IRENA

International Renewable Energy Agency

SOUTHERN AFRICAN POWER POOL:

Planning and Prospects for Renewable Energy

About IRENA

The International Renewable Energy Agency (IRENA) is an intergovernmental organisation that supports countries in their transition to a sustainable energy future, and serves as the principal platform for international cooperation, a centre of excellence, and a repository of policy, technology, resource and financial knowledge on renewable energy. IRENA promotes the widespread adoption and sustainable use of all forms of renewable energy, including bioenergy, geothermal, hydropower, ocean, solar and wind energy in the pursuit of sustainable development, energy access, energy security and low-carbon economic growth and prosperity.

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MODEL FILES DOWNLOAD

All data and results presented here are available on the IRENA website: www.irena.org/SAPP.

The analysis presented here corresponds to following version of the model files.

- Main_2013-04-05_1218.zip (SPLAT model file)
- Demand_all_SAPP_refc.xlsx (demand data file)
- Load_Calibration_all_SAPP.xlsm (load data file)
- Transmission Data_03.xlsx (transmission data file)
- SADC_supply_reference_16b.xlsm (electricity generation data file)
- 0REF_v13_nocostreductions.xlsm (results file for the reference scenario)
- 2RE_v13_highcostreduction.xlsm (results file for the renewable scenario)
- 3RE_v13_highcostreduction_no-Inga.xlsm (results file for the renewable scenario without Inga case)
- Summary_SAPP_v13.xlsx

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Anton Balazh©Highly detailed planet Earth at night/Shutterstock

Abbreviations

CCGT	Combined Cycle Gas Turbine
CCS	Carbon Capture and Storage
CDM	Clean Development Mechanism
Coal PF	Coal Pulverised Fuel
CCGT	Combined Cycle Gas Turbine
DRC	Democratic Republic of Congo
FRM	Firm Reserve Margin
GDP	Gross Domestic Product
GHG	Greenhouse Gases
IAEA	International Atomic Energy Agency
IEA	International Energy Agency
IIASA	International Institute of Applied System Analysis
IRENA	International Renewable Energy Agency
IRP	Integrated Resource Plan (South Africa)
LCOE	Levelised Cost of Electricity
MESSAGE	Model for Energy Supply Strategy Alternatives and their General Environmental Impact
MoU	Memorandum of Understanding
OCGT	Open Cycle Gas Turbine
O&M	Operation and Maintenance
PV	Photovoltaic
RE	Renewable Energy
SADC	Southern African Development Community
SANEDI	South African National Energy Institute
SAPP	Southern African Power Pool
SWI	Shannon-Weiner Index (Systems diversity)
SPLAT	System Planning Test Model for Southern Africa
T&D	Transmission and Distribution
WEO	World Energy Outlook (IEA)


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Executive Summary

The International Renewable Energy Agency (IRENA) has developed a power sector planning tool for Southern African countries called the System Planning Test (SPLAT) model, which enables analysts to design a power system that meets various system requirements, including reliability. It also takes into account economically optimal configurations (including investment and operation costs) for the system to meet daily/seasonally fluctuating demand.

Using the SPLAT model, IRENA developed a Renewable Promotion scenario for continental Southern African Development Community (SADC) countries. The scenario is intended to illustrate how SPLAT can be used, and to provide a robust starting point for planning analysts to stimulate discussion about the model's assumptions and results. In this scenario, IRENA assessed the investment needs in power generation, both on- and off-grid, in domestic transmission and distribution, as well as in international transmission networks to meet the growing demand in the region in the most affordable manner. Existing capital stock, replacement needs and committed investments were explicitly considered. Emphasis was given to integrating renewable technology generation into on- and off-grid power systems, taking into account the differences in generation technologies in responding to demand fluctuations. All continental SADC countries were assessed jointly, which provided insights on the need for investments into regional electricity interconnectors. All data and results are available on the IRENA website: www.irena.org/SAPP.

The main findings from analysing the Renewable Promotion scenario, along with alternative scenarios, are as follows:

» Renewable technologies can play increasingly important roles in providing reliable, affordable, low-cost power in Southern Africa.

» Renewable technologies bring a reduction in fossil fuel consumption; and decentralised renewable options, in particular, reduce investment needs in domestic transmission and distribution networks.

» Over the model period, investment costs for introducing more renewable technologies into the future power system are higher than for fossil or nuclear; however, the cost savings effects (*i.e.* fuel saving and the reduction of transmission and distribution investments) far exceed the additional investment costs.

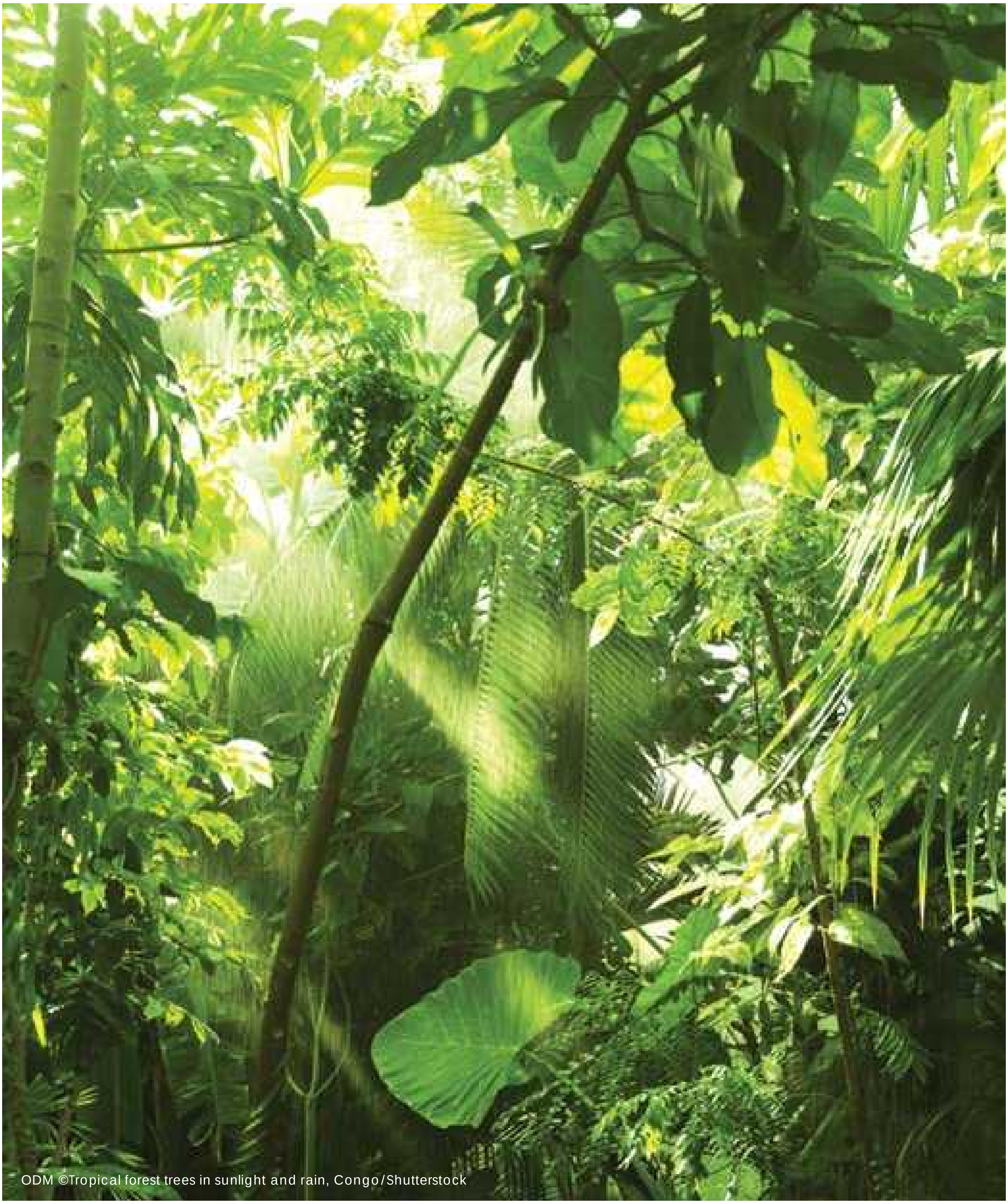
» Deployment and export of hydro power from the Inga hydropower project in the Democratic Republic of Congo (DRC) to the region would significantly reduce average electricity generation costs.

» Financial requirements for interconnector investment are minimal compared to the resulting benefits of international power trade.

IRENA's assessment shows that the share of renewable technologies in electricity production in the region could increase from the current level of 10% to as high as 46% in 2030, provided that the cost of these technologies continues to fall and fossil fuel prices continue to rise. In this scenario, nearly 80% of new capacity additions between 2010 and 2030 would be with renewables technologies. The decentralised renewable technology options would become competitive against grid expansion, particularly in rural areas. More than 20% of total new capacity additions could come from decentralised renewable technology options. The share of renewables in the total capacity would rise from 20% to 62%. Total investment required in the region would amount to nearly USD 314 billion (undiscounted).

IRENA's assessment shows that the promotion of renewable energy and the associated transformation of the power sector could bring down average generation costs by 9% compared to the case without such promotion. The Grand Inga and associated inter-connector projects in Southern African countries would account for five of those nine percentage points of cost reduction.

IRENA has used publicly available information to represent the region's current power supply infrastructure. Further validation of the model by local experts would enhance its robustness. Moreover, the assessment is based on certain assumptions, including fuel costs, infrastructure development and policy developments. These may well be different from the perspective of the energy planners in the region. It is recommended that local experts explore different assumptions and develop and compare their own scenarios to analyse the benefits and challenges of accelerated deployment of renewables.



ODM ©Tropical forest trees in sunlight and rain, Congo/Shutterstock

1. Introduction

Africa needs to raise its electricity supply significantly to enhance energy access for its growing population and provide the necessary energy for economic growth. Currently, many Southern African nations suffer from unreliable power supply, and the economic cost of power outages is high: an estimated 5-7% of the gross domestic product (GDP) for Tanzania, South Africa and Malawi, for example (Eberhard *et al.*, 2011).

Africa has great domestic renewable energy potential, which could be used to provide much needed energy in an affordable and secure manner, and to contribute to universal access to modern energy while avoiding negative environmental impacts. A long-term vision is needed to make optimal use of available domestic resources, given the long-lasting nature of energy infrastructure. Since different power supply technologies have different operational characteristics that could complement each other, the deployment of renewable technologies cannot be planned in isolation from the rest of the power system, but rather needs to be looked at from the perspective of their integration into the system.

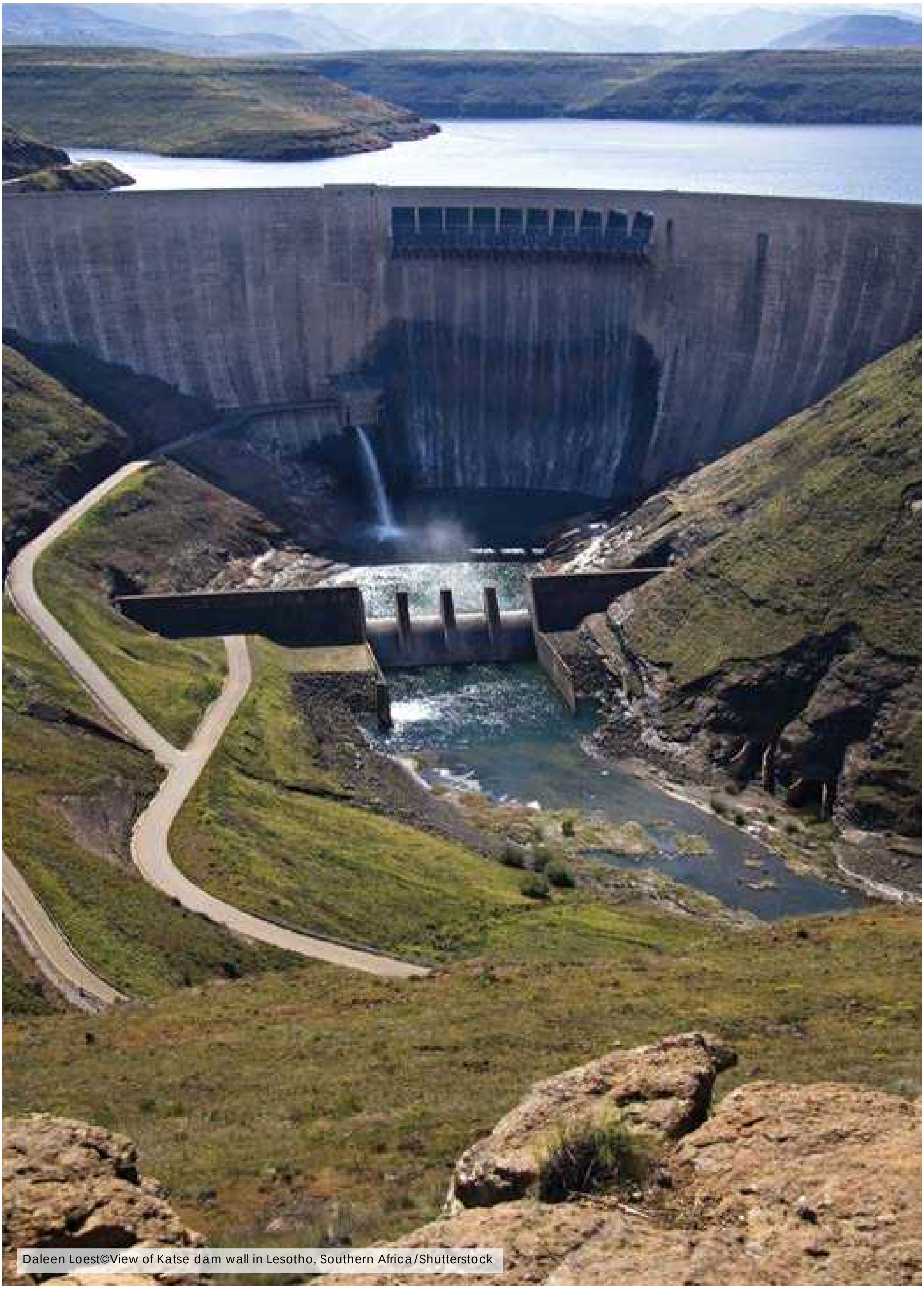
The International Renewable Energy Agency (IRENA) aims to assist its member countries with energy systems planning to make the transition to an energy system that makes maximum use of environmentally friendly, fossil-free renewable technologies. IRENA's earlier work, "Scenarios and Strategies for Africa", was a major input to the IRENA-Africa High level Consultations on Partnership on Accelerating Renewable Uptake for Africa's Sustainable Development, held in Abu Dhabi in July 2011, at which Ministers of Energy and heads of delegation of African countries announced a communique recognising IRENA's role in promoting renewable energy to accelerate Africa's development (IRENA, 2011a).

This report presents a study describing the transition of national power systems to a renewables-oriented future over the period 2010 to 2050 in the Southern African Region, which could be implemented by realizing the long-term cost reduction potential of renewable technologies.

The transition path was computed by a scenario modelling tool, the System Planning Test (SPLAT) model for Southern Africa, in which, *inter alia*, the retirement of the current power infrastructure, the geographical distribution of renewable resources and the generation-adequacy of the systems were taken into account. The economic implications of such systems, in terms of investment needs, fuel savings, energy security, *etc.*, were assessed. This is part of a series of activities that IRENA has been conducting for five regions in Africa, covering all continental African countries.

The SPLAT model created for this study draws on a database of power systems (consisting of existing generation units and international transmission lines, along with a range of future technology options). The model calculates the future configuration of power systems with specified system requirements to meet given and fluctuating power demands. The configuration of power systems is defined primarily by minimising total energy system costs within the planning horizon (*i.e.* 2010-2050).

SPLAT covers the following eleven African countries: Angola, Botswana, the Democratic Republic of Congo (DRC), Lesotho, Malawi, Mozambique, Namibia, Swaziland, Tanzania, Zambia and Zimbabwe. The SPLAT model is calibrated to the current status of the SADC for each country using the SAPP Master Plan (SAPP, 2007) updated with South Africa's Integrated Resource Plan for Electricity (South Africa Department of Energy (SA-DoE), 2011), as well as through the Memorandum of Understanding (MoU) on SAPP Priority Projects adopted on 17 September 2012 by the Summit of the SADC Heads of State: Various national documents were also used to update the information.



Daleen Loest©View of Katse dam wall in Lesotho, Southern Africa/Shutterstock

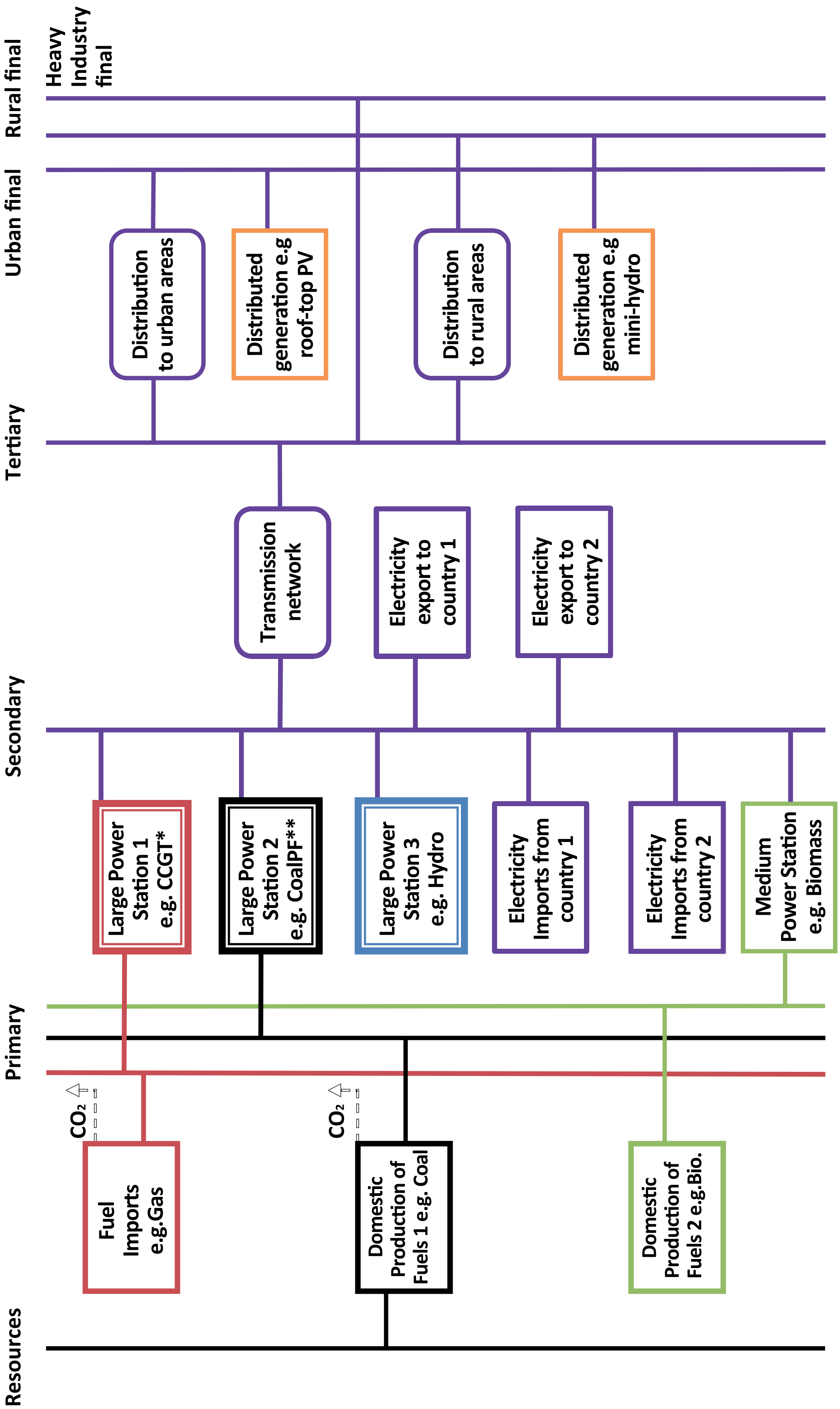
2. Overview of the Methodology

The SPLAT model was developed using the modelling platform software called Model for Energy Supply Strategy Alternatives and their General Environmental Impact (MESSAGE), a dynamic, bottom-up, multi-year energy system model applying linear and mixed-integer optimisation techniques. The modelling platform was originally developed at the International Institute of Applied System Analysis (IIASA), but more recently has been further enhanced by the International Atomic Energy Agency (IAEA). The modelling platform is a flexible framework within which the actual model is developed.

The MESSAGE modelling platform consists of a set of demand projections and a database of power supply technologies characterised by economic and technical parameters, and information regarding the existing capital stock and remaining life span. The model can be guided by so-called "constraints" that reflect policies and scenario assumptions. The model calculates an evolution of technically feasible technology mixes that achieve the least-cost objective (*i.e.* minimal total system costs) while meeting various constraints and a given set of demands. The model's "solution" includes, *inter alia*, a investment in new technologies, production, fuel use and trade. Economic and environmental implications associated with the identified least-cost energy systems can be easily calculated with the model. Using the MESSAGE platform, the IAEA has developed a model and training materials to analyse least-cost power systems for the coming 20 years in the SADC Region (IAEA, 2011). IRENA's SPLAT model was adapted from earlier work by the IAEA, by adding major refinements suitable to analyse renewable energy technologies and by incorporating the latest renewable energy resource and cost information.

In the SPLAT model, each country is modelled as a separate node interlinked by transmission lines. Each node (representing the power system of a single country) is characterised as shown in Figure 1. Once the demand is specified, a technically feasible, least-cost power supply system that meets the given demand while satisfying all the constraints is computed by the model for the specified modelling period. The SPLAT model includes four types of power generation options: existing power plants; power plants to be commissioned; site-specific power plants under consideration; and non-site-specific generic power plants. The SPLAT model is characterised by the following key features:

- » The existing generation and trans-border transmission infrastructure is explicitly modelled.
- » Planned projects in the region for new generation and trans-border transmission installation are explicitly modelled.
- » The demand for electricity is split into three categories (heavy industry; urban residential, commercial and small industries; and rural residential and commercial) to allow for a better representation of decentralised power supply and improve the representation of the load curve.
- » The three demand categories are modelled to require different levels of transmission and distribution infrastructure and incur different levels of losses.
- » The reliability of supply is addressed by assuring 10% reserve margins, while intermittent renewable technologies are given varying levels of "firm" capacity based on the nature and quality of the resource (*i.e.* they do not fully contribute to the reserve margin).
- » The evolution of renewable energy technology costs and performance is taken from the most recent IRENA study (*i.e.* IRENA, 2013).
- » Renewable energy potentials are taken from IRENA's new resource assessment studies (IRENA, 2012b).
- » Base-year fossil fuel prices are based on SA-DoE (2011) and are escalated roughly, based on the International Energy Agency (IEA) World Economic Outlook (WEO) 2012's "Current Policies" scenario.
- » Carbon finance is explicitly modelled.



Where: *CCGT is Combined Cycle Gas Turbine, **CoalPF is Coal Pulverised Fuel

Figure 1. Country Power Sector Model Structure

3. Scenario Assumptions

The following four scenarios have been developed in order to elaborate the development of renewable technology-oriented future power systems:

1) Renewable Promotion Scenario: a scenario in which the potential of renewable energy technologies is fully utilised though investment-cost reduction for renewable energy technologies, given available data on resource potential and given currently considered transmission projects in the region;

2) Renewable High Cost Scenario: a hypothetical scenario in which there is no further reduction in investment costs for renewable energy technologies;

3) No Grand Inga Scenario: a variation of the Renewable Promotion scenario, based on the same assumptions as the Renewable Promotion scenario, except that the Grand Inga hydropower project in the DRC is not fully developed or ready to export power to the rest of the region within the study horizon;

4) No Carbon Finance Scenario: a variation of the Renewable Promotion scenario, based on the same assumptions as the Renewable Promotion scenario, except that carbon finance is not assumed.

3.1 OVERALL ASSUMPTIONS

Overall assumptions across all scenarios are as follows:

» The real discount rate applied is 10%.

» The monetary unit is 2010 US Dollars (USD), and adjustments from data reported in USD from other years are made using the US GDP deflator from the World Bank (WB, 2011).

» The exchange rate used is 7.4 South African Rand (ZAR) to the US Dollar, as per SA-DoE (2011).

» The study horizon spans the period 2010-2050. Modelling between 2010 and 2030 was done on an annual basis, while that covering the period between 2030 and 2050 was conducted with a 10-year interval to obtain indicative results.

» In order to capture the key features of electricity demand load patterns, the year is characterised by three seasons; namely, pre-winter, winter and post-winter. Pre- and post-winter days comprise three blocks of equal demand; namely, “day”, “night” and “evening”. For winter days, an additional block is added to capture the peak recorded by the system. The winter season lasts from 7 May to 6 September.

An important policy assumption was introduced for all scenarios concerning CO_2 emissions. For South Africa, a CO_2 emission limitation of 275 Megatonnes (Mt) from the power sector per year after 2024 is imposed according to the South African Integrated Resource Plan (IRP) (SA-DoE, 2011). Carbon finance is modelled with the CO_2 price ramped up in the model from zero in 2013 to USD 25/tonne in 2030, assuming that the Clean Development Mechanism (CDM) and similar tools will be made more widely available throughout the region.

Fanny Schertzer© Lake Manyara national park, Tanzania/Wikimedia

3.2 ASSUMPTIONS ABOUT ELECTRICITY DEMAND

Two main data sources are used for electricity demand projections, namely the South African IRP (SA-DoE, 2011) for South Africa, and the Southern African Power Pool Regional Generation and Transmission Expansion Plan Study (SAPP, 2007) for the other countries, updated in some cases with data from SAPP (2010). In both cases, the electricity demand was specified as secondary (before T&D) and extrapolated to 2050. The chart in Figure 2 shows the evolution of this demand, which is dominated by South Africa. Actual figures are given in Table 17 in Appendix A. The load profile for electricity demand is based on the hourly profile for South Africa in 2010, with details also in Appendix A.

The demand was broken down into the following three categories,

» **Heavy industry** (*e.g.* mining), which connects to generation at a high voltage and generally requires less transmission and distribution infrastructure;

» **Urban** residential, commercial, and small industries, which are connected to generation via relatively more transmission and distribution infrastructure; and

» **Rural** residential and commercial, which require even more transmission and distribution infrastructure.

