Technical appendixes for

Enhancing the Climate Resilience of Africa's Infrastructure: The Power and Water Sectors

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Zambezi Basin

Hydropower and Storage

The data below in Table A-1 and Table A-2 summarize existing and proposed hydroppower projects in the Zambezi basin. These are based largely on several key documents provided in the reference section below, with the most central one being the 2010 Zambezi Basin Multi-Sector Investment Opportunity Analysis (MSIOA). Others include IRENA (2013), PIDA (2011), and IWRM Strategy and Implementation Plan for the Zambezi (2008).

Table A-1: *Existing hydropower projects in the Zambezi River basin*

Dam/Scheme	River	Country	Hydropower Capacity (MW)
Lake Kariba	Zambezi	Zambia/Zimbabwe	1,470
Cahora Bassa	Zambezi	Mozambique	2,075
Victoria Falls	Zambezi	Zambia	108
Kafue Gorge Upper	Kafue	Zambia	900
Nkhula Falls	Shire	Malawi	122
Kapichira	Shire	Malawi	64
Tedzani	Shire	Malawi	88

Table A-2: *Planned hydropower projects in the Zambezi River basin*

Dam/Scheme	River	Country	Capacity (MW)	Expected Completion
Khlolombizo	Shire	Malawi	240	2018
Batoka Gorge	Zambezi	Zimbabwe	1600	2022
Kafue Gorge Dam Lower	Kafue	Zambia	750	2016
Itezhi – Tezhi	Kafue	Zambia	120	2014

Mphanda Nkuwa	Zambezi	Mozambique	1,500	2017
Devils Gorge	Zambezi	Zambia/ Zimbabwe	1240	2019
Songwe I, II, and III	Songwe	Malawi	340	2014
Lower Fufu	Rukuru	Malawi	100	2015
Rumakali	Rumakali	Tanzania	222	2019
Kariba North Extension	Zambezi	Zambia/ Zimbabwe	360	2013
HCB North Bank	Zambezi	Zambia	850	2015
Lusemfwe Expansion	Lusemfwe	Zambia	255	2018
Lusiwasi	Lusiwasi	Zambia	84	2016
Mpata Gorge	Zambezi	Zambia/ Zimbabwe	543	2023

Irrigation

The MSIOA served as the guiding document for estimating irrigated areas within the Zambezi. Within the WEAP model they are aggregated to 20 or so different regions. While no start years were given for the document, we have arbitrarily set a start date of 2015 and assumed that they are phased in fully by 2025. Details are given in Table A-3 below.

Table A-3: Existing and planned irrigated areas in the Zambezi River basin

Country	Sub-basin	Cropping pattern	Existing area (ha)	Planned area (ha)
Angola	Lungue Bungo	Perennial	250	375
		Dry Season	750	1,125
	Upper Zambezi	Perennial	750	5,750
	Cuando	Perennial	125	125
		Dry Season	375	375

	Luanginga	Perennial	250	250
		Dry Season	500	5,500
Botswana	Chobe	Perennial	0	3,000
		Dry Season	0	5,000
		Wet Season	0	10,800
Malawi	Shire	Perennial	15,810	26,930
		Dry Season	6,815	33,330
		Wet Season	6,089	24,882
	Lake Malawi	Perennial	8,000	8,000
		Dry Season	2,781	12,784
		Wet Season	2,781	9,714
	Rukuru	Dry Season	1,000	1,000
		Wet Season	800	800
Mozambique	Zambezi	Dry Season	943	34,148
		Perennial	6,390	61,390
		Wet Season	22,152	33,136
Tanzania	Songwe	Dry Season	7,510	7,510
		Wet Season	7,135	7,135
	Upper Shire	Dry Season	500	500
		Wet Season	475	475
Zambia	Zambezi	Perennial	60	1,663
		Dry Season	140	5,545
		Wet Season	78	1,681
	Kafue	Perennial	33,788	40,478
		Dry Season	5,410	11,370
		Wet Season	5,410	11,250
	Lusemfwa	Perennial	1,950	2,830
		Dry Season	7,150	10,920

		Wet Season	4,225	7,995
	Luangwa	Perennial	1,950	2,267
		Dry Season	785	1,947
	Luangwa	Wet Season	4,225	4,947
	Kabompa	Perennial	105	1,986
		Dry Season	245	4,664
		Wet Season	136	2,591
Zambia/ Zimbabwe	Zambezi	Perennial	1,394	46,659
		Dry Season	3,766	59,525
		Wet Season	2,483	41,597
Zimbabwe	Gwai	Perennial	356	611
		Dry Season	713	1,024
		Wet Season	735	953
	Sanyati	Perennial	5,920	8,269
		Dry Season	11,846	14,700
		Wet Season	12,196	14,210
	Manyame	Perennial	6,055	9,450
		Dry Season	12,115	16,241
		Wet Season	12,474	15,388
	Luenya	Perennial	3,468	5,121
		Dry Season	6,999	17,007
		Wet Season	6,184	11,601
Total			244,542	668,524

Upper Orange Basin

Hydropower and Storage

The list of infrastructure below represents the Upper Orange Basin, up to the confluence with the Vaal. The main sources of data are based on input from the Orange-Senqu River Commission (ORASECOM). Major impoundments are listed in Table A-4. The location of each facility is shown in a simplified schematic (**Figure A-1**).

Figure A-1: Simplified schematic of upper Orange-Senqu River system (post-development)

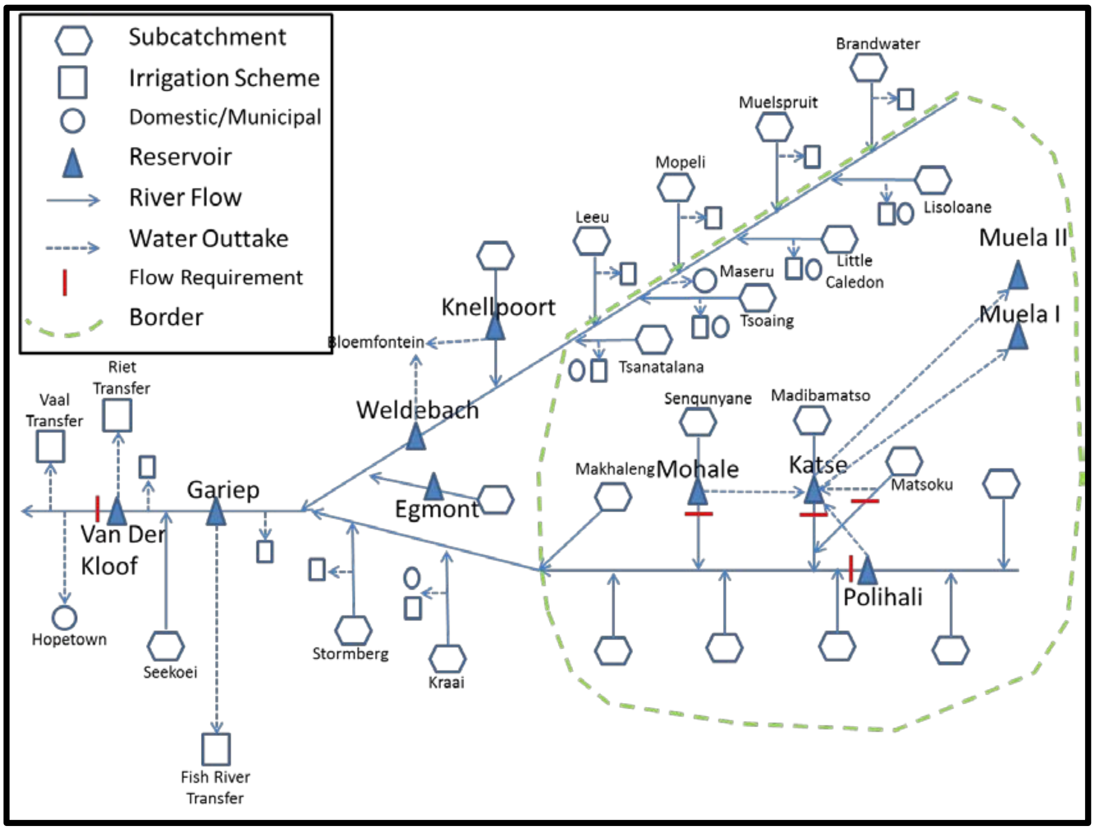

Table A-4: Existing major hydropower plants included in the WEAP model

Dam/Scheme	Country	Capacity (MW)
Van der Kloof	**South Africa**	**240**
Gariep	**South Africa**	**360**
Muela	**Lesotho**	**80**

Table A-5: Planned hydropower projects in the Upper Orange River basin

Dam/Scheme	Country	Capacity (MW)	Year of Completion
Muela II	Lesotho	48	2014
Polihali	Lesotho	N/A	2020

Irrigation

Reliable estimates of irrigated areas within the basin were not readily available for the purposes of this modeling study. Instead, irrigated areas are estimated by the Institute for Water Research at Rhodes University using a GIS assessment of land areas derived from satellite imagery. While these estimates are not expected to be very accurate, they should be sufficiently representative of real conditions for the purposes of modeling. Cropping patterns were informed by De Condappa (2013) and are shown in Table A-5.

Table A-6: Existing irrigated areas

Country	Area (ha)
South Africa	**62,810**
Lesotho	**3,720**

Congo Basin

Hydropower and Storage

The potential of hydroelectric power supply in the Congo Basin continues to be a matter of national and regional discussions, and a few pre-feasibility studies on this river basin highlighted potential sites for the development of more than 40 000 MW of continuous electrical power production (Maher, 1994; Mukheibir, 2007). Opportunities to achieve a further 100 000 MW are also underlined. Based on the opportunities offered by the basin, some project proposals were developed for an international power grid (Maher, 1994; Mukheibir, 2007). Other proposals include the development of an interbasin water transfer scheme from the Palambo Dam to sustain the provision of water resources in the Lake Chad Basin (Umolu, 1990; Chapman and Baker, 1992), inland navigation and expansion of irrigated agriculture to meet the demand of the growing population in the basin. Increasingly, reports of forest logging, mining, rapid urbanization and uncontrolled settlements show a change in the patterns of natural variability of the basin hydrology. Ladel *et al*. (2008) pointed to a decrease in the river flow of about 18 % at the Oubangui River, a major tributary of the Congo Basin. This decrease has affected navigation along the tributary, resulting in increased days of non-economic navigation (the number of days when the water height was less than 90 cm). These changes associated with rapid population growth are likely to exert pressure on available water resources, which will require more infrastructures for management. De Condappa (2013) presents the available information on the current and future water infrastructures in the Congo Basin (only the infrastructures in DRC are presented), summarized below in Table A-7 & Table A-8.

Table A-7: Existing hydropower in the Congo River basin

Dam/Scheme	Country	Capacity (MW)
Inga I & II	Democratic Republic of Congo	1,775
Zongo	Democratic Republic of Congo	40
Ruzizi II	Democratic Republic of Congo/ Rwanda	43

Table A-8: Planned hydropower in the Congo River basin

Dam/Scheme	**Country**	**Capacity (MW)**	**Year of Completion**
Inga III	Democratic Republic of Congo	4,500	2023
Grand Inga	Democratic Republic of Congo	39,000	5 stages at 7 year intervals following implementation of Inga III
Tshopo†	Democratic Republic of Congo	9.75	2016
N'zilo†	Democratic Republic of Congo	120	2016
N'seke†	Democratic Republic of Congo	236	2016
Katende	Democratic Republic of Congo	20	2016
Mobaye†	Democratic Republic of Congo	12	2016
Sanga†	Democratic Republic of Congo	11.5	2016
Busanga	Democratic Republic of Congo	223	2016
Ruzizi III	Democratic Republic of Congo/ Rwanda	270	2016

† Tshopo, N'zilo, N'seke, Mobaye, and Sanga are scheduled to be rehabilitated

Irrigation

There is a paucity of information about the Congo basin. The sole source of information found in the context of this work are FAO (1997) and AQUASTAT (FAO ,2005). The uncertainty about irrigation in the Congo basin is consequently very high.

Table A-9: Existing irrigated areas within the Congo River Basin

Country	Project Cluster	Area (ha)
Tanzania	Cluster Kasulu	1,100
Tanzania	Cluster Kibondo	1,470
Tanzania	Cluster Kigoma (rural + urban)	770
Tanzania	Cluster Mpanda	4,222
Burundi	Imbo-Nord	1,300
Burundi	Imbo-Centre	4,050
Burundi	Cluster Moso Rice	160
Burundi	Moso Sugarcane	1,450
Democratic Republic of Congo	Malebo Pool	2,000
Democratic Republic of Congo	Cluster Bumba	3,760
Total		20,282

Niger Basin

Hydropower

The list of infrastructure below (Table A-10 and Table A-11) represent the existing and planned hydropower projects within the Niger River Basin. The main sources of data are based on input from the Niger Basin Authority (NBA/ABN).

Table A-10: Existing hydropower in the Niger River basin

Dam/Scheme	River	Country	Hydropower Capacity (MW)
Selingue	Sankarani	Mali	47.6
Kainji	Niger	Niger	680

Jebba	Niger	Niger	560
Shiroro	Kaduna	Nigeria	600
Dandin Kowa	Gongola	Nigeria	34
Lagdo	Benue	Cameroun	72

Table A-11: Planned hydropower in the Niger River basin

Dam/Scheme	River	Country	Hydropower Capacity (MW)	Year of Completion
Fomi	Niandan	Guinea	90	2020
Taoussa	Niger	Mali	20	2020
Kandadhi	Niger	Niger	125	2020
Diaraguela	Niger	Guinea	72	2020
Zungeru	Kaduna	Nigeria	950	2017
Guarara	Guarara	Nigeria	360	2015
Mambilla	Donga	Nigeria	3050	2018
			4667	

Irrigation

The type and area of crops for each development zone were estimated using detailed country and site-specific data for crop water demands and areas (including projections out to 2025) from Niger Basin Authority (2007).

Table A-12: Existing and planned irrigation in the Niger River basin

Country	Development Zone		Crops	Area (ha) 2015	Area (ha) 2025
Guinea	1	Upper Niger	Off-Season Rice, Wet Season Rice, Banana, Market Gardening	35,015	50,085
Mali	2	Zone of Malian Offices	Off-Season Rice, Wet Season Rice, Sugar Cane, Market Gardening	209,571	369,571

Mali	3	Bani Basin	Off-Season Rice, Wet Season Rice, Market Gardening	46,361	122,381
Mali	4	Inner Delta	Off-Season Rice, Wet Season Rice	38,124	38,124
Niger	5	Taoussa-Nigeria	Off-Season Rice, Wet Season Rice, Mixed Farming, Market Gardening	108,840	220,890
Burkina Faso	6	Right bank tributaries	Off-Season Rice, Wet Season Rice, Market Gardening	7,958	12,472
Nigeria	7	Sokoto-Rima basin	Millet, Sorghum, Mixed Farming	118,307	198,307
Nigeria	8	Lower Middle Niger	Wet Season Rice, Banana, Mixed Farming	79,120	344,120
Nigeria	9	Upper Benue	Off-Season Rice, Wet Season Rice, Banana, Mixed Farming, Market Gardening	44,295	194,587
Nigeria	10	Lower Benue	Banana, Mixed Farming	24,920	160,920
Nigeria	11	Maritime Delta	Mixed Farming	25,500	80,000
Total				738,011	1,791,457

Volta Basin

Hydropower

The list of infrastructure in Table A-13 and Table A-14 below represents the existing and planned hydropower projects within the Volta River basin. These data are inherited from a previous study of climate change impacts on the basin (IWMI, 2012). The data sources are the Ministry of Water esources, Works and Housing, Ghana; the National Investment Brief, 2008, Burkina Faso; and the Pre-water audit for the Volta River basin, West Africa, 2005.

Table A-13: Existing hydropower in the Volta River basin

Dam/Scheme	River	Country	Hydropower Capacity (MW)
Akosombo	Volta	Ghana	1,038
Kpong	Volta	Ghana	148
Bui	Black Volta	Ghana	400
Juale	Oti	Ghana	87

Table A-14: Planned hydropower in the Volta River basin

Dam/Scheme	River	Country	Hydropower Capacity (MW)	Year of Completion
Samendeni	Black Volta	Burkina Faso	2.4	2027
Bonvale	Black Volta	Burkina Faso	0.3	2024
Bontioli	Black Volta	Ghana	5.1	2024
Bon	Black Volta	Burkina Faso	7.8	2024
Noumbiel	Black Volta	Ghana	48	2024
Gongourou	Noumbiel	Burkina Faso	5	2020
Koulbi	Black Volta	Ghana	68	2020
Ntereso	Black Volta	Ghana	64	2020
Lanka	Black Volta	Ghana	95	2020
Jambito	Black Volta	Ghana	55	2020
Daboya	White Volta	Ghana	43	2020
Pwalugu	White Volta	Ghana	50	2020
Kulpawn	White Volta	Ghana	40	2020
Total			483.6	

Irrigation

The main irrigation projects and their irrigated extent used in the WEAP model are identified in McCartney et al. (2012). The cropping patterns and crop water demands within these projects were estimated using data from De Condappa (2013).

Table A-15: Existing and planned irrigation in the Volta River basin

Country	Project Cluster	Crops	2010 Area (ha)	Future Area (ha)
Mali	Lerinord Irrigation	Monsoon Rice, Off-Season Rice, Tomato, Onion	9,646	9,646
Ghana	Tanoso Irrigation	Monsoon Rice, Tomato, Onion	180	180
Ghana	Bagre Irrigation	Monsoon Rice, Off-Season Rice, Tomato, Onion	4,695	4,695
Burkina Faso	Nangodi Irrigation	Monsoon Rice, Tomato, Onion	184	184
Ghana	Tono Irrigation	Monsoon Rice, Tomato, Soja Bean	4,030	4,030
Ghana	Vea Irrigation	Monsoon Rice, Tomato, Soja Bean	1,798	1,798
Burkina Faso	Nwokuy Irrigation	Monsoon Rice, Off-Season Rice, Tomato, Onion	3,291	3,291
Ghana	Subijna Irrigation	Monsoon Rice, Tomato, Onion	170	170
Burkina Faso	Dapola River Irrigation	Maize, Tomato, Onion	1,462	1,462
Ghana	Senchi Irrigation	Monsoon Rice, Tomato, Onion	308	1,638
Ghana/Togo	Sabari Irrigation	Monsoon Rice, Tomato, Onion	1,915	4,515
Ghana	Noumbiel River Irrigation	Monsoon Rice, Tomato, Onion, Cowpea	230	480
Burkina Faso	Samendeni Irrigation Project	Monsoon Rice, Off-Season Rice, Tomato, Onion	0	5,000
Burkina Faso	Noumbiel Irrigation Project	Monsoon Rice, Tomato, Onion, Cowpea	0	7,800
Ghana	Bui Irrigation Project	Monsoon Rice, Tomato, Onion	0	30,000
Burkina Faso	Kanozoe Irrigation Project	Monsoon Rice, Tomato, Onion	0	2,500

Ghana	Pwalugu Irrigation Project	Monsoon Rice, Tomato, Onion	0	100,000
Total			27,909	177,389

Senegal Basin

Hydropower

The list of infrastructure in Table A-16 and Table A-17 below represent the existing and planned hydropower projects within the Senegal River Basin. The main sources of data are based on input from Organization de Mise en Valeur du fleuve Senegal (OMVS).

Table A-16: Existing hydropower in the Senegal River basin

Dam/Scheme	River	Country	Storage Volume (Mm^3)	Hydropower Capacity (MW)
Manantali	Bafing	Mali	11,300	200

Table A-17: Planned hydropower in the Senegal River basin

Dam/Scheme	River	Country	Storage Volume (Mm^3)	Hydropower Capacity (MW)	Year of Completion
Balassa	Bafing	Guinea	N/A	180.9	2025
Koukoutamba	Bafing	Guinea	3,600	280.9	2020
Boureya	Bafing	Guinea	5,500	160.6	2025
Gouina	Senegal	Mali	N/A	140	2014
Felou	Senegal	Mali	N/A	60	2014
Gourbassi	Faleme	Mali	2,100	25	2025
Moussala	Faleme	Mali	3,000	30	2025
Total				877.4	

Irrigation

The type and area of crops for each irrigation zone were estimated using detailed data for crop water demands and areas (including projections out to 2025) from OMVS (2013), as shown in Table A-18 below.

Table A-18: Existing irrigation within the Senegal River basin

Project Cluster	Crops	Area (ha) 2004	Area (ha) 2025
Guinea	Polyculture, corn	326	19,926
PDIAM	Polyculture, rice	710	1,562
Kayes-Bakel (Mali)	Rice, corn, market gardens-onions-tomatoes	10,039	10,948
Kayes-Bakel (Sen-Maur)	Rice, corn, market gardens-onions-tomatoes	249	862
Bakel-Matam	Rice, corn, market gardens-onions-tomatoes	2,064	7,147
Matam-Podor	Rice, corn, market gardens-onions-tomatoes	17,308	59,936
Podor-Dagana	Rice, corn, market gardens-onions-tomatoes	8,149	28,219
Dagana-Richard-Toll	Rice, corn, market gardens-onions-tomatoes	12,822	44,402
Richard-Toll-Diama	Rice, corn, market gardens-onions-tomatoes	22,688	78,498
Aval Diama	Rice, corn, market gardens-onions-tomatoes	1,105	3,827
Total		75,460	255,327

Nile Basin

Hydropower and Reservoirs

Hydropower development in the Nile Basin: current level of hydropower development in the Nile Basin is very low. Access to electricity in the Nile Basin is one of the lowest in the world. According to the World Bank Economic Indicators [World Bank, 2014], the percentage of population with access to (some) electricity in 2011 ranged from 8.5 percent for Uganda to 99.6 percent for Egypt; most upstream countries have access percentage less than about 43 percent. However, as shown in the Comprehensive Basin Wide

Study of Power Development Options and Interconnection Opportunities of the Nile Basin [NBI-RPP-P, 2011] there is considerable untapped hydropower development potential in the countries. Given the rapid population growth in the 11 Nile Basin riparian countries and the trend in their economic growth – many upstream riparian countries registered steady GDP growth the last ten years - the task of meeting the growing energy demands is expected to be one of the highest priorities in these countries. Therefore, the energy sector has received increasingly more and more attention in a number of Nile Basin countries. One indicator on that is the number of studies (master plans, pre-feasibility and feasibility studies, load forecasts, etc) commissioned in the last 15 years at regional (e.g. NBI, East African Power Pool) and individual country levels. At individual country level, to name a few, the Ethiopian Power Systems Expansion Master Plan Study was completed in 2013 [EEPCO, 2013]; the Tanzanian Power Systems Master Plan update was published in May 2013 [Ministry of Energy and Minerals – Tanzania, 2013]; the Ugandan Power System Planning and Economic Assessment [Ministry of Energy and Mineral Development, 2006] was conducted in 2006. In addition, a number of feasibility studies [Ministry of Water Resources Ethiopia, 2010, 2006, 2001, 1997] on specific hydropower projects have been completed with few currently under construction or near completion. At the regional level, the Comprehensive Basin Wide Study (CBWS) on Power development options and interconnection opportunities [NBI-RPP-P, 2011] carried out under the Regional Power Trade project of the Nile Basin Initiative looked into available power development potential (hydro and others), energy and power demand growth, generation and interconnection opportunities. The Eastern Nile Power Trade Investment Program Study [NBI-ENTRO, 2007] was a similar study conducted earlier by the Eastern Nile Technical Regional Office (ENTRO) covering the countries Egypt, Ethiopia and Sudan. All the studies at country as well as regional levels indicate the following:

- A steady increase in energy demand and pick power requirement.
- Considerable power development potential exist (hydropower being major proportion of that in some of the countries) that hasn't yet been developed;
- Huge investment is required to meet the growing energy demand in the Nile Basin countries.

Given the above, one can reasonably expect that developments in the energy sector (expansion of generation capacities, interconnections, and regional power trade arrangements) will make a sizable proportion of the investments in the Nile Basin countries in the coming decades. Some of the more recent examples in this trend include the Ethiopia-Sudan power systems interconnection (USD 35 M, 100 MW capacity), which was inaugurated in 2013; the Bujagali hydroelectric power plant (250 MW, USD 900 M) and associated storage dams in Uganda that were inaugurated in 2012; the construction of the Rusumo Falls Hydroelectric Power plant that is set to begin in 2015 (80 MW, USD 400 M). The construction of the Grand Ethiopian Renaissance Dam (GERD) with its 6000 MW installed capacity has made steady progress in the last 3 years. A number of power transmission interconnection projects currently under NELSAP portfolio with a total investment cost of USD 370 M are at various stages of study.

The list of infrastructure in Table A-19 and Table A-20 below represent the existing and planned hydropower projects within the Nile River Basin. The main sources of data include the Nile Basin Decision Support System (DSS database and DSS pilot application reports [NBI-WRPMP, 2012); the Nile Equatorial Lakes Subsidiary Action Program (NELSAP) Multi-Sector Investment Strategy Action Plan [NBI-

NELSAP,2012]; Ethiopian Power System Expansion Master Plan Study (EEPCO, 2013], the East African Power Pool master plan [EAPP/EAC, 2011] and a number of feasibility and pre-feasibility study reports on hydropower development in Ethiopia [Ministry of Water Resources – Ethiopia, 2010, 2001, 199]; the Ugandan Power Systems Planning and Economic Assessment report [Ministry of Energy and Mineral Development – Uganda, 2006]. Full list of reference is given in section 3.5. A good deal of information on configuration of dams and hydropower plants was taken from the DSS database and DSS application reports. The Ethiopian Power Master Plan and feasibility and prefeasibility reports on specific hydropower plants provided more detailed information. The information gathered from the DSS database and the study reports was augmented through consultations with senior officials from NBI member countries.

Table A-19: Existing hydropower in Nile River basin

Dam/Scheme	River	Country	Capacity (MW)
High Aswan Dam	Nile	Egypt	2100
Esna	Nile	Egypt	85.68
Nagaa Hamadi	Nile	Egypt	64
Amerti Neshe	Nile	Ethiopia	97
Fincha	Fincha	Ethiopia	128
Tana Beles	Blue Nile	Ethiopia	460
Tis Abbay I	Abbay	Ethiopia	85.12
TK5	Tekeze	Ethiopia	300
Gogo Falls	Sare	Kenya	2
Sondo-Miriu Songoro	Sondo-Miriu	Kenya	81.2
Sennar	Blue Nile	Sudan	15, 50
Roseires	Blue Nile	Sudan	415
Khashm El Girba	Atbara	Sudan	17.8
Gabal Awlia	White Nile	Sudan	28.8
Merowe	Nile	Sudan	1250
Kiira	Victoria Nile	Uganda	200
Bujagali	Kyoga Nile	Uganda	250
Nalubaale	Victoria Nile	Uganda	380
Total			2541.6

--- modeled as Run-of-River

Table A-20: Planned hydropower in Nile River basin

Dam/Scheme	River	Country	Capacity (MW)	Year of Completion
Assiut	Nile	Egypt	32	2017
Rumela Burdana	Tekeze	Sudan	30	2016
Lower Didessa	Didessa	Ethiopia	300	2025
Grand Renaissance	Blue Nile	Ethiopia	6000	2017
Karadobe	Blue Nile	Ethiopia	1600	2025
Mandaya	Blue Nile	Ethiopia	2200	2035
Beko Abo	Blue Nile	Ethiopia	1940	2025
Baro 2	Baro	Ethiopia	500	2020
Birbir R	Birbir	Ethiopia	465	2035
Geba A	Geba	Ethiopia	1071	2025
Tams	Baro	Ethiopia	1060	2020
TK7	Tekeze	Ethiopia	321	2025
Magwagwa	Itare	Kenya	120	2017
Bedden	Bahr el Jebel	South Sudan	570	2030
Fula	Bahr el Jebel	South Sudan	890	2030
Lakki	Bahr el Jebel	South Sudan	410	2030
Shukoli	Bahr el Jebel	South Sudan	235	2030
Dagash	Nile	Sudan	320	2025
Kajbar	Nile	Sudan	360	2021
Low Dal	Nile	Sudan	620	2028
Sabloka	Nile	Sudan	120	2028
Shereiq	Nile	Sudan	420	2020
Kakono	Kagera	Tanzania	53	2025
Rusumo Falls	Kagera	Tanzania	84	2017
Ayago	Victoria Nile	Uganda	600	2018

Isimba	Victoria Nile	Uganda	183.2	2018
Karuma	Victoria Nile	Uganda	600	2018
Kiba	Victoria Nile	Uganda	288	2022
Total			21392.2	

Irrigation

Irrigated Agriculture: the Nile Basin countries is dominated by traditional subsistence level rain-fed agriculture in the upstream countries while over 95 % of the land equipped for irrigation lies in Egypt and Sudan. However, there is a gradual upward trend in expansion of irrigated agriculture in the upstream countries largely as a response to the increasing variability in rainfall and resulting failure of crops. The recently completed Investment Strategy Action Plan [NBI-NELSAP, 2012] prepared under the Nile Equatorial Lakes Subsidiary Action Program (NELSAP) targets to develop a total of 510,000 hectares by 2035 while the estimated total potential in the riparian countries covered by NELSAP is about 3.8 million hectares.

Existing and proposed irrigated areas within the basin were also estimated using data from the NB-DSS. These data are presented below in Table A-21 and Table A-22. The main data sources for the current irrigated areas and planned irrigation schemes include the NELSAP Multi-Sector Investment Opportunity Assessment report [NBI-NELSAP, 2012] and GIS layers; the NB DSS database and pilot application reports (NBI-WRPMP, 2012) and the Farming Systems Report from the FAO-Nile project [FAO, 2011]; cropping calendar and related information was obtained from the FAO [FAO, 2012]. Further information was gathered through consultation with national officials from NBI countries. The report from NELSAP and its associated GIS layers were the main data sources on current and planned irrigation areas for the Nile Equatorial Lakes region. Existing and proposed irrigated areas within the basin were also estimated using data the FAO Food for Thought (F4T) report [FAO, 2011].

For the equatorial Lakes region, irrigation schemes are generally small and scattered. Therefore, they were grouped by sub-basin. For Egypt, cropped areas for different crops were provided by governorate (administrative division) and these were grouped as shown in Table A-21 dividing the Lower Nile into major sections between the large barrages along the Nile. Assumptions were made regarding the future expansi (Table A-22) based on available information in the F4T report in addition to the Eastern Nile Irrigation & Drainage Project [NBI-ENTRO, 2009].

Table A-21: Existing irrigation in Nile River basin

Country	Project Cluster	Sub-Basin	Area (ha)

Burundi	Ruvubu Irrigation	Lake Victoria	110
Burundi	Rwagitugusa Irrigation	Lake Victoria	640
DRC	Lake Edward Irrigation	Lake Albert	360
Egypt	Assuit Cairo Irrigation	Main Nile	829,375
Egypt	Aswan Esna Irrigation	Main Nile	249,804
Egypt	El Salam Canal Irrigation Project	Main Nile	52,107
Egypt	Esna Nagaa Hammadi Irrigation	Main Nile	191,870
Egypt	Nagaa Hammadi Assuit Irrigation	Main Nile	235,702
Egypt	Nile Delta Irrigation	Main Nile	3,323,120
Ethiopia	Fincha Irrigation Scheme	Blue Nile	7,600
Ethiopia	Amerti Neshe Irrigation Scheme	Blue Nile	7,000
Ethiopia	Koga Irrigation Scheme	Blue Nile	7,000
Ethiopia	Abobo Irrigation	Baro-Akobo-Sobat	10,400
Kenya	Awach Kibuon Irrigation	Lake Victoria	932
Kenya	Itare Irrigation	Lake Victoria	4,370
Kenya	Migori Irrigation	Lake Victoria	790
Kenya	Nyando Irrigation	Lake Victoria	3,698
Kenya	Nzoia DS Irrigation	Lake Victoria	20,635
Kenya	Nzoia US Irrigation	Lake Victoria	4,393
Kenya	Nzoia US1 Irrigation	Lake Victoria	9,128
Kenya	Sare Irrigation	Lake Victoria	12,831
Kenya	Sio Irrigation	Lake Victoria	6,370
Kenya	Yala Irrigation	Lake Victoria	217
Rwanda	Nyabarongo Irrigation	Lake Victoria	9,787
South Sudan	Aweil Adior Agot rice farm	Bahr el Ghazal	500
Sudan	Gezira Managil Guneid	Blue Nile	467,600
Sudan	Irrigation areas us Sennar dam	Blue Nile	185,800
Sudan	Hasanab Dongola Irrigation	Main Nile	129,850

Sudan	Tamaniat Hasanab Irrigation	Main Nile	65,740
Sudan	New Halfa	Tekeze-Atbara	168,420
Sudan	Assayla Sugar	White Nile	15,000
Sudan	Kenana Sugar 3	White Nile	36,000
Sudan	White Nile Pump Schemes	White Nile	118,300
Tanzania	Isanga Irrigation	Lake Victoria	1,300
Tanzania	LakeVicWetAreaEast Irrigation	Lake Victoria	5,601
Tanzania	LakeVicWetAreaSouth Irrigation	Lake Victoria	5,570
Tanzania	Mamwe Irrigation	Lake Victoria	13,780
Tanzania	Mara Irrigation	Lake Victoria	210
Tanzania	Rubana Irrigation	Lake Victoria	1,700
Tanzania	Rubare Irrigation	Lake Victoria	1,700
Tanzania	Simiyu Irrigation	Lake Victoria	2,900
Uganda	Kagera Irrigation	Lake Victoria	280
Uganda	Lake Kyoga Irrigation	Victoria Nile	2,000
Uganda	Malaba Irrigation	Victoria Nile	1,950
Total Existing			**6,220,270**

Table A-22: Planned irrigation in Nile River basin.

Country	Project Cluster	Sub-Basin	Area (ha)
Ethiopia	Dumbong Irrigation	Baro-Akobo-Sobat	15,000
Ethiopia	Gilo 2 Irrigation	Baro-Akobo-Sobat	47,000
Ethiopia	Itang Irrigation	Baro-Akobo-Sobat	50,900
Egypt	El Salam Canal Irrigation Project	Main Nile	93,942
Egypt	Toshka Irrigation	Main Nile	252,000
Egypt	West Delta Irrigation Project	Main Nile	79,800
South Sudan	Aweil Adior Agot rice farm	Bahr el Ghazal	4,120
South Sudan	Wau Irrigation	Bahr el Ghazal	21

South Sudan	Bor Irrigation	Bahr el Jebel	21
South Sudan	Pagaru Irrigation	Bahr el Jebel	84
South Sudan	Jebel Lado Irrigation	Bahr el Jebel	84
Ethiopia	Combined Angereb Metema L/R Banks	Tekeze-Atbara	28,319
Ethiopia	Humera	Tekeze-Atbara	34,647
Sudan	Upper Atbara	Tekeze-Atbara	122,280
Kenya	Lower Sio	Lake Victoria	5,090
Kenya	Migori	Lake Victoria	790
Tanzania	Mara	Lake Victoria	3,000
Tanzania	Mamwe	Lake Victoria	6,600
Tanzania	Rubare	Lake Victoria	8,000
Tanzania	Simiyu	Lake Victoria	1,500
Tanzania	LakeVicWetAreaSouth Irrigation	Lake Victoria	4,100
Tanzania	LakeVicWetAreaSouth Irrigation	Lake Victoria	13,052
Tanzania	Isanga	Lake Victoria	2,000
Total Planned			**772,350**

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B. Perfect Foresight Adaptation Modeling Methodology

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Analysis of climate change impacts and adaptation at the planning stage

The economic analysis of impacts and adaptation is based on overall objective function to maximize hydropower production subject to the constraint of allocating sufficient water to meet human needs, environmental quality and –through irrigated crop production- food security targets. The maximization of hydropower production is operationalized as maximizing net revenues from hydropower. This is essentially the same as ensuring that hydropower remains a viable investment in these countries. At the same time, implications for consumers are assessed through estimation of the impacts on the price of electricity, as the cost of producing hydropower increases or decreases in drier or wetter climates, thereby affecting the overall price of electricity. For each river basin and power pool the study evaluates the cost of climate change impacts and the merits of adaptation using the framework summarized in Figure B-1 , which illustrates the approach. The starting point is the reference case A, in which the PIDA+ investment plan is carried out, with a certain cost, and with benefits proxied by the levelized cost of energy and the value of irrigated crops. If climate change occurs, but no adaptation takes place, case B materializes: no adaptation is undertaken, PIDA+ is implemented as planned, and regrets can occur: in the form of lost hydropower production, higher levelized cost, and lower irrigated crop production, in dry scenarios compared to the reference case, and foregone opportunities for higher power production, lower levelized cost, and higher irrigated crop production in wet scenarios.

Figure B-1: Framework for evaluating the impacts of climate change in the energy sector

Case ID	Case Description	Investment Strategy	Assumptions on climate	Adaptation Strategy	Cost of climate change impacts
A	Reference case	PIDA +	Historical climate (no climate change)	None	Zero
B	Climate change, no adaptation	PIDA +	Full range of climate futures	None	For each climate future: reduction or increase in hydropower performance + reduction or increase in irrigated agriculture performance
C	Climate change, "perfect foresight" adaptation	PIDA + with perfect foresight (varies across scenarios)	Full range of climate futures	Adjust PIDA + in order to maximize (for each climate future) net present value of adaptations	Zero
D	Climate change, robust adaptation	PIDA + with robust adaptation (does not vary across scenarios)	Full range of climate futures	Adjust PIDA + to manage regrets across climate futures	For each climate future: reduction or increase in hydropower performance + reduction or increase in irrigated agriculture performance

Case C is a counterfactual introduced to gauge the cost of inaction and the benefits of adaptation action. It is a “perfect foresight” situation in which the PIDA+ is optimized to achieve the best possible performance of the energy system (minimum levelized energy cost, LEC) in each climate future. It corresponds to a hypothetical situation in which investment planners know in advance which climate will unfold, and decide accordingly ex-ante how PIDA+ should be adjusted (for example, installing more hydro in wet scenarios, or less in drier ones).

The final step is the definition of a "robust" adaptation strategy (case D), which requires establishing Case C as a prerequisite. In case D, taking into consideration the full range of possible futures (including climate outcomes and other variables), a modification of the reference investment strategy is adopted. This cannot be the "optimal" plan identified in case C since the future is unknown and there is no way to associate probabilities to individual scenarios. Instead, the adaptation strategy is one that yields acceptable outcomes in as many climate futures as possible. By comparing case D (robust adaptation) with cases B and C, the study gives indications on the potential for reducing regrets (i.e. the benefits of adaptation) and on the costs of doing so.

For some components of the Track 1 analysis, in particular, to estimate perfect foresight adaptations for Case C, we need to focus on a small number of representative climate futures. This small set of futures should provide a good sample of the range of consequences implied by the full range of the 121 climate futures used in the Case B vulnerability analysis. Given the computational and analyst time involved with each perfect foresight calculation, we can conduct approximately six such calculations for each of our seven river basins. The process for identifying an appropriate representative set of six, from among the 121 alternative climate futures in our ensemble, is described in Appendix 2. In summary, the process involves using an indicator, the Climate Moisture Index (CMI), which combines precipitation and temperature and is reasonably well correlated with the hydropower and irrigation impacts expected from each climate projection, to find a set of consistently wet and dry climate futures across the seven basins under analysis.

Estimating Costs and Benefits

The analysis estimates the economic impacts of climate change for Case B and the net benefits of adaptation for Case C and D. For Case B, we estimate impacts as the differences in future basin-wide irrigation and hydropower present value revenues for each of the 121 climate futures from the Case A (reference) scenario revenues. Present value revenues in both the Cases A and B cases assume the PIDA+ infrastructure plan is followed with no modifications between 2010 and 2050. As a result, the physical impacts in the B scenarios are composed of changes in hydropower production and crop yields under each of the climate change (or alternative baseline) scenarios. For each of the climate futures evaluated under Case C, we estimate the net benefits of adaptation as the difference between total present value revenues with and without perfect foresight (i.e., with and without modifications from PIDA+), less (plus) any present value infrastructure costs (savings) of adaptation. So these calculations involve four components: hydropower and irrigation revenues, and reservoir and irrigation infrastructure adaptation costs. The first two components apply to all three cases, and the last two apply to C only, as only case C alters the baseline PIDA+ reservoir and irrigation infrastructure costs.

Hydropower revenue is total annual hydropower generation from WEAP multiplied by annual hydropower producer prices. Annual producer hydropower prices are assumed to be the levelized costs of electricity

(from OSeMOSYS) multiplied by 1.25, where the 1.25 multiplier reflects the fact that producers' revenues are expected to exceed levelized costs by approximately a 25% margin (this figure is based on project team analysis of a set of available pre-feasibility studies). Irrigation revenues are crop revenues per hectare for each crop multiplied by the number of hectares of each crop across the basin. Crop revenues are annual yields multiplied by the annual consumer crop prices.
Consumer crop prices are taken from the International Food Policy Research Institute (IFPRI), which provides crop- and country-specific forecasts of crop prices through 2050. Maximum crop yields are from FAO, and are assumed to rise by 1% each year due to technological advancements. Actual crop yields are the sum of dryland yields i.e., the component of total yield that would occur regardless of irrigation) and yields specifically attributable to irrigation water application. Dryland crop yields are the maximum yield adjusted based on (1) the ratio of effective precipitation to total consumptive crop water demand, and (2) the crop-water response factor (from FAO). Effective precipitation is depth of precipitation that is available for consumptive crop use, and is calculated using procedures outlined by IFPRI. The component of total actual yields attributable to irrigation are based on the ratio of total irrigation water deliveries to total irrigation water demand, adjusted based on irrigation efficiency and deficit irrigation (in the C cases). For both hydropower and irrigation, annual revenues are then discounted to generate present value benefits under the A, B, and C cases.

As discussed in greater depth below, the perfect foresight modeling for case C allows several changes in reservoir and irrigation infrastructure: (1) hydropower turbine capacity, (2) reservoir storage capacity, (3) total planned irrigated area, and (4) field and conveyance irrigation efficiency. Costs or savings (both capital and O&M) of changes in hydropower turbine capacity and reservoir storage capacity are estimated by first disaggregating total planned hydropower facility costs (from a variety of sources) into hydro-electric and reservoir components, and then applying simplified exponential functional forms from the literature that relate changes in storage and turbine capacity to changes in total costs. In the case of planned run-of-river facilities, adaptation costs (but not investment costs) are assumed to be part of the hydro-electric infrastructure. The savings of reductions in irrigated area (consistent with the objective function described above, the C case assumes that planned irrigated area cannot increase from PIDA+, as once food security is established water is allocated to hydropower), are simply the total change in hectares multiplied by the average capital and O&M costs of a new irrigated hectare. Capital costs are the average per hectare expenditures on successful irrigation projects in sub-Saharan Africa from the International Water Management Institute (IWMI). Irrigation efficiency costs are divided into on-farm technology improvements and conveyance, where on-farm improvements are based on IWMI estimates of sub-Saharan Africa per-hectare irrigation costs, and conveyance costs are based on the cost of two levels of canal improvements (lining earthen canals and replacement with concrete canals) from FAO and the Irrigation Training and Research Center (ITRC).

A discount rate of 3% is used for the reference case, with sensitivity analyses at 1% and 5%. The central rate recommendation is consistent with recent thinking on climate change analyses. There are essentially two distinct concepts for discount rates: a social-welfare-equivalent discount rate appropriate for determining whether a given policy would augment social welfare (according to a postulated social welfare function); and a finance-equivalent discount rate suitable for determining whether the policy would offer a potential Pareto improvement. Different rates can be used in these two situations – with the latter usually being higher, as suggested by the discussion in the previous section.

For this study, the use of a higher finance-equivalent rate might be justified. The cost of private capital in Africa is typically quite high, though perhaps as a result of an inefficient finance sector and a high overall growth rate. A high cost of capital can be justified by a high productivity of capital – but it is not clear that those conditions apply broadly in Africa or, particularly, in the case of the large, and largely public, infrastructure projects being considered in this study. Further, lower rates are typically justified when evaluating options over longer time frames, as is being done in this study. The 3% rate chosen for this study rests in part on these types of arguments. The use of 5% and 1% alternatives brackets reasonable rates for longer term financial and social-welfare equivalent rates over our time period.

Methods

The perfect foresight Case C approach is a data and computationally intensive step in the overall methodology. As a result, it is performed on a limited set of six wet and dry scenarios, selected by the study team to span the range of relevant climate outcomes within study basins and across Sub-Saharan Africa, as outlined above.

The perfect foresight analysis is then performed on these scenarios to prescribe the OPTIMAL Water and Power Infrastructure Plan designed with PERFECT FORESIGHT of the future climate and the level of any other non-climate uncertain parameters. The essential objective of the approach is to maximize the difference of present value (PV) of benefits less PV of marginal costs to either expand or contract infrastructure plans. The change in infrastructure plans is measured relative to the reference PIDA investment plan. This maximization problem has a significant set of constraints on the options for adaptation. These options are also different for wet and dry climate projections, as outlined below.

The Goal of Perfect Foresight Adaptation

The objective in the perfect foresight analysis is to generate a modified Water and Power Infrastructure investment plan that takes into account information on future climate, assumed to be known in advance, and can thus provide for increased net PV, compared to a system designed for the historic climate and forced to perform under a different climate.

The increase in net PV in a wet climate future would be where increased benefits of utilizing the extra water met or exceeded the increased costs of additional infrastructure capacity needed to utilize the extra water. The increase in net NPV in a dry climate future could take two forms:

1) The avoided costs of reducing infrastructure capacity not needed due to reduced water, or

2) When the value of benefits restored via adaptation met or exceeded the corresponding costs.

This approach is based on the premise that the net benefits of adaptation must be positive

Objectives and Prioritization of PIDA+ Systems

The overall objective function used in this analysis is the maximization of the net value hydro-power production: an energy resource abundant in much of Sub-Saharan Africa and yet largely untapped. To reflect the political importance of competing uses of water, this objective is assumed to be subject to the constraint of allocating water to human needs, environmental flows, municipal use, industrial demands, and irrigation, ranked in the priority defined in Table B.2, which is consistent with the recent stakeholder driven “Multi-Sector Investment Opportunities Analysis” of the Zambezi Basin.[1]

Table B-1: Water Allocation Priorities

Priority	Sector	Metric
1	Basic Human Water Needs	Volume/person
2	Environmental Reserve Flows	Volume/time
3	Municipal Demands	Volume/time
4	Industrial Demands	Volume
5	Irrigation/Food Security	Crop Production
6	Hydropower	Energy Production

The water use sectors in Table B-1 can be classified into three groups:

1) *Core Sectors*: Human Needs, Environmental Flows, Municipal & Industrial
2) *Irrigation Sector*
3) *Hydropower Sector*

The operationalization of how adaptation takes place in each basin using this priority scheme is different for the three different classes of climate change impacts listed above (core sectors, irrigation, and hydropower). The overall guiding principal of this analysis is to meet the core sectors requirements, including their increase over time due to population and economic growth, followed by irrigation and then hydropower.

[1] In strictly economic terms, the trade-off does not seem to favor intensive irrigation development, despite the employment opportunities and the food security that such development might provide…their development benefits in economic terms are offset by the value lost in hydropower generation. …The development of irrigation in this analysis has another important aspect: direct employment. Building and operating irrigation systems demands a lot of labor and thus creates job opportunities…Hydropower generation also produces direct jobs, of course, but except in the relatively short construction period, employment opportunities are limited to those with necessary skills. (WB, 2010).

Adaptation Framework

In the following sections the framework used to develop basin-wide Infrastructure Adaptation Plans under Perfect Foresight of Future Climate Changes is described from a broad descriptive perspective to the detailed equations of the operations research tools employed.

Adaptation is focused on the planned infrastructure of PIDA+ and not on the autonomous adaptations that farmers and power systems managers will make to decadal climate variability. As such the adaptation plans do not include changes to existing irrigation areas but allow for changes in irrigation efficiency and crops on existing irrigated areas to allow for national scale agricultural production adaptation that includes constrained imports as one option.

We do allow for expansion of turbine capacity at existing hydropower facilities as power plant expansions are actual PIDA projects being analyzed – we also allow for increases and decrease of turbine capacity at PIDA+ planned projects - but we do not allow for changes in the size of existing reservoirs or increases in the maximize size of planned reservoirs based on engineering constraints. We do allow for reduction in size of planned storage projects. The logic of this suite of constraints is that, at the building stage of hydropower projects, turbine capacity can be adjusted, and dam height (which is a key determinant of storage capacity) can be lowered, but we make the reasonable assumption that dam height either cannot be increased owing to site geologic characteristics, or that increasing it would be prohibitively (involving, for example, a series of supplemental saddle dams).

Adaptation goals are different under wet and dry scenarios. Under dry scenarios the goal is to recover as much of the lost benefits from climate change as possible without spending more than the amount of the recovered benefits. Under wet scenarios it is to take advantage of the increase of water resources to the level the marginal benefits equal the marginal costs of additional infrastructure.

Adaptation under a dry scenario

Under the dry scenario the combination of changes in irrigation demands and runoff result in the basin-wide performance of the PIDA+ systems being significantly lower than the performance under the reference historical climate conditions.

Irrigation Adaptation

Implement the following steps until crop production has achieved reference level established through modeled irrigated crop production under historical climate with full implementation of PIDA+ infrastructure investments.

1. Deficit Irrigate: Reduce water application RATE on all cropped areas to the economically optimal level
2. Change Crops within constraints
3. Improve the efficiency of the on-farm irrigation systems to require less water withdrawals to supply crop water requirement as long as NPV of B-C is positive.
4. Import crops within constraints, if cheaper than other options.
5. IF NPV for previous is negative and reliability is still unacceptable: Reduce planned irrigated area until an economically acceptable level of reliability is achieved; the gap in irrigated crop production is assumed to be filled via imports.

Hydropower Adaptation

Holding constant all the adaptation made to the irrigation sector:

1. Increase irrigation conveyance efficiency to reduce water needed to be delivered farm level irrigation systems to the point that marginal economics benefits of increase hydropower equals the marginal costs of reducing conveyance losses (lining, pipes)
2. Make changes to turbine capacity, up or down to the new economically optimal level
3. Make changes to storage level (constant or decreased) to the new economically optimal level

Adaptation under a wet scenario

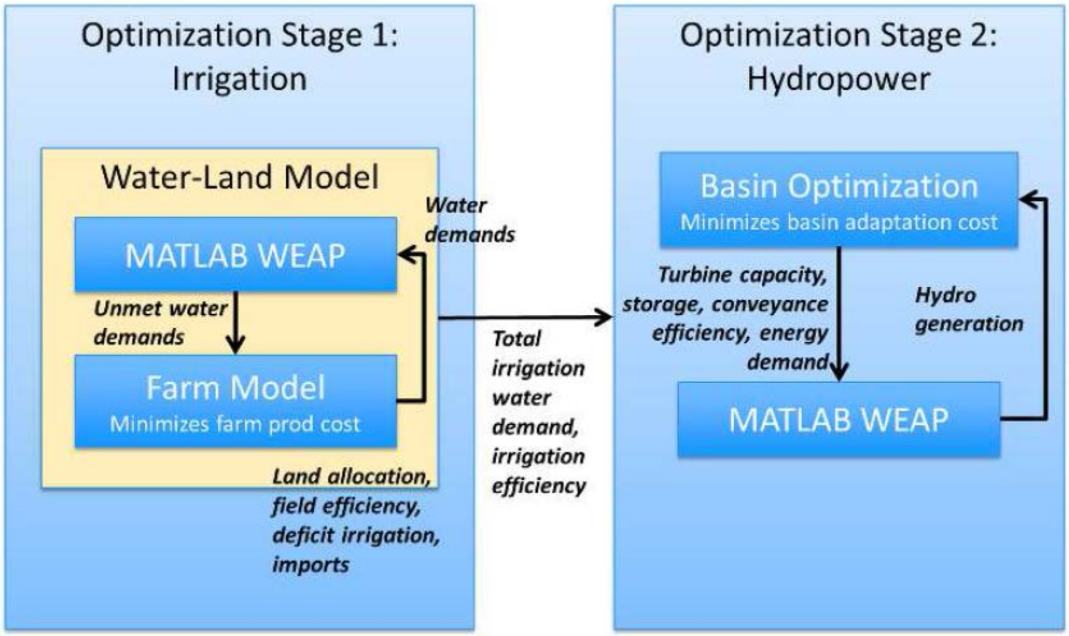
Under wet scenarios all PIDA+ targets are being met, why does one need to adapt? The adaptation is to take advantage of the opportunity that excess water would provide if you knew with perfect foresight that a wet scenario was the climate of the future.

Since under a wet scenario the basic human needs, environmental sustainability, municipal and industrial requirements, and "new climate" irrigation requirements are met, we do not provide additional water to these sectors. Excess water is allocated only hydropower. The priority among these two reflects assessments for the Zambezi basin study (WB, 2010) which found that "*Even if irrigation schemes may be profitable in themselves, their development benefits in economic terms are offset by the value lost in hydropower generation*."

Description of Perfect Foresight Optimization Tools

Figure B-2 is a schematic of the two stage optimization methodology which is implementing the framework presented in the section above.

Figure B-2: Two Stage Optimization Scheme



Figures B.3 and B.4 below are description of the Mathematical Programming Problems (MPP) formulation of the optimization approach using equations in canonical operations research form to describe the modeling approach for the Stage 1 irrigation optimization (Figure B.3) and the Stage 2 hydropower optimization (Figure B.4). Appendix 3 provides detailed descriptions of Farm LP mathematical structure including objective function, constraints, and decision variables.

Figure B-3: Stage 1 Optimization for Irrigation Sector

$$\text{Minimize} \sum_{n=1}^{N}\sum_{c=1}^{C}\sum_{t=1}^{T}\left(\sum_{v=1}^{V} M^{Imp}_{nctv} P^{Imp}_{nctv}\, Prod^{Total}_{nct}\right) \quad \Big\} \text{ Import costs}$$

$$+\sum_{a=1}^{A}\sum_{c=1}^{C}\sum_{t=1}^{T}\left[\left(\sum_{k=1}^{K} b^{K}_{bk} M^{IrrP}_{ac} P^{Irr}_{tk}\, Area^{Plan}_{act}\right)+\left(\sum_{k=1}^{K} b^{K}_{bk} M^{IrrC}_{ac}\left(P^{Irr}_{tk}-P^{Irr}_{tk0}\right) Area^{Curr}_{act}\right)\right] \quad \Big\} \text{ Irrigation and field efficiency costs}$$

$$-\sum_{a=1}^{A}\sum_{c=1}^{C}\sum_{t=1}^{T} P^{C}_{act} Y_{act}\, Area_{act} \quad \Big\} \text{ Irrigation revenues}$$

SUBJECT TO:

CONSTRAINTS:

$$\sum_{c=1}^{C} qIWR_{act} \leq Wdeliver_{at}$$

APPLICATION<=DELIVERIES

$$\sum_{c=1}^{C} IWR_{act} \leq WsupplyReq_{at}$$

NO NEW ADDITIONAL SUPPLY REQ

$$\sum_{v=1}^{V} M^{Imp}_{nctv}\, Prod^{Total}_{nct} + \sum_{a=1}^{A_n} Y_{act} Area_{act} \geq Prod^{Total}_{nct} \quad \forall n$$

COUNTRY PRODUCTION MUST BE MAINTAINED

$$\sum_{c=1}^{C} M^{IrrC}_{ac}\, Area^{Curr}_{ac} = \sum_{c=1}^{C} Area^{Curr}_{ac}$$

EXISTING IRRIGATED HECTARES CONSTANT

$$\sum_{c=1}^{C} M^{IrrC}_{ac}\, Area^{Plan}_{act} \leq \sum_{c=1}^{C} Area^{Plan}_{act}$$

PLANNED IRRIGATED HECTARES MUST NOT INCREASE

Figure B-4: Stage 2 Optimization for Hydropower Sector with Stage 1 Irrigation Constraint

$$\text{Minimize} \sum_{f=1}^{F}\sum_{t=1}^{T} \overbrace{f\left(Cost^{H}_{ft}, Cap^{Plan}_{f}\left(1-M^{H}_{f}\right)\right)}^{\text{Capacity cost function}} - \sum_{f=1}^{F}\sum_{t=1}^{T} \overbrace{P^{P}_{ft}\, Hgen_{ft}}^{\text{Hydro revenues}}$$

$$+\sum_{f=1}^{F}\sum_{t=1}^{T} \underbrace{f\left(Cost^{S}_{ft}, Store^{Plan}_{f}\left(1-M^{S}_{f}\right)\right)}_{\text{Storage cost function}} + \sum_{b=1}^{B} \underbrace{P^{IE}_{b}\, \Delta Area_{b}}_{\text{Conveyance efficiency}}$$

SUBJECT TO:

$$LB_{H} \leq M^{H}_{f} \leq UB_{H}$$

$$LB_{S} \leq M^{S}_{f} \leq UB_{S}$$

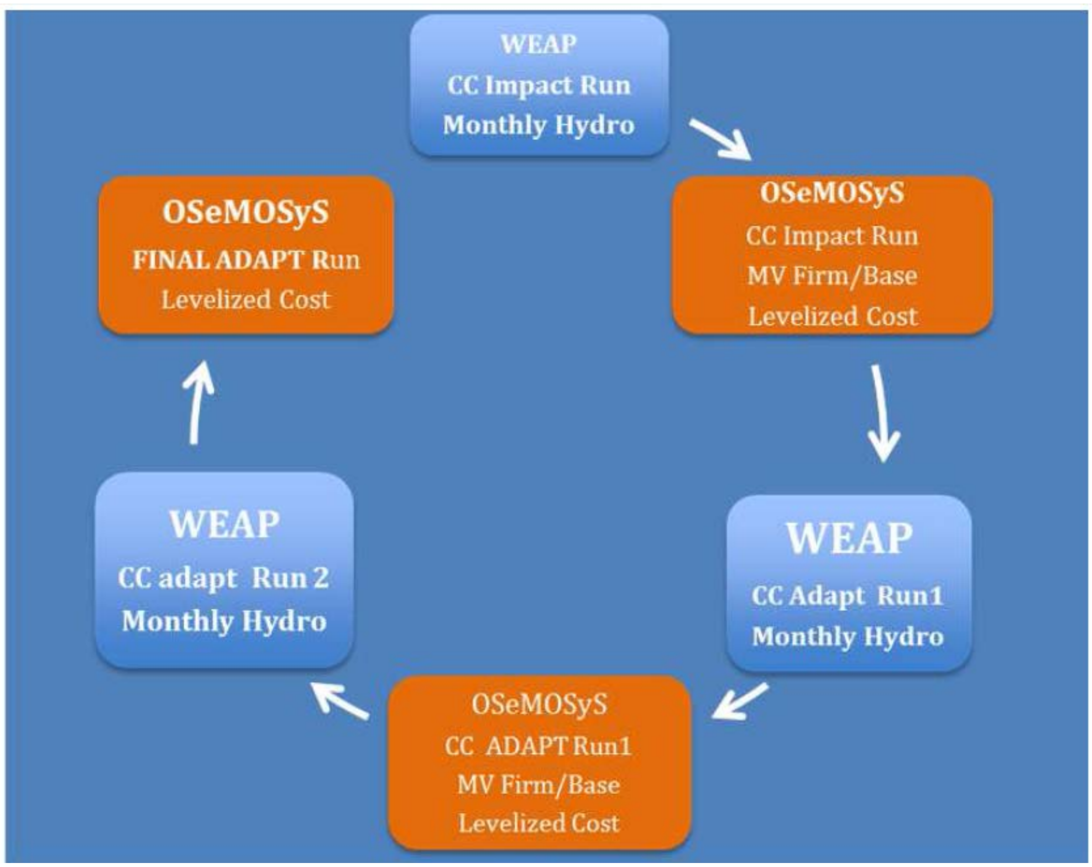
Basin Level Adaptation in the Context of Regional Power Pool Adaption

Hydropower production is part of a both a national multi-fuel electric grid and a regional power pool grid. The impact of climate change on the magnitude and timing of hydropower generated may change the optimal fuel type capacity and generation mix nationally and /or at the power pool level. This changes the

levelized cost and thus the opportunity costs of lost hydropower or economic benefits of production of addition hydropower in the basin, leading to changes in the marginal benefits of firm versus base energy coming from hydropower. This change in desired hydro supply is exogenous to the
River Basin Water Model (WEAP). Stage two of the optimization approach analyzes the economics of the hydro generation expansion or contraction without impacting irrigation or core water use sector performance.

This interaction requires some level of feedback between the WEAP generated hydropower and the energy model OSeMOSYS when designing the optimal energy adaptation plan. A two cycle WEAP-OSeMOSYS feedback was chosen based on the tradeoff of computer time and closeness to true equilibrium. Figure B.5 is a schematic of the WEAP-OSeMOSYS system.

Figure B-5: Two-Cycle Interaction between WEAP and OSeMOSyS



Energy Adaptation under wet and dry scenarios

There is no difference in the adaptation process for the energy sector between a Wet and Dry climate future. The scheme involves implementing the following steps until the minimum levelized cost of electricity is found:

1. Receive WEAP generated Monthly Hydro Energy from Adaptation Run 1
2. Run OSeMOSYS and send to WEAP Desired Firm/Base Production Targets
3. Run WEAP for Adaptation Run 2
4. Receive WEAP generated Monthly Hydro Energy from Adaptation Run 2
5. Run OSeMOSYS and send to WEAP Desired Firm/Base Production Targets
6. Report adapted Levelized Cost of Electricity by country and power pool

Farm LP Model Formulation

Objective Function

Minimize the sum of (1) import costs, (2) planned irrigation costs (including IE costs), (3) irrigation efficiency costs on existing hectares, (4) negative irrigation revenues, and (5) negative deficit irrigation benefits.

$$\boldsymbol{Minimize} \sum_{n=1}^{N}\sum_{c=1}^{C}\sum_{t=1}^{T}\left(\sum_{v=1}^{V} M_{nctv}^{Imp} P_{nctv}^{Imp}\, Prod_{nct}^{Total}\right)$$
$$+\sum_{a=1}^{A}\sum_{c=1}^{C}\sum_{t=1}^{T}\left[\left(\sum_{k=1}^{K} b_{bk}^{K} M_{ac}^{IrrP} P_{tk}^{Irr}\, Area_{act}^{Plan}\right)\right.$$
$$\left.+\left(\sum_{k=1}^{K} b_{bk}^{K} M_{ac}^{IrrC}(P_{tk}^{Irr} - P_{tk0}^{Irr}) Area_{act}^{Curr}\right)\right]$$
$$-\sum_{a=1}^{A}\sum_{c=1}^{C}\sum_{t=1}^{T}\left[P_{act}^{C} Y_{act} Area_{act} + P^{H} a_{act} IWR_{act}\right]$$

Where:

Indices: n = nation; a = irr area; c = crop; t = year; v = import penalty

P_{nctv}^{Imp} import prices – same as Pc for 1st 25%, then 4x Pc for next 25%, and 100x for last 50%

M_{nctv}^{Imp} fraction of production from imports in v pen. bins, M1 and M2 from 0-0.25, and M3 from 0-0.5.

$$Prod_{nct}^{Total} = \sum_{a}^{A_n} Y_{act}^{M}\left(Area_{act}^{Curr} + Area_{act}^{Plan}\right) \ \ \forall n$$

Y_{act}^{M} is the maximum yield

$Area_{act}^{Plan}$ planned irrigated areas in PIDA+.

$\boldsymbol{Area_{act}^{Curr}}$ existing irrigated areas and existing crop distribution, where the variable is repeated across the time dimension.

$\boldsymbol{Area_{act} = M_{ac}^{IrrC} Area_{act}^{Curr} + M_{ac}^{IrrP} Area_{act}^{Plan}}$

$\boldsymbol{P_{act}^{C}}$ consumer crop price, $\boldsymbol{P_{tk}^{I}}$ is per ha irrigation inf price per technology k

$\boldsymbol{M_{ac}^{IrrP}}$, adjustments to planned irrigated hectares are +/-50%. Can go down overall

$\boldsymbol{b_{bk}^{K}}$**,** binary variables on field-level IE technologies, which must sum to 1 within each basin.

$\boldsymbol{P_{tk}^{Irr}}$**,** Price of irr hectare of one of 3 irr technologies, where $\boldsymbol{P_{tk0}^{Irr}}$ is existing tech cost

$\boldsymbol{M_{ac}^{IrrC}}$, adjustments to crop distribution on current hectares, +/-50%. See constraints below

$$\boldsymbol{Y_{act} = \left\{ Y_{act}^{D} + \left(Y_{act}^{M} - Y_{act}^{D}\right)[1-(1-q)]^{\frac{1}{IE_b}} \right\};\ q = I_{at}^{R} \frac{IE_b}{IE_0}; q \le D_{ac}}$$

$$\boldsymbol{Y_{act}^{D} = Y_{act}^{M} \left[1 - Ky_c \left(1 - \frac{Pe_{act}}{ETc_{act}}\right)\right];\ Y_{act}^{D} \ge 0}$$

$\boldsymbol{I_{at}^{R}}$ is the irrigation coverage from WEAP

$\boldsymbol{IE_b}$ is the chosen irrigation efficiency (0.6, 0.7, or 0.8)

$\boldsymbol{IE_0}$ is the initial irrigation efficiency

$\boldsymbol{D_{ac}}$, deficit irrigation multiplier must be between 0 and 1

$\boldsymbol{P^{H}}$ is the value of water saved through deficit irrigation (proxy value for non-ag uses). Currently set to zero for SAPP countries.

$$\boldsymbol{IWR_{act} = \frac{[ETc_{act} - Pe_{act}]}{IE_b} Area_{act}}$$

$\boldsymbol{ETc_{act}}$ total consumptive crop water demand

$\boldsymbol{Pe_{act}}$ is effective precip

$\boldsymbol{a_{act} = I_{at}^{R} - D_{ac}; a_{act} \ge 0}$

CONSTRAINTS

Constraint 1: *total actual water application in each abstraction must be <= water delivered (from WEAP)*

$$\boldsymbol{\sum_{c=1}^{C} qIWR_{act} \le Wdeliver_{at}}$$

$$\boldsymbol{q = I_{at}^{R} \frac{IE_b}{IE_0}; q \le D_{ac}}$$

Constraint 2: *total new supply requirement in each abstraction must be <= initial supply requirement*

$$\boldsymbol{\sum_{c=1}^{C} IWR_{act} \le WsupplyReq_{at}}$$

Where:

$$\boldsymbol{WsupplyReq_{at} = \sum_{c=1}^{C} \frac{[ETc_{act} - Pe_{act}]}{IE_0} \left(Area_{act}^{Curr} + Area_{act}^{Plan}\right)}$$

Constraint 3*: sum of country production of each crop must be maintained (i.e., imports + irrig production >= total production)*

$$\sum_{v=1}^{V} \boldsymbol{M_{nctv}^{Imp} Prod_{nct}^{Total}} + \sum_{a=1}^{A_n} \boldsymbol{Y_{act} Area_{act}} \geq \boldsymbol{Prod_{nct}^{Total}} \ \forall \boldsymbol{n}$$

Constraint 4: *Number of existing irrigated hectares in each irrigation area must remain constant*

$$\sum_{c=1}^{C} \boldsymbol{M_{ac}^{IrrC} Area_{ac}^{Curr}} = \sum_{c=1}^{C} \boldsymbol{Area_{ac}^{Curr}}$$

Constraint 5: *Number of new irrigated hectares in each irrigation area must be less than originally planned*

$$\sum_{c=1}^{C} \boldsymbol{M_{ac}^{IrrC} Area_{act}^{Plan}} \leq \sum_{c=1}^{C} \boldsymbol{Area_{act}^{Plan}}$$

Integration of OSeMOSYS with WEAP modeling

As is also detailed in the OSeMOSYS section, the information flow between the water and the energy modeling is managed using the hydro power plants in the two corresponding frameworks. This was potentially challenging for at least two reasons.
First, OSeMOSYS is an optimization model that considers the best combination of technology and corresponding power dispatch to meet demand at a minimal cost to the system. WEAP is not a dynamic model, it is a very versatile water accounting tool in which the infrastructure is an input from the analyst rather than an output. Second, OSeMOSYS is an abstraction of the geographical reality of the system being represented whereas WEAP is a geo referenced path dependent tool.

As a result, the two frameworks were integrated using a specific multi-stage data exchange protocol through an intermediary, Matlab based, tailored, two tier optimization tool described in this note, with further details in Appendix 3.

Due mainly to the presence of numerous and complex interrelated water requirements, WEAP was selected as the reference for hydro power availability on each potential site in each basin. This means that the accounting framework offers final system results detailing the monthly power availability at each hydro power station as well as the adjusted capacity level that this power station should have if it is still considered both technically and economically viable to modify it.

First, the generation data is translated to energy system constraints in terms of capacity factors:

$\forall\ i,j \in \{technologies\} \times \{time\ slices\} \quad C_f^{i,j} = \frac{E_i}{C_i * \Delta t_j}$ eq.1

E_i Energy generated by the power plant during

Δt_j The corresponding duration (each month of each year) by the

C_i Corresponding power plant capacity

These capacity factors are calculated for each hydro power plant, for each time-slice in each different climate future and therefore convey the relative dry/wet character of the future under consideration.
Since each energy-generation value received from RAND is calculated on a monthly basis, eq.1 is calculated on a monthly basis and the resulting capacity factor is applied to the four time-slices corresponding to that month in the OSeMOSYS modeling framework.

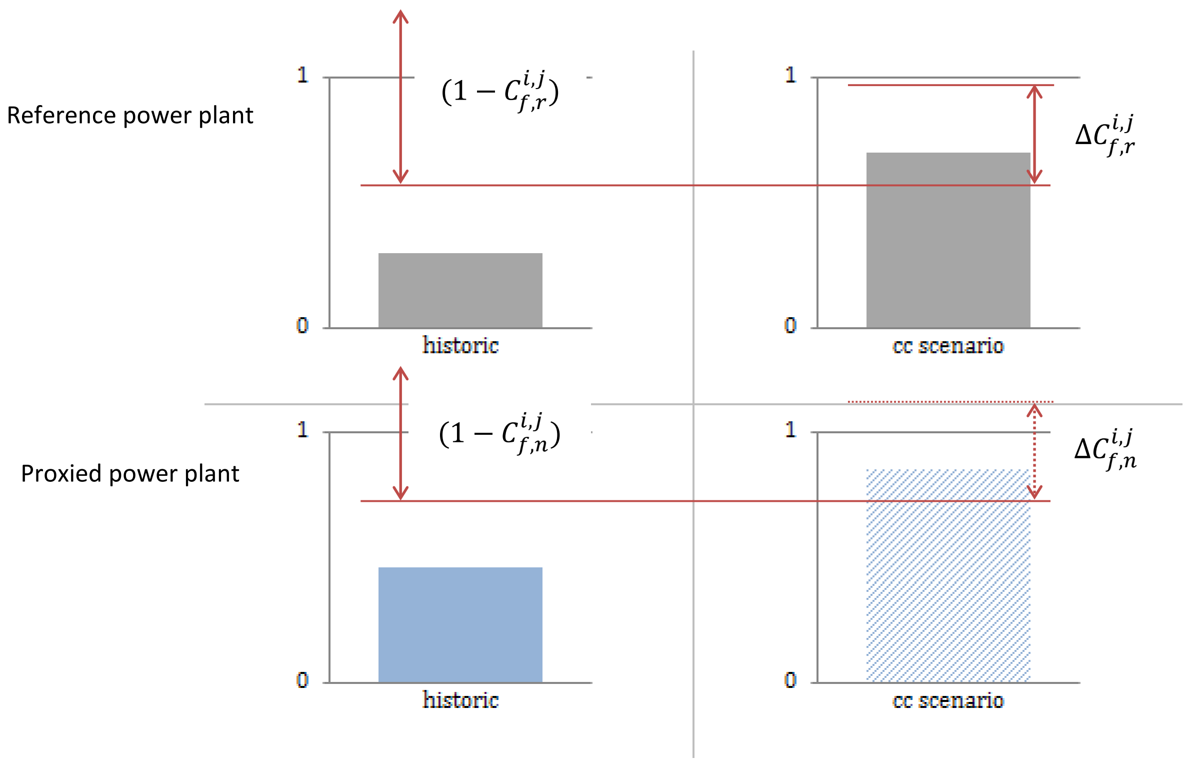
In order to ensure consistent power pool results between the hydro power plants, a proxy system was set up to represent the power plants that were included in the energy modeling but outside of the scope of the basins under consideration. Each of these "energy only" (EO) projects – initially operating under a generic capacity factor – was linked to the closest WEAP represented power plant ensuring that the variation in capacity factor across the power pools are consistent in each climate future:

$$\forall\ i,j \in \{EO\ technologies\} \times \{time\ slices\}\ \exists\ r \in \{WEAP\ technologies\} \quad C_{f,n}^{i,j} = \alpha_{i,j}^{r} * \beta_{i,j}^{r}$$

$$\alpha_{i,j}^{r} = \frac{capacity\ factor\ change}{potential\ change} = \begin{cases} \dfrac{\Delta C_{f,r}^{i,j}}{C_{f,r}^{i,j}};\ \Delta C_{f,r}^{i,j} \leq 0 \\ \dfrac{\Delta C_{f,r}^{i,j}}{1 - C_{f,r}^{i,j}};\ \Delta C_{f,r}^{i,j} \geq 0 \end{cases}$$

$$\beta_{i,j}^{r} = \begin{cases} C_{f,n}^{i,j};\ \Delta C_{f,r}^{i,j} \leq 0 \\ (1 - C_{f,n}^{i,j});\ \Delta C_{f,r}^{i,j} \geq 0 \end{cases}$$

Figure B-6: Hydro proxy capacity factor calculation scheme



Second, the capacity modification is taken into account in the new model run setup. Included in the water sector optimization results as multipliers on the currently planned capacity level, this information is taken into account on each data hand off iteration and for each individual climate future. The capacity values used to calculate the capacity factors for the corresponding climate futures are adjusted accordingly. In parallel, the multipliers are included into the new model runs through the binding constraints used to set up each independent run: the minimal and maximal constraints on capacity addition for each hydro power technology are adjusted to ensure that the correct capacity level is invested in.

C. WEAP River Basin Modeling

C1-WEAP General Modelling Approach

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The Water Evaluation and Planning (WEAP) tool is an integrated water resources planning tool that is used to represent current water conditions in a given area and to explore a wide range of demand and supply options for balancing environment and development objectives. WEAP is widely used to support collaborative water resources planning by providing a common analytical and data management framework to engage stakeholders and decision-makers in an open planning process. Within this setting, WEAP is used to develop and assess a variety of scenarios representing possible basin futures to explore the impacts of physical changes to the system, such as new reservoirs or pipelines, as well as social changes, such as policies affecting population growth or the patterns of water use. Finally the implications of these various policies can be evaluated with WEAP's graphical display of results.

Steps in Developing a WEAP Model

The development of each WEAP application in this study followed a common approach (see Figure C-1: Steps in developing a WEAP modelFigure C-1). The first step in this approach is the study definition, wherein the spatial extent and system components of the area of interest are defined and the time horizon of the analysis is set. Following this initial assessment, the 'current accounts' is defined, which is a baseline representation of the system – including the existing operating rules for both supplies and demands. The current accounts is the calibrated baseline which serves as the point of departure for developing scenarios, which characterize alternative sets of future assumptions pertaining to policies, costs, and factors that affect demands, pollution loads, and supplies. Finally, the scenarios are evaluated with regard to water sufficiency, costs and benefits, compatibility with environmental targets and sensitivity to uncertainty in key variables.

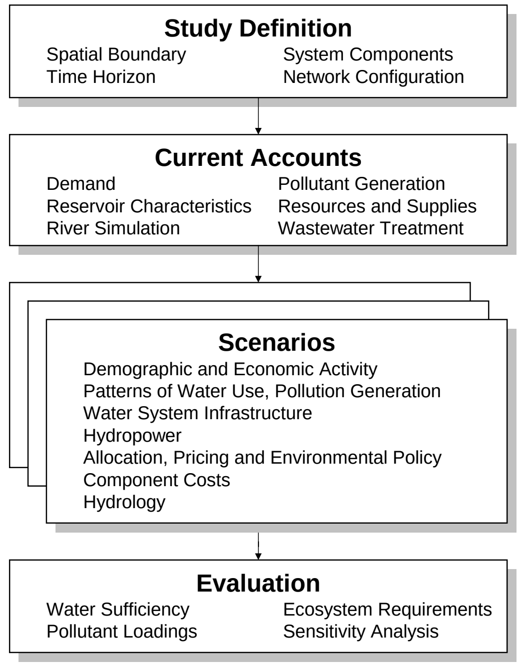


Figure C-1: Steps in developing a WEAP model

The steps in the analytical sequence are described in greater detail in the following sections.

Study Definition

Evaluating the implications of managing diversions and impoundments along a river requires the consideration of the entire land area that contributes to the flow within the river – the river basin. Within WEAP it is necessary to set the spatial scope of the analysis by defining the boundaries of the river basin. Within these boundaries there are smaller rivers and streams (or tributaries) that flow into the main river of interest. Because these tributaries determine the distribution of water throughout the whole basin, it is also necessary to divide the study area into sub-basins such that we can characterize this spatial variability of river flows.

Current Accounts

The current accounts represent the basic definition of the water system as it currently exists. Establishing current accounts requires the user to "calibrate" the system data and assumptions to a point that accurately reflects the observed operation of the system. The current accounts include the specification of supply and demand data (including definitions of reservoirs, pipelines, treatment plants, pollution generation, etc.). This calibration process also includes setting the parameters for WEAP's rainfall-runoff module such that WEAP can use climatic data (i.e. temperature and precipitation) to estimate water supply (i.e. river flows, aquifer recharge) and demand (evaporative water demand) in the delineated basins.

Scenarios

At the heart of WEAP is the concept of scenario analysis. Scenarios are self-consistent story-lines of how a future system might evolve over time. The scenarios can address a broad range of "what if" questions. This allows us to evaluate the implications of intended or unintended changes in the system and then how these changes may be mitigated by policy and/or technical interventions. For example, WEAP may be used to evaluate the water supply and demand impacts of a range of future changes in demography, land use, and climate. The result of these analyses will be used to guide the development of response packages, which are combinations of management and/or infrastructural changes that enhance the productivity of the system.

Evaluation

Once the performance of a set of response packages has been simulated within the context of future scenarios, the packages can be compared relative to key metrics. Often these relate to water supply reliability, water allocation equity, ecosystem sustainability, and cost, but any number of performance metrics and be defined and quantified within WEAP.

WEAP Calculation

At each time step, WEAP first computes the hydrologic flux, which it passes to each river. The water allocation is then made for the given time step, where constraints related to the characteristics of reservoirs and the distribution network, environmental regulations, and the priorities and preferences assigned to points of demands are used to condition a linear programming optimization routine that maximizes the demand “satisfaction” to the greatest extent possible (see Yates et al. 2005a for details). All flows are assumed to occur instantaneously; thus a demand site can withdraw water from the river, consume some, and optionally return the remainder to a receiving water body in the same time step. As constrained by the network topology, the model can also allocate water to meet any specific demand in the system, without regard to travel time. Thus, the model time step should be at least as long as the residence time of the study area. For this reason, a monthly time step was adopted for the seven river basins in our study.

Rainfall-runoff (aka streamflow generation)

WEAP offers three methods to simulate watershed hydrological processes such as evapotranspiration, runoff, and infiltration. These methods include (1) the Rainfall Runoff and (2) the Simplified Coefficient Approach, and (3) the Soil Moisture Method. The Soil Moisture Method is the only method available to WEAP that allows for the separation of flows into different components (i.e. base flow, interflow, and saturated overland flow). This allows for the simulation of a range of hydrologic conditions, whereas simpler methods are suitable only for capturing hydrologic processes that are dominated by overland flow. Thus, we use the Soil Moisture Method for estimating the rainfall-runoff processes at the sub-basin level for each of the seven WEAP models in this study.

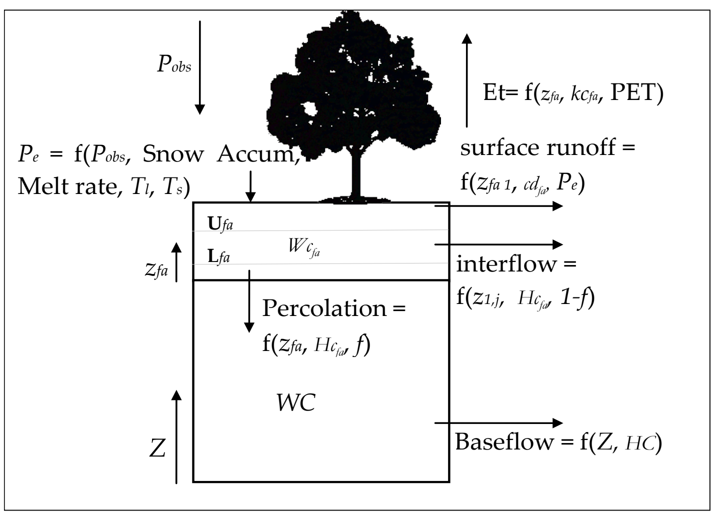
The Soil Moisture module in WEAP is spatially continuous, with a study area configured as a contiguous set of sub-catchments that cover the entire extent of the river basin in question. This continuous representation of the river basin is overlaid with a water management network topology of rivers, canals, reservoirs, demand centres, aquifers and other features (see Yates et al. 2005a and Yates et al. 2005b for details). Each sub-catchment (SC) is fractionally subdivided into a unique set of independent land use/land cover classes that lack detail regarding their exact location within the SC, but which sum to 100% of the SC's area. A unique climate-forcing data set of precipitation, temperature, relative humidity, and wind speed is uniformly prescribed across each sub-catchment.

A one-dimensional, quasi-physical water balance model depicts the hydrologic response of each fractional area within a SC and partitions water into surface runoff, infiltration, evapotranspiration, interflow, percolation, and baseflow components (see Equation C.1 and Figure C-2. Values from each fractional area within the SC are then summed to represent the lumped hydrologic response, with the surface runoff, interflow and baseflow being linked to a river element and evapotranspiration being lost from the system.

Equation C.1.

$$Rd_j \frac{dz_{1,j}}{dt} = P_e(t) - PET(t)k_{c,j}(t)\left(\frac{5z_{1,j} - 2z_{1,j}^2}{3}\right) - P_e(t)z_{1,j}^{RRF_j} - f_j k_{s,j} z_{1,j}^2 - (1 - f_j)k_{s,j} z_{1,j}^2$$

Figure C-2: Diagram of the two-bucket WEAP hydrology model (From Yates et al., 2005a)



WEAP offers a default method for calculating the potential evapotranspiration that uses a modified Penman-Montieth equation or an alternate method that allows the user to define his/her own equation(s). Because the Penman-Montieth relies on variables that were not easily obtained for the suite of climate futures used in our analysis (i.e. wind speed and relative humidity), we chose to use a modified Hargreaves equation developed by Droogers and Allen (2002) that required only estimates of temperature and precipitation.

Irrigation requirements

WEAP offers three methods for using climate inputs to simulate irrigation demands. These methods include (1) Irrigation Demands Only versions of the Simplified Coefficient Approach, (2) the Soil Moisture Method, and (3) the MABIA Method. In each of the seven WEAP models in this study we use the Simplified Coefficient Approach for estimating irrigation demands at the project level.

The Simplified Coefficient Approach estimates irrigation requirements based on total crop water usage and the deficit remaining after the effective precipitation has been consumed by crops. The total crop water usage (*ETcrop*) is calculated using an estimate of the monthly reference evapotranspiration (*ETref*) times a crop coefficient (*Kc*):

$$ETcrop = Kc * ETref$$

Some fraction of precipitation (*P*) may be used to meet *ETcrop*. This is referred to as the 'effective precipitation' (*Peff*) and is expressed in WEAP using a function developed by IFPRI (Rosegrant *et al*., 2002):

$$Peff = (1.253 * P^{0.824} - 2.935)*10^{ETref/1000}$$

This is subject to the conditions:

If $Peff > ETref$ or $Peff > P$, then $Peff$ = minimum ($ETref$, P)
If $P < 12.5$ mm, then $Peff = P$

In the event that *ETcrop* is greater than *Peff*, then WEAP estimates the irrigation water requirement (*Irr*) based on this deficit and the assumed irrigation efficiency (*IE*). Thus, the irrigation requirement is calculated as:

$$Irr = (ETcrop - Peff)/IE$$

Domestic water use

Domestic water use is expressed in WEAP as a function of population and per capita water use rates. These water uses are split between urban areas, where per capita water use is significantly higher and generally well known, and rural areas, where direct abstractions from the river system are much smaller and more diffuse. Population estimates were based on UN country-level data (UN, 2012) and density maps (CIESIN, 2011). These are discussed further in a following section. Per capita water use rates in urban areas were estimated from the best available country-level data sources. Water use rates in rural areas were more generally estimated at reported subsistence-level rates (i.e. 50 liters/day).

Natural lakes and wetlands

In at least four of the river basins in this study (i.e. Congo, Niger, Nile, and Zambezi), there are natural features that significantly affect the timing and magnitude of flows through the basin - most notably, Lake Tanganyika in the Congo, Lake Malawi and Kafue Gorge in the Zambezi, the Sudd wetland in the Nile, and the Inner Delta in the Niger. To approximate the effect of these, we used a combination of WEAP features to represent natural lakes and wetlands. In particular, we used reservoir objects to capture and store upstream flows; flow requirements to draw water out of storage; demand priorities to isolate the lake/wetland from decisions made in other parts of the basin; and, where appropriate, diversions to maintain minimum flows downstream.

Below is an example of where we applied this approach for the Inner Delta of the Niger River (see Figure C-3). In this case, the priority levels (shown in parentheses in the figure below) are set such that the two flow requirements and the reservoir do not draw water from upstream storage nor release water to downstream demands. In this way, we have made this part of the system passive. Relative to one another, however, the priorities are set such that water is allocated first to the 'Bypass Requirement' (in this case up to 600 CMS), next to 'InnerDeltaFlow' (which is conditional upon Inner Delta storage), and lastly to the 'Inner Delta'. In this configuration, the 'InnerDeltaFlow' flow requirement is the only mechanism to draw water out of storage from 'Inner Delta'. This flow requirement is expressed using an empirical relationship between observed storage within the inner delta and observed flow downstream. The results below in

Figure C-4 show that this approach can greatly improve the agreement between observed and simulated flows.

Figure C-3: Example of Natural Lake/Wetland in WEAP

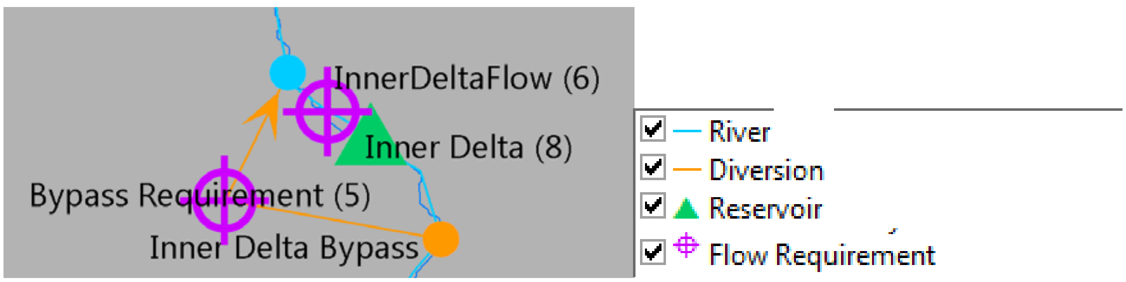
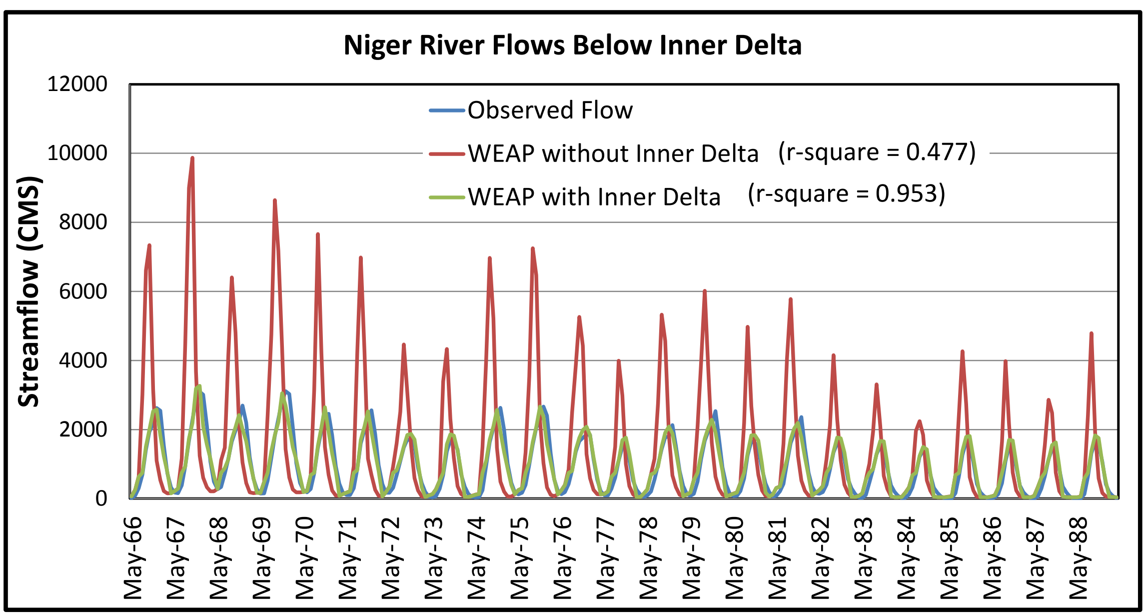


Figure C-4: Observed v. Simulated Flows with and without Natural Lakes/Wetland Model in WEAP



Reservoir Evaporation

Temperature and precipitation climate inputs are used to estimate net evaporative losses from reservoirs. Evaporation rates are based on Droogers and Allen (2002) modified Hargreaves equation, which is offset by precipitation to determine net evaporation. Reservoir volume-to-elevation curves are then used to determine the associated volumetric losses to evaporation.

Hydropower

Hydropower generation is computed from the flow passing through the turbine, based on the reservoir release or run-of-river streamflow, and constrained by the turbine's maximum flow capacity. For reservoirs, all water released downstream is sent through the turbines, but water pumped from the reservoir to satisfy direct reservoir withdrawals is not sent through the turbines.

$Release_H = DownstreamOutflow_H$

For run-of-river hydropower nodes, the "release" is equal to the downstream outflow from the node.

$Release_H = DownstreamOutflow_H$

The volume of water that passes through the turbines is bounded by the maximum turbine flow (entered as data into WEAP). Note that if there is too much water, extra water is assumed to be released through spillways that do not generate electricity.

$VolumeThroughTurbine_H = Min(Release_H, MaxTurbineFlow_H)$

The gigajoules (GJ) of energy produced in a month,

$EnergyFullMonthGJ_H = VolumeThroughTurbine_H \times HydroGenerationFactor_H$

is a function of the mass of water (1000 kg / m^3) through the turbines multiplied by the drop in elevation, the plant factor (fraction of time on-line), the generating efficiency, and a conversion factor (9.806 kN/m^3 is the specific weight of water, and from joules to gigajoules). The plant factor and efficiency are entered as data into WEAP.

$HydroGenerationFactor_H = 1000 \text{ (kg / m^3)} * DropElevation_H \times PlantFactor_H \times PlantEfficiency_H * 9.806 / (1{,}000{,}000{,}000 \text{ J / GJ})$

For reservoirs, the height that the water falls in the turbines is equal to the elevation at the beginning of the month minus the tailwater elevation.

$DropElevation_H = BeginMonthElevation_H - TailwaterElevation_H$

For run-of-river hydropower nodes, the drop in elevation is entered as data.

$DropElevation_H = FixedHead_H$

If a demand priority for hydropower energy has been set for an individual reservoir, WEAP will calculate the supply requirement (volume of water through the turbines) necessary to generate the energy demand.

$SupplyRequirement_H = EnergyDemandFullMonthGJ_H \; / \; HydroGenerationFactor_H$

Water allocation

Two user-defined priority systems are used to determine allocations of water supplies to demands (i.e. urban and agricultural), for instream flow requirements, and for filling reservoirs – demand priorities and supply preferences.

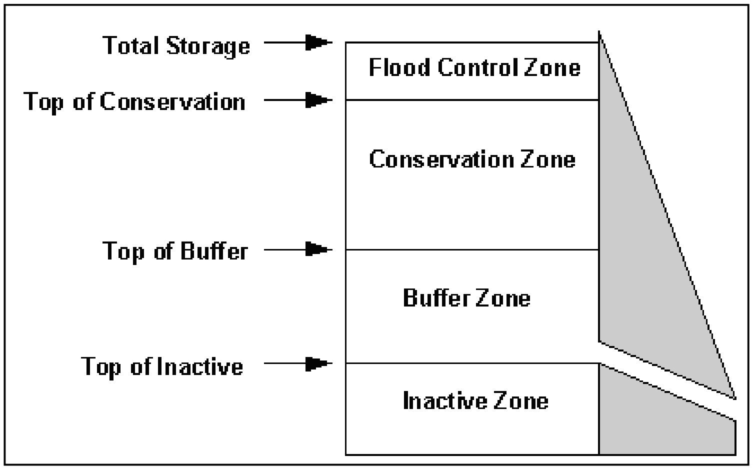
Demand priorities are used to allocate water to competing demand sites and catchments, flow requirements, and reservoir storages. The demand priority is attached to the demand site, catchment, reservoir, or flow requirement and range from 1 to 99, with 1 being the highest priority and 99 the lowest. Many demand sites can share the same priority, which is useful in representing a system of water rights, where water users are defined by their water usage and/or seniority. In cases of water shortage, higher priority users are satisfied as fully as possible before lower priority users are considered. If priorities are the same, shortage will be shared equally (as a percentage of their demands).

When demands sites or catchments are connected to more than one supply source, the order of withdrawal is determined by supply preferences. Similar to demand priorities, supply preferences are assigned a value between 1 and 99, with lower numbers indicating preferred water sources. The assignment of these preferences usually reflects some economic, environmental, historic, legal and/or political realities. In general, multiple water sources are present when the preferred water source is insufficient to satisfy all of an area's water demands. WEAP treats the additional sources as supplemental supplies and will draw from these sources only after it encounters a capacity constraint (expressed as either a maximum flow volume or a maximum percent of the demand) associated with the preferred water source.

WEAP's allocation routine uses demand priorities and supply preferences to balance water supplies and demands. To do this, WEAP must make an assessment of the available water supplies at any given time step. While total supplies may be sufficient to meet all of the demands within the system, it is often the case that operational considerations prevent the release of water to do so. These regulations are usually intended to hold water back in times of shortage so that delivery reliability is maximized for the highest priority water users (often urban indoor demands). WEAP can represent this controlled release of stored water using its built-in reservoir object.

WEAP uses generic reservoir objects that divide storage into four zones, or pools (Figure C-5: Reservoir zones) These include, from top to bottom, the flood-control zone, conservation zone, buffer zone and inactive zone. The conservation and buffer pools together constitute the reservoir's active storage. WEAP will ensure that the flood-control zone is always vacant – i.e. the volume of water in the reservoir cannot exceed the top of the conservation pool. The size of each of these pools can change throughout the year according to regulatory guidelines, such as flood control rule curves.

Figure C-5: Reservoir zones



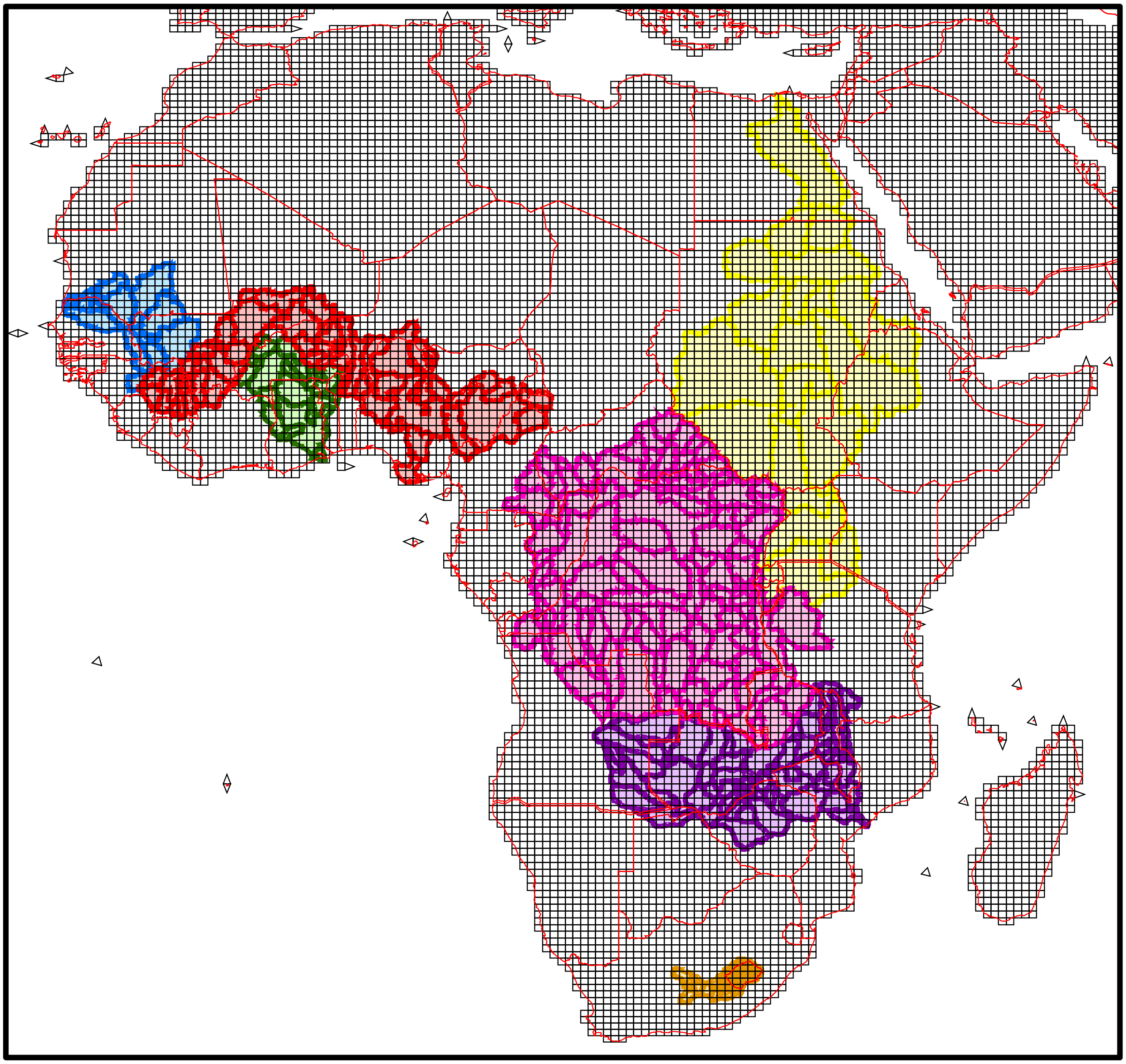
WEAP allows the reservoir to freely release water from the conservation pool to fully meet withdrawal and other downstream requirements. Once the storage level drops into the buffer pool, the release will be restricted according to the buffer coefficient, to conserve the reservoir's dwindling supplies. The buffer coefficient is the fraction of the water in the buffer zone available each month for release. Thus, a coefficient close to 1.0 will cause demands to be met more fully while rapidly emptying the buffer zone, while a coefficient close to 0 will leave demands unmet while preserving the storage in the buffer zone. Water in the inactive pool is not available for allocation, although under extreme conditions evaporation may draw the reservoir into the inactive pool.

Common Data Sources

Climate

The WEAP models for the seven river basins were developed and calibrated using a reconstruction of the historical climate data, 1948-2008, developed by the Terrestrial Hydrology Research Group at Princeton University (Sheffield et al., 2006). These data include climate sequences of monthly temperature and precipitation, spatially averaged for each hydrologically connected catchment (Figure C-6: Princeton 0.5 degree climate grid).

Figure C-6: Princeton 0.5 degree climate grid



These data also served as a baseline climate for the scenarios analysis, in which they are referred to as the *Historical Direct* climate condition. A second set of representative historical climate conditions includes 23 sequences of climate information derived by downscaling global estimates of historical conditions using the Bias-Corrected and Spatially Downscaled (BCSD) method (Brekke *et al.*, 2013)—*Historical Projected*. These data were extracted from the from atmosphere-ocean general circulation model (GCM) simulations, archived by the WCRP Coupled Model Intercomparison Project – Phase 5 (CMIP5, CLIVAR [2011]).

Three sets of climate data were used to represent plausible future climate conditions. The first set included 56 BCSD downscaled GCM simulations from the WCRP Coupled Model Intercomparison Project – Phase 3 (CMIP3, (Meehl *et al.*, 2007))—*Projected CMIP3, BCSD*. The second set includes 43 sequences derived from BCSD GCM simulations from the CMIP5 archive. The third set includes 22 CMIP5 simulations downscaled using the University of Cape Town Climate Systems Analysis Group (CSAG) methodology (Hewitson and Crane, 2006)—*Projected CMIP5, UCT-CSAG*.

In total, 145 simulations were used. These data are organized as numbered subdirectories that accompany the data files for each WEAP model. These climate scenarios are summarized below, with the subdirectory numbers in parentheses:

- Historical Direct (subdirectory 0)
- Historical Projected CMIP5, BCSD (subdirectories 100-122)
- Projected CMIP3, BCSD (subdirectories 1-56)
- Projected CMIP5, BCSD (subdirectories 57-99)
- Projected CMIP5, UCT-CSAG (subdirectories 123-144)

Population

Estimates of total population within each river basin were derived from the United Nations' World Population Prospects (2012). These populations were calculated as the sum of individual country population estimates times the fraction of each country's area within the seven river basins. These are presented in Table C-1.

To distribute these populations across each river basin, we used 2010 population density maps from Columbia University (CIESIN, 2011) to estimate the percentage of the total (basin-wide) population within each catchment (Figure C-7: Population density map. (CIESIN, 2011)

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Figure C-7: Population density map. (CIESIN, 2011)

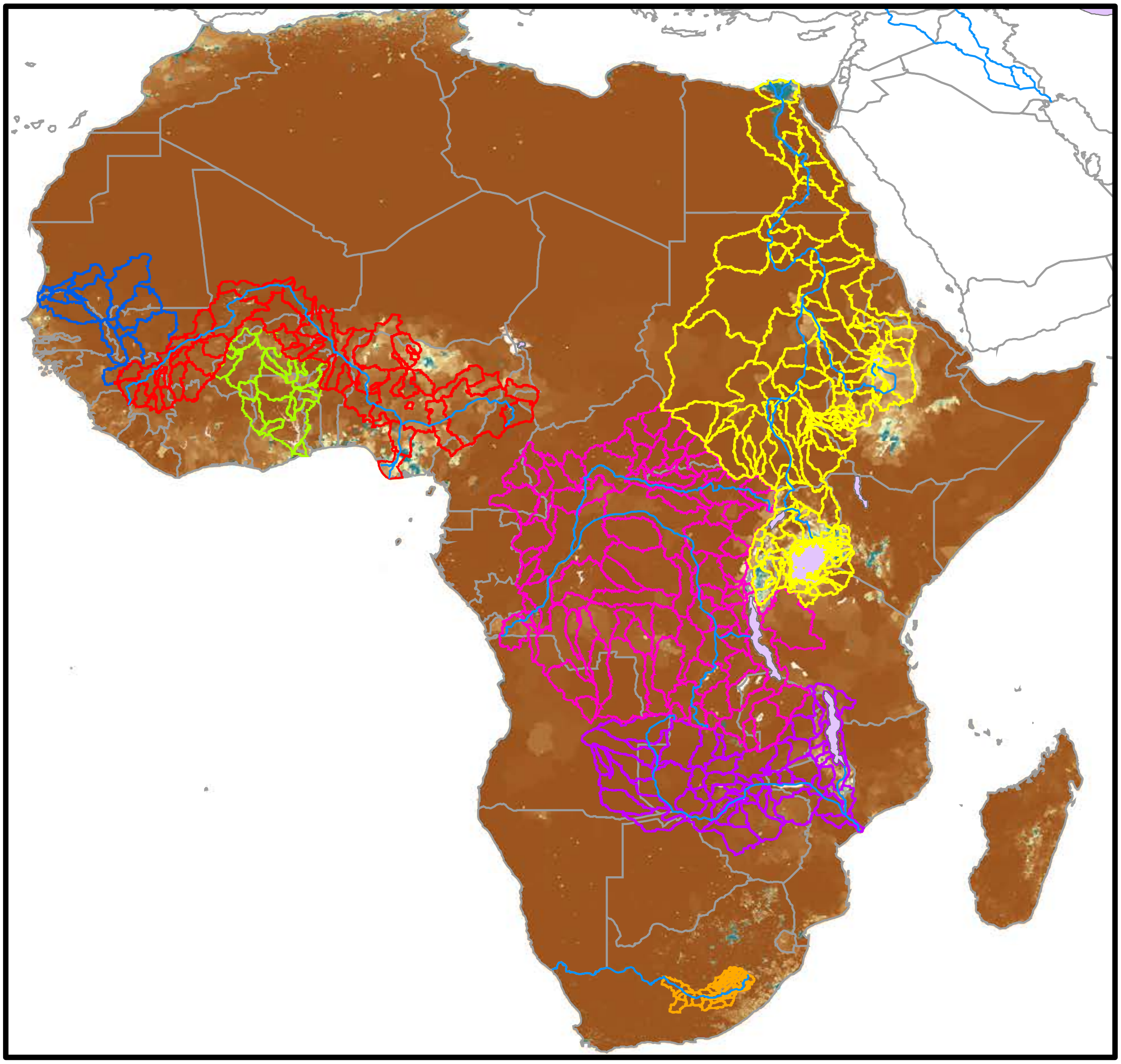


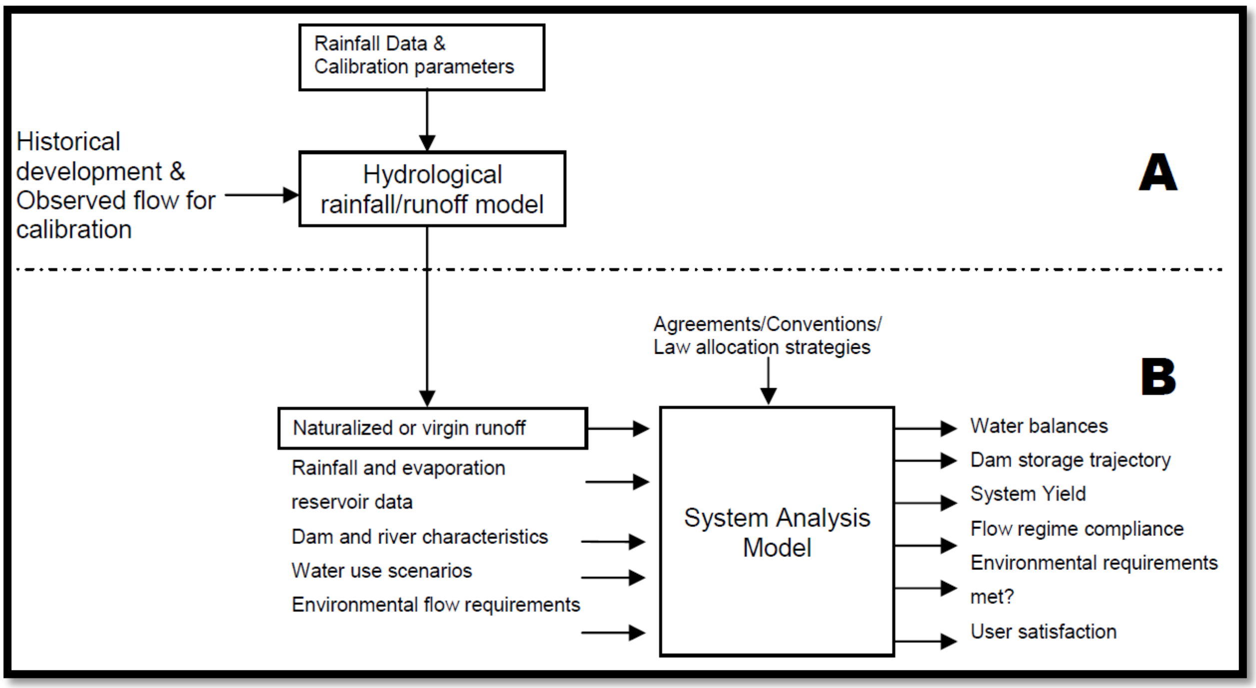
Table C-1: United Nations medium variant population projection by basin (thousands of people)

Basin	2000	2005	2010	2015	2020	2025	2030	2035	2040	2045	2050
Congo	60,341	69,249	79,791	91,565	104,589	118,765	134,028	150,291	167,453	185,312	203,664
Niger	76,184	87,115	100,283	115,737	133,330	153,178	175,506	200,433	227,866	257,510	288,935
Nile	155,806	177,374	202,256	229,637	258,745	289,300	321,249	354,582	388,974	423,866	458,695
Senegal	4,726	5,427	6,267	7,188	8,235	9,391	10,656	12,025	13,492	15,032	16,622
Upper Orange	2,396	2,507	2,629	2,764	2,890	3,007	3,118	3,230	3,345	3,464	3,581
Volta	18,340	21,029	24,115	27,389	30,899	34,634	38,588	42,747	47,055	51,438	55,834
Zambezi	30,630	33,931	38,162	44,151	50,890	58,034	65,860	74,392	83,641	93,583	104,146

Model Development and Calibration Approach

The development of linked hydrologic and systems analysis models generally follows a two-step process, wherein the hydrological model is calibrated first to 'natural' conditions and these flows are then used as inputs to the systems model, which is calibrated to historical operations (i.e. river abstractions , reservoir storage/release , groundwater pumping, etc.). A diagram of this process is presented below in Figure C-8.

Figure C-8: Two-step process for developing a WEAP model



Source: Juizo & Liden, Hydrologic Earth System Sciences (2010).

The WEAP models were calibrated to historical streamflows using a combination of manual methods and computer algorithms, using the PEST software (Doherty, 2002). In general, eight land use parameters were adjusted to achieve calibration of the basin hydrology. These parameters were the evapotranspiration coefficient (Kc), soil water capacity (SWC), deep water capacity (DWC), runoff resistance factor (RRF), root zone conductivity (RZC), deep conductivity (DC), and preferred flow direction (PFD). Model simulations are most sensitive to SWC, RZC, RRF, and PFD. Thus, initial calibrations focused on these four parameters. Further refinements to the shape and timing of the resulting hydrographs were accomplished by adjusting the remaining parameters.

The Nash-Sutcliffe Efficiency (NSE) coefficient is commonly used in hydrologic modeling to evaluate how well modeled stream flow matches observed. If NSE=1, there is a perfect match between the observed and modeled, if NSE=0, the modeled is only as good as the observed mean of the data, and NSE <0 indicates the model performs worse than the mean. Generally in hydrologic modeling, NSE > 0.6 is desired, while NSE > 0.8 is good.

While NSE is a useful one-value indicator of model performance, it is biased by high flows. Additionally, it only captures certain aspects of the model flow deviations from observed. To fully understand and evaluate model performance, NSE must be used in conjunction with other metrics that consider seasonal variation, flow duration curves, and annual totals of the modelled and observed flows. To this end, we considered the root mean squared error (RMSE) as a measure of how much the simulated flows deviated from the observed hydrographs. We considered the ratio of simulated versus observed flow standard deviation (SDR) as a measure of how well the simulated flows matched the flow variability within the historical record. Lastly, we considered the percent annual bias as a measure of the model's ability to match the total volume of flow. These are reported for several control points within each basin in chapters C2-Congo River Basin through C8- Zambezi River Basin.

While calibrating hydrological routines to natural flows is a fairly straightforward exercise, calibrating the system analysis model to historical operations can be much trickier, particularly in situations where the operational rules have changed over time, which is the case in nearly all of the river basins considered in this study. For this reason, we do not attempt to optimize calibration metrics of reservoir storage/elevation (which is the most commonly available measure for calibration) for the WEAP models. Rather, we have used these data as guides for judging whether the models are simulating systems operations within reason, given the fixed operational rules within the models.

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C2-Congo River Basin

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Figure C-9: Congo River Basin, Central Africa

Description of the Basin

The Congo River Basin extends over 3.7 million km^2 between 9°N, 12°E and 13.30°S, 34°E, and encompasses nine political boundaries, namely: Angola, Burundi, Central African Republic, Democratic Republic of Congo, Cameroon, Republic of Congo, Rwanda, Tanzania and Zambia (Figure C-9 and Figure C-10). The Congo is the largest river basin in Africa and covers about 12 percent of the continent.

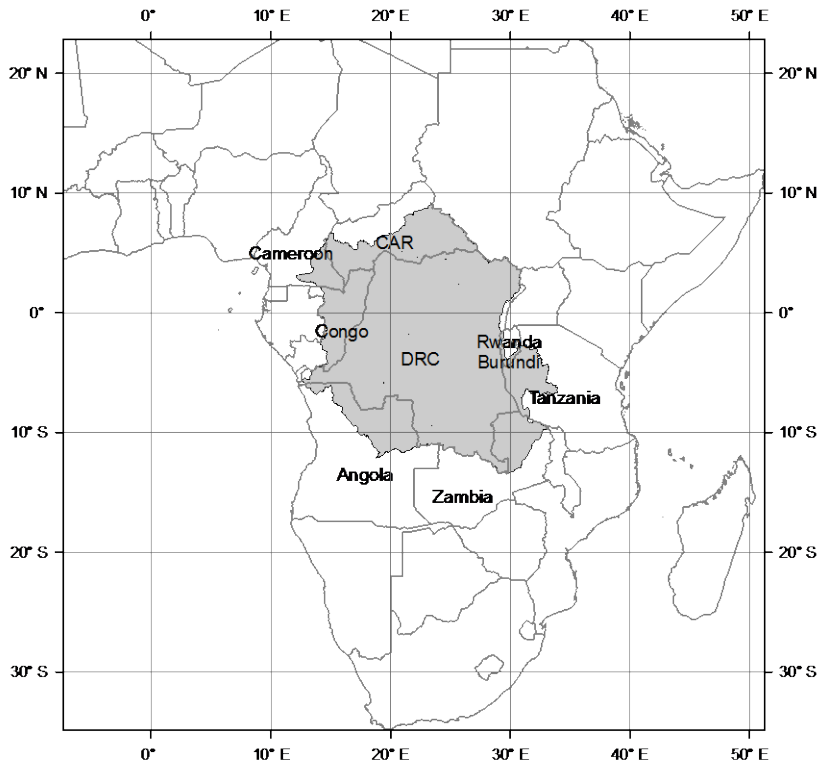
Table C-2: Congo River basin areas by country

Country	Area within Basin (km^2)	Percentage of Basin area (%)	Percentage of Country with the Basin (%)
Angola	285,395	7.5	22.9
Burundi	14,574	0.4	52.4
Cameroon	96,395	2.5	20.3
Central Africa	403,570	10.7	64.8
Congo	246,977	6.5	72.2
DR Congo	2,313,350	61.1	98.7
Rwanda	6,464	0.2	24.5
Tanzania	244,593	6.5	25.9
Zambia	177,735	4.7	23.6
Total	3,789,053	100	

The Congo Basin holds huge potential for water resource development on a regional scale, including hydropower, irrigation, navigation, interbasin water transfer and the trade of water intensive products, called the virtual water trade. These potentials and the uncertainty of future socio-economic development associated with future impacts of environmental changes have prompted efforts to develop adequate approaches to water resource evaluation and allocation in the basin.

In general terms, the Congo basin is composed of four main highlands that frame the central part of the basin characterized by lowlands. The main highlands consist of the Oubangui (north east), Sangha (north west), Lualaba (south east) and Kasai (south west). They consist of deeply weathered Mesozoic Precambrian rocks while the central part of the basin, with low slopes, is covered by unconsolidated Cenozoic sediments (Runge, 2007). The channels in the central part of the basin are very large and flanked by floodplains which are inundated during high water periods (Hughes and Hughes, 1987). The river courses upstream are regulated by several large natural wetlands and lakes that are expected to affect downstream flow regimes. The monthly flow volume at the basin outlet is about 108 147.5 Mm^3 (based on the Kinshasa-Brazzaville gauging site, Tshimanga and Hughes, 2014), which ranks the basin second in the world after the Amazon. This flow volume represents about 40% of the African continent's discharge (Crowley *et al*., 2006).

Figure C-10: Physical layout of the Congo Basin showing the geographical location of the basin and its political boundaries.



The central part of the basin is characterized by high rainfall associated with high temperature and low potential evapotranspiration. Away from the central basin, there is a decrease in mean annual rainfall. This trend is accentuated in the south eastern part of the basin, the extreme north as well as the lower parts of the basin. These areas are also characterized by high evapotranspiration and low temperature compared to the central basin. The mean annual precipitation ranges from 980 to 2080 mm while the mean annual potential evapotranspiration varies from 930 to 1640 mm and the mean annual temperature from 15.9 to 27.5°C.

The seasonal cycle in the basin is characterized by a bimodal pattern of rainfall distribution with maximum rainfall values in March, April, October and November (Juarez *et al*., 2009; Beighley e*t al*., 2011). The rainy season in the north coincides with the dry season in the south and *vice versa;* so heavy rain in the north tends to compensate for light rain in the south, thus maintaining downstream river flow stability throughout the year. Nevertheless, levels in the watercourses of the flat central basin normally exhibit two maxima and two minima each year. During the high water periods vast areas of land adjacent to rivers in the central basin are flooded. These areas drain during the low water periods, which occur twice a year (Tshimanga, 2012).

Land cover varies from dense forest in the central parts to a mosaic of vegetation types including variable density woodlands and shrubland. Similarly, soils and geology are variable throughout the basin.

The Congo River Basin holds significant potentials for water resource development, but this development has been hindered by years of regional conflicts which jeopardized efforts for socio-economic expansion. The current population in the basin is estimated at 126 million with a per capita GDP of 780 USD . More than 60% of the population lives in rural areas. Agriculture is essentially rainfed and the estimated cultivated area is about 36.7% of the total basin. The contribution of agriculture to the GDP is estimated at 31.9%. The Congo Basin is known for its river navigation potential and, since the pre-colonial period, has been used to supply international markets with natural resources such as timber, palm oil, copper, and many other natural resources. The basin presents some 25,000 km of navigable waterways with about four main navigable axes which facilitate regional trade (Oubangui Axis, Tanganyika Axis, Lualaba-Congo Axis, and Kasai Axis).

The first Axis consists of the Oubangui River and offers the possibility of regional connection with the northern countries. The Tanganyika Axis is a regional navigable network that consists of Burundi, DRC, Tanzania and Zambia. The Kasai Axis offers the possibility of connection with southern countries such as Angola, and the Lualaba-Congo Axis connects the Congo River to the Atlantic Ocean. An important navigable water way of about 1,742 km connects the towns of Kisangani and Kinshasa where larger vessels navigate and help provide goods to very remote areas of the basin.

The current and future development plans for the basin are available in the in Appendix A of the main document.

WEAP Schematization

Catchment definition

The WEAP model schematization in the Congo basin followed the procedure applied in Tshimanga and Hughes (2014), which consisted of using the SRTM dataset to delineate the sub-basin units based on overlaying slope classes, elevation classes and the basin drainage network. This produced 99 catchment units that were used to represent the dominant features of elevation and slopes. Areas of wetlands and natural lakes in these features are considered as reservoirs for modelling in WEAP.

Figure C-11 shows the level of disaggregation of the Congo River basin into these 99 catchment units.

Time series of historical and projected climate (i.e. monthly precipitation [mm], average temperature[C], minimum temperature[C], and maximum temperature[C]) were developed for each catchment shown in

Figure C-11. These data were used as drivers for the routines that estimate the hydrological response (i.e. rainfall-runoff and baseflow) and potential evapotranspiration for each sub-catchment.

Figure C-11: Congo River sub-catchments

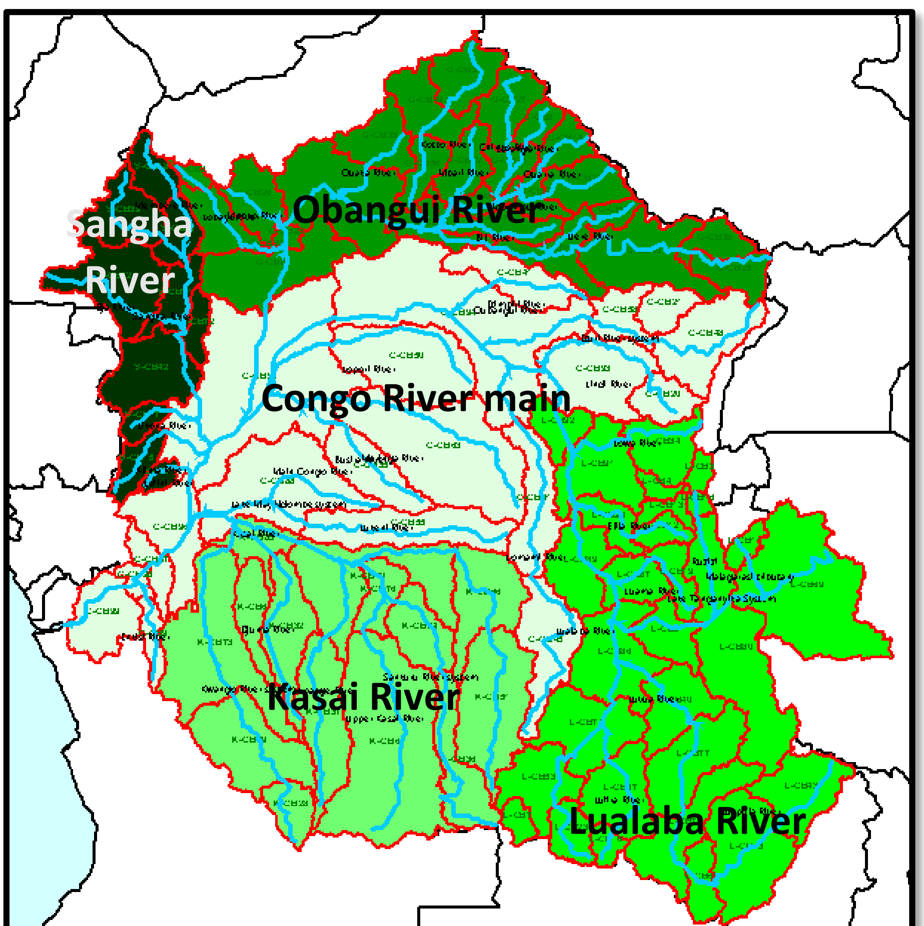


Table C-3: Summary of Congo River catchments

Sub-Basin	Catchment	Area (km^2)	Percent of basin Area	Avg. Rainfall (mm)
Main Congo River	WCCB20	19,873	0.55%	1,371
	WCCB21	16,917	0.47%	1,659
	WCCB35	35,450	0.98%	1,820
	WCCB41	34,913	0.96%	1,670
	WCCB45	46,331	1.28%	1,348
	WCCB48	49,930	1.38%	1,385
	WCCB50	70,097	1.93%	1,827
	WCCB55	57,339	1.58%	1,705
	WCCB58	20,991	0.58%	1,719
	WCCB61	40,764	1.12%	1,675
	WCCB63	11,6990	3.22%	1,872
	WCCB88	86,455	2.38%	1,647
	WCCB9	12,134	0.33%	1,404
	WCCB93	60,975	1.68%	1,643
	WCCB94	160,804	4.43%	1,713
	WCCB95	185,835	5.12%	1,690
	WCCB96	45,236	1.25%	1,634
	WCCB97	15,462	0.43%	1,498
	WCCB98	7,362	0.20%	1,411
	WCCB99	35,655	0.98%	1,196
Lualaba River	WLCB10	8,452	0.23%	1,183
	WLCB11	8,792	0.24%	1,212
	WLCB12	11,140	0.31%	1,467
	WLCB13	8,913	0.25%	1,477
	WLCB16	4,872	0.13%	1,420

	WLCB19	16,334	0.45%	1,243
	WLCB23	17,739	0.49%	1,172
	WLCB3	6,717	0.19%	1,484
	WLCB34	30,507	0.84%	1,380
	WLCB4	5,997	0.17%	1,380
	WLCB40	34,270	0.94%	1,111
	WLCB43	40,706	1.12%	1,187
	WLCB47	39,256	1.08%	1,003
	WLCB53	35,696	0.98%	1,166
	WLCB65	61,405	1.69%	1,213
	WLCB68	17,148	0.47%	1,224
	WLCB69	113,069	3.12%	1,072
	WLCB7	8,539	0.24%	1,259
	WLCB74	48,325	1.33%	1,110
	WLCB75	46,497	1.28%	1,164
	WLCB77	47,125	1.30%	1,115
	WLCB80	98,186	2.71%	1,118
	WLCB81	23,171	0.64%	1,109
	WLCB86	53,385	1.47%	1,151
	WLCB87	22,029	0.61%	1,282
	WLCB89	37,428	1.03%	1,432
	WLCB90	18,196	0.50%	1,472
	WLCB91	45,297	1.25%	1,538
	WLCB92	19,097	0.53%	1,694
Obangui River	WOCB14	19,590	0.54%	1,462
	WOCB2	5,880	0.16%	1,489
	WOCB22	22,153	0.61%	1,550
	WOCB24	26,454	0.73%	1,531

	WOCB25	20,275	0.56%	1,534
	WOCB26	27,081	0.75%	1,523
	WOCB27	26,316	0.73%	1,377
	WOCB29	24,623	0.68%	1,558
	WOCB30	533	0.01%	1,566
	WOCB31	28,847	0.79%	1,263
	WOCB33	28,333	0.78%	1,452
	WOCB38	16,840	0.46%	1,553
	WOCB44	14,447	0.40%	1,549
	WOCB46	12,975	0.36%	1,596
	WOCB49	30,051	0.83%	1,388
	WOCB5	8,802	0.24%	1,610
	WOCB56	17,096	0.47%	1,561
	WOCB60	55,952	1.54%	1,680
	WOCB62	10,575	0.29%	1,596
	WOCB67	28,385	0.78%	1,693
	WOCB70	25,763	0.71%	1,631
	WOCB78	18,048	0.50%	1,636
	WOCB8	11,196	0.31%	1,435
	WOCB82	74,216	2.04%	1,547
	WOCB83	5,011	0.14%	1,565
	WOCB84	56,844	1.57%	1,639
Kasai River	WKCB28	18,110	0.50%	1,253
	WKCB32	41,197	1.14%	1,539
	WKCB36	37,886	1.04%	1,388
	WKCB37	51,060	1.41%	1,388
	WKCB51	71,112	1.96%	1,466
	WKCB54	30,718	0.85%	1,538

	WKCB59	59,837	1.65%	1,265
	WKCB6	22,201	0.61%	1,573
	WKCB64	145,945	4.02%	1,364
	WKCB66	46,634	1.28%	1,545
	WKCB73	93,422	2.57%	1,458
	WKCB76	20,221	0.56%	1,570
	WKCB79	73,149	2.02%	1,601
	WKCB85	21,348	0.59%	1,625
Sangha River	WSC39	34,110	0.94%	1,554
	WSCB1	6,878	0.19%	1,838
	WSCB15	16,503	0.45%	1,827
	WSCB17	10,112	0.28%	1,720
	WSCB18	18,098	0.50%	1,496
	WSCB42	44,485	1.23%	1,670
	WSCB52	53,481	1.47%	1,625
	WSCB57	17,337	0.48%	1,570
	WSCB71	20,288	0.56%	1,643
	WSCB72	11,314	0.31%	1,659

Sources of physiographic data used to inform the model include:

- The NASA Space Shuttle Radar Topography Mission data (SRTM, 3 arc sec or approximately 90 m, http://srtm.csi.cgiar.org/).
- The global land cover map (GLOBCOVER, *Bontemps et al*., 2011).
- A global Leaf Area Index derived from field measurements (Scurlock *et al.*, 2001).
- The Harmonized World Soil Database Version 1.1 (Nachtergaele*et al*., 2010).
- The Soil and Terrain Database and the World Inventory of Soil Emission Potentials (ISRIC-WISE soil type version1).
- The soil depth data from the global dataset on soil particle sizes (Webb *et al.,* 1991).
- The hydro-geological properties of Africa (Seguin, 2005).
- The global groundwater recharge database of Döll and Flörke (2005).

Irrigation

Irrigation water demands are a function of the irrigated area, crop coefficient, rainfall deficit and irrigation efficiency. Irrigated areas and crop coefficients are presented in

Table C-5 and Table C-4. These data are based on inputs from de Condappa (2013) who also estimated that irrigation efficiency across the basin is about 0.45. This estimate, however, contains a high degree of variability and uncertainty. For the purposes of this study, we used an estimate of 0.5.

Table C-4: Irrigated crop areas (ha) in Congo River WEAP model

Area	Crop	2010
Burundi Ag North	First Rice	4050
	Second Rice	4050
	Coffee	650
	Onion	325
	Tomato	325
Burundi Ag South	First Rice	160
	Sugar Cane	1450
Tanzania Ag	First Rice	1358.4
	Second Rice	1358.4
	Maize	1698
	Sorghum	1018.8
	Onion	1403.8
	Banana	192.5
	Tomato	1403.8
DRC Ag Bumba	First Rice	1128
	Second Rice	1128
	Onion	752
	Tomato	752
	Sugar Cane	376
DRC Ag Malebo Pool	Rice	2000

Table C-5: Crop coefficient, Kc, values used for irrigated crops in Congo River WEAP model

Crop	Area	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Banana	Burundi Ag North	0.5	0.57	0.69	0.82	0.94	1.07	1.18	1.19	1.11	0	0.5	0.5
	Burundi Ag South	1	1	1	1	1	1	1	1	1	1	1	1
	DRC Ag Bumba	1	1	1	1	1	1	1	1	1	1	1	1
	Tanzania Ag	0.5	0.57	0.69	0.82	0.94	1.07	1.18	1.19	1.11	0	0.5	0.5
Coffee	Burundi Ag North	1	1	1	1	1	1	1	1	1	1	1	1
	Burundi Ag South	1	1	1	1	1	1	1	1	1	1	1	1
	DRC Ag Bumba	1	1	1	1	1	1	1	1	1	1	1	1
	Tanzania Ag	1	1	1	1	1	1	1	1	1	1	1	1
First Rice	Burundi Ag North	1.16	1.18	1.1	0	0	0	0	0	0	0	1.11	1.11
	Burundi Ag South	1.13	1.14	1.07	0	0	0	0	0	0	0	1.11	1.1
	DRC Ag Bumba	0	0	1.11	1.1	1.12	1.13	1.04	0	0	0	0	0
	Tanzania Ag	1.16	1.18	1.1	0	0	0	0	0	0	0	1.11	1.11
Maize	Burundi Ag North	0.3	0.61	1.14	1.12	0.59	0	0	0	0	0	0	0
	Burundi Ag South	0.3	0.59	1.09	1.07	0.58	0	0	0	0	0	0	0
	DRC Ag Bumba	1	1	1	1	1	1	1	1	1	1	1	1
	Tanzania Ag	0.3	0.61	1.14	1.12	0.59	0	0	0	0	0	0	0

Onion	Burundi Ag North	0	0	0	0	0	0	0.52	0.81	1.02	0.98	0	0
	Burundi Ag South	0	0	0	0	0	0	0.52	0.78	0.97	0.93	0	0
	DRC Ag Bumba	0	0	0	0	0.52	0.76	0.94	0.9	0	0	0	0
	Tanzania Ag	0	0	0	0	0	0	0.52	0.81	1.02	0.98	0	0
Rice	DRC Ag Malebo Pool	1.13	1.05	0	0	0	0	0	0	0	1.11	1.1	1.13
Second Rice	Burundi Ag North	0	0	0	0	1.11	1.11	1.23	1.26	1.17	0	0	0
	Burundi Ag South	0	0	0	0	1.11	1.1	1.16	1.18	1.08	0	0	0
	DRC Ag Bumba	1.05	0	0	0	0	0	0	0	1.11	1.1	1.13	1.13
	Tanzania Ag	0	0	0	0	1.11	1.11	1.23	1.26	1.17	0	0	0
Sorghum	Burundi Ag North	0.3	0.54	0.95	0.95	0.68	0	0	0	0	0	0	0
	Burundi Ag South	0.3	0.52	0.9	0.9	0.61	0	0	0	0	0	0	0
	DRC Ag Bumba	1	1	1	1	1	1	1	1	1	1	1	1
	Tanzania Ag	0.3	0.54	0.95	0.95	0.68	0	0	0	0	0	0	0
Sugar Cane	Burundi Ag North	1.01	1.19	1.19	1.19	1.19	1.19	1.19	1.09	0.94	0.78	0.4	0.6
	Burundi Ag South	1.01	1.19	1.19	1.19	1.19	1.19	1.19	1.09	0.94	0.78	0.4	0.6
	DRC Ag Bumba	1.01	1.19	1.19	1.19	1.19	1.19	1.19	1.09	0.94	0.78	0.4	0.6
	Tanzania Ag	1.01	1.19	1.19	1.19	1.19	1.19	1.19	1.09	0.94	0.78	0.4	0.6
Tomato	Burundi Ag North	0	0	0	0	0.6	0.68	1.08	1.2	1.08	0.86	0	0

	Burundi Ag South	0	0	0	0	0.6	0.67	1.02	1.13	1.01	0.8	0	0
	DRC Ag Bumba	0	0	0.6	0.8	1.62	1.08	0.84	0	0	0	0	0
	Tanzania Ag	0	0	0	0	0.6	0.68	1.08	1.2	1.08	0.86	0	0

Water Allocation

The demand priority in WEAP defines how water is allocated to satisfy competing uses – i.e. reservoir storage, hydropower generation, irrigation, domestic use, and flow. WEAP offers demand priorities ranging in number from 0-99, where the lower numbers indicate a higher priority for water use.

The demand priorities used in the Congo River are listed in Table C-6. These are generally set such that domestic water use has the highest priority, followed by environmental flow requirements as the second priority, irrigated agriculture as the third priority, hydropower generation as the fourth priority, and reservoir storage as the lowest priority. The priority structure also reflects the realities of water usage and the regional management of water within the basin. That is, water users that are high in the basin will tend to use the water that is available to them independently of water usage elsewhere in the basin. This also implies that water users that are quite low in the basin will have a lower demand priority such that they don't compete for the same water as users far upstream nor actively draw water from reservoirs at the headwaters. For example, irrigated agriculture in the lower basin (DRC Ag Maleba Pool) has a demand priority of 51, which is a lower priority than all priorities upstream – meaning water will not be actively released from any reservoir to try to meet that demand.

Table C-6: Allocation priority structure for Congo River WEAP model

Sub-basin	River	Node	WEAP Object	WEAP PRIORITY			
				Storage	Hydropower	Demand	Flow Requirement
Lualaba	Luapula	Bangwelu Swamp	Reservoir	2			
	Luapula	Bangwelu Swamp outflow	Flow Requirement				1
	Luapula	Lubumbashi	Demand			3	
	Luapula	Zambia Rural Lualaba	Demand			3	
	Lualaba	N'zilo	Run of River		1		
	Lualaba	N'seke	Run of River		1		
	Lualaba	Busanga	Run of River		1		
	Lualaba	Upemba Swamp	Reservoir	2			
	Lualaba	Upemba outflow	Flow Requirement				1
	Lualaba	DRC Rural Lualaba 1	Demand			3	
	Ruzizi	Ruzizi II	Run of River		1		
	Ruzizi	Ruzizi III	Run of River		1		
	Ruzizi	Burundi Ag North	Irrigated Catchment			2	
	Ruzizi	Bujumbura	Demand			3	
	Malagarasi Trib	Burundi Ag South	Irrigated Catchment			2	
	Lake Tanganyika system	Tanzania Ag	Irrigated Catchment			2	

	Lake Tanganyika system	Lake Tanganyika	Reservoir	2			
	Lake Tanganyika system	Lake Tanganyika outflow	Flow Requirement				1
	Lake Tanganyika system	Kalemie	Demand			3	
	Lualaba	DRC Rural Lualaba 2	Demand			3	
Kasai	Upper Kasai	Angola Rural Kasai	Demand			1	
	Upper Kasai	Lungudi	Run of River		1		
	Kasai	Katende	Run of River		1		
	Sankuru	DRC Rural U Kasai	Demand			1	
	Kasai	DRC Rural L Kasai	Demand			1	
	Kwango	Angola Rural Kwango	Demand			1	
	Kasai	Bandundu	Demand			2	
Oubangui	Oubangui	DRC Rural Oubangui 1	Demand			1	
	Mbomou	DRC Rural Mbomou	Demand			1	
	Kotto	DRC Rural Kotto	Demand			1	
	Oubangui	Mobayi	Run of River		1		
	Oubangui	Palambo	Reservoir	5	4		
	Oubangui	Lake Chad Basin Transfer	Demand			3	
	Oubangui	Navigation	Flow Requirement				1
	Oubangui	Bangui City	Demand			1	
	Oubangui	DRC Rural Oubangui 2	Demand			3	

Sangha	Sangha	DRC Rural Sangha	Demand			1	
Congo	Main Congo	Tshopo	Run of River		1		
	Ituri	DRC Rural Ituri	Demand			3	
	Lomami	DRC Rural Lomami	Demand			3	
	Main Congo	Kisangani	Demand			6	
	Main Congo	DRC Ag Bumba	Irrigated Catchment			3	
	Main Congo	Mbandaka	Demand			6	
	Maringa	DRC Rural Maringa	Demand			3	
	Main Congo	Lag Flows	Reservoir	50			
	Main Congo	Lag Flows outflow	Flow Requirement				45
	Lukeni	DRC Rural Lukeni	Demand			51	
	Main Congo	Kinshasa City	Demand			51	
	Main Congo	Brazzaville	Demand			51	
	Inkisi	Sanga	Run of River		1		
	Inkisi	Zongo	Run of River		1		
	Main Congo	DRC Ag Malebo Pool	Irrigated Catchment			51	
	Main Congo	Matadi	Demand			51	
	Main Congo	Inga I	Run of River		60		
	Main Congo	Inga II	Run of River		60		
	Main Congo	Inga III	Run of River		60		

	Main Congo	Grand Inga	Reservoir	99	95		

Model Calibration

Flow Simulation

The WEAP model set up for modelling natural hydrology consists of a river network (45 main rivers); four reservoirs to represent natural lakes and wetlands (Lake Tanganyika, Upemba depression, Bangweulu swamp and the Cuvette Centrale). The model was calibrated at the representative flow gauges in the basin. The figures below show the model performance (Simulated against observed flows) for some selected representative gauging sites in the basin. The selected gauging sites are representative of the main drainage areas of the Congo Basin, namely: Oubangui (Rafai, Bangui, Zinga), Sangha (Salo, Ouesso), Kasai (Ilebo, Kutumoke), Lualaba (Bukama, Chembe Ferry, Pont Kalemie-Tanganyika), Congo (Kinshasa). The objective functions used to evaluate the model performance are those typically used in hydrological modeling studies and consist of the Percent Bias of the mean monthly flows (PBIAS, %), Coefficient of Determination (R^2) and Nash-Sutcliffe Coefficient of Efficiency (CE). In this study the three objective functions are calculated for both un-transformed (PBIAS, R^2 and CE) data and natural logarithm transformed values (PBIAS ln, R^2 and CE ln), to ensure that both high and low flow components of the simulations are effectively evaluated.

The sources of streamflow data (Table C-7: Spatial and temporal characteristics of the main streamflow gauging sites in the Congo basin, Tshimanga and Hughes, 2014) include the Global Discharge Data Centre (GRDC: Fekete, 1999), the Office National de Recherche et du Developpement (ONRD: Lempicka*,* 1971), and Hydrosciences Montpellier –Système d'Informations Environnementales (SIEREM, http://hydrosciences.fr/sierem).

