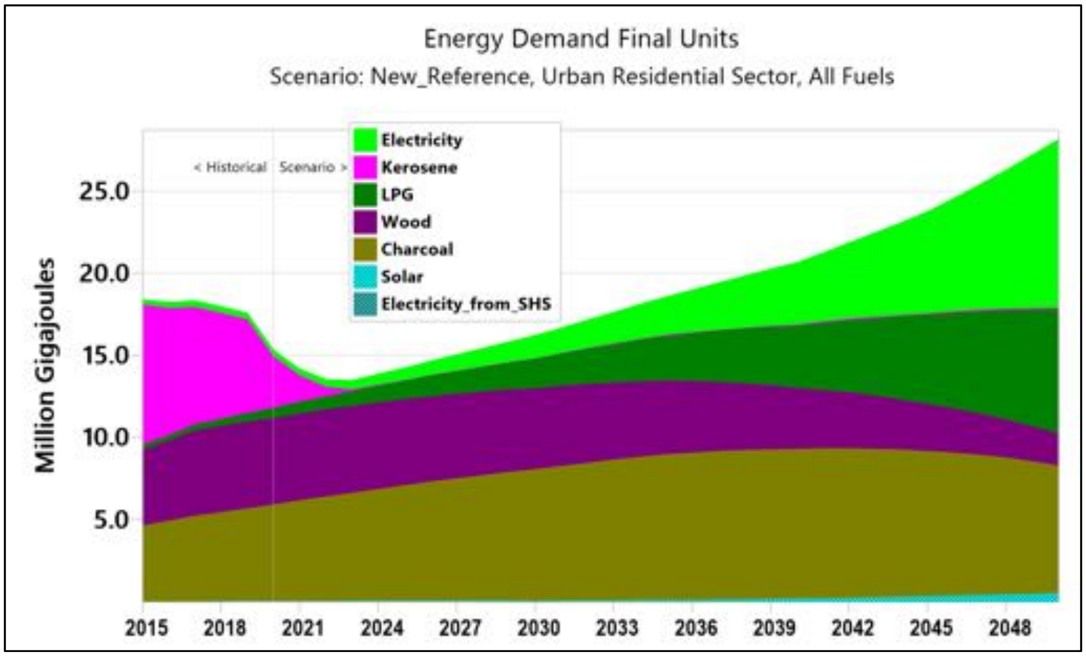

Figure B.6.2-G: Energy Demand in the Urban Residential Sector by Fuel, All Fuels, New Reference Case

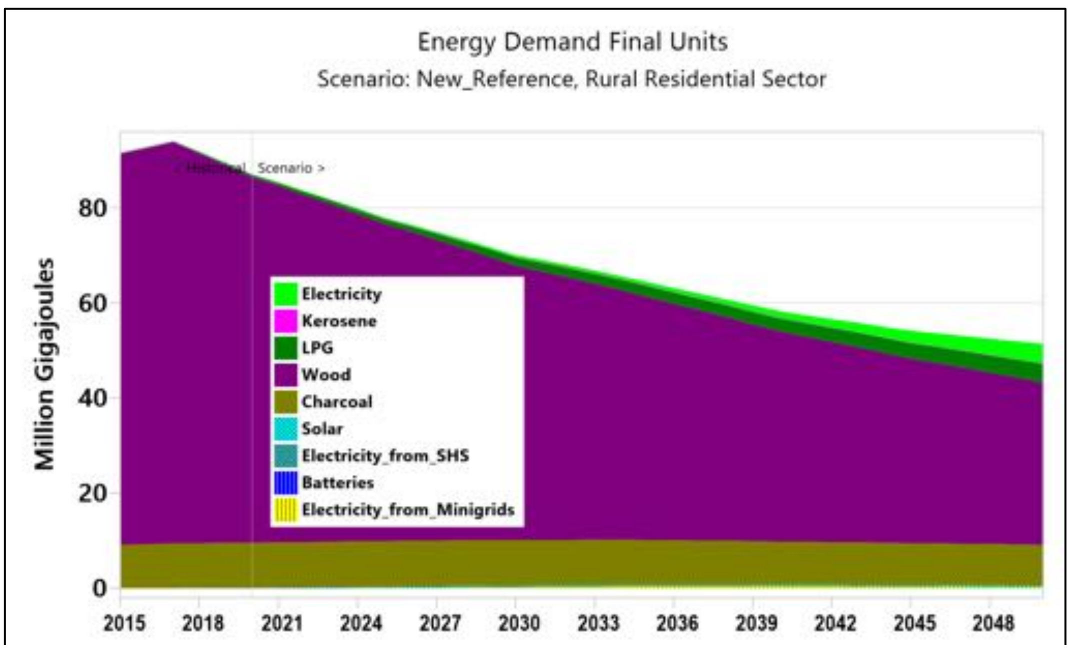

Figure B.6.2-H: Energy Demand in the Rural Residential Sector by Fuel, All Fuels, New Reference Case

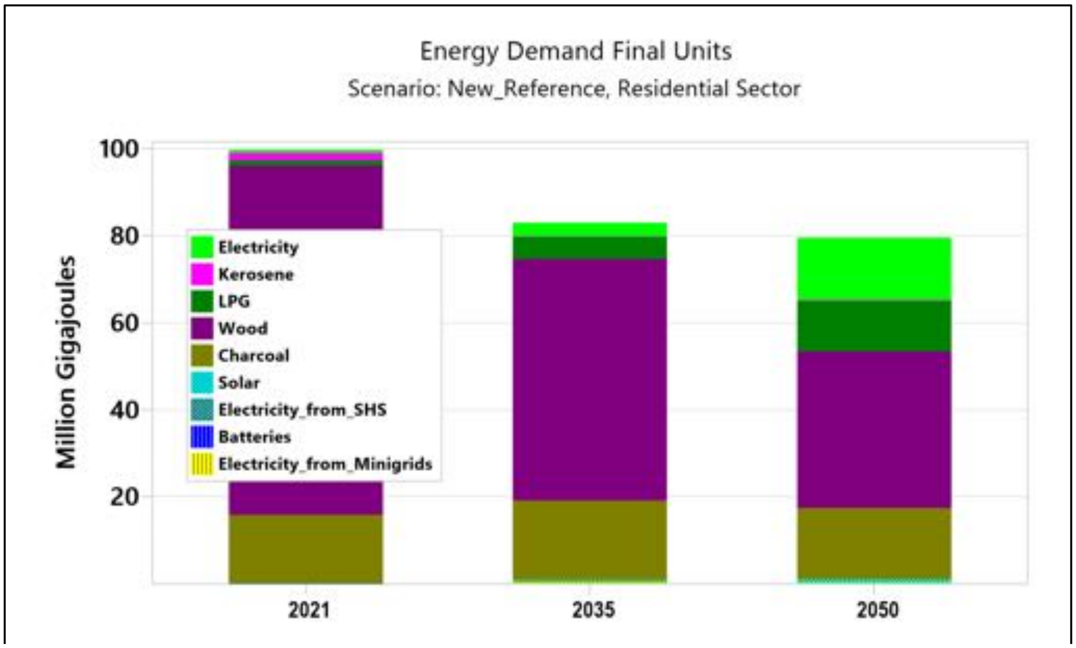

Figure B.6.2-I: Energy Demand in the Residential Sector Overall by Fuel, All Fuels, New Reference Case

Focusing on electricity use, the Figures below show overall electricity demand rising steeply in both urban and rural grid-electrified household, but with urban households accounting for over twice as much electricity use as rural by 2050. Demand is dominated by appliances and lighting electricity demand in both subsectors, but particularly in rural households, where a combination of lower incomes and perhaps more limited supplies of electricity cause households to focus on key end uses, and thus use less electricity for water heating and cooking than in urban households, using primarily other fuels for those end uses.

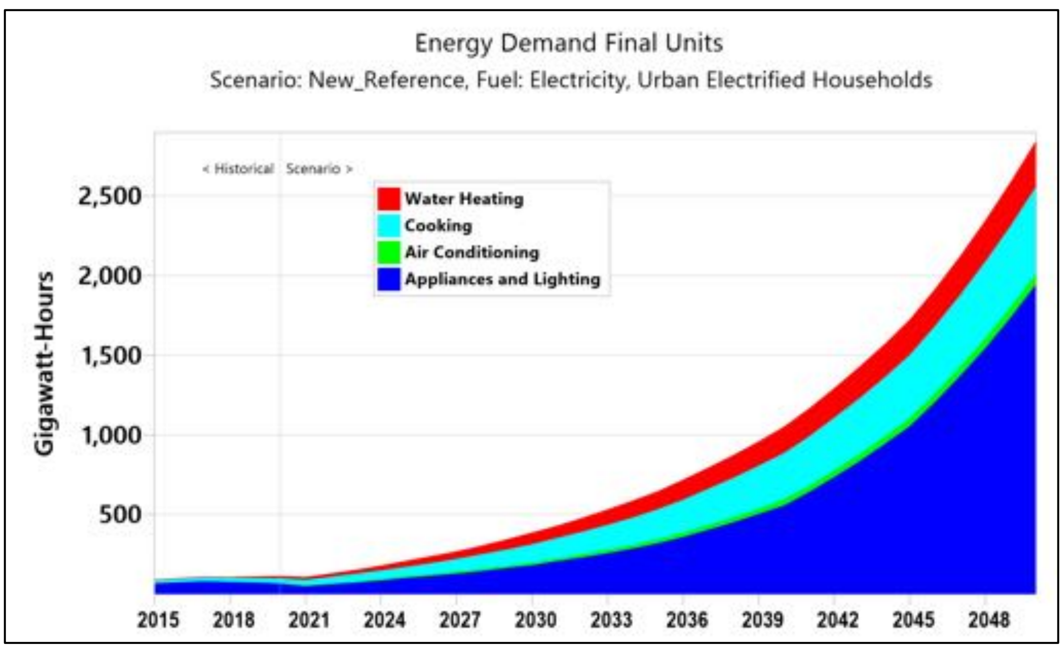

Figure B.6.2-J: Electricity Demand in the Urban Electrified Residential Sector by End Use, New Reference Case

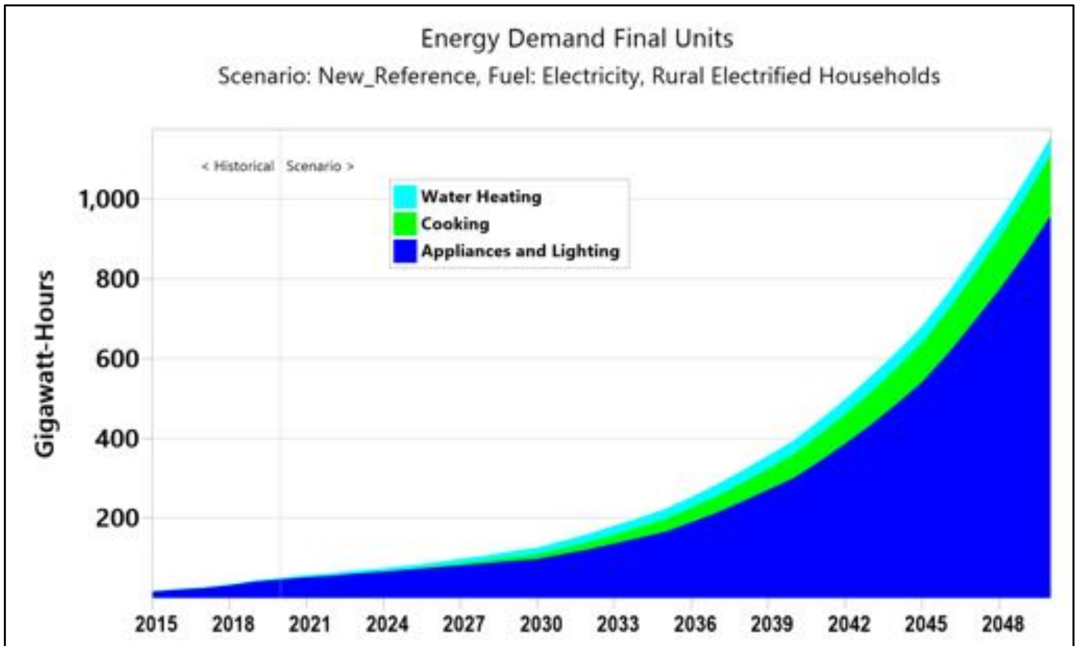

Figure B.6.2-K: Electricity Demand in Rural Electrified Households by End Use, New Reference Case

B.6.3. INDUSTRIAL SECTOR

The Industrial sector in the Rwanda LEAP model is divided into three subsector: manufacturing, mining, and construction, as shown in Figure B.6.3-A. Note that the "All Subsectors" branch shown in the figure is not currently used. Manufacturing is further divided into all electric end uses, solar energy use, motor fuels use, and (other) fossil fuels use. The Mining subsector include electrical, thermal, and motor fuels end uses, and construction includes electricity and motor fuels end uses. The key driving activities for each subsector are overall national GDP and the fraction of national GDP that is accounted for by each industrial subsector. Based on assumptions derived in part from the MAED model, it is assumed that over time the fraction of GDP accounted for by industry in general will rise (Figure B.6.3-B), and within the three industrial subsectors modeled, the fraction of industrial GDP accounted for by manufacturing will grow, as the fractions of mining and construction GDP decline (Figure B.6.3-C). The assumption for growth of the fraction of GDP accounted for the industrial sector, however, departs from that used in MAED in that it grows more slowly stabilizes after 2035, based in part on the assumption that the agricultural fraction of GDP will not fall as sharply as projected in the earlier MAED model.

In each of the three subsectors and for each type of energy use modeled, projections are included for the growth in intensity of energy use. In some cases these projections were adopted from the values implied by MAED model inputs and outputs, but in the case of electricity, lower growth rates for energy intensity were used for the manufacturing subsector, while in the mining and construction subsectors, somewhat higher growth was assumed, reflecting projected greater use of electricity in those subsectors.

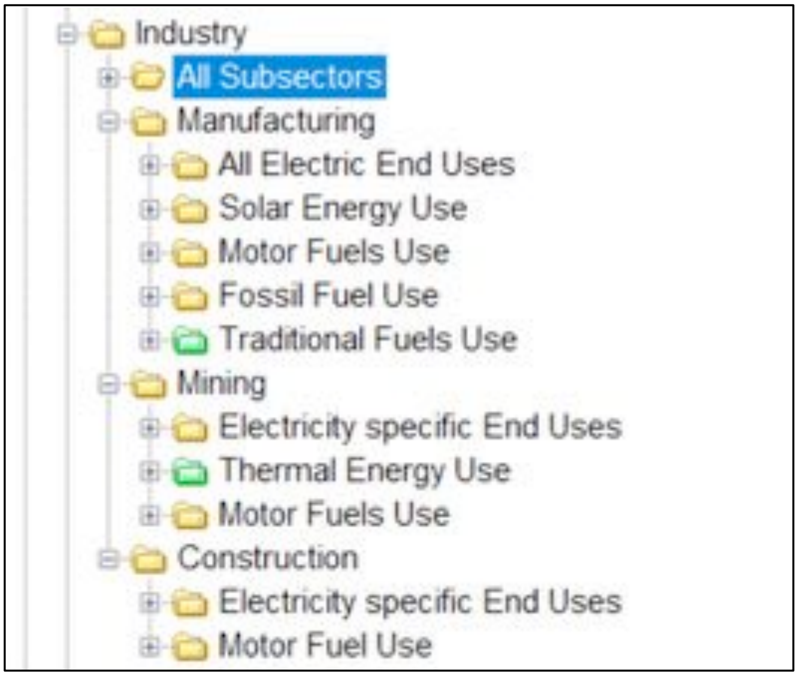

Figure B.6.3-A: Rwanda LEAP Model "Tree" for Industrial Demand Subsectors

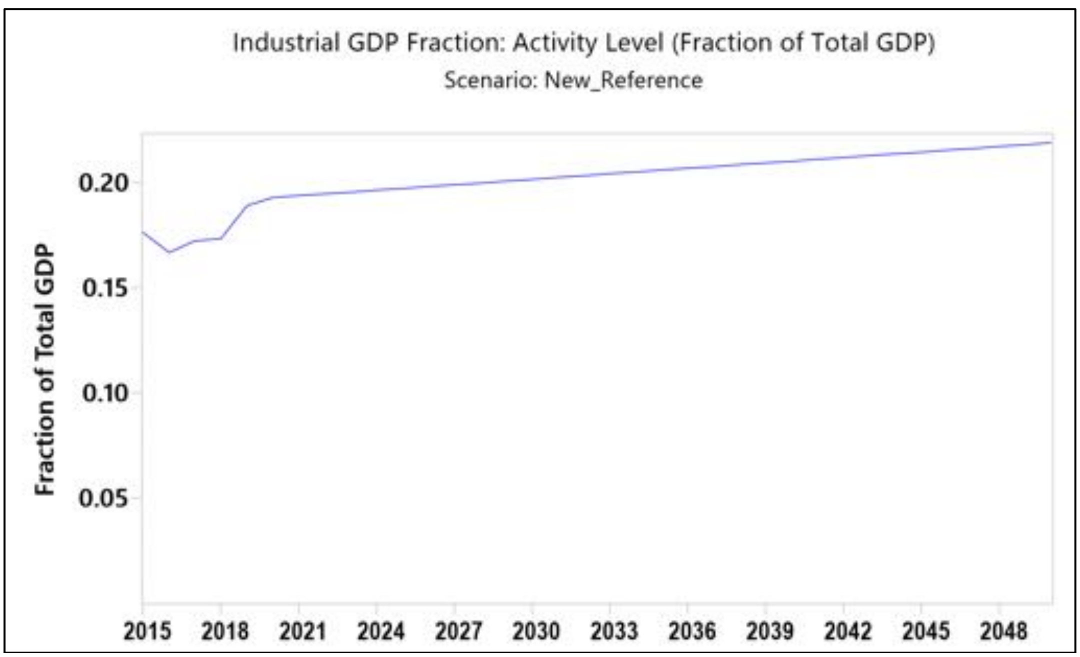

Figure B.6.3-B: Assumptions for Industrial GDP Fraction

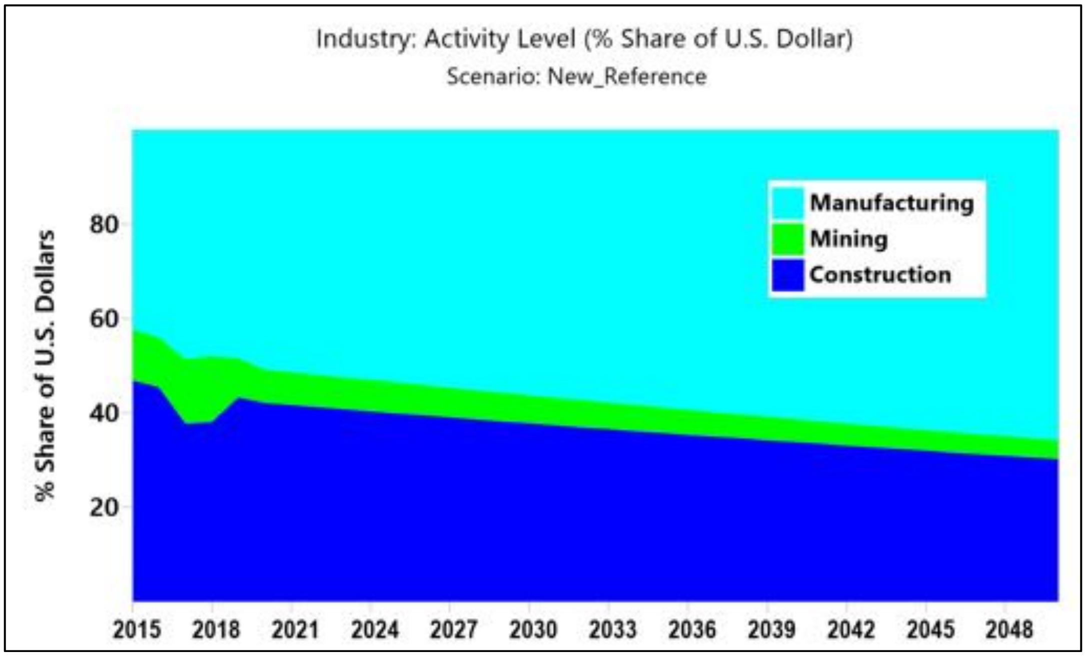

Figure B.6.3-C: Assumptions for Industrial GDP Fractions by Subsector

Figure B.6.3-D shows the overall demand for energy by fuels in the New Reference case, showing the dominance of diesel use in the sector continuing through 2050, even as demand for electricity increases rapidly. Figure B.6.3-E shows industrial demand by fuel and type of end-use, again showing the dominance of diesel use in the industrial, and specifically manufacturing subsector.[173] Figure B.6.3-F shows New Reference case growth in electricity demand in the industrial subsectors. Here manufacturing use of electricity dominates, with the rapid growth a result of the rapid and sustained overall growth in GDP combined with relatively modest growth in electricity use intensity (kWh per USD of GDP).

[173] It would probably be useful for future LEAP users to confirm how diesel and other fossil fuels are used in the manufacturing sectors in Rwanda, as the growth in its use as modeled here, even though lower than in the previous (MAED) modeling effort, seems too high.

