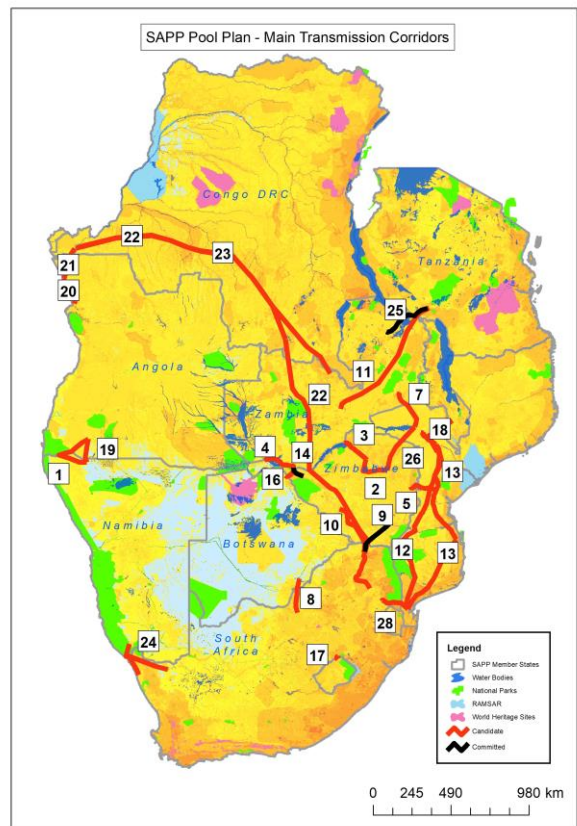
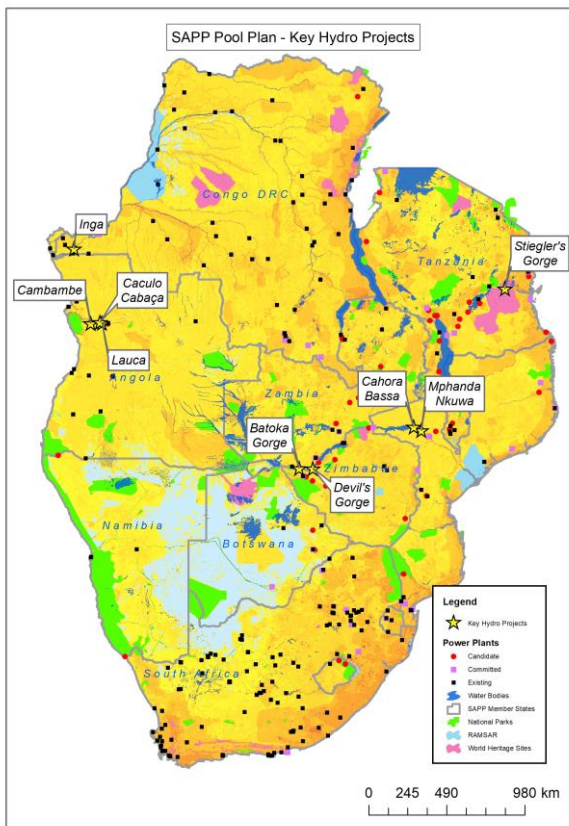


SAPP POOL PLAN 2017



Main Volume

December 2017



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Abbreviations and acronyms

General

aag	Annual average growth
ACEC	Africa Clean Energy Corridor
ad	After diversity
BC	Basse Chute (Inga 3)
BCR	Benefit:cost ratio
BOSA	Botswana-South Africa interconnector
CC	Coordination Centre
CCGT	Combined cycle gas turbine
CRIDF	Climate Resilient Infrastructure Development Facility
CSP	Concentrating Solar Power
DAM	Day Ahead Market
DRC	Democratic Republic of the Congo
E&S	Environmental and Social
EAPP	East African Power Pool
ECA	Economic Consulting Associates
EE	Energy Exemplar
EEDSM	Energy efficiency demand side management
EIRR	Economic internal rate of return
ENS	Energy Not Served
ESC	Environment Sub-Committee of SAPP
FOR	Forced Outage Rate
GDP	Gross Domestic Product
GIS	Geographic Information System
HC	Haute Chute (Inga 3)
HDI	Human Development Index
HFO	Heavy fuel oil
HVAC	High Voltage Alternating Current
HVDC	High Voltage Direct Current
IGCC	Integrated Gasification Combined Cycle
IEA	International Energy Agency

IMF	International Monetary Fund
IPP	Independent Power Producer
IRENA	International Renewable Energy Agency
IRP	Integrated Resources Plan
JICA	Japan International Cooperation Agency
KZN	Kwazulu Natal
LDC	Load Duration Curve
LEAP	Long-range Energy Alternatives Planning
LNG	Liquified natural gas
LOLE	Loss of load expectation
LOLP	Loss of load probability
LT	Long-term
MINEA	Ministério da Energia e Agua (Angola)
MOTRACO	Mozambique Transmission Company
MOZISA	Mozambique-Zimbabwe-South Africa transmission line
MS	Microsoft
MT	Medium-term
NPV	Net present value
OCGT	Open cycle gas turbine
OPF	Optimum Power Flow
PAU	Project Acceleration Unit
PDAM	Post Day Ahead Market
PLEXOS	Generation and transmission optimal planning software
PPA	Power Purchase Agreement
PSC	Planning Sub-Committee of SAPP
PSMP	Power System Master Plan
PSS/E	Power System Simulator for Engineering (transmission planning software)
PV	Photovoltaic
REIPPPP	Renewable energy independent power producer procurement programme (South Africa)
RIAM	Rapid Impact Assessment Matrix
ROA	Real options analysis
SADC	Southern African Development Community
SAPP	Southern African Power Pool
SCADA	Supervisory control and data acquisition



SDP	System Development plan
SRD	Social rate of discount
ST	Short-term
STE	Mozambique transmission project
SVC	Static VAR Compensator
TOR	Terms of Reference
UNDP	United Nations Development Program
(US)\$	United States dollars
VO&M	Variable Operating and Maintenance
WACC	Weighted Average Cost of Capital
WEAP	Water Evaluation and Planning Model
ZIZABONA	Zimbabwe-Zambia-Botswana-Namibia transmission line
ZRB	Zambezi River Basin

Utility acronyms

BPC	Botswana Power Corporation
CEC	Copperbelt Energy Corporation
EdM	Electricidade de Moçambique
ENE	Empresa Nacional de Electricidade (Angola)
ESCOM	Electricity Supply Corporation of Malawi
ESKOM	Eskom Holdings (South Africa)
HCB	Hydroeléctrica de Cahora Bassa
LEC	Lesotho Electricity Company
NAMPOWER	Namibia Power Corporation
RNT	Empresa Rede Nacional de Transporte de Electricidade (Angola)
SEC	Swaziland Electricity Company
SNEL	Société Nationale d'Electricite
TANESCO	Tanzania Electricity Supply Company Ltd
ZESCO	ZESCO Limited (Zambia)
ZETDC	Zimbabwe Electricity Transmission & Distribution Company
ZESA	Zimbabwe Electricity Supply Authority

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The SAPP Pool Plan 2017 is presented in 3 volumes – Executive Summary, Main Volume and Annex Volume. There is a supporting spreadsheet, which gives the detailed results for Components A, B and C for each country, each year from 2017 to 2040, and for both energy (GWh) and capacity (MW).



1 Introduction to SAPP Pool Plan

1.1 Objectives

The Southern African Power Pool (SAPP) was established in 1995 to enable members to coordinate and cooperate in the planning, development and operation of their generation and transmission facilities for mutual benefit. In carrying out this mandate, SAPP contracted a team of consultants to work with the Planning Sub-committee (PSC) to prepare a master plan, known as the Pool Plan (PP), up to the year 2040. As specified in the terms of reference (TOR) for the Pool Plan study:

The Pool Plan shall identify a core set of generation and transmission investments of regional significance that can provide adequate electricity supply to the region under different scenarios in an efficient and economically, environmentally and socially sustainable manner and support enhanced integration and power trade in the SAPP region.

It is well known that regional power sector integration has the potential to deliver significant benefits to participating countries. In particular, increased electricity cooperation in investment and trade:

- ❑ lowers costs through facilitating economies-of-scale investments over the long term and provision of energy from the lowest cost generation capacity that is available in the short term;
- ❑ allows shared generation reserves, lowering overall investment requirements (the costs of regional transmission inter-connectors are typically a small fraction of saved generation capacity costs);
- ❑ ensures greater energy security because of the access to imports during emergency situations;
- ❑ enables greater penetration of renewables which can more easily be integrated into larger systems with more diversified dispatch options;
- ❑ widens economic and social benefits as access to reliable grid-based electricity at lower cost flows-on through the economy;
- ❑ strengthens legal and regulatory systems in the participating countries¹.

Many of these aspects are illustrated and quantified in this report. Although the SAPP Inter-Utility Memorandum of Understanding states that a Pool Plan is purely indicative and does not create an obligation on members to comply it is to be hoped that the member countries will be guided by the Plan in the development and review of their national plans so as to maximise the synergistic benefits over the up-coming decades.

¹ For more detail, see the ECA study on Regional Power Sector Integration published by ESMAP <https://www.esmap.org/node/353>, particularly the Literature Review.

1.2 Unique approach

The conventional approach in a regional power sector master plan is to treat the interconnected region as though it were a single country and use optimisation planning software to derive the least cost generation and transmission investment sequencing. However, an economically optimal regional plan is often not optimal from an individual country perspective due to other important non-cost factors. It is therefore necessary to do an ex-post analysis of the regional plan and adjust it to ensure that legitimate national concerns and obligations are considered.

This study was commissioned to be different in that the TOR require three components to be analysed, with the third component introducing political economy and practical constraints to arrive at a realistic master plan that can be endorsed and implemented with committed confidence by the governments of the member states. The three components are:

- ❑ **Component A** – This is a combination of country-by-country expansion plans based on national master plans extended (where necessary) to 2040 with a consistent set of assumptions. ‘Committed’ generation projects are those identified as such by the countries, and only existing and committed regional inter-connectors are included on the transmission side.

The implications of these restrictions are discussed subsequently. Component A is also referred to in the TOR and in this report as the *“Benchmark Case”*.

- ❑ **Component B** – This is full optimisation case whereby the region is treated as though it is a single country and a least cost sequence of generation and transmission expansion projects is derived.

In principle, there are no constraints on regional trade and the full potential of regional power sector integration can be realised. Component B is also referred to in the TOR and in this report as the *“Full Integration Case”*.

- ❑ **Component C** – This is an intermediate integration case, whereby certain constraints are applied to Component B to ensure that each country, at a minimum, fulfils SAPP security and reliability planning criteria. This was interpreted to mean that by 2040 each country should have sufficient installed or firm imported capacity to be able to meet its maximum demand and reserve obligations, and large thermal power plants should operate at or above minimum capacity factor levels.

Without the capacity factor constraint, existing and new coal and gas plants, installed to meet the maximum demand requirement, would often have to be mothballed or operate at unrealistically low load factors when countries can import cheaper energy. Component C is also referred to as the *“Realistic Integration Case”*.

In addition to the three-component approach another unique aspect of this Pool Plan study was the collation and presentation in GIS format of available spatial data on energy resources, current and proposed generation and transmission infrastructure and other environmental and social thematic mapping in the region. The data was then used for analysis of the environmental and social impacts of different projects and scenarios.

1.3 SAPP generation planning criteria

In November 2011, SAPP published its *Generation Planning Criteria*. This document discusses the approach to be adopted to regional capacity expansion planning, as well as specifying the following criteria:

- ❑ **Security criterion** - The minimum level of internal generation shall have as a long term objective, capacity equal to or greater than 100% of demand. Internal generation shall be committed when existing reserve levels drop below that specified in the reliability criteria.
- ❑ **Reliability criterion** - The Reserve Capacity Obligation of a Member for any given period shall be equal to 10.6 % of the Annual System Peak Obligation of such Member when the generating plant is thermal and 7.6 % when the generating plant is hydro. A weighed average shall apply to Members who have a mixed system².

In Component C, the Security Criterion has been made a requirement through the stipulation that each country should by 2040 have sufficient installed capacity to be able to meet its maximum demand (minimum 0% reserve margin). The Reliability Criterion goes beyond just meeting the maximum demand to require a reserve margin to be maintained, but it is important to note that SAPP permits the Reliability Criterion to be met through a country contracting firm power including auxiliary services from its neighbours. The Reliability Criterion will therefore be met provided there is sufficient reserve capacity (in relation to coincident maximum demand) in the region as a whole and which is economically accessible to each country.

The Security Criterion was established in the context of an orientation of member countries towards self-sufficiency. The basis for self-sufficiency aspirations is as follows:

- ❑ importers have suffered more than exporters during regional shortages in recent years;
- ❑ importers perceive being at risk of arbitrarily high prices set by exporters, as SAPP is yet to develop a transparent pricing system for the long term market similar to what exists in the short term markets;
- ❑ there is no guarantee that exporting countries will complete planned generation and transmission projects on time to meet the needs of importing countries;
- ❑ development of local industry - having own generation plant creates job and skill opportunities.

These concerns need to be counterbalanced with the benefits of importing power at lower costs than can be generated locally, with significant multiplier benefits for the local economy.

The formulation in Component C, the “realistic” integration scenario, whereby countries have installed capacity that is sufficient to meet peak demand, but import energy when it is

² Definitions of the criteria are copied from SAPP (2012): Generation Planning Criteria

available at lower cost than domestic generation (subject to domestic thermal plants maintaining minimum capacity factors) provides a good compromise. The broad political economy context for this is described in a recent paper³.

2 Methodology

2.1 Spatial mapping of energy resources

Overview

For the spatial mapping of energy resources, a Geographic Information Systems (GIS) approach was adopted. This has allowed the creation of a common basis for planning and analysis across all the SAPP countries, based on regionally standardised, integrated data inputs, outcomes and outputs. This GIS based approach supports the critical project requirement for coordinated, standardised planning, and the ability to integrate both spatial and non-spatial (i.e. attribute) environmental and social elements into a common framework.

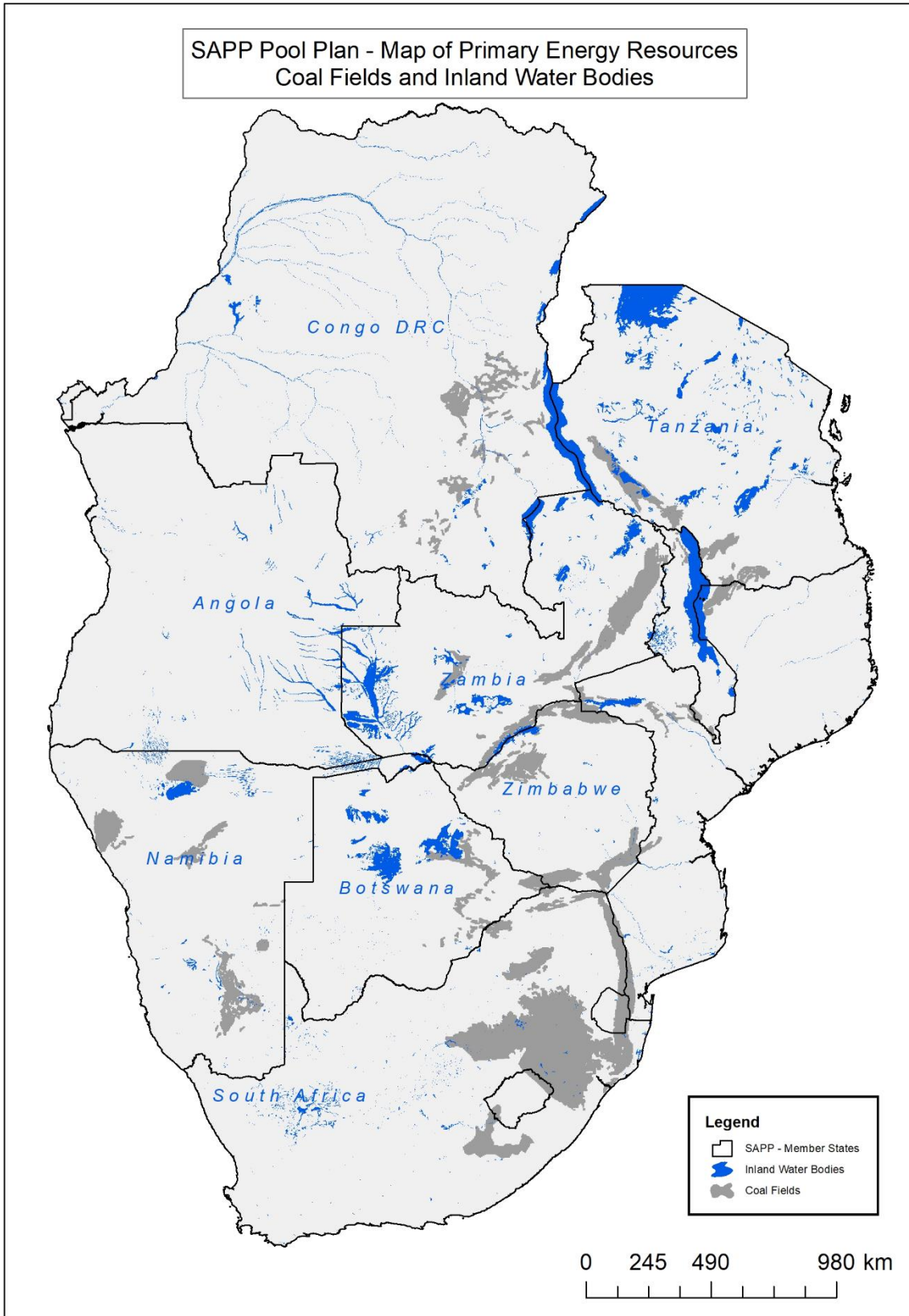
The development of the GIS environment has had two distinct focus areas. One focus area is the spatial representation of all relevant power generation, transmission and load centre information as used in PLEXOS and PSS/E and has been developed as a visualisation, reporting and planning tool. This is supported by other foundation datasets which provide context and background to the above-mentioned data. In the next few pages, a number of maps are presented:

- ❑ Map of SAPP coal resources
- ❑ Map of SAPP solar CSP resources
- ❑ Map of SAPP solar PV resources
- ❑ Map of SAPP wind resources
- ❑ Map of SAPP energy supply ('sources')
- ❑ Map of SAPP energy demand ('sinks')

Hydropower resources are difficult to represent in a region-wide map. However, in Section 3.2, a map of major hydropower dams is provided (Figure 11), together with a map of the main transmission corridors identified during the study (Figure 12).

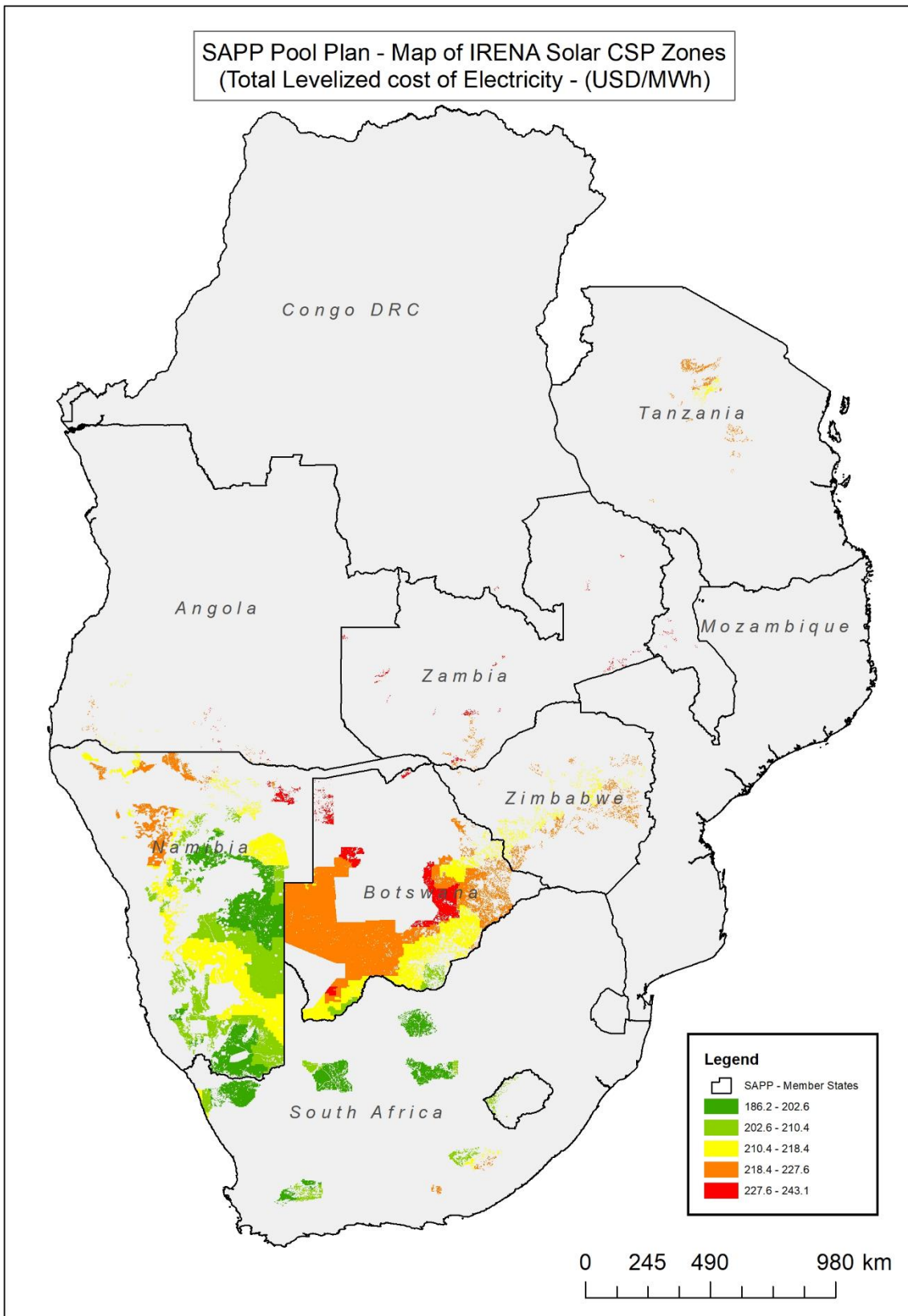
³ S. Mangwengwende, L. Musaba and S Krohn (2014) *Sovereign Security with a cherry on Top: Building Climate Resilience through Virtual Water and Nexus Thinking, (Electricity Power Planning in SADC and the role of SAPP)*, paper prepared for the Climate Resilient Infrastructure Development Facility (CRIDF) project funded by DFID (UK)

Figure 1 Map of SAPP coal resources



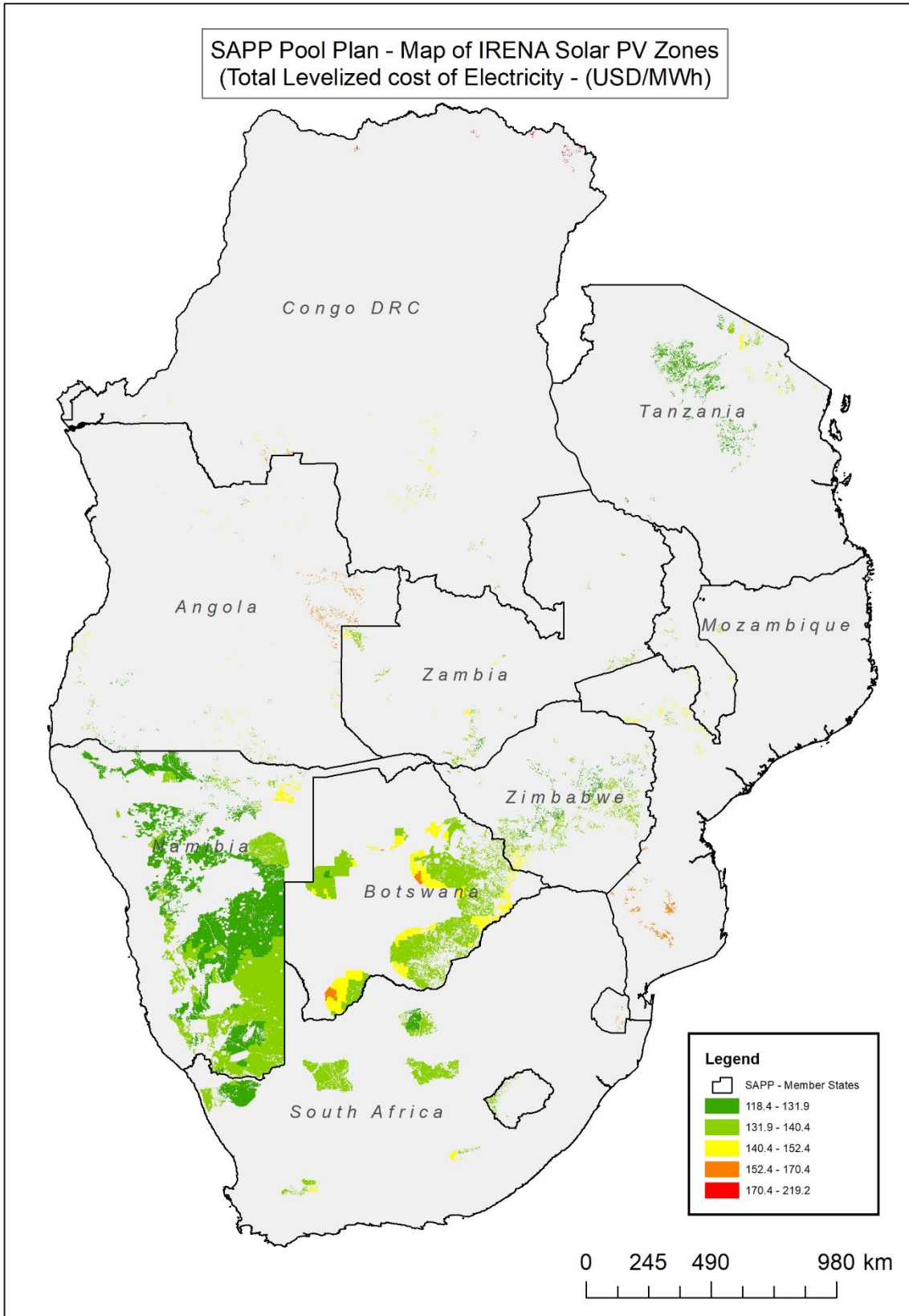
Source: GeoTerraImage, 2016

Figure 2 Map of SAPP solar CSP zones



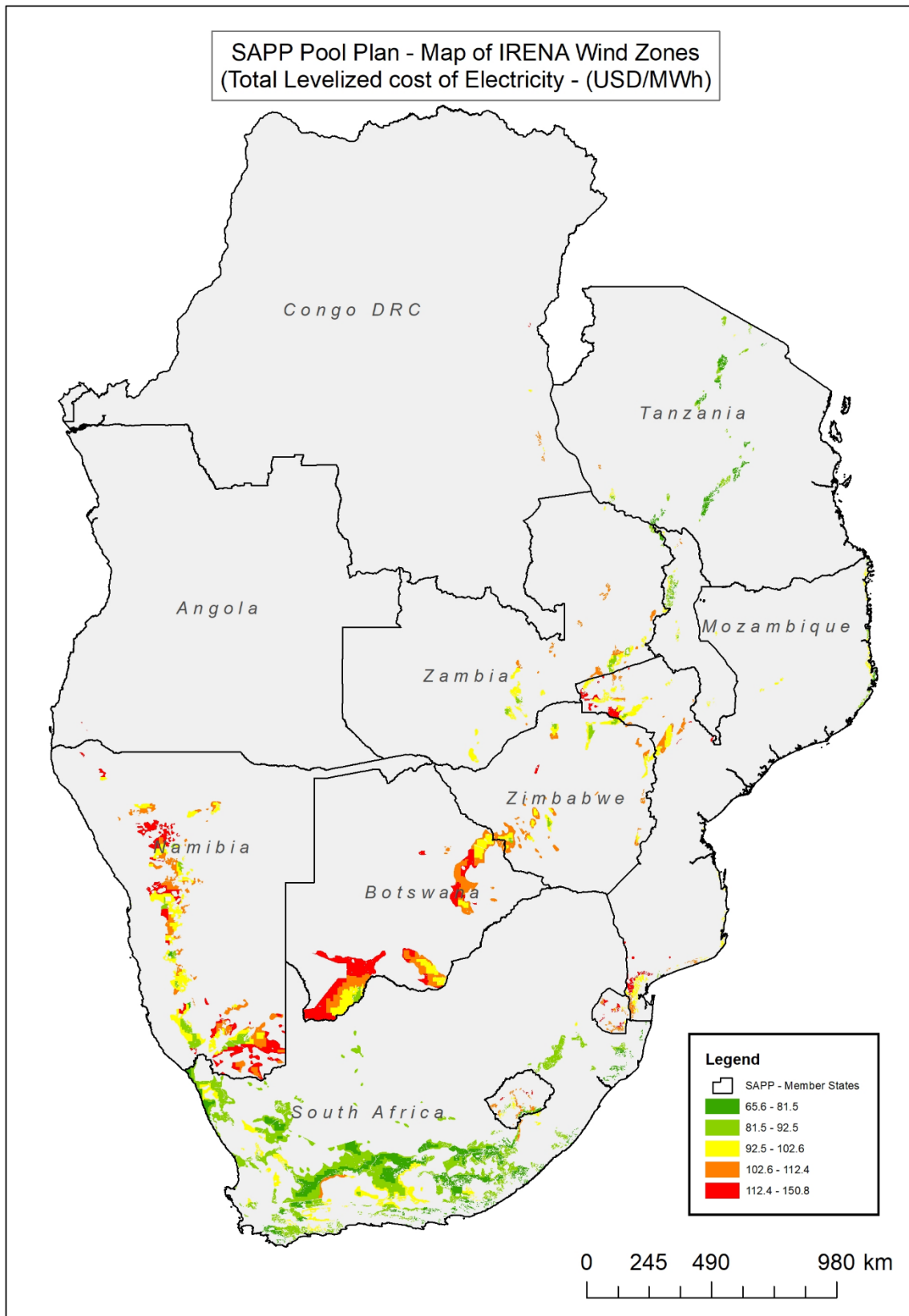
Source: GeoTerraImage, 2016

Figure 3 Map of SAPP solar PV resources



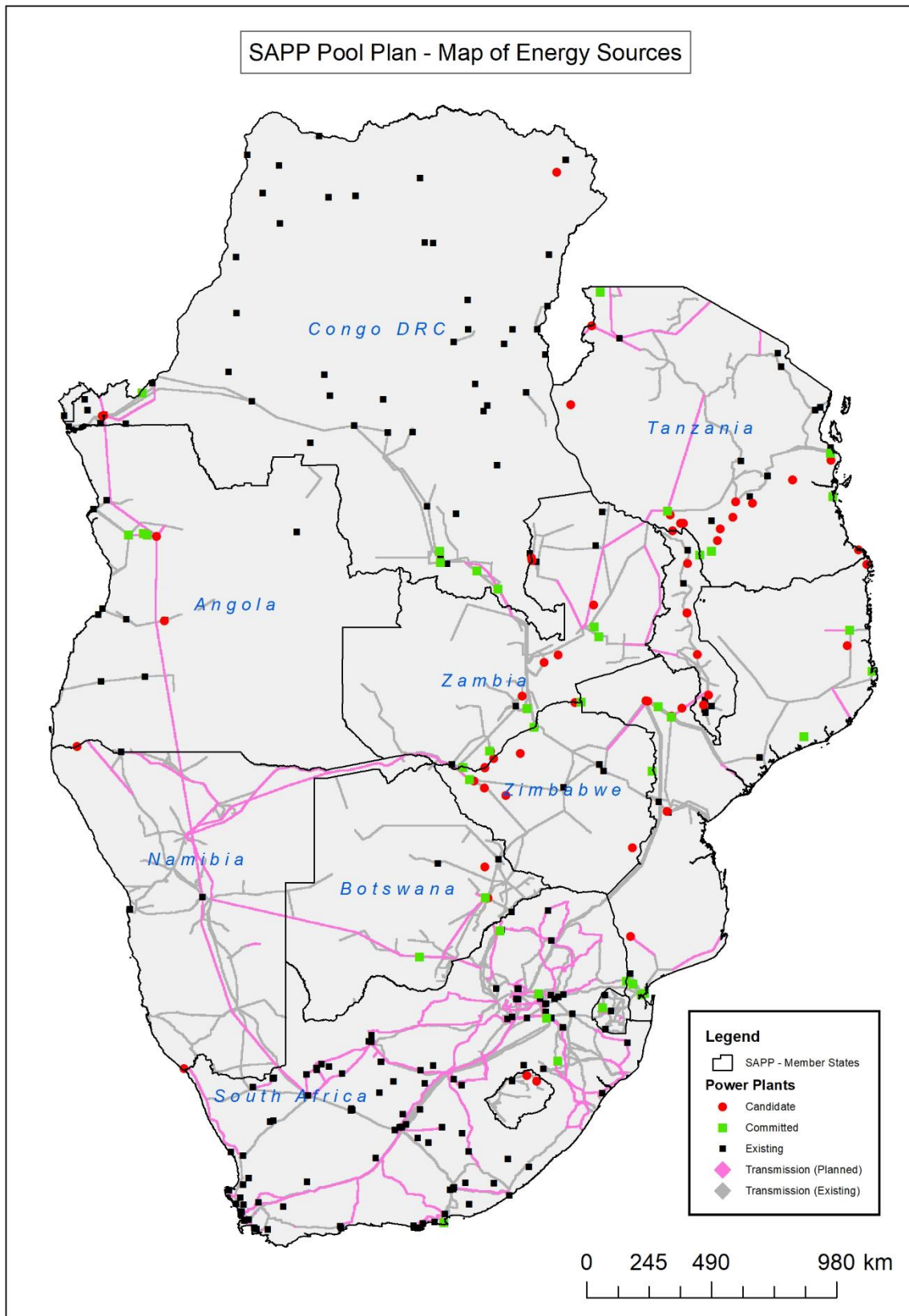
Source: GeoTerraImage, 2016

Figure 4 Map of SAPP wind resources



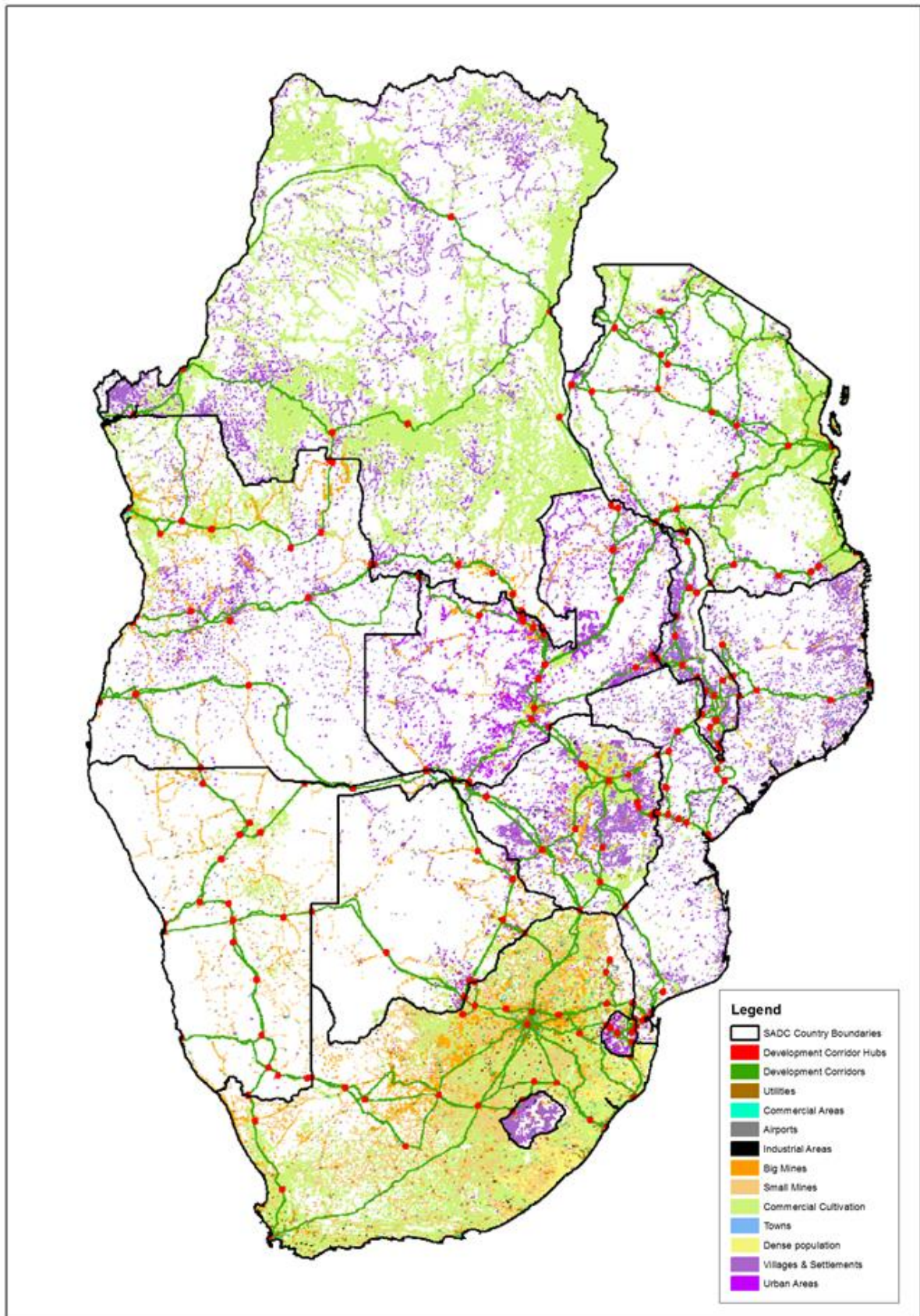
Source: GeoTerraImage, 2016

Figure 5 Map of SAPP energy supply ('sources')



Source: GeoTerraImage, 2016

Figure 6 Map of SAPP energy demand ('sinks')



Source: GeoTerraImage, 2016

The other focus area of the GIS environment is to integrate a diverse set of spatial and non-spatial data into a coherent and consistent dataset for use by the member states within the Rapid Impact Assessment Matrix Tool (RIAM) for Environmental and Social (E&S) Sustainability analysis. The GIS environment allows the visualisation and reporting on spatial context, relationships and patterns across the SAPP region and provides a mechanism to study the region as a whole and understand power generation capabilities, transmission corridors and load centre locations.

The GIS environment will thus provide an easy to use tool to visualise both primary energy resources and power generation and transmission facilities, power sinks or load centres, economic and socio-economic constraints or limitations. The spatial data has been provided as basic GIS elements such as images, points, lines and polygons where appropriate as well as within a 2500m x 2500m grid which summarises the data for ease-of-use within most GIS software packages. Data has been provided as the highest information content and spatial resolution based on the applicable access and copyright restriction.

Data collection

Data collection has been the biggest challenge during the study. Originally, data collection was planned to be completed by 31 March 2016, but in fact was only completed by end of January 2017, with further submissions from utilities being sent during March 2017.

The GIS database for SAPP has been developed from 71 data sets classified as follows:

- Sources – existing and planned power supply infrastructure
- Resources – locations of renewable and non-renewable energy sources
- Sinks – actual and potential demand centres
- Limitations – potentially inaccessible locations
- Constraints – actually inaccessible locations
- Background – natural land features and vegetation

The database has basic GIS elements such as images, points, lines and polygons where appropriate, together with a 2500m x 2500m grid across the SAPP region. This summarises the data for ease-of-use within most GIS software packages.

A more detailed description of the GIS SAPP Database is given in Annex A4 in the accompanying volume of annexes.

Use of RIAM to screen generation and transmission projects

The use of RIAM is demonstrated in the Pool Plan through its use in screening generation and transmission projects. With the level of resolution that is possible with the data that could be assembled during the study, the tool is better suited to assessing transmission rather than generation projects.

However, one generation project (Mupata Gorge) was removed from the candidate project list after screening on the basis of significant impacts to the biological/ecological component and its location in a National Park. Following an iterative process to define transmission line corridors, none of the proposed routes directly impacts on no-go areas. A small number (3-4) of generation projects in national master plans are located in sensitive areas.

2.2 Demand forecast

Approach

As agreed at the kick-off meeting in January 2016, the national demand forecasts are common to all the scenarios examined in the study. It is necessary to use a common forecast to allow a proper comparison on a like-for-like basis. The *'base' demand forecast* which was presented in the September 2016 Demand Forecast Report and was agreed with the utilities at the December 2016 workshop, was reviewed at the June 2017 workshop. The consensus view was that the 'base' forecasts for most countries were on the high side. Rather than have an even higher 'high' case, it was agreed that the modelling team should develop a *'low' demand forecast* scenario which would be used for conducting sensitivity tests.

For PLEXOS, the demand figures required are the 'sent out' peak demand (MW) and energy (GWh). The base demand forecast of the sent out MW and GWh was derived from the national demand forecasts of the SAPP member countries. Different methodologies were used by different countries and the forecasts were over different time periods. For each country, after reviewing the forecast methodology and the form of the forecast, it was recommended either to adopt the current forecast or to adopt a different methodology or make some adjustments to the existing approach. The results were discussed further with country representatives before being adopted. In several cases the figures were changed quite significantly at this stage.

The demand forecasts which are used in the final model runs were modified for two countries after the December 2016 workshop. The first is Botswana, which provided in the first quarter of 2017 a detailed demand forecast study report completed in August 2016, and the second is South Africa, where the earlier demand forecast was modified in consultation with Eskom to take account of the implications on future investment and growth of the economy consequent on the credit agency downgrading of South African bonds.

For the low demand forecast, the starting point was again to use 'low' demand forecasts where these were available from the countries, but there was also greater reliance on making assumptions which would bring the demand forecasts for the different countries onto a similar basis. Lower assumptions about the level of suppressed demand were made for several countries, together with lower growth rates, related to economic prospects and electrification plans in each country. Tables giving comparative results are presented in the next sub-section.

Comparative tables of energy demand drivers

This section presents comparative information about historical and projected drivers of electricity demand growth, principally population growth, GDP growth and access of the

population to electricity ('electrification'). Table 1 shows that electricity growth drivers have in the past varied greatly across countries. Over 2000-2015, population growth varied from 0.9% pa (in Lesotho) to 3.4% pa (in Angola), real GDP growth from -0.8% pa (in Zimbabwe) to 9.3% (in Angola), while the increase in the national electrification rate varied from -0.8% (in Zimbabwe) to 43% in Swaziland. The SAPP-wide averages, weighted by 2015 population, were population growth of 2.6% pa, real GDP growth of 4.8% pa and an increase in the electrification rate of 2.4% between 2000 and 2015.

Table 1 Historical data on electricity growth drivers

Country	Av pop growth, % (2000-15)	Av real GDP growth, % (2000-15)	Increase in electrification % (2000-14)
Angola	3.4	9.3	-9.8
Botswana	1.8	4.4	29.3
Congo, Dem. Rep.	3.2	5.7	6.8
Lesotho	0.9	4.0	27.4
Malawi	2.9	4.7	7.1
Mozambique	2.9	7.8	14.3
Namibia	1.7	4.5	13.1
South Africa	1.4	3.1	15.4
Swaziland	1.3	3.6	43.0
Tanzania	3.1	6.5	5.6
Zambia	2.9	6.7	11.2
Zimbabwe	1.5	-0.8	-0.8
SAPP	2.6	4.8	2.4

Source: World Bank data. SAPP figures are averages weighted by 2015 population.

Table 2 provides data on the 12 countries at the start of the SAPP PP planning period. The total population of the region in 2015 was 295 million, with a combined GDP of nearly \$ 600 billion and an average electrification rate of 32%. Variations between the countries on all indicators, including the Human Development Index (HDI) are again considerable.

Table 2 Current data

Country	Population, m (2015)	GDP, \$ bn (2015)	GDP/capita, 2011 \$, PPP (2015)	Human Development Index (2015)	Electrification rate, % (2014)
Angola	27	103	6,938	0.533	32
Botswana	2	14	14,876	0.698	56
DRC	82	38	737	0.435	14
Lesotho	2	2	2,770	0.497	28
Malawi	18	6	1,112	0.476	12
Mozambique	28	15	1,120	0.418	21
Namibia	2	11	9,778	0.640	50

Country	Population, m (2015)	GDP, \$ bn (2015)	GDP/capita, 2011 \$, PPP (2015)	Human Development Index (2015)	Electrification rate, % (2014)
South Africa	55	315	12,393	0.666	86
Swaziland	1	4	8,122	0.541	65
Tanzania	48	46	2,510	0.531	16
Zambia	16	21	3,602	0.579	28
Zimbabwe	14	14	1,678	0.516	32
SAPP	295	591	4,243	n/a	32

Source: World Bank and UNDP data. SAPP figures are averages weighted by 2015 population.

The first 2 columns of Table 3 provide projections of population and GDP growth over the period 2015-2022. This does not cover the full PP planning period, but does provide a reference point for assessing the Base and Low peak demand forecasts that have been developed for the study. The average population and GDP annual growth rates up to 2022 are 2.5% pa and 2.4% pa respectively, while the annual average rates of growth in peak demand are 3.3% pa in the Base projection and 1.9% pa in the Low projection.

The SAPP totals with diversity are shown separately from the simple additive totals. Diversity is expected to increase over the planning period because of the reduced dominance of South Africa in the overall SAPP demand and the entry of new interconnected members (Tanzania, Malawi and Angola) which will add additional diversity to the region.

Table 3 Forecast growth rates - peak demand (MW)

Country	Av pop growth % (2015-22)	Av real GDP growth, % (2015-22)	Historical MD growth % 2006-2016	MD in 2016 (MW) as reported	Base SAPP MD growth, % (2015-40)	Maximum demand in 2040 (MW)	Low SAPP MD growth, % (2015-40)	Maximum demand in 2040 (MW)
Angola	3.0	1.2	12.6	1,503	7.7	10,259	3.4	3,427
Botswana	1.2	4.0	1.9	607	3.5	1,436	3.1	1,291
DRC	3.0	3.7	2.8	1,517	5.2	4,996	3.8	3,613
Lesotho	0.2	3.3	3.0	149	3.5	321	2.1	229
Malawi	2.9	4.8	1.9	377	11.1	4,620	3.4	763
Mozambique	2.7	6.8	3.5	1,872	3.1	3,840	2.7	3,479
Namibia	0.8	3.4	2.5	646	4.0	1,578	2.5	1,099
South Africa	1.6	1.6	-0.3	34,017	2.5	60,213	1.9	52,350
Swaziland	1.3	0.4	1.6	248	2.3	419	1.6	331
Tanzania	2.0	6.6	4.9	1,250	11.4	14,330	4.9	3,058
Zambia	3.1	4.0	2.4	2,956	4.1	7,807	3.4	4,625
Zimbabwe	2.6	0.5	-2.4	1,841	4.4	5,204	3.5	3,426
SAPP	2.5	2.4	0.4	46,983	3.3	115,025	1.9	77,688
<i>With diversity</i>				45,614	3.5	104,568	1.8	70,626

Source: World Bank, IMF and SAPP utility data; Power Pool Base and Low demand forecasts. Diversity assumed to be 1.03 in 2016 rising to 1.10 in 2040⁴. Note that time period of first 2 columns is 2015-2022, whereas the planning horizon for the Pool Plan extends to 2040.

Finally, in Table 4 the growth in energy sent out in 2015 can be compared with the Base and Low forecasts in 2040, the implied rates of annual average growth being 3.4% pa for the Base forecast and 2.1% pa for the Low forecast. The figures for energy consumption per capita do not reflect actual consumption at the household level, but are instead indicative ratios of the total energy sent out divided by the population. Population growth rates are low enough for energy per capita generally to increase despite the fairly modest annual growth rates in energy sent out, particularly in the Low forecast.

Table 4 Forecast growth rates – energy (GWh)

Country	Energy sent out, GWh (2015)	Energy cons per capita, kWh (2015)	Base growth case, % (2015-40)	Base energy sent out, GWh (2040)	Cons per capita, kWh (2040)	Low growth case, % (2015-40)	Low energy sent out, GWh (2040)	Cons per capita, kWh (2040)
Angola	9,105	364	7.7	58,413	1,132	3.4	19,512	378
Botswana	3,974	1,757	3.5	9,377	3,000	3.0	8,356	2,673
DRC	10,499	136	4.5	31,511	202	3.1	22,788	146
Lesotho	645	302	4.8	2,096	768	3.4	1,491	547
Malawi	1,756	102	11.4	26,105	760	3.7	4,309	125
Mozambique	12,686	479	2.9	25,885	660	2.8	24,073	456
Namibia	3,871	1,574	3.9	10,085	2,651	2.5	7,103	1,867
South Africa	215,693	3,938	2.5	395,600	5,631	1.9	343,940	4,896
Swaziland	1,141	886	2.8	2,276	1,381	2.0	1,796	1,090
Tanzania	6,320	118	11.1	87,880	812	4.6	18,754	173
Zambia	16,764	1,034	3.8	43,086	1,291	3.3	25,835	774
Zimbabwe	9,557	612	3.4	22,270	873	2.8	15,583	611
SAPP	292,010	992	3.4	714,586	1,622	2.1	495,351	1,124

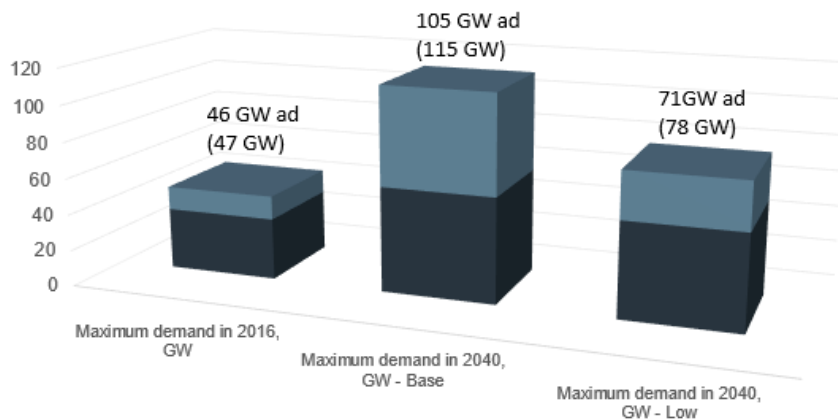
Source: World Bank and SAPP utility data; Power Pool Base and Low demand forecasts

Summaries of the Base and Low demand projections

The graphs below present summaries of the base and low demand forecasts, with South Africa and the rest of SADC shown separately. Over the 2015-2040 planning horizon, South Africa's share of energy demand declines significantly in the base forecast (from 74% to 54%) and to a lesser degree in the low demand forecast (from 76% to 70%). The 2040 proportions for South Africa's peak demand in relation to after diversity regional demand are slightly higher than the energy shares (57% for the base and 74% respectively for the low projection).

⁴ Diversity is sometimes defined as the inverse of the definition used here, in which case diversity would be said to change from 0.97 in 2016 to 0.91 in 2040.

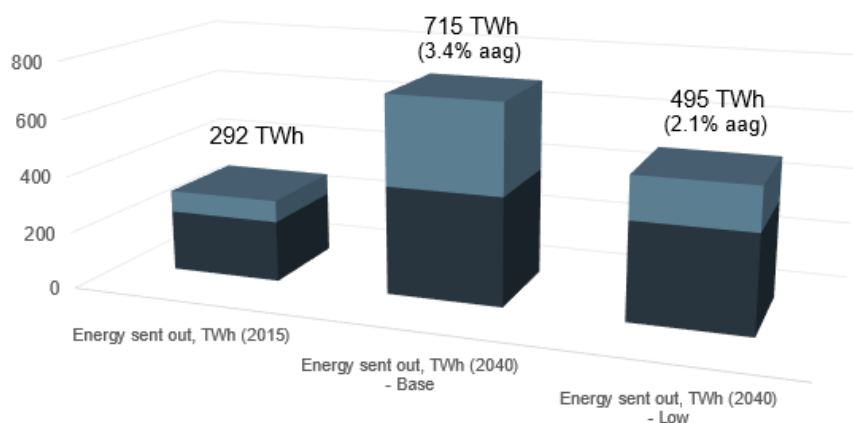
Figure 7 SAPP peak demand growth – base and low demand projections



	Maximum demand in 2016, GW	Maximum demand in 2040, GW - Base	Maximum demand in 2040, GW - Low
■ Rest of SAPP	13	55	26
■ South Africa	34.0	58.2	52.4

Note: ad = after diversity (1.03 in 2016 and 1.10 in 2040)

Figure 8 SAPP energy sent out – base and low demand projections

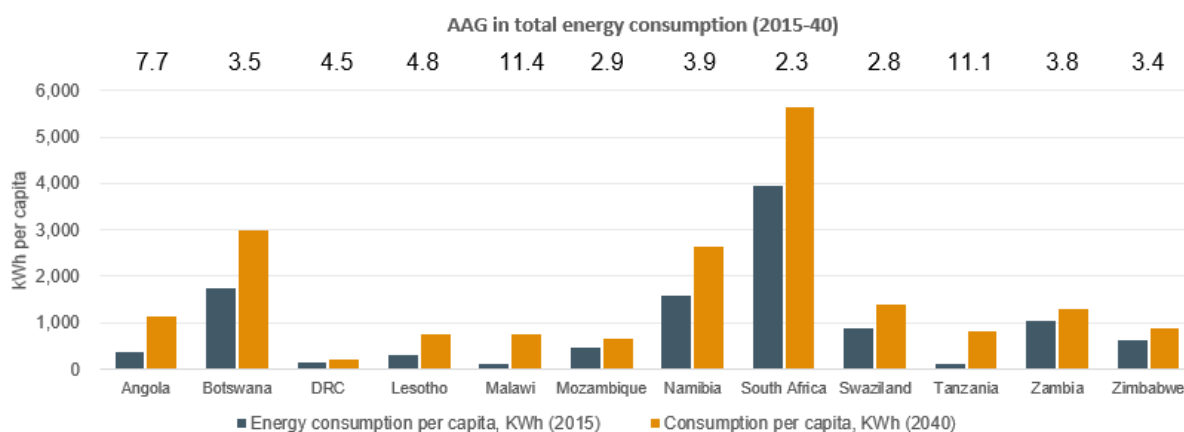


	Energy sent out, TWh (2015)	Energy sent out, TWh (2040) - Base	Energy sent out, TWh (2040) - Low
■ Rest of SAPP	76	319	151
■ South Africa	216	382	344

Note: aag = annual average rate of growth

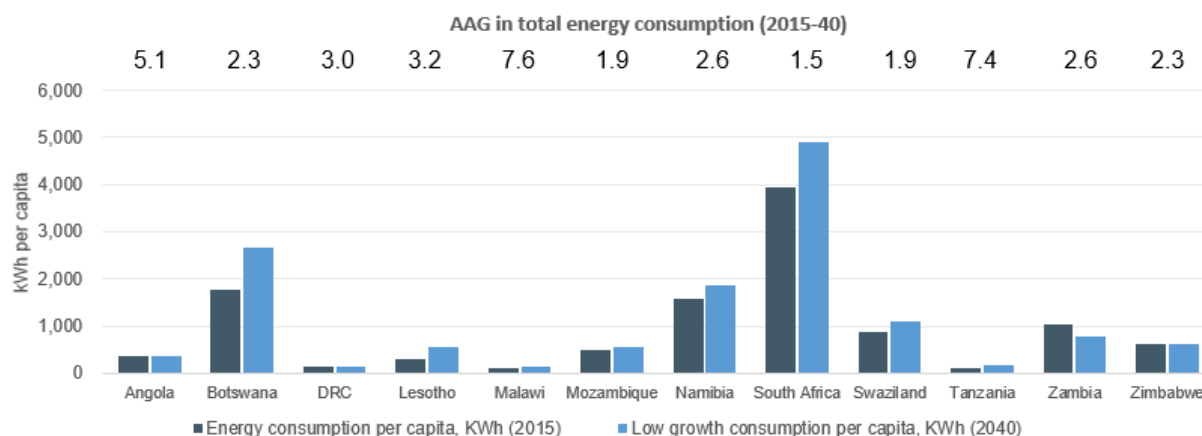
Figure 9 and Figure 10 combine energy growth with population growth to derive growth in per capita energy consumption (measured in kWh/capita) between 2015 and 2040 for the base and low demand forecasts. It is notable that countries currently with low electrification rates (such as Malawi and Tanzania – see Table 2) are striving to achieve high levels of per capita energy consumption.

Figure 9 Per capita consumption in 2015 and 2040 – base demand forecast



Note: AAG = annual average rate of growth

Figure 10 Per capita consumption in 2015 and 2040 – low demand forecast



Note: AAG = annual average rate of growth

Further details on the demand forecast methodology and results for each country are given in the Demand Forecast Report (Annex A1 in the accompanying volume of annexes). Summary demand forecast tables are given in Annex A2.

2.3 Country planning studies - overview

The TOR call for the existing national power sector development plans to be analysed as a precursor to the formulation of the Pool Plan. In particular, the Benchmark Case reflects the plans for generation and transmission expansion in each country, the initial demand/supply balance for each country, country-specific requirements in terms of supply security and their interest in trading power with neighbours. The summary analysis of these issues below has been derived from the country plans or other sources and documents where countries do not have or have not submitted plans. More detailed analysis is in the sections of the report covering the Benchmark Case studies on generation and transmission.

2.3.1 Angola

The Ministry of Energy and Water study on the National Electricity Transmission Grid dated July 2014 is the main source document regarding the most recent information on generation and transmission developments in Angola for the period to 2025.

Generation

The report does not provide explicit information on the national policies with respect to local generation and imports. It is however evident that the country plans significant development of its hydropower resources, estimated at 18 GW. If developed within the timescale envisaged by the Government, this hydropower could play a significant role in regional trade during the early years and in seasons and years with high inflows.

Transmission

Interconnections of the three national networks to create a National Electricity Transmission Grid is the focus of the short term (2014-2017) and future (2018-2025) transmission development plan. This will integrate the existing isolated networks in the north, centre and south of the country and connect planned generation into a national grid comprising 220kV and 400 kV lines. Except for reference to joint hydro power developments with Namibia it is not clear what the Government's policy on interconnections with SAPP is.

2.3.2 Botswana

For Botswana, the country's Master Plan at the time of data collection was still being revised. What was available were power point slides showing the supply-demand outlook and the generation expansion plans for the period of 2015-2025.

Generation

The main focus is refurbishment and extension of the existing coal fired power plant and introducing a greenfield coal-based IPP. This gets the country to be self-sufficient. Shortfalls in the early years before the completion of the proposed projects are expected to be met through non-firm imports from the region.

Transmission

Interconnections will need to be adequate for the assumed non-firm imports. Projects under consideration include ZIZABONA and BOSA. In line with agreements made during the execution of the project, the part of the ZIZABONA project covering the line from Livingstone in Zambia to Hwange in Zimbabwe is seen as committed, whereas the other sub-projects are seen as candidates similar to other interconnections and regional transmission corridors that may support regional integration. Pandamatenga – Victoria Falls (ZIZABONA) and Isang – Watershed (BOSA) are included among these projects.

2.3.3 DRC

Except for brief summaries of proposed projects, no masterplan or national policy documents have been provided by the national utility, SNEL. The modelling team therefore had to rely on the new electricity legislation of June 2014, third party sources of information as well as a presentation by the Transmission Department of SNEL dated February 2013 that provides an overview of the electricity sector and an indication of the key planning issues and policies. The Inter-Utility Study for Integrating Grand Inga Phase 1A dated 3 October 2014 provided at the June 2017 workshop was also a useful source document in view of the centrality of the Grand Inga project to the SAPP Pool Plan. The new DRC legislation calls for the restructuring of the sector to establish a regulatory authority, commercialising SNEL, facilitating private sector investment and increasing electricity access.

Generation

DRC has an estimated 100 GW hydropower potential of which 44 GW is concentrated at Inga. At present the country's installed capacity is 2442 MW but available capacity is only 1228 MW. Current demand is therefore highly suppressed which explains the very high difference between the country's demand forecast and actual consumption figures for 2015. The priority generation projects are rehabilitation of existing power plants to restore capacity and the development of the 4800 MW Inga 3 whose anchor customers are exports to South Africa (2500 MW), supply to mining sector (1300 MW) in the Katanga region and SNEL (1000 MW) to address suppressed demand and expand grid electrification for the rest of the country.

Transmission

Increasing the transfer capacity of the Inga-Katanga corridor to evacuate power to the load centres is the priority transmission development relevant to the SAPP Pool Plan. Connection to Angola would assist in getting the latter to become an operating member of SAPP.

2.3.4 Lesotho

The reference documents used are the Lesotho Generation Master Plan dated 11 November 2010 and the Network Development Plan dated 13 July 2015.

Generation

Local generation resources are hydro, wind and solar. In recent years the issue of concern has been the uncertain availability of imports from Eskom (South Africa) and EDM (Mozambique) due to supply constraints in those countries. This has restricted electricity supply growth in Lesotho. There is therefore an interest in increasing local generation.

Transmission

There are plans to construct stronger links at 132 kV with Eskom.

2.3.5 Malawi

A mini-IRP for the period 2016-2020 and the recently completed work on the full IRP is the source of information. Malawi is not yet interconnected with SAPP and has a hydro based power system which is energy constrained.

Generation

Generation planning aims to balance a number of objectives and considerations that include minimising cost, enhancing security and reliability, electrification growth, mitigation of adverse environmental impacts, minimising foreign currency and participating in SAPP trading. The adverse impact of drought on the current predominantly hydro system has led the Government to champion coal fired generation.

Transmission

Interconnection with Mozambique (and therefore with SAPP) at 400 kV is targeted for 2018. Other interconnections with Mozambique and also with Zambia will strengthen Malawi's integration with SAPP. Interconnection with Tanzania at 400 kV will be another interconnection point for SAPP and EAPP. The vision of Malawi is to become a net exporter through these interconnections.

2.3.6 Mozambique

The latest masterplan update report dated 30 April 2014 notes that Mozambique has abundant hydropower potential (12,000 MW), gas (127 billion cubic metres proven reserves), coal (13 billion tons proven reserves) in addition to renewables such as solar, wind and biomass.

Generation

The Generation Development Strategy for the large hydropower and thermal (coal and gas) power plans is to duplicate that of the current Cahora Bassa power station whose main market is export with an allocation for domestic use. These projects' development is therefore dependent on the availability of an export market. Smaller hydro, coal or gas projects equal to or less than 300 MW would be developed with a focus on the local market.

Transmission

The Mozambique backbone transmission project, STE, is the priority project for evacuating power from the hydro and coal resource rich Tete province to load centres and for interconnecting the country's Northern, Central and Southern networks. The other projects will be to improve reliability of supply and to connect large scale industrial and mining loads. Interconnections with Malawi and Tanzania at 400 kV are also being considered.

2.3.7 Namibia

The National Integrated Resource Plan (NIRP) Update of 2016 is the reference document used for Namibia.

Generation

Security of supply is to be achieved through an appropriate diversification of economically competitive and reliable sources, but with particular emphasis on Namibian resources. Electricity supply in Namibia shall be based on a balance of economically efficient and sustainable electricity sources including gas, hydro-power, other renewable energy sources and imported electricity.

Namibia is one of the few countries with explicit policies on local and import dependency: “Duly considering associated risks, it is the aim of government that 100% of the peak demand and at least 75% of the electric energy demand will be supplied from internal sources by 2010. Risk mitigation measures will be pursued, including the possibility of regional equity participation in, and guarantees for, Namibian generation projects.” The 2010 target has not yet been achieved - only two thirds of the 2015 peak demand of nearly 600 MW and less than 40% of energy requirements could be met from internal sources. The latest IRP estimates that this policy target can be achieved within the next 5 years.

The IRP assumes the following criteria for generation planning:

- ❑ Loss of Load Probability (LOLP) of 5 days per year up to 2020 and 2 days per year thereafter
- ❑ Expected Unsupplied Energy (EUE) is 1% of annual energy demand
- ❑ Reliability criterion (adopted from the SAPP criterion) - the minimum reserve level to be carried on the system should be at least 10.6% of adjusted demand for thermal based power and 7.6% for Hydropower and a weighted average for a combination of both. Adjusted demand is equal to the peak system demand plus the amount of firm tariff power exported minus the amount of firm tariff power imported.

Transmission

Government will facilitate the establishment of new high-voltage interconnections with the neighbouring countries to increase Namibia’s possibilities of engaging actively in regional electricity trading.

2.3.8 South Africa

The Integrated Resource Plan (IRP) 2010 and its updates are the reference documents that guide the power system development strategies of South Africa. As the country has the biggest electricity market in SAPP its IRP's assumptions on exports and imports have a significant influence on regional development. For example, the most recent IRP update has changed assumptions on the next source of hydropower imports from Mozambique to DRC which will have obvious impacts on the timing of generation and transmission developments in these and other neighbouring countries. Other significant changes in assumptions that have had to be considered relate to demand forecast (which is lower than that used for IRP 2010) and having nuclear power plants as candidate rather than committed power plants.

Generation

The Department of Energy, in terms of the Electricity Regulation Act of 2006, on 6 May 2011 published regulations for the Integrated Resource Plan 2010-2030 that included the following policy guidelines:

- ❑ Renewables (solar photovoltaic (PV), concentrated solar power (CSP) and Wind) have been brought forward in order to accelerate a local industry in the construction of the equipment and development of local skills.
- ❑ Dependency on imported uranium, gas and electricity (both hydro and coal) is capped to mitigate risks in cost and delays to construction of both the power plants and interconnections, and the impact of droughts on hydropower generation.
- ❑ Nuclear and combined and open cycle gas turbines (CCGT and OCGT) are included so that security of supply is not compromised because of the uncertainties associated with the costs of renewables and fuels as well as import options. Other uncertainties of renewables include level of safe penetration, operability, lead times to build, etc. Penetration of wind and solar is limited to 10% in 2020 and 20% in 2030.
- ❑ Carbon dioxide emission constraints of 275 million tons per year are deferred to the period after 2024, thereby bringing forward coal generation including imported coal power options that would otherwise have been expected after 2026. For the period between 2030 and 2040 there will be extensive decommissioning of the existing coal fleet which needs to be taken account of in future IRP studies.
- ❑ Adoption of conservative assumptions regarding Energy Efficiency Demand Side Management (EEDSM) measures to mitigate the risk of underdevelopment of additional capacity needed if the EEDSM programme under-achieves.

Transmission

The ESKOM transmission development plan published in October 2015 for the period 2016-2025 has three groups of projects:

- ❑ Reliability projects to ensure compliance of the network to the National Grid Code. This category should include refurbishment of existing infrastructure including Energy Management and SCADA systems.
- ❑ Generation integration projects for evacuation of power from new power stations including imports. Of interest to the regional grid was the assumption of imported hydropower of 2,326 MW in 2022/23 from Northern Mozambique to be transported via Maputo using the proposed Mozambique transmission backbone project, STE. The timing for the development of the STE is sensitive to any changes in the timing of the imports. Updates of the IRP now refer to 2500 MW imports from DRC's Inga 3 which introduces further uncertainties to the development of the regional grid.

- ❑ Grid connection projects for major load centres.

This transmission plan assumes the IRP for Electricity of 2010-2030. To adapt to the uncertainty of future load and generation locations a 2040 Transmission Network Study was undertaken that identified eight 100 km wide power corridors that would be needed to accommodate different generation scenarios. Securing rights and approvals for power corridors will minimise project development time when needed.

2.3.9 Swaziland

The Swaziland Electricity Company's Generation Expansion Plan for the period 2014-2023 dated April 2014 and the associated August 2015 network development plan that covers the period 2015-2034 are the main reference documents.

Generation

The development strategy seeks to address current concerns regarding the absence of local baseload generating capacity which exposes the country to security of supply risks (supply problems in neighbouring countries can adversely affect supply) and to being a price taker in import contracts. Current peak demand exceeds 200 MW but SEC's local supply is mainly from IPPs exporting into the grid and a 60 MW run of river peaking hydro plant with very low dry season output. Subject to confirmation by on-going feasibility studies there is a potential for a 300 MW coal power plant to be in service by 2023 when peak demand is expected to be around 250 MW. Other local projects being investigated include solar PV; bagasse; micro, small and medium scale hydro; natural gas. The desired status is to have local generation capacity that is above local demand.

Transmission

The main objective of the transmission network is to evacuate power from bulk supply points to major load centres.

2.3.10 Tanzania

In December 2016, the Ministry of Energy and Minerals of Tanzania issued an update of the Power System Master Plan which covers the planning horizon to 2040. The Plan reflects the government's vision of transforming the country to middle income status by 2025 and to achieve an electrification target of 75% to 90% of households by 2035. High power demand from mining and industry as well as the increased electrification rate is expected to result in an extremely high growth rate of 11.4% per year over the planning horizon, which is significantly higher than historical growth rates.

Generation

Much of the high demand is expected to be supplied from local resources based on the following mix: 40% gas, 35% coal, 20% hydro and 5% renewable. By 2040 out of an expected 22515 MW installed capacity only 400 MW is expected to be provided from import options. The optimum scenario is selected based on a balance between economy, energy balance and environment impact.

Transmission

The focus is the development of the National Grid by introducing 400 kV in addition to reinforcement and extension of the 220 kV network. Of relevance to the SAPP Pool Plan are planned 400 kV interconnections to the country's EAPP and SAPP neighbours.

2.3.11 Zambia

The System Development Plan Main Report of 2010 produced with funding from JICA does not provide explicit information on the energy policies of Zambia but has sufficient information to give an indication of the national development strategies. A major recent issue to note is the high level of curtailed consumption (load shedding) due to force majeure affecting production from hydro resources that accounted for over 95% of national generating capacity. Difference between forecast and actual was about 30 to 40 per cent.

Generation

The power generation plan that was recommended at the time assumes self-sufficiency based on either domestic hydropower and locally mined coal generation of 200 MW or domestic hydropower and both locally mined and imported coal generation (to meet 25% of demand). Import dependency was considered high risk for the following reasons:

- ❑ SAPP does not have extra capacity because the power demand-supply situation in each member country is tight
- ❑ There is no guarantee that the generation development plan of each SAPP member progresses on schedule
- ❑ SAPP does not have a price transparent market and therefore imports may not be advantageous in terms of cost for Zambia

Revision to the plan to accommodate electricity imports was recommended subject to clarification of availability and price. The report noted that there was no plan for coal imports in the National Energy Policy. To mitigate the drought risk on hydropower, it was recommended that coal accounts for approximately 15% of new generation capacity to 2030.

The recommended plan was designed to meet a very high target reserve margin of 50% of installed capacity and 20% of energy balance (with 16% for dry years). The 50% capacity margin is made up of 16% dry year reserve + 13% planned maintenance + 5% degradation + 5% forced outage + 11% other factors. This is a conservative target that assumes no support from SAPP.

Transmission

Interconnections are recommended for economy and security reasons - importing power to off-set more expensive domestic generating plants, selling surplus power when available and to provide spinning reserve and part of standby reserve power. The Zambian grid can also be developed to facilitate wheeling of power to markets in the south and to Malawi and Tanzania (and hence the East African Power Pool (EAPP)).

2.3.12 Zimbabwe

The main reference document is the April 2016 draft of the ZESA System Development Plan which is presented as the country's plan. Zimbabwe is one of the few countries with explicit policies with respect to the balance between local generation and imports. The country's economic growth is lower than historic levels and therefore the power demand has declined significantly relative to the situation in other countries in the region.

Generation

ZESA's generation development plan is based on the following planning policies:

- ❑ **Security-** The minimum level of internal generation shall have, as a long term objective, capacity greater than 100% of demand with a reserve of no less than the system largest loss
- ❑ **Reliability (adopted from SAPP)** - the minimum reserve level to be carried on the system should be at least 10.6% of adjusted demand for thermal based power and 7.6% for Hydropower and a weighted average for a combination of both. Adjusted demand is equal to the peak system demand plus the amount of firm tariff power exported minus the amount of firm tariff power imported.
- ❑ **Economic-** for economic considerations firm imports may exceed the reserve requirement limit as long as the security criterion is met and sources of energy are significantly diversified in both technology and geography and are cost effective relative to local options.

Transmission

The transmission plan addresses the following objectives:

- ❑ Evacuation of power from power generating stations
- ❑ Connecting major load centres while providing operational flexibility

Facilitate trading with SAPP including wheeling - the system should operate within statutory limits outlined in the Zimbabwe Grid Code and should comply with SAPP Transmission Planning Criteria.

2.4 Approach adopted for Component A

Generation planning

Component A is based on national power master plans, extended where necessary to 2040. The generation planning software that is used is PLEXOS: Integrated Energy Model v7.3. This is a dynamic programming model which minimises the total costs (capital, fuel and

variable operations and maintenance costs), subject to various constraints, over the planning horizon.

The PLEXOS model is solved for three time-horizons:

- ❑ Long term (LT) - system expansion, software selects candidate plants on a least cost basis to complement existing and committed projects; spans entire horizon.
- ❑ Medium (MT) - hydro-thermal coordination which respects hydrology limits and other operating constraints (heat rates, ramp rates, minimum stable output, etc); operates in monthly time steps.
- ❑ Short term (ST) - unit commitment and economic dispatch; operates in hourly time steps.

Generator units are divided into three classes:

- ❑ **Existing** units (including their decommissioning dates where known).
- ❑ **Committed** units; in Component A, these are “almost existing” but not yet in operation in 2017, as well as defined as committed by the countries even if projects are only at very early stages of development; for Components B and C, and for sensitivity cases the definition of committed projects takes account of the development stage.
- ❑ **Candidate** units: generation expansion projects identified by the countries; generic plants for different technologies are also included as candidates in the model.

Key assumptions and simplifications that have been made to build a model that extends over 12 countries with close to 500 generation options are:

- ❑ Large hydropower plants across shared rivers are built as a set; average hydrology assumed for energy output (a sensitivity test analyses ‘dry’ climate).
- ❑ Dispatch of hydro and renewables limited by energy availability; dispatch of thermal plants is cost-based.
- ❑ Investments are incurred at a single point in time and associated costs are ‘overnight’ costs (not including financing costs).
- ❑ Hourly demand curves synthesized from the annual peak demand and energy forecasts; the few available actual recorded curves were used to determine shapes.

