Europa-Universität Flensburg

Modelling electricity supply options for Rwanda in the face of climate change

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Théoneste Uhorakeye (M. Eng.)

Advisors:

Prof. Dr. Bernd Möller
Prof. Dr. Olav Hohmeyer

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To my daughter Stella INEZA, my son Fabrice IRAGUHA and my wife Virginie YANKURIJE this work is dedicated

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Abstract

Expected impacts of climate change are likely to compromise the ability of electricity supply systems to meet power demands, especially in countries like Rwanda where the share of hydropower generation in the total electricity supply mix is high. For such power supply systems, an energy planning approach that takes into account potential impacts of climate change is necessary. This study assessed an alternative power supply scenario that would be resilient to the impacts of the expected climate change and ensure the security of Rwanda's power supply with least emissions towards 2050.

To develop such a scenario, the effects of the future climate of Rwanda on hydropower generation were assessed and integrated into the power supply plans. These effects were assessed for two Representative Concentration Pathways (RCPs): RCP4.5 and RCP8.5; with climate data from two Global Climate Models (GCMs): HadGem2−ES and MIROC−ESM. The Water Evaluation and Planning system (WEAP) model was used to simulate the hydropower generation under different climate conditions. It was found that, compared to the designed energy, the changes in hydropower generation for the 2012−2019 period would range between +2% and +12%. Changes in generation for the 2020−2039 period would vary between −13% and +8% while the period 2040 to 2059 will be characterized only by losses in generation when the changes are projected to vary between −22% and −9%.

To incorporate these changes into the country's power supply plans, different electricity demand and supply scenarios were developed and analysed. For the demand, three scenarios (very low, very likely and very high) were developed based on different electrification, population and economic growth rates. As for the supply, a group of Business As Usual (BAU) and another of alternative power supply scenarios were developed. Each of these two groups includes three sub−scenarios: a scenario with no climate change considerations and scenarios that considered respectively hydropower generation under climate scenarios RCP4.5 and RCP8.5. The bottom−up approach was used to project the demand by the residential sector while the top−down method was applied for the non−residential sector. For both the demand and supply analysis, the Long−range Energy Alternatives Planning system (LEAP) model was used.

The results revealed that, by 2050, the total electricity demand would reach 6,546 GWh for the very low scenario, 8,100 GWh for the very likely scenario and 10,240 GWh for the very high scenario compared to 379 GWh in 2012. Under the BAU supply scenario, the national energy resources will only be able to satisfy the demands under the very low and very likely scenarios. To meet the demand under the very high scenario, more than 20% of electricity requirements would come from imported fossil fuels. Under the suggested

alternative scenario, however, no imported fossil fuels would be needed by 2050.

The average CO_2 emissions per kWh for the 2012−2050 period is 116.42 gCO_2eq for the alternative scenario and 203.24 gCO_2eq for the BAU scenario. Relative to the emissions in the base year (2012), the alternative scenario will generate 21.44% less emission per kWh than the value in 2012 while under the BAU scenario emissions will be 25.67% more than in 2012. The average generation cost per kWh between 2012 and 2050 varies between US$Cents 12.71 and US$Cents 15.76 for the BAU scenario while it ranges between US$Cents 13.20 and US$Cents 13.73/kWh for the alternative scenario.

In brief, the suggested alternative power supply scenario is resilient to climate change effects as it meets the projected power demand when the impacts of climate change on hydropower generation are accounted for. The scenario also ensures the security of the country's power supply because it only relies on the domestic energy resources. Furthermore, CO_2 emissions per kWh are more than 40% lower than the emissions under the BAU scenario.

To successfully implement this scenario, a number of policy and institutional framework adjustments were identified and suggested. One of the suggested policy adjustments is a Feed−In Tariff (FIT) scheme for solar and wind technologies until these technologies mature. As for institutional frameworks, short− and long−term trainings in solar and wind technologies were suggested as investors in these technologies would be interested in investing in areas where they can get manpower with enough skills to operate and maintain installed power plants.

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List of Abbreviations and acronyms

AGECC	UN Secretary−General Advisory Group on Energy and Climate Change
AOGCMs	Atmosphere–Ocean General Circulation Models
AR4	Fourth Assessment Report
AR5	Fifth Assessment Report
ASTER GDEM	Advanced Spaceborne Thermal Emission and Reflection Radiometer Global Digital Elevation Model
BAU	Business As Usual
CD	Concentration Degree
CDO	Climate Data Operators
CH_4	Methane
CMIP3	Coupled Model Intercomparison Project 3
CO_2	Carbon Dioxide
CORDEX	Coordinated Regional Downscaling Experiment
CRU	Climate Research Unit
CSP	Concentrating Solar Power
CV	Coefficient of Variation
DDS	Dynamical Downscaling
DEM	Digital Elevation Model
DEMs	Digital Elevation Models
DRC	Democratic Republic of Congo
DWC	Deep Water Capacity
ECMWF	European Centre for Medium−Range Weather Forecasts

EDCL	Energy Development Corporation Limited
EDPRS	Economic Development and Poverty Reduction Strategy
ELECTROGAZ	Etablissement de Production, de Transport et de Distribution d'Electricité, d'Eau et de Gaz
ESGF	Earth System Grid Federation
ESM	Earth System Model
ESMs	Earth System Models
EUCL	Energy Utility Corporation Limited
FAO	Food and Agriculture Organization
FAR	First Assessment Report
FIT	Feed−In Tariff
FRL	Full Reservoir Level
FRW	Franc Rwandais/Rwandan Franc
FRW	Rwandan Francs
GCM	Global Climate Model
GCMs	Global Climate Models
GDP	Gross Domestic Product
GHG	Greenhouse Gas
GHGs	Greenhouse Gases
GIS	Geographic Information System
GNI	Gross National Income
hurs	relative humidity
ICSs	Improved Cook Stoves
IIASA	International Institute for Applied Systems Analysis
IPCC	Intergovernmental Panel on Climate Change
IPPs	Independent Power Producers
IREARPPP	Increase Rural Energy Access in Rwanda through Public-Private Partnerships
IS92	1992 IPCC Scenarios
ISI−MIP	Inter−Sectoral Impact Model Intercomparison Project
ITCZ	Inter−Tropical Convergence Zone
LAI	Leaf Area Index

LAM	Limited Area Model
LEAP	Long−range Energy Alternatives Planning system
LNG	Liquefied Natural Gas
LIT	Lower Irrigation Threshold
LWH	Land Husbandry Water harvesting and Hillside Irrigation project
MAD	Management Allowable Deficit
MASL	Meters above sea level
MDDL	Minimum Drawdown Level
METI	Japan Ministry of Economy, Trade, and Industry
MINALOC	Ministry of Local Government
MINECOFIN	Ministry of Finance and Economic Planning
MINICOM	Ministry of Trade and Industry
MININFRA	Ministry of Infrastructure
MINIRENA	Ministry of Natural Resources
MRC	Master Recession Curve
NASA	United States National Aeronautics and Space Administration
NISR	National Institute of Statistics of Rwanda
NO_2	Nitrous Oxide
NSE	Nash-Sutcliffe Efficiency
OM	Operation and Maintenance
PBIAS	Percentage Bias
PCD	Precipitation Concentration Degree
PEST	Parameter EStimation Tool
PFD	Preferred Flow Direction
PIK	Potsdam Institute for Climate Impact Research
pr	precipitations
PRSP	Poverty Reduction Strategy Paper
PV	Photovoltaic
r	Pearson's correlation coefficient
RCMs	Regional Climate Models
RCP	Representative Concentration Pathway
RCPs	Representative Concentration Pathways

RDB	Rwanda Development Board
RECO	Rwanda Electricity Corporation
REG	Rwanda Energy Group Ltd
REGIDESO	Régie de Production et de Distribution d'eau et d'électricité
RF	Radiative Forcing
RMA	Rwanda Meteorology Agency
RMSE	Root Mean Square Error
RNRA	Rwanda Natural Resources Authority
RR	Rainfall Rate
RRF	Runoff Resistance Factor
RSR	Ration between RMSE and STDEV
RURA	Rwanda Utilities Regulatory Agency
RWASCO	Rwanda Water and Sanitation Corporation
RZWC	Root Zone Water Capacity
SA90	1990 IPCC Scenario A
SAR	Second Assessment Report
SDS	Statistical Downscaling
SEI	Stockholm Environment Institute
SHSs	Solar Home Systems
SOTER	Soil and Terrain
SRES	Special Report on Emissions Scenarios
SWAT	Soil and Water Assessment Tool
TAR	Third Assessment Report
tas	temperature
TAWC	Total Available Water Capacity
TED	Technology and Environmental Database
TWL	Tail Water Level
USA	United States of America
UIT	Upper Irrigation Threshold
VAT	Value Added Tax
VIC	Variable Infiltration Capacity
WASAC	Water and Sanitation Corporation

WCED	World Commission on Environment and Development
WCRP	World Climate Research Programme
WEAP	Water Evaluation and Planning system
WFD	Water and Global Change (WATCH) Forcing Data
ws	wind speed

List of Units

Unit	Description
%	Percentage
Gt	Gigaton
GWh	Gigawatt hour
h	Hour
ha	Hectare
kg	Kilogram
km^2	Square kilometre
km^3	Cubic kilometre
kPa	Kilopascal
kWh	Kilowatt hour
l	Litre
m	Metre
m/s	Metre per second
m^2	Square metre
m^3	Cubic metre
m^3/s	Cubic metre per second
MJ	Megajoule
mm	Milli metre
Mtoe	Million tons of oil equivalent
MW	Megawatt
MWh	Megawatt hours
toe	Tons of oil equivalent
ton	Tons
TWh	Terawatt hours
W	Watt
Wh	Watt hour
W/m^2	Watt per square metre

Chapter 1

Introduction

Due to expected impacts of climate change, the existing and future energy facilities will operate under conditions different from those they were designed to. Expected changes in temperature, precipitation and frequency and severity of extreme events will likely affect how much energy is produced, delivered and consumed. Therefore a planning approach that takes into account potential impacts of climate change is required in order to minimize losses that may result from it. This study assessed potential impacts of climate change on hydropower generation in Rwanda, and then integrate the identified impacts into the long−term electricity supply plans for the country towards 2050. The current chapter describes the background of the study, research problem, objectives and questions that have to be addressed in order to achieve specified objectives. The research framework and organization of the dissertation are also provided at the end of the chapter.

1.1 Background of the study

Energy plays an essential role in the production of goods and services necessary to sustain human lives. It is an important catalyst for socio−economic development due to its role in poverty alleviation, improving human living standards and enabling economic growth (UNCSD 2005; AGECC 2010). On the global basis, the total world's final energy consumption has increased from 4,667 million tons of oil equivalent (Mtoe) in 1973 to 9,301 Mtoe in 2013, and is projected to reach 12,487 Mtoe by 2040 (IEA 2015a, 28, 46). Most of the projected increase is expected in developing countries where about 95% of the 1.3 and 2.6 billion people worldwide who do not respectively have access to electricity and clean cooking energy are located (IEA 2014g).

In addition, more and more energy will be required as a results of the expected rapid population and economic growths in the developing world. Under different scenarios, around 2 billion more people (compared to the world's population in 2010) are expected in 2050; and most of them will show up in developing countries with the Sub−Saharan African region taking the lead (WEC 2015, 247; IIASA 2012, 391; The World Bank 2006, 2). As for income, a study by The World Bank (2006, 2−3) estimated that the total Gross Domestic Product (GDP) of developing countries in 2050 would be twice that of industrial countries in 2000, while the share of low and middle income countries to the world's income, in 2050, would be 40% (twice their share in 2000). For the Sub−Saharan African region, for example, WEC (2015, 73) projected that, on average, the per capita GDP per year would increase from US$ 1,400 (in 2010 constant US$) in 2010 to between US$ 5,500 and US$ 7,300 (in 2010 constant US$) by 2050. This expected per capita income will lead to an increased purchasing power of the population; hence, the demand for more energy and services that energy provides due to the income effect. Rwanda is one of the countries in which the demand for energy is expected to increase rapidly due the above highlighted factors (i.e. energy access, population and income growths).

1.1.1 Country context

Rwanda is located in the central−eastern African region between latitudes 1°04' and 2°51' south and longitudes 28°45' and 31°15' east. Rwandan relief is hilly and mountainous from which the name *"Land of a Thousand Hills"* (or *"pays des milles collines"*, in French) is derived. The total area of the country is 26,338 km^2 of which 56.95% are covered by arable land, 15.19% by forests and protected areas, 12.48% by marginal land (unsuited for agriculture, pastures, wood−lots, etc.), 6.45% by marsh and wetlands, 5.13% by water bodies and 3.80% by built−up areas (calculated based on data from UNDP 2007b, 7).

Although Rwanda is located in the tropical zone, the country experiences a temperate climate due to its high elevation (McSweeney 2010, 3) that exceeds 4,000 metres above sea level. The average annual rainfalls vary with altitude, with the highest precipitation records ($>$ 1600 mm) in the west and diminish towards the east where less than 900 mm are recorded (McSweeney 2010, 4). The country experiences two rain seasons which alternate with two dry seasons. The rain seasons occur from March to May and October to December while the dry seasons occur from January to February and June to September (Obasi 2005). As for the temperature, the annual average temperature varies between 15℃ in the volcanic region and Congo−Nile ridge and around 21℃ towards the eastern part of the country. The analysis of the temperature evolution by McSweeney (2010, 11) revealed an increasing trend where the mean temperature rise was 0.47℃ per decade for the 1970−2010 period. However, no significant trends were found concerning precipitations, except very high inter−annual variabilities across the country (MINIRENA 2006, 30; McSweeney 2010, 13).

The total population of Rwanda, in 2012, was 10.5 million where females represented 51.8% while males were 48.2% (NISR 2013, 3). Between 2002 and 2012, the average yearly population growth was 2.6% while the population density has increased from 321 inhabitants/km^2 to 415 inhabitants/km^2 (NISR 2013, 6). With such a high population density, Rwanda occupies the second position of the most densely populated African countries behind Mauritius (UNICEF 2014, 33). Furthermore, it is projected that the population will continue to increase in the medium− and long−term so that, by 2032, the country's population would be between 15.4 and 16.9 million (NISR 2014a, 20). By 2050, Rwanda's population is projected to be 21.18 million (UNDESA 2015, 20) which corresponds to more than the double of its population in 2012.

As for the country's income, the nominal total GDP has increased from US$ 1,733.5 million in 2000 (UNDP 2007a, 5) to US$ 4,363 million in 2012 (NISR 2013, 129). The average GDP growth rate for the 2000−2014 period was 7.71% ; the highest growth was observed in 2002 when it was 13.51% while the lowest was experienced in 2003 when it was 1.45% (The World Bank 2015b). Between 2000 and 2012, the per capita income (in current prices) has increased from US$ 207 to US$ 644, the number of people under the poverty line has declined from 60% to 45% and the extreme poverty has decreased from 40% to 24% for the same period (NISR 2013, 15; IMF 2014, 9).

Rwanda's economy is based on services, agriculture and industry. The service sector dominates the country's economy in such a way that for the 2008−2012 period, for example, its share to the county's GDP varied between 51.1% and 52.8% (MINECOFIN 2013, 5). According to the same source, the agricultural sector contributed between 32.0% and 33.9% although about 80% of the country's workforce is engaged in this sector. The share of the industrial sector on the other hand varied between 14.4% and 16.3%. It is projected that by 2020 Rwanda will have achieved its target of being a middle income country when the GDP per capita (in US$ at current market prices) would reach US$ 900 from US$ 207 in 2000 (MINICOFIN 2000, 6). The country has also developed a policy that is intended to enable it to become a developed climate−resilient country and having low carbon based economy by 2050 (GoR 2011a, 17).

Regarding Rwanda's trade balance, imports far exceed exports and deficits are expected to persist in the short− to medium−term due to the increasing demand for capital and oil products (Sennoga and Byamukama 2014, 2). The trade deficits between 2008 and 2012, for example, ranged between 15.4% and 19.6% of the GDP (NISR 2014b, 200). Minerals, tea and coffee are Rwanda's most exported goods while the most imported ones are oil products, construction materials and electrical/electronic equipment (NISR 2014b, 198).

1.1.2 Rwanda's energy demand and supply

Rwanda is one of the countries with a very low electricity access and a very high share of biomass in the total energy balance. The average primary energy consumption in the country, in 2010, was estimated to be 0.17 tons of oil equivalent (toe) per capita per year (MININFRA 2011, 25) which is very low compared to the average consumption in the Sub−Sahara African region of 0.68 toe and more than 4.5 toe in developed countries (The World Bank 2015c). 91% of the total energy supplied in the country is consumed in the residential sector, 4.5% in the transport sector, 2.7% and 1.8% in industrial and service sectors respectively (Safari 2010, 525; UNEP 2014, 11).

In terms of energy for lighting, only 18% of the country's households had access to electricity in 2012 (67% in urban and 6.4% in rural areas); the remaining households relied on kerosene lamps (40%) candles (10%) and firewood (8%) as sources of energy for lighting (NISR 2012a, 87). The per capita electricity consumption was about 20 kWh per year in 2010 (MININFRA 2011, 26) and 41 kWh in 2014 (REG 2014b). Under the Vision 2020, it is planned that the annual electricity consumption per capita will have reached 100 kWh while access to electricity will be 35% by 2020 (MINICOFIN 2000, 6). In a revised program, a new target of an electrification rate of 48% by 2018 was set under the country's Economic Development and Poverty Reduction Strategy (EDPRS) Program (MININFRA 2013, 10). The analysis of the consumed electricity fore the 2000−2010 period reveals that more than a half of the supplied electricity is consumed in the residential sector.

With regard to power supply, the electricity generation in the country depended entirely on hydroelectric power until 2003. After this year imported fossil fuels have been producing almost half of the country's electricity requirements (REG 2014a). The shift from entirely hydroelectric power to nearly equal fossil fuel powered and hydroelectric power systems was attributed to the lack of investments in the power generation and extension of the electrical network (Jolie et al. 2009, 10), the emerging climate (MINIRENA 2006, 27−28) and the overuse of hydroelectric power dams (Hermes 2005, 8). In the attempt to address electricity supply constraints, a number of Renewable Energy (RE) power generation projects have been implemented and others are planned in the nearest future. RE sources are able to ensure the provision of energy services for a sustainable socio−economic development path while mitigating climate change (IPCC 2012). However, the occurring climate change has already compromised the ability of energy supply systems to meet both average and peak demand, especially for countries like Rwanda where the share of hydropower generation in the power supply mix is high.

1.1.3 Climate change impacts on hydropower

As demonstrated in the Fifth Assessment Report (AR5) of the Intergovernmental Panel on Climate Change (IPCC), the global mean temperature will continue to increase throughout the 21st century whereas precipitations will increase in some regions, decrease in some others while others will experience no significant changes (IPCC 2013). Consequently, projected changes in precipitations and temperature may affect energy systems, especially the generation capacity of existing and future hydroelectric power plants as their outputs depend on the amount of available water runoff (Ebinger and Vergara 2011).

On the African continent, limited studies have analyzed impacts of climate change on hydropower generation. In a study by Hamududu (2012), it was found that, towards the end of the 21st century, hydropower generation may decrease by 7% to 34% in the southern African and increase by 6% to 18% in the central African regions. Yamba et al. (2011) assessed implications of climate change and climate variability on hydropower generation in the Zambezi River Basin and concluded that power generation from the existing and planned hydropower plants would increase for the 2010−2016 period and then decrease towards 2070. Harrison and Whittington (2002) assessed the viability of the Batoka Gorge (between Zambia and Zimbabwe) hydropower scheme to climate change. They found that annual flow levels at Victoria Falls would reduce between 10% and 35.5% which would cause reductions in annual electricity production between 6.1% and 21.4%. Beyene et al. (2010) assessed the potential impacts of climate change on the hydrology and water resources of the Nile River basin using an average of 11 GCMs. In this study they concluded that stream flow at the Nile River will increase for the 2010−2039 period, decline for the 2040−2099 period and that the power generation would follow the stream flow's trends.

In Rwanda, climate change is reported to have caused reductions of water levels in the Burera and Ruhondo lakes from which most of the electricity supplied until 2003 came from, which reduced the national electricity production by 60% (MINIRENA 2006; REMA 2011). To cover this gap, emergency diesel generators have been introduced. Eberhard et al. (2008, 13) reported that, in 2005, the costs of running these emergency generators in Rwanda were estimated to be 1.84% of the GDP.

1.2 Problem statement

Due to the expected increase in electrification rate, population growth and economic development in Rwanda, more and more power generation would be required to meet the growing demand. Similar to the past, power generation from hydropower is expected to represent a significant share in the country's total power supply mix. In an Electrification Road Map which covers the 2013−2025 period, for example, the share of hydropower is projected to be about 50% by 2025 (according to data obtained from Rwanda Energy Group Ltd (REG)).

Generally, daily and seasonal historical climate data are used to determine the amount and variability of energy that a given hydropower plant can produce (Ebinger and Vergara 2011, 30); and the existing and planned hydroelectric power plants in Rwanda have been designed in the same way. For example, in the design of the biggest national hydropower plant, Nyabarongo I (28 MW) which started its operation in 2014, climate data covering the 1962−1991 period were used (SMEC 2014, Annexe 3.2). Similarly, the second biggest hydropower plant, Nyabarongo II (20 MW), was designed by using climate data which cover the 1972−1991 period (CNEE 2012, V10−13), and this power plant is expected to start its operation in 2020.

However, due to expected changes in temperature and precipitations, the existing and the planned hydropower plants will operate under climatic conditions different from those they were designed to operate under, which may affect both the demand and the supply (Ebinger and Vergara 2011, 30). On the demand side, it is likely to jeopardize the ability of the electricity supply system to meet the average and peak demands. On the supply side, it might hamper the opportunity of hydroelectric power producers to recover their investments as well as the viability of new investments.

In addition, reduced water availability will increase water competition between hydroelectric power and other water users such as agriculture and public water supply (Wilbanks et al. 2007a; Feeley et al. 2007). In Rwanda this is justified, for instance, by the fact that the agricultural sector has been depending on natural rain−fed, but in 2010, a national Irrigation Master Plan (IMP) was developed. Under the IMP, the surface (runoff, rivers and lakes) and underground water resources will be exploited in order to increase food security and reduce the sector's vulnerability to climate change (Malesu et al. 2010). During the field visit conducted in 2013, and following interviews and discussions with different parties involved in agricultural and power generation sectors, it was found that there was no coordinated water use as each sector was planning independently from the other. Therefore, it can be expected that a part of the water that was previously used in power generation may be diverted to feed irrigation which may affect hydropower generation.

Moreover, the daily water consumption in rural areas where about 80% of the country's population live was, in 2010, estimated to be 8.15 litres per capita (MINIRENA 2011, 7) which is below the international minimum standard of 20 litres per capita per day without taking into account all water needs (WHO 2016) and more than 50 litres when all needs are covered (Brown and Matlock 2011). Under the Water Strategic Plan 2011−2015, there was a plan to increase this consumption to 20 litres per person per day (MINIRENA 2011, 7), and this may affect hydropower generation as well.

Given all these facts, it is essential to assess the extent to which hydro/power generation is likely to be affected, and then account for the impacts into power supply plans. To achieve this, a means of estimating the country's hydrologic response to the expected climate was necessary. The objectives and questions presented in the next section guided this study towards its intended results.

1.3 Objectives and research questions

The main objective of this study is to assess a power supply scenario that would be resilient to the impacts of the expected climate change and ensure the security of Rwanda's power supply with least emissions towards 2050. The specific objectives are to:

1. Calibrate and validate a site−specific hydrologic model that is used for the computation of water balance in the study area under different climate scenarios;
2. Analyse the outputs from available downscaled GCMs and Earth System Models (ESMs) in order to choose those models that fit best the study area;
3. Evaluate the impacts of the expected climate on hydropower generation;
4. Develop electricity demand and supply scenarios of the country and assess impacts of climate change and variability on the whole power supply sector and
5. Suggest policies recommendations to implement the most feasible supply option.

The formulated objectives were achieved through answering the following questions:

1. How has the climate of Rwanda evolved over the past decades?
2. What were the power generation patterns under the observed climate?
3. What is the future climate of Rwanda likely to be?
4. How may the expected climate affect hydroelectric power generation in the country and the whole electricity sub−sector?
5. What could be the alternative electricity supply options under identified major climate change impacts?
6. What could be possible policy adjustments to be in place in order to implement most feasible option?

1.4 Research framework and design

The study comprises two parts: the hydrological modelling and the electricity modelling. The hydrological modelling investigates potential effects of climate change on hydropower generation in Rwanda while the electricity modelling assesses electricity supply possibilities of the country by considering the identified effects.

First of all, an analysis of Rwanda's energy sector is conducted, and then a literature related to energy demand and supply constraints is viewed. More emphasis is put on studies that assessed effects of climate change on energy systems in general and on water resources and hydropower generation in particular. Afterwards, a step−by−step approach is followed in conducting this research mainly because, in most cases, the output information from the previous step is needed for the next step. In total, 7 steps are followed as briefly discussed below.

Step 1: Hydrological model calibration and validation

Because hydropower generation is expected to represent a considerable share in the total power supply in Rwanda, and as this type of power generation is very sensitive to climate fluctuations and climate change, a hydrological model needs to be developed in order to assess effects of the expected climate on hydropower generation.

The outputs of a hydrological model are qualified to be used for climate change impact assessment if the model is scientifically sound, robust and defensible (US EPA 2002). To prove that a considered hydrological model complies with these criteria, the model has to go through calibration and validation (or verification) processes. The calibration process deals with adjusting the model input parameters until the model produced acceptable outputs as compared to natural (or observed) data for the same conditions (Moriasi et al. 2007). A validation process, on the other hand, consists of running the calibrated hydrological model using input parameters determined during the calibration process (Refsgaard 1997; Doherty 2004). To decide about the acceptability or rejection of parameters determined during the calibration and validation processes, a performance test on the model's outputs is necessary.

In this framework, the WEAP model used in this study is calibrated and validated and its outputs are tested in order to check if the model complies with the above criteria. The WEAP model provides four modelling possibilitieies and its soil moisture method is chosen because it complies most with available information. The soil moisture method is a two−layer hydrologic accounting scheme that allows the computation of evapotranspiration, surface and subsurface runoff within a catchment (Sieber and Purkey 2011).

The choice of the WEAP model is based on its additional ability to model hydropower generation and to exchange information with the LEAP tool which is also used in this study for electricity modelling. The WEAP model is calibrated and validated using flow discharge records at the Ruliba station. The boundaries and surface area for the catchment with outlet at the Ruliba stream gauging station are derived on the basis of drainage modelling by means of a 30x30 metres Digital Elevation Model (DEM).

The Water and Global Change (WATCH) Forcing Data (WFD) are used for the calibration and validation processes; and these data are preferred to data from the Rwanda Meteorology Agency (RMA) because the analysis of these two datasets revealed that there are many missing records and abnormal values in the RMA data whereas no missing values and no significant discrepancies are found in the WFD data.

Step 2: Selection of climate scenarios and models

The calibrated and validated WEAP model in the first step requires climate input data in order to simulate the hydrological response of the studied catchment for chosen scenarios. To achieve this, the IPCC climate scenarios were analysed and two of them are considered for the analysis of the future climate of Rwanda and its effects on hydropower generation. The selected scenarios are RCP4.5 and RCP8.5 because they allow exploring the worst (RCP8.5) and the intermediate (RCP4.5) cases of the future climate. The RCP4.5 scenario is a stabilization scenario where the total Radiative Forcing (RF) is stabilized to 4.5 W m^{-2} after 2100 while the RCP8.5 scenario is characterized by increasing Greenhouse Gas (GHG) emissions leading to 8.5 W m^{-2} in 2100 (Wayne 2013).

For the assessment of the future climate, two publicly available datasets were acquired and compared. The first datasets is from the Coordinated Regional Downscaling Experiment (CORDEX) with data at a spatial resolution of 50x50 km (Christensen et al. 2014). The second dataset was developed under the first Inter−Sectoral Impact Model Intercomparison Project (ISI−MIP) by the Potsdam Institute for Climate Impact Research (PIK), and the spatial resolution is about 55x55 km grid (Hempel et al. 2013).

ISI−MIP's data are used in this study as the analysis of these two datasets for the reference period (i.e. 1961−1990 period) revealed that ISI−MIP's data present less discrepancies between simulated and observed climate data as compared to data obtained from CORDEX. As ISI−MIP data are available for 5 GCMs, an assessment was conducted in order to choose the best two of them (HadGem2−ES and MIROC−ESM) in producing historical stream discharges at the Ruliba stream gauging station.

Step 3: Assessment of the expected climate and its impacts on hydropower

The expected climate of the study area is assessed by comparing projected climate parameters with the corresponding quantities recorded for the reference period (i.e. 1961−1990). The impacts of the climate change on hydropower are assessed by running the WEAP model using projected climate parameters. Details on water withdrawal by the main water users (mainly domestic use and irrigation) are also added into the model. It is assumed that, in case of water scarcity, the residential sector will be supplied first, then agricultural second and the hydropower industry the last. In this assessment, the whole catchment is subdivided into sub−catchments and the pour points for different sub−catchments are placed at the location of each hydropower dam for dam−based hydropower plants, and at the intake point for runoff river based hydropower plants.

As the computation of hydropower generation in WEAP requires many more details about the design and operation of each power plant whereas all these details were not available for all the existing and planned power plants in the studied area, 8 (4 runoff and 4 dam based) hydropower plants for which enough information for the simulation was available are analysed.

To quantify potential impacts of climate change on hydropower in the studied area, energy that would have been produced by the existing and planned plants during the reference period (1971−1990) is compared with the projected generation. This is due to the fact that most of the existing and planned hydroelectric power plants in Rwanda had been designed on the basis of daily and seasonal historic climate patterns covering this period.

Effects of the expected climate change on hydropower plants located in the studied area but not simulated in this study as well as the effects on power plants located outside the study area are assessed by applying the identified power generation changes for the analysed power plants to those not simulated assuming similar conditions of operation.

Step 4: Projection of the electricity demand and supply

The analysis of the future electricity consumption is assessed by grouping the power demand into two categories: the residential and the non−residential sectors. The non−residential sector includes the agricultural, industrial, service and transport sectors. These sectors are grouped together because of the lack of disaggregated information on electricity consumption by each of them. For the residential sector the main electricity demand drivers are the electrification rate, population growth and the household size. The number of households with access to electricity every year between 2012 and 2050 is projected based on two electrification scenarios developed by MININFRA (2013) for the period 2013 − 2018 and extended up to 2032 by WJEC (2015).

These scenarios are the likely electrification which anticipates 35% of the country's households with electricity access by 2017 (MININFRA 2013, 47) and 71% in 2032 (WJEC 2015). The second scenario is the ambitious electrification scenario which anticipates that 48% of the country households will have access to electricity by 2017 (MININFRA 2013, 47) and 78% by 2032 (WJEC 2015). However, given difficulties and challenges in the implementation of different power generation and transmission projects, this study considers only the very likely electrification scenario. For the period 2033−2050, this study assumes that the remaining non electrified households will be those located very far away from the national electricity grid so that a 100% electrification would be achieved in 2050.

It is important to be aware that a 100% electrification rate in 2050 does not mean that all households will have access to electricity in this year. There are different off−grid initiatives where households located far away from the national grid will be supported to access electricity through off−grid solutions, but this electrification scheme is not simulated in this study. The assumed 100% electrification by 2050 only means that all households will be connected to the national grid by 2050.

As for population growth and household size, three scenarios are developed and the following assumptions are considered based on NISR (2014a, 20, 47): (1) the *high scenario:* when the population growth rate is expected to decrease from 2.37% in 2013 to 2.18% in 2032 and 2.00% in 2050 while the number of persons per households will decline from 4.3 in 2012 to 3.1 in 2032 and 3.00 in in 2050; (2) the *medium scenario* when the population growth rate was assumed to decrease from 2.37% in 2013 to 1.89% in 2032 and 1.71% in 2050 while the number of persons per households will decline from 4.3 in 2012 to 3.1 in 2032 and 3.00 in in 2050; and (3) the *low scenario* when the population growth rate would decrease to 1.63% in 2032 and 1.45% in 2050 while the number of persons per households would decline from 4.3 in 2012 to 3.1 in 2032 and 3.00 in in 2050.

Similar to the residential sector, three electricity demand scenarios for the non−residential sector are developed based on different GDP growth rates (NISR 2014a, 20, 47). These scenarios are the (1) *high scenario* which envisages Rwanda as a fast developing economy where the GDP growth would slightly decline from 8.0% in 2012 to 6.0% in 2050; (2) *medium scenario* which anticipates a moderate economic development so that the GDP growth rate would decrease from 8.0% in 2012 to 4.5% in 2050 and (3) the *low scenario* where the economy would grow slowly so that the GDP growth rate would decrease from 8.0% in 2012 to 3.0% in 2050. The total electricity demand is obtained by combining the three residential and non−residential demand scenarios which lead to nine different scenarios. Only three representative scenarios (very low, very likely and very high) are analysed in detail as it will be discussed later in Chapter 8.

Step 5: Development of power supply scenarios: BAU scenario

The development of the BAU electricity supply scenarios is based on existing power generation plans and by assuming a moderate development of the country's renewable resources. The considered energy technologies are hydropower, geothermal, methane, peat, solar and imported oil products.

The BAU scenarios include three sub−scenarios, namely the BAU power supply without climate change consideration, the BAU power supply under climate scenario RCP4.5 and the BAU power supply under climate scenario RCP8.5. As indicated by their names, climate change is not considered in the scenario called "BAU power supply without climate change considerations" whereas in the other two scenarios climate change is taken into account. The RCP4.5 power supply scenario uses the power generation obtained during the assessment of impacts of climate change on hydropower generation in case the world's climate evolves according to RCP4.5 climate scenario while the RCP8.5 power supply scenario analyses the performance of Rwanda's power supply system for the case the future world's climate evolves according to climate scenario RCP8.5.

Step 6: Development of power supply scenarios: alternative scenario

A power supply scenario that would be resilient to the expected impacts of climate change and meet the projected power demand with domestic energy resources with least emissions is investigated. To achieve this, five measures: improvements in the efficiency of household appliances, intensive exploitation of the Nyabarongo River, increased use of solar energy, introduction of wind energy in the country's power supply and exploitation of municipal waste to generate electricity are suggested. Similar to the BAU scenarios, the same sub−scenarios are also developed under the alternative scenario and the definitions of the sub−scenarios provided in the case of BAU scenarios are also valid for the alternative power supply scenarios.

For both the demand (Step 5) and supply (Step 6&7) analysis, the LEAP model is used. This model is chosen because it supports the bottom−up and top−down modelling methodologies applied in the projection of the country's electricity demand. In addition LEAP is able to exchange information with the WEAP model used for hydrological modelling. LEAP provides flexible and transparent accounting, simulation and optimization methods which are achieved done by using LEAP's built−in and/or modeller specified expressions and multivariable models (Heaps 2011).

Step 7: Policy and institutional frameworks assessment

The existing policies, laws and incentives in place to facilitate or attract investments in power sector are analysed in this step and required adjustments are identified and suggested. Similarly, institutional frameworks that must be in place in order to sustain the existing energy technologies in the country as well as to allow the development of new ones are identified and also suggested.

A summary of the steps described in this section as well as a brief description of activities conducted in each of these steps are presented in Figure 1.1.

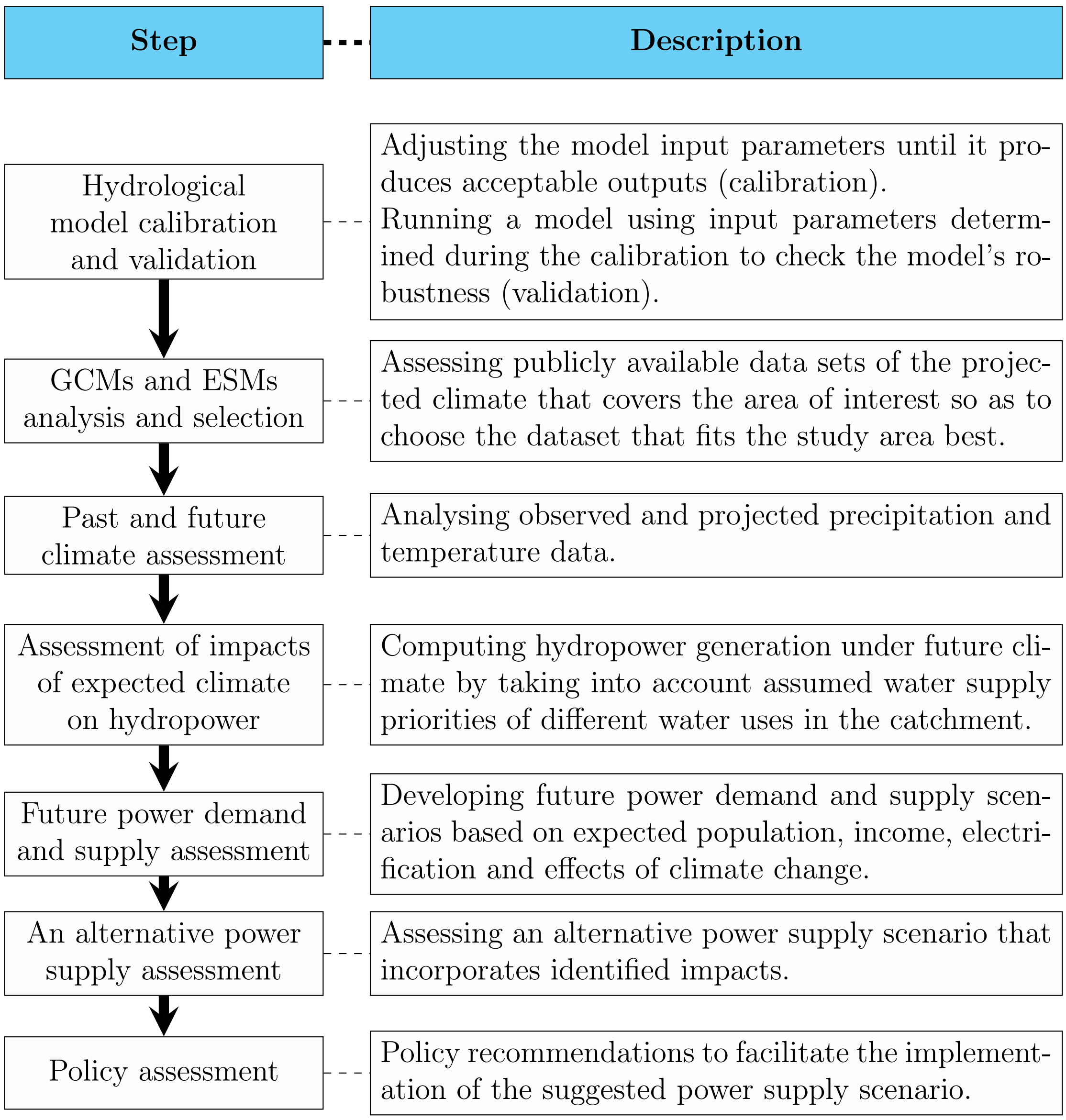


Figure 1.1: Step−by−step research framework

1.5 Structure of the dissertation

Chapter 2 describes the study area with more emphasis on electricity demand and supply in Rwanda. After a short description of the country's socio−economic information, the chapter discusses the evolution of the past electricity consumption and the resources used to meet this demand. The potential of the county's energy resources are also presented and discussed in this chapter.

Chapter 3 synthesizes recent information related to the role that energy plays in the process to achieve sustainable development. Furthermore, the chapter discusses different energy supply constraints with more emphasis on impacts of expected climate change on energy systems. The chapter concludes by briefly describing reported past and future climate situations of Rwanda.

Chapters 4 and 5 describe the approaches and tools used to systematically gather and analyze required information necessary to achieve the study's objectives. The first part of Chapter 4 discusses the methods, tools, data and assumptions used to calibrate and validate the hydrological model that helped to assess effects of expected climate change on hydropower generation. The second part of this chapter describes the ways the past and future climates of Rwanda as well as their impacts on hydropower generation were analyzed. As for chapter 5, it deals with the methodology used to project the evolution of Rwanda's electricity demand as well as the power supply possibilities to meet the projected power demand under different climatic conditions towards 2050.

Chapters 6 and 7 present the hydrologic simulation and climate analysis results. In chapter 6, the results obtained during validation of the WEAP model are presented and discussed. Chapter 7 discusses first the past and projected climates of Rwanda and that of the studied catchment. The potential impacts of the projected climate on water resources and on hydropower plants located in the studied catchment are discussed and then extrapolated to the whole country's hydropower generation in order to assess the overall impacts at the national level.

Chapter 8 presents the simulation results of the electricity demand and supply in Rwanda between 2012 and 2050. The electricity demand projection, the analysis of the electrical power supply, the power generation cost and emissions associated with the power generation are the main points discussed in this chapter. At the end of the chapter a suggested climate resilient electricity supply scenario together with policy recommendations to implement this scenario are discussed.

The last chapter of this dissertation presents the conclusions drawn from this study as well as recommendations on future studies that would clarify some issues that were beyond the scope of this study.

Chapter 2

Country overview and energy sector analysis

In this chapter, the general information about Rwanda is presented. Furthermore, the country's demography and the socio−economic data of Rwanda are presented in the second part of the chapter. Because water plays an important role especially in the generation of the country's electricity which is the focus of the current research, water demand and supply in the country are also presented. At the end of the chapter the energy sector is discussed with a special emphasis on the electricity sub−sector.

2.1 Country's overview

This section presents information about the country's geography and topography, its administrative organization and climate as well as the distribution and characteristics of its soils and land cover.

2.1.1 Geographic and topographic information

Rwanda is one of the 44 landlocked countries in the world and one of the 31 landlocked and least developed countries (UNCTAD 2013, 1). It is located between latitudes 1°04' and 2°51' south and longitudes 28°45' and 31°15' east, with hilly and mountainous relief. The country shares borders with Tanzania in the east, the Democratic Republic of Congo (DRC) in the west, Uganda in the north and Burundi in the south (see Figure 2.1).

The altitude of Rwanda ranges between 900 metres (Bugarama plain in the south) and more than 4500 metres (Karisimbi in the north) above sea level. The topography of

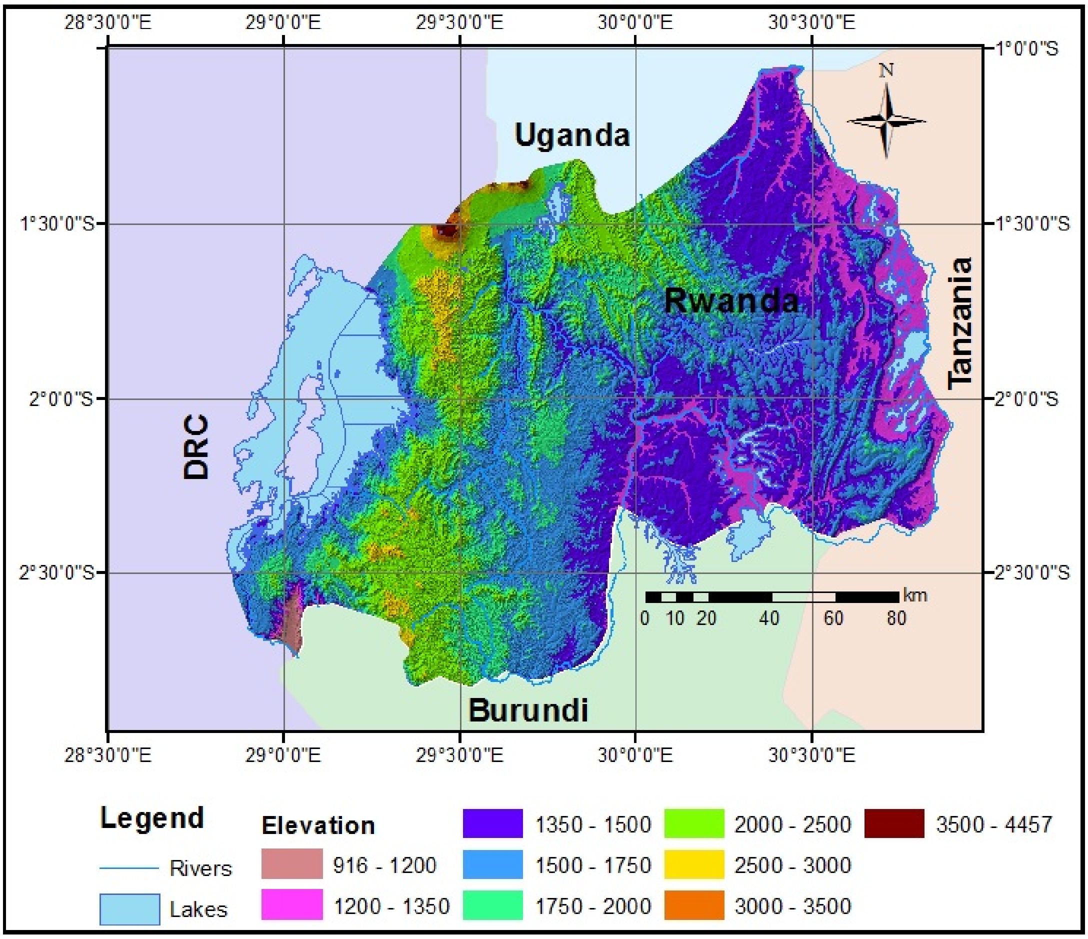


Figure 2.1: Location and topography of Rwanda (Author based on GIS maps obtained from LWH and a DEM from METI and NASA)

Rwanda can be grouped into four categories (see Figure 2.1), namely the Congo–Nil Ridge that runs along the Western branch of the East African Rift with elevations exceeding 2,000 metres, the central plateau ranging between 1,500 and 2,000 metres, the lowlands in the east ranging between 1,000 and 1,500 metres and the lowlands of the south–west in Bugarama plain where the altitude is below 1000 m (Twagiramungu 2006).

2.1.2 Administrative entities

The administration of Rwanda is subdivided into two categories of government: the central and the local. The central government includes the president's and prime minister's offices, the Parliament, ministries and the government agencies. The main role and responsibilities of the central government and its agencies are to formulate policies, regulate and support local governments through capacity building, financing and monitoring and evaluation (The World Bank 2012, 10). The country's Parliament consists of two houses: the Chamber of Deputies and the Senate. There are 80 Deputy members and 26 Senate members. The local government entities comprise provinces, districts, sectors, cells and villages. As it can visualized in Figure 2.2, the country is divided into 5 provinces (East, Kigali City, North, South and West) and 30 districts.

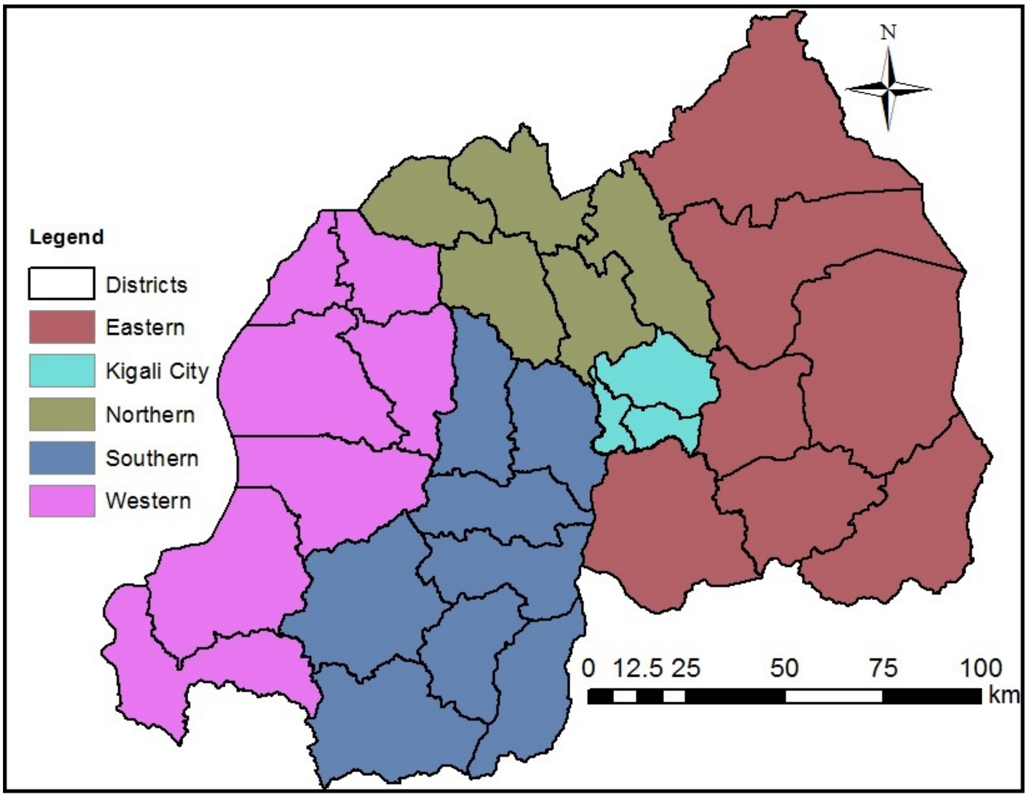


Figure 2.2: Administrative map of Rwanda (the map was obtained from the LWH)

The role of provinces is to coordinate and supervise the implementation of policies and plans from the central government and its agencies (MINALOC 2013). Districts on the other hand are the subdivisions of the provinces, and they are administrative and financial entities with the main responsibilities of promoting the socio−economic development of their population and the solidarity among their residents (GoR 2006b, 2). In addition, districts provide services that are not delivered by its lower level entities (GoR 2013, 88). The spatial distribution of the districts are also shown in Figure 2.2. The direct lower level entities of districts are sectors and the country counts in total 416 sectors. Sectors are also subdivided into cells where the total number of cells is 2,148. The smallest administrative entity is called Village and the country counts 14,835 villages. The village is the closest entity to the people and through this entity the problems, priorities and needs of the people at a grassroots level are supposed to be identified and addressed (MINALOC 2013). The number of districts, sectors, cells and villages per province are presented in Table 2.1.

Table 2.1: Summary of Rwanda's administrative and demographic information (Author based on data from NISR 2012a). In this table 100% of the country's area is equivalent to 26,338 km^2 while 100% population is equivalent to 10.5 million people.

ID	Province	Area (% of national)	Population (% of national)	Population (per km^2)	Districts	Sectors	Cells	Villages
1	Kigali	2.9	10.8	1,556	3	35	161	1,176
2	East	37.4	24.7	275	7	95	503	3,792
3	North	12.9	16.4	528	5	89	414	2,744
4	South	23.6	24.6	435	8	100	532	3,501
5	West	23.2	23.5	421	7	97	538	3,624
	National	100	100	415	30	416	2,148	14,837

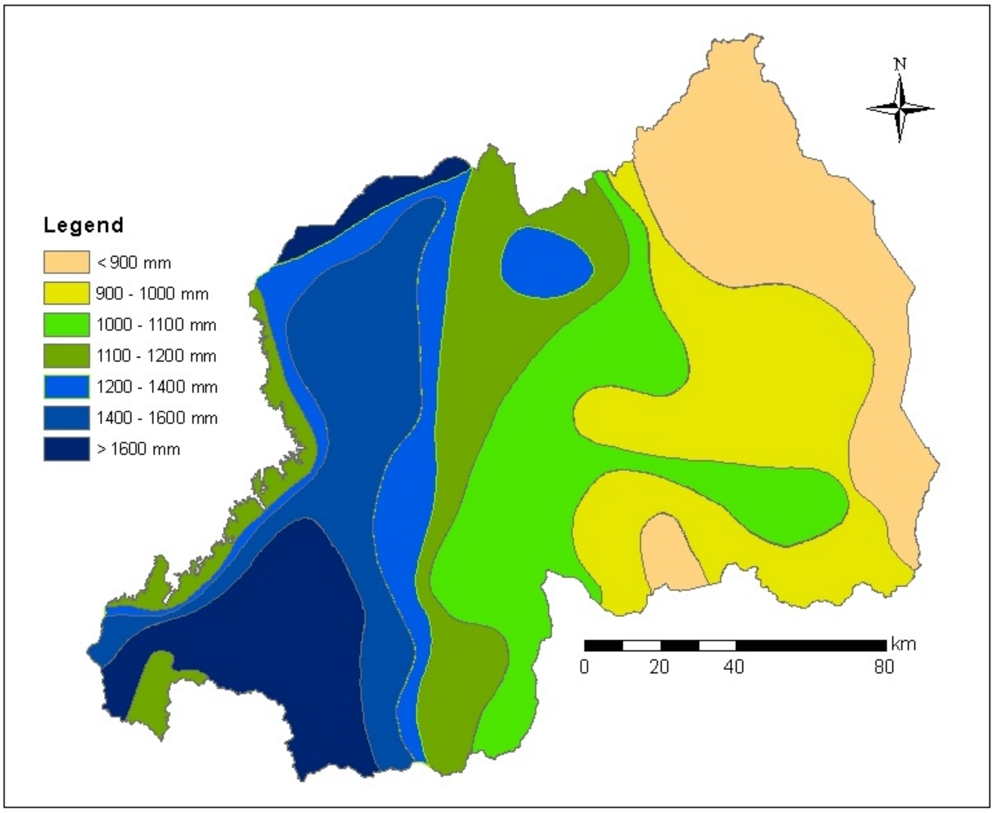
2.1.3 Climate of Rwanda

Although the country is located in the tropical zone, Rwanda's climate is temperate and predominantly influenced by its altitude (McSweeney 2010). As shown in Figure 2.3 (a), the average annual rainfalls vary with the altitude (see Figure 2.1), with the highest totals ($>$ 1600 mm) in the west and then diminishing towards the east ($<$ 900 mm).

The country experiences two rain seasons which alternate with two dry seasons. As Rwanda is located in the Inter−Tropical Convergence Zone (ITCZ), the rain seasons are controlled by the migration of intertropical trade winds (MINIRENA 2006). ITCZ "is an equatorial zonal belt of low pressure, strong convection and heavy precipitation near the equator where the northeast trade winds meet the southeast trade winds; and this band moves seasonally" (IPCC 2013, 1456). Within a year, winds migrate from the northern to the southern Tropics and then back, which give rise to a bimodal rain that, in normal conditions, occur from March to May and September to November (Obasi 2005). However, due to the topography and presence of large lakes in the region where Rwanda is located, the climate patterns are modified in a way that a short rain season occurs from October to December and a long rain season from March to May (McSweeney 2010). During the short rain season, the dominating winds are from the north−east and they carry humidity from the Indian Ocean and the Victoria Lake; whereas the long rain season is influenced by winds from the south−east and south−west, which carry humidity from the South Atlantic passing through the Congolese Basin (MINIRENA 2006, 23). The dry seasons occur from January to February (short dry season) and June to September (long dry season).

In the short dry season, dry and cold air from the Arabian Dorsal penetrate East Africa, but are moderated by the Victoria Lake and the diversity of Rwanda's relief whereas for the case of the long dry season, dry air arrives in Rwanda from the

(a) Rainfall



(b) Temperature

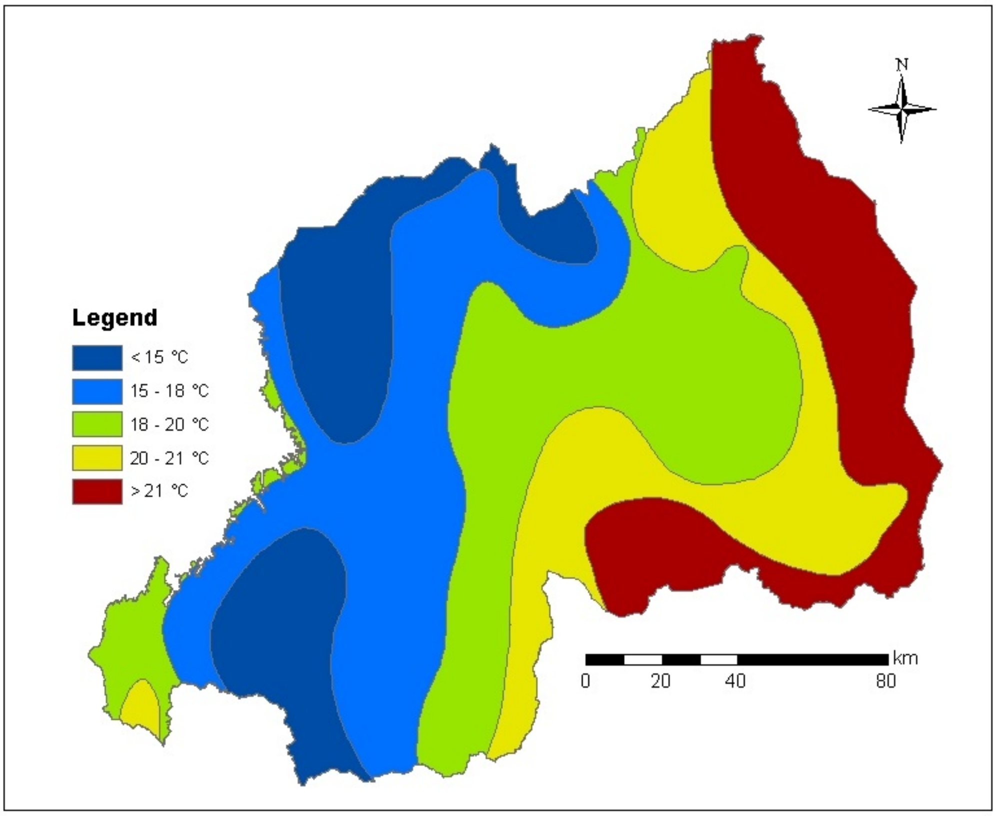


Figure 2.3: Spatial distribution of precipitations and temperatures (GIS maps obtained from the LWH)

south−east (MINIRENA 2006). Similar to precipitations, the temperature varies also with the altitude: lower temperatures are recorded in the highlands while higher ones are observed in the lowlands. As shown in Figure 2.3 (b), the annual average temperature in the volcanic region and the Congo−Nile ridge is less than 15℃ and increases towards the east where it reaches higher values than 21℃.

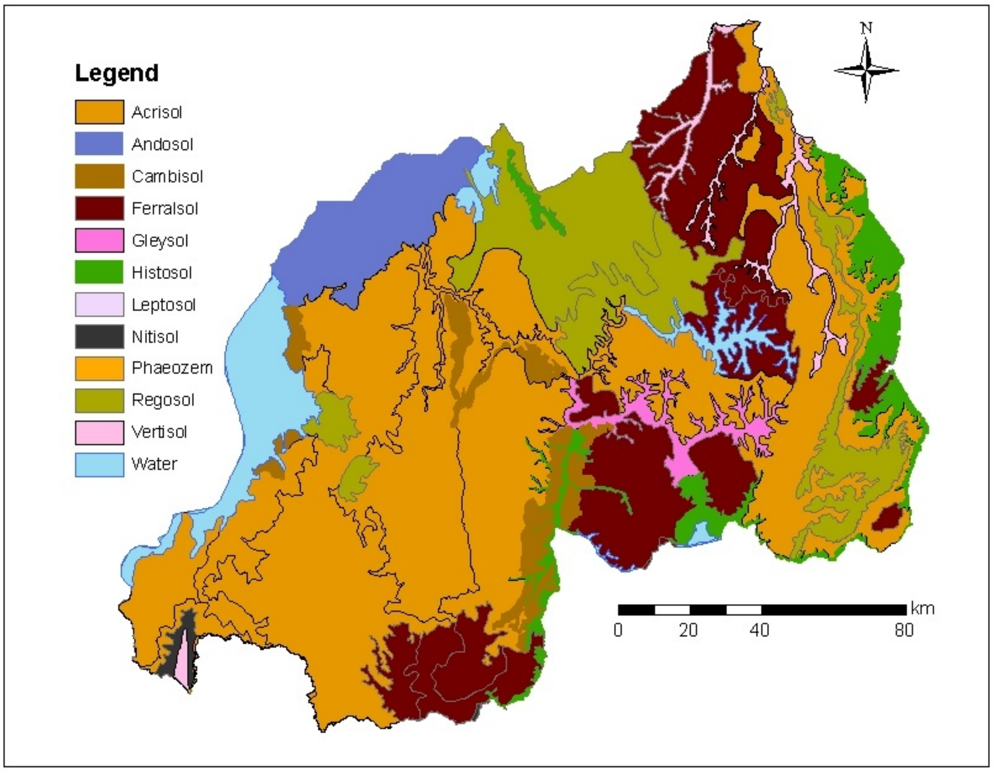
2.1.4 Soil and land cover

As will be discussed in Chapter 4, information on soil properties such as the soil hydraulic conductivity and the soil water holding capacity are very important in the computation of water movement through soils. The soils of Rwanda originate from the physical−chemical alteration of schistose, quartzite, gneissic, granite and volcanic rocks which make up the superficial geology of the country (Harding 2009).

According to FAO soil classifications, Rwandan soils are grouped into acrisols, alisols, andosols, cambisols, ferralsols, gleysols, histosols, lixisols, luvisols, podzols, phaeozems, solonetz and vertisols (Malesu et al. 2010). As reported by Morris et al. (2008), more than 70% of the Rwandan households hold less than one hectare of land which is translated into an over−cultivation of the land. In addition, given the fact that 80% of arable land in Rwanda is on slopes, the cultivation on slopes above 55% is unavoidable (The World Bank 2011), which leads to severe erosions. The spatial distribution of the country's soil according to FAO classification is shown in Figure 2.4 (a).

As for the land cover, the type of the land cover plays a key role in the plants' evapotranspiration process where water is taken up by the roots, transported through the plant's stem, vaporized in plant tissues (mainly in leaves) and then the vapor is rejected to the atmosphere (Allen et al. 1998). Rwanda's land cover is grouped into crop−land, forests and trees, Savannah, shrubs and built−up areas and water bodies (see Figure 2.4 (b)).

(a) Soil



(b) Land cover

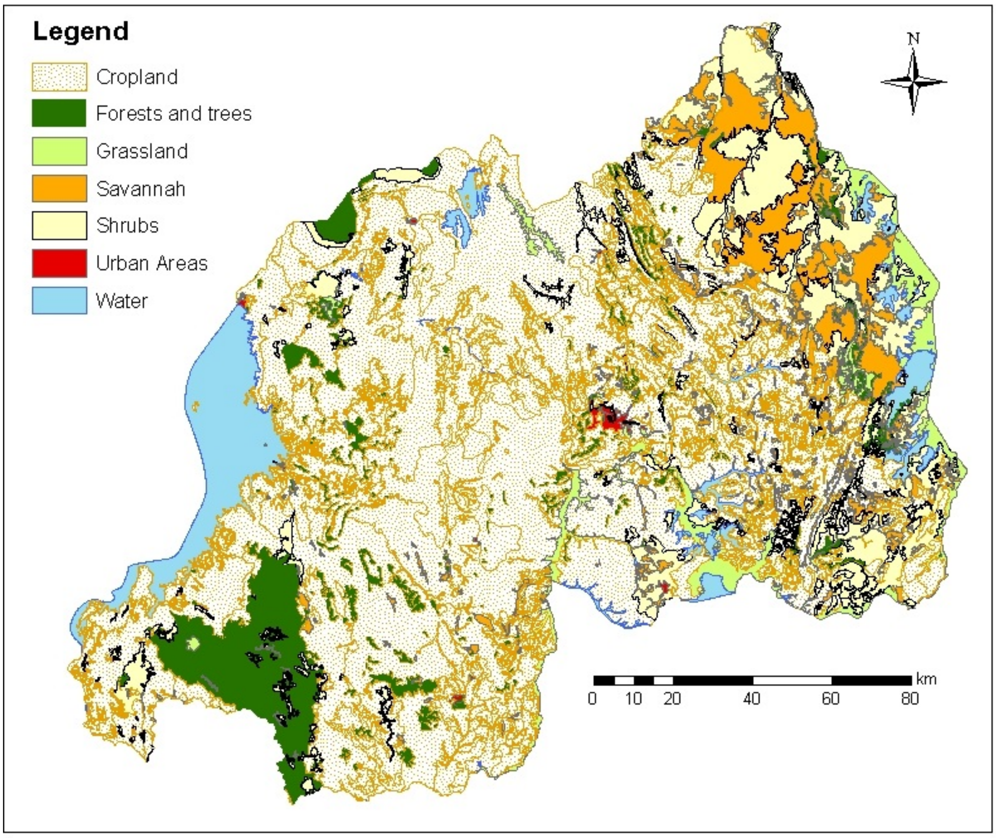


Figure 2.4: Distribution of Rwanda's soil (Batjes 2007) and land cover (GIS map obtained from the LWH)

2.2 Demographic and socioeconomic information

In this section, Rwanda's demographic data are presented together with the socio−economic information. Furthermore, long−term development plans and their intermediate results are highlighted.

2.2.1 Rwandan population

Rwanda is among African countries with the highest population densities. As revealed by NISR (2012a), the total population of the country was about 10.5 million inhabitants in 2012, which gives an average density of more than 415 inhabitants/km^2 (NISR 2012a). Compared to results from the 2002 Census, an increase of more than 2.4 million people was observed which is translated into an average annual growth rate of 2.6%. According to NISR (2012a), 41% of the population were under 15 years while only 3% of the total population were above 65 year as it can be noticed from Figure 2.5. The total fertility rate was 4.6 children per woman which explains the wide base of the population pyramid for both urban and rural areas shown by the distribution of the five−year age group pyramid in Figure 2.5.

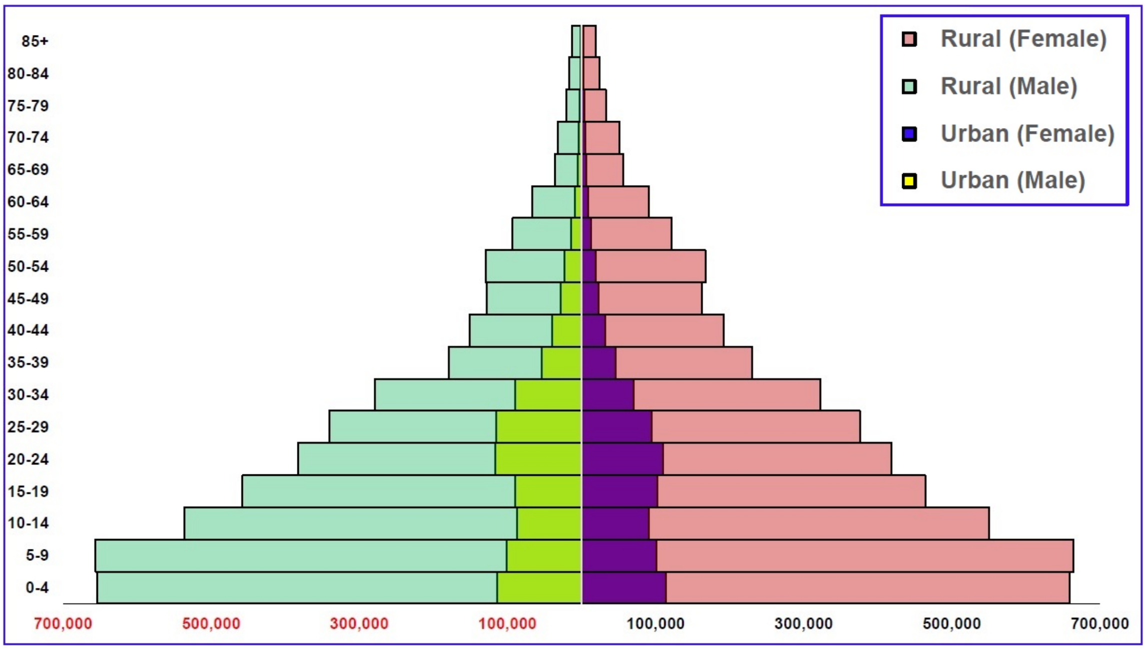


Figure 2.5: Population Pyramid of Rwanda (NISR 2012a)

However, due to the increasing exodus of young people from rural to urban areas mainly for studies or job seeking, an increase in the urban population of young adults between the ages of 20 and 29 for both men and women can be noticed (Figure 2.5). The life expectancy has risen from 55 to 63 years between 2005 and 2012 whereas the number of people living under the poverty line has decreased from 56.7% in 2007 to 44.9% in 2012 (The World Bank 2015a).

2.2.2 Economy of Rwanda

The economy of Rwanda is based on three main sectors namely services, agriculture and industry. Although about 80% of the national workforce is engaged in agriculture, its contribution to the national GDP is relatively low (McSweeney 2010). From Figure 2.6 which presents the contributions of different sectors of the economy, in Billion Rwandan Francs (FRW) between 2000 and 2012, it can be noticed that the agricultural sector contributes about 35% of the GDP while the service and industry sectors represent 45% and 14% of the GDP respectively. The remaining 6% come from the difference between the bank service charges and the Value Added Tax (VAT) and taxes on products (NISR 2013).

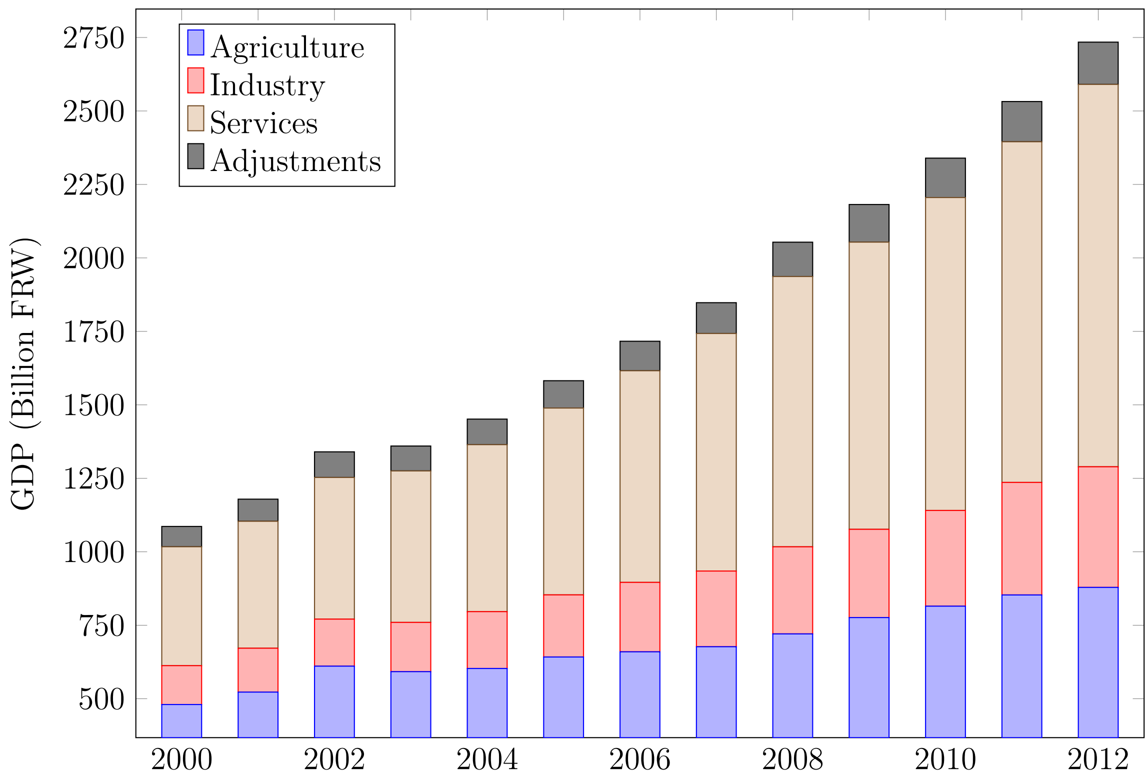


Figure 2.6: Evolution of the GDP (at 2006 constant prices) between 2000 and 2012 (Author based on data from MINICOFIN)

The per capita Gross National Income (GNI) in Rwanda has increased from US$ 223 (in constant 2005 US$) in 2000 to US$ 437 (in constant 2005 US$) in 2014. As it can be noticed from Figure 2.7, Rwanda's GNI per capita has grown fast with reference to its direct neighbours except for Tanzania.

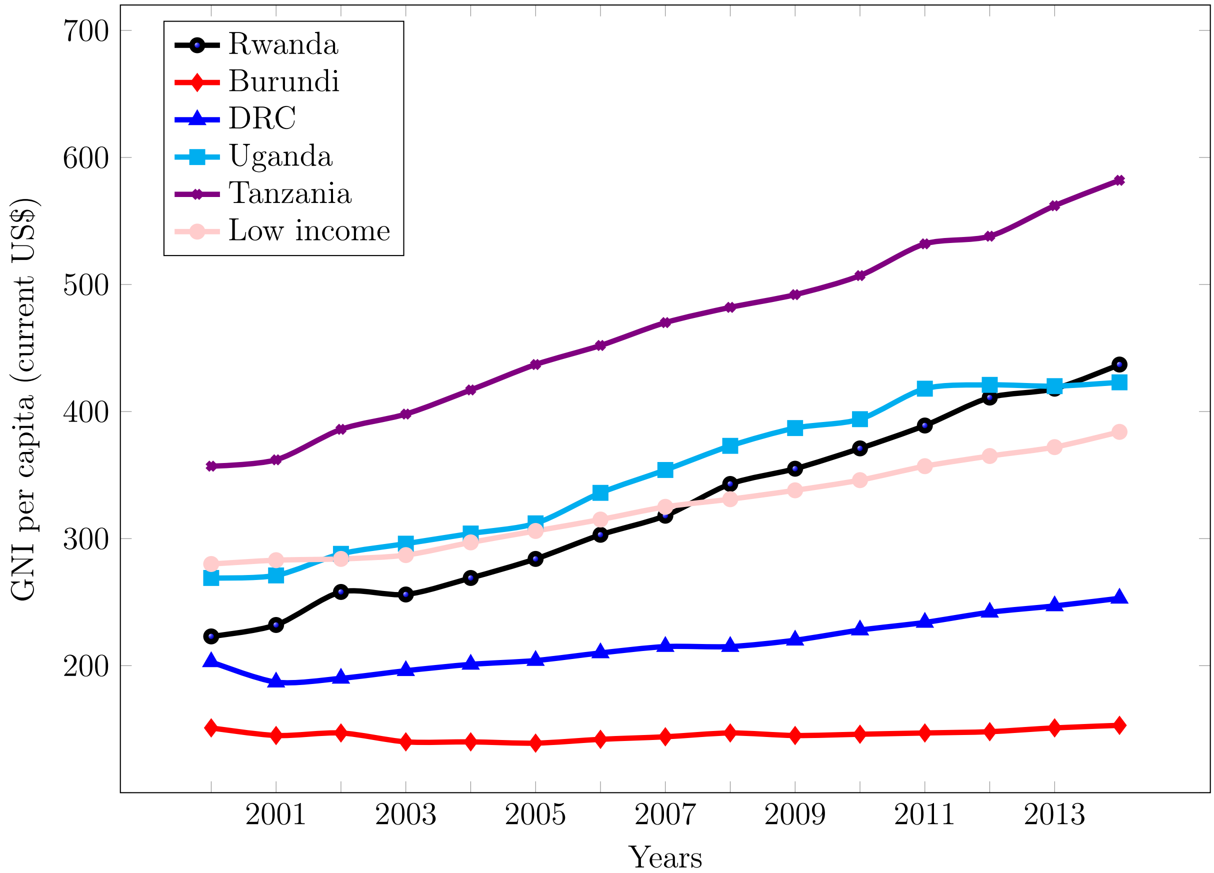


Figure 2.7: Income comparison between Rwanda and its neighbours (Author based on data from The World Bank 2015a)

2.2.3 Short and long term economic development plans

To achieve its target of being a middle income country by 2020, Rwanda has identified six pillars and three cross−cutting areas on which the development will be based in order to achieve the country's aspirations. As stipulated in MINICOFIN (2000), the pillars are good governance, human resource development and a knowledge based economy, a private sector−led economy, infrastructure development, productive and market oriented agriculture, and regional and international economic integration. The three cross−cutting areas comprise gender equality, protection of environment and sustainable natural resource management, and science and technology.

In order to evaluate the progress towards the achievement of the stated goals, the Vision 2020 was subdivided into medium term development frameworks that are assessed over time. These frameworks include Rwanda's first Poverty Reduction Strategy Paper (PRSP) covering the period 2002−2005, Rwanda's EDPRS for the period 2008−2012 (MINICOFIN 2007) and EDPRS2 covering the period 2013−2018 (MINICOFIN 2013). Selected Vision 2020 indicators and mid−term achievements are presented in Table 2.2.

Table 2.2: Selected indicators of Rwanda Vision 2020 (MINICOFIN 2000; NISR 2013)

ID	Indicator	Reference 2000	Target 2010	Achieved 2012	Target 2020
1	Rwandan population (Million)	7.7	10.2	10.5	13
2	Literacy level (%)	48	80	83.2	100
3	Life expectancy (years)	49	50	64	55
4	Women fertility (Number of children)	6.5	5.5	4.6	4.5
5	Infant mortality (per 1000 live births)	107	80	76	50
6	Maternal mortality rate (per 100,000)	1070	600	476	200
7	Population Growth rate (%)	2.9	2.3	2.6	2.2
8	Net primary school enrolment (%	72	100	96.5	100
9	Rate of qualification of teachers (%	20	100	95.6	100
10	Doctors per 100,000 inhabitant	1.5	5	6	10
11	Poverty (%< 1 US$/day)	64	40	44.9	30
12	Average GDP growth rate (%	6.2	8	8	8
13	GDP per capita (in US$ at current prices)	220	400	644	900
14	Access to clean water (%)	52	80	74.2	100
15	Annual electricity consumption (kWh/capita)	30	60	38.8	100
16	Access to electric energy (% of population.)	2	25	16.8	35
17	Wood energy in the national energy consumption (%)	94	50	82	50

In addition to Vision 2020, a national strategy for climate change resilience and low carbon economic development towards 2050 was developed. As described in GoR (2011a, 18), Rwanda seeks to achieve the following objectives by 2050:

- Energy security and a low carbon energy supply that supports the development of green industry and services;
- Sustainable land use and water resource management that results in food security, appropriate urban development and preservation of biodiversity and ecosystem services;
- Social protection and disaster risk reduction that reduces vulnerability to climate change impacts.

2.3 Water sector

Water is an irreplaceable and indispensable resource to human life. There is a correlation between water and socio−economic development, as well as between poverty and water shortage. Furthermore, diseases caused by unclean drinking water and lack of adequate sanitation facilities are among the leading causes of death in the developing world (Salman and McInerney-Lankford 2004). Water plays an essential role to produce goods and services necessary to sustain people's lives. Water is crucial for irrigation, industrial processes, water transportation and energy generation for most countries in the world (Bekchanov 2013). Rwanda is one the nations that depends on water resources to feed its citizens and sustain its economies; and water also plays an important role mainly in domestic use, agricultural production and the generation of electricity in the country.

2.3.1 Water resources

Rwanda is endowed with abundant precipitations distributed temporarily and spatially as discussed in Section 2.1.3. However, due to inadequate management of water resources, about 4.3 km^3 of rainfall are lost as runoff water every year while between 30% and 40% of water are lost in inefficient supply systems (MINIRENA 2011). As it can be noticed from Table 2.3, only between 51.29% and 67.35% of the produced water are billed. The difference between the production and billed water can be justified by the mentioned inefficient supply systems as well as the non−billed water (illegal connections for example).

Table 2.3: Evolution of the total annual water consumption and its distribution by users for the 2007−2013 period (Author based on data from NISR 2012b, 80 and NISR 2014b, 109)

Sector/Year	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**
Water demand and supply balance							
Production	20.72	20.45	23.00	28.62	31.39	38.06	40.10
Consumption	11.68	13.77	14.62	18.57	18.49	19.52	23.12
Demand/supply ratio (%)	56.40	67.35	63.55	64.88	58.91	51.29	57.66
Distribution of water demand							
Households (%)	94.45	94.58	94.55	95.28	94.68	94.48	92.14
Other uses (%)	5.55	5.42	5.45	4.72	5.32	5.52	7.86

The per capita renewable internal freshwater resources (internal river flows and groundwater from rainfall) has declined from 3,114 m^3 in 1962 to 807 m^3 in 2013 (WB 2011) mainly due to the increasing population. Consequently, Rwanda is classified as a water−scarce country according to Falkenmark indicators. According to these indicators, when the annual available water per capita lies between 1,000 and 1,700 m^3, the situation is referred to as stress, and when it is between 500 and 1,000 m^3 it is called scarcity whereas a situation where the supply falls below 500 m^3 is called absolute scarcity (Falkenmark 1989).

2.3.2 Water demand and supply

In terms of water accessibility, about 73% of Rwandan households collect water from improved water sources, among which protected springs and wells (37%) and public taps outside the compound (about 28%) are the most common (NISR 2012a). Households that collect water from unimproved water sources use mostly unprotected springs and wells (13%), rivers (about 6%) and lakes, streams, ponds and surface water (about 6%). Despite the considerable water access rate, there are frequent water shortages because of insufficient water infrastructure to store enough water as precipitation, the main source of water, is unevenly distributed in time and space, with about half of it occurring in one quarter of the year (MINIRENA 2011). As reported by CNEE (2012) for instance, water supply deficits in Kigali, the capital city of the country, were estimated to be 50% of the total water demand in 2012. In addition, the daily water consumption in rural areas is estimated to be 8.15 litres per capita (MINIRENA 2011) which is far below the international standards. According to WHO (2016) a quantity of 20 litres of water per capita per day is required to meet basic water needs related to drinking, food preparation and basic hygiene. Other needs such as bathing, washing clothes, etc. would require additional amounts.

2.4 Introduction to the energy sector

This section synthesizes available and accessible information about the past, current and future information on Rwanda's energy sector in general and electricity in particular. The information presented in this chapter was collected from different reports, publications and data obtained from REG. This section begins with the description of organization of Rwanda's energy sector together with the responsibilities of different stakeholders involved in energy matters in the country. Furthermore, the country's energy balance is presented with more emphasis on electricity demand and supply. The section ends with a presentation and discussion of the projected electricity demand and the planned power generation to meet the demand.

2.4.1 Organization, responsibilities and stakeholders

The management of energy systems in Rwanda involves various ministries and government agencies as well as private entities and individuals. The main parties involved in the energy in the country include the Ministry of Infrastructure (MININFRA), the Ministry of Natural Resources (MINIRENA), the Ministry of Local Government (MINALOC), the Ministry of Finance and Economic Planning (MINECOFIN), the Ministry of Trade and Industry (MINICOM), REG, Rwanda Utilities Regulatory Agency (RURA) and the Independent Power Producers (IPPs). MININFRA is responsible for the development of national policies and strategies related to energy generation in the country (AfDB 2013). In addition, institutional and legal frameworks together with the coordination and supervision of resources mobilisation and partnerships are also among the responsibilities of MININFRA. Although MININFRA is responsible for the development of the implementation strategies for biomass (wood−fuel, charcoal, briquettes and energy production from solid waste), the policies that govern the exploitation of biomass are developed by MINIRENA. With regard to oil products, the policies related to their pricing, taxation and storage fall respectively under MINICOM's, MINECOFIN's and MINIRENA's responsibilities (AfDB 2013).

The policies and strategies developed by the above ministries are implemented by REG according to Law N°87/03 of August 16, 2014 establishing this institution (GoR 2014). It is worth noticing that there have been various restructures in the electricity and water supply sectors since 1939 when the first company, Régie de Production et de Distribution d'eau et d'électricité (REGIDESO), was founded to supply electricity, water and gas in Rwanda and Burundi (EWSA 2010). In 1963 REGIDESO was split into two institutions: REGIDESO Burundi and REGIDESO Rwanda. In 1976, under Law N°18/76 of April 20, 1976, REGIDESO−Rwanda became Etablissement de Production, de Transport et de Distribution d'Electricité, d'Eau et de Gaz (ELECTROGAZ) which was granted a monopoly of supplying electricity and water on Rwandan territory. To attract private investments in the energy sector, in 1999, under Law N°18/99 of October 30, 1999, electricity generation was liberalised, however, ELECTROGAZ kept its transmission and distribution monopoly (EWSA 2010).

In the attempt to achieve operational efficiency by reducing technical and commercial losses and achieve financial self−sufficiency, ELECTROGAZ was placed under a management contract with Lahmayer International in collaboration with Hamburg Water

Works for a 5−year−period since 2003 (Hermes 2005, 6). However, this contract was terminated two years later and the management returned to the Government (EWSA 2010). In 2008, ELECCTROGAZ was split into two companies: Rwanda Electricity Corporation (RECO) and Rwanda Water and Sanitation Corporation (RWASCO) according to Law N°43-44/2008 of September 09, 2008. Two years later, under Law N°43/2010 of December 07, 2010, RECO, RWASCO and the energy sector of the MININFRA were merged to form EWSA (GoR 2011b). According to this law, EWSA was responsible for the implementation of the Government policies and strategies for developing the energy (including also water and sanitation) sector through the coordination, conception, development, monitoring and evaluation of the actions and programmes related to energy.

Similar to its predecessors RECO and RWASCO, EWSA did not last longer because under Law N°87/03 of August 16, 2014 its responsibilities related to energy were transferred to REG Ltd. while those related to water were assigned to Water and Sanitation Corporation (WASAC) (GoR 2014). In addition to the responsibility of implementing the Government policies and strategies , REG Ltd was also mandated to expand, maintain and operate energy infrastructure, and this is done through its two subsidiary companies: the Energy Utility Corporation Limited (EUCL) and the Energy Development Corporation Limited (EDCL) as highlighted in REG (2015a). It is important to mention that REG Ltd is a 100% state owned company (EWSA 2010) which indicates a step backwards from the liberalisation of energy marked in the country.

Another important stakeholder is Rwanda Development Board (RDB) established under the Organic Law N°53/2008 of September 02, 2008 to promote direct investments and entrepreneurship through facilitating business registration, and to ensure that investors comply with environmental standards (GoR 2008). To facilitate private investments by issuing licenses and ensuring that there is an effective competition among all involved players in all businesses in the country including energy business, RURA was established under the Organic Law N°39/2001 of September 13, 2001 (GoR 2001). According to this law, RURA advises the Government during the formulation of its energy policy. In addition, RURA issues licenses to IPPs and ensures that the later comply with the Government's policies. Furthermore, RURA facilitates private investments by ensuring that there is an effective competition and protects them and also consumers from the abuse of monopoly by REG who owns the national transmission and distribution networks.