A full sector bottom-up analysis would be required to project the sectoral demand, but it is beyond the scope

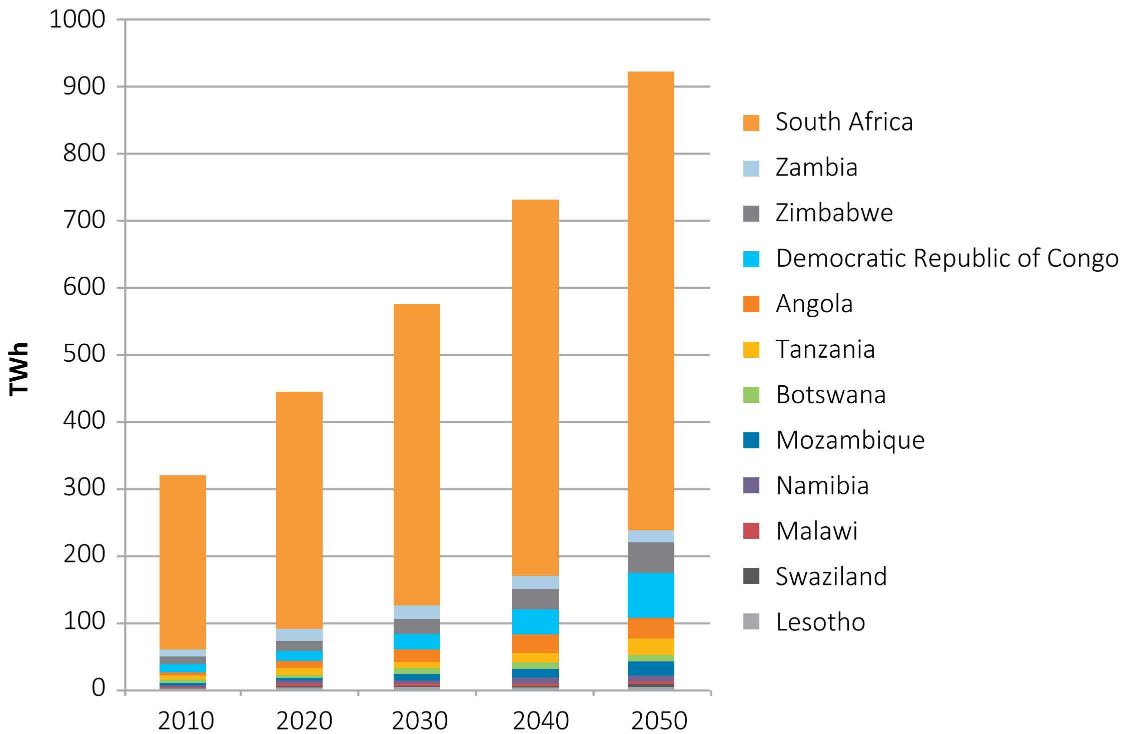


Figure 2. Secondary Electricity Demand Projections

of this publication. A simplified and cruder approach was adopted, which can be described as follows:

- The starting point for electricity demand projections is the Master Plan projection at utility (secondary) level.
- The energy balances were then used to split base-year consumption into “heavy industry” and “other”, with care taken to adjust for differences in losses, assuming that heavy industry has lower losses.
- The evolution of the split over time was roughly estimated, assuming that some small share of the electricity demand would come from rural areas.
- In some countries, the Master Plan explicitly provided the electricity demand for certain mining or industrial projects. For these countries, this additional demand was completely allocated to “heavy industry” with the rest being allocated to “urban” and “rural” sectors.

Figure 3 shows the aggregated final electricity demand in the region in the three categories.

As shown in Figure 4, each demand category is characterised by a different load profile, which is assumed to be common to all the countries. The load profile for each demand category is defined by the shares of demand for each season and each day-block (*i.e.* day, evening, night). Since different countries have different shares of these three categories, the resulting load profile for the total demand is specific to each country.

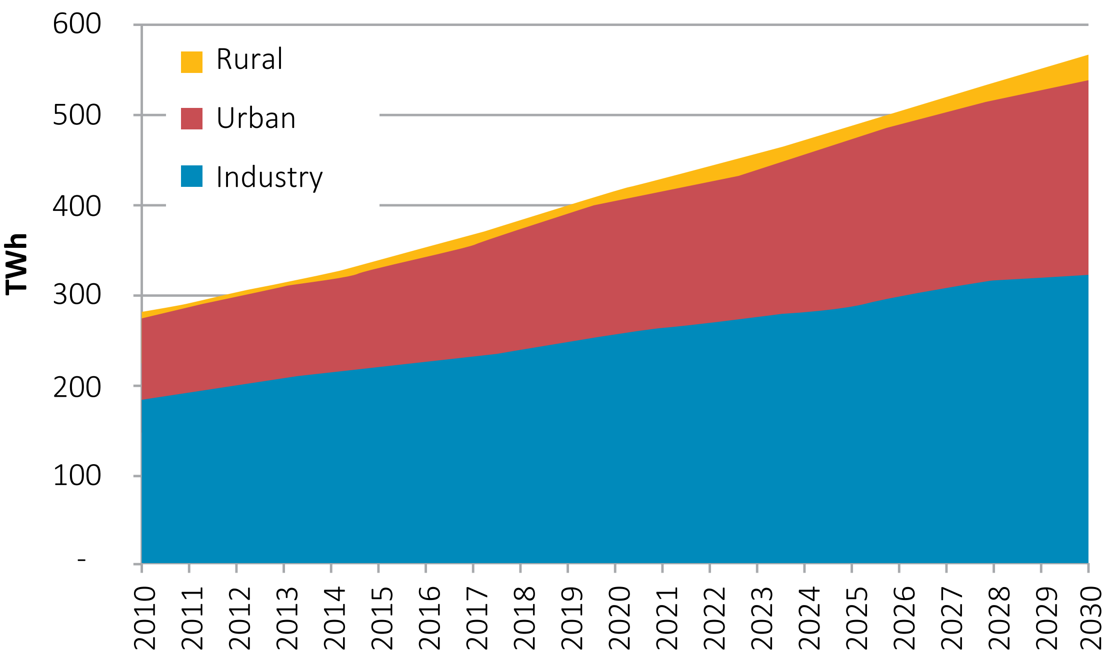


Figure 3. Total Final Electricity Demand by Category

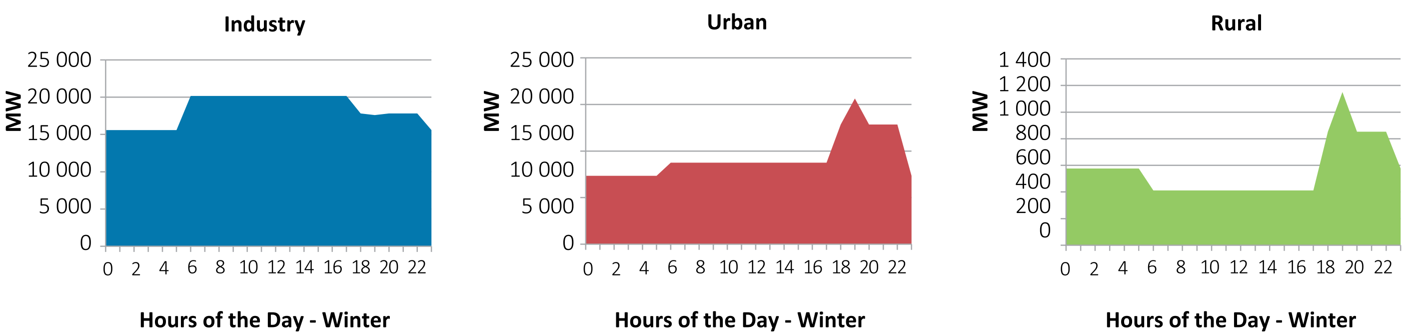


Figure 4. Assumed Load Profile for Three Demand Categories (Winter Season)

3.3 ASSUMPTIONS ON LOCAL TRANSMISSION AND DISTRIBUTION

Transmission and distribution (T&D) requires upstream infrastructure investment to match peak system demand (*i.e.* the grid-connected system peak, not including demand met by off-grid technologies). The needs for T&D infrastructure are modelled to match the peak system demand with some margin, which in turn aligns with installed capacity. Three different levels of cost and losses are defined for the three identified demand categories to account for the different levels of transmission and distribution infrastructure required. Assumptions on T&D costs and average losses are given in Table 1. These are used to calculate the levelised cost of electricity (LCOE), detailed in Table 8. The assumptions on T&D losses are specific to each country, as detailed in Table 24 in Appendix C. For industry, the T&D losses are assumed for 2010 between 5% and 10%, and are reduced to 4-8% by 2030. For the urban customer group, the LCOE is assumed to be 17-35% for 2010 and is reduced to 11-13% by 2030 in all countries. The losses are highest for the rural consumer group, 24-35% in 2010, reduced to 23-25% by 2030 in all countries.

Off-grid technologies do not require transmission and distribution infrastructure so there are no costs or losses associated with them.

3.4 ASSUMPTIONS ABOUT RENEWABLE RESOURCE POTENTIAL

Large Hydro

Large-hydro potential is limited to the identified hydro sites in the SAPP (2007) and SADC (2012a, 2012b) regions and is summarised in Table 2. A "dry-year" scenario is assumed for all hydro sites in all years within the modelling horizon. This underplays the role of hydro in the region but is considered conservative in view of the vulnerability of the region to drought years. A more comprehensive stochastic approach was not possible due to limitations of the MESSAGE modelling platform. Detailed parameters for existing and planned hydro projects are given in Appendix B and Appendix C, respectively.

Other Renewable Energy Potential

Estimates of other renewable resource potential are shown in Table 3. Estimates for solar are based on the Mines ParisTech dataset while wind data are based on the Vortex data set (*i.e.* 9 kilometre (km) resolution) as reported in IRENA (2011b). Small hydro and biomass, which are the least quantified, are based, respectively, on large hydro potential and analysis by IRENA (2011c).

3.5 ASSUMPTIONS ABOUT FUEL AVAILABILITY AND PRICES

For coal supply, eight countries in the SADC region are modelled to have access to domestic coal resources, and for other countries except Lesotho (where demand would be too low to justify the infrastructure required), the import of coal is assumed to be an available option.

For gas supply, some countries have conventional gas resources (*i.e.* "domestic"). Botswana has coalbed methane resources, which it plans to develop; some countries have the possibility of importing gas; and in countries where demand within the study horizon would not be high enough to justify investment in import infrastructure, gas is not available. The cost difference between the "domestic" producers and importing countries reflects the extra costs related to liquefaction, transportation and regasification.

Table 1. Assumptions for Transmission and Distribution Infrastructure[1]

	Cost (USD/kWh)	Average Losses (%)		
		2010	2020	2030
Heavy Industry	0.015	7	7	6
Urban Residential/Commercial/Small Industries	0.05	24	15	13
Rural Residential/Commercial	0.10	30	25	25

[1] Note that the distribution technology costs are modelled as investment costs based on the load.

Table 2. Existing Hydro and Identified Hydro Projects

	Existing Hydro			Identified Hydro Projects		
Country	**Capacity**	**Average Generation**	**Dry Year Generation**	**Capacity**	**Average Generation**	**Dry Year generation**
	MW	GWh	GWh	MW	GWh	GWh
Angola	474	2,595	1,713	6,735	23,438	15,470
Botswana	0	0	0	0	0	0
DRC	2,333	14,259	11,183	20,240	122,806	96,317
Lesotho	73	414	274	190	500	330
Malawi	278	1,391	919	614	2,966	1,958
Mozambique	2,122	15,604	12,107	3,147	15,954	9,139
Namibia	240	1,395	921	360	1,724	1,138
South Africa	665	878	583	0	0	0
Swaziland	62	202	134	0	0	0
Tanzania	561	1,525	1,161	1,972	6,891	6,279
Zambia	1,752	10,043	7,778	4,299	22,632	15,316
Zimbabwe	750	4,000	3,137	1,100	7,280	5,710
Total	**9,310**	**52,306**	**39,910**	**38,657**	**204,190**	**151,657**

Table 3. Estimates of Other Renewable Energy Potential

Country	**Small Hydro**	**Solar Thermal**	**Solar PV**	**Biomass**	**Wind 20%CF**	**Wind 30%CF**
	MW	TWh	TWh	MW	MW	MW
Angola	300	97.9	133.2	500	230	0
Botswana	0	130.7	137.6	10	11,179	1,152
Democratic Republic of Congo	1,500	124.4	228.6	500	2,480	0
Lesotho	20	11.2	9.4	10	683	167
Malawi	100	44.7	52.1	200	2,267	1,159
Mozambique	300	168.5	220.2	1,000	12,335	1,526
Namibia	200	297.2	261.8	50	17,347	1,910
South Africa	200	432.7	422.4	3,000	20,000[2]	10,000
Swaziland	100	5.6	5.7	200	544	37
Tanzania	200	314.8	388.0	1,000	21,068	11,737
Zambia	300	156.9	178.9	1,000	15,102	4,416
Zimbabwe	300	118.7	156.8	1,000	13,855	3,986

[2] Wind data for South Africa was adjusted to 20 Gigawatt (GW) and 10 GW for 20% and 30% load factor sites as per the SA IRP 2010.

In the case of oil supply, countries are regrouped into three price categories, namely "domestic", where resources are available, "coastal" for coastal countries where oil or oil products can be landed in bulk, and "inland", which have to pay a premium for additional transport requirements.

For biomass, only agricultural waste is considered, and three types are distinguished: free biomass available from sugar cane production; moderately priced biomass; and relatively expensive biomass in countries where this resource is scarce. With no recent update on biomass for the SADC region, the price categorisation can only be estimated at this stage. Countries with large existing sugar industries have been allocated to the "free" price category, with the exception of South Africa, which is based on IRP 2010 (SA DoE, 2011). Countries where the industry or other similar industries could potentially make biomass available to the power sector were allocated to the "moderate" category, while the countries with scarce biomass resources were allocated to the "scarce" category.

The assumptions on fuel availability are summarised in Table 4 below. Base-year fuel prices are based on (SA-DoE, 2011) and are projected to evolve as shown in Table 5. The projection for oil prices is based on the Current Policies Scenario from World Energy Outlook (WEO) (IEA, 2011) up to 2035 and extrapolated to 2050. The projection for gas prices is adjusted from the same WEO scenario.

3.6 ASSUMPTIONS ABOUT ELECTRICITY GENERATION OPTIONS

The core of the SPLAT model is the database of power systems consisting of existing generation units and international transmission lines, as well as a range of future technology options.

Existing power generation is based on SA-DoE (2011) and SAPP (2007) with some updates from SAPP (2010), and is summarised in Table 6. Detailed technical and economic parameters are given in Appendix B (Table 18, Table 19, and Table 20).

There are two types of future technology options: site-specific and generic. Site-specific projects are taken from project listings in the SAPP Master Plan (SAPP, 2007) and updated using the SAPP Annual Report 2010 (SAPP, 2010), the latest IRP from South Africa (SA-DoE, 2011), and the Renewable Energy Strategy and Action Plan (SADC, 2012a).

Table 4. Assumptions on Fuel Availability

Country	Coal	Gas	Oil	Biomass
Angola	Import	Domestic	Coastal	Moderate
Botswana	Domestic	Coalbed Methane	Inland	Moderate
DRC	Import	Domestic	Coastal	Moderate
Lesotho	Not Available	Not Available	Inland	Scarce
Malawi	Domestic	Not Available	Inland	Moderate
Mozambique	Domestic	Domestic	Coastal	Free
Namibia	Domestic	Domestic	Coastal	Scarce
South Africa	Domestic	Import	Coastal	Moderate
Swaziland	Domestic	Not Available	Inland	Free
Tanzania	Import	Domestic	Coastal	Free
Zambia	Domestic	Import	Inland	Free
Zimbabwe	Domestic	Import/CBM	Inland	Moderate

Table 5. Fuel Price Projections

USD/GJ	2010	2020	2030	2050
Crude oil (USD/bbl)	100	120	135	135
Heavy fuel oil, coastal	12.9	15.5	17.4	17.4
Heavy fuel oil, inland	16.3	19.5	22	22
Diesel, coastal	21.9	26.3	29.6	29.6
Diesel, inland	25.2	30.2	34	34
Gas, domestic	8.5	9.5	11	11
Gas, imported	11.0	12.3	14.2	14.2
Coal, domestic	2.0	3.0	4.0	4.0
Coal, imported	3.0	4.5	6.0	6.0
Biomass, free (sugar cane)	0.0	0.0	0.0	0.0
Biomass, moderate	1.5	1.5	1.5	1.5
Biomass, scarce	3.6	3.6	3.6	3.6

Where: GJ is gigajoules; and bbl refers to billions of barrels.

Table 6. Existing Power Generating Capacity (MW)

Country	Oil	Coal	Gas	Nuclear	Hydro	Total
Angola	89		174		474	**737**
Botswana		132			0	**132**
DRC					2,333	**2,333**
Lesotho					73	**73**
Malawi	36				278	**314**
Mozambique	64				2,122	**2,186**
Namibia	29	115			240	**384**
South Africa	2,424	36,360		1,616	665	**41,065**
Swaziland					62	**62**
Tanzania	79		640		561	**1,280**
Zambia	10				1,752	**1,762**
Zimbabwe		1,026			750	**1,776**
Total	**2,731**	**37,633**	**814**	**1,616**	**9,310**	**52,104**

Furthermore, new commitments made on the deployment of renewable technologies at the SADC Summit of Heads of State and Government (SADC, 2012b) are incorporated in these scenarios.

Site-Specific Projects

The site-specific projects identify the unit size, capacity factor, efficiency, operation and maintenance (O&M) costs, investment costs, *etc*. Some of the projects are "committed" - that is, they are obliged to be part of future power systems. Other projects are just "under consideration" and may or may not be included in the "optimal solution" computed by the model.

Out of 75 proposed projects compiled from the sources in question, 42 are large hydro projects. Projects listed for coal, diesel and natural gas amount to 13, 6 and 4, respectively, while other renewables account for 10. Table 7 shows the sum of projects in terms of capacity. Hydro power projects account for over 40 GW, out of which 4.3 GW is "committed". Of the total proposed coal power projects of

Table 7. Sum of Capacity of Future Projects (in parenthesis, sum of committed projects): Unit MW

MW	Oil	Coal	Gas	Hydro	Biomass	Wind	Solar	Total
Angola	288	-	-	6,735	-	-	-	**7,023**
	(148)		-	(1,225)				**(1,373)**
Botswana	-	3,630	-	-	-	-	-	**3,630**
	-	(1,200)						**(1,200)**
DRC	-	-	-	20,240	-	-	-	**20,240**
Lesotho	-	-	-	190	-	65	-	**255**
				(110)				**(110)**
Malawi	-	-	-	614	18	-	-	**632**
					(18)			**(18)**
Mozambique	-	1,200	410	3,147	-	-	-	**4,757**
	-	(750)	(410)	(40)				**(1,200)**
Namibia	-	300	774	360	-	60	-	**1,494**
South Africa	-	8,670	260	1,332*	130	1,849	1,649	**13,890**
	-	(8,670)		(1,332)		(1,849)	(1,649)	**(13,500)**
Swaziland	-	1,000	-	-	85	-	-	**1,085**
					(85)			**(85)**
Tanzania	-	600	400	1,972	35	-	-	**3,007**
		(200)	(400)		(35)			**(675)**
Zambia	50	300	-	4,900	-	-	-	**5,250**
	(50)			(1,375)				**(1,425)**
Zimbabwe	-	2,000	300	1,100	90	-	-	**3,490**
				(300)	(90)			**(390)**
Total	**338**	**17,700**	**2,144**	**40,590**	**358**	**1,974**	**1,649**	**34,173**
	(198)	**(10,820)**	**(810)**	**(4,282)**	**(228)**	**(1,849)**	**(1,649)**	**(19,836)**

* This corresponds to Ingula pump storage.

17.7 GW, 10.8 GW of coal power projects are "committed"; 3.7 GW of non-hydro renewable projects are "committed". Table 21 in Appendix C shows all the power generation projects (excluding return to service and refurbishment projects) with their technical and economic parameters as per the above mentioned documents.

Based on the technology parameters for site specific projects shown in Table 21, Figure 5 summarises the ranges of levelised cost of electricity (LCOE) generation by type of technology. Note that it does not include CO_2 costs. It shows that the LCOE of hydropower is highly site-specific and ranges from USD 25-350/Megawatt-hour (MWh).

Generic Technologies

In the SPLAT model, the demand is first met by the existing technologies and committed projects. The remainder of the demand is met by site-specific projects under consideration and/or generic power generation technologies. The generic (*i.e.* non-site-specific) power generation technologies are modelled without a specific reference to any unit size. Certain technologies are assumed to provide electricity only via the grid, while others are assumed to provide on-site electricity.

For thermal technologies, the following options are included as generic technologies:

» **Diesel/Gasoline 1 kW system** to meet urban and rural demand;

» **Diesel 100 kW system** to meet industry demand

» **Diesel Centralised** connected to upstream transmission;

» **Heavy Fuel Oil** connected to upstream transmission;

» **Open Cycle Gas Turbine (OCGT)** connected to upstream transmission;

» **Combined Cycle Gas Turbine (CCGT)** connected to upstream transmission;

» **Supercritical Coal with Carbon Capture and Storage (CCS)** connected to upstream transmission and modelled only for South Africa;

» **Supercritical coal** connected to upstream transmission;

» **Nuclear (Pressurised Water Reactor)** connected to upstream transmission and modelled only for South Africa

For renewable energy technologies, the following options are included as generic technologies:

» **Small hydro** to meet rural demand;

» **On-shore wind** connected upstream transmission. Two wind regimes are considered: namely, one where the capacity factor is above 30% and the other where the capacity factor is 20%;

» **Biomass** mainly in the form of co-generation to be consumed on-site with surplus exported onto the grid (upstream of transmission);

» **Utility PV** or PV farms managed by the utility and connected upstream of transmission.

» **Distributed or Roof-top Solar PV** to meet urban and rural demand;

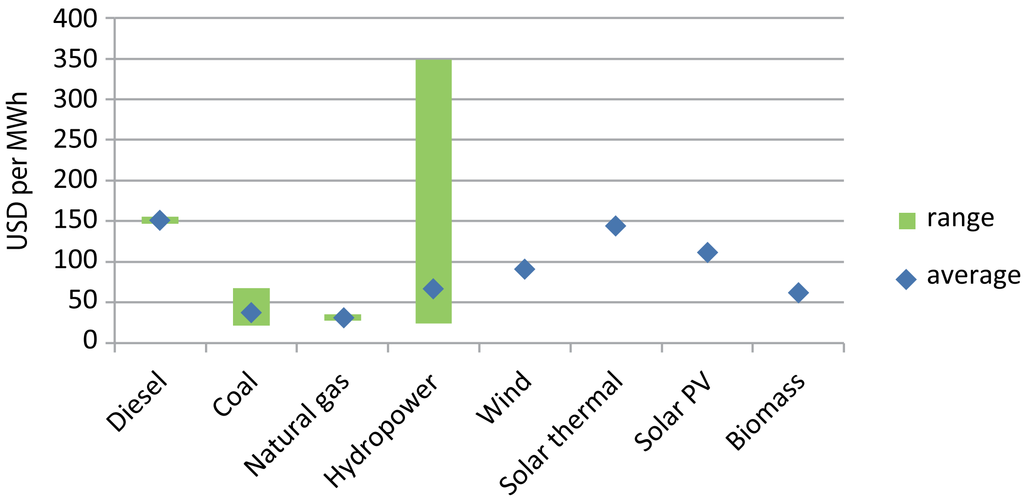


Figure 5. The Ranges of Levelised Cost of Proposed Site-Specific Projects by Type of Technology

- **Distributed or Roof-top Solar PV with one hour of storage** in the form of a battery, for slightly extended use beyond daylight hours;
- **Distributed or Roof-top Solar PV with two hours of storage** in the form of a battery, more extended use beyond daylight hours;
- **Solar CSP without Storage** medium- to large-scale concentrated solar connected upstream of transmission; and
- **Solar CSP with Storage** medium- to large-scale concentrated solar with thermal storage:

Figure 6 shows the overnight investment cost assumptions for generic thermal technologies. No cost reduction from technology learning is assumed.

The evolution of overnight investment costs for renewable options used in the Renewable Promotion scenario is shown in Figure 7. It is based on IRENA (2013). The learning was anticipated from increased global installed capacity in those technologies. A more aggressive cost reduction is projected in this scenario, assuming that this is achieved as a result of active efforts on the parts of governments and the private sector in the region to seek out opportunities to promote: localised manufacturing of equipment to reduce shipment costs; more streamlined regulations and taxation regimes; resolution of bottlenecks in materials supply, including transportation problems such as roadblocks and logistical constraints; economies of scale; and other economic efficiency gains.

Load factor, O&M costs, efficiency, the construction duration, and expected technology life for generic technologies are given in Table 22 in Appendix D. These are identical in all scenarios. The main source of the data for thermal technologies is South Africa's IRP (SA-DoE, 2011).

Based on the above assumptions on the current and projected investment costs under the Renewable Promotion scenario, fuel costs, O&M costs, capacity factor, generation capacity, and expected years of operation, a levelised cost of electricity (LCOE) was computed for generic technology options available to the countries in the region. It was computed for 2010, 2020 and 2030 based on assumptions for the respective years. For delivery of electricity using the grid to serve different demand categories, additional T&D costs were added while taking into account T&D losses as shown in Table 1. In 2010, T&D costs are USD 15/MWh with losses of 7% for the heavy industry category; USD 50/MWh and 24% for the urban category; and USD 100/MWh and 30% for the rural category[3]. The LCOE are presented in Table 8 for 2010 and 2030. A more comprehensive LCOE summary is given in Appendix F.

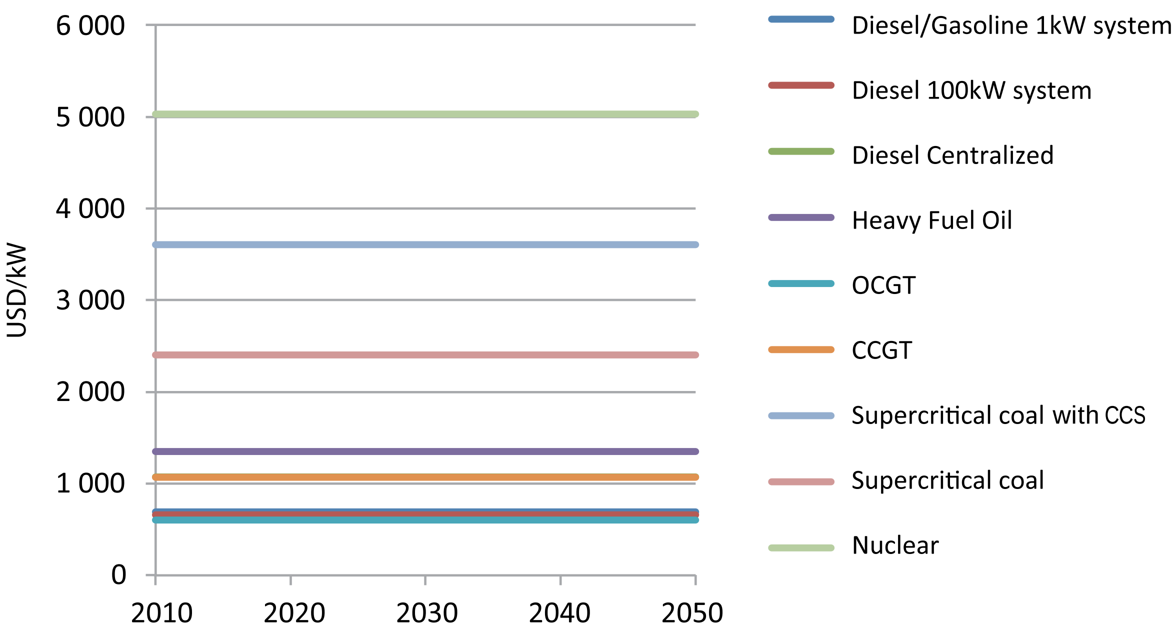


Figure 6.The Overnight Investment Cost Assumptions for Generic Technologies (Thermal)

[3] LCOE for the industry customer = LCOE of generation / (1-loss) + TD costs of industry. For example, for diesel centralised, LCOE for the industry customer is: 291/(1-0.07)+15=328.

