Impact of climate change and irrigation development on hydropower supply in the Zambezi River Basin, and implications for power sector development in the Southern African Power Pool

Dennis Randall Spalding-Fecher

(Student no: SPLDEN002)

Thesis presented for the degree of

DOCTOR OF PHILOSOPHY IN ENERGY AND DEVELOPMENT STUDIES

in the Energy Research Centre, Department of Mechanical Engineering

UNIVERSITY OF CAPE TOWN

January 2018

Abstract

This thesis investigates the hypothesis that the combination of future changes in climate and development (primarily irrigation) in the Zambezi River Basin (ZRB) threatens the technical and economic viability of existing and planned hydropower plants, and in turn the expansion plans and costs of the regional power system for Southern African countries. This hypothesis is evaluated using the following three questions to structure the analysis.

- How could future climate and irrigation expansion in the Zambezi River Basin affect hydropower generation potential?
- How could development in Southern Africa affect power demand, and how might this demand be met?
- How could the changes in water availability for hydropower (i.e. due to climate change and development) affect regional electricity expansion plans, generation costs and greenhouse gas emissions?

The methodological tool used to address the first research question is the Water Evaluation and Planning (WEAP) scenario modelling system, developed by Stockholm Environment Institute. WEAP is a combined hydrological and water allocation model that is widely used internationally. The modelling demonstrates that the change in future climate is the overwhelming driver of future production at almost all hydropower plants in the ZRB over the study period of 2010–2070. The difference in mean generation under wetting and drying climates (i.e. difference between the values under wet and dry scenarios) is 12–16% for individual existing plants. This difference is as much as 30% for individual new plants, with all plants other than Batoka showing variation in mean annual generation of more than 13%. The impact of irrigation, on the other hand, is mainly an issue for plants downstream from Kariba, and even then the magnitude is typically less than a third of the impact of the alternative climates. The water modelling results therefore do not vary significantly across alternative development futures, because the accelerated irrigation development is still not large enough to dramatically impact hydropower.

The second research question is analysed using Stockholm Environment Institute's Long-Range Energy Alternatives Planning (LEAP) model to trace the impacts of socio-economic development on electricity supply and demand. The analysis combines a simulation of current utility plans with a least cost optimisation to meet the remainder of supply needed over the long term. The analysis shows that the underlying socio-economic drivers of demand lead to both a dramatic increase in total electricity demand and a shift across sectors and countries within the region. Total electricity demand for the Southern African Power Pool (SAPP) region increases by 8–14 times over period from 2010 to 2070, with the combined demand from the rapidly growing countries of Democratic Republic of Congo (DRC), Mozambique and Zambia becoming larger than South African demand by 2070. At the sectoral level, the share of total demand from the extractive and manufacturing sectors increases from 59% in 2010 to 70% in 2070 under the most optimistic development scenario, based on a compound annual growth rate of consumption in excess of 5%. Activity level growth is the main driver of demand growth. Comparison with other studies in the region show that the mid-term demand estimates (e.g. 2025–2030) in this study are generally within the range of other research, with somewhat higher demand estimates from the most optimistic development scenario. Total electricity supply required over the longer term is met through the addition of 400–1400 GW of new capacity, or 8–20 times the current capacity of the region. More strikingly, the power mix shifts from almost 80% coal-fired power to 24–44% coal by 2070, with the balance being supplied mainly by solar, wind, hydropower and nuclear generation. The regional shift is no less dramatic, with South Africa's share of total generation declining from 84% to only a third, based on the higher growth rates in countries such as DRC, Mozambique and Zambia.

The third research question is the most important in terms of the original contribution of this PhD thesis. Applying the WEAP and LEAP tools to an integrated multi-country system is a methodological advance pioneered in this thesis, showing that the integrated methodology can provide information to address not only the immediate questions about generation choices under an uncertain future climate, but also system costs and GHG emissions. The analysis shows that the reduction in hydropower generation under a drying climate leads to a shift in both capacity expansion choices and the operation of the regional power system, while the increases in hydropower output under a wetting climate are smaller. In other words, the "downside" of future climate changes is larger than the potential "upside". At an aggregate level, the increases in generation costs are a small share of total generation costs (i.e. less than 1% over the full study period compared to the baseline climate). However, the impact on generation costs for hydro-dependent countries such as Mozambique, Zambia and Zimbabwe is considerably larger, and these countries also gain more under a wetting climate. Finally, because some hydropower could be displaced by coal, regional GHG emissions could increase by more than 6 $MtCO_2$ per year in the medium term, or the equivalent of a large coal-fired power station.

This research has important policy implications for the water and electricity sector in the region. The potential transformation of the electricity supply sector would require a fundamental shift in resource use, grid management and infrastructure development in the region. The shift in the resource base for electricity generation will pose challenges for grid integration and balancing supply and demand across countries and load centres. Historically, the development of transmission capacity, and the resulting trade in electricity, has been constrained by the political and economic realities of the region. There are signs that the politics could be shifting, however, for political, economic and environmental reasons. In addition, the relatively low consumption of water in the Zambezi River Basin in the past meant that explicit trade-offs across sectors and across countries posed less of a challenge for the basin overall. This is very likely to change in the future, as increased demand from all sectors, and major potential changes in climate will require more explicit agreements across both countries and user groups on how best to utilise a limited resource. This research demonstrates the tools that could be used to integrate both climate change and upstream development demands into the feasibility studies before investment decisions are made. The research also illustrates the first steps toward integrating climate change and upstream development considerations into national and regional electricity planning.

The electricity and water sectors are important contributors to the development of the Southern Africa, and hydropower in the ZRB lies at the intersection of these fields. Climate change, however, has the potential to add increased stress on these sectors, both directly and indirectly, and yet is not being considered in many individual hydropower power investments, or in national or regional electricity planning. The integrated scenario analysis approach in this thesis demonstrates how the impacts of climate change, as well as increased irrigation demand for water, could be assessed not only for specific hydropower plants and for the entire sector power sector. Preparing for this possible range of future climates can increase the resilience of the sector and reduce the risk of stranded assets in the power sector.

Table of contents

List of figures

List of tables

List of acronyms

AR4	Fourth Assessment Report (from the IPCC)
AR5	Fifth Assessment Report (from the IPCC)
BAU	Business as usual
bbl	Barrel (of oil)
BFB	Biomass fuelled boiler
CAGR	Compound annual growth rate
CC	Combined cycle
CDKN	Climate and Development Knowledge Network
CEEEZ	Centre for Energy, Environment and Engineering Zambia
CF	Capacity factor
CNRM	Centre for National Weather Research (France)
CO_2	Carbon dioxide
CO2	Carbon dioxide
CORDEX	Coordinated Regional Downscaling Experiment
DFRC	Design flood rule curve
DNA	National Directorate for Water (Mozambique)
DRC	Democratic Republic of Congo
ECHAM	European Centre for Medium-Range Weather Forecasts, Hamburg (Germany)
EDM	Electricidade de Moçambique
ERC	Energy Research Centre (of UCT)
ESCOM	Electricity Supply Corporation (of Malawi)
ETo	Reference evapotranspiration
GCM	Global climate model
GDP	Gross domestic product
GJ	Gigajoule
GPCC	Global Precipitation Climatology Centre
GRDC	Global Runoff Data Center
GW	Gigawatt
HCB	Hidroeléctrica de Cahora Bassa
HFO	Heavy fuel oil
HMNK	Hidroeléctrica de Mphanda Nkuwa
HPP	Hydropower plant
IEA	International Energy Agency
IFs	International Futures (model)
IGCC	Integrated gasification combined cycle
IPCC	Intergovernmental Panel on Climate Change
IRENA	International Renewable Energy Agency
kWh	Kilowatt hour
LEAP	Long-range energy alternatives planning (model)
MSIOA	(Zambezi) Multi-sectoral investment opportunity analysis
MW	Megawatt
MWh	Megawatt hour
O&M	Operating and maintenance
OECD	Organisation for Economic Cooperation and Development
PPP	Purchasing power parity
PV	Photovoltaic
RCM	Regional climate model
RESAP	Renewable Energy Strategy and Action Plan (for SADC)
SADC	Southern African Development Community
SADC Int	SADC Integration (scenario)
SAPP	Southern African Power Pool
SATIM	South Africa TIMES (model)
SEI	Stockholm Environment Institute
SSP	Shared socioeconomic pathways
tCO_2	Tonnes carbon dioxide
TJ	Terajoule

UCT	University of Cape Town
WATCH	Water and Global Change (Programme)
WDI	World Development Indicators
WEAP	Water evaluation and planning (model)
ZAMCOM	Zambezi Basin Commission
ZDSS	Zambezi Decision Support System
ZESCO	Zambia Electricity Supply Corporation (Limited)
ZRA	Zambezi River Authority
ZRB	Zambezi River Basin

Disclaimer

Some of the research undertaken for this thesis was conducted as part of consulting funded by the World Bank. The World Bank requires the following disclaimer: The findings, interpretations, and conclusions expressed in this thesis, however, do not necessarily reflect the views of the World Bank, its Board of Executive Directors, or the governments they represent. The World Bank does not guarantee the accuracy of the data included in the thesis.

Acknowledgements

A project of this scale is not possible without the support of many other people. I would like to thank my collaborators in this field for the last several years, who have offered their insights and experience: Francis Yamba (CEEEZ), Charles Heaps (SEI), Harald Kling (Pöyry Energy), Arthur Chapman (OneWorld), Belynda Petrie (OneWorld), Taylor Binnington (SEI), Brian Joyce (SEI), Mamahloko Senatla (CSIR), Adrian Stone (ERC), Boaventura Cuamba (UEM), Gilberto Mahumane (UEM), Bernard Tembo (UCL), Tony Leiman (UCT), Greyson Himunzowa (CEEEZ), Biness Lukwessa (CEEEZ), Hartley Walimwipi (SS), and Imasiku Nyambe (UNZA).

Significant parts of the research were undertaken as part of projects funded by the Climate & Development Knowledge Network (CDKN) and the World Bank's Cooperation in International Water in Africa (CIWA) program. This funding is gratefully acknowledged.

In addition, many people provided inputs for the analysis and feedback during the course of the research. These include the following: Bruno Merven (ERC), Alison Hughes (ERC), Adrian Stone (ERC), Johnson Maviya (SAPP), Alison Chikova (SAPP), Lawrence Musaba (SAPP), Crispen Munodawafa (ZRA), Kozanai Gurukamba (ZRA), Mavis Nawa (ZRA), Pherry Mwiinga (ZRA), Odala Matupa (SADC), Bonje Muyunda (ZESCO), Shepard Ndhlovu (ZESCO), Overseas Mwangase (Interim ZAMCOM Secretariat), Carl Wesselink (CDKN), Tim Sumner (DFID), Matseliso Moremoholo (SEC), Joseph Phalalo (BPC), Clement Mukosa (ZRA), Brian Joyce (SEI), Annette Huber-Lee (SEI), Charles Young (SEI), Jack Sieber (SEI), David Purkey (SEI), Shehnaaz Moosa (CDKN), Ronald Mukanya (CDKN), Amy Merritt (CDKN), Richard Beilfuss (ICF), Stephanie Midgley (OneWorld), Thomas Alfstad (IAEA), Andrew Takawira (GWP), Freddie Mothlathledi (SADC), Veli-Pekka Heiskanen (SADC), Victor Mundende (ZESCO), Sergio Elisio (HMNK), Joel Kabika (UNZA), João da Costa (DNA), Kanta Kumari Rigaud (World Bank), Ben Davies (DFID), Philipp Stanzel (Poyry Energy), Marcus Wishart (World Bank), Ijeoma Emananjo (World Bank), Cecil Nundwe (World Bank), Members of the SAPP Planning and Environment Sub-Committees, as well as Fazlin Haribi for her support with the UCT administration and Tim James for his stellar proofreading.

Harald Winkler has been a wise and experienced supervisor, always adding new perspectives and providing guidance not only on the detail of the research but also on the overall flow and structure of the argument.

And finally, I am grateful to my wife, Amy, without whose belief and constant support I would not have been able to embark on this project, and to my daughters, Maya and Grace, for whom I pray we can create a more sustainable world.

Permission to include publications

I confirm that I have been granted permission by the University of Cape Town's Doctoral Degrees Board to include the following publication(s) in my PhD thesis, and where co-authorships are involved, my co-authors have agreed that I may include the publication(s):

> Spalding-Fecher, Randall, Arthur Chapman, Francis Yamba, Hartley Walimwipi, Harald Kling, Bernard Tembo, Imasiku Nyambe, Boaventura Cuamba. 2014. The vulnerability of hydropower production in the Zambezi River Basin to the impacts of climate change and irrigation development. Mitigation and Adaptation Strategies for Global Change 21(5): 721-742. DOI: 10.1007/s11027-014-9619-7

> Spalding-Fecher, Randall, Mamahloko Senatla, Francis Yamba, Charles Heaps, Arthur Chapman, Gilberto Mahumane, Bernard Tembo, Biness Lukwessa, Imasiku Nyambe, and Grayson Himunzowa. 2017. Electricity Supply and Demand Scenarios for the Southern African Power Pool. Energy Policy 101:403-414. DOI: 10.1016/j.enpol.2016.10.033

Signed,

Dennis Randall Spalding-Fecher

1 Introduction

1.1 Context

With the population of the Southern African Development Community (SADC) region expected to increase from around 260 million in 2012 to more than 500 million over the next 30 years, and as the SADC region industrialises on its path to improved human development, the demand for electricity is expected to increase dramatically. As a result, the power sector is a key component of infrastructure that drives both regional integration and economic growth, with energy security being increasingly important to continued development across Southern Africa (African Union 2012; Eberhard et al. 2011). At the same time, the chronic power shortages in the region in recent years has hampered short-term economic development. The Southern African Power Pool (SAPP), established in 1995, provides a forum for regional solutions to electricity generation and supply through coordinated planning and operation of the regional power system, which consists of generators and international inter-connectors.

The hydropower resources of the Zambezi River Basin (ZRB) are central to the long-term growth prospects and security of SAPP. While hydropower remains an important but under-represented contributor to SAPP, significant resources are located in the ZRB, with more than 40,000 MW in generation potential (Spalding-Fecher et al. 2016). Hydropower accounts for roughly 40% of the regional hydropower capacity, with twice that amount planned under further development (Miketa and Merven 2013; Spalding-Fecher et al. 2014). Securing the hydropower resources of the ZRB is therefore critical to ensuring regional energy security and stability. Increasingly, climate-related risks have the potential to further undermine the contribution of hydropower resources to the regional power pool and limit economic growth prospects (e.g., Spalding-Fecher et al. 2014; Kling, Stanzel, and Preishuber 2014; Yamba et al. 2011). Furthermore, the institutional structures for managing shared water resources across the entire river basin are only new emerging. Currently a Joint Operating Technical Committee, with representatives from Zambia, Zimbabwe and Mozambique, exists to provide limited coordination of the Kariba Dam and Cahora Bassa Dam. The entry into force of the "Agreement on the Establishment of the Zambezi Watercourse Commission" (the ZAMCOM Agreement) in 2011 and, more importantly, the establishment of a permanent Secretariat in 2014, provides the foundation upon which to develop greater coordination and efficient resource utilisation across the SAPP countries that are part of the Zambezi River Basin. There is, however, still no formal institutional cooperation between the SAPP Coordination Centre and the Zambezi Basin Commission (ZAMCOM), or other regional water management institutions. In addition, while hydropower can be part of low-carbon development strategies for the region, loss of output due to drying climate could shift generation to fossil fuels, making it more difficult for the Southern African countries to meet their climate change mitigation commitments under the Paris Agreement to the United Nations Framework Convention on Climate Change (UNFCCC).

While previous research has examined the impacts of climate change on specific existing and new hydropower plants (Beck and Bernauer 2011; Cervigni et al. 2015; Harrison and Whittington 2002; Spalding-Fecher et al. 2014; Tilmant et al. 2010), they have not been linked to any electricity supply and demand scenarios for the region. Not only does this lack of cross-sectoral coordination jeopardise national energy and economic development, but the lack of risk analysis limits the possibility of attracting much-needed private investment. It is necessary to link the water and power sector analyses in order to assess how climate change impacts on ZRB hydropower plants would affect the national electricity systems of key ZRB riparian states, as well as the overall electricity system performance and evolution in the regional power sector. In addition, the superficial treatment of water demand in many previous studies is an important weakness, because irrigation development could become an important driver of water availability at specific sites, even if overall the available runoff is underutilised. This requires a clear set of scenarios for socio-economic development in the region as well as consideration of future climates, as an input to both water and energy demand modelling. These are the gaps in knowledge that this research seeks to address, using an innovative integrated scenario modelling approach.

1.2 Hypothesis and key questions

Hypothesis: The combination of future changes in climate and development (primarily irrigation) in the Zambezi River Basin threatens the viability of major existing and planned hydropower plants, and in turn the expansion plans and costs of the regional power system for southern Africa.

To test this hypothesis requires answering three key research questions:

1: How could future climate and irrigation expansion in the Zambezi River Basin affect hydropower generation potential?

The first question is how future changes in climate (i.e. mean rainfall, timing of rainfall, mean temperature) and development (primarily irrigation) in the Zambezi River Basin could affect the potential generation from major existing and planned hydropower plants. Given the significant uncertainties in future climate, this research uses scenarios as a key tool to explore the range of future possibilities. In addition, agricultural water demand, specifically for irrigation, could be an important component of increasing water *consumption* in the Zambezi Basin. Therefore, the link between potential increases in irrigation demand – both from new projects and existing irrigated land – and water consumption by the agricultural sector in the Zambezi Basin is a key component of the research. The methodological tool to address this research question is the Water Evaluation and Planning (WEAP) scenario modelling system, developed by Stockholm Environment Institute (SEI). WEAP is a combined hydrological and water allocation model that is widely used internationally. WEAP is used to model the impacts of climate-related changes in runoff and increased irrigated agriculture on water demand and allocation at the sub-basin level, drawing on the Zambezi River Basin Multi-Sectoral Investment Opportunity Analysis study (see description in Chapter 2) for estimates of future potential irrigated area.

2: How could development in Southern Africa affect power demand, and how might this demand be met?

The second major question is how socio-economic development, in terms of GDP growth, demographic changes but also policy decisions and development investments, could affect demand for electricity, which includes the demand for hydropower; and how this demand could be met from a wide range of power supply options.

SEI's Long Range Energy Alternatives Planning (LEAP) model will be used to trace the impacts of development on energy demand, and in turn the demand for hydropower from various sectors of the economy. The power supply options will include not only a simulation of current utility plans but also an optimisation for least cost to meet the remainder of supply needed over the long term.

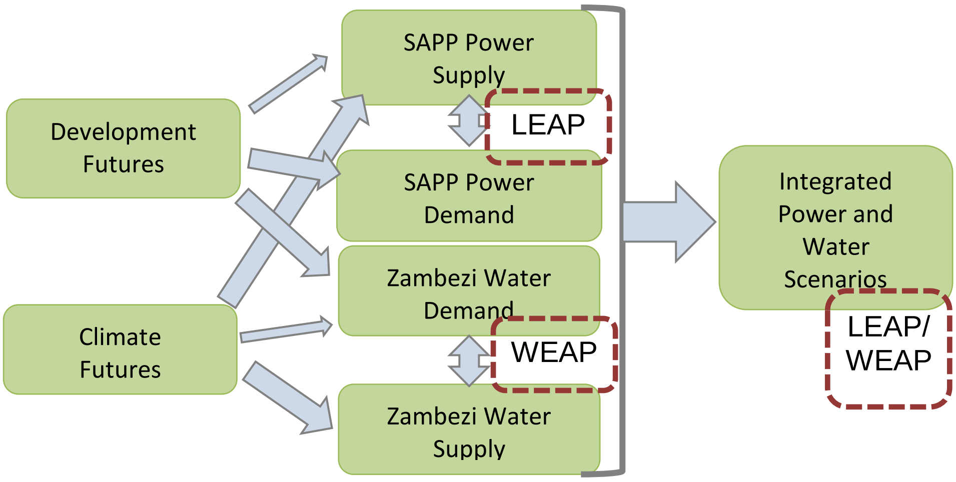
3: How could the changes in water availability for hydropower (i.e. due to climate change and development) affect regional electricity expansion plans, costs and greenhouse gas (GHG) emissions?

The third key question is how the net changes in water availability for hydropower generation, driven by climate change and development, could affect the overall regional electricity system, and particularly the system-wide costs of electricity, as well as the GHG emissions from the sector. Many ZRB countries depend on hydropower for both domestic supply and export revenue (e.g. Mozambique, Zambia, and possibly Zimbabwe and Malawi in the future). The change in availability could, therefore, affect electricity security and so the cost of generation. Hydro-dominated countries outside the ZRB could also be affected, but the generation forecasts for these countries will be held constant in this analysis, due to lack of a detailed hydrological model for those other river basins (e.g. the Congo)[1] under different climate and development futures.

1.3 Overview of methodological approach

The overall structure of the analysis, and the relationship between the different analytical components, is shown in Figure 1. The arrows show how the development and climate futures provide inputs to the water and power supply and demand models.[2] These models then provide the basis for the integrated water and power scenarios. The methodological approach to answer the questions above will be integrated scenarios combining WEAP results for hydropower availability with a LEAP analysis of the power sector

Figure 1. Overview of major analytical components and methodological tools



..

1.3.1 *Water modelling methodology*

While there are variety of simulation and optimisation modelling tools available for water supply and demand modelling, the methodological tool selected for this analysis is the SEI's WEAP modelling system (Yates et al. 2005; Sieber and Purkey 2011). There are several important reasons for choosing WEAP:

- The user-friendly graphic interface and transparent simulation approach make it easier to present results to stakeholders and elicit their feedback on the modelling, thereby increasing the accuracy of the inputs and results. All the parameters and results can be shown in scenario format, and choices on water allocation are explicit in each scenario, so that policy makers can provide direct inputs and see the implications of those decisions.
- The model has the built-in capability to link with an energy modelling tool (i.e. the LEAP model), so that the modelled availability of hydropower plants under various future scenarios can be used in the system-wide energy modelling.

---

[1] Chapter 2 notes that the Enhancing Climate Resilient Infrastructure in Africa (ECRIA) study (Cervigni et al. 2015) study included modelling of the Congo River Basin, but the detailed water model is not in the public domain.

[2] The arrow from climate futures to SAPP Power Supply refers only to the significant climate change impact on hydropower, not on any other sources of electricity generation.

- The model can be implemented as a water balance tool only, if hydrological modelling is not required for the water simulation (see below).

WEAP is a combined hydrological and water allocation model that is widely used internationally (e.g. Mehta et al. 2011; Purkey et al. 2007; D. N. Yates and Miller 2013; Varela-Ortega et al. 2011; Howells et al. 2013; Höllermann, Giertz and Diekkrüger 2010). There are several different hydrological modelling choices within WEAP (e.g. FAO crop requirements), which can be adapted to the needs of the research project. WEAP operates on the basic principle of water balance accounting, and provides an integrated approach to simulating both water supply and demand, with equal attention given to each side of the water balance equation. It is a simulation tool in that the futures are driven by user input, and it does not optimise on any criterion. WEAP is also a database for all water supply and demand parameters, as well as a forecasting tool simulating water demand, supply, flows, storage and pollution. For this thesis research, the runoff data is imported from another peer-reviewed modelling project, and so the focus in this analysis is the water balance modelling.

WEAP uses an intuitive graphical interface to show a schematic of the water system including all the supply sources (e.g. rivers, groundwater, and reservoirs); withdrawal, transmission and wastewater treatment facilities; ecosystem requirements; water demands; and pollution generation. The graphic interface prompts the user, highlights possible errors and provides on-screen guidance. Each of these components then has a corresponding data sheet with fixed parameters as well as time series parameters. Expandable data structures allow the model to evolve during the research, or be modified afterward as more detailed data becomes available.

Finally, as mentioned above, WEAP has a built-in interface to SEI's LEAP modelling system. This means that the two models together can provide a dynamic tool to analyse the implications of climate change and increased irrigation demands, not only on hydropower production from individual facilities but also for the energy system as whole, which is the goal of this overall thesis.

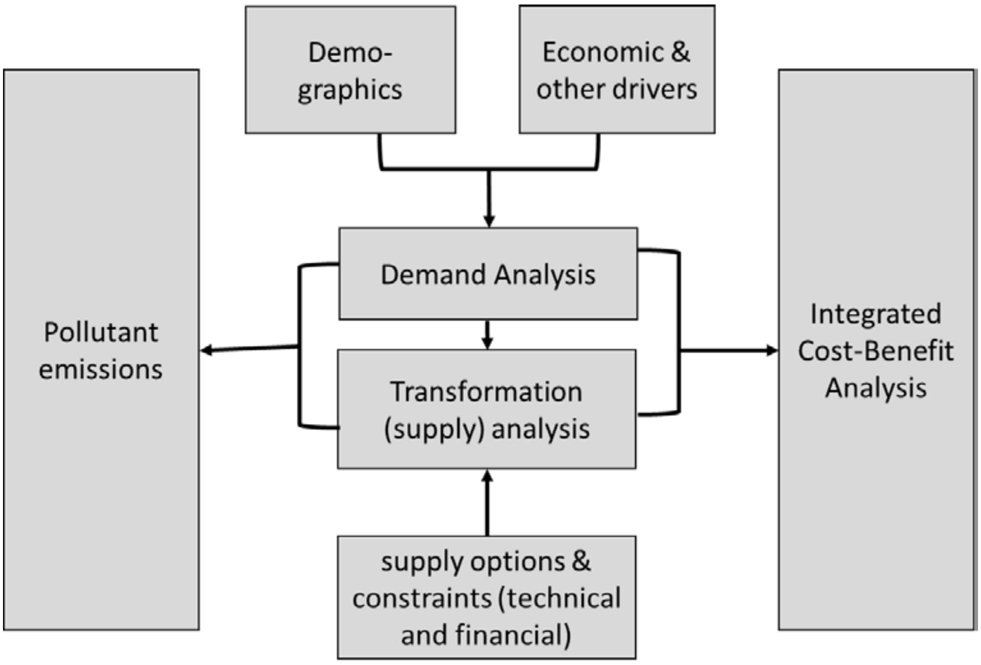
1.3.2 *Electricity modelling methodology*

As Bazilian et al. (2012) and Koppelaar et al. (2016) explain, there are numerous long-term energy forecasting and simulation modelling tools that each has its own strengths and weakness. As mentioned above, the tool selected for this thesis is the LEAP modelling system, developed by SEI (Heaps 2012), and increasingly used as part of integrated water-energy-climate modelling analyses (see, e.g., Howells et al. 2013; Sattler et al. 2012; D. N. Yates and Miller 2013).

The overall structure of LEAP is presented in Figure 2, showing the main flows of information through LEAP for this analysis. LEAP is not a model of a specific energy system, but rather a flexible software framework within which models of different energy systems can be constructed. Its most important features for this thesis are its support for multi-country analysis, alternative scenario projections, and the ability to combine bottom-up energy end-use based demand forecasts with least-cost optimisation modelling of electricity generation[3].

[3] Note that, in addition to LEAP User Manual describing the software in detail (https://www.energycommunity.org/Help/leap.htm), the documentation on the OSeMOSYS optimisation modelling tool is available at http://www.osemosys.org/

Figure 2. Structure of LEAP model as applied in the electricity analysis



Note: "Other drivers" does not include climate. LEAP does not directly incorporate any climate inputs.
Source: Adapted from Heaps (2012)

Electricity system models created using LEAP are demand-driven and typically combine bottom-up energy end-use based demand forecasts with simulation and/or optimisation-based models of energy production and conversion (which in LEAP is referred to as "Transformation"). LEAP's demand models are based around a straightforward accounting approach that calculates energy consumption as the product of some type of activity level and an annual average energy intensity, specified as units of energy consumption per unit of activity. Activity levels are typically broken down into their various components within a hierarchical tree structure displayed within LEAP and used to organise the main sources of data. For example, in the household sector energy intensities may be specified per household by fuel for each major end-use (cooking, lighting, appliances, etc.), while the total number of households in each country may be broken down into urban versus rural households and then into electrified and unelectrified households. The user is free to specify how each of these values may evolve in the future based on, for example, expected rates of population growth, urbanisation, electrification and technology penetration. In industry, services and agriculture sectors, energy consumption can be disaggregated by major subsectors, and energy intensities may be specified per unit of value added in each subsector. LEAP models are typically used for integrated energy planning that considers all fuels and the potential for substitution among fuels and technologies. For this research, however, the demand modelling is limited to consider only demands for electricity. The major macroeconomic and demographic assumptions used in the study are described in detail in Chapter 3.

In terms of the electricity supply analysis, the model developed for this thesis combines a relatively simple set of accounting projections for transmission, distribution and own-use energy losses, with a multi-regional least-cost optimisation model for electricity generation. The existing plants and specific planned investments by the regional utilities are the starting point for future supply – so the simulation aspect of LEAP is used for these power sources. To bridge the gap between the specific planned plants and the actual future demand, a least-cost optimisation analysis is used, based on a set of generic power plant options for each country. LEAP's optimisation calculations are based on the Open Source Energy Modelling System (Howells et al. 2011) and the GNU Linear Programming Kit, a software toolkit intended for solving large scale linear programming problems by means of the revised simplex method and the CPLEX Solver. This system can be used to calculate least-cost pathways for capacity expansion and plant dispatch in any scenario. The supply analysis is elaborated in Chapter 5. Note that, because the focus on this research is on how climate change affects hydropower output, and in turn the electricity system, the modelling scenarios only include supply-side responses to changes in hydropower availability. While the modelling framework could be used to explore how demand-side interventions (e.g. increases in end-use efficiency or increases in water-use efficiency) would affect the electricity system, these are not affected by climate change and so are not the focus on the analysis.

LEAP can also be used to calculate the emissions of GHGs and other local air pollutants in any scenario through the specification of emissions factors, typically entered as emissions per unit of energy combusted. In this research, LEAP's optimisation calculations use an objective function to minimise total economic cost for the entire electricity system. The capability of coupling the electricity modelling with a water modelling system (i.e. SEI's WEAP model) means that the climate change impacts on the power system can be analysed simultaneously.

1.3.3 *Integrated scenario analysis methodology*

The integrated scenarios combine climate futures with alternative development futures, as shown in Table 1. While Chapter 5 presents the results of how the development futures could influence the evolution of the regional power system, this analysis assumes a fixed availability for the major hydropower plants in the ZRB (and often an optimistic one based on the project owners' expectations). The integrated scenarios combine both dimensions of uncertainty – alternative development futures and alternative climate futures. To demonstrate the impact of different future climates, the results from the scenarios using alternative climate futures are compared with results under a modelled "baseline climate" – in other words, the hydropower generation, system costs and GHG emissions that we would expect if the climate from 2010 to 2070 were like the historical climate. (See Chapter 4 for a more detailed explanation of this issue).

Table 1. Nomenclature for the integrated scenarios

		Climate futures		History
		Marker scenario with “drying” (e.g. drying in many sub-basins)	Marker scenario with “wetting” (e.g. wetting in many sub-basins)	Historical climate
Development Futures	BAU (e.g. moderate growth)	“BAU Dry”	“BAU Wet”	“BAU baseline” Modelled baseline
	SADC Int (e.g. stronger growth)	Core future scenarios “SADC Int Dry”	“SADC Int Wet”	“SI baseline”
	Grand deal (e.g. major investment and technology shift)	“GD Dry”	“GD Wet”	“GD baseline”

Note: BAU = Business as usual scenario, SADC Int = SADC Integration scenario, GD = Grand Deal scenario

While the WEAP and LEAP modelling software can transfer results from one model to another in real-time, the practicality of this real-time link depends on the time required to calculate the full set of results for a given scenario. Because of the scale and complexity of both the water and energy systems in this analysis, and because the flow of information was only one-way (i.e. from WEAP to LEAP), the transfer of data is instead carried out off-line for each of the integrated scenarios. The implementation of the integrated scenario analysis includes the following three steps.

1. First, the ZRB WEAP model is used to project monthly hydropower generation from 2010 to 2070 under each of the combined climate and development scenarios (e.g. “BAU Dry”, “BAU Wet”, “Grand Deal Dry”).

2. This data is extracted from WEAP and converted into “availability” (i.e. actual generation divided by potential maximum generation in that month, taking into consideration any capacity expansions) in an Excel spreadsheet. This covers more than a dozen of the largest hydropower investments in the ZRB, with capacity of over 300 MW each. The time steps in the WEAP model are monthly, while the time steps in LEAP are seasonal and weekend versus weekday. The conversion therefore uses, for example, the average of June, July and August monthly availability as “winter weekend” and “winter weekday” availability,[4] and the same with the other seasons (e.g. Dec, Jan, Feb for summer).

3. The electricity supply optimisation calculations are then repeated for each scenario. Comparing the results for generation, costs and GHG emissions across scenarios

[4] Obviously, there is no hydrological reason why availability would vary systematically from weekends to weekdays, though energy demand does vary.

therefore shows the effect of changes in intra-annual and inter-annual variability in generation by ZRB hydropower plants.

1.4 Scope of the analysis

While the analytical framework in this thesis is intended to make an original contribution to the field, based on the gaps identified in the literature review (see Chapter 2), there are important boundaries to the scope of the analysis:

- The electricity and water modelling do not incorporate macroeconomic feedback on demand. In other words, if reduced water supply drives up the costs of electricity in the region, this could reduce the demand for electricity. This feedback loop is not included in the analysis because the economic and demographic inputs for the alternative development futures are exogenous to the electricity modelling.

- Climate change impacts on hydropower are considered only for the ZRB and not for other major river basins in Southern Africa. While the ZRB is currently the most important basin and one of the most important in the future, in terms of potential hydropower capacity, the Congo basin is potentially the largest future source of hydropower if fully developed.

- The optimisation algorithm for electricity supply only considers alternative generation sources, and not alternative transmission and distribution (T&D) investments to allow for more trade. This means that the optimisation is essentially a country-by-country optimisation and not a full regional optimisation. The T&D capacity and flows are exogenous to the modelling. They are derived from an earlier regional power optimisation study (Miketa and Merven 2013), albeit one that did not include an climate change or water availability impacts on power supply.

- Only grid-connected demand and supply sources are analysed. While there are significant numbers of households not connected to the grid, for which distributed power options may be appropriate, the large hydropower plants that could be affected by climate change would all be grid-connected. The demand to which those plants must contribute is grid-connected demand (which also increasingly includes a larger share of households, as grid penetration expands over time).

1.5 Note on own contribution

The author conducted this thesis research alongside two funded research projects, the members of which are noted in the acknowledgements. The author surveyed the literature to identify the research needs, and built both the WEAP model for the ZRB and the LEAP model for SAPP. The author also created all of the integrated scenarios, and the Excel tool that converted the WEAP outputs on hydropower generation into LEAP inputs for hydropower availability. Members of the research teams did provide some specific additional inputs that were critical to the analysis, namely, the South Africa module in the SAPP LEAP model (Mamahloko Senatla), review of the Zambia and Mozambique LEAP modules (Gilberto Mahumane, Bernard Tembo, Francis Yamba, Imasiku Nyambe), the detailed hydrological runoff data as an input to the WEAP water allocation (Harald Kling), and the demographic and economic inputs for the SADC Integration scenario (Arthur Chapman). Other contributions are cited as sources in the text.

As required by UCT, I confirm that I have been granted permission by the University of Cape Town's Doctoral Degrees Board to include the following publication(s) in my PhD thesis, and where co-authorships are involved, my co-authors have agreed that I may include the publication(s):

Spalding-Fecher, Randall, Arthur Chapman, Francis Yamba, Hartley Walimwipi, Harald Kling, Bernard Tembo, Imasiku Nyambe, Boaventura Cuamba. 2014. The vulnerability of hydropower production in the Zambezi River Basin to the impacts of climate change and irrigation development. Mitigation and Adaptation Strategies for Global Change 21(5): 721-742. DOI: 10.1007/s11027-014-9619-7

Spalding-Fecher, Randall, Mamahloko Senatla, Francis Yamba, Charles Heaps, Arthur Chapman, Gilberto Mahumane, Bernard Tembo, Biness Lukwessa, Imasiku Nyambe, and Grayson Himunzowa. 2017. Electricity Supply and Demand Scenarios for the Southern African Power Pool. Energy Policy 101:403-414. DOI: 10.1016/j.enpol.2016.10.033

Because these papers are the published work of the author, and are the based on the same research as much of chapters 4 and 5, respectively, the thesis cites the original primary and secondary sources used in these two areas of analysis, rather than the published journal articles. In addition, some of the policy implications in Chapter 7 are discussed in the journal articles, but these points are not referenced to the articles because the conclusions are the outcome of the overall analysis undertaken in the thesis.

1.6 Structure of thesis

Chapter 2 reviews the relevant literature, with a focus on studies in the ZRB, but also including climate-water-hydropower studies more broadly. The chapter also notes previous studies that solely focused on electricity sector modelling for the SADC region. Chapter 3 then presents the alternative development and climate futures used in the analysis and explains how these futures are combined into a set of integrated climate and development scenarios. Chapter 4 commences the quantitative analysis, presenting the water allocation modelling framework and the assessment of climate and development impacts on existing and planned hydropower plants in the ZRB. In parallel, Chapter 5 presents a model of the SAPP electricity system, with power supply and demand scenarios up to 2070, but without any consideration of climate change. Chapter 6 integrates the water and electricity modelling approaches, by analysing how the climate-induced changes in water availability for hydropower would impact regional electricity system expansion, fuel choices, costs and GHG emissions. Chapter 7 concludes by discussing not only conclusions on the analytical approach and quantitative results but also the energy and climate policy implication of this research.

2 Literature review

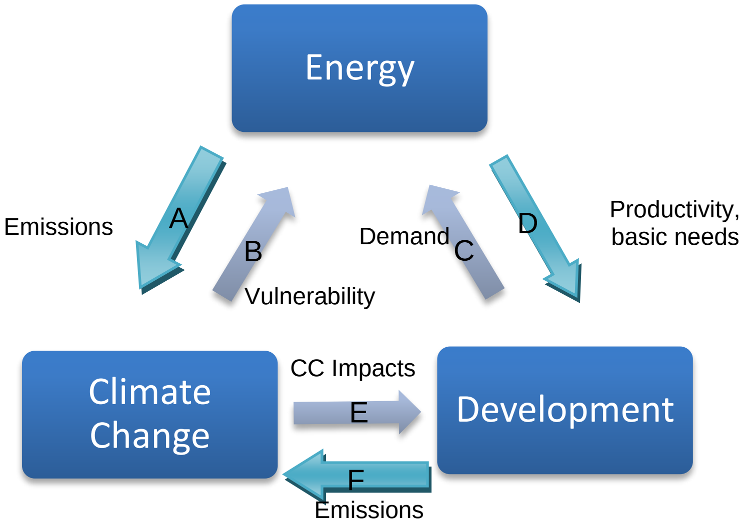
To understand how climate change and development will affect both supply and demand drivers for water and energy in the Zambezi River Basin, and in turn the national and regional electricity systems, first requires an understanding of how these issues have already been addressed in previous research. This chapter begins a short overview of climate, energy and development linkages, and then proceeds to a survey of how previous research has addressed specific dimensions of the overall research question. These dimensions include: the use of a plausible set of climate and development scenarios, the level of detail of demand analysis (particularly water demand from irrigation), the assumptions and modelling approaches for water allocation, the scope of hydropower plants included, which climate impact pathways are considered, and the integration of facility-level analysis with electricity system analysis.[5]

2.1 Climate change and hydropower globally

The overall dynamics among energy, development and climate change are complex (see Figure 3). More importantly, certain aspects of these dynamics are much less well understood than others. The role of the energy sector in providing for basic needs and development (arrow D in the figure) is well understood (DFID 2002; Modi et al. 2006; Spalding-Fecher, Winkler, and Mwakasonda 2005), as are the pathways through which economic and social development drives energy consumption (arrow C) (GEA 2012). While there is a vast literature on the contribution of energy production and consumption on climate change, in terms of GHG emissions (arrow A) (e.g. Solomon et al. 2007; Metz et al. 2007; Edenhofer et al. 2014), however, perhaps the least well understood link is the impact of climate change on the energy sector itself (arrow B). The challenge is that many of these impacts are indirect and have a variety of potential climate interactions that may have conflicting influences. For example, hydropower production is clearly affected by the amount of runoff available at the plant site, but what determines the availability of water? Beyond the obvious drivers of upstream rainfall and evaporation (due to changes in mean temperatures), this will also be influenced by competition for water with upstream irrigation development and by damage to reservoirs and infrastructure from flooding (Spalding-Fecher and Fedorsky 2012).

[5] While the institutional environment for the water and power sectors – and uncertainties over how this will evolve - is relevant for adaption to the impacts of climate change on the water and power sector, the focus on this research is on identifying and quantifying the potential impacts *before* there have been institutional or other policy responses. This chapter does not, therefore, cover the institutional issues in the Southern African water and power sectors.

Figure 3. Energy, climate change and development linkages



Source: Author's analysis

Climate change impacts studies have been conducted in many other sectors (e.g. agriculture, water, health, natural ecosystems) for almost two decades (arrow E), as reviewed in the Working Group II contribution to the IPCC Fourth Assessment Report (e.g. Parry et al. 2007). The water sector has been a major focus, starting with studies at a global level (Frederick and Major 1997; Arnell 2004, 1999), and followed by studies for regions or basins (e.g. Arnell, Hudson, and Jones 2003; Jiang et al. 2007). Only in the last decade have water sector studies made more explicit links with energy production (e.g. Bates et al. 2008). The literature on impacts in the energy sector is relatively new, and many of the early studies focused on climatic influences on energy demand, particularly in industrialised countries (e.g. Baxter and Calandri 1992; Bhartendu and Cohen 1987; Isaac and van Vuuren 2009)

One of the most important syntheses of research on climate impacts on the global energy sector is a recent book from the World Bank (Ebinger and Vergara 2011) and the accompanying journal article (Schaeffer et al. 2012), which highlight vulnerabilities for hydropower production. The authors note that the magnitude of vulnerability depends on the share of total generation from hydropower and the level of integration of the grid(s) through transmission capacity – both of these are central issues in Southern Africa. Schaeffer et al.'s (2012) review of energy sector vulnerability not only highlights the negative impacts on hydropower but also the methodological challenges in this area as a relatively new field. The review also links the climate variability to questions of energy security. While the concept of "energy security" has a wide variety of meanings in the literature, a key factor is almost always supply security (in this case related to hydropower or other resources affected by climate). Bazilian et al. (2011) define energy security as "the uninterrupted physical availability of energy products on the market, at a price which is affordable for consumers". On the supply side, both the performance of hydropower and the availability of biomass resources – the mainstay of the vast majority of poor communities in the world – are potentially vulnerable (Pöyry 2010; Ebinger and Vergara 2011). Given that the most important energy security issue in most developing countries is the lack of access to modern energy services for the majority of the population (Bazilian et al. 2010; Legros et al. 2009; IEA, UNDP, and UNIDO 2010), these negative impacts on biomass and once of the key source of electricity for many developing countries have important implications for energy security.

A few studies have applied changes in climatic variables to calibrated hydrological models of major river basins, where the future climate parameters are used to force the model and estimate potential impact on hydropower (de Lucena et al. 2009; Wilbanks et al. 2007; Lehner, Czisch, and Vassolo 2005; Hamlet et al. 2009). A global analysis of climate impacts on hydropower showed that, while the impacts were highly variable, a number of countries in Africa could be particularly hard hit (Hamududu and Killingtveit 2012). Hamududu and Killingtveit used forecast changes in annual mean flows as a predictor of change in hydropower production, bearing in mind that this assumes that current hydropower generation is only limited by water availability. This is not the case for Africa, of course, where total potential hydropower production is limited by lack of capital. In other words, there is large scope for harnessing more hydropower resources beyond what current plants can produce, but this requires large investments in infrastructure. Nevertheless, the results are instructive. Using an ensemble of 12 global circulation models (GCMs) and IPCC Scenario A1B,[6] runoff for 2050 was mapped for 165 global basins, and results tabulated for each country. While the global average losses were small – at less than 1% of historic generation – the combined annual losses in hydropower production from existing facilities due to climate change in Angola, Malawi, Mozambique, Namibia, Zambia and Zimbabwe were estimated at over 2,700 GWh relative to historical production levels and a historical climate. Note that this study did not include growth in water demand from agriculture or other sectors, and did not include the demand of water from new hydropower facilities. In addition, only one future emissions scenario was considered.

2.2 Studies of climate change and hydropower in Southern Africa, particularly the Zambezi

Several studies have started to make the links between climate change, upstream development and hydropower in the ZRB, albeit not always with a complete picture of these future impacts. The studies reviewed in the following sections are those that analysed water and supply and demand in the ZRB, or in some cases more broadly in the region.[7] Rather than providing a comprehensive description of each study, the focus is on the gaps in the current literature, and what the current research could add to deepen the knowledge base and understanding in this field. By way of introduction, the studies and their main findings are listed here before examining their structure and characteristics. For ease of reference, the labels at the start of each bullet are used throughout this chapter to identify each modelling effort.

- ECRIA: During the latter part of this thesis research, the World Bank published the Enhancing Climate Resilient Infrastructure in Africa (ECRIA) study (Cervigni et al. 2015). The ZRB was one of seven river basins where researchers modelled future supply and demand across multiple end-users, and how this would change under a range of future climate scenarios. This project also included electricity optimisation modelling for regional power pools. The results showed that, under the driest scenarios, total hydropower generation could decline by more than 60%, while wetter scenarios could increase total production by 25%. A case study of Batoka Gorge showed that this range of future climates could reduce the net present value (NPV) by more than 100%, while the wettest climates could increase NPV by just over 40%.

- ZDSS: A consortium led by HYDROC Consult, and including Pöyry Energy, developed a Zambezi Decision Support System (ZDSS) for the Mozambique National Institute for Disaster Management, as part of a larger project on responding to climate change in the

---

[6] The IPCC Fourth Assessment Report (AR4) used different future climate scenarios “families” and groups to characterise the uncertainty in future global policy decisions and socio-economic development (IPCC 2000). Those referenced in this thesis include A1B (rapid economic growth, regional convergence, rapid introduction of more efficient technologies, balance between renewables and fossil fuels), A2 (heterogenous social and economic development, with continued population growth, fragmented technological development), and B1 (convergent world similar to A1 but with faster decarbonisation, economic diversification and improved equity). The Fifth Assessment Report (AR5) developed “reference concentration pathways” (RCP) to guide the scenario analysis, with each pathway defined by the approximate radiative forcing (RF, W m–2) that is reached during or near the end of the 21st century, relative to the pre-industrial period (e.g. RCP4.5 is 4.5 W m^{-2}) (van Vuuren et al. 2011; Moss et al. 2010).

[7] For a map of the ZRB showing the location of the hydropower plants mentioned in this chapter, see Chapter 4.

water sector (Petersen 2012; Kling, Stanzel, and Preishuber 2014). The ZDSS included a comprehensive hydrological water balance model of the ZRB, with 27 sub-basins as well as a water allocation model. The results show a 32% decrease in discharge at Tete, Mozambique with only a 10% decline in mean annual precipitation, highlighting the sensitivity of runoff to changes in climate. Under rapid development scenarios and a changing climate, Cahora Bassa might not be able to release any water during the driest months of the year, because reservoir levels could fall below minimum operation levels.

- Yamba et al: Professor Francis Yamba and his colleagues used a water balance model, the Water Resource Simulation Model (WRSM2000), to analyse future scenarios for hydropower in the Zambezi (Yamba et al. 2011). The focus of the scenarios was to examine how climatic changes up to 2070, along with continued increase in demand, would affect availability of water for existing and new hydropower stations. The study results show that gross hydropower potential at Kariba, Itezhi-Tezhi, Cahora Bassa and Mphanda Nkuwa could fall by more than a third on average between 2010 and 2035. The modelling predicts some recovery of hydropower potential in the period between 2035 and 2050, but this is followed by continued declines after 2050.

- Beck and Bernauer: Beck and Bernauer (2011) developed a lumped rainfall-runoff hydrological supply model for the region, and a demand model covering both consumptive and non-consumptive uses of runoff. For Kariba, the analysis shows that moderate supply and demand changes could reduce power output by 35%, and that a scenario with stronger supply and demand change could eliminate almost all hydropower production during parts of the year. Cahora Bassa could also see a 16% decline under the moderate scenario and a 65% decline under the strong supply and demand changes scenario.

- Tilmant et al: The Tilmant et. al. (2011) team used an economic optimisation model to examine the costs and benefits of different priorities of users in the Zambezi. This included trade-offs between irrigation and hydropower. The results showed that, if irrigation is given priority and 464,000 ha of new irrigated land are developed over the next 25 years, regional hydropower generation would fall by about 10%. The represents a $200 million[8] net loss of economic value, even considering the economic benefits from increased agricultural production.

- MSIOA: The World Bank Multi-Sectoral Investment Opportunity Analysis (MSIOA) Study developed a hydro-economic model to examine key trade-offs and impacts of hydropower and irrigation development in the Zambezi River Basin, based largely on existing flows. The focus was on understanding the optimum balance of irrigation, hydropower development, flood control and environmental flows, and whether there was any potential conflict between these sectors. The study used the HEC-3 reservoir and hydrology model and limited input from a WEAP model of the Zambezi. In terms of climate change, the study found that, "the preliminary indications are that some parts of the Basin would be affected more than others with potential reduction of up to 30% in hydropower generation. As noted, this will need further detailed analysis."

- Harrison et al.: Harrison et al. (2006) studied the impacts on a specific project in their analysis of the proposed 1600 MW Batoka Gorge hydropower plant to assess how climate change might influence the technical and financial viability of that investment. The authors use a simple lumped-parameter water balance model and the HEC-5 reservoir balance model for part of the Zambezi River Basin upstream of Batoka Gorge. The financial analysis showed that a 10% reduction in precipitation would wipe out the NPV of the project, even with a 2ºC rise in temperature instead of a 4ºC rise. This is partly because a 10% change in precipitation leads to a 20% decline in annual river flows. This amplification

[8] In all cases in this thesis, the symbol $ refers to US dollars.

of the change in rainfall is also found in many other river basins in Africa (de Wit and Stankiewicz 2006).

- Mukheibir: Mukheibir (2007) conducted a secondary review of the potential impacts of future climate change in hydropower in Southern Africa more generally. The temperature changes and rainfall changes were taken from analysis at University of Cape Town's Climate Systems Analysis Group (Tadross, Jack, and Hewitson 2005). This paper does not provide a modelling methodology or detailed results, and so is not described further.

2.2.1 *Development futures*

In terms of alternative development futures and how these might impact water supply and demand, many studies did not include any explicit consideration of the broader drivers of supply and demand, and almost none considered alternative futures. Beck and Bernauer did include more than one population and urbanisation scenario, but none of the other studies considered how alternative economic growth and changing structure of the regional economies could impact water systems. For the irrigation sector, the MSIOA did consider the implementation of "identified projects" versus the "high level potential" for irrigated agriculture, and the ZDSS took up this distinction as well but did not provide alternatives for years during which these levels might be achieved, nor were these linked to economic growth assumptions. Similarly, Beck and Bernauer had three different levels of irrigated area, but these were not related to any specific period. The ECRIA study only considered one possible timeline for hydropower and irrigation development, and one included one of the two irrigated area levels (i.e. "identified projects) from the MSIOA in their analysis. Given the major impact of economic development on water (and electricity) demand, and the large uncertainties in the future prospects for Southern Africa, an explicit formulation of development scenarios is important.

2.2.2 *Climate futures*

Projections of future climates have as much uncertainty – if not more – as future economic development projections. Most of the existing studies, however, only have one possible climate future in their analysis, although there are notable exceptions: Yamba et al. (i.e. average of three GCMs under SRES A2), the MSIOA (i.e. midrange of 23 GCMs under SRES A1B) use on climate future, while Beck & Bernauer use one emissions scenario (i.e. SRES A2) with two alternative precipitation levels from non-downscaled GCMs. Tilmant et al. do not consider a change in climate, and Harrison et al. do not use climate scenarios, but simply consider a ±20% change in precipitation across the basin. The ZDSS uses three climate futures based on downscaled GCM data in the WATCH dataset, which cover both drying and wetting futures, The ECRIA study, however, considers 121 future downscaled GCM simulations, covering a range of IPCC AR4 and AR5 scenarios (i.e. A1B, A2, B1, RCP4.5 & RCP8.5). While multiple climate futures are needed to understand the implications of both plausible drying and wetting climate futures, the number of alternatives should be small enough that they can be combined with alternative development scenarios.

2.2.3 *Integrated scenarios*

Only Beck and Bernauer analysed scenarios that considered alternatives in both climate and development. Their two integrated studies, however, were (i) moderate demand changes with moderate drying, and (ii) more rapid demand growth with dramatic drying – so the possibilities of increased rainfall are not considered. All of the other studies either had only a single climate development future, or they analysed these issues separately (e.g. one development future but many climate futures). Given that drivers of both water supply and demand include large uncertainties, understanding the risks for hydropower in the region requires an integrated analysis that varies *both* climate and development drivers.

2.2.4 *Level of detail of demand analysis*

The approach to water demand analysis varies significantly by study, but very few provide detailed demand assumptions. Yamba et al. simply used population growth as the driver of total water demand, without consideration of GDP, and do not model specific drivers of irrigation demand. Harrison et al. and Tilmant et al. used historical flows and demand, so did not account for potential increases in demand by any sectors. The MSIOA and ZDSS studies provided the most detail on reservoir evaporation and evapotranspiration from crops under irrigation ("identified projects" and "high level potential"), as well as including new hydropower plants and planned water transfers, but only the MSIOA addressed industrial demand. The ECRIA study used population to drive urban demand, and used one set of MSIOA assumptions (e.g. "identified projects") to estimate future irrigation demand, but did not include any industrial demand. Beck and Bernauer used GDP growth and earlier demand estimates for irrigation demand, but did not conduct a bottom-up analysis based on irrigated area by crop as in the MSIOA. While industrial demand – and to some extent urban demand – are a very small share of total demand in the ZRB, the lack of detail in many of the studies on irrigation demand is problematic. The foundation in the MSIOA study is the most promising for this task, because of the crop and sub-basin-level analysis.

2.2.5 *Assumptions for water allocation*

Another key issue in the literature is how to account for different priorities – explicit or implicit – given to different sources of demand. This is not only an issue across sectors (e.g. irrigation versus urban demand) but also between upstream and downstream demand, particularly give the number of large hydropower plants in the lower Zambezi. The ZDSS, Yamba et al. and the MSIOA treat hydropower demand as residual, so this is only met after irrigation and urban demand, although the MSIOA includes many variations on which other sources of given priority. Beck and Bernauer, on the other hand, prioritise hydropower over irrigation, while Tilmant et al. explore the implications of changing the priorities of different demand sources. The ECRIA study assigns higher priority to upstream demand sources, and within a given sub-basin prioritises irrigation over hydropower in most cases. Given that there is no basin-wide cooperative water sharing or prioritisation in place currently, assigning higher priorities to upstream demand sources is an important aspect of this analysis. This should be true at each abstraction point or reservoir along the entire river basin system. In addition, however, the priorities should clarify the trade-offs between hydropower reservoir filling versus hydropower generation (i.e. how important it is to keep a reservoir full).

2.2.6 *Scope of hydropower plants included*

The ECRIA study has the most comprehensive set of existing and planned hydropower plants in the literature. The only run-of-river plants not included in that study that were added in this research were Kabompo (40 MW), Kapichira II (64 MW), Boroma (160 MW), Lupata (550 MW) and Mpatamanga (310 MW). More importantly, however, the ECRIA study did not include the possible second phase of Mphanda Nkuwa (as additional 1125 MW) or the two phases of the Chemba hydropower reservoir (1,000 MW total), all in Mozambique – which are all part of this research. The MSIOA covered all of the existing hydropower plants, and eight new hydropower plants of the 22 plants considered here (for discussion of specific new plants, see Chapter 5). The other studies generally include the four or five largest existing plants or reservoirs (e.g. Kariba, Cahora Bassa, Kafue Gorge, Victoria Falls, Itezhi-tezhi) and between two and five new plants (e.g. Mphanda Nkuwa, Batoka, Boroma, Mupata), while Beck and Bernauer did not specify which new plants were included and Harrison et al. only analysed Batoka.

2.2.7 *Climate impact pathways considered*

There are four main pathways for direct climate change impacts on the water availability for hydropower generation. They are (i) change in rainfall; (ii) impact of temperature change on evapotranspiration (i.e. crops and natural vegetation); (iii) impact of temperature change on reservoir evaporation; and (iv) impact of temperature change on evaporation from wetlands. Only the ECRIA and ZDSS studies consider all four of these pathways. Beck and Bernauer and the MSIOA consider all of these except the impact on wetlands (which is significant, given the number and size of the major wetlands in the ZRB), although Beck and Bernauer did not model reservoir evaporation in detail. Harrison et al. considered only rainfall and evapotranspiration. The Yamba et al. study only included rainfall changes.

2.2.8 *Integration of facility level analysis with electricity system analysis*

None of the studies reviewed attempted to integrate the facility-level hydropower analysis with a model of the entire regional power pool, except for the ECRIA. The ZDSS only provides water availability, while Yamba et al. provide hydropower potential at selected individual plants. The other studies that include multiple hydropower plants report on the change in generation (for those limited number of plants included) but do not place this in the context of the overall regional power system. The ECRIA study includes the Zambezi, Orange and Congo River basins, as well as a model of the SAPP using the Open Source Energy Modelling System (OSeMOSYS) (Howells et al. 2011). The results of the ECRIA study therefore show how a variety of climate futures could affect regional power generation economics, but only based on climate change – not based on alternative assumptions about how electricity demand could evolve (see section 2.2.1).

2.3 Summary and limitations of previous studies

Tables 2–5 summarise the different aspects of the climate change and hydropower studies reviewed, highlighting their key characteristics. Several overall observations emerge from this review:

- While the global studies are interesting in pointing to overall risks, they are at too high a level of aggregation (i.e. too coarse a resolution) to provide meaningful results for individual plants or even national systems.
- Many studies did not include any explicit consideration of the broader drivers of water (or electricity) supply and demand, and almost none considered alternative development futures.
- Most studies have only one climate scenario, which implies a certainty about future changes in climate that does not exist. Even those studies that include more than one scenario do not necessarily represent the possible range of both increases and decreases in rainfall in different sub-basins.
- While many studies include different supply and demand climate impact pathways (e.g. reservoir evaporation, runoff changes, evapotranspiration from crops and natural land use), only two include all four of these pathways. Very few studies address climate impacts on demand for water from reservoir and wetlands evaporation.
- Most of the literature does not address projections of future water demand in any detail, particularly the potentially large increase in agricultural demand due to both increased irrigated area and increased evapotranspiration rates.
- Where priorities are explicitly assigned to different water demand sources, these do not necessarily reflect the actual conditions in the river basin (e.g. the de-facto priority of

upstream users and irrigation), and the studies do not generally consider maintaining reservoir storage as an explicit priority.

- While several studies analyse changes in water availability and power production at a specific site, only the ECRIA study follows this dynamic effect through to the impact on national and regional power systems (e.g. impacts on expansion plans and total systems cost). This is particularly important in light of the dependence of the regional utilities' plans for new supply on hydropower projects in the Zambezi. Even this study, however, does not present integrated development-climate-water scenarios that would demonstrate the interaction between the assumptions about future climate with a range of alternative socio-economic development pathways.

- The range of hydropower plants included in most of the studies is limited, particularly for future planned plants.

- In addition, while some studies present their model calibration results explicitly, this is not the case with all of the studies, and some of the studies only calibrate to mean annual runoff, rather than also calibrating to the variability of this runoff (i.e. standard deviation and coefficient of variation).

Table 2. Structure/approach for studies reviewed

Study	Socio-economic scenarios	Climate Scenarios	Irrigation scenarios	Runoff modelling approach	Water demand assumption	Allocation	Calibration	Geography
ECRIA	No	140	No, only one from MSIOA	Hydrology and water balance (WEAP)	Irrigation area growth and change in evapotranspiration (+urban?)	Irrigation generally higher than hydropower; upstream higher priority	Extensive	60 sub-basins
ZDSS	No	CNRM, ECHAM and IPSL downscaled, bias corrected models, from WATCH dataset	Yes, based on World Bank	Water balance model	Irrigation area growth and change in evapotranspiration	Hydropower is residual after environmental flows, irrigation and diversions	Extensive, mean, standard deviation and coefficient of variation	27 sub-basins
Yamba et al.	No	One: SRES A2, Average of 3 GCMs	No, not modelled	Water balance model	Population growth only; same across all countries	Hydro potential is residual after other demand met	Yes	13 sub-basins
Beck & Bernauer	Yes – population, urbanisation	Two: SRES A2, low precipitation and high precipitation scenarios	Three: (1) current (2) moderate and (3) high increases	Lumped Conceptual rainfall-runoff model; Water balance	Scenarios for irrigation demand and hydropower demand	Hydropower as priority	Compare to gridded sub-basin precipitation from CRU, discharge data; also demand	13 sub-basins

Study	Socio-economic scenarios	Climate Scenarios	Irrigation scenarios	Runoff modelling approach	Water demand assumption	Allocation	Calibration	Geography
Tilmant et al.	No	N/A – no climate changes	No	Historical inflows reconstructed with statistical techniques	Historical seasonal demand by sector, driven by area, pop, GDP	Optimisation based on geographically variable values of water by end use; scenarios for priority given to irrigation, power and e-flows		17 nodes (1 for Bot, Ang, Nam)
MSIOA	No	One: SRES A1B, midrange of 23 models (% chg from historic)	Two: identified projects and full potential	Historical inflows, balance requirements at each reservoir	Scenarios for irrigation and hydropower; other sectors do not vary (e- flows may)	Hydropower as residual, basic needs and minimum e-flows come first, then meet irrigation and other demand per scenario	No, no forecasts	13 sub-basins
Harrison et al.	No	Range: –20% to +20% precipitation; +4ºC	No	Water balance model and reservoir balance model	Used historical flows only	Hydropower is residual, but other demands do not change	Calibrated with Victoria Falls flows	Batoka Gorge only
Mukheibir	No	SRES A2 used in the research cited	No	N/A – only changes in precipitation	N/A	N/A	N/A	Entire basin

Note: For complete citation for studies, see the beginning of Section 2.2.

Table 3. Climate impact pathways considered by the studies reviewed

Study	Rainfall	Temperature impact on evapotranspiration	Temperature impact on reservoir evaporation	Temperature impact on wetlands demand
ECRIA	Yes	Yes	Yes	Yes
ZDSS	Yes	Yes	Yes	Yes
Yamba et al.	Yes	No	No	No
Beck & Bernauer	Yes	Yes	Yes	No
Tilmant et al.	No	No	No	No
MSIOA	Yes	Yes	Yes	No
Harrison et al	Yes	Yes	No	No
Mukheibir	Yes	No	No	No

Note: For complete citation for studies, see the beginning of Section 2.2.

Table 4. Key data sources in the studies reviewed

Study	Climate projections and scenarios (GCM models)	Climate data resolution (degrees)	Historical water and climate data	Irrigation demand	Industry demand	Scenario time frame	Population growth
ECRIA	SRES A1B, A2, B1, RCP4.5, RCP8.5	0.5 x 0.5 (50 x 50 km)	1948–2008	World Bank MSIOA	N/A	2010–2050	UN medium variant, allocated geographically by sub-basins
ZDSS	CRNM, ECHAM and IPSL from WATCH under SRES A2	0.5 x 0.5 (50 x 50 km)	1960–1990	World Bank	N/A	2020–2100	N/A
Yamba et al	SRES A2 CCCMA, CSIRO Mk2, HADCM3	3.75x3.68 5.61x3.14 (625 x 350 km) 3.75x2.5	1970–2000	N/A	N/A	2010–2070	UNEP SADC projections?
Beck and Bernauer	(1) HADCM3 lowest mean precipitation; (2) GFDL-CM2.0 higher mean precipitation (ClimateWizard)	0.5 x 0.5 (50 x 50km)		Denconsult 98; FAO, MacDonald 07	ZACPRO/ SADC, GDP growth + transfers	2050 vs 1990–2002	UN, allocated geographically; split rural vs urban
Tilmant et al.	N/A	N/A	10 years			N/A	
MSIOA	CRU TS 2.1, from IPCC SRES A1B	0.5 x 0.5 (50 x 50 km)	1962–2002	2 area scenarios; detailed crop water requirements	Specific projects	1962–2002, with different assumptions to simulate future	Not considered
Harrison et al.	+20% and –20% precip, both with +4ºC	N/A	New et al. (2000), CRU for climate; historic flow at Vic Falls	N/A	N/A	N/A	N/A
Mukheibir	UCT CSAG study used SRES A2 and regional climate models	CSAG study uses 0.5 x 0.5 (50 x 50 km)	UNEP Vital Climate Graphics	N/A	N/A	CSAG study is 2071-2100	N/A

Note: For complete citation for studies, see the beginning of Section 2.2.