As developing new power generation facilities requires considerable amounts of resources and expertise that the Government could not provide, it was necessary to incorporate the private sector. Consequently, Law N°18/99 of October 30, 1999 liberalised electricity generation in the country by abolishing the monopoly that was held by the Government's subsidiary company, ELECTROGAZ. Since the establishment of Law N°18/99, different IPPs are producing or planning to produce electricity and feeding it into the national grid and/or sell it directly to customers. The IPPs include, for example, CALIMAX, ENNY, SOGEMR, RED and REPRO involved in hydropower generation, Stadtwerke Mainz and Gigawatt Global in solar PV, Hakan and REFAD in power from peat, and Kibuye Power and KivuWatt in power from methane gas. Because the implementation of energy projects involves and/or affects local people, MINALOC and local government leaders play an important role in raising awareness and social acceptability of energy technologies as well as energy infrastructure at national and community levels.

2.4.2 National energy policy and strategy

A policy is a statement of plan of action to guide decisions in order to achieve intended goals by a local, regional or national government which has the authority and power to promulgate decisions (UNFCCC 2006, 1; Miller and McTavish 2014, 6). With regard to energy, the role of governments is to determine the energy policy objectives and find the appropriate policy instruments to achieve the objectives (Schläpfer 2009, slide 10).

In the same framework as discussed above, the Government of Rwanda has developed a national energy policy in order to create conditions for the provision of safe, reliable, efficient, and cost−effective energy services to households and to all economic sectors on a sustainable basis. The specific objectives of this policy are to increase electricity generation capacity, increase access to electricity, maintain an economic and regionally competitive tariff, support sustainable and efficient use of biomass and maintain an economic and secure supply of petroleum products (MININFRA 2013, 38).

It is expected that this policy will support the short and medium term country's economic development aspirations which would enable the country to achieve its main objective of being a developed climate−resilient and low carbon economy by 2050 (GoR 2011a, 17). It is planned that by 2050 the economy of Rwanda will be a service based economy where energy needs will be met with low carbon indigenous energy resources which will reduce both the imported fossil fuels for power generation and the country's contribution to global climate change. To achieve these objectives, a number of strategies and proposals were formulated as presented in Table 2.4.

Table 2.4: Rwanda's energy strategies and proposals by 2018 (MININFRA 2013, 10)

	ELECTRICITY
Electricity access	**Grid connections**: extension of the electricity grid across the country to enable the connection of commercial consumers who will drive economic growth and households consuming sufficient electricity to make the connections financially sustainable. **Off−grid installations**: households located far away from the grid or those consuming insufficient electricity to make a grid connection financially viable will be advised to get access through off−grid solutions such as minigrids or solar PV solutions.
Electricity generation	**Electricity demand**: the projections of demand for electricity range between 250 and 470 MW which require installed generation of 300−564 MW (considering a 20% reserve margin). **Powery generation**: increase the installed capacity to 563 MW by 2018.
Tariff and Subsidies	**Subsidies**: Government plans to eliminate subsidies to the tariff by 2015 whilst maintaining a regionally competitive tariff. This will be made possible through phasing out the use of diesel as a major component of generation mix. **Tariff segmentation**: RURA would in consultation with EWSA review the tariff structure to ensure that it is aligned with the objectives of EDPRS II.
	BIOMASS
Sustainable biomass solutions	**Promote** the use of biogas within households and government institutions. The target is to increase the penetration of improved cook−stoves to between 50% and 80%. **Support** improved wood harvesting and charcoal production techniques by scaling up the level of training given to local cooperatives. **Support** the market and research of biomass alternatives such as LPG and Peat briquettes.
	PETROLEUM
Security of supply	**Increase security of supply**: 4 months' supply will be stored by government and private sector. **Decreased import costs and Increased price stability**: Through promoting and facilitating bulk purchasing of petroleum with Rwanda's regional neighbors **Maintain and increase quality**: Improve standards and testing to ensure consistently high quality.

To be able to meet the intended goals, proposed policies have to meet the following criteria (IIASA 2012, 1556):

- effectiveness: the ability of a policy to achieve the intended objectives;
- economic efficiency: the ability of a policy to achieve objectives at the lowest possible cost to society;
- administrative feasibility: the ability of a policy to avoid imposing a functional burden on government that thwarts successful implementation, such as through bureaucratic ineffectiveness or excessive information and monitoring requirements;
- equity: the effect of a policy on income distribution and on disadvantaged groups within society;
- political acceptability: the extent to which a policy can garner sufficient political support to be enacted and effectively sustained;
- policy robustness: the ability of a policy to perform well under highly uncertain and widely contrasted futures; and
- policy consistency: the extent to which a policy works in concert and not in conflict with other policies.

In this regard, a number of laws and regulations have been put in place in order to especially facilitate and attract investments in power generation as well as the efficient use of energy. Among these one can mention Law N°21/2006 of April 28, 2006 that established the customs system. In its article 182, solar energy equipment and accessories destined to power generation are relieved from paying payment of import duties (GoR 2006c, 84). Another similar law is the Law N°25/2010 of May 28, 2010 concerning the code of value added tax. Article 2 point 10 of this law states that energy supplies such as energy saving lamps, solar water−heaters, wind energy systems, liquefied petroleum gas, cylinders and invertors and equipment used in the supply of biogas energy are exempt from paying VAT (GoR 2006a, 25).

To avoid any confusions that might result from these two laws, a complete list of energy supply equipment exempted from paying value added tax was published by MINECOFIN[1]. This list includes solar energy equipment (solar PV modules, inverters, batteries, etc.), wind energy generation equipment and accompanying accessories, energy efficient devices, etc.

In addition to these laws related to imports of clean energy generation and efficient energy use, a FIT scheme for hydropower plants connected to the grid has been approved by RURA in 2012. A FIT is a policy mechanism that provides investment security by

1. http://rra.gov.rw/IMG/pdf/exempted_energy_equipment.pdf

ensuring IPPs tariffs and other incentives that allow them to cover the production costs and earn reasonable returns on their investments and avoid at the same time unnecessary profits (Mendonça et al. 2010, 15). The hydropower FIT was set under the Regulations N°001/ENERGY/RURA/2012 of February 09, 2012 and it determines the applicable tariffs to hydropower and mini−hydropower plants of up to 10 MW capacity (RURA 2012b). The determined hydropower FIT ranges between US$ cents 16.60 and US$ cents 6.0 as indicated in Table 2.5. This FIT was expected to reduce the transaction costs and time associated to tariff negotiations.

Table 2.5: Rwanda renewable energy feed−in tariff for hydropower (RURA 2012b, 10)

ID	Capacity (kW)	Tariff per kWh (US$ Cents)	ID	Capacity (kW)	Tariff per kWh (US$ Cents)
1	P<P≤50	16.60	10	2,000<P≤3,000	8.70
2	50<P≤100	16.10	11	3,000<P≤4,000	7.90
3	100<P≤150	15.207	12	4,000<P≤5,000	7.20
4	150<P≤200	14.30	13	5,000<P≤6,000	7.10
5	200<P≤250	13.50	14	6,000<P≤7,000	7.00
6	250<P≤500	12.90	15	7,000<P≤8,000	6.90
7	500<P≤750	12.30	16	8,000<P≤9,000	6.80
8	750<P≤1,000	11.80	17	9,000<P≤10,000	6.70
9	1,000<P≤2,000	9.50			

2.4.3 Energy supply and consumption

As highlighted in Section 1.1.2, Rwanda is one of the developing countries which rely heavily on biomass to meet their energy needs. The average annual primary energy consumption in the country is estimated to be 0.17 toe per capita per year (MININFRA 2011, 25) which is very low compared to 0.68 toe in Sub−Sahara Africa and more than 4.5 toe in developed countries (The World Bank 2015c). As it can be inferred from Figure 2.8, 86% of the total primary supply in Rwanda come from biomass (firewood, wood for charcoal, agriculture residues and peat) whereas oil products and electricity represent respectively 11% and 3%.

The considerable share of biomass in the total primary supply puts more pressure on the country's forest given the rapid increase of population which requires more and more fuel resources to meet the growing energy needs especially for cooking. This pressure can be justified by the fact that nearly 98% of the country's households rely on biomass of which 82% are from firewood, 13% from charcoal and 3% from biomass residues to meet

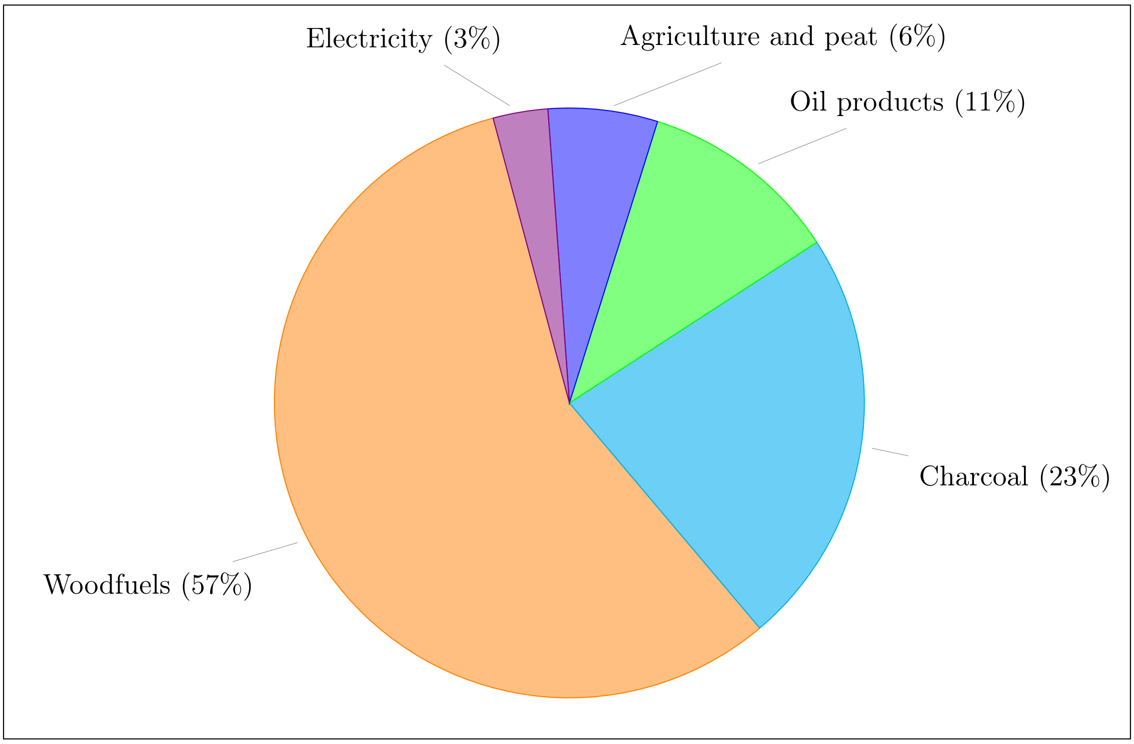


Figure 2.8: Primary energy balance (MININFRA 2013, 11; The World Bank 2012, 14)

their cooking energy needs (NISR 2012a, 92). As highlighted in Section 1.1.2, 91% of the total energy supplied in the country is consumed in the residential sector, 4.5% in the transport sector, 2.7% and 1.8% in industrial and service sectors respectively (Safari 2010, 525; UNEP 2014, 11). Regarding oil products, all the fossil fuel products are imported of which between 80% and 90% are used in the transport sector while the remaining share is used in electricity generation (UNEP 2014, 16). Given that Rwanda is a landlocked country combined with the volatility of oil products on international markets, oil products have always been among the main leading contributors of the macroeconomic instability in the country and takes 55% of the national total export revenues (MININFRA 2013, 66).

As for lighting, according to the results of the Rwanda Fourth Population and Housing Census conducted in 2012, about 40% of households rely on kerosene lamps, 10% on candles and about 8% on firewood and 18% on electricity as sources of energy for lighting (NISR 2012a, 87). The same Census revealed that the electricity access rate differs largely between rural and urban areas as the urban households with access to electricity were 67% in 2012 and 6.4% in rural areas which gives a national electrification rate of 18%. Electricity consumption in Rwanda was about 20 kWh per capita per year in 2010 (MININFRA 2011, 26) and reached 41 kWh in 2014 (REG 2014b). This increase in per capita electricity consumption is a result of an intensive electrification program which is one component of the country's EDPRS. Despite this increase in electricity consumption of about 100% in only 4 years, this consumption is 10 times less compared with 400 kWh average per capita consumption in Sub−Saharan Africa (IEA 2014b, 39) and more than 200 times less than the per capita consumption in industrialised nations (UN-Statistics Division 2015).

The main reason of the very low per capita electricity consumption is the very low electrification rate resulting mainly from a lack of investments in the energy sector, both in the power generation and in the extension of the electrical network (Jolie et al. 2009, 10). This problem was aggravated by the reduction in power generation capacity of hydropower plants, since 2000s, whereas the demand for electricity has continuously risen. To temporarily respond to this situation, emergency diesel generators have been introduced. To ensure an affordable tariff, the Government was obliged to subsidise the electricity sector through paying part of the capacity charges for rented generators as well as the import duties for fuel. This has resulted in cutting expenditures in other sectors such as health and education. Table 2.6 presents information on thermal power generation together with the Government subsidies on this generation between 2008 and 2010.

Table 2.6: Estimations of subsidies on thermal generation (in current prices) for the 2008−2010 period (Author based on data from NISR 2014a, 20−1, 47 and data from REG).

Year	2008	2009	2010	2008	2009	2010
Total demand (GWh)	277.40	313.32	363.02	277.40	313.32	363.02
		Diesel			HFO	
Thermal generation (GWh)	123.05	71.88	80.76	0.00	73.87	74.01
% share of total demand	44.36	22.95	22.25	0.00	23.58	20.39
Fuel consumption (l/MWh)		258			209	
Total fuel (Million litres)	31.75	18.54	20.83	0.00	15.44	15.47
Subsidy (FRW/l)	312	312	312	118	118	118
Exchange rate (FRW/US$)	558.90	571.24	594.45	558.90	571.24	594.45
Subsidy (US$/l)	0.56	0.55	0.52	0.21	0.21	0.20
Total subsidies (Million US$)	17.72	10.13	10.93	0.00	3.19	3.07
Total GDP (Billion US$)	4.45	4.61	5.63	4.45	4.61	5.63
% share of the GDP	0.40	0.22	0.19	0.00	0.07	0.05

Despite all the subsidies the tariff has continuously risen so that the tariff for the residential sector, for example, was increased by more than 60% between 2005 and 2012 (see Figure 2.9). The electricity tariffs (in current prices) have risen from FRW 42/kWh (approx. US$ cents 8/kWh) in 2004 to FRW 81/kWh (approx. US$ Cents 15/kWh) in 2005 (Angel-Urdinola et al. 2006, 236) and to FRW 112/kWh (approx. US$ Cents 22/kWh) in 2007 (Jolie et al. 2009, 10). Since July 01, 2012, the tariffs have been raised again and reached FRW 134/kWh (approx. US$ Cents 26/kWh) for all electricity customers excluding the industrial sector for which the tariffs were set at FRW 105/kWh (approx. US$ Cents 24/kWh) for power consumed between 07.00 am and 05.00 pm, FRW 168/kWh (approx. US$ Cents 33/kWh) between 5.00 pm and 11.00 pm and FRW 96/kWh (approx. US$ cents 18/kWh) between 11.00 pm and 07.00 am (RURA 2012a). These high electricity tariffs are one of the limitations to the economic growth and improvement of people's living standards as electricity is an essential input to produce goods and services necessary to sustain life and improve the economy.

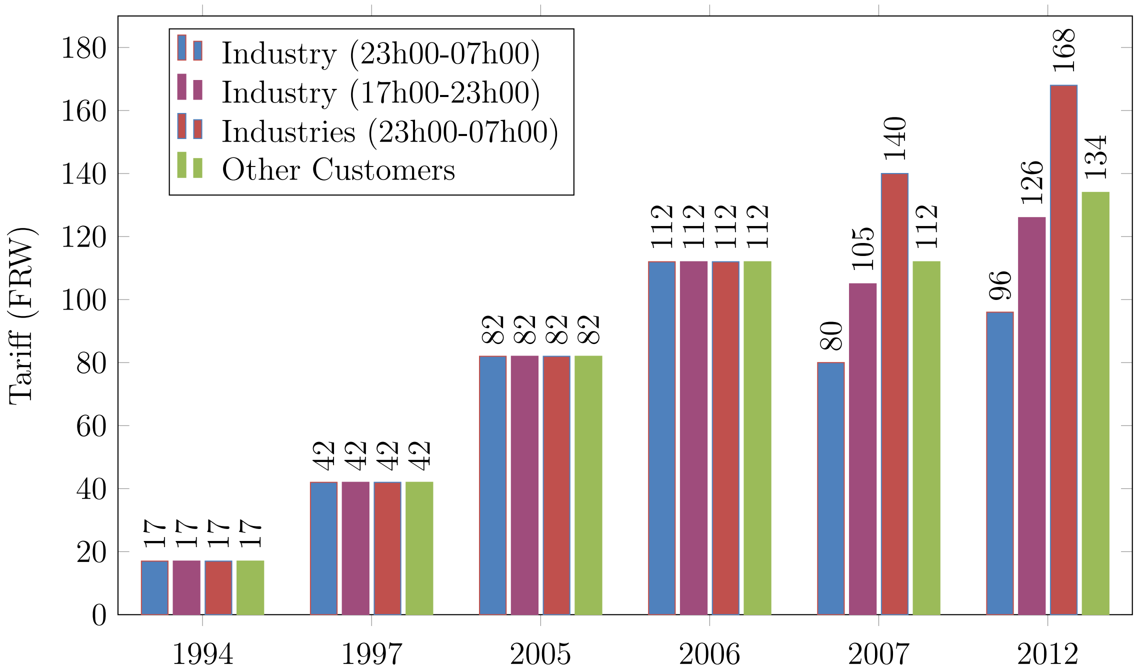


Figure 2.9: Electricity tariff evolution (in current prices) exclusive of VAT (Author based on data from Abdallah et al. 2009, 27 and RURA 2012a, 3)

However, higher tariffs are not unique to Rwanda, they are common in the Sub−Saharan African region where Rwanda is located. As highlighted by IEA (2014b, 66), although income in Sub−Saharan Africa is among the lowest in the world, electricity tariffs in this region rank among the highest (between US$ 130−140/MWh on average) relative to East Asia, Latin America and Eastern Europe (approx. US$80/MWh). Rwanda is one of the leading African countries with high electricity tariffs. For households, for example, the tariff is the highest of the selected countries except for Ghana (see Figure 2.10). The main reasons for high electricity tariffs in Rwanda are the considerable transmission and distribution losses. In general, the energy supply system of Rwanda is characterised by very high losses; between 20% and 25% of the total primary energy are lost in diesel power generation, electricity transmission and distribution losses as well as in the use of inefficient kilns for charcoal production (The World Bank 2012).

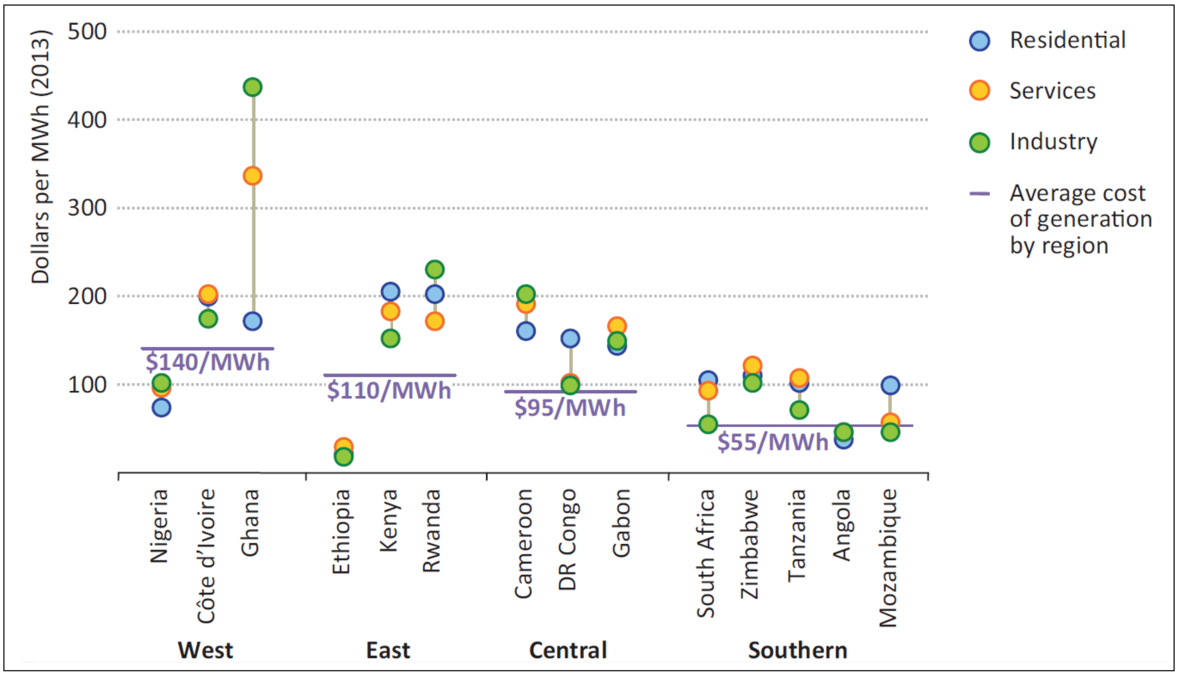


Figure 2.10: Grid electricity prices by end−use sector in selected countries for the year 2013 (IEA 2014b, 66)

2.5 Rwanda's energy resources

Although the energy supply in Rwanda is dominated by traditional biomass, the country is endowed with different types of energy resources, most of these resources, however, remain untapped. This section discusses the potential of Rwanda energy resources in general and electricity resources in particular. The energy resources discussed here are biomass, hydropower, solar, geothermal, methane, peat and wind.

2.5.1 Biomass energy resources

Biomass in Rwanda is used in the form of firewood, charcoal, agriculture residues and biogas mainly for cooking purposes. As highlighted in Section 2.8, 86% of the country's energy demand is met through burning biomass. The annual quantity of biomass requirements in the country was, in 2009, estimated to be about 4,197,000 tons; however, the sustainable quantity of woody biomass that could have been harvested in the same year was estimated to be about 3,327,000 tons (Drigo et al. 2013, 60). To eliminate the biomass supply deficits and achieve a sustainable balance between the supply and demand by 2020, concerned parties are recommended to intensify the dissemination of Improved Cook Stoves (ICSs), promote tree planting in farmlands, improve the management of existing forests, promote efficiency in charcoal making and plant trees on the areas with slope greater than 55% (The World Bank 2012, 68−75).

In the attempt to reduce the pressure on the forest stocks while improving health of biomass users in the country, different initiatives have been undertaken. These mainly include the dissemination of ICSs. On average a household with a traditional stove needs about 1.6 tons of firewood per year to meet its cooking needs (The World Bank 2012, 51) while a household using ICSs requires 23% less wood fuel (see Table 2.7).

Table 2.7: Annual consumption of firewood and charcoal per household and per capita (The World Bank 2012, 51)

Wood fuel type	Stove type	Consumption per household (kg/year)	Consumption per capita (kg/capita/year)
Fuel wood	Traditional/ three stones	1,642	355
	Improved	1,263	273
	Average	1,453	314
Charcoal	Traditional	700	152
	Improved	538	117
	Average	619	134

This show how more use of ICSs can considerably contribute to reduce the current pressure on the country's forests. Rwanda is one of African countries with a high penetration of ICSs (The World Bank 2012, 51) where the penetration level reaches 50% (MININFRA 2013, 10). However, a study conducted by Care International revealed that more than 41.2% of households that own ICSs never use them (Munyehirwe 2008, 36). Therefore, more awareness campaigns regarding the use of ICSs would be required in order to reduce the amount of biomass is necessary.

Another issue of biomass resources is that they are not equally distributed across the country which requires transporting wood and charcoal for long distances. Figure 2.11 shows the spatial distribution of 2009 woody biomass supply potential, woody biomass demand and supply/demand balance. For example in 2009, the Southern and Western provinces presented woody biomass surplus equivalent to 431,000 and 82,000 tons respectively whereas Kigali City, the Northern and Eastern Provinces indicated respectively deficits of 1 million, 290,000 and 80,000 tons. This means that the difference between the demand for biomass and the sustainable biomass supply at the national level was 870,000 tons equivalent to 21.72%.

In addition to ICS, two biogas programs have been initiated in the country in order to reduce the quantity of fuel wood needed and also reduce indoor air pollution that result from cooking with traditional biomass on inefficiently ventilated stoves which claim

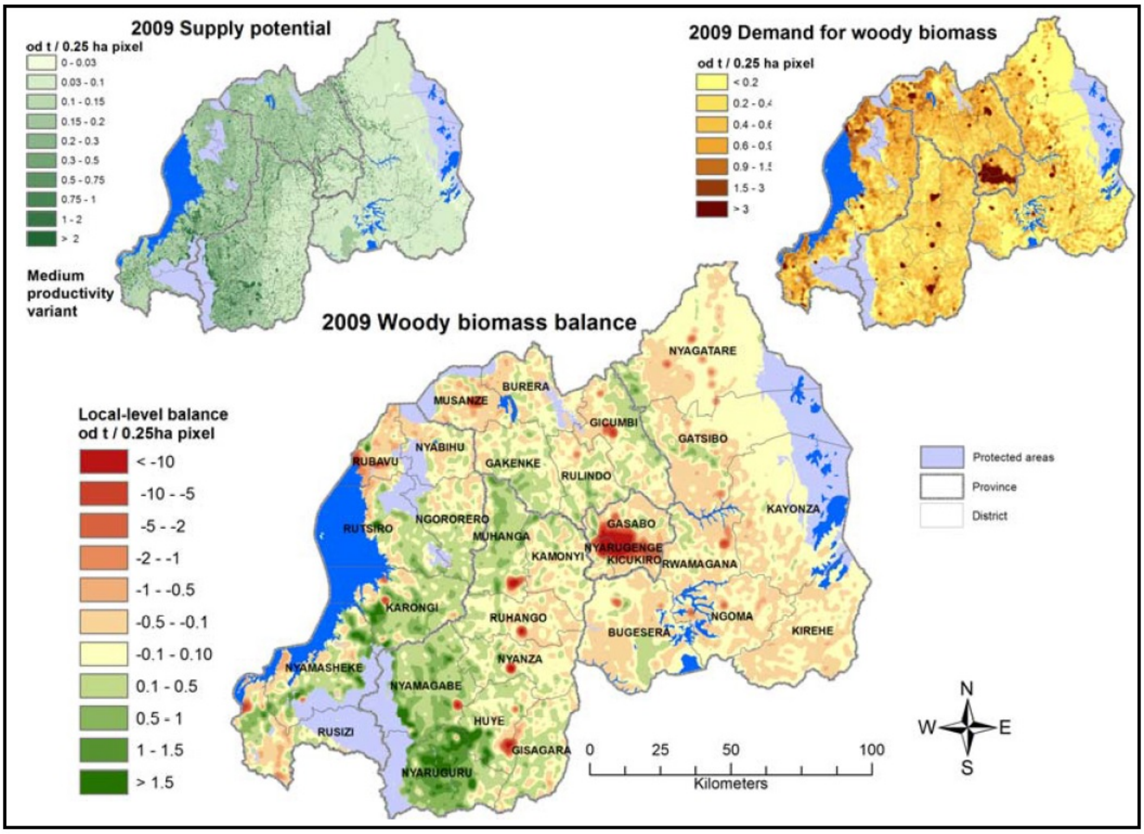


Figure 2.11: Cartographic overview of 2009 woody biomass supply potential, woody biomass demand and supply/demand balance (Drigo et al. 2013, 6)

a considerable number of lives. The two biogas initiatives comprise the domestic and institutional biogas programs. The domestic biogas programs aim to support farmers with 2−4 cows and more to generate biogas from a mixture of animal dung and urine (MININFRA 2011, 48). Under this scheme, the owner of the digester pays 50% of the installation costs while the remaining 50% are covered by subsidies offered by different institutions/donors involved in the dissemination program (MININFRA 2014). On the other hand, the institutional biogas project targets to install biogas digesters in all boarding schools, large health centres and institutions with canteens as well as in prisons (MININFRA 2011, 48). By the end of August 2014, about 4,600 domestic and 76 institutional digesters had been installed across the country (REG 2015b, 1). It is projected that at least 100,000 domestic bio−digesters will be installed by 2017 while the penetration of ICSs would reach 80% from 50% in 2012 (MININFRA 2013, 10).

2.5.2 Hydropower resources

Hydroelectric power has played an important role in the socioeconomic development of Rwanda for decades since the 1950s. By the end of 2012, the estimated hydropower potential was 313 MW of which 64.5 MW, equivalent to 20% of the total potential, was in operation (AfDB 2013). This potential includes both the internal or domestic and regional hydropower potentials. In this study, internal hydropower refers to the potential that is located within the country borders and entirely owned by Rwanda while the regional hydropower potential is that the country shares with its neighbours. The main hydropower plants that have been supplying electricity in the country are Ntaruka in Burera District, Mukungwa I in Musanze District and Gihira and Gisenyi all located in Rubavu District (see the locationsin Figure 2.12).

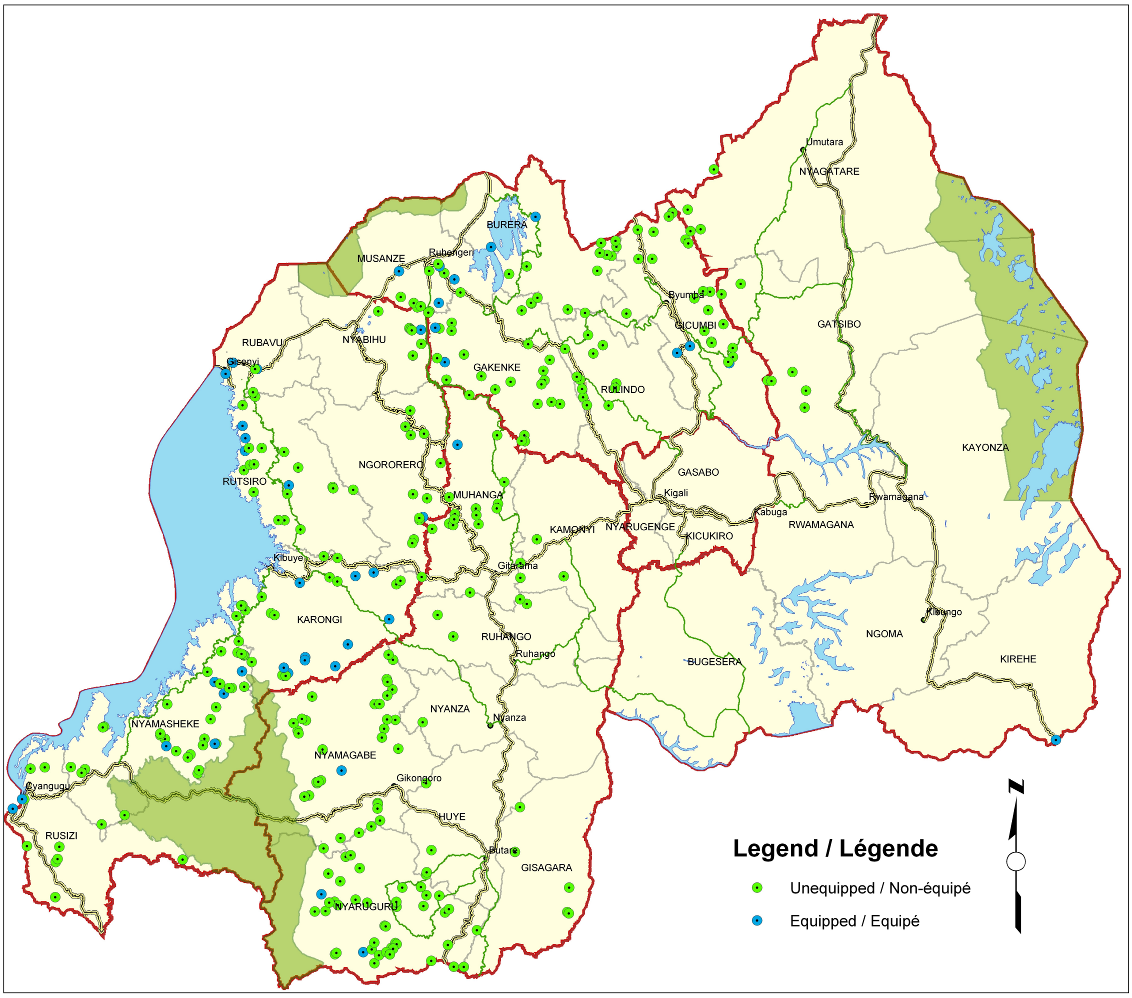


Figure 2.12: Location of the existing hydropower plants and inventoried hydropower sites. Equipped sites mean already developed sites or that are under development whereas unequipped refers to not yet exploited sites (SHER 2008, 30)

The difference between the national electricity demand and production has been covered through imported electricity from Ruzizi I hydropower plant that belongs to DRC and Rusizi II that is owned jointly by Rwanda, Burundi and DRC (see Figure 2.12).

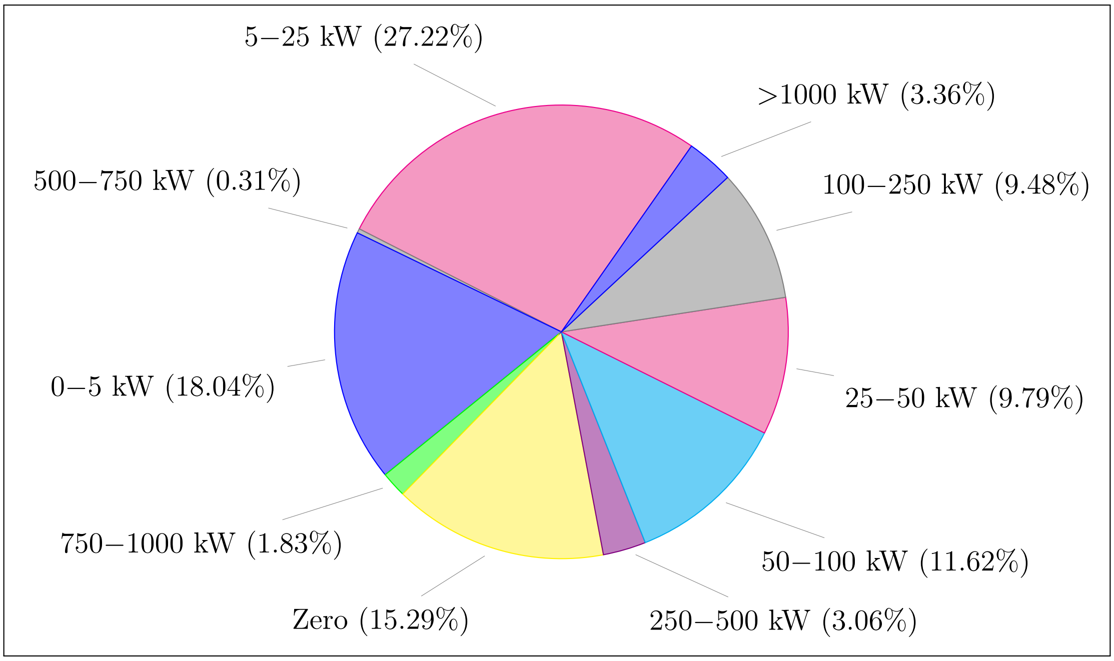


Figure 2.13: Distribution of estimated hydropower potential for all encoded internal sites of Rwanda (SHER 2008, 30)

A study conducted by SHER (2008) revealed an existence of 333 potential hydropower sites of which 227 are internal and 6 are regional sites. The spatial distribution of the internal sites are shown in 2.12 while the percentage distribution of all sites according to their capacity is shown in Figure 2.13. Although the number of power plants/potential sites with installed/estimated capacity of higher than 1,000 kW represent only 3.36% of the total number of sites, these plants/sites represent more than 75% of the total internal hydropower capacity in the county. Almost all potential sites are around the Congo−Nil Ridge that runs along the Western branch of the East African Rift (see Figure 2.12) with elevations exceeding 2000 metres as discussed in Section 2.1.1.

2.5.3 Solar energy

Due to its location, Rwanda is one of the countries that are enormous amounts of solar resources that can support other indigenous domestic resources to overcome the persisting energy supply challenges in the country. Solar energy in Rwanda varies according to the country's topography and increases from the west towards the east. In the western and northern parts of the country, the average annual solar radiation is estimated to be 3.5 kWh/m^2/day whereas in the central, southern and south−eastern regions the radiation can go up to 6.0 kWh/m^2/day (Hammami 2010, 11). Figure 2.14 shows the average spatial distribution of solar energy in Rwanda for the 1994−period.

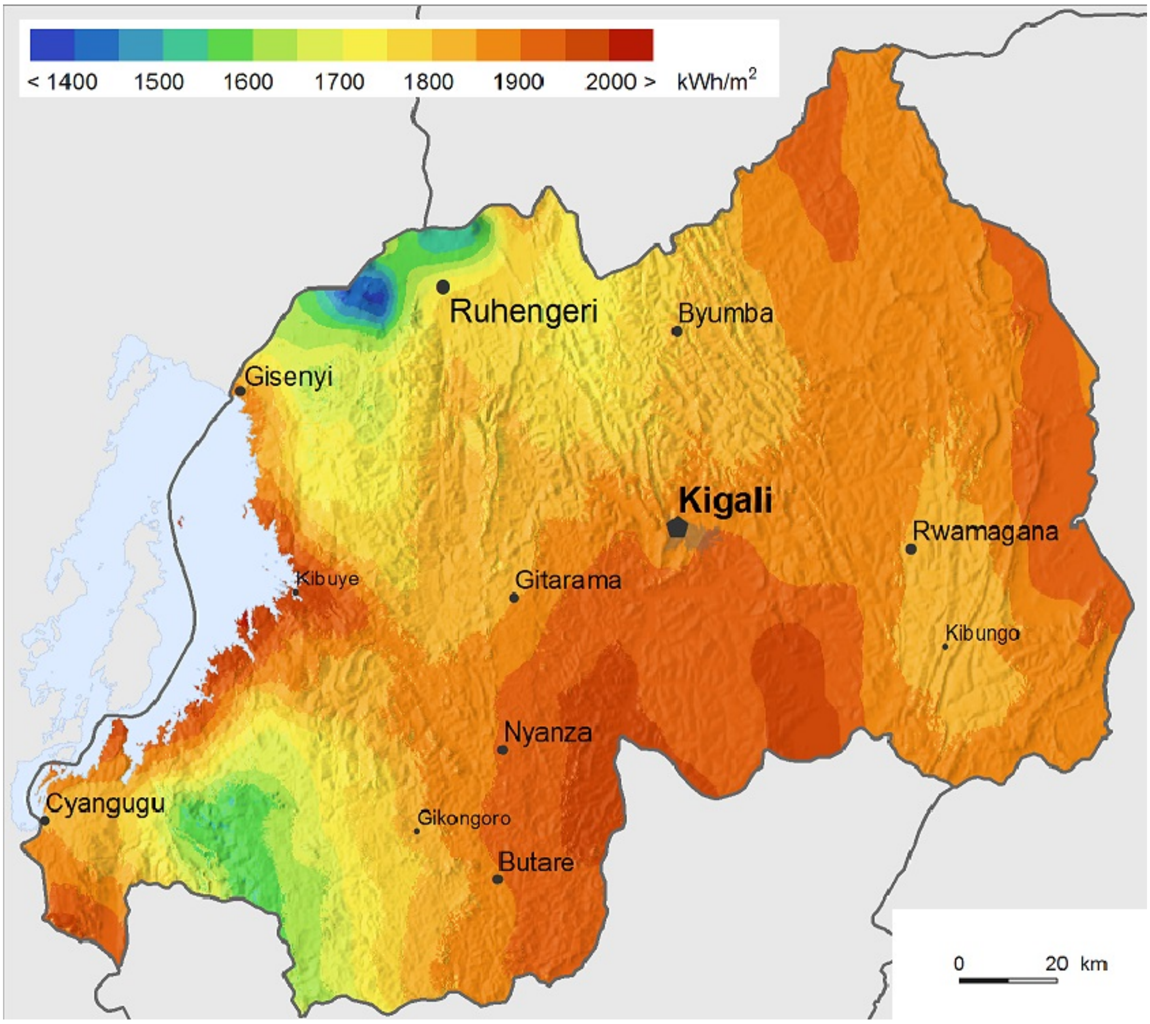


Figure 2.14: Average annual sum of global horizontal irradiation in Rwanda for the 1994–2010 period (GeoSUN Africa 2013)

The total installed capacity for solar energy in Rwanda is not known because many of the installations are privately owned and unregistered in the national statistics (Uhorakeye 2011, 25). Different solar PV systems have been installed in various institutions such as public offices, health centres and schools. By 2010, 85% of district hospitals, 84% of administrative offices of districts, 52% of secondary schools, 26% of health centers, 23% of administrative offices of sectors, and 11% of primary schools were connected to the main grid whereas the remaining percentages used either solar PV installations with storage systems or diesel generators (Safari 2010, 527).

However, many of these installations stopped working shortly after their commissioning mainly due to the limited technical capacity for the installations, the lack of required skills to operate and maintain these installations as well as the costs of the spare parts which were not taken into account when designing these systems (MININFRA 2009).

To overcome these challenges while increasing access to electricity, different projects such as the Increase Rural Energy Access in Rwanda through Public-Private Partnerships (IREARPPP) were initiated in 2008. The main objective of the IREARPPP project was to electrify 300 off−grid rural secondary schools across the country and 15 villages (called Imudugudu) from 15 rural distinct Districts in the country (MININFRA 2013, 45). By the end of 2012 IREARPPP had achieved the following objectives (Bahingana and Gathui 2014, 15):

- 1,494 households in 15 villages were installed with 5 W solar PV systems for lighting, charging cell−phones and operating a radio. It was planned that by the end of May 2014, each of the 1,494 beneficiary households would receive 2 additional solar lamps
- 15 technicians, one from each of the 15 villages were selected and trained in system installation, operation and maintenance to ensure sustainability
- 150 rural off−grid secondary schools, identified by the Ministry of Education in collaboration with the relevant districts and sectors, have been installed and the remaining 150 would be installed by December 2014.
- More than 600 technicians have been trained, comprising at least 2 teachers from each of the 300 schools and 1 person from each sector.

It is planned that about 1.2 million households located far away from the national grid will be facilitated to access electricity through solar PV installations (MININFRA 2013). As for grid connected systems, two solar PV based power plants, one of 250 kW and the other of 8.5 MW, were connected to the national grid (see Table 2.11) by the end of 2014.

2.5.4 Geothermal energy

Geothermal is an environmentally friendly energy source that can be used to produce both electric and heat energy with no or very little amounts of GHG emissions compared to fossil fuels. This type of energy originates from the natural heat of the earth that is generated by the magma and stored in the earth's core, mantle and crust. It is a form of energy that is not affected by the short−term fluctuations in weather or oil prices on the international market.

To exploit geothermal energy, the crust must be fractured in order to enable fluids to flow through it and transfer energy from hot rock formations to reservoirs at depths manageable for commercial drilling (Fridleifsson and Freeston 1994). Depending on the reservoir's temperature, the heat comes to the surface in the form of fumaroles, hot springs, boiling springs, geysers, phreatic explosion craters, and zones of acid alteration (Wohletz and Heiken 1992, 119). Figure 2.15 illustrates the processes of geothermal circulation.

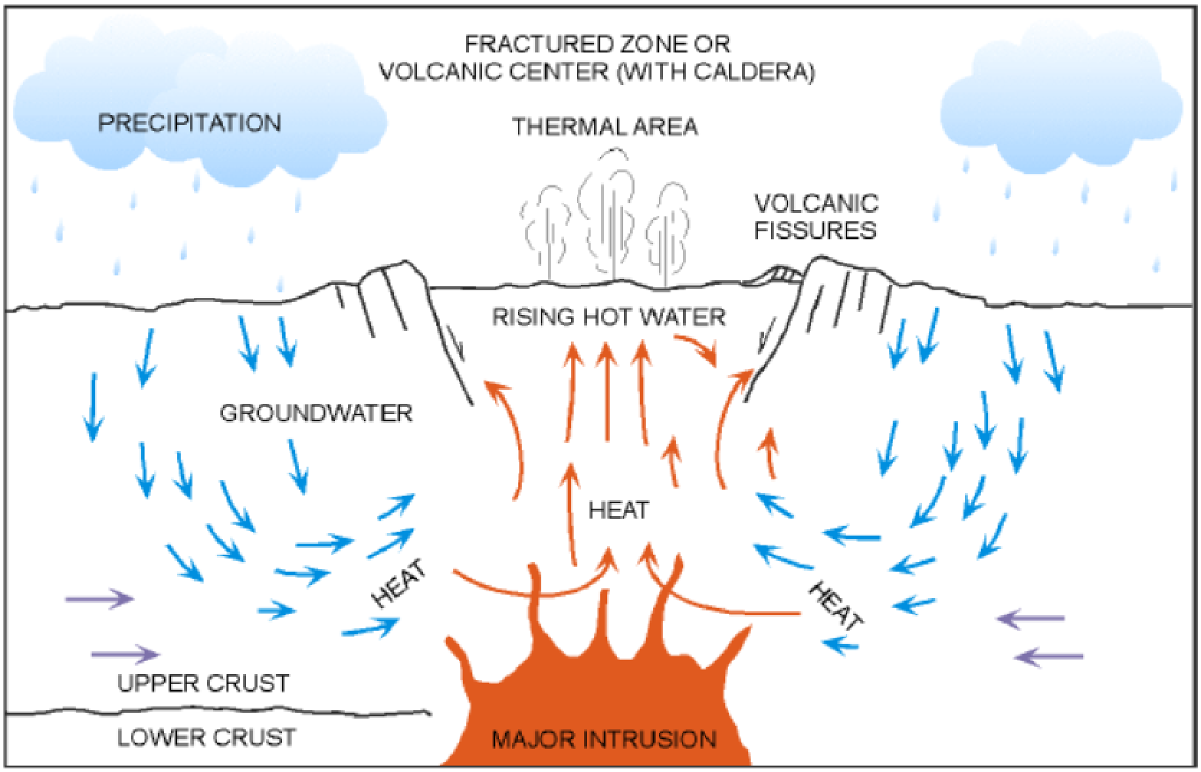


Figure 2.15: Formation of high−temperature geothermal areas (Hjartarson and Sigurdsson 2008)

The exploration of the geothermal resource in Rwanda started in 1982 by the French Bureau of geology and mining research (Uwera and Uhorakeye 2010). Under this survey two potential sites: Gisenyi and Bugarama (see the location in Figure 2.16) were identified, where geothermal reservoirs of more than 100℃ were estimated. However, it is only since 2006 that systematic exploration activities began (see for example Chevron (2006), Jolie et al. (2009), and Onacha (2010)). By the end of 2014, reconnaissance studies for four geothermal prospects: Bugarama, Gisenyi, Kalisimbi and Kinigi (see the location in Figure 2.16) had been completed and detailed survey, exploratory and test drilling had been conducted for the Kalisimbi geothermal field (Uwera et al. 2014). A potential of 170 to 320 MW was estimated by Chevron (2006) and later to about 700 MW by Onacha (2010). However, from the two exploratory wells drilled in Kalisimbi to confirm the potential, no conclusions were made as the drilled wells did not confirm any existence of an underground hot water reservoir.

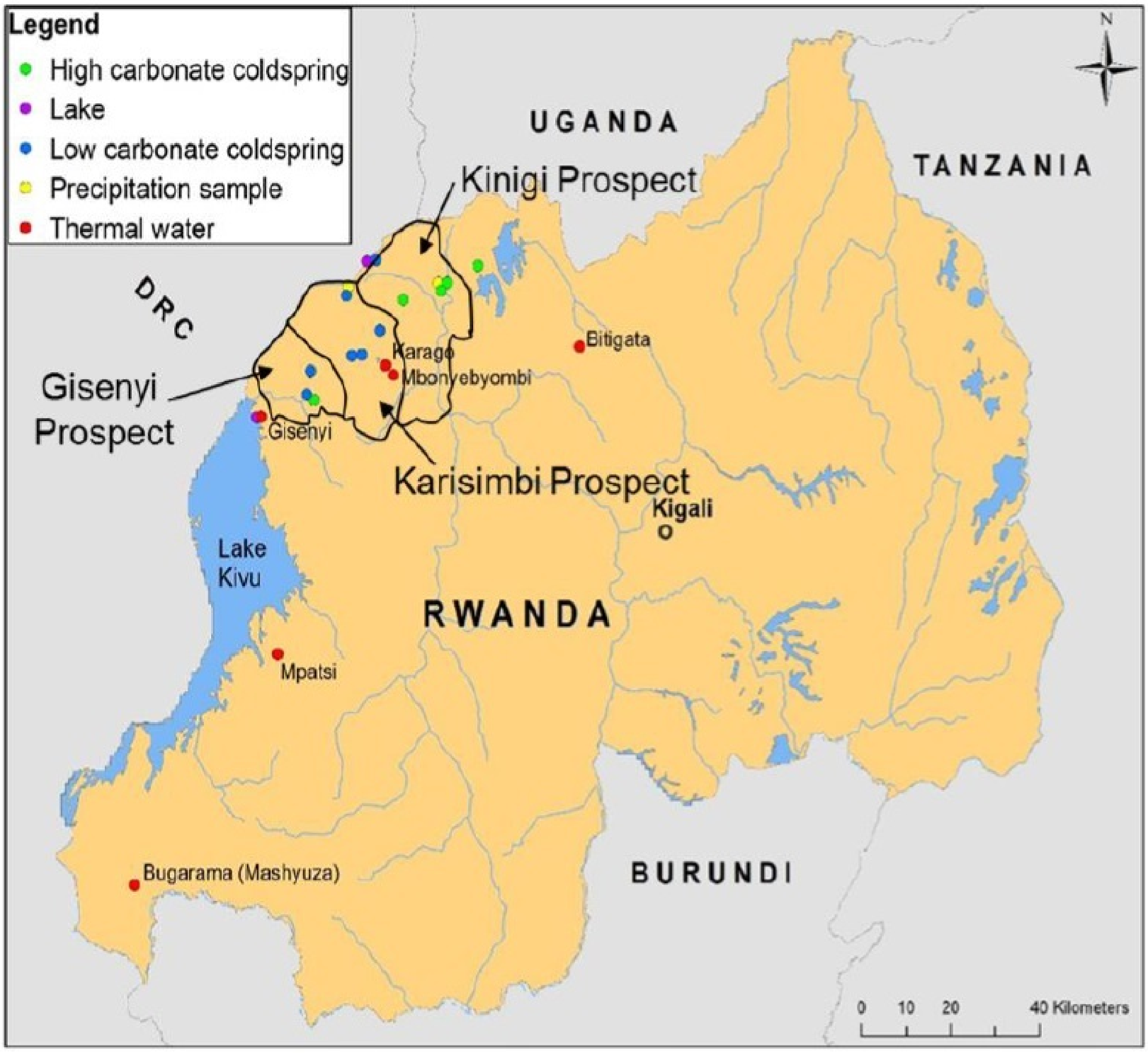


Figure 2.16: Geothermal prospects in Rwanda (Uwera et al. 2014)

2.5.5 Methane reserves

Rwanda's methane (CH_4) resources are dissolved together with Carbon Dioxide (CO_2) in the deep waters of the Kivu Lake at a depth ranging from 270 metres down to the bottom of the lake at more than 450 metres. The Kivu Lake is located between Rwanda and DRC on the western branch of the African rift valley (see Figure 2.16 for illustration). The Kivu Lake is one of the East African great lakes with an estimated area of 2,370 km^2 and a volume of 550 km^3 (Borges et al. 2011). CH_4 and CO_2 gases originate from both the fermentation of organic material by anaerobic bacteria accumulating in the bottom sediment of the lake and from the reduction of volcanic CO_2 by the same bacteria (Doevenspeck 2007). It is estimated that a volume of 55 billion m^3 of CH_4 are deposited in the lake while between 150 and 250 million m^3 are regenerated annually (MININFRA 2010).

It is expected that the exploitation of the Kivu Lake's methane will provide economic and security (health) advantages. The use of CH_4 will provide electricity and reduce CO_2 saturation which avoids the risks of gas eruption that could harm the inhabitants of the lake's shores. There are two similar lakes in Africa: the Monoun Lake and the Nyos Lake in Cameroun with high CO_2 concentration in their deep waters. In 1986, for example, CO_2 eruption from the Nyos Lake killed about 1,800 people; and the Kivu Lake is 1,000 times more saturated than the Nyos Lake (MININFRA 2003). In addition, as CH_4 is continuously emitted into the atmosphere from this Lake, its use in power generation contributes to the reduction of environmental stress because the global warming potential of CH_4 is 25 time more than that of CO_2 (IPCC 2007b, 212).

It is estimated that, from methane reserves, 700 MW of electricity can be produced for a period of 55 years (REG 2015c). It is important to recall that this resource is equally shared between Rwanda and the DRC, therefore each country can develop unilaterally up to one half of the estimated potential. By the end of 2014, a 4.5 MW pilot CH_4 based power plant was connected to the national electricity grid but delivers only 1.5 MW. In the same year different methane−to−power projects were under different development phases of which the most advanced was the Kivuwatt's 25 MW phase I which was under construction (REG 2015c).

2.5.6 Peat reserves

Rwanda possesses a considerable amount of peat resources distributed across the country. A study on peat deposits in the country estimated a potential of about 2,650 m^3 equivalent to 155 million tons of dry peat (GTZ/MARGE 2008, 24). The main regions where peat reserves are found are Akanyaru (Western Province), Nyabarongo (Southern and Western Provinces) and Rugezi (in Northern Province) with respectively 69, 40 and 32 million tons of equivalent dry peat reserves (GTZ/MARGE 2008, 25). Table 2.8 presents the characteristics (area, depth, ash content, estimated potential) of the country's peat reserves.

Table 2.8: Rwanda peat resources (GTZ/MARGE 2008, 25). The wet reserves in this table are in million m^3 while the dry reserves are in million tons.

ID	Site	Area (ha)	Depth (m)	Ash (%)	Wet	Dry
1	Nyabarongo	26,740	2−4	9−20	800	40.00
2	Akanyaru North	460	2−6	7−14	20	1.00
3	Akanyaru North (others)	5,120	2−6	10−20	200	10.00
4	Busoro (Akanyaru South)	800	1−5	6−15	32	1.00
5	Rwamiko (Akanyaru South)	130	1−20	6−8	14	0.675

Table 2.8 – *Continued from previous page*

ID	Site	Area (ha)	Depth (m)	Ash (%)	Wet	Dry
6	Akanyaru South (others)	7,070	2−20	6−15	920	69.00
7	Cyabararika	22.5	1−5	5−17	0.35	0.15
8	Kiguhu (North)	49	1−4	8−14	1.8	0.24
9	Rugezi (North)	6,500	1−11	2−15	650	32.00
10	Gishoma (South West)	410	1−5	6−13	7.85	0.463
11	Gihitasi (West)	8	1−2	14	0.62	0.04
12	Mashya	30	1−5	3	0.79	0.06
13	Kamiranzovu	830	1	6	8.2	0.50
	Total	48,169.5	–	–	2,655.61	155.13

With these considerable amounts of peat resources, it is expected that in addition to its use in power generation, peat can also be treated and be used as improved cooking fuel in the country's transition from traditional biomass to cleaner form of cooking energy which will also reduce the indoor air pollution (MININFRA 2013, 33). The use of peat as fuel presents environmental losses and benefits. The negative impact is that the combustion releases considerable amounts of CO_2 that has been stored in the ground for decades. Similar to the case of CH_4 discussed in Section 2.5.5, the environmental benefit of harvesting and combusting peat is that when peatlands are drained and developed, they stop the emissions of methane (AfDB 2013, 35) because the global warming potential of CH_4 is 25 time more than that of CO_2 (IPCC 2007b, 212). However, there is no study that has been conducted in order to compare the CO_2 that will be released during the development and operation of peat−fired power plants with the naturally released CH_4 from the peatlands. Such a study would provide net emissions that would remove the confusions of whether using peat as a source of energy is environmentally friendly or not.

2.5.7 Wind energy resources

Wind energy resources in Rwanda are limited mainly due to its location and its topography (mountainous). A wind resource assessment conducted by De Volder (2010) on 5 different sites across the country (see Figure 2.17) revealed that annual mean wind speed varies from 2.43 to 5.16 m/s (see Table 2.9). However, because these conclusions were based on measurements covering only 14 months from November 2009 to December 2010, further measurements over an extended period and at various places across the country is necessary for future development of wind power.

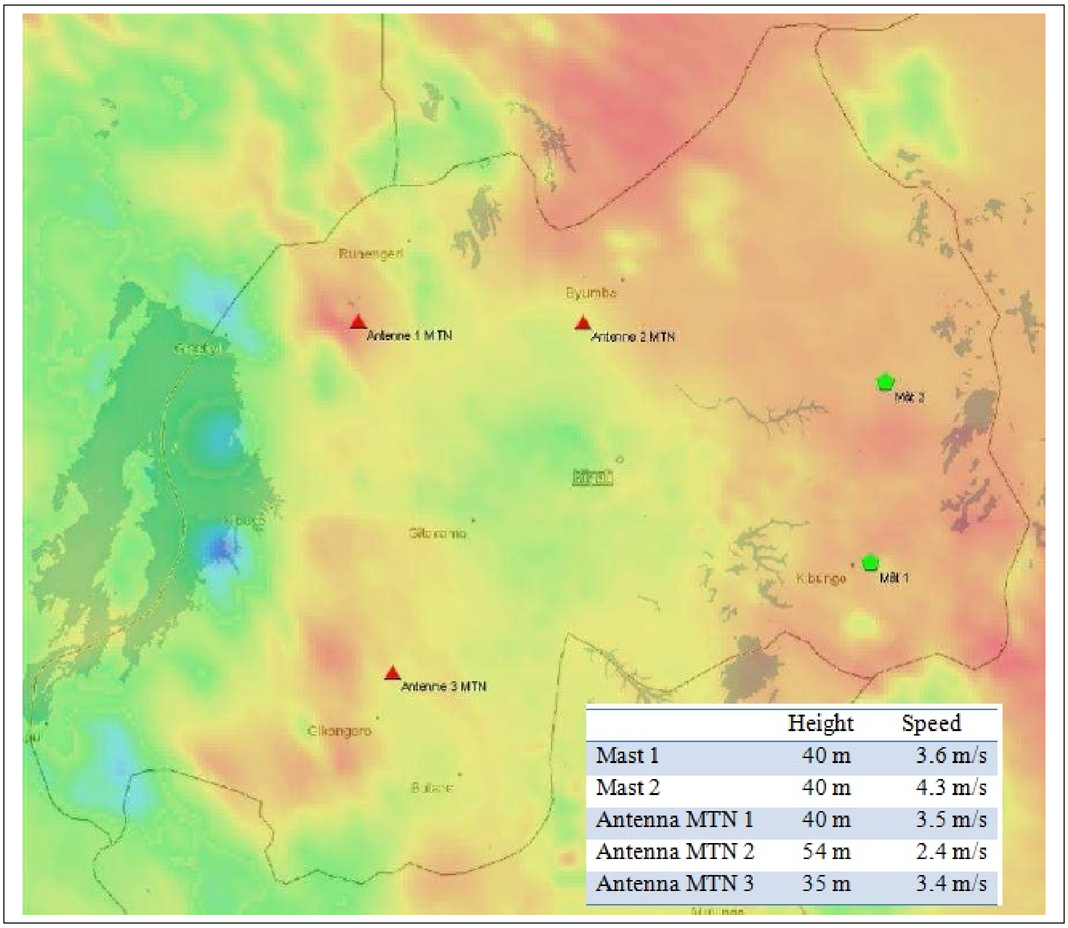


Figure 2.17: Location of the 5 wind measuring stations. The red color indicates areas identified as windy zones during the preliminary study (De Volder 2010, 10)

Table 2.9: Vertical wind profile (Weibul parameters) at measurement locations (De Volder 2010, 10, 27)

ID	Location	Latitude South	Longitude East	Height (metres)	Mean wind speed (m/s)	Weibul A (m/s)	Weibul factor (k)
1	Mast 1	1°47.335’	30°36.148’	55	4.02	4.53	2.236
				70	4.25	4.80	2.311
				100	4.57	5.15	2.400
2	Mast 2	2°9.644’	30°34.344’	55	4.63	5.23	2.420
				70	4.87	5.49	2.494
				100	5.16	5.81	2.596
3	Antenna 1	1°39.980’	29°31.626’	55	3.89	4.39	2.475
				70	4.09	4.60	2.572
				100	4.34	4.88	2.693
4	Antenna 2	1°39.999’	29°59.028’	55	2.69	3.00	1.600
				70	2.79	3.12	1.650
				100	2.91	3.26	1.709
5	Antenna 3	2°23.315’	29°35.978’	55	2.43	2.67	1.424
				70	2.59	2.86	1.471
				100	2.80	3.11	1.529
6	Deutsche Welle Mast	1°54.701’	30°7.142’	55	2.43	2.67	1.424
				70	2.59	2.86	1.471
				100	2.80	3.11	1.529

2.5.8 Municipal waste

Due to the lifestyle in urban areas, there are considerable amounts of post−consumption waste such as organic waste, paper, cardboard and wood that can be used to generate electricity (AfDB 2013, 35). In 2012, for example, between 300 and 400 tons of solid waste were collected every day in Kigali City alone (City of Kigali 2013b, 2). The biggest share of the waste is from organic matters which represented 67.9% of the total waste collected in the city (see Figure 2.18). The other types of waste are papers (8.6%), textiles (4.5%), plastics (4.8%), metals (2.1%), electronic waste (1.5%), glass (1.4%) and hazardous waste (0.6%). The remaining 12.6% are composed of various types of waste such as leather, wood, debris, construction materials. The percentage distribution by waste type at Nduba landfill (where the waste from the City of Kigali are dumped) is shown in Figure 2.18.

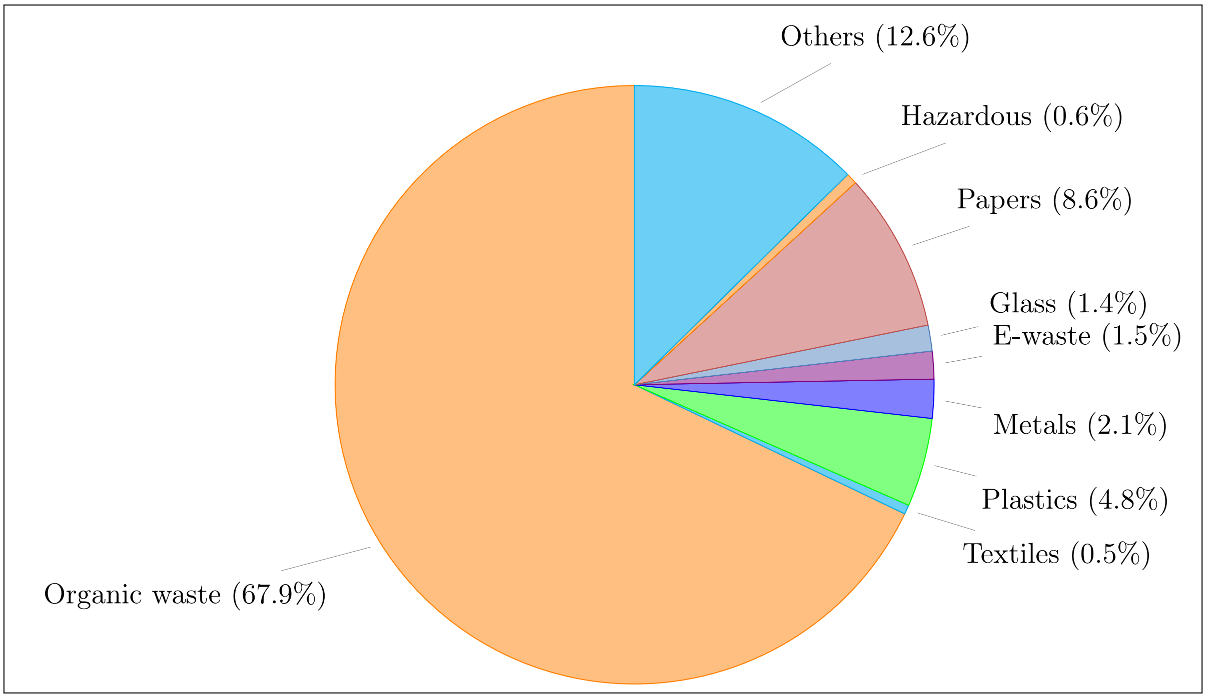


Figure 2.18: Physical composition of municipal solid waste at Nduba landfill (Author based on data from City of Kigali (2013b, 3))

2.6 Electricity sub−sector

This section presents and discusses available and accessible information on the evolution of the electricity demand and supply, power transmission and distribution performance as well as the existing electricity demand and supply projections and plans.

2.6.1 Electricity demand

Due to different reforms within the energy sector in Rwanda and especially the electricity sector, it is necessary to highlight the major electricity demand categories and the difficulties that the planners face when trying to forecast the power demand. It is recognized worldwide that the main electricity demand categories are agriculture, services (or commercial), residential (or households), industrial and transport sectors. However, in some countries such as Rwanda, the consumption by some of these sectors are insignificant in such a way that they are ignored when classifying the demand and some others are split into subcategory for a better management. As it can be noticed from Figure 2.19 (a), the electricity demand categories followed the classical categorization until 2008. After 2008, however, the demand categories are classified into normal customers, medium customers, public customers plus the REG as shown in Figure 2.19 (b). REG is the only power company in the country that has the monopoly of transmitting and distributing electricity. REG owns also electricity generation power plants along with a number of IPPs.

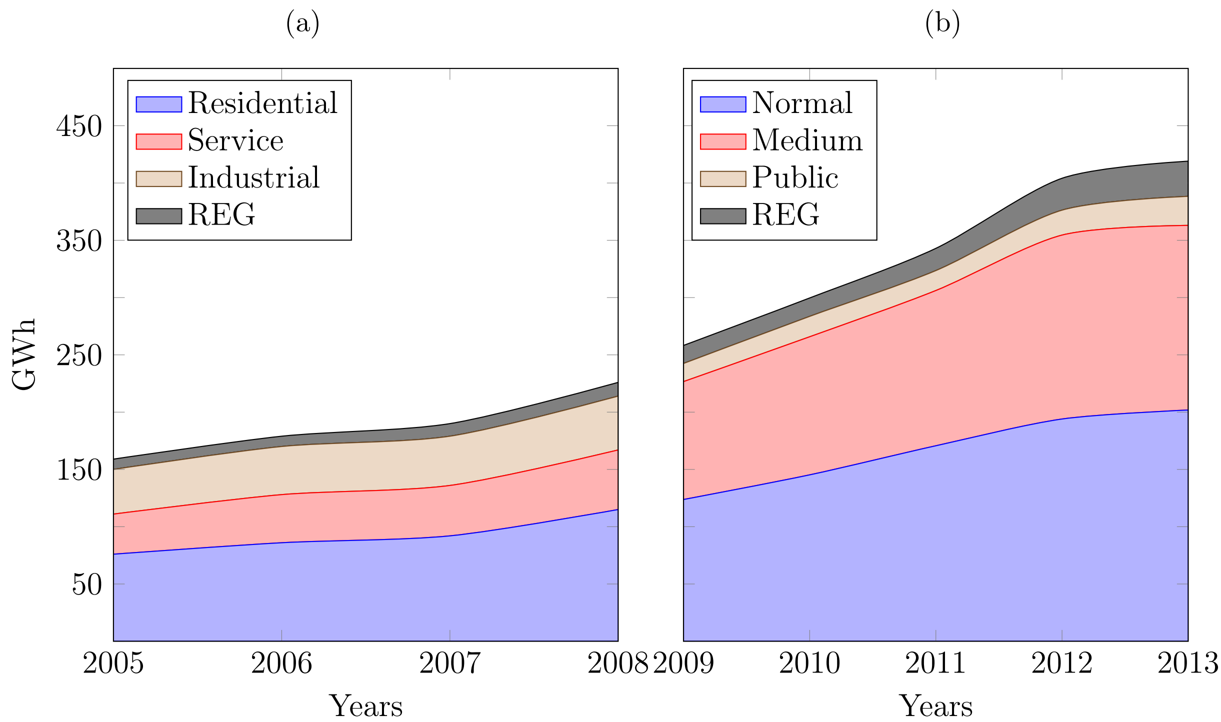


Figure 2.19: Power demand by sector for the 2005 – 2013 period (Author based on data from Fichner and decon 2010a, 6-25) and REG. In (a) the demand according to classification before 2008 is shown while the new EWSA/REG classification is presented in (b).

According to information obtained from REG, medium customers are those customers that are connected to the medium voltage while normal customers are connected to the low voltage network and include mainly households and businesses. Normal customers include both customers with digital and analog energy meters. A project to replace analog meters by digital meters, however, was ongoing during the time of the data analysis. The other category of the electricity demand is the public sector which includes government and private institutions (ministries, schools, hospitals, administrative offices, etc.). The last demand category is the power company REG of which the main consumptions are water pumping and office equipment.

As it can be noticed from Figure 2.20, the total electricity demand has doubled between 2007 and 2012 while the number of electricity customers has quadrupled over the same period. This increase in both the total power demand and the number of electricity customers is a result of an intensive electrification program under the EDPRS Program.

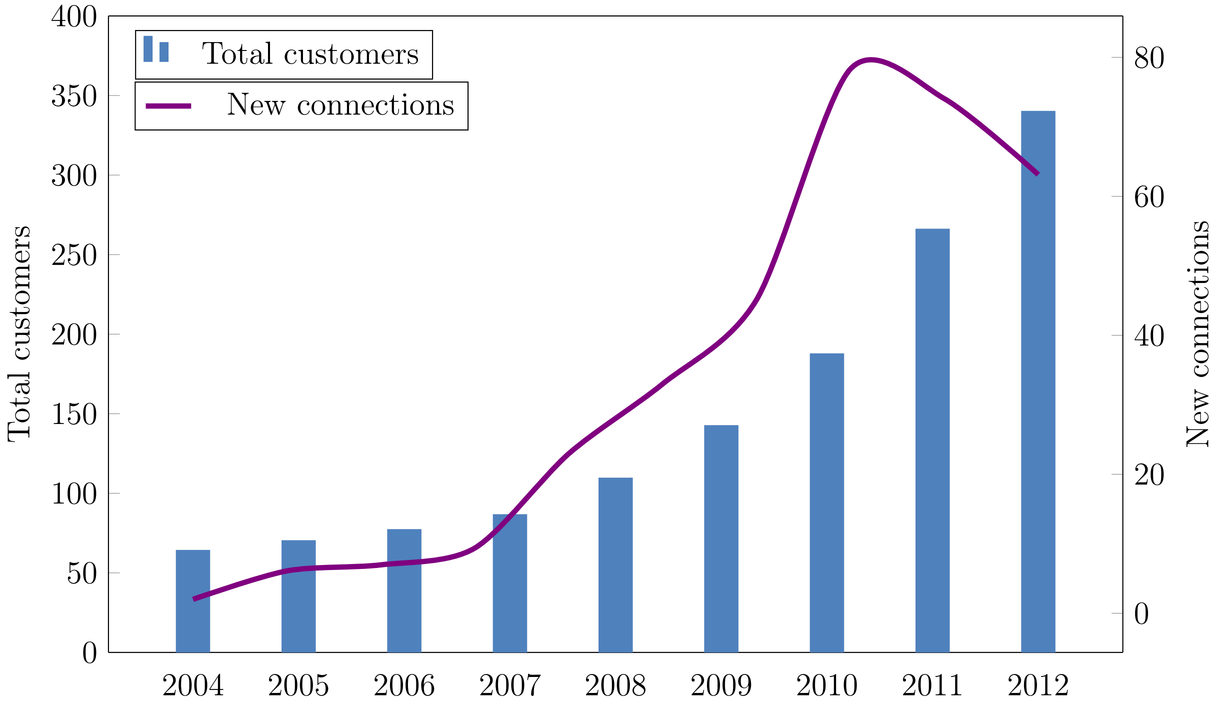


Figure 2.20: Evolution of the number of electricity customers between 2004 and 1012 (Author based on data from REG). The left axis represents the cumulative number of customers while the right axis represents new connections.

Although the electrification program has allowed many households access to electricity, there is a challenge of funding new connections due to high investment costs. According to MININFRA (2013, 22), for a consumer to be able to fund the cost of her/his own connection, she/he would need to use approximately 130 kWh per month. However, as it can be noticed from Table 2.10 more than 75% of the total customers in Rwanda in 2012 consumed less than 50 kWh per month.

As for the evolution of the maximum and minimum hourly demand, between 2003 and

Table 2.10: Monthly Electricity consumption patterns (MININFRA 2013, 22)

Consumption range (kWh)	Share of total consumers (%)
0-5	18.4
6-20	31.2
21-50	26.1
51-150	17.3
>150	7.0

2013 the minimum power demand has increased from 18.5 MW in 2003 to 42.9 MW in 2013 while the maximum peak power demand increased from 43.0 MW to 87.9 MW (see Figure 2.21). It was not possible to analyze the hourly power consumption for a whole year because of many missing data due to frequent load shedding in the country. However the analysis of available data showed no significant difference in power consumption between the days of the week and between the four seasons discussed in Section 2.1.3.

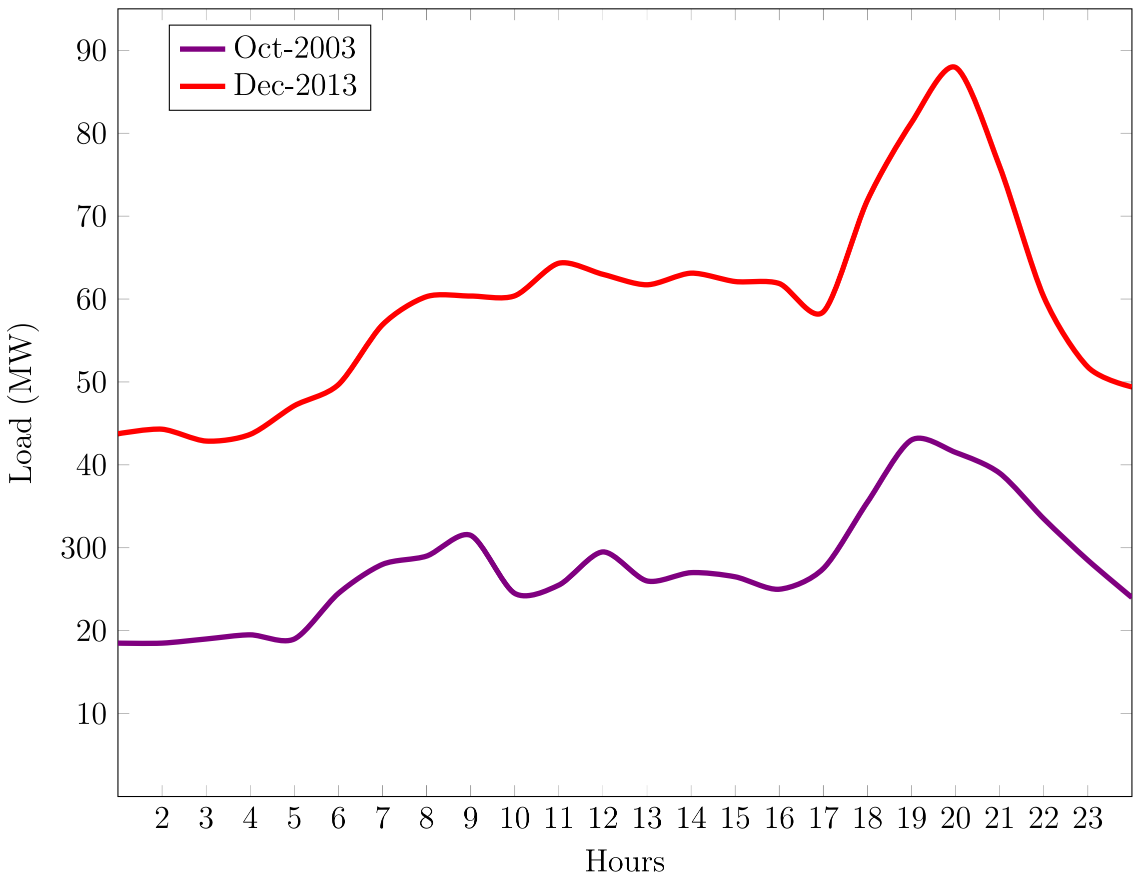


Figure 2.21: Evolution of Rwanda's daily load curve (Author based on data from Lahmeyer International (2004, 5-28) and a database developed by WJEC (2015) obtained from REG Ltd.)

2.6.2 Electricity supply

Until the year 2003, the electricity supply in Rwanda was assured by hydropower generation as shown in Figure 2.22. The generated power was transmitted through two main power lines: the northern and the southern lines. The northern line links hydropower station Gisenyi (1.2 MW), Gihira (1.8 MW), Mukungwa (12 MW) and Ntaruka (11.25 MW). The second power line called southern line linked two hydropower stations: Rusizi (3.5 MW) and Rusizi II (36 MW). The locations od these power plants are shown in Figure 2.13.

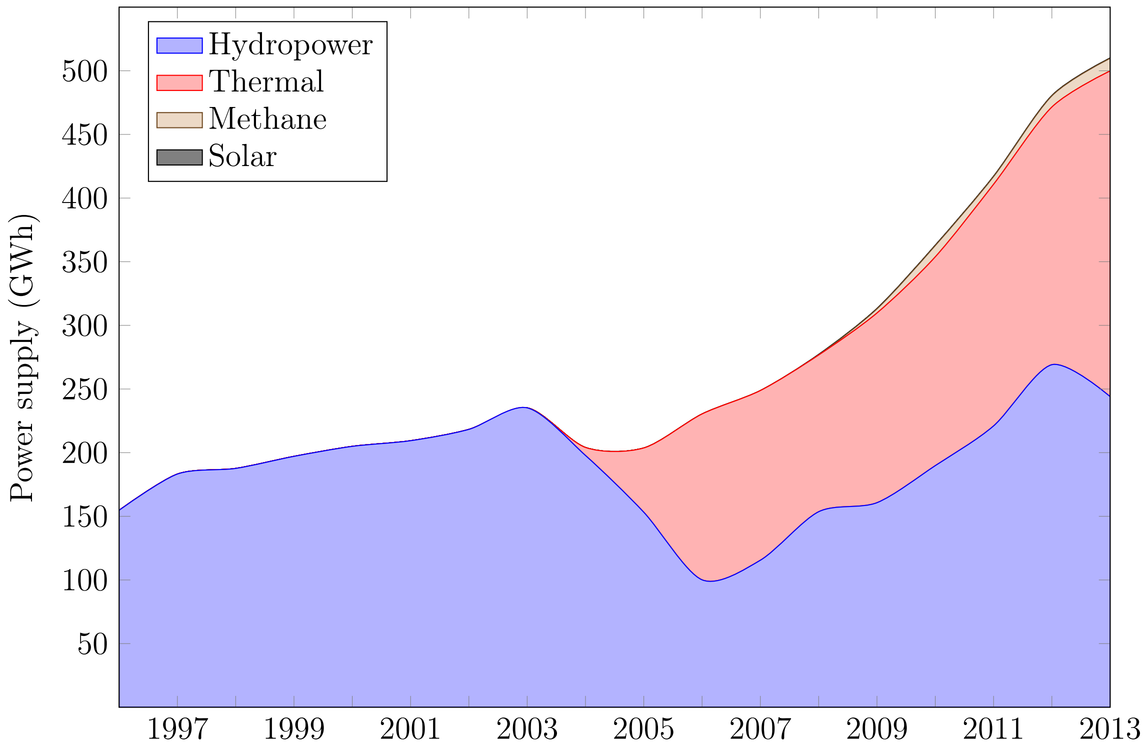


Figure 2.22: Electricity generation between 1996 and 2013 (Author based on data collected from REG)

The two power lines (northern and southern) converge to the national dispatching centre in Kigali to be redistributed across the country. It is worth highlighting that Rusizi II belongs to the three countries (Burundi, DRC and Rwanda) that share the water resources feeding this power plant. Therefore the output power from this power station is shared between the three countries (meaning 12 MW each country). However, due to the persisting insecurity in Congo and Burundi, different companies (e.g. mining companies) have closed their activities and most of the produced electricity from these two power plants was sold to Rwanda.

Between 20003 and 2010, the electricity generation from hydropower stations has declined (see Figure 2.22) so that imported fossil fuels have been used to meet the gap between the demand and hydropower generation. As highlighted in the previous sections, the shift from entirely hydroelectric power to nearly equal fossil fuel powered and hydroelectric power systems was attributed to the lack of investments in the power generation and extension of the electrical network (Jolie et al. 2009, 10), the emerging climate (MINIRENA 2006, 27−28) and the overuse of hydroelectric power dams (Hermes 2005, 8).

After learning from mistakes done in the past, the Government has introduced policies and laws that attracted investments in electricity generation in the country. This resulted into a considerable number of IPPs who started business in power generation in Rwanda as discussed in Section 2.4.1. The list of existing power plants and technologies as well as their installed capacities and their starting dates are shown Table 2.11.

Table 2.11: Power generation plants by 2014 (Author based on data collected from REG)

ID	Name	Technology	Fuel	Start date	Capacity (MW)
1	Gisenyi	Hydropower	Water	1957	1.20
2	Ntaruka	Hydropower	Water	1959	11.25
3	Mukungwa	Hydropower	Water	1982	12.00
4	Gihira	Hydropower	Water	1984	1.80
5	Jabana I	Thermal	Diesel	2004	7.80
6	Aggreko Gikondo	Thermal	Diesel	2005	10.00
7	Aggreko Mukungwa	Thermal	Diesel	2006	10.00
8	Kigali Solar	Solar	Solar	2007	0.25
9	KP1	Thermal	Methane	2008	3.6
10	Jabana II	Thermal	HFO	2009	20.50
11	Murunda	Hydropower	Water	2010	0.10
12	Rukarara	Hydropower	Water	2011	9.50
13	Rugezi	Hydropower	Water	2011	2.20
14	Keya	Hydropower	Water	2011	2.20
15	Cyimbili	Hydropower	Water	2011	0.30
16	Nkora	Hydropower	Water	2011	0.64
17	Mazimeru	Hydropower	Water	2012	0.50
18	Mukungwa II	Hydropower	Water	2013	2.50
19	Musarara	Hydropower	Water	2013	0.44
20	Nyabarongo I	Hydropower	Water	2014	28.00
21	Gigawatt Global	Solar	Solar	2014	8.50

2.6.3 Transmission and distribution of electricity

The electricity network in Rwanda presents considerable losses which varied between 17.00% and more than 33.00% for the 2000−2013 period (see Figure 2.23). These losses comprise both the commercial losses and the technical losses. Commercial losses are due to any illegal consumption of electrical energy, which is not correctly metered, billed and revenue collected which causes commercial losses (Khobragade and Meshram 2014). Technical losses on the other hand are losses in the transmission and distribution lines and they increase with the lack of proper maintenance, inefficient system design and operation of the networks (IEA 2014b, 41).

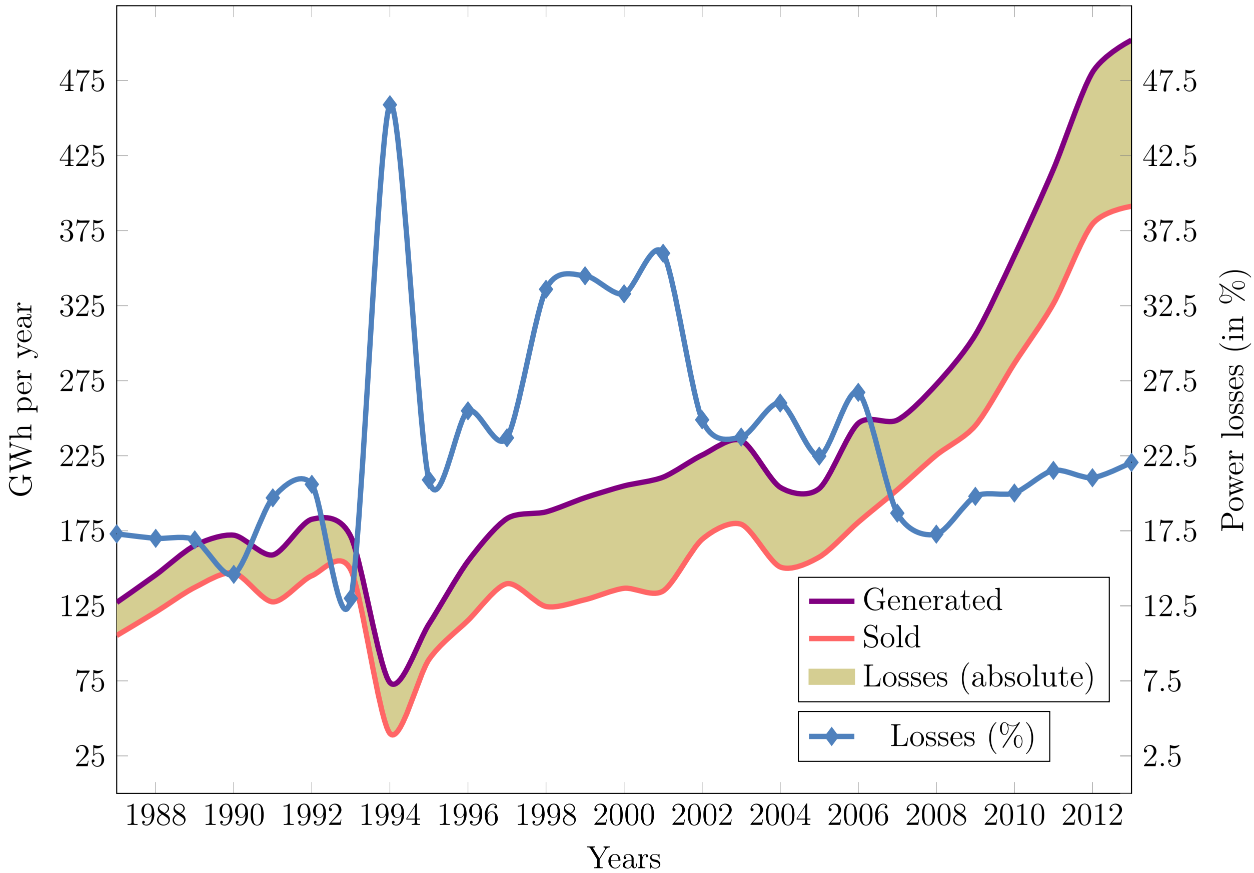


Figure 2.23: Evolution of power generation and demand between 1987 and 2013 (Author based on Lahmeyer International (2004, 5−29) and data collected from REG)

A study conducted in 2013 revealed that the grid losses were 23% of the total generated electricity in this year (SE4All 2014, 43). This study suggested that a decrease in the losses from 23% to 15% (equivalent to 15 MW) would cost US$ 60 million and result in over US$ 180 million of savings (SE4All 2014, 44).