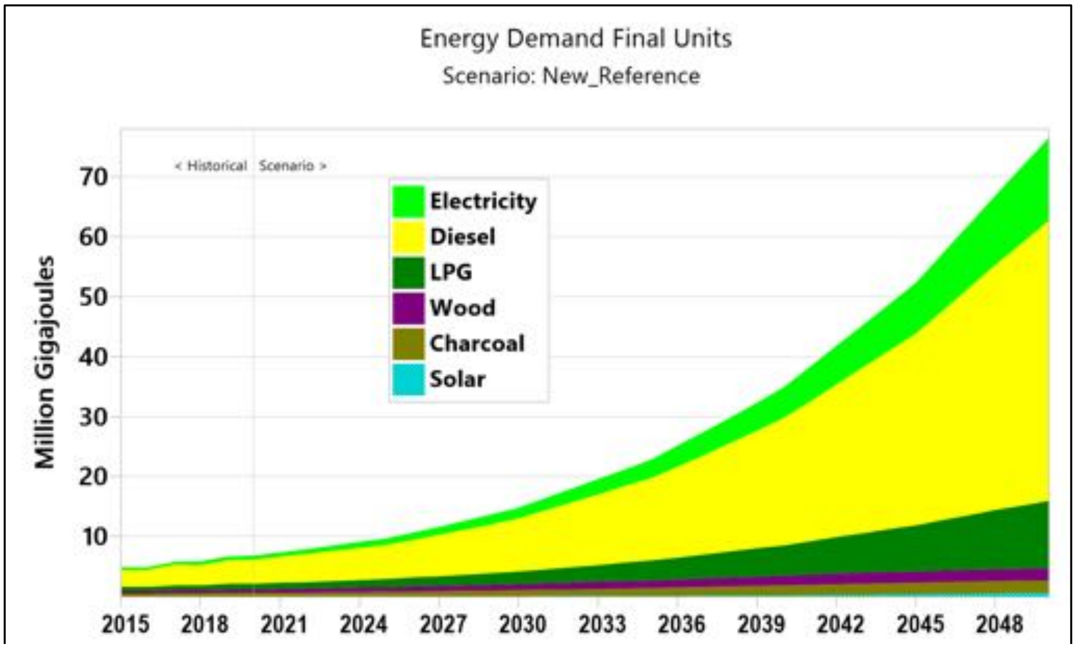

Figure B.6.3-D: New Reference Case Industrial Demand for all Fuels by Fuel Type

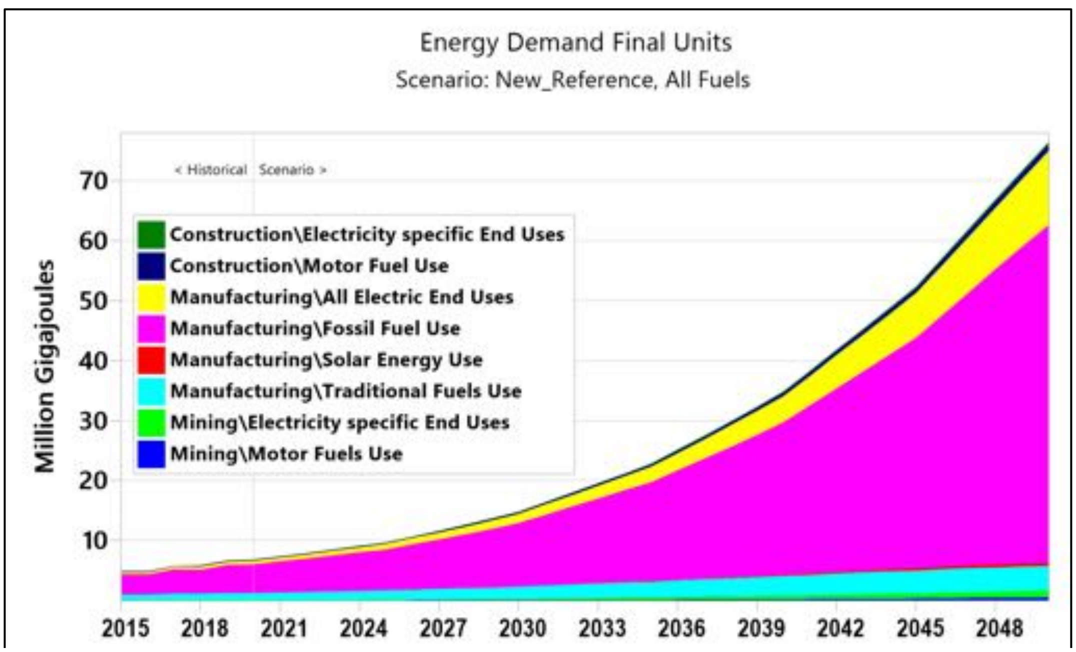

Figure B.6.3-E: New Reference Case Industrial Demand for all Fuels by Subsector and Type of Fuel Use

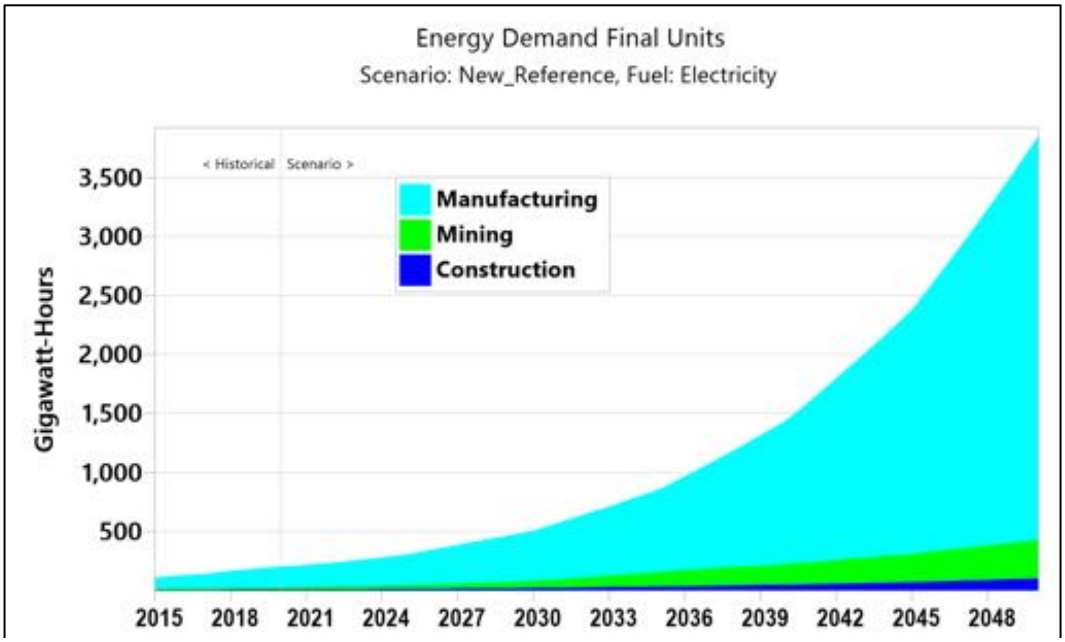

Figure B.6.3-F: New Reference Case Industrial Demand for all Electricity by Sector

B.6.4. COMMERCIAL AND INSTITUTIONAL SECTOR

The commercial and institutional sector in the Rwanda LEAP model (which includes services as well) is represented as a single sector, but is divided into air conditioning, other electric end uses, and non-electric end-uses including traditional biomass, solar hot water heat, fossil fuels (mostly LPG for cooking), and modern biomass stoves, as shown in Figure B.6.4-A.

Figure B.6.4-A: Rwanda LEAP Model “Tree” for the Commercial and Institutional Demand Sector

The major driving activity for this sector is commercial and institutional floorspace per person, which is projected to grow by about a factor of five between 2020 and 2050, although this growth is considerably lower than that projected in the 2017 MAED modeling effort (Figure B.6.4-B). At 5.0 square meters of commercial and institutional floorspace per capita, Rwanda in 2050 would have less than half of the current floorspace per capita of China, but Rwanda has a much warmer climate and different needs for indoor space than in China. In general, even in industrialized nations, the ratio of commercial/institutional floorspace to population varies considerably from country to country.

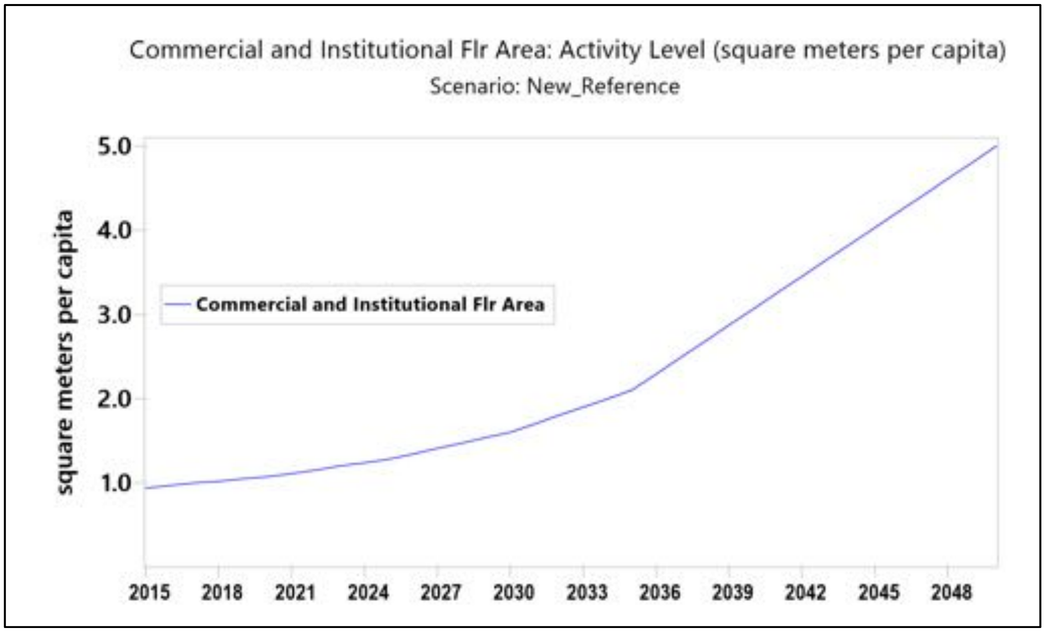

Figure B.6.4-B: Assumption for Trend in Commercial and Institutional Floorspace per Capita in Rwanda LEAP Model

Other key assumptions/projections for the Commercial/Institutional sector in the New Reference case of the Rwanda LEAP model include:

- The saturation of air conditioning (AC) in commercial and institutional floorspace rises from about 8.4 percent in 2020 to 30 percent in 2050, which is somewhat lower than assumed in the earlier MAED modeling effort. The intensity of air conditioning use rises only slightly over time, as trends for lower indoor temperatures (greater comfort) are mostly offset by natural improvements in AC efficiency and in building envelope insulation.
- The intensity of electricity use in standards devices (high-efficiency devices are not phased in as a part of the New Reference case) increases over time, again representing the tradeoff between greater use as incomes rise and improved efficiency of electric devices (Figure B.6.4-C).
- The intensity of traditional use of biomass fuels (both wood and charcoal—see Figure B.6.4-D) use drops significantly over time.
- The energy intensity of modern biomass devices rises (Figure B.6.4-E), with charcoal use making up 80 percent of modern biomass use by 2050, up from 50 percent in 2020.
- The use of solar in the sector rises over time.

- The use of LPG rises. Electricity intensities for the same end-uses are served by LPG are assumed to use a fraction of the energy per unit floorspace as LPG devices (Figure B.6.4-F), but are not phased in as a part of the New Reference scenario.

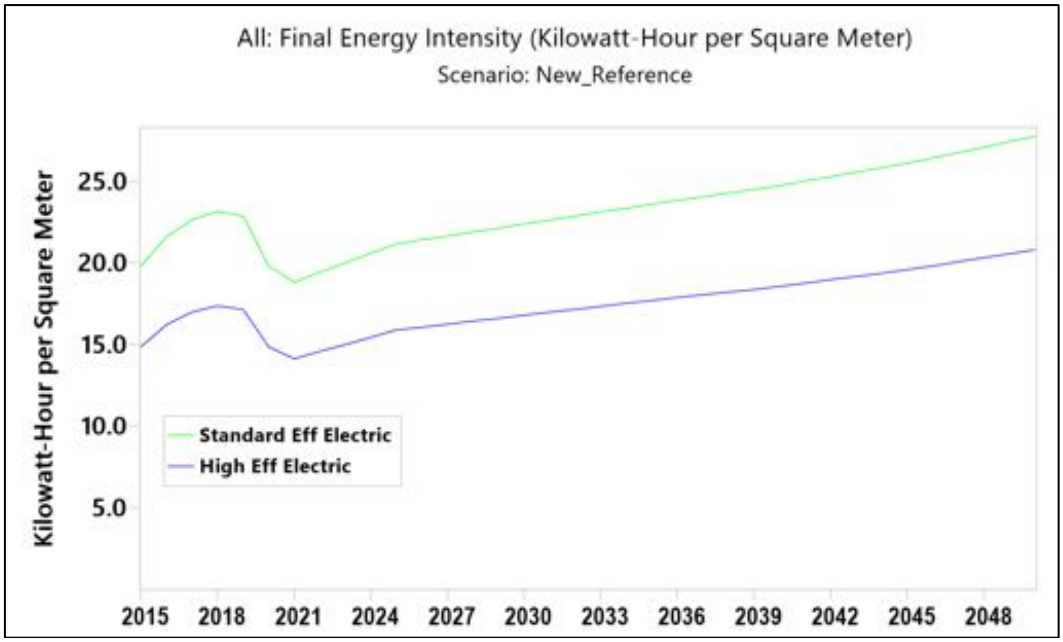

Figure B.6.4-C: Assumption for Trend in Electricity Intensity in Non-AC Commercial and Institutional End Uses

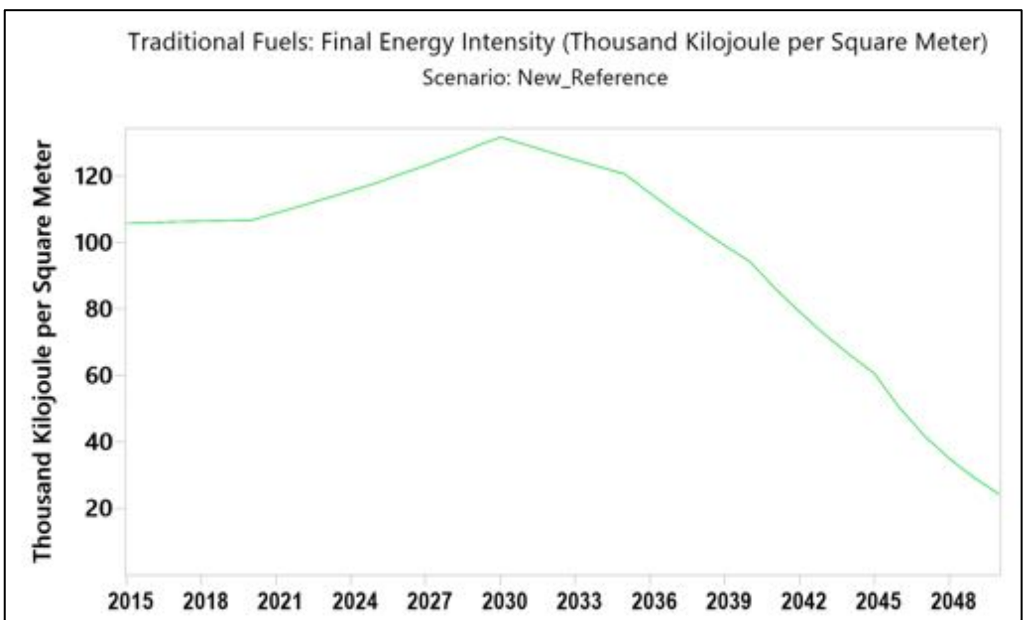

Figure B.6.4-D: Assumption for Trend in Intensity of Traditional Biomass Fuel Use per Unit Commercial and Institutional Floorspace Rwanda LEAP Model

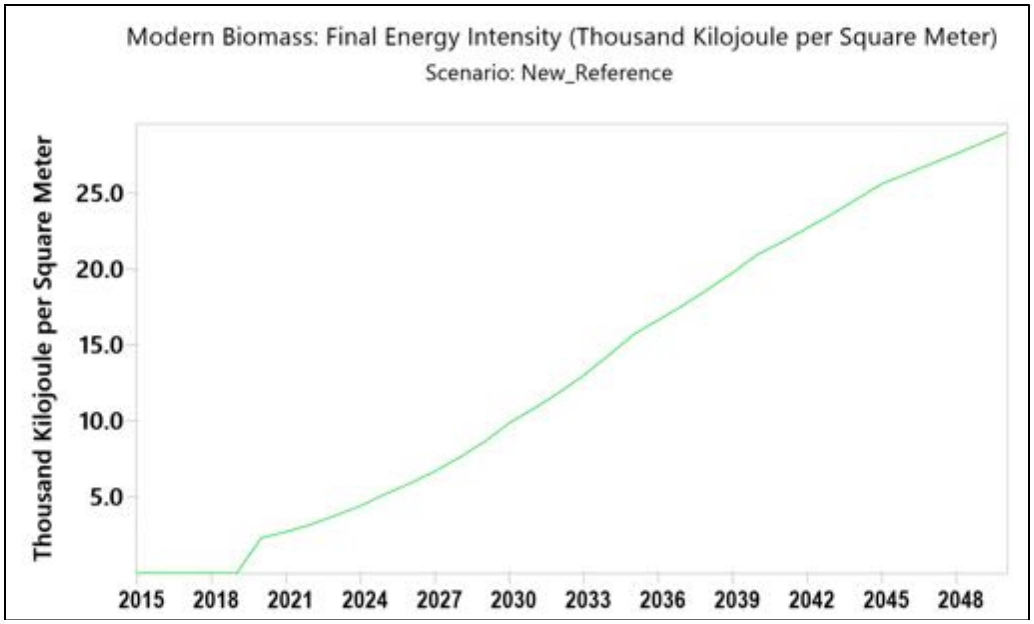

Figure B.6.4-E: Assumption for Trend in Intensity of Modern Biomass Fuel Use per Unit Commercial and Institutional Floorspace Rwanda LEAP Model

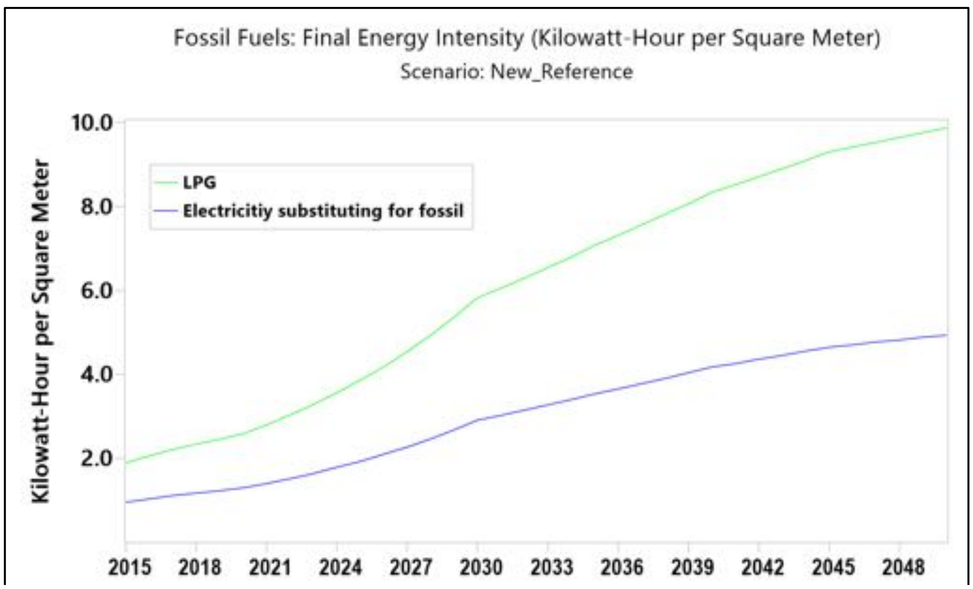

Figure B.6.4-F: Assumption for Trend in Intensity of Current Fossil Fuel End Uses per Unit Commercial and Institutional Floorspace Rwanda LEAP Model

Figure B.6.4-G shows the New Reference case trends in fuel use by end-use and fuel in the Commercial and Institutional sector. Here end uses using electricity, LPG, and solar grow rapidly, but the use of biomass fuels (charcoal and wood) continues to account for a large portion of sectoral energy use, although modern devices for using charcoal and word are phased in. Figure B.6.4-H shows that air conditioning becomes a much more important end-use of electricity in Rwanda over time in the New Reference case, accounting for about 30 percent of electricity demand by 2050. Figure B.6.4-I shows that electricity and LPG use increase as a fraction of overall fuel use, but the use of charcoal and wood remains important in the sector.