Table 5. Hydropower projects examined in the studies reviewed

Study	Existing	Planned	Hydropower demand for water
ECRIA	All plants covered	Most new plant options listed in this thesis, except Kabompo, Kapichira II, Boroma, Lupata and Mpatamanga	Largely residual
ZDSS	Kafue Gorge, Itezhi-tezhi, Kariba, Cahora Bassa	Mainly Batoka and Mphanda Nkuwa	Only shows water availability – no demand
Yamba et al	Kafue Gorge, Itezhi-tezhi, Kariba, Cahora Bassa	Batoka, Mupata, Mphanda Nkuwa	Residual
Beck and Bernauer	Kariba, Kafue Gorge, Cahora Bassa, Vic Falls	Related to SAPP and SADC projections; limited treatment	SAPP 2007 estimates
Tilmant et al	Nkula/ Tedzani/ Kapichira, Kariba, Cahora Bassa, Kafue Gorge, Victoria Falls	Boroma, Mphanda Nkuwa, Itezhi-tezhi, Batoka Gorge	Based on water availability and planned capacity
MSIOA	All plants covered	Mphanda Nkuwa, Kafue Lower, Batoka N/S, Rumakali, Songwe I-III, Lower Fufu, Kholombizo, Itezhi-tezhi, plus extensions Kariba, Cahora Bassa, Kapichira	Not clear how system and plant demand determined
Harrison et al	N/A	Batoka Gorge	N/A
Mukheibir	Not specific plants	Not specific plants	N/A

Note: For complete citation for studies, see the beginning of Section 2.2.

2.4 Studies on regional electricity modelling in Southern Africa

Because this research aims to understand not only how climate change will affect specific hydropower plants but also how this will affect the dynamics of the regional power systems, other regional electricity modelling studies are also relevant, even though none have yet integrated climate change impacts into their analysis. Since the early days of SAPP, numerous studies have examined the outlook for power sector expansion in the region, as well as the potential benefits from increased trade and cooperation on regional projects, but without any consideration of climate change impacts (Alfstad 2005; Bowen, Sparrow, and Yu 1999; Economic Consulting Associates 2009; Nexant 2007; Rowlands 1998). More recently, two studies have looked in more detail at the role of renewable energy in the development of the SAPP system – the SADC Renewable Energy Strategy and Action Plan (RESAP) (CEEEZ 2012) and a study by the Energy Research Centre and the International Renewable Energy Agency (Miketa and Merven 2013). In addition, the SAPP Coordination Centre compiles the demand and supply forecasts from the national utility members and publishes this 10-to-15-year outlook each year, although without any further analysis (e.g. SAPP 2014, 2013). While these studies often provide detailed supply optimisation analysis, none of them include detailed bottom-up demand analysis. In fact, most of the studies either rely on utility estimates (which are rarely based on bottom-up analysis) or simply use a constant annual growth rate over the study period. In addition, the time frame for most studies is limited to 20 years, or even 10 years for the SAPP reports (CEEEZ 2012; Economic Consulting Associates 2009; Miketa and Merven 2013; Nexant 2007; SAPP 2014). Even the recent IRENA study, which extended the timeframe to 2050, simply used an extrapolation of earlier national growth rates for this longer period. The one additional study that did include bottom-up demand analysis up to 2030 (Merven, Davis, and Hughes 2010), did not include any supply analysis. A 20-year timeframe for analysis has two important limitations: first, the declining costs of renewable power alternatives may take several decades to tip the balance away from fossil fuel dependence in supply planning; second, the vulnerability of the hydropower plants to climate change may only be visible over 30–50 years (Spalding-Fecher et al. 2014; Stanzel and Kling 2014). A final important issue with earlier studies is that the underlying drivers of electricity demand, such as population growth, economic growth and the shifts in the structure of the economy, are generally not presented as internally consistent storylines or scenarios. This makes it difficult to compare the results, because the underlying visions of the future may be quite different from study to study, and this is not made explicit in those estimates.

2.5 Conclusions

This literature review highlights the climate change-related risks to hydropower in Southern Africa. More importantly, the review demonstrates the need for a more comprehensive analysis that combines the following elements, which were already highlighted in the thesis methodology in Chapter 1:

- Detailed bottom-up demand modelling for electricity and water, based on a set of plausible alternative development futures.
- Detailed water supply modelling based on a set of plausible alternative climate futures, considering all the relevant climate impact pathways on water availability.
- Explicit prioritisation of water demand sources based on the current situation in the region and the need to maintain reservoir storage levels.
- Detailed electricity supply modelling considering the full range of existing and planned hydropower plants in the ZRB, based on consultation with the national utilities and SAPP.
- Transparent calibration of both the water and electricity models to observed data.

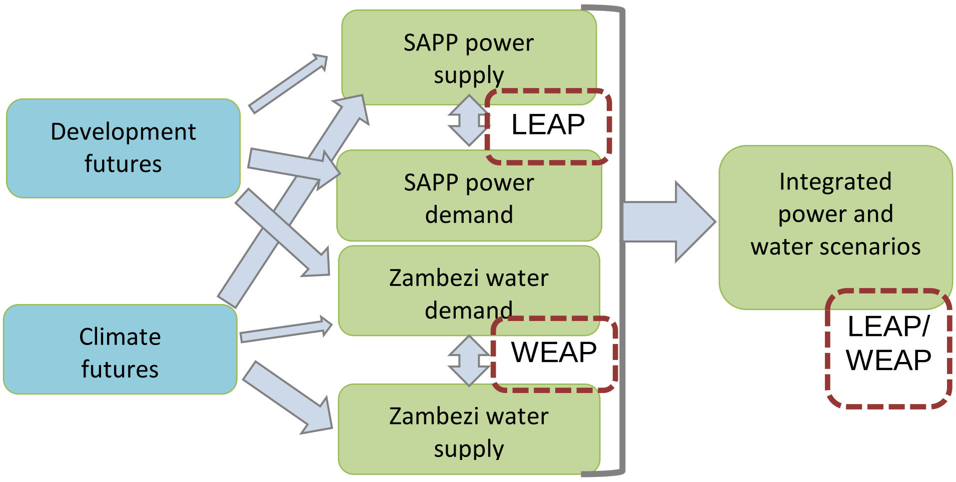
- Linking the electricity modelling to the water modelling, by deriving hydropower availability at major ZRB plants from the water modelling analysis under different climate futures, to provide integrated scenarios that systematically combine the alternative development and climate futures.

The next chapter introduces the climate and development futures that will be used for the water and electricity modelling and to develop the integrated scenarios.

3 Climate and development futures for water and electricity scenarios

One of the key challenges with evaluating the various energy and water analyses for Southern Africa in the literature is that studies often have very different underlying assumptions as well as different conceptual modelling approaches. To see a meaningful impact from different future climate projections, the analysis must be over a long enough period to see major climate change signals, which is why this thesis considers the period up to 2070 (in comparison with, for example, other SADC studies such as CEEEZ (2012)). When considering such a long time-frame, however, small differences in assumptions about economic and population growth can have dramatic impacts on the results. In addition, because climate impacts the water and energy sectors through multiple pathways, a consistent and comprehensive set of climate projections needs to be applied in both the water and energy analyses. This chapter presents the overall scenario approach used for both the water and energy modelling, and the common assumptions about economic growth, demographics, and climate futures that serve as input to all the later analysis.

Figure 4. Role of this chapter in overall methodology



3.1 Scenario approach

Given a long time frame (i.e. 2010–2070) of analysis, and the scientific and political uncertainties within the ZRB, this research utilises a scenario approach for the development and climate inputs to the modelling, as discussed briefly in Chapter 1. In classical scenario planning, the scenarios are essentially storylines about alternative possible futures, with an internally consistent set of assumptions for each alternative (Kahane 2000; Van der Heijden 1996; Kahane 1992; Shell 2001; Kahane 2012). The IPCC has pioneered the application of scenario planning to GHG emissions trajectories and the possible impacts of those emissions (IPCC 2000). More recently, the IPCC has developed a new approach to "shared socio-economic pathways" (SSPs), which will include qualitative and quantitative aspects of future development, including the policy responses to climate change (Arnell et al. 2011). The scenarios in this research combine socio-economic drivers and potential future climates to organise and explain different possible futures. The analysis can therefore illustrate the impacts of these different socio-economic and climate assumptions on energy and water in the Southern African region.

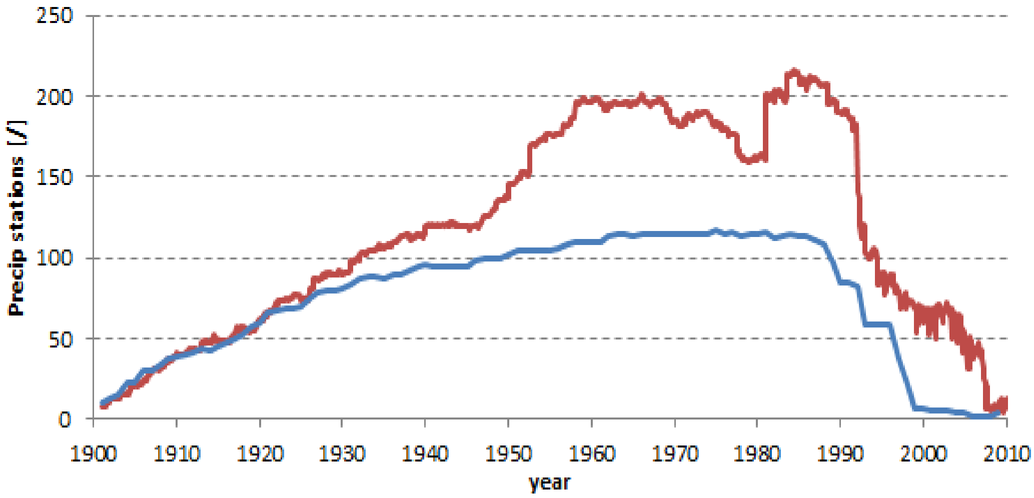
Scenarios are characterised by the elements of uncertainty that they incorporate. The first dimension of uncertainty that must be addressed by the scenarios is socio-economic development, which includes not only GDP and population growth, but also the level of investment in irrigation and hydropower. The developmental drivers, and their combinations into different development futures, are elaborated in Section 3 below. The second dimension of uncertainty is climate, and particularly how patterns of precipitation and temperature could change in the future within the region. The climate uncertainty is characterised by two possible futures that describe the range of projections by downscaled climate model data for the ZRB[9]. In particular, these alternative futures cover both decreases and increases in mean precipitation compared to the historical climate, as these are both plausible under IPCC scenarios. Note that, while many studies focused on future climate modelling or climate impacts use a large ensemble of models and scenarios to describe a range of future outcomes in statistical terms (e.g. mean, standard deviation and coefficient of variation across the entire ensemble), using a limited number of climate scenarios is necessary to create a meaningful set of integrated scenarios that overlay climate uncertainties with development uncertainties.

The current level of development and historical climate are key determinants of the current performance of the hydropower sector. While this actual historical production could serve as a baseline, to eliminate any model bias the baseline should be modelled using current development levels (e.g. current hydropower plant characteristics) with historical climate data. The modelled baseline can then be compared to the future scenarios to see the impacts of climate change and development trends without any bias from the model. The scenarios that overlay alternative climate futures on current development levels show the impact of climate change on its own, without any new demands from new hydropower plants or irrigation developments. Then, the scenarios that combine both climate futures with different rates of development show how these two drivers interact. We would expect the potential for conflict of water resources to be highest under a drying climate with rapid development, and the lowest conflict to be under a wetting climate with slower development, but this must be tested in the modelling. The modelling scenarios are the combination of climate and development futures, as explained in Chapter 1.

As mentioned earlier, because climate change only occurs over many decades, the timeframe for the analysis is from 2010 to 2070. For the water modelling, to calibrate the model, historical data from the 1960s to the present are used. Key water and climate data from 1961 to 1990 are used, because this period has the highest number of reporting weather stations in the ZRB, particularly in the Global Precipitation Climatology Centre (GPCC) dataset (see Figure 5).

[9] There are, of course, also uncertainties in the modelling of the hydrological systems that link future climate to projected available run-off in the river basin. The availability of accurate gauge data for long time periods and the density of precipitation monitoring stations in the region, for example, will affect the accuracy of this hydrological modelling. As discussed in Chapter 3, however, the hydrological modelling was outside the scope of the thesis and surface run-off simulations were sourced from other peer-reviewed modelling studies.

Figure 5. Number of reporting precipitation stations in GPCC (red line) and CRU (blue line) datasets for the Zambezi River Basin



Source: Kling et al. (2014)

3.2 Development futures

The context for the demand and supply models across the water and electricity sectors is the future economic and social development of the SADC countries, particularly those within the ZRB. Because both water and electricity demand are driven by inter-linked demographic and economic trends across all the continental SADC countries (i.e. excluding Madagascar, Mauritius and Seychelles), assessing future risks in the energy system requires a consistent set of assumptions about the economic and social development of the region across both water and electricity demand models. While these assumptions can be compared with other data on GDP or population projections in the literature (e.g. official projections, country-level research papers), realistic and consistent scenarios for the future should avoid using possibly conflicting assumptions from different sources. This section first presents a high-level description of the three development futures, and then elaborates on key parameters use in the modelling, and how these vary across the alternative futures.

For electricity demand, the main drivers are population and wealth, as well as electricity access and urbanisation. For water, the most important distinction in the development futures, however, is the speed and degree to which irrigation and hydropower investments are realised. This is because, for the ZRB, reservoir evaporation and irrigation currently consume 16% and 1.4% of total runoff, respectively, while domestic use is less than 0.1% of runoff (Euroconsult and Mott MacDonald 2007, Table 4.10) Conceptually, more rapid investment in irrigation and hydropower is correlated with stronger GDP growth and investment. The positive economic climate promotes more investment in these two infrastructure sectors, which then have strong “downstream” economic effects. This is why the earlier commissioning dates and higher GDP growth are associated with the futures with more rapid economic growth.

Each socio-economic future is described in broad terms in Box 1. Two of these futures are derived primarily from the work of research groups supporting the Intergovernmental Panel on Climate Change (IPCC) SSP development (O’Neill et al. 2014; Nakicenovic, Lempert, and Janetos 2014; van Vuuren and Carter 2014). As explained by Nakicenovic, Lempert, and Janetos (2014):

> The concept of SSPs [has] emerged to identify, quantify (to the extent possible), and analyze sets of assumptions about ways in which societies may evolve, independently of their decisions about climate change policies. As such the SSPs constitute multiple

baseline pathways, which can be combined with studies specifically about climate related policies, both mitigation and adaptation, for new insights into the sensitivity of strategies to underlying socioeconomic trends, as well as to study the interactions of mitigation and adaptation strategies.

SSPs essentially provide the underlying development futures against which climate policy interventions and future climate change impacts are assessed within the framework of the IPCC and the broader scientific community supporting these assessments.

A third source of forecasts for developing these alternative futures is International Futures (IFs) (Chapman 2012; Hughes et al. 2009; International Futures 2014), which is “a large-scale, long-term, integrated global modelling system. It represents demographic, economic, energy, agricultural, socio-political, and environmental subsystems for 183 countries interacting in the global system”. As Hughes et al. (2009) report, “IFs uses a general equilibrium structure for its 6-sector economic module. IFs is useful for modelling stocks and flows of elements such as goods and services, money, human well-being, environmental conditions, materials status, and knowledge. IFs also has functions for many non-market socio-economic interactions.” IFs has a standard embedded scenario known as the Base Case that has been developed using extensive data from United Nations and other official international and peer-reviewed sources. The Base Case contains mid-range projections using standard international data, and essentially simulates a continuation of status quo trends. It is a “scenario portraying a reasonable dynamic evolution of current patterns and trends”, or a central tendency scenario (Hughes et al. 2009). Two other scenarios that were considered for use with IFs from which to develop forecasts include the “African Renaissance” scenario (see Cilliers, Hughes, and Moyer 2011), which is quite optimistic, with greater investment in development, increased international trade, improved productivity across almost all sectors, and increased foreign direct investment in Africa. The result of these changes is to accelerate economic and social development and reduce population growth. The Arrested Development scenario from the same source models a positive African economic, social and governance environment within a negative global economic climate but at a slower growth rate. All of these three scenarios are already incorporated into the IFs modelling system (International Futures 2014).

Box 1. Qualitative description of development futures

"Business as Usual" (BAU) is a continuation of current and recent historical trends in the region without major policy changes or major changes in the external (global) environment. This is not the same as remaining at the current level of development, because economic and social development would continue to improve over time, but only at the rates typical either currently or in recent decades in Southern Africa. Resource development (e.g. mining, oil production) would be limited by lack of access to capital and by poor governance and policy environments. In addition, limited capital for exploration means that newly discovered resources are not able to replace current dwindling reserves. Technology development would also be slow, including increases in energy efficiency, as would trade within the region relatively limited. Electricity sector integration in the region would improve only slowly, with continued delays in major investments for power generation, transmission, and irrigation development, as has been the case in recent years. Population growth would be higher than in other scenarios, because of the lower rate of GDP per capita growth, given that higher economic and social development generally reduces total fertility. This future is analogous to the IPCC Share Socioeconomic Pathway SSP2 (Middle of the Road or Current Trends Continue). This scenario has the lowest economic growth rates and highest population growth rate of the three.

"SADC Integration" (SADC Int) describes a future where the region takes the initiative to move forward more rapidly on the development of shared resources – particularly in the energy sector – even without major changes in the external (global environment). The bottlenecks to major regional projects are removed through stronger political cooperation and joint financing of major infrastructure investments that benefit multiple countries. This leads to more rapid economic growth and development of key economic sectors. This still takes place, however, in a global environment that has not made major shifts to a low-carbon economy or a comprehensive North-South partnership for development. This means that capital flows to the region are still a constraint to economic development, even though a more positive political climate can facilitate more rapid project implementation. Resource development outside of the energy sector is more rapid than in BAU, but still constrained. The economic development envisioned here is derived from the IFs' model "Base Case", which, although the name implies moderate "baseline" growth, in fact includes relatively rapid economic development for the region (International Futures, 2014).

In contrast to the first two futures, which assume no major changes in global trends, **"Grand Deal" (GD)** is a characterised by a significant global commitment to sustainable development, which further supports region efforts at integration and shared development. The global commitment includes keeping mean global temperatures increases below 2°C above pre-industrial levels, as well as providing universal access to modern energy services. Rapidly falling clean technology prices (for energy efficiency as well as renewable energy supply) and mobilisation of climate finance leads to both greater investment in low carbon development but also more rapid growth in economic and human development in SADC. At the same time, short to medium term inflows of capita allows for greater resource exploration and development, albeit with higher efficiency in mining and beneficiation of basic resources. The future therefore includes the lowest population growth, and highest economic growth, and more rapid investment. This future is analogous to the IPCC Shared Socioeconomic Pathway SSP1.

The most important distinction in the development futures is the degree to which irrigation and hydropower investments are realised. For hydropower, the development futures include different timeframes for constructing the potential hydropower plants. For irrigation, the difference in the development scenarios will be the year in which the "identified irrigation projects" and "high level potential irrigation", as defined in the Zambezi MSIOA study, will be reached (see Table 6). Conceptually, this means that more rapid investment in irrigation and hydropower is a result of stronger GDP growth and investment. The positive economic climate promotes more investment in these two infrastructure sectors. This is why the earlier commissioning dates and higher GDP growth are associated with the higher growth futures.

Table 6. Summary of development futures

	BAU	SADC Int	GD
GDP per capita growth	Low	Medium	High
Population growth	Highest	Lower	Lowest
Hydropower and irrigation investment	Slower	Faster	Much faster
Other clean energy investment	Limited	Some	Rapid
Investment in energy-intensive industry	Current trends	Faster	Faster, but with better technology
Regional trade	Limited	Large	Large
Grand Inga	Much later	Later	Soon
Technology learning for renewable energy	Moderate	Moderate	Fast
Improvement in industrial energy intensity	None	Moderate	Fast

The following sub-sections elaborate on the more details assumptions on economic growth, demographic changes, and investment in hydropower and irrigation.

3.2.1 *Economic development*

Current GDP per capita in the region varies widely, as shown in Table 7. The per capita income for the World Bank country classifications is the average income of that group, not the minimum.[10] In 2010, only Botswana had per capita income (measured using purchasing power parity exchange rates) above the average of upper middle income countries, while Angola, Namibia, South Africa, and Swaziland were above the average of lower-middle-income countries.

[10] In 2014, the minimum income for Lower middle, upper middle and high income country groups was $1,045, $4,125 and $12,746, in current dollars using the Atlas method of exchange rates (i.e. a rolling average market exchange rates).

Table 7. GDP per capita in SAPP, with PPP and MER exchange rates ($2011)

	PPP			MER		
Country	**1990**	**2010**	**CAGR (%)**	**1990**	**2010**	**CAGR (%)**
Angola	4,232	7,047	1.7	1,736	2,891	2.6
Botswana	8,056	13,286	1.7	4,185	6,902	2.5
Congo, Dem. Rep.	1,269	632	-2.3	334	170	-3.3
Lesotho	1,307	2,229	1.8	573	986	2.8
Malawi	636	737	0.5	212	246	0.7
Mozambique	434	885	2.4	210	427	3.6
Namibia	5,758	8,394	1.3	2,998	4,583	2.1
South Africa	9,935	11,862	0.6	5,447	6,500	0.9
Swaziland	5,372	6,512	0.6	2,263	2,743	1.0
Tanzania	1,001	1,501	1.9	328	492	2.0
Zambia	2,537	2,779	0.3	759	832	0.5
Zimbabwe	2,532	1,484	-1.8	761	439	-2.7
Low-income	1,095	1,487		324	441	
Lower-middle-income	2,910	5,286		722	1,284	
Upper-middle-income	4,916	11,474		1,979	4,395	
Upper-income	27,403	37,514		25,463	34,455	

Notes: CAGR = compound annual growth rate; PPP = purchasing power parity; MER = market exchange rates. The values for MER per capita income have been converted from $2005 to $2011 using a USA GDP deflator (BEA 2014). The PPP exchange rates are based on the 2011 International Comparisons Project (ICP).
Source: World Bank (2014), World Development Indicators

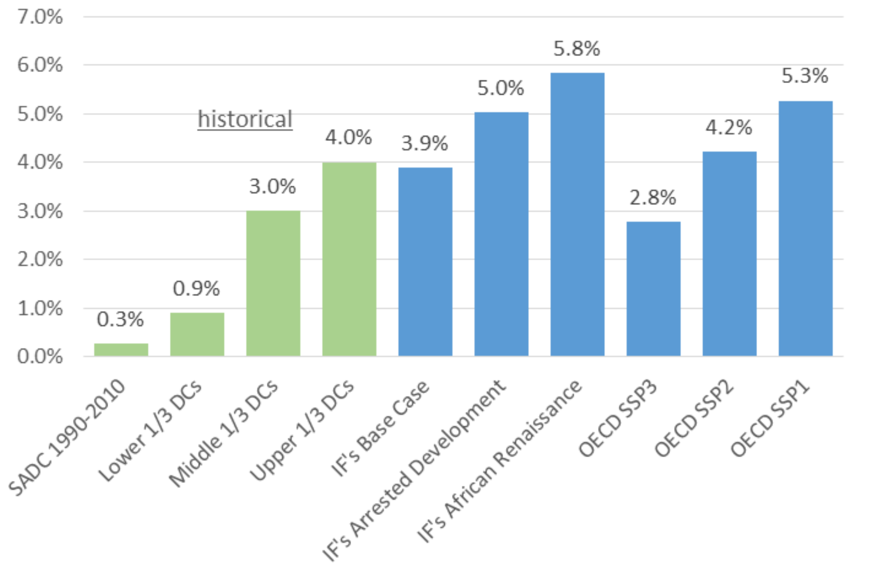
As Figure 6 shows, historical growth in GDP per capita across the region, measured in purchasing power parity (GDP_{PPP}) has been very low, at only 0.3% from 1990 to 2010 when weighted by population. This is even lower than the average for the poorest performing developing countries between 1970 and 2010 elsewhere in the world, according to the World Developing Indicators data (World Bank 2014). The middle- and highest-performing groups of developing countries achieved 3% and 4%, respectively, by comparison. We use PPP in preference to market exchange rates because we are not measuring financial flows or frequently traded products, which would indicate the use of market exchange rates, but a comparison of many other economic variables and non-traded goods.[11]

The IFs Base Case scenario is quite optimistic, with GDP per capita above those of the best performing developing countries historically (based on results from IFs version 7.03)(International Futures 2014). However, the OECD SSP scenarios (Dellink et al. 2015) also include much higher growth rates for SADC than recent history, and include very optimistic outlooks in terms of growth rates. We provide the two other IFs scenarios, “Arrested Development” and “African Renaissance” (see Cilliers, Hughes, and Moyer 2011), by way of comparison. This is not taken further, however, as it appears less plausible than the IFs Base Case and the respective OECD SSP1 and SSP3 scenarios (see Figure 1). The advantage of both of these modelling groups (IFs and OECD) over using simple growth rate extrapolations for the region (e.g. 2%, 3%, and 4%), is that these dynamic models provide an annual time series for each of the SAPP countries and, more importantly, internal model feedbacks that

[11] Argument based in part on an IMF document at http://www.imf.org/external/pubs/ft/fandd/2007/03/basics.htm.

regulate the growth rates of populations and economies through the effects of wealth accumulation and other effects – providing non-linear outputs from a dynamic simulation.

Figure 6. Real GDP PPP per capita compound annual growth (%), (2010–2070 for all projections)



Note: Growth in GDP per capita is based on GDP measured in purchasing power parity ($2011 international dollars) divided by population in the relevant years, so the growth rates are real growth, as opposed to nominal growth. SADC 1990–2010 is the weighted average for 12 continental SADC countries from 1990 to 2010; “DCs” are a group of 72 developing countries (excluding China) with data for GDP per capita in 1970 and 2010 in the World Development Indicators database, with the weighted average (by population) income growth of the lowest, middle and highest performing thirds of that group.
Sources: Dellink et al. (2015), International Futures (2014), World Bank (2014), and author’s analysis

To match the overall scenario storylines in the development futures outlined in the previous section to forecasts, BAU is represented by the SSP3 projections from the OECD, SADC Integration in represented by the IFs Base Case, and the Grand Deal is represented by the SSP1 modelling from the OECD. The Arrested Development and African Renaissance forecasts (see Cilliers, Hughes, and Moyer 2011), while informative, were dropped from the set of chosen forecasts. Unconstrained growth of 5.0–5.8% per year for 60 years is highly unlikely, given historical compound annual growth rates from a minimum of –2.3% to the maximum of +2.4% from 1990 to 2010, with a median near 1%. The high growth scenario, Grand Deal, is represented by the OECD SSP1 with a GDP PPP compound annual growth rate of 5.3%, the upper-bound forecast (Figure 6). The lower-bound BAU scenario is represented by the OECD SSP3 forecast.

The resulting GDP PPP per capita in 2070, as well as the current average GDP per capita of the World Bank country classification groups “high-income” and “upper-middle-income”, are shown in Table 8. In the Grand Deal future, nine of the countries would have GDP per capita in 2070 that is greater than the global average of high-income countries today. Of course, high-income country economies would also grow over this period and might be two or three times their current levels. Nevertheless, this comparison provides a “mental picture” of how these SAPP countries could look in 60 years. In the SADC Integration forecast, only three countries are above the average level of current high incomes countries, while four more are above the average current upper-income countries (as opposed to the current situation in Southern Africa, with only one country above the average of upper-middle income and none above high income – see Table 7). Total GDP is shown in Table 9. Note that, because the socio-economic assumptions are taken from other peer-reviewed scenario analyses, rather than being simply based on different compound annual growth rates, they are not necessarily in the same order in each individual year for each country. In other words, the ranking of scenarios and countries (e.g. by GDP) may not be exactly the same in each time period, because the complex systems models generating the socio-economic scenarios have their own internal dynamics and assumptions about the interactions between social, economic and environmental drivers. As an example, in Table 8 below South Africa's 2030 GDP in the SADC Int scenario is actually lower than in the BAU scenario, even though by 2070 the GDP in the SADC Int is higher than for the BAU scenario.

Table 8. GDP per capita assumptions by scenario ($2011 at PPP)

	Current	2030			2070		
Country	**2010**	**BAU**	**SADC Int**	**Grand Deal**	**BAU**	**SADC Int**	**Grand Deal**
Angola	7,047	8,806	14,903	10,215	8,230	49,685	35,689
Botswana	13,642	21,320	27,661	28,682	34,088	62,686	66,465
DRC	632	2,907	1,189	2,689	7,662	6,578	46,599
Lesotho	2,235	2,440	4,109	5,218	11,581	15,509	49,470
Malawi	737	1,448	1,122	1,706	3,497	4,843	20,842
Mozambique	930	819	2,490	2,893	5,192	24,017	34,301
Namibia	8,433	13,430	14,176	16,845	25,466	33,716	54,333
South Africa	12,087	20,971	17,461	21,494	28,893	49,726	55,703
Swaziland	5,862	11,967	7,052	9,002	14,030	15,224	47,902
Tanzania	2,081	3,618	4,304	5,557	10,664	36,390	46,978
Zambia	3,451	6,124	7,980	9,152	17,899	52,347	77,997
Zimbabwe	1,484	7,058	3,164	3,923	15,319	14,339	62,674
Upper income	39,149						
Upper-mid income	11,080						

Note: PPP = purchasing power parity.

Table 9. GDP assumptions by scenario (billion $2011 at PPP)

Country	Current 2010	2030 BAU	2030 SADC Int	2030 Grand Deal	2070 BAU	2070 SADC Int	2070 Grand Deal
Angola	138	295	531	319	545	3,535	1,593
Botswana	27	57	66	66	86	174	166
DRC	39	198	125	260	1,453	1,307	6,422
Lesotho	4	10	10	12	32	46	112
Malawi	11	34	29	42	250	238	842
Mozambique	22	77	98	98	305	1,621	1,442
Namibia	18	42	43	47	99	134	168
South Africa	614	1,132	1,004	1,314	1,985	3,213	3,528
Swaziland	7	10	11	13	25	33	74
Tanzania	94	328	332	386	1,744	5,069	4,533
Zambia	46	162	180	189	954	2,003	2,358
Zimbabwe	19	50	61	60	321	356	814
Total	1,040	2,395	2,490	2,806	7,798	17,730	22,050

Notes: PPP = purchasing power parity. Future GDP projections are normalised to historical data so that all scenarios have the same starting point (e.g. if one source reports 2010 population for Angola of 20.0 million, then the 2030 projections are multiplied by 0.975 (19.5/20.0)). In addition, values originally reported in $2005 are converted to $2011 by multiplying by 1.12, based on USA GDP deflators.

Source: 2010 to 2014 = World Bank (2014); BAU = OECD Env-Growth analysis of SSP3 (IIASA 2012a; Dellink et al. 2015); SADC Integration = IFs Base Case (International Futures 2014), Grand Deal = OECD Env-Growth analysis of SSP1 (IIASA 2012a; Dellink et al. 2015); GDP deflators = US Bureau of Economic Analysis (2015)

The sectoral share of GDP is also an important means of more accurately relating GDP to energy demands, through decomposition, thereby improving the description of the factors driving energy intensity within an economy. Two countries sharing the same GDP might have very different energy demands because the structures of their economies may substantially differ. For example, one economy may be dominated by the manufacturing and extractive sectors and another by the services sector. Energy demands in each are likely to be very different when compared on a $GDP/kWh basis. The current sectoral shares are shown in Table 10. For future sectoral share, only the IFs model provides this – so we use the IFs Base Case (i.e. SADC Integration scenario for GDP growth) as the assumptions for future share (Table 10).

Table 10. Sectoral share of GDP assumptions (% total GDP)

Country	2010				2070			
	Agri-culture	Manu-facturing	Extrac-tive	Service	Agri-culture	Manu-facturing	Extrac-tive	Service
Angola	10	6	54	30	0.1	11	24	65
Botswana	3	7	34	57	1	14	14	71
DRC	46	5	18	32	2	13	47	39
Lesotho	10	13	18	59	1	21	10	67
Malawi	30	12	8	50	2	25	14	59
Mozambique	30	14	9	47	1	22	20	58
Namibia	8	14	16	63	1	9	19	71
South Africa	3	14	9	68	0.4	17	19	63
Swaziland	8	46	4	42	4	40	11	45
Tanzania	28	10	15	47	1	15	26	58
Zambia	13	24	10	53	1	12	33	54
Zimbabwe	18	18	17	47	3	25	22	50

Note: the same sectoral share is used for all scenarios in 2070.
Source: Current = World Bank (2014), except Zambia (Central Statistics Office 2010), 2070 = IFs Base Case (International Futures 2014)

3.2.2 *Population*

For the energy model, population is the primary driver of residential energy consumption, and also influences transportation demand (Price et al. 1998; Raupach et al. 2007; Wolde-Rufael 2005). For the water model, only urban population projections are used, because rural domestic water demand is very small compared to other major demands (e.g. irrigation). Urban demand growth rates are estimated from national growth rates and urbanisation trends. Current population and growth rates over the last 50 years are shown in Table 11.

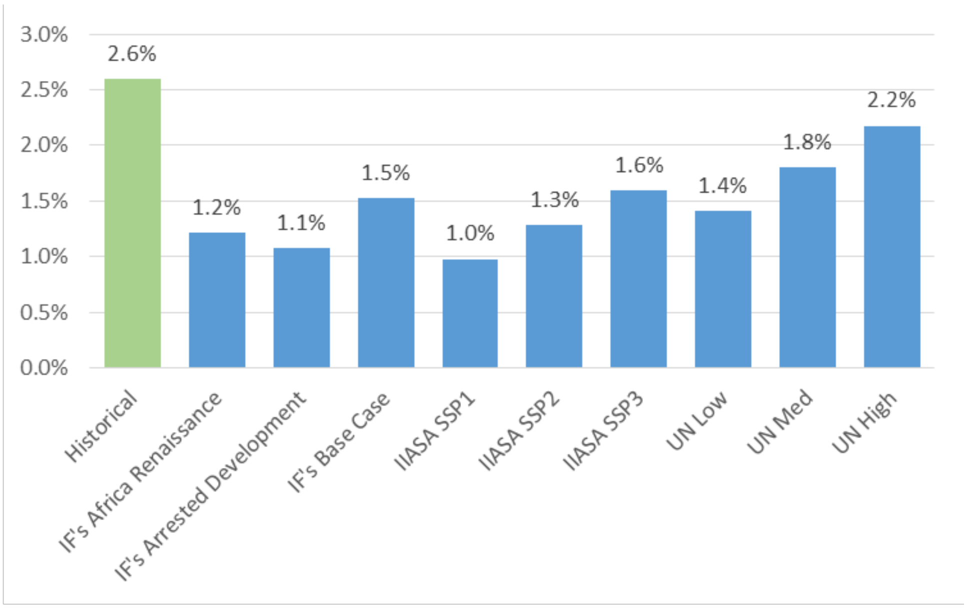
Table 11. Historical and current population (million)

Country	1960	2010	CAGR
Angola	5.0	19.5	2.8%
Botswana	0.5	2.0	2.7%
Congo, Dem. Rep.	15.2	62.2	2.9%
Lesotho	0.9	2.0	1.7%
Malawi	3.5	15.0	2.9%
Mozambique	7.6	24.0	2.3%
Namibia	0.6	2.2	2.6%
South Africa	17.4	50.0	2.1%
Swaziland	0.3	1.2	2.5%
Tanzania	10.1	45.0	3.0%
Zambia	3.1	13.2	3.0%
Zimbabwe	3.8	13.1	2.5%

Source: World Bank (2014)

The three sources of population projections include the IFs model, a set of IIASA scenarios for the IPCC SSPs, and the UN population forecasts for low, medium and high fertility (UNDESA 2012a). All of the projections are for much lower growth rates than in the historical period (see Figure 7), because of the inverse relationship between increasing incomes and decreasing population growth rates. The SSP1 and SSP3 analysis by IIASA provide a reasonable range, albeit with lower growth rates than the highest UN projections. The IFs Base Case includes projected population growth similar to the SSP3 analysis. For consistency with the GDP per capita assumptions, the BAU scenario is represented by the SSP3 projections, SADC Integration by the IFs Base Case, and Grand Deal by SSP1.

Figure 7. Compound annual population growth rates (2010–2070) for SADC overall from various sources, compared to historical growth



Note: historical period is 1960–2010.
Sources: World Bank (2014), IIASA (2012a), KC and Lutz (2014), UNDESA (2012a)

Because population growth is inversely correlated with economic growth and human development, the growth rates are lowest in the Grand Deal scenario, as shown in Table 12. Note that for some countries population in the SADC Integration scenario is somewhat higher than the BAU scenario. This is because the IFs Base Case (the source for this scenario), while projecting *total* population for the region between the BAU and Grand Deal scenarios, includes different dynamics for particular countries, so some may show higher population, while others show lower in comparison to the BAU scenario.

Table 12. Population assumptions by scenario (million people)

Country	Current 2010	2030 BAU	2030 SADC Int	2030 Grand Deal	2070 BAU	2070 SADC Int	2070 Grand Deal
Angola	19.5	34.5	35.6	31.2	66.2	71.1	44.6
Botswana	2.0	2.2	2.4	2.3	2.5	2.8	2.5
DRC	62.2	105.4	105.0	96.7	189.6	198.7	137.8
Lesotho	2.0	2.4	2.5	2.3	2.8	3.0	2.3
Malawi	15.0	27.5	25.9	24.6	71.6	49.2	40.4
Mozambique	24.0	36.5	39.4	33.8	58.7	67.5	42.0
Namibia	2.2	2.9	3.0	2.8	3.9	4.0	3.1
South Africa	50.8	59.8	57.5	61.1	68.7	64.6	63.3
Swaziland	1.2	1.5	1.6	1.5	1.8	2.2	1.5
Tanzania	45.0	78.8	77.1	69.4	163.5	139.3	96.5
Zambia	13.2	24.0	22.6	20.7	53.3	38.3	30.2
Zimbabwe	13.1	17.1	19.4	15.3	21.0	24.8	13.0
Total	250.1	392.7	392.0	361.7	703.5	665.5	477.3

Note: future population projections are normalised to the historical data so that all scenarios have the same starting point (e.g. if one source reports 2010 population for Angola of 20.0 million, then the 2030 projections are multiplied by 0.975 (19.5/20.0)).
Source: Current = (World Bank 2014); BAU = IIASA WiC v9 analysis of SSP3 (IIASA 2012a; KC and Lutz 2014); SADC Integration = IFs Base Case (International Futures 2014); Grand Deal = IIASA WiC v9 analysis of SSP1 (IIASA 2012a; KC and Lutz 2014);

The household size assumptions shown in Table 13 are used to convert from total population to number of households in urban and rural areas. This is necessary because residential electricity consumption is estimated per household rather than per capita.

Table 13. Household size assumptions

Country	Rural	Urban
Angola	4.3	5.1
Botswana	4.5	3.9
DRC	4.5	4.6
Lesotho	4.4	4.4
Malawi	4.5	4.6
Mozambique	4.4	4.4
Namibia	5.6	4.1
South Africa	4.2	3.3
Swaziland	5.2	3.2
Tanzania	5.1	4.3
Zambia	5.3	5.1
Zimbabwe	4.3	4.3

Source: IIASA (2012b), Central Statistics Office (2010); Euromonitor International (2013)

3.2.3 *Urbanisation*

Because residential energy consumption and the mix of fuels used vary significantly between urban and rural areas, the level of urbanisation is a key driver of residential energy demand. It also influences urban water demand, which is driven by total urban population. Both IFs and a set of scenarios from National Center for Atmospheric Research (IIASA 2012a; L. Jiang 2014; L. Jiang and O'Neill 2015) for the SSPs provide urbanisation levels, so that these can be matched to the same scenarios as in the GDP forecasts. The same matching process is used, where the IFs Base Case is used for the SADC Integration scenario, the analysis for IPCC SSP1 is used for Grand Deal, and SSP3 is used for Business as Usual. This provides internal consistency across the drivers, scenarios and forecasts. The current and future urbanisation levels are shown in Figure 4. In all cases, the UN urbanisation prospects projections for 2050 (UNDESA 2012b) fall between the lowest and highest values used in our development futures, suggesting that this is a reasonable "envelope" of future possibilities to investigate. The share of population living in urban areas is shown in Table 14 for each scenario.

Table 14: Percentage of households in urban areas (%)

		2030			2070		
Country	**2010**	**BAU**	**SADC Int**	**Grand Deal**	**BAU**	**SADC Int**	**Grand Deal**
Angola	58.5	63.7	72.5	73.7	69.2	88.1	92.4
Botswana	61.1	65.9	75.8	75.4	68.8	87.2	91.7
DRC	35.2	37.2	49.0	54.9	42.6	71.1	81.2
Lesotho	26.9	31.6	42.8	51.6	41.3	69.5	84.0
Malawi	19.8	23.9	23.8	36.5	31.6	40.3	72.6
Mozambique	38.4	44.5	41.5	60.4	51.9	56.4	83.3
Namibia	38.0	41.6	50.3	56.7	47.4	71.1	81.0
South Africa	61.7	65.2	78.0	75.2	69.2	89.1	91.4
Swaziland	21.4	25.8	19.7	40.0	34.6	19.4	71.6
Tanzania	26.4	29.3	37.2	45.4	37.2	64.4	76.5
Zambia	35.7	38.9	40.3	55.3	45.4	55.1	81.6
Zimbabwe	38.3	40.8	37.3	55.9	46.0	44.5	79.9

Source: for 2010, BAU and Grand Deal, source is L. Jiang and O'Neill (2015); for SADC Int, source is IFs Base Case (International Futures 2014)

3.2.4 *Irrigation investment*

The MSIOA addressed irrigation expansion with two different irrigation levels (roughly in 2025), one based on "identified projects" in national plans and the other on "high level" irrigation potential (i.e. closer to maximum theoretical potential). The advantage of using the same future irrigation projections is that the MSIOA study contains detailed analysis of irrigation area by sub-basin and crop for each level. Given the long time-frame for this analysis, the question is *when* these levels of irrigation will be reached, rather than *whether* they will be reached. Table 15 shows the years where each level of irrigation expansion is reached in the different development futures.

Table 15. Irrigation expansion in each development future

Development future	BAU	SADC Int	Grand Deal
Year when "identified projects" have been realised	2030	2025	2020
Year when "high level" irrigation potential has been realised	2060	2050	2040

3.2.5 *Hydropower investment*

For hydropower infrastructure development, the scenarios include different timeframes for constructing the potential hydropower plants. Because the Grand Deal scenario is the one with the greatest inflow of investment to the region, and greatest capital availability, this is the scenario with the most optimistic commissioning dates. Given the continued delays in most major projects, the start dates reported in the SAPP expansion plans and periodic SAPP updates are considered the most optimistic. For the SADC Integration and BAU scenarios, the commissioning dates are delayed by four and seven years, respectively. The exception is plants with an optimistic start date of 2015 or 2016, where the delays are then two and four years in the two scenarios.

Examples of dates and capacity for new plants are shown in Table 16 below, while the detailed technical characteristics for these plants will be presented in the main electricity modelling report.

Table 16. Examples of hydropower expansion in each development future[12]

Plant	Capacity (MW)	Year of commissioning in each development future		
		BAU	SADC Int	Grand Deal
Cahora Bassa North	1,245	2019	2017	2015
Mphanda Nkuwa I	1,500	2029	2026	2022
Kariba South Extension	300	2025	2022	2018
Kafue Gorge Lower	750	2026	2023	2019
Devil's Gorge	1,000	2033	2030	2026
Batoka Gorge	1,600	2030	2027	2023
Boroma	200	2029	2026	2022
Lupata	600	2028	2025	2021

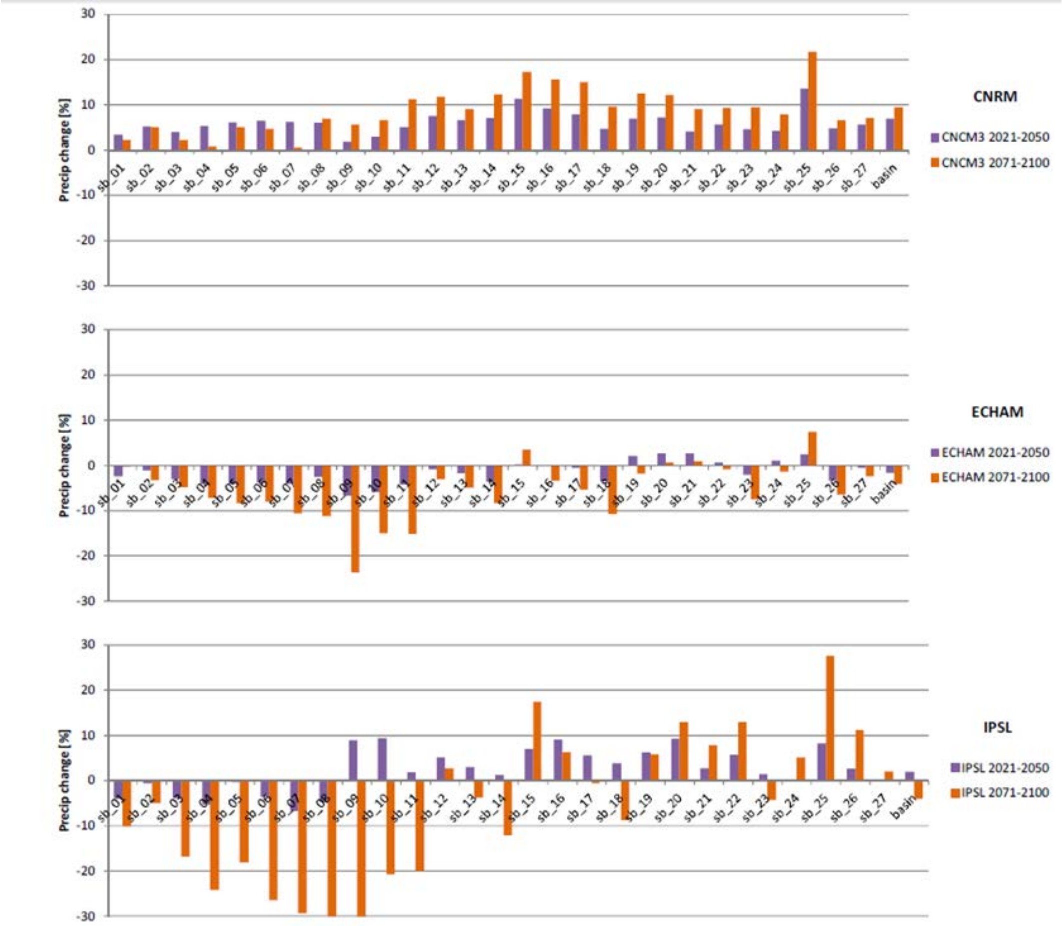
3.3 Climate futures

The development futures having been considered in detail, this section turns to climate futures. In contrast to the previous sections, however, the climate futures were drawn entirely from an external source, as explained in this section. For the climate futures, two criteria are important for this analysis. First, the climate futures should illustrate both possible overall wetting and drying trends in the ZRB. Second, where possible, these futures should use data similar to that in the major studies already undertaken in the Basin. This is to allow for comparison with the results from earlier studies and to build on the stakeholder engagement that already occurred for previous studies. A significant advantage of the downscaled-global circulation

[12] Note that all these commissioning dates were in the future at the time this analysis was conducted during the thesis research process.

model WATCH dataset is that no further bias correction is required, because it has been used in previous studies in the region. The WATCH (Water and Global Change)[13] climate dataset includes the statistically downscaled results of three different GCMs, which span the range of wetting to drying in the ZRB (see Figure 8). For this reason, the CNRM[14] results are used to represent the "wetting" scenario, while the ECHAM[15] results are used for the "drying" scenario. The mid-range IPSL[16] results were not used. The sub-basin numbers shown in the figure are the same as in the water supply model (see Chapter 4), moving roughly from upstream to downstream in the basin.

Figure 8. Change in annual precipitation (compared to the 1961–90 mean) of different sub-basins projected by the GCMs of WATCH.



Source: Kling and Preishuber (2012)

---

[13] The Integrated Project Water and Global Change (WATCH, 2007–2011), funded under the EU FP6, brought together the hydrological, water resources and climate communities to analyse, quantified and predicted the components of the current and future global water cycles and related water resources states, evaluated their uncertainties ,and clarified the overall vulnerability of global water resources related to the main societal and economic sectors (http://www.eu-watch.org/).

[14] CNRM-CM3 global coupled system is the third version of the ocean-atmosphere model initially developed at CERFACS (Toulouse, France), then regularly updated at Center for National Weather Research (CNRM, METEO-FRANCE, Toulouse) (http://www.cnrm.meteo.fr/scenario2004/references_eng.html).

[15] ECHAM is a comprehensive general circulation model of the atmosphere from the Max Planck Institute for Meteorology. The ECHAM GCM has its original roots in global forecast models developed at ECMWF. This model has been modified for climate research, and its development continued to the current cycle ECHAM5 http://www.mpimet.mpg.de/en/wissenschaft/modelle/echam.html).

[16] IPSL is a climate model from the Institut Pierre Simon Laplace https://www.ipsl.fr/en/content/view/full/886

3.4 Conclusions

The development and climate futures presented here underpin the inputs to the water and electricity modelling presented in the following two chapters. The next chapter presents the ZRB water supply and demand modelling, while Chapter 5 presents the SAPP electricity modelling.

4 Water supply and demand scenarios[17]

This chapter presents the water supply and demand modelling that is the first major component of the integrated climate-water-energy analysis. To answer the first research question (How could future climate and irrigation expansion in the ZRB affect hydropower generation potential?) requires a detailed understanding of the drivers of water supply and demand in the basin, and a water balance modelling framework that can incorporate both supply- and demand-side effects (Figure 9).

Figure 9. Role of this chapter in overall methodology

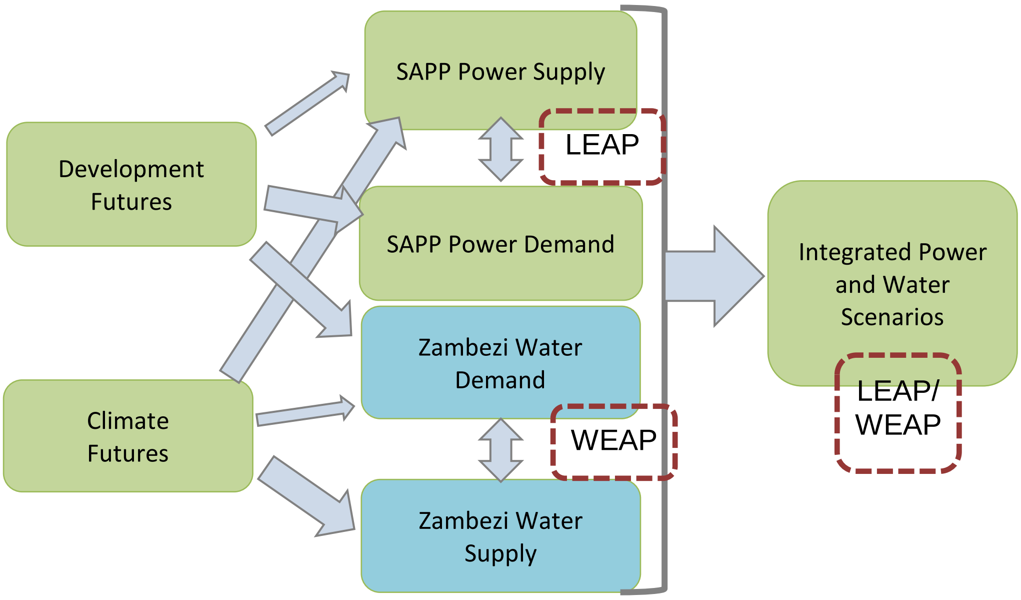
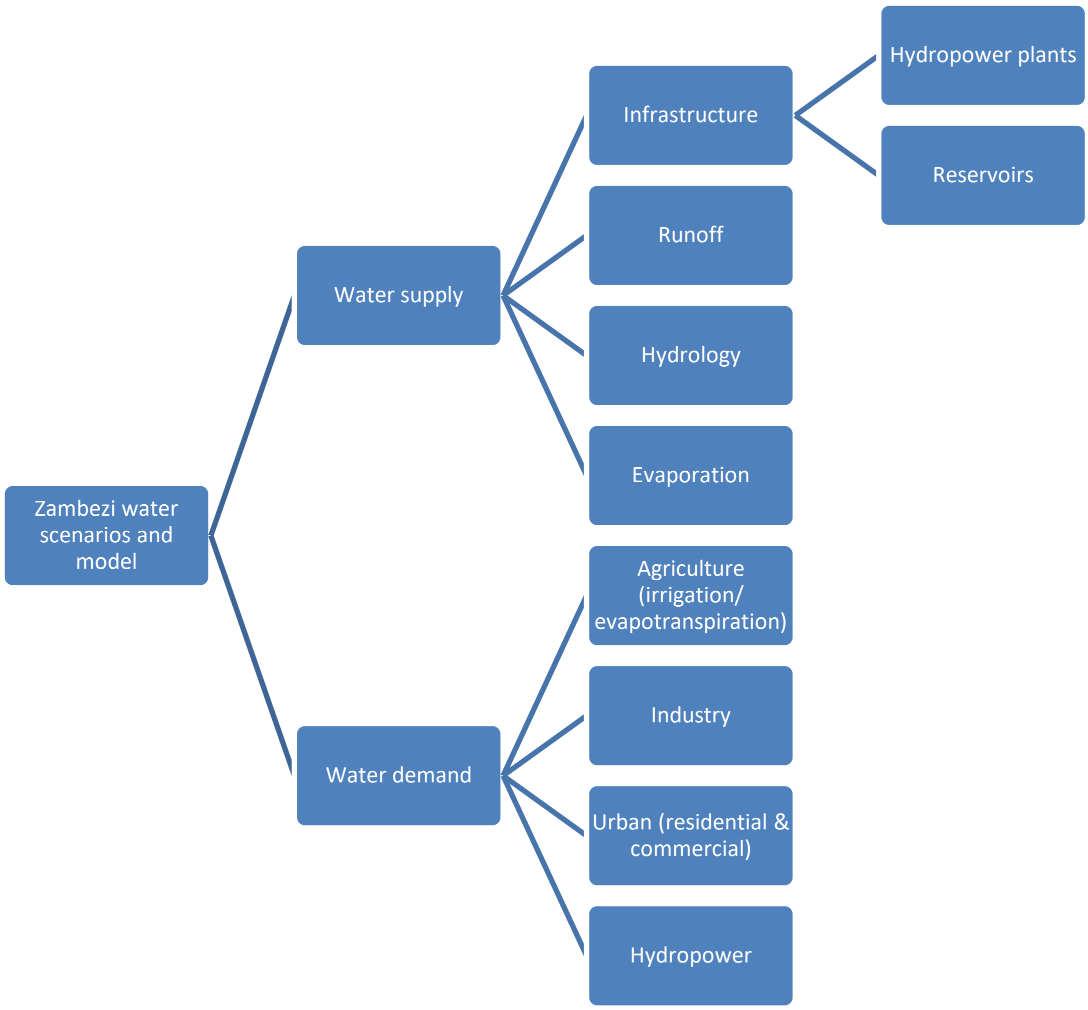


Figure 10 presents the methodological elements required specifically for modelling water supply and demand scenarios for the ZRB.

These elements are each addressed in Sections 4.1 and 4.2, following an introduction to the modelling approach. Section 4.3 demonstrates the validity of the model through the calibration analysis. Section 4.4 then presents the results of the modelling for each of the major hydropower plants, based on the scenarios outlined earlier, and is followed by conclusions on water supply and demand in Section 4.5.

[17] As discussed in section 1.5, this section draws upon the analysis also presented in Spalding-Fecher et al. (2014)

Figure 10. Water scenario inputs and results



4.1 Water supply model

4.1.1 *Hydrological features*

The supply model includes all the major rivers in the ZRB, as well as existing and planned reservoirs that include hydropower production (see Figure 11 and Figure 12). The level of detail for the river definitions are the same as those in the ZDSS and more detailed than the MSIOA study (see Chapter 2 for details of these studies).

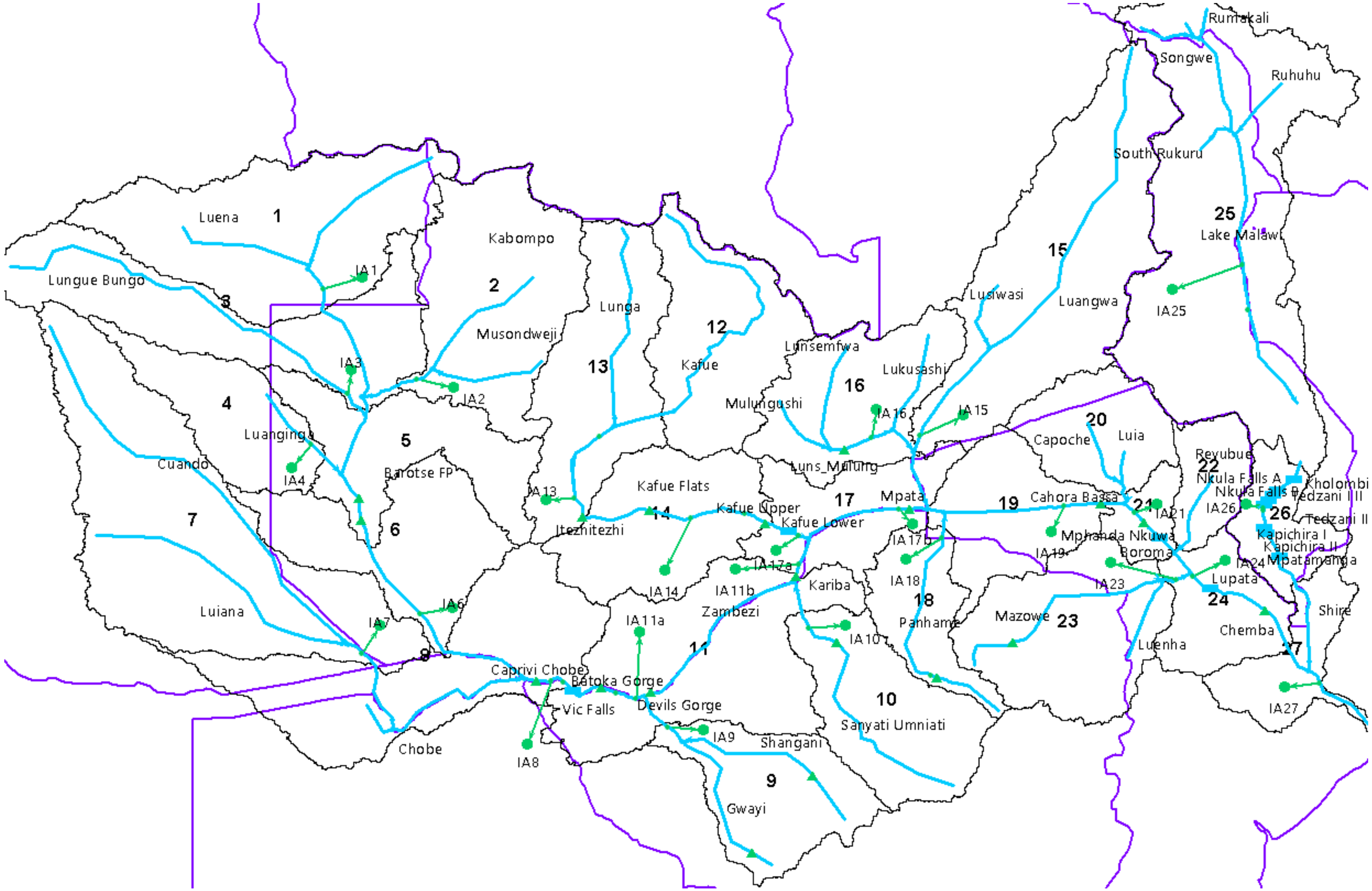
The Lake Malawi system is modelled separately from the Shire River, with calibrated outflows from the outlet of the lake from the ZDSS used as the head flows of the Shire River. The reason for this is the complexity of the Lake Malawi system, the steep gradient in precipitation along the length of the lake, and the fact that the focus of this thesis is on major ZRB hydropower plants. Note that the major hydropower plants in the ZRB outside of Malawi are not affected at all by the Shire River, because there are no hydropower plants below the confluence of the Shire and the Zambezi. However, for the sake of presenting a complete picture of the entire river basin, the Lake Malawi system is still included in this thesis, albeit at a coarser level of detail.

While groundwater is also important in some areas of the ZRB, the source of the groundwater is still rainfall (i.e., it is not fossil groundwater). Because the timing of groundwater replenishment and use is not the focus of this thesis, all the rainfall-runoff flows are treated as surface water.

4.1.2 *Sub-basin boundaries and catchments*

The sub-basin boundaries correspond to the ZDSS, with additional sub-divisions for runoff inflows and irrigation catchment areas to take into consideration the placement of new hydropower plants within a given sub-basin. The 27 main sub-basins used (see Figure 11) are more detailed than the 13 sub-basins used in the MSIOA study.

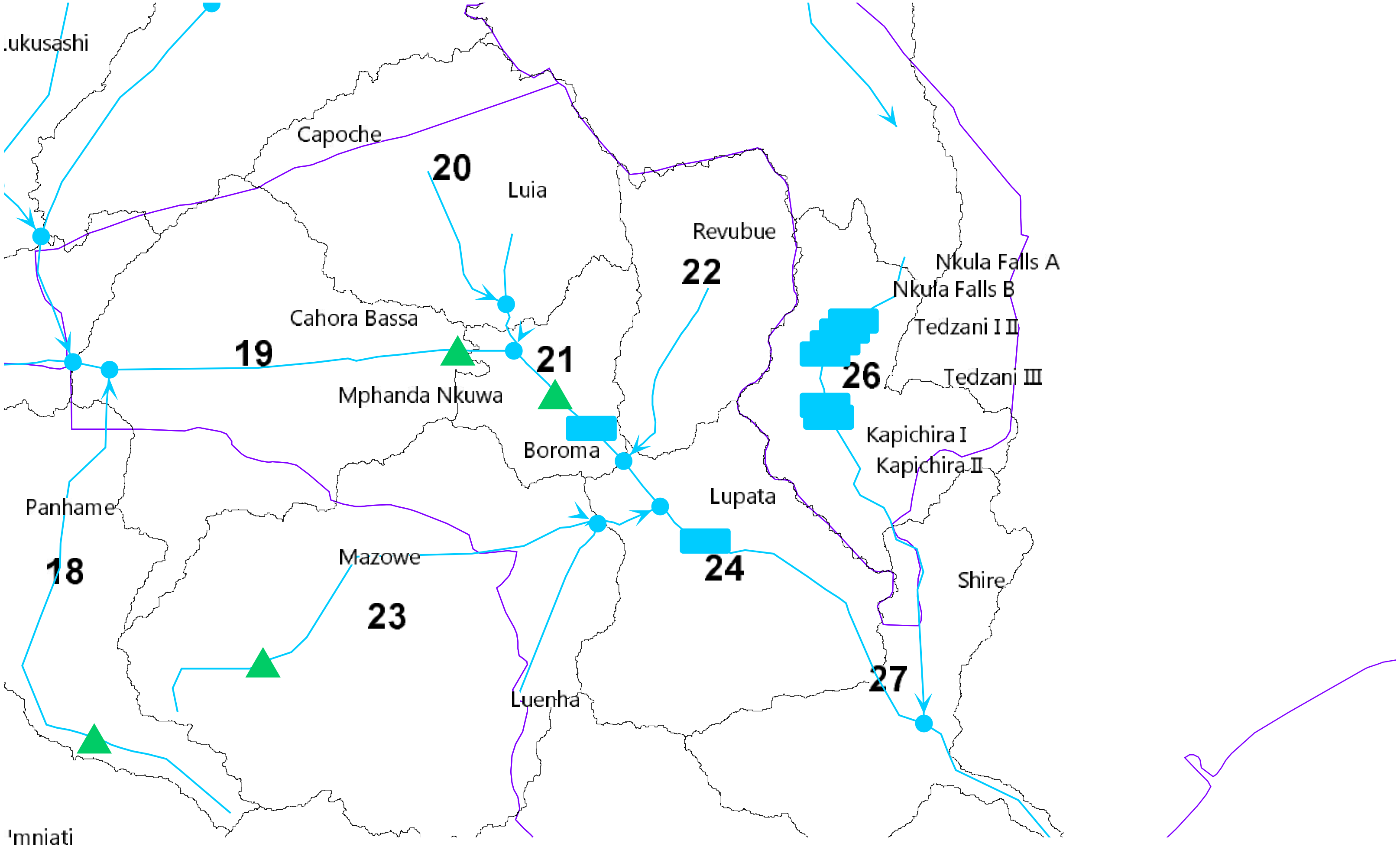
Figure 11. Schematic of rivers, reservoirs, irrigated areas and run-of-river hydropower plants



Note: Natural and man-made reservoirs are green triangles. Run of river hydropower plants are blue rectangles. Irrigated areas are green circles. Only modelled hydropower plants are shown. Green triangles without labels represent the aggregation of multiple small irrigation storage reservoirs.