Paulo César Santos©Kalandula waterfalls of the Lucala-River in Malange, Angola/Wikimedia

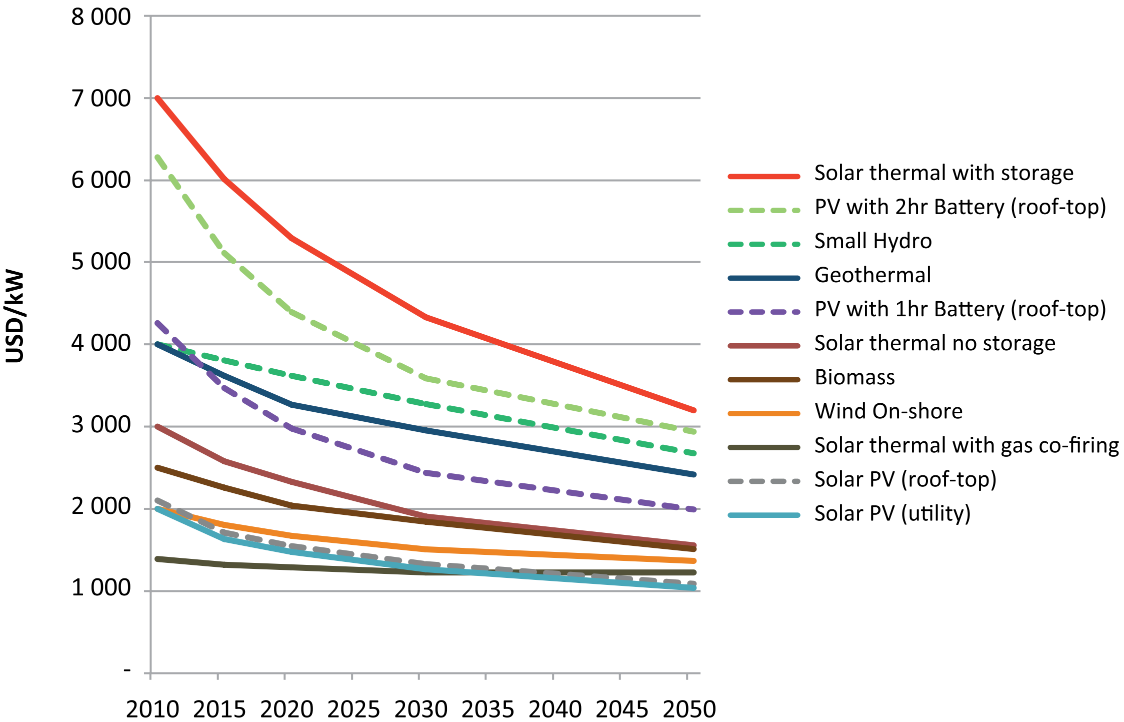
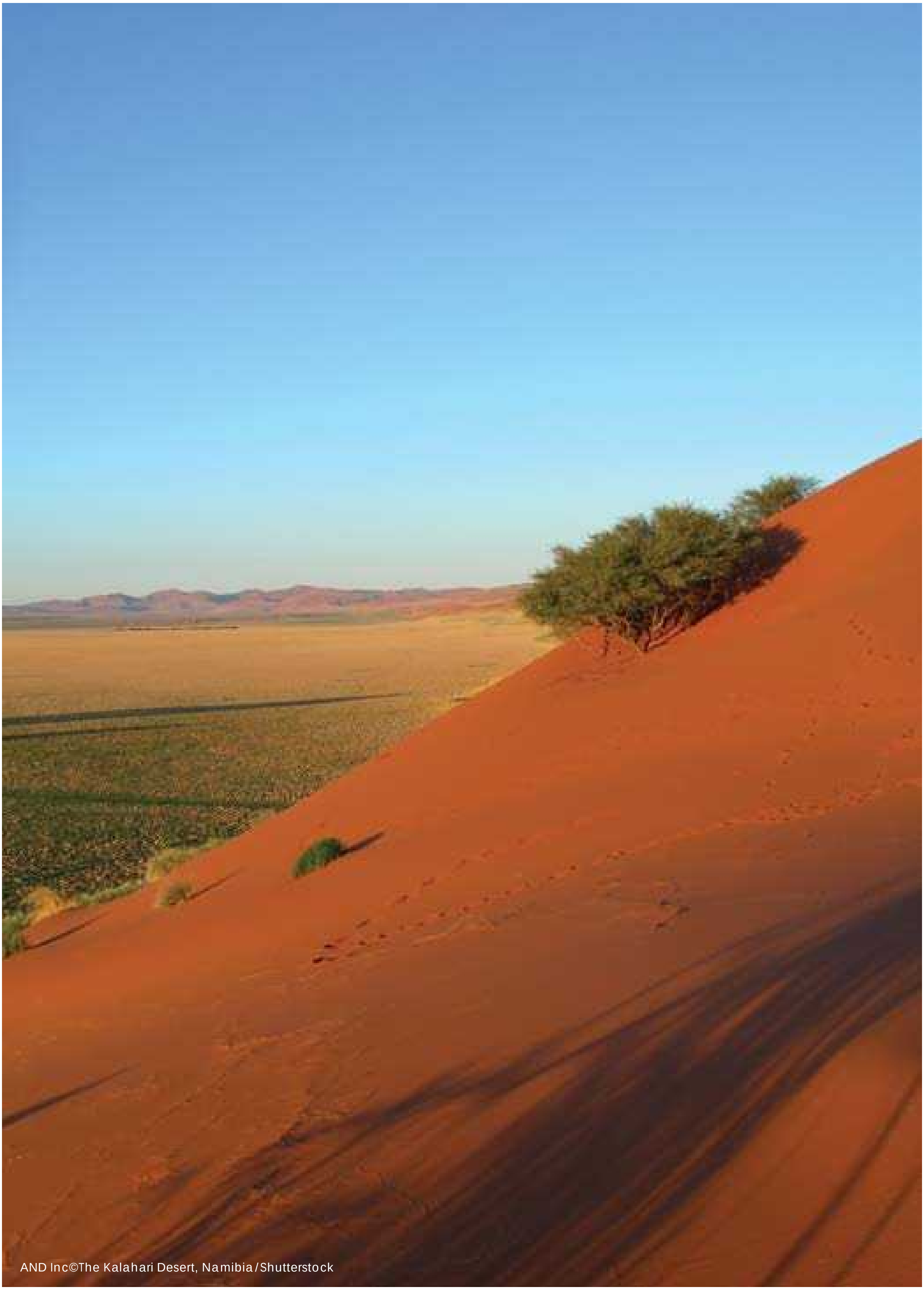


Figure 7.The Overnight Investment Cost for Renewable Technologies in the Renewable Promotion Scenario


AND Inc©The Kalahari Desert, Namibia/Shutterstock

The levelised cost table shows that in 2010 for industrial customers connecting at high voltage, hydro is the cheapest option. For countries that have domestic coal, coal generation is the next cheapest. Combined Cycle Gas Turbine (CCGT) with imported gas is the next cheapest option. Coal and gas are overtaken by high capacity- factor wind power in 2020, as its investment cost comes down and fuel prices go up. Biomass, where available, is the next cheapest. Initially, gas co-fired solar CSP appears cost competitive, but this option is overtaken by photovoltaic (PV) and solar thermal without storage, as the price is expected to go up. PV utility and solar CSP are the next options for countries without any other domestic resources, such as gas, coal, wind or biomass.

For rural customers, small hydro, where available, remains the best option. Distributed/roof-top PV with

Table 8. Levelised Cost of Electricity: Assumptions

LCOE USD/MWh	Generation without T&D		Industry		Urban		Rural	
	2010	2030	2010	2030	2010	2030	2010	2030
Diesel Centralized	291	339	328	376	438	440	516	552
Dist. Diesel 100kW	320	371	320	371				
Dist. Diesel/Gasoline 1kW	604	740			604	740	604	740
HFO	188	216	217	245	301	299	369	389
OCGT (Imported Gas/LNG)	141	161	167	187	238	235	301	315
CCGT (Imported Gas/LNG)	90	102	112	124	170	167	229	236
Supercritical coal with CCS	133	149	158	173	228	221	290	298
Supercritical coal	80	92	101	113	157	156	215	223
Nuclear	111	111	134	133	198	177	258	248
Hydro	62	62	82	81	133	122	189	183
Small Hydro	107	89					107	89
Biomass	104	86	127	107	189	149	249	215
Bulk Wind (30% CF – w. trans. costs)	118	93	142	114	208	157	269	224
Bulk Wind (30% CF – no trans. costs)	102	81	125	101	186	143	246	208
Solar PV (utility)	121	84	145	104	211	146	272	212
Solar PV (roof top)	143	96			143	96	143	96
PV with 1kWh Battery	250	151			250	151	250	151
PV with 2kWh Battery	323	192			323	192	323	192
Solar CSP no storage	147	102	173	123	247	167	311	236
Solar CSP with Storage	179	117	207	139	288	184	355	256
Solar CSP with gas co-firing	103	112	123	134	184	179	244	250

and without storage are expected to become the next best option for these customers in the renewable scenarios.

Note that the LCOE results shown here assume a load factor equal to the availability of the technologies. Given differences in investment cost and fuel cost, the ranking would change at different load factors. For example, gas plants at 80% load factor may be less competitive than coal on a levelised basis, but more competitive at 40%. Diesel or Open Cycle Gas Turbine (OCGT) would be competitive at very low load factors, and may well play a role in meeting peak loads of short durations. The MESSAGE modelling platform takes account of this in the optimisation, which is one of the reasons why the results may differ from what could be expected given the simple LCOE analysis carried out here.

3.7 ASSUMPTIONS ON TRADE BETWEEN COUNTRIES

Regarding future electricity trade options within the SADC region, SPLAT takes electricity trading between countries into account, using the existing transmission infrastructure, as well as planned transmission projects. Existing infrastructure and planned projects for transmission are based on the SAPP Master Plan (SAPP, 2007) with updates from the 2010 SAPP Annual Report (SAPP, 2010) and summarised in Table 9 and Table 10, with details in Appendix C.

3.8 CONSTRAINTS RELATED TO SYSTEM AND UNIT OPERATION

In the SPLAT model, key system constraints are introduced to make sure of the feasibility of the system.

Reserve margin

In order to maintain a certain level of reliability in a power system, excess "operational" capacity needs to be installed over and above peak demand requirements.

The reserve margin is defined as the difference between the operable capacity and the peak demand for a particular year as a percentage of peak demand. In all scenarios, a reserve margin constraint of 10% has been imposed on countries. Only "firm" capacity, which is guaranteed to be available at a given time, is considered to contribute to this requirement. The capacity credit, the share of capacity that is considered firm, is set to "one" for dispatchable technologies, such as thermal and large hydro with dams. For intermittent renewable power technologies, however, the capacity credit depends on the share of their total capacity in a power system and the quality of the intermittent resource in terms of the diversity of sites with low correlation, and is generally lower than the availability factor as this cannot be relied upon to generate power at an any given time due to the variability of wind and solar conditions.

The reserve margin constraint is defined as follows:

$$\sum_{i=1}^{n} \alpha(i) C_P(i) \geq (1 + RM) D$$

Where:

- $\alpha(i)$ is the capacity credit given to power plant/technology *(i)* or share of capacity that is accounted as "firm" (a fraction or percentage);
- $C_P(i)$ is the capacity of power plant/technology *(i)* in Mega-watt (MW) (centralised only);
- *D* is the peak demand on the centralised grid system in MW; and
- *RM* is the reserve margin (*e.g.* 10%).

Ramp Rates

There are some technical limitations as to how fast coal plants can ramp their production up or down. To approximate this limitation, all coal plants in the model were de-rated according to actual availability. For example, a 100 MW coal plant with 85% availability (*i.e.* able to operate 85% of the time in a given year) can only produce up to 85 MW at any given point in time.

Constraints on Variable Renewables

Given that the model has an aggregate representation of the load, the variability of wind and solar PV was accounted for in an aggregate but conservative manner:

- **Flexibility of dispatch:** both wind and solar PV are not given any flexibility in the way they can be dispatched to meet demand. This was done by de-rating the capacity by the availability factor (*i.e.* a 100 MW wind plant with 30% capacity factor is constrained to deliver only 30 MW at any given point in time).

Table 9. Existing Transmission Infrastructure Summary

Country 1	Country 2	Line Capacity (MW)
Botswana	South Africa	800
Botswana	Zimbabwe	650
Lesotho	South Africa	230
DRC	Zambia	260
Mozambique	South Africa	3,850
Mozambique	Swaziland	1,450
Mozambique	Zimbabwe	500
Namibia	South Africa	750
South Africa	Swaziland	1,450
South Africa	Zimbabwe	600
Zambia	Zimbabwe	1,400

Table 10. New Cross-Border Transmission Projects

From	To	Stations	Line Capacity (MW)	Earliest Year
Zizabona (Zimbabwe, Botsana, Namibia, Zambia)			600	2015
Westcor (DRC, Namibia, Angola, Botswana, South Africa)			1,500	2020
765 kV (DRC, Zambia, Zimbabwe, Namibia, South Africa			1,500	2020
Other Projects:				
Angola	DRC	Lunda - Inga	600	2016
Botswana	South Africa	Phokoje - Mmaba	500	2012
DRC	Zambia	KSMBL - MICHL	500	2017
Lesotho	South Africa	Merap - MaBOre	130	2015
Malawi	Mozambique	Phomb - Songo	600	2017
Malawi	Mozambique	Phomb - Matam	300	2015
Malawi	Zambia		200	2018
Mozambique	South Africa	Maputo - Hendr	600	2018
Mozambique	Zimbabwe	Songo - Bindura	500	2017
Namibia	South Africa	Kudu - Juno	300	2018
South Africa	Swaziland	Normandie - NH2	450	2018
Namibia	Angola	Namibia Angola	400	2016
Tanzania	Zambia	Mbeya - Kasma	400	2016
South Africa	Zimbabwe		650	2017

- **Capacity credit:** Centralised PV plants were given a 5% capacity credit to account for their variability and their high sensitivity to cloud cover, as well as poor power matching to current demand peaks that occur in the evenings. Wind was given a different capacity credit for each country as per Table 11. Apart from South Africa, where there is an actual study that undertook to calculate the capacity credit for country (GIZ, 2011), the others are based on rough estimates and require a more thorough analysis.

Additional Transmission Infrastructure Considerations for Wind

Most of the countries in the SPLAT model have only limited transmission infrastructure in place. The model already takes into account the need for transmission infrastructure to match peak demand for grid-connected systems. However, when accommodating a higher share of wind in the grid, additional investment in transmission infrastructure directly linked to wind capacity should be considered for, *inter alia*, the following reasons:

- Wind farms need to be dispersed to level out variability due to local meteorological conditions. Also, wind farms may be built in remote locations far from existing grid networks, which are very sparse in most SADC countries.
- For grid-connected systems, the SPLAT model computes investment in transmission lines in accordance with the peak demand, matching this with the sum of the dispatched generation capacity. However, for wind technology, it tracks only part of the installed wind capacity because of the way wind is modelled (de-rated by the capacity factor) to account for the variability of resource availability at any given time. Additional transmission investment is required to take account of the reality that more than the de-rated capacity may be dispatched.

To account for these, an additional transmission cost of USD 365/kW (*i.e.* the equivalent of a levelised cost of USD 50/MWh) was added to the investment cost of the wind technology in the model. Since it is possible that some of the wind resource may be located near already-existing transmission infrastructure, a 5% generation share from wind is exempt from this additional transmission cost. This may, of course, vary from country to country, and further analysis is required to better estimate what the level of exemption should be for each country.


Yellowj©Desert windmills in dunes energy/Shutterstock

Table 11. Wind Capacity Credit by Country

	Area	Wind Capacity Credit	Justification
	000 km²	%	
Angola	1,250	10%	resource is all along one coast
Botswana	600	5%	resource is concentrated and poor
DRC	2,345	5%	resource is concentrated in one area
Lesotho	30	0%	country is small
Malawi	118.5	5%	country is small and resource is concentrated
Mozambique	800	10%	resource is all along one coast
Namibia	820	10%	resource is all along one coast
South Africa	1,225	20%	resource is spread around country - along long coastline and inland - there is also a study
Swaziland	17	0%	country is small
Tanzania	950	10%	resource is concentrated in two areas that are relatively close
Zambia	750	5%	resource is poor
Zimbabwe	390	5%	resource is poor

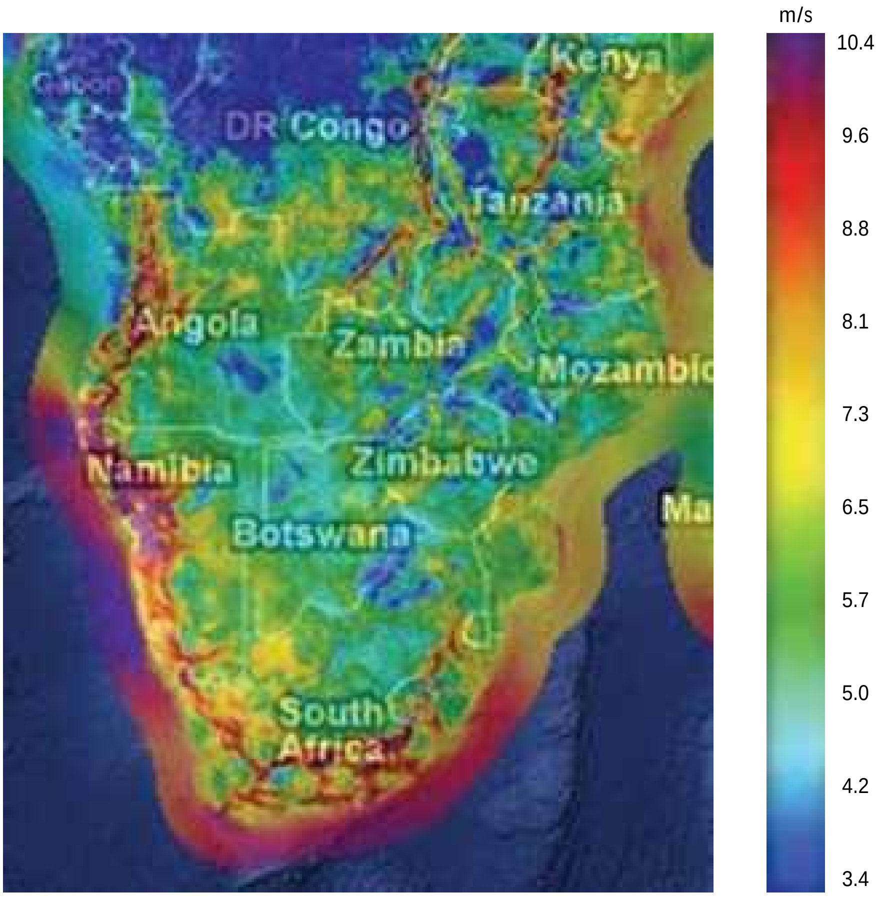


Figure 8. Wind Resource Map (www.vortex.es/africa-wind-map)


Dietmar Temps©Table Mountain with clouds, Cape Town, South Africa/Shutterstock

4. Modelling Results

4.1 Investment and Generation Mix through 2030 under the Renewable Promotion Scenario

In the SADC region, electricity demand is expected to nearly double by 2030 from its current level of 300 terawatt-hours (TWh) to 580 TWh, and to triple to reach 920 TWh by 2050. The installed capacity in 2010 is about 52 GW, 72% of which is based on coal-fuelled power generation, 18% on hydro power generation, and the remainder on oil and nuclear power generation. The South African system is dominant in the SAPP, accounting for 80% of the capacity in the region.

Figure 9, which presents the retirement schedule of existing capacity, shows that by 2030, 15 GW of the currently installed capacity will be retired. In order to meet the growing demand, additional capacity of nearly 110 GW would be needed under the Renewable Promotion scenario and 80 GW under the Renewable High Cost scenario. The Renewable Promotion scenario requires more capacity addition because renewable technologies typically have low availability factors, and a system that has a higher share of intermittent renewable sources requires more back-up capacity.

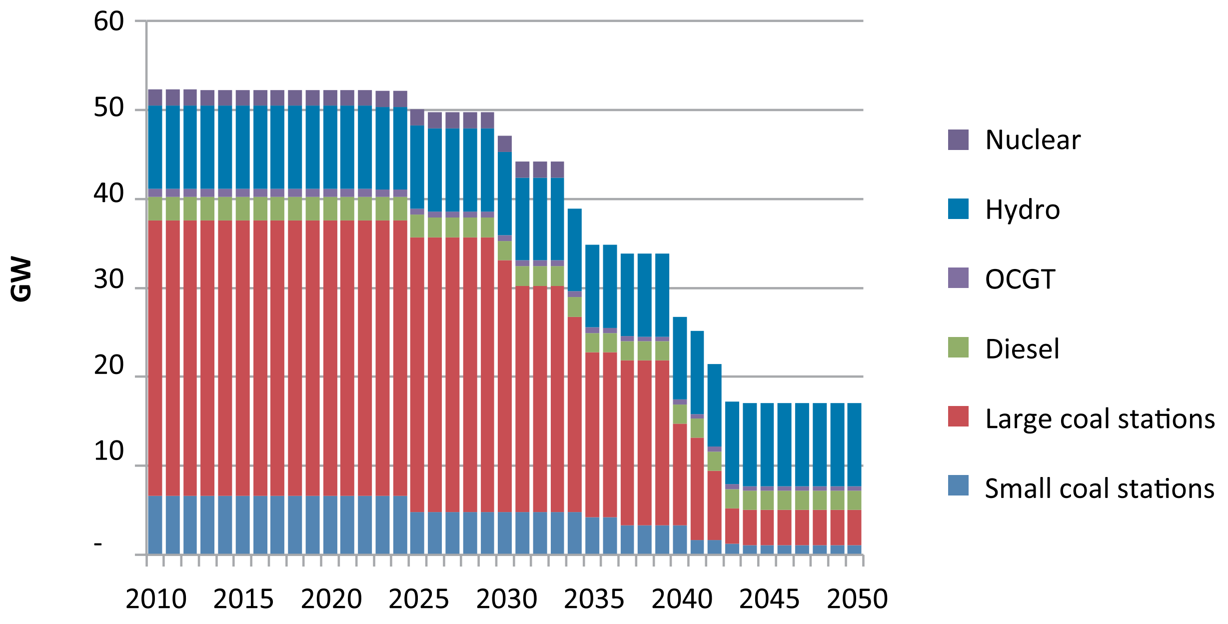


Figure 9. Capacity of Existing Plants

Figure 10 shows the investment schedule under the Renewable Promotion scenario. Appendix G shows all the projects "selected" in this scenario. Under this scenario, in the first decade, 13 GW of coal would be deployed, out of which 10 GW would be accounted for by already committed projects. Out of 41 hydro projects currently under consideration (excluding a pumped-hydro storage project), 32 would be deployed under this scenario (12 of them are already committed). By 2030, the total new capacity addition of hydro power would amount to 24 GW. Approximately half of this would be accounted for by the Grand Inga project, deployed at the annual pace of 0.9 GW as soon as it comes onstream in 2018. By 2021, wind power generation should become cost competitive against all fossil-based generation technologies (as shown in Figure 10) in countries where high quality wind resources are available. During the 2021-2030 period, large-scale deployment of wind generation would be seen in this scenario (*e.g.*, South Africa: 17 GW; Zambia: 590 MW; and Zimbabwe: 375 MW). Major deployment of utility-scale solar PV would be seen from 2023 onward, including 12 GW in South Africa (2021-2030) and 2.6 GW in Tanzania (2026-2030).

A small amount of new nuclear and considerable gas generation options would be deployed in South Africa, where they play an important role in meeting CO_2 targets until renewable generation technologies are more progressively deployed.

Under the Renewable Promotion scenario, out of the total capacity addition of 112 GW required between 2010 and 2030, renewable technologies would account for 78%

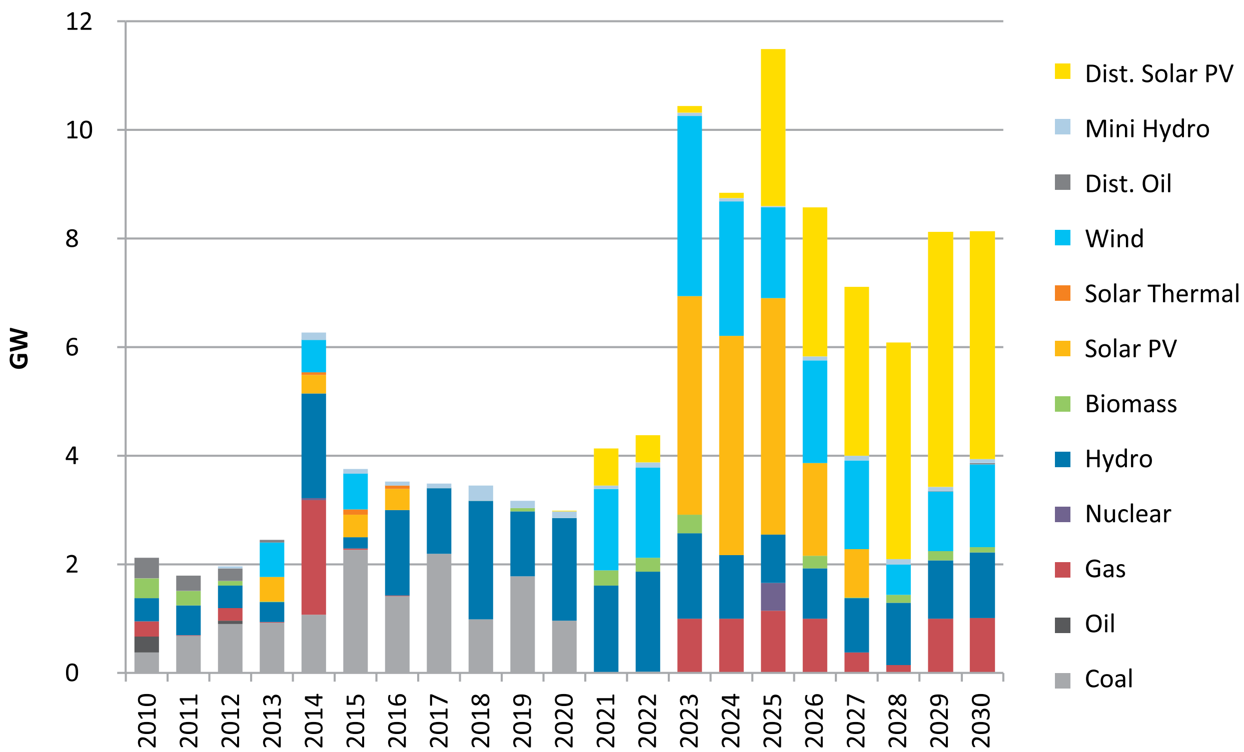


Figure 10. New Capacity Addition under the Renewable Promotion Scenario until 2030

and decentralised renewable options 22%. In particular, small hydro and PV with storage options would become important in meeting rural electricity demand in most SADC countries. In Botswana and South Africa, where hydro resources are scarce, roof-top PV with one-or two-hour battery supply would be deployed to meet rural demand. The deployment of roof-top PV would amount to 23 GW, of which 21 GW would be in South Africa.