2.6.4 Existing projections of electricity demand and supply

There have been different power demand and supply projections covering different time horizons; in this section two relatively long term projections are presented. These include the "Electricity Master Plan 2008−2025" by Fichner and decon (2009) and "Rwanda electricity development plan 2013−2032" by WJEC (2015). Under the electricity master plan, three scenario were developed based on different electrification rates (20%, 30% and 40%) and a GDP growth rate of 8.1%. Based on these assumptions, it was projected that the electricity demand would increase from 188 GWh in 2007 to 1,651 GWh for the minimum scenario, 2,148 GWh for the base scenario and 2,680 GWh for the maximum scenario by 2025(see the projections in Figure 2.24).

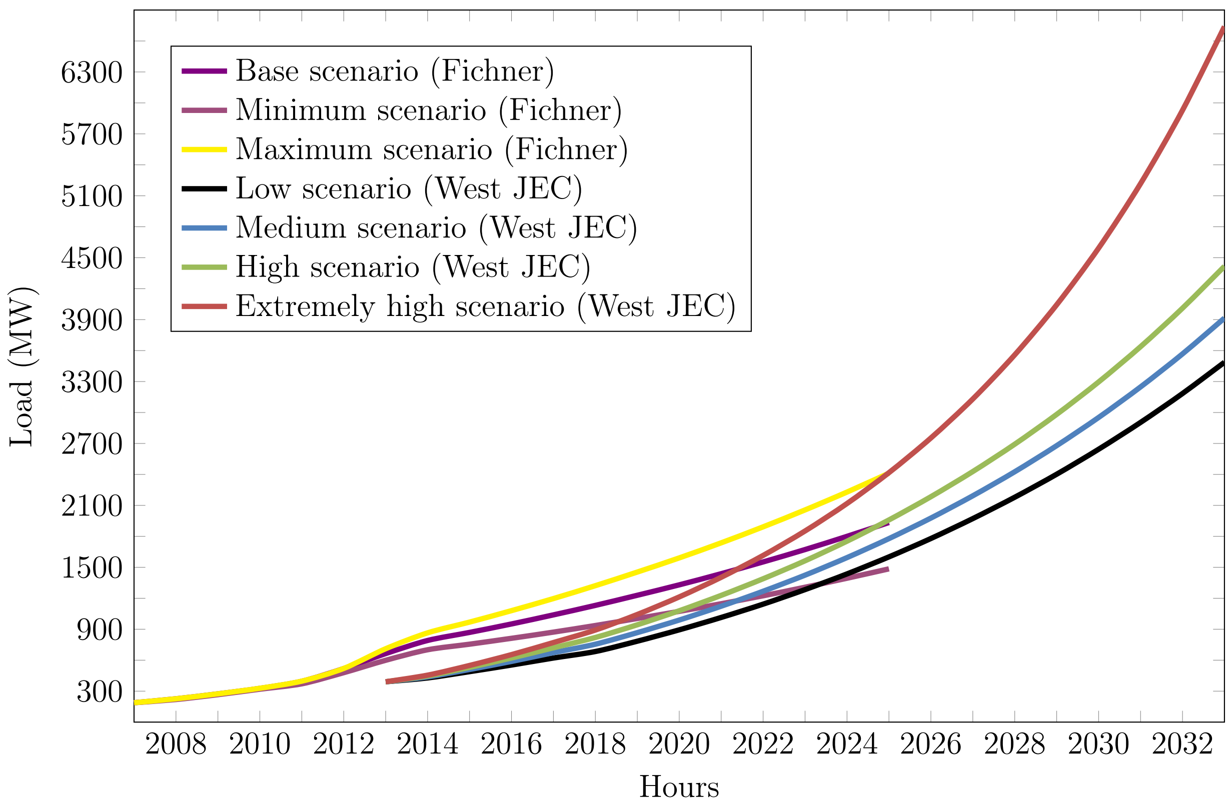


Figure 2.24: Existing electricity demand projection (Author based on data from Lahmeyer International (2004, 5-28) and a database developed by the provided by REG Ltd. developed by the WJEC (2015))

As for Rwanda electricity development plan 2013−2032, four scenarios: the low, medium, high and extremely high scenarios were developed. These scenarios were based on different electrification rates (35%, 42% and 48% by 2018) and GDP growth rates (6.5%, 7.5%, 8.5% and 11.5%). Under these assumptions, it was projected that the electricity demand by 2032 would be 3,487 GWh for the low scenario, 3,915 GWh for the medium scenario, 4,417 GWh for the high scenario and 6,740 GWh for the extremely high scenario (see the projections in Figure 2.24).

As for the power supply, it is projected that by 2025 the total power supply would be 1,300 MW of which 430 MW (or 30%) will come from imported electricity, 260 MW from hydropower, 235 MW from peat and 150 MW, 110 MW, 77 MW and 39 MW from methane gas, geothermal, thermal and solar energy respectively (see Figure 2.25). It is anticipated that the imported electricity will come from Ethiopia (400 MW) and Kenya (30 MW) (Tumwebaze 2014). However, as electrification rates in these two countries are also very low (24% for Ethiopia and 20% for Kenya according to IEA (2015b)), these countries may prioritize satisfying domestic power demands before exporting to other countries.

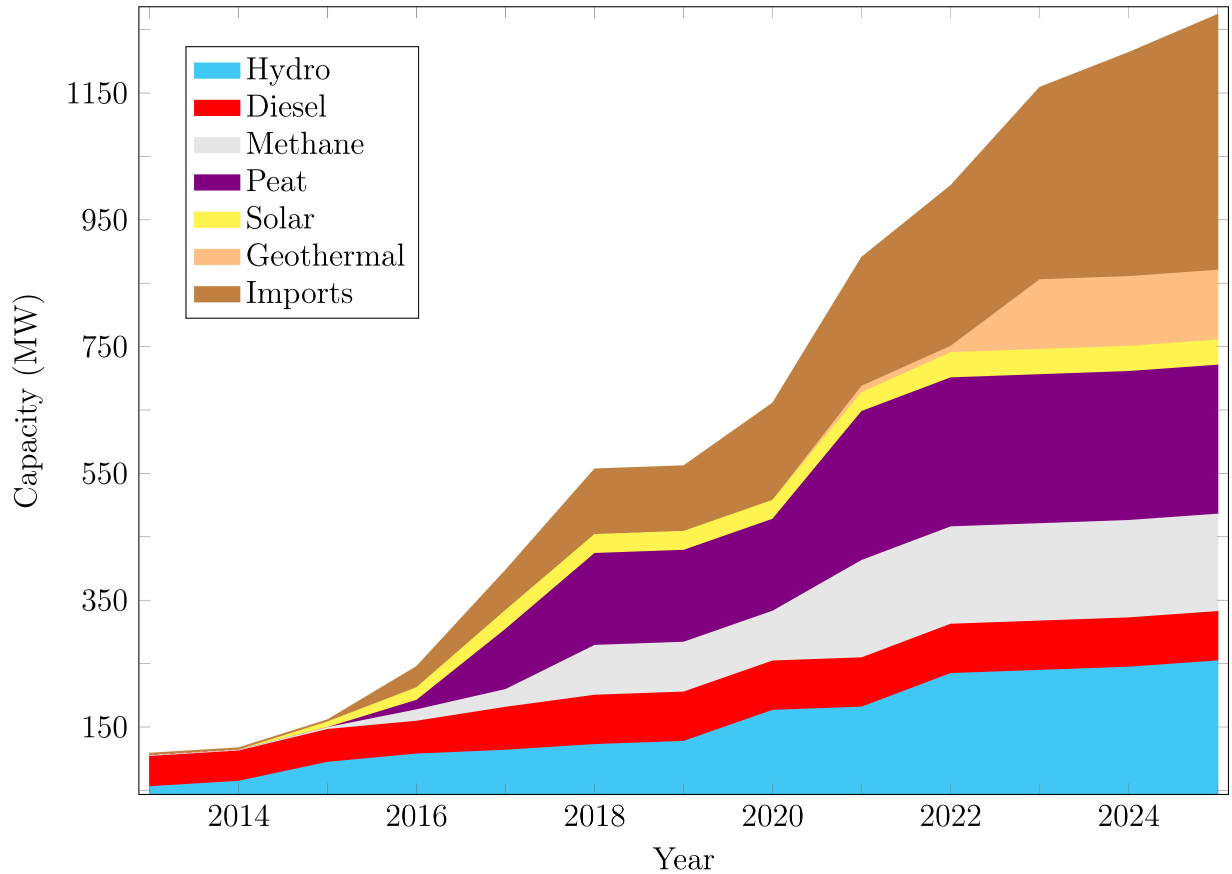


Figure 2.25: Projected installed power capacity by tecgnology for the 2013−2025 horizon (Author based on data from REG)

Chapter 3

Climate change and its impacts on energy systems

Access to energy is one of the essential catalysts for the socio−economic development, as energy is used for the operation of industrial machinery and equipment, powering different services, businesses and institutions (Uhorakeye 2011, 1). Furthermore, the supply of clean, reliable, efficient and affordable energy services is indispensable for poverty alleviation, improving life standards and enabling economic growth in a sustainable manner (AGECC 2010, 7). Being at the heart of the socio−economic development, the supply and use of energy must fulfill the requirements of sustainable development in its social, economic and environmental dimensions. This chapter synthesizes information related to the role energy in the process to achieve sustainable development. Furthermore, it discusses different energy supply constraints with more emphasis on the effects of expected climate change on energy systems. The chapter concludes by briefly describing reported past and future climate situations of Rwanda.

3.1 Energy and sustainable development

Due to the rapid world population growth, expansion in economic activities and improvements in standards of life, there is an increasing energy consumption which results in the overuse of natural resources and in the pollution. This section provides a short historical background of the concept "sustainable development", its dimensions and its linkage with energy supply and use.

3.1.1 Sustainable development and its dimensions

On the global level, the concept of sustainable development was first highlighted in the 1980s in the report "Word Conservation Strategy: Living Resource for Sustainable Development" (Reid 1995, 38). In this report, development is defined as "the modification of the biosphere and the application of human, financial, living and nonliving resources to satisfy human needs and to improve the human quality of life"; and sustainable development as "a development that takes into account social and ecological factors, as well as economic ones; of living and nonliving resource base; and of the long term as well as the short term advantages and disadvantages of alternative actions" (IUCN, UNEP, and WWF 1980, 1). The public awareness of the need for sustainable development was much more raised in 1987, when the World Commission on Environment and Development (WCED) led by Gro H. Brundtland, the former Prime Minister of Norway, released the report "Our Common Future" also known as "Brundtland Report." In Brundtland's Report, sustainable development is defined as *"a development that meets the needs of the present without compromising the ability of future generations to meet their own needs"* (WCED 1987, 8). "Our Common Future" stimulated the broader public to think of the implications of economic development on the biophysical environment because few months after its release, most of the governments and governmental institutions all over the world, began to adopt recommendations from this report (Gibson et al. 2006, 51).

However, a number of commentators and environmental activists criticized Brundtland's definition of sustainable development to be too soft, incomplete, contradictory and not mentioning environmental protection (Diesendorf 2007, 22-23; Reid 1995, 64-65; Gibson et al. 2006, 57). These discussions led to the recognition of the currently accepted social, environmental and economic dimensions of sustainable development (Carew and Mitchell 2006; Gibson et al. 2006, 58). As described by Diesendorf (2007, 22) and Mulder and Biesiot (1988, 6), these three dimensions are processes that lead to a common end point or target of sustainable development: "*the sustainability*."

The social dimension of sustainability addresses issues that hinder the process of improving human living conditions (WBG 2002; EEA 2006). As argued by McKenzie (2004, 2) and Harris (2003, 2), for a system to be socially sustainable it must achieve social equity which means equal opportunities to the access of key social services such as health and education, political accountability and participation, equal opportunities between genders, intra− and inter generations so that future generations will not be disadvantaged by the activities of the current generation. The economic dimension of sustainability deals with issues related to the efficient allocation of the limited economic resources required to improve people's lives (WBG 2002; EEA 2006). For an economic system to be called sustainable, it must be able to utilize available scarce resources to produce goods and services on a continuing basis in order to achieve high living standards and quality of lives for both the current and future generations (Harris 2003, 2). Environmental dimension focuses on the living and physical environment including natural (renewable and non−renewable) resources that help people to sustain and improve their living conditions (WBG 2002; EEA 2006). As highlighted by Harris (2003, 23), a system is said to be environmentally sustainable if the exploitation rate of renewable resources does not exceed their replenishment rate and avoids the depletion of non−renewable resources unless investments are made in adequate substitutes. The linkages between the three dimensions of sustainable development and the supply and use of energy are discussed in Sections 3.1.2 through 3.1.4.

3.1.2 Energy and social sustainability

To be sustainable, energy systems must support poverty alleviation, improve social welfare, provide employment opportunities and not harm the health of present and future generations (Rogner and Popescu 2000, 31). The social requirements of energy systems can be grouped into four main categories namely: accessibility, affordability, acceptability and safety. The first three are related to social equity while the fourth concerns health. AGECC (2010, 13) defines energy accessibility as "access to clean, reliable and affordable energy services for cooking and heating, lighting, communications and productive uses." Energy affordability can be viewed in two ways: affordability in terms of the cost of energy for the end users that should be compatible with their income levels (AGECC 2010, 13), and affordability in terms of consumers' ability to maintain energy technologies and use them cost−effectively (Murphy 2001, 181). Acceptability can be regarded as an attitude towards new technologies; therefore, in order to design, communicate and implement new technologies, it is important to assess factors that can influence acceptability (Huijtsa et al. 2011). As discussed by Assefa and Frostell (2007), perceptions, the fear and the lack of knowledge are the main factors that can influence people to object to new energy technologies. With reference to health, energy production and use should not deteriorate the health of the present and future generations, they should rather support it by improving humans' living standards (Rogner and Popescu 2000, 31).

However, the current energy technologies are characterised by social inequity and deterioration of health especially in developing countries. Contrary to developed countries where energy is available and affordable, about 2.7 billion people in poor nations meet their energy needs through burning biomass in traditional ways, while more than 1.3 billion people do not have access to electricity (IEA 2014g). As reported by IAEA et al. (2005, 16), women who could be engaged in more productive activities and children who could be in school, spend many hours per day to collect biomass fuels. In addition, limited income forces poor households in these countries to stick to traditional fuels and inefficient conversion technologies although modern energy technologies may be accessible (IAEA et al. 2005, 11). As for health, some of the current energy technologies are responsible for different diseases, injuries and accidents that can lead to deaths and other socio−economic losses. For example, the indoor air pollution that results from cooking with traditional biomass and coal in inefficiently ventilated stoves is responsible for 4.3 million deaths per year due to incomplete combustion of fuel carbon(WHO 2014).

3.1.3 Energy and economic sustainability

As highlighted by IAEA et al. (2005, 18), energy contributes to the economic sustainability when the supplied energy to all sectors of the economy (i.e. households, transport, commerce, services and agriculture) is affordable, reliable and efficient. With regard to affordability, energy prices are driving forces for incentives or disincentives for consumption or conservation, or efficiency improvements because they influence consumer choices and behaviour (IAEA et al. 2005, 79; Johansson and Goldemberg 2002, 28). High energy prices may have negative consequences on businesses, employment and social welfare, however they can also stimulate new technologies and improve efficiency as observed during and after the oil crisis of the 1970s (Johansson and Goldemberg 2002, 29−30).

On the other hand, energy security (or reliability) means that energy is available at any time, in required forms and in sufficient quantities (Khatib 2000, 112). The failure to fulfil these requirements can cause substantial financial and economic losses as proven by the electric power sector in Sub−Sahara Africa. As reported by Eberhard et al. (2008, 13) for example, the economic cost resulting from load−shedding in this region was estimated to be about 2.1% of the GDP while the running costs of emergency generators ranged between 1 and 4% of GDP. Interruption of economic activities such as manufacturing, processing and businesses may hinder potential investors to start business in some parts of the world. For example, African manufacturing industry experience power outages on an average of 56 days per year, which is too high compared for instance to the United States of America (USA) where the power shortage is only one day in 10 years (Eberhard et al. 2008, 13).

With regard to efficiency, the production, transportation, distribution, use and by−products of energy may have negative impacts on the environment because inefficient energy systems are responsible for pollution and depletion of non−renewable resources. Therefore, improving efficiency and reducing losses result in more effective utilization of energy resources and in reductions of the pressure on the environment which contribute to the requirements of sustainable development (IAEA et al. 2005, 45).

3.1.4 Energy and environmental sustainability

For energy systems to be in line with environmental sustainability, the production, supply and use of energy should not contribute to the overexploitation of (depletable and non−depletable) natural resources, not harm the health of the present and future generations, and not generate pollutants that exceed the absorptive capacity of the environment (Rogner and Popescu 2000, 31). However, many of the current energy systems are characterised by the overuse of natural resources, and the generation of pollution at the local, national, regional and global levels (IAEA et al. 2005, 19). Pollution comprises mainly the increasing concentration of the anthropogenic GHG emissions, responsible of the present and future climate change (IPCC 2007b, 205).

The described three dimensions of sustainable development are linked, and any improvement of one dimension may influence the others while the deterioration of one of them may affect the others (WBG 2002). For instance, as economic development depends on natural resources, inefficient and overuse of these resources may provide short−term benefits, but limits the country's long−term economy unless the benefits are used to invest in adequate substitute (WBG 2002). Some scholars argued, however, that the three dimensions of sustainable development seem to be contradicting each other especially when it comes to the relationship between economic and environmental issues. One of the main arguments was that efficient and non−polluting energy technologies may be more expensive which can increase the burden on the poor for whom energy costs mean a large proportion of the household's income (Harris 2003, 1). However, this argument holds true only for the current energy systems where damages caused by pollution from energy resource extraction, transportation, conversion and use of the so−called cheap energies is not reflected in the final cost.

Meanwhile, while the entire world is trying to get together in order to address these issues, there are already initiatives that intend to assist the poor to access clean energy at reasonable cost. For example, the UN Secretary−General Advisory Group on Energy and Climate Change (AGECC) has suggested a goal of ensuring universal access to modern energy services by 2030, which can be achieved through a more consistent global partnership in which all countries will have different roles to play. According to AGECC (2010, 9), high−income countries are required to make this goal a first priority in their development assistance; the middle−income countries are expected to share relevant expertise, experience and replicable good practices; while low−income countries are asked to create right and transparent institutions that enable the effective implementation of different initiatives. The discussed linkages of sustainability and energy systems are constrained by some issues that have to be taken in consideration when developing energy systems. These issues are discussed in Section 3.2.

3.2 Global energy supply vulnerabilities

This section discusses the main vulnerabilities to which the global energy sector is currently exposed and those expected in the short− and long−term future. IPCC (2007a, 883) defines vulnerability of a system as *"the degree to which that system is susceptible to, and unable to cope with a selected number of adverse effects."* On the global level, the main challenges of the energy sector include the volatility of oil prices, global financial and credit crisis, and climate change (ESMAP 2009a).

3.2.1 Volatility of fossil fuel prices

The quantities of goods and services that an energy consumer can afford are limited by both her/his income and the market prices. As described by Parkin et al. (2003, 160), a consumer who buys a given quantity of energy and another of other goods and services cannot, for example, increase the quantity of energy he/she purchases without reducing the quantity of other goods and services. Therefore, when the prices of energy increase, the amount of energy that the consumer can afford becomes smaller (price effect) and he/she will tend to substitute a certain quantity of goods and services for a certain amount of energy (substitution effect). Given that the share of oil products in the world total primary energy supply is 35.8% (IEA 2014a, 7), changes in oil prices have implications on global economy. UNDP and ESMAP (2005, 14) estimated the economic losses due to oil price increases for 97 net oil importer and 43 net oil exporter countries when the price of a barrel increases by US$ 10. The results of this analysis are presented in Table 3.1 where figures within square brackets represent the number of countries in considered category. From this table it can be noticed that the poor countries are the most vulnerable to oil price shocks and the losses in GDP increases proportionally to the magnitude of price increases.

In addition, the increase in oil prices influences prices of other energy sources such as natural gas, Liquefied Natural Gas (LNG) and coal (Bhattacharyya 2011, 422). The volatility of oil prices is driven by several factors, of which the most prominent are conflicts in the countries that produce oil or through which oil products are shipped and the rapid worldwide economic expansion and population growth.

With reference to conflicts, Luciani (2011, 3) classified them into three main categories: the 'classic' interstate warfare, which is fought primarily by regular armies; the civil wars, in which armed forces from opposing sides within the same country engage in violent encounters; and terrorism and banditry. For example, revenue losses in the Niger Delta due to oil theft is estimated to be more than US$ 5 billion per year, an amount that

Table 3.1: Percentage change in GDP caused by a US$10 a barrel rise in oil prices (UNDP and ESMAP 2005, 14)

Per capita income (1999-2001 US$)	% change in GDP
Net oil importers	
$GDP \leq 300$ [18]	-1.47
$300 < GDP \leq 900$ [22]	-0.76
$900 < GDP \leq 9,000$ [36]	-0.56
$GDP > 9,000$ [21]	-0.44
Net oil exporters	
$GDP \leq 900$ [10]	$+5.21$
$900 < GDP \leq 9,000$ [17]	$+4.16$
$GDP > 9,000$ [7]	$+1.50$

would be enough to fund universal access to electricity for all Nigerians by 2030 (IEA 2014b, 77).

On the economic expansion and population growth, it is estimated that, by 2035, energy consumption in China and India combined will account for 31% of the total world energy consumption (EIA 2011, 9) while IEA (2009, 81) estimated that the oil demand in China alone will account for about 42% of the increase in the total world oil demand by 2030. In the Sub−Saharan African region, due to the expected population and expansion in economy the demand for oil products is project to double, relative to the consumption in 2012, and reach 4 million barrels per day in 2040; which will make oil products to be the second most consumed fuel in this region (17% of the demand in 2040) behind bioenergy (IEA 2014b, 77).

3.2.2 Financial and credit crisis issues

In general a high level of capital investments are required to develop the energy infrastructure. IEA (2008, 77) estimated that for the 2007−2030 period, US$ 26.3 trillion would be required to develop desired energy supply infrastructure to meet the growing world energy demand. However, due to the global financial crisis accompanied by the increasing difficulties to access credits on financial markets, companies have been forced to cut down their production and cancel or postpone new investments (IEA 2009, 135). In the oil and gas sectors, for example, it was estimated that 19% (or over US$ 90 billion) of planned investments have been cut in 2009, which led into cancellation of 20 planned upstream oil and gas projects (involving about billion barrel of oil per day) and delayed 29 projects (3.8 million billion barrels per day) for at least 18 months (IEA 2009, 135). In the power sector for example, the assessment of the impact of credit crisis on power sector investments in East Asia by ESMAP (2009b, 4) revealed a funding gap of US$ 1.286 billion in Indonesia and US$ 787 million in Vietnam and US$ 1.56 billion in Philippines for the period 2009-−2010.

With regard to emerging economies, developing energy supply systems are capital intensive and many developing countries do not have adequate resources and expertise to establish and manage the necessary infrastructure (Uhorakeye 2011; Rambo 2013). In addition, due to the smallness and scattering of energy resources, the private sector that would develop such projects encounters economic problems as associated transaction costs would increase the tariffs considerably and make the project not feasible (Uhorakeye 2011). Furthermore, poverty has negative impacts on investments in energy sector because initial investments required to access modern energy services such up−front charges for the connection to the grid are too high compared with households' income in these nations (El-Katiri 2014).

3.2.3 Climate change

The current and future climate are expected to impact the existing and planned energy systems in various ways. As demonstrated in AR5 by IPCC (2013), the global mean temperature will continue to rise throughout the 21st century whereas precipitations will increase in some regions, decrease in some others while others will experience no significant change. Therefore, expected changes in temperature, precipitation and the frequency and severity of extreme weather events might impose a set of new operating conditions different from those that they were designed to operate under (Ebinger and Vergara 2011, p. 30). The operation challenges include, for example, weather extremes that may exceed the safety margins of energy infrastructure (Lisperguer and Cuba 2008, 9). In addition, climate change is likely to compromise the ability of the electricity supply system to meet average and peak demands. Furthermore, it might hamper the opportunity of power producers to recover their investments as well as the viability of new investments. As the focus of this study was to analyse electricity supply options for Rwanda under changing climate conditions, a detailed discussion on observed and future climate change is presented in Section 3.3 while potential impacts of climate change on energy systems are summarized in Section 3.4.

3.3 Observed and expected climate

In this section, the observed global climate and its main drivers are presented. Furthermore, the projected climate under different emission scenarios is introduced together with its main drivers. Approaches used to obtain high resolution climate data from global models are discussed at the end of this section.

3.3.1 Global climate and climate change

The earth's weather and climate are determined by the distribution of and the balance between the incoming solar energy to the earth and the outgoing radiant energy from it (Kevin et al. 2007, 311). According to IPCC (2007b, 942), weather reflects, for a specific time, the state of the atmosphere in terms of relevant quantities such as precipitations, temperature and humidity while climate refers to the statistical description in terms of mean and variability of the same quantities over a long−time period, typically 30 years. As it can be noticed from Figure 3.1, about a third of the incoming solar energy is reflected back to space by clouds, atmosphere and the earth's surface while the remaining portion is absorbed by the atmosphere and the earth's surface. As the incoming solar radiations are in the form of visible light (shortwave), they easily pass through the atmosphere and spread back into space during the reflection process (Diesendorf 2007).

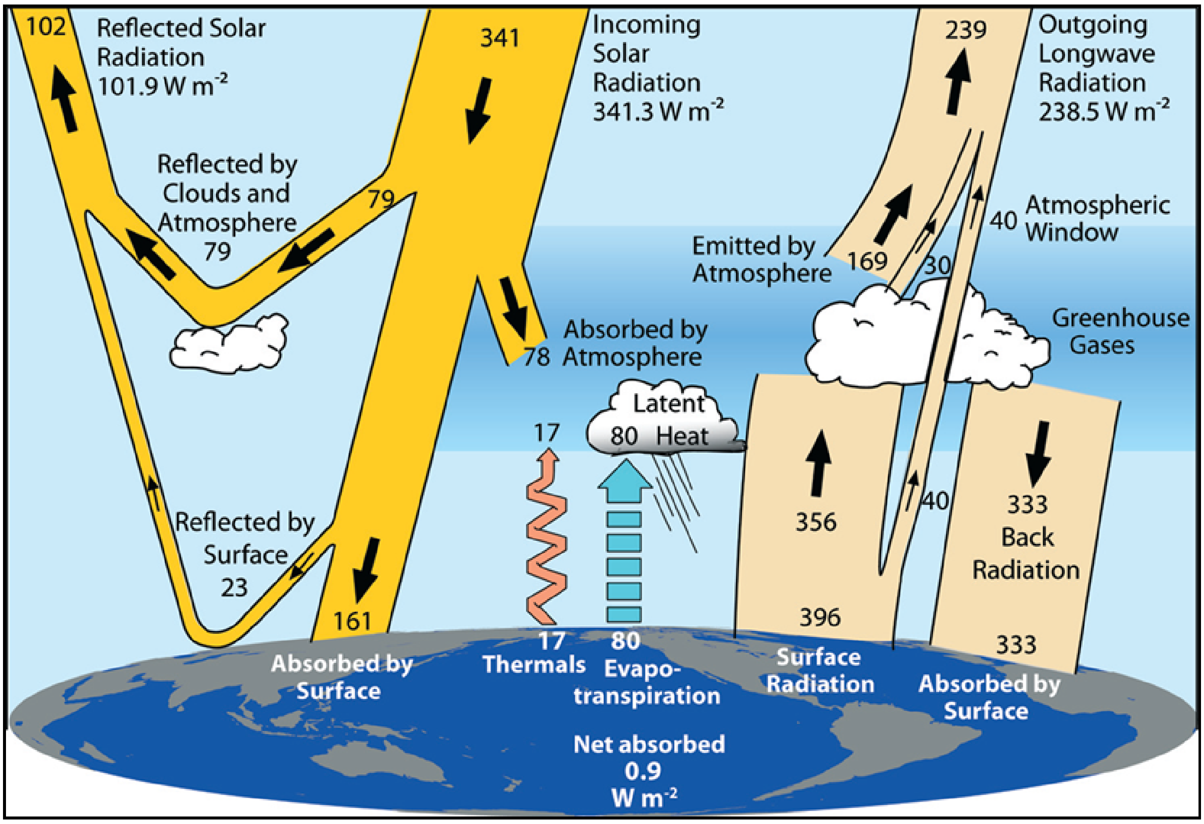


Figure 3.1: Global annual mean earth's energy budget (W m^{-2}) for the March 2000 to May 2004 period (Kevin et al. 2007, 314)

On the other hand the absorbed solar energy warms the earth which emits into the atmosphere an amount of energy in the form of long-wave infrared (heat) radiations.

In order to maintain the earth's temperature at a comfortable level for the life, natural Greenhouse Gases (GHGs) absorb a part of the outgoing radiations that would otherwise escape into space (IPCC 2007b, 97). Climate change occurs when the net energy between the incoming and outgoing solar radiations, known as RF and expressed in W m^{-2}, is disturbed. A positive value of RF has a warming effect while a negative value represents a cooling effect.

3.3.2 Recent changes in the climate system and their main drivers

Relative to 1750, the net anthropogenic RF was 0.57 (0.29 to 0.85) W m^{-2} in 1950, 1.25 (0.64 to 1.86) W m^{-2} in 1980 and 2.29 (1.13 to 3.33) W m^{-2} in 2011; and the contribution of natural RF ranges only between 0.00 and 0.10 W m^{-2} (Myhre et al. 2013). As discussed in Section 3.3.1, the increasing positive values of RF mean that energy has accumulated in the climate system, and consequently, considerable climate anomalies have been recorded over the past years. According to IPCC (2007b, 943), the climate system is "the highly complex system consisting of five major components: the atmosphere, the hydrosphere, the cryosphere, the land surface and the biosphere, and the interactions between them." The main observed changes in the climate system presented below were summarized from AR5 by IPCC (2013).

- ***Atmosphere***: the increase in global (land and ocean combined) average temperature ranges between 0.65℃ and 1.06℃ over the period from 1880 to 2012, and each of the 1983−2012 decades has been successively warmer than any preceding decade since 1850. There has been very little precipitation changes over global land areas but the number of regions which experienced heavy rains has increased more than those where it has decreased. In addition the number of cold days and nights has considerably decreased whereas that of hot days and nights has increased since 1950.

- ***Ocean and sea level***: 90% of the net increase in total energy accumulated in the climate system is stored in the oceans of which 60% is stored in the upper ocean (from 0 to 700 m deep). It was also observed that, since 1950, regions with high salinity have become more saline while those of low salinity have become fresher. As for changes in the sea level, measurements have indicated that the global average sea level rise for the period 1901−2010 was between 1.5 to 1.9 mm yr^{-1}. Glacier mass loss combined with ocean thermal expansion contributed together 75% of the observed global mean sea level rise.

- ***Cryosphere***: the cryosphere is "the component of the climate system consisting of all snow, ice and frozen ground (including permafrost) on and beneath the surface of the Earth and ocean" (IPCC 2007b, 944). The past climate change is responsible of ice loss across the planet so that the average global rate for ice loss (excluding glaciers on the periphery of the ice sheets) was 226 Gt yr^{-1} and 275 Gt yr^{-1} over the period 1971 to 2009 and 1993 to 2009 respectively. The rate of ice loss from the Greenland ice sheet increased from 34 to 215 Gt yr^{-1} over the periods 1992 to 2001 and 2002 to 2011 respectively while that from the Antarctic ice sheet increased from 30 to 147 Gt yr^{-1} over the same periods[1].
- ***Carbon and other biogeochemical cycles***: in 2011, the anthropogenic GHG concentrations in the atmosphere were 391 ppm for CO_2, 1803 ppb for Methane (CH_4) and 324 ppb for Nitrous Oxide (NO_2). These concentrations were about 40%, 150%, and 20% higher relative to 1750 levels for CO_2, CH_4 and NO_2 respectively. Of the total cumulative anthropogenic emissions of about 555 Gt yr^{-1} released in the atmosphere between 1750 to 2011, CO_2 emissions from burning fossil fuel and cement production contributed about 70% while the share of deforestation and other land use change was about 30%.

3.3.3 Expected global climate

In order to estimate what the future climate and its impacts might be, climate modelers first need to have information on possible future atmospheric GHG concentrations and other pollutants to which climate is sensitive. Because of uncertainties in estimating pollution, scenarios are used to cover a range of possible future emission trajectories (IPCC 2000, 3). As defined by IPCC (2013, 945), an emission scenario is "a plausible representation of the future development of emissions of substances that are potentially radiatively active (e.g., greenhouse gases, aerosols), based on a coherent and internally consistent set of assumptions about driving forces (such as demographic and socio−economic development, technological change) and their key relationships." There is a series of emission scenarios available in literature, but in this study only those scenarios used in different reports of the IPCC are presented. The IPCC scenarios are the 1990 IPCC Scenario A (SA90) used in the IPCC First Assessment Report (FAR) published in 1990, the 1992 IPCC Scenarios (IS92) used in the IPCC Second Assessment Report (SAR) published in 1995, the Special Report on Emissions Scenarios (SRES) used in the IPCC Third Assessment Report (TAR) published in 2001, and in the IPCC Fourth Assessment Report (AR4) published in 2007, and the RCPs used in the IPCC AR5 published in 2013 (IPCC 2014). Table 3.2 and Table 3.3 describe respectively the SRES and RCPs scenarios extensively

1. 100 Gt yr^{-1} of ice loss is equivalent to about 0.28 mm yr^{-1} of global mean sea level rise.

Table 3.2: Main characteristics of the four SRES scenarios (IPCC 2000, 4-5)

Scenario	Description
A1	A1 scenario describes a future world of very rapid economic growth and population that peaks in mid−century and declines thereafter. The scenario comprises three groups that describe alternative directions of technological change in the energy system. These groups are (i) fossil intensive (A1FI) leading to a cumulative CO_2 value of 2189 GtC by 2100, (ii) a balance across all sources (A1B) leading to 1,499 GtC, and (iii) non−fossil energy sources (A1T) leading to 1,068 GtC.
A2	A2 scenario describes a very heterogeneous world with self−reliance and preservation of local identities. Fertility patterns across regions converge very slowly, which results in continuously increasing global population. This scenario leads to a cumulative CO_2 value of ,1862 GtC by 2100.
B1	B1 scenario describes a world with the same global population trends as A1 scenario, but with rapid changes in economic structures toward a service and information economy, with reductions in material intensity, and the introduction of clean and resource−efficient technologies. Cumulative CO_2 emissions are projected to be 983 GtC by 2100.
B2	B2 scenario describes a world in which the emphasis is on local solutions to economic, social, and environmental sustainability. It is a world with continuously increasing global population at a rate lower than A2, intermediate levels of economic development, and less rapid and more diverse technological change than in the B1 and A1 scenarios. Cumulative CO_2 emissions are projected to be 1164 GtC by 2100.

used by different climate modelers in the projection of future climate[2].

Figure 3.2 compares the SA90, IS92 and SRES scenarios with Representative Concentration Pathway (RCP) scenarios. The difference observed between IS92, SRES and RCP for the past years originate from knowledge about the emissions which was gained after the TAR and AR4 had been published (IPCC 2013, 146).

2. 1 Gigatons of carbon (1 GtC) = 10^{15} grams of carbon which corresponds to 3.667 $GtCO_2$ (IPCC 2013, 12)

Table 3.3: Overview of Representative Concentration Pathways (Wayne 2013)

Scenario	Description
RCP2.6	The RCP 2.6 represents an emission pathway leading to very low GHG concentration levels. Its RF level reaches a value around 3.1 W m^{-2} by mid-century, and returns to 2.6 W m^{-2} by 2100. In order to reach such a RF levels, GHG emissions (and indirectly emissions of air pollutants) are to be reduced substantially over time.
RCP4.5	The RCP 4.5 scenario is a stabilization scenario where the total RF is stabilized to 4.5 W m^{-2} after 2100 by employment of a range of technologies and strategies for reducing GHG emissions.
RCP6.0	The RCP 6.0 scenario is a stabilization scenario where the total RF is stabilized to 6.0 W m^{-2} after 2100 without overshoot by employment of a range of technologies and strategies for reducing GHG emissions.
RCP8.5	The RCP 8.5 scenario is characterized by increasing greenhouse gas emissions over time leading to 8.5 W m^{-2} in 2100.

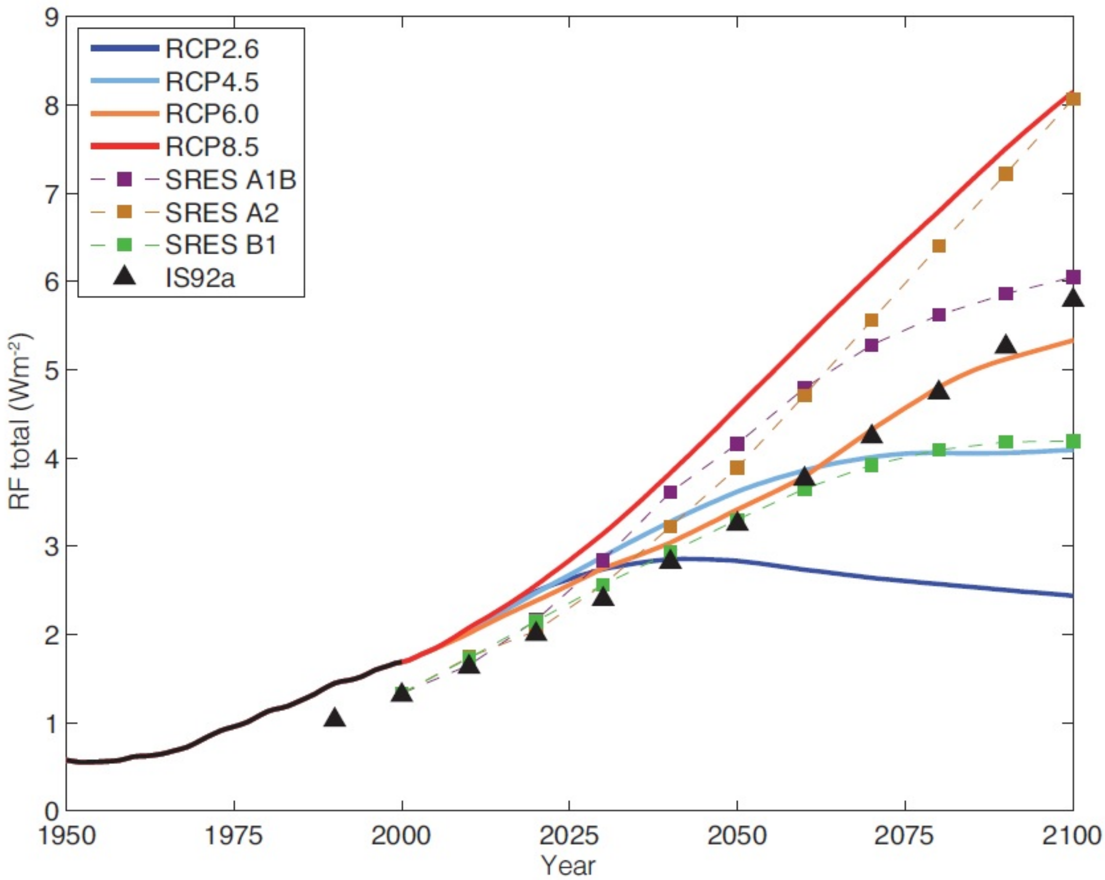


Figure 3.2: Historical and projected total anthropogenic RF (W m^{-2}) between 1950 and 2100 relative to preindustrial values (IPCC 2013, 146)

Once emission scenarios have been determined, climate models are used to simulate the response of the climate system to the identified RF. A climate model is "a numerical representation of the climate system based on the physical, chemical and biological properties of its components, their interactions and feedback processes, and accounting for all or some of its known properties" (IPCC 2007b, 943). Models that simulate the entire planetary climate are referred to as GCMs while those simulating climate at local and national levels are called Regional Climate Models (RCMs). The models used in AR5 are grouped into two categories: the Atmosphere–Ocean General Circulation Models (AOGCMs) and ESMs. AOGCMs simulate the (past and future) dynamics of the physical components of the climate system under different emission trajectories (Flato et al. 2013) while ESMs simulate the same processes but with an added advantage of including biogeochemical processes such as the carbon cycle and its connections to the terrestrial and oceanic ecosystems (Flato 2011). A summary of expected global climate change by IPCC (2013) under different RCPs is presented below[3]:

- ***Atmosphere***: relative to the 1986–2005 average, the temperature change for the 2081 − 2100 period is expected to likely be 0.3°C to 1.7°C for RCP2.6, 1.1°C to 2.6°C for RCP4.5, 1.4°C to 3.1°C for RCP6.0, and 2.6°C to 4.8°C for RCP8.5. By the end of the century, the temperature is projected to likely exceed 1.5°C for RCP4.5, and 2°C for RCP6.0 and RCP8.5 relative to the 1850 − 1900 average. It is anticipated that warming in the Arctic region will be higher than the global mean average and that of land surface larger than that of the oceans. Concerning precipitations, under RCP8.5 the annual mean precipitations are expected to likely increase for the equatorial Pacific Ocean and in many mid−latitude wet regions while a decrease is projected for many mid−latitude and subtropical dry regions. The frequency and intensity of extreme precipitations are projected to very likely increase towards the end of the century.

- ***Ocean and sea level***: throughout the 21st century, ocean is expected to continue warming so that the temperature will range from 0.6°C (RCP2.6) to 2.0°C (RCP8.5) for the ocean layer down to 100 meters and 0.3°C (RCP2.6) to 0.6°C (RCP8.5) for the layer down to 1000 metres. It is projected that the global mean sea level for the 2081–2100 period will likely rise by 0.26 to 0.55 m for RCP2.6, 0.32 to 0.63 m for RCP4.5, 0.33 to 0.63 m for RCP6.0, and 0.45 to 0.82 m for RCP8.5 relative to 1986 − 2005. Of this increase, thermal expansion accounts for 30 to 55% while the melting of glaciers represents 15 to 35%.

- ***Cryosphere***: due to the projected increases in global mean temperature, Arctic and Antarctic sea ice are expected to decrease considerably over the 21st century. Projections indicate that by the end of the century, the global glacier volume (ex-

3. In this chapter the following terms have been used according to IPCC (2013, 36): virtually certain 99–100% probability, very likely 90–100%, likely 66–100%, about as likely as not 33–66%, unlikely 0–33%, very unlikely 0–10%, exceptionally unlikely 0–1%.

cluding Antarctic) will decrease by 15 to 55% for RCP2.6 and by 35 to 85% for RCP8.5. Based on the 1979 to 2012 trend of the Arctic sea ice extend for example, projections reveal that, under RCP8.5, the Arctic might be an ice−free ocean by 2050.

- ***Carbon and other biogeochemical cycles***: based on the simulation results from 15 ESMs, it is anticipated that, for the period 2012−2100, cumulative CO_2 emissions will likely reach 140 to 410 GtC for RCP2.6, 595 to 1005 GtC for RCP4.5, 840 to 1,250 GtC for RCP6.0, and 1,415 to 1910 GtC for RCP8.5 scenarios.

3.3.4 Downscaling climate models

Due to the lower spatial resolution of GCMs and ESMs (usually hundreds of kilometers as it can be noticed from Appendix A), it is not feasible to use their outputs for impact assessments on the local scale. To cope with this deficiency, downscaling techniques that allow obtaining data at desired resolutions from the coarse−resolution models are used (Wilby et al. 2000; Tisseuil et al. 2010; Flato et al. 2013). Two approaches: Statistical Downscaling (SDS)and Dynamical Downscaling (DDS) methods have extensively been discussed in literature.

SDS methods are based on the relationship between the outputs generated by the large scale models and the local scale measurements of the same climate parameters (Ingol 2011). As highlighted by Gutiérrez et al. (2012, 16), statistical methods work in two steps: (i) the establishment of the empirical relationship (statistical model) between the large scale outputs of GCMs and ESMs and the corresponding local historical observations in the area of interest and (ii) the application of the determined statistical model to data from GCMs and ESMs under consideration in order to derive the corresponding local and regional climate parameters under investigation. The commonly used statistical downscaling methods are weather classification schemes, regression (or transfer function) models and stochastic weather generators.

- ***Weather classification schemes*** (also called weather patterns or analog methods) are based on the nearest neighbors meaning that a finite number of days with similar climate patterns are grouped together (Gutiérrez et al. 2012). Then probability distribution functions of observed data are computed and time−series of projected variables can be derived stochastically by applying input sequences of daily weather types to the observed probability distribution functions (Wilby and Wigley 1997, 534).

- ***Regression models*** depend on linear or nonlinear relationships between the large−scale variable data (the predictors) and the local−scale conditions of interest (the predictands or response variable) as described by Chu et al. (2009, 150) and Gutiérrez et al. (2012, 7). The main regression downscaling techniques include artificial neural networks (Crane and Hewitson 1998), canonical correlation analysis (von Storch et al. 1993), and multiple regression (Murphy 1999).

- ***Weather generators*** use projected monthly variable data to stochastically simulate daily climate variables (Gutiérrez et al. 2012; Fowler et al. 2000). Weather generators are based on representations of the occurrence of precipitation via, for example, Markov processes for wet/dry day or spell transitions (Wilby et al. 2004), and they replicate the statistics of the predictands but not recorded sequences of events (Wilks and Wilby 1999).

The main advantage of SDS methods is that they are computationally inexpensive which allows to apply them to a variety of Global Climate Model (GCM) and Earth System Model (ESM) experiments; and their main disadvantage is their assumption that the determined empirical relationship for the present day climate also holds under the different forcing conditions of possible future climates (Wilby et al. 2004, 3).

In the DDS approach, the coarse−resolution model outputs are used as boundary conditions to drive a Limited Area Model (LAM), high−spatial resolution model (or RCMs) to derive smaller−scale information (Chu et al. 2009; Wilby and Wigley 1997; Xue et al. 2007). To achieve this, RCMs use complex algorithms to describe atmospheric process embedded within GCM outputs (Ingol 2011). Castro et al. (2005) proposed four DDS methods, namely:

- *Type 1*: in this type which remembers the global initial atmospheric conditions, the LAM is driven by lateral boundary conditions from a numerical weather prediction GCM or global data reanalysis at regular time intervals (typically 6 or 12 h), by bottom boundary conditions (e.g., terrain), and specified initial conditions.
- *Type 2*: in this type, the initial conditions in the interior of the LAM are forgotten, but the lateral boundary conditions feed real-world data into the regional model.
- *Type 3*: in this type, the GCM is used to create lateral boundary conditions which is forced with specified surface boundary conditions.
- *Type 4*: in this type the global model runs with no prescribed internal forcings. Couplings among the ocean−land−continental ice−atmosphere are all predicted.

One major advantage of DDS methods is that RCMs include the surface forcing (topography, surface heterogeneities) at fine scale, necessary to produce realistic small scale features from the large scale ones (Flaounas et al. 2012). The main disadvantage of these methods is their complexity which requires intensive computational resources and time (Ingol 2011).

3.4 Main climate change impacts on energy systems

Projected changes in precipitations and increased temperature will more likely affect current and future energy systems. In addition, expected changes in the intensity and patterns of extreme weather events may exceed the safety margins of existing and planned energy infrastructure. This section discusses the main impacts of climate change on energy resources, energy system operations and energy demand.

3.4.1 Impacts on energy resources

Hydropower resources: the output power from a given hydropower plant depends on the flow rate of rivers and the water level in reservoirs for runoff river and dam−based plants respectively. The amount of water flow is a function of the difference between precipitations and evapotranspiration (Schaeffer et al. 2011, 2). As demonstrated by the IPCC in its AR5, the global mean temperature will continue to increase throughout the 21st century whereas precipitations will increase in some regions, decrease in some others while others will experience no significant changes (IPCC 2013). Therefore, water in general and hydropower resources in particular in areas where precipitations are expected to change might be negatively or positively affected. Decreased precipitations combined with the increased evapotranspiration are more likely to affect the generation capacity of existing and future hydropower plants (Ebinger and Vergara 2011, 7−8).

On the African continent, there have not been many studies that investigated climate change impacts on energy systems and especially on hydropower. Hamududu (2012) used a multi−model ensemble to simulate impacts of climate on hydropower production potential in Central and Southern Africa under SRES A1B. In this study, it was found that hydropower production potential may decrease by 7 to 34% in the southern African and increase by 6 to 18% in the central African regions towards the end of the century. As highlighted in Section 1.1.3, Yamba et al. (2011) assessed implications of climate change and climate variability on hydropower generation in the Zambezi River Basin and concluded that power generation from the existing and planned hydropower plants would increase for the 2010−2016 period and then decrease towards 2070.

Harrison and Whittington (2002) assessed the viability of the Batoka Gorge hydroelectric scheme to climate change. They found that annual flow levels at Victoria Falls would reduce between 10% and 35.5% which would cause reductions in annual electricity production between 6.1% and 21.4%. Beyene et al. (2010) assessed the potential impacts of climate change on the hydrology and water resources of the Nile River basin using an average of 11 GCMs. In this study they concluded that stream flow discharges at the

Nile River will increase for the 2010−2039 period, decline for the 2040−2099 period and that the power generation would follow the stream flow's trends.

Solar resources: the amount of solar energy that reaches each location on the Earth's surface depends on the atmospheric path length to the location and the pathway properties characterized by its transmissivity (Stanhill and Cohen 2005, 1509). The path length does not change for a specific location, but the transmissivity is affected by climate parameters such as cloud cover, water content and aerosols. As described by Liepert (2002) and Stanhill and Cohen (2005), clouds are the strongest modifiers of surface solar radiation and they are partly influenced by aerosols.

Aerosols promote changes to cloudiness and cloud characteristics which lead to increased frequencies of overcast skies, declining frequencies of clear skies, and increasing cloud optical thickness at overcast conditions (Liepert 2002; Wild et al. 2005). Aerosols scatter and absorb sunlight in the cloud which reduces solar energy reaching the surface (IPCC 2013; Liepert 2002; Pinker et al. 2005, 778). In their study which estimated impacts of climate change on solar radiation in the USA, Pan et al. (2004) found up to 20% seasonally reductions in solar energy resources mainly due to the increased cloud cover.

Wind and marine energy resources: due to different properties of the earth's surface that absorb different quantities of the sun's heat, air motion (here referred to as wind) is generated due to temperature gradient (Lisperguer and Cuba 2008, 11). Consequently, variations in temperature or land cover and water properties may change the geographic distribution of wind resources (Pryor and Barthelmie 2010). Wind speeds (and their variability) define not only the economic feasibility of exploiting wind resources but also the reliability of electricity production once the capacity is installed (Ebinger and Vergara 2011, 28). The variations in wind speed do not only affect wind resources but also marine energy resources. A study conducted by Harrison and Wallace (2005, 9) concluded that the variation in mean wave power follow wind speed changes in a way that a 20% decrease in mean wind speeds, for example, lowers available wave power levels by 67%, while an equivalent increase raises them by 133%.

3.4.2 Impacts on energy system operations

Hydropower plants: when determining the amount and variability of energy that a given hydropower plant can produce, designers generally base on daily and seasonal historical climatic patterns, meaning that they assume stable climate (Ebinger and Vergara 2011, 30). However, the inter−annual variability of the amount of water available for hydropower generation is one of the main challenges that the electricity supply systems face in meeting average and peak demands. For example the difference between the recorded high (2003) and low (2001) hydropower generation years in the USA was 59 TWh (CENR 2008, 20). The variability in power generation can also be influenced by the characteristics of individual plants whether they are runoff−river or dam fed power plants. The runoff−river based plants are highly vulnerable to climate change variations, whereas reservoir storage capacity can compensate for seasonal (or even annual) variations in water inflow, enabling matching of electricity generation to varying power demand (Ebinger and Vergara 2011, 32).

Thermal and solar power plants: climate change impacts on the operation of thermal power plants are mainly related to the temperature of ambient air, cooling water requirements and water availability, and thermal pollution. Because warm air is harder to compress than colder air, the power needed to compress the mixture natural gas/air increases with higher temperature (Rademaekers et al. 2011; Arrieta and Lora 2005; Feeley et al. 2005). Another effect that is applied to all cycles that involve combustion (fossil fuel and biomass power plant) is that since warm air contains less oxygen compared with the same volume of cold air, additional compressing energy will be required to produce the same output which affects the efficiency of the power plant (Rademaekers et al. 2011; Schaeffer et al. 2011).

As for nuclear power, higher ambient temperature affects mainly those plants that use cooling towers because the plant's efficiency depends on the difference between the inlet steam and the condenser temperature which depends on the ambient temperature (Rademaekers et al. 2011). Therefore, increased ambient temperature can reduce the turbine efficiency and also increase fuel consumption if the power output is to be maintained (Arrieta and Lora 2005). In addition, increased temperature of cooling water may reduce the efficiency of the plants and may force operators to run the plants at partial load or to shut them down which implies losses of output (Gonseth and Vielle 2012; Rademaekers et al. 2011). Furthermore, thermal pollution that results from the deviation of legal restrictions about the temperature of cooling water that is brought back to the environment may affect the performance of thermal power plants (Gonseth and Vielle 2012). These regulations may be restrictions of water usage by stipulating the maximum water withdrawal from and/or the maximum temperature of returned water to water bodies (Rothstein and Halbig 2010).

With regard to the operation of solar power plants, increased temperature may reduce the efficiency of both solar Photovoltaic (PV) power plants and Concentrating Solar Power (CSP) (Schaeffer et al. 2011). With regard to impacts of climate change on the operation of CSP, because these plants operate under steam or Rankine cycles, they are exposed to the same effects as thermal and power plants discussed in this subsection.

3.4.3 Impacts on energy transmission and distribution

Due to their long lifespan, existing energy transmission and distribution infrastructure will be exposed to climate conditions different from those they have been designed to. As highlighted by Rademaekers et al. (2011), Schaeffer et al. (2011) and Musilek et al. (2009), energy infrastructure such as electricity, pipelines and railways networks may be damaged as a result of climate extremes such as heavy winds and storms, ice loads, flooding and landslides. Such events as well as lightning strikes, conductor vibrations and galloping avalanches may also disconnect supply facilities and end users. Table 3.4 summarizes reported impacts of extreme events on electric transmission and distribution networks together with associated costs (repair, compensation and reinvestment) for Canada, France, Poland, Sweden and Latvia.

Table 3.4: Impacts of extreme events on the transmission and distribution of electricity supply systems in selected countries (Sundell et al. 2006)

Country	Period	Event	Impacts	Cost estimates
Canada	January 1998	Severe ice storms	Transmission lines, pylons and transformers destroyed or damaged which left about 3.6 million people in darkness.	Canadian $940 million
France	December 1999	Storms	Flooded substations, broken or flattened poles, tangled wires, destroyed or damaged pylons left about 3.5 million people without electricity.	€1.4 billion
Poland	November 2004	Snowstorms and strong winds	Transmission and distribution lines, and transformer stations destroyed or damaged leaving more 0.52 million people without electricity.	€20 million
Sweden	January 2005	Storm	Power network failure which resulted into power outages with more than 0.6 million customers left without electricity.	€257 million
Latvia	January 2005	Storm	Network lines damaged leaving approximately 0.4 million customers without electricity.	€4.7 million

3.4.4 Impacts on energy demand

Impacts of climate change on energy systems are not only limited to energy supply but also the demand side is concerned with it. Expected increase in mean temperature may affect the performance of electric equipment such as motors and engines, lower space heating demand and increase cooling needs. The effects of climate change on heating and cooling energy demand is commonly assessed by using the concept of cooling and heating degree days, which are respectively the sum of negative and positive deviations of the outdoor temperature from the base indoor temperature over a given period of time. The base temperature is defined as the temperature level where there is no need for either heating or cooling (Ebinger and Vergara 2011, 38). Different studies have been conducted to assess the effects of climate change on energy demand and most of them focus on cooling and heating requirements. Isaac and van Vuuren (2009) estimated effects of climate change on heating and cooling energy demand for the residential sector on a global level. The study revealed that energy demand for heating will increase until 2030 and then stabilize while energy for cooling (air conditioning) will increase continuously until the end of the century. Most of the studies were conducted on local and regional levels. The main conclusion is that climate change would reduce heating and increase cooling needs. These studies include Seljom et al. (2012) for the case of Norway, Gonseth and Vielle (2012) for Switzerland, Olonscheck et al. (2011) for Germany and Wilbanks et al. (2007b) for the USA.

3.5 Observed and future climate of Rwanda

Rwanda has been vulnerable to periodic floods and droughts in addition to the increasing temperature and inter−annual variability of precipitations. These challenges are discussed in this section together with associated economic costs. The section concludes by briefly describing what is already known about the future climate of the country.

3.5.1 Past climate change and its economic costs

The past climate of Rwanda was characterized by increasing minimum, average and maximum temperatures. According to the results of the analysis of temperature records from Kigali Airport by McSweeney (2010, 11), the mean temperature increase was found to be 0.47°C per decade since 1970; and the same trend was also reported by MINIRENA (2006, 26). As for precipitations, McSweeney (2010, 16) analysed precipitation records from 4 meteorological stations (Kigali, Kamembe, Gisenyi and Ruhengeri airports) for the 1931−1990. The results revealed no significant trends, but considerable inter−annual variability across the country. In addition, since the 1980s, Rwanda has been repeatedly facing severe droughts, heavy rains and floods. For example El Niño episodes of 1982/83, 1986/87, 1991/92 and 1997/98 and La Niña of 1999/2000 and 2005/2006 have in most of the cases been accompanied by severe droughts and strong heat waves (MINIRENA 2006, 30).

This observed climate is reported to be responsible for the degradation of arable land and forests, desertification trends, water sources drying, lowering of lakes' level and decreased river flows (MINIRENA 2006, 38). A study about Economics of Climate Change in Rwanda conducted by Stockholm Environment Institute (SEI) revealed that recurrent floods and droughts associated respectively with El Niño – Southern Oscillation (ENSO) and droughts associated with La Niña caused significant economic losses in the country (SEI 2009). Estimates of direct economic costs encountered due to 2007 flood events for example were US$ 4 to US$ 22 million (equivalent to about 0.1–0.6% of GDP) for only Musanze, Nyabuhu and Rubavu Districts (SEI 2009). El Niño is a basin−wide warming event originating from the perturbations of the global−scale tropical and subtropical surface pressure pattern called the Southern Oscillation; and its cold phase is called La Niña (IPCC 2007b, 945). In addition to extreme events, the study found that recent trends in temperature may have shifted the altitudinal pattern of malaria and raised the national burden of malaria in recent decades.

With regard to energy issues, especially electricity production, as described in Section 1.1, the electricity generation in Rwanda depended 100% on hydropower resources from 1957 to 2004 (REG 2014a). About 90% of the domestic electricity production came from Ntaruka and Mukungwa hydropower plants and these power stations have played a key role in the country's socio−economic development (Hove et al. 2011). The settings of these power stations are in such a way that Lake Burera feeds Ntaruka power plant and downstream of this plant there is Mukungwa hydropower station. Such a setting explains how water reductions in Lake influence the production of both power plants. This was observed in early 2000 when the level of Lake Burera dropped considerably (see Figure 3.3) which reduced the national electricity production by 60% (see Figure 3.4).

MINIRENA (2006, 14) and REMA (2011, 14) reported that the reason for the decline in the Burera water level was a result of climate change. However, this has to be taken with some reserve because other factors than climate change might have contributed to the reduction in th water level of the lake. As highlighted by Hove et al. (2011), the other contributing factors include poor management of the upstream Rugezi Wetlands, degradation of the surrounding watershed and poor maintenance of the station. Figure 3.3 and Figure 3.4 show how the power station has been operated beyond its designed monthly energy production which resulted into an overuse of the Lake. Therefore, to avoid confusions that might mislead planners and policy−makers, it is imperative to separate the contribution of climate change from that of other factors.

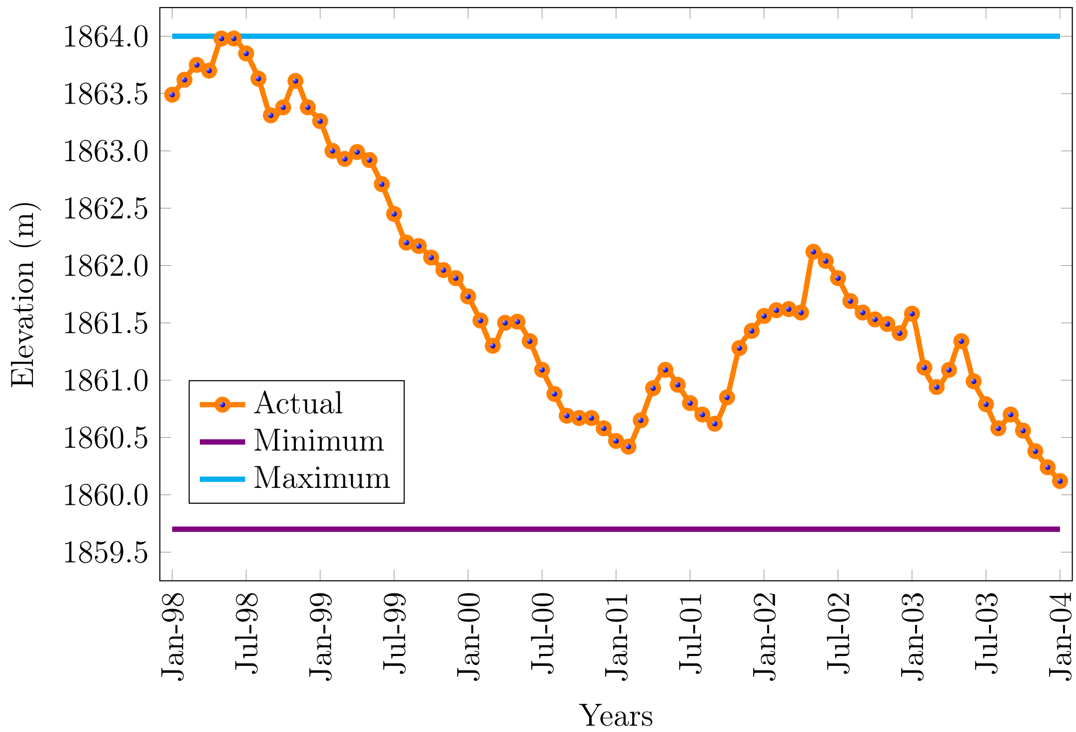


Figure 3.3: Use of the Burera Lake between 1998−2004 (Author based on data extracted from an image available in Hermes (2005, 9) using the WebPlotDigitizer tool develoed by Rohatgi (2015))

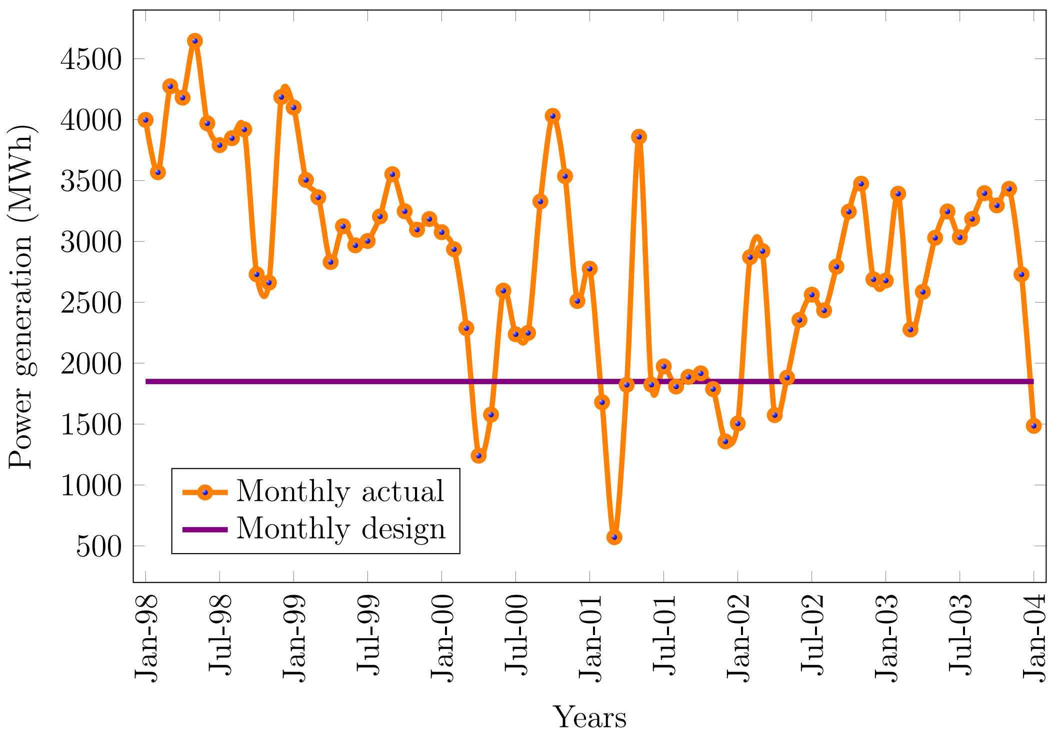


Figure 3.4: Ntaruka power generation between 1998−2004 (the data used to plot this figure were extracted from an image available in Hermes (2005, 8) using the WebPlotDigitizer tool develoed by Rohatgi (2015))

3.5.2 Projected climate

The future climate of Rwanda was assessed by McSweeney (2010) based on data from an ensemble of 19 GCMs from the World Climate Research Programme (WCRP) Coupled Model Intercomparison Project 3 (CMIP3). Considered emission scenarios are A2, A1B and B1 described in Section 3.3.3. As it can be noticed from Table 3.5, the results of the projections reveal an increase in mean temperature under all models and all emissions scenarios. For precipitations, an average increase of 7% by 2099 under A1B and A2 is expected; however this change is too small compared to the inter−annual variability that can go up to approximately ±25% (McSweeney 2010).

Table 3.5: Median (minimum to maximum in brackets) projections for annual changes in rainfall and mean temperature for each emission scenario and timeslice (McSweeney 2010, 22)

Scenario	2010 – 2039	2040 – 2069	2070 – 2099
		Rainfall (% change)	
B1	+3 (-1 to +15)	+5 (-4 to +15)	+5 (-5 to +18)
A1B	+4 (-4 to +10)	+6 (-4 to +18)	+7 (-4 to +31)
A2	0 (-2 to +7)	+3 (-6 to +17)	+7 (-5 to +29)
		Mean temperature (absolute change)	
B1	0.7 (0.4 to 1.1)	1.4 (0.9 to 1.9)	1.9 (1.4 to 2.7)
A1B	0.9 (0.4 to 1.1)	1.9 (1.2 to 2.4)	2.9 (2.0 to 3.8)
A2	0.9 (0.5 to 1.0)	1.8 (1.3 to 2.2)	3.2 (2.5 to 3.8)

It is important to mention here that the projections were based on data extracted from an ensemble of GCMs for the grid cells that cover Rwanda. Due to the coarse resolution of CMIP3–GCMs (typically having a horizontal resolution of between 250 and 600 km), Rwanda falls in one or two GCMs. Therefore, data directly from GCMs cannot provide enough information on local climate, they are rather rough estimations of the evolution of the climate.

Chapter 4

Approach to hydrological and climate change impact assessment

This chapter describes the approaches and tools used to systematically gather and analyse required information necessary to achieve the study's objectives. Furthermore, the sources of used information and the assumptions made for data that could be not obtained are also presented in this chapter. This study was carried out in the following sequences: (1) the selection, calibration and validation of a site−specific hydrologic model, capable of reproducing observed stream flow discharges at the outlet of the studied catchment; (2) the analysis of the outputs of available downscaled GCMs and ESMs in order to extract those GCMs and ESMs that fit most the study area best; (3) the extraction of data from chosen GCMs and ESMs; (4) the analysis of the past and expected climate of the studied area; (5) the simulation of the hydrologic response of the studied catchment to the expected future climate; (6) the simulation of the impacts of expected climate on hydropower generation; (7) the simulation of the future electricity demand and supply of Rwanda taking into account identified climate impacts on hydropower generation; and (8) the investigation of a climate resilient electricity supply option and policy recommendations to implement most feasible options. Steps (1) to (6) are discussed in this chapter while steps (7) and (8) are discussed in Chapter 5.

To achieve intended results, a combination of different tools mainly the GIS, Climate Data Operators (CDO), WEAP, LEAP and R tools were used. Figure 4.1 illustrates the followed methodological flow chart to conduct this study.

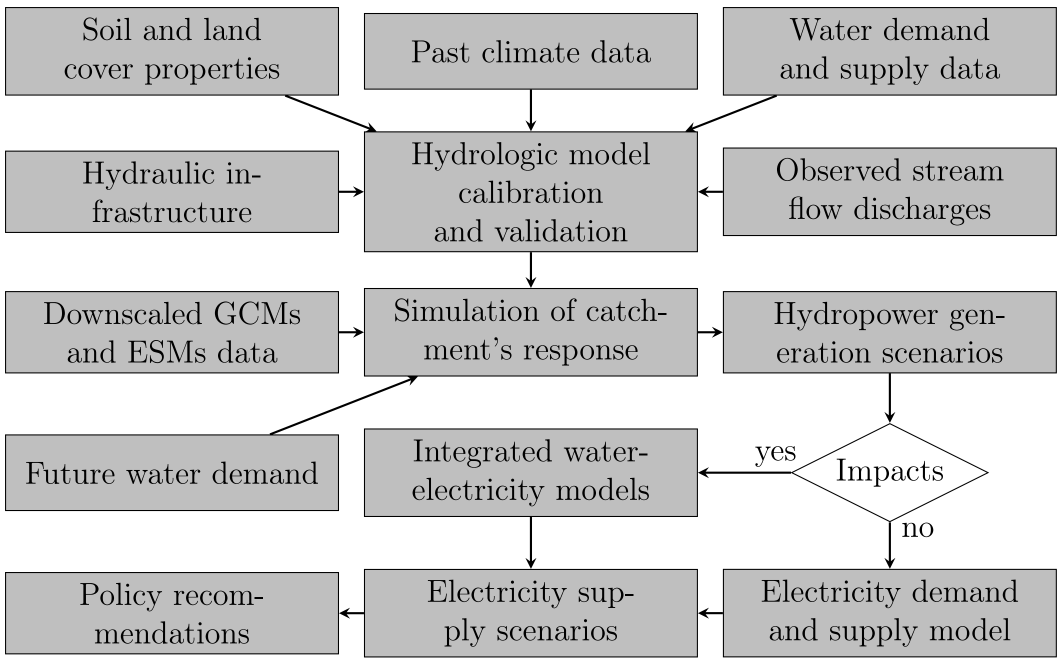


Figure 4.1: Methodological flow chart

4.1 Hydrological model selection and description

The selection of the hydrological model was mainly based on the model ability to simulate hydropower under different climate conditions, and exchange information with energy models. To these ends, the WEAP model was found to fit best the specified selection criteria. Due to its ability to model hydropower generation and to exchange information with the LEAP tool which is also used in this study, WEAP was preferred to other assessed hydrological models such as the Soil and Water Assessment Tool (SWAT) and the Variable Infiltration Capacity (VIC).

WEAP was developed by the SEI and it combines both the hydrological modelling and water allocation capabilities which makes the model one of the widely used water modelling tools worldwide (Sieber and Purkey 2011). The model provides four modelling possibilities namely (1) the rainfall runoff method, (2) the irrigation demand only versions of the Food and Agriculture Organization (FAO) crop requirements approach, (3) the soil moisture method, and the (4) the MABIA method (Sieber and Purkey 2011, 24). Of these four possibilities, the soil moisture method was selected because it was found to comply most with available information. The description provided in this section was extracted from the user guide of the WEAP model according to Sieber and Purkey (2011).

As described in the user manual, the WEAP soil moisture method is a two−layer (see Figure 4.2) hydrologic accounting scheme that allows the computation of evapotranspiration, surface and subsurface runoff within a catchment.

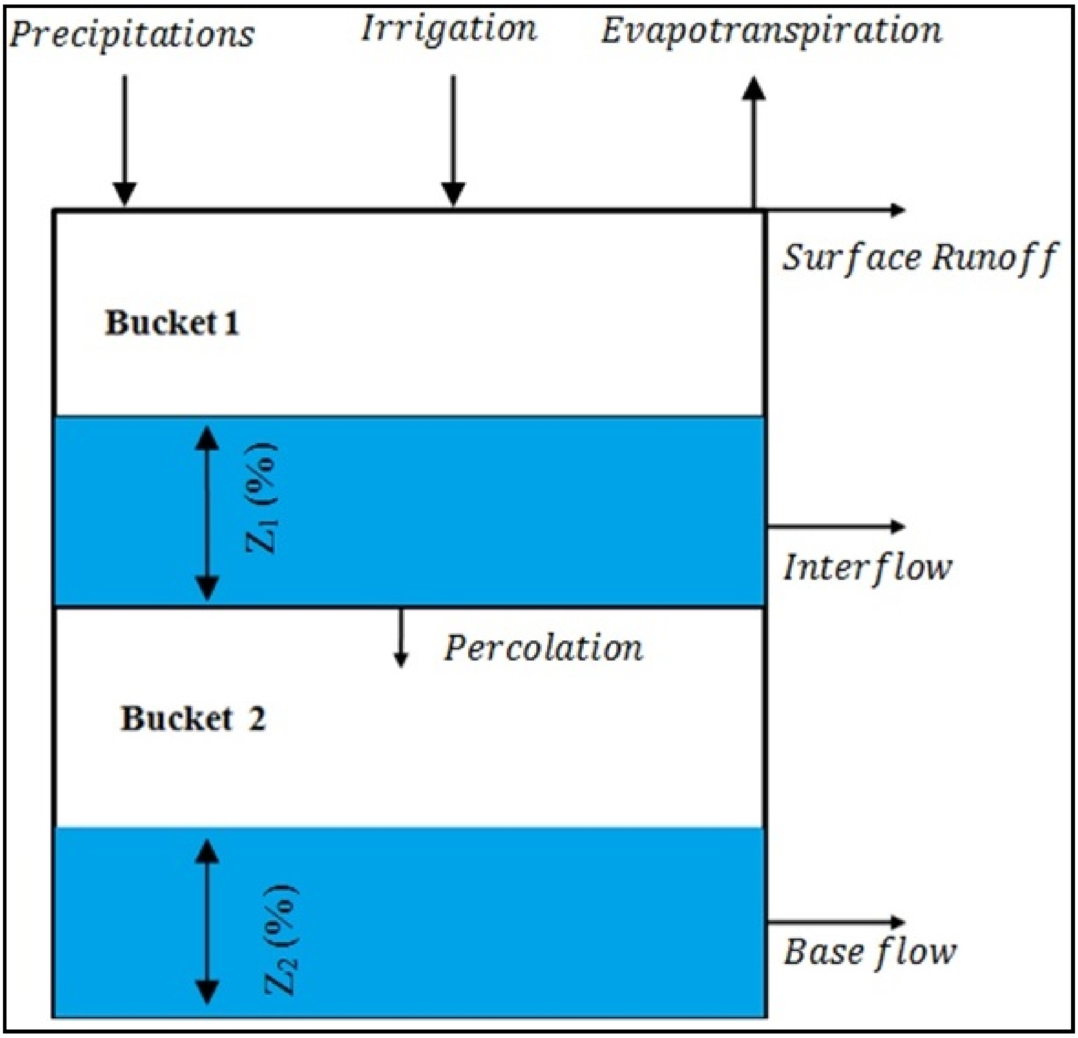


Figure 4.2: Conceptual diagram of the soil moisture model (Sieber and Purkey 2011, 53)

Evapotranspiration, surface runoff, shallow inter flow and changes in the soil moisture are simulated in the upper layer whereas base flow to the river and changes in soil moisture are simulated in the lower soil layer. To compute water balance within a catchment, each watershed unit is divided into N fractional areas representing different land uses and soil types, and for each fractional area j of N in the first bucket, the hydrologic processes are determined according to Equation 4.1.

$$Rd_j \frac{dZ_{1,j}}{dt} = P_e(t) - PET(t)k_{c,j}(t)\frac{5Z_{1,j} - 2Z_{1,j}^2}{3} - P_e(t)Z_{1,j}^{RRF_j} - f_j k_{s,j} Z_{1,j}^2 - (1 - f_j)k_{s,j} Z_{1,j}^2 \quad (4.1)$$

Where:

Rd_j effective storage of the root zone for land cover j (mm),

$Z_{1,j}$ relative storage of the root zone for land cover j (%),

P_e effective precipitation including snowmelt (mm),
RRF_j runoff resistance factor of the land cover j (> 0),
PET Penman-Monteith reference crop potential evapotranspiration ($mm.day^{-1}$),
f_j partitioning coefficient (%),
$k_{s,j}$ hydraulic conductivity for land cover j ($mm/time$),
$k_{c,j}$ crop coefficient for land cover j ($mm/time$),

In Equation 4.1, the term $PET(t)k_{c,j}(t)\frac{5Z_{1,j}-2Z_{1,j}^2}{3}$ represents the actual evapotranspiration, $P_e(t)Z_{1,j}^{RRF_j}$ is the surface runoff component, $f_j k_{s,j} Z_{1,j}^2$ is the interflow while $(1-f_j)k_{s,j}Z_{1,j}^2$ represents the deep percolation. The Penman-Monteith reference crop potential evapotranspiration is determined according to Equation 4.2 (Allen et al. 1998, 24).

$$^{1}ET_o = \frac{0.408\Delta(R_n - G) + \gamma\frac{900}{T-273}u_2(e_s - e_a)}{\Delta + \gamma(1 + 0.34u_2)} \tag{4.2}$$

Where:

ET_o reference evapotranspiration ($mm.day^{-1}$)
R_n net radiation at the crop surface ($MJ.m^{-2}.day^{-1}$),
G soil heat flux density ($MJ.m^{-2}.day^{-1}$),
T mean daily air temperature at $2m$ height (℃),
u_2 wind speed at $2m$ height (ms^{-1}),
e_s saturation vapour pressure (kPa),
e_a actual vapour pressure (kPa),
$e_s - e_a$ saturation vapour pressure deficit (kPa),
Δ slope vapour pressure curve (kPa ℃$^{-1}$),
γ psychrometric constant (kPa ℃$^{-1}$)

The total surface and interflow runoff (RT) at a time t is given by Equation 4.3, and the base flow from the second layer is calculated according to Equation 4.4.

$$RT(t) = \sum_{j=1}^{N} A_j \left(P_e(t)Z_{1,j}^{RRF_j} + f_j k_{s,j} Z_{1,j}^2\right) \tag{4.3}$$

$$S_{max}\frac{dZ_2}{dt} = \left(\sum_{j=1}^{N}(1 - f_j)k_{s,j}Z_{1,j}^2\right) - k_{s2}Z_2^2 \tag{4.4}$$

where A$_j$ is the surface area of land cover j, S$_{max}$ is the deep percolation from the upper

1. ETo in Equation 4.2 is equivalent to PET in Equation 4.1

storage given in Equation 4.1. Z_2 is the relative storage given as a fraction of the total effective storage of the deep layer, and k_{s2} is the saturated hydraulic conductivity of the deep layer. Both Z_2 and k_{s2} are given as a single value for the whole catchment.

4.2 Hydrological model set−up

In order to use model outputs in any activity ranging from regulatory purposes to research, the model should be scientifically sound, robust and defensible (US EPA 2002). Consequently, hydrologic models have to go through calibration and validation (or verification) processes. Model calibration consists of adjusting the model's input parameters until the model produces acceptable outputs as compared to natural (or observed) data for the same conditions (Moriasi et al. 2007). The process consists of comparing simulated outputs with historical observations, and then modifying the model input parameters in order to improve its accuracy (Sieber and Purkey 2011). Under model validation on the other hand, the calibrated model is run using input parameters determined during the calibration process, and statistical tests on its outputs allow deciding if the model can be used for further investigations or not (Refsgaard 1997; Doherty 2004).

This section describes the model's input data, their source and assumption made for data that were not possible to obtain from any sources.

4.2.1 Stream flow discharge data and calibration period

As the model parameters are adjusted based on observed (or measured) stream flow discharge data, a quality control of data from different gauge stations was conducted in order to identify the station with the highest data quality possible. Daily flow discharge data from 18 river gauging stations were obtained from the LWH. The selection criteria included the fact that the surface area that drains into the gauging station covers as many hydropower facilities as possible, recorded stream flow data present less missing values, and the unmatched time periods between stream water discharge and rainfall records should be minimal. One of the challenges for the recorded precipitations and flow discharges was that for many cases high values of stream discharges were recorded whereas no rain was recorded for that period. There are no other reasons for these discrepancies than measurement errors as the catchment under investigation is relatively small so that the time rain takes to reach the stream could justify these differences. Out of the 18 assessed stream gauge stations, Ruliba stream gauge station (see Figure 4.3) was found to meet better the predefined criteria.

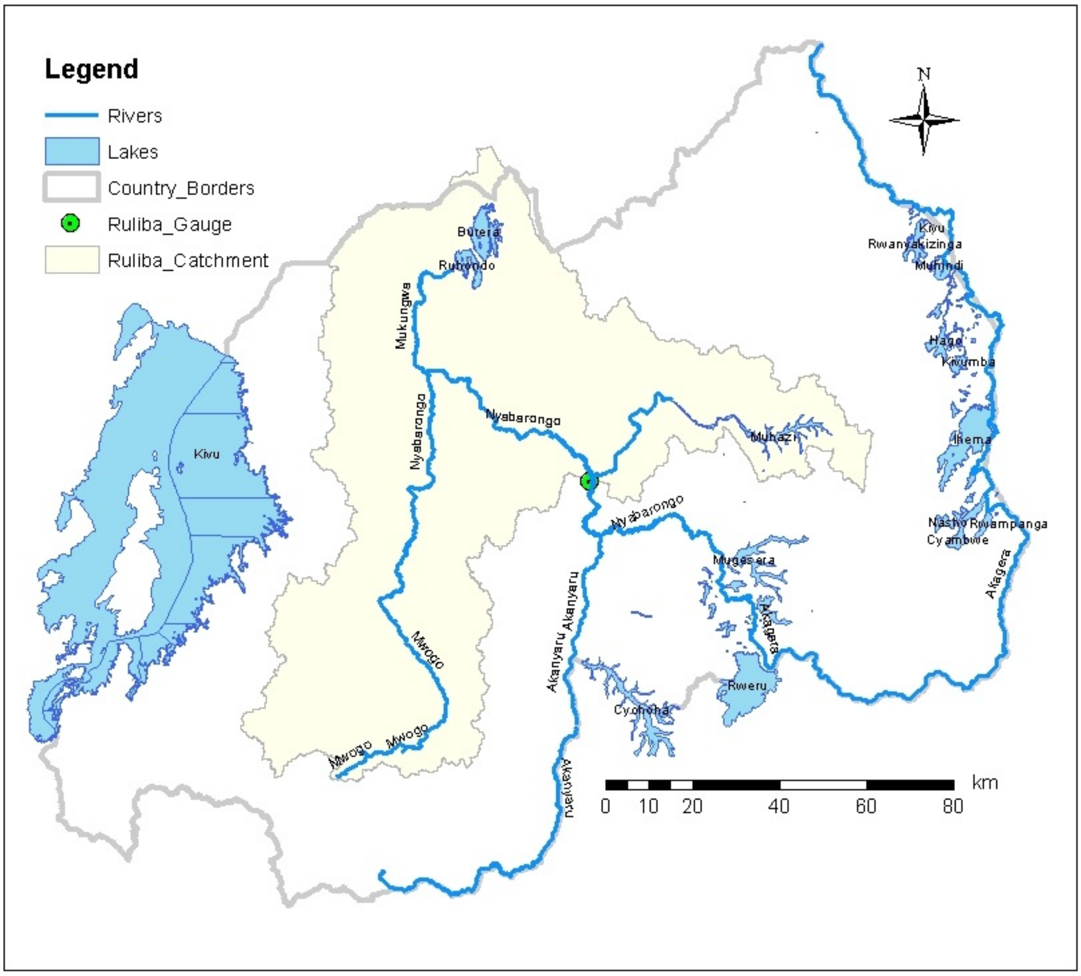


Figure 4.3: Study area location and the catchment outlet (Author based on the ASTER GDEM and shape file maps from the LWH)

The analysis of daily flow discharge records at the Ruliba station revealed that the 1974−1989 period presents less errors in records, consequently this period was chosen for the calibration and validation of the model. Monthly flow discharge data used for the calibration and validation processes together with the rainfall for the same period are presented in Figure 4.4.