Source: WEAP model developed by the author, including GIS files provided by Harald Kling, Pöyry Energy, Vienna

Figure 12. Detail of lower Zambezi and Shire River hydropower plants



Note: Natural and human-made reservoirs are green triangles. Run of river hydropower plants are blue rectangles.
Source: WEAP model developed by the author, including GIS files provided by Harald Kling, Pöyry Energy, Vienna

Although the WEAP model contains almost all the plants mentioned in the literature on the ZRB, not all of these are modelled in detail, because of both the limitations of data availability and the negligible impact of many plants on major hydropower investments. Having the plants in the model, however, allows for future development and expansion of the analysis in particular sub-basins, where more data is made available. The plants included in the modelling are discussed in more detail in Section 4.2.2.

Because of limitations in the spatial resolution of the hydrology modelling (see next section), some smaller hydropower plants and their catchment areas were combined into larger catchments. Examples include the following:

- The Lunsemfwa and Mulungushi Rivers in Zambia are combined into one catchment area, and the two existing power plants on those rivers treated as a combined plant.
- The three future potential plants on the Revubue River mentioned in the earlier Euroconsult Mott McDonald (2007) study are combined into one catchment area.
- The two future potential plants on the Luia and Capoche Rivers mentioned in the earlier Euroconsult Mott McDonald (2007) study are also combined into one catchment area.

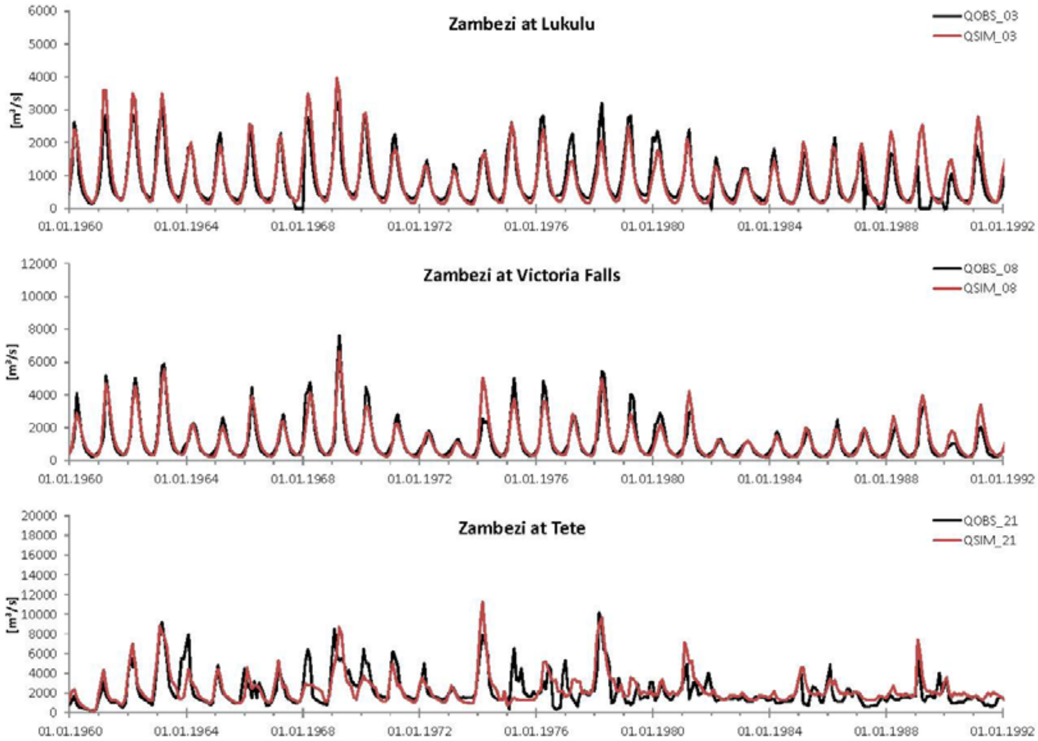
In addition, some of the small plants were not modelled, because of both lack of data and their negligible impact on downstream activities. These include Wovwe in Malawi (5 MW) and Lusiwasi in Zambia (12 MW).

4.1.3 *Hydrology and runoff inputs*

While WEAP has several built-in hydrological models, a fully calibrated hydrology dataset for all the sub-basins is available through the ZDSS tool introduced in Chapter 2, developed by Pöyry Energy for the Mozambique National Institute for Disaster Management.[18] This model and dataset are in the public domain, and are flexible enough to allow extraction of surface inflows at any point in the river network. The underlying precipitation and temperature data can also be similarly extracted. The ZDSS has been calibrated against stream flow gauge data for all of the key sub-basins and reservoirs in the Zambezi, and shows very high correlation at multiple river locations, not only in terms of mean flows but also in terms of seasonality and variability of flows. An example of the calibration of the ZDSS at key points on the Zambezi is shown in Figure 13. This runoff data provides surface inflow inputs to the rivers in the WEAP model, net of any evapotranspiration from vegetation (irrigated agriculture or natural vegetation).

[18] Freely available at http://zdss.ingc.gov.mz/. A full explanatory report (Kling and Preishuber 2012), including hydrology calibration results, is available on the website.

Figure 13. Simulated and observed monthly flow rates at key gauging stations on the Zambezi from the ZDSS, 1960–1992



Source: Kling and Preishuber (2012), Kling, Stanzel, and Preishuber (2014)

The only adjustment necessary to the ZDSS surface inflow is related to runoff from irrigated areas. This means that the runoff estimates already include any excess precipitation from irrigated land (i.e. when rainfall exceeds the demand from crops and the ability of the soil to absorb the moisture). The irrigation demand calculations in WEAP, however, also assume that runoff may occur from irrigated land if the precipitation is in excess of the "effective precipitation" level. This could lead to some double counting in sub-basins where irrigation land is a significant share of total land area (see sub-basins 11, 24, 26 and 27 in Table 17). For those sub-basins, the ZDSS runoff inputs are reduced by the share of irrigated land of the total sub-basin area, so that the runoff calculations for irrigated areas are calculated in WEAP. The share of irrigated land in those sub-basins increases over time, reaching the "current + identified projects" level in 2020 or 2030 and "total" (i.e. including high level potential as well) by 2040 or 2060, depending on the scenario. Note that this adjustment is much less important for sub-basins 26 and 27, because there are no hydropower plants downstream of the surface inflow points.[19]

[19] This adjustment is affected in WEAP using a Key Assumption for "runoff adjustment", interpolating the values for 1960 (zero), 2000 (current), 2025 (current + identified) and 2050 (2025 + high level). The surface inflow data from the ZDSS is then multiplied by (1 – runoff adjustment).

Table 17. Irrigated area versus sub-basin size

Sub-basin	Name	Irrigated areas (ha) Current	Identi-fied	High level	Total	Sub-basin area (km^2)	Irrigation share of total (%) Total	Current + Identified
1	Chavuma Mission	2,500	5,000	10,000	17,500	79,821	0.22	0.09
2	Kabompo	350	6,300	10,000	16,650	66,459	0.25	0.10
3	Lukulu	1,000	500	10,000	11,500	66,345	0.17	0.02
4	Luanginga	750	5,000	10,000	15,750	32,989	0.48	0.17
6	Senanga	200	7,008	10,000	17,208	46,329	0.37	0.16
7	Katima Mulilo	620	300	15,000	15,920	113,501	0.14	0.01
8	Kwando	1,575	13,346	12,300	27,221	71,014	0.38	0.21
9	Gwaai	1,300	566	0	1,866	39,117	0.05	0.05
10	Sanyati	21,600	5,203	0	26,803	45,340	0.59	0.59
11	Kariba	3,711	98,637	430,000	532,348	73,107	7.28	1.40
12,13	Mswebi & Itezhi-tezhi	4,177	6,000	0	10,177	106,569	0.10	0.10
14	Kafue Gorge	35,021	6,650	25,000	66,671	46,167	1.44	0.90
15	Upper Luangwa	1,000	1,479	0	2,479	96,838	0.03	0.03
16	Lower Luangwa	9,100	4,651	25,000	38,751	45,209	0.86	0.30
17	Middle Zambezi	1,960	6,823	0	8,783	33,223	0.26	0.26
18	Panhane	22,085	7,521	0	29,606	24,404	1.21	1.21
19	Cahora Bassa	10	0	100,000	100,010	35,036	2.85	0.00
20	Luia	0	0	0	0	28,698	0.00	0.00
21	Luia	10	150	0	160	28,698	0.01	0.01
22	Revubue	0	0	0	0	16,262	0.00	0.00
23	Luenha	12,713	11,661	0	24,374	53,581	0.45	0.45
24	Mutarara	315	11,000	100,000	111,315	26,166	4.25	0.43
25	Liwonde	25,391	23,887	50,000	99,278	132,277	0.75	0.37
26	Chiromo	17,025	35,625	300,001	352,651	19,259	18.31	2.73
27	Delta	6,998	77,055	100,000	184,053	22,246	8.27	3.78

While this thesis uses the runoff data from the ZDSS, WEAP is used for the water balance model. The runoff data is input as surface inflows at various points along the river network, corresponding to the catchments areas from which the runoff estimates are derived. The advantage of using runoff data and simulations from the ZDSS is that it is a well-calibrated model that has been tested against actual historical flow gauges, and allows calculation of inflows at any point in the river system. The WEAP model created by the author is used for all demand calculations and for water balance modelling and allocation, which is the main value added of this thesis (in addition to linking WEAP to the energy modelling system).[20] The ZDSS also provides projected runoff under the future climate scenarios discussed earlier.

Annex C shows the list of surface inflow points and describes their location and which sub-basins they represent. The sub-basin numbers from the ZDSS and the MSIOA are given for clarity. The rationale for the selection of surface inflow points is to ensure that flows above each hydropower plant (existing and potential) and irrigation abstraction point are in the correct order so that the combined impact of upstream abstractions and flows on each hydropower plant can be analysed. This means that, for example, if there is more than one hydropower plant in a sub-basin, two inflow points may be needed in the model – one above and one below the hydropower plant.

4.1.4 *Wetlands*

There are three key wetlands areas within the ZRB: Barotse, Kafue Flats, and Chobe-Caprivi. These are modelled in WEAP as shallow reservoirs, to ensure that evaporation from wetlands is captured, and, in some cases, with an additional "virtual reservoir" to delay the peak in the hydrograph.

For Kafue Flats, the relationship between discharge and storage volume is taken from the ZDSS, which analysed observed trends in releases over time. These and the other characteristics used for Kafue Flats are shown in Table 18. Because WEAP does not have the capability to calculate releases from instantaneous storage, the expression used for discharge requirements from the natural reservoir is linked to the storage levels in the previous two time steps, using a linear equation derived from the data in the table[21]. In addition, research has shown that water takes up to 90 days to travel between Itezhi-tezhi reservoir and Kafue Gorge, through the Kafue Flats, so a shift in the hydrograph is expected.

Table 18. Hydrological assumptions for Kafue Flats wetlands

Volume (mcm)	15	77	303	989	2,143	3,616	5,285	7,094	8,039	9,006	9,498
Elevation (m amsl)	976	977	978	979	980	981	982	983	983.5	984	984.25
Area (km^2)	30	114	405	950	1,340	1,586	1,745	1,865	1,915	1,955	1,975
Release (cms)	2	11	42	137	298	502	734	985	1,117	1,251	1,319

Source: Beilfuss (2001), Table 4-3, except for release, which is from ZDSS model

For the Barotse Flood Plain, a different approach is used, because of the importance of the observed shift in the hydrograph, such that the peak moves from March to April. Two reservoirs are used in the model. The first has the shallow shape and size of the Barotse as reported in the literature. To ensure that this reservoir is modelled to fill during the wet season (i.e. instead of the water simply passing through), the reservoir filling priority is set higher than downstream demands. This means that WEAP will allocate water to fill the reservoir even when there are downstream hydropower and irrigation demands. This simulates what happens in the natural setting, where the flood plain expands dramatically in size during the wet season, and this is not affected by the large downstream hydropower plants. The second reservoir is large enough to hold two months of peak flow, and discharges an amount in each time period equal to the inflows in the previous time period. In this way, it shifts the hydrograph

[20] As discussed earlier, the WEAP model was constructed, tested and utilised entirely by the author, while the ZDSS data was obtained from the authors of that study and re-formatted to be used as an input to the WEAP model.

[21] Release = 0.5 x S(p) x 0.1389 + 0.5 x S(t) x 0.1389, where S(p) is storage volume in previous period and S(t) is storage volume two periods previously.

by exactly one month, so that peak flows are in April, while the first reservoir attenuates the difference between peak and low flows.

The Chobe-Caprivi wetlands are modelled using the reservoir shape from the literature as shown in Table 19, sourced from the ZDSS.

Table 19. Hydrological assumptions for Chobe-Caprivi wetlands

Volume (mcm)	0	180	720
Area (km^2)	0	10	2,000
Elevation (m amsl)	1,000	1,018	1,018.3

Source: ZDSS model

To improve the simulations of natural reservoirs, operational assumptions about "buffering" were also included in the modelling (see section 4.3.1). A "buffer zone" in operational terms is the reservoir volume at which there is a limit placed on monthly releases, to ensure that the reservoir is not drawn down too fast. The "buffer coefficient" is the percentage of the remaining buffer zone volume that can be released in the next time period. Buffer zones are specified relative to the desirable top level of the reservoir (i.e. the "Top of Conservation" level of the reservoir), which may vary over the year where there is a Design Flood Rule Curve (DFRC) in place (Table 20).

Table 20. Buffering assumptions for natural reservoirs

Reservoir	Buffer zone (% of storage capacity)	Buffer coefficient (%)
Barotse (both reservoirs)	75	10
Chobe-Caprivi	75	10

4.1.5 *Abstraction points*

The irrigation abstraction points in the model are implemented as irrigated catchment areas, with a transmission link from the relevant water source and a return flow for any unused runoff or excess rainfall. This list of abstraction points, and their relationship to previous research under the MSIOA study, is shown in Table 84.

4.2 Water demand model

The largest current source of demand on available runoff is reservoir evaporation, at 16%, as shown in Table 21 below.

Table 21. Demand sources and share of runoff for Zambezi River Basin

	(Mm^3)	(%)
Available run off	103,224	100.00
Reservoir evaporation	16,989	16.46
Irrigated agriculture	1,478	1.43
Urban domestic consumption	175	0.17
Rural domestic consumption	24	0.02
Industrial consumption	25	0.02
Mining	120	0.12
Environmental/flood releases*	1,202	1.16
Livestock	113	0.11
Total water demand	20,126	19.49

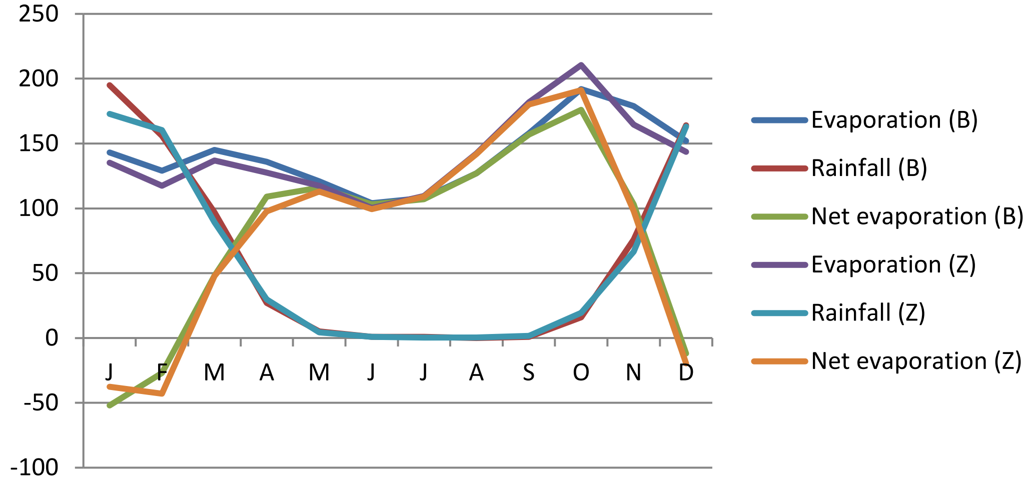
Note: * From Itezh-tezhi only, released for downstream ecosystems so not available for agriculture or hydropower from Itezhi-tezhi.
Source: Euroconsult & Mott MacDonald (2007), Table 4.10

The second-largest source is irrigated agriculture at 1.4%. Urban demand follows at 0.17%, which is small but has been included because of the possible significant increase in urban populations in the ZRB. The focus on the demand analysis is therefore hydropower demand/reservoir evaporation, irrigated agriculture, and urban demand.

4.2.1 *Reservoir evaporation*

As discussed in Chapter 2, changes in reservoir evaporation are one of the key climate impact pathways on the water-energy system. Both historical data and future projections under different climate futures are needed for net evaporation from both natural and human made reservoirs. The operators of the major hydropower reservoirs – particularly Lake Kariba, Lake Cahora Bassa and Itezhi-tezhi – have historical data on rainfall and evaporation, although these data are often estimated from a small number of stations and need to be corrected for the difference in conditions between standard pan evaporation tests and evaporation from a reservoir surface (e.g. relative humidity, wind speed) (Allen et al. 1998). The ZDSS provides monthly evaporation and rainfall data by sub-basin, which has been used for the reservoirs in those sub-basins. This is a finer resolution of climate data than the MSIOA study sub-basins (i.e. 13 vs 26 sub-basins in this thesis). As an example, Figure 4 shows the shows average historical (1960-1990) monthly evaporation and rainfall for Lake Kariba, and how this compares to the assumptions used by Beilfuss and dos Santos (2001).

Figure 14. Evaporation, rainfall and net evaporation at Kariba (mm)



Note: Z = from ZDSS, B = from Beilfuss and dos Santos (2001)

For Lake Kariba, the reservoir with by far the most surface area, the average net evaporation data from the ZDSS and the data presented in Beilfuss and dos Santos (2001) are within 2%. For the other reservoirs, however, such as Cahora Bassa and Itezhi-tezhi, parameters are considerably lower than those reported in Beilfuss and dos Santos. The reason for this is that the Beilfuss paper uses a pan evaporation correction factor of 0.9, while the ZDSS uses much lower values. Typical pan correction factors range from 0.35–0.85 (Allen et al. 1998), and the ZDSS aligns with the lower values based on local conditions.

The sensitivity of evaporation to changes in mean temperature is the same as the sensitivity of reference evapotranspiration. Reservoir evaporation can be calculated using the same basic equations used for evapotranspiration (Kling, Stanzel, and Preishuber 2014) but modified for the non-typical surface of the reservoir and the potential for heat transfer with the water body (e.g. as presented in Allen et al. 1998). The relative change in reservoir evaporation due to increasing temperatures is the same as for potential evapotranspiration. As explained in Section 4.2.3, a one-degree Celsius increase in temperature leads to a 2.5% increase in evapotranspiration, and therefore evaporation as well. Applying the temperature projections from the two climate futures in the relevant sub-basin for each reservoir provides the basis for calculating future evaporation. This combined with future precipitation in each climate future yields future net evaporation.[22]

4.2.2 *Hydropower demand for water*

4.2.2.1 Historical data

The WEAP model utilises required energy production and the characteristics of each reservoir or run-of-river plant to determine the flows necessary for meeting specified hydropower demand. The actual production then depends not only upon water availability, but also other demands upstream and downstream. If more water must pass through the dam than is necessary to produce the required energy demand (e.g. to comply with the Design Flood Rule Curve (DFRC) or to meet a high priority downstream demand), then WEAP pushes this water through the turbines, up to the specified maximum turbine flow. If the maximum turbine flow is

22 Note that all of the data on evaporation and rainfall for the different climate futures is sources from the ZDSS model, and the author re-formatted this as an input to the WEAP model

reached, the water is discharged through spillway gates up to the specified maximum hydraulic flow.

For the historical period, the simulation uses actual monthly hydropower production (see Table 22), generation efficiency, and head height (fixed or variable depending on the plant type) to determine the flows going through the turbines. For plants with reservoirs, the volume-elevation curve is also used, and for the largest plants the modelling includes the tailwater rating curves and DFRC. DFRCs are used for Kariba (ZRA 2013; SADC 2011), Cahora Bassa (from ZDSS analysis of recent operations at this reservoir), and Itezhi-tezhi (Beilfuss and Brown 2010). Table 22 shows the cases where annual or monthly data was available, and for what years. For plants with no annual or monthly data, the average annual production data was used, as per Table 24. Note that both plants on Lake Kariba are treated as one reservoir hydropower plant, with combined energy demand for Kariba South and Kariba North, for practical modelling reasons.

Table 22. Historical generation annual and monthly data availability

Dam/plant name	Commission year	Average annual only	Annual data	Monthly data	Sources	
					Annual	Monthly
Cahora Bassa	1976–77		1977–2012	2004–2013	HCB	HCB
Kafue Gorge Upper	1968		1993–2012	1993–2012	ZESCO	ZESCO
Kariba South	1958		1990–2009		IEA	IEA
Kariba North	1959		1993–2012	1993–2012	ZESCO	ZESCO
Victoria Falls	1972		1993–2012	1993–2012	ZESCO	ZESCO
Mulungushi	1955	✓				
Lunsemfwa	1944	✓				
Nkula Falls A	1966			2005–2012		ESCOM
Nkula Falls B	1981			2005–2012		ESCOM
Tedzani I & II	1977			2005–2012		ESCOM
Tedzani III	1995			2005–2012		ESCOM
Kapichira I	2000			2005–2012		ESCOM

For Cahora Bassa, the average turbine discharge from October 1998 (when the plant was fully back on line after reconstruction) and April 2007 (last data from Mozambique National Water Directorate) was 1,310 cubic metres per second (cms), which would mean the tailwater elevation was approximately 202 m amsl (see Table 70 for rating curve). Over the same period, the mean reservoir elevation was 322 m amsl, so the net head was 120 m. This corresponds to a generation efficiency of 95.6% (see 0 for relationship between net head and efficiency). Similarly, for Itezhi-tezhi, the tailwater elevation is estimated from an average net head of 40 m (Euroconsult and Mott MacDonald 2007) and the average reservoir surface elevation between 1977 and 2002 of 1,025.8 m amsl (Walimwipi 2012).

For generation efficiency for the other plants, all plants in Zambia are assigned the same value as Kariba and Kafue Upper (88%) given in Beilfuss (2001). All new plants in Mozambique are assigned the same efficiency as that of Mphanda Nkuwa (94%), as given by HMNK (2012). For plants in Malawi and Tanzania, a benchmark efficiency of 90% is used to represent a typical hydropower plant (USBR 2005). For technical availability (i.e. net of planned and unplanned outages), where this is not specified by the utility, 93% is used, based on the earlier SAPP Pool Plan Study (Nexant 2007). Plant-specific availability was only available for Cahora Bassa (96%) and Mphanda Nkuwa (91%). Maximum hydraulic flow (turbines and spillway) is only specified for Lake Kariba (9515 cms) (Beilfuss and Brown 2010) and Cahora Bassa

(16,250 cms) (Beilfuss and dos Santos 2001).Maximum turbine flow is a key parameter in WEAP, and must be specified for the model to allow electricity generation. Turbine flow should correspond to the rated capacity of the plant, taking into consideration the net head, efficiency and availability of the plant. In some cases, the reported maximum turbine flow had to be adjusted to match the stated capacity of the plant. For example, Cahora Bassa has a rated output of 2,075 MW and reported maximum turbine flow of 2,250 cms. With an efficiency of 96% and availability of 96%, however, this would produce 2,300 MW at the average net head of 116m. Because WEAP will always direct streamflow to turbines first, the maximum turbine flow must be adjusted downward to 2000 cms to ensure that the model does not yield higher generation than the rated power plant capacity. Other maximum turbine flows are defined for Kariba (1,794 cms), Victoria Falls (117 cms) (MEWD 2010), Kafue Upper (252 cms) (Beilfuss and dos Santos 2001), Nkula Falls A & B (246 cms) (World Bank 2010b), Tedzani I, II & III (276 cms) (World Bank 2010b), and Kapichira I (134 cms) (ESCOM 2013a).[23]

As the catchment area of a hydropower plant decreases, so the certainty of the climate and runoff projections also decreases, because of the relatively low density of reporting weather stations in much of the Zambezi River Basin. For this reason, small stations such as Lusiwasi (12MW) and Wovwe (5MW) are not included in the modelling. In addition, the Lunsemfwa (18MW) and Mulungushi (20MW) plants are combined in one "virtual plant" with the larger reservoir and catchment area, to reduce the uncertainty in runoff projections.

As with natural reservoirs, buffering parameters (see section 4.1.4 for explanation) are also specified for the existing human-made reservoirs, as shown in Table 23, while Table 24 summarises the key data on existing plants.

Table 23. Buffering assumptions for existing reservoirs

Plant*	Buffer zone (% of storage capacity)	Buffer coefficient (%)
Cahora Bassa	58	6
Kafue Gorge Upper	75	10
Kariba	62	6/2 (>2000)**
Itezhi-tezhi	40***	5

Notes: * Calibration for Itezhi-tezhi was most accurate without buffering, so these are not included for this reservoir.
** After 2000, the buffering coefficient for Kariba is reduced to 2%, because of the vulnerability of drying climate and irrigation demand leading to excessive reservoir draw down loss of net head for power production.
*** The Itezhi-tezhi DFRC bring the top of the conservation level down to 45% of the storage capacity for flood control purposes, so buffer zone cannot be above this level.

[23] Because WEAP requires a non-zero maximum turbine flow to allow water to flow through the turbines, for plants without maximum turbine flow specified in the literature, a dummy value of 1000 was used.

Table 24. Key characteristics of existing hydropower plants in the Zambezi River Basin

Dam/plant name	Country	River	Installed capacity (MW)	Commis-sion (year)	Average annual generation (GWh)	Reservoir active storage M m^3)	Surface area when full (km^2)	Reservoir elevation when full (m amsl)	Average head (m)
Cahora Bassa	Mozambique	Zambezi	2,075	1976–77	14,729	51,704	2,665	326	116
Kafue Gorge Upper	Zambia	Kafue	990	1968	5,160	785	805	976.6	394
Kariba South	Zimbabwe	Zambezi	750	1958	3.584	64,798	5,577	488.5	95
Kariba North Bank	Zambia	Zambezi	720	1959	2,859	64,798	5,577	488.5	95
Victoria Falls	Zambia	Zambezi	108	1972	612	N/A	N/A	N/A	112.7
Mulungushi	Zambia	Mulungushi	20	1955	80		31		325
Lunsemfwa	Zambia	Lunsemfwa	18	1944	131		45		380
Itezhi-tezhi Reservoir	Zambia	Kafue	N/A	1977	N/A	4,925	374	1,029.5	40
Nkula Falls A	Malawi	Shire	24	1966	161	N/A	N/A	N/A	52
Nkula Falls B	Malawi	Shire	100	1981	575	N/A	N/A	N/A	57
Tedzani I & II	Malawi	Shire	40	1977	276	N/A	N/A	N/A	37
Tedzani III	Malawi	Shire	53	1995	312	N/A	N/A	N/A	42
Kapichira I	Malawi	Shire	64	2000	427	N/A	N/A	N/A	54

Note: Commission date is for turbines.
Sources: National utilities and energy ministries (HCB 2013; ZESCO 2013c; ESCOM 2013b; MEWD 2010) Beilfuss (2001), Beilfuss and dos Santos (2001) , Beilfuss and Brown (2010), Burian et al. (2012), Euroconsult & Mott MacDonald (2007)

4.2.2.2 Future water demand – planned hydropower plants

Table 26 shows the planned additional hydropower plants in the basin. As with historical plants, these inputs are used to determine the flow requirements at each location. Less data is available on most of these plants, however. In some cases (see table), plants were only reported with their potential capacity in the literature and so could not be included, because this is not sufficient to calculate flow requirements. Where generation efficiency and availability was not specified, the same assumptions as for existing plants were used (see previous section).

Maximum turbine flow was not reported for many of the proposed plants, or the reported values in the literature were too low to yield the projected capacity. For example, the reported maximum flow at Mphanda Nkuwa is 662 cms (HMNK 2012), but 2,568 cms would be required to produce the rated output of 1500 MW for the first phase.[24] The reported maximum flow to Itezhi-tezhi of 312 cms (MEWD 2010), however, is sufficient to deliver the rated output of 108 MW.

For Kariba North, 455 cms would be sufficient to produce 360 MW output. Because this expansion will be used in peaking mode, the expected load factor is very low, however (12%). For the Kariba South expansion, 425 cms is needed for the 300 MW capacity rating. Batoka Gorge is estimated at 1,089 cms maximum turbine flow based on the installed generation capacity, net head, efficiency and availability.

The buffering assumptions for the new reservoirs are shown in Table 25. Itezhi-tezhi maintains the same operating rules as currently (see Table 23).

Table 25. Buffering assumptions for new reservoirs

Plant	Buffer zone (% of storage capacity)	Buffer coefficient (%)
Batoka Gorge	75	10
Chemba	75	10
Devils Gorge	60	5
Mpata Gorge	80	5
Mphanda Nkuwa	75	10

[24] The reported value may be for a single turbine.

*Table 26. Future planned hydropower plants in the Zambezi River Basin included in this analysis**

Plant name	Country	River	Owner	Installed capacity (MW)	Annual generation (GWh)	Reservoir capacity (M m^3)	Surface area when full (km^2)	Reservoir elevation when full (m amsl)	Average head (m)	Earliest start year
Cahora Bassa North	Mozambique	Zambezi	HCB	1,245	2,835	existing	0	0	116	2015
Mphanda Nkuwa I	Mozambique	Zambezi	Mozambique	1,500	8,600	2,324	97	207	67	2022
Mphanda Nkuwa II	Mozambique	Zambezi	Mozambique	750	4,200	“	“	“	“	2025
Batoka Gorge	Zam/Zim	Zambezi	ZRA	1,600	8,728	1,680	25.6	762	166	2023
Chemba I	Mozambique	Zambezi	EdM	600	5,920					2020
Chemba II				400	total	20,080		98	43	2022
Itezhi-Tezhi	Zambia	Kafue	ZESCO/ TATA	120	611	existing	0	0	80	2016
Devils Gorge	Zam/Zim	Zambezi	ZRA	1,240	5,604	31,200	710	592	103.5	2026
Mpata Gorge	Zam/Zim	Zambezi	ZRA	1,086	4,200	20,400	1190	381	55	2025
Kariba South Ext	Zimbabwe	Zambezi	ZESA	300	1,183	existing	0	0	95	2018
Kariba North Ext	Zambia	Zambezi	ZESCO	360	380	existing	0	0	95	2014
Kafue Gorge Lower	Zambia	Kafue	ZESCO	750	2,400	N/A	0	0	186	2019
Boroma	Mozambique	Zambezi	EdM	160	1,168	N/A	0	N/A	17	2022
Lupata	Mozambique	Zambezi	EdM	550	4,171	N/A	0	N/A	27	2021
Kapichira II	Malawi	Shire	ESCOM	64	469	N/A	2	N/A	54	2014
Kholombizo	Malawi	Shire	ESCOM	100		N/A	N/A	N/A	N/A	2018
Mpatamanga	Malawi	Shire	ESCOM	265		N/A	N/A	N/A	N/A	2020

Note: *While there are other potential plants that are mentioned in the literature, these are either much smaller or at such an early stage of conceptual development that insufficient technical data was available to include them in the modelling.
Sources: National utilities and energy ministries (HCB 2013; ZESCO 2013c; ESCOM 2013b; MEWD 2010) Beilfuss (2001), Beilfuss and dos Santos (2001) , Euroconsult & Mott MacDonald (2007), Nexant (2007), ZRA (2013)

The timing of the investments is explained in Chapter 3, while the earliest start date is shown in Table 26. Given that the objective of this thesis is to assess impacts on major plants, most of the analysis focuses on the expansions of Kariba and Cahora Bassa, and the new plants of Batoka Gorge, Chemba, Mphanda Nkuwa. Kafue Gorge Lower and Itezhi-tezhi are also a focus due to their importance for Zambia. Devils Gorge and Mpata Gorge are also considered briefly due to their size.

4.2.3 *Irrigation demand*

Irrigation demand for water is a function of acreage, crop type, growing cycles (and their corresponding crop coefficients), reference evapotranspiration, and effective precipitation within the irrigated area. Using the “irrigation only” demand model in WEAP, the model first calculates the crop requirements and determines whether effective precipitation is sufficient. If it is not, water will be abstracted from the river via the transmission link, taking into consideration the efficiency of the irrigation system. Any rainfall that is above the effective precipitation level, or rainfall in months when there is no crop demand, becomes runoff. This runoff was discussed in section 4.1.3.

The location of the irrigation abstraction points in the river network is specified to reflect the approximate location of major projects and/or potential development areas. These locations have been established based on geographic data provided in the MSIOA and ZDSS, and are presented in Annex C. Acreage and crop type is provided by detailed tables in Volume 4 of the MSIOA study (World Bank 2010b). This study provides current area, area of identified irrigation projects (e.g. short-to-medium term) and high-level irrigation potential (e.g. long term) (see Annex B for detail). The development futures differ by the year when each level of irrigation area will be achieved, as shown in Table 15.

Table 27. Irrigation expansion in each development future

Development future	BAU	SADC Int	Grand Deal
Year when “identified projects” have been realised	2030	2025	2020
Year when “high level” irrigation potential has been realised	2060	2050	2040

Note that the MSIOA study provides acreage for dry season, wet season and perennial crops, but the actual equipped area is less than the sum of these three areas since some land is used for both dry and wet season crops. Unfortunately, there is no simple correspondence between crops being planted on the same land throughout the year and several different wet season crops being planted in one dry season crop area. This presents a problem for the WEAP model, since the model assumes that the precipitation in a particular sub-basin falls year-round on every hectare with a crop designated. In other words, one hectare of winter wheat is assumed to receive rainfall throughout the year, even though that hectare may also be included under the area of summer wheat. This could lead to double counting of rainfall and an overestimate of runoff from irrigated areas (i.e. because the winter wheat area would appear to have significant runoff in the summer, even though in reality that rainfall might be completely used by evapotranspiration from summer crops on the same land). Of course, this is not a problem for perennial crops, nor is it a major problem for wet season crops (i.e. because when there is no crop in the field there is also almost no rainfall, from May to Oct). The problem is with dry season crops, in those sub-basins where irrigated area could become a significant share of total land area. The solution to this in WEAP is to “turn off” the precipitation on dry season crop area during the summer months, by making precipitation a function of crop stage. In other words, when the crop coefficient (Kc) is zero, this means there is no crop in the field. During the months when Kc is zero (generally October to April for dry season crops), the precipitation inputs for that area are set to zero, so that this precipitation is recorded instead under the area designated for wet season irrigated crops. This correction is only necessary in sub-basins where irrigated area is a significant share of total land area (i.e. sub-basins 11, 24, 26 and 27).

Crop coefficients are also sourced from the MSIOA study, which provides decadal (e.g. 10 days) estimates of crop coefficients for all the relevant crops. These are converted to monthly coefficients for the WEAP model (see Annex D). Reference evapotranspiration (ETo) varies by sub-basin and is related to local climate parameters. For the historical data series and two climate futures, monthly ETo is extracted from the ZDSS for each sub-basin. The historical averages are shown in Table 28. Effective precipitation differs from actual precipitation, because in high rainfall periods some water runs off before it can be utilised by vegetation. According to the research behind the MSIOA study, any rainfall above 150 mm/month will be lost to surface runoff, so the actual monthly precipitation is capped at 150 mm/month to yield effective precipitation.

Table 28. Monthly ETo for selected sub-basins

Sub-basins	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Sum
1	118	105	117	122	125	114	128	156	181	176	129	117	1588
2	114	102	113	118	121	111	124	151	176	171	125	113	1539
3	114	102	114	118	121	110	124	151	175	170	125	113	1537
4	121	109	121	126	129	117	132	161	187	181	133	120	1637
5	125	112	124	130	133	121	136	165	192	186	137	123	1684
6	134	119	134	129	121	105	117	149	184	194	156	141	1683

Source: ZDSS Model

For the future scenarios, ETo is adjusted for projected temperatures in each climate scenario as explained in Box 2.

Box 2. Evapotranspiration and future climate

Long-term mean monthly potential evapotranspiration (mPET) data were obtained for the ZDSS analysis from the CLIMWAT dataset of FAO for 30 stations in the region. The Penman-Monteith method was used in the CROPWAT model of FAO to calculate the sensitivity of mPET to changes in temperature. Thus, time-series of monthly potential evapotranspiration (PET) were obtained with the following simple equation:

$$PET_t = mPET_i \cdot (\Delta T_t \cdot F + 1) \qquad \text{Eq. 1}$$

where PET_t is the monthly potential evapotranspiration of time-step t in [mm], $mPET_i$ is the long-term mean monthly potential evapotranspiration of the month i in [mm], ΔT_t is the temperature difference between the current time-step t and the long-term mean monthly temperature of month i in [°C], and F is an empirical factor obtained from sensitivity tests with Penman-Monteith method and specified as 0.025 in [mm/(mm.°C)].

The equation above shows that for an increase in temperature by +1°C there is an increase in PET by +2.5%. The sensitivity analysis did not find significant differences in this factor between stations and months.

Source: Kling (2013)

Irrigation efficiency depends on the mode of irrigation. Gravity-fed schemes are 39% efficient, while pivot/sprinkler systems are 50% efficient (World Bank 2010b: Table A3.6). The MSIOA study notes that the Kafue and Luangwa sub-basins widely use pressurised irrigation, but for the other sub-basins there is either evidence of a large share of gravity fed schemes or no information at all on the shares. The model therefore uses pressurised irrigation efficiency for Kafue (sub-basins 12, 13 and 14) and Luangwa (sub-basin 15) and gravity-fed schemes efficiency for other areas.

4.2.4 *Urban demand*

Change in urban demand in the water model is driven entirely by population growth[25]. The current per capita consumption is taken from the Rapid Assessment Final Report for the Integrated Water Resources Management Strategy for the Zambezi River Basin study (Euroconsult and Mott MacDonald 2007, 37), as 70 litres per day in urban areas and 20 litres per day in rural areas. Given the fact that urban demand is already a very small percentage of runoff in the basin, only the largest urban centres are considered: Lusaka, Harare, Bulawayo, Lilongwe, Blantyre, Copperbelt (Ndola and Kitwe) and Livingstone-Victoria Falls area.

The water source of each major urban centre was identified, as well as the discharge location, because these are not always in the same sub-basin. For Lusaka, the water abstraction is from the Kafue River before the Kafue Gorge Upper hydropower station. The discharge, however, is into the Luangwa River basin. Harare uses the Lake Manyame catchment.[26] For Bulawayo, current water supplies are from dams outside the Zambezi River Basin (e.g. Ncema, Inyankuni, Inciza, Umzingwane). Bulawayo has experienced chronic water shortages, however, and had to severely ration water during recent drought years.[27] The Matabeleland Zambezi Water Trust Project has been proposed to draw water from the Zambezi River to alleviate Bulawayo's water shortages, although this project has seen numerous delays due to political and economic challenges in Zimbabwe.[28] The government of Zimbabwe announced in July 2012 that China had committed $1.2 billion to this project, and that the 400km pipeline and associated dams would be complete within three years.[29] For this reason, Bulawayo water demand is only included in the WEAP model from 2015, and then drawing from the Zambezi River at Lake Kariba.

4.2.5 *Inter-basin transfers*[30]

While a number of inter-basin transfers have been mentioned in the literature (World Bank 2010a; SWECO 1996; WRC 2010; Heyns 2003; JICA 2009), none is at an advanced stage of feasibility study, nor is there any political agreement on these. The MSIOA includes a scenario that considered a proposed scheme for abstracting water from the Chobe-Zambezi area for the Dikgatlhong reservoir in Botswana (in connection with the North-South Carrier Water Project), which would remove 25.7 cms or 810 million cubic metres (mcm)/year. This would be the second phase of the proposed Pandamatanga agricultural abstraction transfer, which would draw up to 16 cms from the same area, before the pipeline is extended all the way to Botswana's North-South Carrier (WRC 2010). Flows at Kasane, however, are rarely below 108 cms – only in 1.3% of the months between 1960 and 1990 – so this withdrawal is unlikely to have major downstream impacts. These smaller-scale transfers have not been included in the modelling.

---

25 This is a simplification, since urban areas would also include industrial and commercial demand related to economic development. However, because urban demand is such a small portion of total water demand in the basin, a more sophisticated modelling approach would be unlikely to significantly change the results.

26 http://www.waterworld.com/news/2012/10/11/harare-water-woes-no-solution-in-sight-75-years-later.html.

27 http://allafrica.com/stories/201208310055.html.

28 http://www.newsday.co.zw/2012/10/02/bulawayo-water-woes-a-crisis-of-leadership/.

29 http://www.newzimbabwe.com/news-8476-China+funds+$1,2bn+Zambezi+Water+Project/news.aspx.

30 This analysis of inter-basin transfers was provided by Arthur Chapman, OneWorld Sustainable Investments, Cape Town.

4.2.6 *Demand priorities*

The model must be clear about which demands to prioritise in case of a shortfall, or, rather, the order in which to fill those priorities. In WEAP this is specified by setting demand priorities for reservoir filling, hydropower generation, irrigation demand and urban demand – with 1 being the highest and 99 being the lowest. WEAP then allocates water to the highest priority demands first, *regardless of their position within the basin*. As discussed in Chapter 2, if upstream demands would, in practice, have first access to flows, then this should be reflected by assigning them a higher priority than downstream demands. Even when there are groups of plants near one another (e.g. Cahora Bassa and Mphanda Nkuwa), in practice the lower reservoir would most likely have a lower priority. In addition, the small size of the “holding reservoirs” at Batoka Gorge (1,680 mcm), Mphanda Nkuwa (2,324 mcm) and Kafue Gorge Upper (785 mcm) means that these must be kept almost full to maintain the head necessary to generate power. For these three plants, therefore, reservoir storage priority should be higher than hydropower, while for all other plants the opposite is true (Table 29). Because urban demand is very small compared to all other demands and is likely to be prioritised for political reasons, urban demand is set at 5 in all scenarios.

Table 29. Demand priorities for hydropower and irrigation

	Generation	Reservoir filling	Irrigation
IA1, IA2, IA3, IA4			4
Barotse		5	
IA6, IA7			6
Caprivi-Chobe		7	
IA8			8
Victoria Falls	9		
Batoka Gorge	11	10	
IA11a, IA9			12
Devils Gorge	13	14	
IA10			15
Kariba	16	17	
IA13			12
Itezhi-tezhi	13	14	
Kafue Flats		14	
IA14,			15
Kafue Gorge Upper	17	16	
Kafue Gorge Lower	18	N/A	
Lunsemfwa-Mulungishi	17	18	
IA15, IA16			19
IA11b, IA17a, IA17b, IA18, IA19			19
Cahora Bassa	20	21	
IA21			22
Mphanda Nkuwa	24	23	
Boroma	25	N/A	
IA23, IA24			26
Lupata	27	N/A	
Chemba	28	29	
IA25, IA26	26		
Kholombizo, Nkula A & B	27		
Tedzani I, II, III	28		
Kapichira I & II, Mpatamanga	29		
IA27	30		

Note: All “IA” entries are irrigated areas (see Annex B for locations).

4.3 Model calibration

Because the WEAP model uses runoff data that has already been calibrated in the ZDSS, all that is necessary is to calibrate the modelling of the operation and evaporation from reservoirs (including demand priorities, and the treatment of wetlands as natural reservoirs) and to check that downstream flows are still accurately modelled when historical irrigation and urban demand are included. In addition, irrigation demand is also compared with published studies (see Section 4.3.3) to check the crop demand model.

4.3.1 *Natural reservoirs*

Calibration of discharges from natural reservoirs was done by comparing downstream gauge data with modelled discharges. In addition to visual calibration of the model results, which WEAP facilitates from the graphical reporting formats available, several statistics were calculated: correlation, bias ratio, variability ratio and a “modified KGE statistic” (Gupta et al. 2009; Kling and Preishuber 2012). The KGE statistic combines correlation, bias ratio and variability ratio, so that the model calibration balances the temporality of flows with the mean volumes and variability, rather than only focusing on one of these issues.

For Kafue Flats, the Nyimba gauge is in the middle of the Flats, so would not be appropriate. The only gauge between the Flats and Kafue Gorge Upper HPP is Kasaka, but this gauge has been affected by the backwater from Kafue Gorge Upper since the plant was in full operation in the late 1960s. For this reason, data from the Kasaka gauge for the period from January 1961 to December 1970 is used for the calibration. As Figure 15 shows, there is a close correlation between the modelled results and observed gauge readings. The statistical results are reported in Table 30. The shift in the hydrograph shown in Figure 16 shows how significantly these large wetlands both attenuate the upstream flows and shift the peak flows, which is consistent with the findings in other modelling studies in the Zambezi, as discussed earlier.

Figure 15. Observed versus modelled flows at Kasaka (1961–1970)

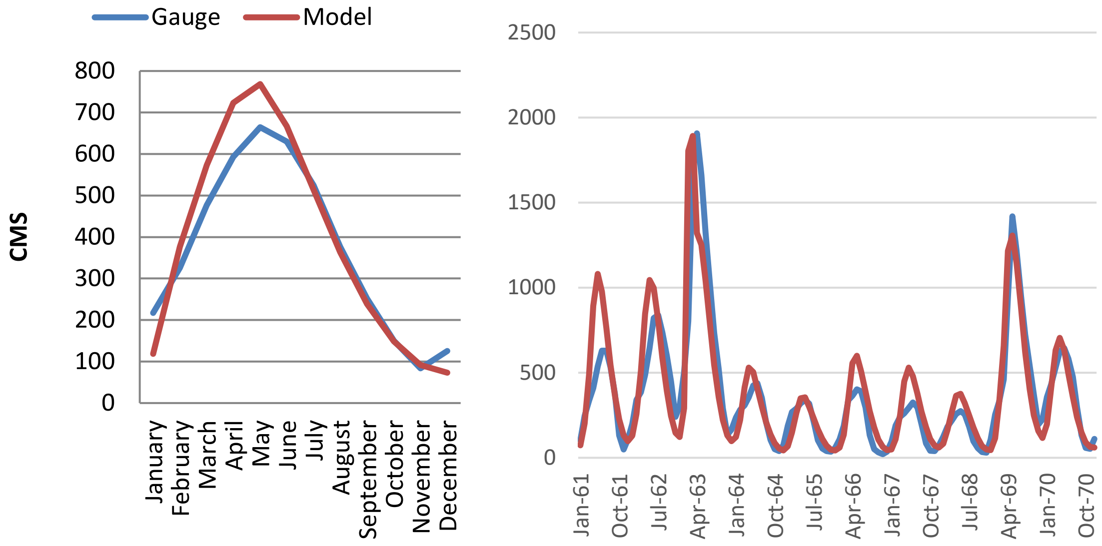
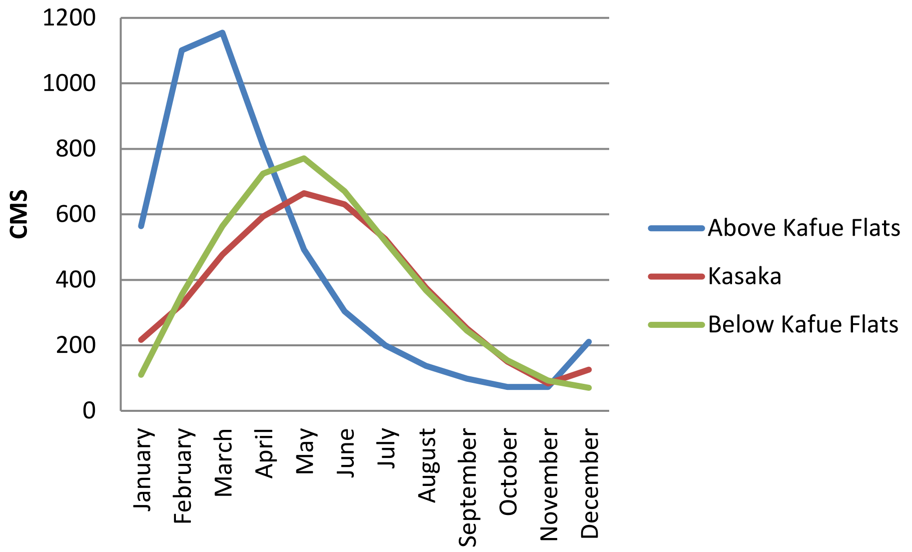
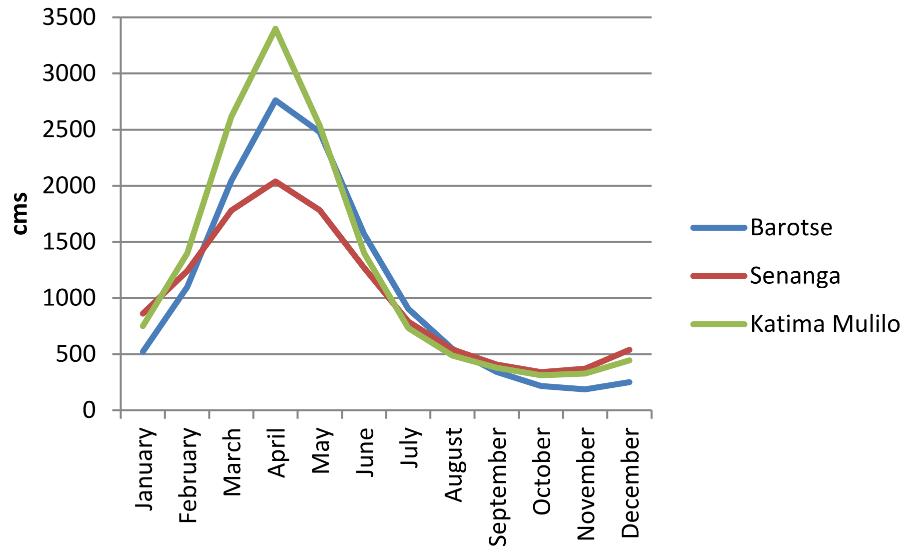


Figure 16. Average monthly flows above and below Kafue Flats (1961–1970)



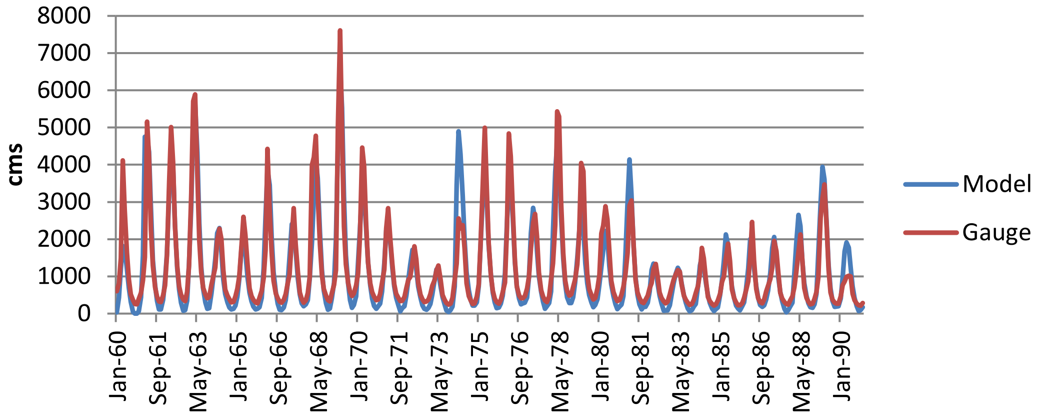
For Barotse, the challenge is that that ZDSS research showed that Senanga tends to under-report peak flows, while Katima Mulilo tends to over-report them. For this reason, the Senanga and Katima Mulilo records are only used to identify the peak flow periods. As Figure 17 below shows, the modelled flows follow the hydrographs for the two gauges very closely, even though magnitude of flows is different, as expected.

Figure 17. Comparison of hydrograph of modelled Barotse flood plain with Senanga and Katima Mulilo gauges



The best calibration for Barotse, and the Chobe-Caprivi wetlands as well, is at the Victoria Falls gauge. The modelled flows versus gauge are shown in Figure 18, demonstrating the good calibration of the model at this point. The calibration statistics are reported in Table 30.

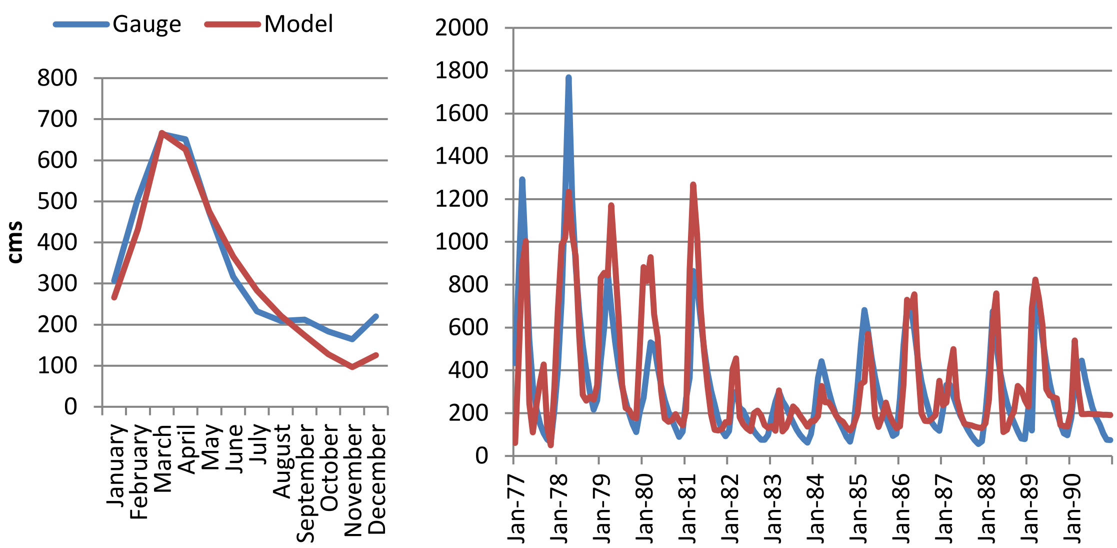
Figure 18. Observed versus modelled flows at Victoria Falls



4.3.2 *Human-made reservoirs*

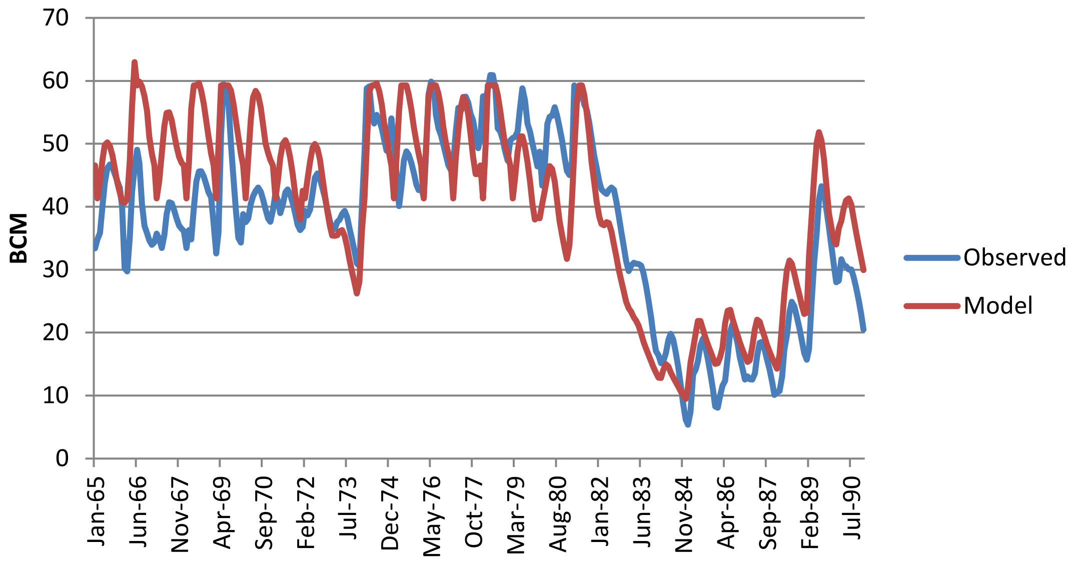
For man-made reservoirs, calibration may be based on observed versus modelled reservoir volume or on discharges. As with natural reservoirs, the KGE statistic is used, as well as its statistical components. For Itezhi-tezhi, the gauge data from GRDC for the outflow point of the reservoir is used, and this has been confirmed by data from ZESCO. The calibration period starts in 1977, when the reservoir was commissioned, and ends in 1990. Note that the Itezhi-tezhi modelled flows were calculated with and without the DFRC assumptions given in Beilfuss (2001), and the calibration statistics with the DFRC showed that this assumption more closely matched the observed data.

Figure 19. Observed versus modelled discharge at Itezhi-tezhi (1977–1990)



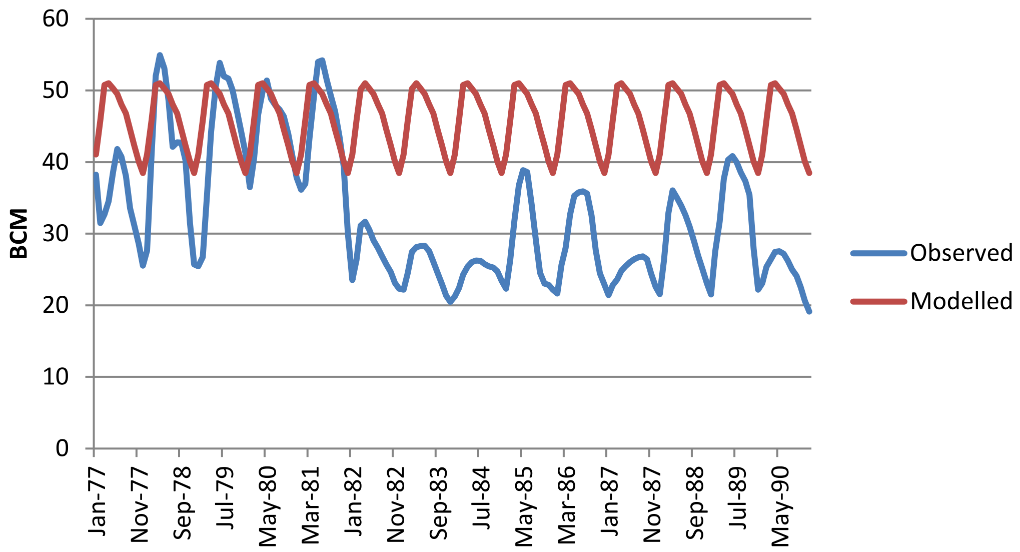
For Lake Kariba, modelled reservoir levels (volume) are also well correlated with observed volume, even during the very dry period of 1983 to 1988, as shown in Figure 20.

Figure 20. Observed versus modelled volume at Lake Kariba



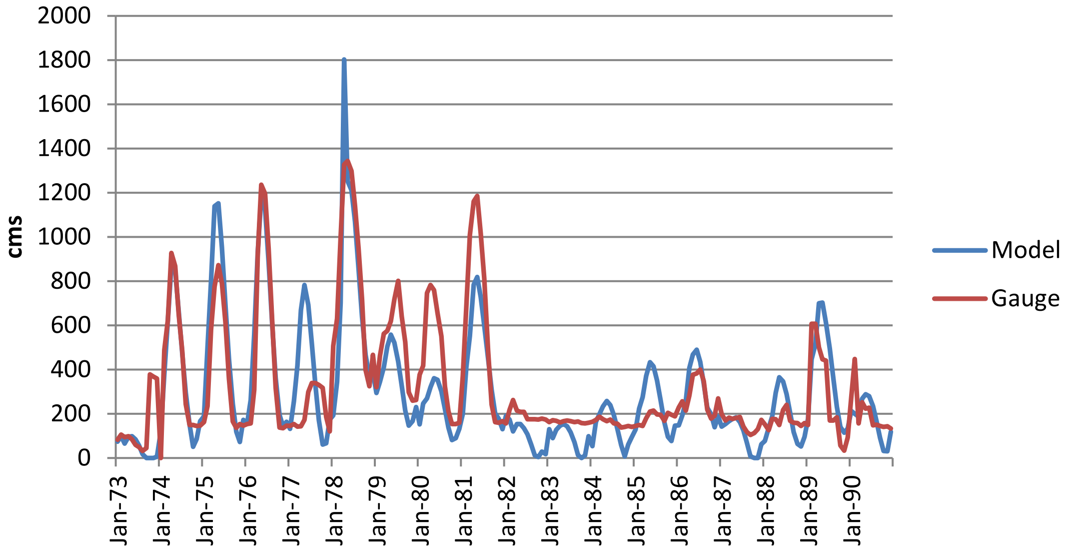
Similarly, for Cahora Bassa, modelled volume is compared with observed volume provided by the Mozambique National Directorate for Water. The difficulty with Cahora Bassa, however, is that during the period from 1983 to 1997, when the transmission lines to South Africa were out of commission, the reservoir did not follow normal operating rules. During this period the reservoir was drawn down even though there was sufficient inflow to maintain higher levels. In addition, operation was erratic during the earlier years after commissioning. For these reasons, a formal calibration is not feasible for Cahora Bassa. Figure 21 does show, however, the model correctly implements the specified DFRC for Cahora Bassa.

Figure 21. Observed versus modelled volume at Cahora Bassa



Kafue Gorge Upper has only a small holding reservoir, so the calibration is conducted with modelled discharge versus gauge data (Figure 22).

Figure 22. Observed versus modelled discharge at Kafue Gorge Upper hydropower plant



The calibration statistics at key points in the ZRB system are shown in Table 30, demonstrating the strong correlation between the modelling results and observed data.

Table 30. Summary reservoir calibration statistics

Reservoir	Gauge	Period	Correlation	Ratio of mean	Ratio of variation	KGE
Kafue Flats	Kasaka	1961–90	0.881	1.054	0.989	0.869
Barotse & Chobe-Caprivi	Vic Falls ZRA	1961–90	0.925	0.948	1.065	0.888
Itezhi-tezhi	Itezhi-tezhi	1977–90	0.799	0.932	1.025	0.787
Kariba	Kariba ZRA*	1965–90	0.854	1.074	0.958	0.831
Kafue Gorge Upper	Kafue Gorge Upper	1973–90	0.843	0.907	1.110	0.787

Note: * Calibration to reservoir volume, instead of monthly discharge.

4.3.3 *Irrigation demand*

Table 31 shows the calculated irrigation water demand in the WEAP model for the current irrigated area versus the estimated abstractions from the MSIOA study. The WEAP sub-basin data are aggregated to the sub-basins from the MSIOA for comparison. The total abstraction demand is virtually the same, and all the major basins are within 10–20%. This is a good fit considering the large uncertainties in irrigation system efficiencies, which are included in the abstraction requirement estimates of both studies.

Table 31. Calculated abstraction requirements for current irrigated area compared to the MSIOA study

Sub-basin names and numbers			Total abstraction (MCM)		
World Bank		WEAP	World Bank	WEAP	WEAP/ WB (%)
Upper Zambezi	12	1	37.6	40.2	107
Kabompo	13	2	4.8	5.6	116
Lungue Bungo	11	3	15.7	16.6	106
Luanginga	10	4	14.2	14.1	99
Barotse	9	6	3.5	3.6	104
Cuando / Chobe	8	7	10.1	10.8	107
Kariba	6	8,9,10,11	649.2	528.4	81
Kafue	7	12,13,14	626.0	727.8	116
Luangwa	5	15,16	120.5	170.7	142
Mupata	4	17	308.6	296.6	96
Tete	2	18,19,20, 21,23,24	669.0	612.6	92
Lake Malawi / Shire	3	25,26	648.6	717.3	111
Zambezi Delta	1	27	127.0	143.2	113
Total			3,234.8	3,287.4	102

Having specified the scenarios that were analysed using the calibrated WEAP model for the ZRB, the following section presents the results of the modelling.

4.4 Results

The results are presented in successive steps to answer the overall questions of how future climate and irrigation expansion in the ZRB affect hydropower generation potential. The following sub-questions help to identify the most important drivers of change in hydropower production for existing and new hydropower plants:

- How will future climate and development impact existing hydropower plants?
- How will future climate and development impact new hydropower plants?
- What is the relative impact of increased irrigation demand for water versus climate on the performance of existing and new hydropower plants?
- To what extent does the pace of development (i.e. the alternative development future) for hydropower and irrigation affect the results?

4.4.1 *Water modelling scenarios*

The scenarios follow the core modelling scenarios explained in in Chapter 3 (see Table 32). In addition, two additional scenarios are added to understand the relative impact of additional downstream hydropower demand (e.g. on Kariba) versus the impact of increased irrigation demand.[31] As discussed in Chapter 3, future hydropower production for the existing plants is compared with baseline modelled generation using historical climate data (1960–1990), to eliminate any bias in the comparisons with future scenarios. In all the subsequent figures displaying the results of the analysis, annual and monthly variables are shown based on processing data inputs from a given climate scenario to determine projected storage levels and generation, based on the modelling specifications presented earlier in this chapter. As discussed in section 3.1, this is not meant to be a prediction, but rather a presentation of a plausible future and an illustration of the response of the modelled system to alternative climate inputs.