Table 12 provides a summary of capacity addition during 2010-2030 by country, presented for centralised and decentralised power generation capacity.

Deployment of the Grand Inga project is economically viable only with accompanying investment in the inter-country transmission network that makes the export of electricity from the DRC possible. Current carrying capacity of international transmission lines in the whole Southern African region is 24 GW. In order to accommodate trading of inexpensive hydro-based electricity in the region, the transmission capacity would need to be doubled by 2030. As detailed in Appendix G, out of the 28 international transmission projects currently being considered, 17 of them would be deployed as priorities by 2030, while seven more would be deployed by 2050. Four projects did not prove to have a viable economic case, given the overall development of the regional generation system.

As a result of these new investments, the share of renewables in the total generation capacity would

Table 12. Capacity Addition during 2010-2030 by Country in MW

	Centralised		Decentralised	
	Total	Renewable	Total	Renewable
Angola	3,101	2,051	295	185
Botswana	1,375	139	163	60
Dem. Rep. Congo	12,629	12,629	354	341
Lesotho	271	230	36	12
Malawi	877	877	39	32
Mozambique	2,982	1,822	80	76
Namibia	968	567	103	51
South Africa	50,257	32,928	22,005	21,907
Swaziland	281	231	84	53
Tanzania	6,013	5,025	1,254	1,214
Zambia	5,159	5,055	590	300
Zimbabwe	2,679	1,227	707	493
Total	**86,593**	**62,781**	**25,710**	**24,725**

increase from 20% in 2010, mostly hydro, to 62% in 2030, of which less than 22 percentage points would be accounted for by hydro. Figure 11 shows the development of capacity balance in the region under the Renewable Promotion scenario.

The implication of these investments on the electricity generation mix under the Renewable Promotion scenario is shown in Figure 12. The general trend shows a replacement of coal-based generation and nuclear power in South Africa with more hydro and other renewable energy technologies. The trends set in around 2020, and the shares of hydro and other renewables in the total electricity supply would reach 21% and 25% by 2030 from 11% and 0% in 2010, respectively. Note that 52% of the large hydro generation would come from the DRC.

In absolute terms, total SADC regional generation would increase from 320 Gigawatt-hour (GWh) to 625 GWh by 2030. About 570 GWh would be generated by plants connected to national/regional grid systems, and 17% of the power generated would be traded internationally. This represents a substantial increase from 12% in 2010.

Although South Africa's share in total regional generation is projected to decrease from 85% to 68% between 2010 and 2030, the regional generation mix, shown in Figure 12, is still bound to heavily reflect South African system evolution. Figure 13 shows each country's generation mix in 2010 and 2030 under the Renewable Promotion scenario. In 2010, only Mozambique and South Africa were net exporters, while seven countries in the region relied extensively (approximately 40-80%) on imported electricity. By 2030, such excessive reliance on imported electricity would cease, and some countries would even become net exporters as they develop their own energy resources and gain greater generation capacities. Deployment of renewable options would diversity the generation mix in all countries by 2030.

Looking more closely at regional electricity trade flows, Figure 14 shows the trade directions and volumes. Coloured bars show the electricity generation mix in TWh in each country in 2030. International transmission-line projects considered in this study are summarised in Table 25 in Appendix E. With the Zizabona project, the Botswana-Namibia link starts to play a role in 2015, with

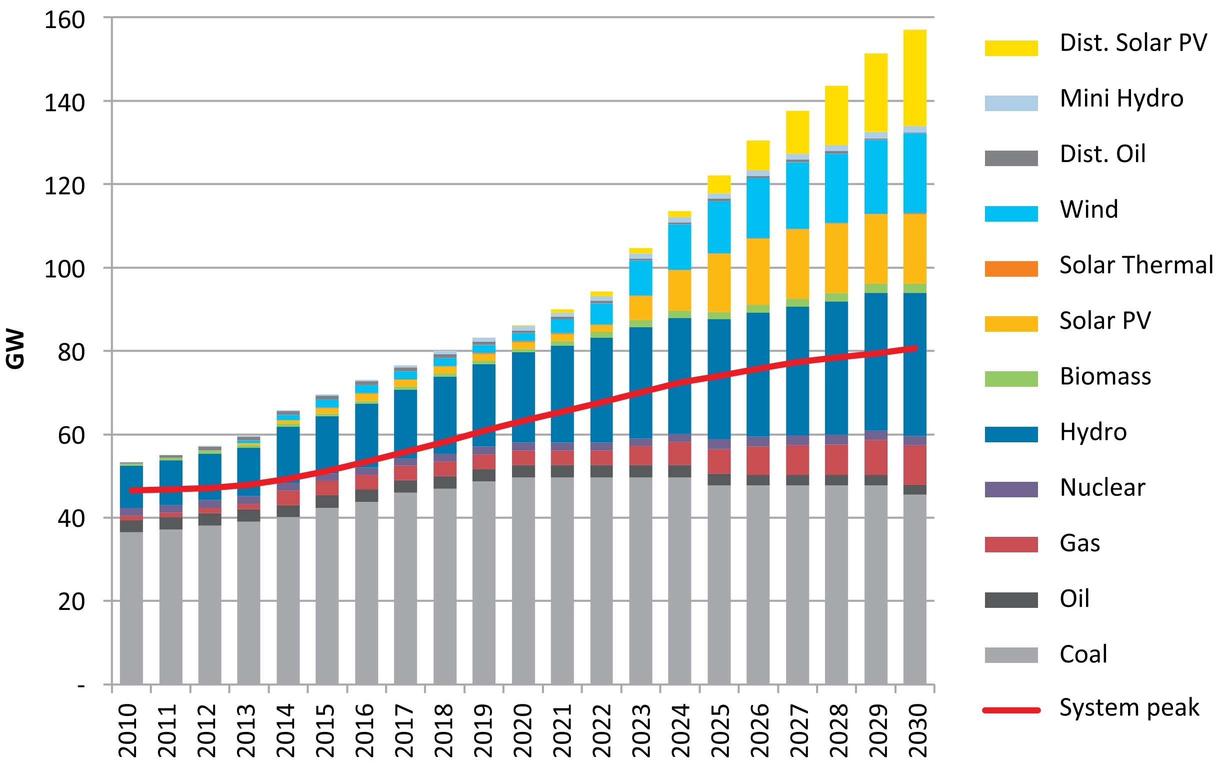


Figure 11. Capacity Balance under the Renewable Promotion Scenario

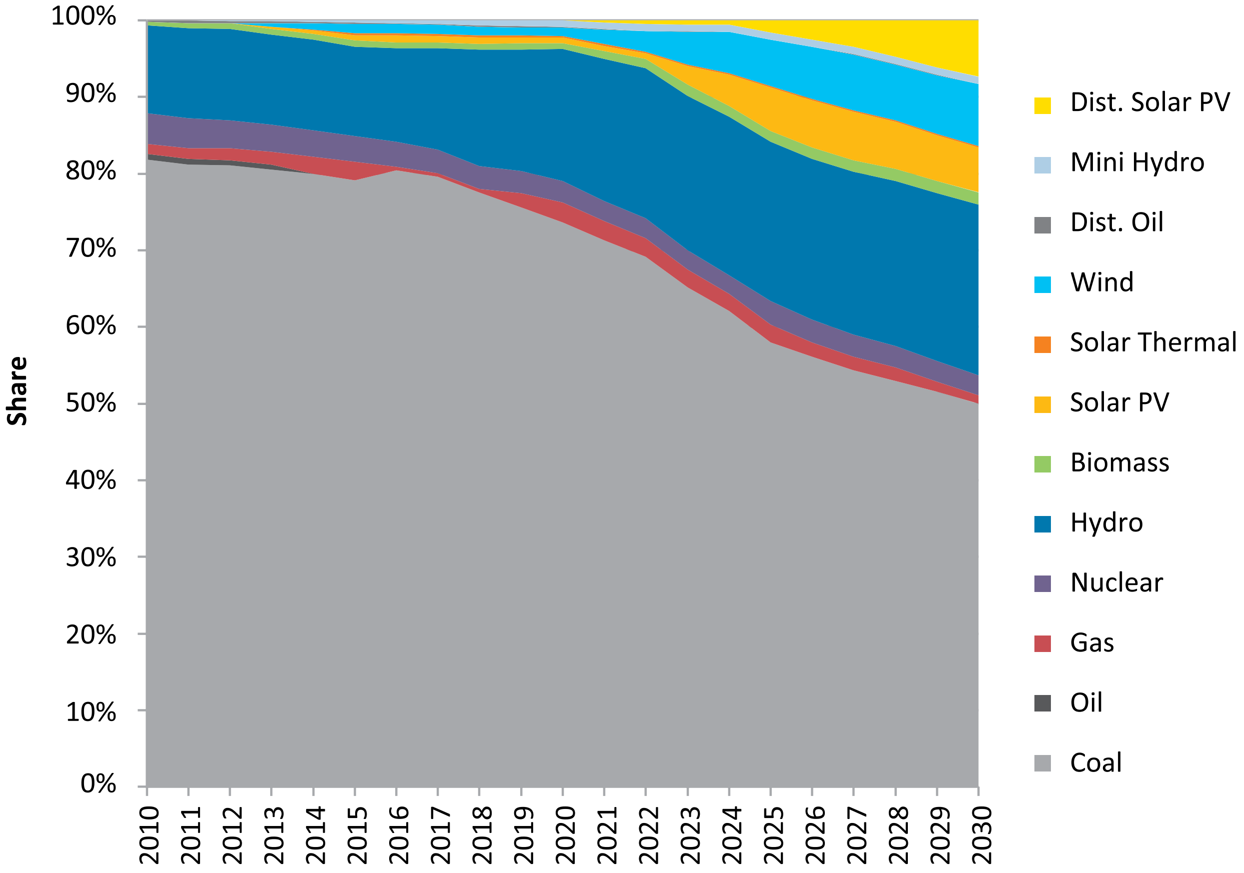


Figure 12. Electricity Generation Mix under the Renewable Promotion Scenario

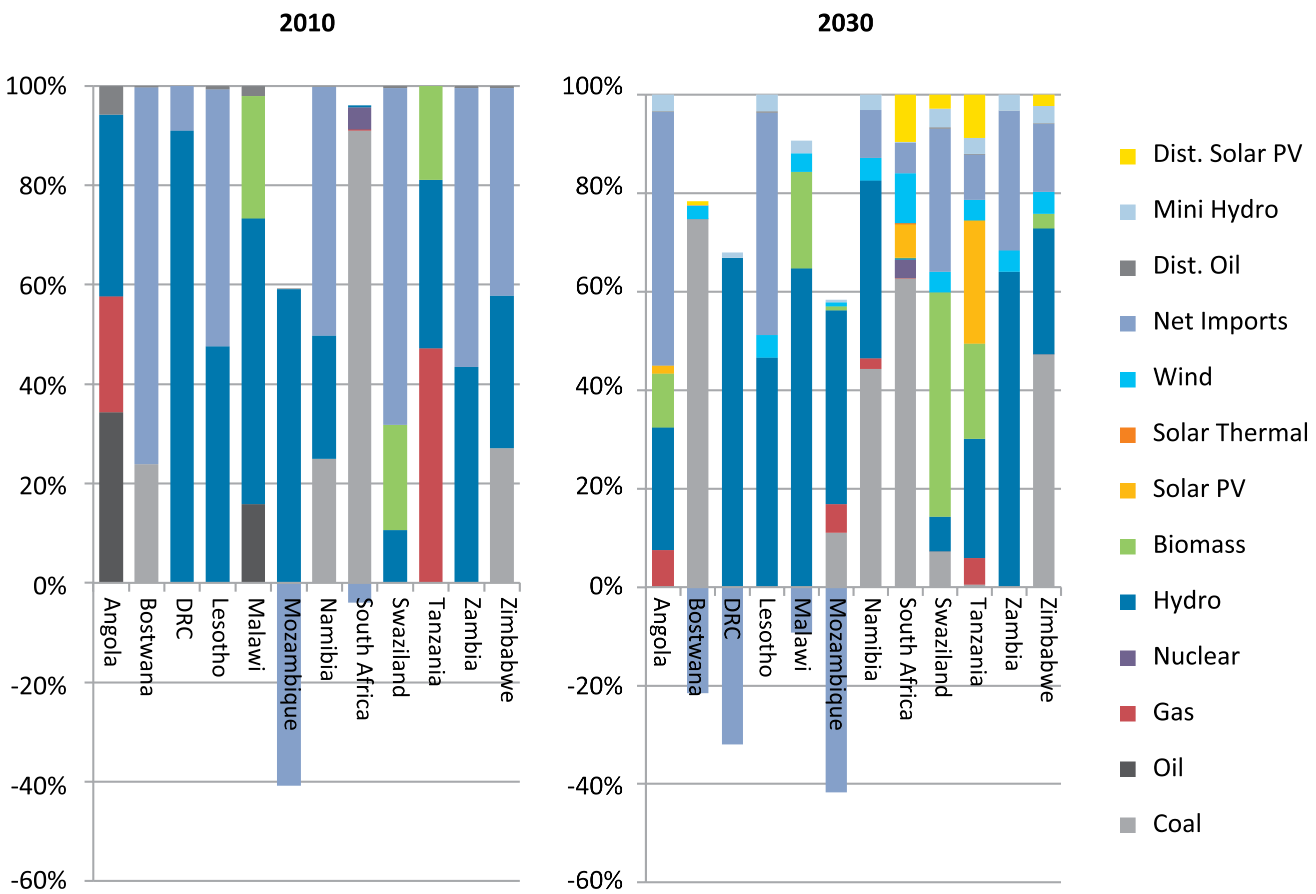


Figure 13. Electricity Production Shares in 2010 and in 2030 under the Renewable Promotion Scenario by Country

electricity flowing mainly from Botswana to Namibia until 2021, when the Westcor line from DRC to Namibia becomes available. From then on, the Botswana-Namibia link operates in reverse, with some of the power from DRC transferred to Botswana. The Westcor project would contribute from 2022 onwards, taking electricity from Grand Inga southward, first directly to Namibia and through to South Africa, and later to Angola as well. As for the third major line project, the 765 kiloVolt (kV) project, only its Zimbabwe-South Africa link, starting in 2025, would play a significant role within the period modelled.

Other important new links would be:

» The Botswana-South Africa link starting in 2023;

» The DRC-Zambia link starting in 2019;

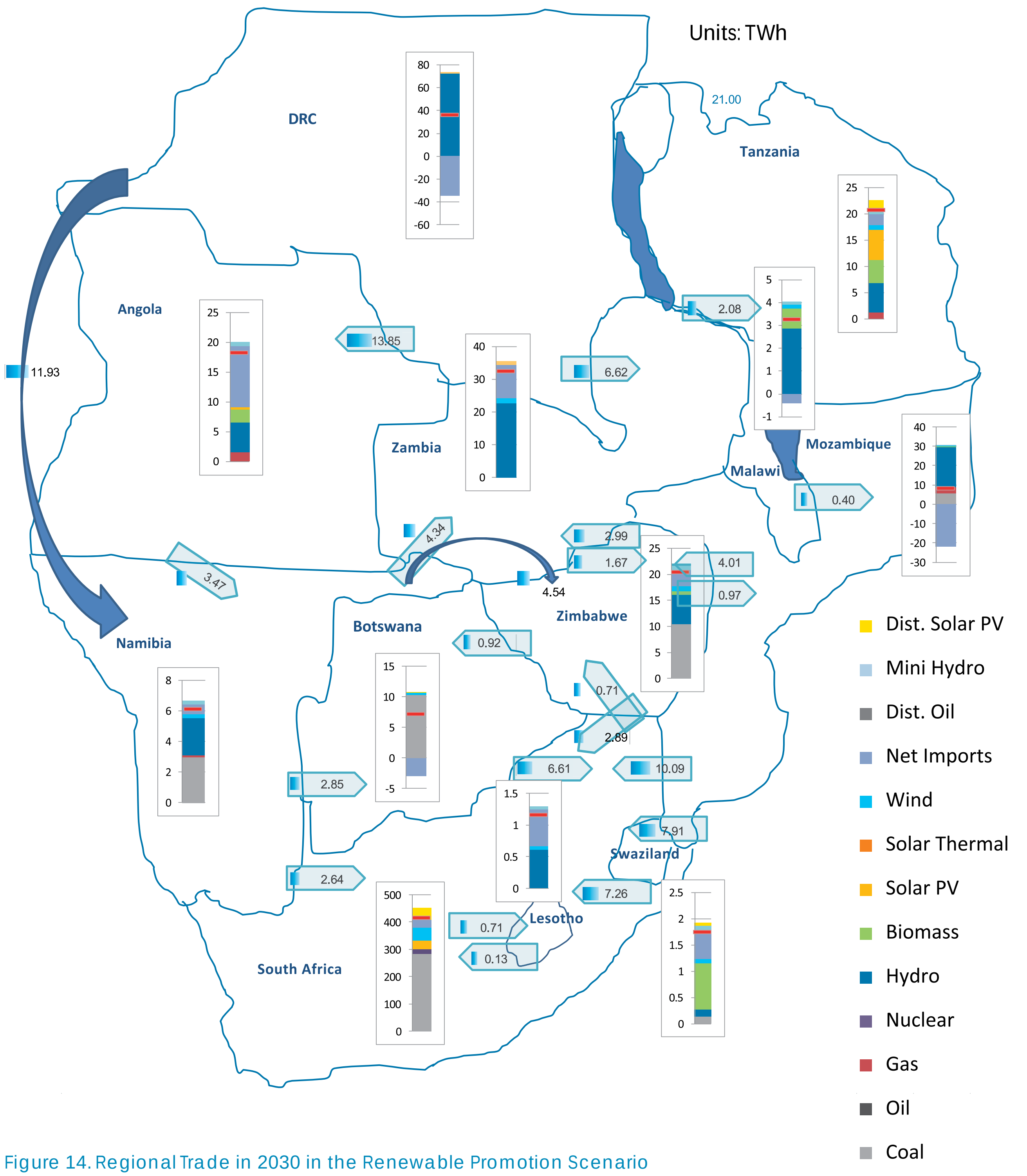


Figure 14. Regional Trade in 2030 in the Renewable Promotion Scenario

- The Mozambique-South Africa link starting in 2018;
- The Mozambique-Zimbabwe link starting in 2017; and
- The DRC-Angola link starting in 2017.

Finally, distributed generation will be more closely examined. Under the Renewable Promotion scenario, 8.3% of the total regional demand would be met by distributed technologies by 2030. For the rural sector (i.e. only 4% of total demand), 59% of the sector's demand would be met through decentralised generation by 2030. Figure 15 shows the shares of electricity supply to the urban and rural sectors in 2030 in the Renewable Promotion scenario. Deployment of decentralised generation in the urban sector would be limited to four countries: South Africa, Swaziland, Tanzania and Zimbabwe, where PV with one- and two-hour storage would be deployed.

For the rural sector, the cost competitiveness of distributed technologies compared with grid extension would be substantial, and their share would exceed 86% by 2030 in countries where mini-hydro resources are available. In Botswana and South Africa, where such resources are limited, solar PV with one- and two-hour storage would be deployed.

In absolute terms, 14 TWh of the total rural electricity demand of 24 TWh in 2030 would be met by decentralised options. For urban electricity demand, 38 TWh out of 219 TWh would be met this way. South Africa's deployment of solar PV with one-hour batteries for urban applications alone would account for 35 TWh by 2030 under this scenario.

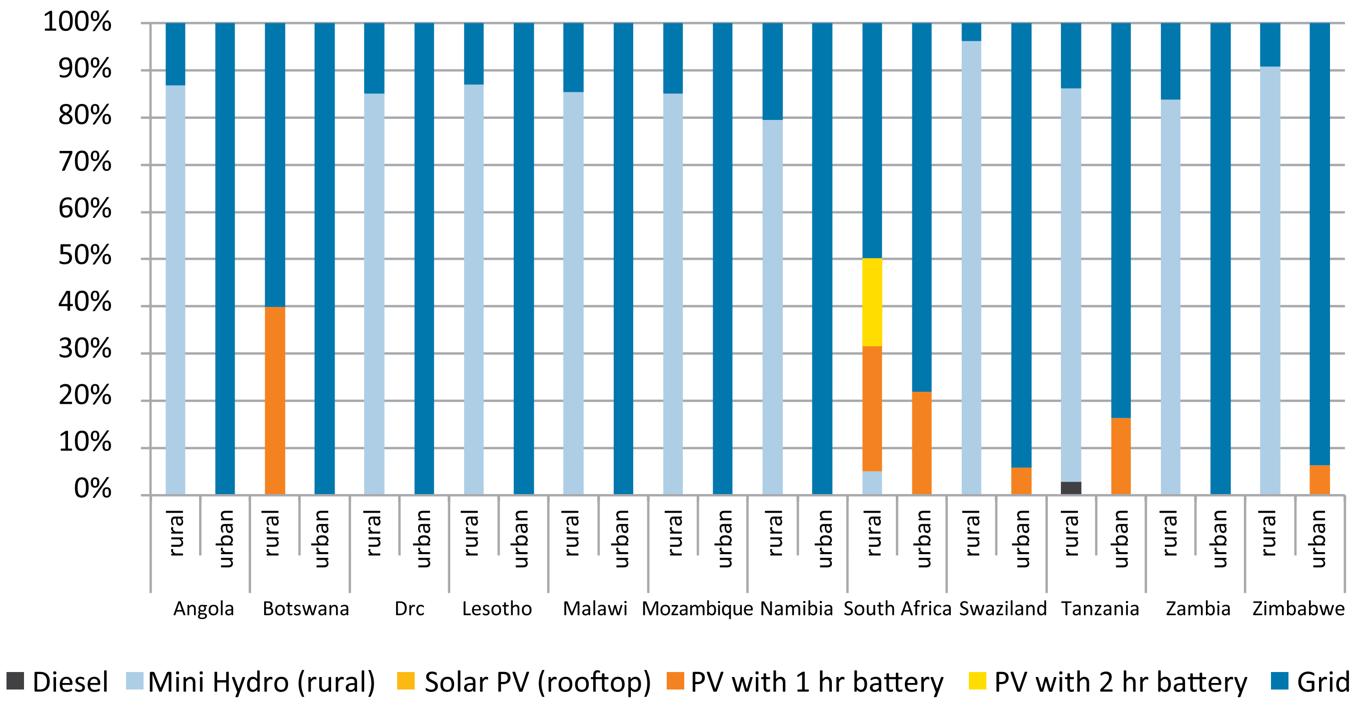


Figure 15. Share of Distributed Generation in Urban and Rural Demands in 2030 under the Renewable Promotion Scenario

4.2 IMPLICATION FOR THE SHARE OF RENEWABLES

Global doubling of the share of renewables by 2030 is one of the three goals of United Nations' Sustainable Energy for All (SE4ALL) Initiative. Given favourable cost development for renewable technologies, the above analysis suggests an economically sound maximum for penetration of renewables in the power sector in Southern African countries and the region as a whole.

Figure 16 shows the shares of renewable-based generation in total electricity generation in 2010 and 2030 under the Renewable Promotion scenario. The regional average would increase from 12% to 46% over this twenty-year period. On a country-by-county basis the increase in share may not look so dramatic. On the regional level, a 10 percentage-point increase from 2010 to 2030 would be contributed by hydro generation, and the remainder would be contributed by non-hydro-based renewables, whose share is currently negligible.

Implication for Energy Security

The International Energy Agency (IEA) defines energy security as the uninterrupted availability of energy sources at an affordable price. Energy security has many aspects. Long-term investment is mainly linked to timely investments to supply energy in line with economic developments and environmental needs. Short-term energy security focuses on the ability of the energy system to react promptly to sudden changes in the supply-demand balance. There is no single indicator for energy security but some aspects that are commonly looked at include diversity of the supply mix, reliability criteria, reliance on imports from a single source and, in hydro systems, the impact of droughts.

The Diversity of the Supply Mix

Systems that rely on multiple sources of primary energy are more robust to shocks, constraints and crises affecting one or another form of supply. A commonly used indicator of systems diversity is the Shannon-Weiner Index (SWI), defined as:

$$\text{SWI} = -\sum p_i \ln(p_i)$$

where p_i is the share of installed capacity for resource i. Table 13 shows the SWI diversity indicator for all the countries in the base year and in 2030 for the Renewable Promotion scenario. Except for the DRC and Malawi, the SWI index of the countries significantly increases. In the case of the DRC, hydro dominates the mix throughout the study horizon. However, energy from the Inga River is very reliable. In the case of Malawi, the share of hydro grows but much of the hydro generation would actually be exported.