4.2.2 Fractional soil and land−cover areas

The boundaries and surface areas for the whole catchment and sub-catchments were derived on the basis of drainage modelling by means of DEM. The DEM used in this study is the ASTER GDEM, developed jointly by the METI and the NASA. ASTER GDEM offers Digital Elevation Models (DEMs) of different grid cell sizes; this study applied a 30x30 metres grid which was downloaded free of charge from the website of the Japanese

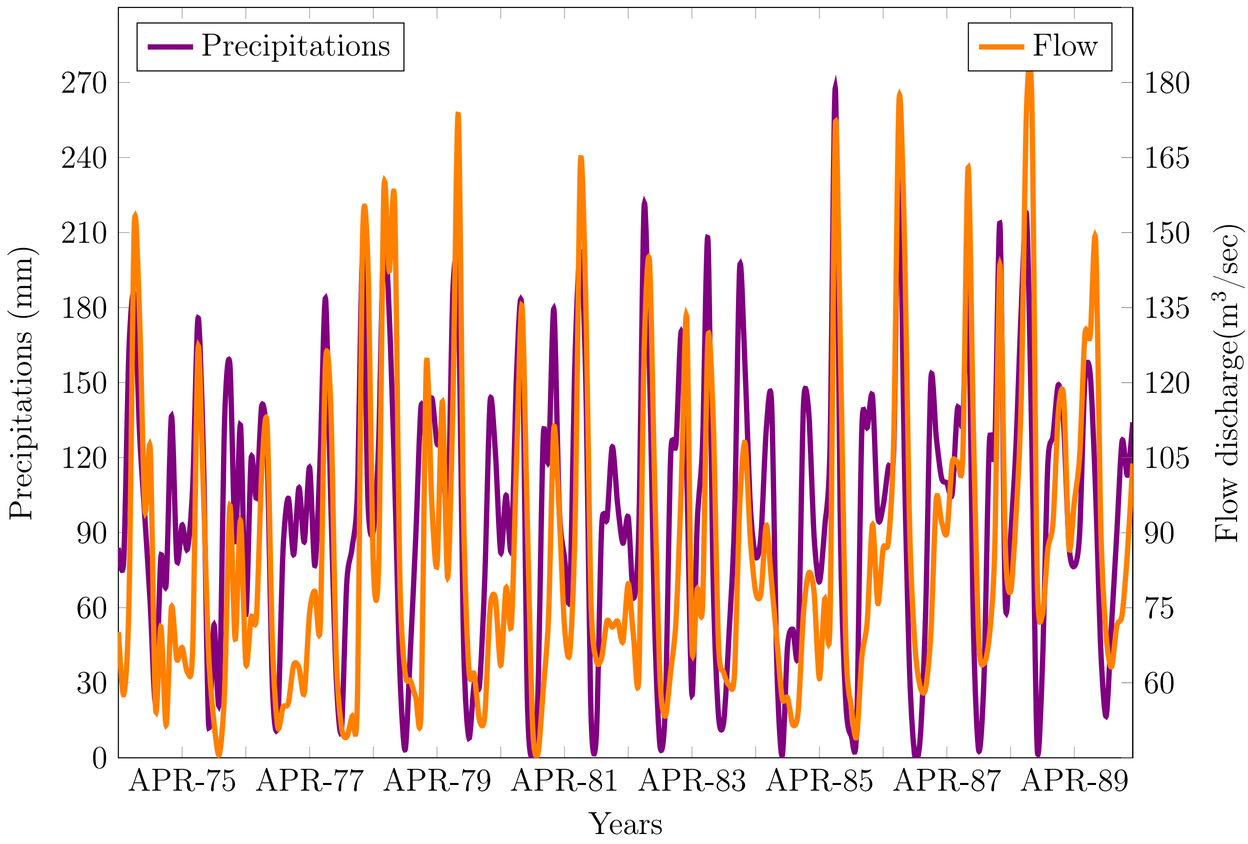


Figure 4.4: Recorded precipitations and stream flows at the Ruliba stream gauge station for the calibration and validation periods (Author based on data from LWH)

Earth Resources Satellite Data Analysis Center[2].

Pour points for different sub−catchments were placed at the location of each hydropower dam for dam−based hydropower plants, and at the intake point for runoff river based hydropower plants. As mentioned in Section 4.2.1 that river flow discharge at the Ruliba station were used for model calibration and validation, the outlet of the entire catchment was therefore placed at this location. Delineated catchment and sub−catchments together with the river network, the hydroelectric power plant locations, the catchment outlet and the lakes located in the study area can be visualised in Figure 4.5.

As it can be noticed from Equation 4.1, the WEAP model requires the area of each fraction j of N in order to compute water balance within a given catchment. Consequently, the geometric intersection between different soil groups and land cover types for each sub−catchment were computed using GIS Intersect Analysis Tool. The soil layer was obtained from the World Soil Information (Batjes 2007) while the land cover layer was received from the Rwanda Natural Resources Authority (RNRA). At first, the intersec-

2. gdem.ersdac.jspacesystems.or.jp

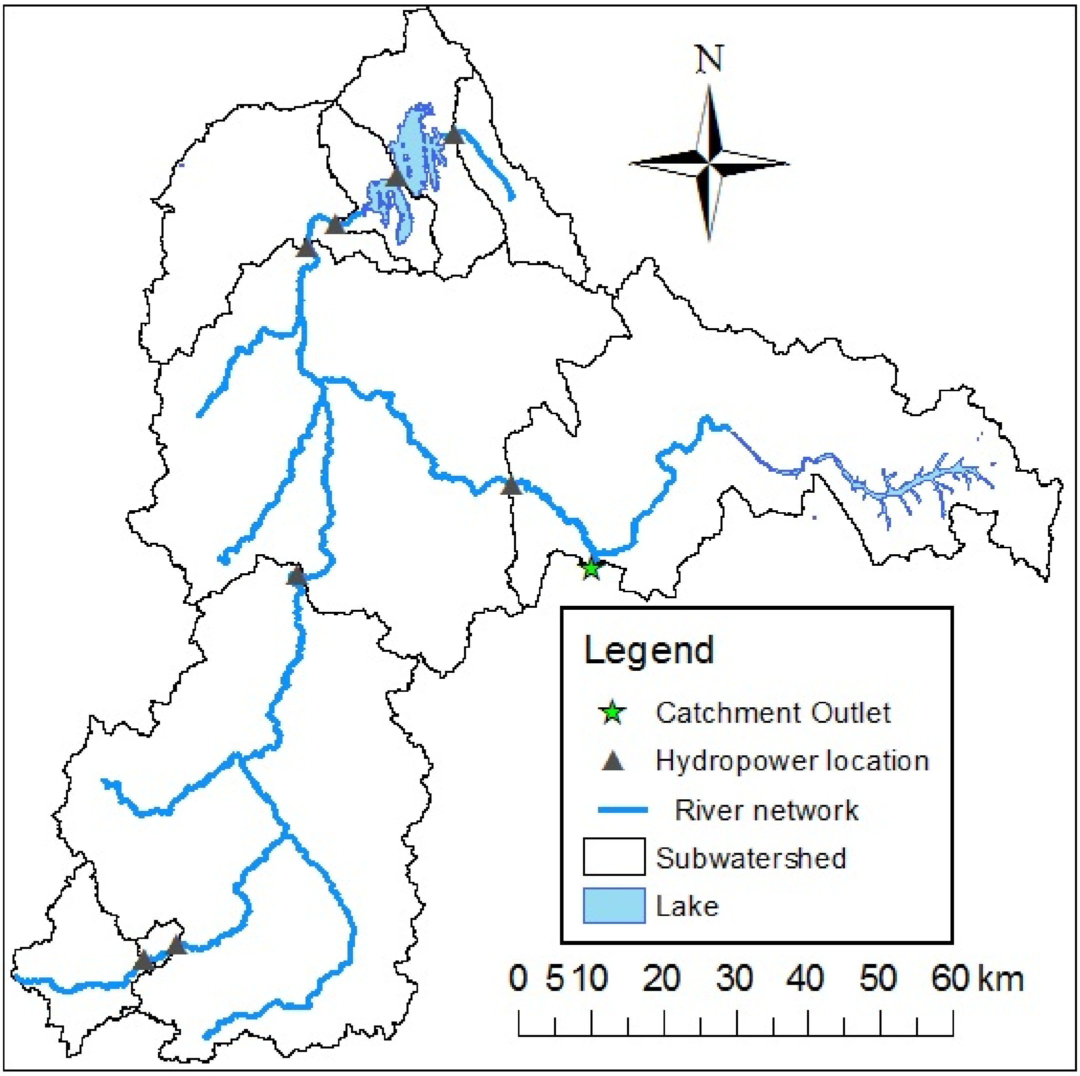


Figure 4.5: Studied catchment (Author based on the ASTER GDEM)

tion between the sub−catchment and the soil layers was computed, and then that between the sub−watershed−soil and land cover type layers was performed. After the intersection processes, the attribute values from the three input feature classes were copied to the output feature class where fractional areas of different land cover types were extracted. A sample of calculated subwatershed−soil−land cover areas for Rugezi and Mukungwa sub−catchments is shown in Table 4.1.

4.2.3 Crop coefficient and runoff resistance factor

During a plant's evapotranspiration process, water is taken up by the roots, transported through the plant's stem, vaporised in plant tissues (mainly in leaves) and then the vapour is rejected to the atmosphere (Allen et al. 1998). The amount of rejected water depends on available water in the root zone and the land cover type according to the term

Table 4.1: Fractional soil−land cover areas for Rugezi and Mukungwa subatchments

ID	Watershed name	ID-Soil	Soil code	ID-cover	Land cover	Area (km^2)	% of soil code
1	Rugezi	1	RW15	1	Agriculture	105.10	89.56
				2	Grass	1.49	1.27
				3	Shrub	10.72	9.13
				4	Water	0.05	0.04
		2	RW16	1	Agriculture	55.71	78.01
				2	Grass	7.27	10.17
				3	Shrub	8.44	11.82
2	Mukungwa	1	RW12	1	Trees	0.30	9.29
				2	Shrub	2.95	90.71
		2	RW13	1	Agriculture	0.94	1.45
				2	Trees	5.56	8.63
				3	Shrub	57.84	89.71
				4	Built-up area	0.13	0.21
		3	RW15	1	Agriculture	13.03	31.06
				2	Shrub	10.24	24.4
				3	Built-up area	2.02	4.8
				4	Water	16.67	39.74
		4	RW17	1	Agriculture	2.91	10.05
				2	Shrub	17.24	59.54
				3	Built-up area	3.52	12.18
				4	Water	5.28	18.23
		5	RWns1	1	Agriculture	1.33	2.98
				2	Shrub	5.99	13.47
				3	Built-up area	8.75	19.65
				4	Water	28.44	63.9

$PET(t)k_{c,j}(t)\frac{5Z_{1,j}-2Z_{1,j}^2}{3}$ of Equation 4.1. To characterize the effects of land cover type on evapotranspiration, a factor called "Crop Coefficient: k$_c$", is attributed to each land cover type. The land cover types in the studied catchment are crop land, grassland, shrubs, forest, water bodies and built up area according to the land cover layer obtained from the RNRA. The main crops found in the study area are rice, vegetables, sorghum, banana, potatoes, beans, cassava, coffee, tea and sugar cane. k$_c$ values were extracted from the FAO's Irrigation and Drainage Paper No. 56 (Allen et al. 1998) except for the built−up area where k$_c$ was taken from Ingol (2011). However, as it was not possible to obtain spatial crop distribution data for the studied area, k$_c$ for the agriculture land cover was determined by simply averaging the crop coefficients of the main crops cultivated in the catchment. k$_c$ values for different land cover types in the studied catchment are presented in Table 4.2.

However, as k$_c$ values have been determined under standard conditions which does not always reflect local conditions, Allen et al. (1998) suggested that k$_c$ values need to be adjusted by multiplying them by the water stress coefficient, k$_s$. Therefore, a k$_s$ value of 0.833 determined by Munyaneza et al. (2012) was used to adjust k$_c$ values as shown in

Table 4.2. A further study to consider the spatial distribution of crops and water stress coefficients for different land cover types in the catchment would improve the accuracy of the outputs of the current modelling.

Table 4.2: k_c and RRF values (Allen et al. 1998; Munyaneza et al. 2012; Ndekezi 2010)

ID	Land cover type	Land cover code in WEAP	k_c	$k_{c,Adj}$	LAI
1	Agriculture	AGRR	1.16	0.96	4.00
2	Shrub	SHRB	1.15	0.95	2.00
3	Forest	FRST	1.20	1.00	5.00
4	Water Bodies	WATB	1.00	1.00	0.10
5	Grassland	GRAS	0.95	0.79	2.50
6	Urban area	URBN	-	0.77	8.00

Similar to k_c which influences evapotranspiration, a parameter called Runoff Resistance Factor (RRF) controls the surface runoff as can be seen in the third term of Equation 4.1. As described by Sieber and Purkey (2011), the RRF is related to factors such as Leaf Area Index (LAI) and land slope. In this study, only LAI was considered and the slope effect was accounted for during the calibration. Customized LAI for the study area were extracted from the land cover database provided by RNRA and the values are also shown in Table 4.2.

4.2.4 Deep soil layer properties

The properties of the deep soil layer that have to be provided into the model are the saturated hydraulic conductivity k_{s2}, the relative storage Z_2 and the Deep Water Capacity (DWC). k_{s2} controls the contribution of the baseflow to the total river flow discharge while Z_2 represents the percentage of DWC available at time t. As indicated by the last term of Equation 4.1, the baseflow is proportional to k_{s2} and Z_2^2 ($B_f = k_{s2} Z_2^2$), therefore baseflow information was used to estimate the initial values of k_{s2} and Z_2^2. To achieve this, base and direct surface flow components of the total stream discharge were separated. There is a variety of baseflow separation methods provided in literature; this study used the automated Master Recession Curve (MRC) method to separate the two components of the daily stream flow time series. As described by Arnold et al. (1995) and Arnold and Allen (1999), the automated MRC method is one of other filter programs that use daily stream flow discharges as input and split them into base flow and direct surface runoff components.

To determine the value of k_{s2}, it was assumed that the highest base flow value during the time period from 1974 through 1989 corresponds to the full saturation; meaning that

$B_f = k_{s2}$ as Z_2=100%. For this period, the highest base flow was found to be 2.2 mm per day equivalent to 66 mm per month. Having k_{s2} and baseflow values, it was possible to estimate Z_2 at any time t between 1974 and 1989.

4.2.5 Root zone layer properties

The required root zone input data are the saturated hydraulic conductivity k_{s1}, the relative storage Z_1 and the Root Zone Water Capacity (RZWC). Before the calibration process was started, k_{s1} was estimated to be 147 mm per month as suggested by Ndekezi (2010) and Z_1 was assumed to be equal to Z_2 (i.e. 66 mm per month). Information on distribution and properties of the soils that cover the study area was extracted from the Soil and Terrain (SOTER) database of the International Soil Reference and Information Centre (ISRIC)−World Soil Information. SOTER database comprises of two types of data: geographic and attribute data. The geographic data type, managed in GIS, hold information on location, extent and geography of each SOTER soil unit whereas the attribute data type describe the characteristics of the spatial data and are managed in a relational database management system (Batjes 2007). Both the geographic and attribute data were downloaded free of charge from ISRIC's website[3]; and GIS was used to extract the information for the area under investigation. The attribute data provide different information on the soil properties including the Total Available Water Capacity (TAWC) for every 20 cm layer from the surface down to 100 cm. To estimate the RZWC, a net layer depth of 100 cm was assumed and the TAWC for each soil type was obtained by aggregating all its TAWCs down to the bottom of the layer. Finally, TAWC was estimated by multiplying the depth of the layer (mm) by the available water capacity (in mm/mm) according to Equation 4.5. In this equation A_i is the area represented by the soil type i and $TAWC_i$ is the available water capacity in the water soil type i.

$$RZWC = \sum_{i=1}^{n} A_i \cdot (TAWC)_i \tag{4.5}$$

4.2.6 Climate data

Hydrologic systems are driven by climate data in the process of exchanging moisture and energy between land and atmosphere. The minimum climate data requirements for the soil moisture method of the WEAP model are precipitations (pr), temperature (tas), relative humidity (hurs) and wind speed (ws). In this study, two climate data sets: one

3. http://www.isric.org/data/data-download

from local and another from international sources were analysed in order to select the data set that presents the highest quality possible.

The local data set was obtained from RMA and it consists of daily data with different starting and ending periods. Local climate measuring stations that were operational during the calibration and validation periods in the study area are shown in Figure 4.6. The analysis of the local data revealed many missing data and especially abnormal values that probably may resulted from applied measurement methods or instruments. Although there was a considerable number of rain gauges, only threes stations (see Figure 4.6) are able to measure temperature, relative humidity and wind speed in addition to rainfall.

The second data set is the WFD which was created by combining the 40−year reanalysis data (ERA−40) of the European Centre for Medium−Range Weather Forecasts (ECMWF) and the Climate Research Unit (CRU) data set (Weedon et al. 2011). The data in NetCDF data format at 0.5x0.5 degree spatial resolution (see. Figure 4.6) were downloaded free of charge from the website[4] of the International Institute for Applied Systems Analysis (IIASA). The temporal resolution is 3−hourly time steps for rainfall and 6− hourly time steps for temperature and wind data. Obtained WFD data set covers the years from 1961 to 2010 inclusive. CDO tool (Schulzweida 2015) was used to extract and average data that cover the study area while R−programming language was used to convert NetCDF data format into text file data that can be read by the WEAP model. After analysing the two datasets, WFD data was selected due its consistence in measurements with no missing values. Another important reason of choosing WDF data is that climate projections used to assess climate change effects in this study were downscaled using WFD data (Hempel et al. 2013). However, the relative humidity used in this study was from RMA as there is no provision of it in WFD.

To compute the areal values of the climate parameters, climate variables (i.e. pr, tas, hurs and ws) were extrapolated by using the Thiessen polygon. This method assumes that the climate value at any point in the catchment is the same as that at the nearest measuring station (Thiessen 1911). Therefore, a weight is assigned to each station based on the area that is closest to it. Thiessen polygons are constructed by adding measuring stations on the map of the area under investigation and then joining all the stations within the studied area and those in its closest neighborhoods so as to form a network of triangles as illustrated in Figure 4.7.

4. ftp://rfdata:forceDATA@ftp.iiasa.ac.at

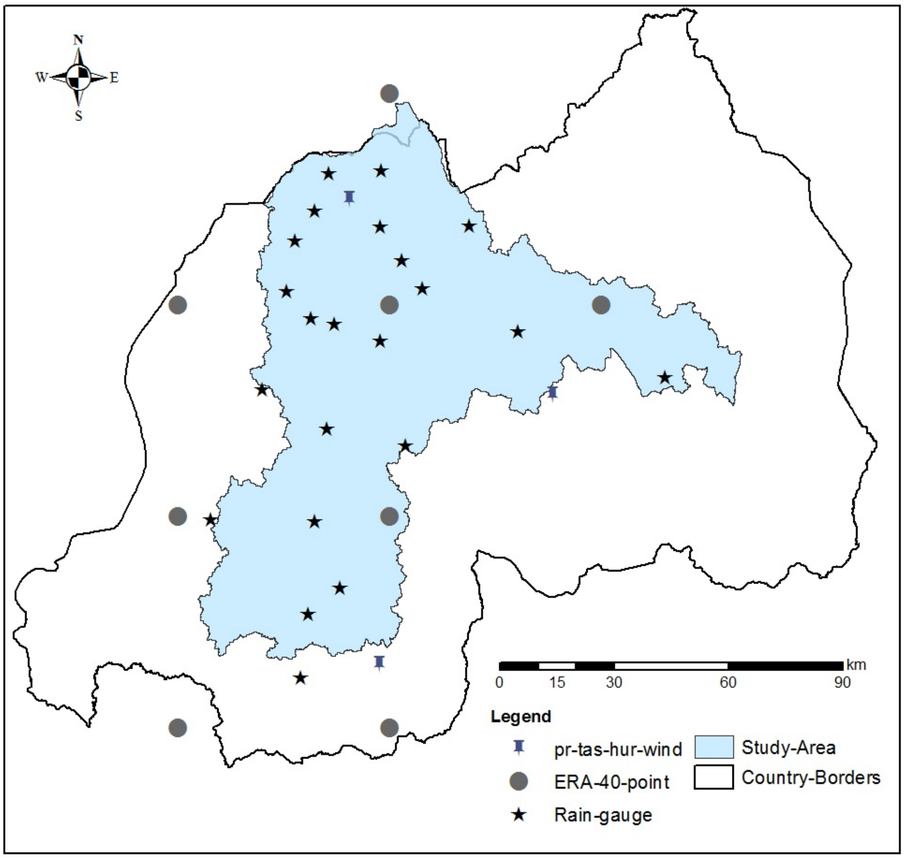


Figure 4.6: Climate measuring stations

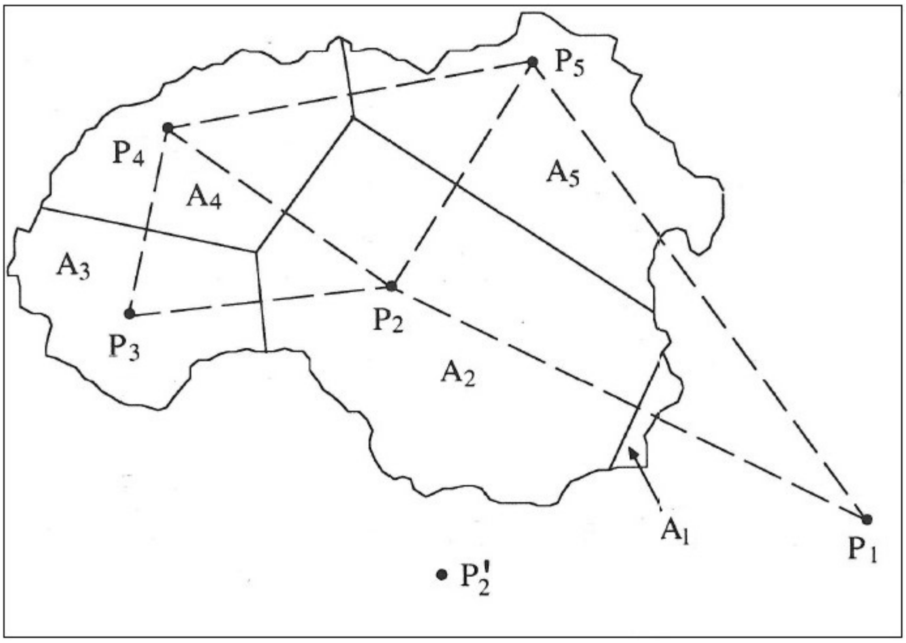


Figure 4.7: Thiessen polygon proccessing (Chow et al. 1988)

Perpendicular bisectors to the triangle sides are then drawn; and these bisectors delineate the closest area to the measuring station. In this study, all the described processes were performed by using the automated Thiessen method incorporated in GIS software. If there are n climate measuring stations, and the area within the catchment is assigned to each area is A_i, and q_i the rainfall recorded at ith station, then the average climate values (pr, tas, hur and wind) for the overall catchment are calculated according to Equation 4.6.

$$\overline{q} = \frac{1}{A}\sum_{i=1}^{n} A_i q_i \tag{4.6}$$

4.2.7 Latitude and preferred flow direction

During evapotranspiration, energy must be supplied in order to change the state of water from liquid to vapour, and the main source of this energy is solar radiation which depends on the location of the transpiring surface and the time of the day and year (Allen et al. 1998). Solar radiation data can directly be entered into the WEAP model; and if not, available sunshine hours or cloud fraction are supplied. If none of these data is available as it is the case for this study, then latitude is entered and solar radiation together with other parameters such as saturation and actual vapour pressures required to compute Equation 4.1 are internally calculated in WEAP thanks to built−in functions (Sieber and Purkey 2011). Therefore, latitude for the centre of each sub−catchment was provided to the model. The last parameter to be entered into the model is the Preferred Flow Direction (PFD). As highlighted in Sieber and Purkey (2011), PFD is used to partition the flow out from the upper layer between interflow and deep percolation (see. Figure 4.2). PFD varies between 0 and 1 corresponding respectively to 100% vertical and horizontal flows. At the beginning of the calibration process PFD was set at 50% and later adjusted as the process was going on.

4.2.8 Calibration and validation processes

As mentioned in Section 4.2, model calibration is an iterative process that deals with adjusting the model's input parameters until the model simulates required outputs. Thanks to a linkage to a Parameter EStimation Tool (PEST) provided in the WEAP model, it was possible to automate the calibration process. PEST requires three types of information in the calibration process namely (1) parameters to be calibrated together with their allowable lower and upper bounds, (2) observations to calibrate to and (3) scenario to be calibrated (Sieber and Purkey 2011). After specifying this information, PEST takes control of the model and runs as many times as is necessary until optimal set of parameters is achieved (Doherty 2004). Calibrated parameters in this study are k_{s1}, RZWC, DWC,

Z_1, Z_2, RRF, and PFD.

After estimating required parameters, a validation process follows to prove that a given site specific model can produce acceptable outputs. According to Refsgaard (1997) and Doherty (2004), model validation consists of running a model using input parameters determined during the calibration process in order to guide decision on the acceptance or rejection of model results. To do this, the data set was split into two periods: 1974−1981 and 1982−1989 for the calibration and validation processed respectively.

4.3 Analysis of the model performance

To check the predictive capability of the hydrological model, a performance test is normally conducted and a decision is made based on the performance ratings of the model. There are different statistical measurements for this purpose, and in this study four of the widely used ones have been considered. The chosen indicators are Pearson's correlation coefficient (r), the Ration between RMSE and STDEV (RSR), Nash-Sutcliffe Efficiency (NSE) and the Percentage Bias (PBIAS).

4.3.1 Pearson's correlation coefficient

Pearson's correlation coefficient (r) is a measure of the relationship between two continuous variables and it can take values from −1 to +1. r is calculated according to Equation 4.7 where $Q_{i,Obs}$ is the ith observed stream flow discharge, $Q_{i,Sim}$ is the ith simulated stream flow discharge, n is the total number of observations, $\overline{Q}_{Obs}$ is the mean of observed stream flow discharge data and $\overline{Q}_{Sim}$ is the mean of simulated stream flow discharge data.

$$r = \frac{\sum_{i=1}^{n}(Q_{i,Obs} - \overline{Q}_{Obs})(Q_{i,Sim} - \overline{Q}_{Sim})}{\sqrt{\sum_{i=1}^{n}(Q_{i,Obs} - \overline{Q}_{Obs})^2(Q_{i,Sim} - \overline{Q}_{Sim})^2}} \tag{4.7}$$

When the correlation is +1, this means that the two variables increase or decrease proportionally. A correlation of −1 suggests that one of the variables increases while the other decreases but in the same level. In both cases the correlation is called perfect and all the points are in a perfect straight line. A correlation of 0 is obtained when there is no relationship between the variables.

4.3.2 Nash−Sutcliffe Efficiency

The NSE proposed by Nash and Sutcliffe (1970) is a normalized measure that compares the mean square error (noise) generated by model simulation to the variance of the observed data (information). It indicates how well the plot of observed versus simulated data fits the 1:1 line (Moriasi et al. 2007). NSE is calculated according to Equation 4.8 and it can take any values between $-\infty$ and $+1$.

$$NSE = 1 - \left[\frac{\sum_{i=1}^{n} (Q_{i,Obs} - Q_{i,Sim})^2}{\sum_{i=1}^{n} (Q_{i,Obs} - \overline{Q}_{Obs})^2} \right] \tag{4.8}$$

There is a perfect match between simulated and observed data when NSE$=1$. When NSE$=0$, this indicates that the model predictions are as accurate as the mean of the observed data whereas NSE<0 suggests that the mean observed value is a better predictor than the simulated value. NSE ratings are presented in Table 4.3

4.3.3 Root mean square error−observations standard deviation ratio

The root mean square error−observations standard deviation ratio (RSR) was introduced by Moriasi et al. (2007) to include recommendations by Singh et al. (2004) about what should be considered a low Root Mean Square Error (RMSE). As correlation and correlation−based statistics are sensitive to outliers, Legates and McCabe (1999) suggested modifications to these statistics by considering the coefficient of efficiency and the index of agreement in order to improve the interpretation of simulation results. Consequently, RSR includes these recommendations and standardizes RMSE using the observations standard deviation (Moriasi et al. 2007). RSR is computed according to Equation 4.9, and it can vary from the optimal value of zero to any large positive values.

$$RSR = \frac{RMSE}{STDEV_{i,Obs}} = \frac{\sqrt{\sum_{i=1}^{n} (Q_{i,Obs} - Q_{i,Sim})^2}}{\sqrt{\sum_{i=1}^{n} (Q_{i,Obs} - \overline{Q}_{Obs})^2}} \tag{4.9}$$

A perfect simulation is achieved when RSR is equal to zero. RSR ratings for monthly stream flow discharge are presented in Table 4.3.

4.3.4 Percentage bias

The percentage bias (PBIAS) represents the measure of the deviation of simulated values from the observations. PBIAS is calculated according to Equation 4.10 and it can take any positive or negative values. A positive value suggests that the model underestimated the variables; a negative value corresponds to an overestimation of the variable and accurate simulations are obtained when PBIAS is equal to zero (Gupta et al. 1999). PBIAS ratings for monthly stream flow discharge are presented in Table 4.3.

$$PBIAS = 100 \left[\frac{\sum_{i=1}^{n} (Q_{i,Obs} - Q_{i,Sim})}{\sum_{i=1}^{n} (Q_{i,Obs})} \right] \tag{4.10}$$

Table 4.3: General performance ratings for recommended statistics for a monthly time step (Moriasi et al. 2007, 891)

Performance	RSR	NSE	PBIAS (%)
Very good	$0.00 \leq$ RSR ≤ 0.50	$0.75 <$ NSE ≤ 1.00	PBIAS $\pm$ 10
Good	$0.50 <$ RSR ≤ 0.60	$0.65 <$ NSE ≤ 0.75	$\pm$ 10 $\leq$ PBIAS $<$ 15
Satisfactory	$0.60 <$ RSR ≤ 0.70	$0.50 <$ NSE ≤ 0.65	$\pm$ 15 $\leq$ PBIAS $<$ 25
Unsatisfactory	RSR > 0.70	NSE ≤ 0.50	PBIAS $\geq \pm$ 25.00

4.4 Past and future climate

This section discusses data used to assess the observed as well as the projected climate of the area under investigation. Applied methods to extract and analyse the data together with the methodology used to quantify possible effects of expected climate on hydropower generation are also described in this section.

4.4.1 Observed climate

The past climate of Rwanda and that of the study area was assessed using a WFD dataset for a 50−year period from 1961 through 2010. Considered climate indicators include the Rainfall Rate (RR), Precipitation Concentration Degree (PCD), monthly and annual total precipitations and annual mean temperature. Total rainfall quantities were computed by aggregating daily rainfall records while mean temperatures were determined by averaging daily temperatures. To compute all these quantities, Thiessen polygon method was used as detailed in Section 4.2.6. As explained in Gutiérrez et al. (2012, 14), RR measures the percentage of the days that are classified as wet. A wet day is a day on which the intensity of recorded precipitations is greater than the threshold value. There are two threshold values of wet days in literature: 0.1 and 1 mm. In this study, 1 mm threshold was applied as it overcomes measurement errors that occur when measuring very small quantities of rainfall (Frei et al. 2003; Frich et al. 2002; Bärring et al. 2006). RR was computed according to Equation 4.11 where n_{wet} represents the total number of wet days while n is the total number of days in considered period.

$$RR = 100 \cdot \frac{n_{wet}}{n} \tag{4.11}$$

$$PCD_{ij} = \frac{\sqrt{R_{xi}^2 - R_{yi}^2}}{\sum_{i=1}^{12} R_i} \tag{4.12}$$

$$R_{xi} = \sum_{i=1}^{12} R_{ij} \cdot cos\theta \tag{4.13}$$

$$R_{yi} = \sum_{i=1}^{12} R_{ij} \cdot sin\theta \tag{4.14}$$

A 100% value of RR indicates that precipitation intensity greater than the threshold value occurred every day while 0% value means that no precipitations greater than the thresholds occurred over the considered period.

PCD on the other hand measures the distribution of precipitations over a given period of time. PCD is computed according to Equation 4.12 (Li et al. 2011, 1683) where PCD_{ij} is the period for which PCD is to be calculated, i represents the year and j the period (day, month, season, etc.). R_{ij} is the total precipitations in the j period of ith year, R_i represents the total precipitations in year i and θ is the azimuth of the jth period. PCD varies between 0 and 1: a PCD value of 1 means that all the precipitations concentrate in one period of the time whereas a PCD value of 0 indicates an evenly temporal distributed precipitations.

4.4.2 Selection of climate scenarios and models

Two climate scenarios, RCP4.5 and RCP8.5 were chosen for the analysis of the future climate of the area under investigation and its potential impacts on hydropower generation. As detailed in Table 3.3, RCP4.5 represents a socio−economic development pathway with relatively ambitious emission reductions which stabilizes shortly after 2100 to a radiative forcing of 4.5 Wm^{-2} (IPCC 2013; Wayne 2013). RCP8.5 on the other hand predicts a world with a minimal effort to reduce emissions which leads to a radiative forcing of 8.5

Wm^{-2} (i)n 2100 (IPCC 2013; Wayne 2013). These two pathways were selected because they allow exploring the worst (RCP8.5) and the intermediate (RCP4.5) cases of the future climate.

As for the selection of climate models, two publicly available data sets of the projected climate that covers the area of interest were acquired and compared. The first set of data is from the CORDEX which is an initiative of the WCRP. CORDEX dataset includes various climate parameters at different resolutions ranging from 0.11x0.11 degree grid resolution (about 12.5x12.5 km) to 0.44x0.44 degree grid resolution, or about 50x50 km (Christensen et al. 2014). Data covering the area under investigation were only at 50x50 km spatial resolution. The other set of data is from the PIK. This data set was developed under the first ISI−MIP, and includes different climate parameters, and all at 0.5x0.5 degree grid resolution, or about 55x55 km grid (Hempel et al. 2013). Although CORDEX data present a relatively higher resolution compared with ISI−MIP data, the analysis of both data sets revealed that CORDEX data present large discrepancies between simulated and observed climate data. Consequently, ISI−MIP data were selected for further investigations. The 5 GCMs/ESMs that compose the ISI−MIP data set are presented in Table 4.4.

Table 4.4: GCM models used to generate ISI−MIP data (Maloney et al. 2013)

ID	Name of modelling center (or group)	Climate model	Resolution (lat,lon)
1	Geophysical Fluid Dynamics Laboratory, USA	GFDL-ESM2M	2.50x2.00
2	Norwegian Climate Center, Norway	NorESM-1M	2.50x1.90
3	Institut Pierre Simon Laplace, France	IPSL-CM5A-LR	3.75x1.80
4	Met Office Hadley Centre, UK	HadGem2-ES	1.80x1.25
5	University of Tokyo and National Institute for Environmental Studies, Japan	MIROC-ESM-CHEM	2.80x2.80

ISI−MIP data was developed by interpolating, in space, the models in order to match the WFD grids (i.e. 0.5x0.5 degree), and then statistically removing biases using WFD data (Hempel et al. 2013). Daily ISI−MIP climate data required to run the WEAP model (i.e. pr, tas and ws) in NetCDF data format and covering the whole world were downloaded free of charge from the Earth System Grid Federation (ESGF) website[5]. CDO tool (Schulzweida 2014) was used to extract the data that cover exactly the area of interest. Again, CDO was used to aggregate and average the daily time step data into monthly and yearly quantities.

Out of the five GCMs/ESMs presented in Table 4.4, the best two of them in producing

5. esg.pik-potsdam.de/esgf-web-fe

historical stream discharges at the Ruliba stream gauging station were selected to be used for climate change impact analysis in this study. Two indicators namely RMSE and the Coefficient of Variation (CV) determined according to Equations 4.15 and 4.16 respectively were used to rank the GCMs/ESMs.

$$RMSE = \sqrt{\frac{\sum_{i=1}^{n}(Q_{i,Obs} - Q_{i,Sim})^2}{n}} \quad (4.15)$$

$$CV_i = 100\ \frac{\sigma_i}{\mu_i} \quad (4.16)$$

In Equation 4.16, CV_i is the coefficient of variation for GCM/ESM_i, μ_i and σ_i are respectively the mean and standard deviation for GCM/ESM_i for the calibration and validation period. As it can be noticed from Figure 4.8, HadGem2−ES and MIROC−ESM models produced monthly observed discharge flow better than any other models.

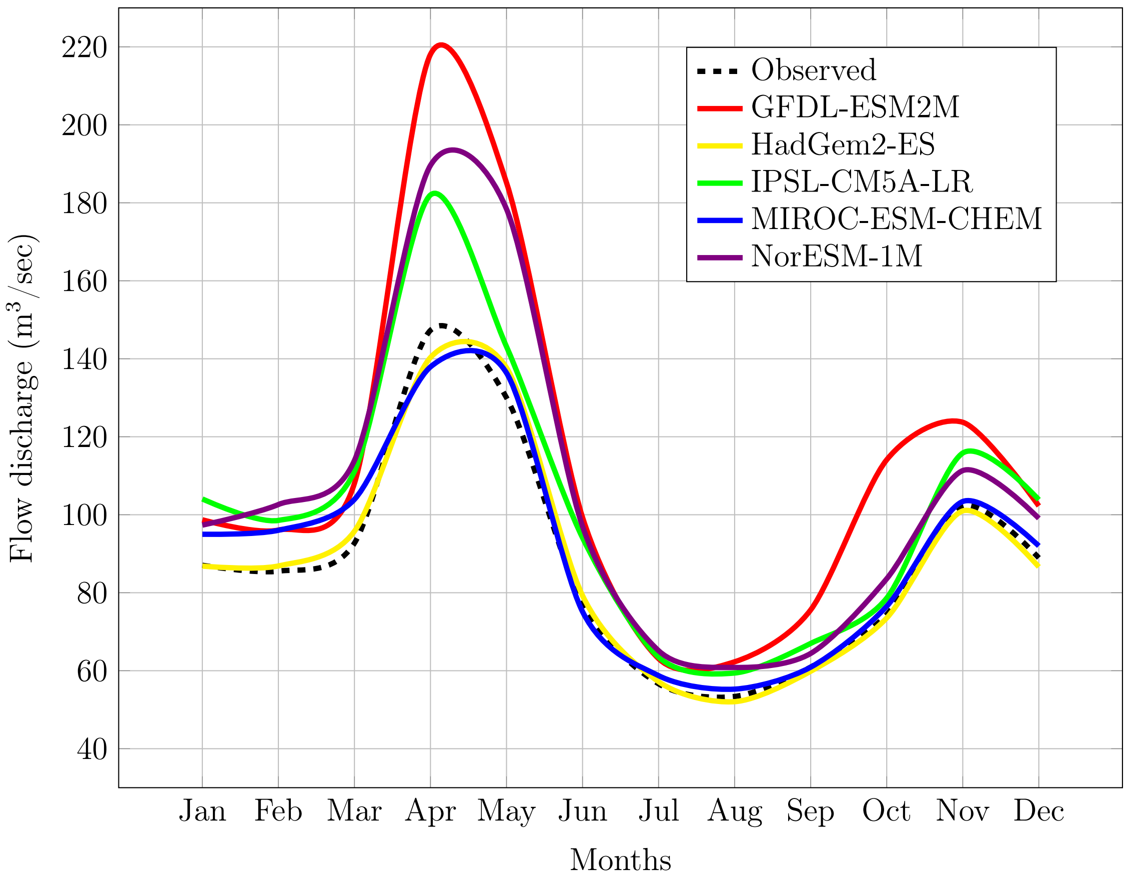


Figure 4.8: Average monthly flow discharge at Ruliba for 5 GCMs/ESMs

Consequently the first were selected for impact assessment. The future climate patterns in the study area were assessed by comparing projected climate parameters with the corresponding quantities recorded for the reference period (1961 to 1990). Monthly and annual anomalies were computed against the baseline period after removing outliers. A comparison was done for each 20−year period from 2020 to 2099.

4.5 Impacts of expected climate on stream flow discharge and hydropower

In this section, the methods and procedures used to estimate effects of climate change on river flow and hydropower generation are discussed. The data and assumptions used to build different climate scenarios are also discussed in the current section.

4.5.1 Base year and reference scenario

The year 2012 was chosen as base year because a national population census, which provided a considerable amount of information for both hydrological and electrical power modelling, was conducted in that year. Consequently, the calibrated and validated WEAP model in Section 4.2 was updated by incorporating further information such as water demand, hydropower generation plant facilities and updating the land cover areas.

The main water users in the studied area include mainly the residential sector and irrigation. For the residential sector, 8.15 litres per person per day was considered for 2012 which would increase to 20 litres per person per day by 2015 (MINIRENA 2011) and to 50 litres per person per day by 2050 (Brown and Matlock 2011). To estimate the number of people that extract water from each sub−catchment, a map of population distribution was first constructed based on the GIS map of sectors and the population per sector obtained from the National Institute of Statistics of Rwanda (NISR). Then the area that overlays the study area was extracted using GIS. Finally the population per each sub−catchment was computed using Tabulate Intersection functionality provided in GIS. The population data at sector level (in excel data format) and geographic map also at sector level (in shape file format) were obtained from the NISR. The computed number of people per each sub−catchment is presented in Table 4.6.

As for irrigation water demand, the soil moisture method of the WEAP model provides an option to set conditions of when to start and to stop irrigation. As described in Sieber and Purkey (2011), the modeler instructs the model to start irrigation when soil moisture falls below a predefined percent level called Lower Irrigation Threshold (LIT) and to cease it when soil moisture reaches a predefined percent level called Upper Irrigation Threshold (UIT). In this study, both the LIT and UIT were set at the Management

Allowable Deficit (MAD) point which is a soil moisture value below which agricultural yield starts to decline (Peters et al. 2013, 4). Recommended MAD values for selected crops are presented in Table 4.5.

Table 4.5: Suggested management allowable deficit points for various chosen crops (Peters et al. 2013, 4; USDA and MSU 1990, 4)

ID	Crop	MAD (%)	ID	Crop	MAD (%)
1	Beans	40	6	Peas	50
2	Carrots	50	7	Potatoes	30
3	Corn	50	8	Strawberries	50
4	Green Beans	50	9	Sweet Corn	40
5	Onions	40	10	Tree Fruit	50

In this study, MAD was set at 50% (the worst case of water demand according to the values in Table 4.5). To determine the irrigated area per each sub catchment, the 2012 land cover map obtained from LWH was used. Similar to population per sub−catchment, GIS was used to extract the area that overlays the study area and GIS's Tabulate Intersection function was used to compute different land use types including irrigated areas. Computed irrigation together with sub−catchment areas are presented in Table 4.6.

Table 4.6: Areas and population per sub−catchment

ID	Sub-catchment/ plant name	Area [km^2]	Irrigated area [%]	Population in 2002	Population in 2012	Population growth rate (%)
1	Muhazi	871.85	1.92	415288	560726	3.50
2	Mukungwa-I	611.24	2.1	378310	470233	2.43
3	Mukungwa-II	186.54	1.36	156625	205205	3.10
4	Mwaka	2174.77	5.41	780390	979052	2.55
5	Ntaruka	374.24	2.69	155906	161001	0.33
6	Nyabarongo-I	224.06	3.18	91562	106536	1.64
7	Nyabarongo-II	2467.46	3.91	1097853	1238032	1.28
8	Rugezi	167.94	3.4	72434	73879	0.20
9	Rukarara-I	22.06	0	4853	5639	1.62
10	Rukarara-II	247.84	0.21	41168	49384	2.00
11	Ruliba	968.2	5.34	763385	1031007	3.51
	Total	8316.2	3.86	3957774	4880695	-

4.5.2 Climate change impacts on hydropower generation

The computation of hydropower generation requires many more details about the design and operation of each power plant; however, it was not possible to acquire data for all the existing and planned power plants within the studied catchment. This was due to the complexity of the system and the fact that most of the mini− and micro− hydropower resources were still under feasibility studies at the time of data collection (2013). Therefore 8 (4 runoff and 4 dam based) hydropower plants for which enough information for the simulation was available were analysed and the impacts were extrapolated to the rest of power plants.

To model hydropower generation in the WEAP, all considered plant facilities must be added to the model. As discussed in Section 4.2.2, sub−catchments were delineated according to the geographic location of the analysed hydropower plants. The amount of electric energy that can be generated from a specific hydropower plant is proportional to the amount of water passing through the turbine and the net head (vertical distance from intake to turbine) according to Equation 4.17.

$$E(t) = Q_{Turb}(t) \cdot g \cdot \eta \cdot h \cdot p_f \cdot t \tag{4.17}$$

where

$E(t)$	Energy (MWh) generation during time t (hours)
$Q_{Turb}(t)$	Volume of water (m^3) passing through the turbine during time t
g	Gravitational acceleration, (m $\cdot s^{-2}$)
η	Overall generating efficiency, (%)
p_f	Plant factor, (%)

Any hydropower turbine operates within two limits: the minimum and maximum flow capacity as indicated by Equation 4.18.

$$Q_{Turb}(t) = \begin{cases} 0 & \text{if } Q(t) < Q_{Tmin}, \\ Q(t) & \text{if } Q_{Tmin} \leq Q(t) < Q_{Tmax}, \\ Q_{Tmax} & \text{if } Q(t) > Q_{Tmax}. \end{cases} \tag{4.18}$$

For run off river based power plants the net head is fixed whereas it depends on the reservoir's level for dam based power plants. As shown in Figure 4.9, a reservoir in WEAP model is divided into four zones: the flood−control zone, conservation zone, buffer zone and inactive zone. The combination of the conservation and buffer zones constitute the reservoir's active storage; and WEAP releases water from the conservation zone to fully meet withdrawal and other downstream requirements, and demand for energy from hydropower (Sieber and Purkey 2011, 81). However, when the level of the reservoir drops into the buffer zone, water is released according to the modeller stated coefficient that specifies the percentage of buffer zone water that can be released.

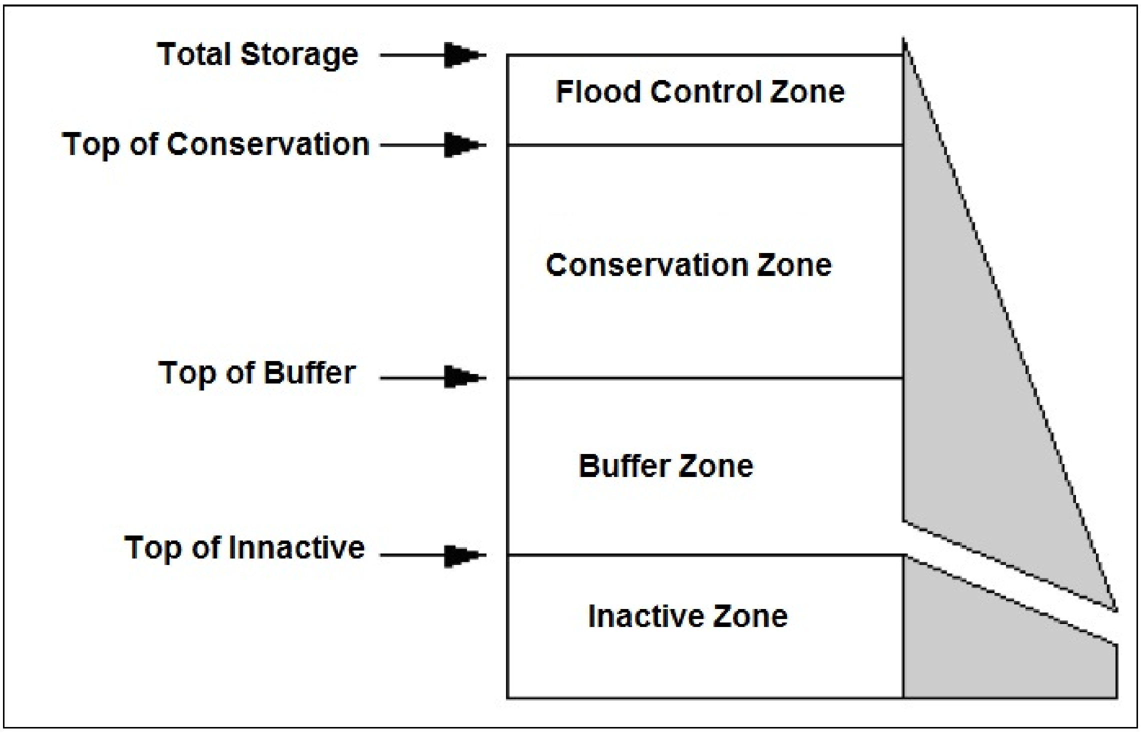


Figure 4.9: Reservoir's zones (Sieber and Purkey 2011, 81)

As there was no information on the capacities of different zones for the four dam based hydropower plants, the top of the inactive zone, in Meters above sea level (MASL), was set at the Minimum Drawdown Level (MDDL) for each dam. The conservation and buffer zones were combined to form one zone and the buffer coefficient was set to be 100% which means that WEAP was allowed to release all the available water in the active zone. The MDDL, Full Reservoir Level (FRL), Tail Water Level (TWL) and other parameters required to compute hydropower generation for the four dam based power plants are presented in Table 4.7 while the input data for the four runoff−based power plants are presented in Table 4.8.

It is important to mention that the active volumes for Mukungwa−I and Ntaruka were not available from the specified sources in Table 4.7; they were estimated by the author using the surface volume function of the GIS tool. In addition, the plant factor and efficiency of Nyabarongo−I (SMEC 2010, 3−10) were applied to the other three power plants as there was no information for each single power plant about these quantities.

As highlighted in Section 1.2, the existing and planned hydroelectric power plants in Rwanda have been designed on the basis of daily and seasonal historic climate patterns meaning that they assumed a stable climate. Climate data used to estimate monthly and annual hydropower production cover mainly the 1971−1990 period. Therefore, to assess potential impacts of the expected climate on hydropower generation, energy that would have been produced by the existing and planned plants during the reference period

Table 4.7: Calculation parameters for dam−based hydropower plants

Plant name	MDDL (MASL)	FRL (MASL)	TWL (MASL)	Volume (x$10^6 m^3$)	Turbine flow ($m^3 s^-1$)	Plant factor (%)	η (%)	Source
Mukungwa−I	1756	1760.5	1644	106	14	95	89.2	(EWSA 1984)
Ntaruka	1859.7	1864	1762	198	12	95	89.2	(RECO 2013)
Nyabarongo−I	1495	1499	1432	13.37	54.75	95	89.2	(SMEC 2014)
Nyabarongo−II	1389.9	1409	1369	307	80.2	95	89.2	(CNEE 2012)

Table 4.8: Calculation parameters for runoff-based hydropower plants

Plant name	Turbine flow ($m^3 s^-1$)	Plant factor (%)	η (%)	Fixed head (m)	Source
Mukungwa−II	10.7	95	88	32	(HPI 2006a)
Rugezi	2.3	95	88	135	(HPI 2006b)
Rukarara−I	9.0	95	88	137	(EPL 2006)
Rukarara−II	5.6	95	88	42.37	(SHER 2009)

was compared with the projected generation. It is important to mention here that for assessing precipitation and temperature change, the 1961−1990 period was considered as reference while for the impacts of the expected climate on hydropower generation the reference was set to be the period from 1971 to 1990.

After providing all required data into WEAP, the model was run and output flow discharge and power generation time series were analysed. Projected annual total generations were compared with the 1971−1990 average of annual total generation. In addition, exceedance probability for historical and projected generations were computed and compared. In general exceedance probability is the probability that an event will be greater than or equal to a given value. In this study exceedance probability means the probability of hydropower generation to be greater than or equal to a given value. Equation 4.19 was used to calculate the exceedance probability of energy generated under each model and scenario. In Equation 4.19 P is the percentage exceedance, m is the ranking from the highest to the lowest of total annual hydropower generation and n is the total number of years in the period.

The analysis of power generation time series on a yearly time step is not enough to conclude about potential impacts of climate change on hydropower production. Because the electricity supply must meet the demand at all times, the distribution of the generation on high temporal resolutions such as seasonal, monthly, daily or sub−daily can provide useful information that cannot be obtained from yearly data. Therefore, Concentration Degree (CD) was used to measure the distribution of power generation across a year. CD is computed according to Equation 4.20 (Li et al. 2011, 1683) where PD_{ij} is the period for which CD is to be calculated, i represents the year and j the period (day, month, season, etc.). R_{ij} is the total power generation in the j period of ith year, R_i is the total power generation in year i and θ is the azimuth of the jth period. CD varies between 0 and 1 where a CD value of 1 means that all the annual hydropower generation was produced during only one month whereas a CD value of 0 indicates an evenly temporal distributed power generation.

$$P = 100 \cdot \frac{m}{n+1} \tag{4.19}$$

$$CD_{ij} = \frac{\sqrt{R_{xi}^2 - R_{yi}^2}}{\sum_{i=1}^{12} R_i} \tag{4.20}$$

$$R_{xi} = \sum_{i=1}^{12} R_{ij} \cdot cos\theta \tag{4.21}$$

$$R_{yi} = \sum_{i=1}^{12} R_{ij} \cdot sin\theta \tag{4.22}$$

To assess the effects of the expected climate change on hydropower plants located located in the study area but not included in the simulations as well as those hydropower plants located outside the study area, identified power generation changes for the analysed power plants were extrapolated to the rest of the country. To achieve this, the percentage changes between the designed and simulated energy generations for each year from 2012 to 2099 and for each model and scenario were determined. Then, computed changes were applied to the annual total hydropower energy generation at the national level.

The values of designed annual energy generation were obtained from the Generation Report of Rwanda Electricity Master Plan 2010−2025 (Fichner and decon 2010a) and Rwanda Energy Sector Review and Action Plan (AfDB 2013). Annual energy generation (E_{an}) for hydropower plants of which installed capacities were available but energy production not available were estimated using Equation 4.23 where 8764 is the number of hours in year 2012, c_f is the capacity factor and P_i is the installed/designed capacity. The plant utilization factors were extracted from Fichner and decon (2010a, 35).

$$E_{an} = 8764 \cdot c_f \cdot P_i \tag{4.23}$$

Chapter 5

Approach to Rwanda's electricity demand and supply analysis

This chapter discusses the methodology used to project the evolution of Rwanda's electricity demand and the supply under different climate conditions towards 2050. In addition, the LEAP model used to simulate the country's electricity demand and to much it with the power supply is described. Furthermore, the sources of information as well as the assumptions made for data that were not available at the time of data analysis are also discussed in this chapter. At the end of the chapter, applied approaches to estimate the generation cost and pollution from power generation are presented.

5.1 Rationale of energy planning

Energy is an essential prime mover to drive the economic development and improve human well−being. The provision of safe, reliable, affordable and environmentally friendly energy is crucial to alleviate poverty, improve living standards and generate wealth in a sustainable manner. All the sectors of the economy (agriculture, commerce, industry, public administration, transportation, etc.) require energy to produce goods and provide services necessary to sustain people's life as well as to enable economic growth. For energy to play such a big role in a sustainable manner, appropriate decisions by policymakers, energy firms and consumers are necessary. To be effective, these decisions have to be based on the clear understanding of factors that influence or affect different components of the energy sector (see Figure 5.1) so that involved parties are aware of implications of considered options. Through energy planning required information to support decision making can be provided.

Energy planning is a process of attempting to balance the demand and supply for energy during the planning horizon (Kahen 1998, 4). To achieve this, possible demand trajectories are developed together with the possibilities of fulfilling that demand (Bhattacharyya 2011, 15) by taking into account energy and environment constraints such as the availability and prices of fuel supplies, penetration rates of certain technologies and emission standards (Nakata 2004, 425). In general terms, energy planning can be viewed as "the process of projecting the production, imports, conversion, consumption, and prices of energy, subject to assumptions on macroeconomic and financial factors, world energy markets, resource availability and costs, behavioral and technological choice criteria, cost and performance characteristics of energy technologies, and demographics (EIA 2013, 1)."

As illustrated in Figure 5.1, an energy system comprises different interdependent subcomponents that interact one with another in order to deliver expected outcomes in each subcomponent.

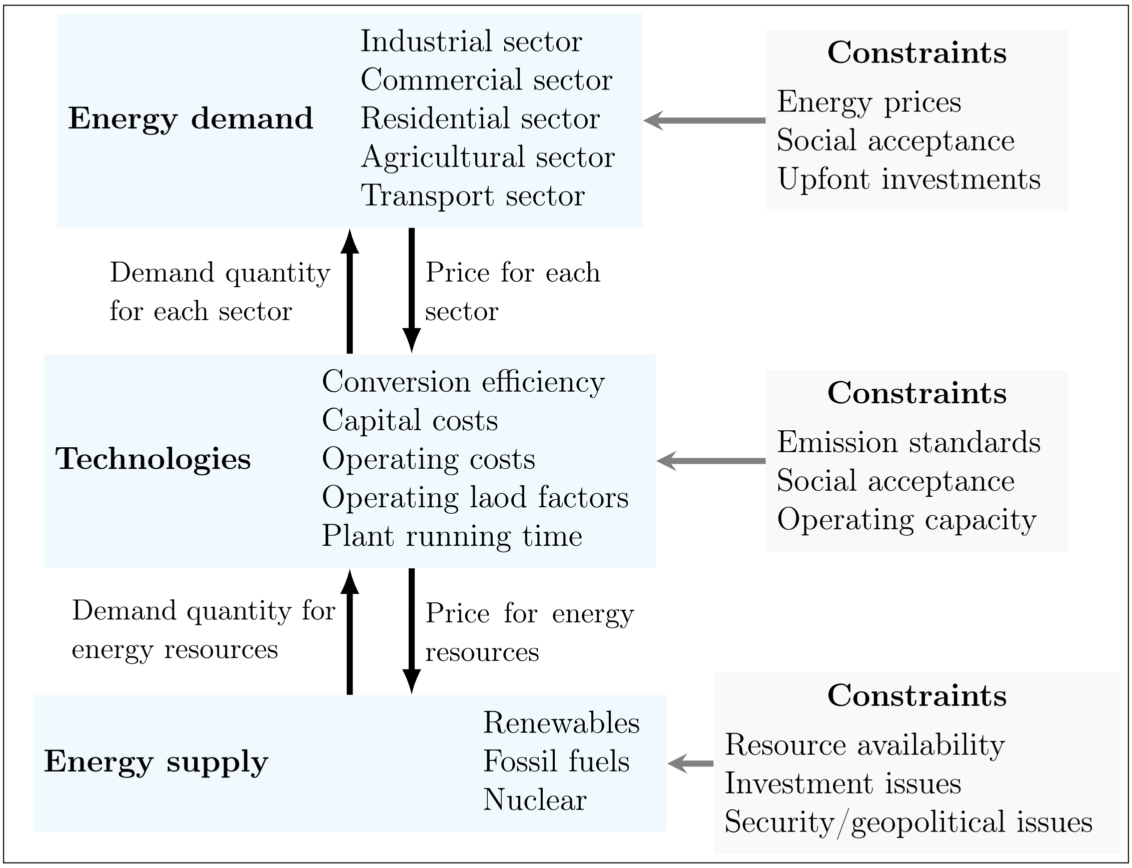


Figure 5.1: Simplified composition and interaction of energy system components (Adjusted from Nakata 2004, 421)

For instance, the demand sector depends on energy supplied by the technological subcomponent but the first is constrained by energy prices, the suitability (acceptability) of supplied energy technologies as well as the up−front investments and charges required to access these technologies. Furthermore, the technological subcomponent relies on resources from the energy supply to produce energy to the end users under emission standards, social acceptance and operating capacity constraints. On the other hand, the energy supply subcomponent is constrained by the availability of energy resources which is influenced by factors such as the depleting energy resources and the emerging climate combined with the insecurity in areas where energy resources are harvested or through which energy resources are shipped.

Due to the complexity of the energy system combined with the increasing energy demand resulting from the rapid global population growth and economic expansion, energy planners are confronted with a huge amount of data. However, thanks to advancements in computer technology, there are now models that allow to represent mathematically the complex components of an energy system and their interactions which facilitates their conceptualization and analysis (Bhattacharyya and Timilsina 2009, 6).

5.2 Electricity demand projection techniques

There is a variety of methodologies and approaches for electricity demand projection which range from simple to complex methods and each of the methods may lead to different results. The commonly used analysis approaches to energy demand projection can roughly be grouped into top−down and bottom−up methods depending on the level of aggregation. In general terms, top−down methodologies evaluate the system from aggregated economic variables, whereas in bottom−up approaches the system under analysis is subdivided into subcomponents and these subsystems are analysed independently one from another (IPCC 2001, 489).

In terms of energy projection, top−down methodologies project energy consumption on aggregated level by combining both the economic theory and statistical analysis to predict the future (Peerce-Landers 2014). The term "top−down" reflects the ways energy modellers apply macroeconomic theory and econometric techniques to historical consumption, price and income data to simulate the final demand of energy (IPCC 2001, 489). To project energy demand with top−down methodologies, the relationship between the past energy consumption and the factors that drive the consumption (such as the consumer's income, price and policy changes) is first determined and then extrapolated into the future (Bhattacharyya 2011, 65, van Beeck 1999, 13). Herbst et al. (2012, 115) describe top−down methodologies as equation based approaches that are driven by factors such as economic growth, inter-industrial structural change, demographic development, and price trends rather than energy-related technological progress, innovations, or intra−industrial structural change.

Equation 5.1 is one of the most used relations to determine the relationship between energy consumption and its main drivers (Bhattacharyya 2011, 53). In this equation $\mathrm{E_t}$ is the energy consumption at time t, $\mathrm{P_E}$ is the relative price of energy, $\mathrm{Y_t}$ is the real income or output at time t, coefficients b and c are respectively price and income elasticities of energy demand while μ_t is the random disturbance.

$$log(E_t) = a + b \cdot log(P_E) + c \cdot log(Y_t) + \mu_t \tag{5.1}$$

Elasticity of energy demand refers to the responsiveness of consumers to changes in driving variables of energy consumption. The price elasticity of electricity demand refers to the change in power demand for each 1% change in price while the GDP elasticity reflects the change in power demand for each 1% change in GDP. The elasticity e_t at time t is calculated after Equation 5.2 where Δ is the change in the variable, E is energy consumption, I is the driving variable of energy consumption such as GDP, price and income.

$$e_t = \frac{\Delta E_t / E_t}{\Delta I_t / I_t} \tag{5.2}$$

From Equation 5.1 it can be noticed that in top−down energy projection approach, the past relationship between energy demand and its macroeconomic driving factors is maintained. This does not allow the consideration of other main factors such as improvements in energy efficiency, technological changes, etc.

Contrarily to top−down methods, end use (or engineering) methods on the other hand are characterized by a high degree of technological detail and disaggregate energy consumption into sectors, subsectors and devices that consume energy (Nakata 2004; Peerce-Landers 2014; van Beeck 1999). In bottom−up energy analysis approach, the consumption of end−use appliances such as cooking devices, refrigerators, information and communication equipment, air conditioning, etc. are analysed individually and then the energy is aggregated to get the total energy consumption (Bastosa et al. 2015). Equation 5.3 is used to estimate the total energy consumption of each sector with bottom−up approach (Heaps 2011, 70).

$$E_t = \sum_{i=1}^{n} A_L \cdot I_i \tag{5.3}$$

$$A_L = \sum_{i=1}^{n} N_i \cdot p_i \tag{5.4}$$

where

E_t	Total energy consumption at time t
A_L	Activity level

I_i	Energy intensity of service i
N_i	Number of potential consumers
p_i	% of potential consumers who use service i

End−use methods are able to incorporate changes in technology such as improvements in energy efficiency, demand side energy conservation (management), energy and policy, physical limits on equipment performance and saturation effects (Peerce-Landers 2014). With bottom−up approach the potential for a possible decoupling of economic growth and energy demand can be explored through the assessment of new energy technologies which is not the case when the top−down method is applied (IPCC 2001, 489). Table 5.1 presents the main differences between top−down and bottom−up approaches.

Table 5.1: Characteristics of top−down and bottom−up models (van Beeck 1999, 12)

ID	Top−down approach	Bottom−up approach
1	Use an economic approach	Use an engineering approach
2	Cannot explicitly represent technologies	Allow for detailed description of technologies
3	Reflect available technologies adopted by the market	Reflect technical potential
4	Most efficient technologies are given by the production frontier (set by market behavior)	Efficient technologies can lie beyond the economic production frontier suggested by market behavior
5	Use aggregated data for predicting purposes	Use disaggregated data for exploring purposes
6	Based on observed market behavior	Independent of observed market behavior
7	Disregard the technically most efficient technologies available, thus underestimate potential for efficiency improvements	Disregard market thresholds (hidden costs and other constraints), thus overestimate the potential for efficiency improvements
8	Determine energy demand through aggregate economic indices but vary in addressing energy supply	Represent supply technologies in detail using disaggregated data, but vary in addressing energy consumption
9	Endogenize behavioral relationships	Assess costs of technological options directly
10	Assumes no discontinuities in historical trends	Assumes interactions between energy sector and other sectors are negligible

In this study, the top−down method was used for projecting the power consumption by the non−residential sector while the bottom−up method was applied for the case of the residential sector. However, because of uncertainties in estimating energy drivers such as, for example, the economic growth, energy prices and the demographic dynamics, scenarios are also used to cover a range of possible future trajectories. According to IPCC (2013, 945), a scenario is "a plausible representation of the future based on a coherent and consistent set of assumptions about driving forces and their key relationships." In both top−down and bottom−up approaches, scenarios can be applied.

5.3 Energy model selection and description

As mentioned in the previous section, energy models allow to mathematically represent the complex components of an energy system and their interactions so that huge amount of information can easily be analysed. As described in Section 4.1, the selection of the hydrological model (WEAP) used in this study was based on the model's ability to simulate hydropower generation under different climate conditions, and exchange information with energy models. The energy model that was found to respond best to these criteria is the LEAP tool. The description of LEAP model in this section is extracted from the LEAP User Guide Version 2011 by Heaps (2011).

LEAP is one of the widely used software tools for energy policy analysis and climate change mitigation assessment; it is also developed by SEI similar to WEAP. LEAP is not a model for a specific energy system, but a tool that can be used to build simple to complex energy systems. LEAP supports a wide range of modeling approaches for both the demand and the supply sides. On the demand side, LEAP supports the bottom−up (or end−use), the top−down (or econometric) and hybrid (or decoupled) modeling methodologies while on the supply side it provides flexible and transparent accounting, simulation and optimization methodologies to model electric sector generation and capacity expansion planning. For calculations LEAP provides two conceptual levels: the first level that comprises LEAP's built−in expressions that handle energy, emissions and cost−benefit calculations; and the second one where the modeler can specify multivariable models such as econometric model or enter spreadsheets like expressions that can be used to specify time−varying data. Figure 5.2 illustrates LEAP structure and its calculation flows.

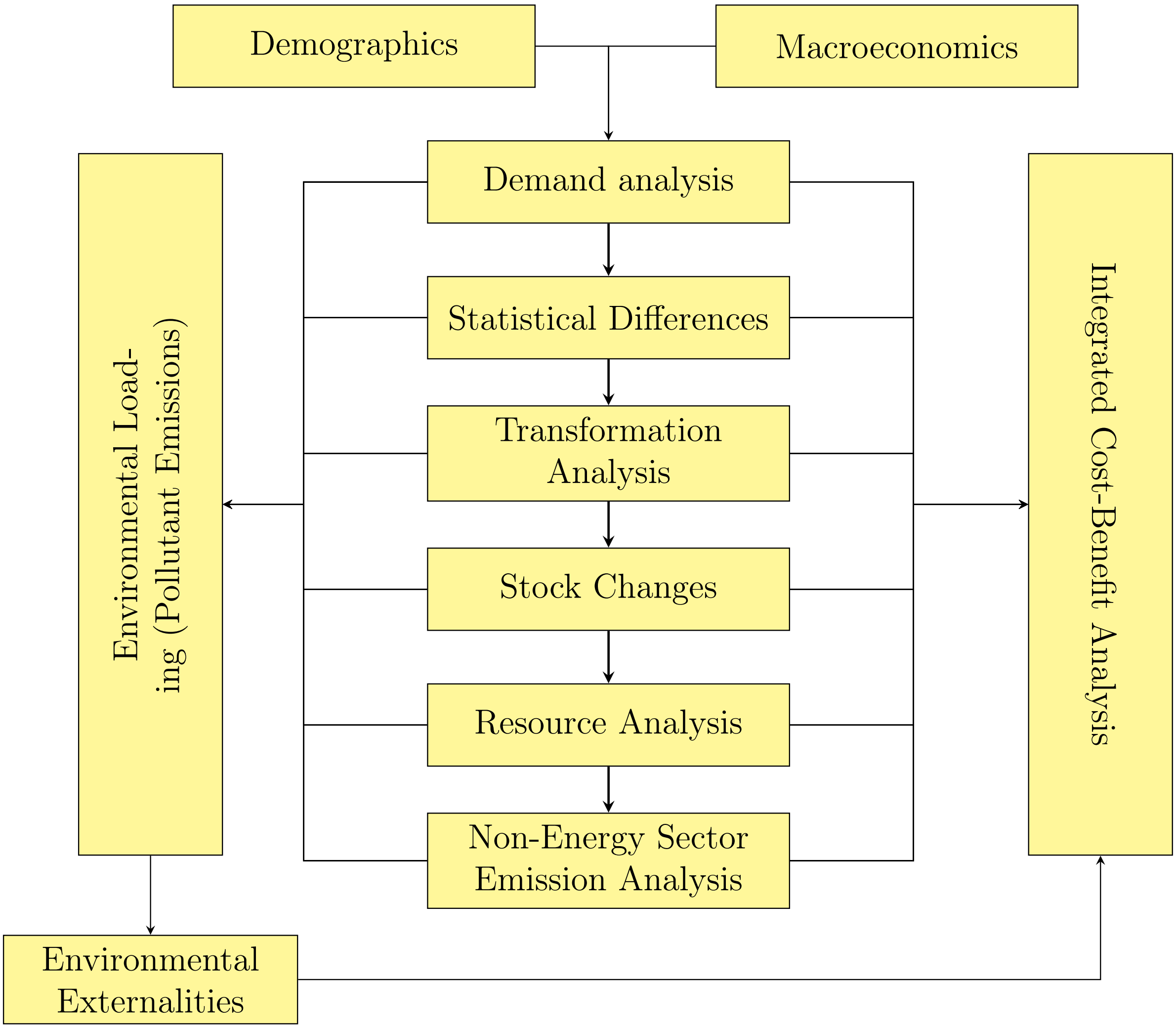


Figure 5.2: LEAP Structure and Calculation Flows

There are different analysis modules in LEAP (see Figure 5.2) but the relevant ones to this study are the demand analysis module, the transformation analysis module, the resource analysis and the integrated cost−benefit analysis described in the following subsections according to Heaps (2011).

5.3.1 Demand analysis

Demands in LEAP are organized into a flexible hierarchical tree structure, basically organized by sector, subsector, end−use and devices. Economic and demographic information as well as energy use information can be used to analyse how energy demand would evolve over time in all sectors of the economy.

There are two ways the demand is calculated in LEAP: the final energy demand analysis and the useful energy demand analysis. In a final energy demand analysis, energy demand is calculated as the product of the total activity level and energy intensity at each given demand technology branch according to Equation 5.5 where E is the energy demand, A_L is the total activity and I is the energy intensity.

$$E = A_L \cdot I \tag{5.5}$$

In a useful energy demand analysis, energy intensities are specified, not for a technology level but at the category with aggregate energy intensity. Equation 5.6 shows how the useful energy is calculated for each technology.

$$E = I \cdot \eta \cdot F_s \tag{5.6}$$

In Equation 5.6 E is the useful energy, I represents the energy intensity in an aggregated branch, F_S is its fuel share while η is the efficiency.

5.3.2 Transformation analysis

In the transformation analysis the energy conversion, transmission and distribution, resource extraction, capacity expansion and process dispatch, imports, exports, primary resource requirements, costs and environmental loadings are simulated. For electricity generation specifically the capacity expansion which states how much capacity to be built and when to build them, and the dispatch rule which defines the ways the built power plants should be operated are highly considered. LEAP dispatches available power plants so that both the total demand and the instantaneous peak demand which varies by hour, day and season are met. Electricity requirements in this module are calculated based on the energy demand analysis and any upstream electricity losses (for example the transmission and distribution). For electric power generation, Equation 5.7 is generally used to simulate the annual energy production from a given process.

$$E_{prod} = 8764 \cdot P_{req} \cdot L_F \tag{5.7}$$

In addition to Equation 5.7, LEAP provides a possibility to specify a process dispatch rule for each process. The process dispatch rule sets how a process is dispatched when the power supply system is trying to meet the energy and power requirements for each module. There are 5 different rules how processes can be dispatched:

- By process share: under this rule a process is set to meet a certain percentage of the requirements in a given module

- In proportion to available capacity: this rule dispatches the process to meet the requirements on a module until the maximum availability is achieved.
- Run to full available capacity: with this rule, processes are run to produce their full available capacity regardless of the requirements. This rule is mainly used to simulate export−driven energy industries for which the level of domestic requirements are unimportant.
- In ascending merit order: this rule dispatches processes according to their specified orders and it is more appropriate when simulating the dispatch of electric generation power plants to meet both the annual demand for electricity as well as the instantaneous demand for power in different periods of the year. Once power plants with high priorities achieve their maximum operating capacity, the plants with the next order are dispatched until they also reach their capacity limits and then the next.
- In ascending order of running cost: the principles governing this rule are the same as in the case of the "In Ascending Merit Order" option except that processes will be dispatched in ascending order of their overall running costs (defined as variable cost + fuel cost).

To satisfy the simulated demand plus associated losses, LEAP imports resources from the resource module and the required amounts, $\mathrm{R_{req}}$, depend on the process efficiency η according to Equation 5.8.

$$R_{req} = \frac{E_{prod}}{\eta} \tag{5.8}$$

5.3.3 Resource and cost analysis

In the resource module, resources can be specified in two ways: (i) enter the amount of available resources, or (ii) indicate if resources have to be imported to meet energy requirements of the transformation module. For renewables resources can be entered as annual total available resources or as resource per unit of land area. For fossil fuels, LEAP provides an option to enter the reserves in the base year and any additional resources during scenarios.

With regard to costs, it is possible to calculate the costs of purchasing and using the technologies in the demand and transformation modules, the costs of extracting primary resources and importing fuels, the external costs of energy as well as the benefits from exporting fuels. Depending on the scope of the energy accounting, LEAP can include all of the following cost elements:

- Demand costs (expressed as total costs, costs per activity, or costs of saving energy relative to some scenario);
- Transformation capital, fixed and variable operating and maintenance costs;
- Costs of indigenous resources and costs of imported fuels;
- Benefits of exported fuels;
- Externality costs from emissions of pollutants and
- Other miscellaneous user−defined costs such as the costs of administering an efficiency program.

5.4 Projection of Rwanda's electricity demand

This section presents and discusses the ways Rwanda's electricity demand analysis was conducted. The data used for the projection and the assumption made for different parameters that were not possible to acquire are also discussed in this section.

5.4.1 Residential sector

As mentioned in different sections of this research, only 16.8% of the total households in Rwanda had access to electricity in 2012. Although the electrification rate is very low, the analysis of electricity demand data obtained from REG reveals that more than 50% of the supplied electricity is consumed in the residential sector. It is therefore important to analyse this sector in more detail as it may continue to represent an important share of the total electricity consumption given the ongoing and planned electrification activities in the country.

Base year power consumption

Before the forecast of the residential sector's power consumption is conducted, the base year electricity demand was assessed. In this study, the bottom−up approach is used to analyse the evolution of the power consumption by the residential sector. This method is chosen in order to take into consideration the physical limits on equipment performance, the saturation effects and the improvements in the efficiency of household appliances. As explained in Section 4.5.1, the year 2012 is chosen as base year because a national population census, which provided a considerable amount of information for both hydrological and electrical power modelings was conducted in this year.

The electricity consumption per household in 20012 is estimated based on the power rating and time of use of main household appliances. The main household appliances considered in this study are light bulbs, radio and television receivers, fridges/refrigerators, computers and cell phones. The average electricity consumption per an electrified household for the base year is estimated according to Equation 5.9.

$$E_{Av} = \frac{E_{resid}}{H_{elec}} = \frac{365}{1000} \cdot \sum_{i=1}^{n} P_i \cdot n_i \cdot h_i \cdot p_{e,i} \tag{5.9}$$

where

E_{Av}	Average annual electricity consumption of an electrified household, (kWh)
E_{resid}	Electricity consumption by the residential sector in 2012, (kWh)
H_{elec}	Number of electrified households in 2012
P_i	Rated power of appliance i, (W)
n_i	Average number of appliance i per household
h_i	Time usage of appliance i per day, (hours)
365	Total number of days per year
1000	Conversion factor from watt hours to kilowatt hours

The power consumption of each appliance, its time usage, its household penetration as well as the estimated annual energy consumption in electrified households are presented in Table 5.2 while the residential model structure built in LEAP is shown in Figure 5.3.

Table 5.2: Households appliances and their estimated energy consumptions (NISR 2012a, 88−98; Fichner and decon 2009, 4−24)

ID	Appliance	Rated power (W) (P_i)	Av. number of devices (n_i)	Use hours per day (h_i)	Use rate per household (%) ($p_{e,i}$)	kWh annual consumption (E_{Av})
1	Cell phone	4.00	2.00	1.00	100.00	2.92
2	CFL	11.00	1.75	4.00	100.00	28.11
3	Computer	80.00	1.00	2.00	14.22	8.30
4	Cook stove	2000.00	1.00	2.00	0.90	13.20
5	Incandescent	60.00	1.75	4.00	100.00	153.30
6	Iron	1000.00	1.00	0.25	10.00	9.13
7	Neon	20.00	1.50	12.00	100.00	131.40
8	Radio	12.00	1.00	6.00	100.00	26.28
9	Refrigeration	220.00	1.00	6.00	9.75	46.96
10	Television	110.00	1.00	3.00	46.90	56.49
	Total (kWh)					476.09

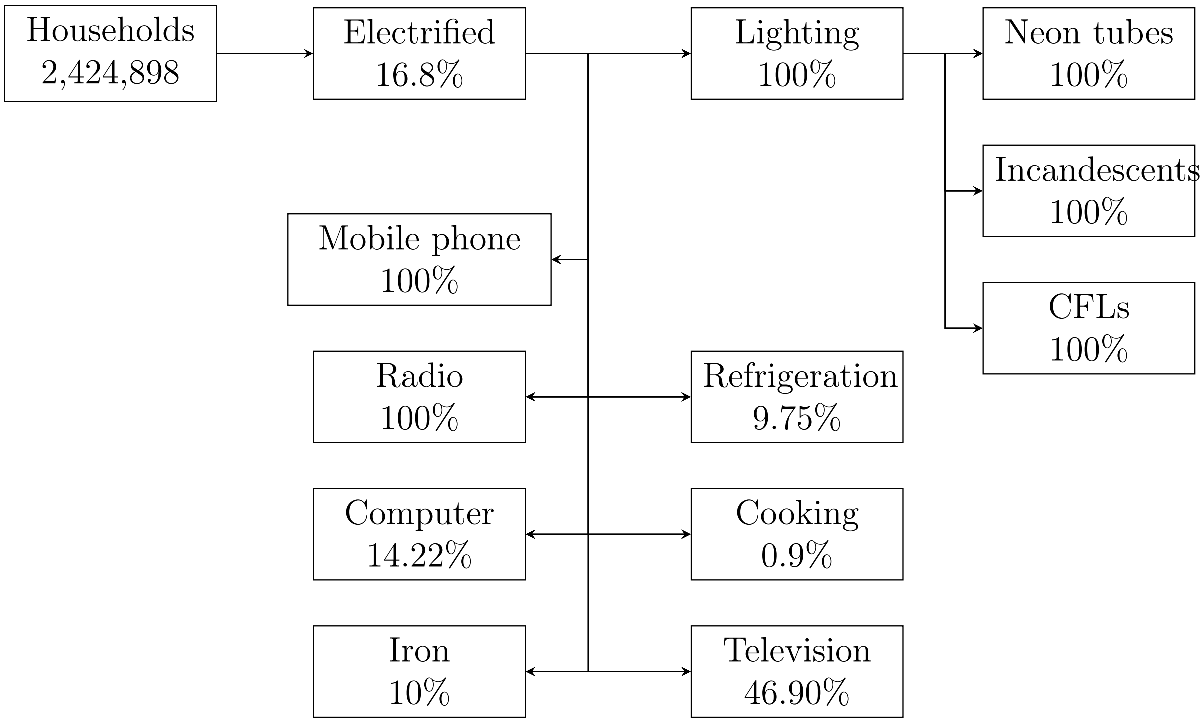


Figure 5.3: Demand data structure for residential sector in Rwanda

Information on the rated power of different appliances and daily time of use was extracted from the "Economic Data Collection and Demand Forecast 2009−2025" by Fichner and decon (2009) while the number of households having the stated appliances were extracted from the 2012 Census report (NISR 2012a). Information that was not available such as the number of households with iron and CFL and incandescent lamps was assumed by the author based on discussions with experienced staff from REG.

According to information extracted from NISR (2012a, 88), the total population in 2012 was 10,515,973 grouped into 2,424,898 households of which 407,818 (or 16.8%) were connected to the national electricity grid, 3,871 (or 0.2%) used electricity from isolated micro hydropower sources, 9,470 (or 0.4%) got electricity from Solar Home Systems (SHSs) while 1,798 (or 0.1%) used thermal power generators.

It is important to highlight that the number of households connected to the national grid differs according to the source of information. While for example NISR (2012a, 88) reports 407,818 connections, the data collected from REG indicates only 370,051 households (WJEC 2015) in 2012 which gives a difference of 37,767 connections (or 10.2%). The considerable difference in the number of households connected to the grid might have resulted from the definitions of household by the NISR and residential customer by REG.

In the 2012 Census, two types of households were differentiated: private and institutional households. According to NISR (2012a, 6), a private household "consists of one or more persons living together and sharing at least one daily meal whereas an institutional household comprises a group of persons who are being provided with institutionalized care, and includes educational institutions, health care institutions, military institutions, religious institutions, or institutions for the elderly or persons with disabilities." For REG, a household customer corresponds to one installed electricity power meter regardless the number of households sharing this meter. In the knowledge of the Author, more than one household can share one electricity power meter especially in the urban areas. Therefore, the number of electrified households from the 2012 Census was considered in the analysis as it represents better the real settings of households in terms of electricity consumption compared to the data from REG.

Projection of the power consumption

In this study, the future electricity consumption by the residential sector is assumed to be driven by both the population and electrification growth rates. To project the total population of Rwanda towards 2050, the existing projections of the country's population for the 2012 − 2032 period by NISR (2014a) is used. For the period beyond 2032, the trends observed the the NISR projections were maintained. The assumed population growth rates are presented in Table 5.3.

Table 5.3: Assumptions for the population projection for the 2012−2032 period (NISR 2014a, 20, 47) and the 2033−2050 period

Scenario	NISR assumptions	This study assumptions
High	• The average number of persons per household would decrease from 4.3 in 2012 to 3.1 in 2032.	• The population growth rate would decrease from 2.37% in 2013 to 2.18% in 2032 and 2.00% in 2050. • The number of persons per households will decline from 4.3 in 2012 to 3.1 in 2032 and 3.00 in in 2050.
Medium	• The average number of persons per household would decrease from 4.3 in 2012 to 3.1 in 2032.	• The population growth rate would decrease from 2.37% in 2013 to 1.89% in 2032 and 1.71% in 2050. • The number of persons per households will decline from 4.3 in 2012 to 3.1 in 2032 and 3.00 in in 2050.
Low	• The average number of persons per household would decrease from 4.3 in 2012 to 3.1 in 2032.	• The population growth rate would decrease from 2.31% in 2013 to 1.63% in 2032 and 1.45% in 2050. • The number of persons per households will decline from 4.3 in 2012 to 3.1 in 2032 and 3.00 in in 2050.

The number of households in each year between 2012 and 2050 was calculated by dividing the total population by the household size. The number of electrified households on the other hand was projected based on the likely electrification scenario which is one of two electrification scenarios developed by MININFRA (2013) for the period 2013 – 2018 and extended up to 2032 by WJEC (2015).

Under the likely electrification scenario it is projected that 35% of the country's households will have access to electricity by 2017 (MININFRA 2013, 47) and 71% in 2032 (WJEC 2015). The second scenario is the ambitious electrification scenario which anticipates that 48% of the country households will have access to electricity by 2017 (MININFRA 2013, 47) and 78% by 2032 (WJEC 2015).

Given observed difficulties and challenges in the implementation of different power generation and transmission projects, only the very likely electrification scenario is considered in this study. To simulate the electrification rate beyond 2032, it was assumed that after 2032 the remaining non electrified households will be those located very far away from the national electricity grid so that 100% electrification can be achieved in 2050. It is important to recall (as highlighted in Section 1.4), that a 100% electrification rate in 2050 does not mean that all households will have access to electricity in this year. It only means that all households will be connected to the national grid by 2050. There are different off-grid initiatives where households located far away from the national grid or those consuming insufficient electricity to make a grid connection financially viable will be supported to access electricity through off-grid solutions such as micro hydropower or solar PV solutions (MININFRA 2013, 10).

In this study it was assumed that by 2050 all household appliances would consume 15% less than the consumption in 2012 thanks to the improvement in energy efficiency. In addition, most of the appliances would saturate towards 2050 due to increase in income as discussed in the next section. The assumed rated power of household appliances in 2050 in comparison with the rated power in 2012 together with assumed appliances' saturation rates in 2050 are presented in Table 5.4.

The total residential sector power consumption each year is then simulated in LEAP according to Equation 5.10 where $\mathrm{E_t}$ is the total power consumption in year t, $\mathrm{N_i}$ is the number of electrified households, $\mathrm{p_i}$ the percentage of electrified households with appliance i and $\mathrm{I_i}$ is the final energy intensity of appliance i in year t.

$$E_t = \sum_{i=1}^{n} N_i \cdot p_i \cdot I_i \tag{5.10}$$

Table 5.4: Assumed evolution of the rated powers and penetration of household appliances in electrified households

ID	Appliance	Power (W) in 2012	Power (W) in 2050	Use rate (%) in 2012	Use rate (%) in 2050
1	Cell phone	4.00	2.00	100.00	100.00
2	CFL	11.00	5.50	100.00	100.00
3	Computer	80.00	40.00	14.22	50.00
4	Cook stove	2000.00	1000.00	0.90	10.00
5	Incandescent	60.00	0.00	100.00	0.00
6	Iron	1000.00	500.00	10.00	30.00
7	Neon	20.00	10.00	100.00	100.00
8	Radio	12.00	6.00	100.00	100.00
9	Refrigeration	220.00	110.00	9.75	50.00
10	Television	110.00	55.00	46.90	80.00

5.4.2 Non−residential sectors

To analyse the evolution of power consumption for electricity demand sectors other than the residential sector, the top−down approach is used with the GDP being the driver of electricity consumption. This method is chosen as the bottom−up approach requires considerable details on the end use electricity equipment, and it was not possible to acquire all these details.