Table C-7: Spatial and temporal characteristics of the main streamflow gauging sites in the Congo basin

Station ID	Lat.	Long.	Station and River names	Drainage area km^2	Drainage area %basin	Period of records	Months	% missing	Source
1	5.17	16.62	Zaoro, Lobaye	5880	0.16	1958-1960	21	0.0	SIEREM
2	5.78	25.13	Dembia, Ouarra	19590	0.54	1953-1975	269	19.3	GRDC
3	4.73	22.68	Loungouba, Mbari	22153	0.61	1967-1973	80	20.0	GRDC
4	5.03	25.15	Zemio, Mbomou	26454	0.73	1952-1975	281	41.3	GRDC
5	3.65	18.10	Safa, Lobaye	30503	0.84	1953-1975	272	11.4	SIEREM
6	3.67	18.30	M'bata, Lobaye	31037	0.86	1950-1975	302	3.3	GRDC
7	5.78	20.68	Bambari, Ouaka	28333	0.78	1952-1975	282	21.3	GRDC
8	4.97	23.92	Rafai, Chinko	51959	1.43	1952-1973	249	16.1	GRDC
9	6.53	22.00	Bria, Kotto	58898	1.62	1959-1975	204	10.8	SIEREM
10	4.60	21.92	Kembe, Kotto	75994	2.10	1953-1965	156	0.0	GRDC
11	4.72	22.82	Bangassou, Mbomou	117644	3.24	1952-1956	57	5.3	GRDC
12	4.30	21.18	Mobaye, Oubangui	389856	10.75	1939-1960	260	5.0	GRDC
13	4.37	18.61	Bangui, Oubangui	492405	13.58	1940-2000	61	0.0	GRDC
14	3.72	18.58	Zinga, Oubangui	524497	14.47	1952-1975	282	16.0	SIEREM
15	4.35	17.07	Kedingue, Lobaye	14259	0.39	1957-1975	218	17.9	GRDC
16	4.93	15.87	Carnot, Membere	18098	0.50	1953-1971	227	22.5	SIEREM
17	2.05	14.92	N'Gbala, Dja	38600	1.06	1968-1978	131	13.0	SIEREM
18	1.62	16.05	Ouesso, Sangha	143314	3.95	1948-1983	432	0.0	GRDC
19	3.18	16.12	Salo, Sangha	69544	1.92	1953-1994	492	35.0	GRDC
20	-4.33	20.58	Port Franqui, Kasai	234770	6.48	1932-1959	336	0.0	GRDC
21	-3.18	17.38	KutuMoke, Kasai	732838	20.21	1932-1959	336	0.0	GRDC
22	-3.06	16.56	Lediba, Kwa	876632	24.18	1950-1959	120	0.0	ONRD
23	-4.02	30.56	Taragi, Malagarasi	8792	0.24	1971-1979	108	5.6	GRDC
24	-9.19	25.86	Bukama, Lualaba	61975	1.71	1950-1959	120	0.0	ONRD
25	-11.97	28.76	Chembe Ferry, Lualaba	119259	3.29	1957-1981	300	0.0	GRDC
26	-7.84	26.98	Mulongo, Lualaba	158099	4.36	1950-1959	120	0.0	ONRD
27	-5.91	29.19	Pont Kalemie, Lukuga	231635	6.39	1957-1959	31	6.5	ONRD

28	-4.53	26.58	Kasongo, Lualaba	751806	20.74	1950-1959	120	0.0	ONRD
29	-2.95	25.93	Kindu, Lualaba	789234	21.77	1933-1959	324	0.0	GRDC
30	-4.30	15.31	Kinshasa, Congo	3570566	98.48	1969-1984	192	0.0	GRDC

Table C-8: Calibration parameter values for catchment nodes

Sub-Basin	Catchment	DWC (mm)	DC (mm)	SWC (mm)	PFD	RZC (mm)	RRF
Main Congo River	WCCB20	1000	20	1000	0.15	20	2
	WCCB21	1000	20	1000	0.15	20	2
	WCCB35	1000	20	1000	0.15	20	2
	WCCB41	1000	20	1000	0.15	20	2
	WCCB45	1000	20	1000	0.15	20	2
	WCCB48	1000	20	1000	0.15	20	2
	WCCB50	1000	20	1000	0.15	20	2
	WCCB55	1000	20	1000	0.15	20	2
	WCCB58	1000	20	1000	0.15	80*(PrevTSValue(Relative Soil Moisture 1[%])/100)^0.8	2
	WCCB61	1200	20	2200	0.15	80*(PrevTSValue(Relative Soil Moisture 1[%])/100)^0.8	If(Precipitation[mm]-50<0.5,200,100+(100/(Precipitation[mm]-50))^(Ln(Precipitation[mm])/5))
	WCCB63	1000	20	1000	0.15	20	If(Precipitation[mm]-50<0.5,200,100+(100/(Precipitation[mm]-50))^(Ln(Precipitation[mm])/5))
	WCCB88	1000	20	1000	0.15	20	2
	WCCB9	1000	20	1000	0.15	20	2

	WCCB93	1000	20	1000	0.15	20	2
	WCCB94	1000	20	1000	0.15	20	2
	WCCB95	1000	20	1000	0.15	20	2
	WCCB96	1000	20	1000	0.15	20	2
	WCCB97	1000	20	1000	0.15	20	2
	WCCB98	1000	20	1000	0.15	20	2
	WCCB99	1000	20	1000	0.15	20	2
Lualaba River	WLCB10	500	20	1500	0.9	120*(PrevTSValue(Relative Soil Moisture 1[%])/100)^0.4	If(Precipitation[mm]-50<0.5,200,100+(100/(Precipitation[mm]-50))^(Ln(Precipitation[mm])/5))
	WLCB11	300	10	1200	0.9	60*(PrevTSValue(Relative Soil Moisture 1[%])/100)^0.6	If(Precipitation[mm]-50<0.5,20,3.5+(250/(Precipitation[mm]-50))^(Ln(Precipitation[mm])/5))
	WLCB12	500	20	1500	0.9	120*(PrevTSValue(Relative Soil Moisture 1[%])/100)^0.4	If(Precipitation[mm]-50<0.5,200,100+(100/(Precipitation[mm]-50))^(Ln(Precipitation[mm])/5))
	WLCB13	500	20	1500	0.9	120*(PrevTSValue(Relative Soil Moisture 1[%])/100)^0.4	If(Precipitation[mm]-50<0.5,200,100+(100/(Precipitation[mm]-50))^(Ln(Precipitation[mm])/5))
	WLCB16	500	20	1500	0.9	120*(PrevTSValue(Relative Soil Moisture 1[%])/100)^0.4	If(Precipitation[mm]-50<0.5,200,100+(100/(Precipitation[mm]-50))^(Ln(Precipitation[mm])/5))
	WLCB19	500	20	1500	0.9	120*(PrevTSValue(Relative Soil Moisture 1[%])/100)^0.4	If(Precipitation[mm]-50<0.5,200,100+(100/(Precipitation[mm]-50))^(Ln(Precipitation[mm])/5))

	WLCB23	500	20	1200	0.9	60*(PrevTSValue(Relative Soil Moisture 1[%])/100)^0.3	If(Precipitation[mm]-50<0.5,20,4.5+(250/(Precipitation[mm]-50))^(Ln(Precipitation[mm])/5))
	WLCB3	500	20	1500	0.9	120*(PrevTSValue(Relative Soil Moisture 1[%])/100)^0.4	If(Precipitation[mm]-50<0.5,200,100+(100/(Precipitation[mm]-50))^(Ln(Precipitation[mm])/5))
	WLCB34	500	20	1500	0.9	120*(PrevTSValue(Relative Soil Moisture 1[%])/100)^0.4	If(Precipitation[mm]-50<0.5,200,100+(100/(Precipitation[mm]-50))^(Ln(Precipitation[mm])/5))
	WLCB4	500	20	1500	0.9	120*(PrevTSValue(Relative Soil Moisture 1[%])/100)^0.4	If(Precipitation[mm]-50<0.5,200,100+(100/(Precipitation[mm]-50))^(Ln(Precipitation[mm])/5))
	WLCB40	1200	20	1500	0.9	120*(PrevTSValue(Relative Soil Moisture 1[%])/100)^0.4	If(Precipitation[mm]-50<0.5,200,100+(100/(Precipitation[mm]-50))^(Ln(Precipitation[mm])/5))
	WLCB43	500	20	1500	0.9	600*(PrevTSValue(Relative Soil Moisture 1[%])/100)^0.3	If(Precipitation[mm]-50<0.5,20,4.5+(250/(Precipitation[mm]-50))^(Ln(Precipitation[mm])/5))
	WLCB47	500	20	1500	0.9	120*(PrevTSValue(Relative Soil Moisture 1[%])/100)^0.4	If(Precipitation[mm]-50<0.5,200,100+(100/(Precipitation[mm]-50))^(Ln(Precipitation[mm])/5))
	WLCB53	500	20	1400	0.9	60*(PrevTSValue(Relative Soil Moisture 1[%])/100)^0.3	If(Precipitation[mm]-50<0.5,20,4.5+(250/(Precipitation[mm]-50))^(Ln(Precipitation[mm])/5))
	WLCB65	500	20	1500	0.9	60*(PrevTSValue(Relative Soil Moisture 1[%])/100)^0.3	If(Precipitation[mm]-50<0.5,20,4.5+(250/(Precipitation[mm]-50))^(Ln(Precipitation[mm])/5))
	WLCB68	500	20	1400	0.9	60*(PrevTSValue(Relative Soil Moisture 1[%])/100)^0.3	If(Precipitation[mm]-50<0.5,20,4.5+(250/(Precipitation[mm]-50))^(Ln(Precipitation[mm])/5))

	WLCB69	300	10	1000	0.9	60*(PrevTSValue(Relative Soil Moisture 1[%])/100)^0.6	If(Precipitation[mm]-50<0.5,20,6+(250/(Precipitation[mm]-50))^(Ln(Precipitation[mm])/5))
	WLCB7	500	20	1200	0.9	60*(PrevTSValue(Relative Soil Moisture 1[%])/100)^0.3	If(Precipitation[mm]-50<0.5,20,4.5+(250/(Precipitation[mm]-50))^(Ln(Precipitation[mm])/5))
	WLCB74	500	20	1500	0.9	60*(PrevTSValue(Relative Soil Moisture 1[%])/100)^0.3	If(Precipitation[mm]-50<0.5,20,4.5+(250/(Precipitation[mm]-50))^(Ln(Precipitation[mm])/5))
	WLCB75	500	20	1500	0.9	120*(PrevTSValue(Relative Soil Moisture 1[%])/100)^0.4	If(Precipitation[mm]-50<0.5,20,4.5+(250/(Precipitation[mm]-50))^(Ln(Precipitation[mm])/5))
	WLCB77	500	20	1500	0.9	120*(PrevTSValue(Relative Soil Moisture 1[%])/100)^0.4	If(Precipitation[mm]-50<0.5,20,4.5+(250/(Precipitation[mm]-50))^(Ln(Precipitation[mm])/5))
	WLCB80	500	20	1500	0.9	120*(PrevTSValue(Relative Soil Moisture 1[%])/100)^0.4	If(Precipitation[mm]-50<0.5,200,100+(100/(Precipitation[mm]-50))^(Ln(Precipitation[mm])/5))
	WLCB81	1400	20	2000	0.9	90*(PrevTSValue(Relative Soil Moisture 1[%])/100)^0.8	If(Precipitation[mm]-50<0.5,20,4.5+(250/(Precipitation[mm]-50))^(Ln(Precipitation[mm])/5))
	WLCB86	1200	20	2100	0.9	90*(PrevTSValue(Relative Soil Moisture 1[%])/100)^0.8	If(Precipitation[mm]-50<0.5,20,4.5+(250/(Precipitation[mm]-50))^(Ln(Precipitation[mm])/5))
	WLCB87	1400	20	2200	0.9	90*(PrevTSValue(Relative Soil Moisture 1[%])/100)^0.8	If(Precipitation[mm]-50<0.5,20,4.5+(250/(Precipitation[mm]-50))^(Ln(Precipitation[mm])/5))
	WLCB89	1200	20	1500	0.9	60*(PrevTSValue(Relative Soil Moisture 1[%])/100)^0.3	If(Precipitation[mm]-50<0.5,20,4.5+(250/(Precipitation[mm]-50))^(Ln(Precipitation[mm])/5))

	WLCB90	500	20	1500	0.9	60*(PrevTSValue(Relative Soil Moisture 1[%])/100)^0.3	If(Precipitation[mm]-50<0.5,20,4.5+(250/(Precipitation[mm]-50))^(Ln(Precipitation[mm])/5))
	WLCB91	500	20	1500	0.9	60*(PrevTSValue(Relative Soil Moisture 1[%])/100)^0.3	If(Precipitation[mm]-50<0.5,200,100+(100/(Precipitation[mm]-50))^(Ln(Precipitation[mm])/5))
	WLCB92	500	20	1500	0.9	60*(PrevTSValue(Relative Soil Moisture 1[%])/100)^0.3	If(Precipitation[mm]-50<0.5,200,100+(100/(Precipitation[mm]-50))^(Ln(Precipitation[mm])/5))
Obangui River	WOCB14	300	12	2200	0.9	120*(PrevTSValue(Relative Soil Moisture 1[%])/100)^4	If(Precipitation[mm]-50<0.5,100,30+(100/(Precipitation[mm]-50))^(Ln(Precipitation[mm])/5))
	WOCB2	400	15	2200	0.9	78*(PrevTSValue(Relative Soil Moisture 1[%])/100)^0.8	If(Precipitation[mm]-50<0.5,100,20+(100/(Precipitation[mm]-50))^(Ln(Precipitation[mm])/5))
	WOCB22	200	12	1200	0.9	80*(PrevTSValue(Relative Soil Moisture 1[%])/100)^1.8	If(Precipitation[mm]-50<0.5,100,20+(100/(Precipitation[mm]-50))^(Ln(Precipitation[mm])/5))
	WOCB24	400	15	2100	0.9	120*(PrevTSValue(Relative Soil Moisture 1[%])/100)^4	If(Precipitation[mm]-50<0.5,100,30+(100/(Precipitation[mm]-50))^(Ln(Precipitation[mm])/5))
	WOCB25	400	19	1900	0.9	40*(PrevTSValue(Relative Soil Moisture 1[%])/100)^3.5	If(Precipitation[mm]-50<0.5,100,15+(100/(Precipitation[mm]-50))^(Ln(Precipitation[mm])/5))
	WOCB26	400	27	1900	0.9	40*(PrevTSValue(Relative Soil Moisture 1[%])/100)^3.5	If(Precipitation[mm]-50<0.5,100,15+(100/(Precipitation[mm]-50))^(Ln(Precipitation[mm])/5))
	WOCB27	300	9	1200	0.9	100*(PrevTSValue(Relative Soil Moisture 1[%])/100)^1.8	If(Precipitation[mm]-50<0.5,100,60+(100/(Precipitation[mm]-50))^(Ln(Precipitation[mm])/5))

	WOCB29	500	15	2200	0.9	80*(PrevTSValue(Relative Soil Moisture 1[%])/100)^0.8	If(Precipitation[mm]-50<0.5,200,100+(100/(Precipitation[mm]-50))^(Ln(Precipitation[mm])/5))
	WOCB30	1200	20	2200	0.9	80*(PrevTSValue(Relative Soil Moisture 1[%])/100)^0.8	If(Precipitation[mm]-50<0.5,200,100+(100/(Precipitation[mm]-50))^(Ln(Precipitation[mm])/5))
	WOCB31	400	25	1950	0.95	65*(PrevTSValue(Relative Soil Moisture 1[%])/100)^2.4	If(Precipitation[mm]-50<0.5,80,40+(100/(Precipitation[mm]-50))^(Ln(Precipitation[mm])/5))
	WOCB33	400	5	1200	0.9	40*(PrevTSValue(Relative Soil Moisture 1[%])/100)^3.5	If(Precipitation[mm]-50<0.5,100,15+(100/(Precipitation[mm]-50))^(Ln(Precipitation[mm])/5))
	WOCB38	400	19	1900	0.9	40*(PrevTSValue(Relative Soil Moisture 1[%])/100)^3.5	If(Precipitation[mm]-50<0.5,100,15+(100/(Precipitation[mm]-50))^(Ln(Precipitation[mm])/5))
	WOCB44	300	8	1200	0.9	80*(PrevTSValue(Relative Soil Moisture 1[%])/100)^1.8	If(Precipitation[mm]-50<0.5,100,60+(100/(Precipitation[mm]-50))^(Ln(Precipitation[mm])/5))
	WOCB46	400	20	1900	0.9	40*(PrevTSValue(Relative Soil Moisture 1[%])/100)^3.5	If(Precipitation[mm]-50<0.5,100,15+(100/(Precipitation[mm]-50))^(Ln(Precipitation[mm])/5))
	WOCB49	400	25	1940	0.95	65*(PrevTSValue(Relative Soil Moisture 1[%])/100)^2.4	If(Precipitation[mm]-50<0.5,80,40+(100/(Precipitation[mm]-50))^(Ln(Precipitation[mm])/5))
	WOCB5	400	8	1900	0.9	40*(PrevTSValue(Relative Soil Moisture 1[%])/100)^3.5	If(Precipitation[mm]-50<0.5,100,15+(100/(Precipitation[mm]-50))^(Ln(Precipitation[mm])/5))
	WOCB56	400	25	1940	0.95	65*(PrevTSValue(Relative Soil Moisture 1[%])/100)^2.4	If(Precipitation[mm]-50<0.5,80,40+(100/(Precipitation[mm]-50))^(Ln(Precipitation[mm])/5))

	WOCB60	400	19	1900	0.9	40*(PrevTSValue(Relative Soil Moisture 1[%])/100)^3.5	If(Precipitation[mm]-50<0.5,100,15+(100/(Precipitation[mm]-50))^(Ln(Precipitation[mm])/5))
	WOCB62	400	16	1900	0.9	40*(PrevTSValue(Relative Soil Moisture 1[%])/100)^3.5	If(Precipitation[mm]-50<0.5,100,15+(100/(Precipitation[mm]-50))^(Ln(Precipitation[mm])/5))
	WOCB67	400	9	1900	0.9	40*(PrevTSValue(Relative Soil Moisture 1[%])/100)^3.5	If(Precipitation[mm]-50<0.5,100,15+(100/(Precipitation[mm]-50))^(Ln(Precipitation[mm])/5))
	WOCB70	400	5	1900	0.9	40*(PrevTSValue(Relative Soil Moisture 1[%])/100)^3.5	If(Precipitation[mm]-50<0.5,100,15+(100/(Precipitation[mm]-50))^(Ln(Precipitation[mm])/5))
	WOCB78	400	5	1900	0.9	40*(PrevTSValue(Relative Soil Moisture 1[%])/100)^3.5	If(Precipitation[mm]-50<0.5,100,15+(100/(Precipitation[mm]-50))^(Ln(Precipitation[mm])/5))
	WOCB8	300	9	1200	0.9	100*(PrevTSValue(Relative Soil Moisture 1[%])/100)^1.8	If(Precipitation[mm]-50<0.5,100,60+(100/(Precipitation[mm]-50))^(Ln(Precipitation[mm])/5))
	WOCB82	400	5	1900	0.9	40*(PrevTSValue(Relative Soil Moisture 1[%])/100)^3.5	If(Precipitation[mm]-50<0.5,100,15+(100/(Precipitation[mm]-50))^(Ln(Precipitation[mm])/5))
	WOCB83	400	5	1900	0.9	40*(PrevTSValue(Relative Soil Moisture 1[%])/100)^3.5	If(Precipitation[mm]-50<0.5,100,15+(100/(Precipitation[mm]-50))^(Ln(Precipitation[mm])/5))
	WOCB84	1000	20	1000	0.15	20	2
Kasai River	WKCB28	500	11	1900	0.9	100*(PrevTSValue(Relative Soil Moisture 1[%])/100)^0.8	If(Precipitation[mm]-50<0.5,20,5+(250/(Precipitation[mm]-50))^(Ln(Precipitation[mm])/5))

	WKCB32	500	11	1900	0.9	100*(PrevTSValue(Relative Soil Moisture 1[%])/100)^0.8	If(Precipitation[mm]-50<0.5,20,5+(250/(Precipitation[mm]-50))^(Ln(Precipitation[mm])/5))
	WKCB36	400	30	2200	0.8	90*(PrevTSValue(Relative Soil Moisture 1[%])/100)^0.8	If(Precipitation[mm]-50<0.5,20,4.5+(250/(Precipitation[mm]-50))^(Ln(Precipitation[mm])/5))
	WKCB37	500	11	1900	0.9	100*(PrevTSValue(Relative Soil Moisture 1[%])/100)^0.8	If(Precipitation[mm]-50<0.5,20,5+(250/(Precipitation[mm]-50))^(Ln(Precipitation[mm])/5))
	WKCB51	400	11	1900	0.9	100*(PrevTSValue(Relative Soil Moisture 1[%])/100)^0.8	If(Precipitation[mm]-50<0.5,20,5+(250/(Precipitation[mm]-50))^(Ln(Precipitation[mm])/5))
	WKCB54	400	30	2200	0.8	90*(PrevTSValue(Relative Soil Moisture 1[%])/100)^0.8	If(Precipitation[mm]-50<0.5,20,4.5+(250/(Precipitation[mm]-50))^(Ln(Precipitation[mm])/5))
	WKCB59	400	11	1900	0.9	100*(PrevTSValue(Relative Soil Moisture 1[%])/100)^0.8	If(Precipitation[mm]-50<0.5,20,5+(250/(Precipitation[mm]-50))^(Ln(Precipitation[mm])/5))
	WKCB6	400	11	1900	0.9	100*(PrevTSValue(Relative Soil Moisture 1[%])/100)^0.8	If(Precipitation[mm]-50<0.5,20,5+(250/(Precipitation[mm]-50))^(Ln(Precipitation[mm])/5))
	WKCB64	400	30	2200	0.8	90*(PrevTSValue(Relative Soil Moisture 1[%])/100)^0.8	If(Precipitation[mm]-50<0.5,20,4.5+(250/(Precipitation[mm]-50))^(Ln(Precipitation[mm])/5))
	WKCB66	400	11	1900	0.9	100*(PrevTSValue(Relative Soil Moisture 1[%])/100)^0.8	If(Precipitation[mm]-50<0.5,20,5+(250/(Precipitation[mm]-50))^(Ln(Precipitation[mm])/5))
	WKCB73	400	11	1900	0.9	100*(PrevTSValue(Relative Soil Moisture 1[%])/100)^0.8	If(Precipitation[mm]-50<0.5,20,5+(250/(Precipitation[mm]-50))^(Ln(Precipitation[mm])/5))

	WKCB76	400	30	2200	0.8	90*(PrevTSValue(Relative Soil Moisture 1[%])/100)^0.8	If(Precipitation[mm]-50<0.5,20,4.5+(250/(Precipitation[mm]-50))^(Ln(Precipitation[mm])/5))
	WKCB79	300	11	1900	0.9	100*(PrevTSValue(Relative Soil Moisture 1[%])/100)^0.8	If(Precipitation[mm]-50<0.5,20,5+(250/(Precipitation[mm]-50))^(Ln(Precipitation[mm])/5))
	WKCB85	400	11	1900	0.9	100*(PrevTSValue(Relative Soil Moisture 1[%])/100)^0.8	If(Precipitation[mm]-50<0.5,20,5+(250/(Precipitation[mm]-50))^(Ln(Precipitation[mm])/5))
Sangha River	WSC39	300	20	1800	0.9	120*(PrevTSValue(Relative Soil Moisture 1[%])/100)^2.2	If(Precipitation[mm]-50<0.5,100,20+(100/(Precipitation[mm]-50))^(Ln(Precipitation[mm])/5))
	WSCB1	1000	20	1000	0.15	20	2
	WSCB15	1000	20	1000	0.15	20	2
	WSCB17	1000	20	1000	0.15	20	2
	WSCB18	300	20	1800	0.9	120*(PrevTSValue(Relative Soil Moisture 1[%])/100)^2.2	If(Precipitation[mm]-50<0.5,100,25+(100/(Precipitation[mm]-50))^(Ln(Precipitation[mm])/5))
	WSCB42	200	15	700	0.9	25	12
	WSCB52	300	15	2300	0.9	90*(PrevTSValue(Relative Soil Moisture 1[%])/100)^3.8	If(Precipitation[mm]-50<0.5,100,20+(100/(Precipitation[mm]-50))^(Ln(Precipitation[mm])/5))
	WSCB57	300	20	1800	0.9	120*(PrevTSValue(Relative Soil Moisture 1[%])/100)^2.2	If(Precipitation[mm]-50<0.5,100,20+(100/(Precipitation[mm]-50))^(Ln(Precipitation[mm])/5))
	WSCB71	300	15	2300	0.9	90*(PrevTSValue(Relative Soil Moisture 1[%])/100)^3.8	If(Precipitation[mm]-50<0.5,100,20+(100/(Precipitation[mm]-50))^(Ln(Precipitation[mm])/5))

	WSCB72	200	20	800	0.9	41	12

Table C-9: Calibrated Kc values for catchment nodes

Sub-Basin	Catchment	Kc
Main Congo River	WCCB20	MonthlyValues(Jan, 1.02, Feb, 1.02, Mar, 1.02, Apr, 1.02, May, 1.02, Jun, 1.02, Jul, 1.03, Aug, 1.03, Sep, 1.03, Oct, 1.02, Nov, 1.02, Dec, 1.02)
	WCCB21	MonthlyValues(Jan, 1.03, Feb, 1.03, Mar, 1.03, Apr, 1.03, May, 1.03, Jun, 1.03, Jul, 1.03, Aug, 1.03, Sep, 1.03, Oct, 1.03, Nov, 1.03, Dec, 1.03)
	WCCB35	MonthlyValues(Jan, 1.02, Feb, 1.02, Mar, 1.02, Apr, 1.02, May, 1.02, Jun, 1.03, Jul, 1.03, Aug, 1.03, Sep, 1.03, Oct, 1.03, Nov, 1.02, Dec, 1.02)
	WCCB41	MonthlyValues(Jan, 1.02, Feb, 1.03, Mar, 1.02, Apr, 1.02, May, 1.02, Jun, 1.02, Jul, 1.02, Aug, 1.02, Sep, 1.02, Oct, 1.02, Nov, 1.03, Dec, 1.03)
	WCCB45	MonthlyValues(Jan, 1.02, Feb, 1.02, Mar, 1.02, Apr, 1.02, May, 1.02, Jun, 1.02, Jul, 1.02, Aug, 1.02, Sep, 1.02, Oct, 1.02, Nov, 1.02, Dec, 1.02)
	WCCB48	MonthlyValues(Jan, 1.03, Feb, 1.03, Mar, 1.03, Apr, 1.02, May, 1.03, Jun, 1.03, Jul, 1.03, Aug, 1.03, Sep, 1.03, Oct, 1.03, Nov, 1.03, Dec, 1.03)
	WCCB50	MonthlyValues(Jan, 1.03, Feb, 1.02, Mar, 1.02, Apr, 1.02, May, 1.02, Jun, 1.02, Jul, 1.02, Aug, 1.02, Sep, 1.02, Oct, 1.02, Nov, 1.02, Dec, 1.03)
	WCCB55	MonthlyValues(Jan, 1.02, Feb, 1.02, Mar, 1.02, Apr, 1.02, May, 1.02, Jun, 1.03, Jul, 1.03, Aug, 1.03, Sep, 1.02, Oct, 1.02, Nov, 1.02, Dec, 1.02)
	WCCB58	MonthlyValues(Jan, 1.02, Feb, 1.02, Mar, 1.02, Apr, 1.02, May, 1.02, Jun, 1.02, Jul, 1.02, Aug, 1.02, Sep, 1.02, Oct, 1.02, Nov, 1.02, Dec, 1.02)
	WCCB61	0.9 * MonthlyValues(Jan, 1.02, Feb, 1.02, Mar, 1.02, Apr, 1.02, May, 1.02, Jun, 1.03, Jul, 1.03, Aug, 1.03, Sep, 1.03, Oct, 1.03, Nov, 1.02, Dec, 1.02)
	WCCB63	MonthlyValues(Jan, 1.02, Feb, 1.02, Mar, 1.02, Apr, 1.02, May, 1.02, Jun, 1.02, Jul, 1.02, Aug, 1.02, Sep, 1.02, Oct, 1.02, Nov, 1.02, Dec, 1.02)
	WCCB88	MonthlyValues(Jan, 1.02, Feb, 1.02, Mar, 1.02, Apr, 1.02, May, 1.02, Jun, 1.02, Jul, 1.02, Aug, 1.02, Sep, 1.02, Oct, 1.02, Nov, 1.02, Dec, 1.02)
	WCCB9	MonthlyValues(Jan, 1.04, Feb, 1.03, Mar, 1.03, Apr, 1.03, May, 1.04, Jun, 1.04, Jul, 1.04, Aug, 1.04, Sep, 1.04, Oct, 1.03, Nov, 1.03, Dec, 1.05)
	WCCB93	MonthlyValues(Jan, 1.02, Feb, 1.02, Mar, 1.02, Apr, 1.02, May, 1.02, Jun, 1.03, Jul, 1.03, Aug, 1.03, Sep, 1.03, Oct, 1.02, Nov, 1.02, Dec, 1.02)

	WCCB94	MonthlyValues(Jan, 1.02, Feb, 1.02, Mar, 1.02, Apr, 1.02, May, 1.02, Jun, 1.02, Jul, 1.02, Aug, 1.02, Sep, 1.02, Oct, 1.02, Nov, 1.02, Dec, 1.02)
	WCCB95	MonthlyValues(Jan, 1.02, Feb, 1.02, Mar, 1.02, Apr, 1.02, May, 1.02, Jun, 1.02, Jul, 1.02, Aug, 1.02, Sep, 1.02, Oct, 1.02, Nov, 1.02, Dec, 1.02)
	WCCB96	MonthlyValues(Jan, 1.03, Feb, 1.02, Mar, 1.02, Apr, 1.02, May, 1.02, Jun, 1.02, Jul, 1.03, Aug, 1.02, Sep, 1.02, Oct, 1.02, Nov, 1.03, Dec, 1.02)
	WCCB97	MonthlyValues(Jan, 1.03, Feb, 1.02, Mar, 1.02, Apr, 1.02, May, 1.03, Jun, 1.03, Jul, 1.03, Aug, 1.03, Sep, 1.03, Oct, 1.03, Nov, 1.03, Dec, 1.03)
	WCCB98	MonthlyValues(Jan, 1.02, Feb, 1.02, Mar, 1.02, Apr, 1.04, May, 1.02, Jun, 1.01, Jul, 1.02, Aug, 1.02, Sep, 1.02, Oct, 1.02, Nov, 1.02, Dec, 1.02)
	WCCB99	MonthlyValues(Jan, 1.03, Feb, 1.02, Mar, 1.02, Apr, 1.02, May, 1.02, Jun, 1.02, Jul, 1.02, Aug, 1.02, Sep, 1.02, Oct, 1.02, Nov, 1.02, Dec, 1.03)
Lualaba River	WLCB10	MonthlyValues(Jan, 1.02, Feb, 1.02, Mar, 1.02, Apr, 1.02, May, 1.02, Jun, 1.02, Jul, 1.03, Aug, 1.02, Sep, 1.02, Oct, 1.02, Nov, 1.02, Dec, 1.02)
	WLCB11	0.93 * MonthlyValues(Jan, 1.05, Feb, 1.04, Mar, 1.04, Apr, 1.04, May, 1.04, Jun, 1.04, Jul, 1.04, Aug, 1.04, Sep, 1.04, Oct, 1.04, Nov, 1.04, Dec, 1.04)
	WLCB12	MonthlyValues(Jan, 1.01, Feb, 1.01, Mar, 1.01, Apr, 1.01, May, 1.01, Jun, 1.02, Jul, 1.02, Aug, 1.02, Sep, 1.01, Oct, 1.01, Nov, 1.01, Dec, 1.01)
	WLCB13	MonthlyValues(Jan, 1.04, Feb, 1.04, Mar, 1.04, Apr, 1.04, May, 1.03, Jun, 1.03, Jul, 1.03, Aug, 1.03, Sep, 1.03, Oct, 1.03, Nov, 1.03, Dec, 1.04)
	WLCB16	MonthlyValues(Jan, 1.06, Feb, 1.05, Mar, 1.06, Apr, 1.05, May, 1.04, Jun, 1.03, Jul, 1.03, Aug, 1.03, Sep, 1.02, Oct, 1.03, Nov, 1.04, Dec, 1.05)
	WLCB19	1.2 * MonthlyValues(Jan, 1.03, Feb, 1.03, Mar, 1.03, Apr, 1.03, May, 1.03, Jun, 1.03, Jul, 1.03, Aug, 1.03, Sep, 1.03, Oct, 1.03, Nov, 1.03, Dec, 1.03)
	WLCB23	MonthlyValues(Jan, 1.03, Feb, 1.03, Mar, 1.03, Apr, 1.03, May, 1.03, Jun, 1.04, Jul, 1.03, Aug, 1.03, Sep, 1.03, Oct, 1.03, Nov, 1.03, Dec, 1.03)
	WLCB3	MonthlyValues(Jan, 1.06, Feb, 1.06, Mar, 1.06, Apr, 1.06, May, 1.07, Jun, 1.06, Jul, 1.06, Aug, 1.06, Sep, 1.06, Oct, 1.07, Nov, 1.06, Dec, 1.07)
	WLCB34	MonthlyValues(Jan, 1.02, Feb, 1.02, Mar, 1.02, Apr, 1.02, May, 1.02, Jun, 1.03, Jul, 1.03, Aug, 1.03, Sep, 1.03, Oct, 1.02, Nov, 1.02, Dec, 1.02)
	WLCB4	MonthlyValues(Jan, 1.01, Feb, 1.01, Mar, 1.01, Apr, 1.00, May, 1.01, Jun, 1.02, Jul, 1.02, Aug, 1.02, Sep, 1.02, Oct, 1.01, Nov, 1.01, Dec, 1.01)
	WLCB40	1.3 * MonthlyValues(Jan, 1.03, Feb, 1.02, Mar, 1.03, Apr, 1.03, May, 1.03, Jun, 1.03, Jul, 1.03, Aug, 1.03, Sep, 1.03, Oct, 1.03, Nov, 1.03, Dec, 1.03)
	WLCB43	1.5 * MonthlyValues(Jan, 1.03, Feb, 1.03, Mar, 1.03, Apr, 1.02, May, 1.03, Jun, 1.03, Jul, 1.03, Aug, 1.02, Sep, 1.02, Oct, 1.02, Nov, 1.03, Dec, 1.03)
	WLCB47	MonthlyValues(Jan, 1.02, Feb, 1.02, Mar, 1.01, Apr, 1.02, May, 1.02, Jun, 1.02, Jul, 1.02, Aug, 1.02, Sep, 1.02, Oct, 1.02, Nov, 1.02, Dec, 1.01)

	WLCB53	MonthlyValues(Jan, 1.02, Feb, 1.04, Mar, 1.02, Apr, 1.02, May, 1.02, Jun, 1.03, Jul, 1.02, Aug, 1.02, Sep, 1.02, Oct, 1.02, Nov, 1.02, Dec, 1.02)
	WLCB65	1.5 * MonthlyValues(Jan, 1.03, Feb, 1.02, Mar, 1.03, Apr, 1.03, May, 1.03, Jun, 1.03, Jul, 1.03, Aug, 1.03, Sep, 1.03, Oct, 1.02, Nov, 1.03, Dec, 1.03)
	WLCB68	1.5 * MonthlyValues(Jan, 1.03, Feb, 1.02, Mar, 1.02, Apr, 1.02, May, 1.02, Jun, 1.02, Jul, 1.02, Aug, 1.02, Sep, 1.01, Oct, 1.02, Nov, 1.02, Dec, 1.03)
	WLCB69	0.9 * MonthlyValues(Jan, 1.03, Feb, 1.03, Mar, 1.03, Apr, 1.03, May, 1.03, Jun, 1.03, Jul, 1.03, Aug, 1.02, Sep, 1.02, Oct, 1.02, Nov, 1.03, Dec, 1.03)
	WLCB7	MonthlyValues(Jan, 1.03, Feb, 1.03, Mar, 1.03, Apr, 1.03, May, 1.03, Jun, 1.03, Jul, 1.03, Aug, 1.03, Sep, 1.03, Oct, 1.02, Nov, 1.03, Dec, 1.03)
	WLCB74	1.5 * MonthlyValues(Jan, 1.02, Feb, 1.03, Mar, 1.02, Apr, 1.02, May, 1.02, Jun, 1.02, Jul, 1.02, Aug, 1.02, Sep, 1.02, Oct, 1.02, Nov, 1.02, Dec, 1.02)
	WLCB75	MonthlyValues(Jan, 1.02, Feb, 1.02, Mar, 1.02, Apr, 1.03, May, 1.03, Jun, 1.03, Jul, 1.03, Aug, 1.03, Sep, 1.03, Oct, 1.03, Nov, 1.02, Dec, 1.02)
	WLCB77	1.3 * MonthlyValues(Jan, 1.03, Feb, 1.03, Mar, 1.03, Apr, 1.03, May, 1.03, Jun, 1.03, Jul, 1.03, Aug, 1.03, Sep, 1.03, Oct, 1.03, Nov, 1.03, Dec, 1.03)
	WLCB80	MonthlyValues(Oct, 0.95, Nov, 0.99, Dec, 1.03, Jan, 1.0, Feb, 1.04, Mar, 1.05, Apr, 0.99, May, 0.93, Jun, 0.93, Jul, 0.92, Aug, 0.95, Sep, 0.95)
	WLCB81	1.3 * MonthlyValues(Jan, 1.02, Feb, 1.02, Mar, 1.02, Apr, 1.03, May, 1.03, Jun, 1.03, Jul, 1.03, Aug, 1.03, Sep, 1.02, Oct, 1.02, Nov, 1.02, Dec, 1.02)
	WLCB86	1.2 * MonthlyValues(Jan, 1.02, Feb, 1.02, Mar, 1.02, Apr, 1.02, May, 1.02, Jun, 1.02, Jul, 1.02, Aug, 1.02, Sep, 1.02, Oct, 1.02, Nov, 1.02, Dec, 1.02)
	WLCB87	MonthlyValues(Jan, 1.02, Feb, 1.02, Mar, 1.02, Apr, 1.02, May, 1.02, Jun, 1.02, Jul, 1.02, Aug, 1.02, Sep, 1.02, Oct, 1.02, Nov, 1.03, Dec, 1.03)
	WLCB89	1.2 * MonthlyValues(Jan, 1.02, Feb, 1.02, Mar, 1.02, Apr, 1.02, May, 1.02, Jun, 1.03, Jul, 1.03, Aug, 1.03, Sep, 1.02, Oct, 1.02, Nov, 1.02, Dec, 1.02)
	WLCB90	MonthlyValues(Jan, 1.02, Feb, 1.02, Mar, 1.02, Apr, 1.02, May, 1.02, Jun, 1.02, Jul, 1.03, Aug, 1.03, Sep, 1.02, Oct, 1.02, Nov, 1.02, Dec, 1.02)
	WLCB91	MonthlyValues(Jan, 1.02, Feb, 1.02, Mar, 1.02, Apr, 1.02, May, 1.02, Jun, 1.03, Jul, 1.03, Aug, 1.03, Sep, 1.03, Oct, 1.02, Nov, 1.02, Dec, 1.02)
	WLCB92	MonthlyValues(Jan, 1.02, Feb, 1.02, Mar, 1.02, Apr, 1.02, May, 1.02, Jun, 1.02, Jul, 1.02, Aug, 1.02, Sep, 1.02, Oct, 1.02, Nov, 1.02, Dec, 1.03)

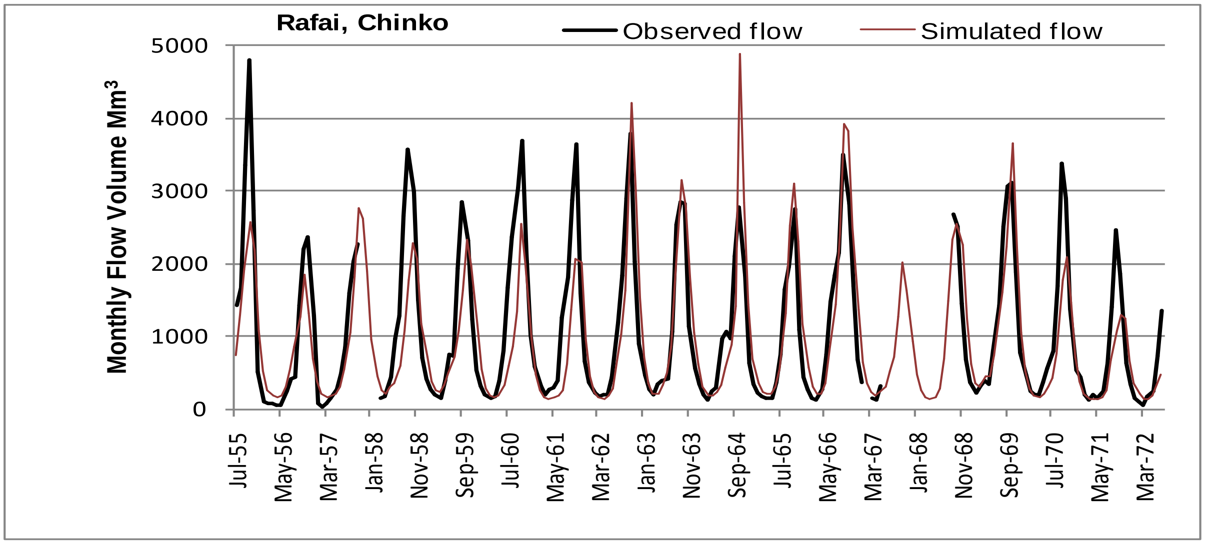
Obangui River	WOCB14	0.9 * MonthlyValues(Jan, 1.03, Feb, 1.03, Mar, 1.03, Apr, 1.03, May, 1.03, Jun, 1.03, Jul, 1.03, Aug, 1.03, Sep, 1.03, Oct, 1.03, Nov, 1.03, Dec, 1.03)
	WOCB2	0.9 * MonthlyValues(Jan, 1.02, Feb, 1.02, Mar, 1.02, Apr, 1.02, May, 1.02, Jun, 1.03, Jul, 1.03, Aug, 1.03, Sep, 1.03, Oct, 1.03, Nov, 1.02, Dec, 1.02)
	WOCB22	0.5 * MonthlyValues(Jan, 1.03, Feb, 1.03, Mar, 1.02, Apr, 1.02, May, 1.03, Jun, 1.03, Jul, 1.02, Aug, 1.02, Sep, 1.02, Oct, 1.03, Nov, 1.03, Dec, 1.03)
	WOCB24	0.9 * MonthlyValues(Jan, 1.03, Feb, 1.03, Mar, 1.03, Apr, 1.03, May, 1.03, Jun, 1.04, Jul, 1.02, Aug, 1.03, Sep, 1.02, Oct, 1.03, Nov, 1.03, Dec, 1.03)
	WOCB25	0.9 * MonthlyValues(Jan, 1.02, Feb, 1.02, Mar, 1.02, Apr, 1.02, May, 1.02, Jun, 1.03, Jul, 1.03, Aug, 1.03, Sep, 1.02, Oct, 1.02, Nov, 1.02, Dec, 1.02)
	WOCB26	0.9 * MonthlyValues(Jan, 1.02, Feb, 1.02, Mar, 1.02, Apr, 1.02, May, 1.02, Jun, 1.03, Jul, 1.02, Aug, 1.02, Sep, 1.02, Oct, 1.02, Nov, 1.02, Dec, 1.03)
	WOCB27	MonthlyValues(Jan, 1.03, Feb, 1.03, Mar, 1.02, Apr, 1.02, May, 1.02, Jun, 1.02, Jul, 1.03, Aug, 1.03, Sep, 1.03, Oct, 1.02, Nov, 1.03, Dec, 1.03)
	WOCB29	0.9 * MonthlyValues(Jan, 1.02, Feb, 1.02, Mar, 1.02, Apr, 1.02, May, 1.02, Jun, 1.03, Jul, 1.03, Aug, 1.03, Sep, 1.03, Oct, 1.02, Nov, 1.02, Dec, 1.02)
	WOCB30	0.9 * MonthlyValues(Jan, 1.02, Feb, 1.01, Mar, 1.02, Apr, 1.01, May, 1.02, Jun, 1.02, Jul, 1.02, Aug, 1.02, Sep, 1.03, Oct, 1.01, Nov, 1.01, Dec, 1.02)
	WOCB31	0.9 * MonthlyValues(Jan, 1.03, Feb, 1.03, Mar, 1.02, Apr, 1.03, May, 1.03, Jun, 1.03, Jul, 1.03, Aug, 1.02, Sep, 1.03, Oct, 1.03, Nov, 1.03, Dec, 1.03)
	WOCB33	0.9 * MonthlyValues(Jan, 1.02, Feb, 1.02, Mar, 1.02, Apr, 1.02, May, 1.02, Jun, 1.03, Jul, 1.02, Aug, 1.03, Sep, 1.02, Oct, 1.03, Nov, 1.02, Dec, 1.03)
	WOCB38	0.9 * MonthlyValues(Jan, 1.02, Feb, 1.02, Mar, 1.01, Apr, 1.02, May, 1.03, Jun, 1.02, Jul, 1.03, Aug, 1.03, Sep, 1.02, Oct, 1.02, Nov, 1.02, Dec, 1.02)
	WOCB44	MonthlyValues(Jan, 1.03, Feb, 1.03, Mar, 1.02, Apr, 1.02, May, 1.03, Jun, 1.04, Jul, 1.03, Aug, 1.03, Sep, 1.03, Oct, 1.03, Nov, 1.02, Dec, 1.03)
	WOCB46	0.9 * MonthlyValues(Jan, 1.02, Feb, 1.02, Mar, 1.02, Apr, 1.02, May, 1.02, Jun, 1.03, Jul, 1.02, Aug, 1.02, Sep, 1.02, Oct, 1.02, Nov, 1.02, Dec, 1.02)

	WOCB49	0.9 * MonthlyValues(Jan, 1.03, Feb, 1.03, Mar, 1.02, Apr, 1.02, May, 1.02, Jun, 1.02, Jul, 1.03, Aug, 1.03, Sep, 1.03, Oct, 1.02, Nov, 1.02, Dec, 1.03)
	WOCB5	0.9 * MonthlyValues(Jan, 1.03, Feb, 1.02, Mar, 1.02, Apr, 1.02, May, 1.02, Jun, 1.04, Jul, 1.03, Aug, 1.03, Sep, 1.03, Oct, 1.02, Nov, 1.02, Dec, 1.03)
	WOCB56	0.9 * MonthlyValues(Jan, 1.03, Feb, 1.02, Mar, 1.03, Apr, 1.03, May, 1.03, Jun, 1.03, Jul, 1.03, Aug, 1.03, Sep, 1.02, Oct, 1.03, Nov, 1.03, Dec, 1.03)
	WOCB60	0.9 * MonthlyValues(Jan, 1.02, Feb, 1.02, Mar, 1.02, Apr, 1.03, May, 1.02, Jun, 1.03, Jul, 1.03, Aug, 1.03, Sep, 1.02, Oct, 1.03, Nov, 1.02, Dec, 1.02)
	WOCB62	0.9 * MonthlyValues(Jan, 1.03, Feb, 1.03, Mar, 1.02, Apr, 1.02, May, 1.03, Jun, 1.04, Jul, 1.03, Aug, 1.03, Sep, 1.03, Oct, 1.03, Nov, 1.02, Dec, 1.03)
	WOCB67	0.9 * MonthlyValues(Jan, 1.02, Feb, 1.03, Mar, 1.02, Apr, 1.03, May, 1.03, Jun, 1.03, Jul, 1.03, Aug, 1.03, Sep, 1.02, Oct, 1.03, Nov, 1.02, Dec, 1.03)
	WOCB70	0.9 * MonthlyValues(Jan, 1.03, Feb, 1.03, Mar, 1.03, Apr, 1.03, May, 1.02, Jun, 1.03, Jul, 1.02, Aug, 1.02, Sep, 1.02, Oct, 1.03, Nov, 1.03, Dec, 1.03)
	WOCB78	0.9 * MonthlyValues(Jan, 1.03, Feb, 1.03, Mar, 1.03, Apr, 1.03, May, 1.03, Jun, 1.03, Jul, 1.02, Aug, 1.02, Sep, 1.02, Oct, 1.03, Nov, 1.03, Dec, 1.03)
	WOCB8	MonthlyValues(Jan, 1.02, Feb, 1.02, Mar, 1.02, Apr, 1.02, May, 1.02, Jun, 1.02, Jul, 1.02, Aug, 1.03, Sep, 1.02, Oct, 1.02, Nov, 1.02, Dec, 1.02)
	WOCB82	0.9 * MonthlyValues(Jan, 1.02, Feb, 1.02, Mar, 1.02, Apr, 1.02, May, 1.02, Jun, 1.03, Jul, 1.02, Aug, 1.02, Sep, 1.02, Oct, 1.02, Nov, 1.02, Dec, 1.02)
	WOCB83	0.9 * MonthlyValues(Jan, 1.02, Feb, 1.02, Mar, 1.02, Apr, 1.02, May, 1.02, Jun, 1.02, Jul, 1.02, Aug, 1.01, Sep, 1.01, Oct, 1.02, Nov, 1.02, Dec, 1.02)
	WOCB84	MonthlyValues(Jan, 1.02, Feb, 1.02, Mar, 1.02, Apr, 1.02, May, 1.02, Jun, 1.02, Jul, 1.02, Aug, 1.02, Sep, 1.02, Oct, 1.02, Nov, 1.02, Dec, 1.02)
Kasai River	WKCB28	0.9 * MonthlyValues(Jan, 1.03, Feb, 1.02, Mar, 1.03, Apr, 1.03, May, 1.03, Jun, 1.03, Jul, 1.03, Aug, 1.03, Sep, 1.03, Oct, 1.02, Nov, 1.02, Dec, 1.03)
	WKCB32	0.9 * MonthlyValues(Jan, 1.03, Feb, 1.02, Mar, 1.02, Apr, 1.02, May, 1.02, Jun, 1.02, Jul, 1.02, Aug, 1.02, Sep, 1.02, Oct, 1.02, Nov, 1.02, Dec, 1.02)

	WKCB36	0.92 * MonthlyValues(Jan, 1.02, Feb, 1.02, Mar, 1.02, Apr, 1.02, May, 1.02, Jun, 1.03, Jul, 1.03, Aug, 1.02, Sep, 1.02, Oct, 1.02, Nov, 1.02, Dec, 1.02)
	WKCB37	0.9 * MonthlyValues(Jan, 1.03, Feb, 1.02, Mar, 1.02, Apr, 1.02, May, 1.02, Jun, 1.02, Jul, 1.02, Aug, 1.02, Sep, 1.02, Oct, 1.02, Nov, 1.02, Dec, 1.02)
	WKCB51	0.9 * MonthlyValues(Jan, 1.02, Feb, 1.03, Mar, 1.02, Apr, 1.02, May, 1.02, Jun, 1.02, Jul, 1.02, Aug, 1.02, Sep, 1.02, Oct, 1.02, Nov, 1.02, Dec, 1.02)
	WKCB54	0.92 * MonthlyValues(Jan, 1.03, Feb, 1.02, Mar, 1.03, Apr, 1.02, May, 1.03, Jun, 1.03, Jul, 1.03, Aug, 1.03, Sep, 1.03, Oct, 1.03, Nov, 1.03, Dec, 1.03)
	WKCB59	0.9 * MonthlyValues(Jan, 1.03, Feb, 1.02, Mar, 1.02, Apr, 1.02, May, 1.03, Jun, 1.03, Jul, 1.03, Aug, 1.02, Sep, 1.02, Oct, 1.02, Nov, 1.02, Dec, 1.02)
	WKCB6	0.9 * MonthlyValues(Jan, 1.03, Feb, 1.02, Mar, 1.03, Apr, 1.02, May, 1.02, Jun, 1.02, Jul, 1.02, Aug, 1.02, Sep, 1.03, Oct, 1.03, Nov, 1.02, Dec, 1.02)
	WKCB64	0.92 * MonthlyValues(Jan, 1.03, Feb, 1.02, Mar, 1.02, Apr, 1.02, May, 1.02, Jun, 1.03, Jul, 1.03, Aug, 1.02, Sep, 1.02, Oct, 1.02, Nov, 1.02, Dec, 1.02)
	WKCB66	0.9 * MonthlyValues(Jan, 1.02, Feb, 1.02, Mar, 1.02, Apr, 1.02, May, 1.02, Jun, 1.02, Jul, 1.02, Aug, 1.02, Sep, 1.02, Oct, 1.02, Nov, 1.03, Dec, 1.02)
	WKCB73	0.9 * MonthlyValues(Jan, 1.03, Feb, 1.02, Mar, 1.02, Apr, 1.03, May, 1.03, Jun, 1.03, Jul, 1.03, Aug, 1.03, Sep, 1.03, Oct, 1.03, Nov, 1.03, Dec, 1.03)
	WKCB76	0.92 * MonthlyValues(Jan, 1.02, Feb, 1.02, Mar, 1.02, Apr, 1.02, May, 1.01, Jun, 1.02, Jul, 1.01, Aug, 1.02, Sep, 1.02, Oct, 1.02, Nov, 1.02, Dec, 1.02)
	WKCB79	0.9 * MonthlyValues(Jan, 1.03, Feb, 1.02, Mar, 1.02, Apr, 1.03, May, 1.03, Jun, 1.03, Jul, 1.03, Aug, 1.03, Sep, 1.03, Oct, 1.03, Nov, 1.03, Dec, 1.02)
	WKCB85	0.9 * MonthlyValues(Jan, 1.02, Feb, 1.02, Mar, 1.02, Apr, 1.02, May, 1.02, Jun, 1.02, Jul, 1.02, Aug, 1.02, Sep, 1.02, Oct, 1.02, Nov, 1.02, Dec, 1.02)
Sangha River	WSC39	0.85 * MonthlyValues(Jan, 1.03, Feb, 1.03, Mar, 1.03, Apr, 1.02, May, 1.02, Jun, 1.03, Jul, 1.02, Aug, 1.02, Sep, 1.02, Oct, 1.03, Nov, 1.03, Dec, 1.03)
	WSCB1	MonthlyValues(Jan, 1.03, Feb, 1.02, Mar, 1.03, Apr, 1.03, May, 1.04, Jun, 1.03, Jul, 1.03, Aug, 1.03, Sep, 1.03, Oct, 1.04, Nov, 1.03, Dec, 1.03)

	WSCB15	MonthlyValues(Jan, 1.02, Feb, 1.02, Mar, 1.02, Apr, 1.02, May, 1.02, Jun, 1.03, Jul, 1.02, Aug, 1.03, Sep, 1.02, Oct, 1.03, Nov, 1.02, Dec, 1.02)
	WSCB17	MonthlyValues(Jan, 1.03, Feb, 1.03, Mar, 1.03, Apr, 1.03, May, 1.03, Jun, 1.02, Jul, 1.03, Aug, 1.02, Sep, 1.02, Oct, 1.03, Nov, 1.03, Dec, 1.03)
	WSCB18	0.85 * MonthlyValues(Jan, 1.02, Feb, 1.03, Mar, 1.02, Apr, 1.02, May, 1.03, Jun, 1.03, Jul, 1.03, Aug, 1.03, Sep, 1.03, Oct, 1.03, Nov, 1.03, Dec, 1.02)
	WSCB42	0.8 * MonthlyValues(Jan, 1.03, Feb, 1.02, Mar, 1.02, Apr, 1.02, May, 1.02, Jun, 1.02, Jul, 1.02, Aug, 1.02, Sep, 1.03, Oct, 1.02, Nov, 1.03, Dec, 1.03)
	WSCB52	0.9 * MonthlyValues(Jan, 1.03, Feb, 1.02, Mar, 1.02, Apr, 1.02, May, 1.02, Jun, 1.03, Jul, 1.03, Aug, 1.03, Sep, 1.03, Oct, 1.03, Nov, 1.02, Dec, 1.03)
	WSCB57	0.85 * MonthlyValues(Jan, 1.02, Feb, 1.02, Mar, 1.02, Apr, 1.02, May, 1.02, Jun, 1.03, Jul, 1.03, Aug, 1.03, Sep, 1.02, Oct, 1.02, Nov, 1.02, Dec, 1.02)
	WSCB71	0.9 * MonthlyValues(Jan, 1.02, Feb, 1.02, Mar, 1.02, Apr, 1.02, May, 1.02, Jun, 1.03, Jul, 1.03, Aug, 1.03, Sep, 1.03, Oct, 1.02, Nov, 1.02, Dec, 1.02)
	WSCB72	0.8 * MonthlyValues(Jan, 1.03, Feb, 1.03, Mar, 1.03, Apr, 1.03, May, 1.02, Jun, 1.02, Jul, 1.02, Aug, 1.02, Sep, 1.03, Oct, 1.03, Nov, 1.03, Dec, 1.03)

Figure C-12: Simulated and observed flows at Rafai Gauging site

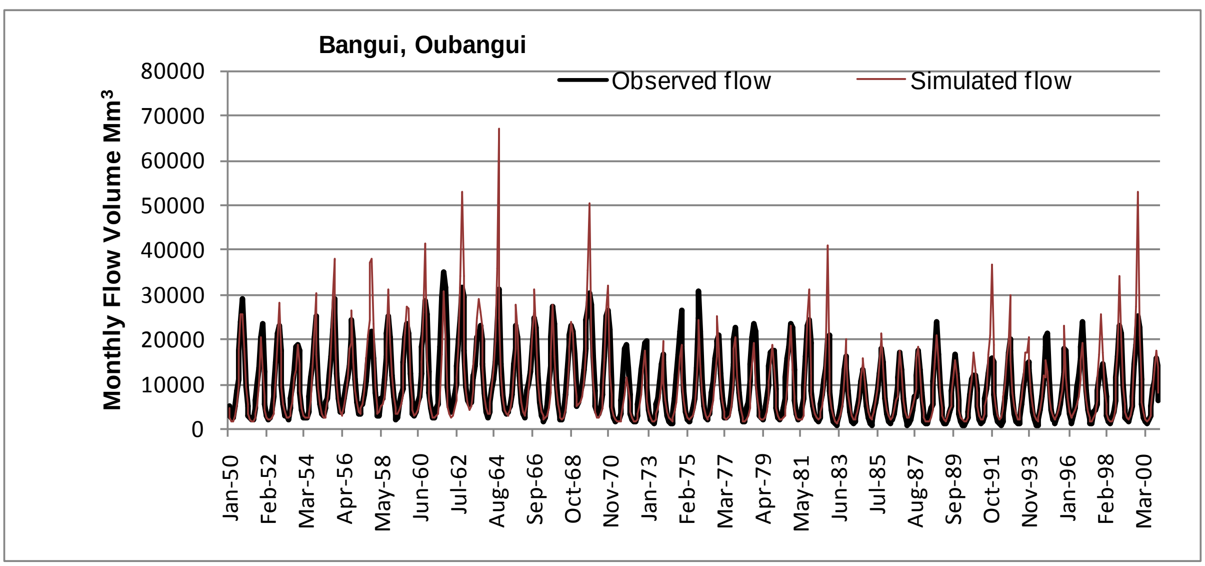


PBIAS: -9.854 PBIAS ln: -0.027

R^2: 0.678 R^2 ln: 0.742

CE: 0.662 CE ln: 0.742

Figure C-13: Simulated and observed flows at Bangui Gauging site

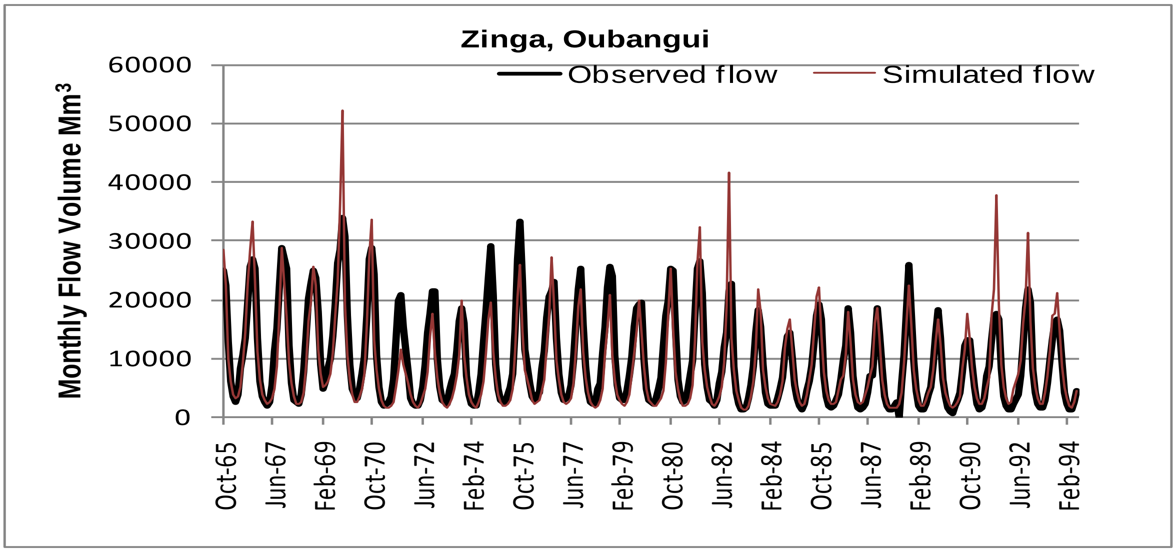


PBIAS: -3.137 PBIAS ln: -0.535

R^2: 0.778 R^2 ln: 0.859

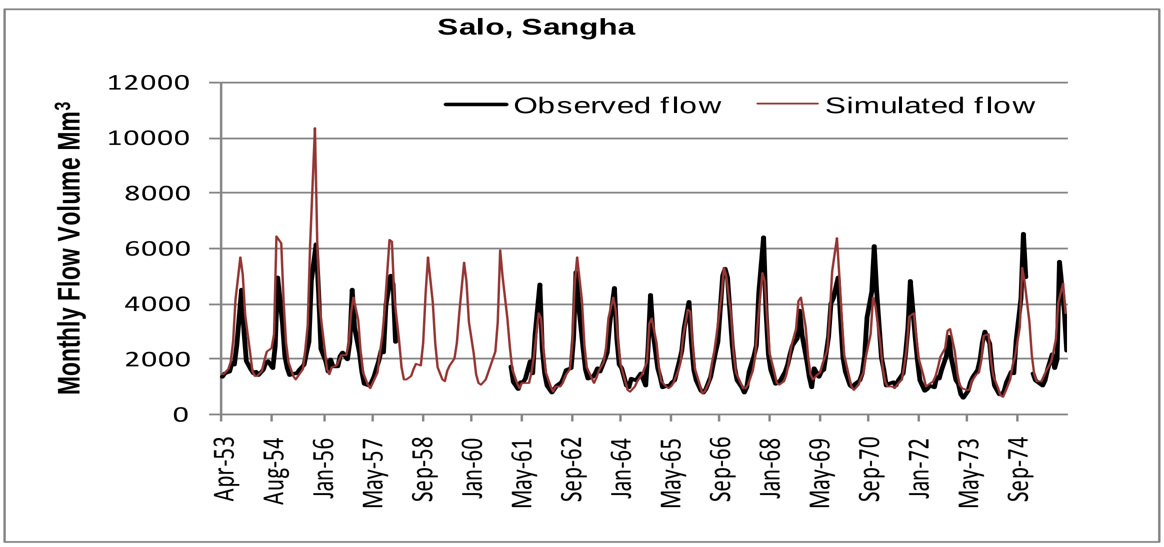
CE: 0.693 CE ln: 0.856

Figure C-14: Simulated and observed flows at Zinga Gauging site



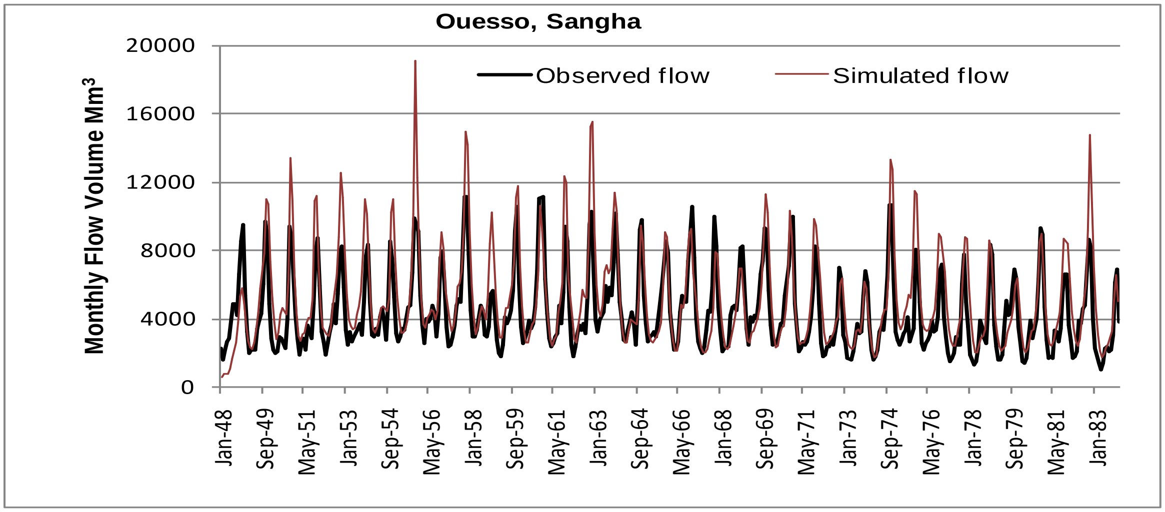
PBIAS: -9.139 PBIAS ln: -0.864
R^2: 0.798 R^2 ln: 0.861
CE: 0.770 CE ln: 0.854

Figure C-15: Simulated and observed flows at Salo Gauging site



PBIAS: 8.809 PBIAS ln: 0.886
R^2: 0.744 R^2 ln: 0.793
CE: 0.641 CE ln: 0.745

Figure C-16: Simulated and observed flows at Ouesso Gauging site

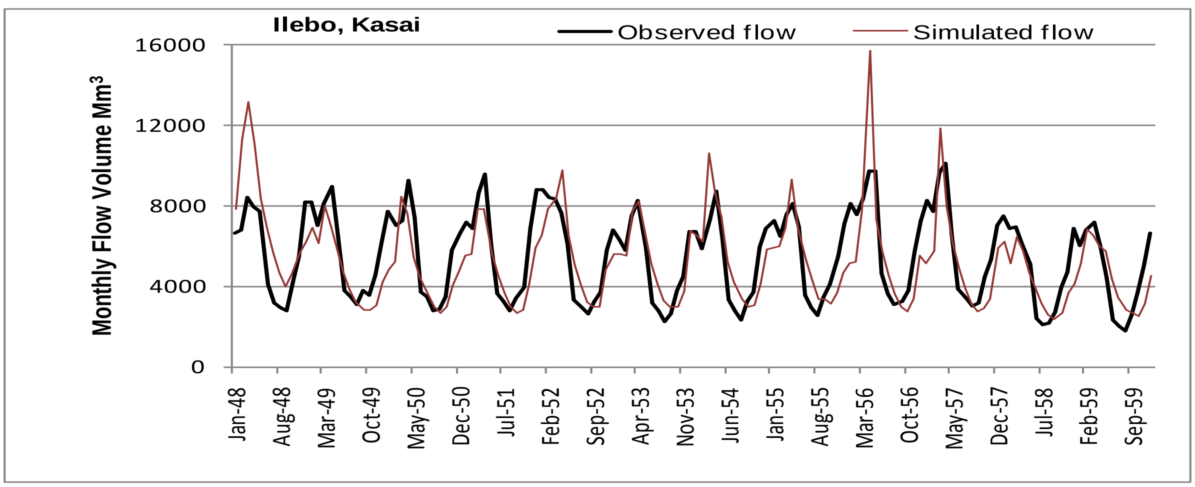


PBIAS: 17.14 PBIAS ln: 1.780

R^2: 0.772 R^2 ln: 0.694

CE: 0.529 CE ln: 0.558

Figure C-17: Simulated and observed flows at Ilebo Gauging site

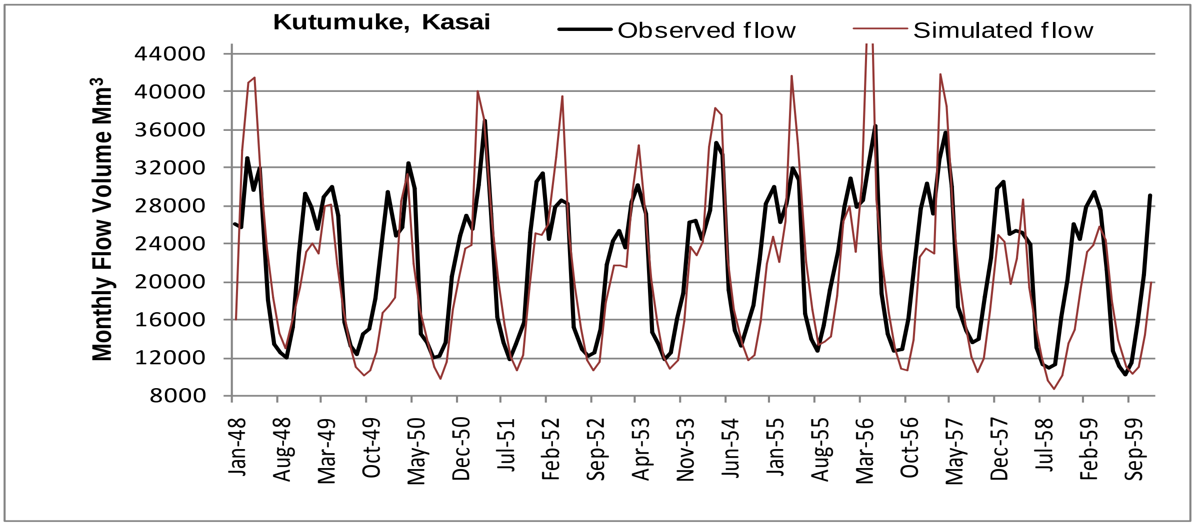


PBIAS: -3.246 PBIAS ln: -0.292

R^2: 0.572 R^2 ln: 0.600

CE: 0.485 CE ln: 0.579

Figure C-18: Simulated and observed flows at Kutumoke Gauging site

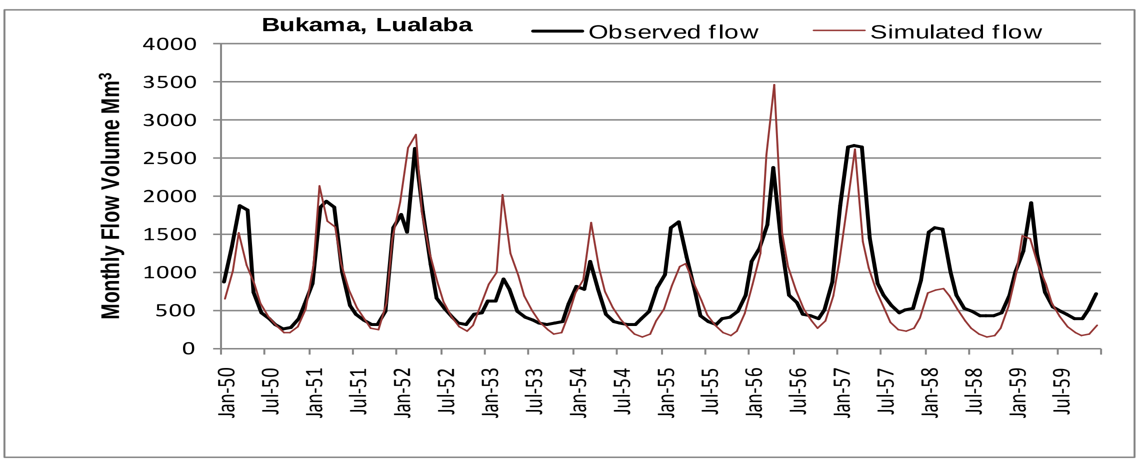


PBIAS: -4.981 PBIAS ln: -0.727

R^2: 0.674 R^2 ln: 0.716

CE: 0.513 CE ln: 0.597

Figure C-19: Simulated and observed flows at Bukama Gauging site

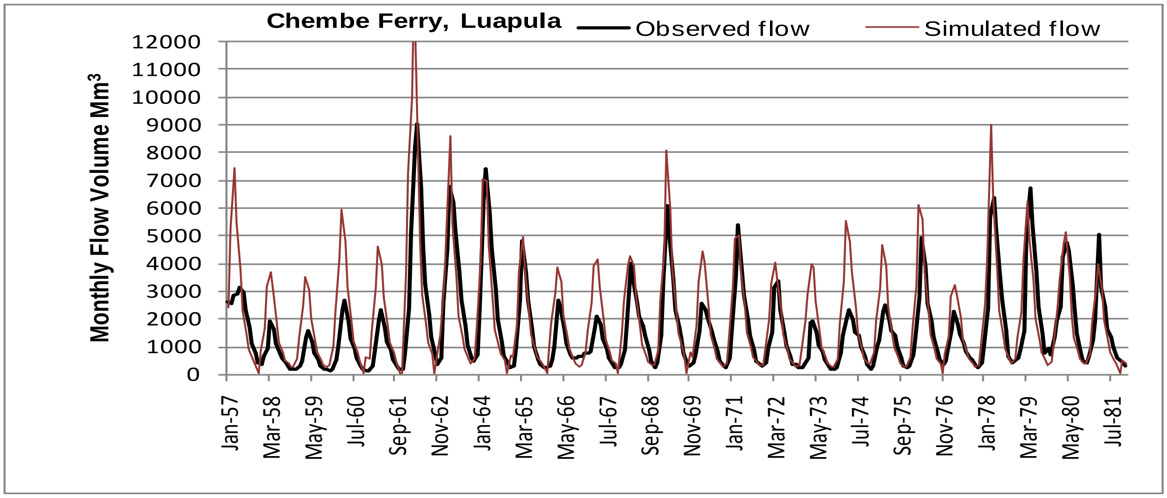


PBIAS: -8.248 PBIAS ln: -2.640

R^2: 0.698 R^2 ln: 0.718

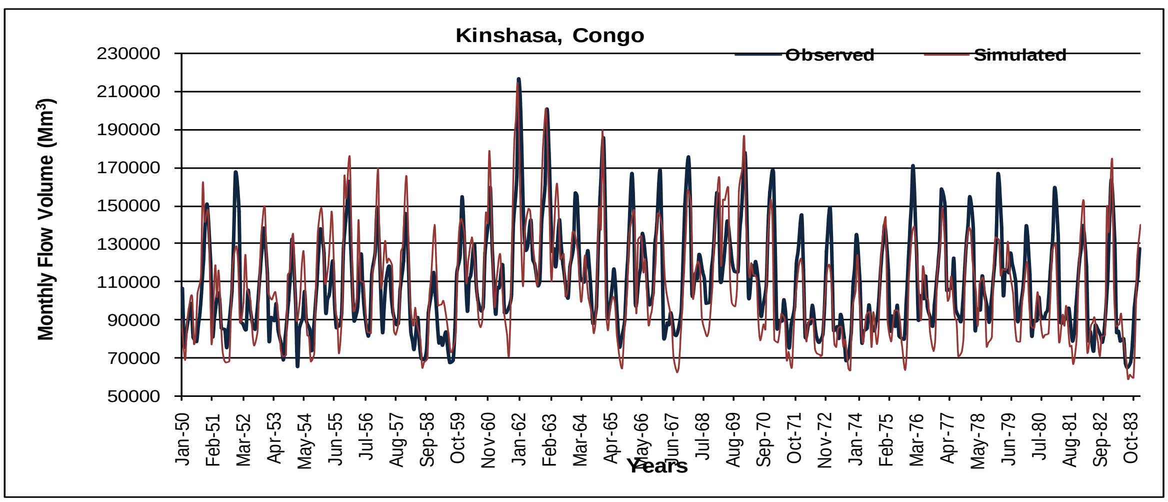
CE: 0.630 CE ln: 0.490

Figure C-20: Simulated and observed flows at Chembe Ferry Gauging site



PBIAS: 25.425 PBIAS ln: 2.150
R^2: 0.671 R^2 ln: 0.603
CE: 0.432 CE ln: 0.57

Figure C-21: Simulated and observed flows at Chembe Ferry Gauging site



PBIAS: -1.595 PBIAS ln: -0.188
R^2: 0.715 R^2 ln: 0.720
CE: 0.659 CE ln: 0.644

Water Resources Simulation

While there are some dams operated in the basin for storage and hydropower, they have not been managed (or monitored) in a way that would allow for a comparison of simulated versus observed values.

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C3- Niger River Basin

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Figure C-22: Niger River Basin, West Africa

Description of the Basin

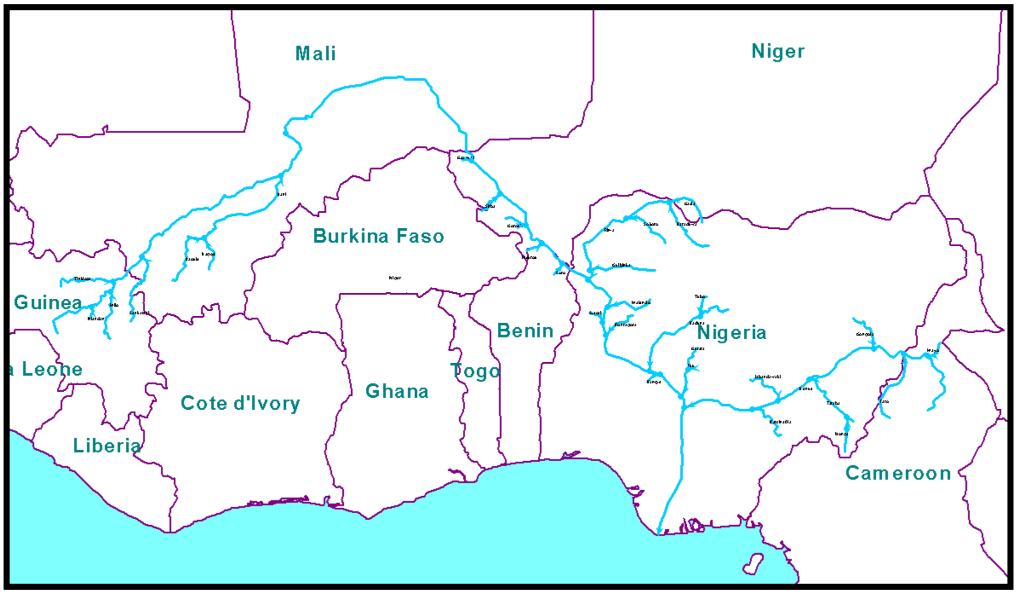
Area

The Niger River basin, located in western Africa, covers a total area of about 2,235,491 km^2 and spreads over nine riparian countries namely: Benin, Burkina Faso, Cameroon, Chad, Côte d'Ivoire, Guinea, Mali, Niger and Nigeria. Parts of the basin in Algeria, Mali, and Niger are hydrologically inactive, which reduces the total effective area to about 1,373,363 km^2 (Table C-10). It covers about 7.25% of the African continental landmass. A remarkable physical and ecological feature of the Niger basin is the "Inner Delta", an area of wetlands located in Mali, downstream of the city of Mopti, where the Niger meets the Bani river, a major right bank tributary.

Table C-10: Niger River basin areas by country

Country	Effective Area within Basin (km^2)	Percentage of Basin area (%)	Percentage of Country within the Basin (%)
Benin	46,570	3.4	40.6
Burkina Faso	89,051	6.5	32.5
Cameroon	87,310	6.4	18.4
Chad	20,355	1.5	1.6
Côte d'Ivoire	23,623	1.7	7.3
Guinea	101,073	7.4	41.1
Mali	337,914	24.6	27.2
Niger	92,971	6.8	7.3
Nigeria	574,493	41.8	62.2
Total	1,373,363	100.0	

Figure C-23: Location of the Niger River (blue lines) and the countries it traverses (purple lines)



The area of the Niger River basin in Guinea is only 4% of the total area of the basin, but the source of the Niger River is located in this country. The volume of water entering Mali from Guinea (40 km^3/year) is greater than the quantity of water entering Nigeria from Niger (36 km^3/year), about 1,800 km further downstream. This is due, among other reasons, to the enormous reduction in runoff in the inner delta in Mali through seepage and evaporation combined with almost no runoff from the whole of the left bank in Mali and Niger.

Mali, Niger and Nigeria each contain 25% of the total area of the Niger Basin. Mali and Niger are almost entirely dependent on the Niger River for their water resources. In the case of Niger, nearly 90% of its total water resources originate outside its borders (the Niger River and other tributaries from Burkina Faso and Benin).

Climate

The Niger Basin is under the influence of a varying climate, Sahelian in the north and more tropical in the south. The climate is characterized by a wet season and a dry season, the sequence of one following the other is regulated by the displacement of two masses of air, the dry harmattan winds coming from the Sahara, and the moist monsoon air coming from the ocean. The rainy season in the north occurs around August for 2-3 months, while in the south its duration is 6-8 months, and 12 months at the mouth of the river.

From south to north, the Niger River passes through several climatic zones. Characterized by different levels of rainfall these are:

- The very humid to humid Guinean zone (> 1500 mm per year);
- The semi-humid to very humid Sudano-Guinean zone (800 – 1500 mm per year);
- The Sudan zone (600 – 800 mm per year);

- The Sudano-Sahelian zone (350 – 600 mm per year);
- The semi-arid Sahelian zone (350 mm per year);
- The Sahara-Sahelian zone (200 mm per year) ;
- The arid semi-desert Sahara zone (< 200 mm per year).

The upper part of the basin forms the source of the Niger River in Guinea. The river flows north-east to Mopti in Mali and crosses the Sudano-Guinean and Sudan zones. The Niger River then enters the lacustrine area situated to the north in the Sahel zone, followed by the semi-desert zone, where the rainfall decreases from 600 mm to less than 150 mm per annum (average annual rainfall at Tombouctou 210 mm). Leaving this zone, the river re-enters the wetter Sahel zone. From Assonga (Mali) the rainfall increases from 287 mm/annum to 315 mm at Ayorou (Niger), to 438 mm at Tillaberi (Niger), and 573 mm at Niamey in Niger. Along the Sahel zone, the rains are characteristically weak, irregular both temporally and spatially, and accompanied by typically violent thunderstorms of short duration.

Further downstream, the river once again enters the Sudan zone of northern Benin and Nigeria, where the rainfall varies from 750 mm to 1000 mm. As the river moves southwards it passes through the Sudano-Guinean zone to the Guinean zone in the south, where the average annual rainfall can reach more than 4000 mm at the mouth of the river in the Gulf of Guinea. Two distinct regions which contribute the majority of the flow to the Niger River are the massif of Fouta Djallon and the Guinean Dorsal in Guinea (in the Sudan-Guinean zone) and the Adamoua massif in Cameroun and Nigeria (located in the Sudano-Guinean and Guinean zones) These two regions receive consistently high amounts of rainfall.

Hydrography

The six hydrographic regions of the Niger Basin are distinguished by their unique topographic and drainage characteristics. The regions are as follows:

- The Upper Niger River Basin and the Bani Watershed: The headwaters of the Niger have an extensive network of steep-sloped tributaries originating in Haute Guinée, whereas the Bani tributary network originates in the low-altitude plateaus of southern Mali and Côte d'Ivoire.
- The Niger River Inland Delta and Lakes District: This region is characterized by an immense, fertile, shallow-sloped alluvial floodplain with an extensive dendritic tributary network and shallow lakes.
- The Middle Niger, Malian-Nigerien, and Beninese-Nigerien Right-Bank Segment: This is a low-altitude plateau region with a series of tributaries that contribute to most of the Niger River's inflow along this segment.
- The Middle Niger Left-Bank Tributaries: This region is characterized by a wadi network in the upstream reach of this segment, with little contribution to the Niger River and an increased inflow from the tributary network in the lower reaches of the segment.
- The Benue River: This is a major tributary to the Lower Niger River originating in the high-altitude Adamawa Plateau in Cameroon.
- The Lower Niger River and the Niger Delta: Both these regions are located in a region of high rainfall, with an increase in the number of tributaries in the Lower Niger River, which flows south, emptying through the Niger Delta, an area characterized by swamps, lagoons, and navigable channels.(The Niger River Basin: A Vision for Sustainable Management)

The current and future development plans for hydropower and irrigation in the basin are available in Appendix A of this report.

Geology and Soil

The entire basin is characterized by ancient pre-Cambrian bedrock of igneous and metamorphic rocks which are overlain, in places, by primary and quaternary sediments. There are 8 majors soil units in the Niger River Basin:

- Brown soil,
- Vertisol,
- Ferruginous soil1,
- Ferruginous soil2,
- Moist soil,
- Debris & lightly developed soil,
- Ferruginous tropical soil and
- Ferruginous ferralitic soil.

Sedimentary deposits with large water-retention capacity are rare in the basin and much of the groundwater is sourced from fissures in the bedrock. (Niger River Basin MissionReport_2003).

WEAP Schematization

The Niger Basin WEAP model was developed using the data and system configuration from a model of the Niger built in MIKEBASIN by the Niger Basin Authority (NBA) (Niger Basin Authority, 2009). Several key differences between the two models are:

1) WEAP is a coupled hydrologic and systems model while MIKEBASIN is only a systems model.

2) WEAP is a linear optimization program while MIKEBASIN is a simulation model that can incorporate non-linear equations.

3) The Niger WEAP model simulates on a monthly timestep while the Niger MIKEBASIN model simulates on either a daily or a monthly timestep.

Catchment definitions

Time series of historical and projected climate (i.e. monthly precipitation [mm], average temperature[C], minimum temperature[C], and maximum temperature[C]) were developed for each sub-basin shown in Figure C-24. These data were used as drivers for the routines that estimate the hydrological response (i.e. rainfall-runoff and baseflow) and potential evapotranspiration for each sub-catchment. Table C-11 presents the monthly rainfall and temperature in Niger basin

Figure C-24: Niger River sub-catchments

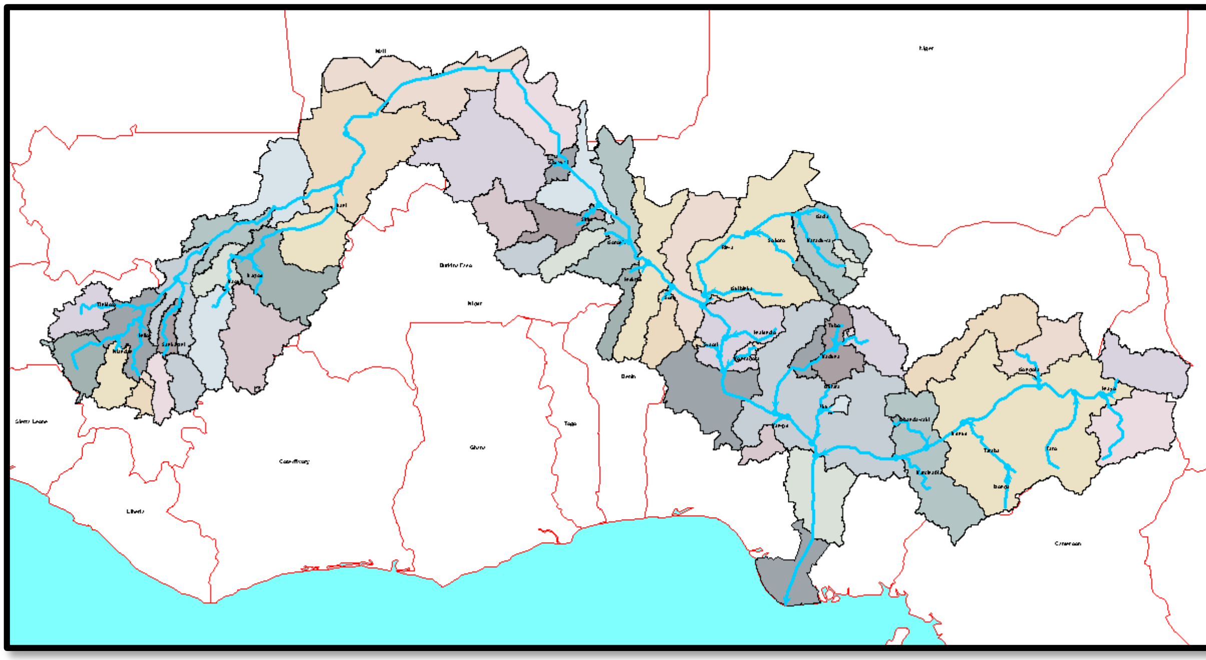


Table C-11: Average monthly rainfall and temperature

Niger Basin		**Rainfall(mm)**	**Temperature**
Upper Niger			
C05_11	Tinkisso	0-600	22-30
C06	Mafou	0-500	22-28
C07	Niandan	0-380	22-28
C08_09	Milo	0-500	22-28
C10_59	Sankarani	0-340	22-28
C12	Niger20	0-320	22-30
C13	Sankarani	0-360	22-30
C14_17	Baoule	0-450	22-32
C15_57	Kankelaba	0-320	24-30
C16	Niger18	0-360	24-32
C18	Niger18	0-320	24-32

C19	Ngora laka	0-400	24-32
C20	Fawara	0-280	24-32
C53	Niger17	0-170	24-34
Inner delta			
C21	Niger 16	0-150	22-34
C22	Niger 16	0-110	22-36
C23	Tilemsi	0-150	22-36
C24	Gourouol	0-170	24-36
C25	Niger	0-200	24-34
C26_28_29	Faga	0-280	24-34
C27	Niger13	0-240	24-34
C30	Niger12	0-320	26-34
C31	Niger12	0-270	24-34
Middle Niger			
C40	Ouora	0-260	24-34
C62	Bunsuru	0-300	22-32
C63	Bunsuru	0-280	24-32
C64	Sokoto2	0-320	24-32
C65	Sokoto1	0-270	25-33
C66	Nono	0-230	26-31
C67-68	Niger8	0-300	26-31
C69	Niger8	0-250	27-31
C70	Teshi	0-270	26-30
C73-74	Gurara	0-300	25-30
C76	chanchaga	0-276	25-30
C81	Gongola	0-330	23-30
C82	Gongola	0-380	26-32

C84	Mayo Kebi	0-360	24-30
C86-87	Kaduna	0-260	22-30
C88	Kaduna	0-290	24-30
C89	Kaduna	0-280	22-30
C90	Bunsuru	0-250	24-30
Lower Niger			
C75	Kampe	0-290	22-28
C80	Benue2	0-320	23-30
C83	Faro	0-280	24-30
C77	Ananbra	0-300	25-30
C78_79	Benue2	0-280	25-30
C76b	Gurara	0-270	25-30

Reservoirs

Within the Niger River basin there are a large variety of dams, diversion weirs, and cascade structures. Many of the structures have a negligible impact on the flow regime of the tributaries they obstruct. For simplicity, the MIKEBASIN and WEAP models incorporate only those structures that are deemed to have a significant impact on the flow regime (i.e. dams with an active storage volume greater than 1000 x 10^9 m^3). The full list of dams included in WEAP is given in Table C-12. Evaporation from reservoirs is estimated by the modified Hargreaves method, where Kc is calibrated to match the MIKEBASIN evaporation and precipitation. There is no groundwater infiltration from any reservoir. Each reservoir begins operations in the model according to the first year of utilization. For planned dams the first year of utilization is assumed to be 2020. Flow requirements associated with each dam are activated in the first year of utilization for that dam.

The Niger Inner Delta is modeled as a reservoir in both MIKEBASIN and WEAP. Additionally, significant reach routing in MIKEBASIN was modeled by artificial “reach delay” reservoirs in WEAP.

Selingue

Selingue is the only existing dam in the Upper Niger basin. Selingue is operated for flood control and hydropower, environmental flows in the Inner Delta, and irrigation demand for the Office of Niger (by far the largest in the region) which is located on the Niger River upstream of the Niger-Bani confluence. Unlike the other dams in the basin, there is limited observed hydropower and elevation data for Selingue beyond the useful descriptions of the region in Zwarts et al. (2005).

Kainji and Jebba

The operations of the Kainji and Jebba dams are difficult to determine because there is limited observed data about storages and outflows. However, the modeled and observed streamflows at the Baro gage in Nigeria match sufficiently well, indicating that the WEAP operations for both dams are reasonable enough approximations (operations of Kainji alone do not lead to good calibrations).

Inner Delta

The Inner Delta is modeled with a reservoir on the main branch of the Niger River and a bypass requirement, similar to the method used in the MIKEBASIN model. The volume-elevation curve is based on the MIKEBASIN data. The reservoir has no operations as normally formulated, but does have constant levels for the conservation and buffer zones. The reservoir is governed by a minimum flow requirement defined as

$$0.5\big(max(0, -350 + 400\, SE_{t-1}) + max(0, 500\, SE_{t-2}) + max(0, 0.1\, SF_{t-3} - 200)\big) - 100$$

where *SE* is the storage elevation (m) at timestep *t* and *SF* is the streamflow (cms) into the Inner Delta.
The minimum flow requirement is calibrated so that flows out of the Inner Delta match the Dire streamgage. The bypass requirement is a constant 50 cms. As with other reservoirs, the evaporation is calculated from the modified Hargreaves method (where Kc is used as a calibration parameter adjusted to match estimated historic evaporation).

Reach Delays

The reach delay reservoirs are implemented wherever there is significant reach routing (greater than half a month) in MIKEBASIN. This routing occurs between Dire and Niamey, where the single peak hydrograph splits into two peaks and is delayed by a month. These reservoirs are modeled after the Inner Delta, but have much smaller volumes, and no bypass requirement. The flow requirements below the reservoir, calibrated to the downstream streamgage, are given a higher priority than the reservoir. For the reach delay reservoirs, the priority given to filling the reservoir is critically important such that flows are properly routed. For example, if the reservoir volume is too large and the priority is too high, excess water is retained in the artificial reservoir, causing unrealistic water shortages downstream. The reach delay reservoirs create artificial separations in the river that also affect the allocation of water. As with other reservoirs, the evaporation is calculated from the modified Hargreaves method (where Kc is calibrated).

The first *ReachDelay* is located between Dire and Tossaye, and the second *ReachDelay2* is located between Kandadji and the Niger-Sirba confluence. The calibrated minimum flow requirement below *ReachDelay* is

$$max(0,\ 0.937\, SF_{t-1} - 0.493\, SF_{t-2} + 300)$$

where *t* is the timestep and *SF* is the streamflow (cms) into *ReachDelay.*

The calibrated minimum flow requirement below *ReachDelay2* is

$$max(0,\ 600 + 0.9\, SF_{t-1} + 0.3\, SF_{t-2})$$

where *t* is the timestep and *SF* is the streamflow (cms) into *ReachDelay2.*

Table C-12: Profiles of Dams on the Niger

Name of the dam	Country	River	Year of Completion	Lake		Energy				
				Total volume (10^6 m^3)	Active volume (10^6 m^3)	Installed power (MW)	Maximum head (m)	Turbine Capacity (CMS)	Plant factor	Generating efficiency
Selingue	Mali	Sankarani	1982	3,247	3,160	47.6	19	320	100	89.5
Kainji	Nigeria	Niger	1968	16,000	12,355	680	38	2,000	100	89.5
Jebba	Nigeria	Niger	1983	4,520	1,900	560	30	2,500	100	89.5
Shiroro	Nigeria	Kaduna/Dinya	1989	8,800	7,850	600	101	540	100	89.5
Lagdo	Cameroun	Benoue	1983	7,680	4,550	72	28	350	89.5	89.5
Dadin Kowa	Nigeria	Gongola	1988	3,509	1,770	34	34	130	80	89.5
Fomi	Guinea	Niandan	2020	5,725	5,055	90	29	425	100	91.5
Taoussa	Mali	Niger	2020	9,248	8,795	20	8	400	100	91.5
Kandadji	Niger	Niger	2020	2,655	2,444	125	20	500	100	91.5
Diaraguela	Guinea	Niger	2020	3,126	2,283	72	38	450	100	91.5
Zungeru	Nigeria	Kaduna/Dinya	2017	60,000	50,000	950	33	900	80	90
Guarara	Nigeria	Guarara	2015	933	900	360	27	390	80	90
Mambilla	Nigeria	Donga	2018	4,100	1,230		939	363	38.3	90

Irrigation

Irrigation water demands are a function of the irrigated area, crop coefficient, rainfall deficit and irrigation efficiency. Irrigated areas and crop coefficients are presented in Table C-13 and Table C-14. These data are based on inputs from a report to the Niger Basin Authority – i.e. *'Assessment of water abstraction and requirements for the Niger basin simulation model'* (BRLi, 2007). Irrigation efficiency factors range between 0.4 and 0.65 across the basin. However, there is a high degree of variability and uncertainty within these estimates. For the purposes of this study, we used an estimate of 0.5.

Table C-13: Crop coefficient, Kc, values in Niger River WEAP model

Crop	Area	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr
Banana	Devel. Zone 1	1	1	1	1	1	1	1	1	1	1	1	1
	Devel. Zone 2	1	1	1	1	1	1	1	1	1	1	1	1
	Devel. Zone 3	1	1	1	1	1	1	1	1	1	1	1	1
	Devel. Zone 4	1	1	1	1	1	1	1	1	1	1	1	1
	Devel. Zone 5	1	1	1	1	1	1	1	1	1	1	1	1
	Devel. Zone 6	1	1	1	1	1	1	1	1	1	1	1	1
	Devel. Zone 7	1	1	1	1	1	1	1	1	1	1	1	1
	Devel. Zone 8	1	1	1	1	1	1	1	1	1	1	1	1
	Devel. Zone 9	1	1	1	1	1	1	1	1	1	1	1	1
	Devel. Zone 10	1	1	1	1	1	1	1	1	1	1	1	1
	Devel. Zone 11	1	1	1	1	1	1	1	1	1	1	1	1
Sugar Cane	Devel. Zone 1	0.8	0.4	0.8	1.04	1.25	1.25	1.25	1.25	1.25	1.24	1.13	0.96
	Devel. Zone 2	0.8	0.4	0.8	1.04	1.25	1.25	1.25	1.25	1.25	1.24	1.13	0.96
	Devel. Zone 3	0.8	0.4	0.8	1.04	1.25	1.25	1.25	1.25	1.25	1.24	1.13	0.96
	Devel. Zone 4	0.8	0.4	0.8	1.04	1.25	1.25	1.25	1.25	1.25	1.24	1.13	0.96
	Devel. Zone 5	0.8	0.4	0.8	1.04	1.25	1.25	1.25	1.25	1.25	1.24	1.13	0.96
	Devel. Zone 6	0.8	0.4	0.8	1.04	1.25	1.25	1.25	1.25	1.25	1.24	1.13	0.96
	Devel. Zone 7	0.8	0.4	0.8	1.04	1.25	1.25	1.25	1.25	1.25	1.24	1.13	0.96
	Devel. Zone 8	0.8	0.4	0.8	1.04	1.25	1.25	1.25	1.25	1.25	1.24	1.13	0.96
	Devel. Zone 9	0.8	0.4	0.8	1.04	1.25	1.25	1.25	1.25	1.25	1.24	1.13	0.96
	Devel. Zone 10	0.8	0.4	0.8	1.04	1.25	1.25	1.25	1.25	1.25	1.24	1.13	0.96
	Devel. Zone 11	0.8	0.4	0.8	1.04	1.25	1.25	1.25	1.25	1.25	1.24	1.13	0.96
Mixed Gardening	Devel. Zone 1	0	0	0	0	0	0	0.64	0.85	1.1	1.03	0.9	0
	Devel. Zone 2	0	0	0	0	0	0	0.64	0.85	1.1	1.03	0.9	0
	Devel. Zone 3	0	0	0	0	0	0	0.64	0.85	1.1	1.03	0.9	0
	Devel. Zone 4	0	0	0	0	0	0	0.64	0.85	1.1	1.03	0.9	0
	Devel. Zone 5	0	0	0	0	0	0	0.64	0.85	1.1	1.03	0.9	0
	Devel. Zone 6	0	0	0	0	0	0	0	0.64	0.85	1.1	1.03	0.9

	Devel. Zone 7	0	0	0	0	0	0	0	0.64	0.85	1.1	1.03	0.9
	Devel. Zone 8	0	0	0	0	0	0	0	0.64	0.85	1.1	1.03	0.9
	Devel. Zone 9	0	0	0	0	0	0	0	0.64	0.85	1.1	1.03	0.9
	Devel. Zone 10	0	0	0	0	0	0	0	0.64	0.85	1.1	1.03	0.9
	Devel. Zone 11	0	0	0	0	0	0	0	0.64	0.85	1.1	1.03	0.9
Millet	Devel. Zone 1	0	0.42	0.77	1	0.65	0.3	0	0	0	0	0	0
	Devel. Zone 2	0	0.42	0.77	1	0.65	0.3	0	0	0	0	0	0
	Devel. Zone 3	0	0.42	0.77	1	0.65	0.3	0	0	0	0	0	0
	Devel. Zone 4	0	0.42	0.77	1	0.65	0.3	0	0	0	0	0	0
	Devel. Zone 5	0	0.42	0.77	1	0.65	0.3	0	0	0	0	0	0
	Devel. Zone 6	0	0.42	0.77	1	0.65	0.3	0	0	0	0	0	0
	Devel. Zone 7	0	0.42	0.77	1	0.65	0.3	0	0	0	0	0	0
	Devel. Zone 8	0	0.42	0.77	1	0.65	0.3	0	0	0	0	0	0
	Devel. Zone 9	0	0.42	0.77	1	0.65	0.3	0	0	0	0	0	0
	Devel. Zone 10	0	0.42	0.77	1	0.65	0.3	0	0	0	0	0	0
	Devel. Zone 11	0	0.42	0.77	1	0.65	0.3	0	0	0	0	0	0
Mixed Farming	Devel. Zone 1	0	0	0	0	0	0	0.64	0.85	1.1	1.03	0.9	0
	Devel. Zone 2	0	0	0	0	0	0	0.64	0.85	1.1	1.03	0.9	0
	Devel. Zone 3	0	0	0	0	0	0	0.64	0.85	1.1	1.03	0.9	0
	Devel. Zone 4	0	0	0	0	0	0	0.64	0.85	1.1	1.03	0.9	0
	Devel. Zone 5	0	0	0	0	0	0	0.64	0.85	1.1	1.03	0.9	0
	Devel. Zone 6	0	0	0	0	0	0	0	0.64	0.85	1.1	1.03	0.9
	Devel. Zone 7	0	0	0	0	0	0	0	0.64	0.85	1.1	1.03	0.9
	Devel. Zone 8	0	0	0	0	0	0	0	0.64	0.85	1.1	1.03	0.9
	Devel. Zone 9	0	0	0	0	0	0	0	0.64	0.85	1.1	1.03	0.9
	Devel. Zone 10	0	0	0	0	0	0	0	0.64	0.85	1.1	1.03	0.9
	Devel. Zone 11	0	0	0	0	0	0	0	0.64	0.85	1.1	1.03	0.9
Off Season Rice	Devel. Zone 1	0	0	0	0	0	0	0	1.2	1.15	1.1	1.1	0.8
	Devel. Zone 2	0	0	0	0	0	0	0	1.2	1.15	1.1	1.1	0.8
	Devel. Zone 3	0	0	0	0	0	0	0	1.2	1.15	1.1	1.1	0.8
	Devel. Zone 4	0	0	0	0	0	0	0	1.2	1.15	1.1	1.1	0.8
	Devel. Zone 5	0	0	0	0	0	0	0	1.2	1.15	1.1	1.1	0.8
	Devel. Zone 6	0	0	0	0	0	0	0	1.2	1.15	1.1	1.1	0.8
	Devel. Zone 7	0	0	0	0	0	0	0	1.2	1.15	1.1	1.1	0.8
	Devel. Zone 8	0	0	0	0	0	0	0	1.2	1.15	1.1	1.1	0.8
	Devel. Zone 9	0	0	0	0	0	0	0	1.2	1.15	1.1	1.1	0.8
	Devel. Zone 10	0	0	0	0	0	0	0	1.2	1.15	1.1	1.1	0.8
	Devel. Zone 11	0	0	0	0	0	0	0	1.2	1.15	1.1	1.1	0.8
Wet Season Rice	Devel. Zone 1	0	1.2	1.15	1.1	1.1	0.8	0	0	0	0	0	0
	Devel. Zone 2	0	1.2	1.15	1.1	1.1	0.8	0	0	0	0	0	0
	Devel. Zone 3	0	1.2	1.15	1.1	1.1	0.8	0	0	0	0	0	0

	Devel. Zone 4	0	1.2	1.15	1.1	1.1	0.8	0	0	0	0	0	0
	Devel. Zone 5	0	1.2	1.15	1.1	1.1	0.8	0	0	0	0	0	0
	Devel. Zone 6	0	1.2	1.15	1.1	1.1	0.8	0	0	0	0	0	0
	Devel. Zone 7	0	1.2	1.15	1.1	1.1	0.8	0	0	0	0	0	0
	Devel. Zone 8	0	1.2	1.15	1.1	1.1	0.8	0	0	0	0	0	0
	Devel. Zone 9	0	1.2	1.15	1.1	1.1	0.8	0	0	0	0	0	0
	Devel. Zone 10	0	1.2	1.15	1.1	1.1	0.8	0	0	0	0	0	0
	Devel. Zone 11	0	1.2	1.15	1.1	1.1	0.8	0	0	0	0	0	0
Sorghum	Devel. Zone 1	0	0.43	0.77	1.1	0.73	0.55	0	0	0	0	0	0
	Devel. Zone 2	0	0.43	0.77	1.1	0.73	0.55	0	0	0	0	0	0
	Devel. Zone 3	0	0.43	0.77	1.1	0.73	0.55	0	0	0	0	0	0
	Devel. Zone 4	0	0.43	0.77	1.1	0.73	0.55	0	0	0	0	0	0
	Devel. Zone 5	0	0.43	0.77	1.1	0.73	0.55	0	0	0	0	0	0
	Devel. Zone 6	0	0.43	0.77	1.1	0.73	0.55	0	0	0	0	0	0
	Devel. Zone 7	0	0.43	0.77	1.1	0.73	0.55	0	0	0	0	0	0
	Devel. Zone 8	0	0.43	0.77	1.1	0.73	0.55	0	0	0	0	0	0
	Devel. Zone 9	0	0.43	0.77	1.1	0.73	0.55	0	0	0	0	0	0
	Devel. Zone 10	0	0.43	0.77	1.1	0.73	0.55	0	0	0	0	0	0
	Devel. Zone 11	0	0.43	0.77	1.1	0.73	0.55	0	0	0	0	0	0

Table C-14: Irrigated crop areas (ha) in Niger River WEAP model

Area	Crop	2005	2015	2025
Development Zone 1	Mixed Gardening	1,817	12,686	14,496
	Off Season Rice	3,934	5,683	10,703
	Wet Season Rice	8,967	16,506	24,746
Development Zone 2	Sugar Cane	5,000	20,000	35,000
	Mixed Gardening	6,000	6,000	6,000
	Off Season Rice	11,967	12,694	12,694
	Wet Season Rice	93,224	170,877	315,877
Development Zone 3	Mixed Gardening	230	230	1,810
	Off Season Rice	2,066	2,066	16,286
	Wet Season Rice	2,066	44,066	104,286
	Off Season Rice	4,801	8,798	8,798

Development Zone 4	Wet Season Rice	16,003	29,326	29,326
Development Zone 5	Mixed Gardening	34,586	48,086	66,086
	Mixed Farming	91	91	91
	Off Season Rice	9,185	26,315	53,865
	Wet Season Rice	10,250	34,349	100,849
Development Zone 6	Mixed Gardening	397	712	1,041
	Off Season Rice	651	1,934	3,223
	Wet Season Rice	2,488	5,313	8,208
Development Zone 7	Millet	8,580	23,000	39,000
	Mixed Farming	29,047	72,307	120,307
	Sorghum	8,580	23,000	39,000
Development Zone 8	Banana	4,270	15,824	68,824
	Mixed Farming	12,810	47,472	206,472
	Wet Season Rice	4,270	15,824	68,824
Development Zone 9	Banana	1,952	7,992	37,992
	Mixed Gardening	1,000	1,219	1,486
	Mixed Farming	7,808	31,968	151,968
	Off Season Rice	1,500	1,500	1,500
	Wet Season Rice	1,595	1,616	1,641
Development Zone 10	Banana	1,250	6,230	40,230
	Mixed Farming	3,750	18,690	120,690
Development Zone 11	Mixed Farming	5,610	25,500	80,000

Water Allocation

The demand priority in WEAP defines how water is allocated to satisfy competing uses – i.e. reservoir storage, hydropower generation, irrigation, domestic use, and flow. WEAP offers demand priorities ranging in number from 0-99, where the lower numbers indicate higher a priority for water use.

The demand priorities used in the Niger River are listed in Table C-15: Allocation priority structure of Niger River WEAP model. These are generally set such that domestic water use has the highest priority, followed by environmental flow requirements as the second priority, irrigated agriculture as the third priority, hydropower generation as the fourth priority, and reservoir storage as the lowest priority. The priority structure also reflects the realities of water usage and the regional management of water within the basin. That is, water users that are high in the basin will tend to use the water that is available to them independent of water usage elsewhere in the basin. This implies that water users that are quite low in the basin will have a lower demand priority such that they don't compete for the same water as users far upstream nor actively draw water from reservoirs at the headwaters. For example, irrigated agriculture in the Niger Delta has a demand priority of 21, which is a lower priority than all priorities upstream – meaning water will not be actively released from any reservoir to try to meet that demand.

Table C-15: Allocation priority structure of Niger River WEAP model

Country	River	Node	WEAP Object	WEAP PRIORITY			
				Storage	Hydropower	Demand	Flow Requirement
Guinea	Niger	Diarguela	Reservoir	4	1		
	Niger	Blw Diarguela	Flow Requirement				1
	Niandan	Fomi	Reservoir	4	1		
	Niandan	Blw Fomi	Flow Requirement				1
	Milo	Abv Siguiri	Demand			1	
	Sankarani	Abv Selingue	Demand			1	
	Niger	ZD01 Irrigation	Irrigated Catchment			2	
	Niger	Abv Banankoro	Demand			1	
Mali	Sankarani	Selingue	Reservoir	4	1		
	Sankarani	Blw Selingue	Flow Requirement				1
	Niger	Abv Koulikoro	Demand			1	
	Niger	Markala	Flow Requirement				1
	Niger	ZD02 Irrigation	Irrigated Catchment			2	
	Bani	ZD03 Irrigation	Irrigated Catchment			1	
	Bani	Abv Bani Outflow	Demand			1	
	Niger	ZD04 Irrigation	Irrigated Catchment			3	

	Niger	Inner Delta Bypass	Flow Requirement				5
	Niger	Inner Delta	Reservoir	8			
	Niger	Inner Delta Outflow	Flow Requirement				6
	Niger	Abv Tossaye	Demand			9	
	Niger	Reach Delay	Reservoir	11			
	Niger	Blw Reach Delay	Flow Requirement				10
	Niger	Taoussa Dam	Reservoir	13	12		
	Niger	Blw Taoussa	Flow Requirement				12
	Niger	Abv Ansongo	Demand			12	
Niger	Niger	Abv Kandadji	Demand			12	
	Niger	Kandadji	Reservoir	13	12		
	Niger	Blw Kandadji	Flow Requirement				12
	Niger	Reach Delay 2	Reservoir	14			
	Niger	Blw Reach Delay 2	Flow Requirement				13
	Niger	Abv Goroubi Trib	Demand			15	
	Niger	ZD05 Irrigation	Irrigated Catchment			15	
Burkina Faso	Gourouol/ Sirba/ Goroubi/ Mekrou/ Soto	ZD06 Irrigation	Irrigated Catchment			4	
	Rima/Niger	ZD07 Irrigation	Irrigated Catchment			15	

Nigeria	Niger	Kainji	Reservoir	16	15		
	Niger	Jebba	Reservoir	16	15		
	Niger	Shiroro	Reservoir	13	12		
	Niger	Blw Shiroro	Flow Requirement				1
	Niger	Zungeru	Reservoir	15	14		
	Niger	ZD08 Irrigation	Irrigated Catchment			16	
	Niger	Abv Kampe outflow	Demand			16	
	Niger	Abv Gurara Trib	Demand			16	
	Gurara	Gurara	Reservoir	15	14		
	Gurara	Gurara Falls	Run of River		14		
	Benue	Abv Gongola Trib	Demand			15	
	Gongola	Dadin Kowa	Reservoir	3	2		
	Gongola	Blw Dadin Kowa	Flow Requirement				1
	Benue	Abv C80	Demand			2	
	Donga	Mambilla	Reservoir	2			
	Donga	Mambilla Power Station	Run of River		1		
	Benue	ZD09 Irrigation	Irrigated Catchment			3	
	Benue	Abv Ubandawaki Trib	Demand			2	
	Benue	ZD10 Irrigation	Irrigated Catchment			4	
	Benue	Abv Benue outflow	Demand			2	

	Niger	Abv C77	Demand			20	
	Niger	ZD11 Irrigation	Irrigated Catchment			21	
	Niger	Abv Delta	Demand			20	
Cameroun	Benue	Ladgo	Reservoir	3	2		
	Benue	Abv Mayo outflow	Demand				1

The Middle Niger (Figure C-31: Simulated and observed Niger River flows at Kandadji, Niger & Figure C-32: Simulated and observed Niger River flows at Niamey, Niger) was the most difficult region to calibrate due to the aridity of the region, and the need for 'reach delay' reservoirs to route the water. Another difficulty was that there are no good observed gages on the Rima River, which is the largest tributary in the middle Niger. Just upstream of Kainji the presence of the "white" and "black" floods of the Niger River becomes observable. The "white" and "black" floods refer respectively to the immediate flood from the surrounding catchments (which exhibit a very flashy hydrology) that has a lighter sediment load and the later flood from the Upper Niger that has heavier sediment loads. Another challenge to calibration, especially in this region, is that the aggregated agriculture demand from the agriculture-specific catchments changes the distribution of water use.

The Lower Niger is below Kainji dam down to the Niger Delta. At Kainji dam the calibration is poor due to the difficulty of simulating the dam operations. At Baro, the calibration becomes again sufficient (Figure C-33: Simulated and observed Niger River flows at Baro, Nigeria), likely due to the operations of Jebba dam, and the added inflow from the Kaduna tributary. At Lokoja, the size of the Benue relative to the Niger drowns out the small discrepancies observed at Kainji dam (Figure C-36: Simulated and observed Niger River flows at Lokoja, Nigeria)

The Benue River, a major tributary to the Lower Niger, is much less developed than the Niger River. The peak flows at WuroBokki are not captured in the simulated flow because the gage is located significantly further downstream from the nearest catchment inflow point, so the observed flows come from a much larger basin area. Further downstream at Ibi (in the middle of the Benue basin) and at Umaisha (just above the confluence of the Benue with the Niger) the differences in observed and simulated flow become much less significant (Figure C-34: Simulated and observed Benue River flows at Ibi, Nigeria and Figure C-35: Simulated and observed Benue River flows at Umaisha, Nigeria).

Figure C-25: Location of all control stations in the Niger basin below presents the location of control station in the Niger basin.

Figure C-25: Location of all control stations in the Niger basin

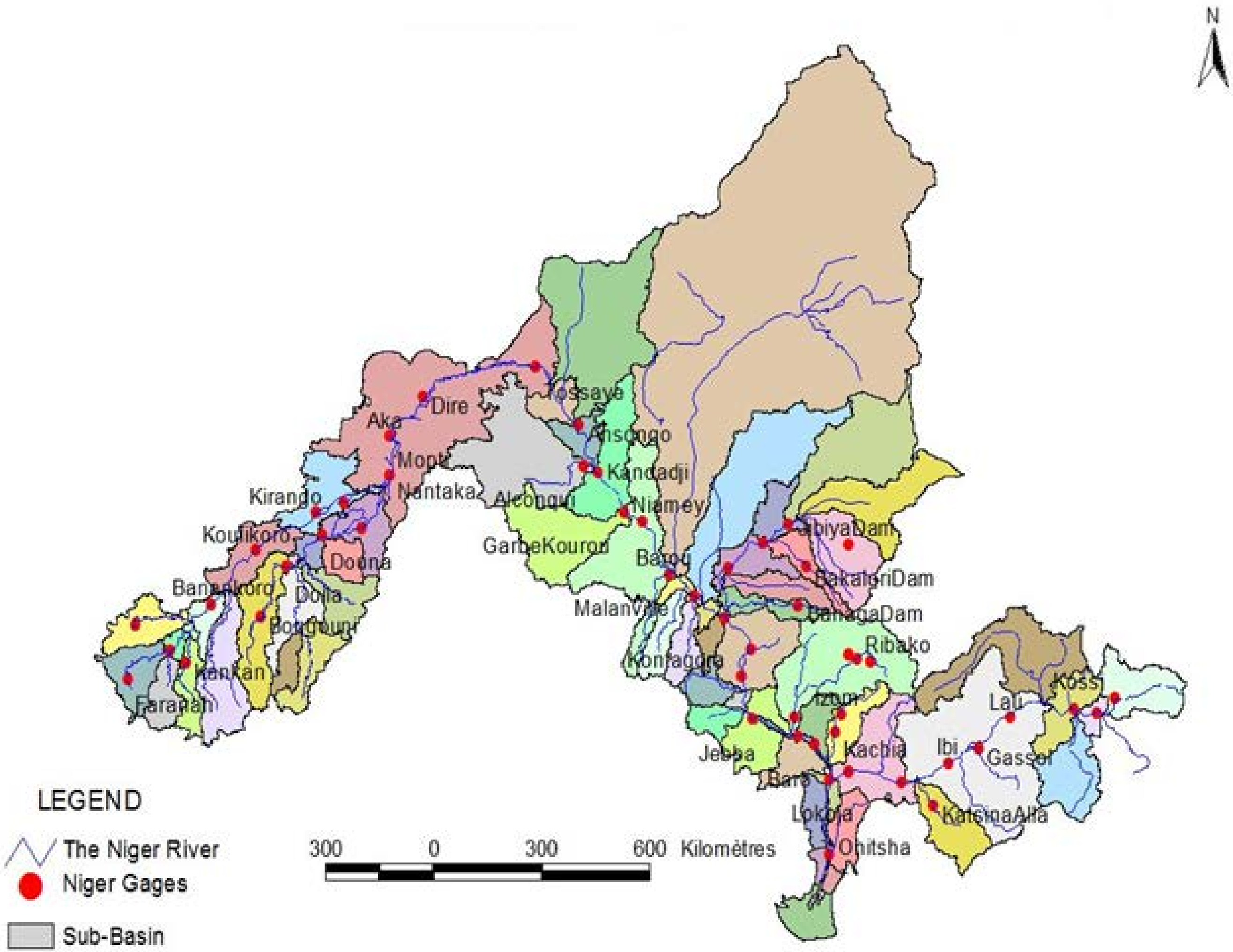


Table C-16: Calibration parameter values for Niger River catchments

Sub-Basin	Catchment	DWC (mm)	DC (mm)	SWC (mm)	PFD	RZC (mm)	RRF
Upper Niger	C05_11	1000	20	1000	0.80	20	MonthlyValues(May, 2.63, Sep, 2.63, Oct, 1.7, Nov, 1.6, Dec, 1.5, Jan, 1.3, Mar, 1.3, Apr, 2.63)
	C06	1000	75	1000	0.80	20	MonthlyValues(May, 2.63, Sep, 2.63, Oct, 1.7, Nov, 0.3, Dec, 0.2, Jan, 1.3, Mar, 1.3, Apr, 2.63)
	C07	1000	75	1000	0.15	20	MonthlyValues(May, 2.63, Sep, 2.63, Oct, 1.7, Nov, 0.3, Dec, 0.2, Jan, 1.3, Mar, 1.3, Apr, 2.63)
	C08_09	1000	20	1000	0.15	20	2
	C10_59	1000	20	1000	0.15	20	MonthlyValues(May, 2.5, Jul, 2.5, Aug, 2.7, Sep, 4, Oct, 6.5, Nov, 2.1, Dec, 1.9, Jan, 2, Apr, 2)
	C12	1000	118	1000	1.00	25	5.62
	C13	1000	20	1000	0.15	20	MonthlyValues(May, 2.5, Aug, 2.5, Sep, 1.3, Oct, 0.5, Nov, 0.2, Dec, 0.2, Jan, 2, Mar, 2, Apr, 2.5)
	C14_17	1000	20	1000	0.15 – 1.0	20	MonthlyValues(May, 2, Aug, 2, Sep, 1, Oct, 0.2, Nov, 0.1, Dec, 0.1, Jan, 1, Mar, 1, Apr, 1.2)
	C15_57	1000	20	1000	0.80	20	MonthlyValues(May, 2.8, Jun, 2.63, Aug, 2.63, Sep, 2.3, Oct, 1.7, Nov, 0.4, Dec, 0.2, Jan, 1.3, Feb, 1.4, Mar, 1.5, Apr, 2.7)
	C16	1000	118	2000	1.00	10	10
	C18	1000	118	2000	0.10	10	10
	C19	1000	150	1000	1.00	121	6
	C20	1000	200	1000	0.00	20	9.31
	C53	1000	20	2000	0.15	10	10

Inner Delta	C21	1000	20	1000	0.90	20	40
	C22	1000	20	1000	0.90	20	40
	C23	1000	20	1000	1.00	100	MonthlyValues(May, 1.5, Nov, 1.5, Dec, 1, Apr, 1)
	C24	1000	0.803	1000	1.00	250	MonthlyValues(Sep, 1.673, Oct, 2, Nov, 1.673)
	C25	1000	20	1000	1.00	100	MonthlyValues(Sep, 1.673, Oct, 2, Nov, 1.673)
	C26_28_29	1000	2.81	1000	1.00	250	5.22
	C27	1000	2.81	1000	1.00	250	MonthlyValues(Jun, 6, Jul, 5.2187, Aug, 7, Sep, 5.2187, Nov, 5.2187, Dec, 6)
	C30	1000	20	1000	0.15	20	MonthlyValues(May, 3, Jul, 3, Aug, 2.5, Sep, 2, Oct, 1.3, Nov, 2, Dec, 20, Jan, 20, Feb, 2, Apr, 2)
	C31	1000	20	1000	1.00	20	MonthlyValues(May, 250, Aug, 250, Sep, 1, Oct, 2, Nov, 2, Dec, 300, Jan, 0.5, Apr, 0.5)
Middle Niger	C40	1000	20	1000	0.15	20	MonthlyValues(May, 2, Aug, 2, Sep, 1, Oct, 0.2, Mar, 0.2, Apr, 1)
	C62	1000	20	1000	0.15	20	MonthlyValues(Jun, 2, Jul, 1.5, Aug, 1.4, Sep, 1.5, Oct, 2)
	C63	1000	20	1000	0.15	20	2
	C64	1000	1	338	0.90	250	6
	C65	1000	20	1000	0.50	20	MonthlyValues(May, 1, Jun, 1, Jul, 1.1, Aug, 0.95, Sep, 1, Oct, 1.3, Nov, 1.3, Dec, 1.1, Jan, 1, Feb, 1, Mar, 1, Apr, 1)
	C66	1000	20	1000	0.15	20	MonthlyValues(May, 25, Jun, 25, Jul, 2.5, Aug, 2.44, Sep, 2.22, Oct, 1.9, Nov, 1.9, Dec, 50, Apr, 50)
	C67_68	1000	20	1000	0.15	20	MonthlyValues(Jul, 2, Aug, 2.2, Sep, 2, Oct, 1.4, Nov, 0.8, Jan, 0.8, Feb, 2)
	C69	1000	145.5	1000	0.15	192	4.4
	C70	1000	138	747	0.15	120	4.1
	C73_74	1000	20	1000	0.15	20	2
	C76	200	73.79	544	0.76	168	4.83

	C81	1000	20	1000	0.15	20	2
	C82	1000	20	1000	0.15	25	2.5
	C84	1000	20	1000	0.85	20	MonthlyValues(May, 4, Jun, 1.75, Jul, 1.75, Aug, 2, Sep, 1.85, Oct, 1, Nov, 0.3, Dec, 0.6, Jan, 4)
	C86_87	1000	20	1000	0.15	20	2
	C88	1000	200	1000	1.00	20	MonthlyValues(Jul, 2, Aug, 0.5, Sep, 0.1, Oct, 0.5, Nov, 2)
	C89	1000	20	1000	0.15	20	1.5
	C90	605	23.74	782	0.03	20	2.37
Lower Niger	C75	1000	20	1000	0.15	20	MonthlyValues(May, 2, Jun, 2.4, Jul, 2.4, Aug, 2.15, Sep, 2.46, Oct, 2.8, Nov, 0.8, Dec, 0.6, Jan, 1, Feb, 2, Mar, 2, Apr, 1.9)
	C80	400	0.1	1000	1.00	20	2.5
	C83	1000	20	1000	0.15	20	MonthlyValues(May, 2.63, Jul, 2.63, Aug, 1.8, Sep, 1.7, Oct, 1.7, Nov, 0.3, Dec, 0.2, Jan, 1.3, Feb, 1.29, Mar, 1.29, Apr, 2.63)
	C77	1000	20	1000	0.15	20	250
	C78_79	400	0.1	600	1.00	20	MonthlyValues(May, 1, Aug, 1, Sep, 0.3, Oct, 0.2, Apr, 0.3)
	C76b	200	73.79	544	0.76	168	4.83

Table C-17: Calibrated Kc values for Niger River catchments

Sub-Basin	Catchment	Kc
Upper Niger	C05_11	MonthlyValues(May, 0.8, Aug, 0.8, Sep, 0.4, Oct, 0.5, Nov, 0.2, Dec, 0.5, Jan, 0.7, Feb, 0.74, Mar, 0.74, Apr, 0.7) * 2.44
	C06	MonthlyValues(May, 0.78, Jun, 0.9, Jul, 0.92, Aug, 0.98, Sep, 0.9, Oct, 0.55, Nov, 0.3, Dec, 0.2, Jan, 0.55, Feb, 0.65, Mar, 0.7, Apr, 0.7) * 2.44
	C07	MonthlyValues(May, 0.78, Jun, 0.6, Jul, 0.6, Aug, 0.6, Sep, 0.5, Oct, 0.45, Nov, 0.25, Dec, 0.1, Jan, 0.45, Feb, 0.45, Mar, 0.6, Apr, 0.7) * 2.44

	C08_09	MonthlyValues(May, 0.8, Jun, 0.5, Jul, 0.4, Oct, 0.4, Nov, 0.35, Dec, 0.5, Jan, 0.5, Feb, 0.8) * 2.44
	C10_59	MonthlyValues(May, 1, Jun, 0.8, Jul, 0.2, Aug, 0.1, Oct, 0.1, Nov, 0.95, Dec, 0.95, Jan, 1) * 2.44
	C12	0.642 * 2.44
	C13	MonthlyValues(Aug, 1, Sep, 0.65, Oct, 1) * 2.44
	C14_17	MonthlyValues(May, 0.5, Aug, 0.5, Sep, 0.1, Dec, 0.1, Jan, 0.5, Mar, 0.5, Apr, 0.7) * 2.44
	C15_57	MonthlyValues(May, 1.5, Jul, 1.5, Aug, 0.98, Sep, 0.1, Oct, 0.55, Nov, 0.6, Dec, 0.2, Jan, 0.55, Feb, 1.5, Mar, 1.5, Apr, 1) * 2.44
	C16	0.642 * 2.44
	C18	MonthlyValues(May, 2, Sep, 2, Oct, 1.4, Apr, 1.4) * 2.44
	C19	MonthlyValues(May, 1.8, Aug, 1.8, Sep, 1.5, Oct, 0.692, Apr, 0.692) * 2.44
	C20	1.484 * 2.44
	C53	2
Inner Delta	C21	1.5 * 2.44
	C22	1.5 * 2.44
	C23	MonthlyValues(May, 1.2, Jun, 1.5, Jul, 1.2, Oct, 1.2, Nov, 0.3, Apr, 0.3) * 2.44
	C24	MonthlyValues(Jul, 1.631, Aug, 1.3, Sep, 1.631, Oct, 2.5, Nov, 1.631) * 2.44
	C25	MonthlyValues(Jul, 1.631, Aug, 1.3, Sep, 1.631, Oct, 2.5, Nov, 1.631) * 2.44
	C26_28_29	1.54 * 2.44
	C27	MonthlyValues(Jul, 1.548, Aug, 2, Sep, 1.548) * 2.44
	C30	MonthlyValues(Aug, 1, Sep, 0.6, Oct, 1, Nov, 1, Dec, 1.5, Jan, 1.5, Feb, 1) * 2.44
	C31	MonthlyValues(May, 1, Nov, 1, Dec, 1.5, Jan, 0.5, Apr, 0.5) * 2.44
Middle Niger	C40	MonthlyValues(Sep, 1, Oct, 0.2, Nov, 1, Dec, 1, Jan, 0.2, Mar, 0.2, Apr, 1) * 2.44
	C62	MonthlyValues(May, 0.3, Jun, 0.01, Jul, 0.01, Aug, 0.1, Sep, 1.4, Oct, 0.9, Nov, 0.6, Dec, 0.3) * 2.44

	C63	MonthlyValues(May, 1, Jun, 1.8, Jul, 1.8, Aug, 2, Sep, 1, Oct, 1, Nov, 1.8, Apr, 1.8) * 2.44
	C64	0.863 * 2.44
	C65	MonthlyValues(May, 0.3, Jun, 0.798, Jul, 1.4, Aug, 1.3, Sep, 1, Oct, 0.819, Nov, 0.6, Dec, 0.3) * 2.44
	C66	MonthlyValues(May, 1.2, Nov, 1.2, Dec, 1.25, Apr, 1.25) * 2.44
	C67_68	MonthlyValues(Sep, 1, Oct, 0.9, Nov, 0.6, Dec, 0.9, Jan, 1) * 2.44
	C69	0.681 * 2.44
	C70	0.903 * 2.44
	C73_74	2
	C76	0.889 * 2.44
	C81	0.57 * 2.44
	C82	1.088 * 2.44
	C84	MonthlyValues(May, 0.78, Jun, 0.9, Jul, 0.92, Aug, 0.86, Sep, 0.9, Oct, 0.3, Nov, 0.1, Dec, 0.2, Jan, 0.55, Feb, 0.7, Mar, 0.75, Apr, 0.75) * 2.44
	C86_87	MonthlyValues(May, 0.9, Jul, 0.9, Aug, 1, Sep, 0.5, Oct, 0.5, Nov, 0.6, Dec, 1, Apr, 1) * 2.44
	C88	MonthlyValues(Jul, 1, Aug, 0.2, Sep, 0.1, Oct, 0.2, Nov, 1) * 2.44
	C89	0.5 * 2.44
	C90	2 * 2.44
Lower Niger	C75	1.2 * 2.44
	C80	MonthlyValues(May, 0.5, Jul, 0.8, Aug, 1.1, Sep, 0.5, Oct, 0.1, Apr, 0.2) * 2.44
	C83	MonthlyValues(May, 0.78, Jun, 0.9, Jul, 0.92, Aug, 0.4, Sep, 0.4, Oct, 0.5, Nov, 0.3, Dec, 0.2, Jan, 0.55, Feb, 0.65, Mar, 0.7, Apr, 0.7) * 2.44
	C77	MonthlyValues(May, 2, Jun, 1.9, Jul, 1.9, Aug, 2, Sep, 1.5, Oct, 3.9, Nov, 3, Dec, 2) * 2.44
	C78_79	MonthlyValues(May, 0.7, Aug, 0.7, Sep, 0.4, Oct, 0.1, Nov, 0.2, Apr, 0.2) * 2.44
	C76b	0.889 * 2.44

Table C-18: Nash-Sutcliffe results for all flow stations in Niger River basin

Sub_Basin Name	Stream Gage	Upstream area (km²)	Source	Calibration	
				Period	**Nash**
C05_11	InflowTinkisso	15,048.3	MIKEBASIN	1966-1989	0.87
C06	InflowNiger	15,713.6	MIKEBASIN	1966-1989	0.78
C07	M_inflowNodan	12,518.4	MIKEBASIN	1966-1989	0.83
C08_09	InflowMilo	5,504.8	MIKEBASIN	1966-1989	0.94
C10_59	InflowSankarani	19,440.2	MIKEBASIN	1966-1989	0.8
C13	M_inflowselingue	5,725.1	MIKEBASIN	1966-1989	0.80
C12	M_Banankoro	21,601.7	MIKEBASIN	1966-1989	0.92
C14_17	O_Doila		MIKEBASIN	1966-1989	0.71
C15_57	M_InflowBagoe	34,584.8	MIKEBASIN	1966-1989	0.76
C16	O_Koulikoro	19,823.2	MIKEBASIN	1966-1989	0.869
C18	O_Kirango	16,096.6	MIKEBASIN	1966-1989	0.795
C19	O_Douna	34,747.2	MIKEBASIN	1966-1989	0.77
C20	M_DounaOutflow	23,587.2	MIKEBASIN	1966-1989	0.755
C22	O_Tossaye	48,115.4	MIKEBASIN	1966-1989	0.27
C23	M_Ansongo	81,756.0	MIKEBASIN	1966-1989	0.70
C24	O_Alconqui	42,444.0	MIKEBASIN	1966-1989	0.48
C25	M_Kandadji	12,980.0	MIKEBASIN	1966-1989	0.78
C26_28_29	O_Garbekourou	38,868.0	MIKEBASIN	1966-1989	0.63
C27	M_Niamey	5,582.0	MIKEBASIN	1966-1989	0.74
C30	Inflow_Goroubi	9,649.0	MIKEBASIN	1966-1989	0.62
C31	M_BelowC31Outflow	34,340.0	MIKEBASIN	1966-1989	0.77
C32	M_inflowMekrou	9,648.0	MIKEBASIN	1966-1989	0.53
C33	M_Malanville	34,117.0	MIKEBASIN	1966-1989	0.65
C34	M_inflowC34	13,410.0	MIKEBASIN	1966-1989	0.69

C40	M_jidereBode	33,790.0	MIKEBASIN	1966-1989	0.38
C53	O_keMacina	26,496.0	MIKEBASIN	1966-1989	0.77
C63	M_AboveGoronyDam	15,870.0	MIKEBASIN	1966-1989	0.51
C64	M_inflowSokoto	4,800.0	MIKEBASIN	1966-1989	0.35
C65	M_RimaOutflow	43,910.0	MIKEBASIN	1966-1989	0.515
C66	M_Svasei	791.0	MIKEBASIN	1966-1989	0.7061
C67_68	M_KontagoraOutflow	2,000.0	MIKEBASIN	1966-1989	0.543
C69	M_BelowC69Outflow	31,360.0	MIKEBASIN	1966-1989	0.74
C70	M_BelowC70outflow	38,735.0	MIKEBASIN	1966-1989	0.53
C75	Inflow_Kampe	1,640.0	MIKEBASIN	1966-1989	0.4378
C76	O_Lokoja	102,710.0	MIKEBASIN	1966-1989	0.14
C77	O_Onitsha	30,725.0	MIKEBASIN	1966-1989	0.99
C78_79	O_Makurdi	46,626.0	MIKEBASIN	1966-1989	0.790
C80	M_Ibi	147,640.0	MIKEBASIN	1966-1989	0.77
C81	M_inflowGongola	30,460.0	MIKEBASIN	1966-1989	0.77
C82	M_BelowC82Outflow	21,080.0	MIKEBASIN	1966-1989	0.53
C83	M_inflowBenue	30,650.0	MIKEBASIN	1966-1989	0.80
C84	O_Kossi	25,000.0	MIKEBASIN	1966-1989	0.70
C88	M_inflowC88	6,380.0	MIKEBASIN	1966-1989	0.49
C89	M_inflowC89	15,800.0	MIKEBASIN	1966-1989	0.36
C90	InflowKaraduwa/ O_Zobe	2,380.0	MIKEBASIN	1966-1989	-0.13

Figure C-26: Location of main control stations in Niger River basin used for model calibration

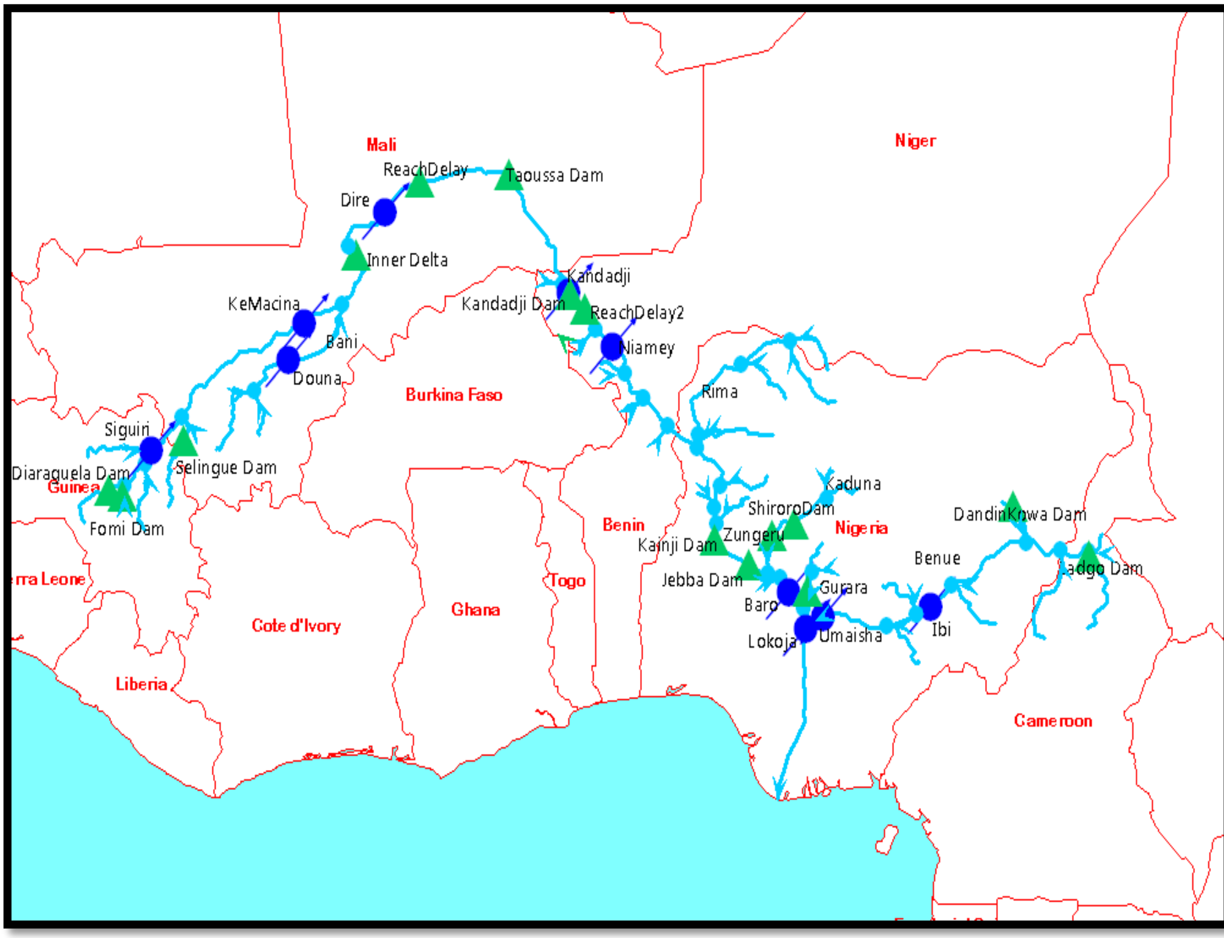


Table C-19: Calibration statistics for main control stations

River	Location	Country	NSE	Bias	SDR	RMSE
Bani	Douna	Mali	0.77	1%	0.85	662
Upper Niger	Siguiri	Guinea	0.87	-9%	0.88	1098
Upper Niger	KeMacina (above Inner Delta)	Mali	0.80	-5%	0.97	1624
Middle Niger	Dire (below Inner Delta)	Mali	0.89	-4%	1.01	690
Middle Niger	Kandadji (Mali-Niger border)	Niger	0.78	-12%	0.70	816
Middle Niger	Niamey	Niger	0.74	-9%	0.71	887
Lower Niger	Baro (above Benue inflow)	Nigeria	0.60	-11%	0.78	2142
Benue	Ibi	Nigeria	0.70	-4%	0.77	3797
Benue	Umaisha	Nigeria	0.66	1%	0.82	5768
Lower Niger	Lokoja (below Benue inflow)	Nigeria	0.69	4%	0.93	7574

Figure C-27: Simulated and observed Bani River flows at Douna, Mali

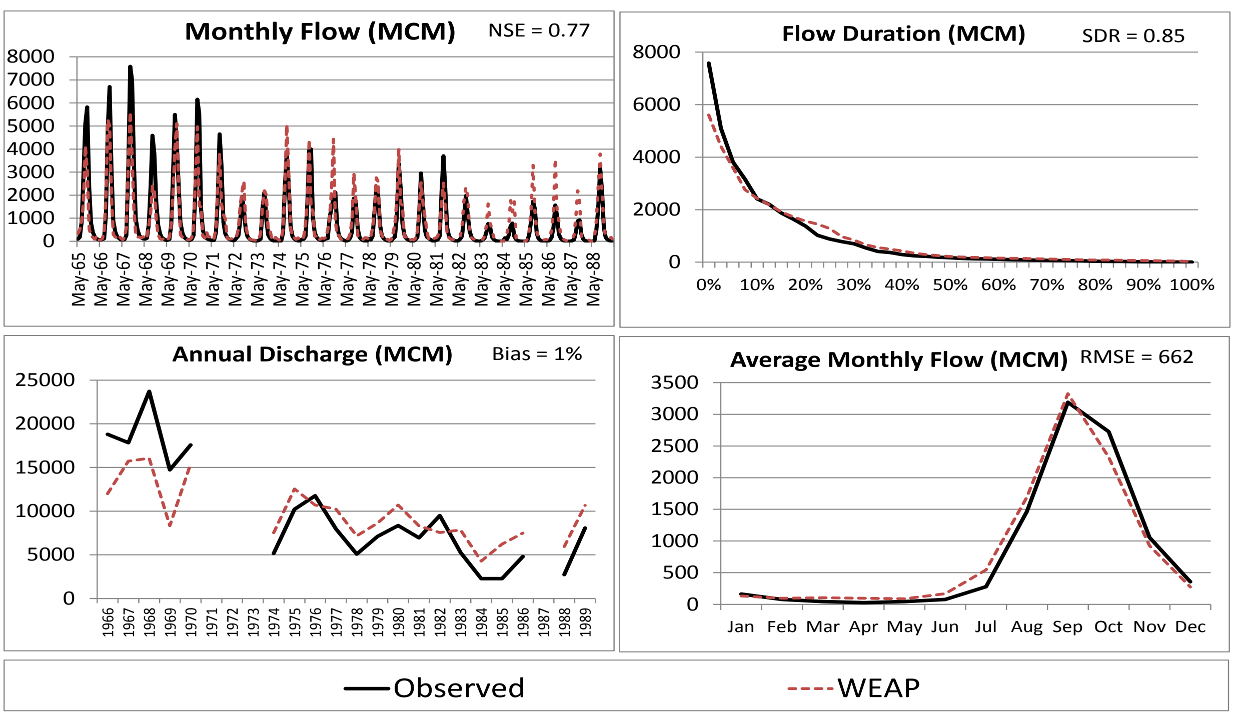


Figure C-28: Simulated and observed Niger River flows at Siguiri, Guinea

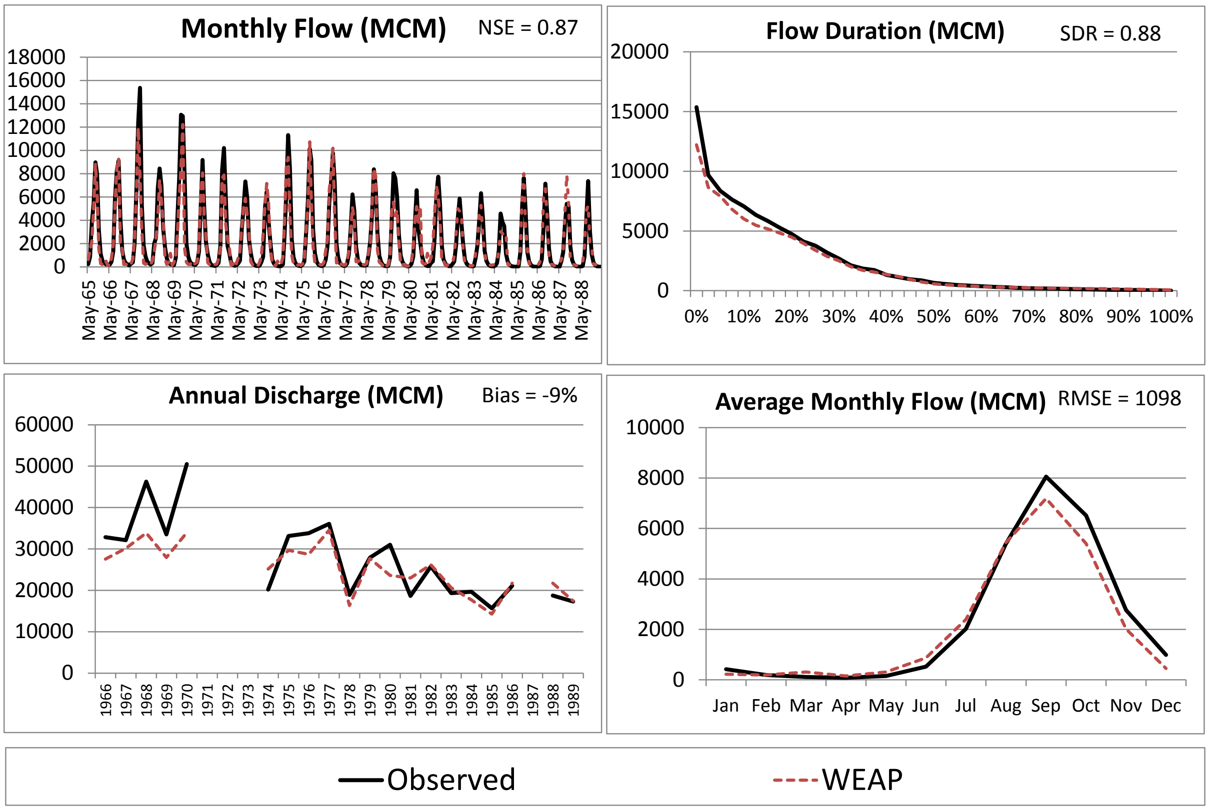


Figure C-29: Simulated and observed Niger River flows at KeMacina, Mali (above Inner Delta)

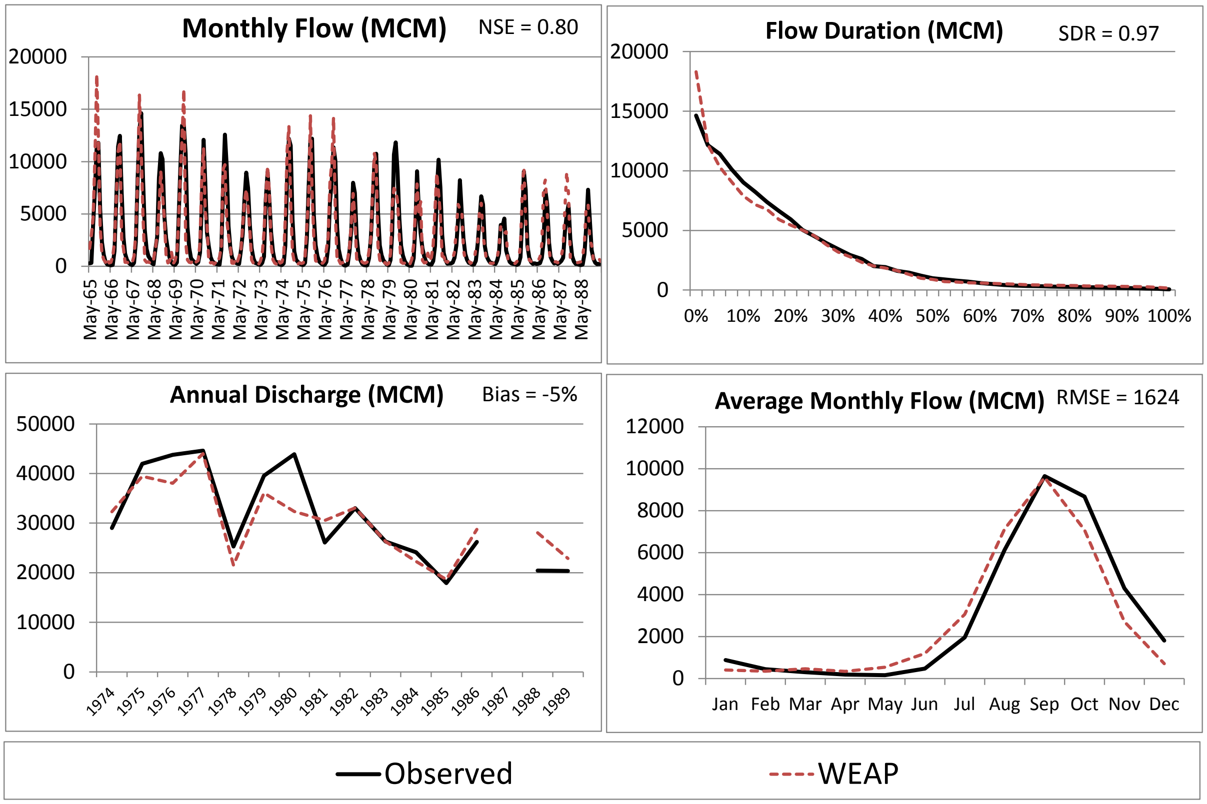


Figure C-30: Simulated and observed Niger River flows at Dire, Mali (below Inner Delta)

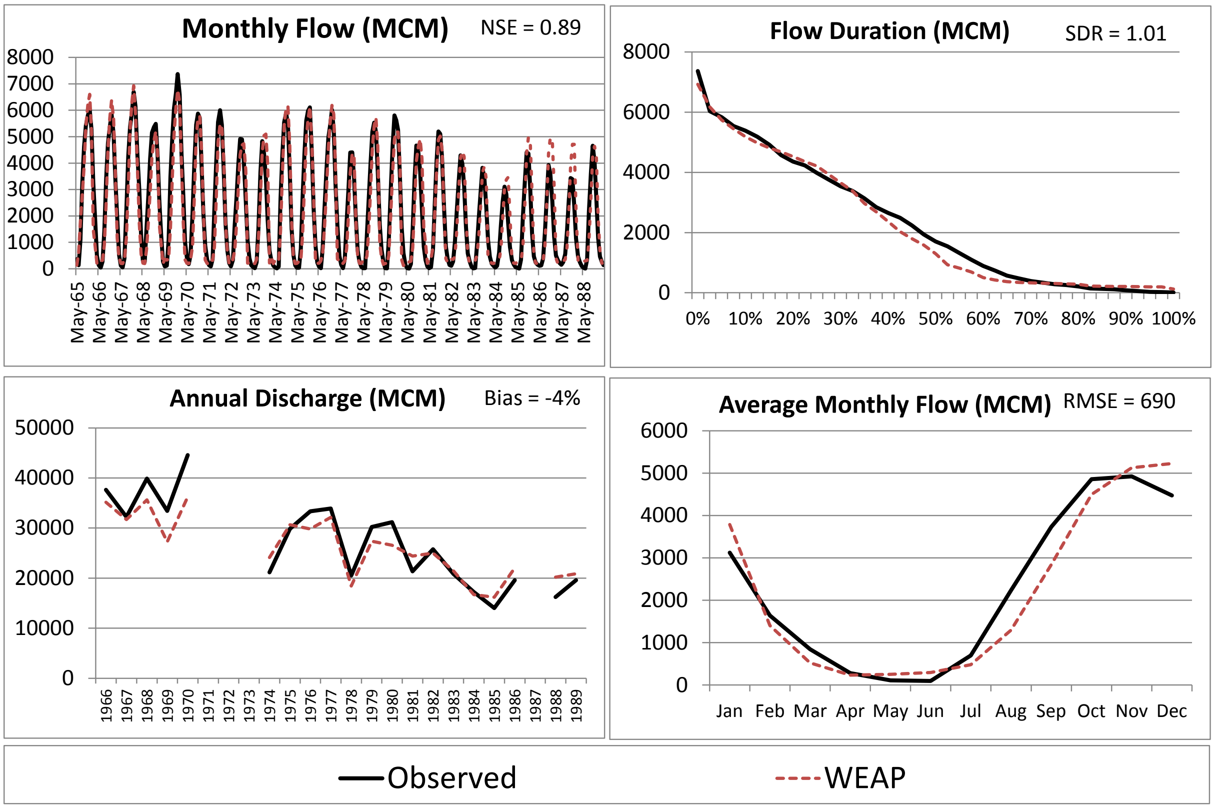


Figure C-31: Simulated and observed Niger River flows at Kandadji, Niger

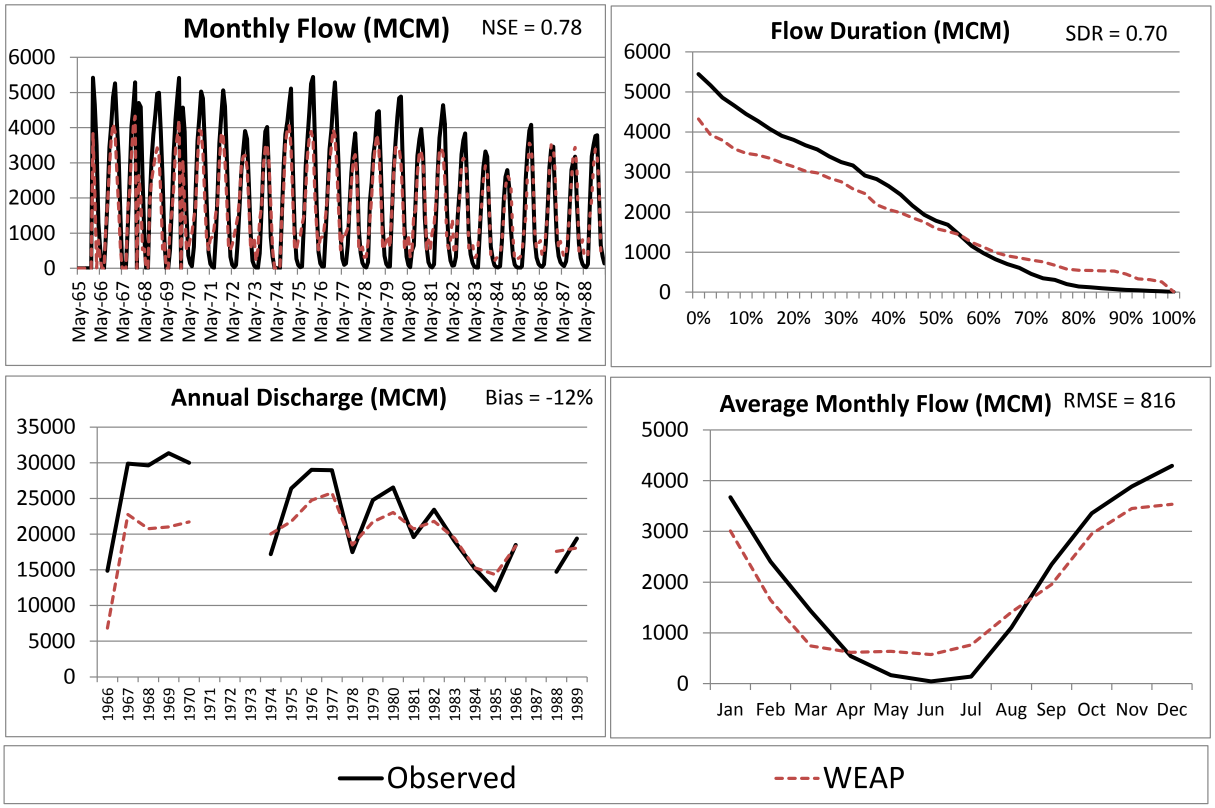


Figure C-32: Simulated and observed Niger River flows at Niamey, Niger

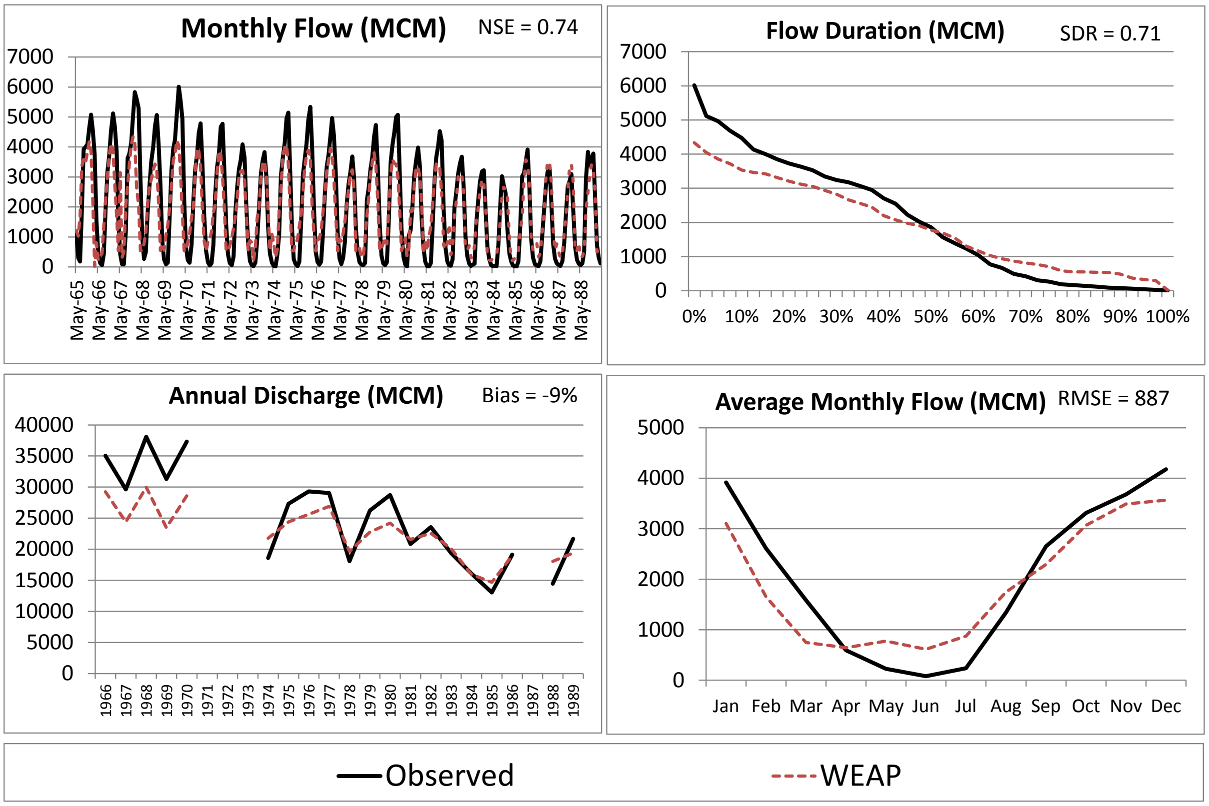


Figure C-33: Simulated and observed Niger River flows at Baro, Nigeria

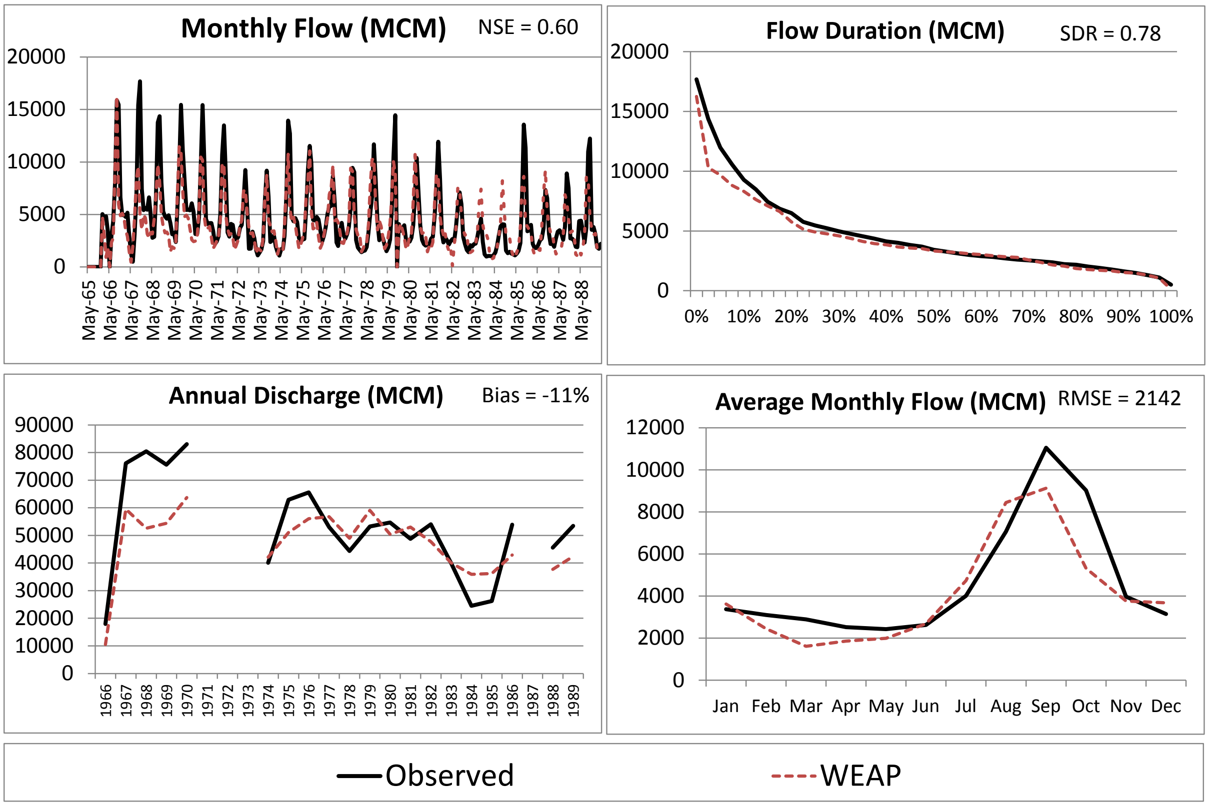


Figure C-34: Simulated and observed Benue River flows at Ibi, Nigeria

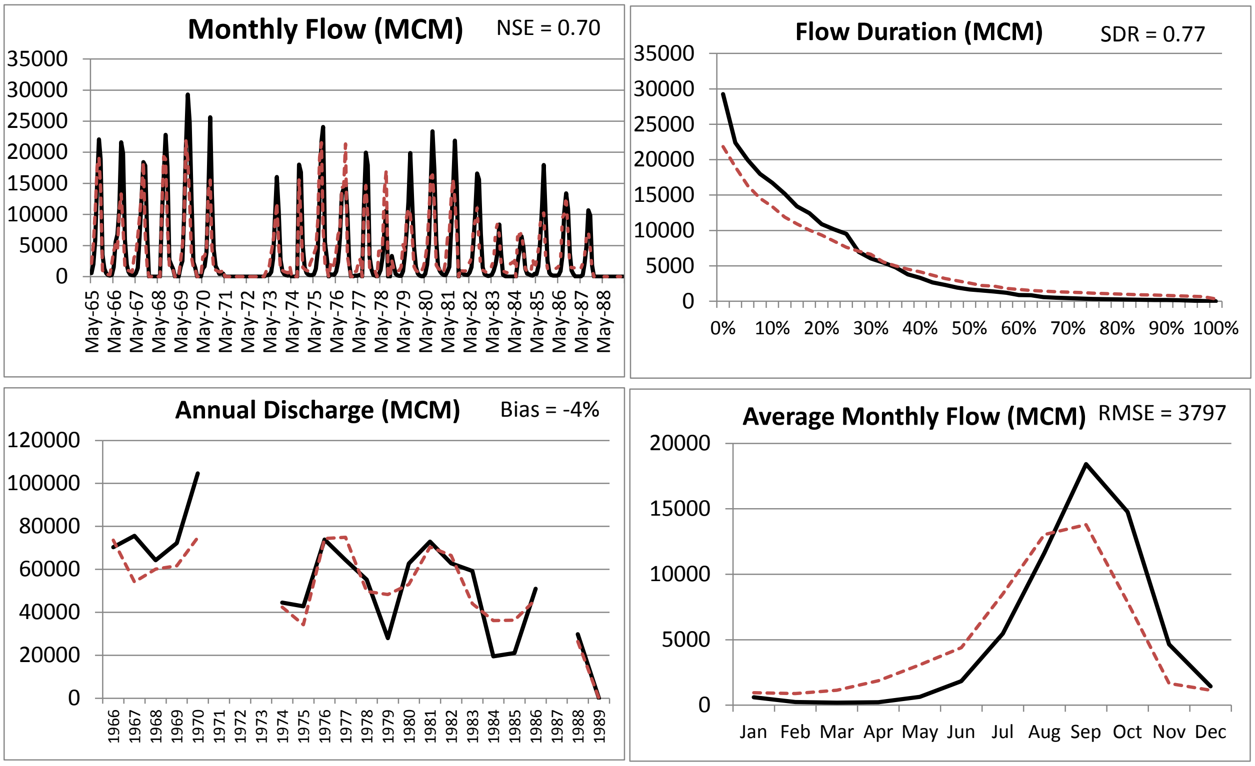


Figure C-35: Simulated and observed Benue River flows at Umaisha, Nigeria

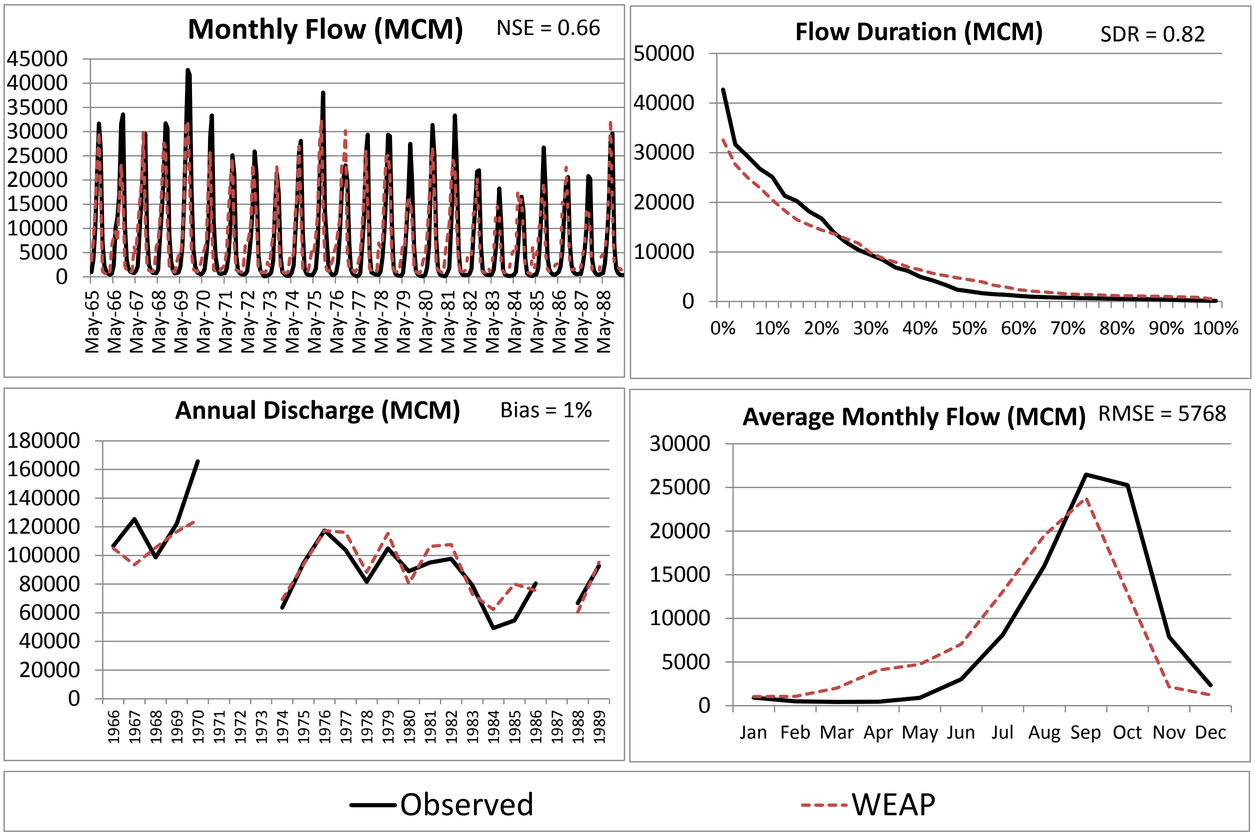


Figure C-36: Simulated and observed Niger River flows at Lokoja, Nigeria

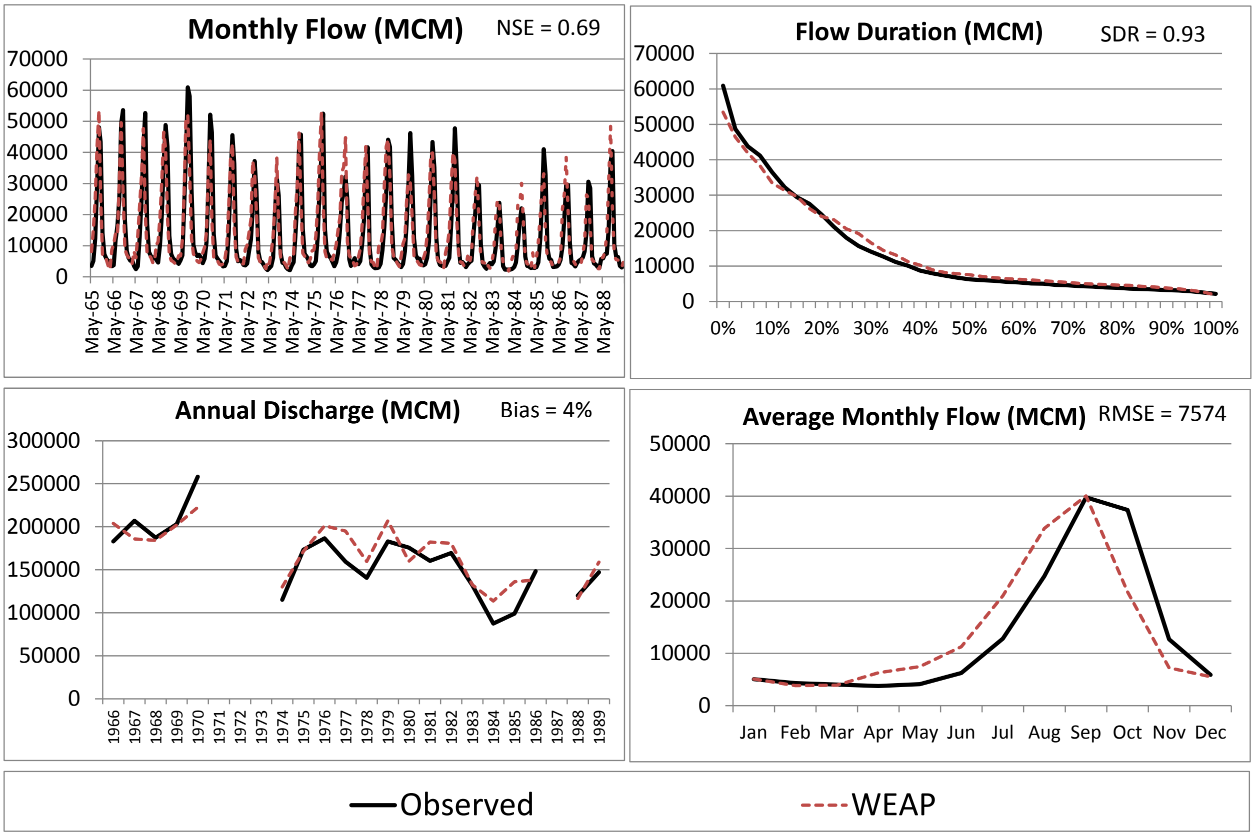


Figure C-37: WEAP versus MIKE Basin simulated Kainji storage

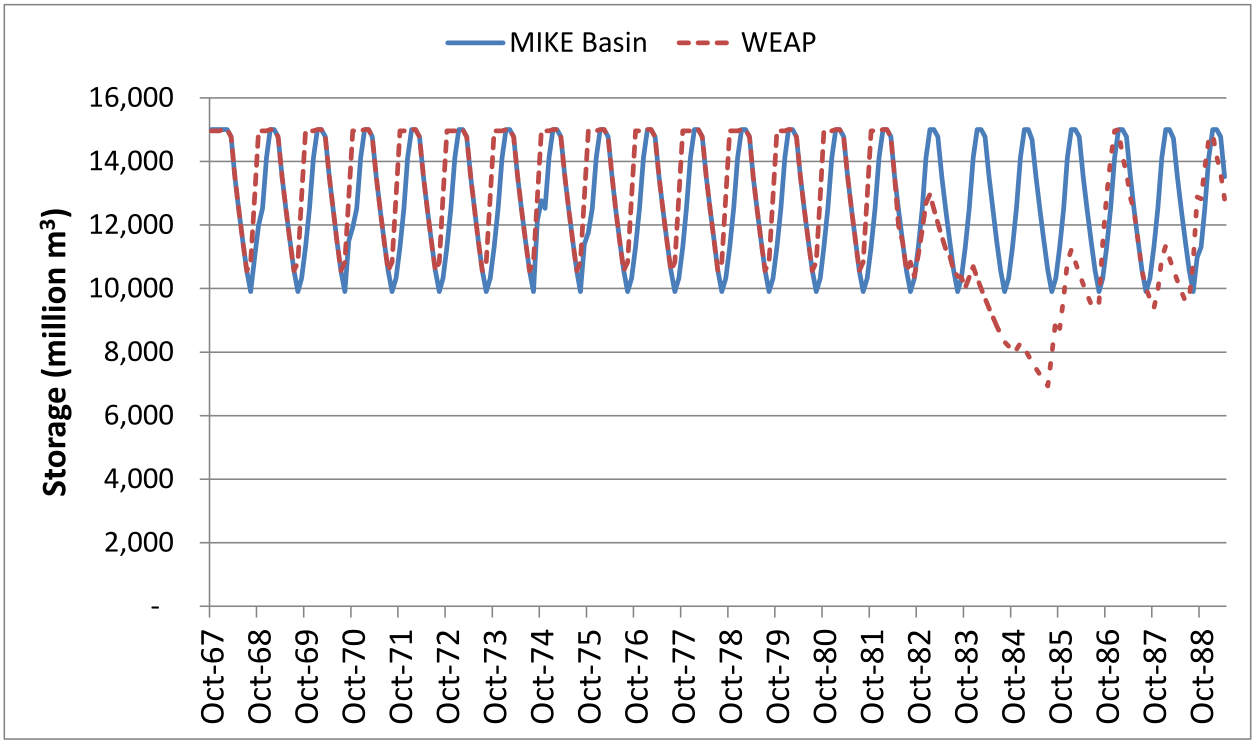
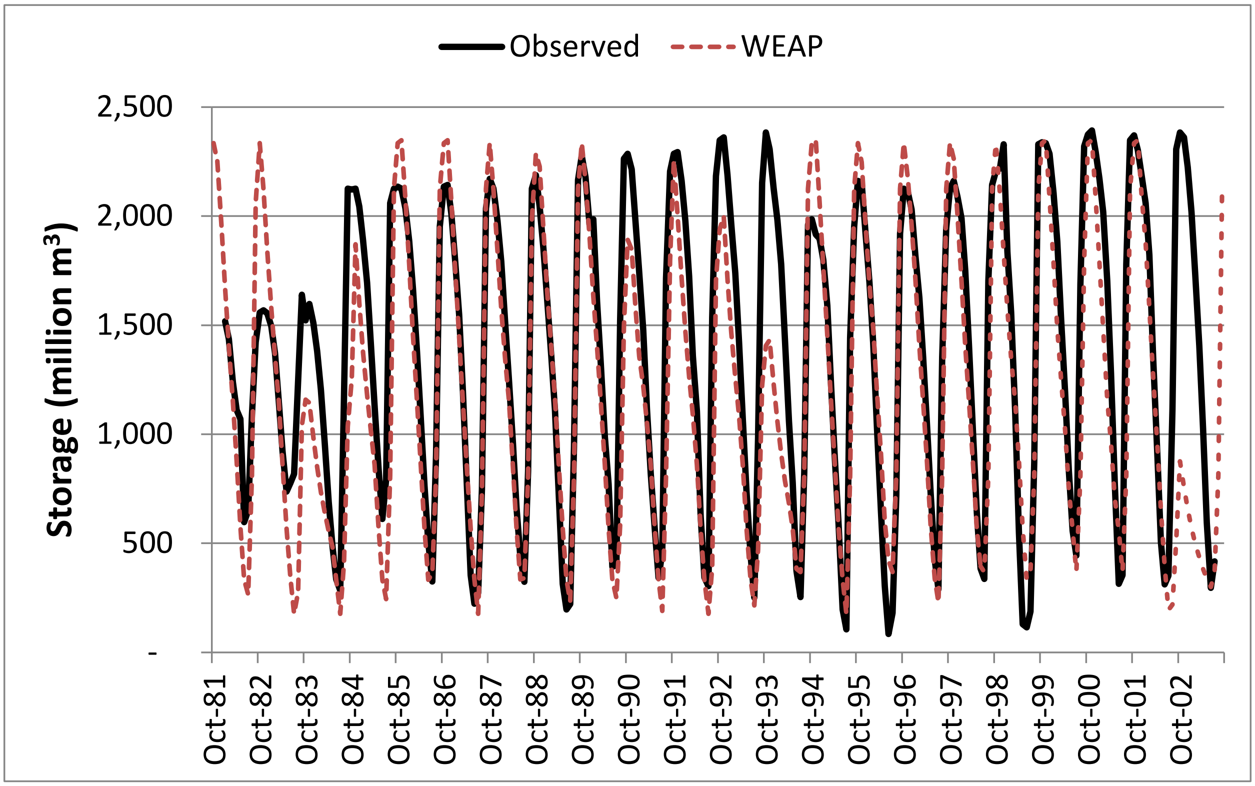


Figure C-38: WEAP versus observed Selingue storage.