Table 32. Specification of scenarios in water supply and demand analysis

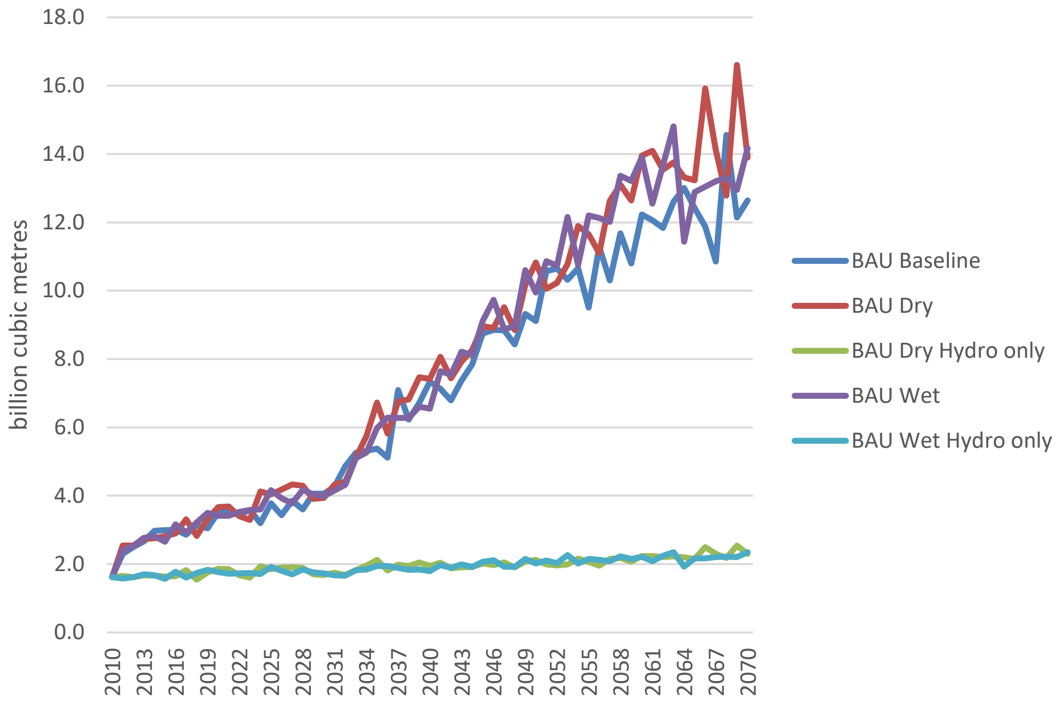
	Hydropower development	**Irrigation development**	**Climate**
BAU Baseline	BAU	BAU	Historical
BAU Dry	BAU	BAU	Dry
BAU Wet	BAU	BAU	Wet
BAU Dry Hydro only	BAU	Historical	Dry
BAU Wet Hydro only	BAU	Historical	Wet
SADC Int Dry	SADC Int	SADC Int	Dry
SADC Int Wet	SADC Int	SADC Int	Wet
GD Baseline	Grand Deal	Grand Deal	Historical
GD Dry	Grand Deal	Grand Deal	Dry
GD Wet	Grand Deal	Grand Deal	Wet

Note: BAU = business as usual; SADC Int = SADC Integration; GD = Grand Deal.

In terms of the effects of irrigation on water demand, Figure 23 illustrates the increase in irrigation demand under the BAU scenarios driven by the increase in irrigated area (i.e. the "BAU Dry Hydro only" and "BAU Wet Hydro only" scenarios do not include any increase in irrigated area, only modest increases in demand from higher average temperatures). Under the "Grand Deal" development scenario, the same demand levels would be reached 10 to 20 years earlier. However, this increase in demand has limited impact on the overall hydropower generation potential, as explained in section 4.3.4.

[31] The scenarios "BAU Dry Hydro only" and "BAU Wet Hydro only" show how hydropower would perform without any change in irrigation demand, while the normal BAU scenarios include this growth in irrigation demand.

Figure 23. Total Zambezi Basin irrigation demand growth under different climate and development futures



The following sub-sections present the analysis and results that address the questions posed at the opening of section 4.4. These results are then summarised and discussed in sections 4.4.6 and 4.5.

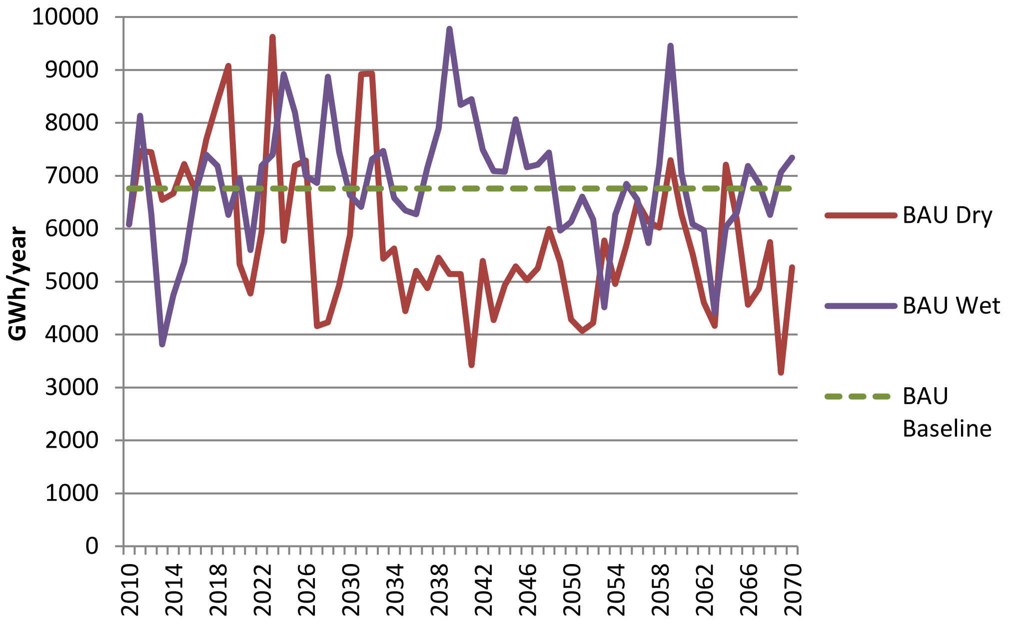
4.4.2 *Future climate and development impact on existing hydropower plants*

This section considers how the three major existing hydropower plants – Kariba, Cahora Bassa and Kafue Gorge Upper – could be affected by different climate futures, assuming BAU development (i.e. irrigation development, new plant commissioning, and population growth). As shown in Section 4.3.1, while the model results are highly correlated with historical measurements, there is still some bias. To eliminate this bias in interpreting the results of the future simulations, it is important to compare future generation with modelled generation using the historical climate data. For example, modelling generation for Kariba from 2010 to 2070 using historical climate data, and taking into consideration the expansions on the North and South Banks and BAU development in the basin, results in mean generation of 6,759 GWh.[32]

Figure 24 below shows that climate has a dramatic effect on hydropower production at Kariba. Mean generation under a wetting climate would only be about 2% higher than the baseline, while a drying climate would lead to a 13% drop in average annual generation (2011–2070) (see summary in Table 33 for mean values).

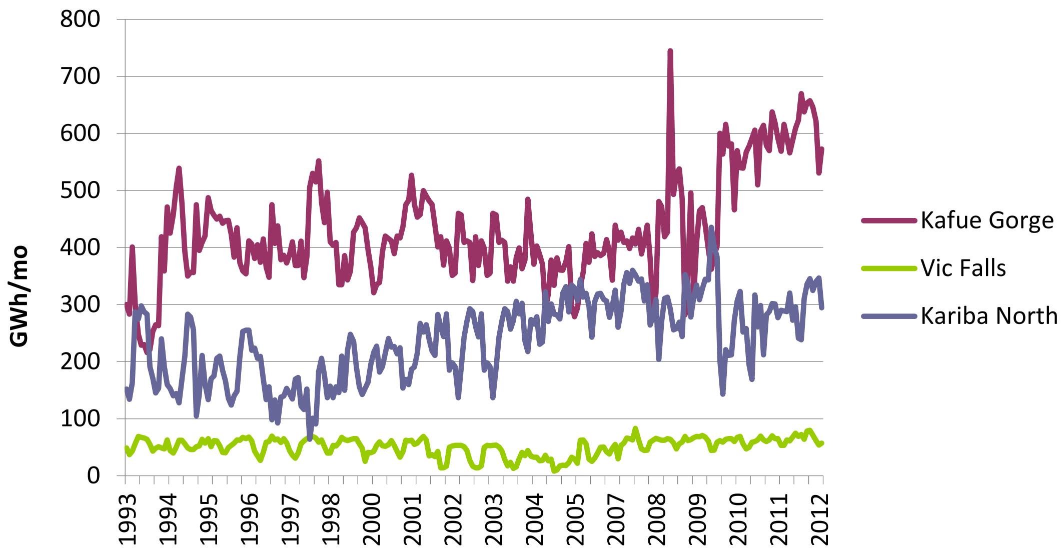
[32] Average annual generation for Kariba from 1960–1990 was approximately 5,750 GWh/yr (Tumbare 2000). More recent average generation from 1993 to 2012 was 6 934 GWh/yr. Kariba North generation is from ZESCO, while Kariba South is total hydropower generation for Zimbabwe as reported by IEA (2011).

Figure 24. Future annual generation at Kariba under BAU development



It is important to remember that actual historical production is also highly variable due to normal climate variability. Figure 25 shows historical monthly generation at Kariba North, Kafue Gorge Upper and Victoria Falls, which all vary by season and between years.

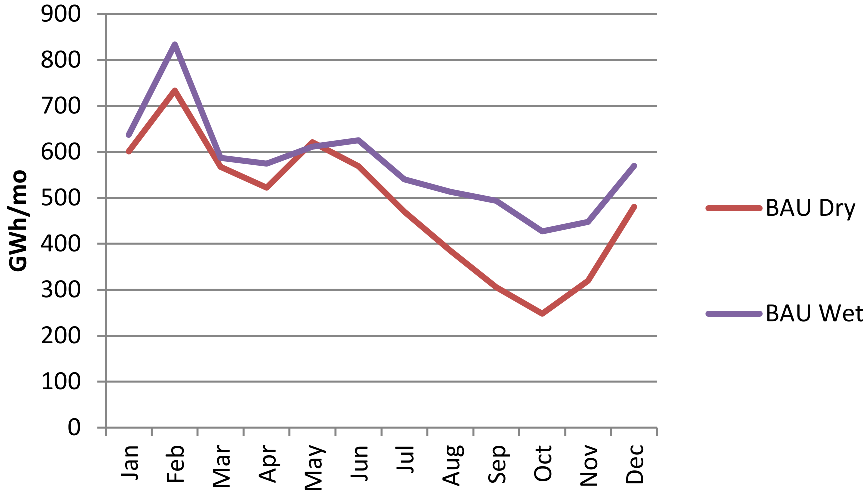
Figure 25. Historical monthly generation (1993-2012) at ZESCO hydropower plants



Source: ZESCO (2013c)

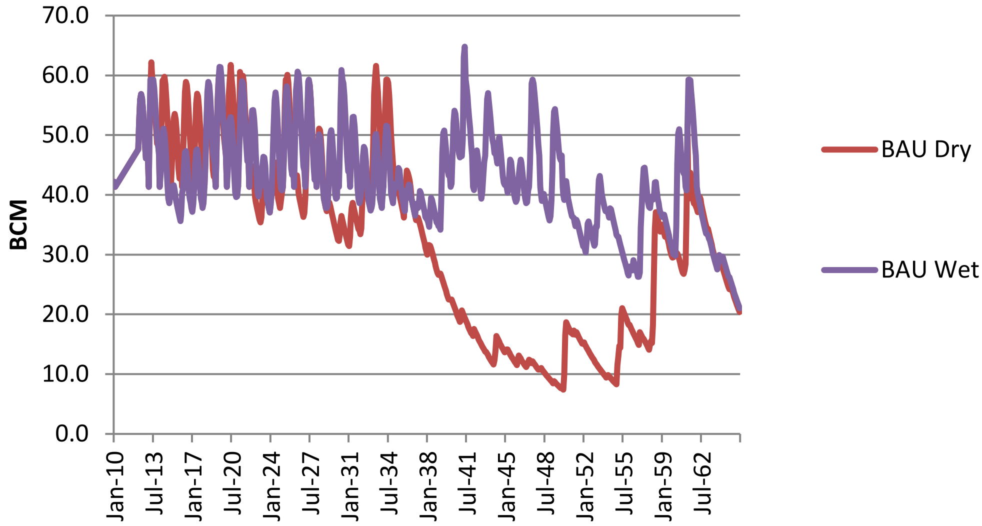
In terms of monthly generation, Figure 26 shows that the drop in generation under the drying scenario is primarily in July to November. The higher generation in February is from lowering the lake level as per the DFRC. The model assumes this additional outflow will pass through the turbines for as long as the flow is less than the maximum turbine flow (which is the case at Kariba).

Figure 26. Future monthly generation at Kariba under BAU development



The reservoir levels generally follow the DFRC for the wetting climate, but even with buffering in the reservoir, the drying climate leads to severe draw-down of the reservoir over the driest decades, which in turn reduces the efficiency of power generation (Figure 27).[33]

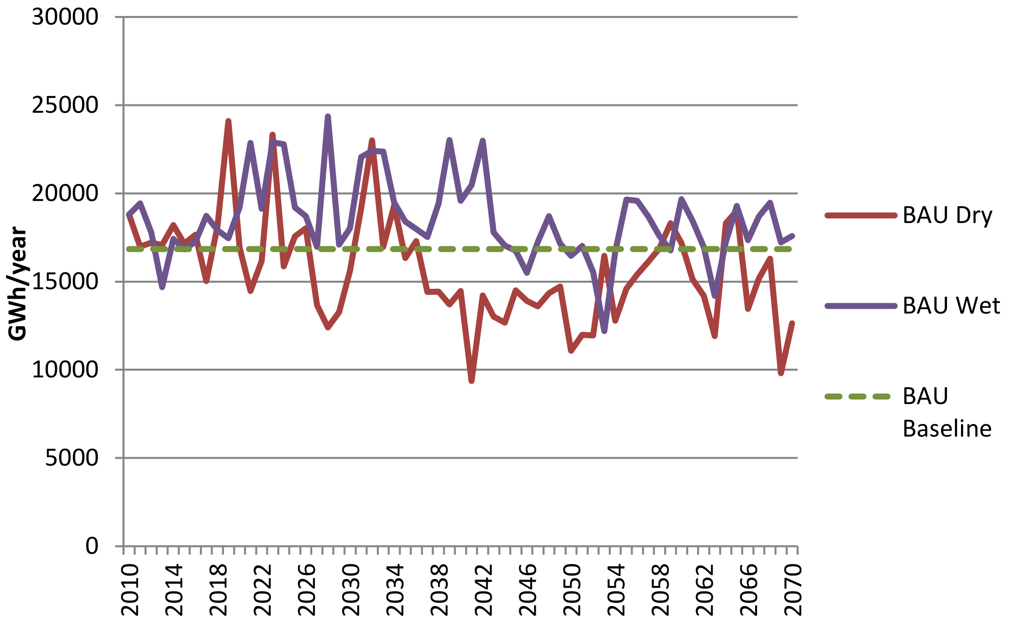
Figure 27. Future reservoir volume at Kariba under BAU development



For Cahora Bassa, modelled generation using historical climate data and BAU development is 16,864 GWh/year. This is about 10% higher than the current target stated by Hidroeléctrica de Cahora Bassa of 15,500 GWh/year. For purposes of comparison with future scenarios, it is therefore important to use the modelled baseline generation, to accurately show the percentage change in generation due to climate and upstream development. While the wetting climate would result in more substantial increases compared to Kariba, the drying climate still results in a more than 7% decline in mean annual generation (Figure 28).

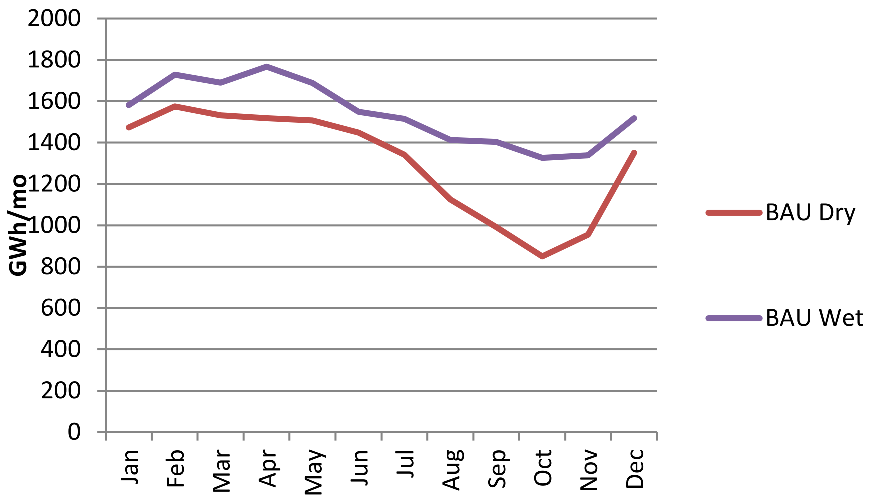
[33] For the BAU Dry scenario, mean storage is 32.3 BCM (Coefficient of Variation=0.46), while for the BAU Wet scenario, mean storage is 42 BCM (Coefficient of Variation=0.21).

Figure 28. Future annual generation at Cahora Bassa under BAU development



Monthly generation declines under a drying climate most significantly in July to November as at Kariba (Figure 29).

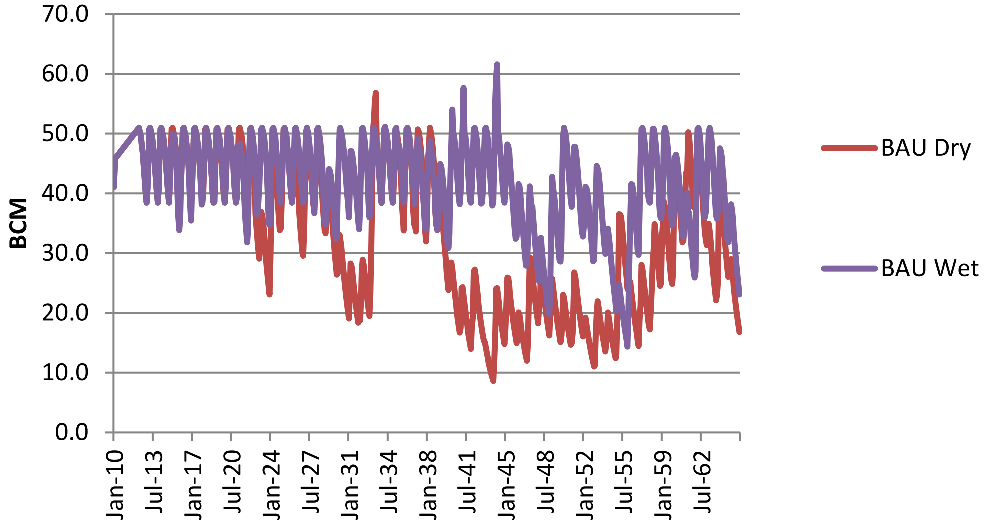
Figure 29. Future monthly generation at Cahora Bassa under BAU development



Reservoir levels are maintained at the level specified in the DFRC under a wetting climate, but the severe drought years in the drying climate result in dramatic draw-down of the reservoir (Figure 30).[34]

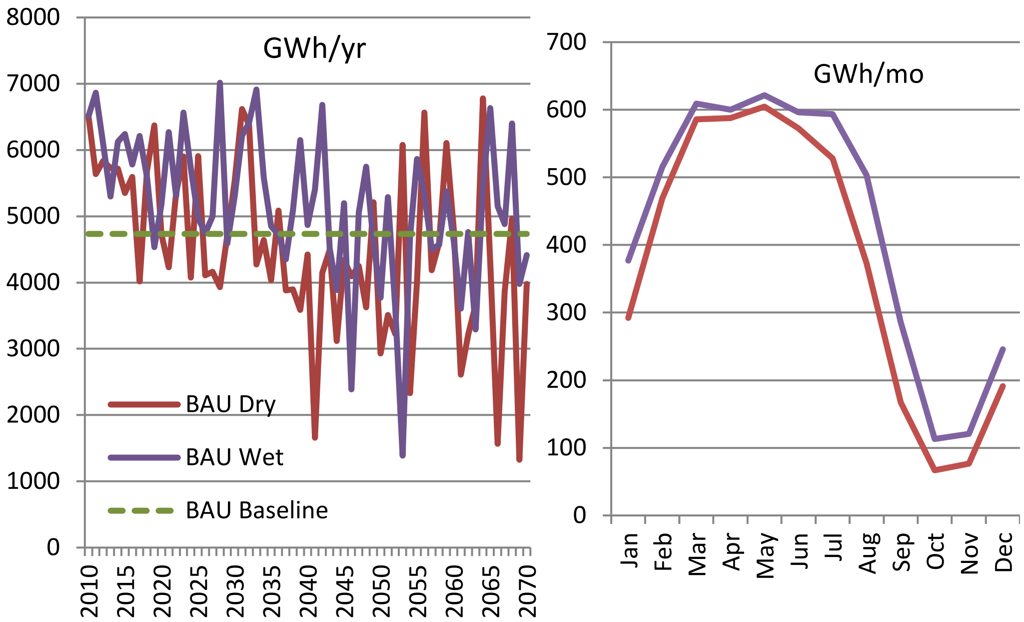
[34] For the BAU Dry scenario, mean storage is 33.1 BCM (Coefficient of Variation=0.36), while for the BAU Wet scenario, mean storage is 41.6 BCM (Coefficient of Variation=0.18).

Figure 30. Future reservoir volume at Cahora Bassa under BAU development



For Kafue Gorge Upper, baseline modelled production is 4,734 GWh/year under BAU development.[35] Kafue Gorge Upper future generation can only meet this level in the future under a wetting climate (Figure 31), with lower generation under a drying climate in almost all months.

Figure 31. Future annual and monthly generation at Kafue Gorge Upper under BAU development



4.4.3 *Future climate and development impact on new hydropower plants*

The key new hydropower plants analysed are Batoka Gorge, Chemba, Itezhi-tezhi, Mphanda Nkuwa, and Kafue Gorge Lower. In addition, Mpata Gorge and Devils Gorge are considered briefly, because of their size (i.e. >1000 MW). For each of the new plants, annual generation under future climates is compared with modelled generation under the historical baseline

35 Actual production in more recent decades was 5,160 GWh/yr (1993–2012).

climate, as well as the target stated by the utilities or in the literature, where this is available. Only the Mphanda Nkuwa feasibility study reports a variable monthly target generation, however, so for the other plants the monthly target is simply constant.

The modelled baseline generation at Itezhi-tezhi under the historical climate is 437 GWh/yr over the period 2030–2070. This is considerably lower than the stated target of 611 GWh/yr in the literature. This suggests that, even without changes in climate, it would be difficult for Itezhi-tezhi to meet generation demands, in part due to the growth of irrigation upstream (which is included in the BAU development scenarios). There may also be some model bias, because under calibration period modelled outflows were 7% lower than gauged outflows (Table 30). In terms of climate impacts, mean generation at Itezhi-tezhi does increase somewhat under a wetting climate and falls almost 8% under a drying climate (Figure 32 and Table 34). The decline under a drying climate is observed in almost all months (Figure 33).

Figure 32. Future annual generation at Itezhi-tezhi under BAU development

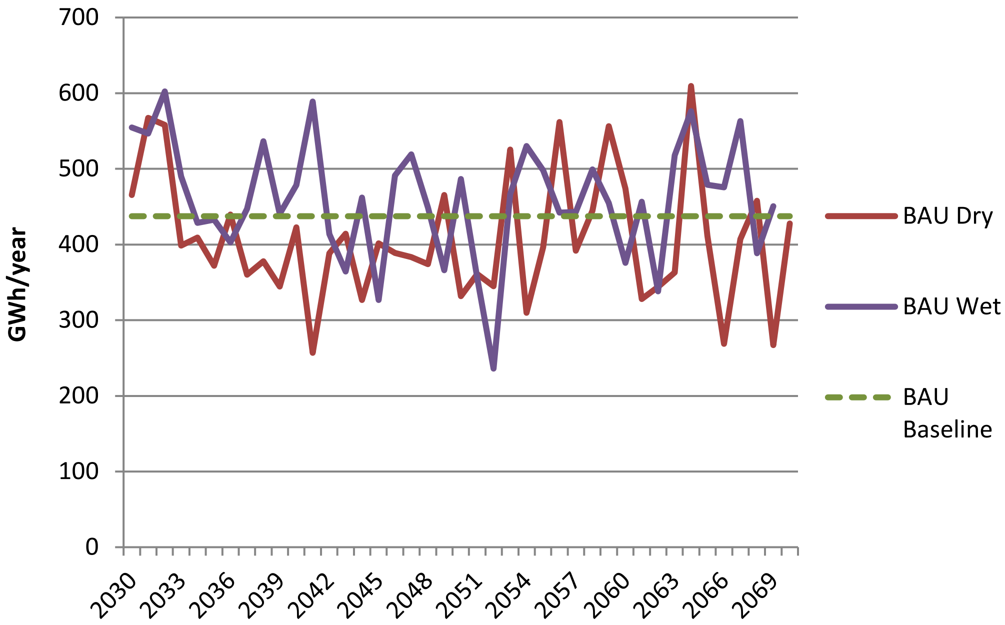
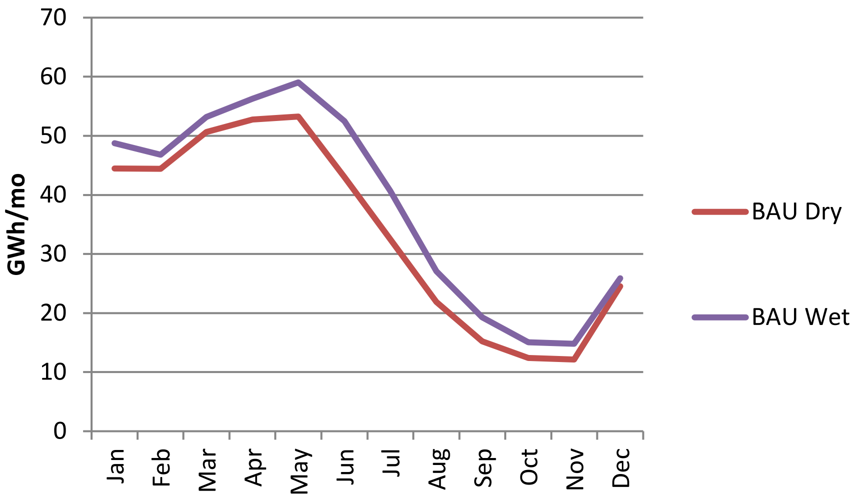
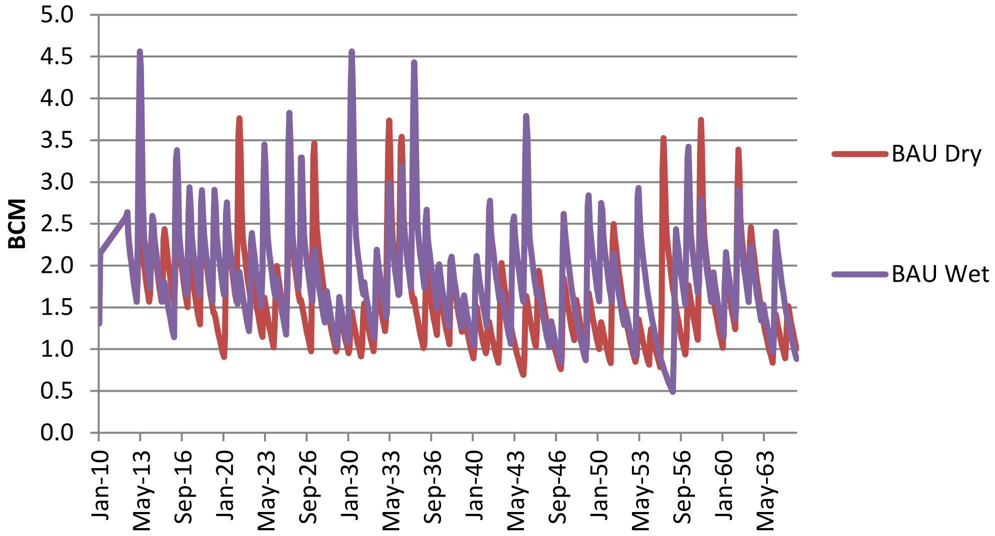


Figure 33. Future monthly generation at Itezhi-tezhi under BAU development



In the future dry years, the reservoir generally follows the DFRC, although it is drawn down somewhat lower during dry years (Figure 34).

Figure 34. Future reservoir volume at Itezhi-tezhi under BAU development



According to the ZRA, the Batoka Gorge feasibility study is currently being revised, but the most recent estimate of generation is 8,728 GWh/year. The modelled generation based on historical climate, however, is considerably lower than this, at just under 7,400 GWh. Under both drying and wetting future climates, however Batoka barely even achieves this level of production, due to inter-annual variability, increased upstream demands and variations in rainfall across the basin (Figure 35, Table 34). The monthly generation curves (Figure 36) show very low generation levels in the dry season, but this is expected, given that Batoka Gorge only has a small reservoir (1,680 mcm) and is meant to operate in conjunction with Kariba.

Figure 35. Future annual generation at Batoka Gorge under, BAU development

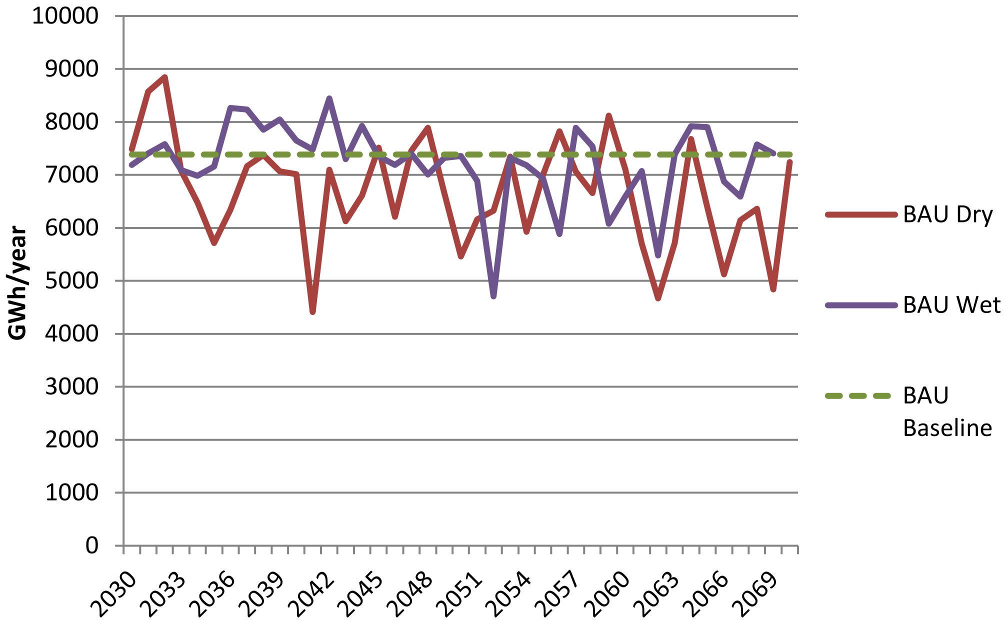
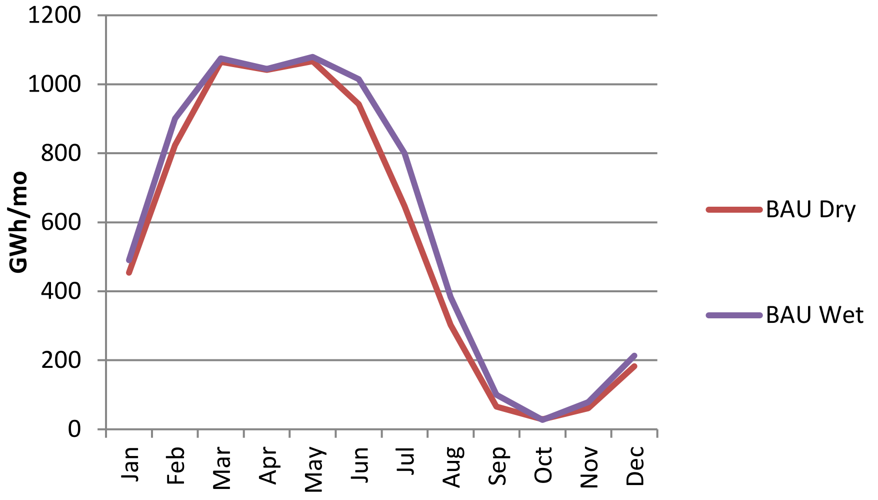


Figure 36. Future monthly generation at Batoka Gorge under BAU development



The published target for Mphanda Nkuwa is 8,600 GWh/yr for a 1500 MW plant, which represents a net availability of 65%. Whether the expansion of 750 MW in phase II would have a similar availability is questionable, given the limited size of the reservoir (i.e. 2,324 mcm vs 65,000 mcm for Cahora Bassa). The modelled baseline production for both phases over the 2035–2070 period is 9,600 GWh/yr, or an average availability of 48%. Under BAU development, the drying climate would reduce generation by more than 10% on average, while a wetting one would increase the mean by 4% (Figure 37, Table 34). Because Mphanda Nkuwa only has a small buffer reservoir, the monthly generation profile follows the Cahora Bassa discharge (compare Figure 29 with Figure 38), and annual generation shows high volatility.

Figure 37. Future annual generation at Mphanda Nkuwa under BAU development

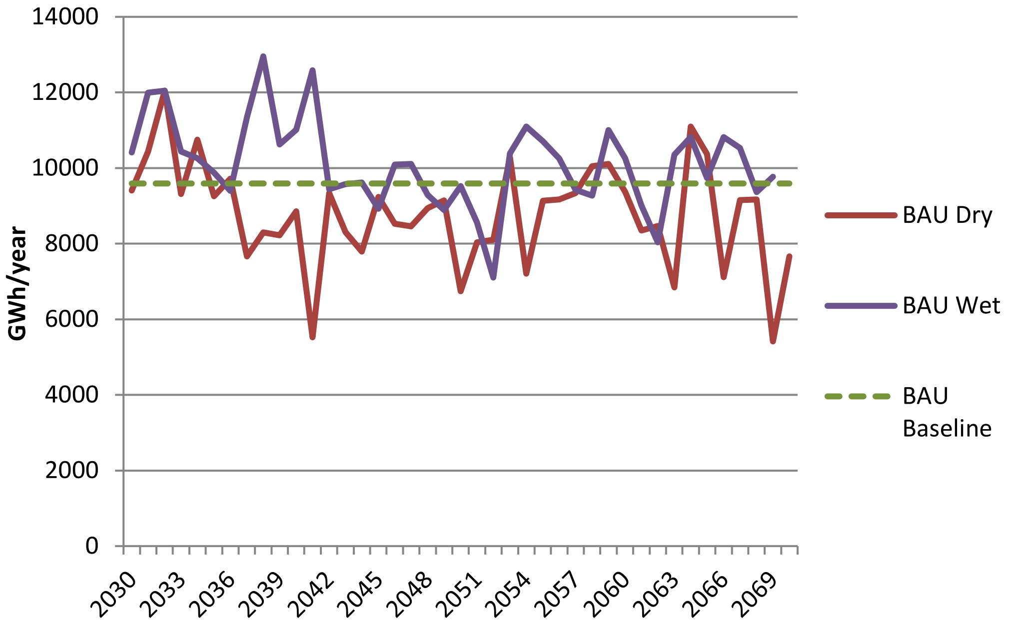
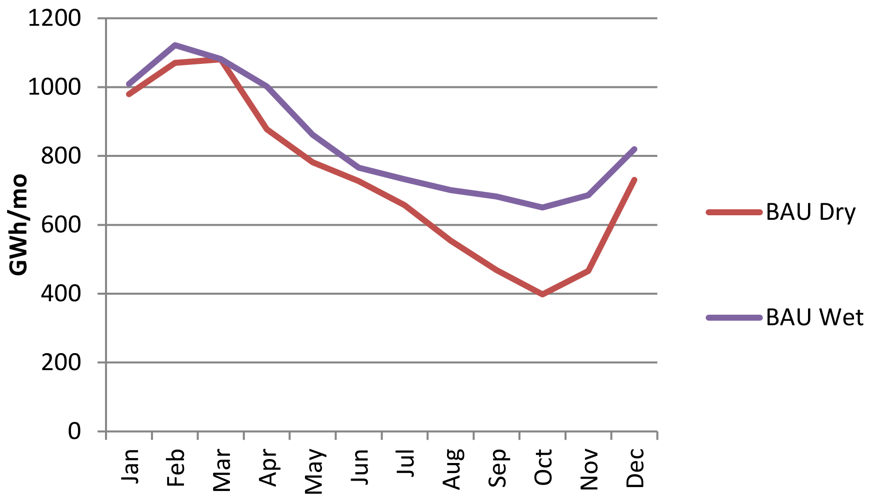
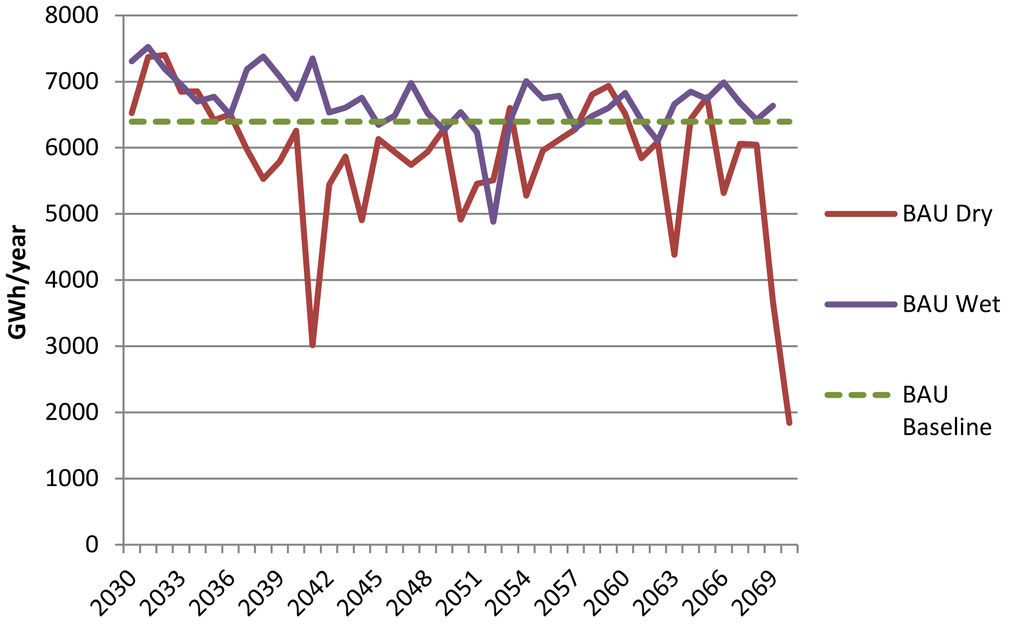


Figure 38. Future monthly generation at Mphanda Nkuwa under BAU development



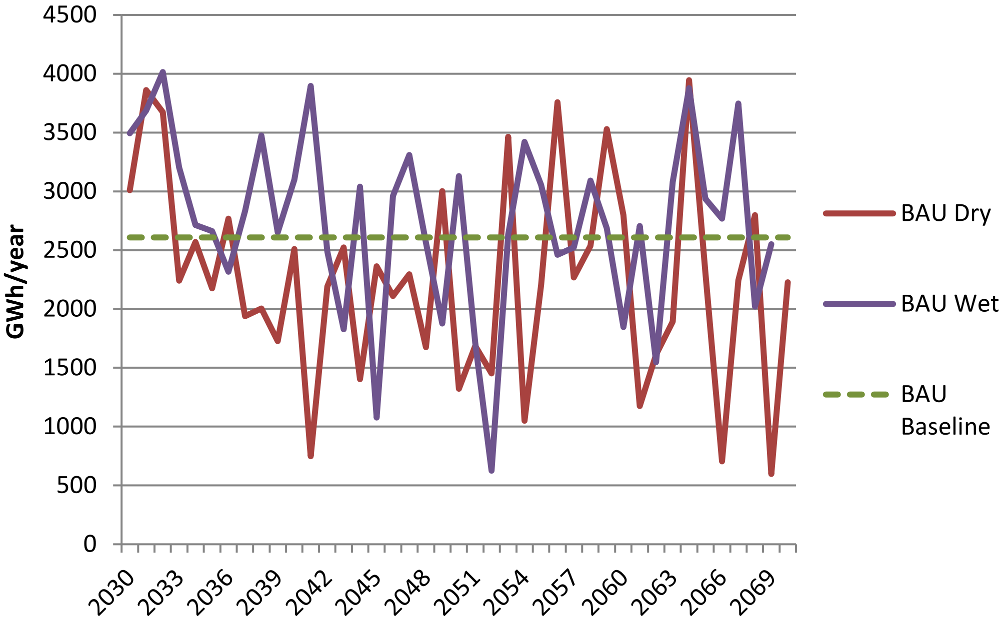
For Chemba, a wetting climate increase mean generation by 4% while a drying climate reduces generation by 9% (Figure 39).

Figure 39. Future annual generation at Chemba under BAU development



As a run-of-river hydropower plant, Kafue Gorge Lower generation is based entirely on releases from Kafue Gorge Upper. This added vulnerability leads to a greater loss of generation under a drying climate (i.e. 15%), with modest (4%) increases under a wetting climate (Figure 40).

Figure 40. Future annual Kafue Gorge Lower generation under BAU development



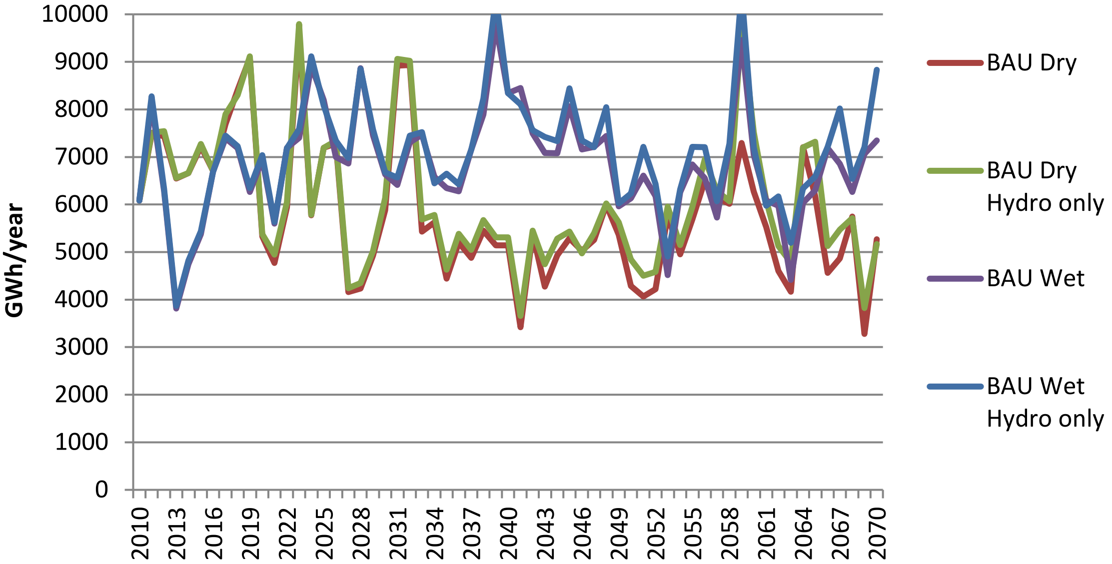
Vulnerabilities for Devils Gorge and Mpata Gorge are reported below in Table 34, with Mpata Gorge showing the highest vulnerability to a drying climate (>25% loss in mean annual generation).

4.4.4 *Relative impact of increased irrigation demand versus climate on the performance of existing and new hydropower plants*

In the previous sections, the hydropower results assumed that irrigation demand also grew under the development future (see Section 4.2.6). This section presents additional scenarios for the water analysis where irrigation demand is capped at historical levels. This means that the difference between these scenarios and the BAU Dry and Wet scenarios presented in the previous section will show the impact on hydropower generation of irrigation demand versus climate.

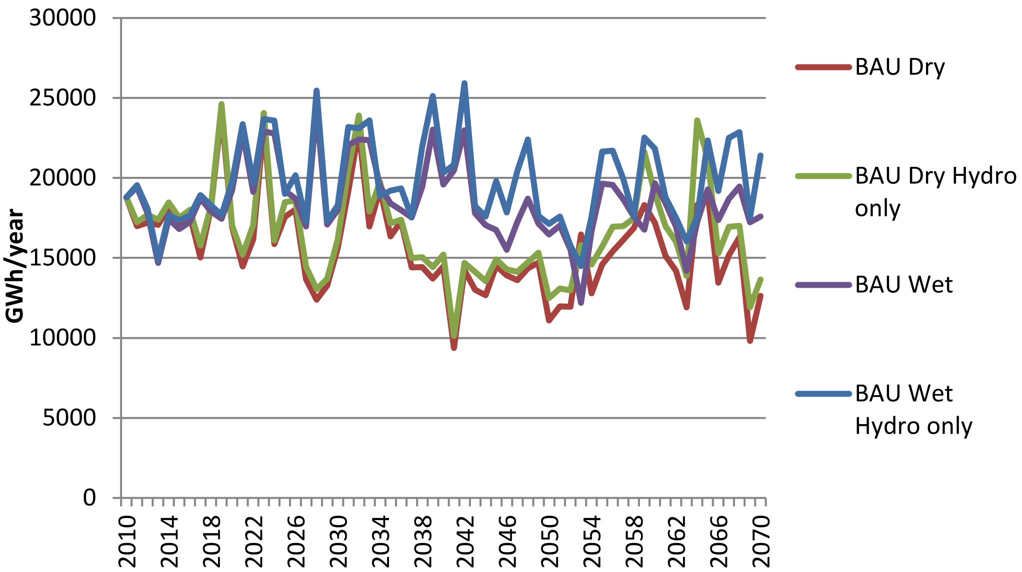
For Kariba, while the climate futures have a dramatic impact on generation, the impact of irrigation demand is modest, despite the large growth within that sub-basin in irrigation for identified projects (i.e. 97,000 ha) and high-level potential (i.e. 470,000 ha).

Figure 41. Future annual generation at Kariba, BAU development with and without growth in irrigation demands



For Cahora Bassa, although the changes are slightly greater (i.e. 6% versus 3% at Kariba – see green versus red line in the later decades) the overall impact is still much less than from the alternative climate futures (Figure 42).

Figure 42. Future annual generation at Cahora Bassa, BAU development with and without growth in irrigation demands



The results for Itezhi-tezhi are more similar to Kariba, with virtually no change in generation whether irrigation demand is included or not (i.e. the lines for "BAU Dry" and "BAU Wet" are not visible because they are the same as the other lines) (Figure 43). This also reflects the modest size of the irrigated areas upstream of Itezhi-tezhi (i.e. high-level potential of 25,000 ha, as compared to 430,000 ha around Kariba). The same phenomenon is observed at Kafue Gorge Upper, but at Kafue Gorge Lower the lack of a substantial reservoir means that generation is more strongly influenced by irrigation demand growth (Figure 44).

Figure 43. Future annual generation at Itezhi-tezhi, BAU development with and without growth in irrigation demands

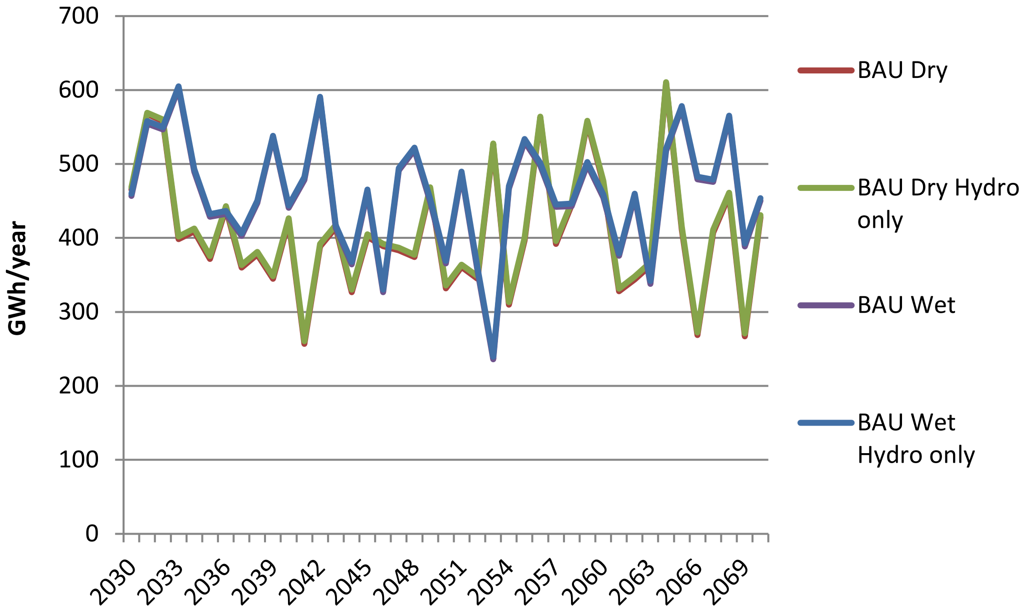
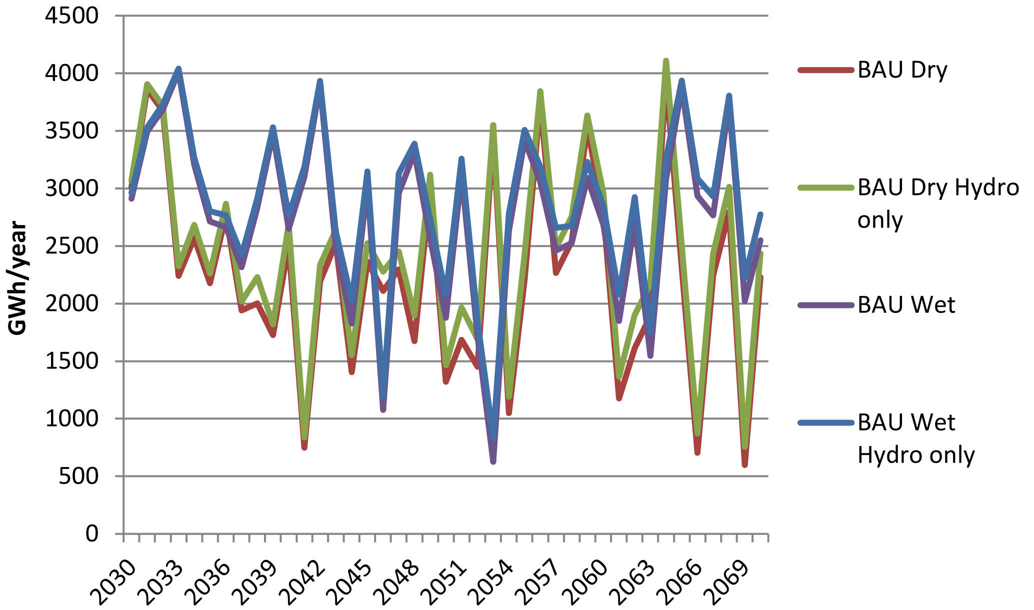
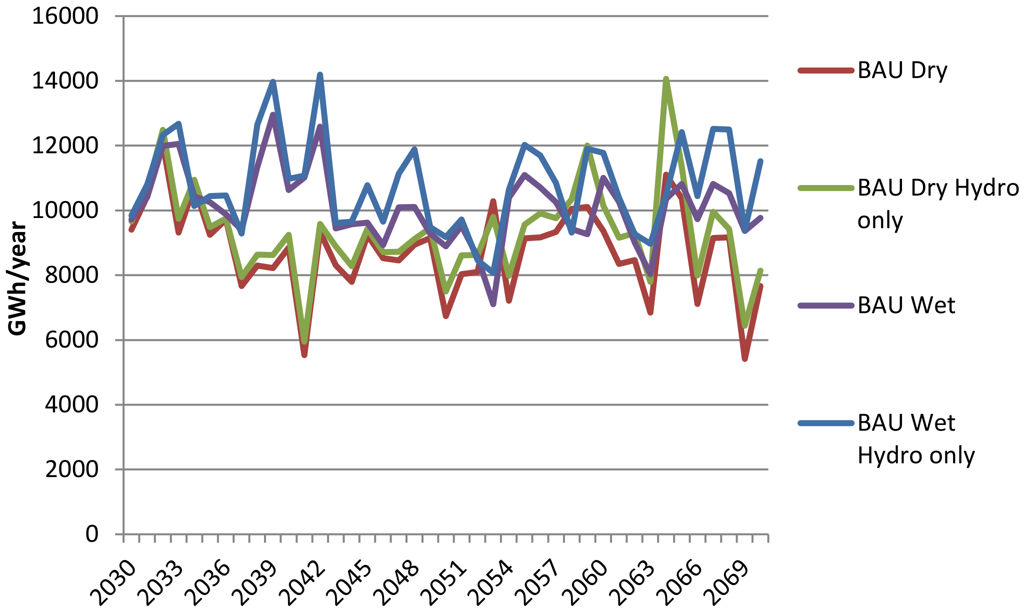


Figure 44. Future annual generation at Kafue Gorge Lower, BAU development with and without growth in irrigation demands



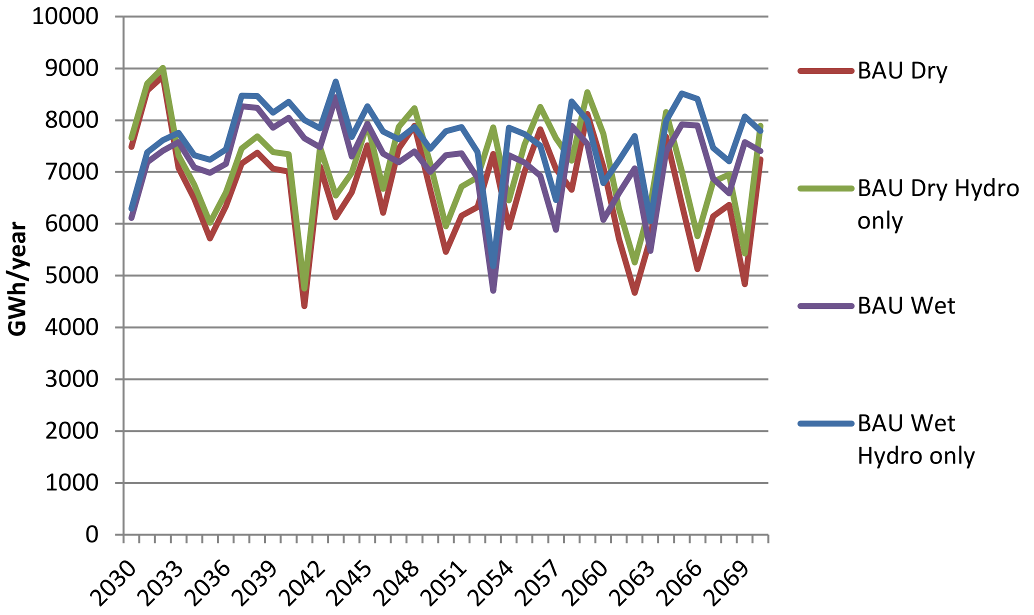
The results for Mphanda Nkuwa are, not surprisingly, more similar to Cahora Bassa. Irrigation demand reduces mean generation by 7% in both dry and wet scenarios (Figure 45 and Table 34).

Figure 45. Future annual generation at Mphanda Nkuwa, BAU development with and without growth in irrigation demands



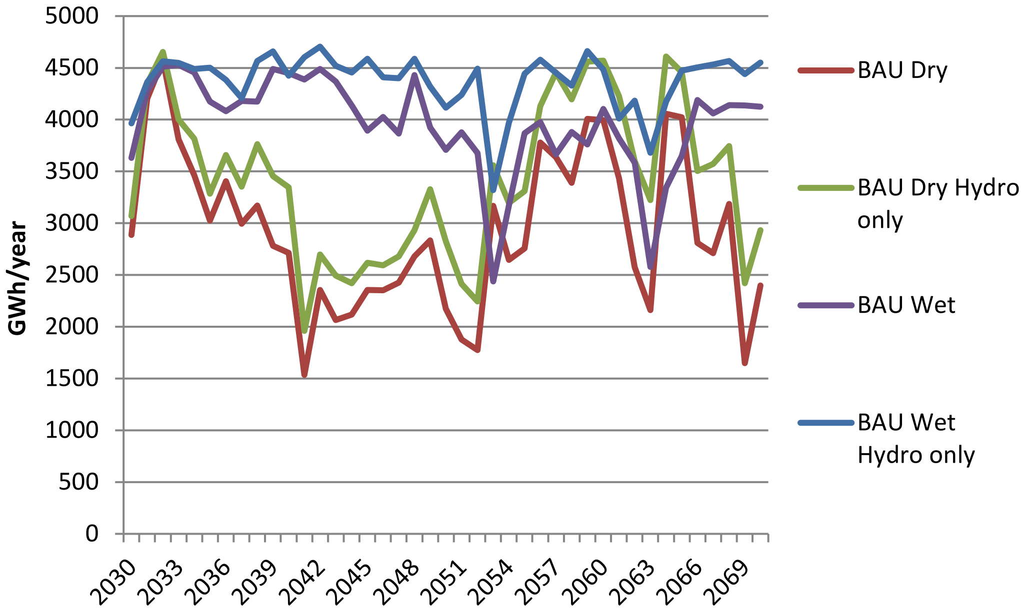
Batoka Gorge is impacted by irrigation demand more than Kariba is, due to the small reservoir size. Mean generation declines by 6% under both drying and wetting scenarios (Figure 46 and Table 34).

Figure 46. Future annual generation at Batoka Gorge, BAU development with and without growth in irrigation demands



The hydropower plant most affected by irrigation demand is Mpata Gorge, with losses of 10–15% in generation in almost all years (Figure 47).

Figure 47. Future annual generation at Mpata Gorge, BAU development with and without growth in irrigation demands



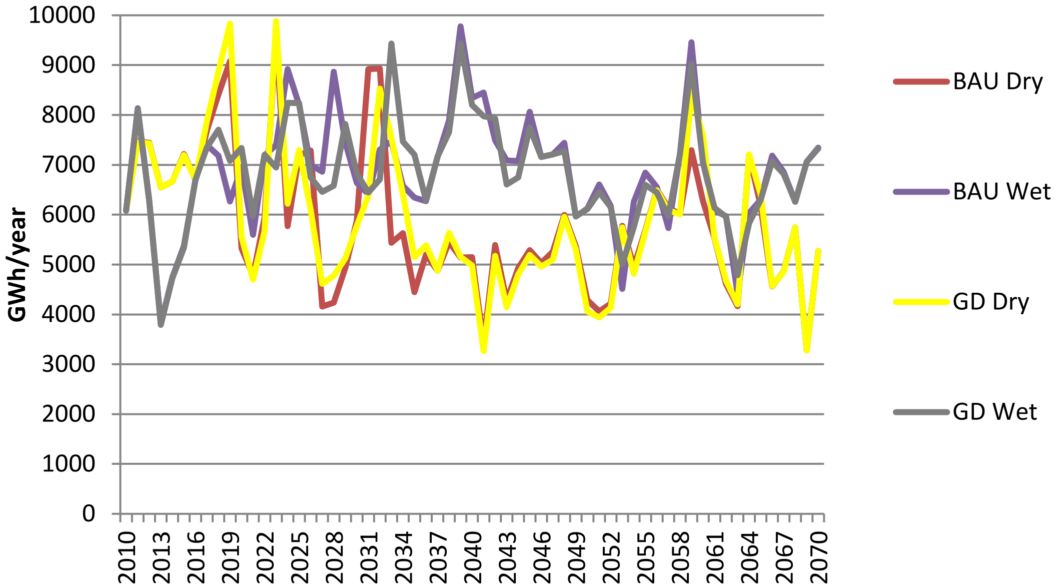
This analysis shows that the impact of irrigation demand depends on the location of the hydropower plant within the overall river basin. Higher up in the system, Itezhi-tezhi and Kariba are less affected, but the lower reservoirs at Mpata Gorge, Cahora Bassa and Mphanda Nkuwa are more vulnerable, because more of the potential irrigated area is lower in the basin. In addition, plants with smaller reservoirs tend to be more vulnerable. Nevertheless, the impact of irrigation demand is in almost all cases less than the impact of alternative climates.

4.4.5 *Effect of the pace of hydropower and irrigation investment on generation potential*

The previous section demonstrated that irrigation demand does have an impact on generation lower in the ZRB, particularly when reservoirs are small. The development futures discussed earlier include the possibility that irrigation demand could grow more quickly than under the BAU future, and that new hydropower investments could also be brought forward. Specifically, under the Grand Deal future, the year for achieving “identified irrigation projects” is brought forward from 2030 to 2020 and “high level potential” from 2060 to 2040. This means that irrigation demand rises much faster in the 2000-2030 period, and has reached a maximum by 2040. To test the impact of these alternative development futures, this section compares the results under the BAU scenarios with the Grand Deal scenarios.

This comparison is illustrated for Kariba in Figure 48. With the exception of a few years where the earlier implementation of other hydropower plants impacts generation, there is almost no difference in average generation under the different development scenarios.

Figure 48. Future generation at Kariba under BAU and Grand Deal development



For Cahora Bassa and Mphanda Nkuwa, performance also shows limited overall change based on the pace of irrigation and hydropower development (Figure 49 and Figure 50).