As discussed in Section 2.6.1, electricity demand sectors in Rwanda are grouped into normal, medium and public service consumers. However, the GDP is reported according to three economic sectors namely agriculture, services and industry plus adjustments. Due to the lack of information on electricity consumption for each of these sectors, they were analysed together as one block of electricity consumption and they are denoted as non−residential sector in this study.

The analysis assumed that the future electricity demand by these sectors would be driven by the GDP and independent from price changes. To determine the relationship between the past electricity consumption of the non−residential sector and the GDP, the method of least squares was used. The least square method allows determining the slope a and intercept b of Equation 5.11 that fits best data (Cantrell 2008).

$$y = ax + b \tag{5.11}$$

To achieve this, the historical electricity consumption of the non−residential sector was first determined. This was done by subtraction the household electricity consumption from the total electricity consumption for the 2005 − 2012 period. Equations 5.12 and 5.13 (Cantrell 2008, 5479) were applied to respectively determine the slope and intercept of the line represented by Equation 5.11. In these two equations, x_i is the total GDP for year i while y_i is the power consumed by the non−residential sector to produce the total GDP for year i.

$$a = \frac{n\sum_{i=1}^{n} x_i y_i - \sum_{i=1}^{n} x_i \sum_{i=1}^{n} y_i}{n\sum_{i=1}^{n} x_i^2 - \left(\sum_{i=1}^{n} x_i\right)^2} \tag{5.12}$$

$$b = \frac{n\sum_{i=1}^{n} x_i^2 \sum_{i=1}^{n} y_i - \sum_{i=1}^{n} x_i \sum_{i=1}^{n} x_i y_i}{n\sum_{i=1}^{n} x_i^2 - \left(\sum_{i=1}^{n} x_i\right)^2} \tag{5.13}$$

The data used to determine the relationship between electricity consumption of the non−residential sector and the GDP are presented in Table 5.5.

Table 5.5: Electricity consumption and GDP data used to determine the demand-GDP relationship (Author based on data from Lahmeyer International (2004, 5-28) and a database developed by WJEC (2015) obtained from REG).

Year	All sectors (GWh)	Residential (GWh)	NR (GWh)	GDP (x10^6 \$US)	log(NR)	log(GDP)
2005	160	76	84	2815	1.92	3.45
2006	180	86	94	3075	1.97	3.49
2007	202	96	106	3314	2.03	3.52
2008	225	109	116	3692	2.07	3.57
2009	245	124	121	3914	2.08	3.59
2010	287	145	142	4210	2.15	3.62
2011	326	171	155	4552	2.19	3.66
2012	379	194	185	4900	2.27	3.69
2013	391	201	190	5159	2.28	3.71

The GDP in million FRW for the period 2005 to 2012 at constant 2006 value was extracted from NISR (2009, 87) and NISR (2013, 131) and then converted into US dollar using the 2006 exchange rate of FRW 558 against US$ 1 (NISR 2009, 87). It is worth to notice that the electricity consumption by REG is also included in the total electricity consumption by the non−residential sector. Figure 5.4 shows the logarithmic relationship between the non−residential electricity consumption and the national GDP.

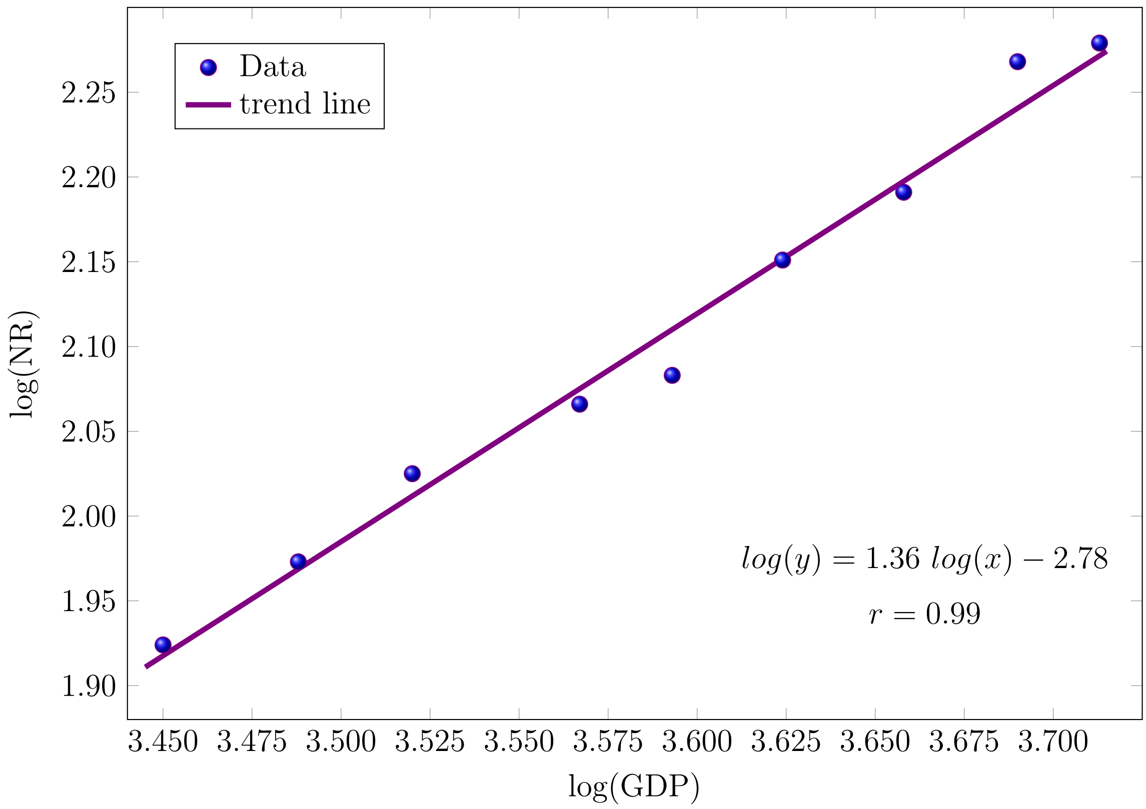


Figure 5.4: Correlation between electricity consumption by productive sectors and the real GDP for the period $2005 - 2013$ (Author based on data from REG). NR in this figure means non$-$residential sector.

According to Equation 5.12, the slope (coefficient a) of the line represented in Figure 5.4 was calculated to be 1.36 while the intercept (coefficient b) is -2.78 according to Equation 5.13. Equation 5.14 shows how the past NR$-$GDP relationship was obtained.

$$logE = 1.36\ log(GDP) - 2.78$$

$$logE = 1.256\ log(GDP) - log10^{2.78}$$

$$logE = log\frac{(GDP)^{1.36}}{10^{2.78}} \tag{5.14}$$

$$logE = log\frac{(GDP)^{1.36}}{10^{2.78}}$$

$$E = \frac{(GDP)^{1.36}}{10^{2.78}}$$

To check the goodness of fit, Pearson's correlation coefficient (r) that measures the relationship between two continuous variables was calculated using Equation 5.15.

$$r = \frac{n\sum_{i=1}^{n} x_i y_i - \sum_{i=1}^{n} x_i \sum_{i=1}^{n} y_i}{\sqrt{\left(n\sum_{i=1}^{n} x_i^2 - \left[\sum_{i=1}^{n} x_i\right]^2\right)\left(n\sum_{i=1}^{n} y_i^2 - \left[\sum_{i=1}^{n} y_i\right]^2\right)}} \tag{5.15}$$

As mentioned in Section 4.3.1, when the correlation is +1, this means that the two variables increase or decrease proportionally whereas a correlation of −1 suggests that one of the variables increases while the other decreases but in the same level. In case of this study a correlation coefficient equivalent to +0.99 (see Figure 5.4) was found which indicates a very high positive correlation between electricity demand of the non−residential sector and the national GDP.

Equation 5.16 derived from Equation 5.14 was used to project the non−residential sector for the 2013−2050 period.

$$E = \frac{(GDP)^{1.36}}{10^{2.78}} \tag{5.16}$$

Because of uncertainties on the evolution of the national GDP, three scenarios are considered in order to accommodate a wide range of possible future economic development trajectories. The scenarios are constructed based on the past economic growth as shown in Fugure 5.5 that shows the evolution of the GDP growth rate between 1996 and 2014. From this figure one can notice that the economic growth presents a diminishing trend with an average growth rate of 8.36% over the 1996−2014 period. In this study three economic diminishing trends rates: the high, the medium and the low GDP growth rates are explored. The high scenario envisages Rwanda as a fast developing economy so that the GDP growth would slightly decline from 8.0% in 2012 to 6.0% in 2050. The second scenario (medium) anticipates a moderate economic development such that the GDP growth rate would decrease from 8.0% in 2012 to 4.5% in 2050. The last scenario is the low development trajectory where the economy would grow slowly so that the GDP growth rate will decrease from 8.0% in 2012 to 3.0% by 2050.

5.4.3 Peak power and total electricity demand

The total national electricity demand was obtained by summing the power consumptions of the residential and non−residential sectors. Because there were three residential and

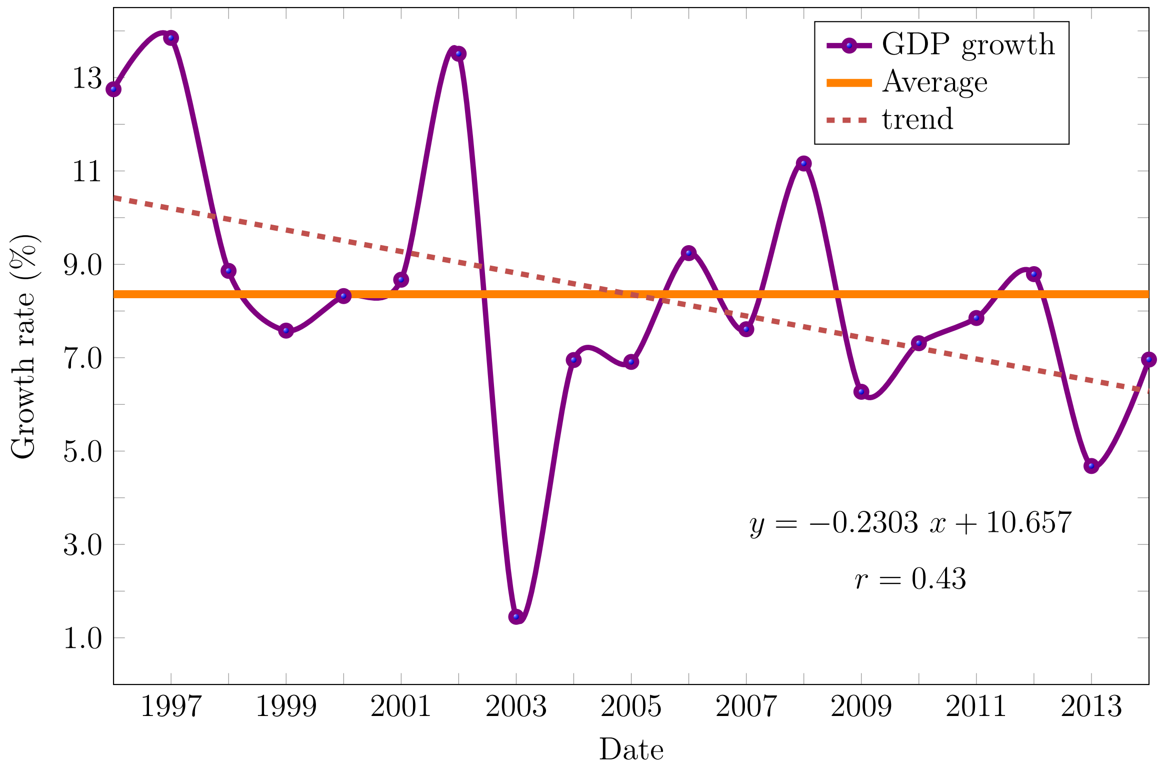


Figure 5.5: Evolution of Rwanda GDP growth rate between 1996 and 2014 (Author based on data from The World Bank 2015b).

three non−residential demand scenarios that would lead to nine different scenarios, only three representative scenarios for the evolution of the total power demand in Rwanda were analysed. These scenarios are called in this study the "very low scenario" which comprises the low scenarios of the residential and non−residential sectors; the "very likely scenario" which includes the medium scenarios of the residential and non−residential sectors; and the "very high scenario" which incorporate the very high scenarios of the residential and non−residential sectors (details are provided in Section 8.1.3).

As for the peak load, the peak power requirements, P_{req} (in MW), were calculated according to Equation 5.17 where E_{req} is the electricity requirements (in MWh), L_F is the load factor while 8760 is the number of hours in a year.

$$P_{req} = \frac{E_{req}}{8764 \cdot L_F} \tag{5.17}$$

The electricity requirements E_{req} in Equation 5.17 is the sum of the total simulated demand and the transmission and distribution losses. The 2013 load factor (see Figure 5.6) is used to calculate the peak load requirements for the simulation period.

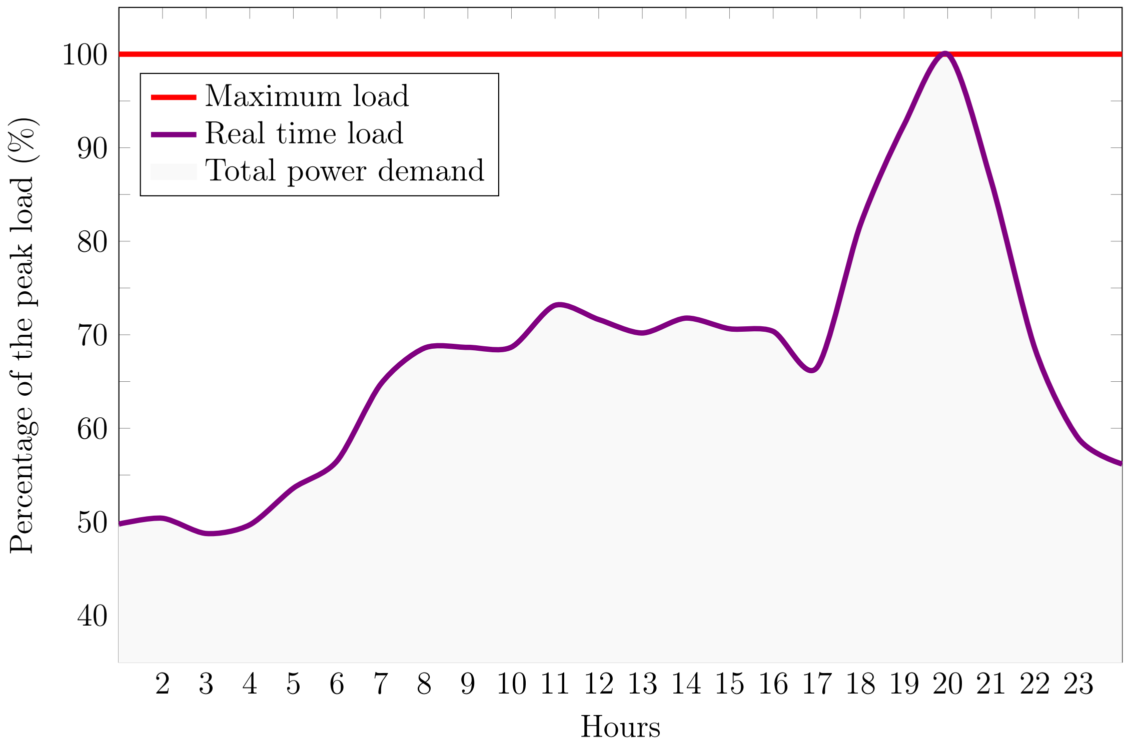


Figure 5.6: Rwanda daily load curve (Author based on data from Lahmeyer International (2004, 5-28) and a database developed by WJEC (2015) obtained from REG.)

From Figure 5.6 it can be noticed that the peak power demand in Rwanda occurs each day at around 08.00 pm while the minimum power demand occurs at around 03.00 am. As meeting the peak demand is too expensive due to the fact that the plant factor of the peaking power plants is low (about 3 hours per day or 12.5% for the case of Rwanda), it is more feasible to reduce the peak demand by, for example, shifting the consumption from peak to off−peak hours. To do this RURA has set different tariffs for the industrial sector since 2012 so that for the power consumed between 07.00 am and 05.00 pm the tariff is, in current prices, 24 US$ cents/kWh, between 5.00 pm and 11.00 pm 1 kWh costs 33 US$ cents while 18 US$ cents/kWh are charged for the power consumed between 11.00 pm and 07.00 am (RURA 2012a). It was not possible to get information that would have allowed checking if these tariffs reduced the peak power demand. Therefore, the option to reduce the peak load further was not assessed in this study.

5.5 Electricity supply analysis

To meet the estimated electricity demand described in Section 5.4, two group of power supply scenarios are assessed. The first group comprises three power supply sub−scenario related to the BAU electricity supply scenario. These scenarios are the BAU power supply without climate change consideration, the BAU power supply under climate scenario RCP4.5 and the BAU power supply under climate scenario RCP8.5. The second group of the power supply scenarios includes also three sub−scenarios related to the suggested alternative power supply scenario. These sub−scenarios are the alternative power supply without climate change considerations, the alternative power supply under climate scenario RCP4.5 and the alternative power supply under climate scenario RCP8.5.

5.5.1 BAU power supply without climate change consideration

Under this scenario, the planned power generation projects are considered. As the existing power generation plans extend up to 2025 (see Table 5.6), the generation capacity beyond 2025 was gradually increased to match the demand by keeping in mind that the maximum resource availability (discussed in Section 2.5) for each technology is not exceeded.

Table 5.6: Planned power generation capacity (in MW) for the 2013−2025 horizon (data from REG except the last year 2050 which is an assumption by the author)

Year	Hydro	Diesel	Methane	Peat	Solar	Geothermal	Imports	Total
2013	55.77	47.80	1.20	0.00	0.25	0.00	3.50	108.52
2014	64.27	47.80	1.20	0.00	0.25	0.00	3.50	117.02
2015	82.27	51.80	3.00	0.00	8.75	0.00	3.50	149.32
2016	107.27	51.80	18.00	15.00	19.75	0.00	33.50	245.32
2017	113.27	67.80	28.00	95.00	29.75	0.00	63.50	397.32
2018	137.27	77.80	78.60	145.00	29.75	0.00	103.50	571.92
2019	127.27	77.80	78.60	145.00	29.75	0.00	103.50	561.92
2020	176.27	77.80	78.60	145.00	29.75	0.00	153.50	660.92
2021	181.27	77.80	153.60	235.00	29.75	10.00	203.50	890.92
2022	234.27	77.80	153.60	235.00	39.75	10.00	253.50	1,003.92
2023	239.27	77.80	153.60	235.00	39.75	110.00	303.50	1,158.92
2024	244.27	77.80	153.60	235.00	39.75	110.00	353.50	1,213.92
2025	254.27	77.80	153.60	235.00	39.75	110.00	403.50	1,273.92
2050	254.27	77.80	350.00	235.00	100.00	320.00	0.00	1,337.07

As one can notice from Table 5.6, it is planned under the BAU scenario that by 2025 a demand of 405.5 MW would be covered by imported electricity. As highligheted in Sectioon 2.6.4, it is anticipated that the imported electricity will come from Ethiopia (400 MW) and Kenya (30 MW) (Tumwebaze 2014). However, these countries may prioritize satisfying domestic power demands before exporting to other countries as electrification rates in these two countries are also still very low: 24% for Ethiopia and 20% for Kenya (IEA 2015b). Therefore the imported electricity are not considered in the simulation.

Imported fossil fuels are used to meet the demand that exceeds the power generation from domestic energy resources.

Under this supply scenario it was assumed that the installed capacity from hydropower generation will increase from the planned 254.27 MW in 2025 to its national proven capacity of 348.6 MW by 2050. The installed capacity for methane and geothermal based power generation was set to increase up to their maximum capacities of 350 MW and 340 MW respectively. Based on the recent development in solar power generation which envisages 39.75 MW by 2025 (see Table 5.6), it was assumed that a cumulative capacity of 100 MW solar power can be achieved by 2050. As for peat based power generation, 300 MW up to 2050 was used in the simulation. The demand that cannot be met with the above power generation technologies are covered by diesel based power generation and the capacity is added internally by LEAP when needed.

5.5.2 BAU power supply under RCP4.5 and RCP8.5 climate scenarios

In the power supply under climate change, two scenarios: RCP4.5 and RCP8.5 are distinguished. RCP4.5 power supply scenario uses the power generation obtained during the assessment of impacts of climate change on hydropower generation in case the world's climate evolves according to RCP4.5 climate scenario. On the other hand, RCP8.5 power supply scenario analyses the performance of Rwanda's power supply system for the case the future world's climate evolves according to climate scenario RCP8.5. The only difference between the power supply under climate change and the BAU supply scenarios is the maximum availability of hydropower plants. In the BAU scenario an average of 62.26% is used while for RCP4.5 and RCP8 Equation 5.18 was used to calculate the availabilities.

$$p_{avail}(\%) = 100 \cdot \frac{E_{i,j}}{P_{i,j}} \tag{5.18}$$

In Equation 5.18 $\mathrm{E_{i,j}}$ is the power generation in year i under climate scenario j while $\mathrm{P_{i,j}}$ is the installed capacity in year i under scenario j. The maximum availability of 62.26% used in the BAU scenario is the weighted average of the maximum availabilities of all the hydropower plants considered in the simulation.

Because this study aim to develop an electricity supply scenario that would allow Rwanda to meet its growing electricity demand with domestic energy resources despite the emerging climate conditions, this study considered the worst cases of hydropower generation. Consequently, for RCP4.5 power supply scenario, the minimum (worst case) generation of HadGem2−ES and MIROC−ESM is determined according to Equation 5.19 while

Equation 5.20 was used for the case of RCP8.5.

$$E_{i,RCP4.5} = Min(HadGem2_{i,RCP4.5}, MIROC_{i,RCP4.5}) \tag{5.19}$$

$$E_{i,RCP8.5} = Min(HadGem2_{i,RCP8.5}, MIROC_{i,RCP8.5}) \tag{5.20}$$

The determined maximum plant availability under RCP4.5 and RCP8.5 are presented graphically in Figure 5.7 on which the designed plant availability can also be seen.

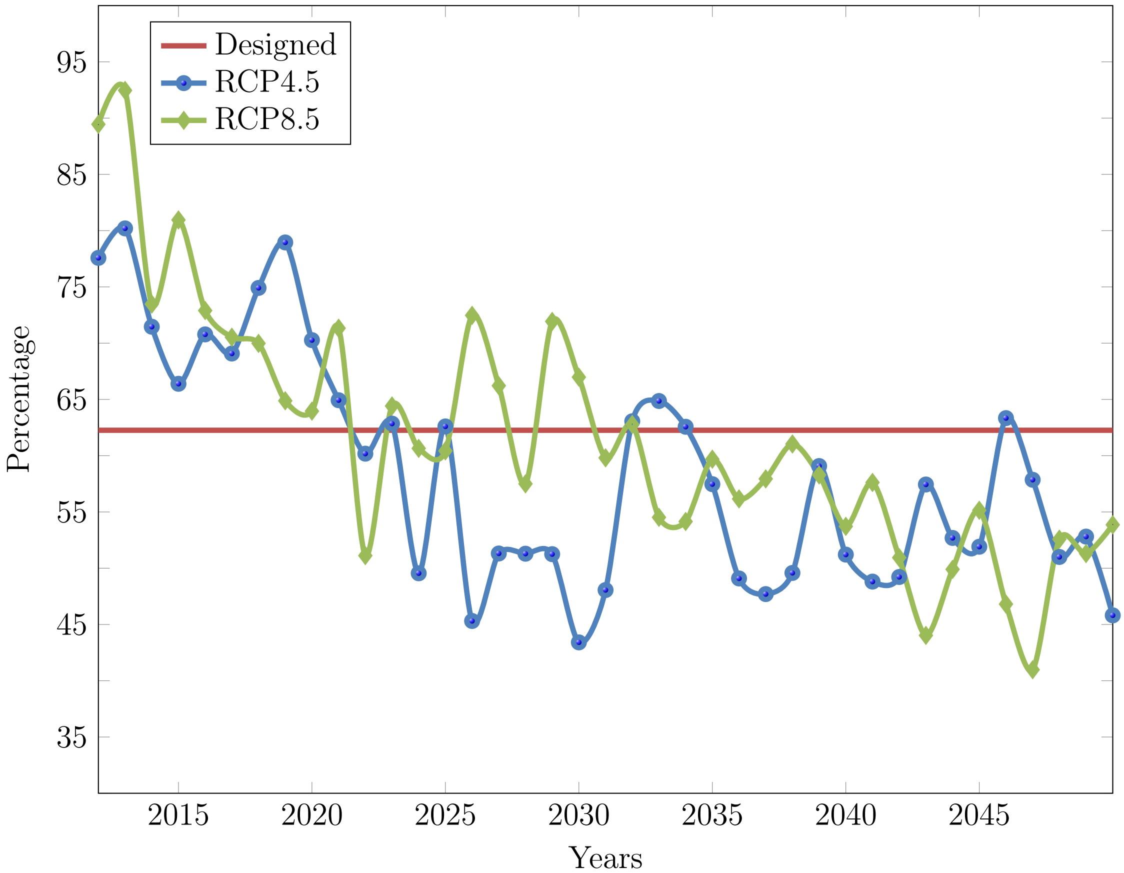


Figure 5.7: Maximum availability of hydropower resources under the reference, RCP4.5 and RCP8.5 scenarios

5.5.3 Assessment of alternative power supply scenario

The alternative scenario presented in this section seeks to identify the power supply option that would be resilient to the expected effects of climate change and meet the projected power demand with domestic energy resources. The main aim of this scenario is to suggest a power supply scenario that allows the country to terminate its dependency on imported oil for its power supply. To achieve this, five measures: improvements in the efficiency of household appliances, intensive exploitation of the Nyabarongo River, increased use of solar energy, introduction of wind energy in the country's power supply and exploitation of municipal waste to generate electricity are suggested.

- **Improvement of efficiency of household appliances**

Under the reference scenario it was assumed that the efficiency of household appliances will increase by 15% by 2050 and it was assumed that these improvements would be voluntarily achieved by the consumers. Under the alternative scenario, it is assumed that the Government will intervene by introducing import standards so that old and non−efficient appliances would not be allowed to enter into the country. It is assumed that due to these measures, 10% consumption reductions can be achieved compared to the BAU as usual scenario.

- **More use of solar energy**

Thanks to its location, Rwanda is one of the countries with considerable solar potential that can support the supply of electricity in the country. The average annual solar radiation in the Northern and Western parts of the country is estimated to be 3.5 kWh/m^2/day while the rest parts of the country it is 6.0 kWh/m^2/day (Hammami 2010, 11). Under the alternative scenario it was assumed that the installed capacity of solar power plants will increase from 0.25 MW in 2012 to 500 MW in 2050.

Based on the existing two solar PV plants of Kigali Solar (250 kW) covers an area of one hectare while Rwamagana Solar (8.5 MW) covers about 21 hectares of land, the suggested 500 MW solar power plants would require a maximum area of about 20 km^2 equivalent to 0.076% of the country's area.

- **Introduction of wind energy**

Based on the results from an assessment of wind energy resources in Rwanda by De Volder (2010) it is possible to economically exploit wind energy in Rwanda. In his study, De Volder (2010) found that in case a 2 MW wind turbine is installed at the location of Mast 2 in Kayonza (see location on Figure 2.17), 2,254 MWh (corresponding to 12.9% capacity factor) can be generated annually. Therefore this study assumed that up to 250 MW wind power plants can be installed in this area with the same plant factor. Considering the same assumption as Hohmeyer (2015, 6) that 10 MW of wind turbines require 1 km^2 of land, the suggested wind power capacity would take 25 km^2 equivalent to 0.09% of the country's area. It is important to mention here that wind energy presents an added advantage over solar energy as except for the area on which the wind tower is implanted and the access to it, the rest of the land can be still used for agriculture.

- **Intensive exploitation of the Nyabarongo River**

The Nybarongo River draws its waters from the northern, southern and western parts of Rwanda and then flows over 350 km before it drains into the Akagera River at Lake Rweru in the south-eastern Rwanda (see Figure 5.8). The main tributaries of the Nyabarongo River are the Akanyaru River and the Mwogo River from the South and the Mukungwa River from the north (see Figure 5.8).

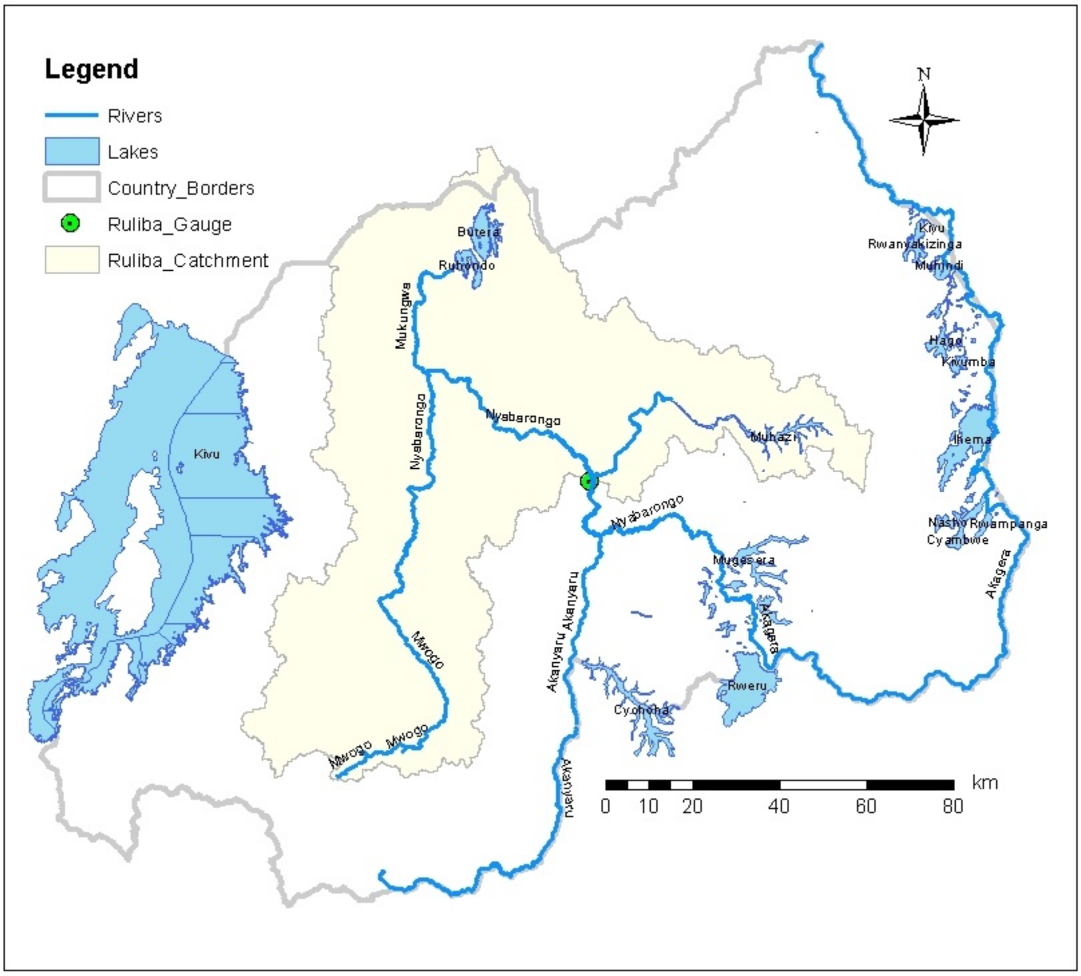


Figure 5.8: River Nyaborongo and its main tributaries

It is important to recall here that the hydrological analysis conducted in Chapter 6 covered a subcatchment of the Nyabarongo River basin named in this study Ruliba catchment with outlet point at the Ruliba stream gauge station (see Figure 5.8).

According to information collected from REG, a multipurpose project that incorporates water supply, agricultural irrigation and power generation from the Nyabarongo River (see Figure 5.9) was under feasibility study in 2015. Under this project scope, four power plants: Shyorongi hydropower plant (37.5 MW), Butamwa pumped Storage (40

MW), Juru pumped storage (40 MW) and Lake Sake hydropower plant (10.5 MW) are envisaged.

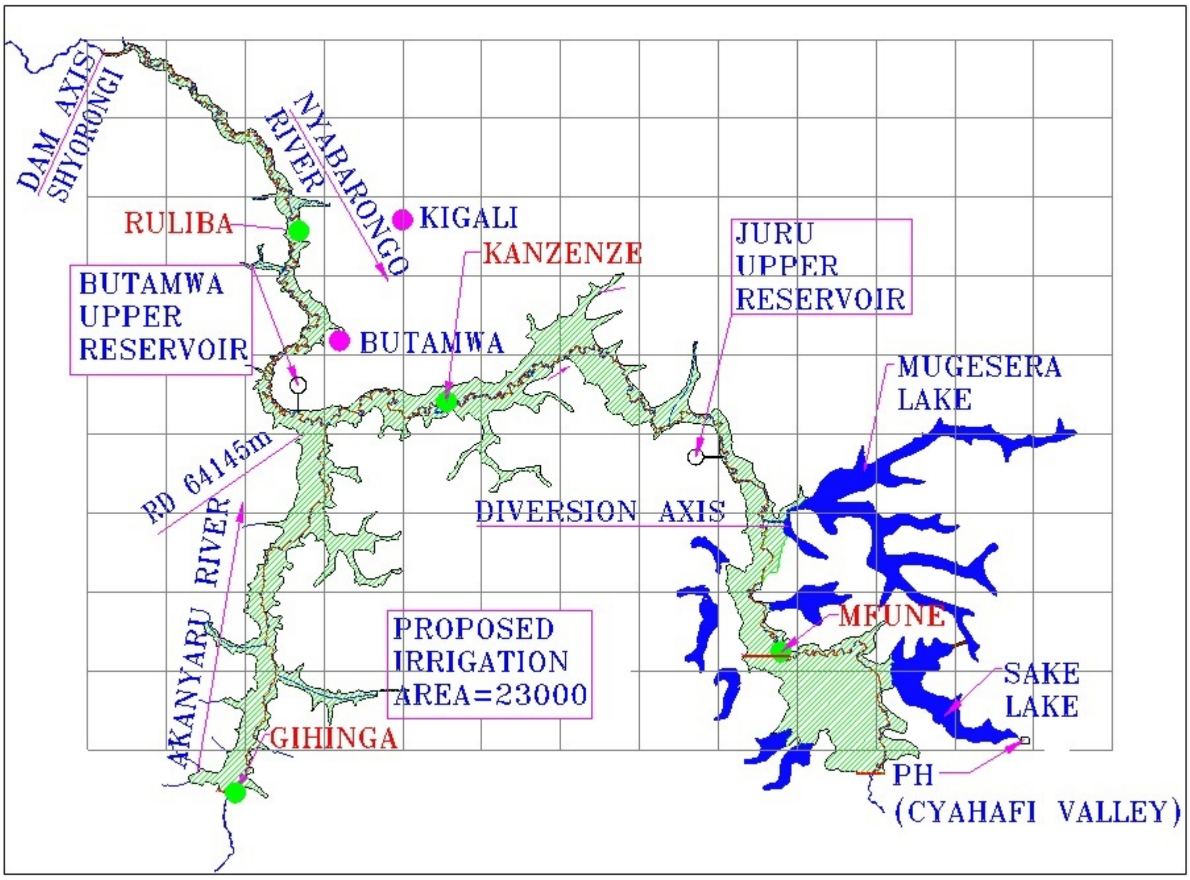


Figure 5.9: Nyaborongo – II multipurpose project (REG, 2015)

Because the feasibility study of this project was not yet ready by the time this dissertation was written, the same plant availabilities as for the case of RCP4.5 and RCP8.5 power supply scenarios are assumed.

- **Municipal waste to power**

As presented in Section 2.5.8, a quantity of 400 tons of solid waste per day (City of Kigali 2013b, 2) or 146,000 tons per year was available in 2012. In this study it was assumed that 75% of the waste (equivalent to 300 tons per day) could be available for power generation. Given a net heat content of 14 GJ per metric ton (Heaps 2011) and an electrical efficiency of 35% (The World Bank 1999, 60), the 300 tons would produce about 408 MWh of electricity per day that corresponds to 17 MW of installed capacity.

As the population of the City of Kigali was 1.114 million inhabitants in 2012 (NISR 2012a, 10), 300 tons of waste corresponds to about 0.27 kg of waste per capita per day. Given the projected population of 3.5 million (under the medium scenario) by 2040 (City of Kigali 2013a, 7), available waste for power production would be 0.27 kg/person times 3.5 million people which gives about 940 tons per day. This quantity of waste is enough to feed a 50 MW waste fired power plant.

5.6 Estimation of the electricity generation costs

This section describes the data and assumptions used to estimate the cost of power generation between 2012 and 2050. Three types of costs: investment costs, the fixed Operation and Maintenance (OM) costs and the variable OM costs were considered.

5.6.1 Investment costs

Hydropower: investment costs for regional hydropower plants namely Rusizi III (48 MW), Rusizi IV (98 MW) and Rusumo Falls (20.5 MW) were estimated to be US$ 150 million, US$ 240 million and US$ 53 million respectively according to AfDB (2013, 34) which corresponds to an average of US$ 2,660/kW. The investment cost of storage based hydropower generation was based on cost estimation of Nyabarongo II. This plant is a multi−purpose project that incorporates hydropower generation, water supply and irrigation. As no details on each of the project components was available at the time of data analysis, it was assumed that hydropower generation will cost 50% of the total project cost which is US$ 158 million (AfDB 2013, 86). Based on these assumptions, the investment cost for hydropower storage based power plant was set to be US$ 4,600/kW. The unit cost for micro− and mini−hydropower plants was set to be US$ 5,500/kW based on the estimates by AfDB (2013, 91). As for the other national power plants (with installed capacity greater than 1 MW) investment cost was estimated as the weighted average unit cost of Nyabarongo I (28 MW), Rukarara I (9.5 MW) and Mukungwa II (2.5 MW) (Fichner and decon 2010b). Estimates of different costs used in this study are summarized in Table 5.7.

Solar: by the year 2015, two solar power plants: Kigali Solar (250 kW) and Rwamagana Solar (8,500 kW) power stations were connected to the national electricity grid. Kigali solar (owned by Stadtwerke Mainz AG) was commissioned in 2007 while Rwamagana Solar (Gigawatt Global Cooperatief U.A.) was commissioned in 2014. To estimate the capital costs for solar based power plants, the unit capital cost for Rwamagana Solar power station was used. The total investment costs of this project were US$ 23.7 million (Gigawatt Global 2014) which corresponds to about US$ 2.78 million per megawatt.

To estimate the investment costs in the future, information from the report “Technology

Roadmap: Solar Photovoltaic Energy" by IEA (2014e, 5) is used. In this report it was projected that on average investment costs for solar PV plants will fall by 25% by 2020, 45% by 2030 and 65% by 2050 relative to the costs in 2012. In this research, the same reductions are applied to the investment costs of 2012 so that the investment cost will fall from US$ 2.78 million per MW in 2012 to US$ 2.10 million by 2020, US$ 1.54 million by 2030 and US$ 0.98 million by 2050.

Wind: because no wind power plant has yet been installed in Rwanda, international average data were used. However, to take into account factors such as transport of wind power generation components as well as the cost of technology transfer, a factor of 10% was added to the international data. Consequently, an average of US$ 2,000/kW was taken as the global average investment costs; and for Rwanda the cost would be 10% higher (i.e. US$ 2,200/kW). According to IEA (2014f, 23), the average investment cost of wind energy is projected to decrease by 25% on land and 45% off shore by 2050. Only land based wind power is possible in Rwanda, therefore a reduction of 25% by 2050 was applied.

Geothermal, methane and peat: the investment costs for geothermal, methane and peat based power plants were set to be respectively US$ 3,440, US$ 3,000 and US$ 2,480 based on information from AfDB (2013) and Fichner and decon (2010b).

Municipal waste: the investment cost of 1 MW was assumed to be US$ 4 million based on CEWEP (2013, 8).

Oil products: investment costs for diesel based power plants were assumed to be US$ 3,300 according AfDB (2013, 47).

5.6.2 Fixed operation and maintenance costs

The OM costs for different technologies were estimated based on three studies: Rwanda Energy Sector Review and Action Plan by AfDB (2013), Energy Mix Strategic Plan 2017 "Supply Oriented" Scenario of the Actualization Study of the Electricity Master plan by Fichner and decon (2010b) and the Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants by IEA (2013). The assumed OM costs in this study are also presented in Table 5.7.

5.6.3 Variable operation and maintenance costs

The variable OM costs for hydropower, geothermal, solar and wind technologies were assumed to be zero according to IEA (2013, 6). Similarly, the variable O&M costs for waste−to−power plants were also set to zero due to the fact that households and institutions pay a fee for the collection of their waste. Consequently, it was assumed that the variable O&M costs will be offset by the paid collection fee. The O&M costs for peat fired power plants, methane gas and diesel based power plants were extracted from AfDB (2013) and Fichner and decon (2010b) and they are presented in Table 5.7.

As for diesel fired power plants, an analysis of the past evolution of crude oil prices and energy imports by The World Bank (2011, 23) revealed that crude oil prices and Rwanda's energy product import prices are highly correlated. Therefore, to estimate future prices of diesel in Rwanda the relative changes in crude oil prices projected by IEA (2014c) were applied to the price of diesel in Rwanda. The IEA developed three scenarios: the 2℃ scenario (2DS), the 4℃ scenario (4DS) and the the 6℃ scenario (6DS). The 2DS projects future energy consumption and supply which are consistent with an emissions trajectory that allows limiting average global temperature increase to 2°C; the 4DS takes into consideration CO_2 limitation measures set by countries which would limit the long term temperature rise to 4℃; the 6DS is largely an extension of current trends where energy use almost doubles (compared with 2009) and the associated CO_2 emissions increase further causing the global mean temperature rise by 6°C (IEA 2014d, 31). In the IEA's projections, it is anticipated that the price of the crude oil (in 2013 US$/bbl) would decrease from US$ 106 in 2012 to US$ 98 by 2050 under the 2DS, increase from US$ 106 in 2012 to US$ 137 by 2050 for the case of the 4DS and from US$ 106 in 2012 to US$ 167 by 2050 under the 6DS. Given the international commitment to limit GHG emissions to 2℃ and the rapid development in renewable energy technology, this study assumed prices under the 2DS scenario. Consequently, a reduction of oil prices of 7.5% by 2050 relative to 2012 value was assumed.

Table 5.7: Assumed costs, plant availabilities and process efficiencies for different energy techonlogies (Author based on information from AfDB (2013, 47), Fichner and decon (2010b, 8–8) and IEA (2013, 6))

ID	Technology	Capital cost (US$/kW)	Fixed O&M (US$/kW·yr)	Variable O&M (US$/MWh)	Availability (%)
1	Domestic hydro	4,120	18.00	0.00	62.00
2	Regional hydro	2,660	18.00	0.00	55.00
3	Storage hydro	4,600	18.00	0.00	62.00
4	Micro hydro	3,850	18.00	0.00	62.00
5	Geothermal	3,400	132.00	0.00	96.00
6	Solar PV	2,780	27.75	0.00	20.00
7	Peat	2,480	80.53	54.88	85.00
8	Methane	3,000	65.00	106.80	92.00
9	Diesel	3,300	65.00	281.27	90.00
10	Waste to power	4,000	392.82	0.00	80.00
11	Wind	2,200	39.55	0.00	12.90

5.7 Pollution from power generation

Emissions from the electricity generation is calculated internally in LEAP depending on the chosen approach. This is done by linking the electricity producing technologies to the model Technology and Environmental Database (TED) which contains hundreds of emission factors including the default emission factors suggested by the IPCC for use in climate change mitigation analyses (Heaps 2011, 75). In this study three GHG emitting fuels namely diesel, methane gas and peat were linked to IPCC Tier 1 Default Emission Factors included in LEAP. Under Tier 1 approach, GHG emissions from stationary combustions are calculated by multiplying the consumed fuel by the default emission factor according to Equation 5.21 (IPCC 2006, 2.11–12).

$$Emission_{GHG,fuel} = Fuel\ consumption_{fuel} \cdot Emission\ factor_{GHG,fuel} \tag{5.21}$$

with:

$\text{Emission}_{\text{GHG,fuel}}$	:	Emissions of a given GHG by type of fuel, (kg GHG)
$\text{Fuel consumption}_{\text{fuel}}$	:	Amount of fuel combusted, (TJ)
$\text{Emission factor}_{\text{GHG, fuel}}$	:	Default emission factor of a given GHG by type of fuel (kg gas/TJ)

Chapter 6

Calibration and validation results

In this chapter, the results obtained during the calibration and validation of the WEAP model are presented and discussed. The model was run using the calibrated parameters and statistics were computed in order to compare the model performance with recommended hydrological model performance ratings. Based on the performance, decisions on acceptance or rejection of the model can be made.

6.1 Calibration and validation processes

During the calibration process, numerous model runs were performed and after each run the model output parameters were analysed to check if the results fall within acceptable and desired limits. This was conducted through the performance assessment of the calibrated hydrological model. To ensure that the model can be used for impact assessment, parameters determined during the calibration process were applied to another set of observed data in order to validate it as recommended by literature such as, for example, US EPA (2002), Doherty (2004) and Refsgaard (1997). The calibration and validation periods at a monthly time step were 1974−1981 and 1982−1989 respectively .

As discussed in Section 4.2, model calibration consists of adjusting the model input parameters until the model produces acceptable outputs as compared to natural data for the same conditions (Moriasi et al. 2007). The applied lower and upper bounds as well as the final values of calibrated parameters are shown in Table 6.1.

As it can be noticed from Table 6.1, the upper soil layer was less saturated at the beginning of the calibration process (26%) compared to the deeper layer (48%). This is mainly due to the fact that January, the first month of simulation, is in the short dry season and that the saturated hydraulic conductivity of the root zone (125 mm/month) is relatively much higher so that it drains water from the upper layer to the lower layer much faster.

Table 6.1: Calibrated soil parameters

Parameter	Lower bound	Upper bound	Final value
k_{s1} (mm/month)	20	280	125
k_{s2} (mm/month)	–	–	66
Z_1 (%)	15	100	26
Z_2 (%)	25	100	48
RZWC (mm)	30	600	440
DWC (mm)	120	1080	560
PFD	0	1	0.11

Table 6.2: Model performance

	Calibration	Validation
r	0.92	0.93
RSR	0.39	0.41
NSE	0.85	0.83
PBIAS	−2.81	3.18

The water holding capacities on the other hand are 440 and 560 mm/month for the root zone and the lower layers respectively. The partitioning value of 0.11 indicates that 89% of available water in the root zone percolate to the deep layer while the remaining 11% are directly converted into interflow.

6.2 Hydrological model performance

As discussed in Section 4.3, a performance test is required in order to decide about the acceptability or rejection of parameters determined during the calibration and validation processes. As proven by the model performance results shown in in Table 6.1, the model performed excellently because all the analysed statistics (i.e. r, RSR, NSE and PBIAS) fall within the limits of the very good performance according to the general performance ratings for recommended statistics for a monthly time step.

Pearson's correlation coefficient (r) that measures the relationship between observed and simulated stream flow discharges is positive 0.92 for the calibration period. This means that both the measured and simulated flows increase proportionally. This can be noticed from Figure 6.1 (a) that shows the relationship between observed (historical) and simulated stream flows at the Ruliba gauging station for the calibration period. The bias between historical and simulated stream flows for the same period is only −2.81% which shows an excellent performance according to Moriasi et al. (2007, 891). The negative value of PBIAS means that the model overestimated the flow (see Figure 6.2).

Similar to the performance during the calibration, the analysis of the simulation outputs during the validation period also revealed an excellent simulation. Pearson's correlation coefficient is found to be 0.93 which indicates a strong positive correlation as it can be seen in Figure 6.1 (b). The model simulated relatively higher flows as compared to observed flows which justifies the positive value of PBIAS equivalent to 3.18% (see Figure 6.3 for illustration).

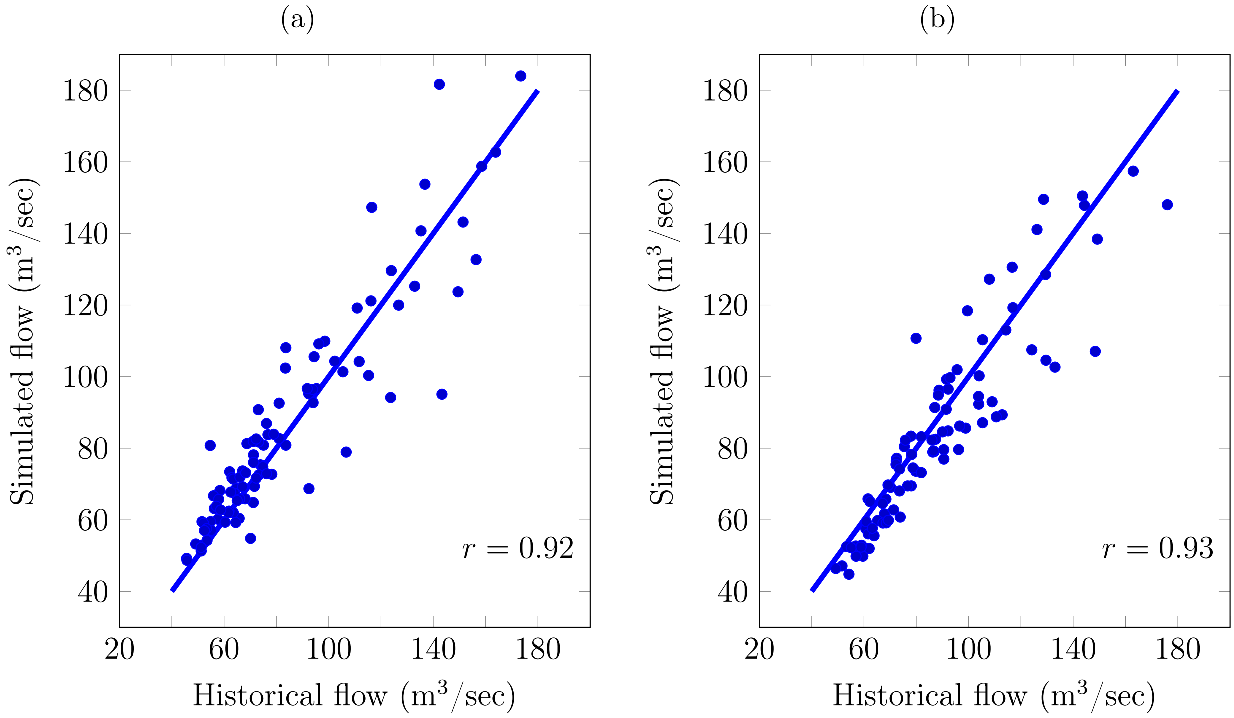


Figure 6.1: Relationship between historical and simulated flow discharge at the Ruliba station. The relationship during the calibration period is shown in (a) while the relationship during the validation period can be visualised in (b).

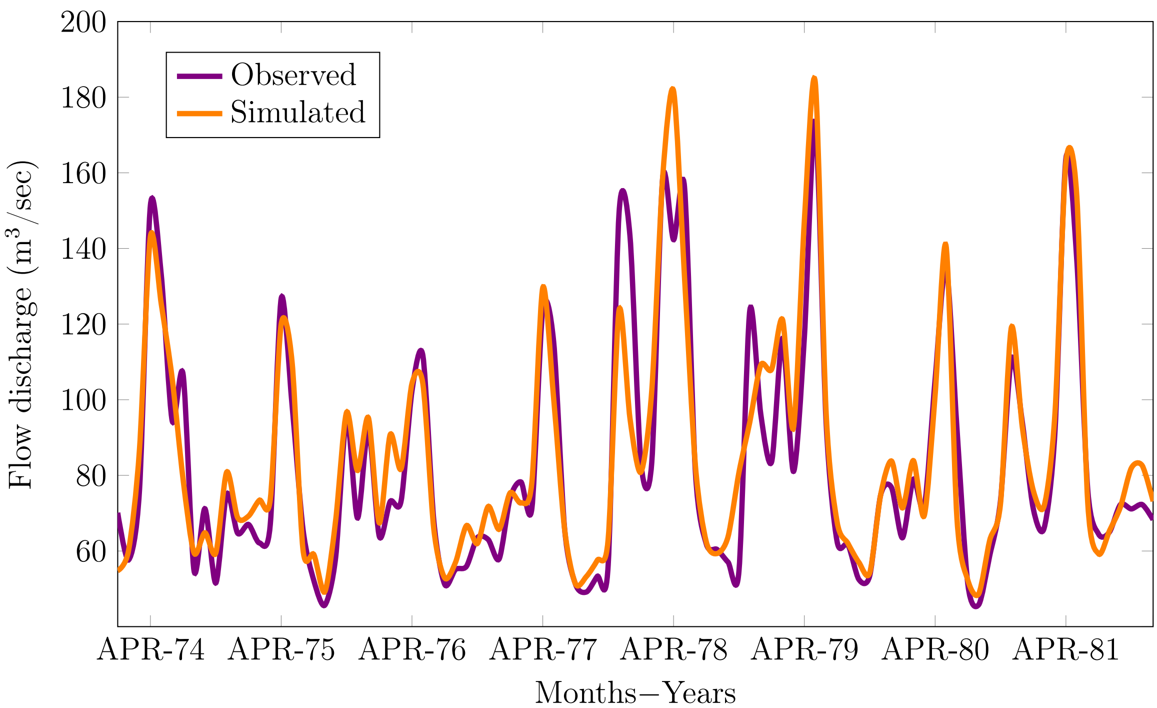


Figure 6.2: Observed and simulated stream flows at the Ruliba during the calibration period

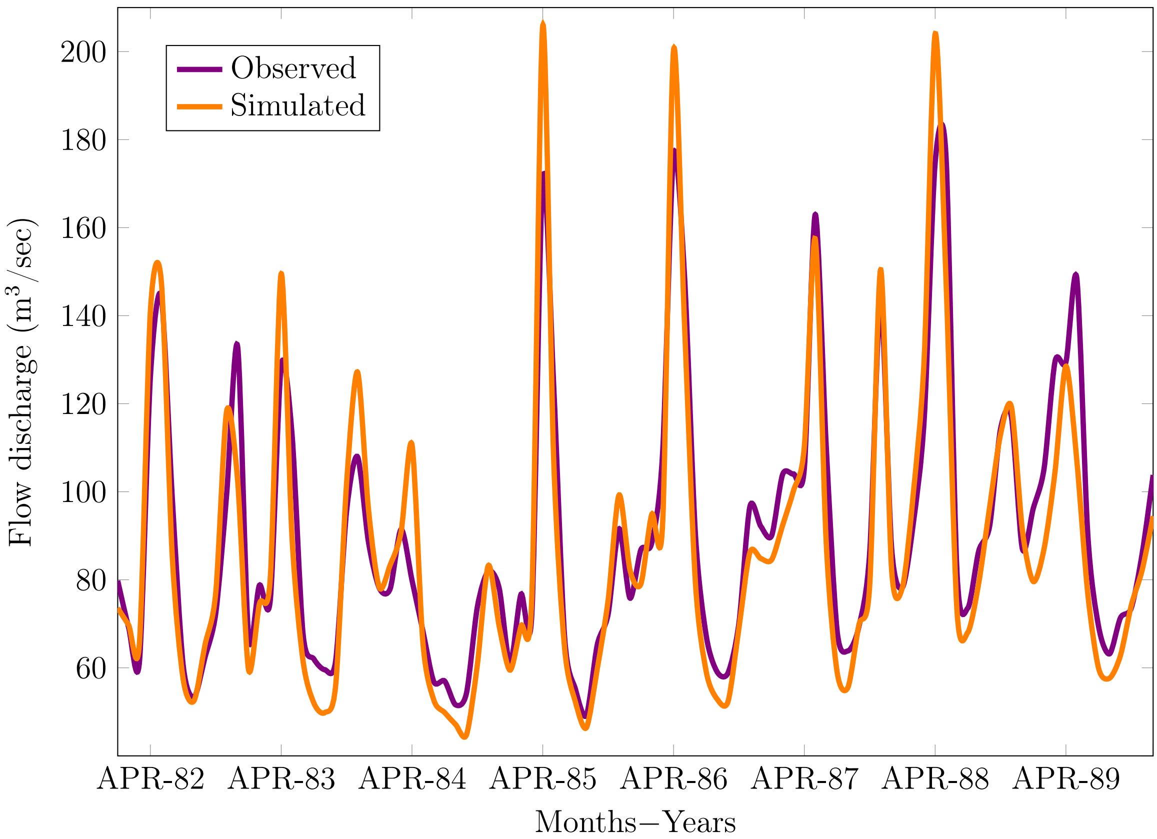


Figure 6.3: Observed and simulated flow discharges during the validation period

As for the goodness of fit, NSE values were found to be respectively 0.85 and 0.83 for the calibration and validation periods. These values are higher than the lower threshold of a very good performance simulation of 0.75 suggested by Moriasi et al. (2007, 891). In addition, RSR values for the calibration and validation were found to be respectively 0.39 and 0.41, and they are smaller than 0.5, the upper threshold of a very good performance as summarized in Table 4.3.

The calibrated parameters allowed to reproduce average monthly stream flows especially during the calibration period as shown in Figure 6.4 (a). As for the validation period, the simulation reproduced historical average monthly flow discharges except for the month of April when the average simulated flow exceeds the historical flow by 18% as it can be seen in Figure 6.4 (b). The analysis of observed and simulated annual flows (see Figure 6.5) revealed that the discrepancies between simulated and historical values are smaller than 9%, with the exception of 1989 when the simulated value is 14% lower than the corresponding recorded value.

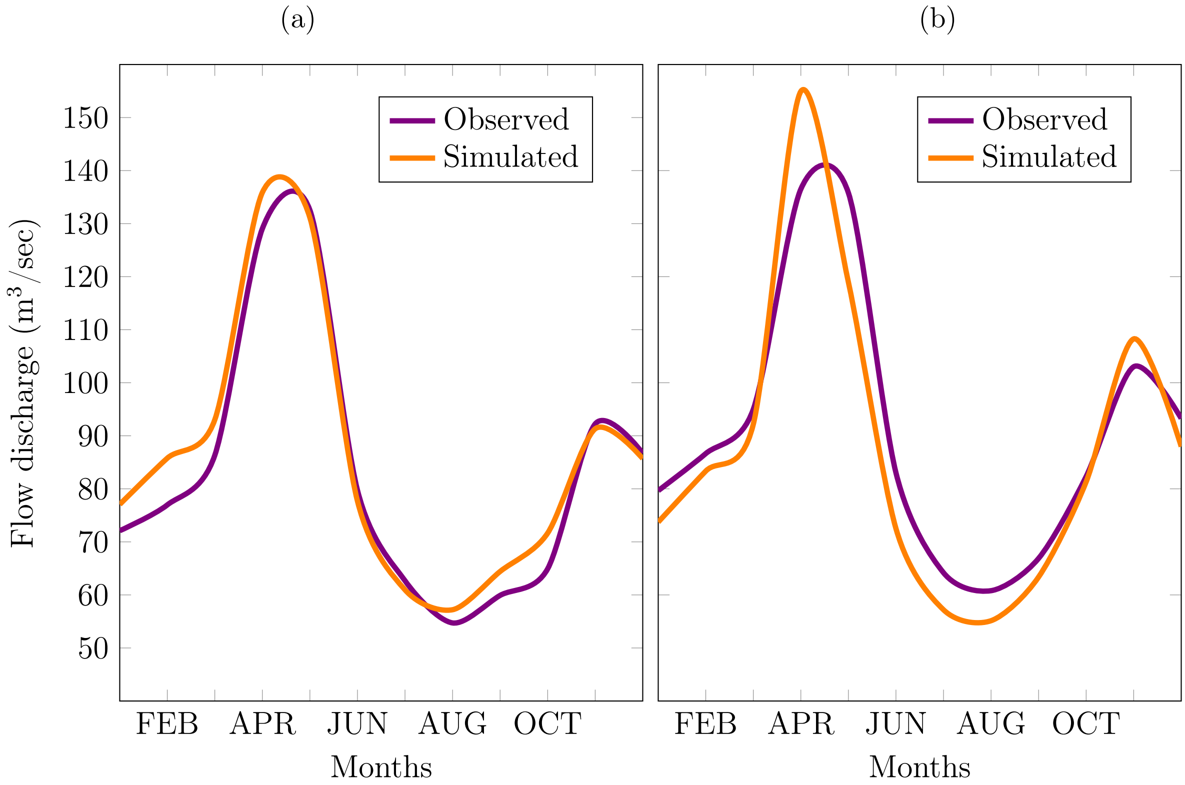


Figure 6.4: Observed and simulated average monthly flows at the Ruliba station. The calibration results can be visualised in (a) and the validation ones in (b).

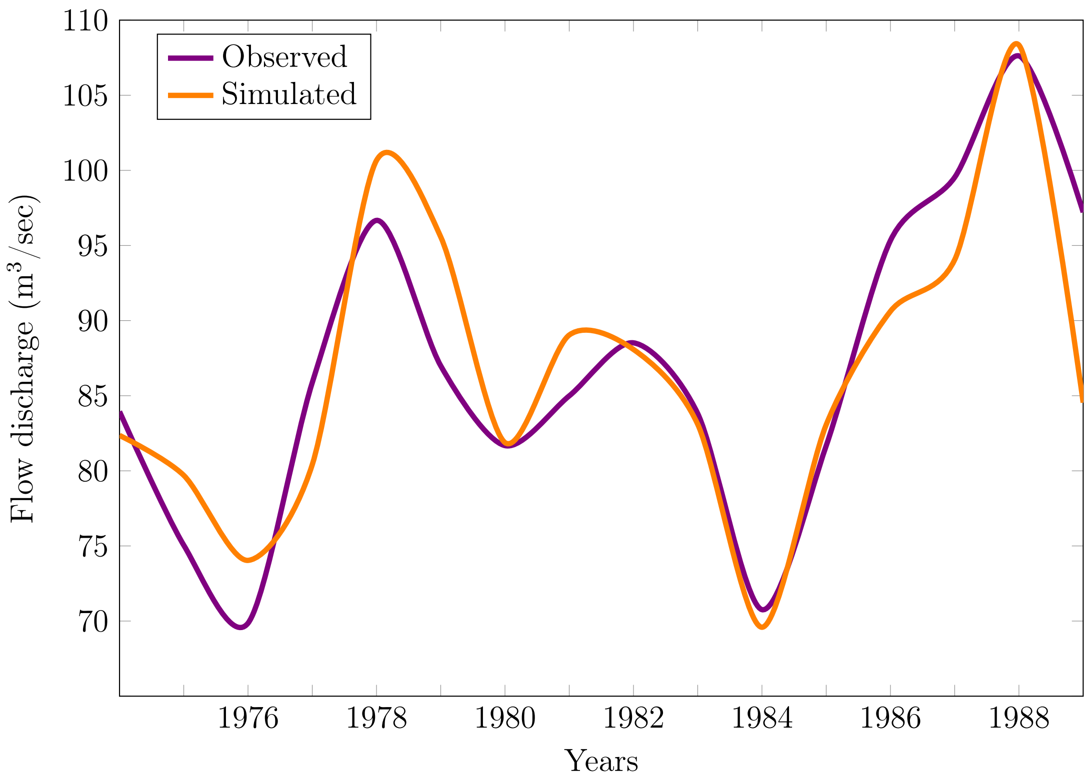


Figure 6.5: Annual observed and simulated stream flows at the Ruliba station

6.3 Discussion

Although the calibration and validation results discussed in this chapter show a very good model performance which qualifies it to be used for climate impact assessment, these results were obtained after long processes and many simulation trials which took too much time than previously planned.

During the design of this study, it was planned to use climate data from the studied catchment, that is why a field visit was conducted in 2013 to collect required data. During the analysis of the acquired daily time series data, however, it was realised that there were many missing records and abnormal values compared to stream gauge records. For many cases high values of stream discharges were recorded whereas no rain was recorded for that period or vice versa. As mentioned in Section 4.2.1 there were no other reasons that could justify these discrepancies than measurement errors as the catchment under investigation is relatively small so that the time rain takes to reach the stream could justify these discrepancies. For the missing value it was thought that interpolation would solve the problem but many simulations were conducted and none of them provided expected results. It was therefore not possible to continue with these data.

In the search of a solution to these challenges, climate data from the WFD was found to solve the above problems (missing records and discrepancies between precipitations and flow discharges) as discussed in Section 4.2.1. It is important to notice, however, that the results were obtained under the assumption that historical flow discharges are error free which is not always true especially in developing countries where measuring instruments may not be precise.

Chapter 7

Projected climate and its impacts on hydropower generation

This chapter discusses first the past climate of Rwanda and that of the studied catchment (Ruliba). Afterwards, the projected climate of Ruliba is analysed together with potential impacts of the projected climate on water resources and on hydropower plants located in this catchment. At the end of the chapter identified impacts are extrapolated to the whole country's hydropower generation in order to assess the overall impacts at the national level.

7.1 Past climate

In this section, the past climate of Rwanda and that of the study area are presented and discussed. The analysed past climate covers the period starting from 1961 through 2010 inclusive. For the analysis only precipitations and temperature are assessed as they are the main drivers of changes in hydropower generation.

7.1.1 Observed precipitations

To evaluate the evolution of the past climate, the annual RR, PCD, annual total precipitations, annual mean temperature and monthly average precipitations were analysed. RR measures the percentage of wet days in a year. As one can notice from Figure 7.1, there are two distinct periods in terms of RR. The first period characterised by a decreasing trend extends from 1961 to 1985. During this period, the number of wet days has decreased by 1.12% per year for the Ruliba catchment and 0.71% per year at the national level. The second period is 1986 to 2010 when RR presents an increasing trend at a rate of 1.96% per year at the Ruliba catchment and 1.62% per year at the national levels. For the whole period 1961 to 2010 the analysis of changes in RR indicates an increasing rate of 0.18% and 0.7% per year for the national and catchment levels respectively.

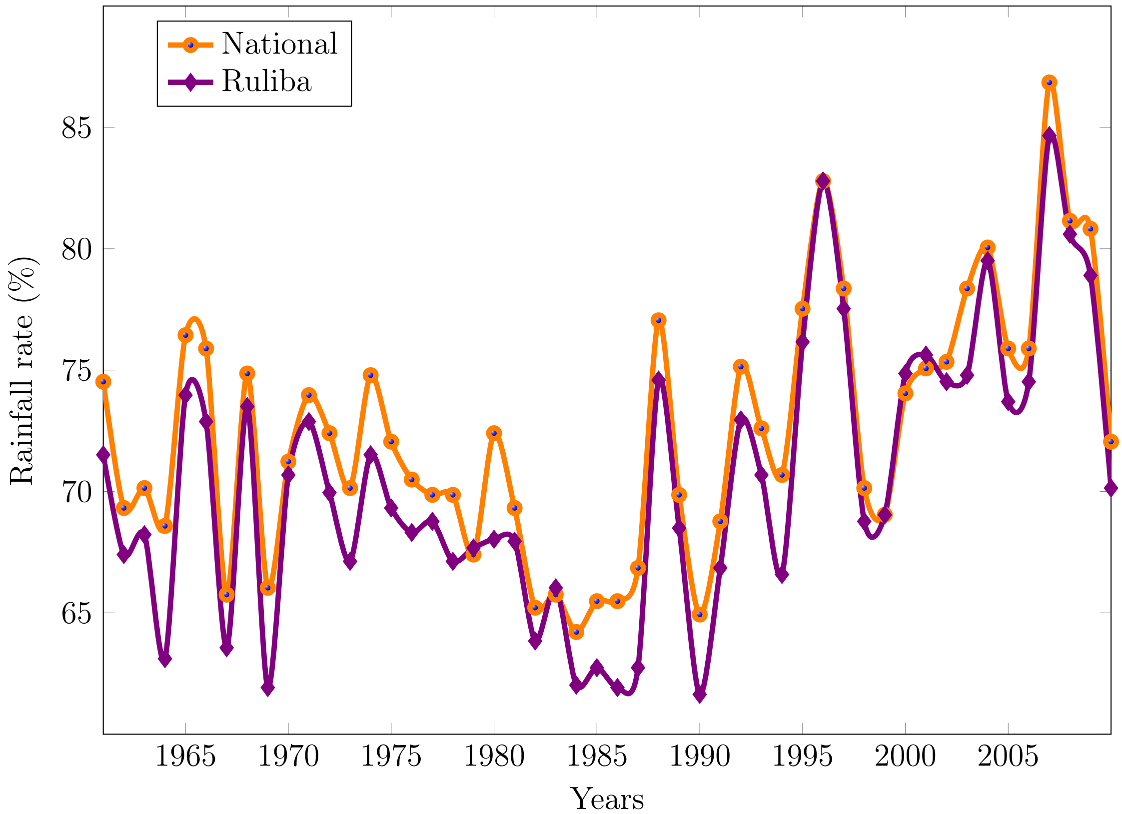


Figure 7.1: Rainfall rate for the 1961 − 2010 period

A diminishing number of wet days (or of RR) means that either the annual total precipitations decrease or the precipitations are more and more concentrating on short periods if the annual total precipitations do not change. On the other hand, increasing values of RR result in increasing annual total precipitations or decreasing intensity of rainfall if annual total precipitation do not change. The analysis of annual total precipitations shows an average of about 1200 mm per year for the national level and 1260 mm per year at the Ruliba station. As it can be noticed from Figure 7.2, there are no observable trends in annual total precipitations. Therefore, the decreasing trend observed in the number of wet days for the 1961−1985 period (see Figure 7.1) can only be explained by the fact that precipitations were gradually concentrating on short time periods as it can also be seen in Figure 7.3. Similarly, the increasing trend in the number of wet days for the 1986−2010 period indicates that precipitations were scattering over many days.

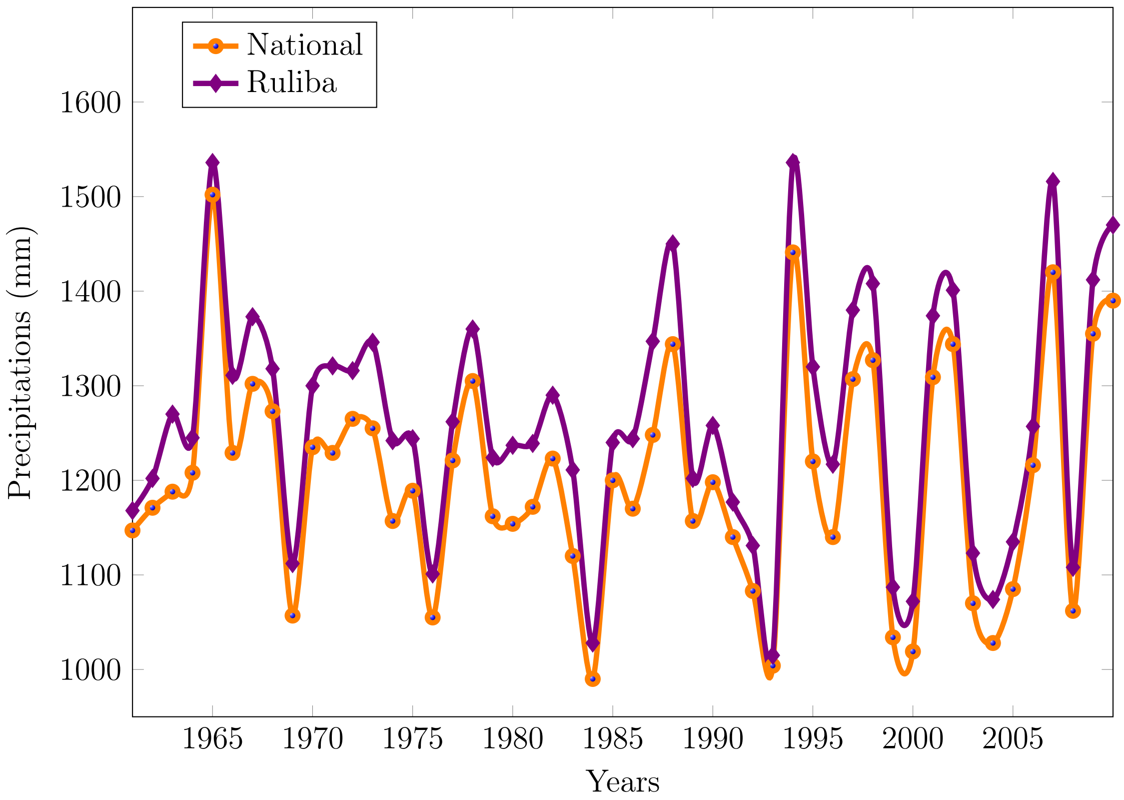


Figure 7.2: Historical annual precipitations for the $1961 - 2010$ period

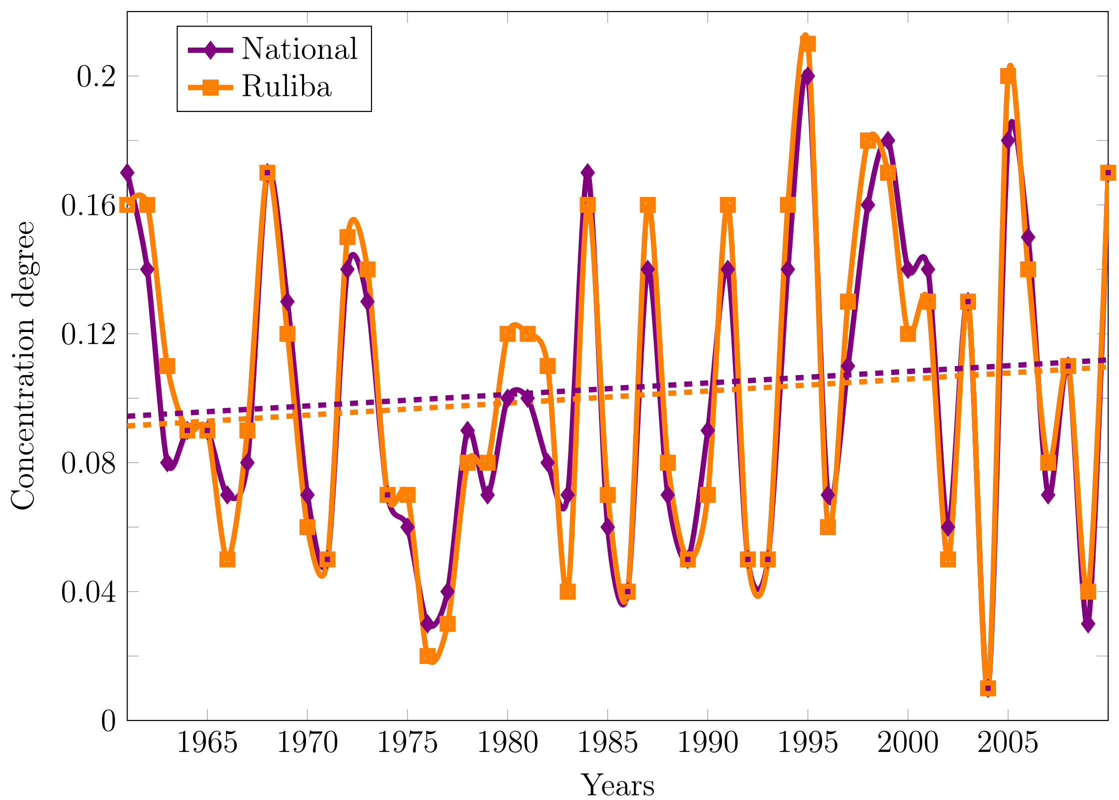


Figure 7.3: Precipitation concentration degree for the $1961 - 2010$ period

Although no trend was detected in the annual total precipitations, the inter−annual variations of precipitations increase in such a way that the deficits and excesses are increasingly escalating. The highest observed precipitation deficits between 1961 and 2010 were 19.7% for the national level and 17.5% at the Ruliba station recorded respectively in 1984 and 1993 (see Figure 7.2). As for excesses, the highest precipitation records were measured in 1965 and were, respectively, 25.17% and 21.52% higher than the annual mean (see Figure 7.2). It was also found that the deficit and excess precipitations appeared at almost regular intervals (4−7 years) and they correspond with El Niño episodes and La Niña discussed in Section 3.5.1. As for the monthly distribution of precipitations, the minimum, 25^{th} percentile, median, 75^{th} percentile and the maximum monthly precipitation value for the 1961−2010 period are shown in Figure 7.4.

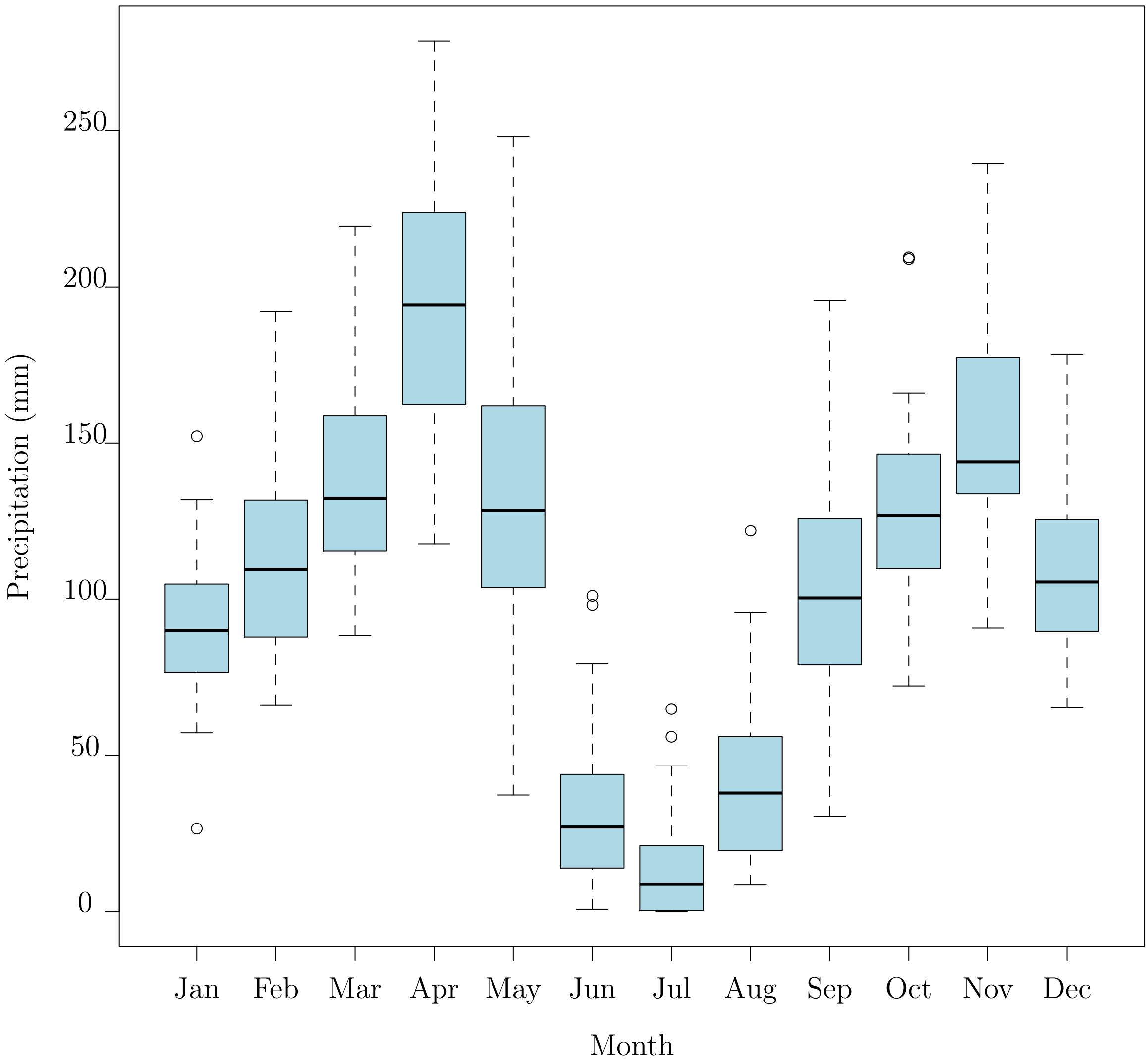


Figure 7.4: Distribution of Monthly precipitations at the Ruliba stream gauge station for the 1961 − 2010 period

To determine the degree of asymmetry of the monthly distribution around the mean, a skew coefficient, S_k, for each month was calculated according to Equation 7.1 (from Excel tool). In this equation n is the total number of years (50 years in this case), x_{ij} is the precipitation record for month j in year i, μ_j and σ_j are, respectively, the mean and standard deviation for month j.

$$S_k = \frac{n}{(n-1)(n-2)} \left(\sum_{i,j=1}^{n} \frac{x_{ij} - \mu_j}{\sigma_j} \right)^3 \tag{7.1}$$

When the distance from the median to the minimum of the distribution is equal to that from the median to the maximum (S_k=0), it can be concluded that the data are symmetrically distributed. In case the median is closer to the upper end (maximum) of the distribution ($S_k < 0$), this means that the tail of the data is on the left hand side and the distribution is said to be skewed left (negatively skewed). When the median is closer to the lower end (minimum) of the distribution ($S_k > 0$), the distribution is said to be positively skewed (or skewed right).

The analysis of the skewness reveals negative skew coefficients for the months of April, September and October which means that the tail of the data is on the left hand side and the distribution is said to be skewed left (negatively skewed). In other words the majority of the precipitation records for these three months are higher than the mean of the entire distribution, but there are few years with extremely low values. Precipitation distributions for the other 9 months are positively skewed (SK$>$ 0) which signifies that the tail of the distribution points toward the positive direction which signifies that most of the precipitation records for these months are lower than the mean but there are some few months characterised by extremely high value. However, the results of the significant test using the values of 2 standard errors of skewness method showed that the months of January, June, July, August and December are significantly skewed right while the rest of the other months can be considered as symmetrically distributed.

7.1.2 Observed temperature

Unlike the situation of precipitations where there is no significant difference between the annual records for the National and Ruliba levels, there is a clear difference in temperature between the national and the catchment levels (see Figure 7.5). The analysis of temperature records shows a clear increasing trend as shown in Figure 7.5. On average, the increasing rate in annual mean temperature since 1961 is 0.035℃ per year (or 0.35℃ per decade) for the national level and 0.032℃ per year (or 0.32℃ per decade) for the Ruliba catchment. This means an overall increase of 1.75℃ and 1.6℃ for the national level and Ruliba respectively between 1961 and 2010. This shows that Rwanda is warming much faster than the increase in global (land and ocean combined) average temperature which ranges between 0.65°C and 1.06°C over the period from 1880 to 2012 (IPCC 2013, 37).

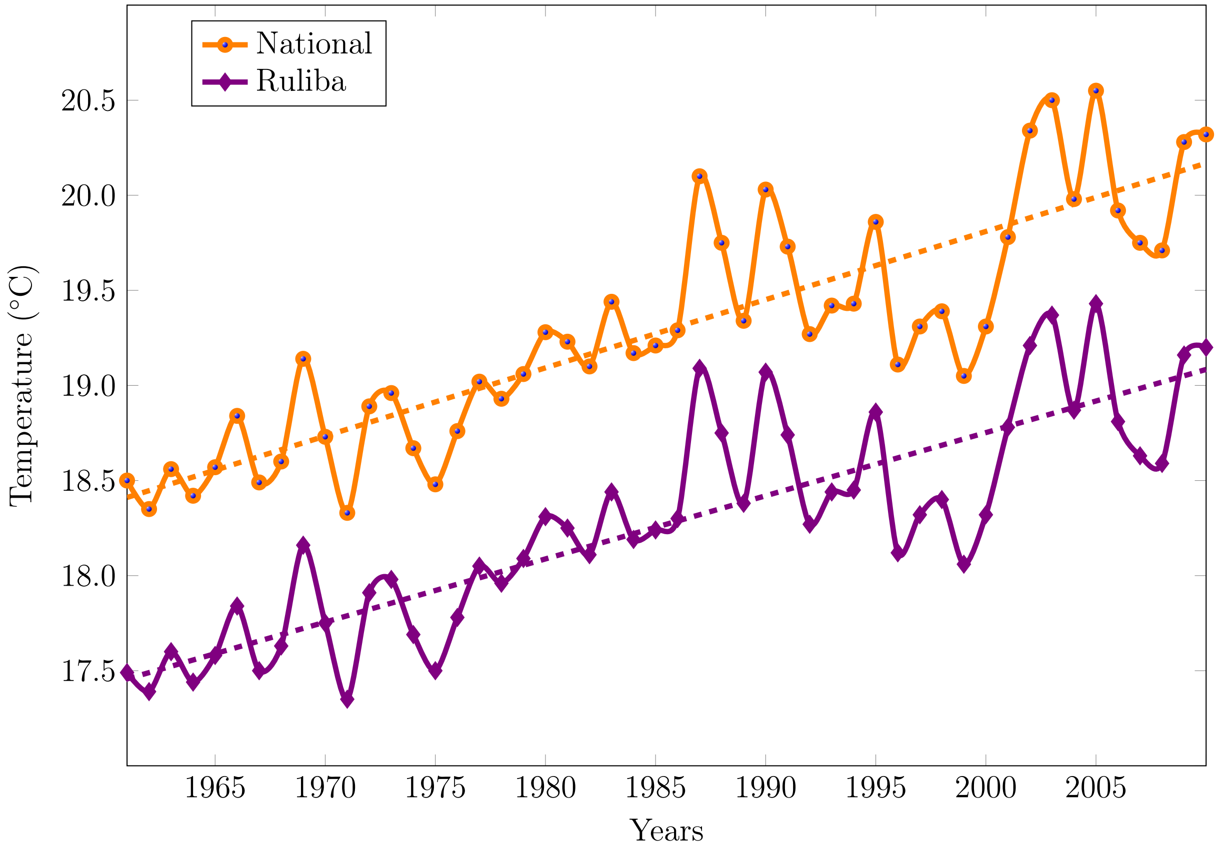


Figure 7.5: Historical annual mean temperature for the 1961 – 2010 period

In brief, from the analysis of historical precipitation and temperature time series for both the national and catchment levels, it can be concluded that the past climate of Rwanda was characterized by no significant trends in monthly and annual precipitations which agrees with the findings by McSweeney (2010). However, temperature records revealed an increase in annual mean temperature at a rate of 0.35°C per decade for the national level and 0.32°C per decade for the Ruliba catchment since 1961.