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C4- Nile River Basin

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Figure C-39: Nile River Basin, Northeast Africa

Description of the Basin

The Nile is the second-largest river basin of Africa, with a total area of just over 3.1 million km^2. Its area represents about 10.3% of the area of the continent and spreads over ten countries, namely: Burundi, Democratic Republic of Congo, Egypt, Eritrea, Ethiopia, Kenya, Rwanda, South Sudan, Sudan, Tanzania, and Uganda. The Nile River is the longest river in Africa and flows north over 6800 km (and 35 degrees latitude) from its sources around the equator to its outlet in the Mediterranean Sea. Its climate ranges from humid regions at the river sources – where rainfall exceeds 1200 mm per year – to deserts in the north of the basin, where precipitation is typically less than 20 mm per year.

Table C-20: Nile River basin areas by country

Country	Area (km^3)	Area falling within Nile basin	Area within Nile basin as % of country area	Area within basin as % of Nile basin area
Burundi	28,062	13,860	49.4%	0.4%
DR Congo	2,401,941	21,796	0.9%	0.7%

Egypt	996,960	302,452	30.3%	9.5%
Eritrea	121,722	25,697	21.1%	0.8%
Ethiopia	1,144,035	365,318	31.9%	11.5%
Kenya	593,116	51,363	8.7%	1.6%
Rwanda	24,550	20,625	84.0%	0.6%
South Sudan	635,150	620,626	97.7%	19.5%
Sudan, The	1,864,049	1,396,230	74.9%	44.0%
Tanzania	933,566	118,507	12.7%	3.7%
Uganda	241,248	240,067	99.5%	7.6%
Source (for Admin boundaries)	GAUL (Global Administrative Unit Layers; Projected GCS - WGS-1984-UTM Zone 36 N			

The current and future development plans for hydropower and irrigation in the basin are available in Appendix A of this report.

WEAP Schematization

The current WEAP application for Nile River basin marks a first attempt to create an integrated hydrological and water systems tool for the entire river basin, including existing and proposed infrastructure. The only other basin-wide hydrological and water resources system of the Nile is the Nile Forecast System (NFS) hosted by the Ministry of Water Resources and Irrigation of Egypt (Elshamy, 2008). The Nile WEAP model was developed using the data and system configuration from hydrologic (NAM) and water systems (MIKEBASIN) models developed for some sub-basins of the Nile under the NBI Water Resources Planning and Management (WRPM) project (2006-2012). The NAM models were used as a guide to define the sub-basin and catchment areas, while the MIKEBASIN model was used to define the main features of the managed system (i.e. reservoir storage capacities, diversion capacities, reservoir release rules, etc.). However, the Nile WEAP schematic improves and expands on those models. Some sub-basins (e.g. Bahr El-Ghazal sub-basin) were not modeled under the NB-DSS and available models for several others sub-basins did not include hydrologic (i.e. rainfall-runoff) components.

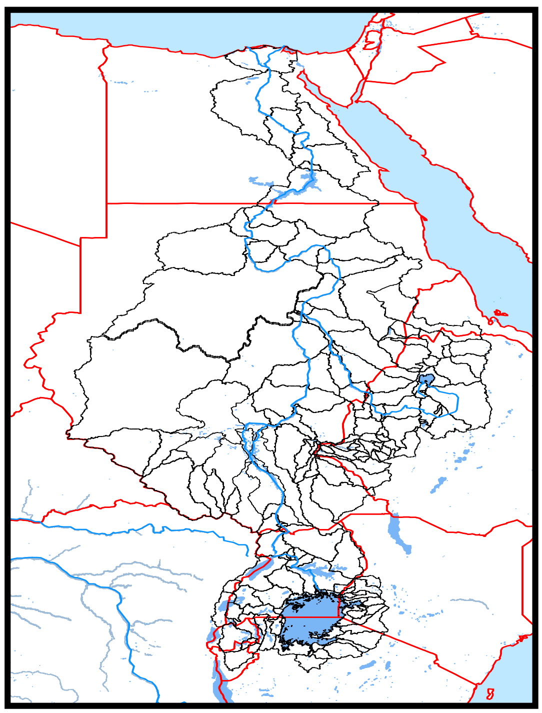
The Nile basin is divided into several sub-basins that are considered independent of one another. While downstream sub-basins (i.e. White Nile and Main Nile) depend upon the natural hydrology and water management in the upper basin, we simulated the upper sub-basins (i.e. Equatorial Lakes region, Bahr el Jebel, Bahr el Ghazal, Baro-Akobo-Sobat, Blue Nile, and Tekeze- Atbara) as operating facilities to satisfy local water demands. Virtual reservoirs were added as necessary to model wetlands in several sub-catchments (e.g. Bahr El-Jebel and Bahr El-Ghazal).

Catchment definitions

Each sub-basin of the Nile was further divided into sub-catchment areas according to the location of the existing and planned project structures, points of confluence of major tributaries and gauging stations. This spatial disaggregation was done via a GIS analysis of identified pour points within the sub-basins. The 3 sec conditioned digital elevation model data from HydroSHEDS (**Hydro**logical data and maps based on **SH**uttle **E**levation **D**erivatives at multiple **S**cales) was used to delineate catchments using ArcGIS software. This resulted in a total of 170 unique catchment areas ranging in size from 70 to 308,000 km2. These are shown graphically in Figure C-40: Nile Basin catchments.

Time series of historical and projected climate (i.e. monthly precipitation (mm), average temperature (C), minimum temperature (C), and maximum temperature (C)) were developed for each sub-catchment shown inFigure C-40. These data were used as drivers for the routines that estimate the hydrological response (i.e. rainfall-runoff and base flow) and potential evapotranspiration for each sub-catchment.

Figure C-40: Nile Basin catchments



Water allocation

The demand priority in WEAP defines how water is allocated to satisfy competing uses – i.e. reservoir storage, hydropower generation, irrigation, domestic use, and flow. WEAP offers demand priorities ranging in number from 0-99, where the lower numbers indicate higher a priority for water use.

The demand priorities used in the Nile River are listed in Table C-21. These are generally set such that domestic water use has the highest priority, followed by environmental flow requirements as the second priority, irrigated agriculture as the third priority, hydropower generation as the fourth priority, and reservoir storage as the lowest priority. The priority structure also reflects the realities of water usage and the regional management of water within the basin. That is, water users that are high in the basin will tend to use the water that is available to them independent of water usage elsewhere in the basin. This implies that water users that are quite low in the basin will have a lower demand priority such that they don't compete for the same water as users far upstream nor actively draw water from reservoirs at the headwaters.

Table C-21: Allocation priority structure of the Nile river WEAP model

Sub-Basin	River	Node	WEAP Object	WEAP Priority			
				Storage	Hydropower	Demand	Flow Requirement
Baro-Akobo-Sobat	Birbir	Birbir R Dam	Reservoir	2	1		
	Geba	Geba A Dam	Reservoir	2	1		
	Geba	Geba R Dam	Reservoir	2	1		
	Baro	Baro 1 Dam	Reservoir	2	1		
	Baro	Baro 2 Dam	Reservoir	2	1		
	Baro	Tams Dam	Reservoir	5	4		
	Baro	Itang Dam	Reservoir	5	4		
	Baro	Itang Irrigation	Irrigated Catchment			1	
	Baro	Lower Baro VR	Reservoir	8			
	Baro	Lower Baro VR Flow	Flow Requirement				7
	Alwero	Dumbong Dam	Reservoir	3	3		
	Alwero	Dumbong Irrigation	Irrigated Catchment			1	
	Alwero	Alwero Dam	Reservoir	3	3		
	Alwero	Abobo Irrigation	Irrigated Catchment			1	
	Gilo	Gilo 2 Irrigation	Irrigated Catchment			1	
	Gilo	Virtual Gilo	Reservoir	6			
	Gilo	Gilo Low Flow	Flow Requirement				5
	Pibor	Virtual Pibor 1	Reservoir	6			
	Pibor	Pibor Routing 1	Flow Requirement				5
	Pibor	Virtual Pibor 2	Reservoir	9			
	Pibor	Pibor Routing 2	Flow Requirement				8
	Machar Bypass	Lower Baro Capacity	Flow Requirement				4
	Machar Diversion	Machar Diversion	Flow Requirement				3
	Machar Diversion	Machar Marshes VR	Reservoir	22			
	Machar Diversion	Machar Marshes ds Req	Flow Requirement				21
Bahr el Ghazal	Jur	Wau Irrigation	Irrigated Catchment			1	

	Lol	Aweil Irrigation	Irrigated Catchment			1	
	Bahr el Ghazal	SS_Rural	Demand			1	
	Bahr el Ghazal	Bahr el Ghazal Swamp VR	Reservoir	4			
	Bahr el Ghazal	BG Flow	Flow Requirement				3
Bahr el Jebel	Bahr el Jebel	Fula Dam	Reservoir	31	30		
	Bahr el Jebel	Shukoli Dam	Reservoir	31	30		
	Bahr el Jebel	Lakki Dam	Reservoir	31	30		
	Bahr el Jebel	Bedden Dam	Reservoir	36	35		
	Bahr el Jebel	Jebel Lado Irrigation	Irrigated Catchment			30	
	Bahr el Jebel	Juba City	Demand			30	
	Bahr el Jebel	Mongalla Irrigation	Irrigated Catchment			31	
	Bahr el Jebel	Bor Irrigation	Irrigated Catchment			32	
	Bahr el Jebel	SS_Rural	Demand			32	
	Yei	Pagaru Irrigation	Irrigated Catchment			33	
	Bahr el Jebel	Bahr el_Zaraf Bifurcation	Flow Requirement				36
	Bahr el Jebel	Sudd Swamp VR1	Reservoir	39			
	Bahr el Jebel	Sudd Swamp VR1	Flow Requirement				38
	Bahr el Zaraf	Sudd Swamp VR2	Reservoir	42			
	Bahr el Zaraf	Sudd Swamp VR2	Flow Requirement				41
Blue Nile	Koga	Koga dam	Reservoir	3	2		
	Koga	Koga Irrigation	Irrigated Catchment			1	
	Blue Nile	Lake Tana	Reservoir	5			
	Blue Nile	LakeTana_FlowReq	Flow Requirement				1
	Blue Nile	Tis_Abbay I	Run-of-River		4		
	Beles	Tana Beles	Run-of-River		4		
	Blue Nile	Karadobe	Reservoir	7	6		
	Fincha	Fincha Dam	Reservoir	6	5		
	Fincha	Fincha Irrigation	Irrigated Catchment			4	
	Amerti	Amerti_Neshe Dam	Reservoir	6	5		
	Amerti	Amerti_Neshe Irrigation	Irrigated Catchment			1	

	Blue Nile	Beko_Abo Dam	Reservoir	7	6		
	Didessa	Didessa Dam	Reservoir	6	5		
	Blue Nile	Mandaya	Reservoir	8	7		
	Blue Nile	ET_Rural	Demand			7	
	Blue Nile	GERD	Reservoir	8	7		
	Blue Nile	Roseires Dam	Reservoir	11	10		
	Blue Nile	US_Sennar_Irrigation	Irrigated Catchment			9	
	Blue Nile	Sennar Dam	Reservoir	14	13		
	Blue Nile	DS_Sennar_Irrigation	Irrigated Catchment			12	
	Blue Nile	Sennar_MinFlowReq	Flow Requirement				11
	Blue Nile	WD_Rural	Demand			15	
Lake Albert	Semliki	Lake Edward Irrigation	Irrigated Catchment			1	
	Semliki	Semliki	Run-of-River		2		
	Albert Nile	UG_Rural	Demand			1	
	Albert Nile	Lake Albert	Reservoir	25			
	Albert Nile	Lake Albert Outflow	Flow Requirement				24
Lake Victoria	Ruvubu	Ruvubu Irrigation	Demand			1	
	Ruvubu	BR_Rural	Demand			1	
	Nyabarongo	Rwagitugusa Irrigation	Demand			2	
	Nyabarongo	Nyabarongo Irrigation	Demand			2	
	Nyabarongo	Kigali city	Demand			1	
	Nyabarongo	Nyabarongo_wetlands	Reservoir	5			
	Nyabarongo	Nyabarongo_Wetlands_req	Flow Requirement				4
	Kagera	Rusumo Falls	Run-of-River		6		
	Kagera	Kagera_Ihema Wetland	Reservoir	9			
	Kagera	Kagera_Ihema_wetlands req	Flow Requirement				8
	Kagera	Kagera_Rushwa_wetland	Reservoir	12			
	Kagera	Kagera_Rushwa_Wetlands req	Flow Requirement				11
	Kagera	Kagera Irrigation	Irrigated Catchment			13	
	Kagera	Kakono HP	Run-of-River		14		

	Rubare	Rubare Irrigation	Irrigated Catchment			1	
	Lake Victoria	LakeVicWetAreaSouth Irrigation	Irrigated Catchment			1	
	Lake Victoria	TZ_Rural	Demand			1	
	Lake Victoria	Mwanza City	Demand			1	
	Isanga	Isanga Irrigation	Irrigated Catchment			1	
	Mamwe	Mamwe Irrigation	Irrigated Catchment			1	
	Simiyu	Simiyu Irrigation	Irrigated Catchment			1	
	Rubana	Rubana Irrigation	Irrigated Catchment			1	
	Mara	Mara Irrigation	Irrigated Catchment			1	
	Lake Victoria	Musoma City	Demand			1	
	Lake Victoria	LakeVicWetAreaEast Irrigation	Irrigated Catchment			1	
	Migori	Migori Irrigation	Irrigated Catchment			1	
	Sare	Sare Irrigation	Irrigated Catchment			1	
	Sare	Gogo Falls	Run-of-River		2		
	Itare	Itare Irrigation	Irrigated Catchment			1	
	Itare	Magwagwa	Reservoir	3	2		
	Awach Kibuon	Awach_Kibuon Irrigation	Irrigated Catchment			1	
	Sondo_Miriu	Sondo_Miriu_Songoro	Run-of-River		4		
	Nyando	Nyando Irrigation	Irrigated Catchment			1	
	Lake Victoria	KN_Rural	Demand			1	
	Lake Victoria	Kisumu City	Demand			1	
	Yala	Yala Irrigation	Irrigated Catchment			1	
	Nzoia	Nzoia_US1 Irrigation	Irrigated Catchment			1	
	Nzoia	Nzoia_US Irrigation	Irrigated Catchment			1	
	Nzoia	Nzoia_DS Irrigation	Irrigated Catchment			1	
	Sio	Sio Irrigation	Irrigated Catchment			1	
	Lake Victoria Virtual	Lake Victoria	Reservoir	22			
	Lake Victoria Virtual	Lake Victoria Flow req	Flow Requirement				21
	Lake Victoria Virtual	Kampala City	Demand			1	
	Lake Victoria Virtual	Jinja City	Demand			23	

	Lake Victoria Virtual	Nalubaale	Run-of-River		24		
	Lake Victoria Virtual	Kiira	Run-of-River		24		
Victoria Nile	Victoria_Kyoga Nile	Isimba	Run-of-River		26		
	Victoria_Kyoga Nile	Bujagali	Run-of-River		26		
	Victoria_Kyoga Nile	Kalagala	Run-of-River		26		
	Victoria_Kyoga Nile	Karuma	Run-of-River		26		
	Victoria_Kyoga Nile	Murchison Falls	Run-of-River		26		
	Victoria_Kyoga Nile	Kiba	Run-of-River		26		
	Victoria_Kyoga Nile	Ayago	Run-of-River		26		
	Malaba	Malaba Town	Demand			1	
	Malaba	Tororo	Demand			1	
	Malaba	Malaba Irrigation	Demand			2	
	Agu	Soroti Town	Demand			1	
	Victoria_Kyoga Nile	UG_Rural	Demand			1	
	Victoria_Kyoga Nile	Lake Kyoga Irrigation	Irrigated Catchment			25	
White Nile	White Nile	Assayla Sugar	Irrigated Catchment			45	
	White Nile	Kenana Sugar 3	Irrigated Catchment			45	
	White Nile	Pump Schemes	Irrigated Catchment			46	
	White Nile	SD_Rural	Demand			53	
	White Nile	Gabal Awlia Dam	Reservoir	52	51		
	White Nile	Gabal Awlia Req	Flow Requirement				50
	White Nile	Khartoum City	Demand			53	
Tekeze-Atbara	Tekeze	TK5 Dam	Reservoir	2	1		
	Tekeze	TK7 Dam	Reservoir	2	1		
	Tekeze	Humera Irrigation	Irrigated Catchment			1	
	Atbara	Combined_Angereb_MetemaLRBanks	Irrigated Catchment			1	
	Atbara	ET_Rural	Demand			4	
	Atbara	RumelaBurdana Dam	Reservoir	5	4		
	Atbara	Upper Atbara Irrigation	Irrigated Catchment			3	
	Atbara	Khashm El Girba Dam	Reservoir	7	6		

	Atbara	New Halfa Irrigation	Irrigated Catchment			6	
	Atbara	SD_Rural	Demand			8	
Main Nile (below Blue/White confluence)	Nile	Sabloka Dam	Reservoir	50	51		
	Nile	Tamniat_Hasanab Irrigation	Irrigated Catchment			49	
	Nile	Shereiq Dam	Reservoir	56	55		
	Nile	Dagash	Run-of-River		99		
	Nile	Merwoe Dam	Reservoir	56	55		
	Nile	SD_Rural	Demand			53	
	Nile	Hasanab_Dongola Irrigation	Irrigated Catchment			54	
	Nile	Kajbar Dam	Reservoir	56	55		
	Nile	Low Dal Dam	Reservoir	56	55		
	Nile	Toshka Irrigation	Irrigated Catchment			54	
	Nile	HAD	Reservoir	89	58		
	Nile	Toshka Spillage	Flow Requirement				90
	Nile	Aswan_Esna Irrigation	Irrigated Catchment			57	
	Nile	Esna Barrage	Run-of-River		99		
	Nile	Esna_Nagaa Hammadi Irrigation	Irrigated Catchment			60	
	Nile	Nagaa Hammadi Barrage	Run-of-River		99		
	Nile	Nagaa Hammadi_Assuit Irrigation	Irrigated Catchment			63	
	Nile	Assuit Barrage	Run-of-River		99		
	Nile	Upper Egypt Urban	Demand			66	
	Nile	Assuit_Cairo Irrigation	Irrigated Catchment			68	
	Nile	Greater Cairo	Demand			69	
	Nile Delta - Damietta Branch	Delta Urban	Demand			70	
	Nile Delta - Damietta Branch	Nile Delta Irrigation	Irrigated Catchment			71	
	Nile Delta - Damietta Branch	ElSalam Canal Irrigation Project	Irrigated Catchment			71	
	Nile Delta - Rosetta Branch	West Delta Irrigation	Irrigated Catchment			71	

Model Calibration

Flow Simulation

The figure below presents the location of control stations in the Nile basin that were used for model calibration. Calibration metrics for the main control stations are listed in Table C-22: Calibration statistics for main control stations. The corresponding graphs are presented in

Figure *C-42* through Figure C-54. Data availability dictated the calibration period which could be used for the each calibration point. For example, catchments in Bahr El-Ghazal were calibrated at a few points using records from 1948-1974 (with gaps) while records for the period 1961-1990 were used in the Blue Nile sub-catchments. For some sub-catchments, only the average monthly hydrographs could be used. No attempt was made to patch the flow records prior to calibration; therefore, calibration metrics were calculated based on months with available data only. This approach maximizes the use of available data and avoids introducing additional errors, since the best methods for patching is through rainfall-runoff modeling.

Figure C-41: Location of control stations in the Nile Basin

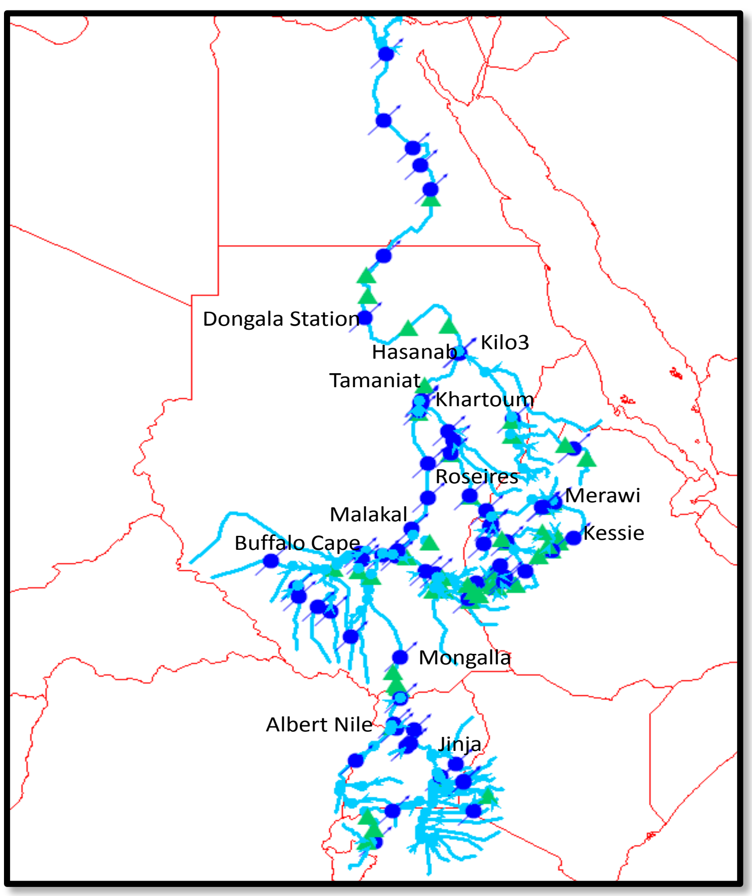


Table C-22: Calibration statistics for main control stations

River	Location	Country	NSE	SDR	RMSE	Bias
Nile	at Dongala	Sudan	0.61	1.30	4027	3%
Nile	at Hasanab	Sudan	0.60	1.38	3071	2%
Nile	at Tamaniat	Sudan	0.61	1.38	3036	2%
Atbara	abv inflow to Nile	Sudan	0.58	0.84	1315	-3%
Blue Nile	abv inflow to Nile	Sudan	0.83	0.79	2518	-12%
Blue Nile	abv Roseires Dam	Sudan	0.82	1.13	2170	-1%
Blue Nile	Koga at Merawi	Ethiopia	0.66	1.07	10	10%
Blue Nile	Abbay at Kessie	Ethiopia	0.35	1.36	1362	14%
White Nile	at Malakal	South Sudan	0.35	1.23	772	-2%
White Nile	at Melut	South Sudan	0.19	1.33	822	0%
Bahr el Jebel	at Buffalo Cape	South Sudan	0.35	0.63	97	-6%
Bahr el Jebel	at Mongalla	South Sudan	0.91	0.84	492	1%
Albert Nile	abv inflow to Nile	Uganda	0.92	0.84	447	0%
Victoria Nile	Jinja/Owen Falls	Uganda	0.92	0.99	296	-2%

Figure C-42: Simulated and observed Victoria Nile River flows at Jinja, Uganda (Lake Victoria outflow)

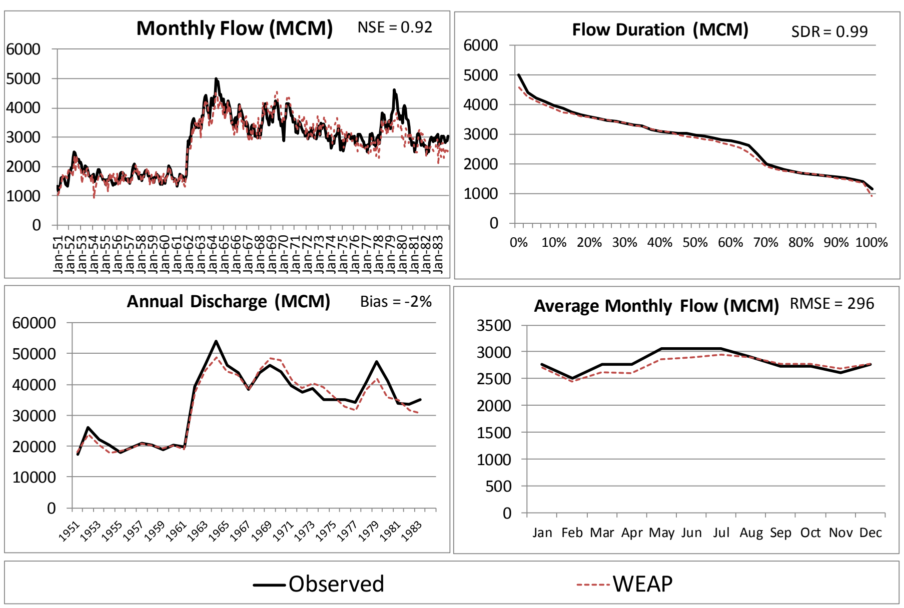


Figure C-43: Simulated and observed Albert Nile River flows above confluence with Bahr el Jebel

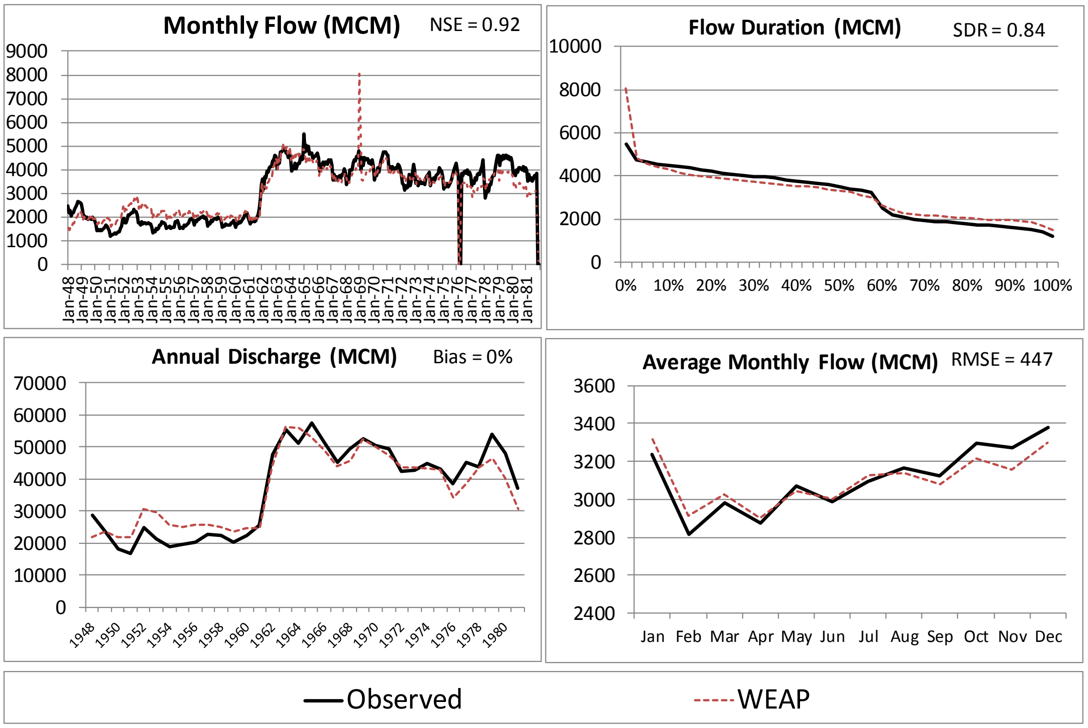


Figure C-44: Simulated and observed Bahr el Jebel flows at Mongalla, South Sudan (upstream of Sudd wetland)

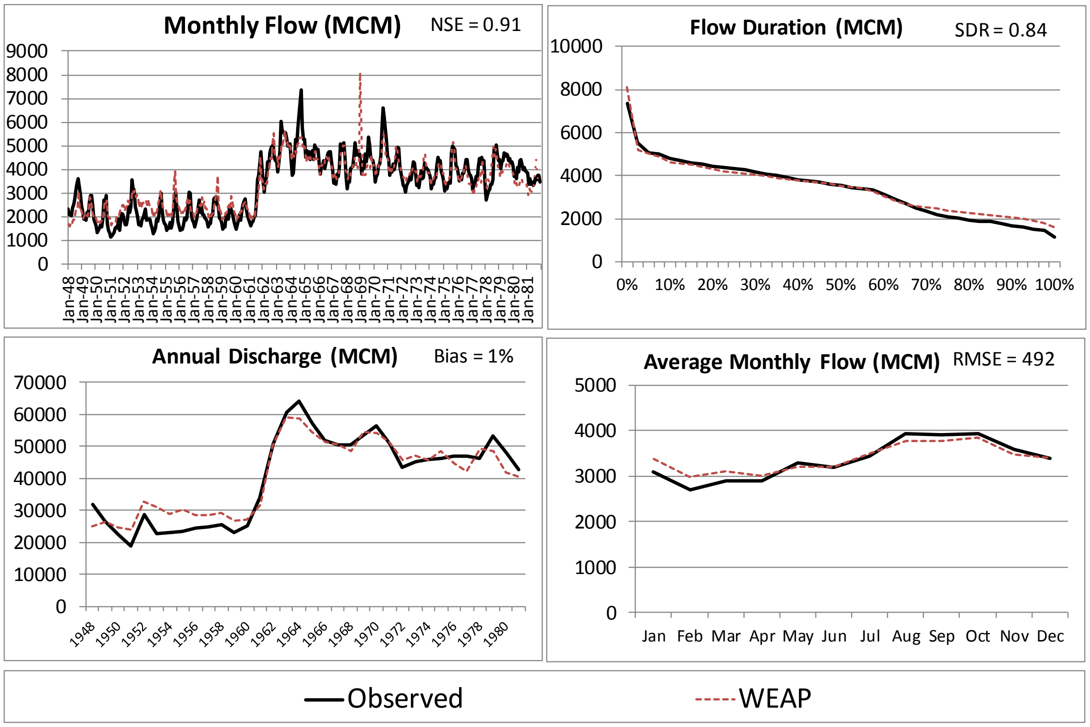


Figure C-45: Simulated and observed Barh el Jebel River flows at Buffalo Cape, South Sudan (downstream of Sudd wetland)

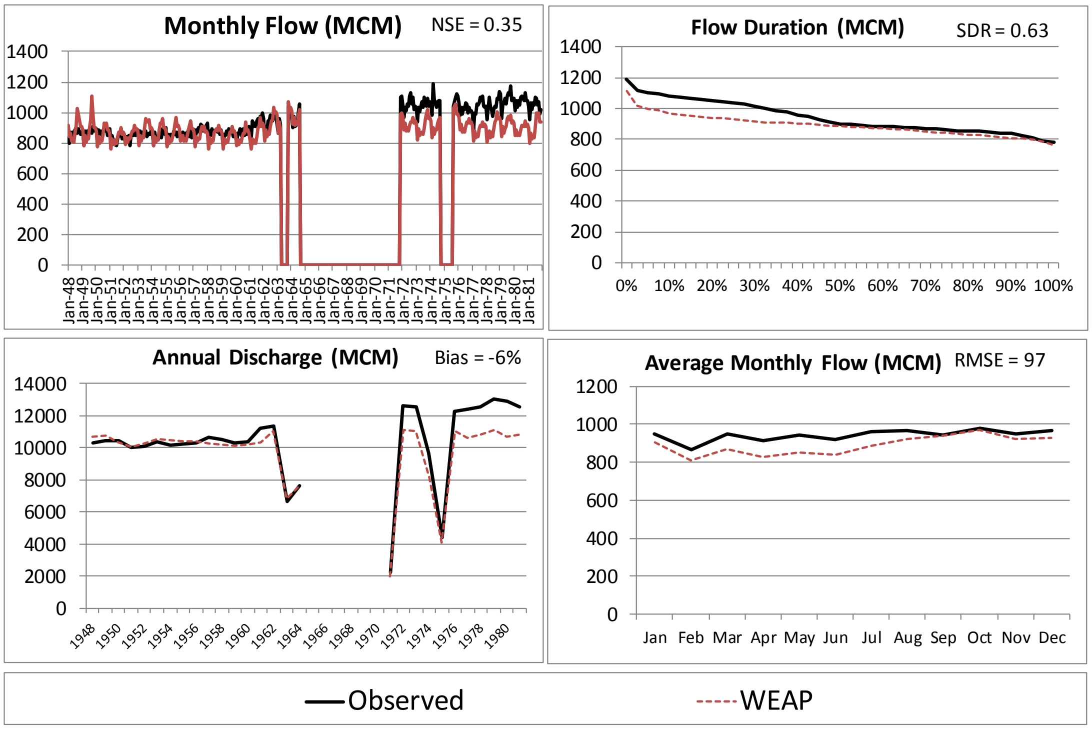


Figure C-46: Simulated and observed White Nile River flows at Malakal, South Sudan (downstream of Sobat River inflow)

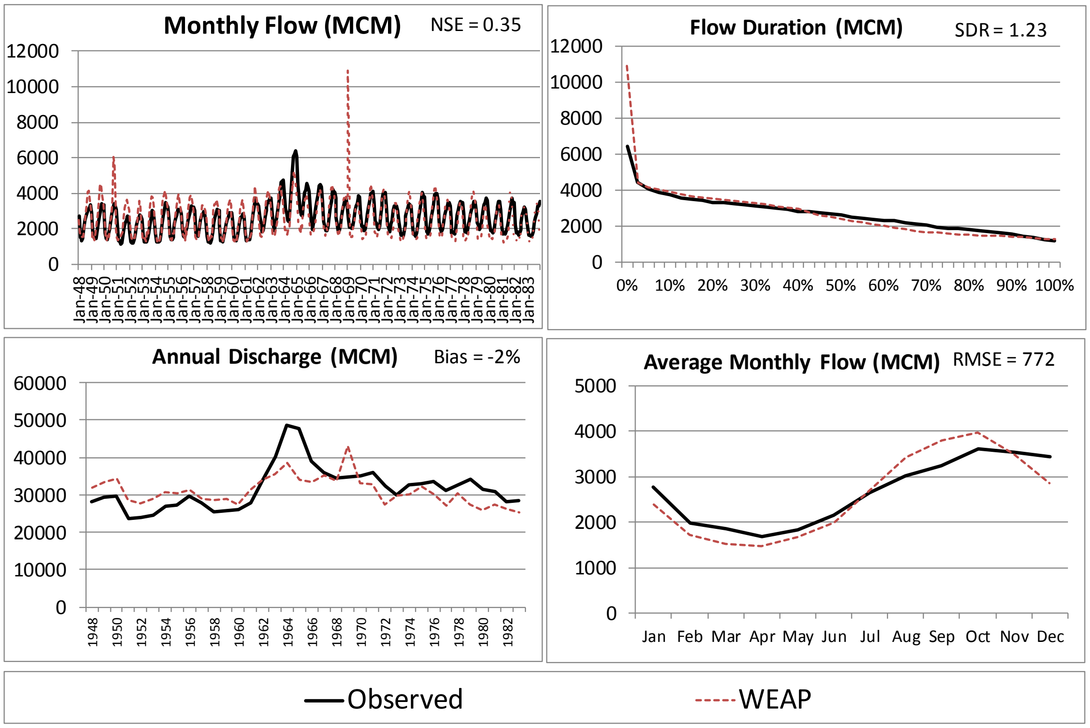


Figure C-47: Simulated and observed Blue Nile River flows at Kessie, Ethiopia (below Lake Tana)

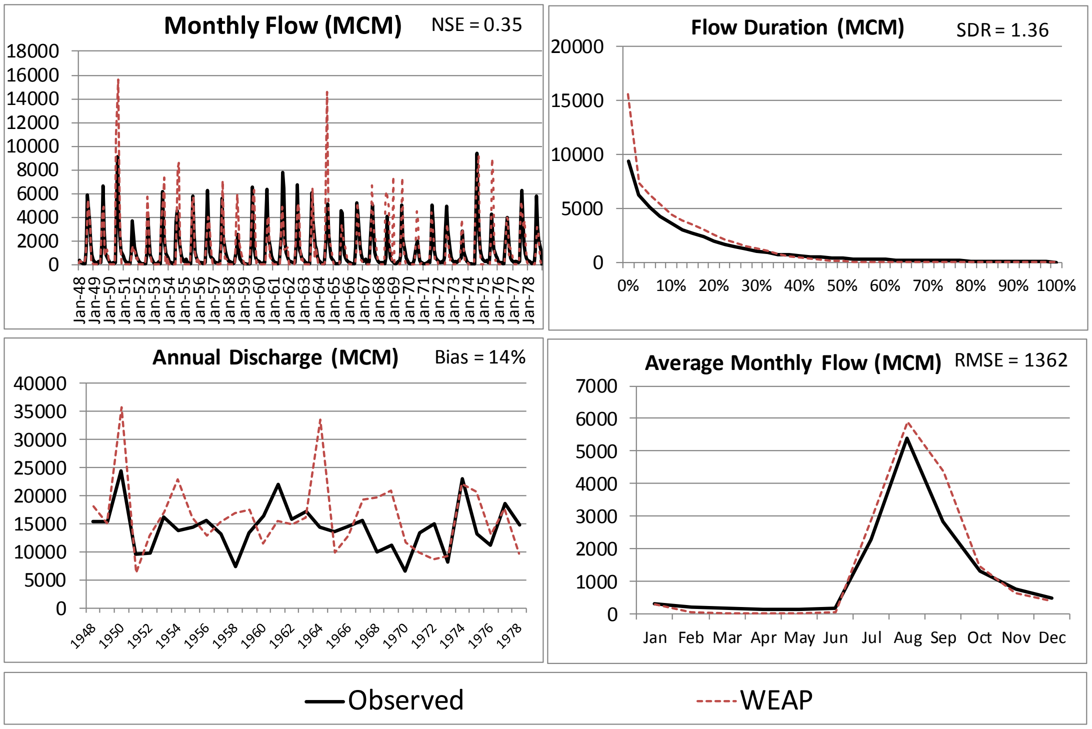


Figure C-48: Simulated and observed Koga River flows at Merawi, Ethiopia (Blue Nile above Lake Tana)

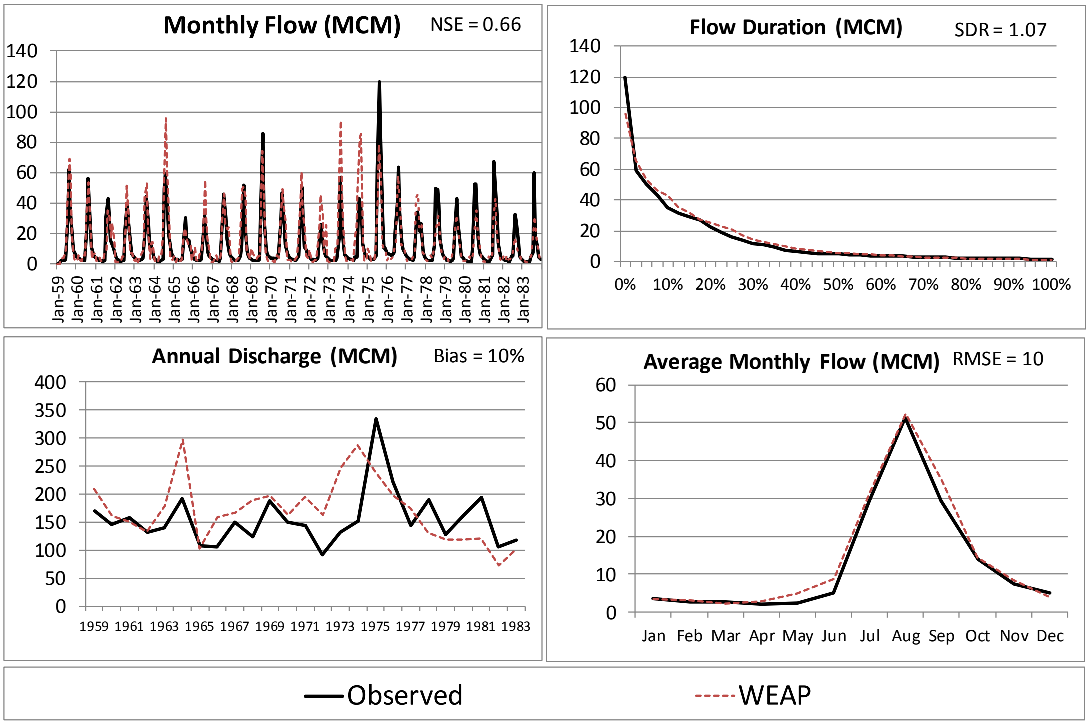


Figure C-49: Simulated and observed Blue Nile River flows below Roseires Dam (Sudan)

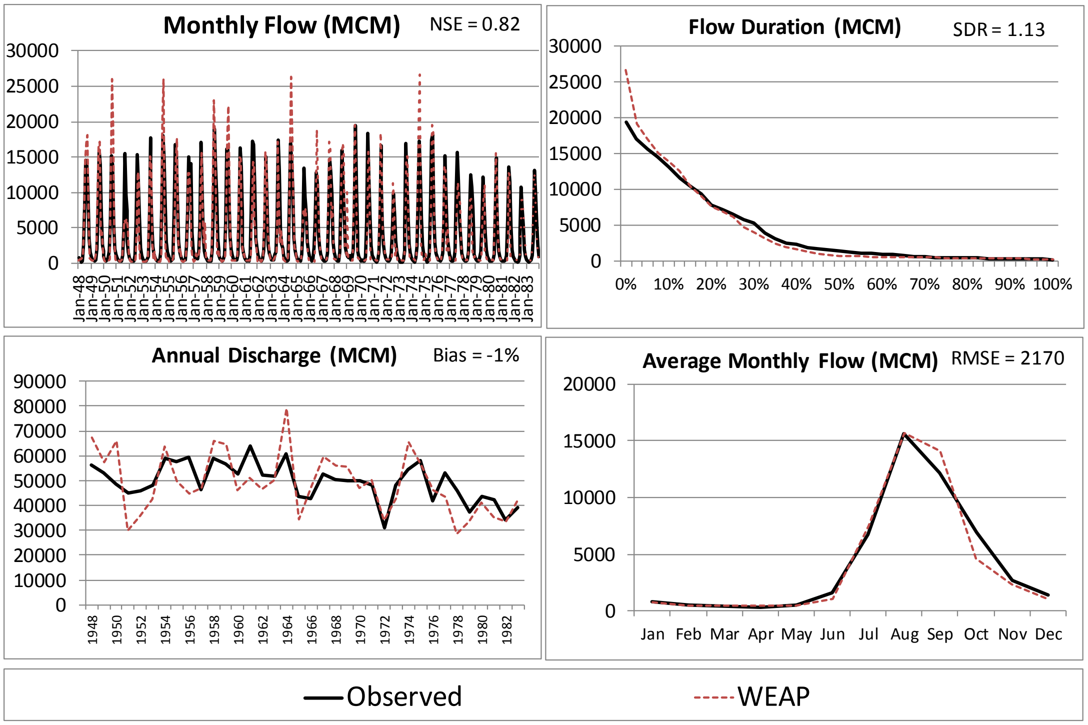


Figure C-50: Simulated and observed Blue Nile River flows at Khartoum, Sudan

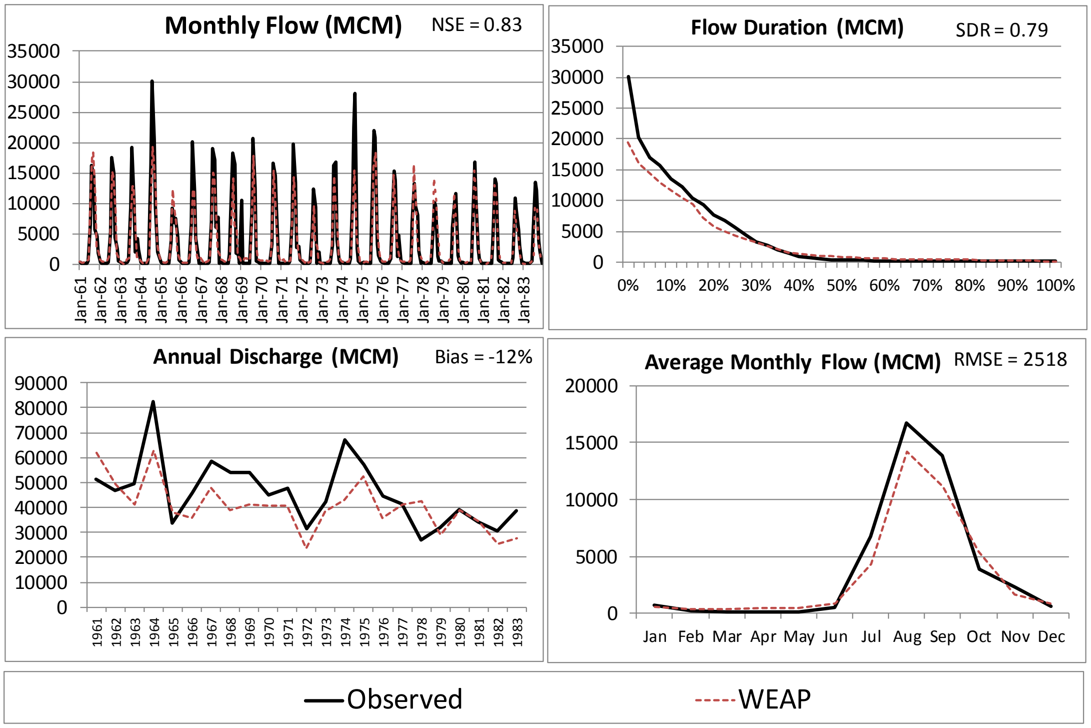


Figure C-51: Simulated and observed Nile River flows at Tamaniat, Sudan (downstream of Blue Nile inflow)

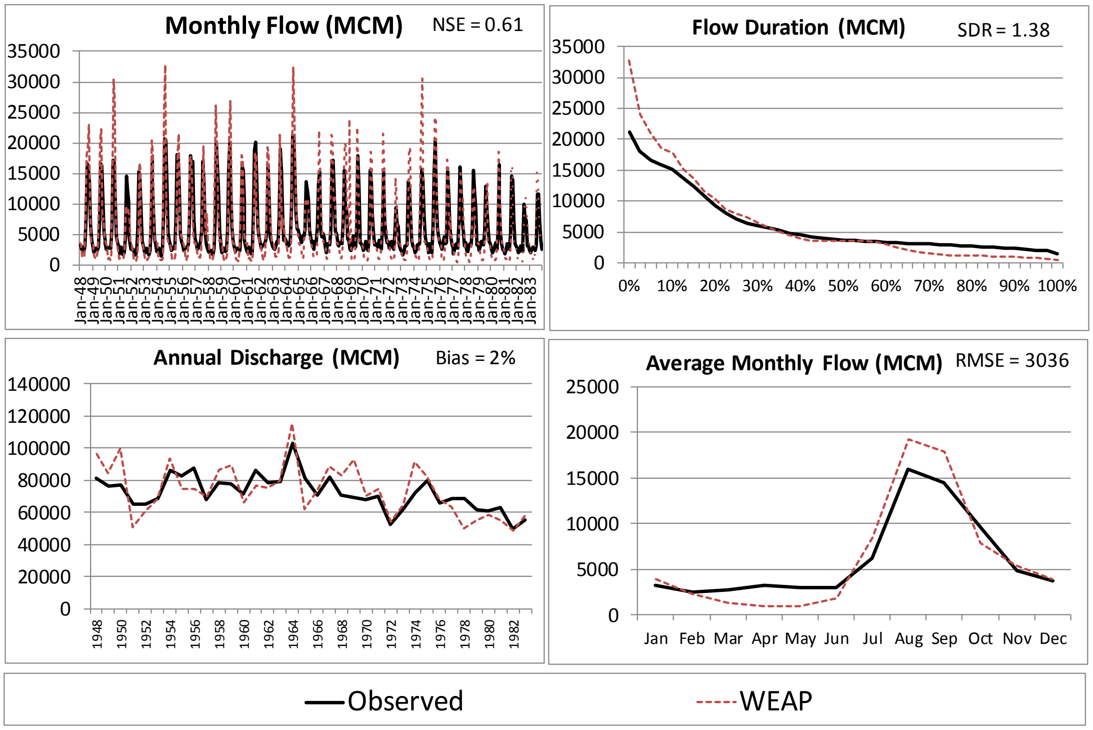


Figure C-52: Simulated and observed Atbara River flows at Kilo3, Sudan (above confluence with Nile River)

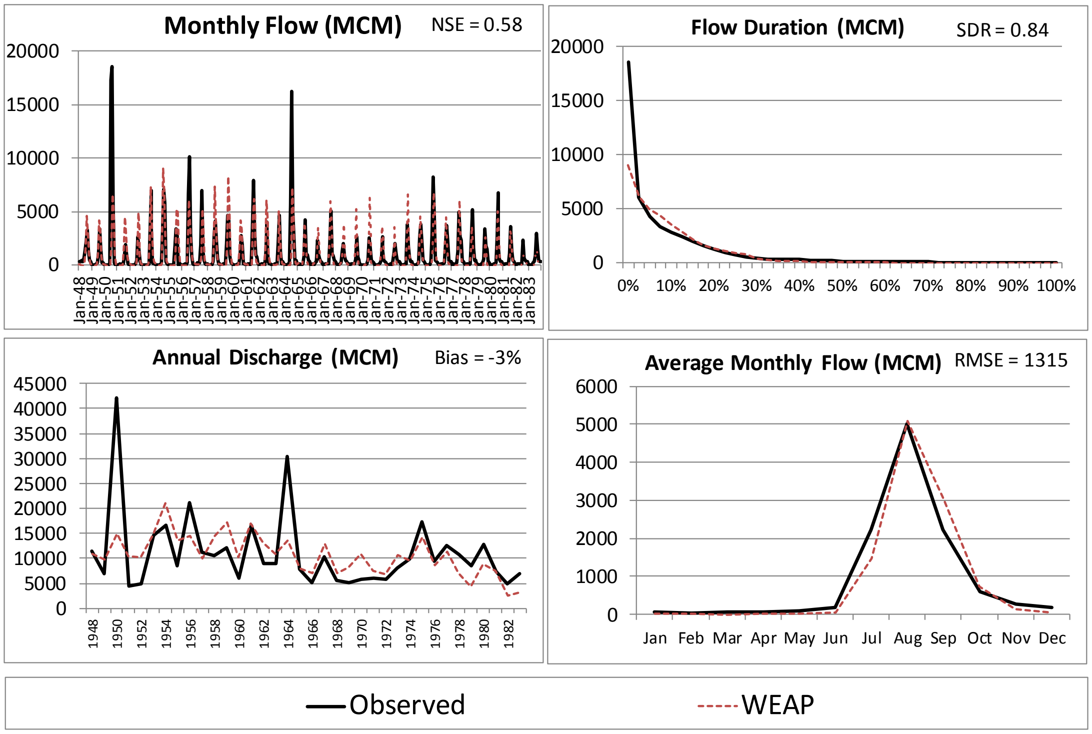


Figure C-53: Simulated and observed Nile River flows at Hasanab, Sudan (upstream of Atbara River inflow)

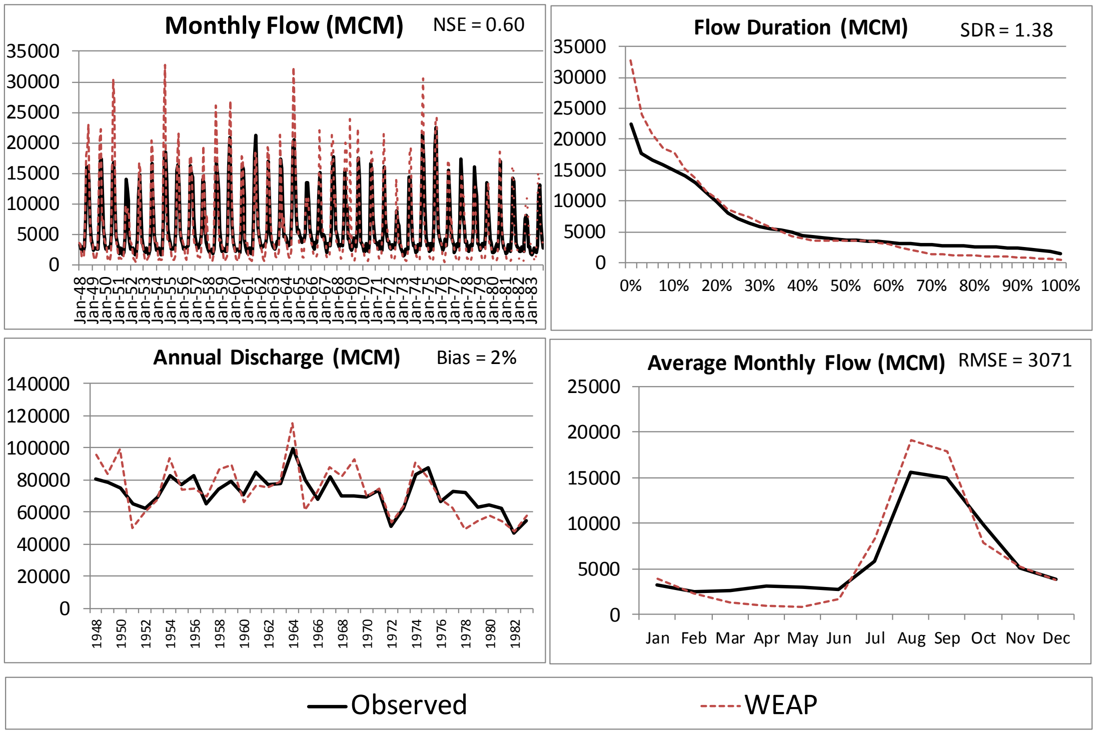
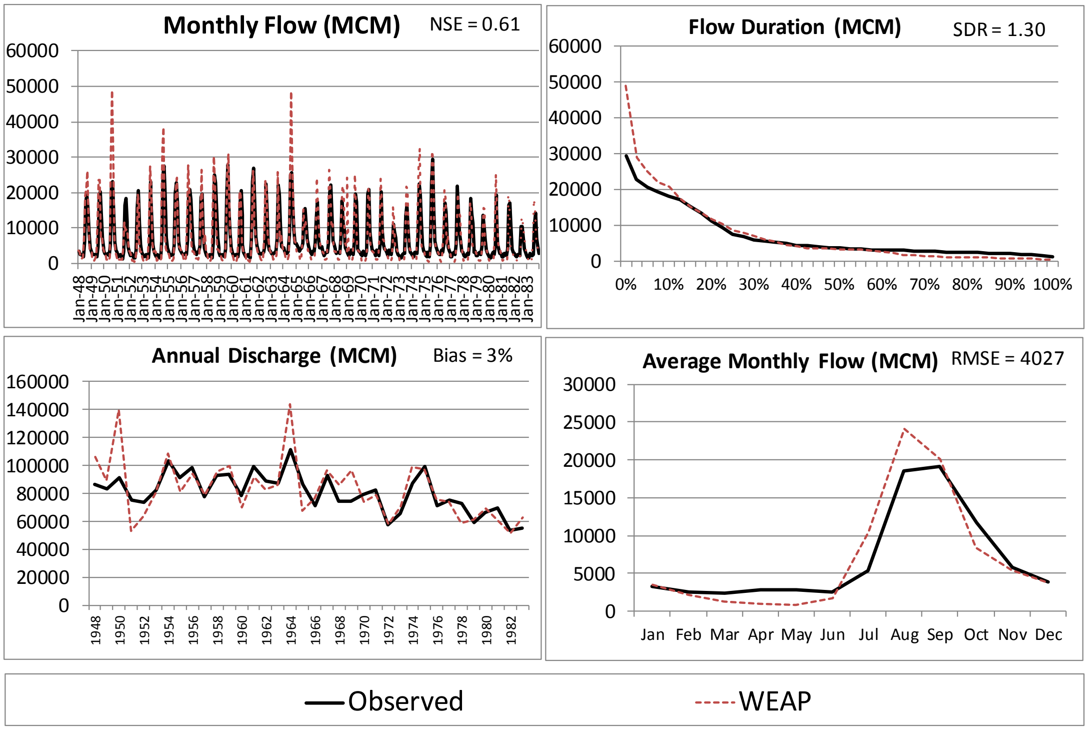


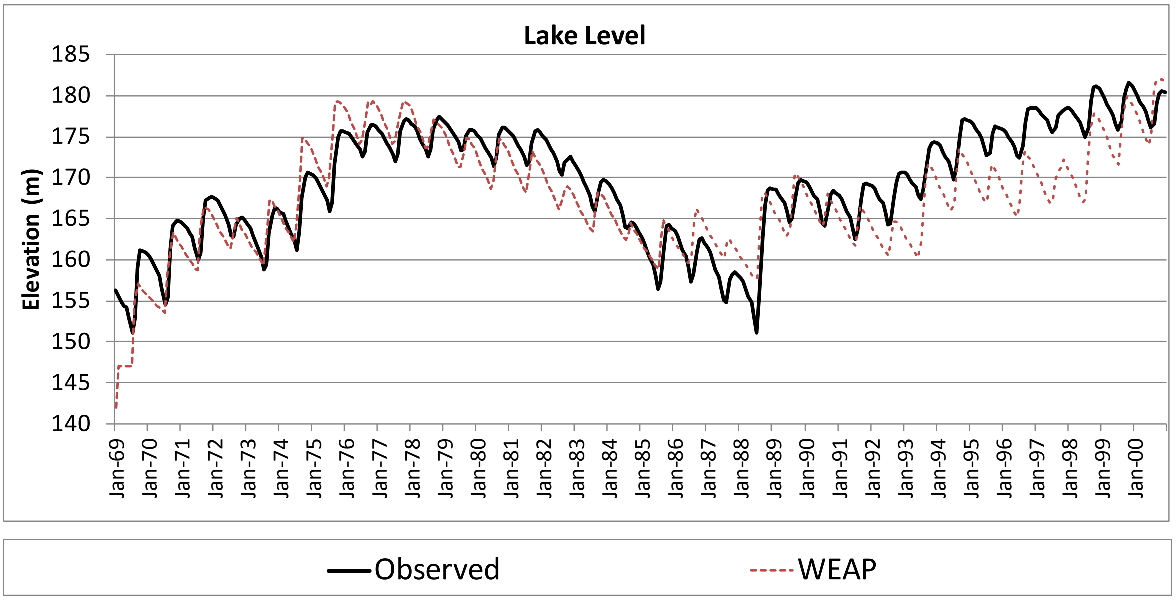
Figure C-54: Simulated and observed Nile River flows at Dongola Station, Sudan



Water Resources Simulation

For the calibration of system operations, we focused on the simulated versus observed reservoir storage for the one reservoirs with historical records that are sufficiently long to reflect a range of climatic and hydrologic conditions – i.e. Lake Nasser. In general, the WEAP model was found to approximate the long-term (i.e. decadal) changes in storage relative to the historical observations. While the simulations did not accurately reproduce the observed monthly changes in storage, the yearly fluctuations in reservoir storage were similar in magnitude to the historical observations. Deviations from the monthly observations are not surprising given the variation in system operations that occurred over the observation period and considering that occasional isolated changes that happen at the discretion of operators (i.e. augmented or foregone reservoir releases) can have lasting impacts on reservoir storage levels, which cannot be captured in a model with fixed operating rules. However, despite these differences, the simulated storage levels can be considered a reasonable approximation of existing conditions that serve as a baseline for evaluating the relative impact of future scenarios (Figure C-55).

Figure C-55: Simulated and observed storage levels in Lake Nasser



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C5- Upper Orange River Basin

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Figure C-56: Orange River Basin, Southern Africa

Description of the Basin

The Upper Orange River basin is defined as the area of the Orange River upstream of the confluence with the Vaal River, with a total area of 99,297 km^2 (including some 7,000 km^2 of endoreic, pan areas in the lower reaches). The upper parts of the basin are located within the mountains of the Kingdom of Lesotho and the lower parts within South Africa. There is a large variation in rainfall, potential evapotranspiration, topography, land use and water resources infrastructure development. The major tributaries include the Caledon River (following the western border of Lesotho), the Kraai River (in South Africa), the Makheleng River (in south eastern Lesotho), and the headwater Lesotho tributaries of the Senqunyane, Malibamatso and Senqu Rivers (Table C-23). The quaternary catchment classification numbers referred to in Table C-23 are those used by the Department of Water Affairs (DWA) of South Africa (Midgley et al., 1994).

Figure C-57: Simplified schematic of upper Orange-Senqu River system (post-development)

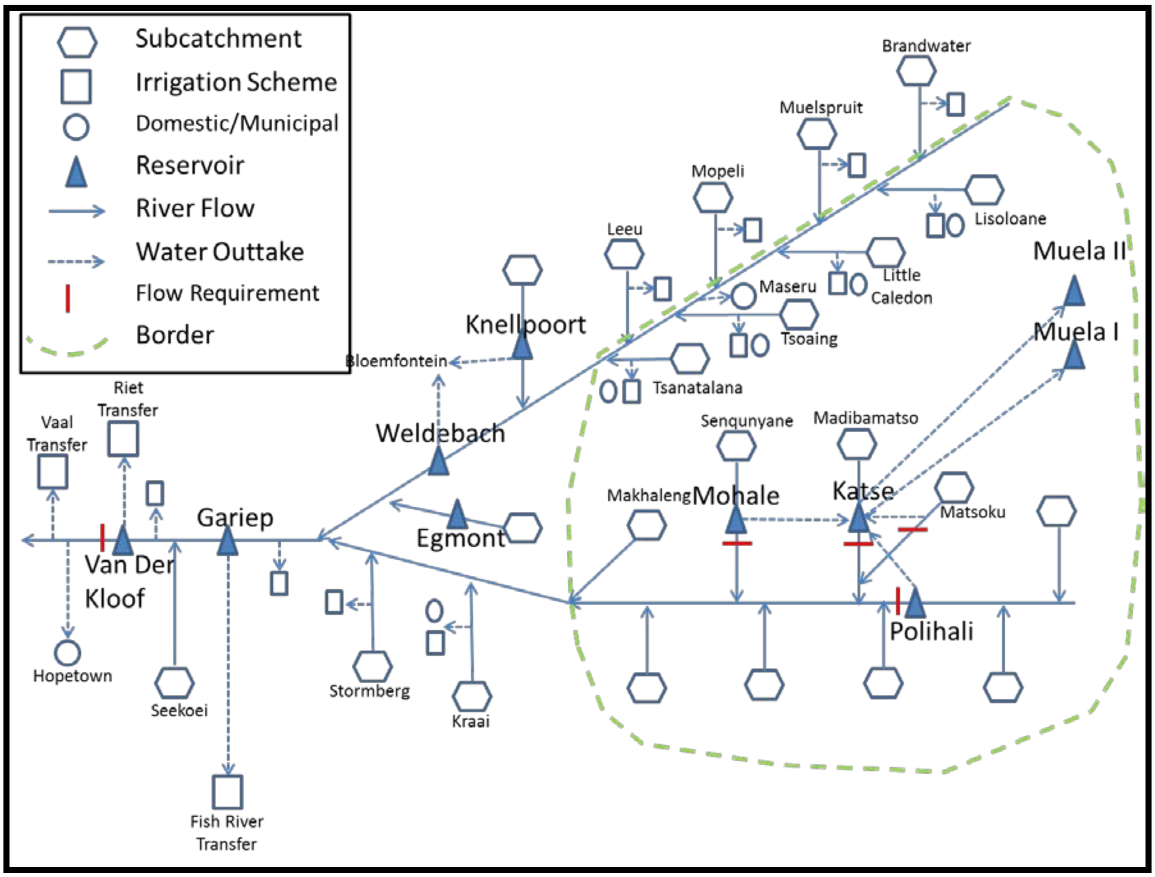


Table C-23: Summary of the hydro-meteorological characteristics of the Upper Orange sub-basins

Sub-basin	Area (km^2)	Quaternary catchments	MAP (mm)	MAE (mm)
Malibamatso	3,360	D11	750 – 1,200	1,300 – 1,400
Upper Senqu	4,520	D16	640 – 1,200	1,300 – 1,400
Sequnyane	7,179	D17	670 – 1,000	1,370 – 1,400
Lower Senqu	6,260	D18	660 – 820	1,470 – 1,500
Makheleng	3,360	D15	600 – 980	1,450 – 1,530
Kraai	9,354	D13	530 – 810	1,470 – 1,630
Middle reaches & tribs.	9,112	D12, D14	430 – 720	1,540 – 1,700
Caledon	21,884	D21 to D24	430 – 1,020	1,270 – 1,650
Lower reaches & tribs.	27,369	D31 to D35	270 – 440	1,700 - 2,200

Notes: The area for the lower reaches and tributaries exclude some 7,000 km^2 of endorheic areas in the lower reaches of the Upper Orange River basin. MAP and MAE refer to mean annual precipitation and mean annual potential evaporation, respectively. MAE is based Symons Pan estimates. The source of this information is Midgley et al. (1994), and some of the individual sub-basin estimates have been more recently updated by various studies.

The current and future development plans for hydropower and irrigation in the basin are available in Appendix A of this document.

WEAP Schematization

Catchment definitions

The WEAP study was run in parallel with a more detailed modelling study of the Caledon River that used an uncertainty version of the Pitman model (Hughes, 2013). This offered a number of opportunities to assess and compare the ways in which the two models simulated the different components of the natural hydrology. The Caledon River sub-basin was therefore setup with more spatial detail than the rest of the Upper Orange River basin. The details of the natural hydrology nodes used within the WEAP model setup are provided in Table C-24 to Table C-26. The nodes are named using the quaternary catchment names (Midgley et al., 1994). In the areas where distributed farm dams are used to support irrigation, each runoff/catchment node is divided into two components, one that generates runoff without passing through farm dams and a second that is affected by the farm dam storage and associated abstractions.

The division of the total area has been based on estimates using a GIS layer of farm dams derived from satellite imagery. The volumes are based on the surface areas from the same GIS layer together with an assumed relationship between area and volume. While neither of these estimates is expected to be very accurate, they should be sufficiently representative of real conditions for the purposes of modelling.

Time series of historical and projected climate (i.e. monthly precipitation [mm], average temperature[C], minimum temperature[C], and maximum temperature[C]) were developed for each sub-catchment area shown in Figure C-58. These data were used to as drivers for the routines that estimate the hydrological response (i.e. rainfall-runoff and baseflow) and potential evapotranspiration for each sub-catchment.

Figure C-58: Upper Orange River sub-catchments

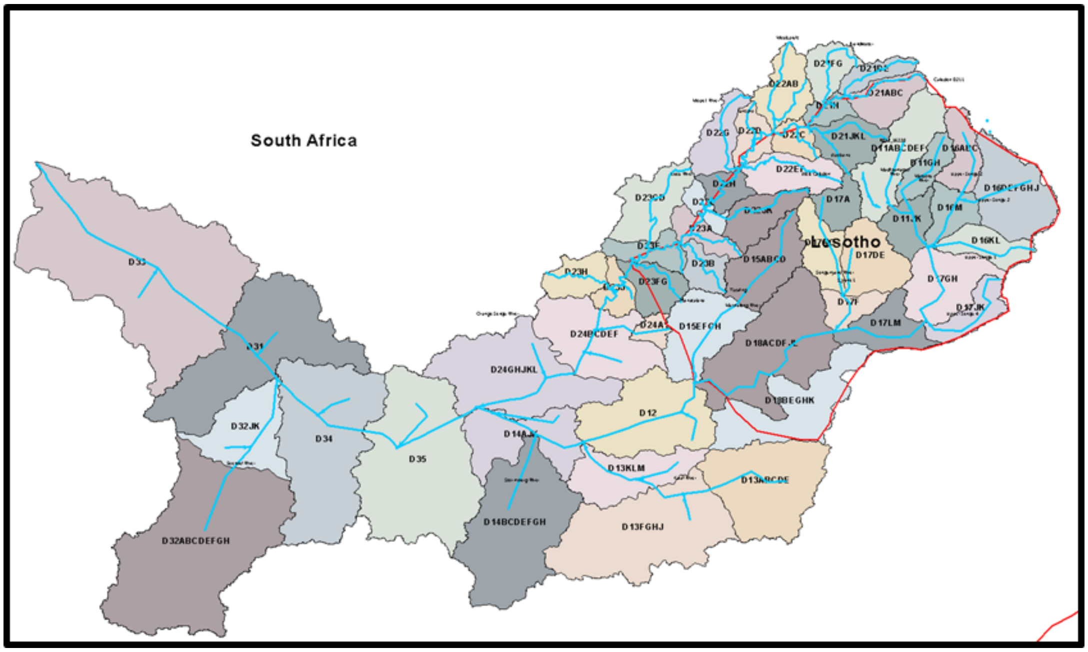


Table C-24: Catchment nodes in the Lesotho parts of the Upper Orange River basin

Catchment Node	Area (no dams) (km^2)	Area (with dams) (km^2)	Farm dam volume (m^3 * 10^6)	Additional information
D11 A-F	1,859.9	0	0	Above Katse Dam
D11 GH	678.0	0	0	Above Matsoku Weir
D11 JK	820.5	0	0	
D16 A-C	844.4	0	0	
D16 D-J	2,056.0	0	0	
D16 KL	861.4	0	0	
D16 M	752.8	0	0	
D17 GH	1,699.4	0	0	
D17 JK	820	0	0	
D17 LM	1,118.1	0	0	
D17 A	938	0	0	Above Mohale Dam
D17 BC	666	0	0	
D17 DE	1,352.8	0	0	
D17 F	582.0	0	0	
D18 ACDFJL	3,746.0	0	0	
D18 BEGHK	2,514.0	0	0	
D15 ABCD	1,542.9	0	0	
D15 E-H	1,816.7	0	0	

Table C-25: Catchment nodes in the Caledon River sub-basin

Catchment Node	Area (no dams) (km^2)	Area (with dams) (km^2)	Farm dam volume (m^3 * 10^6)	Additional information
D21 A-C	717.5	197.0	0.6	

D21 DE	206.2	313.6	3.3	
D21 FG	282.9	474.7	6.6	
D21 H	304.6	76.2	3.1	
D21 J-L	894.3	95.1	1.3	
D22 AB	132.1	960.3	18.9	
D22 C	48.5	436.9	4.0	
D22 D	94.2	533.5	12.0	
D22 EF	1,067.5	63.3	0.3	
D22 G	96.9	872.4	21.0	
D22 H	162.3	378.6	7.9	
D22 JK	975.3	0.0	0	
D22 L	150.6	225.8	6.6	
D23 A	121.6	486.4	10.0	
D23 B	594.0	2.9	0.0	
D23 CD	84.7	1,341.2	63.6	
D23 E	280.0	421.3	14.5	
D23 FG	153.5	709.7	13.1	
D23 H	116.4	659.6	19.0	
D23 J	80.0	453.6	14.0	Includes Welbedacht Dam
D24 A	310.0	0.0	0.0	Above Egmont Dam
D24 B-F	630.5	1,891.5	61.5	
D24 G-L	1,134.6	2,647.4	76.0	

Table C-26: Catchment nodes in the remainder of the Upper Orange River basin

Catchment Node	Area (no dams) (km^2)	Area (with dams) (km^2)	Farm dam volume (m^3 * 10^6)	Additional information

D12	1,780.2	1,186.8	53.1	
D13 A-E	2,871.6	319.7	3.7	
D13 F-J	2,203.0	2,203.0	51.5	
D13 K-M	351.4	1,405.6	55.7	
D14 AJK	191.3	1,721.7	52.5	
D14 B-H	432.2	3,808.8	133.4	
D35	526.8	4,741.2	115.4	Includes Gariep Dam
D34	502.0	4,518.0	82.6	
D32 A-H	721.6	6,494.9	81.7	Seekoei River
D32 J-K	932.5	932.5	19.2	
D31	2,131.3	2,131.3	38.2	Includes VanderKloof Dam
D33	3063.6	340.4	32.6	

Irrigation

Irrigation water demands are a function of the irrigated area, crop coefficient, rainfall deficit and irrigation efficiency. Irrigated areas and crop coefficients are presented in Table C-27 and

Table C-28. These data are based on a GIS assessment of land areas and inputs from de Condappa (2013). According to de Condappa (2013), irrigation efficiency factors range between 0.45 and 0.65 across the basin. However, there is a high degree of variability and uncertainty within these estimates. Thus, for the purposes of this study, we used an estimate of 0.5.

Table C-27: Crop coefficient, Kc, values used in Organge River WEAP model

Crop	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP
Fodder	0.75	0.97	0.97	0.97	0.97	0.97	0.94	0.4	0.4	0.4	0.4	0.4
Maize	0	0	0.35	0.97	1.22	0.9	0.39	0	0	0	0	0
Winter Wheat	1.2	0.71	0	0	0	0	0	0	0.4	0.4	0.62	1.09

Table C-28: Crop areas in Orange River WEAP model

Subbasin	Area	Winter Wheat	Maize	Fodder	Fallow
Caledon	D21 ABC	21	15	15	9
	D21 DE	94.5	67.5	67.5	40.5
	D21 FG	185.5	132.5	132.5	79.5
	D21 H	87.5	62.5	62.5	37.5

	D21 JKL	38.5	27.5	27.5	16.5
	D22 AB	535.5	382.5	382.5	229.5
	D22 C	105	75	75	45
	D22 D	437.5	312.5	312.5	187.5
	D22 EF	7	5	5	3
	D22 G	525	375	375	225
	D22 H	210	150	150	90
	D22 L	192.5	137.5	137.5	82.5
	D23 A	210	150	150	90
	D23 B	0	0	0	0
	D23 CD	1855	1325	1325	795
	D23 E	350	250	250	150
	D23 FG	133	95	95	57
	D23 H	525	375	375	225
	D23 J	350	250	250	150
	D24 BCDEF	1015	725	725	435
	D24 GHJKL	1470	1050	1050	630
	Egmont	224	160	160	96
Orange/Senqu (above Caledon inflow)	D12	700	500	500	300
	D13 ABCDE	283.5	202.5	202.5	121.5
	D13 FGHJ	637	455	455	273
	D13 KLM	199.5	142.5	142.5	85.5
	D14 AJK	700	500	500	300
	D14 BCDEFGH	420	300	300	180
	Kraai	1225	875	875	525
Orange/Senqu (below Caledon inflow)	D31	222.6	159	159	95.4
	D32 ABCDEFGH	14	10	10	6
	D32 JK	7	5	5	3
	D33	661.5	472.5	472.5	283.5
	D34	819	585	585	351
	D35	612.5	437.5	437.5	262.5
	Orange	1386	990	990	594
	Orange-Vaal	2839.55	2028.25	2028.25	1216.95
	Van der Kloof	1983.45	1416.75	1416.75	850.05
Total		21282.1	15201.5	15201.5	9120.9

Water Allocation

The demand priority in WEAP defines how water is allocated to satisfy competing uses – i.e. reservoir storage, hydropower generation, irrigation, domestic use, and flow. WEAP offers demand priorities ranging in number from 0-99, where the lower numbers indicate higher a priority for water use.

The demand priorities used in the Upper Orange River are listed in Table C-29. These are generally set such that domestic water use has the highest priority, followed by environmental flow requirements as the second priority, irrigated agriculture as the third priority, hydropower generation as the fourth priority, and reservoir storage as the lowest priority. The priority structure also reflects the realities of water usage and the regional management of water within the basin. That is, water users that are high in the basin will tend to use the water that is available to them independent of water usage elsewhere in the basin. This implies that water users that are quite low in the basin will have a lower demand priority such that they don't compete for the same water as users far upstream nor actively draw water from reservoirs at the headwaters.

Table C-29: Demand priorities used in Upper Orange WEAP model

Subbasin	River	Node	WEAP Object	WEAP PRIORITY			
				Storage	Hydropower	Demand	Flow Requirement
Caledon	Caledon	D21ABC Direct Abs	Demand			3	
	Caledon	D21ABC Irrigation	Irrigated Catchment			1	
	Caledon	D21DE Farm Dam	Reservoir	2			
	Caledon	D21DE Direct Abs	Demand			3	
	Caledon	D21DE Irrigation	Irrigated Catchment			1	
	Brandwater	D21FG Farm dam	Reservoir	2			
	Brandwater	D21FG Irrigation	Irrigated Catchment			1	
	Local inflow	D21H Farm dam	Reservoir	2			
	Local inflow	D21H Direct Abs	Demand			3	
	Local inflow	D21H Irrigation	Irrigated Catchment			1	
	R012_16330	D21JKL Farm dam	Reservoir	2			
	R012_16330	D21JKL Direct Abs	Demand			3	
	R012_16330	D21JKL Irrigation	Irrigated Catchment			1	
	Meulspruit	D22AB Farm Dam	Reservoir	2			
	Meulspruit	D22AB Irrigation	Irrigated Catchment			1	
	R2241	D22C Farm dam	Reservoir	2			
	R2241	D22C Direct Abs	Demand			3	

	R2241	D22C Irrigation	Irrigated Catchment			1	
	Rantsho	D22D Farm Dam	Reservoir	2			
	Rantsho	D22D Direct Abs	Demand			3	
	Rantsho	D22D Irrigation	Irrigated Catchment			1	
	Little Caledon	D22EF Farm dams	Reservoir	2			
	Little Caledon	D22EF Direct Abs	Demand			3	
	Little Caledon	D22EF Irrigation	Irrigated Catchment			1	
	Mopeli River	D22G Farm dam	Reservoir	2			
	Mopeli River	D22G Irrigation	Irrigated Catchment			1	
	Local inflow	D22H Farm Dam	Reservoir				
	Local inflow	D22H Direct Abs	Demand			3	
	Local inflow	D22H Irrigation	Irrigated Catchment			1	
	Local inflow	D22JK Direct Abs	Demand			3	
	Local inflow	D22L Farm dam	Reservoir	2			
	Local inflow	D22L Direct Abs	Demand			3	
	Local inflow	D22L Irrigation	Irrigated Catchment			1	
	R013_13039	D23AFarm Dams	Reservoir	2			
	R013_13039	D23A Direct Abs	Demand			3	
	R013_13039	D23A Irrigation	Irrigated Catchment			1	
	Tsoaing	D23B Farm Dam	Reservoir	2			

	Tsoaing	D23B Direct Abs	Demand			3	
	Tsoaing	D23B Irrigation	Irrigated Catchment			1	
	Leeu River	D23CD Farm dam	Reservoir	2			
	Leeu River	D23CD Irrigation	Irrigated Catchment			1	
	Likhetleng	D23E Farm Dam	Reservoir	2			
	Likhetleng	D23E Direct Abs	Demand			3	
	Likhetleng	D23E Irrigation	Irrigated Catchment			1	
	Tsanatalana	D23FG Farm Dams	Reservoir	2			
	Tsanatalana	D23FG Direct Abs	Demand			3	
	Tsanatalana	D23FG Irrigation	Irrigated Catchment			1	
	Local inflow	D23H farm dam	Reservoir	2			
	Local inflow	D23H Irrigation	Irrigated Catchment			1	
	Local inflow	D23J Farm Dams	Reservoir	2			
	Local inflow	D23J Irrigation	Irrigated Catchment			1	
	Caledon	D24 Dom	Demand			3	
	Local inflow	D24 B_F Farm Dam	Reservoir	2			
	Local inflow	D24 B_F Irrig	Irrigated Catchment			1	
	Local inflow	D24 G_L Farm Dam	Reservoir	2			
	Local inflow	D24 G_L Irrig	Irrigated Catchment			1	
	Caledon	Maseru Reservoir	Reservoir	99			

	Egmont	Egmont	Reservoir	8			
	Caledon	Weldebacht	Reservoir	20			
	Knellpoort	Knellpoort	Reservoir	20			
Orange/Senqu (above Caledon inflow)	Madibamatso	Katse	Reservoir	5			
	Madibamatso	Katse EFR	Flow Requirement				2
	Senqunyane	Mohale	Reservoir	5			
	Senqunyane	Mohale EFR	Flow Requirement				2
	Mohale Transfer	Mohale Transfer	Flow Requirement				5
	Matsoku	Matsoku Weir	Flow Requirement				3
	Matsoku	Matsoku EFR	Flow Requirement				1
	LHWP Transfer	Muela	Run-of-River		1		
	LHWP Transfer	LHWP Transfer	Flow Requirement				1
	Orange/Senqu	Polihali	Reservoir	10			
	Diversion	Polihali to Katse Transfer	Flow Requirement				10
	Orange/Senqu	Polihalie EFR	Flow Requirement				1
	Orange/Senqu	D11 Dom	Demand			11	
	Orange/Senqu	D12 Dom	Demand			11	
	Local inflow	D12 Farm Dam	Reservoir	2			
	Local inflow	D12 Irrig	Irrigated Catchment			1	
	Orange/Senqu	D13 Dom	Demand			11	

	Kraai River	D13 A_E Farm Dam	Reservoir	2			
	Kraai River	D13A_E_Irrig	Irrigated Catchment			1	
	Local inflow	D13 F_J Farm Dam	Reservoir	2			
	Local inflow	D13 F_J Irrig	Irrigated Catchment			1	
	Local inflow	D13 K_M Farm Dam	Reservoir	2			
	Local inflow	D13 KLM Irrig	Irrigated Catchment			1	
	Orange/Senqu	D14 Dom	Demand			11	
	Local inflow	D14 AJK Farm Dam	Reservoir	12			
	Local inflow	D14 AJK Irrig	Irrigated Catchment			11	
	Stormberg River	D14 B_H Farm Dam	Reservoir	2			
	Stormberg River	D14 B_H Irrig	Irrigated Catchment			1	
	Orange/Senqu	D15 Dom	Demand			11	
	Orange/Senqu	D16 Dom	Demand			11	
	Orange/Senqu	D17 Dom	Demand			11	
	Orange/Senqu	D18 Dom	Demand			11	
	Kraai River	Irrig@Kraai	Demand			11	
	Kraai River	Kraai Urban	Demand			11	
Orange/Senqu below Caledon inflow	Orange/Senqu	Orange Irrig	Irrigated Catchment			15	
	Orange/Senqu	VanDerKloof	Reservoir	20	19		
	Orange/Senqu	VanDerKloof EFR	Flow Requirement				18

	Orange/Senqu	Gariep	Reservoir	20	19		
	Orange/Senqu	Gariep EFR	Flow Requirement				18
	D31 Farm River	D31 Farm Dam	Reservoir	16			
	D31 Farm River	D31 Irrig	Irrigated Catchment			15	
	Orange/Senqu	D32 Dom	Demand			17	
	Seekoei River	D32 A_H Farm Dam	Reservoir	16			
	Seekoei River	D32 A_H Irrig	Irrigated Catchment			15	
	D32 JK Farm River	D32 JK Farm Dam	Reservoir	15			
	D32 JK Farm River	D32 JK Irrig	Irrigated Catchment			16	
	Orange/Senqu	D33 Dom	Demand			20	
	D33 Farm River	D33 Farm Dam	Reservoir	16			
	D33 Farm River	D33 Irrig	Irrigated Catchment			15	
	Orange/Senqu	D34 Dom	Demand			21	
	D34 Farm River	D34 Farm Dam	Reservoir	16			
	D34 Farm River	D34 Irrig	Irrigated Catchment			15	
	Orange/Senqu	D35 Dom	Demand			14	
	D35 Farm River	D35 Farm Dam	Reservoir	16			
	D35 Farm River	D35 Irrig	Irrigated Catchment			15	
	Orange/Senqu	Orange Vaal Irrigation	Irrigated Catchment			19	
	Orange/Senqu	Orange_Riet Transfer	Irrigated Catchment			19	

	Orange/Senqu	VDK Irrigation catch	Irrigated Catchment			19	

Model Calibration

The official modeling tools used for joint water resources studies in the Orange River basin are the Pitman hydrological model (Pitman, 1973) and the Water Resources Yield Model, or WRYM (Mackenzie and van Rooyen, 1999). These tools have been used extensively to study the management of the upper Orange River and they rely upon an official time series of historical climate that has been vetted by ORASECOM and basin stakeholders. The latest version of this climate data covers the period from 1920-2005 and is referred to herein as WR2005.

The WR2005 climate data were compiled for the tertiary and quaternary catchments modeled in this study. The average of these data over the upper Orange River basin is compared to similar data from the Princeton dataset in Figure C-59 and Figure C-60. This comparison suggests that Princeton dataset does a reasonable job at capturing the monthly and annual variation in precipitation, but it may overestimate the fluctuation in average monthly temperature over the basin.

While the Princeton data were used in the Track I and Track II analyses of this study, we began the calibration of the Upper Orange River WEAP model by first using the WR2005 climate data. By fixing these data, we reduced the number of degrees of freedom in the modeling uncertainty such that we could make direct comparisons of WEAP and Pitman model outputs. This enabled us to more easily transfer model formulations from the Pitman model to WEAP. The WR2005 data also provides a longer period of record (1920-2005) over which to consider the model performance.

To maintain consistency across all seven basins in the Track I analysis, the WEAP model was subsequently re-calibrated using the Princeton climate data. Because of the similarities in the two climate datasets, this secondary calibration focused on adjusting the few model parameters (mainly Kc) that affect evapotranspiration. The results of both calibration phases are presented in the following sections.

Figure C-59: Comparison of WR2005 and Princeton average temperature (1950-2005)

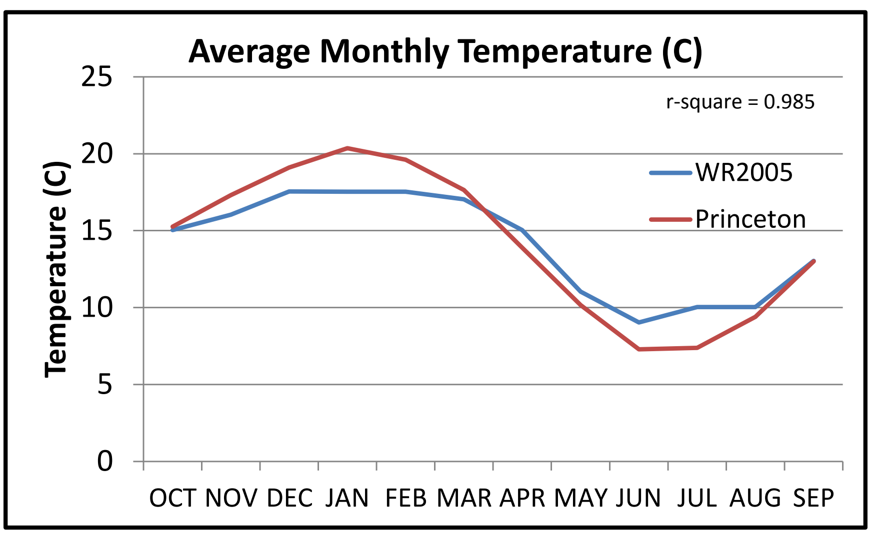
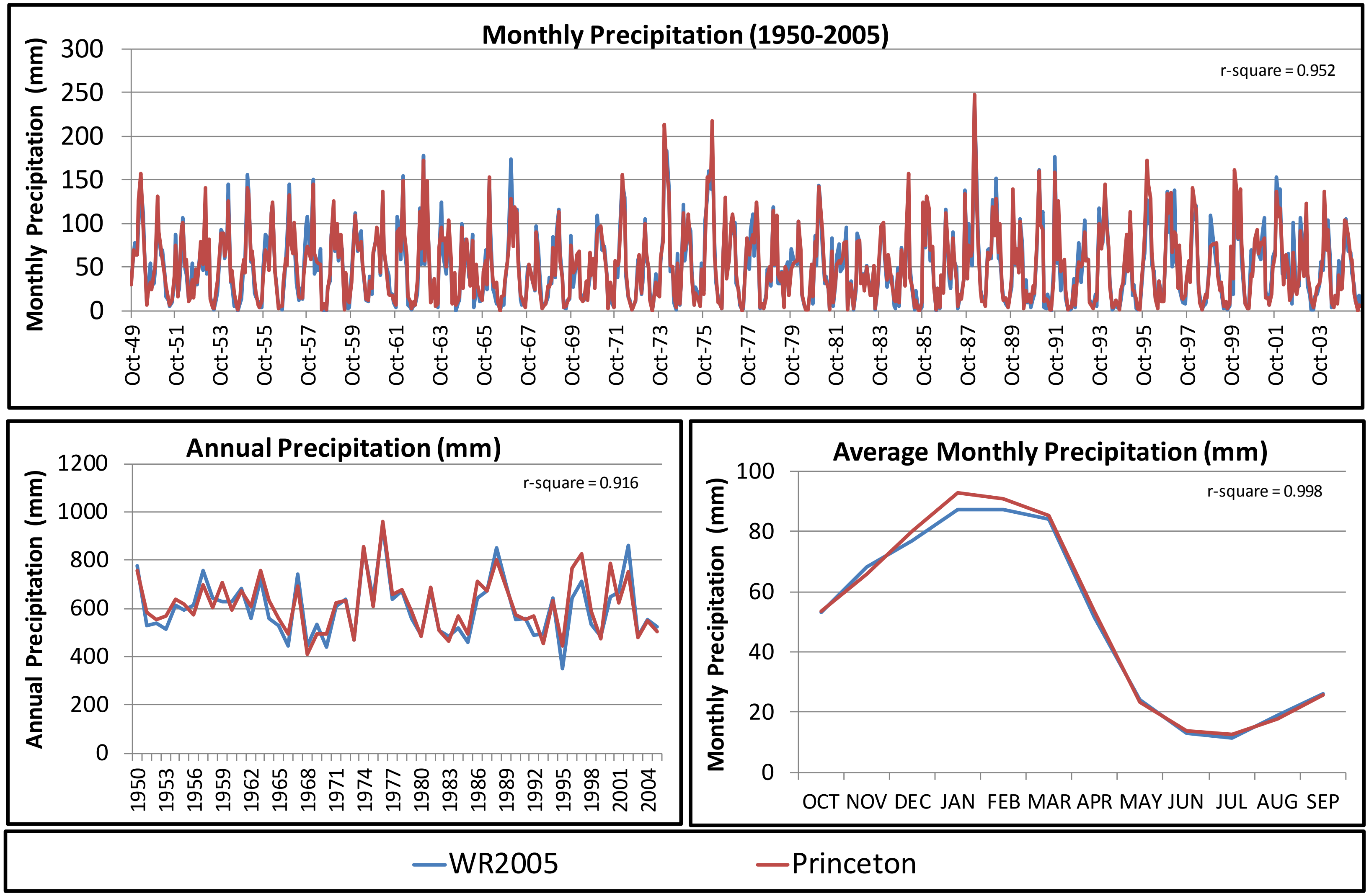
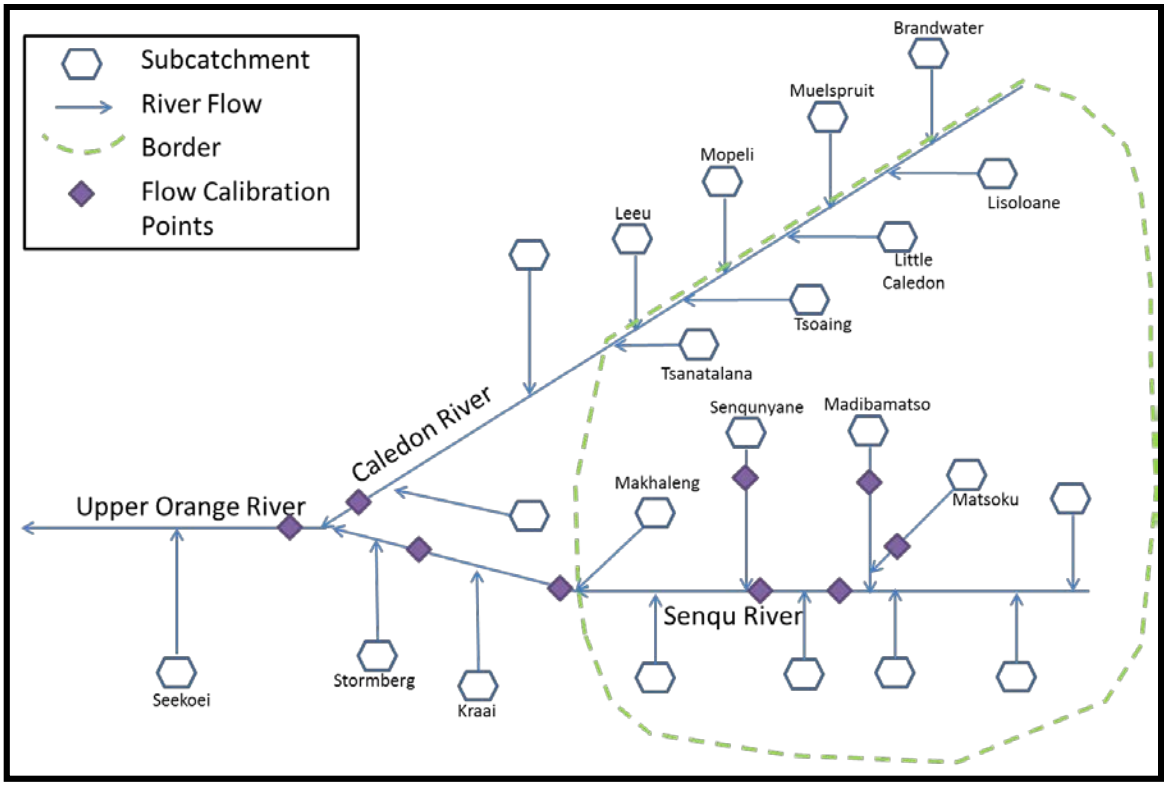


Figure C-60: Comparison of WR2005 and Princeton precipitation data (1950-2005)



Flow Simulation – WR2005 Climate

Figure C-61: Simplified schematic of upper Orange-Senqu River system (pre-development)



A number of stream flow gauging stations within the basin are operated by either DWA or the Lesotho Ministry of Water (Table C-30). Not all of the available data are considered useful for model calibration, either because of inaccuracies in the rating tables, rating tables that do not include high flows, or because of poorly defined upstream water use, typically associated with distributed irrigation and domestic water use. The basin has also been subject to many previous hydrological modelling and water resources yield studies that have all used the Pitman monthly rainfall-runoff model (Pitman, 1973; Hughes, 2013) combined with the South African Water Resources Yield model (WRYM). The results for the most recent of these studies are available from ORASECOM (Orange-Senqu River Commission). Early on within the WEAP study it was decided that the WEAP model results for natural and present day development conditions should be aligned as closely as possible to the most recent Pitman/WRYM results. Therefore these results have been used to guide the calibration of the WEAP model together with the observed stream flow gauging records. The rationale behind this approach is that the most recent water resources assessments (hydrological and water use simulations) have been accepted by the various stakeholders from Lesotho, South Africa, Namibia and Botswana that are part of ORASECOM (Namibia and Botswana are riparian countries in the lower Orange River basin and are impacted by flows from the Upper Orange). The rainfall and potential evaporation data used in the WEAP model were also aligned with the most recent data available from ORASECOM.

Table C-30: Summary of stream flow gauging stations that have been included in the study for evaluating simulated stream flows (either natural or impacted by major developments).

Station ID	Quaternary catchment	Upstream area (km^2)	Period of record available
D1H005	D17L	10,680	1932 – 2001
D1H006	D15G	2,969	1948 – 2005+
D1H009	D12A	24,550	1960 – 2005+
D1H003	D14A	37,075	1920 – 2005+
D1H011	D13L	8,688	1966 – 2005+
D2H001	D23F	13,421	1920 – 1978
D2H012	D21E	518	1968 – 2005+
D3H015	D32J	8,266	1980 – 2005+

Notes: The modelling period used was from October 1949 to September 2000, while some of the gauging records continue to the present day.

The approach to calibrate for natural conditions was largely based on trial runs of the WEAP model in the Caledon River and comparisons with an existing setup of the Pitman model. The main idea was to try to make use of the Pitman model parameters that are available for the Upper Orange to guide the initial settings of the WEAP parameters and therefore to speed up the calibration process and to be as consistent as possible in parameter values across the different sub-basins. Part of this process involved some initial comparisons of the structure of the two models. The outcomes of these comparisons also led to the development of expressions for the Runoff Resistance Factor for all catchment nodes and for the Root Zone Conductivity in dry catchments with ephemeral flow regimes.

Runoff Resistance Factor

In the Pitman model, surface runoff is determined from a triangular distribution of catchment absorption rates and the monthly rainfall total. The soil moisture storage only plays a role in the generation of surface runoff if the capacity is exceeded. As this is very different to the approach used in WEAP, the following expression was developed after much trial and error to get a better alignment of the patterns of surface runoff generated by the two models.

$$If\,(Precip[mm] - RRF1 < 0.5, 20, RRF2 + \left(\frac{RRF3}{Precip[mm]} - RRF1\right))^{\ln(\frac{Precip[mm]}{5})}$$

The principles used to calibrate the three parameters (RRF1, RRF2 and RRF3) are as follows. To reduce runoff:

- Increase the 'RRF1' parameter to increase the threshold at which surface runoff starts. This will have a larger effect on lower rainfalls than higher rainfalls.
- Increase the 'RRF3' parameter to reduce the effect of large rainfalls during wet conditions.

- Increase the ‘RRF2’ parameter to give overall lower runoff resistance factors for rainfalls over the threshold of ‘RRF1’.

Root Zone Conductivity (RZC)

There are several ephemeral river tributaries in the Upper Orange and the normal WEAP approach to generating interflow does not allow for zero flows. The following expression was therefore used in the more arid parts of the basin:

$$If(RSM < RZC1)\ then\ RZC = O$$

$$Else$$

$$RZC = \frac{RZC2 * (RSM - RZC1)}{RSM}$$

Where RSM is the relative soil moisture value and RZC1 and RZC2 are parameters.

Table C-31 and Table C-32 provide the details of the catchment parameters used for each of the catchment nodes. These were determined by calibration against the observed flow data referred to in Table C-30 (using only those parts of the observed record that could be considered reasonably natural) as well as the ORASECOM simulations and some other Pitman model simulations for the Caledon River. The rows that are highlighted in bold represent the nodes where detailed calibration was used, while the parameters for the other nodes were set based on physical similarity with the calibration nodes. The downstream nodes that are highlighted were used as a validation check to ensure that the transferred parameters were appropriately quantified and to ensure that the simulations for major sub-basins were adequate compared to either observed flows or the existing ORASECOM simulations.

Table C-31: Catchment parameters for the Caledon River nodes

Catchment Node	SWC (mm)	RZC (mm)	PFD	DWC (mm)	DC (mm)	Kc	RRF1 (mm)	RRF2 (mm)	RRF3 (mm)
D21 A-C	120	20	0.99	25	0.1	0.90	50	1.3	250
D21 DE	150	16	0.99	35	0.1	0.90	50	1.3	250
D21 FG	150	12	0.99	25	0.1	0.90	50	1.3	250
D21 H	150	12	0.99	25	0.1	0.90	50	1.3	250
D21 J-L	120	20	0.99	35	0.1	0.90	50	1.3	250
D22 AB	150	12	0.99	25	0.1	0.91	50	1.3	250
D22 C	150	12	0.99	25	0.1	0.90	50	1.3	250
D22 D	150	12	0.99	25	0.1	0.91	50	1.3	250

D22 EF	130	16	0.99	25	0.1	0.91	50	1.3	250
D22 G	150	8	0.99	50	0.1	0.91	60	1.4	280
D22 H	180	12	0.99	20	0.1	0.90	60	1.4	280
D22 JK	130	16	0.99	30	0.1	0.91	50	1.3	250
D22 L	180	12	0.99	20	0.1	0.91	60	1.4	280
D23 A	180	12	0.99	20	0.1	0.91	60	1.4	280
D23 B	130	16	0.99	25	0.1	0.91	50	1.3	250
D23 CD	150	8	0.99	50	0.1	0.91	60	1.4	280
D23 E	180	12	0.99	20	0.1	0.91	60	1.4	280
D23 FG	130	16	0.99	25	0.1	0.91	50	1.3	250
D23 H	150	8	0.99	25	0.1	0.91	60	1.4	280
D23 J	130	12	0.99	25	0.1	0.91	60	1.4	280
D24 A	180	4	0.99	40	0.1	0.91	60	1.4	280
D24 B-F	200	4	0.99	40	0.1	0.91	60	1.4	280
D24 G-L	200	4	0.99	40	0.1	0.91	60	1.5	280

Notes: SWC = Soil Water Capacity, RZC = Root Zone Conductivity, PFD = Preferred Flow Direction, DWC = Deep Water Capacity, DC = Deep Conductivity.

Table C-32: Catchment parameters for the other nodes

Catchment Node	SWC (mm)	RZC (mm)	PFD	DWC (mm)	DC (mm)	Kc	RRF1 (mm)	RRF2 (mm)	RRF3 (mm)
D11 A-F	100	50	0.95	50	3.0	0.79 to 0.97	10	0.4	150
D11 GH	100	40	0.95	50	3.0	0.79 to 0.97	20	0.5	150
D11 JK	100	30	0.95	50	3.0	0.79 to 0.97	20	0.7	160
D16 A-C	100	30	0.95	50	3.0	0.79 to 0.97	20	0.6	160
D16 D-J	100	30	0.95	50	3.0	0.79 to 0.97	20	0.6	160
D16 KL	100	30	0.95	50	3.0	0.79 to 0.97	20	0.7	160
D16 M	100	30	0.95	50	2.0	0.79 to 0.97	20	0.7	160

D17 GH	100	30	0.95	50	2.0	0.80 to 1.05	40	0.8	180
D17 JK	100	30	0.95	50	2.0	0.80 to 1.05	40	0.8	180
D17 LM	100	30	0.95	50	2.0	0.80 to 1.05	40	0.8	180
D17 A	100	38	0.95	50	3.0	0.80 to 1.05	10	0.4	150
D17 BC	100	30	0.95	50	3.0	0.80 to 1.05	40	0.8	180
D17 DE	100	30	0.95	50	3.0	0.80 to 1.05	40	0.8	180
D17 F	100	30	0.95	50	3.0	0.80 to 1.05	40	0.8	180
D18 ACDFJL	140	30	0.95	50	2.0	0.84 to 1.12	50	0.9	200
D18 BEGHK	120	40	0.95	50	2.0	0.84 to 1.12	50	0.9	200
D15 ABCD	100	40	0.95	50	3.0	0.84 to 1.12	40	0.8	180
D15 E-H	160	35	0.95	50	2.0	0.84 to 1.12	40	0.8	180
D12	140	8	0.95	50	2.0	0.84 to 1.12	50	0.9	200
D13 A-E	100	30	0.95	50	2.0	0.84 to 1.12	20	0.8	180
D13 F-J	120	15	0.95	50	2.0	0.84 to 1.12	30	0.8	180
D13 K-M	140	8	0.95	50	2.0	0.84 to 1.12	50	0.9	200
D14 AJK	200	2	1.00	50	2.0	0.84 to 1.12	60	1.4	280
D14 B-H	150	5	1.00	50	1.0	0.84 to 1.12	60	1.5	280
D35	200	15/8	1.00	N/A	N/A	0.84 to 1.12	50	1.5	200
D34	200	15/8	1.00	N/A	N/A	0.84 to 1.12	50	1.5	200
D32 A-H	150	20/6	1.00	N/A	N/A	0.84 to 1.12	50	2.0	200
D32 J-K	150	11/12	1.00	N/A	N/A	0.84 to 1.12	50	1.5	200
D31	200	15/6	1.00	N/A	N/A	0.84 to 1.12	50	1.5	200
D33	200	15/6	1.00	N/A	N/A	0.84 to 1.12	50	1.5	200

Notes: The two values for RZC in the arid catchments are parameters RZC1 and RZC2

Table C-33 provides some of the calibration results comparing the WEAP simulated flows with either observed data (where they exist and are adequately representative of natural conditions) or the ORASECOM cumulative flow simulations. The objective function statistics used are the Nash-Sutcliffe efficiency, applied to both the un-transformed flows (NSE) and natural log transformed flows (NSE{ln}), and the percent bias of annual discharge mean monthly (also applied to untransformed and transformed flows - %Bias and %Bian{ln}).

The calibration approach was largely based on fitting the flow duration curves of the WEAP simulations to either the observed data or the existing ORASECOM simulations (to ensure alignment of the WEAP results with existing simulations that have been accepted by a range of stakeholders within the basin). Figure C-71 to Figure C-80 illustrate some of the results at key sites using a sample of the time series as well as the flow duration curves for the whole comparison period given in Table C-33.

Table C-33: Summary of flow calibration results with WR2005 climate data

Site	WEAP compared with	Records used	NSE	NSE{ln}	%Bias	%Bias{ln}
D11 A-F (Katse)	ORASECOM	1920 - 2005	0.741	0.784	-0.98	0.34
D11 GH (Matsoku)	ORASECOM	1920 – 2005	0.514	0.710	8.90	8.89
D11 & D16	ORASECOM	1920 - 2005	0.717	0.796	3.18	0.14
D1H005	Observed	1933 – 2005	0.500	0.555	13.93	2.15
D17A (Mohale)	ORASECOM	1920 - 2005	0.595	0.562	-3.40	-3.12
D1H009	Observed	1961 - 2005	0.538	0.689	2.34	-0.96
	ORASECOM	1920 – 2005	0.668	0.782	4.85	-1.17
D1H011 (Kraai)	Observed	1967 – 2005	0.505	0.601	-14.10	-4.30
D1H003	Observed	1921 – 2005	0.595	0.701	4.82	2.77
D24J (Caledon)	ORASECOM	1920 – 2005	0.829	0.869	2.59	0.99
Orange/Caledon confluence	ORASECOM	1920 - 2005	0.788	0.833	1.97	-1.78

While some of the objective function values presented in Table C-33 are relatively poor, the overall results illustrated in Figure C-62 to Figure C-70 are generally acceptable. Where there are observed data available that can be considered reasonably representative of natural flow conditions, the WEAP model is able to reproduce the frequency characteristics. The sometimes poor values for NSE are likely to be partly associated with inadequate rainfall data to accurately quantify individual monthly rainfall totals at the catchment scale, the effects of different spatial distributions of rainfall for the same monthly spatially-averaged depth and the effects of different temporal distributions of rainfall for the same monthly depth (i.e. different daily distributions). None of these types of uncertainty can be resolved with a monthly time-step model applied in an area the size of the Upper Orange River basin where many parts of the basin are inadequately gauged. Differences between the ORASECOM and WEAP simulations can also be partly attributed to the different approaches used in the two models to simulate surface runoff. It is possible to calibrate the WEAP model to have very similar flow duration curve (FDC) characteristics, but individual high flow months are very likely to be different. This is also reflected in the fact that most of the %Bias and %Bias{ln} values are well within acceptable ranges, while some of NSE values are close to 0.5, a value that might be considered somewhat low for an acceptable level of agreement between two time series.

The example time series plots provided on the left hand side of Figure C-62 to

Figure *C-70* illustrate that the WEAP model faithfully represents wet and dry periods, relative to both the available observed data as well the ORASECOM simulations. The overall conclusion is that the WEAP model has been more than adequately calibrated to represent the natural stream flow regime of the Upper Orange River basin. It is therefore reasonable to suggest that the WEAP simulated natural flows can be used as the basis for assessing the various water resource management options available for the basin.

Figure C-62: WEAP versus ORASECOM results for D11 A-F (inflows to Katse Dam)

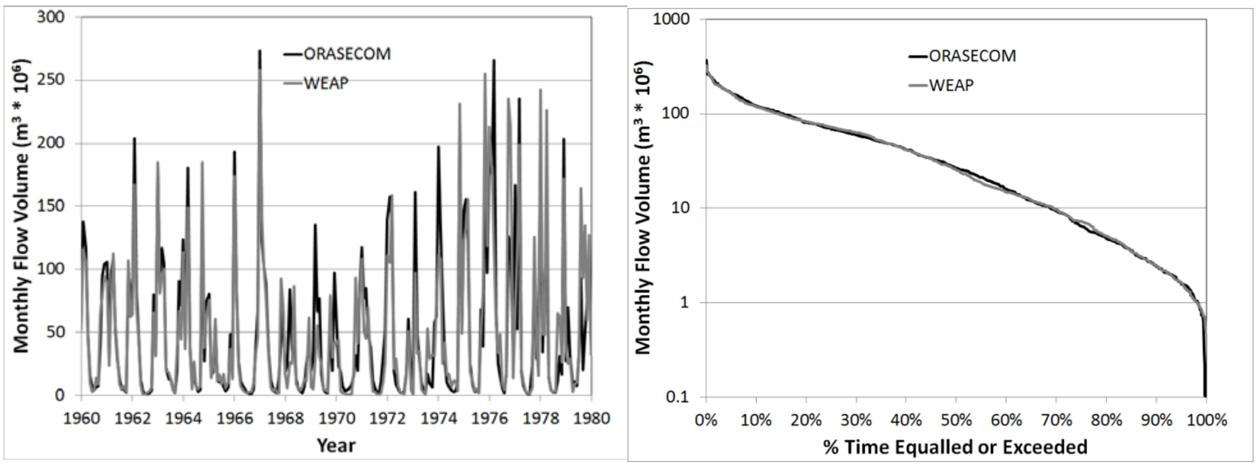


Figure C-63: WEAP versus ORASECOM results for the total outlet of D11 and D16 (headwaters of the Upper Senqu River)

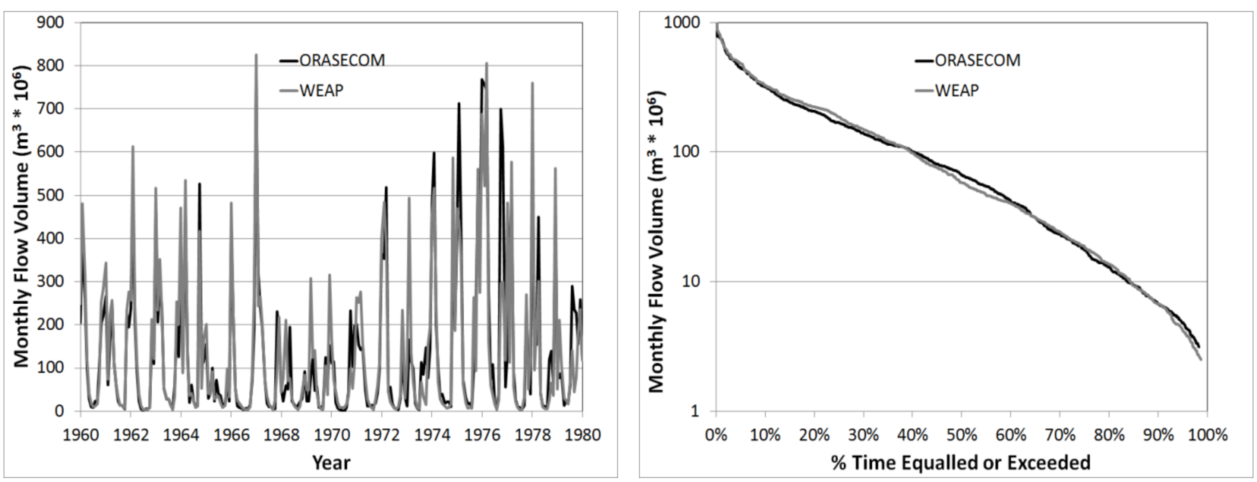


Figure C-64: WEAP versus observed flows for D1H005 (within D17L). The FDC plot is based on only those months for which observed data are available and there are many missing months within the total observed record of 1933 to 2005.

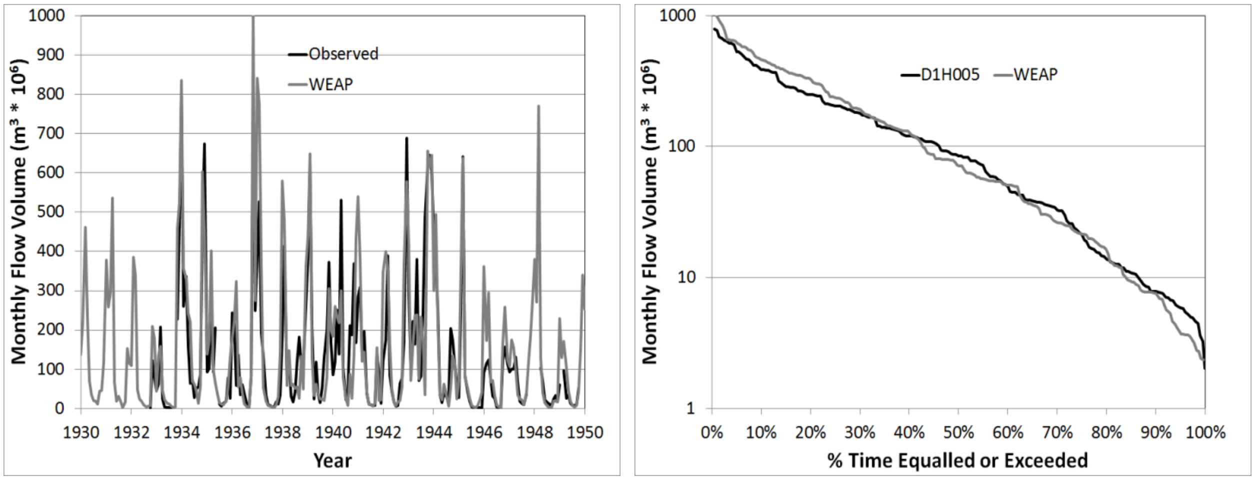


Figure C-65: WEAP versus ORASECOM results for D17A (inflows to Mohale Dam)

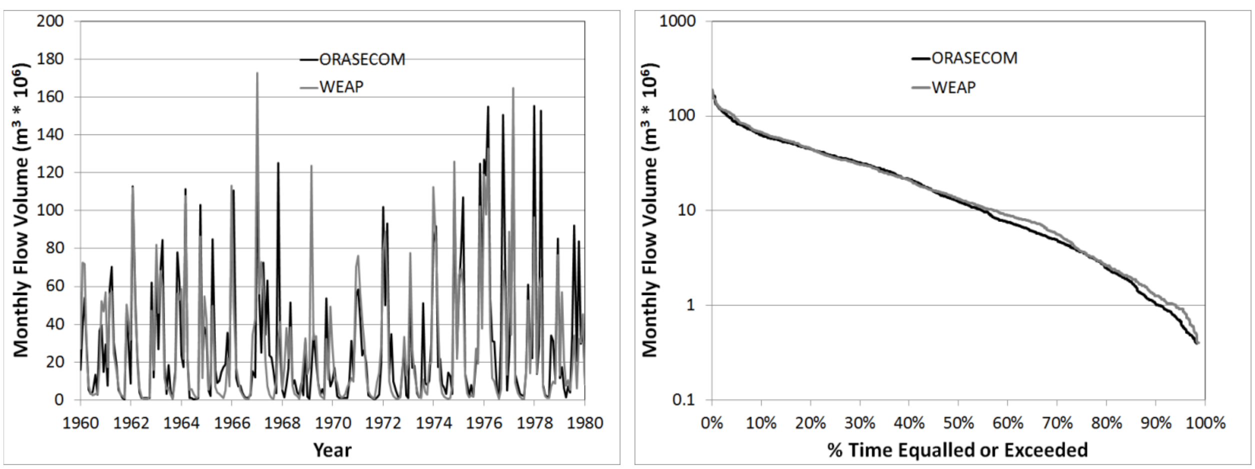


Figure C-66: WEAP versus ORASECOM and observed flows for D1H009 (Lesotho/South Africa border below confluence of the Senqu and Makhaleng rivers). The FDC plot is based on only those months for which observed data are available

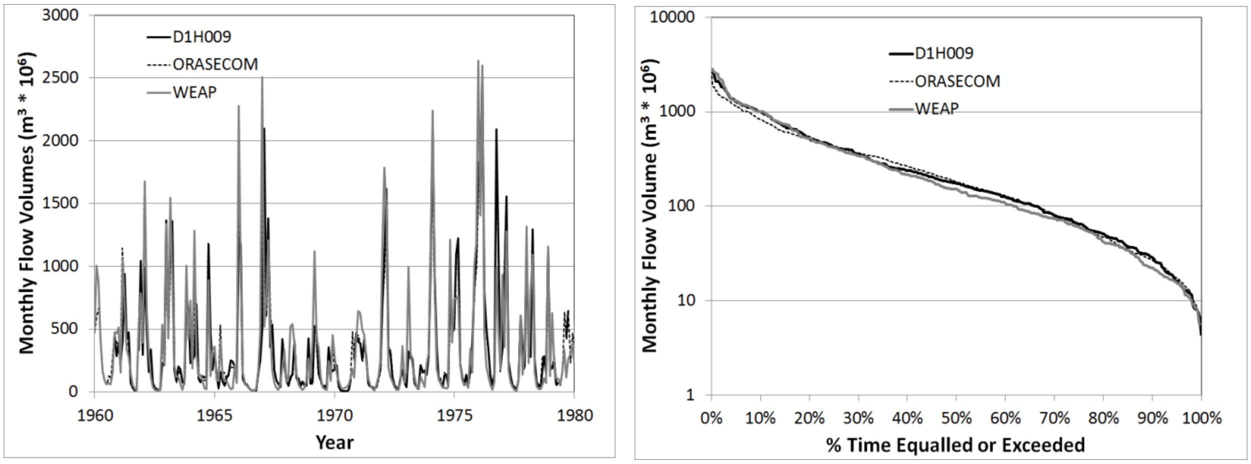


Figure C-67: WEAP versus observed flows for D1H011 (Kraai River). The FDC plot is based on only those months for which observed data are available

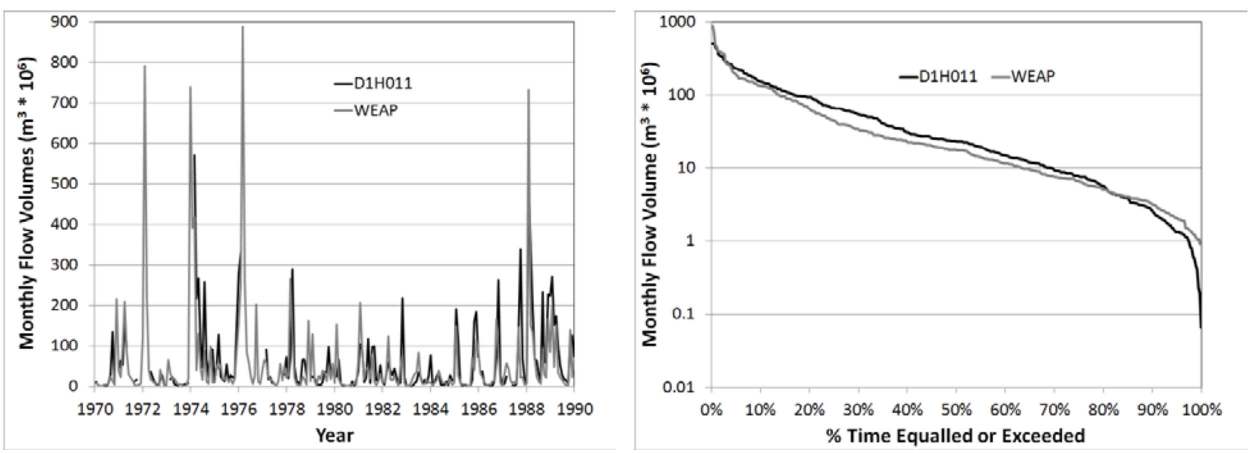


Figure C-68: WEAP versus observed flows for D1H003 (Orange River below confluence with the Kraai River). The discrepency in the low flows are a result of some abstractions in the lower parts of the system that are reflected in the observed data but not in the WEAP

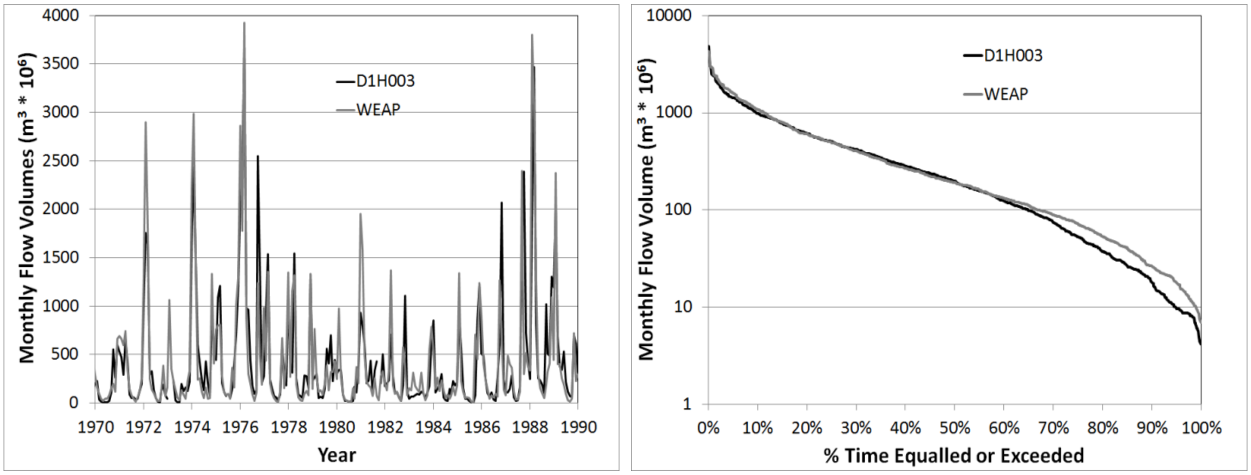


Figure C-69: WEAP versus ORASECOM results for D24J (Caledon River)

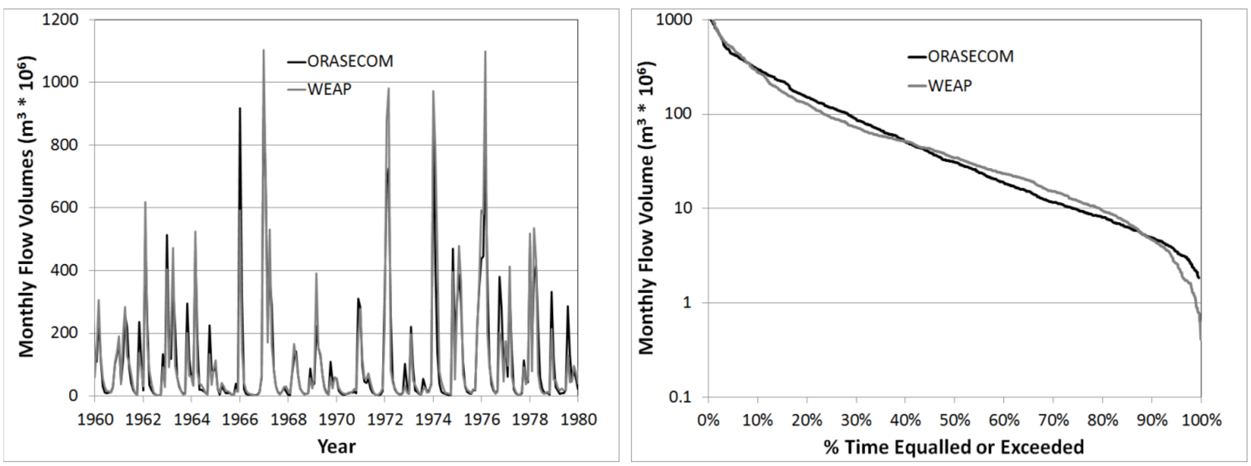
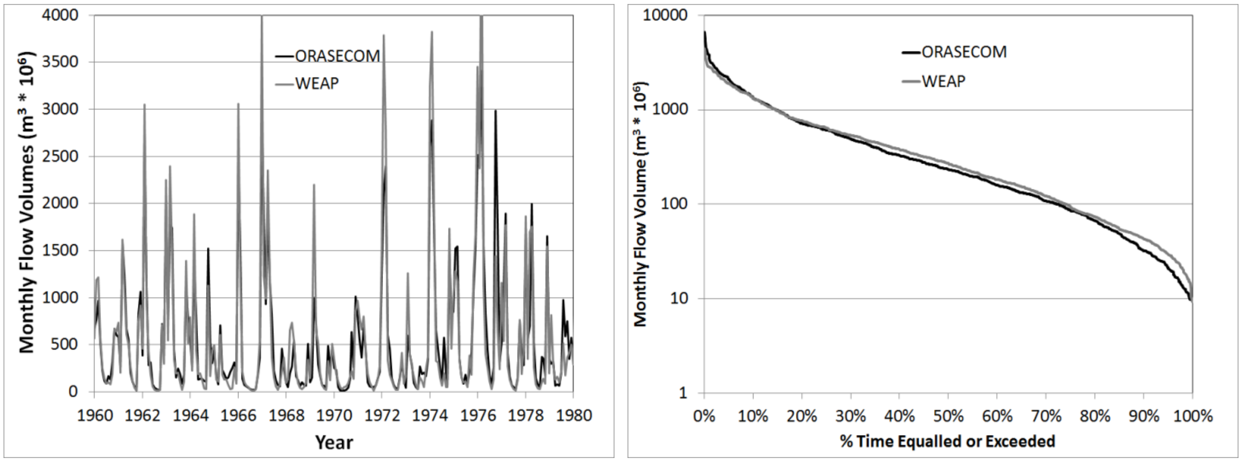


Figure C-70: WEAP versus ORASECOM results for Orange River below confluence with the Caledon River



Flow Simulation – Princeton Climate

Because of the similarity in precipitation between the two climate datasets, the recalibration of the WEAP-simulated streamflows with the Princeton climate data focused on the calculation of evapotranspiration within the catchments. The model adjustments centered around the crop coefficient parameter, Kc. The overall results of the recalibration are shown in Table C-34. The adjusted Kc values are presented in Table C-35 and Table C-36.

Table C-36: Updated Kc values for other nodes

Catchment Node	Kc
D11 A-F	1.15 * MonthlyValues(Oct, 0.91, Nov, 0.93, Dec, 1, Jan, 0.96, Feb, 0.9, Mar, 0.85, Apr, 0.8, May, 0.85, Jun, 0.75, Jul, 0.73, Aug, 0.87, Sep, 0.92)
D11 GH	1.05 * 0.73*MonthlyValues(Oct, 1.25, Nov, 1.4, Dec, 1.48, Jan, 1.5, Feb, 1.45, Mar, 1.32, Apr, 1.18, May, 1.025, Jun, 0.83, Jul, 0.85, Aug, 0.95, Sep, 1.07)
D11 JK	1.05 * MonthlyValues(Oct, 0.91, Nov, 0.93, Dec, 0.97, Jan, 0.96, Feb, 0.9, Mar, 0.83, Apr, 0.79, May, 0.85, Jun, 0.75, Jul, 0.73, Aug, 0.85, Sep, 0.92)
D16 A-C	0.945*MonthlyValues(Oct, 1.25, Nov, 1.4, Dec, 1.48, Jan, 1.5, Feb, 1.45, Mar, 1.32, Apr, 1.18, May, 1.025, Jun, 0.83, Jul, 0.85, Aug, 0.95, Sep, 1.07)
D16 D-J	0.93*MonthlyValues(Oct, 1.25, Nov, 1.4, Dec, 1.48, Jan, 1.5, Feb, 1.45, Mar, 1.32, Apr, 1.18, May, 1.025, Jun, 0.83, Jul, 0.85, Aug, 0.95, Sep, 1.07)
D16 KL	0.88*MonthlyValues(Oct, 1.25, Nov, 1.4, Dec, 1.48, Jan, 1.5, Feb, 1.45, Mar, 1.32, Apr, 1.18, May, 1.025, Jun, 0.83, Jul, 0.85, Aug, 0.95, Sep, 1.07)
D16 M	0.925*MonthlyValues(Oct, 1.25, Nov, 1.4, Dec, 1.48, Jan, 1.5, Feb, 1.45, Mar, 1.32, Apr, 1.18, May, 1.025, Jun, 0.83, Jul, 0.85, Aug, 0.95, Sep, 1.07)
D17 GH	1.05 * MonthlyValues(Oct, 0.98, Nov, 1, Dec, 1.05, Jan, 1.03, Feb, 0.97, Mar, 0.89, Apr, 0.85, May, 0.91, Jun, 0.8, Jul, 0.78, Aug, 0.91, Sep, 0.99)

D17 JK	1.05 * MonthlyValues(Oct, 0.98, Nov, 1, Dec, 1.05, Jan, 1.03, Feb, 0.97, Mar, 0.89, Apr, 0.85, May, 0.91, Jun, 0.8, Jul, 0.78, Aug, 0.91, Sep, 0.99)
D17 LM	1.05 * MonthlyValues(Oct, 0.98, Nov, 1, Dec, 1.05, Jan, 1.03, Feb, 0.97, Mar, 0.89, Apr, 0.85, May, 0.91, Jun, 0.8, Jul, 0.78, Aug, 0.91, Sep, 0.99)
D17 A	1.05 * MonthlyValues(Oct, 0.95, Nov, 1, Dec, 1.05, Jan, 1.03, Feb, 0.97, Mar, 0.89, Apr, 0.85, May, 0.91, Jun, 0.75, Jul, 0.78, Aug, 0.85, Sep, 0.9)
D17 BC	1.05 * MonthlyValues(Oct, 0.98, Nov, 1, Dec, 1.05, Jan, 1.03, Feb, 0.97, Mar, 0.89, Apr, 0.85, May, 0.91, Jun, 0.8, Jul, 0.78, Aug, 0.91, Sep, 0.99)
D17 DE	1.05 * MonthlyValues(Oct, 0.98, Nov, 1, Dec, 1.05, Jan, 1.03, Feb, 0.97, Mar, 0.89, Apr, 0.85, May, 0.91, Jun, 0.8, Jul, 0.78, Aug, 0.91, Sep, 0.99)
D17 F	1.05 * MonthlyValues(Oct, 0.98, Nov, 1, Dec, 1.05, Jan, 1.03, Feb, 0.97, Mar, 0.89, Apr, 0.85, May, 0.91, Jun, 0.8, Jul, 0.78, Aug, 0.91, Sep, 0.99)
D18 ACDFJL	1.05 * MonthlyValues(Oct, 1.05, Nov, 1.07, Dec, 1.12, Jan, 1.1, Feb, 1.04, Mar, 0.96, Apr, 0.91, May, 0.98, Jun, 0.86, Jul, 0.84, Aug, 0.98, Sep, 1.06)
D18 BEGHK	1.05 * MonthlyValues(Oct, 1.05, Nov, 1.07, Dec, 1.12, Jan, 1.1, Feb, 1.04, Mar, 0.96, Apr, 0.91, May, 0.98, Jun, 0.86, Jul, 0.84, Aug, 0.98, Sep, 1.06)
D15 ABCD	1.05 * 0.89*MonthlyValues(Oct, 1.05, Nov, 1.07, Dec, 1.12, Jan, 1.1, Feb, 1.04, Mar, 0.96, Apr, 0.91, May, 0.98, Jun, 0.86, Jul, 0.84, Aug, 0.98, Sep, 1.06)
D15 E-H	1.05 * 0.83*MonthlyValues(Oct, 1.05, Nov, 1.07, Dec, 1.12, Jan, 1.1, Feb, 1.04, Mar, 0.96, Apr, 0.91, May, 0.98, Jun, 0.86, Jul, 0.84, Aug, 0.98, Sep, 1.06)
D12	1.05 * 0.84*MonthlyValues(Oct, 1.1, Nov, 1.19, Dec, 1.23, Jan, 1.22, Feb, 1.23, Mar, 1.03, Apr, 0.98, May, 0.98, Jun, 0.88, Jul, 0.85, Aug, 1, Sep, 1.06)
D13 A-E	1.05 * 0.94*MonthlyValues(Oct, 1.01, Nov, 1.09, Dec, 1.13, Jan, 1.12, Feb, 1.13, Mar, 0.95, Apr, 0.9, May, 0.9, Jun, 0.81, Jul, 0.78, Aug, 0.92, Sep, 0.98)
D13 F-J	1.05 * 0.91*MonthlyValues(Oct, 1.1, Nov, 1.19, Dec, 1.23, Jan, 1.22, Feb, 1.23, Mar, 1.03, Apr, 0.98, May, 0.98, Jun, 0.88, Jul, 0.85, Aug, 1, Sep, 1.06)
D13 K-M	1.05 * 0.85*MonthlyValues(Oct, 1.11, Nov, 1.2, Dec, 1.24, Jan, 1.24, Feb, 1.24, Mar, 1.05, Apr, 0.99, May, 0.99, Jun, 0.89, Jul, 0.86, Aug, 1.01, Sep, 1.07)
D14 AJK	1.05 * 0.81*MonthlyValues(Oct, 1.15, Nov, 1.24, Dec, 1.29, Jan, 1.28, Feb, 1.29, Mar, 1.08, Apr, 1.03, May, 1.02, Jun, 0.93, Jul, 0.89, Aug, 1.05, Sep, 1.11)
D14 B-H	1.05 * 0.85*MonthlyValues(Oct, 1.16, Nov, 1.26, Dec, 1.3, Jan, 1.3, Feb, 1.3, Mar, 1.1, Apr, 1.04, May, 1.04, Jun, 0.94, Jul, 0.9, Aug, 1.06, Sep, 1.13)
D35	1.05 * MonthlyValues(Oct, 1.18, Nov, 1.28, Dec, 1.32, Jan, 1.32, Feb, 1.32, Mar, 1.11, Apr, 1.06, May, 1.05, Jun, 0.95, Jul, 0.91, Aug, 1.08, Sep, 1.14)
D34	1.05 * MonthlyValues(Oct, 1.2, Nov, 1.27, Dec, 1.35, Jan, 1.36, Feb, 1.25, Mar, 1.15, Apr, 1.12, May, 1.21, Jun, 1.11, Jul, 1.09, Aug, 1.19, Sep, 1.17)
D32 A-H	1.05 * MonthlyValues(Oct, 1.28, Nov, 1.36, Dec, 1.44, Jan, 1.45, Feb, 1.33, Mar, 1.22, Apr, 1.19, May, 1.29, Jun, 1.19, Jul, 1.17, Aug, 1.27, Sep, 1.25)

D32 J-K	1.05 * MonthlyValues(Oct, 1.27, Nov, 1.35, Dec, 1.42, Jan, 1.44, Feb, 1.32, Mar, 1.21, Apr, 1.18, May, 1.28, Jun, 1.17, Jul, 1.16, Aug, 1.26, Sep, 1.24)
D31	1.05 * MonthlyValues(Oct, 1.25, Nov, 1.44, Dec, 1.55, Jan, 1.55, Feb, 1.43, Mar, 1.26, Apr, 1.15, May, 1.1, Jun, 0.93, Jul, 0.88, Aug, 1.04, Sep, 1.13)
D33	1.05 * MonthlyValues(Oct, 1.36, Nov, 1.52, Dec, 1.6, Jan, 1.65, Feb, 1.55, Mar, 1.41, Apr, 1.35, May, 1.34, Jun, 1.19, Jul, 1.15, Aug, 1.24, Sep, 1.29)

Table C-34: Summary of flow calibration results with Princeton climate data

Site	WEAP compared with	Records used	NSE	Annual Bias (%)	SDR	RMSE (MCM)
D11 A-F (Katse)	ORASECOM	1949 – 2000	0.22	0.4	1.06	50.0
D11 GH (Matsoku)	ORASECOM	1949 – 2000	0.06	-4.0	0.96	12.3
D11 & D16	ORASECOM	1949 – 2000	0.18	-0.3	1.08	150.5
D1H005	Observed	1949 – 2000	0.16	-17.8	0.84	164.1
D17A (Mohale)	ORASECOM	1949 – 2000	0.26	5.2	1.05	27.5
D1H009	ORASECOM	1949 – 2000	0.25	-3.8	1.13	334.6
D1H003	Observed	1949 – 2000	0.31	-1.4	1.09	418.3
D24J (Caledon)	ORASECOM	1949 – 2000	0.59	11.4	0.78	143.5
Orange/Caledon confluence	ORASECOM	1949 – 2000	0.39	-4.8	1.20	496.6

In general, the re-calibrated simulated flows do not agree with the historical time series as well as the initial calibration on a month-to-month basis (as seen with the decrease in NSE). This decrease in model performance with the Princeton data is likely due to inaccuracies associated with the downscaling of the climate to a resolution consistent with the catchments used in the model. That is, at the basin scale the two datasets agree well, but that same agreement does not always hold true at the catchment scale.

However, while the monthly time series of flows do not agree as well with the historical flows, the overall mass balance of flows is comparable to the previous simulations. That is, the model continues to simulate the total annual discharge, seasonal flows patterns, and variation in flow (i.e. flow duration) with an acceptable degree of performance. These results are highlighted in Figure C-71 to Figure C-79.

The accuracy of these results relative to the initial calibration suggest that it may be preferable to use the WR2005 climate data in situations where the analysis seeks to report on the absolute values of model results. However, in situations where model results will be reported relative to some baseline, then either climate dataset would be sufficient to generate results representative of system operations within the basin.

Table C-35: Updated Kc values for Caledon River nodes

Catchment Node	Kc
D21 A-C	0.888
D21 DE	0.841
D21 FG	0.840
D21 H	0.839
D21 J-L	0.851
D22 AB	0.788
D22 C	0.775
D22 D	0.793
D22 EF	0.850
D22 G	0.784
D22 H	0.784
D22 JK	0.803
D22 L	0.774
D23 A	0.784
D23 B	0.784
D23 CD	0.765
D23 E	0.784
D23 FG	0.784
D23 H	0.803
D23 J	0.803
D24 A	0.840
D24 B-F	0.861

D24 G-L	0.767

Table C-36: Updated Kc values for other nodes

Catchment Node	Kc
D11 A-F	1.15 * MonthlyValues(Oct, 0.91, Nov, 0.93, Dec, 1, Jan, 0.96, Feb, 0.9, Mar, 0.85, Apr, 0.8, May, 0.85, Jun, 0.75, Jul, 0.73, Aug, 0.87, Sep, 0.92)
D11 GH	1.05 * 0.73*MonthlyValues(Oct, 1.25, Nov, 1.4, Dec, 1.48, Jan, 1.5, Feb, 1.45, Mar, 1.32, Apr, 1.18, May, 1.025, Jun, 0.83, Jul, 0.85, Aug, 0.95, Sep, 1.07)
D11 JK	1.05 * MonthlyValues(Oct, 0.91, Nov, 0.93, Dec, 0.97, Jan, 0.96, Feb, 0.9, Mar, 0.83, Apr, 0.79, May, 0.85, Jun, 0.75, Jul, 0.73, Aug, 0.85, Sep, 0.92)
D16 A-C	0.945*MonthlyValues(Oct, 1.25, Nov, 1.4, Dec, 1.48, Jan, 1.5, Feb, 1.45, Mar, 1.32, Apr, 1.18, May, 1.025, Jun, 0.83, Jul, 0.85, Aug, 0.95, Sep, 1.07)
D16 D-J	0.93*MonthlyValues(Oct, 1.25, Nov, 1.4, Dec, 1.48, Jan, 1.5, Feb, 1.45, Mar, 1.32, Apr, 1.18, May, 1.025, Jun, 0.83, Jul, 0.85, Aug, 0.95, Sep, 1.07)
D16 KL	0.88*MonthlyValues(Oct, 1.25, Nov, 1.4, Dec, 1.48, Jan, 1.5, Feb, 1.45, Mar, 1.32, Apr, 1.18, May, 1.025, Jun, 0.83, Jul, 0.85, Aug, 0.95, Sep, 1.07)
D16 M	0.925*MonthlyValues(Oct, 1.25, Nov, 1.4, Dec, 1.48, Jan, 1.5, Feb, 1.45, Mar, 1.32, Apr, 1.18, May, 1.025, Jun, 0.83, Jul, 0.85, Aug, 0.95, Sep, 1.07)
D17 GH	1.05 * MonthlyValues(Oct, 0.98, Nov, 1, Dec, 1.05, Jan, 1.03, Feb, 0.97, Mar, 0.89, Apr, 0.85, May, 0.91, Jun, 0.8, Jul, 0.78, Aug, 0.91, Sep, 0.99)
D17 JK	1.05 * MonthlyValues(Oct, 0.98, Nov, 1, Dec, 1.05, Jan, 1.03, Feb, 0.97, Mar, 0.89, Apr, 0.85, May, 0.91, Jun, 0.8, Jul, 0.78, Aug, 0.91, Sep, 0.99)
D17 LM	1.05 * MonthlyValues(Oct, 0.98, Nov, 1, Dec, 1.05, Jan, 1.03, Feb, 0.97, Mar, 0.89, Apr, 0.85, May, 0.91, Jun, 0.8, Jul, 0.78, Aug, 0.91, Sep, 0.99)
D17 A	1.05 * MonthlyValues(Oct, 0.95, Nov, 1, Dec, 1.05, Jan, 1.03, Feb, 0.97, Mar, 0.89, Apr, 0.85, May, 0.91, Jun, 0.75, Jul, 0.78, Aug, 0.85, Sep, 0.9)
D17 BC	1.05 * MonthlyValues(Oct, 0.98, Nov, 1, Dec, 1.05, Jan, 1.03, Feb, 0.97, Mar, 0.89, Apr, 0.85, May, 0.91, Jun, 0.8, Jul, 0.78, Aug, 0.91, Sep, 0.99)
D17 DE	1.05 * MonthlyValues(Oct, 0.98, Nov, 1, Dec, 1.05, Jan, 1.03, Feb, 0.97, Mar, 0.89, Apr, 0.85, May, 0.91, Jun, 0.8, Jul, 0.78, Aug, 0.91, Sep, 0.99)
D17 F	1.05 * MonthlyValues(Oct, 0.98, Nov, 1, Dec, 1.05, Jan, 1.03, Feb, 0.97, Mar, 0.89, Apr, 0.85, May, 0.91, Jun, 0.8, Jul, 0.78, Aug, 0.91, Sep, 0.99)
D18 ACDFJL	1.05 * MonthlyValues(Oct, 1.05, Nov, 1.07, Dec, 1.12, Jan, 1.1, Feb, 1.04, Mar, 0.96, Apr, 0.91, May, 0.98, Jun, 0.86, Jul, 0.84, Aug, 0.98, Sep, 1.06)

D18 BEGHK	1.05 * MonthlyValues(Oct, 1.05, Nov, 1.07, Dec, 1.12, Jan, 1.1, Feb, 1.04, Mar, 0.96, Apr, 0.91, May, 0.98, Jun, 0.86, Jul, 0.84, Aug, 0.98, Sep, 1.06)
D15 ABCD	1.05 * 0.89*MonthlyValues(Oct, 1.05, Nov, 1.07, Dec, 1.12, Jan, 1.1, Feb, 1.04, Mar, 0.96, Apr, 0.91, May, 0.98, Jun, 0.86, Jul, 0.84, Aug, 0.98, Sep, 1.06)
D15 E-H	1.05 * 0.83*MonthlyValues(Oct, 1.05, Nov, 1.07, Dec, 1.12, Jan, 1.1, Feb, 1.04, Mar, 0.96, Apr, 0.91, May, 0.98, Jun, 0.86, Jul, 0.84, Aug, 0.98, Sep, 1.06)
D12	1.05 * 0.84*MonthlyValues(Oct, 1.1, Nov, 1.19, Dec, 1.23, Jan, 1.22, Feb, 1.23, Mar, 1.03, Apr, 0.98, May, 0.98, Jun, 0.88, Jul, 0.85, Aug, 1, Sep, 1.06)
D13 A-E	1.05 * 0.94*MonthlyValues(Oct, 1.01, Nov, 1.09, Dec, 1.13, Jan, 1.12, Feb, 1.13, Mar, 0.95, Apr, 0.9, May, 0.9, Jun, 0.81, Jul, 0.78, Aug, 0.92, Sep, 0.98)
D13 F-J	1.05 * 0.91*MonthlyValues(Oct, 1.1, Nov, 1.19, Dec, 1.23, Jan, 1.22, Feb, 1.23, Mar, 1.03, Apr, 0.98, May, 0.98, Jun, 0.88, Jul, 0.85, Aug, 1, Sep, 1.06)
D13 K-M	1.05 * 0.85*MonthlyValues(Oct, 1.11, Nov, 1.2, Dec, 1.24, Jan, 1.24, Feb, 1.24, Mar, 1.05, Apr, 0.99, May, 0.99, Jun, 0.89, Jul, 0.86, Aug, 1.01, Sep, 1.07)
D14 AJK	1.05 * 0.81*MonthlyValues(Oct, 1.15, Nov, 1.24, Dec, 1.29, Jan, 1.28, Feb, 1.29, Mar, 1.08, Apr, 1.03, May, 1.02, Jun, 0.93, Jul, 0.89, Aug, 1.05, Sep, 1.11)
D14 B-H	1.05 * 0.85*MonthlyValues(Oct, 1.16, Nov, 1.26, Dec, 1.3, Jan, 1.3, Feb, 1.3, Mar, 1.1, Apr, 1.04, May, 1.04, Jun, 0.94, Jul, 0.9, Aug, 1.06, Sep, 1.13)
D35	1.05 * MonthlyValues(Oct, 1.18, Nov, 1.28, Dec, 1.32, Jan, 1.32, Feb, 1.32, Mar, 1.11, Apr, 1.06, May, 1.05, Jun, 0.95, Jul, 0.91, Aug, 1.08, Sep, 1.14)
D34	1.05 * MonthlyValues(Oct, 1.2, Nov, 1.27, Dec, 1.35, Jan, 1.36, Feb, 1.25, Mar, 1.15, Apr, 1.12, May, 1.21, Jun, 1.11, Jul, 1.09, Aug, 1.19, Sep, 1.17)
D32 A-H	1.05 * MonthlyValues(Oct, 1.28, Nov, 1.36, Dec, 1.44, Jan, 1.45, Feb, 1.33, Mar, 1.22, Apr, 1.19, May, 1.29, Jun, 1.19, Jul, 1.17, Aug, 1.27, Sep, 1.25)
D32 J-K	1.05 * MonthlyValues(Oct, 1.27, Nov, 1.35, Dec, 1.42, Jan, 1.44, Feb, 1.32, Mar, 1.21, Apr, 1.18, May, 1.28, Jun, 1.17, Jul, 1.16, Aug, 1.26, Sep, 1.24)
D31	1.05 * MonthlyValues(Oct, 1.25, Nov, 1.44, Dec, 1.55, Jan, 1.55, Feb, 1.43, Mar, 1.26, Apr, 1.15, May, 1.1, Jun, 0.93, Jul, 0.88, Aug, 1.04, Sep, 1.13)
D33	1.05 * MonthlyValues(Oct, 1.36, Nov, 1.52, Dec, 1.6, Jan, 1.65, Feb, 1.55, Mar, 1.41, Apr, 1.35, May, 1.34, Jun, 1.19, Jul, 1.15, Aug, 1.24, Sep, 1.29)

Figure C-71: WEAP versus ORASECOM results for D11 A-F (inflows to Katse Dam) with Princeton climate data.

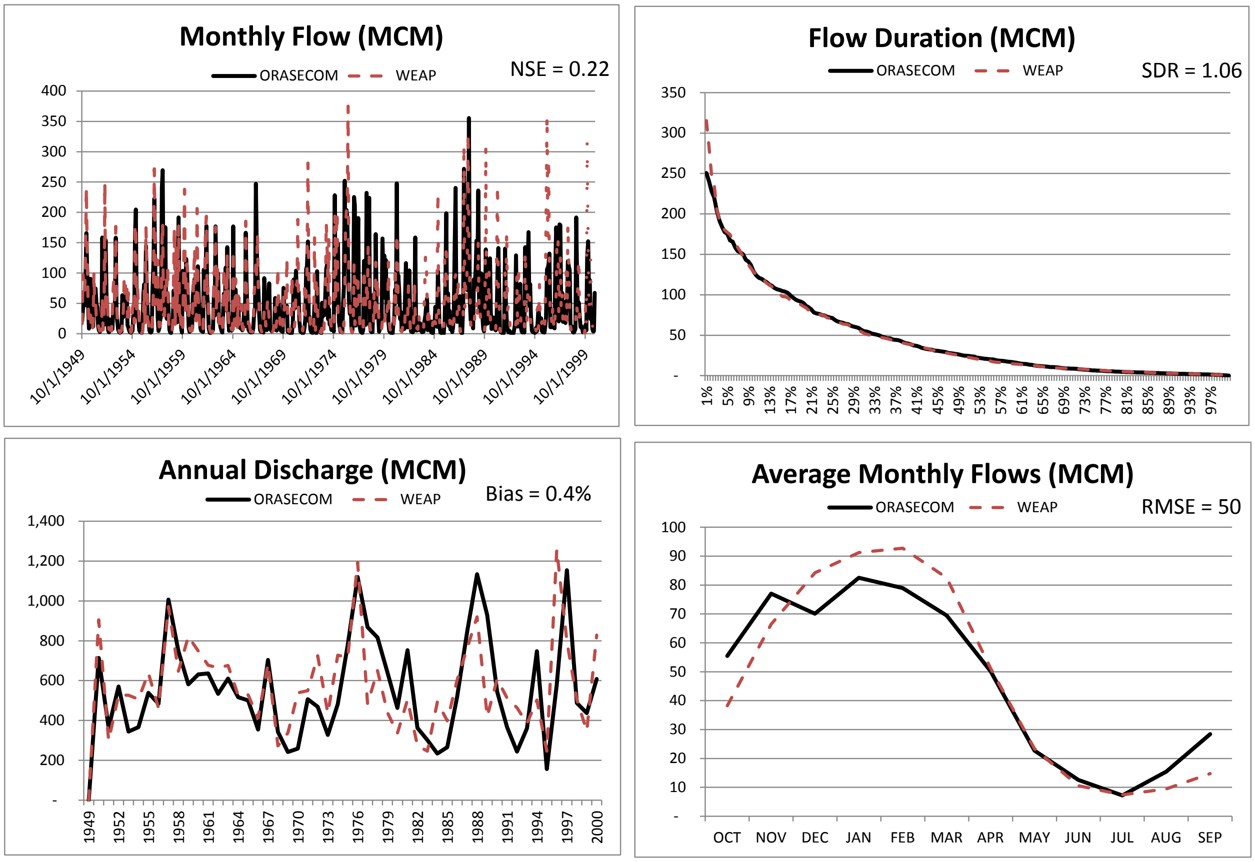


Figure C-72: WEAP versus ORASECOM results for Matsoku River with Princeton climate data

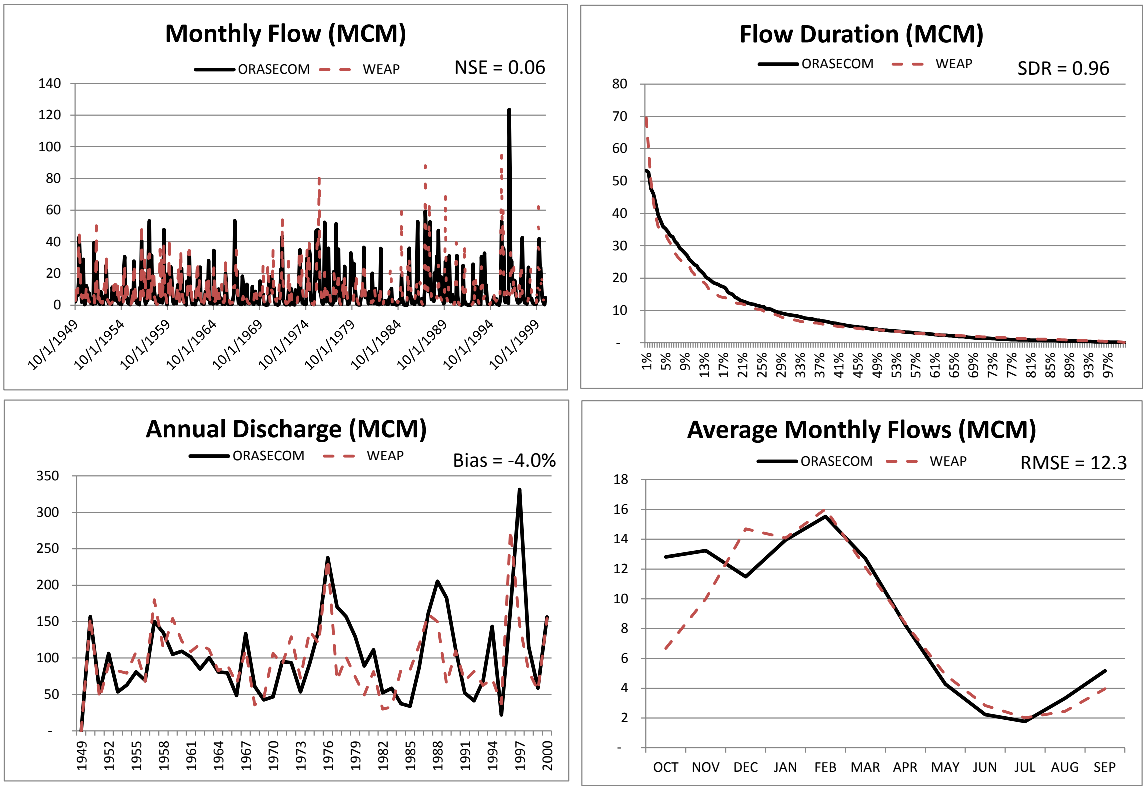


Figure C-73: WEAP versus ORASECOM results for the total outlet of D11 and D16 (headwaters of the Upper Senqu River) with Princeton climate data

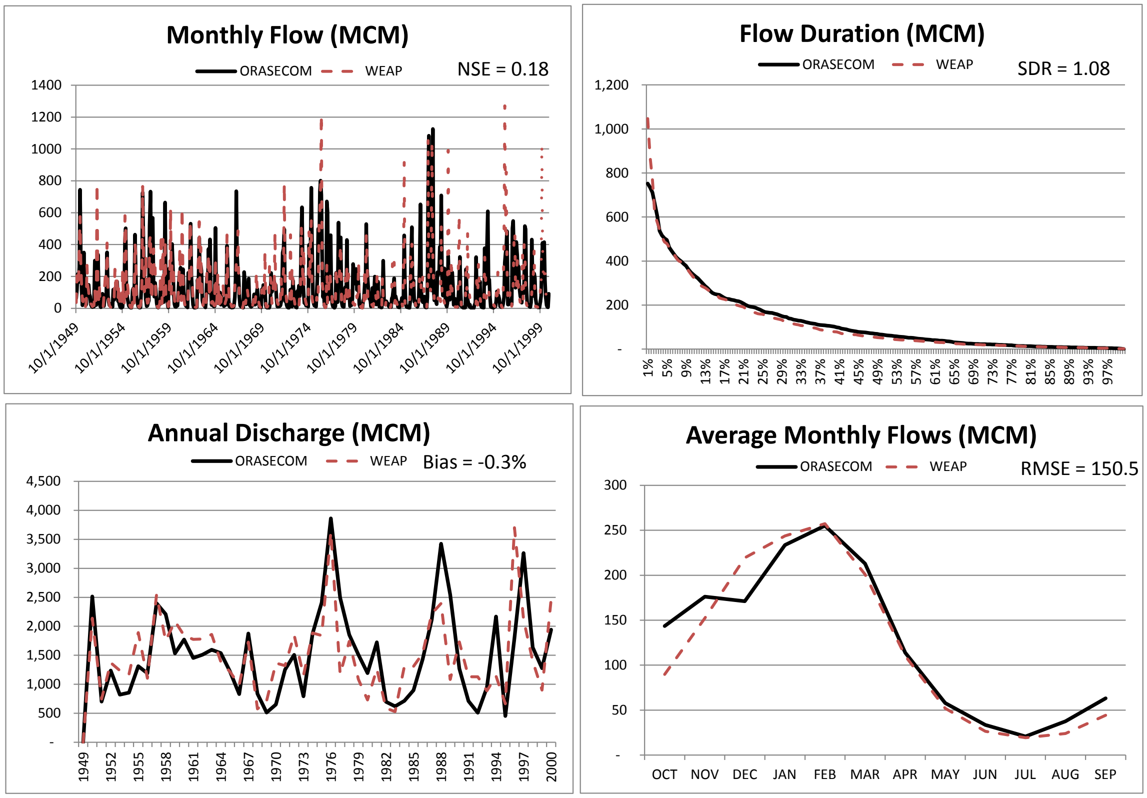


Figure C-74: WEAP versus observed flows for D1H005 (within D17L) with Princeton climate data

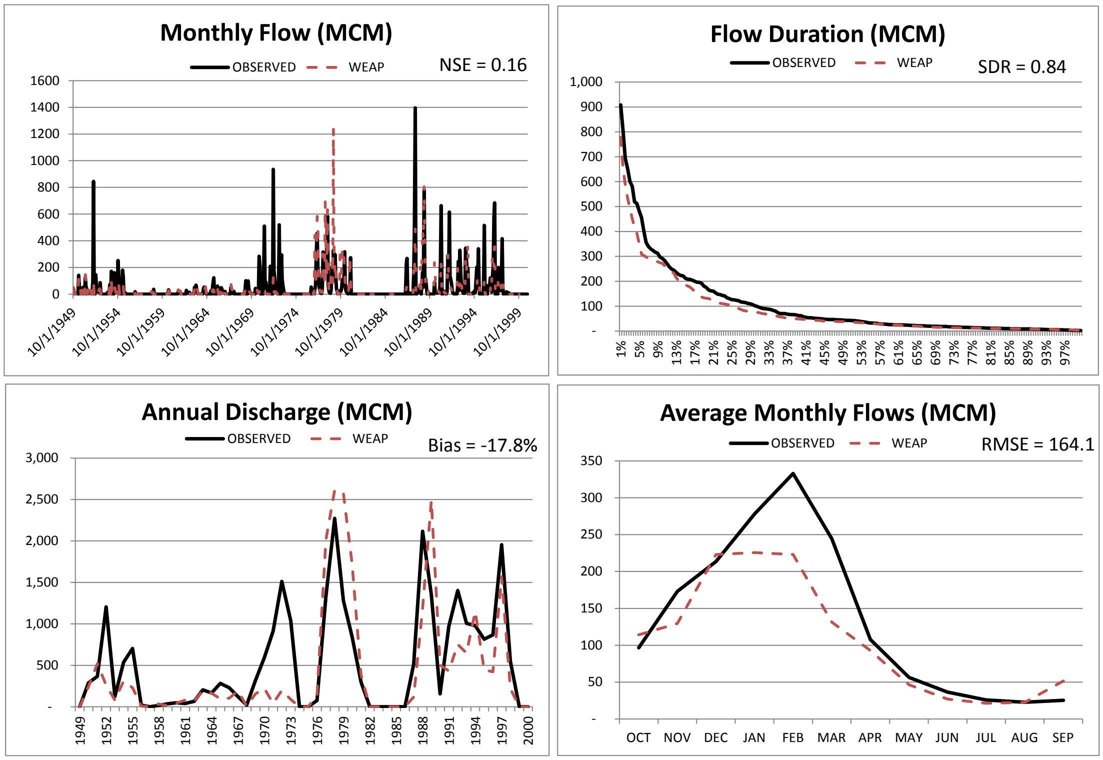


Figure C-75: WEAP versus ORASECOM results for D17A (inflows to Mohale Dam) with Princeton climate data

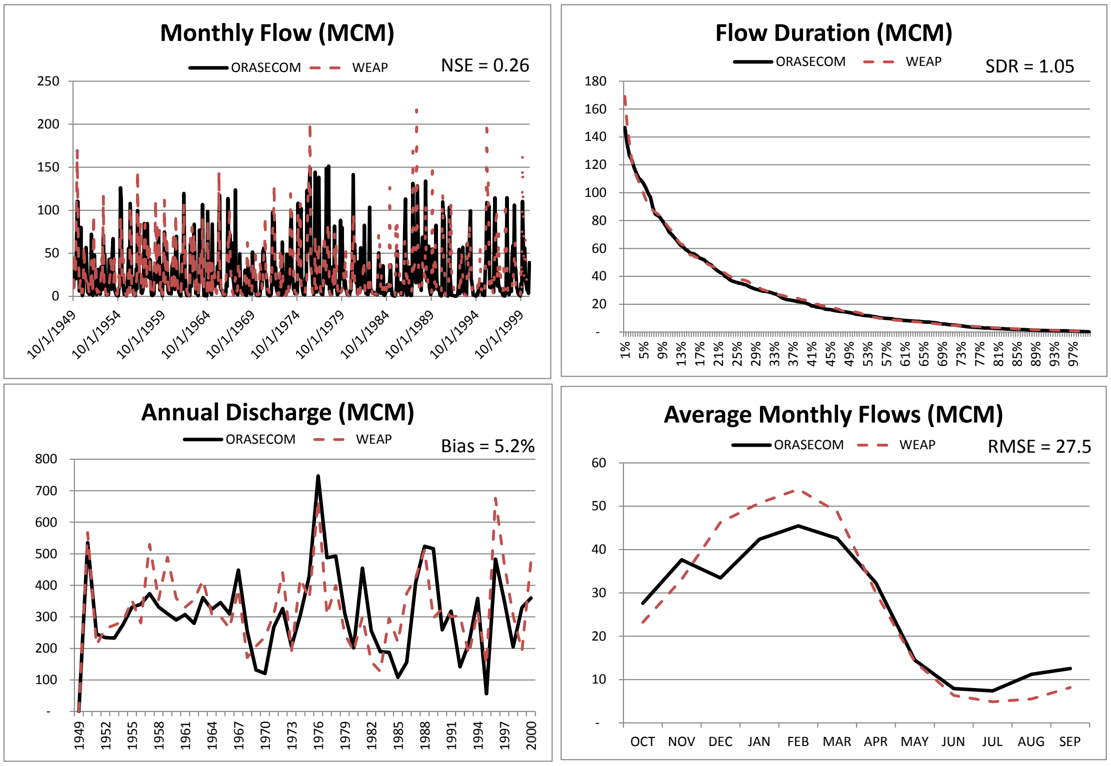


Figure C-76: WEAP versus ORASECOM and observed flows for D1H009 (Lesotho/South Africa border below confluence of the Senqu and Makhaleng rivers) with Princeton climate data.