Assumptions that result in anomalous Component A results

Component A tracks the national power master plans, and hence many of the future project options have been specified by the utilities as ‘committed’ rather than as ‘candidates’. Component A respects nationally specified in-service dates and sequences of development.

These assumptions lead to implausible Component A results for some countries, such as new power plants being built but hardly being used.

These anomalies are also the result of the restrictive transmission assumptions for Component A. After considerable discussion at the workshop in Johannesburg in December 2016, the only interconnectors in Component A are as follows:

- ❑ Existing transmission lines connecting member utilities
- ❑ Projects that are likely to be implemented in the short term - 3 to 4 years. The agreed new transmission projects included in Component A are:
 - ❑ Zambia – Tanzania (assuming a 200 MW transfer limit which is feasible for the 3-4 year horizon)
 - ❑ The Zimbabwe – South Africa link as part of the MOZISA project
 - ❑ The Livingstone – Hwange link as part of the ZIZABONA project

Having only a limited number of transmission lines available limits trade in Component A. This results in some countries having large installed capacity which is hardly used, while other countries experience unserved demand.

These anomalies, which are also a result of generation assumptions, disappear in Components B and C, where most new generation options are treated as candidates and sufficient transmission capacity is provided to optimise trade in the region. Lower levels of generation investment then become possible, as well as lower fuel and variable operations and maintenance (O&M) costs. As is discussed in subsequent sections, this has the effect of reducing the overall net present value (NPV) cost of the investment sequence when compared with Component A.

Sensitivity test – Component A

It was agreed at the June 2017 workshop in Johannesburg that there should be a sensitivity test on Component A. The requested sensitivity study of Component A is an optimized and more realistic version that considers less optimistic demand assumptions and allows more optimization space for the software by reviewing the commitment status of projects based on their development stage.

There is concern that the demand forecasts may be too optimistic, and the restricted optimization leads to results that cannot be used as a good reference case. The modelling team was empowered to review the demand forecast, according to their own professional judgment. Committed plants are restricted to only those plants that are under construction or have reached financial close.

2.5 Approach adopted for Component B

In Component B, only those projects which are under construction or have reached financial close are treated as 'committed'. Some exceptions to this rule have been made for projects

such as Batoka where there is strong commitment from more than one country and there are on-going activities to get funding. This expands the list of 'candidate' generation options, thereby removing one of the main constraints associated with Component A. The transmission aspect of Component B is developed iteratively:

- ❑ First step is to remove transmission constraints completely in order to identify the least cost regional generation options – all trade is possible between utilities with zero transmission capacity constraints and cost.
- ❑ Second step is to introduce transmission line capacity constraints and costs into PLEXOS (from the PSS/E modelling) and to re-optimize.
- ❑ This step needs to be iterated multiple times in order to bring the PSS/E analysis and PLEXOS transmission assumptions into harmony.

In the first step, there are instances of low cost generation being selected that are very far from the load centres. This is modified as the costs and capacity constraints on transmission lines are introduced. However, interconnector costs are low in relation to the costs of generation investments and thus the first step of Component B provides good insights into the economic distribution of generation capacity across the region.

Once the full iterative process is complete, the optimised 'full integration' scenario provides the least cost way of investing and using generation capacity to meet the load forecast for the region as a whole.

2.6 Approach adopted for Component C

Main Component C scenario

Component B is an 'idealised' case. The objective of Component C is to adjust the full integration case to a realistic, implementable plan, by introducing the following constraints derived from the SAPP Planning criteria and recognition that in practice countries will, for various reasons, operate rather than mothball key power plants within their borders:

- ❑ Security constraint: each country should have sufficient installed capacity to be able to meet its maximum demand in 2040
- ❑ Minimum capacity factors: large thermal power plants should operate at or above minimum capacity factor levels.

The second set of constraints is needed to avoid existing and new thermal plants operating at very low or even zero capacity factors.

The focus in Component C is on examining the key transmission corridors that make trade possible, and in the process reduce investment requirements and deliver reductions in operational costs.

Iteration is again required between the PSS/E modelling and PLEXOS to ensure that the assumptions are consistent and the results coherent. The transmission investments have to meet the following criteria:

- ❑ Security and reliability of supply – each interconnector is to have adequate transfer capacity which is used to an extent that justifies its construction
- ❑ Adequate transmission capacity is to be provided to evacuate power from new generation stations
- ❑ To facilitate trade, national grid reinforcements may be needed to provide adequate wheeling capacity.

The focus is on the interconnectors and investments that support trade. The scope does not include detailed planning of internal transmission networks of each utility.

Sensitivity tests and Real Options Analysis

The sensitivity tests on Component C and Real Options Analysis (ROA) applied to key transmission corridors have the intention of testing whether Component C is sufficiently robust in the face of significant future changes resulting from the resolution of uncertainties to be treated as the “preferred” scenario and hence the recommended Pool Plan. There are two aspects:

- ❑ ‘Robust’ implies that the basic generation and transmission investment sequence would not have to be radically altered should the sensitivity scenarios materialise.
- ❑ The ROA component examine the benefits of phased development of key interconnector projects, which will typically require higher upfront unit costs, but will allow savings to be made when investment sequences can be modified in the light of the resolution of future uncertainties.

The sensitivity tests discussed and agreed with the participants at the June 2017 workshop are:

- ❑ Impact of ‘drier’ climate change
- ❑ Impact of delays in bringing key projects to commercial operation for whatever reason, in particular delayed implementation of Inga
- ❑ Impact of lower than expected demand
- ❑ Impact of South Africa’s Integrated Resource Plan requiring a cap on imports of electricity
- ❑ Impact of a high renewables scenario.

2.7 Integration across Components A, B and C

It is important to observe that in the TOR it was anticipated that Components A, B and C would be analysed and reported upon sequentially. In practice, it was found that the complexity of the interconnected system across 12 countries is such that runs of the different components repeatedly led to inconsistencies in data being identified and resolved and

improvements in model specification being made. The final runs of the three components were therefore done at the same time.

In view of the inter-relatedness of the 3 components, it was also agreed at the June 2017 workshop that a consolidated report covering Components A, B and C would be produced, rather than individual A, B and C reports and then a consolidated report (as specified in the original TOR). This report is the Final Report, finalised after receiving comments following the SAPP Executive Committee meeting in the third week of March 2018.

2.8 Specific assumptions made in the modelling

Fuel prices

Prior to the June 2017 workshop, the assumptions about fuel prices did not have significant variation across countries. The prices were criticised for being fixed over time and for being on the low side for gas. A thorough re-assessment of fuel price assumptions was made after the workshop and subsequent runs of the PLEXOS models incorporate updated fuel price assumptions which change (in real terms) from year-to-year. These are shown (for selective years) in Table 5 below.

Fuel type	2017	2030	2040
Gas (domestic)	2.6	3.3	3.9
Gas (LNG netback)	9.1	11.5	13.7
Coal (domestic)	2.5	2.7	3.0
Coal (Malawi)	3.1	3.4	3.7
Crude oil (reference)	8.1	14.8	16.5
Uranium	1.4	1.4	1.4
Diesel	10.7	19.5	21.8
HFO	7.3	13.3	14.9

Sources: Compound assumptions based on International Energy Agency (IEA) World Energy Outlook 2016 and Bloomberg data provided by World Bank.

The prices are based on international prices, adapted to Southern Africa. The South African gas price is estimated as an LNG netback price, with data sourced from the Integrated Resources Plan (IRP) model and updated for the exchange rate. The coal transport costs in Malawi are extracted from the recently completed IRP. HFO and Diesel are linked to the price of crude oil. Following IEA-based analysis of the relationship between crude oil and refined products, prices were set according to their ratio to the world price of crude oil. For Diesel it is set to 1.32 of the price of oil, and for HFO the factor is 0.9.

Technology prices

Unit investment prices were also reviewed after the June workshop. Seven main sources were used, as summarised in Table 6 below.

Tech- neology	Sub- category	EIA(US) 2016	Lazard 2016	IRENA 2016	ESKOM 2015	IEA 2015	SEM Ireland 2016	Bloom- berg/WB 2016	SAPP PP 2017
Gas	OCGT		900		694	700	795		795
	CCGT	978	1,150		786	1,014			1,014
	ICE engines	1,342	875		1,086				1,086
Coal	Subcritical		5,700		3,105	2,264			2,264
	Supercritical	3,636			3,739				3,739
	IGCC		9,250		5,779				5,779
Hydro	Small					5,281			4000- 4200
	Large					2,493			3,000
Solar	Thermal CSP		6,500	3,600	3,987				3,987
	PV	2,671	1,375	790	1,500		990		990
Wind	On shore	1,877	1,475		1,663	1,841		1,720	1,720
	Offshore		3,625						
Biomass		4,985	3,250		6,500	4,060			4,060
Nuclear			6,800		6,137	4,896			6,137

EIA US Energy Information Administration: Capital costs estimate for utility scale electricity generation plants (Nov 2016)

Lazard Lazard Levelized cost of energy analysis, December 2016; average capital cost taken from specified range.

UK Dept for Business, Energy and Industrial Strategy: Electricity Generation Costs, 2016

IRENA The Power to Change - Solar and Wind Cost Reduction Potential to 2025, IRENA, June 2016

ESKOM ESKOM SA IRP 2015 PLEXOS model

IEA IEA: International Energy Agency: Projected costs of generating electricity, 2015

Bloomberg Bloomberg New Energy Finance, 2016

For many of the capital costs, the prices which have been adopted are from the South Africa IRP model, because this is most relevant for the region. It is to be noted that South African coal has high sulphur content and local regulation requires desulphurization making the capital costs of supercritical units more expensive. The next alternative of Integrated Gasification Combined Cycle (IGCC) is significantly more expensive.

The capital costs of gas-fired units have been adjusted upwards according to recent trends observed in international documents. Renewable source costs have been adjusted according to the Bloomberg document provided by the World Bank.

Discount rate

The discount rate that is used for discounting costs to obtain the summary net present values (NPVs) for each scenario is 6%. This value was chosen because it is the value recommended in a recent study by the World Bank on the social rate of discount (SRD) that is suitable to be used in infrastructure projects⁵. It is to be noted, however, that SAPP normally uses a social discount rate of 8%.

2.9 Unserved energy

The economic cost of unserved energy is high, but assigning a precise value is difficult. After discussions with the World Bank, a value of \$1,000/MWh (\$1/kWh) has been used to quantify unserved energy in the NPVs which are reported in the Section 3.1. In a situation of exceptional and unexpected load shedding, this is a reasonable cost to assume. In practice, in countries where load shedding has been frequent in the past, pre-announcing load shedding plans could reduce the economic damage below the calculated level. Furthermore, incentives can be provided to consumers to shift their load and hence limit the amount of load shedding that would be necessary.

In the PLEXOS model, a higher value of unserved energy was used through assigning a value of \$3,000/MWh to the 'Internal Value of Lost Load' parameter. If this parameter is set at a relatively low level, the model can allow unserved energy under certain constraints (such as emission limits), even when generation is available. The intention behind using a very high value was that the model would always choose available generation and transmission resources ahead of load shedding.

However, at the end of the planning period, close to 2040, it may be economically efficient to allow some degree of unserved energy, because the next available increase in generation capacity may be large in relation to the amount of unserved energy, and the investment would not be warranted. In the scenario runs, there is unserved energy in 2017 in DRC, Malawi, Mozambique, Namibia and Zambia. This is quickly eliminated through committed investments in Component A and through trade in Components B and C. Unserved energy persists into the 2020s in Mozambique until the internal transmission system has been fully interconnected.

⁵ World Bank (2016): Discounting Costs and Benefits in Economic Analysis of World Bank Projects

In the final year, 2040, unserved energy emerges once more due to the ‘planning boundary’ reasons described above. In Component C, Angola has 264 GWh of unserved demand (0.5% of national demand), while Lesotho has used up all transmission capacity for imports and has 81 GWh of unserved demand (3.8% of national demand). In Component B in 2040, unserved energy is somewhat higher because PLEXOS decides it is not economical to eliminate all unserved energy, whereas in Component C it is a requirement that the domestic capacity meets peak demand.

Overall, the NPV of the costs of unserved energy is higher in Components B and C than in Component A. This counter-intuitive result arises from a mix of slightly different generation plant mixes and transmission constraints in the early years, which count the most in the NPV calculation. A most startling case is Namibia, which is in deficit at the start of the planning horizon, but is able to import a higher level of energy in 2017 in Component A (1,578 GWh) than in Components B and C (1,080 GWh and 1,1516 GWh respectively). As a result, unserved energy in 2017 in Component A at 299 GWh is lower than unserved energy in Components B and C (797 GWh and 361 GWh respectively). The highest level of unserved energy across the region is 3,768 GWh in 2018 in Components B and C, but this is still a small proportion (1.1%) of total energy demand that year (335,344 GWh).

2.10 Limitations of the methodology

A regional planning exercise with 12 countries, 291 existing, 93 committed and 134 candidate generation (including generic) options and a similarly large proliferation of transmission interconnector options, inevitably means that simplifications have to be made in the analysis. The lack of comprehensive, accurate data and consequent need to make ‘best estimate’ assumptions constrains the accuracy of the results. Even if ‘perfect’ data had been supplied by all 12 utilities early on in the study, and the entire study period had been spent exploring different scenarios, there would still be limitations.

These are implicitly recognised by SAPP in that the Pool Plan is considered an *indicative* rather than a *prescriptive* plan. Nonetheless, it is important that the precise nature and extent of the limitations be clearly identified and understood. Although the plan is the result of applying powerful planning tools, including a least cost dynamic programming algorithm for generation and transmission investment planning and optimising the short-run production of energy, the following constraints need to be recognized:

- ❑ **Demand forecasting:** The information about the methodology and basis for load forecasting in several cases turned out to be inconsistent with the projections which were finally agreed with the PSC members. In some countries, the demand forecast figures for the base year differed significantly from the actual figures supplied for 2015 and 2016, the discrepancy being attributed to suppressed demand. The PSC members insisted on their figures being adopted, but the planning team was subsequently encouraged to apply professional judgment while constructing the ‘low’ scenario.
- ❑ **Generation planning:** The data supplied on the costs and operational characteristics of the generation projects was not always complete and consistent. No feasibility studies were made available, and the planning team had to make its own assumptions to fill in gaps and resolve anomalies.

- ❑ **Load profile data:** this proved all but impossible to access. No hourly generation data was supplied. The planning team had to synthetically construct load profile data, starting from a previous regional PLEXOS data set.
- ❑ **Transmission planning:** data was mainly provided in PSS/E format and for some utilities in DigSilent Power Factory format, but mostly only models for load flow analysis. Dynamic models for future, long-term scenarios were generally not made available. The planning team had to apply its own assumptions and extend the horizon to 2040.
- ❑ **Modelling limitations:** each country is modelled in PLEXOS as a single node, except in countries (such as Angola, DRC and Mozambique) where there are currently isolated or weakly connected systems or, for particular loads as in the case of MOZAL. The optimisation in PLEXOS focused on transmission investments supporting regional integration. Costs and transfer capacities for such projects are included in the model, and key generation projects in the Pool Plan have power evacuated on such regional transmission projects. To take account of transmission investments which would be required for new 'internal' generation projects, the capital costs of these projects were raised to prevent the (small) cost bias which would otherwise have existed towards these projects being chosen.
- ❑ **Constraints** – unserved energy and the Component C requirement that installed capacity be at least equal to maximum demand in 2040 are modelled as 'soft' constraints in PLEXOS. There is a penalty for not meeting demand or the capacity constraint rather than a strict requirement. This implies that it may sometimes be economic for unserved energy to be allowed or the capacity constraint to be breached. At the end of the planning period, these issues would be resolved if the horizon were to be extended as investments in relatively large units in small countries would then make sense.
- ❑ **Renewables:** general assumptions about the energy available from renewable technologies had to be made. Ideally the prices and resource availability data for each site should be incorporated in the database.

These limitations should not be taken to imply that the planning exercise is not of value, but rather that the absolute numerical results should not be given undue credence. As we trust is demonstrated by subsequent sections of this report, the strength of the Pool Plan that has been produced lies in the insights it provides into the opportunities and risks of deepening regional power sector integration in Southern Africa. The key generation projects of regional significance and transmission interconnectors have been identified, and a direction provided for the next steps in commissioning pre-feasibility and feasibility studies to confirm the importance of these projects.

3 SAPP Generation Investments

3.1 Net present value of costs

Table 7 and Table 8 provide the headline net present value (NPV) results from the PLEXOS model. The objective function in the optimisation is to minimise investment costs (overnight capital costs discounted from the year of commissioning), short-term operational costs (fuel and O&M costs), plus the costs of unserved energy⁶. The NPV of the total costs is the main indicator that can be used to rank the Components.

The results in Table 7 show that, as compared with Component A (the Benchmark Case), Component B (the Full Integration Case) involves building 17 GW less generation capacity⁷. Although transmission investment is higher in B, this is a small proportion of total investment costs, leading to an overall investment cost saving of \$38 b. Short-term operational costs are also lower, but only \$4 b less in B as compared to A. This is somewhat surprising because the Full Integration case makes it possible for demand to be satisfied by the large hydropower generation stations on the Zambezi, Congo and other river systems, rather than incurring the costs of fuel and O&M involved in thermal generation. However, the increasing role of hydropower generation in satisfying demand occurs in the later years of the planning horizon and hence the discounted savings do not impact so significantly on the overall NPV of costs. Overall, the NPV of costs of the Full Integration Case is \$40 b lower than the Benchmark Case (\$42 b lower if the notional costs of unserved energy are excluded).

Table 7 NPV of costs of Components A, B, C and differences in absolute terms

\$b / GW differences	Component A	Component B	Component C	B<>A	C<>A	C<>B
Investment costs (\$ b)	155	117	121	-38.1	-34.3	3.8
<i>of which - generation</i>	154.2	113.5	117.7	-40.6	-36.5	4.1
<i>- transmission</i>	1.1	3.6	3.3	2.5	2.2	-0.3
Short-term operational costs (\$ b)	128	123	125	-4.1	-2.9	1.2
Unserved energy (UE) cost (\$b)	12	13	13	1.7	1.5	-0.3
SAPP w/o UE (\$ b)	283	241	246	-42.2	-37.2	5.0
SAPP with UE (\$ b)	294	254	259	-40.5	-35.7	4.8
Installed generation capacity (GW)	143	127	130	-17	-14	3

Source: PLEXOS model results. All references to '\$' in this report are to 'US\$'. b = billion (10⁹).

Table 8 below gives the same NPV information, but shows the differences in relative rather than absolute terms. The table indicates that Component B (the Full Integration Case) has an

⁶ The approach used for unserved energy is spelt out in Section 2.9.

⁷ Calculated values from the tables may differ from some of the entries due to rounding.

NPV of costs that is 14% less than Component A (the Benchmark Case). The main cost savings are in investment costs, where B is 25% less costly than A. The difference in short-term operational costs is much smaller (3% lower in B as compared with A).

Table 8 NPV of costs of Components A, B, C and differences in %

% differences	Component A	Component B	Component C	B<>A	C<>A	C<>B
Investment costs (\$ b)	155	117	121	-25%	-22%	3%
<i>of which - generation</i>	154.2	113.5	117.7	-26%	-24%	4%
<i>- transmission</i>	1.1	3.6	3.3	228%	198%	-9%
Short-term operational costs (\$ b)	128	123	125	-3%	-2%	1%
Unserviced energy (UE) cost (\$b)	12	13	13	15%	13%	-2%
SAPP w/o UE (\$ b)	283	241	246	-15%	-13%	2%
SAPP with UE (\$ b)	294	254	259	-14%	-12%	2%
Installed generation capacity (GW)	143	127	130	-12%	-10%	2%

Source: PLEXOS model results. Note that the transmission component of investment costs is a small portion of the total (\$3.6 b or 3.1% in Component B and \$3.3 b or 2.7% in Component C)

As explained previously, Component A is an aggregation and extension of national generation and transmission plans, with only existing and already committed transmission inter-connectors being available for trade. This imposes an inward focus, where the countries require many of the generation options to be treated as 'committed' rather than as 'candidates'. As a result, the total net new build over the planning horizon is 88 GW, with the total installed capacity in 2040 being 143 GW, significantly above the regional maximum demand (115 GW without diversity and 105 GW with diversity). The total of short-term operational costs to meet energy demand is \$128 b.

In Component B, the regional transmission system is opened up to provide sufficient capacity for regional trade in electricity to be fully exploited. This allows the cost-saving advantages to be reaped, particularly in respect of reducing the requirement for net new generation capacity to 72 GW, leading to a total installed capacity in 2040 of 127 GW. The reason for the installed capacity having reserve capacity at regional level being much higher than is required by the planning criteria is due to the modelling assumptions that have hydropower plants being built as a set, with unit sizes designed to optimise the energy available rather than to meet the immediate demand. As already discussed, it is the savings in generation investment costs which are most significant in making B less costly than A. Operational costs are not significantly different and the (minor) costs of unserved energy are almost the same.

Component B is an idealised least cost case, which would not in practice be used as the basis for national planning because it does not take account of political economy constraints. Component C is the 'Realistic Integration' case, which incorporates the following restrictions:

- ❑ *SAPP security criterion* - by 2040, each country should have sufficient installed capacity to be able to meet its maximum demand.

- *Minimum capacity factors* – to avoid mothballing or very low load factors when low cost imports are available, large thermal power plants are constrained to operate at or above minimum capacity factor levels.

In comparing Components B and C, what is significant from the above tables is that the restrictions do not make C much more expensive than B. Relating C and B to A, it is evident that the Realistic Integration case (C) delivers almost the same cost savings over the Benchmark case (A) as Full Integration (B), while being much more acceptable as a basis for national planning.

Installed capacity in 2040 in C is 130 GW, only 3 GW higher than B and 14 GW lower than A. The installed capacity is still 24% above what is needed to meet collective maximum demand, which is 105 GW after diversity (115 GW without diversity being taken into account). Component C requires that the Security Criterion be met in each country, and there is more than sufficient installed capacity in the region for countries not meeting the Reliability Criterion from their own capacity to contract reserves from other SAPP members.

The savings from requiring less installed capacity mean that the investment costs of Component C in relation to Component A are significantly lower (by \$34 b or 22%). Operating costs are also lower, and costs of unserved energy almost the same, so that Component C is \$36 b (12%) less costly than Component A overall.

A satisfying finding of the study flows from the above discussion, in that the imposition of 'realism' constraints on the idealised full integration case involves only a limited cost, which does not significantly dilute the benefits of regional power sector integration.

Another important finding that emerges from the above tables is that the cost of transmission interconnectors is only a small fraction of the generation investment costs. On an NPV basis, in Component C investment costs are only \$3.3 b out of total investment of \$121 b, or less than 3%. There is thus a strong case to prioritise regional interconnector investments, which create opportunities for flexible responses to the out-turn of uncertainties, as well as generally making an important contribution to strengthening national transmission grids. This theme is analysed further elsewhere in the report, notably in Sections 5.3 and 10.

3.2 Key projects of regional significance

Subsequent sub-sections provide details of the generation mix and the investment sequencing, but to provide a prior overview of the drivers of the Pool Plan it is useful first to consider the main projects of regional significance. These are the projects that would be unlikely to be built without there being a commitment to trade in electricity in the SAPP region.

Generation projects meeting this description are mainly large hydropower schemes, but it is useful to start with documenting the main non-hydro projects. Table 9 below records projects of more than 100 MW based on coal, gas and non-hydro renewables (solar and geothermal) which are developed in the Benchmark Case (Component A).

Table 9 Major Thermal and Renewable Energy Projects in the Benchmark Case

Country	Technology	Total installed (MW)	MW installed by year	Plant Name
Angola	OCGT NG	500	100 in 2031; 400 in 2037	Generic
	Gas	750	500 in 2017; 250 in 2018	Soyo I
Botswana	Coal	732	300 in 2019;	Morupule 5&6;
			350 in 2035	Generic
DRC	Coal	500	500 in 2020	Gecamines
	Solar	600	3x200 in 2020	Generic
Malawi	Coal	1743	43 in 2019; 86 in 2020; 129 in 2021	Kammawamba
			120 in 2029	Pamodzi
			273 in 2030, 2032, 2034, 2036 and 2037	Generic
Mozambique	Gas	400	400 in 2022	Sasol
	Coal	1500	1200 in 2023; 300 in 2028	Tete & Moatize
	Gas	300	300 in 2026	ENRC
	CCGT	125	125 in 2036	Generic
Namibia	Gas	800	400 in 2024; 400 in 2035	Kudu
South Africa	Coal	14426	450 in 2017	Khanyisa
			1600 in 2017; 800 in 2018; 1600 in 2019; 800 in 2020	Kusile
			2538 in 2017; 2538 in 2018	Medupi
			750 in 2036; 750 in 2037	Generic (Large)
			800 in 2020; 800 in 2022 and 1000 in 2024	Generic (Medium)
	CSP	300	300 in 2020	Generic
	CCGT	1625	250 in 2022; 250 in 2024; 500 in 2025; 250 in 2027; 375 in 2030; 250 in 2033	Generic

Country	Technology	Total installed (MW)	MW installed by year	Plant Name
	OCGT	700	200 in 2024; 200 in 2026 and 300 in 2028	Generic
Tanzania	Coal	3900	300 in 2019; 200 in 2031; 400 in 2032; 400 in 2034; 400 in 2035	Generic
			200 in 2018; 200 in 2020	Kiwira I and II
			300 in 2020; 400 in 2022; 300 in 2026	Muchuchuma I, II and III
			400 in 2019; 400 in 2021	Ngaka I and II
	CGT3	4230	300 in 2019; 200 in 2031; 400 in 2032; 400 in 2034; 400 in 2035	Generic
	OCGT	150	150 in 2017	Kinyerezi I
	CCGT	885	240 in 2018; 300 in 2019	Kinyerezi II and III
345 in 2018			Somanga	
Geothermal	200	100 in 2029; 100 in 2034	Generic	
Zambia	Coal	600	600 in 2022	Maamba
Zimbabwe	Coal	2460	600 in 2019	Hwange Extension
			900 in 2024; 300 in 2025	Gokwe North
			330 in 2034; 330 in 2036	Southern Energy

Source: PLEXOS model results for Component A (base Benchmark case).

Regional generation projects of significance are those which are large in relation to national demand but which offer significant economies of scale and low operational costs. Once constraints on regional trade are removed, these projects in the SAPP region are mainly the large hydropower projects in the Zambezi, Congo and other river basins. Table 10 provides a summary of the main hydropower projects and the years in which they come into operation in the 3 components⁸. This provides an introductory perspective on the impact of the Pool Plan at the level of each country, as shown in the final column. The location of the key regional hydropower generation projects and the associated transmission interconnectors are illustrated in full page maps which are presented later in this section.

⁸ Committed projects that are to be commissioned in the next year are not included.

Table 10 Major hydropower projects in the SAPP region

Hydropower project	Component A	Component B	Component C	Comments
Camambe II (Angola)	700 MW in 2017	700 MW in 2017	700 MW in 2017	Angola is an exporter in the early part of plan period. Rapid demand growth results in net imports by 2040.
Lauca (Angola)	2,004 MW in 2017	2,004 MW in 2017	2,004 MW in 2017	
Caculo Cabaça (Angola)	2,160 MW in 2022	2,160 MW in 2022	2,160 MW in 2022	
Batoka (Zambia and Zimbabwe)	2,400 MW in 2023	2,400 MW in 2023	2,400 MW in 2023	Zambia absorbs the capacity through rapid growth, Zimbabwe becomes an exporter.
Devil's Gorge (Zambia and Zimbabwe)	1,200 MW in 2025	1,200 MW in 2033	1,200 MW in 2032	
Mphanda Nkuwa (Mozambique)	1,500 MW in 2025	1,500 MW in 2025	1,500 MW in 2028	Key project, together with gas and coal, of Mozambique being a major exporter.
Cahora Bassa North Bank (Mozambique)	1,245 MW in 2026			This project is committed in A, but not chosen in B and C.
Inga 3&4 (DRC)	4,800 in 2020 15,366 MW in 2030	4,800 in 2030, 9,427 MW in 2033, rising yearly to 11,654 MW in 2036	4,800 in 2030 9,426 MW in 2032, rising yearly to 11,654 MW in 2034	DRC becomes a major exporter once Inga is developed.
Stiegler's Gorge (Tanzania)	1,048 MW in 2025 2,096 MW in 2037	1,048 MW in 2038	1,048 MW in 2036 2,096 MW in 2039	Hydro complements TZ's big investments in gas and coal.

Source: PLEXOS model results.

The countries with rapid growth in demand, notably Angola and Tanzania, turn from being net exporters to importers despite heavy investments in new capacity (thermal as well as hydropower). Towards the end of the plan period, the small exporters are Botswana (coal) and Zimbabwe (coal and hydropower), while the big exporters are Mozambique (hydropower, gas and coal) and DRC (hydropower).

From the mid-2020s, the biggest importer is South Africa. A key feature of the optimised components B and C is that investment in new generation capacity in South Africa is minimal, so that over the planning horizon South Africa turns from a net exporter to a major importer. This allows large generation projects and associated transmission projects to be developed in the exporting countries. South Africa's demand for imported electricity is thus a primary driver of the Pool Plan. One of the sensitivity tests in Section 9.2 explores the implications of South Africa placing a cap on imports.

Turning to **transmission**, the results of the modelling indicate that Angola and Malawi should be integrated into SAPP early on. The following interconnections are therefore clearly recommended for early development:

- ❑ N'Zeto/Angola – Inga/DR Congo

- ❑ Cahama/Angola – Kunene/Namibia
 - ❑ Possibly via Baynes if a decision to implement this project is firmed up.
- ❑ Matambo/Mozambique – Phombeya/Malawi

The addition of Batoka by 2023 can be supported through existing and already committed transmission projects. When Mphanda Nkuwa is added in 2028 (in Component C), the STE project in Mozambique will have to be in place. The existing MOTRACO system linking South Africa and the southern part of the grid in Mozambique along with the existing DC link from Songo to Apollo and also the link from Songo to Zimbabwe, would provide adequate capacity for trade with other SAPP members for some time once the STE backbone grid is in place. The STE grid therefore provides additional capacity for regional trade.

The largest hydropower project by far is Inga, which is also the most remote from the centres of demand it has the potential to serve (as shown on the subsequent map). The development of Inga therefore needs to be supported by major transmission line projects, which are listed in the table below, together with details of the STE project.

Table 11 Major transmission projects in the SAPP region

Transmission line	Characteristics	Component B	Component C	Utilisation in 2040
Inga-Angola	3 x 400 kV HVAC	1,100 MW in 2023 (i.e. two lines) 1,600 MW in 2033 (with third line)	1,100 MW in 2020 (i.e. two lines) 1,600 MW in 2034 (with third line)	14 TWh (Full load)
Inga-Luano (Zambia)	500 kV HVDC	2,000 MW in 2030	2,000 MW in 2029	10.7 TWh (61%)
Inga-Limpopo (Gauteng) (SA)	600 kV HVDC	3,000 MW in 2033	3,000 MW in 2032	26.4 TWh (Full load)
Kabwe (Za) - Mbeya (Tz)	500 kV HVDC	1,500 MW in 2030		
STE (Mozambique)	1 x 400 kV HVAC north to central 1 x 400 kV HVAC central to south 500 kV HVDC bi-pole line, first stage only on converters	In 2023, to cover local demand in Beira In 2027, providing 400 MW capacity north to south In 2027, 1,325 MW	In 2023, to cover local demand in Beira In 2028, 400 MW capacity north to south In 2028, 1,325 MW	STE (Mozambique)

Source: PLEXOS model results. The HVDC schemes are using two mono-pole lines except for the STE project which is assumed to be one bi-pole line. The first section of STE HVAC line links North and Central and is added a few years earlier than the southern part linking Central and South. The HVDC bi-pole line links North and South Mozambique. Further strengthening of the HVAC system is part of the plan in later years in some scenarios. In 2040, there are flows in both directions in the HVAC STE lines.

Figure 11 Map showing the location of key hydro projects

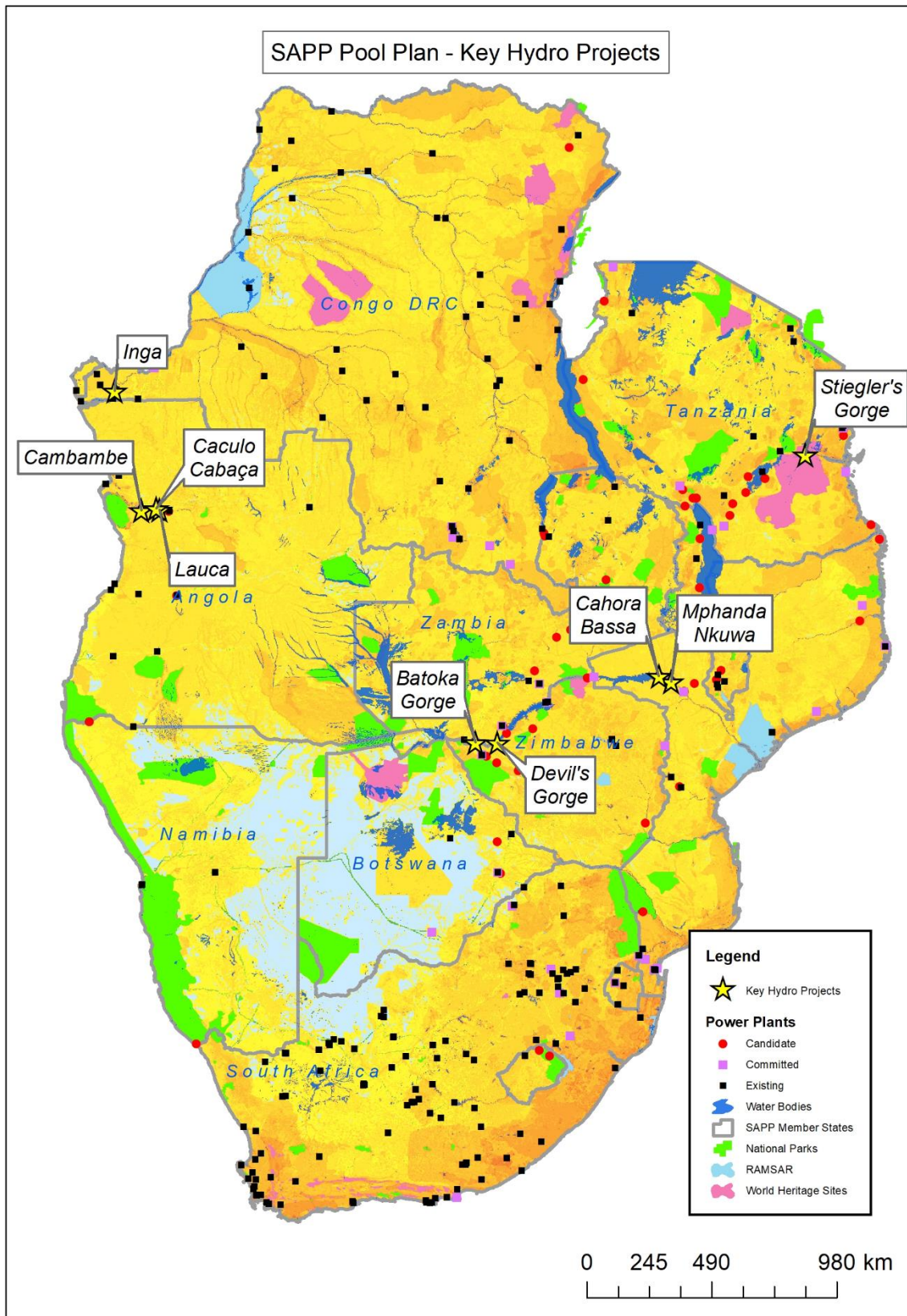
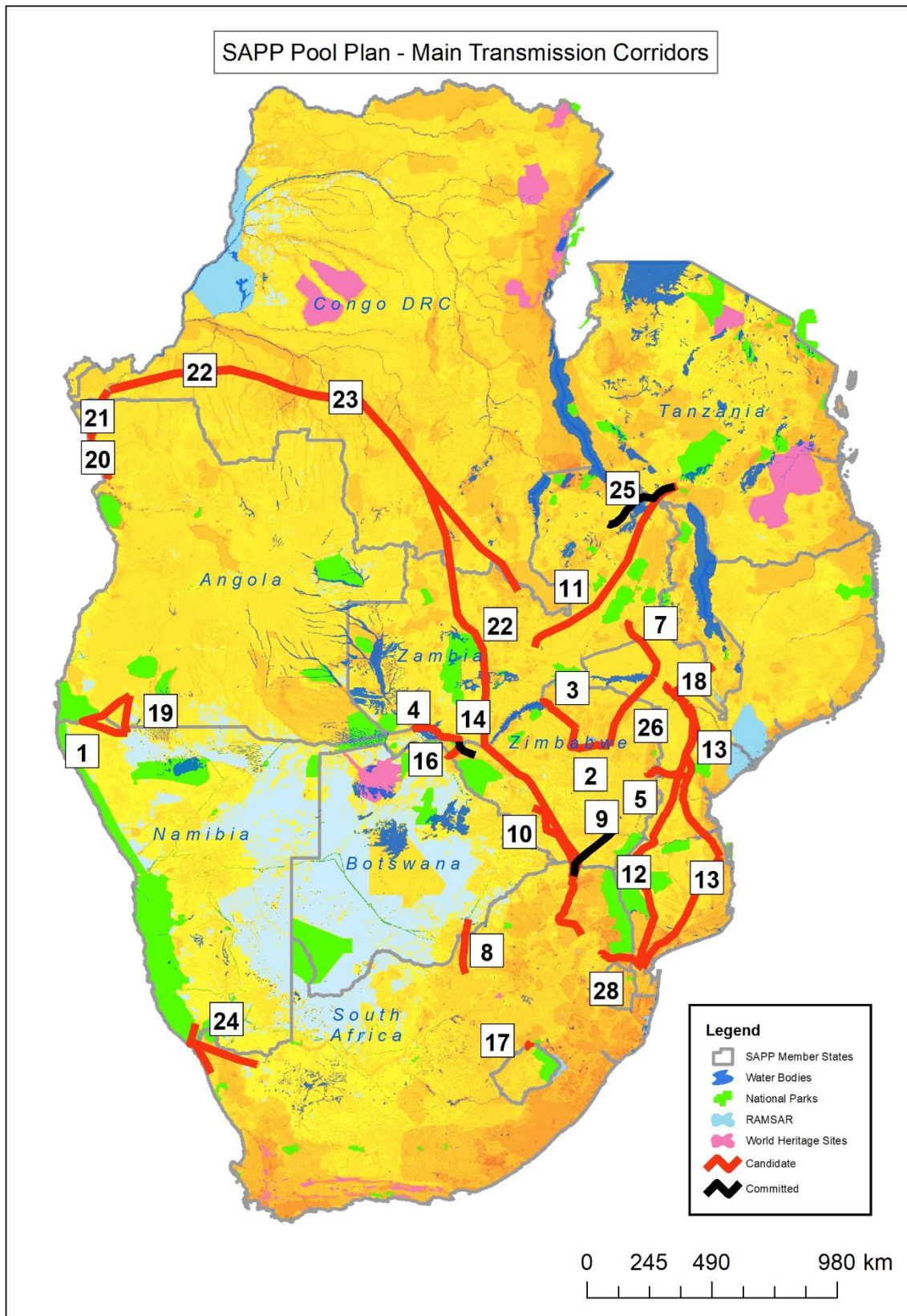


Figure 12 Map showing the location of the main transmission corridors



3.3 Capacity additions by technology and investment costs

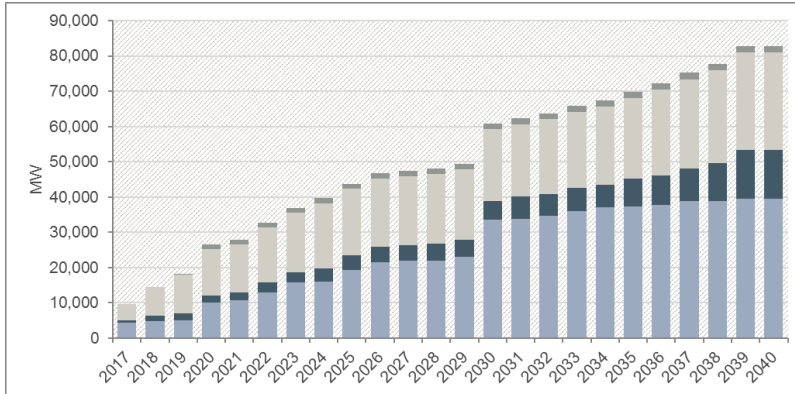
Most of the difference in the NPV of costs for the three components is driven by lower investment costs; \$155 b in Component A, compared with \$117 b and \$121 b in Component B and Component C respectively. The first two sets of graphs below show how the paths of generation capacity in Components B and C achieve lower investment costs - not only by adding less capacity over the period, but also by delaying investment expenditure until needed compared with the benchmark case.

Figure 15 shows the effect of capacity additions on the reserve margin across the period, relative to the base forecast for energy demand. In all 3 Components a reserve margin of over 20% is maintained at the end of the period, with Component A having the greatest margin of 36%.

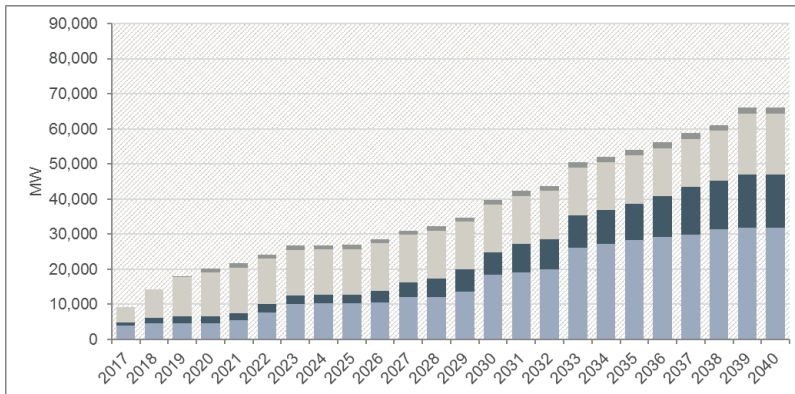


Figure 13 SAPP breakdown of cumulative new generation capacity by technology (MW)

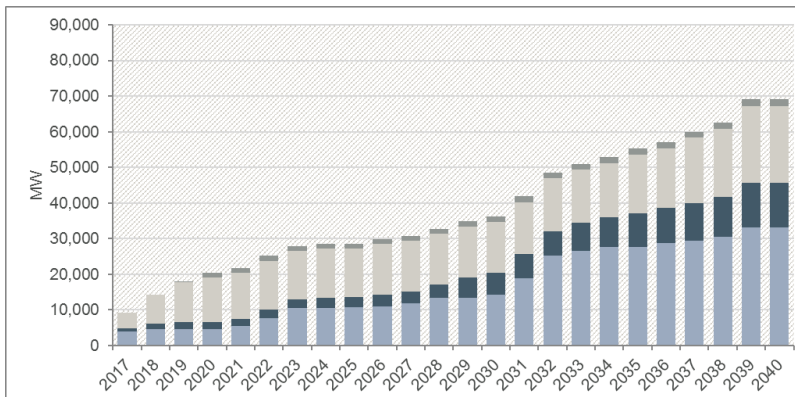
Component A



Component B



Component C



■ Hydro ■ Thermal (ex. Coal) ■ Coal ■ Renewables

These graphs show how new generation capacity (excluding already committed plants) varies across Component A (82,874 MW), Component B (66,115 MW) and Component C (69,068 MW).

While capacity is lower in both thermal and hydro plants in components B and C, the reduction of capacity is largely driven by a reduction in coal investment.

By relaxing the commitment assumptions in Component A, Components B and C are free to delay some of the costlier hydro investments to reduce NPV cost.

For instance, in Component A 40,000 MW of additional capacity has been built by 2024, whereas this amount of capacity is not reached until 2031 in the other Components.



Figure 14 SAPP capacity additions by category and investment costs (MW and \$m)

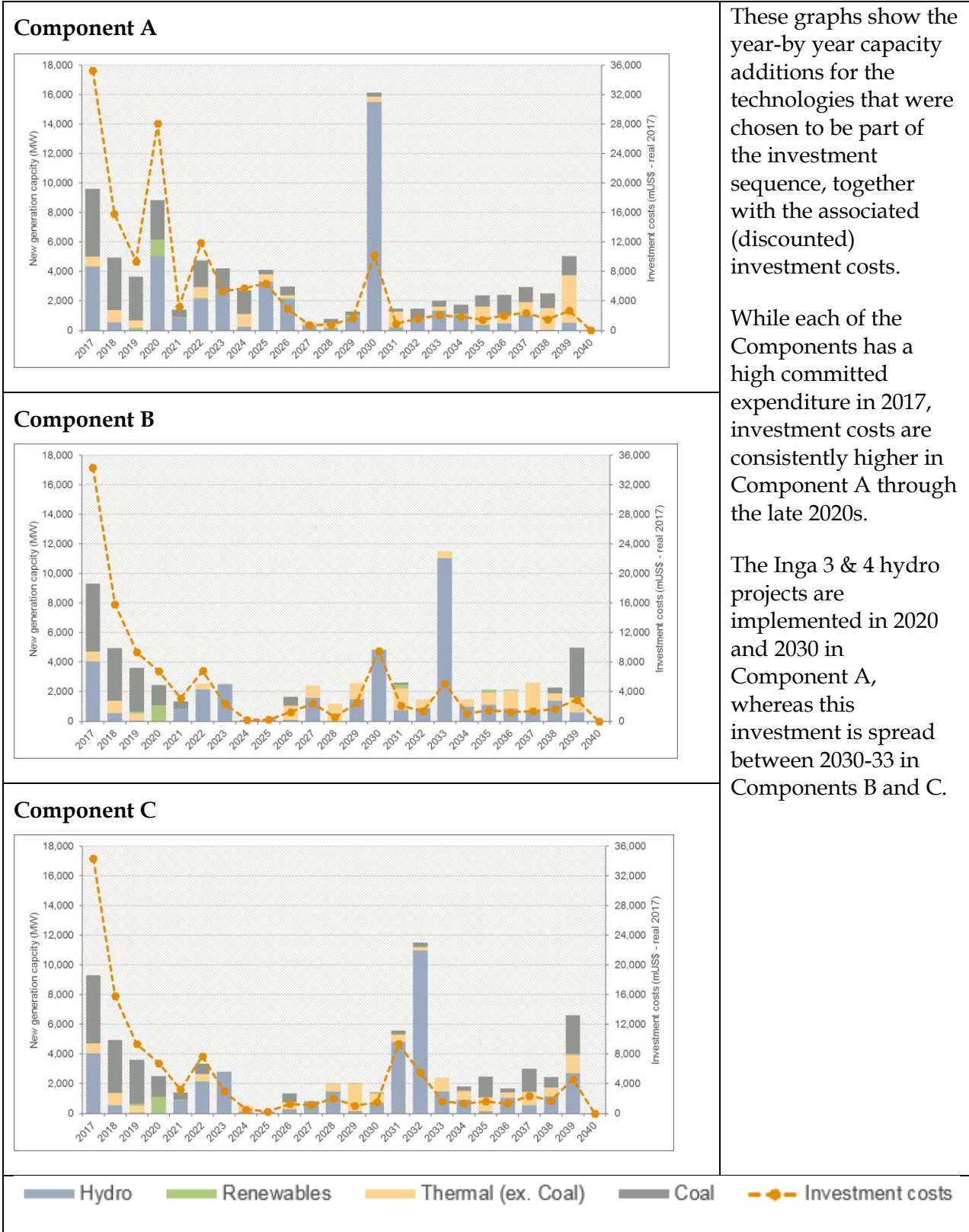
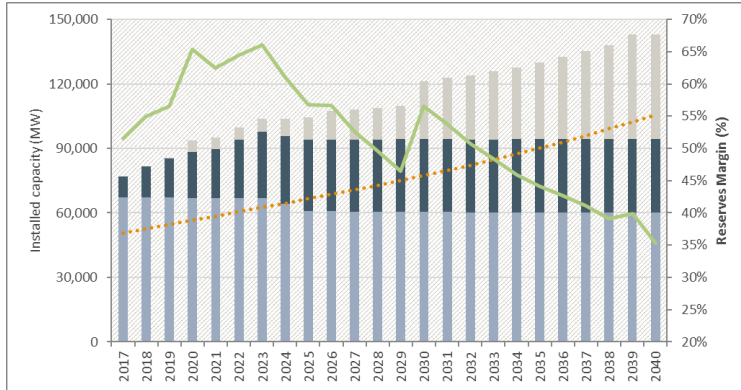


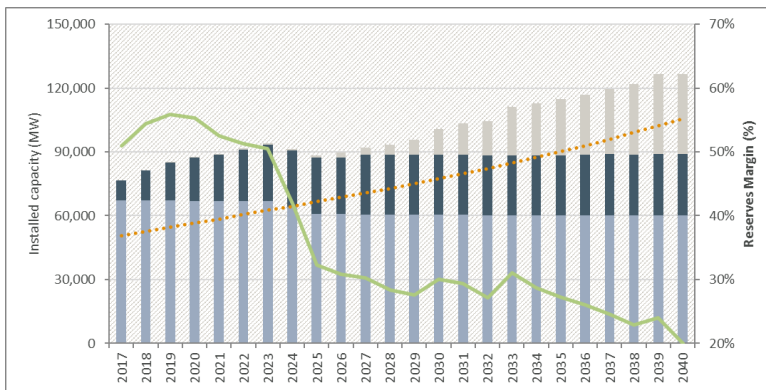
Figure 15 SAPP total generation capacity and reserve margin 2017-2040 (MW and %)

Component A



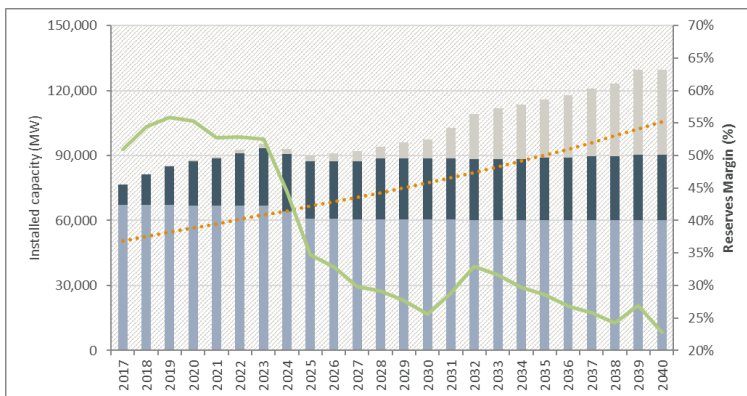
These graphs show the extent to which total capacity (existing generation capacity, less retirements and augmented by new generation) is able to meet maximum demand once diversity is accounted for. The capacity bars show the degree to which new investment is committed as opposed (in later years) to candidate plants which have been chosen.

Component B



In Component A, the system-wide reserve margin is very large in early years but declines to a still high 35% in 2040. These high reserve margins do not reflect a high level of security of supply in SAPP countries, but are rather a consequence of the Component A transmission assumptions which result in some countries having large excess capacity and other countries having unserved energy. This is discussed further in subsequent sections.

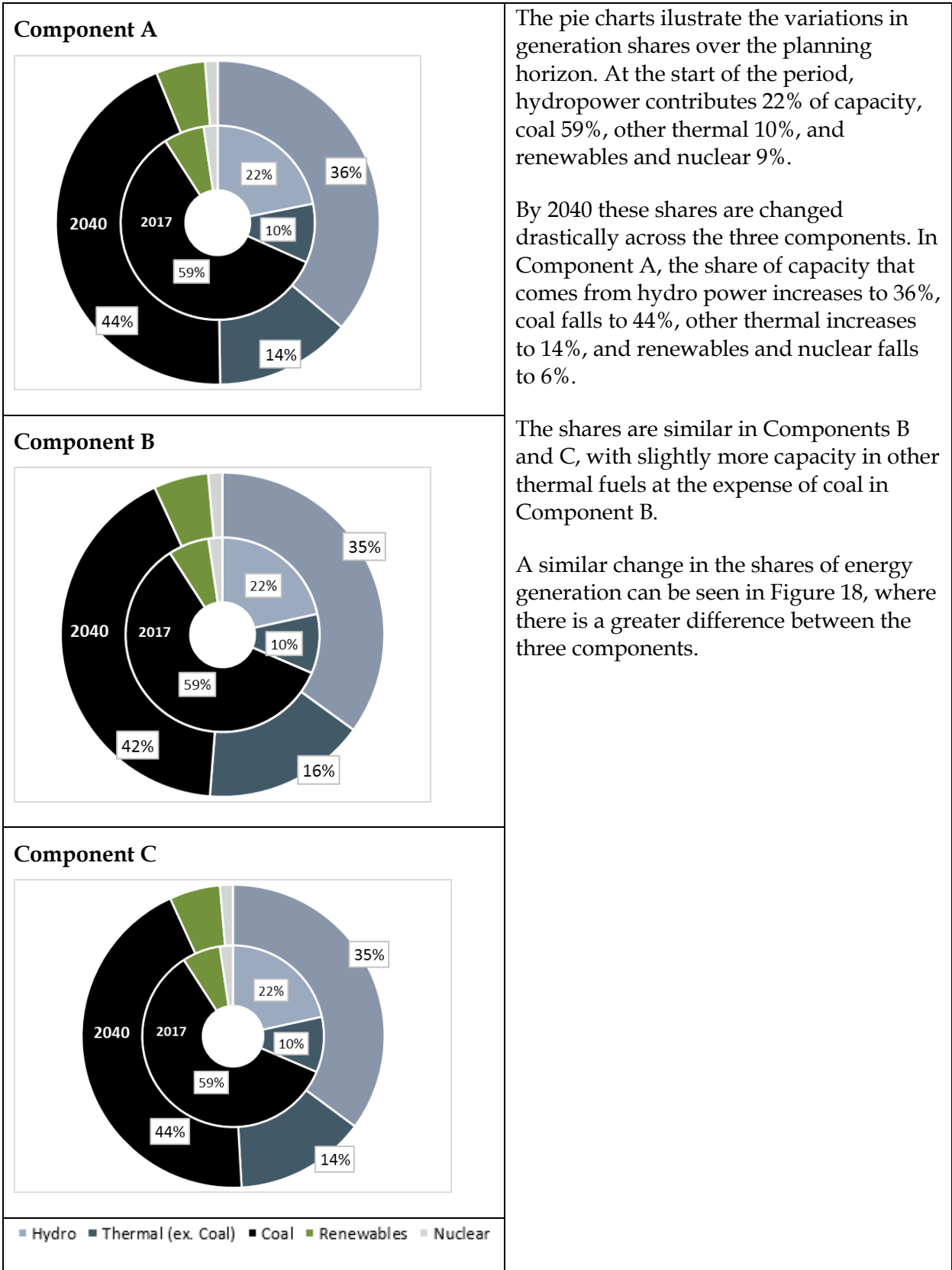
Component C



In Components B and C, the reserve margin reaches 20% and 23% by the end of the period.

Existing Committed Candidate Peak demand Reserves margin

Figure 16 Share of major generation technologies in total capacity in 2017 and 2040 (%)



The pie charts illustrate the variations in generation shares over the planning horizon. At the start of the period, hydropower contributes 22% of capacity, coal 59%, other thermal 10%, and renewables and nuclear 9%.

By 2040 these shares are changed drastically across the three components. In Component A, the share of capacity that comes from hydro power increases to 36%, coal falls to 44%, other thermal increases to 14%, and renewables and nuclear falls to 6%.

The shares are similar in Components B and C, with slightly more capacity in other thermal fuels at the expense of coal in Component B.

A similar change in the shares of energy generation can be seen in Figure 18, where there is a greater difference between the three components.

3.4 Energy Balances

Figure 17 SAPP mix of generation to meet energy demand (GWh)

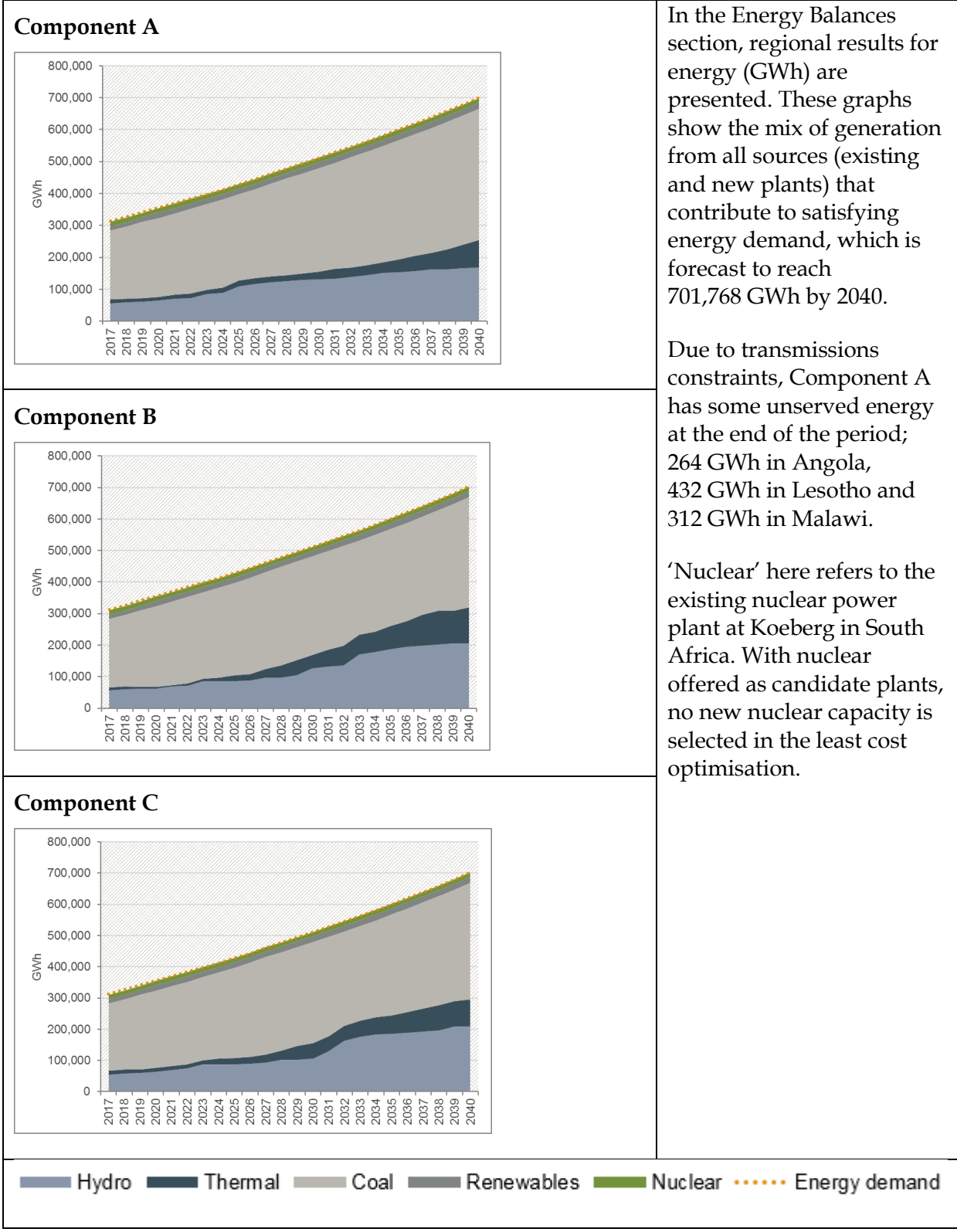
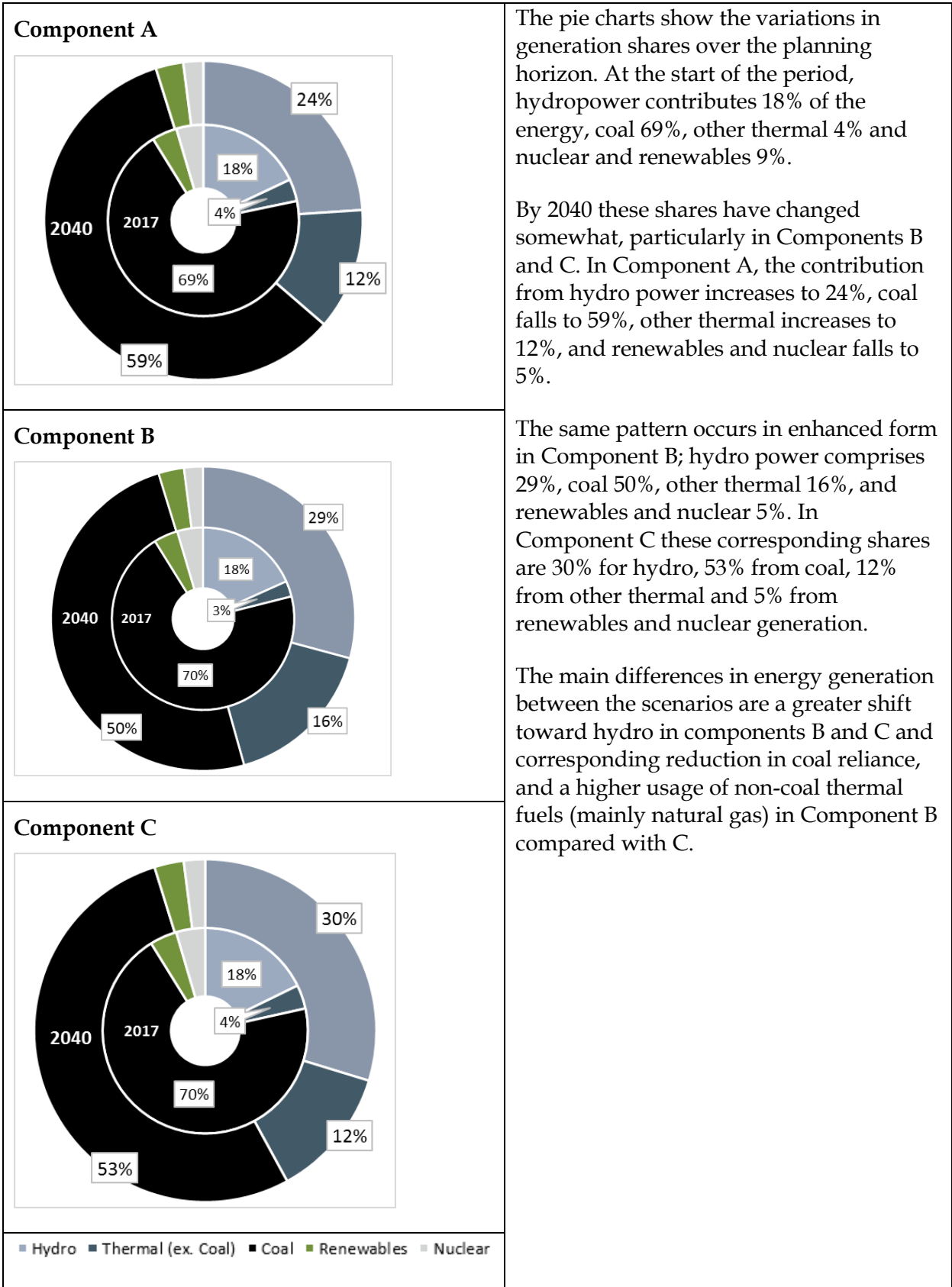


Figure 18 Share of major generation technologies in meeting projected demand (%)



The pie charts show the variations in generation shares over the planning horizon. At the start of the period, hydropower contributes 18% of the energy, coal 69%, other thermal 4% and nuclear and renewables 9%.

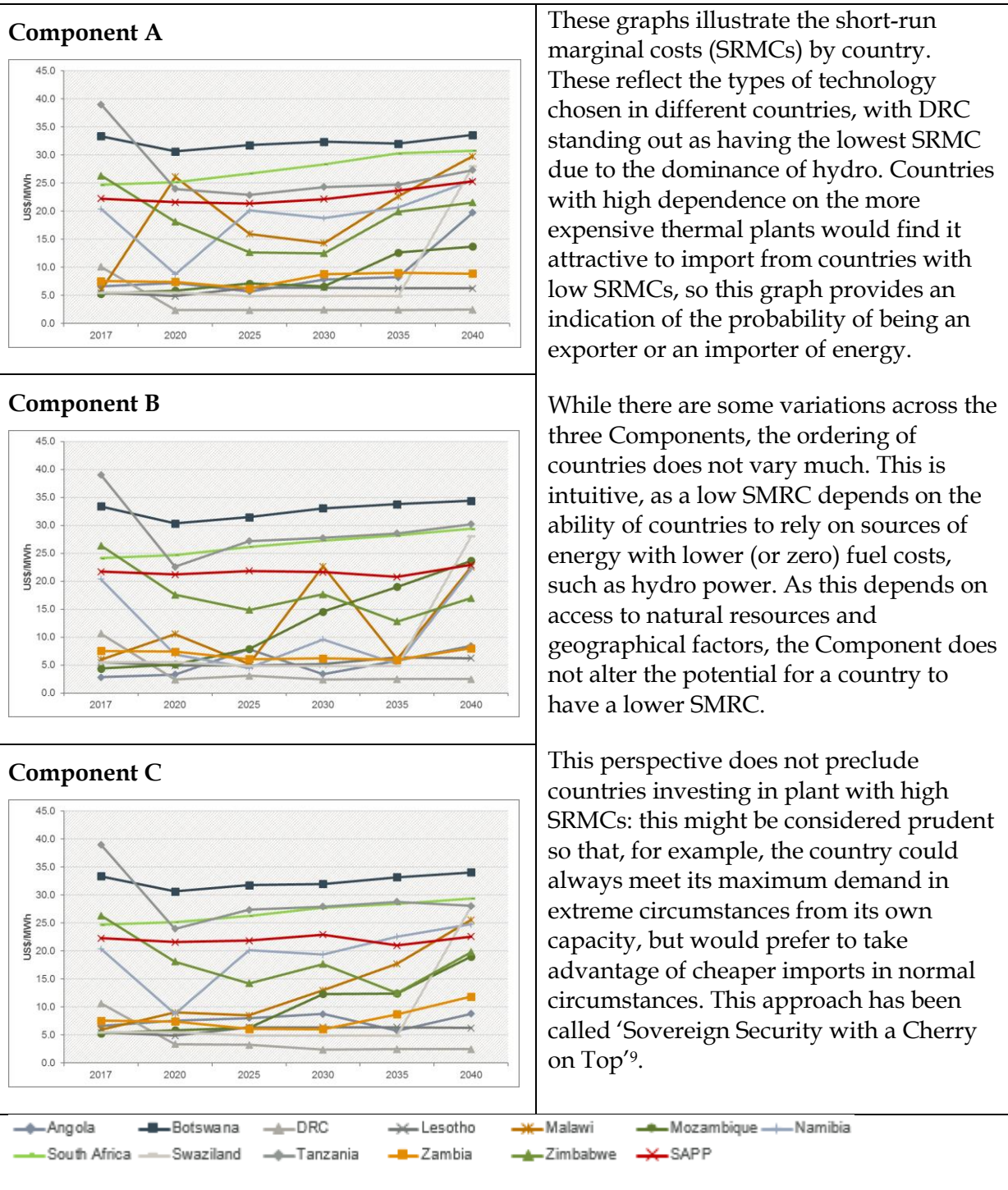
By 2040 these shares have changed somewhat, particularly in Components B and C. In Component A, the contribution from hydro power increases to 24%, coal falls to 59%, other thermal increases to 12%, and renewables and nuclear falls to 5%.

The same pattern occurs in enhanced form in Component B; hydro power comprises 29%, coal 50%, other thermal 16%, and renewables and nuclear 5%. In Component C these corresponding shares are 30% for hydro, 53% from coal, 12% from other thermal and 5% from renewables and nuclear generation.

The main differences in energy generation between the scenarios are a greater shift toward hydro in components B and C and corresponding reduction in coal reliance, and a higher usage of non-coal thermal fuels (mainly natural gas) in Component B compared with C.

3.5 Short-run marginal costs and export/import status

Figure 19 Short-run marginal costs by country (\$/MWh)



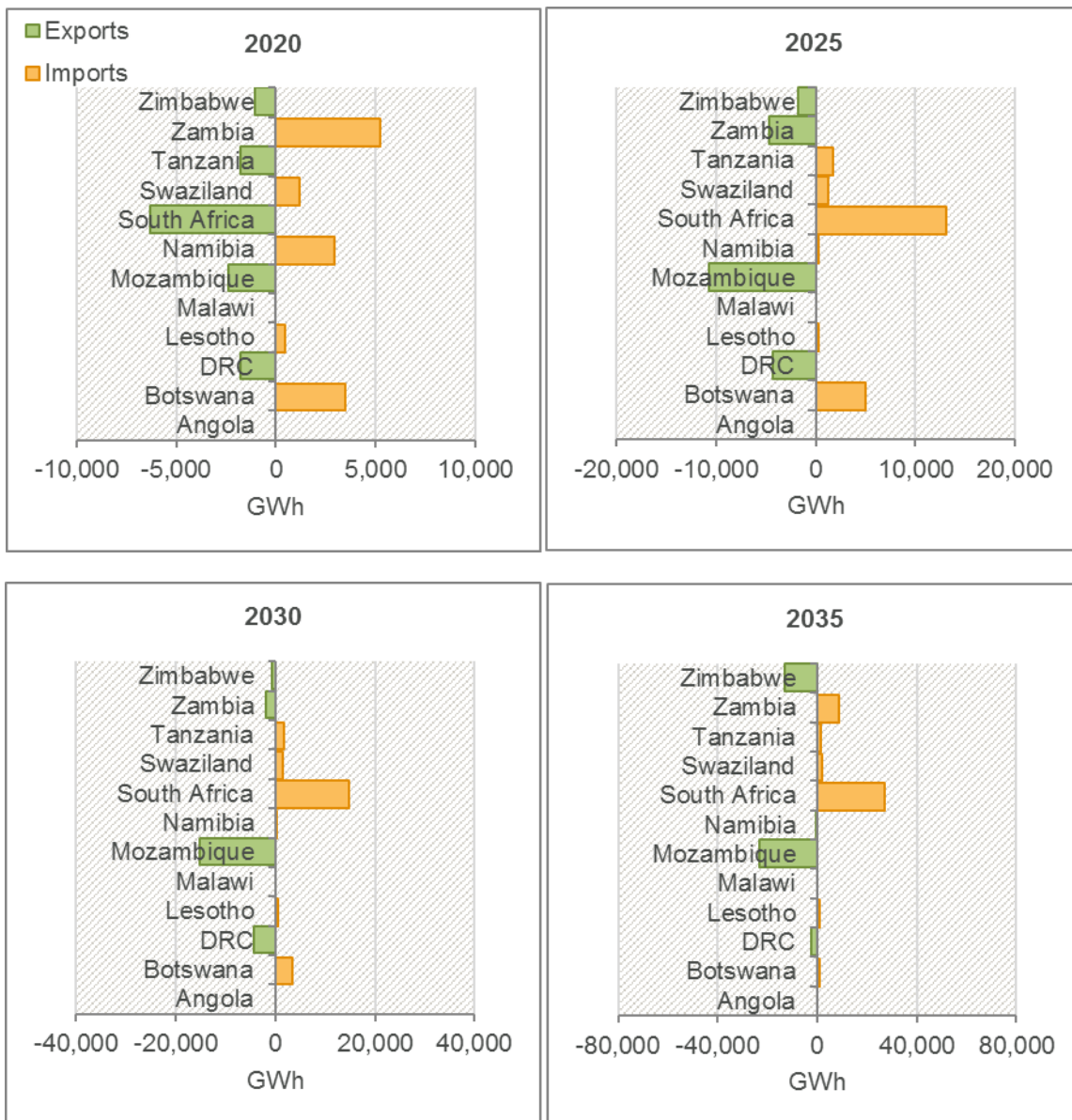
⁹ See S. Mangwengwende, L. Musaba and S. Krohn (2014) *Sovereign Security with a cherry on Top: Building Climate Resilience through Virtual Water and Nexus Thinking, (Electricity Power Planning in SADC and the role of SAPP)*, paper prepared for the Climate Resilient Infrastructure Development Facility (CRIDF) project funded by DFID (UK)

The actual trade that is forecast under the three Components is illustrated in Figure 20. The clear message from these graphs is how the transmission constraints in Component A affect trade volumes by 2040. With each country prioritising domestic production, most countries are forecast to import / export very little energy by 2040 relative to the Component B and Component C cases. Total trade in 2040 is 40,363 GWh in Component A, compared with 114,466 GWh in Component B and 97,266 GWh in Component C.