7.2 Projected climate

As mentioned methodology chapter, only the Ruliba catchment is considered for the analysis of the projected climate. The future climate in the Ruliba catchment was assessed by comparing projected precipitations and temperatures with their corresponding average values of the 1961−1990 period. The comparison was conducted on four periods of 20−years each from 2020 (i.e. 2020−2039, 2040−2059, 2060−2079 and 2080−2099). Before presenting the projected climate under HadGem2−ES and MIROC−ESM climate models, it is important to look at their performance to simulate observed rainfall and temperature during the reference period (i.e. 1961−1990). As it can be noticed from Figure 7.6 (a), the two models tend to reproduce observed precipitations with HadGem2−ES being more accurate than MIROC−ESM.

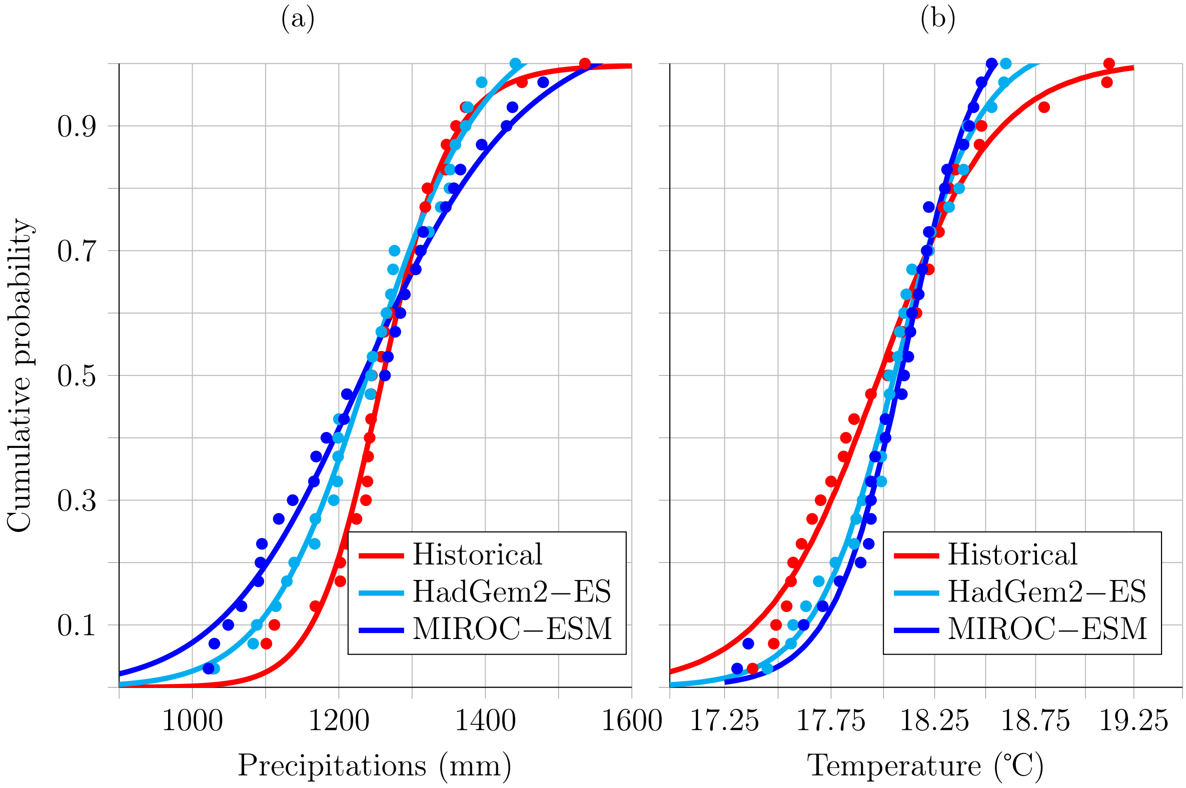


Figure 7.6: Cumulative distribution function of annual total precipitations (a) and annual mean temperature (b) for the 1961 − 1990 period. The dots represent the real data and the solid lines are the curve fits to the data smoothed using the four parameter logistic equation.

The analysis of occurrence probability of historical precipitation over this period shows that 93.33% of observed annual precipitations are concentrated between 1100 mm and 1400 mm. Within the same range fall 86.67% and 66.67% probabilities for HadGem2−ES and MIROC-ESM respectively. This means that the distribution of annual total rainfall simulated using MIROC−ESM data is more spread compared to that simulated by HadGem2−ES as well as that recorded between 1961 and 1990. In addition, out of 30 years of the reference period, simulated precipitations present many values below 1200 mm (12 for MIROC−ESM and 9 for HadGem2−ES) compared to historical precipitations (only 3). In terms of quantifying the discrepancies between historical and simulated precipitations, the biases are +5.28% and +4.90% for HadGem2−ES and MIROC−ESM respectively. The positive values of PBIAS mean that the models underestimated annual total precipitations (see Figure 7.6 (a)).

As for temperatures during the reference period, the simulations also tend to reproduce the observed temperature as it can be seen in Figure Figure 7.6 (b). For temperatures below 18℃, historical records are lower than the simulated ones and they are higher for temperature above 18.75℃. In this case, 83.33% of historical annual mean temperature fall within 17.5℃ and 18.25℃. Within the same range fall 86.67% and 90.00% of simulated HadGem2−ES and MIROC−ESM respectively. PBIAS for HadGem2−ES is −0.38% while it is −5.83% for MIROC−ESM. Based on PBIAS levels in producing historical annual precipitation and temperature values, it can be concluded that the models performed well in the reference period.

7.2.1 Projected precipitations

Concerning projected precipitations, the results of the analysis of annual total precipitation time series are summarised in Table 7.1. In this table, a negative median means that precipitation deficits are projected to be observed for at least 10 years while a positive median indicates excess precipitations for at least 10 years of the considered period (out of 20 years in this case). Under RCP4.5 scenario, the medians of changes in annual total rainfall at the Ruliba station are all negative for each analysed period from 2020 to 2079 which means that precipitation deficits are expected to last at least during half of the 2010−2079 period (see Table 7.1). In addition, deficits are projected to be more considerable than excess precipitations (see Figure 7.7 and Figure 7.8). However, towards the end of the century, both HadGem2−ES and MIROC−ESM models project excess precipitations are expected to be observed for at least 10 years of the 2080−2099 period. Similar to historical precipitations, there is no significant trend in the projected annual precipitations under RCP4.5 scenario where the average of percentage change in annual total precipitations varies from −4.11% to −1.48% for HadGem2−ES and −5.81% to +3.21% for MIROC−ESM models. These trends in annual total precipitations are, however, smaller compared to the interannual variability which are projected to range from −23.83% to +22.91% for HadGem2−ES and −24.48% to +29.20% for MIROC−ESM models.

On the other hand, it is expected, under RCP8.5, that out of the 20 years between 2020 and 2039, precipitation excess will be recorded for at least 10 years while at least 10 years of precipitation deficits are projected for the 2040−2059 period (see Table 7.1).

Table 7.1: Projected changes (%) in annual total rainfall at the Ruliba station. The given values are medians of the changes for the whole period while the values within brackets represent the minimum to maximum changes.

Period	HadGem2−ES	MIROC−ESM
	RCP4.5	
2020 – 2039	−1.10 (−20.08 to +14.43)	−5.73 (−24.49 to +26.06)
2040 – 2059	−4.26 (−18.14 to +6.19)	−9.41 (−22.81 to +20.35)
2060 – 2079	−1.46 (−23.00 to +16.20)	−7.02 (−24.80 to +11.99)
2080 – 2099	+0.94 (−24.04 to +22.30)	+3.51 (−15.40 to +27.26)
	RCP8.5	
2020 – 2039	+0.29 (−20.20 to +23.66)	+2.26 (−18.57 to +30.28)
2040 – 2059	−5.07 (−33.29 to +9.68)	−5.24 (−11.05 to +14.48)
2060 – 2079	−4.85 (−28.22 to +1.68)	+10.80 (−11.05 to +35.45)
2080 – 2099	−3.57 (−15.15 to +10.96)	+27.60 (−4.52 to +47.93)

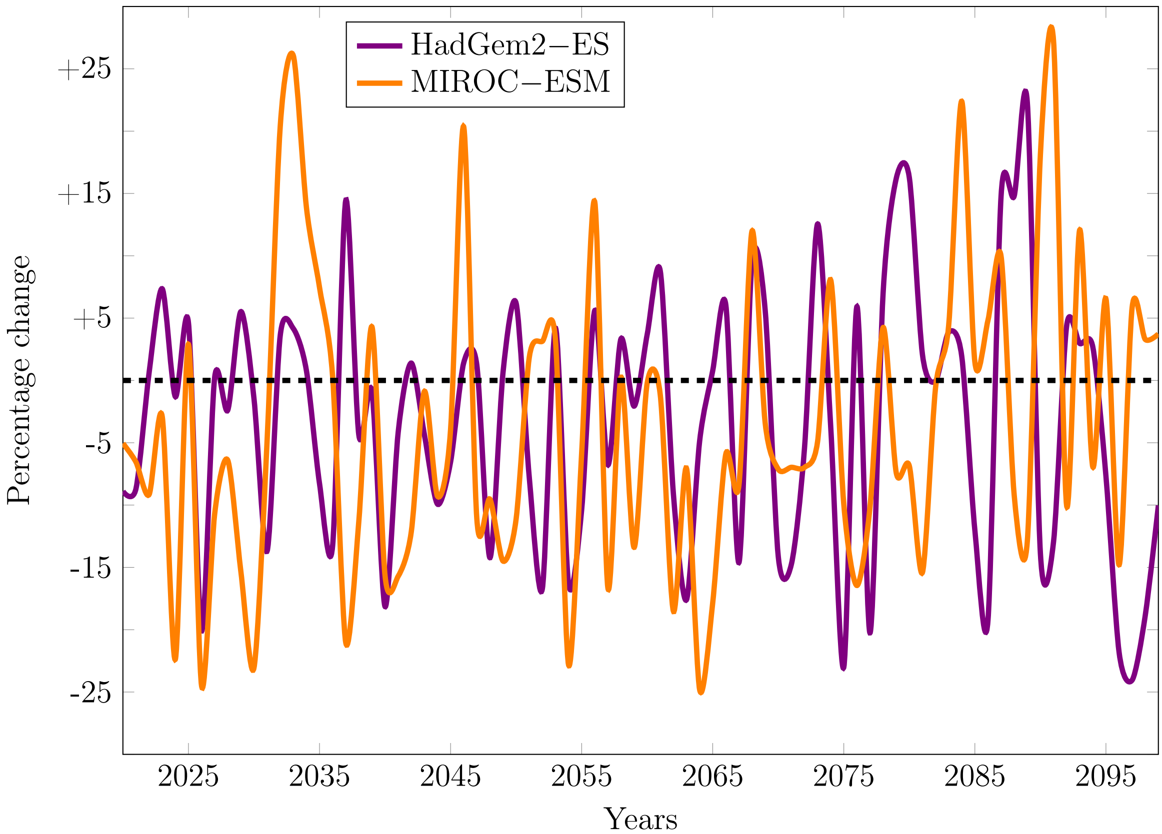


Figure 7.7: Precipitation anomalies under RCP4.5 relative to the 1961 – 1990 average

For the period from 2060 to 2099, excess precipitations are projected under MIROC−ESM while deficits are expected for HadGem2−ES models (see Figure 7.8). There is an increasing trend in annual total precipitation change for MIROC−ESM but no significant trend

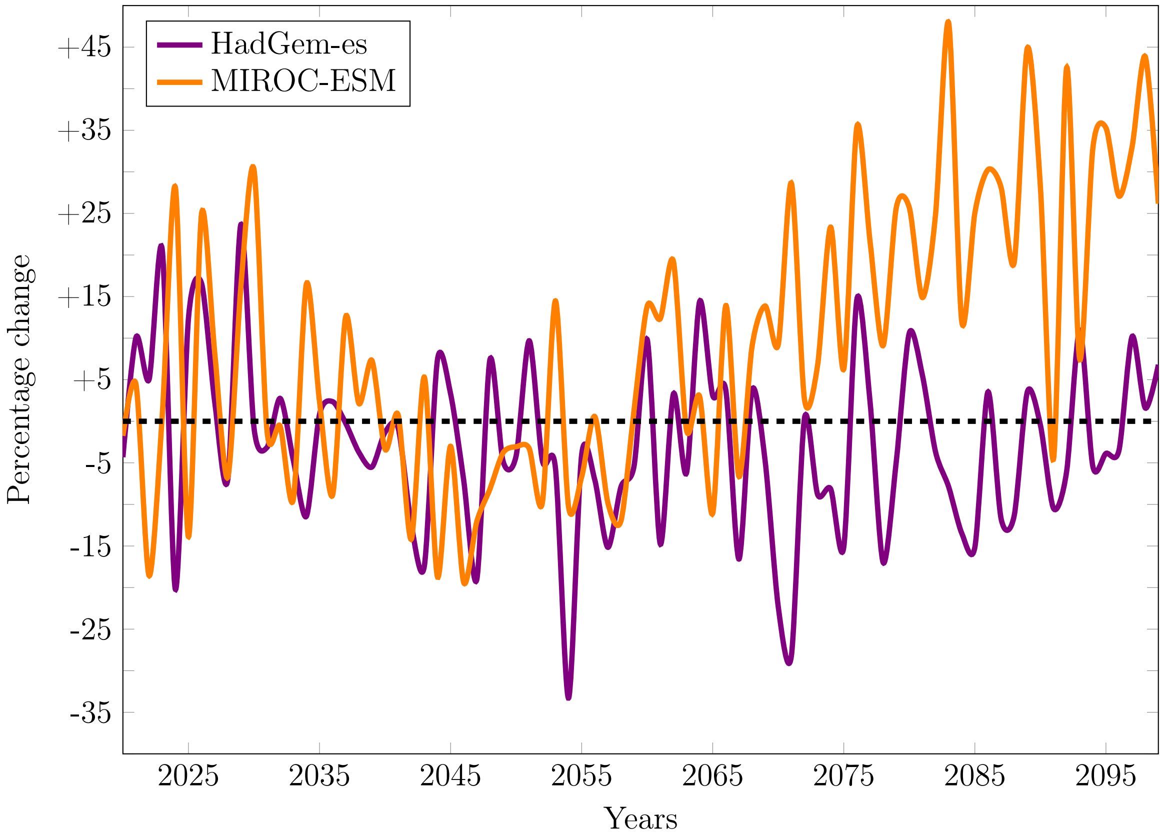


Figure 7.8: Precipitation anomalies under RCP8.5 scenario relative to the 1961 – 1990 average

in HadGem2−ES projections. Under RCP8.5, the average of percentage change in annual total precipitations vary from −5.55% to +2.40% for HadGem2−ES and −4.77% to +28.53% for MIROC−ESM models. In terms of in interannual variations, these are projected to range from −32.94% to +24.50% for HadGem2−ES and −19.25% to +50.21% for MIROC−ESM models.

To assess the distribution of projected precipitations across the months, PCD was computed for each model and scenario for the period 2020 to 2099 and the results are shown in Figure 7.9. As discussed in Section 4.4.1, PCD varies between 0 and 1 where a PCD value of 1 refers to a situation where all the precipitations concentrate on one period of the time (months in this study) whereas a PCD value of 0 indicates evenly temporal distributed precipitations. From Figure 7.9 it can be seen that observed precipitations tend to concentrate on a short time period compared to simulated precipitations.

In summary, the analysed climate models suggest very small changes in annual total precipitations for RCP4.5 scenario. Both HadGem2−ES and MIROC−ESM climate models under both RCP4.5 and RCP8.5 scenarios anticipate a decrease in annual precipitations for the mid-century (2030 – 2060) with very pronounced deficits in case of RCP8.5 scen-

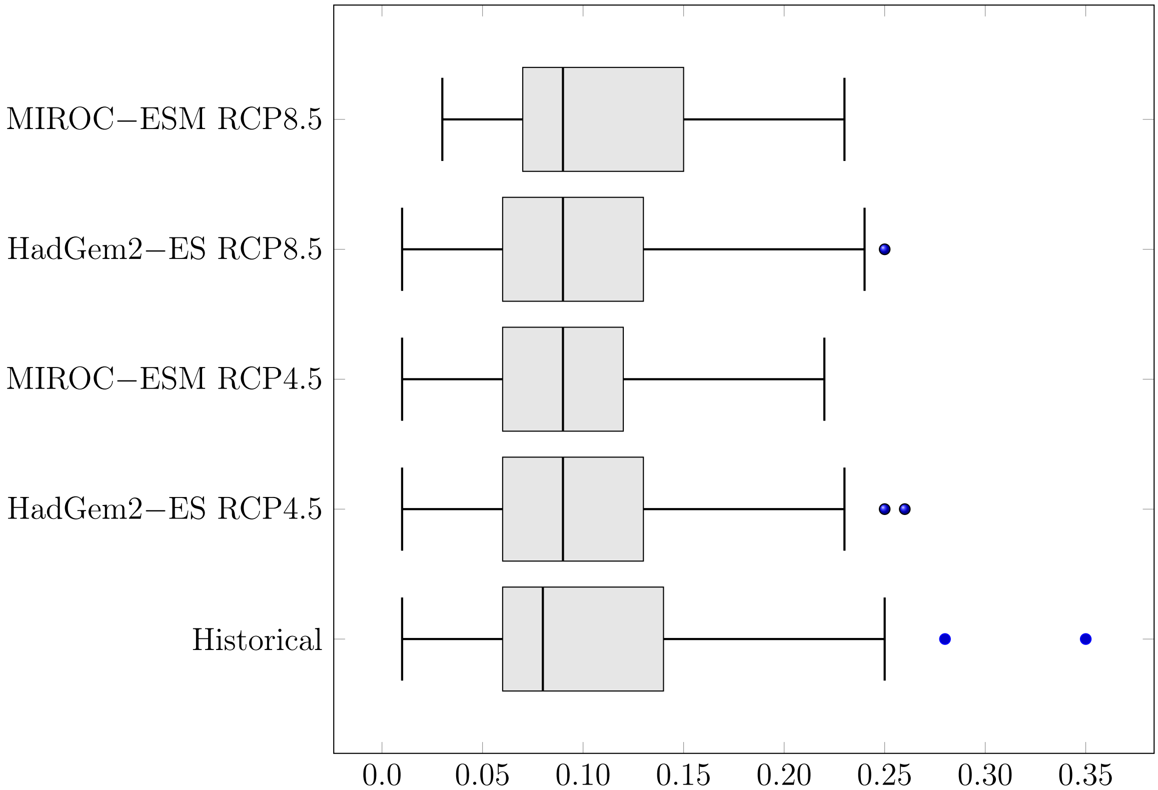


Figure 7.9: Distribution of historical and projected monthly precipitation concentration degree at the Ruliba station

ario (see Figure 7.8). Towards the end of the century, an increasing trend is identified in MIROC−ESM precipitation time series under RCP8.5 while in other cases no significant changes are detected (see Figures 7.7 and 7.8). However, similar to the past climate, interannual variations in total annual precipitations are projected to dominate the future climate of the study area where changes are expected to reach 50%.

7.2.2 Projected temperature

Contrary to precipitation projections where positive and negative anomalies are expected, increase in annual mean temperatures is expected to be positive under RCP4.5 and RCP8.5 scenarios for both HadGem2−ES and MIROC−ESM models (see Table 7.2). The increase in temperature is expected to be much faster under RCP4.5 scenario than under RCP8.5 scenario (see Figure 7.10). The analysis of annual mean temperature time series under RCP4.5 scenario revealed an average increase rate of 0.032℃ per year (or 0.32℃ per decade) for HadGem2−ES model and 0.021℃ per year (or 0.21℃ per decade) for MIROC−ESM between 2020 and 2099. Under this scenario, it is projected that the average temperature for the 2080−2099 period will be 2.19℃ (MIROC−ESM) to 3.72℃ (HadGem2−ES) higher relative to the 1961−1990 average. As for RCP8.5

Table 7.2: Projected changes in annual mean temperatures. The given values are medians of the changes for the whole period while the values within brackets represent the minimum to maximum changes.

Period	HadGem2−ES	MIROC−ESM
	RCP4.5	
2020 – 2039	+1.72 (+1.24 to +2.26)	+0.92 (+0.23 to +1.38)
2040 – 2059	+2.72 (+2.33 to +3.27)	+1.42 (+0.92 to +2.05)
2060 – 2079	+3.38 (+2.74 to +3.87)	+1.77 (+1.23 to +2.13)
2080 – 2099	+3.69 (+3.10 to +4.52)	+2.20 (+1.59 to +3.15)
	RCP8.5	
2020 – 2039	+1.83 (+0.99 to +2.42)	+1.68 (+1.03 to +2.12)
2040 – 2059	+3.03 (+2.22 to +4.62)	+2.48 (1.77 to +3.81)
2060 – 2079	+4.65 (+3.54 to +5.51)	+3.54 (+2.76 to +4.48)
2080 – 2099	+6.09 (+5.25 to +6.38)	+5.16 (+4.3 to +5.83)

scenario, an increase rate of 0.069℃ per year (or 0.69℃ per decade) is expected for HadGem2−ES model and 0.06℃ per year (or 0.6℃ per decade) for MIROC−ESM. By 2100, the temperature change relative to the reference period is projected to range between 5.19℃ (MIROC−ESM) and 5.98℃ (HadGem2−ES).

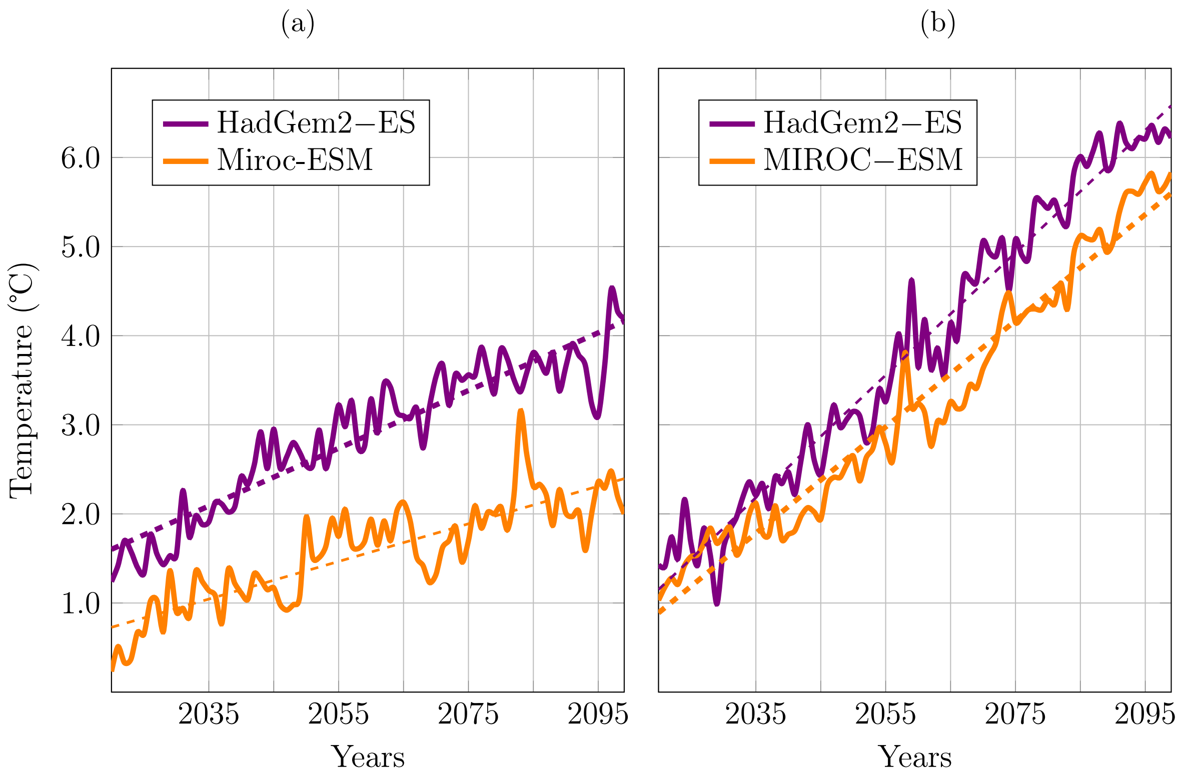


Figure 7.10: Temperature anomalies for the 2020−2099 period relative to 1961−1990 average. Anomalies for the RCP4.5 scenario are shown in (a) and those simulated under RCP8.5 scenario are presented in (b).

Compared to the expected global mean temperature, the simulated temperature for the Ruliba catchment is much higher under the two considered scenarios and the two climate models. Relative to the 1986−2005 average, the global annual mean temperature change for the 2081−2100 period is expected to range from 1.1℃ to 2.6℃ for RCP4.5 and 2.6℃ to 4.8℃ for RCP8.5 scenarios (IPCC 2013, 20). These changes are smaller than those simulated for Ruliba that range between 2.19℃ to 3.72℃ for RCP4.5 and between 5.19℃ and 5.98℃ for RCP8.5 scenarios. From the presented precipitation changes in Section 7.2.1 and the increasing temperature in this section, it can be anticipated that the future climate of the area under investigation is likely to be characterized by diminishing water resources. This is due to the fact that no significant trend was detected in precipitation time series until the end of the century except for precipitations simulated by MIROC−ESM under RCP8.5 scenario. Therefore, the increasing temperature will result in a high rate of evapotranspiration which will negatively affect water availability and increase competition between different water users as discussed in the next section.

7.3 Impacts of expected climate on water and hydropower generation

In this section, the potential impacts of the expected climate on water resources in general and hydropower generation in particular are discussed. The impacts on water resources were assessed by comparing projected flow discharges at the Ruliba stream gauging station with historical flows. The historical flow time series cover the 1971−1990 period. This period was selected because most of the existing and planned hydropower plants have been designed on the basis of daily and seasonal historical climatic patterns covering this period. As for climate change impacts on hydraulic power plants, only those plants located in the study area have been included in the simulation and identified impacts were extrapolated in order to estimate the overall impacts at the national level.

7.3.1 Impacts on water resources

To assess the effects of the expected climate on water resources, the calibrated and validated hydrologic model discussed in Chapter 6 was used to simulate future stream flows under RCP4.5 and RCP8.5 scenarios for HadGem2−ES and MIROC−ESM climate models. Monthly and annual mean historical (1971−1990 period) stream flows at the Ruliba gauging station are compared with simulated flows at the same station. The analysis was conducted on four periods of 20 years each from 2020 to 2099. In Figure 7.11 flow discharge anomalies (in %) at the outlet of the Ruliba catchment are shown for RCP4.5 and

RCP8.5 scenarios. From this figure it can be noticed that although there were no significant trends in precipitations (except for precipitations simulated by MIROC−ESM under RCP8.5 scenario), there are clear decreasing trends in flow discharge for RCP4.5 scenario ranging from 0.23% to 0.75% per year from 2020 to 2099 relative to the 1971−1990 annual average.The means of changes in stream flows at the Ruliba station are projected, under RCP4.5 scenario, to range from −3.96% to −6.93% for the 2020−2039 period, −16.79 to −15.03% for the 2040−2059 period, −24.51% to −23.53% for the 2060 − 2079 period and −38.47% to −20.88% for the 2080−2099 period.

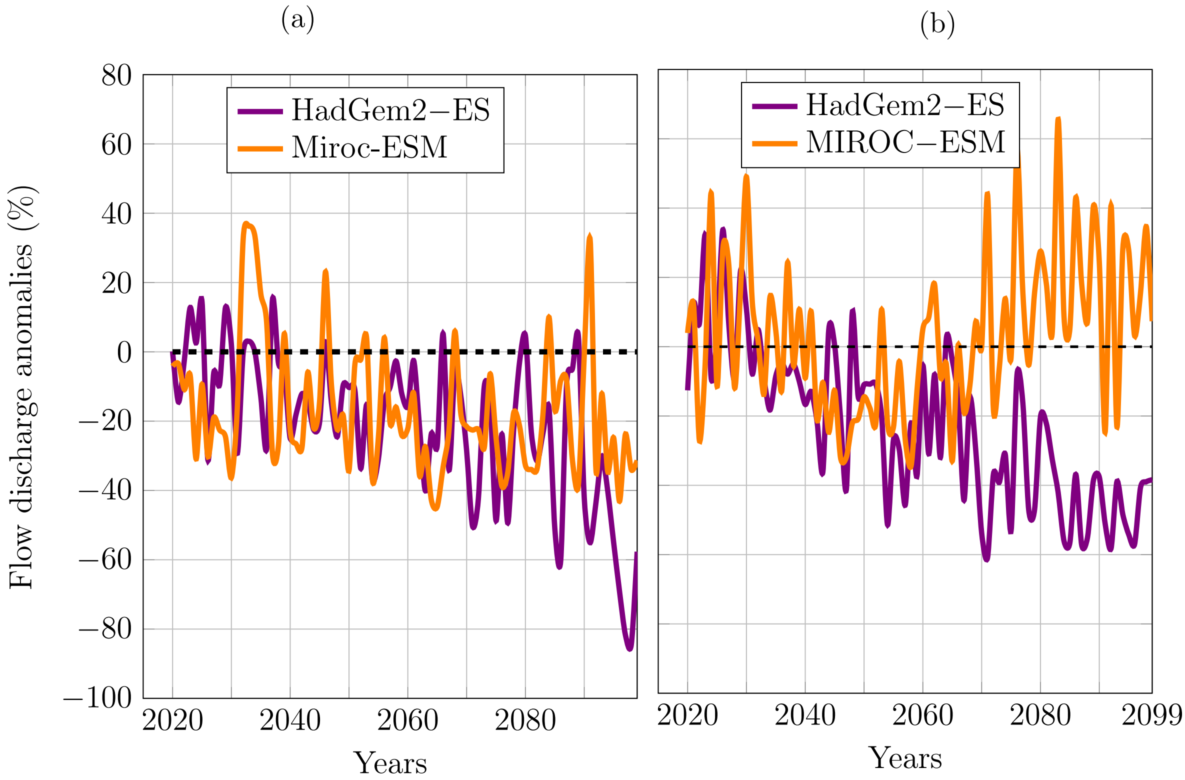


Figure 7.11: Flow discharge anomalies at Ruliba station under RCP4.5 in (a) and RCP8.5 in (b).

Similar to flow discharges under RCP4.5 scenario, the changes in flow discharges under RCP8.5 scenario are much more moderate for the 2020 − 2039 period compared to the other three periods. Under this scenario, changes in stream flow are projected to range from +1.58% to +8.0% for the 2020 − 2039 period, −20.70% to +17.08% for the 2040 − 2059 period, −28.77% to −3.78% for the 2060 − 2079 period and −44.04% to +18.62% for the 2080 − 2099 period. The increase in stream flows observed in this scenario towards the end of the century are simulated under MIROC−ESM data and these follow the precipitation patterns shown in Figure 7.8.

Having found no significant increase in annual total precipitations and assuming that irrigated areas will remain equal to their 2012 values, the main drivers of reductions in water flow discharges are the increasing domestic water demand and the rate of evapotranspiration. It is projected that the total domestic water withdrawal will increase from about 11 million cubic metres in 2012 to 40 million in 2025 and to 400 million in 2050. It is important to recall here that 8.15 litres per person per day were considered for 2012 which would increase to 20 litres per person per day by 2015 (MINIRENA 2011) and to the international standard of 50 litres per person per day in 2050 (Brown and Matlock 2011).

7.3.2 Impacts on hydropower generation

Like in the case of flow discharge, expected impacts of climate change on hydropower generation were assessed by comparing simulated power production with what would have been the power generation if the power plants were operated between 1971 and 1990. It is important to notice that the average of annual hydropower generation over the 20−year period from 1971 to 1990 corresponds exactly with the designed annual power production (about 445 GWh). This supports also the results obtained during the calibration and validation discussed in Chapter 6.

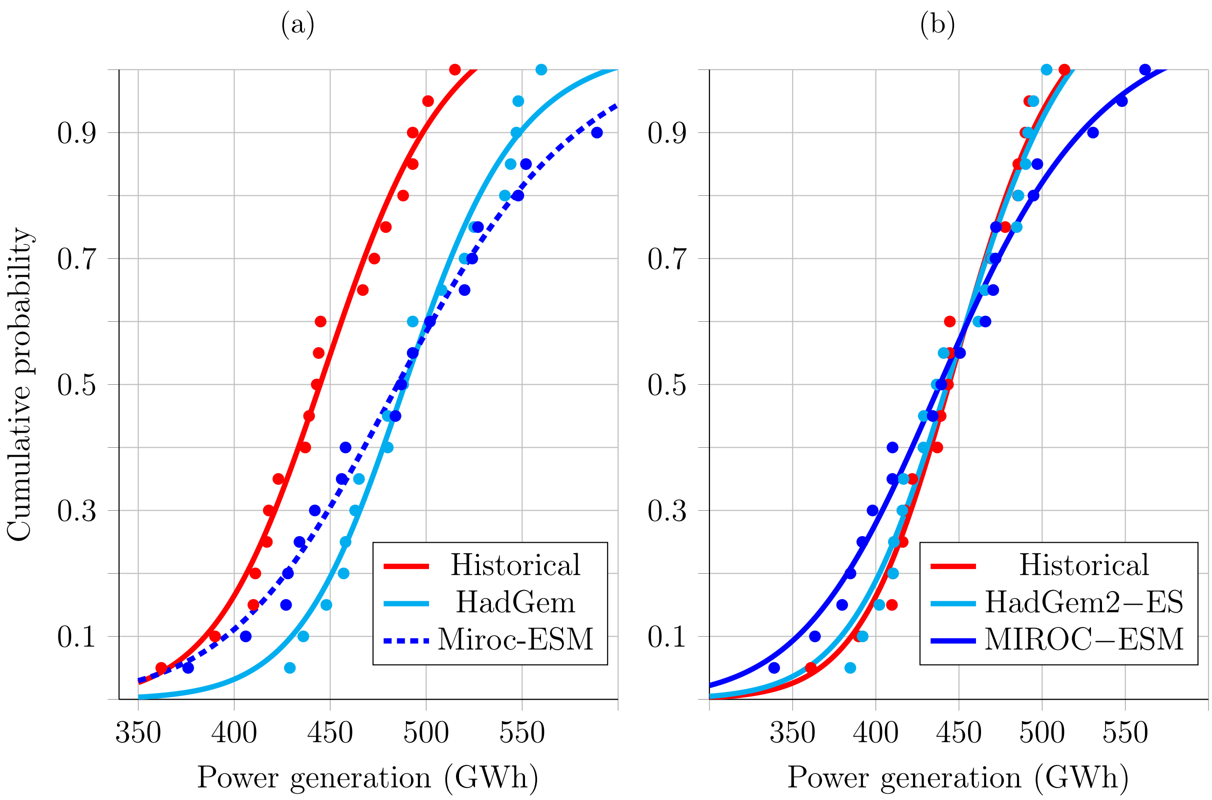


Figure 7.12: Cumulative distribution functions of annul total hydropower generation the 1971−1990 period. In (a) the biases are still in the distribution and in (b) the biases have been removed.

As it can be seen in Figure 7.12 (a), during the 1971−1990 period, both HadGem2−ES and MIROC−ESM models simulated more energy than the historical production. Because of these biases it is appropriate to first remove them in order to have a common comparison basis. Therefore, the bias correction (or simply calibration) technique was used to determine the relationship between historical and simulated time series. The bias correction deals with determining the transfer function that relates simulated and measured or recorded data (Ho et al. 2012; Hempel et al. 2013). Consequently, to remove the bias between historical and simulated power generation, a multiplicative correction factor method on monthly power generation time series was applied. Under this method, each time−step of the time series is multiplied by a constant factor which conserves the trends observed in the original time series whilst removing the discrepancies between recorded and simulated data (Hempel et al. 2013, 57). The correction factor C_i for each month was calculated according to Equation 7.2 where $E_{i,hist}$ represents historical power production for month i and $E_{i,sim,ref}$ is the simulated power generation for month i during the reference period.

$$C_i = \frac{\sum_{i=1}^{n=20} E_{i,hist}}{\sum_{i=1}^{n=20} E_{i,sim,ref}} \qquad (7.2)$$

$$E_{i,Sim,adj} = C_i \cdot E_{i,sim} \qquad (7.3)$$

The computed monthly correction factors are presented in Table 7.3. Equation 7.3 was used to remove discrepancies from simulated hydropower generation time series. In Equation 7.3 $E_{i,Sim,adj}$ represent the adjusted power generation for simulated power generation $E_{i,sim}$ for month i. Figure 7.12 (b) compares historical power generation with bias corrected simulations for the 1971−1990 period. Over this period, the historical annual mean power generation would have been 448 GWh with a standard deviation of 40 GWh. As for HadGem2−ES and MIROC−ESM models, their simulated means over the reference period are 497.65 GWh and 496.00 GWh respectively. This means that 10.7% more energy production than the historical generation. However their standard deviations are relatively diverse (41.6 GWh in case of HadGem2−ES and 66.5 GWh for MIROC−ESM models). After the bias correction, the annual mean power generation become 445 GWh for both models and the standard deviations become 38 GWh and 60 GWh for HadGem2−ES and MIROC−ESM models respectively. As it can be seen in Figure 7.12 (b), the performed bias correction resulted in a good HadGem2−ES model fitting in terms of mean and dispersion than for the case of MIROC−ESM model. However, the cumulative power production for the three cases (historical, HadGem2−ES and MIROC−ESM) are all equal to approximately 8,915 GWh.

Table 7.3: Correction factors used to remove biases from simulated power generation. Historical generation refers to the average of the corresponding month over 1971 − 1990 period.

Month	Historical generation (GWh)	% of annual generation	C_i HadGem2−ES	C_i MIROC−ESM
January	34.18	7.62	0.84	0.82
February	35.65	7.95	0.88	0.86
March	40.91	9.12	0.84	0.84
April	53.35	11.90	0.94	0.96
May	51.93	11.58	0.93	0.95
June	34.06	7.60	0.88	0.94
July	27.81	6.20	0.90	0.89
August	26.44	5.90	0.92	0.89
September	29.03	6.47	0.92	0.91
October	33.98	7.58	0.89	0.92
November	41.85	9.33	0.91	0.91
December	39.17	8.74	0.89	0.88
Total	448.37	100.00	−	−

After computing the correction factor for each month, the simulated hydropower genenration was adjusted (using Equation 7.3) and Figure 7.13 compares the projected annual power generation with the average power that would have been generated if the power plants were operated over the 1971−1990 period. The analysis for each 20−year time period from 2020 to 2099 can be visualized in Figure 7.14 through Figure 7.17. As indicated in this section, the designed annual mean production of the analysed hydropower plant is 448 GWh and it ranged between 360 GWh and 515 GWh during the reference period. Power generation between the maximum and the designed one was achieved for about 50% of the time similar to the production between the minimum (360 GWh) and the designed (448 GWh) energy.

For the period 2020 to 2039 (Figure 7.14), the probability that power generation will be greater than or equal to the designed energy for RCP4.5 scenario is about 50% for HadGem2−ES and 34.5% for MIROC−ESM models. The analysis of cumulative annual energy productions over this period revealed a reduction of power generation equivalent to 3.2% for HadGem2−ES and 6.6% for MIROC−ESM models relative to the average production during the 1971 − 1990 period. The annual power production for this scenario ranges between 330.5 GWh and 492.5 GWh for HadGem2−ES model, and between 316.4 GWh and 548.8 GWh for MIROC−ESM model. The annual power generations under RCP4.5 are distributed in such a way that the means and standard deviations (in brack-

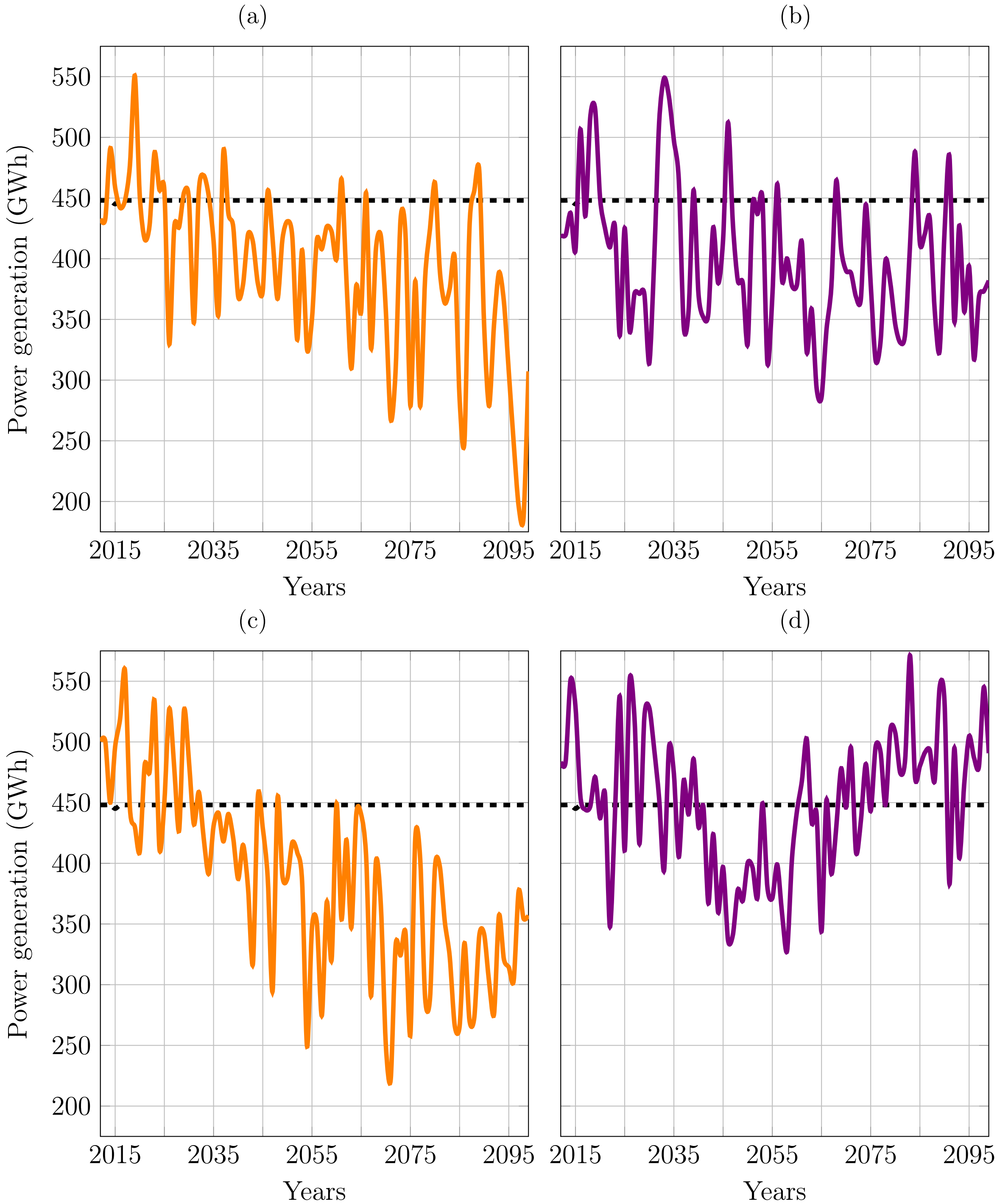


Figure 7.13: Projected hydropower generation between 2012 and 2099: (a) HadGem2−ES RCP4.5, (b) MIROC−ESM RCP4.5, (c) HadGem2−ES RCP8.5 and (d) MIROC−ESM RCP8.5. The dashed black line represents the 1971−1990 average

ets) of power generation are 434 (42) GWh and 418 (66) GWh for HadGem2−ES and MIROC−ESM models respectively. This shows how the dispersion of the production is conserved for HadGem2−ES and increased for the case of MIROC−ESM models relative to the reference period. Peaks in power productions as well as very pronounced deficits

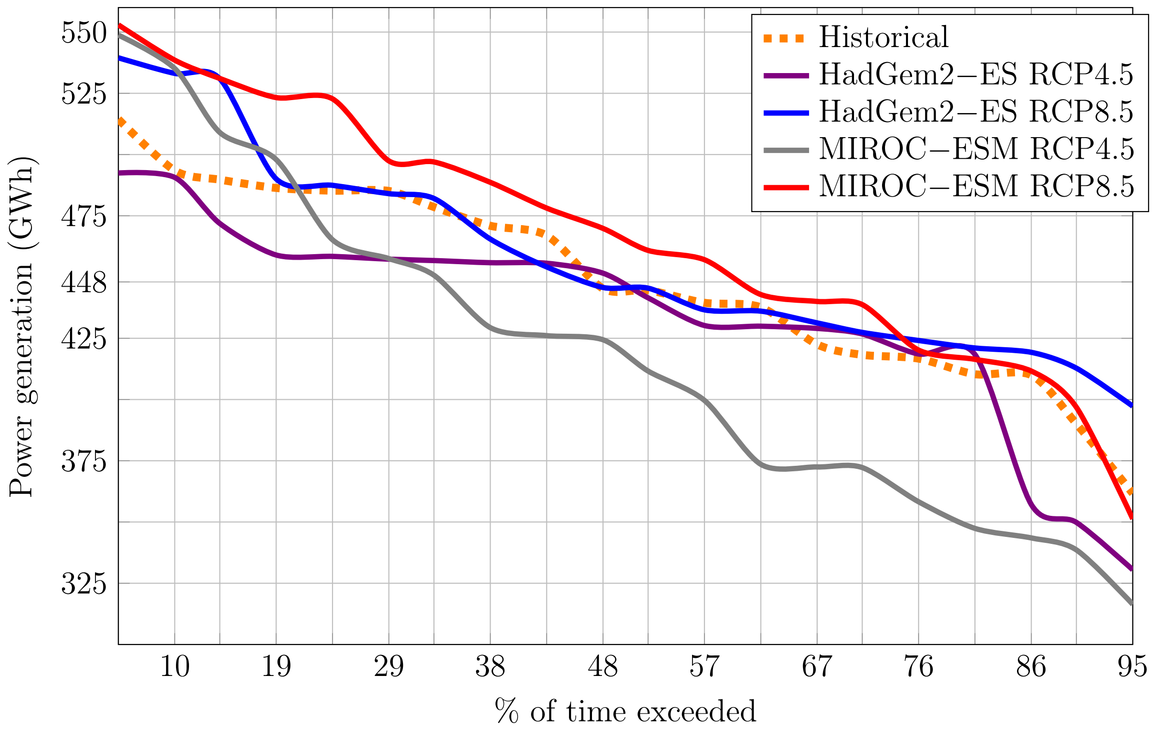


Figure 7.14: Hydropower generation curve for the 2020−2039 period

are projected to be more frequent for MIROC−ESM than for HadGem2−ES models.

As for RCP8.5, the power generation duration curve in Figure 7.14 shows that the probability that the generated power will be above the designed energy is approximately 50% and 60% for HadGem2−ES and MIROC−ESM models respectively. During this period, increases in power generation of 2.2% for HadGem2−ES and 4.1% for MIROC−ESM models are expected. The 20−year annual means and standard deviations (shown in brackets) for this period are 458 (41) GWh for HadGem2−ES and 466 (51) GWh for MIROC−ESM. Similar to RCP4.5, HadGem2−ES model conserves the same dispersion of the production around the mean compared to the 1971 − 1990 distribution of annual power generation.

The analysis of projected power generation for the 2040 − 2059 period reveals that this period will be characterized by power generation deficits for the two analysed scenarios and for the two climate models (see Figure 7.15). During this period, power generations equal or above the designed energy will be produced for a period less than 15% of the time (approximately 3 years) and power generation deficits will be observed during the rest of the time. The 20−year annual mean power productions under RCP4.5 scenario are about 400 GWh for both HadGem2−ES and MIROC−ESM models. The analysis of cumulative energy production over this period indicates an energy generation reduction of about 10% relative to the energy that would have been produced during the reference period. Over this period, the standard deviations are 33 GWh for HadGem2−ES and 46

GWh for MIROC−ESM models. Similar to the 2020 − 2039 period, the simulated power by HadGem2−ES model is lesser spread than that obtained in case of MIROC−ESM model.

With regard to simulations under the RCP8.5 scenario, reductions in cumulative energy generation in the range 6.4% for HadGem2−ES and 13.6% for MIROC−ESM models are projected for the 20−year period between 2040 and 2059. On average, it is projected that 375 GWh for HadGem2−ES and 387 GWh for MIROC−ESM models will be generated annually. The simulated generations under the HadGem2−ES model are more spread out (the standard deviation is 56 GWh) compared to the power generations simulated under the MIROC−ESM model (the standard deviation is 33 GWh). Power generations under the HadGem2−ES model range from 250 GWh to 462 GWh while those simulated under MIROC−ESM model range from 330 GWh to 448 GWh.

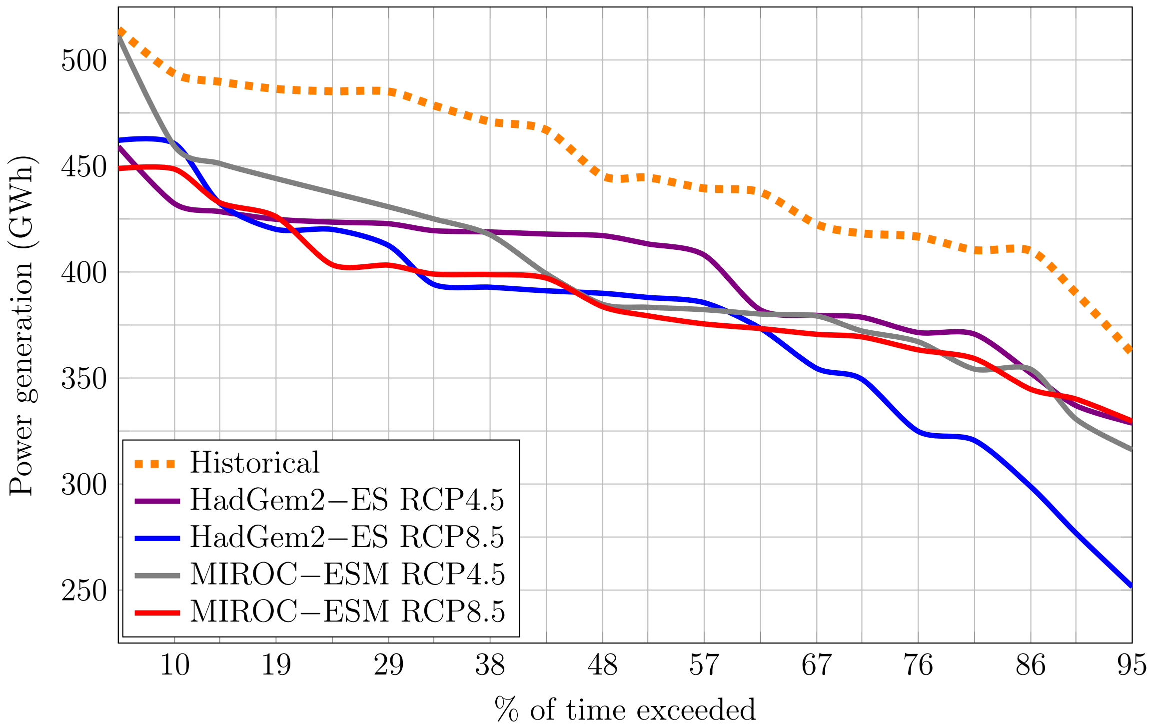


Figure 7.15: Power generation duration curve for the 2040 − 2059 period. The figure shows the percentage of the time over the 20 years when generated energy exceeds a certain value.

The last two periods 2060−2079 and 2080−2099 are expected to be charcterised by power generation below the designed energy except for MIROC−ESM under RCP8.5 scenario. As it can be visualized in Figure 7.16 and Figure 7.17, the percentage of time when projected power generation exceeds the designed one is about 50% for MIROC−ESM model under RCP8.5 scenario for the period from 2060 to 2079 and around 90% for the 2060 − 2079 period.

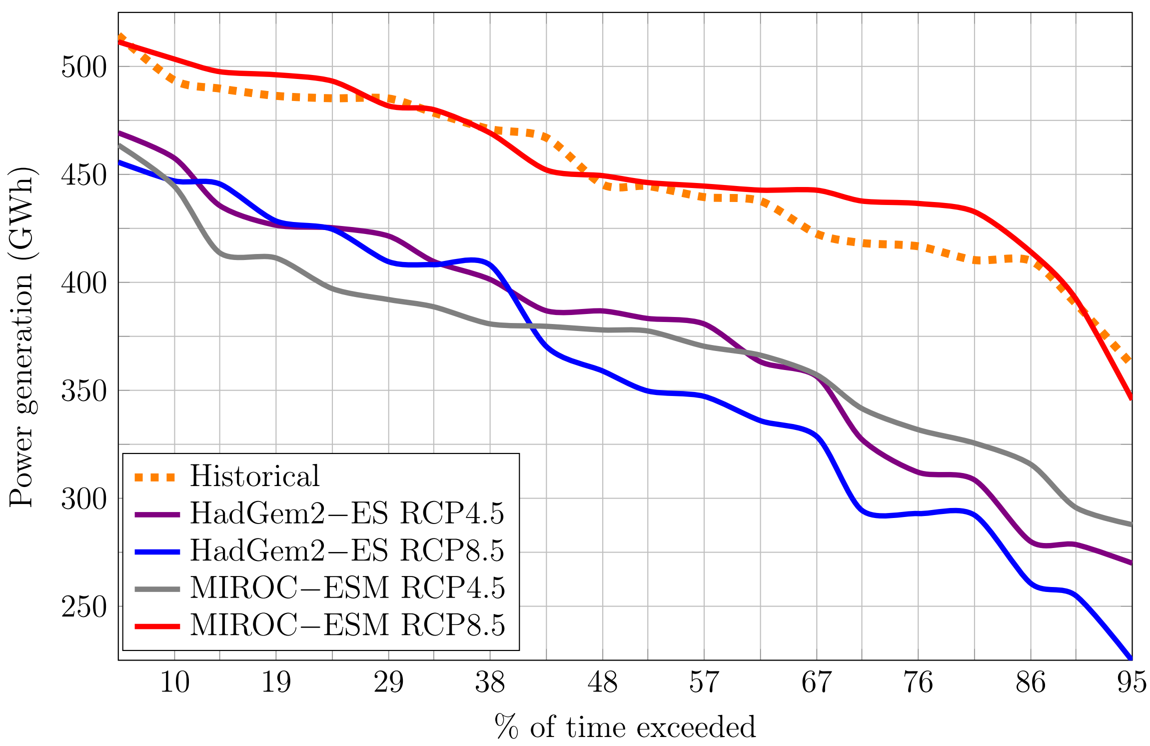


Figure 7.16: Power generation duration curve for the 2060 − 2079 period. The figure shows the percentage of the time over the 20 years when generated energy exceeds a certain value.

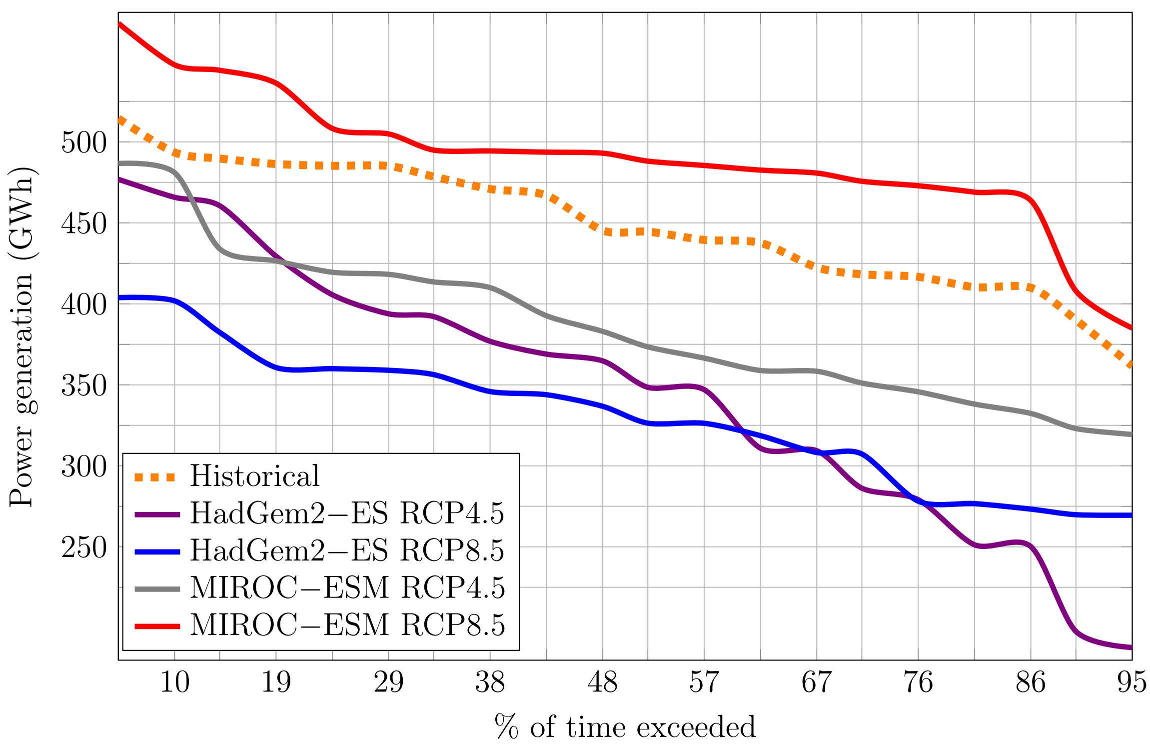


Figure 7.17: Hydropower generation curve for the 2080 − 2099 period

For the other cases, energy generation that is greater than or equal to the designed energy can only be generated during 15% of the time similarly to the $2040 - 2059$ period. Under RCP4.5 scenario and for the period $2060 - 2079$, the 20−year annual mean power generations are projected to be 374 GWh for HadGem2−ES and 370 GWh for MIROC−ESM. For the period from $2080 - 2099$, the annual mean production under the same scenario are 345 GWh and 386 GWh for HadGem2−ES and MIROC−ESM respectively. As for RCP8.5 scenario, it is projected that 356 GWh for HadGem2−ES and 453 GWh for MIROC−ESM can annually be produced during the $2060 - 2079$ period. Over the $2080 - 2099$ period, 330 GWh for HadGem2−ES and 490 GWh for MIROC−ESM model are projected to be generated under this scenario. The analysis of cumulative energy production over these two periods shows an increase of power generation for MIROC−ESM model equivalent to 1.1% and 9.3% for the $2060 - 2079$ and $2080 - 2099$ periods respectively relative to the $1971 - 1990$ cumulative energy. Power generations for other cases are projected to decrease by 16.6% (HadGem2−ES RCP4.5), 20.4% (HadGem2−ES RCP8.5) and 17.3% (MIROC−ESM RCP4.5) for the period from 2060 to 2079. Over the $2080 - 2099$ period the deficits are anticipated to achieve 23% for HadGem2−ES RCP4.5, 26.3% for HadGem2−ES RCP8.5 and 13.8% for MIROC−ESM RCP4.5.

The analysis of power generation time series on a yearly time step is not enough to conclude about potential impacts of climate change on hydropower production. Because the electricity supply needs to meet the demand at all times, the distribution of the generation on high temporal resolutions such as seasonal, monthly, daily or sub-daily can provide useful information that cannot be obtained from yearly data. Therefore, the concentration degree of generated power across the year was analysed. As discussed in Section 4.5.2, the concentration degree can take any value between 0 and 1 where a value of 0 means that annual quantity (power production, precipitations, stream flow discharges, etc.) is equally distributed over a considered time step (monthly or daily time step) while a value of 1 means that all the annual quantity occurs during one time step. Figure 7.18 illustrates annual concentration degree from 2012 to 2099 in comparison with the $1971 - 1990$ average.

For the reference period, the concentration degree ranges between 0.04 and 0.12 with an average of 0.08. For the period $2012 - 2099$, the average concentration degree and the minimum to the maximum (in brackets) under RCP4.5 are 0.08 (0.03 to 0.19) for HadGem2−ES and 0.07 (0.0 to 0.13) for MIROC−ESM. As for RCP8.5, the concentration degrees are 0.09 (0.03 to 0.18) for HadGem2−ES and 0.07 (0.02 to 0.15) for MIROC−ESM models. As it can be noticed in Figure 7.18 (a) and (c), power generation simulated using data from HadGem2−ES model will tend to be concentrated on few months compared to the reference period.

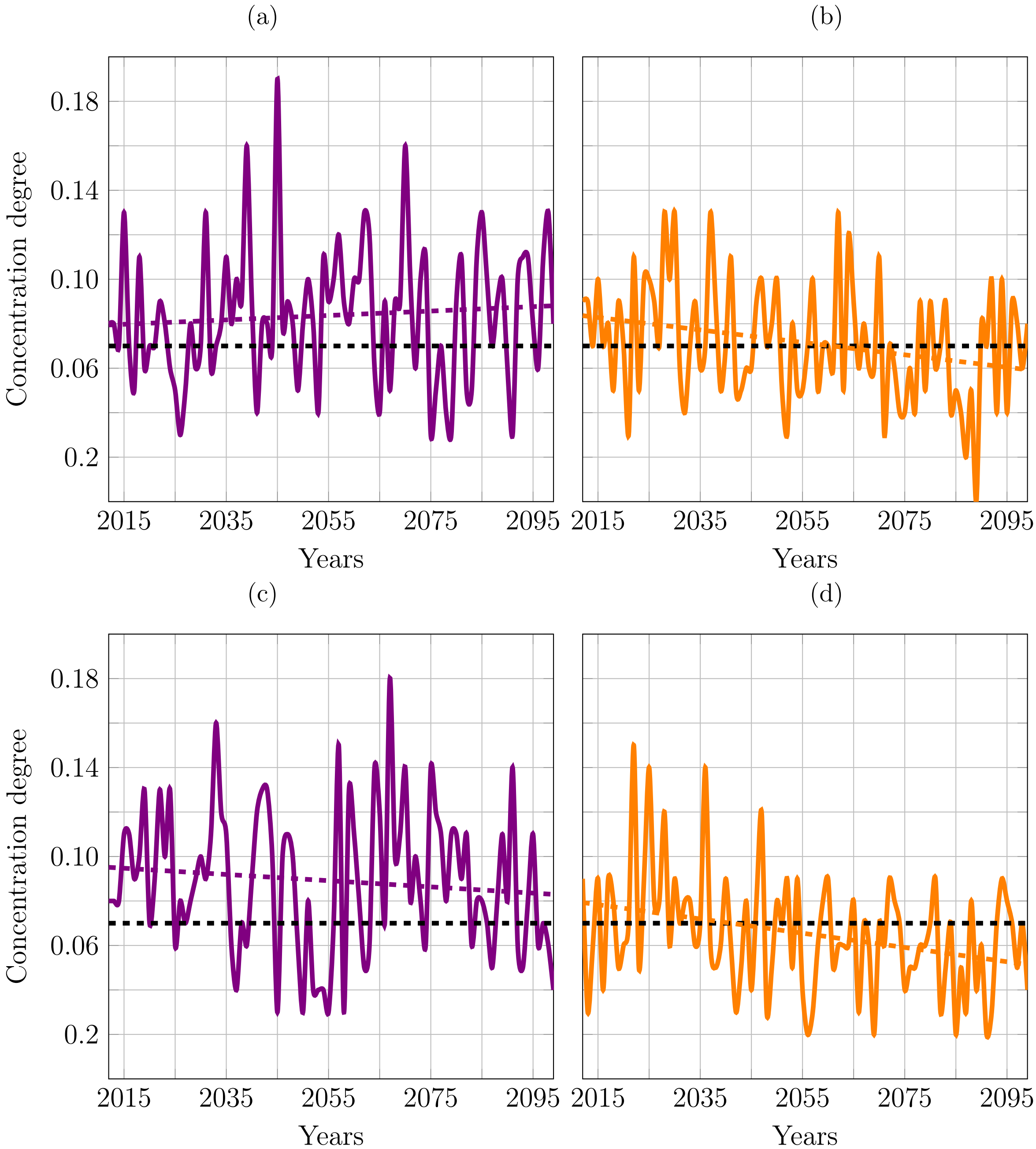


Figure 7.18: Changes in hydropower generation concentration degree relative to the 1971−1990 average: (a) HadGem2−ES RCP4.5, (b) MIROC−ESM RCP4.5, (c) HadGem2−ES RCP8.5 and (d) MIROC−ESM RCP8.5. The dashed black line represents the 1971−1990 average while other dashed lines represent trends of the concentration degree time series

The highest peaks in concentration degree are also projected to occur under this model where they are expected to reach 0.19 for HadGem2−ES RCP4.5 and 0.18 for HadGem2−ES RCP8.5 scenario. There is a slight increasing trend for RCP4.5 scenario and a decreasing one for RCP8.5 scenario. With regard to projections obtained by using climate data from the MIROC−ESM model, it can be observed in Figure 7.18 (b) and

(d) that power generation will tend to be more spread on different months than it was in the past. Variations in the concentration degree of projected power generations are not as high as they are in case of HadGem2−ES model.

7.3.3 Impacts on the overall country's hydropower

As discussed in Section 4.5.2, the assessment of climate change effects on hydropower generation at the national level is done by extrapolating identified power generation changes of the analysed power plants to hydropower plants located in the studied area but not simulated in this study as well as the effects on power plants located outside the study area assuming similar conditions of operation. To achieve this, the percentage changes between the designed and simulated energy generations for each year from 2012 to 2099 and for each model and scenarios were determined. Then, computed changes were applied to the annual total hydropower energy generation at the national level. The values of designed annual energy generation were obtained from the Generation Report of Rwanda Electricity Master Plan 2010 − 2025 (Fichner and decon 2010a) and Rwanda Energy Sector Review and Action Plan (AfDB 2013). Annual energy generation (E_{an}) for hydropower plants of which installed capacities were available but energy production not available were estimated using Equation 7.4 where 8760 is the number of hours in a (non leap) year, c_f the capacity factor and P_i. The plant utilization factors were extracted from Fichner and decon (2010a, 35).

$$E_{an} = 8764 \cdot c_f \cdot P_i \qquad (7.4) \qquad\qquad E_{mon,i} = s_i \cdot E_{an,j} \qquad (7.5)$$

To assess the future national hydropower generation on monthly a basis, the same average monthly distribution (in %) of power generation for the 1971 − 1990 period was assumed for the hydropower plants not simulated in the hydrological model because most of the obtained data about designed hydropower energy generation were annual values. Consequently, the annual values were distributed across different months by multiplying annual values with the percentage share of the given month according to Equation 7.5. In this equation $E_{i,j}$ refers to the monthly power generation for month i in the year j. i varies between 1 and 12 while j varies between 2012 and 2099. S_i is the percentage of the annual energy generated in month i and $E_{an,j}$ is the annual designed energy generation in year j. The limits of projected hydropower generation for RCP4.5 and RCP8.5 scenarios can be visualized in Figure 7.19 and Figure 7.20 respectively. Minimum power generation values were computed according to Equation 7.6 while Equation 7.7 was used to calculate maximum production values.

$$Min = Min(HadGem2, MIROC) \quad (7.6) \qquad Max = Max(HadGem2, MIROC) \quad (7.7)$$

The analysis of the projected hydropower production at the national level under RCP4.5 scenario reveals that changes in cumulative energy generation between 2012 and 2019 will range between 70 GWh and 400 GWh equivalent to 2% to 10% more relative to the designed energy production. As for RCP8.5, it is found that 400 GWh to 530 GWh (or 10% to 12%) more than designed energy will be generated for the same period. For the period $2020-2039$ under RCP4.5, the analysis of cumulative energy over this period shows that changes in power production will range between $-4{,}240$ GWh and $+744$ GWh (or -13% to $+3\%$). On the other hand, it is projected that between -853 GWh and $+2{,}482$ GWh equivalent to -3% to 8% relative to the designed energy will be generated under RCP8.5. Negative generation means loss in energy generated and positive values refer to excess generation with reference to the designed energy generation. The period 2040 to 2059 is unique because it is characterized by losses in power generation under both RCP4.5 and RCP8.5 scenarios (see Figure Figure 7.19 and Figure 7.20).

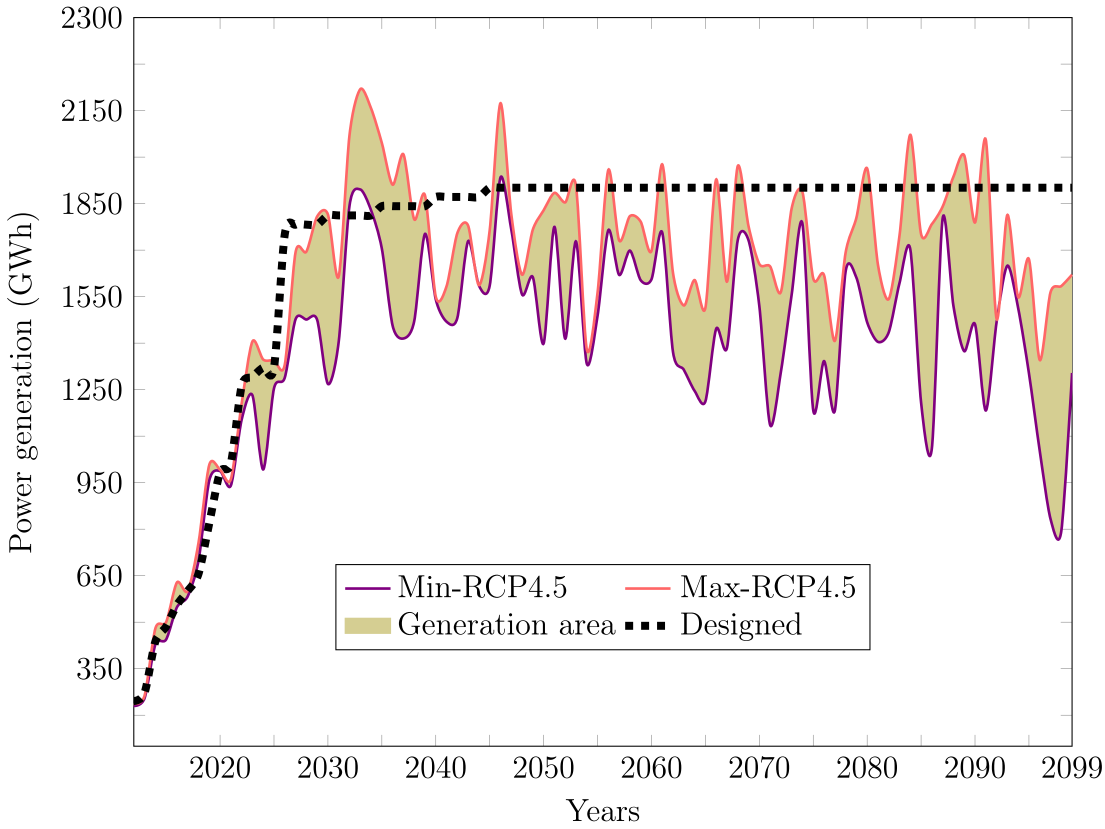


Figure 7.19: Projected total annual hydropower generation for the $2012-2099$ period under RCP4.5 scenario

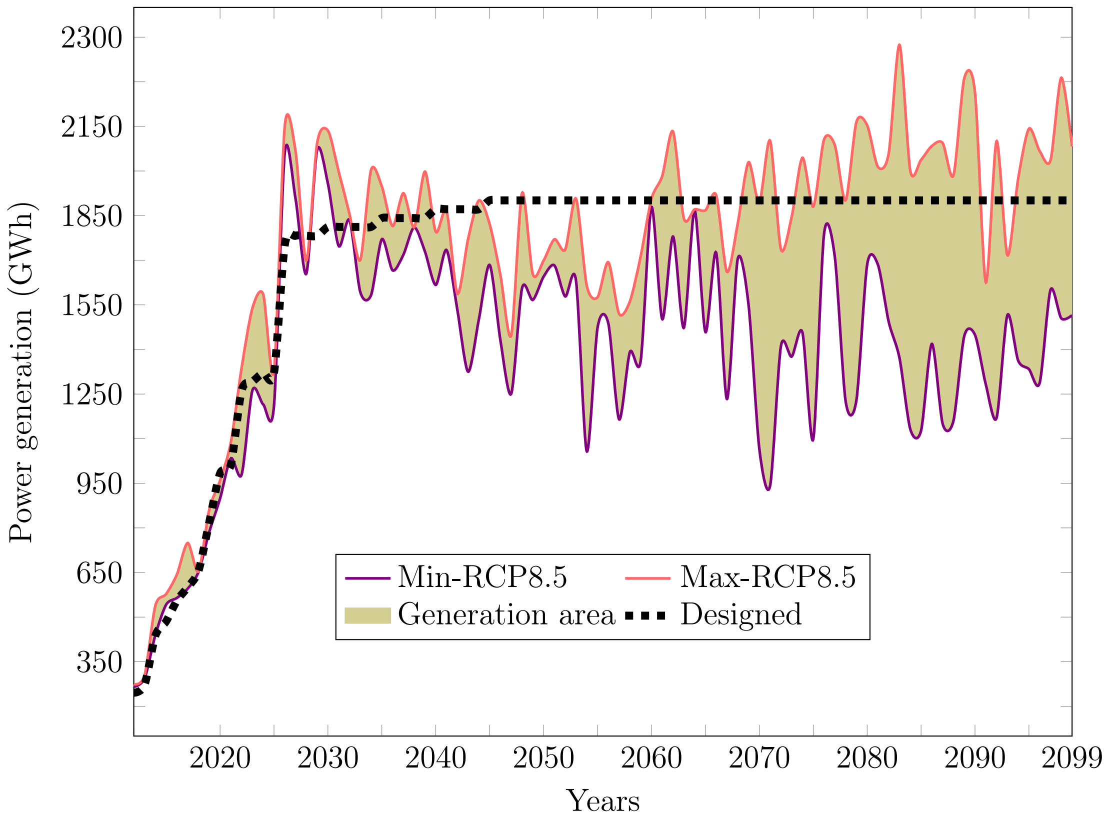


Figure 7.20: Projected total annual hydropower generation for the 2012 − 2099 period under RCP8.5 scenario

Relative to the cumulative designed energy generation over this period, losses in generation would range between 9% and 15% (2,773 GWh and 5,790 GWh) for RCP4.5 scenario, and between 12% and 22% (3,668 GWh and 8,154 GWh) for RCP8.5 scenario. Between 2060 and 2079, changes in cumulative hydropower generation would range between −8,971 GWh and −4,092 GWh equivalent to −24% to −14% for RCP4.5, and −8,550 GWh and +770 GWh (or −22% to +3%) for RCP8.5 scenario. For the last 20−year period of the century, it is projected that hydropower generation change would vary between −29% (or −10,896 GWh) and −12% (or −3,259 GWh) for RCP4.5 scenario. As for RCP8.5 scenario, changes in power generation are projected to range from −27% (or −10,339 GWh) to +12% (or +3,460 GWh).

7.4 Discussion

Simulation results under both HadGem2−ES and MIROC−ESM climate models under RCP4.5 and RCP8.5 scenarios indicate decreases in annual precipitations for the period 2030 to 2060. In addition, inter-annual variations in total annual precipitations are expected to dominate the future climate where changes are expected to reach 50%. With regard to temperature changes, it is projected that warming in the Ruliba catchment will be much more than the projected average global warming. For Ruliba, temperature changes relative to the $1961 - 1990$ average are projected to range between from 2.19℃to 3.72℃for RCP4.5 scenario and 5.19℃to 5.98℃for RCP8.5 scenario. However, changes in the projected global average temperature range from 1.1℃to 2.6℃for RCP4.5 scenario and 2.6℃to 4.8℃for RCP8.5 scenarios (IPCC 2013, 20).

These changes combined with the increasing water demand are expected to lower the amount of river runoff as discussed in this chapter. As the output power from any given hydropower plant depends on the flow rate of rivers and water level in reservoirs for runoff river and dam based power plants respectively, the reduction in water flows will negatively impact the future generation of hydropower plants. This is confirmed by the simulation results discussed in this chapter where many of the existing and planned hydropower plants are expected to produce the designed energy for less than 15% of the considered time. For instance for the period from 2040 to 2059, losses in generation will range between 9% and 15% (2,773 GWh and 5,790 GWh) for RCP4.5 scenario, and between 12% and 22% (3,668 GWh and 8,154 GWh) for RCP8.5 scenario.

Based on these evidences, it can be concluded that the future of hydropower generation in Rwanda will be characterized by losses in energy output as a result of changing climate patterns especially during the the period from 2030 to 2060. Having its electricity supply system heavily depending on hydropower, the future power supply of the country may become unreliable unless these vulnerabilities are early integrated into the planning and operation of the electricity supply system.

Chapter 8

Projected electricity demand and supply

This chapter presents the simulation results of the future evolution of Rwanda's electricity demand and supply between 2012 and 2050. The chapter is subdivided into four main sections namely the electricity demand projection, the analysis of the electrical power supply, the power generation cost and emissions associated with the power generation. At the end of the chapter, policy and institutional frameworks required to implement a suggested power supply scenario are discussed.

8.1 Projected electricity demand

In this section, the projected electricity demand for both the residential and non−residential sectors is presented and discussed. Before the electricity demand is discussed, the evolution of its drivers (i.e. population for the residential and the GDP for the non−residential sectors) for the period 2012 to 2050 are first presented. The section concludes by discussing the total electricity to be supplied, the required capacity as well as the projected peak power demand.

8.1.1 Residential sector

Projected total population and number of households

The projection results of the population of Rwanda show that by 2050 the total population will reach 20.52 million under the low scenario of the population growth, 22.15 million for the medium scenario and 23.99 million for the high scenario (see Table 8.1). As discussed in Section 5.4.1, the population growth rate is projected to decrease from 2.37% in 2013 to 2.00% for the high scenario of population growth, from 2.37% in 2013 to 1.71% for the medium scenario and from 2.37% in 2013 to 1.45% in 2050 for the low scenario. However, even though the population growth rate presents decreasing trends in all scenarios (see Figure 8.1 (a)), the total population will continue to rapidly increase as it can be seen in Figure 8.1 (b).

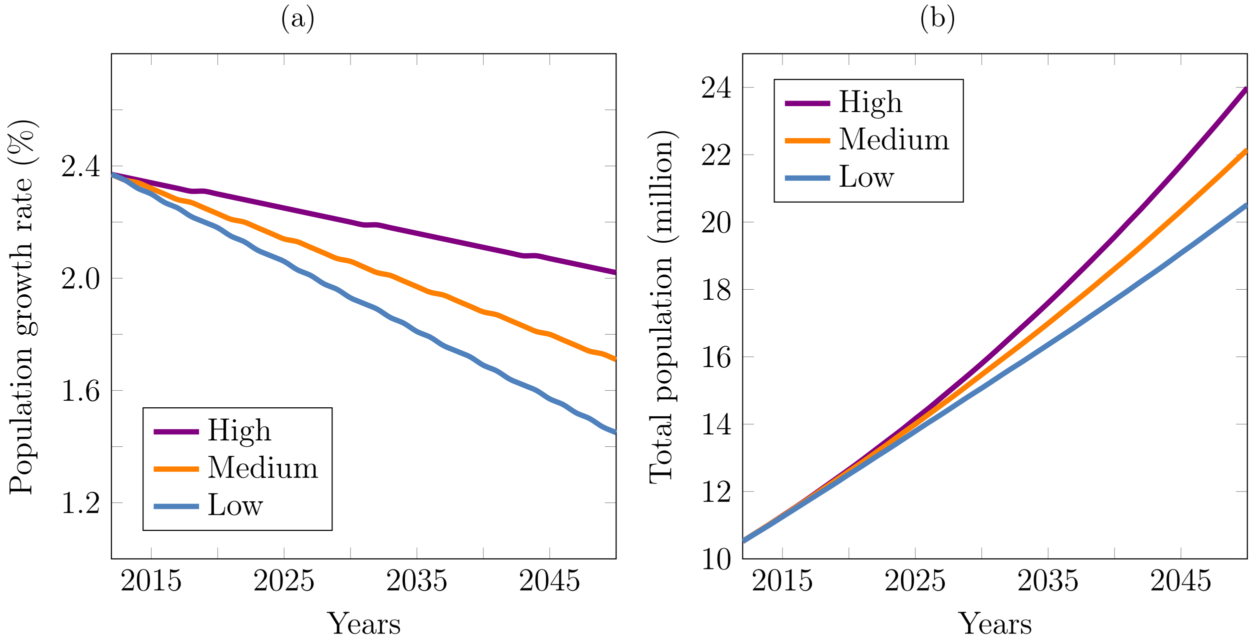


Figure 8.1: Projected population growth rate and total population by 2050. The evolution of the population growth rate in % in shown in (a) while the total population can be visualised in (b).

With regard to the number of households, it is projected that the total number of households will increase from 2.45 million in 2012 to 6.84 million in 2050 under the low scenario of the population growth, 7.38 million under the medium scenario and 7.99 million under the high scenario. The household size on the other hand is assumed to decrease from 4.3 in 2012 to 3.0 by 2050. The projected total population, number of households and household size for the 2012 – 2050 period are presented in Table 8.1.

Compared to the 2012 population, the population is expected to double in the year 2044 for the high scenario and in 2047 for the case of the medium scenario (see Table 8.1). Under the low scenario the population is projected to double beyond the year 2050. As for the number of households, it is projected that the households will double in 2030 and triple in 2047 under the high scenario. For the medium scenario the number of households is projected to double in 2031 and triple in 2050. For the low scenario the projection results show that the number of household will double in 2032 and triple beyond 2050.

Table 8.1: Projected population and total number of households between 2012 and 2050. The letters D and T in superscript indicate respectively the doubling and tripling times.

Years	Population (in millions)			Households (in millions)			Household size
	Low	Medium	High	Low	Medium	High	
2012	10.52	10.52	10.52	2.45	2.45	2.45	4.30
2013	10.76	10.77	10.77	2.54	2.54	2.54	4.24
2014	11.00	11.02	11.02	2.63	2.64	2.64	4.18
2015	11.25	11.27	11.28	2.73	2.74	2.74	4.12
2016	11.50	11.53	11.54	2.83	2.84	2.84	4.06
2017	11.75	11.79	11.81	2.94	2.95	2.95	4.00
2018	12.00	12.06	12.09	3.05	3.06	3.07	3.94
2019	12.25	12.33	12.37	3.16	3.18	3.19	3.88
2020	12.51	12.60	12.65	3.27	3.30	3.31	3.82
2021	12.76	12.87	12.94	3.39	3.42	3.44	3.76
2022	13.02	13.15	13.24	3.52	3.55	3.58	3.70
2023	13.27	13.43	13.54	3.65	3.69	3.72	3.64
2024	13.53	13.72	13.84	3.78	3.83	3.87	3.58
2025	13.79	14.00	14.16	3.92	3.98	4.02	3.52
2026	14.05	14.29	14.47	4.06	4.13	4.18	3.46
2027	14.30	14.58	14.80	4.21	4.29	4.35	3.40
2028	14.56	14.87	15.13	4.36	4.45	4.53	3.34
2029	14.82	15.17	15.46	4.52	4.62	4.71	3.28
2030	15.07	15.47	15.80	4.68	4.80	$\mathbf{4.91}^{D}$	3.22
2031	15.33	15.77	16.15	4.85	$\mathbf{4.99}^{D}$	5.11	3.16
2032	15.59	16.07	16.51	$\mathbf{5.03}^{D}$	5.18	5.32	3.10
2033	15.84	16.37	16.87	5.12	5.29	5.45	3.09
2034	16.10	16.68	17.23	5.21	5.40	5.58	3.09
2035	16.36	16.99	17.60	5.30	5.51	5.71	3.08
2036	16.62	17.31	17.98	5.40	5.62	5.84	3.08
2037	16.88	17.63	18.37	5.49	5.74	5.98	3.07
2038	17.15	17.95	18.76	5.59	5.85	6.12	3.07
2039	17.42	18.28	19.16	5.69	5.97	6.26	3.06
2040	17.69	18.61	19.56	5.79	6.09	6.40	3.06
2041	17.96	18.94	19.98	5.89	6.21	6.55	3.05
2042	18.24	19.28	20.39	5.99	6.33	6.70	3.04
2043	18.51	19.63	20.82	6.09	6.46	6.85	3.04
2044	18.79	19.98	$\mathbf{21.25}^{D}$	6.20	6.59	7.01	3.03

Table 8.1 – *Continued from previous page*

Years	Population (in millions)			Households (in millions)			Household size
	Low	Medium	High	Low	Medium	High	
2045	19.08	20.33	21.69	6.30	6.71	7.16	3.03
2046	19.36	20.69	22.14	6.41	6.84	7.32	3.02
2047	19.65	**21.05**^{D}	22.59	6.51	6.98	**7.49**^{T}	3.02
2048	19.94	21.41	23.05	6.62	7.11	7.66	3.01
2049	20.23	21.78	23.52	6.73	7.25	7.83	3.01
2050	20.52	22.15	23.99	6.84	**7.38**^{T}	8.00	3.00

It is important to highlight that the evolution of the total number of households is driven by two main factors: the population and the household size growth rates. It is shown in Figure 8.1 (a) that the population growth rates present decreasing trends for the three scenarios which would result in a decrease in the total number of households. However, the effect of the decreasing trends in population growth rates is offset by the decreasing trend in the size of a household (from 4.30 in 2012 to 3.00 in 2050). The reducing household size over time results in an increased total number of households despite the decrease in the population growth rates. The comparison of the number of households in 2012 and 2050 shows that on average the households will increase by 4% per year for the low scenario, 6% for the medium scenario and 8% for the high scenario. These increases are very high compared to the average population growth of 1.88% per year for the low scenario, 2.04% for the medium scenario and 2.19% for the high scenario. The high number of households means that more and more energy would be required to electrify the non-electrified households as well as the new created households.

Projected electricity demand for the residential sector

As discussed in the above paragraphs, it is projected that, by 2050, the total number of households will respectively reach 6.84 million, 7.38 million and 7.99 million under the low, medium and high scenarios of the population growth respectively. To achieve a 100% electrification rate in 2050, an average of 200,000 new connections per year from 2012 will have to be achieved for the high scenario, 183,000 for the medium scenario and 169,000 for the low scenario. Figure 8.2 illustrates the number of electrified households every five years between 2012 and 2050.