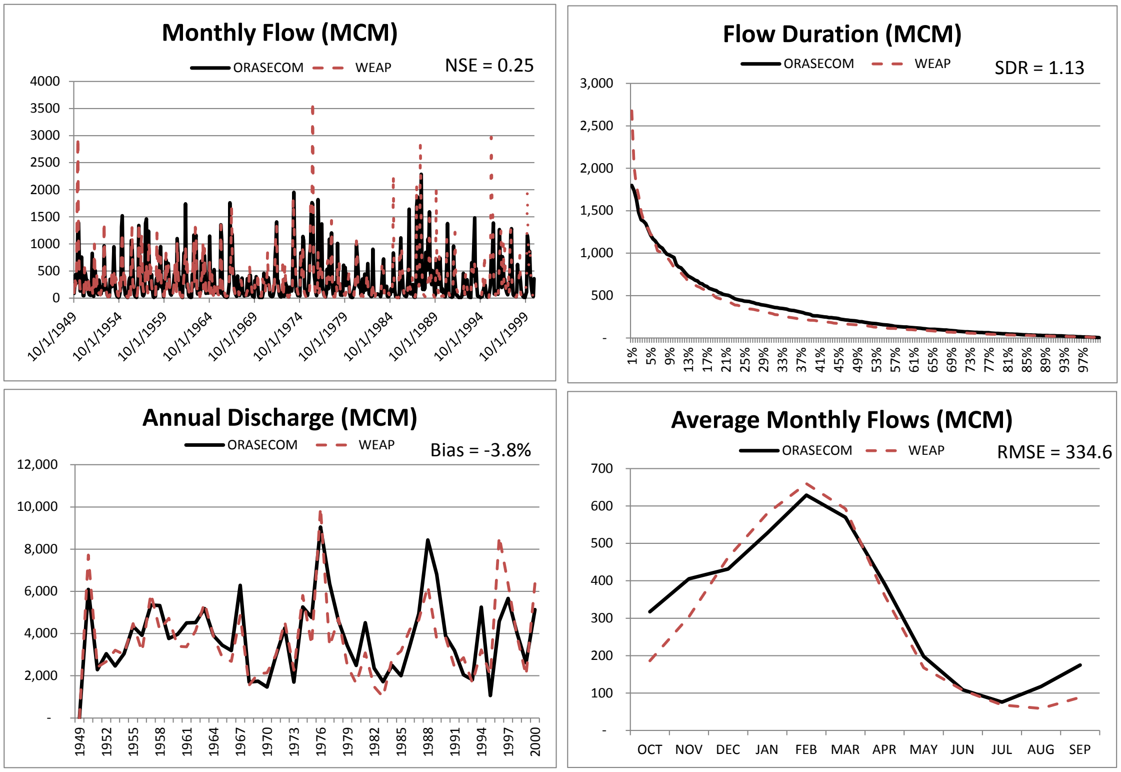


Figure C-77: WEAP versus observed flows for D1H003 (Orange River below confluence with the Kraai River) with Princeton climate data

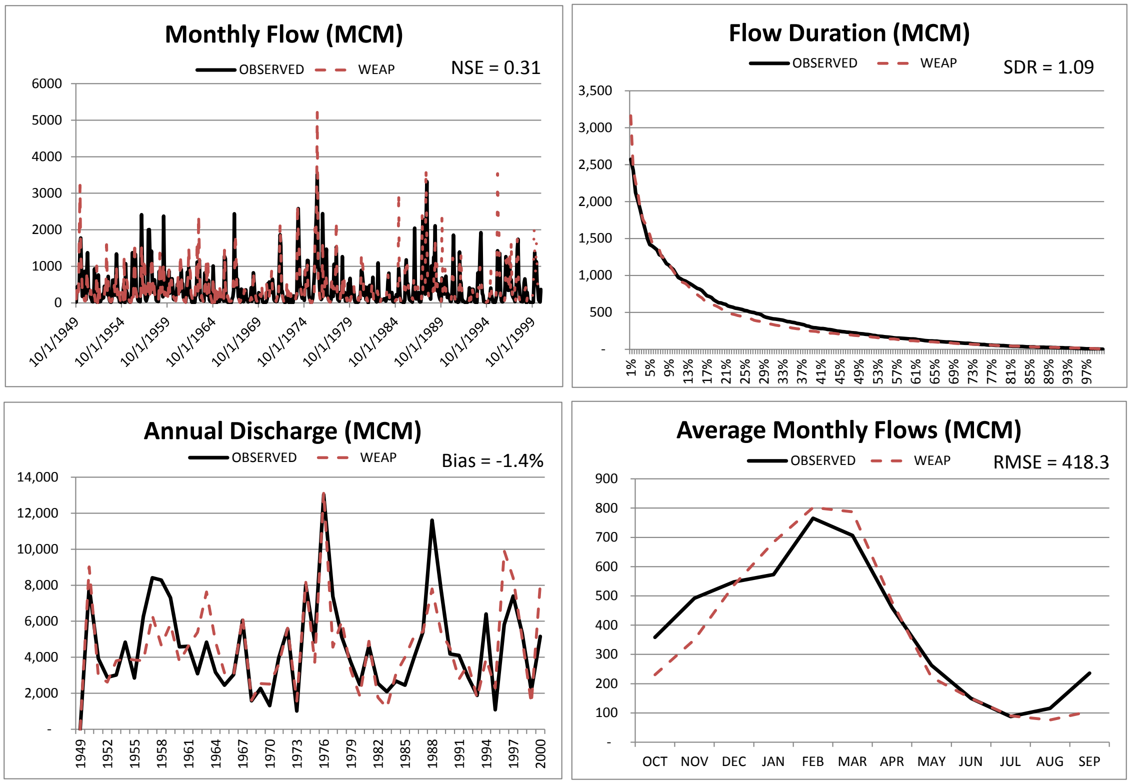


Figure C-78: WEAP versus ORASECOM results for D24J (Caledon River) with Princeton climate data

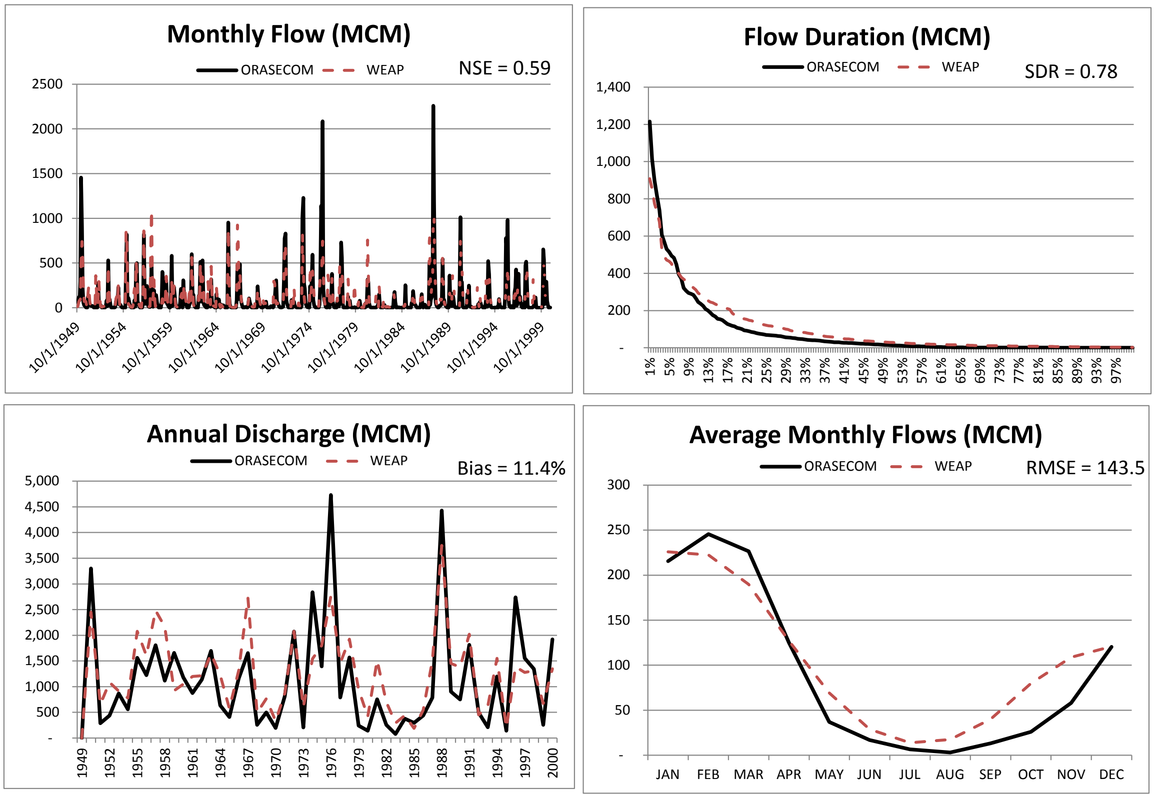
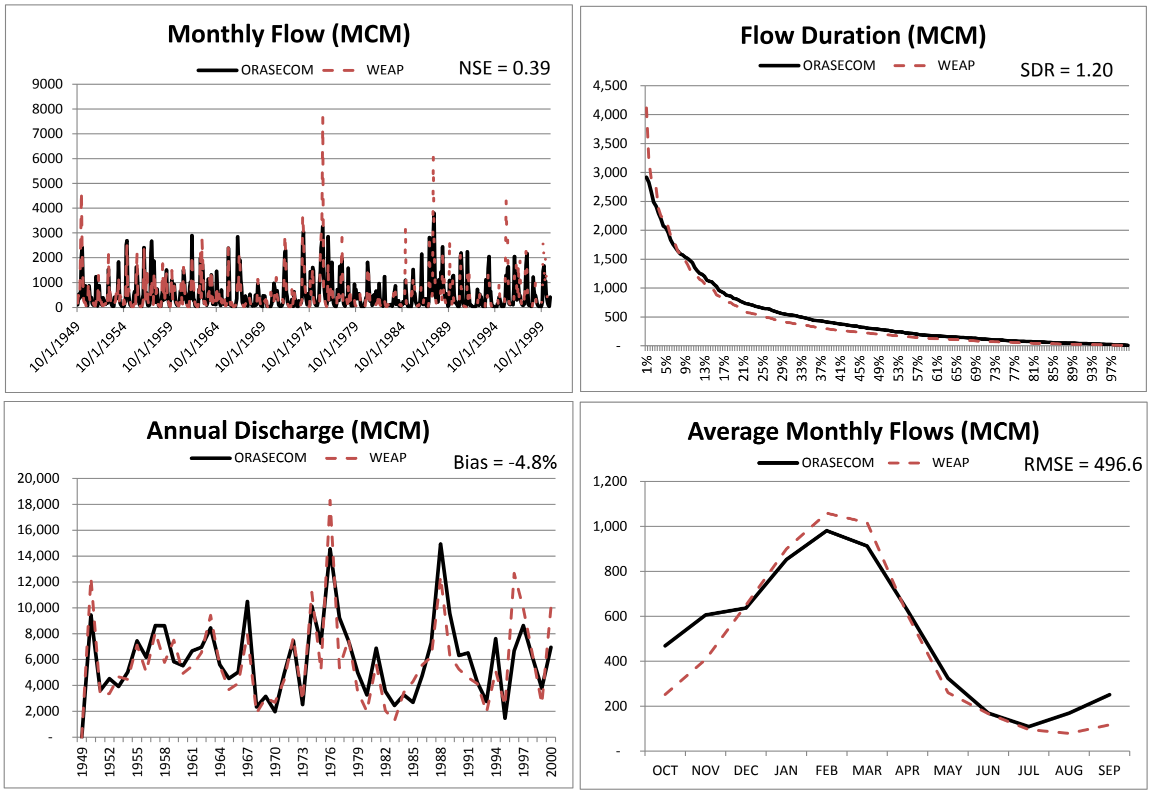


Figure C-79: WEAP versus ORASECOM results for Orange River below confluence with the Caledon River with Princeton climate data



Water Resources Simulation

The WEAP model is a demand-driven model that seeks to meet various water needs (i.e. domestic, flow requirements, irrigation, and hydropower) subject to physical and operational rules and constraints. This implies that the allocation of water at each timestep is determined by the system of demand priorities. Within the upper Orange River WEAP model, we assumed the following ordering of demand priorities (highest to lowest):

1. Domestic/municipal water users
2. Ecological flow requirements
3. Lesotho Highlands Water Project Operations
4. In-basin irrigation
5. Inter-basin transfers (excluding LHWP)
6. Hydropower generation (Gariep and Van Der Kloof)
7. Reservoir storage

For the calibration of system operations, we focused on the simulated versus observed reservoir storage for the two reservoirs with historical records that are sufficiently long to reflect a range of climatic and hydrologic conditions – i.e. Van Der Kloof and Gariep reservoirs. Results of the WRYM model for a baseline condition were also included as an additional point of comparison to demonstrate how well WEAP performs in relation to the de facto water resources model for the basin. In general, the WEAP model was found to approximate the historical fluctuations in storage in both reservoirs at a level of accuracy that is at least as good as the WRYM model.

Figure C-80: Simulated versus observed Van Der Kloof reservoir storage (1976-2005)

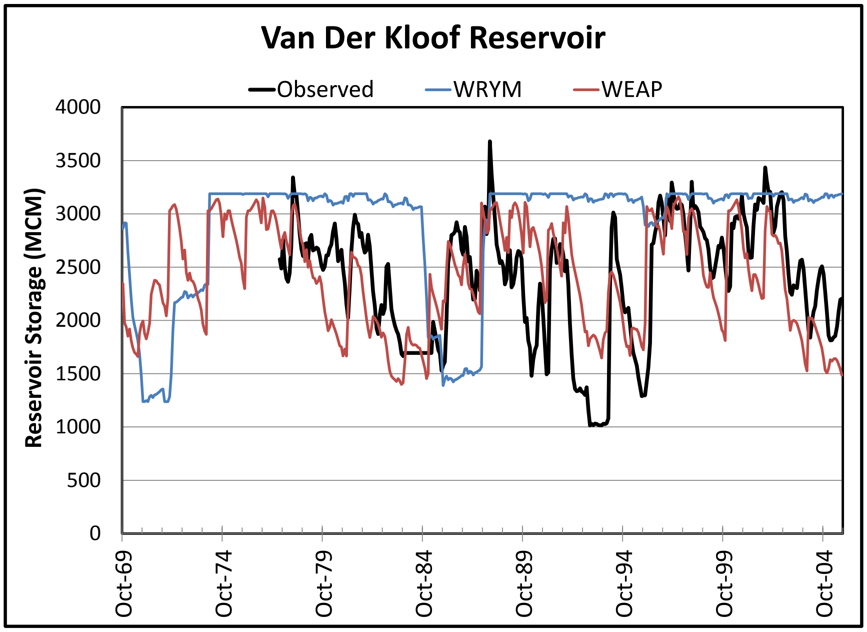
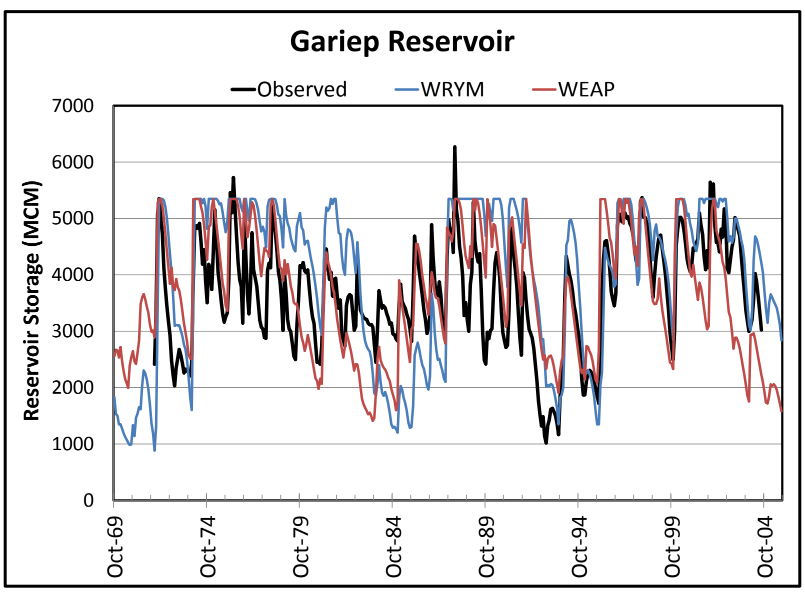


Figure C-81: Simulated versus observed Gariep reservoir storarge (1970-2005)



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C6-Senegal River Basin

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Figure C-82: Senegal River Basin, West Africa

Description of the Basin

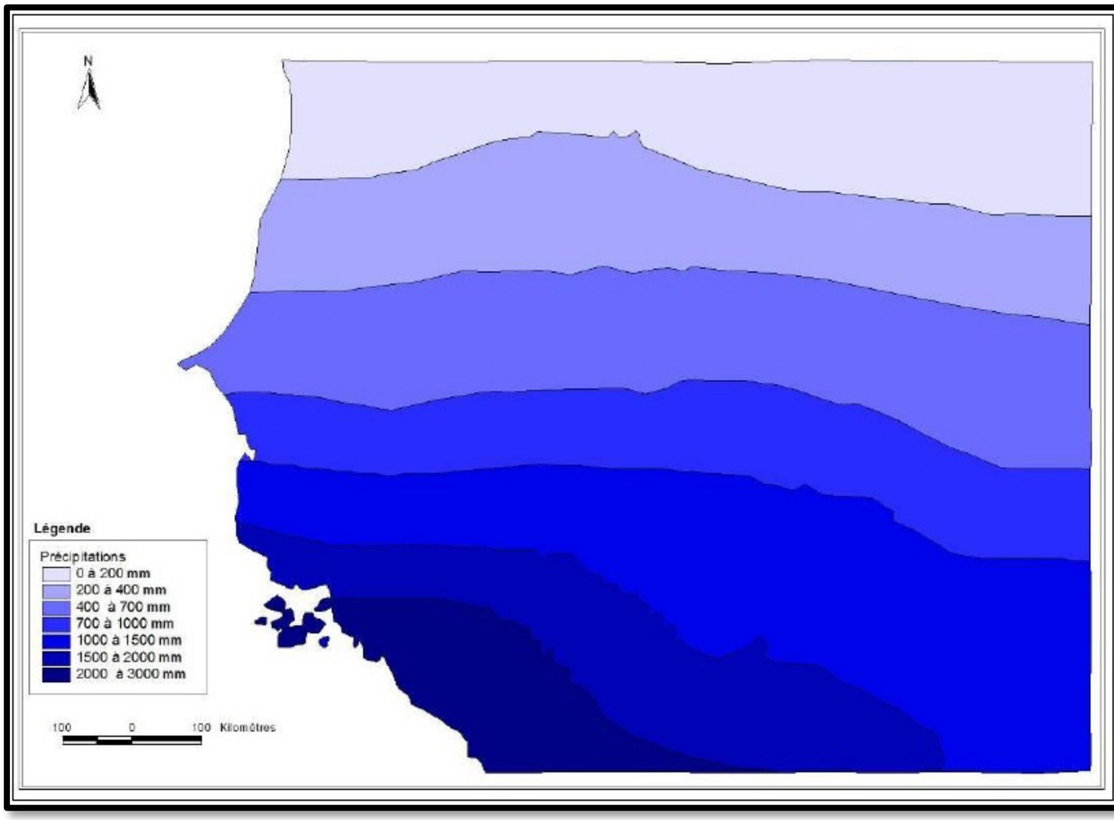
The Senegal River basin, located in western Africa, covers a total area of about 483,181 km^2 and spreads over four riparian countries namely: Guinea, Mali, Mauritania, and Senegal. It covers about 1.6% of the African continental landmass.

Table C-37: Senegal River basin areas by country

Country	Area within Basin (km^2)	Percentage of Basin area (%)	Percentage of Country within the Basin (%)
Guinea	29,475	6.1	12.0
Mali	139,098	28.8	11.2
Mauritania	242,742	50.2	23.7
Senegal	718,66	14.9	36.5
Total	483,181	100.0	

There are several types of climate within the Senegal River basin. The climate in the southern basin is sub-Guinean; the central basin is Sudanese; and the north is Sahel. The climatic diversity of the Upper Basin is due to the movements of northern Intertropical Convergence Zone (ITCZ) that separates the harmattan (tropical dry air) and monsoon (equatorial wet air).

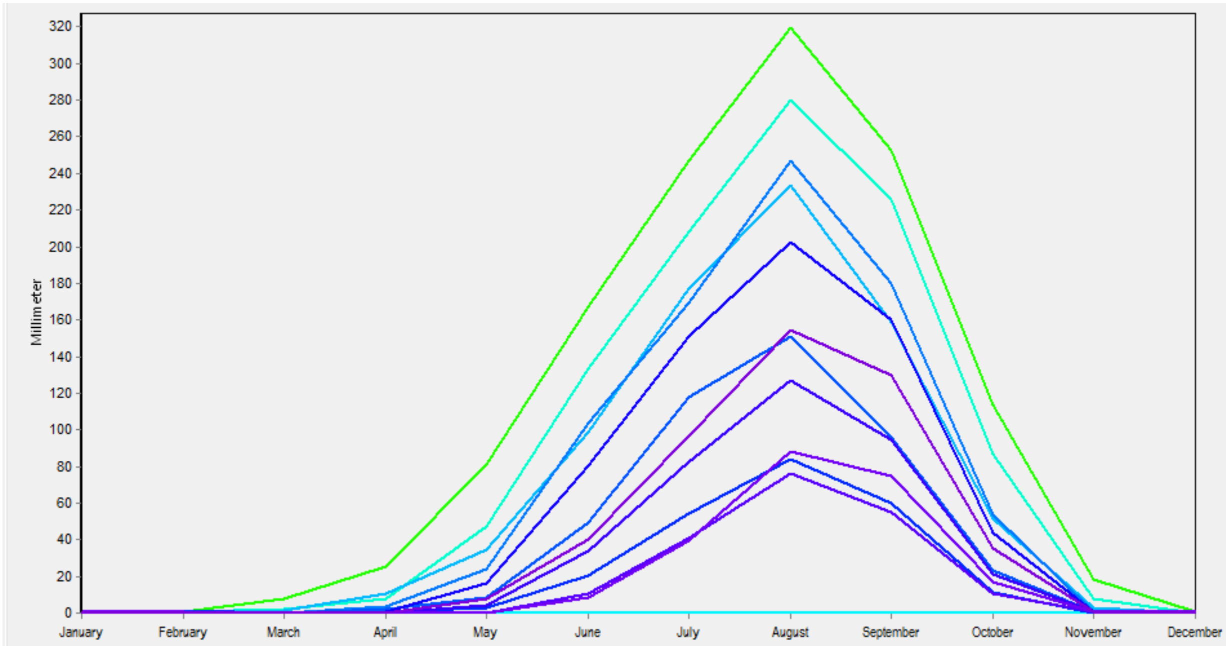
Figure C-83: Average rainfall in the basin of the River Senegal: example of Senegalese part of the basin (1960-1990) (From Rasmussen et al, 1999)



The headwaters of the basin are located in the south, in an area characterized by the dry tropical climate, with large amount of rainfall where temperatures and the rate of evaporation are lower. In this region the tropical mountain climate (said foutanien) dominates in the higher area of Guinea (Fouta Djallon). The central, semiarid Sahelian, experiences the lowest rainfall with a very high inter-annual variability. Coastal areas experience warmer and wetter conditions, but with less rainfall and more regular rainfall regime. The Senegal River Delta, because of the oceanic influence, benefits from Northwest trade winds whose moisture softens the climate. The Senegal River Basin is generally characterized by two seasons in the year: a rainy season centered on the summer (July-October) and the dry season centered on the winter-spring (November to June).

The figure below shows the distribution of rainfall in the Senegal basin. In general, we see the decreasing trend in precipitation as we move north from the Bafing River located in Guinea, where the monthly rainfall is highest and the rainy season is the longest (about 8 months of rain). Rainfall is highest during the month of August across the basin and decreases very quickly as soon as we move from Guinea into Senegal and Mali. Rainfall of the Senegal River valley is characterized by low rainfall, irregular (intra and inter) spread over a short period (2-3 months) between late June and late September. Overall, the amount and number of rainy days decreases from south to north. They are of the order of 1600 mm / year to 2000 mm / year in the Upper Basin, 500 to 600 mm / year in the Upper Valley, 300 to 400 mm / year in the Valley average, 200 to 300 mm / year in the Lower Valley and the Delta.

Figure C-84: Distribution of precipitation in the Senegal River basin.



The current and future development plans for hydropower and irrigation in the basin are available in Appendix A of this document.

WEAP Schematization

Catchment definitions

The Senegal River Basin was divided according to the location of the existing and project structures and points of confluence of major tributaries. This was made possible by a comparison of the areas indicated in the hydraccess base (OMVS) with those obtained by the exploitation of DTM (Digital Terrain Model). *Source Dacosta H. & Coly A. Tropis DHI, 2007*.

Given the different results obtained from various sources to characterize the Senegal River, it was recommended by OMVS to keep official figures defined in the monograph of 1974. The proposed division is shown in the Figure C-85 and summarized in Table C-38.

Timeseries of historical and projected climate (i.e. monthly precipitation [mm], average temperature[C], minimum temperature[C], and maximum temperature[C]) were developed for each sub-basin shown in Figure C-85. These data were used to as drivers for the routines that estimate the hydrological response (i.e. rainfall-runoff and baseflow) and potential evapotranspiration for each sub-catchment.

Figure C-85: Senegal River sub-catchments

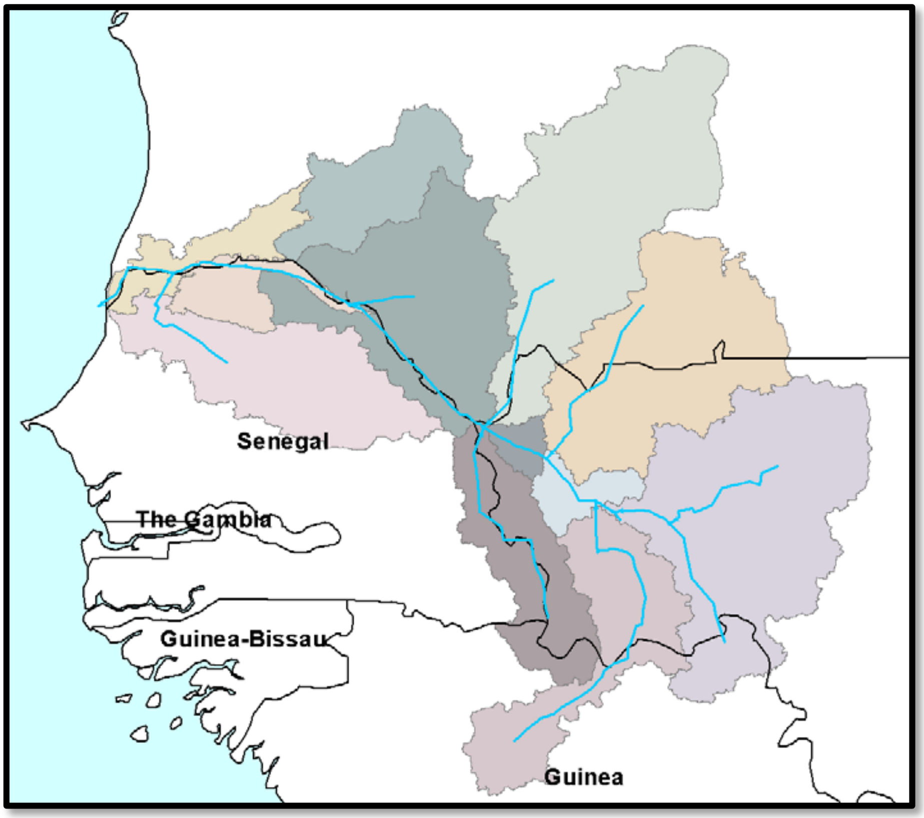


Table C-38: Summary of Senegal River sub-catchments

Sub-Basin	Catchment	Area (km²)	Range of Precipitation (mm)	Range of Temperature (°C)	Potential Evaporation (mm)
Bafing	SB_01	1,710	0-450	15-37	186
	SB_02	8,890	0-450	15-37	186
	SB_03	4,150	0-450	15-37	186
	SB_04	1,450	0-450	15-37	186
	SB_05	11,600	0-450	15-37	186
	SB_06	10,600	0-450	15-37	186
Falémé	SB_07	7,400	0-400	15-40	315
	SB_08	9,700	0-400	15-40	315

	SB_09	11,800	0-400	15-40	315
Baoulé	SB_10	58,800	0-350	14-40	263
	SB_11	700	0-350	14-40	263
Bakoye	SB_12	15,600	0-350	14-40	210
	SB_13	700	0-350	14-40	210
	SB_14	10,000	0-350	14-40	210
	SB_15	500	0-350	14-40	210
Senegal Upstream	SB_16	2,300	0-350	14-40	212
	SB_17	4,000	0-350	14-40	212
	SB_18	26,000	0-200	12-44	212
	SB_19	30,000	0-180	12-44	212
Senegal downstream	SB_20	1,700	0-280	12-44	210
	SB_21	12,000	0-220	12-44	210
	SB_22	36,000	0-150	12-44	210
	SB_23	2,000	0-200	12-44	210
	SB_24	-	-	-	210
	SB_25	-	-	-	210
	SB_26	-	-	-	210
	SB_27	-	-	-	210
Ferlo / Guiers	SB_28	40,808	0-250	14-40	208

Irrigation

Irrigation water demands are a function of the irrigated area, crop coefficient, rainfall deficit and irrigation efficiency. Crop coefficients for the main crop types grown within the irrigation schemes are presented below in Table 6. These data are based on previous estimates of irrigation development within the basin (OMVS, 2013) and an assessment of irrigation practices (de Condappa, 2013). These studies estimated that irrigation efficiency across the basin range between 0.4 and 0.6. These estimates, however, contain a high degree of variability and uncertainty. Thus, for the purposes of this study, we used an estimate of 0.5.

Table C-39: Crop coefficients, Kc, values used for irrigated crops in the Senegal River Model

Crop	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
Sugar Cane	1.25	1.24	1.13	0.96	0.8	0.4	0.8	1.04	1.25	1.25	1.25	1.25
Off-Season Corn	1.2	1.2	1.2	0.41	0	0	0	0	0	0	0	0.62
Wet Season Corn	0	0	0	0	0	0	0.62	1.2	1.2	1.2	0.41	0
Market Garden	1.15	1.15	1.09	0.8	0.8	0	0	0	0	0	0.6	1.15
Polyculture (i.e. Mixed Farming)	1.15	1.15	1.09	0.8	0.8	0	0	0	0	0	0.6	1.15
Off-Season Rice	0	0	0.69	0.34	0.80	1.05	0.96	0	0	0	0	0
Wet Season Rice	0	0	0	0	0	0	1.2	1.06	1.15	1.2	1.18	0

Water allocation

The demand priority in WEAP defines how water is allocated to satisfy competing uses – i.e. reservoir storage, hydropower generation, irrigation, domestic use, and flow. WEAP offers demand priorities ranging in number from 0-99, where the lower numbers indicate higher a priority for water use.

The demand priorities used in the Senegal River are listed in Table C-40. These are generally set such that domestic water use has the highest priority, followed by environmental flow requirements as the second priority, irrigated agriculture as the third priority, hydropower generation as the fourth priority, and reservoir storage as the lowest priority. The priority structure also reflects the realities of water usage and the regional management of water within the basin. That is, water users that are high in the basin will tend to use the water that is available to them independent of water usage elsewhere in the basin. This implies that water users that are quite low in the basin will have a lower demand priority such that they don't compete for the same water as users far upstream nor actively draw water from reservoirs at the headwaters.

Table C-40: Allocation priority structure for Senegal River WEAP model

Subbasin	River	Node	WEAP Object	WEAP PRIORITY			
				Storage	Hydropower	Demand	Flow Requirement
Bafing	Bafing	Balassa	Run-of-River		4		
	Bafing	Koukoutamba	Reservoir	5	4		
	Bafing	Guinea Irrigation	Irrigated Catchment			2	
	Bafing	Boureya	Reservoir	5	4		
	Bafing	Bafing Guinea Domestic	Demand			1	
	Bafing	Bafing Mali Domestic	Demand			1	
	Bafing	Manantali	Reservoir	5	4		
	Bafing	PDIAM Irrigation	Irrigated Catchment			6	
	Bafing	EFR	Flow Requirement				3
Falémé	Falémé	Moussala	Reservoir	5	4		
	Falémé	Gourbassi	Reservoir	5	4		
	Falémé	Gourbassi EFR	Flow Requirement				2
	Falémé	Faleme Domestic	Demand			1	
Bakoye	Bakoye	Bakoye Domestic	Demand			1	
	Bakoye	EFR	Flow Requirement				2

Senegal Upstream	Senegal	Gouina	Run-of-River		5		
	Senegal	Felou	Run-of-River		5		
	Kolinbine	Kolinbine Domestic	Demand			1	
	Senegal	Kayes Domestic	Demand			1	
	Senegal	Kayes-Bakel Mali Irrigation	Irrigated Catchment			6	
	Karakoro	Karakoro Domestic	Demand			1	
	Senegal	Kayes-Bakel SenegalMauritania Irrigation	Irrigated Catchment			6	
Senegal Downstream	Senegal	Controlled Flooding	Flow Requirement			1	
	Senegal	Bakel EFR	Flow Requirement			1	
	Senegal	Bakel-Matam Irrigation	Irrigated Catchment			6	
	Senegal	Matam Domestic	Demand			1	
	Senegal	Matam-Podor Irrigation	Irrigated Catchment			6	
	Senegal	Reach Delay	Reservoir	20			
	Senegal	Reach Delay outflow	Flow Requirement				19
	Senegal	Podor-Dagana Irrigation	Irrigated Catchment			26	
	Senegal	Podor Domestic	Demand			21	
	Senegal	Dagana-Richard Toll Irrigation	Irrigated Catchment			26	
	Senegal	Richard Toll Irrigation	Irrigated Catchment			26	

	Senegal	Diama Domestic	Demand			1	
	Senegal	Diama	Reservoir	90			
	Senegal	Aval Diama Irrigation	Irrigated Catchment			21	
	Senegal	Diama Release	Flow Requirement				
Ferlo/Guiers	Ferlo	Ferlo Domestic	Demand			1	
	Ferlo	Lac de Guiers	Reservoir			99	
Out of Basin	N/A	Dakar	Demand			18	

Model Calibration

Flow Simulation

The Senegal water resources management and in particular Manantali and Diama infrastructures is made on the basis of information collected at hydrometrics stations. These stream gages are chosen, because of their data available and their strategic position on the river. Hydrometric stations considered in the study are the following:

Table C-41: Streamflow calibration points for Senegal River basin.

Stream gages	Upstream Area (km²)	Data available	Latitude	Longitude
Bakel	218,000	1949-1965	14°54'	12°27'
Dagana	268,000	1950-1965	16°31'	15°30'
Dakka_Saidou	15,700	1952-1965	11°57'	10°37'
Dibia	33,500	1951-1965	13°14'	10°48'
Fadougou	9,300	1966-1989	12°31'	11°23'
Kidira	28,900	1946-1963	14°27'	12°13'
Matam	230,000	1949-1965	15°39'	13°15'
Ouila	84,700	1951-1965	13°36'	10°23'
Toukoto	16,500	1952-1965	13°27'	9°53'
Kayes	157,400	1949-1965	14°27'	11°27'
Makana	22,000	Module	12°27'	10°17'
Gourbassi	17,100	Module (1957-1963)	13°24'	11°38'

Source: Hydrologic Monograph ORSTOM N°1

The WEAP model was calibrated to each of these stations over their periods of record overlapping the model calibration period, 1960-1999. Results of the WEAP calibration at each station are summarized in Table C-42. Calibration parameter values are presented in Table C-43.

In general, simulated flows agree well with the historical time series and produce NSE values that give us confidence in monthly flow simulations for all calibration stations. Additionally, the overall mass balance of flows is comparable to the historical flows. That is, the model reproduces the total annual discharge, seasonal flows patterns, and variation in flow (i.e. flow duration) with an acceptable degree of performance. These results are highlighted in Figure C-87 to Figure C-98.

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Figure C-86: Location of main control stations in Senegal River basin used for model calibration

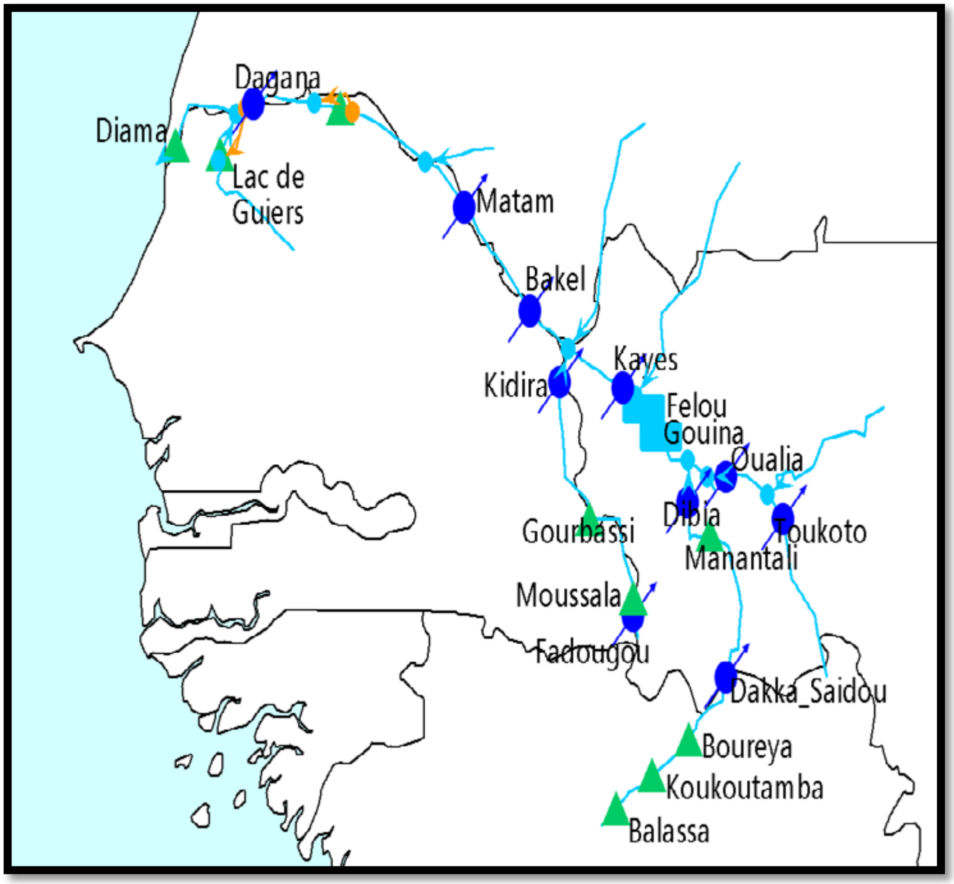


Table C-42: Calibration statistics for main flow gages

River	Location	Country	NSE	Bias	SDR	RMSE
Bafing	Dakka-Saidu	Guinea-Mali Border	0.77	-1%	0.94	424
Bafing	Manantali	Mali	0.89	3%	0.98	384
Bafing	Dibia	Mali	0.88	-2%	0.85	457
Bakoye	Toukoto	Mali	0.84	1%	0.80	136
Bakoye	Oualia	Mali	0.79	0%	0.74	322
Faleme	Gourbassi	Mali	0.64	1%	0.78	380
Faleme	Kidira	Mali	0.79	0%	0.76	410
Senegal	Gouina	Mali	0.89	-5%	0.77	732
Senegal	Kayes	Mali	0.90	-2%	0.79	678
Senegal	Bakel	Senegal	0.88	-1%	0.78	1049
Senegal	Matam	Senegal	0.88	1%	0.85	1168
Senegal	Dagana	Senegal	0.68	-3%	0.96	1244

Table C-43: Calibration parameter values for Senegal River catchments

Basin	Sub-basin	DWC (mm)	DC (mm)	SWC (mm)	PFD	RZC (mm)	RRF
Bafing	SB_01	500	19.85	1000	1.00	105	3
	SB_02	500	19.85	1000	1.00	105	3
	SB_03	500	19.85	1000	1.00	105	3
	SB_04	500	19.85	1000	1.00	105	3
	SB_05	500	19.85	1000	1.00	50	5
	SB_06	500	19.85	1000	1.00	50	5
Falémé	SB_07	1000	1	800	1.00	20	4
	SB_08	1000	20	1000	0.05	20	10
	SB_09	1000	20	600	0.15	20	5
Baoulé	SB_10	1000	20	1000	1.00	55	5
	SB_11	1000	20	1000	1.00	55	5
Bakoye	SB_12	1000	20	1000	0.98	90	3
	SB_13	1000	20	1000	0.98	90	3
	SB_14	1000	20	1000	0.98	90	3
	SB_15	1000	20	1000	0.98	90	3
Senegal Upstream	SB_16	1000	20	500	0.80	20	2
	SB_17	1000	20	1000	0.15	20	2
	SB_18	1000	20	1000	0.15	20	2
	SB_19	1000	20	1000	0.15	20	2
Senegal downstream	SB_20	1000	20	1000	0.15	20	2
	SB_21	1000	20	1000	0.15	20	2
	SB_22	1000	20	1000	0.15	20	2
	SB_23	1000	20	1000	0.15	20	2
Ferlo / Guiers	SB_28	1000	20	1000	0.15	20	2

Figure C-87: Simulated and observed Bafing River flow at Dakka-Saidu (Guinea-Mali Border)

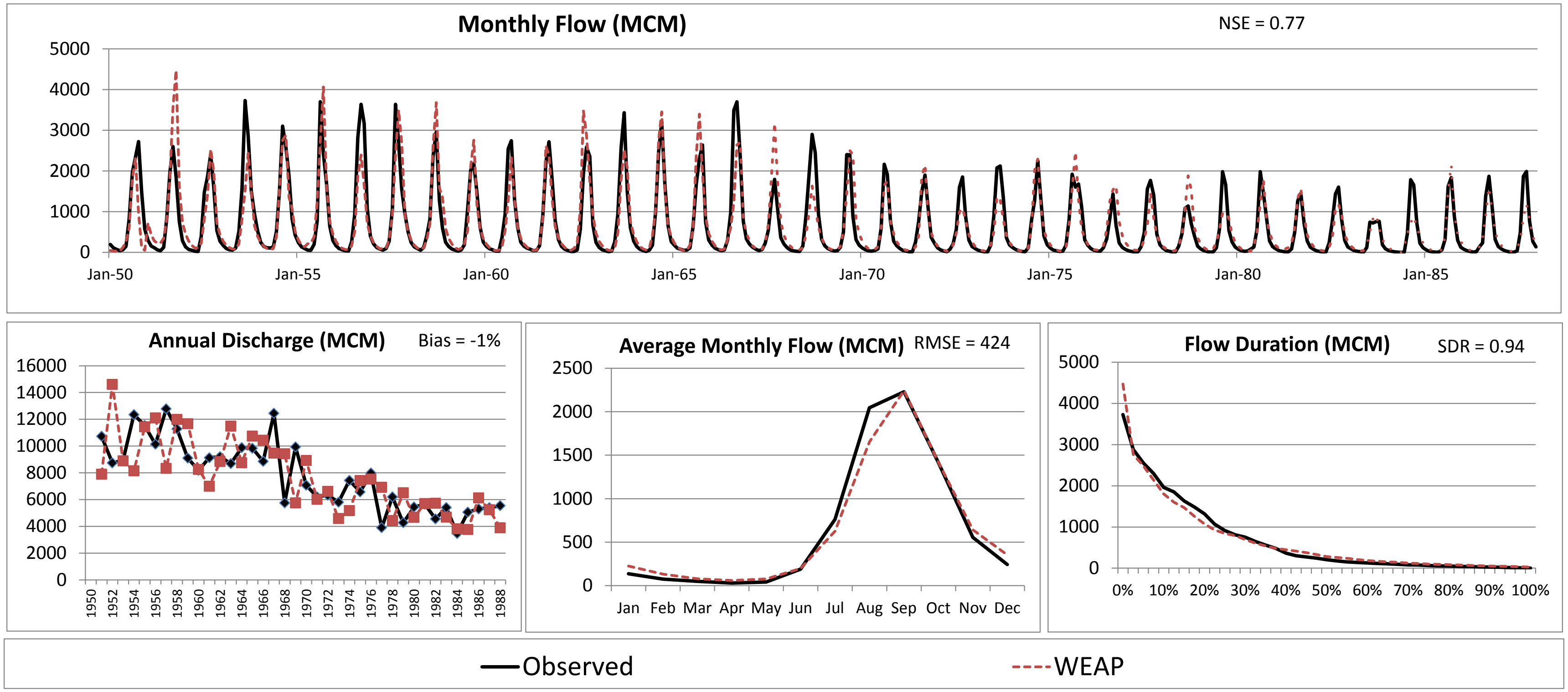


Figure C-88: Simulated and observed Bafing River flow below Manatali dam (Mali)

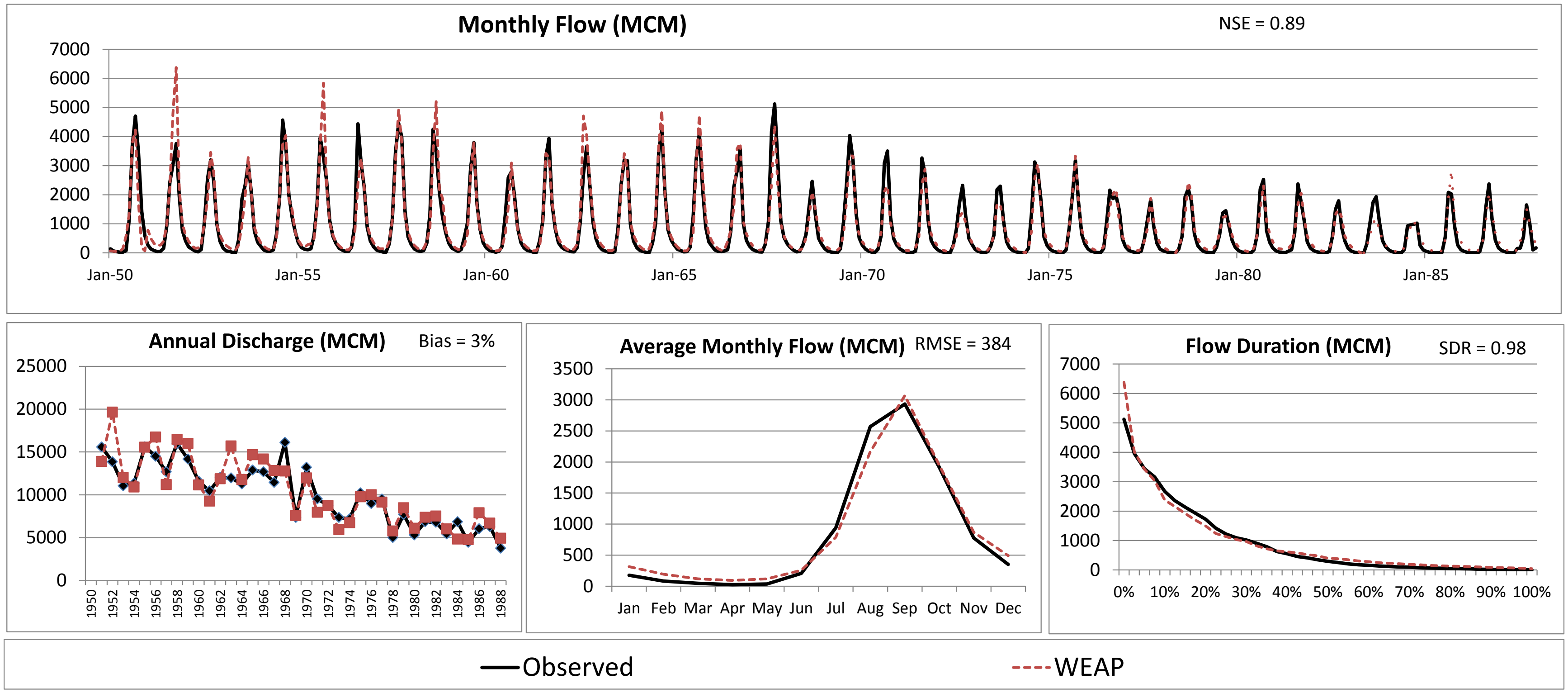


Figure C-89: Simulated and observed Bafin River flow at Dibia, Mali

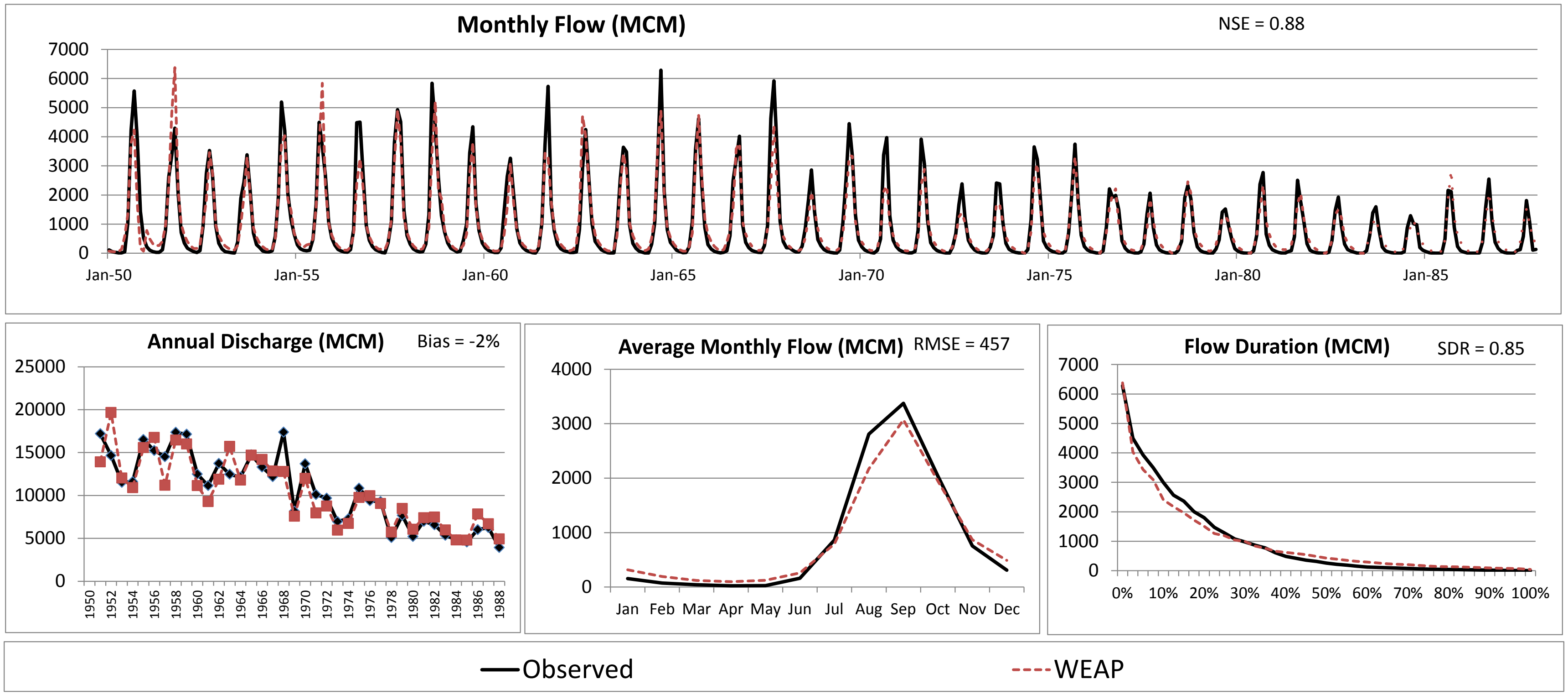


Figure C-90: Simulated and observed Bakoye River flows at Toukoto, Mali

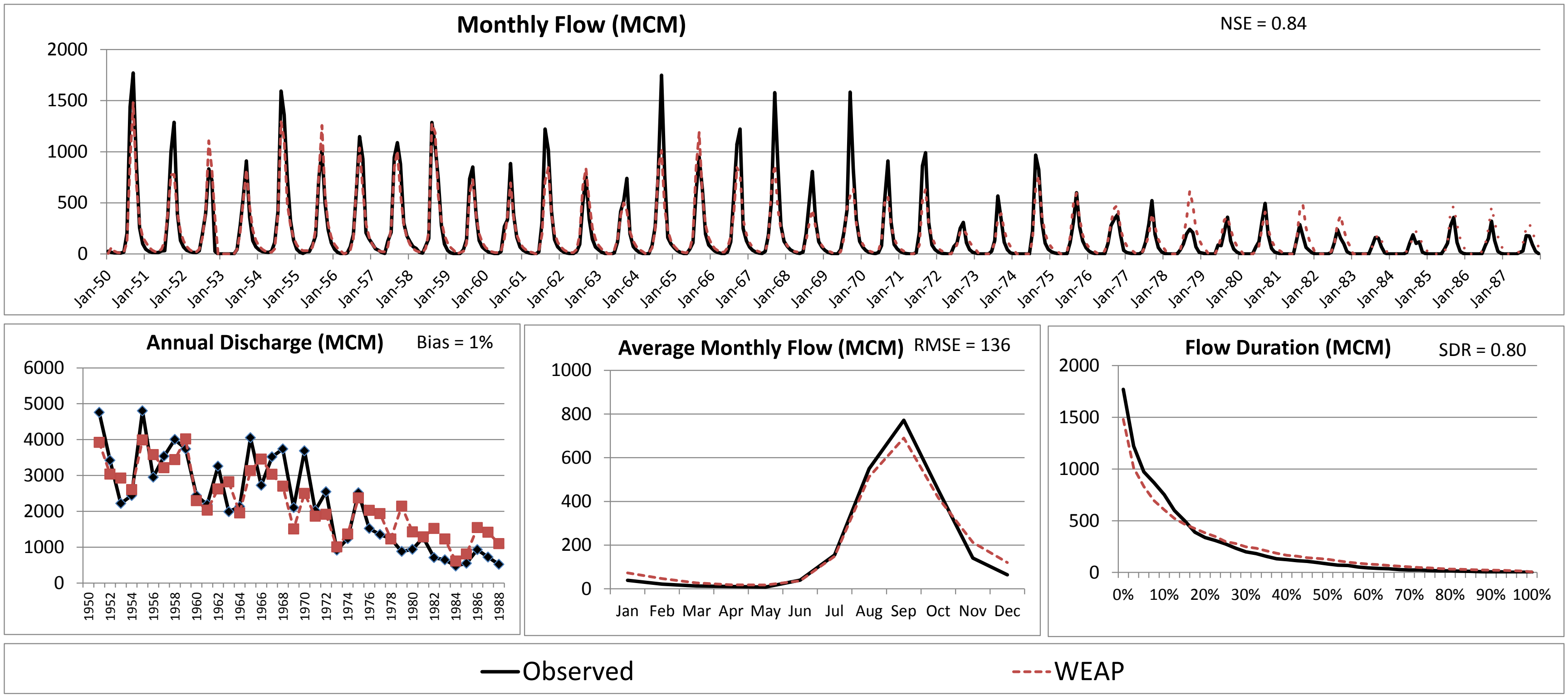


Figure C-91: Simulated and Observed Bakoye River flows at Oualia, Mali

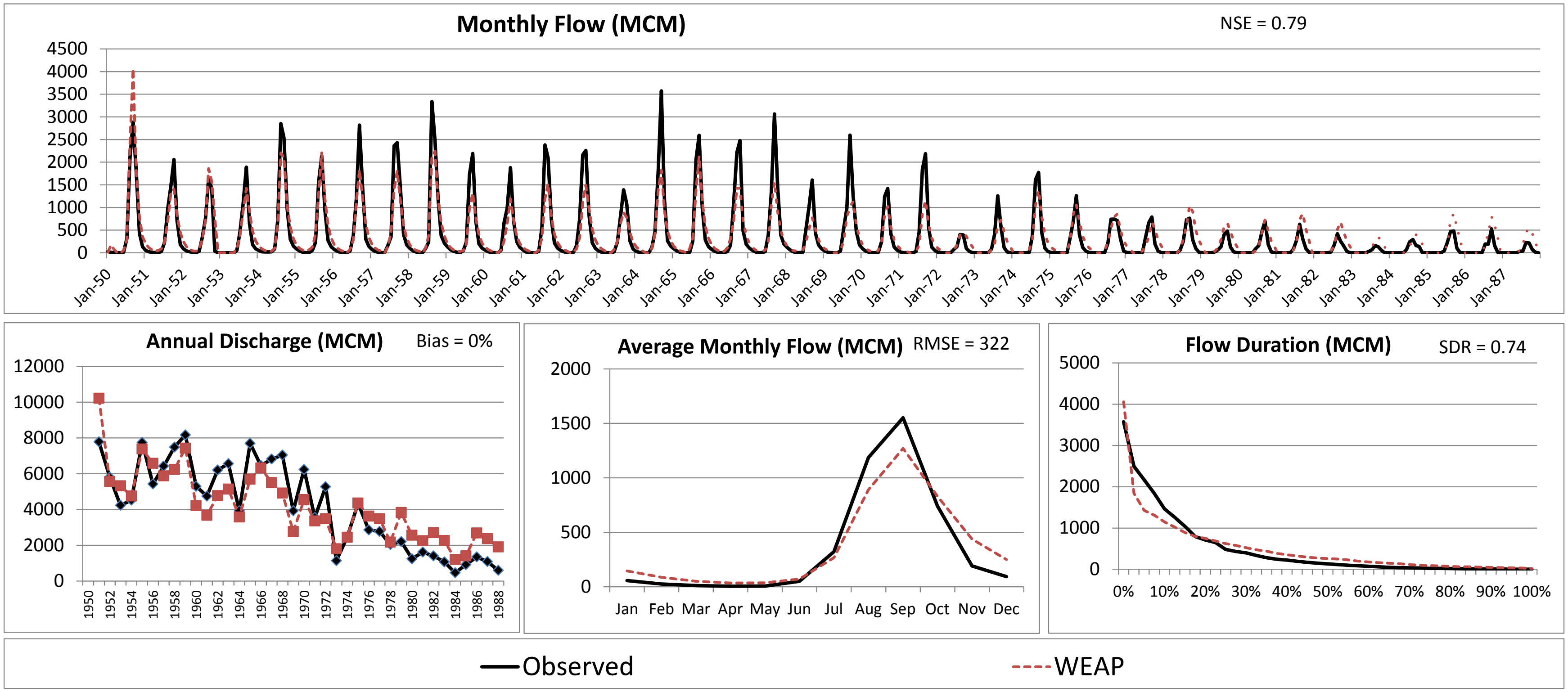


Figure C-92: Simulated and observed Faleme River flows at Gourbassi, Mali

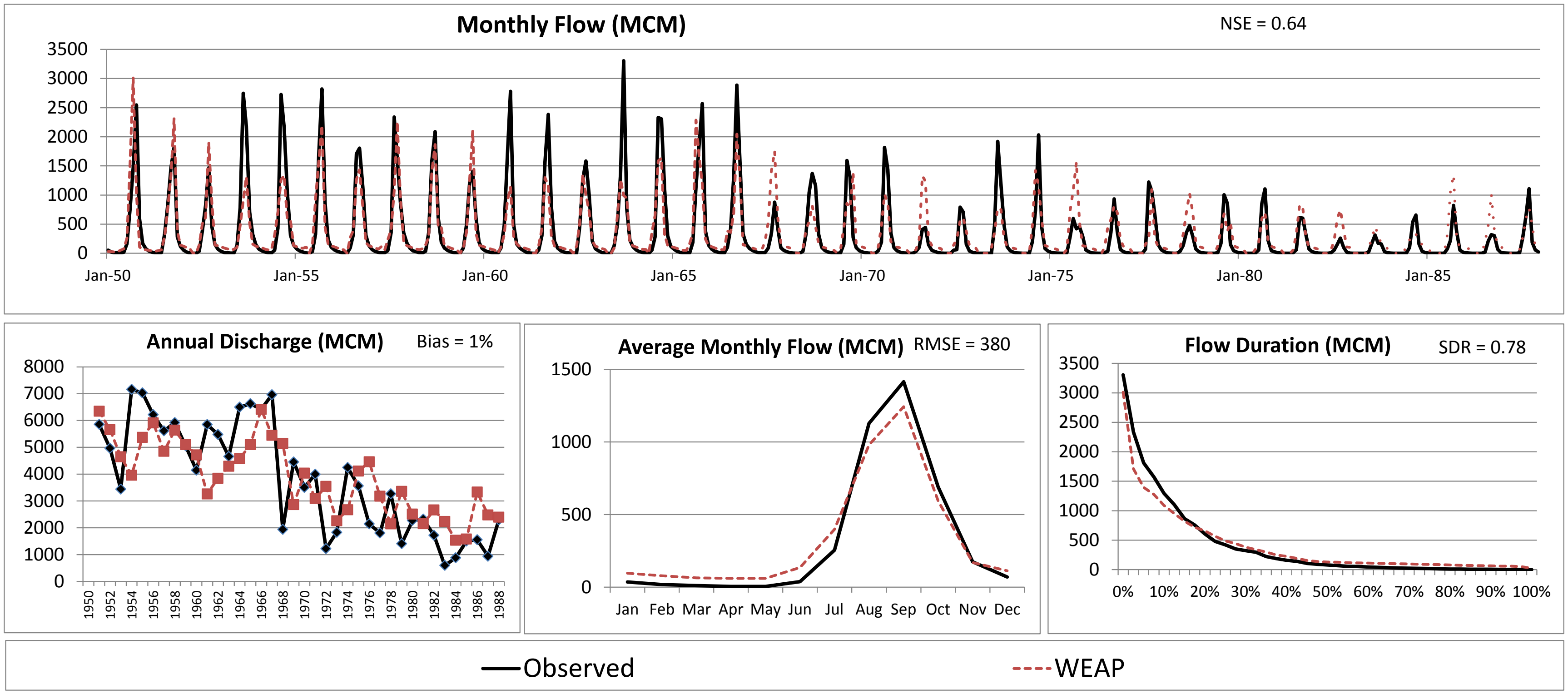


Figure C-93: Simulated and observed Faleme River flows at Kidira, Mali

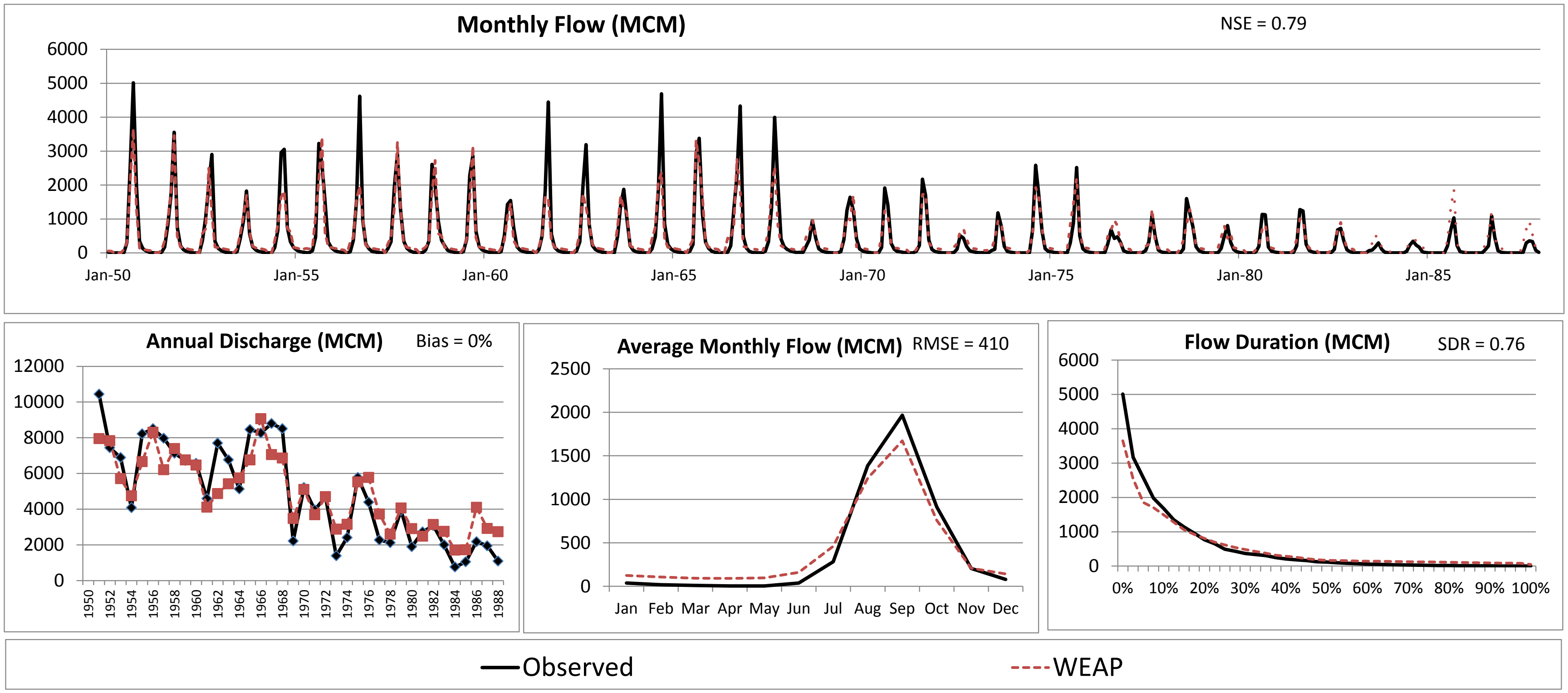


Figure C-94: Simulated and observed Senegal River flows at Gouina, Mali

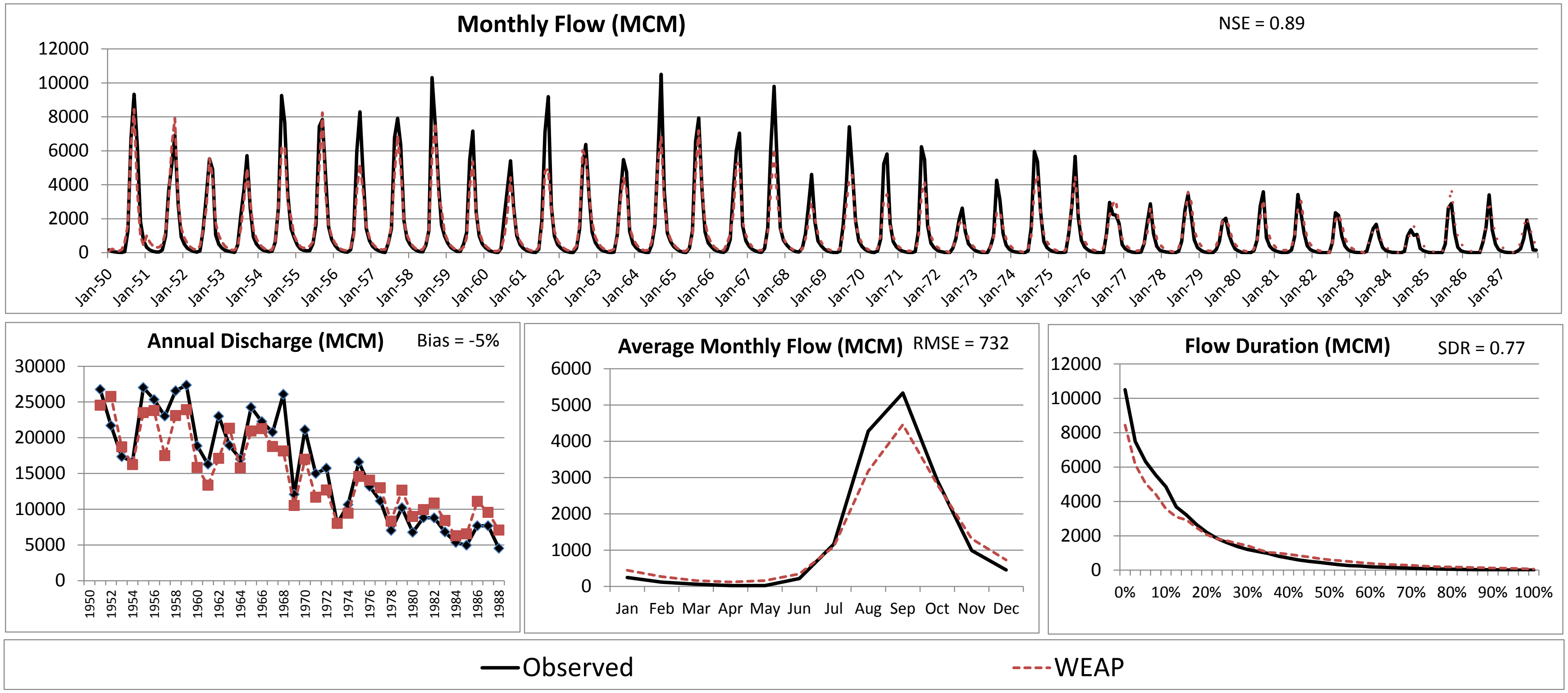


Figure C-95: Simulated and observed Senegal River flows at Kayes, Mali

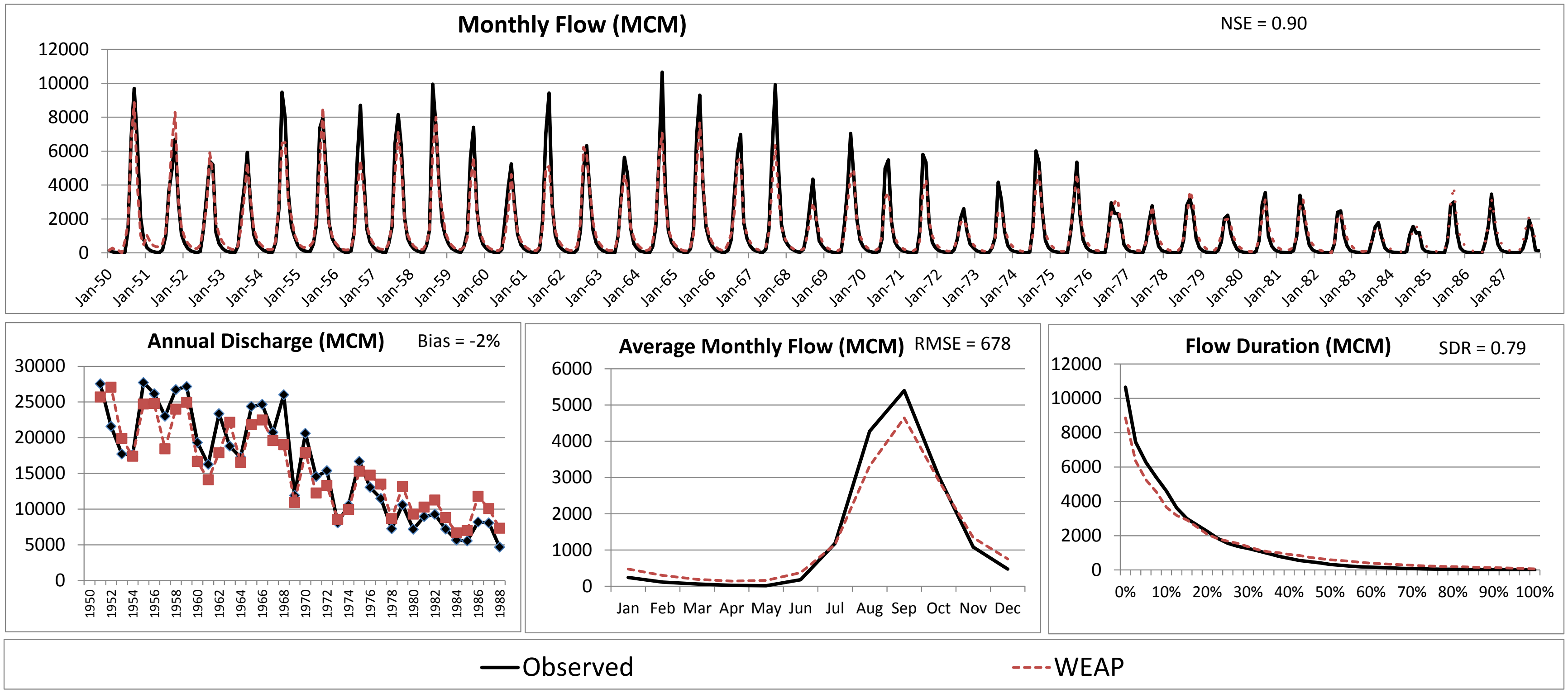


Figure C-96: Simulated and observed Senegal River flows at Bakel, Senegal

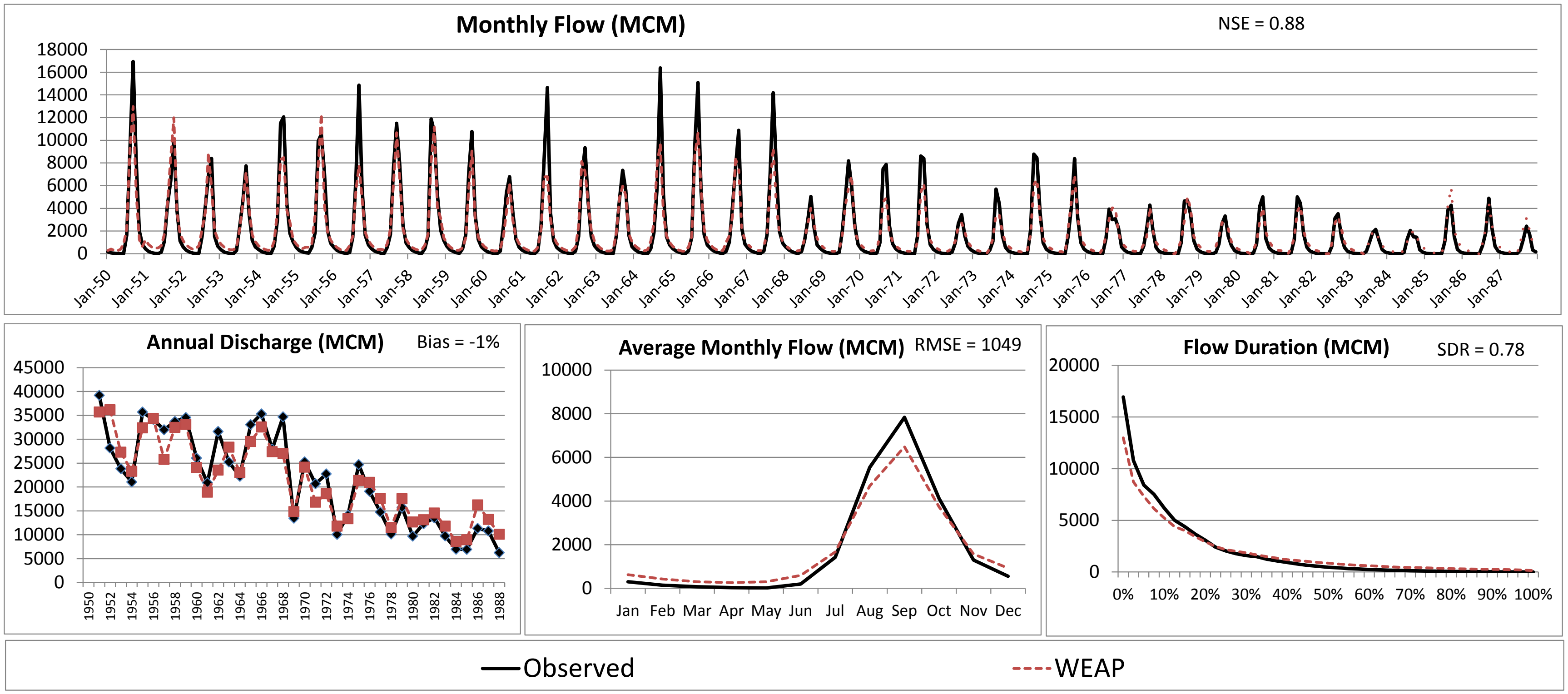


Figure C-97: Simulated and observed Senegal River flows at Matam, Senegal

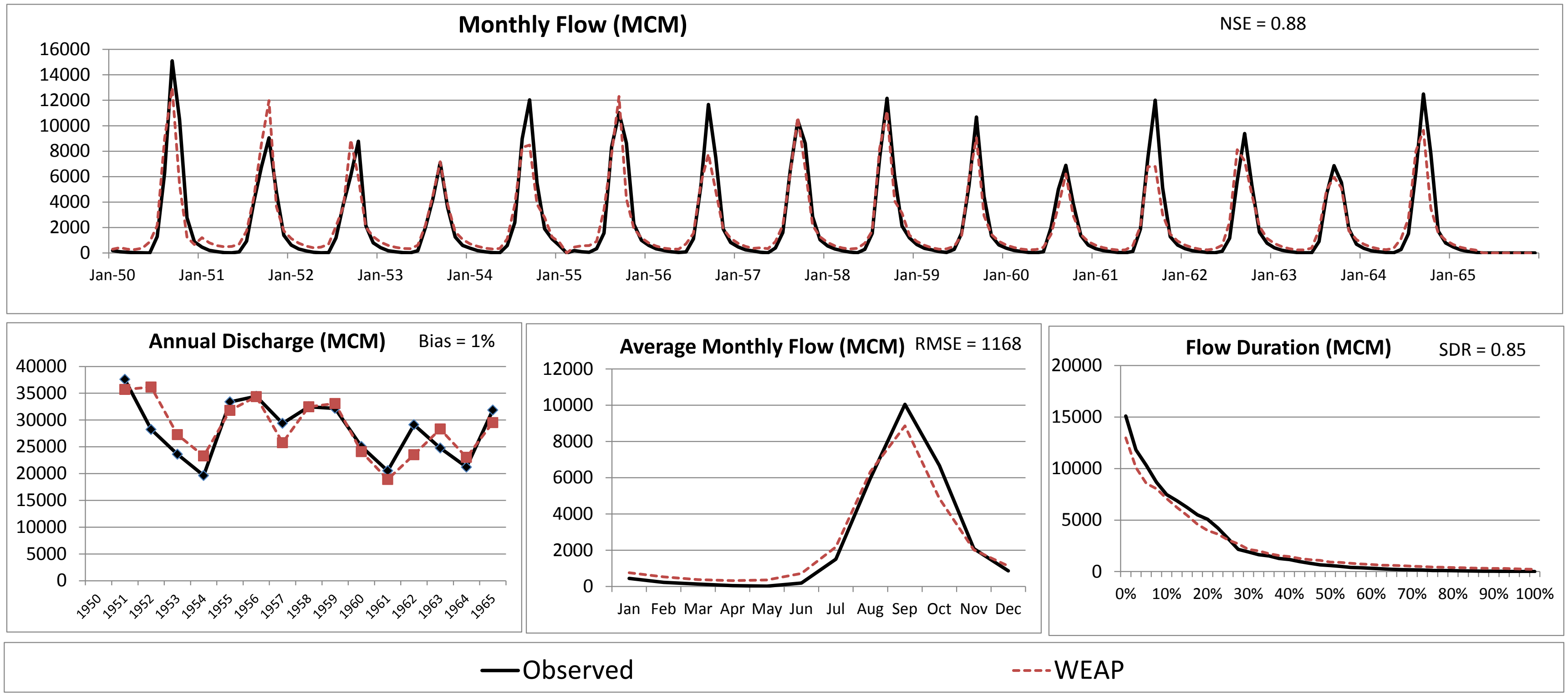
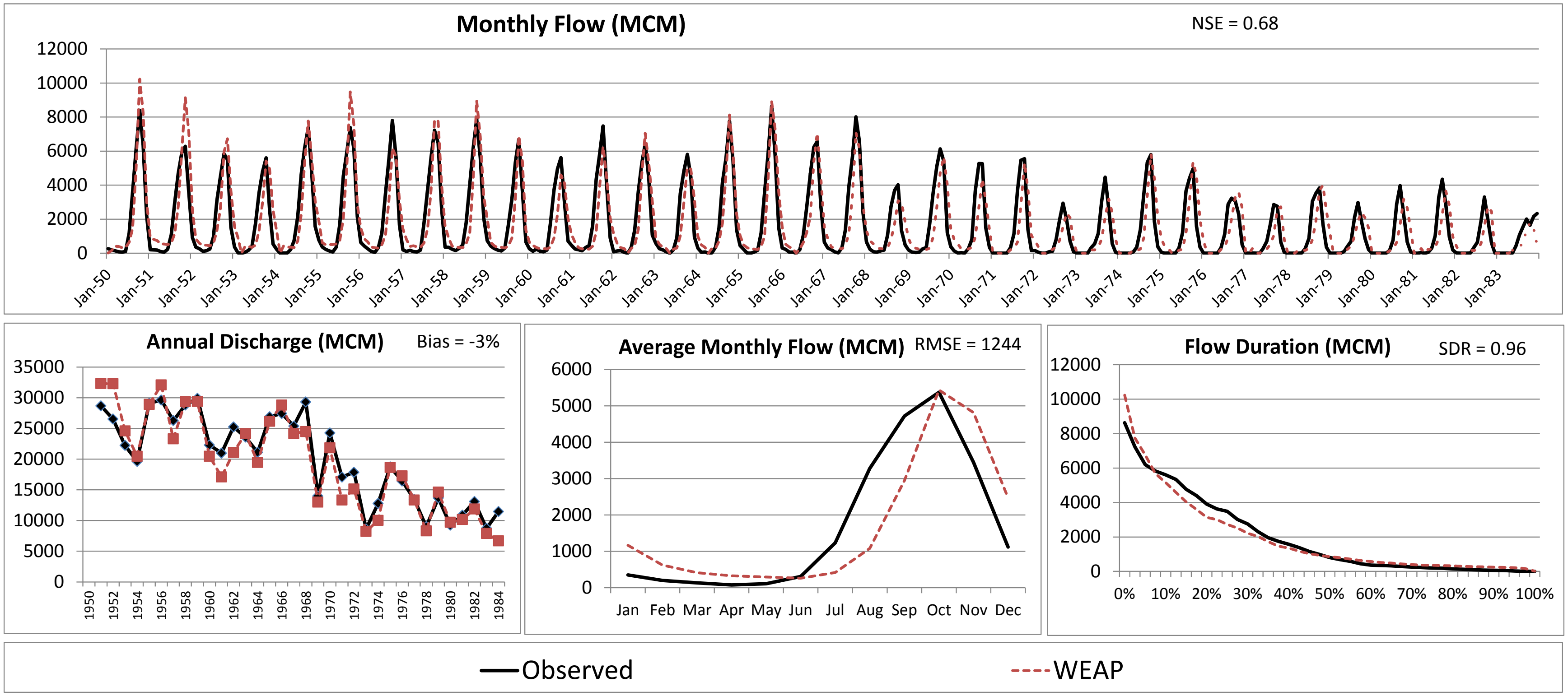


Figure C-98: Simulated and observed Senegal River flows at Dagana, Senegal

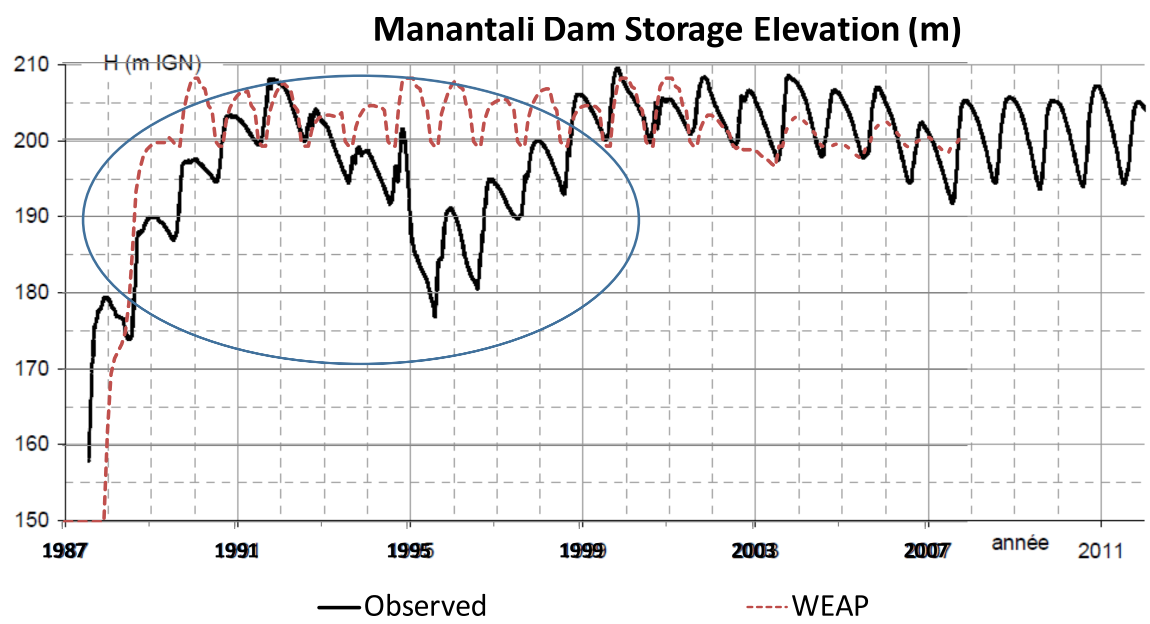


Water Resources Simulation

For the calibration of system operations, we focused on the simulated versus observed reservoir storage for the one reservoir with historical records sufficiently long to reflect a range of climatic and hydrologic conditions – i.e. Manatali Dam. Unfortunately, the operating rules for Manantali dam were continually evolving over the first several years after its construction and its operations sometime appear ad hoc due to discretionary actions that did not repeat with any regularity. This fluidity in operations makes it inherently difficult to calibrate a model with fixed operating rules. With this in mind, we found that the WEAP model was able to approximate the historical storage fluctuations over the period since dam operations have stabilized (i.e. since 2001).

We found that the simulated reservoir levels are sensitive to hydropower demands, which were inconsistent over the calibration period. In particular, it was noted that Manantali dam was completed in 1988, but did not start producing electricity until 2001.

Figure C-99: **Timeline of Manantali Dam Storage Elevation**



Reference

OMVS (2009). SDAGE du fleuve Sénégal. Phase 1: Etat des lieux et diagnostic du fleuve Sénégal. Organisation pour la Mise en Valeur du Fleuve Sénégal (OMVS).

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C7- Volta River Basin

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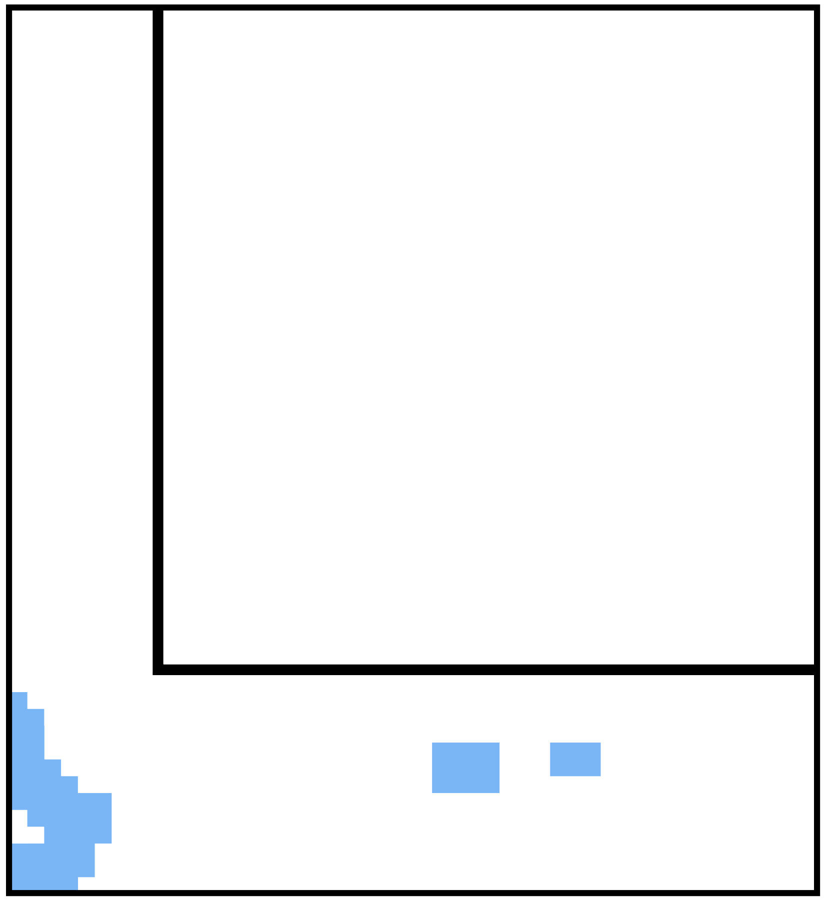
Figure C-100: Volta River Basin, West Africa



Description of the Basin

The Volta River basin, located in western Africa, covers a total area of about 394,196 km^2 and spreads over six riparian countries namely: Benin, Burkina Faso, Cote d'Ivoire, Ghana, Mali, and Togo. It covers about 1.3% of the African continental landmass.

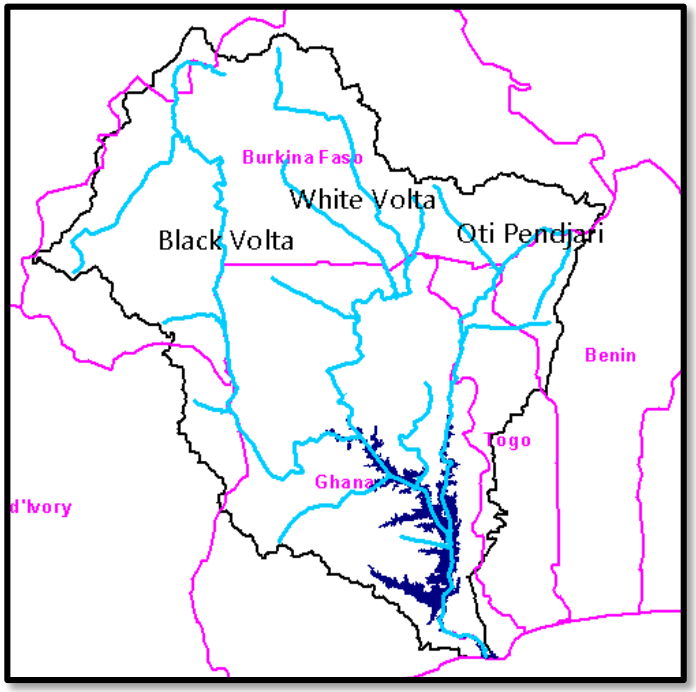
Table C-44: Volta River basin areas by country

Country	Area within Basin (km^2)	Percentage of Basin area (%)	Percentage of Country within the Basin (%)
Benin	16,000	4.1	14.2
Burkina Faso	183,000	46.4	66.8
Côte d'Ivoire	7,000	1.8	2.2
Ghana	152,000	38.6	63.7
Mali	9,496	2.4	0.8
Togo	26,700	638.0	47.0
Total	394,196	100.0	

The Volta River has three main tributaries – The Black Volta (or Mouhoun), the White Volta (or Nakambe), and the Oti/Pendjari, which combine to flow into Lake Volta in southern Ghana. The Black Volta originates in the southwest of Burkina Faso and flows south into Ghana and contributes about 23 percent of the annual flow into Lake Volta. The White Volta originates in the north of Burkina Faso and flows south into Ghana, where it joins with the Red Volta. The Red and White Volta together contribute an additional 23 percent of the annual flow into Lake Volta. The Pendjari River originates in Benin and flows through northern Togo where it becomes known as the Oti River. It then flows south into Ghana and contributes between 35 and 40 percent of the annual flow into Lake Volta. Lake Volta was created after the construction of Akosombo dam in the early 1960's and is considered the largest reservoir by surface area in the world and the fourth largest by water volume. It discharges an estimated 38,000 Mm^3/year to the sea – much of which is used to generate hydropower.

The climate in the Volta River basin ranges from arid in the far north of Burkina Faso (mean precipitation <500mm/year), semi-arid in the middle part of Burkina Faso (about 700 mm/year) to sub-humid in southern Ghana (about 1600 mm/year).

Figure C-101 : Rivers in the Volta Basin



The current and future development plans for hydropower and irrigation in the basin are available in Appendix A.

WEAP Schematization

The German Ministry of Education and Research funded the GLOWA Volta project from 2001-2009, which produced a climate-driven, basin-level water planning tools using WEAP. This model contained all of the relevant features of the watershed to evaluate the current conditions. It also used WEAP's hydrologic routines to estimate watershed rainfall-runoff processes such that it could consider the impacts of climate change on the basin. It was subsequently modified by IWMI to include information about several planned hydropower and irrigation projects (McCartney et al, 2012). Thus, the WEAP model that was used as the starting point for the current project already provided an integrated hydrologic and water planning model. However, this model needed to be recalibrated to a new set of climate inputs that were developed for this study.

Catchment definitions

Timeseries of historical and projected climate (i.e. monthly precipitation [mm], average temperature[C], minimum temperature[C], and maximum temperature[C]) were developed for each sub-basin shown in Figure C-103. These data were used to as drivers for the routines that estimate the hydrological response (i.e. rainfall-runoff and baseflow) and potential evapotranspiration for each sub-catchment.

Figure C-102: Simplified schematic of Volta River system

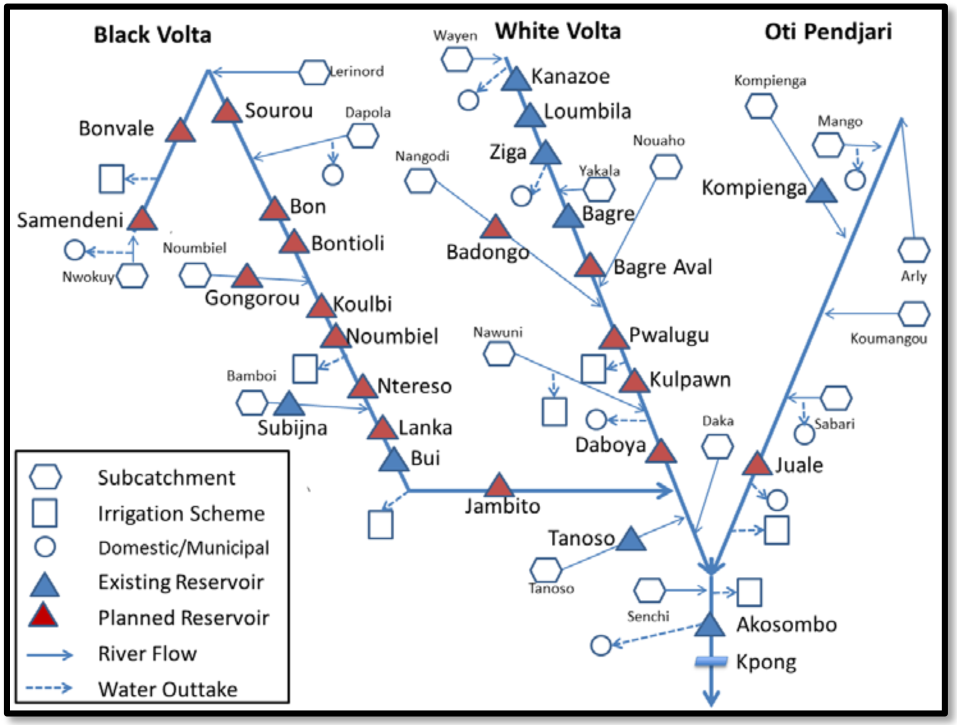


Figure C-103: Volta River sub-catchments

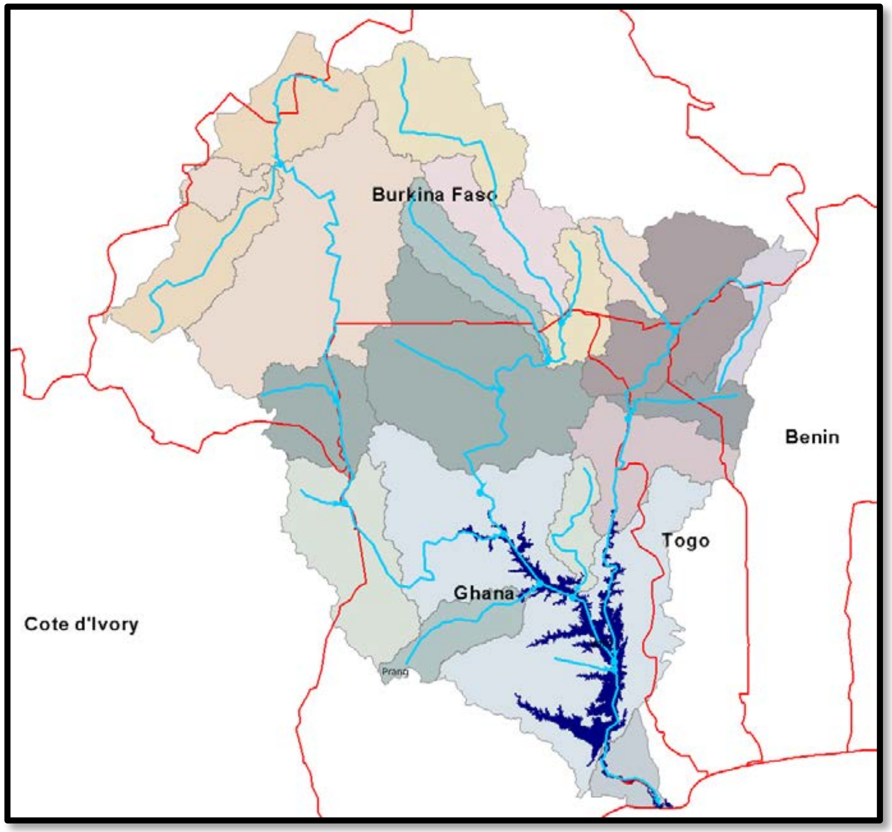


Table C-45: Summary of catchments

Sub-Basin	Catchment	Area (km^2)	Percent of basin Area	Average Annual Rainfall (mm)
Black Volta	Nwokuy	16,126	4.2%	961

	Lerinord	16,163	4.3%	678
	Dapola	55,368	7.4%	895
	Prang	9,193	1.3%	1224
	Noumbiel	14,268	2.1%	1043
	Bamboi	23,739	3.5%	1132
White Volta	Wayen	20,045	7.9%	697
	Yakala	15,408	2.5%	871
	Nangodi	11,205	1.8%	936
	Pwalugu	8,988	1.5%	1001
	Nawuni	43,146	7.3%	1033
Oti/Pendjari	Arly	6,818	1.2%	972
	Kompienga	5,772	1.1%	903
	Mango	27,533	5.1%	971
	Koumangou	7,542	1.5%	1154
	Sabari	16,169	3.2%	1201
Lower Volta	Ekumdipe	6,350	1.2%	1203
	Senchi	84,229	17.6%	1210

Irrigation

Irrigation water demands are a function of the irrigated area, crop coefficient, rainfall deficit and irrigation efficiency. Crop coefficients for the irrigated areas described in Table C-45 are presented below in Table C-46 . These data are based on previous estimates of irrigation development within the basin (McCartney et al, 2012) and an assessment of irrigation practices (de Condappa, 2013). These studies estimated that irrigation efficiency across the basin range between 0.4 and 0.6. These estimates, however, contain a high degree of variability and uncertainty. Thus, for the purposes of this study, we used an estimate of 0.5.

Table C-46: Crop coefficient, Kc, values for irrigated crops in Volta River WEAP model

Crop	Climwat Station	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Cowpea	Akuse	0	0	0	0	0	0	0	0	0	0	0	0
	Navrango	0	0	0	0	0	0	0	0	0	0	0	0
	Ouahigouya	0	0	0	0	0	0	0	0	0	0	0	0
	Tamale	1	1.14	0.73	0	0	0	0	0	0	0	0	0.45
	Wenchie	0	0	0	0	0	0	0	0.45	0.96	1.09	0.65	0
Maize	Akuse	0	0	0	0	0	0	0	0	0	0	0	0
	Navrango	0	0	0	0	0	0	0	0	0	0	0	0
	Ouahigouya	0	0	0	0	0	0.3	0.59	1.13	1.07	0.55	0	0
	Tamale	0	0	0	0	0	0	0	0	0	0	0	0
	Wenchie	0	0	0.3	0.6	1.11	1.05	0.54	0	0	0	0	0
Monsoon Rice	Akuse	0	0	0	0	0	1.16	1.08	1.12	1.15	1.12	1.01	0
	Navrango	0	0	0	0	1.17	1.08	1.11	1.12	1.09	1	0	0
	Ouahigouya	0	0	0	0	1.17	1.08	1.11	1.16	1.16	1.09	1.03	0
	Tamale	0	0	0	0	1.17	1.08	1.11	1.13	1.1	1	0	0
	Wenchie	0	0	0	0	0	0	0	0	0	0	0	0
Okra	Akuse	0	0.72	0.94	1.01	0.94	0	0	0	0	0	0	0
	Navrango	0	0	0	0	0	0	0	0	0	0	0	0
	Ouahigouya	0	0	0	0	0	0	0	0	0	0	0	0
	Tamale	0	0	0	0	0	0	0	0	0	0	0	0
	Wenchie	0	0	0	0	0	0	0	0	0	0	0	0
Onion	Akuse	0	0	0	0	0	0	0	0	0	0	0	0
	Navrango	0	0	0	0	0	0	0	0	0	0	0	0
	Ouahigouya	0.5	0.64	0.93	0.99	0	0	0	0	0	0	0	0
	Tamale	0.79	0.98	0.94	0	0	0	0	0	0	0	0	0.52

	Wenchie	0	0	0	0	0	0	0	0	0	0	0	0
Soja Bean	Akuse	0	0	0	0	0	0	0	0	0	0	0	0
	Navrango	1.14	0.83	0	0	0	0	0	0	0	0	0	0.6
	Ouahigouya	0	0	0	0	0	0	0	0	0	0	0	0
	Tamale	0	0	0	0	0	0	0	0	0	0	0	0
	Wenchie	0	0	0	0	0	0	0	0	0	0	0	0
Tomato	Akuse	0	0	0	0	0	0	0	0	0	0	0	0
	Navrango	1.03	1.14	1.05	0.82	0	0	0	0	0	0	0.6	0.66
	Ouahigouya	0.83	1.15	1.13	0.88	0	0	0	0	0	0	0	0.6
	Tamale	1.02	1.13	1.04	0.81	0	0	0	0	0	0	0.6	0.66
	Wenchie	0.82	1.12	1.12	0.88	0	0	0	0	0	0	0	0.6
Winter Rice	Akuse	1.08	1.13	1.17	1.14	1.03	0	0	0	0	0	0	1.17
	Navrango	0	0	0	0	0	0	0	0	0	0	0	0
	Ouahigouya	1.11	1.19	1.21	1.13	0	0	0	0	0	0	0	1.11
	Tamale	0	0	0	0	0	0	0	0	0	0	0	0
	Wenchie	0	0	0	0	0	0	0	0	0	0	0	0

Water Allocation

The demand priority in WEAP defines how water is allocated to satisfy competing uses – i.e. reservoir storage, hydropower generation, irrigation, domestic use, and flow. WEAP offers demand priorities ranging in number from 0-99, where the lower numbers indicate higher a priority for water use.

The demand priorities used in the Volta River are listed in

Table C-47. These are generally set such that domestic water use has the highest priority, followed by environmental flow requirements as the second priority, irrigated agriculture as the third priority, hydropower generation as the fourth priority, and reservoir storage as the lowest priority. The priority structure also reflects the realities of water usage and the regional management of water within the basin. That is, water users that are high in the basin will tend to use the water that is available to them independent of water usage elsewhere in the basin. This implies that water users on the lower end of the basin will have a lower demand priority such that they do not compete for the same water as users far upstream nor actively draw water from reservoirs at the headwaters.

Table C-47: Allocation priority structure for Volta River WEAP model

Subbasin	River	Node	WEAP Object	WEAP PRIORITY			
				Storage	Hydropower	Demand	Flow Requirement
Black Volta	Sourou	Lerinord SR	Reservoir	2			
	Sourou	Lerinord Domestic	Demand			3	
	Black Volta Mouhoun	Nwokuy SR	Reservoir	2			
	Black Volta Mouhoun	Samendeni	Reservoir	7	6		
	Black Volta Mouhoun	Nwokuy Domestic	Demand			3	
	Black Volta Mouhoun	Samendeni Irrigation Project	Irrigated Catchment			5	
	Black Volta Mouhoun	Nwokuy Irrigation	Irrigated Catchment			5	
	Black Volta Mouhoun	Bonvale	Reservoir	9	8		
	Black Volta Mouhoun	Sourou Dam	Reservoir	10			
	Black Volta Mouhoun	Lerinord Sourou Irrigation	Irrigated Catchment			5	
	Black Volta Mouhoun	Dapola Domestic	Demand			6	
	Black Volta Mouhoun	Dapola River Irrigation	Irrigated Catchment			8	
	Black Volta Mouhoun	Bon	Reservoir	14	13		
	Black Volta Mouhoun	Bontioli	Reservoir	14	13		
	Noumbiel	Gongourou	Reservoir	14			
	Noumbiel	Noumbiel River Irrigation	Irrigated Catchment			12	

	Noumbiel	Noumbiel Domestic	Demand			10	
	Black Volta Mouhoun	Koulbi	Reservoir	14	13		
	Black Volta Mouhoun	Noumbiel	Reservoir	16	15		
	Black Volta Mouhoun	Noumbiel Irrigation Project	Irrigated Catchment			13	
	Bamboi	Subijna	Reservoir	16			
	Bamboi	Subijna Irrigation	Irrigated Catchment			16	
	Black Volta Mouhoun	Ntereso	Reservoir	18	17		
	Black Volta Mouhoun	Lanka	Reservoir	18	17		
	Black Volta Mouhoun	Bui dam	Reservoir	18	17		
	Black Volta Mouhoun	Bui Irrigation Project	Irrigated Catchment			16	
	Black Volta Mouhoun	Bamboi Domestic	Demand			14	
	Black Volta Mouhoun	Jambito	Reservoir	24	22		
	Black Volta Mouhoun	Ecological Flow	Flow Requirement				15
White Volta	White Volta Nakambe	Wayen Domestic	Demand			1	
	White Volta Nakambe	Kanozoe Dam	Reservoir	11			
	White Volta Nakambe	Kanozoe Irrigation	Irrigated Catchment			3	
	White Volta Nakambe	Loumbila	Reservoir	11			
	White Volta Nakambe	Ziga	Reservoir	11			
	White Volta Nakambe	Yakala Domestic	Demand			7	
	White Volta Nakambe	Bagre	Reservoir	11	30		
	White Volta Nakambe	Bagre Irrigation	Irrigated Catchment			9	

	White Volta Nakambe	Bagre Aval	Reservoir	14	17			
	Nouaho	Pwalugu Domestic	Demand				1	
	Red Volta Nazinon	Badongo	Reservoir	5	22			
	Red Volta Nazinon	Nangodi Domestic	Demand				1	
	Red Volta Nazinon	Nangodi River Irrigation	Irrigated Catchment				4	
	White Volta Nakambe	Pwalugu Hydropower	Reservoir	16	15			
	White Volta Nakambe	Pwalugu Irrigation	Irrigated Catchment				15	
	White Volta Nakambe	Kulpawn Hydropower	Reservoir	16	15			
	Nawuni River	Tono Reservoir	Reservoir	15	13			
	Nawuni River	Tono Irrigation	Irrigated Catchment				14	
	Nawuni River	Vea Reservoir	Reservoir	15				
	Nawuni River	Vea Irrigation	Irrigated Catchment				14	
	White Volta Nakambe	Daboya Hydropower	Reservoir	18	15			
	White Volta Nakambe	Ecological Flow	Flow Requirement					16
Oti/Pendjari	Oti Pendjari	Arly Domestic	Demand				1	
	Kompienga	Kompienga Domestic	Demand				1	
	Kompienga	Kompienga	Reservoir	3	19			
	Oti Pendjari	Mango Domestic	Demand				3	
	Koumangou	Koumangou Domestic	Demand				1	
	Oti Pendjari	Sabari Domestic	Demand				8	
	Oti Pendjari	Sabari Irrigation	Irrigated Catchment				10	
	Oti Pendjari	Juale	Reservoir	20	22			

	Oti Pendjari	Ecological Flow	Flow Requirement				18
Lower Volta	Daka	Ekumdipe SR	Reservoir	2			
	Daka	Ekumdipe Domestic	Demand			3	
	Prang	Tanoso	Reservoir	18			
	Prang	Tanoso Irrigation	Irrigated Catchment			3	
	Senchi Local	Senchi Domestic	Demand			17	
	Senchi Local	Senchi Irrigation	Irrigated Catchment			19	
	Volta	Akosombo	Reservoir	35	30		
	Volta	Kpong	Run-of-River		30		
	Volta	Ecological Flow	Flow Requirement				28

Model Calibration

Flow Simulation

The WEAP model was calibrated to several streamflow gages that span multiple years of the historical calibration period, 1960-1999. These observation data were obtained from the Volta HYCOS database. Results of the WEAP calibration at each station are summarized in Table C-48. Calibration parameter values are presented in Table C-49 and Table C-50.

In general, simulated flows agree well with the historical time series and produce NSE values greater than 0.7 for all calibration stations. Additionally, the overall mass balance of flows is comparable to the historical flows. That is, the model reproduces the total annual discharge, seasonal flows patterns, and variation in flow (i.e. flow duration) with an acceptable degree of performance. These results are highlighted in Figure C-104 to Figure C-109.

Table C-48: Volta Basin flow stations and calibration metrics

Gauging Station	Upstream Area (km2)	Source	Calibration				
			Period	RMSE	NSE	Bias	SDR
Black Volta at Nwokuy	16,126	Volta - HYCOS	1960-1988	41	0.71	-2%	1.07
Black Volta at Bamboi	125,664	Volta – HYCOS	1960-1975	475	0.78	15%	0.85
White Volta at Pwalugu	55,646	Volta – HYCOS	1960-1974	341	0.72	7%	0.80
White Volta at Nawuni	98,792	Volta – HYCOS	1960-2005	464	0.77	-16%	0.76
Pendjari at Mango	40,123	Volta – HYCOS	1960-1973	311	0.74	4%	0.96
Pendjari at Sabari	63,834	Volta – HYCOS	1960-2005	711	0.73	0.06%	0.86
Koumangou	7,542	Volta – HYCOS	1959-1973	110	0.84	-8%	0.93
Daka at Ekumdipe	6,350	Volta - HYCOS	1963-1973	104	0.83	15%	0.92

Table C-49: Calibration parameter values for Volta River catchments

Sub-Basin	Catchment	DWC (mm)	DC (mm)	SWC (mm)	PFD	RZC (mm)	RRF
Black Volta	Nwokuy	1000	20	700*2	0.95	75 *Max(0.333, Min(1,PrevTSValue(Effective Precip for ET[m],1,2, Average)/0.180))	15
	Lerinord	1000	20	200*2	0.95	20 + 100*(PrevTSValue(Relative Soil Moisture 1[%])/100)^2	9
	Dapola	1000	20	400*2	0.95	20 + 100*(PrevTSValue(Relative Soil Moisture 1[%])/100)^2	9
	Prang	1000	20	400*2.5	0.95	75 *Max(0.333, Min(1,PrevTSValue(Effective Precip for ET[m],1,2, Average)/0.180))	7
	Noumbiel	1000	20	500*2	0.95	75 *Max(0.333, Min(1,PrevTSValue(Effective Precip for ET[m],1,2, Average)/0.180))	9
	Bamboi	1000	20	500*3	0.95	75 *Max(0.333,Min(1,PrevTSValue(Effective Precip for ET[m],1,2, Average)/0.180))	12
White Volta	Wayen	1000	20	200*3	0.95	75 *Max(0.333, Min(1,PrevTSValue(Effective Precip for ET[m],1,2, Average)/0.180))	18
	Yakala	1000	20	300*2	0.95	75 *Max(0.333, Min(1,PrevTSValue(Effective Precip for ET[m],1,2, Average)/0.180))	18
	Nangodi	1000	20	200*3	0.95	75 *Max(0.333, Min(1,PrevTSValue(Effective Precip for ET[m],1,2, Average)/0.180))	Max(1, 9*2 - PrevTSValue(Effective Precip for ET[m], 1, 1, Average) * 30)
	Pwalugu	1000	20	500	0.95	75 *Max(0.333, Min(1,PrevTSValue(Effective Precip for ET[m],1,2, Average)/0.180))	12
	Nawuni	1000	20	1500	0.95	20 + 100*(PrevTSValue(Relative Soil Moisture 1[%])/100)^2	Max(1, 7 - PrevTSValue(Effective Precip for ET[m], 1, 1, Average) * 10)
Oti/Pendjari	Arly	1000	20	200*2	0.95	75 *Max(0.333, Min(1,PrevTSValue(Effective Precip for ET[m],1,2, Average)/0.180))	Max(1, 9 - PrevTSValue(Effective Precip for ET[m], 1, 1, Average) * 10)

	Kompienga	1000	20	450	0.95	75 *Max(0.333, Min(1,PrevTSValue(Effective Precip for ET[m],1,2, Average)/0.180))	Max(1, 6 - PrevTSValue(Effective Precip for ET[m], 1, 2, Average) * 15)
	Mango	1000	20	500*2	0.95	75 *Max(0.333, Min(1,PrevTSValue(Effective Precip for ET[m],1,2, Average)/0.180))	Max(1, 9 - PrevTSValue(Effective Precip for ET[m], 1, 1, Average) * 10)
	Koumangou	1000	20	400*2	0.95	75 *Max(0.333, Min(1,PrevTSValue(Effective Precip for ET[m],1,2, Average)/0.180))	Max(1, 6 - PrevTSValue(Effective Precip for ET[m], 1, 2, Average) * 15)
	Sabari	1000	20	600*0.5	0.95	75 *Max(0.5, Min(1,PrevTSValue(Effective Precip for ET[m],1,2, Average)/0.180))	5
Lower Volta	Ekumdipe	1000	20	400*1	0.95	35 *Max(0.333, Min(1,PrevTSValue(Effective Precip for ET[m],1,2, Average)/0.180))	4
	Senchi	1000	20	350*2*1.75	0.99	75 *Max(0.333, Min(1,PrevTSValue(Effective Precip for ET[m],1,2, Average)/0.180))	7

Table C-50: Calibrated Kc values for Volta River catchments

Sub-Basin	Catchment	Kc
Black Volta	Nwokuy	1.025 * MonthlyValues(Jan, 1, Feb, 1, Mar, 1, Apr, 1, May, 1, Jun, 1.25, Jul, 1.75, Aug, 1.75, Sep, 1.75, Oct, 1.5, Nov, 1.35, Dec, 1.1)
	Lerinord	1.025 * MonthlyValues(Jan, 1, Feb, 1, Mar, 1, Apr, 1, May, 1, Jun, 1.25, Jul, 1.75, Aug, 1.75, Sep, 1.75, Oct, 1.5, Nov, 1.35, Dec, 1.1)
	Dapola	1.025 * MonthlyValues(Jan, 1, Feb, 1, Mar, 1, Apr, 1, May, 1, Jun, 1.25, Jul, 1.75, Aug, 1.75, Sep, 1.75, Oct, 1.5, Nov, 1.35, Dec, 1.1)
	Prang	1.025 * MonthlyValues(Jan, 1, Feb, 1, Mar, 1, Apr, 1, May, 1, Jun, 1.25, Jul, 1.75, Aug, 1.75, Sep, 1.75, Oct, 1.5, Nov, 1.35, Dec, 1.1)
	Noumbiel	1.025 * MonthlyValues(Jan, 1, Feb, 1, Mar, 1, Apr, 1, May, 1, Jun, 1.25, Jul, 1.75, Aug, 1.75, Sep, 1.75, Oct, 1.5, Nov, 1.35, Dec, 1.1)
	Bamboi	1.025 * MonthlyValues(Jan, 1, Feb, 1, Mar, 1, Apr, 1, May, 1, Jun, 1.25, Jul, 1.75, Aug, 1.75, Sep, 1.75, Oct, 1.5, Nov, 1.35, Dec, 1.1)
White Volta	Wayen	1.025 * MonthlyValues(Jan, 1, Feb, 1, Mar, 1, Apr, 1, May, 1, Jun, 1.25, Jul, 1.75, Aug, 1.75, Sep, 1.75, Oct, 1.5, Nov, 1.35, Dec, 1.1)
	Yakala	1.025 * MonthlyValues(Jan, 1, Feb, 1, Mar, 1, Apr, 1, May, 1, Jun, 1.25, Jul, 1.75, Aug, 1.75, Sep, 1.75, Oct, 1.5, Nov, 1.35, Dec, 1.1)

	Nangodi	1.025 * MonthlyValues(Jan, 1, Feb, 1, Mar, 1, Apr, 1, May, 1, Jun, 1.25, Jul, 1.75, Aug, 1.75, Sep, 1.75, Oct, 1.5, Nov, 1.35, Dec, 1.1)
	Pwalugu	1.025 * MonthlyValues(Jan, 1, Feb, 1, Mar, 1, Apr, 1, May, 1, Jun, 1.25, Jul, 1.75, Aug, 1.75, Sep, 1.75, Oct, 1.5, Nov, 1.35, Dec, 1.1)
	Nawuni	1.025 * MonthlyValues(Jan, 1, Feb, 1, Mar, 1, Apr, 1, May, 1, Jun, 1.25, Jul, 1.75, Aug, 1.75, Sep, 1.75, Oct, 1.5, Nov, 1.35, Dec, 1.1)
Oti/Pendjari	Arly	1.025 * MonthlyValues(Jan, 1, Feb, 1, Mar, 1, Apr, 1, May, 1, Jun, 1.25, Jul, 1.75, Aug, 1.75, Sep, 1.75, Oct, 1.5, Nov, 1.35, Dec, 1.1)
	Kompienga	1.025 * MonthlyValues(Jan, 1, Feb, 1, Mar, 1, Apr, 1, May, 1, Jun, 1.25, Jul, 1.75, Aug, 1.75, Sep, 1.75, Oct, 1.5, Nov, 1.35, Dec, 1.1)
	Mango	1.025 * MonthlyValues(Jan, 1, Feb, 1, Mar, 1, Apr, 1, May, 1, Jun, 1.25, Jul, 1.75, Aug, 1.75, Sep, 1.75, Oct, 1.5, Nov, 1.35, Dec, 1.1)
	Koumangou	1.025 * MonthlyValues(Jan, 1, Feb, 1, Mar, 1, Apr, 1, May, 1, Jun, 1.25, Jul, 1.75, Aug, 1.75, Sep, 1.75, Oct, 1.5, Nov, 1.35, Dec, 1.1)
	Sabari	1.025 * MonthlyValues(Jan, 1, Feb, 1, Mar, 1, Apr, 1, May, 1.25, Jun, 1.49, Jul, 1.75, Aug, 1.75, Sep, 1.3, Oct, 1.18, Nov, 1.1, Dec, 1.03)
Lower Volta	Ekumdipe	1.025 * MonthlyValues(Jan, 1, Feb, 1, Mar, 1, Apr, 1, May, 1, Jun, 1.25, Jul, 1.55, Aug, 1.55, Sep, 1.55, Oct, 1.43, Nov, 1.3, Dec, 1.1)
	Senchi	1.025 * MonthlyValues(Jan, 1, Feb, 1, Mar, 1, Apr, 1, May, 1, Jun, 1.25, Jul, 1.75, Aug, 1.75, Sep, 1.75, Oct, 1.5, Nov, 1.35, Dec, 1.1)

Figure C-104: Simulated vs. Observed Black Volta Streamflow at Nwokuy

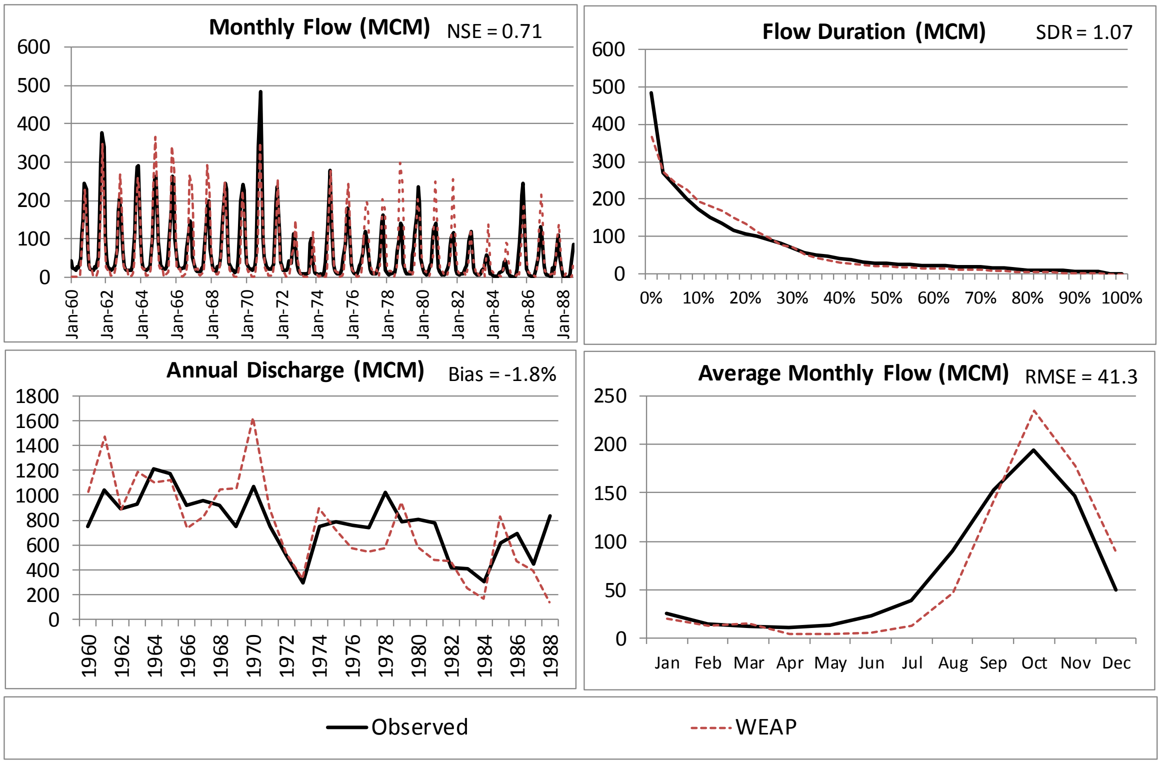


Figure C-105: Simulated vs. Observed Black Volta Streamflow at Bamboi

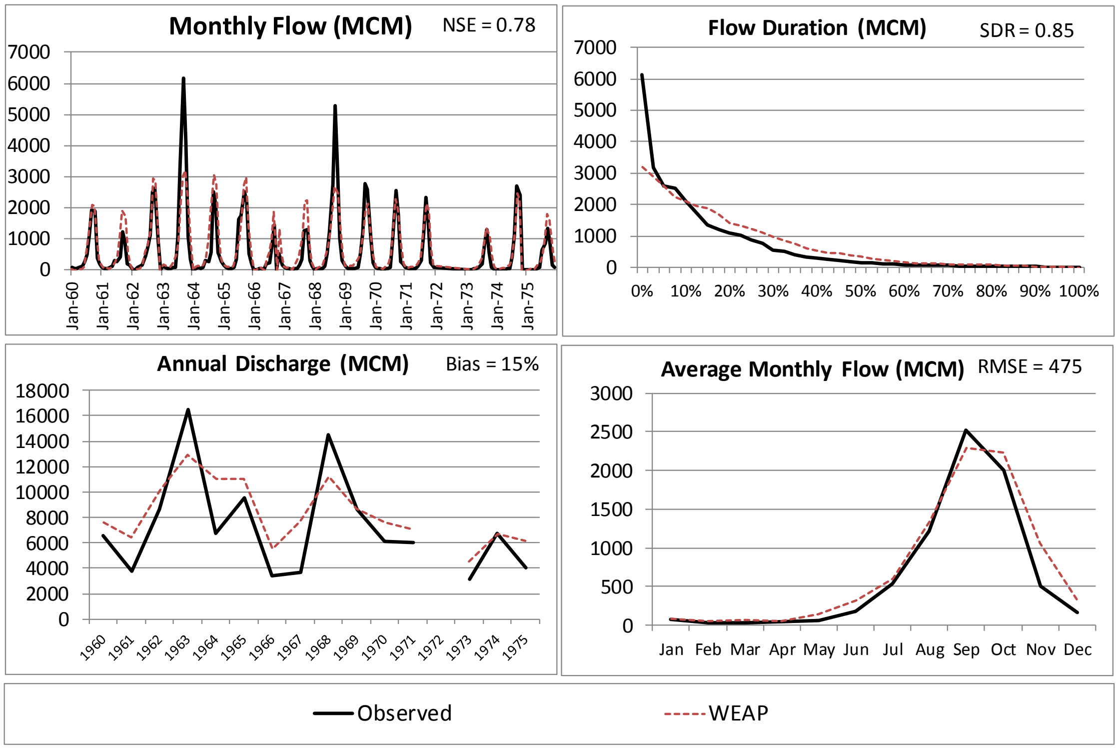


Figure C-106: Simulated vs. Observed White Volta Streamflow at Pwalugu

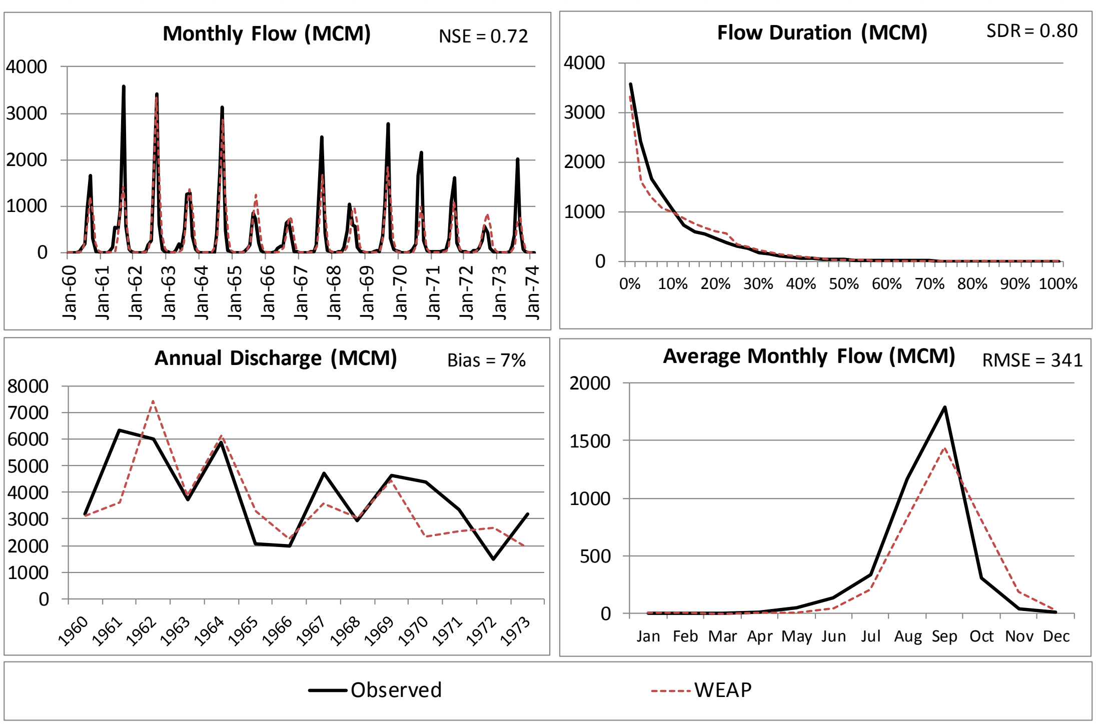


Figure C-107: Simulated vs. Observed White Volta Streamflow at Nawuni

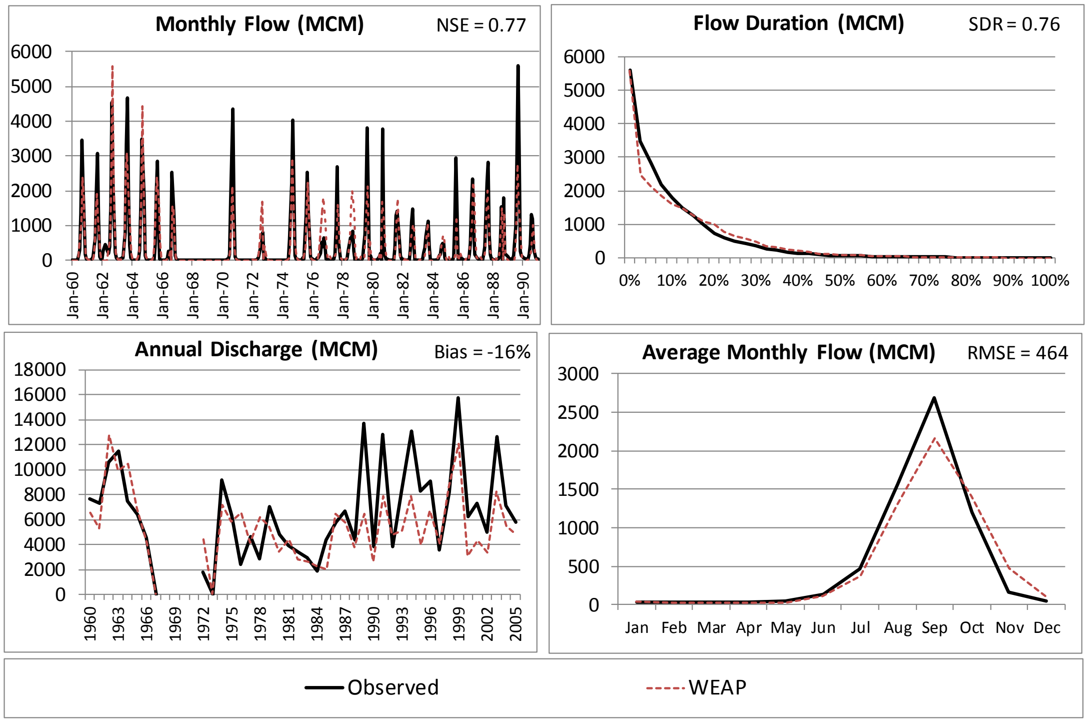


Figure C-108: Simulted vs. Observed Pendjari River Streamflow at Mango

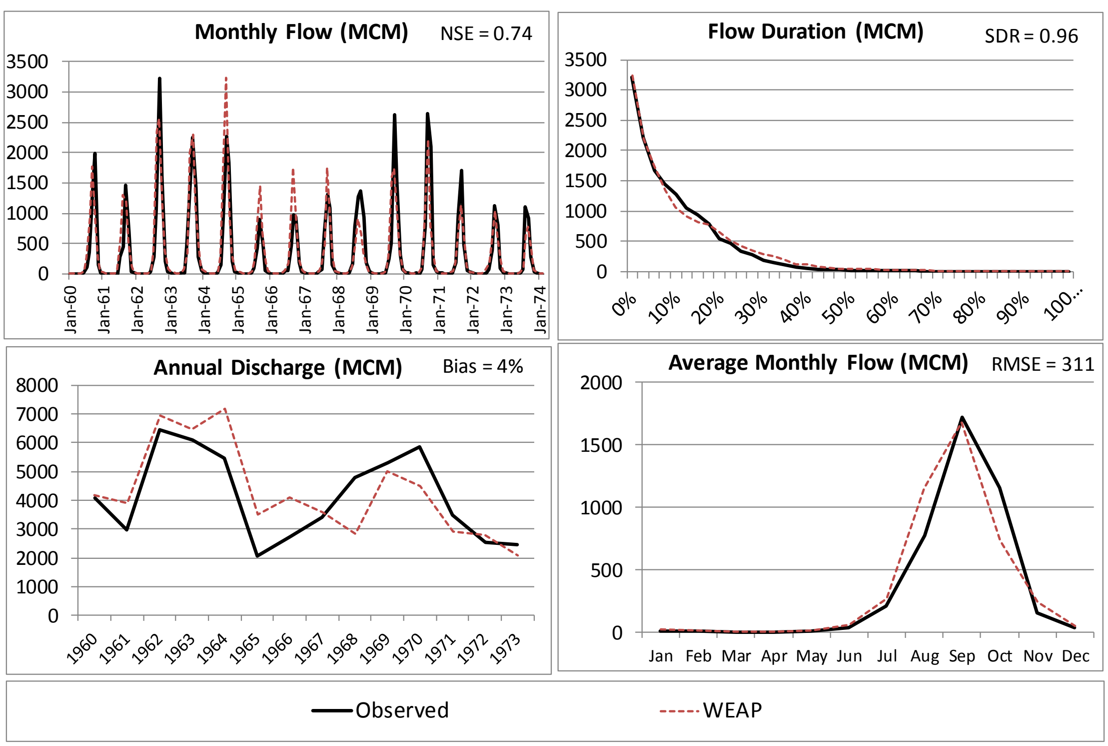
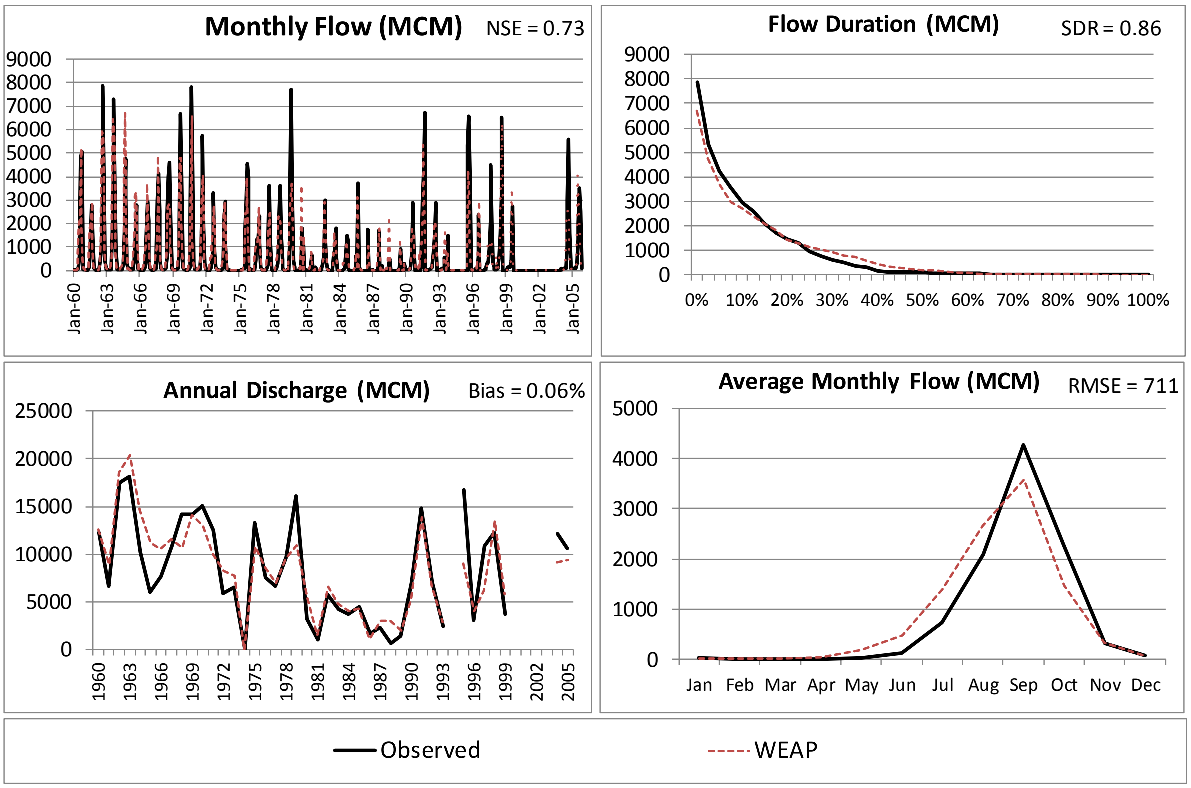


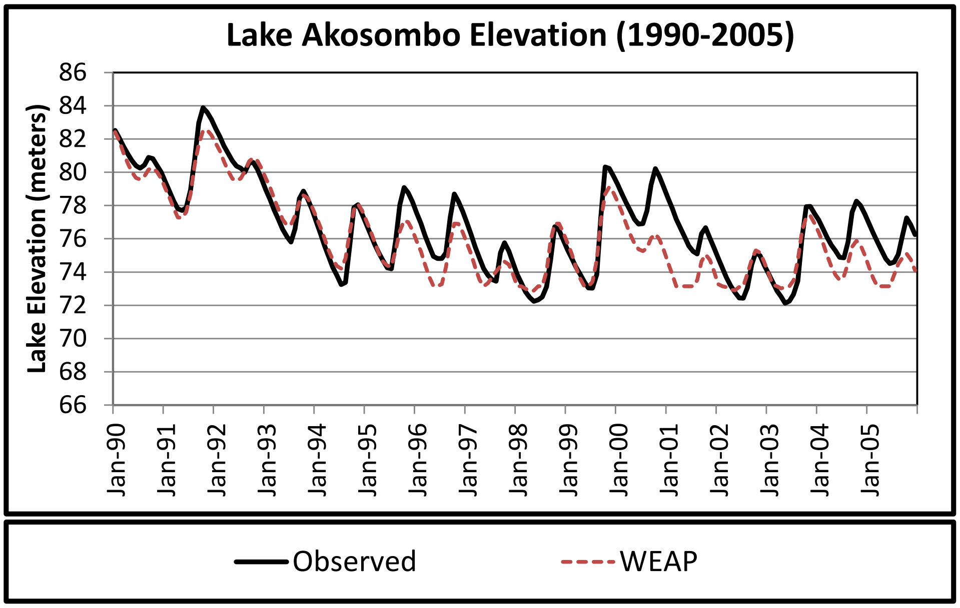
Figure C-109: Simulated vs. Observed Pendjari River Streamflow at Sabari



Water Resources Simulation

For the calibration of system operations, we focused on the simulated versus observed reservoir storage for the one reservoir with historical records sufficiently long to reflect a range of climatic and hydrologic conditions: Lake Akosombo. In general, the WEAP model was found to approximate the historical fluctuations in storage with an acceptable level of accuracy given the variation in system operations that occurred over the observation period (Figure C-110).

Figure C-110: Comparison of Observed and WEAP Simulated Elevations in Lake Akosombo (1990-2005)



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C8- Zambezi River Basin

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Figure C-111: Zambezi River Basin, South East Africa

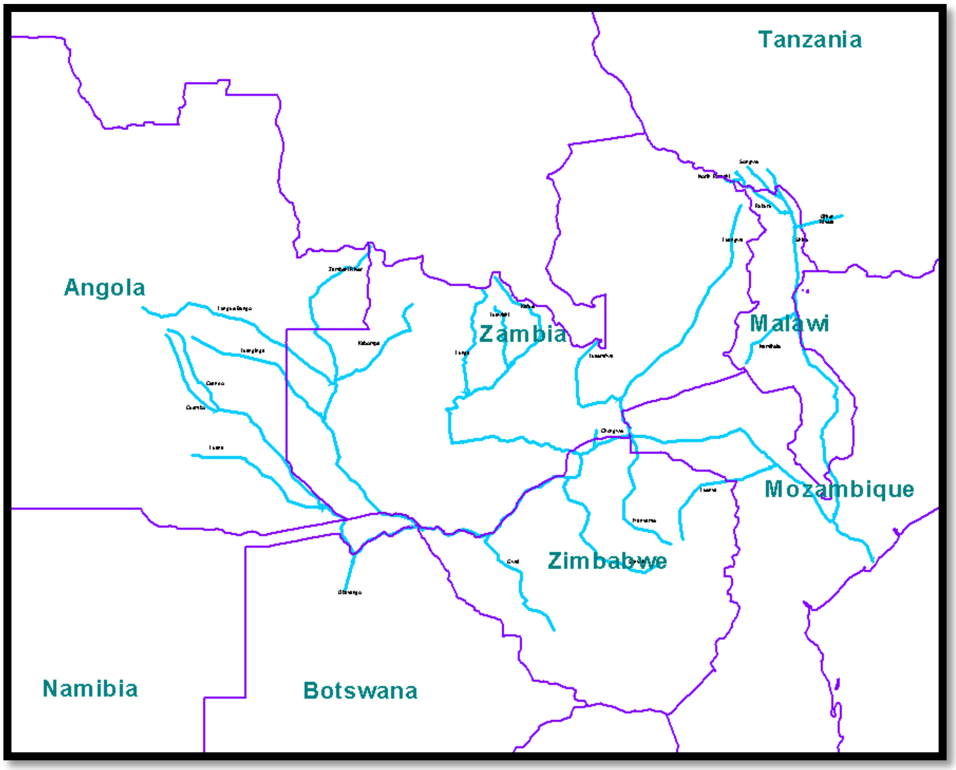
Description of the Basin

The Zambezi basin is the fourth-largest river basin of Africa, with a total area of just over 1.3 million km2. Its area represents about 4.5% of the area of the continent and spreads over eight countries, namely: Angola, Botswana, Malawi, Mozambique, Namibia, Tanzania, Zambia, and Zimbabwe (Table C-51 and Figure C-112). The Zambezi River flows eastwards for about 3000 km from its sources to the Indian Ocean.

Table C-51: Zambezi River basin areas by country

Country	Area within Basin (km^2)	Percentage of Basin area (%)	Percentage of Country with the Basin (%)
Angola	235,423	17.4	18.9
Botswana	12,401	0.9	2.1
Malawi	108,360	8.0	91.5
Mozambique	162,004	12.0	20.2
Namibia	17,426	1.3	2.1
Tanzania	27,840	2.1	2.9
Zambia	574,875	42.5	76.4
Zimbabwe	213,036	15.8	54.5
Total	1,351,365	100.0	

Figure C-112: Location of the Zambezi River (blue lines) and the countries it traverses (purple lines)



The current and future development plans for hydropower and irrigation in the basin are available in Appendix A.

WEAP Schematization

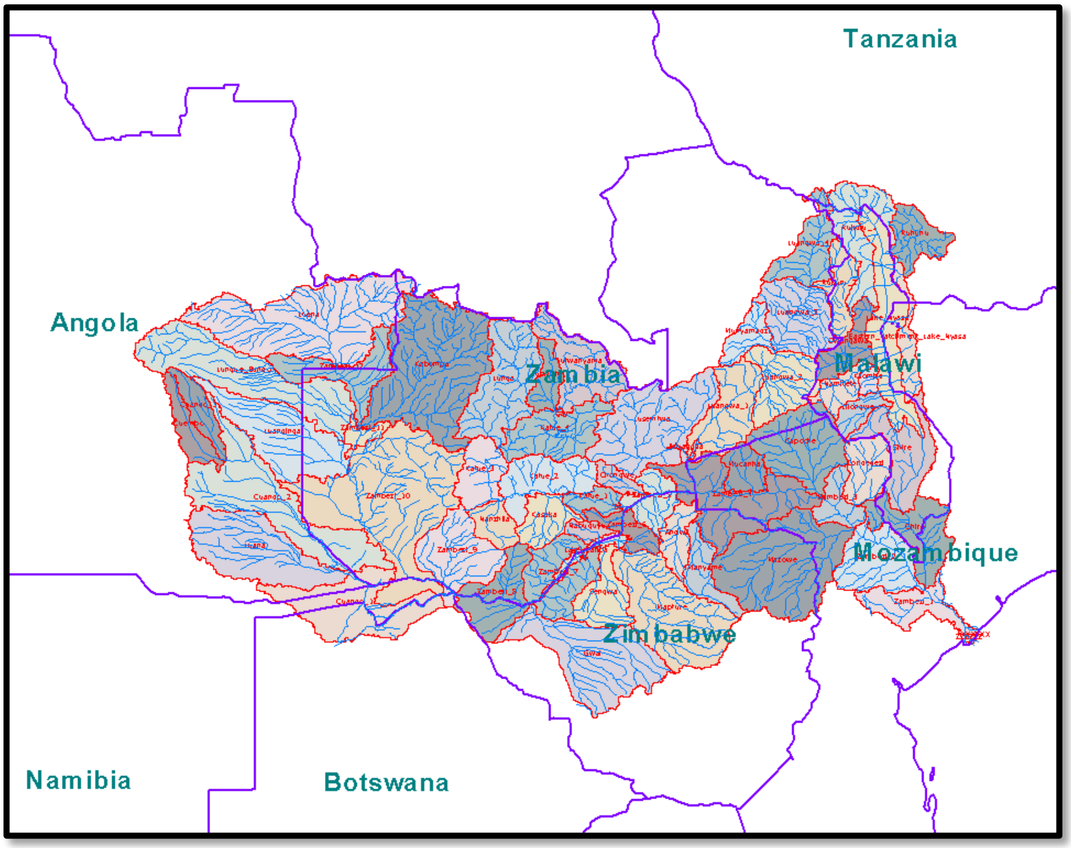
A WEAP model for the Zambezi River basin was provided to the project based on previous work by a project support team within Industrial Economics, Inc. The prior application used an external hydrologic model (CliRun) to simulate rainfall-runoff processesat key points in the WEAP schematic. This WEAP application, with its configuration of existing and planned infrastructure and water use, was used as the starting point for the model described here. The main change that was made to this application was to add catchment nodes such that we could model the hydrology of the basin without use of the external hydrologic model.

Catchment definitions

Previous hydrological modelling on the Zambezi River – specifically the Kafue Basin and some of the tributaries – was used as the basis for setting up the hydrologic routines in WEAP. Theses of two postgraduate students at the IWR, who had used the Pitman hydrological model (Mwelwa, 2005; Tirivarombo, 2013), were used as the primary references. A total of 60 sub-catchments were defined so as to match those used in the Pitman model developed by Tirivarombo (2013). These sub-catchment areas vary in size between 1,053 (Aruangua) to 86,442 km^2 (Zambezi10). They are shown below in

Figure C-113. Time series of historical and projected climate (i.e. monthly precipitation [mm], average temperature[C], minimum temperature[C], and maximum temperature[C]) were developed for each sub-basin shown in Figure C-113. These data were used to as drivers for the routines that estimate the hydrological response (i.e. rainfall-runoff and baseflow) and potential evapotranspiration for each sub-catchment.

Figure C-113: Zambezi River sub-catchments



The Zambezi was conceptually divided into 3 sections: upper (Cuando and Kabompa tributaries joining the Zambezi River, up to Victoria Falls), middle (Kafue tributary and the section of Zambezi from Victoria Falls to where Kafue River joins the Zambezi) and lower (below Kafue River confluence and including the Shire and Luangwa tributaries). A summary of the catchment data (derived from Mwelwa, 2005; Tirivarombo, 2013) is presented in Table C-52 to Table C-54. The rainy season in the Zambezi basin is from December to March.

Table C-52: Summary of key characteristics of the sub-catchments in the upper Zambezi. The averages were calculated using rainfall data for 1955 to 2000 generated by the model.

Catchment Name	Area (km^2)	Avg. rainfall (mm/month)	Avg. min. monthly rainfall (mm)	Avg. max. monthly rainfall (mm)	Potential annual evapotranspiration (mm)
Luena	70,473	90.94	2.0 (Jun)	200.8 (Jan)	1,558
Kabompa	70,020	93.21	2.1 (Jun)	230.7 (Dec)	1,441
Lungue Bungo	50,956	80.68	1.8 (Jun)	202.6 (Jan)	1,429
Luana	40,597	60.11	1.3 (Jun)	177.8 (Feb)	2,213
Luanginga	34,621	61.96	1.3 (Jun)	168.0 (Jan)	1,563
Cuembo	10,177	79.83	1.7 (Jun)	213.4 (Jan)	2,335
Cuando3	9,640	82.77	1.8 (Jun)	220.1 (Jan)	2,309
Cuando2	53,124	68.78	1.5 (Jun)	192.6 (Jan)	2,316
Cuando1	78,593	48.97	1.2 (Jun)	145.8 (Feb)	2,300
Zambezi12	21,944	92.35	2.1 (Jun)	221.2 (Jan)	1,453
Zambezi11	4,142	81.82	1.7 (Jun)	214.3 (Jan)	1,512
Zambezi10	86,442	60.70	1.4 (Jun)	170.0 (Jan)	1,579
Zambezi9	27,500	57.86	1.8 (Jun)	169.7 (Jan)	2,306

Table C-53: Summary of key characteristics of the sub-catchments in the middle Zambezi. The averages were calculated using rainfall data for 1955 to 2000 generated by the model.

Catchment Name	Area (km^2)	Average rainfall (mm/month)	Avg. min. monthly rainfall (mm)	Avg. max. monthly rainfall (mm)	Potential annual evapotranspiration (mm)
Zambezi8	20,494	53.90	1.2 (Jun)	166.1 (Jan)	2,303
Zambezi7	17,353	61.83	1.5 (Jun)	187.5 (Jan)	2,294
Zambezi6	8,535	59.85	1.7 (Jun)	180.2 (Jan)	1,612
Zambezi5	27,516	59.99	1.4 (Jun)	181.0 (Jan)	1,621
Gwai	45,423	52.02	2.4 (Jun)	151.2 (Jan)	1,977
Lunga	21,445	103.44	2.2 (Jun)	279.8 (Jan)	1,730
Lufwanyama	23,257	98.88	2.2 (Jun)	274.5 (Jan)	1,370
Sengwa	15,197	61.85	2.0 (Jun)	184.5 (Jan)	1,611
Nabuguyu	3,921	63.04	1.4 (Jun)	191.2 (Jan)	1,608
Sanyati	46,191	58.69	3.2 (Jun)	171.0 (Jan)	1,917
Chongwe	4,915	66.06	1.4 (Jun)	211.0 (Jan)	1,744
Luswishi	8,782	97.52	2.1 (Jun)	269.7 (Jan)	2,137
Kafue4	13,727	60.93	1.3 (Jun)	176.2 (Dec)	2,277
Kafue3	19,166	69.34	1.5 (Jun)	199.3 (Dec)	1,813
Kafue2	47,138	67.29	1.4 (Jun)	204.9 (Dec)	1,942
Kafue1	6,635	64.96	1.4 (Jun)	198.2 (Jan)	1,999
Kafue_S	10,619	57.91	1.3 (Jun)	171.7 (Dec)	1,629
Kafue_J	2,534	98.88	2.2 (Jun)	274.5 (Jan)	1,615
Kafue_Q	3,963	81.23	1.7 (Jun)	234.9 (Dec)	2,224

Table C-54: Summary of key characteristics of the sub-catchments in the lower Zambezi. The averages were calculated using rainfall data for 1955 to 2000 generated by the model.

Catchment Name	Area (km^2)	Average rainfall (mm/month)	Avg. min. monthly rainfall (mm)	Avg. max. monthly rainfall (mm)	Potential annual evapotranspiration (mm)
Lusemfwa	45,886	80.2	2.1 (Jun)	242.5 (Jan)	1,613
Zambezi4	38,990	60.8	1.7 (Jun)	186.7 (Jan)	1,638
Zambezi3	1,930	64.0	4.2 (Sep)	190.8 (Jan)	1,728
Zambezi2	24,244	75.6	10.5 (Sep)	207.1 (Jan)	1,631
Zambezi1	16,135	100.2	19.0 (Sep)	226.3 (Feb)	1,595
Chire	10,000	90.0	13.6 (Sep)	220.0 (Jan)	1,627
Luangwa4	18,026	85.4	3.1 (Jun)	230.7 (Jan)	1,805
Luangwa3	25,357	78.9	2.1 (Jun)	235.6 (Jan)	1,784
Luangwa2	20,929	78.4	1.8 (Jun)	239.1 (Jan)	1,825
Luangwa1	24,101	79.6	2.2 (Jun)	239.0 (Jan)	1,882
Munyamadzi	9,586	84.0	2.0 (Jun)	243.3 (Jan)	1,868
Owangawa	12,424	92.2	5.9 (Sep)	244.4 (Jan)	1,653
Namitete	10,718	81.2	3.2 (Jun)	241.8 (Jan)	1,545
Shire	23,254	83.2	6.0 (Sep)	246.9 (Jan)	1,634
Condedezi	14,551	80.1	5.4 (Sep)	235.4 (Jan)	1,635
Mucanha	9,329	70.4	1.5 (Jun)	209.8 (Jan)	1,642
Capoche	31,352	80.5	2.8 (Jun)	227.0 (Jan)	1,639
Angwa	9,700	60.2	2.4 (Jun)	179.3 (Jan)	1,590
Manyame	11,620	69.3	3.6 (Jun)	211.7 (Jan)	1,575
Aruangua	1,053	69.3	1.5 (Jun)	207.1 (Jan)	1,863
Mazowe	4,000	72.1	5.7 (Aug)	225.0 (Jan)	1,505
Mazowe2	51,408	68.7	5.5 (Aug)	214.3 (Jan)	1,456
Rumphi	6,614	87.7	6.3 (Sep)	222.1 (Mar)	2,017

ELNyasa	9,469	113.8	7.6 (Aug)	295.0 (Mar)	1,504
Lilongwe	6,634	81.2	3.2 (Jun)	266.1 (Jan)	1,445
Songwe	1,890	87.7	6.3 (Sep)	222.1 (Mar)	1,769
Lufira	1,790	87.7	6.3 (Sep)	222.1 (Mar)	1,769
Rukuru	16,193	81.1	5.8 (Sep)	205.4 (Mar)	2,034
Rukuru2	12,035	87.7	6.3 (Sep)	222.1 (Mar)	2,383

Reservoirs

Reservoirs: Most of the data inputs for the existing and proposed projects were obtained from a WEAP model developed for a previous World Bank project. Additional reports that were consulted were FAO (1997) and Euroconsult Mott MacDonald (2007).

Seven reservoirs were modelled as part of the Zambezi River under the present scenario. The reservoir parameters were obtained from the original CliRUN model provided by IEc. The characteristics of the reservoirs are presented in Table C-54.