AdeleD©Mist rising above the Katse dam wall in Lesotho, Southern Africa/Shutterstock

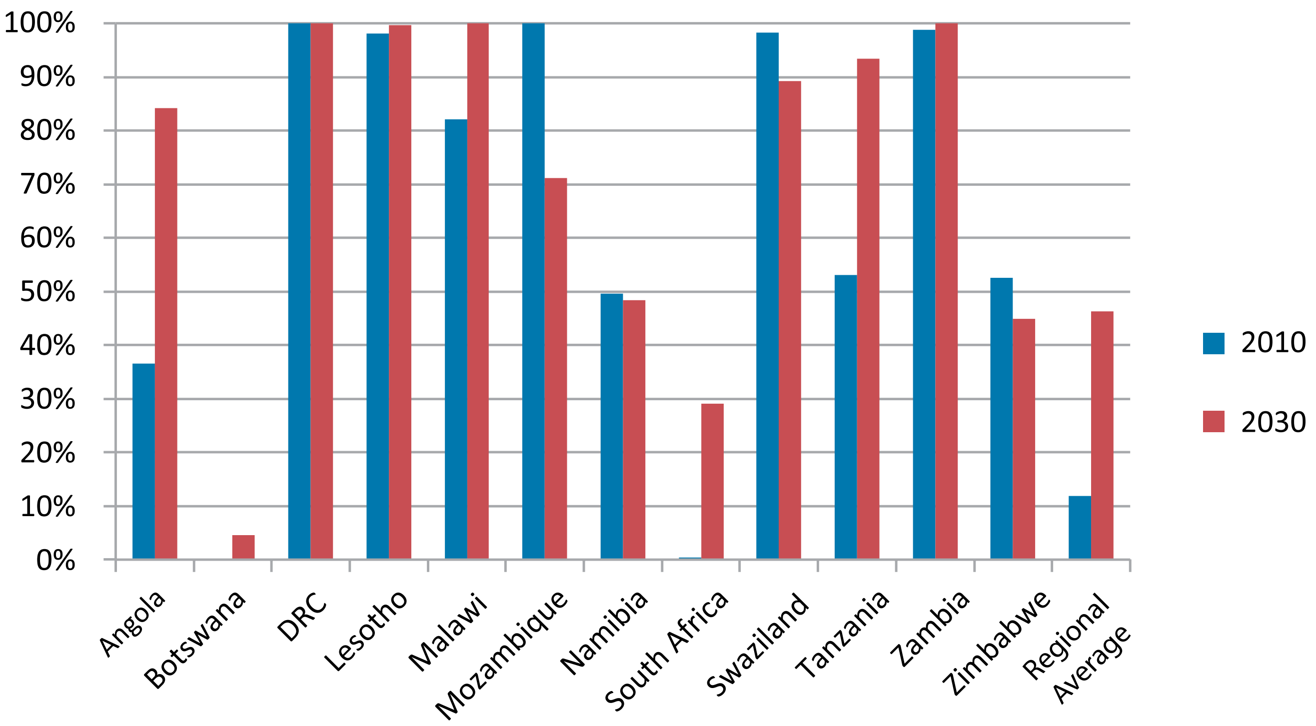


Figure 16. Share of Renewable-Based Generation in Total Electricity Generation

Table 13. Diversity of Supply for the Renewable Promotion Scenario

	SWI in 2010	SWI in 2030 for the Renewable Promotion Scenario
Angola	41%	56%
Botswana	0%	18%
DRC	0%	0%
Lesotho	0%	31%
Malawi	35%	29%
Mozambique	6%	39%
Namibia	36%	53%
South Africa	27%	65%
Swaziland	30%	53%
Tanzania	50%	67%
Zambia	2%	17%
Zimbabwe	27%	58%

Reliability Criteria

The adequacy of generation capability depends upon factors such as the installed capacity, unit size, plant reliability and demand forecasting error. The Reserve Margin is a deterministic criterion, which provides a measure of system security. Firm Reserve Margin (FRM) takes into account the variability of some of the supply sources and is defined in section 3.8. Table 14 shows the FRM for the countries in the base year and in 2030 for the Renewable Promotion scenario. As mentioned above, a 10% FRM is imposed as a constraint on all countries and this is verified in the table. Exporting countries end up with very high reserve levels as expected.

Reliance on Imports

If there is good regional integration, reliance on imports may be beneficial although most countries would prefer not to rely solely on a single neighbouring country. Table 15 shows imports as a share of total final demand. Other than Angola and South Africa, all countries would reduce their reliance on imports. For Angola, although it is well endowed with hydro resources, these perform poorly in a "dry year" scenario, making imports from the DRC (with the Inga dams close by) a very attractive option. In the case of South Africa, low-carbon energy imports help to meet CO_2 targets.

Impact of Droughts

A system that relies heavily on hydro is susceptible to shortages due to droughts and water shortages. In this model, a "dry-year" assumption was used for all modelling periods to mitigate this risk and is inherent in this model.

Sean Nel©Brewing thunderstorm in the dessert area of the Karoo in South Africa/Shutterstock

Table 14. Firm Reserve Margin for the Renewable Promotion Scenario

	FRM in 2010	FRM in 2030 for the Renewable Promotion Scenario
Angola	18%	10%
Botswana	-79%	23%
DRC	17%	168%
Lesotho	-27%	38%
Malawi	52%	83%
Mozambique	357%	294%
Namibia	-27%	26%
South Africa	14%	10%
Swaziland	-38%	12%
Tanzania	70%	12%
Zambia	-28%	21%
Zimbabwe	-28%	12%

Table 15. Share of Imports for the Renewable Promotion Scenario

	Share of Imports in 2010	Share of Imports in 2030 for the Renewable Promotion Scenario
Angola	0%	57%
Botswana	88%	0%
DRC	11%	0%
Lesotho	61%	51%
Malawi	0%	0%
Mozambique	0%	0%
Namibia	58%	11%
South Africa	0%	7%
Swaziland	80%	32%
Tanzania	0%	10%
Zambia	67%	31%
Zimbabwe	49%	15%


Andrei Orlov©View of solar panels in the desert/Shutterstock

4.3 ECONOMIC IMPLICATIONS OF THE RENEWABLE PROMOTION SCENARIO

The SPLAT model computes economic implications of a given scenario in terms of investment cost (in generation, transmission and distribution), fuel costs, O&M costs and gain from carbon finance. The sum of these cost elements constitutes the system cost that the model tries to minimise.

Figure 17 shows the breakdown of undiscounted system costs between 2010 and 2030 in the Renewable Promotion scenario. Note that the investment costs are annualised over the lifetime of each technology. The figure shows that, despite large investments in hydro and other renewable technologies, fuel cost is still the largest cost component at 40% in 2030, followed by annualised investment costs of generation at 32%, O&M costs of generation, and domestic transmission and distribution investment costs, each at around 15%. CO_2 financing reduces overall costs by 1.3%. Cross-border interconnector investment costs account for a small share, at 0.2%. Cumulative system costs between 2010 and 2030 amount to USD 877 billion (undiscounted) or USD 295 billion (discounted).

It is worth noting that, although the economic benefit of carbon finance is quite marginal, its impact on the cost competitiveness of technologies and consequently the choice of technology mix (as discussed in a later section) is significant.

Figure 18 shows investment requirements by year. Contrary to Figure 17, the investment cost here is not annualised in order to assess the financial requirement by year. The financial requirement for investments between 2010 and 2030 amounts to USD 104 billion at present value (*i.e.* discounted). The sum of the undiscounted investment during the period is USD 314 billion. Investments in the transmission and distribution sector should not be underestimated, amounting to nearly USD 100 billion, whereas investments in grid-connected generation are about USD 160 billion.

Massive investment in distributed generation starting from 2025 mostly corresponds to the deployment of solar roof-top PV systems with one-hour batteries for urban applications in South Africa.

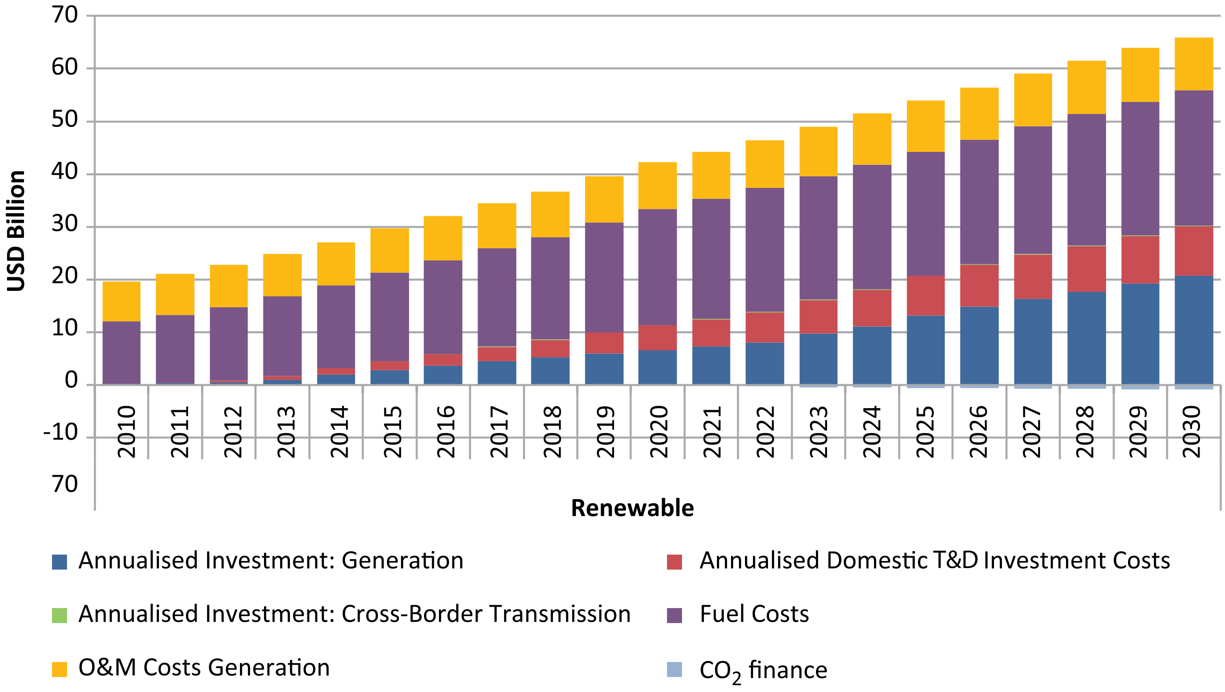


Figure 17. Total Undiscounted System Costs in the Renewable Promotion Scenario

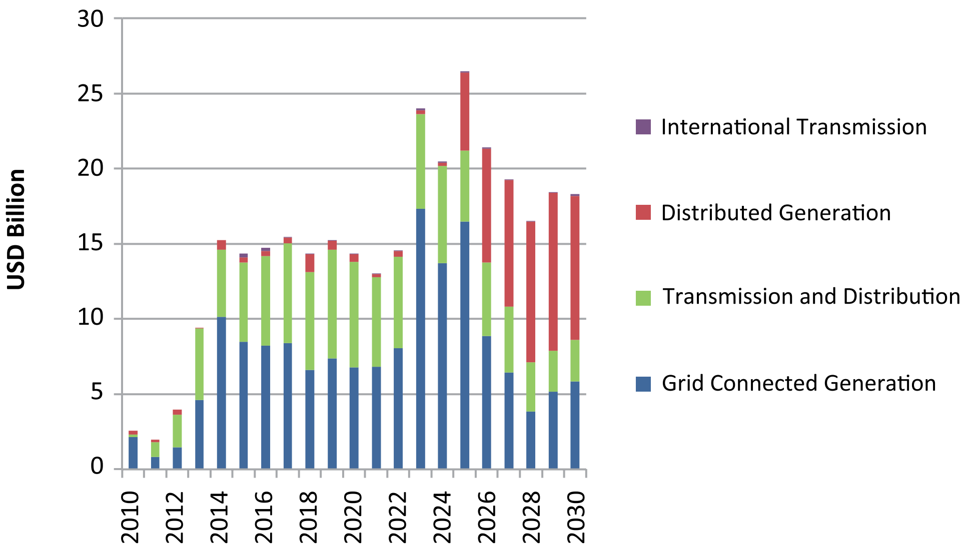


Figure 18. Investment Requirements by Year (Undiscounted) in the Renewable Promotion Scenario

4.4 COMPARISON WITH ALTERNATIVE SCENARIOS

Figure 19 shows shares of different energy sources in electricity production under three alternative scenarios. Compared with the Renewable Promotion scenario (Figure 12), these three graphs show what drives the technology-mix transition. Higher investment costs for renewable technology make nuclear and gas relatively more important. Unavailability of the Inga project necessitates more aggressive deployment of all other types of renewable technologies, as well as nuclear power. Under the No Inga scenario, the electricity trade volume in 2030 is 67 TWh, 36% lower than the volume under the Renewable Promotion scenario, where the Grand Inga's potential is fully deployed. Without carbon finance, the reduction in coal reliance is significantly slowed down. Shares of renewables by 2030 are 29% in the High-Cost scenario, 43% in the No Inga scenario, and 40% in the No Carbon Finance scenario, compared with 46% in the Renewable Promotion scenario.

Four scenarios using the SPLAT model are defined to meet the energy demand specified for each year between 2010 and 2030, and for two distant years, 2040 and 2050. The optimisation of the system was executed for the entire period of 2010 through 2050. Figure 20 shows the electricity production mix between 2030 and 2050 under the four scenarios. Solar thermal technology is expected to be cost-competitive and to start being deployed after 2030 in all scenarios except the High-Cost scenario, where nuclear power is deployed as the primary generation technology.

Figure 21 shows CO2 emissions under the four scenarios. The impact of carbon finance is significant, resulting in about 35 Mt of difference in CO2 emissions by 2030, and more than 185 Mt by 2050. As discussed later, the economic impact of carbon finance is relatively marginal. However, it does affect the transition away from fossil-based technologies.

The difference between the Renewable Promotion scenario and the High-Cost scenario in CO2 emissions is around 32 Mt in 2030. However, by 2050, the difference is more than 215Mt, since, under the High-Cost scenario, more coal- and gas-based power is deployed. In terms of system costs, all scenarios generated similar costs, for discounted costs: around USD 300 billion between 2010 and 2030, and for undiscounted costs, about USD 890-910

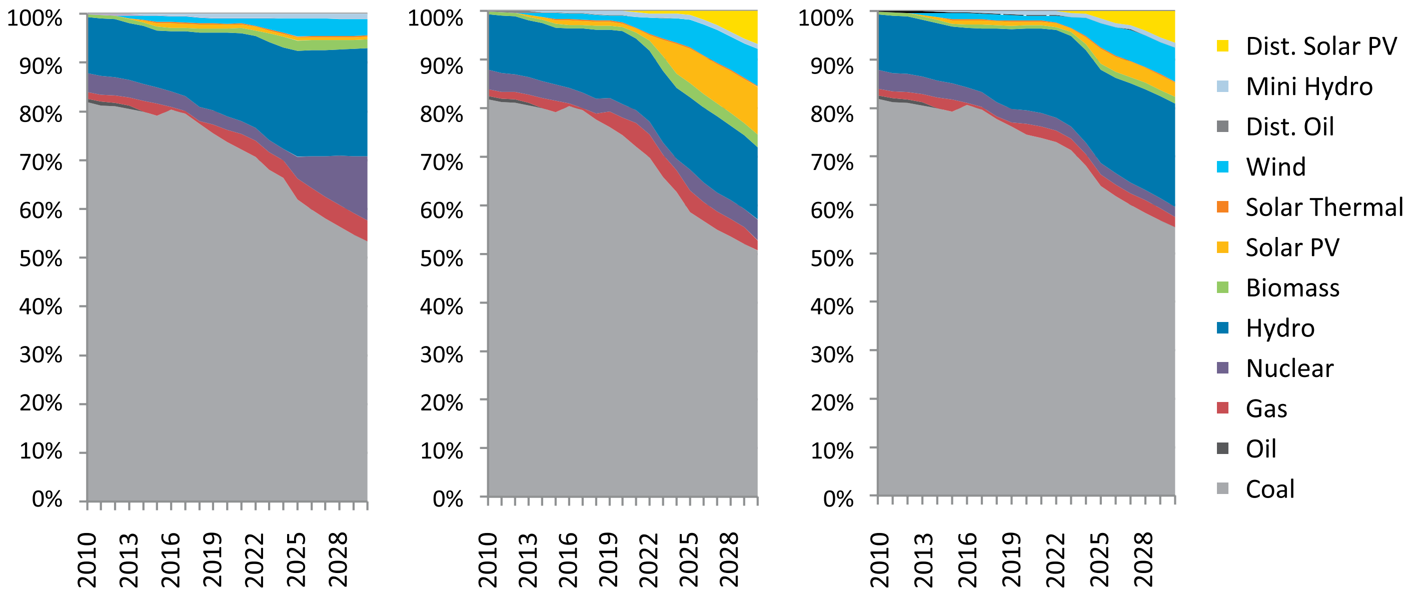


Figure 19. Electricity Production Shares under Three Alternative Scenarios: High-Cost Scenario (left), No Inga Scenario (middle) and No Carbon Finance Scenario (right)

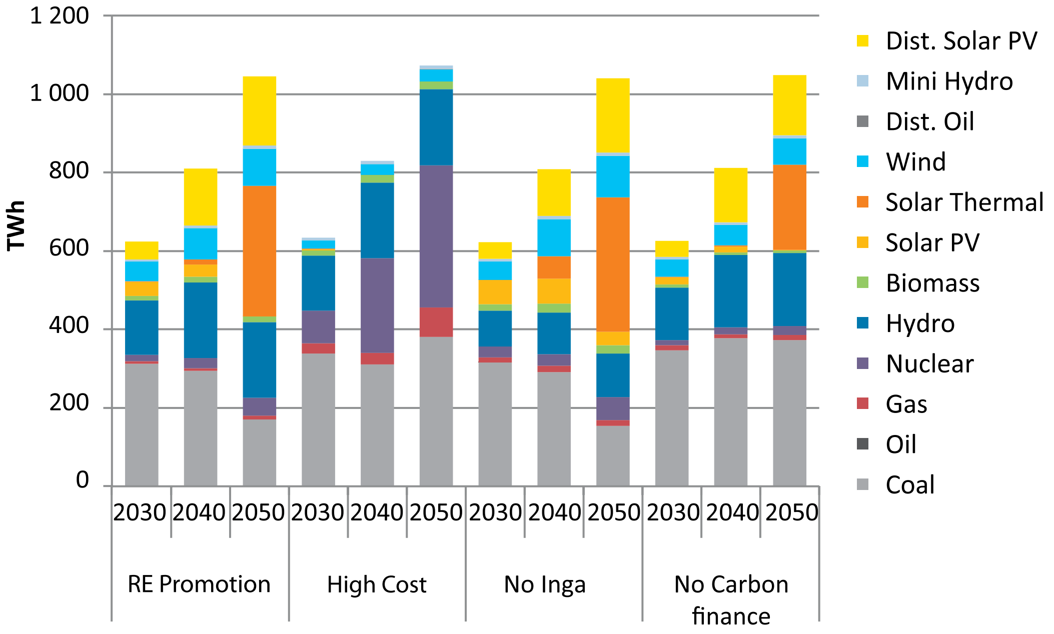


Figure 20. Electricity Production between 2030 and 2050 under the Four Scenarios

Figure 21. Carbon Dioxide Emissions under the Four Scenarios

billion (Table 16). The differences in the cumulative total system costs between the Renewable Promotion scenario and the High-Cost scenario during the 2010-2030 period is USD 7 billion (2% difference) and USD 36 billion (4% difference), discounted and undiscounted, respectively. The cumulative cost differences are modest because up to 2020, the development of the energy mix would be very similar with either scenario, due to committed projects that would be implemented in any case.

Figure 22 compares the annualised system costs between the Renewable Promotion scenario and the High-Cost scenario over time and by cost components. The differences in the first decade are insignificant because current, committed projects would be implemented during this time; thus, there is not enough room for differentiation between the investment paths under the two scenarios. But the differences between the two scenarios grow in the longer term. In particular, the transformation of the power system to a more renewables-based one brings significant fuel cost savings, as well as reductions in domestic transformation and distribution costs, due to the progressive deployment of decentralised systems.

In fact, if the cumulative system costs between 2030 and 2050 are taken into account, the differences in the two scenarios amount to USD 72 billion when discounted and USD 815 billion when not discounted. They correspond to 5% and 8% differences, respectively.

Figure 23 shows average total system costs per unit of energy consumption in the four scenarios. The differences between the Renewable Promotion scenario and the No Inga scenario highlight the great cost reduction potential of the Inga project alone for the entire Southern African region, through providing access to cheap hydro-electricity from the DRC to neighbouring countries. Promotion of renewable technologies, combined with Inga, could bring average generation costs down by 9% by 2030 compared to the High-Cost scenario.

Table 16. Cumulative System Costs between 2010-2030 in Billion US Dollars under the Four Scenarios

	Renewable Promotion Scenario		High-Cost Scenario		No Inga Scenario		No Carbon Finance Scenario	
	Discounted	Undiscounted	Discounted	Undiscounted	Discounted	Undiscounted	Discounted	Undiscounted
Investment (Generation)	42	171	42	169	43	173	40	159
Investment (Domestic T&D)	25	96	26	102	25	96	25	97
Investment (international transmission)	0	1	0	2	0	1	0	1
Fuel costs	155	426	161	459	160	447	159	449
O&M costs	74	188	73	185	74	191	73	185
Carbon finance	-1	-6	-1	-5	-1	-5	0	0
Total system costs	295	877	302	913	301	904	298	892

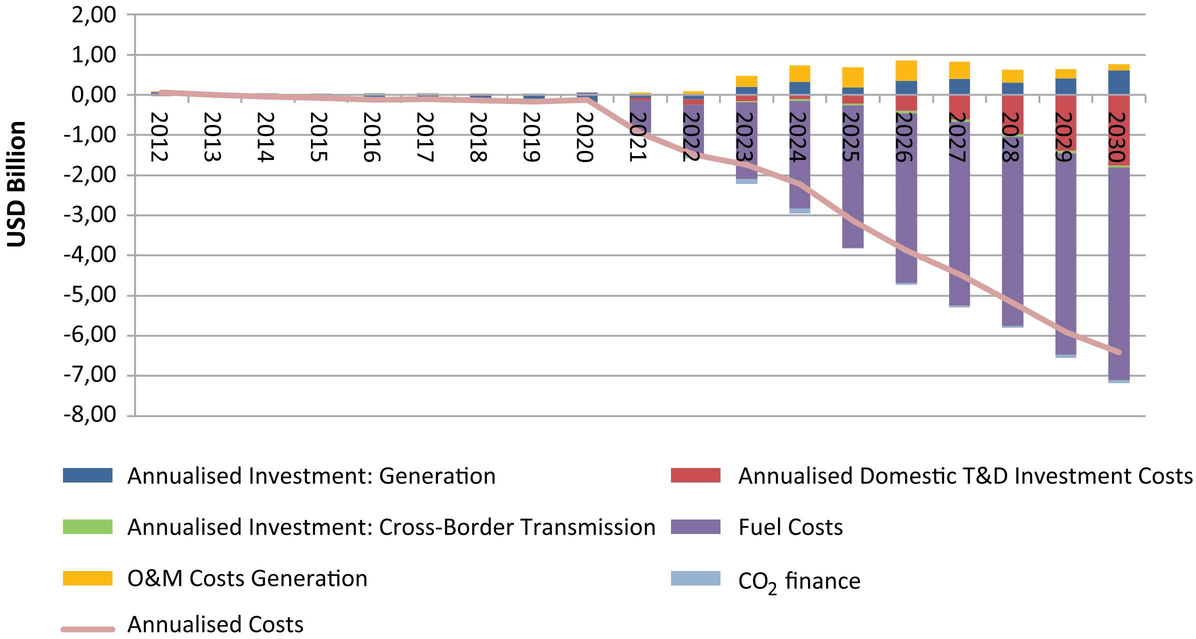


Figure 22. Differences in System Costs (Itemised) between the Renewable Promotion Scenario and the Reference Scenario

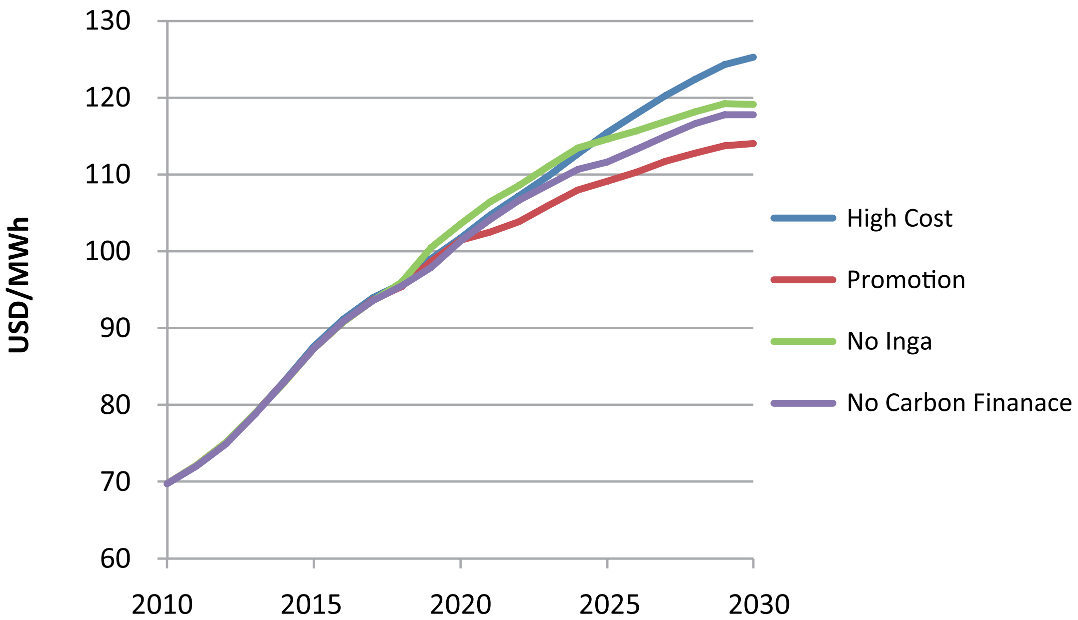
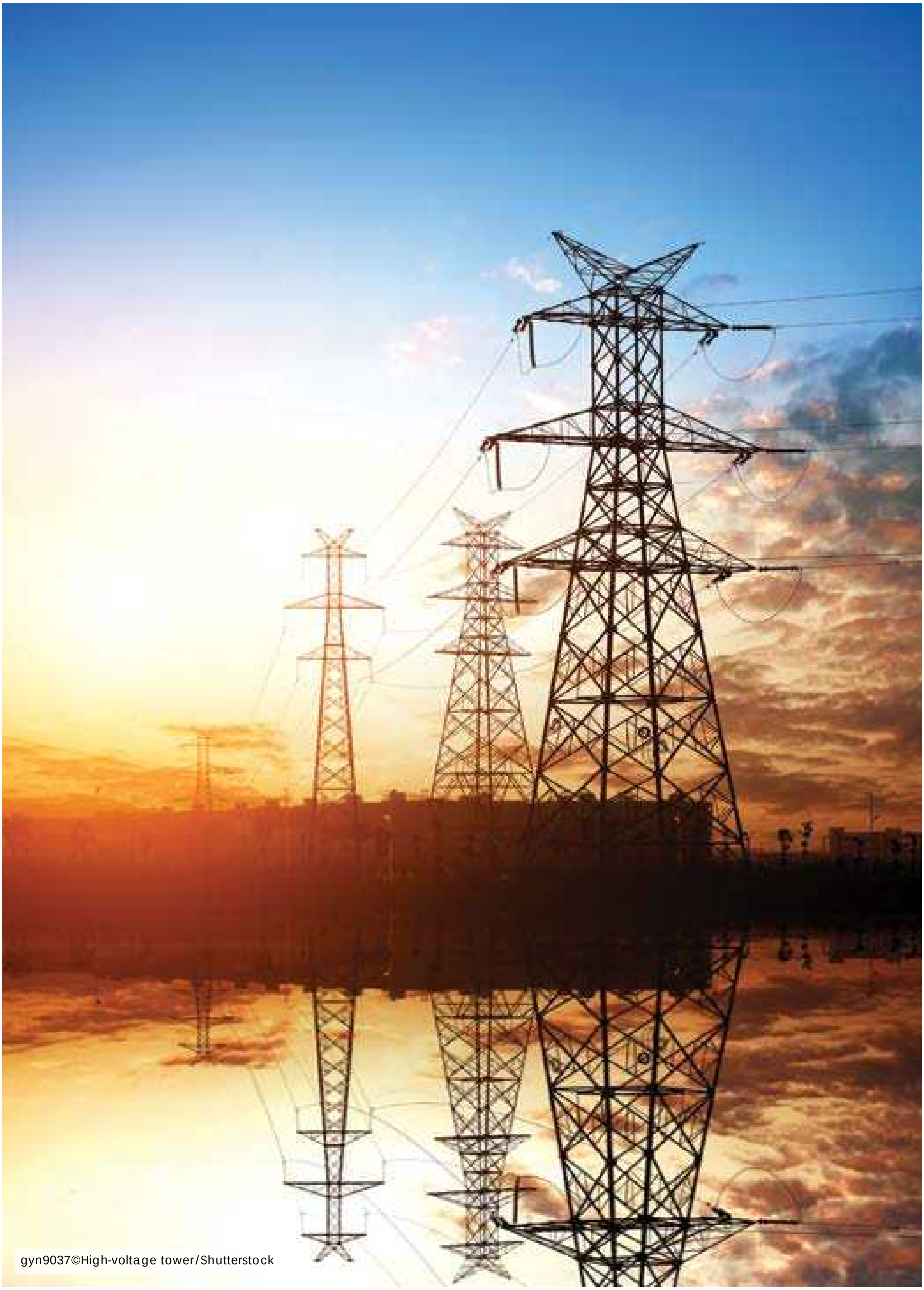


Figure 23. Total System Costs per Unit of Energy Consumption in the Four Scenarios



gyn9037©High-voltage tower/Shutterstock

5. Long-term Energy Planning and Integration of Renewable Energy in Power Systems

The SPLAT model used in this analysis was developed primarily to help IRENA Member countries to take ownership of the process of developing long-term renewable integration scenarios and strategies, by transferring these to interested countries' energy planning offices. In developing such long-term scenarios and strategies, a formal power-system modelling technique, as shown in this report, could play an important role.