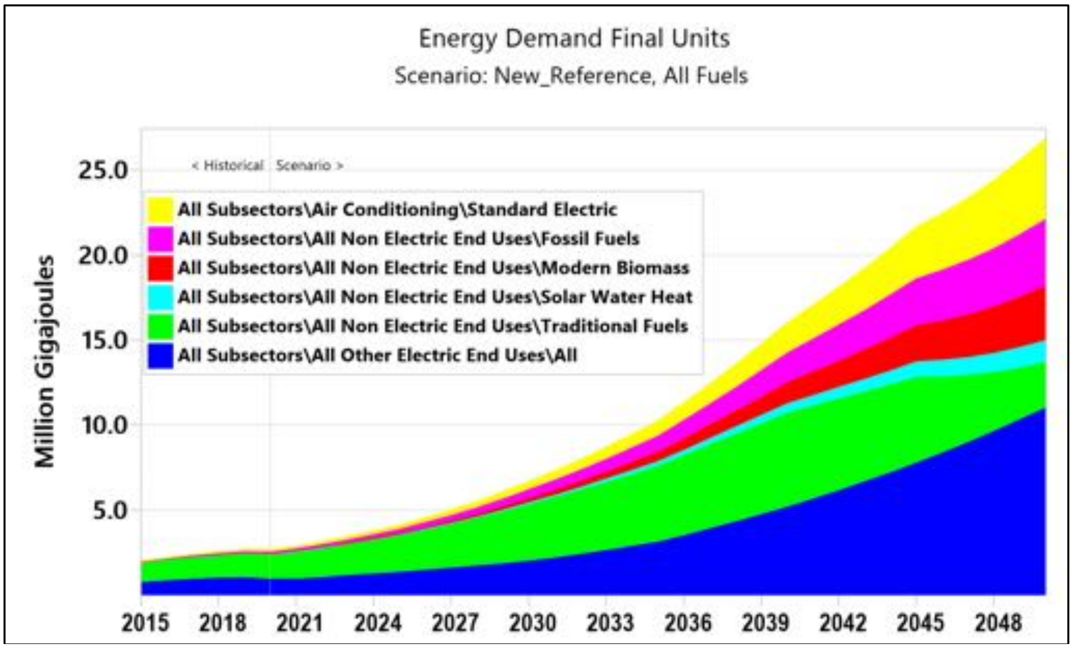

Figure B.6.4-G: Commercial and Institutional New Reference Case Results: Overall Energy Use by End-use and Fuel Type

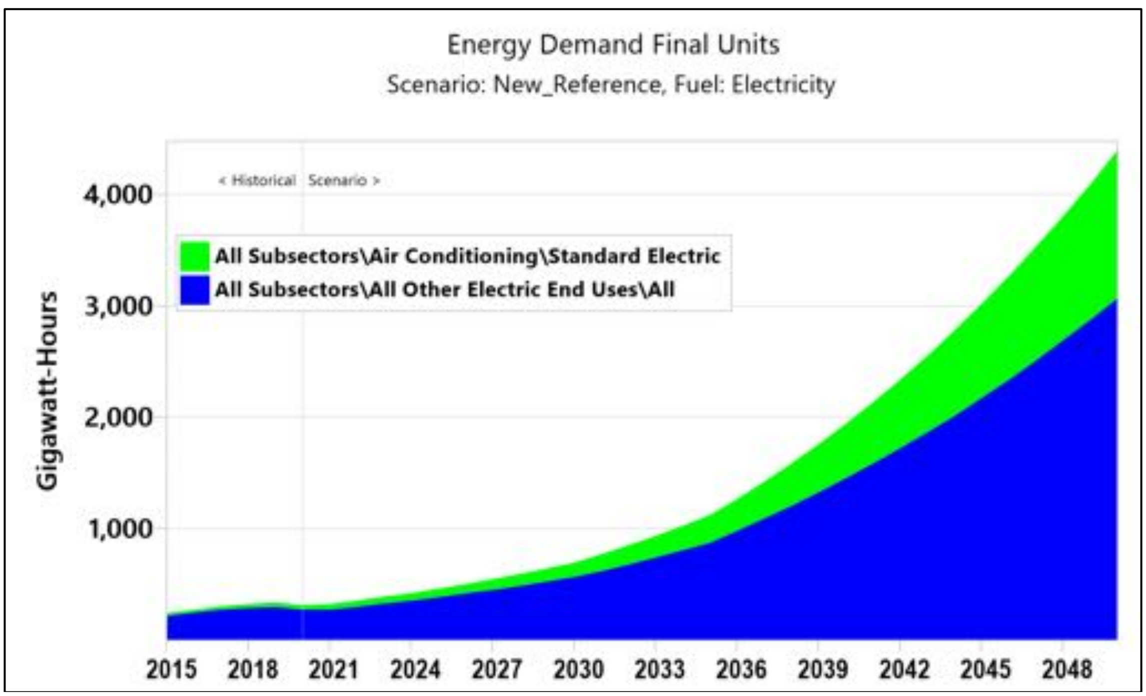

Figure B.6.4-H: Commercial and Institutional New Reference Case Results in Rwanda LEAP Model: Electricity Use by End-use

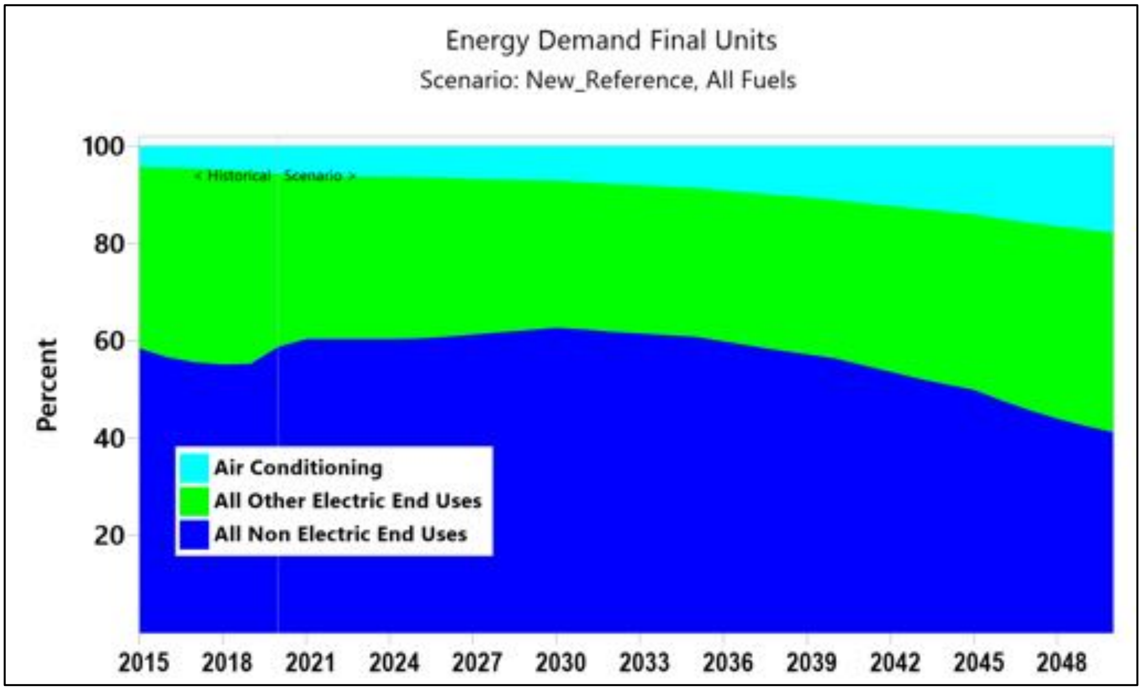

Figure B.6.4-I: Commercial and Institutional New Reference Case Results in Rwanda LEAP Model: Fraction of Energy Use by End-use

B.6.5. TRANSPORTATION SECTOR

The structure of the transportation sector in the Rwanda LEAP model generally follows the structure and much of the input data of the earlier MAED model. Transportation activity and energy use is divided into four subsectors denoting different types of transport: urban passenger transport, intercity passenger transport, freight transport, and international passenger transport. Each of these subsectors is divided into different vehicle types and/or transportation modes, as shown in Figure B.6.5-A.
The main driving activities—billion passenger-km per year—for the urban passenger transport and intercity passenger transport subsectors are shown in Figure B.6.5-B. In both cases growth is less than in the original MAED model, but intercity passenger transport still grows by a factor of 10, and urban transport by a factor of five, in the LEAP New Reference case between 2020 and 2050.

Figure B.6.5-A: Rwanda LEAP Model "Tree" for the Transportation Sector

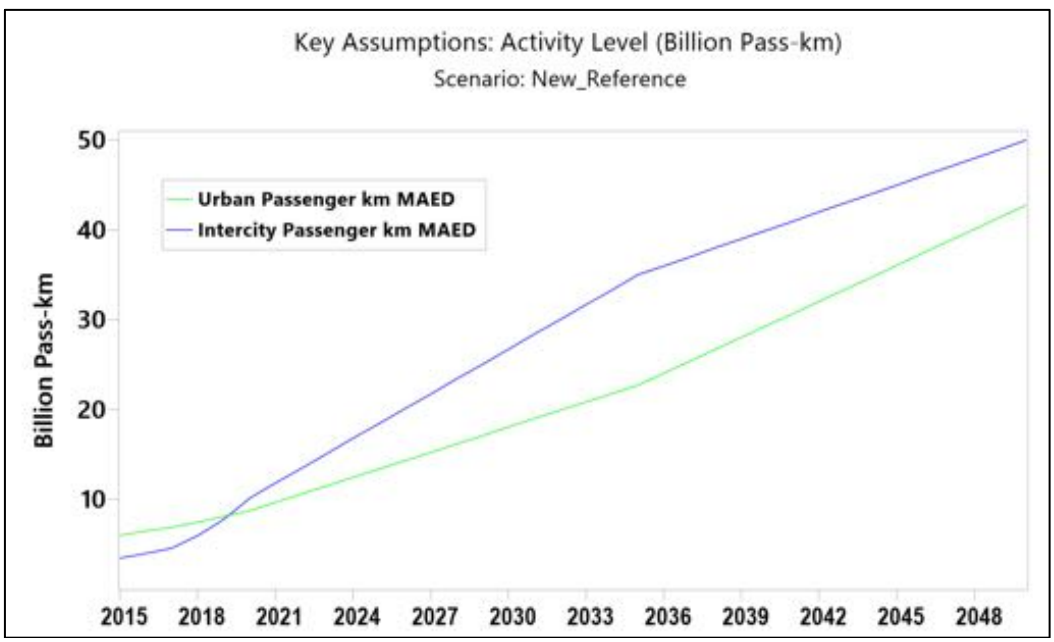

Figure B.6.5-B: Key Driving Activities for the Urban Passenger and Intercity Passenger Subsectors in the Rwanda LEAP Model (Billion Passenger-km)

In the urban passenger transport subsector, the share of cars, SUVs (sports utility vehicles) and pickups increase over time, mostly at the expense of the share of urban transport by bus, with some reduction in the share of travel by motorbike/motorcycle, as household incomes rise (Figure B.6.5-C). Based on assumptions from the MAED model, "Sand/Minibuses" continue to transport the dominant share of urban public passengers—60 to 65 percent.[174] In the New Reference case, electricity is introduced as an energy source for urban transport starting int the 2020s, with the fraction of vehicles using electricity in the urban sector rising by 2050 to 35 percent for cars/SUVs/pickups, 30 percent for buses, and 75 percent for motorbikes and motorcycles, which are already being rapidly electrified in many places, most notably China. The overall energy intensities of fossil-fueled vehicles (energy used per passenger-km) in most cases are assumed to fall slowly over time as improved vehicles are available, with the exception being electric vehicles, where intensities—already much lower than for fossil-fueled vehicles—are assumed to change very little over time, probably reflecting offsetting changes such as improvements in efficiency but the addition of larger electric vehicles to the fleet.

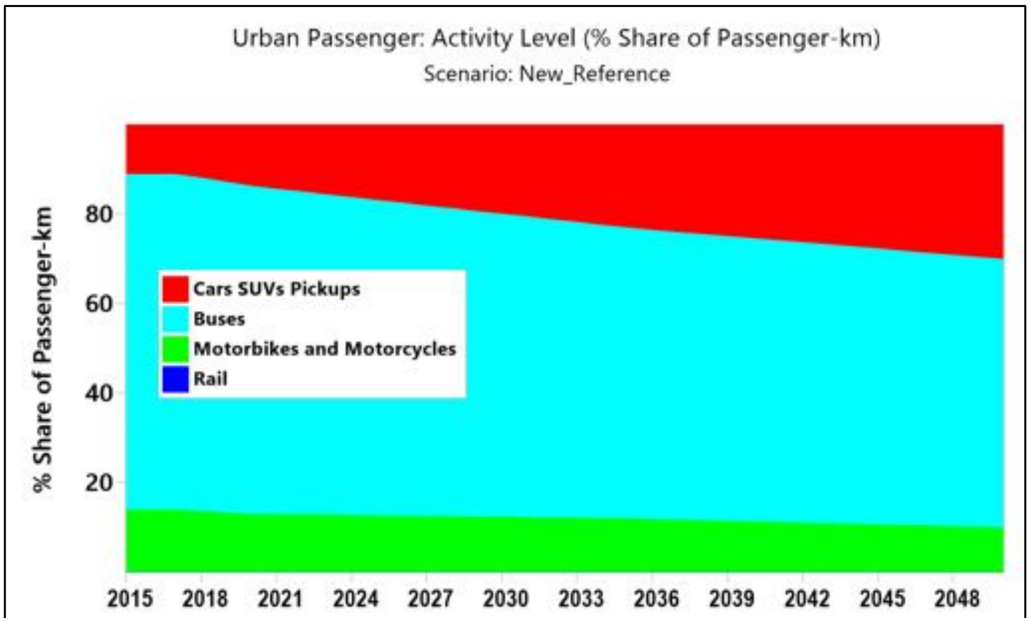

Figure B.6.5-C: Fraction of Urban Passenger Activity by Type of Vehicle in the Rwanda LEAP Model (Share of Passenger-km)

Intercity passenger transport is split into transport in public and private vehicles. The share of intercity transport in public vehicles (now busses) is assumed to slowly fall from about the 80 percent level currently and in 2030 to 70 percent in 2050, as incomes rise and citizens are able to afford more private intercity transport. Of private vehicles, the share of transport on motorbikes and motorcycles falls from about the 30 percent level currently to zero in 2050 (Figure B.6.5-D), which might, for example, reflect the improvement of intercity roads in Rwanda and prohibitions on long-distance transport by motorcycle for safety reasons, as well as rising incomes. This assumption is derived from the earlier

[174] The dominance of mini-buses in the modeling of intercity passenger transport here (and in the earlier MAED model) appears to be somewhat at odds with previously announced government plans (see for example, *The New Times* (2011), "Mini-buses to be phased out", dated October 31, 2011, and available as https://www.newtimes.co.rw/section/read/36360), and should probably be reviewed in the next versions of the LEAP model.

MAED model, and as with others, could be revisited as in the next version of the LEAP model.[175] For private sector intercity transport, 40 percent of cars/SUVs and pickups are assumed to be electric by 2050, but all intercity motorcycle/motorbike use remains gasoline-powered. In public intercity transport, rail is phased in starting in 2031, but accounts for only five percent of passenger-km by 2050, with busses accounting for the rest. All rail is assumed to be electric, and 40 percent of bus passenger-km are in electric vehicles by 2050. Over time, the use of larger buses largely replace "Sand Mini Buses" in intercity passenger transport (Figure B.6.5-E) presumably as improved roads and transit terminals make larger buses the preferred alternative. A placeholder category for "microbus" transport is included in the model, but no data have been added for this vehicle type as yet. Based on MAED model inputs, the intensities of diesel buses fall over time, but those of electric buses stay fairly stable. The relative intensities of diesel and electric buses should be investigated and revised in the next version of the LEAP model.

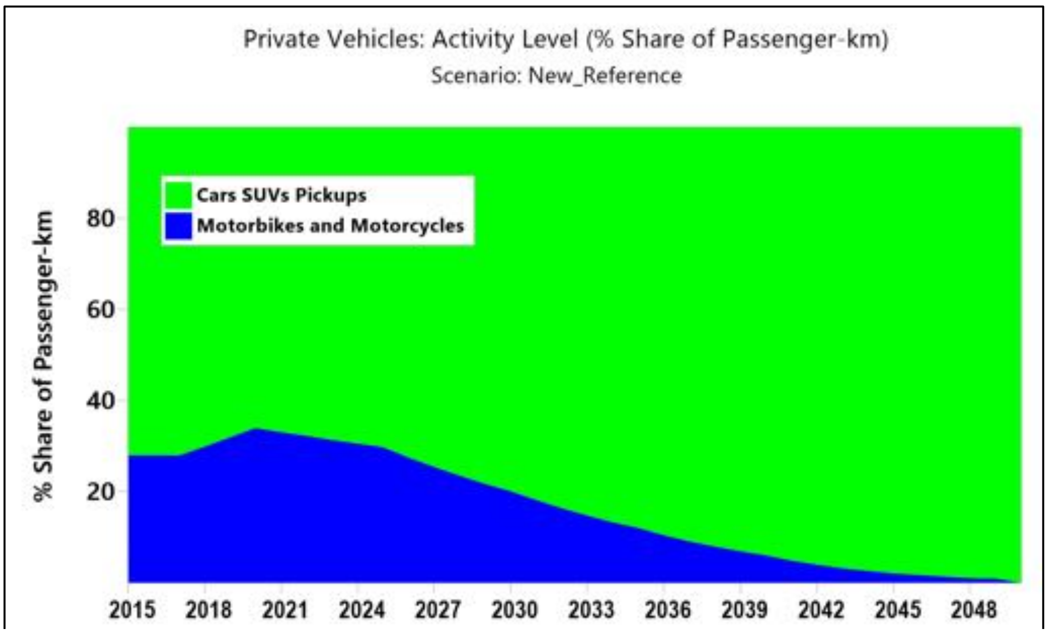

Figure 4: Fraction of Intercity Private Passenger Activity by Type of Vehicle for the Rwanda LEAP Model (Share of Passenger-km)

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[175] Note, for example, that intercity motorcycle transport in the US and Europe, while certainly a small percentage of total intercity passenger-km, is definitely non-zero. Although not directly on the topic of motorcycle transport, the EUROPEAN MOBILITY ATLAS (2021), published by the Heinrich-Böll-Stiftung European Union, Brussels, Belgium, and available as https://eu.boell.org/sites/default/files/2021-02/EUMobilityatlas2021_FINAL_WEB.pdf provides some interesting thoughts and figures on the current status and future options for transportation in Europe and beyond.

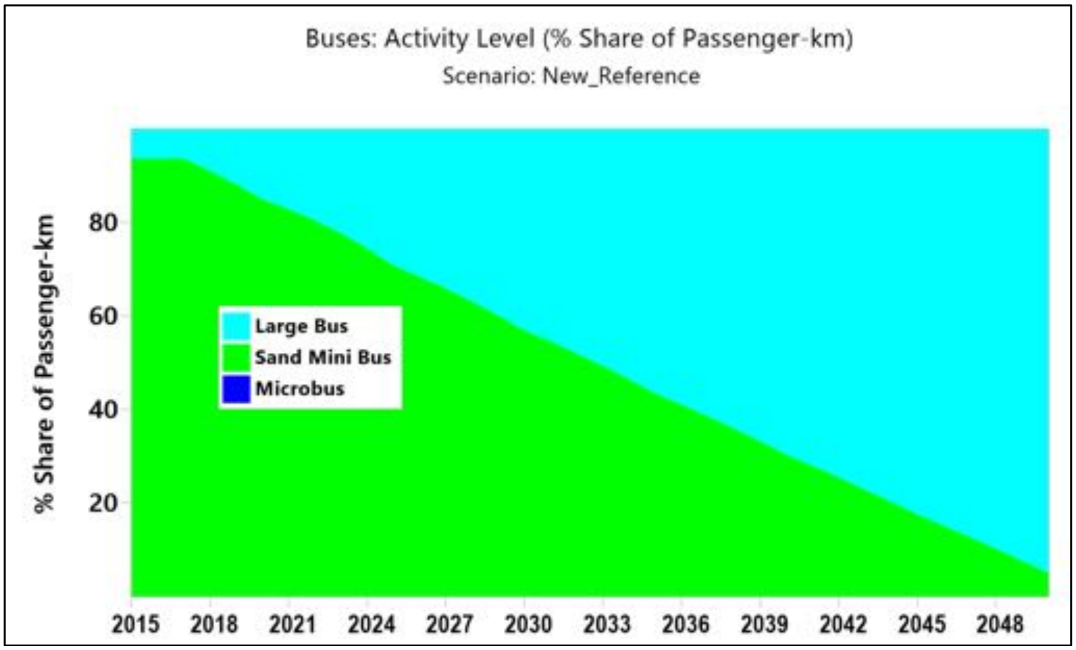

Figure B.6.5-E: Fraction of Intercity Public Bus Transit by Type of Bus for the Rwanda LEAP Model (Share of Passenger-km)

The main driving assumption in the freight transport subsector in the Rwanda LEAP model is the growth in freight tonne-km transported (see Figure B.6.5-F). This growth, while still rapid, particularly after 2035, is considerably less than the growth assumed in the Rwanda MAED dataset, with the difference largely due to the lower GDP growth rate used in the LEAP dataset. Freight is the LEAP model is carried by trucks and electric rail, with rail starting to be used in 2031 and rising to 20 percent of freight carried by 2050 (Figure B.6.5-G). Truck freight transport is by diesel pickups and larger diesel trucks, with the fraction carried in diesel pickups rising from about 11 percent in 2020 to 19 percent in 2030, remaining at about that level for the remainder of the modeling period. A category for gasoline trucks is provided in the model, but the share of freight carried in gasoline trucks is currently set to zero, pending additional data. Electric trucks are not phased in as a part of the New Reference case, which is an assumption that might be revisited in later LEAP modeling efforts. The energy intensities of all types of trucks, measured in energy units per tonne-km of freight transported, fall slightly between 2020 and 2050.

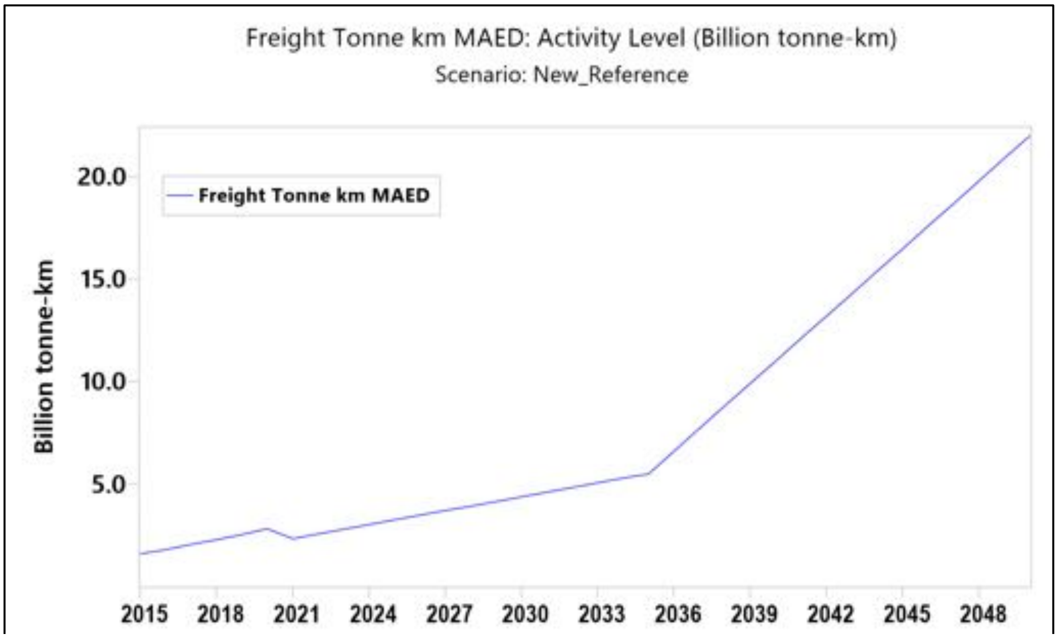

Figure B.6.5-F: Freight Tonne-km Growth Trend for the Rwanda LEAP Model

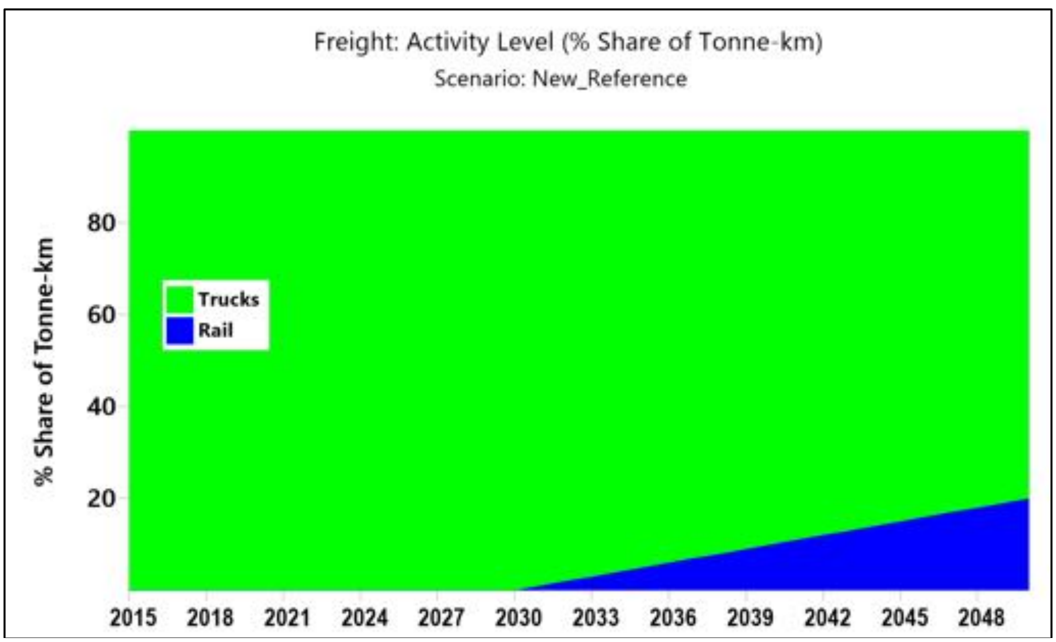

Figure B.6.5-G: Fraction of Freight Tonne-km Carried by Mode for the Rwanda LEAP Model

International passenger transport grows steadily over the modeling period, from 1.1 billion passenger-km per year in 2020 to over 12 billion passenger-km per year in 2050. At present, although there are categories for rail and air international transport in the model, only bus transport is currently included, due to the lack of available energy data (in the case of air transport), and the lack of information as to whether international passenger rail service is planned for Rwanda. These two transport modes therefore represent opportunities for model enhancement in the future. International bus transport is all diesel through 2050, and the intensity of diesel bus transport declines slowly over the modeling period.