Natural Lakes and Wetlands: Lakes and Wetlands are an important part of the hydrology of the Zambezi basin, in that they absorb seasonal high flows and evapotranspire a higher fraction of water, resulting in a shifting of the peak flow by weeks or months due to their large storage capacity. Modelling of lakes and wetlands was conducted using a reservoir and two flow requirements - a bypass requirement and a flow requirement below the reservoir. The main lakes and wetlands considered within the model are summarized in Table C-55.

Table C-55: Summary of key characteristics of the natural lakes and wetlands in the Zambezi River basin.

River	Name	Country	Storage capacity (Mm^3)	Lake or Wetland?
Shire	Lake Malawi	Malawi	200,000	Lake
Shire	Lake Chilwa swamp	Mozambique	55,000	Natural
Kafue	Kafue flats	Zambia	10,887	Wetland
Kafue	Lukanga swamp	Zambia	7,400	Wetland
Zambezi	Barotse	Zambia	50,000	Wetland
Cuando	Cuando	Angola	10,000	Wetland

Besides these, other wetlands in the form of flooded river banks can be found on the Zambezi, which are visible on Google Earth, such as on the Luswishi River, a tributary of the Kafue River. There are no data available on these wetlands and thus, modelling of these is difficult. Therefore, model catchment parameters were generally manipulated so as to match stream gauge measurements.

Water Allocation

The demand priority in WEAP defines how water is allocated to satisfy competing uses – i.e. reservoir storage, hydropower generation, irrigation, domestic use, and flow. WEAP offers demand priorities ranging in number from 0-99, where the lower numbers indicate higher priority for water use.

The demand priorities used in the Zambezi River are listed in Table C-56. These are generally set such that domestic water use has the highest priority, followed by environmental flow requirements as the second priority, irrigated agriculture as the third priority, hydropower generation as the fourth priority, and reservoir storage as the lowest priority. The priority structure also reflects the realities of water usage and the regional management of water within the basin. That is, water users that are high in the basin will tend to use the water that is available to them independent of water usage elsewhere in the basin. This also implies that water users that are quite low in the basin will have a lower demand priority such that they do not compete for the same water as users far upstream nor actively draw water from reservoirs at the headwaters. For example, irrigated agriculture in the Zambezi Delta has a demand priority of 39, which is higher than all but the priority for Cahora Bassa and Mphanda Nkuwa storage. This assures that water in the model will not be released from any other reservoir to try to meet that demand

Table C-56: Allocation priority structure for Zambezi River WEAP model

Subbasin	River	Node	WEAP Object	WEAP PRIORITY			
				Storage	Hydropower	Demand	Flow Requirement
Upper Zambezi	Zambezi	Irrig_UZ	Irrigated catchment			9	
	Zambezi	Pop_UZ	Demand			1	
	Zambezi	Env_UZ	Flow Requirement			2	
	Lungue Bungo	Irrig_LB	Irrigated catchment			9	
	Lungue Bungo	Pop_LB	Demand			1	
	Lungue Bungo	Env_LB	Flow Requirement			2	
	Kabompa	Irrig_KB	Irrigated catchment			9	
	Kabompa	Pop_KB	Demand			1	
	Kabompa	Env_KB	Flow Requirement			2	
	Luaninga	Irrig_LG	Irrigated catchment			9	
	Luaninga	Pop_LG	Demand			1	
	Zambezi	Upper Zambezi Wetland Bypass	Flow Requirement				10
	Zambezi	Upper Zambezi Wetland	Reservoir	12			
	Zambezi	Upper Zambezi Wetland Outflow	Flow Requirement				11
	Zambezi	Irrig_BT	Irrigated catchment			15	
	Zambezi	Pop_BT	Demand			14	
	Cuando	Irrig_CU	Irrigated catchment			9	
	Cuando	Pop_CU	Demand			1	

	Cuando	Cuando Wetland Bypass	Flow Requirement				10
	Cuando	Cuando Wetland	Reservoir	12			
	Cuando	Cuando Wetland Outflow	Flow Requirement				11
	Chobe	Irrig_CH	Irrigated catchment			13	
	Zambezi	Env_Vic Falls	Flow Requirement				15
Middle Zambezi	Zambezi	Irrig_KB1 and KB2	Irrigated catchment			15	
	Zambezi	Victoria Falls	Run of River		16		
	Zambezi	Batoka Gorge	Reservoir	20	19		
	Zambezi	Irrig_KB3	Irrigated catchment			9	
	Gwai	Irrig_KB4	Irrigated catchment			9	
	Zambezi	Devil's Gorge	Reservoir	20	19		
	Zambezi	Pop_KRB	Demand			14	
	Sanyati	Sanyati	Reservoir	10			
	Sanyati	Irrig_KB5	Irrigated catchment			9	
	Zambezi	Irrig_KB6	Irrigated catchment			9	
	Zambezi	Lake Kariba	Reservoir	30	29		
	Zambezi	Env_Kariba	Flow Requirement				25
	Kafue	Pop_KF rural	Demand			3	
	Kafue	Env UpKF	Flow Requirement				4
	Kafue	Lukanga Swamp Bypass	Flow Requirement				5
	Kafue	Lukanga Swamp	Reservoir	7			
	Kafue	Lukanga Swamp Outflow	Flow Requirement				6

	Kafue	Irrig_KF1	Irrigated catchment			8	
	Kafue	Iztezhi Tezhi	Reservoir	10	9		
	Kafue	Irrig_KF2	Irrigated catchment			11	
	Kafue	Pop KF urban	Demand			9	
	Kafue	Kafue Flats	Reservoir	20			
	Kafue	Kafue Flats Outflow	Flow Requirement				18
	Kafue	Pop_Lusaka	Demand			19	
	Kafue	Kafue Gorge Upper	Reservoir	30	29		
	Kafue	Kafue Gorge Lower	Reservoir	30	29		
	Kafue	Env_low Kafue	Flow Requirement				25
Lower Zambezi	Zambezi	Irrig_MP	Irrigated catchment			29	
	Zambezi	Pop_MP	Demand			28	
	Zambezi	Mpata Gorge	Run of River		30		
	Luangwa	Irrig_LW2	Irrigated catchment			9	
	Lusiwasi	Lusiwasi	Run of River		1		
	Luangwa	Pop_LW rural	Demand			1	
	Luangwa	Pop_LW urban	Demand			1	
	Lusemfwa	Lusemfwa - Mulungushi	Reservoir	20	19		
	Lusemfwa	Irrig_LW1	Irrigated catchment			9	
	Manyame	Manyame Local	Reservoir	10			
	Manyame	Irrig_TT1	Irrigated catchment			9	
	Zambezi	Cahora Bassa	Reservoir	40	39		

	Zambezi	Mphanda Nkuwa	Reservoir	40	39		
	Zambezi	Irrig_TT2	Irrigated catchment			39	
	Zambezi	Irrig_TT3	Irrigated catchment			39	
	Zambezi	Irrig_TT4	Irrigated catchment			39	
	Zambezi	Pop_Tete	Demand			34	
	Zambezi	M_TT1	Demand			34	
	Zambezi	M_TT2	Demand			34	
	Luenya	Pop_Harare	Demand			1	
	Luenya	Luenya Local	Reservoir	10			
	Luenya	TT5 and TT6	Irrigated catchment			9	
	Luenya	Env_Luenya	Flow Requirement				2
	Upper Shire	Irrig_SL12	Irrigated catchment			6	
	Upper Shire	Rumakali	Reservoir	8	7		
	Songwe	Irrig_SL5 and SL6	Irrigated catchment			6	
	Songwe	Songwe I	Reservoir	8	7		
	Songwe	Songwe II	Reservoir	8	7		
	Songwe	Songwe III	Reservoir	8	7		
	Upper Shire	Irrig_SL8 and SL10	Irrigated catchment			9	
	Rukuru	Irrig_SL7	Irrigated catchment			9	
	Rukuru	Lower Fufu	Run of River		1		
	Upper Shire	Pop_SH rural	Demand			8	
	Upper Shire	Irrig_SL9 and SL11	Irrigated catchment			9	

	Upper Shire	Lake Malawi	Reservoir	10			
	Upper Shire	Lake Malawi Outflow	Flow Requirement				8
	Shire	Kholombizo	Run of River		12		
	Shire	Pop_SH urban	Demand			11	
	Shire	Irrig_SL4	Irrigated catchment			17	
	Shire	Nkhula Falls	Run of River		12		
	Shire	Irrig_SL3	Irrigated catchment			17	
	Shire	Tedzani	Run of River		12		
	Shire	Irrig_SL2	Irrigated catchment			17	
	Shire	Kapichira	Run of River		12		
	Shire	Irrig_SL1	Irrigated catchment			17	
	Shire	Shire Marsh	Reservoir	20			
	Shire	Shire Marsh Outflow	Flow Requirement				18
	Zambezi Delta	Irrig_ZD	Irrigated catchment			39	
	Zambezi Delta	Pop_ZD rural	Demand			38	

Model Calibration

Flow Simulation

Evapotranspiration - The parameter Kc was calibrated so that the monthly values for ETPotential generated by WEAP matched the mean monthly evapotranspiration for the catchments (calculated from annual pan evaporation in mm and the mean monthly percent evaporation; Tirivarombo, 2013). The potential evaporation data were obtained from the International Water Management Institute's (IWMI, 2009) World Climate portal (Tirivarombo, 2013).

Model parameters - The Pitman model setup of Tirivarombo (2013) was used to populate data on catchment area, soil water capacity and deep conductivity. Three main parameters in the WEAP model were varied so that the simulation matches the measurements by the stream gauges; these parameters were the rainfall-runoff factor (RRF), root zone conductivity and preferred flow direction. Deep water capacity was generally fixed to 1000 mm.

An equation for the WEAP parameter RRF was developed by Denis Hughes (Institute for Water Research) to relate it to the amount of precipitation, based on trial and error tests of comparing the WEAP results with those from the Pitman model. The default equation was:

$$\text{If (Precip(mm) - Pthresh} < 0.5, 20, \text{Base}_{RRF} + \{\text{MaxP} / (\text{Precip(mm)} - \text{Pthresh})\}^{\ln(\text{Precip})/5)}$$

Pthresh represents the monthly rainfall amount below which surface runoff is not expected to occur regardless of the state of the soil water storage. *Base$_{RRF}$* represents a nominal value of the RRF which is then adjusted upwards by the additional expression. *MaxP* represents a relatively high rainfall used in the scaling of the Base$_{RRF}$ parameter. The default values in this equation for the Zambezi River catchments were:

Pthresh = 50

Base$_{RRF}$ = 1.3

MaxP = 250

Stream flow gauge data available from Mwelwa (2005), Tirivarombo (2013) and some that were included with the CliRUN model, were used to calibrate the system. The gauge labels were obtained from these documents, and a prefix of "SP_" was added to indicate that the data were obtained from Mwelwa (2005) or Tirivarombo (2013) and prefix "CLI_" indicated the source to be the CliRUN model. Some of these gauges, particularly those downstream, are impacted by water use and extraction and therefore these data needed to be input for calibration. The water use data for irrigation and populations were obtained from Mwelwa (2005; for the Kafue River) and Euroconsult Mott MacDonald (2007) and are shown in Table C-57 and Table C-58. According to Mwelwa, the stream gauge data for the Kafue River is collected by The Department of Water Affairs in Zambia it is then managed as part of the Hydrological Data database, which was developed by the Centre for Ecology and Hydrology in UK. Tirivarombo obtained the gauge data from The Global Runoff Data Center (GRDC) based in Koblenz, Germany (discharge data are accessible at http://www.bafg.de/GRDC/EN/Home/homepage_node.html).

A number of the stream gauges have large gaps in their collected data (e.g. Figure C-114) which made calibration difficult. When displaying simulation and recorded data in the figures below, the years with missing data have been deleted from the figures. Calibration was done for the years 1955 and 2000, noting that gauge data for these years was not always available. In the following sections, the results for the major gauges where sufficient data were available are discussed.

Calibration: Upper Zambezi

The upper Zambezi (Figure C-114) is fed by a number of tributaries and it has two main wetlands, labelled Cuando and Upper Zambezi wetland. The reservoir storage capacity of these wetlands was defined to be 12,000 million m^3 and 50,000 million m^3, respectively. The diversion flow was 25 m^3/s (or 64.8 million m^3 per month) for the Cuando wetland and 800 m^3/s (2,073.6 million m^3 per month) for the Upper Zambezi wetland. The main stream gauges SP_Zam10 and SP_Zam8 on the Zambezi River (shown in Figure C-114) were used for calibrating the system and for determining the equations for the flow requirements below the wetland reservoirs (results shown in Figure C-115 to Figure C-117).

Figure C-114: WEAP schematic for the upper Zambezi.

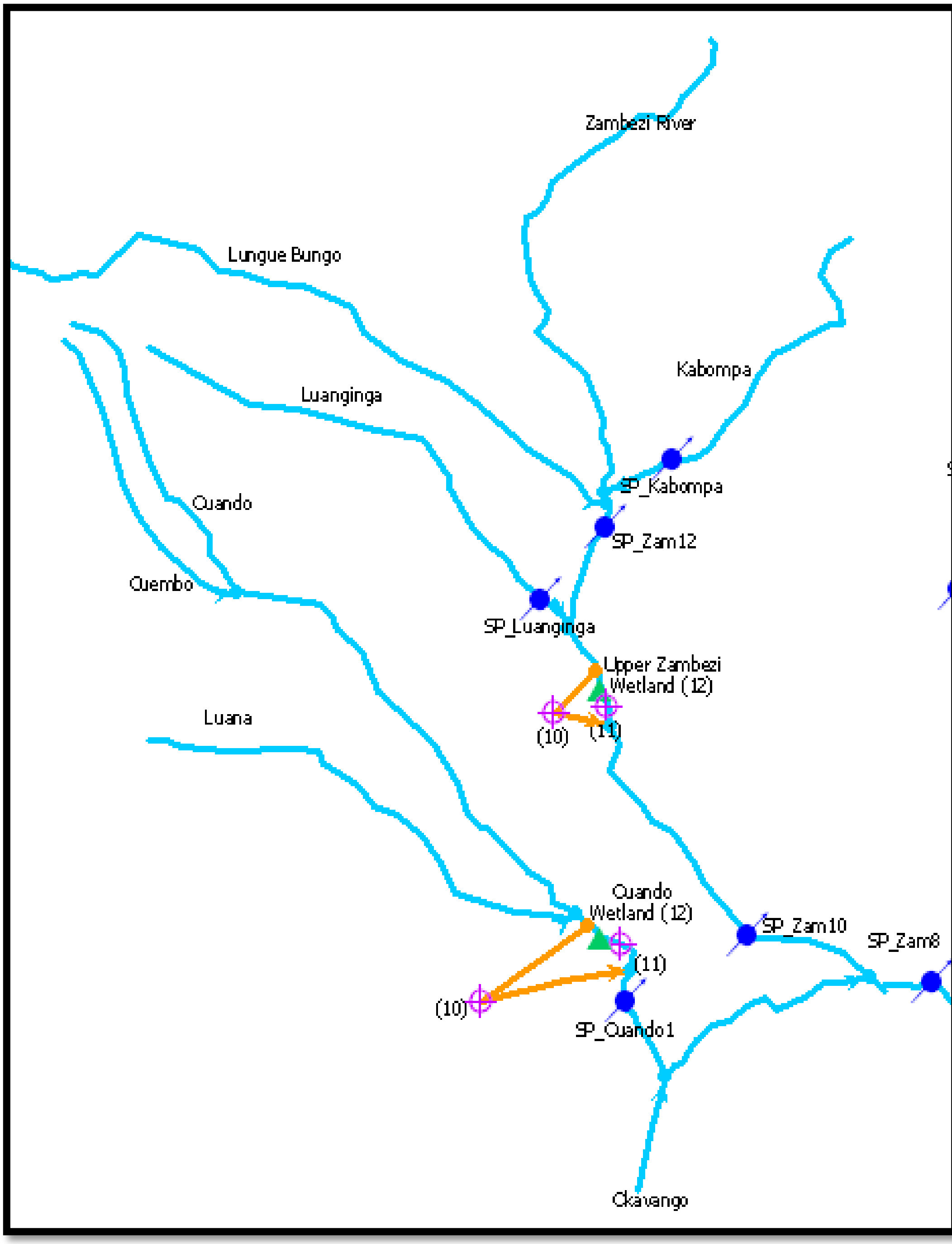


Table C-57: Calibration parameters values for Upper Zambezi catchments

Catchment	DWC (mm)	DC (mm)	SWC (mm)	PFD	RZC (mm)	RRF
Luena	1000	10	1063	0.80	22.267	If(Precipitation[mm]-50<0.5,20,5+(250/(Precipitation[mm]-50))^(Ln(Precipitation[mm])/5))
Kabompa	1000	10	1200	0.70	19	If(Precipitation[mm]-50<0.5,15,5+(250/(Precipitation[mm]-50))^(Ln(Precipitation[mm])/5))
Lungue Bungo	1000	8	746	0.80	53.647	If(Precipitation[mm]-50<0.5,20,5+(250/(Precipitation[mm]-50))^(Ln(Precipitation[mm])/5))
Luana	1000	15	1798	0.60	10.554	If(Precipitation[mm]-50<0.5,20,1.3+(250/(Precipitation[mm]-50))^(Ln(Precipitation[mm])/5))
Luanginga	500	4	1000	0.90	25 + 50 * (PrevTSValue(Relative Soil Moisture 1[%])/100)	If(Precipitation[mm]-200<0.5,5,7+(250/(Precipitation[mm]-200))^(Ln(Precipitation[mm])/5))
Cuembo	1000	15	1273	0.60	11.504	If(Precipitation[mm]-50<0.5,20,1.3+(250/(Precipitation[mm]-50))^(Ln(Precipitation[mm])/5))
Cuando3	1000	15	1614	0.90	16.526	If(Precipitation[mm]-50<0.5,20,1.3+(250/(Precipitation[mm]-50))^(Ln(Precipitation[mm])/5))
Cuando2	1000	15	1550	0.90	21.043	If(Precipitation[mm]-50<0.5,20,1.3+(250/(Precipitation[mm]-50))^(Ln(Precipitation[mm])/5))
Cuando1	1000	10	1798	0.60	10.554	If(Precipitation[mm]-50<0.5,20,1.3+(250/(Precipitation[mm]-50))^(Ln(Precipitation[mm])/5))
Zambezi12	1000	9	1000	0.70	6	If(Precipitation[mm]-50<0.5,20,5+(250/(Precipitation[mm]-50))^(Ln(Precipitation[mm])/5))
Zambezi11	1000	10	1000	0.70	10	If(Precipitation[mm]-50<0.5,20,5+(250/(Precipitation[mm]-50))^(Ln(Precipitation[mm])/5))
Zambezi10	1000	9	750	0.85	90	If(Precipitation[mm]-50<0.5,20,8+(100/(Precipitation[mm]-50))^(Ln(Precipitation[mm])/5))
Zambezi9	1000	10	1800	0.60	10	If(Precipitation[mm]-50<0.5,20,8+(250/(Precipitation[mm]-50))^(Ln(Precipitation[mm])/5))

Table C-58: Calibrated Kc values for Upper Zambezi catchments

Catchment	Kc
Luena	1.09 * MonthlyValues(Jan, 0.759, Feb, 0.903, Mar, 0.751, Apr, 0.727, May, 0.682, Jun, 0.720, Jul, 0.715, Aug, 0.741, Sep, 0.749, Oct, 0.699, Nov, 0.749, Dec, 0.793)
Kabompa	1.03 * MonthlyValues(Jan, 0.852, Feb, 0.908, Mar, 0.771, Apr, 0.737, May, 0.665, Jun, 0.662, Jul, 0.662, Aug, 0.742, Sep, 0.756, Oct, 0.716, Nov, 0.783, Dec, 0.882)
Lungue Bungo	1.02 * MonthlyValues(Jan, 0.761, Feb, 0.888, Mar, 0.712, Apr, 0.688, May, 0.638, Jun, 0.678, Jul, 0.689, Aug, 0.704, Sep, 0.737, Oct, 0.685, Nov, 0.731, Dec, 0.773)
Luana	0.99 * MonthlyValues(Jan, 1.237, Feb, 1.429, Mar, 1.190, Apr, 1.138, May, 1.001, Jun, 1.026, Jul, 1.025, Aug, 1.049, Sep, 1.114, Oct, 1.072, Nov, 1.128, Dec, 1.151)
Luanginga	1.04 * MonthlyValues(Jan, 0.832, Feb, 0.960, Mar, 0.777, Apr, 0.741, May, 0.694, Jun, 0.734, Jul, 0.726, Aug, 0.729, Sep, 0.773, Oct, 0.703, Nov, 0.743, Dec, 0.787)
Cuembo	1.03 * MonthlyValues(Jan, 1.246, Feb, 1.443, Mar, 1.155, Apr, 1.089, May, 1.003, Jun, 1.092, Jul, 1.120, Aug, 1.105, Sep, 1.190, Oct, 1.098, Nov, 1.184, Dec, 1.209)
Cuando3	1.03 * MonthlyValues(Jan, 1.253, Feb, 1.446, Mar, 1.130, Apr, 1.060, May, 0.966, Jun, 1.052, Jul, 1.083, Aug, 1.071, Sep, 1.170, Oct, 1.103, Nov, 1.201, Dec, 1.231)
Cuando2	1.04 * MonthlyValues(Jan, 1.247, Feb, 1.439, Mar, 1.173, Apr, 1.116, May, 1.008, Jun, 1.062, Jul, 1.054, Aug, 1.093, Sep, 1.160, Oct, 1.082, Nov, 1.134, Dec, 1.185)
Cuando1	1.03 * MonthlyValues(Jan, 1.169, Feb, 1.343, Mar, 1.160, Apr, 1.091, May, 0.984, Jun, 0.999, Jul, 0.956, Aug, 1.032, Sep, 1.113, Oct, 1.103, Nov, 1.181, Dec, 1.167)
Zambezi12	1.03 * MonthlyValues(Jan, 0.771, Feb, 0.898, Mar, 0.731, Apr, 0.710, May, 0.670, Jun, 0.688, Jul, 0.681, Aug, 0.739, Sep, 0.739, Oct, 0.687, Nov, 0.741, Dec, 0.808)
Zambezi11	1.01 * MonthlyValues(Jan, 0.873, Feb, 0.921, Mar, 0.768, Apr, 0.746, May, 0.679, Jun, 0.683, Jul, 0.684, Aug, 0.763, Sep, 0.775, Oct, 0.715, Nov, 0.750, Dec, 0.843)
Zambezi10	1.03 * MonthlyValues(Jan, 0.863, Feb, 0.953, Mar, 0.790, Apr, 0.759, May, 0.694, Jun, 0.711, Jul, 0.692, Aug, 0.766, Sep, 0.802, Oct, 0.749, Nov, 0.781, Dec, 0.838)
Zambezi9	1.07 * MonthlyValues(Jan, 1.195, Feb, 1.322, Mar, 1.113, Apr, 1.078, May, 1.032, Jun, 1.088, Jul, 1.022, Aug, 1.168, Sep, 1.231, Oct, 1.154, Nov, 1.198, Dec, 1.197)

Figure C-115: Simulated and observed Kabompa River inflow to Zambezi River

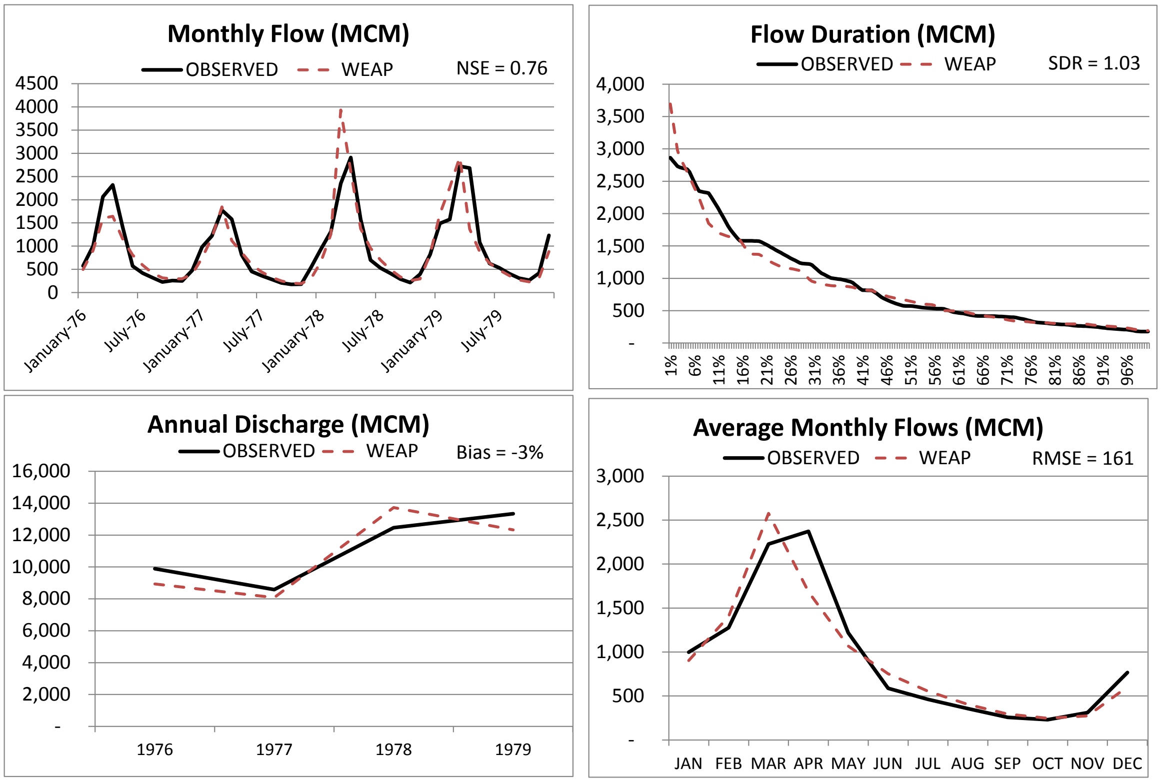


Figure C-116: Simulated and observed Luaninga River inflow to Zambezi River

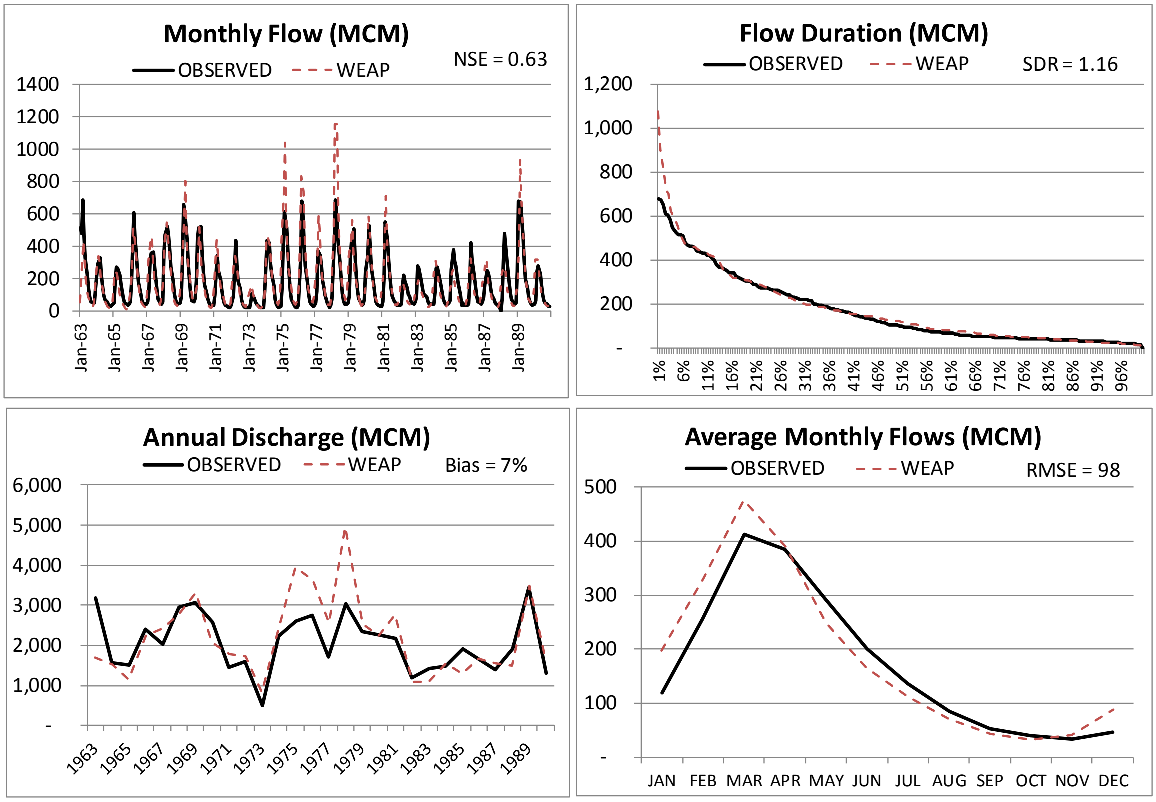
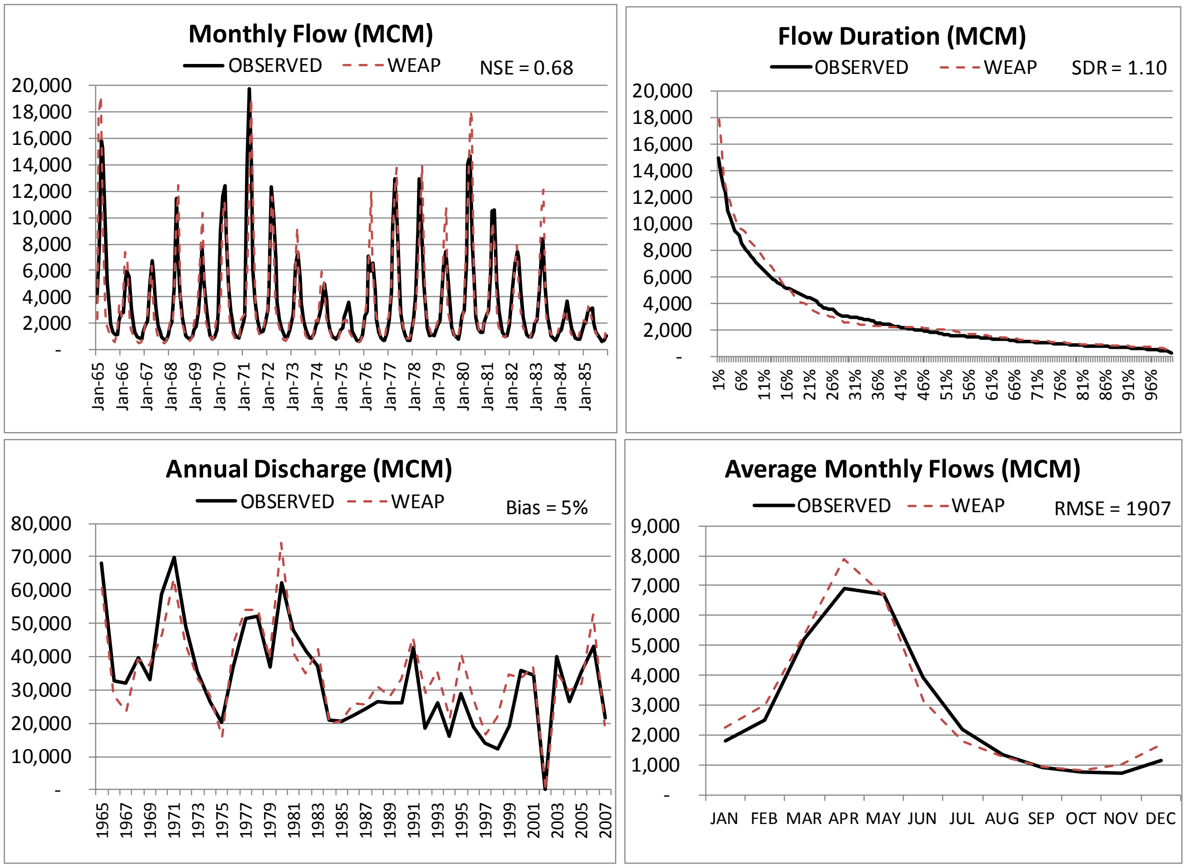


Figure C-117: Simulated and observed Zambezi River flows above Victoria Falls



Calibration: Middle Zambezi

Due to the large amount of data and the Institute's experience with modelling the Kafue River (in the middle Zambezi section), the WEAP calibration was begun on this basin. The Kafue River consists of the Lunga, Luswishi and Kafue tributaries that join together upstream of Iztezhi Tezhi dam (Figure C-118). Two major wetlands lie within the Kafue River basin - the Lukanga Swamp upstream of Iztezhi Tezhi and the Kafue Flats between Iztezhi Tezhi and Kafue Gorge. These were modeled using information from McCartney (2007) and Mwelwa (2005). Simulated flows at each of the main calibration points showed seasonal and inter-annual variability similar to observed flow records (see Figure C-119).

Figure C-118: WEAP schematic for the Kafue River, showing the location of the reservoirs and wetlands

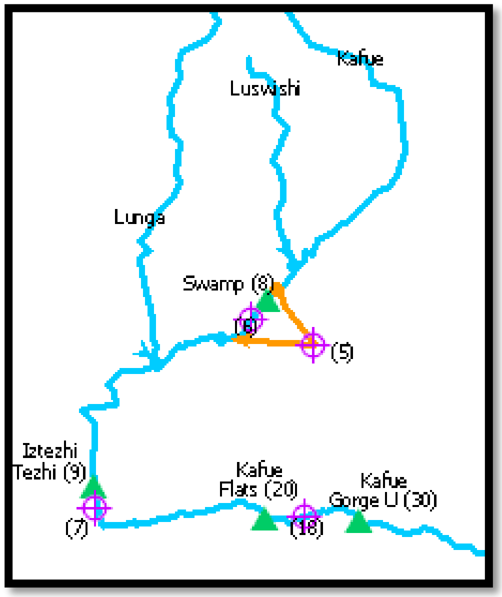


Figure C-119: Simulated and observed Kafue River flows above Iztezhi Tezhi dam

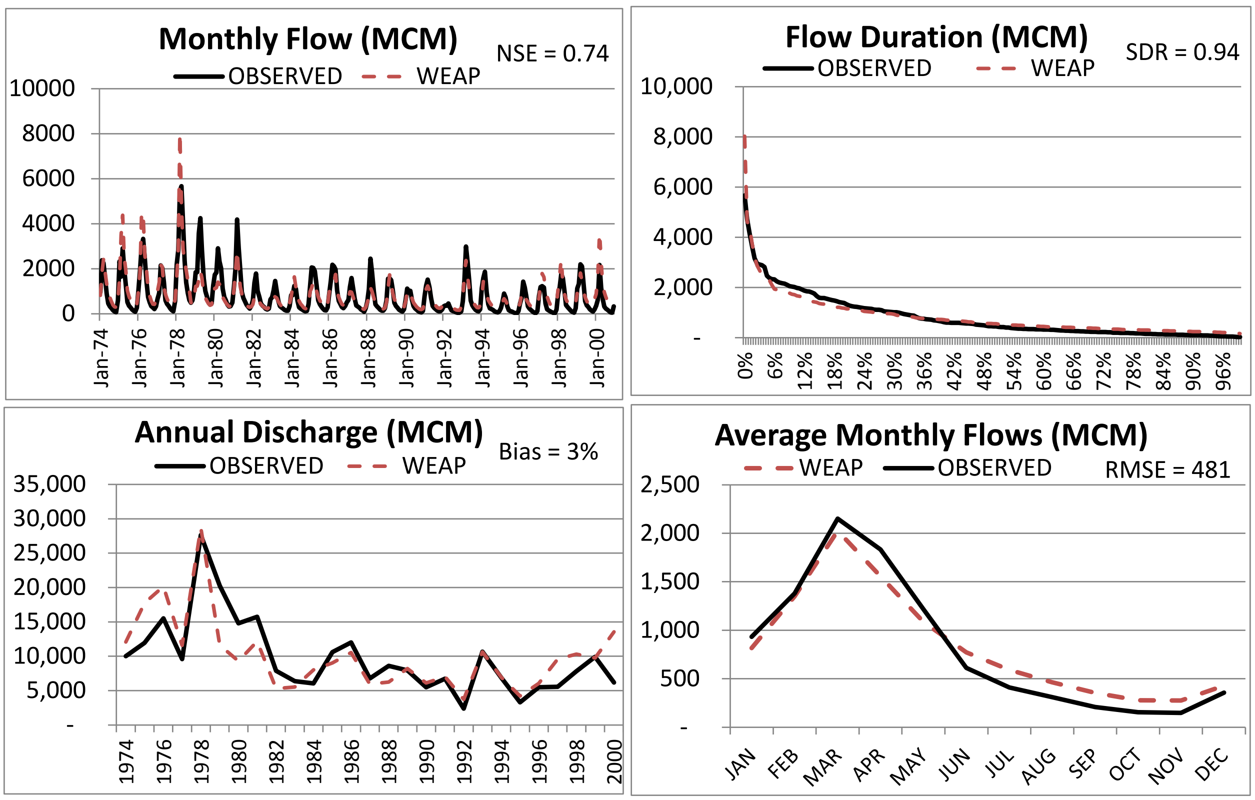


Table C-59: Calibration parameter values for Middle Zambezi catchments

Catchment	DWC (mm)	DC (mm)	SWC (mm)	PFD	RZC (mm)	RRF
Zambezi8	1000	10	1800	0.60	10	If(Precipitation[mm]-50<0.5,20,8+(250/(Precipitation[mm]-50))^(Ln(Precipitation[mm])/5))
Zambezi7	1000	2	1800	0.80	10	If(Precipitation[mm]-50<0.5,20,5+(250/(Precipitation[mm]-50))^(Ln(Precipitation[mm])/5))
Zambezi6	1000	5	1150	0.80	122.39	If(Precipitation[mm]-50<0.5,20,5+(250/(Precipitation[mm]-50))^(Ln(Precipitation[mm])/5))
Zambezi5	1000	5	1150	0.80	122.39	If(Precipitation[mm]-50<0.5,20,5+(250/(Precipitation[mm]-50))^(Ln(Precipitation[mm])/5))
Gwai	1000	2	400	0.80	8.5	If(Precipitation[mm]-50<0.5,20,6+(250/(Precipitation[mm]-50))^(Ln(Precipitation[mm])/5))
Lunga	1000	12	1150	0.75	22	If(Precipitation[mm]-50<0.5,30,6+(230/(Precipitation[mm]-50))^(Ln(Precipitation[mm])/5))
Lufwanyama	100	6	1500	0.75	30	If(Precipitation[mm]-50<0.5,20,4+(180/(Precipitation[mm]-50))^(Ln(Precipitation[mm])/5))
Sengwa	1000	10	405	0.50	7.45	If(Precipitation[mm]-50<0.5,20,5+(250/(Precipitation[mm]-50))^(Ln(Precipitation[mm])/5))
Nabuguyu	1000	10	1150	0.50	122.39	If(Precipitation[mm]-50<0.5,20,5+(250/(Precipitation[mm]-50))^(Ln(Precipitation[mm])/5))
Sanyati	500	50	1000	0.50	6	If(Precipitation[mm]-50<0.5,30,4+(250/(Precipitation[mm]-50))^(Ln(Precipitation[mm])/5))
Chongwe	1000	1	1150	0.80	10	If(Precipitation[mm]-50<0.5,45,3+(250/(Precipitation[mm]-50))^(Ln(Precipitation[mm])/5))
Luswishi	1000	5	1200	0.95	36	60
Kafue4	1000	6	850	0.65	5	If(Precipitation[mm]-50<0.5,25,6+(180/(Precipitation[mm]-50))^(Ln(Precipitation[mm])/5))
Kafue3	500	8	800	0.80	40	If(Precipitation[mm]-50<0.5,15,3+(280/(Precipitation[mm]-50))^(Ln(Precipitation[mm])/5))
Kafue2	1000	8	1600	0.80	12	If(Precipitation[mm]-50<0.5,20,3+(150/(Precipitation[mm]-50))^(Ln(Precipitation[mm])/5))
Kafue1	1000	8	1200	0.80	60	If(Precipitation[mm]-50<0.5,20,3+(250/(Precipitation[mm]-50))^(Ln(Precipitation[mm])/5))

Kafue_S	1000	12	1200	0.50	70	If(Precipitation[mm]-50<0.5,10,3+(230/(Precipitation[mm]-50))^(Ln(Precipitation[mm])/5))
Kafue_J	1000	10	1000	0.75	30	10
Kafue_Q	1000	6	750	0.80	5	10

Table C-60: Calibrated Kc values for Middle Zambezi catchments

Catchment	Kc
Zambezi8	1.09 * MonthlyValues(Jan, 1.241, Feb, 1.315, Mar, 1.113, Apr, 1.085, May, 1.064, Jun, 1.130, Jul, 1.067, Aug, 1.207, Sep, 1.298, Oct, 1.215, Nov, 1.232, Dec, 1.187)
Zambezi7	1.04 * MonthlyValues(Jan, 1.422, Feb, 1.449, Mar, 1.196, Apr, 1.170, May, 1.114, Jun, 1.153, Jul, 1.139, Aug, 1.306, Sep, 1.414, Oct, 1.353, Nov, 1.353, Dec, 1.277)
Zambezi6	1.01 * MonthlyValues(Oct, 1.007, Nov, 1.001, Dec, 0.951, Jan, 0.984, Feb, 1.019, Mar, 0.825, Apr, 0.815, May, 0.755, Jun, 0.811, Jul, 0.798, Aug, 0.919, Sep, 1.027)
Zambezi5	1.00 * MonthlyValues(Oct, 1.057, Nov, 1.102, Dec, 1.144, Jan, 1.129, Feb, 1.072, Mar, 0.825, Apr, 0.729, May, 0.632, Jun, 0.633, Jul, 0.637, Aug, 0.788, Sep, 0.969)
Gwai	1.04 * MonthlyValues(Jan, 1.162, Feb, 1.196, Mar, 1.022, Apr, 1.008, May, 0.967, Jun, 1.023, Jul, 0.988, Aug, 1.127, Sep, 1.209, Oct, 1.125, Nov, 1.119, Dec, 1.066)
Lunga	1.03 * MonthlyValues(Jan, 1.019, Feb, 1.078, Mar, 0.919, Apr, 0.890, May, 0.818, Jun, 0.840, Jul, 0.825, Aug, 0.934, Sep, 0.967, Oct, 0.917, Nov, 0.932, Dec, 1.032)
Lufwanyama	1.08 * MonthlyValues(Jan, 1, Feb, 1.1, Mar, 0.95, Apr, 0.8, May, 0.619, Jun, 0.55, Jul, 0.5, Aug, 0.55, Sep, 0.6, Oct, 0.715, Nov, 0.851, Dec, 0.92)
Sengwa	1.00 * MonthlyValues(Oct, 1.018, Nov, 1.098, Dec, 1.077, Jan, 1.191, Feb, 1.128, Mar, 0.807, Apr, 0.734, May, 0.623, Jun, 0.628, Jul, 0.628, Aug, 0.785, Sep, 0.978)
Nabuguyu	1.00 * MonthlyValues(Oct, 0.997, Nov, 1.075, Dec, 1.068, Jan, 1.138, Feb, 1.071, Mar, 0.784, Apr, 0.706, May, 0.594, Jun, 0.602, Jul, 0.603, Aug, 0.754, Sep, 0.908)
Sanyati	1.00 * MonthlyValues(Oct, 1.176, Nov, 1.282, Dec, 1.251, Jan, 1.363, Feb, 1.234, Mar, 0.933, Apr, 0.856, May, 0.711, Jun, 0.731, Jul, 0.735, Aug, 0.901, Sep, 1.121)
Chongwe	1.04 * MonthlyValues(Oct, 0.984, Nov, 0.989, Dec, 1.009, Jan, 1.024, Feb, 1.008, Mar, 0.997, Apr, 0.975, May, 0.952, Jun, 0.934, Jul, 0.944, Aug, 0.958, Sep, 0.990)
Luswishi	1.06 * MonthlyValues(Jan, 1.262, Feb, 1.323, Mar, 1.115, Apr, 1.069, May, 0.968, Jun, 1.017, Jul, 1.003, Aug, 1.153, Sep, 1.203, Oct, 1.149, Nov, 1.143, Dec, 1.353)

Kafue4	1.06 * MonthlyValues(Jan, 1.335, Feb, 1.396, Mar, 1.188, Apr, 1.142, May, 1.042, Jun, 1.091, Jul, 1.076, Aug, 1.226, Sep, 1.276, Oct, 1.221, Nov, 1.215, Dec, 1.425)
Kafue3	1.05 * MonthlyValues(Jan, 1.018, Feb, 1.076, Mar, 0.918, Apr, 0.889, May, 0.818, Jun, 0.839, Jul, 0.825, Aug, 0.934, Sep, 0.967, Oct, 0.916, Nov, 0.931, Dec, 1.030)
Kafue2	1.07 * MonthlyValues(Jan, 1.141, Feb, 1.187, Mar, 0.992, Apr, 0.980, May, 0.907, Jun, 0.953, Jul, 0.938, Aug, 1.062, Sep, 1.109, Oct, 1.070, Nov, 1.051, Dec, 1.162)
Kafue1	1.04 * MonthlyValues(Jan, 1.236, Feb, 1.275, Mar, 1.028, Apr, 1.037, May, 0.973, Jun, 1.036, Jul, 1.027, Aug, 1.169, Sep, 1.251, Oct, 1.228, Nov, 1.218, Dec, 1.238)
Kafue_S	1.06 * MonthlyValues(Jan, 0.893, Feb, 0.952, Mar, 0.801, Apr, 0.784, May, 0.737, Jun, 0.778, Jul, 0.749, Aug, 0.856, Sep, 0.894, Oct, 0.867, Nov, 0.874, Dec, 0.893)
Kafue_J	1.08 * MonthlyValues(Jan, 0.971, Feb, 1.030, Mar, 0.870, Apr, 0.841, May, 0.769, Jun, 0.791, Jul, 0.776, Aug, 0.885, Sep, 0.919, Oct, 0.868, Nov, 0.883, Dec, 0.983)
Kafue_Q	1.06 * MonthlyValues(Jan, 1.335, Feb, 1.396, Mar, 1.188, Apr, 1.142, May, 1.042, Jun, 1.091, Jul, 1.076, Aug, 1.226, Sep, 1.276, Oct, 1.221, Nov, 1.215, Dec, 1.425)

Figure C-120: Simulated and observed Kafue River flows below Iztezhi Tezhi dam

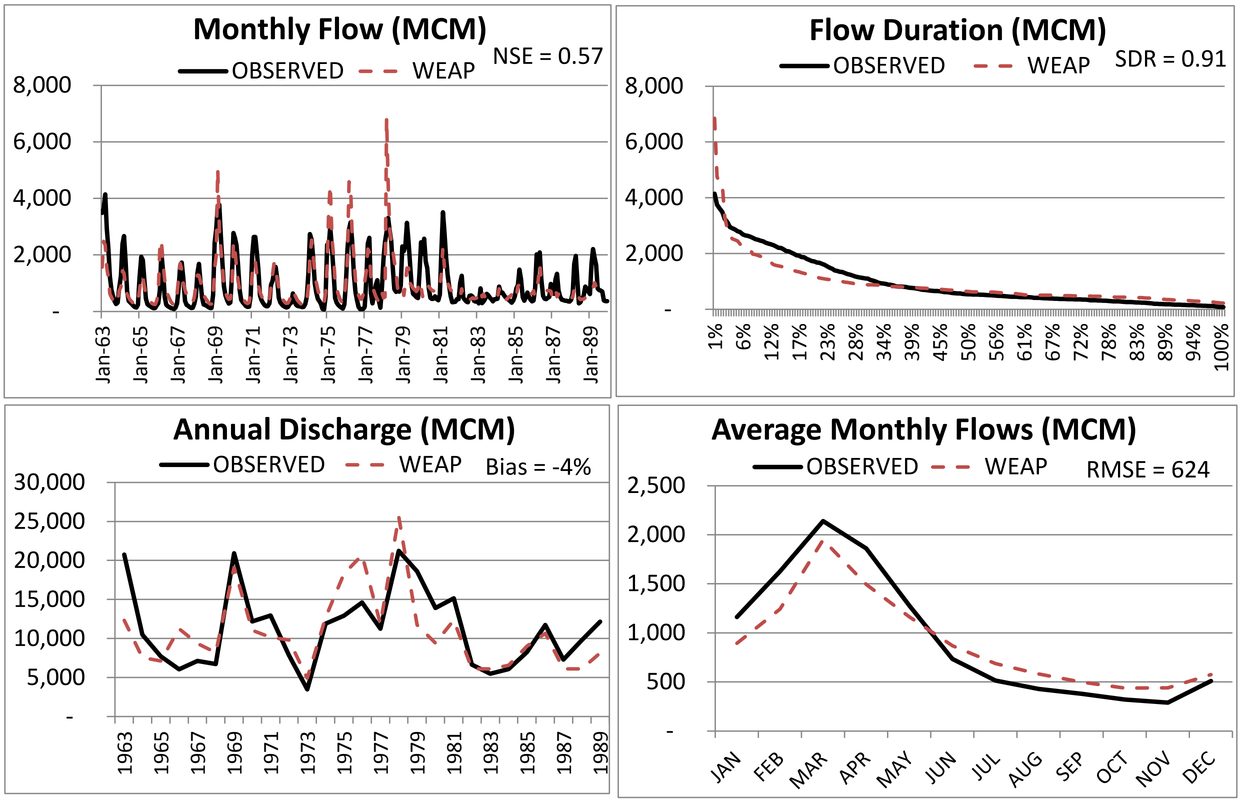
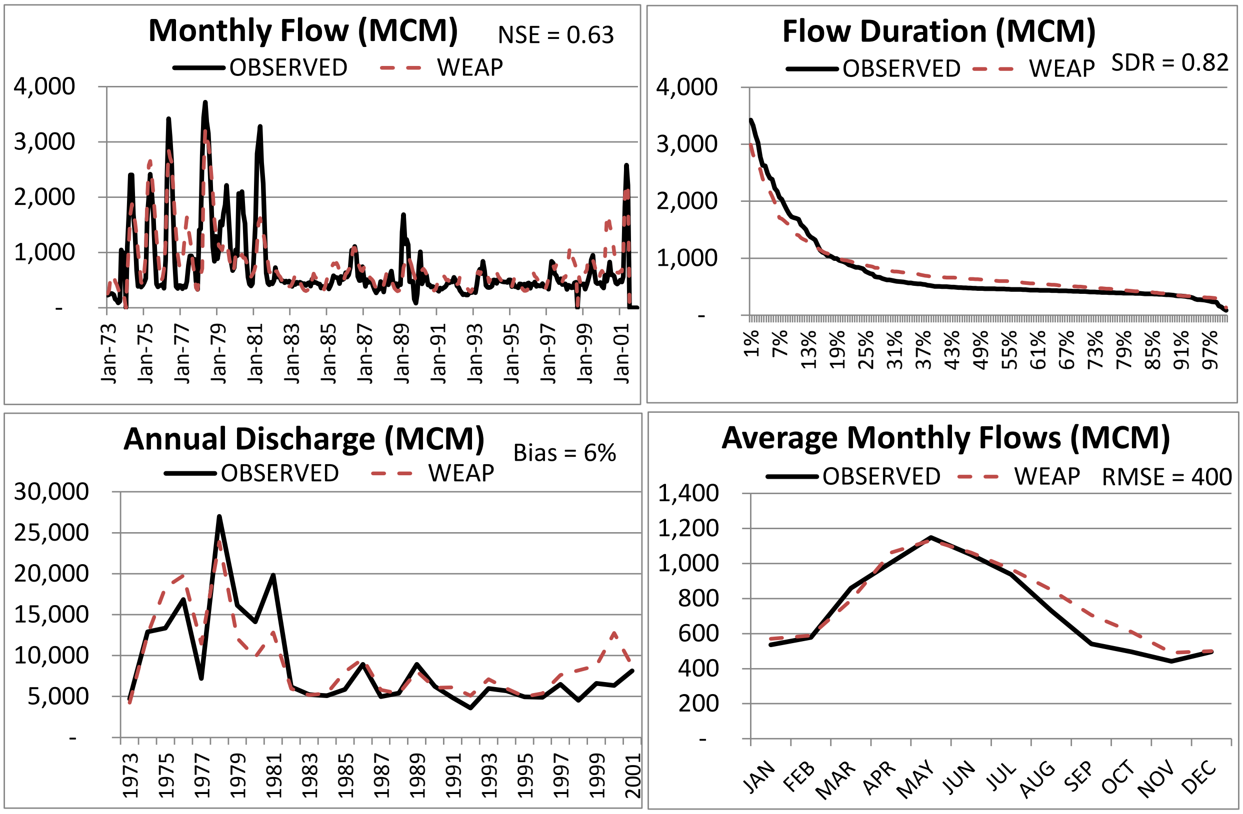


Figure C-121: Simulated and observed Kafue River flows below Kafue Flats wetland



Calibration: Lower Zambezi

The 2 main gauges on the Shire River, CLI_Liwonde (located below Lake Malawi; Figure C-123) and CLI_Chikwawa (near the confluence with Zambezi River; Figure C-124) were used to determine the equations for the flow requirement below Lake Malawi and Shire Marsh, shown in Figure C-120. The gauge on the Zambezi River near Tete in Mozambique (CLI_Tete) was used to calibrate the Cahora Bassa Dam on the Zambezi River before the river joins the Shire River (Figure C-126). The lower Zambezi, with the Luangwa and Shire Rivers as its major tributaries, is shown in Figure C-122 .

Figure C-122: WEAP schematic for lower Zambezi including the Luanga and Shire Rivers

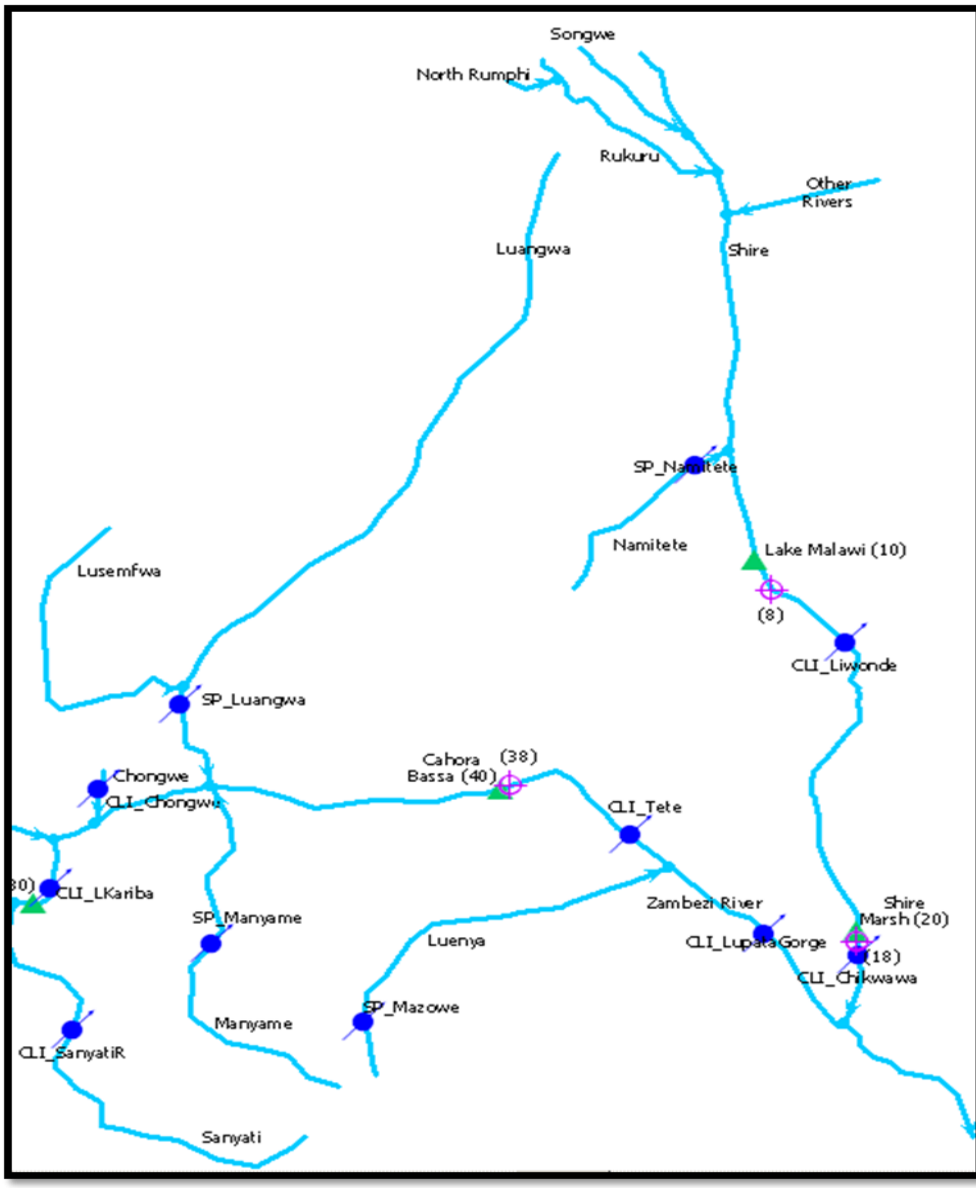


Table C-61: Calibration parameter values for Lower Zambezi catchments

Catchment	DWC (mm)	DC (mm)	SWC (mm)	PFD	RZC (mm)	RRF
Lusemfwa	1000	5	750	0.90	13	If(Precipitation[mm]-50<0.5,30,9+(250/(Precipitation[mm]-50))^(Ln(Precipitation[mm])/5))
Zambezi4	1000	5	1150	0.90	122.39	10
Zambezi3	1000	5	1300	0.80	20	10
Zambezi2	1000	5	1150	0.80	122.39	10
Zambezi1	1000	8	1150	0.80	122.39	10
Chire	1000	8	1150	0.90	122.39	10
Luangwa4	1000	5	1185	0.90	47.177	If(Precipitation[mm]-50<0.5,30,8+(250/(Precipitation[mm]-50))^(Ln(Precipitation[mm])/5))
Luangwa3	1000	5	421	0.90	22.425	If(Precipitation[mm]-50<0.5,30,8+(250/(Precipitation[mm]-50))^(Ln(Precipitation[mm])/5))
Luangwa2	1000	5	460	0.90	8.63	If(Precipitation[mm]-50<0.5,30,9+(250/(Precipitation[mm]-50))^(Ln(Precipitation[mm])/5))
Luangwa1	1000	5	504	0.90	45.462	If(Precipitation[mm]-50<0.5,30,9+(250/(Precipitation[mm]-50))^(Ln(Precipitation[mm])/5))
Munyamadzi	1000	5	1200	0.90	52	If(Precipitation[mm]-50<0.5,30,7+(250/(Precipitation[mm]-50))^(Ln(Precipitation[mm])/5))
Owangawa	1000	5	916	0.90	67.491	10
Namitete	1000	5	600	0.80	30	10
Shire	1000	8	650	0.90	150	10
Condedezi	1000	5	1150	0.80	122.39	10
Mucanha	1000	5	1150	0.80	122.39	10
Capoche	1000	10	1150	0.70	122.39	10
Angwa	1000	2	400	0.80	13	10

Manyame	500	50	500; 600	0.50	13	If(Precipitation[mm]-50<0.5,20,5+(250/(Precipitation[mm]-50))^(Ln(Precipitation[mm])/5))
Aruangua	1000	5	1200	0.90	65	If(Precipitation[mm]-50<0.5,25,8+(250/(Precipitation[mm]-50))^(Ln(Precipitation[mm])/5))
Mazowe	1000	10	500	0.90	45	10
Mazowe2	1000	10	900	0.90	45+ 50 * (PrevTSValue(Relative Soil Moisture 1[%])/100)^2	10
Rumphi	1000	100	750	0.50	150	4.5
ELNyasa	1000	10	416	0.80	55.491	10
Lilongwe	1000	10	700	0.80	150	10
Songwe	1000	10	200	0.90	82+ 50 * (PrevTSValue(Relative Soil Moisture 1[%])/100)^2	10
Lufira	1000	10	200	0.90	82+ 50 * (PrevTSValue(Relative Soil Moisture 1[%])/100)^2	10
Rukuru	1000	100	750	0.80	150	If(Precipitation[mm]-50<0.5,10,1.3+(250/(Precipitation[mm]-50))^(Ln(Precipitation[mm])/5))
Rukuru2	1000	100	750	0.75	150	If(Precipitation[mm]-50<0.5,10,1.3+(250/(Precipitation[mm]-50))^(Ln(Precipitation[mm])/5))

Table C-62: Calibrated Kc values for Lower Zambezi catchments

Catchment	Kc
Lusemfwa	1.04 * MonthlyValues(Oct, 1.010, Nov, 1.025, Dec, 1.171, Jan, 1.142, Feb, 1.078, Mar, 0.844, Apr, 0.771, May, 0.680, Jun, 0.696, Jul, 0.696, Aug, 0.841, Sep, 0.956)
Zambezi4	1.04 * MonthlyValues(Oct, 1.028, Nov, 1.075, Dec, 1.098, Jan, 1.151, Feb, 1.052, Mar, 0.814, Apr, 0.715, May, 0.608, Jun, 0.600, Jul, 0.600, Aug, 0.763, Sep, 0.943)
Zambezi3	1.06 * MonthlyValues(Oct, 1.105, Nov, 1.206, Dec, 1.225, Jan, 1.288, Feb, 1.182, Mar, 0.953, Apr, 0.834, May, 0.707, Jun, 0.695, Jul, 0.676, Aug, 0.859, Sep, 0.999)
Zambezi2	1.01 * MonthlyValues(Oct, 1.057, Nov, 1.194, Dec, 1.204, Jan, 1.356, Feb, 1.203, Mar, 1.004, Apr, 0.836, May, 0.662, Jun, 0.639, Jul, 0.625, Aug, 0.791, Sep, 0.932)

Zambezi1	0.91 * MonthlyValues(Oct, 1.099, Nov, 1.277, Dec, 1.281, Jan, 1.447, Feb, 1.329, Mar, 1.198, Apr, 0.983, May, 0.742, Jun, 0.699, Jul, 0.680, Aug, 0.820, Sep, 0.988)
Chire	0.83 * MonthlyValues(Oct, 1.069, Nov, 1.201, Dec, 1.297, Jan, 1.374, Feb, 1.264, Mar, 1.077, Apr, 0.890, May, 0.704, Jun, 0.667, Jul, 0.644, Aug, 0.796, Sep, 0.942)
Luangwa4	1.2 * MonthlyValues(Oct, 1.079, Nov, 1.072, Dec, 1.129, Jan, 1.108, Feb, 1.217, Mar, 1.028, Apr, 0.930, May, 0.815, Jun, 0.807, Jul, 0.804, Aug, 0.944, Sep, 1.049)
Luangwa3	1.2 * MonthlyValues(Oct, 1.080, Nov, 1.083, Dec, 1.112, Jan, 1.064, Feb, 1.129, Mar, 0.933, Apr, 0.842, May, 0.754, Jun, 0.740, Jul, 0.737, Aug, 0.906, Sep, 1.016)
Luangwa2	1.2 * MonthlyValues(Oct, 1.045, Nov, 1.047, Dec, 1.106, Jan, 1.106, Feb, 1.074, Mar, 0.879, Apr, 0.779, May, 0.703, Jun, 0.698, Jul, 0.705, Aug, 0.865, Sep, 0.987)
Luangwa1	1.2 * MonthlyValues(Oct, 1.039, Nov, 1.057, Dec, 1.174, Jan, 1.161, Feb, 1.114, Mar, 0.863, Apr, 0.784, May, 0.690, Jun, 0.693, Jul, 0.700, Aug, 0.854, Sep, 0.966)
Munyamadzi	1.2 * MonthlyValues(Oct, 1.015, Nov, 1.015, Dec, 1.096, Jan, 1.036, Feb, 1.045, Mar, 0.893, Apr, 0.818, May, 0.740, Jun, 0.730, Jul, 0.735, Aug, 0.878, Sep, 0.982)
Owangawa	1.15 * MonthlyValues(Oct, 1.166, Nov, 1.256, Dec, 1.296, Jan, 1.218, Feb, 1.252, Mar, 1.095, Apr, 0.914, May, 0.793, Jun, 0.789, Jul, 0.775, Aug, 0.970, Sep, 1.086)
Namitete	1.16 * MonthlyValues(Oct, 1.077, Nov, 1.150, Dec, 1.138, Jan, 1.155, Feb, 1.088, Mar, 0.927, Apr, 0.773, May, 0.688, Jun, 0.700, Jul, 0.689, Aug, 0.858, Sep, 1.007)
Shire	0.88 * MonthlyValues(Oct, 0.653, Nov, 1.007, Dec, 1.904, Jan, 2.129, Feb, 1.888, Mar, 1.122, Apr, 0.958, May, 0.898, Jun, 1.010, Jul, 0.890, Aug, 0.801, Sep, 0.651)
Condedezi	1.06 * MonthlyValues(Oct, 1.140, Nov, 1.229, Dec, 1.323, Jan, 1.282, Feb, 1.214, Mar, 0.988, Apr, 0.878, May, 0.811, Jun, 0.822, Jul, 0.782, Aug, 0.954, Sep, 1.096)
Mucanha	1.07 * MonthlyValues(Oct, 1.035, Nov, 1.090, Dec, 1.150, Jan, 1.184, Feb, 1.095, Mar, 0.828, Apr, 0.736, May, 0.627, Jun, 0.618, Jul, 0.619, Aug, 0.787, Sep, 0.957)
Capoche	1.08 * MonthlyValues(Oct, 1.081, Nov, 1.133, Dec, 1.221, Jan, 1.239, Feb, 1.138, Mar, 0.901, Apr, 0.805, May, 0.715, Jun, 0.715, Jul, 0.706, Aug, 0.876, Sep, 1.013)
Angwa	1.01 * MonthlyValues(Oct, 1.027, Nov, 1.088, Dec, 1.097, Jan, 1.136, Feb, 1.075, Mar, 0.806, Apr, 0.707, May, 0.595, Jun, 0.596, Jul, 0.608, Aug, 0.757, Sep, 0.952)
Manyame	1.06 * MonthlyValues(Oct, 1.004, Nov, 1.105, Dec, 1.125, Jan, 1.219, Feb, 1.119, Mar, 0.823, Apr, 0.716, May, 0.587, Jun, 0.585, Jul, 0.593, Aug, 0.738, Sep, 0.922)
Aruangua	1.2 * MonthlyValues(Oct, 1.036, Nov, 1.075, Dec, 1.199, Jan, 1.184, Feb, 1.091, Mar, 0.835, Apr, 0.750, May, 0.655, Jun, 0.658, Jul, 0.671, Aug, 0.815, Sep, 0.948)
Mazowe	1.09 * MonthlyValues(Oct, 0.994, Nov, 1.081, Dec, 1.078, Jan, 1.220, Feb, 1.063, Mar, 0.825, Apr, 0.712, May, 0.583, Jun, 0.570, Jul, 0.568, Aug, 0.725, Sep, 0.905)
Mazowe2	1.05 * MonthlyValues(Oct, 0.994, Nov, 1.081, Dec, 1.078, Jan, 1.220, Feb, 1.063, Mar, 0.825, Apr, 0.712, May, 0.583, Jun, 0.570, Jul, 0.568, Aug, 0.725, Sep, 0.905)
Rumphi	1.04 * MonthlyValues(Jan, 1.5, Feb, 1.6, Mar, 1.7, Apr, 1.6, May, 1.25, Nov, 1.25, Dec, 1.5)
ELNyasa	0.91 * MonthlyValues(Oct, 1.085, Nov, 1.214, Dec, 1.453, Jan, 1.325, Feb, 1.355, Mar, 1.266, Apr, 1.032, May, 0.788, Jun, 0.757, Jul, 0.741, Aug, 0.898, Sep, 1.006)

Lilongwe	1.05 * MonthlyValues(Oct, 1.091, Nov, 1.172, Dec, 1.267, Jan, 1.268, Feb, 1.174, Mar, 0.992, Apr, 0.838, May, 0.729, Jun, 0.741, Jul, 0.723, Aug, 0.887, Sep, 1.011)
Songwe	1.05 * MonthlyValues(Oct, 1.269, Nov, 1.328, Dec, 1.427, Jan, 1.329, Feb, 1.471, Mar, 1.257, Apr, 1.114, May, 0.935, Jun, 0.915, Jul, 0.900, Aug, 1.053, Sep, 1.186)
Lufira	1.05 * MonthlyValues(Oct, 1.269, Nov, 1.328, Dec, 1.427, Jan, 1.329, Feb, 1.471, Mar, 1.257, Apr, 1.114, May, 0.935, Jun, 0.915, Jul, 0.900, Aug, 1.053, Sep, 1.186)
Rukuru	1.04 * MonthlyValues(Jan, 1.5, Feb, 1.6, Mar, 1.7, Apr, 1.6, May, 1.25, Nov, 1.25, Dec, 1.5)
Rukuru2	1.04 * MonthlyValues(Jan, 1.65, Feb, 1.75, Mar, 2, Apr, 1.75, May, 1.5, Nov, 1.5, Dec, 1.65)

Figure C-123: Simulated and observed Shire River flows below Lake Malawi

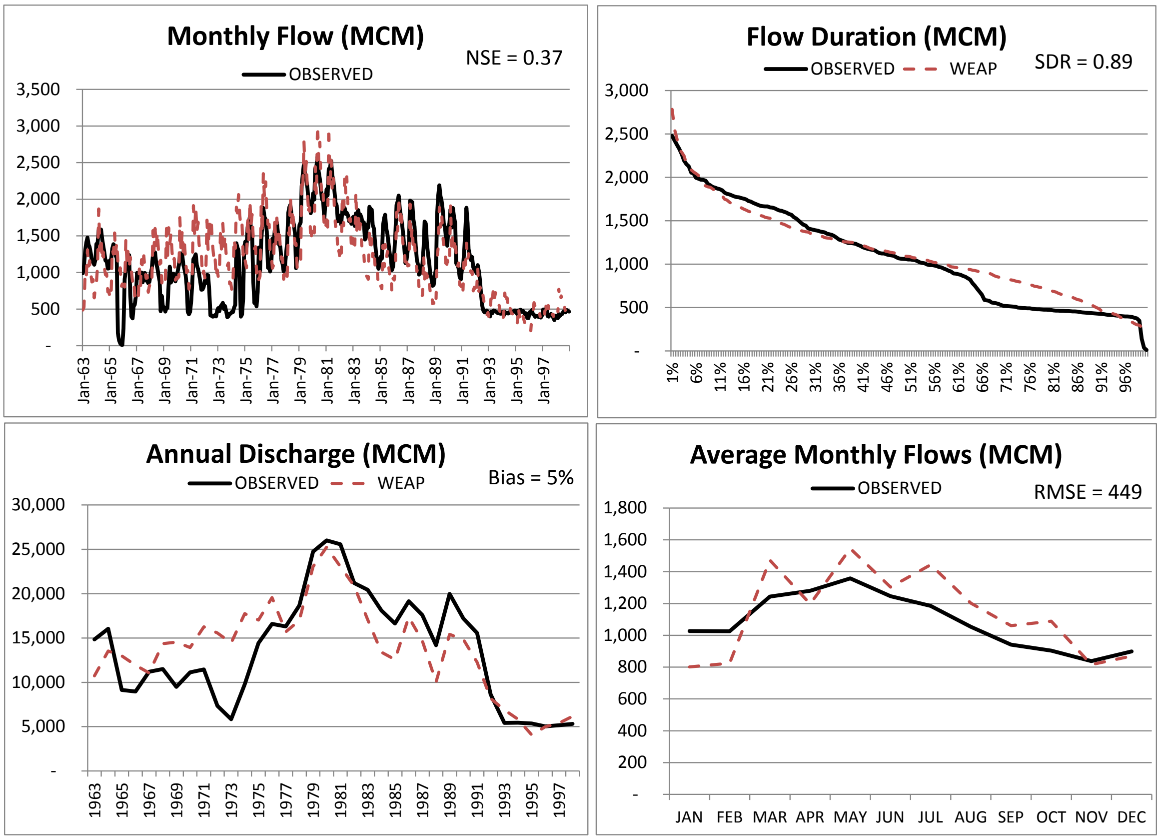


Figure C-124: Simulated and observed Shire River flows below Shire Marsh

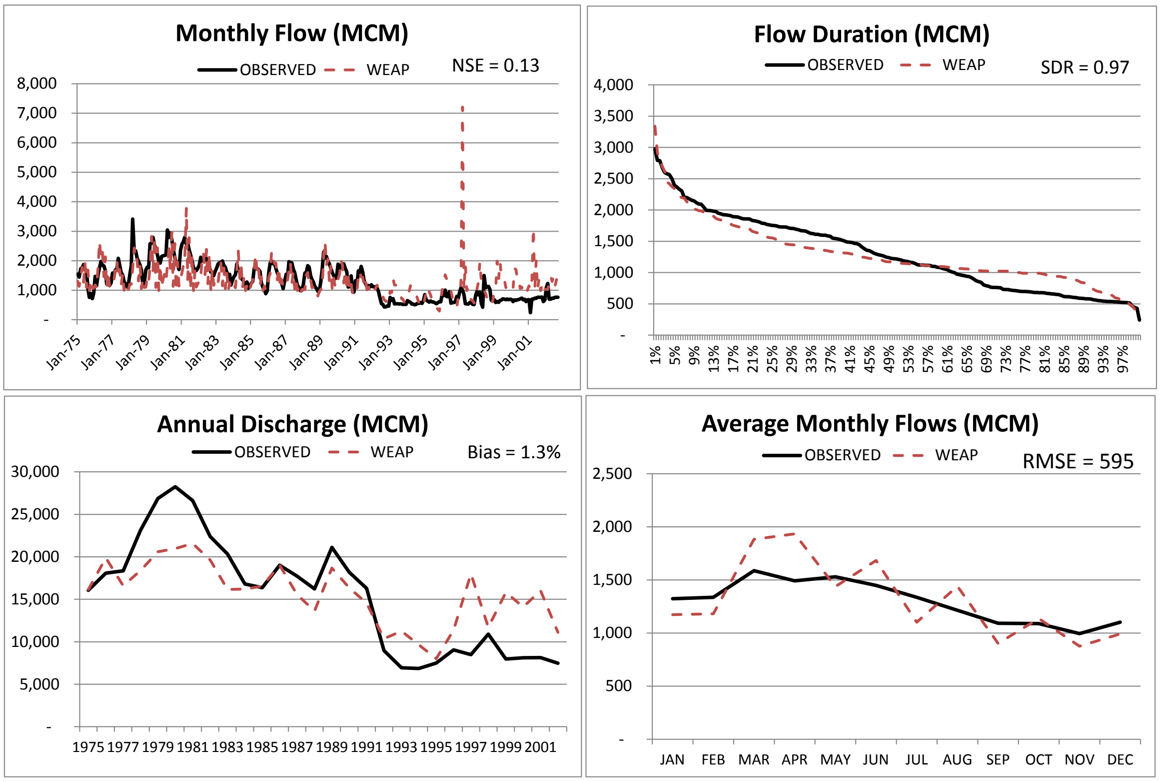


Figure C-125. Simulated and observed Luangwa River inflow to Zambezi River

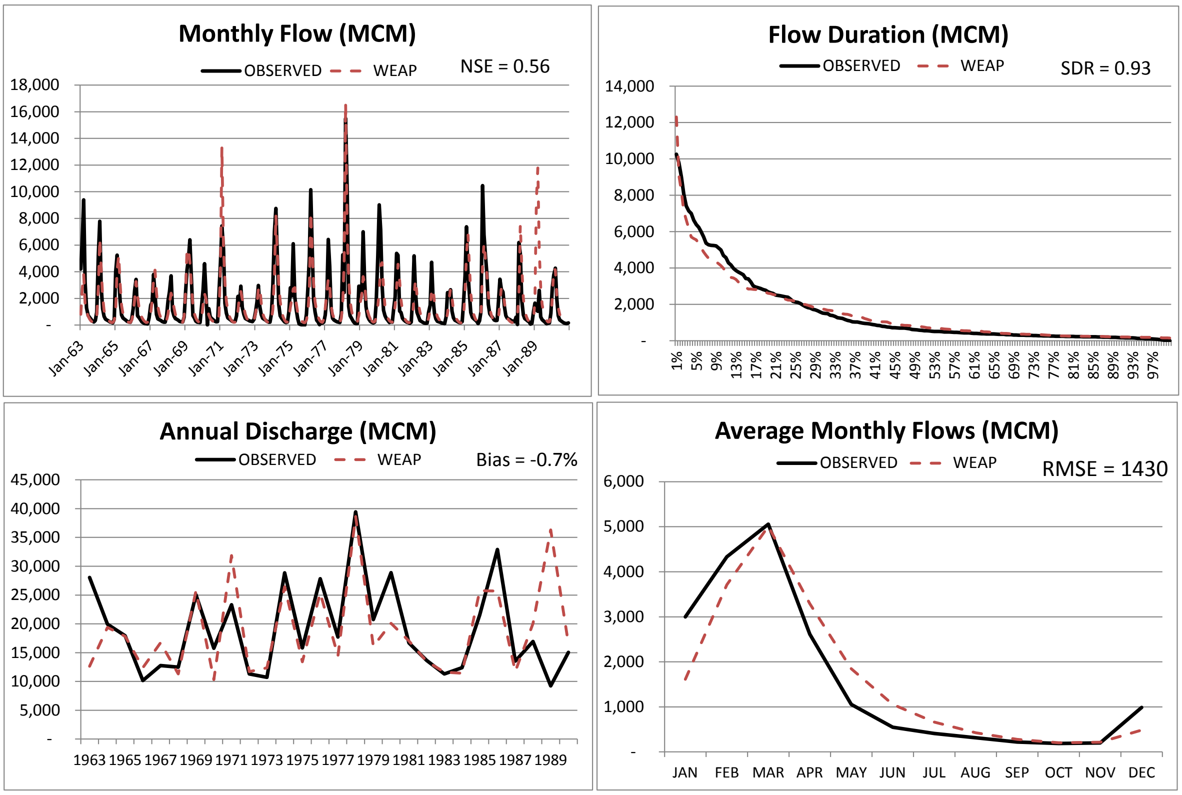
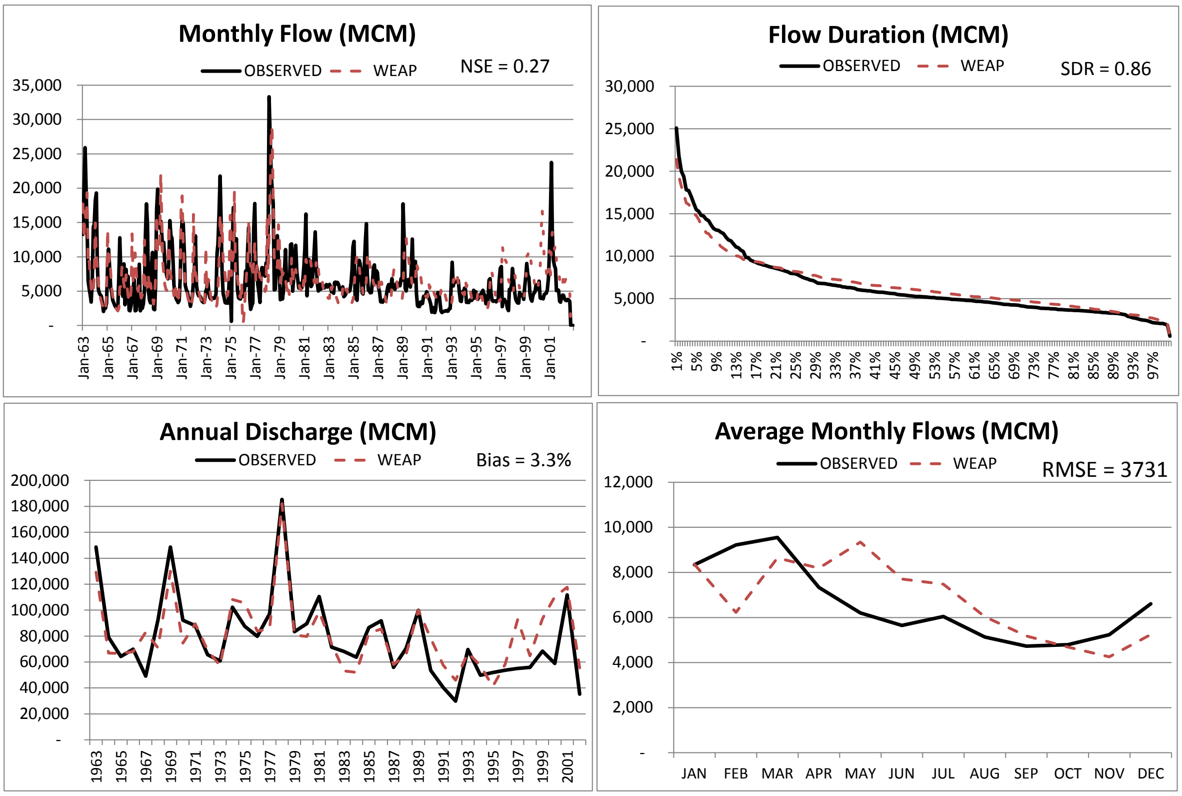


Figure C-126: Simulated and observed Zambezi River flows at Tete



Water Resources Simulation

For the calibration of system operations, we focused on the simulated versus observed reservoir storage for the two reservoirs with historical records that are sufficiently long to reflect a range of climatic and hydrologic conditions – i.e. Lake Kariba and Cahora Bassa. In general, the WEAP model was found to approximate the historical fluctuations in storage in both at an acceptable level of accuracy given the variation in system operations that occurred over the observation period (Figure C-127 & Figure C-128).

In particular, we found that the simulated reservoir levels are inevitably sensitive to hydropower demands, which were inconsistent over the calibration period. This was particularly true with Cahora Bassa, which did not follow normal operating rules during 1983-1997, when transmission lines to South Africa were out of commission.

Figure C-127: Simulated and observed Lake Kariba storage

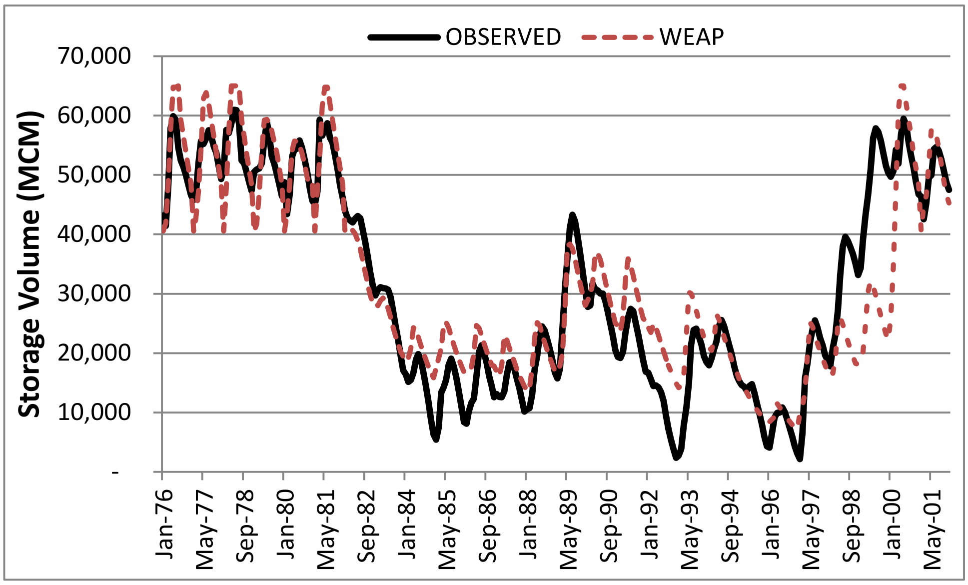
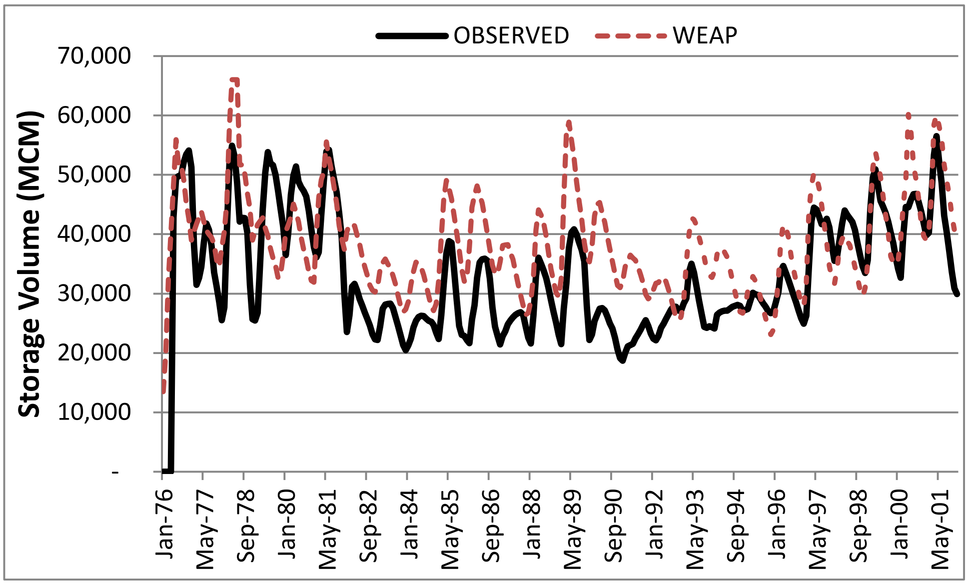


Figure C-128: Simulated and observed Cahora Bassa storage



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D. Power Pool Modeling

D1- OSeMOSYS Common Modeling Assumptions

Introduction to the Methodology

The model was developed using the Open Source energy Modeling System (OSeMOSYS). OSeMOSYS is a dynamic, bottom-up, multi-year energy system model applying linear optimization techniques.

The model framework consists of demand projections and a database of power supply technologies that are characterised by economic, technical and environmental parameters, and information regarding the existing capital stock and its remaining life span. Energy resource prices and quantities are defined by the model user. Furthermore, the model is restricted by so-called "constraints" used to reflect, amongst others, operational requirements, governmental policies, or socio-economic realities. All parameters entered in the modeling framework are time dependent and can be adjusted over the study horizon to represent a variety of potential futures.

The regions modelled in this exercise include the four power pools of Sub Saharan Africa (SSA) and cover all continental countries thereof. Specifically, we represent:

- The Southern African Power Pool with: The Democratic Republic of the Congo, The Kingdoms of Lesotho and Swaziland, The Republics of Angola, Malawi, Mozambique, Namibia, South Africa, Zambia and Zimbabwe as well as the United Republic of Tanzania.
- The Western African Power Pool with: The Republics of Benin, Côte d'Ivoire, Ghana, Guinea, Guinea-Bissau, Liberia, Mali, Niger, Senegal and Sierra Leone, the Federal Republic of Nigeria, the Togolese Republic as well as Burkina Faso and The Gambia
- The Eastern African Power Pool with: The Republics of Burundi, Djibouti, Kenya, the Sudan, Rwanda, and Uganda, the State of Eritrea, the Federal Democratic Republic of Ethiopia, the Federal Republic of Somalia, the United Republic of Tanzania, the Democratic Republic of Congo and Egypt.
- And the Central African Power Pool with: The Republics of Angola, Burundi, Cameroon, Chad, Equatorial Guinea, Gabon Congo, and Rwanda as well as the Central African Republic (CAF), the Democratic Republic of Congo.

These power pools are modelled in parallel to the development of corresponding River Basin water models for seven of the major basins of SSA – namely the Congo, the Niger, the Nile, the Orange, the Senegal, the Volta and the Zambezi.

OSeMOSYS is a least cost system optimization tool: it reports on the investment and production mix of technologies and fuels required to best meet a given energy demand. In the case of this study, each power pool is modelled separately in successive steps. The objective function of the modelling framework is thus to minimise sequential power pool level costs on a full model horizon basis. Technical, economic and environmental implications associated with the identified least-cost energy systems can be easily extracted from the model results. Like other optimization models, OSeMOSYS assumes a perfect market with perfect competition and foresight.

The technologies considered include existing power generation options as well as new generic options. Future plans for technology installation are taken into account and are split into three categories, i.e., committed, proposed and generic, whereas:

- Each identified hydro power project is represented by a specific technology
- Technologies relating to committed projects are forced into operation on the planned year of installation at the relevant capacity level
- Potential projects – available from their anticipated installation dates – are modelled as options which the model may choose to invest in.
- Site specific projects are populated with site specific cost and performance data.
- The model may also invest in generic technology categories, which are represented by generic cost and performance data.

Improving the model's representation of the role of decentralized power options, for which renewables can offer a significant cost advantage over fossil based options, the power demand was split into three categories: namely industrial, urban and rural electricity use. Each demand is provided for through a dedicated "energy chain", linking it through a chain of technologies with the available resources. These separate chains allow the modeller to consider different capital costs for distribution line technologies depending on the assumed remoteness of the demand, but also enable distinct generation options to be made available to each different demand category.

The model and approach is technology neutral. All options available are represented. These include: Fossil, Nuclear and Renewable technologies. Fossil fuels are drawn from either domestic reserves or are imported where available on a geographical basis. Nuclear fuel requirements are implicitly considered in the generation costs of nuclear power plants, but are not accounted for explicitly. Renewable fuels are represented based on the available national potentials.as per the latest available assessment conducted through GIS based resource analysis by KTH dESA in collaboration with the International Renewable Energy Agency (IRENA) (Hermann et al., 2014). Finally, transmission and distribution is modelled explicitly: secondary transmission as well as sector specific distribution technologies are included for each country. This structure allows for a simplified inclusion of distributed generation systems – e.g. standalone generation or mini grid systems – as end use generation options. From an electricity trade perspective, existing and committed trans-national connections are included as fixed installation. Future identified options that are not currently commited have also been added to the model as options.

The Model Framework & Reference Energy System

Energy models are computational representations of the physical systems that enable a country or region to generate and distribute their energy. As such, they abstract from the geographical aspect of the system and simulate a network of interconnected technologies that allow different energy carriers to flow from resources to demands. A technology in this context can represent anything that supplies or converts energy, from a coal-mine to a household appliance. The schematic representation of the different paths these flow can take across so-called “energy chains” is called a Reference Energy System (RES).

The RES diagrams presented in Figure D-1 and Figure D-2 show the generic way in which each country is set up inside the modeling framework. With flows going from left to right, each final demand of electricity if provided for by a selection of energy chains transforming primary fuel resources into multiple grades of intermediary fuels that are used to generate the requested electricity.

From a structural point of view, each vertical 'line' element of the RES represents a change in the nature of the energy or in the grade of the commodity flowing through the system. (Adjacent lines are normally thought to be at the same 'level'. i.e. All resources are grouped at the 'primary' level, as 'demands' at the 'tertiary' level etc.). This change between fuels is enabled by the horizontal connections that link successive energy levels and represent the different generation and transmission technologies available to the system. The structure is used to model the typical way in which energy carriers are transported and transformed in a country, this includes:

- Raw **resources** being extracted or imported
- Refined **primary fuels**
- **Secondary electricity** feeding into high voltage transmission
- **Tertiary electricity** after step down transformers and before low voltage distribution
- **Final energy** meeting the demand

From a more conceptual point of view, Figure D-1 shows the connection between the water and the energy systems and the related information flow. The water simulation modeling, performed by SEI, for each of the water basins includes a certain number of hydropower facilities which each provide their specific set of water services including reservoir storage, hydropower generation, irrigation, domestic use, and flow[2]. Once all other services are accounted for, the water availability for power generation at the corresponding site is assessed. This information is transferred to the energy models by adjusting the capacity factors[3] of the respective hydro power plants (see Integration with the WEAP modeling detailing the linkage between WEAP and OSeMOSYS)

Going into further detail, Figure D-2 shows the types of technologies that are available to each country as well as the final demands that they participate in serving. Each country is equipped with national options (where they exist) for fossil fuel extraction as well as relevant import options.

It is important to notice that, in the present setup, the different countries are represented by parallel and separate sets of energy chains leading to the respective country level demands. This, in effect, creates a multi-regional model where exchanges between different national energy chains occur through dedicated International Transmission technologies (e.g. “C1_C2Link” in Figure D-2).

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[2] Specific assumptions regarding the water allocation from each hydro power station is available in the corresponding River Basin WEAP Annexes (B,B1-7).

[3] The capacity factor is calculated for each scenario and for each power plant using information regarding the amount of available water in the system at each month of each year for that power plant. A proxy system adjusts power plants that are in OSeMOSYS models but not in the WEAP water system model.

The current set up enables a separation between centralized and de-centralized options, as visible in Figure D-2. For example, coal power plants feed into the secondary – centralized – level and can distribute power to all levels of demand. Conversely distributed solar PV feeds into the final levels and is specific between demand types. Since the final demand is broken down per sector, different sectors are fed by different parts of the grid which are characterized by different technical and economic parameters. This allows consider of cost variations, which, e.g., may make distributed generation more interesting for the provision of rural demand. A full list of technologies included in the models is detailed in **Table D-3: National Transmission and Distribution technology characteristics**.

Figure D-1: General RES - Connections between the Water and the Energy modeling

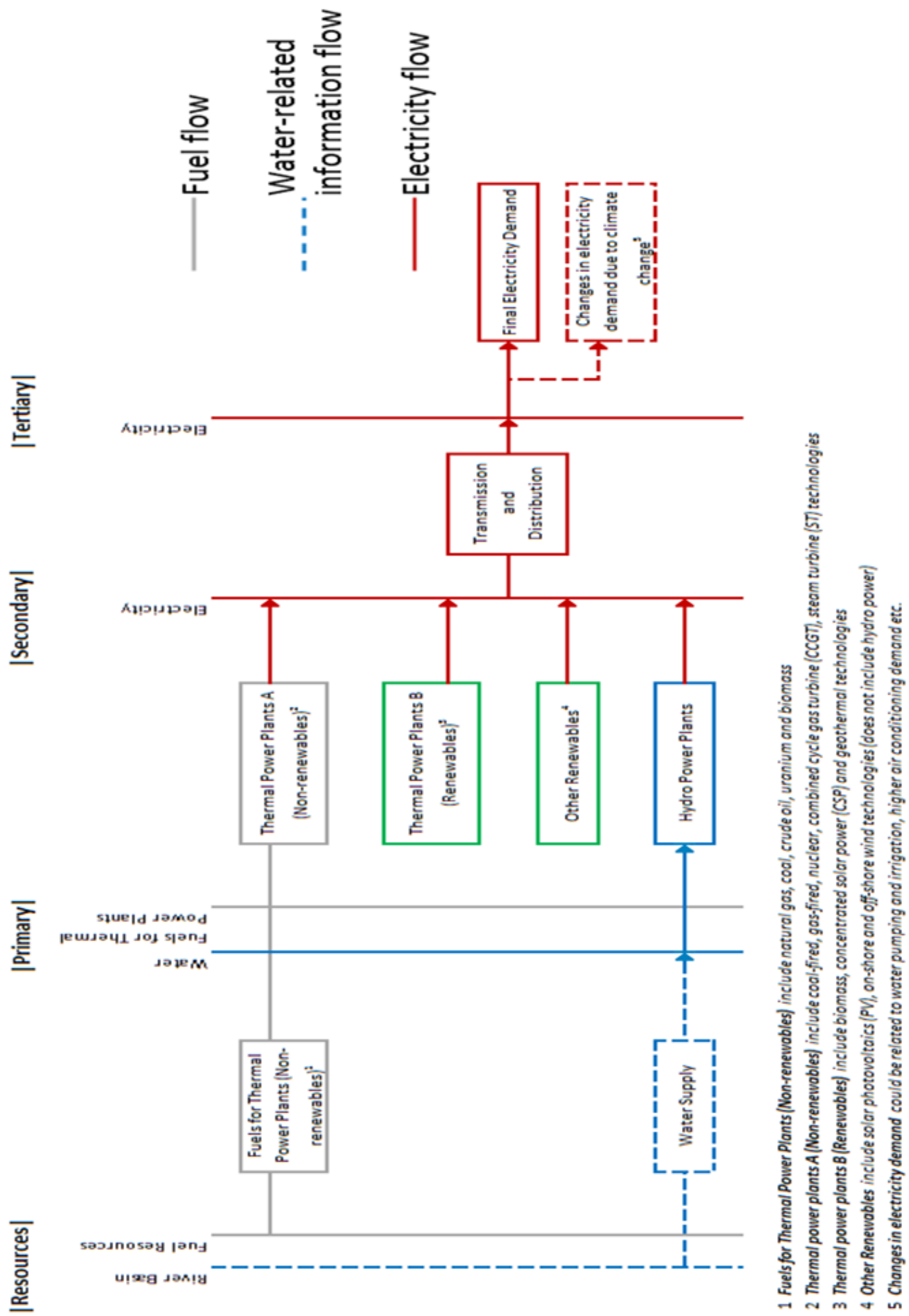
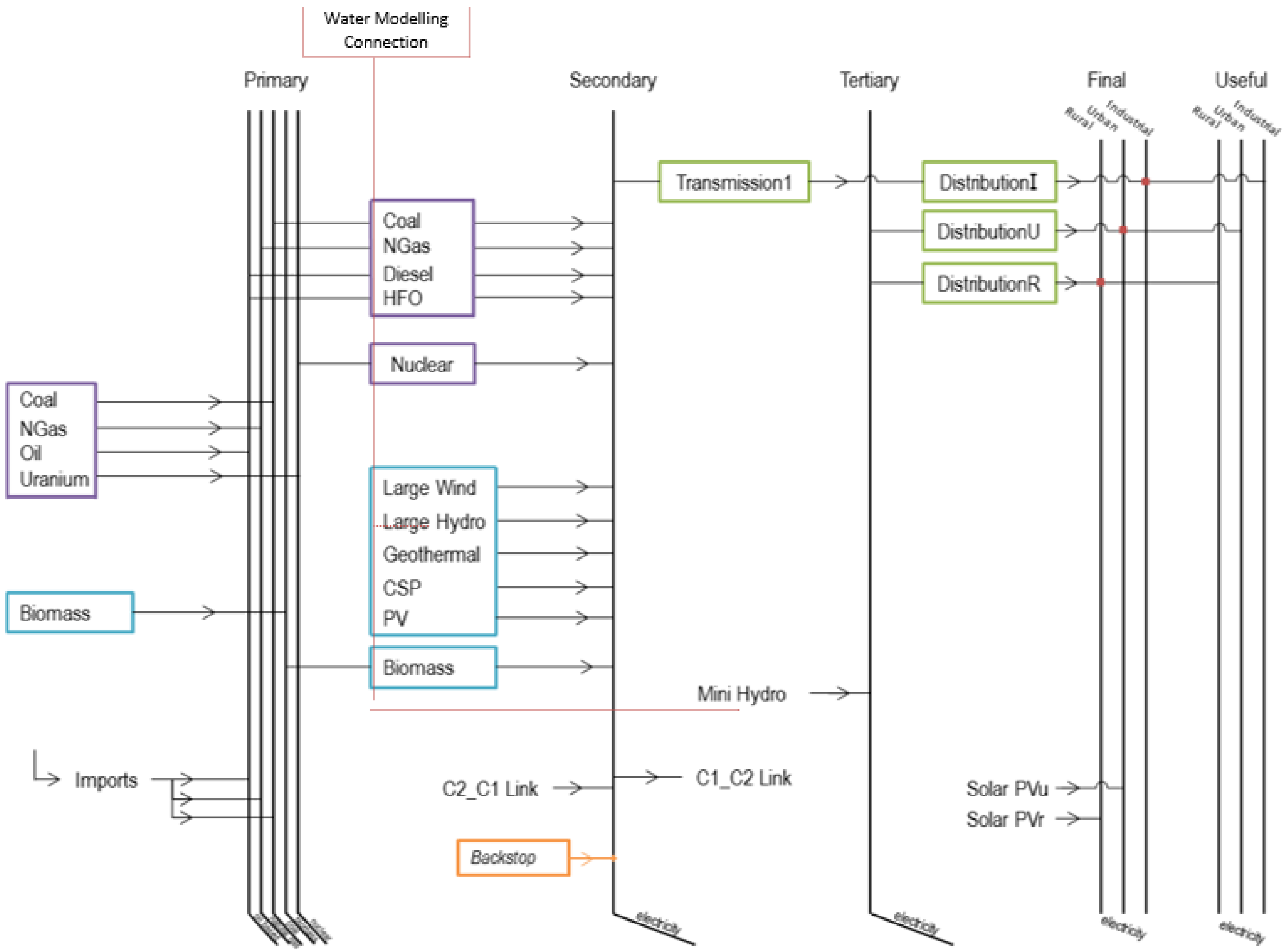


Figure D-2: Reference Energy System used for this study



Overview of General Modeling Assumptions

Overarching Model Assumptions

A certain number of assumptions are fundamental in defining the structure and general context of the modeling effort. The following parameters are maintained constant throughout the analysis:

- The real discount rate applied is 5%[4].
- The monetary unit is 2010 US$
- An exchange rate of 7.4 South African Rand to the US dollar was considered (Miketa and Merven, 2013)
- The reporting horizon of this study spans from 2010 to 2050. Simulations are undertaken on a yearly basis for the entire model period.
- The modeling framework is extended between 2050 and 2060 in order to avoid so called 'edge-effect' considerations from affecting the reported results.
- The year is represented by 48 characteristic time periods per year. See the next section as well in the specific power pool reports for further detail.
- As mentioned in the introduction: OSeMOSYS assumes a perfect market with perfect competition and foresight

Time Slices & Load Curves

When considering an energy system, it becomes apparent that different energy carriers are subject to different intrinsic constraints. For energy carriers that need to be produced in the exact moment in which they are consumed – i.e. for which no, very few, or expensive storage solutions exist in the system – such as heat or electricity, it is important to represent variations of demand within the year rather than simply specifying a total annual fuel requirement. These different "parts" of a same year are called "time-slices" and are typically chosen to be representative of a given state of the system. Within a same time-slice, all variables and parameters related to demand and generation are assumed to remain constant. All energy balances and constraints are assessed on a time-slice level (or group of time-slices) on which they apply. Defining the time slice structure thereby defines the level of detail that can be represented within the energy model. A higher number of time slices is usually associated with more accurate results. This however comes at the cost of higher computing requirements, resulting in a trade-off between gains in accuracy versus increases in computing time.

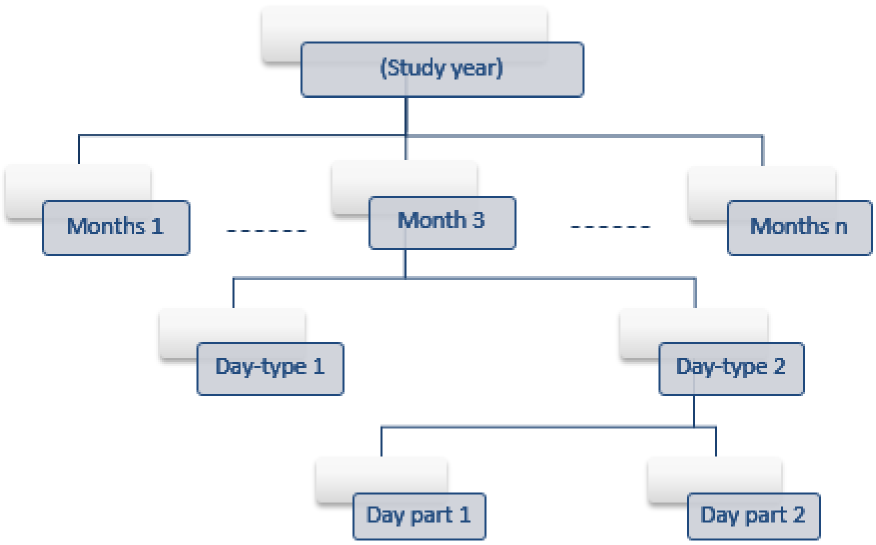
The present modeling approach has a clear focus on water integration in the energy system and the impact of water availability changes on the energy infrastructure across multiple climate scenarios. It is therefore important to capture the variations in water availability for power generation on a representative scale within the basic model structure. In order to account for both long term and annual scale climate variations, water availability was considered on a monthly scale. Each year was thus broken down into twelve time periods. Additionally, in order to capture variations in energy demands, each month was split up in two day types (weekdays and weekends) and each specific day type was further split up in two separate parts to represent periods of low and high demand. Consequently the total number of time-slices amounts to 48[5] (See Figure D-3). The fraction of the demand occurring in each of these time slices as well as the availability of technologies in each of these

[4] Explain choice of 5% based on Jim's mail regarding the discount rates.

[5] 12 being the minimum acceptable number of time slices, small scale models were used to test the run time vs. result benefit of increasing detail. It was assumed that 48 was the most appropriate breakdown considering the size of the power pool models under development.

time-slices (e.g., hydro power) has to be specified by the analyst. The values for these ratios are reported in each individual power pool report.

Figure D-3: Time slice structure in OSeMOSYS



This temporal resolution of the energy model is complemented by describing the consumption pattern for each final fuel. The load curve used here typically represents energy demand per hour for a reference year. This data defines the model from an energy use perspective and each time-slice is allocated a corresponding fraction of the total energy. As an example,Table D-1: Time slice definition – Fraction of year accounted for in each time slice (SAPP case) below references the values used in the case of the Southern African Power Pool. All other power pool specific annexes contain their own corresponding table.

Table D-1: Time slice definition – Fraction of year accounted for in each time slice (SAPP case)

	Day Part 1	Day Part 2	Day Part 3	Day Part 4
January	0.0248	0.0425	0.0088	0.0088
February	0.0224	0.0384	0.008	0.008
March	0.0248	0.0425	0.0088	0.0088
April	0.024	0.0411	0.0085	0.0085
May	0.0248	0.0425	0.0131	0.0046
June	0.024	0.0411	0.0136	0.0035
July	0.0248	0.0425	0.0141	0.0036
August	0.0248	0.0425	0.0141	0.0036
September	0.024	0.0411	0.0094	0.0077
October	0.0248	0.0425	0.0088	0.0088
November	0.024	0.0411	0.0085	0.0085
December	0.0248	0.0425	0.0088	0.0088

Energy Demand

Electricity demand on the useful level (see Figure D-1) is the main driver of the model: final demand for any fuel in the model has to be met and balanced at the exact time at which it is required. This forces the model to invest and operate technologies throughout the energy chains accordingly.

Each power pool model uses its own demand assumptions, the general approach to how this demand is calculated however remains the same in all cases. The final values on a country level are derived by calculating past (and expected future) correlations between final electricity demands and macro-economic, social or other national indicators (e.g. GDP and Total Population). These indicators are then projected over the study period and the correlations are applied to calculate the final energy demand.

Once the country level values have been derived, other past and projected national statistics – including population share between urban and rural populations, electrification rates, share of industrial activity in total GDP, market penetration of certain key technologies and their corresponding energy intensities on a household basis – can be used to split the country level value into the three components under review in this study:

- Heavy industry (e.g. mining), which connects to generation at a high voltage level and generally requires less transmission and no distribution infrastructure;
- Urban residential, commercial, and small industries, which are connected to generation via a more extensive transmission and distribution system with associated higher losses;
- Rural residential, which require even more transmission and distribution infrastructure.

As the driving element of this energy system optimization framework, the useful level and shape of each individual sectorial demand has a high impact on the final results. Further, considering the uncertainties associated with the projections for national and international macroeconomic parameters, it is important to realise that final values of demand calculation within this study are merely indicative. While using best available data, they should not be considered forecasts. In cases of new industrial sector growth in developing countries for example, the introduction of high energy intensive activities could be responsible for stepwise increases in energy demand from one year to the next. Such changes cannot be captured by demand forecasting methodologies that are simply based on regressions – and assume a smooth evolution of GPD or population.

Finally, it should be noted that – where available – demand data was also considered from the latest available regional or country level studies. Such cases are referenced in the body of the power pool level annexes that follow.

Technologies included in the models

Generation Technologies[6]

OSeMOSYS uses so-called technologies as the basic building blocks for the energy system that it represents. For this analysis, a wide span of technologies were considered and is summarised in the categories detailed in **Table D-2: Detailed Technology Categories included in the Energy Models**

A distinction is made between centralized options – i.e., containing technologies that generate energy into the secondary level of the energy system, feeding into the transmission and distribution grid – and

[6] Please see individual power pool annexes for details regarding techno-economic parameters used for each technology type (e.g. efficiencies, capacity factors, availabilities etc.)

decentralized options, which provide energy both on a site specific level (household PV or industrial diesel generator) and on the tertiary level, i.e., feeding into the distribution grid.

Table D-2: Detailed Technology Categories included in the Energy Models

	Fossil	Renewable
Centralized	Diesel	Geothermal
	HFO	Bagasse Boiler
	Gas: OCGT, CCGT	Hydro
	Supercritical coal	Wind
	Nuclear	Solar PV
		CSP with or without storage
		CSP with gas co-firing
Decentralized	Standalone Diesel	Small Hydro
		Solar PV (multiple options)
		Wind Power

Centralized options based on oil are further split into two different plant types - i.e., reciprocating engines and steam cycle based generation - whereas the nuclear technology considered is the Pressurised Water Boiler (PWR).

Renewable options included as generic technologies can be further detailed as follows:

- **Hydro power** is split into run of river and reservoir based options
- **Small or mini hydro** to supply the rural demand
- **On-shore wind** connected on the secondary level. Two wind regimes are considered, namely one where the capacity factor is above 30% and the other where the capacity factor is 25%. These values and approach are in line with the resources extracted from (Hermann et al., 2014) Further, values are amended to higher percentages in cases of high wind availability – see specific power pool level reports for details
- **Biomass** mainly in the form of co-generation to be consumed on-site with surplus exported onto the grid (upstream of transmission).
- **Utility PV** connected upstream of transmission. They were modelled to only produce electricity during the day.
- **Distributed or roof-top Solar PV** to supply either urban residential demands, commercial demands and small industries, or rural residential and commercial demands. They were modelled to only produce electricity during the day.
- **Distributed or roof-top Solar PV with 1 or 2hr battery** storage, for slightly extended use beyond daylight hours. They can produce some electricity in the evening
- **Solar CSP with no Storage, representing** medium to large scale concentrated solar power plants connected upstream of transmission
- **Solar CSP with Storage to model** medium to large scale concentrated solar with thermal storage. It can produce electricity during the day and in the evening.

- **Solar CSP with Gas Co-firing** can produce electricity to specifications similar to other thermal plants in terms of operation time and load factor.

The framework of the model for each Power Pool consists of two sets of technologies. The first are generic options that offer typical solutions for power production in the region at corresponding typical costs. Since the aim of this project is to enable clear correspondence between water and energy models in order to assess the impacts of Climate Change in a consistent manner between frameworks, these generic options are complemented by so-called 'site specific' technologies. These represent identified projects that are of importance to the region and for which more specific techno-economic parameters are available in the literature. In order to keep model complexity and size to a minimum, the use of these site specific technologies is reserved for the representation of hydropower plants which are expected to be particularly affected by the direct effects of climate change in the region.

These two sets of technologies can be further divided with respect to their current status, namely whether they are existing, or future power plants.

Finally, shortfalls in energy demand can be met, if needed, by so called "Backstop" technologies. Such structures are "modeling" entities that do not correspond to elements from the physical energy system itself. They relate to the obligation that the model has to achieve an exact balance between demand and supply of a specific commodity: if this balance is not met then the optimization framework will consider that no feasible solution exists.

The investigation of corresponding generation results will show the potential use of these backstop technologies, highlighting inadequate system capacity to meet demand. In the context of developing countries this would represent the level of unserved demand

Transmission and distribution

These technologies are used to represent the country's national grid, considering both high and medium-to-low voltage energy delivery. All technologies feeding into the secondary level (and above – i.e. upstream of transmission technologies) are so-called centralized generation technologies and are typically larger projects owned and operated by private or national corporations. All technologies downstream of transmission either feed into the tertiary level (see Figure D-2) or provide directly for the demand on a final energy level. The first typically contain distributed – smaller scale – hydro power projects, while the second are on site roof top solar PV or smaller diesel generators for households or industries.

In order to provide realistic representation of each type of connection as well as offer maximum model flexibility, each separate distribution technology connecting the different demand levels is populated with different techno-economic data (see **Table D-3: National Transmission and Distribution technology characteristics**) Note that the differences in cost for infrastructure installation act in favour of meeting "hard to connect" demand with de-centralized options rather than developing a new extension of the national grid. This setup offers a first pass answer to questions of local electrification vs. national grid expansion in the countries under consideration.

Table D-3: National Transmission and Distribution technology characteristics

	T&D Cost		Losses*
	US cents/kWh	USD/kW	%
Transmission (all sectors)		364.97	5
Heavy Industry	1.5	840.38	5
Urban Residential/commercial/small industries	5	2433.26	10
Rural Residential/commercial	10	4233.6	20

*Note that such losses may differ by power pool – please refer to individual power pool level annexes

Source: (Miketa and Merven, 2013)

International trade

Cross border transmission lines play a fundamental role in distributing the energy resources that are scattered unevenly between the countries of each power pool region. Indeed, certain countries may be extremely rich in either lower cost fossil or renewable resources, giving them potential for electricity export to areas where production costs are higher. Since the energy models investigate minimal overall system cost, higher levels of trade can lead to lower total power pool expenditures – which translate into lower cost of electricity.

In OSeMOSYS, these transmission lines are represented by technologies that link two parallel energy chains from two neighboring or "interconnected" countries. They transfer electricity from one secondary level to the other and are set up as so called "two way" connectors. The same technology (with the same techno-economic parameters) can transfer energy in both directions during any time-slice.

The power pool models take into account multiple categories of international trade technology and differentiate between:

- Existing capacity: available from (or before) the first model year with a long life expectancy so that the technology remains available throughout the model period. Techno-economic parameters are as site specific as locally available data permits.

- Future capacity:

o Committed: are lines that are already either under construction or for which the design and implementation process is far enough ahead for them to be considered as certain. These lines are installed in the energy system at their anticipated date of commissioning.

o Planned projects: are lines that are being considered but that have not yet gained sufficient support to be considered certain. These technologies are initially optional and are made available at their current "earliest on" date with corresponding project specific techno-economic data.

Note, that consistent with political development we model power pools separately - with each of their constituent countries represented. However, the power pools themselves have (limited) trade linkages. Such trade is partially included through a certain number of shared countries (see Optimizing Power Plants belonging to multiple Power Pools), but is not the focus of the present energy modeling effort.

Techno-economic Parameters

Each of the aforementioned technology types included in the power pool modeling frameworks is described by a standard set of parameters that define both the technical and economic characteristics of each specific generation option.

Considering the specificity of the OSeMOSYS modeling framework and the parameters that are required / available to describe each technology, **Table D-4: Techno-economic parameters in OSeMOSYS** below offers a list of the terminologies along with a description of their use in general and in the present modeling exercise.

Table D-4: Techno-economic parameters in OSeMOSYS

Name	**A/TS – TD/TID**[7]	**Unit / Value**	**Description**
Availability Factor	*A – TD*	*∈[0-1]*	*Ratio of available time to total time over the year.*
Capacity Factor	*TS – TD*	*∈[0-1]*	*Ratio of real output to the full theoretical output at total nameplate capacity.*
Capacity To Activity Unit	*NA – TID*	-	*Relation between units used for capacity and activity – here 1GW will produce 31.536 PJ in one year.*[8]
Discount Rate	*NA – TID*	-	*Discount rate used for a specific technology to calculate NPV.*
Fixed Cost	*A – TD*	*MUSD/GW*	*Fixed costs related to installed capacity of a specific technology and year – typically O&M.*
Input Activity Ratio	*A – TD*	-	*Ratio between energy carrier/fuel input and activity of the technology. Used in correlation with the Output Activity Ratio to describe efficiencies.*
Operational Life	*NA – TID*	*Years*	*The lifetime of a technology. Does not apply to residual capacities.*
Output Activity Ratio	*A – TD*	-	*Ratio between energy carrier/fuel output of and the activity of the technology.*
Residual Capacity	*A – TD*	*GW*	*Time series representing the retirement schedule of capacity in existence when the model period starts.*
Specified Annual Demand	*A – TD*	*PJ*	*Demand for a specific energy carrier in a specific year.*
Specified Demand Profile	*TS – TD*	*∈[0-1]*	*Share of the Specified Annual Demand that is used in each specific time slice.*

[7] Defined on an A: Annual or TS: Time Slice these parameters are either TD: Time Dependent or TID: Time Independent – meaning that, for a given technology, these parameters are either constant throughout the study period or can be changed over time by the analyst if useful for the analysis.

[8] Note that this parameter is not related to the capacity factor or the availability of the technology and simply ensures unit adequacy in the modelling framework.

Total Annual Max Capacity Investment[9]	*A – TD*	*GW*	*The maxim capacity of a specific technology that can be invested in a specific year.*
Total Annual Min Capacity Investment[8]	*A – TD*	*GW*	*The minimum capacity of a specific technology that is to be invested in for a specific year.*
Total Technology Annual Activity Lower Limit[8]	*A – TD*	*PJ*	*The lowest amount of energy that must be produced by a specific technology a specific year.*
Total Technology Annual Activity Upper Limit[8]	*A – TD*	*PJ*	*The maximum amount of energy that can be produced by a specific technology a specific year.*
Variable cost	*A – TD*	*MUSD/PJ*	*Variable operation and maintenance costs relating to normal plant activity.*

The reader is referred to each individual power pool annex for the specific values and references relating to each of these parameters for all technology options. Please note also that all parameters are not necessarily required and specified for all technology options.

Fuel provision and fuel costs

The case of fossil fuels

Referring to Figure D-2, fossil fuels can be introduced into the system in two ways: each energy carrier is provided either through a national extraction technology or through a corresponding import option. In both cases, the technology used is an abstraction of the entire supply chain responsible for fuel provision on the ground and, as such, this work does not model the corresponding detailed infrastructure that accompany either domestic or foreign imported fuels.

From a technical perspective, this modeling considers the use of four fossil fuel sources, namely diesel – heavy fuel oil (HFO) – coal – and natural gas. In each case, the "per kWh" unit cost of each fuel is included in the model as a variable cost on the use of both the national extraction and the import technologies[10]. By default, the variable cost applied to import options is assumed to be 10% higher than the cost of using the corresponding national extraction option. In parallel, the national extraction option is constrained to countries that are endowed with the corresponding natural resources, considering their resource potentials. Further, imports of certain commodities are not allowed for countries where this would represent an unrealistic solution.

The specific values considered for fuel reserves in each country are listed in **Table D-5: Fossil Fuel Reserves on a National level**. Initial data was retrieved from the International Energy Agency's (IEA) International Energy Statistics database (EIA, 2014a) and converted using EIA conversion factors for typical fuel energy content (EIA, 2014b). These are listed in Table D-6.

[9] Note that these parameters are used to constrain the scenario runs to ensure that committed and planned capacity for each technology is available or that generation patterns are consistent between different model runs and different power pools. Refer to the explanation of Model Run Types for a more detailed explanation of their use in the climate scenario runs.

[10] Note that the variable costs on the generation technologies – e.g. on a coal power plant – therefore represente only Operation and Maintenance costs.

Table D-5: Fossil Fuel Reserves on a National level

	Recoverable Coal Reserves (2008 - Million Short Tons)			Crude Oil Proved Reserves (Billion Barrels)		Proved Reserves of Natural Gas (Trillion Cubic Feet)	
Country	**Coal**	**Hard Coal**	**Lignite**	**2012**	**2013**	**2012**	**2013**
Angola	NA	NA	NA	9.50	10.47	10.95	12.93
Benin	NA	NA	NA	0.01	0.01	0.04	0.04
Botswana	44.09	44.09	0.00	0.00	0.00	0.00	0.00
Burkina Faso	NA	NA	NA	0.00	0.00	0.00	0.00
Burundi	NA	NA	NA	0.00	0.00	0.00	0.00
Cameroon	NA	NA	NA	0.20	0.20	4.77	4.77
Central African Republic	3.31	0.00	3.31	0.00	0.00	0.00	0.00
Chad	NA	NA	NA	1.50	1.50	0.00	0.00
Congo (Brazzaville)	NA	NA	NA	1.60	1.60	3.20	3.20
Congo (Kinshasa)	97.00	97.00	0.00	0.18	0.18	0.04	0.04
Cote d'Ivoire (Ivory Coast)	NA	NA	NA	0.10	0.10	1.00	1.00
Djibouti	NA	NA	NA	0.00	0.00	0.00	0.00
Egypt	17.64	17.64	0.00	1.10	1.10	1.30	1.30
Equatorial Guinea	NA	NA	NA	0.00	0.00	0.00	0.00
Eritrea	NA	NA	NA	0.00	0.00	0.88	0.88
Ethiopia	NA	NA	NA	2.00	2.00	1.00	1.00
Gabon	NA	NA	NA	0.00	0.00	0.00	0.00
Gambia, The	NA	NA	NA	0.66	0.66	0.80	0.80
Ghana	NA	NA	NA	0.00	0.00	0.00	0.00
Guinea	NA	NA	NA	0.00	0.00	0.00	0.00

Guinea-Bissau	NA	NA	NA	0.00	0.00	0.00	0.00
Kenya	NA	NA	NA	0.00	0.00	0.00	0.00
Lesotho	NA	NA	NA	0.00	0.00	0.00	0.00
Liberia	NA	NA	NA	47.10	48.01	0.00	0.00
Libya	NA	NA	NA	0.00	0.00	0.00	0.00
Malawi	2.20	0.00	2.20	0.00	0.00	4.50	4.50
Mali	NA	NA	NA	0.00	0.00	2.20	2.20
Mozambique	233.69	233.69	0.00	0.00	0.00	0.00	0.00
Namibia	NA	NA	NA	NA	NA	180.46	182.00
Niger	77.16	77.16	0.00	37.20	37.20	2.00	2.00
Nigeria	209.44	23.15	186.29	0.00	0.00	0.00	0.00
Rwanda	NA	NA	NA	0.00	0.00	0.00	0.00
Somalia	NA	NA	NA	0.00	0.00	0.20	0.20
South Africa	33241.30	33241.30	0.00	0.02	0.02	NA	NA
Sudan and South Sudan	NA	NA	NA	5.00	5.00	3.00	3.00
Swaziland	158.73	158.73	0.00	0.00	0.00	0.00	0.00
Tanzania	220.46	220.46	0.00	0.00	0.00	0.23	0.23
Togo	NA	NA	NA	0.00	0.00	0.00	0.00
Uganda	NA	NA	NA	1.00	2.50	0.50	0.50
Zambia	11.02	11.02	0.00	0.00	0.00	0.00	0.00
Zimbabwe	553.36	553.36	0.00	0.00	0.00	0.00	0.00

Source: (EIA, 2014a)

Table D-6: Energy Conversion

	Million Btu (British thermal units)	**Giga (10^9) Joules**	**TOE (Metric Tons of Oil Equivalent)**	**TCE (Metric Tons of Coal Equivalent)**
Million Btu (British thermal units)	1	0.94782	39.6832	27.77824
Giga (10^9) Joules	1.05506	1	41.868	29.3076
TOE(Metric Tons of Oil Equivalent)	0.0252	0.02388	1	0.7
TCE(Metric Tons of Coal Equivalent)	0.036	0.03412	1.42857	1

Source: (EIA, 2014b)

Table D-7: Energy Conversion

Energy Content	**Value**	**Unit**	**per**
Coal	19.341	million Btu	Short ton
Oil	6.058	million Btu	Barrel
Natural Gas	1021	Btu	Cubic Foot

Source: (EIA, 2014b)

The case of "Renewable fuels"

Renewable technologies RET do not typically 'use' any material fuel in the common sense of the word. In many modeling representations, RET are therefore specified in the detail required by the analysis. In this exercise, the following noteworthy features of renewable energy technologies are included:

- Hydro power: is scrutinized on a "project by project" basis within this exercise. The upper generation limits are informed by the basin modeling yielding water availability information through which the generation is constrained by monthly capacity factors. Note that micro hydro is aggregated into one technology providing electricity directly to the final demand level. Although these represent a very small share of the hydropower their capacity factors are varied following the proxy method described in (
-
- **Figure D-4: Hydro proxy capacity factor calculation** scheme)
- Wind and Solar power: are both represented by multiple technological options available for installation over the entire model period. However, the total available power is limited by the total annual insolation and wind speed level conditions on a country per country basis. These conditions are controlled using a dummy "fuel" representing the solar and wind influx into the Primary level. No cost is associated to this fuel.
- Biomass power: is linked to a "physical" resource, it's set up is managed in much the same way as it is done for fossil fuel based systems.

It is important to note that none of the renewable resources are burdened with a fuel cost except for biomass which is costed – again – in much the same way as fossil fuels are.

The theoretical availability of each individual renewable fuel was extracted from previous and very detailed GIS mapping developed within KTH-dESA for IRENA (Hermann et al., 2014). Based on continent wide information regarding wind speeds, solar irradiation and local biomass characteristics, multi-layered resource maps were developed. These maps took natural, human and technical constraints into account and exclusion areas were defined, where renewable energy cannot be exploited. When overlain, the final map makes it possible to extract the theoretical potential for the use of a given renewable technology type in the country of interest. The corresponding data is shown on a national level in tables listed for each individual power pool.

Technology emission factors

Depending on the scenario that is being investigated, it is important to be able to track the amount of carbon dioxide emissions being produced in order to meet the final electricity demand. In certain cases, this may need to be taken one step further and the modeler may need to assign a certain time dependent cost to CO_2 production, thereby giving an economic value to this important externality.

Carbon dioxide emissions, and more generally greenhouse gas emissions, are contained within each unit of fuel and are released when it is burned and transformed to electricity: they are an intrinsic characteristic that can be tied directly to each unit of each specific fuel. Different technology types have different levels of final emissions for the same unit of basic fuel. This is not included in the present modeling effort: for simplicity and model size issues all technologies burning the same type and amount of fuel are assumed to produce the same amount of undesirable CO_2. Considering that fossil entry points into the modeling system are limited and each unit of fossil fuel being brought into the system will be consumed, it is possible to define the "CO_2 constraint" for each fuel directly on the two technologies that extraction and import the commodity.

With this in mind,Table D-8 shows the multiplication factors applied to each fuel chain on introduction into the system: these are set as emission factors on the output from import and extraction technologies in each country.

Table D-8: CO2 emission factors applied per fuel

Fuel	CO_2 emission Mt/PJ
Coal	0.0893
Diesel	0.0709
Oil	0.0709
Gas	0.0503

From a technical perspective, the use of these emission factors supposes the following set up within the OSeMOSYS framework:

- Existence of one "Emission" parameter for each externality that is to be monitored or constrained. In this case, "CO_2 emissions" are introduced on a country level for each country in each regional model.
- Introduction of corresponding country level emissions penalty and annual emission limits. By default, these are respectively set to [NULL] and [99,999] constant values – non binding constraints. For specific scenario investigations these can be combined to set the boundaries of allowable emissions for a country as well as a cost for each unit of emission generated within these boundaries.
- Introduction of fuel production technology related emission ratios describing the amount of a given emission generated per unit of fuel output (time dependent variable). By default these are set to constant time series containing the values defined in Table D-8
- It is import to note that all of these parameters are user defined time series that can vary considerably over time and therefore offer very flexible means to constraint each individual country and represent different policy possibilities.

Potential cost of CO2 emissions

The present exercise does not include the cost of CO_2 emissions as part of the standard model parameterizations. This means that the emissions are simply accounted for within the model frameworks and reported in the results as mega tons (Mt) of carbon dioxide emissions. They are however not "costed" and therefore do not influence the optimization process.

Although their financial impact is not included in the optimization decision, this information is useful for the post treatment of the results for each individual scenario. By applying a potential (fictitious) trend of CO_2 penalties we can observe what the GHG related increase in energy cost to both the system and the consumer might be. With this in mind, a linear trend is considered when developing certain key messages for each power pool in the following annexes. A three stage in cost increase per ton of emissions:

1- A linear increase from 0 to 12 USD/t between 2015 and 2020
2- A linear increase from 12 to 25 USD/t between 2020 and 2028
3- A constant cost of 25 USD/t after 2028

Integration with the WEAP modeling

As also explained in the Perfect Foresight Annex, the information flow between the water (WEAP) and the energy modeling is managed by harmonizing techno-economic characteristics of the hydro power plants in the two corresponding frameworks. This was challenging due to the different characteristics of OSeMOSYS and WEAP. First, OSeMOSYS is an optimization model that considers the best combination of technology and corresponding power dispatch to meet demand at a minimal cost to the system. WEAP (SEI, 2014) is not an infrastructure expansion model. It is a versatile water accounting tool in which the infrastructure is an input from the analyst rather than an output. Second, WEAP, unlike OSeMOSYS, is a geo referenced and topology dependent tool. Third, the OSeMOSYS model contains a much larger amount of hydro power plants than were included in the river basin models of WEAP (e.g.,. there are hydro-power plants outside of the basins modelled). Considering that the objective of the study is to investigate the impact of climate change in the region through the changes in water availability on a facility level, this was a potential challenge. It was overcome by introducing a proxying procedure to ensure trend consistencies in water availability in different climate scenarios. The power plants for which this was used will be referred to in the following paragraphs as "energy only" hydropower – or EO.

To account for these different characteristics, the water and energy frameworks were integrated using a specific multi-stage data exchange protocol through an intermediary, Matlab based two tier optimization tool managed by IeC[11]. Using economic valuations of the benefits of specific infrastructure adaptation options, the algorithm adjusts first the agriculture component and second the hydropower infrastructure. These changes offer new sets of water availability for the different facilities in the energy model (see Boehlert, Strzepek & Neumann (forthcoming) assessing the climate impact on infrastructure in Africa)

Due to the numerous and complex geographical representation of interrelated water requirements in WEAP, it was selected as the reference for hydro power availability on each potential site in each basin. This means that the monthly power availability at each hydro power station was derived from WEAP results. Further, the intermediary water infrastructure optimization tool results (from IeC) were used as a reference in order to adjust capacity levels that each power station should have, if it is considered both technically and economically viable to modify it. These two pieces of information – i.e. capacity levels and corresponding available hydro generation at a power plant level – are then fed into the Power Pool models as follows. This process was iterated for each climate run in order to converge towards an optimal hydropower infrastructure within the realm of possible size configurations for each site.

First, the generation data derived from the Matlab version of the WEAP models is translated to energy system constraints in terms of capacity factors C_f:

[11] Industrial Economics Inc., one of the partners in the project.

$$\forall\, i,j \in \{technologies\} \times \{time\ slices\} \quad C_f^{i,j} = \frac{E_i}{C_i * \Delta t_j} \quad \text{eq.1}$$

E_i Energy generated by the power plant i
Δt_j The corresponding duration (each month of each year)
C_i Power plant capacity

These capacity factors are calculated for each hydro power plant, for each time-slice in each different climate scenario and therefore convey the relative dry/wet character of future time periods. Since each energy-generation value received from the water modeling is calculated on a monthly basis, eq.1 is calculated on a monthly basis and the resulting capacity factor is applied to the four time-slices corresponding to that month in the OSeMOSYS modeling framework.

A proxy approach was set up to represent the power plants that were included in the energy model but outside of the scope of the river basins under consideration. This approach was used to adjust all remaining power plant capacity factors in each climate scenario. For each of these EO projects – initially operating under a generic capacity factor – there is a "closest" or "most appropriate" WEAP represented power plant to which the that can be used to ensure that the variation in capacity factor across the power pools are consistent in each climate scenario and in each time slice: Please refer to

Figure D-4: Hydro proxy capacity factor calculation scheme.

$$\forall\, i \in \{EO\ technologies\} \exists\, r \in \{WEAP\ technologies\} \backslash \forall j \in \{time\ slices\}: \quad C_{f,n}^{i,j} = \alpha_{i,j}^{r} * \beta_{i,j}^{r}$$

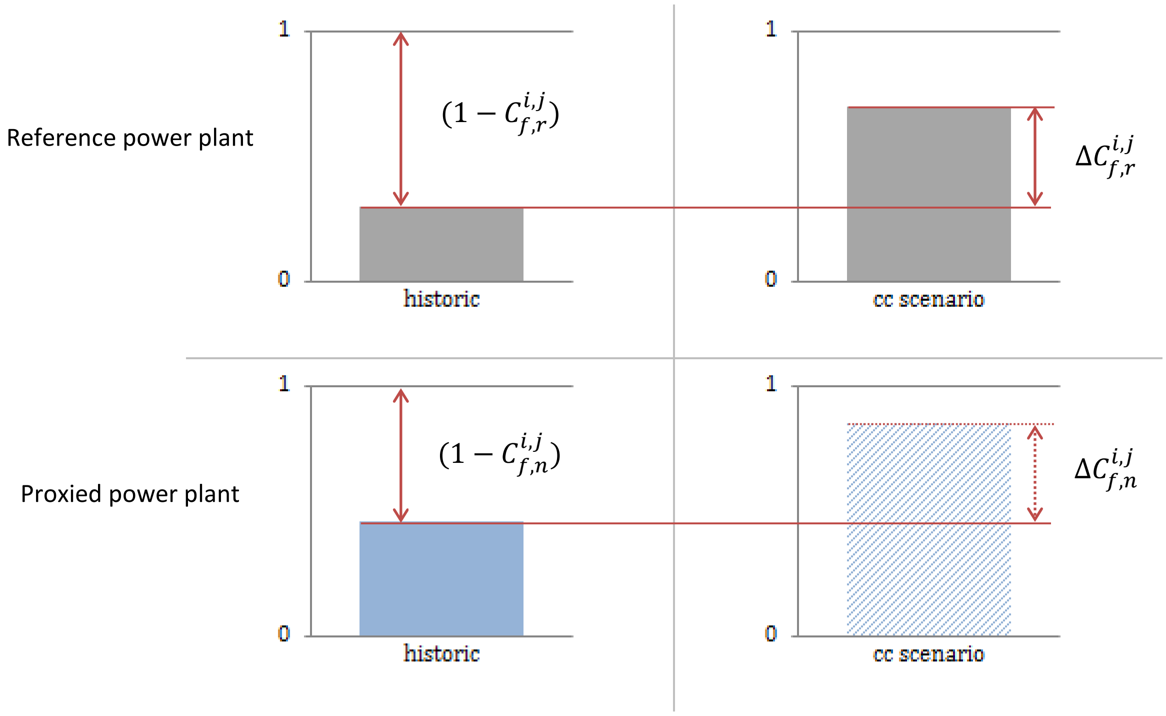
$$\alpha_{i,j}^{r} = \frac{capacity\ factor\ change}{potential\ change} = \begin{cases} \dfrac{\Delta C_{f,r}^{i,j}}{C_{f,r}^{i,j}};\ \Delta C_{f,r}^{i,j} \le 0 \\ \dfrac{\Delta C_{f,r}^{i,j}}{1 - C_{f,r}^{i,j}};\ \Delta C_{f,r}^{i,j} \ge 0 \end{cases}$$

$$\beta_{i,j}^{r} = \begin{cases} C_{f,n}^{i,j};\ \Delta C_{f,r}^{i,j} \le 0 \\ (1 - C_{f,n}^{i,j});\ \Delta C_{f,r}^{i,j} \ge 0 \end{cases}$$

The alpha parameter captures the magnitude of the change in capacity factor. In the graphical representation, the reference power plant has a higher capacity factor in the climate change scenario case than in the base case. Because capacity factors cannot exceed 1, this increase is accounted for as a percentage of the potential increase available in the base case: if the base CF is 0.3, it can theoretically increase by as much as 0.7 and a corresponding CC value of 0.4 would represent an alpha value of 14.28%.

The beta parameter looks at the proxied power pool determines the value to which the alpha percentage is applied. In the figure the CF are increasing, the beta parameter takes the remainder to 1 value of the proxied power plant. Conversely, if the CFs are decreasing the beta parameter is simply the base case value of the proxied CF.

Figure D-4: Hydro proxy capacity factor calculation scheme



Second, the capacity change on a facility level resulting from the intermediary adaptation step is taken into account in the new model run setup. Included as multipliers on the currently planned capacity level, this information is taken into account on each data hand off iteration and for each individual climate scenario. The capacity values used to calculate the capacity factors for the corresponding climate scenarios are adjusted accordingly. In parallel, the multipliers are included into the new model runs through the binding constraints used to set up each independent run: the minimal and maximal constraints on capacity addition for each hydro power technology are adjusted to ensure that the correct capacity level is invested in.

In sum, for each climate scenario we adjust hydro power plant capacity factors for all power plants, and modify capacity levels of power plants existing in both the WEAP and OSeMOSYS frameworks.

Finally, water basins spreading across more than one power pool as well as the inclusion of a certain number of countries within multiple power pools cause methodological problems for the optimization of the overall system. This specific problem is explained in more detail in Optimizing Power Plants belonging to multiple Power Pools).

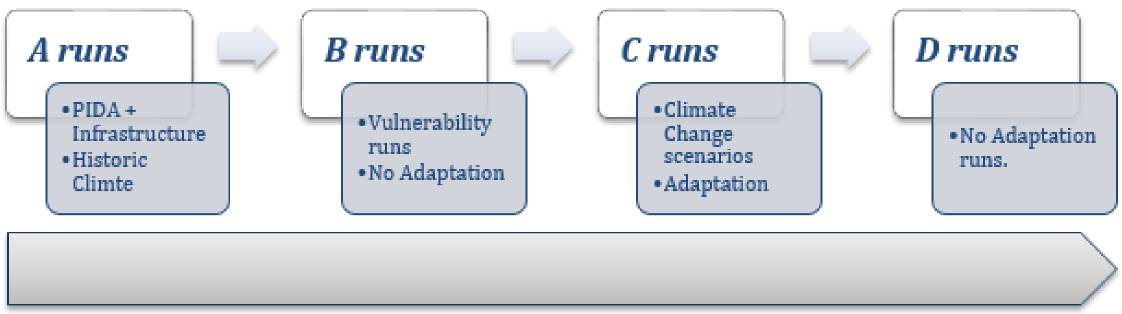
Typical model run types

The diversity of modeling frameworks involved in this analysis lead the project team to consider a specific data circulation methodology (see Main Data Circulation Methodology Memo). This bespoke approach was then internally translated into several different typical run types that correspond to typical OSeMOSYS modeling framework setups.

As pictured in

Figure D-4: Hydro proxy capacity factor calculation scheme, there are four different types of run from the project perspective. These allow overall reporting to investigate A. how current PIDA+ infrastructure plans may fair in what is accepted as a historic climate projection, B. what the economic vulnerability of that infrastructure investment plan would fare under a wide range of varying climate projections, C. how the actual investment plan might be changed if planning authorities had better information regarding a smaller – but representative – set of climate futures for the continent and D. what a realistic and climate robust strategy might look like considering that perfect information – although lacking in the first years – could be available in the future.

Figure D-5: OSeMOSYS model run types



With these successive types of analysis runs in mind, the OSeMOSYS framework is used to inform the investigation process through direct runs in cases A, C and D while cases B use economic data output from the A cases in a more extensive vulnerability assessment.

Run type 1

In this reference case the climate is assumed to follow what is referred to as a historic trend while the infrastructure investment plans keep to a business as usual trajectory. This means that all large power generation and transmission projects that have been committed to as part of the PIDA+ plan are forced into the energy system infrastructure from their first year of operation. No other constraints are imposed upon the system which is left free to make up remaining shortfalls of energy generation as optimally as possible – with new investments and changing power plant operation. It is important however to note that different types of planned infrastructure are treated differently in the system:

- Identified power plant projects that are as yet uncommitted remain available for installation from their tentative first year of operation: if they are economically viable solutions they will be invested in either in full or in part.

- Identified international transmission line projects that have not been committed to are not allowed into the solution space and no generic option is made available either (Though trivial to implement, a conservative outlook was adopted in this analysis.).

The rationale for these type 1 runs is to investigate how well current plans would fare as long as our experience of the climate remains constant and system planners are considered to be aware of and reactive to potential changes in their natural constraints. It is, in effect, the best case scenario considering the committed infrastructure that will be installed regardless of any new information in the coming years as represented by PIDA+.

Run type 2

The growing scientific body of future climates, and their downscaled effects inform the next run type. Considering the range of possible scenarios described in the literature six representative cases were selected for further investigation of climate change's potential consequences for continent wide infrastructure investments. These consequences are assessed using different assumptions about how it is believed people will react to climate change signals in the future.

In contrast to B cases, where it is assumed that no change in behavior take place and infrastructure investments are made with an "old" understanding of local – national – and continental climate, C cases quantify the difference that a limited level of adaption makes to overall system performance and cost. From an energy system optimization point of view, this requires that:

- Investment plans valid under Historic climate are forced into the model solution: outputs from Type 1 runs are used to constrain the new models.
- The system has the ability to make up shortfalls using a restricted variety of fossil based options: new investment and optimal operation of centralized and distributed diesel, coal and natural gas based generation is freed up.
- No other option is available to the optimization process: it can either draw on infrastructure that would have been committed to in a historic climate – or – use the limited (and potentially more expensive) freed up options to complement the energy mix.

The rationale behind these runs relates to allowing for a certain level of adaptation while restricting the complementary investment options to fossil based generation that are typically well known – expensive to run solutions.

In detail, the steps required to constrain the parameters of the Type 2 models are:

1. Run the corresponding Type 1 model
2. Extract results regarding "NewCapacity" from the solution file – time series on a yearly basis
3. Generate corresponding time series for all infrastructure investments except selected fall back generation options:
    a. $\mathit{TotalAnnualMinCapacityInvestment}_{new} = \begin{cases} 0 & ;\mathrm{NewCapacity} \leq 0.0005 \\ \mathrm{NewCapacity} - 0.0005; & \end{cases}$
    b. $\mathit{TotalAnnualMaxCapacityInvestment}_{new} = \begin{cases} 0 & ;\mathrm{NewCapacity} \leq 0.0001 \\ \mathrm{NewCapacity}; & \end{cases}$
    c. $\mathit{TotalAnnualMaxCapacity}_{new} = \mathrm{TotalAnnualMaxCapacity}_{hist} + 0.0005$
4. Update the new model by including the new time series

5. Ensure that selected fall back technologies are constrained adequately allowing for "last minute" investments to complement the inadequate infrastructure:
   a. $TotalAnnualMinCapacityInvestment_{new} = \begin{cases} 0 \ ; \text{NewCapacity} \leq 0.0005 \\ \text{NewCapacity} - 0.0005; \end{cases}$
   b. No new constraints on TotalAnnualMaxCapacityInvestment.
   c. $TotalAnnualMaxCapacity_{new} = \text{TotalAnnualMaxCapacity}_{hist} + 0.0005$

Additionally, these Type 2 models take into account IeC Perfect Foresight (PF) Run information regarding the potential interest of scaling up or down certain specific pieces of the hydro infrastructure. After taking into account the Power Pool wide cost of energy resulting from the corresponding Type 1 run, each round of PF run yields an adjusted infrastructure plan represented by power plant specific capacity multipliers and hydro power generation data. For each set of Type 2 so-called "Climate Change Scenario" runs, the final capacity constraint values are therefore adjusted using the capacity multipliers and the capacity factor calculation is repeated and updated with the latest generation values.

This approach is adopted for each of the six scenarios identified in the initial RAND screening process and is repeated on each of the two data exchanges with the IeC Water Optimization process.

Run type 3

Finding an acceptable baseline in order to both compare results to and extract meaningful insights is a fundamental part of modeling exercises. In the present case, two comparison baselines have been adopted: the first, from a climate perspective, the second, from an adaptation view point.

In the first, the six representative scenarios that were identified are compared to what is considered to be an acceptable trending of historic climate into a "no climate change" pathway. When compared, these two run types show relevant insights as to the implications of adapting to different versions of plausible climate change futures as compared to a situation where no adaptation is required.

In the second, the perspective of a no adaptation case shows just how much is at stake in the very same climate futures if system operators to not adjust.

Optimizing Power Plants belonging to multiple Power Pools

Problem Statement

The perspectives of the energy and water models being developed as part of this project are different. The first are representative on a national and power pool level while the second take their full meaning on a water basin level directly from a geo-physical perspective. Although certain power pools fully include certain river basins and most countries are included in only one "basin/power pool" pair, the overlap is not perfect. This means that certain countries may be included in multiple power pools, may include multiple basins, or may include a basin that has been paired with another power pool.

This uneven overlap between the power pools and the river basins poses a methodological issue related to the optimization of the energy/water system for the continent. Since the first unit of the analysis sequence is linked to the water modeling, it is important that the subsequent process stay within the boundaries of what is possible for the corresponding basin. At the same time, the optimization process applied in the analysis iterations is intended to adapt national level infrastructure to the consequences of climate change based on power pool level cost results – regardless of the power plant's basin connection.

This problem is further complicated by the fact that certain power plants are not included in the WEAP models but are included in the Power Pool models. Since these hydro power plants are proxied to the WEAP power plant that is most representative from a hydrological perspective, this means that power plants that are in one power pool model will be dependent on WEAP runs from basins linked to another power pool optimization and therefore be linked to the price seen in that neighboring power pool.

Points of Reference

- ❖ The SAPP is by far the largest power pool in the region and will have the highest need for power over the study period that the present project spans.
- ❖ Using published results from a parallel project lead by KTH relating to trade between a five piece power pool model of the African continent, it seems that power trade from the DRC is shared mainly between the SAPP and the WAPP regions with a split of 75 to 25% resp. for power traded between 2010 and 2030. (note: this modeling assumes very open trade links between the region reaching much higher capacities than are allowed in the present project - this work also assumes equal potential for trade between the different regions: it does not favor the SAPP from a structural perspective – for further detail please see (Taliotis et al., 2014))
- ❖ The main issue in resolving this problem is to ensure that the cost signals received in the different optimization iterations between IeC and KTH do not skew the scaling of the WEAP system while allowing for the energy optimization to trade power in as representative a way as possible.
- ❖ The preference is for a relatively simple group of assumptions to ensure relevant results while limiting the extra work charge of conducting re-runs of previously finalized parts of the project. It is not the ambition of this memo to produce a perfect correlation between the Power Pool and Water Basin level of analysis as this would require much higher levels of iteration and input than are possible within the framework of this initial analysis.

Methodological guidelines

Point 1 – Each river basin and each country can have only one optimal solution per scenario

- Considering that the output from this work is to feed into robust infrastructure decision support it is important to maintain a consistent answer to a single problem for each decision-making entity: namely national, power pool and water basin scales.
- On a basin level, the outcome is closely related to the cost of power seen by the IeC optimization models. Each basin therefore must be optimized within only one single power pool. Considering the current setup, this translates into the following layout:
    - SAPP is optimized with the Congo - Zambezi - Orange basins
    - EAPP is optimized with the Nile basin
    - WAPP is optimized with the Volta - Senegal - Niger basins
    - CAPP is dependent on the results that emanate from the previous three optimizations and is not directly linked to a specific basin.

- Since certain countries belong to multiple models, the power pools are optimized sequentially. The results from a higher priority power pool are used to constraint the runs of a lower priority power pool[12].
- Power Pools are prioritized based on size. Considering the size of the power pools and the trade patterns between the power pools, the following order is applied
    - SAPP>WAPP>EAPP>CAPP.

Note: the direct consequence of this approach is that the CAPP power pool is optimized only within the OSeMOSYS framework, there will be no so-called "perfect foresight" iterations between KTH and IeC for this power pool. The CAPP will thus be a price taker from other power pools

Point 2 – Consider different power pools as having different priority levels

- The SAPP is the largest consumer in the region and is also the one for which the analysis is at the most advanced stage. The runs are nearly completed and the project team intends to avoid repeating them for time constraint reasons.
- Considering that the trade lines in place in this power pool follow committed projects, the levels of trade that are seen in the 7 scenarios (ref+6CC) will be maintained as a fixed output from the DRC into each of the subsequent power pools in which it is being included.
- In a similar fashion, the infrastructure solution we seen for the DRC as part of the SAPP is related this power pools' needs and energy cost levels. It will be kept as a minimum level of investment when including DRC into other power pool optimizations.
- Taking the example of the DRC further, other countries that are part of several power pools will be constrained in order to maintain at least the same investment pattern as in the power pool with higher priority
    - *for example: when running the DRC as part of the CAPP, the investment profile will enforce a minimum capacity level in line with what was required to provide energy when the country was run with the SAPP/WAPP and EAPP connections – thereby following a so called scaling approach for countries within multiple power pools.*

Point 3 – Consider upper limits for trade from DRC to the WAPP

- In parallel to the fixed output from DRC to a "SAPP connection" in all power pools that include the DRC, a fixed upper limit on total traded power from DRC to the WAPP will be set at 1/3 of the total traded power from DRC to the SAPP resulting from the SAPP model runs.

Point 4 – Run power plants to the basin they belong to regardless of power pools

- These measures concern mostly power plants that are inside the OSeMOSYS Power Pool models but outside WEAP Basin models.
- Hydro power plants located in countries that are outside their river basins' Main Power Pool will be proxied to the most relevant power plant inside the Main Power Pool. This results mainly in the fact that these power plants will be affected by the situation in their neighboring power pool.
- Since the CAPP is the only power pool that has not been paired with any given river basin, the power plants inside CAPP countries will all be linked to basins that have been optimized as part of neighboring power pools.

The main issue with this approach is that each power pools' climate change scenarios are run with reference to the historic run results. In the case where we include e.g. the DRC into the model but use

[12] These constraints ensure that capacity additions, energy dispatch and trade levels from countries that have already been optimised in one power pool are maintained when optimising the next power pool that they belong to. Note that, due to the time consuming nature of a full power pool optimization within this interconnected methodology, no other power pool sequence was tested.

the outputs from the "Main Power Pool" in terms of minimal investment plan we are creating a slight discontinuity in the modeling.

Other notes on the methodology

❖ The most recent updates on the memberships to the EAPP show that the DRC has been added to this power pool as well (http://www.eappool.org/members-of-eapp.html). The DRC is also part of the SAPP and the CAPP (Infrastructure Consortium for Africa, 2011)

❖ Regarding connections between the DRC and the EAPP

   a. Data available for the existing power infrastructure in the region – in particular relating to the power transmission – shows no direct connections from the Inga site over the border to the EAPP. (AICD, 2010)

   b. However the DRC is currently connected to Burundi and Rwanda through three relatively small lines – one of which is considered for upgrade by early 2030s in the EAPP master plan (EAPP/EAC, 2011). New projects are envisaged as part of this MP with the addition of two 330MW lines – one for each country respectively. Initially planned for 2014, their current status is unclear.

❖ What impact this might have on the Inga site power will be subsequent to the developments required and secured for the WAPP and the SAPP.

❖ Regarding DRC, Burundi and Rwanda power pools and concerns about shared infrastructure such as Ruzizi

   a. Burundi and Rwanda are in the EAPP

Ruzizi is a shared power plant: the energy models consider it to be included into each country with the capacity values reflecting the share that is expected to be available.

Results Handling Assumptions

Results in OSeMOSYS

The OSeMOSYS modeling framework is a fully fledged optimization system with full output flexibility. All input parameters, modeling variables and intermediary variables are accessible as an output in the solution file. Further, bespoke outputs can be computed within the optimization step and stored in additional variables ready for result export.

Considering the usual applications of the OSeMOSYS framework, this typically amounts to very large amounts of potentially available data describing the full solution over all technologies, all time-slices and all years of the study horizon. In order to limit any possible confusion – but also in order to limit file size and computational intensity of the entire process – the standard print statements that populate the solution file with the required information have been reduced to include only variables and parameters of interest for the present study. These include the following elements:

- Total Cost
- Total Annual Capacity
- Annual Production By Technology
- Annual Use By Technology
- Annual Emissions
- Annual Emissions By Technology
- Undiscounted Capital Investment

- Discounted Capital Investment
- Total Discounted Cost By Technology
- Total Discounted Cost
- Operating Costs Variable
- Operating Costs Fixed Annual
- Emissions Penalty By Technology
- Residual Capacity

From these standard values on output, result tables are designed to follow the evolution of the energy systems on both a country and a power pool level. This is done in terms of capacity expansion and infrastructure development, ability to meet demand, corresponding generation mix, and international trade within the region as well overall system costs and emissions. Since the detail is available on a per technology level, it is also used to assess the relevance of certain specific projects (here hydro) and the timing of individual power plants on a national or regional basis. These different metrics are assessed and compared between the different scenarios under consideration and gain insight into the trade-offs and benefits of certain pathways as compared to others.

Result Generation and Extraction Process

The developing nature of the OSeMOSYS modeling framework means that generating and extracting results remains a relatively data and time intensive part of the analysis. Generating a typical set of scenario runs therefore follows a specific set of steps that are summarized in Figure D-5**.**

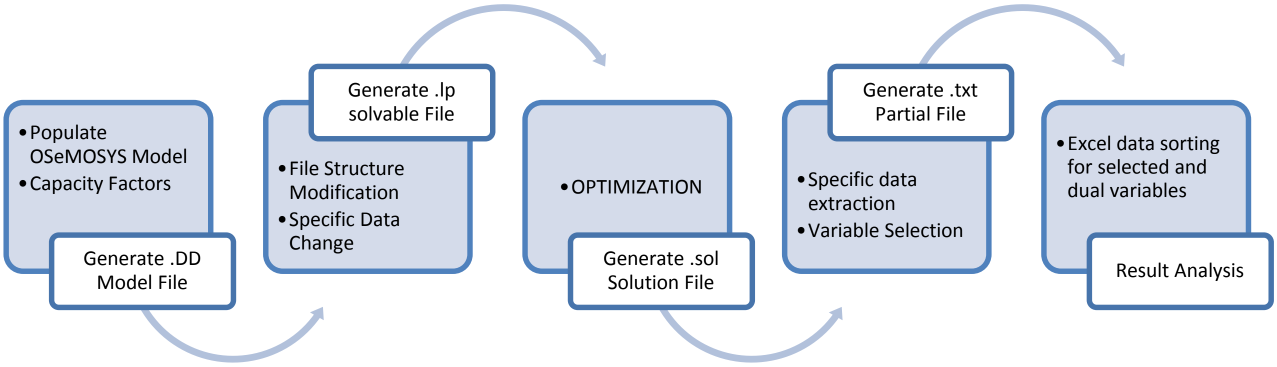
First, a model interface was used for easy editing of the model data in an excel format. The generation data received from the WEAP models is transferred to capacity factors and used to constrain the corresponding power plants. Further constraints are set into the model depending on the run type. This interface is then used to generate a .DD model file based on the modified OSeMOSYS model code.

Considering that certain defaults settings (e.g. reserve margin) are not included in the standard analysis, the corresponding parts of this first file are removed and the .DD file is converted to a fully solvable .lp file using the open source GLPK solver application (Makhorin, 2008).

The .sol solution file that is generated by this process contains the complete model solution description for each of the aforementioned parameters. Typically a minimum a 20GB, this solution file is never opened directly. Instead, a dedicated Python script reads the contents for the parameters that are of main interest and reorganizes it into easily extractable tables. This is done for both actual result values and their dual values – necessary for marginal cost of electricity value generation on national and power pool levels.

In a final step, these tables are read into standardized Excel files that analyze both country and power pool level data for generation mix, capacity levels, trade levels and cost levels.

Figure D-6: Typical Model Run Process



Standard Result Calculations

Based on the full complement of detailed parameter results, the data is systematically aggregated from a technology perspective based on the fuel that it uses to generate power. These categories split results among the following list: Coal, HFO, Diesel, Gas, Hydro, Nuclear, Wind, Solar, Geothermal, Biomass, Dist. Diesel, Dist. Solar and Mini Hydro. Results are then aggregated by country as well as on a power pool level on a yearly basis. Summary tables and graphs are also generated for a higher level of aggregation grouping the previous list into the following categories: Fossil (incl. Coal, HFO and Gas), Diesel (incl. Diesel and Dist. Diesel), Renewables (Incl. Wind, Solar, Biomass and Dist. Solar), Nuclear and Hydro (Incl. Hydro and Dist. Hydro).

Cost calculations are inclusive of all the different system costs and reported as undiscounted annualized cost of energy in the corresponding country or power pool. This final cost of energy considers:

- Annual costs: costs that are incurred on an annual basis through standard system operation. These include Fixed and Variable Operation and Maintenance Cost, Fuel Costs and the Cost of Carbon related to the CO_2 financing scheme assumed to be in place,
- Annualized costs: costs that are incurred in one year for a larger investment and that are divided over the number of years that the corresponding investment will be available in the system. These are related only to Capital Costs for new infrastructure investment and existing infrastructure.

Please note that:

- All cost values are Undiscounted.
- The value of imports/exports is excluded from this calculation. The annualized cost of energy therefore represents the cost of generating one unit of energy inside a give country or region using the corresponding national or regional system.

- The existing infrastructure is assigned an annualized investment cost by multiplying the Residual Capacity of a given technology by the corresponding generic Annualized Investment Cost Unit – i.e. the typical present day investment cost per unit of installed capacity divided by the expected lifetime of that technology.

Standard System Performance Metrics

These metrics designate parameters and variables that are extracted and aggregated from the model run results in order to assess the overall energy system performance. This assessment is carried out both on a national and a power pool basis and is systematically broken down into four interlinked aspects.

- **Capacity** adequacy and dynamics
- **Generation** addressed in regard to national energy demand
- **International Trade** volumes and general flows
- **System Cost** from a national and regional perspective and on a per unit of energy basis

The general dynamics of these four aspects are used to balance the initial model set up and check that all results make economic and technical sense.

Further insight is achieved through extracting a specific set of dual values from the optimization solution. Since the minimization problem we are considering is described by a set of linear constraints binding the primal problem variables, there exists a dual maximization problem in which each primal constraint is represented by a dual variable which represent the constraint limits in the primal problem. When considering the correct primal constraint it is possible to use the corresponding dual value as a representation of the marginal cost of energy on the corresponding level. Such values are extracted and analyzed for equation EBa11 (See Annex B6 regarding the specific OSeMOSYS code).

Limitations and next steps

Looking back at the present exercise, it appears to the energy modeling team that – although the area of modeling and type of methodology that was developed is clearly on the cutting edge of research – it raises many interesting questions for further investigation. These are often linked to areas that fell outside the present scope of work. The following paragraphs detail a certain number of these areas of interest.