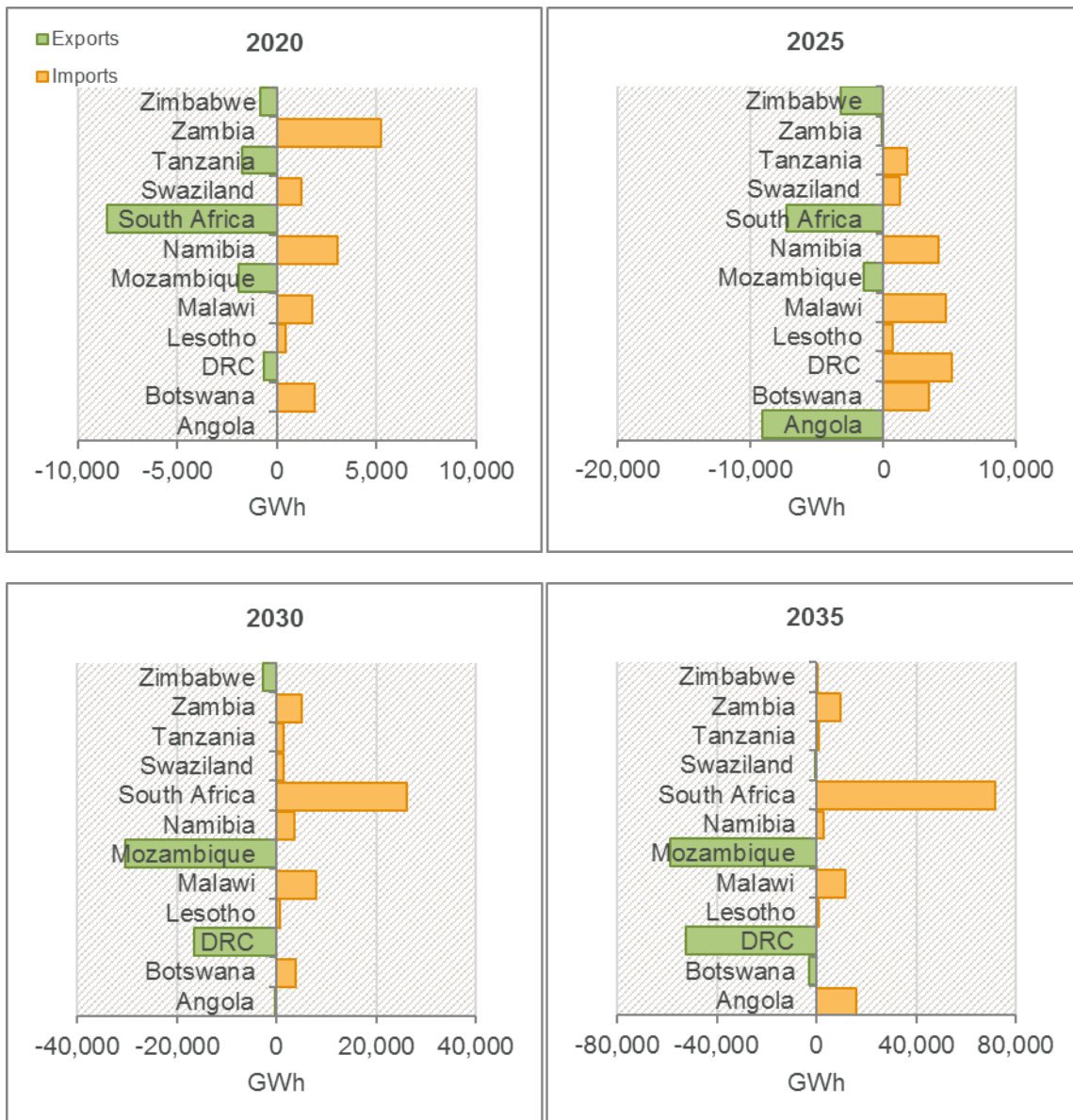
As expected from the SMRC analysis, the DRC is an exporter in all three Components, whereas importers such as South Africa have higher SMRCs than the SAPP average.

Figure 20 Exporters and importers in the SAPP region in 2020, 2025, 2030 and 2035

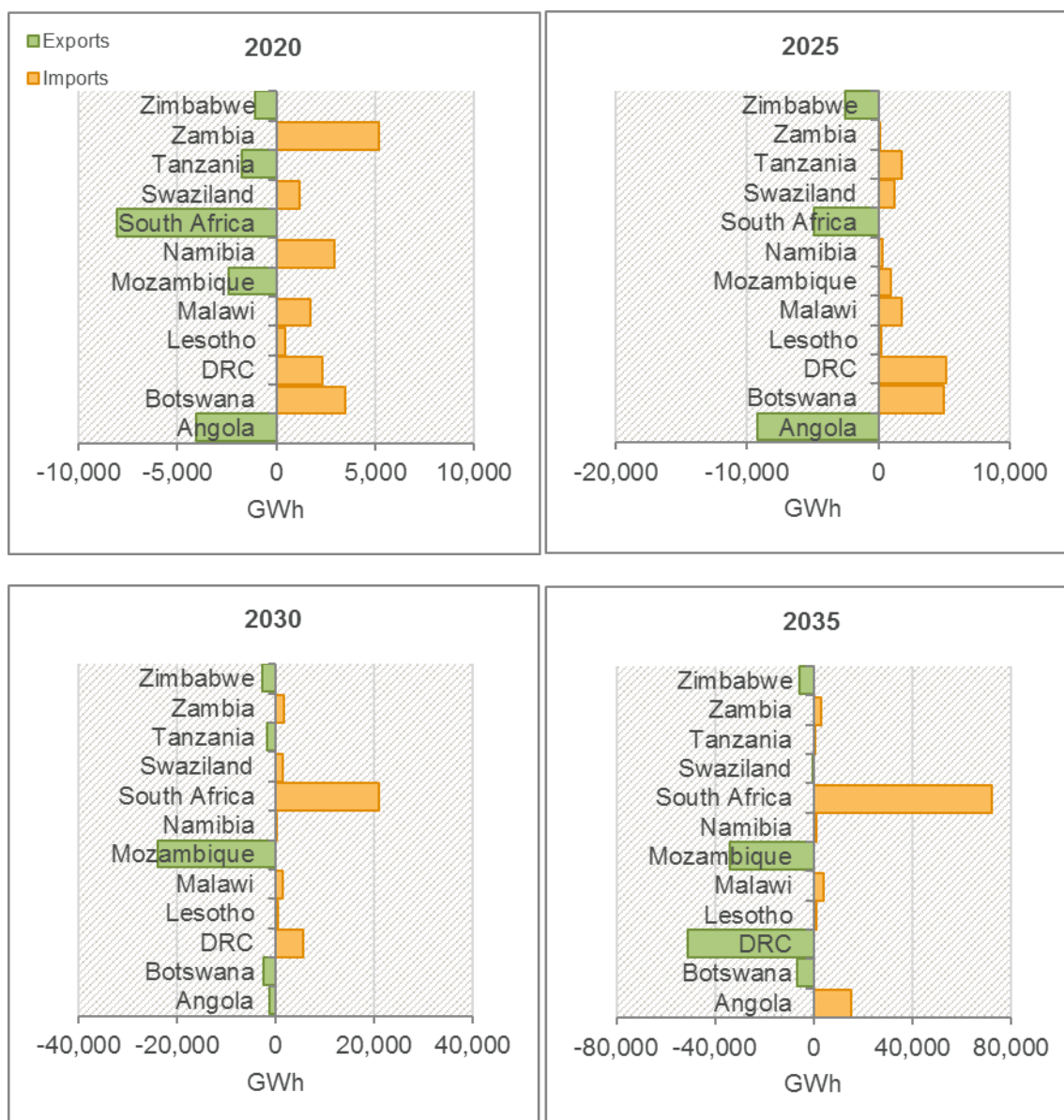
Component A



Component B



Component C



3.6 Average short-run electricity prices across SAPP

Average short-run prices across the SAPP region for Component C are shown in the table below. These are load weighted prices, which are the costs to the consumer divided by the consumer demand. In the italicised years, the costs are raised by the presence of unserved energy, which is valued here at the same price used elsewhere in the report of \$1,000/MWh (see Section 2.9). For the other years, the figures are the average short-run generation costs, and these are low (between 2.7 c/kWh and 4.7 c/kWh).


Table 12 Average short-run prices for Component C (\$/MWh and c/kWh)

Units	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
\$/MWh	140.6	130.5	50.5	28.9	28.9	28.2	26.7	28.5	30.0	30.1	32.6	35.3
\$/kWh	14.1	13.1	5.0	2.9	2.9	2.8	2.7	2.9	3.0	3.0	3.3	3.5
Units	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
\$/MWh	37.0	46.7	36.8	31.8	31.7	35.2	35.8	36.9	40.0	41.7	40.1	56.2
\$/kWh	3.7	4.7	3.7	3.2	3.2	3.5	3.6	3.7	4.0	4.2	4.0	5.6

Low electricity prices have in the past given the SAPP region a comparative advantage in the costs of production, particularly of energy-intensive mineral products. If Component C is followed, the above short-run costs will be an important element of keeping the average prices of traded electricity low into the future.

4 Country Generation Plans

The full details of the Component A country generation plans are given in Annex A3 in the Annex Volume and the accompanying Excel sheet. For each country, each year from 2017 to 2040, and for both energy (GWh) and capacity (MW), the following details are given:

- ❑ Energy and capacity of each power plant, with separate panels for existing, committed and the candidate projects which have been selected
- ❑ Energy totals - national generation, imports, exports, unserved energy and energy demand
- ❑ Capacity totals - total national installed capacity, peak demand and reserve margin. Comments are made to indicate how each country fulfils SAPP planning criteria.

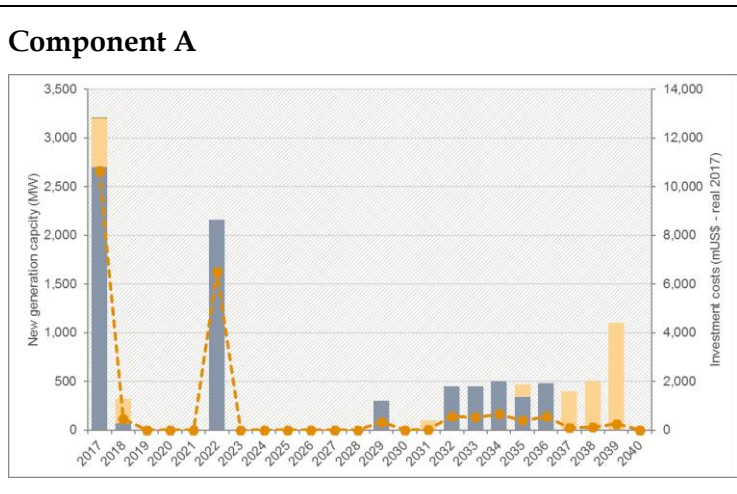
The country-by-country description below presents the results in graphical form:

- ❑ Capacity additions by year, technology and investment costs (MW and \$ millions)
- ❑ Total installed capacity, peak demand and reserve margins (MW and %)
- ❑ Mix of generation to meet energy demand (GWh)

The text accompanying the diagrams highlights key features and acknowledges some anomalous results. As explained in Section 1, these are the result of the agreed restrictive generation and transmission assumptions which have been adopted for Component A. In particular, some countries have large installed capacity which is hardly used, while other countries experience unserved demand. These anomalies disappear in Components B and C where sufficient transmission capacity is provided to optimise trade in the region.

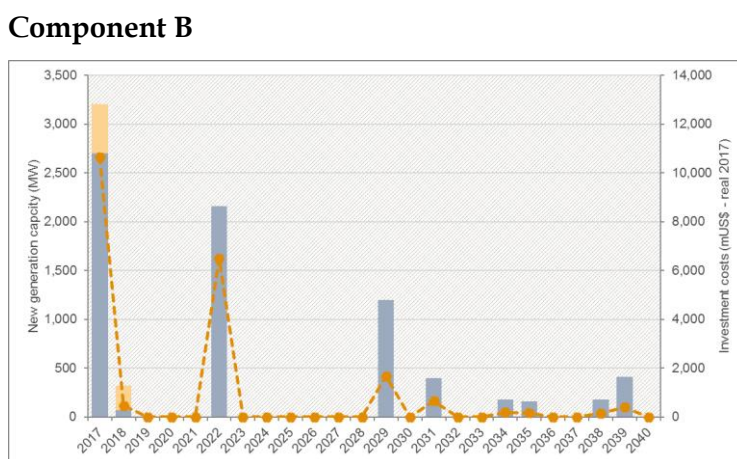
4.1 Angola

Figure 21 Angola capacity additions by year, technology and investment costs (MW / \$m)

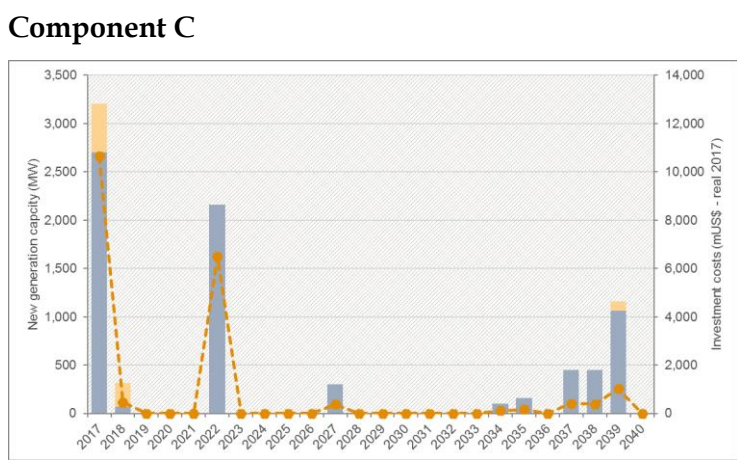


The total new generation capacity installed in Angola over the period 2017-2040 varies from 8,203 MW in Component B to 10,428 MW in Component A. The bulk of the new capacity is in hydro in each Component. Other investment is in natural gas generation.

These investments are illustrated in Figure 21. There are significant committed investments in 2017, with this year seeing a spike in new capacity in each of the three Components. The projects involved are Lauca hydro (2,004 MW), Cambambe II hydro (700 MW) and Soyo I natural gas (500 MW), giving a total of 3,204 MW.



As shown in Figure 21, there is also an investment spike in 2022, when the largest single hydropower project (Caculo Cabaça, 2,160 MW) is commissioned.



Differences in Components materialise from 2027, where Component C selects Baynes hydro (300 MW) 2 years before this plant is chosen in Components A and B. Component B also constructs the hydro plants Tumulo do and Zenzo I (450 MW each) in 2029 Caçador, allowing increased hydro generation in the medium term. In contrast, Component A builds more natural gas plants toward the end of the period, which are required to meet capacity requirements and energy demand in this more restrictive scenario - discussed further below.

■ Hydro
 ■ Renewables
 ■ Thermal (ex. Coal)
 ■ Coal
 -●- Investment costs

Figure 22 Angola share of major generation technologies in total capacity (%)

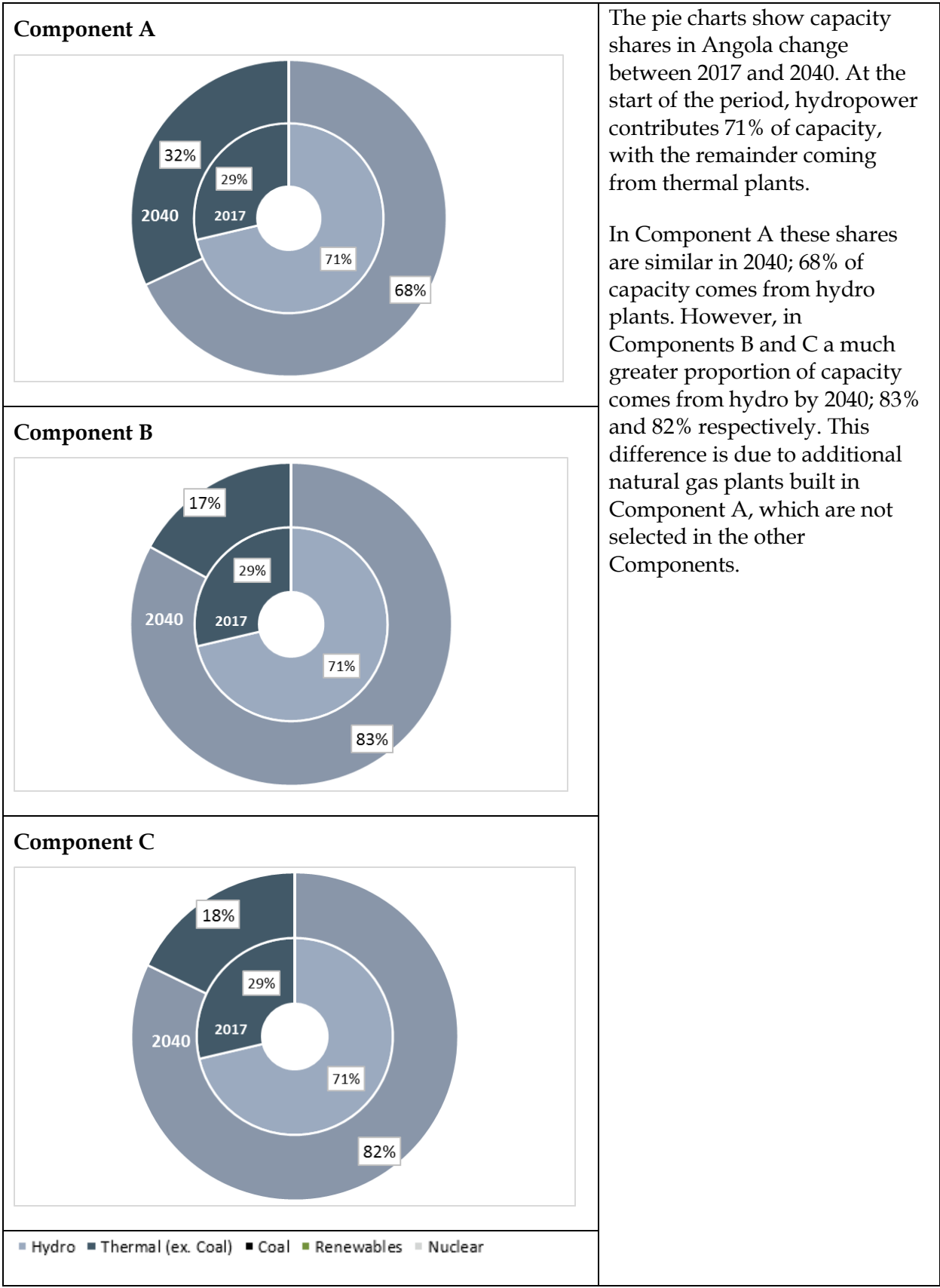
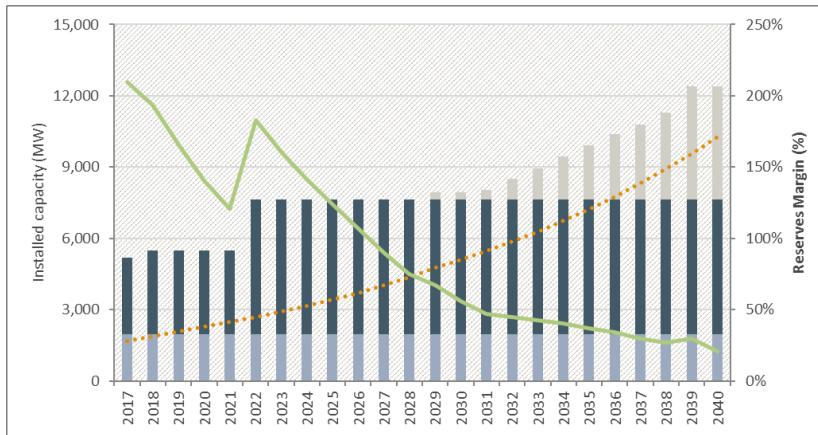


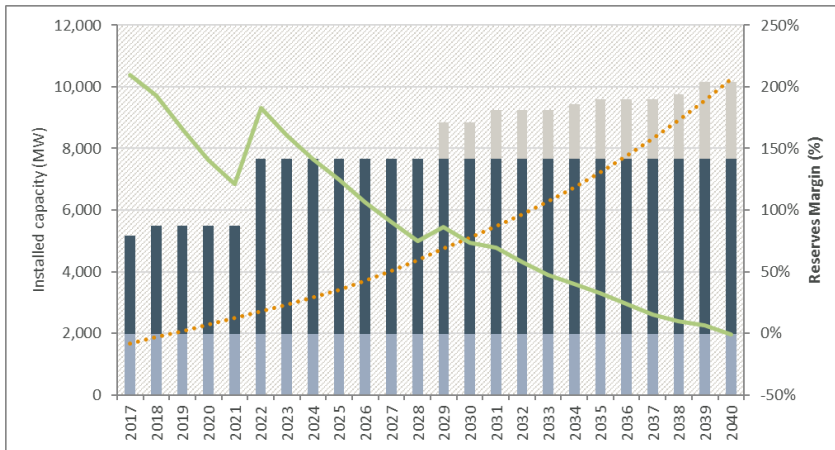
Figure 23 Angola total generation capacity and reserve margin 2017-2040 (MW and %)

Component A



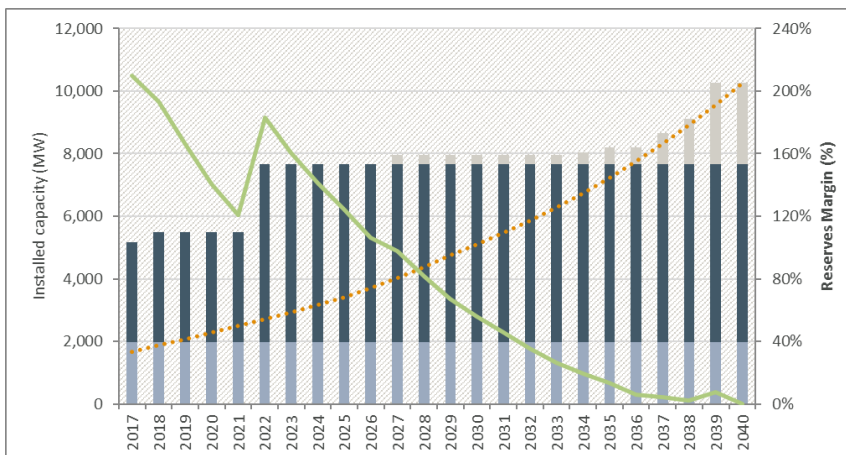
The existing installed capacity in Angola is 1,969 MW. The average net capacity of 1,702 MW in 2015 is barely sufficient to serve existing demand which peaked at 1,869 MW in 2016. The addition of committed new capacity in 2017 of 3,204 MW results in a very high initial reserve margin (210%). This is somewhat notional and the situation in the electricity sector is normalised when the existing isolated grids are integrated into a national grid in the mid 2020s.

Component B



In Components A, B and C, total capacity is increased to 12,397 MW, 10,172 MW and 10,272 MW respectively.

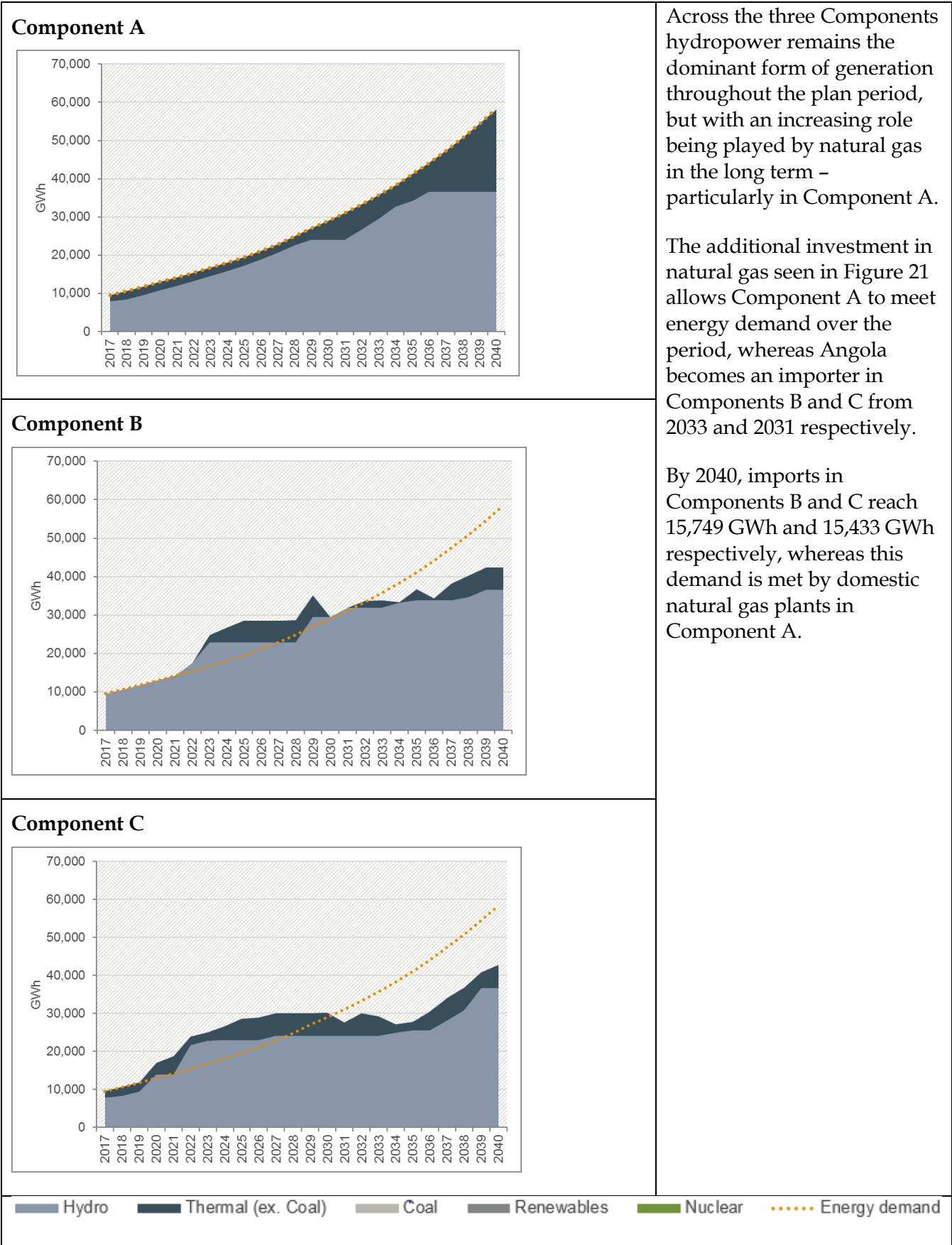
Component C



Despite vast additions to capacity, rapid growth in peak demand eventually results in the reserve margin being heavily reduced across all three Components, to 21% in A, -1% in B and 0% in C. This is because imports are much more accessible in Components B and C, following increased investment in transmission lines, further discussed in Figure 24.

Existing Committed Candidate Peak demand Reserves margin

Figure 24 Angola mix of generation to meet energy demand (GWh)



4.2 Botswana

Figure 25 Botswana capacity additions by year, technology & investment costs (MW / \$m)

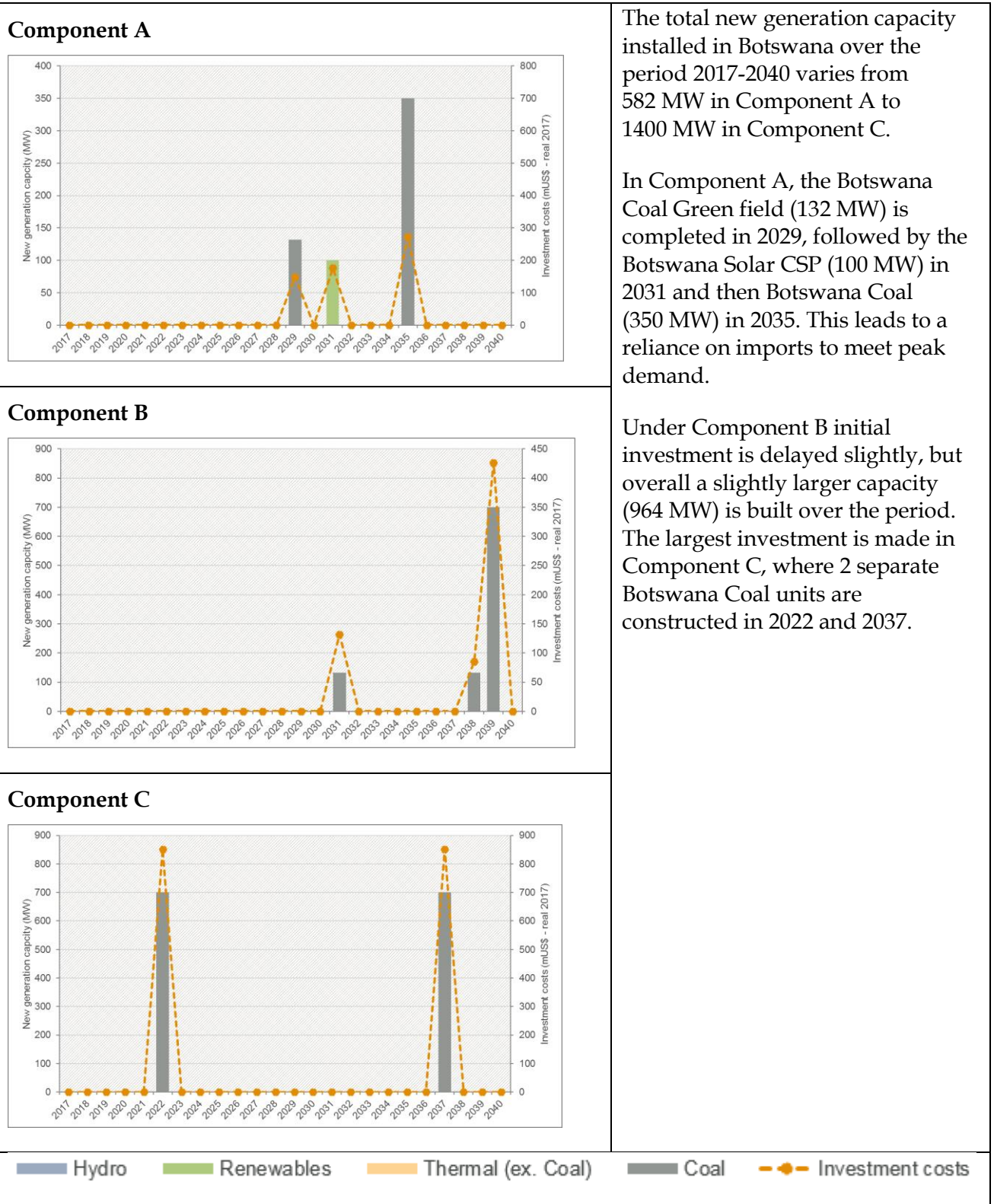


Figure 26 Botswana share of major generation technologies in total capacity (%)

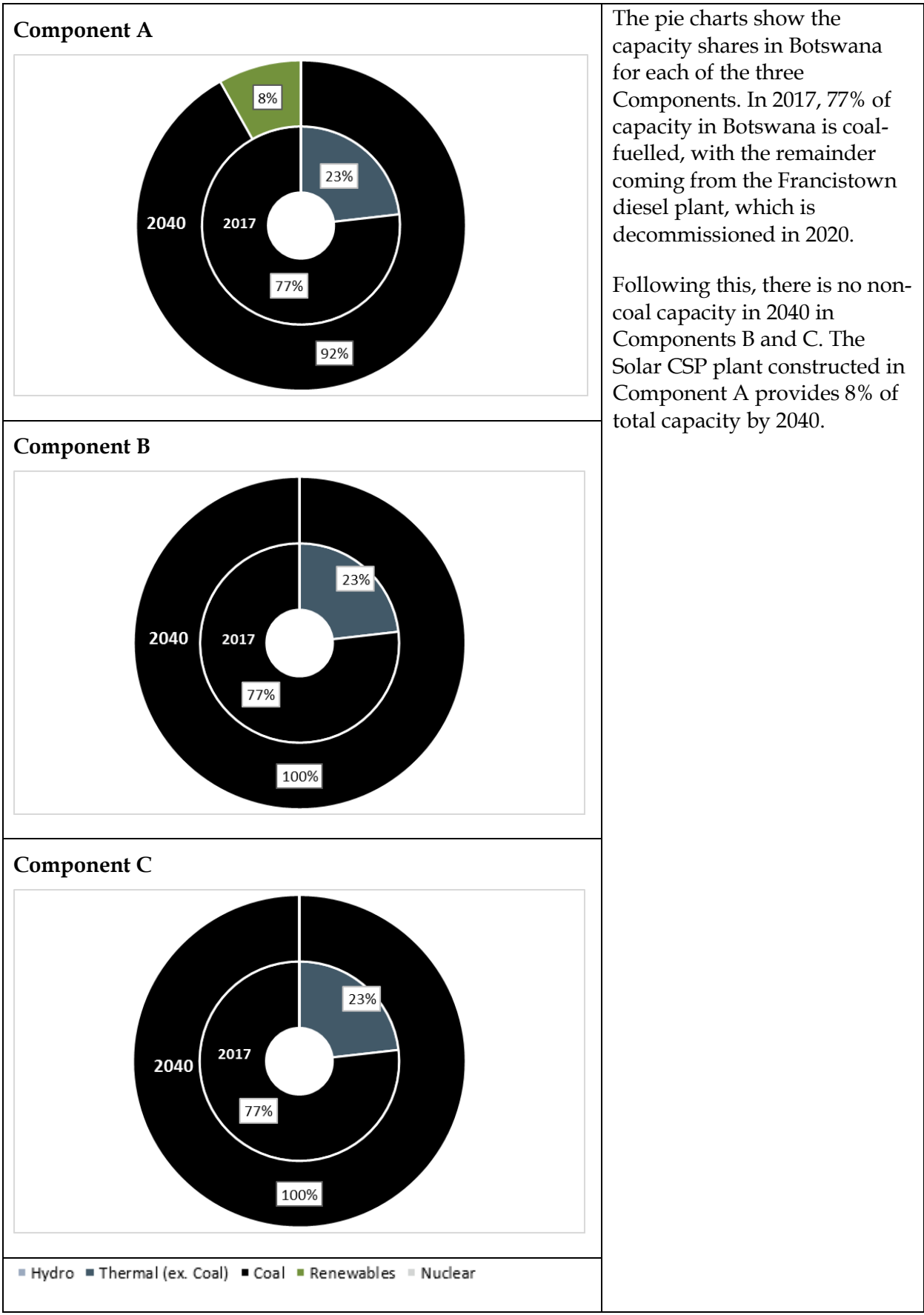
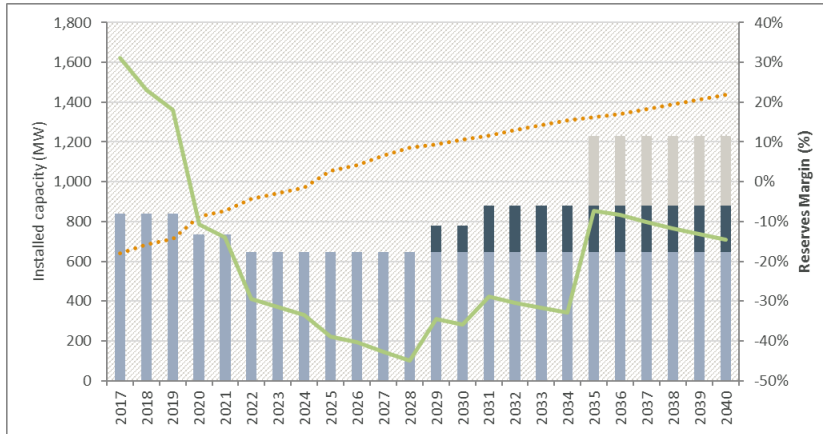


Figure 27 Botswana total generation capacity and reserve margin 2017-2040 (MW and %)

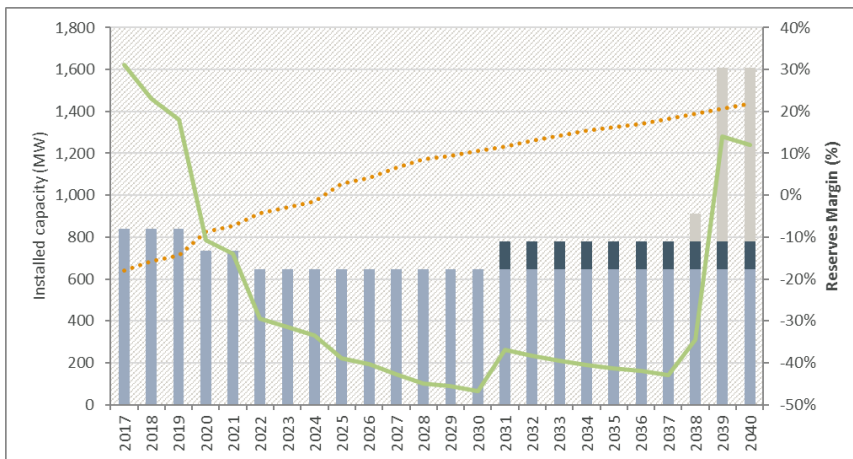
Component A



The existing installed capacity is 841 MW, which is sufficient to serve existing demand. By 2020, however, the reserve has been eliminated and Botswana becomes reliant on imports.

In Component A the reserve margin remains negative throughout the period, and in 2040 Botswana maintains a margin of -15%.

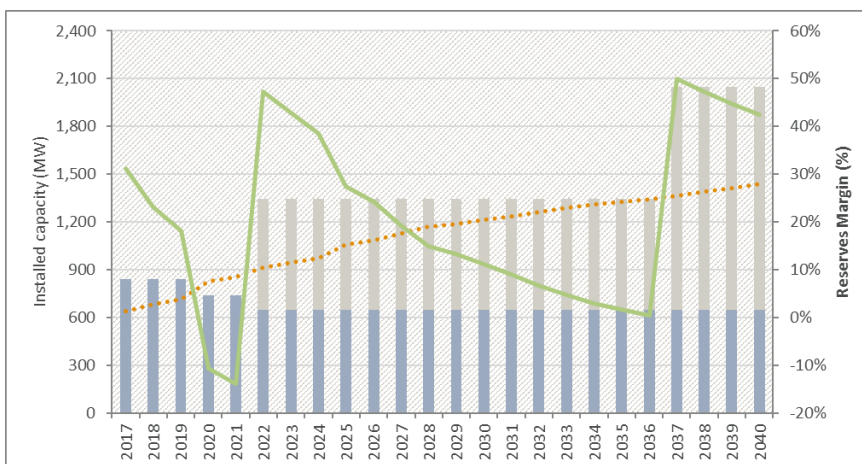
Component B



In Component B the reserve margin remains negative until 2039, when new coal powered capacity meets peak demand.

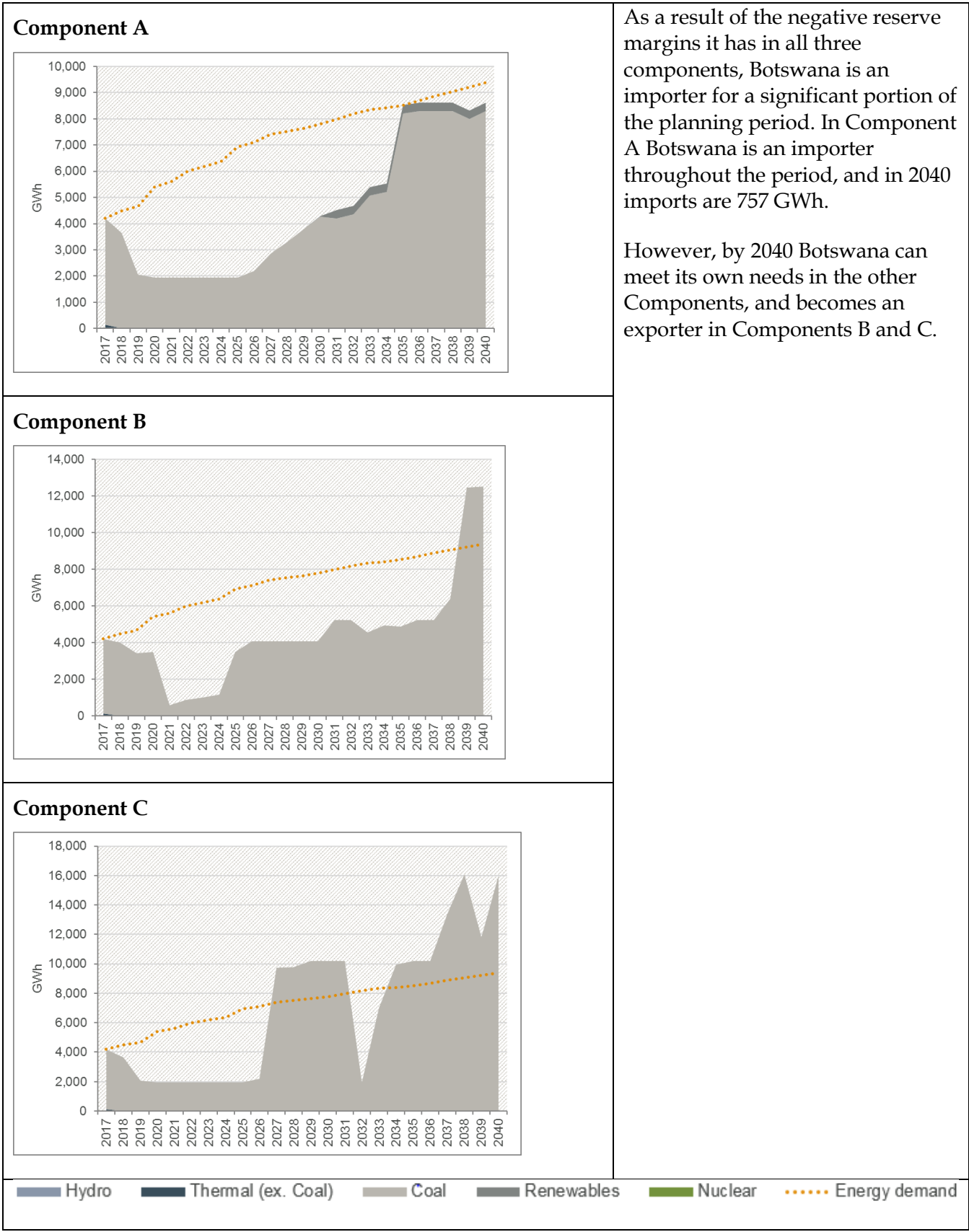
In Component C, the coal investment in 2022 ensures the reserve margin is positive for the rest of the period.

Component C



Existing Committed Candidate Peak demand Reserves margin

Figure 28 Botswana mix of generation to meet energy demand (GWh)



4.3 DRC

Figure 29 DRC capacity additions by year, technology and investment costs (MW and \$m)

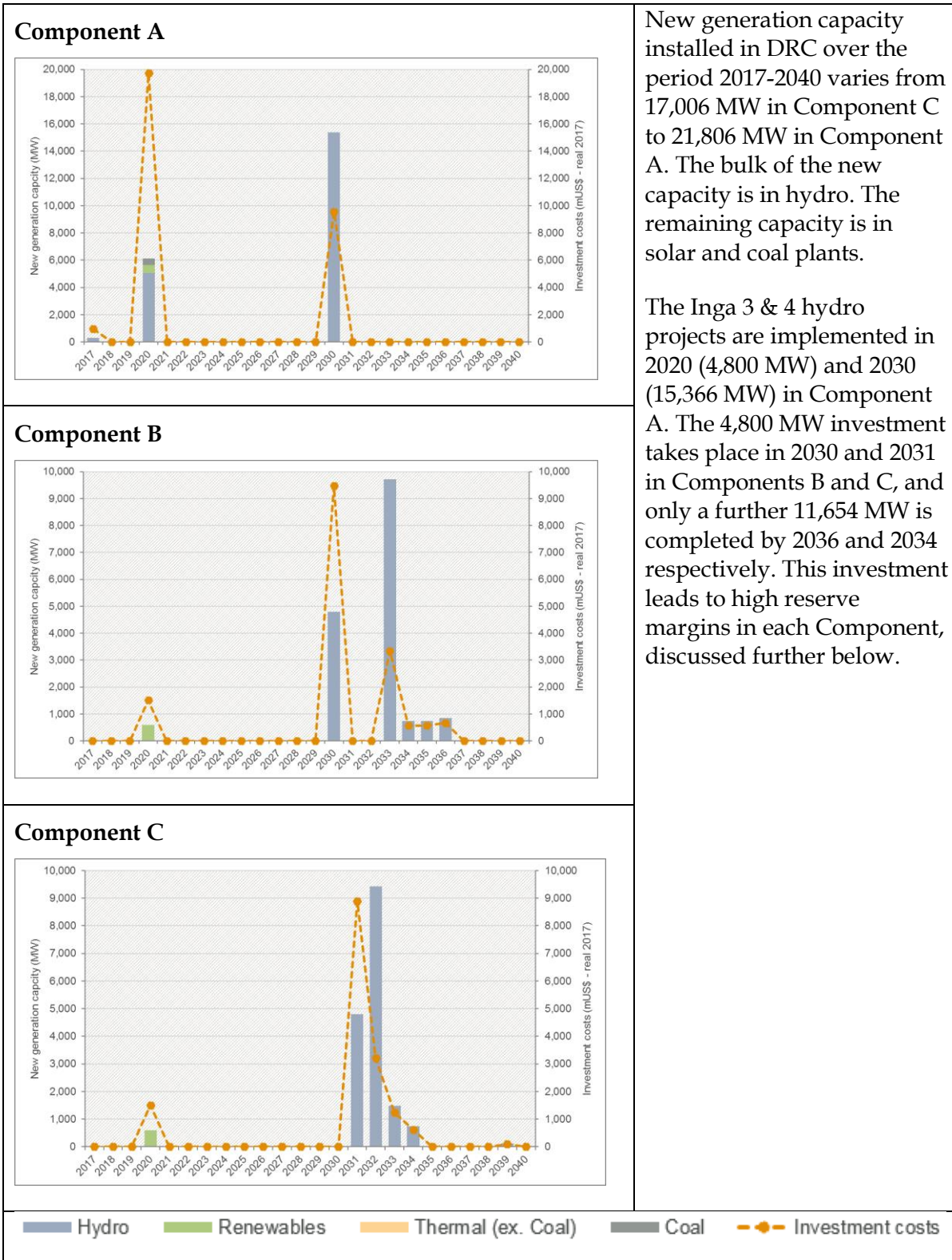


Figure 30 DRC share of major generation technologies in total capacity (%)

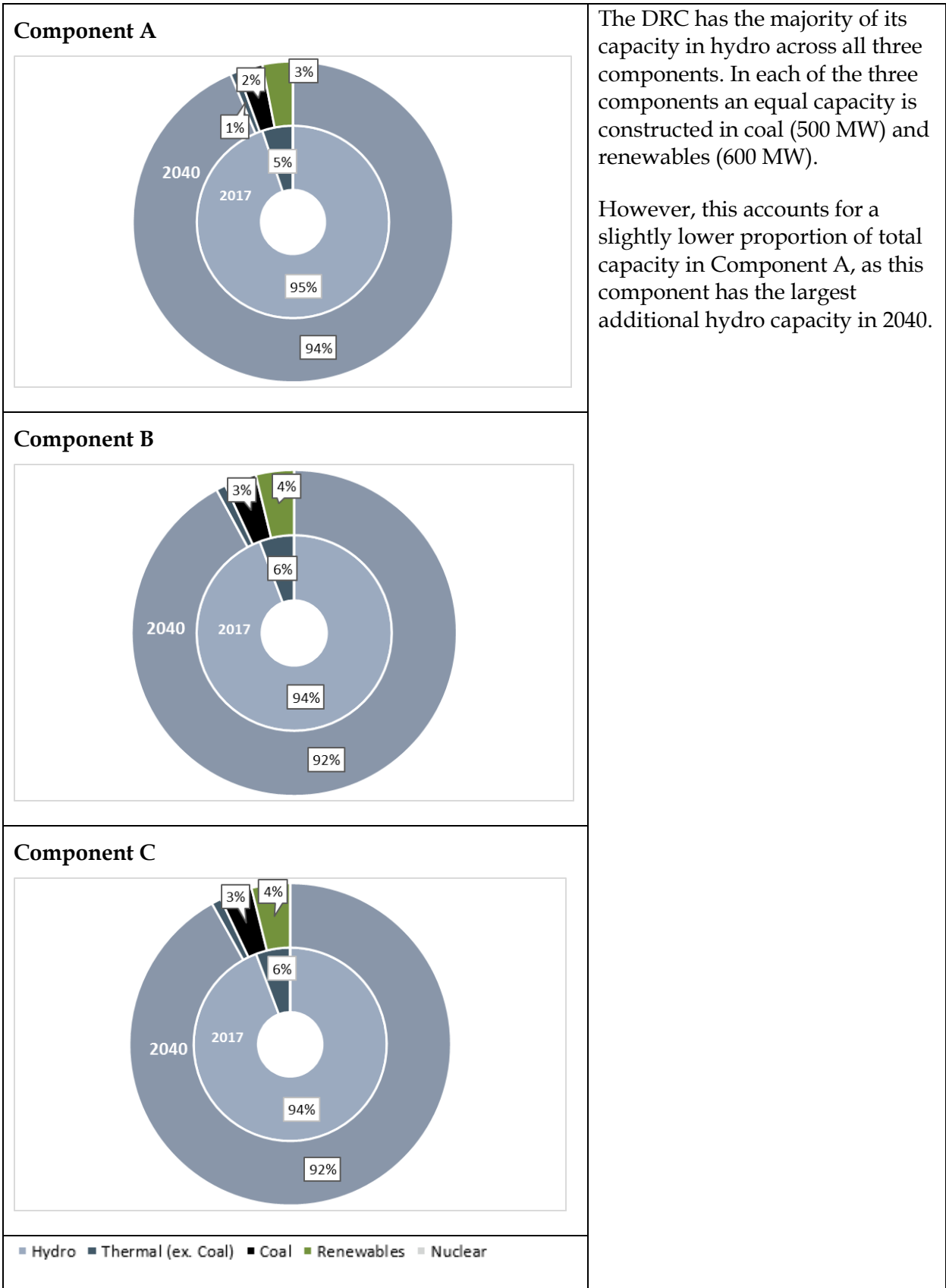


Figure 31 DRC total generation capacity and reserve margin 2017-2040 (MW and %)

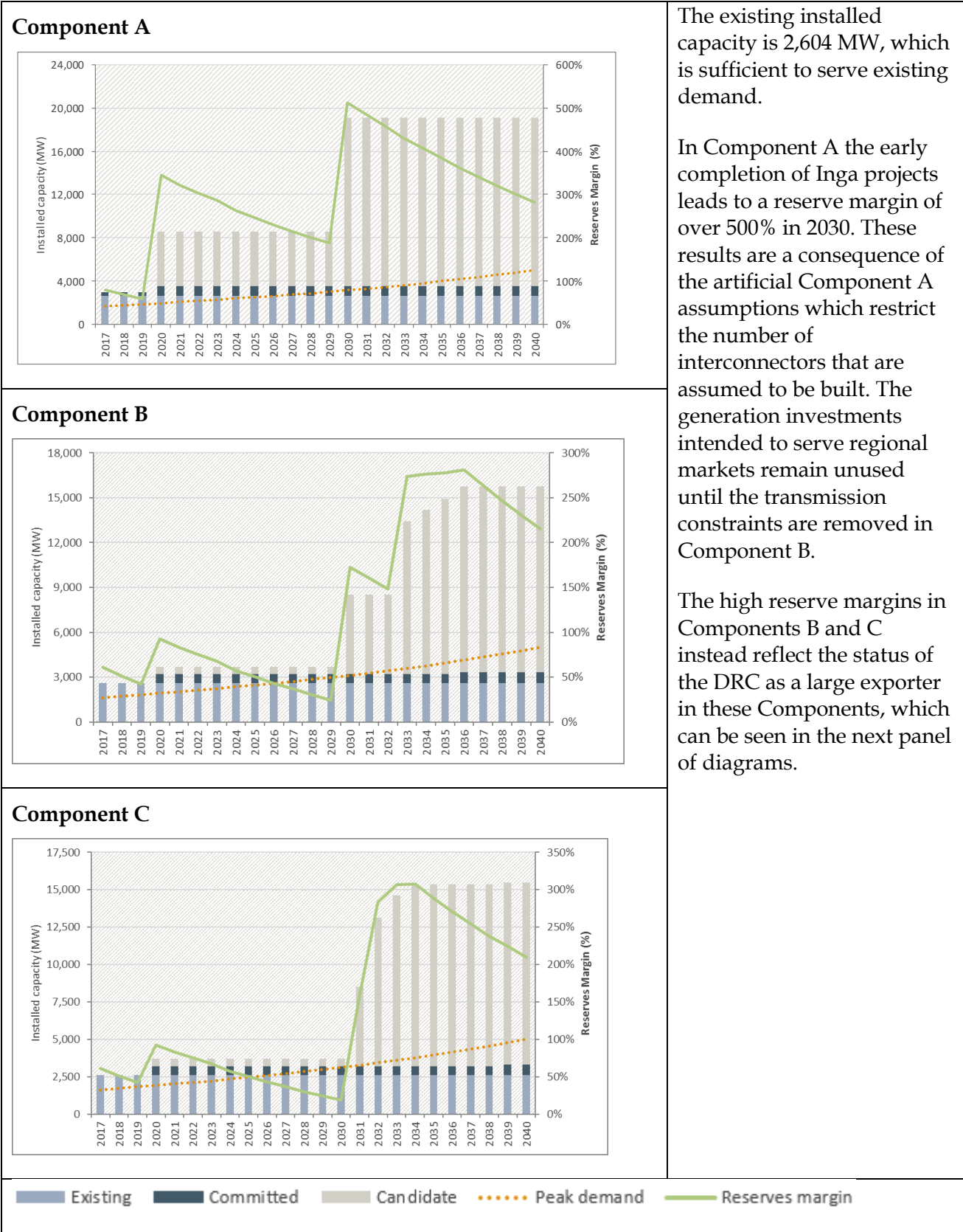
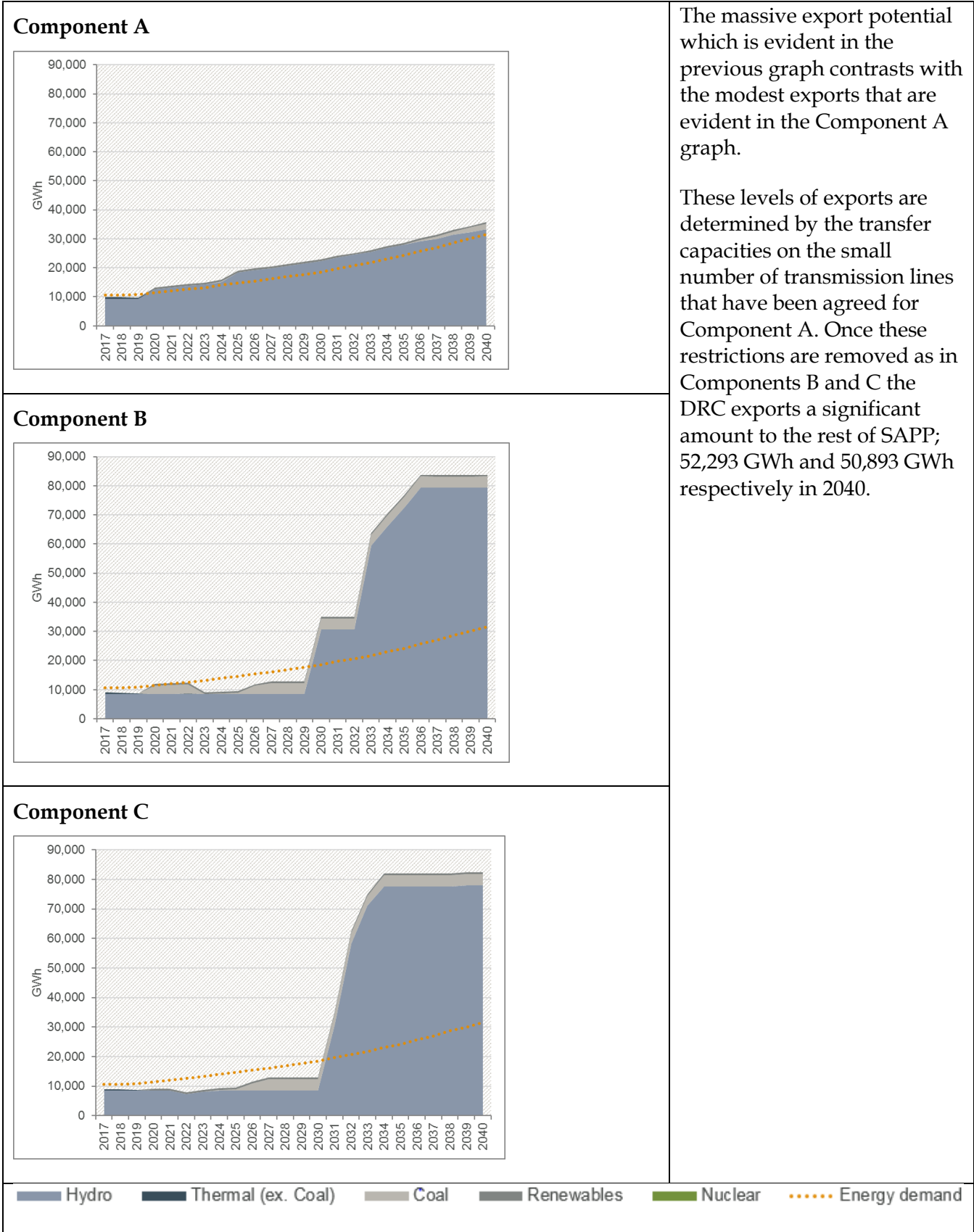


Figure 32 DRC mix of generation to meet energy demand (GWh)

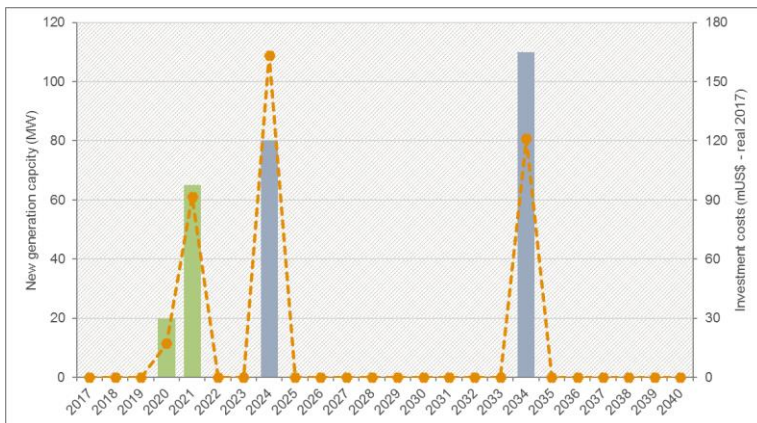


4.4 Lesotho

Figure 33 Lesotho capacity additions by year, technology & investment costs (MW / \$m)

■ Hydro ■ Renewables ■ Thermal (ex. Coal) ■ Coal - - Investment costs

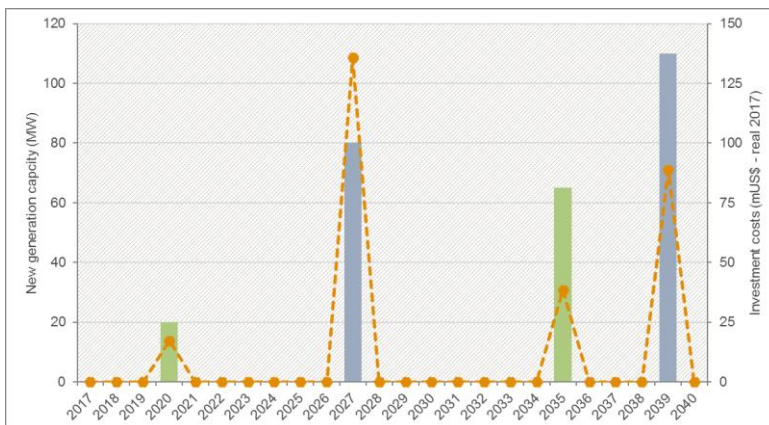
Component A



The total new generation capacity installed in Lesotho over the period 2017-2040 is 275 MW in each of the Components. The bulk of the new capacity (69%) is in hydro (190 MW). There is also investment in solar PV (20 MW) and wind generation (65 MW).

Relaxing the constraints on Component A allows the plants to be delayed, reducing the discounted investment costs from \$393 m in Component A to \$280 m in Component B.

Component B



It is to be noted that the Monont'sa 1,200 MW pumped storage scheme, which is quintessentially a regional project, is not part of the investment sequence, but it seems likely it would be selected close to 2040 if the planning horizon were to be extended.

Component C

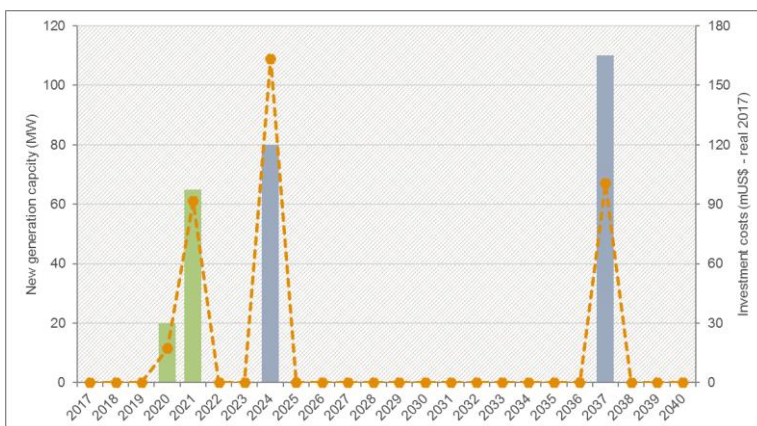


Figure 34 Lesotho share of major generation technologies in total capacity (%)

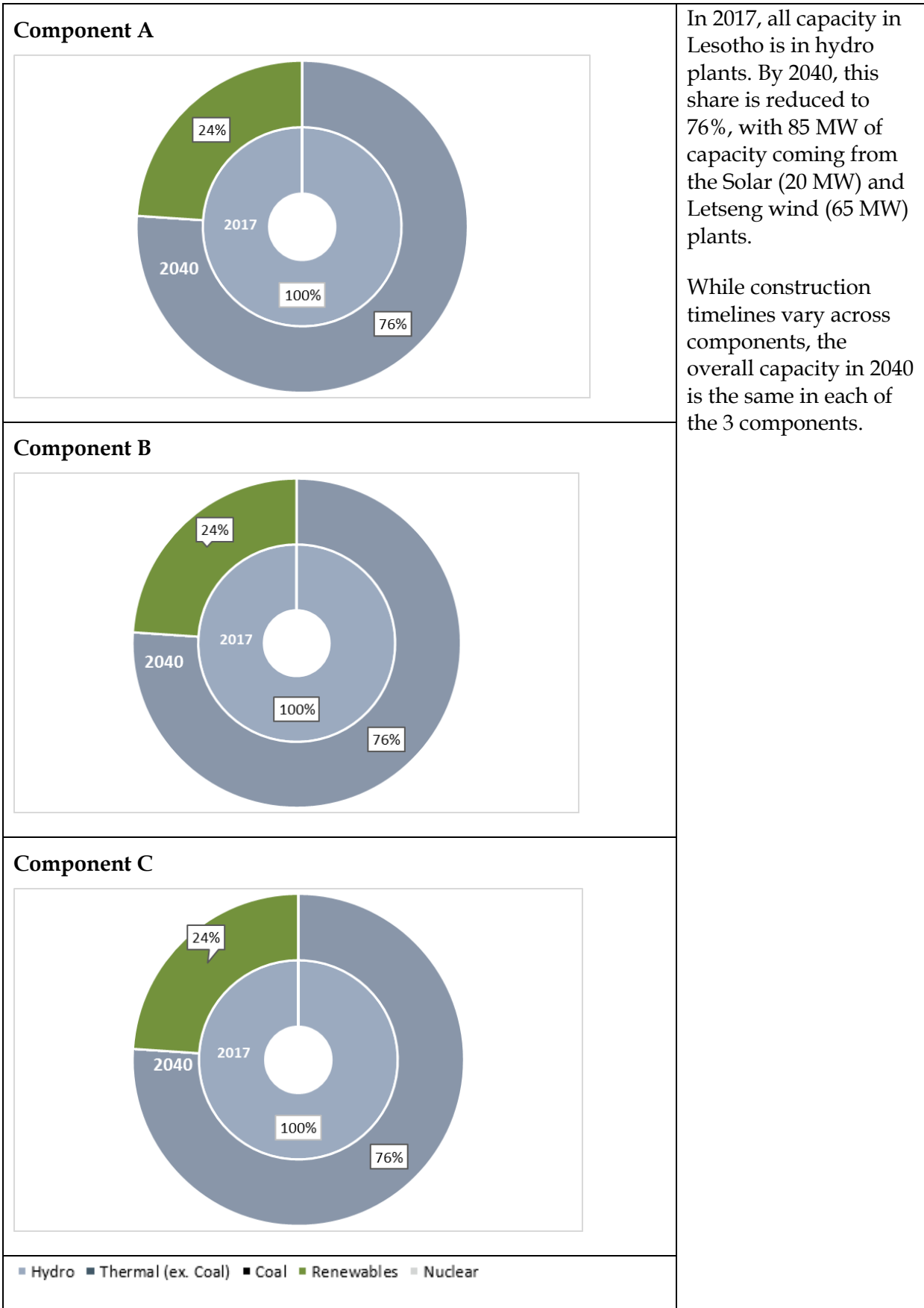
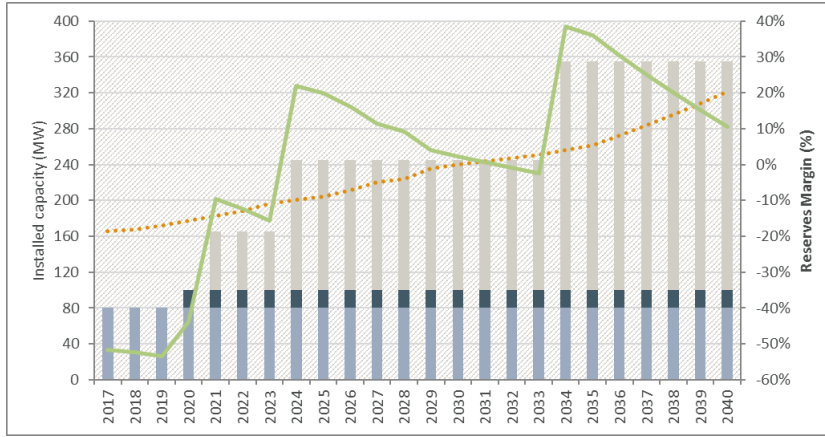


Figure 35 Lesotho total generation capacity and reserve margin 2017-2040 (MW and %)

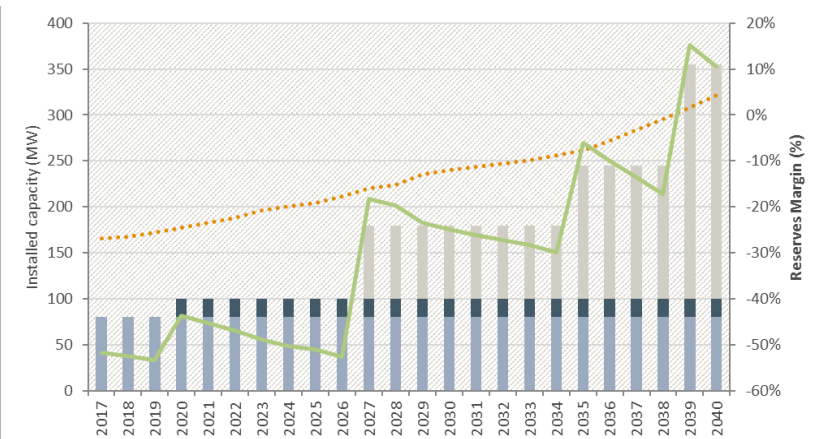
Component A



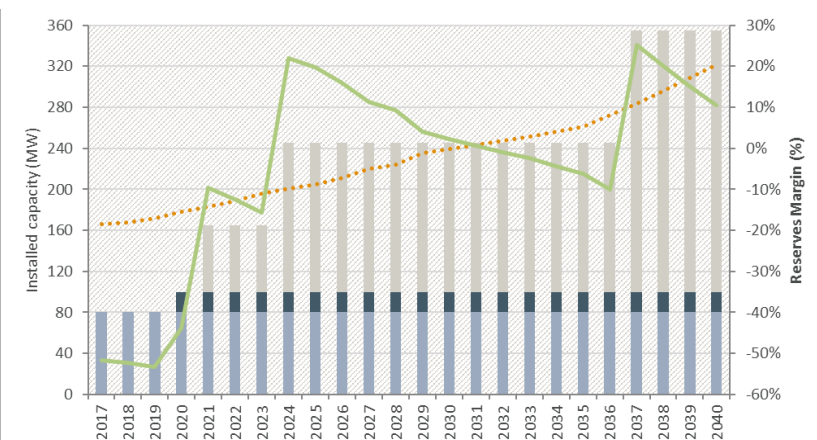
As shown in the graphs, the initial reserve margin in Lesotho is significantly negative (-52%). The existing installed capacity is only 80 MW. Demand is met through imports.

Capacity expansions allow the reserve margin to be restored to satisfactory levels by the end of the period (10%).

Component B

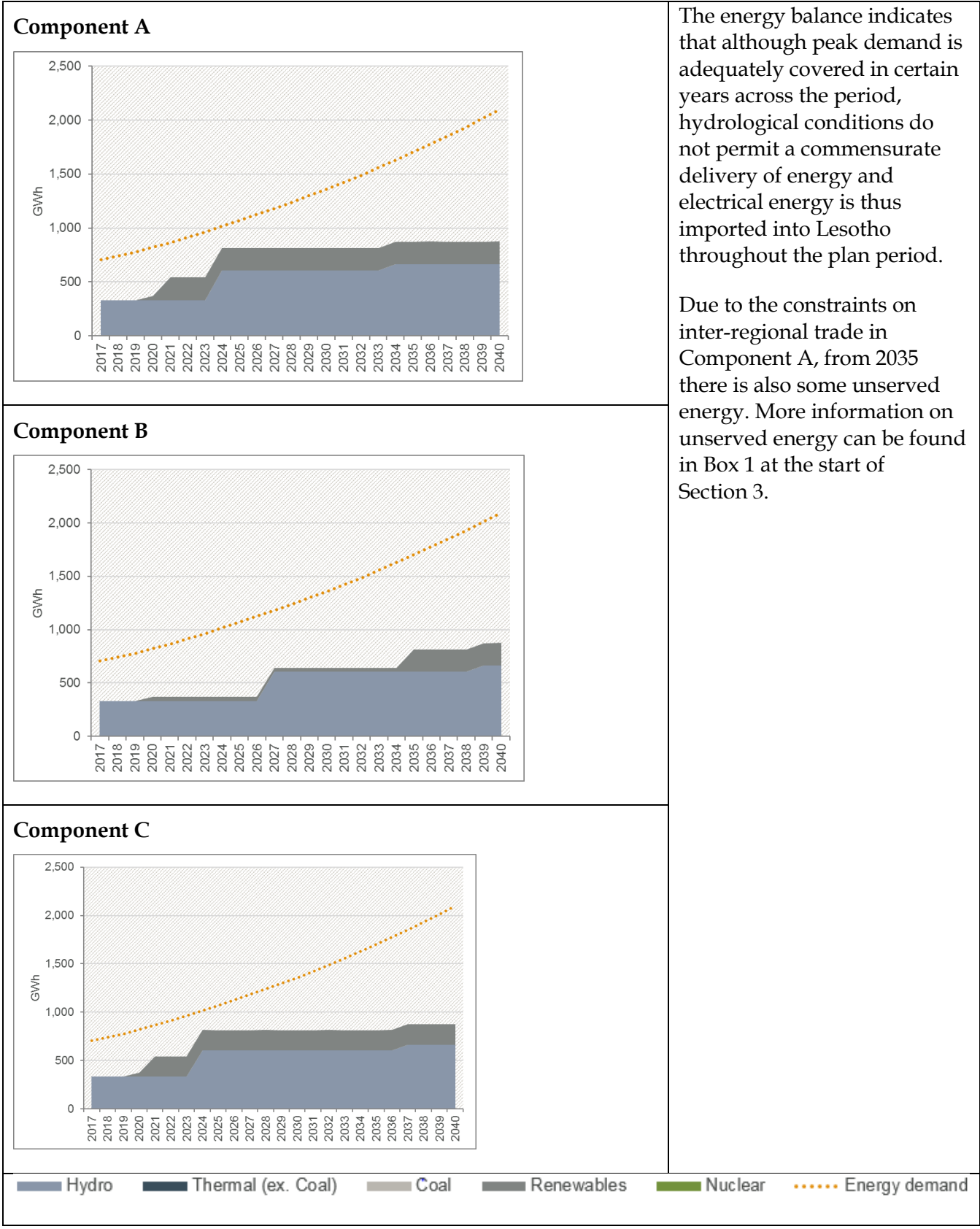


Component C



Existing Committed Candidate Peak demand Reserves margin

Figure 36 Lesotho mix of generation to meet energy demand (GWh)

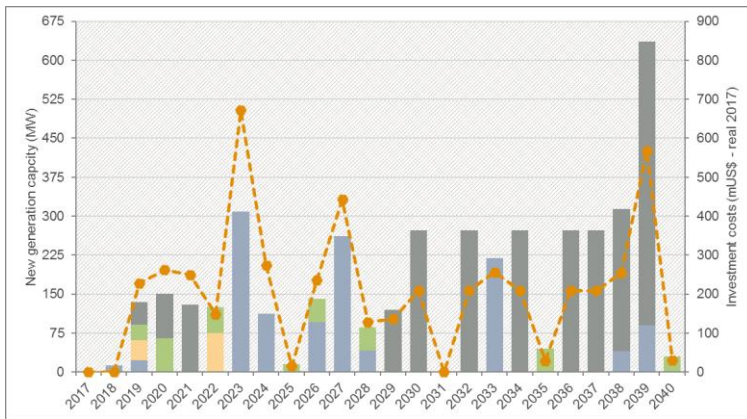


4.5 Malawi

Figure 37 Malawi capacity additions by year, technology & investment costs (MW/ \$m)

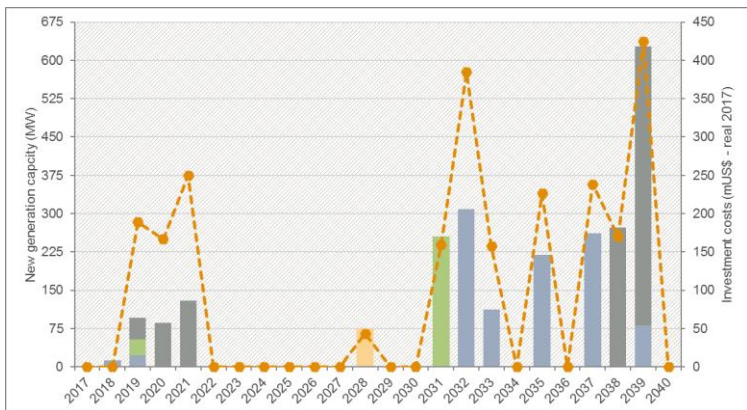
Hydro Renewables Thermal (ex. Coal) Coal Investment costs

Component A



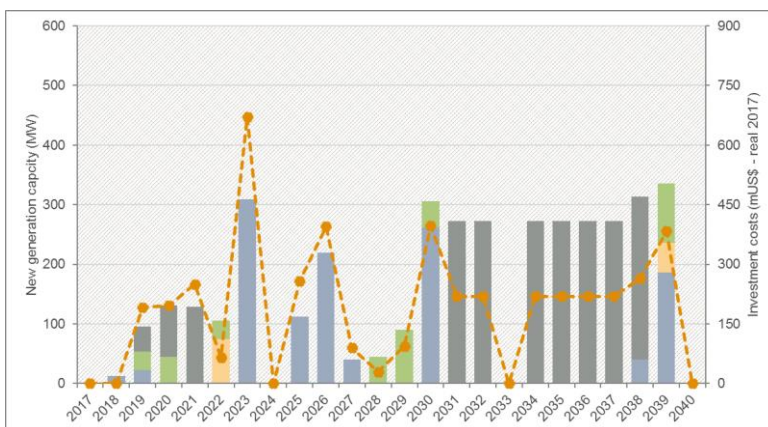
The total new generation capacity installed in Malawi over the period 2017-2040 varies from 2,454 MW in Component B to 4,203 MW in Component A. This disparity leads to a large difference in costs – with total discounted investment costs of \$2,410 million in Component B compared to \$4,973 million in Component A.