The results of the New Reference case for the transportation sector by subsector and type of vehicle are shown in in Figure B.6.5-H. The major users of energy in the sector by 2050 are cars, SUVs, and pickups, both in urban and intercity transport, and diesel trucks (and pickups) used for freight transport. Energy use by motorbikes and motorcycles in urban transport shows a decline, but mostly after 2040. Overall, energy use for transport grows by nearly a factor of six between 2020 and 2050.

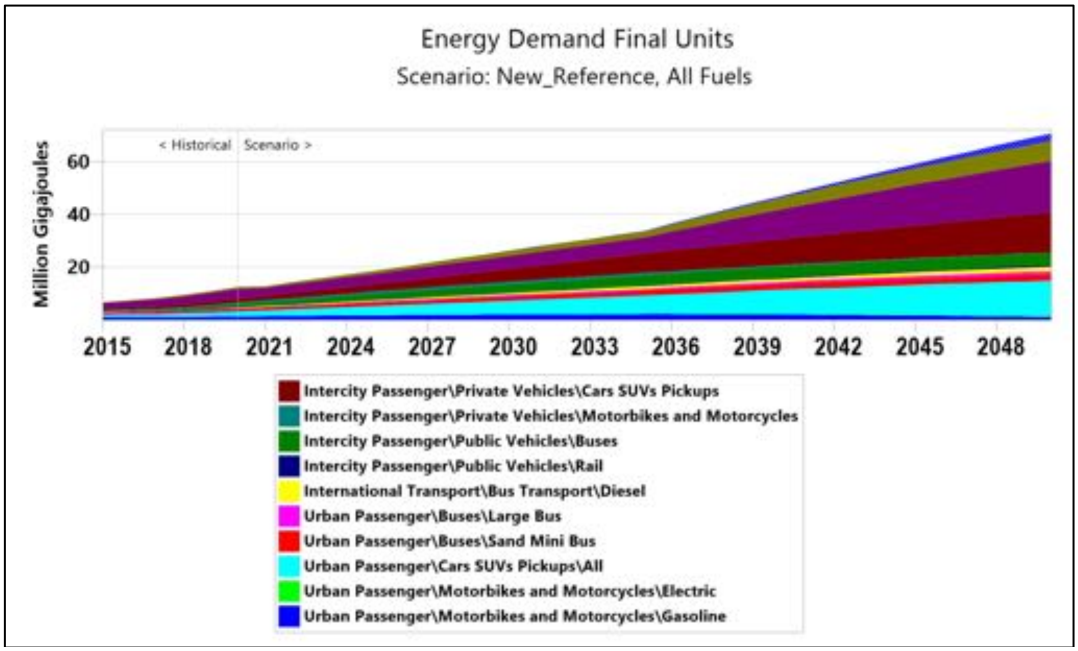

Figure B.6.5-H: Transport Sector Results in the New Reference Case by Subsector and Type of Vehicle for the Rwanda LEAP Model

Diesel is and remains the dominant fuel for transport in Rwanda, with electricity phased in so as to account for about 16 percent of total energy use in the sector by 2050 in the Reference case (Figure B.6.5-I). Total electricity use in the transport sector rises from near zero in 2020 to over 3000 GWh annually by 2050 (Figure B.6.5-J).

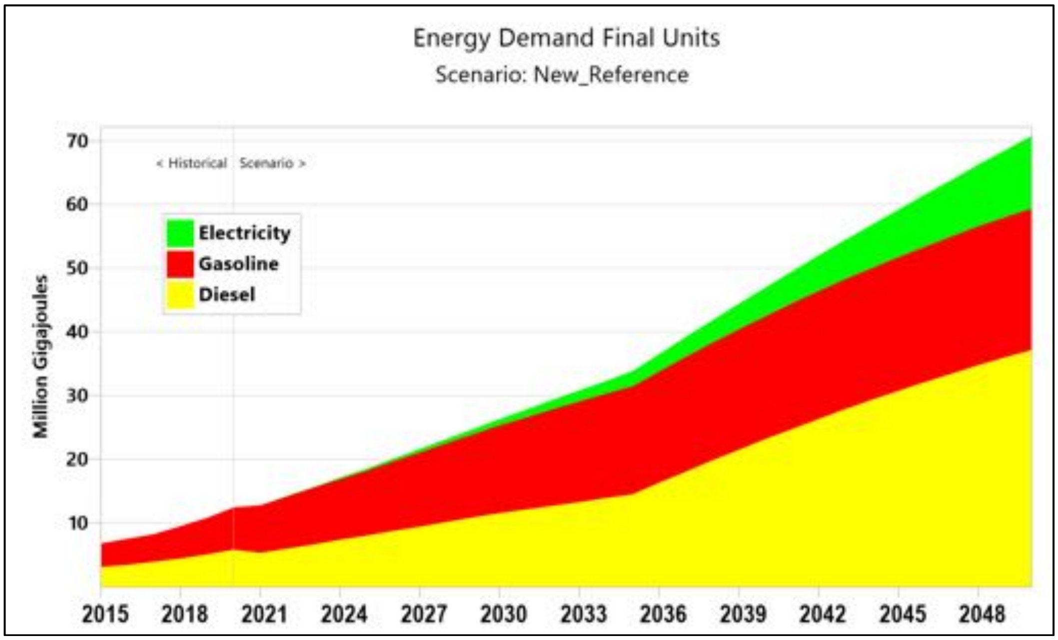

Figure B.6.5-I5: Transport Sector Results in the New Reference Case by Fuel for the Rwanda LEAP Model

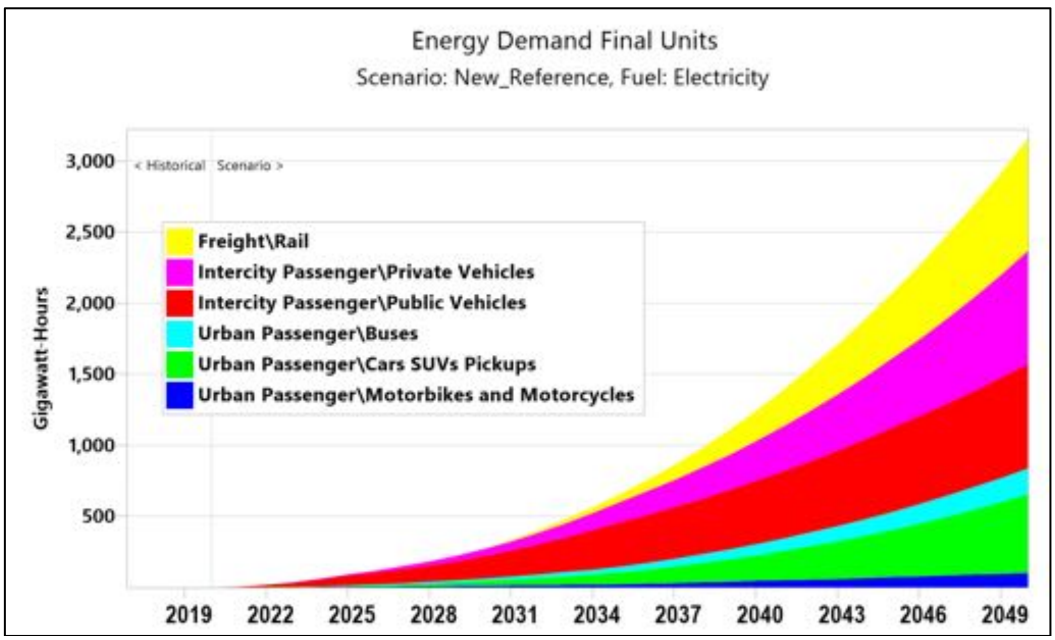

Figure B.6.5-J: Transport Sector Electricity Use Results in the New Reference Case by Subsector and Vehicle for the Rwanda LEAP Model

B.6.6. AGRICULTURAL SECTOR

The LEAP model structure for the Agricultural sector in Rwanda is shown in Figure B.6.6-A. Note that although separate subsectors are provided for Field Crops, Livestock, and Forestry, these branches are not currently used, as no energy data use data were immediately available for those branches. As a result, all agricultural energy use is modeled in the "All Agric by GDP" branch, with electricity-specific end uses and motive power (powered either by diesel and electricity) covered in separate sub-branches.

The main driver of growth in agricultural energy use is growth in agricultural GDP, which expands by about a factor of 10 between 2020 and 2050, as shown in Figure B.6.6-A), although the fraction of total GDP accounted for by agricultural output is assumed to decline slowly over time at the Rwanda economy matures.

Figure B.6.6-A: Rwanda LEAP Model "Tree" for the Agricultural Sector

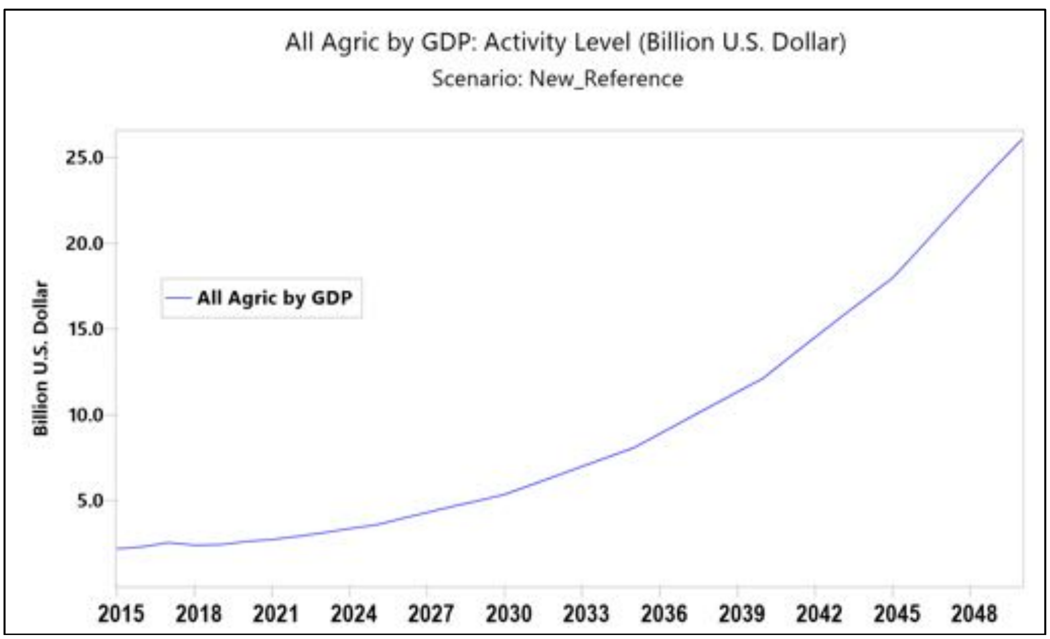

Figure B.6.6-B: Projection for Agricultural GDP in the Rwanda LEAP Model

The intensity of electricity use in the Agricultural sector in Rwanda, measured in energy units per constant USD of GDP, is assumed to increase over time, although at a much lower rate as was assumed in the earlier MAED modeling effort. The intensity of the use of electrical devices—including pumps, processing equipment, and lighting, for example—is assumed to grow by about a factor three between 2020 and 2050, reflecting a combination of greater mechanization of agriculture, probably a trend toward larger farms, higher agricultural incomes so that more equipment can be purchased, greater needs for irrigation pumping, and greater availability of electricity as a result of rural electrification

efforts. The energy intensities of motive power end-uses (diesel fueled) likewise increase, for many of the same reasons, but only by about 50 percent between 2020 and 2050. No conversion of diesel end-uses to electric power occurs in the Agricultural sector in the New Reference case.
Figure B.6.6-C shows the results for Agricultural sector energy use by fuel. Overall energy use grows by nearly a factor of 20 between 2020 and 2050, with electricity use in the sector growing even faster, by nearly a factor of 30 by the end of the modeling period.

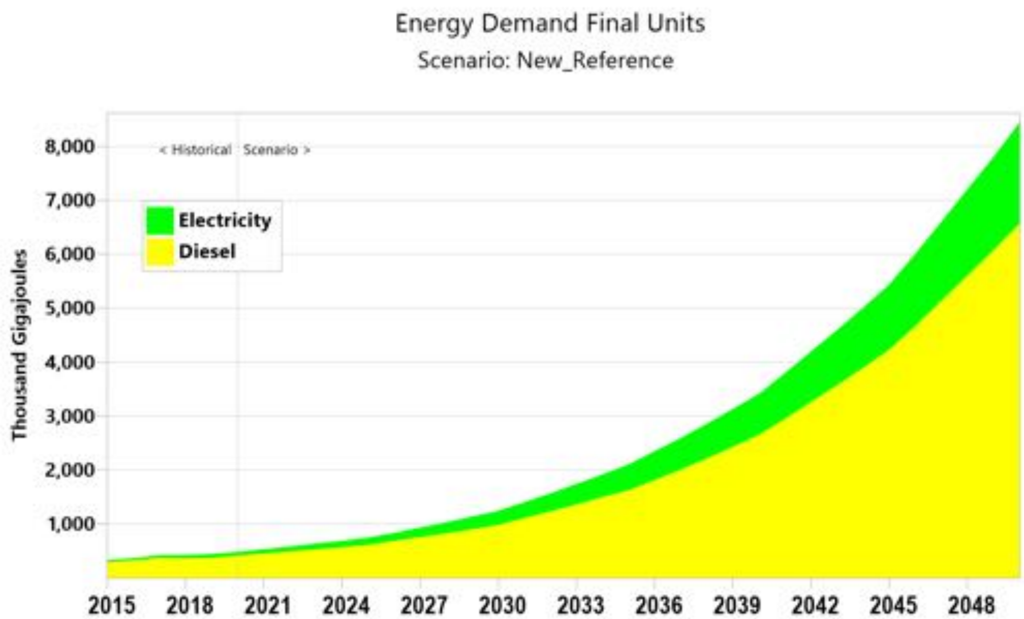

Figure B.6.6-C: Agricultural Sector Results in the New Reference Case by Fuel for the Rwanda LEAP Model

B.6.7. WATER PROVISION AND TREATMENT SECTOR

The final sector under Demand in the Rwanda LEAP model covers the provision of water and water and wastewater treatment. This sector is not covered by the earlier MAED model, but is based on evaluation of water and water treatment sector electricity use from RURA Statistics, as well as activity data from Rwanda national statistics. Although, as shown in Figure B.6.7-A, a branch is provided for non-electric end uses, this branch is not currently used, so only electricity use in the sector is covered. The activity driver for water sector energy use is the fraction of GDP made up by the sector, and the growth in national GDP. The fraction of GDP provided by the water Pumping and Treatment sector grows by about 50 percent between 2020 and 2050, to about 1 percent of GDP, reflecting greater needs for water and water treatment as the population, and particularly the urban population, of Rwanda expands. The intensity of electricity use in the sector, in energy units per unit of sectoral GDP, is assume to grow only slightly during the modeling period, but, as shown in Figure B.6.7-B, overall electricity use in the sector expands rapidly due to the assumed rapid growth rate in overall national GDP.

Figure B.6.7-A: Rwanda LEAP Model "Tree" for the Water Pumping and Treatment Sector

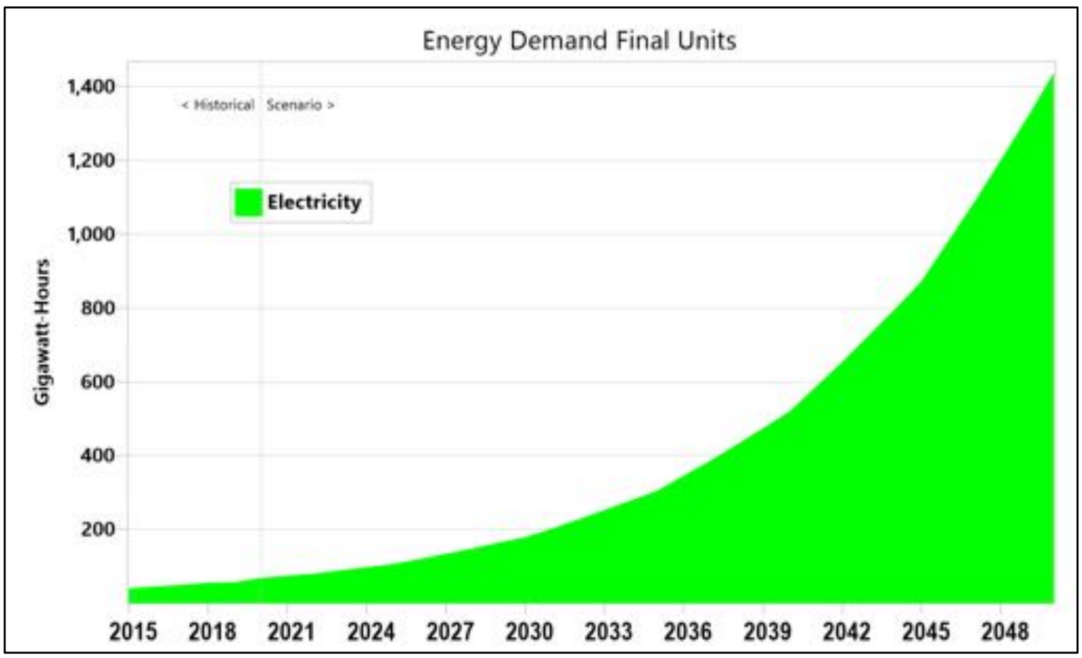

Figure B.6.7-B: Water and Water Treatment Sector Electricity Use Results in the New Reference Case by Fuel for the Rwanda LEAP Model

B.6.8. OVERALL LEAP DEMAND RESULTS

A selection of overall LEAP Demand results across sectors is provided below. Figure B.6.8-A shows overall all-fuels demand by sector and subsector. Growth in the manufacturing subsector and (relatedly) in freight, intercity, and urban transport are notable, as is the reduction in overall rural residential use due mostly to the reduction in the use of wood and other biomass fuels as well as to urbanization.

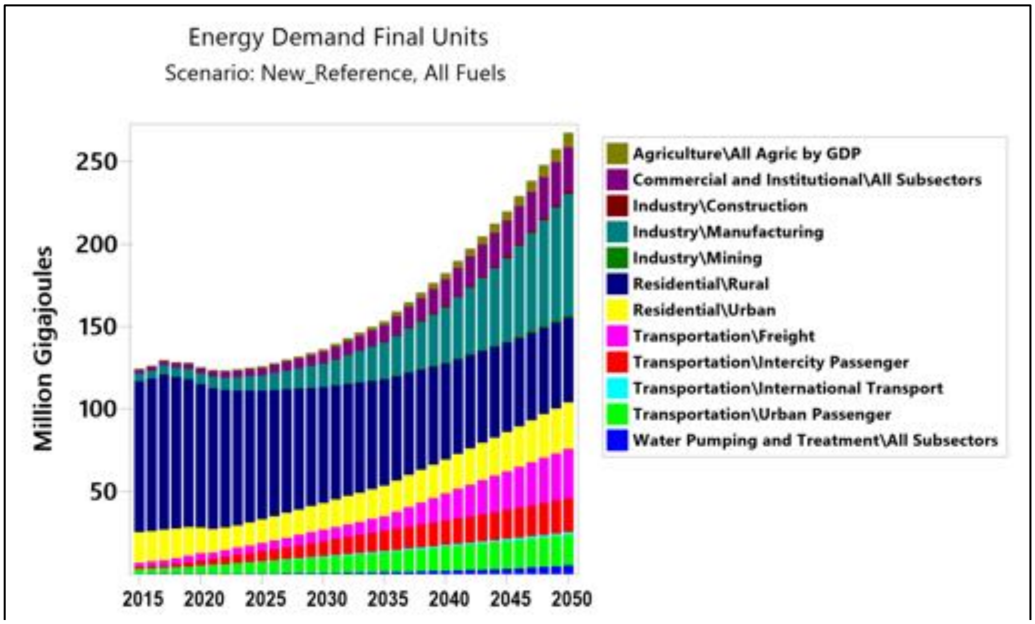

Figure B.6.8-A: Demand Results by Sector and Subsector for All Fuels in the New Reference Case of the Rwanda LEAP Model

Figure B.6.8-B shows overall demand results by fuels for the New Reference scenario. Here growth in electricity and diesel use dominate, with the reduction and low growth in the use of wood and charcoal fuels reducing the growth in overall demand. As shown in Figure B.6.8-C on the other hand, growth in electricity demand is rapid and continuing, thanks to a combination of GDP growth, urbanization, manufacturing and commercial/institutional electricity use growth, electrification of transportation, and rural electrification. Figure B.6.8-D focuses on the use of electricity from solar home systems and mini-grids in meeting a portion of residential electricity demand, showing how these forms of electricity use are phased out over time as the central electricity grid reaches more areas.