First, it appears that water connections between the WEAP modeling and the OSeMOSYS modeling could be further developed. Currently thermal power plants in Sub Saharan Africa rely heavily on water for cooling purposes. Including this water requirement in the interaction methodology between Water and Energy models in parallel could provide an insight into non trivial consequences for national and regional water bodies of developing the energy system in a given way. Further, including the option for the energy optimization process to select a corresponding dry cooling thermal system – with corresponding techno economic cost description – would give this methodology the potential to assess a. if support policies for such options are required b. what such support mechanisms might be and c. what their resulting cost implications could become. (South Africa currently uses dry dryer cooling technologies. A trend that may be optimal to follow.)

Second, it seems that certain data limitations that have affected the present exercise could be investigated. Although the data that is used in the studies were the latest available at the time of writing, it would be valuable to iterate, develop and improve the modeling with direct input from and collaboration with local stakeholders. Not only would this lend stronger credibility to an already robust methodology, but it would also participate in local interest arousal and potential capacity building for local modeling implementation. Topics to be improved might include:

- Country specific techno-economic data for new project implementation.
- Industrial demand representation: present demand calculations do no cater for future large scale – and potentially unexpected – industrial site developments. Such infrastructure additions could change the demand requirements in a country/region and impact the outcome of this analysis.
- Load curve and load region definition improvement: better detail from one country to another in terms of load curve definition – would improve the trade dynamics in the region.

Third, the sheer size of the modeling structures to be developed has impeded fully fledged representation of certain de-centralized system option. Relating to issues of local data and knowledge gaps, but also to questions about methodology and computing power for actual model run implementation, it remains difficult to look into remote demand provision with a fully appropriate modeling structure.

Fourth, it seems natural that after having completed a first round of work where the power pools are – by force (again) of the size of the models – disconnected the one from the other, that a next step of project development might include increased computing power with the potential of connecting the power pools into a larger sub-Saharan model.

Similarly, it would seem appropriate to consider breaking out national modeling approaches from this broader picture. Transforming this large body of work is one of the first attempts at formalizing an interaction between river basin and energy system studies into a tool that can be used by national system planners when addressing infrastructure development plans. This bespoke tool would be of great interest in assessing the various aspects of new infrastructure projects and their resilience when analyzed through this mixed Robust Decision Making procedure.

Finally, in order to quantify the impact of such sudden changes in the energy demand structure over short periods of time, a certain number of investigative scenarios might be set up on a case per case basis. Looking into specific potential for country level development of such activities, these scenarios might show how robustness could change in situations of high demand uncertainty.

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D2- The Southern African Power Pool: Energy Modeling Assumptions, Data and Results

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Introduction: The Southern African Power Pool

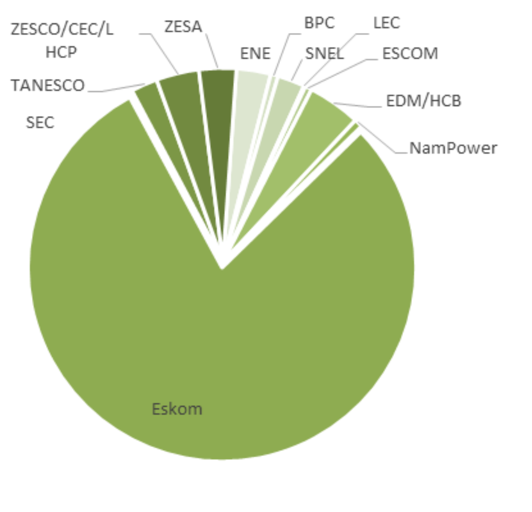
In place since 1995, the Southern African Power Pool (SAPP) was created with the primary aim to provide reliable and economical electricity supply to the consumers of each of the SAPP members, consistent with the reasonable utilisation of natural resources and the effect on the environment. Presently, these countries include The Democratic Republic of the Congo[13], The Kingdoms of Lesotho and Swaziland, The Republics of Angola, Malawi, Mozambique, Namibia, South Africa, Zambia and Zimbabwe as well as the United Republic of Tanzania. Member country's long standing operational, planning and policy co-operation in the region is consistent with the SAPP objective of supporting the development of an open electricity market within the Southern African Development Community (SADC). In practice, the utilities from member countries work under the common understanding of equal and fair participation in developing this vision ranging from sharing information and lessons learnt through to technical wheeling agreements and mutual support. (SAPP, 2014)

The installed capacity of each member of the power pool is noted on Figure D-7. The total installed capacity in the region reached 57,182 MW as of March 2013 with an overall availability of 90.4%. Further, 94% of this capacity is interconnected and available to the power pool as a region (SAPP, 2013a). It is important to note however the large relative size of the South African system for the power pool: with the largest installed and available capacity in Southern Africa the RSA system is eighteen times larger than that of the Democratic Republic of Congo – second largest in the region. This means that the RSA is a fundamental factor of stability for the regional grid system as it provides 74.7% of the regional Operating Reserve. (Southern African Power Pool, 2014)

Table D-9: SAPP Reserve Specifications for 2013

Utility	Largest	Max	Spinning	Quick	Operatin
	MW	MW	MW	MW	MW
ESKOM	930	35136	521.4	521.4	1042.8
ZESA	220	1546	47.5	47.5	95
ZESCO	180	1611	42.8	42.8	85.6
BPC	150	578	27.1	27.1	54.2
Edm	38	629	12.3	12.3	24.6
NAMPO	80	611	17.8	17.8	35.6
SNEL	62	1048	20.3	20.3	40.6
LEC	24	129	4.7	4.7	9.4
SEC	10	204	3.7	3.7	7.4
TOTAL	1694	41492	697.6	697.6	1395.2

Figure D-7: SAPP Capacity - March 2013



Although capacity in some parts of the region is growing fast, it is important to note that there is still a relatively large shortfall on a SAPP level: as per their annual report total demand reaches 53,833MW for an available capacity of 51,702MW which – accounting for peak demand, suppressed demand and reserves – totals a shortfall of 7,709MW i.e. 14.32% of demand is unserved.

[13] Note that DRC is also considered to be part of the remaining three power pools – either officially or through trade links to neighbouring countries from those regions. Refer to the main methodology document to read about the specific conditions of the optimisation relative to this country.

In order to address this situation, a large amount of planned new capacity is expected to come online by the end of 2016 totalling 17.071GW of new power. Referring to Table D-10, fast growing countries include Angola, South Africa, Tanzania and Zambia. They share 81.3% of the new installations.

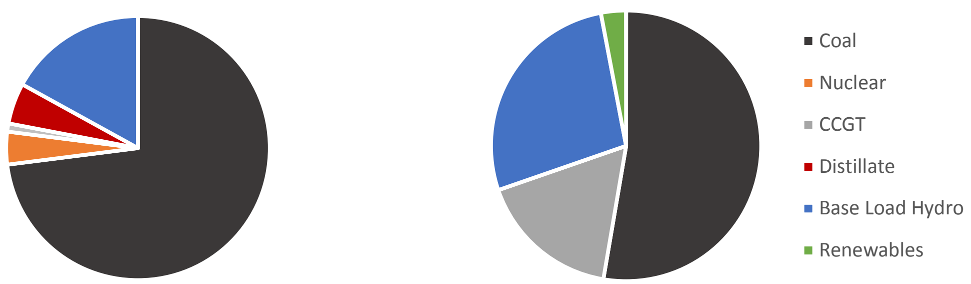
Table D-10: SAPP Committed Capacity – 2013 to 2016 [MW]

Country	2013	2014	2015	2016	TOTAL
Angola	389	640	550	1246	2825
Botswana	600			300	900
DRC	55		580		635
Lesotho			35		35
Malawi	64				64
Mozambique		150	300	300	750
Namibia			120	50	170
South Africa	923	3105	2543	1322	7893
Swaziland					0
Tanzania	60	160	500	1110	1830
Zambia	230	180	435	494	1339
Zimbabwe		300	30	300	630
TOTAL	2321	4535	5093	5122	17071

Source: (SAPP, 2013b)

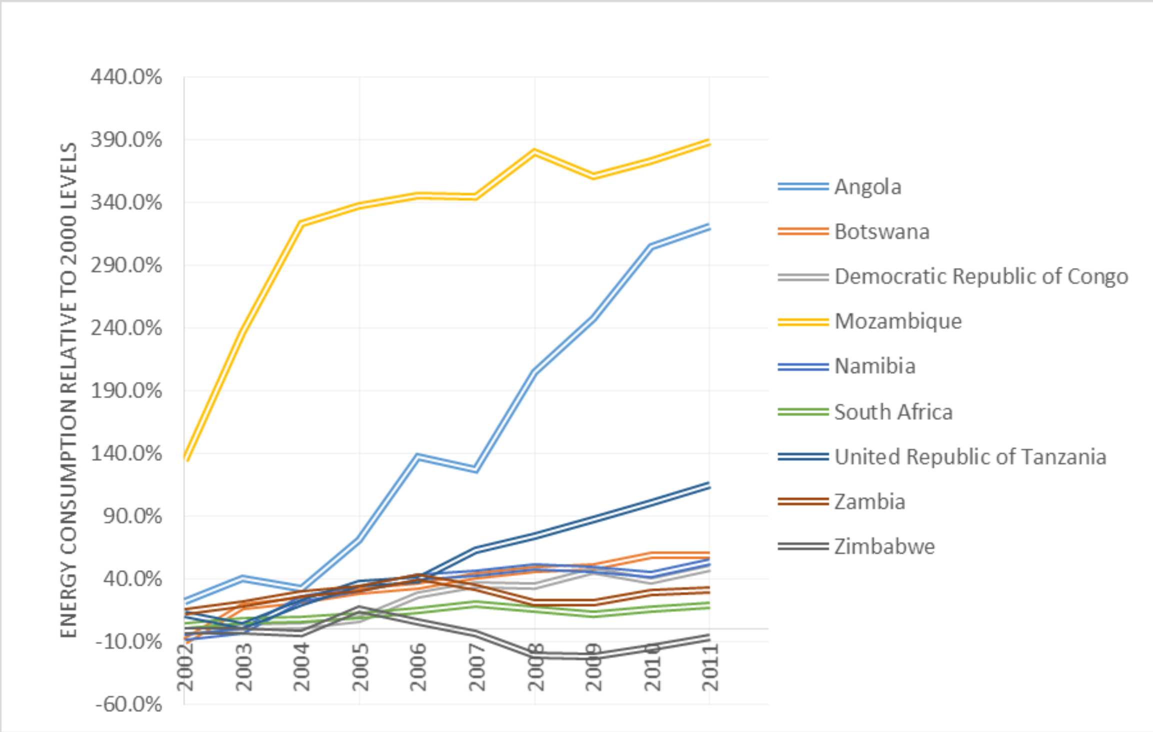
Following the existing split that favours coal based generation (near to 45% of the mix), the new capacity nevertheless includes large amounts of base load hydro power facilities totalling 15% of planned new generation with 27.3MW of added turbine capacity.

Figure D-8: Existing in 2013 (left) and New Capacity installed by 2016 (right) - share per fuel



Although not available for all countries, international records show final consumption of electricity growing steadily over the second half of the twentieth century. Linked initially to a near linear increasing trend in the largest market in the region – South Africa – this growing energy consumption became increasingly linked to the energy system development in all other countries in the region from the mid nineteen nineties onwards (IEA, 2013). In fact, a majority of countries in the Southern African Power Pool have reached energy consumptions between 20% and 100% higher as compared to initial country levels in 2000. Considering Figure D-9, the potential need for energy in the region is clear. There is a direct correlation between final consumption increases and the connection of large new power stations. This is true in particular for DRC and Angola with the connection of the first stage of the Inga project in 2000 -power consumption in the two closest interconnected systems increased significantly.

Figure D-9: Final Energy Consumption increase - selected countries



Source: (IEA, 2013)

Looking forward, SAPP utilities' independent demand projections expect an annual growth of 3.5% per annum – not taking into account potential savings from DSM measures – until 2030 effectively adding 20GW of strain on the system between 2017 and 2027. The regional expectation is that total final demand will exceed 85GW of power by 2030.

In parallel, a large number of demand side management initiatives have been launched on a regional basis and are applied to reduce the load through multiple programmes that currently stand at different stages of implementation. Such initiatives include the Compact Fluorescent Lamp, Hot Water Load Control, Solar Water Heating and Commercial Lighting load reduction programmes totalling 2,305MW avoided power requirements in 2012. This value falls slightly short of the planned target of 3,200MW. (SAPP, 2013b)

Finally environmental concerns are built in to SAPP management structures and represented by the Environmental Sub Committee since 1996. Their role is mainly related to steering the power pool towards best environmental practise by developing adequate guidelines in the areas of water and air quality as well as land use and climate change management. Recent reports go one step further with respect to the energy system supporting statements of intention to both make more room for renewables in the system as a whole and develop a consistent so called "SAPP Position on Renewables" to help policy support in that general direction. (SAPP, 2013b, p. 6)

SAPP Specific Assumptions and Data Tables

Energy Demands

Final electricity consumption in the region varies from one country to the next with high disparities between South Africa and the rest of the power pool. Representing 82.4% of the demand in the region, the South African system is initially the main driver for the SAPP energy system development. Over time however, the share of RSA in the regional demand is grows smaller falling to approx. 68% by the end of the study period. This is mainly due to faster relative demand growths in neighboring countries with five year averages consistently above 4% per annum in six of the twelve power pool members (namely: Lesotho, Malawi, Mozambique, Zambia, Zimbabwe and Tanzania).

From a regional perspective, demand growth values show an expected average growth of 6% for the five year period from 2010 to 2015 dropping gradually over the study horizon to 3.5% by 2050 and multiplying the current demand by more than 3. Although population growth in the region is currently at an average of 2.4% with extremes in Zimbabwe and South Africa respectfully at 3.2% and 0.77% – expected to decrease to resp. 0 and 1.59% by 2050 – this overall increase in demand is also due to a significant increase in energy consumption per capita. Once again however the regional impact of RSA is extremely large as SAPP wide per capita consumption drops from 1714.2 kWh/capita in 2050 to 1452.5 kWh/capita without South Africa[14].

Figure D-10: Total SAPP Energy demand per country

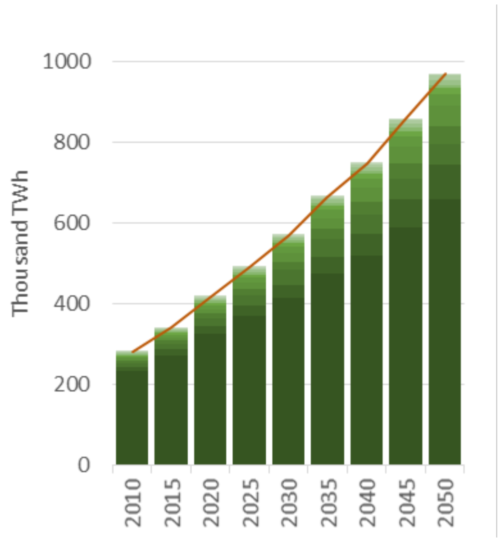
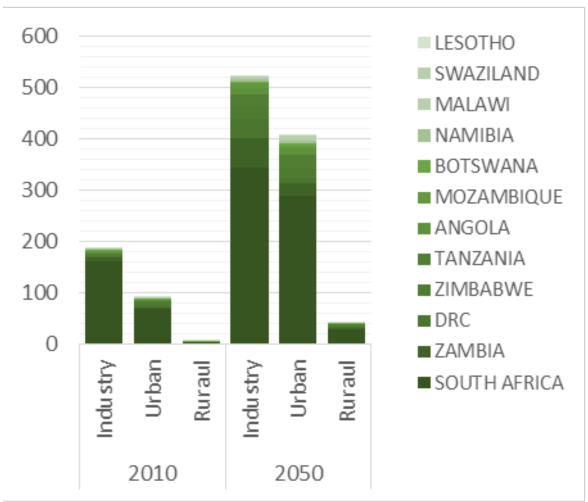


Figure D-11: SAPP Energy Demand: Sectorial Split



Detailed demand values for each individual country and sector are presented in Table D-25 at the end of the present Annex.

[14] Note that keysource documents for this paragraph include (Miketa and Merven, 2013) and (*World Population Prospects, the 2012 Revision*, 2013)

Time Slices and Load Curve

The SAPP OSeMOSYS model considers a break-down of the year into twelve months and four different day parts bringing the total number of time slices to 48. This split is done on the duration of each of the time slice types relative to the total duration of one year. The final values are presented in Table D-11 as a share of the total year.

Table D-11: SAPP Time Slice definition (share)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Day Part 1	0.02480	0.02240	0.02480	0.02400	0.02480	0.02400	0.02480	0.02480	0.02400	0.02480	0.02400	0.02480
Day Part 2	0.04247	0.03836	0.04247	0.04110	0.04247	0.04110	0.04247	0.04247	0.04110	0.04247	0.04110	0.04247
Day Part 3	0.00883	0.00798	0.00883	0.00855	0.01308	0.01364	0.01410	0.01410	0.00940	0.00883	0.00855	0.00883
Day Part 4	0.00883	0.00798	0.00883	0.00855	0.00459	0.00345	0.00357	0.00357	0.00770	0.00883	0.00855	0.00883

This time slice structure defines the smallest unit of time over which all energy balances are made inside of the energy modelling framework. In addition to this break down, a specific demand load curve is defined for each demand type describing the amount of energy used in a specific time slice relative to the total annual demand. These data series are presented in Table D-12 through Table D-14 respectively for Industrial, Rural and Urban demands. Note that these values are constant for all countries in the SAPP.

Table D-12: Industrial Demand Load Curve

Industrial	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Day Part 1	0.02390	0.02159	0.02390	0.02313	0.02084	0.01945	0.02010	0.02010	0.02323	0.02478	0.02398	0.02478
Day Part 2	0.04439	0.04010	0.04439	0.04296	0.04455	0.04314	0.04458	0.04458	0.04430	0.04602	0.04453	0.04602
Day Part 3	0.00854	0.00771	0.00854	0.00826	0.01224	0.01271	0.01313	0.01313	0.00925	0.00885	0.00856	0.00885
Day Part 4	0.00854	0.00771	0.00854	0.00826	0.00427	0.00314	0.00324	0.00324	0.00766	0.00885	0.00856	0.00885

Table D-13: Rural Demand Load Curve

Rural	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Day Part 1	0.02501	0.02259	0.02501	0.02421	0.02432	0.02338	0.02416	0.02416	0.02481	0.02593	0.02509	0.02593
Day Part 2	0.02997	0.02707	0.02997	0.02900	0.02966	0.02863	0.02959	0.02959	0.02982	0.03106	0.03006	0.03106
Day Part 3	0.01520	0.01373	0.01520	0.01471	0.01941	0.01977	0.02043	0.02043	0.01600	0.01575	0.01524	0.01575
Day Part 4	0.01520	0.01373	0.01520	0.01471	0.00850	0.00667	0.00689	0.00689	0.01381	0.01575	0.01524	0.01575

Table D-14: Urban Demand Load Curve

Urban	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Day Part 1	0.01991	0.01798	0.01991	0.01927	0.01889	0.01804	0.01864	0.01864	0.01965	0.02064	0.01997	0.02064
Day Part 2	0.04696	0.04241	0.04696	0.04544	0.03981	0.03687	0.03810	0.03810	0.04540	0.04867	0.04710	0.04867
Day Part 3	0.00925	0.00836	0.00925	0.00896	0.01683	0.01804	0.01864	0.01864	0.01074	0.00959	0.00928	0.00959
Day Part 4	0.00925	0.00836	0.00925	0.00896	0.00637	0.00549	0.00567	0.00567	0.00865	0.00959	0.00928	0.00959

Regional Fuel provision and costs

Additionally to the general assumptions for this paragraph that are detailed in the body of the Main Modelling Annex, the Southern African Power Pool has a specific set of data assumptions regarding the availability and cost of fossil fuels due to its particular level of reserves.

In accordance with current levels as identified by international sources, Table D-15 lists the identified fossil resources available to each country in the region. The corresponding cost of extracting these fuels is included in the overall fuel price listed in Table D-16. As a first pass assumption used to differentiate the two types of fuel, imports of a given commodity are costed using the domestic per unit cost increased by a standard 10%. (see D1- OSeMOSYS Common Modeling Assumptions– Main Methodology Assumptions for further details)

Table D-15: National identified fossil reserves in TWh – SAPP

Country	Coal*	Crude Oil **	Natural Gas*
Angola	0.00	18588.77	3867.51
DRC	549.85	319.58	10.47
Lesotho	0.00	0.00	0.00
Malawi	12.50	0.00	0.00
Mozambique	1324.63	0.00	1346.52
Namibia	0.00	0.00	658.30
South Africa	188422.00	26.63	0.00
Swaziland	899.75	0.00	0.00
Tanzania	1249.65	0.00	68.82
Zambia	62.48	0.00	0.00
Zimbabwe	3136.62	0.00	0.00

* 2008 Data, **2011 Data

Source: (EIA, 2011)

From a cost of fuel perspective, each type of fuel is costed differently in cases of imports and domestic production. Table D-16 presents the values used to describe domestic fuel resource extraction. The unit costs are reported in USD/ToE and vary from country to country. Correspondently, the cost of export is obtained by increasing that of domestic extraction by 10%.

Table D-16: Cost of domestic fuel extraction [USD/ToE]

	Angola	Botswana	DRC	Lesotho	Malawi	Mozambique	Namibia	Swaziland	Tanzania	South Africa	Zambia	Zimbabwe
Biomass[15]	62.4	62.4	62.4	151.1	62.4	0.0	151.1	0.0	0.0	62.4	62.4	62.4
Coal	125.6	83.7	125.6	125.6	83.7	83.7	83.7	83.7	125.6	83.7	83.7	83.7
Diesel	917.3	1055.5	917.3	1055.5	1055.5	917.3	917.3	1055.5	917.3	917.3	1055.5	1055.5
HFO	540.5	682.4	540.5	682.4	682.4	540.5	540.5	682.4	540.5	540.5	682.4	682.4
Natural Gas	355.9	431.7	355.9	0.0	791.3	355.9	355.9	791.3	355.9	460.5	431.7	431.7

Source: (Department Of Energy, 2011) (Miketa and Merven, 2013)

[15] Biomass is reported here for ledgibility reasons but is – of course – considered to be a renewable source of energy.

Renewable Energy Potentials

Renewable energy potentials over Africa in general, and Southern Africa in particular, are non-negligible. Based on the latest IRENA research for the continent (Hermann et al., 2014), the total theoretically available renewable power for the SAPP including solar and wind based sources could fall just short of 600 thousand TWh. In South Africa alone the potential for concentrated solar power would be sufficient to provide 18.7% of the total demand on a yearly basis. This resource however is unevenly spread within the region. Due in part to the definition criteria regarding what constitutes technically available resource and to the corresponding area exclusions in the energy potential mapping, this distribution highlights the potential advantage of increased interconnection. As renewable resource availability suffers from unpredictability, a strong interconnected grid becomes an advantage for both distributing risk and absorbing the resource as soon as it becomes available.

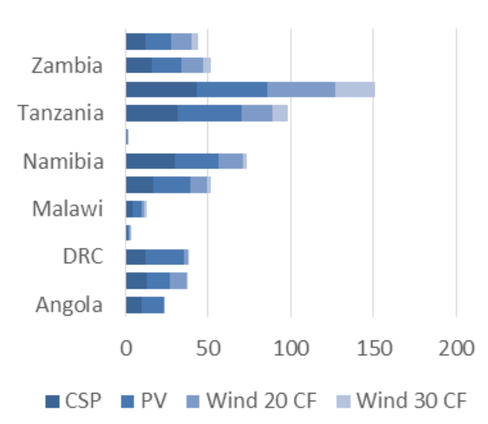
As a summary of these potentials, Table D-17 presents the upper limits extracted from the literature and used in the present modelling to provide resource constraints for the renewable technology options available as part of future energy generation options during the optimisation.

Table D-17: Renewable Energy Potential per Country

	[TWh per year]			
	CSP	PV	Wind 20 CF	Wind 30 CF
Angola	9786	13319	202	0
Botswana	13070	13764	9793	1211
DRC	12439	22862	2173	165
Lesotho	1122	938	599	160
Malawi	4474	5210	1986	1048
Mozambique	16851	22024	10805	1584
Namibia	29716	26183	15196	1988
Swaziland	599	572	476	39
Tanzania	31482	38804	18456	9181
South Africa	43275	42243	41195	24305
Zambia	15691	17894	13229	4580
Zimbabwe	11874	15684	12137	4001

Source: (Hermann et al., 2014)

Figure D-12: Thousand TWh of Renewable Potential



In parallel to these resource availability limits, the energy models consider two types of constraints on renewable technologies. The first assumes a cap on the amount of new capacity that can be added to the system on a yearly basis, while the second restricts the total penetration of renewable energy in the overall mix in order to ensure conservative shares of lower reliability technologies in the final generation.

Please note that assumptions regarding Hydropower are listed in a separate paragraph due to the important focus of the present study on this specific resource.

Techno-economic Parameters

The technology options available inside of the power pool model are linked to corresponding generic parameter values. These are presented and referenced in Table D-18.

Table D-18: Techno Economic Data for generic power plants

Power Plant (Technologies)	Capital Cost ($/kW)	Variable O&M Cost (USD/GJ) [16]	Life time (Years)	Construction (Years)
Biomass	3660	5.56	30	4
Coal	3519	3.96	35	4
Diesel 100 kW (Industrial)	659	15.38	20	0
Diesel 1kW (Rural)	692	9.23	10	0
Diesel 1kW (Urban)	692	9.23	10	0
Diesel (Centralized)	1177	4.72	30	1
Geothermal	5856	1.39	25	4
HFO	1634	4.17	25	2
Gas Turbine (Combined cycle)	1423	0.80	30	3
Gas turbine (Other cycles)	730	5.53	25	2
Nuclear	10778	3.87	60	8
CSP	4392	6.20	25	4
CSP with Storage	10249	4.56	25	4
CSP with Gas Co-firing	2033	4.56	25	4
Solar PV Utility	2200	5.58	25	1
PV Rural Rooftop	2100	4.16	20	<1
PV Rural rooftop 1hr storage	4258	4.16	20	<1
PV Rural rooftop 2hr storage	6275	4.76	20	<1
PV Urban Rooftop	2100	4.16	20	<1
PV Urban rooftop 1hr storage	4258	4.76	20	<1
PV Urban rooftop 2hr storage	6275	5.29	20	<1
Wind 25% Capacity Factor	2862	3.97	25	2
Wind 30% Capacity Factor	2420	3.97	25	2
Generic Large Hydro	3221	1.66	50	5
Generic Micro Hydro	4800	1.51	30	2

Source: (Miketa and Merven, 2013)

Planned infrastructure investments

Energy infrastructure development is a long process that goes through a number of project phases before the physical power plant comes online and actually begins to provide energy to the system. In order to take into account this lead time in project development, the first years of the modelling framework are constrained to ensure that actual infrastructure investment results and current committed national plans line up. These committed investments are summarised in the latest available literature review of Power Pool level planning documents used in the preparation of recent modelling work by the International Renewable Energy Agency (See Table 2.1 of the corresponding project report for the SAPP - (Miketa and Merven, 2013)).

With a specific focus on hydro power, Table D-19 details the specific list of power plants that are included in the OSeMOSYS energy modelling framework. These power plants fall into six different categories:

[16] This cost excludes fuel costs. These are borne by the fuel provision technologies. See Annex B1 Main Methodology Assumptions.

- One split into two categories are based on their presence or not in the WEAP water models: this defines whether or not the power plant receives direct or proxied information for the climate scenario runs.
- A second split into three categories based on the status of the power plant: i.e. whether the facility is historic capacity (existing), committed new capacity or planned new capacity.

The table further details the correspondence between the OSeMOSYS power plants and their WEAP counterparts. In cases where the power plant is not directly included in the WEAP models this correspondence designates the proxy that was used to derive capacity factor variations related to the six climate change scenarios under analysis.

Table D-19: Site Specific Hydro power plant parameters

Energy Model Naming	**WEAP Proxy**	**River Basin**	**Capacity (MW)**	**Capital Cost ($/kW)**	**Fixed Cost ($/kW)**	**Variable Cost ($/GJ)**	**Status** [17]	**Earliest on**
Angola								
Capanda II	Busanga	Congo	260	1417.8	9.35	0.45	CON	2010
Cambambe II	Busanga	Congo	860	3181.8	9.35	0.45	CON	2012
Kuanza Basin	Busanga	Congo	5480	1878.6	9.35	0.45	PLN	2014
Gove	Busanga	Congo	135	1036.3	9.35	0.45	CON	2012
Low availability (Mabubas, Biopia)	Busanga	Congo	26	0	9.35	0.45	HC	
High availability (Cambambe, Capanda, Matala)	Busanga	Congo	474	0	9.35	0.45	HC	
DRC								
Busanga	Busanga	Congo	240	3221.02	9.35	0.45	PLN	2016
Mwadingusha		Congo	68	0	9.35	0.45	HC	
Grand Inga	Grand Inga	Congo	39000	3221.02	9.35	0.45	PLN	2027
Inga 3	Inga 3	Congo	7.8	3221.02	9.35	0.45	PLN	2016
Nseke	Nseke	Congo	236	3221.02	9.35	0.45	HC	
Inga I	Inga I	Congo	360	0	9.35	0.45	HC	
Zonga	Zongo	Congo	40	0	9.35	0.45	HC	
Sanga	Sanga	Congo	11.5	3221.02	9.35	0.45	HC	
Nzilo	Nzilo	Congo	120	3221.02	9.35	0.45	HC	
Koni		Congo	42	0	9.35	0.45	HC	
Inga II	Inga II	Congo	1424	0	9.35	0.45	HC	
Ruzizi II	Ruzizi II	Congo	14.3	3221.02	9.35	0.45	HC	
Ruzizi III	Ruzizi III	Congo	90	3221.02	9.35	0.45	PLN	2016
Mobaye	Mobaye	Congo	12	3221.02	9.35	0.45	PLN	2016
Katende	Katende	Congo	20	3221.02	9.35	0.45	PLN	2016
Tshopo	Tshopo	Congo	9.5	3221.02	9.35	0.45	PLN	2016
Lesotho								
Oxbow	Muela	Orange	80	3344.87	9.35	0.45	PLN	2017
Muela II	Muela	Orange	48	3344.87	9.35	0.45	PLN	2014
Historic capapcity (Muela I)	Muela	Orange	80	0	9.35	0.45	HC	
Malawi								
Fufu	Fufu	Zambezi	100	1511	9.35	0.45	PLN	2015
Kholombizo	Kholombizo	Zambezi	240	1745.7	9.35	0.45	PLN	2018
Mpatanga	Nkhula Falls	Zambezi	200	1636.4	9.35	0.45	PLN	2020
Songwe	Songwe	Zambezi	340	1339.6	9.35	0.45	PLN	2014
Kapichira Existing	Kapichira	Zambezi	68	0	9.35	0.45	HC	
Tedzani	Tedzani	Zambezi	88	0	9.35	0.45	HC	
Nkula	Nkhula Falls	Zambezi	121.6	0	9.35	0.45	HC	

[17] CON: Under Construction; HC: Historic Capacity, i.e. existing; PLN: Planned Capacity

Kapichira Planned	Kapichira	Zambezi	64	1348	9.35	0.45	PLN	2014
Mozambique								
Massingir	Kariba	Zambezi	40	1473.5	9.35	0.45	HC	
HCB North Bank	Cahora Bassa	Zambezi	850	972	9.35	0.45	PLN	2015
Luirio	Kariba	Zambezi	183	1991.1	9.35	0.45	PLN	2020
Mphanda Nikuwa	Mphanda	Zambezi	1500	1648.2	9.35	0.45	PLN	2017
Quedas & Ocua	Kariba	Zambezi	179	2029.7	9.35	0.45	PLN	2011
Other (Chicamba, Corumana, Mavuzi)	Kapichira	Zambezi	47	0	9.35	0.45	HC	
Cahora Bassa	Cahora Bassa	Zambezi	2075	0	9.35	0.45	HC	
Namibia								
Baynes	Iztezhi-Tezhi	Zambezi	360	1905.4	9.35	0.45	PLN	2020
Ruacana Historic	Iztezhi-Tezhi	Zambezi	240	0	9.35	0.45	HC	
Swaziland								
(Ezulwini, Edwaleni, Magud, Maguga)	Vanderkloof	Orange	62	0	9.35	0.45	HC	
Tanzania								
Kakono	Rumakali	Orange	53	2492.7	9.35	0.45	PLN	2016
Rusomo	Ruzizi II&III	Congo	21	2492.7	9.35	0.45	PLN	2016
Masigira	Rumakali	Orange	118	2492.7	9.35	0.45	PLN	2020
Rumakali	Rumakali	Orange	220	2492.7	9.35	0.45	PLN	2019
Stieglers Gorge	Rumakali	Orange	1.2	2492.7	9.35	0.45	PLN	2023
Hydro (kidatu, kihansi)	Rumakali	Orange	384	0	5.7656	0	HC	
Other (Pangani Falls, Mtera, Nyumba ya Mungu, Hale)	Rumakali	Orange	177	0	11.24	0	HC	
Ruhudji	Rumakali	Orange	358	1829.3	9.35	0.45	PLN	2017
South Africa								
Drakensberg	Vanderkloof	Orange	1000	3221.02	8.57	1.54	HC	
Ingula	Vanderkloof	Orange	1332	3221.02	8.7	5.44	PLN	2014
Palmiet	Vanderkloof	Orange	400	0	9.14	2.06	HC	
Steenbras	Vanderkloof	Orange	180	3221.02	6.57	2.06	HC	
Tubatse	Vanderkloof	Orange	1500	3221.02	8.7	5.44	DLY	
Gariep	Gariep	Orange	360	0	9.35	0.45	HC	
Vanderkloof	Vanderkloof	Orange	240	0	9.35	0.45	HC	
Zambia								
Hydro (Viktoria Falls and other small hydro)		Zambezi	132	0	9.35	0.45	HC	
Kafue gorge upper	Kafue Upper	Zambezi	900	0	9.35	0.45	HC	
Generic new Hydro		Zambezi	600	3221.02	0	1.66	PLN	2020
Kabompo	Iztezhi-Tezhi	Zambezi	40	4286.7	9.35	0.45	CON	2015
Mpata	Mpata Gorge	Zambezi	543	2679.2	9.35	0.45	PLN	2021
Mambililma Falls	Busanga	Congo	326	2679.2	9.35	0.45	PLN	2025
Mumbotula	Busanga	Congo	301	2679.2	9.35	0.45	PLN	2016
LusumfweMulungushi	LusumfwaMulungus	Zambezi	255	2679.2	9.35	0.45	PLN	2018
Kariba North	Kariba	Zambezi	360	1339.6	9.35	0.45	CON	2013
Karfue gorge Lower	Karfue Lower	Zambezi	750	2143.3	9.35	0.45	CON	2016
Kalungwishi		Zambezi	220	3215	9.35	0.45	PLN	2018
Itezhi-tezhi	Iztezhi-Tezhi	Zambezi	120	2232.6	9.35	0.45	CON	2014
Devils gorge	Devil's Gorge	Zambezi	1240	2679.2	9.35	0.45	PLN	2019
Lusiwasi	Lusiwasi	Zambezi	84	2679.2	9.35	0.45	PLN	2010
Batako Gorge	Batoka Gorge	Zambezi	800	2679.2	9.35	0.45	PLN	2022
Kariba North	Kariba	Zambezi	720	0	9.35	0.45	HC	
Zimbabwe								
Kariba south extension	Kariba	Zambezi	300	1333.3	9.35	0.45	CON	2016
Kariba south	Kariba	Zambezi	750	0	9.35	0.45	HC	
Batoka Gorge	Batoka Gorge	Zambezi	800	3375	9.35	0.45	PLN	2022

Source:(Miketa and Merven, 2013) (World Bank, 2010)

Transmission and Distribution

National transmission and distribution systems include four types of lines connecting two different levels of the energy system. Since data regarding current levels of system development on a national level are not readily available, initial balancing of the regional SAPP model is used to determine the capacity levels required to cover existing demand in each individual country. These levels are then considered fixed in the first year of the modelling.

Further, each type of line suffers from losses which translate into different transmission efficiencies. These efficiencies can also vary for a single type of line from one country to another depending on the state of the system. The values used in this study and presented in Table D-20 follow data shared during interactions with local stakeholders and presented at a regional level during the 2014 SAPP planning and environmental subcommittee meetings – Walvis Bay - Namibia. These values are detailed on an annual basis from 2030 to 2050.

Table D-20: National T&D line efficiencies

Line Type	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
ANGOLA																					
Transmission	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95
Dist_Industry	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.981	0.982	0.983	0.984	0.985	0.986	0.987	0.988	0.989	0.99
Dist_Urban	0.8	0.805	0.81	0.815	0.82	0.825	0.83	0.835	0.84	0.845	0.85	0.857	0.864	0.871	0.878	0.885	0.892	0.899	0.906	0.913	0.92
Dist_Rural	0.7	0.71	0.72	0.73	0.74	0.75	0.76	0.77	0.78	0.79	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
BOTSWANA																					
Transmission	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95
Dist_Industry	0.97	0.971	0.972	0.973	0.974	0.975	0.976	0.977	0.978	0.979	0.98	0.981	0.982	0.983	0.984	0.985	0.986	0.987	0.988	0.989	0.99
Dist_Urban	0.85	0.855	0.86	0.865	0.87	0.875	0.88	0.885	0.89	0.895	0.9	0.902	0.904	0.906	0.908	0.91	0.912	0.914	0.916	0.918	0.92
Dist_Rural	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
DRC																					
Transmission	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95
Dist_Industry	0.97	0.971	0.972	0.973	0.974	0.975	0.976	0.977	0.978	0.979	0.98	0.981	0.982	0.983	0.984	0.985	0.986	0.987	0.988	0.989	0.99
Dist_Urban	0.75	0.765	0.78	0.795	0.81	0.825	0.84	0.855	0.87	0.885	0.9	0.902	0.904	0.906	0.908	0.91	0.912	0.914	0.916	0.918	0.92
Dist_Rural	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
LESOTHO																					
Transmission	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95
Dist_Industry	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.981	0.982	0.983	0.984	0.985	0.986	0.987	0.988	0.989	0.99
Dist_Urban	0.88	0.882	0.884	0.886	0.888	0.89	0.892	0.894	0.896	0.898	0.9	0.902	0.904	0.906	0.908	0.91	0.912	0.914	0.916	0.918	0.92
Dist_Rural	0.75	0.755	0.76	0.765	0.77	0.775	0.78	0.785	0.79	0.795	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
MALAWI																					
Transmission	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95
Dist_Industry	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.981	0.982	0.983	0.984	0.985	0.986	0.987	0.988	0.989	0.99
Dist_Urban	0.8	0.81	0.82	0.83	0.84	0.85	0.86	0.87	0.88	0.89	0.9	0.902	0.904	0.906	0.908	0.91	0.912	0.914	0.916	0.918	0.92
Dist_Rural	0.7	0.71	0.72	0.73	0.74	0.75	0.76	0.77	0.78	0.79	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
MOZAMBIQUE																					
Transmission	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95
Dist_Industry	0.95	0.951	0.952	0.953	0.954	0.955	0.956	0.957	0.958	0.959	0.96	0.961	0.962	0.963	0.964	0.965	0.966	0.967	0.968	0.969	0.97
Dist_Urban	0.7	0.715	0.73	0.745	0.76	0.775	0.79	0.805	0.82	0.835	0.85	0.857	0.864	0.871	0.878	0.885	0.892	0.899	0.906	0.913	0.92
Dist_Rural	0.7	0.71	0.72	0.73	0.74	0.75	0.76	0.77	0.78	0.79	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
NAMIBIA																					
Transmission	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95
Dist_Industry	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.981	0.982	0.983	0.984	0.985	0.986	0.987	0.988	0.989	0.99
Dist_Urban	0.8	0.81	0.82	0.83	0.84	0.85	0.86	0.87	0.88	0.89	0.9	0.902	0.904	0.906	0.908	0.91	0.912	0.914	0.916	0.918	0.92
Dist_Rural	0.75	0.755	0.76	0.765	0.77	0.775	0.78	0.785	0.79	0.795	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8

SOUTH AFRICA											
Transmission	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95
Dist_Industry	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99
Dist_Urban	0.83	0.837	0.844	0.851	0.858	0.865	0.872	0.879	0.886	0.893	0.9
Dist_Rural	0.75	0.755	0.76	0.765	0.77	0.775	0.78	0.785	0.79	0.795	0.8
SWAZILAND											
Transmission	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95
Dist_Industry	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98
Dist_Urban	0.85	0.855	0.86	0.865	0.87	0.875	0.88	0.885	0.89	0.895	0.9
Dist_Rural	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
TANZANIA											
Transmission	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95
Dist_Industry	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98
Dist_Urban	0.83	0.837	0.844	0.851	0.858	0.865	0.872	0.879	0.886	0.893	0.9
Dist_Rural	0.75	0.755	0.76	0.765	0.77	0.775	0.78	0.785	0.79	0.795	0.8
ZAMBIA											
Transmission	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95
Dist_Industry	0.96	0.961	0.962	0.963	0.964	0.965	0.966	0.967	0.968	0.969	0.97
Dist_Urban	0.75	0.76	0.77	0.78	0.79	0.8	0.81	0.82	0.83	0.84	0.85
Dist_Rural	0.7	0.71	0.72	0.73	0.74	0.75	0.76	0.77	0.78	0.79	0.8
ZIMBABWE											
Transmission	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95
Dist_Industry	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98
Dist_Urban	0.83	0.835	0.84	0.845	0.85	0.855	0.86	0.865	0.87	0.875	0.88
Dist_Rural	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8

SOUTH AFRICA										
Transmission	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95
Dist_Industry	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99
Dist_Urban	0.902	0.904	0.906	0.908	0.91	0.912	0.914	0.916	0.918	0.92
Dist_Rural	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
SWAZILAND										
Transmission	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95
Dist_Industry	0.981	0.982	0.983	0.984	0.985	0.986	0.987	0.988	0.989	0.99
Dist_Urban	0.902	0.904	0.906	0.908	0.91	0.912	0.914	0.916	0.918	0.92
Dist_Rural	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
TANZANIA										
Transmission	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95
Dist_Industry	0.981	0.982	0.983	0.984	0.985	0.986	0.987	0.988	0.989	0.99
Dist_Urban	0.902	0.904	0.906	0.908	0.91	0.912	0.914	0.916	0.918	0.92
Dist_Rural	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
ZAMBIA										
Transmission	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95
Dist_Industry	0.971	0.972	0.973	0.974	0.975	0.976	0.977	0.978	0.979	0.98
Dist_Urban	0.857	0.864	0.871	0.878	0.885	0.892	0.899	0.906	0.913	0.92
Dist_Rural	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
ZIMBABWE										
Transmission	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95
Dist_Industry	0.981	0.982	0.983	0.984	0.985	0.986	0.987	0.988	0.989	0.99
Dist_Urban	0.884	0.888	0.892	0.896	0.9	0.904	0.908	0.912	0.916	0.92
Dist_Rural	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8

Source: (Miketa and Merven, 2013)

In addition to national level T&D, each country in the region is either connected – or has the potential for connection to – neighbouring systems. Considering the latest available data regarding the SAPP, Table D-21 presents the countries with existing high voltage connections along with their current rating. Similarly, Table D-22 presents the project options that are included in the modelling framework. Note that these are divided between "Committed" and "Future" in relation to the level of certainty that the corresponding project will be implemented. The first are therefore forced in to the solution space whereas the second are simply made available to the system and are considered as part of the optimisation. Note that the denominations "Country1" resp. 2 are simply used to define the two neighbours that are connected by the transmission project. Energy is not constrained to flow in a particular direction but rather is traded depending on the unit cost of production in each country.

Table D-21: International Transmission - Existing Infrastructure

Country 1	**Country 2**	**Capacity (MW)**
Botswana	South Africa	800
	Zimbabwe	650
Lesotho	South Africa	230
DRC	Zambia	260
Mozambique	South Africa	3850
	Swaziland	1450
	Zimbabwe	500
Namibia	South Africa	750
South Africa	Swaziland	1450
	Zimbabwe	600
Zambia	Zimbabwe	1400

Source: (Miketa and Merven, 2013)

Table D-22: Future International transmission projects

Country 1	Country 2	Line capacity (MW)	Earliest year
Zizabona (Zimbabwe, Botswana, Namibia, Zambia)		600	2015
Westcor (DRC, Namibia, Angola, Botswana, South Africa)		1500	2020
765 kV (DRC, Zambia, Zimbabwe, Namibia, South Africa)		1500	2020
Angola	DRC	600	2016
Botswana	South Africa	500	2012
DRC	Zambia	500	2017
Lesotho	South Africa	130	2015
Malawi	Mozambique	600	2017
	Mozambique	300	2015
	Zambia	200	2018
Mozambique	South Africa	600	2018
	Zimbabwe	500	2017
Namibia	South Africa	300	2018
	Angola	400	2016
South Africa	Swaziland	450	2018
	Zimbabwe	650	2017
Tanzania	Zambia	400	2016

Source: (Miketa and Merven, 2013)

Integration with other power pools

This modelling effort was conducted as an integral component of the larger vulnerability assessment of African infrastructure. In this study, the four Sub Saharan power pools (CAPP; EAPP; SAPP and WAPP) were modelled separately but have a certain number of overlapping countries and overlapping infrastructure: i.e. certain countries are included in multiple power pools and certain river basins give water input into several power pools. Considering that each power pool is optimized separately under an iterative approach with the water modelling component of the project, this overlap adds an extra level of complication.

To ensure that results are consistent between power pools, a few simple procedures were applied. First, power pools were optimized in a specific order aligned with the perceived importance of their impact on continent scale results: SAPP was followed by WAPP, EAPP and CAPP. Second, countries that were included in several power pools were optimized only once along with the first power pool in which they appear. Thereafter, when contributing to other power pools they are constrained both in terms of capacity and minimum dispatch to respect the results from the previous model runs.

The specific impact of this part of the methodology on the SAPP however is null since this power pool is optimized first: the results of each of the scenario runs will be used as inputs to other power pools to ensure that subsequent optimizations of countries shared by the SAPP do not compromise the validity of the results for this power pool.

For further details about the constraints applied and the corresponding countries that they were applied to, please refer to the main methodology annex (D1- OSeMOSYS Common Modeling Assumptions).

Results

Regional Overview

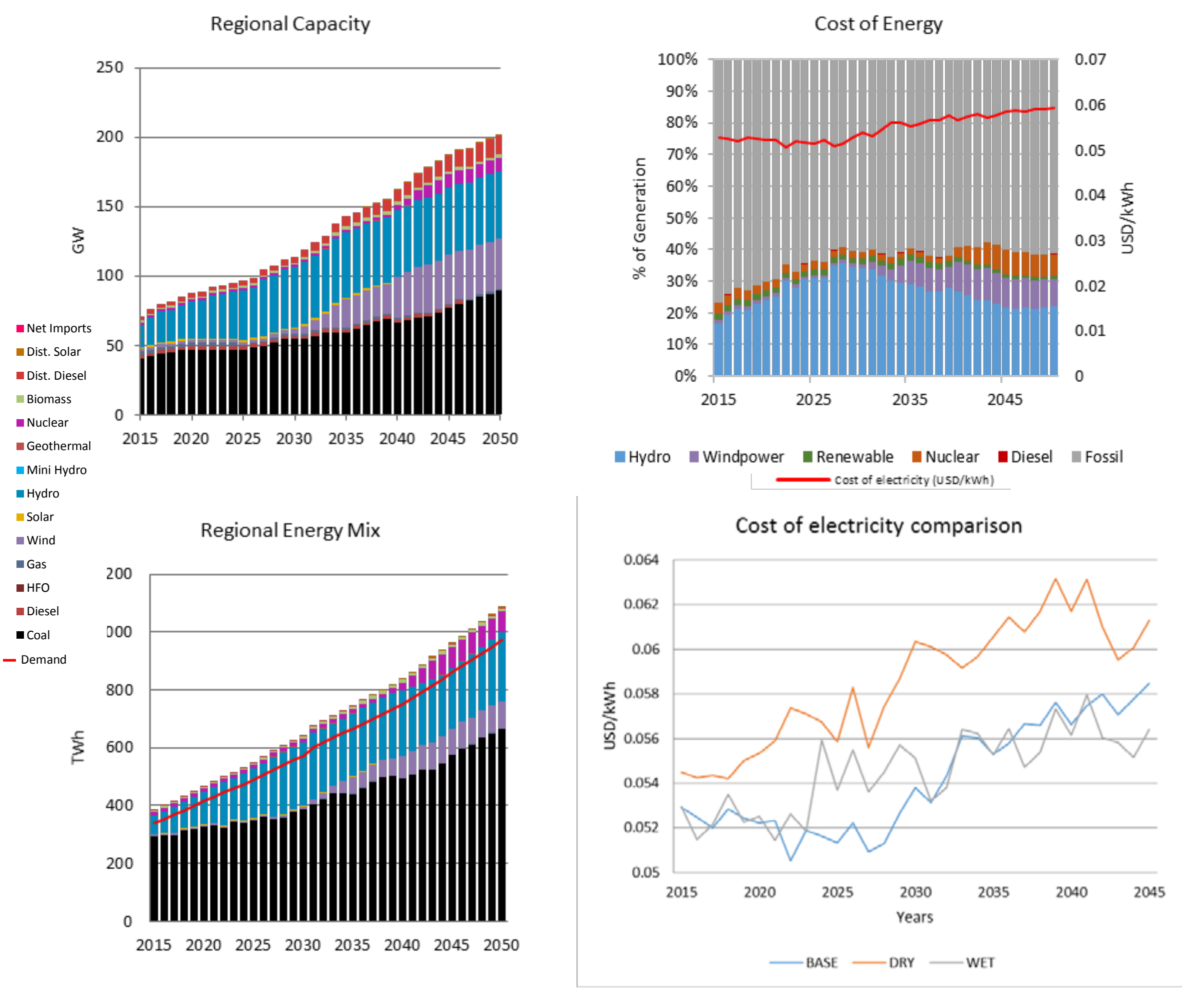
General Energy System Results

The SAPP system is growing steadily. The main results regarding capacity and generation per fuel category as well as the ensuing cost of power are shown below in

Figure D-13. First, it is expected that installed capacity will double in order to meet current and future demand growth levels. Given retirements during the period, the current system will be gradually replaced with a new one that is at least three times as large by the end of the modelling period reaching a total installed capacity of around 200 GW by 2050.

Following the existing energy situation, and unimpeded by any carbon tax, the regional capacity mix relies highly on coal based generation responsible for 61% of the generated power by the end of the period. This constant base is complemented by a share of renewable power split between hydropower contributions, 22%, and windpower, 8.8%, in 2050. Following new investments in 2035 and – more importantly – in 2040, nuclear power takes a small yet constant share of generation producing between 7 and 10% of annual electricity requirements over the last ten years of the modelling period.

Figure D-13: Capacity and Generation mix Summary

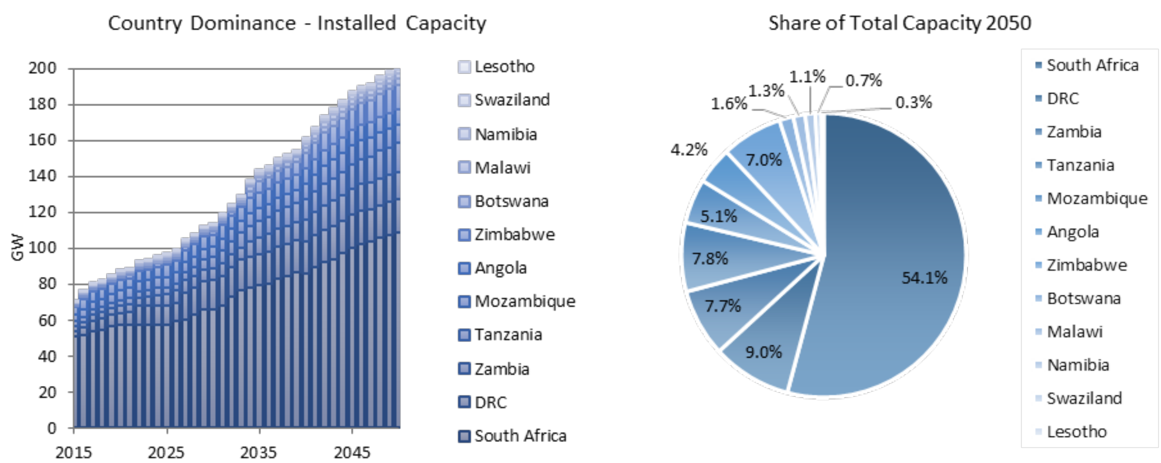


From a cost perspective, the large share of coal based generation along with the nuclear power and the availability of alternative renewable solutions offer a relative price stability both over the time horizon of this study as well as between scenarios with reasonable costs of energy never exceeding 0.07 USD/kWh. It is nevertheless important to notice that the SAPP remains vulnerable to the effects of climate change. Although the level of hydro power generation – as a share of the total generation in the region – may seem relatively low, the effects on Power Pool wide cost of electricity production[18] of a Dry scenario (case n°80) can be as high as an increase by 13.5% (see comparison of costs between scenarios – bottom right in Figure D-13[19]). This is due mainly to the fact that different countries are vulnerable to different levels of impact in relation to their importance and size in the system. South Africa does not rely on a very large amount of hydropower and has the means to increase coal based generation when water resources are reduced. More vulnerable countries however are open to higher impacts due to their dependence on large investments in hydropower infrastructure.

A regional system with an important player – South Africa

With a share of total installed capacity in excess of 50% by the end of the modelling period, the Republic of South Africa is expected to play an important role from a regional perspective (see Figure D-14). Although its share in the regional demand is expected to decrease from 82% to 68% between 2010 and 2050, the net increase for the country itself still represents a near twofold increase as compared to current levels. Further, the South African system is currently more than twice as large as all other countries of the SAPP put together and remains in the order of 1 to 9 between RSA and DRC (second largest system) in 2050.

Figure D-14: Country capacity of the SAPP



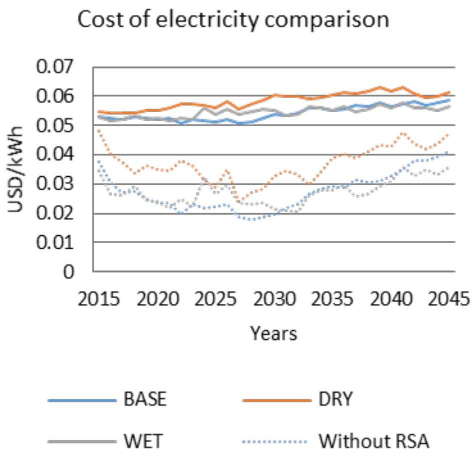
With such a large energy demand, South Africa weighs heavily on its comparatively smaller neighbors. This is responsible for both a large relative increase in the regional cost of electricity generation across all scenarios, and lower inter year variability in the cost to consumers (see Figure D-15). With lower levels of hydro generation, South Africa both increases the cost of electricity production in the region

[18] Calculated for the region as the total annualised system cost divided by the total generation in the power pool. Annualised system costs are the undiscounted sum of all annual running costs as well as investment costs spread over power plant operational life time. On a national level this cost is adjusted to include the costs (resp. benefits) of traded energy valued using the regional (resp. domestic) cost of generation.

[19] Note that the cost trends have different starting values in 2015 in different scenarios. This is due to the fact that the first model year is 2010 and that slight differences in the infrastructure rollouts between the climate scenarios induce overall cost of electricity differences already by 2015.

as well as reduces climate change related fluctuations in cost. Artificially excluding South Africa from the production cost calculation, would result in a drop in regional production costs by as much as 50%, during periods of the model run. From an inter year variability perspective (i.e. absolute change in unit cost of electricity generation from one year to the next) however, removing the RSA from the overall system can increase fluctuation levels by up to 70.6% in a dry PF case. The minimum increase in variability is achieved for a wet PF case but still reaches 61%.

Figure D-15 : Cost of electricity variation: the impact of RSA throughout all scenarios



This general dominance of the system by a single country also has impacts on the levels and directions of trade within the region since South Africa will tend to absorb large amounts of available energy using the different levels of international connections available throughout the modelling period. This is why, although it relies on a large amount of coal based generation to provide for its domestic energy demand, South Africa is also – to some extent – vulnerable to reduced levels of cheaper imported hydropower generation in scenarios where water availability in the region is reduced.

Key messages

In order to maintain a level of consistency between the Power Pool studies, increase report readability as well as offer more opportunity for result comparison between power pools, seven key messages – also reported in the global project Synthesis report – have been developed and are presented in the following paragraphs. Please note that, throughout these explanations, the terminology “Wet” and “Dry” is adopted to describe scenarios that are considered to have respectively higher or lower amounts of available water for energy generation over the period. This does not however translate to each and every month/year of the corresponding scenario being systematically richer/poorer in water resource than the base: this terminology is true “on average over the model period” only.

Further, while a full description of scenarios and methodology are included in the 'Main Methodology Annex' of this work it is worth noting that two scenario families reported here. These include 'perfect foresight’ (PF) scenarios, in which the model is allowed some level of freedom to invest in an array of non-hydro alternatives while a certain level of capacity adjustments are made in parts of the hydro infrastructure. This PF scenarios setup allows the model to ‘anticipate’ climate change and – to some degree – adapt accordingly. The second set of families includes so called 'no adaptation' (NA) scenarios, in which climate change is not anticipated and electricity generation shortfalls are met with expensive back-up generators. Each family is run across the same set of selected climate futures. The 'historic' climate is one future based on historic trends.

Large infrastructure investments are required to underpin future growth in Africa

As noted in previous paragraphs, the Southern African system is growing consistently: base scenario results show yearly capacity increasing in the system at an average rate of 3% per annum over the study period reaching extremes of 7% to 10% in chosen years. Totalling new capacity additions of 214 GW, including retirements, Table D-23 shows the share of each country and the split between generation technologies of the new investments in the system. Two things are clearly noticeable:

- The RSA is cumulates more than half the new investments in capacity in the region of the study period.
- Fossil and oil based additions to the SAPP between 2015 and 2050 represent three times more new capacity than for Hydropower.

Table D-23: Cumulative New Capacity per country and Fuel Category – 2015 to 2050 - SAPP

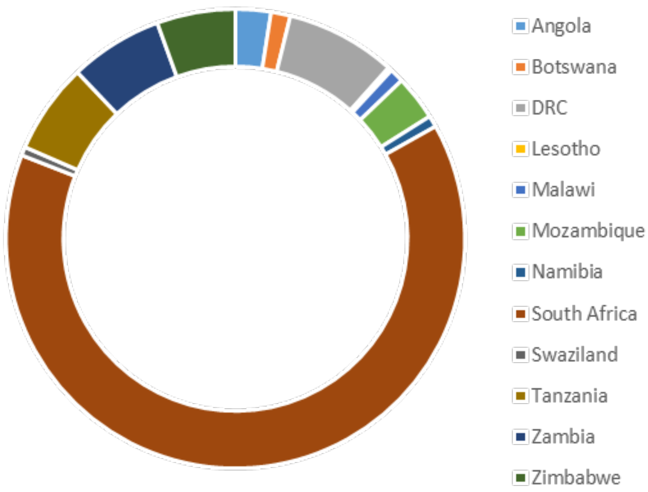
	GW	%
Angola	9.33	4.36%
Botswana	4.24	1.98%
DRC	17.01	7.95%
Lesotho	0.62	0.29%
Malawi	2.64	1.24%
Mozambique	9.07	4.24%
Namibia	2.22	1.04%
South Africa	121.59	56.80%
Swaziland	1.46	0.68%
Tanzania	17.99	8.40%
Zambia	14.38	6.72%
Zimbabwe	13.52	6.31%

	GW
Coal	89.24
Oil	30.45
Gas	2.84
Hydro	40.02
Nuclear	8.03
Wind	38.32
Solar	1.63
Geothermal	0.30
Biomass	3.25

In investment terms, these new additions mean that the region has to consider an undiscounted cost over the period in excess of 580 Billion USD. In line with capacity data, the main component of this total is dedicated to coal based capacity investments reaching 47.7% of the total. The remainder is split near equally between hydropower (17.3%), wind power (15.6%) and nuclear capacity investments (14.6%). When including the cost of transmission and distribution system expansion, this total increases to 826 Billion USD.

From a national perspective, the RSA is clearly the largest investor over the study period standing for 64% of the regional total. For the remaining countries, Figure D-16 shows that Tanzania, Zambia, Zimbabwe and DRC share similar levels of investment between 6% and 7% while all other systems remain relatively small in comparison.

Figure D-16: Country share on Undiscounted Investments (2015-2050)



Trade is required to 'unleash' the potential of much low-cost hydropower

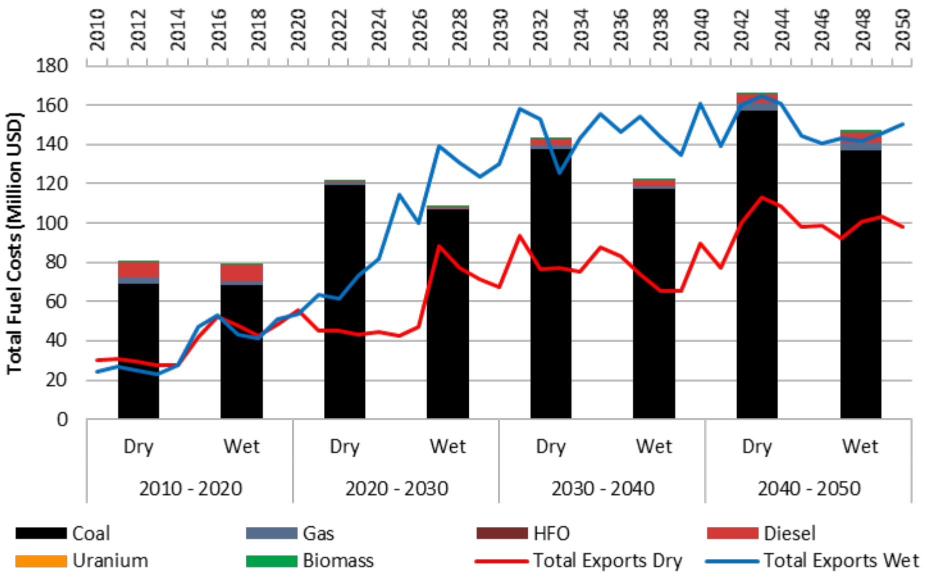
Future international transmission for the SAPP reaches 6.1 GW of new capacity available within the first fifteen years of the model period. This represents 54,7% increase in available transmission power compared to the existing 11.14GW. These site specific projects between neighbouring countries are further increased by regional multicountry interconnector projects including Westcor, Zizabona and the 756 kV line link (see Table D-22).

The amount of power traded with the region varies from one scenario to the next. In the base case assuming historic climate conditions, total exported energy in the region exceeds 4.8 thousand TWh – 88.6% of which result in net traded power. Important exporting countries on the regional level include the DRC, Mozambique and Zimbabwe contributing respectively 34%, 16.1% and 13.1% of the total exports over the study period. From an energy destination's perspective, RSA is by far the largest consumer in the region totalling 53.1% of all positive net imported energy in the region. Far behind come Zambia and Angola with 17.1% and 8.7% respectively. These first insights into trade dynamics highlight two important messages:

- Large consumers play a key role in supporting large supply projects such as Inga in the DRC.
- Cooperation and flexible contracting should be a focal point of future trade agreements.

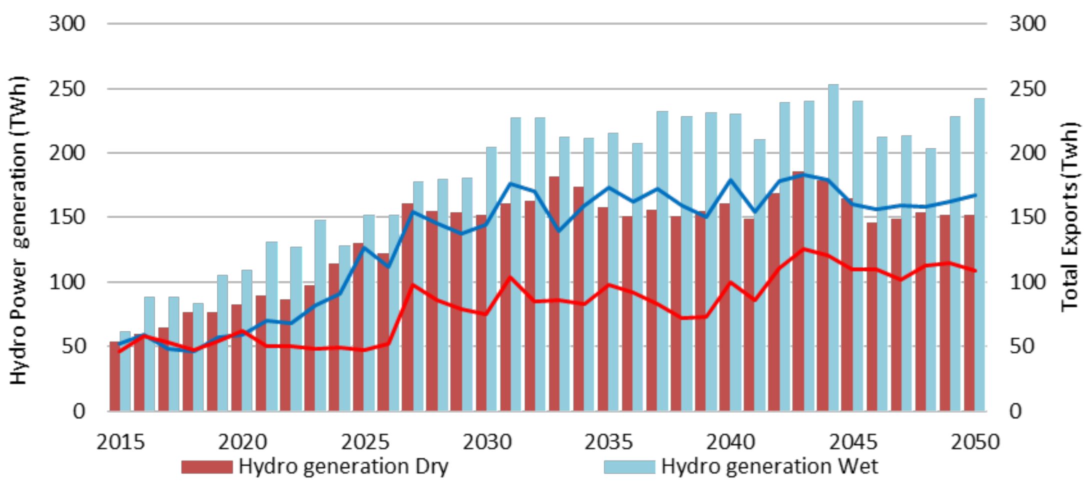
Further, exports become important in reducing regional fuel costs when the system is faced with adverse effects of climate change. Indeed, switching between the two extreme scenarios that affect the SAPP reduces the amount of fossil based generation thereby reducing the fuel component of the final cost to consumers quite significantly over the mode period (See Figure D-17). This phenomenon is also increased by the lower level of exports linked to the dryer climate situation. Indeed, following these two metrics in parallel on the figure below shows that the direction of change in total fuel expense in each decade is mirrored by the relative amounts of traded energy in corresponding scenarios. The relative fuel expense over the periods 2030-40 and 2040-50 is respectively 17% and 13% higher in the dry case than in the wet, correspondingly total exports reduce respectively by 47% and 35% from the wet to the dry case in the same decades.

Figure D-17: Total Electricity Exports vs. Total Fuel Expenditure



It is also important to note that the level of trade, in the SAPP in particular, is clearly related to the availability levels of the hydropower resources in the area. Considering Figure D-18, it is visible that any changes relating to hydropower and affecting the generation, related directly to the climate scenario that is under investigation, have repercussions on the final cost of providing consumers with useful electricity. More specifically, when comparing the extremes – i.e. the difference between the dry and the wet scenario cases for the SAPP – it appears that the hydropower projection is affected by a total potential generation drop of 25.7% over the study period. This translates into a total increase in expenditure of 25% (see Table D-24 relation between PF dry and wet scenarios) and a corresponding drop in exported power of 36.7% between 2010 and 2050.

Figure D-18: Total Electricity Exports vs. Hydro Power Generation (TWh)



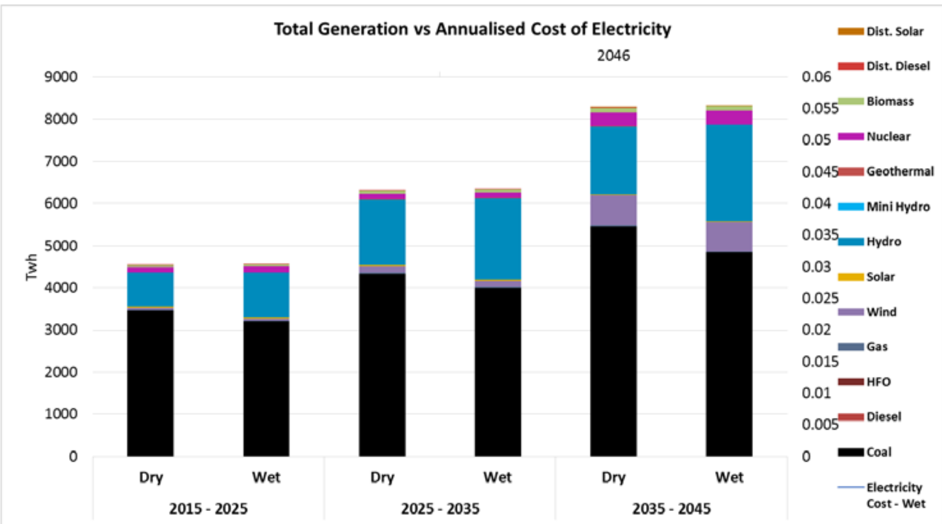
Adapting to climate change: the role of fossil fuels and non-hydro renewables

Climate change, in this exercise, can have both positive and negative impacts on a country relating specifically to the overall rainfall that can be expected over the study period. In both cases however the difficulty in predicting the changes in weather patterns as well as this patterns intra & inter year variability is cause for increased system costs (See main methodology clarifications relating to the Perfect Foresight Adaptation approach).

In dry cases, overall rainfall is lower than in the regional reference climate case and the variability of the climate means that large amounts of hydropower may be unavailable from one year to the next. In this situation, the overall system is impacted negatively: new investments in fossil based generation are required and in turn generate higher annual running costs.

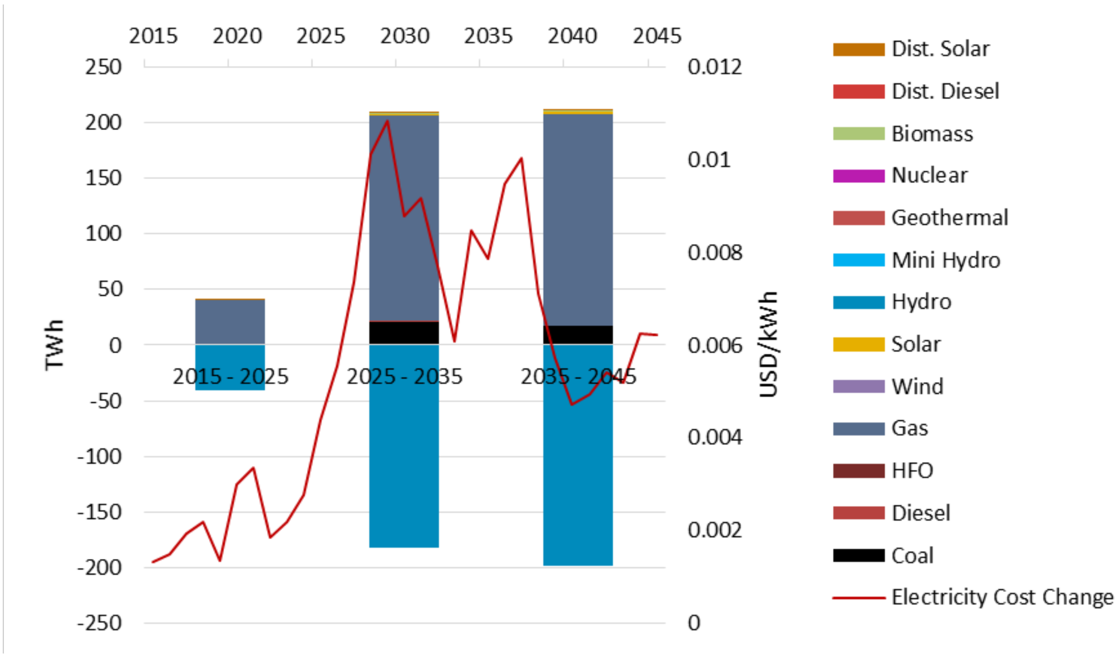
Similarly, wetter cases are expected to offer less stressing conditions both on national and regional levels through higher overall water availability. This however is true only to an extent since large variability from one year to the next will mean that unexpected shortages in hydro based generation will be replaced by fossil based generation. The level of the corresponding costs to consumers in the SAPP are however considerably lower.This is due mainly to the averaging effect relating to the size of the energy system of the RSA. Figure D-19 shows a clear split between the two extreme scenarios for this power pool appearing as early as 2020. On a regionl level however this increase in cost does not exceed 0.01USD/kWh between 2035 and 2045. This is due mainly to the averaging effect relating to the size of the energy system of the RSA.

Figure D-19: Total Generation vs. Annualised cost of Electricity



Considering the relative difference between the two extreme scenarios identified for the SAPP offers insights into the trade-offs that may arise in cases of inappropriate adaptation strategy implementation. The displacement of coal based generation by hydro power in the wetter case as well as the change of this displacement over time is correlated to corresponding impacts on the price to consumers. This gives an idea of the potential consequences of making inappropriate decisions as to adaptation. These are shown here on a regional level however and are highly variable from one country to the next depending on the size of the system, its domestic security of supply and its level of available hydropower.

Figure D-20: Relative range of Generation mix and Annualised cost change



Putting things into a sharper perspective, Figure D-20 reveals the total amount of fossil based generation that is displaced by hydropower between the wet and the dry cases and relates this power to the corresponding change in cost on a regional basis. It shows clearly that, under the dry scenario, the fossil based consumption increases significantly over time and translates in increased unit cost of energy production of between 0.001USD/kWh and 0.007 USD/kWh from 2030 onwards.

The effect of Climate Change on electricity costs differs from country to coutnry

Thus far it appears that, from a national perspective, the higher the penetration of hydro power in the energy system – or the higher its penetration in the system of neighbouring countries with high levels of trade – the more susceptible the country becomes to impacts from the changing climate.

Taking these results down to the consumer level, it is important to notice that climate change has the potential to have significant impacts on their total energy expenditure. This variation may be more or less significant depending on the country under analysis. In Table D-24 we report this total expenditure with reference to either Perfect Foresight Adaptation or No Adaptation strategies[20].

[20] Please refer to the Main methodology annex for full description of these two cases

Table D-24: Relative change of consumer expenditure on electricity, with and without PF adaptation – Dry and Wet cases. [Billion USD]

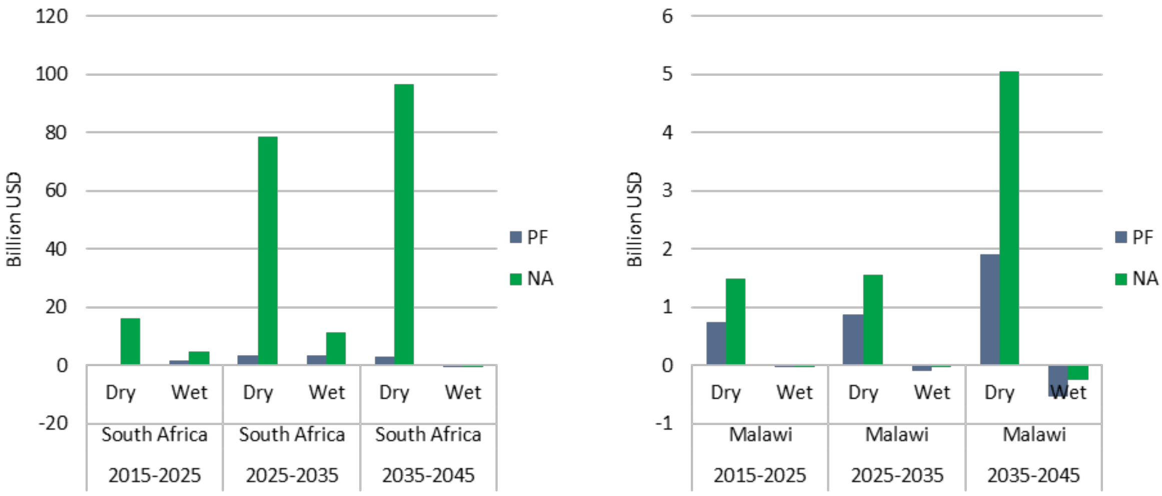
SAPP[21]		No adaptation Sc.		PF adaptation Sc.		Robust adaptation, designed to minimize:			
	No CC	Driest	Wettest	Driest	Wettest	Max regret	90% highest regret	75% highest regret	River Basin
AO	33.2	42.1	18.5	37.5	20.7	24.0	24.0	24.0	Congo
BW	20.6	19.8	21.1	20.1	21.0	NA	NA	NA	NA
CD	18.1	23.8	22.1	21.7	21.8	21.8	21.8	21.8	Congo
LS	3.0	3.3	3.0	3.1	3.0	NA	NA	NA	Orange
MW	6.3	18.2	5.7	11.3	4.9	5.0	4.9	5.0	Zambezi
MZ	12.7	22.6	11.0	19.2	10.2	11.0	13.5	10.9	Zambezi
NA	14.5	20.1	13.4	17.9	14.0	15.1	15.1	15.1	Congo
SZ	4.9	5.0	5.0	4.8	5.0	NA	NA	NA	NA
ZA	1214.5	1473.0	1232.9	1223.4	1219.6	1220.4	NA	NA	Congo/Zambezi
ZM	62.4	99.9	57.5	86.1	54.5	58.6	62.5	61.1	Zambezi
ZW	59.0	66.3	58.2	62.7	57.8	58.6	58.3	59.5	Zambezi
Total	1449.0	1794.2	1448.4	1507.6	1432.5				

In order to illustrate the different levels of impact that exist between different countries, Figure D-21 shows the results in a graphic format – per period – for South Africa and Malawi. In both cases, the lack of adaptation strategy has a large impact on the cost to consumers leading to an increase of respectively 0.8% and 82.7% for RSA and Malawi in a dry case scenario over the last ten year period alone. This is a significant cost to bear and has the potential to affect consumers negatively in the future, but it also illustrates the large spread in vulnerability levels of different countries depending on their specific energy system.

Further, the illustration shows that the perfect adaptation strategies applied in the SAPP are effective. This is espescially true for the dry case scenario where failing to take action when faced with changing climatic conditions stands to increase total customer expenditure in the region. This increase could be as large as 19.8% relative to the corresponding perfect foresight climate case for a dry climate. This is true for all countries but Botswana where the costs are extremely close due to the high reliance of this small system on both imports and domestic coal generation. Considering the wet scenarios, the differences are less marked in absolute values although the relative changes remain important in magnitude. The comparison made below between Mali and RSA shows the higher resilience of countries with higher levels of domestic hydropower: the wet PF scenario saves over twice as much expenditure as the NA case does when compared to the reference scenario.

[21]AO: Angola, BW:Botswana, CD:Democratic Republic of the Congo, LS: Lesotho, MW: Malawi, MZ:Mozambique, NA: Namibia, SZ: Swaziland, ZA: South Africa, ZM: Zambia, ZW: Zimbabwe

Figure D-21: Accumulated cost to consumer in different climate and foresight scenarios[22]



It is also noticeable that the two countries have different scales of total expenditure due mainly to the difference in a. the size of the domestic energy demand and b. the domestic energy mix supplying that energy. Finally, following the lead of these two examples the rest of the SAPP shows marked differences between potential consequences of Wetter and Dryer climates: the first having low absolute costs and small gains to adaptation while the second showing much larger total costs as well as significant risk for higher expenditures if no (or inadequate) adaptation strategies are considered.

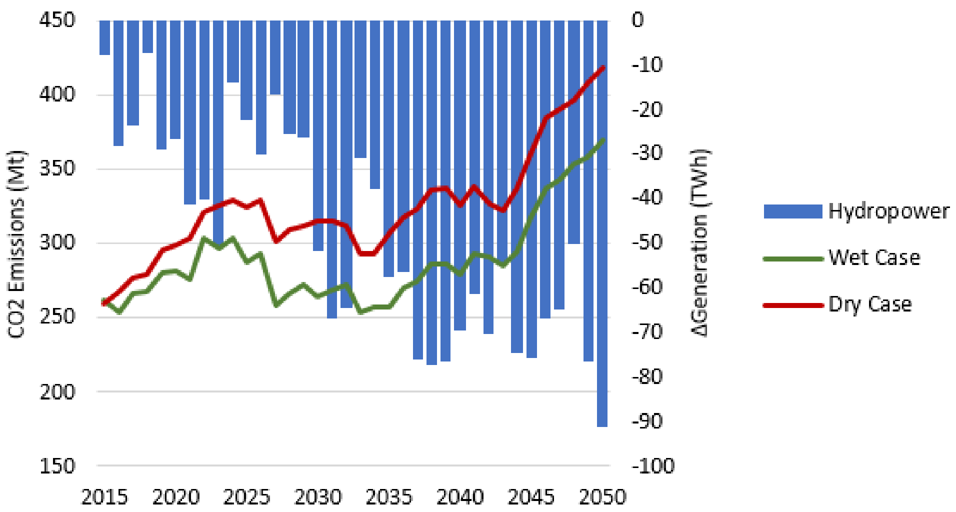
CO_2 emission levels differ between adaptation strategies

Flowing from the messages developed in the previous paragraphs, the relation between carbon dioxide emissions per scenario and its specific climate classification are relatively intuitive.

More specifically: the dryer the scenario gets, the higher the emission levels linked to fossil based generation replacing the missing hydro power. This however is variable from one year to the next as the emissions are directly related to the fuel use: in a year where water availability is "unexpectedly" higher, the corresponding use of coal based generation is reduced and displaced by either domestic generation or imports from neighbouring countries with higher hydro potentials. Considering Figure D-22 showing the trade- off in water availability for energy generation between a Dry and a Wet scenario in regard to the corresponding tonnage of CO_2 release, the inverse correlation between the two variables appears clearly.

[22] PF (perfect foresight) and NA (no adaptation)

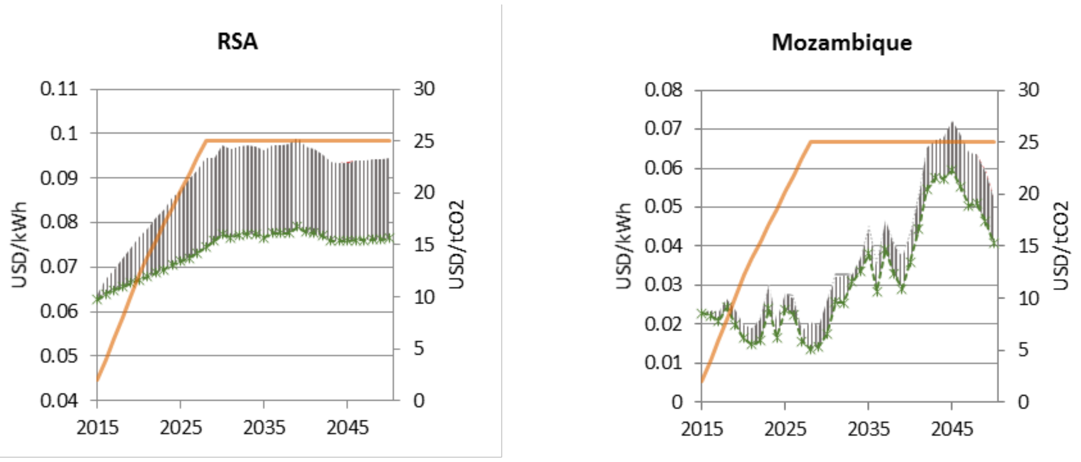
Figure D-22: Regional GHG emissions vs Change in Hydropower generation between Wet and Dry scenarios



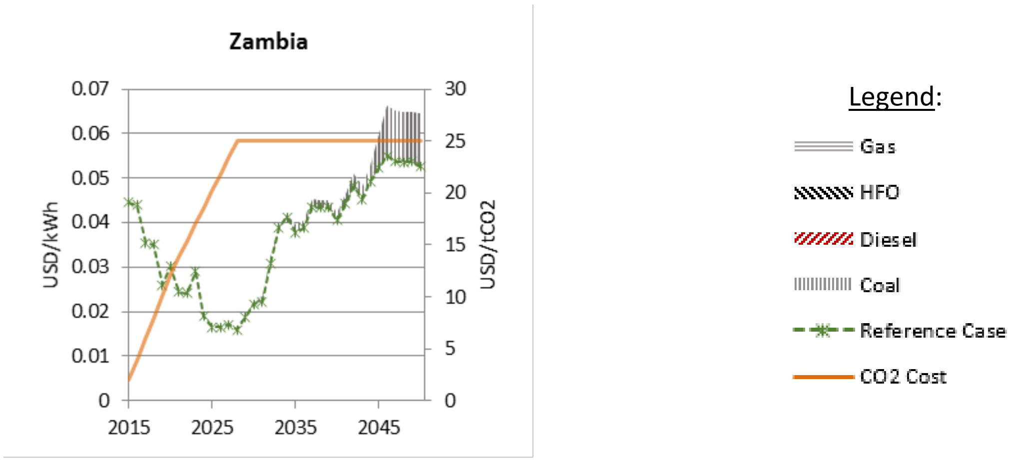
The impacts of this correlation however vary significantly from one country to the next (consider

Figure D-23) pursuant to their domestic levels of water resource availability for hydro generation as well as their corresponding installed capacity. In the case of RSA for example, the country is stable and has a secure supply of energy throughout the period. This supply however is based on coal generation and only on a very small relative level of imports capitalising on neighbouring hydropower generation in the region. This means that, in a case where carbon emissions were to bear a cost in the overall system, the final cost to consumer of such a system development would be significantly higher. On the other hand Zambia, although a country with a much less stable energy cost signal, would be relatively unaffected by any carbon dioxide related expense due chiefly to its large resource levels in renewable power.

Figure D-23: Impact of CO_2 emissions costing on the domestic price of energy to consumers[23]



[23]Please note: these figures show the additional cost of applying a selected cost of carbon dioxide emissions – shown by the orange line – as a post treatment step to sets of results obtained from models. Accordingly the models do not attempt to reduce emissions and mitigate those costs, i.e. these additional costs are not included in the models' objective function. The graphs are used simply to illustrate potential consequences of fossil based generation systems in a region as well as the variability of these consequences from one country to the next.



From a general perspective, the resilience of each country in the region to this new energy cost is also linked to the country's security of supply situation. In cases where supplying the domestic demand relies heavily on imported energy from fossil intensive systems, the final consumer potentially stands to bear the increased expense of the CO_2 financing scheme in that country.

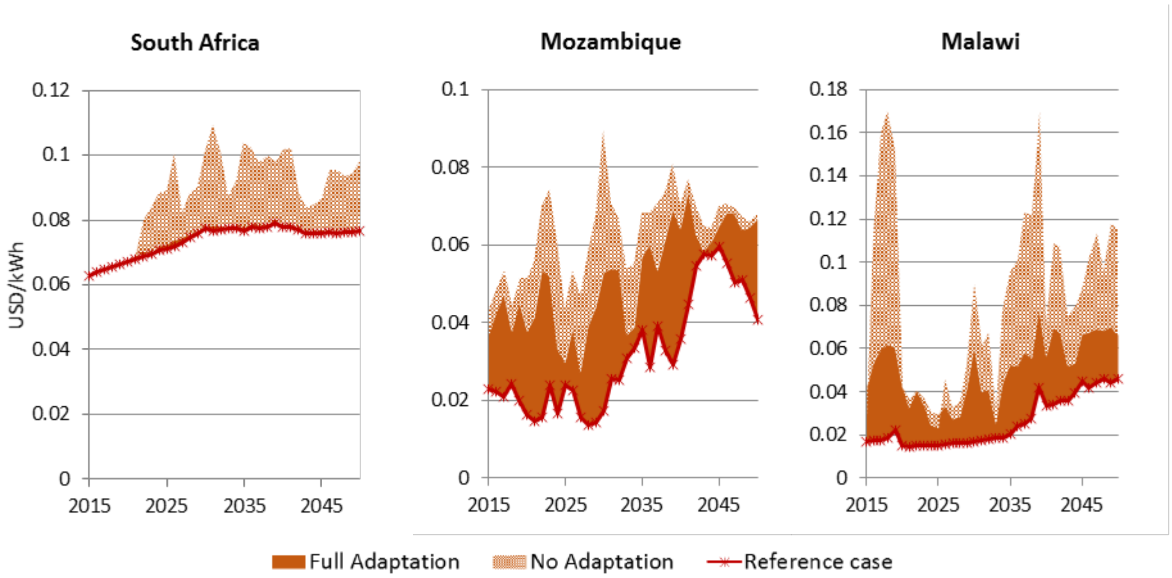
Choosing to adapt is a "low regret" decision

Referring to Figure D-24, we can note the incremental cost to consumers of the different strategies for countries that have either higher or lower vulnerability levels to climate change (figures presented for the Dry case). Visualising the marginal increase in cost that each scenario has on its "predecessor", this graphic shows the difference between having a reactive attitude to the impacts of climate change – materialised by the high annual changes in the level of the lighter "no adaptation" colour – and following a given strategy, albeit flawed, to attempt to anticipate the adverse effects of these future changes. With this "worst case scenario", it appears that:

- There are circumstances in which each country might benefit from applying an adaptation strategy with some level of foresight. In fact, in South Africa (with the exception of carbon emissions) it costs barely more than the base case to adapt to climate change. In other countries, although the cost to consumers will inevitably and invariably be higher than in baseline cases where climate is assumed to follow historic trends, there is potential to reduce the overall impact of these problematic "future climate pathways".
- The impacts are particularly visible on a national level: previous aggregations on a power pool level transfers the characteristics of the dominant countries to the region thereby "drowning" the smaller systems. This national representation shows impacts on smaller and potentially more vulnerable and fluctuating systems.

- The impacts are significant on a national level: consumer energy prices are endemic to national energy systems (with influence from imports/exports[24]) and should therefore be considered on a national level where potential decisions might be made to reduce adverse impacts of changes in the climate.
- Certain countries with low energy prices but high reliance on hydropower stand to suffer significantly from "drought year" effects forcing the system to use costly and expensive stop gap fossil based systems. This effect is greatly reduced however through adapting.

Figure D-24: Cumulative impacts of CC to consumer cost of electricity – Dry case



[24] Imports and exports in this exercise are valued at the regional cost of electricity generation.

Conclusions and Recommendations

Climate change is a complex and diverse phenomenon the effects of which are neither yet agreed upon nor fully understood. In such a context, the present work is a leading attempt to ensure that – notwithstanding the arguably low degree of certainty that affects the data upon which investment decisions need to be made – the different actors of an integrated water and energy system may have a better understanding of the implications inherent to different available courses of action.

It is important to consider results on a multitude of levels: countries are aggregated into Power Pools that are interconnected by varying levels of trade, each country and each power pool are linked to one or several of the river basins that are analysed as separate entities in the water modelling framework etc. This means that although all results can be extracted on all levels of this analysis they are not totally independent one from the other.

In the specific case of the Southern African power pool, regional level results may seem relatively reassuring. The span of scenarios that were investigated in this exercise show a cost of power ranging from a minimum of 5.1 cts/kWh to a maximum of 6.5 cts/kWh between 2015 and 2050 with relatively low year to year variations. This apparent stability however is to be taken in the context of a dominating South African system still representing 60% of total SAPP generation in 2050. With relatively low imports and high reliance on domestic coal, this country has a buffer effect on regional level metrics. Removing the RSA from the averaged regional results shows a greater variability of energy prices both between scenarios and from one year to the next. Such variations follow directly from changes in hydro availability – mostly located on the Zambezi river basin – that affect both national level energy mix and price in “hydro rich” countries as well as energy trade in the region. It appears therefore that, although climate change is a complex question with no one answer, the scenarios under analysis have shown a clear incentive to adapt within the realm of available infrastructure measures. They have also shown that taking carbon financing into account has the potential to change country level cost of electricity production and therefore overall energy system design.

Finally, hydro power will play an important role in the SAPP in all scenarios. It is therefore key to ensure that this integrated approach be considered in future planning activities with a clear focus on detailed analyses of hydro facility timings, design, capacity and dispatch. This message transpires throughout the results discussion and is due to the importance of hydropower as a domestic source of energy for certain countries in the region. This importance is however also transferred to the power pool scale due to the interconnectedness of the system and the levels of trade that exist between the countries.

Limitations and next steps

In addition to general methodology and overall project limitations described in the general assumptions text, the following bullets might advantageously outline areas of future work that would improve either the applicability or quality of the results discussed above. Such areas are listed below:

- Further scenarios development: specifically with respect to trade in the region. As an important lever for stability of supply and renewable resource dissemination, it would be advantageous for individual projects to be evaluated more specifically or for general “corridors” for energy transmission to be assessed both within and between power pools.
- Higher focus on security of supply: in particular investigating the cost benefit analyses of such issues when balanced with their cost trade-offs and implications.
- “Endoginising” carbon costing into the optimisation: this element being thus far taken as a post treatment calculation foes not influence the choice of one technology over another in the present exercise. It would be of interest however to include a representation of different “carbon financing” schemes into the current setup in order to assess their potential impact of different countries and power pools.
- Increasing levels of interaction with the power pool authorities: achieving their integration on a procedural level would greatly benefit such projects by increasing data accuracy and output applicability, but also through their potential inclusion into capacity building activities in the context of iterative and improved PP planning processes.
- Bridging potential gaps in the analysis toolbox to inform relations between national and power pool level systems: such applications may be of specific interest when considering shared planning activities on a project level.
- Investigating the potentials for the power pools to promote clean energy use and assess the corresponding clean energy scenarios.
- Investigating implications of financing limits. Power system investments are significant, but so too are other investment needs in the economy. If finance to power investments crowds out opportunities to invest in other projects, or access to finance is simply limited, scenarios to investigate these constraints may provide important insights.
- Improve the load region definition by detailing individual country load data. This would not increase the complexity of the model however may have a marginal impact of specific time-slices where trade occurs: if two neighbouring countries have their peak demand occurring at during different time-slices there is a potential for higher trade efficiency and lower installed capacity levels on a regional basis. This data however is both sensitive in nature from a utility’s perspective and thus far unavailable for many countries as part of public energy data bases.

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Detailed Annex Tables

Table D-25: Energy Demand per Country - GWh

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
ANGOLA																																									
Industry	1771.3	1999.9	2239.1	2495.7	2776.9	3074.8	3362.1	3671.3	4003.3	4359.9	4719.9	5044.0	5383.9	5740.4	6111.9	6499.9	6869.6	7241.0	7634.3	8081.1	8589.2	8604.9	8964.2	9323.5	9682.7	10042.0	10401.2	10760.5	11119.7	11479.0	11838.3	12049.6	12260.8	12472.1	12683.4	12894.7	13106.0	13317.3	13528.6	13739.9	13951.2
Urban	3278.0	3539.9	3794.0	4049.7	4318.7	4585.9	4793.5	5005.5	5219.2	5436.5	5629.2	5929.6	6239.7	6556.9	6881.9	7214.7	7516.1	7807.8	8114.4	8465.7	8868.6	8791.5	9037.1	9282.7	9528.3	9773.8	10019.4	10265.0	10510.5	10756.1	11001.7	11068.3	11135.0	11201.7	11268.3	11335.0	11401.7	11468.3	11535.0	11601.7	11668.3
Rural	84.1	102.5	123.5	146.3	172.6	201.5	246.2	296.1	352.2	414.3	481.8	508.1	535.2	563.3	591.3	621.1	648.2	674.5	702.6	734.1	770.9	768.3	794.8	821.4	848.0	874.5	901.1	927.7	954.3	980.8	1007.4	1019.4	1031.4	1043.4	1055.4	1067.4	1079.4	1091.4	1103.4	1115.4	1127.4
BOTSWANA																																									
Industry	1964.9	2169.9	2269.7	2453.7	2622.7	2738.4	2799.7	3066.0	3239.4	3500.5	3558.3	3614.4	3670.4	3724.8	3779.1	3831.6	3884.2	3938.5	3992.8	4041.0	4057.6	4017.3	3943.8	3870.4	3796.9	3723.4	3649.9	3576.4	3502.9	3429.4	3356.0	3263.4	3170.8	3078.2	2985.6	2893.0	2800.4	2707.8	2615.2	2522.6	2430.0
Urban	1653.0	1752.9	1761.6	1827.3	1874.6	1877.3	1909.7	2080.5	2186.5	2350.3	2376.6	2416.9	2457.2	2496.6	2536.0	2574.6	2613.1	2652.5	2691.9	2727.9	2741.9	2864.5	2974.2	3083.9	3193.6	3303.3	3413.0	3522.7	3632.4	3742.1	3851.8	3955.8	4059.9	4164.0	4268.0	4372.1	4476.2	4580.3	4684.3	4788.4	4892.5
Rural	64.8	77.1	85.8	99.0	112.1	122.6	141.9	173.4	202.4	239.1	263.7	268.1	271.6	275.9	279.4	282.9	286.5	290.0	294.3	297.0	297.8	302.2	304.1	305.9	307.8	309.6	311.5	313.3	315.2	317.0	318.9	319.7	320.6	321.5	322.4	323.2	324.1	325.0	325.9	326.7	327.6
DRC																																									
Industry	3893.8	4396.6	4955.5	5576.6	6265.2	7029.0	7875.2	8812.6	9850.6	10998.2	12267.5	13365.1	14559.1	15859.1	17273.8	18640.4	19924.6	21297.3	22762.9	24328.3	25999.7	27559.8	28386.9	29213.9	30041.0	30868.0	31695.0	32522.1	33349.1	34176.2	35003.2	35120.6	35238.0	35355.4	35472.7	35590.1	35707.5	35824.9	35942.3	36059.7	36177.0
Urban	3546.0	3744.0	3944.6	4145.2	4345.0	4542.1	4708.5	4862.7	4999.3	5113.2	5199.9	5534.6	5889.3	6264.3	6661.1	7015.9	7317.2	7630.0	7952.3	8285.2	8629.5	9147.2	9421.7	9696.2	9970.6	10245.1	10519.6	10794.1	11068.6	11343.0	11617.5	11656.5	11695.5	11734.5	11773.4	11812.4	11851.4	11890.4	11929.4	11968.4	12007.3
Rural	142.8	169.9	199.7	233.9	271.6	314.5	385.4	465.2	554.5	656.1	770.0	832.2	898.8	970.6	1047.7	1121.3	1188.7	1259.7	1335.9	1415.6	1500.6	1590.8	1638.5	1686.2	1733.9	1781.6	1829.3	1877.0	1924.7	1972.4	2020.1	2026.9	2033.7	2040.6	2047.4	2054.2	2061.1	2067.9	2074.7	2081.6	2088.4
LESOTHO																																									
Industry	53.4	61.3	70.1	78.8	88.5	99.0	109.5	121.8	134.0	147.2	161.2	168.2	175.2	183.1	191.0	198.9	207.6	216.4	226.0	235.6	246.2	254.0	268.1	282.1	296.1	310.1	324.1	338.1	352.2	366.2	380.2	401.5	422.8	444.0	465.3	486.6	507.9	529.2	550.5	571.8	593.1
Urban	424.0	436.2	449.4	462.5	475.7	489.7	502.8	516.0	528.2	542.2	555.4	579.9	605.3	631.6	659.6	689.4	719.2	751.6	785.8	821.7	857.6	885.6	934.6	983.6	1032.5	1081.5	1130.4	1179.4	1228.3	1277.3	1326.3	1400.5	1474.7	1548.9	1623.1	1697.3	1771.4	1845.6	1919.8	1994.0	2068.2
Rural	7.9	9.6	10.5	12.3	14.0	15.8	18.4	21.9	25.4	28.9	33.3	34.2	35.9	36.8	38.5	40.3	42.0	43.8	45.6	47.3	49.9	51.7	54.5	57.3	60.2	63.0	65.8	68.6	71.4	74.3	77.1	81.4	85.7	90.0	94.3	98.6	102.8	107.1	111.4	115.7	120.0
MALAWI																																									
Industry	521.2	642.1	672.8	703.4	734.1	764.7	803.3	843.6	885.6	929.4	975.9	1025.8	1078.4	1133.5	1191.4	1251.8	1315.8	1383.2	1454.2	1527.7	1605.7	1686.3	1789.7	1893.0	1996.4	2099.8	2203.1	2306.5	2409.9	2513.2	2616.6	2781.1	2945.6	3110.2	3274.7	3439.2	3603.7	3768.2	3932.7	4097.2	4261.7
Urban	766.5	952.2	1007.4	1061.7	1118.7	1174.7	1240.4	1308.7	1380.6	1456.8	1536.5	1617.1	1702.1	1790.5	1884.3	1983.3	2086.6	2196.1	2310.9	2431.8	2558.8	2686.7	2851.3	3015.9	3180.5	3345.1	3509.6	3674.2	3838.8	4003.4	4168.0	4430.1	4692.2	4954.3	5216.4	5478.5	5740.6	6002.7	6264.8	6526.9	6789.0
Rural	21.0	28.9	34.2	38.5	44.7	49.9	60.4	71.8	85.0	98.1	113.9	119.1	125.3	131.4	138.4	145.4	152.4	160.3	168.2	177.0	185.7	194.5	206.4	218.4	230.4	242.4	254.3	266.3	278.3	290.2	302.2	321.2	340.2	359.2	378.3	397.3	416.3	435.3	454.3	473.3	492.3
MOZAMBIQUE																																									
Industry	2713.0	2852.3	3011.7	3111.6	3221.9	3333.2	3416.4	3518.9	3613.5	3710.7	3808.8	3908.7	4011.2	4114.6	4219.7	4327.4	4436.1	4546.4	4658.6	4772.4	4888.1	5063.3	5276.1	5488.8	5701.6	5914.4	6127.1	6339.9	6552.7	6765.4	6978.2	7274.8	7571.4	7868.1	8164.7	8461.3	8757.9	9054.5	9351.1	9647.7	9944.4
Urban	450.3	510.7	579.9	644.7	715.7	793.7	862.0	940.8	1022.3	1109.9	1204.5	1313.1	1430.5	1554.9	1688.9	1831.7	1984.1	2147.1	2320.5	2506.2	2704.2	2832.1	2994.6	3157.0	3319.5	3481.9	3644.4	3806.8	3969.3	4131.7	4294.2	4543.6	4793.1	5042.6	5292.1	5541.6	5791.1	6040.5	6290.0	6539.5	6789.0
Rural	49.9	59.6	70.1	80.6	92.0	105.1	124.4	147.2	171.7	198.0	226.9	235.6	245.3	254.9	265.4	275.9	287.3	298.7	310.1	323.2	335.5	349.5	366.0	382.4	398.9	415.3	431.8	448.2	464.7	481.1	497.6	521.6	545.6	569.6	593.6	617.6	641.6	665.6	689.6	713.6	737.6
NAMIBIA																																									
Industry	2076.1	2111.2	2162.8	2203.1	2259.2	2326.7	2361.7	2394.1	2431.8	2469.4	2506.2	2591.2	2678.8	2769.9	2864.5	2960.0	3066.9	3168.5	3271.9	3382.2	3483.0	3657.3	3751.9	3846.5	3941.1	4035.7	4130.3	4224.9	4319.6	4414.2	4508.8	4640.3	4771.7	4903.2	5034.7	5166.2	5297.7	5429.2	5560.7	5692.2	5823.6
Urban	1073.1	1099.4	1134.4	1163.3	1201.0	1244.8	1321.0	1399.8	1486.6	1577.7	1674.0	1732.7	1794.0	1857.1	1922.8	1988.5	2063.0	2133.9	2206.6	2282.9	2353.8	2498.4	2597.6	2696.9	2796.2	2895.5	2994.8	3094.0	3193.3	3292.6	3391.9	3539.7	3687.6	3835.5	3983.3	4131.2	4279.1	4427.0	4574.8	4722.7	4870.6
Rural	52.6	59.6	67.5	74.5	83.2	92.0	108.6	125.3	144.5	164.7	185.7	191.8	198.9	205.0	212.0	218.1	226.0	233.9	240.9	248.8	255.8	269.8	278.4	286.9	295.5	304.1	312.6	321.2	329.8	338.3	346.9	359.2	371.6	384.0	396.3	408.7	421.0	433.4	445.7	458.1	470.4
SOUTH AFRICA																																									
Industry	160.1	164.4	169.2	175.1	179.2	185.3	188.4	191.8	195.6	199.6	202.6	206.6	210.1	213.2	216.4	220.8	225.1	228.8	232.1	235.4	237.1	248.9	252.8	256.8	260.7	264.7	268.6	272.5	276.5	280.4	284.4	290.3	296.2	302.1	308.0	314.0	319.9	325.8	331.7	337.6	343.6
Urban	68.1	70.1	72.3	75.0	76.9	79.7	85.6	91.9	98.8	106.3	113.6	118.0	122.2	126.4	130.7	135.9	141.2	146.2	151.1	156.2	160.2	170.0	174.9	179.8	184.7	189.5	194.4	199.3	204.2	209.1	213.9	221.3	228.6	236.0	243.3	250.6	258.0	265.3	272.7	280.0	287.3
Rural	3.7	4.2	4.8	5.4	6.0	6.7	7.0	7.2	7.6	7.9	8.2	9.0	9.8	10.6	11.5	12.4	13.4	14.4	15.4	16.5	17.4	18.4	18.8	19.1	19.5	19.9	20.3	20.7	21.1	21.5	21.9	22.5	23.1	23.6	24.2	24.8	25.4	26.0	26.6	27.2	27.8
SWAZILAND																																									
Industry	410.8	430.1	452.0	470.4	487.1	500.2	527.4	559.8	586.9	616.7	640.4	650.0	657.0	665.8	674.5	684.2	693.8	703.4	713.1	722.7	734.1	754.2	765.7	777.2	788.7	800.2	811.7	823.1	834.6	846.1	857.6	874.2	890.7	907.3	923.8	940.4	956.9	973.5	990.1	1006.6	1023.2
Urban	642.1	672.8	708.7	740.2	768.3	790.2	802.4	819.1	826.9	837.5	838.3	848.0	855.9	865.5	875.1	884.8	895.3	904.9	915.4	925.9	938.2	963.6	978.2	992.8	1007.4	1022.0	1036.6	1051.2	1065.8	1080.4	1095.0	1116.2	1137.4	1158.6	1179.8	1201.0	1222.2	1243.4	1264.6	1285.8	1307.0
Rural	19.3	21.9	25.4	28.9	31.5	35.0	35.9	36.8	37.7	38.5	39.4	42.0	45.6	49.1	52.6	55.2	58.7	63.1	66.6	70.1	74.5	76.2	77.4	78.5	79.7	80.9	82.1	83.2	84.4	85.6	86.7	88.4	90.1	91.7	93.4	95.0	96.7	98.4	100.0	101.7	103.4
TANZANIA																																									
Industry	902.3	987.3	1126.5	1307.9	1500.6	1719.6	1931.6	2226.8	2494.0	2763.8	3059.0	3331.4	3626.6	3984.0	4375.6	4804.0	5273.5	5787.7	6351.0	6966.8	7640.5	8310.6	8868.8	9427.0	9985.2	10543.4	11101.6	11659.9	12218.1	12776.3	13334.5	14128.7	14922.8	15717.0	16511.2	17305.4	18099.6	18893.7	19687.9	20482.1	21276.3
Urban	2980.2	3082.6	3334.9	3673.1	4007.7	4372.1	4693.6	5178.0	5556.5	5905.1	6274.8	6658.5	7064.9	7565.1	8100.4	8672.4	9283.0	9935.6	10632.9	11377.5	12172.0	13090.9	13747.6	14404.2	15060.8	15717.4	16374.0	17030.6	17687.2	18343.8	19000.4	19819.0	20637.5	21456.0	22274.6	23093.1	23911.6	24730.2	25548.7	26367.2	27185.8
Rural	69.2	79.7	95.5	115.6	137.5	162.9	177.8	198.0	215.5	232.1	249.7	284.7	324.1	370.5	422.2	480.0	544.9	615.8	695.5	784.0	882.1	952.2	1006.0	1059.9	1113.7	1167.5	1221.3	1275.2	1329.0	1382.8	1436.6	1507.9	1579.1	1650.3	1721.5	1792.7	1864.0	1935.2	2006.4	2077.6	2148.8

ZAMBIA																					
Industry	7439.0	7806.9	8233.5	8682.9	9156.0	9656.1	10282.5	10947.4	11653.4	12403.3	13199.6	13874.1	14582.8	15327.4	16110.5	16933.1	17798.6	18707.0	19662.7	20666.6	21722.2
Urban	3681.0	3877.2	4102.3	4340.6	4591.1	4855.7	4966.9	5072.0	5169.3	5258.6	5338.3	5652.0	5982.2	6332.6	6703.2	7093.8	7507.3	7944.4	8407.0	8895.8	9411.7
Rural	180.5	191.8	204.1	217.2	231.3	246.2	340.8	445.9	563.3	692.9	837.5	879.5	923.3	969.7	1017.9	1068.7	1122.2	1178.2	1236.9	1299.1	1363.9
ZIMBABWE																					
Industry	4294.2	4564.8	4850.4	5151.8	5469.7	5804.4	6157.4	6528.8	6921.3	7333.9	7768.4	8087.2	8419.2	8765.3	9124.4	9499.3	9889.2	10295.6	10717.9	11157.6	11615.8
Urban	4282.8	4380.0	4476.4	4571.8	4666.5	4760.2	4831.1	4898.6	4961.7	5020.4	5072.9	5299.8	5537.2	5784.2	6042.6	6312.5	6594.5	6888.0	7195.5	7516.1	7850.7
Rural	155.9	177.8	202.4	227.8	254.9	284.7	335.5	389.8	447.6	509.8	576.4	599.2	623.7	648.2	674.5	701.7	729.7	758.6	789.3	820.8	853.2

ZAMBIA																				
Industry	22820.7	24236.6	25652.5	27068.4	28484.3	29900.2	31316.1	32732.0	34147.9	35563.8	37829.9	40095.9	42362.0	44628.0	46894.0	49160.1	51426.1	53692.1	55958.2	58224.2
Urban	9882.2	10487.6	11093.0	11698.4	12303.8	12909.2	13514.6	14120.0	14725.5	15330.9	16295.1	17259.3	18223.5	19187.7	20151.9	21116.2	22080.4	23044.6	24008.8	24973.0
Rural	1432.3	1520.0	1607.7	1695.4	1783.0	1870.7	1958.4	2046.1	2133.8	2221.5	2361.3	2501.2	2641.0	2780.8	2920.6	3060.4	3200.2	3340.0	3479.8	3619.6
ZIMBABWE																				
Industry	12080.9	12649.1	13217.4	13785.6	14353.8	14922.1	15490.3	16058.5	16626.8	17195.0	18020.7	18846.4	19672.2	20497.9	21323.6	22149.3	22975.0	23800.7	24626.5	25452.2
Urban	8164.3	8548.4	8932.5	9316.6	9700.6	10084.7	10468.8	10852.9	11236.9	11621.0	12179.1	12737.2	13295.3	13853.4	14411.5	14969.6	15527.7	16085.8	16643.9	17202.0
Rural	887.4	929.1	970.9	1012.7	1054.4	1096.2	1137.9	1179.7	1221.4	1263.2	1323.8	1384.4	1445.0	1505.7	1566.3	1626.9	1687.5	1748.1	1808.8	1869.4

(**South African energy demand data is listed in TWh)

D3- The Eastern African Power Pool: Energy Modeling Assumptions, Data and Results

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Introduction: The Eastern African Power Pool

Created in 2005 by the establishment of a seven nation international memorandum of understanding and cooperation, the Eastern African Power Pool (EAPP) is today a specialized institution recognized by the Common Market of Eastern African States (COMESA) and dedicated to fostering the development of electric power institutions and systems in the region. Extended from its funding members, the EAPP currently includes the Republics of Burundi, Djibouti, Kenya, the Sudan, Rwanda, and Uganda, the State of Eritrea, the Federal Democratic Republic of Ethiopia, the Federal Republic of Somalia, the United Republic of Tanzania, the Democratic Republic of Congo and Egypt.

With a clear vision of supporting the development of a fully integrated regional electricity market, the EAPP aims to provide sustainable power to meet demand in both a cost effective and efficient way throughout its member states in the future. To this end, a number of capacity expansions have been committed to in each member country and are listed in Table D-26. Consistent with the latest eastern African power pool development plan (EAPP/EAC, 2011), this shows significant capacity additions in Sudan, Ethiopia and Egypt with respectively 22%, 20% and 49.8% of total committed capacity to 2016.

Table D-26: EAPP Committed Capacity – 2013 to 2016 [MW]

	2013	2014	2015	2016	Total
Burundi	0	0	20	10	30
Djibouti	0	0	43	84	127
Egypt	3450	2200	2900	3250	11800
Ethiopia	1870	422	1726	714	4732
Kenya	510	140	2.926	0	652.926
Rwanda	170	0	0	0	170
Sudan	5339	0	0	0	5339
Tanzania	440	0	0	0	440
Uganda	0	0	0	394	394
Total	11779	2762	4691.926	4452	

Source:(EAPP/EAC, 2011)

Such developments come as part of answers to important challenges that affect the power pool now and in the future. The significant disparities in access to electricity currently varies from one country to the next with values for 2011 varying from 15% in Tanzania to 99.6% in a highly connected Egypt with an average for available countries of just 33% (IEA, 2013). Considering complementary data from recent IEA census for seven of the twelve countries within the power pool – this represents in excess of 198 million people without access to electricity (IEA, 2011). Further, the connections that do exist are under challenges related to down time and power outages that currently affect the various systems in the region and are responsible for non-negligible economic losses: percentages of sales lost in recorded countries can be as high as 17.6% as recorded for Tanzania in 2013 (World Bank, 2014).

From a regional perspective, although they represent a diverse sub-group of Sub Saharan Africa the EAPP member countries share a number of challenges in the future. Economically, the International Monetary Fund classifies eleven of the twelve EAPP countries as Low Human Development countries with indexes in 2013 spanning from 0.338 in the DRC to 0.535 in Kenya. Egypt is the only country to gain access to the Medium Human Development group with an index of 0.682. This picture changes however when considering index progression relative to 2005 levels. These show a relative increase in 2013 of between 10% and 15% for five member states; of up to 29% and 28% for Rwanda and Ethiopia; .and of as little as 5.7% for Egypt (UNDP, 2014).

Consistently, per capita energy consumption across the EAPP is low in a large majority of cases. Egypt has the highest recorded value for 2010 with 1,670 kWh/capita. This is ten times larger than Kenya taking up second place with 154kWh/capita. The most challenging situation was recorded for Eritrea with 47.4 kWh/capita in 2010 (World Bank, 2014).

From a population perspective, the EAPP is less diverse in terms of total population than other power pools might be. Specifically, the domination of one country in front of all other members of the power pool is not clear and total population in 2014 is split according to Table D-27 with Ethiopia and Egypt as the largest demand pool in the region representing respectively 24.5% and 21.1% of the total population.

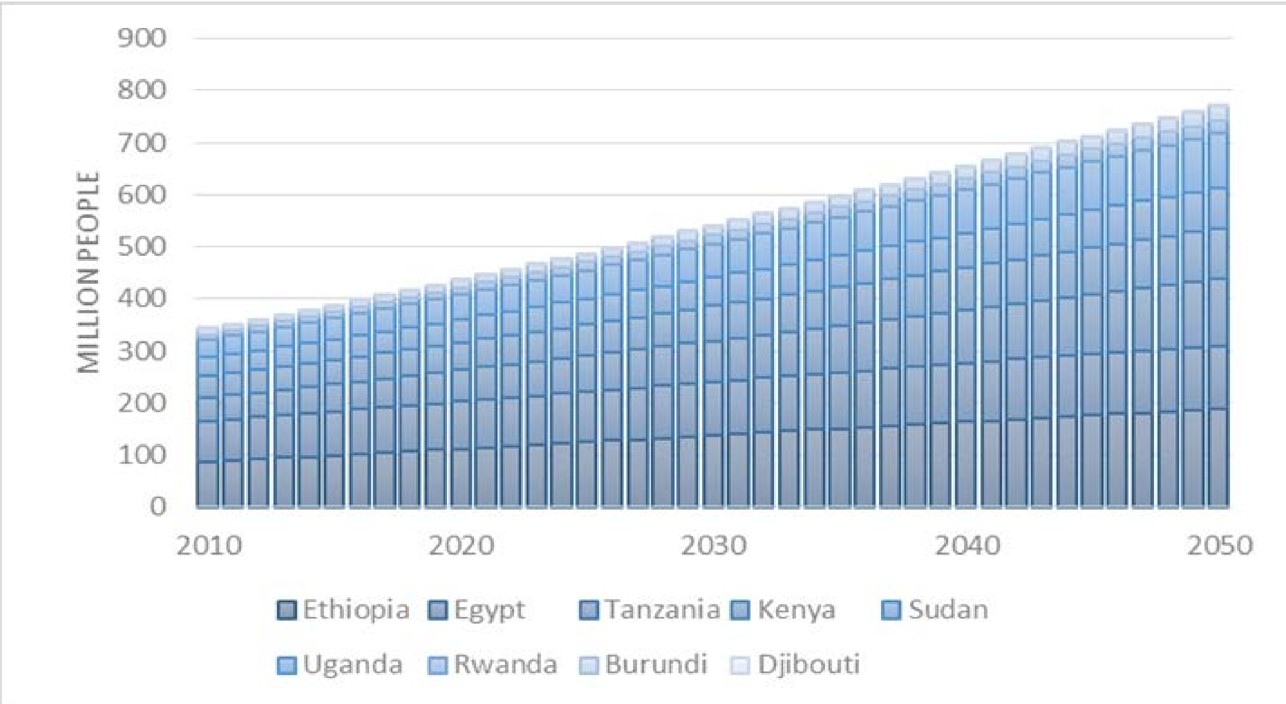
Table D-27: Share of demand per country – 2014

Ethiopia	Egypt	Tanzania	Kenya	Sudan	Uganda	Rwanda	Somalia	Burundi	Eritrea	Djibouti
24.5%	21.1%	12.9%	11.5%	9.8%	9.8%	3.1%	2.7%	2.7%	1.7%	0.2%

Source:(*World Population Prospects, the 2012 Revision*, 2013)

Considering Figure D-25 below shows that population growth in the region is expected to be comparable from one country to the next leading to a twofold increase in total number of inhabitants in the EAPP by the end of the model period.

Figure D-25: Regional Population – EAPP



EAPP Specific Assumptions and Data Tables

Energy Demands

Final electricity consumption in the region varies from one country to the next with high disparities, especially between Egypt and the rest of the power pool. Representing a total of 83% of all demand in the region in 2010, with a domestic consumption that stands to be multiplied by close to ten over the study period, Egypt is initially the main driver for energy system development in the region.

From a regional perspective, demand growth data shows an expected average growth of between 6.9% for the five year period from 2010 to 2015, stabilizing gradually over the study horizon at just over 4% by 2050 - multiplying the current demand by 6.8 between 2015 and 2050. Individual country-level five-year average growth rates vary, reaching extremes of 14.8% in Sudan in the beginning of the period and 1.9% in Djibouti by 2050, with the regional average (excl. Egypt) decreasing from 9.5% to 5.1% between 2015 and 2050. (refer to Figure D-26 for overall demand trends)

In this modelling exercise, the total final consumption of electricity is split between three sectors. Figure D-27 shows both a relatively important industrial demand in Egypt and a significant share of rural demand in all countries.

Figure D-26: Total EAPP Energy demand per country

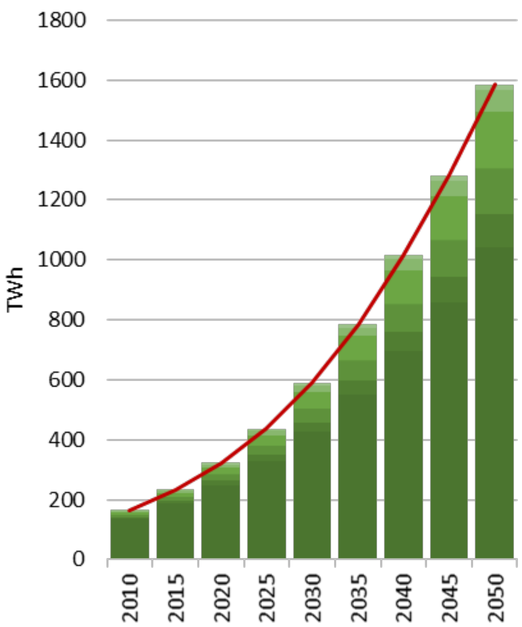
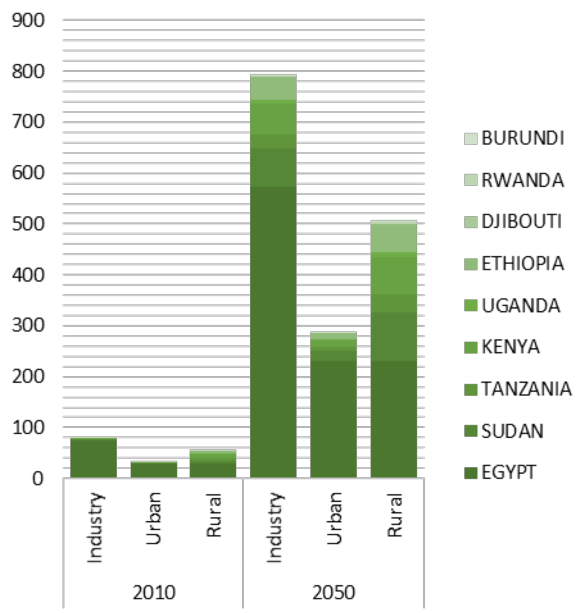


Figure D-27: EAPP Energy Demand: Sectorial Split



Source: (EAPP/EAC, 2011)

Although all demands increase significantly over the study period, it is important to take them into perspective. Current recorded energy consumption per capita is limited to part of the region only and does not exceed 154.51 KWh/capita in 2010 (excl. Egypt) which is 42 times lower than the current average value for the EU (World Bank, 2014).

Time Slices and Load Curve

The EAPP model considers a breakdown of the year into twelve months and four different day parts, bringing the total number of time slices to 48. This split is done on the duration of each of the time slice types relative to the total duration of one year and results in the values presented in Table D-11. Correspondingly, a certain amount of the total energy requirements occur in each time slice. This percentage is calculated for the three demand types that are considered and reported in Table D-29, Table D-30 and Table D-31. In the EAPP model these fractions are maintained constant for all countries.

Table D-28: EAPP Time Slice definition

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Part 1	0.01945	0.01757	0.01945	0.01882	0.01945	0.01882	0.01945	0.01945	0.01882	0.01945	0.01882	0.01945
Part 2	0.04603	0.04158	0.04603	0.04455	0.04603	0.04455	0.04603	0.04603	0.04455	0.04603	0.04455	0.04603
Part 3	0.01418	0.01281	0.01418	0.01373	0.01418	0.01373	0.01418	0.01418	0.01373	0.01418	0.01373	0.01418
Part 4	0.00527	0.00476	0.00527	0.00510	0.00527	0.00510	0.00527	0.00527	0.00510	0.00527	0.00510	0.00527

Table D-29: Industrial Demand Load Curve

Industrial	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Part 1	0.01537	0.01388	0.01536	0.01456	0.01503	0.01426	0.01473	0.01443	0.01396	0.01443	0.01396	0.01443
Part 2	0.04997	0.04513	0.04993	0.04734	0.04886	0.04637	0.04788	0.04691	0.04540	0.04691	0.04540	0.04691
Part 3	0.01859	0.01679	0.01858	0.01762	0.01818	0.01725	0.01782	0.01746	0.01689	0.01746	0.01689	0.01746
Part 4	0.00419	0.00379	0.00419	0.00397	0.00410	0.00389	0.00402	0.00394	0.00381	0.00394	0.00381	0.00394

Table D-30: Rural Demand Load Curve

Rural	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Part 1	0.01537	0.01388	0.01536	0.01456	0.01503	0.01426	0.01473	0.01443	0.01396	0.01443	0.01396	0.01443
Part 2	0.04997	0.04513	0.04993	0.04734	0.04886	0.04637	0.04788	0.04691	0.04540	0.04691	0.04540	0.04691
Part 3	0.01859	0.01679	0.01858	0.01762	0.01818	0.01725	0.01782	0.01746	0.01689	0.01746	0.01689	0.01746
Part 4	0.00419	0.00379	0.00419	0.00397	0.00410	0.00389	0.00402	0.00394	0.00381	0.00394	0.00381	0.00394

Table D-31: Urban Demand Load Curve

Urban	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Part 1	0.01537	0.01388	0.01536	0.01456	0.01503	0.01426	0.01473	0.01443	0.01396	0.01443	0.01396	0.01443
Part 2	0.04997	0.04513	0.04993	0.04734	0.04886	0.04637	0.04788	0.04691	0.04540	0.04691	0.04540	0.04691
Part 3	0.01859	0.01679	0.01858	0.01762	0.01818	0.01725	0.01782	0.01746	0.01689	0.01746	0.01689	0.01746
Part 4	0.00419	0.00379	0.00419	0.00397	0.00410	0.00389	0.00402	0.00394	0.00381	0.00394	0.00381	0.00394

Regional Fuel provision and costs

In addition to the general assumptions for this section, that are detailed in the body of the Main Modelling Annex, the Eastern African Power Pool has a specific set of data assumptions regarding the availability and cost of fossil fuels due to its particular level of reserves.

The identified fossil resources available to each country in the region listed in Table D-32 are in accordance with current levels as identified by international sources. The corresponding cost of extracting these fuels is included in the overall fuel price listed in Table D-33. As a first-pass assumption used to differentiate the two types of fuel, imports of a given commodity are assigned a cost using the domestic per unit cost increased by a standard 10%. (see Annex D1- OSeMOSYS Common Modeling Assumptions – Main Methodology Assumptions for further details)

Table D-32: National identified fossil reserves in TWh – EAPP [2013]

Country	Coal*	Crude Oil **	Natural Gas
Burundi	0.00	0.00	0.00
Djibouti	0.00	0.00	0.00
Egypt	99.97	7811.90	23100.30
Ethiopia	0.00	0.76	263.32
Kenya	0.00	0.00	0.00
Rwanda	0.00	0.00	598.45
Sudan	0.00	8877.16	897.68
Tanzania	1249.65	0.00	68.82
Uganda	0.00	4438.58	149.61

*2008 data, **2011 data

Source: (EIA, 2014)

Table D-33: Cost of domestic fuel extraction [USD/ToE]

	Burundi	Djibouti	Egypt	Ethiopia	Kenya	Rwanda	Sudan	Tanzania	Uganda
Biomass	150.7	150.7	150.7	150.7	150.7	150.7	150.7	150.7	150.7
Coal	150.7	150.7	150.7	150.7	150.7	150.7	150.7	150.7	150.7
Diesel	0.0	704.6	704.6	704.6	704.6	704.6	704.6	704.6	704.6
HFO	569.4	569.4	569.4	569.4	569.4	569.4	569.4	569.4	569.4
Natural Gas	242.8	242.8	242.8	242.8	242.8	242.8	242.8	242.8	242.8

Source: (EAPP/EAC, 2011)

Note that the costs presented in Table D-33 are maintained constant over the modelling period due to relatively lower levels of information and high level of uncertainty regarding the potential evolution of fossil fuel costs in the future.

Renewable Energy Potentials

Renewable energy potentials over Africa in general are significant. This holds true for the East with specific regard the wind based resources. Based on the latest IRENA research for the continent (Hermann et al., 2014), the total theoretically available renewable power for the EAPP, including solar and wind based sources, is approximately 600 thousand TWh. In Sudan alone the combined resource of wind and solar exceeds 200 thousand TWh per year. This resource, however, is unevenly spread within the region, highlighting the potential advantage of increased interconnections between countries. Note that the extremely low values in Burundi, Djibouti and Rwanda are also related to the screening criteria applied in the renewable energy potential assessment. Specifically, these countries are significantly smaller than others in the region giving them comparatively less available land to develop renewable power plants.

As renewable resource availability suffers from unpredictability, a strong interconnected grid becomes an advantage for both distributing risk and absorbing a resource as soon as it becomes available.

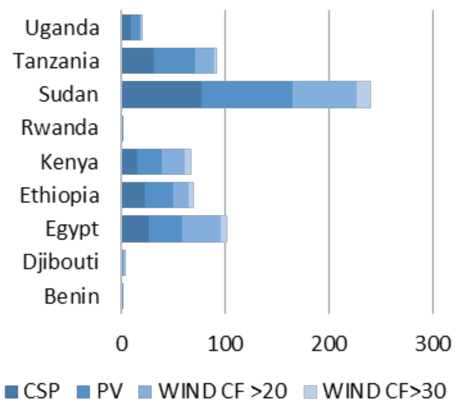
To summarize these renewable resource potentials, Table D-34 presents the upper limits extracted from the literature, and used in the present modelling, to provide resource constraints for the renewable technologies available as part of future energy generation options during the optimization.

Table D-34: Renewable Energy Potential per Country

	[TWh per year]			
	CSP	PV	Wind 20 CF	Wind 30 CF
Burundi	785	888	0	0
Djibouti	851	946	934	226
Egypt	26604	32218	36601	6757
Ethiopia	22959	27154	14838	4983
Kenya	15399	23045	22476	6185
Rwanda	788	892	0	0
Sudan	77422	87817	61661	12784
Tanzania	31842	38804	18455	3084
Uganda	8581	9470	815	125

Source: (Hermann et al., 2014)

Figure D-28: Thousand TWh of Renewable Potential



In parallel to these resource availability limits, the energy models consider two types of constraints on renewable technologies. The first assumes a cap on the amount of new capacity that can be added to the system on a yearly basis, while the second restricts the total penetration of renewable energy in the overall mix in order to ensure conservative shares of technologies with lower reliability in the final generation.

Please note that assumptions regarding Hydropower are listed in a separate paragraph due to the important focus of the present study on this specific resource.

Techno-economic Parameters

The technology options available inside of the power pool model are linked to corresponding generic parameter values. These are presented and referenced in Table D-18.

Table D-35: Techno Economic Data for generic power plants

Power Plant (Technologies)	**Capital Cost ($/kW)**	**Variable O&M Cost (USD/GJ)**	**Life time (Years)**	**Construction (Years)**
Biomass	3660	5.56	30	4
Coal	3519	3.96	35	4
Diesel 100 kW (Industrial)	659	15.38	20	0
Diesel 1kW (Rural)	692	9.23	10	0
Diesel 1kW (Urban)	692	9.23	10	0
Diesel (Centralized)	1177	4.72	30	1
Geothermal	5856	1.39	25	4
HFO	1634	4.17	25	2
Gas Turbine (Combined cycle)	1423	0.80	30	3
Gas turbine (Other cycles)	730	5.53	25	2
Nuclear	10778	3.87	60	8
CSP	4392	6.20	25	4
CSP with Storage	10249	4.56	25	4
CSP with Gas Co-firing	2033	4.56	25	4

Power Plant (Technologies)	**Capital Cost ($/kW)**	**Variable O&M Cost (USD/GJ)**	**Life time (Years)**	**Construction (Years)**
Solar PV Utility	2200	5.58	25	1
PV Rural Rooftop	2100	4.16	20	<1
PV Rural rooftop 1hr storage	4258	4.16	20	<1
PV Rural rooftop 2hr storage	6275	4.76	20	<1
PV Urban Rooftop	2100	4.16	20	<1
PV Urban rooftop 1hr storage	4258	4.76	20	<1
PV Urban rooftop 2hr storage	6275	5.29	20	<1
Wind 25% Capacity Factor	2861.65	3.97	25	2
Wind 30% Capacity Factor	2420	3.97	25	2
Generic Large Hydro	3221	1.66	50	5
Generic Micro Hydro	4800	1.51	30	2

Source: (Miketa and Merven, 2013)

Planned infrastructure investments

Energy infrastructure development is a long process that goes through a number of project phases before the physical power plant comes online and actually begins to provide energy to the system. In order to take into account this lead time in project development, the first years of the modelling framework are constrained to ensure that actual infrastructure investment results and current committed national plans align. These investments are summarized based on the latest regional endorsed Power Pool Plan (EAPP/EAC, 2011) and adjusted using available data from the World Energy Power Plants database (UDI PLATTS, 2012).

With a specific focus on hydro power, Table D-36 details the specific list of power plants that are included in the OSeMOSYS model of the EAPP. These power plants fall into six different categories:

- One split into two categories are based on their presence or not in the WEAP water models: this defines whether or not the power plant receives direct or 'proxied' information for the climate scenario runs.
- A second split into three categories based on the status of the power plant: i.e. whether the facility is historic capacity (existing), committed new capacity or planned new capacity.

The table further details the correspondence between the OSeMOSYS power plants and their WEAP counterparts. In cases where the power plant is not directly included in the WEAP models this correspondence designates the proxy that was used to derive capacity factor variations related to the six climate change scenarios under analysis.

Table D-36: Site Specific Hydro power plant parameters

Power Plant Name	**WEAP Proxy**	**River Basin**	**Capacity (MW)**	**Capital Cost ($/kW)**	**Fixed Cost ($/kW)**	**Variable Cost ($/GJ)**	**Status[25]**	**Earliest on**
Burundi								
Consolidated Historic	Rusumo Falls	Nile	30.1	0	21	0.32	HC	
Kabu 16	Rusumo Falls	Nile	20	2943	3.826	0.06	CON	2015
Mphanda	Rusumo Falls	Nile	10	6548	4.108	0.06	CON	2016
Siguvyayae	Rusumo Falls	Nile	90	4869	3.824	0.06	PLN	2016
Rusumo	Rusumo Falls	Nile	20	0	21	0.32	PLN	2017
Ruzizi III	Rusumo Falls	Nile	48.3	2553	21	0.32	PLN	2018
Ruzizi IV	Rusumo Falls	Nile	95.7	2553	21	0.32	PLN	2019
Mule 34	Rusumo Falls	Nile	17	3070	21	0.32	PLN	2016
Jiji 3	Rusumo Falls	Nile	16	4179	21	0.32	PLN	2016
Kaganuzi A	Rusumo Falls	Nile	34	2296	21	0.32	PLN	2016

[25] CON: Under Construction; HC: Historic Capacity, i.e. existing; PLN: Planned

Kaganuzi Complex	Rusumo Falls	Nile	39	5357	21	0.32	PLN	2016
Ruzizi II (Historic)	Rusumo Falls	Nile	12	2553	21	0.32	HC	
Egypt								
High Aswan Dam	-	Nile	2100	0	21	0.32	HC	
Esna	-	Nile	85.8	0	21	0.32	HC	
Nagaa Mamadi	-	Nile	640	0	21	0.32	HC	
Aswan	HAD	Nile	592	0	21	0.32	HC	
Gabal Galala	-	Nile	650	2552	21	0.32	PLN	2018
Asyut	-	Nile	32	2552	21	0.32	PLN	2017
Zefta	Assuit Barrage	Nile	5.5	2552	21	0.32	PLN	2018
Faiyun	Assuit Barrage	Nile	0.8	2552	8.5713	0.32	HC	
Ethiopia								
Gibe II	Geba A Dam	Nile	420	0	21	0.32	HC	
Tana Beles	-	Nile	460	2553	21	0.32	CON	
Tekeze I	-	Nile	300	0	21	0.32	HC	
Gibe III	Geba A Dam	Nile	1870	1148	4.249	0.06	CON	2013
Gibe IV	Geba A Dam	Nile	1468	1899	4.137	0.06	CON	2015
Halele Worabesa	Geba A Dam	Nile	422	1438	3.891	0.06	CON	2014
Chemoga Yeda	Geba A Dam	Nile	280	1722	3.942	0.06	CON	2016
Geba I	-	Nile	214.5	1680	3.959	0.06	PLN	2025
Genale 3D	Geba A Dam	Nile	258	1410	3.973	0.06	CON	2015
Baro 1 and 2 + Genji	-	Nile	900	4308	3.928	0.06	PLN	2025
Mandaya	-	Nile	2200	1495	3.775	0.06	CON	2035
Border	GERD	Nile	1200	1706	3.887	0.06	PLN	2019
GIbe V	Geba A Dam	Nile	662	1672	4.332	0.07	PLN	2019
Beko Abo	-	Nile	935	1820	3.907	0.06	PLN	2025
Karadobi	-	Nile	1600	2173	3.852	0.06	PLN	2025
Genale 6D	Geba A Dam	Nile	246	1863	3.69	0.06	CON	2016
Gojeb	Geba A Dam	Nile	150	2251	4.2	0.06	CON	2016
Tekeze II TK7	-	Nile	450	5071	4.125	0.06	PLN	2025
Aleltu East	Geba A Dam	Nile	186	2906	3.974	0.06	PLN	2018
Aleltu West	Geba A Dam	Nile	265	2612	4.146	0.06	PLN	2019
Awash 4	Fincha Dam	Nile	38	1559	4.042	0.06	CON	2016
Amerti neshe	-	Nile	97	0	21	0.32	HC	
Fincha	-	Nile	128	0	21	0.32	HC	

Tis abbay (1&2)	-	Nile	85.2	0	21	0.32	HC	
Awash (1,2,3)	Fincha Dam	Nile	107	0	21	0.32	HC	
Malka Wajana	Geba A Dam	Nile	153	0	21	0.32	HC	
Gilgel Gibe 1	Geba A Dam	Nile	192	0	21	0.32	HC	
Lower Didessa	-	Nile	550	1463	21	0.32	PLN	2025
Grand Renaissance	-	Nile	6000	800	21	0.32	CON	2017
Birbir R	-	Nile	465	3442	21	0.32	PLN	2035
Tams	-	Nile	1060	7406	21	0.32	PLN	2020
Geba 2	-	Nile	157	957	3.959	0.06	PLN	2025
Kenya								
Gogo falls	-	Nile	2	0	21	0.32	HC	
Sondo-Miriu Songoro	-	Nile	81.2	0	21	0.32	HC	
Kambaru	Magwagwa	Nile	94	0	21	0.32	HC	
Gitaru	Magwagwa	Nile	225	0	21	0.32	HC	
Kindaruma	Magwagwa	Nile	40	0	21	0.32	HC	
Masinga	Magwagwa	Nile	40	0	21	0.32	HC	
Kiambere	Magwagwa	Nile	164	0	21	0.32	HC	
Turkwell	Magwagwa	Nile	106	0	21	0.32	HC	
Consolidated (Tana,Wanji,Misc)	Magwagwa	Nile	37	0	21	0.32	HC	
Magwagwa	-	Nile	120	3683	4.04	0.06	CON	2017
Sangoro	Magwagwa	Nile	21	2553	21	0.32	CON	2010
Kindaruma U3	Magwagwa	Nile	25	2553	21	0.32	CON	2012
Tana Extension	Magwagwa	Nile	10	2553	21	0.32	CON	2010
Mutonga	Magwagwa	Nile	60	4537	3.834	0.06	PLN	2016
low Grand falls	Magwagwa	Nile	60	4537	3.924	0.06	PLN	2016
Total Ewaso Ngiro	Magwagwa	Nile	180	2739	1.328	0.02	PLN	2017
Karura	Magwagwa	Nile	56	4049	13.639	0.21	PLN	2016
Rwanda								
Mukungwa	Rusumo Falls	Nile	12.5	2000	21	0.32	HC	
Gihiria	Rusumo Falls	Nile	1.8	2000	21	0.32	HC	
Gisenyi	Rusumo Falls	Nile	1.2	2000	21	0.32	HC	
Nyabarongo	Rusumo Falls	Nile	28	5342	3.895	0.06	PLN	2014
Rukarara	Rusumo Falls	Nile	95	2553	21	0.32	PLN	2014
Ruzizi II (12MW, shared)	Rusumo Falls	Nile	12	0	21	0.32	HC	

Ruzizi I (15MW, shared)	Rusumo Falls	Nile	15	0	21	0.32	HC	
Ruzizi III (48,3MW, shared)	Rusumo Falls	Nile	48.3	2553	21	0.32	0	2018
Ruzizi IV (95,7MW, shared)	Rusumo Falls	Nile	95.7	2553	21	0.32	0	2019
Sudan								
Sennar and Extension	-	Nile	15	2553	21	0.32	HC	
Roseires	-	Nile	280	2553	21	0.32	HC	
Kashm El Girba	-	Nile	17.8	2553	21	0.32	HC	
Jebel Aulia	Gabal Awlia Dam	Nile	28.8	2553	21	0.32	HC	
Merowe	-	Nile	28.8	2553	21	0.32	HC	
Bedden	-	Nile	400	2973	0.273	0.00	PLN	2030
Fula	-	Nile	720	2474	1.112	0.02	PLN	2030
Lakki	-	Nile	210	2629	6.936	0.10	PLN	2030
Shukoli	-	Nile	210	2571	3.642	0.05	PLN	2030
Dagash	-	Nile	284.8	3792	9.82	0.15	PLN	2025
Kagbar	-	Nile	300	3433	4.513	0.07	PLN	2021
Low Dal	-	Nile	340	4124	1.522	0.05	PLN	2028
Sabloka	-	Nile	120	6383	12.503	0.19	PLN	2028
Shereiq	-	Nile	315	3613	3.559	0.05	PLN	2020
Rumela	-	Nile	30	8116	13.041	0.20	CON	2013
Tanzania								
Mtera	Rumakali	Zambezi	80	2553	21	0.32	HC	
Kidatu	Rumakali	Zambezi	204	2553	21	0.32	HC	
Hale	Magwagwa	Nile	21	2553	21	0.32	HC	
Kihansi	Rumakali	Zambezi	180	2553	21	0.32	HC	
Pagani Falls	Pangani	Nile	680	2553	21	0.32	HC	
Nyumba Ya Mungu	Magwagwa	Nile	8	2553	21	0.32	HC	
Ruhudji	Rumakali	Zambezi	358	1717	3.869	0.01	PLN	2016
Russomo	-	Nile	80	5486	32.021	0.06	PLN	2017
Kakono	-	Nile	53	1962	50.58	0.09	PLN	2025
Songwe Bigupu	Songwe	Nile	34	3638	113.223	0.19	PLN	2017
Songwe Sofre	Songwe	Nile	157	2390	29.045	0.05	PLN	2017
Songwe Manolo	Songwe	Nile	149	2561	35.935	0.06	PLN	2017
Masigira	Rumakali	Zambezi	118	2088	50.569	0.09	PLN	2020
Mpanga	Rumakali	Zambezi	144	2041	44.883	0.08	PLN	2018
Tevete	Rumakali	Zambezi	145	3031	51.218	0.09	PLN	2020

Rumakali	-	Nile	222	2568	35.72	0.06	PLN	2019
Ikondo	Rumakali	Zambezi	340	2181	26.829	0.05	PLN	2019
Stieglers Gorge 1	Rumakali	Zambezi	300	3614	19.311	0.03	PLN	2023
Stieglers Gorge 2	Rumakali	Zambezi	600	644	10.411	0.02	PLN	2023
Stieglers Gorge 3	Rumakali	Zambezi	300	1056	22.331	0.04	PLN	2023
Kishanda	Rumakali	Zambezi	207	1313	21	0.32	PLN	2016
Uganda								
Kiira	-	Nile	200	0	21	0.32	HC	
Bujagali	-	Nile	250	2553	21	0.32	CON	2011
Nalubaale	-	Nile	380	0	21	0.32	HC	
Ayago	-	Nile	612	3516	3.5014	0.05	PLN	2018
Isimba	-	Nile	100	3630	3.501	0.05	PLN	2018
Karuma High	-	Nile	700	3990	3.5	0.05	PLN	2019
KIBA	-	Nile	288	2553	21	0.32	PLN	2022
Murchison Falls	-	Nile	750	2211	3.503	0.05	PLN	2037

Source: (UDI PLATTS, 2012) (EAPP/EAC, 2011)

Transmission and Distribution

National transmission and distribution (T&D) systems include four types of lines connecting two different levels of the energy system. Since data regarding current levels of system development on a national level are not readily available in the region, initial balancing of the regional EAPP model is used to determine the capacity levels required to cover existing demand in each individual country. These levels are then considered fixed in the first year of the modelling.

Further, each type of line suffers from losses which translate into different transmission efficiencies. These efficiencies can also vary for a single type of line from one country to another depending on the state of the system. The values used in this study are presented in Table D-37 for reference. Note that these are maintained constant over the study period from lack of valid data regarding their specific evolution over time.

Table D-37: National T&D line efficiencies

	Burundi	**Djibouti**	**Egypt**	**Ethiopia**	**Kenya**	**Rwanda**	**Sudan**	**Tanzania**	**Uganda**
Transmission	0.9865	0.9767	0.9641	0.9663	0.9466	0.982	0.9301	0.9336	0.9769
Dist. Industrial	0.989	0.9963	0.969	0.9987	0.9931	0.9991	0.9757	0.9791	0.9963
Dist. Urban	0.9845	0.964	0.9875	0.956	0.9045	0.9928	0.8949	0.8925	0.9648
Dist. Rural	0.88	0.88	0.88	0.88	0.88	0.88	0.88	0.88	0.88

In addition to national level T&D, each country in the region is either connected – or has the potential for connection to – neighboring systems. Considering the latest available data regarding the Eastern African Power Pool master plan documentation, Table D-38 presents the countries with existing high voltage connections along with their current capacity. Similarly,

Table D-39 presents the project options that are included in the modelling framework. Note that these are divided between "Committed" and "Future" in relation to the level of certainty that the corresponding project will be implemented. The first are therefore forced in to the solution space whereas the second are simply made available to the system and are considered as part of the optimization. Note that the denominations "Country1" resp. 2 are simply used to define the two neighbors that are connected by the transmission project. Energy is not constrained to flow in a particular direction but rather is traded depending on the unit cost of generation in each country.

Table D-38: International Transmission - Existing Infrastructure

Country 1	Country 2	Capacity (MW)
Uganda	Kenya	418
	Rwanda	250
	Tanzania	59
Burundi	Rwanda	100
Ethiopia	Sudan	200
	Djibouti	180
DRC	Rwanda	157

Table D-39: Future International transmission projects[26]

Country 1	Country 2	Capacity (MW)	Earliest
Tanzania	Kenya	1520	2015
	Uganda	700	2023
Uganda	Kenya	440	2023
Ethiopia	Kenya	2000	2016
		2000	2020
	Sudan	1600 x 2	2020
		1600	2025
Egypt	Sudan	2000	2016
		2000	2020
		2000	2025
DRC	Rwanda	370	2014
	Burundi	330	2014

Source:(EAPP/EAC, 2011)

Integration with other power pools

This modelling effort was conducted as an integral component of the larger vulnerability assessment of African infrastructure. In this study, the four Sub Saharan power pools (CAPP; EAPP; SAPP and WAPP) were modelled separately but have a certain number of overlapping countries and overlapping infrastructure: i.e. certain countries are included in multiple power pools and certain river basins give water input into several power pools. Considering that each power pool is optimized separately under an iterative approach with the water modelling component of the project, this overlap adds an extra level of complication.

[26] Note that this exercise does not include "generic" international transmission technologies. This is due on the one hand to the extra computational complexity they introduce and to the focus of the project being on the adaptation of hydro power infrastructure.

To ensure that results are consistent between power pools, a few simple procedures were applied. First, power pools were optimized in a specific order aligned with the perceived importance of their impact on continent scale results: SAPP was followed by WAPP, EAPP and CAPP. Second, countries that were included in several power pools were optimized only once along with the first power pool in which they appear. Thereafter, when contributing to other power pools they are constrained both in terms of capacity and minimum dispatch to respect the results from the previous model runs.

For further details about the constraints applied and the corresponding countries that they were applied to, please refer to the main methodology annex (D1- OSeMOSYS Common Modeling Assumptions).

Results

Regional Overview

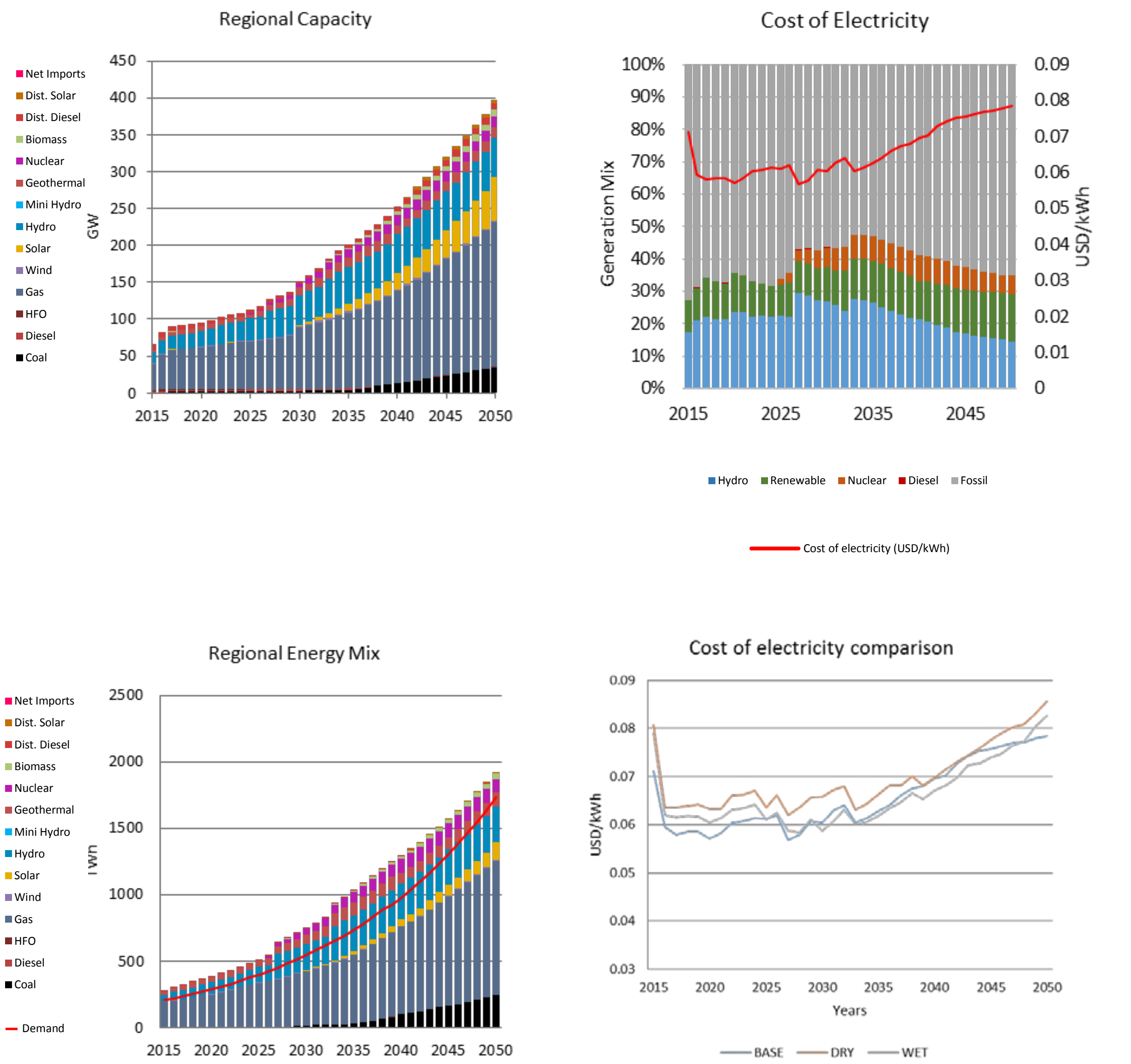
General Energy System Results

The Eastern African Power Pool is a resource-rich region of SSA. With access to both domestic coal in Tanzania and to relatively distributed reserves of natural gas, the EAPP also counts with strong availability of renewables including important levels of energy-grade geothermal power. Hydropower in the region is concentrated along the Nile river basin and stands to generate a substantial amount of power during the study period.

The initial results shown in Figure D-29: Capacity and Generation mix Summary are extracted for a base run of the energy model assuming historic climate conditions prevail over the study period. From a capacity perspective, the system is expected to grow very substantially from a current under-installed reaching near to 400GW of total capacity in 2050. In effect, this represents a six-fold increase in system size. From an energy mix perspective, the EAPP relies heavily on gas based systems representing up to 49.2% of total capacity in 2050. Baseload generation is also ensured by 8.8% of coal-based systems, 13.2% hydropower, and a noticeable 3.6% of nuclear, again, in 2050. Other renewables complete the picture with an important contribution of centralized solar systems.

From a national perspective, the picture varies considerably depending on both the size of the demand and the domestic access to renewables-based power. In the region, resources of particular interest – in addition to hydropower – include geothermal along the Eastern Rift Valley, as well as high levels of solar power.

Figure D-29: Capacity and Generation mix Summary



From a generation mix perspective, the amount of energy produced by renewable sources is the highest among all other power pools. Between 2015 and 2050 this share reaches a maximum of 40.2% with an average share of 32.4%. Adding the contributions of nuclear generation in Egypt increases this "non-fossil" share to 37.4% by the end of the study period. The corresponding cost of electricity generation projection for the region shows a unit price increasing progressively from 0.06USD/kWh to 0.08 USD/kWh as the amount of fossil fuel used and the number of system expansion investments increase over the study period. The change in unit cost[27] related to the impact of climate change seems relatively smaller than in other power pools of SSA. Reaching a maximum change of 13.5% over the study period (dry to base scenario comparison), these cost trends would seem to indicate a relatively robust regional system. Studying these results to the national level however shows that this reality is

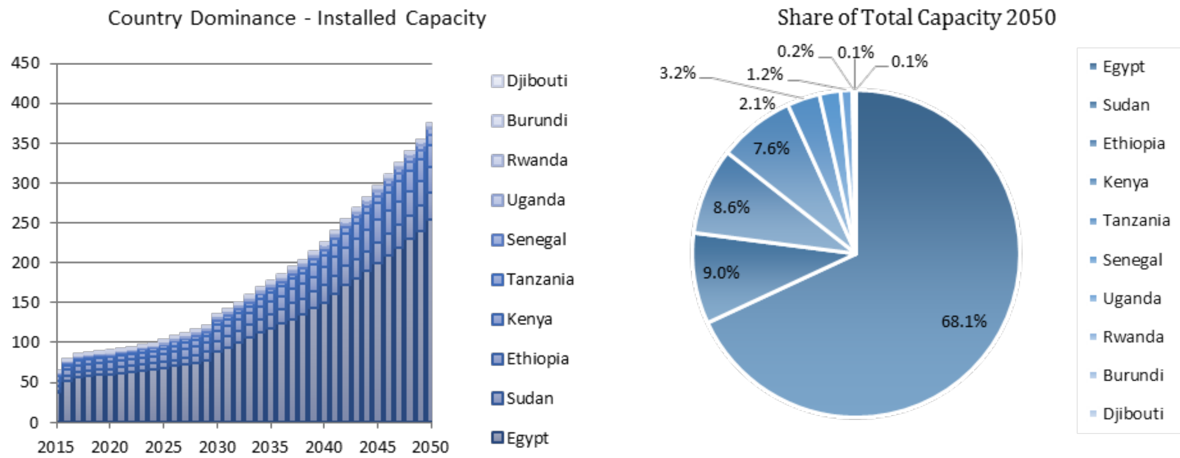
[27] Calculated for the region as the total annualised system cost divided by the total generation in the power pool. Annualised system costs are the undiscounted sum of all annual running costs as well as investment costs spread over power plant operational life time. On a national level this cost is adjusted to include the costs (resp. benefits) of traded energy valued using the regional (resp. domestic) cost of generation.

different from one country to the next dependent on both the amount of hydropower used on a national scale and the level of trade that exists between each country and the rest of the region.

A regional system with an important player – Egypt

As in the other power pools, one national system in the EAPP is considerably larger than its neighbors and is expected to maintain that position throughout the model period. Egypt is a large system both today and in the future representing up to 68.1% of all installed capacity by 2050. The second largest country by the end of the period is Sudan, more than seven times smaller in terms of installed capacity than Egypt. It is followed closely by Ethiopia. This comparison however is slightly mitigated when considering individual country system growth in terms of capacity over the mode period. Although Egypt remains at the top of the list multiplying its system size by 5.4 in thirty five years, both Sudan and Tanzania show higher growths than Ethiopia – the three countries' systems being respectively increased by a factor of 5.2, 4.8 and 4 over the same time span.

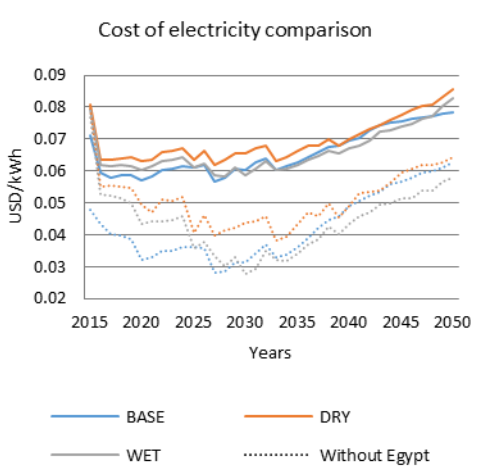
Figure D-30: Egypt dominating the power sector of the EAPP



From a cost perspective, the system dominance of a single country weighs heavily on its comparatively smaller neighbors. This is responsible for both a relatively large increase in the regional cost of production across all scenarios, and lower inter-year variability in the cost to consumers (see Figure D-31). Specifically, Egypt uses gas and invests in nuclear based generation in both 2025 and 2030. Egypt represents 69% of the total generation in the region over the study period, 77% of which is based on the use of a variety of fossil fuels. This is responsible for the noticeable step up increase caused by adding Egypt into the regional cost of electricity generation calculation.

Further, considering that the other countries in the region have smaller systems with high levels of hydropower and other renewables, the cost trends that remain for the power pool when Egypt is removed show considerably lower overall values but significantly increased final cost variability. This translates in to a higher regional climate variability for a system in which the buffering effect of Egyptian fossils has been removed. One can notice however that the regional dynamics remain stable over time both with and without Egypt: the graphs follow the same overall trends.

Figure D-31: Cost of electricity variation: the impact of Egypt throughout all scenarios



Key Messages

In order to maintain a level of consistency between the Power Pool studies, increase report readability as well as offer more opportunity for result comparison between power pools, six key messages – also reported in the global project Synthesis report – have been developed and are presented in the following paragraphs. Please note that, throughout these explanations, the terminology “Wet” and “Dry” is adopted to describe scenarios that are considered to have respectively higher or lower amounts of available water for energy generation over the period. This does not however translate to each and every month/year of the corresponding scenario being systematically richer/poorer in water resource than the base: this terminology is true “on average over the model period” only.

Further, while a full description of scenarios and methodology are included in the 'Main Methodology Annex' of this work it is worth noting that two scenario families reported here. These include 'perfect foresight’ (PF) scenarios, in which the model is allowed some level of freedom to invest in an array of non-hydro alternatives while a certain level of capacity adjustments are made in parts of the hydro infrastructure. This PF scenarios setup allows the model to ‘anticipate’ climate change and – to some degree – adapt accordingly. The second set of families includes so called 'no adaptation' (NA) scenarios, in which climate change is not anticipated and electricity generation shortfalls are met with expensive back-up generators. Each family is run across the same set of selected climate futures. The 'historic' climate is one future based on historic trends.