Component B



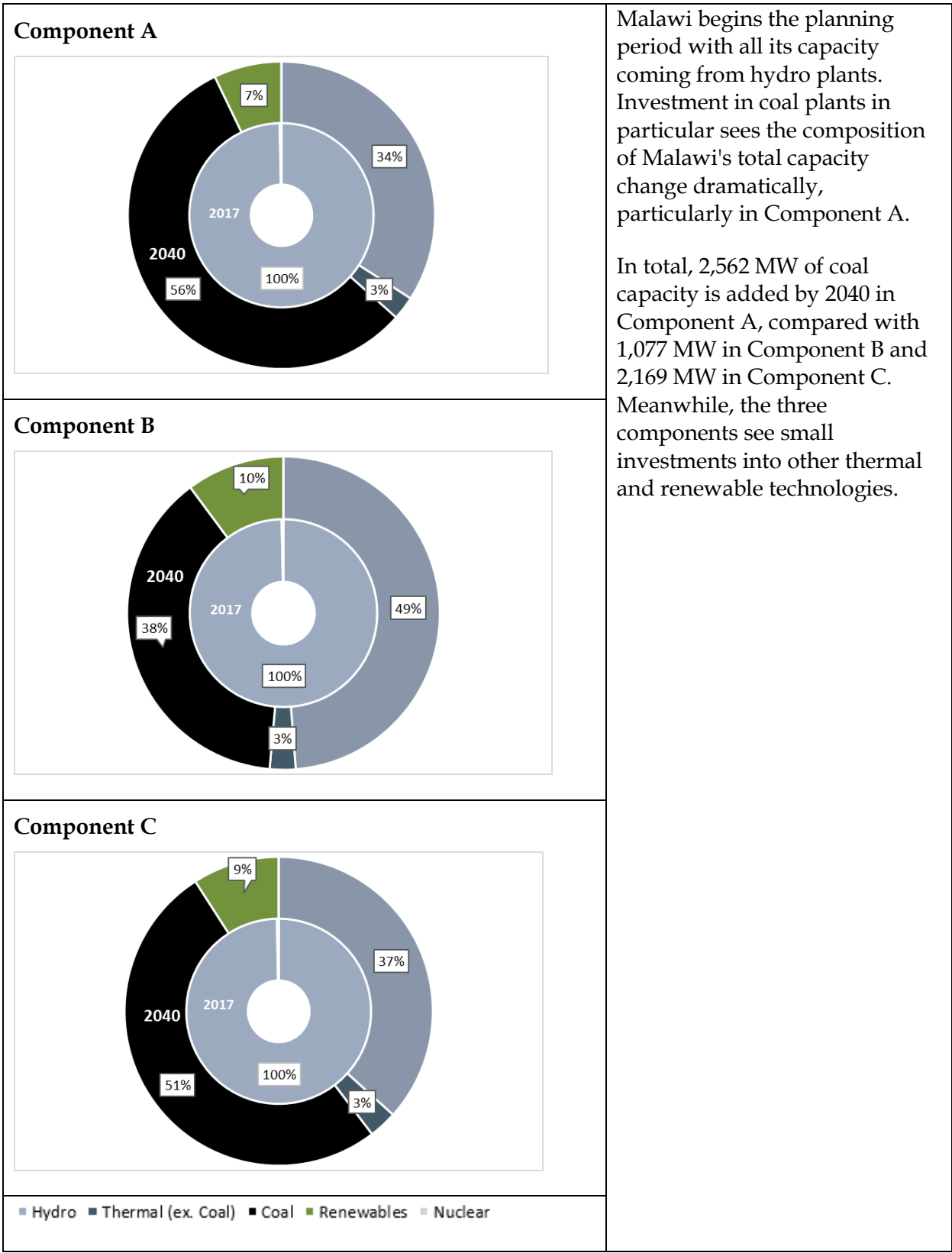
In Component A, the bulk of the new capacity is in coal (2,562 MW) and hydro (1,113 MW). There is also investment in renewables (solar PV 165 MW, wind 120 MW and biomass 40 MW) and some thermal back-up (138 MW).

Component C



Component C has a similar level of investment over the period to Component A, with 3,882 MW of new capacity at a discounted cost of \$4,600 million.

Figure 38 Malawi share of major generation technologies in total capacity (%)

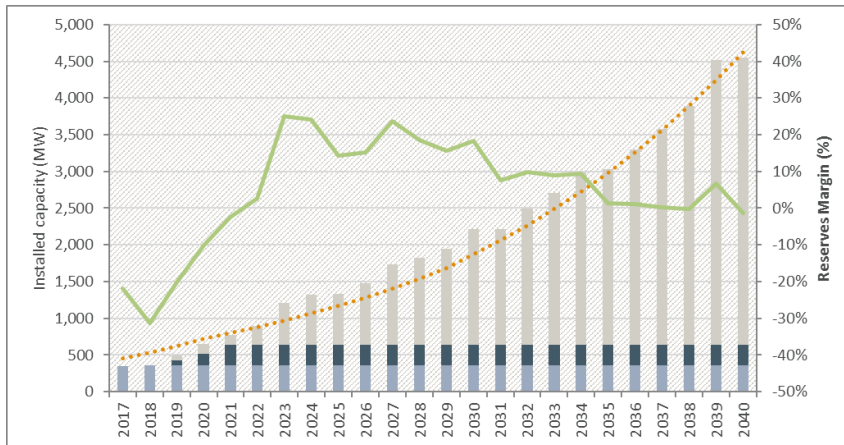


Malawi begins the planning period with all its capacity coming from hydro plants. Investment in coal plants in particular sees the composition of Malawi's total capacity change dramatically, particularly in Component A.

In total, 2,562 MW of coal capacity is added by 2040 in Component A, compared with 1,077 MW in Component B and 2,169 MW in Component C. Meanwhile, the three components see small investments into other thermal and renewable technologies.

Figure 39 Malawi total generation capacity and reserve margin 2017-2040 (MW and %)

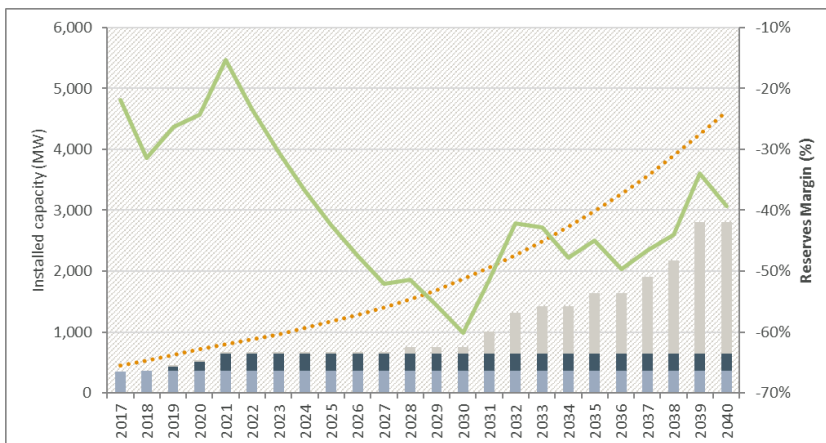
Component A



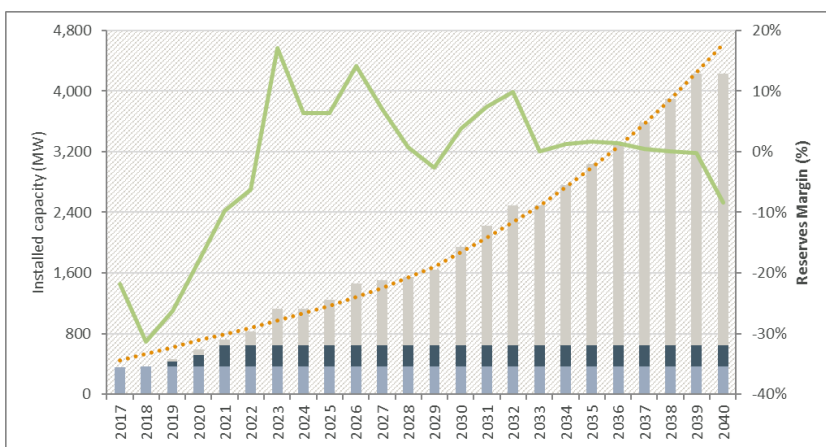
The initial reserve margin in Malawi is negative (-22%) and peak demand is met through imports. Capacity expansions result in satisfactory levels of reserve margin from the mid-2020s in Component A.

In contrast, Component B never has capacity installed to meet peak demand over the period, suggesting an ongoing reliance on imports.

Component B

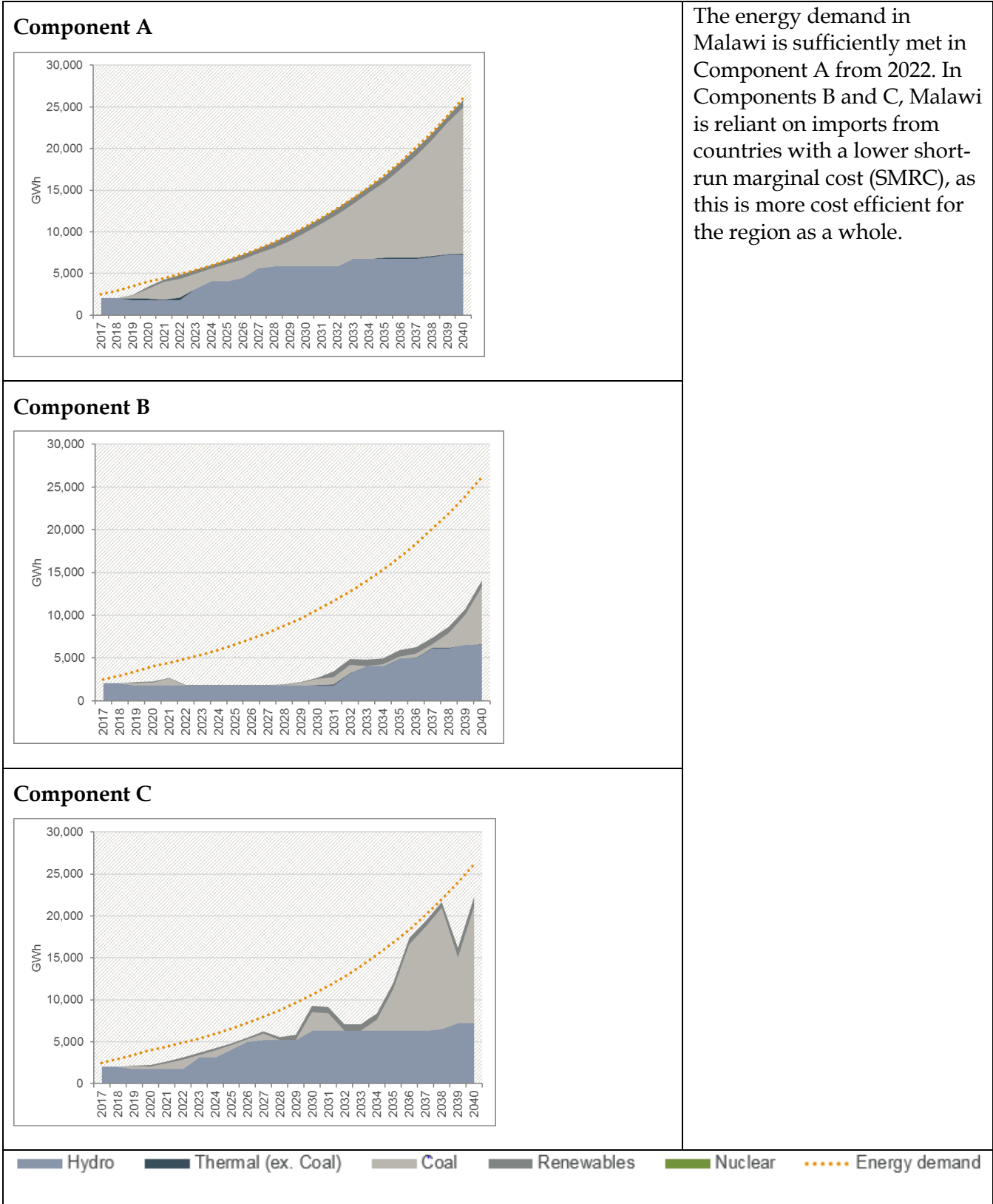


Component C



Existing Committed Candidate Peak demand Reserves margin

Figure 40 Malawi mix of generation to meet energy demand (GWh)



4.6 Mozambique

Figure 41 Mozambique capacity additions by year, technology & inv. costs (MW/\$m)

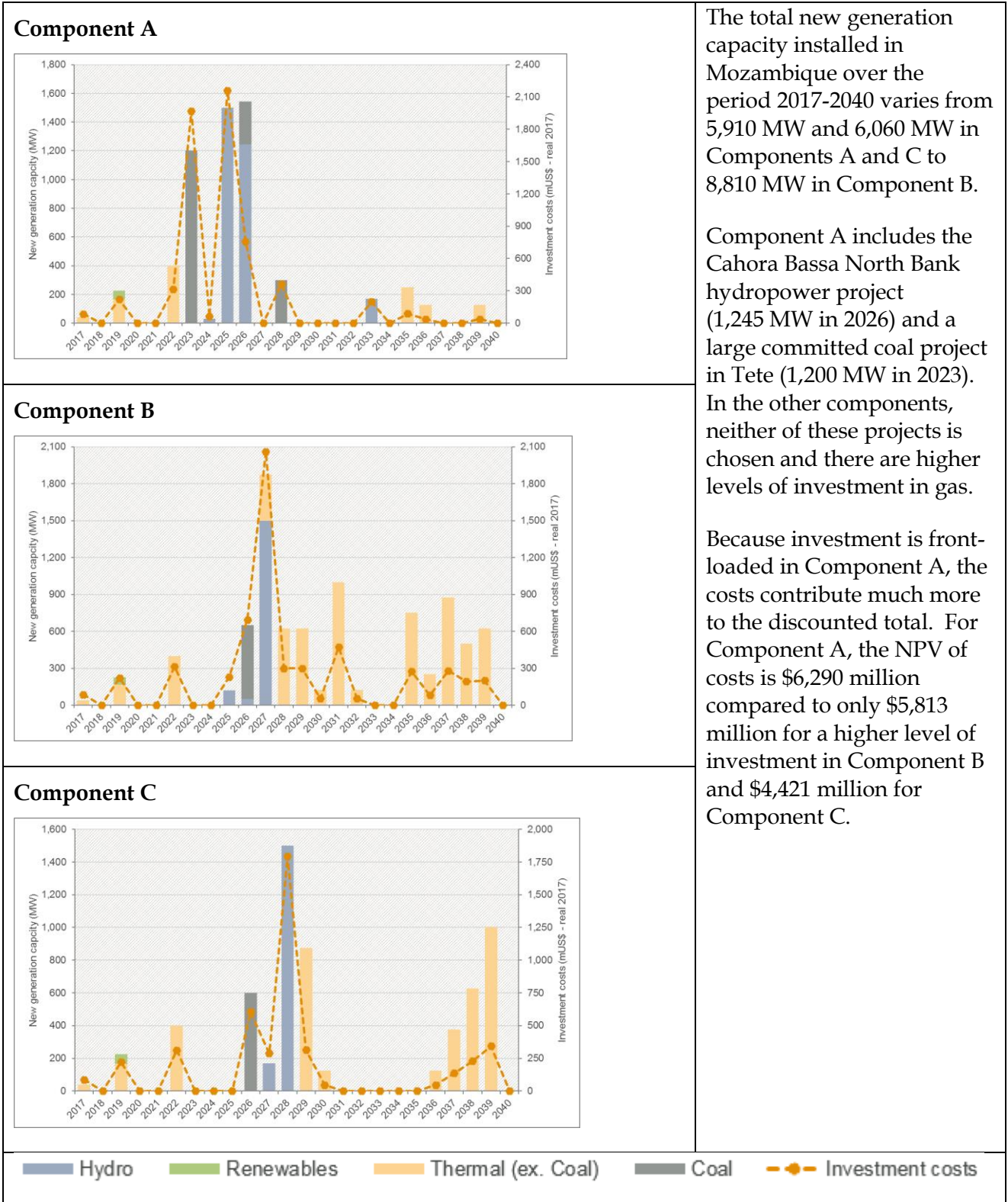
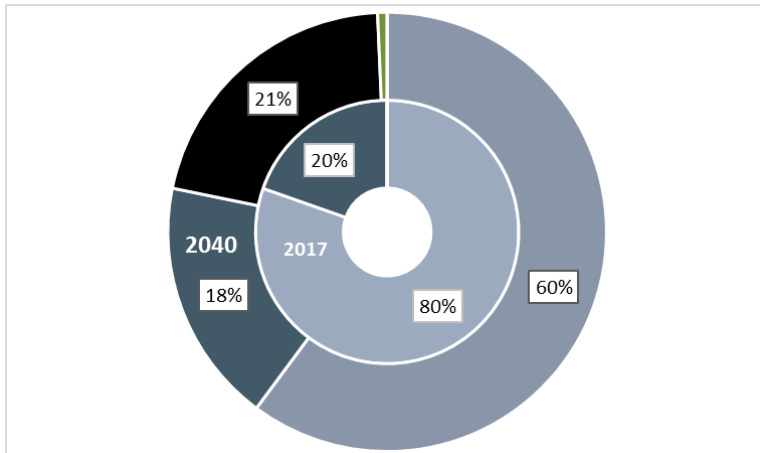


Figure 42 Mozambique share of major generation technologies in total capacity (%)

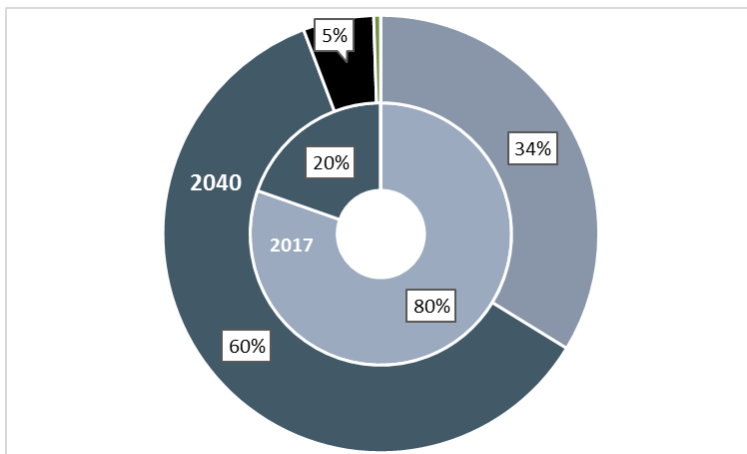
Component A



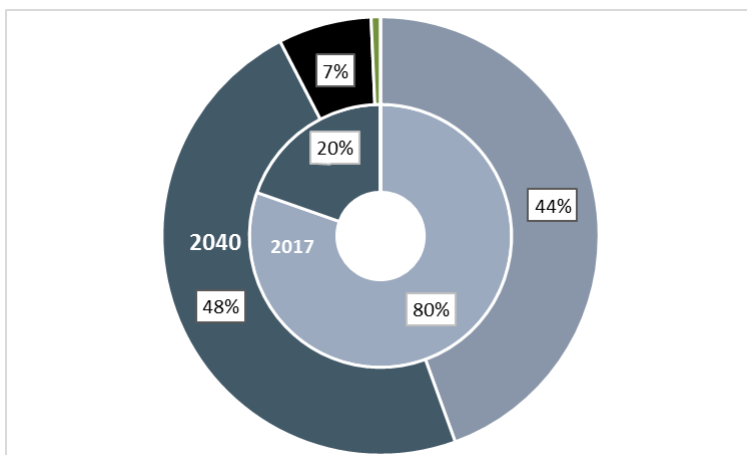
Mozambique has 80% of its capacity in hydro (2,189 MW) at the beginning of the study period, with the remainder in a combination of diesel (96 MW) and natural gas (439 MW) plants.

In Component A, there is substantial investment in coal-powered capacity over the period, whereas in Component B and C there are higher levels of investment in gas, particularly CCGT.

Component B



Component C



■ Hydro ■ Thermal (ex. Coal) ■ Coal ■ Renewables ■ Nuclear

Figure 43 Mozambique total generation capacity and reserve margin 2017-2040 (MW / %)

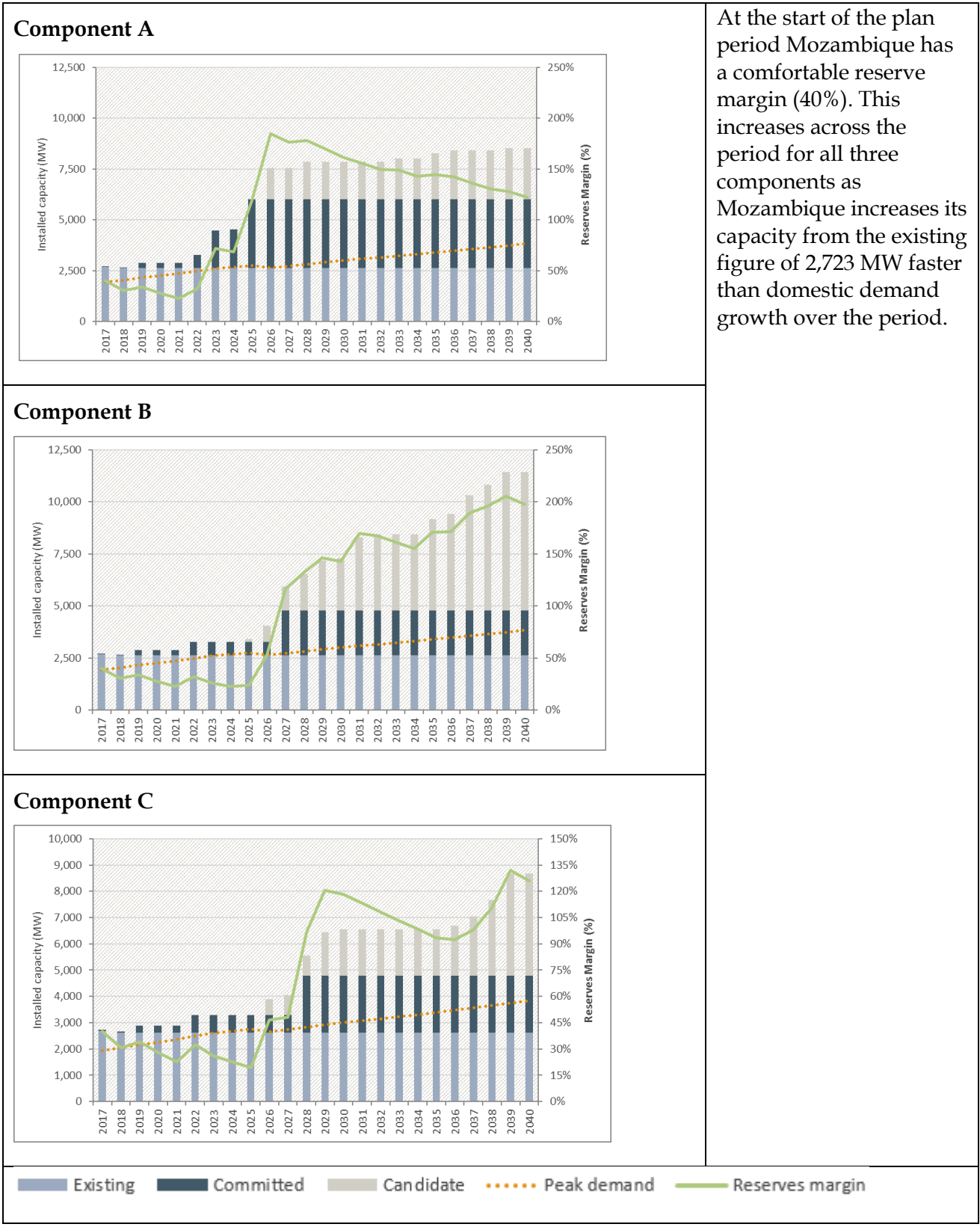
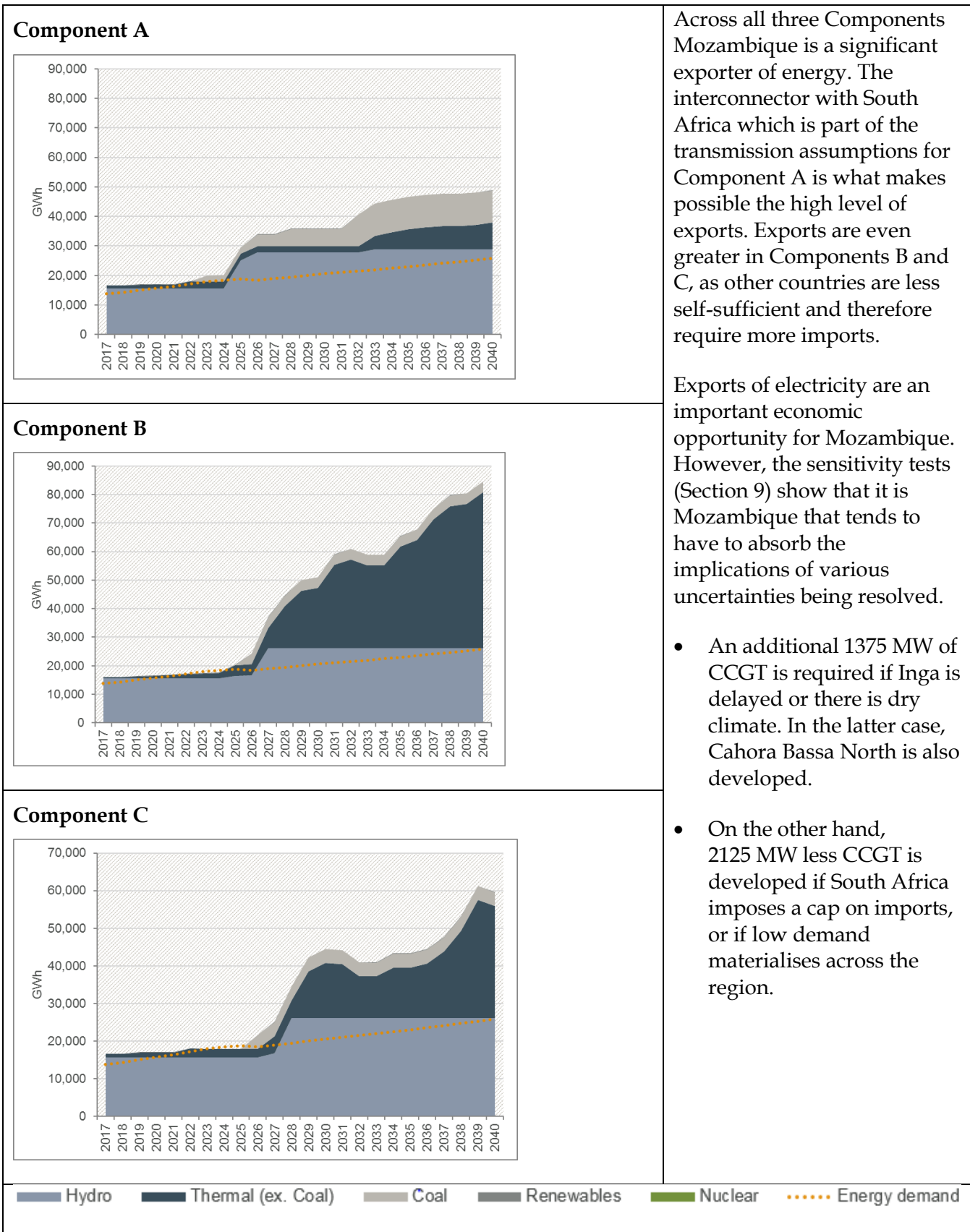


Figure 44 Mozambique mix of generation to meet energy demand (GWh)



4.7 Namibia

Figure 45 Namibia capacity additions by year, technology & investment costs (MW / \$m)

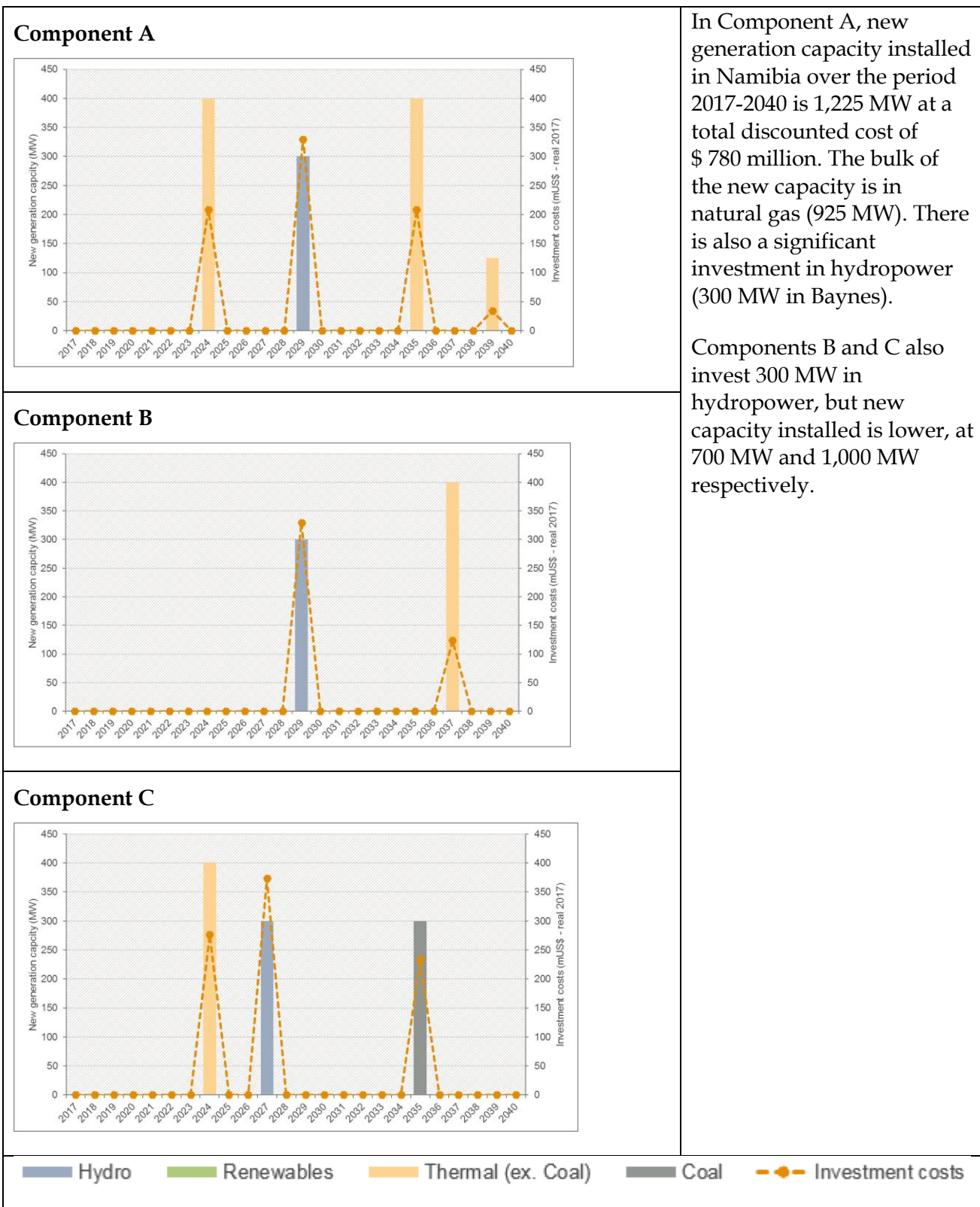


Figure 46 Namibia share of major generation technologies in total capacity (%)

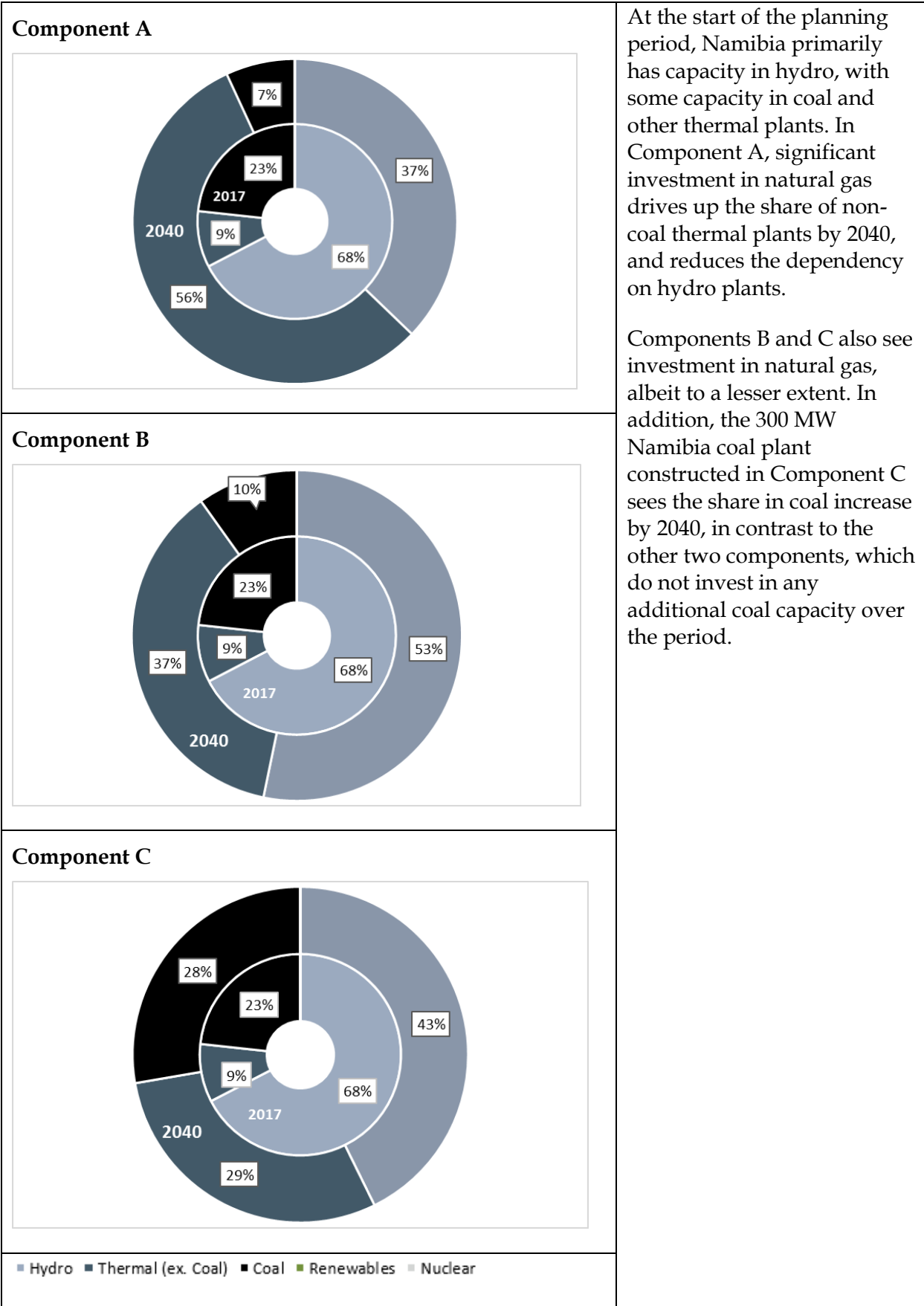


Figure 47 Namibia total generation capacity and reserve margin 2017-2040 (MW and %)

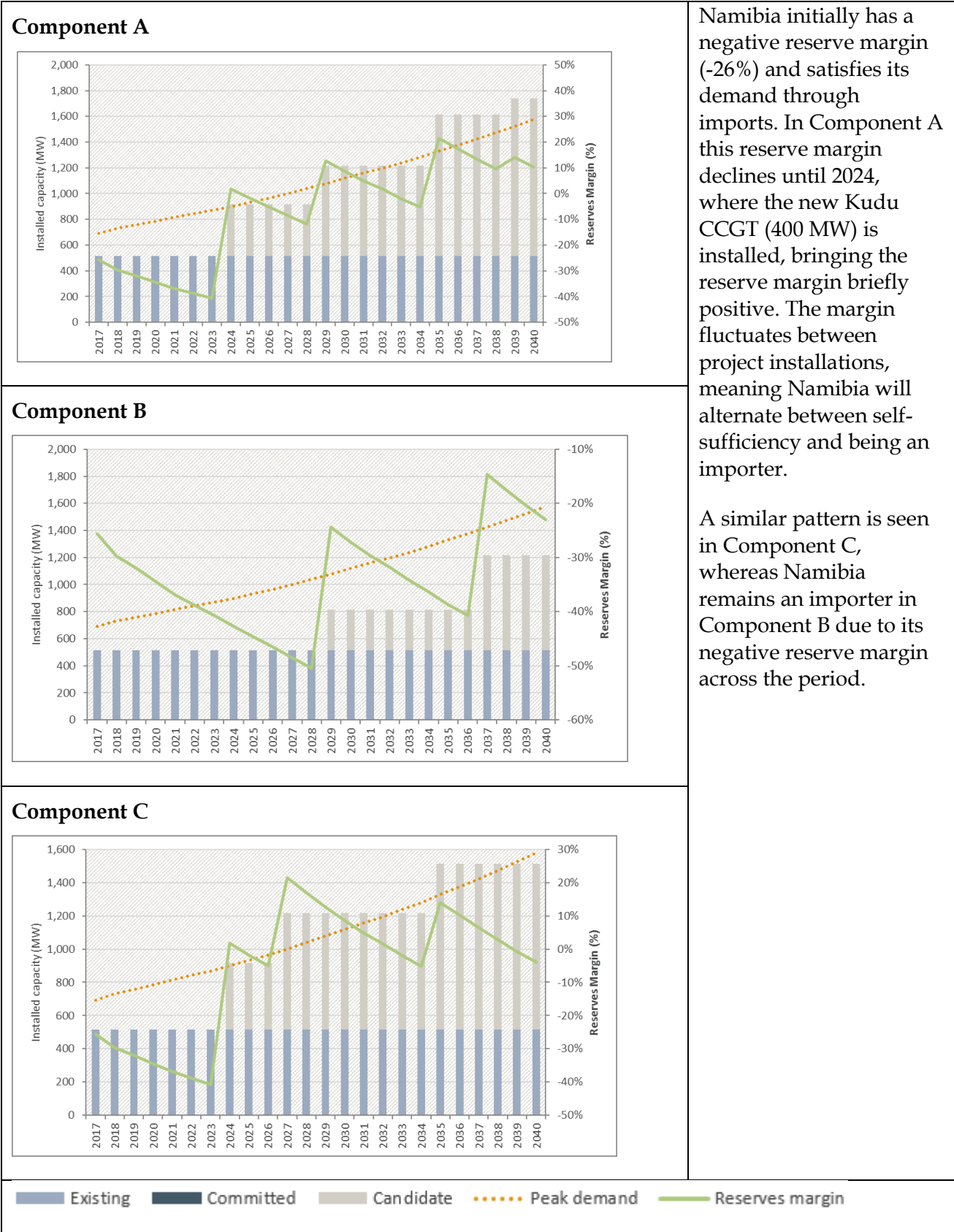
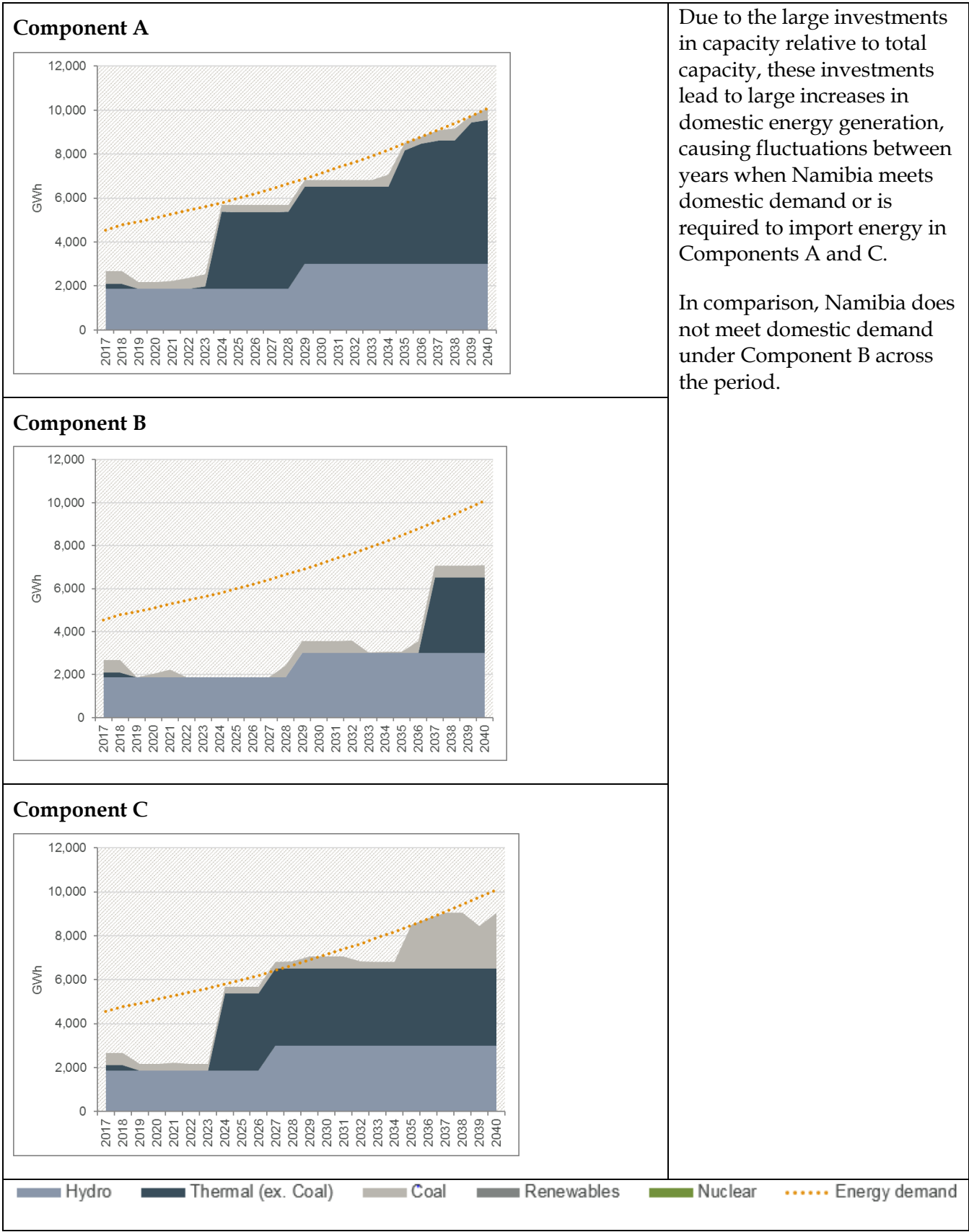


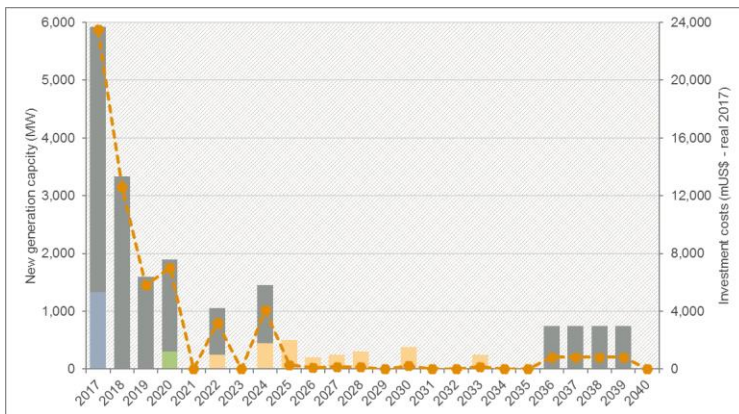
Figure 48 Namibia mix of generation to meet energy demand (GWh)



4.8 South Africa

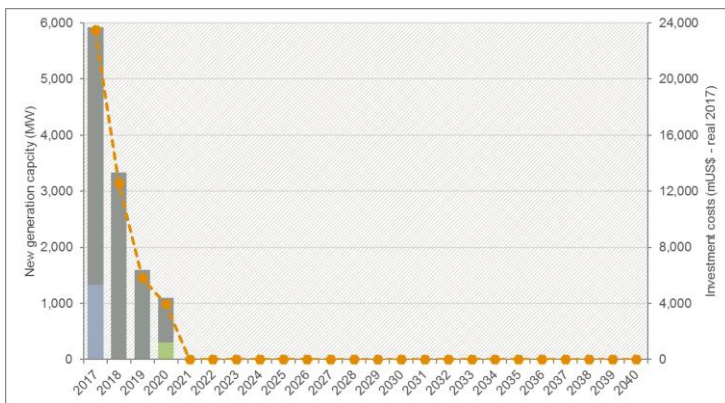
Figure 49 South Africa capacity additions by year, technology & inv. costs (MW / \$m)

Component A



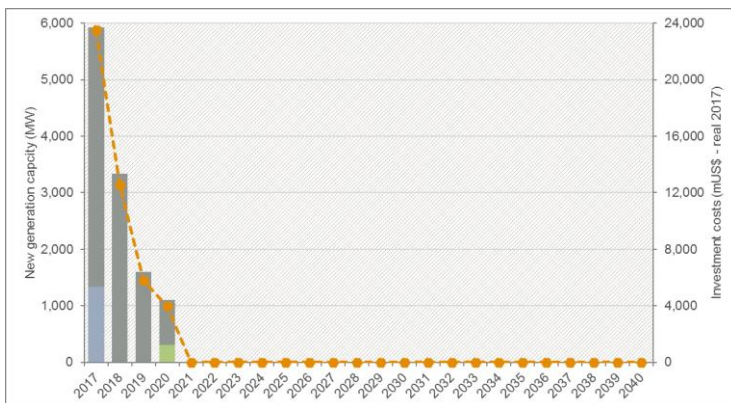
In Component A, new generation capacity installed in South Africa over the period 2017-2040 is 20,133 MW at a total discounted cost of \$ 60,552 million. The bulk of the new capacity is in coal (15,926 MW). There is also investment in natural gas generation (2,575 MW), hydropower (1232 MW) and a CSP plant (300 MW%).

Component B



As South Africa becomes a much larger importer in Components B and C there is less capacity built domestically - 11,958 MW in each Component, at a discounted cost of \$39,533 million.

Component C



Hydro Renewables Thermal (ex. Coal) Coal Investment costs

Figure 50 South Africa share of major generation technologies in total capacity (%)

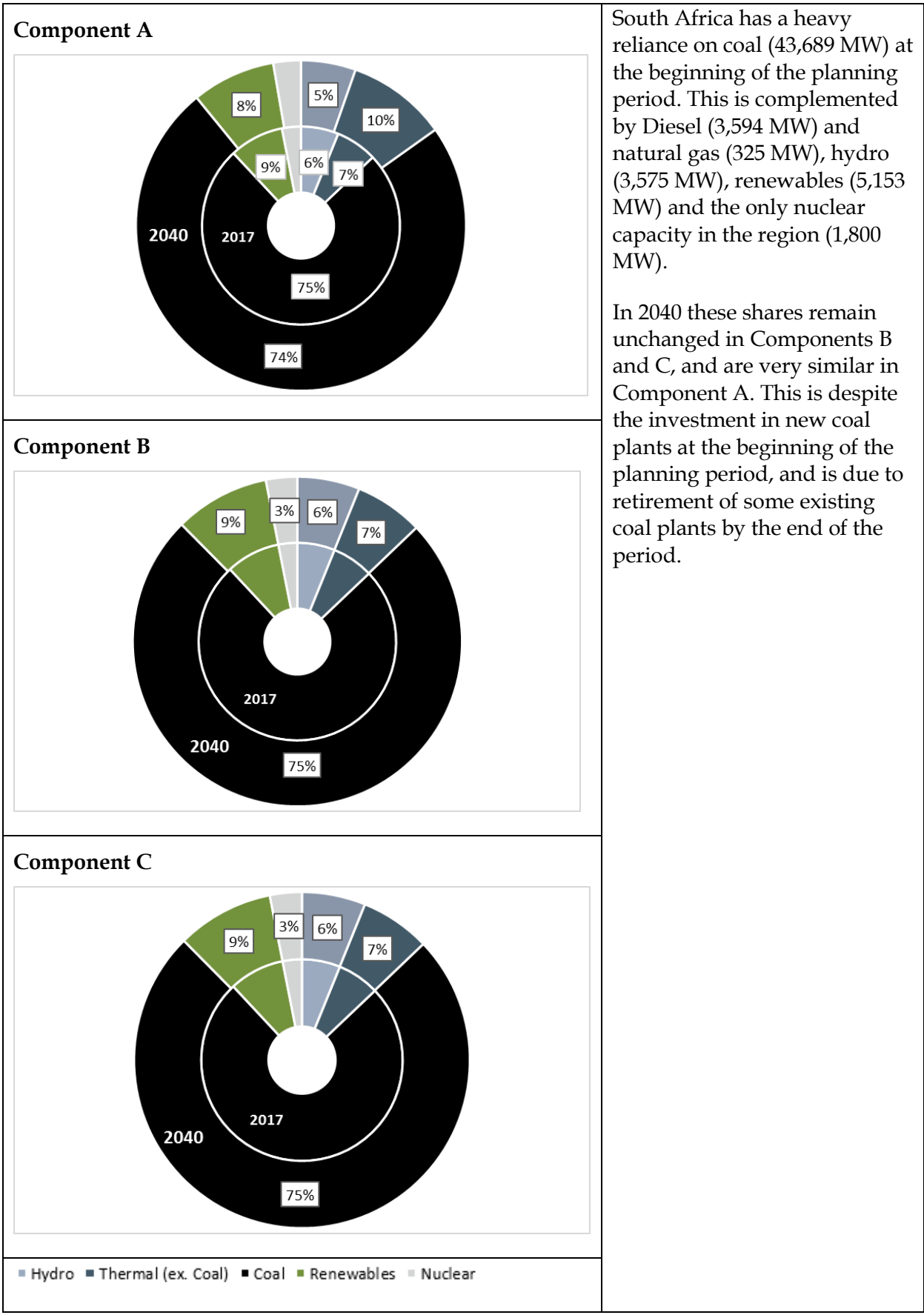
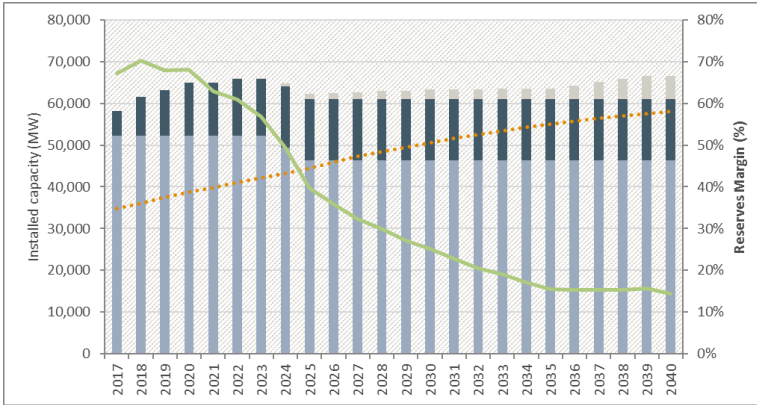


Figure 51 South Africa total generation capacity and reserve margin 2017-2040 (MW / %)

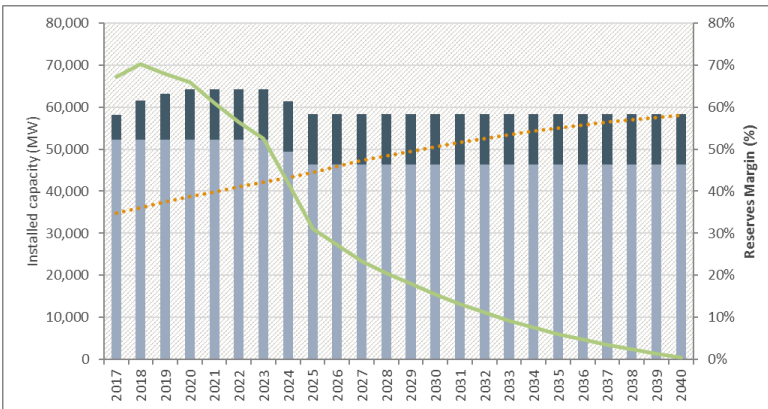
Component A



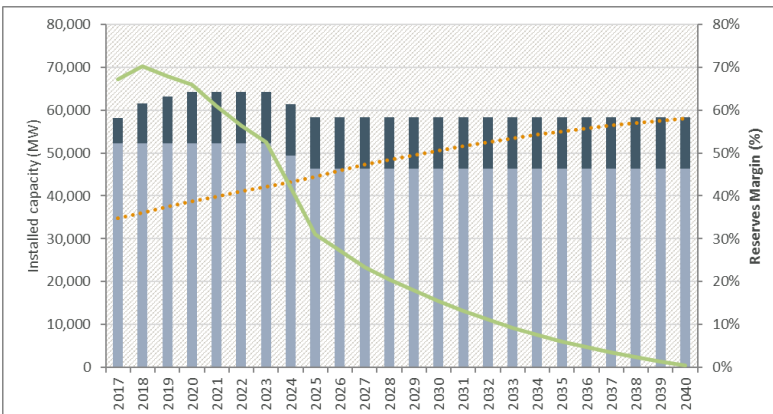
The initial reserve margin of South Africa is relatively high at 67%. In each of the scenarios this peaks in 2018, declining to 14% by 2040 in Component A and to 0% in Components B and C.

This decline in reserve margin is accompanied by South Africa making a transition from exporter to importer.

Component B

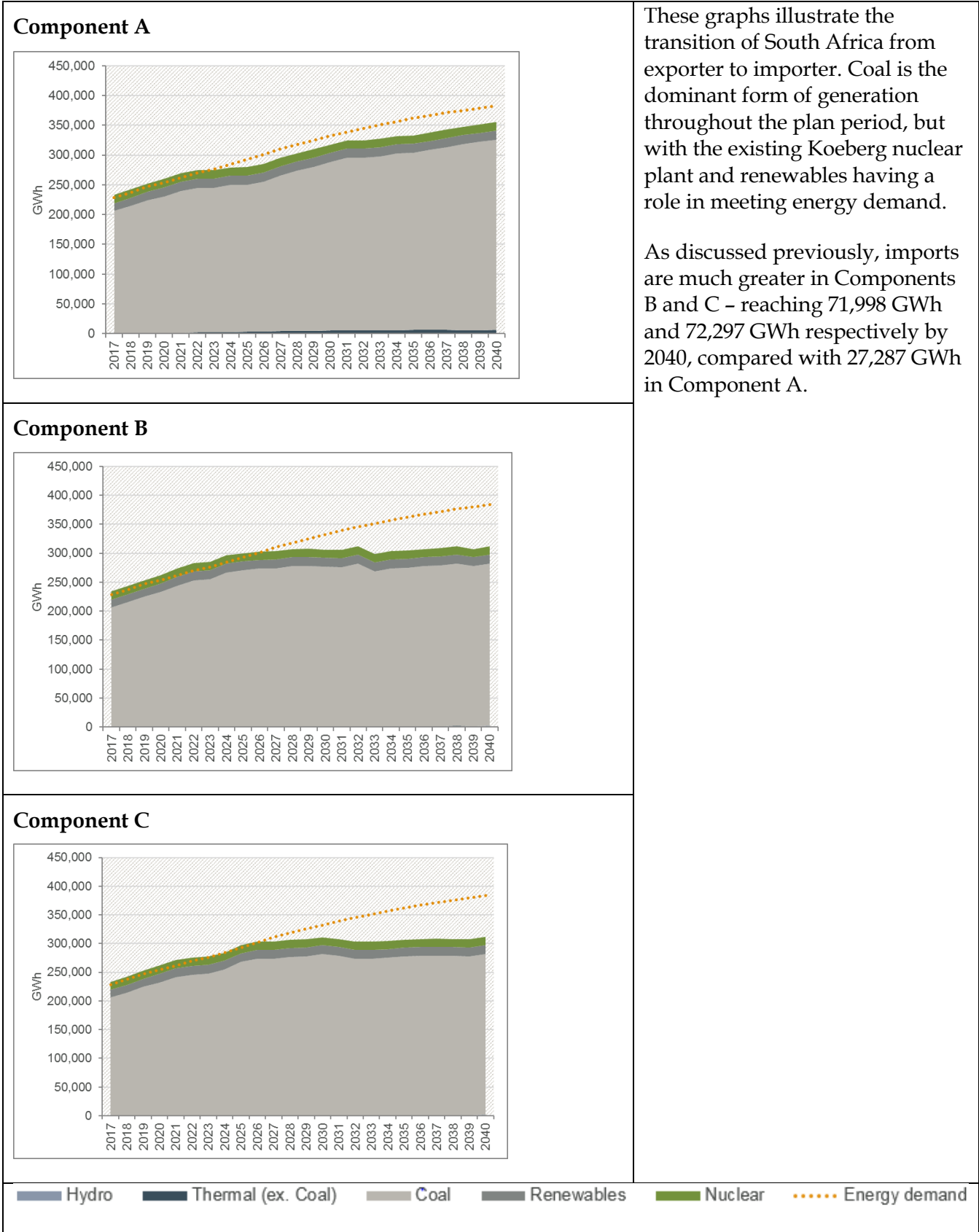


Component C



Existing Committed Candidate Peak demand Reserves margin

Figure 52 South Africa mix of generation to meet energy demand (GWh)



4.9 Swaziland

Figure 53 Swaziland capacity additions by year, technology & inv. costs (MW/\$m)

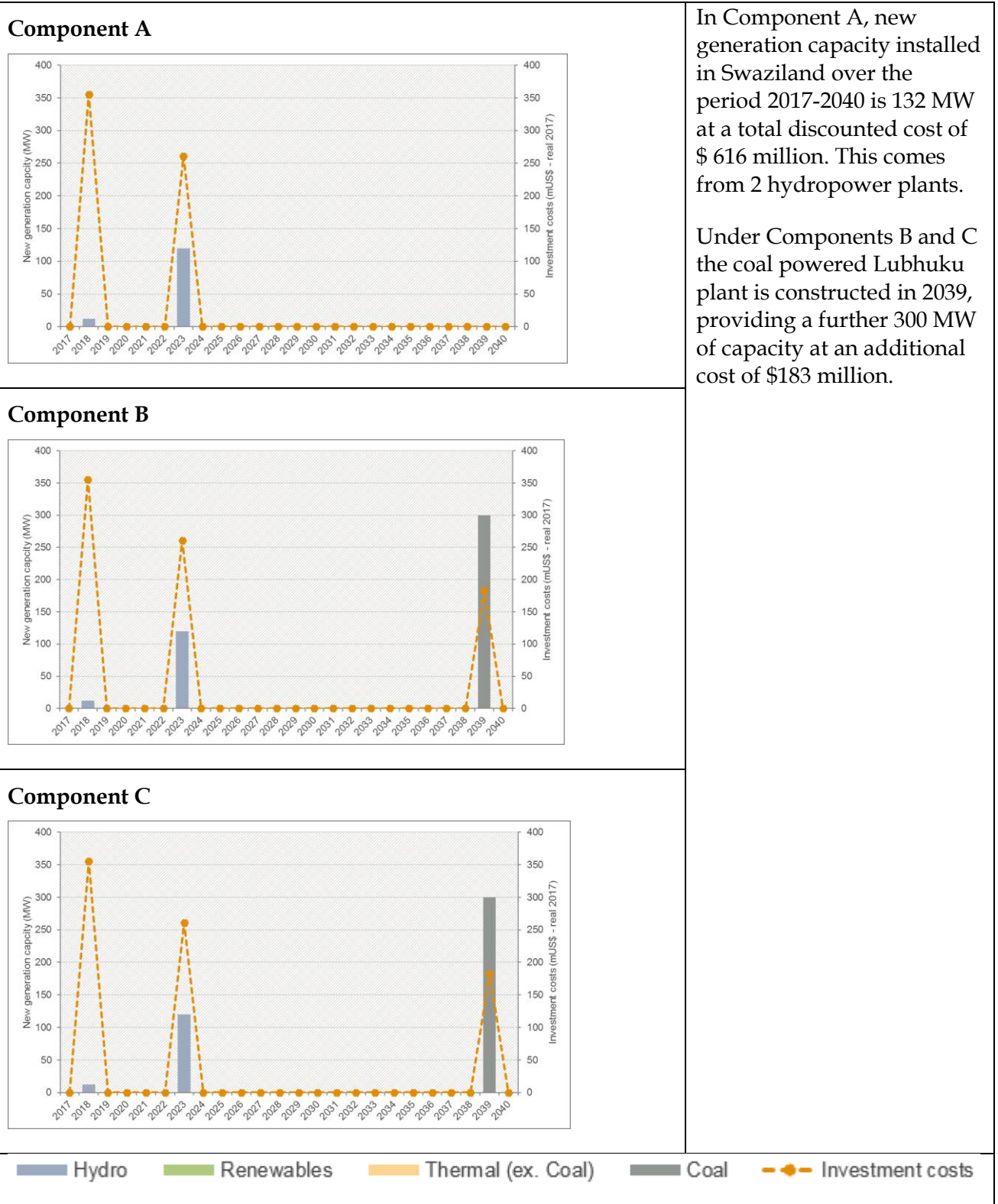


Figure 54 Swaziland share of major generation technologies in total capacity (%)

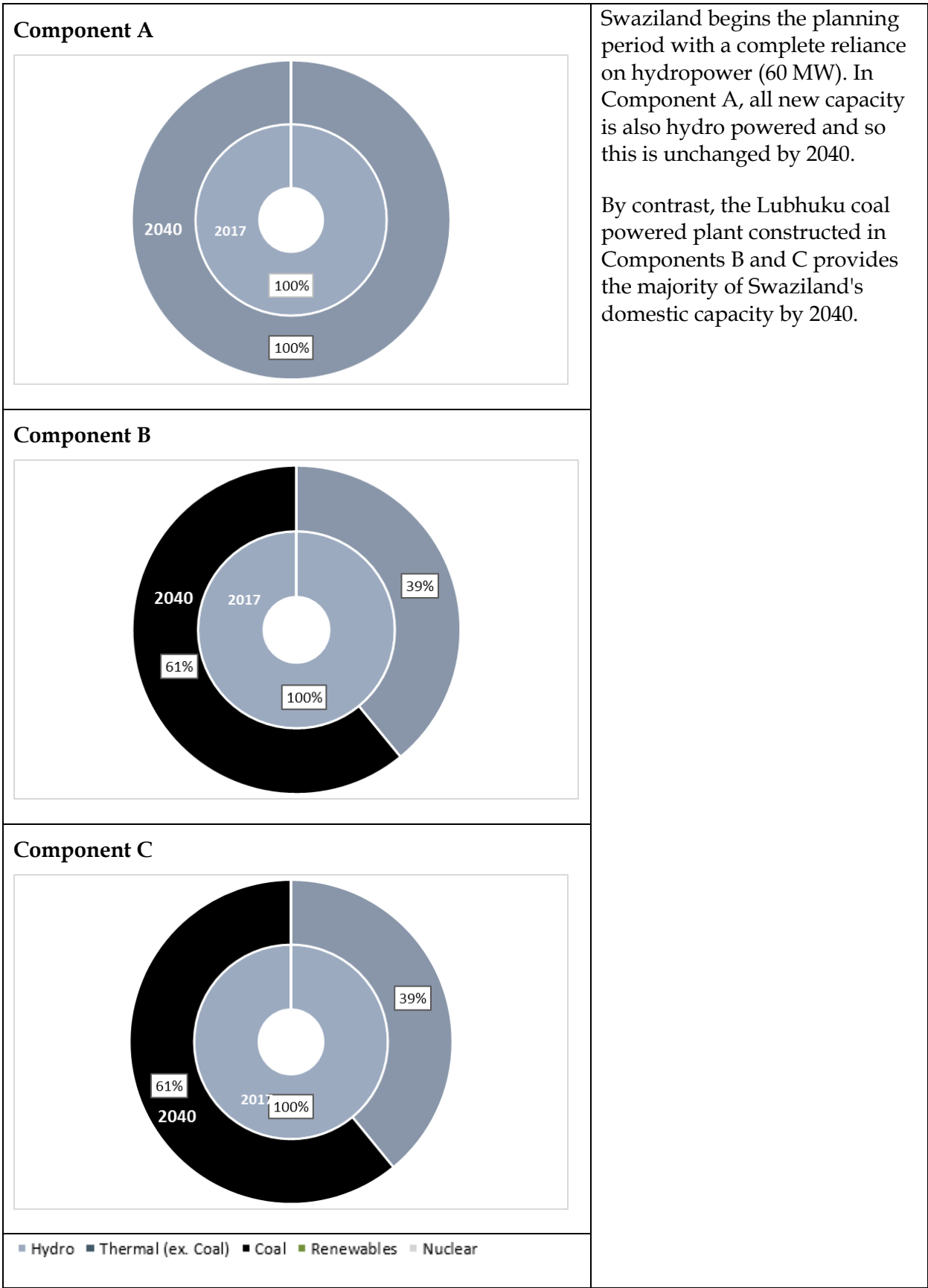
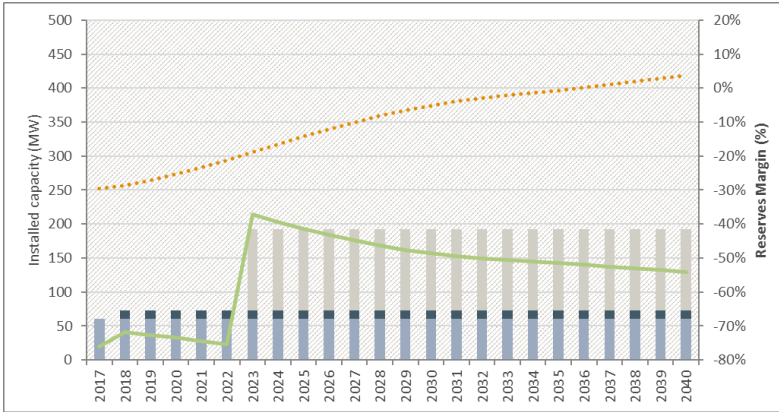


Figure 55 Swaziland total generation capacity and reserve margin 2017-2040 (MW and %)

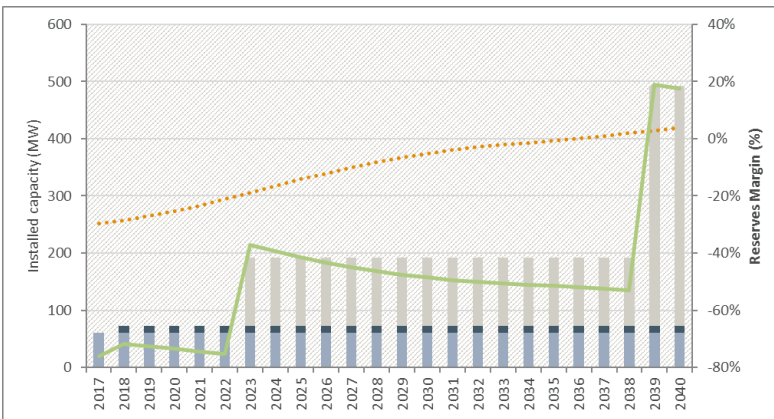
Component A



The initial reserve margin in Swaziland is significantly negative (-73%). Demand is met through imports.

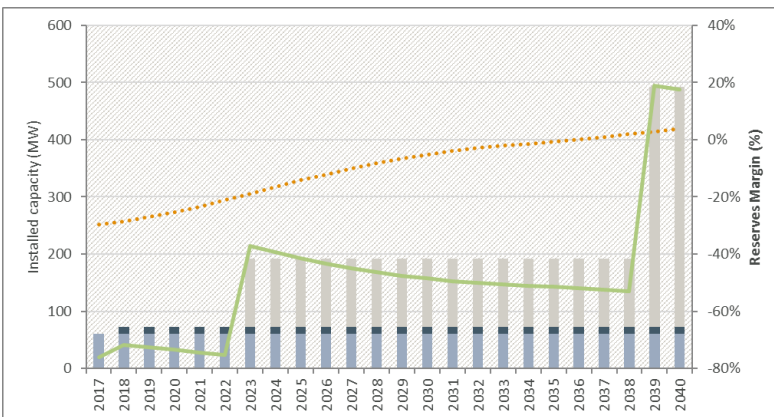
Early capacity expansions improve the reserve margin, but it is only after the Lubhuku project is commissioned in 2039 in Components B and C that the country is able to meet its maximum demand and provide its own reserve margin of 18% by 2040.

Component B



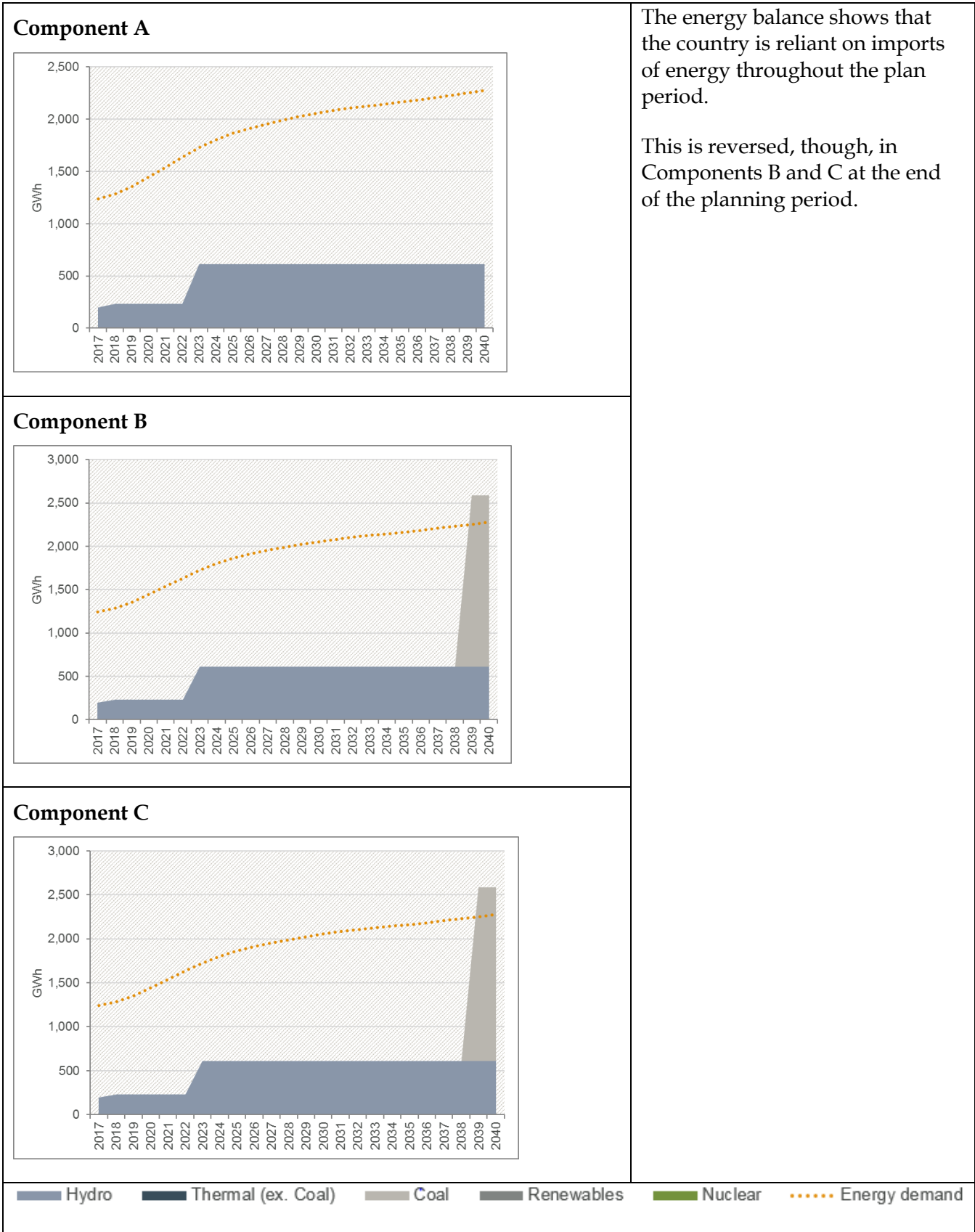
This contrasts with the highly negative reserve margin that endures in Component A (-54%).