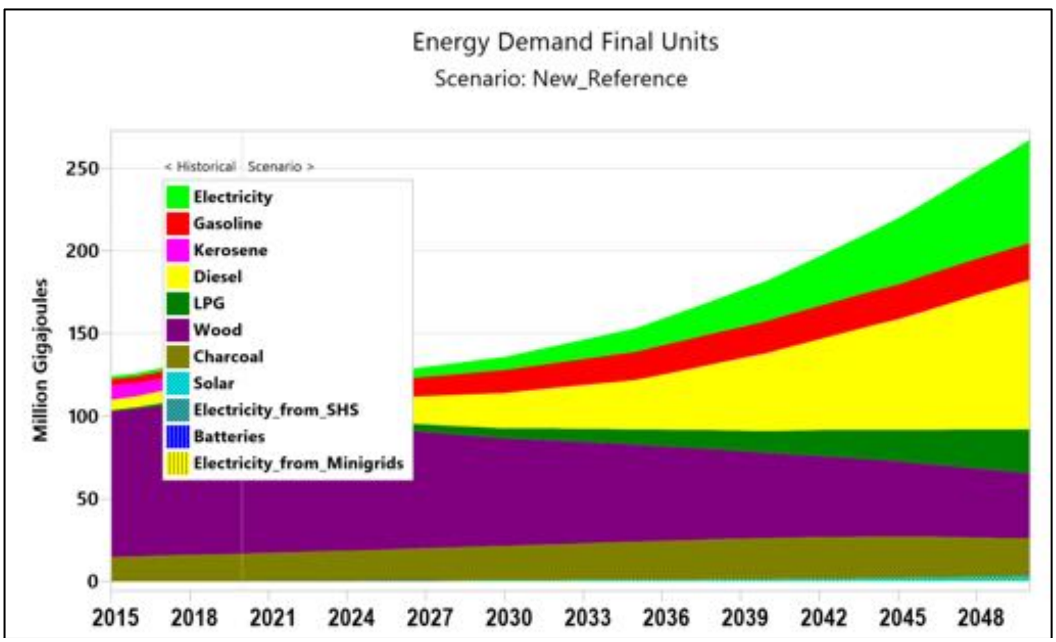

Figure B.6.8-B: Demand Results by Fuel for All Sectors in the New Reference Case of the Rwanda LEAP Model

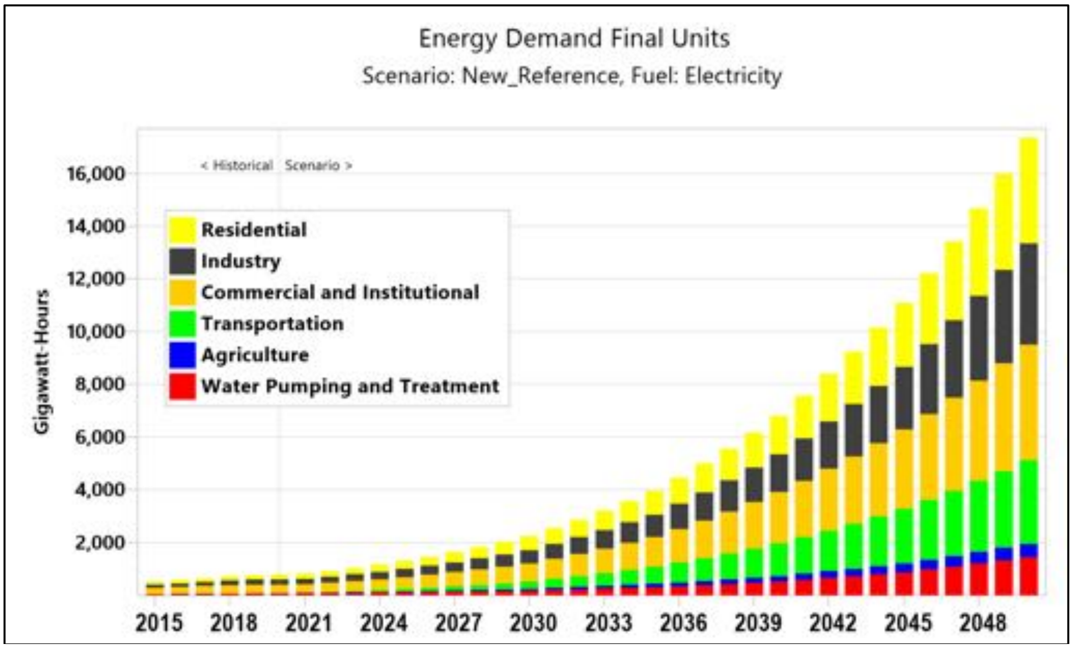

Figure B.6.8-C: Electricity Demand Results by Sector in the New Reference Case of the Rwanda LEAP Model

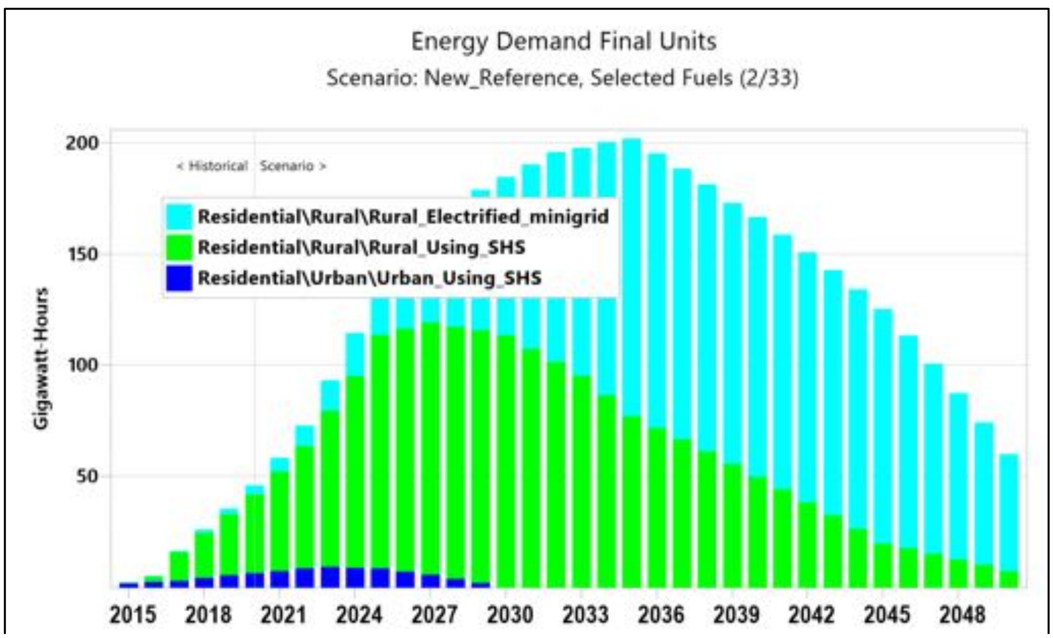

Figure B.6.8-D: Electricity Demand Results by Sector in the New Reference Case of the Rwanda LEAP Model

Overall diesel demand in the New Reference Case grows nearly as rapidly as electricity use, dominated by the manufacturing and freight transport subsectors (Figure B.6.8-E). Wood and related fuels (vegetal wastes and charcoal) demand, on the other hand, continually decline, as incomes rise and households opt for cleaner and more convenient fuels (Figure B.6.8-F). By 2050, however, demand for these fuels is still significant, at about 60 percent of 2020 levels.

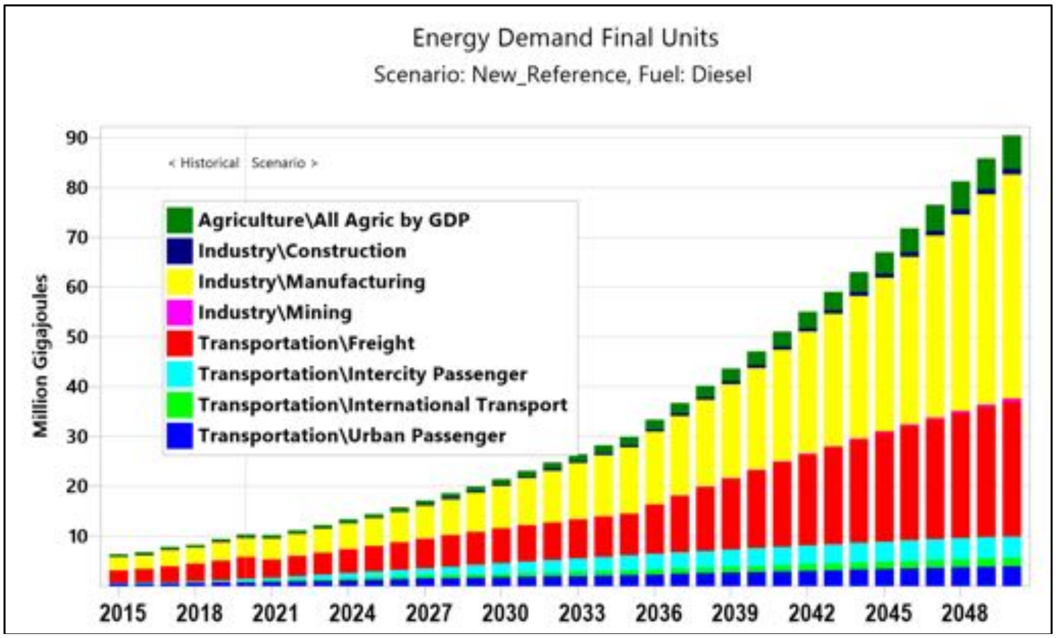

Figure B.6.8-E: Diesel Demand Results by Sector in the New Reference Case of the Rwanda LEAP Model

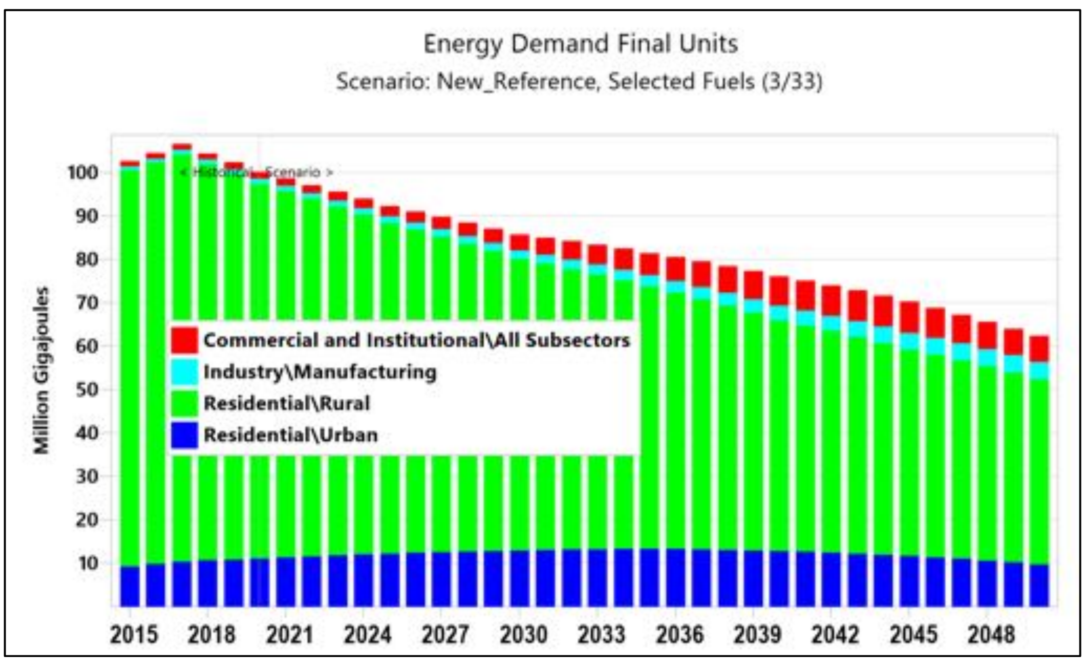

Figure B.6.8-F: Wood, Charcoal, and Vegetal Waste Demand Results by Sector in the New Reference Case of the Rwanda LEAP Model

B.6.9. OVERALL RESULTS: ENERGY BALANCES

Energy balances, and related Sankey diagrams, provide an overview of both energy supply and demand by fuel and by category of fuel production, conversion, and use. Table B.6.9-A, Table B.6.9-B and Table B.6.9-C show, respectively, energy balances for Rwanda for 2021, 2035, and 2050, and Figure B.6.9.-A and Figure B.6.9.-B show the 2035 and 2050 energy balances in graphical form as Sankey diagrams. Over time, as shown in the diagrams, the importance of wood and other biomass fuels in the economy decreases, and the roles of electricity and fossil fuels increase.

TABLE B.6.9-A. MODELED RWANDA ENERGY BALANCE FOR 2021, NEW REFERENCE SCENARIO

Energy Balance for Area "Rwanda_4-7-22"
Scenario: New_Reference, Year: 2021, Units: Million Gigajoule

	Electricity	Gasoline	Kerosene	Diesel	Residual Fuel Oil	LPG	Peat	Wood	Charcoal	Solar	Hydro	Electricity from SHS	Methane Lake Kivu	Electricity Imported	Batteries	Electricity from Minigrids	Generator Diesel	Total
Production	-	-	-	-	-	-	0.4	55.0	-	0.2	2.9	-	0.3	-	-	-	-	58.7
Imports	-	7.5	1.7	10.2	0.2	2.4	-	101.1	-	-	-	0.1	-	0.1	0.0	-	0.0	123.4
Exports	-0.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-0.0
Total Primary Supply	-0.0	7.5	1.7	10.2	0.2	2.4	0.4	156.1	-	0.2	2.9	0.1	0.3	0.1	0.0	-	0.0	182.1
Electricity for Pumped Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Natural Gas Imports	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Charcoal Production	-	-	-	-	-	-	-	-74.5	17.1	-	-	-	-	-	-	-	-	-57.4
Electricity Minigrids	-	-	-	-	-	-	-	-	-	-0.0	-0.0	-	-	-	-	0.1	-	-
Electricity Generation SHS	-	-	-	-	-	-	-	-	-	-0.1	-	0.1	-	-	-	-	-	-
Peat Mining	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Electricity Generation	3.4	-	-	-0.1	-0.2	-	-0.4	-	-	-0.1	-2.8	-	-0.3	-0.1	-	-	-0.0	-0.6
Transmission and Distribution	-0.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-0.5
Total Transformation	2.9	-	-	-0.1	-0.2	-	-0.4	-74.5	17.1	-0.2	-2.9	0.1	-0.3	-0.1	-	0.1	-0.0	-58.5
Residential	0.6	-	1.7	-	-	1.2	-	80.3	15.6	0.0	-	0.2	-	-	0.0	0.0	-	99.6
Industry	0.8	-	-	4.3	-	1.0	-	0.6	0.6	-	-	-	-	-	-	-	-	7.4
Commercial and Institutional	1.1	-	-	-	-	0.1	-	0.7	0.9	0.0	-	-	-	-	-	-	-	2.9
Transportation	0.0	7.5	-	5.4	-	-	-	-	-	-	-	-	-	-	-	-	-	12.8
Agriculture	0.1	-	-	0.4	-	-	-	-	-	-	-	-	-	-	-	-	-	0.5
Water Pumping and Treatment	0.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.3
Total Demand	2.9	7.5	1.7	10.1	-	2.4	-	81.7	17.1	0.0	-	0.2	-	-	0.0	0.0	-	123.6
Unmet Requirements	0.0	-	-0.0	-0.0	-	0.0	-	-0.0	-	0.0	-	-	-	-	-	-0.1	-	-0.1

TABLE B.6.9-B. RWANDA ENERGY BALANCE FOR 2035, NEW REFERENCE SCENARIO

Energy Balance for Area "Rwanda_4-22-22_with_exercise"
Scenario: New_Reference, Year: 2035, Units: Million Gigajoule

	Electricity	Natural Gas	Gasoline	Kerosene	Diesel	LPG	Peat	Wood	Charcoal	Solar	Hydro	Municipal Solid Waste	Electricity from SHS	Methane Lake Kivu	Electricity Imported	Utility Solar Cost Category 1	Electricity from Minigrids	Imported Natural Gas	Generator Diesel	Total
Production	-	-	-	-	-	-	5.7	55.0	-	1.2	7.4	1.9	-	5.7	-	0.4	-	-	-	77.3
Imports	-	0.0	17.0	0.2	30.2	9.2	-	103.2	-	-	-	-	0.0	-	1.9	-	-	1.7	1.9	165.3
Exports	-0.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-0.0
Total Primary Supply	-0.0	0.0	17.0	0.2	30.2	9.2	5.7	158.2	-	1.2	7.4	1.9	0.0	5.7	1.9	0.4	-	1.7	1.9	242.6
Electricity for Pumped Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Natural Gas Imports	-	1.7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-1.7	-	-
Charcoal Production	-	-	-	-	-	-	-	-99.6	22.8	-	-	-	-	-	-	-	-	-	-	-76.7
Electricity Minigrids	-	-	-	-	-	-	-	-	-	-0.3	-0.2	-	-	-	-	-	0.5	-	-	-
Electricity Generation SHS	-	-	-	-	-	-	-	-	-	-0.3	-	-	0.3	-	-	-	-	-	-	-
Peat Mining	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Electricity Generation	16.0	-1.7	-	-	-0.3	-	-5.7	-	-	-0.1	-7.3	-1.9	-	-5.7	-1.9	-0.4	-0.0	-	-1.9	-10.8
Transmission and Distribution	-1.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-1.8
Total Transformation	14.2	-0.0	-	-	-0.3	-	-5.7	-99.6	22.8	-0.6	-7.4	-1.9	0.3	-5.7	-1.9	-0.4	0.4	-1.7	-1.9	-89.4
Residential	3.1	-	-	0.2	-	4.9	-	55.6	18.2	0.2	-	-	0.3	-	-	-	0.4	-	-	83.0
Industry	3.1	-	-	-	13.8	3.3	-	1.3	1.3	0.1	-	-	-	-	-	-	-	-	-	22.8
Commercial and Institutional	4.0	-	-	-	-	0.9	-	1.7	3.3	0.3	-	-	-	-	-	-	-	-	-	10.3
Transportation	2.4	-	17.0	-	14.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	33.8
Agriculture	0.5	-	-	-	1.6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.1
Water Pumping and Treatment	1.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.1
Total Demand	14.2	-	17.0	0.2	29.9	9.2	-	58.6	22.8	0.6	-	-	0.3	-	-	-	0.4	-	-	153.2
Unmet Requirements	0.0	-	-	-0.0	0.0	-	-	-	-0.0	-	-0.0	-	-	-	-	-	-0.0	-	-	-0.0

TABLE B.6.9-C RWANDA ENERGY BALANCE FOR 2050, NEW REFERENCE SCENARIO

Energy Balance for Area "Rwanda_4-7-22"
Scenario: New_Reference, Year: 2050, Units: Million Gigajoule

	Electricity	Natural Gas	Gasoline	Kerosene	Diesel	LPG	Peat	Wood	Charcoal	Solar	Hydro	Municipal Solid Waste	Electricity from SHS	Methane Lake Kivu	Electricity Imported	Utility Solar Cost Category 1	Electricity from Minigrids	Imported Natural Gas	Generator Diesel	Total
Production	-	-	-	-	-	-	5.4	55.0	-	3.2	4.4	1.9	-	10.7	-	1.7	-	-	-	82.4
Imports	0.2	0.0	22.2	0.2	90.4	26.6	-	84.8	-	-	7.0	-	-	-	7.2	-	-	51.0	57.3	346.9
Exports	-0.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-0.0
Total Primary Supply	0.2	0.0	22.2	0.2	90.4	26.6	5.4	139.8	-	3.2	11.4	1.9	-	10.7	7.2	1.7	-	51.0	57.3	429.3
Electricity for Pumped Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Natural Gas Imports	-	51.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-51.0	-	-
Charcoal Production	-	-	-	-	-	-	-	-100.5	23.1	-	-	-	-	-	-	-	-	-	-	-77.4
Electricity Minigrids	-	-	-	-	-	-	-	-	-	-0.3	-0.2	-	-	-	-	-	0.5	-	-	-
Electricity Generation SHS	-	-	-	-	-	-	-	-	-	-0.0	-	-	0.0	-	-	-	-	-	-	-
Peat Mining	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Electricity Generation	67.7	-51.0	-	-	-	-	-5.4	-	-	-0.1	-11.2	-1.9	-	-10.7	-7.2	-1.7	-0.3	-	-57.3	-79.0
Transmission and Distribution	-5.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-5.4
Total Transformation	62.3	-0.0	-	-	-	-	-5.4	-100.5	23.1	-0.4	-11.4	-1.9	0.0	-10.7	-7.2	-1.7	0.2	-51.0	-57.3	-161.9
Residential	14.4	-	-	0.2	-	11.4	-	36.1	16.3	0.9	-	-	0.0	-	-	-	0.2	-	-	79.6
Industry	13.8	-	-	-	46.7	11.3	-	2.0	2.0	0.7	-	-	-	-	-	-	-	-	-	76.5
Commercial and Institutional	15.8	-	-	-	-	3.9	-	1.2	4.7	1.3	-	-	-	-	-	-	-	-	-	26.9
Transportation	11.4	-	22.2	-	37.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	70.8
Agriculture	1.9	-	-	-	6.6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8.4
Water Pumping and Treatment	5.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.2
Total Demand	62.5	-	22.2	0.2	90.4	26.6	-	39.3	23.1	2.8	-	-	0.0	-	-	-	0.2	-	-	267.4
Unmet Requirements	-0.0	-	-	-	-0.0	-	-	0.0	-	-	-0.0	-	-	-	-	-	0.0	-	-	0.0

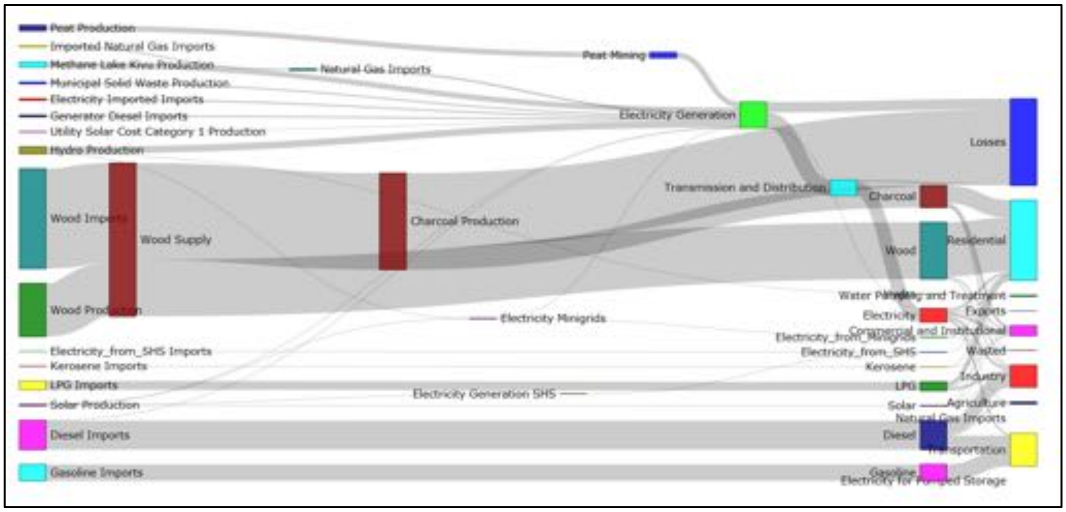

Figure B.6.9-A: Sankey Diagram for the Rwanda LEAP Model in 2035, New Reference Scenario

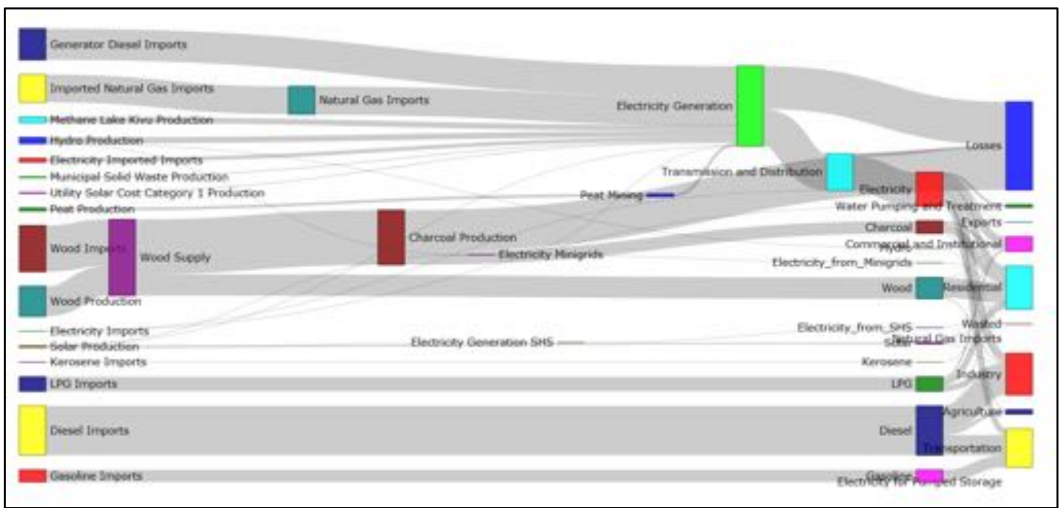

Figure B.6.9-B: Sankey Diagram for the Rwanda LEAP Model in 2050, New Reference Scenario

B.7. ELECTRICITY AND OTHER ENERGY TRANSFORMATION IN RWANDA

B.7.1. INTRODUCTION

The energy Transformation portion of the Rwanda LEAP model converts energy resources into intermediate fuels or into fuels and other energy forms (such as electricity) for final demand by end users, or moves fuels from one place to another. The Rwanda LEAP model includes the Transformation "modules" shown in the "Tree" in Figure B.7.1-A. Given the focus of the study that this Annex is a part of, several modules have to do with electricity generation, either on-grid, off-grid, or for peaking power, plus the transmission and distribution module to model losses in moving power to consumers. Each of these modules are discussed briefly below.