To achieve such high new connections, it is projected that the electricity consumption by the residential sector by 2050 will reach 3,830 GWh for the low scenario of the population growth, 4,130 GWh for the medium scenario and 4,475 GWh for the high scenario from 194 GWh in 2012. Figure 8.3 shows the evolution of the residential power consumption for the three population scenarios considered in this study.

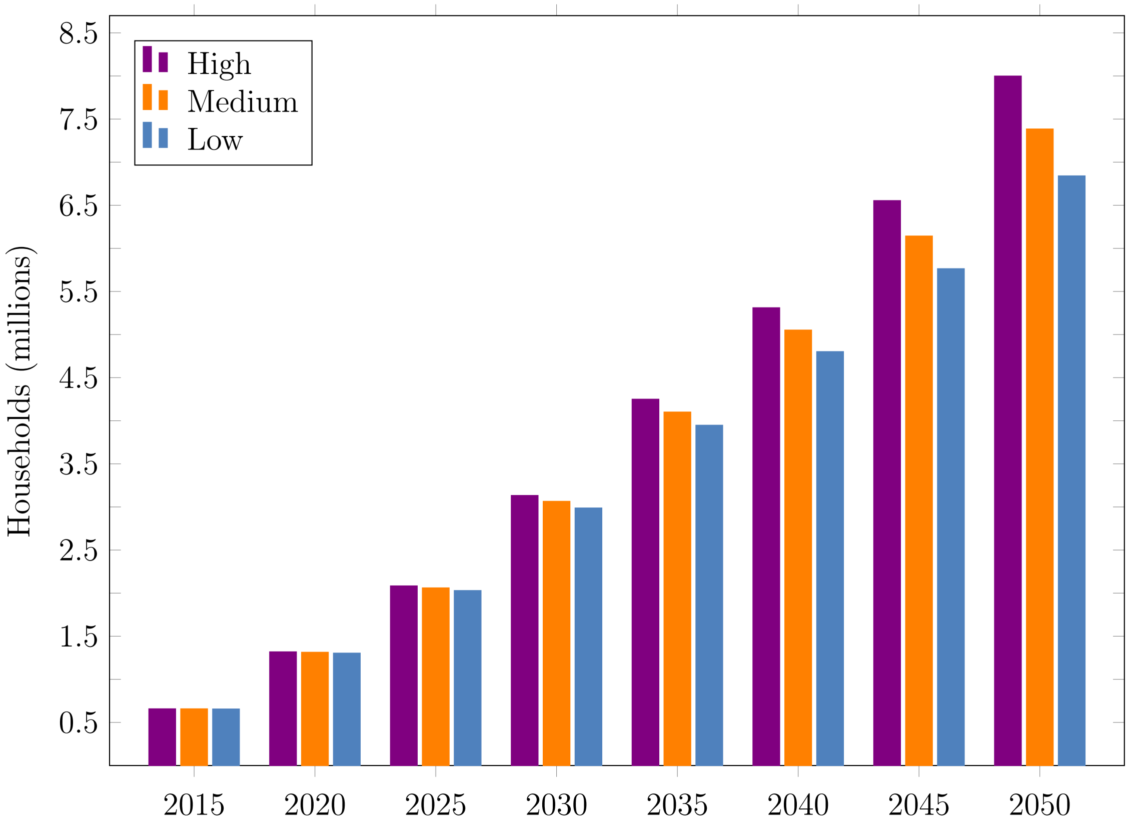


Figure 8.2: Projected number of households with access to electricity for the 2012 – 2050 period

The total electricity consumption by the residential sector is driven by three main factors: the increasing number of households, the increasing saturation of households by electrical appliances and the assumed improvement in energy efficiency. As presented in the previous section, the number of households is expected to double and triple during the simulation period. This means that the total residential sector electricity demand would also double and triple at the same period in case the rated power of the household appliances and their penetration remain the same. However, due to an expected increase in the national income that will be discussed in the next section, it can be expected that the saturation of different household appliances will increase (income effect) which will raise the average power consumption per household. On the other hand, it is expected that the same electricity services obtained in the base year will still be achieved with reduced power rating of the household appliances (i.e. 15% less compared to 2012) due to assumed improvements in efficiency.

In terms of specific electricity consumption, it is projected that the average demand for electricity per each electrified household will increase from 476.50 kWh in 2012 to 657.50 kWh in 2050. The percentage contributions of different appliances to the total annual power consumption per household will decline for the appliances that are saturated or

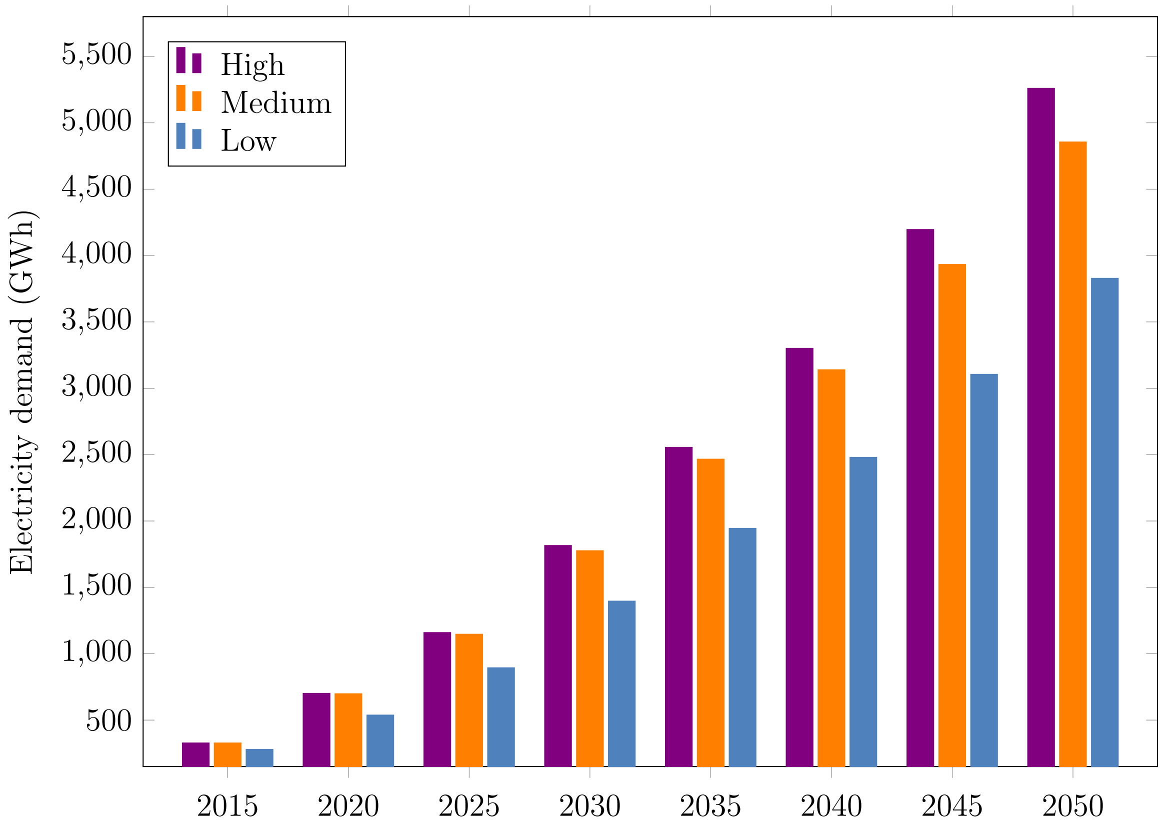


Figure 8.3: Projected demand for electricity by the residential sector for the 2012 – 2050 period

almost saturated in the base year while the shares of those appliances with low saturation in the base year will increase. In 2012 (see Figure 8.4), lighting purposes represented the highest share (65.63%) of the annual household's electricity consumption and it was followed by audio & video (15.53%) and refrigeration (9.86%). In 2050 (see Figure 8.5), the share of lighting in the household's power demand will remain on lead but is reduced to 40.44%. Cooking, refrigeration and audio & video will represent the second, third and fourth positions in the consumption of electricity and they will represent respectively 18.87%, 15.57% and 13.16%.

Although the share of cooking looks high in 2050 (18.87%), electric cook stoves will still be the least used household appliance in 2050 (only by 10% of the electrified households). The relatively high share is due to the higher power rating of electric stoves which is estimated to be about 2,000 kW in 2012 and 1,700 kW in 2050. As comparison, one electric stove is equivalent (in terms of rated power) to about 180 CFL light bulbs, 18 TV sets, 9 fridges or 2 irons.

A comparison of specific average household electricity consumption with a fully saturated household (i.e. a household possessing and using all the presented household appliances) shows that a fully saturated household consumed 2,588.25 kWh in 2012 while the average

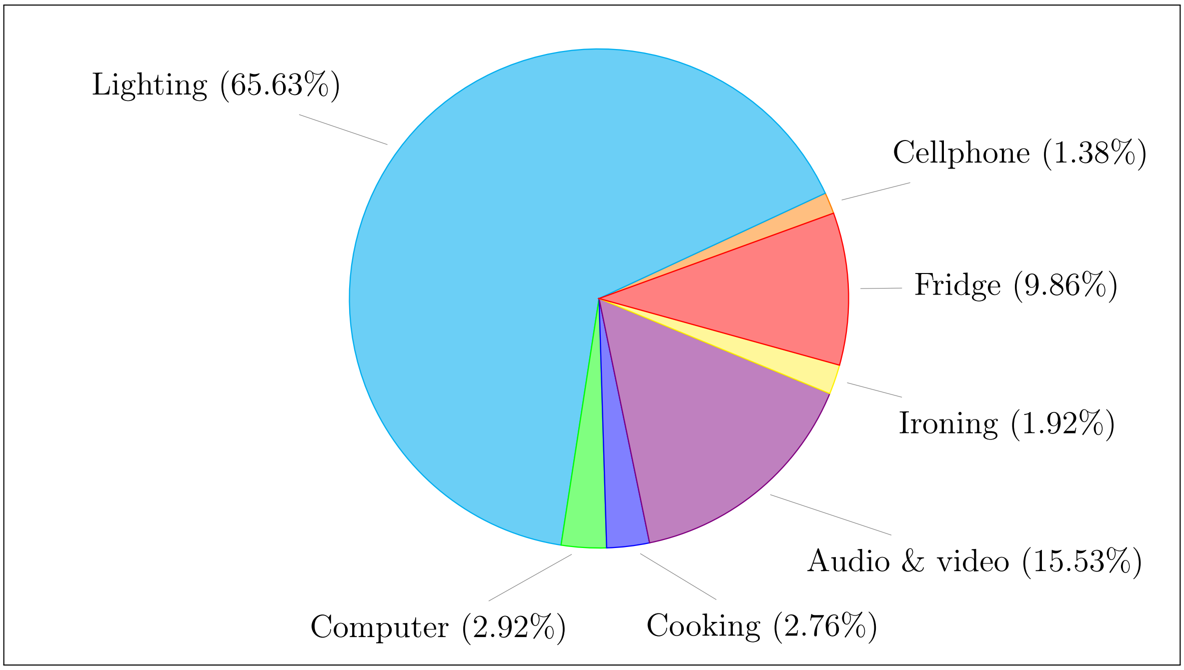


Figure 8.4: Distribution of specific household power consumption in 2012 (100%=476.50 kWh)

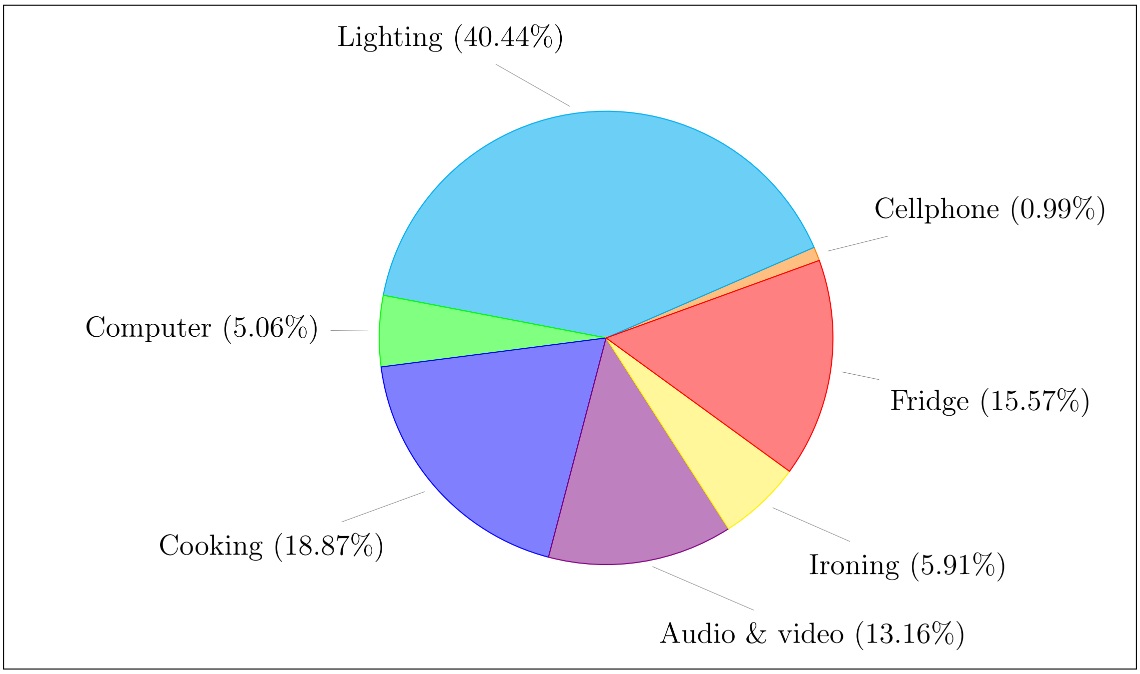


Figure 8.5: Distribution of specific household power consumption in 2050 (100%=657.50 kWh)

power consumption by an electrified household in the same year was 476 kWh equivalent to 18.41% of the fully saturated household. On the other hand, it is projected that in 2050 a fully saturated household will consume 2,200 kWh while the average consumption by an electrified household will be 657.50 kWh. It is also projected that a household will gradually saturate with the considered appliances where for example the percentage saturation of computers, electric cook-stoves and audio/visio devices will respectively increase from 14.22%, 0.9% and 53.63% in 2012 to 40.00%, 10.00% and 73.81% in 2050 (see Table 8.2).It is worth highlighting that the specific household power consumption will be limited by the assumed improvement in efficiency of the household appliances. In this study it is assumed that by 2050 all the household appliances will consume 85% of their power consumption in 2012.

Table 8.2: Comparison of a fully saturated household with the average power consumption of an electrified household between the base and the end years

Appliance	2012			2050		
	Saturated (kWh)	Average (kWh)	% of saturated	Saturated (kWh)	Average (kWh)	% of saturated
Cellphone	6.57	6.57	100.00	6.6	6.57	100.00
Computer	97.82	13.91	14.22	83.1	33.26	40.00
Cooking	1,460.00	13.14	0.90	1,241.0	124.10	10.00
Iron	91.25	9.13	10.00	77.6	38.78	50.00
Lighting	312.81	312.81	100.00	265.88	265.88	100.00
Audi & video	138.00	74.01	53.63	117.27	86.56	73.81
Refrigeration	481.80	46.98	9.75	409.5	102.38	25.00
Total	**2,588.25**	**476.54**	**18.41**	**2,200.97**	**657.54**	**29.87**

8.1.2 Non−residential sector

Before the projected electricity consumption by the non−residential sector is discussed, a presentation on the expected national GDP is first provided. In Section 5.4.2 it was assumed that under the high scenario of the economic growth, the GDP growth rate will decrease from 8.0% in 2012 to 6.0% by 2050. For the medium scenario, the GDP is projected to reach 4.5% while it is anticipated to be 3.0% for the case of the low scenario. The evolution of the country's GDP growth rate under the considered three scenarios can be visualised in Figure 8.6 (a). Based on these economic growth assumptions, it is projected under the low scenario that the total Rwandan GDP will increase from US$ 4.90 billion in 2012 to US$ 11.92 billion in 2025 and US$ 36.47 billion in 2050. As for the medium scenario, it is anticipated that the national GDP will reach 12.33 billion US dollar in 2025 and 48.17 billion US dollar in 2050. The high scenario on the other hand will achieve 12.75 billion US dollar in 2025 and 63.46 billion US dollar in 2050. The evolution of the national GDP between 2012 and 2050 under theses scenarios considered in this study are graphically shown in Figure 8.6 (b).

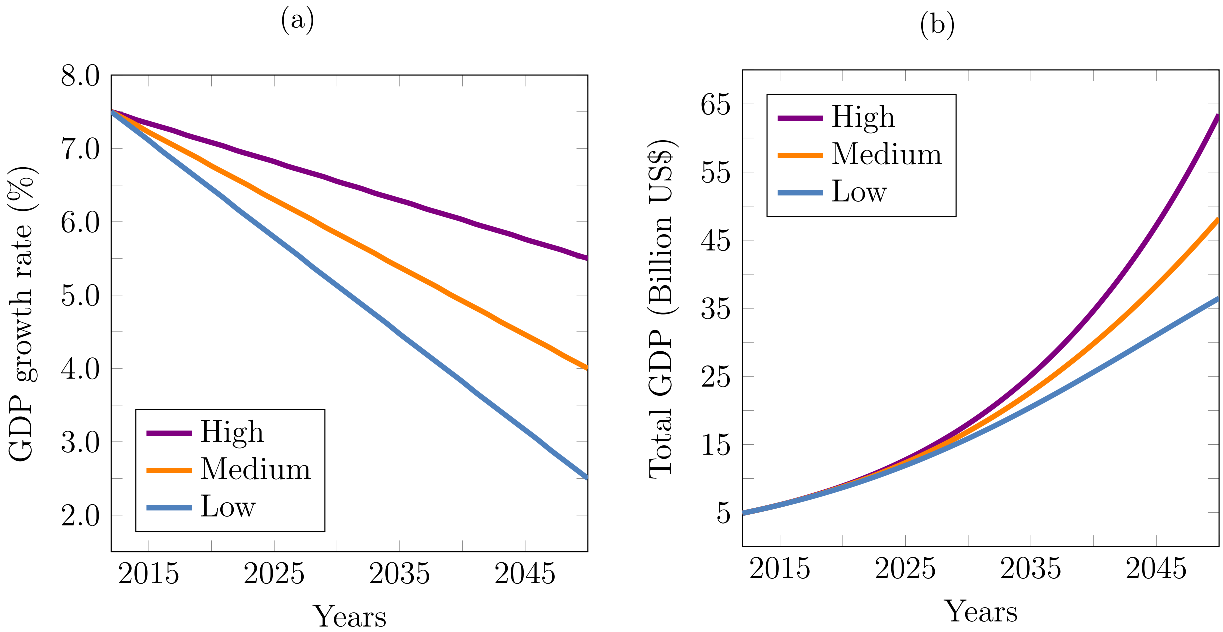


Figure 8.6: Projected GDP growth rates and total GDP between 2012 and 2050. The evolution of the GDP growth rates can be visualised in (a) while the total GDP is shown in (b).

To produce the projected GDP, the electricity demand by the non−residential sector will have to increase from 185 GWh in 2012 to 594 GWh by 2025 and to 2,718 GWh by 2050 for the low scenario. In case the economic development follows the medium scenario, 622 GWh will be needed by 2025 and 3,968 GWh by 2050. As for the high scenario, 651 GWh will be required by 2025 and 5,773 GWh by 2050. Table 8.3 presents the base year values for the GDP and electricity consumption as well as the projected GDP and corresponding electricity demand every 5 years from 2015 to 2050 while Figure 8.7 shows the evolution of the electricity demand for the non−residential sector between 2012 and 2050.

Table 8.3: National GDP (at 2006 constant US$) and nonresidential power demand for chosen years between 2012 and 2050

Years	GDP (in billion US$)			Power demand (in GWh)		
	Low	Medium	High	Low	Medium	High
2012	4.90	4.90	4.90	185	185	185
2015	6.13	6.14	6.16	240	241	242
2020	8.68	8.79	8.91	386	392	400
2025	11.92	12.32	12.75	594	622	651
2030	15.87	16.91	18.01	877	956	1,041
2035	20.49	22.70	25.14	1,240	1,426	1,638
2040	25.63	29.82	34.65	1,682	2,067	2,535
2045	31.06	38.32	47.18	2,185	2,907	3,858
2050	36.47	48.17	63.46	2,718	3,968	5,773

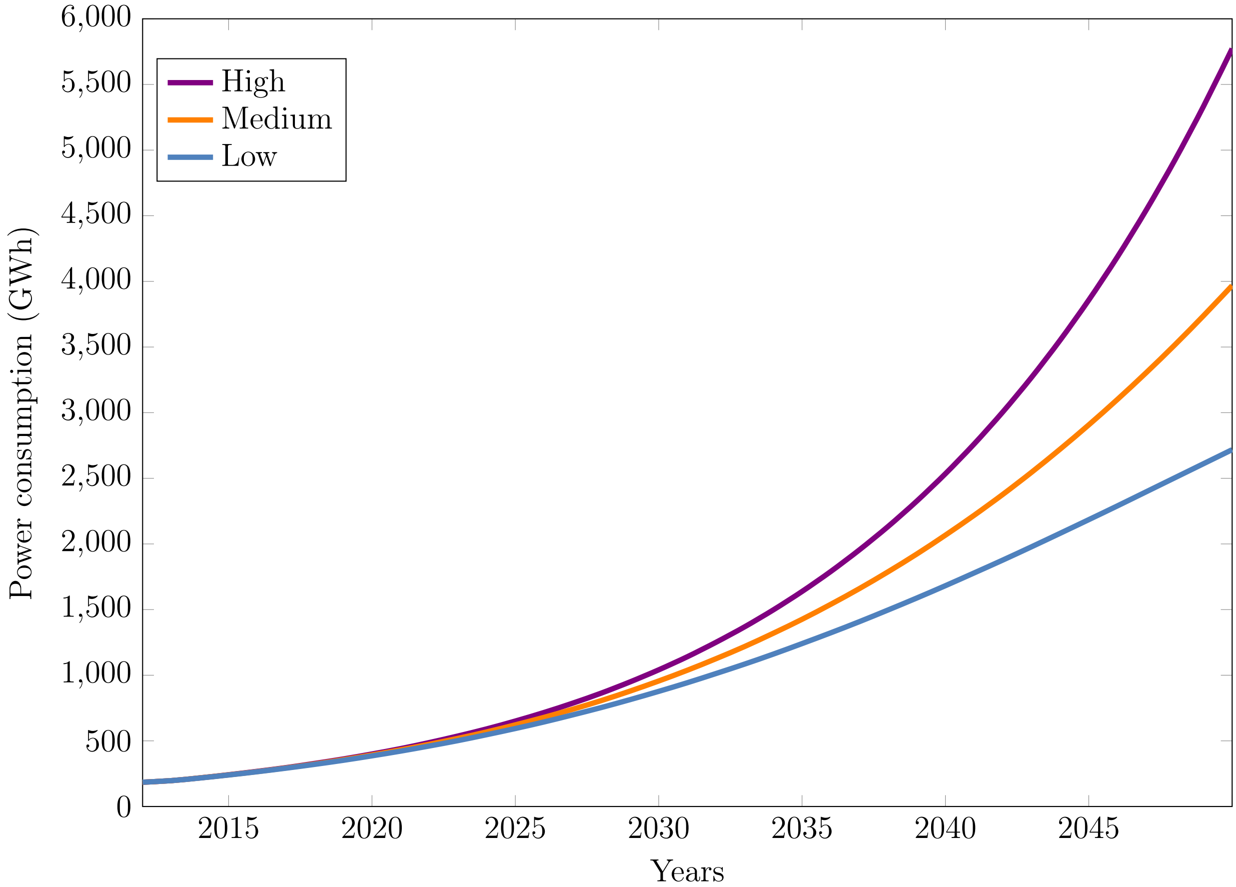


Figure 8.7: Evolution of the non−residential sector electricity consumption between 2012 and 2050

8.1.3 Total national electricity demand

The total national electricity demand is obtained by combining the residential and non−residential sector demands. The three residential and three nonresidential demand scenarios lead to nine different scenarios (see Table 8.4). As it can be noticed in Figure 8.8, the scenarios can be grouped into three main categories: the upper three of which each includes the high scenario of the non−residential sector; the middle group where each scenario includes the medium scenario of the non−residential sector and lower group where each of the scenarios of this group includes the lower scenario of the non−residential sector. Because the scenarios comprising each group are very close (see Figure 8.8), one scenario from each group was selected to represent the national electricity demand. These scenarios are uppermost scenario (i.e. $H_{NR} + H_R$) referred in the following sections to as very high scenario, the middle scenario (i.e. $M_{NR}+M_R$) referred to as likely scenario and the lower scenario (i.e. $L_{NR}+L_R$) referred in this study to as very low scenario.

Table 8.4: Possible electricity demand scenarios at national level. In the table, capital letters L refers to low scenario, M and H are respectively the medium and high scenarios. The subscripts R and NR represent the residential and non−residential sectors respectively.

ID	Residential	Non−residential	Abbreviation	Retained
1	High	High	$H_{NR} + H_R$	Very high
2	High	Medium	$H_{NR}+M_R$	
3	High	Low	$H_{NR}+L_R$	
4	Medium	High	$M_{NR}+H_R$	
5	Medium	Medium	$M_{NR}+M_R$	Very likely
6	Medium	Low	$M_{NR}+L_R$	
7	Low	High	$L_{NR}+H_R$	
8	Low	Medium	$L_{NR}+M_R$	
9	Low	Low	$L_{NR}+L_R$	Very low

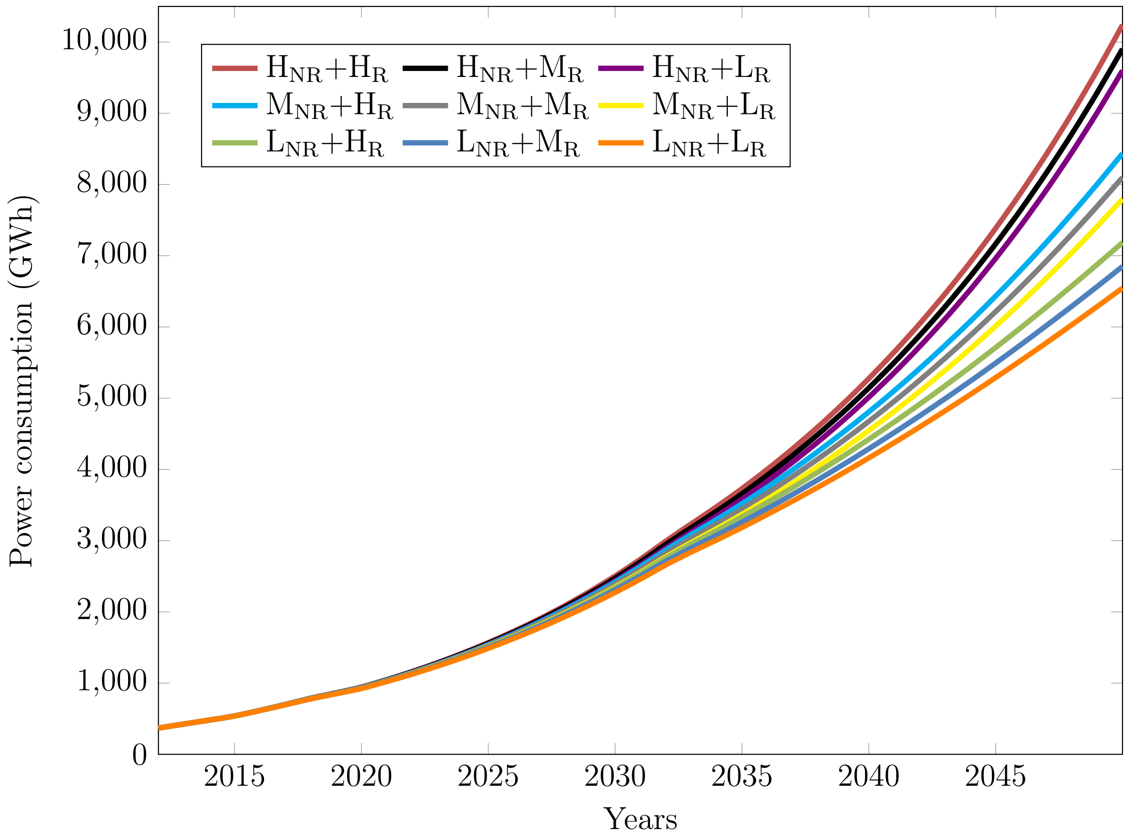


Figure 8.8: Evolution of the national electricity consumption between 2012 and 2050

Total power consumption per scenario

The analysis of the selected scenarios show that for the very low scenario, the total electricity consumption in Rwanda would increase from about 379 GWh in 2012 to 1,487 GWh by 2025 and 6,546 GWh by 2050. For the case of the very likely scenario, the national electricity demand is projected to reach 1,529 by 2025 and 8,100 GWh by 2050. As for the very high scenario, the total annual electricity consumption in the country is expected to be 1,568 GWh by 2025 and 10,240 GWh by 2050. On average, additional 163 GWh, 203 GWh and 360 GWh per year respectively under the very low, very likely and the very high scenarios would be required to meet the growing electricity demand. The total power consumption as well as the percentage shares of the residential and non−residential sectors to the national power demand are presented in Table 8.5. The evolution of the electricity demand under the three scenarios at the national level can be visualised in Figure 8.9 (a) for the very low scenario, (c) for the very likely scenario and (e) for the very high scenario.

Table 8.5: Projected total power demand and its distribution between residental and non−residential sectors. In this table, Resid. means residential sector while Nonresid. represents the Non−residential sector.

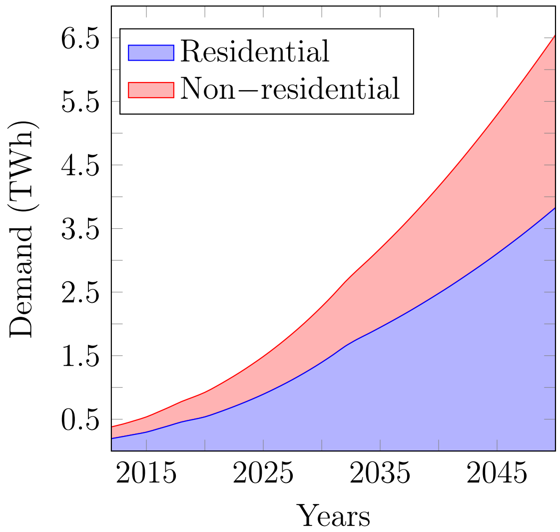
Year	Very low			Very likely			Very high		
	Total (kWh)	Resid. (%)	Nonres. (%)	Total (kWh)	Resid. (%)	Nonres. (%)	Total (kWh)	Resid. (%)	Nonres. (%)
2012	380	51.32	48.68	380	51.32	48.68	380	51.32	48.68
2013	425	53.75	46.25	425	53.75	46.25	425	53.74	46.26
2014	479	54.65	45.35	480	54.64	45.36	480	54.61	45.39
2015	537	55.26	44.74	538	55.24	44.76	540	55.18	44.82
2016	614	56.81	43.19	616	56.76	43.24	618	56.66	43.34
2017	694	57.94	42.06	698	57.85	42.15	700	57.70	42.30
2018	778	58.75	41.25	783	58.62	41.38	788	58.41	41.59
2019	848	58.51	41.49	857	58.32	41.68	863	58.05	41.95
2020	923	58.19	41.81	934	57.93	42.07	943	57.59	42.41
2021	1,020	58.65	41.35	1,036	58.32	41.68	1,048	57.89	42.11
2022	1,126	59.06	40.94	1,145	58.64	41.36	1,163	58.13	41.87
2023	1,238	59.42	40.58	1,263	58.91	41.09	1,287	58.30	41.70
2024	1,359	59.76	40.24	1,391	59.14	40.86	1,422	58.42	41.58
2025	1,487	60.07	39.93	1,529	59.34	40.66	1,568	58.50	41.50
2026	1,625	60.36	39.64	1,677	59.50	40.50	1,727	58.54	41.46
2027	1,772	60.63	39.37	1,836	59.64	40.36	1,899	58.55	41.45
2028	1,928	60.90	39.10	2,006	59.77	40.23	2,084	58.53	41.47

Table 8.5 – *Continued from previous page*

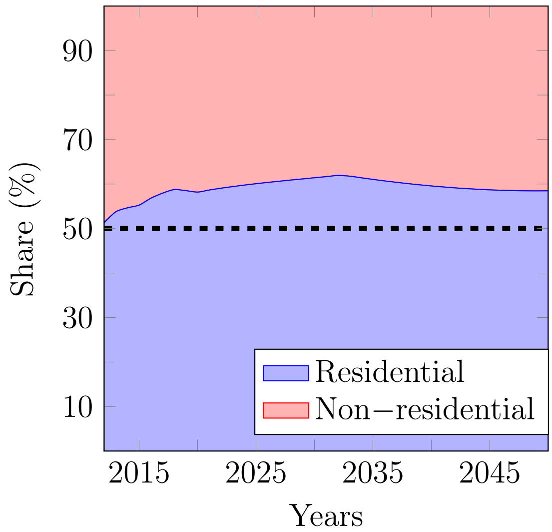
Year	Very low			Very likely			Very high		
	Total (kWh)	Resid. (%)	Nonres. (%)	Total (kWh)	Resid. (%)	Nonres. (%)	Total (kWh)	Resid. (%)	Nonres. (%)
2029	2,095	61.15	38.85	2,190	59.87	40.13	2,286	58.49	41.51
2030	2,272	61.41	38.59	2,387	59.96	40.04	2,504	58.42	41.58
2031	2,460	61.66	38.34	2,598	60.05	39.95	2,739	58.33	41.67
2032	2,660	61.92	38.08	2,823	60.13	39.87	2,995	58.23	41.77
2033	2,839	61.77	38.23	3,031	59.78	40.22	3,236	57.69	42.31
2034	3,008	61.40	38.60	3,234	59.19	40.81	3,475	56.89	43.11
2035	3,185	61.04	38.96	3,445	58.60	41.40	3,730	56.08	43.92
2036	3,367	60.70	39.30	3,668	58.03	41.97	4,002	55.26	44.74
2037	3,555	60.39	39.61	3,902	57.45	42.55	4,291	54.44	45.56
2038	3,751	60.09	39.91	4,148	56.89	43.11	4,599	53.61	46.39
2039	3,953	59.82	40.18	4,405	56.33	43.67	4,927	52.78	47.22
2040	4,161	59.57	40.43	4,675	55.79	44.21	5,276	51.95	48.05
2041	4,375	59.35	40.65	4,957	55.25	44.75	5,647	51.11	48.89
2042	4,595	59.14	40.86	5,251	54.73	45.27	6,043	50.27	49.73
2043	4,821	58.97	41.03	5,559	54.22	45.78	6,463	49.43	50.57
2044	5,052	58.82	41.18	5,881	53.72	46.28	6,910	48.59	51.41
2045	5,289	58.69	41.31	6,215	53.23	46.77	7,385	47.76	52.24
2046	5,531	58.59	41.41	6,564	52.76	47.24	7,889	46.92	53.08
2047	5,778	58.52	41.48	6,926	52.30	47.70	8,425	46.09	53.91
2048	6,030	58.48	41.52	7,303	51.85	48.15	8,994	45.26	54.74
2049	6,286	58.46	41.54	7,694	51.42	48.58	9,599	44.44	55.56
2050	6,546	58.48	41.52	8,099	51.01	48.99	10,240	43.63	56.37

Similar to the past, the residential sector will continue to dominate the national demand for electricity so that, under the very low scenario, the share of the power consumption by households is projected to increase to 60.07% (or 893 GWh) by 2025 and then slightly decrease to 58.48% (or 3,827 GWh) by 2050, from 51.9% (or 194 GWh) in 2012. The high share of the residential sector is due to the expected electrification rate that is projected to increase from 16.8% in 2012 and reach 70% in 2032 and 100% by 2050. The non−residential sector on the other hand will experience a decrease its share from 48.81% (equivalent to 185 GhW) in 2012 to 39.93% (or 594 GWh) by 2025 and then increase slightly to 41.52% (or 2,718GWh) by 2050. The low share of the non−residential sector in this scenario is due to two main factors: the assumed GDP growth rate which is projected to decrease from 8% in 2012 to 3% in 2050; and the fast electrification rate as explained above.

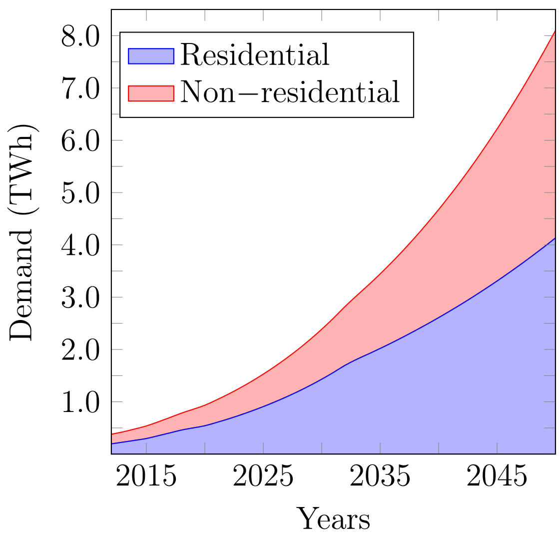
(a) Very low scenario: totals



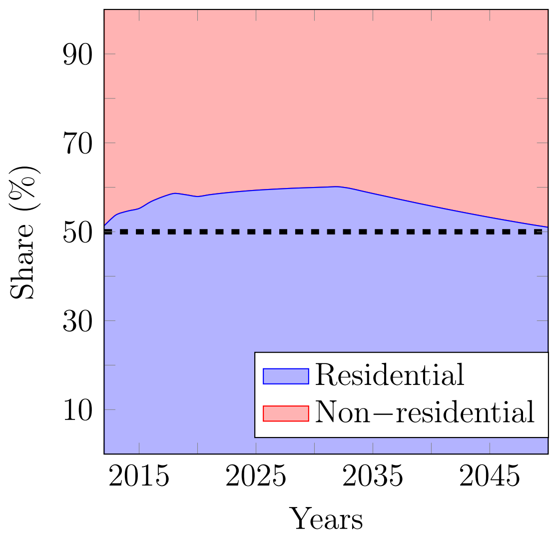
(b) Very low scenario: shares



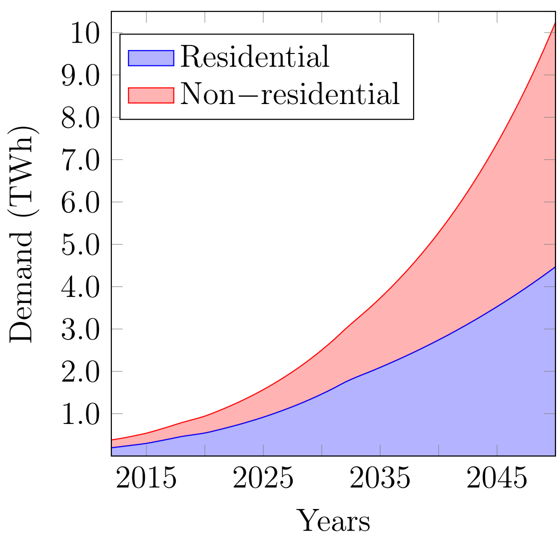
(c) Likely scenario: totals



(d) Likely scenario: shares



(e) Very high scenario: totals



(f) Very high scenario: shares

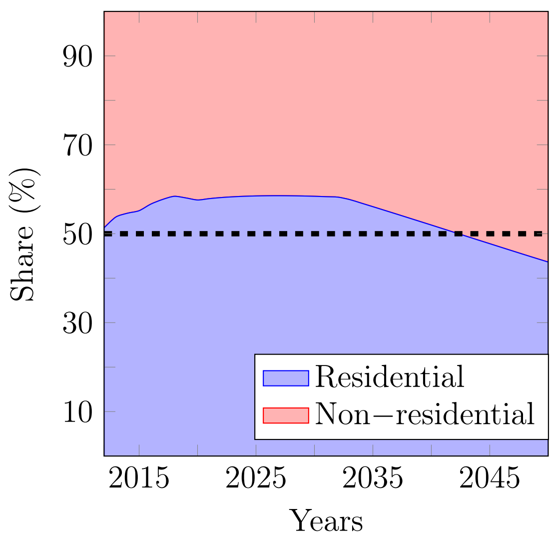


Figure 8.9: Total and distribution of the projected Rwanda's electricity demand

As for the very likely scenario, it projected that the share of the residential sector to the national power consumption will increase from 51.19% (or 194 GWh) in 2012 to 59.34% (or 907 GWh) by 2025 and then decrease to 51.01% (or 4,131 GWh) by 2050. The non−residential sector of this scenario will record a decrease of its share from 48.81% (or 185 GhW) in 2012 to 40.66% (or 622 GWh) by 2025 and then increases to 48.99% (or 3,968 GWh) by 2050.

With regard to the high scenario, the share of the residential sector in the total power consumption is also projected to dominate the country's power consumption except for the 2041−2050 decade when the non−residential sector will take a lead. Under this scenario, the share of the residential sector in the total power demand is expected to increase from 51.19% (or 194 GWh) in 2012 to 58.50% (equivalent to 917 GWh) by 2025 and then falls to 43.63% (4,467 GWh) by 2050. The non−residential sector's share on the other hand is projected to decrease from 48.81% (or 185 GhW) in 2012 to 41.50% (equivalent to 651 GWh) by 2025 and then gradually increase to 56.37% (or 5,773 GWh) by 2050. This higher increase in the share of the non−residential sector power consumption is due to assumed GDP growth rate which is projected to change from 8% in 2012 to 6% by 2050.

The evolution of the power consumption shares for the residential and non−residential shares can be visualised in Figure 8.9 (b) for the very low scenario, (d) for the very likely scenario and (f) for the very high scenario while detailed values of the the total power consumptions and its percentage distribution among residential and non−residential sectors are presented in Table 8.5.

Per capita GDP and power consumption

The analysis of the GDP and population projections show that the GDP per capita per year is expected to increase from US$ 466 (in 2006 constant US$) in 2012 to US$ 864 for the very low scenario, US$ 881 for the very likely scenario and US$ 900 for the very high scenario by 2025. In 2050 the GDP per capita is projected to reach US$ 1,777 under the very low scenario, US$ 2,175 for the very likely scenario and US$ 2,645 for the case of the very high scenario. As it can be noticed from Figure 8.10, before the year 2035 the difference between the per capita GDP of the three scenarios is very small but it increases towards 2050. On average the per capita GDP will increase by 3.59% per year for the very low scenario, 4.14% for the likely scenario and 4.68% for the very high scenario.

As for power consumption, the per capita electricity consumption per year is projected to increase from 36 kWh in 2012 to 108 kWh for the very low scenario, 109 kWh for the very likely scenario and 111 kWh for the very high scenario by 2025. Similar to the GDP per capita there is no big difference between the scenarios before the year 2030 (see Figure 8.11). However, the difference becomes more and more clear after the year 2030 as it can be noticed from the same figure. By 2050 the per capita electricity consumption is projected to be 319 kWh for the very low scenario, 366 kWh and 429 kWh for the very likely and very high scenarios respectively. On average, an increase in per capita power consumption of 5.94% per year will be achieved under the low very scenario, 6.31% under the very likely scenario and 6.74% for the very high scenario.

Compared to the consumption in the base year, the per capita power consumption in 2025 is projected to be about three times higher than the consumption in 2012 (for all the three scenarios). In 2050 however, the electricity consumption is expected to be 9 times higher for the very low scenario, 10 times for the very likely scenario and 12 times for the very high scenario relative to the consumption in 2012.

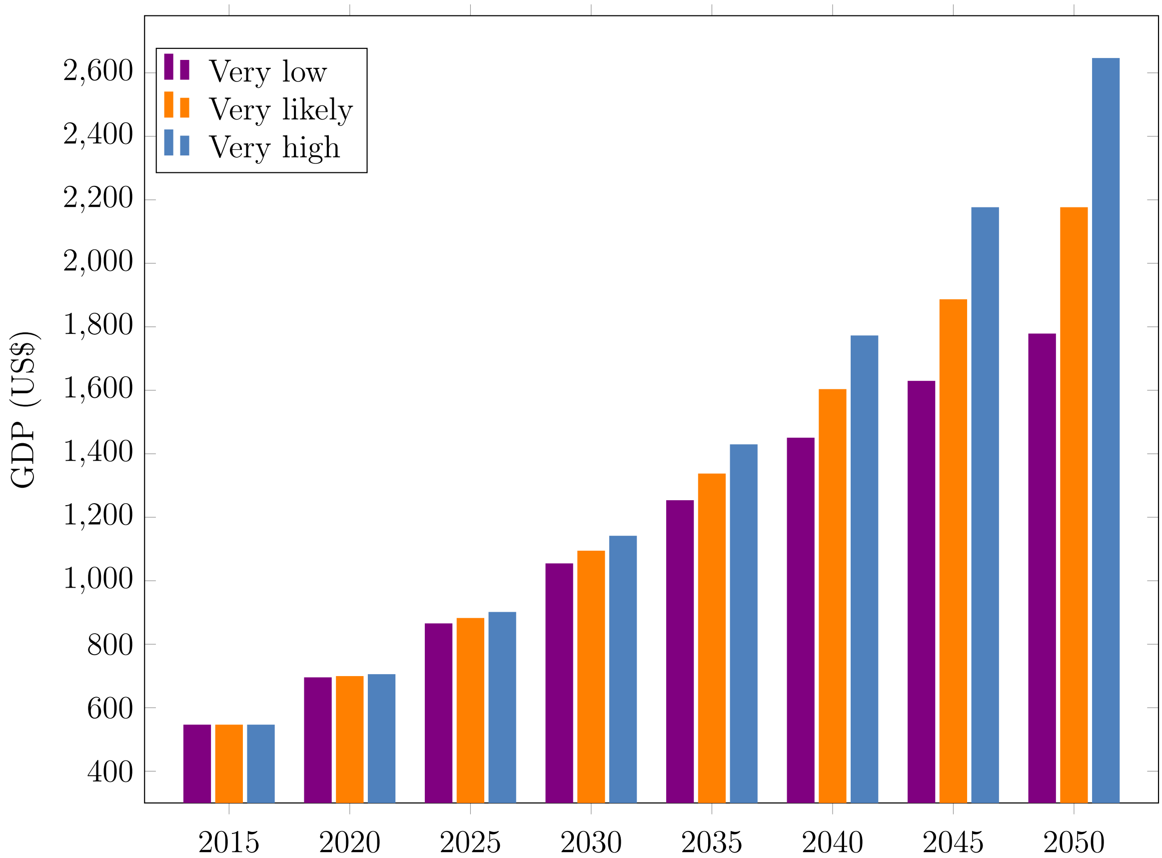


Figure 8.10: Projected per capita GDP (in current market prices) for the 2012 – 2050 period

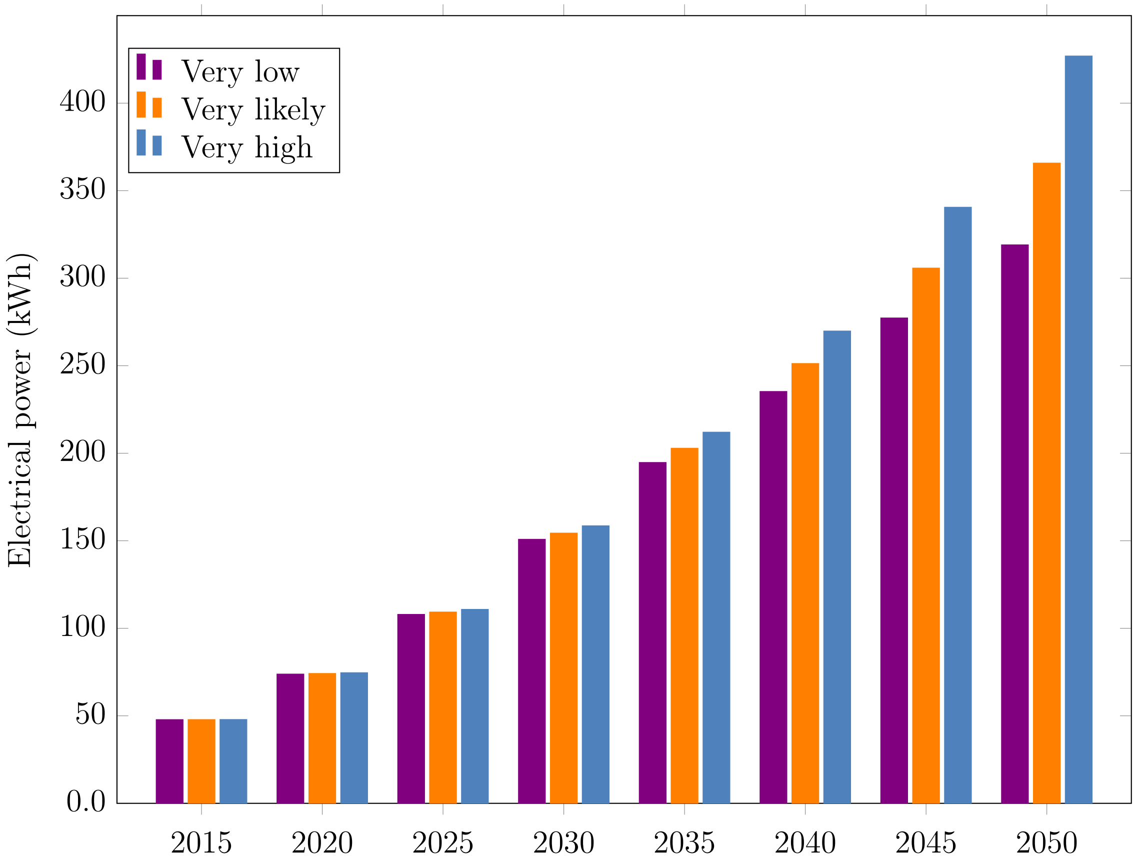


Figure 8.11: Projected per capita electricity consumption between 2012 and 2050

8.1.4 Required electricity generation and peak power

As explained in Section 5.4.3, the total energy to be generated in order to meet the simulated power demand is a sum of the total power consumption and the transmission losses. in this study it is assumed that the transmission and distribution losses will decrease from their 2012 level of 21% to 10% by 2020 and then be maintained at this level during the rest of the simulation period. Based on these assumptions it is projected that, by 2025, the electricity generation requirements would be 1,653 GWh for the very low scenario, 1,699 GWh for the very likely scenario and 1,742 GWh for the very high scenario from 480 GWh in 2012. In 2050 the required electricity generation is projected to be 7,273 GWh under the very low scenario, 9,000 GWh under the very likely scenario and 11,378 GWh for the case of the very high scenario. The evolution of the electricity to be generated between 2012 and 2050 can be visualised in Figure 8.12.

It is important to highlight that the real electricity requirements may exceed that presented in this section if losses are not reduced to the assumed values. It was planned under EDPRS 2008−2012, for example, that through the introduction of cheaper energy sources

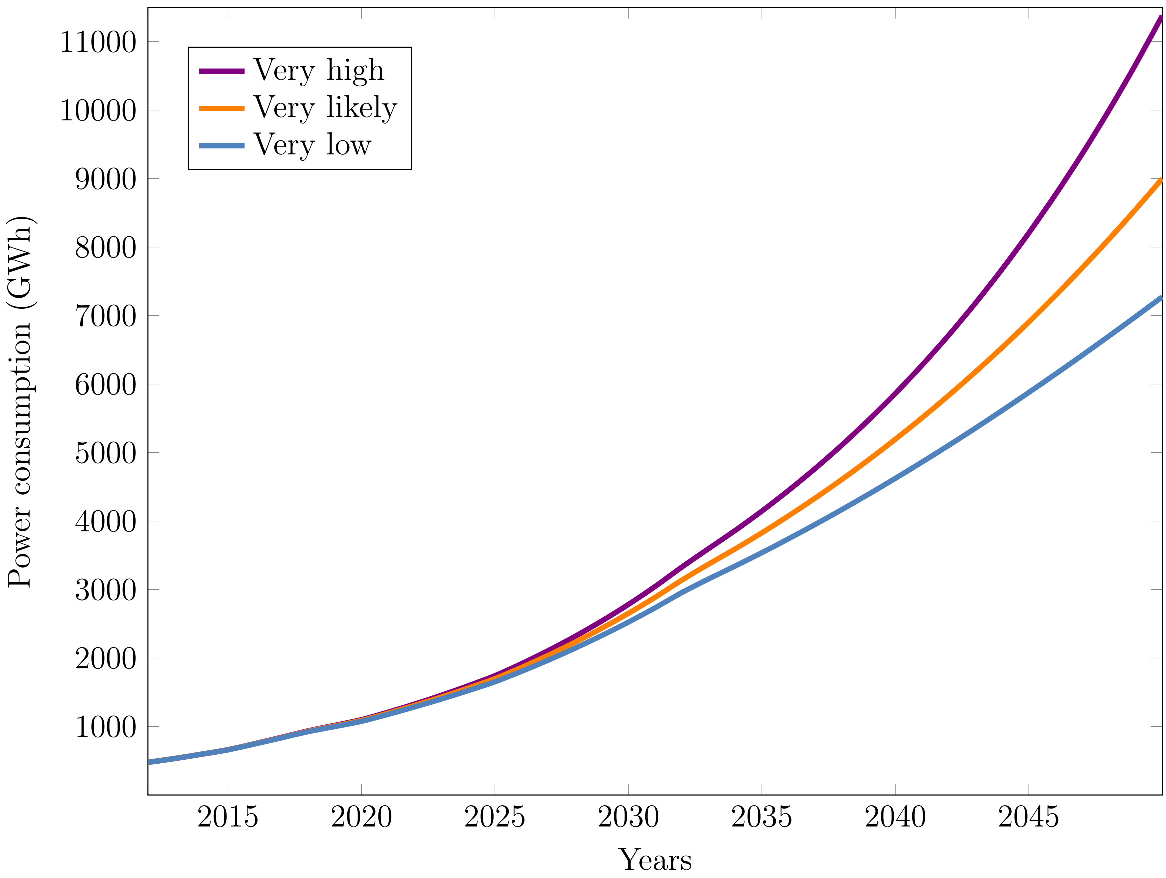


Figure 8.12: Required electricity generation for the 2012 – 2050 horizon

and the reduction of technical losses from 20% in 2007 to 15% by 2012, electricity tariffs could have been reduced while assuring that the national unique company in charge of power transmission and distribution remains financially sound (MININFRA 2009, 10). This target has not, however, been achieved as losses have increased over this period and reached 21.04% in 2012 and 22.06% in 2013. Consequently, instead of reducing the tariffs as previously planned, they have been increased from US$ 0.22 per kWh (or FRW 112 per kWh) in 2007 (Jolie et al. 2009, 10) to US$ 0.26 per kWh (or FRW 134 per kWh) for all electricity customers excluding the industrial sector (RURA 2012a).

With regard to the peak power demand, it is projected that by 2025, the peak power requirements would reach 280 MW for the very low scenario, 288 MW for the very likely scenario and 295 MW for the very high scenario, from 77 MW in 2012. By 2050 the peak demand is projected to reach 1,232 MW for the very low scenario, 1,524 MW for the very likely scenario and 1,927 MW for the very high scenario. By assuming a reserve margin of 20%, the required installed capacity by 2025 is projected to be 336 MW for the very low scenario, 345 MW for the very likely scenario and 354 MW for the very high scenario. By 2050 the projected peak power requirement is expected to reach 1,478 MW for the very low scenario, 1,829 MW for the very likely scenario and 2,312 MW for the very high scenario. The evolution of the peak power demand with and without reserve margins between 2012 and 2050 are presented in Figure 8.13.

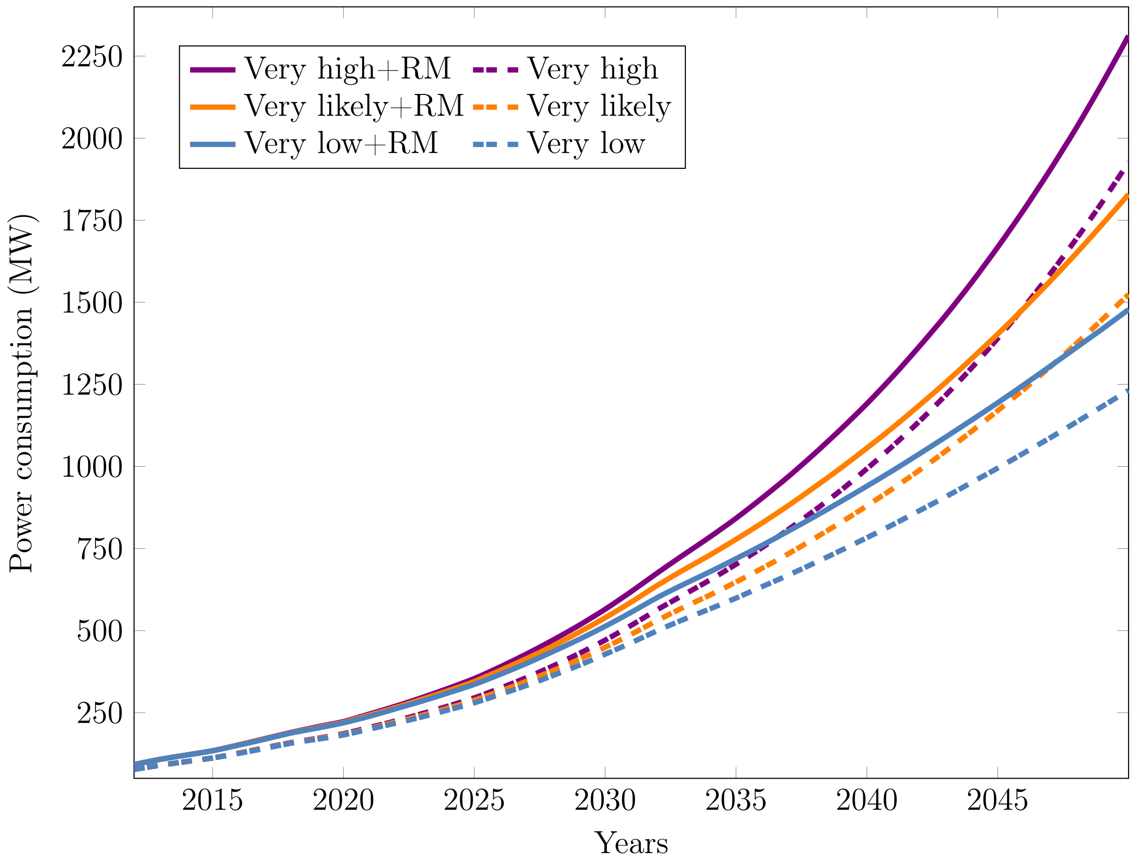
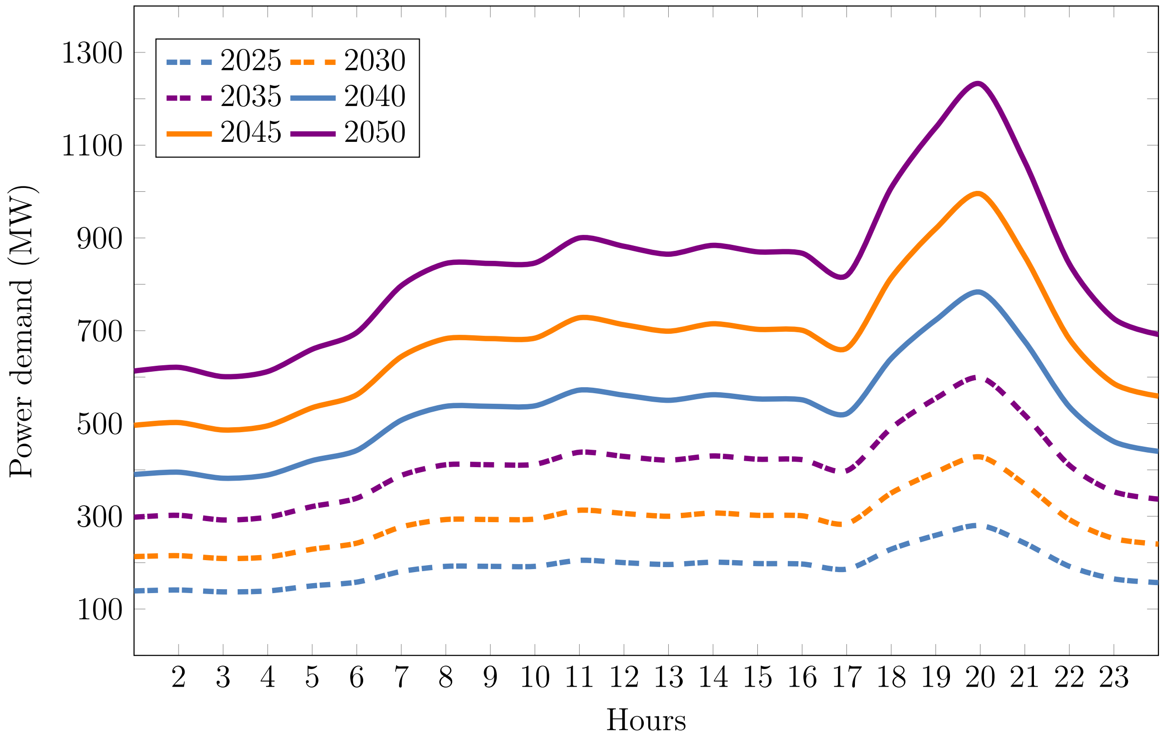


Figure 8.13: Evolution of the annual peak power requirements for the 2012−2050 horizon. Letters RM in the legend mean Reserve Margin (20% in this study).

As for the minimum power demand, it is projected that, by 2025, the minimum power demand would reach 138 MW under the very low scenario, 141 MW for the likely scenario and 145 MW for the very high scenario, from 38 MW in 2012. In 2050, the minimum power demand is projected to be 601 MW, 744 MW and 940 MW for the very low, very likely and the high scenarios respectively. The evolution of the daily load curve for the very low and the very high power demand scenarios can be visualised in Figure 8.14.

(a)



(b)

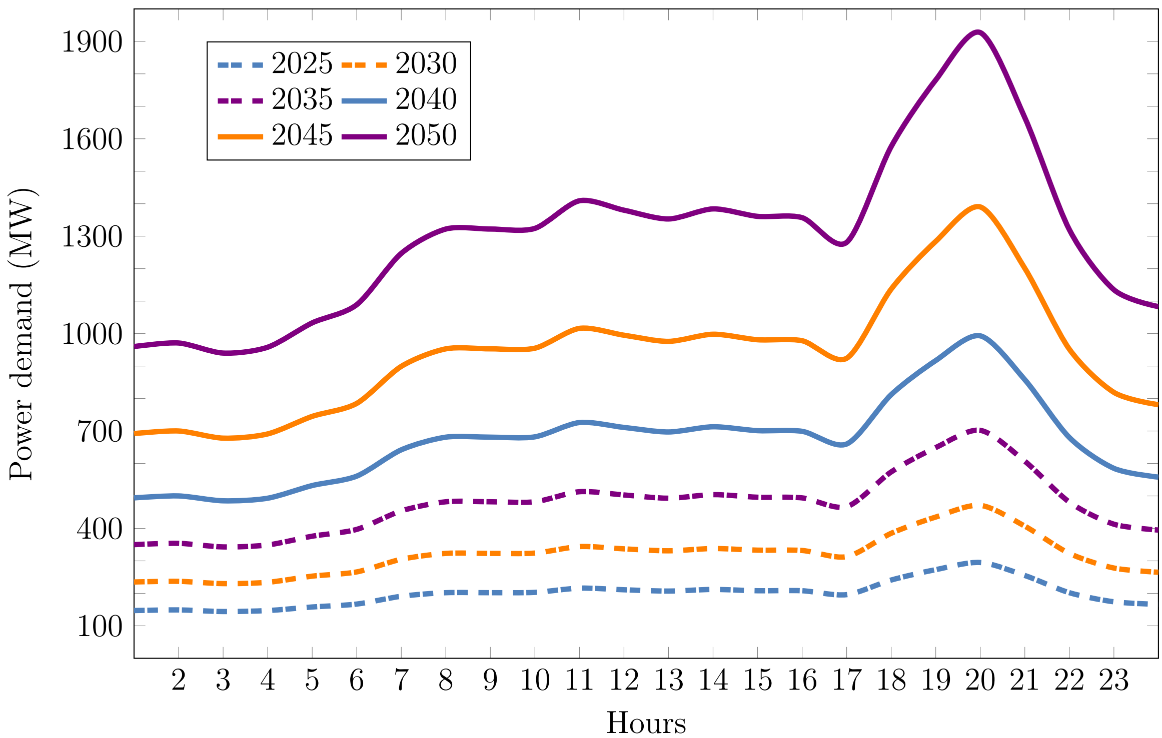


Figure 8.14: Evolution of the daily load curve every five years between 2025 and 2050. The load curve for the very low scenario is shown in (a) while the load curve for the very high scenario is presented in (b).

8.2 Electricity supply analysis

In this section the electricity supply options to meet the power demand scenarios presented in the previous section are analysed and discussed. These supply scenarios are grouped into two categories: a category related to the BAU scenario and another related to the suggested alternative scenario. Each of these two categories includes three sub−scenarios: a sub−scenarios with no consideration of climate change effects on hydropower generation, and sub−scenarios where effects of climate change under climate scenarios RCP4.5 and RCP8.5 are considered.

8.2.1 BAU power supply without climate change considerations

BAU power supply and the very low power demand scenarios

This scenario assumes that hydropower plants will continuously produce their designed annual power for the whole simulation period. As presented in Section 8.1.4, the electricity generation requirements for the very low power demand scenario is projected to increase from 480 GWh in 2012 to 7,273 GWh by 2050. Under these conditions, the national electricity demand between 2016 and 2050 can 100% be covered by domestic renewable energy resources as shown in Figure 8.15.

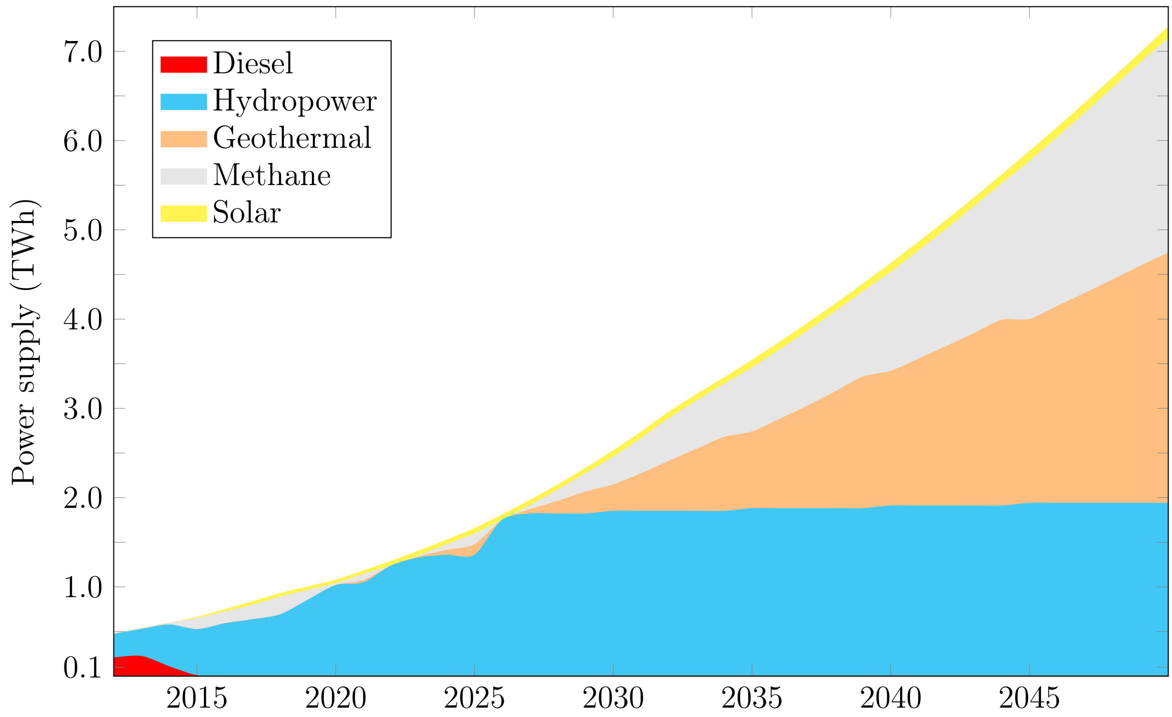


Figure 8.15: Electricity supply by resource type under the BAU scenario with no climate change considerations for the very low power demand scenario

Under this supply scenario, the share of hydropower in the electricity supply mix is projected to increase from 55.61% (of 480 GWh) in 2012 to 81.93% (of 1,653 GWh) in 2025 and then decline to 26.62% (of 7,273 GWh) in 2050. The highest shares of hydropower in the electricity supply mix is expected to be recorded in 2022 when it would represent 95.93% and in 2026 when it is expected to be 96.72% of the total power supply. These high shares of hydropower are due to the assumed coming in operation of three hydroelectric power stations: Rusumo Falls (27 MW) in 2021, Rusizi III (48 MW) in 2022 and Rusizi IV (96 MW) in 2026.

The share of solar power generation is expected to increase from 0.06% (of 480 GWh) in 2012 to 4.70% (of 834 GWh) in 2017 and then decline to 3.59% (of 1,653 GWh) in 2025 and to 1.81% (of 7,273 GWh) in 2050. According to the simulation results of the power supply under this current scenario, 100% of the electricity demand can be met with hydro and solar power productions in 2022 and 2026. It is worth to recall here that hydroelectric and solar power plants are in these circumstances operating at their maximum capacity according to the assigned dispatch priorities: solar and runoff based hydroelectric power plants are dispatched first (priority N°1) while dam based hydropower plants are assigned priority N°2. Methane and geothermal based power plants are dispatched at the third place while power from peat and diesel are assigned priorities N°4 and N°5 respectively.

As for power generation from methane, its share is projected to increase from 1.85% (of 480 GWh) in 2012 to 7.35% (of 1,653 GWh) in 2025 and to 33.05% (of 7,273 GWh) in 2050. Power generation from geothermal power on the other hand is projected to increase from 0% in 2012 to 7.14% (of 1,653 GWh) in 2025 and 38.52% (of 7,273 GWh) in 2050. Under this power demand scenario, no peat based power generation would be required for the whole simulation period. Power generation from diesel would only be required during the first year (until about 2016) before more hydropower, solar and methane based power plants come in operation (see Figure 8.15).

BAU power supply and the very likely power demand scenarios

In case the evolution of the national electricity demand follows the very likely scenario, the electricity generation requirements will be 9,000 GWh in 2050, from from 480 GWh in 2012. As hydropower and solar power plants are dispatched first and as they had achieved their maximum production capacities in case of very low scenario, their contributions (in terms of energy) are will remain the same as in the previous case. Therefore, to meet the power demand under this very likely scenario, the shares from other energy resources than hydropower and solar will have to increase their contributions. The evolution of the BAU power supply requirements by resource types for the very likely electricity demand scenario can be visualised in Figure 8.16.

The share of hydroelectric power generation is projected to increase from 55.61% (of 480 GWh) in 2012 to 79.70% (of 1,699 GWh) by 2025 and then decline to 21.51% (of 7,273 GWh) in 2050. Similar to the previous case, the highest share of hydropower generation is projected to be achieved in 2026 when it wouldrepresent 96.00% due to the same reasons as the case of the very low scenario. The share of solar power generation on the other hand would peak to 4.67% (of 838 GWh) in 2017 and then decline to 3.49% (of 1,699 GWh) in 2025 and to 1.46% (of 7,273 GWh) in 2050.

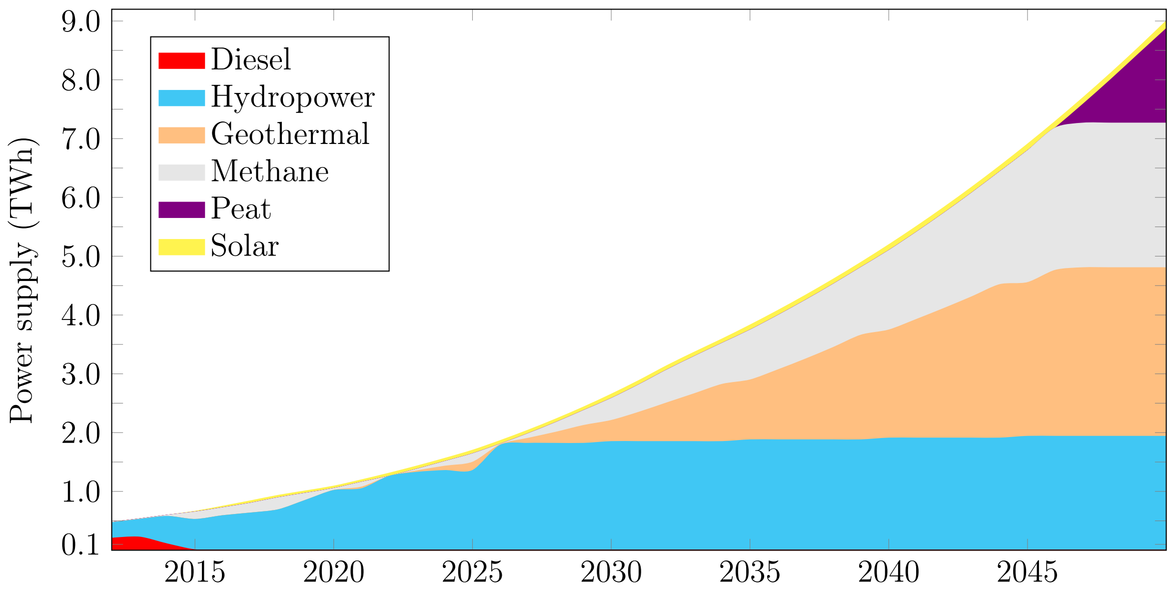


Figure 8.16: Electricity supply by resource type under the BAU scenario with no climate change considerations for the very likely power demand scenario

As for the contribution of power generation from methane, it is projected that the share of methane based power generation would increase from 1.85% (of 480 GWh) in 2012 to 8.53% (of 1,699 GWh) by 2025 before it peaks to 33.21% (of 7,293 GWh) in 2046 and then declines to 27.33% by 2050. The contribution of geothermal based power generation on the other hand is expected to be 8.28% (of 1,699 GWh) in 2025, peak to 38.71% (of 7,293 GWh) in 2046 and gradually declines to 31.86% (of 7,273 GWh) in 2050.

In 2047, all hydropower, solar, methane and geothermal power plants will be operating at their maximum capacities which will require additional capacities from other resources. The power demand that cannot be met by these four technologies is expected to be supplied by power from peat resources. In 2046, the share of peat based power generation will be 4.18% (of 7,696 GWh) and quickly increase to 17.84% (of 9,000 GWh) in 2050.

BAU power supply and the very high power demand scenarios

The power supply requirements to meet the power demand under the very high scenario is estimated to be 11,378 GWh by 2050. The distribution of energy between different technologies (see Figure 8.17) is such that the share of hydropower generation will increase from 55.61% (of 480 GWh) in 2012 to 77.72% (of 1,742 GWh) in 2025 and then decline to 17.01% (11,378 GWh) in 2050. The highest share of hydropower under this scenario is projected to be achieved in 2022 when it will represent 96.06% of the total power supply in that year (i.e. 1,329 GWh).

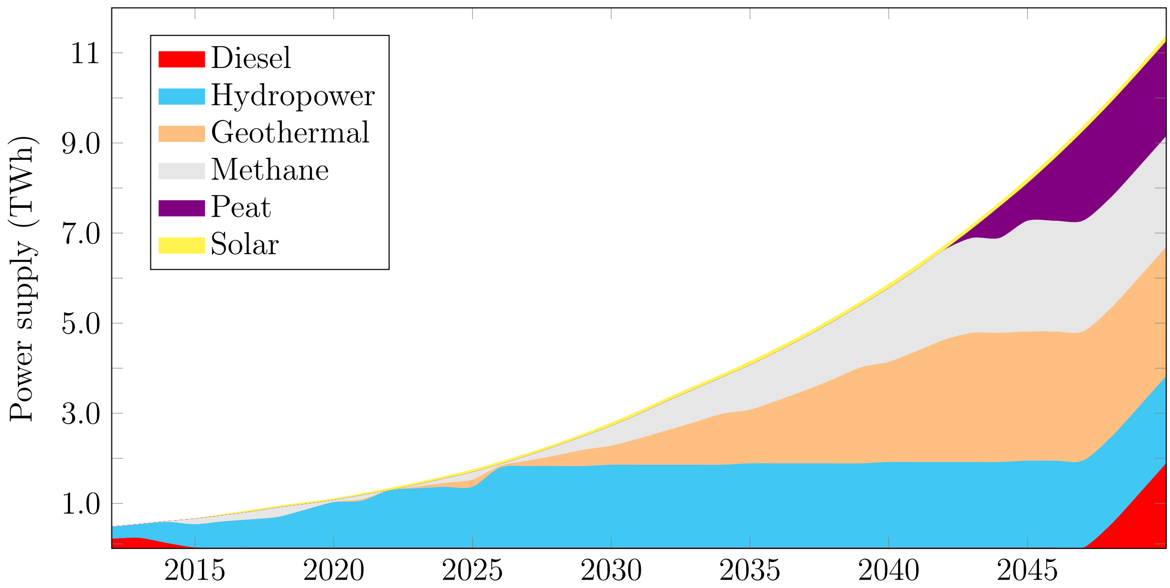


Figure 8.17: Electricity supply by resource type under the BAU scenario with no climate change considerations for the very high power demand scenario

As for the share of the solar based power generation, its contribution to the national power supply under the current scenario is expected to increase from 0.06% (of 480 GWh) in 2012, peak to 4.66% (of 842 GWh) in 2017 and then decline to 3.40% (of 1,742 GWh) by 2025 and 1.16% (of 11,378 GWh) by 2050. The share of methane and geothermal power generations are expected respectively to be 9.58% and 9.30% (of 1,742 GWh) by 2025 and 21.62% and 25.20% (of 11,378 GWh) by 2050. The biggest shares of these two technologies are expected in 2042 when they will represent respectively 29.72% and 40.42% (of 6,714 GWh).

Under this scenario, peat and diesel based power generations would be needed to meet excess demand that cannot be covered using hydropower, solar, methane and geothermal power production. Under the current scenario's assumptions, the power generation from peat would be first required in 2043 when its share is projected to be 2.80% (of 7,181 GWh) and quickly increase to 18.53% (of 11,378 GWh) by 2050. As all the suggested power generations based on national resources will not be able to cover the growing total power demand, power generation from diesel based power plants will be necessary from the year 2048. In this year, the share of power generation from diesel power plants is projected to be 5.12% (of 9,994 GWh) which will increase to 16.48% (of 11,378 GWh) by 2050.

The percentage shares of different technologies used under this power supply scenario to meet the projected electricity demand under the very low, very likely and the very high scenarios every five year between 2015 and 2050 as well as the shares during the base year are presented in Table 8.6. The required power supply for each of the considered year is also shown in the table.

Table 8.6: Distribution of the electricity supply by resource type under the BAU power supply scenario with no climate change considerations for chosen years

Scenario	Technology	2012	2015	2020	2025	2030	2035	2040	2045	2050
Very low	Diesel (%)	42.48	0.68	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Hydro (%)	55.61	78.37	94.32	81.93	73.13	53.02	41.23	32.94	26.62
	Geothermal (%)	0.00	0.00	0.15	7.14	11.76	24.3	32.64	35.07	38.52
	Methane (%)	1.85	19.2	1.89	7.35	12.25	20.25	24	30.09	33.05
	Peat (%)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Solar (%)	0.06	1.75	3.64	3.59	2.87	2.42	2.14	1.91	1.81
	Total (TWh)	**0.48**	**0.64**	**1.05**	**1.64**	**2.50**	**3.50**	**4.58**	**5.82**	**7.20**
Very likely	Diesel (%)	42.48	0.93	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Hydro (%)	55.61	78.18	93.21	79.70	69.61	49.00	36.69	28.03	21.51
	Geothermal (%)	0.00	0.00	0.23	8.28	13.55	26.60	35.38	37.86	31.86
	Methane (%)	1.85	19.15	2.96	8.53	14.11	22.16	26.02	32.48	27.33
	Peat (%)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	17.84
	Solar (%)	0.06	1.75	3.60	3.49	2.73	2.24	1.90	1.62	1.46
	Total (TWh)	**0.48**	**0.66**	**1.09**	**1.70**	**2.65**	**3.83**	**5.20**	**6.90**	**9.00**
Very high	Diesel (%)	42.48	1.08	0.00	0.00	0.00	0.00	0.00	0.00	16.48
	Hydro (%)	55.61	78.06	92.29	77.72	66.36	45.26	32.51	23.59	17.01
	Geothermal (%)	0.00	0.00	0.30	9.30	15.20	28.73	37.92	34.94	25.20
	Methane (%)	1.85	19.12	3.84	9.58	15.84	23.94	27.88	29.98	21.62
	Peat (%)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	10.13	18.53
	Solar (%)	0.06	1.74	3.56	3.40	2.60	2.07	1.69	1.36	1.16
	Total (TWh)	**0.48**	**0.66**	**1.10**	**1.74**	**2.78**	**4.14**	**5.86**	**8.20**	**11.38**

8.2.2 BAU power supply under climate scenario RCP4.5

BAU power supply and the very low power demand scenarios

In case the climate of Rwanda evolves following climate scenario RCP4.5, the power generation from hydropower, solar, methane and geothermal energy resources is able to meet the projected electricity demand under the very low scenario up to 2049 (see Figure

8.18). Under this supply scenario, the share of hydropower in the electricity supply mix is projected to increase from 55.61% (of 480 GWh) in 2012 to 77.86% (of 1,653 GWh) in 2025 which is 4.06% less compared to the case of the no climate change consideration scenario. In 2050 the share of hydropower generation in the total power supply is expected to be 19.69% (of 7,273 GWh) against 26.62% for the case of the no climate change consideration scenario. These reductions of the share of hydropower generation are due to the projected effects of climate change discussed in this study. As for the contribution of solar energy, its share is projected to be the same as in the previous scenario meaning that it will increase from 0.06% (of 480 GWh) in 2012 and peak to 4.70% (of 834 GWh) in 2017 and then decline to 3.59% (of 1,653 GWh) in 2025 and to 1.81% (of 7,273 GWh) in 2050.

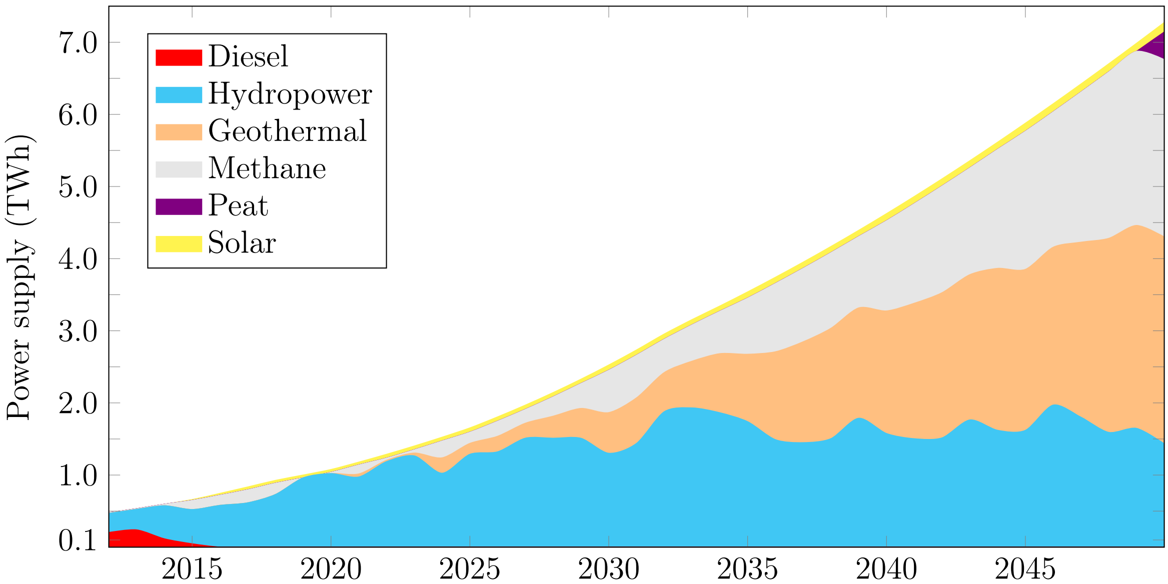


Figure 8.18: Electricity supply by resource type under the BAU evolving under climate scenario RCP4.5 for the very low power demand scenario

With regard to power generation from methane, its share will increase from 1.85% (of 480 GWh) in 2012 to 9.41% (of 1,653 GWh) in 2025 (against 7.35% for the no climate change consideration scenario) and to 33.82% (of 7,273 GWh) in 2050 (against 33.05% for the case of BAU scenario). Power generation from geothermal resource on the other hand will increase from 0% in 2012 to 9.14% (of 1,653 GWh) in 2025 (against 7.14% under the BAU scenario) and to 39.42% (of 7,273 GWh) in 2050 (against 38.52% under the no climate change consideration scenario). The slight increase in the shares of methane and geothermal based power generations is a result of the declining hydropower generation due to expected changes in the country's climate.

Contrary to the case of the no climate change consideration scenario where power generation from hydropower, solar energy, methane gas and geothermal energy was enough to cover the projected electricity demand, under this scenario power generation from peat will be necessary in 2050 when it will represent 5.26% (of 7,273 GWh).

BAU power supply evolving under climated scenario RCP4.5 and the very likely power demand scenario

To meet the projected electricity demand under the very likely scenario, the electricity generation requirements will increase from 480 GWh in 2012 to 9,000 GWh by 2050. The share of hydropower generation will increase from 55.61% (of 480 GWh) in 2012 to 75.75% (of 1,699 GWh) by 2025 (against 79.70% for the same power demand scenario under no climate change consideration scenario) and then decline to 15.91% (of 7,273 GWh) in 2050 (against 21.51% for the case of the no climate change consideration scenario). Similar to the previous case, the highest share of hydropower generation is projected to be achieved in 2026 when it will represent 96.00% due to the same reasons as the case of the very low scenario (see the distribution in Figure 8.19). The share of solar power generation on the other hand will peak to 4.67% (of 838 GWh) in 2017 and then decline to 3.49% (of 1,699 GWh) in 2025 and to 1.46% (of 7,273 GWh) in 2050.