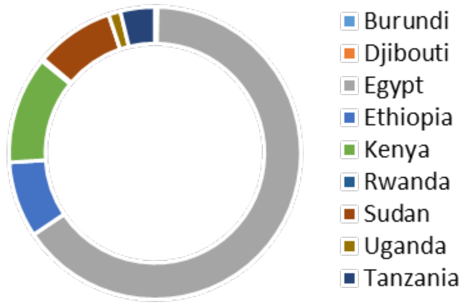
Large infrastructure investments are required to underpin future growth in Africa

Providing the growing demand requirements in the EAPP is a challenge for this developing region and stands to expand the existing system by an additional 390GW (incl. retirements) between 2015 and 2050 in the base scenario. Reaching a total installed capacity of 397GW by the end of the modelling period, this represents a fivefold increase as compared to current levels; a significant part of which will take place in Egypt – 72.02% of all new capacities – followed by smaller systems like Sudan –8.5% (see Table D-40). These figures also show that the smaller systems –including Burundi, Djibouti and Rwanda – remain small on a regional basis in terms of domestic capacity. From a national perspective relying on combinations of hydropower and imports (Burundi and Rwanda) or imports and domestic coal based capacity (Djibouti).

Table D-40: Cumulative New Capacity per country and Fuel Category – 2015 to 2050 - EAPP

	GW	%
Burundi	0.39	0.10%
Djibouti	0.49	0.12%
Egypt	284.00	72.07%
Ethiopia	28.59	7.25%
Kenya	31.32	7.95%
Rwanda	0.65	0.17%
Sudan	33.49	8.50%
Tanzania	11.31	2.87%
Uganda	3.83	0.97%
Total	**394.07**	

Figure D-32: Country share on Undiscounted Investments (2015-2050)



In investment terms, these new additions mean that the region has to consider an undiscounted cost over the period in excess of 868 Billion USD. In line with capacity data, Egypt represents 66% of this total expenditure. In terms of capacity, the main share of investments goes to gas based generation with 31.1% of expenditures, while remaining fuels share amounts relatively equally with shares between 11% and 15%. When including the cost of transmission and distribution system expansion, this total increases to 1,316 Billion USD

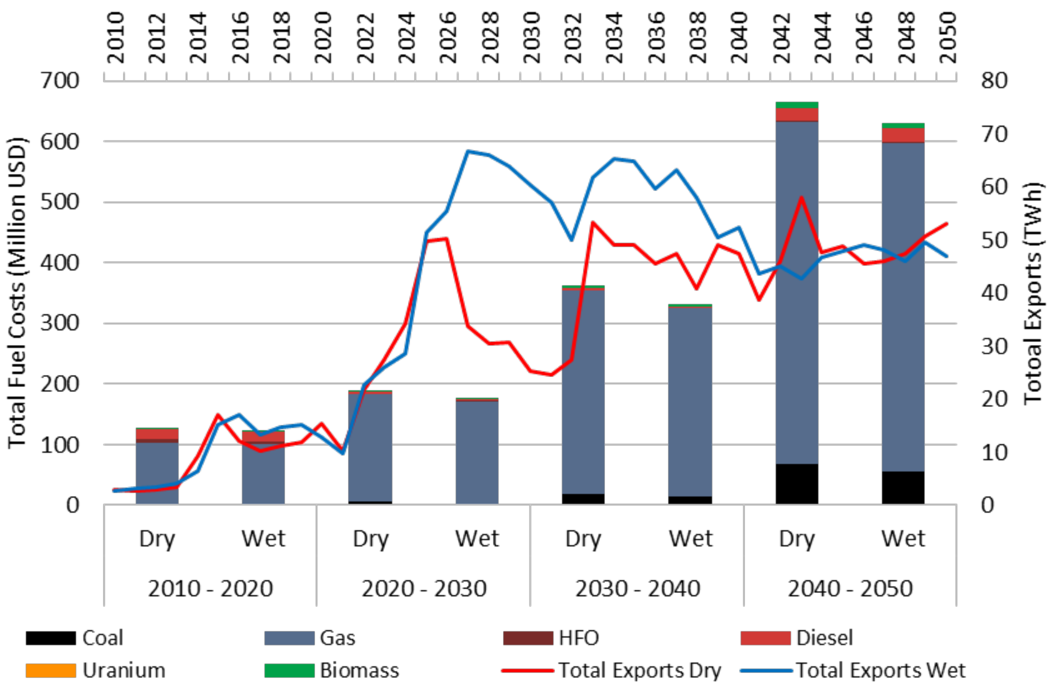
Trade is required to 'unleash' the potential of much low cost hydropower

In the scenarios analyzed for this exercise, neighboring countries within the EAPP are linked together by committed trade lines with different levels and connection coming in at different points in time over the modelling period. These lines allow for renewable resource re-allocation in a power pool heavily reliant on natural gas and coal based generation. Such dynamics are intricate and vary significantly from one year to the next as well as between scenarios depending on resource availability and with direct implications on the final unit cost of electricity generation.

The fuel cost expenditure related in

Figure *D-33* shows the variations in fuel use – and of the cost thereof – over successive modelling periods. The increase in natural gas based expenditure is explicit with maximum increases from one period to the next of 88% in the dry case and 83% in the wet case (both from period 2 to period 3) showing the importance of this fuel for the regional energy mix. Further, the reduction in expenditure from the wet to the dry scenarios over the entire period is minimal reaching a maximum of just 4.89% for gas and 1.82% for coal. The incursion of diesel at the end of the period is linked to water shortages in the region in both the dry and the wet cases.

Figure D-33: Total Electricity Exports vs. Total Fuel Expenditure



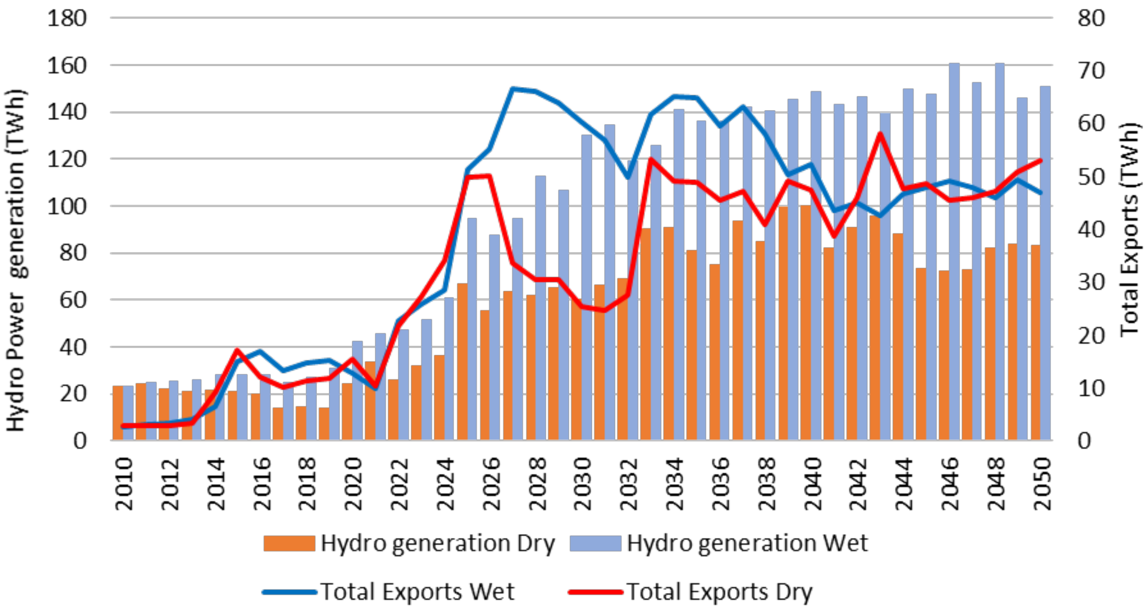
Going deeper into the analysis of the differences between the two climate export trends shows the direct relation these values have to local climate and water availability in the region; this relates to several simultaneous phenomena (see both

Figure *D-33* and Figure D-34):

- First, it appears that Ethiopia exports 55% more power in the wet case than in the dry. This power is exported to Sudan – a country that relies on natural gas for 87% of its domestic generation in 2050 and will use any cheaper import when available.
- Second, Tanzania has high inter year variations in domestic hydropower generation while also importing from Uganda (near 100% hydro based). Between 2024 and 2032, an exceptional high in water availability in the region means that enough power is available to transit through Tanzania to Kenya. This is additional to higher direct exports from Uganda to Kenya. The final impact represents a difference of 124TWh of net imports in Kenya replacing an energy mix largely based on coal.

Third, this difference appears less clear towards the end of the period with a counterintuitive "high" in exports under the dry scenario corresponding to a large drop in Tanzanian hydro generation having repercussions on exports Kenya, Uganda and Ethiopia to ensure that demand is met.

Figure D-34: Total Electricity Exports vs. Hydro Power Generation (TWh)



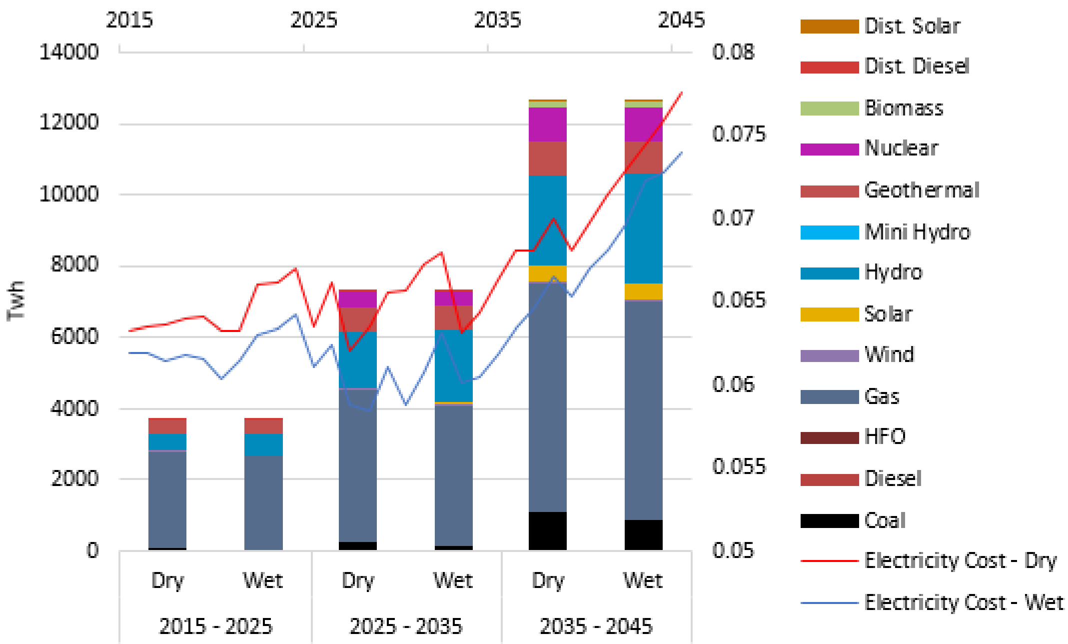
Adapting to climate change: the role of fossil fuels and non-hydro renewables

Climate change, in this exercise, can have both positive and negative impacts on a country relating specifically to the overall rainfall that can be expected over the study period. In both cases however it is challenging to predict the degree of these changes with any certainty. Further, it is changes in weather pattern as well as each patterns' intra & inter year variability that is cause for increased system costs (See main methodology clarifications relating to the Perfect Foresight Adaptation approach).

In dry cases, overall rainfall is lower than in the reference climate case and the variability of the climate means that large amounts of hydropower may be unavailable from one year to the next. In this situation, the overall system is impacted negatively: new investments in fossil based generation are required and in turn generate higher annual running costs. Similarly, wetter cases are expected to offer less stressing conditions both on national and regional levels through higher overall water availability. However variability from one year to the next will mean that unexpected shortages in hydro based generation will be replaced by fossil based generation.

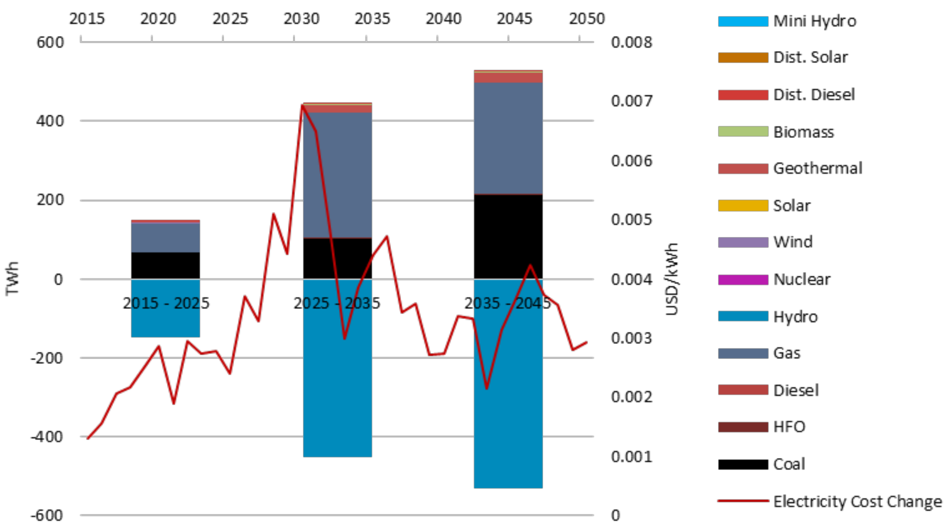
Considering Figure D-35, it is clear that the change in climate is correlated to the final unit cost of power in the region through the amount of available hydropower as well as through the alternative that is used to replace it should it not be available. The absolute difference between the two scenarios is low however and does not exceed 0.0069 USD/kWh over the study period (see Figure D-36). From a relative stand point, experiencing a dry instead of a wet climate will have but a small impact causing an increase in total expenditure on energy of just 4.6% (see paragraph Table D-41 hereafter).Finally, it appears that the overall cost of generation increases at a higher rate towards the end of the study period in relation to the relative increase in fossil fuel use in the system.

Figure D-35: Total Generation vs. Annualised cost of Electricity



Considering the potential trade-offs between the two extreme – dry and wet – climate cases under consideration in the EAPP shows that the more noticeable impacts occur in the second decade of the results. At this point, the reliance on hydro generation in the wet case has increased compared to the first few years of the simulation and would be replaced by larger investments in and use of both natural gas and coal based systems. This is also where the largest difference in cost to consumers between the two scenarios occurs. Finally, the "incursion" of hydropower in the wet case has the possibility of offsetting respectively 672TWh of gas 387TWh of coal and oil based generation.

Figure D-36: Relative range of Generation mix and Annualised cost change



The effect of Climate Change on electricity costs differs from country to country

The consumer perspective is a relevant one to follow when assessing the performance of the different adaptation strategies that were assessed under this project. With this in mind, Table D-41 lists the total national level electricity expenditure both indifferent scenarios and – under a given scenario – considering different adaptation strategies to the changing climate. Several inferences appear clearly:

- First, different countries stand to suffer different cost impacts of climate change even under perfect foresight adaptation. Burundi, for example, stands to have a near threefold increase in expenditure under a dry scenario as compared to a wet case, whereas for Egypt or Kenya the change respectively reaches just 2.4 % and 1% of total expenditure.
- Second, adaptation does not seem to achieve great cost reductions on a regional basis – saving only 17 Billion USD or 0.73% of total expenditure from the NA to the PF dry case – but can have extensive effects on a national basis for smaller and more hydro dependent systems saving up to 6.6% and 6.4% of the expenditure in Uganda and Burundi.

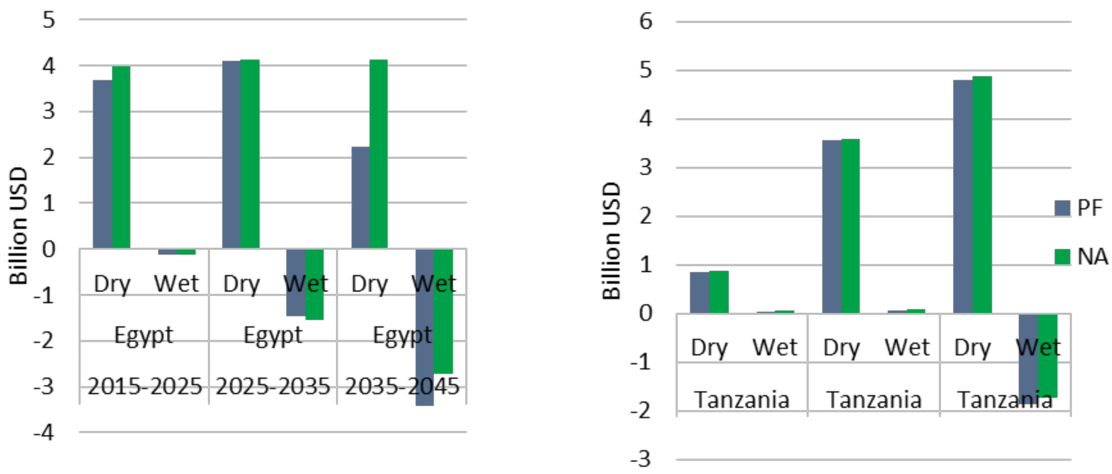
Table D-41: Consumer Expenditure on Electricity with and without PF (US$ Billion, 2015 to 2050)

EAPP 28	**No adaptation Sc.**		**PF adaptation Sc.**		**Robust adaptation, designed to minimize:**			
	No CC	**Driest**	**Wettest**	**Driest**	**Wettest**	**Max regret**	**90% highest regret**	**75% highest regret**	***River Basin***
BI	1.6	3.1	1.2	3.3	1.2	2.3	2.3	2.5	*Nile*
DJ	3.9	4.9	4.6	4.3	4.2	4.2	4.2	4.2	*Nile*
EG	1716.0	1732.0	1711.6	1729.0	1711.1	1715.2	1715.2	1714.9	*Nile*
ET	71.1	91.4	74.5	88.7	72.6	75.4	75.4	72.1	*Nile*
KE	180.0	185.0	177.8	181.9	177.5	178.7	178.7	178.9	*Nile*
RW	8.2	9.9	7.7	10.2	7.8	9.5	9.5	9.6	*Nile*
SD	306.6	317.1	270.3	309.8	269.7	284.7	284.7	290.0	*Nile*
TZ	70.1	86.4	66.6	85.5	66.4	68.4	68.4	71.5	*Nile*
UG	9.5	12.1	7.7	11.3	7.7	7.7	7.7	7.8	*Nile*
Total	2367.0	2441.7	2322.1	2423.9	2318.2	2346.0	2346.0	2351.4	

Illustrating the different levels of impact that exist across different countries, Table D-41shows the results in a graphic format – per period – for Egypt and Tanzania. In both cases, failing to adapt – i.e. choosing a NA case over a PF case in this methodology – has a small yet visible impact on the cost to consumers leading to an increase in relative costs of respectively 1.92 and 0.1 Billion USD for the two countries in a dry case scenario over the last ten year period alone. Further, this figure shows that adapting to climate change is near systematically an advantageous decision for countries that are either large systems or smaller ones with higher or lower amounts of available trade or hydro.

[28] BI: Burundi, DJ: Djibouti, EG: Egypt, ET: Ethiopia, KE: Kenia, RW: Rwanda, SD: Sudan, TZ: Tanzania, UG: Uganda

Figure D-37: Accumulated cost to consumer in different climate and foresight scenarios

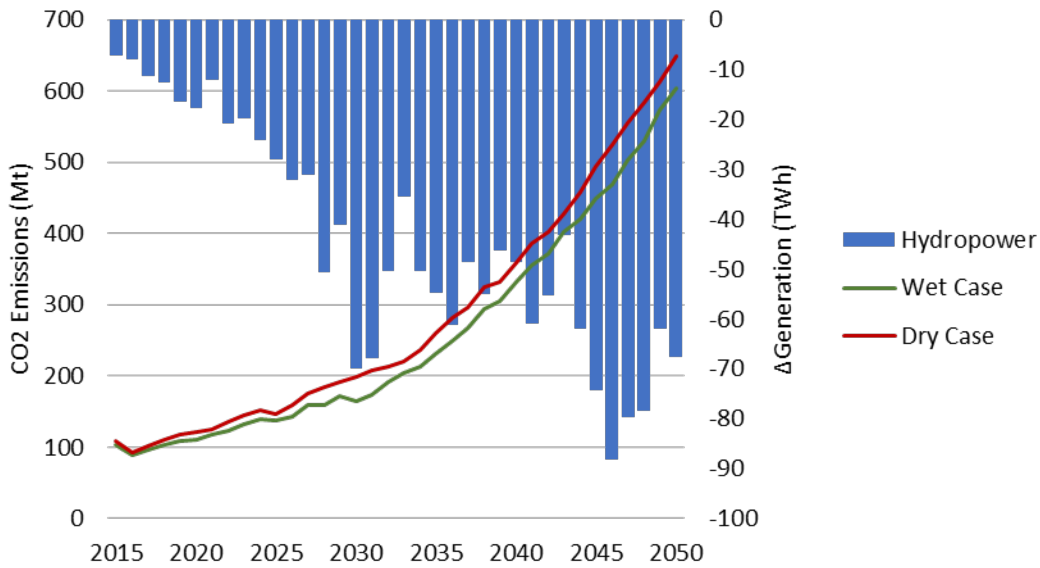


CO_2 emission levels differ between adaptation strategies

Through the different climate scenarios investigated in this exercise the modelling teams have subjected the regional infrastructure of the EAPP to varying levels of water availability for both energy and non-energy related applications. In the energy modelling framework, this variation translates into varying levels varying levels of installed hydro capacity between scenarios as well as varying power plant capacity factors within a given scenario. From an operational perspective, this means that dryer climate runs can be more affected by "sudden" drought years as well as overall lows in water levels for power generation thereby forcing the systems to increase their levels of fossil fuel use. This has a direct impact on levels of carbon dioxide emissions.

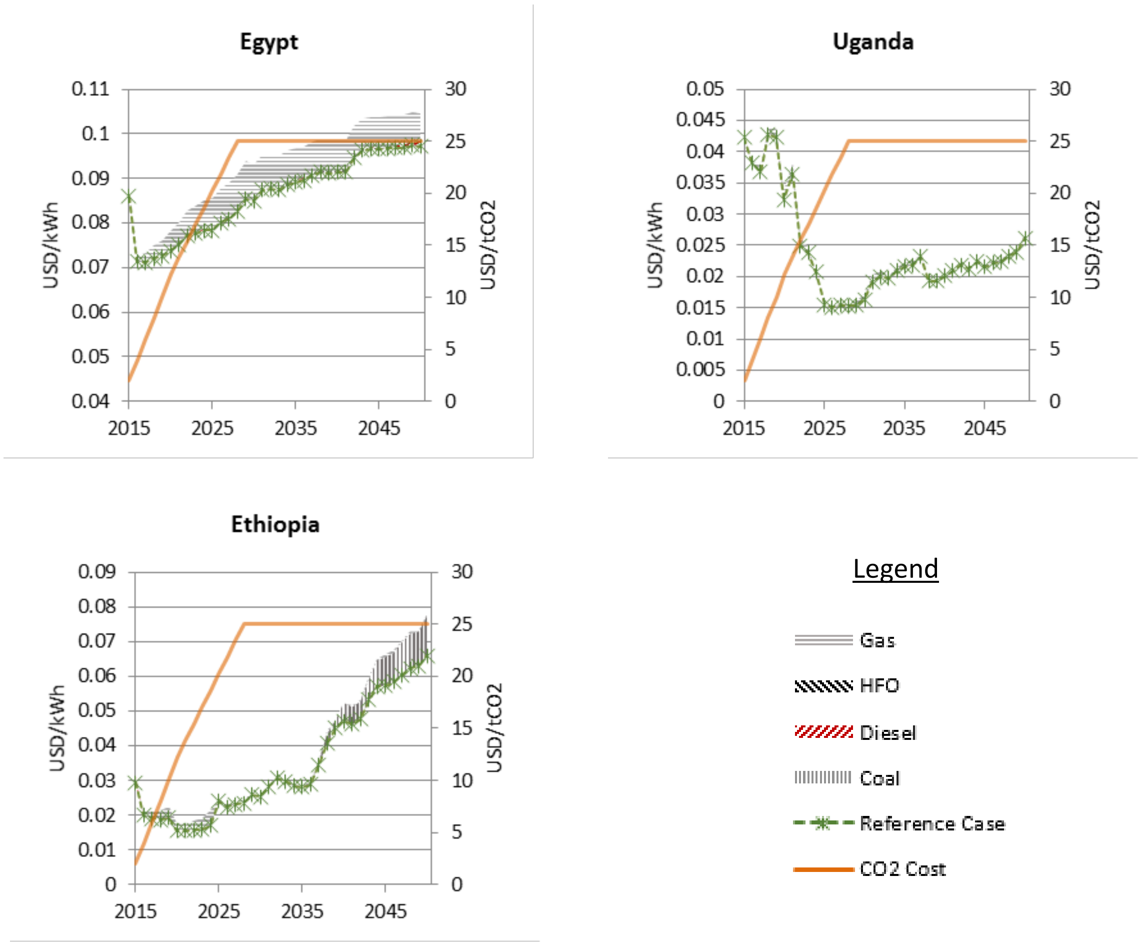
When comparing Figure D-38 to corresponding representations for the Western African power pool similar trends in both hydropower generation change and carbon dioxide emission levels are apparent. It is important to notice however that the overall magnitude of these emissions is three times larger in the EAPP than in the WAPP. From a regional perspective, the correlation noted in other regions between total power pool emissions the corresponding level of hydropower generated in the region remains visible: sudden offsets of potential hydropower between the dry and the wet scenario in 2030 have their parallel in lower CO_2 emissions for the same scenario. Overall however, it appears that the difference in terms of emissions from one climate change case to the next is negligible: over a period of 35 years from 2015 to 2050 the relative decrease in emissions "achieved" by experiencing a wetter rather than a dryer scenario does not exceed 8.6% (or 911 Mt CO_2).

Figure D-38: Regional GHG emission trends vs Relative Hydropower generation



From a country level perspective however these considerations regarding GHG emissions become more diverse. Investigating what these might mean for national level energy cost, it appears that different countries show different levels of resilience and stand to pay different penalty levels depending on their choice of power system structure. On the one hand, potentially stable countries from an energy perspective that rely on large amounts of fossil based generation are tied in to levels of emission that can cause noticeable changes in the final cost of power. Specifically, Egypt uses natural gas to generate 67% of its domestic power supply in 2050 and could expect energy prices to increase by up to 11% between 2015 and 2050. Conversely, Uganda is a seemingly less stable country from a cost perspective: it shows high intra year variability due to its changing levels of hydro power generation complemented by small amounts of fossil fuel use making up the corresponding shortfalls. Ensuing emission levels are however extremely low making the country relatively more resilient than its much larger counterpart from a cost of electricity generation perspective.

Figure D-39: Impact of CO_2 emissions costing on the price of energy to consumers[29]



Choosing to adapt is a "low regret" decision

Referring to Figure D-40, the incremental cost to consumers of the different strategies for countries that have either higher or lower vulnerability levels to climate change is visible. Please note that figures are presented here for a Dry scenario. Visualizing the marginal increase in cost that each scenario has on its "predecessor", this graphic shows the difference between having a reactive attitude to the impacts of climate change – materialized by the high annual changes in the level of the lighter "no adaptation" color – and following a given strategy, albeit flawed, to attempt to anticipate the adverse effects of these future changes. It also highlights the extra cost that cannot be avoided

In a similar way to what was noted for the other power pools, this "worst case scenario" delivers several messages:

- First, that there often circumstances – i.e. given years – in which each country might benefit from using some level of foresight to develop an adaptation strategy for its energy system. In

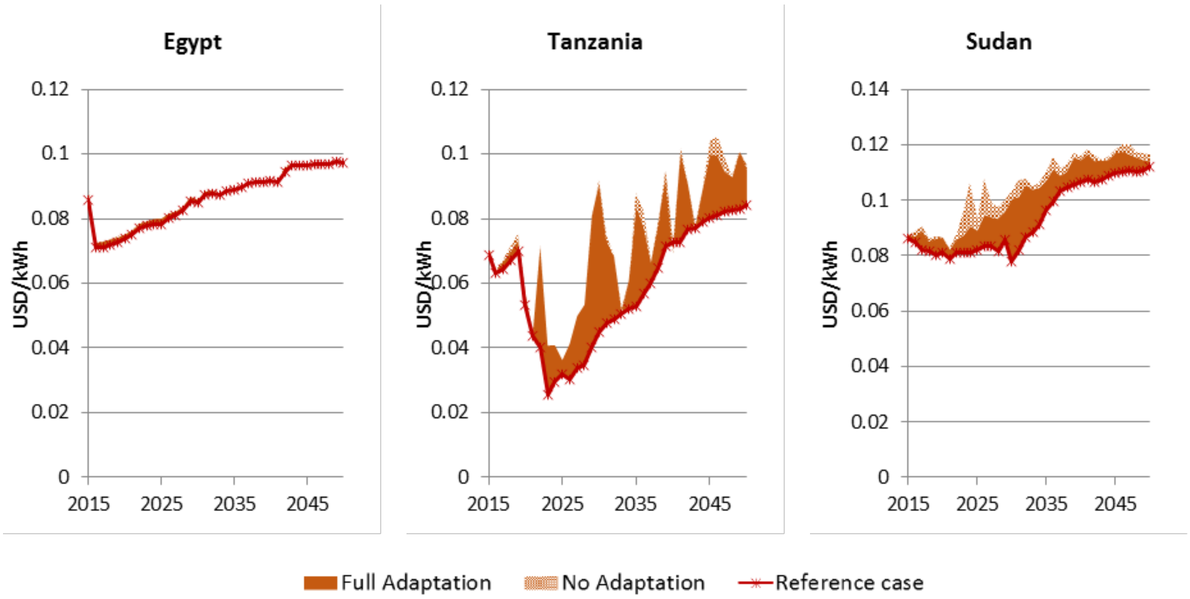
[29] Please note: these figures show the additional cost of applying a selected cost of carbon dioxide emissions – shown by the orange line – as a post treatment step to sets of results obtained from models. Accordingly the models do not attempt to reduce emissions and mitigate those costs, i.e. these additional costs are not included in the models' objective function. The graphs are used simply to illustrate potential consequences of fossil based generation systems in a region as well as the variability of these consequences from one country to the next.

fact, in the case of Egypt, it even costs little more than it does in the base scenario to adapt. In most cases though, the cost to consumers will nearly inevitably and invariably be higher than in baseline case where climate is assumed to follow historic trends, there is potential to reduce the overall impact of these problematic "future climate pathways".

- Second, the impacts are more visible on a national level: previous aggregations on a power pool level drown most of the variability and reflect the characteristics of the dominant countries to the region before those of smaller systems. This national representation shows impacts on potentially more vulnerable and fluctuating systems.
- Finally, certain countries with low energy prices but high reliance on hydropower stand to suffer significantly from "drought year" effects forcing the system to use costly and expensive stop gap fossil based systems. The specific case here is Tanzania where prices can be seen to double from one period to the next.

Unlike other power pools however, the examples of countries where adaptation offers a very significant saving as compared to the NA cases are few. Although it is near always cheaper to adapt, the low margin that it offers would seem to indicate that changes in climate in the future climate – at least within those that were assessed under this exercise – will not be significant enough to make adaptation indispensable.

Figure D-40 :Cumulative impacts of CC to consumer cost of electricity – Dry case



Conclusions and Recommendations

Climate change is a complex and diverse phenomenon the effects of which are neither yet agreed upon nor fully understood. In such a context, the present work is a leading attempt to ensure that – notwithstanding the arguably low degree of certainty that affects the data upon which investment decisions need to be made – the different actors of an integrated water and energy system may have a better understanding of the implications inherent to different available courses of action.

From an overall perspective on this specific approach, it is important to consider results on a multitude of levels: countries are aggregated into Power Pools that are interconnected by varying levels of trade, each country and each power pool are linked to one or several of the river basins that are analyzed as separate entities in the water modelling framework etc. This means that although all results can be extracted on all levels of this analysis they are not totally independent one from the other. Adaptation to climate change is also a complex question. The scenarios under analysis have shown that, in most situations, there is a clear – albeit potentially small in best case scenarios – incentive to adapting.

From a regional perspective in the EAPP however, the current results show a system that is relatively less affected by climate change than its neighboring regions even though they do share consistent result dynamics that confirm the impacts to be expected from different trends. The EAPP is a resource rich region that makes good use of its fossil reserves with small incursions of hydropower, and other renewables. On a national scale, the picture is more diverse with high dependencies on hydropower, geothermal generation, and significant levels of trade that play a key role in ensuring power supply in dry year situations.

From a unit cost of generation perspective, the impact of changing climate on the absolute expenditure by consumers is significant when compared to a base case scenario. The same comparison however between different adaptation strategies for a given climate does not have the same significance. Nevertheless, adaptation as a policy choice remains – in a vast majority of cases – the cheaper option. This situation may be nuanced however by the introduction of a carbon costing scheme which has the potential to increase the cost of power generated with fossil fuels and traded as support to smaller systems with less stability of supply. Trade with the DRC however may dampen this effect to some level through small infections of power into the southern area of the power pool region.

Limitations and next steps

In addition to general methodology and overall project limitations described in the general assumptions text, the following bullets might advantageously outline areas of future work that would improve either the applicability or quality of the results discussed above. Such areas are listed below:

- Further scenarios development: specifically with respect to trade in the region. As an important lever for stability of supply and renewable resource dissemination, it would be advantageous for individual projects to be evaluated more specifically or for general “corridors” for energy transmission to be assessed both within and between power pools.
- Higher focus on security of supply: in particular investigating the cost benefit analyses of such issues when balanced with their cost trade-offs and implications.
- “Endoginizing” carbon costing into the optimization: this element being thus far taken as a post treatment calculation foes not influence the choice of one technology over another in the present exercise. It would be of interest however to include a representation of different “carbon financing” schemes into the current setup in order to assess their potential impact of different countries and power pools.
- Increasing levels of interaction with the power pool authorities: achieving their integration on a procedural level would greatly benefit such projects by increasing data accuracy and output applicability, but also through their potential inclusion into capacity building activities in the context of iterative and improved PP planning processes.
- Bridging potential gaps in the analysis toolbox to inform relations between national and power pool level systems: such applications may be of specific interest when considering shared planning activities on a project level.
- Investigating the potentials for the power pools to promote clean energy use and assess the corresponding clean energy scenarios.
- Investigating implications of financing limits. Power system investments are significant, but so too are other investment needs in the economy. If finance to power investments crowds out opportunities to invest in other projects, or access to finance is simply limited, scenarios to investigate these constraints may provide important insights.
- Improve the load region definition by detailing individual country load data. This would not increase the complexity of the model however may have a marginal impact of specific time-slices where trade occurs: if two neighboring countries have their peak demand occurring at during different time-slices there is a potential for higher trade efficiency and lower installed capacity levels on a regional basis. This data however is both sensitive in nature from a utility’s perspective and thus far unavailable for many countries as part of public energy data bases.

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Table D-42: Final Energy Demand per sector [GWh]

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Burundi																					
Industrial	10.0	11.6	13.2	17.1	21.5	26.5	32.3	39.0	46.5	54.9	64.4	74.7	86.5	99.6	114.0	130.1	147.6	166.6	187.3	209.8	233.6
Rural	1.2	1.4	1.6	2.1	2.7	3.3	4.1	5.0	5.9	7.0	8.3	9.7	11.2	13.0	14.9	17.0	19.4	21.9	24.7	27.7	30.9
Urban	81.9	86.0	89.2	105.9	122.9	140.3	158.7	178.3	198.6	219.5	241.6	263.8	287.8	312.9	338.6	366.1	393.5	421.4	450.3	479.4	508.1
Djibouti																					
Industrial	33.7	43.1	57.8	74.0	89.3	103.1	118.0	129.1	140.9	152.2	163.9	175.1	186.8	198.8	211.4	224.3	237.5	251.3	265.5	280.2	295.4
Rural	4.0	5.2	7.1	9.1	11.1	12.9	14.9	16.4	18.0	19.5	21.1	22.6	24.2	25.9	27.6	29.3	31.2	33.0	35.0	37.0	39.1
Urban	277.0	320.4	391.5	459.5	510.6	544.8	579.0	590.3	601.8	608.8	615.5	618.4	621.8	624.8	628.1	630.9	633.3	635.8	638.0	640.4	642.4
DRC*																					
Industrial	3.9	4.4	5.0	5.6	6.3	7.0	7.9	8.8	9.9	11.0	12.3	13.4	14.6	15.9	17.3	18.7	19.9	21.3	22.8	24.3	26.0
Rural	0.1	0.2	0.2	0.2	0.3	0.3	0.4	0.5	0.6	0.7	0.8	0.8	0.9	1.0	1.0	1.1	1.2	1.3	1.3	1.4	1.5
Urban	3.5	3.7	3.9	4.1	4.3	4.5	4.7	4.9	5.0	5.1	5.2	5.5	5.9	6.3	6.7	7.0	7.3	7.6	8.0	8.3	8.6
Egypt*																					
Industrial	70.4	70.4	73.4	76.4	79.6	82.9	86.4	91.6	97.3	103.0	108.9	115.2	121.8	128.8	136.1	144.3	152.9	161.9	171.4	181.5	192.1
Rural	28.4	28.4	29.6	30.8	32.1	33.4	34.9	36.9	39.2	41.5	43.9	46.5	49.1	51.9	54.9	58.2	61.6	65.3	69.1	73.2	77.4
Urban	28.4	28.4	29.6	30.9	32.2	33.5	34.9	37.0	39.3	41.6	44.0	46.6	49.2	52.0	55.0	58.3	61.8	65.4	69.3	73.3	77.6
Eritrea																					
Industrial	13.9	19.0	25.0	32.3	40.6	49.9	60.6	72.2	85.0	98.7	113.6	130.8	149.1	169.5	191.9	216.1	242.1	270.1	301.1	334.2	369.6
Rural	3.4	4.2	5.2	6.3	7.5	8.9	10.4	12.1	13.9	15.8	17.9	20.2	22.7	25.5	28.5	31.8	35.2	38.9	43.1	47.4	52.1
Urban	252.4	277.4	303.5	335.2	365.8	396.2	428.6	459.2	489.3	517.6	546.0	578.5	609.0	641.8	675.4	709.1	742.5	775.5	811.1	845.8	880.3
Ethiopia*																					
Industrial	0.2	0.3	0.5	0.6	0.8	1.0	1.2	1.4	1.7	2.0	2.4	2.8	3.2	3.7	4.2	4.8	5.5	6.2	7.1	8.0	8.6
Rural	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.3	0.3	0.4	0.4	0.5	0.6	0.6	0.7	0.8	0.9	1.0	1.1	1.3
Urban	4.8	5.3	5.9	6.5	7.2	8.0	8.7	9.5	10.2	11.0	11.8	12.5	13.4	14.2	15.1	16.1	17.1	18.1	19.2	20.4	22.0
Kenya*																					
Industrial	0.6	0.8	1.0	1.2	1.5	1.9	2.2	2.5	2.9	3.3	3.8	4.4	4.9	5.6	6.4	7.2	8.2	9.2	10.3	11.5	12.9
Rural	0.1	0.1	0.1	0.2	0.2	0.3	0.3	0.4	0.4	0.5	0.5	0.6	0.7	0.8	0.9	1.0	1.1	1.2	1.4	1.6	1.7
Urban	6.8	7.5	8.2	9.1	10.3	11.4	12.2	13.0	13.8	14.6	15.5	17.0	17.8	18.9	20.2	21.6	22.9	24.3	25.8	27.4	29.1
Rwanda																					
Industrial	28.6	37.3	46.6	57.3	68.9	81.3	98.8	118.0	138.6	160.8	184.5	215.7	249.2	284.7	322.5	362.3	409.0	458.0	511.1	568.1	629.1
Rural	3.4	4.5	5.7	7.1	8.6	10.2	12.5	15.0	17.7	20.6	23.8	27.9	32.3	37.0	42.1	47.4	53.7	60.2	67.4	75.0	83.2
Urban	234.7	277.4	315.6	355.5	393.6	430.0	485.0	539.5	592.0	643.2	692.7	761.9	829.6	894.5	958.1	1019.0	1090.5	1158.8	1228.5	1298.3	1368.2
Somalia																					
Industrial	35.0	42.6	51.2	61.8	73.3	85.9	100.2	115.5	131.9	149.2	168.0	189.5	212.1	237.1	264.4	293.8	325.2	358.6	395.7	434.9	476.7
Rural	4.2	5.1	6.2	7.6	9.1	10.8	12.6	14.7	16.8	19.1	21.6	24.5	27.5	30.9	34.5	38.4	42.7	47.2	52.1	57.4	63.1
Urban	287.5	316.3	346.5	383.3	418.7	454.2	492.0	527.9	563.4	596.9	630.6	669.3	705.9	745.2	785.6	826.3	867.0	907.3	951.0	993.8	1036.7
Sudan*																					
Industrial	1.0	1.3	1.5	1.8	2.1	2.5	2.9	3.4	3.9	4.5	5.1	5.9	6.7	7.6	8.6	9.7	10.9	12.1	13.6	15.2	16.8
Rural	0.1	0.1	0.1	0.1	0.2	0.2	0.3	0.3	0.4	0.5	0.5	0.6	0.7	0.8	1.0	1.1	1.3	1.4	1.6	1.8	2.1
Urban	4.6	5.3	6.0	6.8	7.7	8.6	9.7	10.8	11.9	13.2	14.5	15.9	17.4	19.0	20.8	22.6	24.5	26.2	28.4	30.4	32.5
Tanzania*																					
Industrial	0.7	0.8	1.0	1.1	1.3	1.4	1.7	1.9	2.1	2.3	2.5	2.8	3.0	3.4	3.7	4.0	4.4	4.7	5.2	5.6	6.1
Rural	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.3	0.3	0.3	0.4	0.4	0.5	0.5	0.6	0.6	0.7	0.8
Urban	3.5	3.8	4.2	4.7	4.9	5.3	5.8	6.4	6.8	7.1	7.5	7.9	8.2	8.7	9.1	9.6	10.0	10.5	11.0	11.5	12.0
Uganda																					
Industrial	262.1	308.2	355.5	408.7	470.0	536.5	607.9	686.6	773.0	860.8	948.4	1055.3	1178.2	1309.2	1449.1	1597.0	1750.9	1913.7	2085.6	2266.8	2456.6
Rural	31.1	37.1	43.4	50.4	58.5	67.2	76.7	87.1	98.6	110.4	122.1	136.4	152.8	170.3	189.1	209.0	229.7	251.6	274.8	299.3	325.0
Urban	2152.4	2290.9	2407.3	2536.4	2686.3	2836.2	2983.6	3138.7	3301.0	3442.9	3561.0	3727.3	3922.0	4114.0	4305.2	4491.9	4668.2	4842.1	5012.7	5180.4	5342.5

	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Burundi																				
Industrial	259.5	287.6	317.3	348.8	382.8	419.2	457.8	497.7	541.0	586.5	619.3	653.1	687.9	723.5	760.1	797.7	836.2	875.6	915.9	957.2
Rural	38.2	46.5	55.5	65.4	76.3	88.3	101.3	115.1	130.3	146.6	154.8	163.3	172.0	180.9	190.0	199.4	209.0	218.9	229.0	239.3
Urban	533.7	559.3	583.9	607.4	630.9	653.9	675.8	695.3	715.0	733.1	774.2	816.4	859.8	904.4	950.2	997.1	1045.2	1094.4	1144.9	1196.5
Djibouti																				
Industrial	310.9	326.8	343.3	360.3	377.9	395.9	414.4	433.3	448.8	467.5	475.0	482.5	490.1	497.6	505.1	512.6	520.1	527.6	535.1	542.7
Rural	45.8	52.8	60.0	67.5	75.3	83.4	91.7	100.2	108.1	116.9	118.8	120.6	122.5	124.4	126.3	128.2	130.0	131.9	133.8	135.7
Urban	639.2	635.5	631.8	627.4	622.8	617.6	611.8	605.3	593.1	584.4	593.8	603.2	612.6	622.0	631.4	640.8	650.1	659.5	668.9	678.3
DRC*																				
Industrial	27.6	28.4	29.2	30.1	30.9	31.7	32.5	33.4	34.2	35.0	35.1	35.3	35.4	35.5	35.6	35.7	35.8	36.0	36.1	36.2
Rural	1.6	1.6	1.7	1.7	1.8	1.8	1.9	1.9	2.0	2.0	2.0	2.0	2.0	2.0	2.1	2.1	2.1	2.1	2.1	2.1
Urban	9.2	9.4	9.7	10.0	10.3	10.5	10.8	11.1	11.4	11.6	11.7	11.7	11.7	11.8	11.8	11.9	11.9	11.9	12.0	12.0
Egypt*																				
Industrial	203.4	215.5	228.3	241.8	256.3	271.9	288.4	306.0	324.7	344.6	365.1	386.8	409.6	433.8	459.2	486.2	514.7	544.5	575.6	608.2
Rural	82.0	86.9	92.0	97.5	103.3	109.6	116.3	123.4	130.9	138.9	147.2	155.9	165.2	174.9	185.1	196.0	207.5	219.5	232.1	245.2
Urban	82.2	87.1	92.2	97.7	103.5	109.8	116.5	123.6	131.2	139.2	147.5	156.3	165.5	175.2	185.5	196.4	207.9	220.0	232.6	245.7
Eritrea																				
Industrial	407.7	448.8	493.3	540.8	591.9	646.7	705.4	767.8	834.6	905.9	954.0	1004.1	1056.3	1110.5	1166.8	1225.4	1286.2	1349.4	1415.1	1483.2
Rural	63.5	76.0	89.8	104.8	121.2	139.0	158.4	179.3	202.0	226.5	238.5	251.0	264.1	277.6	291.7	306.3	321.6	337.4	353.8	370.8
Urban	908.6	936.6	964.7	991.5	1017.9	1043.5	1068.0	1090.7	1112.3	1132.3	1192.5	1255.2	1320.3	1388.1	1458.5	1531.7	1607.8	1686.8	1768.8	1854.0
Ethiopia*																				
Industrial	9.3	10.0	10.9	11.7	12.7	13.7	14.8	16.0	15.9	25.6	27.6	29.7	32.0	34.4	37.0	39.7	42.6	45.6	48.8	52.2
Rural	1.6	1.9	2.3	2.8	3.3	3.9	4.5	5.2	5.6	6.4	6.9	7.4	8.0	8.6	9.2	9.9	10.6	11.4	12.2	13.0
Urban	23.6	25.3	27.1	29.0	31.1	33.3	35.7	38.2	37.9	32.0	34.5	37.2	40.0	43.0	46.2	49.6	53.2	57.0	61.0	65.2
Kenya*																				
Industrial	14.4	16.0	17.8	19.7	21.8	24.1	26.6	29.3	30.3	33.3	35.8	38.3	41.1	44.0	47.0	50.3	53.7	57.3	61.1	65.1
Rural	2.2	2.6	3.2	3.7	4.4	5.1	5.9	6.8	7.3	8.3	8.9	9.6	10.3	11.0	11.8	12.6	13.4	14.3	15.3	16.3
Urban	30.5	31.9	33.4	35.0	36.5	38.1	39.6	41.1	40.1	41.7	44.7	47.9	51.3	55.0	58.8	62.8	67.1	71.6	76.3	81.3
Rwanda																				
Industrial	694.9	765.2	840.2	919.8	1004.6	1094.5	1189.8	1290.5	1325.5	1437.3	1518.9	1603.4	1691.0	1781.7	1875.5	1972.6	2073.0	2176.6	2283.7	2394.3
Rural	102.4	123.6	146.9	172.4	200.2	230.5	263.2	298.5	319.3	359.3	379.7	400.9	422.8	445.4	468.9	493.2	518.2	544.2	570.9	598.6
Urban	1428.9	1488.3	1546.1	1601.8	1655.7	1707.4	1756.5	1802.8	1751.8	1796.6	1898.6	2004.3	2113.8	2227.1	2344.4	2465.8	2591.2	2720.8	2854.7	2992.9
Somalia																				
Industrial	521.5	569.6	621.6	676.7	736.0	799.4	867.1	938.7	1015.3	1096.8	1155.1	1215.8	1278.9	1344.5	1412.7	1483.6	1557.3	1633.8	1713.3	1795.8
Rural	76.8	92.0	108.7	126.9	146.7	168.3	191.8	217.1	244.6	274.2	288.8	303.9	319.7	336.1	353.2	370.9	389.3	408.5	428.3	449.0
Urban	1072.2	1107.8	1143.8	1178.5	1213.1	1247.0	1280.0	1311.4	1341.9	1370.9	1443.9	1519.7	1598.6	1680.6	1765.9	1854.5	1946.6	2042.3	2141.6	2244.8
Sudan*																				
Industrial	18.6	20.6	22.7	24.9	27.3	29.9	32.6	35.6	36.4	39.6	42.4	45.2	48.2	51.4	54.7	58.1	61.7	65.4	69.3	73.4
Rural	2.6	3.1	3.8	4.5	5.3	6.1	7.1	8.1	8.7	9.9	10.6	11.3	12.1	12.8	13.7	14.5	15.4	16.4	17.3	18.3
Urban	34.5	36.5	38.5	40.5	42.5	44.5	46.6	48.6	47.5	49.6	53.0	56.5	60.3	64.2	68.3	72.6	77.1	81.8	86.6	91.7
Tanzania*																				
Industrial	6.6	7.2	7.9	8.6	9.4	10.3	11.3	12.3	12.6	13.8	14.8	15.9	17.1	18.3	19.7	21.1	22.7	24.3	26.1	28.0
Rural	0.9	1.1	1.3	1.6	1.8	2.1	2.4	2.8	3.0	3.4	3.7	4.0	4.3	4.6	4.9	5.3	5.7	6.1	6.5	7.0
Urban	12.5	13.0	13.6	14.1	14.8	15.4	16.1	16.9	16.5	17.2	18.5	19.9	21.3	22.9	24.6	26.4	28.4	30.4	32.6	34.9
Uganda																				
Industrial	2656.0	2865.1	3083.9	3312.1	3551.1	3800.5	4060.5	4321.0	4503.5	4830.8	5055.5	5290.8	5537.0	5794.6	6064.2	6346.1	6640.9	6949.0	7270.8	7606.9
Rural	391.4	462.8	539.3	620.8	707.8	800.2	898.1	999.4	1084.8	1207.7	1263.9	1322.7	1384.2	1448.7	1516.0	1586.5	1660.2	1737.2	1817.7	1901.7
Urban	5461.4	5572.5	5675.0	5767.7	5852.6	5928.4	5994.4	6036.3	5952.0	6038.5	6319.4	6613.4	6921.2	7243.3	7580.2	7932.6	8301.1	8686.2	9088.5	9508.7

**Demands listed in TWh for legibility reasons*

D4- The Western African Power Pool: Energy Modeling Assumptions, Data and Results

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Introduction: The Western African Power Pool

The Western African Power Pool (WAPP) is an institution of the Economic Community of West African States (ECOWAS) in existence since their 22nd Heads of State and Government Submit in 2000. It has since been mandated by its fourteen member states – including Benin, Côte d'Ivoire, Burkina Faso, Ghana, Gambia, Guinea, Guinea Bissau, Liberia, Mali, Niger, Nigeria, Senegal, Sierra Leone and Togo – to support reliability, adequacy, integration and mutual support of the regional power grid with the goal of fostering a Regional Electricity Market ("West African Power Pool," 2014).

From a regional perspective the countries of the WAPP share a number of challenges in the future although they represent a diverse sub-group of Sub Saharan Africa. From an economic perspective, the International Monetary Fund classifies all ECOWAS countries as Emerging and Developing Countries. Further, the World Bank classifies all WAPP countries as low income (Lee and Leal, 2014). Correspondently HDI values for the power pool lie between lows of 0.337 (Niger) and 0.573 (Ghana) in 2013 setting all but Ghana in the Low Development Category. From an evolution point of view however, country level HDI index values are growing at different rates with increases as high as 23.1% (Liberia) and as low as 2.3% (Guinea-Bissau) – with most countries clustered between 6% and 13% – compared to 2005 values (UNDP, 2014).

With an average access to electricity barely exceeding 43% and ranging from as low as 28.2% in Benin and Togo to as high as 72% in Ghana in 2011, disparity and inadequacy of the region's energy infrastructure are important challenges that need to be faced in order to provide for the 129 million people still without electricity in the region (IEA, 2013a). Currently, the region has a total installed capacity of 13.13 GW split between fossil based thermal generation – mainly diesel and natural gas based systems – and hydro power for approximately a 2/3rd to 1/3rd share respectively. (Miketa and Merven, 2013).

In order to answer part of this challenge in the future, the region has committed capacity installations totaling 3.403 GW by 2016. Considering Table D-43 shows that the main part of these capacity additions are expected to take place in Nigeria – totaling 59% of installations with 2.027 GW – followed by the Côte d'Ivoire, Ghana and Guinea – respectively with 12.9%, 7.1% and 12.8 %.

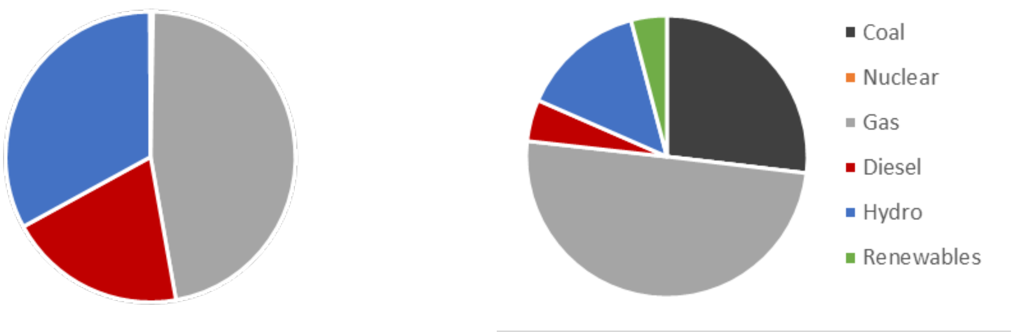
Table D-43: WAPP Committed Capacity – 2013 to 2016 [MW]

Country	2013	2014	2015	2016	Total
Burkina Faso	0	0	0	0	0
Benin	80	0	0	0	80
Côte d'Ivoire	110	0	220	110	440
Ghana	0	0	242	0	242
Gambia	0	0	0	0	0
Guinea	0	0	368	0	368
Guinea-Bissau	0	0	0	0	0
Liberia	0	0	66	0	66
Mali	0	90	0	0	90
Niger	0	0	0	0	0
Nigeria	1337.4	0	360	330	2027.4
Sierra Leone	0	0	40	0	40
Senegal	0	50	0	0	50
Togo	0	0	0	0	0
Total	1527.4	140	1296	440	

Source:(UDI PLATTS, 2012) (Miketa and Merven, 2013)

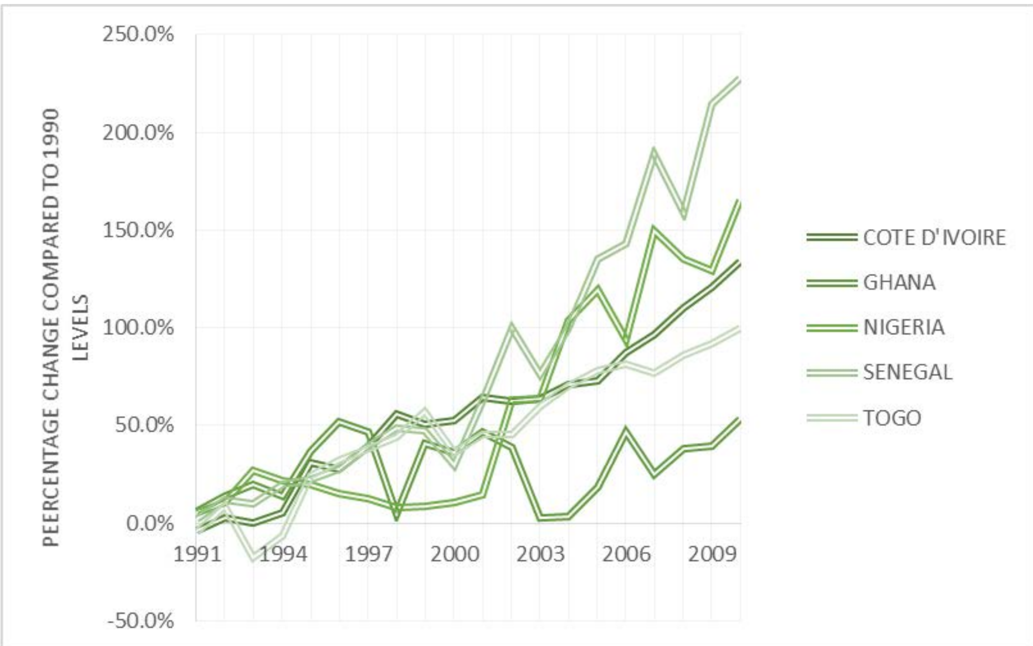
Although not available for all countries, international records show final consumption of electricity growing steadily over the second half of the twentieth century. Considering Figure D-42, showing relative country demand on a yearly basis as compared to 1990 levels for selected countries, demand for electricity has invariably increased in the region. Although unsteady, levels in 2010 range between 53% in Ghana and over 100% in Nigeria and Senegal when compared to the values twenty years prior in 1990 (IEA, 2013a). Corresponding available data for per capita consumption shows that the WAPP remains far below current industrialized country levels: comparison on the basis of available country data for the power pool show 2010 levels of around 210 kWh per capita, over thirty times lower than current EU data averaging at 6598 kWh per capita.

Figure D-41: Existing (left) and Planned Capacity (right) – share per fuel



Looking forward to the end of the study period, these demands are expected to increase at a faster rate reaching 292 thousand TWh by 2050 – i.e. yet another eightfold increase as compared to 2010 levels.

Figure D-42: Final Energy Consumption - relative increase for selected countries

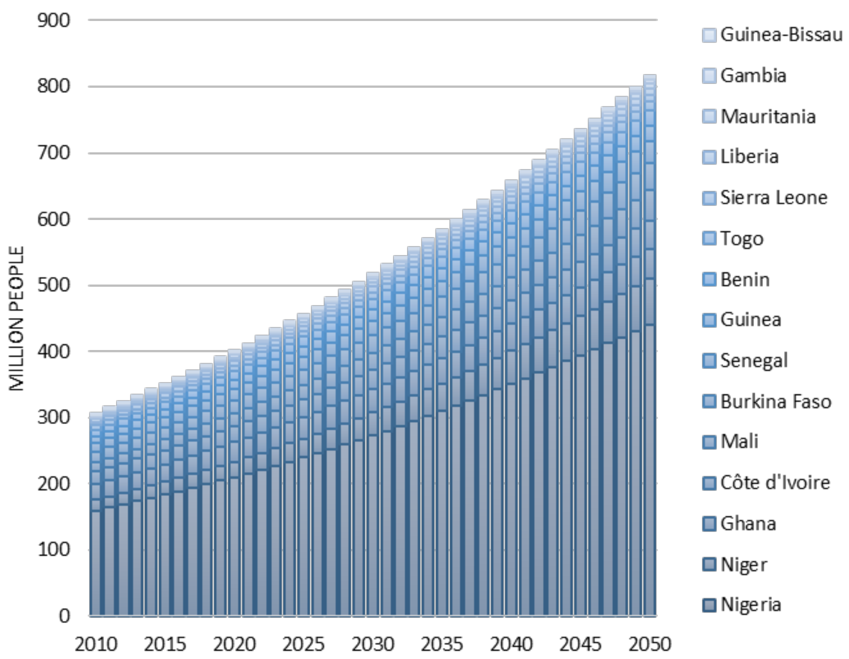


<u>Source</u>: (IEA, 2013b)

From an economic perspective, the inadequacy of the system is a significant hindrance to growth and stands for shares of losses in sales revenues varying between 5 and 14% relating directly to power outages in the country (World Bank, 2014). Further, challenges exist in the ECOWAS countries with respect to the GDP energy intensity of the region. Comparisons made in 2012 by the ECOWAS *Centre for Renewable Energy and Energy Efficiency (ECREEE) show that the region has both a relatively high energy intensity value – 0.56 ktoe/Million USD in 2009 translating a relatively inefficient system compared to similar data for Latin America or China respectively with 0.13 and 0.46 ktoe/Million USD – and a low improvement rate for this ratio over the past years – less than 1% improvement per year since 1980 when excluding Nigeria translating very slow improvements to the energy efficiency in the area.* (ECREEE, 2012).

Recent estimates of population increase in the region have shown consistent growth rates for all continental countries typically ranging from 1.5% to 4% between 1990 and 2010. Corresponding medium fertility projections for the same region show no signs of reduced growth before 2020 with a global "WAPP Region" growth rate expected at 2,58% and dominated by Nigeria and Mali respectively with 3.9% and 3.16% between 2020-2025. As a consequence, population in the region is expected to near double – 160% increase – by 2050, Nigeria standing for 55.1% of additional population in 2050 as compared to 2010 levels (See Figure D-43).

Figure D-43: Regional Population – WAPP



From an energy system perspective, the WAPP is structured in a similar way to the Southern African Power Pool – in so much as one country largely dominates the others in terms of energy systems metrics – but is a smaller overall system with a total installed capacity just shy of 35 GW in 2050.

WAPP Specific Assumptions and Data Tables

Energy Demands

Final electricity consumption in the region varies from one country to the next with high disparities between different countries within the power pool. These however are less remarkable than in the case of the Southern Power Pool where RSA was clearly the only large demand. In the present case, Nigeria is both the largest the fastest growing demand in the region followed Ghana and Côte d'Ivoire. Respectively, these three countries are responsible for 59.3%, 18.8% and 7.5% of total demand in 2050 totaling 440TWh. After an initial high of 8.2%, the five year average growth rate of demand on a regional level remains within a more reasonable range of 4 to 5%.

In this modelling exercise, the total final consumption of electricity is further split between three sectors. Shown in Figure D-45,this data mirrors the significant urbanization of populations in Western Africa: by the end of the study period the regional urban, industrial and rural demands are expected to stand for respectively 49.4%, 43.4% and 7.2% of total final consumption.

Figure D-44: Total WAPP Energy demand per country

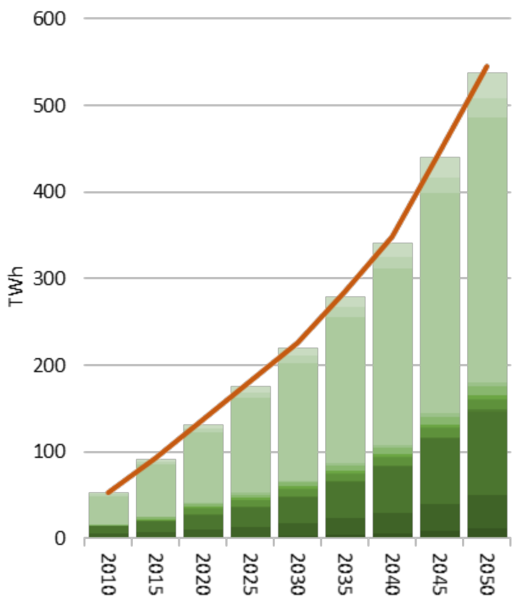
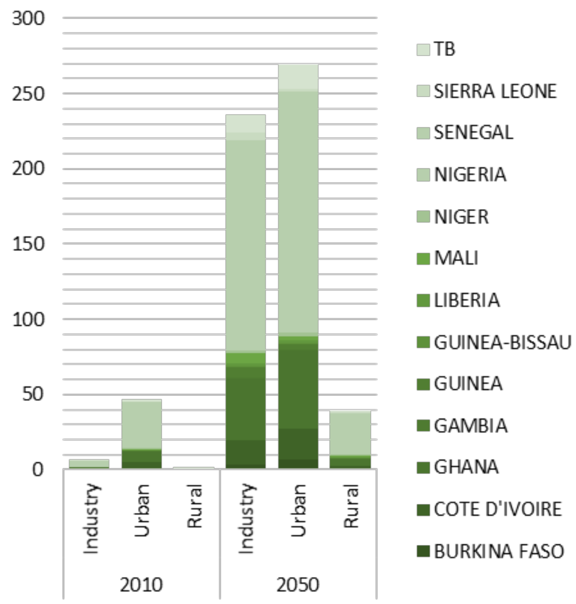


Figure D-45: WAPP Energy Demand: Sectorial Split



(Miketa and Merven, 2013)[30]

Although these demands increase significantly over the study period, it is important to take them into perspective. Current recorded energy consumption per capita is limited to part of the region only and does not exceed 299 KWh/capita in 2011 which is 22 times lower than the current average value for the EU (World Bank, 2014). Looking forward, the large increase in demand is compensated – to some

[30] Demand projections were detailed and calculated as part of this recent power pool level study for energy planning with a focus on renewable energy. The same projections were used in this work. See final demand summary table for detailed – per country – per sector data.

extent – by a corresponding increase in population meaning that the per capita consumption is only expected to increase, at best, threefold over the study period.

Time Slices and Load Curve

The WAPP model considers a break-down of the year into twelve months and four different day parts bringing the total number of time slices to 48. This split is done on the duration of each of the time slice types relative to the total duration of one year and gives the values presented in Table D-11.

Correspondingly, a certain amount of the total energy requirements occur in each time slice. This percentage is calculated for the three demand types that are considered and reported in Table D-45, Table D-46 and Table D-31. These fractions are the same for all countries[31].

Table D-44: WAPP Time Slice definition

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Part 1	0.02480	0.02240	0.02480	0.02400	0.02480	0.02400	0.02480	0.02480	0.02400	0.02480	0.02400	0.02480
Part 2	0.04247	0.03836	0.04247	0.04110	0.04247	0.04110	0.04247	0.04247	0.04110	0.04247	0.04110	0.04247
Part 3	0.00883	0.00798	0.00883	0.00855	0.00883	0.00855	0.00883	0.00883	0.01304	0.01418	0.01373	0.01418
Part 4	0.00883	0.00798	0.00883	0.00855	0.00883	0.00855	0.00883	0.00883	0.00406	0.00348	0.00337	0.00348

Table D-45: Industrial Demand Load Curve

Industrial	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Day Part 1	0.02326	0.02101	0.02326	0.02251	0.02338	0.02265	0.02341	0.02341	0.02138	0.02189	0.02119	0.02189
Day Part 2	0.04320	0.03902	0.04320	0.04181	0.04343	0.04207	0.04347	0.04347	0.04633	0.04855	0.04698	0.04855
Day Part 3	0.00831	0.00750	0.00831	0.00804	0.00835	0.00809	0.00836	0.00836	0.01307	0.01430	0.01384	0.01430
Day Part 4	0.00831	0.00750	0.00831	0.00804	0.00835	0.00809	0.00836	0.00836	0.00404	0.00353	0.00342	0.00353

Table D-46: Rural Demand Load Curve

Rural	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Day Part 1	0.02434	0.02199	0.02434	0.02356	0.02447	0.02370	0.02449	0.02449	0.02522	0.02630	0.02546	0.02630
Day Part 2	0.02916	0.02634	0.02916	0.02822	0.02931	0.02840	0.02934	0.02934	0.03081	0.03222	0.03118	0.03222
Day Part 3	0.01479	0.01336	0.01479	0.01431	0.01487	0.01440	0.01488	0.01488	0.02058	0.02224	0.02153	0.02224
Day Part 4	0.01479	0.01336	0.01479	0.01431	0.01487	0.01440	0.01488	0.01488	0.00821	0.00750	0.00726	0.00750

Table D-47: Urban Demand Load Curve

Urban	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Day Part 1	0.01937	0.01750	0.01937	0.01875	0.01948	0.01887	0.01950	0.01950	0.01954	0.02030	0.01965	0.02030
Day Part 2	0.04320	0.03902	0.04320	0.04181	0.04343	0.04207	0.04347	0.04347	0.04041	0.04149	0.04015	0.04149
Day Part 3	0.01025	0.00926	0.01025	0.00992	0.01031	0.00998	0.01032	0.01032	0.01836	0.02030	0.01965	0.02030
Day Part 4	0.01025	0.00926	0.01025	0.00992	0.01031	0.00998	0.01032	0.01032	0.00651	0.00618	0.00598	0.00618

[31] Future work might include finding more appropriate – and currently unavailable – coutnry level data that could be used to specify different load curves on a national scale. This would potentially increase the potential for trade due to Peak requirements being shifted from one country to the next.

Regional Fuel provision and Costs

Additionally to the general assumptions for this paragraph that are detailed in the body of the Main Modelling Annex, the West African Power Pool has a specific set of data assumptions regarding the availability and cost of fossil fuels due to its particular level of reserves.

In accordance with current levels as identified by international sources, Table D-48 lists the identified fossil resources available to each country in the region. The corresponding cost of extracting these fuels is included in the overall fuel price listed in Table D-49. As a first pass assumption used to differentiate the two types of fuel, imports of a given commodity are costed using the domestic per unit cost increased by a standard 10%[32] (see D1- OSeMOSYS Common Modeling Assumptions – Main Methodology Assumptions for further details).

Table D-48: National identified fossil reserves in TWh – WAPP

Country	Coal	Crude Oil **	Natural Gas
Benin	0.00	14.20	11.97
Cote d'Ivoire	0.00	177.54	299.23
Burkina Faso	0.00	0.00	0.00
Ghana	0.00	1171.78	239.38
Gambia, The	0.00	0.00	0.00
Guinea	0.00	0.00	0.00
Guinea-Bissau	0.00	0.00	0.00
Liberia	0.00	0.00	0.00
Mali	0.00	0.00	0.00
Niger	437.38	0.00	0.00
Nigeria	1187.17	66046.05	54459.27
Senegal	0.00	0.00	0.00
Sierra Leone	0.00	0.00	0.00
Togo	0.00	0.00	0.00

* 2008 Data, **2011 Data

Source: (EIA, 2011)

Table D-49: Cost of domestic fuel extraction [USD/ToE]

	Burkina Faso	Benin	Côte d'Ivoire	Ghana	Gambia	Guinea	Guinea-Bissau	Liberia	Mali	Niger	Nigeria	Sierra Leone	Senegal	Togo
Biomass	150.7	150.7	150.7	150.7	150.7	150.7	150.7	150.7	150.7	150.7	150.7	150.7	150.7	150.7
Coal	125.6	125.6	125.6	125.6	125.6	173.3	173.3	173.3	173.3	173.3	173.3	173.3	173.3	173.3
*Diesel**	0.0	916.9	916.9	916.9	916.9	916.9	916.9	916.9	1055.1	1055.1	916.9	916.9	916.9	916.9
HFO	486.1	486.1	486.1	486.1	486.1	486.1	486.1	486.1	486.1	486.1	486.1	486.1	486.1	486.1
Natural Gas	355.9	355.9	355.9	355.9	355.9	355.9	355.9	355.9	355.9	355.9	355.9	355.9	355.9	355.9

*the cost listed for Diesel is the cost of Imported fuel as the region is assumed to not have any domestic reserves.

Source: (Miketa and Merven, 2013)

[32] Used in recent power pool assessments by IRENA referenced in this report, the validity of this assumption varies from one country to the next and depends on local availability of fuel, national policy on fuel subsidy, as well as availability of import options.

Renewable Energy Potentials

Renewable energy potentials over Africa in general, and of selected countries of Western Africa in particular, are non-negligible. Based on the latest IRENA research for the continent (Hermann et al., 2014), the total theoretically available renewable power for the WAPP including solar and wind based sources exceeds the 150 thousand TWh. Although around four times lower than in the Southern power pool, the potential for solar based generation in Nigeria would be sufficient to provide on thousand times the domestic demand for 2010.

Regionally, this resource is spread unevenly and countries with high fossil resources seem to also be heavily favoured. Due in part to the definition criteria regarding what constitutes technically available resource and to the corresponding area exclusions in the energy potential mapping, this distribution highlights the potential advantage of increased interconnection. As renewable resource availability suffers from unpredictability, a strong interconnected grid becomes an advantage for both distributing risk and absorbing the resource as soon as it becomes available.

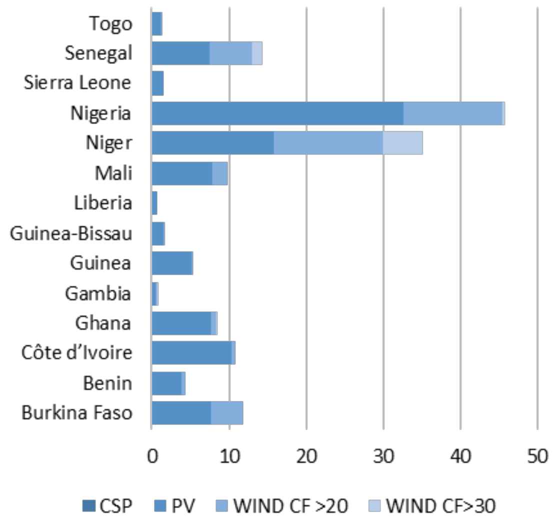
Finally, it is noticeable that wind power may represent be of significant interest in given countries where the amount of resource available tallies with the amount of solar power: Niger has the highest wind resource in the region representing 55% of its domestic renewables (excl. hydro and biomass) while Senegal and Burkina Faso sit respectively at 47% and 35%.

Table D-50: Renewable Energy Potential per Country

	[TWh/Year]			
	CSP	PV	WIND	
			CF >20	CF>30
Burkina Faso	0	7742	4154	0
Benin	0	3898	405	0
Côte d'Ivoire	2	10325	430	
Ghana	2	7644	606	10
Gambia	3	474	173	5
Guinea	5	5204	2	0
Guinea-Bissau	9	1493	124	0
Liberia	0	667	0	0
Mali	0	7906	1923	0
Niger	88	15669	14268	5048
Nigeria	100	32456	12857	381
Sierra Leone	2	1499	0	0
Senegal	15	7519	5454	1294
Togo	0	1257	79	0

Source: (Hermann et al., 2014)

Figure D-46: Thousand TWh of Renewable Potential



In parallel to these resource availability limits, the energy models consider two types of constraints on renewable technologies. The first assumes a cap on the amount of new capacity that can be added to the system on a yearly basis, while the second restricts the total penetration of renewable energy in the overall mix in order to ensure conservative shares of lower reliability technologies in the final generation. The constraints on the solar and wind energy penetration in the system were obtained from the WAPP study by IRENA. These were applied across all countries(Miketa and Merven, 2013).

Please note that assumptions regarding Hydropower are listed in a separate paragraph due to the important focus of the present study on this specific resource.

Techno-economic Parameters

The technology options available inside of the power pool model are linked to corresponding generic parameter values. These are presented and referenced in Table D-18.

Table D-51: Techno Economic Data for generic power plants

Power Plant (Technologies)	**Capital Cost ($/kW)**	**Variable O&M Cost (USD/GJ)**	**Life time (Years)**	**Construction (Years)**
Biomass	3660	5.56	30	4
Coal	3519	3.96	35	4
Diesel 100 kW (Industrial)	659	15.38	20	0
Diesel 1kW (Rural)	692	9.23	10	0
Diesel 1kW (Urban)	692	9.23	10	0
Diesel (Centralized)	1177	4.72	30	1
Geothermal	5856	1.39	25	4
HFO	1634	4.17	25	2
Gas Turbine (Combined cycle)	1423	0.80	30	3
Gas turbine (Other cycles)	730	5.53	25	2
Nuclear	10778	3.87	60	8
CSP	4392	6.20	25	4
CSP with Storage	10249	4.56	25	4
CSP with Gas Co-firing	2033	4.56	25	4
Solar PV Utility	2200	5.58	25	1
PV Rural Rooftop	2100	4.16	20	<1
PV Rural rooftop 1hr storage	4258	4.16	20	<1
PV Rural rooftop 2hr storage	6275	4.76	20	<1
PV Urban Rooftop	2100	4.16	20	<1
PV Urban rooftop 1hr storage	4258	4.76	20	<1
PV Urban rooftop 2hr storage	6275	5.29	20	<1
Wind 25% Capacity Factor	2862	3.97	25	2
Wind 30% Capacity Factor	2420	3.97	25	2
Generic Large Hydro	3221	1.66	50	5
Generic Micro Hydro	4800	1.51	30	2

Source: (Miketa and Merven, 2013)

Planned infrastructure investments

Energy infrastructure development is a long process that goes through a number of project phases before the physical power plant comes online and actually begins to provide energy to the system. In order to take into account this lead time in project development, the first years of the modelling framework are constrained to ensure that actual infrastructure investment results and current committed national plans line up.

With a specific focus on hydro power, Table D-52 details the specific list of power plants that are included in the OSeMOSYS energy modelling framework for the WAPP. These power plants fall into six different categories:

- One split into two categories are based on their presence or not in the WEAP water models: this defines whether or not the power plant receives direct or proxied information for the climate scenario runs.

- A second split into three categories based on the status of the power plant: i.e. whether the facility is historic capacity (existing), committed new capacity or planned new capacity.

The table further details the correspondence between the OSeMOSYS power plants and their WEAP counterparts by naming the power plant that was used to derive capacity factor variations related to the six climate change scenarios under analysis. Finally, power plant level techno-economic data is listed in regard to each facility. Where site specific data was not available it was replaced by generic data.

The number of power plants considered here is extensive. Covering 133 facilities but totaling only a relatively modest 18GW of available new capacity. Only one third of these facilities are included in the WEAP framework which increases the relative importance of proxying the capacity factors of the remaining stock while potentially decreasing the system impact of climate change artificially.

Table D-52: Site Specific Hydro power plant parameters

Power Plant Name	**River Basin**	**Proxy**	**Capital Cost** ($/kW)	**Max Capacity (GW)**	**Variable Cost ($/GJ)**	**Status**[33]	**Earliest on**
Burkina Faso							
Bagre		-	0	0.018	0.56	HC	
Kompienga		Pwalgu	0	0.0154	0.56	HC	
Nlofila		Bon	0	0.0019	0.56	HC	
Tourni		Bon	0	0.0006	1.51	HC	
Diebougou		Samendheni	2553	0.05	0.56	PLN	2020
Natena		Bon	2553	0.048	0.56	PLN	2020
Nubere		Bon	2553	0.048	0.56	PLN	2020
Bougouriba		Bon	10125	0.012	0.56	PLN	2021
Samendeni		-	44723	0.0024	0.56	PLN	2027
Bonvale		-	2553	0.0003	0.56	CON	2025
Bon		-	2553	0.0078	0.56	CON	2024
Gougourou		-	2553	0.005	0.56	CON	2020
Badongo		-	2553	0.003	0.56	CON	2024
Ketou		Ketou	2105	0.16	1.51	PLN	2018
Côte d'Ivoire							
Taabo		Bui	0	0.21	0.56	HC	
Kossou (1,2,3)		Bui	0	0.174	0.56	HC	
Buyo (1,2,3)		Bui	0	0.171	0.56	HC	
Ayame I		Bui	0	0.0274	0.56	HC	
Ayame II		Bui	0	0.0304	0.56	HC	
Faye		Bui	0	0.005	0.56	HC	
Soubre		Bui	2296	0.27	0.56	PLN	2018
Gribo Popoli		Bui	3249	0.112	0.56	PLN	2027
Boutoubre		Bui	2570	0.156	0.56	PLN	2028
Louga		Bui	4751	0.28	0.56	PLN	2029
Tiassale		Bui	4068	0.051	0.56	PLN	2030
Aboisso Comoe		Bui	2756	0.09	0.56	PLN	2026
Ghana							
Akosombo		-	0	1.038	0.56	HC	
Kpong		-	0	0.148	0.56	HC	
BUI		-	2553	0.4	0.56	HC	
Hemang		Bui	3270	0.093	0.56	PLN	2015
Pwalugu		-	5470	0.05	0.56	CON	2020
Juale		-	4276	0.087	0.56	CON	2015

[33] CON: Under Construction; HC: Historic Capacity, i.e. existing; PLN: Planned Capacity

Tonoso		Bui	2553	0.065	0.56	PLN	2018
Awisam		Bui	2553	0.05	0.56	PLN	2020
Daboya		-	7334	0.043	0.56	CON	2020
Kulpawn		-	11286	0.04	0.56	CON	2020
Bonsa		Bui	2553	0.017	0.56	PLN	2020
Dekoto		Bui	2553	0.0058	0.56	PLN	2020
Tsatsudui		Bui	4840	0.0003	1.50684	PLN	2020
Bontioli		-	2553	0.0051	0.56	CON	2024
Koulbi		-	2553	0.068	0.56	CON	2020
Ntereso		-	2553	0.064	0.56	CON	2020
Lanka		-	2553	0.095	0.56	CON	2020
Jambito		-	2553	0.055	0.56	CON	2020
Noumbiel		-	5185	0.048	0.56	CON	2024
Gambia							
Sambangalou (OMVG)		Gourbassi	3386	0.0154	0.56	PLN	2016
Digan (OMVG)		Koukoutamba	1201	0.0112	0.56	PLN	2018
Fello Sounga(OMVG)		Koukoutamba	3474	0.0098	0.56	PLN	2018
Saltinho (OMVG)		Koukoutamba	4273	0.0024	0.56	PLN	2018
Guinea							
Garafiri		Koukoutamba	0	0.075	0.56	HC	
Grandes Chutes 1		Koukoutamba	0	0.0176	0.56	HC	
Grandes Chutes 2		Koukoutamba	0	0.0126	0.56	HC	
Donkea		Koukoutamba	0	0.0164	0.56	HC	
Kinkon		Koukoutamba	0	0.0032	0.56	HC	
Tinkisso		Fomi	0	0.0012	0.56	HC	
La Loffa Mico		Koukoutamba	0	0.0002	1.50684	HC	
Kaleta		Koukoutamba	1794	0.238	0.56	CON	2018
Kogon		Koukoutamba	2553	0.13	0.56	CON	2015
Niandan		Fomi	2553	0.09	0.56	PLN	2020
Djiploo		Koukoutamba	2553	0.014	0.56	PLN	2020
Planned facilities (aggregated)			1542	2.314	0.56	PLN	2014
Sambangalou		Gourbassi	3386	0.0512	0.56	PLN	2016
Digan (OMVG)		Koukoutamba	1201	0.037	0.56	PLN	2018
Fellousounga (OMVG)		Koukoutamba	3474	0.0328	0.56	PLN	2018
Saltinho (OMVG)		Koukoutamba	4273	0.002	0.56	PLN	2018
Balssa		-	1237	0.181	0.56	CON	2025
Boureya		-	2964	0.161	0.56	CON	2025
Koukoutamba		-	3180	0.281	0.56	CON	2020
Other OMVS			2015	0.2254	0.56	PLN	2020
Fomi		-	2268	0.09	0.56	CON	2020
Diaraguela		-	3235	0.072	0.56	CON	2020
Baneah		Koukoutamba	0	0.005	0.56	HC	
Guinea Bissau							
SALTINHO OMVG		Koukoutamba	4273	0.0005	0.56	PLN	2018
Sambangalou OMVG		Gourbassi	3386	0.003	0.56	PLN	2016
FellouSounga OMVG		Koukoutamba	3474	0.002	0.56	PLN	2018
Digan OMVG		Koukoutamba	1201	0.002	0.56	PLN	2018
Liberia							
Yandohun Micro		Koukoutamba	4840	0.0001	1.54284	HC	
Mt coffee			5803	0.066	0.56	CON	2016
Consolidated			3499	0.698	0.56	PLN	2020
Mali							
Manantali		-	0	0.104	0.56	HC	

Selingue		-	0	0.0476	0.56	HC	
Sotuba		Koukoutamba	0	0.0057	0.56	HC	
Kenie		Taoussa	3671	0.0344	0.56	PLN	2020
Gourbassi		-	22811	0.021	0.56	CON	2025
Taoussa		-	13675	0.02	0.56	CON	2020
Felou OMVS 45%		-	3708	0.027	0.56	CON	2014
Markala		Koukoutamba	4025	0.01	0.56	PLN	2020
Farako micro		Koukoutamba	4840	0.0002	1.50684	PLN	2020
Gouina OMVS 45%		-	3075	0.063	0.56	CON	2014
Moussala		-	3801	0.03	0.56	CON	2026
Consolidated			2971	0.12	0.56	PLN	2020
Niger							
Kandadji		-	4240	0.125	0.56	CON	2020
Gambou		Taoussa	4712	0.1225	0.56	PLN	2020
Dyodyonga		Taoussa	2293	0.026	0.56	PLN	2020
Nigeria							
Shiroro		-	0	0.6	0.56	HC	
Guraradam		-	0	0.03	0.56	HC	
Jekko Falls		Zungeru	0	0.008	0.56	HC	
Kurra Falls		Zungeru	0	0.004	0.56	HC	
Anwil		Shiroro	0	0.0031	0.56	HC	
(Waya & Enugu) dam micro		#N/A	0	0.0002	1.50684	HC	
Makurdi		Mambilla	1500	1.1	0.56	PLN	2020
Mambilla		-	1538	2.6	0.56	PLN	2020
Guarara Falls		-	2836	0.36	0.56	CON	2015
Zungeru		-	1737	0.95	0.56	CON	2017
Kiri dam		Dadin Kowa	2553	0.035	0.56	PLN	2020
Zungeru dam		-	2553	0.032	0.56	PLN	2018
Dadin-Kowa		-	0	0.034	0.56	HC	
Ekiti		Zungeru	2553	0.015	0.56	PLN	2020
Tiga Dam		Shiroro	2553	0.0006	0.56	PLN	2020
Challawan Goje		Shiroro	2553	0.0015	0.56	PLN	2020
Kainji		-	0	0.68	0.56	HC	
Jebba		-	0	0.56	0.56	HC	
Kwall		Zungeru	0	0.003	0.56	HC	
Sierra Leone							
Bumbuna		Fomi	0	0.05	0.56	HC	
Guma Dam		Fomi	0	0.006	0.56	HC	
Bumbuna II		Fomi	1950	0.04	0.56	CON	2015
Bekongor 1,2,3		Fomi	2447	0.201	0.56	PLN	2020
Yben dam		Fomi	2553	0.051	0.56	PLN	2020
Bumbuna III		Fomi	1950	0.09	0.56	PLN	2017
Bumbuna IV		Fomi	1950	0.095	0.56	PLN	2017
Gummed II		Fomi	6709	0.006	0.56	PLN	2015
Consolidated		#N/A	2970	0.2334	0.56	PLN	2020
Senegal							
Sambangalou		Gourbassi	3386	0.0512	0.56	PLN	2016
Manantali DAM		-	0	0.07	0.56	HC	
Digan		Koukoutamba	1201	0.037	0.56	PLN	2018
FellouSounga		Koukoutamba	3474	0.033	0.56	PLN	2018
Saltinho		Koukoutamba	4273	0.008	0.56	PLN	2018
Felou OMVS 25%		-	3708	0.015	0.56	CON	2014
Gouina OMVS 25%		-	3075	0.035	0.56	CON	2014
Togo							
Nangbeto		Juale	0	0.0656	0.56	HC	
KPIME MICRO		Juale	0	0.0012	1.50684	HC	
Adjarala		Juale	2265	0.147	0.56	CON	2017
Tététou		Juale	3174	0.05	0.56	PLN	2018

Source: (UDI PLATTS, 2012) (Miketa and Merven, 2013)

Transmission and Distribution

National transmission and distribution systems include four types of lines connecting two different levels of the energy system. Since data regarding current levels of system development on a national level are not readily available in the region, initial balancing of the regional WAPP model is used to determine the capacity levels required to cover existing demand in each individual country. These levels are then considered fixed in the first year of the modelling.

Further, each type of line suffers from losses which translate into different transmission efficiencies. These efficiencies can also vary for a single type of line from one country to another depending on the state of the system. The values used in this study are presented in Table D-53 for reference.

Table D-53: National T&D line efficiencies

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Burkina Faso																					
Transmission	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95
Rural	0.75	0.755	0.76	0.765	0.77	0.775	0.78	0.785	0.79	0.795	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
Urban	0.83	0.837	0.844	0.851	0.858	0.865	0.872	0.879	0.886	0.893	0.9	0.902	0.904	0.906	0.908	0.91	0.912	0.914	0.916	0.918	0.92
Industrial	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99
Benin																					
Transmission	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95
Rural	0.75	0.755	0.76	0.765	0.77	0.775	0.78	0.785	0.79	0.795	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
Urban	0.83	0.837	0.844	0.851	0.858	0.865	0.872	0.879	0.886	0.893	0.9	0.902	0.904	0.906	0.908	0.91	0.912	0.914	0.916	0.918	0.92
Industrial	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99
Cote d'Ivoire																					
Transmission	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95
Rural	0.75	0.755	0.76	0.765	0.77	0.775	0.78	0.785	0.79	0.795	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
Urban	0.83	0.837	0.844	0.851	0.858	0.865	0.872	0.879	0.886	0.893	0.9	0.902	0.904	0.906	0.908	0.91	0.912	0.914	0.916	0.918	0.92
Industrial	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99
Ghana																					
Transmission	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95
Rural	0.75	0.755	0.76	0.765	0.77	0.775	0.78	0.785	0.79	0.795	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
Urban	0.83	0.837	0.844	0.851	0.858	0.865	0.872	0.879	0.886	0.893	0.9	0.902	0.904	0.906	0.908	0.91	0.912	0.914	0.916	0.918	0.92
Industrial	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99
Gambia																					
Transmission	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95
Rural	0.75	0.755	0.76	0.765	0.77	0.775	0.78	0.785	0.79	0.795	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
Urban	0.83	0.837	0.844	0.851	0.858	0.865	0.872	0.879	0.886	0.893	0.9	0.902	0.904	0.906	0.908	0.91	0.912	0.914	0.916	0.918	0.92
Industrial	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99
Guinea																					
Transmission	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95
Rural	0.75	0.755	0.76	0.765	0.77	0.775	0.78	0.785	0.79	0.795	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
Urban	0.83	0.837	0.844	0.851	0.858	0.865	0.872	0.879	0.886	0.893	0.9	0.902	0.904	0.906	0.908	0.91	0.912	0.914	0.916	0.918	0.92
Industrial	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99
Guinea-Bissau																					
Transmission	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95
Rural	0.75	0.755	0.76	0.765	0.77	0.775	0.78	0.785	0.79	0.795	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
Urban	0.83	0.837	0.844	0.851	0.858	0.865	0.872	0.879	0.886	0.893	0.9	0.902	0.904	0.906	0.908	0.91	0.912	0.914	0.916	0.918	0.92
Industrial	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99
Liberia																					
Transmission	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95
Rural	0.75	0.755	0.76	0.765	0.77	0.775	0.78	0.785	0.79	0.795	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
Urban	0.83	0.837	0.844	0.851	0.858	0.865	0.872	0.879	0.886	0.893	0.9	0.902	0.904	0.906	0.908	0.91	0.912	0.914	0.916	0.918	0.92
Industrial	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99

Mali																					
Transmission	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95
Rural	0.75	0.755	0.76	0.765	0.77	0.775	0.78	0.785	0.79	0.795	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
Urban	0.83	0.837	0.844	0.851	0.858	0.865	0.872	0.879	0.886	0.893	0.9	0.902	0.904	0.906	0.908	0.91	0.912	0.914	0.916	0.918	0.92
Industrial	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99
Niger																					
Transmission	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95
Rural	0.75	0.755	0.76	0.765	0.77	0.775	0.78	0.785	0.79	0.795	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
Urban	0.83	0.837	0.844	0.851	0.858	0.865	0.872	0.879	0.886	0.893	0.9	0.902	0.904	0.906	0.908	0.91	0.912	0.914	0.916	0.918	0.92
Industrial	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99
Nigeria																					
Transmission	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95
Rural	0.75	0.755	0.76	0.765	0.77	0.775	0.78	0.785	0.79	0.795	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
Urban	0.83	0.837	0.844	0.851	0.858	0.865	0.872	0.879	0.886	0.893	0.9	0.902	0.904	0.906	0.908	0.91	0.912	0.914	0.916	0.918	0.92
Industrial	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99
Senegal																					
Transmission	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95
Rural	0.75	0.755	0.76	0.765	0.77	0.775	0.78	0.785	0.79	0.795	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
Urban	0.83	0.837	0.844	0.851	0.858	0.865	0.872	0.879	0.886	0.893	0.9	0.902	0.904	0.906	0.908	0.91	0.912	0.914	0.916	0.918	0.92
Industrial	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99
Sierra Leone																					
Transmission	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95
Rural	0.75	0.755	0.76	0.765	0.77	0.775	0.78	0.785	0.79	0.795	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
Urban	0.83	0.837	0.844	0.851	0.858	0.865	0.872	0.879	0.886	0.893	0.9	0.902	0.904	0.906	0.908	0.91	0.912	0.914	0.916	0.918	0.92
Industrial	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99
Togo																					
Transmission	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95
Rural	0.75	0.755	0.76	0.765	0.77	0.775	0.78	0.785	0.79	0.795	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
Urban	0.83	0.837	0.844	0.851	0.858	0.865	0.872	0.879	0.886	0.893	0.9	0.902	0.904	0.906	0.908	0.91	0.912	0.914	0.916	0.918	0.92
Industrial	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99

Source: (Miketa and Merven, 2013)

In addition to national level T&D, each country in the region is either connected – or has the potential for connection to – neighboring systems. Considering the latest available data regarding the WAPP, Table D-54 presents the countries with existing high voltage connections along with their current rating. Similarly, Table D-55 resents the project options that are included in the modelling framework. Note that these are divided between "Committed" and "Future" in relation to the level of certainty that the corresponding project will be implemented. The first are therefore forced in to the solution space whereas the second are simply made available to the system and are considered as part of the optimization. Note that the denominations "Country1" resp. 2 are simply used to define the two neighbors that are connected by the transmission project. Energy is not constrained to flow in a particular direction but rather is traded depending on the unit cost of power generation in each country.

Table D-54: International Transmission - Existing Infrastructure

Country 1	**Country 2**	**Capacity (MW)**
Ghana	Cote d'Ivoire	327
	Togo/Benin	965.2
Senegal	Mali	100
Cote d'Ivoire	Burkina Faso	327
Nigeria	Togo/benin	686
	Niger	169.2

Table D-55: Future International transmission projects

Country 1	**Country 2**	**Capacity (MW)**	**Earliest Year**
Dorsale (committed)			
Cote d'Ivoire	Ghana	655.2	2015
CLSG (committed)			
Cote d'Ivoire	Liberia	337.6	2014
Liberia	Guinea	337.6	2014
Liberia	Sierra Leone	303.4	2014
Sierra Leone	Guinea	333.7	2014
OMVG (committed)			
Senegal	Guinea	286.3	2017
Senegal	Gambia	340.7	2017
Gambia	Guinea-Bissau	329.1	2017
Guinea-Bissau	Guinea	309.6	2017
Corridor Nord			
Nigeria	Niger	633.1	2014
Niger	Togo/Benin	649.7	2014
Niger	Burkina Faso	637.5	2014
Hub Intrazonal			
Ghana	Burkina Faso	332.2	2014
Burkina Faso	Mali	305.8	2015
Mali	Cote d'Ivoire	319.7	2016
Guinea	Mali	321.3	2020
Dorsale Mediane			
Nigeria	Togo/Benin	646.7	2020
Togo/Benin	Ghana	654.5	2020
OMVS			
Mali	Senegal	329.1	2020

Integration with other power pools

This modelling effort was conducted as an integral component of the larger vulnerability assessment of African infrastructure. In this study, the four Sub Saharan power pools (CAPP; EAPP; SAPP and WAPP) were modelled separately but have a certain number of overlapping countries and overlapping infrastructure. In the case of the WAPP, this is particularly relevant for the Grand Inga projects and the DRC. Considering that each power pool is optimized separately under an iterative approach with the water modelling component of the project, this overlap adds an extra level of complication.

To ensure that results are consistent between power pools, a few simple procedures were applied. First, power pools were optimized in a specific order aligned with the perceived importance of their impact on continent scale results: SAPP was followed by WAPP, EAPP and CAPP. Second, countries that were included in several power pools were optimized only once along with the first power pool in which they appear. Thereafter, when contributing to other power pools they are constrained both in terms of capacity and minimum dispatch to respect the results from the previous model runs.

In the case of the WAPP, this translates to the DRC being included in the overall power pool model with 1) a minimum build out schedule for the Grand Inga projects, 2) a minimum dispatch to a demand representing the SAPP and 3) a link to the WAPP through Nigeria limited to a maximum of 10 GW capacity available from 2025[34].

For further details about the constraints applied and the corresponding countries that they were applied to, please refer to the main methodology annex (D1- OSeMOSYS Common Modeling Assumptions).

Results

Regional Overview

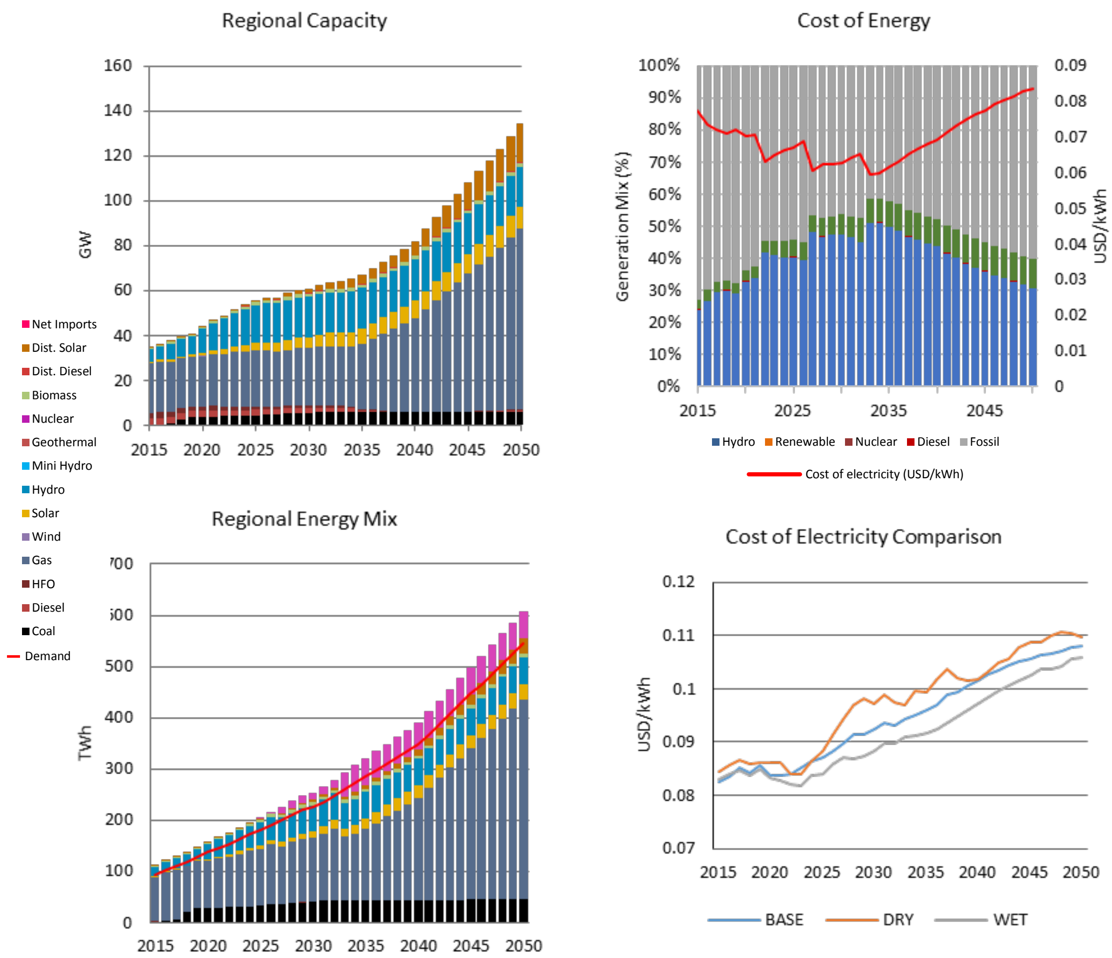
General Energy System Results

From a regional perspective, the WAPP is a resource rich region with availability of both local fossil fuel extraction in the form of Nigerian gas reserves and spread resources of renewable power. The power pool benefits from three major river basins that are the Niger, Senegal and Volta while having large potential for wind and solar power implementation.

Considering results from a base run that assumes historical climate conditions continue to prevail into the future shows a regional system split between large installed gas and relatively smaller hydro based generation, the remainder being made up with quantities of coal as well as solar based renewables. Installed capacity in the region increasing from a total of 34.5GW in 2015 to 134GW in 2050 thereby affecting over a sevenfold increase. Corresponding, the final generation mix shown in Figure D-47 mirrors the capacity split with large contributions from gas based power providing 64% of total generation (incl. imports) by 2050 with a lowest share over the period of 42.5%. This large fossil base is further complemented by coal – responsible for generating 9.7% of all energy provided between 2015 and 2050.

[34] (Miketa and Merven, 2013)

Figure D-47: Capacity and Generation mix Summary



Nevertheless, renewables play a significant role in supporting the WAPP. Hydropower is smaller here than in the Southern power pool – both in absolute and relative terms – but it still represents as much as 17% of yearly generation in the region and maintains a constant contribution to the growing system over time. It can also be noticed that the WAPP relies on a significant contribution from so called imports coming – in this case – exclusively from hydropower in the Inga region, DRC. In real terms, this increases the hydro reliance of the WAPP from 8.6% to 17.25% in 2050[35]. Finally, solar power is of relative importance to the power pool and also contributes 9.8% of required power using both centralized and distributed systems.

From a cost of generation perspective[36], even the smaller contribution of hydropower to the system is an advantage when accounted for with the remaining renewables and the relatively cheaper imported power from DRC. Comparing trends between scenarios further shows that this system stands to suffer only mildly on a regional basis from a low relative vulnerability to climate change. Considering the comparison between the base, dry and wet scenarios investigated in this exercise the power pool's

[35] Note that the scenarios run for this project assume a fixed build out of the Grand Inga (GI) project following a stepwise increment in available capacity. No scenarios were tested where GI was not built.

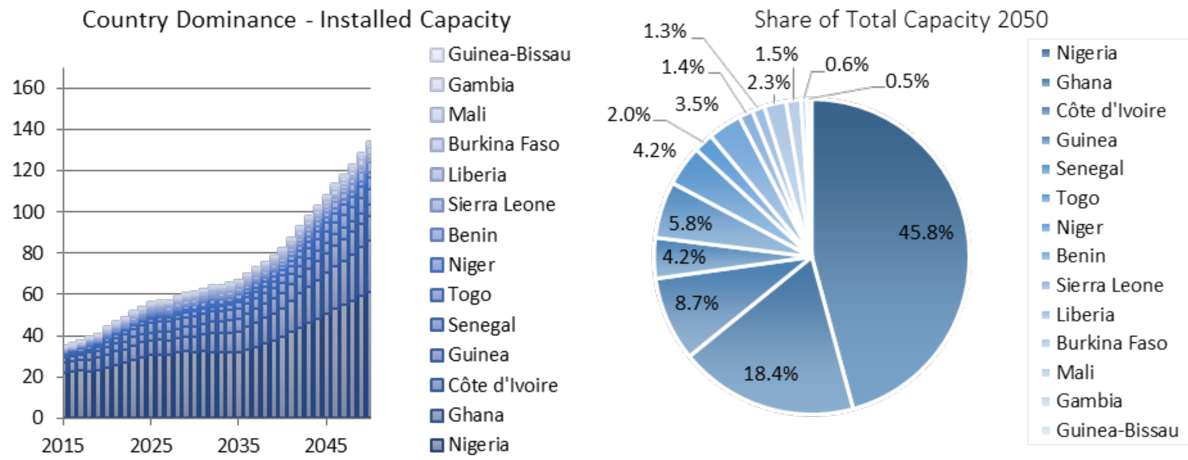
[36] Calculated for the region as the total annualised system cost divided by the total generation in the power pool. Annualised system costs are the undiscounted sum of all annual running costs as well as investment costs spread over power plant operational life time. On a national level this cost is adjusted to include the costs (resp. benefits) of traded energy valued using the regional (resp. domestic) cost of generation

unit cost of electricity generation varies by at most 0.01 USD/kWh over the model period between extremes of changing climate conditions in the future.

A regional system with an important player – Nigeria

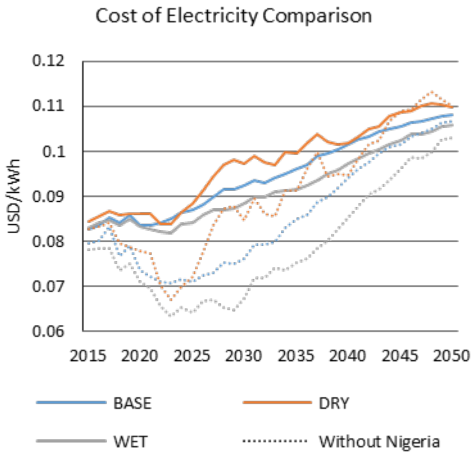
Fourth country in terms of shear geographical area, Nigeria is the largest in the region in nearly all other terms. From an energy systems perspective, installed capacity in 2015 reaches 21.9GW representing 63% of the regional total. The second largest system by the end of the study period is Ghana, which remains 59.9% smaller than Nigeria in the same year with 24.6GW of total installed capacity against 61.4GW in Nigeria. The rest of the region remains comparatively small with: considering systems that represent less than 5% of regional capacity in 2050 shows that 17% of the capacity is spread between nine countries representing 62% of the geographical area in the region. This points to the importance of trade in the WAPP.

Figure D-48: Nigeria dominating the power sector of the WAPP



With such a large energy demand, Nigeria weighs heavily on its comparatively smaller neighbors. This is specifically responsible for a significant relative increase in the regional cost of generation across all scenarios causing variations by as much as 25% in certain scenarios (see Figure D-49).Conversely to the SAPP however, this has little apparent impact on inter year price variability. This is related to the fact that – without counting the DRC – the system contains relatively less hydro, leading to higher reliance on fossil generation as a stable base for providing the demand.

Figure D-49: Cost of electricity variation: the impact of Nigeria throughout all scenarios



This system dominance by a single country also has impacts on the levels and directions of trade within the region. This is specifically true because Nigeria is both a potential producer and exporter of fossil based energy as well as a large importer of hydropower directly from the DRC. Depending on the climate scenario this can mean that the country either uses its own resources or interrupts the flow of cheaper hydropower in order to provide more of its domestic demand.

Key messages

In order to maintain a level of consistency between the Power Pool studies, increase report readability as well as offer more opportunity for result comparison between power pools, six key messages – also reported in the global project Synthesis report – have been developed and are presented in the following paragraphs. Please note that, throughout these explanations, the terminology “Wet” and “Dry” is adopted to describe scenarios that are considered to have respectively higher or lower amounts of available water for energy generation over the period. This does not however translate to each and every month/year of the corresponding scenario being systematically richer/poorer in water resource than the base: this terminology is true “on average over the model period” only.

Further, while a full description of scenarios and methodology are included in the 'Main Methodology Annex' of this work it is worth noting that two scenario families reported here. These include 'perfect foresight' (PF) scenarios, in which the model is allowed some level of freedom to invest in an array of non-hydro alternatives while a certain level of capacity adjustments are made in parts of the hydro infrastructure. This PF scenarios setup allows the model to ‘anticipate’ climate change and – to some degree – adapt accordingly. The second set of families includes so called 'no adaptation' (NA) scenarios, in which climate change is not anticipated and electricity generation shortfalls are met with expensive back-up generators. Each family is run across the same set of selected climate futures. The 'historic' climate is one future based on historic trends.

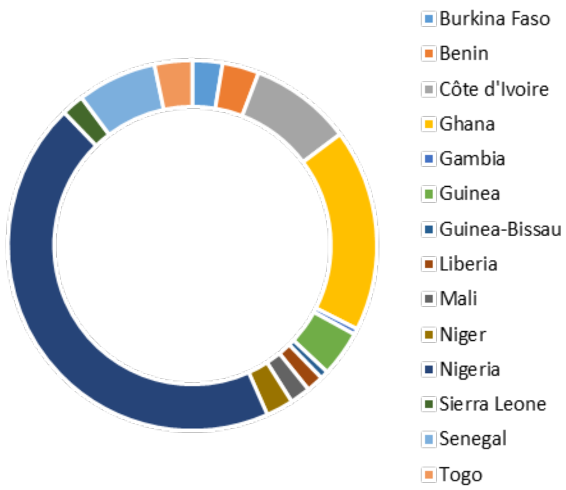
Large infrastructure investments are required to underpin future growth in Africa

In order to provide the growing demand requirements over the study period the energy system in the WAPP is expected to increase by near 280% (plus retirements) between 2015 and 2050. This significant increase in capacity will take place mainly in Nigeria – 46.7% of all new capacities – and The Gambia – 18.57% (see Table D-56).

Table D-56: Cumulative New Capacity per country – 2015 to 2050 – WAPP

	GW	%
Burkina Faso	4.92	3.71%
Benin	3.25	3.32%
Cote d'Ivoire	12.41	4.93%
Ghana	0.87	0.65%
Gambia	24.66	18.57%
Guinea	5.90	4.44%
Guinea-Bissau	0.76	0.58%
Liberia	1.88	1.42%
Mali	2.03	1.53%
Niger	2.95	2.22%
Nigeria	62.04	46.71%
Sierra Leone	7.89	5.94%
Senegal	2.24	1.69%
Togo	5.72	4.31%
Total	132.82	

Figure D-50: Country share on Undiscounted Investments (2015-2050)



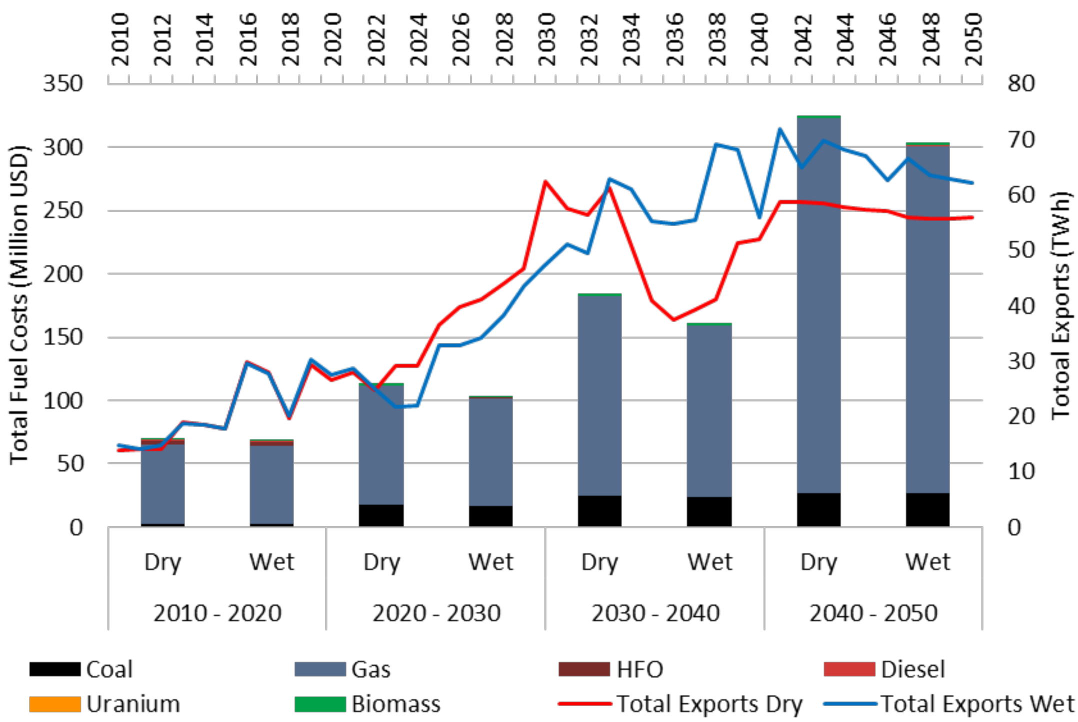
In investment terms, these new additions mean that the region has to consider an undiscounted cost over the period in excess of 338 Billion USD. In line with capacity data, the main component of this total is dedicated to gas based capacity investments reaching 61.7% of the total. The remainder is split between hydropower & other renewables (34%) and new coal investments (2.3%). When including the cost of transmission and distribution system expansion, this total increases to 402 Billion USD.

Trade is required to 'unleash' the potential of much low cost hydropower

Although it invests in and uses small amounts of coal based generation over the modelling period, the fossil basis of the WAPP's energy system remains natural gas. The fuel cost expenditure related in

Figure *D-51* shows that the use of this commodity is expected to grow considerably from 2010 to 2050 irrespective of the scenario under consideration. The correlation to trade in the region however seems unclear: whereas a higher level of fossil fuel use up to 2030 is linked with a consistently higher level of total exports within the WAPP, a corresponding situation between 2020 and 2030 is mirrored by a considerable drop in electricity trade levels.

Figure D-51: Total Electricity Exports vs. Total Fuel Expenditure

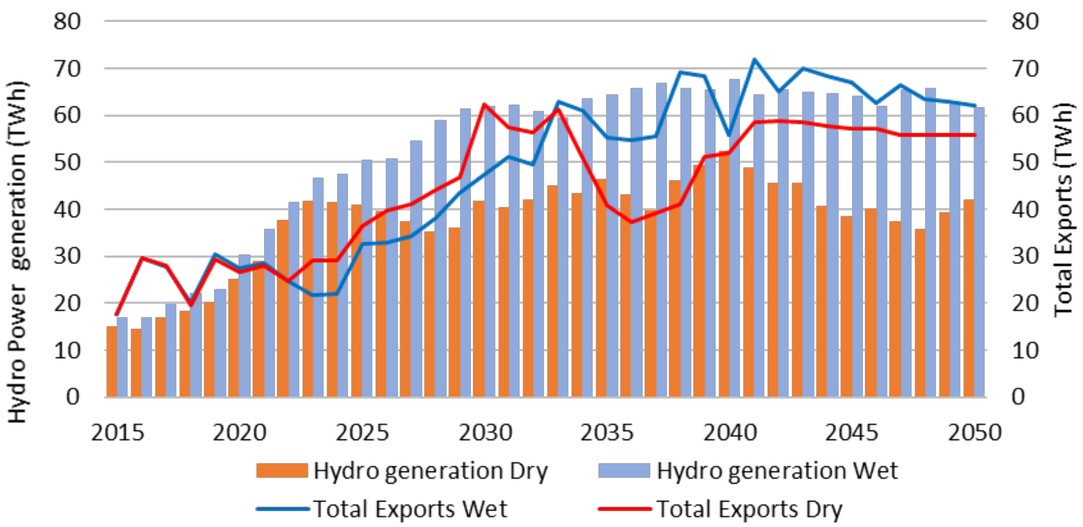


Considering Figure D-52, a similar correlation is visible. First, it appears that the WAPP's hydro generation potential is relatively unaffected by the climate scenario under consideration. Following years however show a significant potential loss in hydro generation in the region: the trade-off between a wet and a dry case accounts for a total potential loss of 571TWh of generation over the study period (97% of which is concentrated between 2020 and 2050) representing a 28.6% drop from one scenario to the other. This value is in the same order of magnitude as results extracted for the Southern African Power Pool where corresponding potential offsets in generation from wet to dry scenarios represent 25% of the "wet case" hydro generation.

Second, the levels of trade in the region appear variable with a direct correlation to hydro power generation offsets in the later part of the modelling period. Conversely, it appears that higher levels of trade are expected in dryer scenario cases until an important "flip" between 2030 and 2035. Although counter intuitive, this result is consistent with the situation of the power pool:

- The WAPP is connected to the DRC through Nigeria which then dispatches energy through Benin, Togo and Ghana.
- In the dryer case, Nigeria receives lower levels of traded power from the DRC in the first half of the period and therefore invests higher levels of capital in gas based generation. This generation is traded to the previous route until hydro generation levels in DRC pick up during the latter part of the model period and new capacity is installed in Ghana thereby reducing the power traded in the region.
- In the wetter case, levels of available hydro generation from DRC and within the WAPP are higher and offset the higher installed fossil capacity in Nigeria while providing sufficient power both domestically and through trade over the model period.

Figure D-52: Total Electricity Exports vs. Hydro Power Generation (TWh)



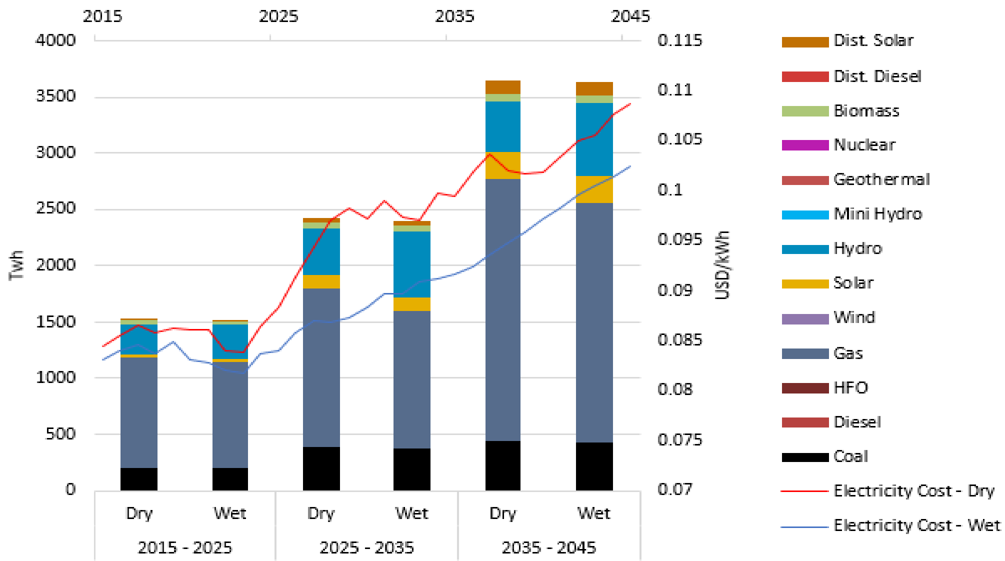
Adapting to climate change: the role of fossil fuels and non-hydro renewables

Climate change, in this exercise, can have both positive and negative impacts on a country relating specifically to the overall rainfall that can be expected over the study period. In both cases however it is challenging to predict the degree of these changes with any certainty. Further, it is changes in weather pattern as well as each patterns' intra & inter year variability that is cause for increased system costs (See main methodology clarifications relating to the Perfect Foresight Adaptation approach).

In dry cases, overall rainfall is lower than in the regional reference climate case and the variability of the climate means that large amounts of hydropower may be unavailable from one year to the next. In this situation, the overall system is impacted negatively: new investments in fossil based generation are required and in turn generate higher annual running costs.

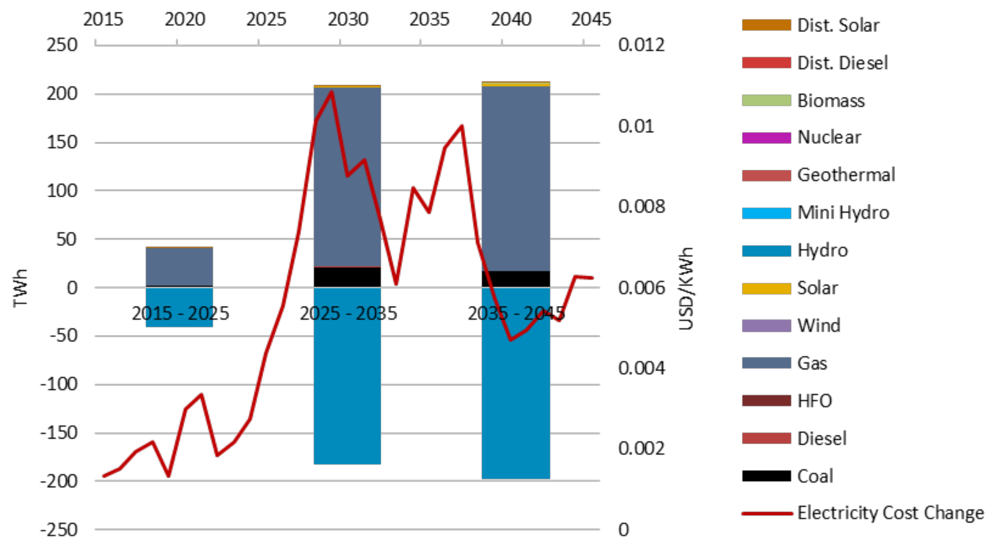
Similarly, wetter cases are expected to offer less stressing conditions both on national and regional levels through higher overall water availability. This however is true only to an extent since variability from one year to the next will mean that unexpected shortages in hydro based generation will be replaced by fossil based generation. The level of the corresponding costs to consumers in the SAPP are however considerably lower: Figure D-53 shows a split between the two extreme scenarios for this power pool appearing as early as 2025 and causing a difference of up to 0.01 USD/kWh between 2035 and 2045 (i.e. a 12% potential increase in the unit cost of electricity generation).

Figure D-53: Total Generation vs. Annualised cost of Electricity



With further consideration of the figure above in parallel to Figure D-54 (relative potential tradeoffs in generation mix between wet and dry cases with corresponding relative variations in unit cost of generation), it is first apparent that both wet and cases rely on increasing levels of fossil based generation complemented by similar ratios of renewables on both a centralized – hydropower and central PV – and decentralized – household solar – solutions. Further, comparing the potential outcomes of dry and wet cases shows that the WAPP has the possibility of offsetting relatively significant amounts of fossil generation: over the entire period, hydropower has the potential to displace respectively 413TWh and 40TWh of gas and oil based generation (i.e. 2.9% of total regional generation between 2015 and 2050).

Figure D-54: Relative range of Generation mix and Annualised cost change



Note that these effects have to be taken into context with the imports situation of the WAPP with respect to DRC hydropower based power. As mentioned above, the situation of the climate in the WAPP conditions the trade routes and amounts that are made available throughout the region.

The effect of Climate Change on electricity costs differs from country to country

Looking at results from a consumer perspective and on a national scale reveals that future changes in regional climate and water availability can have significant effects on the total expenditure of final customers for their energy. The spread of this variation is presented in Table D-57 referencing the aggregated – undiscounted – expenditure for electricity consumption between 2015 and 2050. It compares the consequences of failing to adapt or the potential gains that can be achieved from successful and adequate changes in infrastructure.

Table D-57: Consumer Expenditure on Electricity with and without PF (US$ Billion, 2015 to 2050)

WAPP[37]		No adaptation Sc[38].		PF adaptation Sc.		Robust adaptation, designed to minimize:			
	No CC	Driest	Wettest	Driest	Wettest	Max regret	90% highest	75% highest	River Basin
BF	15.8	16.9	15.2	16.7	15.2	16.7	16.7	16.7	Volta
BJ	30.0	30.4	29.2	30.1	29.3	30.1	30.1	30.1	Volta
CI	68.4	76.1	64.5	74.5	64.3	74.5	74.5	74.5	Volta
GH	174.3	173.6	162.5	169.5	159.4	169.5	169.5	169.5	Volta
GM	5.5	5.0	4.5	4.9	4.5	4.5	4.5	4.5	Senegal
GN	13.4	19.9	11.0	20.0	11.0	11.8	11.8	11.8	Senegal
GW	5.2	5.4	5.2	5.3	5.2	5.2	5.2	5.2	Senegal
LR	5.1	5.3	5.1	5.1	5.1	5.1	5.1	5.1	Senegal
ML	18.4	22.2	17.7	21.0	17.7	18.7	18.7	18.7	Senegal
NE	12.1	12.2	11.9	12.2	12.0	12.0	12.0	12.0	Niger
NG	683.7	691.5	677.4	689.7	678.9	690.0	690.0	690.0	Niger
SL	12.9	21.0	14.0	20.7	14.0	15.2	15.2	15.2	Senegal
SN	43.6	43.7	42.0	43.5	42.0	42.1	42.1	42.1	Senegal
TG	31.9	32.5	29.1	32.5	29.1	32.5	32.5	32.5	Volta
Total	1120.2	1155.5	1089.2	1145.7	1087.5	1127.9	1127.9	1127.9	

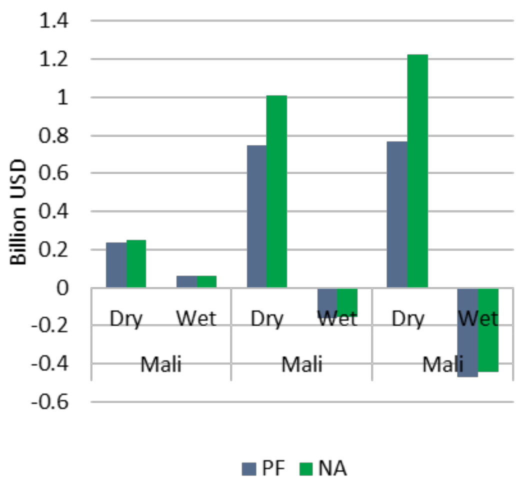
[37] BF: Burkina Faso, BJ: Benin, CI: Côte d'Ivoire, GH: Ghana, GM: Gambia, GN: Guinea, GW: Guinea-Bissau, LR: Liberia, ML: Mali, NE: Niger, NG: Nigeria, SL: Sierra-Leone, SN: Senegal, TG: Togo.
[38] Please refer to the Main methodology annex for full description of these two cases

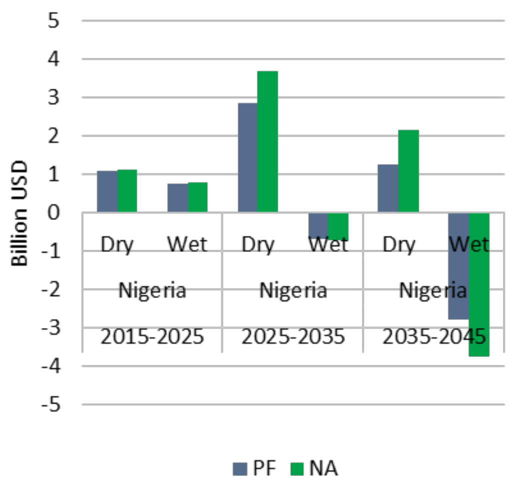
Illustrating the different levels of impact that exist across different countries, Figure D-55 shows the results in a graphic format – per period – for Mali and Nigeria. In both cases, failing to adapt – i.e. choosing a NA case over a PF case in this methodology - has a notable impact on the cost to consumers leading to an increase in additional costs of respectively 0.45 and 0.88 Billion USD for the two countries in a dry case scenario over the last ten year period. This small absolute increase still represents a 60 to 70% increase in the cost difference between these scenarios and the base.

Further, the figure is a relative comparison of the adaptation options in each climate case with the base and shows a range of positive and negative values translating that:

- Climate change will invariably cause relative price increases in the initial model years
- This increase is maintained over the entire study period under a dry scenario and heightened by failing to adapt
- Under a wet scenario however the tendency is for relatively cheaper costs with a lower relative impact of clear adaptation strategies

Figure D-55: Accumulated cost to consumer in different climate and foresight scenarios



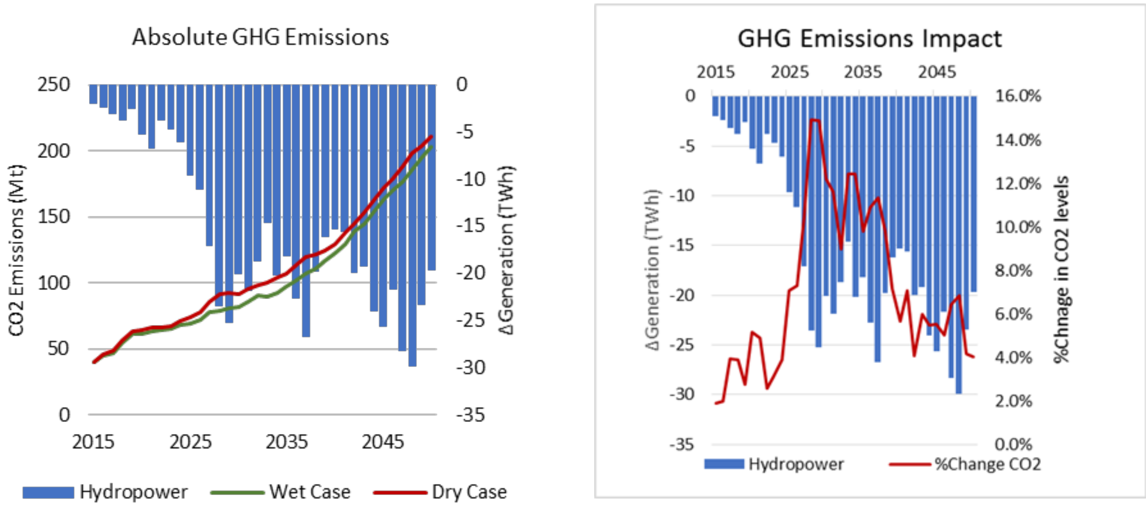


CO_2 emission levels differ between adaptation strategies

Through the different climate scenarios investigated in this exercise the modelling teams have subjected the regional infrastructure of the EAPP to varying levels of water availability for both energy and non-energy related applications. In the energy modelling framework, this variation translates into varying levels varying levels of installed hydro capacity between scenarios as well as varying power plant capacity factors within a given scenario. From an operational perspective, this means that dryer climate runs can be more affected by "sudden" drought years as well as overall lows in water levels for power generation thereby forcing the systems to increase their levels of fossil fuel use. This has a direct impact on levels of carbon dioxide emissions.

On a regional perspective, the WAPP stands to emit between 3,911 and 4,174 Mt of carbon dioxide over the study period depending on the climate scenario under consideration. Compared to a base case where climate remains within recorded historic data, this represents a total change of between 69Mt and 332Mt. When comparing the extremes within the range of climates that were analyzed, we note the same correlation between changes in emission levels and change in potential hydro generation as in the other power pools. Typically, the sudden relative drops in regional hydropower generation between wet and dry cases noted between 2028 and 2030 are mirrored in corresponding increases in CO_2 emissions in the driest case. Overall however, it appears that the difference in terms of emissions from one climate change case to the next is negligible: over a period of 35 years from 2015 to 2050 the relative decrease in emissions “achieved” by experiencing a wetter rather than a dryer scenario does not exceed 6.7% (or 263 Mt CO_2).

Figure D-56: Regional GHG emission trends vs Relative Hydropower generation

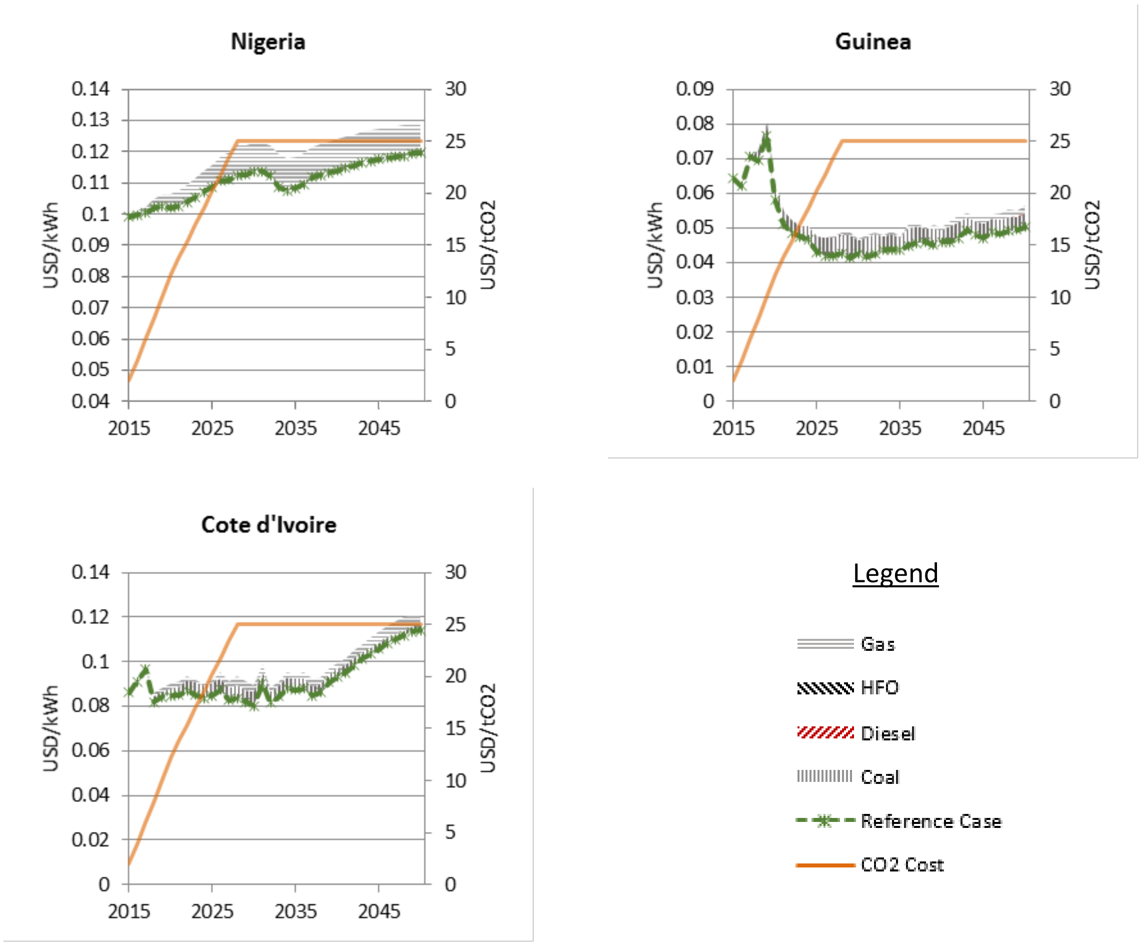


In a similar fashion to the Southern African power pool, the potential inclusion of a carbon financing scheme in the WAPP has a diverse effect on the cost of power depending on the country under consideration. Countries such as Nigeria – apparently stable with an acceptable cost of electricity generation throughout the modelling period – have a high reliance on fossil based generation that could cause increases of up to 8.3% in 2050.

Although it is the cause of comparatively more variable energy prices on an inter-annual basis due to rainfall pattern changes under climate change futures, the high reliance of Guinea on hydropower generation means that the inclusion of relatively expensive CO_2 payment schemes should leave the country comparatively unaffected. Although this is true from an absolute point of view – i.e. the cost of power in Guinea remains lower than half the regional average in 2050, the increase caused by the additional carbon emissions payment scheme would represent a 12% increase in unit energy cost the same year.

The analysis remains just as true for intermediary countries such as Côte d’Ivoire where the presence of a constant base of domestic fossil generation, although offset by capitalizing of available solar and hydro resources, could stand for as much as a 6% increase in unit cost of electricity generation by the end of the period.

Figure D-57: Impact of CO2 emissions costing on the price of energy to consumers[39]



Choosing to adapt is a "low regret" decision

Referring to Figure D-58, the incremental cost to consumers of the different strategies for countries that have either higher or lower vulnerability levels to climate change is visible. Please note that figures are presented here for a Dry scenario. Visualizing the marginal increase in cost that each scenario has on its "predecessor", this graphic shows the difference between having a reactive attitude to the impacts of climate change – materialized by the high annual changes in the level of the lighter "no adaptation" color – and following a given strategy, albeit flawed, to attempt to anticipate the adverse effects of these future changes.

In a similar way to what was noted for the Southern African Power Pool, this "worst case scenario" delivers several messages:

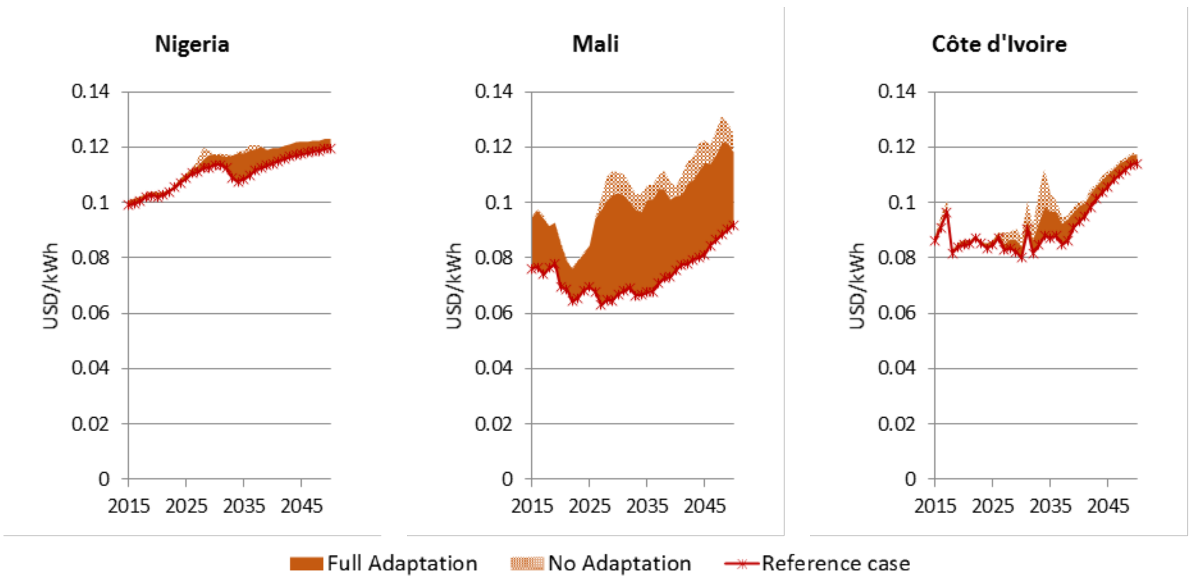
- First, that there are always circumstances – i.e. given years – in which each country might benefit from using some level of foresight to develop an adaptation strategy for its energy system. Although the cost to consumers will nearly inevitably and invariably be higher than in

[39] Please note: these figures show the additional cost of applying a selected cost of carbon dioxide emissions – shown by the orange line – as a post treatment step to sets of results obtained from models. Accordingly the models do not attempt to reduce emissions and mitigate those costs, i.e. these additional costs are not included in the models' objective function. The graphs are used simply to illustrate potential consequences of fossil based generation systems in a region as well as the variability of these consequences from one country to the next.

baseline case where climate is assumed to follow historic trends, there is potential to reduce the overall impact of these problematic "future climate pathways".

- Second, the impacts are particularly visible on a national level: previous aggregations on a power pool level drown a large proportion of the variability and reflects the characteristics of the dominant countries to the region before those of smaller systems. This national representation shows impacts on potentially more vulnerable and fluctuating systems.
- Third, the impacts take on higher significance on a national level: consumer energy prices are endemic to national energy systems (with influence from imports/exports[40]) and should therefore be considered on a national level where potential decisions might be made to reduce adverse impacts of changes in the climate.
- Finally, certain countries with low energy prices but high reliance on hydropower stand to suffer significantly from "drought year" effects forcing the system to use costly and expensive stop gap fossil based systems.

Figure D-58: Cumulative impacts of CC to consumer cost of electricity – Dry case



[40] Imports and exports in this exercise are valued at the regional cost of generation.

Conclusions and Recommendations

Climate change is a complex and diverse phenomenon the effects of which are neither yet agreed upon nor fully understood. In such a context, the present work is a bleeding edge attempt to ensure that – notwithstanding the arguably low degree of certainty that affects the data upon which investment decisions need to be made – the different actors of an integrated water and energy system may have a better understanding of the implications inherent to different available courses of action.

It is important to consider results on a multitude of levels: countries are aggregated into Power Pools that are interconnected by varying levels of trade, each country and each power pool are linked to one or several of the river basins that are analyzed as separate entities in the water modelling framework etc. This means that although all results can be extracted on all levels of this analysis they are not totally independent one from the other.

Adaptation to climate change is also a complex question. The scenarios under analysis have shown that, in most situations, there is a clear – albeit potentially small in best case scenarios – incentive to adapting.

Taking carbon financing into account has the potential to change country level cost of generation and therefore overall energy system design.

From the power pool's perspective, the vulnerabilities of the energy to the impacts of climate change are variable and should be taken in context. The WAPP is a developing power pool with significant energy challenges in the future. Systems in all countries are expected to increase in size at high relative growth rates and therefore have the opportunity of including CC into their decision processes. Considering their specific resources levels, it appears that trade will play an important role in supporting this development and in mitigating the potential cost of changing climates. Hydropower is a small, yet non negligible factor from a power pool perspective but takes all its sense on a national scale for countries with higher levels of potential. Indeed, whereas unit cost of electricity generation differences remain low between climate change scenarios for the power pool, higher impacts on consumers of individual nations are to be expected and can be yet worse for systems with inadequate adaptation strategies. Finally, a high regional reliance on fossil based generation means that potential inclusions of CO_2 costing, be it on a regional or national basis for selected countries, could have significant effects on the unit cost of power and therefore impact the "robustness" of certain system development strategies.

Limitations and next steps

In addition to general methodology and overall project limitations described in the general assumptions text, the following bullets might advantageously outline areas of future work that would improve either the applicability or quality of the results discussed above. Such areas are listed below:

- Further scenarios development: specifically with respect to trade in the region. As an important lever for stability of supply and renewable resource dissemination, it would be advantageous for individual projects to be evaluated more specifically or for general "corridors" for energy transmission to be assessed both within and between power pools.
- Higher focus on security of supply: in particular investigating the cost benefit analyses of such issues when balanced with their cost trade-offs and implications.
- "Endoginizing" carbon costing into the optimization: this element being thus far taken as a post treatment calculation foes not influence the choice of one technology over another in the present exercise. It would be of interest however to include a representation of different "carbon financing" schemes into the current setup in order to assess their potential impact of different countries and power pools.
- Increasing levels of interaction with the power pool authorities: achieving their integration on a procedural level would greatly benefit such projects by increasing data accuracy and output applicability, but also through their potential inclusion into capacity building activities in the context of iterative and improved PP planning processes.
- Bridging potential gaps in the analysis toolbox to inform relations between national and power pool level systems: such applications may be of specific interest when considering shared planning activities on a project level.
- Investigating the potentials for the power pools to promote clean energy use and assess the corresponding clean energy scenarios.
- Investigating implications of financing limits. Power system investments are significant, but so too are other investment needs in the economy. If finance to power investments crowds out opportunities to invest in other projects, or access to finance is simply limited, scenarios to investigate these constraints may provide important insights.

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D5- The Central African Power Pool: Energy Modeling Assumptions, Data and Results

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Introduction: The Central African Power Pool

The Central African Power Pool is an institution of the Economic Community for Central African States (ECCAS). ECCAS was established in 1983. Ten African countries are part of the ECCAS (and of the Power Pool): Angola, Burundi, Cameroon, Central African Republic (CAF), Chad, Congo, Democratic Republic of Congo, Equatorial Guinea, Gabon, and Rwanda.

The countries in the CAPP share a number of challenges. According to UNDP's Human Development Report 2014, most ECCAS countries have a low Human Development Index, namely – from the lowest HDI to the highest - Congo (Democratic Republic of the) (0.333), Central African Republic (0.365), Chad (0.37), Burundi (0.386), Cameroon (0.501), Rwanda (0.502) and Angola (0.524). Three countries are considered to have a medium HDI: Equatorial Guinea (0.556), Congo (0.561) and Gabon (0.67). In economic terms the International Monetary Fund classifies all ECCAS countries as developing economies.

Regarding access to electricity, the average in the region barely exceeds 40%. This ranges from a minimum of 10% in the Democratic Republic of Congo, to a maximum of 60% in Gabon (World Bank, 2014). Currently the region has an installed capacity of 4.8 GW, of which over 3.8 GW comprises of Hydro generation. The rest of the capacity is almost equally split between Diesel, Oil and Gas generation. Other renewables constitute a negligible share. In Figure D-59 the share per fuel is shown for Existing and Planned capacity. As noticeable, Hydro generation will dominate also the planned capacity with almost 95% of the capacity in 2025. The capacity figures showing a system with the Democratic Republic of Congo artificially removed show the importance of this country that represents 48% of installed capacity and almost 65% of the planned. In Figure D-60 existing and anticipated capacities without DRC are shown. Hydro still represents most of the capacity, however Diesel Oil and Gas based generation now accounts for almost 40% of the existing capacity and 20 % of the planned capacities.

Figure D-59: Existing (left) and Planned Capacity (right) - share per fuel

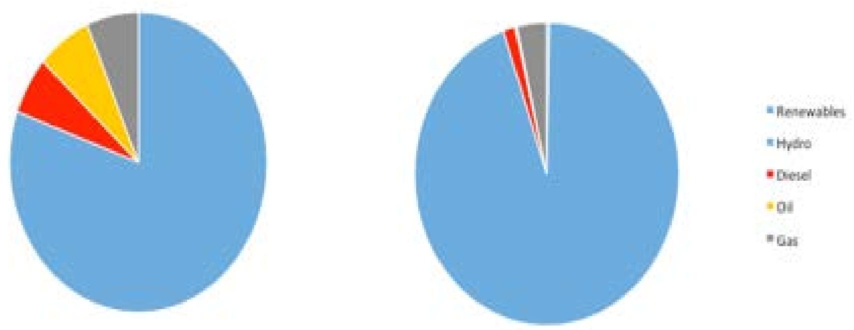
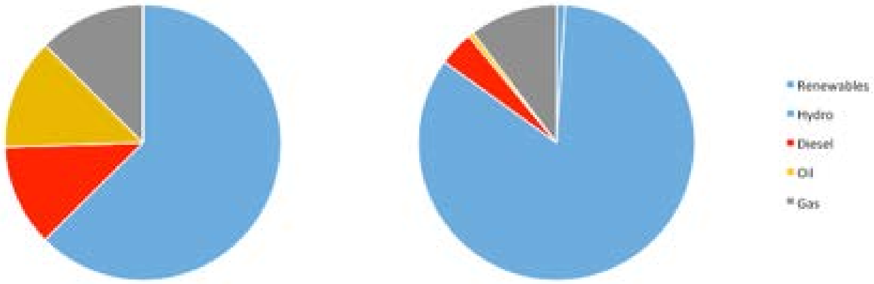
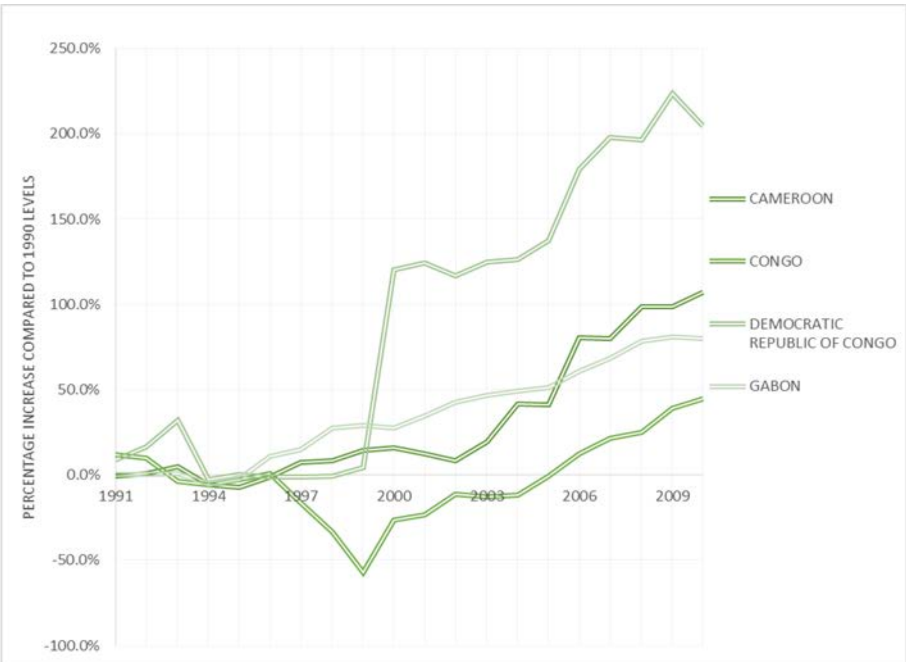


Figure D-60: Existing (left) and Planned Capacity (right) without DRC by generation type



Although not available for all countries, international records show final consumption of electricity growing steadily over the second half of the twentieth century, except for the country of Congo. **Figure D-61**, shows relative country demand on a yearly basis as compared to 1990 levels for selected countries. Levels in 2010 lie between 45% and 100% higher than their corresponding values twenty years before with the exception of Cameroon where the consumption has increased multifold. Compared to the others ECCAS country it is possible to notice special dynamics for the final energy consumption for Congo, after the year 1997. The drop in consumption in Congo after 1997 is amenable to the Civil War during the years 1997-1999. With a final energy consumption in Congo in 1999 as much as 50% lower than the levels in 1990, this is a clear example of how political instabilities can highly influence the energy system of a country. It is as well possible to notice how after the civil war the levels of consumption grew back steadily, until reaching in 2010 levels 44% higher than in 1990.

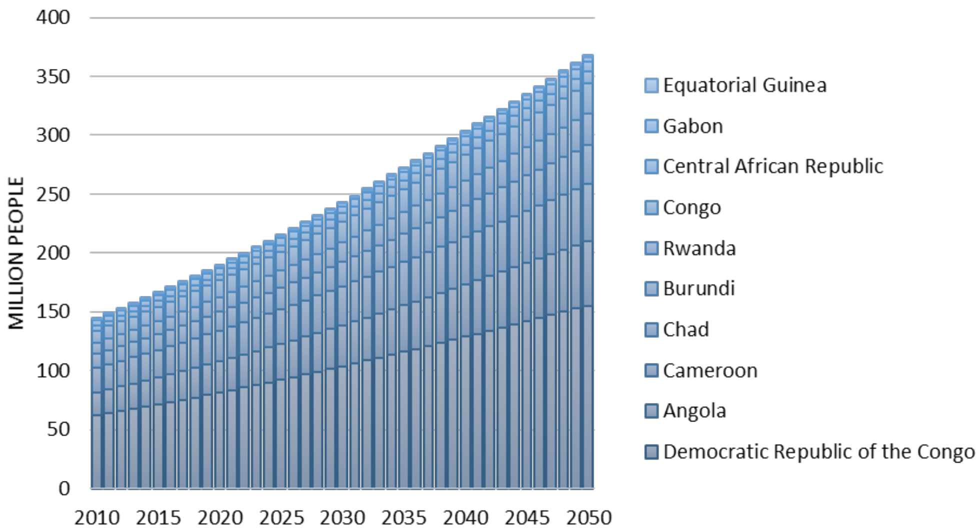
Figure D-61: Final Energy Consumption - relative increase for selected countries



Source: (IEA, 2013)

Regarding population, ECCAS countries, had a combined population of approximately 170 million people in 2014, the Democratic Republic of Congo being the most populous state with almost 80 million inhabitants. Projected growth rates, shown in Figure D-62 , are on average over 2% in the region during the years 2015-2050 (IMF, 2014). As a consequence population in the region is expected to be over double in 2050 – 120 % increase – compared to the levels of 2015. The Democratic Republic of Congo accounts for over 40% of the additional population in the years 2015-2040.

Figure D-62: Regional Population – CAPP



Source: (*World Population Prospects, the 2012 Revision*, 2013)

CAPP Specific Assumptions and Data Tables

Energy demands

The energy demand in the Central African Power Pool varies by country, with relative disparities between different countries within the region. With a total demand in 2050 estimated to reach 151TWh by the end of the study period however, the CAPP remains the smallest of the four power pools analysed for this exercise respectively by ratios 6.4, 3.6 and 10.5 for the SAPP, WAPP and EAPP. The three largest countries in terms of absolute consumption are the DRC, Angola and Cameroon – respectively. They account for 38.5%, 19.9% and 25.5% of the total demand between 2015 and 2050. Remaining countries share 17% of regional power requirements relatively equally with absolute values of between 0.4GWh and 7GWh in 2050. From a demand growth perspective the region is expected to progress at rates of between 4% and 12% (average five year growth rates) until 2030 and most countries maintain these high values through to 2040 falling to an average of 1.6% for the last five year period only.

In this modelling exercise, the total final consumption of electricity is further split between three sectors. This specific split is shown in Figure D-64 showing a small progression of rural demand relative to much larger progressions of urban and industrial sectors.

Figure D-63: Total WAPP Energy demand per country

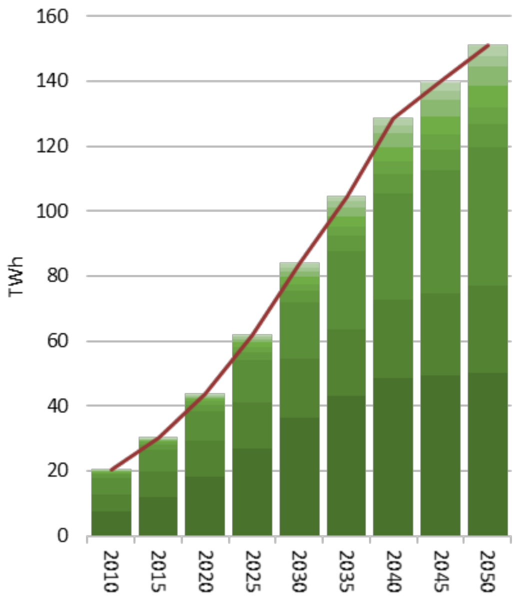
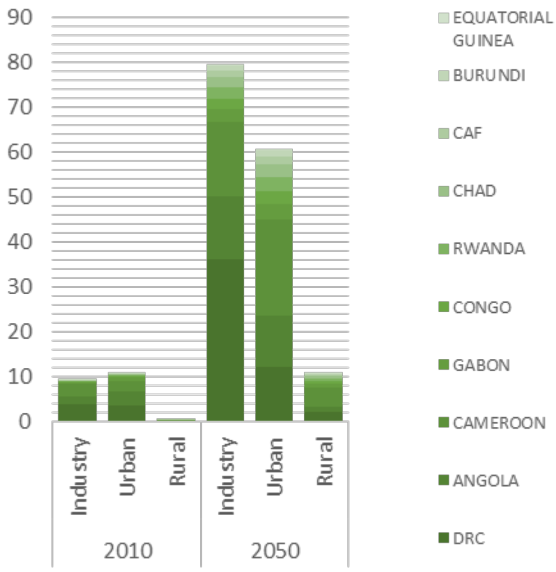


Figure D-64: WAPP Energy Demand: Sectorial Split



Time Slices and Load Curve

The CAPP model considers a break-down of the year into twelve months and four different day parts bringing the total number of representative 'time slices' to 48. The fraction of the year accounted for in each 'time slice' is given in Table D-11.

Correspondingly, a certain amount of the total energy requirements occur in each time slice. This percentage is calculated for the three demand types that are considered and reported in Table D-59, Table D-60 and Table D-62. In the absence of more detailed data, these fractions are maintained constant from one country to the next and over the whole study period.

Table D-58: EAPP Time Slice definition

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Part 1	0.02123	0.01918	0.02123	0.02055	0.02123	0.02055	0.02123	0.02123	0.02055	0.02123	0.02055	0.02123
Part 2	0.02477	0.02238	0.02477	0.02398	0.02477	0.02397	0.02477	0.02477	0.02398	0.02477	0.02398	0.02477
Part 3	0.02123	0.01918	0.02123	0.02055	0.02123	0.01769	0.01769	0.01769	0.02009	0.02123	0.02055	0.02123
Part 4	0.01769	0.01598	0.01769	0.01712	0.01769	0.01998	0.02123	0.02123	0.01758	0.01769	0.01712	0.01769

Table D-59: Industrial Demand Load Curve

Industrial	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Day Part 1	0.02123	0.01918	0.02123	0.02055	0.02123	0.02055	0.02123	0.02123	0.02055	0.02123	0.02055	0.02123
Day Part 2	0.02477	0.02238	0.02477	0.02398	0.02477	0.02398	0.02477	0.02477	0.02398	0.02477	0.02398	0.02477

Day Part 3	0.02123	0.01918	0.02123	0.02055	0.02123	0.01769	0.01769	0.01769	0.02009	0.02123	0.02055	0.02123
Day Part 4	0.01769	0.01598	0.01769	0.01712	0.01769	0.01997	0.02123	0.02123	0.01758	0.01769	0.01712	0.01769

Table D-60: Rural Demand Load Curve

Rural	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Day Part 1	0.02123	0.01918	0.02123	0.02055	0.02123	0.02055	0.02123	0.02123	0.02055	0.02123	0.02055	0.02123
Day Part 2	0.02477	0.02238	0.02477	0.02398	0.02477	0.02398	0.02477	0.02477	0.02398	0.02477	0.02398	0.02477
Day Part 3	0.02123	0.01918	0.02123	0.02055	0.02123	0.01769	0.01769	0.01769	0.02009	0.02123	0.02055	0.02123
Day Part 4	0.01769	0.01598	0.01769	0.01712	0.01769	0.01997	0.02123	0.02123	0.01758	0.01769	0.01712	0.01769

Table D-61: Urban Demand Load Curve

Urban	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Day Part 1	0.02123	0.01918	0.02123	0.02055	0.02123	0.02055	0.02123	0.02123	0.02055	0.02123	0.02055	0.02123
Day Part 2	0.02477	0.02238	0.02477	0.02398	0.02477	0.02398	0.02477	0.02477	0.02398	0.02477	0.02398	0.02477
Day Part 3	0.02123	0.01918	0.02123	0.02055	0.02123	0.01769	0.01769	0.01769	0.02009	0.02123	0.02055	0.02123
Day Part 4	0.01769	0.01598	0.01769	0.01712	0.01769	0.01997	0.02123	0.02123	0.01758	0.01769	0.01712	0.01769

Regional fuel provision and costs

Additional to the general assumptions for this paragraph that are detailed in the body of the Main Modelling Annex, the Central African Power Pool has a specific set of data assumptions regarding the availability and cost of fossil fuels due to its particular level of reserves Table D-62 lists the identified fossil resources available to each country in the region. The corresponding cost of extracting these fuels is included in the overall fuel price listed in Table D-63 .As a first pass assumption used to differentiate the two types of fuel, imports of a given commodity are costed using the domestic per unit cost increased by a standard 10%. (See Annex D1- OSeMOSYS Common Modeling Assumptions Main Methodology Assumptions for further details)

Table D-62: National identified fossil reserves in TWh – CAPP [2013]

Country	Coal*	Crude Oil **	Natural Gas
Angola	0.00	18588.77	3867.51
CAF	18.74	0.00	0.00
Congo	0.00	2840.69	957.53
Cameroon	0.00	355.09	1427.31
Gabon	0.00	3550.86	299.23
Equatorial Guinea	0.00	1952.97	388.99
Chad	0.00	2663.15	0.00
DRC	549.85	319.58	10.47
Rwanda	0.00	0.00	598.45

Burundi	0.00	0.00	0.00

*2008 data, **2011 data
Source: (EIA, 2014)

Table D-63: Cost of domestic fuel extraction [USD/ToE]

	Angola	Burundi	DRC	CAF	Congo	Cameroon	Gabon	Equatorial Guinea	Rwanda	Chad
Biomass	62.4	150.7	62.4	62.4	62.4	62.4	62.4	62.4	150.7	62.4
Coal	125.6	150.7	125.6	83.7	83.7	83.7	83.7	83.7	150.7	83.7
Diesel	0.0	640.6	917.3	1055.5	1055.5	1055.5	1055.5	1055.5	640.6	1055.5
HFO	540.5	569.4	540.5	682.4	682.4	682.4	682.4	682.4	569.4	682.4
Natural Gas	355.9	242.8	355.9	431.7	431.7	431.7	431.7	431.7	242.8	431.7

Source: (Miketa and Merven, 2013) (Department Of Energy, 2011)

Renewable Energy Potentials

Renewable energy potentials over Sub Saharan Africa are significant. In addition to the levels of hydropower available in each country, solar and wind based potentials for electricity generation are included. Based on recent IRENA estimates for the continent (Hermann et al., 2014), the total theoretically available renewable power for the CAPP could fall just short of 109 thousand TWh. Although six times lower than corresponding levels in the SAPP, this power represents an important opportunity.