Figure B.7.1-A 6: Rwanda LEAP Model "Tree" for Transformation Modules and Resources

B.7.2. TRANSMISSION AND DISTRIBUTION

The Transmission and Distribution (T&D) Module models the movement of two energy forms around Rwanda: electricity and natural gas. Natural gas, for which imports begin the 2030s under the New Reference case, largely to fuel electricity generation, is assumed to have a loss rate of 0.3 percent in transmission and distribution, which is roughly consistent with values for modern, well-maintained natural gas T&D systems. The assumptions for the changes in electricity losses over time are shown in Figure B.7.2-A. Note that these losses do not include non-technical losses, that is, theft of electricity. Electricity lost through theft or pilferage is considered to be electricity demand, and both T&D loss fractions and demand (in the residential and commercial sectors) have been adjusted to account for these unpaid uses of electricity. Electricity T&D losses in historical years are based on REG and RURA statistics. In the future, electricity T&D losses are assumed to decline as the grid is extended and improved.

Figure B.7.2-B shows the inputs of electricity to the Transmission and Distribution module, reflecting the sum of the demand requirements and the losses in each year.

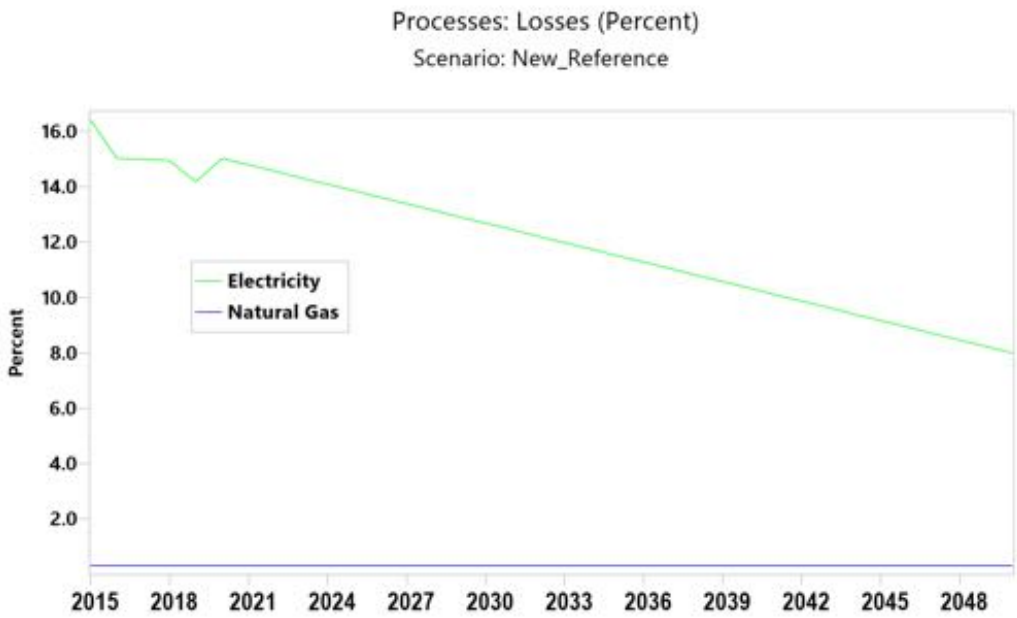

Figure B.7.2-A 7: Transmission and Distribution Loss Assumptions in the Rwanda LEAP Model

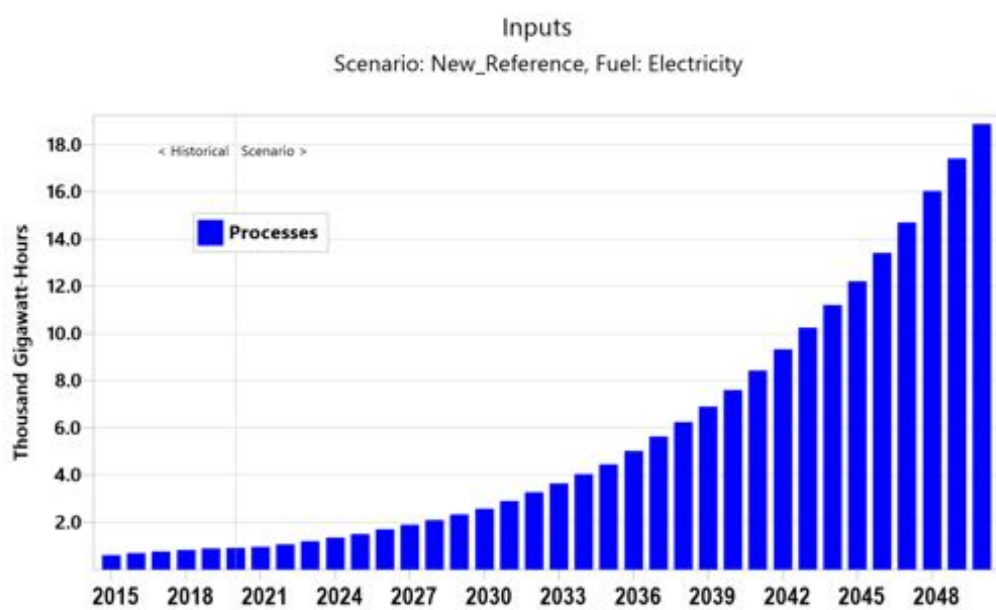

Figure B.7.2-B: Transmission and Distribution Electricity Inputs in the Rwanda LEAP Model

B.7.3. GRID ELECTRICITY SUPPLY

In the Rwanda LEAP model, most existing or planned plants larger than 1 MW are listed individually, while classes of potential new resources are also listed, often differentiated by parameters such as interconnection cost and application (solar), hub height (wind), or fuel type used. Each of these plant types (Figure B.7.3-A) are referred to as Processes within the Electricity Generation Module, meaning each is a device, technology, or procedure for converting one or more fuels or resources into electricity.

In terms of generation capacity, the New Reference case includes assumptions as to existing capacity and capacity additions through the late 2020s as provided by REG colleagues and included in REG documents such as the LCPDP. Most of these assumptions are included in the data compilation workbooks shared with REG. After 2030, in the New Reference Case, the LEAP model was set up with some additional specified ("exogeneous") capacity additions, including hydroelectric plants, following the trends of earlier years, but as these and the already-developed plants are insufficient to meet electricity demand, the New Reference case also included additions automatically added by LEAP ("endogenous additions"). The latter include new diesel-engine generation plants and natural gas simple-cycle (combustion turbine) and combine cycle plants.

Most of the assumptions used in the LEAP model for the cost and performance of existing and new generation options for Rwanda are documented in the data compilation workbooks and/or in the Levelized Cost of Energy workbook, the results of which are described in the main Report. Table B.7.3.-A presents a summary of the initial (capital) cost trends for the candidate future plants used in the New Reference and other scenarios. Generally, capital costs for most hydro, fossil fueled, lake methane, and peat plants do not change much over time, while wind power costs decline to some extent, and solar photovoltaic costs decline more steeply.

Figure B.7.3-A: Electricity Generation Processes in the Rwanda LEAP Model

Two additional cost-related assumptions included in the Electricity module are the net price assumed for electricity, based on existing tariffs (assuming fixed tariff of $180/MWh after 2019, with some growth as losses are reduced (the effective price rises over time because T&D losses fall, so revenue per unit of output rises), the trend for which is shown in Figure, plus the non-generation costs associated with providing electricity, including administration costs, which are assumed to track overall generation, and are shown in Figure B.7.3-B. Figure B.7.3-C through Figure B.7.3-F show, respectively, New Reference case results for total generation capacity, generation capacity added by year, greenhouse gas emissions by plant/plant type, and a module cost balance, each through 2050. In the module cost balance for the New Reference case, assuming fixed tariffs (as above), costs begin to exceed income in about 2035, as expensive-to-fuel diesel and natural gas plants begin to be required to meet demand.

TABLE B.7.3-A INITIAL (CAPITAL) COSTS OF GENERATION OPTIONS CONSIDERED IN ELECTRICITY MODULE, NEW REFERENCE SCENARIO IN SELECTED YEARS

Variable: Processes: Capital Cost (Thousand USD/MW)
Scenario: New_Reference
Branch: Transformation\Electricity Generation\Processes
Region: Region 1

Branch	2020	2030	2040	2050
New Diesels	$ 1,325	$ 1,325	$ 1,325	$ 1,325
New Peat Fired	$ 3,100	$ 3,100	$ 3,100	$ 3,100
New Methane	$ 7,846	$ 7,846	$ 7,846	$ 7,846
New Hydro Class I	$ 3,865	$ 3,865	$ 3,865	$ 3,865
New Hydro Class II	$ 4,090	$ 4,090	$ 4,090	$ 4,090
Pumped Storage Hydro	$ 3,500	$ 3,500	$ 3,500	$ 3,500
Wind 50m Class I	$ 2,458	$ 1,817	$ 1,664	$ 1,525
Wind 50m Class II	$ 2,612	$ 1,971	$ 1,818	$ 1,679
Wind 100m Class I	$ 1,605	$ 1,185	$ 1,085	$ 994
Wind 100m Class II	$ 1,668	$ 1,248	$ 1,147	$ 1,056
Wind 150m Class I	$ 1,596	$ 1,176	$ 1,075	$ 984
Wind 150m Class II	$ 1,615	$ 1,195	$ 1,094	$ 1,056
Utility Solar Class I	$ 1,489	$ 824	$ 724	$ 624
Utility Solar Class II	$ 1,623	$ 895	$ 795	$ 695
Utility Solar Class III	$ 1,761	$ 1,070	$ 970	$ 870
Utility Solar Class IV	$ 2,128	$ 1,232	$ 1,132	$ 1,032
Utility Solar Class I BES	$ 2,559	$ 1,974	$ 1,676	$ 1,430
Utility Solar Class II BES	$ 2,693	$ 2,108	$ 1,809	$ 1,563
Agri PV Class I	$ 2,177	$ 1,900	$ 1,574	$ 1,311
Agri PV Class II	$ 2,339	$ 2,061	$ 1,736	$ 1,473
Floating PV Class I	$ 1,911	$ 1,680	$ 1,410	$ 1,191
Floating PV Class II	$ 2,041	$ 1,811	$ 1,540	$ 1,322
Res Solar Dist PV	$ 2,142	$ 764	$ 670	$ 588
Res Solar Dist PV BES	$ 3,559	$ 1,779	$ 1,545	$ 1,342
ICI Solar Dist PV	$ 1,348	$ 688	$ 604	$ 530
ICI Solar DIst PV BES	$ 2,316	$ 1,261	$ 1,095	$ 951
Waste to Energy New	$ 5,621	$ 5,284	$ 4,968	$ 4,672
New Biomass fired Plants	$ 2,549	$ 2,387	$ 2,236	$ 2,094
Geothermal	$ 9,650	$ 9,203	$ 8,778	$ 8,374
New Natural Gas CC	$ 1,200	$ 1,200	$ 1,200	$ 1,200
New Natural Gas Simple	$ 600	$ 600	$ 600	$ 600

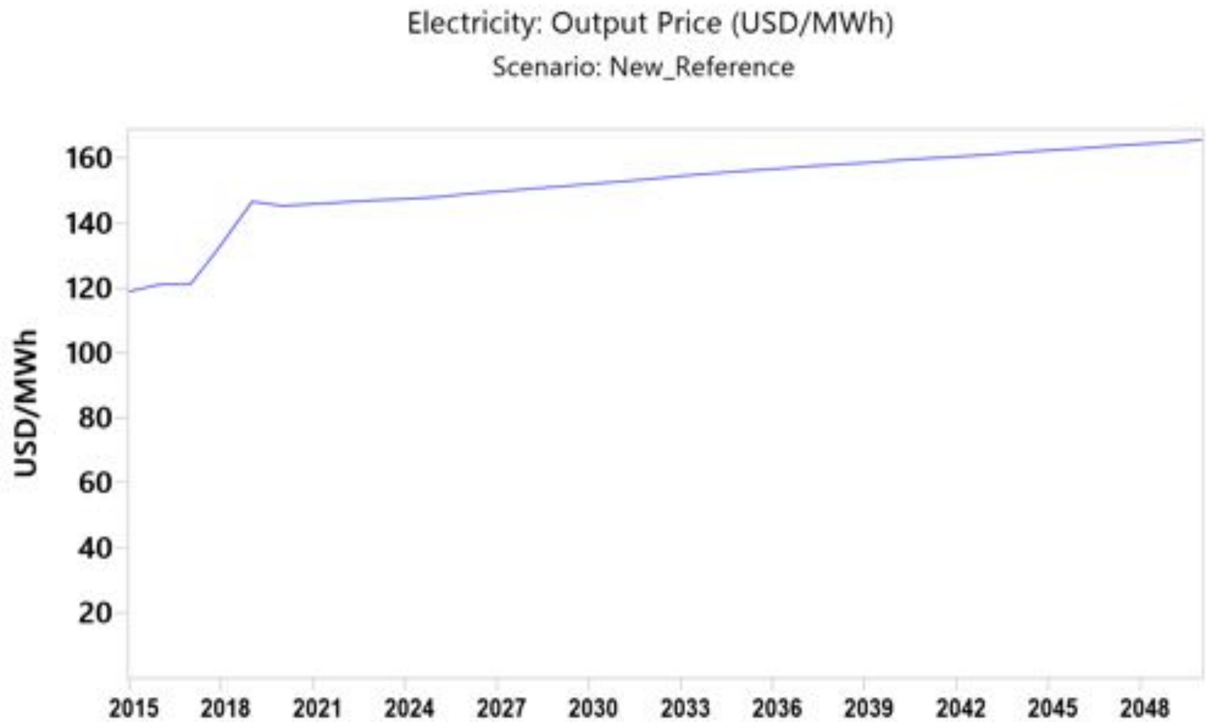

Figure B.7.3-B: Electricity Output Price Assumption in the Rwanda LEAP Model

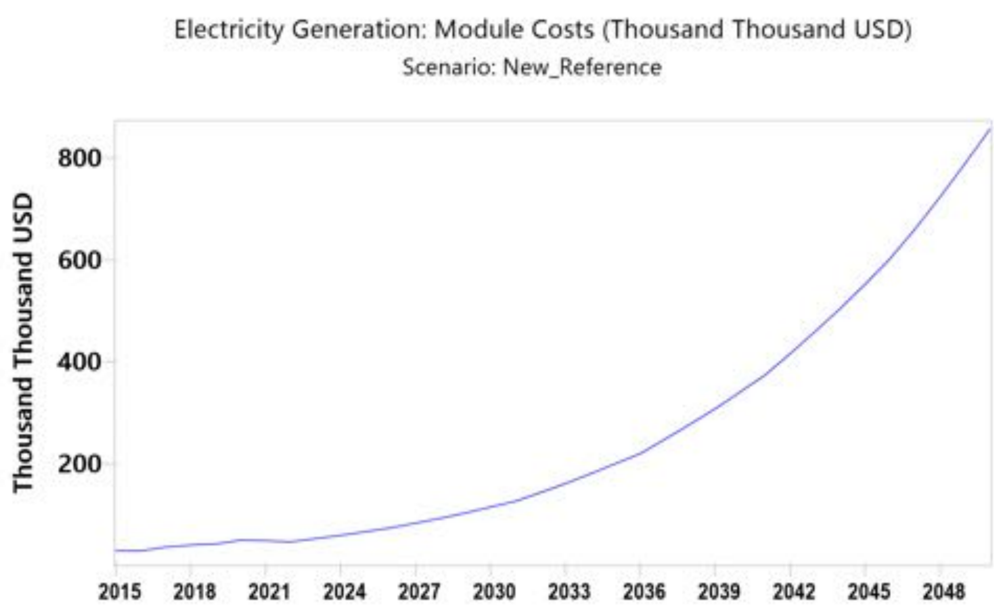

Figure B.7.3-C: Electricity "Module Costs" Assumptions in the Rwanda LEAP Model

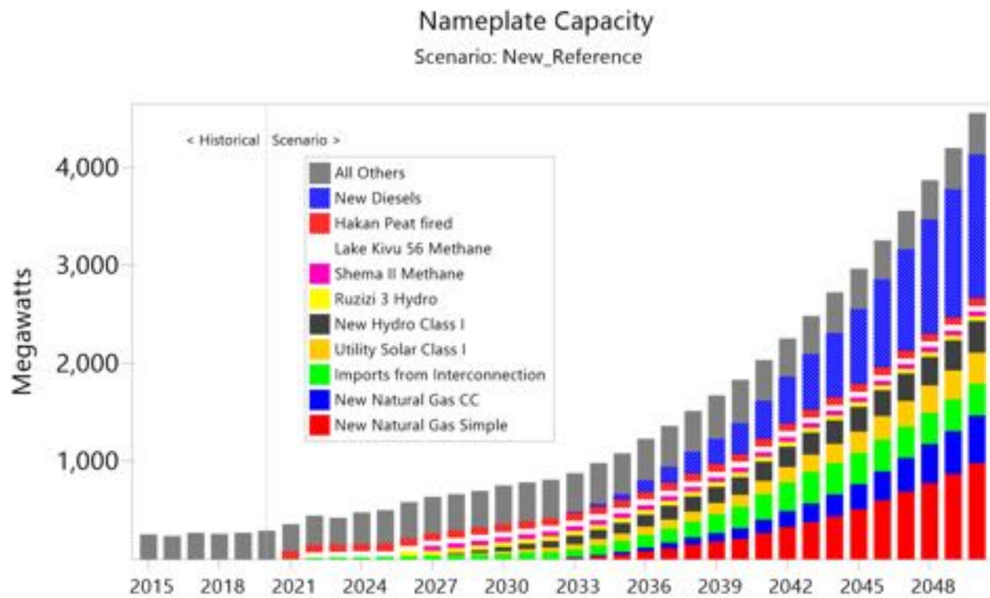

Figure B.7.3-D: Electricity Generation Nameplate Capacity Trends in the New Reference Case of the Rwanda LEAP Model

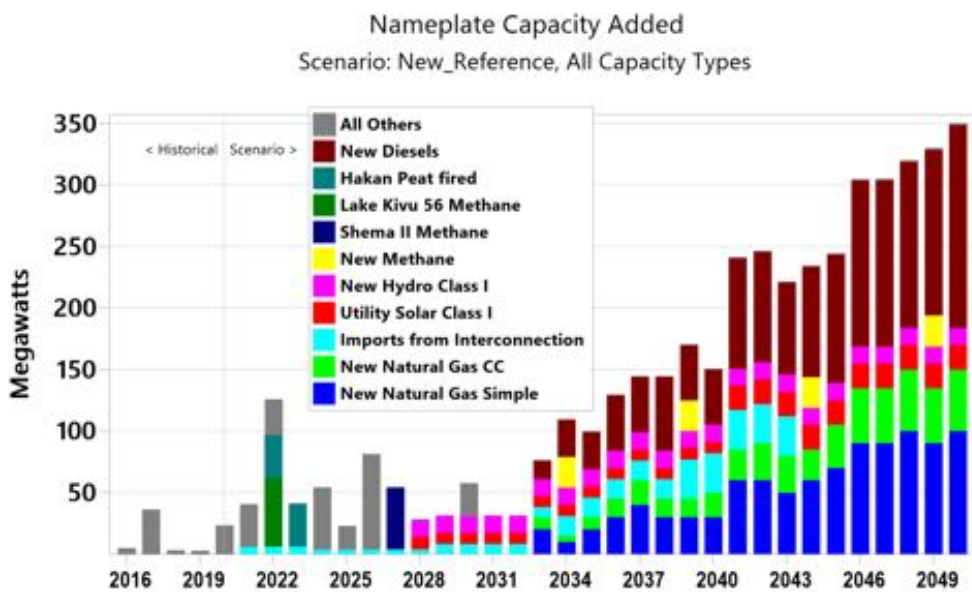

Figure B.7.3-E: Electricity Generation Nameplate Capacity Additions Trends in the New Reference Case of the Rwanda LEAP Model