Figure 49. Future generation at Cahora Bassa with different levels of hydropower and irrigation development, all with irrigation prioritised

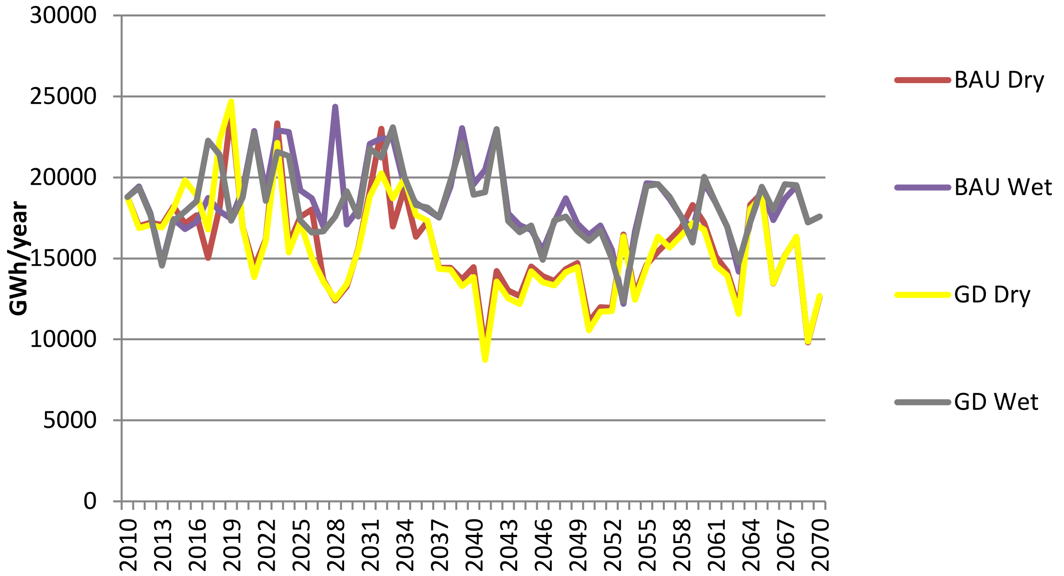
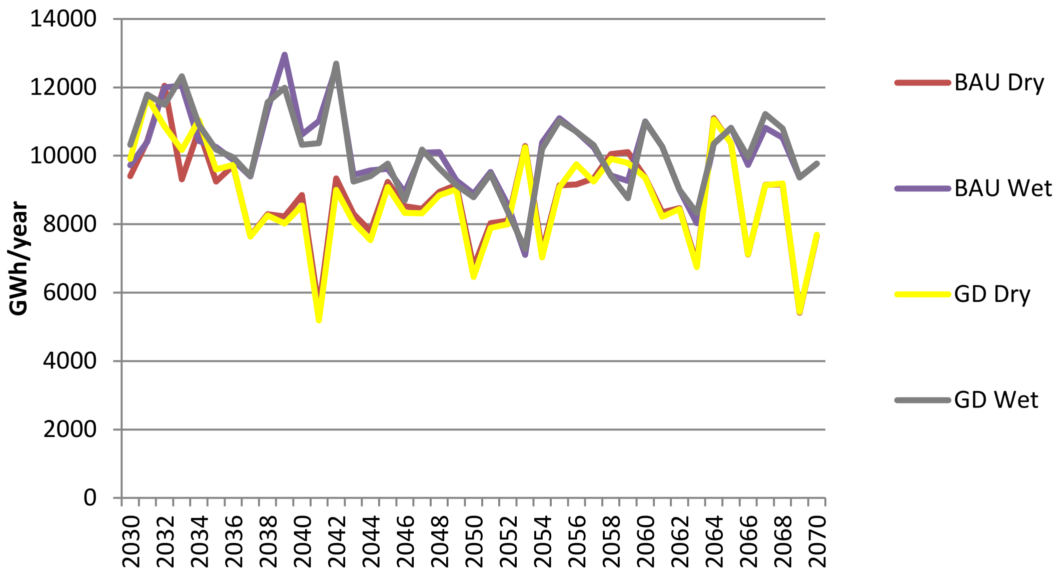


Figure 50. Future generation at Mphanda Nkuwa with different levels of hydropower and irrigation development, all with irrigation prioritised

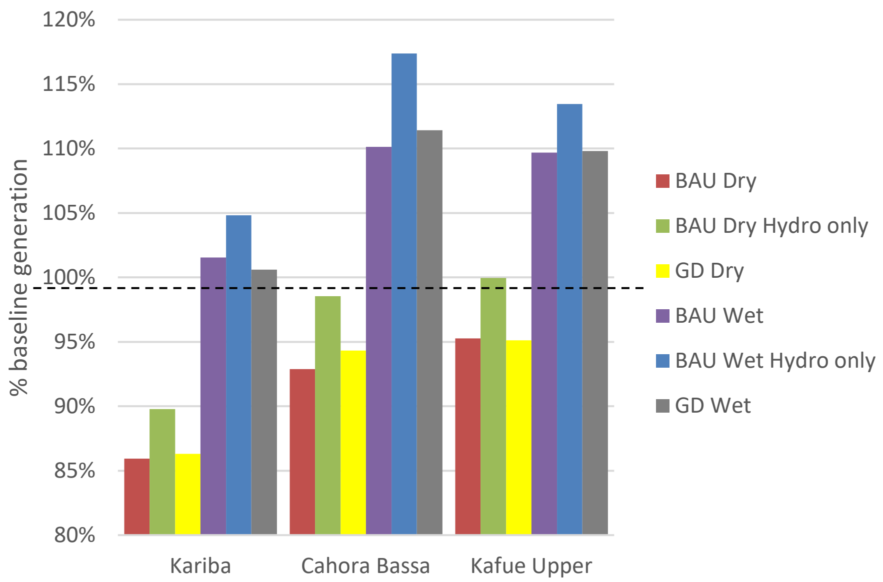


For the other plants, there is rarely more than 1% difference in mean generation due to the change in the development scenario, except for Mpata Gorge, which loses 2–4%, and Batoka Gorge, which losses 2% more production under the Grand Deal versus BAU scenarios.

4.4.6 *Summary of aggregate results*

In terms of the impact of the different climate futures, Kariba is the most vulnerable of the current major hydropower plants, while Cahora Bassa and Kafue Gorge Upper benefit more from the potential increases under a wetting climate (Figure 51).

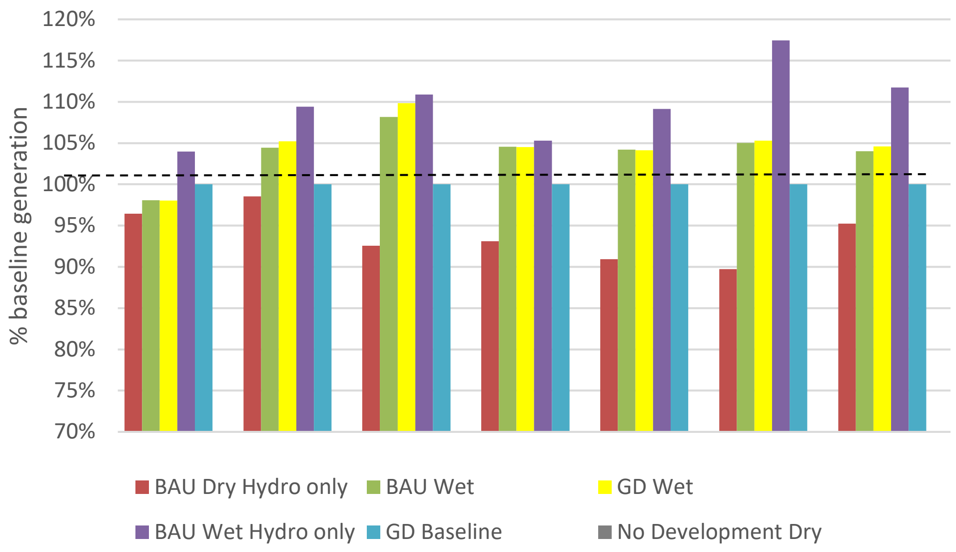
Figure 51. Generation relative to modelled baseline climate for existing plants under BAU development



Among the proposed new hydropower plants, almost all would lose 10–15% of mean generation under a drying climate, with Mpata Gorge seeing declines of 25% (Figure 52). The total change between the wetting and drying climates (i.e. the spread between BAU Dry and

BAU Wet or between GD Dry and GD Wet) is 12–16% of mean generation for all three existing plants, while the range varies much more for new plants, from 8-12% for Batoka, Itezhi-tezhi and Chemba, up to 20% for Devils Gorge and almost 30% for Mpata Gorge.

Figure 52. Generation relative to modelled baseline for new plants, BAU development



In terms of the impact of irrigation demand on hydropower production, most of the existing and new plants would lose 4–7% of mean annual generation regardless of the climate (Figure 53), because irrigation reduces the instream flows available for hydropower generation. Losses under drying climates are typically 1% greater than under wetting climates. Itezhi-tezhi and Mpata are the extremes, with the former being untouched by irrigation demand and the latter losing 10–15% of generation due to demands from upstream irrigation.

Figure 53. Impact of irrigation on generation (change in % mean generation)

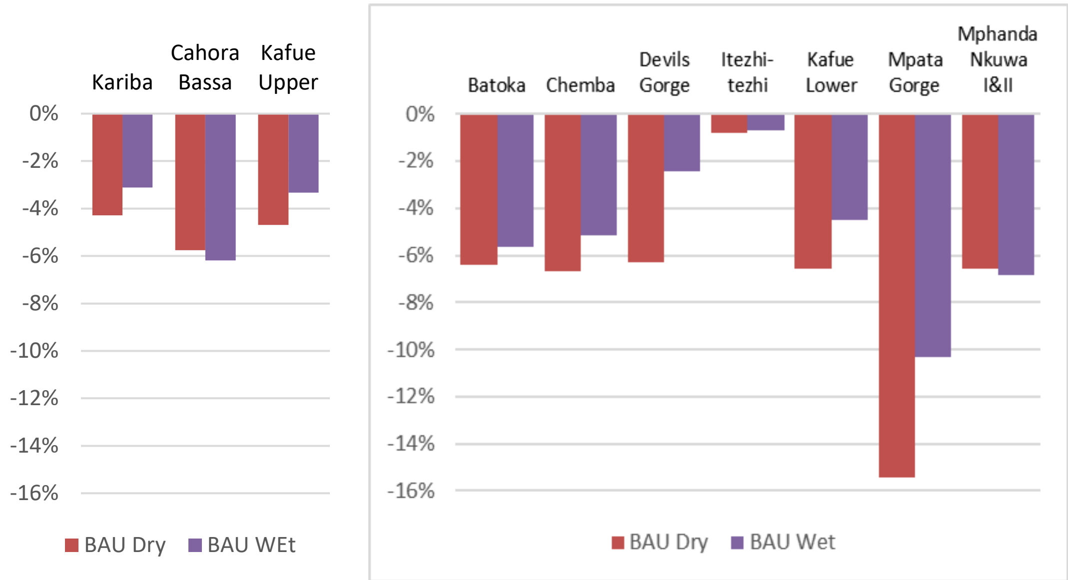


Table 33 and Table 34 summarise the results for existing and new hydropower plants, respectively, in terms of changes in mean generation versus the generation under the baseline climate. In addition, the tables report the absolute generation levels projected in the modelling.

Table 33. Summary results for existing hydropower plants with expansions under different climates and irrigation scenarios

Scenario	2011–70 mean generation (GWh) and coefficient of variation in generation (%)						Generation versus baseline (%)		
	Kariba		Cahora Bassa		Kafue Upper		Kariba	Cahora Bassa	Kafue Upper
BAU Baseline	6,770	30%	16,832	20%	4,704	30%	100	100	100
BAU Dry	5,868	24%	15,591	19%	4,482	28%	87	93	95
BAU Dry Hydro only	6,079	23%	16,553	18%	4,702	25%	90	98	100
BAU Wet	6,876	16%	18,543	12%	5,160	21%	102	110	110
BAU Wet Hydro only	7,095	17%	19,738	13%	5,338	19%	105	117	113
GD Baseline	6,810	29%	16,479	18%	4,680	31%	100	100	100
GD Dry	5,883	24%	15,557	20%	4,451	28%	86	94	95
GD Wet	6,857	15%	18,347	12%	5,139	21%	101	111	110
SADC Int Dry*	5,882	24%	15,685	19%	4,466	28%			
SADC Int Wet*	6,850	15%	18,497	11%	5,149	21%			

Note: *the SADC Int scenarios does not have generation versus baseline because there is no "SADC Baseline" scenario – they are only shown to illustrate the negligible difference with the Grand Deal scenarios.

Table 34. Summary results for new hydropower plants under different scenarios (2030-70 average annual generation, GWh)

Scenario	Batoka	Chemba	Devils Gorge	Itezhi-tezhi	Kafue Lower	Mpata Gorge	Mphanda Nkuwa I&II
BAU Baseline	7,378	11,845	5,795	439	2,630	3,726	9,601
BAU Dry	6,662	10,885	5,025	406	2,234	2,821	8,558
BAU Dry Hydro only	7,117	11,662	5,364	409	2,392	3,336	9,159
BAU Wet	7,236	12,361	6,268	459	2,740	3,924	10,003
BAU Wet Hydro only	7,670	13,031	6,426	463	2,870	4,377	10,740
GD Baseline	7,261	11,721	5,692	442	2,623	3,675	9,475
GD Dry	6,541	10,736	5,087	408	2,220	2,718	8,476
GD Wet	7,119	12,242	6,252	461	2,732	3,865	9,950
SADC Int Dry	6,601	10,846	5,133	407	2,227	2,768	8,540
SADC Int Wet	7,177	12,307	6,265	460	2,736	3,920	9,995

4.5 Discussion and conclusions

The objective of this chapter has been to answer the question: "How could future climate and irrigation expansion in the Zambezi River Basin affect hydropower generation potential?", based on an analysis of impacts on specific, major ZRB hydropower plants. The analysis covered major existing plants (i.e. Kariba, Cahora Bassa and Kafue Gorge Upper), extensions to existing plants (i.e. Kariba North and South Bank, Cahora Bassa North Bank) and major new plants (i.e. Batoka Gorge, Chemba, Itezhi-tezhi, Mphanda Nkuwa, Kafue Gorge Lower and, to a lesser extent, Devils Gorge and Mpata Gorge).

While future climate is subject to scientific uncertainty, the impact of irrigation is a policy and economic uncertainty. The latter is both because the level of irrigation investment is driven by political and economic priorities, and because the priority given to irrigation demand versus hydropower demand for water is a political decision. In the context of the ZRB, prioritisation is an international political decision as well, because of the different countries utilising the resources of the Zambezi. However, because there is currently no regime to negotiate the priorities of various water demands across sectors and countries, upstream abstraction or use has *de facto* higher priority. In other words, by not setting deliberate priorities, the riparian states are essentially agreeing to *de facto* priorities entirely based on geography (i.e. upstream users get first use of the water).

Change in future climate is the overwhelming driver of future production at almost all hydropower plants. The difference in mean generation under wetting and drying climates is substantial for existing plants, ranging from 12–16% of mean generation. For new plants, however, the variation could even be greater for some sites – as much as 30% – although for Batoka Gorge it is estimated at 8% of generation. The impact of irrigation, on the other hand, is mainly an issue for plants below Kariba, and even then the magnitude is typically less than a third of the impact of the alternative climates. The water modelling results, therefore, do not vary significantly across alternative development futures, because the accelerated irrigation development is still not large enough to dramatically impact hydropower. That said, a 5–6% decline in mean generation for a power plant that is already marginal in terms of financial returns could be enough to impact the economic viability of some new investments. This needs to be considered on a case-by-case basis in the feasibility studies for new hydropower plants.

While most of the focus here is on the relative changes in generation, some discussion of the absolute levels of production is also important. Average output at Kariba between 1993 and 2012 has been more than 6,400 GWh/yr (MEWD 2010; IEA 2011; ZESCO 2013b), and the national utilities expect an additional 1500 GWh/yr from the Kariba North and South Bank expansions (MEWD 2010; Nexant 2007). The modelling suggests, however, that, even with the additional turbines available, there may not be enough water to generate significantly more than historical levels. The limitations on output have become clear in recent years, as continued drought and lack of coordination on discharges have drawn down Lake Kariba to perilously low levels (Tsiko 2016), jeopardising future generation. Similarly, for Cahora Bassa, the North Bank extension is expected to deliver another 2,835 GWh on top of a current target for 15,500 GWh (Nexant 2007; HCB 2013). Only the wetting scenarios demonstrate the possibility of achieving this level of output, while the drying scenarios fall far short of this level. In terms of new plants, the Zambezi River Authority has stated that Batoka Gorge should deliver more than 8,700 GWh/yr (ZRA 2013; MEWD 2010), but there are no modelled scenarios in which generation is this high. Even taking into consideration the possibility of model bias, this calls into question the prospects of meeting these generation targets. Output at Mphanda Nkuwa is beyond the first phase target of 8,600 GWh, but this is only after adding additional turbines for the second phase. The second phase could be underutilised, with overall availability falling to less than 50%. Whether this is problematic or not depends on the incremental costs of the second phase expansion, and what levels of production are needed to make this project financially viable.

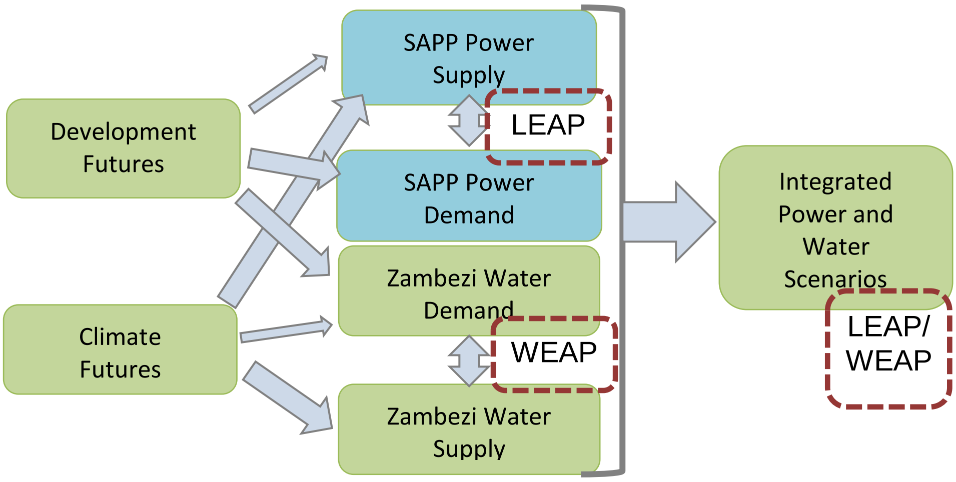
The dramatic potential impacts of future climate on hydropower potential in the Zambezi River Basin point to the need to explicitly consider climate change in both project planning and overall system expansion planning. The next chapter presents that electricity sector model for the region that will be used for this assessment, while Chapter 6 takes the results for the water modelling and integrates them with the power system analysis.

5 Electricity supply and demand scenarios for the Southern African Power Pool[36]

The previous chapter addressed the first research question of how future climate and irrigation expansion in the Zambezi River Basin affect hydropower generation potential. This chapter now turns to the second research question: How could development in Southern Africa affect power demand, and how might this demand be met? To answer this question, this chapter presents the modelling methodology, assumptions, and results for electricity supply and demand for the SAPP. The relationship to the overall thesis methodology is shown in Figure 4, highlighting the analysis in this chapter.

Section 5.1 defines the scope, followed by 5.2 with the structure of the demand modelling. Both the underlying development drivers and the electricity intensity assumptions for the demand modelling are presented in Section 5.3. The inputs for electricity supply modelling are presented in Section 5.4, after which Section 5.5 outlines the assumptions on transmission and trading. Section 5.6 then covers the model calibration, where the base year modelling results are compared to actual reported electricity demand and available capacity. The results for both demand and supply modelling, including costs and environmental impacts, are presented in Section 5.7, followed by discussion and conclusions in 5.8.

Figure 54. Role of Chapter 5 in the overall methodology



5.1 Scope of electricity modelling

As with the water modelling, the base year for the electricity modelling is 2010, with the first simulation year being 2011, which was the most recent year with reasonable complete datasets for all of the countries included. The study period of 2010–2070 is considerably longer than that for other studies on the SADC (or even national) energy demand and supply (Merven, Davis, and Hughes 2010; SAPP 2014; DoE 2013; Economic Consulting Associates 2009). The system boundary for costs is electricity generation only (i.e. not demand-side costs and not transmission and distribution costs)[37], and all costs are reported in 2010 US dollars. The system boundary for electricity modelling, however, includes demand projections.

The electricity model covers the 12 continental SADC countries: Angola, Botswana, Democratic Republic of Congo (DRC), Lesotho, Malawi, Mozambique, Namibia, South Africa,

[36] As discussed in section 1.5, this section draws upon the analysis also presented in Spalding-Fecher et al. (2017)

[37] Because transmission and distribution costs are not expected to vary significantly across the scenarios, this exclusion does not materially affect the results of the analysis.

Swaziland, Tanzania, Zambia, and Zimbabwe. Even though Angola, Malawi and Tanzania are not currently connected to the SAPP regional grid, there are inter-connector projects currently underway. In terms of the LEAP dataset, all 12 of the countries are considered “regions” and inherit key equations and parameters from a generic country template.

The SADC dataset developed for this research covers only the electricity sector (supply and demand) and the fuel inputs for power generation. It does not address primary energy sources used for non-electric end uses (e.g. biomass) or the use of other fuels directly in electricity consuming sectors (e.g. fuel use in boilers). Power plants are grouped into existing plants, specific plants (i.e. new planned projects where the project site is specified), and generic plants (i.e. ones that could be built anywhere in the country).

5.2 Sectoral demand structure

The starting point for disaggregating sectoral demand is the primary economic sectors used in the World Development Indicators database (agriculture, manufacturing, other industry, and services),[38] plus the residential sector. This also matches the main International Energy Agency (IEA) categories (IEA 2014c), as shown in Table 35.

Table 35. Demand sector definitions

Sector name in this study	World Development Indicators	International Energy Agency
Agriculture	Agriculture	Agriculture/ forestry, fishing
Manufacturing	Manufacturing	All of industry except mining and quarrying
Extractive	Industry – manufacturing	Mining and quarrying
Services	Services	Commerce and public services
Residential	N/A	Residential

Because transportation sector consumption of electricity is almost non-existent in most SAPP countries, this was not included in the modelling. The exception is South Africa, where electric rail for passengers and freight is included because electricity consumption from rail could become increasingly important in the future. Residential demand was further disaggregated into urban and rural households, as shown in Table 36.

Table 36. Residential demand structure for all countries except South Africa

Sector	Sub-sector	Additional level
Residential	Urban	Electrified
		Unelectrified
	Rural	Electrified
		Unelectrified

Source: Adapted from ERC (2013)

For South Africa, more detailed data is available on sub-sector energy demand and demand drivers, created for this study but based on previous research by the Energy Research Centre

[38] The WDI reports “industry” as a percentage of GDP, and “manufacturing” as a sub-set of industry. The difference between total industry, and manufacturing, which is “other manufacturing”, is what is called “extractive” in this study because it includes mining, quarrying and oil extraction.

(ERC 2013), so this country has more detailed demand structure in the modelling, as shown in Table 37.

Table 37: Demand structure for South Africa

Sector	Sub-sector	Additional level
Residential	Urban	Low income electrified
		Middle income electrified
		High income electrified
		Low income non-electrified
		Middle income non-electrified
	Rural	Low income electrified
		Middle income electrified
		High income electrified
		Low income non-electrified
		Middle income non-electrified
Agriculture	None	End uses
Manufacturing	Iron and steel	End uses
	Chemicals	
	Precious and non-ferrous metals	
	Food beverages tobaccos	
	Non-metallic metals	
	Pulp and paper	
	Other industry	
Extractive	Mining	End uses
Services	None	End uses
Transport	Passenger	Road
		Rail
	Freight	Road
		Rail

Source: Adapted from ERC (2013)

5.3 Demand modelling

The future demand projections used in this modelling analysis are entirely “bottom-up”, meaning that they are based on an understanding of the fundamental drivers of demand and how these may evolve over time. This bottom-up approach is one of the most important value-added components of this research versus other regional energy and electricity analysis, which typically use aggregated, “top-down” assumptions for electricity demand growth. The detailed logic and assumptions behind the development scenarios are presented in Chapter 3, including the inputs for population and economic development that are used in the electricity demand model. The sections below first present the additional inputs on drivers of demand beyond what is included in Chapter 3, and then (from Section 5.3.3 onward) outline the assumptions used to link the development drivers to electricity final demand (i.e. the electricity intensity of different activities). Importantly, the bottom-up approach means that it is possible to disaggregate the effects of changing activity levels (e.g. GDP), changing structure of demand (e.g. electricity access, share of GDP) and energy intensity (e.g. consumption per household or per dollar of GDP).

5.3.1 *Access to electricity*

The current access to electricity for each country is shown in Table 38. The Grand Deal scenario assumes that all countries reach 100% access in rural and urban areas by 2040. For the other two scenarios, the access levels in 2070 are shown in Table 39. For those countries that reach 100% in the latter two scenarios, Table 40 shows the year when that is reached.

Table 38. Share of population with access to grid electricity, 2010 (%)

Country	Total	Urban	Rural
Angola	40	63	8
Botswana	45	68	10
DRC	15	37	4
Lesotho	17	43	7
Malawi	9	37	2
Mozambique	15	36	2
Namibia	44	78	23
South Africa	76	88	76
Swaziland	30	65	20
Tanzania	15	46	4
Zambia	19	48	2
Zimbabwe[a]	37	79	11
Sub-Saharan Africa	29	58	12
Latin America	93	99	70
China & East Asia	90	96	86
North Africa	99	100	98
ASEAN	72	91	55

Note: a=ZESA reports that current Zimbabwe rural access is 18%.

Source: IEA (2012), Legros et al. (2009), StatsSA (2013)

Table 39. Rural and urban electricity access projections by 2070 in BAU and SADC Integration scenarios

	BAU		SADC Int	
Country	**Urban**	**Rural**	**Urban**	**Rural**
Angola	80	40	90	50
Botswana	100	100	100	100
DRC	70	30	80	40
Lesotho	70	30	80	40
Malawi	70	30	80	40
Mozambique	70	30	80	40
Namibia	80	40	90	50
South Africa	100	100	100	100
Swaziland	80	40	90	50
Tanzania	70	30	80	40
Zambia	70	30	80	40
Zimbabwe	80	30	90	40

Source: author's own assumptions based on discussions with regional experts.

Table 40. Forecast year in which 100% electricity access is achieved (only for countries achieving 100% access)

	BAU		SADC Int	
	Urban	**Rural**	**Urban**	**Rural**
Botswana	2050	2050	2070	2070
South Africa	2050	2050	2070	2070

Note: other countries do not reach 100% access in the study period.

5.3.2 *Transportation drivers*

The assumptions and detailed analysis of transportation energy use are taken directly from an earlier Energy Research Centre analysis of the South African transport sector (Merven et al. 2012).

5.3.3 *Residential electricity intensity*

For residential demand, the electricity intensity parameter is the average electricity consumption per household with access to electricity. This will, of course, be much higher than average consumption across all households, because of the low levels of access in most countries. For six countries, consumption per household can be calculated directly from residential demand reported by utilities and the estimated number of households with electricity access in those countries. This data was available for Botswana, Lesotho, Mozambique, Namibia, South Africa, and Zambia. This also means that, for these six countries, modelling residential electricity demand in 2010 is exactly the same as reported data. For DRC, Swaziland and Zimbabwe, the average consumption was estimated to be the same as Mozambique (based on similar socio-economic characteristics), while Malawi was set at the same level as Lesotho. For Angola and Tanzania, the Mozambique consumption levels had to be adjusted downward so that modelled national electricity demand (i.e. across all sectors) would match reported demand. These lower consumption levels may reflect different patterns of electricity usage, or they may point to other uncertainties in the data on number of households with access (i.e. there may be fewer households that have access than the data used to estimate access levels in this study).

Urban households with access to electricity typically consume more than rural households, in large part due to income differences. A detailed bottom-up analysis of electricity use in urban and rural households from South Africa shows that urban households consume 1.9 times the amount of electricity that rural households do. This ratio was used, along with the number of urban and rural electrified households, to estimate per household consumption in urban and rural areas in each country (Table 41).

Table 41. Estimated annual electricity consumption per household with access to electricity, 2010 (kWh)

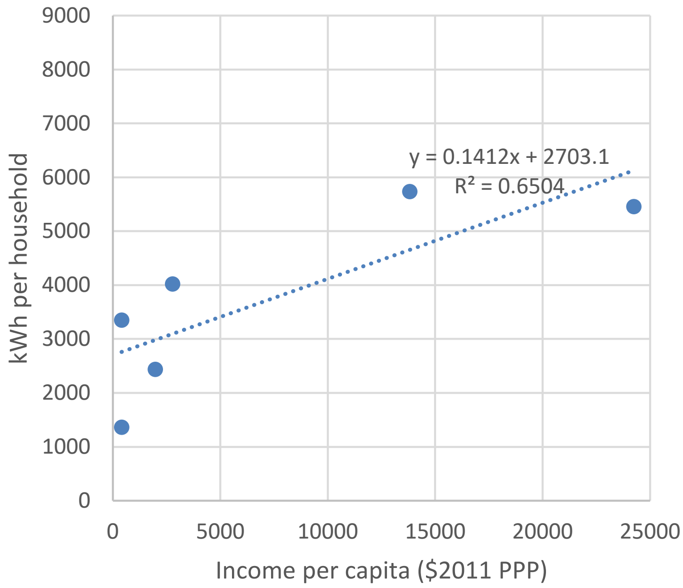
Country	National	Urban	Rural
Angola	900	943	505
Botswana	3,641	3,770	2,019
DRC	1,017	1,097	587
Lesotho	2,146	2,517	1,348
Malawi	1,976	2,149	1,151
Mozambique	1,093	1,130	605
Namibia	3,364	3,828	2,050
South Africa	3,803	4,411	2,363
Swaziland	3,479	4,303	2,305
Tanzania	900	968	519
Zambia	5,809	6,015	3,221
Zimbabwe	1,093	1,193	639

Source: Based on residential sectoral demand (IEA 2015b, 2015a; BPC 2010; LEC 2011; Banda 2015; EdM 2011; Hatch 2012; Simelane 2015; CSO 2013) and population, access and urbanisation assumptions presented earlier. Rural versus urban consumption derived from ERC SATIM analysis (ERC 2013, 2014).

To estimate future consumption per household, the relationship between per capita income and household consumption was investigated, using data from six different household types in South Africa (ERC 2014, 2013). The regression analysis showed that, for each increase of \$1 of annual income per capita, annual consumption increases by 0.14 kWh. Assuming a constant ratio of GDP to household income of 1.71, based on South African data, this means that an increase in \$1 of GDP per capita leads to an increase in household consumption of 0.0826 kWh (Figure 55).[39]

[39] While other factors outside of income could also affect consumption, and the relationship between income and consumption may not be precisely linear, there is insufficient data available to reliably describe a more complex relationship. Given the very small impact of household consumption on overall flows in the Zambezi, this assumption would not affect the results of the analysis.

Figure 55. Relationship between income and electricity consumption, South Africa



Source: ERC (2013, 2014)

For the South African demand analysis, electricity consumption is further disaggregated into end-uses, as shown in Table 42.

Table 42: Electricity consumption per household by consumer type and end use, South Africa (electrified households only)

Location	Income group	Lighting	Cooking	Space-heating	Water-heating	Refrigeration
Urban	Low income	248	876	1,314	290	365
	Middle income	117	370	767	456	913
	High income	218	1,004	2,190	1,102	1 323
Rural	Low income	61	730	657	286	730
	Middle income	117	730	1,314	602	730
	High income	255	443	1,095	1,013	1,323

Source: Based on household data from Statistics South Africa (StatsSA 2013) and electricity consumption from Eskom's annual report (Eskom 2014).

5.3.4 *Other sectoral final energy intensity and elasticity of demand*

For the other major sectors, in eight countries sectoral electricity intensity can be calculated from current aggregate sectoral electricity consumption and current sectoral GDP: Botswana, DRC, Malawi, Mozambique, Namibia, South Africa, Swaziland and Zambia (Table 43). For the other four countries, the starting point was to use a country with similar income levels, but adjusted to match modelled national demand with reported national consumption from SAPP and the IEA (see Section 10.1). These assumptions are used in the model to calculate sectoral demand each year using total GDP, sectoral share of GDP and electricity intensity in that year.

Table 43. Final electricity intensity by sector (kWh/$2011 PPP GDP)

Country	Agriculture	Manufacturing	Extractive	Service
Angola	0.014	0.019	0.019	0.008
Botswana	0.106	0.126	0.126	0.055
DRC	0.005	0.634	0.311	0.019
Lesotho	0.002	0.300	0.148	0.009
Malawi	0.004	0.467	0.229	0.014
Mozambique	0.000	3.135	0.255	0.067
Namibia	0.090	0.306	0.451	0.037
South Africa	0.393	0.988	0.611	0.074
Swaziland	0.002	0.234	0.115	0.007
Tanzania	0.002	0.234	0.115	0.007
Zambia	0.026	0.202	1.384	0.031
Zimbabwe	0.008	1.085	0.533	0.032

Note: Extractive is the difference between the World Bank/IMF categories "industry" and "manufacturing" (World Bank 2014), and is essentially mining and quarrying (including oil production but not processing).
Source: Based on sectoral demand sources (IEA 2015b, 2015a; BPC 2010; LEC 2011; Banda 2015; EdM 2011; Hatch 2012; Simelane 2015; CSO 2013) and GDP data presented in Chapter 3.

For future electricity intensity, the IEA (2008) reports that, between 1990 and 2005, the energy intensity of IEA member countries declined by an average of –0.9% per year (p.26), while industrial energy intensity declined by an average of –1.4% per year (p.29). For the service sector, the same report showed that energy intensity declined in Canada and Japan but increased in the USA (p.55). While energy intensity levels in developing countries are generally higher than industrialised countries when GDP is reported at market exchange rates, this is not the case when GDP is reported in purchasing power parity (PPP) (p.21). Based on these trends, sectoral energy intensity growth rates for the different development scenarios are included as shown in Table 44.

Table 44. Change in final energy intensity (2010-2070) (% per year)

Country	Manufacturing and extractive			Service	Agriculture
	BAU	***SADC Int***	***Grand Deal***	***All***	***All***
All countries	0.0	-0.7	-1.4	0.0	0.0

Source: Based on IEA (2008)

The more detailed demand analysis for South Africa is based on useful energy analysis (i.e. the energy services required by various end-uses). Useful energy is the product of final energy demand and the efficiency of a process of technology. The useful energy demand for industrial end-uses in shown in Table 45.

Table 45: Useful energy intensity for industrial end uses, South Africa (MJ/$ GDP PPP)

End-uses	Iron and steel	Chemi-cals	Precious and non-ferrous metals	Food, beverage, tobacco	Non-metallic metals	Pulp and paper	Other
Electric heating	0.473	0.008	0.009	0.012	0.066	0.009	0.029
Compressed air	0.003	0.003	0.000	0.000	0.002	0.008	0.002
Lighting	0.012	0.005	0.003	0.003	0.004	0.013	0.007
Cooling	0.024	0.042	0.000	0.082	0.000	0.000	0.031
HVAC	0.021	0.008	0.008	0.010	0.005	0.016	0.023
Pumping	0.024	0.119	0.000	0.040	0.019	0.124	0.031
Fans	0.043	0.027	0.000	0.006	0.021	0.000	0.013
Other motive	0.392	0.068	0.050	0.030	0.090	0.050	0.088
Electrochemical	0.000	0.026	0.607	0.000	0.000	0.000	0.003
Boiler process heating	1.169	0.386	0.006	0.330	0.502	0.823	1.301
Average intensity	2.16	0.69	0.68	0.51	0.71	1.04	1.53

Source: Based on SATIM modelling (ERC 2013, 2014)

Technological improvements in efficiency usually happen as a result of fuel-switching or retrofitting of more efficient appliances using the same fuel. The analysis assumes that there is limited fuel-switching (e.g. from electricity to other fuels and vice versa). There is a possibility of switching from coal to natural gas in boilers to reduce GHG emissions, but this is not included in the analysis because the focus of this study is power generation rather than other industrial fuel applications.

In terms of energy efficiency improvements at the end-use level, electrical appliances in South Africa are assumed to increase their efficiency by 5%, 10% and 30% by 2030, 2050 and 2070 respectively, across all sectors.

5.3.5 *System peak-load shape*

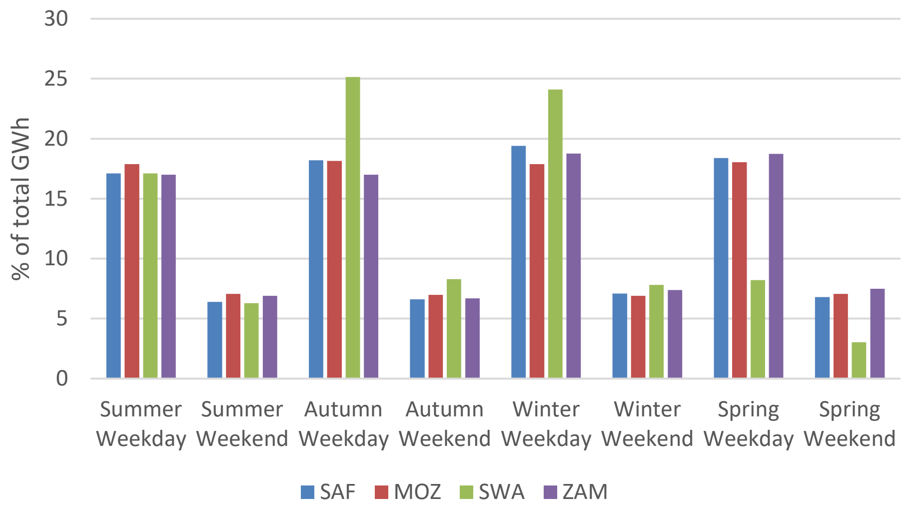
Electrical load forecasts form the basis of power system planning and an integral part of electricity sector modelling, as this forecast provides information on expected consumption increases (Malik and Kuba 2013). To represent the variation in loads over time, a load curve is often used. While this curve often shows the percentage of the annual peak-load in each time period, the LEAP optimisation algorithm requires a load curve that provides the share of total annual consumption in each time slice (i.e. share of GWh, not percentage of maximum demand). The definition of time slices should balance accuracy (i.e. representing the variation in demand) with computational requirements (i.e. too many time slices makes the optimisation unsolvable with the linear programme tool in a reasonable amount of time). Based on previous experience modelling the South African power system, this study uses eight time slices, as shown in Table 46. A further advantage of seasonal (rather than time-of-day) time slices, is that the water model that will be used to project hydropower availability operates on monthly time slices.

Table 46. Definition of time slices for electricity modelling

Name	Start	End	Days	Hours
Summer weekday	1-Dec	28-Feb	64	1,536
Summer weekend	1-Dec	28-Feb	26	624
Autumn weekday	1-Mar	31-May	66	1584
Autumn weekend	1-Mar	31-May	26	624
Winter weekday	1-Jun	31-Aug	66	1,584
Winter weekend	1-Jun	31-Aug	26	624
Spring weekday	1-Sep	30-Nov	65	1,560
Spring weekend	1-Sep	30-Nov	26	624

Hourly load data was available for South Africa, Mozambique, Swaziland and Zambia, so for these countries this data was aggregated into the time slices presented above. The other countries were assigned the South Africa yearly load shape as a proxy. The shares of energy use in each time slice for the four countries are shown in Figure 56.

Figure 56. Share of annual energy use in each time slice by country



5.4 Electricity generation modelling

To complement the analysis of electricity demand, this section elaborates on the assumptions uses for project electricity supply and includes the options available to each country. The analysis includes all of the major existing power plants in the SAPP region, as well as on future generation options. For future plants, these are separated into "specific plants" (i.e. where there is a site specified as well as some technical and financial data) and "generic plants" (i.e. plants that could be located anywhere within a country and in any country). The sections below summarise this generation capacity, while the detailed assumptions are presented in Annex E, Annex F, and Annex G.

5.4.1 *Existing plants in SAPP countries*

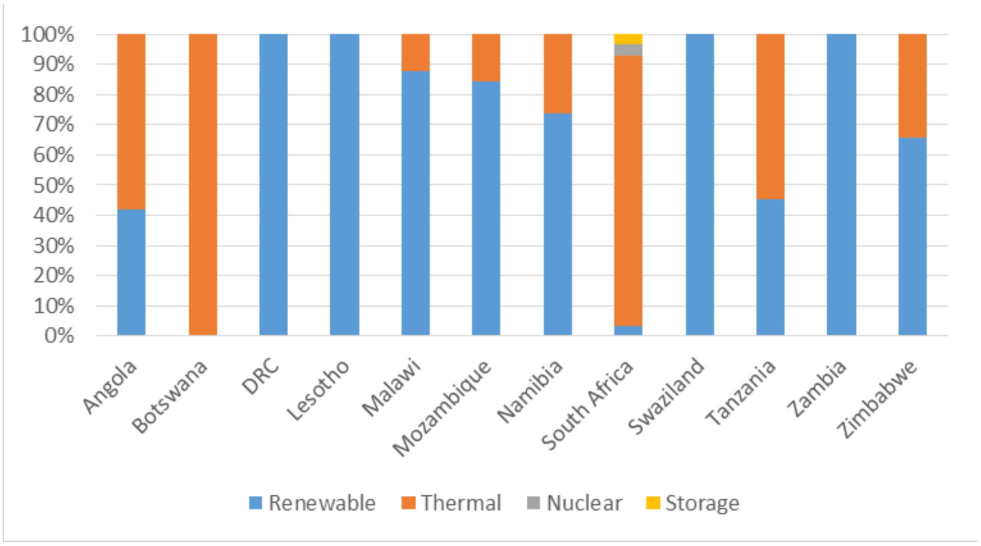
The capacity of existing power plants by type in each country is shown in Table 47. More than 78% of the existing capacity is in South Africa, and 75% of the region's existing capacity is thermal (of which almost 90% is coal-fired). In contrast to South Africa and Botswana, most of the other countries in the region rely primarily on renewable power, all of which is hydropower outside of South Africa (Figure 57). The technical and financial characteristics of these plants are shown in Annex E.

Table 47. Existing capacity by type and country, 2014 (MW)

Country	Renewable	Thermal	Nuclear	Storage	Total
Angola	776	1,075	0	0	1,851
Botswana	0	450	0	0	450
DRC	1,689	0	0	0	1,689
Lesotho	74	0	0	0	74
Malawi	334	46	0	0	380
Mozambique	2,175	399	0	0	2,574
Namibia	347	125	0	0	472
South Africa	1,640	44,582	1,860	1,580	49,662
Swaziland	171	0	0	0	171
Tanzania	562	684	0	0	1,246
Zambia	2,077	0	0	0	2,077
Zimbabwe	750	394	0	0	1,144
Total	10,595	47,755	1,860	1,580	61,789

Note: Storage = pumped storage plants; for detail of plants and sources, see Annex E.

Figure 57: Share of existing capacity by type, 2014



The pumped storage facilities in South Africa are a special case because, although they are hydropower generators, the water is pumped into the storage reservoir at night using predominantly coal-fired power from the South African grid. These plants are therefore designated as coal-fired in the LEAP model, and their efficiency is the efficiency of large coal plants multiplied by the efficiency of the pumped storage unit (i.e. 0.38 for coal x 0.75 for storage) (Yang and Jackson 2011).

5.4.2 *Specific planned plants*

This section covers planned future plants where there is a specific site identified and some technical and/or economic data available, as opposed to the generic options discussed in the next section. The total capacity of specific future plants considered in the modelling is shown in Table 48 by country and type. Note that the South Africa Integrated Resource Plan calls for more than 36,000 MW of new coal by 2030, but not all of this is a “specific” plant (DoE 2013). In this research, part of this growth will be captured in the generic plant options.

Table 48: Total capacity of specific proposed plants by type and country (MW)

Country	Renewable	Thermal	Nuclear	Storage	Total
Angola	5,165	500	0	0	5,665
Botswana	0	600	0	0	600
DRC	45,821	0	0	0	45,821
Lesotho	205	0	0	1,200	1,405
Malawi	845	100	0	0	945
Mozambique	6,545	2,225	0	0	8,770
Namibia	300	774	0	0	1,074
South Africa	10,663	9,656	0	1,332	21,651
Swaziland	137	300	0	0	437
Tanzania	2,262	2,340	0	0	4,602
Zambia	4,108	600	0	0	4,708
Zimbabwe	2,593	3,350	0	0	5,943
Total	78,644	20,445	0	2,532	101,621

Note: For detail of plants and sources, see Annex F.

The largest individual specific project is the Grand Inga hydropower cascade in the DRC, with an estimated total potential of more than 42 GW (Taliotis et al. 2014). Because this area must be developed in stages, in each scenario Grand Inga is commissioned in 3,000–7,000 MW sections each five years, the difference being the starting date and total capacity. For the Grand Deal and SADC Integration scenarios, the full capacity is eventually realised, with the first phase in 2025 and 2030, respectively. As with existing plants, the detailed technical and financial characteristics of all of these plants are presented in Annex F.

5.4.3 *Generic future options*

This section considers generic power generation options that are available to the SAPP countries, beyond the list of specific planned plants presented in the previous section. The wide range of generic future options for generation included in the modelling is shown in Table 49. The detailed technical and financial characteristics of these plants are presented in Annex G. Note all plants types are available in each country (e.g. South Africa does not have large hydropower), so these limitations are also shown in Annex G.

Table 49. Generic power generation technologies used in the modelling

Fuel	Technologies
Biomass	Pulverised bed, fluidised bed, combined cycle
Municipal waste	Combined heat of power, landfill gas open cycle combustion
Diesel	Utility scale open cycle
Geothermal	Direct
Hydro	Large and small scale
Natural gas	Open cycle, combined cycle
Coal	Fluidised bed, supercritical (with and without CCS), integrated gasification combined cycle
Nuclear	Pressurised water reactor
Heavy fuel oil	Open cycle
Solar PV	Utility scale
Solar thermal	Parabolic trough with and without storage
Wind	20% and 30% load factors

Source: Adapted from Miketa and Merven (2013)

A key feature of new emerging technologies is the potential for significant cost reductions over time from global experience (IEA 2014b; IEA and OECD 2000). For the Grand Deal scenario, the most optimistic cost reductions from the International Renewable Energy Agency (IRENA) study are used for the technologies shown in Table 50.

Table 50.Technology learning: annual reduction in capital costs for Grand Deal scenario (%)

Technology	2010–2015	2015–2020	2020–2030	2030–2050
Bagasse	2.0	2.0	1.0	1.0
Biomass BFB	2.0	2.0	1.0	1.0
Biomass CC	2.0	2.0	1.0	1.0
Geothermal	2.0	2.0	1.0	1.0
Hydro	0.0	0.0	0.0	0.0
Small hydro	1.0	1.0	1.0	1.0
Solar PV utility fixed	4.0	2.0	1.5	1.0
Solar parabolic trough 0 storage	3.0	2.0	2.0	1.0
Solar parabolic trough 03 hrs storage	3.0	2.5	2.0	1.5
Wind (20% CF)	2.0	1.6	1.0	0.5
Wind (30% CF)	2.0	1.6	1.0	0.5

Source: Optimistic scenario in IRENA SAPP study (Miketa and Merven 2013)

The BAU scenario uses the "pessimistic" scenario (i.e. no reductions), while the SADC Integration scenario (Table 51) uses the "reference case" assumptions. No cost reductions were included for nuclear or fossil fuel technologies.

Table 51.Technology learning: annual reduction in capital costs for SADC Integration scenario (%)

Technology	2010–2015	2015–2020	2020–2030	2030–2050
Bagasse	1.0	1.0	0.5	0.5
Biomass BFB	1.0	1.0	0.5	0.5
Biomass CC	1.0	1.0	0.5	0.5
Geothermal	1.0	1.0	0.5	0.5
Hydro	0.0	0.0	0.0	0.0
Small hydro	0.5	0.5	0.5	0.5
Solar PV utility fixed	2.0	1.0	0.8	0.5
Solar parabolic trough 0 storage	1.5	1.0	1.0	0.5
Solar parabolic trough 03 hrs storage	1.5	1.3	1.0	0.8
Wind (20% CF)	1.0	0.8	0.5	0.3
Wind (30% CF)	1.0	0.8	0.5	0.3

Source: Reference scenario in IRENA SAPP study (Miketa and Merven 2013)

5.4.4 *Fuel characteristics and costs*

The technical characteristics of the fuels used in the generation modelling are shown in Table 52. "Other coal" refers to the "other bituminous" coal most common in Southern Africa. Coal is based on the assumptions in the South Africa TIMES model (ERC 2013),[40] while the other fuels are from IEA data (IEA 2014c). GHG emission factors for fossil fuels are shown in Table 53.

Table 52. Technical characteristics of fuels used in the modelling

Name	Net energy content		LHV/HHV Ratio	Density (kg/litre)
Natural gas	34.2	MJ/m^3	0.90	0.000712
Residual fuel oil (HFO)	40.2	GJ/t	0.95	0.95
Diesel	43.3	GJ/t	0.95	0.87
Other coal	21.0	GJ/t	0.95	1.33
Bagasse	8.2	GJ/t	0.90	0.60
Biomass (solid)	15.5	GJ/t	0.90	0.71
Industrial waste	14.0	GJ/t	0.90	0.30
Municipal waste	14.0	GJ/t	0.90	0.30

Source: DoE (2013); IEA (2014c)

[40] TIMES is an acronym for "The Integrated MARKAL-EFOM System".

Table 53. Fuel emission factors (tonnes CO_2 per TJ)

Fuel	Emission factor
Diesel	74.1
Residual fuel oil	77.4
Other coal (sub- bituminous)	94.6
Natural gas	56.1

Source: IPCC (2006)

This research uses the same fossil fuel costs as the IRENA SAPP study (Miketa and Merven 2013). Fuel prices increase over time in real terms during the study period, as shown in Table 54.

Table 54. Fuel price assumptions, current and future

Fuel	2010	2020	2030	2040	2050
Oil price ($/bbl)	100.0	120.0	135.0	135.0	135.0
All other costs in ($/GJ)					
HFO coastal	12.9	15.5	17.4	17.4	17.4
HFO inland	16.3	19.6	22.0	22.0	22.0
Diesel coastal	21.9	26.3	29.6	29.6	29.6
Diesel inland	25.2	30.2	34.0	34.0	34.0
Gas domestic	8.5	9.5	11.0	11.0	11.0
Gas imported	11.0	12.3	14.2	14.2	14.2
Coal domestic	2.0	3.0	4.0	4.0	4.0
Coal imported	3.0	4.5	6.0	6.0	6.0

Source: IRENA SAPP Study (Miketa and Merven 2013)

The change in oil and oil product prices is close to that values in the IEA's Energy Technology Perspectives (ETP) forecasts (IEA 2014b) (i.e. 0.75% in this study vs –0.4% to +1.1% in ETP). The coal price increases are higher, at 1.75% per year average between 2012 and 2050, but this reflects the very low absolute prices of coal in southern Africa (i.e. almost half of the Organisation for Economic Cooperation and Development import price)[41] and the move towards greater uniformity of prices over the coming decades. For the natural gas prices, this study includes a steeper increase than the ones forecast for North American and Japan.

Biomass prices depend on the specific fuel type. In the countries with the largest sugar industries (i.e. Mozambique, Swaziland, Tanzania, and Zambia), the fuel is essentially free, but it is not available in the other countries.

5.4.5 *Planning reserve margin*

According to the SAPP Coordination Centre, the short-term goal for reserve margin is 10.2%, rising to 15% in 2020 (Maviya 2014). This is used for all countries to derive the capacity requirements to meet peak demand after 2015. Up to 2015, the actual regional reserve margin, as reported by SAPP, is used (Maviya 2014; SAPP 2012b).

[41] Data from the EIA also shows South African coal prices being only a fraction of those in North America and Europe (http://www.eia.gov/countries/prices/coalprice_elecgen.cfm).

5.5 Transmission, distribution and trade

5.5.1 *Losses and own use*

Technical losses occur during local distribution, intra-national transmission, and international transmission. The combined transmission and distribution losses for each country are shown in Table 55. Own use by power plants is also shown for each country in the same table. Both losses and own use are held constant throughout the study period.

Table 55. Transmission and distribution losses and own use by country, 2010

Country	% losses	% own use
Angola	11.8	2.5
Botswana	10.6	1.9
DRC	18.1	1.8
Lesotho	9.0	1.0
Malawi	24.0	1.0
Mozambique	24.0	1.0
Namibia	10.4	1.0
South Africa	10.0	1.8
Swaziland	24.0	1.0
Tanzania	20.0	2.4
Zambia	15.0	2.4
Zimbabwe	9.8	3.0

Source: Losses: IEA (2014a), National utilities and regulators (LEC 2015; NERSA 2006; ZESCO 2013b, 2013a; EdM 2010) with additional historical IEA energy balances; Malawi and Swaziland estimated from Mozambique. Own use: IEA (2014a), National utilities and regulators (LEC 2015; NERSA 2006; ZESCO 2013b, 2013a; EdM 2010); Malawi and Swaziland estimated from Mozambique.

5.5.2 *Existing electricity trade flows*

Trade flows are specified exogenously in LEAP, because the least-cost optimisation calculation for future capacity expansion and operation does not consider trade as a resource in a multi-region model. The starting point for trade-flow projections is the current imports and exports, as reported by SAPP member utilities in the SAPP annual reports, as well as in IEA statistics (SAPP 2014, 2010, 2013, IEA 2014a, 2011). The SAPP data are reported per utility, however, and not per country, which requires adjustments for Mozambique and South Africa. For Mozambique, national exports are the net quantity of electricity sent to South Africa – which is the exports from Hidroeléctrica de Cahora Bassa to South Africa less the re-import of this electricity via Motraco for the Mozal aluminium smelter (Mahumane and Mulder 2015a, 2015b). This is why Mozambique exports in the last column of Table 57 are 3,609 GWh and not 12,712 GWh as cited by the IEA (note that the SAPP data refer only Electricidade de Moçambique imports and exports). Similarly, South Africa imports and exports are also net of the wheeling of 8,466 GWh from northern Mozambique to Mozal in southern Mozambique through South Africa. The reason for this accounting practice is that, over the study period, the high capacity transmission line from northern to southern Mozambique will be complete so it will not be necessary to use the South African grid to wheel electricity to the Mozal or other industrial developments in southern Mozambique. In addition, LEAP treats each country as an integrated grid, rather than multiple sub-grids.

LEAP uses four parameters to simulate trade flows. First, "in-area import fraction" is the share of imports for each country that come from within the area covered by the model (i.e. the SAPP region in this case). Because there are negligible imports from outside the SAPP region, this value is set to 100% of electricity for all countries. Secondly, the "in-area export fraction" is the share of total exports within the region originating from a given country. For example, Table 57 shows that for 2010 approximately 44% of the exports in the region originated in South Africa. The third parameter is an import target (in GWh) for each country, which is part of the specifications of the transformation module in LEAP, and is shown in the second to last column of Table 57. Because LEAP does not allow exports and imports in the same country (i.e. a country must either be an importer or an exporter), the actual LEAP inputs are "net imports" (i.e. imports less exports).

Table 56. Trade flow assumptions for 2010 (GWh)

	Imports			Exports			LEAP Inputs	
	SAPP		IEA	SAPP		IEA	Imports	Exports
Country	2011/ 2010	2010/ 2009	2010	2011/ 2010	2010/ 2009	2010	2010	2010
Angola	27	27	0	0	0	0	27	0
Botswana	2,945	2,945	2,985	0	0	0	2,945	0
DRC	38	38	161	871	871	916	161	871
Lesotho	49	49	201	7	7	6	49	7
Malawi	0	0	0	0	0	21	0	21
Mozambique*	2,326	2,326	7,928	309	309	12,712	67	3,609
Namibia	2,462	2,462	2,462	294	294	207	2,462	294
South Africa	10,047	10,047	18,851	13,754	13,754	13,899	1,581	5,288
Swaziland	909	909	909	0	0	0	909	0
Tanzania	2192	52	52	5	0	0	2,192	0
Zambia	0	0	13	942	942	578	0	942
Zimbabwe	1,531	710	5,338	1,025	0	56	1,531	1,025
Total	20,334	19,565	38,900	16,331	15,301	28,394	11,924	12,057

Notes: Mozambique imports and exports in SAPP column are EDM only. LEAP inputs for Mozambique are net national trade (i.e. Cahora Bassa export to South Africa less re-imports for Mozal via Motraco). South Africa imports and exports under SAPP are for Eskom, while LEAP inputs for South Africa does not include import and re-export of Cahora Bassa power for Mozal. Zambia exports in SAPP column are from ZESCO statistics Tanzania imports in SAPP column are for 2011/2012 (and are also reported at this level for 2012/13).
Source: IEA (2011), Mahumane and Mulder (2015a, 2015b), National and regional utilities (ZESCO 2013b, 2013a, SAPP 2011, 2012a)

5.5.3 *Future electricity trade flows*

Because transmission infrastructure is one of the main constraints on trade, the scenarios with the highest foreign and regional investment rates would have the most trade. For the most aggressive growth scenario – Grand Deal – trade at the end of the study is based on the most optimistic forecast in the IRENA study (i.e. the "renewables promotion" scenario in Miketa and Merven 2013), as shown in the last two columns of Table 58. The SADC Integration Scenario is set to 60% of this trade, while BAU is 20% (which is still almost three times current trade flows). The exception to using the IRENA study inputs is the case of Angola and Lesotho, which both have large investments in capacity within "specific plants" that are being constructed for exports. Generation from this capacity (i.e. Kobong Pumped Storage Scheme for Lesotho and Kuanza Basin developments in Angola) has been used as the proxy for exports from these countries after their construction, and so does not vary across scenarios.

Table 57. Trade flow assumptions by scenario (net imports, GWh)

	BAU		SADC Int		Grand Deal	
Country	**2030**	**2070**	**2030**	**2070**	**2030**	**2070**
Angola	–7,000	–10,500	–7,000	–10,500	–7,000	–10,500
Botswana	–2,144	–1,461	–4,288	–2,921	–6,497	–4,426
DRC	–11,424	–20,648	–22,848	–41,295	–34,618	–62,569
Lesotho	–2,630	–2,630	–2,630	–2,630	–2,630	–2,630
Malawi	–82	386	–163	772	–247	1,169
Mozambique	–9,537	–3,657	–19,074	–7,315	–28,900	–11,083
Namibia	–1,835	–623	–3,670	–1,246	–5,561	–1,888
South Africa	20,554	12,580	41,109	25,160	62,286	38,122
Swaziland	–1,338	–1,259	–2,677	–2,519	–4,056	–3,816
Tanzania	11	2	23	4	35	6
Zambia	2,396	7,988	4,791	15,976	7,260	24,206
Zimbabwe	–988	–1,843	–1,977	–3,687	–2,995	–5,586

Source: Based on IRENA SAPP study (Miketa and Merven 2013)

5.6 Model calibration

Calibration with current data is important to validate the potential of any model to create accurate scenarios for the future. The SAPP LEAP model was calibrated to actual demand and supply data for 2010, the base year for the analysis. For future projections, uncertainties depend on both the drivers of demand but also whether these relationships could change as the power sector evolves. This section presents the calibration results for the base year.

5.6.1 *Demand calibration*

Modelled national electricity demand was compared with reported consumption from SAPP annual reports and/or other utility and official sources, as shown in Table 59. The modelled results are within less than 1% in all cases.

Table 58. Modelled versus reported national electricity demand, 2010 (GWh)

Country	Modelled	Reported	Source for actual	% difference
Angola	3,499	3,498	SAPP	0
Botswana	2,933	2,936	SAPP	0
DRC	6,262	6,263	IEA	0
Lesotho	615	615	LEC	0
Malawi	1,420	1,419	SAPP	0
Mozambique	10,920	10,920[a]	EDM, HCB	0
Namibia	3,332	3,376	IEA	-1
South Africa	225,164	225,813[a]	Eskom, NERSA	0
Swaziland	1,019	1,019	SAPP	0
Tanzania	4,160	4,176	MEM	0
Zambia	9,107	9,107	CSO	0
Zimbabwe	7,352	7,367	SAPP	0
Total	275,755	276,509		

Note: a. Mozambique national demand includes Mozal, although this power is provided contractually by Eskom. The Mozal demand has been removed from South African demand (see Mahumane and Mulder (2015a)).
Source: Actual demand for 2010 taken from SAPP (SAPP 2011), IEA (IEA 2011), Eskom (Eskom 2010); Zambia CSO (CSO 2013); EDM (EdM 2011); MEM (MEM 2013); LEC (LEC 2011); National Energy Regulator for South Africa; and HCB (HCB 2011)

5.6.2 *Supply calibration*

For the supply calibration, modelled capacity was compared with reported available capacity. LEAP does not directly distinguish between installed and available capacity, except through the “maximum availability” parameter,[42] so the model should match the available power and not include installed plants that are not operational (these can be added back in future years). The installed and available capacity reported by SAPP is generally only the power plants owned by the SAPP utilities. For this reason, the national utilities were asked to update national capacity, taking into consideration IPPs and municipal generation, as well as any units that were out of service in 2010. Table 60 shows that the modelled capacity is very close to this updated utility capacity in all cases. For DRC, where updated capacity was not available, the modelled capacity is between the reported installed and available capacities. The ongoing renovation of Inga 2 and Inga 3 during this period meant that different units were not available in different years. Given these uncertainties, therefore, the calibration results are positive.

[42] For example, if a power plant with six units had two units out of service for the full year, the maximum availability for the entire plant could be 60% (or less, considering other planned and unplanned outages on the available units).

Table 59. Modelled versus reported generation capacity, 2010 (MW)

Country	*Modelled*	*SAPP – installed*	*SAPP – available*	*Utility - available*
Angola	1,090	1,399	1,142	N/A
Botswana	120	132	120	120
DRC.	1,647	2,442	1,200	N/A
Lesotho	74	72	70	74
Malawi	316	287	267	316
Mozambique	2,175	2,308	2,249	2175
Namibia	365	393	360	365
South Africa	42,114	44,175	40,870	42,117[a]
Swaziland	172	71	70	171[b]
Tanzania	1,246	1,008	780	1,246
Zambia	1,657	1,812	1,215	1,657[c]
Zimbabwe	1,144	1,962	1,240	1,145[d]
Total	52,120	56,061	49,583	

Notes: N/A = not available from utility; a = includes sugar plant cogeneration, Sasol generation, Steenbras pumped storage (owned by City of Cape Town), non-Eskom small hydro, and gas combined heat and power plants; b = included sugar plant cogeneration; c = includes IPPs and only 750 MW for Kafue Gorge Upper; d = includes municipal-owned coal plants.
Source: actual capacity taken from SAPP reports (SAPP 2011, 2012b) and personal communications with members of the SAPP Planning Sub-Committee.

5.7 Electricity modelling results

The electricity modelling results are presented in the following sections, starting with national and sectoral demand trends in Section 5.7.1. This is followed by the results for difference types of electricity supply in Section 5.7.2 – existing plants, specific new plants and generic plants that are added to optimise future supply to meet demand.

5.7.1 *Demand*

Depending on the scenario, total electricity demand for the SAPP region increases by 8–14 times over the period from 2010 to 2070 (Table 61). In fact, by 2070, the rapidly growing countries of DRC, Mozambique, and Zambia reach demand levels higher than current South African demand under most scenarios. High growth rates in Tanzania put this country at a level higher than current South African demand in one scenario as well, while Malawi has rapid growth but it still relatively small as a demand centre.

Although total demand for the region increases across the three scenarios (e.g. BAU as lowest, then SADC Integration, then Grand Deal), this is not necessarily true for each country. This is because the scenarios are not meant to be “low”, “middle” and “high”, but are, instead, independent storylines and approaches to envisioning the future (see Chapter 5.3 above) and do not simply change proportionally across each scenario. This is why Zambia, for example, has higher total demand in the SADC Integration scenario than under the Grand Deal scenario.

Table 60. Total electricity final demand by scenario, all sectors, 2010 and 2070 (000 GWh)

		2070		
Country	**2010**	**BAU**	**SADC Int**	**Grand Deal**
Angola	3.5	15.1	69.6	33.2
Botswana	2.9	8.8	14.3	12.3
DRC	6.3	425.3	276.8	876.2
Lesotho	0.6	4.0	5.2	10.4
Malawi	1.4	36.9	29.7	72.4
Mozambique	10.9	232.8	823.5	510.9
Namibia	3.3	15.9	16.9	16.7
South Africa	225.2	779.7	1,176.0	1,572.2
Swaziland	1.0	3.2	3.5	6.6
Tanzania	4.2	103.3	214.2	164.9
Zambia	9.1	404.3	557.5	465.0
Zimbabwe	7.4	140.0	106.5	167.2
Total	275.8	2,169.3	3,293.7	3,908.1

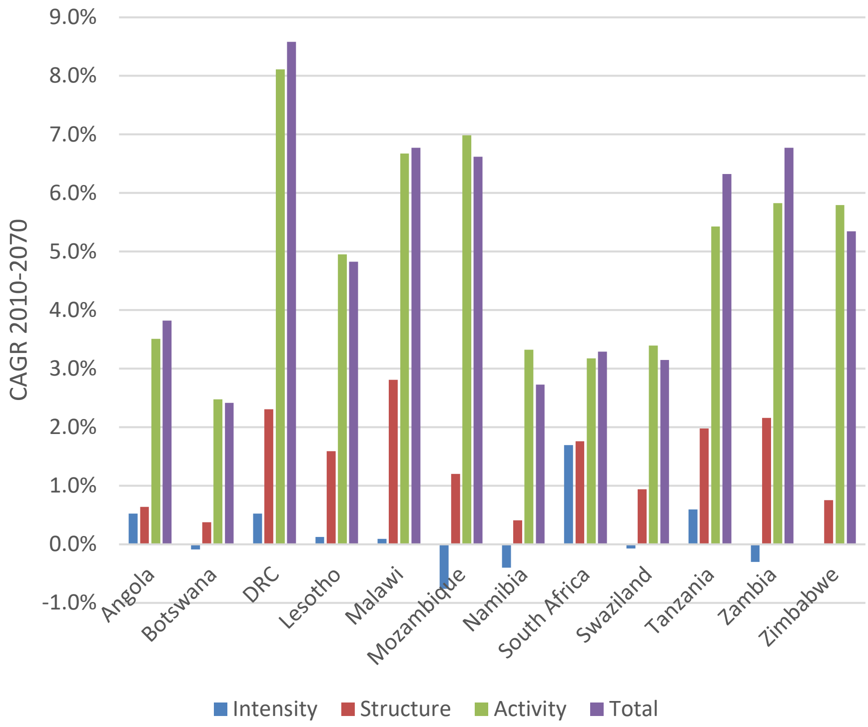
The sectors driving the growth in demand are primarily manufacturing and extractive, as shown in Table 62. In fact, demand from the extractive sector increases between 44 and 58 times from 2010 and 2070, because of both GDP growth and a rapid industrialisation of the region's economies. These combined effects lead to a 6.5–7.0% compound annual growth rate for extractive sector demand.

Table 61. Total electricity final demand by sector, all countries, 2010 and 2070 (000 GWh)

		2070		
Sector	**2010**	**BAU**	**SADC Int**	**Grand Deal**
Residential	57	185	275	376
Agriculture	6	4	6	8
Services	40	166	321	383
Manufacturing	111	787	1,514	1,392
Extractive	53	913	1,074	1,349
Transport	10	114	104	402
Total	276	2,169	3,294	3,908

Changes in electricity demand are a product of the changes in the activity level of key drivers (e.g. population, GDP), changes in energy intensity (e.g. industrial electricity intensity, consumption per household), and changes in the structure of demand (e.g. share of GDP by sector, share of households with access, urbanisation). Figure 58 below shows the contribution of each of these three components to the total change in electricity demand over the study period under the Grand Deal scenarios.