Firstly, it provides a rational basis for decision making. A formal modelling technique assesses the overall investment needed to meet a given demand and also helps to prioritise alternative investment options based on economic criteria (*e.g.* cost minimisation), as well as on social (*e.g.* import dependency, supply reliability, rural electrification) and environmental (*e.g.* emissions of air pollutants, greenhouse gases) criteria. It facilitates various "what-if" analyses to compare the implications of different policy options.

Secondly, the processes for developing long-term scenarios using a formal modelling technique provide a platform for consensus-making among stakeholders who may have conflicting objectives. A formal modelling technique does not allow for conflicting systemic objectives since a feasible system may be mutually exclusive in terms of objectives.

For the first reason, analytical work using formal modelling tools is a basic "must" in designing a long-term vision of energy sector development. Electricity master plans are typically developed based on full-fledged analyses using such modelling tools. However, in many African countries, local capacity to use such tools, or even access to such tools, is often limited. For the second reason —that the process of planning is as important as the plan itself— having local capacity to use such tools is important. Local capacity allows for timely planning updates, which are often a problem when relying on analyses done by foreign consultancy firms. The landscape surrounding the power sector, and in particular renewable technologies, is rapidly changing, and modelling tools allow for addressing these changes.

Another advantage of owning the process of energy planning through formal modelling tools is that it allows for full appreciation of possible caveats relating to such tools. Any model output must be considered in the light of the input data, the model structure and modelling framework constraints.

It is against this backdrop that IRENA developed the SPLAT model. Special attention has been focused on the representation of renewable power supply options and their integration into the power system. The aim is to make the SPLAT model available to interested energy planners and academics in the region, so that they can use it to explore alternative scenarios for national and regional power sector development. The SPLAT model provides links to IRENA's latest resource and technology cost assessments. It is configured with information in the public domain but can be easily enhanced by country experts in the region with the latest information that may not be in the public domain.

The analysis presented in this report shows one applied example of the SPLAT model. The scenarios presented here could provide a starting point for further analysis. Energy planning is a continuous process that requires constant revision as new information becomes available. Further scenarios can be built for policy assessments.

In November 2012, IRENA, in cooperation with the South African National Energy Institute (SANEDI), organised a workshop to discuss the role of energy planning in developing the energy sector and promoting renewable energy, to present IRENA's SPLAT model and to identify areas of collaboration in the field of energy planning. Invited participants from SADC countries, representing energy planning offices in governments and utilities, as well as academic institutions and NGOs, acknowledged that having access to planning tools, such as SPLAT, was important, though access to and capacity to use such tools were limited in some countries. In particular, the fact that the SPLAT model has a refined representation of renewables and provides linkages with IRENA's latest work on resource assessments, technology briefs and cost assessments was welcomed. Several organisations asked IRENA to assist them in using SPLAT. IRENA, together with its partner organisations, is planning to set up a capacity-building support framework.

Yellowj©Desert windmills in dunes energy/Shutterstock

6. Conclusions

The SPLAT model was developed to provide decision makers and analysts in the region with an up-to-date planning tool to assess the future role and investment opportunities for renewable power generation. Four scenarios were developed using the SPLAT model as a basis for further analysis and possible elaboration.

The main findings from analysing these scenarios were as follows:

» Renewable technologies can play increasingly important roles in providing reliable, affordable, low-cost power.

» Renewable technologies bring a reduction in fossil fuel consumption; and decentralised renewable options in particular reduce investment needs in domestic transmission and distribution networks.

» Within the modelling horizon, investment costs for introducing more renewable technologies into the future power system are higher than for fossil and nuclear; however the cost savings effects (*i.e.* fuel saving and reduction in T&D investment) far exceed the additional investment costs.

» Deployment and export of hydro power from the Inga hydropower project in DRC to the region could have a significant impact on average electricity generation costs.

» Compared to the benefit of international power trade, the financial requirements for interconnector investment are minimal.

The SPLAT model allows us to quantify and substantiate the above points.

In the Renewable Promotion scenario electricity production from renewables (except large hydro) accounts for 24% of the total generation mix by 2030. The share of large hydro increases from around 11% in 2010 to 22% by 2030, out of which 42% is from Grand Inga in the DRC. When the Grand Inga project is not included as an option, the non-large hydro renewable share is higher to compensate for it. In the Renewable Promotion scenario, total capacity additions between 2010 and 2030 amount to 110 GW, of which 78% are renewable-based, while 22% involve decentralised renewable energy technologies. These decentralised renewable energy technologies become important in supplying electricity to rural areas. A large share of rural electricity can be met through such options. Investment required in the region over the period 2010 to 2030 under this scenario amounts to USD 314 billion.

Fuel price escalation increases average electricity generation costs from about USD 70/MWh in 2010 to USD 125/MWh in 2030 under the High-Cost scenario. Under the Renewable Promotion scenario, the average generation cost is 9% lower than in the High -Cost scenario. Of that 9%, the export of hydro power from DRC alone account for 5 percentage points. Compared to the High-Cost scenario, the Renewable Promotion scenario increases the investment and O&M costs for power generation, but the resulting fuel-savings effect, as well as reduction in domestic T&D costs, brings about an overall reduction in average generation costs.

Analysis of scenarios also shows that despite the large economic benefit (reduction of undiscounted system costs by USD 30 billion between 2010 and 2030) that the deployment and export of hydro power from the DRC would bring, the financial requirements for interconnector investment are minimal (USD 1 billion).

These scenarios are intended to illustrate how SPLAT can be used, and to provide a starting point for planning analysts to discuss various assumptions and results. Further validation of the model by local experts would enhance its robustness. Moreover, the assessment is based on certain assumptions, including fuel costs, infrastructure development and policy developments. These may well be different from the perspective of energy planners in the region. It is recommended that local experts explore different assumptions and develop and compare their own scenarios to analyse the benefits and challenges associated with the accelerated deployment of renewables in the region.

PhotoSky©River coming from dam wall, Kwazulu-Natal, South Africa/Shutterstock

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Appendix A: Detailed Demand Data

orxy ©Patterns in the Namib desert/Shutterstock

Table 17. Secondary Electricity Demand (upstream of transmission) Projections in GWh

	Angola	Botswana	Democratic Republic of Congo	Lesotho	Malawi	Mozam-bique	Namibia	South Africa	Swazi-land	Tanzania	Zambia	Zimba-bwe	Total
2010	6,343	4,202	9,390	576	1,600	3,758	2,992	258,870	1,262	4,820	13,509	13,221	320,543
2011	6,929	4,545	9,781	600	1,971	3,996	3,042	265,868	1,319	5,021	14,208	13,592	330,872
2012	7,516	4,659	10,188	625	2,065	4,269	3,117	273,591	1,386	5,230	14,497	13,990	341,133
2013	8,122	4,935	10,612	651	2,158	4,464	3,175	283,104	1,443	5,448	14,725	14,400	353,237
2014	8,772	5,173	11,054	678	2,253	4,678	3,256	289,731	1,494	5,675	14,955	14,828	362,547
2015	9,437	5,298	11,514	706	2,347	4,898	3,353	299,618	1,534	5,911	15,188	15,317	375,121
2016	10,032	5,411	11,947	736	2,443	5,084	3,461	309,438	1,573	6,158	15,427	15,829	387,539
2017	10,658	5,919	12,444	767	2,539	5,302	3,569	319,949	1,624	6,415	15,669	16,358	401,213
2018	11,316	6,247	12,962	798	2,636	5,515	3,688	331,581	1,658	6,683	15,870	16,905	415,859
2019	12,008	6,744	13,502	832	2,734	5,736	3,812	343,929	1,698	6,962	16,070	17,470	431,497
2020	12,674	6,848	13,848	866	2,833	5,966	3,940	354,899	1,720	7,252	16,168	18,055	445,069
2021	13,364	6,949	14,369	902	2,934	6,205	4,069	365,033	1,743	7,555	16,474	18,660	458,257
2022	14,077	7,049	14,967	940	3,020	6,454	4,203	374,242	1,760	7,871	16,677	19,285	470,545
2023	14,812	7,147	15,590	979	3,108	6,713	4,341	383,125	1,783	8,200	16,777	19,932	482,507
2024	15,568	7,243	16,239	1,020	3,199	6,982	4,485	392,092	1,805	8,543	17,086	20,601	494,863
2025	16,345	7,336	16,915	1,063	3,293	7,262	4,629	403,573	1,828	8,900	17,291	21,295	509,730
2030	20,294	7,730	21,225	1,309	3,667	8,840	5,420	453,069	1,952	10,923	18,003	25,153	577,584
2040	28,029	8,178	35,373	2,000	4,153	13,099	7,335	561,059	2,294	16,452	18,978	35,252	732,203
2050	34,647	8,246	62,921	3,085	4,231	19,410	9,806	688,187	2,745	24,781	19,209	49,625	926,892

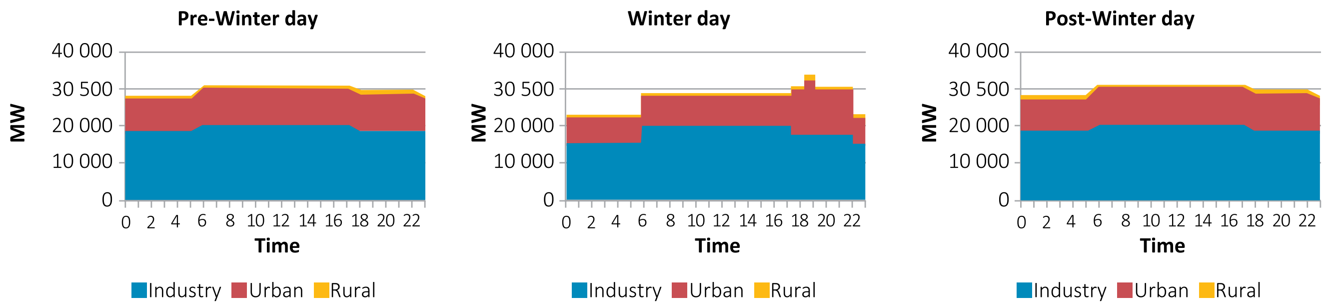

Figure 24. Load Shape Data - South Africa in 2010

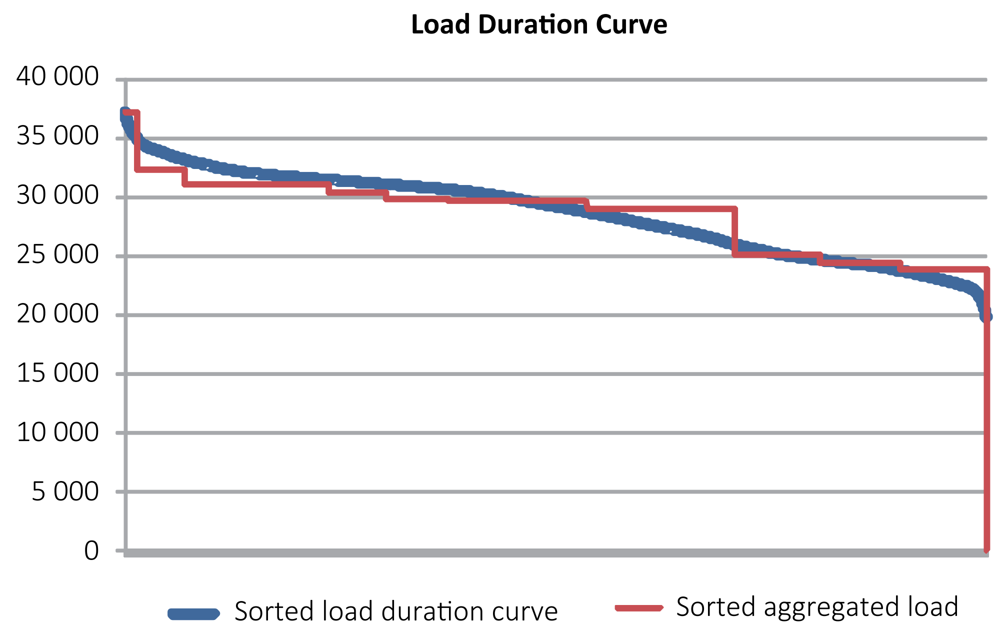

Figure 25. Load Duration Curve - South Africa in 2010

Appendix B: Detailed Power Plant Assumptions for the Existing System

Table 18 shows the parameters for all the existing power plants in South Africa. Not every single plant is modelled separately, but some plants are lumped together in the model. The abbreviations under "MESSAGE name" represent the groupings modelled, which cover the plants listed in the table.

Table 18. South Africa: Existing System

Name of Station	MESSAGE Name	Heat Rate	Efficiency	Output 2006	# of Units
		Btu/kWh		GWh	
Existing coal Large	EPCOAEXPFLU		35.4%	199,706	54
Existing coal Small	EPCOAEXPFSU		28.5%	20,118	53
(De-) Mothballed Coal					
Camden		12,214	27.9%	1,769	8
Grootvlei		12,638	27.0%	-	6
Komati		13,382	25.5%	-	5
Eskom Coal					
Arnot		0,555	32.3%	12,683	6
Duvha		9,831	34.7%	25,246	6
Hendrina		10,792	31.6%	11,718	10
Kendal		9,755	35.0%	27,934	6
Kriel		9,510	35.9%	19,209	6
Lethabo		9,671	35.3%	24,868	6
Majuba Dry		9,763	35.0%	8,570	3
Majuba Wet		9,074	37.6%	9,222	3
Matimba		9,648	35.4%	28,212	6
Matla		9,692	35.2%	25,388	6
Tutuka		9,100	37.5%	18,374	6
Non-Eskom Coal					
Kelvin "A"		14,239	24.0%	231	3
Kelvin "B"		13,688	24.9%	942	3
Pretoria West		14,545	23.5%	130	4
Rooiwal		13,688	24.9%	816	4
Sasol SSF		13,419	25.4%	4,513	10
OCGT liquid fuels	EPODSEXOC				
Acacia		12,186	28.0%	36	3
Atlantis		10,432	32.7%	-	9
Mossel Bay		10,177	33.5%	-	5
Port Rex		12,186	28.0%	22	3
Hydro	EPHYDEX			2,734	7
Mini Hydros				-	1
Gariep				1,325	4
Vanderkloof				1,409	2
Pumped storage	EPPSGEXST		73.0%	3,096	9
Drakensberg				2,033	4
Palmiet				900	2
Steenbras				163	3
PWR nuclear	EPNUCEXPW	10,663	32.0%	13,668	2
Interruptible	EIEX				

Max unit Capacity	Plant Category	Total Capacity	Planned Outage Rate	Forced Outage Rate	Availability	Variable Costs	Fixed Costs	Fuel Costs	Year Online	Retire. yr	Life
MW		MW				ZAR/MWh	ZAR/kW	ZAR/GJ			
564	10	30,471	7.54%	5.84%	87.06%	7.21	175	5.06			55
115	9	5,054	8.07%	12.23%	80.69%	8.84	245	5.51			55
190	small	1,520	7.96%	16.99%	76.40%	7.00	127	7.56	1986	2022	50
190	small	380	7.96%	16.99%	76.40%	4.39	204	6.70	1988		50
101	small	202	7.96%	16.99%	76.40%	2.65	187	5.62	1989	2025	50
380	large	2,280	8.95%	7.15%	84.54%	10.00	314	5.47	1975	2024	50
575	large	3,450	8.98%	4.74%	86.71%	3.00	169	3.73	1980		50
190	small	1,900	7.37%	9.15%	84.15%	8.00	351	3.58	1970	2020	50
640	large	3,840	5.89%	3.20%	91.10%	4.00	122	5.02	1988		50
475	large	2,850	6.98%	9.38%	84.29%	8.00	298	3.49	1976	2026	50
593	large	3,558	8.05%	6.81%	85.69%	8.00	129	5.14	1985		50
617	large	1,851	5.78%	5.78%	88.77%	7.00	134	6.84	1996		50
664	large	1,992	6.78%	5.83%	87.79%	13.00	90	6.84	1996		50
615	large	3,690	7.80%	5.49%	87.14%	6.00	200	3.90	1987		50
575	large	3,450	5.46%	6.73%	88.18%	10.00	188	2.98	1979		50
585	large	3,510	10.09%	4.65%	85.73%	7.00	127	8.66	1985		50
25	small	75	10.09%	9.38%	81.48%	18.00	371	5.46	1982	2016	50
51	small	153	10.09%	9.38%	81.48%	18.00	302	5.95	1982	2025	50
25	small	100	10.09%	9.38%	81.48%	18.00	697	5.12	1982	2018	50
51	small	204	10.09%	9.38%	81.48%	17.00	241	5.12	1982		50
52	small	520	8.98%	7.15%	84.51%	14.00	138	5.72	1982	2025	50
120		2400		5.14%	6.00%	244.56	66	72.20			50
57		171	3.48%	4.55%	6.00%	101.00	67	72.20	1976		50
147		1,323	7.36%	5.25%	6.00%	268.00	65	72.20	2007		50
147		735	7.36%	5.25%	6.00%	268.00	67	72.20	2007		50
57		171	3.26%	4.35%	6.00%	106.00	71	72.20	1976		50
95		665			15.08%		115				100
65		65	3.91%	8.50%	13.78%		114		1976		100
90		360	4.85%	4.99%	12.70%		115		1971	2025	100
120		240	3.91%	8.50%	19%		115		1977		100
176		1,580	5.13%	6.80%	19.40%	3.37	59.42				55
250		1,000	5.51%	7.80%	18.80%	3.00	60		1981		55
200		400	4.00%	3.86%	24.50%	4.00	64		1988		55
60		180	5.51%	7.80%	11.40%	4.00	46		1971	2023	55
900		1,800	11.23%	8.71%	81.0%	10.00	416	3.01	1984		50
		2,535			1%	246.60					20

Table 19 and Table 20 show existing thermal power plants and hydro power plants in the SAPP countries except South Africa. The tables are organised in a same format as Table 18. The data for South Africa comes from The Integrated Resource Plan for Electricity 2010-2030, South Africa Department of Energy (SA-DoE, 2011). Data for other countries come from the following reports:

» SADC (2012a), SADC Renewable Energy Strategy and Action Plan, SADC.

» SADC (2012b), SADC Memorandum of Understanding on SAPP Priority Projects, SADC.

» SA-DoE (2011).

» Southern African Power Pool (SAPP) (2007), SAPP Regional Generation and Transmission Expansion Plan Study. Draft Report Volume 2. Main Report, SAPP.

» SAPP (2010), SAPP Annual Report 2010, SAPP.

Sean Nel©Straw bales on a harvested wheat field at Riversdale in South Africa/Shutterstock

Table 19. Other SAPP Countries: Existing Thermal

Name of Station	Heat Rate (Max Cap)	E□-ciency	# of Units	Unit Capacity	Plant Capacity	Capacity Factor	Fuel	Variable O&M	Fixed O&M	Fixed Fuel Costs	Install Year	Life
	kJ/kWh			MW	MW			USD/MWh	USD/kW	USD/kW		
Angola					**263**							
SCGT	18,000	20.0%	5	50	250	86.13%	Nat gas	4.18	19	40	2000	25
Diesel	12,142	29.6%	1	13	13	80.10%	Distillate	3	0.8	0	2006	7
Botswana					**132**							
Morupule	12,000	30.0%	4	30	132	88.00%	Coal	1.26	56.67	0		
Malawi					**36**							
Existing Distillate	12,142	29.6%			36	80.10%	Distillate	3	0.8	0		
Lilongwe	12,142	29.6%			20	80.10%	Distillate	3	0.8	0		
Mzuzu	12,142	29.6%			6	80.10%	Distillate	3	0.8	0		
Blantyre	12,142	29.6%			10	80.10%	Distillate	3	0.8			
Mozambique					**64**							
Existing Distillate	12,142	29.6%	3	21	64	80.10%	Distillate	3	0.8	0		
Maputo	12,142	29.6%	2	26	52	80.10%	Distillate	3	0.8	0		
Beira	12,142	29.6%	1	12	12	80.10%	Distillate	3	0.8	0		
Namibia					**144**							
Van Eck	12,000	30.0%	4	27	120	88.00%	Coal	1.26	56.67	65.91		14
Paratus	12,000	30.0%	4	6	24	95.90%	Distillate	5.35	4.86	0		
Tanzania					**563**							
Existing NatGas	12,000	30.0%	14	35	485	95.90%	Nat gas	5.35	4.86	0		25
SONGAS	12,000	30.0%	4	50	200	95.90%	Nat gas	5.35	4.86	0		
IPTL	12,000	30.0%	2	50	100	95.90%	Nat gas	5.35	4.86	0		
Ubungo Rented Aggreco	12,000	30.0%	2	20	40	95.90%	Nat gas	5.35	4.86	0		
Ubungo Rented Richmo	12,000	30.0%	1	20	20	95.90%	Nat gas	5.35	4.86	0		
Ubungo Rented Richmo	12,000	30.0%	4	20	80	95.90%	Nat gas	5.35	4.86	0		
Tegeta - Wartsila	12,000	30.0%	1	45	45	95.90%	Nat gas	5.35	4.86	0		
Existing Distillate	12,128	29.8%	21	4	78	80.10%	Distillate	3	0.8	0		25
Mwansa - ALSTOM	12,000	30.0%	2	20	40	80.10%	Distillate	3	0.8	0		
Diesel Remote	12,142	29.6%	19	2	38	80.10%	Distillate	3	0.8	0		
Zambia					**10**							
Diesel	12,142	29.6%	1	10	10	80.10%	Distillate	3	0.8	0		
Zimbabwe					**360**							
Existing Coal	12,000	30.0%	17	60	360	88.00%	Coal	1.26	56.67	0	2000	30
Hwange 1-6	12,000	30.0%	6	130	342	88.00%	Coal	1.26	56.67	0		
Munyati	12,000	30.0%	4	20	10	88.00%	Coal	1.26	56.67	0		
Bulawayo	12,000	30.0%	3	30	4	88.00%	Coal	1.26	56.67	0		
Harare	12,000	30.0%	4	19	4	88.00%	Coal	1.26	56.67	0		