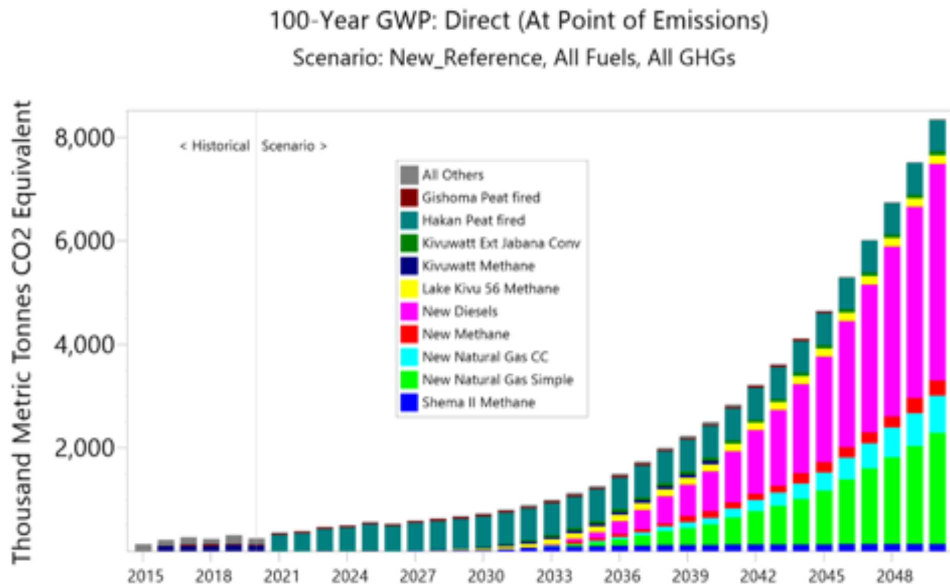

Figure B.7.3-F: Greenhouse Gas Emissions by Type of Generation Capacity in the New Reference Case of the Rwanda LEAP Model

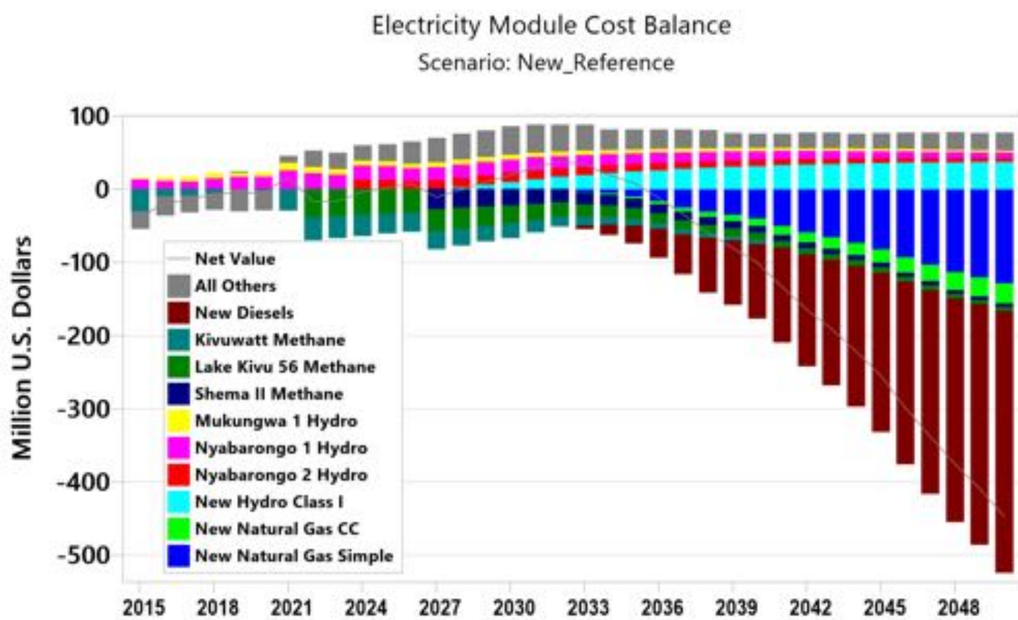

Figure B.7.3-H: Module Cost Balance for Electricity Module in the New Reference Case of the Rwanda LEAP Model

B.7.4. MICROGRID ELECTRICITY SUPPLY

In the Microgrid Electricity Supply module, generation from micro-hydro and solar PV plants are added to existing plants to meet the needs of micro- and mini-grids developed to serve some of the rural residential villages that would not be soon served by central grid extension. These plants produce an output, "Electricity_from_Minigrids", that is used in residential rural households served by minigrids, and as those households begin to be served by the central grid, the excess output of the mini- and microgrid generators is routed to the central grid.[176]

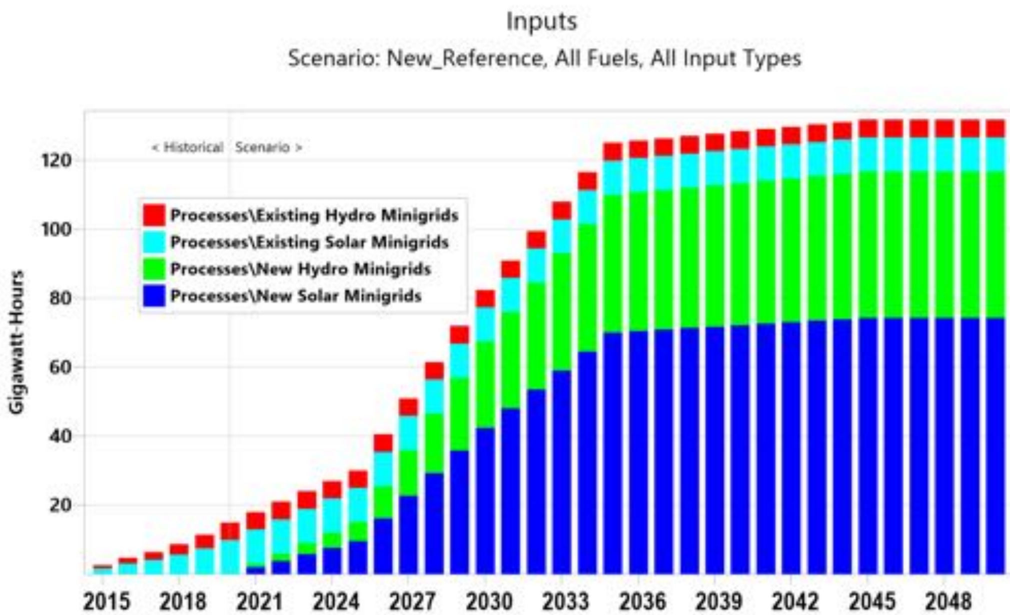

Figure B.7.4-A: Generation by Minigrids in the New Reference Case of the Rwanda LEAP Model

B.7.5. SOLAR HOME SYSTEMS

In the Solar Home Systems Electricity Supply module, generation from small solar home system PV panels meet the needs of urban (in the early years of the projection period) and rural households for whom minigrid or central grid power is not available. These systems produce an output, "Electricity_from_SHS", that is used in residential households but when those households begin to be served by the central grid (or by minigrids), it is assumed that those systems are retired or are repurposed for other uses, such as providing light in non-grid-connected outbuildings or charging devices on an auxiliary basis to grid or minigrid power. The trend in electricity output of SHS over time in the New Reference case is shown in Figure B.7.5-A.

[176] Note that costs of mini/microgrid generation have not yet been included in the Rwanda LEAP model, although they likely should be. Since generation from these resources do not change in the different scenarios so far explored with the model, the relative costs of the different scenarios are not affected by leaving out these costs.

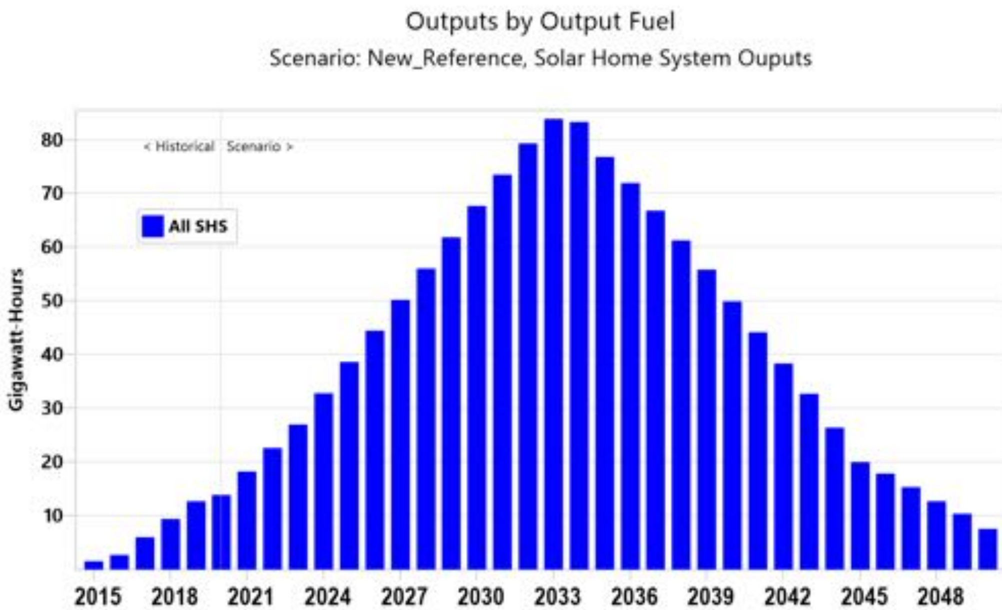

Figure B.7.5-A: Generation by Solar Home Systems in the New Reference Case of the Rwanda LEAP Model

B.7.6. ELECTRICITY GENERATION FOR STORAGE

As solar PV and other intermittent power, such as wind power, play increasingly larger roles in Rwanda—although for this study, more in scenarios other than the New Reference case—there is a need to balance demand during periods when solar energy is not available, particularly during evening peak periods (see load curves discussion below). To accomplish this balance, battery energy storage (BES), pumped-storage hydroelectric plants, or other types of electricity storage will be needed. BES in the Rwanda LEAP model is modeled within the main Electricity Generation module as a set of variant technologies for solar PV that, rather than having their output constrained by the time of day, use batteries to be able to store the output of the solar panels for use during peak periods. Longer-term storage can be provided by pumped-storage hydro, for which solar PV power is used to pump water into an upper reservoir from a lower reservoir through a connecting pipe (or "penstock"), and when power is needed the water is allowed to flow downhill back through a turbine. In the Rwanda LEAP model, this situation is modeled in the Electricity for Pumped Storage module by having solar PV capacity (assumed to be of the "utility solar I" type) effectively dedicated to producing "Electricity_for_Pumping", which is then used in the main Electricity Generation module by the "pumped storage hydro" process to produce electricity at an efficiency of 77.5 percent. The costs of the solar PV plants used for pumping are currently set higher than those for utility solar in the main Electricity Generation module, which should be reviewed and revised in future versions of the model.

B.7.7. OTHER ENERGY TRANSFORMATION

The three remaining energy transformation modules currently used in the Rwanda LEAP Model are:

- The **Peat Mining** module, which produces peat used in the Electricity Generation module, and specifies output capacities and an effective cost of production, input as a Variable O&M cost, that reflects the cost of peat to power generation using a fuel cost calculated from the peat cost value provided in reference P-9 of the Phase I Report on this project to be about or $1.1 per GJ.[177]

- The **Charcoal Production** module, which produces charcoal from wood at an assumed efficiency of about 23 percent, but does not specify productive capacity, given that charcoal production is in part an informal industry in Rwanda at present.[178]
- The **Natural Gas Imports** module, which takes in "Imported Natural Gas" and produces "Natural Gas" for use in Rwanda. Capital and O&M costs associated with the operation of gas imports are assumed to be included in the overall price of gas, which is about $29 per GJ (entered in Resources—see below). Capacity to import gas is added endogenously by the model as needed starting in 2033. In the New Reference Case, gas imports are as shown in Figure B.7.7-A, all of which is used to fuel electricity generation, although scenarios could be developed in which gas meets energy demand in various sectors as well.

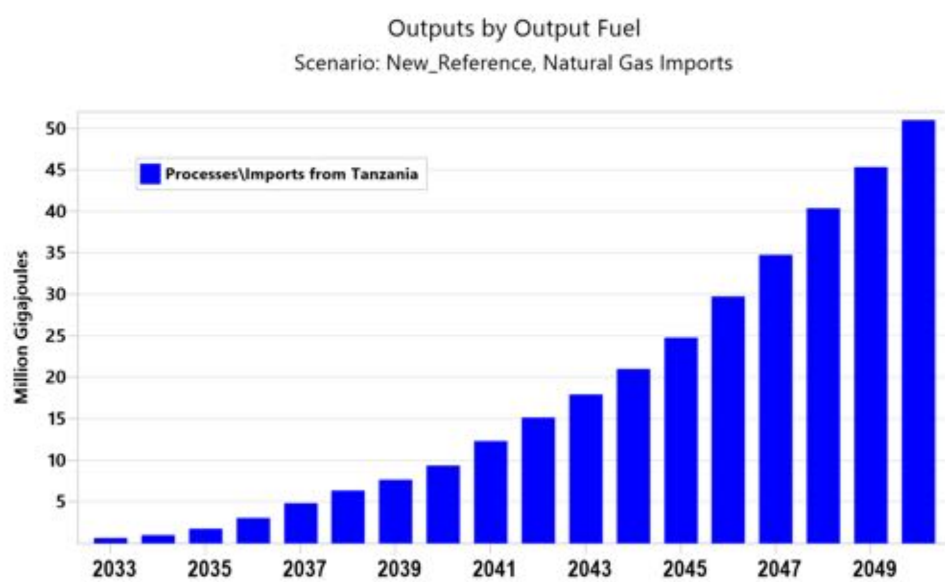

Figure B.7.7-A: Natural Gas Output from Natural Gas Imports Module in the New Reference Case of the Rwanda LEAP Model

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[177] At 407,652 FRW/17.63 t peat (based on the publication "A Life Cycle Assessment Approach to Electricity Generation from Gishoma Peat Power Plant", by Eustache Hakizimana, N. Gaetan, Danna Sandoval, and Umaru Garba Wali, *Iranian Journal of Energy and Environment*, dated January, 2018, and available as https://www.researchgate.net/publication/340887413_A_Life_Cycle_Assessment_Approach_to_Electricity_Generation_from_Gishoma_Peat_Power_Plant); and the following assumptions: 970 FRW/USD; 21.5 GJ/t peat, or $1.1 per GJ.

[178] Efficiency calculated based on statement that "...8.1 kg of wood is needed to produce 1kg of charcoal in the current charcoaling efficiency." in Rwanda Ministry of Infrastructure and Ministry of Finance, *National Survey on Cooking Fuel Energy and Technologies in Households, Commercial and Public Institutions in Rwanda FINAL REPORT*, dated December 2020, and provided to the project team by REG staff, July 2021.

B.7.8. RESOURCES

Values for the available annual yield or total reserves available for resources such as solar, wind, geothermal, lake methane, and peat are provided, based on the work done in the EAEP Resource Assessment project, in the LEAP "Resources" section. This section also allows the assignment of import costs, export benefits, and other values associated with primary resources (such as solar, hydro, peat, crude oil) or secondary resources (such as refined petroleum products or electricity). In the Rwanda LEAP model, import costs are provided for natural gas (from Tanzania) and for refined petroleum products, with the former based on costs provided by REG, and the latter based on recent import costs of fuels into Rwanda and growing based on international oil price projections.

B.8. TREATMENT OF LOAD CURVES AND ELECTRICITY SUPPLY CURVES IN RWANDA LEAP MODEL

B.8.1. INTRODUCTION

In LEAP, plants are dispatched to meet both total demand (in MWh) as well as the instantaneous peak demand which varies by hour, day and season. In order to describe how needs for electricity vary over time, LEAP users can exogenously specify an annual load-duration curve, or a set of daily load curves and LEAP will dispatch plants by merit order. Alternatively, load shapes be specified for each demand device so that the overall system load is calculated endogenously. Thus, the effect of DSM policies on the overall load shape can then be explored in scenarios (but very data-intensive). Plant dispatch can also then be varied by season (for example, to reflect how hydro dispatch may vary between wet and dry seasons, as in Rwanda, or over the course of the day, as for solar power output. The remainder of this section describes how load curves and electricity supply curves were used in the Rwanda LEAP model. These curves were derived using data provided by REG, and are documented in the load curve/supply curve workbooks described earlier in this Annex.

B.8.2. "TIME SLICES" USED TO VARY TIMING OF DEMAND AND SUPPLY

In order to enter data on time-varying demand and supply in LEAP, a set of "time slices", dividing the year into categories, must be defined. LEAP requires data to be input in two or four seasons, although Rwanda's climate is more typically characterized as three seasons. Four seasons were thus set up to divide the year as:

- "Middle": Jan
- "Early Wet": Feb, Mar, Apr
- "Dry": May, June, July, Aug
- "Late Wet": Sept, Oct, Nov, Dec

These seasons were further divided into weekdays and weekends, so that a total of 192 time slices were used, 96 for each type of day, as shown in Table B.8.2.-A.

TABLE B.8.2-A "TIME SLICES" USED FOR ELECTRICITY LOADS AND HYDRO AND SOLAR IN RWANDA LEAP MODEL (ONLY WEEKDAY SET SHOWN)

		Fraction of Peak Demand, 2017-2020			
Slice		Middle	Early Wet	Dry	Late Wet
Weekday (Mon-Fri): Hour 1	1:00	54.8%	54.9%	57.2%	58.3%
Weekday (Mon-Fri): Hour 2	2:00	53.0%	53.0%	55.6%	56.7%
Weekday (Mon-Fri): Hour 3	3:00	52.2%	52.1%	54.9%	56.0%
Weekday (Mon-Fri): Hour 4	4:00	52.0%	51.8%	55.0%	56.1%
Weekday (Mon-Fri): Hour 5	5:00	52.6%	52.7%	56.0%	57.0%
Weekday (Mon-Fri): Hour 6	6:00	55.3%	54.6%	57.7%	58.7%
Weekday (Mon-Fri): Hour 7	7:00	55.5%	55.6%	58.1%	59.9%
Weekday (Mon-Fri): Hour 8	8:00	59.3%	60.4%	63.5%	65.8%
Weekday (Mon-Fri): Hour 9	9:00	63.2%	64.4%	68.2%	70.1%
Weekday (Mon-Fri): Hour 10	10:00	65.4%	66.7%	70.3%	71.9%
Weekday (Mon-Fri): Hour 11	11:00	66.3%	67.8%	71.0%	73.3%
Weekday (Mon-Fri): Hour 12	12:00	66.8%	67.7%	71.1%	73.0%
Weekday (Mon-Fri): Hour 13	13:00	64.9%	65.4%	68.7%	70.6%
Weekday (Mon-Fri): Hour 14	14:00	65.0%	65.3%	68.9%	70.2%
Weekday (Mon-Fri): Hour 15	15:00	66.0%	65.8%	70.0%	71.6%
Weekday (Mon-Fri): Hour 16	16:00	66.0%	66.5%	70.5%	71.7%
Weekday (Mon-Fri): Hour 17	17:00	65.5%	66.3%	70.1%	71.0%
Weekday (Mon-Fri): Hour 18	18:00	67.3%	69.6%	74.1%	76.0%
Weekday (Mon-Fri): Hour 19	19:00	79.8%	81.7%	86.7%	88.0%
Weekday (Mon-Fri): Hour 20	20:00	84.2%	84.0%	87.7%	89.3%
Weekday (Mon-Fri): Hour 21	21:00	81.8%	80.1%	83.3%	84.6%
Weekday (Mon-Fri): Hour 22	22:00	72.9%	70.4%	73.7%	74.6%
Weekday (Mon-Fri): Hour 23	23:00	65.1%	63.1%	65.9%	67.2%
Weekday (Mon-Fri): Hour 24	0:00	59.4%	58.4%	60.8%	61.9%

B.8.3. LOAD CURVES

The goal in deriving load curve was to characterize the timing of current and future electricity load in Rwanda to determine its correspondence with the availability and timing of electricity supply options. Starting with data provided by REG showing hourly generation from individual generators in Rwanda for each day in 2017-2020 (see workbook described earlier), data were aggregated to provide the total load (in MW) met by generators (plus unmet load, when applicable) for each hour of each day. These load data were then evaluated to determine typical peak periods over the course of days and weeks, and variations by month and season to characterize inputs to LEAP as load curves fitted to "time slices", in this case, the 192 slices described above, representing each hour of typical weekdays and weekends in each of four different "seasons".

Data for each year over 2017-2020 were plotted together to show year over year growth and changes in demand. The resulting daily load curves show consistent growth in total demand year over year and time-of-day use (see Figure B.8.3.-A). The curves show daytime energy consumption is increasing year over year, with a higher average fraction of peak demand (with about a 10% increase between 2017 and 2020). In addition, on a year-to-year basis over 2017-2020, the period of peak demand was expanding in the evening with a longer period of high consumption. Annual averages were then combined (in MW) and calculated as a fraction of peak demand to create a load curve for Rwanda demand for input into LEAP.

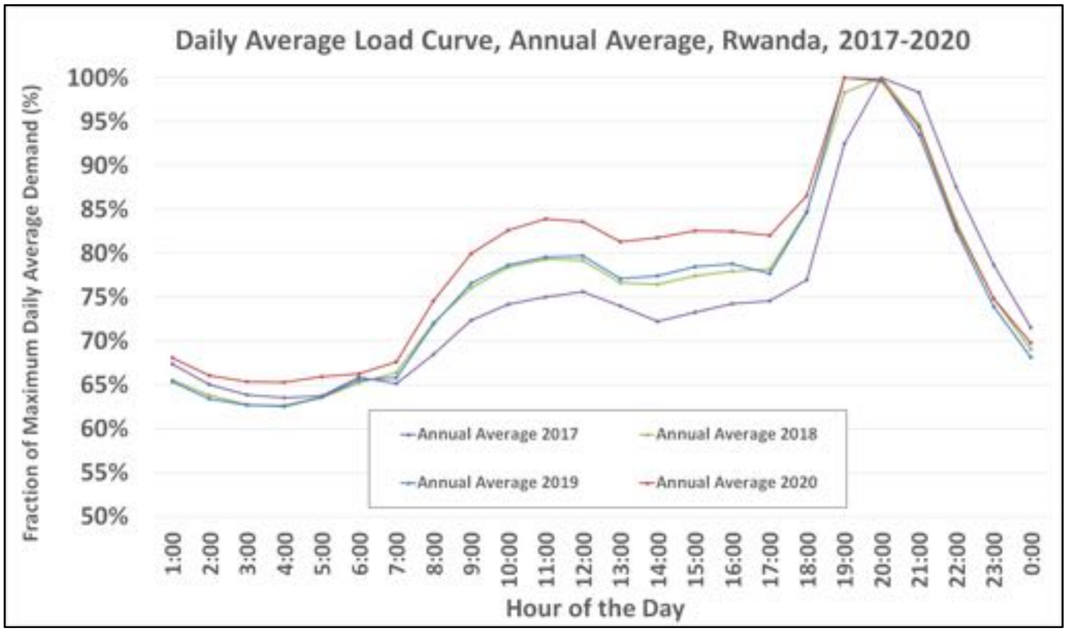

Figure B.8.3-A: Daily Average Load Curves for the Year 2017 and 2020 in Rwanda

Hourly generation data were then used to show changes in demand patterns between weekday and weekend use on a monthly and annual basis. Demand was calculated both as a fraction of average of weekly and monthly peak demand to remove effects of new generation/load growth within each year, given the relatively strong growth in electricity supplies in Rwanda over the course of each year during that period. The load data showed higher consumption on weekdays vs. weekend days, with higher average daytime consumption as a fraction of peak demand on weekdays than on weekends. The data show increased demand trends in September and October, with lowest demand in April—as shown in Figure B.8.3-B. The final step was to develop an average demand curve as a fraction of annual peak demand for years 2017-2020 (Figure B.8.3-C).