Component C



Existing Committed Candidate Peak demand Reserves margin

Figure 56 Swaziland mix of generation to meet energy demand (GWh)



4.10 Tanzania

Figure 57 Tanzania capacity additions by year, technology and inv. costs (MW / \$m)

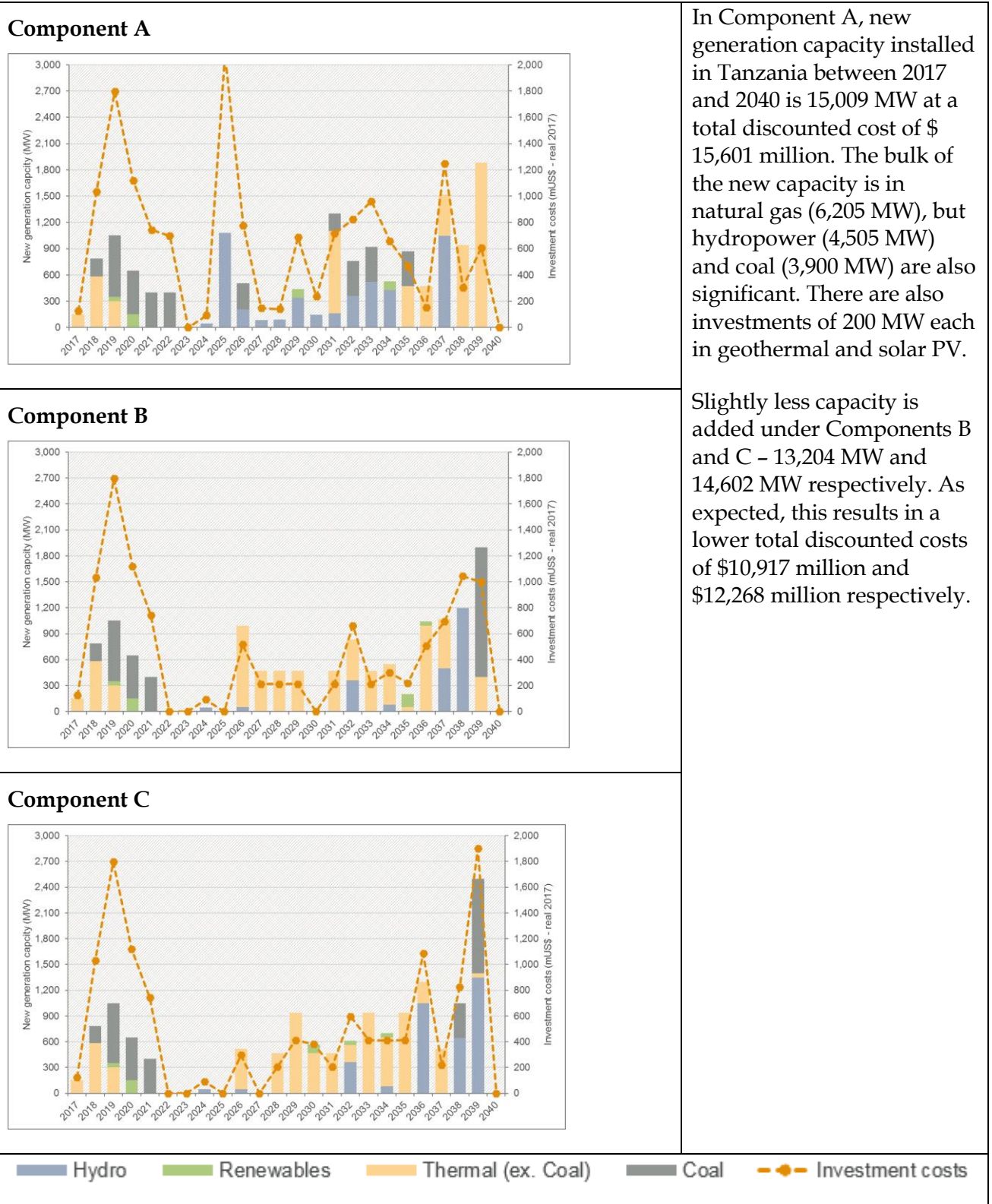


Figure 58 Tanzania share of major generation technologies in total capacity (%)

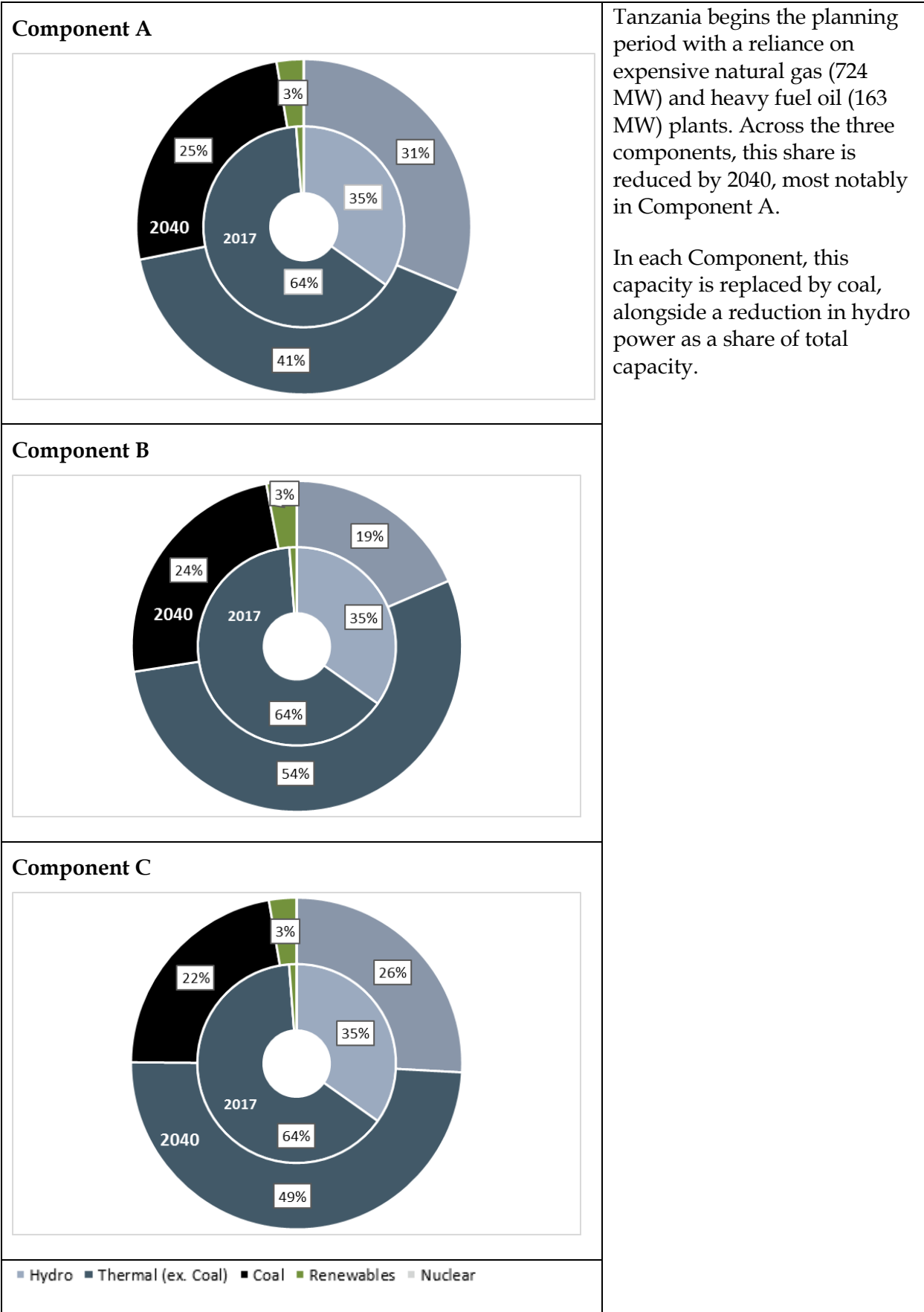


Figure 59 Tanzania total generation capacity and reserve margin 2017-2040 (MW and %)

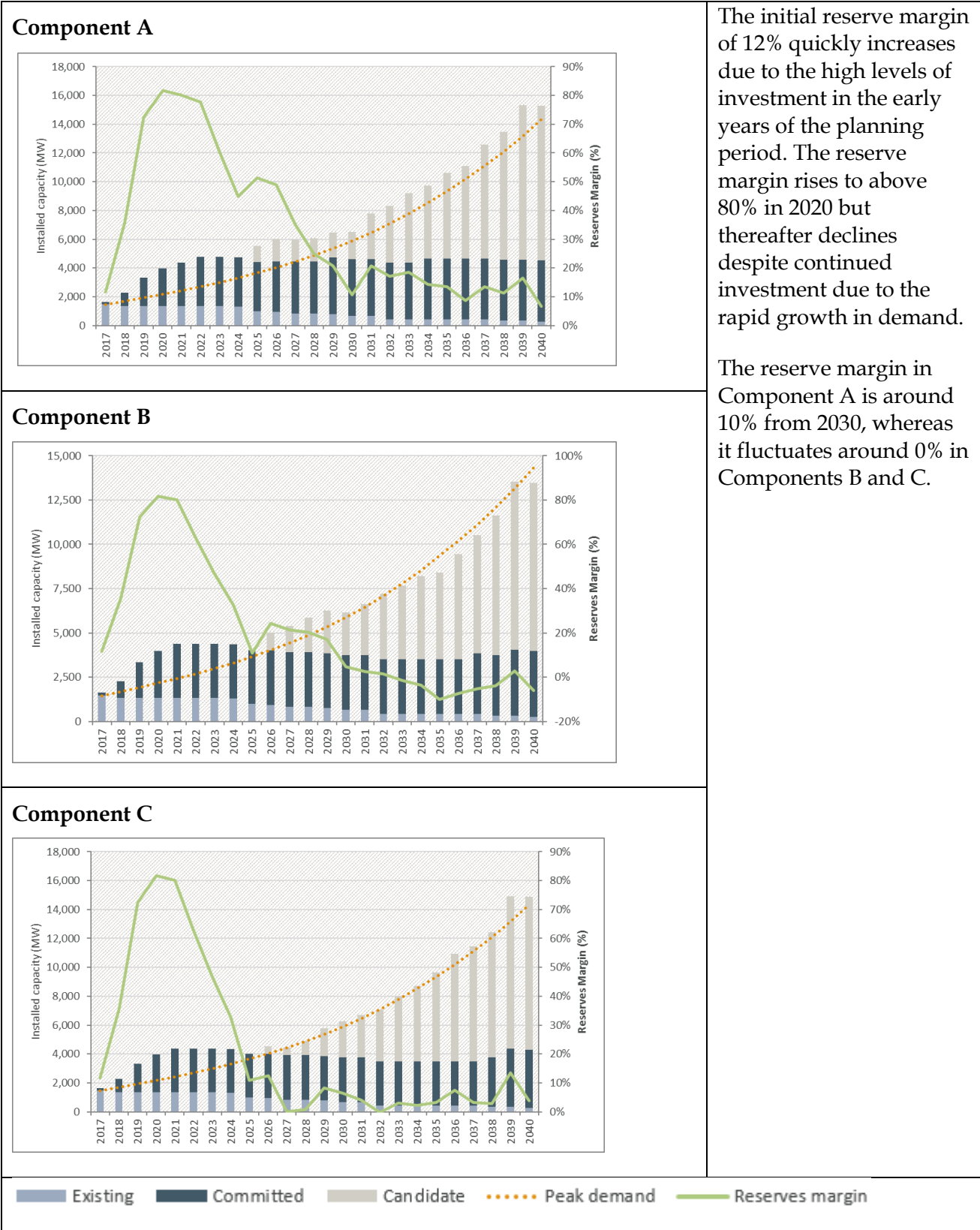
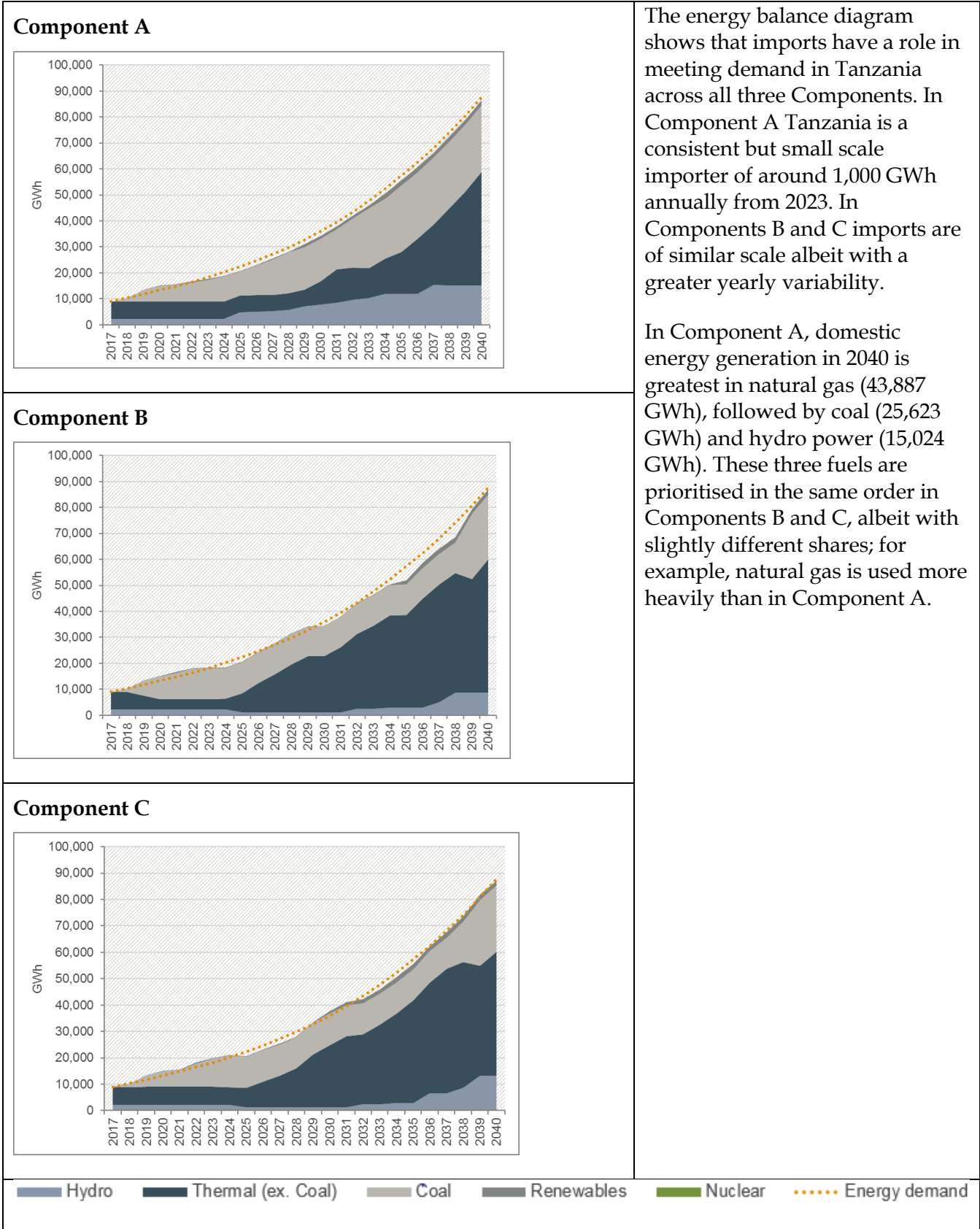


Figure 60 Tanzania mix of generation to meet energy demand (GWh)



4.11 Zambia

Figure 61 Zambia capacity additions by year, technology and investment costs (MW/\$m)

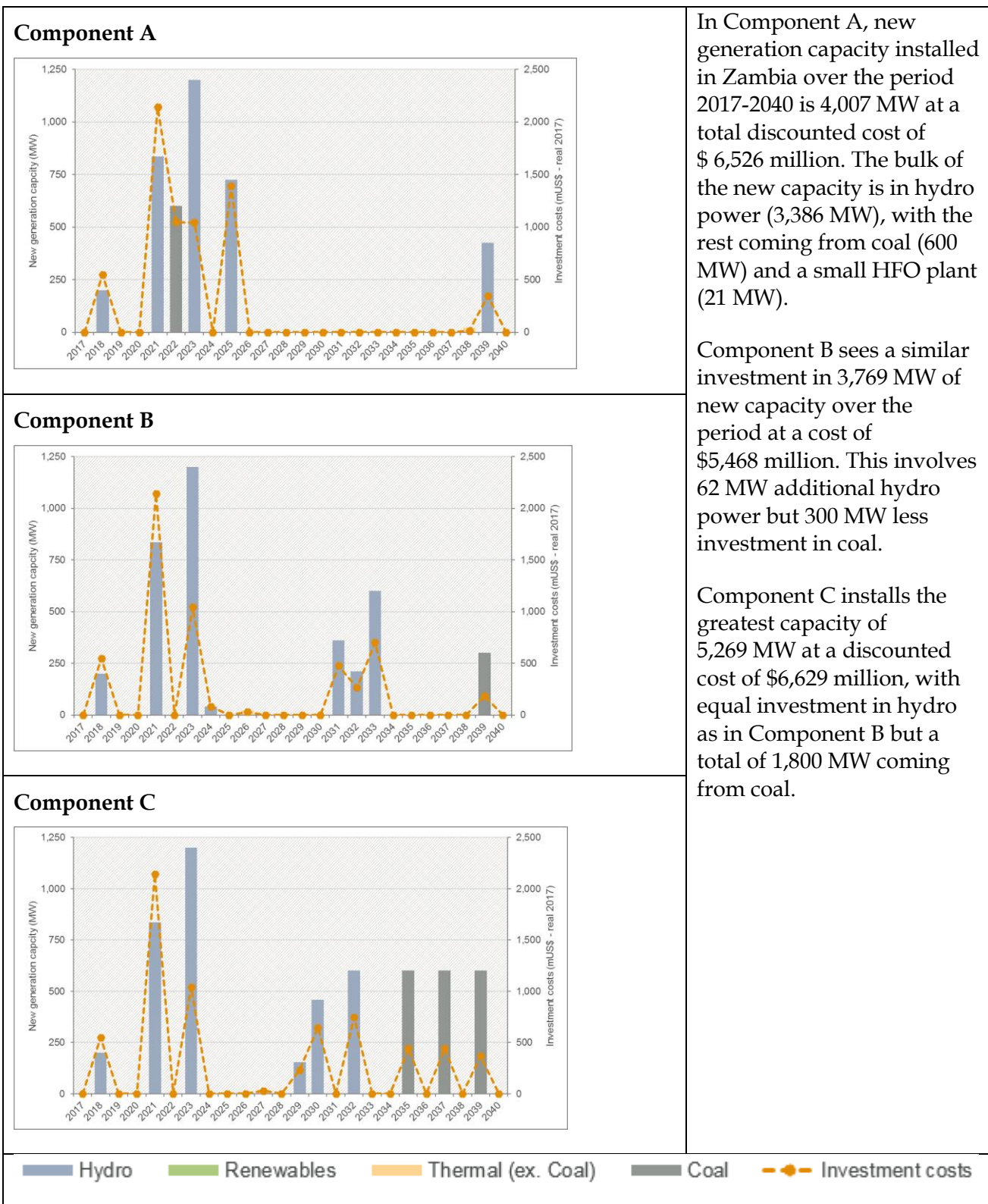
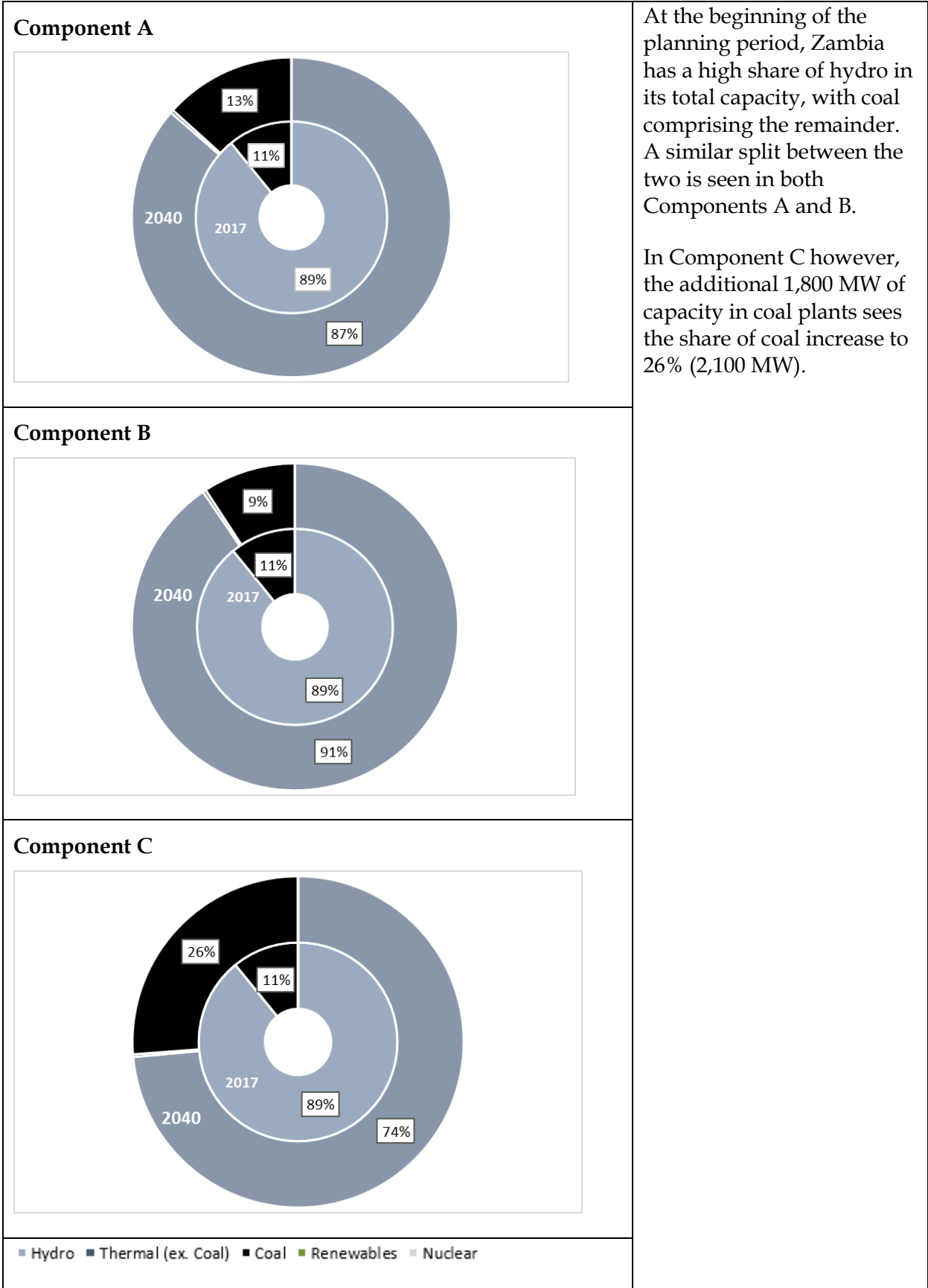


Figure 62 Zambia share of major generation technologies in total capacity (%)

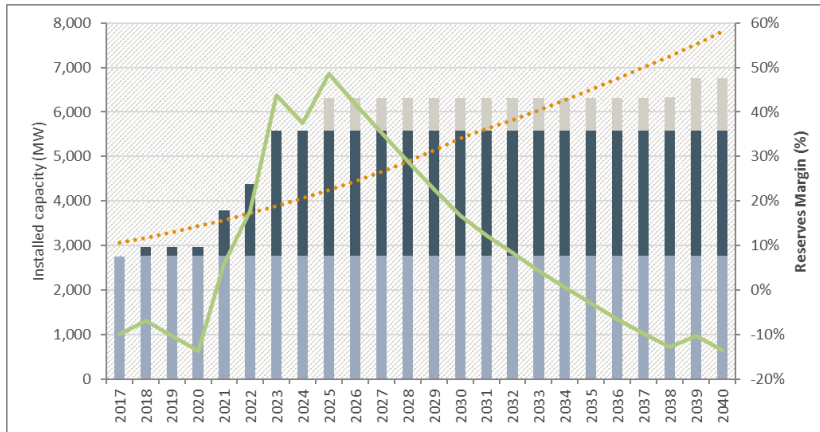


At the beginning of the planning period, Zambia has a high share of hydro in its total capacity, with coal comprising the remainder. A similar split between the two is seen in both Components A and B.

In Component C however, the additional 1,800 MW of capacity in coal plants sees the share of coal increase to 26% (2,100 MW).

Figure 63 Zambia total generation capacity and reserve margin 2017-2040 (MW and %)

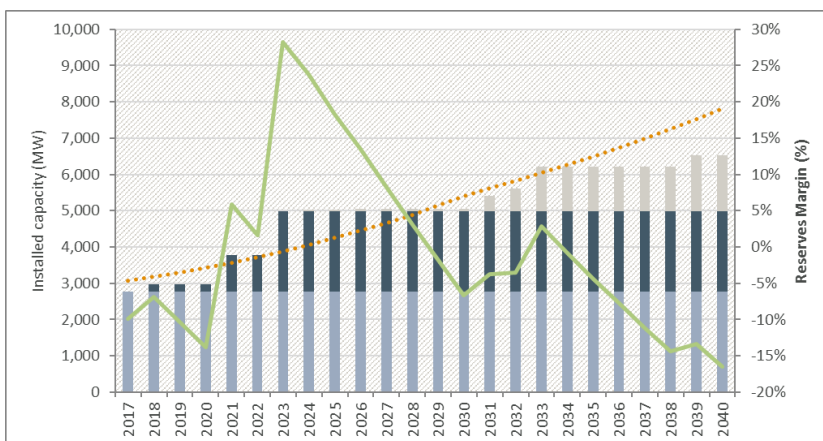
Component A



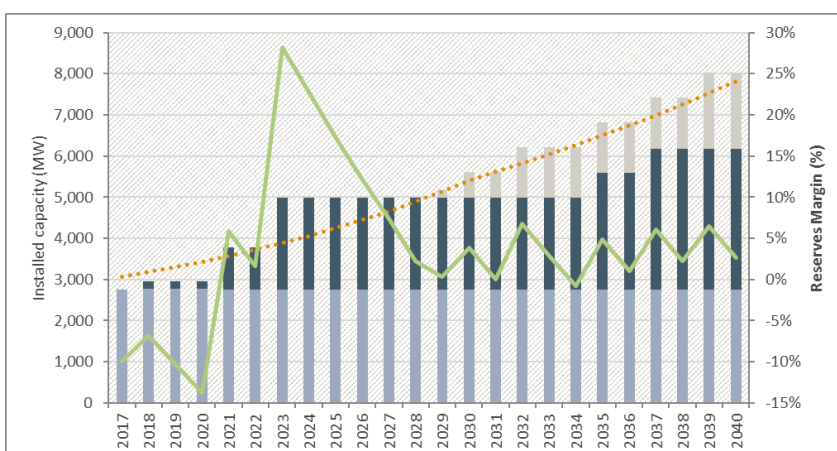
The reserve margin in Zambia at the start of the plan period is negative (-10%). Significant expansion in generation capacity in 2021-2025 reverses this position, with the reserve margin rising to 49% in 2025.

Rapid growth in demand results in a progressive decline from this level, with reserve margins becoming negative by 2040 in Component A (-13%) and Component B (-17%).

Component B

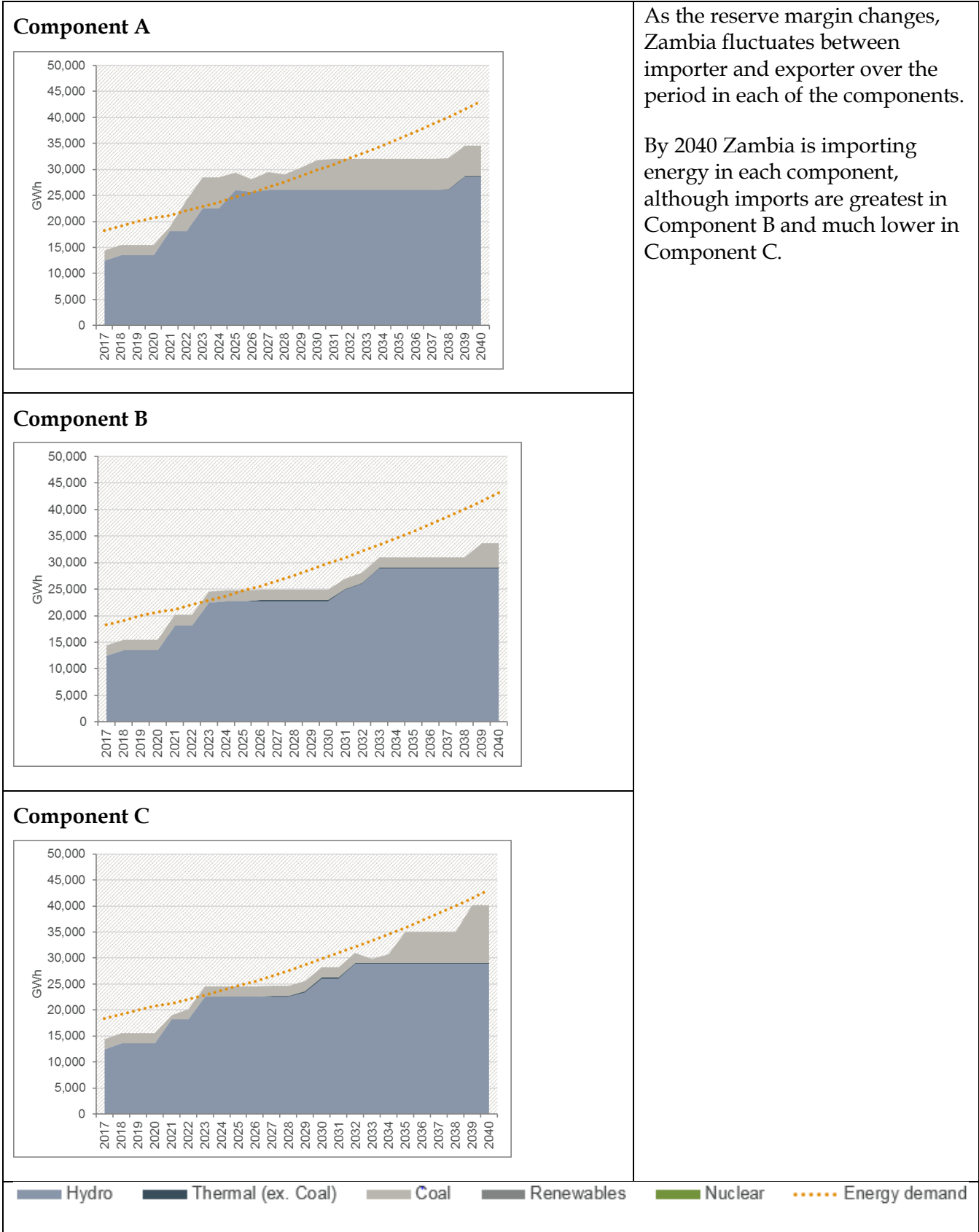


Component C



Existing Committed Candidate Peak demand Reserves margin

Figure 64 Zambia mix of generation to meet energy demand (GWh)



4.12 Zimbabwe

Figure 65 Zimbabwe capacity additions by year, technology & inv. costs (MW/\$m)

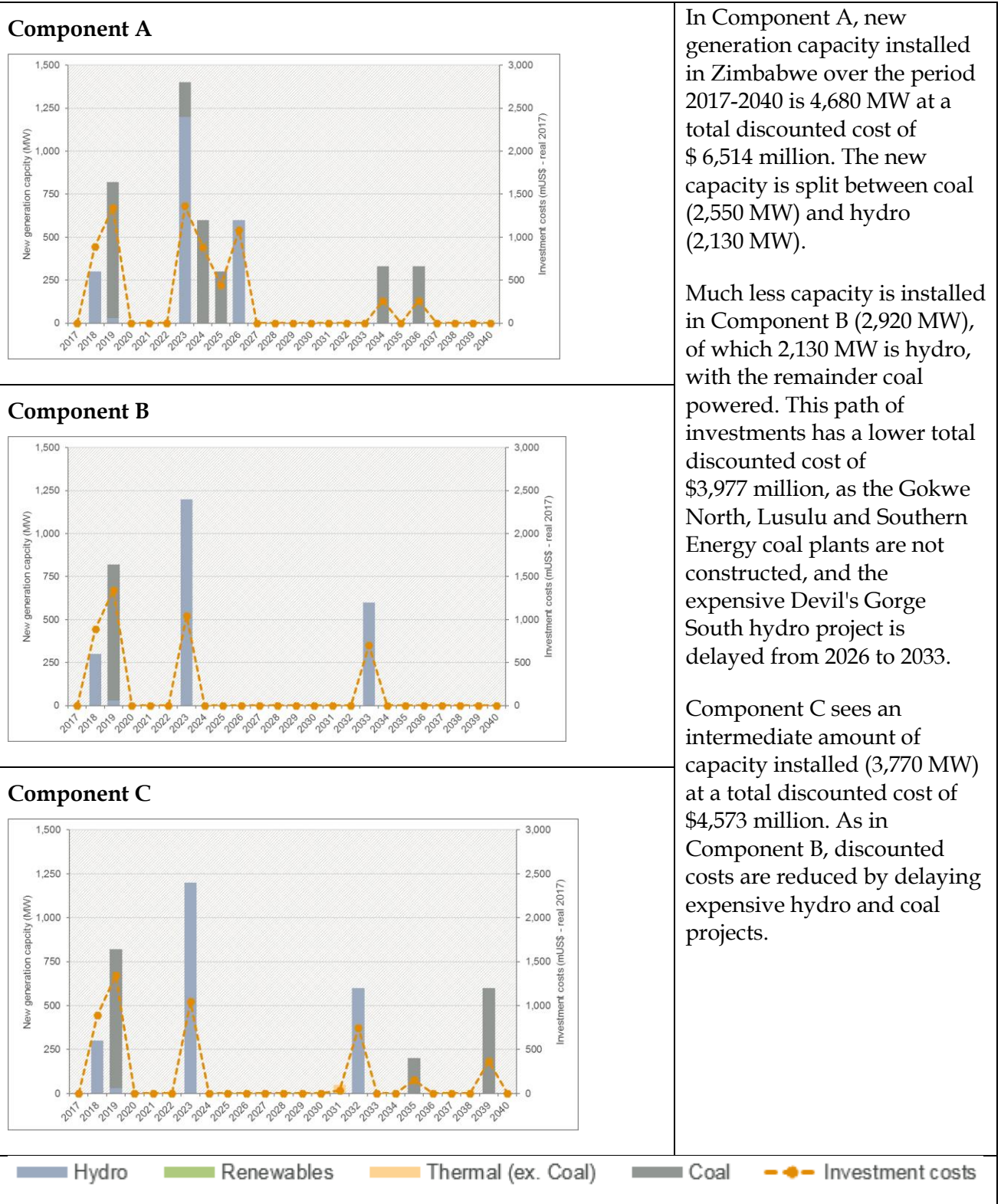
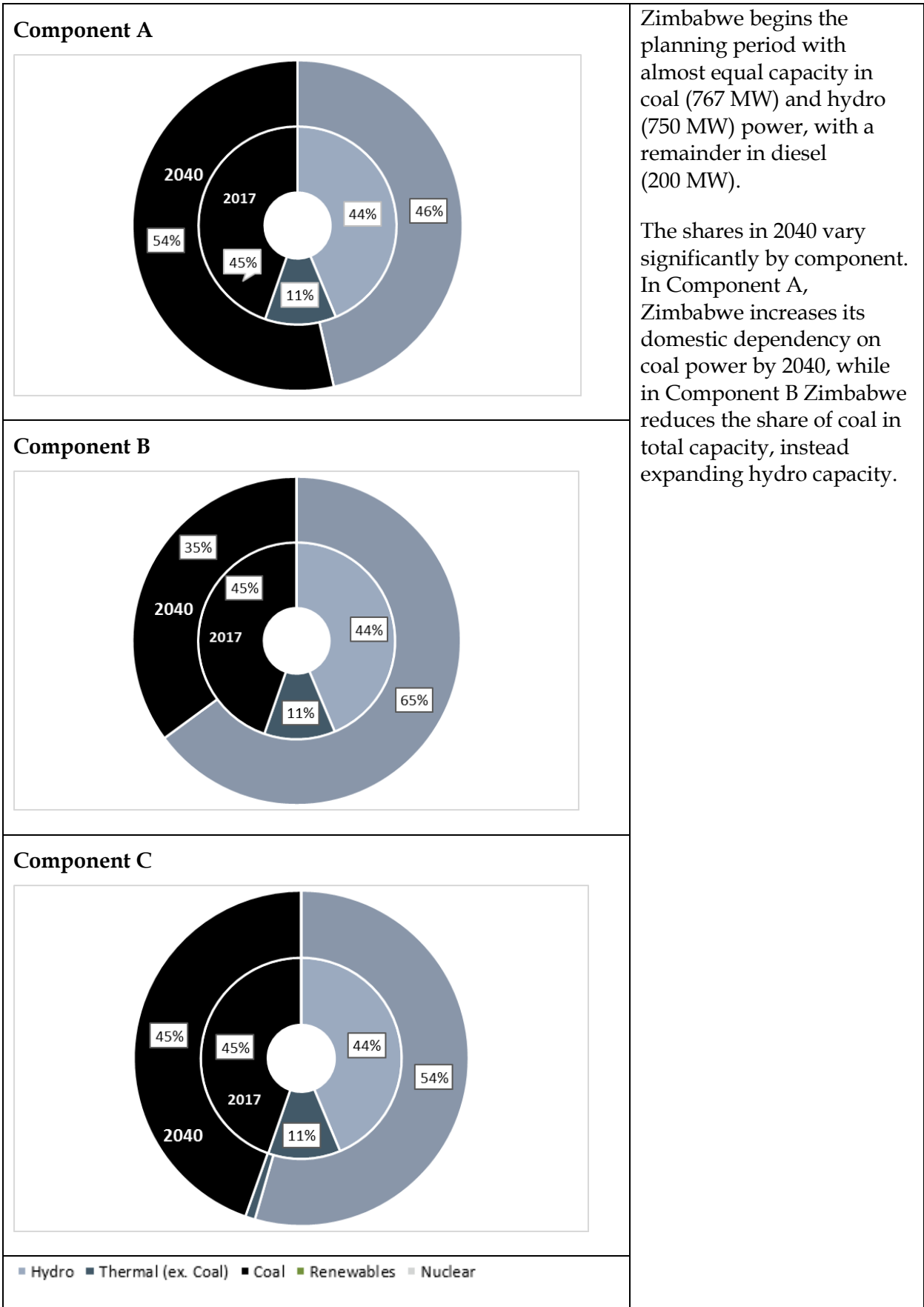


Figure 66 Zimbabwe share of major generation technologies in total capacity (%)



Zimbabwe begins the planning period with almost equal capacity in coal (767 MW) and hydro (750 MW) power, with a remainder in diesel (200 MW).

The shares in 2040 vary significantly by component. In Component A, Zimbabwe increases its domestic dependency on coal power by 2040, while in Component B Zimbabwe reduces the share of coal in total capacity, instead expanding hydro capacity.

Figure 67 Zimbabwe total generation capacity and reserve margin 2017-2040 (MW and %)

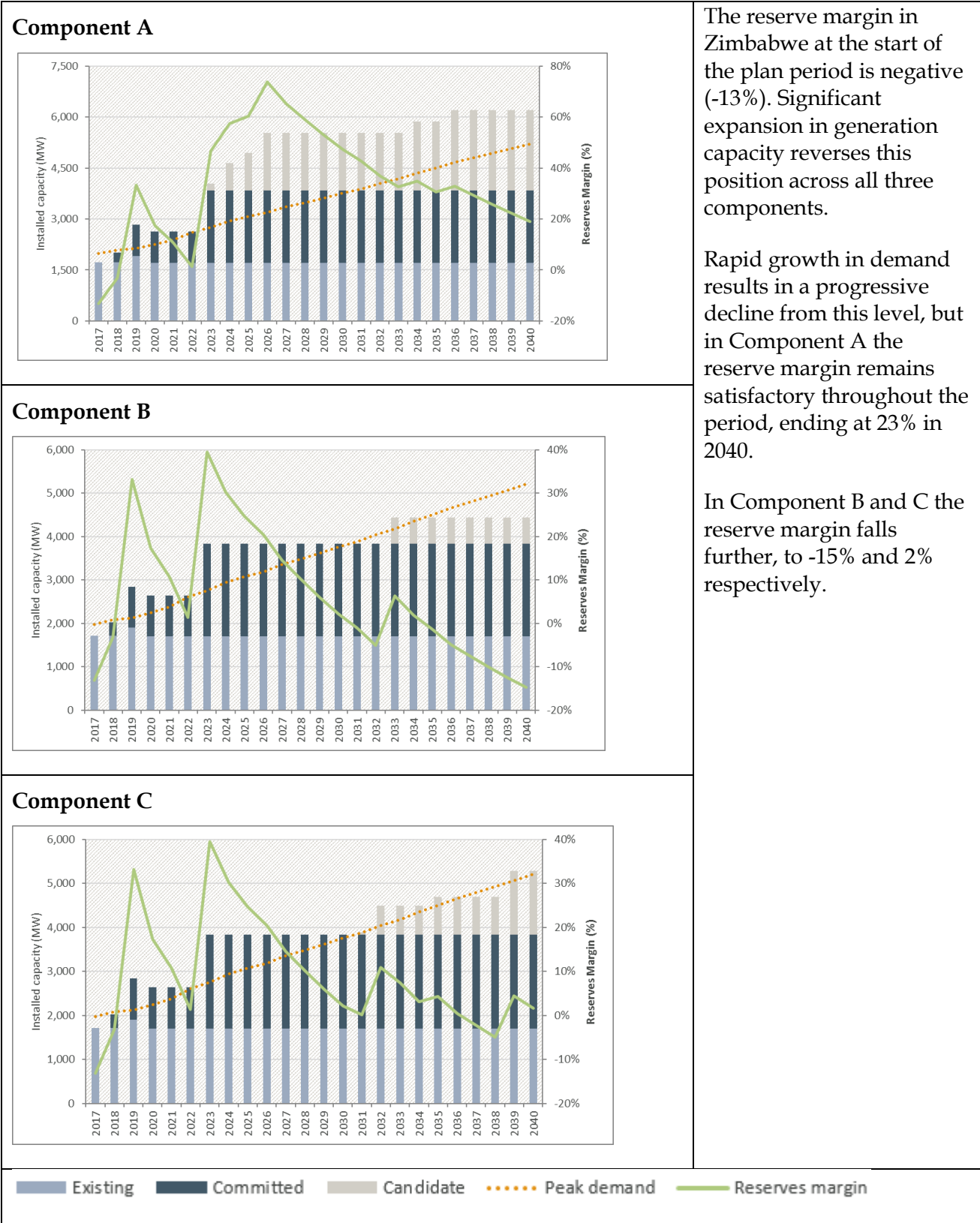
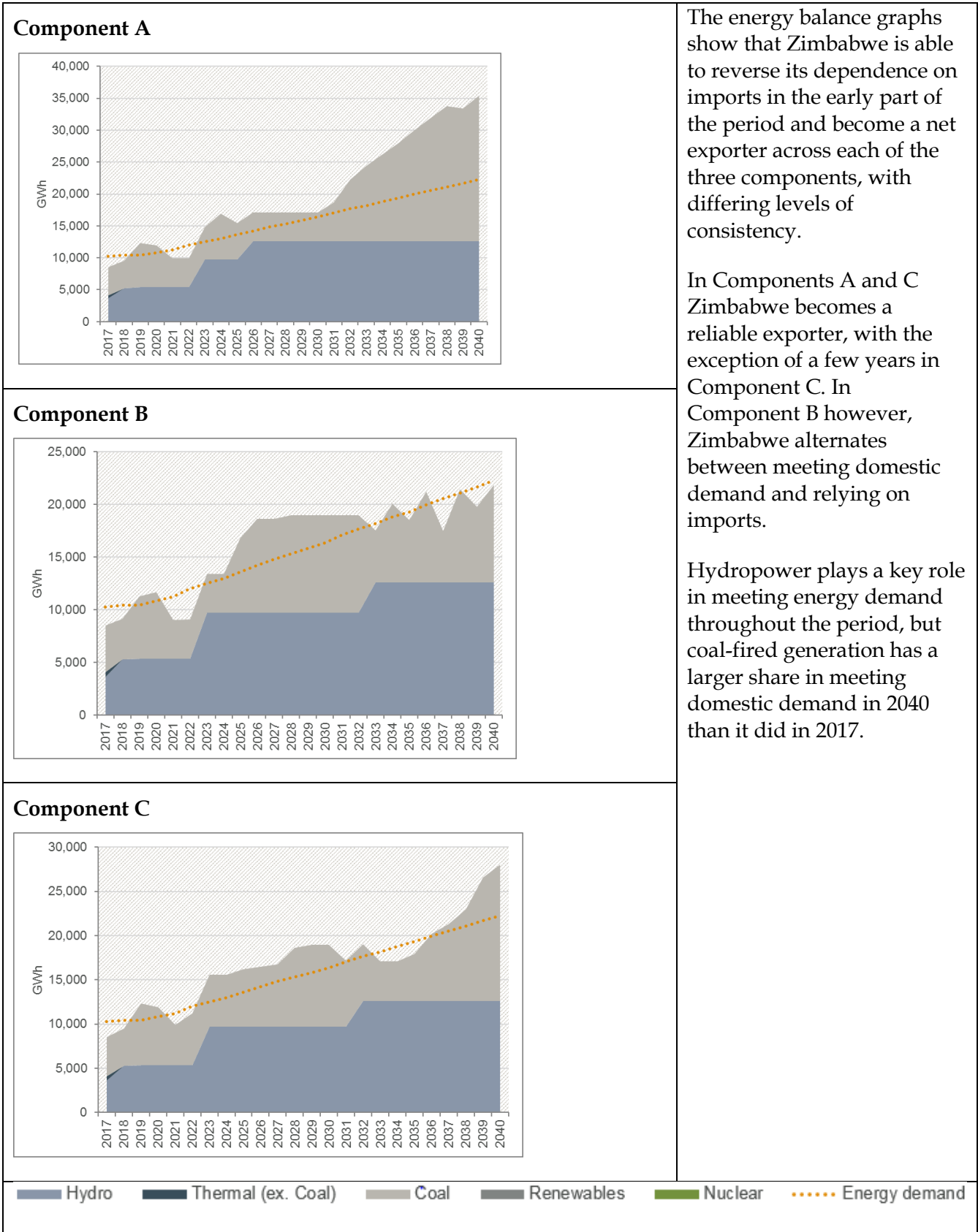
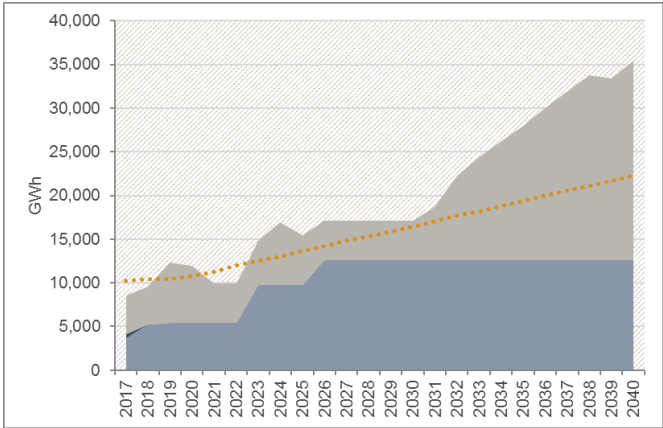


Figure 68 Zimbabwe mix of generation to meet energy demand (GWh)



Component A

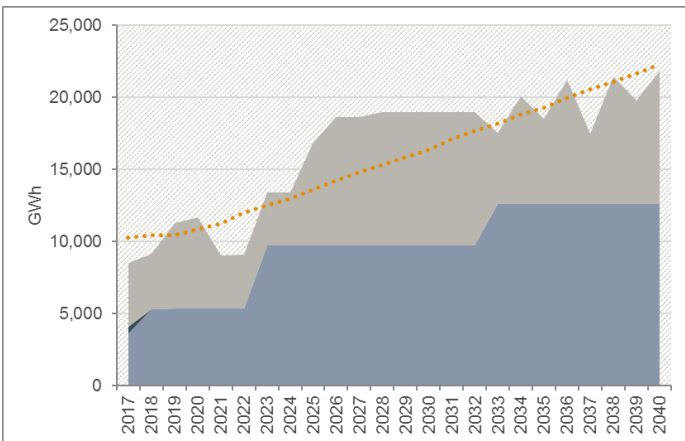


The energy balance graphs show that Zimbabwe is able to reverse its dependence on imports in the early part of the period and become a net exporter across each of the three components, with differing levels of consistency.

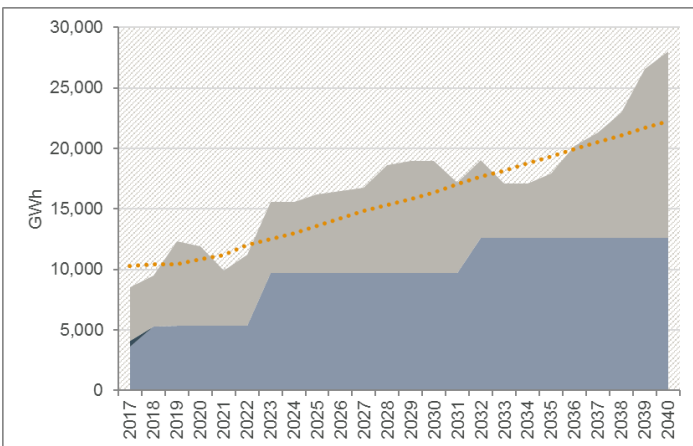
In Components A and C Zimbabwe becomes a reliable exporter, with the exception of a few years in Component C. In Component B however, Zimbabwe alternates between meeting domestic demand and relying on imports.

Hydropower plays a key role in meeting energy demand throughout the period, but coal-fired generation has a larger share in meeting domestic demand in 2040 than it did in 2017.

Component B



Component C



Legend: Hydro (blue), Thermal (ex. Coal) (dark blue), Coal (grey), Renewables (light grey), Nuclear (green), Energy demand (dotted orange)

5 Transmission Planning

5.1 List of available data for modelling

The data available for transmission modelling of the system mainly consist of system development plans and master plans supported by computer models of the existing system and in some cases models for future stages in the short to medium term. The computer models have mainly been provided in PSS/E format and for some utilities in DigSilent Power Factory format – see Annex A6 for an overview.

However, most of the computer models provided cover only models for load flow analysis, and models for future, long-term scenarios are not available (only a few utilities covering the period up to 2030). Models to support stability analyses are in most cases available only for existing plants. Generic models for future plants are added as required.

Details on line routes for future proposed transmission line projects have generally not been available for the Pool Plan study (pre-feasibility and feasibility studies certainly exist for many of the projects, and should be used for further, more detailed planning of the projects at later stages of project preparation).

Details on the information available is included as part of the presentation for each country.

Although the transmission information provided was substantially less detailed than anticipated at the start of the study, it is however considered adequate for an indicative master plan as this Pool Plan study is. However, further detailed planning of the projects that may be recommended as a result of findings in this Pool Plan, will obviously be required before making decisions on investment.

In the models provided for the study, many power plants were missing data for power system stability studies. The study is therefore based on generic models for typical plants. Inertia constants and main impedances used, and water time constants for hydropower units, are therefore uncertain in many cases. Some information, like submissions on dynamics data for machines in South Africa, came too late to be accounted for in this study.

5.2 Study Approach

Information provided in national plans in most cases covered only the period up to 2020-2025. Developments beyond 2030 to 2040 were generally not covered in the country plans provided. The full transmission plan for the SAPP area towards the horizon year 2040 therefore required expansion of most country plans beyond 2030.

Based on the information provided, case files for 2020 and 2025 were used to reflect actual plans as provided by the utilities - representing developments in the short to medium term. For the longer-term scenarios, the study needed to paint a broad picture of likely developments towards 2040. Detailed case files for stage 2030 were also developed for most parts of the system and used to test projects beyond that stage.

The studies for Component A seek to verify that the national plans meet the agreed planning criteria within SAPP, and some minor adjustment of the timing of planned projects may be made to ensure that all parts of the grid meet the same reliability criteria. It is noted though that the transmission system in certain parts of SAPP do not meet the N-1 planning criteria at present. Neither is it practical nor economical to reinforce the system to meet such criteria in all areas. Sound engineering judgement is therefore applied in the use of the deterministic planning criteria – keeping in mind that the target is a least-cost development approach balancing investments, losses, operation and maintenance and cost of supply interruptions.

It is noted that some utilities assumed that part of the future load growth would be covered by imports and excess capacity would be absorbed by exports. To the extent there are no firm plans for how to cover such imports or exports, sound engineering judgements had to be made on which generation projects might support planned imports or exports. The further analysis in Component B (Full Integration Case) and Component C (Intermediate Integration Cases) then identifies the potentially least-cost options for such imports and exports.

5.3 Key findings on regional interconnectors

The next two sections of the report present detailed analyses of national transmission plans and interconnectors for each country. In order for the reader to have a prior overview of the key findings for the Pool Plan, we present these in this section.

The key transmission corridors identified in the Pool Plan study are shown on the map below. The large hydropower projects like Batoka, Mphanda Nkuwa and Inga are key drivers for regional integration. Required funding for the largest project may certainly be an obstacle for implementation, but grid developments should likely still take some lead from what appears to be the most promising projects. This would ensure that short to medium term projects may support development of the key projects further down the line.

Transmission developments in the early part of the Pool Plan period

The study indicates that Angola and Malawi should be interconnected to SAPP early on. In the case of Malawi, an interconnection would help meet growth in the short term and would provide options for trade later. Angola's generation expansion plan provides some surplus capacity in the short to medium term. This surplus could be exported via interconnections both to DR Congo and Namibia. Similarly, in the long term, Angola may benefit from import especially via interconnections from Inga once this project is developed. The following interconnections are therefore clearly recommended for early development:

- ❑ N'Zeto/Angola – Inga/DR Congo
- ❑ Cahama/Angola – Kunene/Namibia
 - ❑ Possibly via Baynes if a decision to implement this project is firmed up.
- ❑ Matambo/Mozambique – Phombeya/Malawi

Figure 69 Map of main transmission corridors supporting regional integration

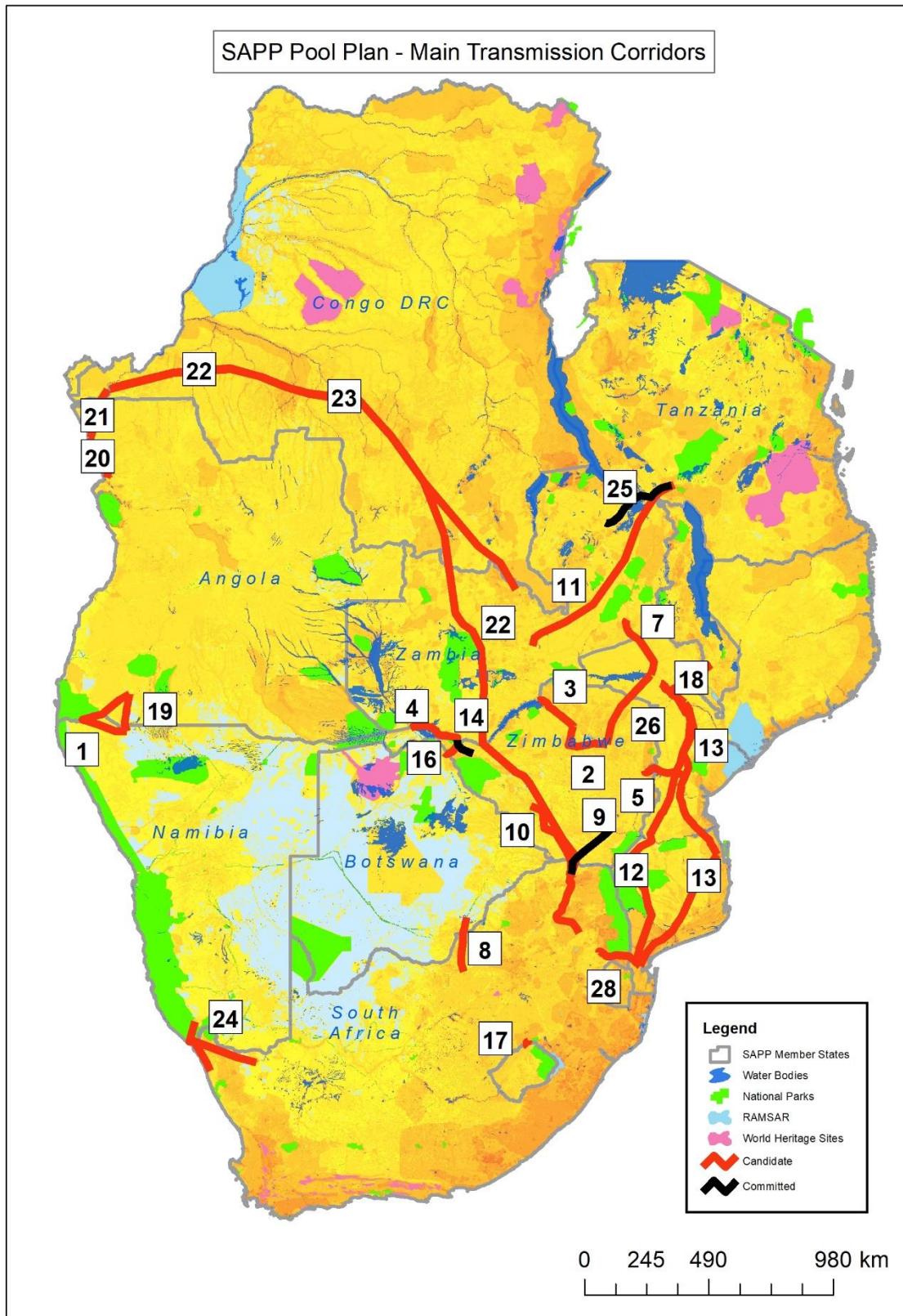


Table 13 List of main transmission corridors supporting regional integration

No	From	To	Comment
1	Cahama, Angola	Kunene, Namibia	Via Baynes
2	Alaska	Chakari	Upgrade from 330 kV to 400 kV + new lines in Zimbabwe
	Chakari	Selous	
	Selous	Dema	
3	Kariba North, Zambia	Alaska, Zimbabwe	
4	Livingstone, Zambia	Zambezi, Namibia	Reinforcing link to the HVDC in Namibia
5	Inchope, Mozambique	Orange Grove, Zimbabwe	Part of MOZISA
7	Songo, Mozambique	Msoro, Zambia	
8	Isang, Botswana	Watershed, South Africa	
9	Triangle, Zimbabwe	Nzhelele, South Africa	Committed – part of MOZISA
10	Insukamini, Zimbabwe	Nzhelele, South Africa	
11	Kabwe, Zambia	Mbeya, Tanzania	HVDC
12	Cataxa, Mozambique	Maputo, Mozambique	HVDC – part of STE
13	Cataxa, Mozambique	Maputo, Mozambique	HVAC via Inchope – part of STE
14	Livingstone, Zambia	Hwange, Zimbabwe	Committed – part of ZIZABONA
16	Pandamatenga, Botswana	Victoria Falls, Zimbabwe	
17	Clarens, South Africa	Khukhune, Lesotho	
18	Matambo, Mozambique	Phombeya, Malawi	Possibly linked to Ncondezi, Mozambique
19	Cahama, Angola	Kunene, Namibia	Direct route an option if Baynes is developed late or if two lines are required in future
20	N'Zeto, Angola	Luanda area, Angola	
21	N'Zeto, Angola	Inga, DR Congo	
22	Inga, DRC	Merensky, South Africa	HVDC line – Alternative route could be via Angola, Namibia and Botswana
23	Inga, DRC	Luano, Zambia	HVDC line
24	Kudu, Namibia	Oranjemund, South Africa	Connections to Obib, Gromis and Aggeneis
25	Kasama, Zambia	Mbeya, Tanzania	Committed, 330 kV in Zambia, 400 kV in Tanzania
26	Songo, Mozambique	Bindura/Dema, Zimbabwe	Upgrade existing line from 330 kV to 400 kV – possibly add second 400 kV
28	Maputo, Mozambique	Marathon, South Africa	3 rd 400 kV line supporting MOTRACO

The linking of Angola to other utilities in SAPP needs to be considered carefully in further feasibility studies for the proposed interconnections. The Pool Plan studies are based on generic models for power plants in Angola. Models based on actual plant data should be prepared, in order to improve on the quality of assessment of the transient stability of the system (preferably verified by comparing the model with actual system response during disturbances). This is important in view of internal faults in Angola, but also in order to correctly simulate the system response following faults on the interconnectors and also

events on the system outside Angola – not least faults that impact on the transfer level on the DC link from Inga to Kolwezi.

The potential stability problems identified in this study are linked to the long distance from the main power generation hub on the Kwanza River to other main load and generation centres in the SAPP system. The supply to the south of Angola and the export to SAPP via Namibia will also be limited by steady state voltage constraints on the system, and the actual transfer limit will depend both on load growth in the central and southern parts of the system in Angola as well as grid expansion and reactive power compensation. Use of one or more Static VAR Compensators (SVCs) to support and stabilise the voltage on the grid in the south is likely to be required in the future.

On the first interconnection to Malawi, the import limit will at least initially be set by the impact on system frequency in Malawi following a sudden loss of the circuit. High levels of import would certainly require load shedding to arrest the frequency drop. Actual import limits would therefore be dependent on level of spinning reserve as well as the level of load shedding that can be managed without causing operational problems. In view of the fact that large parts of the transmission system in Malawi will not meet typical N-1 planning criteria in the short to medium term, some load shedding seems acceptable following loss of a single interconnection, but this problem also points to the benefit of having two or more circuits between Malawi and other SAPP (or EAPP) members in future.

Completion of ongoing generation projects over the next 4-5 years, are not seen to result in new regional interconnections beyond the links outlined above. The results indicate that for the first few years, exports from South Africa will be limited by transfer capacity on the interconnections to neighbouring countries – in particular to Namibia and via Botswana to Zimbabwe. The Songo – Bindura line is also fully used to support load in Zimbabwe and Zambia, and the flow from Zimbabwe to Zambia at Kariba is also limited by the capacity on the grid in this area.

The completion of the Kafue Gorge hydropower project in Zambia along with planned projects like the extension of the coal fired plant at Hwange, some smaller hydro projects in Zambia, the Gecamines coal fired plant in Katanga and a number of PV plants will change the energy balance in the short to medium term. With the additional capacity for trade created by the Triangle – Nzhelele, the Livingstone – Hwange and the Kasama – Mbeya links, the simulations indicate that there will be fewer limitations on the grid in the early 2020s than have been experienced recently. Years with poor hydrology may still represent challenges, and in this regard, it may be important for regions with large storage capacity to start importing power well before there is a risk of running the dams too low to support full generation at peak demand.

The transfer limit between Zambia and Tanzania as well as between South Africa and Zimbabwe may be constrained due to steady state voltage violations, unless reactive power support is provided. Installation of SVCs at Kasama in Zambia and in the Tokwe-Triangle area in Zimbabwe may be reasonable measures to enhance transfer capacity (additional lines are not found to be justified economically). SVCs in the range of 150-200 MVar would seem required. The load growth in the relevant parts of the grid also impact on the transfer limit, and in the case of the Zambia – Tanzania link, local generation may play an important role in supporting trade (for instance the Kalungwishi project in Zambia).

Transmission developments from the early 2020s

The Batoka and the Mphanda Nkuwa projects are part of developments in the early to mid-2020s:

- ❑ The addition of Batoka by 2023 means that Zambia and Zimbabwe will shift from being importers to becoming exporters for some years. The existing and committed interconnectors (i.e. Livingstone – Hwange, Triangle – Nzhelele and Kasama – Nakonde – Mbeya) will support such development. It is also recommended to link the power plants on either side of the river at Batoka. Such a link would also improve the transient stability of the plant following faults on the line evacuating the power from the two power plants (one on either bank), and would also support trade between the two countries and the region.

A similar link should be made at Devil’s Gorge if and when this project is added.

- ❑ The Mphanda Nkuwa project is part of the least-cost plan by 2027/28 in the base case for the regional integration scenarios. The DC and AC line making up the STE backbone grid from Cataxa/Tete in the north to Maputo in the south must be in place at the same time to evacuate power from Mphanda Nkuwa. The existing MOTRACO system linking South Africa and the southern part of the grid in Mozambique along with the existing DC link from Songo to Apollo and also the link from Songo to Zimbabwe would provide adequate capacity for trade with other SAPP members for some time once the STE backbone grid is in place. The STE grid therefore provides additional capacity for regional trade.

A characteristic of the Component C scenario, which requires that each country shall have sufficient capacity to meet its maximum demand, is that the power and energy exchange on the system is less than compared to Component B, which basically assumes least-cost expansion of the overall system. Relatively few new regional interconnections are therefore required in the Component C scenario until around 2030.

In view of the fact that some of the AC interconnections that are being considered have a relatively low cost, it may still be of interest to consider early implementation of some of these projects:

- ❑ Advancing some of the projects a few years may be attractive to ensure adequate capacity for import in case domestic generation projects are delayed (also considering low inflows on systems reliant on hydropower).
- ❑ Increased capacity for trade may provide access to export markets in case domestic load growth is less than expected.
- ❑ Some of the interconnectors may also be important in providing back-up supply in border areas which may otherwise require significant investment in the national grid.

It is therefore likely that some of the regional transmission projects identified as part of the Pool Plan may be justified earlier on when accounting for such domestic needs and local benefits. In this context, it is important to note that the increment in present value of costs associated with advancing relatively low-cost transmission projects requires relatively small

benefits for the projects to become economically viable. The important issue would be to ensure that the selected projects are aligned with the long-term development scenarios likely to be implemented on a regional basis.

Inga-related transmission investments

The next major regional grid developments are linked to further development of the hydropower potential at Inga in DRC. The base case scenarios for regional integration indicates that Inga 3 and the first units at Inga 4 should be added shortly after Mphanda Nkuwa – around 2030-33. As mentioned above, part of the power from Inga could support growth in Angola, but HVDC links are required to evacuate the high capacity planned for at Inga.

The Katanga and Copperbelt areas are foreseen to need further in-feed of power by 2030. Furthermore, the grid in Zambia will need to be developed to support the north-western part of the system based on supply from the new power plants at Kafue Gorge Lower and Batoka in the medium term. The same grid would also provide capacity for wheeling of power from a DC terminal in the Copperbelt area in the long term. Terminating an HVDC link from Inga in this area therefore seems feasible.

As South Africa is one of the main markets for power, a DC link to South Africa is also required. The Pool Plan study therefore recommends further studies of the following DC schemes from Inga:

- ❑ Inga/DRC – Luano/Zambia
- ❑ Inga/DRC – Limpopo or Gauteng/South Africa

The maximum infeed at Luano is estimated at 2,000 MW. With the expansion of the system and the grid reinforcements required in Zambia by the time the infeed from Inga is seen as economically viable, the system is seen as stable for loss of a single pole on such a DC link between Inga and Luano. Protection systems shedding load will be required to handle loss of both poles. Further feasibility level studies need to consider the overload capability and the co-ordination with the operation of the existing DC link from Inga to Kolwezi.

For the DC link from Inga to South Africa, the practical, technical limit for the DC link is evaluated to be around 3,000 MW. This is considerably higher than the maximum transfer on the existing Songo – Apollo link, but seems a reasonably high step up from the STE DC link which will have a maximum transfer capacity of 2,650 MW (with some back-up via the AC system though). Load shedding for loss of both poles will be required. Economically, even higher transfer levels for the link from Inga to South Africa may be attractive. However, 3,000 MW is at this stage considered close to the maximum that could be technically viable. As for the Inga – Luano link, further details should be covered in a feasibility study.

The two DC links from Inga outlined above will combined provide a capacity of 5,000 MW. At such a high transfer level, a multi-terminal link from Inga, with two or more inverter stations in neighbouring countries, has not been considered a viable option from a technical point of view. The risk of a loss of the full 5,000 MW capacity would seem too high. Furthermore, the two schemes as outlined (DRC-Zambia and DRC-South Africa) still

provide a solution that is economically attractive compared to other generation and transmission expansion options in the region.

Routing of the HVDC line from Inga to South Africa via Angola, Namibia and Botswana towards the Johannesburg area could be an alternative to a line through Zambia and Zimbabwe towards the Limpopo Province in South Africa. A line via Angola may also provide benefits by opening up potential for a multi-terminal solution, with the possibility of adding a terminal close to the large hydropower plants on the Kwanza River. Further analyses of HVDC schemes from Inga/DRC to South Africa should preferably consider alternative line routes.

Establishing two independent HVDC line routes may also present benefits – not least if higher transfer capacities than 2,500-3,000 MW are evaluated. Furthermore, the study indicates that an HVDC link from Kabwe in Zambia to Tanzania (terminated at the border at Nakonde/Tunduma or at Mbeya) may be an option once the DC link from Inga to Luano is in place. This project is part of the expansion plan in Component B, but not viable in Component C.

Transmission links supporting regional trade

In addition to the HVDC links discussed above, several AC links also prove to be required to support regional trade, but in many cases the viability of inter-utility AC interconnections would seem to depend on local benefits. It is therefore recommended to closely co-ordinate the grid expansion planning for meeting local demand and the planning of such interconnections. The likely outcome is that many of these projects will be found to be viable at an earlier stage than what is indicated in this Pool Plan which is focused on the regional benefits of such interconnections.

Table 14 presents some key results for the main corridors that are found to support regional trade. There are three projects treated as committed (as agreed during the preparation of the Pool Plan) and a number of candidates. The ID number for the individual projects refers to the map presented above.

The transfer level on most of the AC lines is relatively moderate compared to the thermal capacity of the lines even using the minimum conductor size and configuration with respect to corona losses. The transmission losses on the AC interconnectors are therefore relatively moderate throughout the study period. Correct optimisation of voltage level and conductor size and configuration on the DC lines is important though – especially on the link from Inga to South Africa as this line would seem to be fully loaded most of the time.

On the other hand, the HVDC line that is part of the STE grid in Mozambique may see lower levels of utilisation as the local demand on the system increases, and indications are that the increase in converter capacity as planned for a second stage of this project, may not be required. This is obviously dependent on development of local generation projects, in particular the North Bank at Cahora Bassa and possibly also Boroma and Lupata downstream of Mphanda Nkuwa. The potential development also depends on off-takers of such power outside Mozambique. Finally, generation from gas fields may also have a bearing on this issue in the medium to long term.

Table 14 Key results - Main transmission corridors supporting regional integration

Interconnections / Regional Transmission Corridors		Type		Incr. Transf. Cap. *) (MW)	ID	In-Service Year by Component											
						Main			Sensitivities								
						A	B	C	C 1	C 2	C 3	C 4	C 5				
Committed	Mbeya	TAN	Kasama	ZAM	HVAC	200	25	2019	2019	2019	2019	2019	2019	2019	2019		
	Livingstone	ZAM	Hwange	ZIM	HVAC	250	14	2019	2019	2019	2019	2019	2019	2019	2019		
	Triangle	ZIM	Nzhelele	South	HVAC	300	9	2021	2021	2021	2021	2021	2021	2021	2021		
Candidates	West	N'zeto 1	ANG	Inga 1	DRC	HVAC	300	21		2023	2020	2020	2020	2020	2020		
		N'zeto 2	ANG	Inga 2	DRC	HVAC	800	21		2023	2020	2020	2020	2020	2020		
		N'zeto 3	ANG	Inga 3	DRC	HVAC	800	21 & 20									
		N'zeto	ANG	Catete	ANG					2033	2034	2040	2035	2038	2035	2038	
		Cahama	ANG	Kunene	NAM	HVAC	250	1/19	2029	2022	2022	2022	2022	2022	2022	2022	
		Livingstone	ZAM	Zambezi	NAM	HVAC	150	4		2035	2039	2034	2032				
		Zambezi	NAM	Gerus	NAM	HVDC upgrd	300	-		2040		2034	2032				
		Obib/ Kudu	NAM	Oranjemund/ Gromis & Agg.	SA	HVAC	350	24		2037	2024	2024	2020	2024	2024	2022	
		Central	Inga	DRC	Lubumbashi	DRC	HVDC	1000	23	2025							
			Inga	DRC	Luano	ZAM	HVDC	2000	23		2030	2031	2036	2031	2032	2032	
			Inga	DRC	Gauteng/ Limpopo	SA	HVDC	3000	22		2033	2032		2034	2033	2034	
			Kabwe	ZAM	Nakonde/ Mbeya	TAN	HVDC	1500	11		2030		2035				
			Kariba North	ZAM	Alaska	ZIM	HVAC	300	3			2033	2036	2030			
			Alaska	ZIM	Chakari/Dema	ZIM	HVAC	500	2			2033	2038	2040			
	Victoria Falls		ZIM	Pandamatenga	BOT	HVAC	400	16		2028	2032	2028	2032			2024	
	Isang		BOT	Watershed	SA	HVAC	700	8		2039	2031	2032	2032			2035	
	Insukamini		ZIM	Nzhelele	SA	HVAC	300	10		2038	2039	2033	2038				
	East		Songo	MOZ	Msoro	ZAM	HVAC	400	7		2040		2040	2040			
			Songo 1	MOZ	Bindura/ Dema 1	ZIM	HVAC upgrd	200	26		2037		2033	2040			
			Songo 2	MOZ	Bindura 2	ZIM	HVAC	400	26		2038		2033				
			Matambo	MOZ	Phombeya	MAL	HVAC	200	18		2020	2020	2020	2020	2020	2020	2023
			Matambo	MOZ	Blantyre West	MAL	HVAC	800	18		2022	2028	2026	2021	2028	2024	
		Matambo	MOZ	Mpatamanga	MAL	HVAC	500	18		2033							
		Cataxa	MOZ	Maputo	MOZ	HVDC	1325	12	2025	2027	2028	2028	2027	2028	2032	2034	
		Upgrade converters Cataxa&Maputo: 1325 MW to 2650 MW								2032							
		Cataxa	MOZ	Maputo	MOZ	HVAC	400	13	2025	2027	2028	2028	2027	2028	2032	2034	
		Inchope	MOZ	Orange Grove	ZIM	HVAC	150	5		2040					2035		
	Maputo	MOZ	Marathon	SA	HVAC	700	28		2030	2032	2031	2031			2035		
*) Incremental transfer capacities are indicative only, see comments below.																	
The Pool Plan has considered a number of other transmission candidates as well.																	
Only candidates selected as part of the least-cost plan for the scenarios presented are included in this table.																	
Sensitivities:		C1 Inga Postponed C2 Dry Hydro				C3 SA Imp 2800 C4 Renewables				C5 Low Demand							

It should be noted that the incremental transfer limits presented in the table above are indicative only. Furthermore:

- ❑ The figures indicate incremental capacity across borders resulting from the candidate projects - not transfer limits on the actual lines.
- ❑ Transfer limits are dependent on load level and sequencing of the different projects (including generation projects on the system).
- ❑ Transfer limits may also differ depending on the direction of flow.