Figure 58. Decomposition of changes in demand into activity level, structure of demand, and electricity intensity, Grand Deal scenario



Note: CAGR = Compound Annual Growth Rate; "Intensity", "structure" and "activity" show the growth rates with the other two components of demand held constant.

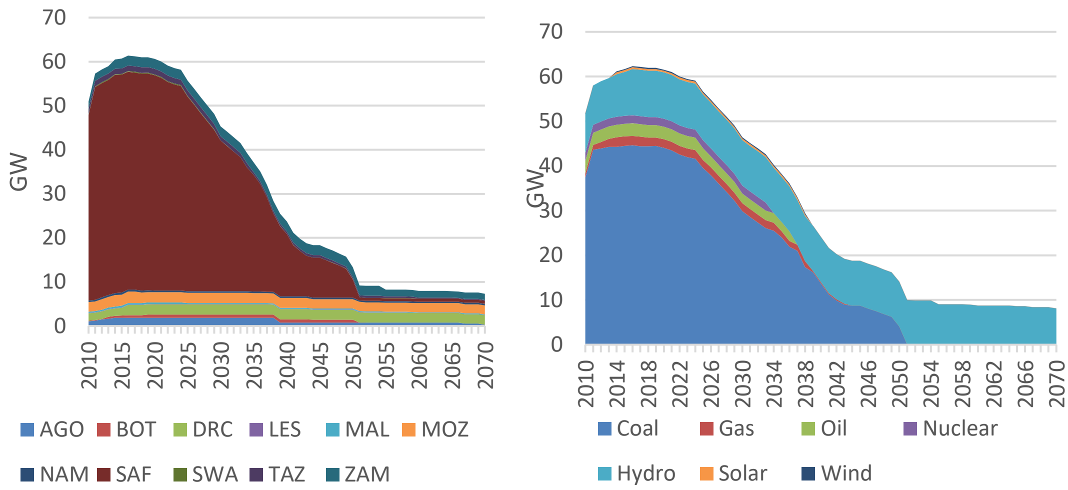
Activity level growth is clearly the main driver of demand growth, although changes in structure of demand are also important for many countries. The decreases in energy intensity, while important, are much smaller than the changes in activity levels.[43]

5.7.2 *Supply*

As discussed earlier, power generation capacity in the region has three components: existing plants, specific planned plants, and generic plants (i.e. necessary beyond the existing and specific plants to meet growing demand). Existing plant capacity increased from 2010 to 2015 due to expansions at existing facilities, largely coal plants in South Africa, and some small increases in the region are still scheduled for the next two years (Figure 59). Existing plants are largely decommissioned during the study period (based on their estimated life from previous studies (ERC 2013, 2014) and from inputs from SAPP Planning Sub-Committee members). Much of the South African coal fleet is retired, although some large South African coal plants operate until 2070 and large hydropower in the Zambezi continues throughout the study period (Figure 60). This assumes that these large power plants will not only be maintained but also rehabilitated over time when necessary, which has been the case in recent decades.

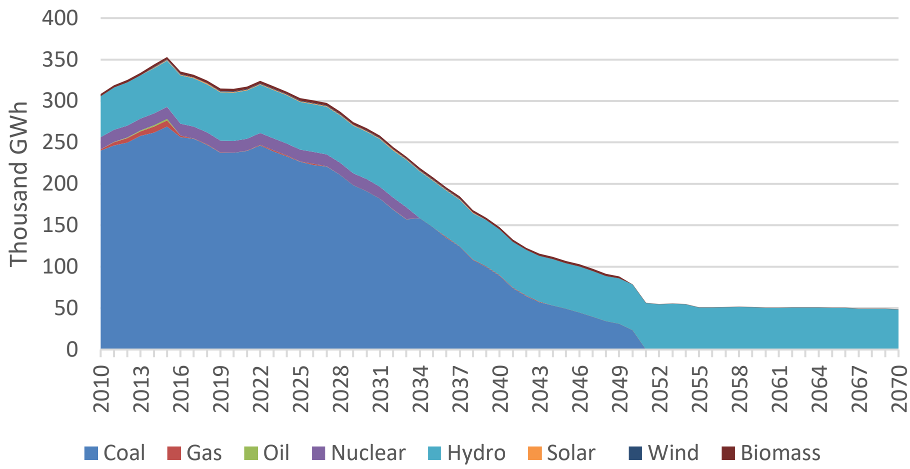
[43] Demand can increase even in the "intensity" scenario because decreases in industrial electricity intensity are offset by increases in consumption per household.

Figure 59. Capacity of existing plants over time by region and fuel, all scenarios



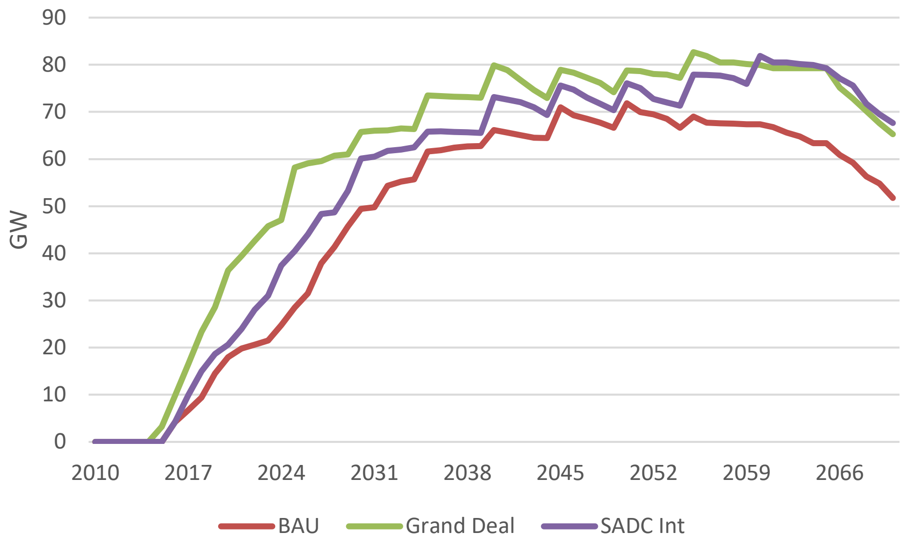
Note: hydro in this figure includes all pumped storage (1580MW), although coal-fired power is used as supply for these plants in South Africa.

Figure 60. Generation from existing plants by fuel, BAU scenario



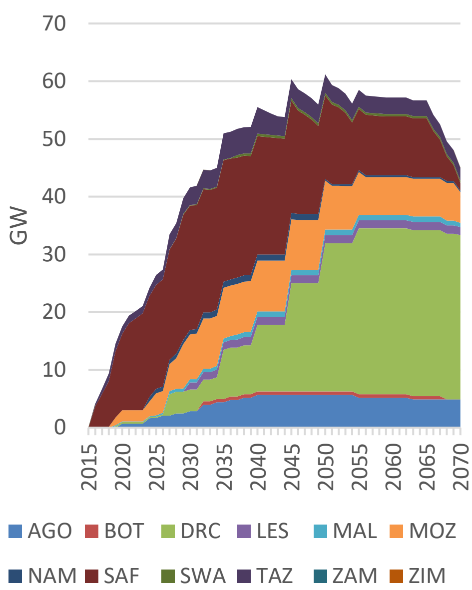
Growth in capacity from new specific power plants is fastest in the Grand Deal scenario and adds a total of nearly 80,000 MW to regional generation (Figure 61). The difference in the peak of the BAU scenario and the others is the lower total capacity from Grand Inga. In addition, the timeframe to 2070 is sufficiently long that some new plants in early years must be retired before the end of the study period. The declines from 2040 to 2044, for example, are the decommissioning of some of the solar and wind power in South Africa that is installed early in the study period.

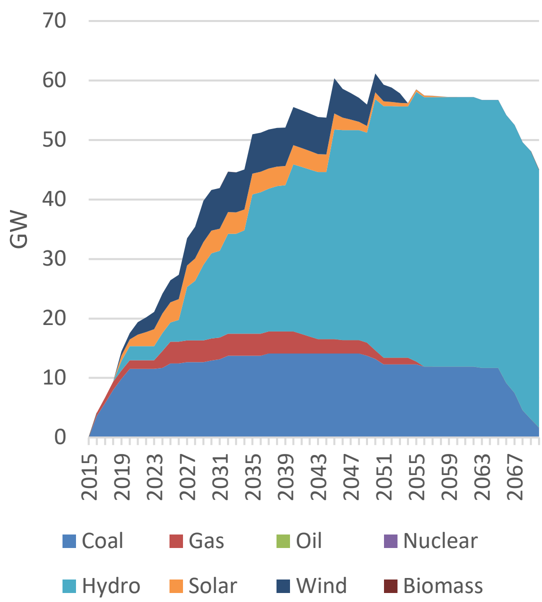
Figure 61. Capacity from specific planned plants under each scenario



The largest component of specific planned capacity is the Grand Inga Dam, which represents up to 42,000 MW in the DRC (see Figure 62). The South African expansion, which includes large investments in coal-fired power, is based in part on the expansion of Kusile and Medupi and in part on the generic plants used in optimisation, so specific plant capacity does not show the full expansion of coal in South Africa in the coming two decades. Specific plant capacity for the other two scenarios would look the same as the illustrated in Figure 62, but shifted forward by four and seven years for the SADC Integration and Grand Deal scenarios, respectively.

Figure 62. Capacity from specific planned plants by region, BAU scenario





Note: hydro includes new pumped storage (4,030 MW total)

The growth of generic capacity, however, is far greater than the other two capacity types over the longer term, because of the very large increase in demand that must be met. As discussed in Section 5.7.1, by 2070 demand in the region could increase to between eight and thirteen times current levels. Capacity will therefore need to increase similarly, as shown in Figure 63.

As discussed earlier, a key assumption behind the supply analysis is that generation will be built to meet all of demand, regardless of the investment requirements. The reason for ignoring the constraints on capital in the region is that the focus of the overall analysis is how climate change will impact generation choices, costs and emissions, not on the other financial and policy challenges facing the sector.

Figure 63. Total capacity for all plants by scenario

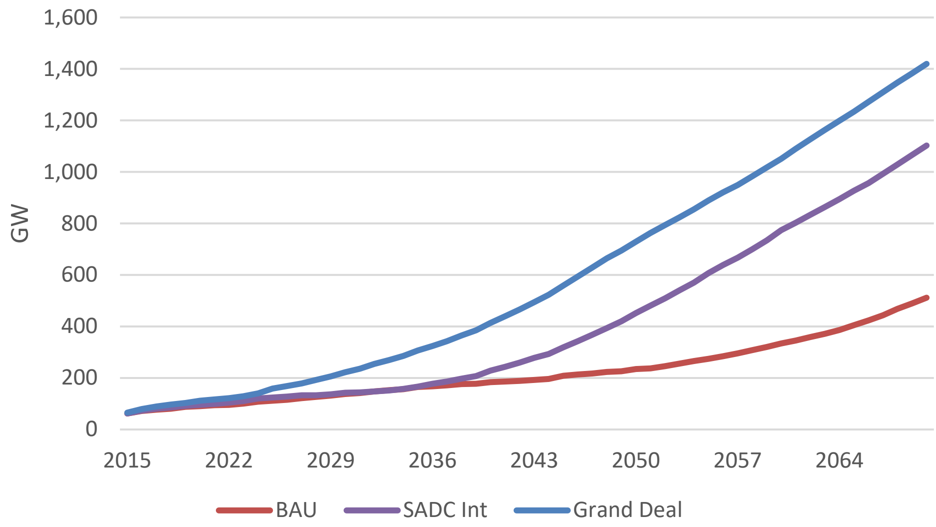
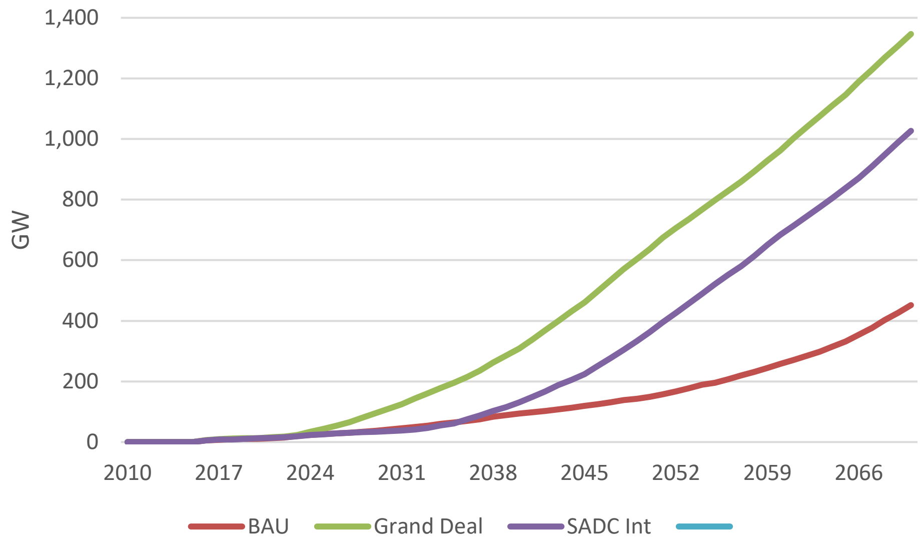


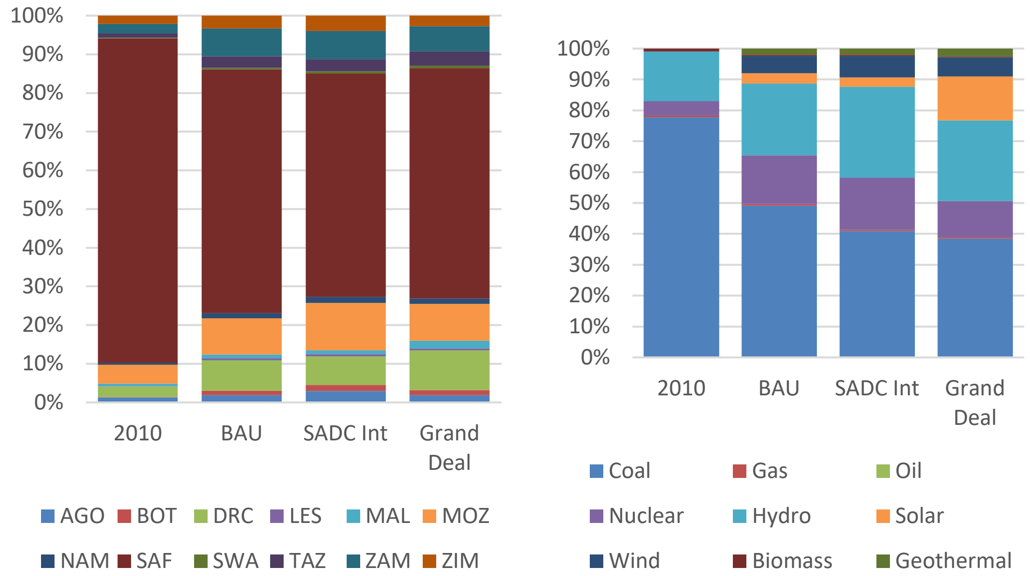
Figure 64 shows that, out of that total, generic capacity of 800 to 1,400 GW will be needed by 2070 to supply the region, compared to the total regional capacity in 2010 of 52 GW.

Figure 64. Capacity from generic plants by scenario



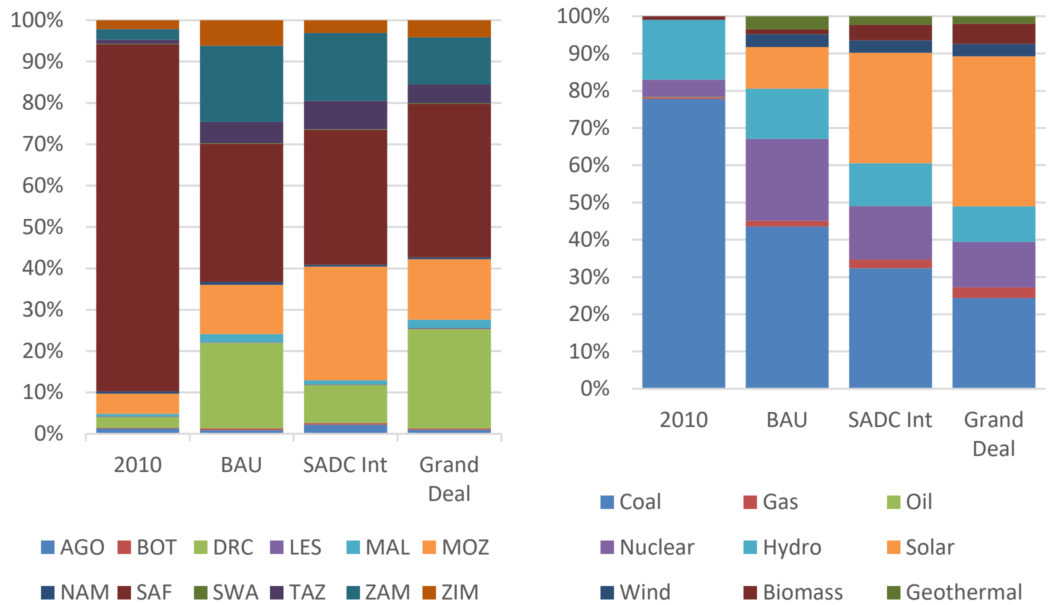
The dramatic growth in demand and supply over the full study period would result in a major shift in the regional power sector, both in terms of geography and fuel mix. As shown in Figure 65, already by 2030 South Africa's share of regional capacity is declining in all scenarios, as DRC, Mozambique and Zambia's power sectors rapidly expand. The fuel mix shifts away from coal and toward hydro in all scenarios, with a large share of solar in the Grand Deal scenario.

Figure 65. Share of generation by country and fuel, 2030



By 2070 the shift is even more dramatic, with South Africa generating only a third of the region's power, and the fuel dominated by renewables – particularly utility-scale solar photovoltaics (Figure 66). The share of renewables increases under the SADC Integration and Grand Deal scenarios because of the declines in capital costs over time as discussed in Section 5.4.3 above.

Figure 66. Share of generation by country and fuel, 2070



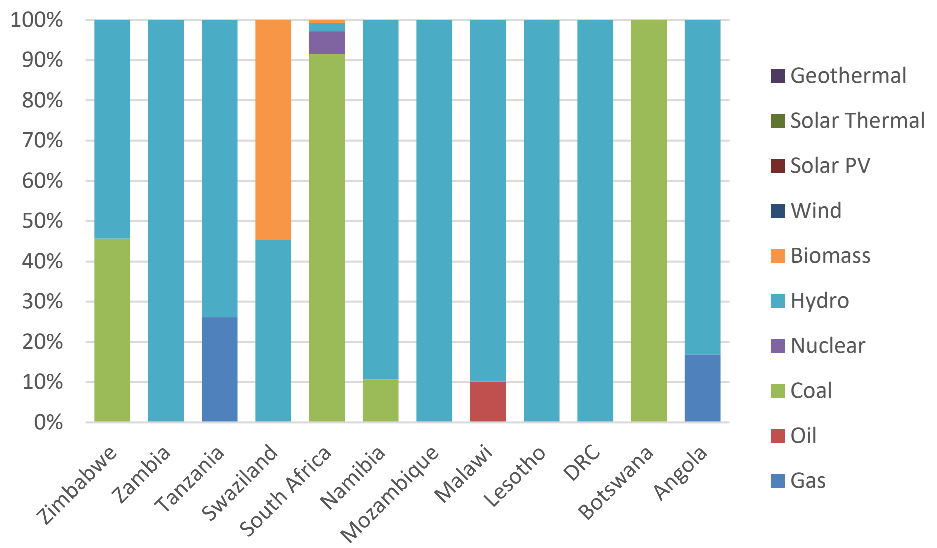
Total capacity for each country in 2030 and 2070, as well as the base year, is shown in Table 63. Note that the earliest year shown in 2010, while Table 47 shows capacity in 2014.

Table 62. Generation capacity by country and scenario, 2030 and 2070 (GW)

		2030			2070		
	2010	**BAU**	**SADC Int**	**Grand Deal**	**BAU**	**SADC Int**	**Grand Deal**
Angola	1.09	5.35	7.45	6.74	6.90	42.07	18.65
Botswana	0.12	1.48	3.04	3.24	2.49	9.16	9.28
DRC	1.65	13.53	13.06	19.89	164.18	73.11	327.35
Lesotho	0.07	1.54	1.66	2.21	2.61	3.48	6.95
Malawi	0.32	1.61	1.63	6.43	7.66	18.17	52.44
Mozambique	2.18	13.29	14.23	17.83	42.08	272.54	219.54
Namibia	0.36	2.19	3.66	4.35	4.28	8.14	9.22
South Africa	42.11	71.42	68.29	121.16	134.50	309.84	395.65
Swaziland	0.17	0.63	0.87	2.23	0.98	1.92	7.28
Tanzania	1.25	5.95	5.93	8.51	26.57	101.79	72.48
Zambia	1.66	11.73	12.15	16.13	92.28	205.72	196.34
Zimbabwe	1.14	7.97	8.83	7.71	25.60	54.98	102.87
Total	52.12	136.70	140.79	216.42	510.13	1100.94	1418.04

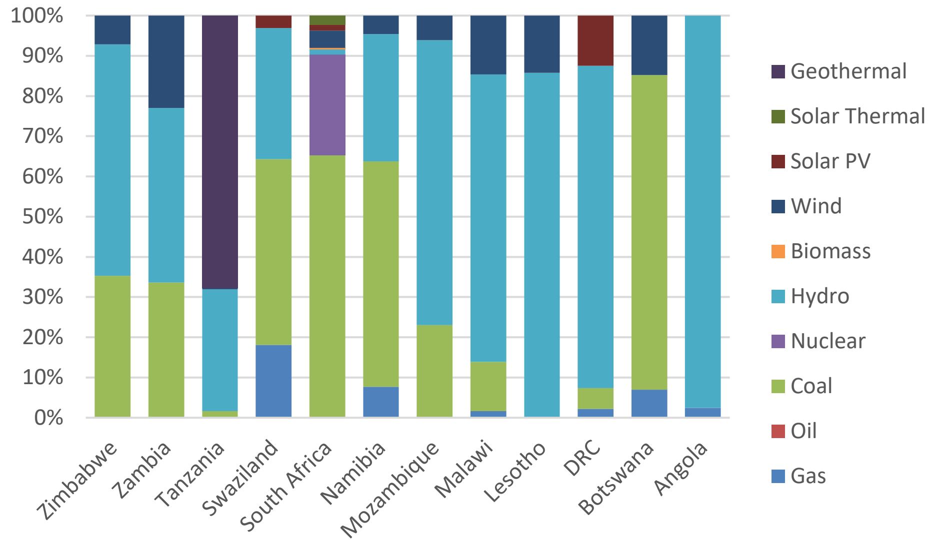
To understand the implications of the scenarios for individual countries, a more disaggregated view of the scenario results is required. The starting fuel mix for each country in 2010 is presented in Figure 67, showing the domination of hydropower for most of the SAPP countries except Botswana, South Africa, and Zimbabwe – countries with rich coal resources that have been well developed.

Figure 67. Share of generation by fuel and country, 2010



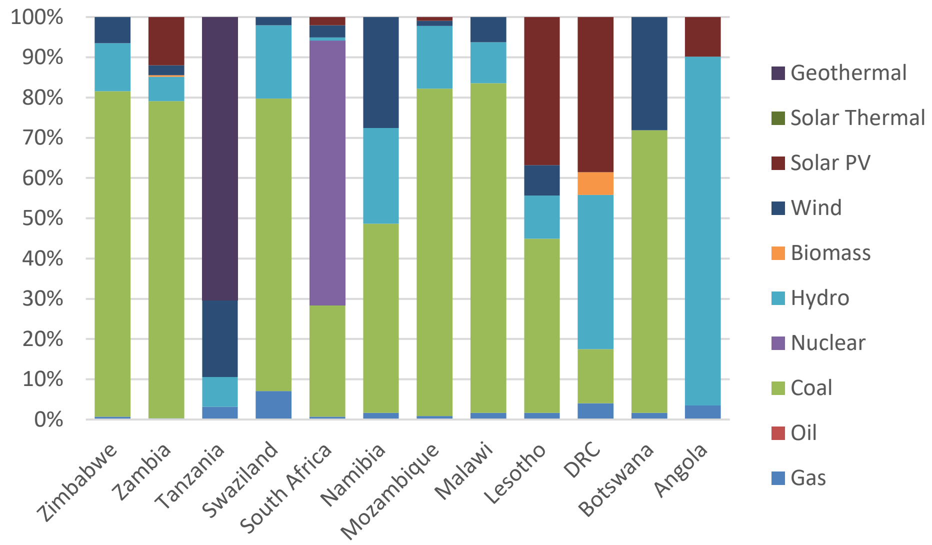
Even under the BAU scenario, this fuel mix starts to shift by 2030, with Tanzania developing geothermal power, solar PV playing a larger role in a few countries, coal starting in Zambia, Swaziland and Malawi, hydropower increasing in Namibia, and nuclear playing a larger role in the South African electricity mix (Figure 68).

Figure 68. Share of generation by fuel and country, 2030, BAU scenario



By 2070 under the BAU scenario, however, the role of coal has increased dramatically, because most large-scale hydropower resources are already exploited by 2040 or 2050. Nuclear provides the major source of South Africa's generation, while most other countries are dominated by coal. The exceptions are a large share of solar PV in Lesotho and DRC, a significant share of wind in Botswana and Namibia, and Tanzania's reliance on geothermal (Figure 69).

Figure 69. Share of generation by fuel and country, 2070, BAU scenario



Under the Grand Deal scenario, solar PV and wind have already become much more prominent in the generation mix by 2030 (Figure 70). Solar PV plays a significant role in Lesotho, Malawi, Mozambique, Namibia, South Africa, Swaziland and Zambia, while wind is a significant share of generation in Botswana, Malawi, Namibia and Zambia, displacing gas in some of those countries. The share of coal in South Africa is down to less than 60%. By 2070 under the Grand Deal scenario, declining capital costs makes solar PV a low-cost resource for most countries, and solar PV comprises the majority of generation in nine of the twelve countries (Figure 71). Including biomass, solar thermal, wind and geothermal, renewable power provides the majority of generation in all SAPP countries except South Africa, where renewable sources would be approximately 35% of generation.

Figure 70. Share of generation by fuel and country, 2030, Grand Deal scenario

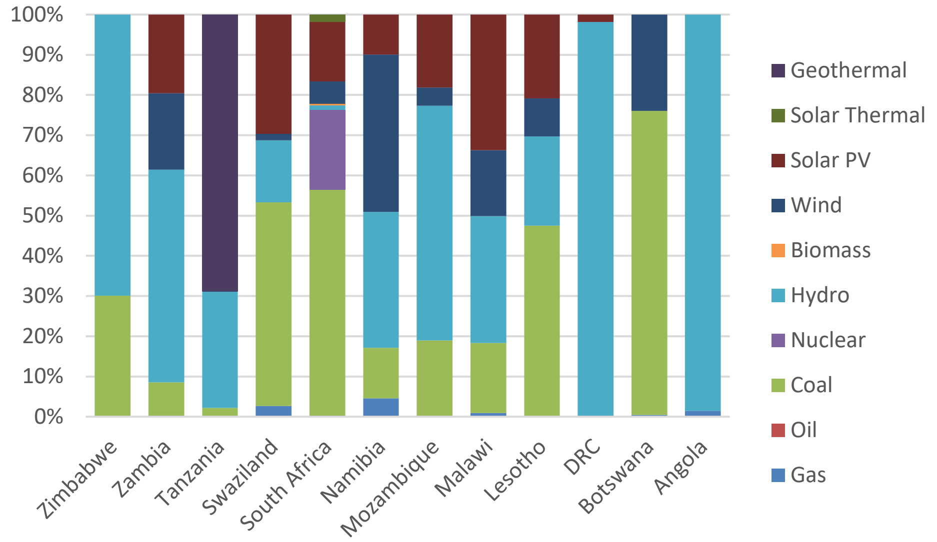
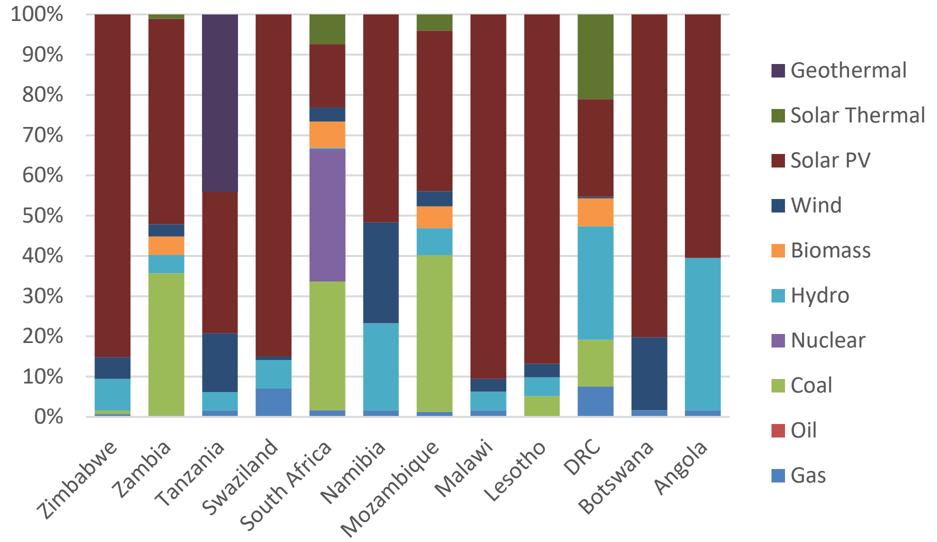


Figure 71. Share of generation by fuel and country, 2070, Grand Deal scenario



5.7.3 System costs

The scope of cost analysis is limited to the costs of generation, including all investment, operating and maintenance and fuel costs required for generating electricity over the entire study period. Transmission and distribution costs are not included, nor are the cost of end-use appliances and energy-using equipment. No external costs of generation are included, although carbon dioxide emissions are calculated. This is not only because of a lack of data for the other costs, but also because the focus of the research is how development and climate change impact generation options and costs. For capital costs, the amortised investment costs are included for each year, so this investment is spread out over the life of the plant, rather than all in one or two years. This means that “unit generation costs” are essentially average costs.

The total cost for all three scenarios is shown in Figure 72, showing GD and SADC with higher system costs than BAU, while the shift towards capital costs and, under the Grand Deal, variable operating and maintenance costs is shown in Figure 73. These costs do not include the “sunk costs” of the existing generation plants, even though the utilities may well have outstanding debt that must still be paid on those plants. This means that the total cost shown here underestimates utility cost in the early years of the scenarios. In addition, these costs do not include revenue from exported electricity or the cost of imported electricity – they only include the costs of domestic generation.

Figure 72. Total generation costs by scenario

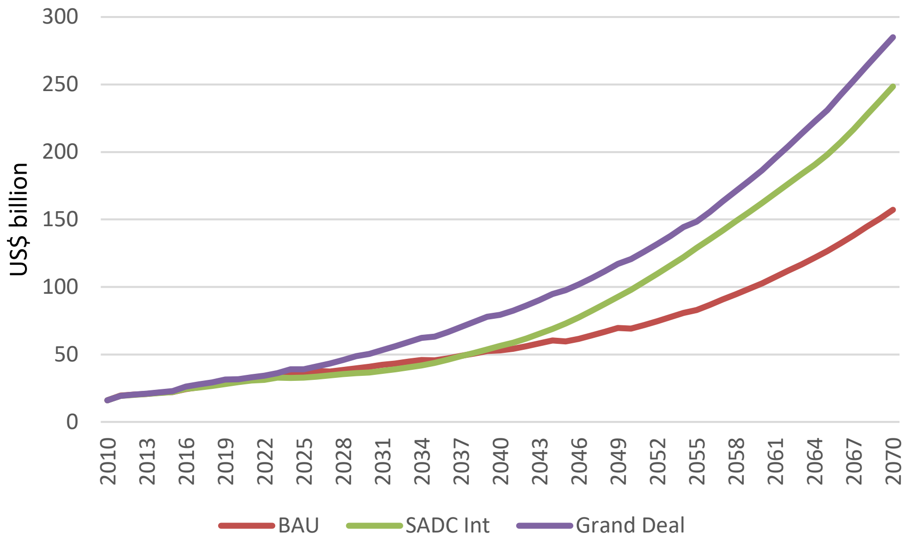
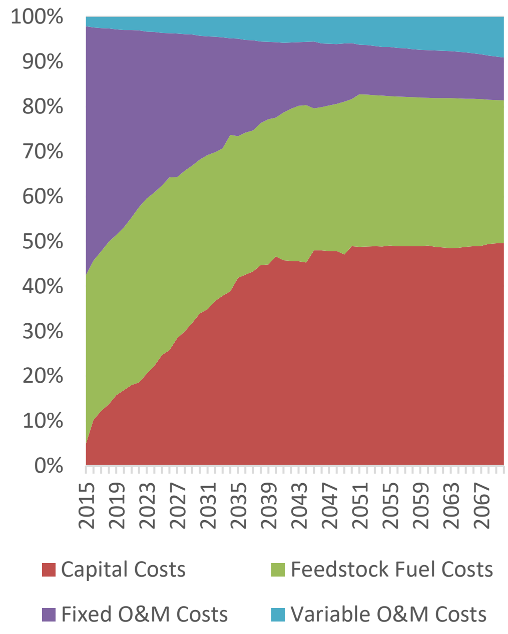
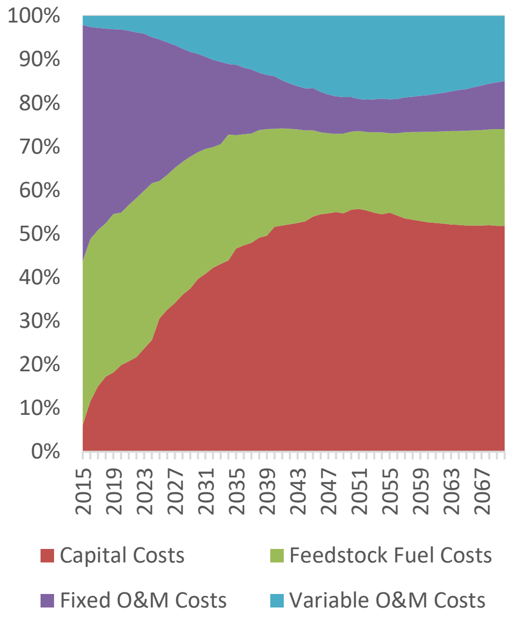


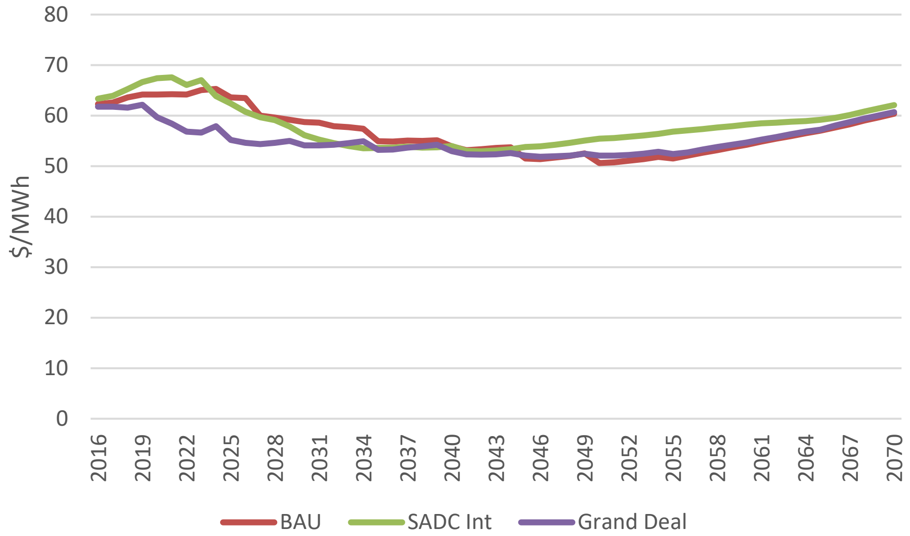
Figure 73. Share of generation cost by component, BAU and Grand Deal scenarios





Although total costs increase in future years, the unit cost of generation for the entire region is relatively stable across all scenarios, as shown in Figure 74. This reflects both the fact that the annual change in capacity is relatively small across the entire region, and includes the influence of averaging across also 12 countries. For the different scenarios, renewable power options only displace fossil fuels when they have simlar costs, so the average cost for the entire sector does not vary significantly across scenarios.

Figure 74. Unit generation costs across scenarios



At a country level, unit costs vary more widely because each time a new plant is built, the added amortised capital costs are added to the total generation cost even before the plant is fully utilised.

5.7.4 *Greenhouse gas emissions*

The IPCC emission factors shown earlier included CO_2 emissions from fossil fuel combustion. Only CO_2 emissions are included in the assessment, as these account for the vast majority of power station emissions.[44] Currently the majority of emissions are from South Africa, due to the amount of coal-fired capacity in that country versus total regional capacity (Table 47). Note also that previous research has shown that increasing access does not, on its own, contribute significantly to CO_2 emissions (Tait and Winkler 2012), which fits with the primary role of industrial and manufacturing growth in driving electricity demand shown in this study (see Table 62).

Total emissions for the region for each scenario is shown in Figure 75. All the scenarios show large growth in CO_2 emissions, starting from a low base, because fossil fuel power increases in absolute terms even though the *share* of total power generation from fossil fuels declines Emissions at the end of the study period are equivalent to Japan's CO_2 emissions in 2012 (i.e. approximately 1,200 million tCO_2). Because so much of the additional capacity in the Grand Deal scenario, when compared to the BAU and SADC Integration scenarios, is from renewable power, the GHG emissions of the three scenarios are largely the same. This means that the per unit emissions for the Grand Deal scenario is much lower than for the other two, given the much higher generation in this scenario (Figure 76).

[44] While new hydropower reservoirs in shallow, heavily vegetated river valleys can lead to methane emissions from decaying submerged vegetation, the large hydropower plants in SAPP are on existing reservoirs and/or are in narrow, steep canyons with limited vegetation and therefore would not have significant methane emissions (see explanation of methane issues in Hertwich (2013)).

Figure 75. Carbon dioxide emissions for each scenario

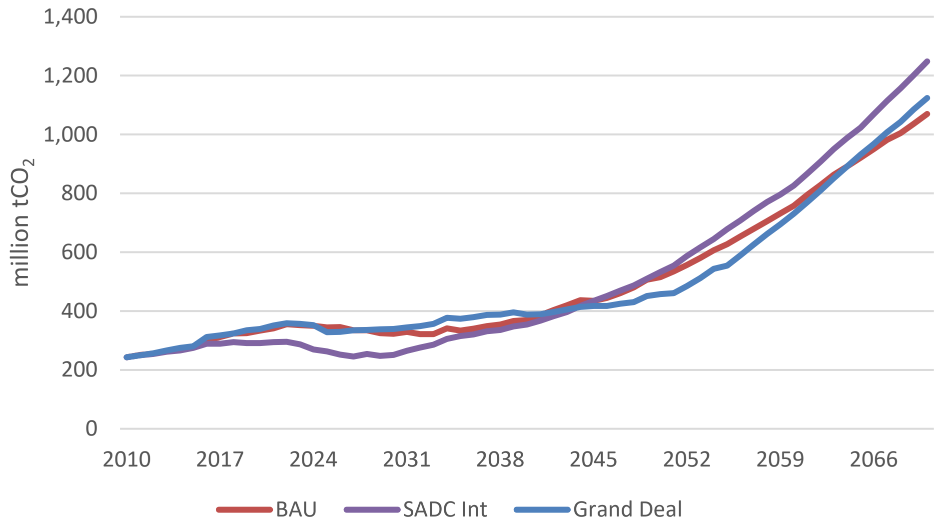
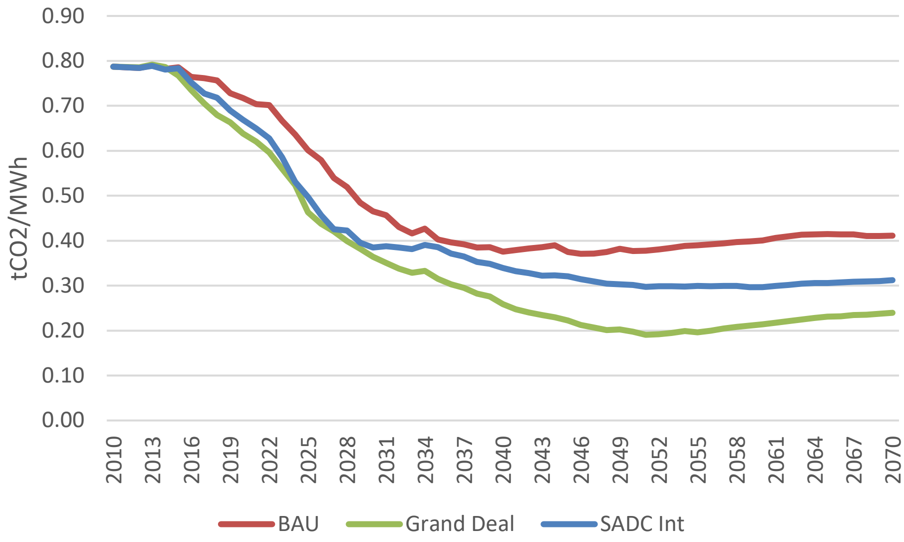


Figure 76. Carbon dioxide emissions per unit of electricity generated for each scenario



5.8 Discussion and conclusions

The analysis in this chapter addressed the second research question: How could development in Southern Africa affect power demand, and how might this demand be met? Over the study period, changes in the underlying drivers of demand lead to not only a dramatic increase in total electricity demand but also a shift across sectors and countries within the region. The modelling results show that, given the assumptions described earlier, SAPP electricity demand increases by 8–14 times between 2010 and 2070. The combined demand of the rapidly-growing countries of DRC, Mozambique, and Zambia reaches 120% of South Africa's demand by 2070, compared to only 12% currently. Compound annual growth rates of more than 5% for the extractive and manufacturing sectors push their share of total demand from 59% in 2010 to 70% by 2070 under the Grand Deal scenario. Although changes in structure of demand are also important for many countries, activity level growth is the main driver of demand growth. An additional 400–1400 GW of new capacity is required to meet 2070 demand, or 8–20 times the current capacity of the region.[45] More strikingly, the mix of energy supply sources shifts from almost 80% coal-fired power to only 24–44% coal by 2070, with the balance being supplied mainly by solar, wind, hydropower and nuclear generation. The regional shift is no less dramatic, as higher growth rates in countries such as DRC, Mozambique and Zambia lead to South Africa's share of total generation declining from 84% to only a third of the region's power.

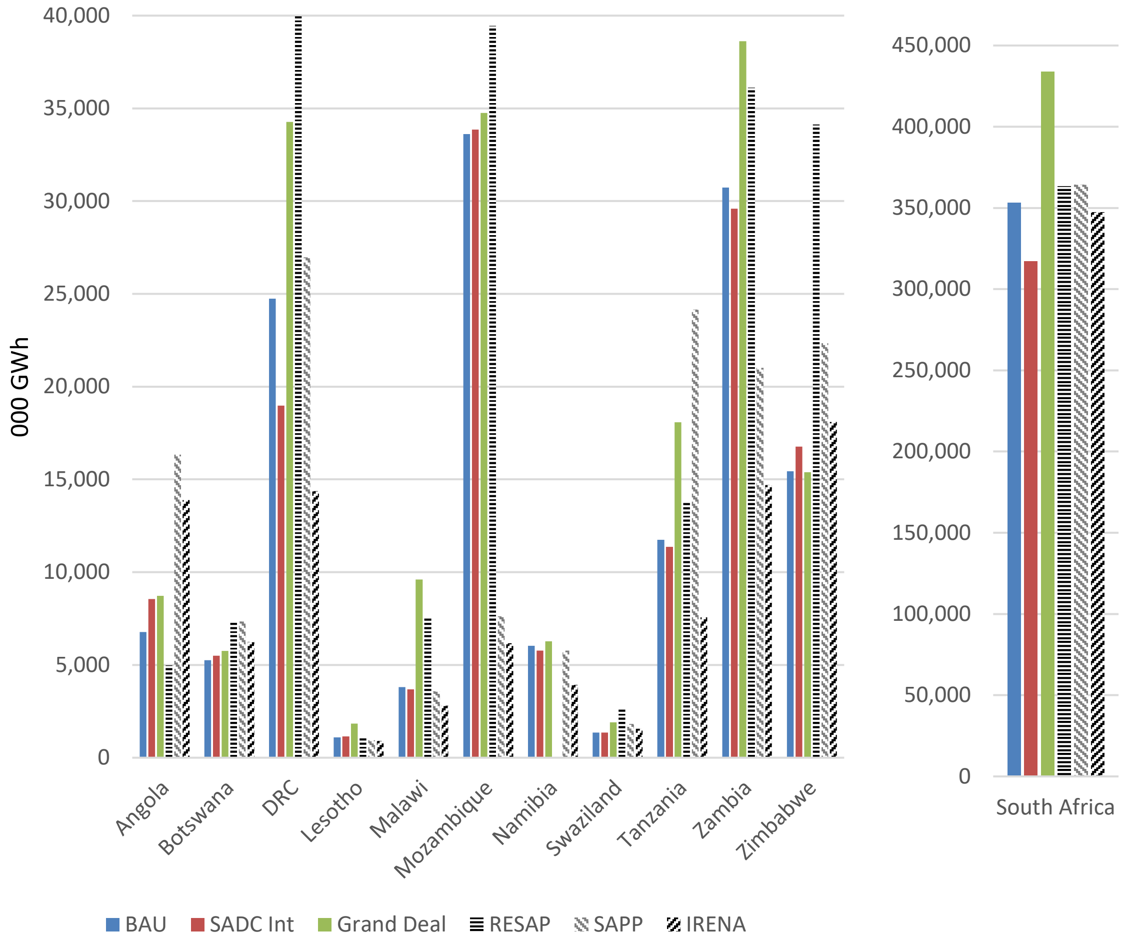
Comparing these results to other studies in the region provides a useful context for discussion. Because other studies of regional electricity supply and demand have generally only extended to 2025 or 2030, however, only a medium-term comparison of results is possible. The modelling results for demand are within the range of other studies that considered future demand out to 2025 (i.e. the last year of the SAPP forecasts). The earlier studies to which the present analysis is compared are RESAP (CEEEZ 2012); SAPP (SAPP 2014) and IRENA (Miketa and Merven 2013). For the region as a whole, the modelled results are 450,000–610,000 GWh total final demand for electricity, while the three other studies cited range from 440,000–560,000 GWh. Given the optimistic assumptions used in the Grand Deal scenario (e.g. very rapid economic growth, full access to electricity by 2040), the fact that the high end of the modelled results for that scenario exceed the other studies is reasonable. This comparison is important for understanding the longer-term results for this modelling exercise, because it means that the mid-term starting point (i.e. 2025) is also similar to what other regional initiatives considered. At the same time, the level of uncertainty obviously increases with the longer time period for analysis. As discussed earlier, the methodology assumes that demand is not constrained by lack of available investment and so provides a picture of what investment is necessary to meet development needs.

There are some important differences in the demand results at a country level (Figure 77) that also highlight the importance of bottom-up approaches to demand simulation. The RESAP (CEEEZ 2012) study, for example, used a constant growth rate for regional demand applied to each country (i.e. a top-down approach), so this assumes that countries all grow at the same rate. Most of the SAPP forecasts, compiled from individual utilities, use almost the same growth rate in each year, even though this varies by country. The more detailed approach used in this study yields more conservative demand projections for Angola, Botswana and Zimbabwe, but more ambitious ones for Zambia. Note that the differences in Angola may also be related to the poor data availability, because the current data reported to SAPP imply very different energy intensities than other countries (i.e. suggesting that there could be underlying reporting problems). The major differences in Mozambique are because of the geographic definition of demand. Mozal and similar industrial demands, which are not part of Mozambique demand in other studies or SAPP reports, are considered part of the Mozambican national demand in this study. Because this study takes an approach that considers all demand within national boundaries as part of national demand, Mozambique demand is therefore much higher than forecast in SAPP reports, because it covers the full industrial base within the country. This is critical for policy-makers in Mozambique, since it implies a different trajectory of power sector development to support industrial growth. For all the countries, an important advance in this study is that the demand projections are based on scenarios covering national, regional and global development, which can be updated over time or used to test alternative assumptions about the future.

---

[45] The variation for supply is greater than for demand because of the low capacity factor renewable energy generation units included in the supply anlaysis.

Figure 77. Modelled demand versus other studies, 2025



Note: the two charts have different scales but the same legend.
Sources: RESAP Study (CEEEZ 2012); SAPP (2014); IRENA SAPP Study (Miketa and Merven 2013)

One of the challenges of greater regional integration is maintaining national supply security, and the political acceptability of relying on imports for a substantial portion of national demand. Table 64 shows net imports (i.e. imports minus exports) as a share of national demand, to illustrate where national energy security concerns might arise. Countries with negative net imports are net exporters, which is almost all countries except Zambia and South Africa, as well as Malawi in 2070. By 2070, imports for these countries are less than 5% of national demand in all scenarios. In the medium term, however, net imports by 2030 could be a significant share of domestic demand under the SADC Integration and Grand Deal scenarios. This tension between the savings from trade and national energy security has been a recurring theme in many previous studies (Nexant 2007; Economic Consulting Associates 2009; Rowlands 1998; Graeber and Spalding-Fecher 2000), and must be addressed at a political as well as technical level within the region.

Table 63. Net imports as a share of national final demand by country (%)

	2030			2070		
	BAU	**SADC Int**	**Grand Deal**	**BAU**	**SADC Int**	**Grand Deal**
Angola	-57	-48	-43	-34	-9	-20
Botswana	-23	-45	-75	-8	-12	-22
DRC	-18	-29	-102	-2	-9	-4
Lesotho	-125	-78	-139	-32	-29	-16
Malawi	-1	-1	-4	1	3	2
Mozambique	-13	-27	-44	-1	-1	-1
Namibia	-16	-34	-61	-2	-4	-7
South Africa	5	8	17	2	2	2
Swaziland	-56	-81	-197	-20	-42	-36
Tanzania	0	0	0	0	0	0
Zambia	5	8	17	2	3	5
Zimbabwe	-3	-7	-11	-1	-2	-2

Note: The similarity between the South Africa and Zambia results in 2030 is coincidental, as the underlying total demand is entirely different.

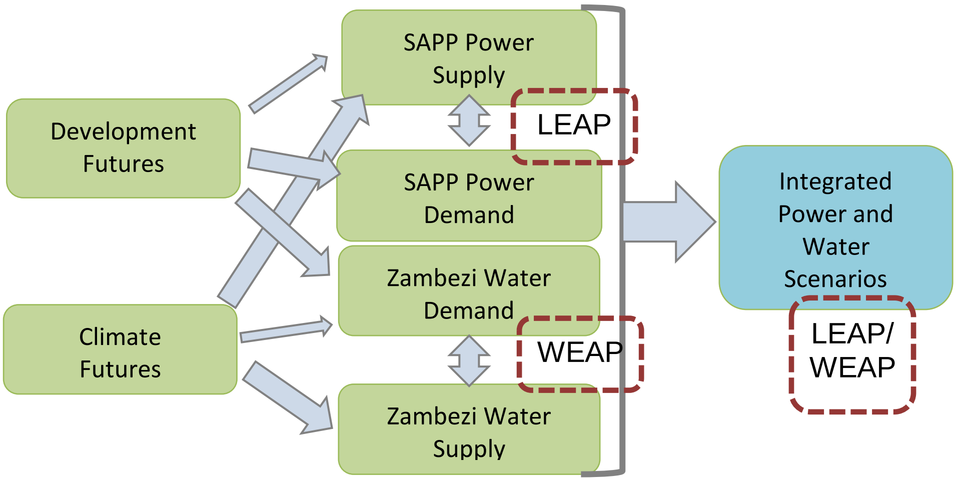
The potential transformation of the supply sector presented in these scenarios would require a fundamental shift in resource use, grid management and infrastructure development in the region. For decades, South Africa, Botswana and, to a lesser extent, Zimbabwe have built largely coal-fired plants while the rest of the region has been dominated by hydropower, with more recent inroads from gas-fired power. Given the assumptions in this research about the declining costs of renewable energy technologies – particularly solar photovoltaics and wind – the shift away from fossil fuels toward renewables could be dramatic over the coming decades, and not driven by political or environmental reasons but by economic and financial ones. This follows a global trend highlighted by recent research showing renewable power not only achieving parity with traditional generation, but become less expensive and therefore comprise the majority of future generation (see, e.g. BNEF 2015; Randall 2015). Even with this shift, however, the absolute growth in fossil fuel generation means the regional CO_2 emissions will rise rapidly, just not as fast as they would without the larger share of renewables.

One major gap in this type of electricity sector analysis, however, is that the availability of large hydropower plants is largely based on historical river flow data, as provided by the regional utilities and previous regional research studies. The contribution of this thesis is, in part, to integrate the climate vulnerability demonstrated in the water analysis into the electricity sector analysis, as explained in Chapter 1. The next chapter therefore links the projected seasonal availability of ZRB hydropower plants under alternative future climates to the inputs for electricity sector modelling.

6 Integrated water and electricity scenarios

This chapter addresses the third key research question: How could the changes in water availability for hydropower (i.e. due to climate change and development) affect regional electricity expansion plans, costs and greenhouse gas emissions? To do so, the chapter combines the electricity supply and demand analysis for SAPP (Chapter 5) with the water supply and demand analysis of the Zambezi River Basin (Chapter 4) to show how the climate change and irrigation impacts on water availability for specific existing and planned hydropower plants will affect the expansion of the regional electricity system (i.e. driven by socio-economic development), as well as the costs and GHG emissions from that system. Figure 4 illustrates the chapter's role in the overall methodology of the thesis.

Figure 78. Role of this chapter in overall methodology



The water supply and demand analysis in Chapter 4 demonstrated that there were no material differences in the performance of the hydropower plants across the development scenarios, but dramatic impacts across the alternative climate futures, as well as important interactions between irrigation and hydropower. For this reason, the integrated scenarios only consider two of the development future – BAU and Grand Deal. The integrated scenarios are therefore a combination of these two development futures with the two climate futures, as shown in Table 65 (a condensed version of Table 1). The integrated scenarios are compared to modelled baseline scenarios, as discussed in Chapter 1.

Table 64. Condensed set of integrated scenarios

		Climate futures	
		Marker scenarios with "drying" (e.g. drying in many sub-basins)	Marker scenarios with "wetting" (e.g. wetting in many sub-basins)
Development Futures	BAU (e.g. moderate growth)	"BAU Dry"	"BAU Wet"
	Grand Deal (e.g. major investment and technology shift)	"GD Dry"	"GD Wet"

The rationale for exploring the WEAP-LEAP linkage for this analysis is related to the policy questions for decisions-makers in the region. For example, from the point of view of most SAPP utilities, the question is not so much: What is the optimal power system under changing climate and development conditions? But rather: How will our current expansion plans be affected by changing climate and development conditions? Applying the WEAP and LEAP tools for an integrated multi-country system is a methodological advance pioneered in this thesis, showing that the integrated methodology can provide information to answer the third overall research question of this thesis: How could the changes in water availability for hydropower (i.e. due to climate change and development) affect regional electricity expansion plans, costs and greenhouse gas emissions? In addition, using WEAP and LEAP facilitates a capacity-building process with decision-makers to walk through the flow of the scenarios and simulations. In a highly uncertain environment, what decision-makers need is not necessarily the one "best solution" or the optimal one, but the solution or solutions that are robust under a wide variety of conditions. This, again, is where simulation models combined with some optimisation functionality provide transparent and user-friendly tools to guide decision-makers through an assessment of how their current plans may be impacted by future climates or development.

It is important to bear in mind that hydropower constitutes only 10–14% of total generation by 2070 across the three development scenarios (23–26% in 2030), and only 24% of potential regional hydropower capacity is located in the ZRB (i.e. 17,600 MW of 76,100 MW). This means that ZRB hydropower capacity would be between 2.5% and 6% of total regional capacity, even though this is much higher in Zambia, Zimbabwe, Mozambique and Malawi because of their dependency on hydropower. Note that, as discussed in Chapter 5, because the electricity supply results for the SADC Integration scenario were similar to those for the Grand Deal scenario, results are only shown for the BAU and Grand Deal development futures. In addition, to focus the analysis on the most important contributors to total capacity, the integrated scenario analysis focuses on existing and new plants of 300 MW or larger (see Table 66). Other smaller plants are still included in the water and electricity model, but their availability is held constant rather than driven by the climate futures.

Table 65. ZRB hydropower plants using availability derived from the water model

Name	**Capacity (MW)**
Cahora Bassa	2,075
Batoka Gorge	1,600
Mphanda Nkuwa I	1,500
Mphanda Nkuwa II	750
Kariba North & South existing	1,470
Cahora Bassa North Bank Extension	1,245
Mpata Gorge	1,086
Chemba I & II	1,000
Devils Gorge	1,000
Kafue Gorge Upper	900
Kafue Gorge Lower	750
Lupata	600
Kariba North Extension	360
Kariba South Extension	300

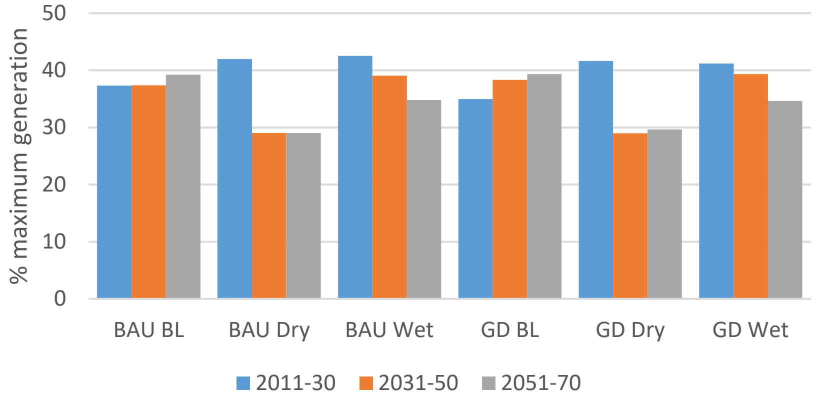
The following sections present the results of the integrated modelling for hydropower availability, power sector expansion plans, power sector operation, and GHG emissions.

6.1 Impact on hydropower availability

As an example of integrated results that are the core of this thesis research, the average availability of Kariba (existing plant and all extensions) is shown in Figure 79, with variations in both climate and development taken into consideration. In other words, the figure shows how the combination of different changes in climate and changes in the pace of irrigation and hydropower development would affect the availability of the power station (i.e. the amount of power generation as a share of the maximum possible generation).

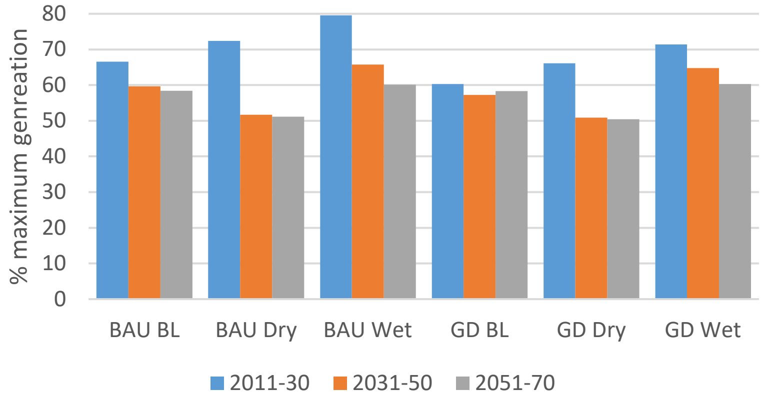
While availability increases somewhat in the short term, over the long term it declines dramatically, and even the wetting climate shows lower availability by 2051–2070. The results do not vary significantly for alternative development futures.

Figure 79. Average annual availability at Kariba under different climate and development scenarios, by time period



For Cahora Bassa, availability similarly declines 5–8% under a drying climate but increases by 2–8% in a wetting climate (Figure 80). This is despite an almost 50% increase in capacity up to 2020 (bearing in mind that the new capacity is for peaking and is expected to have a low load factor).

Figure 80. Average annual availability at Cahora Bassa under different climate and development scenarios, by time period



For both Kariba and Cahora Bassa, water availability increases in the 2011–2030 period under both future climates. This is largely a function of how the baseline climate data is generated. The baseline climate data series starting in 2011 is a repeat of historical climate data from the 1960–1990 period. The specific data used for the early years of the future scenarios (e.g. 2011–2030) are from a historical period with above-average rainfall. This is not predicted for 2011–2020 by the climate models used as the sources for the “Dry” and “Wet” scenarios. The comparison over the entire period is more important, therefore, than for only this early period. This also relates to the presentation of figures in Chapter 4 with an average value across the entire period for the baseline climate. The impacts, over the entire study period, of alternative climate and development futures on plant output is summarised below in Figure 81 and Figure 82.

Figure 81. Change in average annual generation from existing plants, 2011-2070

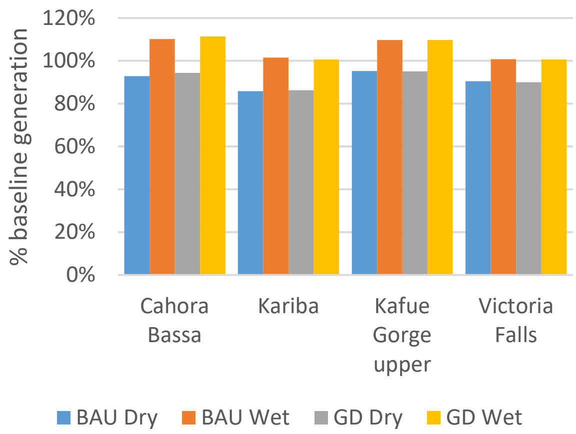
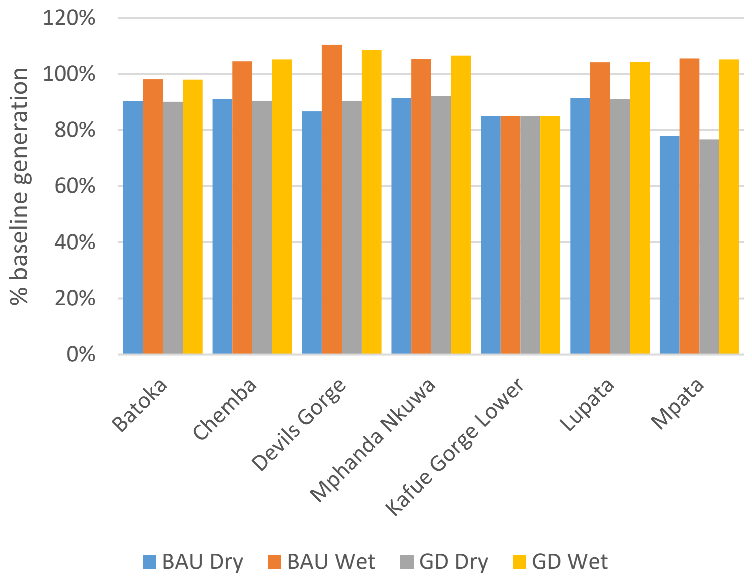


Figure 82. Change in average annual generation from specific new plants, 2031-2070



6.2 Impact on power sector expansion

If hydropower is less available during certain time periods under a different future climate, then other capacity must be installed to meet electricity demand during these time periods. Conversely, if increased water availability consistently increases production, less capacity from other technologies may be needed. One way of understanding the impact of climate change on the power system, therefore, is to examine how the capacity of other types of plants (including hydropower outside of the ZRB) would change under different climates, based on the need to optimize for a least-cost power system to meet the same demands (explained in Chapter 1). Because the optimisation algorithm in LEAP has "perfect foresight",[46] loss of one type of capacity not only leads to both increases and decreases of other generation types, but also the model attempts to find the optimal mix - over the entire time period - of baseline load and peaking plants from a new combination of technologies, taking into consideration the existing and specific planned plants whose commissioning dates are fixed exogenously.