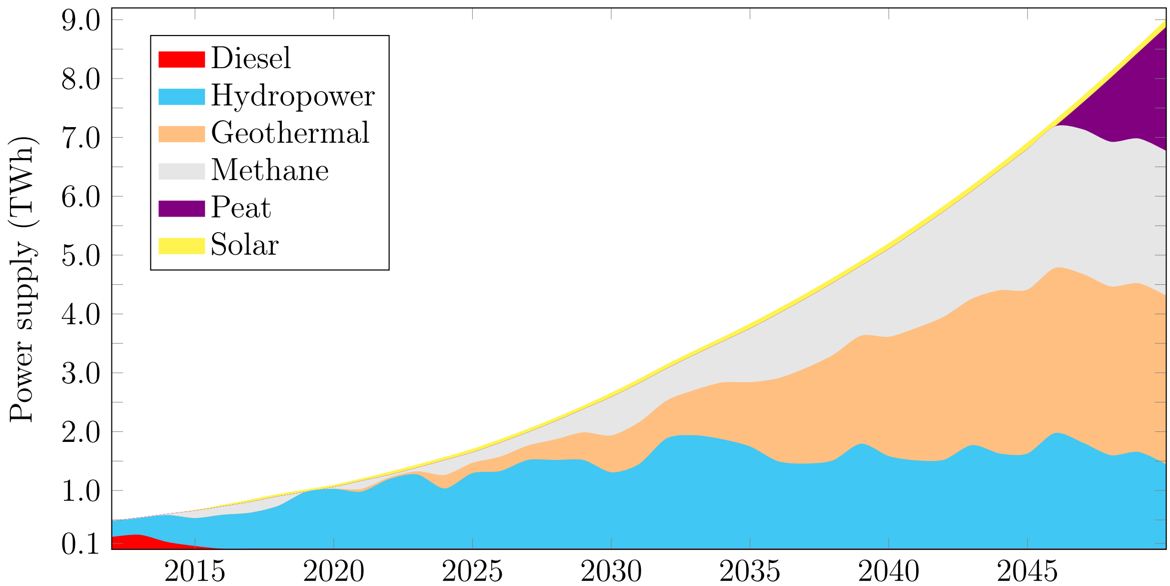


Figure 8.19: Electricity supply by resource type under the BAU scenario evolving under climate scenario RCP4.5 for the very likely power demand scenario

The contribution of methane based power generation is projected to increase from 1.85% (of 480 GWh) in 2012 to 10.54% (of 1,699 GWh) by 2025 (against 8.53% under the case of no climate change considerations), peak to 34.60% (of 6,905 GWh) in 2045 and then decline to 27.33% by 2050 similar to the case of no climate change consideration scenario. The share of geothermal power is expected to increase from 0.00% in 2012 to 10.23% (of

1,699 GWh) in 2025 (against 8.28% for no climate change consideration scenario), peak to 42.47% (of 6,533 GWh) in 2044 and then decline to 31.86% (of 7,273 GWh) in 2050 similar to the supply under the no climate change consideration scenario. Peat based power generation will firstly be needed in 2047 when it will represent 5.93% (of 7,696 GWh) and then increase to 23.42% (of 9,000 GWh) in 2050 (against 17.84% under the no climate change consideration scenario). Under this scenario, no diesel power generation will be needed except for the first years of the simulation period as shown in Figure 8.19.

BAU power supply evolving under climated scenario RCP4.5 and the very high power demand scenarios

Under the very high power demand scenario, 1,742 GWh by 2025 and 11,378 GWh by 2050 will be required to meet the projected electricity demand. To meet this demand under climate scenario RCP4.5, the contribution of different technologies (see Figure 8.20) will be such that the share of hydropower generation will increase from 55.61% (of 480 GWh) in 2012 to 73.86% (of 1,742 GWh) in 2025 (against 77.72% under the BAU−CC scenario) and then decline to 12.59% (of 11,378 GWh) in 2050 (against 17.01% under the no climate change consideration scenario).

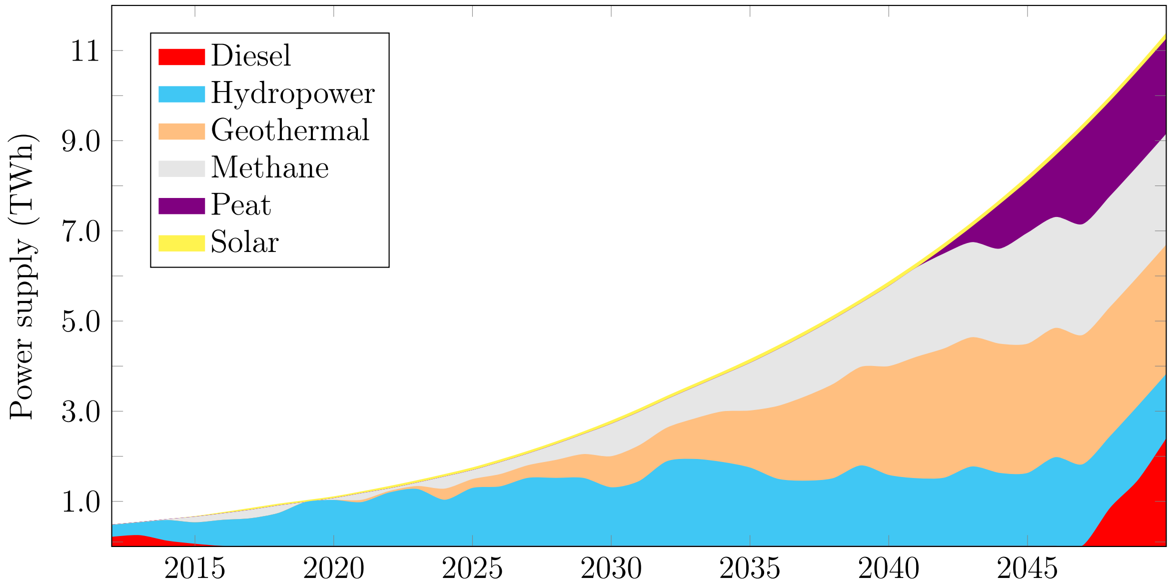


Figure 8.20: Electricity supply by resource type under the BAU scenario evolving under climate scenario RCP4.5 for the very high power demand scenario

The highest share of hydropower under this scenario is projected in 2019 when it will represent 96.14% of the total power supply in that year (i.e. 1,017 GWh) due to expected abundant precipitations in this year. The share of the solar power generation is expected to increase from 0.06% (of 480 GWh) in 2012, peak to 4.66% (of 842 GWh) in 2017, decline to 3.40% (of 1,742 GWh) by 2025 and then to 1.16% (of 11,378 GWh) by 2050. The share of methane based power generation is expected to be 11.54% (of 1,742 GWh) by 2025 (against 9.58% under no climate change considerations) and 21.62% (of 11,378 GWh) by 2050 similar to the scenario where climate change is not considered.

As for power generation from geothermal energy, its contribution is projected to be 11.20% (of 1,742 GWh) by 2025 (against 9.30% under the no climate change consideration scenario) and 25.20% (of 11,378 GWh) by 2050 similar to the no climate change consideration scenario. Power generation from peat will start contributing in 2042 with 1.87% (of 6,714 GWh) and then increase its share to 18.53% (of 11,378 GWh) by 2050 similar to the no climate change consideration scenario. Power generation from diesel under this scenario will start its contribution in 2047 when it will represent 0.14% (of 9,361 GWh) and then increase to 20.91% (of 11,378 GWh) by 2050 (against 16.48% under the no climate change consideration scenario). The total power supply requirements and the percentage shares of different technologies used under this power supply scenario are presented in Table 8.7.

Table 8.7: Distribution of the electricity supply by resource type under the BAU scenario evolving under climate scenario RCP4.5 for chosen year

Scenario	Technology	2012	2015	2020	2025	2030	2035	2040	2045	2050
Very low	Diesel (%)	42.48	7.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Hydro (%)	55.61	72.05	94.72	77.86	51.55	49.14	34.06	27.54	19.69
	Geothermal (%)	0.00	0.00	0.12	9.14	22.33	26.42	36.77	37.97	39.42
	Methane (%)	1.85	19.20	1.51	9.41	23.26	22.02	27.03	32.58	33.82
	Peat (%)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	5.26
	Solar (%)	0.06	1.75	3.64	3.59	2.87	2.42	2.14	1.91	1.81
	Total (TWh)	**0.48**	**0.64**	**1.05**	**1.64**	**2.50**	**3.50**	**4.58**	**5.82**	**7.20**
Very likely	Diesel (%)	42.48	7.24	0.00	0.00	0.00	0.00	0.00	0.00	0.01
	Hydro (%)	55.61	71.87	93.61	75.75	49.06	45.42	30.32	23.44	15.91
	Geothermal (%)	0.00	0.00	0.20	10.23	23.61	28.55	39.06	40.34	31.86
	Methane (%)	1.85	19.15	2.59	10.54	24.59	23.79	28.72	34.60	27.33
	Peat (%)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	23.42
	Solar (%)	0.06	1.75	3.60	3.49	2.73	2.24	1.90	1.62	1.46
	Total (TWh)	**0.48**	**0.66**	**1.09**	**1.70**	**2.65**	**3.83**	**5.20**	**6.90**	**9.00**
Very high	Diesel (%)	42.48	7.38	0.00	0.00	0.00	0.00	0.00	0.00	20.91
	Hydro (%)	55.61	71.75	92.69	73.86	46.77	41.95	26.86	19.73	12.59
	Geothermal (%)	0.00	0.00	0.27	11.20	24.80	30.54	41.18	34.94	25.20
	Methane (%)	1.85	19.12	3.48	11.54	25.83	25.45	30.28	29.98	21.62
	Peat (%)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	13.99	18.53
	Solar (%)	0.06	1.74	3.56	3.40	2.60	2.07	1.69	1.36	1.16
	Total (TWh)	**0.48**	**0.66**	**1.10**	**1.74**	**2.78**	**4.14**	**5.86**	**8.20**	**11.38**

8.2.3 BAU power supply under climate scenario RCP8.5

BAU power supply and the very low power demand scenarios

Under this scenario it is projected that the power generation from hydropower, solar, methane and geothermal energy resources will be able to meet the projected electricity demand under the very low scenario up to 2049 (see Figure 8.21). The share of hydropower in the electricity supply mix is projected to increase from 55.61% (of 480 GWh) in 2012 to 75.22% (of 1,653 GWh) in 2025 (against 81.93% under the no climate change consideration scenario). In 2050 the share of hydropower generation in the total power supply is expected to be 23.08 % (of 7,273 GWh) against 26.62% when climate change impacts are not considered. With regard to the contribution of solar energy, its share is projected to be the same as for the case of no climate change consideration scenario (i.e. 0.06% in 2012, 3.59% in 2025 and 1.81% in 2050).

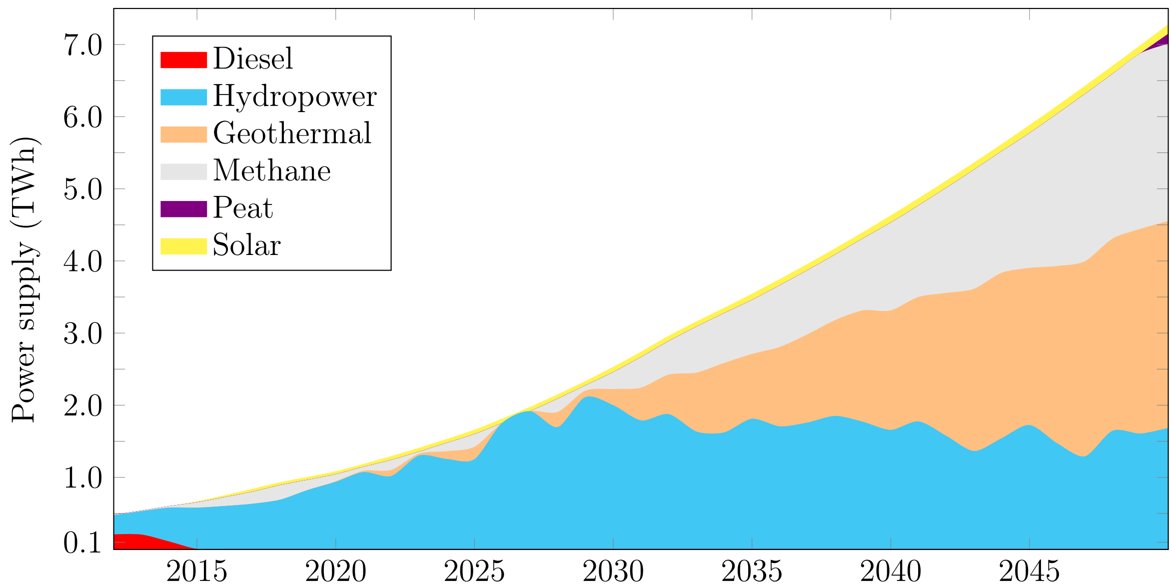


Figure 8.21: Electricity supply by resource type under the BAU scenario evolving under climate scenario RCP8.5 for the very low power demand scenario

As for power generation from methane, it is projected that its share will increase from 1.85% (of 480 GWh) in 2012 to 10.75% (of 1,653 GWh) in 2025 (against 7.35% for the no climate change consideration scenario) and to 33.82% (of 7,273 GWh) in 2050 (against 33.05% for the case of the no climate change consideration scenario). As for power generation from geothermal resource, it will increase from 0% in 2012 to 10.40% (of 1,653 GWh) in 2025 (against 7.14% under the no climate change consideration scenario) and to 39.42% (of 7,273 GWh) in 2050 (against 38.52% under the no climate change consideration scenario). The slight increase in the shares of methane and geothermal based power generations is a result of the declining hydropower generation due to expected changes in the country's climate towards 2050 as in the previous cases. It is important to highlight that the simulation results showed that hydropower and solar based generations will be enough to cover annual total power demand in 2026 and 2027. This is due to a combination of two factors: the assumed coming in operation of three hydroelectric power stations: Rusumo Falls (27 MW) in 2021, Rusizi III (48 MW) in 2022 and Rusizi IV (96 MW) in 2026 and the expected abundant precipitations that are expected to be 24.96% more than the annual average in 2026 and 8.33% in 2027. Under this supply scenario, about 1.90% (of 7,273 GWh) from peat based power generation will be required to meet the extra power demand that is beyond the capacity of the four stated technologies.

BAU−RCP8.5 power supply and the very likely power demand scenarios

Under the very likely power demand scenario, 1,699 GWh by 2025 and 9,000 GWh by 2050 will be required. To meet this demand when the climate is evolving under RCP8.5 scenario, the distribution of different technologies (see Figure 8.22) will be such that the contribution of hydropower generation to the total power supply will increase from 55.61% (of 480 GWh) in 2012 to 73.18% (of 1,699 GWh) by 2025 (against 79.70% under the no climate change consideration scenario) and then decline to 18.65% (of 7,273 GWh) in 2050 (against 21.51% for the case of the no climate change consideration scenario). The highest share of hydropower generation is projected in 2026 when it will represent 96.82% due to the same reasons as in the previous case. The share of solar power generation on the other hand will increase from 0.06% (of 480 GWh) to 3.49% (of 1,699 GWh) in 2025 and to 1.46% (of 7,273 GWh) in 2050.

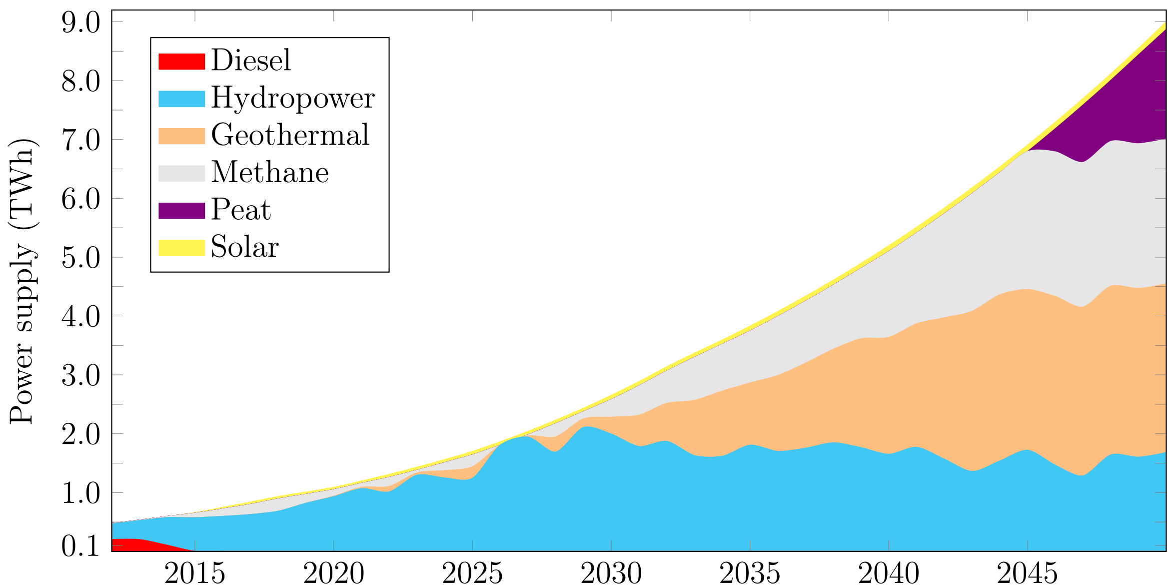


Figure 8.22: Electricity supply by resource type under the BAU scenario evolving under climate scenario RCP8.5 for the very likely power demand scenario

As for power from methane based, its share is projected to increase from 1.85% (of 480 GWh) in 2012 to 11.84% (of 1,699 GWh) by 2025 (against 8.53% under the no climate change consideration scenario), peak to 33.94% (of 6,905 GWh) in 2045 and then decline to 27.33% by 2050. The share of geothermal power generation is expected to increase from 0.00% in 2012 to 11.49% (of 1,699 GWh) in 2025 (against 8.28% for the no climate change consideration scenario), peak to 44.04% (of 7,181 GWh) in 2043 and then decline to 31.86% (of 7,273 GWh) in 2050 similar to the supply under the no climate change consideration scenario. Peat based power generation will firstly be needed in 2046 when it will represent 5.37% (of 7,696 GWh) and then increase 20.70% (of 9,000 GWh) in 2050 (against 17.84% under the no climate change consideration scenario). Under this scenario no diesel power generation will be needed except for the first years of the simulation period as shown in Figure 8.22, similar to the previous case.

BAU power supply and the very high power demand scenarios

It is projected under the very high power demand scenario that the power supply requirements will increase from 480 GWh in 2012 to 11,378 GWh by 2050. The power supply distribution between different technologies (see Figure 8.23) when the climate evolution follows climate RC8.5 will be such that the share of hydropower will increase from 55.61% (of 480 GWh) in 2012 to 71.36% (of 1,742 GWh) in 2025 (against 77.72% under no climate change consideration scenario) and then decline to 14.75% (of 11,378 GWh) in 2050 (against 17.01% under the no climate change consideration scenario). The highest share of hydropower under this scenario is projected in 2026 when it will represent 96.91% of the total power supply in that year due to same reasons as in the previous cases.

The share of the power generation from solar energy will remain the same as for the previous case while the contribution of methane based power generation is projected to be 12.80% (of 1,742 GWh) by 2025 (against 9.58% under the no climate change consideration scenario) and 21.62% (of 11,378 GWh) by 2050 similar to the no climate change consideration scenario. With regard to power generation from geothermal energy, its contribution to the total power supply under this scenario is projected to be 12.43% (of 1,742 GWh) by 2025 (against 9.30% under the no climate change consideration scenario) and 25.20% (of 11,378 GWh) by 2050 similar to the case of the no climate change consideration scenario. Peat based power generation will start its contribution in 2042 with 1.09% (of 6,714 GWh) and then increase to 18.53% (of 11,378 GWh) by 2050 similar. Under this scenario power generation from diesel will start its contribution in 2047 where it will represent 5.67% (of 9,361 GWh) and then increase rapidly to 18.74% (of 11,378 GWh) by 2050 (against 16.48% under the no climate change consideration scenario). Table 8.8 summarises the total power supply requirements and the percentage shares of different technologies used under this power supply scenario.

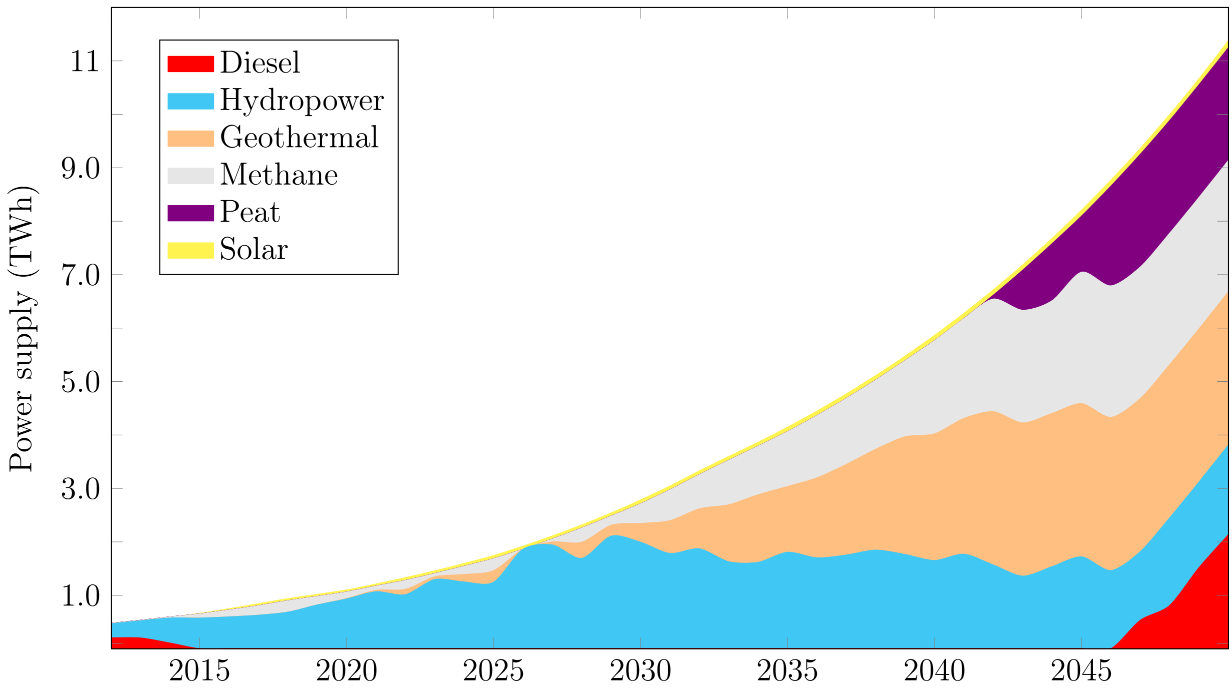


Figure 8.23: Electricity supply by resource type under the BAU scenario evolving under climate scenario RCP8.5 for the very high power demand scenario

Table 8.8: Distribution of the electricity supply by resource type under the BAU scenario evolving under climate scenario RCP8.5 for chosen years

Scenario	Technology	2012	2015	2020	2025	2030	2035	2040	2045	2050
Very low	Diesel (%)	42.48	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Hydro (%)	55.61	86.87	86.47	75.22	78.91	51.01	35.71	29.23	23.08
	Geothermal (%)	0.00	0.00	0.72	10.44	8.92	25.40	35.82	37.07	39.42
	Methane (%)	1.85	11.38	9.17	10.75	9.29	21.17	26.34	31.80	33.82
	Peat (%)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.87
	Solar (%)	0.06	1.75	3.64	3.59	2.87	2.42	2.14	1.91	1.81
	Total (TWh)	**0.48**	**0.64**	**1.05**	**1.64**	**2.50**	**3.50**	**4.58**	**5.82**	**7.20**
Very likely	Diesel (%)	42.48	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Hydro (%)	55.61	86.66	85.45	73.18	75.11	47.14	31.78	24.88	18.65
	Geothermal (%)	0.00	0.00	0.79	11.49	10.85	27.61	38.22	39.56	31.86
	Methane (%)	1.85	11.60	10.16	11.84	11.30	23.01	28.10	33.94	27.33
	Peat (%)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	20.70
	Solar (%)	0.06	1.75	3.60	3.49	2.73	2.24	1.90	1.62	1.46
	Total (TWh)	**0.48**	**0.66**	**1.09**	**1.70**	**2.65**	**3.83**	**5.20**	**6.90**	**9.00**
Very high	Diesel (%)	42.48	0.00	0.00	0.00	0.00	0.00	0.00	0.00	18.74
	Hydro (%)	55.61	86.52	84.61	71.36	71.60	43.54	28.16	20.94	14.75
	Geothermal (%)	0.00	0.00	0.86	12.43	12.63	29.67	40.43	34.94	25.20
	Methane (%)	1.85	11.74	10.97	12.80	13.16	24.73	29.73	29.98	21.62
	Peat (%)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	12.78	18.53
	Solar (%)	0.06	1.74	3.56	3.40	2.60	2.07	1.69	1.36	1.16
	Total (TWh)	**0.48**	**0.66**	**1.10**	**1.74**	**2.78**	**4.14**	**5.86**	**8.20**	**11.38**

Comparison of the BAU related scenarios

As it can be noticed from Figure 8.24 that shows the evolution of the annual designed hydropower generation towards 2050 together with the generations under RCP4.5 and RCP8.5 climate scenarios, it is clear that after 2035 none of the BAU−RCP4.5 and BAU−RCP8.5 power supply scenarios will achieve the designed hydropower generation (except BAU−RCP8.5 in 2046).

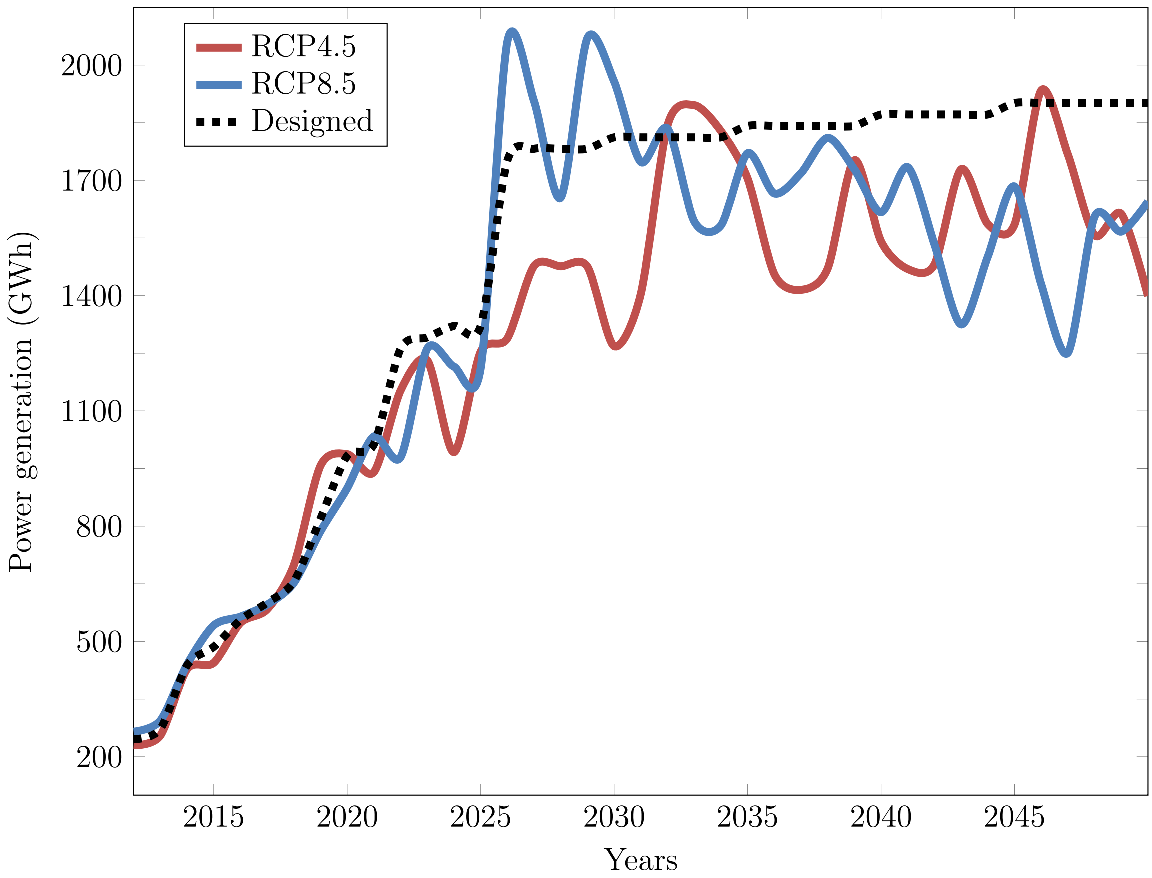


Figure 8.24: Projected total annual hydropower generation for the 2012 − 2050 period under climate change consideration

The analysis of the hydropower production between 2012 and 2050 can be divided into three periods: 2012 − 2021, 2023 − 2031 and 2032 − 2050. As it can be noticed from Figure 8.25, there is no significant difference between the designed and the simulated hydropower generations until the year 2021. Over this period, the cumulative hydropower generation anomalies are only +3 GWh for both RCP4.5 and RCP8.5 climate scenarios. Between 2022 and 2031 there are deficits in generation (equivalent to −2,895) under the RCP4.5 climate scenario while the RCP8.5 climate scenario shows surplus in power generation equivalent to +149 GWh. The period from 2032 to 2050 on other hand shows that almost all the years over this period will record deficits in power generation.

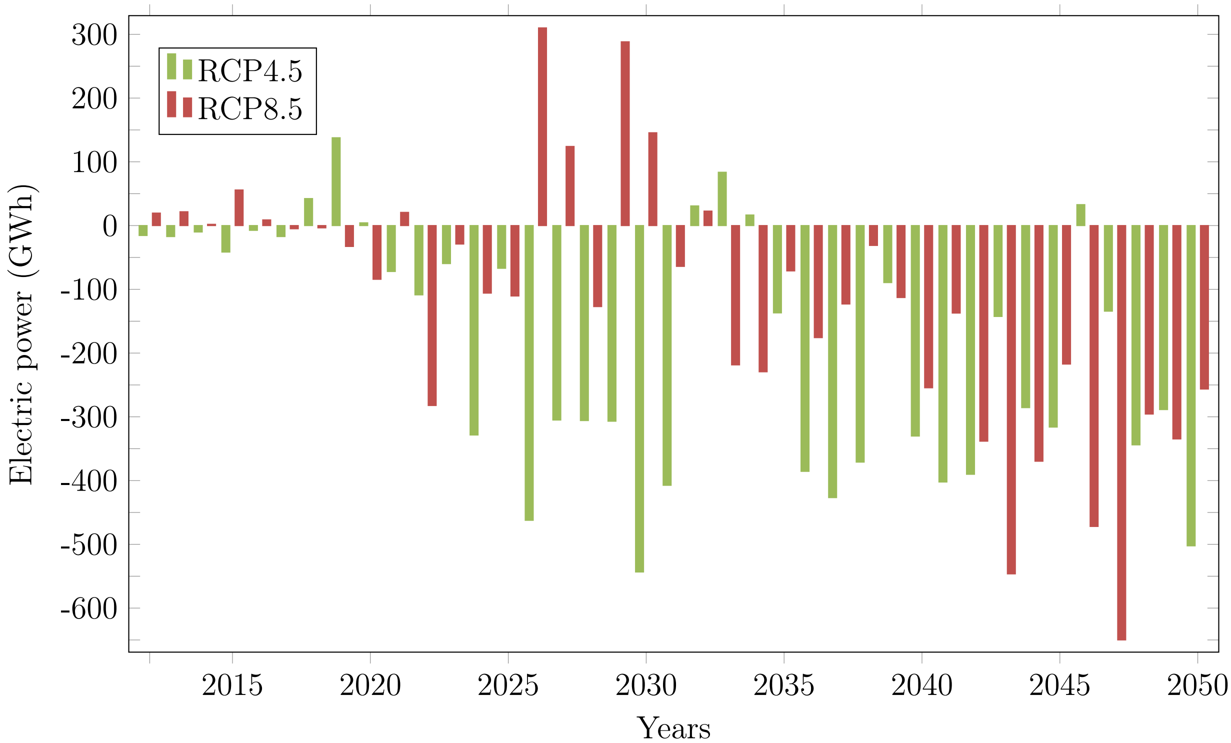


Figure 8.25: Hydropower generation anomalies between 2012 and 2050 under RCP4.5 and RCP8.5 climate scenarios

Table 8.9 presents every five years (four years for the first period) cumulative hydropower production anomalies for the 2012 – 2050 period.

Table 8.9: Cumulative hydropower generation anomalies (in GWh) for the 2012 – 2050 period. Negative values mean deficits while positive values indicate surplus power productions.

Period	RCP4.5	RCP8.5	Period	RCP4.5	RCP8.5
2012–2015	−85	+99	2031–2035	−413	−147
2016–2020	+160	−117	2036–2040	−1,603	−697
2021–2025	−636	−507	2041–2045	−1,537	−1,609
2026–2030	−1,924	741	2046–2050	−1,236	−2,009

It can be deduced from Table 8.9 that the cumulative anomalies are −7,273 GWh for the RCP4.5 climate scenario and −4,659 GWh for the case of the RCP8.5 climate scenario.

8.2.4 Alternative power supply with no climate change consideration

Although there are three power demand scenarios (i.e. very high, medium and very low), only the power supply scenario that allows meeting the very high power demand scenario is assessed under the alternative power supply scenario. This is due to the fact that the simulation results discussed in the previous sections reveal that the national energy resources are enough to meet the projected demand under the very low and very likely scenarios for the whole 2012−2050 period. As for the very high power demand scenario, more than 20% of the total electricity requirements in 2050 would be met through power generation from diesel based power plants.

It is worth recalling that the main assumptions governing this scenario are improvement of efficiency of household appliances, intensive exploitation of the River Nyabarongo, intensive exploitation of solar energy, introduction of wind energy in the country's power supply mix and the use of municipal waste to generate electricity. Due to the assumed improvement in the efficiency of household appliances, the electricity consumption by the residential sector is expected increase from 194 GWh in 2012 to 3,994 GWh in 2050 which implies a reduction of 11.84% relative to the consumption under the BAU scenario of 4,467 GWh. The contribution of the improved efficiency of household appliances to the reduction of the total power requirements by 2050 (i.e. 10,240 GWh) is about 605 GWh equivalent to 6.28% less than the projected power consumption under the very high electricity demand scenario.

To meet the very high electricity demand. 10,705 GWh would be required in 2050 from 480 GWh in 2012. Under the no climate change consideration sub−scenario of the alternative power supply scenario, no diesel based power generation would be required over the whole simulation period (see Figure 8.26). The share of hydropower generation in the total power supply would increase from 55.61% (of 480 GWh) in 2012 and attain its maximum contribution of 88.59% (of 1,077 GWh) in 2020 and then reduce its share to 23.70% (of 10,705 GWh) by 2050. As for the power generation from solar energy, its contribution will start from 0.06% in 2012, peak to 13.48% (of 3,197 GWh) in 2032 and then decline to 8.21% in 2050. The power generation from methane gas is expected to increase its share from 1.85% (of 480 GWh) in 2012, peak to 27.37% (of 4,120 GWh) in 2048 and then decline to 26.42% (of 10,705 GWh) by 2050. Under the power plants' dispatch strategies described in Section 5.5.1, the contribution of power generation from geothermal energy would first be required in 2032 with a share of 1.20% (of 3,197 GWh), peak to 29.48% (of 4,120 GWh) in 2048 and then decline to 26.78% (of 10,705 GWh) by 2050.

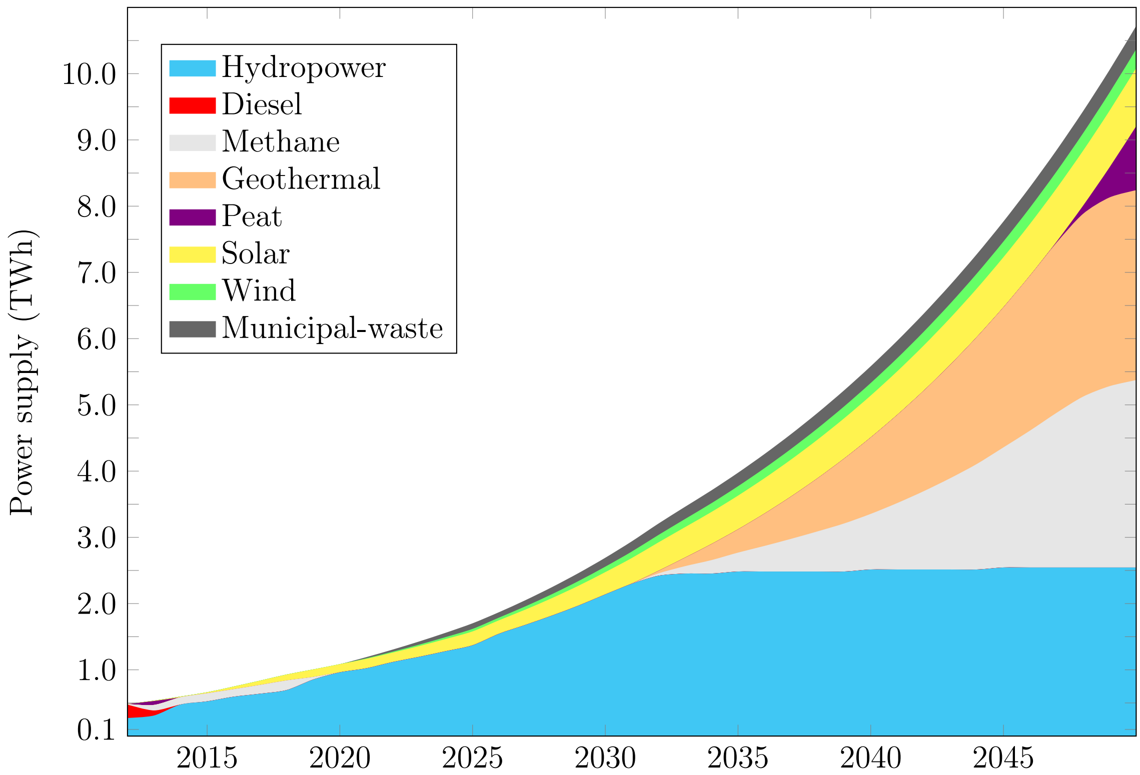


Figure 8.26: Electricity supply by resource type under the alternative scenario with no climate change consideration for the very high power demand scenario

With regard to power generation from wind energy, it is projected that its share will start from 0.69% (of 1,184 GWh) in 2021, peak to 3.37% (of 3,700 GWh) in 2034 and then declines to 2.65% (of 10,705 GWh) by 2050. Power generation from municipal waste on the other hand would start contributing to the national electricity supply in 2021 when its share will be 1.55% (of 1,184 GWh), peak to 5.38% (of 3,198 GWh) in 2032 and then decline to 3.28% (of 10,705 GWh) by 2050. As for power generation from peat resources, its first contribution is expected in 2047 when it will represent 0.15% (of 8,831 GWh) and then rise to 16.47% in 2050. Under this supply scenario, it is expected that between 2020 and 2031, hydropower, solar, wind and waste−to−power generations alone are sufficient to meet the projected power demand over this period as one can notice it in Figure 8.26.

8.2.5 Alternative power supply under climate scenario RCP4.5

In case the future climate follows climate scenario RCP4.5, and the power are plants dispatched according to the rules described in Section 5.5.1, the share of hydropower generation in the total power supply would increase from 55.61% (of 480 GWh) in 2012 and peak to 89.66% in 2019 and then reduce to 78.93% (of 1,694 GWh) in 2025 and to 17.51% (of 10,705 GWh) in 2050. The share of power generation from solar energy on the other hand is projected to increase from 0.06% in 2012, to peak to 14.48% (of 1,553 GWh) in 2024 before it falls to 12.58% in 2025 and to 8.21% in 2050 (see the distribution in Figure 8.27).

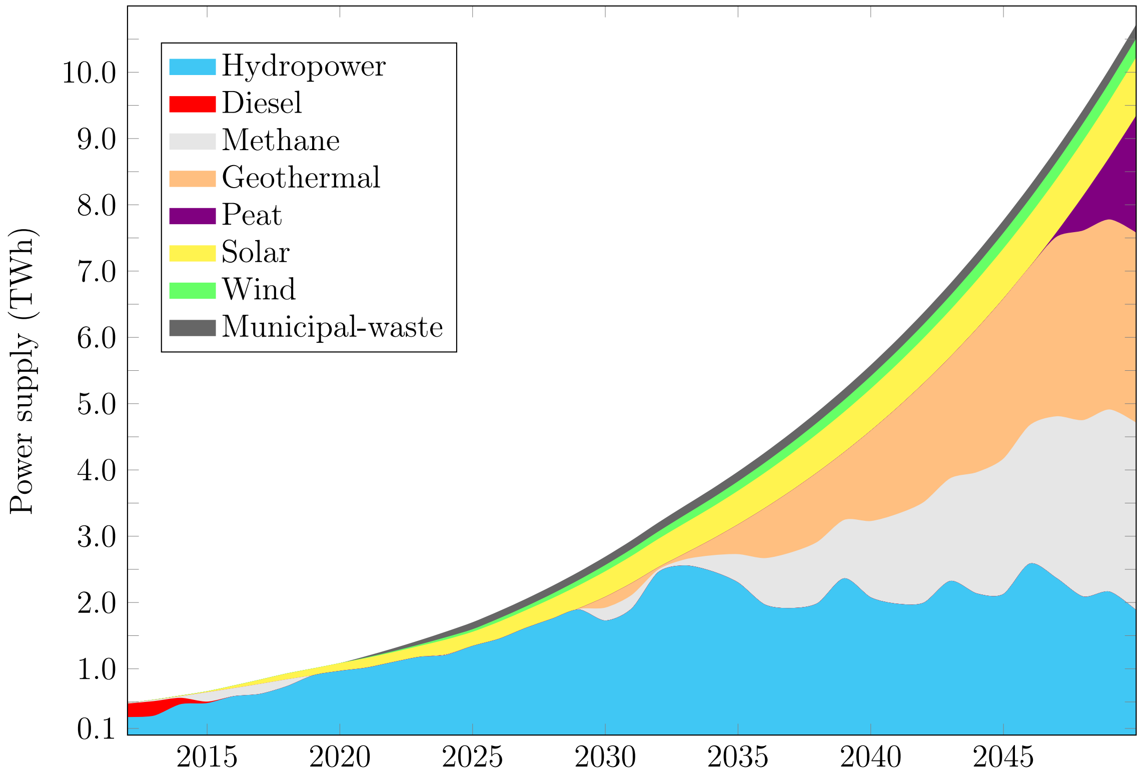


Figure 8.27: Electricity supply by resource type under the alternative scenario evolving under climate scenario RCP4.5 for the very high power demand scenario

As for methane based electricity generation, its contribution would increase its percentage share from 1.85% in 2012 to 18.08% (of 829 GWh) in 2017 and fall to 0.00% in 2019. The reduction of the share of methane based power generation to zero is due to the deployment of more hydropower, solar, wind and waste−to−power power plants. As the demand increases towards 2050 the share of electricity generation from methane increases and reaches its peak of 28.21% (of 9,419 GWh) in 2048 and then slightly falls to 26.42% in 2050. Power production from hydropower, solar, wind and waste−to−power alone would meet the annual power demand between 2019 and 2029 so that power generation from geothermal resources would start its contribution in 2030 when it would represent 6.04% (of 2,683 GWh). Then its share would increase and hit its peak of 31.12% (of 7,756 GWh) in 2045 and then fall to 26.78% in 2050.

Concerning power generation from wind and municipal waste, these two technologies are projected to come in line in 2021 when their contributions are projected to be 0.71% (of 1,184GWh) for wind power generation and 1.78% (of 1,184GWh) for waste− t− power based electricity generation. In 2025, the share of power generation from wind energy is projected to reach 2.27% and then peaks to 3.57% (of 3,700 GWh) in 2033 before it falls to 2.65% in 2050. The share of waste-to-power on the other hand would reach its maximum value of 6.22% in 2025 and then declines to 1.97% by 2050.

Power generation from peat based power plants are assumed to be dispatched after all other technologies (except power from diesel based power generation which is dispatched last), due to the fact that the use of peat for power generation may result into excessive emissions as no study had been conducted (until the year 2015) to compare CO_2 that will be released during the development and operation of peat−fired power plants with the naturally released CH_4 from the peatlands. That is why the first peat based power generation is dispatched in 2047 when it will represent 0.74% (of 8,831 GWh) and quickly rise to 16.47% in 2050. The distribution of different technologies to this supply scenario can be visualised in Figure 8.27.

8.2.6 Alternative power supply under climate scenario RCP8.5

The performance of the proposed alternative power supply under climate scenario RCP8.5 differs from that discussed in the previous section (RCP4.5) with regard to the amount of available hydropower production which dictates the shares of the other energy technologies. Under this scenario (see the distribution of used resources in Figure 8.28), the share of hydropower generation in the total power supply would increase from 55.61% (of 480 GWh) in 2012, peaks to 88.26% in 2020 and then reduces to 78.50% (of 1,694 GWh) in 2025 and to 20.54% (of 10,705 GWh) in 2050. Solar based power generation will increase from 0.06% in 2012 to 12.95% (of 1,694 GWh) in 2025, peak to 13.52 (of 2,930 GWh) in 2031 before it falls to 8.21% in 2050 similar to the case of climate scenario RCP4.5.

Between 2020 and 2030 the power generation from hydropower, solar, wind and waste−to−energy power technologies would be enough to meet the demand so that no methane and geothermal based power generation would be required based on the assumptions governing this scenario. The contribution of power generation from methane would increase from 1.85% in 2012 to 16.60% (of 829 GWh) in 2017 and fall to 0.00% in 2020. In 2031 methane will start again its contribution from 0.41% (of 2,682 GWh), reach its maximum of 29.19% in 2047 and slightly decline to 26.42% (of 10,705 GWh) in 2050. Power generation from geothermal on the other hand would start its contribution in 2031 when it would represent 0.36% (of 2,682 GWh), hit its peaks of 32.77% (of 8,277 GWh) in 2046 and slightly decline to 26.88% (of 10,705 GWh) in 2050.

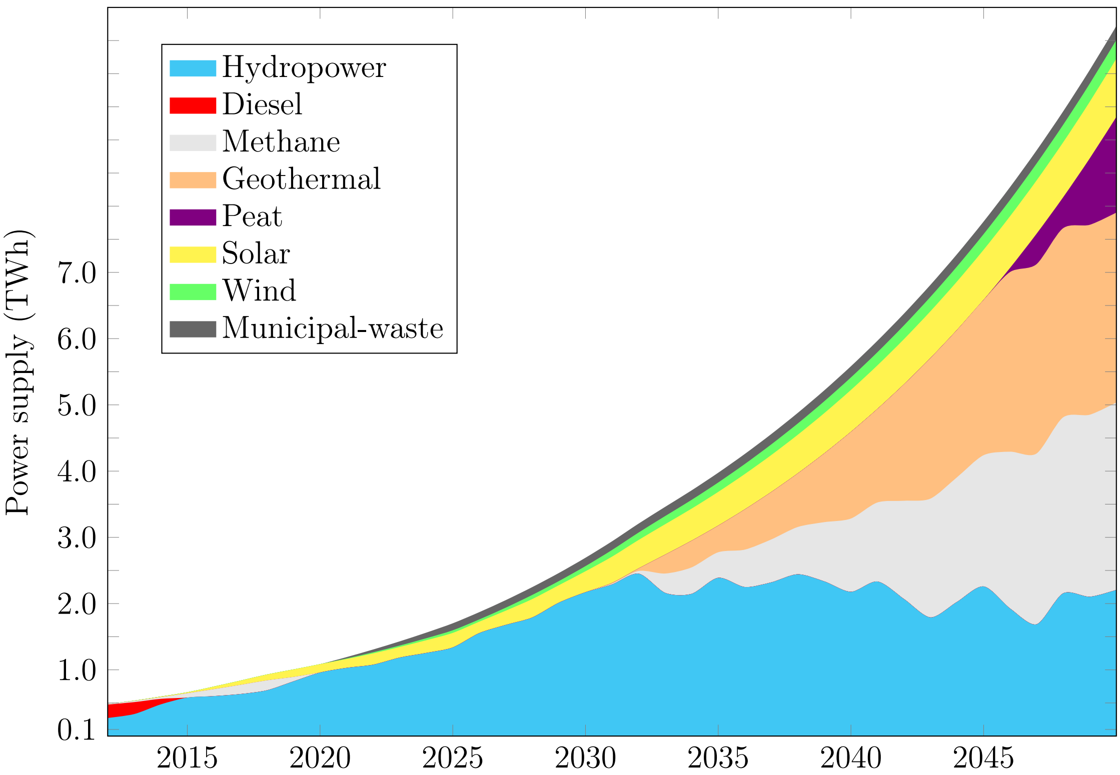


Figure 8.28: Electricity supply by resource type under the alternative scenario evolving under climate scenario RCP8.5 for the very high power demand scenario

The shares of wind and municipal waste are projected to increase from 0.65% (of 1,184GWh) for wind power generation and 1.78% (of 1,184GWh) for waste−to−power based electricity generation in 2021 to 2.33% and 6.22% respectively in 2025. The maximum share of wind power is projected to be reached in 2035 when it would represent 3.57% (of 3,965 GWh) while its share in 2050 would be 2.65% (of 10,705 GWh). The share of waste−to−power based generation would reach its maximum contribution of 6.22% in 2025 and then decline to 1.95% (of 10,705 GWh) by 2050. Peat based power generation would first be dispatched in 2046 when it would represent 0.73% (of 8,277 GWh) and quickly rise to 13.44% in 2050.

The distribution of different technologies for the alternative power supplu with no climate change considerations, the alternative power supply under climate scenarios RCP4.5 and RCP8.5 are summarised in Table 8.10.

Table 8.10: Distribution of the electricity supply by resource type under the alternative scenario. In this table "No CC" means no climate change considerations.

Scenario	Technology	2012	2015	2020	2025	2030	2035	2040	2045	2050
No CC	Hydro (%)	55.61	79.10	88.59	80.41	79.40	62.43	44.98	32.72	23.70
	Solar (%)	0.06	2.35	11.41	12.38	12.51	12.82	11.34	9.74	8.21
	Methane (%)	1.85	18.54	0.00	0.00	0.00	7.20	15.06	23.36	26.42
	Geothermal (%)	0.00	0.00	0.00	0.00	0.00	8.84	20.69	27.25	26.78
	Peat (%)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	8.96
	Wind (%)	0.00	0.00	0.00	2.23	3.07	3.57	3.39	3.04	2.65
	Waste (%)	0.00	0.00	0.00	4.98	5.02	5.14	4.54	3.90	3.28
	Oil (%)	42.48	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Total (TWh)	**0.48**	**0.65**	**1.08**	**1.69**	**2.68**	**3.97**	**5.57**	**7.76**	**10.70**
RCP4.5	Hydro (%)	55.61	72.72	89.18	78.93	64.13	57.84	37.14	27.34	17.51
	Solar (%)	0.06	2.35	10.82	12.58	14.36	12.82	11.34	9.74	8.21
	Methane (%)	1.85	21.51	0.00	0.00	7.23	10.79	20.67	26.31	26.42
	Geothermal (%)	0.00	0.00	0.00	0.00	6.04	11.26	24.44	31.12	26.78
	Peat (%)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	16.47
	Wind (%)	0.00	0.00	0.00	2.27	3.52	3.57	3.39	3.04	2.65
	Waste (%)	0.00	0.00	0.00	6.22	4.71	3.72	3.03	2.45	1.97
	Oil (%)	42.48	3.41	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Total (TWh)	**0.48**	**0.65**	**1.08**	**1.69**	**2.68**	**3.97**	**5.57**	**7.76**	**10.70**
RCP8.5	Hydro (%)	55.61	87.68	88.26	78.50	80.63	60.05	38.94	29.02	20.54
	Solar (%)	0.07	2.35	11.74	12.95	11.77	12.82	11.34	9.74	8.21
	Methane (%)	1.85	9.96	0.00	0.00	0.00	9.71	19.84	25.54	26.42
	Geothermal (%)	0.00	0.00	0.00	0.00	0.00	10.13	23.46	30.21	26.78
	Peat (%)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	13.44
	Wind (%)	0.00	0.00	0.00	2.33	2.88	3.57	3.39	3.04	2.65
	Waste (%)	0.00	0.00	0.00	6.22	4.71	3.72	3.03	2.45	1.97
	Oil (%)	42.48	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Total (TWh)	**0.48**	**0.65**	**1.08**	**1.69**	**2.68**	**3.97**	**5.57**	**7.76**	**10.70**

8.3 Emissions from power generation

In this section, CO_2 emissions from the power generation are presented and discussed; and each time, a comparison between BAU and alternative power supply scenarios is made.

8.3.1 Emissions under no climate change considerations

When effects of climate change on hydropower generation are not taken into account, under the BAU scenario, CO_2 emissions per kWh would decline from 359.40 gCO_2eq in 2012 to a minimum of 5.49 gCO_2eq in 2022 and then rise rapidly to 483.50 gCO_2eq by 2050. The projected emission reductions for the 2012−2026 period are due to the expected hydropower projects that are planned until 2026 (see Figure 8.29).

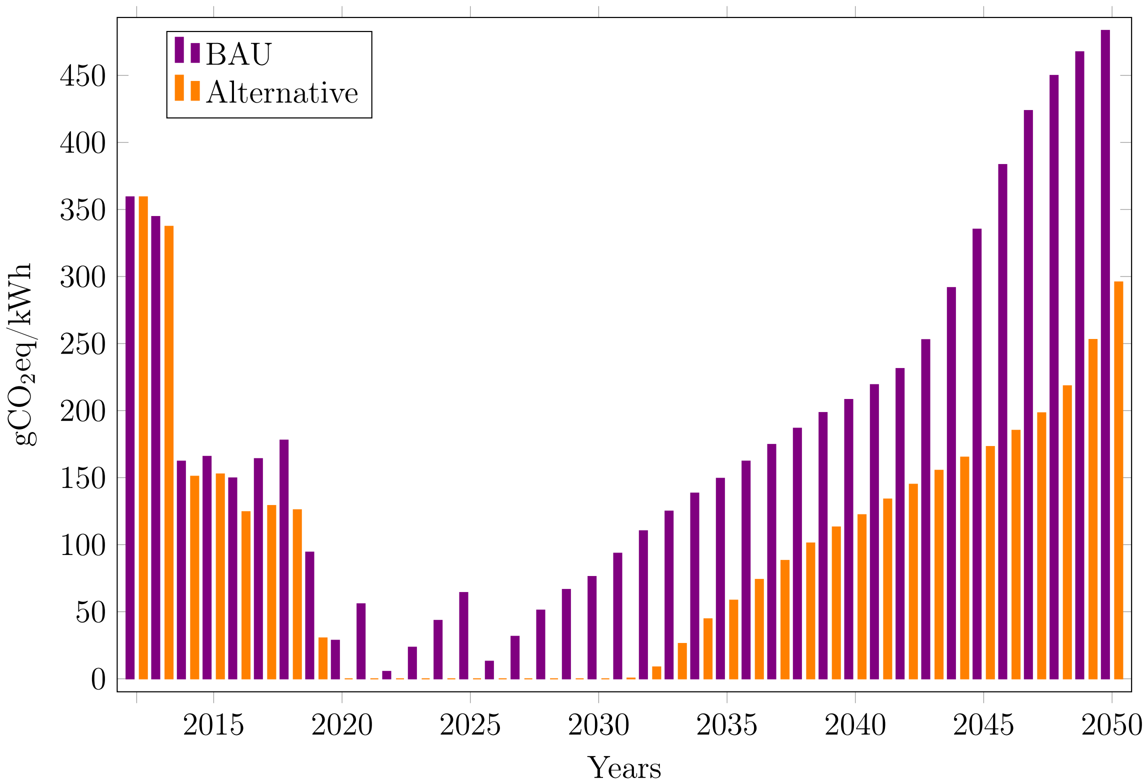


Figure 8.29: Evolution of CO_2 emmisions per kWh for the 2012−2050 period under no climate change consideration

As for the alternative power supply scenario it is projected that CO_2 emissions will drop from 359.40 gCO_2eq/kWh in 2012 to 0.00 in 2020. Under this supply scenario, the electricity requirements will be met by mainly hydroelectric, solar, wind and geothermal power generations for the whole 2020−2030 period as presented in Section 8.2.4. As the emission factor for these technologies is zero, no emissions are generated during this period. After 2030, emissions will gradually rise and reach 295.93 gCO_2eq/kWh by 2050 (see Figure 8.29). Relative to the emissions in the base year, the alternative scenario will generate 21.44% less emission per kWh than the value in 2012 while under the BAU scenario emissions will be 25.67% more than in 2012. Between 2012 and 2050 the cumulated emissions will be 18,157 million tons of CO_2eq for the alternative scenario and 36,908 million tons of CO_2eq for the BAU scenario. These values indicate that the implementation of the alternative scenario would reduce emissions by more than 50% relative to the BAU scenario.

8.3.2 Emissions under climate scenario RCP4.5

In case the BAU power supply scenario evolves under climate scenario RCP4.5, CO_2 emissions per supplied kWh hour will decline from 359.40 gCO_2eq in 2012 to 7.87 gCO_2eq in 2019 and then rise to 515.25 gCO_2eq by 2050. Concerning the alternative power supply scenario evolving under the same climate scenario, it is anticipated that CO_2 emissions per kWh hour will decline from 359.40 gCO_2eq in 2012 to 0.00 gCO_2eq in 2019 and remain until 2028 when it will rise gradually to 363.13 gCO_2eq by 2050.

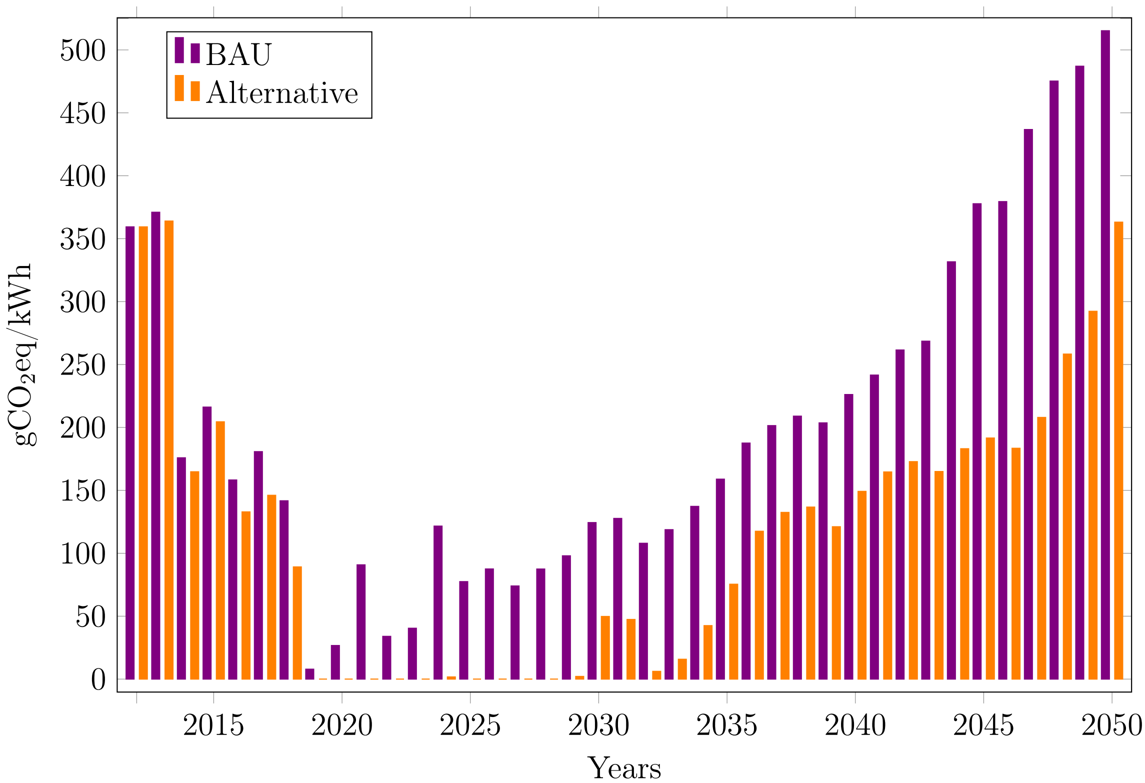


Figure 8.30: Evolution of CO_2 emmisions per kWh for the 2012−2050 period under climate scenario RCP4.5

Compared to emissions in the base and end years, CO_2eq/kWh in 2050 will only be 1.04% higher than the value in 2012 for the alternative power supply, whereas it will be 43.37% more than its value in 2012 under the BAU scenario. On average, CO_2 emissions per kWh for the 2012−2050 period is 116.42 gCO_2eq for the alternative and 203.24 gCO_2eq for the BAU scenarios. In terms of total emissions, it is projected that the cumulated CO_2 emissions from power generation between 2012 and 2050 will be 21.14 million tons of CO_2eq for the alternative and 39.91 million tons of CO_2eq for the BAU scenarios. From these values it can be deduced that the proposed alternative power supply scenario allows reducing emissions by 47.06% relative to emissions under the BAU scenario.

8.3.3 Emissions under climate scenario RCP8.5

Under climate scenario RCP8.5, emissions from the BAU power supply scenario is expected to decline from 359.40 gCO_2eq/kWh in 2012 to 0.00 gCO_2eq in 2026 and then rise to 499.71 gCO_2eq/kWh by 2050 (see Figure 8.31).

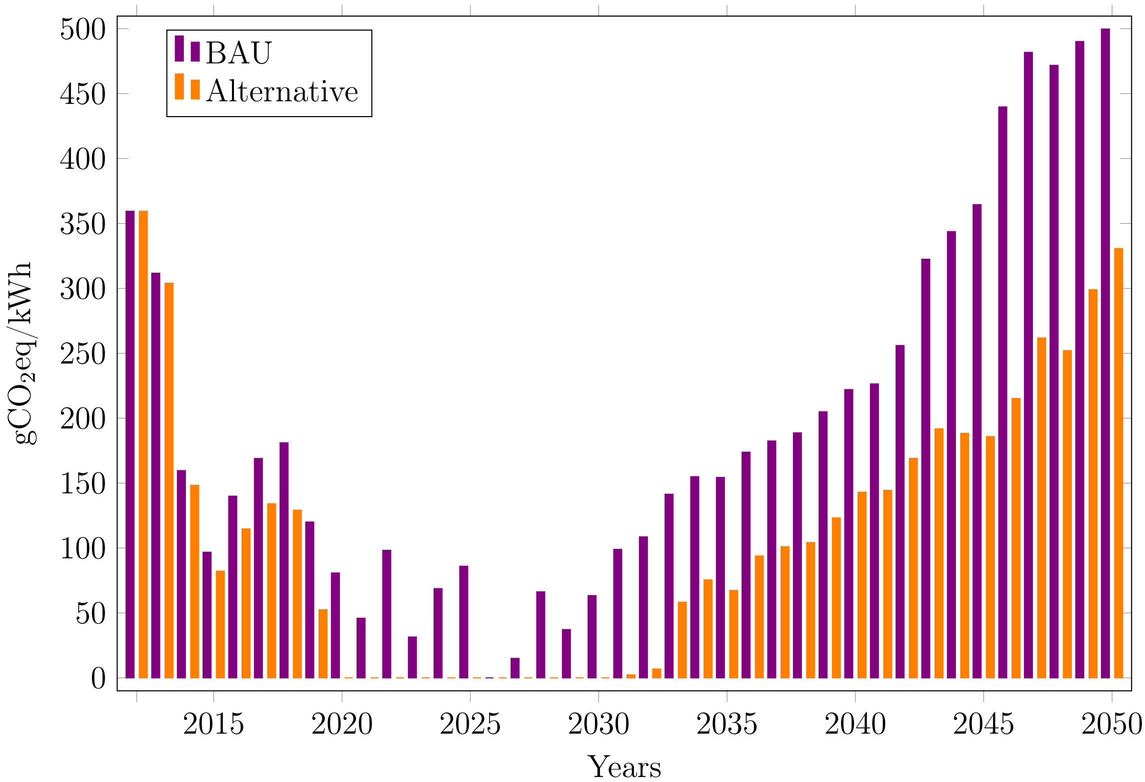


Figure 8.31: Evolution of CO_2 emmisions per kWh for the 2012−2050 period under climate scenario RCP8.5

Under the alternative scenario on the other hand, it is expected that CO_2 emissions per kWh will decline from 359.40 gCO_2eq in 2012 to 0.00 gCO_2eq in 2020 and stay at this value until 2030 due to suggested renewable energy technologies over this period. After 2030, CO_2 emissions per kWh will gradually rise and reach 330.98 gCO_2eq by 2050 (see Figure 8.31). Relative to emissions in 2012, the alternative power supply suggests emission reductions equivalent to 7.99% in 2050 while an increase in emissions of 39.04% is expected for the case of the BAU scenario. In total, 40,035 million tons of CO_2eq will have been emitted into the atmosphere under the BAU scenario by 2050 while 21,063 million tons of CO_2eq are expected for the alternative power supply scenario. Similar to the previous case, the implementation of the alternative power supply scenario will result into CO_2 emission reductions equivalent to 47.39% relative to emissions under the BAU power supply scenario.

A summary of the projected average emissions per kWh from power generation for the 2012−2050 period are presented in Table 8.11.

8.4 Power generation costs

Similar to the same reasons as for the case of CO_2 emissions, generation costs for different power supply scenarios presented in this section are related to the electricity generation required to meet the projected demand under the very high electricity scenario. It is important to mention that the costs presented in this section are only those related to power generation; costs related to transmission and distribution are not analysed.

Based on the assumption discussed in Section 5.6, the analysis of the simulated generation costs shows that, with no climate change considerations, the average generation cost between 2012 and 2050 is projected to be US$Cents 12.71/kWh under the BAU scenario against US$Cents 13.20/kWh for the alternative scenario. In case the evolution of Rwanda's climate follows RCP4.5 climate scenario, the power generation costs per unit would be US$Cents /kWh for the BAU scenario and US$Cents 13.73/kWh for the alternative scenario. As for the generation costs under climate scenario RCP8.5, it is anticipated that the generation cost per kWh would be US$Cents 15.76 for the BAU power supply scenario and US$Cents 13.24 for the alternative scenario.

A summary of estimated average generation costs for the 2012−2050 period is presented in Table 8.11. From this table one can conclude that the average cost of climate change on the electricity supply sector in Rwanda between 2012 and 2050 would be US$Cents 0.42 per kWh for climate scenario RCP4.5 and US$Cents 3.05 per kWh under climate scenario RCP8.5.

Under the alternative scenario the cost of climate change on this sector is US$Cents 0.53 per kWh under climate scenario RCP4.5 and US$Cents 0.04 for climate scenario RCP4.5,

Table 8.11: Projected emissions and generation costs per kWh between 2012 and 2050. The average presented in this table represents the average emissions for the 2012−2050 period.

Scenario	Sub−scenario	Emissions (gCO_2eq/kWh)			Generation cost (US$Cents/kWh)
		2012	2050	Average	
BAU	No impacts	359.40	483.50	183.72	12.71
	RCP4.5	359.40	515.25	203.24	13.13
	RCP8.5	359.40	499.71	192.03	15.76
Alternative	No impacts	359.40	295.93	101.87	13.20
	SRCP4.5	359.40	363.13	116.42	13.73
	RCP8.5	359.40	330.68	104.70	13.24

however, the cost of climate change is US$Cents 1.02 per kWh (against US$Cents 0.42 per kWh for climate scenario RCP4.5). It is important to recall that the presented costs are exclusive of emission costs, otherwise the unit costs would have been higher especially for the BAU related scenarios due to their high level of CO_2 emissions per kWh.

8.5 Policy and institutional frameworks

The proposed alternative power supply option is in line with the country's long−term development aspiration of being a developed climate−resilient country and having a low carbon based economy by 2050 (GoR 2011a, 17). This power supply scenario ensures the security of the country's electricity supply while protecting the environment and supporting sustainable development.

In Section 2.4 existing laws, policies and incentives as well as institutional frameworks to attract private investments in the energy sector were discussed. To successfully implement the suggested alternative power supply, however, much more enabling policies as well as institutional frameworks must be in place. In this section, a set of policy instruments as well as capacity building in renewable energy technologies are identified and proposed.

A policy that allows IPPs to cover the production costs and earn reasonable returns on their investments is required at the first place. As presented in Section 2.4.2, a FIT scheme for hydropower plants of up to 10 MW has been approved by RURA in 2012, and as a result, many IPPs are now producing or expecting to produce electricity from hydropower across the country (details were provided in Section 2.4.1). It is important also for solar and wind technologies to be supported until these technologies mature. In addition to FIT, other incentives such as the construction of access roads to the power plant sites and transmission lines connecting new plants to the national grid would also attract IPPs.

FIT policy will not only increase the share of renewable energy in the country power supply mix, also through the implementation and operation of solar and wind projects, thousands of jobs will be created, especially in rural areas where more than 80% of the country's population live.

In addition, the alternative scenario can yield significant savings of foreign currency as the transition away from fossil fuel in electricity generation will reduce the gap in the trade balance presented in Section 1.1.1.

However, to operate these two technologies a know−how is required, therefore a training component should be given a priority in the deployment of solar and wind technologies in the country. In the past the Government of Rwanda, in partnership with its development partners, has organized trainings on hydropower projects development and management in and outside the country (Uhorakeye 2011, 45). In the Author's knowledge this has considerably reduced the number of hydropower projects that failed shortly after their commissioning due to inadequate maintenance and management. Therefore capacity building through short− and long−term trainings in solar and wind technologies is recommended as IPPs will be interested in investing in areas where they can get manpower with enough skills to operate and maintain installed plants.

8.6 Summary and discussion

In this chapter, results of the evolution of Rwanda's electricity demand and supply towards 2050 were presented and discussed. On the demand side, three scenarios: the very low, the very likely and the very high were analysed. By 2050, the demand for electricity is projected to reach 6,546 GWh under the very low scenario, 8,100 GWh under the very likely scenario and 10,240 GWh for the case of the very high scenario.

To meet these projected demands, three BAU and three alternative power supply based scenarios were assessed. These scenarios were differentiated by climate scenarios in which they are evolving: no effects of climate change on the power supply (hydropower generation), the power supply evolving under climate scenarios RCP4.5 and RCP8.5. For the BAU power supply based scenarios, it was found that the national energy resources are able to meet the projected demands under the very low and very likely scenarios. As for the demand under the very high scenario, more than 20% of electricity requirements were projected to come from diesel power generation. With regard to the proposed alternative power supply scenario, it was found that no diesel based power generation would be needed by 2050 and also the share of power generation from peat was reduced relative to the BAU based power supply scenario.

It is important to emphasize that the results presented in this section are valid for considered assumptions on capacity, demand and deployment time: any other assumptions different from those used in this study may lead to different results. For instance it was planned to develop Karisimbi Geothermal Pilot Project by 2014 , Karisimbi I Project with 75 MW capacity by 2015 and Kalisimbi II Project with 75 MW capacity by 2017. However, because two exploratory wells drilled in Kalisimbi geothermal prospect did not confirm any existence of underground hot water reservoir, the first operation of a geothermal power plant was projected to 2020.

Due to delays in the deployment of planned power generation technologies such as hydropower, methane extraction facilities and geothermal drilling, testing and pipelines, peat can be used as intermediate fuel for power generation while the country is developing more sustainable resources. For instance during the time this report was being written, construction work on the Gishoma Peat Power plant was taking place whereas the simulation results showed that no peat based power generation will be necessary until 2042.

Chapter 9

Conclusions and recommendations

The main objective of this study was to assess a power supply scenario that would be resilient to the impacts of the expected climate change and ensure the security of Rwanda's power supply with least emissions towards 2050. Climate was brought into the analysis because hydropower generation in the country which is expected to represent a considerable share in the total power supply mix is very sensitive to precipitation and temperature changes. To achieve the study's objectives the country's hydrologic response to the expected climate and its impacts on hydropower generation was simulated using the WEAP model. Then the identified impacts of climate change were considered in the simulation of the country's power demand and supply analysis using the LEAP tool. This chapter highlights conclusions drawn during this study and recommendations that could help to improve the findings of this study.

9.1 Conclusions

The starting point was to adapt the WEAP model to the study area and this was done through calibration and validation processes. The calibration and validation results showed a very good model performance; however the analysis covered a short period of time (1974−1989) due to a very poor quality of recorded data necessary for the calibration and validation processes.

After adapting the WEAP model to the study area, the evolution of the future climate of Rwanda under climate scenarios RCP4.5 and RCP8.5 was assessed for two climate models: HadGem2−ES and MIROC−ESM. The analysis of projected precipitations revealed no significant trends in the projected annual precipitations for both models. However, interannual variabilities are projected to range from −32.94% to +24.50% for HadGem2−ES and from −24.48% to +50.21% for MIROC−ESM models. As for the projected temperature, it was found that the average increase rate in annual mean temperature would vary between 0.032℃ per year (or 0.32℃ per decade) and 0.069℃ per year (or 0.69℃per decade) for the HadGem2−ES model. For MIROC−ESM, the increase in temperature is projected to range between 0.021℃ per year (or 0.21℃ per decade) and 0.06℃ per year (or 0.6℃ per decade).

Due to the expected variations in precipitations and increase in the annual mean temperature, power generation will vary year by year depending on availability and timing of rainfall as well as the increasing temperature. Relative to the designed hydropower generation, it is projected, under climate scenario RCP4.5, that changes in cumulative power generation would range between 2% and 10% for the 2012−2019 period, between −13% and +3% for the 2020 − 2039 period, from −15% to −9% for the period from 2040 to 2059, between −24% and −14% for the 2060−2079 period and from −29% to −12% for the 2080−2099 period. With regard to hydropower generation under climate scenario RCP8.5, it is expected that hydropower generation changes between 2012 and 2019 would vary between 10% and 12% more than designed generation, and between −13% and +3% for the 2020−2039 period. Between 2040 and 2059 changes in hydropower generation are expected to range from −3% to +8% and from +9% to +15% for the 2040−2059 period. Between 2060 and 2079 it is projected that change in hydropower generation would range between −22% and +3% while changes for the last 20 year of the century would vary between −27% and +12% of the designed generation.

To assess the impacts of these power generation changes on the country's electricity supply, three power demand scenarios: the very low, the very likely and the very high demand were first developed assessed. It is projected that the country's total demand for electricity by 2050 would be 6,546 GWh under the very low scenario, 8,100 GWh under the very likely scenario and 10,240 GWh for the case of the very high scenario. Under the BAU power supply scenarios, it was found that the national energy resources are sufficient to only meet the projected demand for electricity under the very low and very likely scenarios. For the very high power demand scenario, more than 20% of the total electricity requirements in 2050 would be met through power generation from imported fossil fuels.

To terminate this dependency on imported fossil fuels for power generation, an alternative power supply scenario was identified and suggested. Under this scenario the following plan of actions are suggested:

- Improved efficiency of household appliances by 10% relative to the BAU scenario;
- Intensive exploitation of the Nyabarongo River (up to 110 MW);
- Intensive exploitation of solar energy (up to 500 MW by 2050);

- Introduction of wind energy into the power supply (up to 250 MW by 2050) and
- Use of municipal waste to generate electricity (up to 50 MW by 2050).

With the improved efficiency measure it is found that the total electricity requirements under the very high scenario would be reduced to 9,635 GWh from 10,240 GWh (that is to say a reduction of 6.28%) by 2050. Under the BAU scenario it is projected that between 16.48% and 20.91% of the electricity requirements in 2050 would be met by diesel based power generation. With the suggested power supply scenario no diesel based power generation would be required over the whole simulation period. In addition, it was also simulated under the BAU power supply scenario that 18.53% of the demand in 2050 would be met by power generation from peat. However, under the suggested alternative power supply it is possible to reduce this share to between 13.44% and 16.47%.

The average CO_2 emissions per kilowatt hour for the 2012−2050 period are projected to be 101.87 gCO_2eq and 183.72 gCO_2eq respectively under the alternative and the BAU scenarios when climate change is not taken into account. Under climate scenario RCP4.5, the average CO_2 emissions per kilowatt hour would be 116.42 gCO_2eq for the suggested power supply and 203.24 gCO_2eq for the BAU scenario. In case the future climate evolves following cimate scenario RCP8.5, emissions per kilowatt hour would be 104.70 gCO_2eq for the suggested scenario and 192.03 gCO_2eq for the BAU scenario.

The generation costs are such that for the BAU power supply scenario, the average unit costs between 2012 and 2050 are projected to be US$Cents 12.71/kWh under no climate change considerations, US$Cents 13.13/kWh under climate scenario RCP4.5 and US$Cents 15.76/kWh under climate scenario RCP8.5. As for the alternative power supply scenario, the average unit generation costs are anticipated to be US$Cents 13.20/kWh when the impacts of climate change are not considered, US$Cents 13.73/kWh under climate scenario RCP4.5 and US$Cents 13.24/kWh when the climate evolves following climate scenario RCP8.5.

Based on these findings, it is concluded that the suggested alternative power supply scenario is resilient to climate change effects as it meets the projected power demand when the impacts of climate change on hydropower generation are accounted for. The scenario also ensures the security of the country's power supply because it only relies on the domestic energy resources. Furthermore, CO_2 emissions per kWh are more than 40% lower than the emissions under the BAU scenario.

To successfully implement the suggested scenario, however, policy adjustments such as a FIT scheme for solar and wind technologies until these technologies mature would be necessary. The FIT policy will not only help to terminate the country's dependence on imported fossils, also through the implementation and operation of solar and wind projects, thousands of jobs will be created, especially in rural areas where more than 80% of the country's population live. In addition to policy adjustments, short− and long−term trainings in solar and wind technologies are very important as suggested as investors in these technologies would be interested in investing in areas where they can get manpower with enough skills to operate and maintain installed power plants.

9.2 Contribution of the research

In the design of hydropower plants in Rwanda (and in many other countries all over the world), planners have been relying on daily and seasonal historical climatic patterns, which means that they assumed stable climate. However, observed climate change has already compromised the ability of the country's power supply to meet both average and peak demand as discussed in Section 1.1.2.

However, by 2015, no study had been conducted to specifically investigate the response of the country's hydrologic system to the expected climate change, and assess what the impacts on stream flow discharges and hydropower generation are likely to be. This research provides a new energy planning approach would help to reduce the vulnerability of the country's power supply to the expected impacts of climate change by considering them during the energy facility designs and power plant operations. Therefore, decision− and policy−makers, hydropower plant operators and potential future investors as they can base on the finding of this study to make appropriate decisions on required adaptation policies and management strategies in order to reduce future negative costs.

Even though the focus in this study is on the energy sector, the analysed future climate and the calibrated and validated climate model can be used by other sectors such as agricultural and water supply sectors. In addition, not only Rwanda can benefit from this study; findings can be of use for other countries in the region with similar conditions.

9.3 Limitations

Not all planned activities under this study were undertaken as previously designed due to the following constraints:

- The main challenges faced during this study is the quality of the data necessary for the calibration and validation of the WEAP hydrologic model. The past precipitation, temperature and stream gauge data present many missing records as well as many non−realistic values.

- The WEAP model calibrated in this research covers only 8,316 km^2 (about one third of the country's area) and identified impacts were extended to the rest of the country. Covering the whole country would have provided a better picture of the future of hydropower generation. To achieve this, however, it would have been necessary to acquire data from the neighbouring countries as the stream gauge (Rusumo) that presents many records of better quality, and to which almost the whole country's area drains its water extends also to Burundi and Tanzania. To do this it would have required too much time and too may resources that were not available for this study.
- The other problem was the lack of information on emission tax from power generation that did not allow the consideration of pollution in the final unit power generation cost. The presented costs are subjected to increase if emission tax is included.

9.4 Recommendations

The following recommendations could help to improve the findings of this research as well as help the country to cope with the emerging climate.

- Because of the limitation of not simulating the whole country's hydrologic system in the WEAP model, it was not possible to link the hydrologic model (WEAP) and the energy model (LEAP) as previously planned. The linkage of the two models would have allowed building scenarios and examine the influence of hydropower generation on agriculture for example and vice versa depending on chosen water allocation priorities. Such an exercise can provide relevant information on which decision− and policy−makers can base to make appropriate policies that allocate the scarce water resource in ways that generate the highest benefit to the society.
- Tariffs for solar and wind technologies that ensure IPPs that they can recover generation costs and earn reasonable returns on their investments are recommended. It is also equally important to organize short− and long−term trainings in solar and wind technologies so that once IPPs will be starting their investments in the country skilled staff to operate and maintain installed power plants will be available.

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Appendix A

GCMs and ESMs used in AR5

Model	**Expanded name**	**Center**	**Resolution**
ACCESS1.0	Australian Community Climate and Earth-System Simulator, version 1.0	Commonwealth Scientific and Industrial Research Organization / Bureau of Meteorology, Australia	1.875 x 1.25
BCC-CSM1.1	Beijing Climate Center, Climate System Model, version 1.1	Beijing Climate Center, China Meteorological Administration, China	2.8 x 2.8
CanCM4	Fourth Generation Canadian Coupled Global Climate Model	Canadian Centre for Climate Modeling and Analysis, Canada	2.8 x 2.8
CanESM2	Second Generation Canadian Earth System Model	Canadian Centre for Climate Modeling and Analysis, Canada	2.8 x 2.8
CCSM4	Community Climate System Model, version 4	National Center for Atmospheric Research, United States	1.25 x 1
CNRM-CM5.1	Centre National de Recherches Météorologiques Coupled Global Climate Model, version 5.1	National Centre for Meteorological Research, France	1.4 x 1.4
CSIRO Mk3.6.0	Commonwealth Scientific and Industrial Research Organisation Mark, version 3.6.0	Commonwealth Scientific and Industrial Research Organization/ Queensland Climate Change Centre of Excellence, Australia	1.8 x 3 1.8
EC-EARTH	EC-Earth Consortium	EC-Earth Consortium	1.125 x 1.12

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Table A.1 – *Continued from previous page*

Model	**Expanded name**	**Modelling center**	**Resolution (lon, lat)**
FGOALS-s2	Flexible Global Ocean Atmosphere Land System Model grid point, second spectral version	State Key Laboratory of Numerical Modeling for Atmospheric Sciences and Geophysical Fluid Dynamics (LASG), Institute of Atmospheric Physics, Chinese Academy of Sciences	2.8 x 1.6
GFDL CM3	Geophysical Fluid Dynamics Laboratory Climate Model, version 3	NOAA/Geophysical Fluid Dynamics Laboratory, United States	2.5 x 3 2.0
GFDL-ESM2G/M	Geophysical Fluid Dynamics Laboratory Earth System Model with Generalized Ocean Layer Dynamics (GOLD) component (ESM2G) and with Modular Ocean Model 4 (MOM4) component (ESM2M)	NOAA/Geophysical Fluid Dynamics Laboratory, United States	2.5 x 2.0
GISS-E2H/-E2-R	Goddard Institute for Space Studies Model E, coupled with the HYCOM ocean model (GISS-E2H) and coupled with the Russell ocean model (GISS-E2-R)	National Aeronautics and Space Administration (NASA) Goddard Institute for Space Studies, United States	2.5 x 2.0
HadCM3	Hadley Centre Coupled Model, version 3	Met Office Hadley Centre, United Kingdom	3.75 x 2.5
HadGEM2-CC	Hadley Centre Global Environment Model, version 2–Carbon Cycle	Met Office Hadley Centre, United Kingdom	1.8 x 1.25
HadGEM2-ES	Hadley Centre Global Environment Model, version 2–Earth System	Met Office Hadley Centre, United Kingdom	1.8 x 1.25
INM-CM4.0	Institute of Numerical Mathematics Coupled Model, version 4.0	Institute of Numerical Mathematics, Russia	2 x 1.5
IPSL-CM5A-LR	L'Institut Pierre-Simon Laplace Coupled Model, version 5, coupled with NEMO, Low Resolution	L'Institut Pierre-Simon Laplace, France	3.75 x 1.8

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Table A.1 – *Continued from previous page*

Model	**Expanded name**	**Modelling center**	**Resolution (lon, lat)**
IPSL-CM5A-MR	L'Institut Pierre-Simon Laplace Coupled Model, version 5, coupled with NEMO, Mid Resolution	L'Institut Pierre-Simon Laplace, France	2.5 x 1.25
MIROC5	Model for Interdisciplinary Research on Climate, version 5	Atmosphere and Ocean Research Institute (The University of Tokyo), National Institute for Environmental Studies, and Japan Agency for Marine-Earth Science and Technology, Japan	1.4 x 1.4
MIROC-ESM	Model for Interdisciplinary Research on Climate, Earth System Model	Japan Agency for Marine-Earth Science and Technology, Atmosphere and Ocean Research Institute (The University of Tokyo), and National Institute for Environmental Studies, Japan	2.8 x 2.8
MIROC-ESM-CHEM	Model for Interdisciplinary Research on Climate, Earth System Model, Chemistry Coupled	Japan Agency for Marine-Earth Science and Technology, Atmosphere and Ocean Research Institute (The University of Tokyo), and National Institute for Environmental Studies, Japan	2.8 x 2.8
MPI-ESM-LR	Max Planck Institute Earth System Model, Low Resolution	Max Planck Institute for Meteorology, Germany	1.9 x 1.9
MRI-CGCM3	Meteorological Research Institute Coupled Atmosphere Ocean General Circulation Model, version 3	Meteorological Research Institute, Japan	1.1 x 1.1
NorESM1-M and NorESM1-ME	Norwegian Earth System Model, version 1 (intermediate resolution) and with carbon cycle	Norwegian Climate Center, Norway	2.5 x 1.9

Source: IPCC 2013, 854−863

Versicherung nach §5 (3) der Promotionsordnung der Universität Flensburg

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