The transfer limits as applied in PLEXOS seek to account for these effects.

In future updates of the Pool Plan, it may be worthwhile enhancing the detail in the PLEXOS model by adding parts of the transmission grid. This may be important to reflect critical boundaries inside the different countries in addition to transfer limits across national borders (the PLEXOS model used includes some such boundaries like in Mozambique).

As an example, evacuation of power from generation in the middle Zambezi is not necessarily limited by the transfer capacity between Zambia and Zimbabwe, but rather the boundary created by transmission lines north and south of this generation hub. Additional boundaries around generation hubs and/or large load centres may therefore provide more accurate results than the model developed so far.

6 Country Transmission Plans

The following sections present details on background information and overview of expansion plans as presented by the different utilities in each country.

6.1 Angola

Relevant documents

The following recent study on the transmission system in Angola has been made available for the preparation of the Pool Plan:

- ❑ Estudos de Planeamento da Rede Nacional de Transporte de Electricidade Ministerio da Energia e Aguas (MINEA), Julho 2014

In December 2016, RNT indicated that actual progress on expansion of the grid is lagging behind the expansion plan outlined in the MINEA study. The expansion plan has also been modified in some areas. RNT provided updated PSS/E files (load flow models only) to support the assessment. These models have been used to reassess the expansion plan presented in the MINEA study:

- ❑ PSS/E files provided by RNT for peak load cover:
 - ❑ Stage 2017
 - ❑ Stage 2020
 - ❑ Stage 2025

It should be noted that the said PSS/E models are assuming a significantly higher load growth than the forecast applied for the SAPP Pool Plan Study. In general, the load level in the PSS/E file for stage 2020 matches the forecast for stage 2023/24 and the PSS/E file for stage 2025 matches the forecast for 2032/33. The differences are accounted for in the analysis of the Benchmark Case.

Planning criteria in use

The transmission planning criteria used in the MINEA study are in line with the N-1 deterministic criteria in use throughout the SAPP region. However, due to the nature of the system, long radial lines will be required to integrate the different sub-systems in Angola, and parts of the system will not meet the N-1 criteria in the short term.

Two issues to note are:

- ❑ A short time overload (10 %) has been applied during contingencies.

- ❑ A fault clearance time of 150 ms at 400 kV and 220 ms at 220 kV has been applied in the transient stability study.

The transient stability criterion is a rather strict requirement. Normal protection schemes would clear faults well within 100 ms which is the typical fault clearance time for three-phase faults applied in transmission studies throughout other SAPP utilities. For the Pool Plan study, the transient stability is proposed tested for three-phase faults cleared in 100 ms (in specific cases, the margin to instability may be indicated by estimating the critical fault clearance time, but this will not be presented in general for any fault on the system).

Furthermore, for a high-level study of long term development options like the Pool Plan study, it is proposed that short time overloads should not be accepted. The study will in general seek robust solutions that can meet changes in load growth and provide reasonable transfer capacities across the region for varying dispatch scenarios (and even to some extent for alternative generation scenarios).

Current development plan

MINEA Study

The MINEA study covers the following periods:

- ❑ Short term 2014 – 2017
- ❑ Future 2018 – 2025

The plan is ambitious. Just for the short-term period, the plan presents projects with a total of:

- ❑ 18 new transmission lines at 400 kV – in total 2075 km
- ❑ 32 new transmission lines at 220 kV – in total 2203 km
- ❑ 14 new 400/220 kV transformers – total installed capacity 5500 MVA

Furthermore, significant reactive power compensation facilities are required to support the voltage control on the system – including fixed and switched shunt capacitor banks and shunt reactors.

One of the objectives of the short-term development plan is to integrate the North, Central and South systems.

For the period 2018-2025, the plan includes a total of:

- ❑ ~1200 km of transmission lines at 400 kV
- ❑ ~1500 km of transmission lines at 220 kV
- ❑ 10 new 400/220 kV transformers – total installed capacity 4200 MVA

The following tables summarises the 400 kV transmission line projects as presented in the MINEA study (based on the generation expansion plan presented in the same study).

Short Term (2014-2017)

The development plan presented in the study from 2014, includes the following new transmission lines.

Table 15 Short Term (2014-2017) transmission lines included in the development plan

System	From	To	Circuit No.	Voltage (kV)	Conductor Type	Rating (MVA)	Length (km)
North	Viana	Catete	1	400	Sorbus x 2	1514	42
North	Centraldo Soyo	Soyo	1	400	Sorbus x 2	1514	4.5
North	Centraldo Soyo	Soyo	2	400	Sorbus x 2	1514	4.5
North	Soyo	N'Zeto	1	400	Sorbus x 3	2271	138
North	Soyo	N'Zeto	2	400	Sorbus x 3	2271	138
North	N'Zeto	Kapary	1	400	Sorbus x 3	2271	191
North	N'Zeto	Kapary	2	400	Sorbus x 3	2271	191
North	Kapary	Catete	1	400	Sorbus x 2	1514	58
North	Kapary	Catete	2	400	Sorbus x 2	1514	58
North	Cambutas	Catete	1	400	Sorbus x 2	1514	125
North	Cambutas	Kilamba	1	400	Sorbus x 2	1514	173
North	Lauca	Catete	1	400	Sorbus x 2	1514	190
North	Lauca	Catete	1	400	Sorbus x 2	1514	190
North	Lauca	Waku Kungo	1	400	Sorbus x 2	1514	205
North	Catete	Kilamba	1	400	Sorbus x 2	1514	54
North	Lauca	Kilamba	1	400	Sorbus x 2	1514	223
North	Lauca	Capanda	1	400	Sorbus x 2	1514	44
North	Cambutas	Lauca	1	400	Sorbus x 2	1514	73
North/Central	Waku Kungo	Huambo	1	400	Sorbus x 2	1514	196

Source: Angola development plan, 2014

RNT has advised that the double circuit lines from N'Zeto to Kapary and from Kapary to Catete were commissioned in 2016. Other recent additions are listed in Table 15. Projects not already ongoing were assumed to be completed later than 2017.

It should be noted that several 220 kV lines are also expected to be built within the same period. The 400 kV and 220 kV projects must naturally be coordinated to reap the full benefit of the plan and to be able to supply the loads in the different areas covered by the expansion plan.

Future (2018-2025)

The development plan includes the following new transmission lines in the medium term:

Table 16 Future (2018-2025) transmission lines included in the development plan

System	From	To	Circuit No.	Voltage (kV)	Conductor Type	Rating (MVA)	Length (km)
South	Huambo	Lubango	1	400	Sorbus x 2	1514	378
North	Cambutas	C. Cabaca	1	400	Sorbus x 2	1514	58
North	Cambutas	C. Cabaca	2	400	Sorbus x 2	1514	58
North	C. Cabaca	Lauca	1	400	Sorbus x 2	1514	25
North	C. Cabaca	Lauca	2	400	Sorbus x 2	1514	25
North	C. Cabaca	Keve	1	400	Sorbus x 2	1514	160
North/Central	Keve	Biopio	1	400	Sorbus x 2	1514	170
North/Central	Keve	Biopio	2	400	Sorbus x 2	1514	170
Central	Huambo	Biopio	1	400	Sorbus x 2	1514	250

Source: Angola development plan, 2014

The study does not indicate developments beyond 2025.

Up-to-Date Plan based on Information from RNT

RNT provided an update on actual progress on implementation of the plan outlined in the MINEA study in December 2016. Details on grid development by 2017 and expected plans for 2020 and 2025 were provided in the form of updated PSS/E models for the transmission system. The following information is extracted from the computer models provided.

New 400 kV lines in service by 2017

Combining the information from the MINEA study and the PSS/E files provided by RNT¹⁰, the following new 400 kV lines have been added recently (i.e. in addition to the first 400 kV line from Capanda to Luanda).

Table 17 Recent transmission lines added in Angola

System	From	To	Circuit No.	Voltage (kV)	Conductor Type	Rating (MVA)	Length (km)
North	Centraldo Soyo	Soyo	1	400	Sorbus x 2	1514	4.5
North	Centraldo Soyo	Soyo	2	400	Sorbus x 2	1514	4.5
North	Soyo	N'Zeto	1	400	Sorbus x 3	2271	138
North	Soyo	N'Zeto	2	400	Sorbus x 3	2271	138
North	N'Zeto	Kapary	1	400	Sorbus x 3	2271	194
North	N'Zeto	Kapary	2	400	Sorbus x 3	2271	194
North	Kapary	Catete	1	400	Sorbus x 2	1514	58

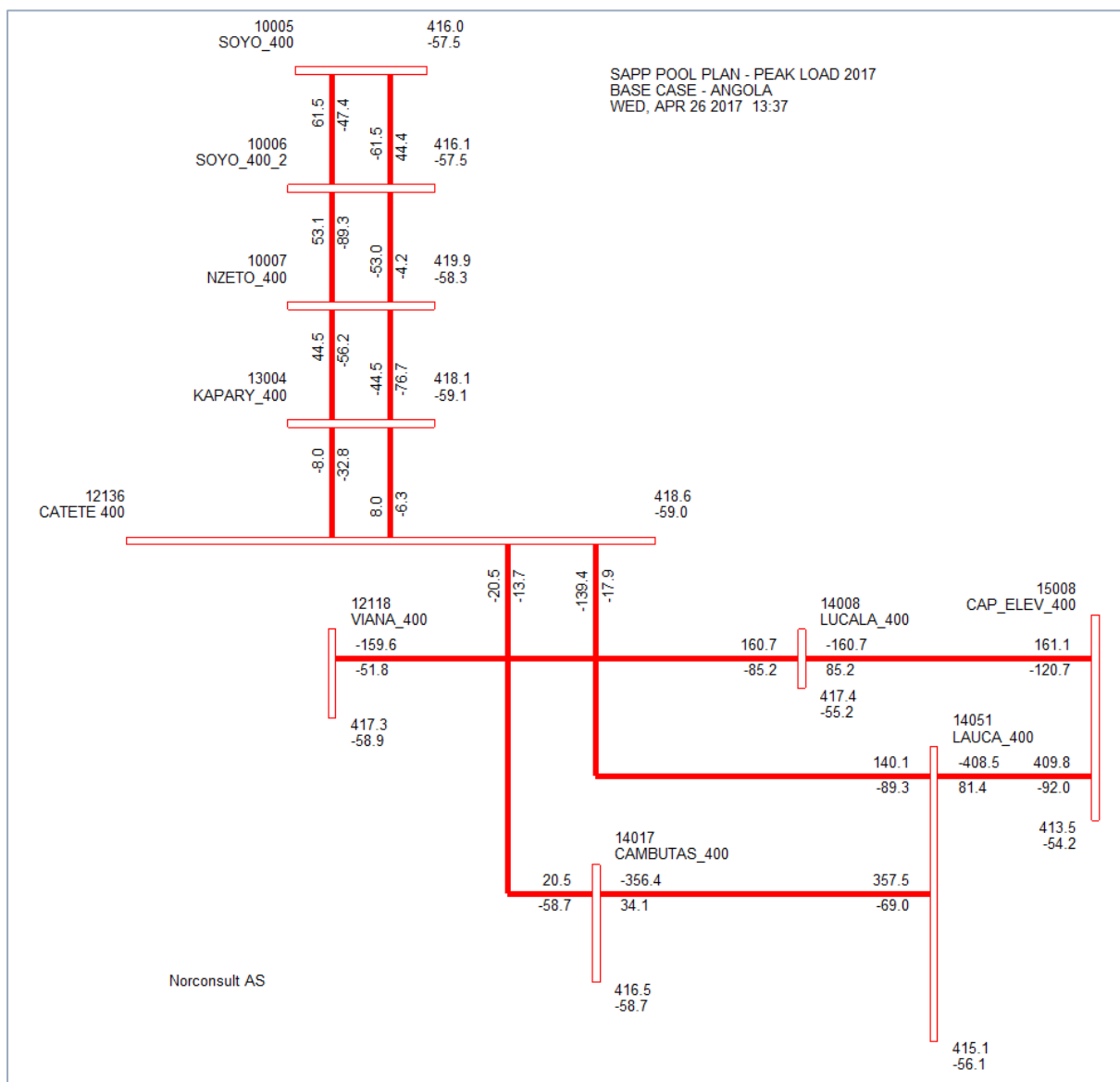
¹⁰ Accounting for the latest feedback from RNT that both 400 kV circuits between Catete, Kapary and N'Zeto are in service.

System	From	To	Circuit No.	Voltage (kV)	Conductor Type	Rating (MVA)	Length (km)
North	Kapary	Catete	2	400	Sorbus x 2	1514	58
North	Cambutas	Catete	1	400	Sorbus x 2	1514	123
North	Lauca	Catete	1	400	Sorbus x 2	1514	190
North	Cambutas	Lauca	1	400	Sorbus x 2	1514	76

Source: Angola development plan, 2014 (MINEA) – PSS/E files (RNT)

The following single line diagram shows the 400 kV system in operation at peak demand in 2017 (load adjusted to match forecast used for the Pool Plan).

Figure 70 400 kV system in Angola - Stage 2017



Source: RNT, 2016 - Note: Although not included in PSS/E files received from RNT, both 400 kV circuits between Catete and N'Zeto are in service since 2016 according to the latest information from RNT.

The diagram above depicts the situation before the generators at Lauca comes online (as presented in RNT's PSS/E files for 2017).

Short Term (2017-2020)

Further investments in the 400 kV grid are aimed at increasing the capacity between the hydro plants on the Kwanza River and Luanda as well as integrating the north, central and south. The following 400 kV grid expansion program is foreseen over the next 3-4 years.

Table 18 Short Term (2017-2020) transmission lines included in the development plan

System	From	To	Circuit No.	Voltage (kV)	Conductor Type	Rating (MVA)	Length (km)
North	Cambutas	Bitá	1	400	Sorbus x 2	1514	172
North	Lauca	Waku Kungo	1	400	Sorbus x 2	1514	202
North	Catete	Bitá	1	400	Sorbus x 2	1514	55
North/Central	Waku Kungo	Dango	1	400	Sorbus x 2	1514	196
Central/South	Dango	Lubango	1	400	Sorbus x 2	1514	343

Source: Angola development plan, 2014 (MINEA) – PSS/E files (RNT)

Medium Term (2020-2025)

400 kV projects in the medium term are aimed at reinforcing the northern network and extending the 400 kV system to the south to the border with Namibia.

Table 19 Medium Term (2020-2025) transmission lines included in the development plan

System	From	To	Circuit No.	Voltage (kV)	Conductor Type	Rating (MVA)	Length (km)
North	Catete	Viana	1	400	Sorbus x 2	1514	42
South	Lubango	Cahama	1	400	Sorbus x 2	1514	190
South	Cahama	Baynes	1	400	Sorbus x 2	1514	112

Source: Angola development plan, 2014 (MINEA) – PSS/E files (RNT)

Recent information from Angola indicates that the Caculo Cabaca hydropower project will be commissioned in 2022. Connections to Lauca and Cambutas have been added in the Benchmark case (with the line to Cambutas connecting to a future plant at Zenzo as well).

Availability of transmission system models

As stated above, RNT provided updated PSS/E case files for stage 2017, 2020 and 2025 in December 2016. The files included only the load flow models.

Future stages matching the case files used in the MINEA study as well as the dynamic model used in the same study, were not made available to the Pool Plan technical team. Correct modelling of the hydropower plants on the main rivers in Angola will be essential for assessing the transient and dynamic response of the system following disturbances. As hydropower plant characteristics vary widely depending on a number of parameters like inertia of the machines, head and waterways, generic models cannot provide reliable results. For the Benchmark Case (Component A), this is not as critical as for the other scenarios to be

studied as the system in Angola will not be interconnected to neighbouring systems in this case.

The models provided have been modified to match the load forecast prepared for the Pool Plan and further extensions towards 2040 reflect the outcome of the generation expansion plan for the Benchmark Case.

Grid capacity and extension towards 2040

The following analysis presents an assessment of the grid capacity accounting for the planned expansion program and the generation expansion plan presented for the Benchmark Case (Component A). The analysis also covers a high-level expansion plan towards 2040 based on the same generation scenario (and the load forecast as used for this Pool Plan).

Short to medium term

The grid expansion plan for Angola as presented in the PSS/E files provided by RNT for the period up to 2025 will provide a reasonable capacity and reliability for the load forecast as used in the Pool Plan. The 400 kV grid in the north meets the steady state planning criteria in use in SAPP. Generally, the 400 kV transmission lines will be relatively lightly loaded and allow for further load growth and connection of some additional generation before further reinforcement will be required.

However, an outage of the single 400 kV line towards the south may cause a voltage collapse on the underlying 220 kV system at peak load. Increasing the reactive power support may address such problems, but the long term solution would be to add a second 400 kV line – at least in some areas. Initially, it would likely not be economical to improve the reliability level unless a significant part of the load in the area has a high cost of outages. The need for a second line towards the south is also dependent on the generation expansion in addition to load growth and expansion of the 220 kV system. It seems reasonable to assume though that a second 400 kV line towards the south is required by 2025 or at least not much later.

For the purpose of the SAPP Pool Plan, the following reinforcement is assumed by 2025.

Table 20 Medium Term (2025) transmission lines included in the development plan

System	From	To	Circuit No.	Voltage (kV)	Conductor Type	Rating (MVA)	Length (km)
North to South	Caculo Cabaca	Biopio	1	400	Sorbus x 3	2271	360
South	Biopio	Lubango	1	400	Sorbus x 2	1514	250

A connection to Keve is included on the line from Caculo Cabaca to Biopio.

Towards 2040

The generation expansion plan for the benchmark case indicates a number of hydropower projects on the Kwanza River as candidates for further expansion of the system. Further reinforcement of the transmission system towards the main load centres from power plants on the Kwanza River would therefore be required. As part of such reinforcement, a third 400 kV line from this area towards the south may be required sometime around 2030-2040, but timing and optimal termination points would be very dependent on actual load growth in the different parts of the system, and it would be highly speculative to indicate details of such a project at this stage.

Transmission expansion plan for the Benchmark Case

The following table summarises the transmission system expansion plan for Angola in the Benchmark Case.

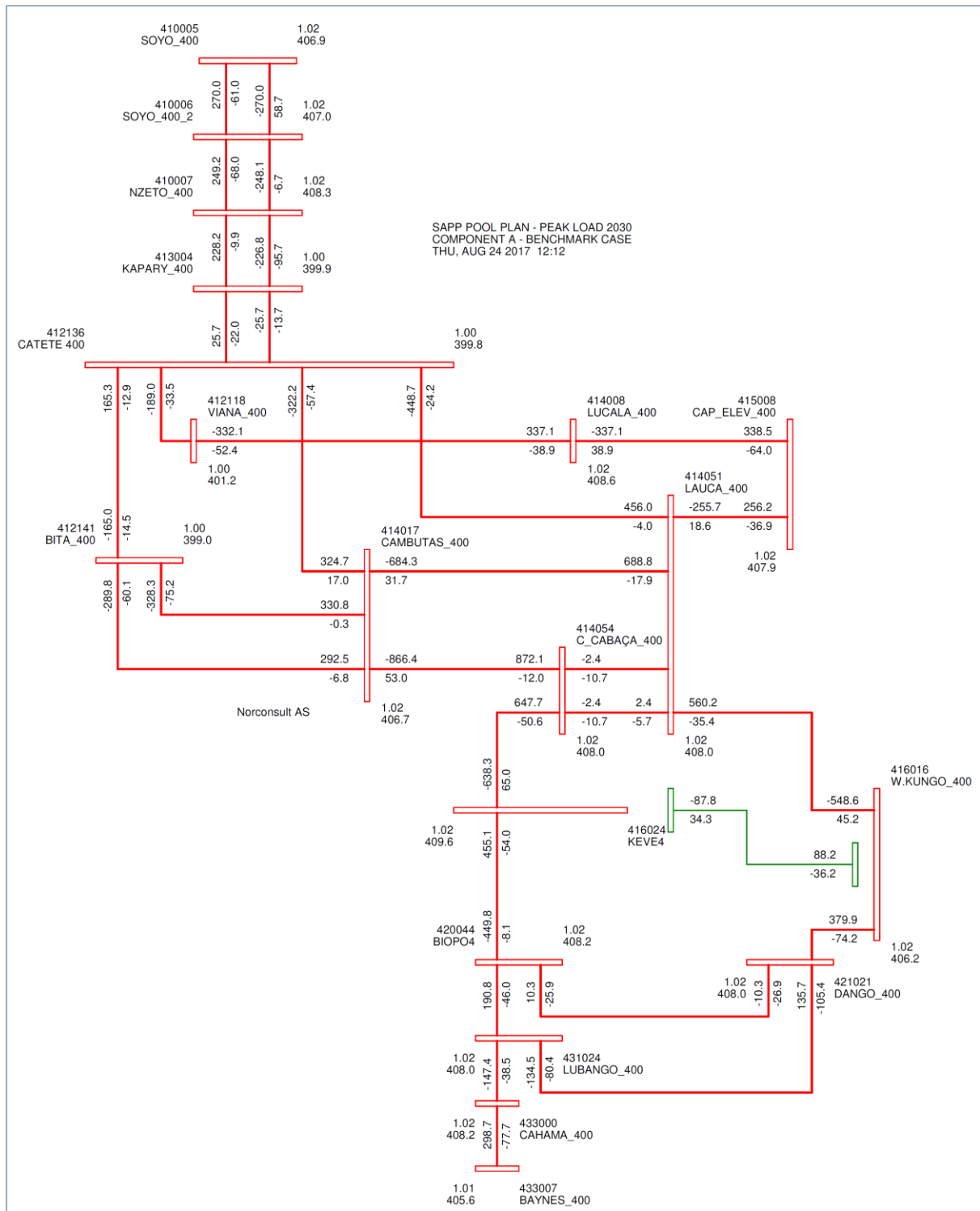
Figure 71 Angola transmission system expansion plan

TRANSMISSION PROJECTS									
Voltage [kV]	Substation		Distance [km]	Conductor type	Circuits	Tower type	In service by year		
	From	To					Comp A	Comp B	Comp C
400	Cambutas	Bitá	172	2 x Sorbus	1	Y SgCkt	2017-20	2017-20	2017-20
400	Catete	Bitá	55	2 x Sorbus	1	Y SgCkt	2017-20	2017-20	2017-20
400	Lauca	Waku Kongo	202	2 x Sorbus	1	Y SgCkt	2017-20	2017-20	2017-20
400	Waku Kungo	Dango	196	2 x Sorbus	1	Y SgCkt	2017-20	2017-20	2017-20
400	Dango	Lubango	343	2 x Sorbus	1	Y SgCkt	2017-20	2017-20	2017-20
400	Viana	Catete	42	2 x Sorbus	1	Y SgCkt	2020-25	2020-25	2020-25
400	Lubango	Cahama	190	2 x Sorbus	1	Y SgCkt	2020-25	Part of evaluation in Component Band C	
400	Lauca	Caculo Cabaca	25	3 x Sorbus	1	Y SgCkt	2022		
400	Lauca ckt. 2	Caculo Cabaca ckt. 2	25	3 x Sorbus	1	Y SgCkt	2022		
400	Caculo Cabaca	Cambutas	75	3 x Sorbus	1	Y SgCkt	2022		
400	- line connecting to Zenzo in future, by:						2033		
400	Caculo Cabaca	Biopio	390	3 x Sorbus	1	Y SgCkt	2022		
400	Biopio	Dango	250	2 x Sorbus	1	Y SgCkt	2025		
400	Biopio	Lubango	250	2 x Sorbus	1	Y SgCkt	2025		
400	Cambutas ckt. 2	Bitá ckt. 2	172	2 x Sorbus	1	Y SgCkt	2025		
400	Tumulo do Cacador	Cambutas	20	2 x Sorbus	1	Y SgCkt	2031		
400	Cahama	Baynes	112	2 x Sorbus	1	Y SgCkt	2029		

Full comparisons between Component A and the scenarios based on further regional integration – Components B and C – are provided in Section 7.1.

As explained above, further strengthening by adding another 400 kV line from the generation hub on the Kwanza River towards the south is seen as likely between 2030 and 2040. Details of such a link cannot be estimated with any certainty (indicative length of such a link would be in the range of at least 600-700 km and would likely connect to at least three or four substation/power plants along the way).

Figure 72 400 kV system in Angola - Stage 2030



6.2 Botswana

Relevant documents

The expansion plan for Botswana has been extracted from PSS/E case files for stages 2015, 2019 and 2025 received from BPC on 30 May 2016. No further documentation in the form of master plans or system development plans nor any feasibility studies have been available to support the evaluation of the national development plan.

Some clarifications on the expansion plan were discussed with BPC via e-mail communication following the submission of the said PSS/E models. The PSS/E files provided are understood to represent planned reinforcements in Botswana and also include data on future options for new interconnections to neighbouring utilities.

Planning criteria in use

From previous studies, our understanding is that the transmission grid in Botswana in general has been planned in line with the SAPP Planning Criteria. The N-1 reliability criteria is not necessarily fulfilled in all areas as there are (and will be for some time) long radial feeders on the system. For the future 400 kV system and the interconnections to neighbouring utilities, the system must meet the SAPP planning criteria so as not to risk instability on the interconnected SAPP transmission system.

Current development plan

From the PSS/E files provided, the following projects are seen as committed to reinforce and extend the transmission system in the short term – i.e. by 2019 – although construction has to our knowledge not started on all the lines and therefore in principle there could be changes. In the context of the SAPP Pool Plan, these investments will be treated as firm plans.

Table 21 Committed projects to reinforce and extend the transmission system

From	To	Ckt. No.	Voltage (kV)	Design	Length (km)
Morupule	Orapa	1	400	3 x Tern	220
Orapa	Mawana (Maun)	1	400	3 x Tern	280
Phokoje	Dukwi	1	400	3 x Tern	230
Dukwi	Pandamatenga	1	400	3 x Tern	289
Morupule	Isang	2	400	3 x Tern	214.96

The plan includes 60 MVar line shunt reactors at either end of each of the above 400 kV lines except for the Morupule – Orapa line which is planned with a line shunt reactor only at the Orapa end and the second Morupule – Isang line which is planned with 50 MVar line shunts at either end – i.e. similar to circuit 1.

The 400 kV line from Phokoje to Dukwi may provide connection for two new coal fired power plants in the area – one at an estimated 70 km from Phokoje and another about 120 km from Phokoje (i.e. the distance between the projects estimated at about 50 km).

The following transmission line is considered an option for reinforcing the north-west grid. The line is assumed in service in the case file for 2025 provided by BPC (i.e. added between 2019 and 2025).

Table 22 Option for reinforcing the north-west grid

From	To	Ckt. No.	Voltage (kV)	Design	Length (km)
Mawana (Maun)	Pandamatenga	1	400	3 x Tern	290

The above line also includes 60 MVAR line shunt reactors at either end of the line.

Furthermore, the following interconnections are considered for future integration (timing uncertain).

Table 23 Interconnections considered for future integration

From	To	Ckt. No.	Voltage (kV)	Design	Length (km)
Pandamatenga	Victoria Falls	1	400	3 x Tern	76
Isang	Watershed	1	400	3 x Tern	260

The line from Pandamatenga to Victoria Falls is part of the ZIZABONA projects that has been under consideration for some time. This project also includes a 400 kV line from Hwange to Victoria Falls in Zimbabwe as well as a 400 kV line from Victoria Falls to a new 330/220 kV substation at Livingstone in Zambia (see also comments on the transmission development plans for Zambia and Zimbabwe). The model for the ZIZABONA project provided by BPC assumes 330 kV operation of the system linking Pandamatenga, Hwange and Livingstone. As there are plans to extend the 400 kV system in Zimbabwe to Hwange (in conjunction with plans to increase the coal fired generation in the area), it may be preferable to energise this part of the ZIZABONA project at 400 kV and include step-down from 400 kV to 330 kV at Livingstone substation rather than at Pandamatenga.

Modifying the configuration of the ZIZABONA project should also be considered. The link between Zambia, Zimbabwe and Botswana has so far been planned configured as a “Y” with a substation at Victoria Falls linking substations at Livingstone, Hwange and Pandamatenga. A fault on any one leg of the “Y” would mean that one country is disconnected from the other two in this area. A “Delta” configuration with three lines Livingstone – Hwange, Livingstone – Pandamatenga and Pandamatenga – Hwange would ensure that all three countries remain interconnected for a single fault on any one of the three lines linking the utilities in this region. A higher transfer limit and improved system stability would likely be the results – although at a higher cost for the transmission lines, but with some savings on the substation at Victoria Falls in Zimbabwe.

Availability of transmission system models

BPC has provided PSS/E models for three stages: 2015, 2019 and 2025. The files include both a peak load and a light load case as well as dynamic models for the different plants.

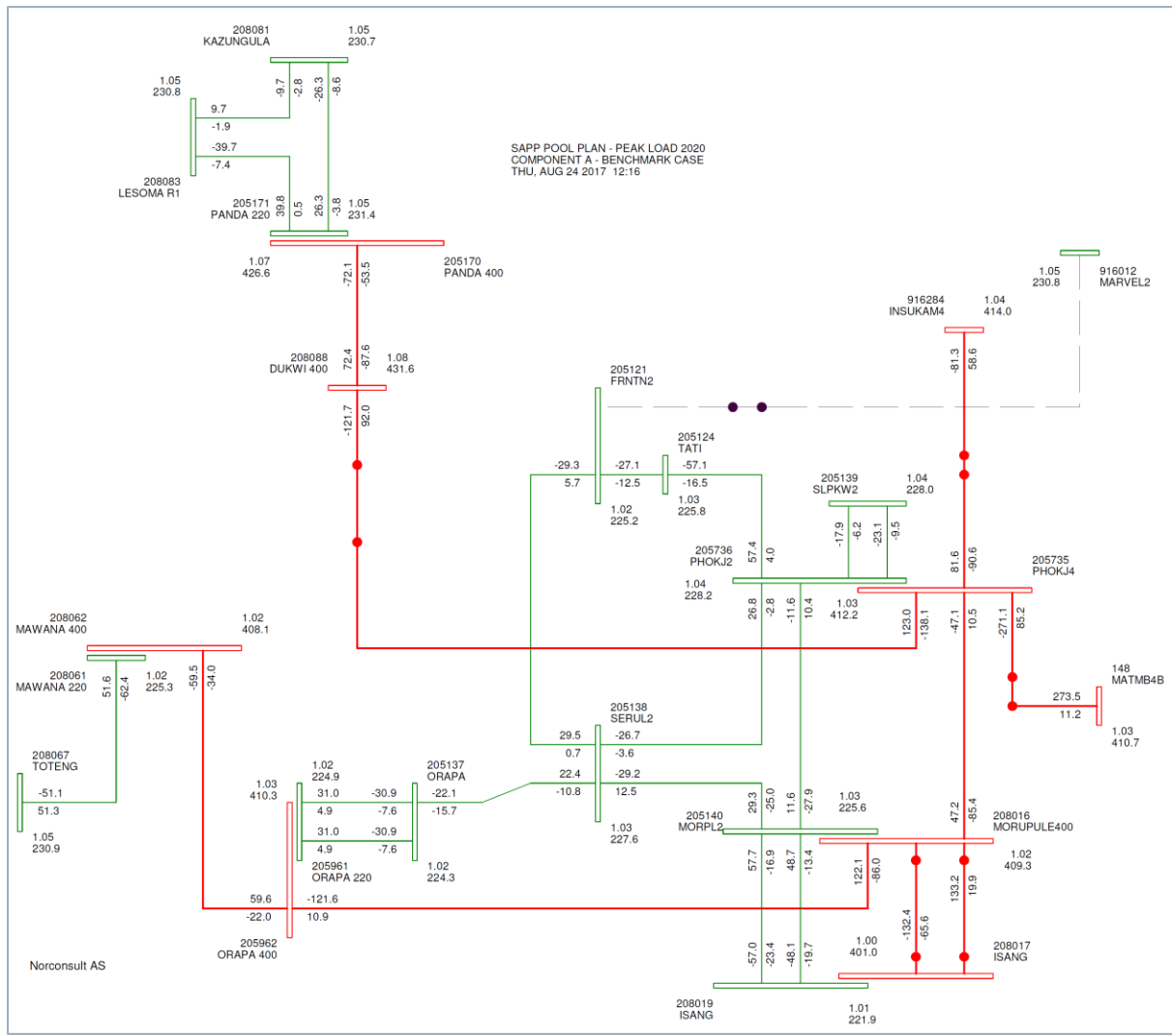
Grid capacity and extension towards 2040

The following analysis presents an assessment of the grid capacity accounting for the planned expansion program and the generation expansion plan presented for the Benchmark Case (Component A). The analysis also covers a high-level expansion plan towards 2040 based on the same generation scenario (and the load forecast as used for this Pool Plan).

Short to medium term

The following diagram depicts the peak load conditions at stage 2020 assuming that the Mawana – Pandamatenga line is not yet added on the system and that the load is supported by generation expansion at Morupule.

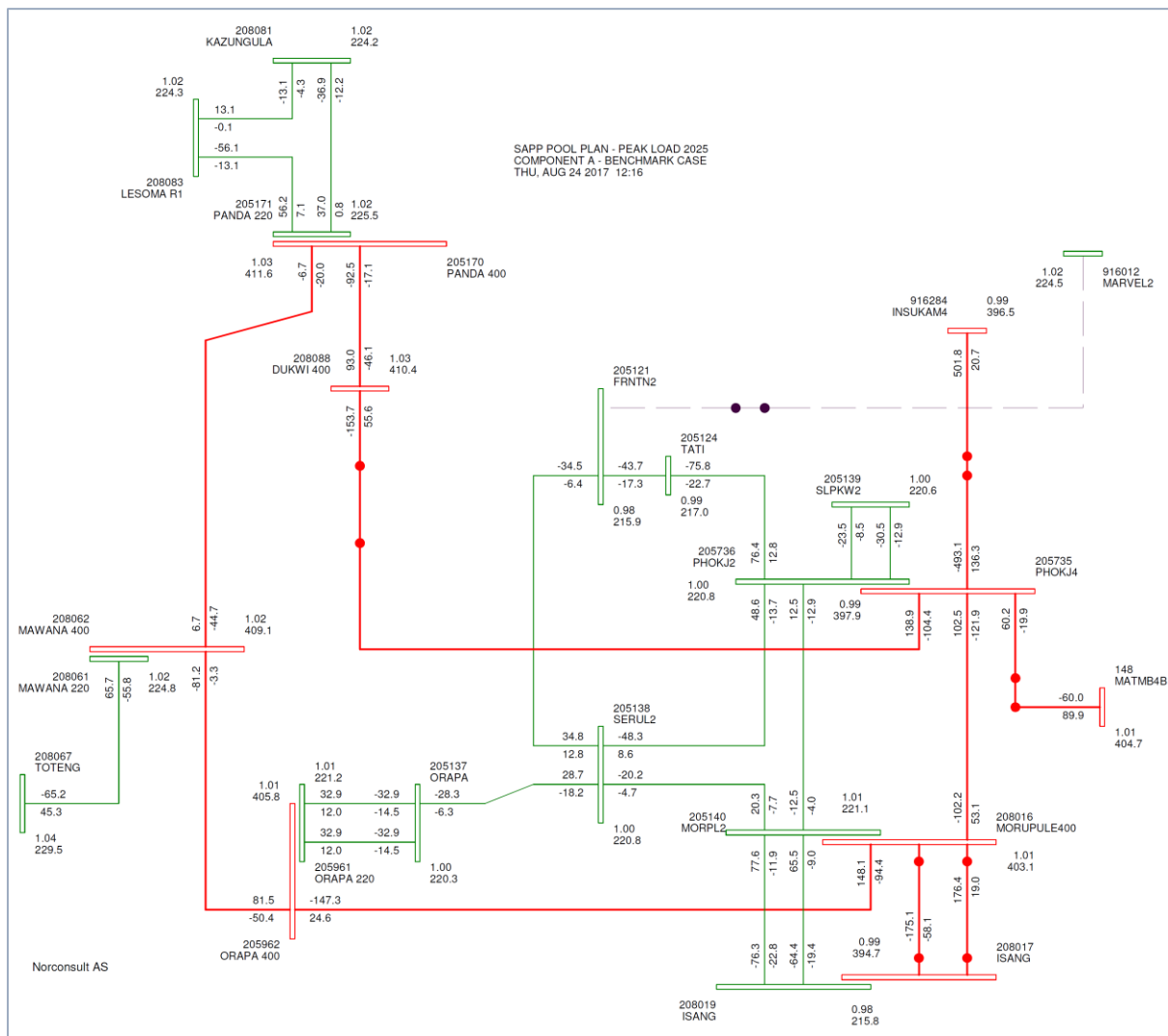
Figure 73 Botswana load flow diagram for peak load 2020



Outages of radial 400 kV feeders will naturally cause supply interruptions, but otherwise the system is relative lightly loaded with a reasonably good voltage profile throughout. If loss of load following radial 400 kV feeders is accepted, the 400 kV transmission as presented in the above figure could actually support the domestic load towards the end of the study period.

Adding a 400 kV line between Mawana and Pandamatenga would provide backup for outages on the 400 kV system (see load flow diagram for peak load 2025 presented below).

Figure 74 Botswana load flow diagram for peak load 2025



However, outages on the 400 kV line from Morupule to Orapa and Mawana and also from Phokoje towards Dukwi and Pandamatenga, would result in long radial 400 kV feeders with poor voltage control. SVCs must therefore be added at Pandamatenga and Mawana to support the system in this case. It should be noted that the Benchmark Case by definition does not include new interconnections like the Pandamatenga – Victoria Falls line as planned for on the ZIZABONA project.

Towards 2040

With the relatively moderate growth in Botswana, the planned reinforcements as presented above are considered adequate to support the load at the bulk supply points towards 2040. The voltage on the 220 kV system in the north feeding Francistown may hit the lower limit following outages on the lines towards Francistown towards the end of the study period. To the extent that this becomes a problem, some additional reactive power compensation would most likely be the optimal solution. The 220 kV system south of Isang is being reinforced by adding a new 220/132 kV substation at Rakola in Gaborone. With this project in place, the 220 kV system in the area would also be adequate to meet demand in the long

term in the Gaborone area as well. A new 400 kV substation in the area is therefore not required within the study period. However, depending on the need to reinforce the 132 kV system as part of expansion of the sub-transmission grid, it may be prudent to consider alternatives based on further expansion of the 220 kV system.

Projects for export

The Benchmark Case (Component A) indicates that Botswana would remain a net importer in Component A throughout most of the study period. Two 150 MW coal fired units are added (2029 and 2035) to meet local demand in addition to a CSP plant in 2031. The assumption in the Benchmark Case is that such projects for domestic demand are developed at Morupule (either as an extension of Morupule 1-4, i.e. Morupule 5&6, or as a greenfield development at Morupule). An alternative may have been development for instance in the Serule area which may see coal plants for exports (along with other areas considered previously as well).

Transmission expansion plan for the Benchmark Case

The following table summarises the transmission system expansion plan for Botswana in the Benchmark Case.

Figure 75 Transmission system expansion plan for Botswana

TRANSMISSION PROJECTS										
Voltage [kV]	Substation		Distance [km]	Conductor type	Circuits	Tower type		In service by year		
	From	To						Comp A	Comp B	Comp C
400	Morupule	Orapa	220	3 x Tern	1	Guyed V	SgCkt	2019	2019	2019
400	Orapa	Mawana (Maun)	280	3 x Tern	1	Guyed V	SgCkt	2019	2019	2019
400	Phokoje	Dukwi	230	3 x Tern	1	Guyed V	SgCkt	2019	2019	2019
400	Dukwi	Pandamatenga	289	3 x Tern	1	Guyed V	SgCkt	2019	2019	2019
400	Morupule (ckt. 2)	Isang (ckt. 2)	215	3 x Tern	1	Guyed V	SgCkt	2019	2019	2019
400	Mawana	Pandamatenga	290	3 x Tern	1	Guyed V	SgCkt	2025	To be evaluated in Component B and C	
400	SVC at Pandamatenga (+100 MVar)							2025		
400	SVC at Mawana (+100 MVar)							2025		

Full comparisons between Component A and the scenarios based on further regional integration – Components B and C – are presented in Section 7.2. The projects expected to be in service by 2019 are all seen as committed projects and are also included in Components B and C.

6.3 DR Congo

Relevant documents

A number of documents have been provided, however, none give a clear and concise description of transmission system development plans.

Developments in the Katanga Province in DRC are seen as most important for the development of the SAPP Pool Plan.

Planning criteria in use

It has not been possible to establish details on the planning criteria in use. However, the network in the Katanga Province is understood to be planned in line with typical deterministic planning criteria applied throughout SAPP.

Current development plan

No concrete information on further reinforcement or extension of the 220 kV system from Kolwezi to Lubumbashi and further towards Zambia has been made available for the preparation of the SAPP Power Pool Plan. The existing system is included in SAPP models, including the recently completed double circuit 220 kV line from Lubumbashi across the border to Zambia.

From publicly available information, it is understood that the HVDC terminals on the link from Inga to Kolwezi may have been or shortly will be upgraded. For the purpose of this study, the link is assumed to have a transfer capacity of 900 MW for all future scenarios.

The increase in capacity on the HVDC link (if implemented) and further development of local hydropower resources as well as the addition of a 500 MW local coal fired power plant may provide adequate capacity for further growth in the Katanga Province. However, the 220 kV system from Kolwezi towards Lubumbashi may soon restrict further developments. In-feed from local generation projects including projects on the Luapula River on the border with Zambia may support this part of the grid. Depending on location of loads and a possible in-feed from a second DC link from Inga, introduction of a higher voltage level may also be required.

Although details of the plan for integration of the new 500 MW coal plant is not known, the understanding is that the coal resources are located at Luena north of Kolwezi and Fungurume. A connection towards Kolwezi may be part of the plan, but in view of the limitations on the grid east of Kolwezi, connection at Fungurume would seem a better solution, and the further assessments in this Pool Plan is therefore based on such a solution. If implemented early on, such a project may postpone the requirement for upgrade of the DC link from Inga to Kolwezi. Nevertheless, the assumption is still that the upgrade of the existing DC is a committed project.

With the new coal plant connected to Fungurume, the transfer limit on the lines from Kolwezi to Fungurume would be of less importance as regards possible export from DRC to Zambia via the 220 kV lines from Katanga to the Copperbelt. Nevertheless, the 220 kV system in Katanga seems to restrict the power transfer compared to the actual capacity of the interconnectors.

In view of the in-feed of power to Kolwezi from local power plants and the existing DC from Inga, it would be beneficial to terminate a second HVDC link from Inga further east than Kolwezi. The Lubumbashi area is an obvious option which would also open up for export to Zambia via the existing 220 kV lines crossing the border. Information from SNEL indicates that the intention is to develop Inga 3 early on. Contracting and construction of a second DC

link would naturally take time, and for the purpose of the transmission analyses, such a link has not been foreseen to be in place by 2020, but added by 2025. Actual timing in this period does not impact on other grid investments (or the generation expansion plan in DRC for that matter).

Availability of transmission system models

Only the SAPP CC model for stage 2015/16 has been made available for the study. This model covers only the Katanga Province in the south-west, and the study will therefore focus on this area – which also provides the main link to the rest of the SAPP system.

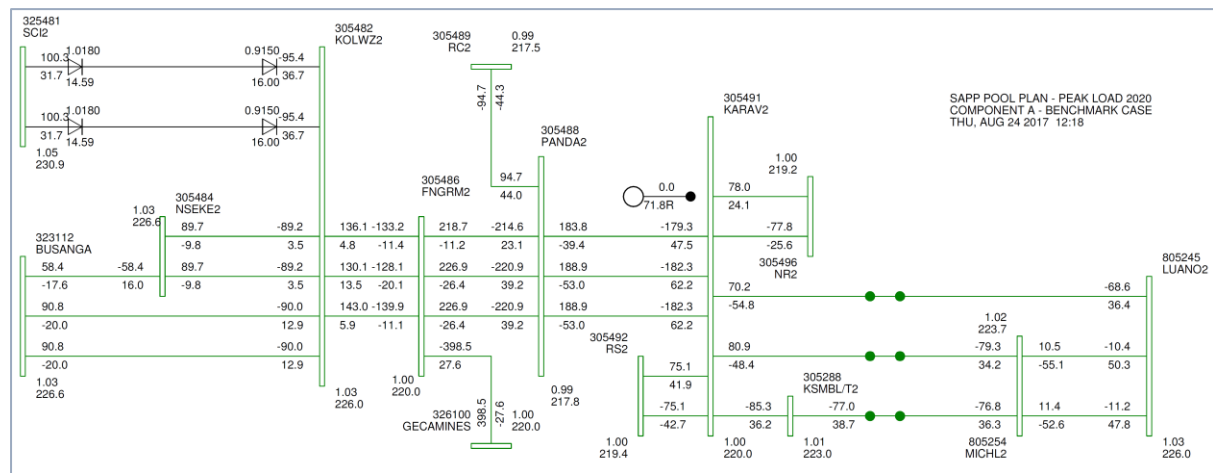
The Inga power station and the HVDC link to Kolwezi and possible extensions of Inga will be represented in a similar way to the existing model provided by SAPP CC.

Grid capacity and extension towards 2040

Based on the limited information available, the following transmission grid models with assumptions on grid expansion have been prepared for the Benchmark Case.

In the short term, the grid in Katanga is foreseen fed via the HVDC link from Inga to Kolwezi and local hydropower stations. Local hydropower plants and an upgraded DC link will have adequate capacity to cover the peak demand as of 2020 as presented below.

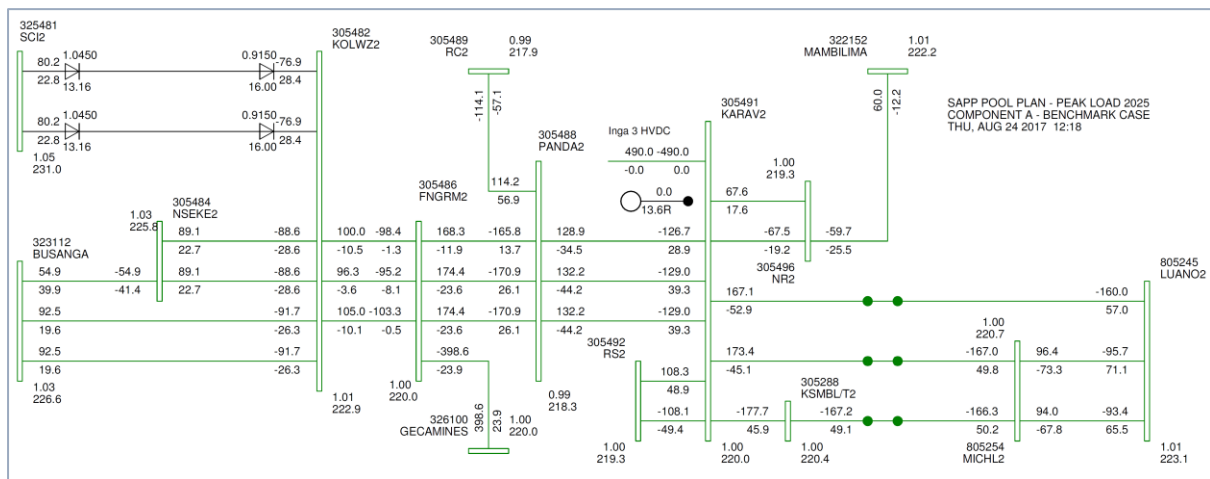
Figure 76 Katanga Province in DRC - 2020



As shown above, the Busanga Project is assumed linked to the nearby Nseke power plants as well as with the 220 kV substation at Kolwezi. The 220 kV grid depicted above meets the planning criteria at this stage.

The PLEXOS simulations indicate that both the Mambilima I project on the Luapula River should be added by 2025. As stated above, the second HVDC link from Inga to the Katanga Province is also added by 2025. Grid connections for these projects are indicated in the diagram below – assuming that the capacity of any developments on the Luapula River will be shared equally between the two countries.

Figure 77 Grid connections for DC Inga-Karavia and Mambilima I projects - 2025

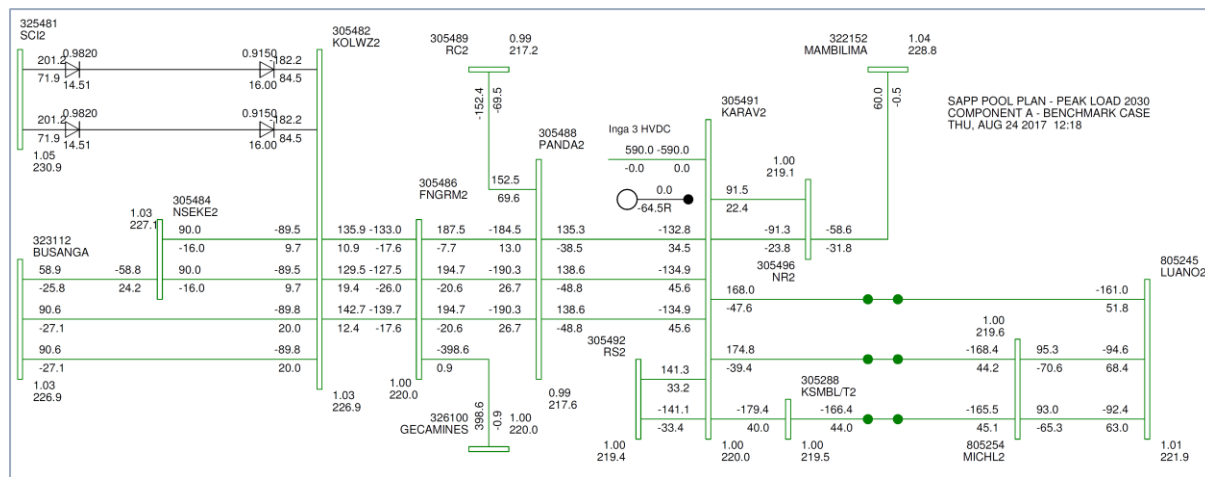


Only Mambilima I (124 MW) and Mambilima II (202 MW) of the projects considered on the Luapula River are seen as viable in the Benchmark Case. Assuming that the power is shared equally between Zambia and DRC, the relatively moderate capacity means that a single circuit 220 kV link to the Lubumbashi area would be adequate to evacuate DRC’s share from the two power plants. The proposed grid connections represent the shortest possible grid connection alternatives for these plants.

With the new DC link from Inga 3 added in the Benchmark Case by 2025, the 220 kV grid between Kolwezi, Fungurume, Panda and Karavia/Lubumbashi would be adequate to meet domestic demand. In line with the definition of the Benchmark Case in the Terms of Reference (“no new interconnections”), such a DC link would have to be terminated in the Katanga Province. In Component B and C, the Pool Plan has evaluated the benefit of terminating the DC in other parts of the SAPP system.

The main structure of the 220 kV grid in the Katanga Province beyond 2025 will therefore be as depicted in the diagram below. It is realised that the 220 kV system is likely to be expanded to support load growth outside the corridor covered by the existing 220 kV lines between Kolwezi, Fungurume, Panda/Likasi and Karavia/Lubumbashi. In a regional context – i.e. as relevant for the SAPP Pool Plan – the power flow across this part of the transmission system is still seen to provide a reasonable representation of developments in the Benchmark Case.

Figure 78 220 kV grid in the Katanga Province by 2030



Note that the new HVDC is shown as a simple in-feed to the Karavia substation in central Lubumbashi in the above single line diagrams. If a new DC converter is to be built in the Lubumbashi area, this will naturally have to be located outside built-up areas (the Karavia substation would hardly be a practical option as other infrastructure and buildings in the area would block further expansion). A location to the south of Lubumbashi would seem preferable. A converter station in this area should be connected to the 220 kV lines towards Kasumbalesa and Zambia. In a regional perspective, higher AC voltages may be required to integrate a high capacity DC link, and this issue has been evaluated as part of components B and C.

For cost estimation of the DC link in the Benchmark case, two mono-pole DC lines are required to minimise the probability of simultaneous outages of both DC poles. A staged development of the DC link could still be foreseen with for instance only half the converter station capacity being installed for the initial phase. A sudden loss of more than 400-500 MW in-feed to the Katanga Province is likely to lead to a transient instability on the existing system in the area. However, in future, and assuming that the DC systems will be built and/or operated allowing for some transfer of power from one pole to the remaining pole or to the parallel DC link, a capacity per pole on the new DC link in the region of 1000 MW may be a reasonable target. The new DC link could therefore be designed for 2000 MW normal steady state transfer with 1000 MW developed in the initial phase (which would be adequate for the Benchmark Case). Further discussion of maximum rating of a second DC link from Inga is included in the preliminary optimisation of such a scheme for Component B and C.

Transmission expansion plan for the Benchmark Case

The following table summarises the transmission system expansion plan for the Katanga Province in DRC in the Benchmark Case.

Figure 79 Transmission system expansion plan for the Katanga Province in DRC

TRANSMISSION PROJECTS										
Voltage [kV]	Substation		Distance [km]	Conductor type	Circuits	Tower type		In service by year		
	From	To						Comp A	Comp B	Comp C
220	Busanga	Nseke	10	2xAster 228	1	Guyed V	SgCkt	2020	To be evaluated in Component B and C	
220	Busanga	Kolwezi	55	2xAster 228	1	Guyed V	SgCkt	2020		
220	Busanga	Kolwezi	55	2xAster 228	1	Guyed V	SgCkt	2020		
220	Mambilima	Lubumbashi NR2	200	2xAster 228	1	Guyed V	SgCkt	2025		
500	HVDC Inga III - Stage I - 1000 MW	HVDC Lubumbashi - Stage I - 1000 MW	1900	4 x Martin	2	Mono-pole lines		2025		

Note: Details on the location the new 500 MW coal plant and how this will be integrated to the grid in Katanga are not known and therefore not included in the above table. The assumption is that the bulk of the power will be fed into Fungurume. Grid connection assumed independent of regional grid integration scenarios.

Full comparisons between Component A and the scenarios based on further regional integration – Components B and C – are presented in Section 7.3.

6.4 Lesotho

Relevant documents

A number of documents covering plans for Lesotho have been provided by LEC. Key information on the transmission system are included in the following documents:

- ❑ Network Development Plans – June 2015 (Power Point presentation)
- ❑ National Electrical Infrastructure Expansion Plan (Excel file)

An update on the timing of some of the transmission projects were received in conjunction with the workshop on the Pool Plan in December 2016.

Planning criteria in use

The documents provided do not present the planning criteria applied. Presumably, the planning criteria are less stringent for the main 132 kV system in Lesotho than the SAPP Planning Criteria aimed at inter-utility and regional trade on higher transmission voltages.

Current development plan

The documents provided presents the following plans for extension and reinforcement of the 132 kV system.

Table 24 Plans for extension and reinforcement of the 132 kV system

From:	To:	Voltage (kV)	Length (km)	Type of Circuit *	Proposed Year of Implementation
Mazenod	Ramabanta	132	35	Single	19/20

From:	To:	Voltage (kV)	Length (km)	Type of Circuit *	Proposed Year of Implementation
Ramabanta	Semonkong	132	65	Single	20/21
Semonkong	Mosi	132	80	Single	21/22
Mosi	Qachasnek	132	50	Single	22/23
Khukhune	Belo	132	30	Single	18/19
Mazenod	Thetsane	132	25	Double	19/20
Mt Moorosi	Mosi	132	70	Single	23/24
Lejone	Polihali	132	80	Double	18/19
Polihali	Mokhotlong	132	30	Single	25/26
Letseng	Mokhotlong	132	60	Single	26/27
Khukhune	Letseng	132	75	Single	18/19
Letseng	Liqhobong	132	50	Single	20/21

Note: * All circuits with single Bear conductors

The network development plan also includes a number of 66 kV projects. The SAPP Pool Plan projects to be evaluated are not foreseen to have any impact on the development plans at this voltage level.

Availability of transmission system models

A DigSilent model has been provided for stage 2019 for Lesotho. Relevant information from this model has been extracted and used together with the SAPP CC model for 2015/2016. The information provided for Lesotho covers only data for load flow modelling.

Benchmark Case Developments

The peak demand in Lesotho is forecast to double from about 160 MW in 2017 to 320 MW by 2040. The grid expansion plan outlined above is considered adequate to meet such growth although the PLEXOS simulations indicate some unserved energy in the last few years. This indicates that a new interconnection (which by definition cannot be added in the Benchmark Case) may be required, and the viability of such a project has been assessed in Components B and C.

The regional interconnection projects from the result of the analysis in Components B and C of the Pool Plan, do not have an impact on the grid developments in Lesotho.

6.5 Malawi

Relevant documents

Short term investment plans for the transmission system in Malawi are outlined in:

- ❑ Malawi's Mini Integrated Resource Plan 2016-2020 Strategic Roadmap of Malawi's Power Sector, Ministry of Natural Resources, Energy and Mining (MoNREM, Department of Energy (DoE) and Electricity Supply Corporation of Malawi (ESCOM), December 2015

Planning criteria in use

Specific transmission planning criteria used in the preparation of the Mini IRP are not included in the report provided. In the context of the SAPP Pool Plan, it is primarily the planning of the 400 kV system in Malawi that will be of interest. As a future operating member of SAPP, Malawi would be expected to adopt the planning criteria in use throughout the SAPP region for the planning of the 400 kV grid.

Current development plan

The Mini IRP lists the following transmission projects by 2020:

- ❑ Construction of a new 400 kV line from Phombeya (near Blantyre) to Nkhoma (near Lilongwe)
 - ❑ Construction of 200 MVA 400/132 kV Phombeya substation
 - ❑ Construction of 200 MVA 400/132 kV Nkhoma substation
- ❑ New Double Circuit 132 kV Nkhoma to Nanjoka Substation (Salima including transformer upgrade) – Nkhotakota – Dwangwa – Chintheche at an estimated cost of \$50 Million.
- ❑ New 132 kV Dwangwa – Chatoloma transmission line at an estimated cost of \$9.7 Million.
- ❑ New 132/33 kV Substation in Blantyre at an estimated cost of \$ 6 Million.
- ❑ New 132 kV Single Circuit Phombeya – Mangenue – Machinga – Zomba – New Blantyre at an estimated cost of \$13.6 Million.
- ❑ Upgrade 66 kV Single Circuit Golomoti to Monkey bay Overhead line to 132 kV Transmission Line at an estimated cost of \$5.4 Million.
- ❑ 132 kV Nchalo – Nsanje
- ❑ 132 kV Karonga – Kayerekera (energised at 66 kV up to 2022)
- ❑ 400 kV Nkhoma – Bwengu

- ❑ 132 kV Blantyre West – Fundi’s X – Mange
- ❑ 400 kV Phombeya – Makanjira

The 400 kV line from Phombeya to Nkhoma is committed – including the 400/132 kV substations at either end of the line. Other projects are understood to be undergoing further studies before implementation.

Feasibility studies have been initiated or are planned to be executed for several interconnection projects at 400 kV:

- ❑ Tete (Mozambique) – Phombeya (Malawi) – Expected commissioning 2019
- ❑ Phombeya (Malawi) – Nampula/Namialo (Mozambique) (Malawi – Mozambique Extension)
- ❑ 400 kV Malawi – Tanzania – Expected commissioning 2022
- ❑ 400 kV Malawi – Zambia

Availability of transmission system models

A DigSILENT file has been received for the system in Malawi. The file covers load flow models for the existing system and provides some information on future expansion plans. Generic models for the power plants will be added as required.

Grid capacity and extension towards 2040

The following analysis presents an assessment of the grid capacity accounting for the planned expansion program and the generation expansion plan presented for the Benchmark Case (Component A). The analysis also covers a high-level expansion plan towards 2040 based on the same generation scenario (and the Pool Plan load forecast).

From the above description, it is clear that Malawi sees possible benefits of adding interconnections to neighbouring utilities. However, the Benchmark Case described in the following reflects a scenario without significant trade among the SAPP members – based on the assumption that no new interconnectors will be added and trade therefore limited to existing interconnections (and a few seen as committed, but not between Malawi and its neighbours). The scenario as such is included to demonstrate the likely benefits of adding interconnections (in Components B and C) and also to identify the most promising interconnections (with associated generation projects) from a regional perspective.

The power system in Malawi is experiencing power shortages and widespread load shedding. In addition to the limitations on the generation side, voltage constraints on the system towards the north also limit the load that can be added on the system. Upgrade of part of the 66 kV system and reinforcement and expansion of the 132 kV system is therefore required. Furthermore, to meet the expected load growth and to remove bottlenecks on the system and allow for connection of new power generation facilities, the 400 kV system must also be expanded on.

With the relatively low load density in many areas in Malawi, it has not been economical to build a transmission system that can provide reserves in case of outages of many of the existing 132 kV and 66 kV lines. Many areas are supported only by radial feeders. In the future, and in particular once several power stations are added, it will be important to ensure that a system-wide collapse is not caused by faults on key transmission lines. As the system is expanded, the normal planning criteria applied for the interconnected transmission system in SAPP will therefore be applicable to main parts of the grid in Malawi. An exception would be 132 kV lines that mainly feed smaller loads in remote areas where a higher level of reliability would not be economical. Loss of load on such lines would not put the overall system at risk.

In general, the future 400 kV system will therefore have to be planned to meet the typical “N-1” criteria applied within SAPP, and the power plants should not be at risk of dropping out of synchronism following common disturbances on the system.

Transmission expansion plan for the Benchmark Case

Construction of the first 400 kV line from Phombeya to Nkhoma is ongoing. Further extension of the 400 kV grid will be required to integrate new power plants and meet growth throughout the country. Towards the end of the study period, the 400 kV grid is foreseen to stretch from the coal fields near Karonga in the north via Lilongwe to Blantyre in the south, see the diagram on the next page.

The following table summarises the transmission system expansion plan for Malawi in the Benchmark Case. (Note that the summary does not include sub-transmission investments on 132 kV and the possible need for a second 400/132 kV in-feed to Lilongwe and Blantyre towards the end of the study period. Such projects are evaluated to be independent of regional integration in the context of the Pool Plan.)

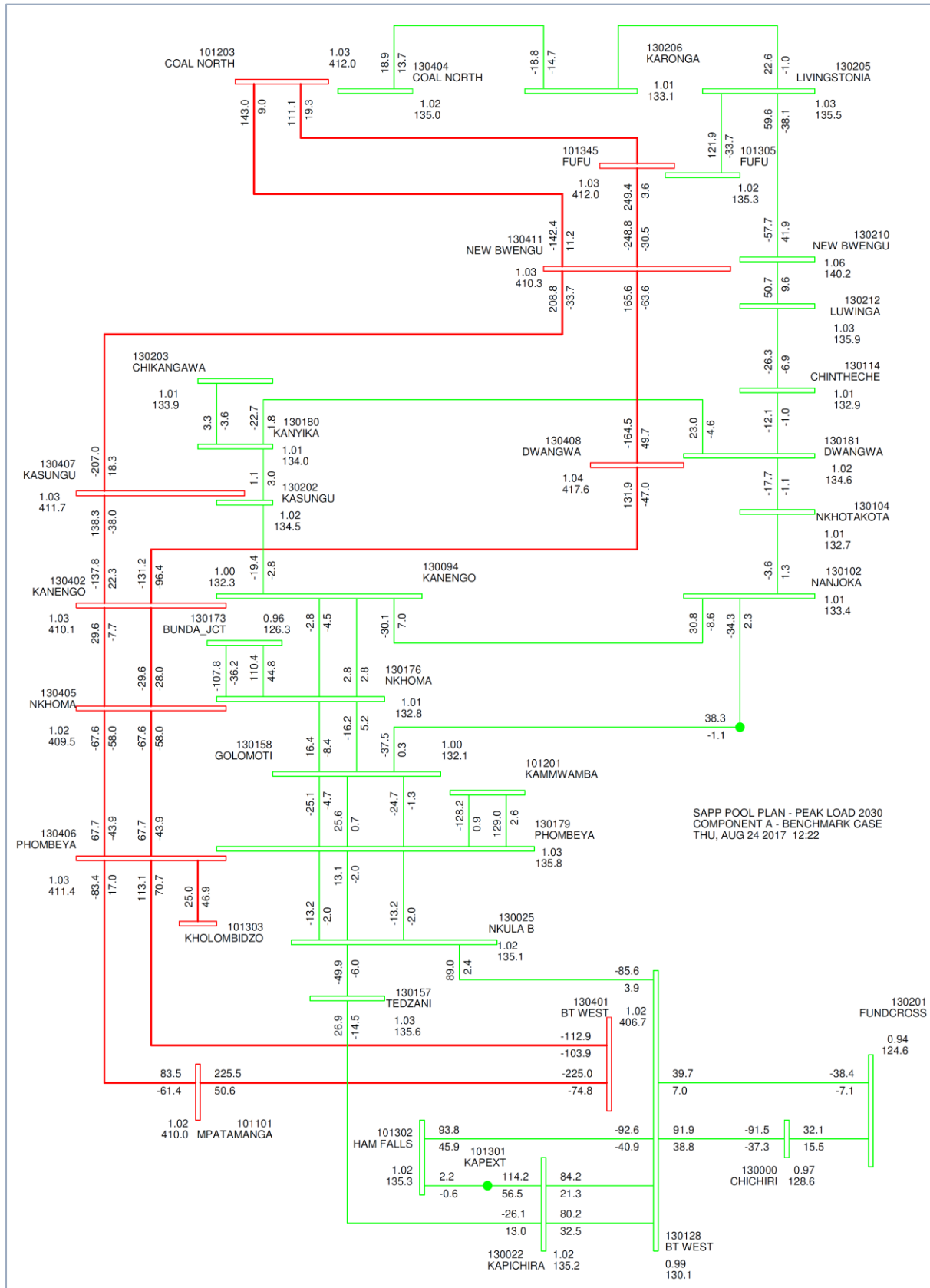
Figure 80 Transmission system expansion plan for Malawi (1)

TRANSMISSION PROJECTS										
Voltage [kV]	Substation		Distance [km]	Conductor type	Circuits	Tower type	In service by year			
	From	To					Comp A	Comp B	Comp C	
400	Phombeya ckt. 1 only	Nkohma ckt. 1 only	173	2 x Bluejay	1	Y	DbCkt	2017/18	2017/18	2017/18
400	Phombeya string ckt. 2	Nkohma string ckt. 2	173	2 x Bluejay	1	Y	DbCkt	2021	2021	2021
400	Nkhoma	Kasungu	200	3 x Tern	1	Y	SgCkt	2020	2020	2020
400	Kasungu	New Bwengu	235	3 x Tern	1	Y	SgCkt	2023	2023	2023
400	Phombeya	Blantyre West	60	3 x Tern	1	Y	SgCkt	2023	Part of evaluation in Component B and C	
400	Phombeya	Mpatamanga	70	3 x Tern	1	Y	SgCkt	2023		
400	Mpatamanga	Blantyre West	50	3 x Tern	1	Y	SgCkt	2023		
400	Nkhoma	Kanengo	60	3 x Tern	1	Y	SgCkt	2024		
400	New Bwengu	Fufu	55	3 x Tern	1	Y	SgCkt	2027		
400	Kanengo	Dwangwa	220	3 x Tern	1	Y	SgCkt	2028		
400	Dwangwa	New Bwengu	250	3 x Tern	1	Y	SgCkt	2028		
400	Fufu	Coal North	120	3 x Tern	1	Y	SgCkt	2030		
400	New Bwengu	Coal North	175	3 x Tern	1	Y	SgCkt	2030		
400	Phombeya	Kholombidzo	15	3 x Tern	1	Y	SgCkt	2033		

Note: The table does not include sub-transmission investments on 132 kV and the possible need for a second 400/132 kV in-feed to Lilongwe and Blantyre towards the end of the study period. Such projects are evaluated to be independent of regional integration in the context of the Pool Plan.

Full comparisons between Component A and the scenarios based on further regional integration – Components B and C – are presented in Section 7.5.

Figure 81 Transmission system expansion plan for Malawi - 2030



6.6 Mozambique

Relevant documents

EdM has provided access to the recent Master Plan documents:

- ❑ Master Plan Update Project, 2012 – 2027
- ❑ Final Master Plan Update Report, Norconsult / Vattenfall – April 2014

The Master Plan report provides background information on several projects, but status of implementation and order of priority has since been modified, and alternative generation projects that may impact on the transmission development plans are being considered. Some temporary, emergency measures have also been implemented in order to support the system. This includes for instance the power barge currently in operation at Nacala.

Planning criteria in use

The transmission studies in the recent Master Plan were based on a deterministic N-1 planning criterion in line with the SAPP planning criteria. However, large areas of Mozambique are fed via radial transmission lines covering areas with low load density, and it is not economical to establish N-1 reserve in these areas at the time being. Future growth may justify this once the economic cost of outages balances the investments required.

Furthermore, it should be noted that the STE transmission grid for power evacuation from the Tete area to the Maputo area relies on use of system protection schemes shedding generation in the Tete area in order to avoid cascading or transient instability. However the planned AC and DC lines on the STE system will meet N-1 planning criteria in terms of stability and no loss of load as long as generator tripping is done in a controlled manner.

Current development plan

Following the PSC meeting in Johannesburg in December 2016, EdM provided an updated list of transmission projects based on the most recent assessment of likely generation expansions. It should be noted that power generation from gas is likely to be advanced compared to previous generation development plans, whereas the large hydropower projects like Mphanda Nkuwa will take longer to finance and implement than previously assumed.

Table 25 List of transmission projects

Project	Voltage [kV]	From	To	Length [km]	COD	Status
Chibata-Dondo	220	Chibata	Dondo	170	2017	Constr.
Ressano Garcia – Dzimbene	275	Ressano Garcia	Dzimbene (Macia)	142	2017	Constr.
Lindela – Massinga	110	Lindela	Massinga	110	2018	Constr.

Project	Voltage [kV]	From	To	Length [km]	COD	Status
Cuamba – Marrupa	110	Cuamba	Marrupa	110	2019	Constr.
Massinga – Vilanculos	110	Massinga	Vilanculos	159.4	2020	FS
Maputo – Beluluane	275	Maputo	Beluluane	2	2020	Planned
Dondo – Manga	220	Dondo	Manga	19	2022	Concept
Chibabava – Vilanculos	110	Chibabava	Vilanculos	240	2022	Concept
Mozambique – Malawi	400	Matambo (Tete)	Phombeya	218	2022	FS
Caia – Nacala	400	Chimura (Caia)	Namialo	780	2022	
	220	Namialo	Nampula	90	2022	FS
	220	Nampula	Nacala	100	2022	
STE Project	STE Phase 1 (initial part of STE) HVAC Vilanculos – Maputo (under MGD 400 MW Generation Project)					
	400	Vilanculos	Chibuto	339.5	2022	Planned
	400	Chibuto	Matalane	179.3	2022	Planned
	400	Matalane	Maputo	43.6	2022	Planned
	STE Phase 2 A (initial part of STE) HVAC Songo – Matambo					
	400	Songo	Cataxa	53.7	2022	FS
	400	Cataxa	Matambo	64.1	2022	FS
	STE Phase 2 B – HVAC Matambo – Maputo					
	400	Matambo	Lupata	80.4	2025	FS
	400	Lupata	Inchope	303.6	2026	FS
	400 ckt. 2	Inchope	Vilanculos	352.2	2026	FS
	400 ckt. 2	Vilanculos	Chibuto	339.5	2026	FS
	400 ckt. 2	Chibuto	Matalane	179.3	2026	FS
	400 ckt. 2	Matalane	Maputo	43.6	2026	FS
	STE Phase 2 HVDC Cataxa – Maputo					
500	Cataxa	Maputo	1276	2026	FS	
STE Phase 3 – HVDC Cataxa – Maputo-Increased converter capacity						
500	Cataxa	Maputo	1276	2026	FS	
Reinforcement of North Region	110	Metoro	Montepuez	115	2024	Concept
	110	Marrupa	Montepuez	97	2024	Concept
Nampula - Angoche	110	Nampula	Angoche	180	2025	Concept
Namialo - Metoro	220	Namialo	Metoro	216	2025	FS
Mozambique - Zambia	400	Matambo (Tete)	Chipata	?	2025	Concept

Project	Voltage [kV]	From	To	Length [km]	COD	Status
Mozambique - Tanzania	400	Namialo	Mtwara	700 **)	2025	Concept
MOZISA *) interconnection	400	Songo	Cataxa	60 ***)	2025	FS
	400	Cataxa	Inchope	360	2025	FS
	400	Inchope	Orange Grove	185	2025	FS
Inhaminga	400	Chimuara	Inhaminga	125	2030	Concept
	400	Inhaminga	Inchope	140	2030	Concept
	220	Inhaminga	Dondo	130	2030	Concept

*) Includes Triangle - Nzhelele between Zimbabwe and South Africa

***) Not mentioned in EdM's documents, but distance requires intermediate substation

***) From Songo via Cahora Bassa North Bank to Cataxa

Source: EdM, 2016

The above plan does not include a 400 kV line between Lupata and Chimuara which seems to be required based on other 400 kV projects in the area. Furthermore, the Ncondezi coal fired power plant is understood to be connected on the 220 kV system between Matambo and Chimuara, but with lines designed for 400 kV. This would facilitate connection to the STE grid at the switchyard for the Lupata power plant on the Zambezi River (establishing a switching station at or close to Lupata prior to development of the power plant may also be an option).