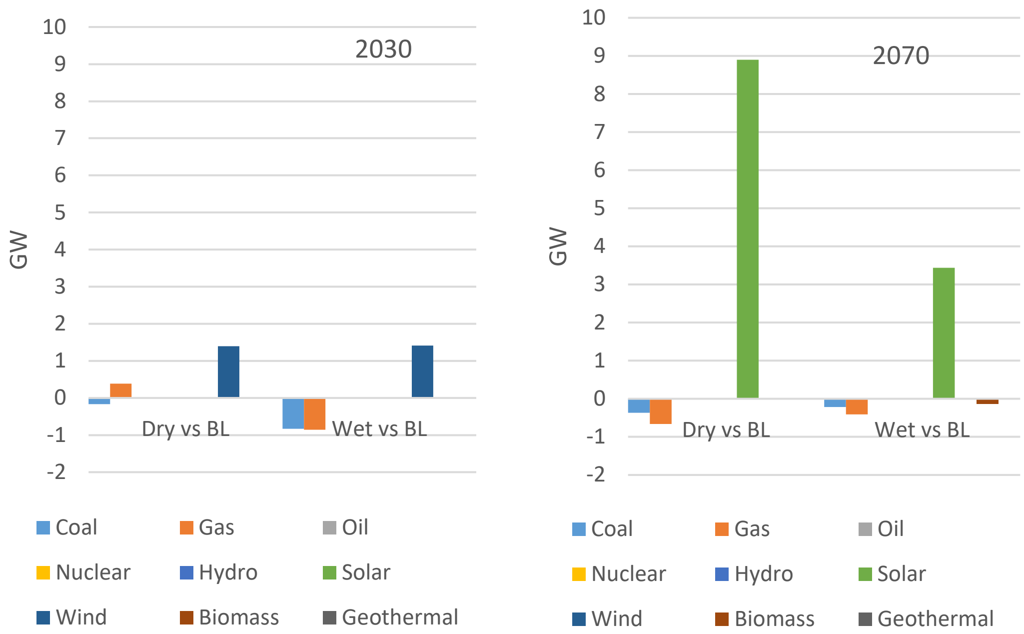
Figure 83 shows the changes in capacity under the BAU development scenario for both dry and wet climates by 2030 and 2070. In the BAU dry scenario, an additional 1.4 GW of wind and 0.4 GW of gas are built by 2030, with a small drop in new coal capacity. Overall, alternative capacity must increase by 1.8 GW by 2030 and by 8.9 GW by 2070 under the dry climate to replace the loss of hydropower generation, with the additional 2070 capacity coming from solar. Note that there is no decline in hydropower capacity because all large hydropower plants are treated as "specific" plants, that will definitely be built but whose commissioning date varies by development scenario. The optimisation algorithm used to choose the best mix of "generic" plants to meet regional demand does not include large hydropower as an option, since the potential locations for these plants is limited.

In the BAU wet scenario, significantly less coal and natural gas capacity is needed by 2030 because of higher hydropower output – 1.7 GW less in total. There are still increases in wind capacity, possibly because large hydropower reservoirs with ample water supply allows for greater use of intermittent resources and is the most economical during this period. By 2070,

46 Perfect foresight models are used widely in energy system optimisation and work as though there is a decision-maker who has complete information about the future. This is not meant, however, as an assumption about how the sector actually operates, but rather as a way to show what the optimal solution would be with sufficient information about the future. Examples of such analysis include Azar, Lindgren, and Andersson (2003); Barreto and Kypreos (2002); Ma (2010).

however, the costs of solar PV have declined enough to make this is a more economical intermittent power supply source, which expands with the help of increased water availability for reservoirs to balance the intermittency. Modest increases in water available cannot lead to more hydropower capacity, however, because, as discussed above, additional large hydropower sites (i.e. beyond those presented in Chapter 4) are limited, so they are not part of the generic capacity options available to optimise future supply and demand.

Figure 83. Change in capacity due to dry or wet climate versus baseline climate, BAU development, 2030 (left) & 2070 (right)



In addition to constructing alternative capacity, the operation of installed plants (existing and new) may also change because of changes in hydropower availability. Figure 84 shows the average annual change in generation (i.e. over 20-year periods) for each major technology in the dry and wet climates under BAU development. This shows the substantial decreases in hydropower generation under a dry climate after 2030 (see hydro in red), replaced largely with generation from coal-based thermal power stations. Under a wet climate, hydropower generation does increase over the 2011–2050 period and displaces the need for higher marginal cost coal and gas.

Under the Grand Deal development scenario (Figure 85), the more rapid fall in solar PV costs means that lower hydropower generation under a dry climate is replaced almost entirely by solar. Conversely, the increased generation from a wet climate in the 2011–2050 period under the Grand Deal development scenario displaces fossil fuels (coal and gas), but it also displaces renewable power (both solar and wind), because renewable power capacity would need to be constructed if hydropower average generation levels were higher. The absolute magnitude of these changes under the wet climate scenarios is lower in all cases, which is related to the fact that potential increases under a wet climate are much smaller than losses under a dry one.

Figure 84. Change in average annual generation compared to modelled baseline for dry (left) and wet (right) climates, BAU development

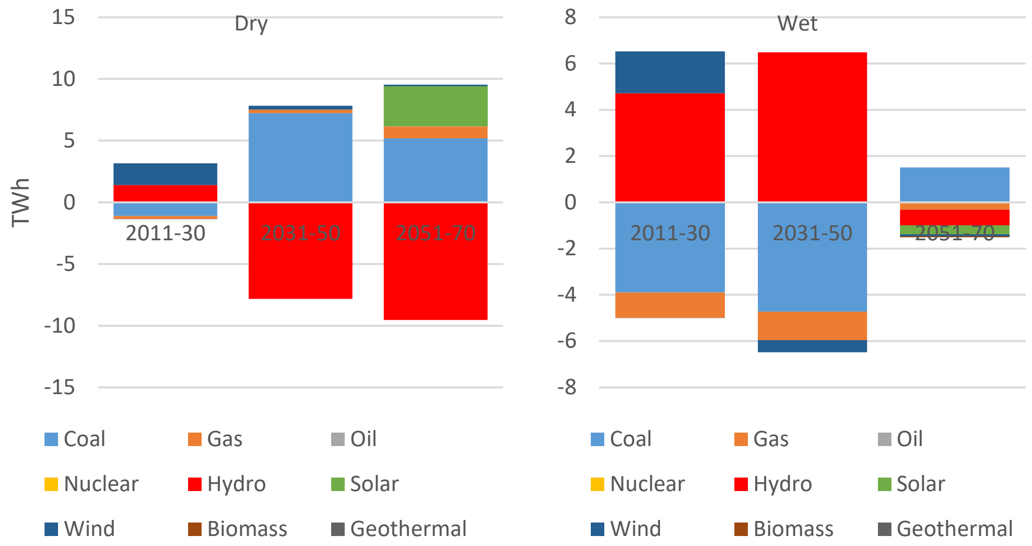
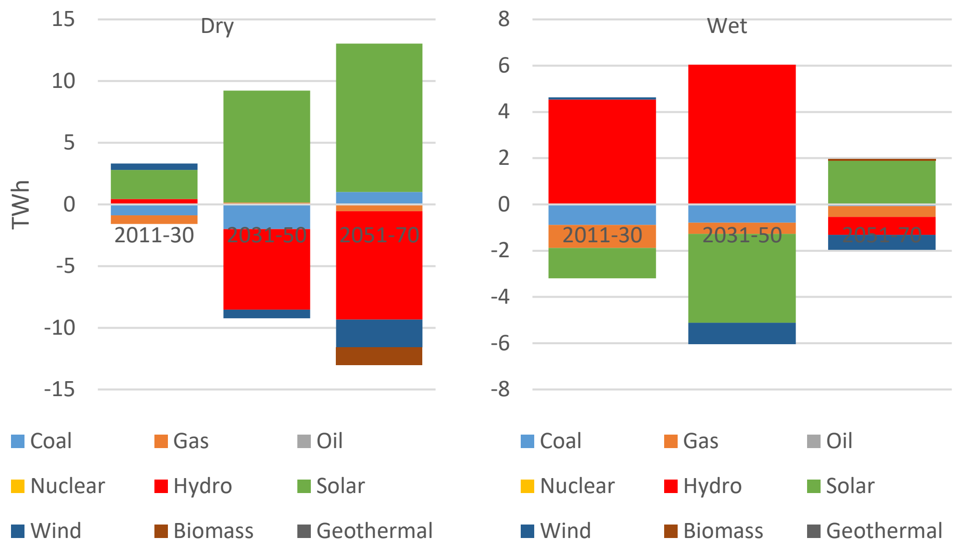


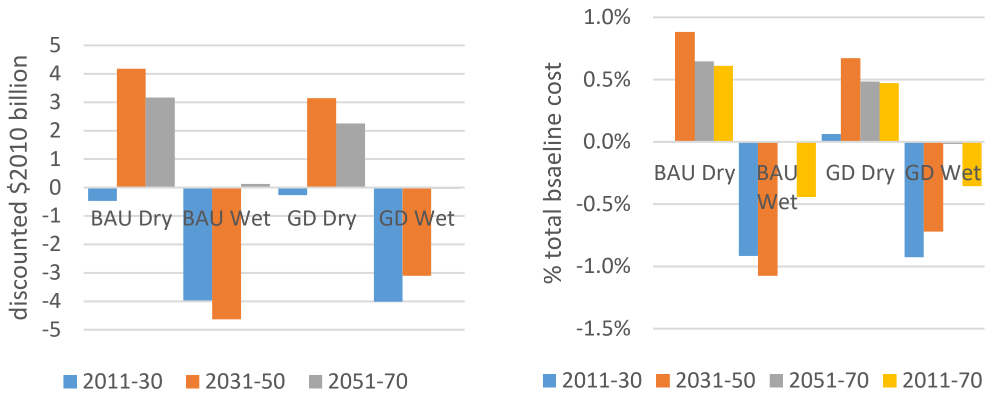
Figure 85. Change in average annual generation compared to baseline for dry (left) and wet (right) climates, Grand Deal development



6.3 Impact on electricity generation system costs

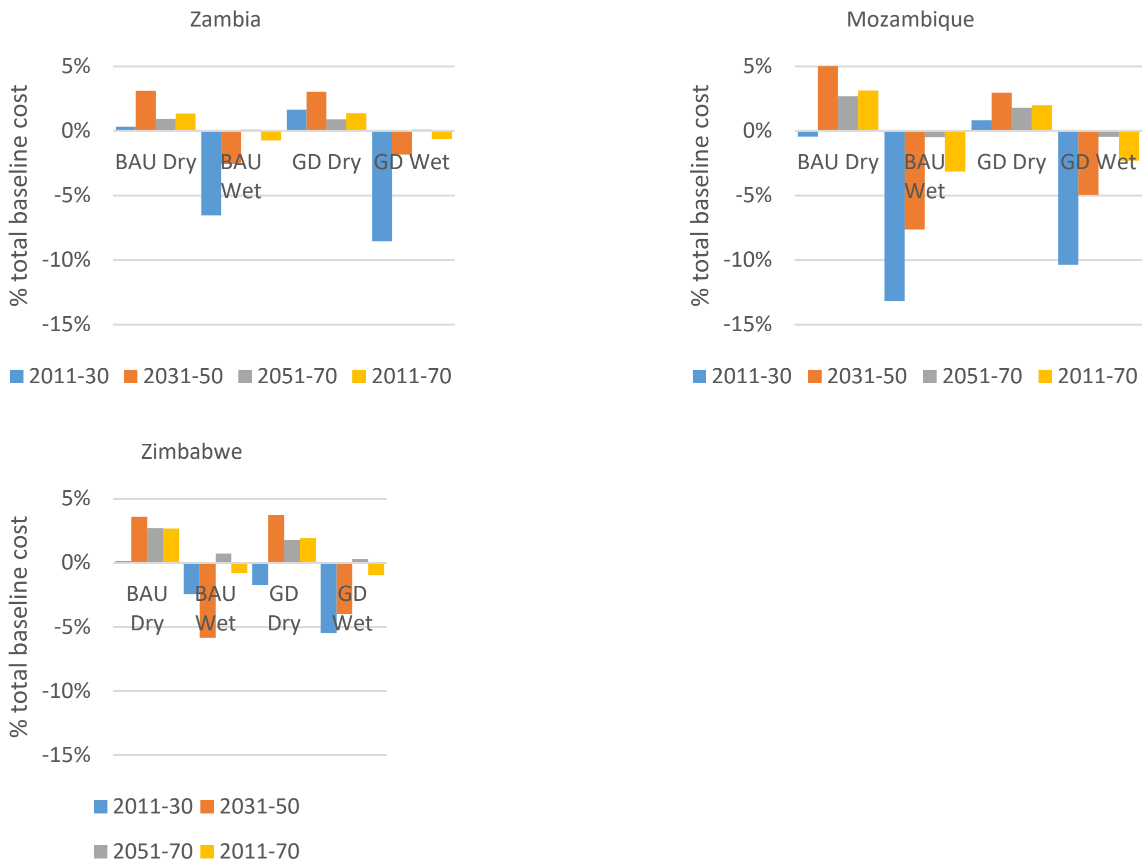
As discussed in Chapter 5, the electricity cost analysis includes the full cost of generation, but not transmission and distribution. Decreased production from low-cost hydropower resources would potentially increase total generation costs for the region, because of both additional capital costs for replacement capacity and the higher operating costs of fossil fuel plants. Figure 86 shows the impact on generation costs for the 20-year time periods, in terms of absolute change (i.e. billion dollars, discounted at 3% to 2010) and relative change (i.e. percentage of total generation costs). As expected, costs increase under the drying scenario and decrease under a wetting scenario.

Figure 86. Change in total regional generation costs due to dry and wet climate, by time period



Although the cost increases are almost $7 billion in total, this is less than 1% of total generation costs for the entire electricity system over the period. For individual countries that are dependent on hydropower, the impact is obviously much greater. Figure 87 shows that for Mozambique, Zambia and Zimbabwe the impact on generation costs could be up to 5%, while a wetting climate could see reductions of 5–15% in costs.

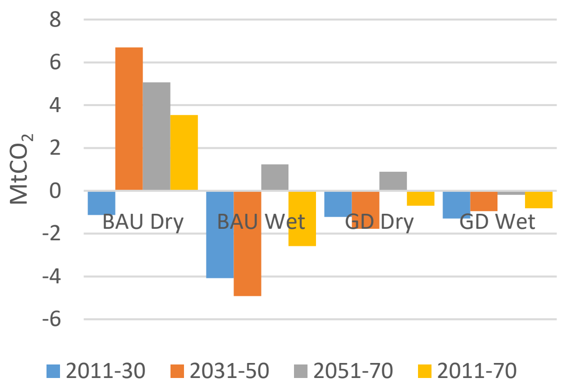
Figure 87. Change in generation cost relative to baseline climate (% total generation cost) for selected hydro-dependent countries



6.4 Impact on greenhouse gas emissions

If hydropower generation is replaced by fossil fuel generation, then a drying climate could lead to increases in GHG emissions. Conversely, if increased hydropower generation can displace fossil fuel generation, the opposite would be true. Figure 88 show the changes in average annual CO_2 emissions, during each period, under the different climates. By way of comparison, a 1000 MW coal fired power plant operating at 70% load factor would emit roughly 6 $MtCO_2$ per year. Under a dry climate, emissions typically increase by up to 6.7 $MtCO_2$ per year, while a wet climate would decrease emissions by up to 5 $MtCO_2$ per year. This effect is less pronounced under the Grand Deal development scenarios, because increased hydropower output leads to less construction of solar as well as displacement of fossil fuels (see Figure 85).

Figure 88. Average annual difference in emissions versus baseline climate



6.5 Discussion and conclusions

The analysis presented in this chapter has shown how the changes in water availability for hydropower affect regional electricity expansion plans, costs and GHG emissions, addressing the third key question for this thesis. The reduction in hydropower generation under a drying climate will lead to a shift in both capacity expansion choices and the operation of the regional power system, while the increases in hydropower output under a wetting climate are smaller. At an aggregate level, the increases in costs are a small share of total generation costs (less than 1% over the full study period). The impact on generation costs for hydro-dependent countries such as Mozambique, Zambia and Zimbabwe is larger, with significant savings under a wetting climate. Finally, because some hydropower could be displaced by coal, regional GHG emissions could increase by the equivalent of a large coal-fired power station under a drying climate. The implications of these results are discussed in more detail in the following chapter, which not only summarises the entire thesis research but also considers the broader ramifications for regional energy policy and climate policy.

7 Conclusions

The purpose of this final chapter is threefold: first, to articulate the answers to the original research questions and evaluation of its hypothesis, based on the findings of the PhD research; second, to clarify the limitations of the research and the conclusions; and, finally, to reflect on the broader policy implications of the results – both for the regional power sector and for the climate policy in the region.

7.1 Recap of results and evaluation of hypothesis

The hypothesis for this thesis was that the combination of future changes in climate and development (primarily irrigation) in the ZRB threatens the technical and economic viability of existing and planned hydropower plants, and in turn the expansion plans and costs of the regional power system for Southern African countries (see Section 1.2, together with detailed research questions).

The first step in addressing this hypothesis was to answer the question: How could future climate and irrigation expansion in the Zambezi River Basin affect hydropower generation potential? As demonstrated in Chapter 4, change in future climate is the overwhelming driver of future production at almost all hydropower plants. The difference in mean generation under wetting and drying climates (compared to a modelled baseline using the historical climate) is 12–16% (i.e. the difference between the values under a wet and dry scenario) for individual existing plants. This difference is as much as 30% for individual new plants, with all plants other than Batoka showing variation in mean annual generation or more than 13%. The impact of irrigation, on the other hand, is mainly an issue for plants downstream from Kariba, and even then the magnitude is typically less than a third of the impact of the alternative climates. The water modelling results therefore do not vary significantly across alternative development futures, because the accelerated irrigation development is still not large enough to dramatically impact hydropower.

The second step in the research was to answer the question: How could development in Southern Africa affect power demand, and how might this demand be met? The electricity sector analysis in Chapter 5 shows that the underlying socio-economic drivers of demand lead to both a dramatic increase in total electricity demand and a shift across sectors and countries within the region. Total electricity demand for the SAPP region increases by 8–14 times over the period from 2010 to 2070, with the combined demand from the rapidly growing countries of DRC, Mozambique, and Zambia becoming larger than South African demand by 2070. At the sectoral level, the share of total demand from the extractive and manufacturing sectors increases from 59% in 2010 to 70% in 2070 under the Grand Deal scenario, based on a compound annual growth rate of consumption in excess of 5%. Activity-level growth is the main driver of demand growth. Comparison with other studies in the region show that the mid-term demand estimates (e.g. 2025–2030) in this study are generally within the range of other research, with somewhat higher demand estimates from the Grand Deal scenario. Total electricity supply required over the longer term is met through the addition of 400 to 1400 GW of new capacity, or 8–20 times the current capacity of the region. More strikingly, the power mix shifts from almost 80% coal-fired power to 24–44% coal by 2070, with the balance being supplied mainly by solar, wind, hydropower and nuclear generation. The regional shift is no less dramatic, with South Africa's share of total generation declining from 84% to only a third of the region's power, based on the higher growth rates in countries such as DRC, Mozambique and Zambia.

The third question investigate in this research was: How could the changes in water availability for hydropower (i.e. due to climate change and development) affect regional electricity expansion plans, costs and greenhouse gas emissions? As discussed in Chapter 6, applying the WEAP and LEAP tools to an integrated multi-country system is a methodological advance pioneered in this thesis, showing that the integrated methodology can provide information to answer this question. The analysis shows that the reduction in hydropower generation under a drying climate will lead to a shift in both capacity expansion choices and the operation of the regional power system, while the increases in hydropower output under a wetting climate are smaller. In other words, the "downside" of future climate changes is larger than the potential "upside". At an aggregate level, the increases in costs are a small share of total generation costs (i.e. less than 1% over the full study period compared to the baseline climate). The impact on generation costs for hydro-dependent countries such as Mozambique, Zambia and Zimbabwe, however, is considerably larger, and these countries also gain more under a wetting climate. Finally, because some hydropower could be displaced by coal, regional GHG emissions could increase by more than 6 $MtCO_2$ per year in the medium term, or the equivalent of a large coal-fired power station. These results of the integrated analysis are fundamental to the contribution of this PhD thesis to knowledge.

7.2 Limitations of the analysis

While the thesis makes a contribution to knowledge, the scope is necessarily limited and therefore it may not address all of the questions related to the impacts of climate change and hydropower on regional electricity sector development. One limitation discussed in Section 1.4 is not being able to include new transmission investments in the optimisation analysis. The modelling tools chosen to integrate energy and water modelling – for the reasons discussed in Chapter 1 – do not allow this type of analysis, although the inputs on trade drawn from the IRENA SAPP study were the result of a combined transmission and generation optimisation. This means that the optimisation is a country-by-country optimisation rather than a combined regional one. In addition, future work using time-of-day time slices in the generation modelling might provide additional insights on the value of trading, because peak demand is not at the same time in each of the SAPP countries, nor is the availability of renewable energy sources constant across time and space.

The geographical scope of the thesis is the ZRB. Linking additional Southern Africa river basins (e.g. the Congo Basin) to the SAPP electricity model would also provide valuable insights, because patterns of wetting and drying in the river basins are not necessarily the same. Similar trends in the Zambezi and Congo could exacerbate the vulnerabilities highlighted here, while contrasting climate patterns could reduce the overall impacts of climate change, assuming sufficient transmission capacity is available for the required regional trade (see discussion below on regional cooperation).

The thesis focuses on the impact pathway from climatic change to water availability at hydropower plants, and how this then influences power system operation and expansion. An alternative approach, however, would be to explore how prioritizing hydropower production over irrigation demand under a changing climate could affect food production, although this analysis could be conducted using only the WEAP model.

Finally, the costs included for optimising power generation expansion include only the private, financial costs for power plant construction and operation – because the purpose of the analysis is to simulate the current investment decision-making environment. The construction and operation of hydropower plants, however, as well as other forms of power generation, has additional environmental and social impacts. Including these external costs in the energy optimisation analysis could be an important subject of future research.

7.3 Energy policy implications

The electricity modelling presented in Chapter 5 has important policy implications for the energy sector in its own right, even without considering climate change. The potential transformation of the electricity supply sector would require a fundamental shift in resource use, grid management and infrastructure development in the region. For decades, South Africa, Botswana and Zimbabwe have built largely coal-fired plants, while the rest of the region has been dominated by hydropower, with more recent inroads from gas-fired power. Because of the declining levelised costs of non-hydro renewable energy technologies – particularly solar photovoltaics and wind – the shift away from fossil fuels toward renewables could be dramatic over the coming two to three decades. More importantly, this shift may not be driven by political or environmental reasons but by economic and financial ones. This trend has been seen recently in South Africa's Renewable Energy Independent Power Producer Procurement Programme (REI4P) and follows a global trend highlighted by recent research showing renewable power not only achieving parity with traditional generation but becoming less expensive and therefore comprising the majority of future capacity additions (see, e.g., BNEF 2015; Randall 2015; Eberhard, Kolker, and Leigland 2014; Eberhard et al. 2016). None of the short-to-medium-term plans put forward for the region (e.g. the consolidated SAPP forecasts for capacity and demand) fully address the magnitude of this transition to a more diverse energy mix over the longer term, and many ignore it entirely. The modelling approach in this study not only allows for a deeper and longer-term analysis of supply, but also a more nuanced understanding of demand drivers (i.e. as opposed to the straight-line growth projections in some other studies).

This shift in the resource base for electricity generation will pose challenges for grid integration and balancing supply and demand across countries and load centres. In fact, the lack of availability of adequate transmission capacity, the ability to balance dispatchable and non-dispatchable sources of supply, and the lack of availability of cost-effective storage, could be the most important limitations on realising an optimal expansion plan. Although the SAPP Coordination Centre does manage the regional short-term "day ahead market", trading in this market is very small, and so there is currently no regional-level mechanism for forecasting and balancing supply on the scale required. In addition, currently the only major storage in the region other than the two major hydropower reservoirs at Kariba and Cahora Bassa currently is the pumped storage capacity in South Africa (1.58 GW). Even with another 1.2 GW of storage in South Africa and 1.3 GW in Lesotho planned, these are far smaller than the additional solar and wind power investments over the next two decades. Major advances in chemical or other storage technologies are therefore important in realising the magnitude of solar power expansion. In the short-to-medium term, exploring the possibility of "banking" energy from non-dispatchable resources (e.g. solar PV, wind) in large hydropower reservoirs in the region, as mentioned earlier, could be one important strategy for this new supply regime. This will require a greater focus on commissioning new transmission capacity, but also an analysis of whether modifying the operating rules at major regional hydropower reservoirs could comprise their other functions (e.g. flood control, ecological flow releases).

Historically, the development of transmission capacity, and the resulting trade in electricity, has been constrained by the political and economic realities of the region. The tension between the potential for savings from trade versus the additional costs of maintaining national self-sufficiency has been a recurring theme in many previous studies (Nexant 2007; Economic Consulting Associates 2009; Rowlands 1998; Graeber and Spalding-Fecher 2000), and requires both political and technical solutions to address security of supply concerns. As discussed in Chapter 5, while this electricity sector analysis does not imply compromising energy security for SAPP countries in the medium-to-long term, South Africa and Zambia would potentially be relying on imports for up to 17% of domestic consumption in 2030 under the Grant Deal scenario. Regional infrastructure plans have identified political commitment, as well as strong institutions, as keys to greater cooperation (SADC 2012). To date, trade in the short-term electricity market has been thin, and the SAPP Coordination Centre has not directly facilitated longer-term contracts and negotiations. For the largest source of demand in the region – South Africa – imported electricity has played a very limited role in future planning (DoE 2013; Resnick, Tarp, and Thurlow 2012). There are signs that the politics could be shifting, however, for several key reasons. The first is the political commitment and financing available for major regional energy infrastructure projects. At the continental level, the Programme on Infrastructure Development in Africa initiative of the African Union and the New Partnership for African Development represent a new level of political commitment to mobilise several hundred billion dollars for infrastructure projects, including regional energy infrastructure projects to facilitate greater energy trade (Mandelli et al. 2014). In Southern Africa specifically, the World Bank launched the SAPP Program for Accelerating Transformational Energy Projects to provide transaction advisory and other services to address the technical and economic barriers large and complex transmission projects.

The differences in medium-term demand projections for some countries between this study and the SAPP compilation of utility forecasts (Figure 77) also suggest that the lack of national planning frameworks driven by bottom-up demand analysis could lead to significant over- or under-investment. Capacity among utilities for developing detailed bottom-up demand analysis and supply optimisation analysis varies widely. Several SAPP utilities reported to the author that they have no planning model for their power sector, and this reflects the weak institutional capacity in utilities and regulators across Africa (Eberhard et al. 2011; Eberhard and Shkaratan 2012). A dedicated capacity-building program for the regional utilities could address this, but only if it combines both management level buy-in on greater cooperation with greater technical skill, data sharing and collaborative planning among member utilities.

The findings of this research, as well as interacting with stakeholders during the process of the doctoral research, also highlight some of the benefits of using LEAP as a tool for national and regional planning in Southern Africa. The author had the opportunity to meet with regional electricity planners as part of related research projects (see Chapter 1.5), to discuss both the conceptual framework and the modelling tools. The fact that LEAP can combine simulation analysis with optimisation analysis allows the current SAPP Planning Framework to be used as an input to the analysis. This has important implications for the policy impact of this approach because decision-makers contributing elements of the SAPP plan have a greater stake in the outputs. The SADC RESAP study (CEEEZ 2012) also used LEAP, and has been reviewed by not only SADC staff and management but also the energy ministers. Because some of the barriers to greater regional cooperation relate to institutional and technical capacity, the accessibility of the analytical tool is relevant to the policy impact of the analysis. In addition, the affordability of the tools is relevant to policy impact, because affordability influences whether regional institutions can continue to update and use the analysis in the future. LEAP is available without cost to public sector and academic users in developing countries and is supported by a professional team at no cost to these users.

7.4 Integrated modelling policy implications

An important contribution of this thesis is developing integrated regional scenarios based on energy-water modelling, to understand how these sectors interact under an uncertain future climate. The integrated scenario analysis not only addresses the immediate questions about generation choices, system costs and GHG emissions, but also points to important policy implications that extend beyond the electricity sector.

The relatively low consumption of water in the ZRB in the past meant that explicit trade-offs across sectors and across countries posed less of a challenge for the basin overall. Hydropower plant operators and development have therefore not needed to consider changes in water availability as a constraint on power sector expansion. This is very likely to change in the future, as increased demand from all sectors, and major potential changes in climate will require more explicit agreements across both countries and user groups on how to best utilise a limited resource. In fact, Turton (2016) suggests that the growing scarcity of water in the largest economies of Southern Africa, which will be exacerbated by climate change, could force a political shift, as the relative political power of countries with more water and other unexploited natural resources grows.

For the expansion of existing hydropower plants and construction of new ones (both reservoir and run-of-river), this research demonstrates the tools that could be used to integrate both climate change and upstream development demands into the feasibility studies before investment decisions are made, and to consider possible adaptations in design and operation. Ignoring these factors could lead to “stranded assets” for investors due to climate change impacts (Caldecott 2017; Burton et al. 2016). Beyond the level of individual investments, however, the research also illustrates the first steps toward integrating climate change and upstream development considerations into national and regional electricity planning. The effects of climate change on hydropower may mean that diversity of power sources must be given a higher priority than it has had in the past, and that this quality must be included in the supply optimisation analysis. Future research could also address whether changes in operating rules at the major reservoirs could increase the resilience of the electricity system, as well as how demand-side improvements in water and energy use efficiency could minimize the impacts of decreased water availability.

This research also has important implications against the background of the multi-year drought that has left Lake Kariba at only 29% full in September 2016 (Tsiko 2016). A combination of excessive use of the reservoir and unseasonably low rainfall is crippling the power sectors – and in turn the economies – of Zambia and Zimbabwe, despite Kariba being the largest human-made reservoir in the world, by volume. This points not only to the risks from climate variability and long-term climate change but also to the need for strong and cooperative governance arrangements to manage shared water resources in the region, across both countries and sectors. The expansion of irrigation and construction of numerous new hydropower reservoirs and power plants along the main stem of the Zambezi River will only intensify the need for shared governance. As discussed earlier, ZAMCOM has only recently been operationalised with a Secretariat, and there is no formal cooperation with SAPP. Cooperative governance may need to look beyond simple allocation of resources, however, because of the differential impacts of climate change on countries that are more or less vulnerable. For example, if a hydropower plant is constructed in Mozambique for export, but future changes in climate could reduce the performance of that asset, the electricity export price and contractual arrangements will need to anticipate possible future fluctuations or additional investments needed (e.g. larger storage, alternative power supply sources) to guarantee future delivery of power.

An additional policy implication is related to global climate change governance. With the entry into force of the Paris Agreement under the UNFCCC in November 2016, all of the countries in the SAPP region will have some form of climate change-related commitments (Obergassel et al. 2016; UNFCCC 2015). Most of the countries, including hydro-rich Zimbabwe and Zambia, included quantitative commitments to reduce their greenhouse gas emissions relative to a specified “business-as-usual” growth path in their nationally determined commitments (NDCs) (Mozambique and Malawi have only committed to actions, not quantitative reductions) (UNFCCC 2017). The challenge specifically for Zambia and Zimbabwe is that the impacts of climate change could potentially make it more difficult to meet their mitigation commitments. The request for international support to meet their commitments, as elaborated in their NDCs, is therefore critical, because they will need financing, capacity building and technology transfer to achieve mitigation goals within the context of an uncertain climate.

The electricity and water sectors are important contributors to the development of the SADC region, and hydropower in the ZRB lies at the intersection of these fields. Climate change, however, has the potential to add increased stress on these sectors, both directly and indirectly, and yet is not being considered in many individual hydropower power investments, or in national or regional electricity planning. The integrated scenario analysis approach in this thesis demonstrates how the impacts of climate change could be assessed not only for specific hydropower plants and for the entire sector power sector. The results suggest that the downside from a drying climate is significant, particularly for countries with high dependency on hydropower, while the benefits of a wetting climate are limited. Preparing for this possible range of future climates can increase the resilience of the sector and reduce the risk of stranded assets in the power sector.

8 References

Alfstad, Thomas. 2005. 'Development of a Least Cost Energy Supply Model for the SADC Region'. Master of Science in Engineering, Cape Town: University of Cape Town, Energy Research Centre. www.erc.uct.ac.za.

Allen, Richard G, Luis S Pereira, Dirk Raes, and Martin Smith. 1998. 'Crop Evapotranspiration - Guidelines for Computing Crop Water Requirements – FAO Irrigation and Drainage Paper 56.' Rome: Food & Agricultural Organisation of the United Nations. http://www.fao.org/docrep/X0490E/x0490e00.htm.

Arnell, Nigel W. 1999. 'Climate Change and Global Water Resources'. *Global Environmental Change* 9, Supplement 1 (0): S31–49. doi:10.1016/S0959-3780(99)00017-5.

———. 2004. 'Climate Change and Global Water Resources: SRES Emissions and Socio-Economic Scenarios'. *Global Environmental Change* 14 (1): 31–52. doi:10.1016/j.gloenvcha.2003.10.006.

Arnell, Nigel W., D. A. Hudson, and R. G. Jones. 2003. 'Climate Change Scenarios from a Regional Climate Model: Estimating Change in Runoff in Southern Africa'. *Journal of Geophysical Research* 108 (D16): 4519. doi:10.1029/2002JD002782.

Arnell, Nigel W., Tom Kram, Timothy Carter, Kristie Ebi, Jae Edmonds, Stephane Hallegatte, Elmar Kriegler, et al. 2011. 'A Framework for a New Generation of Socioeconomic Scenarios for Climate Change Impact, Adaptation, Vulnerability and Mitigation Research'. Boulder, Colorado: Integrated Science Program, National Center for Atmospheric Research. http://www.isp.ucar.edu/sites/default/files/Scenario_FrameworkPaper_15aug11_0.pdf.

AU. 2012. 'Africa Energy Sector Phase III Report. The Programme for Infrastructure Development in Africa': African Union.

Azar, Christian, Kristian Lindgren, and Björn A Andersson. 2003. 'Global Energy Scenarios Meeting Stringent CO2 Constraints—cost-Effective Fuel Choices in the Transportation Sector'. *Energy Policy* 31 (10): 961–76. doi:10.1016/S0301-4215(02)00139-8.

Banda, Binnie. 2015. Malawi sectoral electricity demand from Escom. Interview by Randall Spalding-Fecher. Email.

Barreto, Leonardo, and Socrates Kypreos. 2002. 'Multi-Regional Technological Learning in the Energy Systems MARKAL Model'. *International Journal of Global Energy Issues* 17 (3): 189. doi:10.1504/IJGEI.2002.000940.

Bates, B, Z Kundzewicz, S Wu, and J Palutikof. 2008. 'Climate Change and Water'. IPCC Technical Paper VI. Geneva: Intergovernmental Panel on Climate Change. http://www.ipcc.ch/pdf/technical-papers/climate-change-water-en.pdf.

Baxter, Lester W., and Kevin Calandri. 1992. 'Global Warming and Electricity Demand'. *Energy Policy* 20 (3): 233–44. doi:10.1016/0301-4215(92)90081-C.

Bazilian, Morgan, Benjamin F. Hobbs, Will Blyth, Iain MacGill, and Mark Howells. 2011. 'Interactions between Energy Security and Climate Change: A Focus on Developing Countries'. *Energy Policy* 39 (6): 3750–56. doi:10.1016/j.enpol.2011.04.003.

Bazilian, Morgan, Patrick Nussbaumer, Hans-Holger Rogner, Abeeku Brew-Hammond, Vivien Foster, Shonali Pachauri, Eric Williams, et al. 2012. 'Energy Access Scenarios to 2030 for the Power Sector in Sub-Saharan Africa'. *Utilities Policy* 20 (1): 1–16. doi:10.1016/j.jup.2011.11.002.

Bazilian, Morgan, Ambuj Sagar, Reid Detchon, and Kandeh Yumkella. 2010. 'More Heat and Light'. *Energy Policy* 38 (10): 5409–12. doi:10.1016/j.enpol.2010.06.007.

BEA. 2014. 'National Income and Product Account Tables'. *US Bureau of Economic Analysis*. http://www.bea.gov//national/nipaweb/DownSS2.asp.

Beck, Lucas, and Thomas Bernauer. 2011. 'How Will Combined Changes in Water Demand and Climate Affect Water Availability in the Zambezi River Basin?' *Global Environmental Change* 21 (3): 1061–72. doi:10.1016/j.gloenvcha.2011.04.001.

Beilfuss, Richard. 2001. 'Prescribed Flooding and Restoration Potential in the Zambezi Delta, Mozambique. Working Paper #4. Program for the Sustainable Management of the

Cahora Bassa Dam and the Lower Zambezi Valley’. Baraboo, Wisconsin: International Crane Foundation. http://www.savingcranes.org/images/stories/pdf/conservation/Zambezi_modeling_Working_Paper4.pdf.

Beilfuss, Richard, and Cate Brown. 2010. ‘Assessing Environmental Flow Requirements and Trade-Offs for the Lower Zambezi River and Delta, Mozambique’. *International Journal of River Basin Management* 8 (2): 127–38. doi:10.1080/15715121003714837.

Beilfuss, Richard, and David dos Santos. 2001. ‘Patterns of Hydrological Change in the Zambezi Delta, Mozambique. Working Paper #2. Program for the Sustainable Management of the Cahora Bassa Dam and the Lower Zambezi Valley’. Baraboo, Wisconsin: International Crane Foundation. http://www.savingcranes.org/images/stories/pdf/conservation/Zambezi_hydrology_Working_Paper2.pdf.

Bhartendu, S., and S.J. Cohen. 1987. ‘Impact of CO2-Induced Climate Change on Residential Heating and Cooling Energy Requirements in Ontario, Canada’. *Energy and Buildings* 10 (2): 99–108. doi:10.1016/0378-7788(87)90012-0.

BNEF. 2015. ‘New Energy Outlook 2015. Long Term Projections for the Global Energy Sector. Executive Summary’. Bloomberg New Energy Finance. http://www.bloomberg.com/company/new-energy-outlook/.

Bowen, Brian H., F.T. Sparrow, and Zuwei Yu. 1999. ‘Modeling Electricity Trade Policy for the Twelve Nations of the Southern African Power Pool (SAPP)’. *Utilities Policy* 8 (3): 183–97. doi:10.1016/S0957-1787(99)00019-3.

BPC. 2010. ‘Botswana Power Corporation Annual Report 2010’. Gaborone: Botswana Power Corporation. http://www.bpc.bw/Documents/bpc_annual_report_2010.pdf.

Burian, Martin, Peter Zhou, Francis Masawi, Francis Yamba, and Florian Baumgard. 2012. ‘Analysis of Grid Emission Factors for the Electricity Sector in Sub-Saharan Africa’. Roskilde, Denmark: UNEP Risoe Centre.

Burton, J, T Caetano, Bruno Merven, Alison Hughes, F Ahjum, and B McCall. 2016. ‘The Impact of Stranding Power Sector Assets in South Africa. Mitigation Action Plans and Scenarios (MAPS).’ Cape Town: Energy Research Centre, University of Cape Town. http://www.erc.uct.ac.za/sites/default/files/image_tool/images/119/Papers-2016/2016-Burtonetal-Impact_stranding_power_sector_assets.pdf.

Caldecott, Ben. 2017. ‘Introduction to Special Issue: Stranded Assets and the Environment’. *Journal of Sustainable Finance & Investment* 7 (1): 1–13. doi:10.1080/20430795.2016.1266748.

CEEEZ. 2012. ‘SADC Renewable Energy Strategy and Action Plan (RESAP). Draft Main Report’. Gaborone: Southern African Development Community.

Central Statistics Office. 2010. ‘2010 Census of Population and Housing: National Analytical Report’. Lusaka, Zambia.

Cervigni, Raffaello, Rikard Liden, James E. Neumann, and Kenneth M. Strzepek. 2015. ‘Enhancing the Climate Resilience of Africa’s Infrastructure: The Power and Water Sectors’. Washington, D. C.: World Bank. https://openknowledge.worldbank.org/handle/10986/21875.

Chapman, Arthur. 2012. ‘Socio-Economic Futures of the Zambezi River Basin’. Cape Town: OneWorld Sustainable Investments. www.oneworldgroup.co.za.

Cilliers, J, B Hughes, and J Moyer. 2011. ‘African Futures 2050: The next Forty Years, Technical Report’. Pretoria: Institute for Security Studies.

CSO. 2013. ‘Zambia Energy Statistics. Energy Statistics 2000- 2010’. Lusaka, Zambia: Central Statistical Office. www.zamstats.gov.zm.

Dellink, Rob, Jean Chateau, Elisa Lanzi, and Bertrand Magne. 2015. ‘Long-Term Economic Growth Projections in the Shared Socioeconomic Pathways’. *Global Environmental Change*. doi:10.1016/j.gloenvcha.2015.06.004.

Department of Energy. 2014. ‘Energy Programmes and Projects’. Pretoria, South Africa. http://www.energy.gov.za/IPP/Electricity-Infrastructure-Industry-Transformation-30June2014.pdf.

DFID. 2002. 'Energy for the Poor: Underpinning the Millennium Development Goals'. London: Department for International Development.

DoE. 2013. 'Integrated Resource Plan for Electricity 2010-2030. Update Report 2013'. Pretoria: Department of Energy. http://www.doe-irp.co.za/content/IRP2010_updatea.pdf.

Eberhard, Anton, Katharine Gratwick, Elvira Morella, and Pedro Antmann. 2016. 'Independent Power Projects in Sub-Saharan Africa: Lessons from Five Key Countries'. Washington, D. C.: World Bank. https://www.researchgate.net/publication/301363533_Independent_Power_Produces_in_Sub-Saharan_Africa_Lessons_from_Five_Key_Countries.

Eberhard, Anton, J Kolker, and J Leigland. 2014. 'South Africa's Renewable Energy IPP Procurement Programme: Success Factors and Lessons. Washington, Public Private Infrastructure Advisory Facility'. Washington, D.C.: World Bank. http://www.gsb.uct.ac.za/files/ppiafreport.pdf.

Eberhard, Anton, Orvika Rosnes, Maria Shkaratan, and Haakon Vennemo. 2011. 'Africa's Power Infrastructure. Investment, Integration, Efficiency'. Washington, D. C.: World Bank. https://openknowledge.worldbank.org/handle/10986/2290.

Eberhard, Anton, and Maria Shkaratan. 2012. 'Powering Africa: Meeting the Financing and Reform Challenges'. *Energy Policy* 42 (March): 9–18. doi:10.1016/j.enpol.2011.10.033.

Ebinger, Jane, and Walter Vergara. 2011. 'Climate Impacts on Energy Systems: Key Issues for Energy Sector Adaptation'. Washington, D. C.: World Bank. http://www.esmap.org/esmap/sites/esmap.org/files/E-Book_Climate%20Impacts%20on%20Energy%20Systems..pdf.

Economic Consulting Associates. 2009. 'The Potential of Regional Power Sector Integration. South African Power Pool (SAPP) Transmission & Trading Case Study'. Washington D. C.: Energy Sector Management Assistance Programme. http://www.esmap.org/esmap/sites/esmap.org/files/BN004-10_REISP-CD_South%20African%20Power%20Pool-Transmission%20%26%20Trading.pdf.

Edenhofer, O, R Pichs-Madruga, Y Sokona, E Farahani, S Kadner, K Seyboth, A Adler, et al., eds. 2014. *Climate Change 2014, Mitigation of Climate Change. Contribution of Working Group III to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change*. Cambridge, United Kingdom and New York, NY, USA: Cambridge University Press. http://ipcc.ch/report/ar5/wg3/.

EdM. 2010. 'Annual Statistical Report 2010. Relatória Anual De Estatística'. Maputo: Electricidade de Moçambique.

———. 2011. 'Annual Statistical Report 2011. Relatória Anual De Estatística'. Maputo: Electricidade de Moçambique.

EPRI. 2012. 'Power Generation Technology Data for Integrated Resource Plan of South Africa'. Palo Alto, California: Electric Power Research Institute. http://www.doe-irp.co.za/content/EpriEskom_2012July24_Rev5.pdf.

ERC. 2013. 'Assumptions and Methodologies in the South African TIMES (SATIM) Energy Model'. Version 1.0. Cape Town: Energy Research Centre, University of Cape Town. http://www.erc.uct.ac.za/Research/Otherdocs/Satim/SATIM%20Methodology%20v1.0.pdf.

———. 2014. 'SATIM Online Model Files [Public]. Energy Research Centre'. Google drive. *SATIM Online Model Files [Public], DMD_PRJ.Xlsm*. https://drive.google.com/drive/folders/0B7HshZgHUl6HVVBFS1RnRnRfTlU/0B1qvzdPa0eX2aXVvM2RfSFg5Y2c/0Bx0_GWD0yNIITVhzRHFRN2NsOW8.

ESCOM. 2013a. 'Kapichira Power Station - Electricity Supply Corporation of Malawi'. http://www.escom.mw/station-kapichira.php.

———. 2013b. Personal Communication with Elenestina Mwelwa Interview by Randall Spalding-Fecher. Data provided in Excel Spreadsheet.

Eskom. 2010. 'Integrated Report 2010'. Johannesburg: Eskom Holdings Limited. http://www.eskom.co.za/annreport10/downloads/eskom_ar2010.pdf.

———. 2014. ‘Eskom Integrated Report 2014’. Johannesburg: Eskom.

Euroconsult, and Mott MacDonald. 2007. ‘Integrated Water Resources Management Strategy and Implementation Plan for the Zambezi River Basin. Final Report, Rapid Assessment’. Gaborone, Botswana and Lusaka, Zambia: South African Development Community Water Division and Zambezi River Authority. http://www.elmed-rostov.ru/Projects/Zamwis_php/Reports/RA%20Water%20Resources%20Zambezi%2002Jan2008.pdf.

Euromonitor International. 2013. ‘The World Economic Fact Book 2014’. 21st Edition. London, England: Euromonitor International Ltd. http://www.euromonitor.com/medialibrary/PDF/Book_WEF_2014.pdf.

Frederick, K D, and D C Major. 1997. ‘Climate Change and Water Resources’. *Climate Change* 37 (1): 7–23. doi:10.1023/A:1005336924908.

GEA. 2012. *Global Energy Assessment - Toward a Sustainable Future*. Cambridge University Press, Cambridge, UK and New York, NY, USA and the International Institute for Applied Systems Analysis, Laxenburg, Austria. www.globalenergyassessment.org.

Graeber, Bernhard, and Randall Spalding-Fecher. 2000. ‘Regional Integrated Resource Planning and Its Role in the Regional Electricity Co-Operation and Development in Southern Africa’. *Energy for Sustainable Development* 4 (2): 32–37.

Gupta, Hoshin V., Harald Kling, Koray K. Yilmaz, and Guillermo F. Martinez. 2009. ‘Decomposition of the Mean Squared Error and NSE Performance Criteria: Implications for Improving Hydrological Modelling’. *Journal of Hydrology* 377 (1–2): 80–91. doi:10.1016/j.jhydrol.2009.08.003.

Hamlet, Alan F., Se-Yuen Lee, Kristian E.B. Mickelson, and Marketa M. Elsner. 2009. ‘Effects of Projected Climate Change on Energy Supply and Demand in the Pacific Northwest and Washington State. Chapter 4: Energy’. In *The Washington Climate Change Impacts Assessment: Evaluating Washington’s Future in a Changing Climate*. Seattle: JISAO climate impacts Group, University of Washington. http://cses.washington.edu/db/pdf/wacciach4energy647.pdf.

Hamududu, Byman, and Aanund Killingtveit. 2012. ‘Assessing Climate Change Impacts on Global Hydropower’. *Energies* 5 (2): 305–22. doi:10.3390/en5020305.

Harrison, G. P., H. W. Whittington, and A. R. Wallace. 2006. ‘Sensitivity of Hydropower Performance to Climate Change’. *International Journal of Power and Energy Systems* 26 (1). http://www.see.ed.ac.uk/~gph/publications/IJPES_Draft.pdf.

Harrison, Gareth P., and H. (Bert) W. Whittington. 2002. ‘Susceptibility of the Batoka Gorge Hydroelectric Scheme to Climate Change’. *Journal of Hydrology* 264: 230–41.

Hatch. 2012. ‘National Integrated Resource Plan. Load Forecast Final Report. H338829-0000-90-124-003, Rev. 0’. Ontario, Canada: World Bank Group & Electricity Control Board of Namibia.

HCB. 2011. ‘Balanço de Actividades 2010 e 2011’. Hidroeléctrica de Cahora Bassa. www.hcb.co.mz.

———. 2013. Personal Communication with Sergio Elisio Interview by Randall Spalding-Fecher. Data provided in Excel Spreadsheet.

Heaps, Charles. 2012. *Long-Range Energy Alternatives Planning (LEAP) System* (version 2015.0.1). Somerville, MA: Stockholm Environment Institute. www.energycommunity.org.

Hertwich, Edgar G. 2013. ‘Addressing Biogenic Greenhouse Gas Emissions from Hydropower in LCA’. *Environmental Science & Technology* 47 (17): 9604–11. doi:10.1021/es401820p.

Heyns, P. 2003. ‘Water Resources in Southern Africa’. In *Opportunities and Risks. International Waters in Southern Africa*, edited by M Nakayama, 5–37. United Nations University.

HMNK. 2012. ‘Mphanda Nkuwa HPP Project. Technical and Economical Feasibility Study Consolidation [Restricted]’. Maputo, Mozambique: Hidroelectrica Mphanda Nkuwa.

Höllermann, Britta, Simone Giertz, and Bernd Diekkrüger. 2010. ‘Benin 2025—Balancing Future Water Availability and Demand Using the WEAP “Water Evaluation and

Planning" System'. *Water Resources Management* 24 (13): 3591–3613. doi:10.1007/s11269-010-9622-z.

Howells, Mark, Sebastian Hermann, Manuel Welsch, Morgan Bazilian, Rebecka Segerström, Thomas Alfstad, Dolf Gielen, et al. 2013. 'Integrated Analysis of Climate Change, Land-Use, Energy and Water Strategies'. *Nature Climate Change* 3 (7): 621–26. doi:10.1038/nclimate1789.

Howells, Mark, Holger Rogner, Neil Strachan, Charles Heaps, Hillard Huntington, Socrates Kypreos, Alison Hughes, et al. 2011. 'OSeMOSYS: The Open Source Energy Modeling System'. *Energy Policy* 39 (10): 5850–70. doi:10.1016/j.enpol.2011.06.033.

Hughes, B, M Irfan, H Khan, K Kumar, D Rothman, and J. Solórzano. 2009. 'Reducing Global Poverty: Patterns of Potential Human Progress: Volume 1 Technical Report'. Denver, Colorado: Frederick S. Pardee Center for International Futures, University of Denver. http://www.ifs.du.edu/assets/documents/PPHP1/PPHP1FULL.pdf.

IEA. 2008. 'Worldwide Trends in Energy Use and Efficiency. Key Insights from IEA Indicator Analysis'. Paris: International Energy Agency. http://www.iea.org/publications/freepublications/publication/Indicators_2008-1.pdf.

———. 2011. 'Energy Balances of Non-OECD Countries 2011 Edition'. Paris: International Energy Agency.

———. 2012. 'World Energy Outlook 2012. Electricity Access Database'. Paris: International Energy Agency. http://www.iea.org/media/weowebsite/energydevelopment/2012updates/WEO2012Electricitydatabase_WEB.xlsx.

———. 2014a. 'Energy Balances of Non-OECD Countries 2014 Edition'. Paris: International Energy Agency.

———. 2014b. 'Energy Technology Perspectives 2014'. Paris: International Energy Agency. http://www.iea.org/publications/freepublications/publication/energy-technology-perspectives-2014---executive-summary---english-version.html.

———. 2014c. 'Key World Energy Statistics 2014'. Paris: International Energy Agency. http://www.iea.org/publications/freepublications/publication/key-world-energy-statistics-2014.html.

———. 2015a. 'Botswana: Electricity and Heat for 2010'. *International Energy Agency*. http://www.iea.org/statistics/statisticssearch/report/?year=2010&country=Botswana&product=ElectricityandHeat.

———. 2015b. 'Congo, Democratic Republic of: Electricity and Heat for 2010'. *International Energy Agency*. http://www.iea.org/statistics/statisticssearch/report/?country=CONGOREP&product=ElectricityandHeat&year=2010.

IEA, and OECD. 2000. 'Experience Curves for Energy Technology Policy'. Paris: International Energy Agency, Organisation for Economic Co-operation and Development.

IEA, UNDP, and UNIDO. 2010. 'Energy Poverty: How to Make Modern Energy Access Universal? Special Early Excerpt of the World Energy Outlook 2010 for the UN General Assembly on the Millennium Development Goals'. Paris: International Energy Agency, United Nations Development Programme and United Nations Industrial Development Organisation. http://www.worldenergyoutlook.org/docs/weo2010/weo2010_poverty.pdf.

IIASA. 2012a. 'SSP Database (Version 0.93) Website'. https://secure.iiasa.ac.at/web-apps/ene/SspDb/dsd?Action=htmlpage&page=about.

———. 2012b. 'Supplementary Note for the SSP Data Sets. SSP Database (Version 0.93) Website'. Laxenburg, Austria: International Institute for Applied Systems Analysis. https://secure.iiasa.ac.at/web-apps/ene/SspDb/static/download/ssp_suplementary%20text.pdf.

International Futures. 2014. *International Futures (IFs) Modeling System, Version 7.00.* Frederick S. Pardee Center for International Futures, Josef Korbel School of International Studies, University of Denver, Denver, CO. http://pardee.du.edu/access-ifs#sthash.bAjXVZgU.dpuf.

IPCC. 2000. ‘Special Report on Emissions Scenarios. A Special Report of Working Group III of the IPCC.’ Cambridge: Cambridge University Press.
———. 2006. ‘2006 IPCC Guidelines for National Greenhouse Gas Inventories’. Geneva: Intergovernmental Panel on Climate Change. www.ipcc-nggip.iges.or.jp/public/2006gl/vol2.htm.
Isaac, Morna, and Detlef P. van Vuuren. 2009. ‘Modeling Global Residential Sector Energy Demand for Heating and Air Conditioning in the Context of Climate Change’. *Energy Policy* 37 (2): 507–21. doi:10.1016/j.enpol.2008.09.051.
Jiang, Leiwen. 2014. ‘Internal Consistency of Demographic Assumptions in the Shared Socioeconomic Pathways’. *Population and Environment* 35 (3): 261–85. doi:10.1007/s11111-014-0206-3.
Jiang, Leiwen, and Brian O’Neill. 2015. ‘Global Urbanization Projections for the Shared Socioeconomic Pathways’. *Global Environmental Changes*, April. doi:10.1016/j.gloenvcha.2015.03.008.
Jiang, Tao, Yongqin David Chen, Chong-yu Xu, Xiaohong Chen, Xi Chen, and Vijay P. Singh. 2007. ‘Comparison of Hydrological Impacts of Climate Change Simulated by Six Hydrological Models in the Dongjiang Basin, South China’. *Journal of Hydrology* 336 (3–4): 316–33. doi:10.1016/j.jhydrol.2007.01.010.
JICA. 2009. ‘Lusaka City Master Plan: The Study on Comprehensive Urban Development Plan for the City of Lusaka in the Republic of Zambia., Technical Report’. Lusaka, Zambia: Japanese International Cooperation Agency.
Kahane, Adam. 1992. ‘Scenarios for Energy: Sustainable World vs Global Mercantilism’. *Long Range Planning* 25 (4): 38–46. doi:10.1016/0024-6301(92)90006-N.
———. 2000. ‘How to Change the World: Lessons for Entrepreneurs from Activists. Draft’. Hamilton: Centre for Generative Leadership.
———. 2012. *Transformative Scenario Planning: Working Together to Change the Future*. San Francisco: Berrett-Koehler Publishers.
KC, Samir, and Wolfgang Lutz. 2014. ‘The Human Core of the Shared Socioeconomic Pathways: Population Scenarios by Age, Sex and Level of Education for All Countries to 2100’. *Global Environmental Change*, July. doi:10.1016/j.gloenvcha.2014.06.004.
Kling, Harald, and Martin Preishuber. 2012. ‘Zambezi Decision Support System – User’s Manual. A Web-Based Decision Support System to Analyze the Impact of Climate Change and Water Resources Development on Runoff in the Zambezi Basin.’ Vienna: Pöyry Energy GmbH. http://zdss.ingc.gov.mz/help/manual.pdf.
Kling, Harald, Philipp Stanzel, and Martin Preishuber. 2014. ‘Impact Modelling of Water Resources Development and Climate Scenarios on Zambezi River Discharge’. *Journal of Hydrology: Regional Studies* 1 (July): 17–43. doi:10.1016/j.ejrh.2014.05.002.
Koppelaar, Rembrandt H.E.M., James Keirstead, Nilay Shah, and Jeremy Woods. 2016. ‘A Review of Policy Analysis Purpose and Capabilities of Electricity System Models’. *Renewable and Sustainable Energy Reviews* 59 (June): 1531–44. doi:10.1016/j.rser.2016.01.090.
LEC. 2011. ‘Annual Report 2011’. Maseru: Lesotho Electricity Company. http://www.lec.co.ls/news/publications/download.php?file=Annual%20Report%202011.pdf.
———. 2015. Transmission and distribution losses in Lesotho. Interview by Mamahloko Senatla.
Legros, Gwénaëlle, Ines Havet, Nigel Bruce, and Sophie Bonjour. 2009. ‘The Energy Access Situation in Developing Countries. A Review Focusing on the Least Developed Countries and Sub-Saharan Africa’. New York: United Nations Development Programme and World Health Organisation. http://content.undp.org/go/cms-service/stream/asset/?asset_id=2205620.
Lehner, Bernhard, Gregor Czisch, and Sara Vassolo. 2005. ‘The Impact of Global Change on the Hydropower Potential of Europe: A Model-Based Analysis’. *Energy Policy* 33 (7): 839–55. doi:10.1016/j.enpol.2003.10.018.

Lucena, André Frossard Pereira de, Alexandre Salem Szklo, Roberto Schaeffer, Raquel Rodrigues de Souza, Bruno Soares Moreira Cesar Borba, Isabella Vaz Leal da Costa, Amaro Olimpio Pereira Júnior, and Sergio Henrique Ferreira da Cunha. 2009. 'The Vulnerability of Renewable Energy to Climate Change in Brazil'. *Energy Policy* 37 (3): 879–89.

Ma, Tieju. 2010. 'Coping with Uncertainties in Technological Learning'. *Management Science* 56 (1): 192–201. doi:10.1287/mnsc.1090.1098.

Mahumane, Gilberto, and Peter Mulder. 2015a. 'Introducing MOZLEAP: An Integrated Long-Run Scenario Model of the Emerging Energy Sector of Mozambique. Research Memorandum 2015-2'. Amsterdam: Vrije Universiteit Amsterdam. http://www.petermulder.net/sites/default/files/page/files/MahumaneMulder_IntroducingMOZLEAP_FEWEB_RM_2015-2.pdf.

———. 2015b. 'Mozambique Energy Outlook, 2015-2030. Data, Scenarios and Policy Implications. Research Memorandum 2015-7'. Amsterdam: Vrije Universiteit Amsterdam. http://www.petermulder.net/sites/default/files/page/files/MahumaneMulder_EnergyOutlookMozambique_FEWEB_RM_2015-7.pdf.

Malik, Arif S., and Cornelius Kuba. 2013. 'Power Generation Expansion Planning Including Large Scale Wind Integration: A Case Study of Oman'. *Journal of Wind Energy* 2013 (July): e735693. doi:10.1155/2013/735693.

Mandelli, Stefano, Jacopo Barbieri, Lorenzo Mattarolo, and Emanuela Colombo. 2014. 'Sustainable Energy in Africa: A Comprehensive Data and Policies Review'. *Renewable and Sustainable Energy Reviews* 37 (September): 656–86. doi:10.1016/j.rser.2014.05.069.

Marais, Ronald. 2015a. South Africa conventional generation schedule for the TDP period 2016 to 2025. Interview by Randall Spalding-Fecher. Email.

———. 2015b. South Africa renewable generation schedule for the TDP period 2016 to 2025. Interview by Randall Spalding-Fecher. Email.

Maviya, Johnson. 2014. 'SAPP Upcoming New Projects (2014- 2017)'. presented at the AfDB Mission for Supervision of IPPF Projects in the SAPP, Harare, July 15.

Mehta, Vishal K., David E. Rheinheimer, David Yates, David R. Purkey, Joshua H. Viers, Charles A. Young, and Jeffrey F. Mount. 2011. 'Potential Impacts on Hydrology and Hydropower Production under Climate Warming of the Sierra Nevada'. *Journal of Water and Climate Change* 2 (1): 29. doi:10.2166/wcc.2011.054.

MEM. 2013. 'United Republic of Tanzania. Power System Master Plan 2012 Update'. Ministry of Energy & Minerals. http://tanesco.co.tz/index.php?option=com_docman&task=doc_download&gid=68&Itemid=172.

Merven, Bruno, Stephen Davis, and Alison Hughes. 2010. 'An Analysis of Energy Consumption for a Selection of Countries in the Southern African Development Community'. *Journal of Energy in Southern Africa* 21 (1): 11–24.

Merven, Bruno, Adrian Stone, Alison Hughes, and Brett Cohen. 2012. 'Quantifying the Energy Needs of the Transport Sector for South Africa: A Bottom-up Model'. Cape Town: Energy Research Centre, University of Cape Town. http://www.erc.uct.ac.za/Research/publications/12-Merven-etal_Quantifying_energy_needs_transport%20sector.pdf.

Metz, B., O.R. Davidson, P.R. Bosch, R. Dave, and L.A. Meyer. 2007. *Climate Change 2007: Mitigation. Contribution of Working Group III to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change*. Cambridge: Cambridge University Press. http://www.ipcc.ch/publications_and_data/ar4/wg3/en/contents.html.

MEWD. 2010. 'Power System Development Master Plan for Zambia 2010-2030'. Lusaka, Zambia: Ministry of Energy and Water Development, Republic of Zambia.

Miketa, Asami, and Bruno Merven. 2013. 'Southern African Power Pool: Planning and Prospects for Renewable Energy. Abu Dhabi, IRENA.' Abu Dhabi: International Renewable Energy Agency. www.irena.org/SAPP.

Modi, Vijay, Susan McDade, Dominique Lamment, and Jamal Saghir. 2006. 'Energy Services for the Millennium Development Goals'. Millennium Project. New York: Energy Sector Management Assistance Programme, United Nations Development Programme, UN Millennium Project, and World Bank.

Moss, Richard H., Jae A. Edmonds, Kathy A. Hibbard, Martin R. Manning, Steven K. Rose, Detlef P. van Vuuren, Timothy R. Carter, et al. 2010. 'The next Generation of Scenarios for Climate Change Research and Assessment'. *Nature* 463 (7282): 747–56. doi:10.1038/nature08823.

Mukheibir, P. 2007. 'Possible Climate Change Impacts on Large Hydroelectricity Schemes in Southern Africa'. *Journal of Energy in Southern Africa* 18 (1): 4–9.

Nakicenovic, Nebojsa, Robert J. Lempert, and Anthony C. Janetos. 2014. 'A Framework for the Development of New Socio-Economic Scenarios for Climate Change Research: Introductory Essay: A Forthcoming Special Issue of Climatic Change'. *Climatic Change* 122 (3): 351–61. doi:10.1007/s10584-013-0982-2.

NERSA. 2006. 'Electricity Supply Statistics for South Africa 2006'. Pretoria: National Energy Regulator of South Africa. http://www.nersa.org.za/Admin/Document/Editor/file/News%20and%20Publications/Publications/Current%20Issues/Electricity%20Supply%20Statistics/Electricity%20supply%20statistics%202006.pdf.

Nexant. 2007. 'SAPP Regional Generation and Transmission Expansion Plan Study. Draft Report. Volume 2. Main Report'. Submitted to: Southern Africa Power Pool Coordination Centre. San Francisco: Nexant.

Obergassel, Wolfgang, Christof Arens, Lukas Hermwille, Nicolas Kreibich, Florian Mersmann, Hermann E Ott, and Hanna Wang-Helmreich. 2016. 'Phoenix from the Ashes: An Analysis of the Paris Agreement to the United Nations Framework Convention on Climate Change - Part II'. *Environmental Law and Management* 28 (1).

O'Neill, Brian C., Elmar Kriegler, Keywan Riahi, Kristie L. Ebi, Stephane Hallegatte, Timothy R. Carter, Ritu Mathur, and Detlef P. Vuuren. 2014. 'A New Scenario Framework for Climate Change Research: The Concept of Shared Socioeconomic Pathways'. *Climatic Change* 122 (3): 387–400. doi:10.1007/s10584-013-0905-2.

Parry, M.L., O.F. Canziani, J.P. Palutikof, P.J. van der Linden, and C.E. Hanson. 2007. *Climate Change 2007: Impacts, Adaptation and Vulnerability. Contribution of Working Group II to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change*. Cambridge: Cambridge University Press. http://www.ipcc.ch/publications_and_data/ar4/wg2/en/contents.html.

Petersen, G. 2012. 'Responding to Climate Change in Mozambique: Theme 5: Water'. Maputo: National Institute for Disaster Management (INGC). http://ingc.dirisa.org/repository/phase-2-theme-reports/theme-reports-final/Theme%205%20Water%20ENG.pdf/view.