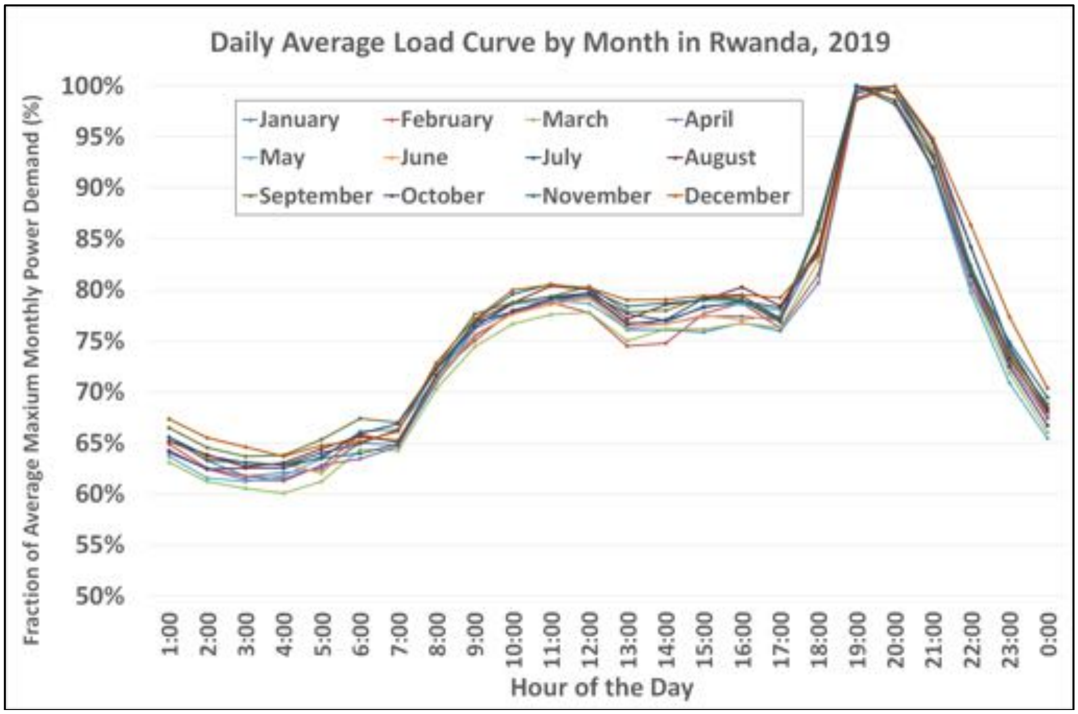

Figure B.8.3-B: Daily Average Load Curves by Month for the Year 2019 in Rwanda

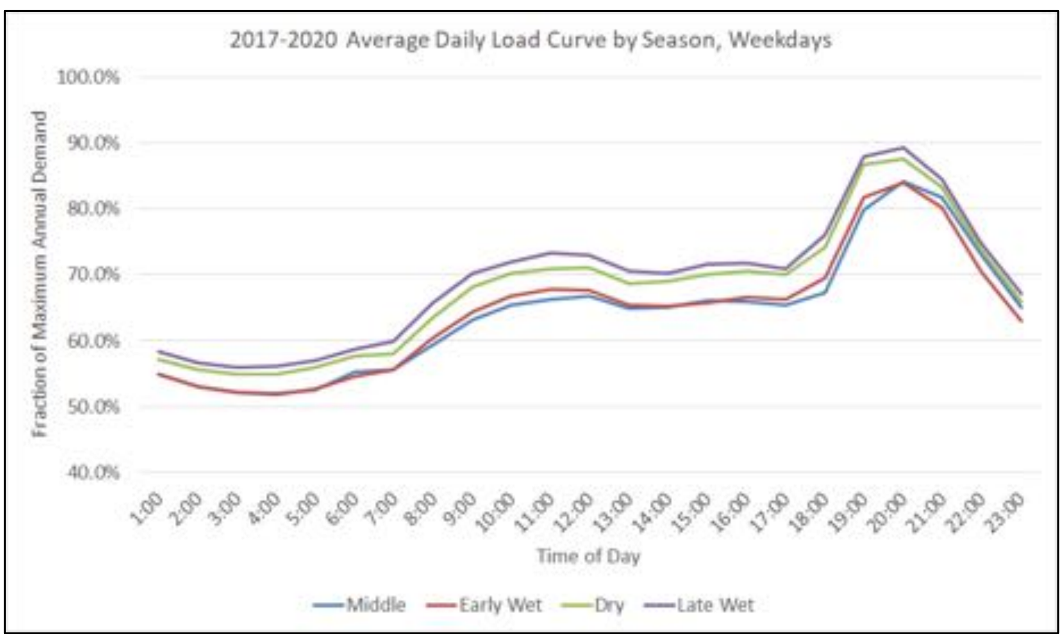

Figure B.8.3-C: Weekday Average Load Curves by Season Average over 2017-2020 for Use in the Rwanda LEAP Model

Future upgrades to the treatment of load curves in the Rwanda LEAP model might include considering how the shape of the demand curve might change over time with (for example):

- Changes in end uses in one or more sectors, such as increased penetration of air conditioning.
- Changes in the relative fractions of demand accounted for by the different sectors, such as a change in industrial demand relative to residential demand (or vice versa, depending on the trends chosen).
- Changes in the timing of end uses with changes in activities and/or technologies.

Then, using that information, modified load curves can be developed to assign to different periods in the future, such as for 2050. Note that future load curves can be different in different LEAP scenarios.

B.8.4. ELECTRICITY SUPPLY CURVES: HYDRO AND SOLAR

For hydroelectric and solar generators, the approach that follows was used to derive load curves for use in LEAP. The goal of the derivation was to characterize the timing of current and future hydro and solar output in Rwanda to determine their correspondence with electricity demand and thus the ability of a given generation fleet to meet demand over time. The derivation stated with data provided by REG showing hourly generation from individual generators in Rwanda for each day in 2017 -2020. For output curve development, data were typically only taken from years where a generator was operational for the entire year in order to serve as representative examples for current and future output. Data sets were aggregated to provide average hourly generation for each generator on a monthly basis for years 2017-2020.

For hydro, which can and is used to follow load throughout the day, the goal was to determine changes in availability for hydro resources over the course of the seasons. As such, results were not differentiated between weekdays and weekends as was done with total generation data (see above). Average hourly generation was calculated, as well as total monthly output, and results were plotted monthly and annually for each plant (see example in Figure B.8.4-A), then averaged over the four seasons and over the four data years. A "maximum capacity factor" was derived for each season, based on the maximum month of output in each year, thus yielding 4 total values among the 192 "time slices" (Figure B.8.4-B). To do so, the maximum monthly generation in each year was used as the indicator of "100% availability," for each plant, with other months represented by a fraction of that total, providing a curve for generation throughout the year and across years. Availability factors for each plant were calculated by month and aggregated into seasonal totals and averages. The plants were then combined into four output curves by season for entry into LEAP, representing the Ntaruka, Mukungwa I & II, and Nyabarongo plants individually, with a separate "Other Hydro" category for the other (smaller) plants in the database. A single value was assigned to all time slices in each season to compare seasonal output.

Options for future steps to augment hydroelectric load curves for use in the Rwanda LEAP model include development of output curves for additional hydro generation (existing, planned, and potential), and/or changes to output curves for existing (or new) generation due to changes in operation as the electricity grid evolves or to the environment (amounts and timing of water availability) as a result of the changing climate.

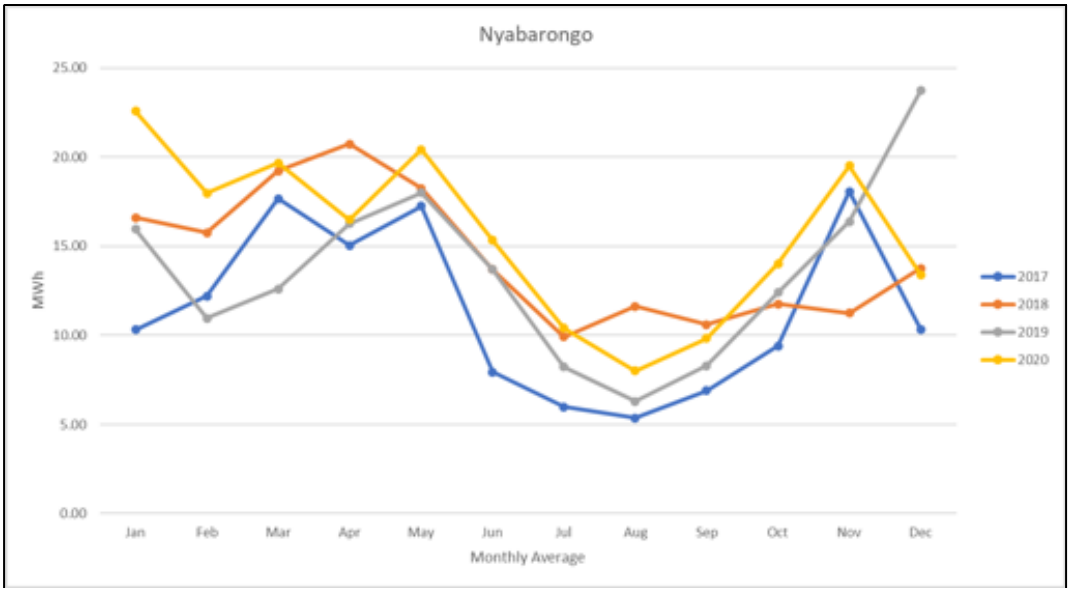

Figure B.8.4-A: Monthly Average Hydro Output Curves, Example for Nyabarongo Plant, for the Years 2017-2020

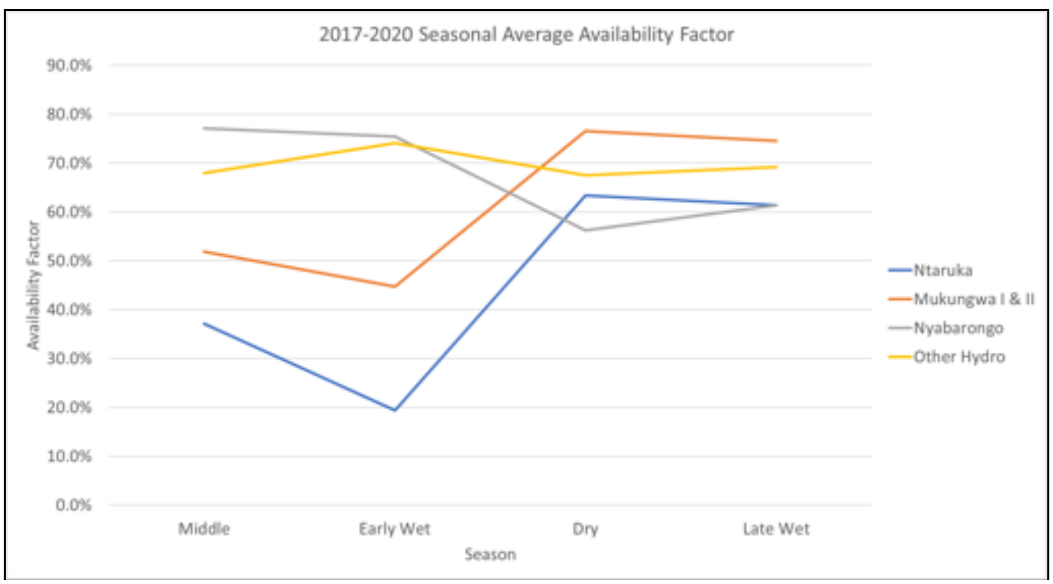

Figure B.8.4-B: Seasonal Average Availability as Derived for Selected Hydro Plants in Rwanda for the Years 2017-2020, as used in Rwanda LEAP Model

Because solar output varies by hour and season but not by day of the week (weekday or weekend), maximum output data were calculated based on peak capacity rating for four seasons and 24 hours each day, thus with 96 total values among the 192 "time slices".

Starting with data provided by REG for two existing solar PV plants in Rwanda, Gigawatt and Nasho Solar. For these plants, average hourly generation was calculated for each month (see Figure B.8.4-C. Seasonal availability was then calculated for each plant, and a weighted average was used to produce a seasonal solar generation curve. A low variance between years and seasons was found, with slightly higher peak generation during dry seasons (which is assumed to be due to reduced cloud cover). Installed capacity was used as the baseline for "100% availability," and generation plotted as a fraction of maximum availability.

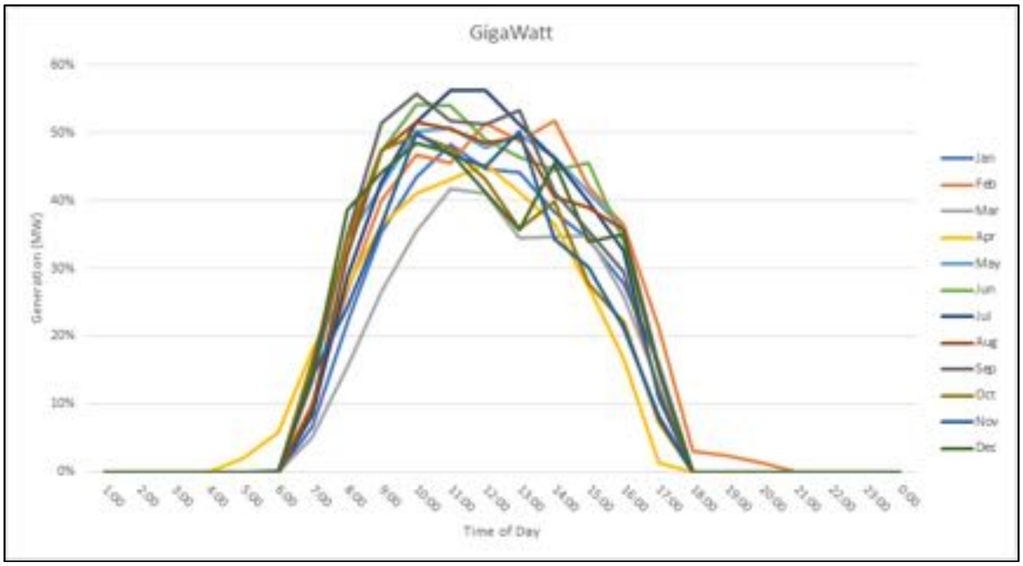

Figure B.8.4-C: Monthly Average Solar Output Curves, Example for GigaWatt Plant, for the Year 2020

Data were entered into LEAP as a daily curve with 24 one-hour time slices, one for each season (96 total unique values among the total 192 time slices), as shown in Figure B.8.4-D). A slight adjustment was made in LEAP to make sure that total annual average output for the solar supply curve used totaled 1500 kWh/year per kW of peak capacity, consistent with the average values used in the solar resource assessment.

These solar supply curves may change somewhat in the future if there are significant changes in cloudiness in Rwanda, and/or if technologies used change—for example, if the use of 1-axis or 2-axis tracking PVs are used. In general, they are expected to remain fairly stable. Other sources for solar supply curves are available in international data compendia such as the Global Solar Atlas, available as https://globalsolaratlas.info/download/world, which includes a Rwanda-specific solar output map available from https://globalsolaratlas.info/download/rwanda.

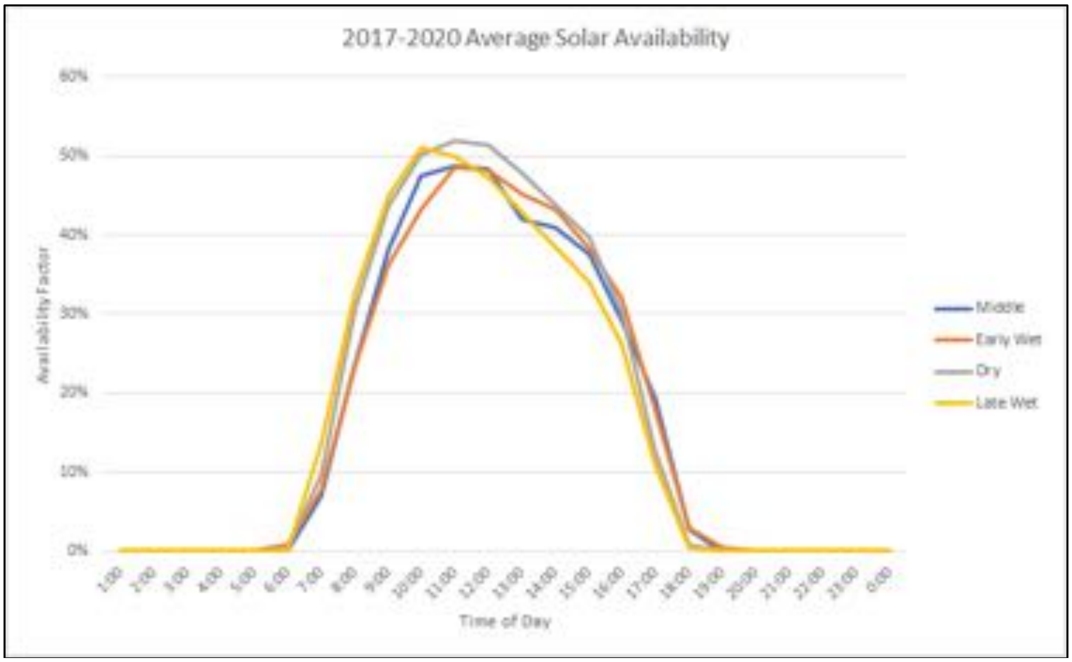

Figure B.8.4-D: Seasonal Average Availability as Derived for Solar Plants in Rwanda for the Years 2017-2020, as used in Rwanda LEAP Model

B.9.FUTURE AUGMENTATION AND USE OF RWANDA LEAP MODEL

B.9.1. MODEL UPDATES

Periodic updating of the Rwanda model will be required to update both information for the base year and recent historical years, and of future projections. Base and recent year updates will typically be required in areas such as:

- Key Variables (population, GDP, industrial output, transportation activity, and others)
- Demand (both activities, including, for example, share of electrified households, and energy intensities)
- Transformation (capacities and historical output, for example)

Updates in projections (in growth rates, future outputs, energy intensities, and other parameters) may be required to reflect changes in national plans and priorities, to better reflect recent trends, or for other reasons. Updates in emission factors or global warming potentials (GWPs) may or may not be required to reflect changes in technology or in scientific understanding. Updates in costs may be needed to reflect changes in technology costs, fuel prices, efficiencies, and other parameters, particularly for newer or fast-changing technologies.

Some of the basic approaches to preparing updates in LEAP include:

- Update the base year, and change base year values throughout the dataset.
- Retain the old base year, but shift to a new "first scenario year", allowing you to enter additional data for historical years (and to see output for earlier years as well as for projected years.

General tools and techniques for updates include:

- Compile updated information in Excel workbooks, themselves "living documents" updated periodically, and transfer updated data to LEAP.
- Connect Excel workbooks to LEAP (expert users).
- Enter updated information directly into LEAP.

In any of the above, remember to update notes in LEAP (and Excel) so that you have a record of the changes you have made, when you made them, and why you made them, for you and others to follow.

B.9.2. FUTURE APPLICATIONS OF RWANDA LEAP MODEL

General applications of LEAP models, and of the Rwanda LEAP model, include:

- Further integration of LEAP into the REG LCPDP (Least-cost Power Development Planning) process.
- Integrated energy planning and Integrated Resource Planning (IRP, for electricity and other utility planning), and energy-environment scenario studies, at the local, national, regional (East Africa), and potentially contributing to global modeling.
- Greenhouse gas and other air pollutant emissions mitigation analysis (including "green growth" scenarios).
- Preparation of energy balances and environmental inventories, including GHG inventories.
- Economic analysis of individual energy projects, programs, and policies.
- Preparation of National GHG mitigation plans and communications.
- Researching, assessing, and initial prioritization of National-level mitigation actions.
- Organization and compilation of National energy data.
- Demand forecasting for electricity and other fuels.
- Sensitivity analyses.
- Training and education, including at the undergraduate and graduate levels (for example, for preparation of Masters projects and Ph.D. dissertations).

Some ideas for improvement of the current Rwanda LEAP Model include:

- Add detail in some sectors—for example, commercial/institutional, some industrial subsectors, transport, and residential.
- Add more detail and depth to analysis of energy efficiency measures.
- Improve end-use data (especially in the residential sector), including more detail on non-electric and traditional fuels use and on modeling of transitions away from traditional fuels use.
- Research and augment modeling of Rwanda-specific mitigation options (including costs).
- Research and include Rwanda-specific emission factors for key devices/processes (especially stoves).
- Consider extending electricity analysis to include peak power demand factors for devices.
- Consider the use of stock modeling for transport (stocks of vehicles).

- Coordination of LEAP power sector model with hydro/water supply and demand modeling using the WEAP water planning model, as done in earlier Rwanda Water Resources Board project with the Stockholm Environment Institute.
- Possible integration of LEAP with other modeling tools
- Although detailed dispatch, reliability, and transmission modeling in Rwanda will require more advanced or different tools, LEAP could help provide inputs to those tools, and outputs of those models could be used in LEAP.

Further work with the LEAP model in Rwanda presents an opportunity for working across organizations in Rwanda to more tightly integrate the planning process in related sectors. Such inter-agency planning could benefit from the development of a high-level cross-ministerial committee on climate planning and mitigation assessment, potentially involving government and other stakeholders tasked with working together to advise on/facilitate national and regional efforts. Elements of such an effort could include developing and training Technical Working Groups under the high-level group at a National level and possibly at a regional level within the country, if desired, and with coordination to the National level. For such an effort, tasks for High-level Committee could include:

- Select Technical Working Group members and arrange for training as needed.
- Decide upon and implement stakeholder involvement policy.
- Set policy for interactions with outside parties providing technical assistance for mitigation planning and actions.
- Facilitate access to data and planning documents for Technical Working Group
- Identify future actions of Technical Working Group.
- Guide implementation of mitigation actions.

Tasks for Technical Working Groups working under a High-level Committee like that above could include:

- Develop data collection plan (for LEAP and/or GHG Inventories).
- Data collection (from existing sources).
- Design and commission surveys for data not now available.
- Coordinate between national and regional level.
- Interact with stakeholders as appropriate.
- Update LEAP models periodically (every 2-3 years, for example).
- Prepare revised mitigation reports (national/regional).
- Convene workshops to review draft reports (under authority of high-level committee).