Table 20. Other SAPP Countries: Existing Hydro

Name of Station	# of Units	Unit Capacity	Plant Capacity	Average Generation	Dry Year Generation	Average CF	Dry Year CF	Variable O&M	Fixed O&M	Install Year	Life
		MW	MW	GWh	GWh			USD/MWh	USD/kW		
Angola			**474**	**2,595**	**1,713**						
High Availability	8	56	448	2,500	1,650	63.70%	42.04%	1.51	8.72		100
Cambambe	4	43	172	900	594	59.70%	39.42%	1.51	8.72		
Capanda	2	130	260	1,500	990	65.90%	43.47%	1.51	8.72		
Matala	2	8	16	100	66	71.30%	47.09%	1.51	8.72		
Low Availability	6	4.3	26	95	63	41.71%	27.66%	1.51	8.72		
Mabubas	2	9	18	60	40	38.10%	25.37%	1.51	8.72		
Biopio	4	2	8	35	23	49.90%	32.82%	1.51	8.72		
Democratic Republic of Congo			**2,333**	**14,259**	**11,183**						
Inga	25	71	1,784	12,000	9,411	76.79%	60.22%	1.51	8.72	2000	100
Inga 1	6	60	360	2,400	1,882	76.10%	59.68%	1.51	8.72		
Inga 2	8	178	1,424	9,600	7,529	77.00%	60.36%	1.51	8.72		
High Availability	11	36.2	398	1,970	1,545	56.50%	44.31%	1.51	8.72	2000	100
Nseke	4	62	248	1,200	941	55.20%	43.31%	1.51	8.72		
Nzilo	4	27	108	570	447	60.20%	47.25%	1.51	8.72		
Koni	3	14	42	200	157	54.40%	42.67%	1.51	8.72		
Low Availability	13	11.5	151	289	227	21.85%	17.16%	1.51	8.72	2000	100
Mwadingusha	6	11	68	200	157	33.60%	26.36%	1.51	8.72		
Zongo	5	15	75	80	63	12.10%	9.59%	1.51	8.72		
Sanga	2	4	8	9	7	12.80%	9.99%	1.51	8.72		
Lesotho			**73**	**414**	**274**						
Existing hydro	4	18	73	414	274	64.74%	42.85%	1.51	8.72		
Muela	3	24	72	410	271	65.00%	42.97%	1.51	8.72		
Small Hydro	1	1	1	4	3	45.70%	34.25%	1.51	8.72		
Malawi			**277.6**	**1,391**	**919**						
Nkula	30	4	121.6	402	265	37.74%	24.88%	1.51	8.72		
Nkula A	3	7.2	21.6	112	74	59.00%	39.11%	1.51	8.72		
Nkula B	5	18	100	290	191	36.80%	21.80%	1.51	8.72		
Tedzani	18	4.6	88	511	338	66.29%	43.85%	1.51	8.72		
Tedzani I&II	4	9	36	255	169	81.00%	47.70%	1.51	8.72		
Tedzani III	2	23.2	52	256	169	63.00%	37.10%	1.51	8.72		
Other Hydros	10	6.8	68	478	316	80.24%	53.05%	1.51	8.72		
Kapichira I	2	32	64	469	310	83.70%	55.29%	1.51	8.72		
Wowve	3	1.4	4	9	6	24.50%	17.12%	1.51	8.72		

Name of Station	# of Units	Unit Capacity	Plant Capac-ity	Average Genera-tion	Dry Year Genera-tion	Average CF	Dry Year CF	Variable O&M	Fixed O&M	Install Year	Life
		MW	MW	GWh	GWh			USD/MWh	USD/kW		
Mozambique			**2,122**	**15,604**	**12,107**						
Cahora Bassa	5	415	2,075	15,300	12,000	84.20%	66.02%	1.51	8.72		
Other Hydros	4.5	10.4	47	304	107	73.84%	25.99%	1.51	8.72	2000	100
Chicamba	1	17	17	46	10	15.40%	6.72%	1.51	8.72		
Corumana	2	6	12	21	11	20.40%	10.46%	1.51	8.72		
Mavuzi	1.5	12	18	237	86	75.20%	54.54%	1.51	8.72		
Namibia			**240**	**1,395**	**921**						
Ruacana	3	80	240	1,395	921	66.40%	43.81%	1.51	8.72		
Swaziland			**62**	**202**	**134**						
Hydros	26	2.4	62	202	134	37.19%	24.67%	1.51	8.72		100
Ezulwini, Edwaleni, Magud	3	14	42	125	83	34.00%	22.56%	1.51	8.72		
Maguga	2	10	20	77	51	43.70%	29.11%	1.51	8.72		
Tanzania			**561**	**1,525**	**1,161**						
Large Hydros	21	18.3	384	1,525	1,161	45.34%	34.51%	0	5.77		
Kidatu	4	51	204	1,013	669	56.70%	37.44%	0	6		
Kihansi	3	60	180	512	492	32.50%	31.20%	0	5.5		
Other Hydros	10	17.8	177	812	483	52.37%	31.15%	0	11.24		
Mtera	4	20	80	374	195	53.40%	27.83%	0	7		
Pangani Falls	2	34	68	308	203	51.70%	34.08%	0	8		
Hale	2	11	21	93	61	50.60%	33.16%	0	30		
Nyumba ya Mungu	2	4	8	37	24	52.80%	34.25%	0	32		
Zambia			**1,752**	**10,043**	**7,778**						
Large Hydros	38	42.6	1,620	9,256	7,259	65.22%	51.15%	1.51	8.72	2000	100
Kariba North	4	180	720	4,000	3,137	63.40%	49.74%	1.51	8.72		
Kafue Gorge Upper	6	150	900	5,256	4,122	66.70%	52.28%	1.51	8.72		
Other Hydros	17	7.9	132	787	519	68.06%	44.88%	1.51	8.72		
Victoria	10	11	108	662	437	70.00%	46.19%	1.51	8.72		
Small Hydro	1	24	24	125	82	60.00%	39.00%	1.51	8.72		
Zimbabwe			**750**	**4,000**	**3,137**						
Kariba South	6	125	750	4,000	3,137	60.90%	47.75%	1.51	8.72		

Appendix C: Detailed Power Plant Assumptions for Planned Projects

Table 21. SAPP Planned Generation Projects

Project Name	Type	Commit-ted?	Capacity MW	Efficiency	Invest-ment Costs USD/kW	Variable O&M Cost USD/MWh	Fixed O&M Cost USD/kW/yr	Capacity Factor[4]	First Year	Life
Angola										
Benguela Thermal	Distillate	Yes	83	33%	774	4.18	19.00	86.1%	2010	25
TG-40	Distillate		80	33%	707	4.18	19.00	86.1%	2010	25
TG-60	Distillate		60	33%	607	4.18	19.00	86.1%	2010	25
TG-20	Distillate	Yes	20	33%	906	4.18	19.00	86.1%	2010	25
TG-12.5	Distillate	Yes	38	33%	994	4.18	19.00	86.1%	2010	25
Diesels	Distillate	Yes	7	33%	1,325	4.18	19.00	86.1%	2010	25
Capanda II hydro	Hydro	Yes	260		1,418	1.51	8.72	26.1%	2010	50
Gove, Lomaun, Mabubas hydro	Hydro	Yes	135		1,036	1.51	8.72	33.1%	2012	50
Cambambe II hydro	Hydro	Yes	860		3,182	1.51	8.72	26.1%	2012	50
Kuanza Basin[5]	Hydro		5,480		1,879	1.51	8.72	26.1%	2014	50
Botswana										
Morupule B coal	Coal	Yes	1,200	33%	1,266	4.18	38.00	88.0%	2012	35
Mmamabula coal	Coal		2,430	37%	2,812	0.96	20.00	88.0%	2015	35
Democratic Republic of Congo										
Busanga hydro	Hydro		240		2,000	1.51	8.72	47.0%	2015	50
Grand Inga[6]	Hydro		20,000		2,000	1.51	8.72	58.8%	2018	50
Lesotho										
Muela 2 hydro	Hydro	yes	110		2,077	1.51	8.72	6.1%	2016	50
Oxbow hydro	Hydro		80		2,077	1.51	8.72	38.7%	2017	50
Letseng Wind Farm	Wind		65		2,000	14.3		30%	2013-2014	25
Malawi										
New biomass	Biomass	Yes	18		2,500	5.4		50%	2010	30
Kapichira II hydro	Hydro		64		837	1.51	8.72	25.1%	2013	50
Fufu hydro	Hydro		100		1,511	1.51	8.72	42.9%	2015	50
Kholombizo hydro	Hydro		100		1,746	1.51	8.72	47.1%	2018	50
Mpatamanga hydro	Hydro		200		1,636	1.51	8.72	36.2%	2020	50
Songwe hydro	Hydro		150		1,340	1.51	8.72	29.9%	2014	50
Mozambique										
Temane (Aggreko) gas	Nat gas	Yes	410	53%	581	4.18	19.00	86.1%	2011	25
Moatize coal	Coal	Yes	750	37%	2,278	0.96	19.97	88.0%	2015	35
Benga Coal	Coal		450	37%	2,250	0.96	19.97	88.0%	2015	35
Lurio Hydro	Hydro		183		1,991	1.51	8.72	21.4%	2020	50
Massingir hydro	Hydro	Yes	40		1,474	1.51	8.72	21.4%	2010	50
Quedas & Ocua hydro	Hydro		179		2,030	1.51	8.72	22.4%	2011	50
Mphanda Nkuwa hydro	Hydro		1,500		1,648	1.51	8.72	63.7%	2017	50
HCB North Bank hydro	Hydro		1,245		972	1.51	8.72	0.0%	2015	50
Namibia										
Kudu gas	Nat gas		774	53%	974	1.64	-	94.1%	2015	25
Walvis coal	Coal		300	37%	2,215	0.96	19.97	88.0%	2016	35
Baynes hydro	Hydro		360		1,905	1.51	8.72	36.1%	2020	50
NamPower Wind Farm	WInd		60		2,000	14.3		30%	2014	25

[4] For the hydro power plants, this refers to dry year capacity factor.
[5] SADC Power sector Review and Consultation Mission to Angola (SADC, 2009) pg 8 has 6580 for Kwanza basin including Cambambe and Capanda (520 and 580)
[6] There is a 900 MW upper limit on annual new capacity for Grand Inga to model the phasing in of the project. In the 'no Grand Inga' scenario, the upper limit on overall installed capacity is reduced to 2500 MW.

Project Name	Type	Commit-ted?	Capacity MW	Efficiency	Invest-ment Costs USD/kW	Variable O&M Cost USD/MWh	Fixed O&M Cost USD/kW/yr	Capacity Factor	First Year	Life
South Africa										
Medupi coal	Coal	Yes	4,332	37%	2,812	1.0	20.0	88.0%	2013	35
Kusile coal	Coal	Yes	4,338	37%	2,869	1.0	20.0	88.0%	2014	35
Ingula Pump Storage		Yes	1,332	73%	1,659	1.51	8.70	19.0%	2014	50
New Gas Plants (Sasol)			260	50%	1,551	2.9		85.0%	2010	50
REIPPP Wind	Wind	Yes	1,849		2,000	14.3		30%	2013-2015	25
REIPPP Solar PV	Solar	Yes	1,449		2,000	20.1		25%	2013-2016	25
REIPPP Solar Thermal	Solar thermal	Yes	200		7,000	16.4		63%	2014-2016	25
CHP Biomass	Biomass		130	35%	2,500	5.4		50%	2011	30
Swaziland										
New biomass	Biomass	Yes	85		2,500	5.4		50%	2012	30
Lubombo coal	Coal		1,000	37%	2,812	0.96	20.00	88.0%	2015	35
Tanzania										
New biomass	Biomass	Yes	85		2,500	5.4		50%	2012	30
Kinyerezi gas	Nat gas	Yes	400	42%	1,119	1.45	24.01	85.4%	2014	25
Mchuchuma coal	Coal		400	33%	2,812	4.18	38.32	88.0%	2015	35
Kiwira coal	Coal	Yes	200	30%	3,376	7.40	56.67	88.0%	2014	35
Ruhudji	Hydro		358		1,829	1.51	8.72	37.9%	2017	50
Rusomo	Hydro		21		2,493	1.51	8.72	70.1%	2015	50
Kakono	Hydro		53		2,493	1.51	8.72	72.2%	2016	50
Rumakali	Hydro		222		2,493	1.51	8.72	46.7%	2019	50
Masigira	Hydro		118		2,493	1.51	8.72	47.6%	2020	50
Stieglers Gorge	Hydro		1,200		2,493	1.51	8.72	30.7%	2023	50
Zambia										
Indola Energy HFO plant		Yes	50	35%	2,679	15		80%	2012	30
Maamba Coal fired	Coal		300	37%	2,679	0.96	20	88.0%	2016	35
New Mini hydro (Indola+IPP)	Hydro	Yes	21		4,000	5.4		50%	2014	50
Itezhi-Tezhi hydro	Hydro	Yes	120		2,233	1.51	8.72	42.4%	2014	50
Kariba North Extension hydro	Hydro	Yes	360		1,340	1.51	8.72	29.4%	2013	50
Lunsenfwa	Hydro		255		2,679	1.51	8.72	39.6%	2018	50
Lusiwasi	Hydro	Yes	84		2,679	1.51	8.72	44.9%	2016	50
Devils Gorge	Hydro		500		2,679	1.51	8.72	44.9%	2019	50
Mumbotula Fall	Hydro		301		2,679	1.51	8.72	44.9%	2021	50
Mpata Gorge	Hydro		543		2,679	1.51	8.72	44.9%	2023	50
Mambililma Falls	Hydro		326		2,679	1.51	8.72	44.9%	2025	50
Batoka Gorge hydro	Hydro		800		2,679	1.51	8.72	44.9%	2022	50
Kafue Gorge Lower hydro	Hydro	Yes	750		2,143	1.51	8.72	35.5%	2016	50
Kalungwishi hydro	Hydro		220		3,215	1.51	8.72	30.1%	2018	50
Kabompo	Hydro	Yes	40		4,287	1.51	8.72	30.1%	2015	50
Zimbabwe	Hydro									
Hwange 7-8 coal	Coal		600	37%	1,800	0.96	19.97	88.0%	2016	35
Gokwe North coal	Coal		1,400	37%	2,578	0.96	19.97	88.0%	2017	35
Lupane gas	Methane		300	53%	1,550	1.45	24.01	85.4%	2017	25
Chisumbanje Biomass	Biomass	Yes	90		2,500	5.4		50%	2012-2013	30
Kariba South Extension hydro	Hydro	Yes	300		1,333	1.51	8.72	35.3%	2016	50
Batoka Gorge hydro	Hydro		800		3,375	1.51	8.72	68.2%	2022	50

Leksele©The Maletsunyane Falls in the central Lesotho highlands/Shutterstock

Appendix D: Generic Technology Parameters

Table 22. Technical Parameters for Generic Technologies

	Load Factor	O&M Costs	Efficiency	Construction Duration	Life
	%	USD/MWh	%	years	years
Diesel/Gasoline 1kW system (urban/rural)	30	33.2	16	0	10
Diesel 100kW system (industry)	80	55.4	35	0	20
Diesel Centralised	80	17	35	1	25
Heavy Fuel Oil	80	15.0	35	2	25
Open cycle Gas turbine (OCGT)	85	19.9	30	2	25
Combined Cycle Gas Turbine (CCGT)	85	2.9	48	3	30
Supercritical coal with CCS[7]	85	36.0	28	5	35
Supercritical coal	85	14.3	37	4	35
Nuclear (Pressurised Water Reactor)[8]	85	13.9	33	8	60
Hydro	50	6.0	100	5	50
Small Hydro	50	5.4	100	2	50
Biomass	50	20.0	38	4	30
Geothermal	85	5.0	100	4	25
Bulk Wind (20% CF)	20	17.4	100	2	25
Bulk Wind (30% CF)	30	14.3	100	2	25
Solar PV (utility)	25	20.1	100	1	25
Solar PV (roof top)	20	15.0	100	<1	20
PV with 1 kWh Battery	22.5	17.1	100	<1	20
PV with 2 kWh Battery	255	19.0	100	<1	20
Solar thermal no storage	35	22.3	100	4	25
Solar thermal with Storage	63	16.4	100	4	25
Solar thermal with gas co-firing	85	16.4	53	4	25

[7] Only modelled in South Africa

[8] Assuming 1.125 kW installed PV unit for 1 kWh storage system and 1.25 kW installed PV unit for 2 kWh storage

Appendix E: Detailed Transmission Data

Table 23. Detailed Data for Existing Transmission Infrastructure

Country 1	Country 2	Line Voltage	Line Capacity	Loss	Forced Outage Rate
		kV	MW	%	%
Botswana	South Africa	400, 132, 132, 132	800	1.7%	0.2%
Botswana	Zimbabwe	400	650	2.5%	1.2%
Lesotho	South Africa	132	230	0.6%	1.9%
Democratic Republic of Congo	Zambia	220	260	5.6%	0.9%
Mozambique	South Africa	533, 400, 110, 275	3,850	14.0%	0.8%
Mozambique	Swaziland	400	1,450	1.6%	0.4%
Mozambique	Zimbabwe	330	500	3.0%	0.9%
Namibia	South Africa	400, 220, 220	750	5.0%	0.8%
South Africa	Swaziland	400, 132	1,450	1.6%	1.0%
South Africa	Zimbabwe	400	600	0.0%	0.0%
Zambia	Zimbabwe	330, 330	1,400	0.0%	0.2%

Table 24. Projections of Domestic Transmission and Distributions Losses by Country

		2010	2020	2030			2010	2020	2030
Angola	Transmission	5%	5%	5%	**Namibia**	Transmission	3%	3%	3%
	Industry	2%	2%	1%		Industry	2%	2%	1%
	Urban	20%	15%	8%		Urban	20%	10%	8%
	Rural	30%	20%	20%		Rural	25%	20%	20%
Botswana	Transmission	4%	4%	4%	**South Africa**	Transmission	4%	4%	4%
	Industry	3%	2%	1%		Industry	1%	1%	1%
	Urban	15%	10%	8%		Urban	17%	10%	8%
	Rural	20%	20%	20%		Rural	25%	20%	20%
Democratic Republic of Congo	Transmission	5%	5%	5%	**Swaziland**	Transmission	5%	5%	5%
	Industry	3%	2%	1%		Industry	2%	2%	1%
	Urban	25%	10%	8%		Urban	15%	10%	8%
	Rural	20%	20%	20%		Rural	20%	20%	20%
Lesotho	Transmission	5%	5%	5%	**Tanzania**	Transmission	5%	5%	5%
	Industry	2%	2%	1%		Industry	2%	2%	1%
	Urban	12%	10%	8%		Urban	17%	10%	8%
	Rural	25%	20%	20%		Rural	25%	20%	20%
Malawi	Transmission	5%	5%	5%	**Zambia**	Transmission	4%	4%	4%
	Industry	2%	2%	1%		Industry	4%	3%	2%
	Urban	20%	10%	8%		Urban	25%	15%	8%
	Rural	30%	20%	20%		Rural	30%	20%	20%
Mozambique	Transmission	5%	5%	5%	**Zimbabwe**	Transmission	4%	4%	4%
	Industry	5%	4%	3%		Industry	2%	2%	1%
	Urban	30%	15%	8%		Urban	17%	12%	8%
	Rural	30%	20%	20%		Rural	20%	20%	20%

Table 25. Detailed Data for Future Transmission Projects

From	To	Stations	Voltage	Capacity per line	Dis-tance	Losses	Forced Outage Rate	Total Invest-ment	Invest-ment cost	Earliest year
			kV	[MW]	km	%		USD million	USD/kW	
Zizabona project										
Botswana	Zimbabwe	??- Hwange	330	600		2%	0.0%	45.0	75.0	2015
Namibia	Botswana	Sesheke - ??	330	600		2%	0.0%	45.0	75.0	2015
Namibia	Zimbabwe	Sesheke - Hwange	330	600		2%	0.0%	45.0	75.0	2015
Namibia	Zambia	Sesheke - Victoria	220	600		2%	0.0%	45.0	75.0	2015
Zambia	Zimbabwe	Victoria - Karib N-S	330	600		1%	0.0%	45.0	75.0	2015
Westcor project										
DRC	Namibia	Inga - Auas	600-800 kVDC	2000	2100	9.0%	3.8%	405.8	202.9	2020
Namibia	South Africa	Auas - Omega	600-800 kVDC	1500	1400	8.0%	2.6%	340.7	227.1	2020
DRC	Angola	Inga - Cuanza	600-800 kVDC	1500	700	8.0%	1.3%	205.4	137.0	2020
Angola	Botswana	Cuanza - Gaborone	600-800 kVDC	1500	2100	24.0%	3.8%	335.6	223.8	2020
Botswana	South Africa	Gaborone - Pegasus	600-800 kVDC	1000	700	12.0%	1.3%	205.4	205.4	2020
765 kV project										
DRC	Zambia	Inga - Kolwezi - Luano	600 kVDC, 765 kVAC	1500	450	6%	0.8%	905	603.3	2020
Zambia	Zimbabwe	Luano - Kariba S - Insukamini	765	1500	450	6%	0.8%	660	440.0	2020
Zimbabwe	Namibia	Insukamini - Witkop	765	1500	450	6%	0.8%	330	220.0	2020
Zimbabwe	South Africa	???	765	1500	450	6%	0.8%	330	220.0	2020

From	To	Stations	Voltage	Capacity per line	Dis-tance	Losses	Forced Outage Rate	Total Invest-ment	Invest-ment cost	Earliest year
			kV	[MW]	km	%		USD million	USD/kW	
Other Transmission Projects										
Angola	DRC	Lunda - Inga	400	600	250	2%	0.5%	93.8	156.3	2016
Botswana	South Africa	Phokoje - Mmaba	400	500	200	2%	0.4%	48.8	97.6	2012
DRC	Zambia	KSMBL - MICHL	220	500	250	0	0.5%	35.1	70.2	2017
Lesotho	South Africa	Merap - MaBOre	132	130			0.0%	6.5	50.0	2015
Malawi	Mozambique	Phomb - Songo	400	600	250	2%	0.5%	58.9	98.2	2017
Malawi	Mozambique	Phomb - Matam	220	300	220	3%	0.4%	35.1	117.0	2015
Malawi	Zambia	???	220	200		4%	0.0%	83.2	416.0	2018
Mozambique	South Africa	Maputo - Hendr	400	600	330	2%	0.6%	73.6	122.7	2018
Mozambique	Zimbabwe	Songo - Bindura	400	500	250	3%	0.5%	49.0	98.0	2017
Namibia	South Africa	Kudu - Juno	400	300	410	7%	0.8%	96.0	320.0	2018
South Africa	Swaziland	Normandie - NH2	132	450	50	1%	0.1%	7.0	15.6	2018
Namibia	Angola	Namibia Angola	400	400	500	1%	0.9%	96.0	240.0	2016
Tanzania	Zambia	Mbeya - Kasma	330	400	410	6%	0.8%	81.6	204.0	2016
South Africa	Zimbabwe			650	450	0.06	0.0082	330	220	2017

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Appendix F: Levelised Cost of Electricity Comparisons

Table 26. Levelised Cost of Electricity Comparisons in 2010

	Grid connection	Generation without T&D	Industry	Urban	Rural
			LCOE USD/MWh		
Diesel Centralised	Y	291	328	438	516
Dist. Diesel 100kW	N	320	320		
Dist. Diesel/Gasoline 1kW	N	604		604	604
HFO	Y	188	217	301	369
OCGT (Imported Gas/LNG)	Y	141	167	238	301
CCGT (Imported Gas/LNG)	Y	90	112	170	229
Supercritical coal with CCS	Y	133	158	228	290
Supercritical coal	Y	80	101	157	215
Nuclear	Y	111	134	198	258
Hydro	Y	62	82	133	189
Small Hydro	N	107			107
Biomass	Y	104	127	189	249
Bulk Wind (30% CF – w. trans. costs)	Y	118	142	208	269
Bulk Wind (30% CF – no trans. costs)	Y	102	125	186	246
Solar PV (utility)	Y	121	145	211	272
Solar PV (roof top)	N	143		143	143
PV with 1kWh Battery	N	250		250	250
PV with 2kWh Battery	N	323		323	323
Solar CSP no storage	Y	147	173	247	311
Solar CSP with Storage	Y	179	207	288	355
Solar CSP with gas co-firing	Y	103	126	186	248

Table 27. Levelised Cost of Electricity Comparisons in 2020

	Grid Con-nection	Ref. Gen-eration without T&D	RE Gen-eration without T&D	RE Ind.	RE Urban	RE Rural	RE CO_2 25USD/ tonne Urban	Ref. Gener-ation with-out T&D	RE Genera-tion without T&D	RE Ind.	RE Urban	RE Rural	RE CO_2 25USD/ tonne Urban
		LCOE USD/MWh						Ranking (Cheapest to Most Expensive)					
Diesel Centralised	Y	325	325	364	432	533	451	19	19	16	18	19	18
Dist. Diesel 100kW	N	355	355	355				20	20	15			
Dist. Diesel/Gasoline 1kW	N	693	693		693	693	735	21	21		19	20	19
HFO	Y	208	208	238	295	377	315	16	17	14	17	18	17
OCGT (Imported Gas/ LNG)	Y	154	154	180	231	305	247	14	15	13	15	17	16
CCGT (Imported Gas/ LNG)	Y	98	98	120	165	230	175	3	7	6	7	9	7
Supercritical coal with CCS	Y	143	143	169	219	291	223	12	14	12	14	16	14
Supercritical coal	Y	88	88	110	154	217	177	2	3	3	4	6	8
Nuclear	Y	111	111	134	180	248	180	8	11	9	10	13	9
Hydro	Y	62	62	82	123	183	123	1	1	1	2	4	2
Small Hydro	N	107	97			97		6	6			1	
Biomass	Y	104	92	114	158	222	158	5	4	4	5	7	4
Bulk Wind (30% CF – w. trans. costs)	Y	118	101	124	169	235	169	9	8	7	8	11	6
Bulk Wind (30% CF – no trans. costs)	Y	102	88	109	153	217	153	4	2	2	3	5	3
Solar PV (utility)	Y	121	94	116	161	226	161	10	5	5	6	8	5
Solar PV (roof top)	N	143	109		109	109	109	11	10		1	2	1
PV with 1kWh Battery	N	250	181		181	181	181	17	16		11	3	10
PV with 2kWh Battery	N	323	231		231	231	231	18	18		16	10	15
Solar CSP no storage	Y	147	119	143	190	259	190	13	12	10	12	14	12
Solar CSP with Storage	Y	179	139	165	214	285	214	15	13	11	13	15	13
Solar CSP with gas co-firing	Y	111	109	132	178	245	188	8	10	9	10	13	12

Table 28. Levelised Cost of Electricity Comparisons in 2030

	Grid Con-nection	Ref. Gen-eration without T&D	RE Gen-eration with-out T&D	RE Ind.	RE Urban	RE Rural	RE CO_2 25USD/ tonne Urban	Ref. Gener-ation with-out T&D	RE Gen-eration with-out T&D	RE Ind.	RE Urban	RE Rural	RE CO_2 25 USD/ tonne Urban
		LCOE USD/MWh						Ranking (Cheapest to Most Expensive)					
Diesel Centralised	Y	339	339	376	440	552	459	19	19	16	18	19	18
Dist. Diesel 100kW	N	371	371	371				20	20	15			
Dist. Diesel/Gasoline 1kW	N	740	740		740	740	782	21	21		19	20	19
HFO	Y	216	216	245	299	389	319	16	18	14	17	18	17
OCGT (Imported Gas/ LNG)	Y	161	161	187	235	315	252	14	16	13	16	17	16
CCGT (Imported Gas/ LNG)	Y	102	102	124	167	236	178	3	10	8	10	12	10
Supercritical coal with CCS	Y	149	149	173	221	298	226	13	14	12	15	16	15
Supercritical coal	Y	92	92	113	156	223	179	2	6	5	7	9	11
Nuclear	Y	111	111	133	177	248	177	7	11	9	11	13	9
Hydro	Y	62	62	81	122	183	122	1	1	1	2	4	2
Small Hydro	N	107	89			89		6	5			1	
Biomass	Y	104	86	107	149	215	149	5	4	4	5	8	5
Bulk Wind (30% CF – w. trans. costs)	Y	118	93	114	157	224	157	9	7	6	8	10	7
Bulk Wind (30% CF – no trans. costs)	Y	102	81	101	143	208	143	4	2	2	3	6	3
Solar PV (utility)	Y	121	84	104	146	212	146	10	3	3	4	7	4
Solar PV (roof top)	N	143	96		96	96	96	11	8		1	2	1
PV with 1kWh Battery	N	250	151		151	151	151	17	15		6	3	6
PV with 2kWh Battery	N	323	192		192	192	192	18	17		14	5	14
Solar CSP no storage	Y	147	102	123	167	236	167	12	9	7	9	11	8
Solar CSP with Storage	Y	179	117	139	184	256	184	15	13	11	13	15	12
Solar CSP with gas co-firing	Y	115	112	134	179	250	188	8	12	10	12	14	13