Pöyry. 2010. 'Energy, Climate Change and the Millennium Development Goals'. R-2010-05. Submitted to OneWorld Sustainable Investments. Stockholm: Econ Pöyry.

Price, Lynn, Laurie Michaelis, Ernst Worrell, and Marta Khrushch. 1998. 'Sectoral Trends and Driving Forces of Global Energy Use and Greenhouse Gas Emissions'. *Mitigation and Adaptation Strategies for Global Change* 3: 269–319.

Purkey, D. R., B. Joyce, S. Vicuna, M. W. Hanemann, L. L. Dale, D. Yates, and J. A. Dracup. 2007. 'Robust Analysis of Future Climate Change Impacts on Water for Agriculture and Other Sectors: A Case Study in the Sacramento Valley'. *Climatic Change* 87 (S1): 109–22. doi:10.1007/s10584-007-9375-8.

Randall, Tom. 2015. 'The Way Humans Get Electricity Is About to Change Forever. These Six Shifts Will Transform Markets over the next 25 Years'. *Bloomberg Business*, June 23. http://www.bloomberg.com/news/articles/2015-06-23/the-way-humans-get-electricity-is-about-to-change-forever.

Raupach, M. R., G. Marland, P. Ciais, C. Le Quere, J. G. Canadell, G. Klepper, and C. B. Field. 2007. 'Global and Regional Drivers of Accelerating CO2 Emissions'.

Proceedings of the National Academy of Sciences 104 (24): 10288–93. doi:10.1073/pnas.0700609104.

Resnick, Danielle, Finn Tarp, and James Thurlow. 2012. ‘The Political Economy of Green Growth: Cases from Southern Africa’. *Public Administration and Development* 32 (3): 215–28. doi:10.1002/pad.1619.

Rowlands, Ian. 1998. *Climate Change Co-Operation in Southern Africa*. London: Earthscan.

SADC. 2011. ‘Dam Synchronisation and Flood Releases in the Zambezi River Basin Project. Annex 2. Concepts and Recommendations for Dam Management’. Gaborone: Southern African Development Community. http://agriwaterpedia.info/wiki/File:SADC_(2011)_Dam_Synchronisation_and_Flood_Releases_in_the_Zambezi_River_Basin_Project_Annex_2.pdf.

———. 2012. ‘Regional Infrastructure Development Master Plan: Energy Sector Plan’. Gaborone: Southern African Development Community. http://www.sadc.int/files/5413/5293/3528/Regional_Infrastructure_Development_Master_Plan_Energy_Sector_Plan.pdf.

SAPP. 2010. ‘Annual Report 2010’. Harare: Southern African Power Pool. http://www.sapp.co.zw/docs/2010%20Annual%20report.pdf.

———. 2011. ‘Annual Report 2011’. Harare: Southern African Power Pool. http://www.sapp.co.zw/docs/SAPP%20annual%20report.pdf.

———. 2012a. ‘Annual Report 2012’. Harare: Southern African Power Pool. http://www.sapp.co.zw/docs/SAPP%202012%20annual%20report.pdf.

———. 2012b. *PSC Report to Plenary. SAPP Meetings in Arusha, Tanzania*. Harare: Southern African Power Pool.

———. 2013. ‘Annual Report 2013’. Harare: Southern African Power Pool. http://www.sapp.co.zw/docs/22867%20Annual%20Report%20New.pdf.

———. 2014. ‘Annual Report 2014’. Harare: Southern African Power Pool. http://www.sapp.co.zw/docs/Annual%20report-2014.pdf.

Sattler, S, J Macknick, D Yates, F Flores-Lopez, A Lopez, and J Rogers. 2012. ‘Linking Electricity and Water Models to Assess Electricity Choices at Water-Relevant Scales’. *Environmental Research Letters* 7 (4): 045804. doi:10.1088/1748-9326/7/4/045804.

Schaeffer, Roberto, Alexandre Salem Szklo, André Frossard Pereira de Lucena, Bruno Soares Moreira Cesar Borba, Larissa Pinheiro Pupo Nogueira, Fernanda Pereira Fleming, Alberto Troccoli, Mike Harrison, and Mohammed Sadeck Boulahya. 2012. ‘Energy Sector Vulnerability to Climate Change: A Review’. *Energy* 38 (1): 1–12. doi:10.1016/j.energy.2011.11.056.

Shell. 2001. ‘Energy Needs, Choices and Possibilities: Scenarios to 2050’. London: Shell International.

Sieber, Jack, and David Purkey. 2011. ‘WEAP: Water Evaluation And Planning System. User Guide’. Somerville, MA: Stockholm Environment Institute, U.S. Center. http://weap21.org/downloads/WEAP_User_Guide.pdf.

Simelane, Samkelo. 2015. Swaziland sectoral electricity demand from Swaziland Electricity Company. Interview by Randall Spalding-Fecher. Email.

Solomon, S., D. Qin, M. Manning, Z. Chen, M. Marquis, K.B. Averyt, M. Tignor, and H.L. Miller. 2007. *Climate Change 2007: The Physical Science Basis. Contribution of Working Group I to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change*. Cambridge: Cambridge University Press. http://www.ipcc.ch/publications_and_data/ar4/wg1/en/contents.html.

Spalding-Fecher, Randall, Arthur Chapman, Francis Yamba, Hartley Walimwipi, Harald Kling, Bernard Tembo, Imasiku Nyambe, and Boaventura Cuamba. 2014. ‘The Vulnerability of Hydropower Production in the Zambezi River Basin to the Impacts of Climate Change and Irrigation Development’. *Mitigation and Adaptation Strategies for Global Change* 21 (5): 721–42. doi:10.1007/s11027-014-9619-7.

Spalding-Fecher, Randall, and Catherine Fedorsky. 2012. ‘Energy Resources and Climate Change: Vulnerability of Energy Resources in Southern Africa. Synthesis Report for RCCP Output 1’. Knowledge for Adaptation Series: 4 For the Regional Climate Change

Programme for southern Africa (RCCP), UK Department for International Development (DFID). Cape Town: OneWorld Sustainable Investments. www.oneworldgroup.co.za/getfile.php?id=1263.

Spalding-Fecher, Randall, Mamahloko Senatla, Francis Yamba, Charles Heaps, Arthur Chapman, Gilberto Mahumane, Bernard Tembo, Biness Lukwessa, Imasiku Nyambe, and Grayson Himunzowa. 2016. 'Electricity Supply and Demand Scenarios for the Southern African Power Pool. Climate Change Assessment of the Energy-Water Nexus in the Zambezi River Basin. A Report for the World Bank'. Washington, D. C.: World Bank.

———. 2017. 'Electricity Supply and Demand Scenarios for the Southern African Power Pool'. *Energy Policy*, no. 101: 403–14. doi:http://dx.doi.org/10.1016/j.enpol.2016.10.033.

Spalding-Fecher, Randall, Harald Winkler, and Stanford Mwakasonda. 2005. 'Energy and the World Summit on Sustainable Development: What Next?' *Energy Policy* 33 (1): 99–112.

Stanzel, P, and H Kling. 2014. 'Future Hydropower Production in the Lower Zambezi under Possible Climate Change Influence'. *Water SA* 40 (4): 639. doi:10.4314/wsa.v40i4.9.

StatsSA. 2013. 'Census 2011: The South Africa I Know, the Home I Understand'. Government. http://www.statssa.gov.za/census2011/default.asp.

SWECO. 1996. 'Bulawayo-Zambezi-Matabeleland Water Supply Feasibility Study. Final Report., Technical Report'. Bulawayo, Zimbabwe: Ministry of Local Government, Rural and Urban Development. Matabeleleland Zambezi Water Trust.

Tadross, M, C Jack, and B Hewitson. 2005. 'On RCM-Based Projections of Change in Southern African Summer Climate'. *Geophysical Research Letters* 32 (December). http://media.csag.uct.ac.za/gisdata/SAEON_Climate_Change_Workshop/Extra/saeon_grl_tadross.pdf.

Tait, L, and Harald Winkler. 2012. 'Estimating Greenhouse Gas Emissions Associated with Achieving Universal Access to Electricity for All Households in South Africa'. *Journal of Energy in Southern Africa* 23 (4): 8–17.

Taliotis, Constantinos, Morgan Bazilian, Manuel Welsch, Dolf Gielen, and Mark Howells. 2014. 'Grand Inga to Power Africa: Hydropower Development Scenarios to 2035'. *Energy Strategy Reviews* 4 (August): 1–10. doi:10.1016/j.esr.2014.01.001.

Tilmant, A., W. Kinzelbach, L. Beevers, and D. Juizo. 2010. 'Optimal Water Allocation in the Zambezi Basin'. In *2010 International Congress on Environmental Modelling and Software*, edited by David A. Swayne, Wanhong Yang, A. A. Voinov, A. Rizzoli, and T. Filatova. Ottawa, Canada: International Environmental Modelling and Software Society. http://www.iemss.org/iemss2010/index.php?n=Main.Proceedings.

Tilmant, A., W. Kinzelbach, D. Juizo, L. Beevers, D. Senn, and C. Casarotto. 2011. 'Economic Valuation of Benefits and Costs Associated with the Coordinated Development and Management of the Zambezi River Basin'. *Water Policy* In Press. doi:10.2166/wp.2011.189.

Tsiko, Sifelani. 2016. 'Lake Kariba Water Level to Improve'. *Sunday New Online*, August 18. http://www.sundaynews.co.zw/lake-kariba-water-level-to-improve/.

Turton, Anthony. 2016. 'The Future of SADC: An Investigation into the Non-Political Drivers of Change and Regional Integration'. In *Building Climate Resilience through Virtual Water and Nexus Thinking in the Southern African Development Community*, edited by Anna Entholzner and Charles Reeve, 45–86. Switzerland: Springer.

UNDESA. 2012a. 'World Population Prospects: The 2012 Revision'. New York: United Nations, Department of Economic and Social Affairs, Population Division. http://esa.un.org/wpp/Excel-Data/population.htm.

———. 2012b. 'World Urbanisation Prospects: The 2011 Revision'. New York: United Nations, Department of Economic and Social Affairs, Population Division. http://esa.un.org/unpd/wup/CD-ROM/Default.aspx.

UNFCCC. 2015. 'Paris Agreement. Annex to Decision 1/CP.21, Document FCCC/CP/2015/10/Add.1. 29 January 2016'. Bonn: United Nations Framework

Convention on Climate Change. http://unfccc.int/resource/docs/2015/cop21/eng/10a01.pdf#page=2.
———. 2017. 'NDC Registry (Interim)'. *United Nations Framework Convention on Climate Change*. Accessed March 17. http://www4.unfccc.int/ndcregistry/Pages/All.aspx.
US BEA. 2015. 'Table 1.1.9. Implicit Price Deflators for Gross Domestic Product'. *U.S. Bureau of Economic Analysis*. http://www.bea.gov/iTable/iTable.cfm?ReqID=9&step=1#reqid=9&step=3&isuri=1&903=13.
USBR. 2005. 'Reclamation - Managing Water in the West. Hydropower'. Washington, D. C.: U.S. Department of Interior, Bureau of Reclamation. http://www.usbr.gov/power/edu/pamphlet.pdf.
Van der Heijden, Kees. 1996. *Scenarios: The Art of Strategic Conversation*. Chichester: Wiley.
Varela-Ortega, Consuelo, Irene Blanco-Gutiérrez, Christopher H. Swartz, and Thomas E. Downing. 2011. 'Balancing Groundwater Conservation and Rural Livelihoods under Water and Climate Uncertainties: An Integrated Hydro-Economic Modeling Framework'. *Global Environmental Change* 21 (2): 604–19. doi:10.1016/j.gloenvcha.2010.12.001.
Vuuren, Detlef P. van, and Timothy R. Carter. 2014. 'Climate and Socio-Economic Scenarios for Climate Change Research and Assessment: Reconciling the New with the Old'. *Climatic Change* 122 (3): 415–29. doi:10.1007/s10584-013-0974-2.
Vuuren, Detlef P. van, James A. Edmonds, Mikiko Kainuma, Keywan Riahi, and John Weyant. 2011. 'A Special Issue on the RCPs'. *Climatic Change* 109 (1–2): 1–4. doi:10.1007/s10584-011-0157-y.
Walimwipi, Hartley. 2012. Personal communication Interview by Randall Spalding-Fecher. Data provided in Excel Spreadsheet.
Wilbanks, Thomas J., Vatsal Bhatt, Daniel E. Bilello, Stanley R. Bull, James Ekmann, William C. Horak, Joe Huang, et al., eds. 2007. *CCSP, 2007: Effects of Climate Change on Energy Production and Use in the United States. A Report by the U.S. Climate Change Science Program and the Subcommittee on Global Change Research*. Washington, D. C.: Department of Energy, Office of Biological & Environmental Research. http://www.climatescience.gov/Library/sap/sap4-5/final-report/sap4-5-final-all.pdf.
Wit, Maarten de, and Jacek Stankiewicz. 2006. 'Changes in Surface Water Supply across Africa with Predicted Climate Change'. *Science* 311: 1917–21. doi:DOI: 10.1126/science.1119929.
Wolde-Rufael, Yemane. 2005. 'Energy Demand and Economic Growth: The African Experience'. *Journal of Policy Modeling* 27 (8): 891–903. doi:10.1016/j.jpolmod.2005.06.003.
World Bank. 2010a. 'The Zambezi River Basin: A Multi-Sector Investment Opportunities Analysis. Volume 2. Basin Development Scenarios'. Washington, D. C.: World Bank.
———. 2010b. 'The Zambezi River Basin: A Multi-Sector Investment Opportunities Analysis. Volume 4. Modeling, Analysis and Input Data'. Washington, D. C.: World Bank.
———. 2014. 'World Development Indicators Database'. May 6. http://databank.worldbank.org/databank/download/WDIandGDF_excel.zip.
WRC. 2010. 'Feasibility Design Study on the Utilization of the Water Resources of the Chobe/Zambezi River. Technical Report, Republic of Botswana Ministry of Minerals, Energy and Water Resources, Department of Water Affairs, Tender No. PR 10/3/1/09, Draft Prefeasibility/Feasibility Design Study Report'. Gaborone: Republic of Botswana Ministry of Minerals.
Yamba, Francis Davison, Hartley Walimwipi, Suman Jain, Peter Zhou, Boaventura Cuamba, and Cornelius Mzezewa. 2011. 'Climate Change/Variability Implications on Hydroelectricity Generation in the Zambezi River Basin'. *Mitigation and Adaptation Strategies to Global Climate Change* 16: 617–28. doi:10.1007/s11027-011-9283-0.
Yang, Chi-Jen, and Robert B. Jackson. 2011. 'Opportunities and Barriers to Pumped-Hydro Energy Storage in the United States'. *Renewable and Sustainable Energy Reviews* 15 (1): 839–44. doi:10.1016/j.rser.2010.09.020.

Yates, David N., and Kathleen A. Miller. 2013. ‘Integrated Decision Support for Energy/Water Planning in California and the Southwest’. *International Journal of Climate Change: Impacts and Responses* 4 (1): 49–64.

Yates, David, Jack Sieber, David Purkey, and Annette Huber-Lee. 2005. ‘WEAP21—A Demand-, Priority-, and Preference-Driven Water Planning Model: Part 1: Model Characteristics’. *Water International* 30 (4): 487–500. doi:10.1080/02508060508691893.

ZESCO. 2013a. ‘ZESCO Annual Statistical Report 2009/10. Excel Format’. Lusaka: ZESCO.

———. 2013b. ‘ZESCO Annual Statistical Report 2010/11. Excel Format’. Lusaka: ZESCO.

———. 2013c. Personal Communication with Ernest Banda Interview by Randall Spalding-Fecher. Data provided in Excel Spreadsheet.

ZRA. 2013. Personal communication from Clement Mukosa Interview by Randall Spalding-Fecher. Via email.

Annex A. Hydropower plant and reservoir data

Table 66. Volume-elevation curve for Cahora Bassa

Volume (mcm)	0	4,745	10,689	17,963	26,699	37,026	51,704	62,977	65,991
Elevation (m amsl)	295	300	305	310	315	320	326	330	331
Area (km^2)	838	1,065	1,317	1,597	1,902	2,233	2,665	2,974	3,054
Spillway (cms)	6,760	7,990	9,060	10,020	10,890	11,700	12,600	14,173	15,683

Source: HCB (2013), Beilfuss (2001)

Table 67. Turbine efficiency rating for Cahora Bassa

Net head (m)	90	95	100	105	110	115	120	125	125	130
Efficiency	89.3%	92.7%	95.8%	95.6%	95.6%	95.9%	95.6%	95.2%	94.2%	92.9%

Source: Beilfuss (2001)

Table 68. DFRC for Cahora Bassa

Month	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Level (m amsl)	321.7	323.6	325.6	325.7	325.4	325.1	324.5	324	323.1	322.2	321.3	320.6

Source: ZDSS (modified from HCB data, based on observation of more recent actual operation)

Table 69. Tailwater curve for Cahora Bassa

Discharge (cms)	0	500	1,000	2,000	3,000	5,000	8,000	10,500	15,000	22,000
Level (m amsl)	194	198.89	201.08	204.29	206.86	211.05	216.05	221.5	226.14	232

Source: HCB (2013), Beilfuss (2001)

Note: Maximum turbine flow at Cahora Bassa is 2,250 cms (HCB)

Table 70. Volume-elevation curve for Lake Kariba

Volume (mcm)	54	2,272	6,706	11,278	15911	20613	25962	30,408
Elevation (m amsl)	475.5	476	477	478	479	480	481	482
Area (km^2)	4354	4,405	4,507	4,608	4,709	4,811	4,901	4,991
Spillway (cms)					7,528	7,751	7,973	8,168

Volume (mcm)	35,427	40,568	45,778	51,088	56,507	64,798	76,854
Elevation (m amsl)	483	484	485	486	487	488.5	489.5
Area (km^2)	5,081	5,171	5,261	5,350	5,440	5,577	5671
Spillway (cms)	8,381	8,584	8,786	8,974	9,161	9,445	9,515

Source: Beilfuss (2001)

Table 71. DFRC for Lake Kariba

Month	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
Level (m amsl)	484	485.4	487.75	488.5	488.5	488.5	488	487.5	487	486.5	486	485.5

Source: ZRA (2013), SADC (2011)

Table 72. Tailwater rating curve for Lake Kariba

Discharge (cms)	0	479	719	959	1,319	1,518	3,000	9,000	12,000	15,000
Level (m amsl)	380	383.7	384.86	386.19	387.67	388.48	391.96	399.87	402.55	404.55

Source: Beilfuss (2001)

Table 73. Volume-elevation curve for Kafue Gorge Upper

Volume (mcm)	0	20	69	170	423	785	1,178	2,845
Elevation (m amsl)	972.3	973	974	975	976	9,76.6	977	978
Area (km^2)	20	35	70	142	430	805	1,175	2,160
Spillway (cms)	780	1,076	1,420	1,804	2,220	2,496	2,668	3,132

Source: (Beilfuss 2001)

Table 74. Volume-elevation curve for Itezhi-tezhi

Volume (mcm)	699	894	1,119	1,377	1,673	2,008	2,387
Elevation (m amsl)	1,006	1,008	1,010	1,012	1,014	1,016	1,018
Area (km^2)	90	105	120	138	158	177	203

Volume (mcm)	2,814	3,291	3,551	4,118	4,746	5,439	5,624	7,049
Elevation (m amsl)	1,020	1,022	1,024	1,026	1,028	1,029	1,029.5	1,035
Area (km^2)	224	253	284	314	346	364	374	446

Source: Beilfuss (2001)

Table 75. DFRC for Itezhi-tezhi

Month	Jan	Feb	Mar	Apr	May	Jun
Elevation (m amsl)	1023.5	1025.9	1027.5	1028.5	1028.6	1028.2
Month	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
Elevation (m amsl)	1,027.6	1,026.8	1,025.7	1,024.5	1,023.2	1,022.5

Source: Beilfuss (2001)

Table 76. Volume-elevation curve for Mphanda Nkuwa

Elevation (m)	145	150	155	160	165	170	175	180
Area (km^2)	4	6	10	13	17	24	32	41
Volume (mcm)	14	39	79	137	212	313	452	634

Elevation (m)	185	190	195	200	205	210	215	220
Area (km^2)	51	62	73	84	97	109	123	136
Volume (mcm)	863	1,144	1,480	1,872	2,324	2,838	3,418	4,065

Source: HMNK (2012)

Table 77. Volume-elevation curve for Batoka Gorge

Elevation (m)	620	640	660	680	700	720	740	760	780	800
Area (km^2)	1.30	3.80	5.65	9.22	12.48	16.15	20.24	25.07	30.72	37.31
Volume (mcm)	0	51	146	294	511	798	1161	1615	2172	2853

Source: ZRA (2013)

Table 78. Volume-elevation curve for Devils Gorge

Elevation (m)	468	476	484	492	500	508	516	524	532
Area (km^2)	8.8	21.5	37	56.8	80	104.3	132.7	165.4	203.1
Volume (mcm)	83.6	153.5	384.2	760	1,002	2,040	2,995	4,182	5,643
Elevation (m)	540	548	556	564	572	580	588	596	
Area (km^2)	246.7	297.3	352.9	424.6	497	570	666	762	
Volume (mcm)	7,443	,9663	12,218	15,853	19,560	23,268	28,547	33,947	

Source: : ZRA (2013)

Annex B. Irrigation area data

Table 79. Current irrigated area by crop and sub-basin

					Dry season crops							Perennial crops						Wet season crops						
World Bank sub-basin name	Irrigation abstraction point	Sub-basins ZDSS	WB sub-basin	Abstraction Point (WB)	Winter Wheat	Winter Rice	Winter Maize	Vegetables	Beans	Winter Cotton	Other	Sugar-cane	Tea	Coffee	Citrus	Banana	Pasture	Maize	Soy-beans	Sorghum	Cotton	Tobacco	Rice	Equipped area (ha)
Upper Zambezi	IA1	1	12			1,000		750							750									2500
Kabompo	IA2	2	13		136			64			45				23		82	88				48		350
Lungue Bungo	IA3	3	11			500		250							250									1,000
Luanginga	IA4	4	10			250		250							250									750
Barotse	IA6	6	9		78			36			26				13		47	51				27		200
Cuando/Chobe	IA7	7	8	I.08.01-3	0	350	0	145	0	0	0	0	0	0	125	0	0	0	0	0	0	0	0	620
Kariba	IA8	8	6	I.06.01-4	613	0	0	278	0	0	202	21	2	4	99	0	356	387	8	0	10	209	0	1,575
Kafue	IA13	12.13	7	I.07.01	4,135											42			4,135					4177
	IA14	14	7	I.07.03	1,275							33,068		596		82			773			502		35,021
Kariba	IA9	9	6	I.06.09	503			84			126	356	42	63	42		84	121	131		171	81		1,300
	IA10	10	6	I.06.10	8,362			1,394			2,090	5,920	697	1,046	697		1,394	2,007	2,174		2,843	1,338		21,600
	IA11a	11	6	I.06.07-8	389	0	0	123	0	0	113	137	16	24	48	0	149	173	50	0	66	99	0	999
	IA11b	11	6	I.06.11-12	836	0	0	415	0	500	297	0	0	0	137	25	502	562	0	0	500	293	0	2,712
Luangwa	IA15	15	5	I.05.02	464			250	24		47				155		60	302				162		1,000
	IA16	16	5	I.05.01	4,225			2,275	217		433				1,408		542	2,746				1,479		9,100
Mupata	IA17a	17	4	I.07.05	960														960					960
	IA17b	17	4	I.04.01-2	5,240	0	0	1,072	0	0	1,277	3,618	426	1,069	646	0	852	1,311	1,329	0	1,737	864	0	14,200
	IA18		2	I 02.01	8,552			1,426			2,137	6,055	713	1,063	713		1,426	2,053	2,224		2,908	1,368		22,085

					Dry season crops							Perennial crops						Wet season crops						
World Bank sub-basin name	Irrigation abstraction point	Sub-basins ZDSS	WB sub-basin	Abstraction Point (WB)	Winter Wheat	Winter Rice	Winter Maize	Vegetables	Beans	Winter Cotton	Other	Sugar-cane	Tea	Coffee	Citrus	Banana	Pasture	Maize	Soy-beans	Sorghum	Cotton	Tobacco	Rice	Equipped area (ha)
Tete	IA19	18, 19, 21, 22, 23, 24	2	I.02.02				10																10
	IA21		2	I.02.03					2						8			1						10
	IA24		2	I.02.04			95	170							50			48	17	8	23			315
	IA23		2	I.02.05-6.	4,898	0	0	817	60	0	1,224	3,468	408	613	408	0	817	1,206	1,285	5	1,679	784	0	12,713
Lake Malawi/	IA25	25	3	I.03.04-12	0	13,250	2,804	1,277	0	0	0	6,000	2,060	0	0	0	0	1,402	505	224	673	0	13,250	25,391
Shire	IA26	26	3	I.03.01-3	0	450	775	50	0	0	0	13,750	2,000	0	0	0	0	388	140	62	186	0	450	17,025
Zambezi Delta	IA27	27	1					666				5,666			666									6,998
Total					4,0666	15,800	3,674	11,802	303	500	8,017	78,059	6,364	4,478	6,488	149	6,311	12,846	13,731	299	10,796	7,254	13,700	182,611

Source: World Bank (2010b)

Table 80. Identified irrigation projects area by crop and sub-basin

					Dry season crops							Perennial crops						Wet season crops						
World Bank sub-basin name	WB sub-basin	Sub-basins ZDSS	Abstraction point (WB)	Irrigation abs-traction point	Winter wheat	Winter ice	Winter maize	Vegetables	Beans	Winter cotton	Other	Sugar-cane	Tea	Coffee	Citrus	Banana	Pasture	Maize	Soybeans	Sorghum	Cotton	Tobacco	Rice	Equipped area (ha)
Upper Zambezi	12	1		IA1								5,000												5,000
Kabompo	13	2		IA2	2455			1,145			819				409		1,472	1,596				859		6,300
Lungue Bungo	11	3		IA3		250		125							125									500
Luanginga	10	4		IA4		5000																		5,000
Barotse	9	6		IA6	1603			3,801			1				1,601		2	1,042				561		7,008
Cuando / Chobe	8	7	I.08.01-3	IA7	150			150				0	0	0	0	0	0	0	0	0	0	0	0	300
Kariba	6	8	I.06.01-4	IA8	539		5,000	1,681			161	166	20	29	3,070	0	222	5,254	2,061	2,300	80	144	0	13,346
Kafue	7	12,13	I.07.01	IA13	5760			120							120				5,760					6,000
Kafue	7	14	I.07.03	IA14						80		6570									80			6,650
Kariba	6	9	I.06.09	IA9	219			37			55	155	18	27	18		37	52	57		74	35		566
	6	10	I.06.10	IA10	2014			336			504	1426	168	251	168		336	483	524		685	322		5,203
	6	11	I.06.07-8	IA11a	539	0	0	181	0	0	161	166	20	29	70	0	222	254	61	0	80	144	0	1,388
	6	11	I.06.11-12	IA11b	37,649	0	0	6,306	0	0	9,417	26,586	3,130	4,696	3,146	0	6,319	9,076	9,763	0	12,767	6,042	0	97,249
Luangwa	5	15	I.05.02	IA15	687			370	35		70				229		88	361				361		1,479
	5	16	I.05.01	IA16	3,570				200						355		525	2,658				1,113		4,651
Mupata		17	I.07.05	IA17b	950											10			950					960
		17	I.04.01-2	IA17c	1,611	0	0	777	0	0	319	905	107	1,261	670	0	213	523	332	0	434	320	0	5,863
		18	I 02.01	IA18	2,912			486			728	2,062	242	363	242		486	699	758		991	466		7,521

					Dry season crops							Perennial crops						Wet season crops						
World Bank sub-basin name	WB sub-basin	Sub-basins ZDSS	Abstraction point (WB)	Irrigation abs-traction point	Winter wheat	Winter ice	Winter maize	Vegetables	Beans	Winter cotton	Other	Sugar-cane	Tea	Coffee	Citrus	Banana	Pasture	Maize	Soybeans	Sorghum	Cotton	Tobacco	Rice	Equipped area (ha)
Tete	2	19	I.02.02	IA19																				0
		21	I.02.03	IA21			75		75									75	27	12	36			150
		24	I.02.04	IA24	11,000													5,500	1,980	714	2,640			11,000
		23	I.02.05-06	IA23	1,418	0	0	4,236	4,000	0	354	1,004	118	177	118	0	236	2,340	1,088	320	1,442	227	0	11,661
Lake Malawi /	3	25	I.03.04-12	IA25	0	11,030	7,611	1,929	942	503	1,812	0	60	0	0	0	0	4,277	1,541	685	2,053	0	11,040	23,887
Shire		26	I.03.01-3	IA26		4,919	12,460	0	0	6,172	954	11,120	0	0	0	0	0	7,803	3,816	754	83	0	4,919	35,625
Zambezi Delta	1	27		IA27		22,055						55,000											22,055	77,055
Total					73,076	43,254	25,146	21,680	5,252	6,755	15,355	110,160	3,883	6,833	10,341	10	10,158	41,993	28,718	4,785	21,445	1,094	38,014	331,903

Source: World Bank (2010b)

Table 81. High level potential irrigation area by crop and sub-basin

					Dry season crops							Perennial crops						Wet season crops						
World Bank sub-basin name	WB sub-basin	Sub-basins ZDSS	Abstraction point (WB)	Abstraction pt	Winter wheat	Winter Rice	Winter maize	Vegetables	Beans	Winter cotton	Other	Sugar-cane	Tea	Coffee	Citrus	Banana	Pasture	Maize	Soybeans	Sorghum	Cotton	Tobacco	Rice	Equipped area (ha)
Upper Zambezi	12	1		IA1		5,000		2,500							2,500									10,000
Kabompo	13	2		IA2	3,897			1,817			1,300				649		2,337	2533				1,364		10,000
Lungue Bungo	11	3		IA3		5,000		2,500							2,500									10,000
Luanginga	10	4		IA4		5,000		2,500							2,500									10,000
Barotse	9	6		IA6	2,287			5,424			1				2,285		3	1487				801		10,000
Cuando / Chobe	8	7	I.08.01-3	IA7				3,000				12,000												15,000
Kariba	6	8	I.06.01-4	IA8			5,000	1,500							3,000			5,000	2,000	2,300				12,300
Kafue	7	12,13	I.07.01	IA13																				0
		14	I.07.03	IA14	12,000			250		150		12,350			250				12,000		150			25,000
Kariba	6	9	I.06.09	IA9																				0
	6	10	I.06.10	IA10																				0
	6	11	I.06.07-8	IA11a																				0
	6	11	I.06.11-12	IA11b	167,095	0	0	53,595	0	0	48,916	57,559	6,777	10,166	20,857	0	65,035	75,281	21,137	0	27,640	43,037	0	430,000
Luangwa	5	15	I.05.02	IA15																				0
	5	16	I.05.01	IA16	15,408			3,125	833		591				2,888		2,155	10,197				6044		25,000
Mupata		17	I.07.05	IA17a																				0
		17	I.04.01-2	IA17b																				0
		18	I 02.01	IA18																				0

Tete	2	19	I.02.02	IA19	50,000			25,000	25,000									37,500	13,500	6,000	18,000			100,000
		21	I.02.03	IA21																				0
		24	I.02.04	IA24	50,000			25,000	25,000									37,500	13,500	6,000	18,000			100,000
		23	I.02.05-6	IA23																				0
Lake Malawi /	3	25	I.03.05-12	IA25		42,280	4974	2,487					259					2,487	895	398	1,194		42,280	50,000
Shire		26	I.03.01-3	IA26		27,023	114932	20,162	14,015	18,481	28,757	76,631						68,058	26,795	9,764	24,329		27,023	300,001
Zambezi Delta	1	27		IA27		25,000						75,000											25,000	100,000
Total					30,0687	109,303	124,906	148,860	64,848	18,631	79,565	233,540	7,036	10,166	37,429	0	69,530	240,043	89,827	24,462	89,313	51,246	94,303	1,207,301

Source: World Bank (2010b)

Annex C. Surface flow points and irrigation abstraction points

Table 82. Surface inflow points in river network

Upstream surface inflow point	World Bank sub-basin name	WB sub-basin	ZDSS Sub-basin	Inflow description
SI1	Upper Zambezi	12	1	All of SB1
SI2	Kabompo	13	2	All of SB2
SI3a	Lungue Bungo	11	3	Lungue Bungo within SB3
SI3b		11	3	Additional Zambezi and Kabompo inflows within SB3
SI4	Luanginga	10	4	All of SB4
SI5	Barotse	9	5	Additional Zambezi inflows within SB5
SI6		9	6	Additional Zambezi inflows within SB6
SI7	Cuando / Chobe	8	7	All inflows in SB7 (Cuando and Luiana)
SI8a		8	8	Additional Zambezi/Chobe inflows to Caprivi Floodplain
SI8b		8	8	Additional Zambezi inflows down to Victoria Falls
SI13	Kafue	7	12,13	SB12 and 13 above Itezhi-tezhi
SI14a		7	14	Kafue inflows between Itezhi-tezhi and Kafue Flats
SI14b		7	14	Kafue inflows between Kafue Flats and Kafue Gorge
SI9	Kariba	6	9	All inflows in SB9 (Shangani and Gwayi)
SI10		6	10	All inflows in SB10 (Sanyati-Umniati)
SI11a		6	11	All Zambezi inflows from Vic Falls to Gwayi River inflow
SI11b		6	11	All Zambezi inflows from Gwai River to Kariba Dam (incl into reservoir)
SI15	Luangwa	5	15	All of SB15
SI16a		5	16	Lunsemfwa and Mulungushi rivers up to their confluence
SI16b		5	16	All of SB16 inflows except above confluence of Lunsemfwa and Mulungishi
SI17	Mupata	4	17	All inflows to Zambezi between Kariba and Chogwe gauging station plus inflows to Kafue between Kafue Gorge and joining the Zambezi
SI18a		2	18	Lake Manyame and upstream Hunyani River
SI18b	Tete	2	18	All of Hunyani/Panhane River flows below Lake Manyame
SI19		2	19	All inflows to Zambezi between Chongwe and Cahora Bassa HPP
SI20		2	20	SB20 - Luia and Capoche rivers
SI21		2	21	Inflows to Zambezi between Cahora Bassa and Mphanda Nkuwa
SI24a		2	24	Additional Zambezi inflows between Mphanda Nkuwa and Lupata
SI24b		2	24	Additional Zambezi inflows between Lupata and Chemba
SI23		2	23	All of Luenya and Mazowe in SB23
SI22		2	22	All of SB22 (Revubue River)

Upstream surface inflow point	World Bank sub-basin name	WB sub-basin	ZDSS Sub-basin	Inflow description
SI25a	Lake Malawi /	3	25	Inflows to Rumakali above Rumakali HPP
SI25b	Shire		25	Inflows to Ruhuhu above Masigira HPP
SI25c			25	Inflows to Songwe above Songwe HPP
SI25d			25	Inflows to North Rumphi above North Rumphi HPP
SI25e			25	Inflows to South Rukuru above Lower Fufu HPP
SI25f			25	All inflows to Lake Malawi
SI25g		3	25	Net **outflow** from Lake Malawi, from ZDSS
SI26		3	26	All inflows from Lake Malawi to end of SB26
SI27	Zambezi Delta	1	27	inflows in SB27 and below Chemba HPP in SB24

Table 83. Irrigation abstraction points relative to sub-basin definitions

World Bank sub-basin name	WB sub-basin	Sub-basin ZDSS	Abstraction Point (WB)	IA Point	IA point description
Upper Zambezi	12	1	I.12.01	IA1	All irrigation in SB1
Kabompo	13	2	I.13.01	IA2	All irrigation in SB2
Lungue Bungo	11	3	I.11.01	IA3	All irrigation in SB3
Luanginga	10	4	I.10.01	IA4	All irrigation in SB4
Barotse	9	6	I.09.01	IA6	All irrigation in SB6
Cuando / Chobe	8	7	I.08.01-3	IA7	Cuando before entering Namibia
Kariba	6	8	I.06.01-4	IA8	Chobe-Cuando above Zambezi
	7	12,13	I.07.01	IA13	Above Itezhi-tezhi
Kafue	7	14	I.07.02		No irrigation planed – not used
	7	14	I.07.03	IA14	Below Kafue Flats, above Kafue Gorge HPP
	6	9	I.06.09	IA9	All irrigation in SB9
	6	10	I.06.10	IA10	Sanyati river before Kariba
Kariba	6	11	I.06.05-6		no irrigation planed –not used
	6	11	I.06.07-8	IA11a	Between Batoka Gorge and Devils Gorge (both sides)
	6	11	I.06.11-12	IA11b	Bottom of Kariba Reservoir
Luangwa	5	15	I.05.02	IA15	all of SB15
	5	16	I.05.01	IA16	SB16, all below HPPs
Mupata	4	17	I.07.04		no irrigation planed – not used
		17	I.07.05	IA17a	between Kafue Lower and Zambezi
		17	I.05.03-4		no irrigation planed – not used
		17	I.04.01-2	IA17b	between confluence of Kafue and Chongwe gauging station
		18	I 02.01	IA18	All of SB18
Tete	2	19	I.02.02	IA19	from Cahora Bassa Reservoir
		21	I.02.03	IA21	between Cahora Bassa and Mphanda Nkuwa
		24	I.02.04	IA24	All of SB24
		23	I.02.05-06	IA23	All of SB23
Lake Malawi/	3	25	I.03.04-12	IA25	All irrigation in SB25
Shire		26	I.03.01-3	IA26	All irrigation between Lake Malawi and confluence with Zambezi
Zambezi Delta	1	27		IA27	All irrigation in SB27

Annex D. Crop coefficients

Table 84. Crop coefficients by month

Monthly mean	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Winter wheat	0.00	0.00	0.00	0.00	0.33	0.68	1.14	1.00	0.40	0.00	0.00	0.00
Summer maize	1.06	1.01	0.46	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.45	0.71
Winter maize	0.00	0.00	0.00	0.00	0.45	0.71	1.06	1.01	0.46	0.00	0.00	0.00
Summer rice	1.13	1.19	1.20	0.80	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.05
Winter rice	1.13	1.19	1.20	0.80	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.05
Sugarcane	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95
Vegetables	0.00	0.00	0.00	0.70	0.86	1.07	1.10	1.10	1.10	0.68	0.10	0.00
Soybeans	0.96	1.15	0.93	0.25	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.46
Beans	0.00	0.00	0.00	0.00	0.13	0.59	1.09	0.88	0.12	0.00	0.00	0.00
Tea	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	0.95	0.98	1.00
Coffee	1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.05
Summer cotton	0.90	1.15	0.98	0.65	0.11	0.00	0.00	0.00	0.00	0.00	0.27	0.53
Winter cotton	0.00	0.00	0.00	0.00	0.27	0.53	0.90	1.15	0.98	0.65	0.11	0.00
Tobacco	1.20	0.80	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.33	0.85
Banana	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90
Citrus	0.73	0.70	0.67	0.65	0.65	0.65	0.75	0.75	0.75	0.75	0.75	0.75
Pasture	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Other (tomatoes)	0.00	0.00	0.00	0.70	0.86	1.07	1.10	1.10	1.10	0.68	0.10	0.00
Sorghum	0.76	1.05	0.50	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.44

Source: World Bank (2010b), Table A3.3

Annex E. Existing power plant characteristics

Table 85. Technical and financial characteristics of existing power plants

Country	Plant name	Fuel	2014 capacity (MW)	Efficiency (%)	Availability (%)	Fixed O&M ($/kW)	Variable O&M ($/MWh)
AGO	AGO Diesel	Diesel	7	33	86	19.00	4.18
AGO	Angola Diesel IC	Diesel	13	30	80	0.80	3.00
AGO	Biopio	Hydro	9	100	50	8.72	1.51
AGO	Cambambe I	Hydro	192	100	60	8.72	1.51
AGO	Capanda I	Hydro	240	100	66	8.72	1.51
AGO	Capanda II	Hydro	240	100	40	8.72	1.51
AGO	Gove	Hydro	44	100	50	8.72	1.51
AGO	Mabubas	Hydro	25	100	38	8.72	1.51
AGO	Matala	Hydro	26	100	71	8.72	1.51
AGO	Angola SCGT	Natural gas	1,035	20	86	19.00	4.18
AGO	Benguela	Residual fuel oil	20	33	86	19.00	4.18
BOT	Morupule A	Other coal	0	30	88	56.67	0.86
BOT	Morupule B	Other coal	450	33	88	38.00	4.18
DRC	Inga 1	Hydro	250	100	76	8.72	1.51
DRC	Inga 2	Hydro	890	100	77	8.72	1.51
DRC	Mwadingusha	Hydro	68	100	34	8.72	1.51
DRC	Nseke Koni	Hydro	290	100	55	8.72	1.51
DRC	Nzilo	Hydro	108	100	60	8.72	1.51
DRC	Zongo Sanga	Hydro	83	100	12	8.72	1.51
LES	LES Small Hydro	Hydro	2	100	46	8.72	1.51
LES	Muela I	Hydro	72	100	65	8.72	1.51

Country	Plant name	Fuel	2014 capacity (MW)	Efficiency (%)	Availability (%)	Fixed O&M ($/kW)	Variable O&M ($/MWh)
MAL	Malawi Distillate	Diesel	46	30	80	0.80	3.00
MAL	Kapichira I	Hydro	64	100	76	8.72	1.51
MAL	Kapichira II	Hydro	64	100	84	8.72	1.51
MAL	Nkula A	Hydro	13.6	100	77	8.72	1.51
MAL	Nkula B	Hydro	100	100	66	8.72	1.51
MAL	Tedzani I II	Hydro	36	100	88	8.72	1.51
MAL	Tedzani III	Hydro	52	100	68	8.72	1.51
MAL	Wowve	Hydro	4	100	25	8.72	1.51
MOZ	Cahora Bassa	Hydro	2,075	100	81	8.72	1.51
MOZ	Chicamba	Hydro	38	100	15	8.72	1.51
MOZ	Corumana	Hydro	14	100	20	8.72	1.51
MOZ	Mavuzi	Hydro	48	100	75	8.72	1.51
MOZ	Aggreko	Natural gas	224	37	60	19.00	4.18
MOZ	Ressano Garcia EDM SASOL	Natural gas	175	48	95	19.00	4.18
MOZ	Moz Distillate	Residual fuel oil	0	30	80	0.80	3.00
NAM	Ruacana	Hydro	347	100	66	8.72	1.51
NAM	Van Eck	Other coal	90	30	88	56.67	0.00
NAM	Anixas	Residual fuel oil	22.5	30	96	4.86	5.35
NAM	Paratus	Residual fuel oil	12	30	96	4.86	5.35
SAF	Biomass bagasse	Bagasse	100	25	91	131.35	1.17
SAF	OCGT liquid fuels existing	Diesel	2,460	32	95	8.95	0.00
SAF	Hydro existing	Hydro	670	100	93	46.49	0.00
SAF	Biomass/coal CHPs existing	Industrial waste	228	25	91	839.36	0.00
SAF	Gas CHPsexisting	Natural gas	99	75	91	839.36	0.00

Country	Plant name	Fuel	2014 capacity (MW)	Efficiency (%)	Availability (%)	Fixed O&M ($/kW)	Variable O&M ($/MWh)
SAF	Sasol CCGT	Natural gas	140	0	91	20.00	0.00
SAF	Nuclear existing	Nuclear	1,860	100	91	664.96	0.38
SAF	Coal Eskom large dry Existing	Other coal	13,660	34	90	304.16	1.25
SAF	Coal Eskom large existing	Other coal	21,150	34	90	201.52	1.25
SAF	Coal Eskom small existing	Other coal	6,503	29	90	304.16	1.25
SAF	Coal municipal existing	Other coal	470	25	90	304.16	1.25
SAF	Drakensberg	Other coal	1,000	70	19	8.11	0.43
SAF	Palmiet	Other coal	400	70	19	8.65	0.57
SAF	Sasol Infrachem	Other coal	50	25	90	304.16	1.25
SAF	Sasol SSF	Other coal	50	25	90	304.16	1.25
SAF	Steenbras	Other coal	180	70	19	6.22	0.57
SAF	SAIPPP PV existing	Solar PV	388	100	25	28.11	0.00
SAF	SAIPPP wind existing	Wind	255	100	30	1.45	0.00
SWA	RSSC	Bagasse	70	38	65	8.72	1.51
SWA	Ubombo	Bagasse	40	38	55	8.72	1.51
SWA	Ezulwini Edwaleni Maguduza	Hydro	41	100	34	8.72	1.51
SWA	Maguga	Hydro	20	100	44	8.72	1.51
TAZ	HNwMU	Hydro	30	100	52	31.00	0.00
TAZ	Kidatu	Hydro	204	100	57	6.00	0.00
TAZ	Kihansi	Hydro	180	100	33	5.50	0.00
TAZ	Mtera	Hydro	80	100	53	7.00	0.00
TAZ	Pangani Falls	Hydro	68	100	52	8.00	0.00
TAZ	Taz Gas	Natural gas	441	30	96	4.86	5.35
TAZ	Taz distillate	Residual fuel oil	243	30	80	0.80	3.00

Cou ntry	Plant name	Fuel	2014 capacity (MW)	Efficiency (%)	Availabi lity (%)	Fixed O&M ($/kW)	Variable O&M ($/MWh)
ZAM	Zam diesel	Diesel	0	30	80	0.80	3.00
ZAM	Kafue Gorge Upper	Hydro	990	100	59	8.72	1.51
ZAM	Kariba North	Hydro	720	100	45	8.72	1.51
ZAM	Kariba North Extension	Hydro	180	100	24	8.72	1.51
ZAM	Victoria Falls	Hydro	108	100	65	8.72	1.51
ZAM	Zam small hydro	Hydro	79	100	60	8.72	1.51
ZIM	Kariba South	Hydro	750	100	55	8.72	1.51
ZIM	Zim coal existing	Other coal	394	30	88	56.67	0.00

Notes: Kariba North extension is 180 MW in 2014, but 360 MW in 2015.

Source: Most original plant data from IRENA SAPP Study (Miketa and Merven 2013); All South African plants updated from Eskom and Energy Research Centre sources (ERC 2013; Eskom 2014, 2010; Marais 2015a), South Africa renewable programme data from South Africa Department of Energy and Eskom (Department of Energy 2014; Marais 2015b); Mozambique gas plants updated from Mahumane and Mulder (2015a); All plant capacities checked with the SAPP Planning Sub-Committee members, and have been either updated or confirmed. Availability date confirmed or updated from Spalding-Fecher et al. (2014).

Table 86. Combinations of existing plants treated as one plant in modelling

Combined plant name	Country	2014 Capacity (MW)	Plants included
Angola SCGT	AGO	1,035	Lobito, Cabinda, Huambo, Kuito, Saurimo, Luena, Caala, Namibe, other existing gas plants (also covers TG12.5, etc.)
Nseke Koni	DRC	290	Nseke & Koni
Zongo Sanga	DRC	83	Zongo & Sanga
LES small hydro	LES	2	Katse, Semonkong
Malawi distillate	MAL	46	Lilongwe, Mzuzu, Blantyre
Moz distillate	MOZ	0	Maputo, Beira
Biomass Bagasse existing	SAF	100	Generic for all CHP in sugar industry
OCGT liquid fuels existing	SAF	2,460	Acacia, Ankerlig, Mossel Bay, Port Rex
Hydro Existing	SAF	670	Gariep, Vanderkloof and mini hydros (Bethlehem etc.)
Biomass/coal CHPs existing	SAF	228	Sappi Stanger, Mondi Merebank, Mondi Felixton,Mondi Umhlathuze
Nuclear existing	SAF	1,860	Koeberg
HNwMU	TAZ	30	Hale & Nyumba ya Mungu, Uwemba
Taz Gas	TAZ	441	SONGAS, IPTL, Ubongo Rented Aggreco, Ubungo Rented Richmo x 2, Tegata - Wartsila
Taz distillate	TAZ	243	Mwansa-ALSTOM, Thermal, Diesel remote
Zam small hydro	ZAM	79	Lunsemfwa, Mulungishi, ZESCO small hydro
Zim coal existing	ZIM	394	Hwange 1-6, Munyati, Bulawayo, Harare

Annex F. Specific new power plant characteristics

Table 87. Technical and financial characteristics of specific new power plants

Country	Plant name	Fuel	Capacity (MW)	Efficiency (%)	Availability (%)	Fixed O&M (USD/kW)	Variable O&M (USD/MWh)	Capital cost (USD/kW)	Earliest start year	Life (years)
AGO	Baynes Ago	Hydro	300	100	55	8.72	1.51	1,778	2025	50
AGO	Caculo Cabaca	Hydro	2,100	100	40	8.72	1.51	1,753	2025	50
AGO	Cambambe II	Hydro	700	100	40	8.72	1.51	2,969	2016	50
AGO	Lauca	Hydro	2,000	100	40	8.72	1.51	1,753	2017	50
AGO	Lomaum	Hydro	65	100	40	8.72	1.51	2,969	2018	50
AGO	Soyo	Natural gas	500	35	86	19.00	4.18	600	2017	30
BOT	Coal IPP B	Other coal	600	37	88	20.00	0.96	2,624	2025	35
DRC	Busanga	Hydro	240	100	60	8.72	1.51	1,250	2015	50
DRC	Grand Inga	Hydro	42,081	100	75	8.72	1.51	671	2030	50
DRC	Inga 3	Hydro	3,500	100	75	8.72	1.51	494	2020	50
LES	Kobong	Hydro	1,200	70	25	8.72	1.51	1,208	2030	50
LES	Muela II	Hydro	110	100	9	8.72	1.51	1,938	2025	50
LES	Oxbow	Hydro	80	100	59	8.72	1.51	1,938	2030	50
LES	Quthing	Hydro	15	100	25	8.72	1.51	1,938	2030	50
MAL	Fufu	Hydro	140	100	46	8.72	1.51	1,410	2015	50
MAL	Hamilton Falls	Hydro	100	100	71	8.72	1.51	1,629	2030	50
MAL	Kholombizo	Hydro	100	100	71	8.72	1.51	1,629	2018	50
MAL	Mpatamanga	Hydro	265	100	55	8.72	1.51	1,527	2020	50
MAL	Songwe Mal	Hydro	240	100	45	8.72	1.51	1,250	2022	50
MAL	Coal IPP M	Other coal	100	37	88	20.00	0.96	2,624	2030	35
MOZ	Alto Malema	Hydro	80	100	33	8.72	1.51	1,850	2020	50

Country	Plant name	Fuel	Capacity (MW)	Efficiency (%)	Availability (%)	Fixed O&M (USD/kW)	Variable O&M (USD/MWh)	Capital cost (USD/kW)	Earliest start year	Life (years)
MOZ	Boroma	Hydro	200	100	67	8.72	1.51	1,850	2022	50
MOZ	Chemba I	Hydro	600	100	96	8.72	1.51	1,700	2020	50
MOZ	Chemba II	Hydro	400	100	96	8.72	1.51	1,700	2022	50
MOZ	HCB North Bank Extension	Hydro	1,245	100	26	8.72	1.51	907	2015	50
MOZ	Lugenda	Hydro	150	100	50	8.72	1.51	1,850	2024	50
MOZ	Lupata	Hydro	600	100	79	8.72	1.51	1,700	2021	50
MOZ	Majawa	Hydro	50	100	70	8.72	1.51	1,850	2022	50
MOZ	Massingir	Hydro	27	100	35	8.72	1.51	1,375	2018	50
MOZ	Mavuzi II	Hydro	38	100	50	8.72	1.51	1,850	2023	50
MOZ	Messalo	Hydro	50	100	50	8.72	1.51	1,850	2024	50
MOZ	Meugeba	Hydro	150	100	50	8.72	1.51	1,850	2022	50
MOZ	Meutelele	Hydro	50	100	50	8.72	1.51	1,850	2022	50
MOZ	Molocue	Hydro	40	100	50	8.72	1.51	1,850	2023	50
MOZ	Mphanda Nkuwa I	Hydro	1,500	100	65	8.72	1.51	1,538	2022	50
MOZ	Mphanda Nkuwa II	Hydro	750	100	65	8.72	1.51	1,538	2025	50
MOZ	Pavue	Hydro	300	100	70	8.72	1.51	1,850	2017	50
MOZ	Quedas and Ocua	Hydro	180	100	50	8.72	1.51	1,858	2020	50
MOZ	Ruo	Hydro	85	100	50	8.72	1.51	1,850	2028	50
MOZ	Tsate	Hydro	50	100	50	8.72	1.51	1,850	2021	50
MOZ	Central Buzi_Power	Natural gas	20	35	70	19.00	4.18	600	2020	25
MOZ	Central Electrotec	Natural gas	40	48	80	19.00	4.18	900	2017	30
MOZ	Central Termica de Maputo	Natural gas	100	48	70	19.00	4.18	900	2018	30
MOZ	Gigawatt	Natural gas	100	37	95	19.00	4.18	700	2016	30

Country	Plant name	Fuel	Capacity (MW)	Efficiency (%)	Availability (%)	Fixed O&M (USD/kW)	Variable O&M (USD/MWh)	Capital cost (USD/kW)	Earliest start year	Life (years)
MOZ	Kuvaninga	Natural gas	40	35	60	19.00	4.18	600	2016	25
MOZ	Projecto ENI	Natural gas	75	35	70	19.00	4.18	650	2017	30
MOZ	Temane Sasol	Natural gas	400	35	70	19.00	4.18	600	2018	30
MOZ	Benga	Other coal	250	35	88	19.97	0.96	2,100	2016	35
MOZ	ENRC Chirondzi	Other coal	150	34	70	19.97	0.96	1,800	2017	25
MOZ	Jindal	Other coal	150	34	70	19.97	0.96	1,800	2018	30
MOZ	Moatize	Other coal	300	35	70	19.97	0.96	2,126	2016	30
MOZ	Nacala	Other coal	300	34	70	19.97	0.96	1,800	2018	25
MOZ	Ncondezi	Other coal	300	34	70	19.97	0.96	1,800	2018	25
NAM	Baynes Nam	Hydro	300	100	55	8.72	1.51	1,778	2025	50
NAM	Kudu	Natural gas	774	53	94	0.00	1.64	909	2017	25
SAF	Coal IPP SA	Other coal	800	36	96	49.32	13.39	3,337	2019	30
SAF	Ingula	Other coal	1,332	70	19	8.70	1.51	1,548	2015	50
SAF	Kusile	Other coal	4,428	37	88	61.49	1.67	2,678	2014	45
SAF	Medupi	Other coal	4,428	37	88	61.49	1.67	2,624	2014	45
SAF	SAIPPP Solar PV	Solar PV	2,589	100	25	28.11	0.00	2,827	2016	25
SAF	SAIPPP Solar CSP	Solar thermal	1,200	100	96	66.08	0.00	5,544	2016	30
SAF	SAIPPP Wind	Wind	6,874	100	30	35.95	0.00	2,007	2016	25
SWA	Lower Maguduza	Hydro	12	100	90	0.00	5.99	4,620	2019	50
SWA	Lower Maguga	Hydro	5	100	90	0.00	5.42	4,620	2025	50
SWA	Ngwempisi	Hydro	80	100	44	0.00	5.99	4,620	2022	50
SWA	Lubombo	Other coal	300	37	88	20.00	0.96	2,624	2030	35
SWA	Solar PV SWA	Solar PV	40	100	25	0.00	20.10	2,200	2020	25
TAZ	Kakono	Hydro	53	100	72	8.72	1.51	2,326	2022	50

Country	Plant name	Fuel	Capacity (MW)	Efficiency (%)	Availability (%)	Fixed O&M (USD/kW)	Variable O&M (USD/MWh)	Capital cost (USD/kW)	Earliest start year	Life (years)
TAZ	Masigira	Hydro	118	100	61	8.72	1.51	2,326	2020	50
TAZ	Ruhudji	Hydro	358	100	57	8.72	1.51	1,707	2020	50
TAZ	Rumakali	Hydro	222	100	68	8.72	1.51	2,326	2020	50
TAZ	Rusomo	Hydro	21	100	70	8.72	1.51	2,326	2018	50
TAZ	Songwe Taz	Hydro	240	100	45	8.72	1.51	1,250	2022	50
TAZ	Stieglers Gorge	Hydro	1,200	100	31	8.72	1.51	2,326	2023	50
TAZ	Kilwa Somanga	Natural gas	320	42	85	24.01	1.45	1,044	2018	25
TAZ	Kinyerezi	Natural gas	1,320	42	85	24.01	1.45	1,044	2018	25
TAZ	Kiwira	Other coal	200	30	88	56.67	7.40	3,150	2020	35
TAZ	Mchuchuma	Other coal	300	33	88	38.32	4.18	2,624	2023	35
TAZ	Ngaka	Other coal	200	30	88	56.67	7.40	3,150	2024	35
TAZ	Singida	Wind	50	100	30	0.00	14.29	2,310	2017	25
ZAM	Batoka Gorge Zam	Hydro	800	100	62	8.72	1.51	2,500	2023	50
ZAM	Devils Gorge Zam	Hydro	500	100	64	8.72	1.51	2,500	2026	50
ZAM	ItezhiTezhi	Hydro	120	100	58	8.72	1.51	2,083	2016	50
ZAM	Kabompo	Hydro	40	100	59	8.72	1.51	4,000	2018	50
ZAM	Kafue Gorge Lower	Hydro	750	100	37	8.72	1.51	2,000	2019	50
ZAM	Kalungwishi expansion	Hydro	220	100	46	8.72	1.51	3,000	2018	50
ZAM	Lunsenfwa expansion	Hydro	14	100	68	8.72	1.51	2,500	2019	50
ZAM	Lusiwasi expansion	Hydro	86	100	68	8.72	1.51	2,500	2019	50
ZAM	Mambililma Falls	Hydro	326	100	68	8.72	1.51	2,500	2025	50
ZAM	Mpata Gorge Zam	Hydro	543	100	68	8.72	1.51	2,500	2025	50
ZAM	Muchinga	Hydro	263	100	68	8.72	1.51	2,500	2023	50
ZAM	Mulungishi expansion	Hydro	45	100	68	8.72	1.51	2,500	2018	50

Country	Plant name	Fuel	Capacity (MW)	Efficiency (%)	Availability (%)	Fixed O&M (USD/kW)	Variable O&M (USD/MWh)	Capital cost (USD/kW)	Earliest start year	Life (years)
ZAM	Mulungishi lower	Hydro	100	100	68	8.72	1.51	2,500	2025	50
ZAM	Mumbotula Falls	Hydro	301	100	68	8.72	1.51	2,500	2025	50
ZAM	EMCO	Other coal	300	37	88	19.97	0.96	2,500	2020	35
ZAM	Maamba	Other coal	300	37	88	19.97	0.96	2,500	2016	35
ZIM	Batoka Gorge Zim	Hydro	800	100	62	8.72	1.51	1,563	2023	50
ZIM	Devils Gorge Zim	Hydro	500	100	64	8.72	1.51	2,500	2026	50
ZIM	Gairezi	Hydro	30	100	68	8.72	1.51	4,000	2017	50
ZIM	Kariba South Extension	Hydro	300	100	45	8.72	1.51	667	2018	50
ZIM	Middle Sabi	Hydro	300	100	68	8.72	1.51	2,500	2018	50
ZIM	Mpata Gorge Zim	Hydro	543	100	68	8.72	1.51	2,500	2025	50
ZIM	Mutare emergency	Hydro	120	100	68	8.72	1.51	2,500	2017	50
ZIM	Lupane	Natural gas	150	53	85	24.01	1.45	1,349	2021	25
ZIM	Gokwe North	Other coal	1,400	37	88	19.97	0.96	1,144	2021	35
ZIM	Gwai Caseco	Other coal	600	37	88	19.97	0.96	1,144	2018	35
ZIM	Hwange 78	Other coal	600	37	88	19.97	0.96	984	2019	35
ZIM	Southern Energy Makomo	Other coal	600	37	88	19.97	0.96	1,144	2019	35

Notes: Hydropower plants along Zambia-Zimbabwe border (e.g. Mpata Gorge) have 50/50 split of capacity;

Source: Most original plant data from the SAPP IRENA study (Miketa and Merven 2013); South African specific plants updated from Eskom (Marais 2015a), South Africa renewable programme data from South Africa Department of Energy and Eskom (Department of Energy 2014; Marais 2015b); Mozambique plants updated from Mahumane and Mulder (2015a); All plant capacities and start date checked with the SAPP Planning Sub-Committee members, and have been either updated or confirmed.

Annex G. Generic power plant characteristics

Table 88. Technical and financial characteristics of generic new power plants

Plant name	Fuel	Efficiency (%)	Availability (%)	Fixed O&M ($/kW)	Variable O&M ($/MWh)	PV capital cost ($/kW)	Overnight capital cost ($/kW)	Earliest start year	Life (years)	Capacity credit (%)
Bagasse	Bagasse	38	50	349	5.16	3,191	2,500	2016	30	100
Biomass BFB	Biomass	38	50	106	5.26	5,120	4,012	2025	30	100
Biomass CC	Biomass	57	50	356	17.49	10,472	8,205	2025	30	100
Diesel	Diesel	35	80	0	17.00	1,177	1,070	2016	25	100
Geothermal	Geothermal	100	85	0	5.02	5,105	4,000	2016	25	100
Small Hydro	Hydro	100	50	0	5.42	4,620	4,000	2016	30	0
Landfill gas	Municipal waste	35	50	129	0.00	3,635	2,848	2016	30	100
Municipal waste	Municipal waste	19.4	85	349	5.16	11,596	9,086	2016	30	100
CCGT	Natural gas	48	85	0	2.90	1,297	1,069	2016	30	100
OCGT	Natural gas	30	85	0	19.92	696	603	2016	25	100
PWR nuclear	Nuclear	33	85	65	3.60	7,906	5,028	2023	60	100
Fluidized bed combustion coal	Other coal	35.7	96	49	13.39	3,337	2,615	2031	30	100
IGCC	Other coal	36.9	90	112	1.95	4,671	3,660	2031	30	100
Supercritical coal	Other coal	37	96	61	1.67	3,358	2,631	2016	30	100
Supercritical coal w CCS	Other coal	28	96	0	35.98	4,842	3,605	2030	35	100
HFO	Residual fuel oil	35	80	0	15.00	1,559	1,350	2016	25	100
Solar PV utility fixed	Solar PV	100	25	0	20.10	2,200	2,000	2016	25	5
Solar parabolic trough 0 storage	Solar thermal	100	25	57	0.00	5,601	4,376	2017	30	30
Solar parabolic trough 3 hrs storage	Solar thermal	100	30.9	69	0.00	7,638	5,967	2017	30	100
Wind (20% CF)	Wind	100	20	0	14.29	2,732	2,365	2016	25	10
Wind (30% CF)	Wind	100	30	0	14.29	2,310	2,000	2016	25	15

Source: IRENA SAPP Study (Miketa and Merven 2013), ERC (2013) EPRI (2012)

Table 89. Availability of generic plants in each country

Generic plant type	Angola	Bots-wana	DRC	Lesotho	Malawi	Mozam-bique	Namibia	South Africa	Swazi-land	Tanza-nia	Zambia	Zimba-bwe
Bagasse	No	No	No	No	No	Yes	No	No	Yes	Yes	Yes	No
Biomass fluidized bed	Yes	Yes	Yes	No	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes
Biomass combined cycle	Yes	Yes	Yes	No	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes
Municipal waste	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Landfill gas	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Diesel	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Geothermal	No	No	No	No	No	No	No	No	No	Yes	No	No
Small hydro	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
CCGT	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
OCGT	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
PWR nuclear	No	No	No	No	No	No	No	Yes	No	No	No	No
Fluidized bed combustion coal	Yes	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Integrated gasification combined cycle coal	Yes	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Supercritical coal	Yes	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Supercritical coal with CCS	Yes	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Heavy fuel oil	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Solar PV utility fixed	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Solar parabolic trough no storage	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Solar parabolic trough 3 hrs storage	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Bulk wind (20% capacity factor)	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Bulk wind (30% capacity factor)	No	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes

Table 90. Fuel availability assumptions for generic plants

Country	Coal	Gas	Oil	Biomass
Angola	Import	Domestic	Coastal	Moderate
Botswana	Domestic	Coalbed Methane	Inland	Moderate
DRC	Import	Domestic	Coastal	Moderate
Lesotho	Not Available	Not Available	Inland	Scarce
Malawi	Domestic	Not Available	Inland	Moderate
Mozambique	Domestic	Domestic	Coastal	Free
Namibia	Domestic	Domestic	Coastal	Scarce
South Africa	Domestic	Import	Coastal	Moderate
Swaziland	Domestic	Not Available	Inland	Free
Tanzania	Import	Domestic	Coastal	Free
Zambia	Domestic	Import	Inland	Free
Zimbabwe	Domestic	Import/CBM	Inland	Moderate