Availability of transmission system models

PSS/E files from the Master Plan study have been made available for the Pool Plan project. These files have been adapted to reflect the changes in the generation expansion plans for the national Benchmark Case. The development will still feature the STE backbone grid with an HVDC link from the Tete area to Maputo and a 400 kV AC line in parallel to the HVDC.

Grid capacity and extension towards 2040

The generation expansion plan from EdM lists a number of high-capacity generation projects in the Tete Province as committed projects. It is uncertain whether this is actually reflecting the real status of these projects. Including the 400 MW gas-fired plant at Vilanculos, the committed projects amounts to a total of about 4500 MW by 2026. Total load in Mozambique is forecast to grow by about 700 MW by 2026. Roughly 3700 MW new capacity would therefore be available for export which seems to exceed the transfer limits on the existing interconnections (even accounting for the fact that power flow on the MOTRACO system could be reversed).

The transmission plan presented by EdM assuming that one HVDC link is built from north to south therefore seems reasonable as this would provide adequate capacity to feed the southern system and probably utilise the MOTRACO system to its full capacity. (This naturally depends on whether customers can be found outside Mozambique – if not, the

generation expansion and the build-up of capacity on the STE grid should be postponed). The plan to build both Phase 1 and Phase 2 as described above is therefore kept unchanged in the Benchmark case (still, generation in the Tete area may be restricted at times).

The STE project will create bulk supply points in the area between Tete and Maputo that would meet requirements in long term.

Furthermore, the plans for extension of the 400 kV system towards the north seems reasonable although a second line may be required to increase reliability towards the end of the study period. Developments would depend both on load growth in the area and possible additional gas fired generation in the Palma area. A 400 kV line between Lupata and Chimuara has been added in the Benchmark case to support the planned 400 kV line from Chimuara to Namialo.

Strengthening of the 275 kV grid in the Maputo area may be required within the study period, but such developments are seen as independent of regional integration projects to be evaluated as part of the SAPP Pool Plan.

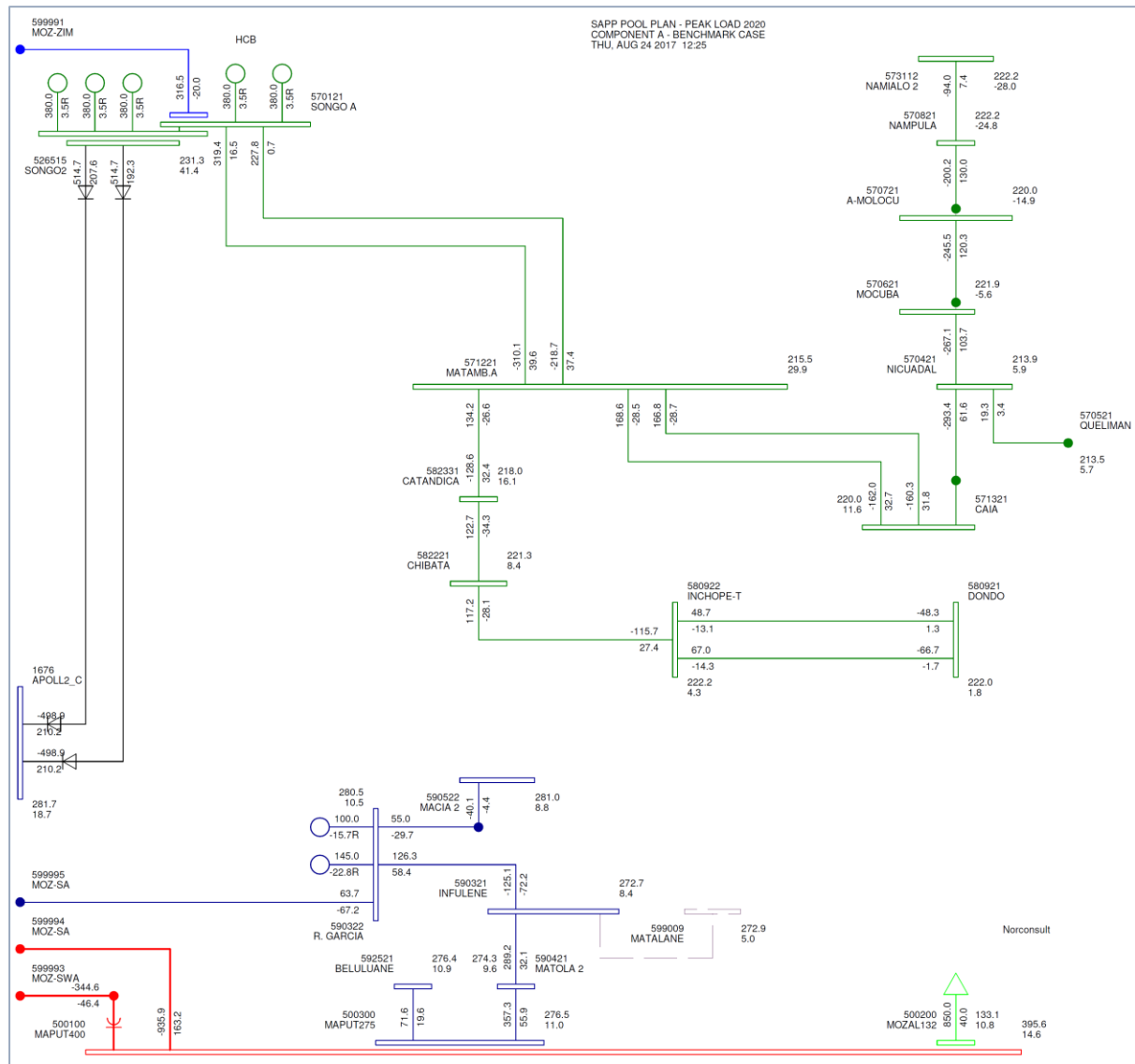
Figure 82 Transmission system expansion plan for Mozambique

TRANSMISSION PROJECTS											
Voltage [kV]	Substation		Distance [km]	Conductor type	Circuits	Tower type		In service by year			
	From	To						Comp A	Comp B	Comp C	
220	Chibata	Dondo	170		1		SgCkt	2017	2017	2017	
275	Ressano Garcia	Dzimbene	142	2 x Bear	1		SgCkt	2017	2017	2017	
275	Maputo	Beluluane	2	2 x Bear	1	Guyed V	SgCkt	2020	2020	2020	
400	Chimuara (Caia)	Namialo	780	3 x Tern	1	Guyed V	SgCkt	2022			
220	Namialo	Nampula	90	2 x Tern	1	Guyed V	SgCkt	2022			
220	Namialo	Nacala	100	2 x Tern	1	Guyed V	SgCkt	2022			
400	Vilanculos	Chibuto	340	4 x Tern	1	Guyed V	SgCkt	2022			
400	Chibuto	Matalane	179	4 x Tern	1	Guyed V	SgCkt	2022			
400	Matalane	Maputo	44	4 x Tern	1	Guyed V	SgCkt	2022			
400	Songo	Catata	54	4 x Tern	1	Y	SgCkt	2021			
400	Catata	Matambo	64	4 x Tern	1	Y	SgCkt	2021			
400	Mphanda Nkuwa 1	Catata 1	18	4 x Tern	1	Y	SgCkt	2025			
400	Mphanda Nkuwa 2	Catata 2	18	4 x Tern	1	Y	SgCkt	2025			
400	Catata ckt. 2	Matambo ckt. 2	64	4 x Tern	1	Y	SgCkt	2025			
220	Namialo	Metoro	216	2 x Tern	1	Guyed V	SgCkt	2025			
400	Matambo	Lupata	80	4 x Tern	1	Guyed V	SgCkt	2023			
400	Lupata	Chimuara	210	3 x Tern	1	Guyed V	SgCkt	2023			
400	Lupata ckt. 2	Chimuara ckt. 2	210	3 x Tern	1	Guyed V	SgCkt	2025			
400	Lupata	Inchope	304	4 x Tern	1	Guyed V	SgCkt	2025			
400	Inchope	Vilanculos	352	4 x Tern	1	Guyed V	SgCkt	2025			
400	Vilanculos ckt. 2	Chibuto ckt. 2	340	4 x Tern	1	Guyed V	SgCkt	2025			
400	Chibuto ckt. 2	Matalane ckt. 2	179	4 x Tern	1	Guyed V	SgCkt	2025			
400	Matalane ckt. 2	Maputo ckt. 2	44	4 x Tern	1	Guyed V	SgCkt	2025			
500	HVDC Catata	HVDC Maputo	1276	4 x Martin	1	Bi-pole DC line		2025			
500	Increased converter capacity at Catata and Maputo								2032		
400	Songo	Cahora Bassa North	54	4 x Tern	1	Y	SgCkt	2026			
400	Cahora Bassa North	Catata	64	4 x Tern	1	Y	SgCkt	2026			

Part of evaluation in Component B and C

The figures on the next pages shows the power flow at peak demand for 2020, 2025 and 2030.

Figure 83 Transmission system in Mozambique - 2020



The thermal capacity of the simplex 220 kV line north of Mocuba is slightly exceeded in this case, and the Alto Molocue – Nampula line is on the limit. The case ignores the local temporary power plant (power ship) in Nacala. If this is still in operation in 2020, these overloads will be avoided, but the case clearly demonstrates the need for the proposed 400 kV from Chimuara (Caia) to Namialo and the other planned reinforcements in the area.

Of note is also that the simplex 220 kV circuit between Songo and Matambo is almost fully loaded and the reserve for an outage of the duplex line is critical – even accounting for the temporary power generation at Nacala (if still available). The 400 kV line from Songo via Cataxa to Matambo, planned as part of the STE project, is therefore moved forward to 2020/21 to improve reliability in advance of the Mphanda Nkuwa project and the other reinforcements planned as part of the STE grid.

Furthermore, the reserve for the load in the Beira corridor (Chibata – Dondo) is limited to local generation. The 400 kV AC line on the STE project will address this issue (and should possibly be built earlier than 2025 to resolve this problem).

Figure 84 Transmission system expansion plan for Mozambique - 2025

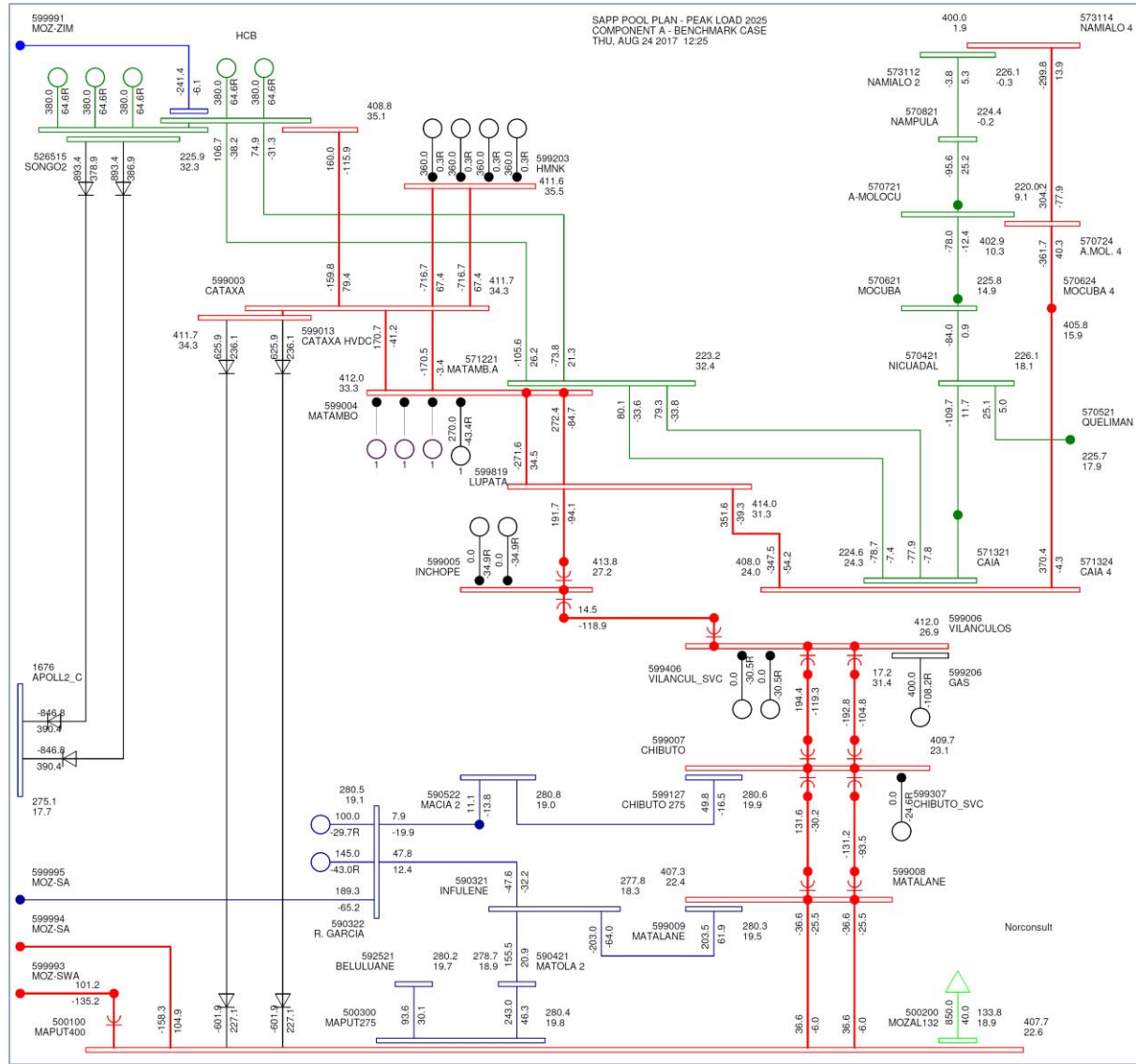
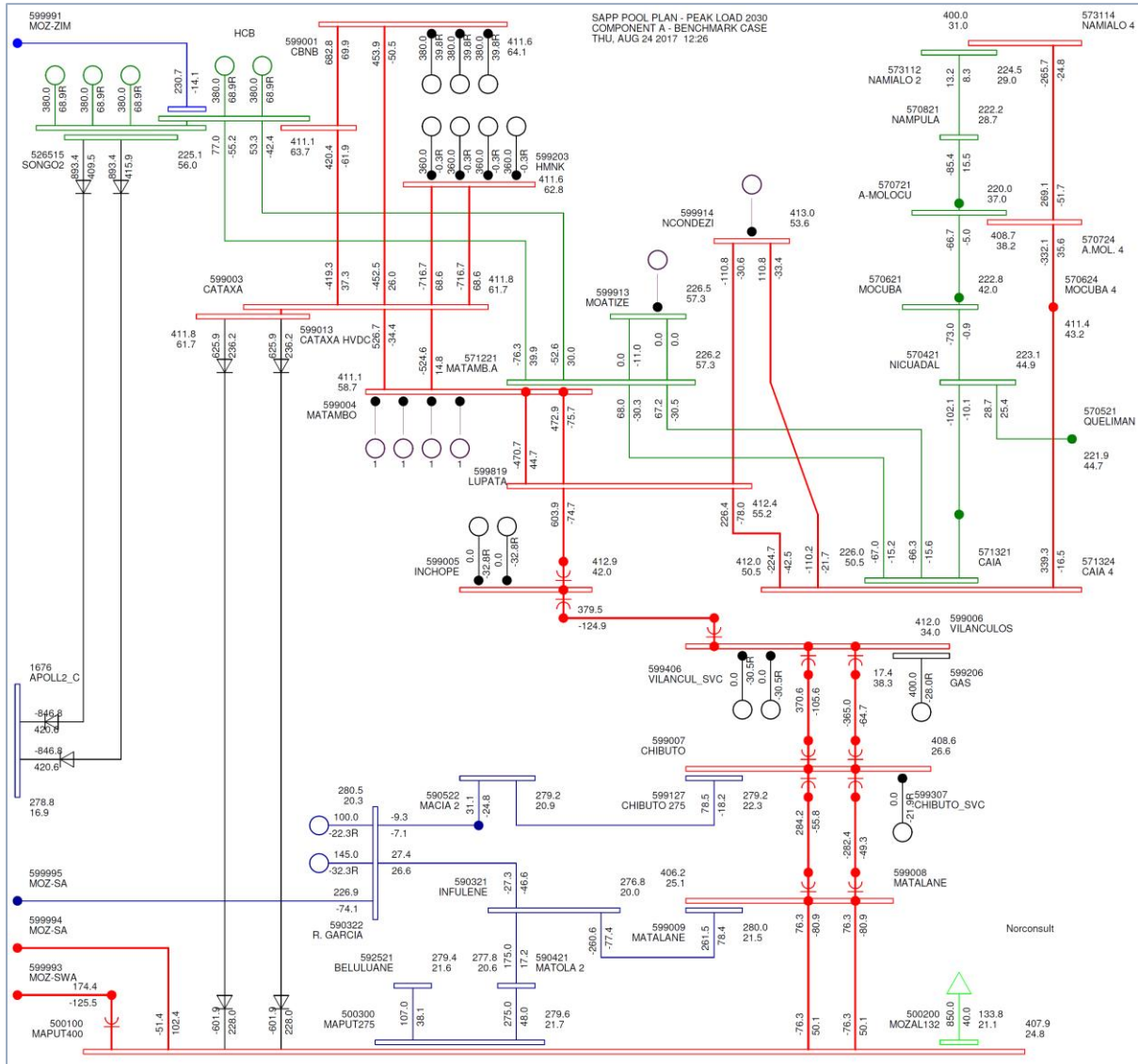


Figure 85 Transmission system expansion plan for Mozambique - 2030



6.7 Namibia

Relevant documents

The following document on transmission plans for Namibia has been received from NamPower:

- ❑ Transmission Master Plan Update 2016
- ❑ Addendum to the 2012 Transmission Master Plan, NamPower 2016

The report covers the period 2016 to 2020. The report states that there is significant uncertainty regarding the generation development plan, and that a commitment to a final transmission backbone development plan should be made once all parties have agreed to a generation development plan for Namibia.

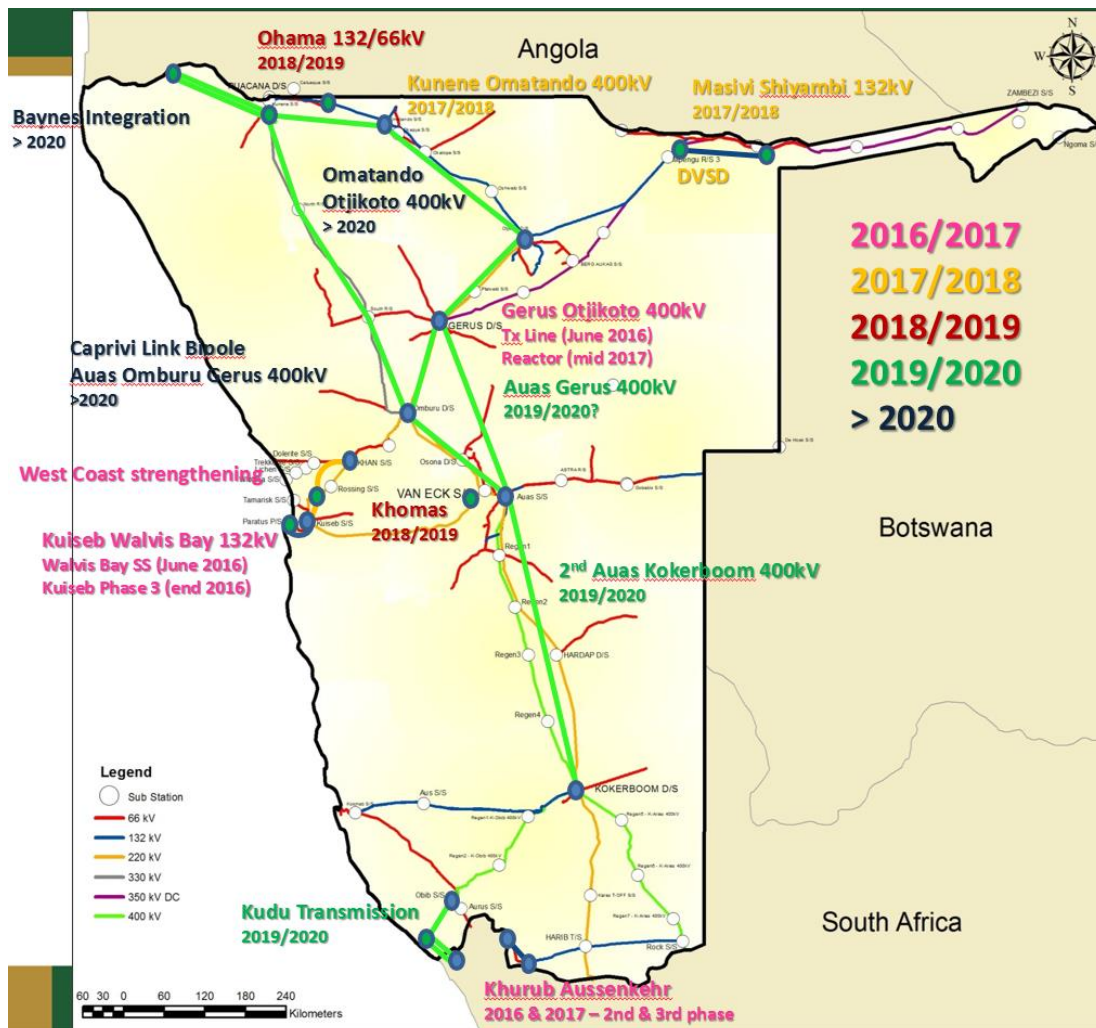
The technical team also received an update of the IRP for Namibia being covered by a consultant:

- ❑ National Integrated Resource Plan (NIRP) Review and Update Project Preliminary Draft of Partial Final Report Hatch, 19 February 2016

This report presents a load forecast along with generation expansion scenarios, but includes very limited information on expansion plans for the transmission system.

Projects included on the Master Plan are also indicated on the map on the next page.

Figure 86 Transmission Master Plan in Namibia



Source: NamPower, 2016

Planning criteria in use

The Namibian Grid Code has been applied in the transmission planning covered for the Transmission Master Plan Update report referred to above. This code is understood to reflect deterministic N-1 planning criteria in line with SAPP Pool Plan Transmission Planning Criteria.

Current development plan

Ongoing Projects

According to the information received, there are two projects under construction/ implementation:

- ❑ 400 kV Kunene – Omatando
- ❑ 400 kV line Kunene – Omatando

- ❑ New 400 kV substation at Kunene – initially operated at 330 kV
 - Provision for 400/330 kV coupling transformer
 - Future integration of the Baynes hydropower project at 400 kV
- ❑ Extension of Omatando substation at 400(330)/132 kV
- ❑ 400 kV Gerus – Otjikoto
 - ❑ 400 kV line Gerus – Otjikoto completed in 2015 – initially operated at 220 kV
 - ❑ Busbar reactor at Otjikoto first half 2017

Projects Proposed for Further Investigation

Only the two projects mentioned above are seen as committed. Further transmission investment will be dependent on the generation expansion plan (and in principle also any agreements on export, import or major wheeling). The Master Plan Update Study has proposed or recommended the following projects for further investigation within the next five years:

- ❑ 400 kV Omatanda – Otjikoto
 - ❑ Completing a 400 kV link Gerus – Otjikoto – Omatando – Kunene
- ❑ 400 kV Auas – Gerus
 - ❑ The project would support the 220 kV network in the Omburu – Van Eck area
 - ❑ The line may support further/increased trade/wheeling on the Gerus – Zambezi HVDC link
- ❑ 2nd 400 kV Kokerboom – Auas
 - ❑ Depending on generation expansion scenario, the strengthening of this link may be required to support growth and improve system reliability.
- ❑ 2nd 400 kV line to Eskom
 - ❑ The system south of Auas may require a second line to Eskom / South Africa to support the system. The 2nd Kokerboom – Auas line mentioned above could be part of such a link. The possible development of the Kudu project may impact on the solution south of Kokerboom, see next bullet point.
- ❑ Integration of the Kudu Power Station

The NamPower Master Plan indicate the following solution for the grid connection of this power plant:

- ❑ 400 kV line Kudu – Obib
- ❑ Two 400 kV lines Kudu – Oranjemund (in South Africa)
- ❑ Additional Reinforcements in South Africa:
 - ❑ Oranjemund – Gromis – Juno
 - ❑ Oranjemund – Aggeneis

Possible Developments Post 2020

The Master Plan Update report lists the following projects as possible developments post 2020:

- ❑ 400 kV line Auas – Omburu – Gerus
 - ❑ Possibly linked to upgrade of the Caprivi HVDC link from 300 to 600 MW
- ❑ Integration of Baynes:
 - ❑ Upgrade Omburu to 400 kV
 - ❑ Upgrade Omburu – Kunene to 400 kV
 - ❑ Add 2nd 400 kV Omburu - Kunene

Availability of transmission system models

Apart from the base case model provided by SAPP CC, the technical team was provided a PSS/E model and a DigSilent PowerFactory model to support the study:

- ❑ PSS/E Model:
“SAPP_2017Peak_ZZBN2_ZE300_C300_N100_SE0_GerOmbAusIN_KuduIN_Ze
sco+BPC_04-04-2013_(17 14) - Mod 1 DSCN bots zim zam Katanga.sav”
- ❑ DigSilent Model: “NamPower Model 2016-03 rev 0”

The PSS/E model reflects a peak load case for 2017 (as indicated in the file name), whereas the DigSilent model includes data for stage 2016 and a future scenario for stage 2025.

Grid capacity and extension towards 2040

The generation expansion plan for the Benchmark Case includes the Kudu project by 2024 followed by the Baynes hydropower plant later on in 2029.

In line with NamPower’s plan for grid connection of these two projects, the Benchmark case therefore includes completion of the 400 kV “ring” in the north resulting in two 400 kV lines from Kunene (Ruacana) towards the central substations Gerus and Auas in conjunction with the implementation of the Baynes project.

For the Kudu project, the Benchmark Case differs from what has been outlined in NamPower's planning document. By definition, the Benchmark Case reflects a scenario without new interconnections, and trade among the SAPP members is therefore limited. To support growth in Namibia, the Kudu project is therefore assumed connected to Kokerboom via two 400 kV lines in the Benchmark Case – i.e. two new lines from Kudu to Obib and one additional line between Obib and Kokerboom. (Kudu remains part of developments in the main case for Component B and C as well, but with a grid connection in line with the solution indicated in NamPower's planning documents.)

The system in Namibia will be dependent on imports in the Benchmark Case – especially early on. To maintain a high level of reliability, additional interconnectors may be seen as required, but would only be considered for Component B and C as explained above.

Transmission expansion plan for the Benchmark Case

The following table summarises the transmission system expansion plan for Namibia in the Benchmark Case.

Figure 87 Transmission system expansion plan in Namibia

TRANSMISSION PROJECTS										
Voltage [kV]	Substation		Distance [km]	Conductor type	Circuits	Tower type		In service by year		
	From	To						Comp A	Comp B	Comp C
400	Kunene	Omatando	190	3 x Tern	1	Cross Rope	SgCkt	2017	2017	2017
400	Gerus	Otjikoto	174.6	3 x Tern	1	Cross Rope	SgCkt	2017	2017	2017
400	Auas	Gerus	265	3 x Tern	1	Cross Rope	SgCkt	2019	2019	2019
330	Ruacana	Kunene	20	3 x Tern	1	Cross Rope	SgCkt	2020	2020	2020
400	Kudu ckt.1	Obib ckt.1	50	4 x Tern	1	Cross Rope	SgCkt	2024	Part of evaluation in Component B and C	
400	Kudu ckt.2	Obib ckt.2	50	4 x Tern	1	Cross Rope	SgCkt	2024		
400	Obib	Kokerboom	252	4 x Tern	1	Cross Rope	SgCkt	2024		
400	Kokerboom	Auas	445.8	4 x Tern	1	Cross Rope	SgCkt	2024		
400	Auas	Omburo	200	4 x Tern	1	Cross Rope	SgCkt	2024		
400	Omburo	Gerus	140	4 x Tern	1	Cross Rope	SgCkt	2024		
400	Baynes	Kunene	180	3 x Tern	1	Guyed V	SgCkt	2029		
400	Kunene	Omburu	481.5	3 x Tern	1	Cross Rope	SgCkt	2029		
400	Omatando	Otjikoto	275	3 x Tern	1	Cross Rope	SgCkt	2029		

Full comparisons between Component A and the scenarios based on further regional integration – Components B and C – are presented in Section 0.

Figure 88 Transmission system in Namibia - 2025

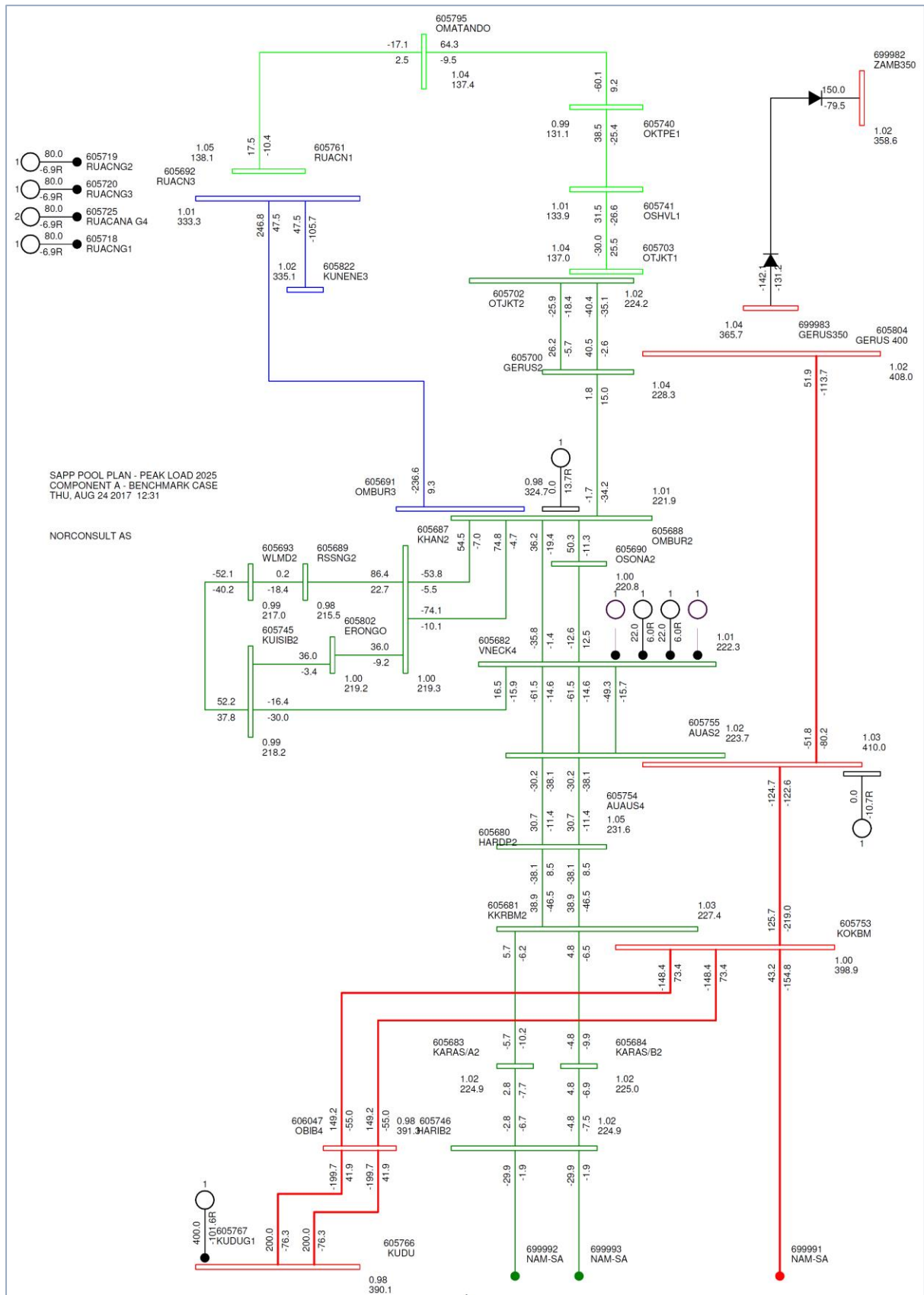
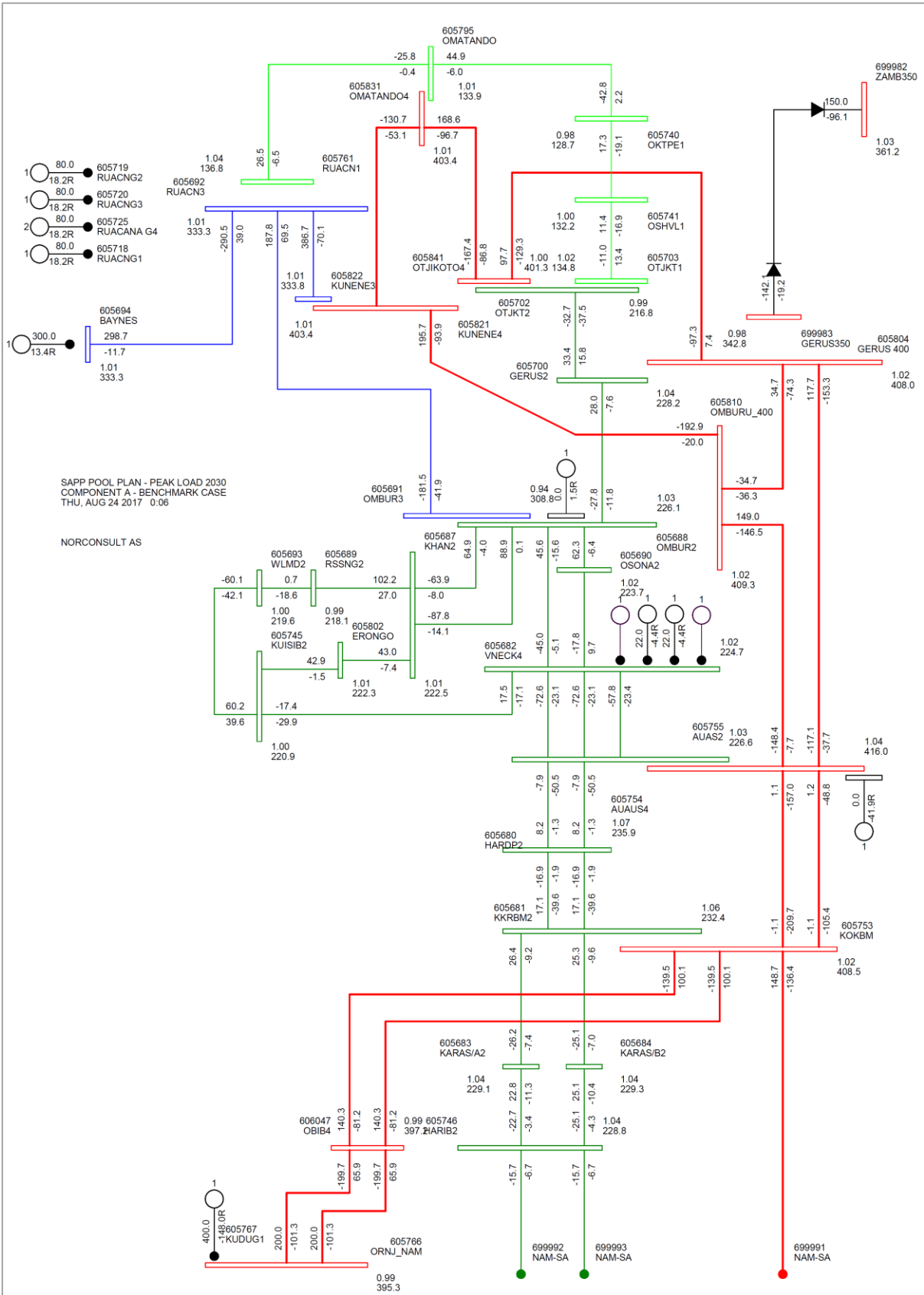


Figure 89 Transmission system in Namibia - 2030



6.8 South Africa

Relevant documents

The following documents have been provided as input to the transmission development plan for South Africa:

- ❑ Transmission System Development Plan, 2016 – 2025, Eskom Transmission Group, October 2015
- ❑ 2040 Transmission Network Study Part 4 – Overview of the 2040 Study Eskom, Grid Planning, May 2014
- ❑ Assumptions Paper for the 2040 Transmission Network Study, Eskom Grid Planning, August 2011

In November/December 2016, Eskom provided a set of PSS/E load flow files covering what is understood to present changes as reflected in the update of the Integrated Resource Plan. Information has been extracted from these files on grid development in the border areas – i.e. in areas where significant changes in trade on SAPP may impact on the investments required (whether this would lead to postponement, advancement or other significant changes to the grid).

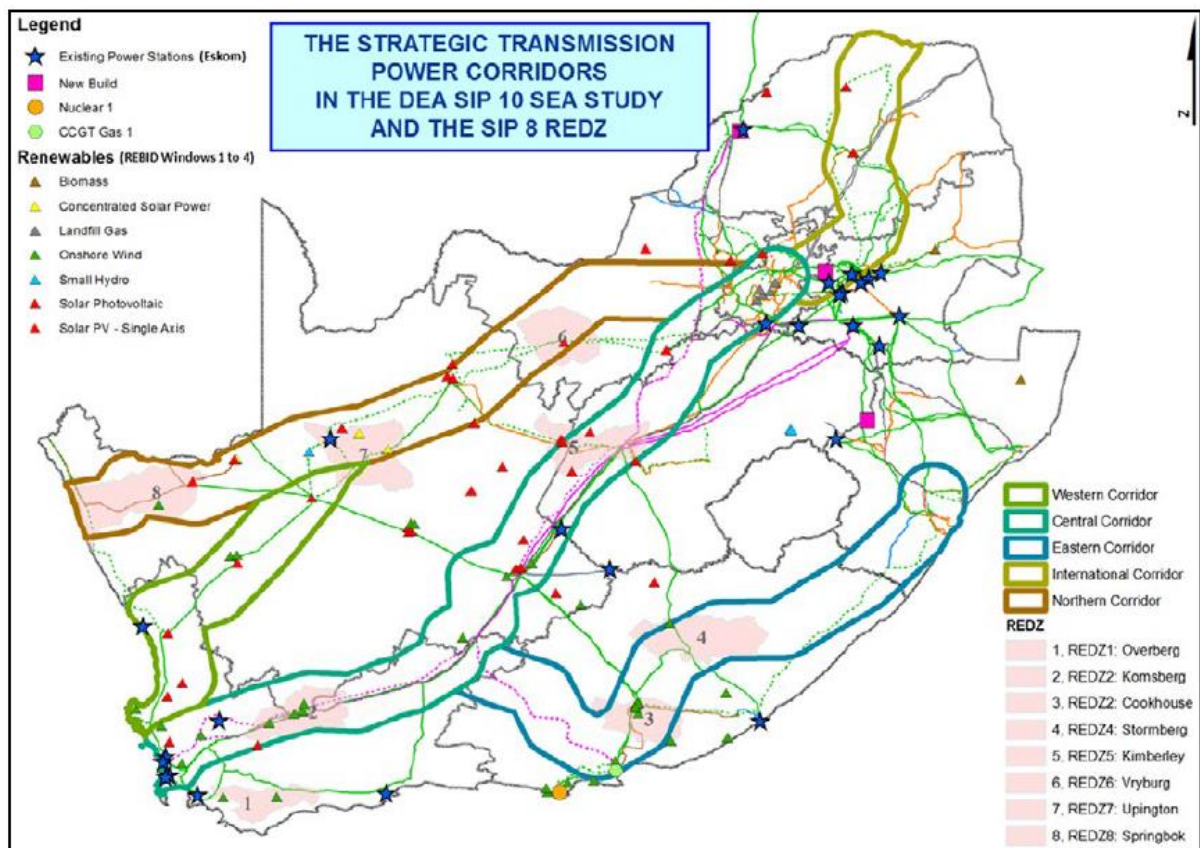
Planning criteria in use

The planning of the transmission system is understood to be based on the Grid Code for South Africa (available on the web page of the National Energy Regulator, NERSA; www.nersa.org.za). This Grid Code includes a Network Code (version 9, July 2014) describing least-cost economic criteria, reliability/contingency criteria and technical limits and targets for long-term planning as well as describing the planning process. The criteria are in line with – possibly somewhat more stringent than – the SAPP Transmission Planning Criteria.

Current development plan

The Renewable Energy Independent Power Producers Procurement Programme (REIPPPP) as well as the IPP coal programme and the IPP gas generation programme in South Africa has created challenges on how to integrate new generation on the transmission grid. Significant work has been carried out in order to develop strategies that provide a flexible and robust grid that can meet changing needs in the future. The 2040 Transmission Network Study referred to above, identified five main power corridors that would need to be developed under all the different generation scenarios considered. These are indicated in the following map.

Figure 90 Power Corridors in South Africa



Source: Eskom – Transmission System Development Plan 2016 – 2025

The 10 year transmission development plan covers the period 2016 – 2025, and consist of:

- approved projects;
- projects prepared for approval, and;
- projects likely to be taken for approval within the planning period.

The transmission development plan is naturally closely linked to the load forecast and the generation development plan. Of note in the context of the planning of the transmission system for the SAPP Pool Plan, is the assumptions on import of hydropower: 1 143 MW of imported hydropower in 2022 and a further 1 183 MW in 2023 – in total close to 2300 MW. The study is based on the assumption that the hydropower is from projects on the Zambezi River in Mozambique, and that the STE backbone transmission project in Mozambique (HVAC and HVDC lines from the Tete area to Maputo) will feed the power into the system in Southern Mozambique and specifically connect to the 400 kV MOTRACO system at Maputo substation. In view of current developments in Mozambique, implementing these projects by 2022/23 (generation and transmission facilities) may not be realistic.

The following tables summarise recently completed, ongoing and planned projects as presented in the Transmission System Development Plan from October 2015.

Figure 91 Recently completed projects - FY2014/2015 and 2015/16

PROVINCE	PROJECT NAME
Eastern Cape	Neptune-Vuyani 1st 400 kV line
	Vuyani (Mthatha) 400/132 kV substation (1st and 2nd 250 MVA transformers)
	Eros-Vuyani 1st 400 kV line
Free State	Merapi Ext. 3rd 250 MVA 275/132 kV transformer
Gauteng	Apollo-Pluto 400 kV loop-in-out Thuso
	Thuso 400/132 kV substation (1st and 2nd 250 MVA transformers)
Limpopo	Dinaledi-Spitskop 1st 400 kV line
	Dinaledi-Spitskop 2nd 400 kV line
	Medupi-Spitskop 1st 400 kV line
	Medupi-Marang 1st 400 kV
	Medupi 400/132 kV 2 x 250 MVA substation
Mpumalanga	Kusile 400 kV loop-in (Apollo-Kendal 1st 400 kV line)
Northern Cape	Mercury-Mookodi (Vryburg) 1st 400 kV line
	Ferrum Ext. 1st and 2nd 500 MVA 400/132 kV transformers
	Ferrum-Mookodi (Vryburg) 1st 400 kV line
Western Cape	Gamma Ext. 765 kV busbar establishment
	Kappa 400 kV loop-ins (Droërvier-Bacchus and Droërvier-Muldersvlei 400 kV lines)
	Kappa 765/400 kV substation
	Kappa Ext. 400 kV 100 MVar shunt reactor
	Gamma-Kappa 1st 765 kV line

Source: Eskom, 2016

Figure 92 Projects planned to be completed by 2015/16

PROVINCE	PROJECT NAME
Gauteng	Kookfontein Ext. 3rd 315 MVA 275/88 kV transformer and 3rd Glockner-Kookfontein 275 kV line
Mpumalanga	Vulcan 400 kV bypass and reconfiguration
	Gumeni 400/132 kV substation (1st 500 MVA 400/132 kV transformer)
	Hendrina-Gumeni 1st 400 kV line
Northern Cape	Kronos-Cuprum 1st and 2nd 132 kV
Western Cape	Kappa-Sterrekus (Omega) 1st 765 kV line
	Sterrekus (Omega) 400 kV loop-in (Koeberg-Muldersvlei 400 kV line)
	Sterrekus (Omega) 765/400 kV substation

Source: Eskom, 2016

The following transmission line projects at 400 kV and above are extracted from the provincial summaries provided in the Transmission Development Plan for 2016 – 2025 (400 kV lines initially energised at 275 kV are also included). Loop-in of existing 400 kV transmission lines to new substations are not included in this list. Furthermore, projects at lower voltage levels are considered to be largely independent of the generation scenarios to be evaluated as part of the SAPP Pool Plan (except for transmission lines specifically required to integrate generation plants). Similarly, many of the reactive power compensation plants are not included. A number of such facilities are planned in order to remove voltage constraints – which could be related both to local load levels and transfer levels across the extended transmission system. To the extent alterations to major reactive power compensation facilities will be required due to changes in imports, exports or wheeling as well as local generation in the different scenarios to be evaluated as part of the Pool Plan, the study sought to address such issues. The focus of such evaluations was on reactive power compensation requirements of the transmission corridors required to meet increased regional trade in SAPP.

Table 26 Projects of Gauteng Province

Scheme name	Project name	Expected year
Vaal Strengthening Phase 2	Glockner – Etna 1st and 2nd 400 kV line (operate at 275 kV)	2018
Soweto Strengthening	Etna – Quattro 1st and 2nd 400 kV lines (energised at 275 kV)	2020
West Rand Strengthening: Westgate 400 kV Integration	Hera – Westgate 1st 400 kV line	2021
Johannesburg East Strengthening: North Rand Integration	Construct a 15 km double-circuit 400 kV line (to be energised at 275 kV) from Apollo towards Esselen and bypass Esselen by connecting the double-circuit line to the Esselen-North Rand 1 and 2 275 kV lines to form 2 x Apollo-North Rand 275 kV lines North Rand – Sebenza 1st and 2nd 400 kV lines (to be energised at 275 kV)	2022
Johannesburg East Strengthening: Jupiter B Integration	Matla – Jupiter B 1st and 2nd 400 kV line (operated at 275 kV)	2022
Johannesburg North Strengthening: Craighall Integration	Craighall B/Donatello – Sebenza 1st 400 kV line (operated at 275 kV)	2024
West Rand Strengthening: Etna 400 kV Integration	Glockner – Etna 1st and 2nd 400 kV lines – operate at 400 kV	2024

Source: Eskom, 2016

Table 27 Projects of Kwazulu-Natal Province

Scheme name	Project name	Expected year
Greater East London Strengthening - Phase 1	Eros - Vuyani 1st 400 kV line Energised	2015
Ariadne - Venus 2nd 400 kV Line	Ariadne - Venus 2nd 400 kV line	2020
Ingula Pumped Storage Power Station Transmission Substation Integration	Ingula - Venus 2nd 400 kV line Loop-in Majuba - Venus 2 400 kV line into Ingula Substation	2015
KZN 765 kV Strengthening - Empangeni Integration	Mbewu 1 x 2000 MVA 765/400 kV Substation Loop-in Athene - Umfolozi 1 400 kV line & Invubu - Umfolozi 1 400 kV line into Mbewu Substation Umfolozi - Mbewu 765 kV line (extension of Majuba - Umfolozi 1 765 kV line) Invubu - Mbewu 2nd 400 kV line	2023
KZN 765 kV Strengthening - Lambda Substation	Lambda 2 x 2000 MVA 400/765 kV Substation Majuba - Lambda 1st 400 kV line Divert Tutuka - Majuba 400 kV line from Majuba Substation to Lambda Substation and form Tutuka - Lambda 1st 400 kV line	2023
KZN 765 kV Strengthening - Pinetown Integration	Isundu 1 x 2000 MVA 765/400 kV Substation Loop-in Ariadne - Hector 2 400 kV (de-energised) circuit into Isundu Substation 2025 Lambda-Isundu 1st 765 kV line	2025
KZN 765 kV Strengthening - Isundu - Mbewu 1st & 2nd 400 kV Lines	Isundu - Mbewu 1st & 2nd 400 kV lines	2026
eThekweni Electricity Network Strengthening	2 x Hector - Shongweni 1st and 2nd 400 kV lines	2024
South Coast Strengthening	Ariadne - Eros 2nd 400 kV line	2021
NKZN Strengthening Phase 1	Normandie - Candover 1st 400 kV line	2022
NKZN Strengthening Phase 2	Duma - Candover 1st 400 kV line	2026

Source: Eskom, 2016

Table 28 Projects of Limpopo Province

Scheme name	Project name	Expected year
Nzhelele 400 kV Integration	Tabor - Nzhelele 400 kV line 2021 Borutho - Nzhelele 1st 400 kV line	2021
Tubatse Strengthening Scheme Phase 1	Tubatse - Senakangwedi B 1st 400 kV line	2020
Highveld North-West and Lowveld North Reinforcement Phase 2	Emkhiweni (Rockdale B) - Silimela 400 kV line Tubatse 400 kV switching station Turn in Duvha - Leseding 400 kV line into Tubatse switching station Tubatse - Silimela (Marble Hall) 400 kV line	2019
	Borutho 400 kV loop-in (Matimba - Witkop 1st 400 kV line)	2015
Medupi Transmission Integration	Medupi - Borutho 1st 400 kV line Medupi - Borutho 2nd 400 kV line	2016
	Medupi - Ngwedi (Mogwase) 1st 400 kV line Medupi - Ngwedi (Mogwase) 1st 765 kV line (energised at 400 kV)	2017
Medupi Stability Integration at 400 kV	Borutho - Marble Hall 1st 400 kV line Medupi - Phokoje 1st 400 kV line Medupi - Witkop 1st 400 kV line Witkop - Senakangwedi B 1st 400 kV line Remote-end reactors	2022
Limpopo East Corridor Strengthening	Foskor-Spencer 1st 400 kV line (110 km) Merensky-Foskor 2nd 275 kV line change-over to 400 kV line	2022

Source: Eskom, 2016

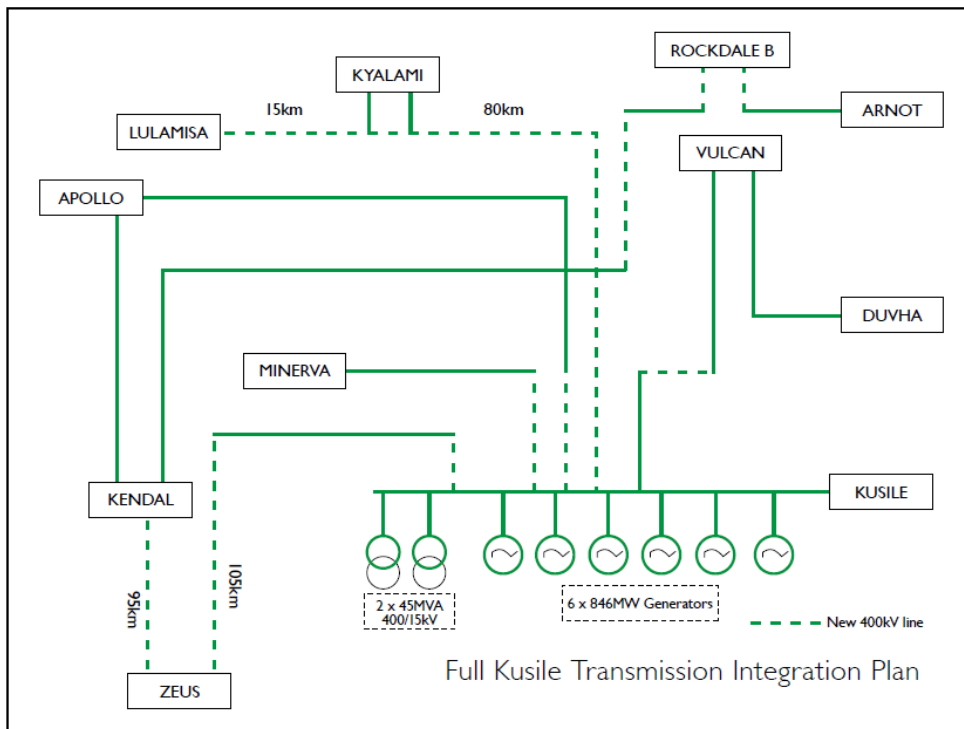
Note that the above plan for Medupi includes a 400 kV line from Medupi to Phokoje. This line is only considered as part of Component B and C in the Pool Plan as the Benchmark case in Component A per definition should not include new interconnections (exception for Nzhelele - Triangle and also initial development of Hwange - Livingstone on the ZIZABONA project and the extension of the 330 kV from Kasama in Zambia into Tanzania at Nakonde/Mbeya).

Table 29 Projects of Mpumalanga Province

Scheme name	Project name	Expected year
Kusile Integration Phase 2 Lulamisa	Kusile-Lulamisa 1st 400 kV line	2018
Kusile Integration Phase 3A 400 kV Duhva bypass	Kusile 400 kV bypass Duvha (to form Kusile - Vulcan 400 kV line)	2018
Kusile Integration Phase 3B 400 kV loop-in	Kusile 400 kV (Apollo-Kendal 1st 400 kV line)	2018
Kusile Integration Phase 4A	Kendal-Zeus 1st 400 kV line	2020
Kusile Integration Phase 4B	Kusile 400 kV bypass Kendal (Kendal bypass required to form the Kusile-Zeus 400 kV line from Kusile-Kendal and Kendal-Zeus lines)	2020
	Kendal-Zeus 2nd 400 kV line	2021
Lowveld Strengthening Phase 2B	Gumeni-Marathon 400 kV line	2023
Lowveld 400 kV Strengthening - Phase 3B	Gumeni-Marathon 2nd 400 kV line	2024
Malelane 275 kV Reinforcement - Phase 3	Khanyazwe (Malelane) - Marathon 400 kV line (operated as 2nd 275 kV line)	Customer dependent
Mpumalanga Underrated Equipment Upgrade Phase 3	Bypass Tutuka substation by interconnecting the Tutuka ends of the Majuba - Tutuka and Kendal - Tutuka 400 kV lines.	Not specified

Source: Eskom, 2016

Figure 93 Kusile Power Station Integration



Source: Eskom, 2016

Table 30 Projects of North West Province

Scheme name	Project name	Expected year
Watershed (Backbone) Strengthening Phase 3	Pluto – Mafikeng 400 kV line	2022
	Mookodi – Mafikeng 400 kV line	
Kimberley Strengthening Phase 3	Hermes – Mookodi (Vryburg) 1st 400 kV line	2020
Medupi Integration Phase 2A: Mogwase	Medupi – Ngwedi 1st 400 kV line	2016 to 2019
	Medupi – Ngwedi 1st 765 kV line (energised at 400 kV)	

Source: Eskom, 2016

Table 31 Projects of Free State Province

Scheme name	Project name	Expected year
Bloemfontein Strengthening Phase 1B	Everest – Merapi 400 kV line (operated at 275 kV)	2018
	2 x Beta – Harvard 400 kV lines	
Bloemfontein Strengthening Phase 2	Harvard – Merapi 400 kV line	2023
		2026

Source: Eskom, 2016

Table 32 Projects of Northern Cape Province

Scheme name	Project name	Expected year
Upington Strengthening Ph.1A	Nieuwehoop – Upington 1st 400 kV line	2018
Upington Strengthening Ph.1B	Aries – Upington 1st 400 kV line Aries – Upington 2nd 400 kV line	2023
Upington Strengthening Ph.1C	Ferrum – Upington 1st 400 kV line	2024
Kimberly Strengthening Ph.2	Ferrum – Mookodi 1st 400 kV line Mookodi – Mercury 1st 400 kV line	2015
Kimberley Strengthening Phase 3	Hermes – Mookodi 1st 400 kV line Mookodi – Umtu 1st 400 kV line Umtu – Ferrum 400 kV 1st 400 kV line	2019
Kimberley Strengthening Phase 4A	Beta – Ulco 1st 400 kV double-circuit line Ulco – Manganore 1st 400 kV double-circuit line Manganore – Ferrum 1st 400 kV double-circuit line	2023
Northern Cape Reinforcement	Aries 400 MVar SVC (Capacitive 250 MVar and Inductive 150 MVar)	2018
Namaqualand Strengthening	Juno – Gromis 400 kV line	2020
Northern Cape Reinforcement: Ferrum-Nieuwehoop-Aries 400 kV	Aries – Nieuwehoop 400 kV line Ferrum – Nieuwehoop 400 kV line	2016 2018

Source: Eskom, 2016

Table 33 Projects of Eastern Cape Province

Scheme name	Project name	Expected year
Greater East London Phase 3	Neptune – Pembroke 400 kV line	2019
Greater East London Phase 4	Poseidon – Pembroke 400 kV line	2023
Southern Grid Phase 3	1st Gamma – Grassridge 765 kV line	2024
Nuclear 1 Integration	Thyspunt Port Elizabeth SS Integration	2024
Southern Grid Phase 4	2nd Gamma – Grassridge 765 kV line	2027

Source: Eskom, 2016

Table 34 Projects of Western Cape Province

Scheme name	Project name	Expected year
Cape Corridor Phase 2: Gamma - Kappa - Sterrekus 765 kV Line	Gamma - Kappa 1st 765 kV line	Completed
	Kappa-Sterrekus 1st 765 kV line	2016
Muldersvlei SVC	Decommission Muldersvlei SVC	2016
Ankerlig-Sterrekus	Ankerlig-Sterrekus 1st and 2nd 400 kV lines	2019
PCB Phase-out Plan	Decommission Helios series capacitor	2019
Koeberg-Acacia	2nd Koeberg-Acacia 400 kV line	2020
Philippi Substation Extension	Philippi-Erica 400 kV line	2020
Agulhas Substation (Vryheid Transmission Substation)	Loop-in-and-out Bacchus-Proteus 400 kV line	2022
	Bypass Bacchus series capacitor bank	
Saldanha Bay Network Strengthening (Phase 1)	Construct 2 x 400 kV lines (operated at 132 kV) from Aurora substation to the new distribution Blouwater substation	2022
Narina Substation (Blanco Transmission Substation)	Loop-in-and-out Droërvier-Proteus 400 kV line	2021
	Relocate Proteus series capacitor bank to Narina	
PCB Phase-out Plan	Decommission Juno, Victoria and Hydra series capacitors	2022
Cape Corridor Phase 4	Zeus-Perseus 1st 765 kV line	2027
	Series compensation at Zeus and Perseus	
	Perseus-Gamma 2nd 765 kV line	
	Gamma-Kappa 2nd 765 kV line	
Droërvier-Narina-Gourikwa	Kappa-Sterrekus 2nd 765 kV line	2022
	Droërvier-Narina-Gourikwa 400 kV line	
Cape Corridor Phase 3	Series compensation on the 765 kV lines between Perseus and Kappa	Deferred
Cape Corridor Phase 5	3rd 765 kV line (West Coast alignment)	Strategic

Source: Eskom, 2016

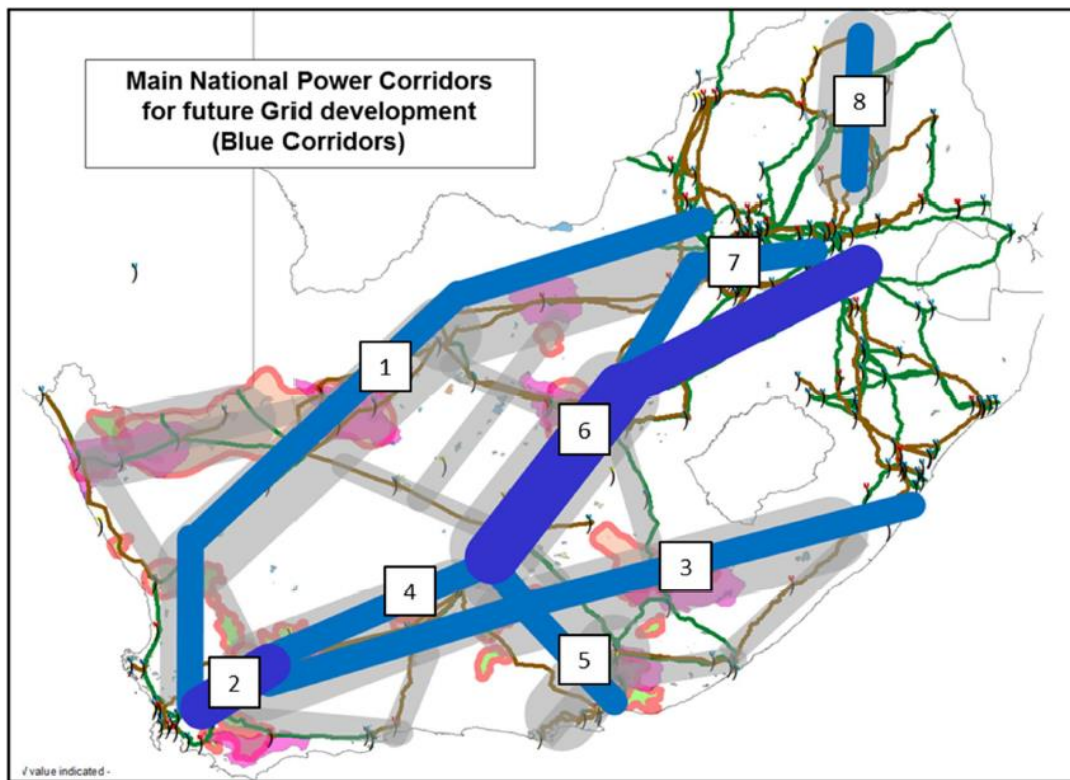
The Transmission Development Plan includes comments on the impact of a few optional generation scenarios. The study indicates that additional generation in the Northern Cape and Western Cape provinces may require significant additional investments or modifications to the transmission plans outlined above.

Towards 2040

The 2040 Transmission Network Study seeks to identify critical power corridors based on evaluation of a number of generation scenarios – including scenarios with significant imports (up to 10 000 MW in 2040). Impacts of substantial generation from renewables are also considered.

The study proposed eight main power corridors for future development as indicated on the following map.

Figure 94 Main power corridors for future development



Source: Eskom, 2016

Potential transfer capacities and transmission technology for the eight main power corridors are summarised in the following table.

Figure 95 Potential transfer capacities and transmission technology for the eight main power corridors

No.	Corridor	Power Transfer Capacity Range (MW)	Potential HV Transmission Technology
1	Western Coastal & Northern Solar Corridor	1,000 MW to 5,500 MW	Meshed 400kV lines for large Solar, Wind or Gas and possible HVDC if nuclear fleet committed
2	Main Cape South Corridor	1,000 MW to 4,000 MW	Combination of 400kV and 765kV with HVDC overlay if nuclear fleet committed
3	Eastern Coastal Corridor	2,3000 MW to 5,500 MW	Meshed 400kV lines and overlay of HVDC if nuclear fleet committed
4	Central Karoo Corridor	3,000 MW to 6,000 MW	Combination of 400kV and 765kV with HVDC overlay if nuclear fleet committed
5	Eastern Cape Corridor	1,000 MW to 3,000 MW	Combination of 400kV and 765kV
6	Main Cape Corridor	3,000 MW to 6,000 MW	Combination of 400kV and 765kV with HVDC overlay if nuclear fleet committed
7	North West Cape Corridor	3,000 MW to 6,000 MW	Combination of 400kV and 765kV with HVDC overlay if nuclear fleet committed
8	Northern Import Corridor	5,000 MW to 7,000 MW	Meshed 400kV with potential of 500kV to borders as well as possible HVDC for direct imports

Source: Eskom, 2016

Update on current development plan – Information extracted from PSS/E

The plan reflected above has been undergoing further studies. In the following, we have highlighted the expansion plan in border areas in the west, north and east of the grid in South Africa – i.e. the parts of the grid that likely will see the biggest impact of increased trade within SAPP. The information is extracted from the PSS/E files provided by Eskom in November/December 2016. The in-service year may therefore differ from the information above extracted from the development plan presented in October 2015. The PSS/E files are understood to reflect the most up-to-date information.

WESTERN areas towards Namibia

Year:	Project:			
2017	400 kV	Aries	Niuwehoop	
			400 kV substation at Niuwehoop	
	400 kV	Niuwehoop	Upington	
			400/132 kV substation at Upington	
2019	400 kV	Ferrum	Niuwehoop	
2021	400 kV	Juno	Gromis	
			400/220 kV substation at Gromis	
	400 kV	Mookodi	Hotazel	
	400 kV	Ferrum	Hotazel	
			400/132 kV substations at Hotazel	
2022	400 kV	Aries	Upington	
2023	400 kV	Aries	Upington	circuit 2
	400 kV	Ferrum	Upington	

NORTHERN areas towards Botswana and Zimbabwe

The following projects are understood to be part of the ongoing system expansion for integration of the new large coal fired power plants in South Africa. The projects are as such seen to be part of committed projects to facilitate power evacuation not least from the Medupi project.

Year:	Project:			
2018	400 kV	Medupi	Ngwedi	Circuit 1
	400 kV	Medupi	Ngwedi	Circuit 2
2020	400 kV	Senakangwedi substation – tie-in on Arnot – Merensky		
	400 kV	Tubat substation – tie-in on Duvha – Leseding		

	400 kV	Tubat	Senakangwedi	
	400 kV	Tubat	Silimela	
2021	400 kV	Masa	Medupi	Circuit 1
	400 kV	Masa	Medupi	Circuit 2
	400 kV	Wildebees substation – tie-in on Apollo – Dinaledi		
2022	400 kV	Emkhiweni substation – tie-in on Arnot – Kendal		
	400 kV	Borutho	Silimela	
	400 kV	Silimela	Emkhiweni	
2023	400 kV substation at Nzhelele			
	400 kV	Borutho	Nzhelele	
	400 kV	Tabor	Nzhelele	
2025	400 kV	Phoebus substation – tie-in on Apollo/Wildebees – Dinaledi		
2026	400 kV	Masa	Witkop	

It is noted that the above plan as extracted from Eskom's PSS/E files indicate that the 400 kV substation at Nzhelele is planned for 2023. In line with the decision made at the PSC meeting in Johannesburg in December 2016, the interconnection between Triangle in Zimbabwe and Nzhelele should be included among committed project to be implemented within 3-4 years. In the Pool Plan, it is therefore assumed that the substation at Nzhelele including the 400 kV lines to Borutho and Tabor are in service no later than 1 January 2021 – i.e. at the same time as the interconnector between the two countries.

We note that the PSS/E files do not include any 400 kV link to Watershed, but understand that a possible future interconnection from the Isang substation in Botswana to Watershed may include 400 kV connections to for instance Mookodi and Pluto. Such reinforcement of the grid may be part of Component B and C in the Pool Plan, but based on the latest information from Eskom, the internal 220 kV system is understood not to require such support in the short to medium term.

EASTERN Areas towards Swaziland and Mozambique

The following projects are understood to be part plans to reinforce the grid towards the border with Mozambique:

Year:	Project:			
2022	400 kV	Arnot	Gumeni	
2023	400 kV	Gumeni	Marathon	
	400/275 kV substation at Marathon			

It is also noted that the PSS/E files received from Eskom includes assumptions on power exchange with the southern part of Mozambique. The power flow across the MOTRACO

system is ~1100 MW in the 2024 case file (representing wheeling of power for EdM from Songo via Apollo to Southern Mozambique and power export from South Africa to MOZAL). This level is reduced to half this value in 2025, and close to zero in 2026. This is understood to represent the implementation of the STE backbone grid project in Mozambique (with the STE grid supporting both gas fired generation in the Vilanculos area as well as hydropower and coal fired generation in the Tete Province). Power flow on the HVDC Songo – Apollo is maintained at the same level in all these cases (~1200 MW).

Whether this change in power flow across the MOTRACO system interconnecting South Africa and Mozambique is seen to represent Eskom importing power from Mozambique or Mozambique taking over the supply contract for MOZAL, the impact on the grid is the same: The grid in the east towards Mozambique will become more lightly loaded at this stage if such grid developments in Mozambique takes place.

Availability of transmission system models

Originally, Eskom provided load flow cases for each year up to and including year 2025 in PSS/E format. Towards the end of 2016, updated case files covering the period up to 2016 were received. The studies in this Pool Plan are based on the latest submission. However, a corresponding model with dynamic data for stability studies was only provided shortly prior to the dissemination workshop in June 2017. This came too late as stability studies had to be covered earlier on to firm up parts of the study on the interconnections. As dynamic models for (most of the) existing plants were available in the PSS/E model provided by SAPP CC, generic data were used for plants not documented in any of the models received. The lack of data is not seen as critical for the planning of the regional interconnectors that are the main focus of the preparation of the SAPP Pool Plan.

The SAPP technical team did not have access to models used for the 2040 Transmission Network Study.

Transmission expansion plan for the Benchmark Case

The development of the transmission grid in the border areas as described above, is seen to provide adequate capacity for load growth in these areas. No further strengthening of the grid is therefore seen as required to support load growth. Neither is the generation expansion plan towards 2040 seen to require reinforcement in these areas. The diagrams on the next few pages illustrate the peak load condition in these areas as at peak demand by stage 2030.

Figure 96 Peak load condition 2030 (1)

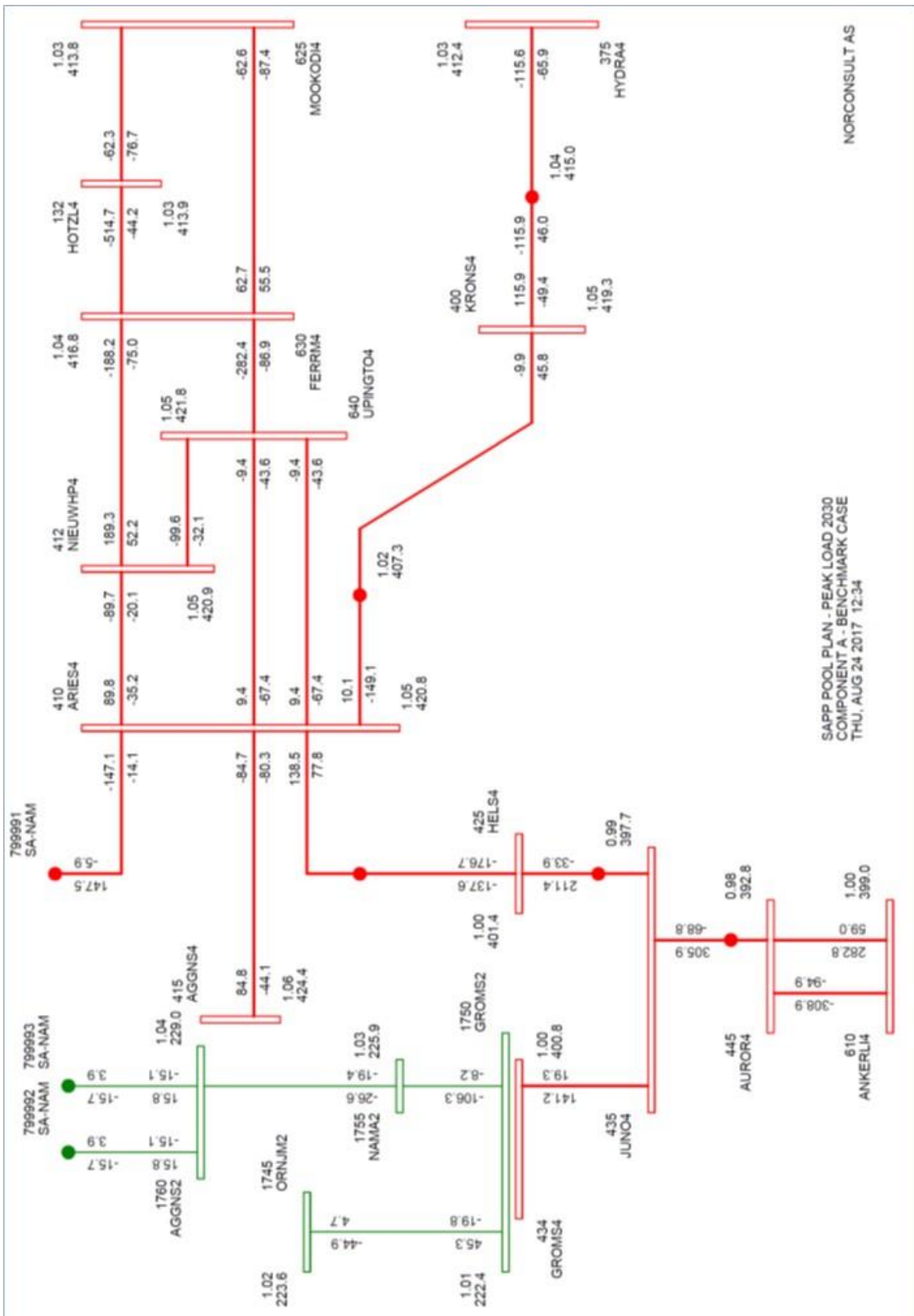
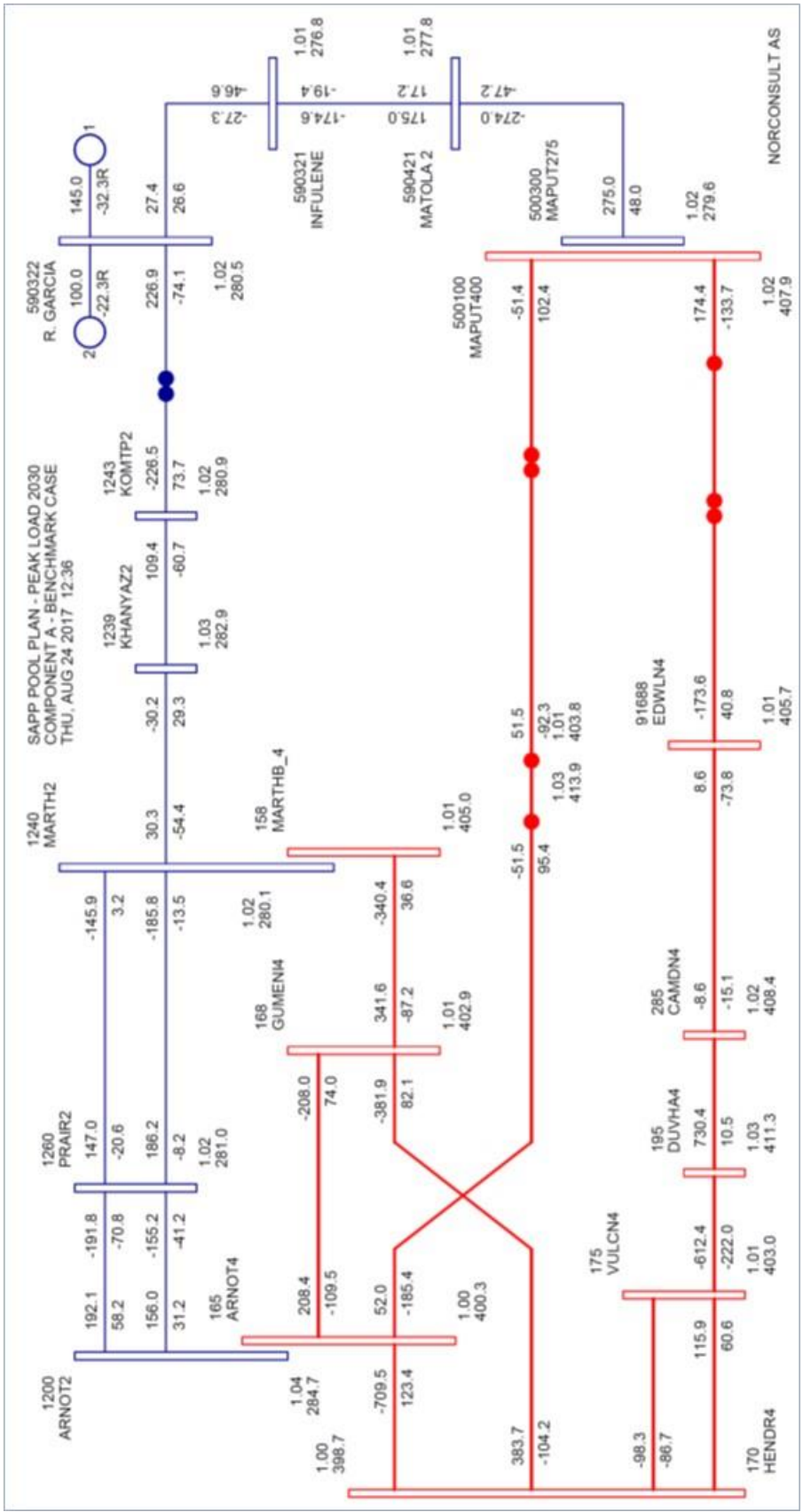


Figure 98 Peak load condition 2030 (3)



The following table summarises the transmission system expansion plan for relevant border areas in South Africa in the Benchmark Case.