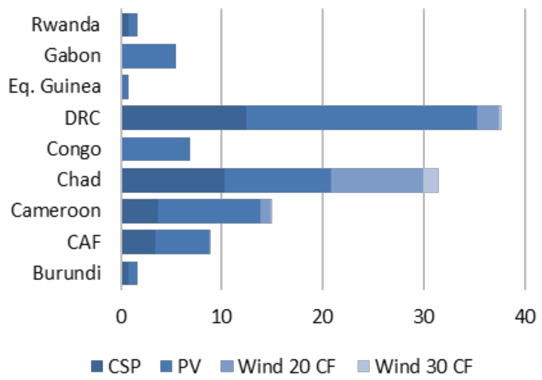
From a geographical perspective this resource spread unevenly between the countries in the region. Due in part to the difference between effective resource levels and their technical availability, this distribution highlights the potential advantage of increased interconnection. As renewable resource availability suffers from variable intermittency, a strong interconnected grid becomes an advantage for both distributing risk and absorbing the resource as soon as it becomes available.

As a summary of these potentials, Table D-64 presents the upper limits extracted from the literature and used in to provide country level resource constraints for the renewable technology options.

Table D-64: Renewable Energy Potential per Country

	[TWh per year]			
	CSP	PV	Wind	
			20 CF	30 CF
Burundi	786	888		
CAF	3,471	5,284	79	
Cameroon	3,706	10,105	979	15.9
Chad	10,284	10,506	9,165	1,519.40
Congo	2	6,887		
DRC	12,439	22,862	2,173	165
Eq. Guinea		706		
Gabon	6	5,402		
Rwanda	789	892		

Figure D-65: Thousand TWh of Renewable Potential



Source: (Hermann et al., 2014)

In parallel to these resource availability limits, the energy models consider two types of constraints on renewable technologies. The first assumes a cap on the amount of new capacity that can be added to the system on a yearly basis, while the second restricts the total penetration of renewable energy in the overall mix in order to ensure conservative shares of lower reliability technologies in the final generation.

Please note that assumptions regarding Hydropower are listed in a separate paragraph due to the important focus of the present study on that specific resource.

Techno Economic parameters

The technology options available within of the power pool model are linked to corresponding generic parameter values. These are presented and referenced in Table D-18.

Table D-65: Techno Economic Data for generic power plants

Power Plant (Technologies)	**Capital Cost ($/kW)**	**Variable O&M Cost (USD/GJ)**	**Life time (Years)**	**Construction (Years)**
Biomass	3660	5.6	30	4
Coal	3519	4.0	35	4
Diesel 100 kW (Industrial)	659	15.4	20	0
Diesel 1kW (Rural)	692	9.2	10	0
Diesel 1kW (Urban)	692	9.2	10	0
Diesel (Centralized)	1177	4.7	30	1
Geothermal	5856	1.4	25	4
HFO	1634	4.2	25	2
Gas Turbine (Combined cycle)	1423	0.8	30	3
Gas turbine (Other cycles)	730	5.5	25	2

Nuclear	10778	3.9	60	8
CSP	4392	6.2	25	4
CSP with Storage	10249	4.6	25	4
CSP with Gas Co-firing	2033	4.6	25	4
Solar PV Utility	2200	5.6	25	1
PV Rural Rooftop	2100	4.2	20	<1
PV Rural rooftop 1hr storage	4258	4.2	20	<1
PV Rural rooftop 2hr storage	6275	4.8	20	<1
PV Urban Rooftop	2100	4.2	20	<1
PV Urban rooftop 1hr storage	4258	4.8	20	<1
PV Urban rooftop 2hr storage	6275	5.3	20	<1
Wind 25% Capacity Factor	2862	4.0	25	2
Wind 30% Capacity Factor	2420	4.0	25	2
Generic Large Hydro	3221	1.7	50	5
Generic Micro Hydro	4800	1.5	30	2

Source: (Miketa and Merven, 2013)

Assumptions about planned infrastructure investments

Energy infrastructure development is a long process that goes through a number of project phases before the physical power plant comes online and provides energy to the system. In order to take into account this lead time in project development, the first years of the modelling framework are constrained to ensure that actual infrastructure investment results and current committed national plans line up. Note that in the case of the CAPP there is little documentation available in terms of either national or regional level Master Plan relating to power systems development in the future. The data representing existing thermal power is therefore re-aggregated based on (UDI PLATTS, 2012).

With a specific focus on hydro power, Table D-66 details the specific list of power plants that are included in the OSeMOSYS energy modelling framework for the CAPP. These power plants fall into five different categories:

- Power plants are split into two categories are based on (1) their presence or (2) not in the regional WEAP water models: this defines whether or not the power plant receives direct or proxied information for the climate scenario runs.
- A second split into three categories based on the status of the power plant: i.e. whether the facility is (A) historic capacity (existing), (B) committed new capacity or (C) planned new capacity.

The table further details the correspondence between the OSeMOSYS power plants and their WEAP counterparts by naming the power plant that was used to derive capacity factor variations related to the six climate change scenarios under analysis. Finally, power plant level techno-economic data is listed in regard to each facility. Where site specific data was not available it was replaced by generic data.

The number of power plants considered here covers 55 facilities and totals a relatively modest 11.4GW of available and new capacity. It is worth noting is that a large majority of the CAPP countries are outside the catchment area of the major river basins considered in this study. Specifically, only two facilities from DRC and one facility from Burundi are directly included in the WEAP basin models to which this power pool is related.

Table D-66: Site Specific Hydro power plant parameters

Name of the plant	WEAP Proxy	River Basin	Capacity (MW)	Capital Cost ($/kW)	Fixed Cost ($/kW)	Variable Cost ($/GJ)	Status[41]	Earliest Year
Angola								
Capanda II	Busanga	Congo	260	1418	9.35	0.45	CON	2010
Cambambe II	Busanga	Congo	860	3182	9.35	0.45	CON	2012
Kuanza Basin	Busanga	Congo	5480	1879	9.35	0.45	PLN	2014
Gove	Busanga	Congo	135	1036	9.35	0.45	CON	2012
Low availability (Mabubas, Biopia)	Busanga	Congo	26	0	9.35	0.45	HC	
High availability (Cambambe, Capanda, Matala)	Busanga	Congo	474	0	9.35	0.45	HC	
Burundi								
Consolidated Historic	Rusumo Falls	Nile	30.1	0	21.00	0.32	HC	
Kabu 16	Rusumo Falls	Nile	20	2943	3.83	0.06	CON	2015
Mphanda	Rusumo Falls	Nile	10	6548	4.11	0.06	CON	2016
Siguvyayae	Rusumo Falls	Nile	90	4869	3.82	0.06	PLN	2016
Rusumo	Rusumo Falls	Nile	20	0	21.00	0.32	PLN	2017
Ruzizi III	Rusumo Falls	Nile	48.3	2553	21.00	0.32	PLN	2018
Ruzizi IV	Rusumo Falls	Nile	95.7	2553	21.00	0.32	PLN	2019
Mule 34	Rusumo Falls	Nile	17	3070	21.00	0.32	PLN	2016
Jiji 3	Rusumo Falls	Nile	16	4179	21.00	0.32	PLN	2016
Kaganuzi A	Rusumo Falls	Nile	34	2296	21.00	0.32	PLN	2016
Kaganuzi Complex	Rusumo Falls	Nile	39	5357	21.00	0.32	PLN	2016
Ruzizi II (Historic)	Rusumo Falls	Nile	12	2553	21.00	0.32	HC	
DRC								
Busanga	Busanga	Congo	240	3221	9.35	0.45	PLN	2016
Mwadingusha		Congo	68	0	9.35	0.45	HC	
Grand Inga	Grand Inga	Congo	39000	3221	9.35	0.45	PLN	2027
Inga 3	Inga 3	Congo	7.8	3221	9.35	0.45	PLN	2016
Nseke	Nseke	Congo	236	3221	9.35	0.45	HC	
Inga I	Inga I	Congo	360	0	9.35	0.45	HC	
Zonga	Zongo	Congo	40	0	9.35	0.45	HC	
Sanga	Sanga	Congo	11.5	3221	9.35	0.45	HC	
Nzilo	Nzilo	Congo	120	3221	9.35	0.45	HC	
Koni		Congo	42	0	9.35	0.45	HC	
Inga II	Inga II	Congo	1424	0	9.35	0.45	HC	
Ruzizi II	Ruzizi II	Congo	14.3	3221	9.35	0.45	HC	
Ruzizi III	Ruzizi III	Congo	90	3221	9.35	0.45	PLN	2016
Mobaye	Mobaye	Congo	12	3221	9.35	0.45	PLN	2016
Katende	Katende	Congo	20	3221	9.35	0.45	PLN	2016
Tshopo	Tshopo	Congo	9.5	3221	9.35	0.45	PLN	2016
Central African Republic								
Baidou	Mobayi	Congo	3.31	4000	21.00	1.51	PLN	2015
Boali-III	Mobayi	Congo	10	1282	21.00	0.32	PLN	2018
Dimoli	Mobayi	Congo	185	1282	21.00	0.32	PLN	2020
Boali	Mobayi	Congo	18.65	2553	21.00	0.32	HC	
Small Hydro I	Mobayi	Congo	0.101	2553	0.00	1.51	HC	
Republic of Congo								

[41] CON: Under Construction; HC: Historic Capacity, i.e. existing; PLN: Planned Capacity

Imboulou	Sanga	Congo	120	1282	21.00	0.32	CON	2012
Komo	Sanga	Congo	12	4000	21.00	1.51	PLN	2015
Gamboma	Sanga	Congo	14	1282	21.00	0.32	PLN	2018
Liouesso	Sanga	Congo	13	1282	21.00	0.32	PLN	2018
Djoue	Sanga	Congo	15	2553	21.00	0.32	HC	
Moukoukoulou	Sanga	Congo	74	2553	21.00	0.32	HC	
Cameroon								
Kadey River	Ladgo	Niger	12	4000	21.00	1.51	PLN	2018
Bini	Ladgo	Niger	75	1282	21.00	0.32	PLN	2018
Memve	Ladgo	Niger	200s	1282	21.00	0.32	CON	2016
Lom-Pangar	Ladgo	Niger	29.6	1282	21.00	0.32	CON	2016
Songmbengue	Ladgo	Niger	1000	1282	21.00	0.32	PLN	2020
Nachtigal	Ladgo	Niger	330	1282	21.00	0.32	PLN	2020
Small Hydro II	Ladgo	Niger	0.069	2553	0.00	1.51	HC	
Existing Hydro I	Ladgo	Niger	654.6	2553	21.00	0.32	HC	
Ladgo	Ladgo	Niger	80	2553	21.00	0.32	HC	
Gabon								
Fene	Guarara	Niger	0.2	4000	21.00	1.51	PLN	2011
Okano	Guarara	Niger	290	1282	21.00	0.32	Partly	2014
Mbigou	Guarara	Niger	0.2	2553	0.00	1.51	HC	
Bongolo	Guarara	Niger	6.23	2553	21.00	0.32	HC	
Kinguele	Guarara	Niger	163.76	2553	21.00	0.32	HC	
Equatorial Guinea								
Djibloho	Guarara	Niger	120	1282	21.00	0.32	CON	2012
Small Hydro III	Guarara	Niger	1.35	2553	0.00	1.51	HC	
Riaba	Guarara	Niger	3.6	2553	21.00	0.32	HC	
Rwanda								
Mukungwa	Rusumo Falls	Nile	12.5	2000	21.00	0.32	HC	
Gihiria	Rusumo Falls	Nile	1.8	2000	21.00	0.32	HC	
Gisenyi	Rusumo Falls	Nile	1.2	2000	21.00	0.32	HC	
Nyabarongo	Rusumo Falls	Nile	28	5342	3.90	1.51	PLN	2014
Rukarara	Rusumo Falls	Nile	95	2553	21.00	0.32	PLN	2014
Ruzizi II (12MW, shared)	Rusumo Falls	Nile	12	1	21.00	0.32	HC	
Ruzizi I (15MW, shared)	Rusumo Falls	Nile	15	0	21.00	0.32	HC	
Ruzizi III (48,3MW, shared)	Rusumo Falls	Nile	48.3	2553	21.00	0.32	0	2018
Ruzizi IV (95,7MW, shared)	Rusumo Falls	Nile	95.7	2553	21.00	0.32	0	2019

Source:(Miketa and Merven, 2013) (UDI PLATTS, 2012)

Assumptions regarding Transmission and Distribution

National transmission and distribution systems include four types of lines connecting two different levels of the energy system. Since data regarding current levels of system development on a national level are not readily available, initial model runs of the regional CAPP model is used to reverse engineer the capacity levels required to cover existing demand in each individual country. These levels are then considered fixed in the first year of the modelling.

Further, each type of line suffers losses which translate into different transmission efficiencies. These efficiencies may also vary for a single type of line from one country to another depending on the state of the system. The values used in this study and presented in Table D-67 for reference. Note that these are maintained constant over the study period from lack of valid data regarding their specific evolution over time.

Table D-67: National T&D line efficiencies

	Angola	Burundi	Cameroon	CAF	Chad	Congo	DRC	Eq. Guinea	Gabon	Rwanda
Transmission	0.95	0.9865	0.9865	0.9865	0.9865	0.9865	0.95	0.9865	0.9865	0.982
Dist. Industrial	0.98	0.989	0.989	0.989	0.989	0.989	0.97	0.989	0.989	0.9991
Dist. Urban	0.8	0.9845	0.9845	0.9845	0.9845	0.9845	0.75	0.9845	0.9845	0.9928
Dist. Rural	0.7	0.88	0.88	0.88	0.88	0.88	0.8	0.88	0.88	0.88

In addition to national level T&D, each country in the region has the potential for connection to neighbouring systems. In the specific situation of the CAPP however the number of – and available information regarding – existing connection lines between countries is comparatively low with respect to the other power pools of SSA. What data is available is presented in Table D-68 for existing systems while Table D-69 summarises the project options that are included in the modelling framework. Note that these are divided between "Committed" and "Future" in relation to the level of certainty that the corresponding project will be implemented. The first are therefore forced in to the solution space whereas the second are simply made available to the system and are considered as part of the optimisation. Note that the denominations "Country1" resp. 2 are simply used to define the two neighbours that are connected by the transmission project. Energy is not constrained to flow in a particular direction but rather is traded bi-directionally depending on the unit cost of electricity generation in each country.

Table D-68: International Transmission - Existing Infrastructure

Country 1	Country 2	Capacity (MW)
DRC	Rwanda	157
	Burundi	45
	Burundi	100
	Congo	60

Table D-69: Future International transmission projects

Country 1	Country 2	Capacity (MW)	Earliest
Westcor (DRC, Namibia, Angola, Botswana, South Africa)		1500	2020
DRC	Burundi	330	2014
	Rwanda	370	2014
	Angola	600	2016
Angola	Namibia*	400	2016
Congo	Gabon	600	2020
Gabon	Equitorial Guinea	600	2020
Equitorial Guinea	Cameroon	600	2020
Burundi	Rwanda	330	2015
Cameroon	Chad	125	2020

**Country not considered in this model – simply taken into account using trade from previous power pool runs.*
Source: (EAPP/EAC, 2011) (ICA, 2011)

Integration with other power pools

This modelling effort was conducted as an integral component of the larger vulnerability assessment of African infrastructure. In this study, the four Sub Saharan power pools (CAPP; EAPP; SAPP and WAPP) were modelled separately but have a certain number of overlapping countries and overlapping infrastructure. In the case of the WAPP, this is particularly relevant for the Grand Inga projects and the DRC. Considering that each power pool is optimized separately under an iterative approach with the water modelling component of the project, this overlap adds an extra level of complication.

To ensure that results are consistent between power pools, a few simple procedures were applied. First, power pools were optimized in a specific order aligned with the perceived importance of their impact on continent scale results: SAPP was followed by WAPP, EAPP and CAPP. Second, countries that were included in several power pools were optimized only once along with the first power pool in which they appear. Thereafter, when contributing to other power pools they are constrained both in terms of capacity and minimum dispatch to respect the results from the previous model runs.

For further details about the constraints applied and the corresponding countries that they were applied to, please refer to the main methodology annex

Results

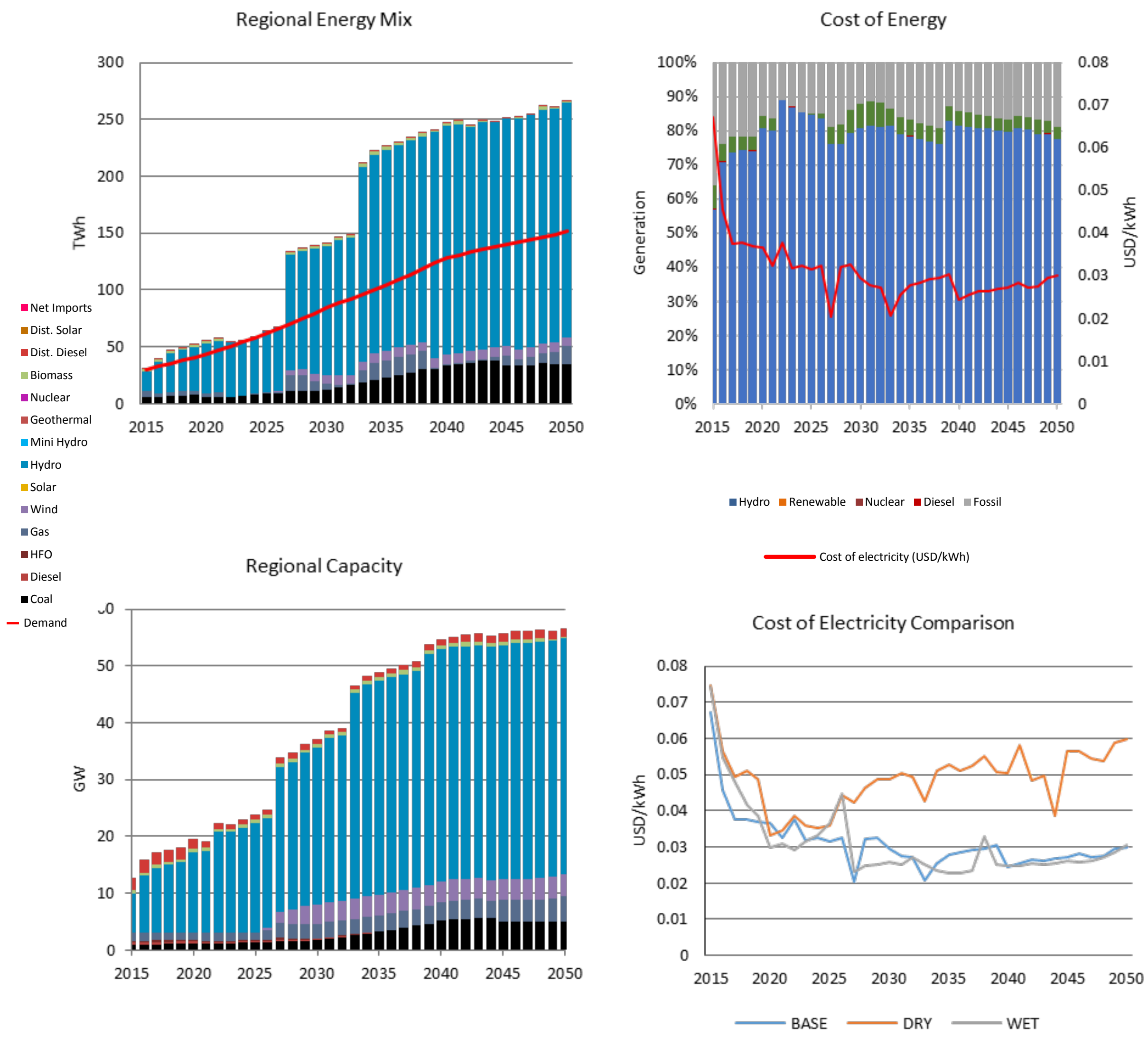
Regional Results

The Central African Power Pool differs from other power pools considered in this study in so much as it is optimised separately from the seven river basins that were accounted for. As such, the results that are presented here do not include significant adaptation measures as are available in other power pools where hydropower is scaled – where possible – as a function of the climate.

From a regional perspective, the CAPP is also the smallest of the existing systems in SSA. With an installed capacity in 2015 of just 12.6 GW, this power pools represents 18% of the corresponding capacity in 2015 in the SAPP or one-third of the Egyptian system.

To illustrate its expansion, we report results from a base run that assumes historical climate conditions continue to prevail into the future that show a regional system dominated by hydropower (see Figure D-66). Related mainly to the level of capacity available in the Inga region, the DRC represents 77% of all power generated in the power pool. Making up the remainder, other countries also rely on hydropower – where available – as well as small amounts of centralized fossil based generation is complemented by contributions from wind power and distributed diesel systems. Note that the high level of generation as compared to the demand in the region relates to the important levels of trade between the DRC and the other power pools.

Figure D-66: Capacity and Generation mix Summary



This high reliance on large amounts of hydropower has a clear impact on the cost of power generation[42] bringing it to levels as low as 0.03 USD/kWh in both base and wet climates and never exceeding 0.06 USD/kWh in the driest scenario. This value is relatively higher in the beginning of the simulation due to the inadequacy of existing capacity levels in the region which causes significant difficulties for meeting demand on a national level. In the present setup only expensive oil based systems are assumed available in these early periods as they are easy and fast to install with little to no planning. It is also noticeable that the region stands to pay relatively higher energy prices in dryer scenarios than in wetter ones: related mostly to the large infrastructure in the DRC, but also to smaller capacities spread out in the rest of the power pool, this could multiply the unit cost of electricity generation by as much as 2.3 in selected years.

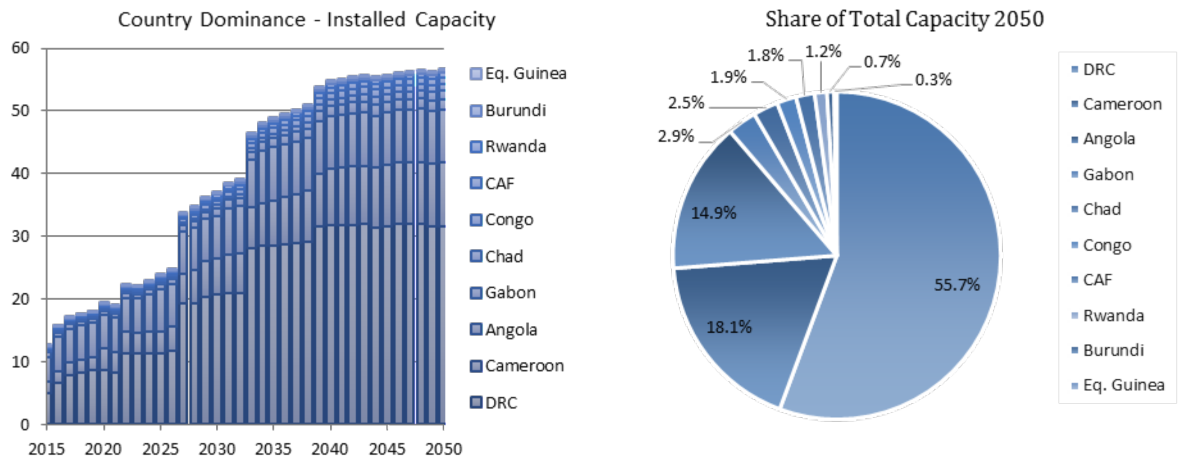
[42] Calculated for the region as the total annualised system cost divided by the total generation in the power pool. Annualised system costs are the undiscounted sum of all annual running costs as well as investment costs spread over power plant operational life time. On a national level this cost is adjusted to include the costs (resp. benefits) of traded energy valued using the regional (resp. domestic) cost of generation.

A regional energy system with an important player: DRC

Largest country in SSA in terms of shear geographical area, and eleventh country worldwide, the Democratic Republic of the Congo represents 55.7% of all installed capacity in the Central African Power Pool by the end of the modelling period. Followed by Cameroon, two thirds smaller, and Angola, this represents a total installed capacity of 31.5 GW. Consisting of a majority of hydropower, this total increases incrementally over the study horizon with each new instalment of the Grand Inga project, each of which is larger than the total installed capacity of Gabon – fourth largest system in the region by 2050.

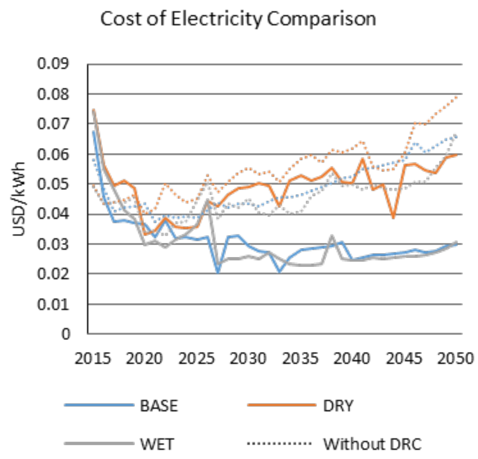
The driver for these large investments into the DRC and the seemingly over-installed situation of this country is linked to the large amounts of exported energy that it delivers to the other power pools over the study period. Trade connections also exist within the CAPP but are currently under developed and under exploited leaving smaller systems to develop much in isolation at their own expense.

Figure D-67: Country capacity of the SAPP



When considering the system removed of the DRC however the cost picture changes significantly. The domination of hydropower is reduced to 48% of total installed capacity in 2050 – which is still remarkable – and is complemented by 18.5% coal, 12% gas 6% oil and 15.5% other renewable based generation. This translates into an overall increase in scenario unit cost of electricity generation trends. Considering Figure D-68, it appears that this increase is minimal in the wetter of the two climate cases presented where it will nevertheless reach highs of 34% between 2015 and 2050. It also appears that the spread between these two extremes is reduced with maximum cost differences from the wet to the dry scenario being reduced to 0.02 from 0.033 USD/kWh over the study period.

Figure D-68: Cost of electricity variation: the impact of the DRC throughout all scenarios



Key Messages

In order to maintain a level of consistency between the Power Pool studies, increase report readability as well as offer more opportunity for result comparison between power pools, key messages – also reported in the global project Synthesis report – have been developed and are presented in the following paragraphs. Please note that, throughout these explanations, the terminology "Wet" and "Dry" is adopted to describe scenarios that are considered to have respectively higher or lower amounts of available water for energy generation over the period. This does not however translate to each and every month/year of the corresponding scenario being systematically richer/poorer in water resource than the base: this terminology is true "on average over the model period" only.

Further, while a full description of scenarios and methodology are included in the 'Main Methodology Annex: D1- OSeMOSYS Common Modeling Assumptions' of this work it is worth noting that two scenario families reported here. These include 'perfect foresight' (PF) scenarios, in which the model is allowed some level of freedom to invest in an array of non-hydro alternatives while a certain level of capacity adjustments are made in parts of the hydro infrastructure. This PF scenarios setup allows the model to 'anticipate' climate change and – to some degree – adapt accordingly. The second set of families includes so called 'no adaptation' (NA) scenarios, in which climate change is not anticipated and electricity generation shortfalls are met with expensive back-up generators. Each family is run across the same set of selected climate futures. The 'historic' climate is one future based on historic trends.

Large infrastructure investments are required to underpin future growth in Africa

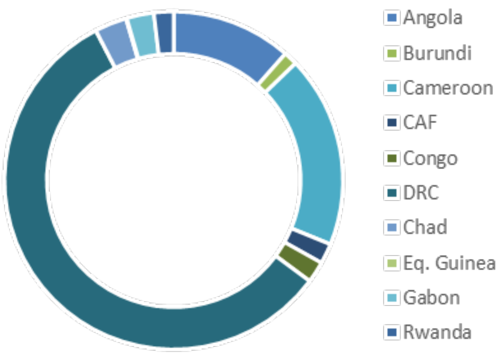
Providing the growing demand requirements in the CAPP is a challenge for this developing region and stands to expand the existing system by an additional 59.8GW (incl. retirements) between 2015 and 2050 in the base scenario. This includes significant increases in installed capacity in the DRC representing 54.3% of this total. Reaching a total installed capacity of 56.6GW by the end of the modelling period, this represents a factor 4.5 increase as compared to current levels; a significant part of which will take place in Cameroon and Angola which are, after DRC, the second and third largest systems in the region with 18.39% and 15.6% of all new capacity investments (see Table D-70)[43].

When including the DRC, hydro accounts 64% of the aforementioned total – 72.1% of which is located in the DRC. . When considering the subsystem of the CAPP with DRC artificially removed, the picture changes and gives a significantly larger share of new capacity to fossil fuels: natural gas, oil and coal based systems represent 12.6%, 14% and 20.2% respectively. The remaining share is composed of 10.6GW of hydropower – i.e. 38.8% of new capacity – and 3.8GW of wind power.

Table D-70: Cumulative New Capacity per country – 2015 to 2050 – CAPP

	GW	%
Angola	9.33	15.60%
Burundi	0.39	0.65%
Cameroon	11.00	18.39%
CAF	1.17	1.96%
Chad	1.55	2.59%
Congo	1.20	2.01%
DRC	32.5	54.35%
Eq. Guinea	0.16	0.27%
Gabon	1.85	3.09%
Rwanda	0.65	1.09%
TOTAL	**59.8**	

Figure D-69: Country share on Undiscounted Investments (2015-2050)



In investment terms, these new additions mean that the region will expend an undiscounted cost over the model period in excess of 138 Billion USD to generate electricity. This total increases to 181.6 Billion USD when including transmission and distribution system expansion costs. In line with capacity data, the DRC accounts for 57.2% of this total and is followed by Cameroon (18%) and Angola (11%). Finally, considering that the infrastructure cost for hydropower investments is high relative to conventional thermal power plants, this large share of new capacity requires 77% of the total expenditure (excl. T&D) leaving 16% to fossil based generation and 6% only to other renewables.

Note that DRC is reported in both the CAPP and the SAPP reports and has a very specific situation. The resource in hydropower that is available from development projects in the Inga region are substantial and stand to be traded to all four power pools of SSA thereby causing this apparent over installation in the CAPP.

The specific methodology that was followed with regard to including this country in multiple power pool models is described in the main methodology annex and explains the difference in installed capacity reported here and in the SAPP power pool report.

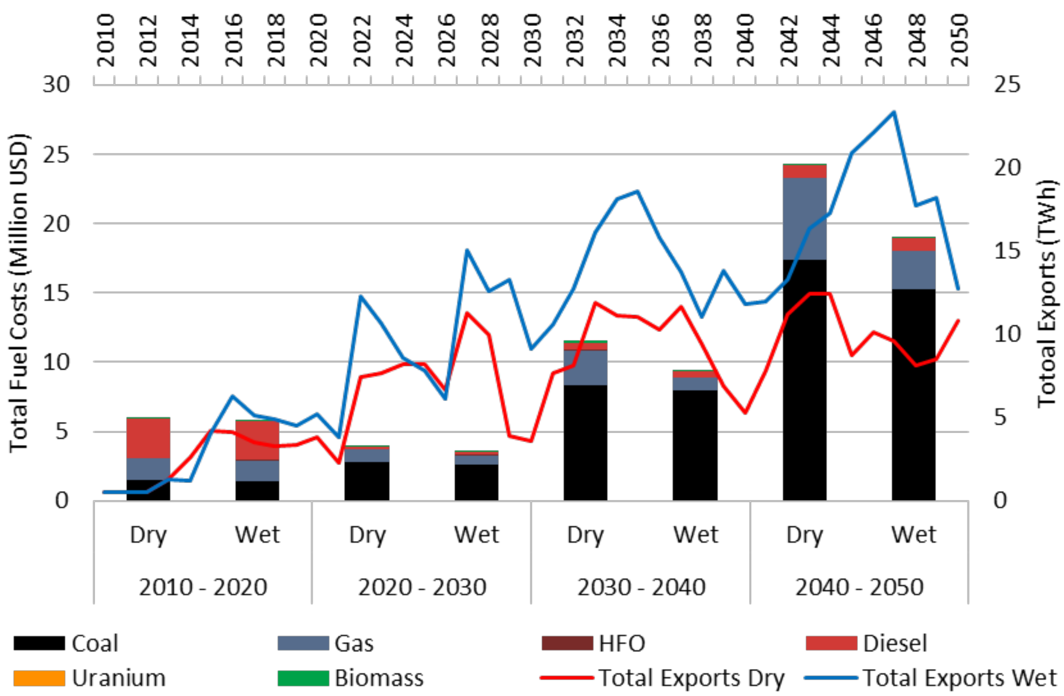
[43] Note that the results presented in this paragraph are extracted for a reference case where the climate is assumed to follow historic evolution trends.

Trade is required to 'unleash' the potential of low cost hydropower

Although the CAPP uses large amounts of domestic hydropower to provide for its growing power needs, it invests in and uses small amounts of fossil based generation over the modelling period in smaller more isolated systems in the center of the region. Based on coal, these systems have a fuel expenditure – shown in Figure D-70 – that is expected to grow significantly from 2010 to 2050 irrespective of the scenario under consideration. These costs are complemented by large expenditures in diesel fuel in the first period – relating to insufficient capacity in countries with developing systems that use this technology as a stop-gap solution – and in natural gas in later years.

The correlation between the levels of trade in the region and the corresponding fuel expenditures has noticeable consequence. On the one hand, it seems apparent that higher levels of trade in the "wetter" scenario happen in parallel to a reduction in overall fossil based fuel spending in the power pool. It is also apparent that the levels of trade between the wet and the dry case differ increasingly over the model period, as do the accumulated fuel expenditures. Finally, the trends for total export amounts in the region follow similar variations over time in both climate scenarios with marked highs/lows at repeated intervals. This relates specifically to the indirect influence of the DRC in the region: the successive increases in hydropower capacity in this country – similar in both scenarios – and the ensuing generation that is made available impacts neighboring countries both inside and outside the power pool through the various trade routes in existence.

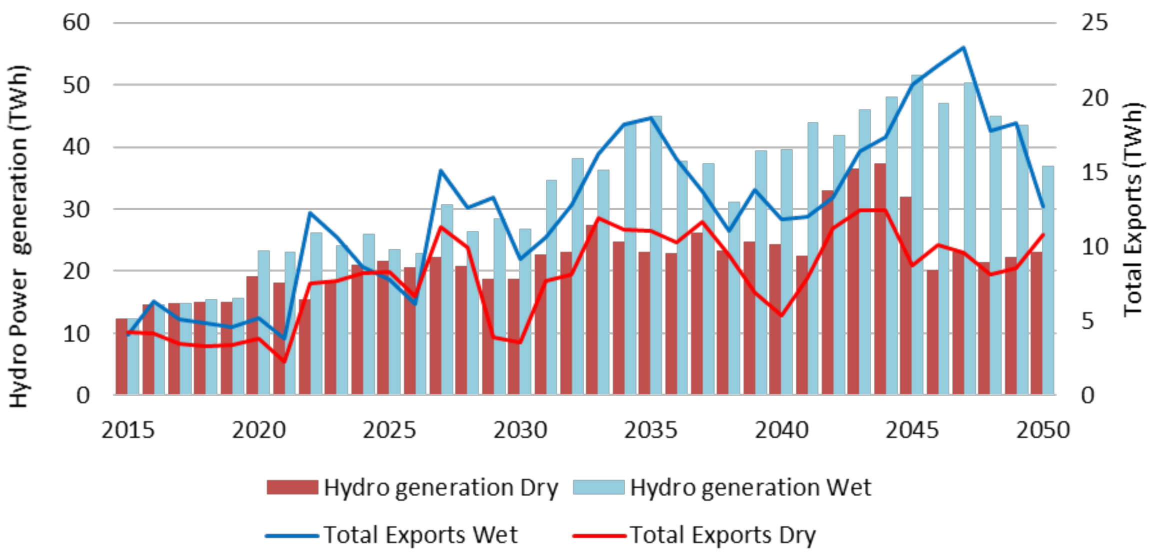
Figure D-70: Total Electricity Exports vs. Total Fuel Expenditure[44]



[44] These results do not contain the DRC the inclusion of which distorts observed dynamics due to its high export volumes to other power pools..

Figure D-71 shows higher levels of detail with regard to the relation between amount of trade taking place in the CAPP and the amount of hydropower generation in occurring in the region. First, it is apparent that levels of hydro based generation vary markedly between the two extreme cases under consideration in this analysis with a change of 33% from the wet to the dry PF scenario – i.e. a reduction of 391 TWh between 2015 and 2050. Second – and notwithstanding the relation to hydro capacity changes in the DRC – the annual variations of total export appear in clear regard to periods of relative hydropower generation change between the two scenarios (see 2045 to 2050 specifically where a change in hydrogenation of 48% corresponds completely to a reduction in volumes of traded power by 51.4%). The inclusion of the DRC confirms these observations although it hides the dynamics of the smaller CAPP region by drowning it in much larger volumes of hydro generation intended – to high degree – for trade to neighboring power pools.

Figure D-71: Total Electricity Exports vs. Hydro Power Generation (TWh)



Adapting to climate change: the role of fossil fuels and non-hydro renewables

Climate change, in this exercise, can have both positive and negative impacts on a country relating specifically to the overall rainfall that can be expected over the study period. In both cases however it is challenging to predict the degree of these changes with any certainty. Further, it is changes in weather pattern as well as each patterns' intra & inter year variability that is cause for increased system costs (See main methodology clarifications relating to the Perfect Foresight Adaptation approach). Finally, it should be noted that

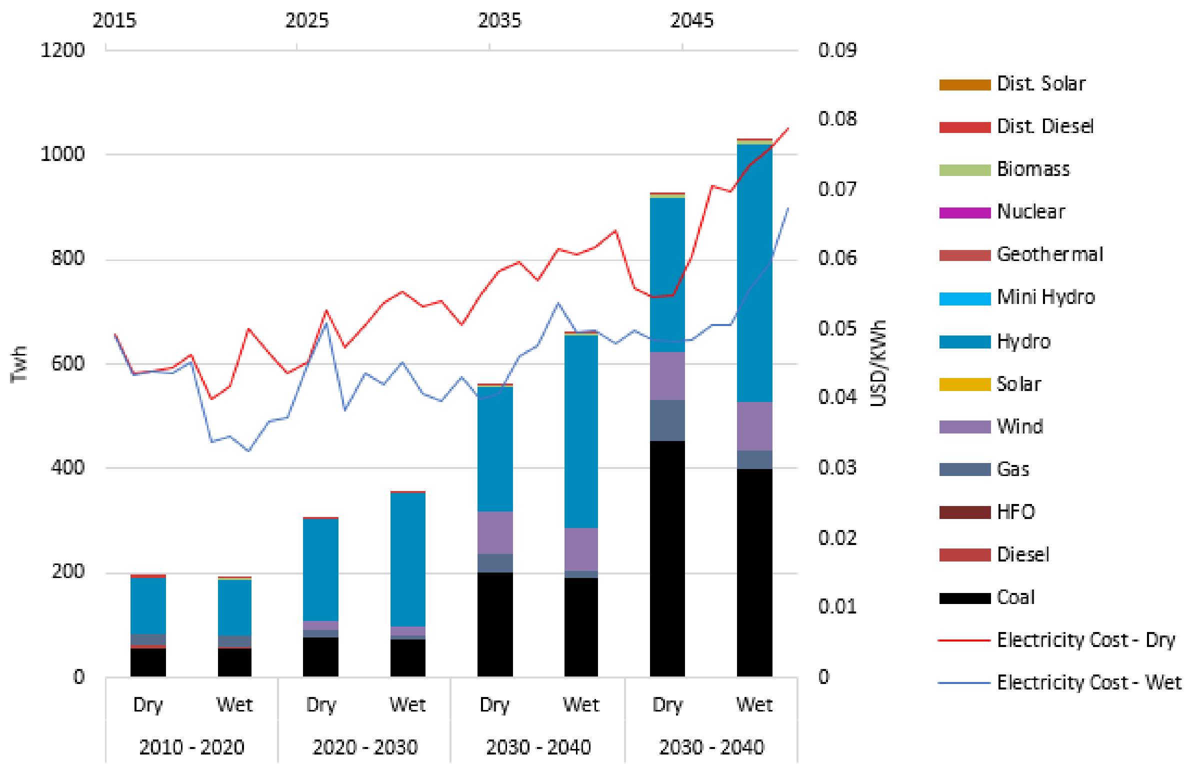
- On the one hand, only a limited number of countries in the CAPP are directly linked to a river basin that was included in this study. This has a bearing on the level of impact that is visible in the results.

- On the other hand, the DRC represents a very large part of this system which is visible in the form and magnitude of many results.

In dry cases, overall rainfall is lower than in the regional reference climate case and the variability of the climate means that large amounts of hydropower may be unavailable from one year to the next. In this situation, the overall system is impacted negatively: new investments in fossil based generation are required and in turn generate higher annual running costs. Conversely, wetter cases offer less stressing conditions through higher overall water availability. Variability from one year to the next remains a challenge though and will mean that unexpected shortages in hydro based generation will be replaced by fossil based generation.

These elements of system dynamics translate into the corresponding costs to consumers in the CAPP. On the one hand, Figure D-72 shows at the regional benefit of the wetter climate resulting in lower costs over the modelling period and correlating with relative clarity to the fossil fuel use offset by hydropower. On the other, the annual variability of the cost trends – including over the wetter scenario, translates both annual change in water availability for hydropower generation, as well as yearly changes in import/export patterns in the region relating to regional climate.

Figure D-72: Total Generation vs. Annualised cost of Electricity[45]

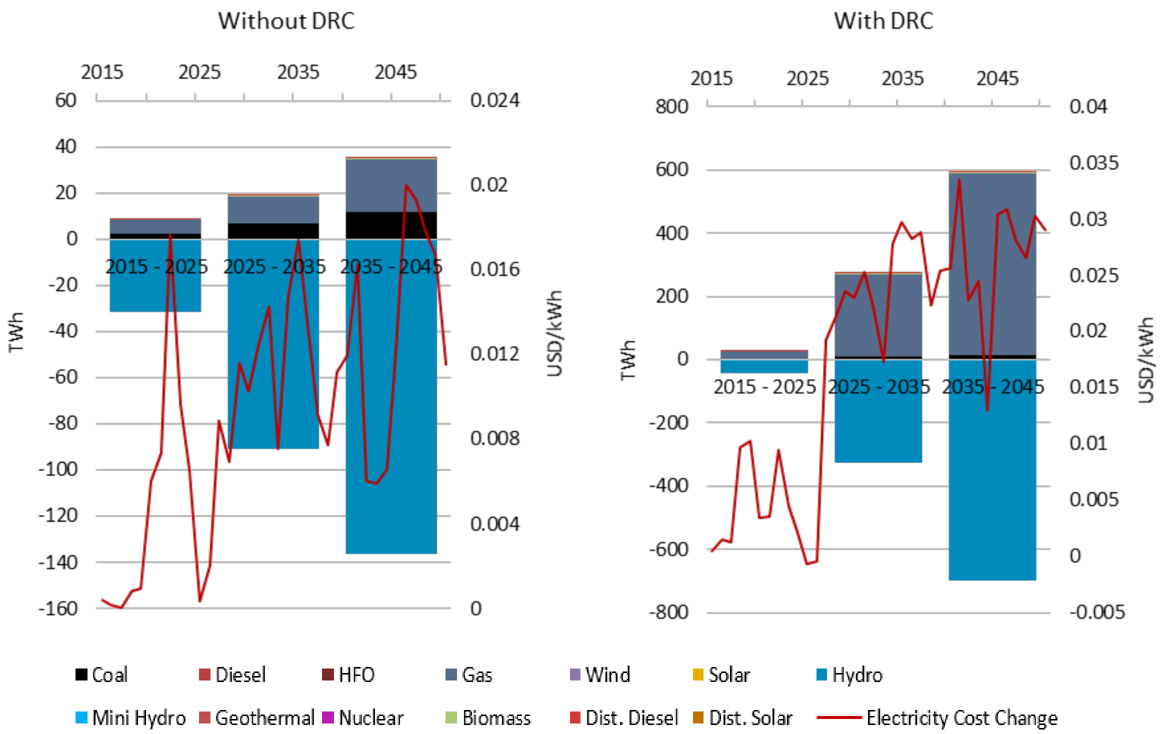


Highlighting more specific dynamics, Figure D-73 shows the relative potential trade-offs in generation mix that arise between wet and dry cases while tracing the corresponding relative variations in unit cost of generation. Further, these results show the large impact that the DRC has on the CAPP as a region. In both cases it appears that the coal and gas based generation would be replaced by regional

[45] These results do not contain the DRC the inclusion of which exacerbates the trends that appear here.

hydropower generation in wetter climate scenarios. Further, illustrated in these graphics it appears that larger amounts of hydropower are required to replace the fossil based generation that is displaced. This relates to the levels of trade in the region: in dryer cases, significant levels of hydropower generation are replaced by a mix of domestic generation and higher levels of trade – in particular in neighbouring countries to the DRC. Finally, comparing the cost impacts of climate change in the system both with and without the DRC shows potential unit cost of electricity increases by up to a factor two. This relates directly to the significant amount of fossil fuel that complements the energy mix in the DRC by the end of the modelling period: although the capacity for hydropower development in the region is considerable the restrictions in terms of timing along with the constraints structure in terms of trade between the DRC and the successive power pools causes higher natural gas incursions into the country's capacity.

Figure D-73: Relative range of Generation mix and Annualised cost change of the 'dry' versus 'wet' climate



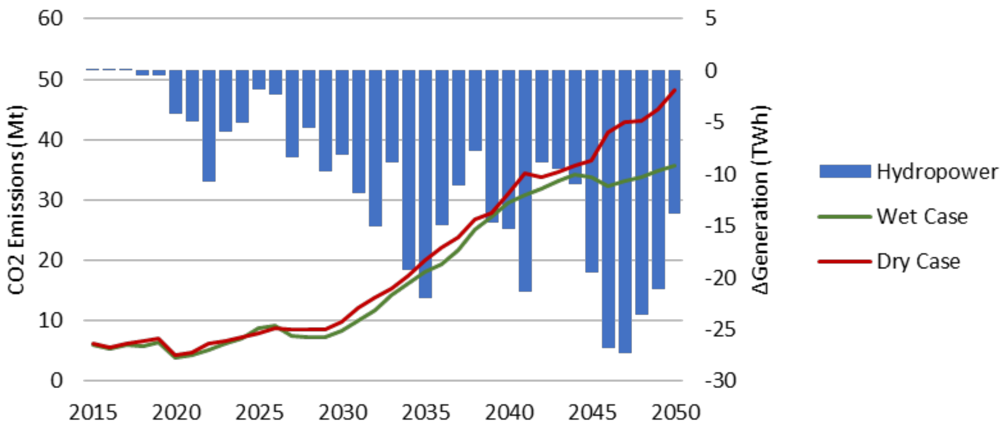
CO_2 emission levels differ between adaptation strategies

Through the different climate scenarios investigated in this exercise the modelling teams have subjected the regional infrastructure of SSA to varying levels of water availability for both energy and non-energy related applications. Considering the overlap between the power pool and river basin definitions, this variation translates into varying levels of installed hydro capacity in the Eastern, Western and Southern regions. This however is not applied in such a direct way in the CAPP where most of the infrastructure is not part of the adaptation methodology that was applied in this study (See the Main Methodology Annex: D1- OSeMOSYS Common Modeling Assumptions for more detail). Nevertheless, the proxying approach relating each infrastructure from the OSeMOSYS framework to one representative power plant from the WEAP structure was applied and results in relative changes in hydropower availability in the region.

From an operational perspective, this means that dryer climate runs can be more affected by "sudden" drought years as well as overall lows in water levels for power generation thereby forcing the systems to increase their levels of fossil fuel use. This has a direct impact on levels of carbon dioxide emissions.

On a regional perspective[46], the CAPP stands to emit between 632 and 720 Mt of carbon dioxide between 2015 and 2050 depending on the climate scenario under consideration. Compared to a base case where climate remains within recorded historic data, this represents a total change of between 2.9Mt and 90Mt. When comparing the extremes within the range of climates that were analysed, we note a similar correlation between changes in emission levels and change in potential hydro generation as in the other power pools. Typically, the relative drops in regional hydropower generation between wet and dry cases noted between 2030 and 2050 are mirrored in corresponding increases in CO_2 emissions in the driest case. Overall however, it appears that the difference in terms of emissions from one climate change case to the next is small: over a period of 35 years from 2015 to 2050 the relative decrease in emissions "achieved" by experiencing a wetter rather than a dryer scenario comes to 13.8% (or just 87 Mt CO_2).

Figure D-74: Regional GHG emission trends vs Relative Hydropower generation



Correspondingly to all other power pool systems, the potential inclusion of a carbon financing or tax scheme in the CAPP might a diverse effect on the cost of power which varies depending on the country under consideration. It is apparent however that, since most countries in the region rely on a certain amount of fossil based generation, most would be affected by increased unit costs of energy. The magnitude of this impact however is relative to both the level of domestic hydropower in the system as well as the reliance of each individual country on imports from neighboring systems.

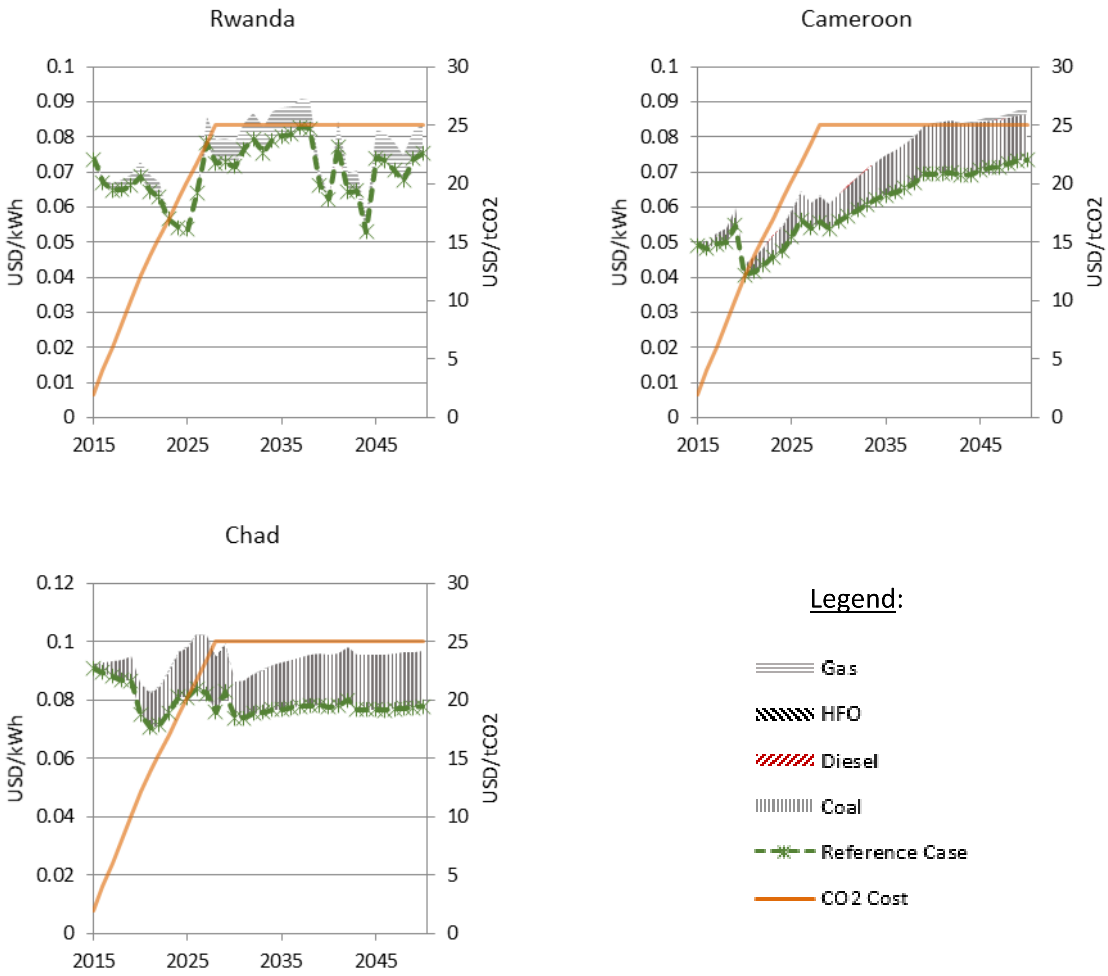
More specifically, countries like Chad, which benefit from apparent year to year cost stability throughout the modelling period, also have a high reliance on fossil based generation. If that were to be penalized by a carbon tax of 25 USD/t by 2027, it could cause cost increases of close to 25% in 2050 (It is assumed that the system was constrained to continue using its fleet of fossil based plants). Conversely, countries like Burundi rely on a more diverse mix of energy sources – both domestic and foreign. Although this offers a lower apparent cost stability in a base "historic climate" situation, it also reduces the potential impact of a carbon penalty scheme on the unit cost of electricity generation in the country.

[46] These values are calculated on a regional basis but exclude the DRC in order to extract more significant messages for the smaller CAPP countries.

The insight applies for intermediary countries such as Cameroon where the presence of a slowly growing base of fossil based generation, although offset by capitalizing on available hydro resources, could stand for as much as a 22% increase in unit cost of electricity generation by the end of the period. (Again, this assumes that the fleet of fossil plants is constrained to operate at reference levels).

While maintaining the set of fossil power plants penalties may be incurred, there is potential to take advantage of carbon financing and mitigate emissions by changing the power mix. This would shift the relative cost of different energy generation options, this could increase final energy mix diversity and affect the levels of trade between different national systems.

Figure D-75: Impact of CO_2 emissions costing on the domestic price of energy to consumers[47]



Choosing to adapt is a "low regret" decision

Figure D-76 shows the incremental cost to consumers of the different strategies for countries to adapt to climate change for countries that have either higher or lower vulnerability levels to climate change is visible. Please note that figures are presented here for a Dry scenario. Visualising the marginal

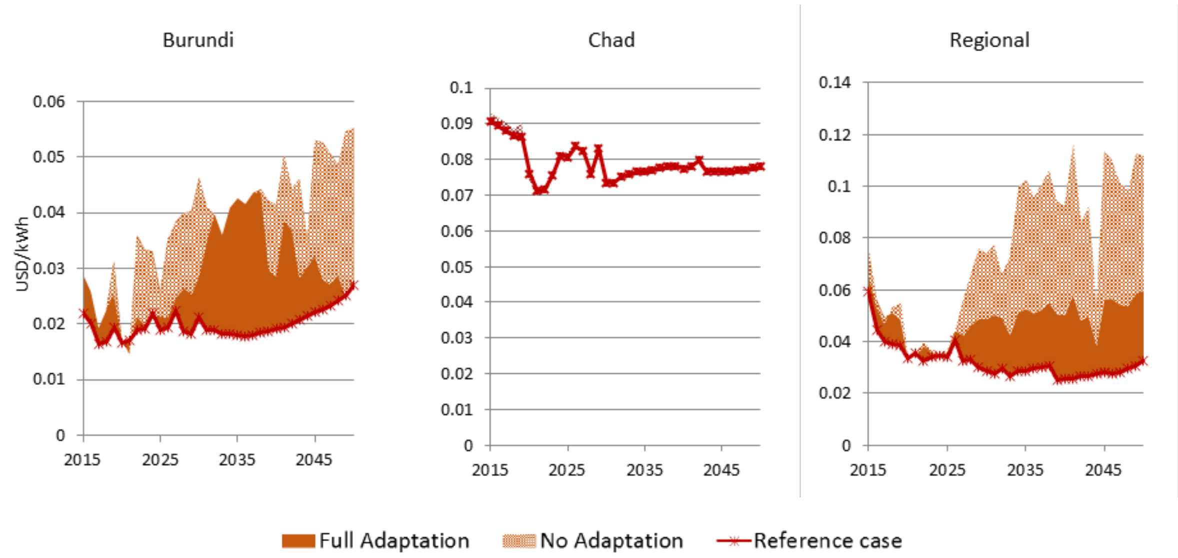
[47] Please note: these figures show the additional cost of applying a selected cost of carbon dioxide emissions – shown by the orange line – as a post treatment step to sets of results obtained from models. Accordingly the models do not attempt to reduce emissions and mitigate those costs, i.e. these additional costs are not included in the models' objective function. The graphs are used simply to illustrate potential consequences of fossil based generation systems in a region as well as the variability of these consequences from one country to the next.

increase in cost that each scenario has on its "predecessor", this graphic shows the difference between having a reactive attitude to the impacts of climate change – materialised by the high annual changes in the level of the lighter "no adaptation" colour – and following a given strategy, albeit flawed, to attempt to anticipate the adverse effects of these future changes.

In the context of the CAPP, two types of countries are discernible. The first relate to the case of Burundi. Relying on relatively large amounts of domestic hydropower and small complements of fossil based generation, this country also has connections to cheaper regional power from the DRC and relies heavily on imports. These imports are directly related to the amount of regional hydropower that is available for international trade in the power pool. In years where these levels are reduced due to dryer climatic conditions, Burundi would benefit greatly from having adapted its energy system in order to have access to alternative generation systems. In a NA scenario the unit cost of electricity generation stands to double over such periods due to the use of higher amounts of oil based generation. The second type of country relates to the example of Chad. Developed much in isolation from other systems, this country has low domestic levels of hydropower and a high reliance on fossil based generation: it does not benefit from lower regional energy prices but seems relatively less affected by dryer climatic conditions in the power pool.

The regional perspective reflects the situation of the DRC. With lower available levels of hydropower in the power pools that the DRC participates in and a given time lag between each new instalment of Grand Inga, the system relies on larger amounts of gas based power. In a NA scenario these are replaced by much more expensive oil based generation exposing the CAPP to much higher power pool level unit costs of energy.

Figure D-76: Cumulative impacts of CC to consumer cost of electricity – Dry case



Conclusions and Recommendations

Climate change is a complex and diverse phenomenon the effects of which are neither yet agreed upon nor fully understood. In such a context, the present work is a bleeding edge attempt to ensure that – notwithstanding the arguably low degree of certainty that affects the data upon which investment projections need to be made – the different actors of an integrated water and energy system may have a better understanding of the implications inherent to different available courses of action.

From an overall perspective on this specific approach, it is important to consider results on a multitude of levels: countries are aggregated into Power Pools that are interconnected by varying levels of trade, each country and each power pool are linked to one or several of the river basins that are analysed as separate entities in the water modelling framework etc. This means that although all results can be extracted on all levels of this analysis they are not totally independent one from the other. Adaptation to climate change is also a complex question. The scenarios under analysis have shown that, in most situations, there is a clear – albeit potentially small in best case scenarios – incentive to adapting.

In particular in the Central African region trade and increasing transmission capacity is important: members of the CAPP currently possess small systems that would benefit greatly from interconnection. This is both due to the specific role of the DRC as a hydro rich exporter, but also because efficient responses to dryer climates include higher levels of trade within the region. As a net exporter, the CAPP is also a key electricity 'transport corridor' between the remaining power pools and requires transmission to support wheeling power to its neighbours.

Limitations and next steps

In addition to general methodology and overall project limitations described in the general assumptions text, the following bullets might advantageously outline areas of future work that would improve either the applicability or quality of the results discussed above. Such areas are listed below:

- Further scenarios development: specifically with respect to trade in the region. As an important lever for stability of supply and renewable resource dissemination, it would be advantageous for individual projects to be evaluated more specifically or for general “corridors” for energy transmission to be assessed both within and between power pools.
- Higher focus on security of supply: in particular investigating the cost benefit analyses of such issues when balanced with their cost trade-offs and implications.
- “Endoginising” carbon costing into the optimisation: this element being thus far taken as a post treatment calculation foes not influence the choice of one technology over another in the present exercise. It would be of interest however to include a representation of different “carbon financing” schemes into the current setup in order to assess their potential impact of different countries and power pools.
- Increasing levels of interaction with the power pool authorities: achieving their integration on a procedural level would greatly benefit such projects by increasing data accuracy and output applicability, but also through their potential inclusion into capacity building activities in the context of iterative and improved PP planning processes.
- Bridging potential gaps in the analysis toolbox to inform relations between national and power pool level systems: such applications may be of specific interest when considering shared planning activities on a project level.
- Investigating the potentials for the power pools to promote clean energy use and assess the corresponding clean energy scenarios.
- Investigating implications of financing limits. Power system investments are significant, but so too are other investment needs in the economy. If finance to power investments crowds out opportunities to invest in other projects, or access to finance is simply limited, scenarios to investigate these constraints may provide important insights.
- Improve the load region definition by detailing individual country load data. This would not increase the complexity of the model however may have a marginal impact of specific time-slices where trade occurs: if two neighbouring countries have their peak demand occurring at

during different time-slices there is a potential for higher trade efficiency and lower installed capacity levels on a regional basis. This data however is both sensitive in nature from a utility's perspective and thus far unavailable for many countries as part of public energy data bases.

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E. Climate Scenarios and Representative Climates

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One of the key datasets used to estimate climate change impacts to Africa's infrastructure is a set of Bias-Corrected and Spatially Disaggregated (BCSD) climate projections based on GCM runs from both the CMIP3 and CMIP5 IPCC archives. The purpose of this Annex is to describe the method used to generate the BCSD projections for Africa, and to describe the organization of the dataset. It is important to note that the time step included in the BCSD dataset is monthly.

Methodology

The methodology used to generate the BCSD projections follows that outlined by Maurer and others as part of a project jointly funded by multiple U.S. agencies to bias correct and downscale climate and hydrology projections based on the CMIP3 archive. Results of this project and methods employed are documented on a website hosted by the Lawrence Livermore National Laboratory (LLNL). Our approach involves four steps: (1) select the baseline historical dataset and GCM-emissions combinations, (2) resolve GCMs and baseline to a common spatial resolution, (3) bias correct the GCM outputs, and (4) spatially downscale those outputs.

Step 1: select observed baseline dataset and GCM runs

The first step is to select the observed baseline and set of GCM-emissions combinations from available IPCC archives. The observed baseline dataset we employ in this analysis was generated by the Princeton Land Surface Hydrology Research Group (henceforth, Princeton dataset), and is available globally from 1948 to 2008 at a monthly or daily time step at 0.5 x 0.5 degree for average temperature (tmean) and precipitation, and at 1 x 1 degree for maximum and minimum daily temperature (tmax and tmin). To produce baseline tmax and tmin at a 0.5 x 0.5 degree resolution, we assume that the information contained in each 1 x 1 degree Princeton grid cell can be transferred to the underlying four 0.5 x 0.5 degree grid cells. For each month and 1 x 1 degree grid cell, we first calculate the difference between tmean and tmin, and between tmax and tmean, and then apply those differences uniformly to the tmean value in each of the four corresponding 0.5 x 0.5 degree grids.

Step 2: resolve baseline and GCMs to common spatial resolution

Spatial resolutions of the GCMs range from 1.13 x 1.13 degrees to 4 x 5 degrees. Following the first step in the BCSD process outlined by Maurer and others, we normalize each of the GCMs and the Princeton baseline to a common resolution of 2 x 2 degrees by spatial averaging. Our calculation procedures incorporate the non-uniform spacing of latitude bands employed in the gridding of each GCM. To include only the African continent, we then bound the longitudes between 18 degrees west and 52 degrees east, and latitudes between 36 degrees south and 40 degrees north. In total, this created a grid with dimensions 35 by 38 containing 1330 unique 2 x 2 degree grid cells.

Step 3: apply bias correction

With the GCMs and observed baseline gridded at a common 2 x 2 degree resolution, the next step was to bias correct the GCM outputs for each of the 1330 grid cells. We employ a baseline period of 1950 to 1999, and a projection period of 2001 to 2050. The three datasets used in the bias correction of each unique grid cell-GCM run combination for precipitation and temperature include:

1. Observed baseline between 1950 and 1999
2. Modeled baseline between 1950 and 1999
3. Modeled projections between 2001 and 2050

Using these three datasets, we proceeded with GCM bias correction, taking the steps outlined below for each month and grid cell of each GCM run (i.e., the process below was repeated for 12 months x 1330 grid cells x 56 CMIP3 GCM/emissions scenario combinationss, and 43 CMIP5 GCM/emissions scenario combinations).

***Step 3-1: Create a quantile map between the observed and modeled baselines*.** The quantile map includes the empirical cumulative density functions (CDF) of the observed and modeled baselines, which are essentially the two 50-element datasets ranked and plotted side-by-side. This quantile map serves as the translator between each modeled projected value and its bias corrected equivalent. Given our chosen baseline, the quantile map is made up of two 50-year time series, and there is a unique quantile map for each month, GCM, grid cell, and meteorological variable (i.e., temperature and precipitation).

Step 3-2: Remove the temperature trend from the projected series. The bias correction process does not operate properly if the projected dataset is non-stationary. As a result, prior to applying bias correction, we remove the trend in temperature from the 2001 to 2050 GCM outputs. Based on the approach employed by LLNL, the annual trend for each month was taken as the difference between a nine-year moving average of projected temperatures and the mean monthly baseline level. Following LLNL, we assumed no precipitation trend through the 2050 period.

Step 3-3: Bias correct the projected precipitation and temperature series. For each year of the projected precipitation and temperature time series, we then used the quantile map to create a bias corrected output. The general approach is to find the position of the projected value within the modeled baseline series, and then find the corresponding value in the observed series using the quantile map. That observed value is the bias corrected value. However, because not all projected values fall within the range of the modeled baseline series, the procedure differs depending on whether the projected value falls within or outside of the range of the modeled baseline time series.

- ***Within modeled baseline range*.** If the temperature or precipitation value falls within the modeled baseline range, then we find the non-exceedance probability of that value on the modeled baseline empirical CDF using interpolation, and take the corresponding observed baseline value at that non-exceedance probability as the bias corrected value.
- ***Outside modeled baseline range*.** If the value falls above or below the modeled baseline range, then we extrapolate by fitting a distribution to the baseline modeled data, finding the location of the projected value on that theoretical distribution, and then mapping that location to its equivalent on a distribution fit to the observed data. Following LLNL, for temperature values either above or below the modeled baseline, we extrapolate using a normal

distribution. For precipitation values above the baseline range, we fit a Gumbel distribution, and for values under the baseline range, we use a Weibull distribution.

The result of this procedure is that each of the projected temperature and precipitation values in the modeled projection time series is converted to its bias corrected equivalent.

Step 3-4: Add the temperature trend back into the bias corrected series. Finally, we add the temperature trend calculated in Step 3-1 back into the bias corrected series.

Step 4: apply spatial downscaling

Having generated bias-corrected temperature and precipitation time series for each GCM, we then apply the LLNL approach to spatially downscale the bias-corrected outputs from 2 x 2 degrees to the resolution of the Princeton baseline dataset, or 0.5 x 0.5 degrees. This procedure applies to the 2 x 2 temperature and precipitation grid maps of Africa for each month, year, and GCM. First, we calculate the differences between bias corrected temperatures and the observed baseline (i.e., delta T), and the ratios between the bias corrected precipitation and the observed baseline (i.e., ratio P). These are the datasets to be spatially downscaled. Second, we apply inverse distance weighting to increase the resolution of the delta T and ratio P datasets from 2 x 2 degrees to 0.5 x 0.5 degrees. Finally, we combine these downscaled deltas and ratios with the Princeton tmax, tmin, and precipitation data to produce our final BCSD dataset.

Output Organization Data

The BCSD dataset includes a series of NetCDF files, each representing one of the climate scenarios and one of the four variables: precipitation (prcp), mean temperature (tas), tmax (tmax), and tmin (tmin). The file names reflect this combination of variable and GCM-SRES name, for example, "BCSDproj_prcp_bccr_bcm2_0-a1b.nc" is precipitation data for the the bccr-bcm2-0 GCM and the A1B SRES scenario. This attribute information is also included in the NetCDF files containing the data.

The dimensions of each file are 152 y-grids x 140 x-grids x 50 years x 12 months, with the bounding longitude and latitude lines described above: 18 degrees west to 52 degrees east, and 36 degrees south to 40 degrees north. The grid cells are each 0.5 x 0.5 degrees, and the year range is 2001 to 2050, which can be trimmed to a 2011 to 2050 time period as needed.

We also include the 0.5 x 0.5 degree monthly Princeton baseline precipitation and mean, maximum, and minimum temperature for the 1950 to 1999 period and within the bounding coordinates specified above. Note that the tmax and tmin results are based on the 1 x 1 degree Princeton data "downscaled" to the 0.5 x 0.5 degree resolution using the procedure described in Step 1 of the methodology section above. The baseline dataset is 152 y-grids x 140 x-grids x 50 years x 12 months for each of the four variables.

Choosing Representative Climate Futures

In order to estimate perfect foresight adaptations, we need to focus on a small number of representative climate futures. This small set of futures should provide a good sample of the range of consequences implied by the full range of hundred+ climate projections. The goal was to identify six scenarios to be applied across all African basins we studied – these are same scenarios across basins, allowing for cross-basin comparisons.

CMI Index

To identify an appropriate representative set, we first calculate the CMI index for each basin for each climate projection. The CMI, which combines precipitation and temperature, is well correlated with the hydropower and irrigation impacts expected from each climate projection (see for example, Sutton et al. 2013). We consider the CMI averaged over the 2010-2050 time period because our calculations are sensitive to impacts over that full time period.

Search Criteria

Given our analytic constraints, we seek a set of six representative futures that best represents the full ensemble of 121 futures, we first ran a search looking for sets of six futures that had at least one low, mid, and high CMI value for each basin. We defined a low value as a CMI among the six lowest of futures (5^{th} percentile), a high value as among the six highest futures (95^{th} percentile), and a middle value as among middle 24 futures (40^{th} to 60^{th} percentile). One can draw more than 3.8 billion unique combinations of six futures from the ensemble of 121 futures. Using a relatively crude but easy to implement search procedure, we randomly tested combinations of futures for approximately 180 computing hours. The search found 31 alternative six-future sets that met our criteria of at least one low, mid, and high CMI value for each basin.

We aim to choose the set that best meets the following criteria:

1. Includes an extreme wet and dry future for each of the seven basins. We define an extreme future as one outside the 5%-95% range for the full ensemble of runs. This criterion ensures we consider a stressing future for each basin.
2. Includes futures with extremes for several basins. This criterion ensures that we consider futures that stress multiple basins simultaneously.
3. Include a future close to the average over the full ensemble. This criterion ensures that we have an appropriate comparison for the extreme cases.
4. Includes a significant number of CIMP5 runs, and derives from a mix of medium and high emissions scenarios. This criterion helps to ensure that the set of futures includes the most recent climate information and provides some information regarding how alternative emission trajectories might affect infrastructure investment plans.

To identify the set of six climate futures that best meets these criteria, we construct a search algorithm over the full set of futures that identifies candidate sets that meet criteria #1. It turns out that a significant number of sets of five projections meet this criterion. From these candidates, we then choose several sets that meet #2. We then use a search algorithm to identify climate futures that satisfy #3. We then combine the candidate sets of five for criterion #1 and #2 with a future from #3 to form a set of six that bests meets all four criteria.

Final Selection of 6 Climate Futures

To choose among the 31 candidate sets, we ranked them by the maximum number of basins with either a high or low CMI value in any single climate future. This criterion enables us to explore the implications of climate correlations among the basins. We identified one preferred set, which included a climate sequence that had "high" CMI in five basins, as shown in Figure E.1. This set also does a relatively good job of sampling the correlations among each pair of basins, as shown in Figure E.2.

Before settling on this sequence, we also considered the range of emissions scenarios and of climate data sources. As shown in Table E.1, our chosen futures represent a diversity of "High" (RCP8.5 and A2) and "Mid" (RCP4.5 and A1B) emissions scenarios and a diversity of CMIP3 and CMIP5 projections (from the Coupled Model Intercomparison Projects of the IPCC Fourth and Fifth Assessment Reports, respectively), as well as CMIP5 projections with both the BSCD (bias correction spatial disaggregation) and UCT (University of Cape Town) downscaling methods (see main text for further explanation).

Table E-1: Source of six representative climate futures by GCM, vintage (CMIP3 or CMIP5), emissions scenario, and downscaling method

GCM	Emissions	Vintage	Downscaling
bcc-csm1-1-rcp85	RCP 8.5	CMIP5	UCT
GISS-E2-H_run1-rcp45	RCP 4.5	CMIP5	Princeton-BCSD
ipsl_cm4-a2	A2	CMIP3	Princeton-BCSD
micro3_2_medres-a1b	A1B	CMIP3	Princeton-BCSD
MIROC-ESM_CHEM-rcp45	RCP 4.5	CMIP5	UCT
MIROC-ESM_CHEM-run1_rcp85	RCP 8.5	CMIP5	Princeton-BCSD

The next best alternative set of six representative futures had only a sequence with a maximum of four basins with “high” CMI and has less diversity of emissions scenarios. Ultimately, we determined we would instead prefer to include more highly correlated climate sequences, though it required sacrificing the inclusion of a “Low” emissions scenario.

We expected that each of these 31 sets originally identified in our search would produce relatively similar results in the subsequent phases of our analysis and thus that the regret of choosing any one of them is relatively low

***Figure E-1:** CMI by basin for each of six representative climate futures (red) and all 121 futures (grey) considered in the Case B vulnerability analysis*

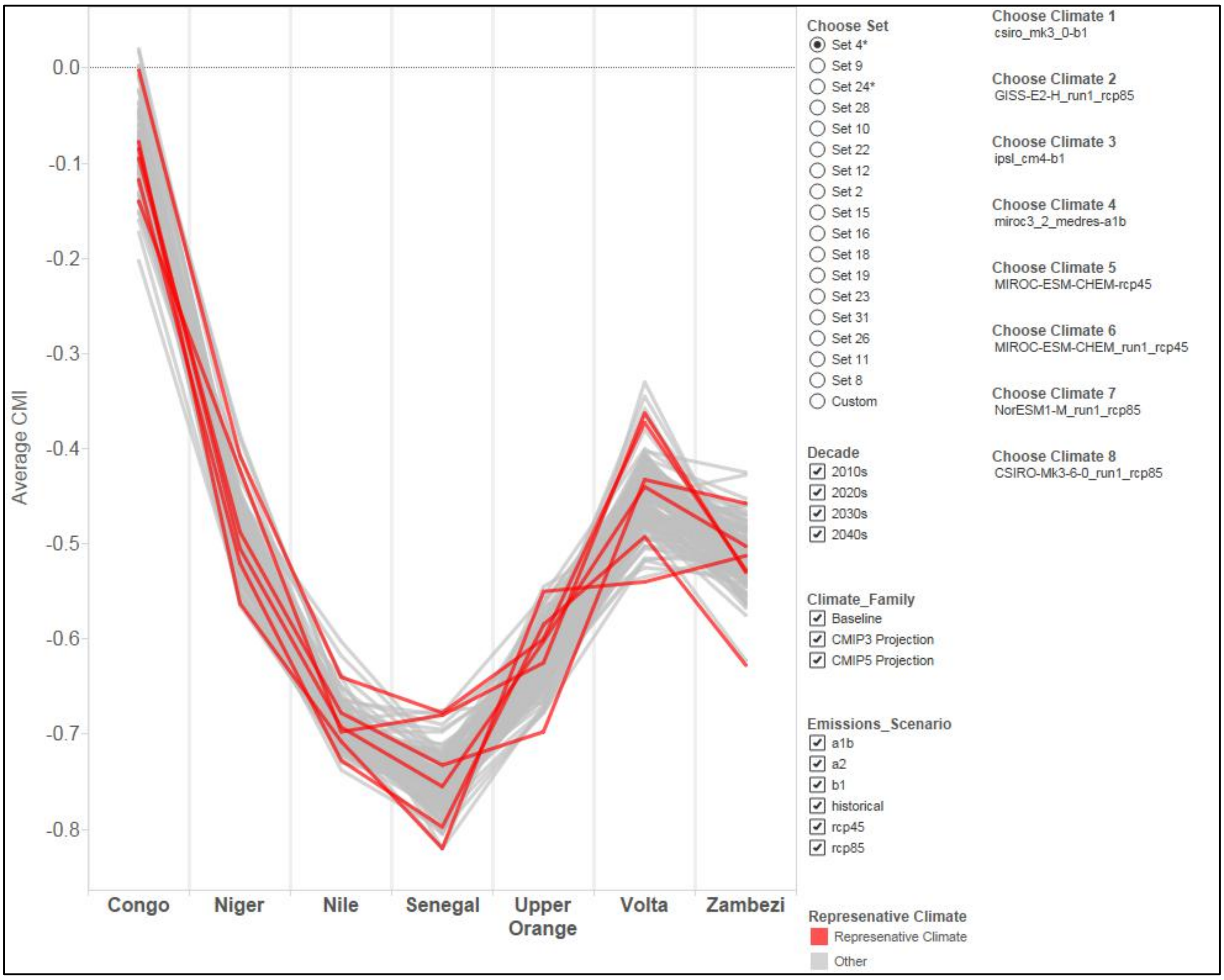
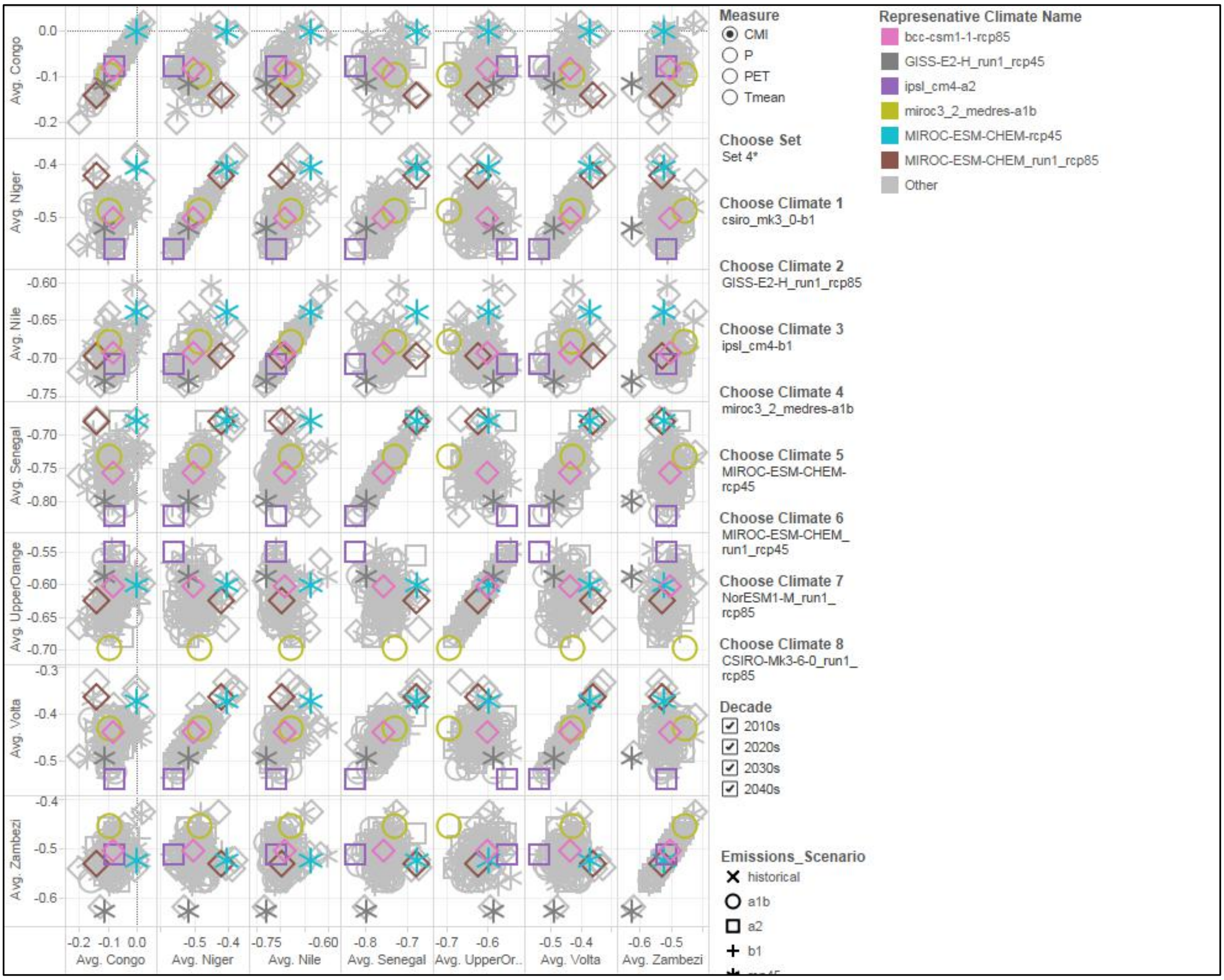


Figure E-2: *Comparative CMI for each pair of basins for each of six representative climate future (colored shapes) and all 121 futures (grey shapes) considered in the Case B vulnerability analysis*



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F. Robust Decision Making Approach

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In Chapters 5 and 6 of the main text, we examine the performance of the PIDA+ infrastructure over a wide range of climate projections and suggest robust adaptations. Chapter 7 examines the performance of individual infrastructure projects. These analyses suggest that climate change may have significant impacts on the performance of planned infrastructure investments, that these impacts may have important economic consequences, and that impacts could vary significantly among regions and economic sectors. A key challenge for quantifying these risks and responses is that future climate conditions, as well as other significant socio-economic trends, are currently and likely to remain deeply uncertain (Milly et al. 2008; Weaver et al. 2013). To address such conditions, this study adopts an approach called Robust Decision Making (RDM).

This Annex provides additional information on RDM and its specific applications in this study. The annex first provides a more detailed description of RDM than appears in the main text, including specific "best practices" recommendations for how it can be applied to decision making under uncertainty. The final two sections of the annex describe in more detail the specific application of RDM to the Track I and Track II analyses.

General Description of the Approach

RDM is an iterative, quantitative, decision support methodology designed to address the challenges of planning amid uncertainty about the future (Lempert et al. 2003; Lempert et al. 2006; Hallegatte et al. 2012). The approach[48] has been applied with increasing frequency to flood risk (Fischbach 2010; Fischbach et al. 2012; Lempert et al. 2013) and water management applications (Groves et al. 2007; Groves et al. 2008; Means et al. 2010; Groves et al. 2013; Moss et al. 2014). Deep uncertainty occurs when the parties to a decision do not know—or do not agree on—the best model for relating actions to consequences or the likelihood of future events (Lempert et al. 2003).

RDM rests on a simple concept. Rather than using models and data to describe a best-estimate future, RDM runs models over hundreds to thousands of different sets of assumptions to describe how plans perform in many plausible futures. The approach then uses statistics and visualizations on the resulting large database of model runs to help decision-makers identify those future conditions where their plans will perform well and poorly. This information can help decision-makers develop plans more robust to a wide range of future conditions.

This simple concept contains two particularly important ideas. First, quantitative risk and decision analysis typically uses a **predict-then-act** approach. Analysts assemble available evidence into best-estimate predictions of the future and then use models and tools to suggest the best strategy given these predictions. These methods, which include probabilistic risk analysis, work well when the predictions are accurate and non-controversial. Otherwise, the methods may have difficulty generating consensus among stakeholder who hold differing expectations about the future and may lead to solutions that fail when the future turns out differently than expected.

In contrast, RDM runs the analysis "backwards," using a **vulnerability-and-response** approach. Analysts begin with one or more strategies under consideration (often a current plan) and then, using

[48] Lempert, R. J., S. W. Popper, D. G. Groves, N. Kalra, J. R. Fischbach, S. C. Bankes, B. P. Bryant, M. T. Collins, K. Keller, A. Hackbarth, L. Dixon, T. LaTourrette, R. T. Reville, J. W. Hall, C. Mijere and D. J. McInerney (2013). Making Good Decisions Without Predictions: Robust Decision Making for Planning Under Deep Uncertainty, RAND, RB-9701.

potentially the same models and tools, characterize the future conditions where a strategy fails to meet its goals (is vulnerable). This serves as a stress test of strategies and helps decision-makers identify “robust” strategies – those that perform reasonably well regardless of what the future brings -- and identify the key tradeoffs among potential robust strategies. Often, the robust strategies identified by RDM are adaptive,[49] designed to evolve over time in response to new information (Lempert *et al.* 2010).

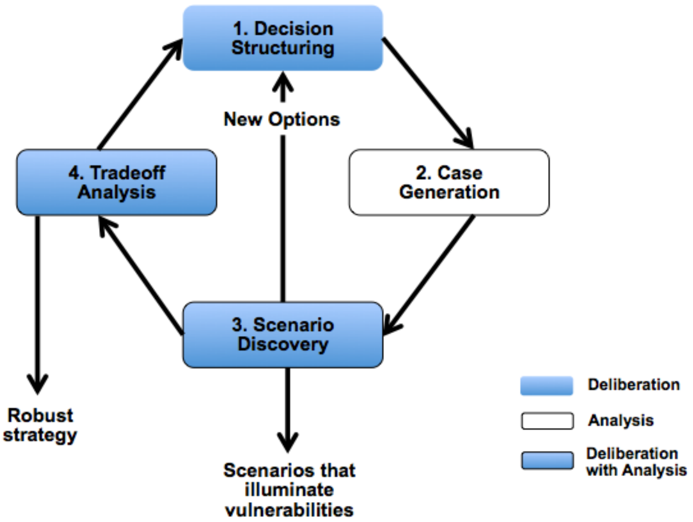
Second, traditional risk and decision analysis condenses information about a range of potential futures into a single probabilistic prediction, i.e. the best estimate future. But RDM assembles the results of many hundreds or thousands of computer simulation model runs and uses this database of runs to comprehensively explore and summarize the challenges and opportunities the future might bring. By embracing many plausible futures, RDM can help reduce overconfidence and the deleterious impacts of surprise, can systematically include imprecise information in the analysis, and can help decision-makers and stakeholders with differing expectations about the future nonetheless reach consensus on action (Lempert *et al.* 2005; Groves *et al.* 2007; Hallegatte *et al.* 2012).

To implement the above concepts, RDM follows an interactive series of steps, as shown in Figure F-1, consistent with the “deliberation with analysis” decision support process recommended by the U.S. National Research Council (2009). Deliberation with analysis begins with the participants to a decision working together to define the policy questions and develop the scope of the analysis to be performed. Subsequent steps involve expert data collection, modeling, and analysis, along with deliberations based on this information in which choices and objectives are revisited. This process is particularly appropriate for decisions with diverse stakeholders whose goals emerge from collaboration and may change over time.

As shown in Figure F-1, RDM’s process begins with a decision structuring exercise that defines the goals, values, uncertainties, and choices under consideration. A key step in this process identifies one or more policies that will be the focus of the initial iterations of the analysis. For instance, we consider the PIDA+ plans in Chapters 5 and 6 and consider the pre-feasibility designs for infrastructure projects in Chapter 7. Analysts next use computer models to generate a large database of runs, where each such case represents the performance of a proposed policy in one plausible future. In a process called “scenario discovery,” (Groves *et al.* 2007; Bryant *et al.* 2010; Lempert 2013) computer visualization and statistics on this database then help decision-makers identify clusters representing scenarios that illuminate vulnerabilities of the policies. For instance, in this study such vulnerable scenarios may contain those futures where PIDA+ investments have significantly lower economics returns to investment than expected. These scenarios can then help decision-makers identify potential new ways to address those vulnerabilities and evaluate through tradeoff analysis whether these choices are worth adopting. The process continues until decision-makers settle on a robust strategy.

[49] Applied to strategies, the word “adaptive” denotes a plan explicitly designed to evolve over time in response to new information. This contrasts to the word “adaptation,” which denotes a process of adjusting over time to changing conditions, such as due to economic development or climate change.

Figure F-1: Iterative, Participatory Steps of an RDM Analysis



It is useful to compare this RDM approach to traditional probabilistic risk management. A full probabilistic assessment begins by collecting analysts' judgments at the start of the process. Once the probability distributions over future states of the world are defined, that analysis yields recommendations that follow deductively from the probability estimates and the explicit representations of the decision-makers' preferences. As its primary products, the analysis provides distributions of the outputs of interest to the decision-makers and prescriptive ranking of decision options. In general, probabilistic assessments use optimization criteria, aimed at identifying the best strategy contingent on the best-estimate distributions and other assumptions.

In contrast, the RDM process begins with one or more proposed decisions and uncertainties of interest. The analysis uses simulation models to test the policies over a wide range of futures. Statistics and visualization of the resulting database of simulation model results helps decision-makers identify the conditions in which proposed policies will not meet their goals and the tradeoffs among alternative strategies. In general, RDM analyses do not provide a strict ranking of options, but rather help organize information for decision-makers so that they can better weigh their choices. RDM analyses can use a variety of alternative robustness criteria, ranging from trading some optimal performance for less sensitivity to broken assumptions to satisficing over a wide range of plausible futures (Lempert *et al.* 2007). A concept first introduced by Herbert Simon (1959), "satisficing" refers a strategy that performs at least as well as some benchmark level. In this study, as is often the case, it proves useful to use robustness criteria that involve measures of regret, a comparative measure that tracks how well any particular strategy performs in a future state of the world in relation to the best performing strategy in that state of the world (Savage 1954).

In general, the alternative robustness criteria that can be used in RDM analyses suggest similar strategies as most robust, though the criteria differ in the ease of implementation and the amount of information they provide to decision-makers. In addition, RDM and probabilistic risk analyses generally give the same results when using similar assumptions (Lempert *et al.* 2007; Lempert *et al.* 2012). Under conditions of deep uncertainty, however, RDM analyses can reduce the potential for disagreement among stakeholders who have different expectations about the future, increase understanding of the sensitivity of proposed plans to potentially stressing futures, and help yield strategies which are more robust against the uncertainties.

In this study, we adapted the RDM process to meet the particular needs of the Track I and Track II analyses, as described below.

Track I RDM Analysis

An RDM process often begins at the top of Figure F-1 with a participatory scoping activity in which stakeholders and decision-makers define the objectives and metrics of the decision problem, strategies that could be used to meet these objectives, the uncertainties that could affect the success of these strategies, and the relationships that govern how strategies would perform with respect to the metrics (Step 1). This scoping activity often uses a framework called "XLRM," described below, to organize the simulation modeling. This study was largely conducted as a tabletop exercise, so the project team managed much of the scoping. However, we did conduct two workshops during the course of the study, one in Maseru, Lesotho and the other in Accra, Ghana and conducted RDM scoping exercises. As described below, these workshops provided important input to this study and also suggested how the methods described here can be effectively transferred to local planners and officials in Africa. The Track I analysis focuses on future climate as its primary uncertainty. Policy levers include PIDA+ and potential modifications to the timing and size of its infrastructure investments. The Track I analysis uses infrastructure output (i.e., irrigation water delivery and electric energy production), net present value, and consumer prices as its primary performance metrics.

We divided the Track I analysis into four sections, as shown in Table F-1, which map onto two iterations of the RDM process shown in Figure F-1. As discussed in the previous Chapter, we first estimated the performance of PIDA+ in historic climate (A) and over a wide range of future climate projections (B), which corresponds to Steps 1 and 2 of the RDM process. The vulnerability analysis (Step 3) presented in Chapter 3 identifies how climate change could affect PIDA+ infrastructure performance.

Table F-1: Framework for evaluating the impacts of climate change and adaptations in the water and energy sectors

Case ID	Case Description	Investment Strategy	Assumptions on climate	Adaptation Strategy	Cost of climate change impacts
A	Reference case	PIDA +	Historical climate (no climate change)	None	Zero
B	Climate change, no adaptation	PIDA +	Full range of climate futures	None	For each climate future: reduction or increase in hydropower performance + reduction or increase in irrigated agriculture performance
C	Climate change, "perfect	PIDA + with perfect foresight	Full range of climate futures	Adjust PIDA + in order to maximize (for each climate	Zero

	foresight" adaptation	(varies across scenarios)		future) net present value of adaptations	
D	Climate change, robust adaptation	PIDA + with robust adaptation (does not vary across scenarios)	Full range of climate futures	Adjust PIDA + to manage regrets across climate futures	For each climate future: reduction or increase in hydropower performance + reduction or increase in irrigated agriculture performance

The economic analysis of impacts and adaptation is based on overall objective function to maximize hydropower production subject to the constraint of allocating sufficient water to meet human needs, environmental quality and –through irrigated crop production- food security targets. The maximization of hydropower production is operationalized as maximizing net revenues from hydropower. This is essentially the same as ensuring that hydropower remains a viable investment in these countries. At the same time, implications for consumers are assessed through estimation of the impacts on the price of electricity, as the cost of producing hydropower increases or decreases in drier or wetter climates, thereby affecting the overall price of electricity.

For each river basin and power pool the study evaluates the cost of climate change impacts and the merits of adaptation using the framework summarized in Table F-1: Framework for evaluating the impacts of climate change and adaptations in the water and energy sectors, which illustrates the approach. The starting point is the reference case A, in which the PIDA+ investment plan is carried out, with a certain cost, and with benefits proxied by the levelized cost of energy and the value of irrigated crops. If climate change occurs, but no adaptation takes place, case B materializes: no adaptation is undertaken, PIDA+ is implemented as planned, and regrets can occur: in the form of lost hydropower production, higher levelized cost, and lower irrigated crop production, in dry scenarios compared to the reference case, and foregone opportunities for higher power production, lower levelized cost, and higher irrigated crop production in wet scenarios.

Case C is a counterfactual introduced to gauge the cost of inaction and the benefits of adaptation action. It is a “perfect foresight” situation in which the PIDA+ is optimized to achieve the best possible performance of the energy system (minimum levelized energy cost, LEC) in each climate future. It corresponds to a hypothetical situation in which investment planners know in advance which climate will unfold, and decide accordingly ex-ante how PIDA+ should be adjusted (for example, installing more hydro in wet scenarios, or less in drier ones).

The final step is the definition of a “robust” adaptation strategy (case D), which requires establishing Case C as a prerequisite. In case D, taking into consideration the full range of possible futures (including climate outcomes and other variables), a modification of the reference investment strategy is adopted. This cannot be the “optimal” plan identified in case C since the future is unknown and there is no way to associate probabilities to individual scenarios. Instead, the adaptation strategy is one that yields acceptable outcomes in as many climate futures as possible. By comparing case D (robust adaptation) with cases B and C, the study gives indications on the potential for reducing regrets (i.e. the benefits of adaptation) and on the costs of doing so.

For each of the climate futures evaluated under Case C, we estimate the net benefits of adaptation as the difference between total present value revenues with and without perfect foresight (i.e., with and without modifications from PIDA+), less (plus) any present value infrastructure costs (savings) of adaptation. So these calculations involve four components: hydropower and irrigation revenues, and reservoir and irrigation infrastructure adaptation costs. The first two components apply to all three cases, and the last two apply to C only, as only case C alters the baseline PIDA+ reservoir and irrigation infrastructure costs.

Based on this vulnerability analysis, we conduct the Case C analyses discussed in the next chapter. This involves choosing six representative climate futures that capture the range of impacts climate change could have on PIDA+ infrastructure investments (Step 3). The analysis then identifies perfect foresight adaptations for each of these representative climate futures (Step 1), evaluates each perfect foresight adaptation in all the climate futures (Step 2), and identifies the types of futures in which each perfect foresight adaptation performs poorly and well (Step 3). The analysis then uses several alternative robustness criteria to suggest which adaptations are most robust. For instance, some criteria weigh potential worst cases more heavily than others. The analysis uses alternative criteria because it does not aim to provide a prescriptive ranking of alternative investments. Rather it aims to clarify the key tradeoffs facing policy makers and to provide information that can help them choose the option that for them best balances among risks and opportunities.

Track II RDM Analysis

The Track II analysis uses the RDM process in Figure F-1 , but somewhat differently than for Track I. The consultant team conducted the scoping step in close consultation with Bank experts. The five case studies generally consider a broader set of uncertainties than Track I. In addition to climate change, the case studies consider factors such as demand and electricity prices. The policy levers are specific to each case study, but focus on engineering design choices such as dam height, storage, and turbine size. The metrics include firm yield (hydropower), safe yield (water supply), levelized cost of hydropower generation and water supply, and net present value of the investment.

The Track II analyses each conduct one iteration of the RDM process. The scoping process includes defining a range of alternative designs, which include one appropriate for historic climate but also including variations appropriate for wetter or drier climates (Step 1). Each design is evaluated for each of 145 climate projections (including 24 alternative historic trajectories - Step 2). The analysis then summarizes the design's strengths and weaknesses compared to other designs (Step 3). The analysis then employs three alternative robustness criteria to suggest the most robust strategy. In general, the criteria give similar rankings that yield different information about the comparative strengths and weaknesses of the designs.

As with Track I, the analysis does not aim to provide a definitive ranking of alternative designs, but rather it aims to clarify the key tradeoffs facing policy makers and suggest ways in which they might choose among the options available to them.

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G. Data Used as Inputs to the Analysis

Data	Units	Type	Source	Link	Where used in Analysis	Notes
WEAP – ALL BASINS ----------						
Precipitation	*mm/month*	*Meteorological*	*Terrestrial Hydrology Research Group at Princeton University*	*http://hydrology.princeton.edu/data/pgf/0.5deg/monthly/*	*Hydrology, Agriculture, Reservoir Evaporation*	*'Historical Direct' climate scenario*
Maximum Temperature	*C*	*Meteorological*	*Ibid*	*Ibid*	*Hydrology, Agriculture, Reservoir Evaporation*	*'Historical Direct' climate scenario*
Minimum Temperature	*C*	*Meteorological*	*Ibid*	*Ibid*	*Hydrology, Agriculture, Reservoir Evaporation*	*'Historical Direct' climate scenario*
Average Monthly Temperature	*C*	*Meteorological*	*Ibid*	*Ibid*	*Hydrology, Agriculture, Reservoir Evaporation*	*'Historical Direct' climate scenario*
Precipitation	*mm/month*	*Meteorological*	*THE WCRP CMIP3 Multimodel Dataset*		*Hydrology, Agriculture, Reservoir Evaporation*	*'Projected CMIP3, BCSD' climate scenarios*
Maximum Temperature	*C*	*Meteorological*	*Ibid*		*Hydrology, Agriculture, Reservoir Evaporation*	*'Projected CMIP3, BCSD' climate scenarios*
Minimum Temperature	*C*	*Meteorological*	*Ibid*		*Hydrology, Agriculture, Reservoir Evaporation*	*'Projected CMIP3, BCSD' climate scenarios*
Average Monthly Temperature	*C*	*Meteorological*	*Ibid*		*Hydrology, Agriculture, Reservoir Evaporation*	*'Projected CMIP3, BCSD' climate scenarios*

Data	Units	Type	Source	Link	Where used in Analysis	Notes
Precipitation	*mm/month*	*Meteorological*	*WCRP Coupled Model Intercomparison Project - Phase 5 - CMIP5*		*Hydrology, Agriculture, Reservoir Evaporation*	*'Historical Projected' and 'Projected CMIP5, BCSD' climate scenarios*
Maximum Temperature	*C*	*Meteorological*	*Ibid*		*Hydrology, Agriculture, Reservoir Evaporation*	*'Historical Projected' and 'Projected CMIP5, BCSD' climate scenarios*
Minimum Temperature	*C*	*Meteorological*	*Ibid*		*Hydrology, Agriculture, Reservoir Evaporation*	*'Historical Projected' and 'Projected CMIP5, BCSD' climate scenarios*
Average Monthly Temperature	*C*	*Meteorological*	*Ibid*		*Hydrology, Agriculture, Reservoir Evaporation*	*'Historical Projected' and 'Projected CMIP5, BCSD' climate scenarios*
Precipitation	*mm/month*	*Meteorological*	*University of Cape Town Climate Systems Analysis Group (CSAG)*		*Hydrology, Agriculture, Reservoir Evaporation*	*'Projected CMIP5, UCT-CSAG' climate scenarios*
Maximum Temperature	*C*	*Meteorological*	*Ibid*		*Hydrology, Agriculture, Reservoir Evaporation*	*'Projected CMIP5, UCT-CSAG' climate scenarios*
Minimum Temperature	*C*	*Meteorological*	*Ibid)*		*Hydrology, Agriculture, Reservoir Evaporation*	*'Projected CMIP5, UCT-CSAG' climate scenarios*

Data	Units	Type	Source	Link	Where used in Analysis	Notes
Average Monthly Temperature	*C*	*Meteorological*	*Ibid)*		*Hydrology, Agriculture, Reservoir Evaporation*	*'Projected CMIP5, UCT-CSAG' climate scenarios*
Population	*people*	*Demographic*	*United Nations World Population Prospects (2012)*	*http://esa.un.org/undp/wpp/index.htm*	*Water Demand*	
Population Density	*people /km²*	*Demographic*	*Center for International Earth Science Information Network (CIESIN), Columbia University*	*http://sedac.ciesin.columbia.edu/data/dataset/grump-v1-population-density*	*Water Demand*	
Irrigated Areas	*ha*	*Crops*	*FAO, AquaStat*	*http://www.fao.org/nr/water/aquastat/dbase/index.stm*	*Agriculture*	
Crop coefficients	*N/A*	*Crops*	*FAO, CropWat*	*http://www.fao.org/nr/water/infores_databases_cropwat.html*	*Agriculture*	
***WEAP – CONGO BASIN*------------**						
Sub-catchment areas	*km2*	*Topographic*	*Tshimanga and Hughes (2014); Derived from NASA Space Shuttle Radar Topography Mission data*	*http://onlinelibrary.wiley.com/doi/10.1002/2013WR014310/abstract* *http://srtm.csi.cgiar.org/)*	*Hydrology*	
Discharge	*m3/s*	*Hydrological*	*Global Discharge Data Centre (GRDC: Fekete, 1999), the Office National de Recherche et du Developpement (ONRD: Lempicka, 1971), and Hydrosciences Montpellier – Système d'Informations Environnementales*	*SIEREM, http://hydrosciences.fr/sierem*	*Calibration of streamflow/hydrology*	
Reservoir Storage Capacity	*MCM*	*Engineering*	*Cifarham (1994), Les ressources hydro-électriques du Zaïre, SNEL; Ministere du Plan (2012), Cartographie des projets des infrastructures économiques de base de la RDC*		*System operation*	
Reservoir Volume-Elevation Curves	*MCM-to-m*	*Engineering*	*Ibid*		*Hydropower generation and Reservoir evaporation*	
Reservoir Evaporation	*mm/month*	*Engineering*	*Ibid*		*Calibration of reservoir storage*	

Data	Units	Type	Source	Link	Where used in Analysis	Notes
Reservoir Elevation	*m*	*Engineering*	*Ibid*		*Calibration of system operations*	
Hydropower Capacity	*MW*	*Engineering*	*Ibid*		*Hydropower generation*	
Turbine Capacity	*m3/s*	*Engineering*	*Ibid*		*Hydropower generation*	
Maximum Head	*m*	*Engineering*	*Ibid*		*Hydropower generation*	
Irrigated Cropped Areas	*ha*	*Crops*	*FAO, AquaStat*	*http://www.fao.org/nr/water/aquastat/dbase/index.stm*	*Agriculture*	
Cropping Patterns	*ha*	*Crops*	*Ibid*	*Ibid*	*Agriculture*	
Crop Coefficients	*N/A*	*Crops*	*FAO, CropWat*	*http://www.fao.org/nr/water/infores_databases_cropwat.html*		
***WEAP – ORANGE BASIN*------------------------**						
Sub-catchment areas	*km2*	*Topographic*	*Department of Water Affairs (DWA) of South Africa. Midgley et al., 1994. Surface water resources of South Africa 1990. Volumes I to VI*		*Hydrology*	
Discharge	*m3/s*	*Hydrological*	*Department of Water Affairs (DWA) of South Africa; Lesotho Ministry of Water*		*Calibration of streamflow/hydrology*	
Reservoir Storage Capacity	*MCM*	*Engineering*	*The Orange-Senqu River Basin Infrastructure Catalogue. 2013. ORASECOM*	*http://wis.orasecom.org/orange-senqu-infrastructure-catalogue-reservoirs/*	*System operation*	
Reservoir Volume-Elevation Curves	*MCM-to-m*	*Engineering*	*Ibid*	*Ibid*	*Hydropower generation and Reservoir evaporation*	
Reservoir Evaporation	*mm/month*	*Engineering*			*Calibration of reservoir storage*	
Reservoir Elevation	*m*	*Engineering*	*Ibid*	*Ibid*	*Calibration of system operations*	
Hydropower Capacity	*MW*	*Engineering*	*Ibid*	*Ibid*	*Hydropower generation*	
Turbine Capacity	*m3/s*	*Engineering*	*Ibid*	*Ibid*	*Hydropower generation*	
Maximum Head	*m*	*Engineering*	*Ibid*	*Ibid*	*Hydropower generation*	

Data	Units	Type	Source	Link	Where used in Analysis	Notes
Irrigated Cropped Areas	*ha*	*Crops*	*FAO, AquaStat*	*http://www.fao.org/nr/water/aquastat/dbase/index.stm*	*Agriculture*	
Cropping Patterns	*Ha*	*Crops*	*Ibid*	*Ibid*	*Agriculture*	
Crop Coefficients	*N/A*	*Crops*	*FAO, CropWat*	*http://www.fao.org/nr/water/infores_databases_cropwat.html*	*Agriculture*	
WEAP – NIGER BASIN---						
Sub-catchment areas	*km2*	*Topographic*	*Niger Basin Authority (2009), Niger River Basin sustainable development action plan final report*	*http://www.abn.ne/index.php?option=com_content&view=category&layout=blog&id=48&Itemid=42&lang=en*	*Hydrology*	
Discharge	*m3/s*	*Hydrological*	*Niger Basin Authority & World Bank (2012), Niger River Basin strategic development plan: Phase 1 of the NRB climate risk assessment: Future water demands in the Niger Basin; The Study on the National Water Resources Master Plan (NWRMP) by JICA (1995); Andersen et al. (2005), The Niger River Basin: A vision for sustainable management ; Zwarts et al. (2005), The Niger, a lifeline. Effective water management in the Upper Niger Basin; ORSTOM;*		*Calibration of streamflow/hydrology*	
Reservoir Storage Capacity	*MCM*	*Engineering*	*Hydrosystems Research Group (2010), Building resilience and increasing mitigation for climate-related risks in investments in the Niger River Basin; Niger Basin Authority (2009), Niger River Basin sustainable development action plan final report*	*http://www.abn.ne/index.php?option=com_content&view=category&layout=blog&id=48&Itemid=42&lang=en*	*System operation*	
Reservoir Volume-Elevation Curves	*MCM-to-m*	*Engineering*	*Ibid*	*Ibid*	*Hydropower generation and Reservoir evaporation*	

Data	Units	Type	Source	Link	Where used in Analysis	Notes
Reservoir Evaporation	*mm/month*	*Engineering*	*Ibid*	*Ibid*	*Calibration of reservoir storage*	
Reservoir Elevation	*m*	*Engineering*	*Ibid*	*Ibid*	*Calibration of system operations*	
Hydropower Capacity	*MW*	*Engineering*	*Ibid*	*Ibid*	*Hydropower generation*	
Turbine Capacity	*m3/s*	*Engineering*	*Ibid*	*Ibid*	*Hydropower generation*	
Maximum Head	*m*	*Engineering*	*Ibid*	*Ibid*	*Hydropower generation*	
Irrigated Cropped Areas	*ha*	*Crops*	*Niger Basin Authority. 'Assessment of water abstraction and requirements for the Niger basin simulation model' (BRL, 2010).*		*Agriculture*	
Cropping Patterns	*ha*	*Crops*	*Ibid*		*Agriculture*	
Crop Coefficients	*N/A*	*Crops*	*Ibid*			
WEAP – NILE BASIN--						
Sub-catchment areas	*km2*	*Topographic*	*Nile Basin Initiative (NBI)*		*Hydrology*	
Discharge	*m3/s*	*Hydrological*	*NBI-WRPMP (2012), Nile Basin Decision Support system*		*Calibration of streamflow/hydrology*	
Reservoir Storage Capacity	*MCM*	*Engineering*	*Ibid*		*System operation*	
Reservoir Volume-Elevation Curves	*MCM-to-m*	*Engineering*	*Ibid*		*Hydropower generation and Reservoir evaporation*	
Reservoir Evaporation	*mm/month*	*Engineering*	*NBI-WRPMP (2012), Nile Basin Decision Support system; NBI-NELSAP (2012), Nile Equatorial Lakes Subsidiary Action Program; EEPCO (2013), Ehtiopian Power System Expansion Master Plan Study; EAPP/EAC (2011), East African Power Pool Master Plan*		*Calibration of reservoir storage*	

Data	Units	Type	Source	Link	Where used in Analysis	Notes
Reservoir Elevation	*m*	*Engineering*	*Nile Basin Initiative Decision Support System*		*Calibration of system operations*	
Hydropower Capacity	*MW*	*Engineering*	*NBI-WRPMP (2012), Nile Basin Decision Support system; NBI-NELSAP (2012), Nile Equatorial Lakes Subsidiary Action Program; EEPCO (2013), Ehtiopian Power System Expansion Master Plan Study; EAPP/EAC (2011), East African Power Pool Master Plan*		*Hydropower generation*	
Turbine Capacity	*m3/s*	*Engineering*	*Ibid*		*Hydropower generation*	
Maximum Head	*m*	*Engineering*	*Ibid*		*Hydropower generation*	
Irrigated Cropped Areas	*ha*	*Crops*	*FAO (2012), AquaStat*	*http://www.fao.org/nr/aquastat*	*Agriculture*	
Cropping Patterns	*ha*	*Crops*	*Ibid*	*Ibid*	*Agriculture*	
Crop Coefficients	*N/A*	*Crops*	*FAO, CropWat*	*http://www.fao.org/nr/water/infores_databases_cropwat.html*	*Agriculture*	
WEAP – SENEGAL BASIN-----						
Sub-catchment areas	*km2*	*Topographic*	*OMVS (2013), Actualisation de la Monographie Hydrologique du Fleuve Senegal.*	*http://www.portail-omvs.org/gestion-ressource-et-environnement/sdage/schema-directeur-damenagement-sdage*	*Hydrology*	
Discharge	*m3/s*	*Hydrological*	*Ibid*	*Ibid*	*Calibration of streamflow/hydrology*	
Reservoir Storage Capacity	*MCM*	*Engineering*	*OMVS (2011), SDAGE Du Fleuve Senegal.*	*http://www.portail-omvs.org/sites/default/files/fichierspdf/annexes_phase_3_definitives.pdf*	*System operation*	
Reservoir Volume-Elevation Curves	*MCM-to-m*	*Engineering*	*Ibid*	*Ibid*	*Hydropower generation and Reservoir evaporation*	
Reservoir Evaporation	*mm/month*	*Engineering*	*Ibid*	*Ibid*	*Calibration of reservoir storage*	
Reservoir Elevation	*m*	*Engineering*	*Ibid*	*Ibid*	*Calibration of system operations*	

Data	Units	Type	Source	Link	Where used in Analysis	Notes
Hydropower Capacity	*MW*	*Engineering*	*Ibid*	*Ibid*	*Hydropower generation*	
Turbine Capacity	*m3/s*	*Engineering*	*Ibid*	*Ibid*	*Hydropower generation*	
Maximum Head	*m*	*Engineering*	*Ibid*	*Ibid*	*Hydropower generation*	
Irrigated Cropped Areas	*ha*	*Crops*	*OMVS (2010), Plan d'Action Regional pour l'Amelioration des Culture Irriguees dan le Bassin de Fleuve Senegal*		*Agriculture*	
Cropping Patterns	*ha*	*Crops*	*Ibid*		*Agriculture*	
Crop Coefficients	*N/A*	*Crops*	*FAO, CropWat*	*http://www.fao.org/nr/water/infores_databases_cropwat.html*	*Agriculture*	
WEAP – VOLTA BASIN--						
Sub-catchment areas	*km2*	*Topographic*	*McCartney et al (2012), IWMI Research Report 146: The Water Resource Implications of Changing Climate in the Volta River; de Condappa et al (2009), A decision-support tool for water allocation in the Volta Basin*	*http://www.iwmi.cgiar.org/Publications/IWMI_Research_Reports/PDF/PUB146/RR146.pdf*	*Hydrology*	
Discharge	*m3/s*	*Hydrological*	*HYCOS*	*http://www.whycos.org/cms/content/volta-hycos-english*	*Calibration of streamflow/hydrology*	
Reservoir Storage Capacity	*MCM*	*Engineering*	*McCartney et al (2012), IWMI Research Report 146: The Water Resource Implications of Changing Climate in the Volta River; de Condappa et al (2009), A decision-support tool for water allocation in the Volta Basin*	*http://www.iwmi.cgiar.org/Publications/IWMI_Research_Reports/PDF/PUB146/RR146.pdf*	*System operation*	
Reservoir Volume-Elevation Curves	*MCM-to-m*	*Engineering*	*Ibid*	*Ibid*	*Hydropower generation and Reservoir evaporation*	
Reservoir Evaporation	*mm/month*	*Engineering*	*Ibid*	*Ibid*	*Calibration of reservoir storage*	
Reservoir Elevation	*m*	*Engineering*	*Volta River Authority*		*Calibration of system operations*	

Data	Units	Type	Source	Link	Where used in Analysis	Notes
Hydropower Capacity	*MW*	*Engineering*	*McCartney et al (2012), IWMI Research Report 146: The Water Resource Implications of Changing Climate in the Volta River; de Condappa et al (2009), A decision-support tool for water allocation in the Volta Basin*	*http://www.iwmi.cgiar.org/Publications/IWMI_Research_Reports/PDF/PUB146/RR146.pdf*	*Hydropower generation*	
Turbine Capacity	*m3/s*	*Engineering*	*Ibid*	*Ibid*	*Hydropower generation*	
Maximum Head	*m*	*Engineering*	*Ibid*	*Ibid*	*Hydropower generation*	
Irrigated Cropped Areas	*ha*	*Crops*	*McCartney et al (2012), IWMI Research Report 146: The Water Resource Implications of Changing Climate in the Volta River*	*http://www.iwmi.cgiar.org/Publications/IWMI_Research_Reports/PDF/PUB146/RR146.pdf*	*Agriculture*	
Cropping Patterns	*ha*	*Crops*	*FAO, AquaStat*	*http://www.fao.org/nr/water/aquastat/dbase/index.stm*	*Agriculture*	
Crop Coefficients	*N/A*		*FAO, CropWat*	*http://www.fao.org/nr/water/infores_databases_cropwat.html*	*Agriculture*	
***WEAP – ZAMBEZI BASIN*------------**						
Sub-catchment areas	*km2*	*Topographic*	*Fant et al (2013), Impact of climate change on crops, irrigation, and hydropower in the Zambezi River basin; Tirivarombo (2013), Climate variability and climate change in water resources management of the Zambezi River basin*	*http://www.wider.unu.edu/publications/working-papers/2013/en_GB/wp2013-039/_files/89507107340419138/default/WP2013-039.pdf*	*Hydrology*	
Discharge	*m3/s*	*Hydrological*	*Global Runoff Data Center*	*http://www.bafg.de/GRDC/EN/Home/homepage_node.html*	*Calibration of streamflow/hydrology*	
Reservoir Storage Capacity	*MCM*	*Engineering*	*World Bank (2010), The Zambezi River Basin: A Multi-Sector Investment Opportunities Analysis*	*http://documents.worldbank.org/curated/en/2010/06/13236172/zambezi-river-basin-multi-sector-investment-opportunities-analysis-vol-1-4-summary-report*	*System operation*	

Data	*Units*	*Type*	*Source*	*Link*	*Where used in Analysis*	*Notes*
Reservoir Volume-Elevation Curves	*MCM-to-m*	*Engineering*	*Ibid*	*Ibid*	*Hydropower generation and Reservoir evaporation*	
Reservoir Evaporation	*mm/month*	*Engineering*	*Ibid*	*Ibid*	*Calibration of reservoir storage*	
Reservoir Elevation	*m*	*Engineering*	*Ibid*	*Ibid*	*Calibration of system operations*	
Hydropower Capacity	*MW*	*Engineering*	*Ibid*	*Ibid*	*Hydropower generation*	
Turbine Capacity	*m3/s*	*Engineering*	*Ibid*	*Ibid*	*Hydropower generation*	
Maximum Head	*m*	*Engineering*	*Ibid*	*Ibid*	*Hydropower generation*	
Irrigated Cropped Areas	*ha*	*Crops*	*Ibid*	*Ibid*	*Agriculture*	
Cropping Patterns	*ha*	*Crops*	*Ibid*	*Ibid*	*Agriculture*	
Crop Coefficients	*N/A*		*Ibid*	*Ibid*	*Agriculture*	

Data	Units	Type	Source	Link	Where used in Analysis	Notes
Data used in the Power Modeling --						
Cost of domestic fuel	*USD/ToE*	*Cost*	*East African Power Pool Master Plan report*	*http://www.eac.int/energy/index.php?option=com_docman&task=cat_view&gid=51&Itemid=70*	*Define the cost of extracting domestic resources of fossil fuels for energy generation in East African countries.*	*These costs are converted from the original unit using conversion tables as referenced herein. The cost of import in a country is set by these values assuming a 10% marginal increase.*
Emission Factors	*Kg/MMBtu*	*Environmental*	*U.S. Energy Information Administration*	*http://www.eia.gov/oiaf/1605/coefficients.html*	*Post treatment of the results to investigate the potential effect of carbon financing shemes in the region.*	*This concerns emissions of GHG including CO2, N2O and CH4. Converted to Mt/PJ for use in the OSeMOSYS modelling framework.*
Energy Consumption	*TWh*	*Energy*	*United Nations Energy Statistics Data Base*	*http://data.un.org/Explorer.aspx?d=EDATA*	*Extract national level consumption for base year demands in 2010.*	*Calibration of demand trends based on PIDA documentation.*
Energy Demand - CAPP	*PJ*	*Energy*	*Programme for Infrastructure Development in Africa*	*http://www.nepad.org/regionalintegrationandinfrastructure/knowledge/doc/2156/pida-study-phase-i-report*	*Extract national level energy demand for remaining countries not yet convered in other three power pools*	*Demands adjusted to current demand.*
Energy Demand - EAPP	*PJ*	*Energy*	*East African Power Pool Master Plan report, Vol II & Appendix E*	*http://www.eac.int/energy/index.php?option=com_docman&task=cat_view&gid=51&Itemid=70*	*Extract national level energy demands for the Eastern African Power Pool*	*Values taken as sent out generation requirements.*
Energy Demand - WAPP, SAPP	*PJ*	*Energy*	*IRENA - Southern African Power Pool*	*http://www.irena.org/DocumentDownloads/Publications/SAPP.pdf*	*Extract national level energy demands as well as corresponding sectorial splits between industrial, urban and rural clients.*	*Latest available demand estimations finalised through local stakeholder workshoping in the ECOWAS and SADC regions.*
Energy Unit Conversions	*na*	*Energy*	*U.S. Energy Information Administration*	*http://www.eia.gov/cfapps/ipdbproject/docs/unitswithpetro.cfm*	*Used to convert various energy resource types of energy resource data into usable units within the energy modelling framework.*	
Existing and planned hydropower	*na*	*Infrastructure*	*World Energy Power Plants database - Platts*	*http://www.platts.com/products/world-electric-power-plants-database*	*In parallel to other sources, establish a database of operational and planned hydropower infrastructure in SSA. Used as a reference for all countries.*	*Detailed on a national basis, this database contains up to date detailed listings of power infrastructure by generatl location, size, and year of installation. This data is copyright protected and is not shared in any state that would enable its reconstruction inside these reports.*

Data	Units	Type	Source	Link	Where used in Analysis	Notes
Existing and planned power infrastructure	*na*	*Infrastructure*	*East African Power Pool Master Plan report*	*http://www.eac.int/energy/index.php?option=com_docman&task=cat_view&gid=51&Itemid=70*	*Establish a database of operational and planned infrastructure in the Eastern African Power Pool.*	*This includes both hydropower and other power generation infrastructure. This data also summarises techno-economic information regarding site specific hydropower plants.*
Existing and planned power infrastructure	*na*	*Infrastructure*	*IRENA - Southern and Western African Power Pool analyses*	*http://www.irena.org/DocumentDownloads/Publications/SAPP.pdf ; http://www.irena.org/DocumentDownloads/Publications/WAPP.pdf*	*WAPP and SAPP model structure population*	*Latest power pool analyses summarising available data for the WAPP and the SAPP re. Generation as well as transmission technologies.*
Hydro Proxy	*na*	*Infrastructure*	*Communications with SEI*	*na*	*Relate power plants present in the OSeMOSYS energy modelling framework to power plants represented in the WEAP modelling structure.*	*This relation is done through adjusting the capacity factors of the proxied power plants accordingly to their reference power plant to mirror climate effects throughout the power pool under consideration.*
Hydropower capacity	*MW*	*Infrastructure*	*SEI - ETH summary on hydropower in the Zambezi*	*http://bscw-app1.let.ethz.ch/pub/bscw.cgi/d11577751/Hydropower%20overview_Zambezi.pdf*	*Complemetary information regarding capacity levels of power plants related to the Zambezi river basin.*	*Used in accordance with data present in the corresponding facilities in the WEAP modelling.*
Recoverable Coal Reserves	*Million Short Tons*	*Energy*	*U.S. Energy Information Administration*	*http://www.eia.gov/countries/data.cfm*	*Maximum constraints on domestic coal availability*	*Detailed on a country level, this data is used to limit the total amount of domestic fuel that is available for energy generation within the energy modelling framework.*
Recoverable Natural Gas Reserves	*Trillion Cubic Feet*	*Energy*	*Ibid*	*Ibid*	*Maximum constraints on domestic natural gas availability*	*Detailed on a country level, this data is used to limit the total amount of domestic fuel that is available for energy generation within the energy modelling framework.*
Recoverable Oil Reserves	*Billion Barrels*	*Energy*	*Ibid*	*Ibid*	*Maximum constraints on domestic oil availability*	*Detailed on a country level, this data is used to limit the total amount of domestic fuel that is available for energy generation within the energy modelling framework.*

Data	Units	Type	Source	Link	Where used in Analysis	Notes
Renewable Energy Potentials	*TWh*	*Energy*	*Estimating the Renewable Energy Potential in Africa - A GIS-based approach*	*www.irena.org/menu/index.aspx?mnu=Subcat&PriMenuID=36&CatID=141&SubcatID=440*	*Maximum constraints on energy use from renewable power sources*	*These limits are detailed on a country level for all countries of SSA detailed in this study. They concern wind and solar power specifically.*
Techno-economic parameters	*na*	*Cost and Efficiency*	*IRENA - Southern African Power Pool*	*http://www.irena.org/DocumentDownloads/Publications/SAPP.pdf*	*Default technical specifications for generic power plants.*	*These include efficiencies, operation and maintenance costs, investment costs, power plant availability, plant lifetime as well as required construction years.*
Techno-economic parameters	*na*	*Cost and Efficiency*	*ETSAP Technology Biefs*	*http://www.iea-etsap.org/Energy_Technologies/Energy_Supply.asp*	*Default technical specifications for generic power plants.*	*Used to complement data from other sources for standard power generation technology description*
Techno-economic parameters	*na*	*Cost and Efficiency*	*International Energy Agency*	*http://www.iea.org/publications/freepublications/publication/projected_costs.pdf*	*Default technical specifications for generic power plants.*	*Used to complement data from other sources for standard power generation technology description*
Transmission Infrastructure	*na*	*Infrastructure*	*The Infrastructure consortium for Africa*	*http://www.icafrica.org/fileadmin/documents/Knowledge/Energy/ICA_RegionalPowerPools_Report.pdf*	*Information relating to priority projects for cross-border interconnections in each power pool.*	*Complementary information was also extracted from Power Pool Master Plans for the WAPP, SAPP and EAPP*

Data	Units	Type	Source	Link	Where used in Analysis	Notes
Scenario Analysis -----						
Precipitation	*mm/ month*	*Meteorological*	*Terrestrial Hydrology Research Group at Princeton University*	*http://hydrology.princeton.edu/data.pgf.php*	*Hydrology, Agriculture, Reservoir Evaporation*	*'Historical Direct' climate scenario*
Maximum Temperature	*C*	*Meteorological*	*Ibid*	*Ibid*	*Hydrology, Agriculture, Reservoir Evaporation*	*'Historical Direct' climate scenario*
Minimum Temperature	*C*	*Meteorological*	*Ibid*	*Ibid*	*Hydrology, Agriculture, Reservoir Evaporation*	*'Historical Direct' climate scenario*
Average Monthly Temperature	*C*	*Meteorological*	*Ibid*	*Ibid*	*Hydrology, Agriculture, Reservoir Evaporation*	*'Historical Direct' climate scenario*
Precipitation	*mm/ month*	*Meteorological*	*THE WCRP CMIP3 Multimodel Dataset*	*http://www-pcmdi.llnl.gov/ipcc/about_ipcc.php*	*Hydrology, Agriculture, Reservoir Evaporation*	*'Projected CMIP3, BCSD' climate scenarios*
Maximum Temperature	*C*	*Meteorological*	*Ibid*	*Ibid*	*Hydrology, Agriculture, Reservoir Evaporation*	*'Projected CMIP3, BCSD' climate scenarios*
Minimum Temperature	*C*	*Meteorological*	*Ibid*	*Ibid*	*Hydrology, Agriculture, Reservoir Evaporation*	*'Projected CMIP3, BCSD' climate scenarios*
Precipitation	*mm/ month*	*Meteorological*	*WCRP Coupled Model Intercomparison Project - Phase 5 - CMIP5*	*http://cmip-pcmdi.llnl.gov/cmip5/*	*Hydrology, Agriculture, Reservoir Evaporation*	*'Historical Projected' and 'Projected CMIP5, BCSD' climate scenarios*
Maximum Temperature	*C*	*Meteorological*	*Ibid*	*Ibid*	*Hydrology, Agriculture, Reservoir Evaporation*	*'Historical Projected' and 'Projected CMIP5, BCSD' climate scenarios*
Minimum Temperature	*C*	*Meteorological*	*Ibid*	*Ibid*	*Hydrology, Agriculture, Reservoir Evaporation*	*'Historical Projected' and 'Projected CMIP5, BCSD' climate scenarios*
Average Monthly Temperature	*C*	*Meteorological*	*Ibid*	*Ibid*	*Hydrology, Agriculture, Reservoir Evaporation*	*'Historical Projected' and 'Projected CMIP5, BCSD' climate scenarios*
Precipitation	*mm/ month*	*Meteorological*	*University of Cape Town Climate Systems Analysis Group (CSAG)*	*na*	*Hydrology, Agriculture, Reservoir Evaporation*	*'Projected CMIP5, UCT-CSAG' climate scenarios*
Maximum Temperature	*C*	*Meteorological*	*Ibid*	*Ibid*	*Hydrology, Agriculture, Reservoir Evaporation*	*'Projected CMIP5, UCT-CSAG' climate scenarios*

Data	Units	Type	Source	Link	Where used in Analysis	Notes
Minimum Temperature	*C*	*Meteorological*	*Ibid*	*Ibid*	*Hydrology, Agriculture, Reservoir Evaporation*	*'Projected CMIP5, UCT-CSAG' climate scenarios*
Average Monthly Temperature	*C*	*Meteorological*	*Ibid*	*Ibid*	*Hydrology, Agriculture, Reservoir Evaporation*	*'Projected CMIP5, UCT-CSAG' climate scenarios*
Latitude centroid of basin or grid cell	*Decimal degrees*	*Meteorological*	*GIS analysis*	*na*	*PET calculation*	*Used as part of the solar radiation estimation in the Modified Hargreaves equation, which is used to estimate PET*
Crop Yields ---						
Crop yields	*Tonnes/ha*	*Irrigation*	*FAOSTAT*	*http://faostat.fao.org/*	*Calculation of irrigation revenues*	*Average yields for the most recent five years taken at the country level. Assigned to irrigated areas based on location.*
Crop yield increases	*%/year*	*Irrigation*	*IFPRI projections*	*na*	*Ramps up crop yields over time*	
Irrigation costs	*USD/ha*	*Irrigation*	*IWMI 2007*	*http://www.ifad.org/events/hs/doc/irrigation_projects.pdf*	*Used to estimate the costs/savings of one hectare of irrigation.*	
Cost of field irrigation efficiency improvements	*USD/ha*	*Irrigation*	*Ibid*	*Ibid*	*Used to estimate the costs of adopting irrigation efficiency improvements.*	*Based on a comparison of three technologies: basic flooding, improved flooding, and sprinkler.*
Cost of conveyance efficiency improvements	*USD/ha*	*Irrigation*	*ITRC 2010.*	*http://www.itrc.org/papers/pdf/canalseepage.pdf*	*Used to estimate the costs of improving conveyance efficiency*	*Estimates are based on the per kilometer costs of canal lining and piping.*
Crop coefficients (Kc)	*Unitless*	*Irrigation*	*FAO irrigation and drainage paper 56*	*http://www.fao.org/docrep/x0490e/x0490e00.htm*	*Used to translate PET into crop water demand*	*A monthly crop-specific coefficient that lumps crop characteristics into a single value.*
Crop water response (Ky)	*Unitless*	*Irrigation*	*FAO irrigation and drainage paper 56*	*http://www.fao.org/docrep/x0490e/x0490e00.htm*	*Used to translate the effects of deficit irrigation into crop yield outcomes*	
Crop price trajectory	*USD/tonne*	*Irrigation*	*IFPRI projections*	*na*	*Used to estimate total crop revenues*	*Crop prices are in real terms, and trajectory is from 2011 to 2050.*
Crop areas	*Ha*	*Irrigation*	*WEAP models*	*na*	*Used to estimate total crop revenues*	

Data	*Units*	*Type*	*Source*	*Link*	*Where used in Analysis*	*Notes*
Unmet irrigation water demand	*%*	*Irrigation*	*MATLAB WEAP*	*na*	*With deficit irrigation, used to estimate actual crop yields*	*A monthly time series of unmet irrigation water demands for each irrigated area. Modeled outputs.*
Hydropower generation	*MWH/ mo*	*Hydropower*	*MATLAB WEAP*	*na*	*Used to estimate revenues of hydropower.*	*A monthly time series of hydropower generation for each facility. Modeled outputs.*

Data	***Units***	***Type***	***Source***	***Link***	***Where used in Analysis***	***Notes***
Data used by KTH ---						
Cost of domestic fuel	*USD/ToE*	*Cost*	*East African Power Pool Master Plan report*	*http://www.eac.int/energy/index.php?option=com_docman&task=cat_view&gid=51&Itemid=70*	*Define the cost of extracting domestic resources of fossil fuels for energy generation in East African countries.*	*These costs are converted from the original unit using conversion tables as referenced herein. The cost of import in a country is set by these values assuming a 10% marginal increase.*
Emission Factors	*Kg/MMBtu*	*Environmental*	*U.S. Energy Information Administration*	*http://www.eia.gov/oiaf/1605/coefficients.html*	*Post treatment of the results to investigate the potential effect of carbon financing shemes in the region.*	*This concerns emissions of GHG including CO2, N2O and CH4. Converted to Mt/PJ for use in the OSeMOSYS modelling framework.*
Energy Consumption	*TWh*	*Energy*	*United Nations Energy Statistics Data Base*	*http://data.un.org/Explorer.aspx?d=EDATA*	*Extract national level consumption for base year demands in 2010.*	*Calibration of demand trends based on PIDA documentation.*
Energy Demand - CAPP	*PJ*	*Energy*	*Programme for Infrastructure Development in Africa*	*http://www.nepad.org/regionalintegrationandinfrastructure/knowledge/doc/2156/pida-study-phase-i-report*	*Extract national level energy demand for remaining countries not yet covered in other three power pools*	*Demands adjusted to current demand.*
Energy Demand - EAPP	*PJ*	*Energy*	*East African Power Pool Master Plan report, Vol II & Appendix E*	*http://www.eac.int/energy/index.php?option=com_docman&task=cat_view&gid=51&Itemid=70*	*Extract national level energy demands for the Eastern African Power Pool*	*Values taken as sent out generation requirements.*
Energy Demand - WAPP, SAPP	*PJ*	*Energy*	*IRENA - Southern African Power Pool*	*http://www.irena.org/DocumentDownloads/Publications/SAPP.pdf*	*Extract national level energy demands as well as corresponding sectorial splits between industrial, urban and rural clients.*	*Latest available demand estimations finalized through local stakeholder workshopping in the ECOWAS and SADC regions.*
Energy Unit Conversions	*na*	*Energy*	*U.S. Energy Information Administration*	*http://www.eia.gov/cfapps/ipdbproject/docs/unitswithpetro.cfm*	*Used to convert various energy resource types of energy resource data into usable units within the energy modelling framework.*	
Existing and planned hydropower	*na*	*Infrastructure*	*World Energy Power Plants database - Platts*	*http://www.platts.com/products/world-electric-power-plants-database*	*In parallel to other sources, establish a database of operational and planned hydropower infrastructure in SSA. Used as a reference for all countries.*	*Detailed on a national basis, this database contains up to date detailed listings of power infrastructure by general location, size, and year of installation. This data is copyright protected and is not shared in any state that would enable its reconstruction inside these reports.*

Data	Units	Type	Source	Link	Where used in Analysis	Notes
Existing and planned power infrastructure	*na*	*Infrastructure*	*East African Power Pool Master Plan report*	*http://www.eac.int/energy/index.php?option=com_docman&task=cat_view&gid=51&Itemid=70*	*Establish a database of operational and planned infrastructure in the Eastern African Power Pool.*	*This includes both hydropower and other power generation infrastructure. This data also summarizes techno-economic information regarding site specific hydropower plants.*
Existing and planned power infrastructure	*na*	*Infrastructure*	*IRENA - Southern and Western African Power Pool analyses*	*http://www.irena.org/DocumentDownloads/Publications/SAPP.pdf ; http://www.irena.org/DocumentDownloads/Publications/WAPP.pdf*	*WAPP and SAPP model structure population*	*Latest power pool analyses summarizing available data for the WAPP and the SAPP re. Generation as well as transmission technologies.*
Hydro Proxy	*na*	*Infrastructure*	*Communications with SEI*	*na*	*Relate power plants present in the OSeMOSYS energy modelling framework to power plants represented in the WEAP modelling structure.*	*This relation is done through adjusting the capacity factors of the proxied power plants accordingly to their reference power plant to mirror climate effects throughout the power pool under consideration.*
Hydropower capacity	*MW*	*Infrastructure*	*SEI - ETH summary on hydropower in the Zambezi*	*http://bscw-app1.let.ethz.ch/pub/bscw.cgi/d11577751/Hydropower%20overview_Zambezi.pdf*	*Complementary information regarding capacity levels of power plants related to the Zambezi river basin.*	*Used in accordance with data present in the corresponding facilities in the WEAP modelling.*
Recoverable Coal Reserves	*Million Short Tons*	*Energy*	*U.S. Energy Information Administration*	*http://www.eia.gov/countries/data.cfm*	*Maximum constraints on domestic coal availability*	*Detailed on a country level, this data is used to limit the total amount of domestic fuel that is available for energy generation within the energy modelling framework.*
Recoverable Natural Gas Reserves	*Trillion Cubic Feet*	*Energy*	*Ibid*	*Ibid*	*Maximum constraints on domestic natural gas availability*	*Detailed on a country level, this data is used to limit the total amount of domestic fuel that is available for energy generation within the energy modelling framework.*
Recoverable Oil Reserves	*Billion Barrels*	*Energy*	*Ibid*	*Ibid*	*Maximum constraints on domestic oil availability*	*Detailed on a country level, this data is used to limit the total amount of domestic fuel that is available for energy generation within the energy modelling framework.*

Data	*Units*	*Type*	*Source*	*Link*	*Where used in Analysis*	*Notes*
Renewable Energy Potentials	*TWh*	*Energy*	*Estimating the Renewable Energy Potential in Africa - A GIS-based approach*	*www.irena.org/menu/index.aspx?mnu=Subcat&PriMenuID=36&CatID=141&SubcatID=440*	*Maximum constraints on energy use from renewable power sources*	*These limits are detailed on a country level for all countries of SSA detailed in this study. They concern wind and solar power specifically.*
Techno-economic parameters	*na*	*Cost and Efficiency*	*IRENA - Southern African Power Pool*	*http://www.irena.org/DocumentDownloads/Publications/SAPP.pdf*	*Default technical specifications for generic power plants.*	*These include efficiencies, operation and maintenance costs, investment costs, power plant availability, plant lifetime as well as required construction years.*
Techno-economic parameters	*na*	*Cost and Efficiency*	*ETSAP Technology Briefs*	*http://www.iea-etsap.org/Energy_Technologies/Energy_Supply.asp*	*Default technical specifications for generic power plants.*	*Used to complement data from other sources for standard power generation technology description*
Techno-economic parameters	*na*	*Cost and Efficiency*	*International Energy Agency*	*http://www.iea.org/publications/freepublications/publication/projected_costs.pdf*	*Default technical specifications for generic power plants.*	*Used to complement data from other sources for standard power generation technology description*
Transmission Infrastructure	*na*	*Infrastructure*	*The Infrastructure consortium for Africa*	*http://www.icafrica.org/fileadmin/documents/Knowledge/Energy/ICA_RegionalPowerPools_Report.pdf*	*Information relating to priority projects for cross-border interconnections in each power pool.*	*Complementary information was also extracted from Power Pool Master Plans for the WAPP, SAPP and EAPP*

Note: Hydropower project installed capacity and start dates were harmonized with input from SEI and relevant basin authorities. Refer to each individual basin infrastructure (memo).

Data	Units	Type	Source	Link	Where used in Analysis	Notes
Track II - Lower Fufu --						
Infrastructure Design Parameters	*m3/sec*	*Design*	*Unpublished pre-feasibility report*		*Develop alternative project designs*	
Project costs	*2013 US $*	*Cost*	*Estimated using cost model developed by Black & Veatch*		*Calculate capital cost for different project designs*	
Monthly Inflow	*m3/sec*	*Environmental*	*Estimated using WEAP*		*As input for hydro power generation estimation*	
Historical streamflows for calibration	*m3/sec*	*Environmental*	*Unpublished pre-feasibility report*		*As input for WEAP model calibration*	
Track II - Batoka --						
Infrastructure Design Parameters	*Dam Storage (Million cubic meter); Hydropower Turbine Capacity (m3/sec);*	*Design*	*Unpublished feasibility report*		*Develop alternative project designs*	
Project costs	*2013 US $*	*Cost*	*Estimated using cost model developed by Black & Veatch*		*Calculate capital cost for different project designs*	
Monthly Inflow	*m3/sec*	*Environmental*	*Estimated using WEAP*		*As input for hydro power generation estimation*	
Historical streamflows for calibration	*m3/sec*	*Environmental*	*Unpublished feasibility report*		*As input for WEAP model calibration*	
Power purchase agreement price	*$/kWh*	*Benefit*	*Estimated based on Track I regional analysis for Southern Africa*		*As input for estimating the benefit of the project*	
Track II - Mwache --						
Infrastructure Design Parameters	*Dam Storage (Million cubic meter)*	*Design*	*Unpublished water supply master plan design document*		*Develop alternative project designs*	
Project costs	*2013 US $*	*Cost*	*Estimated using cost model developed by Black & Veatch*		*Calculate capital cost for different project designs*	
Monthly Inflow	*m3/sec*	*Environmental*	*Estimated using WEAP*		*As input for hydro power generation estimation*	

Data	Units	Type	Source	Link	Where used in Analysis	Notes
Historical streamflows for calibration	*m3/sec*	*Environmental*	*Provided by World Bank*		*As input for WEAP model calibration*	
Urban water demand projections	*million m3/year*	*Demand*	*Unpublished water supply master plan design document*		*As input for hydro power generation estimation*	
Unit irrigation benefit	*$/hectare irrigated*	*Benefit*	*Unpublished water supply master plan design document*		*As input for estimating the benefit of the project*	Unit irrigation benefit
Reference value of water	*$/m3*	*Benefit*	*Unpublished water supply master plan design document*		*As input for estimating the benefit of the project*	
Track II - Polihali---						
Infrastructure Design Parameters	*Dam Storage (Million cubic meter); Average annual transfer target (m3/sec); Guaranteed transfer level (m3/sec)*	*Design*	*Unpublished prefeasibility report*		*Develop alternative project designs*	
Project costs	*2013 US $*	*Cost*	*Estimated using cost model developed by Black & Veatch*		*Calculate capital cost for different project designs*	
Monthly Inflow	*m3/sec*	*Environmental*	*Estimated using WEAP*		*As input for hydro power generation estimation*	
Historical streamflows for calibration	*m3/sec*	*Environmental*	*Agreed hydrology provided by World Bank*		*As input for WEAP model calibration*	
Reference water diversion target	*m3/sec*	*Performance target*	*Unpublished prefeasibility report*		*As input for estimating the benefit of the project*	
Reference value of water	*$/m3*	*Benefit*	*Unpublished South Africa water resources assessment report, converted rand to US dollar based on Dec,2013 exchange rate.*		*As input for estimating the benefit of the project*	
Track II – Pwalugu---						

Data	Units	Type	Source	Link	Where used in Analysis	Notes
Infrastructure Design Parameters	*Dam Storage (Million cubic meter); Turbine capacity (m3/sec); Irrigation area (hectare)*	*Design*	*Unpublished pre-feasibility report*		*Develop alternative project designs*	
Project costs	*2013 US $*	*Cost*	*Estimated using cost model developed by Black & Veatch*		*Calculate capital cost for different project designs*	
Monthly Inflow	*m3/sec*	*Environmental*	*Estimated using WEAP*		*As input for hydro power generation estimation*	
Historical streamflows for calibration	*m3/sec*	*Environmental*	*Unpublished pre-feasibility report*		*As input for WEAP model calibration*	
Reference irrigation area	*hectare*	*Irrigation*	*Unpublished pre-feasibility report*		*As input for hydro power generation estimation*	
Reference unit irrigation benefit	*$/hectare irrigated-year*	*Benefit*	*Unpublished pre-feasibility report*		*As input for estimating the benefit of the project*	
Reference unit irrigation cost	*$/hectare irrigated*	*Cost*	*Unpublished pre-feasibility report*		*As input for estimating the cost of the project*	
Reference unit hydropower benefit	*$/kWh*	*Benefit*	*Unpublished pre-feasibility report*		*As input for estimating the benefit of the project*	

Data	Units	Type	Source	Link	Where used in Analysis	Notes
Perfect Foresight Congo Basin--						
Palambo Dam	*USD*	*Cost Data*	*PIDA 2013.*	*http://www.au-pida.org/node/156*	*Perfect Foresight*	
Tshopo	*USD*	*Cost Data*	*Hydroelectric Power Plants in Congo and Congo DR*	*http://www.industcards.com/hydro-congo-congo-rep.htm.*	*Perfect Foresight*	
Nzilo	*USD*	*Cost Data*	*Average KTH per MW cost*		*Perfect Foresight*	
Nseke	*USD*	*Cost Data*	*Ibid*		*Perfect Foresight*	
Busanga	*USD*	*Cost Data*	*SinoHydro. DR Congo, Busanga Hydropower Station. Accessed from*	*http://eng.sinohydro.com/index.php?m=content&c=index&a=show&catid=42&id=32.*	*Perfect Foresight*	
Katende	*USD*	*Cost Data*	*Average KTH per MW cost*		*Perfect Foresight*	
Mobayi	*USD*	*Cost Data*	*Ibid*		*Perfect Foresight*	
Sanga	*USD*	*Cost Data*	*Ibid*		*Perfect Foresight*	
Ruzizi III	*USD*	*Cost Data*	*Infrastructure Trust Fund, European Union, Africa.*	*http://www.eu-africa-infrastructure-tf.net/activities/grants/ruzizi.htm*	*Perfect Foresight*	
Perfect Foresight Nile Basin--						
Assiut	*USD*	*Cost Data*	*KTH*		*Perfect Foresight*	
Ayago	*USD*	*Cost Data*	*EAPP Master plan; Appendix B II*		*Perfect Foresight*	
Baro 2	*USD*	*Cost Data*	*Ibid*		*Perfect Foresight*	
Bedden	*USD*	*Cost Data*	*Ibid*		*Perfect Foresight*	
Beko Abo	*USD*	*Cost Data*	*KTH*		*Perfect Foresight*	
Birbir R	*USD*	*Cost Data*	*Ibid*		*Perfect Foresight*	
Dagash	*USD*	*Cost Data*	*EAPP Master plan; Appendix B II*		*Perfect Foresight*	
Dal (low)	*USD*	*Cost Data*	*Ibid*		*Perfect Foresight*	
Fula	*USD*	*Cost Data*	*Ibid*		*Perfect Foresight*	
Geba 1	*USD*	*Cost Data*	*Geba HEP feasibility study report (final)*		*Perfect Foresight*	
Geba 2	*USD*	*Cost Data*	*Ibid*		*Perfect Foresight*	
Grand Renaissance	*USD*	*Cost Data*	*KTH*		*Perfect Foresight*	
Isimba	*USD*	*Cost Data*	*EAPP Master plan; Appendix B II*		*Perfect Foresight*	
Kajbar	*USD*	*Cost Data*	*Ibid*		*Perfect Foresight*	
Kakono	*USD*	*Cost Data*	*Ibid*		*Perfect Foresight*	
Karadobe	*USD*	*Cost Data*	*KTH*		*Perfect Foresight*	
Karuma	*USD*	*Cost Data*	*EAPP Master plan; Appendix B II*		*Perfect Foresight*	
Kiba	*USD*	*Cost Data*	*KTH*		*Perfect Foresight*	
Lakki	*USD*	*Cost Data*	*EAPP Master plan; Appendix B II*		*Perfect Foresight*	

Data	Units	Type	Source	Link	Where used in Analysis	Notes
Lower Didessa	*USD*	*Cost Data*	*Ethiopia power master plan (2012)*		*Perfect Foresight*	
Magwagwa	*USD*	*Cost Data*	*KTH*		*Perfect Foresight*	
Murchison Falls	*USD*	*Cost Data*	*EAPP Master plan; Appendix B II*		*Perfect Foresight*	
Rumela Burdana	*USD*	*Cost Data*	*KTH*		*Perfect Foresight*	
Rusumo Falls	*USD*	*Cost Data*	*EAPP MP Report Vol I p 133 refers to 63MW installed capacity & 4845USD/kW*		*Perfect Foresight*	
Sabloka	*USD*	*Cost Data*	*EAPP Master plan; Appendix B II*		*Perfect Foresight*	
Shereiq	*USD*	*Cost Data*	*Ibid*		*Perfect Foresight*	
Shukoli	*USD*	*Cost Data*	*Ibid*		*Perfect Foresight*	
Tams	*USD*	*Cost Data*	*Ethiopia power master plan (2012)*		*Perfect Foresight*	
TK7 (Tekeze II)	*USD*	*Cost Data*	*Ibid*		*Perfect Foresight*	
Upper Mandaya	*USD*	*Cost Data*	*KTH*		*Perfect Foresight*	
Perfect Foresight Niger Basin--						
Fomi	*USD*	*Cost Data*	*Revised ECOWAS Master Plan For the Generation and Transmission of Electrical Energy*	*http://www.ecowapp.org/?page_id=136*	*Perfect Foresight*	
Taoussa	*USD*	*Cost Data*	*Ibid*	*Ibid*	*Perfect Foresight*	
Kandadji Dam	*USD*	*Cost Data*	*Ibid*	*Ibid*	*Perfect Foresight*	
Diaraguela	*USD*	*Cost Data*	*Ibid*	*Ibid*	*Perfect Foresight*	
Zungeru	*USD*	*Cost Data*	*Aid Data*	*http://china.aiddata.org/projects/30460*	*Perfect Foresight*	
Mambilla	*USD*	*Cost Data*	*KTH*		*Perfect Foresight*	
Gurara II	*USD*	*Cost Data*	*Nigerian Ministry of Power*	*http://www.slideshare.net/fullscreen/TransformNG/ministry-of-power/2*	*Perfect Foresight*	
Perfect Foresight Senegal Basin--						
Balassa	*USD*	*Cost Data*	*Update of the ECOWAS Revised Master Plan For the Generation and Transmission of Electrical Energy*	*http://www.ecowapp.org/?dl_id=451 - Tractebel Engineering*	*Perfect Foresight*	
Koukoutamba	*USD*	*Cost Data*	*Nodalis - Hydropower Project Structuring(French)*	*http://www.ppiaf.org/sites/ppiaf.org/files/documents/PPP_hydro_guinee_vbase.pdf*	*Perfect Foresight*	

Data	Units	Type	Source	Link	Where used in Analysis	Notes
Boureya	*USD*	*Cost Data*	*Ibid*	*Ibid*	*Perfect Foresight*	
Gouina	*USD*	*Cost Data*	*Update of the ECOWAS Revised Master Plan For the Generation and Transmission of Electrical Energy*	*http://www.ecowapp.org/?dl_id=451 - Tractebel Engineering*	*Perfect Foresight*	
Felou	*USD*	*Cost Data*	*Update of the ECOWAS Revised Master Plan For the Generation and Transmission of Electrical Energy*	*http://www.ecowapp.org/?dl_id=451*	*Perfect Foresight*	
Moussala	*USD*	*Cost Data*	*KTH*		*Perfect Foresight*	
Gourbassi	*USD*	*Cost Data*	*OMVS - SDAGE of the Senegal River (French)*	*http://www.portail-omvs.org/sites/default/files/fichierspdf/rapport_sdage_phase_3_drfinitif.pdf*	*Perfect Foresight*	
Perfect Foresight Volta Basin**---**						
Samendeni	*USD*	*Cost Data*	*Burkina Faso – The Samendeni Growth Pole*	*http://www.burkinafasoindia.org/documents/Samendeni%20FINAL%20English.pdf*	*Perfect Foresight*	
Bonvale	*USD*	*Cost Data*	*Sirte Water and Energy*	*http://www.sirtewaterandenergy.org/docs/reports/BurkinaFaso-Rapport2.pdf*	*Perfect Foresight*	
Bontioli	*USD*	*Cost Data*	*Ibid*	*Ibid*	*Perfect Foresight*	
Bon	*USD*	*Cost Data*	*Ibid*	*Ibid*	*Perfect Foresight*	
Noumbiel	*USD*	*Cost Data*	*Wikhydro – Prioritizing large dam projects in the West African Region*	*http://wikhydro.developpement-durable.gouv.fr/index.php/Prioritizing_large_dams_projects_in_the_West_African_region/en*	*Perfect Foresight*	
Daboya	*USD*	*Cost Data*	*Revised ECOWAS Master Plan For the Generation and Transmission of Electrical Energy*	*http://www.ecowapp.org/?page_id=136*	*Perfect Foresight*	
Koulbi	*USD*	*Cost Data*	*KTH*		*Perfect Foresight*	
Lanka	*USD*	*Cost Data*	*Ibid*		*Perfect Foresight*	
Ntereso	*USD*	*Cost Data*	*Ibid*		*Perfect Foresight*	
Badongo	*USD*	*Cost Data*	*Ibid*		*Perfect Foresight*	
Gongourou	*USD*	*Cost Data*	*Ibid*		*Perfect Foresight*	
Jambito	*USD*	*Cost Data*	*Ibid*		*Perfect Foresight*	
Juale	*USD*	*Cost Data*	*Ibid*		*Perfect Foresight*	

Data	Units	Type	Source	Link	Where used in Analysis	Notes
Pwalugu	*USD*	*Cost Data*	*Revised ECOWAS Master Plan For the Generation and Transmission of Electrical Energy*	*http://www.ecowapp.org/?page_id=136*	*Perfect Foresight*	
Kulpawn	*USD*	*Cost Data*	*Ibid*	*Ibid*	*Perfect Foresight*	
***Perfect Foresight Zambezi Basin*---**						
Lake Kariba	*USD*	*Cost Data*	*1. Energy Regulation Board. Press Statement: ZESCA Limited and Kariba Bank North Extension Corporation Limited Power Purchase Agreement March 2011. 2011.* *2. KTH Cost estimates (South Extension)*	*http://www.erb.org.zm/press/statements/ZescoKNBEPC-PPA.pdf (North extension)*	*Perfect Foresight*	
Batoka Gorge	*USD*	*Cost Data*	*1. The Infrastructure Consortium for Africa (ICA). Regional Power Status in African Power Pools. 2011.* *2. Common Market for Eastern and Southern Africa (COMESA). Batoka Gorge Hydropower Project Profile.* *3. The Herald. Batoka Power Project on Course. 2013.* *4. Southern African Development Community (SADC). Regional Infrastructure Development Master Plan: Water Sector Plan. 2012.*	*http://www.comesa.int/attachments/article/842/Batoka%20Gorge%20%20-%20Project%20Profile%20130526.pdf, http://www.herald.co.zw/batoka-power-project-on-course/, http://www.safri.de/upload/SADC_RIDMP_Water_1009.pdf*	*Perfect Foresight*	
Cahora Bassa	*USD*	*Cost Data*	*1. Southern African Development Community (SADC). Regional Infrastructure Development Master Plan Short Term Action Plan. 2013. Available:* *2. National Investment Brief, Mozambique. 2008.*	*https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/183295/UK_TI_SADC_PUBLIC_selected_infrastructure_project_opportunities_March_2013.pdf*	*Perfect Foresight*	
Mphanda Nkuwa	*USD*	*Cost Data*	*1. The Infrastructure Consortium for Africa (ICA). Regional Power Status in African Power Pools. 2011.* *2. Programme for Infrastructure Development in Africa (Pida). Summary of Energy Generation in Mozambique – Mphanda Nkuwa.* *3. FAO-Aquastat. Project Portfolio: Mozambique. 2008.*	*http://www.au-pida.org/node/162, http://www.fao.org/nr/water/aquastat, /sirte2008/MOZ-Project%20Portfolio-en.pdf*	*Perfect Foresight*	

Data	Units	Type	Source	Link	Where used in Analysis	Notes
Devils Gorge	*USD*	*Cost Data*	*1. Energy Projects [in Zambia].* *2. Southern African Development Community (SADC). Regional Infrastructure Development Master Plan: Energy Sector Plan. 2012.*	*http://www.zambiaembassy.se/Energy%20Projects.pdf, http://invest-tripartite.org/wp-content/uploads/2013/06/RIDMP-Energy-Sector-Plan-August-2012.pdf*	*Perfect Foresight*	
Iztezhi Tezhi	*USD*	*Cost Data*	*1. African Development Bank Group. Itzehi Tehzi Hydro Power and Transmission Line Project, Project Appraisal Report. 2012.* *2. Energy Regulation Board (ERB) [Zambia]. 2010 Energy Sector Report.*	*http://www.afdb.org/fileadmin/uploads/afdb/Documents/Project-and-Operations/Zambia%20-%20AR%20-%20Itezhi-Tezhi%20Hydro%20Power%20and%20Transmission%20Line%20Project%20-%20Rev%201.pdf, http://www.erb.org.zm/reports/ERBeNergySectorReport2010.pdf*	*Perfect Foresight*	
Kafue Gorge L	*USD*	*Cost Data*	*1. International Finance Cooperation (IFC). Climate Risk and Business: Hydropower: Kafue Gorge Lower: Zambia. 2011.* *2. Kafue Gorge Lower Hydropower Project: Project Brief. 2013. This source is based off the feasibility study done by the Sinohydro Corporation.*	*http://invest-tripartite.org/wp-content/uploads/2013/06/12-Kafue-Gorge-Lower-Hydropower-Project-Brief-26-05-2013.pdf.*	*Perfect Foresight*	
Rumakali	*USD*	*Cost Data*	*East African Community (EAC). Regional Power Systems Master Plan and Grid Code Study, Appendix B. 2011.*		*Perfect Foresight*	
Songwe	*USD*	*Cost Data*	*1. Southern African Development Community (SADC). Regional Infrastructure Development Master Plan: Water Sector Plan. 2012.* *2. East African Community (EAC). Regional Power Systems Master Plan and Grid Code Study, Appendix B. 2011* *3. Energy Projects [in Zambia].*	*http://www.safri.de/upload/SADC_RIDMP_Water_1009.pdf, http://www.zambiaembassy.se/Energy%20Projects.pdf*	*Perfect Foresight*	

Data	***Units***	***Type***	***Source***	***Link***	***Where used in Analysis***	***Notes***
Lusumfwe Mulungushi	*USD*	*Cost Data*	*Deputy Minister of Mines, Energy and Water Development [Zambia]. Presentation to 6th German African Energy Forum. Investment Opportunities in the Energy Sector. 2012.*	*http://www.energyafrica.de/fileadmin/user_upload/Energy-Africa__12/Presentation_Ministry%20of%20Energy%20Zambia_Investment%20Opportunities%20in%20the%20Energy%20Sector_.pdf*	*Perfect Foresight*	
Mpata Gorge	*USD*	*Cost Data*	*1. Southern African Development Community (SADC). Regional Infrastructure Development Master Plan: Water Sector Plan. 2012.* *2. Energy Projects [in Zambia].*	*http://www.safri.de/upload/SADC_RIDMP_Water_1009.pdf, http://www.zambiaembassy.se/Energy%20Projects.pdf*	*Perfect Foresight*	
Kholombizo	*USD*	*Cost Data*	*1. COMESA Regional Investment Agency (RIA). COMESA Investment Teaser 2011.* *2. Malawi Government. Concept Paper for Energy Sector 2011-2016.*	*http://www.comesaria.org/site/en/download.php?id_doc=47 See page 148-149, http://www.mca-m.gov.mw/documents/final_submission/Off_Grid_Project_Concept_Paper_15052009.pdf*	*Perfect Foresight*	
Lower Fufu	*USD*	*Cost Data*	*Malawi Government. Concept Paper for Energy Sector 2011-2016.*	*http://www.mca-m.gov.mw/documents/final_submission/Off_Grid_Project_Concept_Paper_15052009.pdf*	*Perfect Foresight*	
Lusiwasi	*USD*	*Cost Data*	*Zesco - Christopher Mubemba, Director Transmission. Electricity Infrastructure Development for Economic Growth.*	*http://www.eiz.org.zm/phocadownload/2013-09th-May-South-CPD-Presentatation-ZESCO.pdf*	*Perfect Foresight*	