Appendix G: Detailed Build Plan in the Renewable Promotion Scenario

NEW TRANSMISSION CAPACITY SUMMARY

Zizabona Project

- 2015 Botswana to Zimbabwe 600MW, Namibia to Botswana 600MW, Namibia to Zimbabwe 600MW, Namibia to Zambia 600MW, Zambia to Zimbabwe 600MW

Wescor Project

- 2022 DRC to Angola 61MW
- 2023 DRC to Namibia 102MW, DRC to Angola 200MW
- 2024 DRC to Namibia 203MW, DRC to Angola 85MW
- 2025 DRC to Namibia 227MW, DRC to Angola 73MW
- 2026 DRC to Namibia 318MW
- 2027 DRC to Namibia 228MW, DRC to Angola 77MW
- 2028 DRC to Namibia 273MW, DRC to Angola 21MW
- 2029 DRC to Angola 278MW
- 2030 DRC to Namibia 65MW, DRC to Angola 202MW

765 Project

- 2030 Zimbabwe to South Africa 293MW

Other Projects

- 2015 Malawi to Mozambique 11MW
- 2016 Angola to DRC 34MW, Malawi to Mozambique 9MW, Namibia to Angola 400MW, Tanzania to Zambia 400MW
- 2017 Angola to DRC 1MW, DRC to Zambia 286MW, Malawi to Mozambique 10MW, Mozambique to Zimbabwe 204MW
- 2018 Angola to DRC 64MW, Mozambique to South Africa 218MW, South Africa to Swaziland 450MW
- 2019 Malawi to Mozambique 11MW, Mozambique to South Africa 366MW
- 2020 Angola to DRC 124MW, DRC to Zambia 214MW, Malawi to Mozambique 39MW, Mozambique to South Africa 16MW
- 2021 Angola to DRC 109MW, Malawi to Mozambique 26MW
- 2022 Angola to DRC 268MW
- 2023 Botswana to South Africa 500MW
- 2030 Malawi to Mozambique 114MW

NEW GENERATION CAPACITY SUMMARY

Angola

Centralised

- 2010 Refurbishments of Thermal Plants 17MW, Benguela Thermal 83MW, TG-40 80MW, TG-60 60MW, TG-20 20MW, TG-12.5 38MW, Diesels 7MW, Capanda II hydro 260MW
- 2011 Refurbishments of Thermal Plants 18MW
- 2012 Refurbishments of Thermal Plants 17MW, Gove hydro 135MW, Cambambe II hydro 80MW
- 2013 Refurbishments of Thermal Plants 20MW, Solar PV (utility) 156MW
- 2014 Cambambe II hydro 80MW, CCGT 690MW
- 2016 Cambambe II hydro 700MW
- 2026 Biomass 182MW
- 2028 Biomass 118MW
- 2029 Biomass 136MW
- 2030 Kuanza Basin 140MW, Biomass 64MW

De-Centralised

- 2010 Diesel 100kW system (industry) 51MW, Diesel/Gasoline 1kW system (Rural) 3MW
- 2011 Diesel 100kW system (industry) 44MW, Diesel/Gasoline 1kW system (Rural) 5MW
- 2012 Diesel/Gasoline 1kW system (Rural) 6MW
- 2013 Diesel/Gasoline 1kW system (Rural) 1MW
- 2014 Small Hydro 28MW
- 2015 Small Hydro 15MW
- 2016 Small Hydro 6MW
- 2018 Small Hydro 27MW
- 2019 Small Hydro 14MW
- 2020 Small Hydro 18MW
- 2021 Small Hydro 7MW
- 2022 Small Hydro 15MW
- 2023 Small Hydro 7MW
- 2025 Small Hydro 5MW
- 2026 Small Hydro 6MW

- 2027 Small Hydro 6MW
- 2028 Small Hydro 6MW
- 2029 Small Hydro 7MW
- 2030 Small Hydro 18MW

Botswana

Centralised

- 2012 Morupule B coal 600MW
- 2014 OCGT 37MW
- 2015 Morupule B coal 300MW
- 2016 Morupule B coal 300MW
- 2022 Bulk Wind (30% CF) 127MW
- 2023 Bulk Wind (30% CF) 1MW
- 2024 Bulk Wind (30% CF) 2MW
- 2025 Bulk Wind (30% CF) 2MW
- 2026 Bulk Wind (30% CF) 2MW
- 2027 Bulk Wind (30% CF) 2MW
- 2028 Bulk Wind (30% CF) 2MW
- 2029 Bulk Wind (30% CF) 2MW
- 2030 Bulk Wind (30% CF) 1MW

De-Centralised

- 2010 Diesel 100kW system (industry) 27MW
- 2011 Diesel 100kW system (industry) 23MW, Diesel/Gasoline 1kW system (Rural) 1MW, Diesel/Gasoline 1kW system (Urban) 24MW
- 2012 Diesel/Gasoline 1kW system (Rural) 1MW
- 2013 Diesel 100kW system (industry) 19MW, Diesel/Gasoline 1kW system (Rural) 7MW
- 2020 PV with 1h Battery (roof top - rural) 14MW
- 2021 PV with 1h Battery (roof top - rural) 8MW
- 2022 PV with 1h Battery (roof top - rural) 7MW
- 2023 PV with 1h Battery (roof top - rural) 24MW
- 2024 PV with 1h Battery (roof top - rural) 4MW
- 2026 PV with 1h Battery (roof top - rural) 1MW
- 2027 PV with 1h Battery (roof top - rural) 1MW
- 2028 PV with 1h Battery (roof top - rural) 1MW
- 2029 PV with 1h Battery (roof top - rural) 1MW

DRC

Centralised

- 2010 Refurbishments of Inga 1&2 76MW, Refurbishments of hydro (Nseke, Nzilo, Koni) 28MW, Refurbishments of hydro (Mwadingusha, Zongo, Sanga) 10MW
- 2011 Refurbishments of Inga 1&2 76MW, Refurbishments of hydro (Nseke, Nzilo, Koni) 28MW, Refurbishments of hydro (Mwadingusha, Zongo, Sanga) 10MW
- 2012 Refurbishments of Inga 1&2 76MW, Refurbishments of hydro (Nseke, Nzilo, Koni) 27MW, Refurbishments of hydro (Mwadingusha, Zongo, Sanga) 11MW
- 2013 Refurbishments of Inga 1&2 76MW, Refurbishments of hydro (Nseke, Nzilo, Koni) 29MW, Refurbishments of hydro (Mwadingusha, Zongo, Sanga) 11MW
- 2014 Refurbishments of Inga 1&2 76MW, Refurbishments of hydro (Nseke, Nzilo, Koni) 27MW, Refurbishments of hydro (Mwadingusha, Zongo, Sanga) 10MW
- 2015 Refurbishments of Inga 1&2 74MW, Refurbishments of hydro (Nseke, Nzilo, Koni) 32MW, Refurbishments of hydro (Mwadingusha, Zongo, Sanga) 12MW, Busanga hydro 28MW
- 2016 Busanga hydro 157MW
- 2017 Busanga hydro 32MW
- 2018 Grand Inga 900MW
- 2019 Busanga hydro 22MW, Grand Inga 900MW
- 2020 Grand Inga 900MW
- 2021 Grand Inga 900MW
- 2022 Grand Inga 900MW
- 2023 Grand Inga 900MW
- 2024 Grand Inga 900MW
- 2025 Grand Inga 900MW
- 2026 Grand Inga 900MW
- 2027 Grand Inga 900MW
- 2028 Grand Inga 900MW
- 2029 Grand Inga 900MW
- 2030 Grand Inga 900MW

De-Centralised

- 2011 Diesel/Gasoline 1kW system (Rural) 7MW
- 2012 Diesel/Gasoline 1kW system (Rural) 5MW
- 2013 Diesel/Gasoline 1kW system (Rural) 2MW
- 2014 Small Hydro 19MW
- 2015 Small Hydro 22MW
- 2016 Small Hydro 35MW
- 2017 Small Hydro 25MW

» 2019 Small Hydro 42MW

» 2020 Small Hydro 29MW

» 2021 Small Hydro 15MW

» 2022 Small Hydro 16MW

» 2023 Small Hydro 17MW

» 2024 Small Hydro 18MW

» 2025 Small Hydro 17MW

» 2026 Small Hydro 15MW

» 2027 Small Hydro 16MW

» 2028 Small Hydro 17MW

» 2029 Small Hydro 18MW

» 2030 Small Hydro 19MW

Lesotho

Centralised

» 2014 Bulk Wind (30% CF) 40MW, 41MW

» 2016 Muela 2 hydro 110MW

» 2021 Oxbow hydro 80MW

De-Centralised

» 2010 Diesel 100kW system (industry) 7MW, Diesel/Gasoline 1kW system (Rural) 1MW, Diesel/Gasoline 1kW system (Urban) 2MW

» 2011 Diesel/Gasoline 1kW system (Urban) 3MW

» 2012 Diesel/Gasoline 1kW system (Urban) 4MW

» 2013 Diesel 100kW system (industry) 3MW, Diesel/Gasoline 1kW system (Urban) 1MW

» 2014 Small Hydro 2MW

» 2015 Diesel 100kW system (industry) 2MW, Small Hydro 4MW

» 2019 Small Hydro 1MW

» 2020 Small Hydro 1MW

» 2022 Small Hydro 1MW

» 2026 Small Hydro 1MW

» 2030 Small Hydro 1MW

Malawi

Centralised

- 2010 Biomass 90MW
- 2011 Biomass 99MW
- 2012 Biomass 11MW
- 2013 Kapichira II hydro 64MW
- 2014 Songwe hydro 103MW
- 2018 Fufu hydro 100MW
- 2019 Kholombizo hydro 100MW
- 2020 Mpatamanga hydro 97MW, Songwe hydro 47MW
- 2021 Mpatamanga hydro 103MW
- 2026 Bulk Wind (30% CF) 59MW
- 2027 Bulk Wind (30% CF) 2MW
- 2028 Bulk Wind (30% CF) 2MW
- 2029 Bulk Wind (30% CF) 1MW

De-Centralised

- 2010 Diesel 100kW system (industry) 5MW
- 2011 Diesel/Gasoline 1kW system (Rural) 1MW
- 2012 Diesel/Gasoline 1kW system (Rural) 1MW
- 2014 Small Hydro 7MW
- 2016 Small Hydro 3MW
- 2017 Small Hydro 1MW
- 2018 Small Hydro 3MW
- 2019 Small Hydro 6MW
- 2020 Small Hydro 4MW
- 2021 Small Hydro 2MW
- 2022 Small Hydro 1MW
- 2023 Small Hydro 1MW
- 2024 Small Hydro 1MW
- 2025 Small Hydro 1MW
- 2026 Small Hydro 1MW
- 2027 Small Hydro 1MW
- 2028 Small Hydro 1MW
- 2029 Small Hydro 1MW

Mozambique

Centralised

- 2010 Refurbishments of Chicamba, Corumana and Mavuzi Hydro 18MW, Massingir hydro 40MW
- 2011 Refurbishments of Chicamba, Corumana and Mavuzi Hydro 17MW
- 2012 Temane (Aggreko) gas 110MW
- 2014 Temane (Aggreko) gas 300MW
- 2015 Moatize coal 375MW
- 2016 Moatize coal 375MW
- 2017 Mphanda Nkuwa hydro 750MW
- 2018 Mphanda Nkuwa hydro 750MW
- 2022 Biomass 73MW
- 2023 Biomass 21MW
- 2026 Bulk Wind (30% CF) 131MW
- 2027 Bulk Wind (30% CF) 5MW
- 2028 Bulk Wind (30% CF) 5MW
- 2029 Bulk Wind (30% CF) 6MW
- 2030 Bulk Wind (30% CF) 6MW

De-Centralised

- 2011 Diesel/Gasoline 1kW system (Rural) 3MW
- 2012 Diesel/Gasoline 1kW system (Rural) 1MW
- 2014 Small Hydro 6MW
- 2015 Small Hydro 7MW
- 2016 Small Hydro 7MW
- 2017 Small Hydro 4MW
- 2018 Small Hydro 6MW
- 2019 Small Hydro 13MW
- 2020 Small Hydro 9MW
- 2021 Small Hydro 2MW
- 2022 Small Hydro 2MW
- 2023 Small Hydro 5MW
- 2024 Small Hydro 2MW
- 2026 Small Hydro 3MW
- 2027 Small Hydro 3MW
- 2028 Small Hydro 3MW

» 2029 Small Hydro 3MW

» 2030 Small Hydro 3MW

Namibia

Centralised

» 2012 Expansion of Ruacana Hydro 90MW

» 2014 OCGT 120MW

» 2015 Kudu gas 18MW

» 2016 Walvis coal 21MW

» 2017 Walvis coal 21MW

» 2018 Walvis coal 30MW

» 2019 Walvis coal 29MW

» 2020 Walvis coal 163MW, Baynes hydro 91MW

» 2021 Baynes hydro 269MW

» 2023 Bulk Wind (30% CF) 93MW

» 2024 Bulk Wind (30% CF) 3MW

» 2026 Bulk Wind (30% CF) 7MW

» 2027 Bulk Wind (30% CF) 3MW

» 2028 Bulk Wind (30% CF) 3MW

» 2029 Bulk Wind (30% CF) 4MW

» 2030 Bulk Wind (30% CF) 3MW

De-Centralised

» 2010 Diesel 100kW system (industry) 16MW, Diesel/Gasoline 1kW system (Rural) 1MW, Diesel/Gasoline 1kW system (Urban) 3MW

» 2011 Diesel/Gasoline 1kW system (Rural) 2MW, Diesel/Gasoline 1kW system (Urban) 6MW

» 2012 Diesel/Gasoline 1kW system (Rural) 1MW, Diesel/Gasoline 1kW system (Urban) 12MW

» 2013 Diesel/Gasoline 1kW system (Rural) 2MW, Diesel/Gasoline 1kW system (Urban) 8MW

» 2014 Small Hydro 5MW

» 2015 Small Hydro 4MW

» 2016 Small Hydro 8MW

» 2017 Diesel/Gasoline 1kW system (Rural) 1MW, Small Hydro 7MW

» 2019 Small Hydro 3MW

» 2020 Small Hydro 4MW

» 2021 Small Hydro 7MW

» 2022 Small Hydro 5MW

» 2023 Small Hydro 2MW

» 2024 Small Hydro 2MW

» 2029 Small Hydro 1MW

» 2030 Small Hydro 4MW

South Africa

Centralised

» 2010 Refurbishments of Camden, Grootvlei and Komati 380MW, CCGT 260MW

» 2011 Refurbishments of Camden, Grootvlei and Komati 679MW, Biomass 130MW

» 2012 Refurbishments of Camden, Grootvlei and Komati 303MW

» 2013 Refurbishments of Camden, Grootvlei and Komati 101MW, Medupi coal 722MW, Bulk Wind (30% CF) 634MW, Solar PV (utility) 300MW

» 2014 Medupi coal 722MW, Ingula Pump Storage 1332MW, Bulk Wind (30% CF) 562MW, Solar PV (utility) 331MW, Solar thermal with Storage 50MW

» 2015 Medupi coal 1444MW, Bulk Wind (30% CF) 653MW, Solar PV (utility) 417MW, Solar thermal with Storage 100MW

» 2016 Medupi coal 722MW, Solar PV (utility) 401MW, Solar thermal with Storage 50MW

» 2017 Medupi coal 722MW, Kusile coal 1446MW

» 2018 Kusile coal 723MW

» 2019 Kusile coal 1446MW, Biomass 50MW

» 2020 Kusile coal 723MW

» 2021 Bulk Wind (30% CF) 1500MW

» 2022 Bulk Wind (30% CF) 1500MW

» 2023 OCGT 1000MW, Bulk Wind (20% CF) 984MW, Bulk Wind (30% CF) 1500MW, Solar PV (utility) 4025MW

» 2024 OCGT 1000MW, Bulk Wind (20% CF) 1500MW, Bulk Wind (30% CF) 735MW, Solar PV (utility) 4037MW

» 2025 OCGT 1000MW, PWR nuclear 502MW, Bulk Wind (20% CF) 1500MW, Bulk Wind (30% CF) 85MW, Solar PV (utility) 4356MW

» 2026 OCGT 1000MW, Bulk Wind (20% CF) 1500MW, Bulk Wind (30% CF) 98MW

» 2027 OCGT 371MW, Bulk Wind (20% CF) 1500MW, Bulk Wind (30% CF) 65MW

» 2028 OCGT 64MW, Bulk Wind (20% CF) 474MW, Bulk Wind (30% CF) 18MW

» 2029 OCGT 1000MW, Bulk Wind (20% CF) 1042MW

» 2030 OCGT 1000MW, Bulk Wind (20% CF) 1500MW

De-Centralised

» 2011 Diesel/Gasoline 1kW system (Rural) 30MW

- 2012 Diesel/Gasoline 1kW system (Rural) 69MW
- 2017 Small Hydro 32MW
- 2018 Small Hydro 168MW
- 2021 PV with 1h Battery (roof top - rural) 681MW
- 2022 PV with 1h Battery (roof top - rural) 499MW
- 2023 PV with 1h Battery (roof top - rural) 99MW
- 2024 PV with 1h Battery (roof top - rural) 103MW
- 2025 PV with 1h Battery (roof top - rural) 973MW, PV with 2h Battery (roof top - rural) 45MW, PV with 1hr Battery (roof top - urban) 1872MW
- 2026 PV with 1hr Battery (roof top - urban) 2748MW
- 2027 PV with 1hr Battery (roof top - urban) 3112MW
- 2028 PV with 2h Battery (roof top - rural) 451MW, PV with 1hr Battery (roof top - urban) 3531MW
- 2029 PV with 2h Battery (roof top - rural) 600MW, PV with 1hr Battery (roof top - urban) 3591MW
- 2030 PV with 2h Battery (roof top - rural) 371MW, PV with 1hr Battery (roof top - urban) 3032MW

Swaziland

Centralised

- 2010 Biomass 61MW
- 2011 Biomass 30MW
- 2012 Biomass 73MW
- 2013 Biomass 10MW
- 2014 OCGT 8MW
- 2015 OCGT 6MW
- 2016 OCGT 5MW
- 2017 Biomass 7MW
- 2018 Biomass 4MW
- 2019 Biomass 5MW
- 2020 Biomass 2MW
- 2021 Biomass 3MW
- 2022 Lubombo coal 18MW, Biomass 4MW, Bulk Wind (30% CF) 31MW
- 2030 OCGT 12MW

- De-Centralised
- 2010 Diesel 100kW system (industry) 15MW
- 2011 Diesel 100kW system (industry) 3MW
- 2012 Diesel 100kW system (industry) 11MW

- 2013 Diesel/Gasoline 1kW system (Rural) 1MW
- 2014 Small Hydro 1MW
- 2015 Small Hydro 2MW
- 2016 Small Hydro 1MW
- 2017 Small Hydro 1MW
- 2018 Small Hydro 1MW
- 2019 Small Hydro 1MW
- 2020 Small Hydro 1MW
- 2021 Small Hydro 1MW
- 2022 Small Hydro 3MW
- 2023 Small Hydro 1MW
- 2024 Small Hydro 2MW
- 2025 Small Hydro 1MW
- 2026 Small Hydro 2MW
- 2027 Small Hydro 2MW
- 2028 Small Hydro 2MW
- 2029 Small Hydro 2MW, PV with 1hr Battery (roof top - urban) 13MW
- 2030 Small Hydro 2MW, PV with 1hr Battery (roof top - urban) 14MW

Tanzania

Centralised

- 2010 Biomass 211MW
- 2012 Reburbishments/upgrade of Ubongo 100MW, Reburbishments/upgrade of Mwanza HFO 60MW
- 2014 Kinyerezi gas 400MW, Kiwira coal 200MW
- 2015 Rusomo 21MW
- 2016 Kakono 53MW
- 2017 Ruhudji 175MW
- 2018 Ruhudji 183MW
- 2019 Rumakali 179MW
- 2020 Rumakali 43MW, Masigira 118MW
- 2021 Biomass 284MW
- 2022 Biomass 177MW
- 2023 Biomass 327MW
- 2024 Bulk Wind (30% CF) 202MW
- 2025 Geothermal 150MW, Bulk Wind (30% CF) 73MW

- 2026 Bulk Wind (30% CF) 22MW, Solar PV (utility) 1710MW
- 2027 Bulk Wind (30% CF) 23MW, Solar PV (utility) 888MW
- 2028 Stieglers Gorge 150MW, OCGT 78MW, Bulk Wind (30% CF) 25MW
- 2029 Stieglers Gorge 76MW, Bulk Wind (30% CF) 7MW
- 2030 Stieglers Gorge 69MW, Bulk Wind (30% CF) 8MW

De-Centralised

- 2011 Diesel/Gasoline 1kW system (Rural) 2MW
- 2012 Diesel/Gasoline 1kW system (Rural) 3MW
- 2013 Diesel/Gasoline 1kW system (Rural) 1MW
- 2014 Small Hydro 20MW
- 2015 Small Hydro 4MW
- 2016 Small Hydro 7MW
- 2017 Small Hydro 10MW
- 2018 Small Hydro 6MW
- 2019 Small Hydro 4MW
- 2020 Small Hydro 4MW
- 2021 Small Hydro 8MW
- 2022 Small Hydro 9MW
- 2023 Small Hydro 11MW
- 2024 Small Hydro 18MW
- 2025 Small Hydro 7MW
- 2026 Small Hydro 15MW
- 2027 Small Hydro 25MW
- 2028 Small Hydro 39MW
- 2029 Diesel/Gasoline 1kW system (Rural) 6MW, Small Hydro 12MW, PV with 1hr Battery (roof top - urban) 492MW
- 2030 Diesel/Gasoline 1kW system (Rural) 26MW, PV with 1hr Battery (roof top - urban) 523MW

Zambia

Centralised

- 2011 Refurbishments of Kariba North and Kafue Gorge Upper 420MW
- 2013 Kariba North Extension hydro 180MW
- 2014 Itezhi-Tezhi hydro 120MW, Kariba North Extension hydro 180MW, OCGT 105MW
- 2015 Kabompo 40MW
- 2016 Kafue Gorge Lower hydro 250MW

» 2017 Kafue Gorge Lower hydro 250MW

» 2018 Kafue Gorge Lower hydro 250MW

» 2020 Hydro 600MW

» 2021 Devils Gorge 250MW

» 2022 Devils Gorge 250MW, Mumbotula Fall 301MW, Batoka Gorge hydro 400MW

» 2023 Mpata Gorge 272MW, Batoka Gorge hydro 400MW, Bulk Wind (30% CF) 440MW

» 2024 Mpata Gorge 272MW, Bulk Wind (30% CF) 22MW

» 2026 Mambililma Falls 31MW, Bulk Wind (30% CF) 48MW

» 2027 Bulk Wind (30% CF) 26MW

» 2028 Bulk Wind (30% CF) 27MW

» 2029 Bulk Wind (30% CF) 28MW

De-Centralised

» 2010 Diesel 100kW system (industry) 151MW, Diesel/Gasoline 1kW system (Rural) 2MW

» 2011 Diesel 100kW system (industry) 19MW, Diesel/Gasoline 1kW system (Rural) 4MW, Diesel/Gasoline 1kW system (Urban) 52MW

» 2012 Small Hydro 37MW, Diesel/Gasoline 1kW system (Urban) 62MW

» 2014 Small Hydro 15MW

» 2015 Small Hydro 27MW

» 2018 Small Hydro 46MW

» 2019 Small Hydro 29MW

» 2020 Small Hydro 37MW

» 2021 Small Hydro 10MW

» 2022 Small Hydro 22MW

» 2023 Small Hydro 12MW

» 2024 Small Hydro 8MW

» 2026 Small Hydro 12MW

» 2027 Small Hydro 13MW

» 2028 Small Hydro 13MW

» 2029 Small Hydro 14MW

» 2030 Small Hydro 5MW

Zimbabwe

Centralised

» 2013 Refurbishments of Hwange Coal 100MW

- 2014 Refurbishments of Hwange Coal 150MW, OCGT 452MW
- 2015 Refurbishments of Hwange Coal 150MW
- 2016 Kariba South Extension hydro 300MW
- 2018 Hwange 7-8 coal 229MW
- 2019 Hwange 7-8 coal 300MW
- 2020 Hwange 7-8 coal 71MW
- 2023 Bulk Wind (30% CF) 294MW
- 2024 Bulk Wind (30% CF) 12MW
- 2026 Biomass 48MW, Bulk Wind (30% CF) 25MW
- 2027 Batoka Gorge hydro 100MW, Biomass 18MW, Bulk Wind (30% CF) 13MW
- 2028 Batoka Gorge hydro 100MW, Biomass 23MW, Bulk Wind (30% CF) 14MW
- 2029 Batoka Gorge hydro 100MW, Biomass 27MW, Bulk Wind (30% CF) 14MW
- 2030 Batoka Gorge hydro 100MW, Biomass 36MW, Bulk Wind (30% CF) 4MW

De-Centralised

- 2010 Diesel 100kW system (industry) 99MW, Diesel/Gasoline 1kW system (Rural) 2MW
- 2011 Diesel 100kW system (industry) 20MW, Diesel/Gasoline 1kW system (Rural) 7MW, Diesel/Gasoline 1kW system (Urban) 27MW
- 2012 Diesel 100kW system (industry) 50MW, Diesel/Gasoline 1kW system (Rural) 10MW
- 2014 Small Hydro 34MW
- 2016 Small Hydro 16MW
- 2017 Small Hydro 9MW
- 2018 Small Hydro 20MW
- 2019 Small Hydro 31MW
- 2020 Small Hydro 18MW
- 2021 Small Hydro 6MW
- 2022 Small Hydro 16MW
- 2023 Small Hydro 6MW
- 2024 Small Hydro 5MW
- 2026 Small Hydro 15MW
- 2027 Small Hydro 15MW
- 2028 Small Hydro 16MW
- 2029 Small Hydro 16MW
- 2030 Small Hydro 17MW, PV with 1hr Battery (roof top - urban) 252MW

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