Figure 99 Transmission system expansion plan in South Africa

TRANSMISSION PROJECTS										
Voltage [kV]	Substation		Distance [km]	Conductor type	Circuits	Tower type		In service by year		
	From	To						Comp A	Comp B	Comp C
Western area towards Namibia										
400	Aries	Niuwehoop	90		1	Cross Rope	SgCkt	2017		
400	Niuwehoop	Upington	70		1	Cross Rope	SgCkt	2017		
400	Ferrum	Niuwehoop	239		1	Cross Rope	SgCkt	2019		
400	Juno	Gromis	260		1	Cross Rope	SgCkt	2021		
400	Mookodi	Hotazel	237		1	Cross Rope	SgCkt	2021		
400	Ferrum	Hotazel	53		1	Cross Rope	SgCkt	2021		
400	Aries	Upington	145		1	Cross Rope	SgCkt	2022		
400	Aries - ckt. 2	Upington - ckt. 2	145		1	Cross Rope	SgCkt	2023		
400	Ferrum	Upington	225		1	Cross Rope	SgCkt	2023		
Northern area towards Botswana and Zimbabwe										
400	Medupi - ckt. 1	Ngwedi - ckt. 2	200		1	Cross Rope	SgCkt	2018		
400	Medupi - ckt. 2	Ngwedi - ckt. 2	200		1	Cross Rope	SgCkt	2018		
400	Tubat	Senakangwedi	60		1	Cross Rope	SgCkt	2020		
400	Tubat	Silimela	50		1	Cross Rope	SgCkt	2020		
400	Masa - ckt. 1	Medupi - ckt. 2	20		1	Cross Rope	SgCkt	2021		
400	Masa - ckt. 2	Medupi - ckt. 2	20		1	Cross Rope	SgCkt	2021		
400	Borutho	Silimela	100		1	Cross Rope	SgCkt	2022		
400	Simimela	Emkhiweni	80		1	Cross Rope	SgCkt	2022		
400	Borutho	Nzhelele	250		1	Cross Rope	SgCkt	2021		
400	Tabor	Nzhelele	170		1	Cross Rope	SgCkt	2021		
400	Nzhelele	Triangle (to border)	60	3 x Tern	1	Cross Rope	SgCkt	2021		
400	Masa	Witkop	220		1	Cross Rope	SgCkt	2026		
Eastern area towards Swaziland and Mozambique										
400	Arnot	Gumeni	55		1	Cross Rope	SgCkt	2022		
400	Gumeni	Marathon	92		1	Cross Rope	SgCkt	2023		

See evaluation in Component B and C

Full comparisons between Component A and the scenarios based on further regional integration – Components B and C – are presented in Section 7.8.

6.9 Swaziland

Relevant documents

SEC has provided access to the recent Master Plan for Swaziland:

- ❑ Network Master Plan, Volume 1: Executive Summary (Rev. 2, September 2015), Volume 2: Transmission Network (Rev. 2, August 2015), Volume 4 Audit and Refurbishment (Rev. 2, August 2015), MEGAR Engineering

The report lists numerous projects required to reinforce and expand the 66 kV and 132 kV networks divided into projects on:

- ❑ Short term 2014 – 2020
- ❑ Medium term 2021 – 2027
- ❑ Long term 2028 – 2034

An outlook for the 132 kV backbone after 2034 is also given.

The grid development plan presented in the Master Plan is based on the development of two major generation projects in the short term:

- ❑ Ngwempisi hydro – 120 MW – by 2017
- ❑ Lubhuku coal – 300 MW – by 2018

However, according to information provided by SEC in March 2017, both these projects have been deferred from short term to medium term projects and should be treated as candidates rather than committed projects.

Some smaller renewable projects are foreseen as well, and the Master Plan study indicates that long term requirements may be supported by use of natural gas.

Planning criteria in use

The transmission planning carried out as part of the recent Master Plan has been based on deterministic N-1 planning criteria. In general, thermal rating of equipment shall not be exceeded – whether in normal operation (network intact – all elements in service) or following single contingencies. Furthermore, steady state voltages shall typically remain within 95-105 % of nominal in normal operation while the voltage may drop to 90% during contingencies before control actions.

Specific security of supply criteria are applied by substation depending on substation load category (domestic, commercial, agricultural etc.).

Maximum step change in voltage due to switching operations are also defined – 3 % under healthy conditions and 5 % under contingency conditions.

In general, the planning criteria are in line with the SAPP planning criteria.

Current development plan

As the Master Plan was completed only recently, it is assumed that SEC's current development plan will follow the proposals made in this plan (no other information on ongoing projects or short-term investment plans have been provided). As mentioned, the Master Plan outlines numerous projects on 66 kV and 132 kV to support further growth in Swaziland.

In the context of scenarios for inter-utility trade being considered in the SAPP Pool Plan, it is primarily the development plans for the use of the 400 kV that runs through Swaziland from South Africa to Mozambique that is of interest. This line feeds the Edwaleni II substation and accounts for more than 70 % of the power demand in Swaziland at the time being. The country will naturally be highly dependent on this infeed also in the future, but if internal generation projects are realised, the import to Swaziland via this line may drop and this impacts on the regional transfer capacity on the MOTRACO system. Swaziland may also import power from South Africa via the Nhlanguano II substation.

Although the Master Plan mentions the possibility of adding a second 400/132 kV infeed either in the Mankayane area or in the KaLanga area – both options fed from the same 400 kV line between Camden in South Africa and Maputo in Mozambique – current SEC planning as informed in March 2017 is aiming at increasing domestic generation and a second 400/132 kV substation has been put on hold.

The grid development plan recommended in the Master Plan includes:

- ❑ 52 km, 132 kV double circuit line Edwaleni II – Stonehenge - by 2017
(only one circuit strung initially)
- ❑ 48 km, 132 kV line Sithobela II – Encandweni - by 2018
- ❑ A number of new 132/66 kV substation
(some requiring minor short extensions on 132 kV and/or 66 kV
to turn in existing lines to the new substations)
- ❑ A number of upgrades and extensions at 66 kV
- ❑ 17 km, 132 kV double circuit line Edwaleni II – Mnkinkomo - by 2029
(2nd line to improve reliability)
- ❑ Third 250 MVA, 400/132 kV transformer at Edwaleni II - by 2030

In March 2017, SEC informed that the two projects planned for 2017 and 2018 are on hold pending funding.

Availability of transmission system models

SEC has provided a PSS/E file for peak load for stage 2018. The file covers only load flow models for the system. Files for future stages in line with the planned developments as reflected in the Master Plan and data for dynamic modelling of the system have not been



made available. It is primarily the 400 kV line connecting Swaziland to South Africa and Mozambique that is of interest as regards future regional trade. A second substation to further integrate the system in Swaziland with the rest of the SAPP system may be required to meet local load growth and increase the reliability of supply. Overall, developments in Mozambique – particularly the possibility of developing large power generation projects based on hydropower, gas and coal resources in Mozambique – may be seen to have a bigger impact on the utilisation of the 400 kV line running through Swaziland than the load/generation balance in Swaziland itself.

Benchmark Case Developments

The peak demand in Swaziland is expected to increase from about 250 MW in 2017 to 420 MW by 2040. The grid development plan outlined above is considered adequate to support such growth. With some new local power plants as identified in the generation expansion plan, the energy imports are expected to remain more or less at current levels. The 400/132 kV in-feed at Edwaleni should therefore provide adequate capacity for trade on the SAPP system. Regional grid expansion plans in Components B and C are therefore not foreseen to impact on grid developments in Swaziland.

6.10 Tanzania

Relevant documents

The following documents have been provided for the Pool Plan study:

- ❑ Power System Master Plan 2012 Update, Ministry of Energy and Minerals, United Republic of Tanzania, May 2013
- ❑ Power System Master Plan – 2016 Update, Ministry of Energy and Minerals, December 2016

Both documents present very ambitious plans. Current status of the projects proposed for early implementation are uncertain, and it seems clear that implementation of the plans has been delayed and will take time. For the purpose of the Pool Plan, the transmission analyses is therefore proposed to focus on the system in the border areas towards Zambia, Malawi and Mozambique.

Furthermore, TANESCO has provided PSS/E files for stage 2015 and 2020. The file for stage 2020 represents an unrealistic extension of the transmission system by year 2020, with about 4500 km of new 400 kV lines being added over the next few years. The load flow file for stage 2020 is therefore understood to represent something closer to a possible target transmission system, but is not in line with the recent Master Plan presented in 2016.

Added to this, the information in the Master Plans and in the PSS/E file for 2020 is describing fairly different development scenarios. In view of the very high load growth expected on the system, it is naturally difficult to foresee how the system will grow, and the expansion of the grid will be highly dependent on the development of the generation system.

For the development of the SAPP Pool Plan, it is the load/generation balance and the possible realisation of the Tanzania-Zambia interconnector (and the possible reinforcement of this link) that will be of key interest. Further assessment of the system in Tanzania will attempt to shed light on possible scenarios for this part of the grid as internal grid developments will likely be determined first and foremost by developments in Tanzania itself rather than power trade with neighbours.

Planning criteria in use

Deterministic N-1 planning criteria have been used in the preparation of the Power System Master Plans. The criteria allow for short-time overload of transmission lines. Otherwise, the criteria are in line with the SAPP Pool Plan criteria for transmission planning.

It should be noted that several areas in Tanzania are supplied via radial transmission lines, these parts of the network obviously do not meet the N-1 criterion. Reinforcing the supply to provide reserves would only become economical once the load is considerably higher than at the time being. The future back-bone, and once interconnected to Kenya and Zambia, should meet the N-1 criterion in order to avoid wide-spread black-outs following separation, voltage collapse or transient instability.

Current development plan

As stated above, detailed information on the current status of the transmission grid development plan required to arrive at the National Benchmark Case is not available. The plan for development of a 400 kV backbone system and the interconnections to Kenya and Zambia (and possibly also Malawi and Mozambique) are of particular interest to the development of the SAPP Pool Plan. The backbone would also be important in linking the areas around Dar es Salaam – which has both significant generation and a high load – and the hydropower plants and future renewable plants in central areas, and the load centres in the north and towards Arusha.

We are also aware of the potential for renewable power plants – including solar and wind – that are at an advanced planning stage in Tanzania. These projects are located close to or will likely be integrated on the backbone grid creating a north-south link in Tanzania.

Further development of the transmission system in Tanzania is partly linked to development of the generation system and partly foreseen to be required to extend the electricity supply to off-grid areas.

Currently, the power system in Tanzania consists of 220, 132 and 66 kV voltage levels. The first part of the Backbone Project, i.e. a double circuit 400 kV transmission line between Iringa and Shinyanga, was commissioned in 2016. All new 400 kV lines proposed for development by 2020 as described in the recent Power System Master Plan are listed in the tables below and a map indicating main grid developments by 2040 is included as well.

The PSS/E model provided by TANESCO does not include many of these projects, and is not a suitable starting point for creating a valid model for Tanzania in line with the plan presented in the Master Plan. As indicated above, the important issue in the context of the preparation of the SAPP Pool Plan seems to be the plans for interconnection between Tanzania and Zambia, and possibly Tanzania and Malawi as well as Tanzania and Mozambique at a later stage.

Figure 100 Proposed 400 kV Transmission Lines added by Stage 2020

Rated Voltage (kV)	from	to	Remarks	Route Length (km)	No. of Circuit	Conductor			Year to be Commissioned	Current Rating ¹ (Amps)	Full Rating (MVA)	Normal Rating ² (MVA)
						Code Name	No. of Cond. per Phase	Aluminum Sectional Area (mm ²)				
400	Dodoma	Singida	Backbone Project	210	2	Bluejay	2	564	2016	1,092	3,026	2,421
400	Iringa	Dodoma	Backbone Project	237	2	Bluejay	2	564	2016	1,092	3,026	2,421
400	Singida	Shinyanga	Backbone Project	200	2	Bluejay	2	564	2016	1,092	3,026	2,421
220	Kinyerezi	Ubungo-Pai	Jacobson	8	1	Bluejay	2	564	2016	1,092	832	666
220	Ubungo-Pai	Kinyerezi	Jacobson	8	1	Bluejay	2	564	2016	1,092	832	666
132	Kinyerezi	FZ-II		5	1	Wolf	1	150	2016	406	93	74
132	Morogoro	Mibwa	MCC. F/S completed	88	1	Hawk	1	242	2016	659	151	121
220	Wind Project	Singida		10	1	Bluejay	2	564	2017	1,092	832	666
400	Kin-Som SwS1	Kin-Som SwS2		53	2	Bluejay	8	564	2018	1,092	12,105	9,684
400	Kin-Som SwS2	Kin-Som SwS3		53	2	Bluejay	8	564	2018	1,092	12,105	9,684
400	Kin-Som SwS3	Somanga Fungu P/S	210 MW	53	2	Bluejay	8	564	2018	1,092	12,105	9,684
400	Kinyerezi	Kin-Som SwS1		53	2	Bluejay	8	564	2018	1,092	12,105	9,684
400	Kisada	Iringa		106	2	Bluejay	8	564	2018	1,092	12,105	9,684
400	Kisada	Madaba		243	2	Bluejay	8	564	2018	1,092	12,105	9,684
400	Muchuchuma P/S	Madaba	Total 1,800 MW	15	2	Bluejay	4	564	2018	1,092	6,052	4,842
220	Geita	Nyakanazi		130	2	Bluejay	2	564	2018	1,092	1,664	1,332
220	Madaba	Songea		171	1	Bluejay	2	564	2018	1,092	832	666
220	Makambako	Madaba		162	1	Bluejay	2	564	2018	1,092	832	666
220	Nyakanazi	Rusumo Falls P/S	30 MW	97	1	Bluejay	4	564	2018	1,092	1,664	1,332
220	Rusumo Falls P/S	Kyaka	30 MW	150	1	Bluejay	4	564	2018	1,092	1,664	1,332
220	Shinyanga	Geita		240	2	Bluejay	4	564	2018	1,092	3,329	2,663
400	Arusha	Singida		317	2	Bluejay	2	564	2019	1,092	3,026	2,421
400	Arusha	Isinya (Kenya)	up to Kenya border	114	2	Flint	3	375	2019	790	3,284	2,627
400	Lindi	Somanga Fungu		216	2	Bluejay	8	564	2019	1,092	12,105	9,684
400	Mwara P/S	Lindi	400 MW	74	2	Bluejay	4	564	2019	1,092	6,052	4,842
220	Arusha	Niro (Arusha existing)		5	2	Bluejay	4	564	2019	1,092	3,329	2,663
220	Iringa	Lower Kihansi PS (Hydro)	(36+52+120) MW	120	1	Bluejay	2	564	2019	1,092	832	666
220	Solar I	Dodoma	50 MW	10	1	Bluejay	1	242	2019	1,092	416	333
132	Wind Project	Makambako	100 MW	10	1	Hawk	1	242	2019	659	151	121
400	Chalinze	Segera		175	1	Bluejay	4	564	2020	1,092	3,026	2,421
400	Chalinze	Dodoma		336	1	Bluejay	2	564	2020	1,092	1,513	1,210
400	Chalinze	Segera		175	1	Bluejay	4	564	2020	1,092	3,026	2,421
400	Kigoma	Mbanda		290	2	Bluejay	8	564	2020	1,092	12,105	9,684
400	Kinyerezi	Chalinze		138	2	Bluejay	4	564	2020	1,092	6,052	4,842
400	Kisada	Mbeya		186	2	Bluejay	8	564	2020	1,092	12,105	9,684
400	Kiwira P/S	Mbeya	400MW in 2020	110	2	Bluejay	8	564	2020	1,092	12,105	9,684
400	Mbea	Nakonde(Zambia)	up to Zambia border	93	2	Bluejay	2	564	2020	1,092	3,026	2,421
400	Mbe - Sum SwS	Sumbawanga		150	2	Bluejay	8	564	2020	1,092	12,105	9,684
400	Mbeya	Mbe - Sum SwS		150	2	Bluejay	8	564	2020	1,092	12,105	9,684
400	Mbanda	Mpa-Sum SwS		119	2	Bluejay	8	564	2020	1,092	12,105	9,684
400	Mpa-Sum SwS	Sumbawanga		119	2	Bluejay	8	564	2020	1,092	12,105	9,684
400	Mwara	Namialo(Mozambique)	up to Mozambique border	51	2	Bluejay	2	564	2020	1,092	3,026	2,421
400	Nyakanazi	Kigoma		317	2	Bluejay	8	564	2020	1,092	12,105	9,684
400	Segera	Arusha		366	1	Bluejay	4	564	2020	1,092	3,026	2,421
400	Somanga Fungu P/S	Somanga P/S(PPP)	300MW	20	2	Bluejay	2	564	2020	1,092	3,026	2,421
220	Bagamoyo (Zinga)	Kibaha-Pai		45	1	Bluejay	1	564	2020	1,092	416	333
220	Bunda	Musona		60	1	Bluejay	4	564	2020	1,092	1,664	1,332
220	Kibaha-Pai	Bagamoyo (Zinga)		45	1	Bluejay	1	564	2020	1,092	416	333
220	Kinyerezi	Ubungo		12	2	Bluejay	1	564	2020	1,092	832	666
220	Kishapu Solar	Shinyanga	150 MW	10	1	Bluejay	1	382	2020	1,092	416	333
220	Kyaka	Masaka(Uganda)	up to Uganda border	30	1	Bluejay	2	564	2020	1,092	832	666
220	Kyela	Karonga(Malawi)	up to Malawi border	20	1	Bluejay	2	564	2020	1,092	832	666
220	Lusu	Tabora		139	1	Bluejay	2	564	2020	1,092	832	666
220	Mbeya	Kyela		106	1	Bluejay	2	564	2020	1,092	832	666
220	Musona	Nyamongo		90	1	Bluejay	4	564	2020	1,092	1,664	1,332
220	Mwanza	Bunda		150	1	Bluejay	4	564	2020	1,092	1,664	1,332
220	Segera	Tanga		76	2	Bluejay	2	564	2020	1,092	1,664	1,332
220	Shinyanga	Lusu		64	1	Bluejay	1	564	2020	1,092	416	333
132	Kinyerezi	FZ-II		5	2	Hawk	2	242	2020	659	603	482
132	Morogoro	Mibwa		88	1	Hawk	1	242	2020	659	151	121
66	Babati	Mbulu		85	2	Wolf	2	150	2020	406	186	149

Source: Power System Master Plan, 2016

Figure 101 Proposed 400 kV Transmission Lines added by Stage 2025

Rated Voltage (kV)	from	to	Remarks	Route Length (km)	No. of Circuit	Conductor			Year to be Commissioned	Current Rating ¹ (Amps)	Full Rating (MVA)	Normal Rating ² (MVA)
						Code Name	No. of Cond. per Phase	Aluminum Sectional Area (mm ²)				
400	Kinyerezi	Mkuranga P/S	300 MW	70	2	Bluejay	8	564	2022	1,092	12,105	9,684
400	Madaba	Songea		171	2	Bluejay	2	564	2023	1,092	3,026	2,421
400	Masasi	Lindi		141	2	Bluejay	4	564	2023	1,092	6,052	4,842
400	Ngaka P/S	Songea	600MW in 2023	37	2	Bluejay	4	564	2023	1,092	6,052	4,842
400	Songea	Tunduru		230	2	Bluejay	4	564	2023	1,092	6,052	4,842
400	Tunduru	Masasi		194	2	Bluejay	4	564	2023	1,092	6,052	4,842
400	Sumbawanga	Rukwa P/S	300MW in 2024	46	2	Bluejay	8	564	2024	1,092	12,105	9,684
132	Malagarasi P/S(Stage III)	Kigoma	44.7 MW	74	1	Hawk	1	242	2024	659	151	121
400	Chalinze	Bagamoyo		102	2	Bluejay	8	564	2025	1,092	12,105	9,684
400	Shinyanga	Mwanza		140	2	Bluejay	8	564	2025	1,092	12,105	9,684
220	Bagamoyo	North DSM		40	2	Bluejay	4	564	2025	1,092	3,329	2,663
220	Geothermal 1	Mbeya	(2 x 50 MW) x2	35	1	Bluejay	1	564	2025	1,092	416	333
220	Kinyerezi	South DSM		25	2	Bluejay	4	564	2025	1,092	3,329	2,663
220	Mkuranga	South-east DSM		50	2	Bluejay	4	564	2025	1,092	3,329	2,663
220	South DSM	South-east DSM		30	2	Bluejay	2	564	2025	1,092	1,664	1,332
132	Kyaka	Kibeta/Bukoba		54	1	Hawk	2	242	2025	659	301	241
66	Mbulu	Karatu		65	2	Wolf	2	150	2025	406	186	149

Source: Power System Master Plan, 2016

Figure 102 Proposed 400 kV Transmission Lines added by Stage 2030

Rated Voltage (kV)	from	to	Remarks	Route Length (km)	No. of Circuit	Conductor			Year to be Commissioned	Current Rating ¹ (Amps)	Full Rating (MVA)	Normal Rating ² (MVA)
						Code Name	No. of Cond. per Phase	Aluminum Sectional Area (mm ²)				
220	Geothermal 1	Geothermal 2	2 x 50 MW	20	1	Bluejay	1	564	2026	1,092	416	333
220	Ibosa P/S (Hydro)	Inga-L. Kihansi T branch	(36+52+120) MW	20	2	Bluejay	2	564	2026	1,092	1,664	1,332
220	Ibosa P/S (Hydro)	Nginayo P/S (Hydro)	52MW	10	1	Bluejay	1	564	2026	1,092	416	333
220	Zinga P/S	Bagamoyo	200 MW	15	1	Bluejay	2	564	2027	1,092	832	666
132	Kakono P/S (Hydro)	Kyaka	87 MW	39	1	Hawk	1	242	2027	659	151	121
400	Mnyera S/S (new)	Kisada	(668.2+358) MW	180	2	Bluejay	4	564	2028	1,092	6,052	4,842
220	Ruahā 2 P/S (Hydro)	Mnyera S/S (new)	(60.3+137.4+143.9) MW	33	1	Bluejay	2	564	2028	1,092	832	666
132	Songwe B S/S	Kyela	(79.5 + 88.1) MW	7	2	Hawk	1	242	2028	659	301	241
132	Songwe Mandolo P/S (Hydro)	Songwe B S/S	88.1 MW	17	1	Hawk	1	242	2028	659	151	121
220	Kwanini P/S (Hydro)	Mnyera S/S-Ruahā2 T/L	T-branch	10	1	Bluejay	2	564	2029	1,092	832	666
220	Mnyera 2 P/S (Hydro)	Mnyera S/S-Ruahā2 T/L	T-branch	10	1	Bluejay	2	564	2029	1,092	832	666
400	Shinyanga	Tabora		200	2	Bluejay	8	564	2030	1,092	12,105	9,684
400	Somanga Fungu S/S	Future CGT3-1	4x470 MW	20	2	Bluejay	4	564	2030	1,092	6,052	4,842
400	Tab-Mpa SwS	Mpanda		150	2	Bluejay	8	564	2030	1,092	12,105	9,684
400	Tabora	Tab-Mpa SwS		150	2	Bluejay	8	564	2030	1,092	12,105	9,684
220	Bagamoyo	Mlandizi		40	2	Bluejay	1	564	2030	1,092	832	666
220	Kinyerezi	West DSM		20	2	Bluejay	4	564	2030	1,092	3,329	2,663
220	Mnyera S/S (new)	Taveta 3 P/S (Hydro)	(119.8+83.9+122.9) MW	26	1	Bluejay	2	564	2030	1,092	832	666
220	Pumbwe P/S (Hydro)	Mnyera S/S-Taveta3 T/L	T-branch	10	1	Bluejay	2	564	2030	1,092	832	666
220	West DSM	North DSM		20	2	Bluejay	2	564	2030	1,092	1,664	1,332
132	Njiru (Arusha existing)	Kiyungi	T-branch to KIA	77	2	Hawk	4	242	2030	659	1,205	964

Source: Power System Master Plan, 2016

As indicated above, the key issue for the Pool Plan will be developments towards the border areas with Zambia, Malawi and Mozambique. The recent Power System Master Plan indicates that 400 kV double circuit lines shall be extended up to Mbeya close to the border to Zambia and Malawi by 2020 and also to Lindi close to Mozambique by the same stage. Lindi would be located relatively close to power plants in Tanzania and could therefore possibly provide significant capacity or power export. Export from Mbeya could be more limited unless local power plants are developed. The Master Plan seems to have been considering exports of up to 200 MW from Tanzania to Zambia, Malawi and/or Mozambique from both substations. Export and import options have been evaluated further as part of the Component B and C studies. Such evaluations will include the HVDC link being considered between Tunduma and Kabwe in Zambia – a project which may have a capacity of 1000 MW initially and then be increased to 2000 MW in future.

Full comparisons between Component A and the scenarios based on further regional integration – Components B and C – are presented in Section 7.10.

6.11 Zambia

Relevant documents

The recent Master Plan for the Power System in Zambia is presented in the document:

- ❑ The Study for Power System Development Master Plan in Zambia, Japan International Cooperation Agency, Chubu Electric Power Co., Inc., Final Report February 2010

This Master Plan is supported by a map of generation and transmission projects entitled:

- ❑ ZESCO Grid 33 kV to 330 kV and Regional Transmission Line Interconnectors Drawing no. ZAM-GEN-DE-08-C-11847 revised 06.06.2012

As the plan is relatively old, ZESCO has provided a list of projects representing what we understand to be the up-to-date Transmission Development Plan for 2016 to 2030 along with a similar list of generation projects covering the same period:

- ❑ ZESCO Ltd -Transmission Development Plan 2016 to 2030 (Word document)
- ❑ ZESCO -Generation Project Status - March 2016 (Word document)

Planning criteria in use

The Master Plan from 2010 applied the following criteria in the formulation of the plan:

Table 35 Planning criteria in the formulation of the plan

Item	Criteria
Station Bus Voltages	Steady state: +/-5% of the nominal value
	Contingency conditions: +/-10% of nominal value
Equipment Loading	Steady state: Within Rated Current of equipment
	Short time overload: 20% above Rated Current for 20 minutes maximum
System Operation Security	System should stand a single contingency
System Stability	System stability (voltage and angle) is to be maintained following a single contingency outage after a permanent line to ground fault on any transmission line or transformer. For single circuit supply arrangements, the criterion will be relaxed.
Power Factor	0.95 (for transmission planning)
Frequency	With SAPP Interconnection: 49.95 - 50.05 Hz range 90% of the time
	Isolated Case: above 49 Hz

Source: ZESCO, 2016

The study noted that the N-1 criterion was not met in all areas (supply via single radial lines in the north-eastern and western areas) – neither would it be economical to secure such a

high level of reliability on areas with a low demand density. Areas not meeting the planning N-1 planning criterion was therefore sought reduced over time (presumably, as load growth would justify this from an economical point of view).

It is understood that the projects included on the transmission development plan for the period 2016 to 2030 are based on a similar approach. It is noted that the criteria allow for short time overloads. This is not a common approach across the utilities in the region. Otherwise, the planning criteria are in general aligned with the agreed SAPP criteria.

For the transmission planning to be covered as part for the Pool Plan, it is proposed not to accept short-time overload of any equipment. The Pool Plan study comments on whether this changes the timing of projects included on the national development plan for Zambia

Current development plan

The following table summarises the transmission projects included on the ZESCO plan for 2016 to 2030:

Table 36 2016 – 2020 Transmission Projects

SN	Name of Project	Voltage [kV]	Length [km]	Costs (\$ m)	Source of funding	Year in Service
1	Establishment of LSMFEZ substation	330/132/33	-	35	LSMFEZ/ ZESCO	2016
2	Itezhi Tezhi - Mumbwa - Lusaka West	220 [330]	310	90	AfDB/EIB/ AFD	2016
3	Mumbwa - Kalumbila	330	400	150	FQM	2016
4	Power Evacuation for Maamba Collieries Limited	330	55	20	MCL	2016
5	Connection of North Western Province to the grid	132	850	163	EKN/ORDIA (Standard Bank)	2017
6	Kafue Town - Muzuma - Victoria Falls Upgrade	330	348	100	EIB/World Bank	2017
7	Connection of Luangwa to the grid	132	211	63.4	Exim Bank of India	2017
8	Upgrade of Nampundwe - Sanje	88	96	8	ZESCO/Luiri/ Amatheon	2017
9	330 kV Mpika substation	330/66	-	38	TBA	2018
10	Livingstone - Hwange Interconnector (ZIZABONA Phase 1)	330	10	4	TBA	2018
11	Kafue West - Lusaka West	330	34	12	TBA	2018
12	Lusiwasi Upper Evacuation Line	132	10	4	TBA	2018
13	Kariba Lakeshore Electrification	132	170		TBA	2019

SN	Name of Project	Voltage [kV]	Length [km]	Costs (\$ m)	Source of funding	Year in Service
14	Kasama Nakonde Transmission Project			239	TBA	2019
	Kasama - Nakonde	330	300			
	Kasama - Kayambi	132	170			
	Kasama - Mporokoso	132	171			
15	Pensulo – Mansa Transmission Project			224	TBA	2019
	Pensulo - Mansa	330	294			
	Mansa - Samfya	132	62			
16	Kabwe - Pensulo 2nd Line	330	298	120	TBA	2019
17	Chipata - Lundazi - Chama	132	325	64	TBA	2019
18	Upgrade of transformers at Kitwe and Luano	330	-	35	ZESCO	2019
19	Livingstone - Muzuma - Kafue West – Double circuit line – not necessarily connected at Muzuma	330	348	75	JICA	2019
20	LTDRP 132kV	132	54	271	World Bank/EIB	2019
21	Muzuma - Choma	2 X 132	26	8	TBA	2019
22	Kafue Town - Mazabuka	132	55	8	TBA	2019
23	Kafue Gorge Lower Power Evacuation	330	45	75	TBA	2020
24	Sesheke - Mongu shangombo	220	315	90	TBA	2020
25	SVC for Luano and Kalumbila			60	ZESCO	2020
26	Zambia - Tanzania - Kenya Interconnector	330	1023	575	TBA	2020
27	Electrification of Vubwi	132	120	41	TBA	2020
28	Reinforcement of Power Supply to Katete, Petauke and Nyimba	132	207	52	TBA	2020
2021 – 2025 Transmission Projects						
SN	Name of Project	Voltage [kV]	Length [km]	Costs (\$ m)	Source of funding	Year in Service
19	Livingstone - Sesheke (ZIZABONA Phase 2)	330	210	70	TBA	2022
24	Kalungwishi Power Evacuation	330	200	51	TBA	2022
25	Lufubu Power Evacuation	330	200	51	TBA	2022
28	Lusaka West - Kabwe	330	100	30	TBA	2022

SN	Name of Project	Voltage [kV]	Length [km]	Costs (\$ m)	Source of funding	Year in Service
30	Copperbelt Transmission & Distribution Rehabilitation Project	132	150	196	TBA	2022
36	Solwezi – Kolwezi Interconnector	330	124	40	TBA	2022
34	Malawi 330 kV Interconnector	330	23	6	TBA	2023
35	Mozambique 330 kV Interconnector	330	74	20	TBA	2023
42	Kabwe - Kapiri Line	132	75	10	TBA	2023
26	Luapula Basin Evacuation Lines	330	130	35	TBA	2024
40	Luano - Lumwana 330 kV 2nd Line	330	262	63	TBA	2024
41	Kansanshi - Kalumbila 2nd Line	330	140	35	TBA	2024
31	Muzuma Mumbwa	330	270	81	TBA	2025

Source: ZESCO, 2016

Table 37 2026 – 2030 Transmission Projects

SN	Name of Project	Voltage [kV]	Length [km]	Costs (\$ m)	Source of funding	Year in Service
45	Mongu Kaoma 220 kV	220	185	40	TBA	2028
46	Mutinondo Luchenene Mpika	132	75	10	TBA	2028
47	Mpata Gorge - Leopards Hill	2 X 330	127	65	TBA	2029
39	Lusaka West - Kabwe2nd Line	330	100	30	TBA	2030
43	Kalungwishi - Nchelenge	132	75	10	TBA	2030
44	Devils Gorge evacuation line to Muzuma	2 X 330	130	70	TBA	2030
48	Lusemfwā - Kabwe Step Down	330	100	30	TBA	2030

Source: ZESCO, 2016

The plan as presented by ZESCO does not include a grid solution for the Batoka power plant on the Zambezi River. Information provided in December 2016 states that the plan is to connect the plant to Livingstone at 330 kV via two single circuit lines.

Several of the projects listed above, are related to reinforcement and extension of the sub-transmission system. Such projects are understood to be mainly driven by load growth and are as such independent of the regional scenarios considered as part of the Pool Plan.

Availability of transmission system models

ZESCO has provided a PSS/E case file for peak load 2016. Future scenarios for Zambia have been created using this file and the SAPP CC file as well as information in the old Master

Plan. Generic models for power plants have been added as required (the file provided by ZESCO covers a load flow model only).

Grid capacity and extension towards 2040

The benchmark case studies include an assessment of the grid capacity accounting for the planned expansion program as presented above and the generation expansion plan presented for the Benchmark Case (Component A). The analysis also covers a high-level expansion plan towards 2040 based on the same generation scenario (and the load forecast as used for this Pool Plan).

In general, the expansion plan as presented by ZESCO is kept unchanged. However, the need to support growth in the Copperbelt requires additional grid investments from the power stations in the southern parts of the country. Additional transmission capacity is found to be required from Muzuma towards Mumbwa and Kitwe/Luano. An alternative may be to upgrade the old 330 kV lines from the Lusaka area via Kabwe towards the Copperbelt Province. Use of a higher voltage may also have been of interest in optimising the solution. However, it has been chosen to base the Benchmark Case on new lines from Muzuma via Mumbwa to Luano. Furthermore, the assumption is that such lines will be operated at 330 kV as ZESCO is planning future expansion at this voltage level, although all other countries are planning for 400 kV. However, to meet the required transfer capacity, some of the new lines are assumed built using triple Bison instead of twin Bison. A small modification has also been made to the termination of the new lines from the west by integrating these at Lusaka West rather than at Kafue West (in order to avoid overload on Kafue West – Lusaka West in some cases).

Transmission expansion plan for the Benchmark Case

The following table summarises the transmission system expansion plan for Zambia in the Benchmark Case.

Figure 104 Transmission system expansion plan for Zambia

TRANSMISSION PROJECTS											
Voltage [kV]	Substation		Distance [km]	Conductor type	Circuits	Tower type		In service by year			
	From	To						Comp A	Comp B	Comp C	
330	Maamba	Muzuma	46	2 x Bison	2	Y	DbCkt	2016	2016	2016	
330	Livingstone	Muzuma	159	2 x Bison	1	Guyed V	SgCkt	2017	2017	2017	
330	Muzuma	Kafue Town	189	2 x Bison	1	Guyed V	SgCkt	2017	2017	2017	
330	Kafue West	Lusaka West	42	2 x Bison	1	Guyed V	SgCkt	2018	2018	2018	
400	Livingstone	Hwange (to border)	10	3 x Bison	1	Guyed V	SgCkt	2020	2020	2020	
330	Kasama	Nakonde	200	2 x Bison	1	Guyed V	SgCkt	2019	2019	2019	
330	Pensulo	Mansa	294	2 x Bison	1	Guyed V	SgCkt	2019	2019	2019	
330	Kabwe	Pensulo	298	2 x Bison	1	Guyed V	SgCkt	2019	2019	2019	
330	Livingstone	Muzuma	159	2 x Bison	2	Y	DbCkt	2019	2019	2019	
330	Muzuma	Lusaka West	239	2 x Bison	2	Y	DbCkt	2019	2019	2019	
330	Luano SVC (+/- 100 MVar)								2019	2019	2019
330	Kalumbila (+/- 100 MVar)								2019	2019	2019
330	Kasama (+/- 150 MVar)								2020	2020	2020
330	Lusaka West	Kabwe	100	2 x Bison	1	Guyed V	SgCkt	2020	2020	2020	
330	Kafue Gorge Lower	Kafue Gorge	15	2 x Bison	1	Guyed V	SgCkt	2021	2021	2021	
330	Kafue Gorge Lower	Kafue West	57	2 x Bison	1	Guyed V	SgCkt	2021	2021	2021	
330	Kafue Gorge Lower	Lusaka West	100	2 x Bison	1	Guyed V	SgCkt	2021	2021	2021	
330	Batoka	Livingstone	22	3 x Bison	2	Y	DbCkt	2023	Part of evaluation in Component B and C		
330	Luano	Lumwana	262	2 x Bison	1	Guyed V	SgCkt	2024			
330	Kansanshi	Kalumbila	140	2 x Bison	1	Guyed V	SgCkt	2024			
330	Muzuma	Mumbwa	270	2 x Bison	1	Guyed V	SgCkt	2025			
330	Mumbwa	Luano	300	3 x Bison	2	Y	DbCkt	2025			
330	Devil's Gorge	Muzuma	130	2 x Bison	1	Guyed V	SgCkt	2025			
330	Lusaka West	Kabwe	100	2 x Bison	1	Guyed V	SgCkt	2030			

Full comparisons between Component A and the scenarios based on further regional integration – Components B and C – are presented in Section 7.11.

The load flow diagram presented below shows the resulting load flow at peak demand by stage 2030.

6.12 Zimbabwe

Relevant documents

The plans for the transmission system expansion are presented in the document:

- ❑ Zimbabwe Electricity and Transmission and Distribution Company (ZETDC) System Development Plan, ZETDC System Development Division, April 2016

Our understanding is that this document reflects up-to-date development plans for Zimbabwe.

Furthermore, the response to the data request includes details on transmission projects not covered as part of the above System Development Plan:

- ❑ SAPP POOL PLAN DATA all in one file (Word document)

Further details on the transmission system infrastructure have been provided as part of a section in the Transmission Planning Manual in use with ZETDC:

- ❑ Section 11-Transmission Data 2014 (Word document)

Planning criteria in use

The target of the transmission planning covered by the System Development Plan for Zimbabwe has been to arrive at a least-cost transmission plan capable of supplying the forecasted load in a reliable manner, while providing operational flexibility.

Furthermore, the System Development Plan states that the transmission planning carried out as part of the work on this study is based on an N-1 planning criterion, which complies with the Transmission Planning Criteria approved by SAPP as well as provisions of the Zimbabwe Grid Code.

Current development plan

The System Development Plan dated April 2016 (prepared by the ZETDC System Development Division) states that the objective of the plan is “just to highlight the transmission projects necessary to connect the recommended generation expansion projects to the grid”. The focus of the plan is therefore on the expansion of the generation system required to meet requirements as identified in the forecast.

Further details on the projects are included in the response to the data request for the preparation of the Pool Plan. Of note is the inclusion of projects required to integrate the transmission scheme from Grand Inga at a substation at Chivu.

Generation Transmission Integration Projects

The projects included as part of the plan for integration of new, major generation projects are listed in the following tables.

Table 38 Generation Transmission Integration Projects

Project Title	Project Description	Proposed in Service Year
Hwange Stage III (7 & 8)	<p>Stage 3 2 x 300 MW Generation Units Construction and commissioning of a green field Hwange substation equipped with:</p> <p><u>Hwange Substation</u> 2 x 630 MVA 400/330 kV Transformers Construction of 20 km Triple Bison (1750 MVA) 400 kV line from new Hwange 400 kV Substation – Proposed Southern Energy 400 kV Substation 3 x 40 MVAr reactors on 330 kV lines 1 x 100 MVAr reactor on 400 kV line</p> <p><u>Insukamini Substation</u> Installation of a second 750 MVA 400/330 kV transformer at Insukamini 1 x 100 MVAr reactor on Hwange 400 kV line.</p> <p><u>Marvel Insukamini Line</u> Construction and commissioning of: 1 X 42 km of 400 kV Triple Bison line to be energised at 330 kV from Marvel to Insukamini</p> <p><u>Sherwood B Substation</u> Construction and commissioning of a green field substation equipped with: 1 x +/- 125 MVAr SVC Turn in and out Hwange – Sherwood 1 & 2, Alaska – Sherwood 1 & proposed 2 into Sherwood B 1 x 250 MVA 330/(132)88 kV transformer 3 x dressed 132 kV line bays</p>	2019
Southern Energy	Construction of 1 x 70 km 400 kV (1750 MVA) lines from Southern Energy to proposed CASECO 400 kV Substation	2019
Gwayi Power Station CASECO	Construction of 240 km 400 kV (1750 MVA) line from CASECO to Insukamini 400 kV substation	2018
	Construction of 290 km 400 kV (1750 MVA) line from CASECO to Proposed Sherwood B substation	
	<u>Sherwood B Substation</u> Installation of 2 x 750 MVA 400/330 kV transformers at Sherwood B substation	2018
		2019

Project Title	Project Description	Proposed in Service Year
Kariba South Extension	2 x 150 MW 3 x 40 MVar line reactors on 3 x Kariba – Alaska 330 kV lines	2018
Batoka Gorge	6 x 200 MW 1 x 70 km, 400 kV Triple Bison lines from Batoka Power Station to new Hwange 400 kV substation Construction of 400 km 2 x 400 kV line from new Hwange 400 kV Substation to Chakari substation Chakari is located on Sherwood – Alaska: 59.1 km from Sherwood and 97.1 km from Alaska	2022
Sherwood B Substation	<u>Substation Upgrading:</u> Installation of 1 x 750 MVA 400/330 kV transformers (This project is also included under the Gwayi Power Station)	2019
Tawana Power (Condo)	Construction of 400 kV 40 km triple bison line from Condo to Orange Grove Substation 400/330 kV substation	2020
Gokwe North	Construction of a 2 x 235 km 400 kV line from Gokwe North to Selous 400 kV substation. Construction of 1 x 85 km 400 (330) kV line from Selous to Dema. Construction of 1 x 225 km 400 kV line from Gokwe North to Sherwood B. Installation of 2 x 750 MVA 400/330 kV transformers at Selous <u>Sherwood B Substation</u> Installation of 2 x 750 MVA 400/330 kV transformers (This project is also included under the Gwayi Power Station)	2022
Evacuation of Power from Grand Inga	The scope will involve the following: 1 x 400 kV line (300 km) from Kariba South to Sherwood B substation. Construction of Chivhu 400 kV switching station. 1 x 400 kV line (120 km) from Sherwood B to Chivhu switching station. 1 x 400 kV line (220 km) from Chivhu switching station to Triangle substation. 1 x 400 kV line (320 km) from Triangle to Nzhelele (RSA)	2024
Demba Emergency power peaking plant	Construction of 2 x 132 kV 1 km lines from the power plant to Demba 330/132 kV substation	2016
De Green Rhino	Construction of a 2 x 4.3 km 132 kV line from the solar plant to the Marondera – Bromley 132 kV line cut-in point. Installation of 1 x 20 MVar fast response reactor at Marondera 132 kV substation	2017

Transmission infrastructure projects

The following projects are identified in the information received as required to supply the expected demand and to safeguard the operations of the system.

Table 39 Transmission infrastructure projects

Project Title	Project Description	Proposed in Service Year
Installation of Reactors	Hwange Substation Installation of 40 MVar line/bus reactors on Hwange - Sherwood 1 & 2, Hwange - Insukamini 330 kV lines Sherwood Substation Installation of 40 MVar line/bus reactors on Hwange - Sherwood 1 & 2, 330 kV lines Insukamini Substation Installation of 40 MVar line/bus reactors on Hwange - Insukamini 330 kV line	2017
ZIZABONA Project	The project shall be implemented as follows; 115 km of 400 kV Triple Tern Line from Hwange to Livingstone. 79 km of 400 kV Triple Tern Line from Vic Falls to Pandamatenga (Botswana) Construction of Victoria Falls switching station	2019
Bindura- Mutorashanga 330 kV line	Construction and commissioning of: 1 X 80.2km of 400 kV Triple Bison line to be energised at 330 kV from Bindura to Mutorashanga	2017
Second Alaska - Sherwood 330 kV Line	Construction and commissioning of: 1 X 160 km of 400 kV Triple Bison line to be energised at 330 kV from Alaska to Sherwood The Pool Plan Study will assume that Chakari - Sherwood B is energized at 400 kV once these two substations are commissioned	2017
Orange Grove - Triangle Project	Construction and commissioning of Triangle 330/132 kV substation: 2 x 175 MVA 330/132 kV Transformers Energising the existing Tokwe - Triangle 132 kV line at 330 kV Construction and commissioning of the Orange Grove - Triangle 400 kV project: 300 km Triangle - Orange Grove 400 kV Triple Bison line Orange Grove 400/330/132k V substation with: 2 x 750 MVA 400/330 kV transformers Triangle 400/330 kV Substation with: 2 x 750 MVA 400/330 kV transformers	2017 2018
	Interconnector projects: 320 km Triangle - Nzhelele 400 kV triple Bison line The Pool Plan Study will assume triple Tern in South Africa 440 km Orange Grove - HCB (via Inchope) 400 kV triple Bison line	2018

During the PSC meeting in Johannesburg in December 2016, it was agreed that the interconnection between Triangle and Nzhelele (South Africa) as well as the interconnection between Hwange and Livingstone (Zambia) should be treated as committed projects to be implemented within the next 3-4 years. Other interconnections (including additional stages on the ZIZABONA project) should be seen as candidates for inclusion in Component B and C. The Triangle – Nzhelele project would require voltage support in the Tokwe-Triangle area in future in order to support the transfer on this part of the system – in particular during outages on the Zimbabwe – Botswana – South Africa link. Such voltage support would be required both during high levels of export and import. A 200 MVar SVC at Triangle is considered a reasonable solution (higher MVar rating would not provide much additional transfer capacity), and has been included in the investment plan by 2025.

Availability of transmission system models

PSS/E files for peak load 2016, 2020, 2025 and 2030 have been provided by ZETDC. Load flow models have been provided for all stages, but the dynamics data does not cover future stages.

Grid capacity and extension towards 2040

The preparation of the Benchmark case includes an assessment of the grid capacity accounting for the planned transmission expansion program and the generation expansion plan presented for the Benchmark Case (Component A). The analysis also covers a high-level expansion plan towards 2040 based on the same generation scenario (and the load forecast as used for this Pool Plan).

In view of the decision to include the 400 kV line from Hwange to Livingstone as a committed project – i.e. the first stage of the ZIZABONA project – the grid connection of the Batoka project has been modified slightly compared to the ZETDC plan presented above. Rather than adding a 400 kV line from Batoka to Hwange, this line is assumed connected to the Hwange – Livingstone line at the planned Victoria Falls substation on this interconnection.

Further developments in the Benchmark case are in general in line with the proposals made in the system development plan presented above. A 400 kV grid linking the new thermal projects in the west and the hydropower plants on the Zambezi upstream of Kariba needs to be added. These lines are proposed integrated into the central parts of Zimbabwe at new 400/330 kV substations at Sherwood and Chakari.

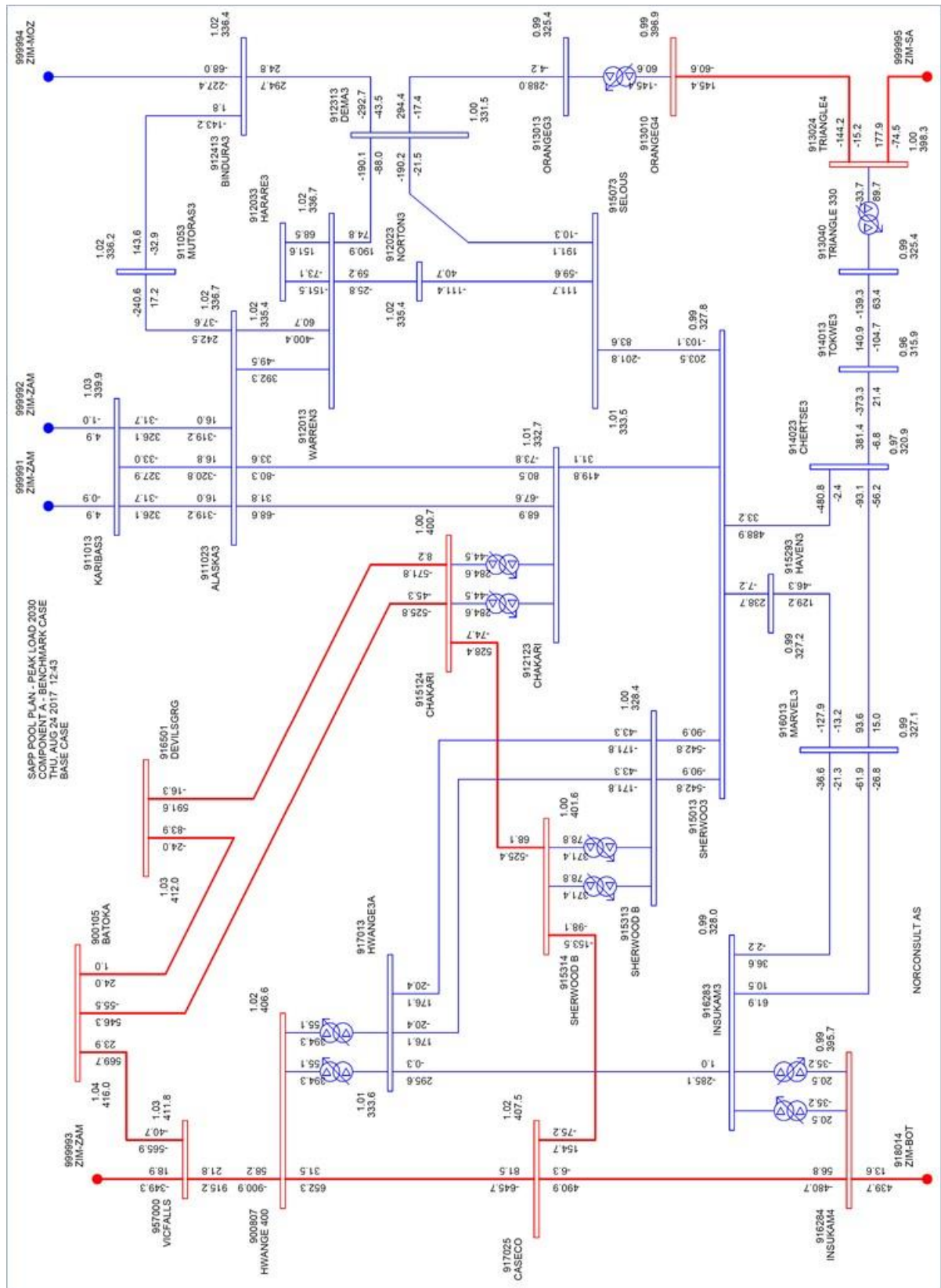
Strengthening of the grid towards the greater Harare area will also be required. The previously proposed 2nd line between Sherwood and Alaska (with the Sherwood – Chakari converted to 400 kV operation once the new 400 kV substations are in) will increase transfer capacity on the grid east of Sherwood/Chakari. Further increase in reliability and transfer capacity will be achieved by adding the Mutorashanga – Bindura and Selous – Dema lines. The Selous station is also seen as a good point for further development of the 400 kV system towards the end of the study period.

Furthermore, the analyses for the Benchmark case covers two different generation dispatch scenarios for the power generation in Zimbabwe - as illustrated in the load flow diagrams presented on the following pages. Both figures illustrate conditions at a load level equal to

peak demand for stage 2030. The first single line diagram shows power flow during the wet season with full output from the hydropower plants, whereas the second illustrates a “dry” scenario or year with limited peaking power from the hydropower plants. In the latter case, output from plants upstream of Kariba – with unregulated in-flows – is assumed limited due to low flows. Generation at Kariba has also been reduced in order to save water.

The proposed grid is seen as adequate to support load growth and grid connection for main power plants in both scenarios.

Figure 106 Load flow diagram 2030 in Zimbabwe (wet season)



Transmission expansion plan for the Benchmark Case

The following table summarises the transmission system expansion plan for Zimbabwe in the Benchmark Case.

Figure 107 Transmission system expansion plan in Zimbabwe

Voltage [kV]	TRANSMISSION PROJECTS							In service by year		
	Substation		Distance [km]	Conductor type	Circuits	Tower type		Comp A	Comp B	Comp C
	From	To								
400 ^{*)}	Bindura	Mutorashanga	80	3 x Bison	1	Guyed V	SgCkt	2018	2018	2018
400 ^{*)}	Sherwood	Alaska	160	3 x Bison	1	Guyed V	SgCkt	2018	2018	2018
400	Hwange	Livingstone (to border)	104	3 x Bison	1	Guyed V	SgCkt	2020	2020	2020
400	Hwange	Southern Energy	20	3 x Bison	1	Guyed V	SgCkt	2019	2019	2019
400	Southern Energy	CASECO	70	3 x Bison	1	Guyed V	SgCkt	2019	2019	2019
400	CASECO	Insukamini	160	3 x Bison	1	Guyed V	SgCkt	2019	2019	2019
400	CASECO	Sherwood B	294	3 x Bison	1	Guyed V	SgCkt	2019	2019	2019
400 ^{*)}	Insukmaini	Marvel	42	3 x Bison	1	Guyed V	SgCkt	2019	2019	2019
330	Sherwood B SVC (+/- 150 MVAR)							2019	2019	2019
400	Orange Grove	Triangle	300	3 x Bison	1	Guyed V	SgCkt	2021	2021	2021
400	Triangle	Nzhelele (to border)	215	3 x Bison	1	Guyed V	SgCkt	2021	2021	2021
400 ^{*)}	Selous	Dema	95	3 x Bison	1	Guyed V	SgCkt	2022	Part of evaluation in Component B and C	
400	Batoka	Vic. Falls	30	3 x Bison	1	Guyed V	SgCkt	2023		
400	Batoka	Chakari	400	3 x Bison	2	Guyed V	SgCkt	2023		
400	Devils Gorge	I/O Batoka-Chakari	25	3 x Bison	2	Guyed V	SgCkt	2026		
400	Gokwe	Selous	236	3 x Bison	2	Guyed V	SgCkt	2030		
400	Gokwe	Sherwood B	225	3 x Bison	1	Guyed V	SgCkt	2030		

^{*)} These lines may be operated at 330 kV initially.

Full comparisons between Component A and the scenarios based on further regional integration – Components B and C – are presented in Section 7.12.

The plan means that 400/330 kV substations will be established at Hwange, Sherwood B, and Chakari as illustrated in the above diagrams. Selous may also become a 400/330 kV substation once Gokwe North is connected to the grid.

7 Interconnections resulting from regional integration

A number of new interconnections will be required to support the generation scenarios evaluated for the generation expansion plans in Component B and C. Such interconnections may naturally also impact on the country transmission plans as presented in the previous section.

The possible development of relatively large, low-cost hydro projects are key drivers for the integration of the systems. Many of these projects – like Mphanda Nkuwa in Mozambique and certainly Inga in DRC – would require major investment in new HVDC links. Upgrade of existing AC interconnections and addition of new cross-border transmission lines would also be required.

A number of candidates have been evaluated as presented in the following sections. Cost and transfer capacity of options and alternatives have been included in the optimisation in PLEXOS, and the viability of each project and the combination of different projects have therefore been assessed as part of the least-cost optimisation in PLEXOS.

This approach may differ somewhat from what individual utilities in the region are doing in their planning. Often the transmission grid expansion plan is based on use of the technical planning criteria only, i.e. the expansion of the grid is set to meet the N-1 planning criteria without verifying whether it would actually be economical to add the element(s) required to meet a specific generation dispatch that may require the reinforcement in question. For the Pool Plan, the transfer limits for certain stages of development are set using the N-1 planning criteria in SAPP – and adhered to in the PLEXOS simulations, but the economic viability of the investment is tested in PLEXOS. The result may be (and proves to be) that certain interconnections may be running at or close to full capacity, but that the project(s) that may relieve such constraints are not selected. In such cases, it may clearly be possible to create a generation dispatch that would result in violation of the N-1 criterion in a load flow or stability study as part of the transmission analysis. The important point to observe though, is that if PLEXOS does not select the project that would remove such a constraint, it is because the relevant reinforcement would not be economical even if allowing for a different dispatch. (Similarly, the PLEXOS simulations may show unserved energy in some areas although a new transmission line may have solved the problem, but at a higher total economic cost.) In addition, PLEXOS naturally also optimises the generation expansion plan within the transmission constraints.

In many areas, the transfer limits will be dependent on load growth as well as generation dispatch. Off-peak transfer limits may also be different from limits at peak demand. The approach has been to set the transfer limits relatively conservatively at peak demand. It should also be noted that this study has a regional approach and that local benefits of certain interconnection projects may not be fully reflected in the analysis. The approach is also based on a least-cost economic development approach. Wheeling costs and other commercial aspects of contracts that would have to be taken into account when two or more utilities are developing an interconnection project, may lead to different conclusions not only on required capacity of the different interconnection projects, but also on which projects would be preferred. Such issues may also lead to other projects being brought forward than the least-cost regional projects that have been identified as part of the least-cost plan in this Pool Plan study.

The following description follows the country-by-country approach used in Section 6, and highlights the different interconnections evaluated and the impact the power exchanges in Component B and C may have on the domestic projects within each country. The transmission system expansion plan for each country is summarised in tables presenting all three components A, B and C. Furthermore, an overview of the interconnections and typical flows at peak demand is shown in diagrams in Annex 8. The annexes also include tables documenting the indicative transfer limits and cost of the interconnections considered in this study.

7.1 Angola

Angola's development of hydropower resources may support significant exports in the early part of the study period. Power exchange with DRC in the north and Namibia in the south are natural options considering the recent grid expansion in the north and ongoing and planned efforts to interconnect the system in the north with the central and southern parts of the country. The Pool Plan has therefore investigated the option of interconnecting the system in Angola by extending the AC system to Inga in DRC and to Kunene close to Ruacana in Namibia. A strong link to Inga also seems a promising alternative in view of the fact that once further developments take place at Inga (i.e. Inga 3 and 4 etc.), Angola may benefit from imports from DRC to cover domestic demand in the long term.

Export from Angola to other parts of the SAPP system, like load centres in Zambia, Zimbabwe and/or South Africa, may be technically feasible via HVDC, but as the PLEXOS simulations indicate that Angola would benefit from imports from DRC in the long term, such HVDC solutions would only seem viable if based on alternatives for wheeling of power from Inga via Angola to such markets.

An HVDC link from Inga to South Africa via the main power plants on the Kwanza River is therefore an alternative to the link from Inga via Zambia and Zimbabwe to South Africa (Limpopo) commented on in other sections of this report. If such a DC link is terminated in the Johannesburg area, a line route via Angola, Namibia and Botswana may be shorter than a line route via Zambia and Zimbabwe to a central point in the grid in the Limpopo Province in South Africa. From such a point of view, it would seem reasonable to consider both options in future planning of an HVDC link from Inga in DRC to South Africa.

For an AC link from Angola to DRC, 400 kV AC lines from N'zeto to Inga have been considered the most attractive option. A line route from Soyo to Inga may be marginally shorter, but would create a weaker link to the main hydropower stations on the Kwanza River. Furthermore, the 400 kV grid north of Luanda would also have to be reinforced to achieve the transfer levels that may be required, and overall investments would therefore be lower if connecting from N'zeto to Inga than from Soyo.

Up to three 400 kV AC lines between N'zeto and Inga have been considered. The transfer limit on the first line is set at a modest 300 MW to ensure that the frequency response of the system is acceptable following a loss of the line. The line should have a high rating though to allow for significantly higher transfer levels once the second and third line is added. Total transfer limit is estimated at 1100 MW with two lines in service and 1900 MW with three lines in service. To achieve the high transfer level once the third line is added requires that a

third circuit is added also on the system south of N'zeto towards Luanda and also that SVCs are added at N'zeto and also at the point of termination in Luanda (possibly Catete).

Information available at this stage does not allow for accurate modelling of the power plants in the area, and the transient stability limit would therefore have to be verified at a later stage once details of power plant design is available. The indicative, high transfer limits once the second and third 400 kV line is added may require that system protection schemes are in place to ensure system stability. Modulation of the power on the DC link(s) out of Inga may support the system. Alternatively, system protection schemes tripping of one or more generators in critical cases may be necessary (but without shedding any load on the system, just as a measure to reduce the transfer level on critical boundaries following certain outages¹¹).

The PLEXOS results indicate that the first two 400 kV lines between Angola and DRC are justified early on in order to support export from Angola, whereas once further development of Inga takes place, the power flow would be in the opposite direction. Such export from DRC also would justify the third 400 kV line towards the end of the study period (2033 in Component B and 2034 in C). Results for the last few years in the study period indicate that an even higher transfer capacity may be justified - postponing further investment in local generation in Angola (projects like Tumulo do Cacador, Zenzo I and Cafula).

In the south, the development of the 400 kV system in Angola may limit the potential for power exchange with Namibia. It is understood that the timing of the different sections on the 400 kV system is still uncertain, but the plan presented by RNT indicates that Lubango will have two 400 kV lines from the north and that one 400 kV line will be built to Cahama just north of the border to Namibia. This line is planned to be connected to Baynes if this hydropower project is developed. Depending on the timing of the Baynes project, a link to Namibia could therefore be via Baynes or along a shorter route more directly towards Kunene in Namibia. The direct route has been added in PLEXOS to test the viability of the interconnection. The results are that the line is selected for implementation early on in Components B and C based on power export from Angola - even based on a relatively conservative estimate for the transfer capacity of only 250 MW. Even if Baynes is not developed, the interconnection is therefore seen as a very promising regional project. Notably, Baynes is added in 2027 in Component C, i.e. two years earlier than in Component A.

Detailed studies of this interconnection project should address the issue of potential savings if using a line route via Baynes - alternatively seeing this as the second interconnection. An option for a second interconnection has been tested in PLEXOS though, but has not been selected as part of the least-cost plan. Part of the reason is that such development is considered to require reinforcement of the 400 kV system north of Lubango and also between Lubango and Cahama. The second AC link between Angola and Namibia would therefore be more costly. Furthermore, the capacity for wheeling in Namibia is limited, meaning that a higher transfer capacity from Angola to Namibia may not benefit the overall system much. It would seem more important to try to ensure that the capacity of the first interconnection is increased for instance by adding SVCs on the system. Such measures

¹¹ I.e. similar to the planning of the STE grid in Mozambique which also allows for tripping of generators following certain faults on the transmission system.

would increase the voltage stability limit on the system and would be required in case a second interconnection is added.

It should be noted that once Angola is interconnected to DRC and Namibia, there are likely to be some operational concerns that need to be evaluated in detail. One issue is related to parallel operation of the DC link from Inga to Kolwezi (and in future possibly also new links to other SAPP countries) and the AC system from Inga via Angola into Namibia and the rest of SAPP. System protection schemes must certainly be in place to avoid the transfer of excessive power to the AC system following major disturbances on the DC system. Parallel operation may even have to be avoided – leaving some units at Inga feeding the DC links and other units feeding the AC system.

Another issue is the sudden loss of the interconnection between Angola and DRC and the impact on the link between Angola and Namibia. As the synchronous AC grid outside Angola is and will remain considerably larger than the system in Angola, any sudden change in the power flow between Angola and DRC due to a fault on this link, will be reflected on the connection between Angola and Namibia. In such a case, it may not be possible to keep the system in Angola in synchronism with the rest of SAPP via this relatively weak link. The PLEXOS simulations indicate that it would be economical to add two lines between Angola and DRC, and the risk of loss of both lines at the same time is low. Nevertheless, in order to minimise the risk of black-outs and to maintain a high level of reliability, it should be considered carefully if system protection schemes are required to handle such events.

Power export from Angola to or via Namibia will be limited by steady state voltages during outages on the 400 kV system from the main power plants on the Kwanza River towards the southern parts of the country. The actual transfer limit will naturally be dependent on load growth in this part of the grid and the staging of 400 kV (and 220 kV) investments in the area. Reactive power compensation on the system will also be important and the use of SVCs in addition to fixed shunt capacitor banks may be important to support high transfer levels.

In addition, transient stability on this part of the system may be a limiting factor. Detailed models for the power plants in Angola have not been available for this study, and the simulations carried out are therefore based on generic models for the key power plants. The simulations carried out indicate that a third 400 kV line from the main power plants on the Kwanza River towards the south will be required in the medium term to ensure that the system in Angola will remain in synchronism with the rest of SAPP for outages of a 400 kV line from north to central to south in Angola.

This is demonstrated by the results in the following two graphs indicating that the system is stable with two 400 kV lines towards the south in 2025, whereas a third line is required by 2030 (although the system may be stable with only two lines even at this stage if the fault is cleared very rapidly within 70 ms). The two figures show the rotor angle difference between generators in Angola and one of the main power plants in South Africa for stage 2025 and 2030, respectively:

Figure 108 Outage of a 400 kV line south of the Kwanza River, stage 2025. Two 400 kV lines south of the Kwanza River.

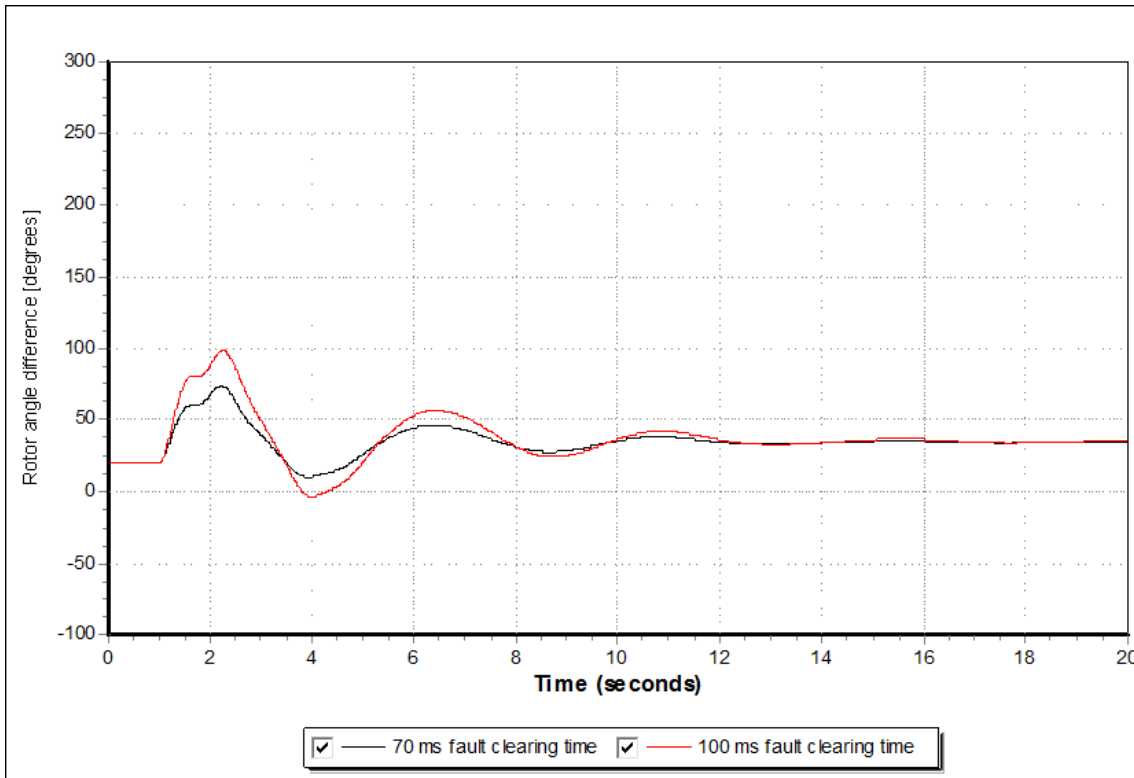
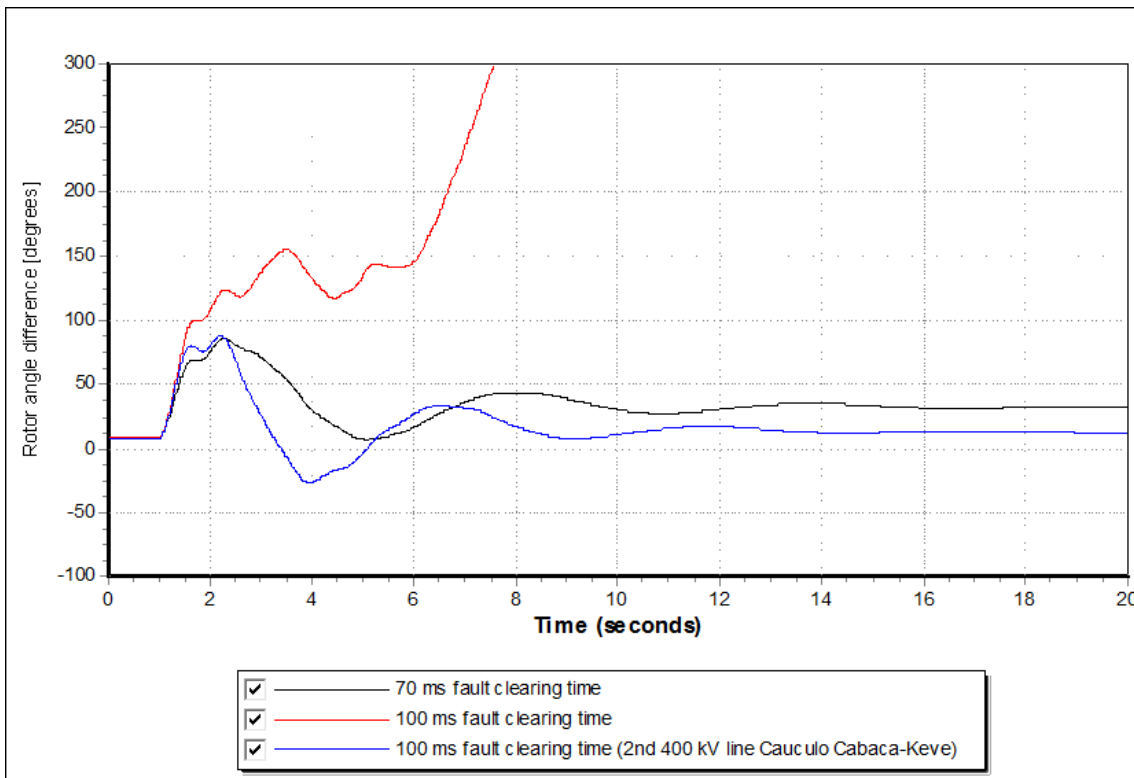


Figure 109 Outage of a 400 kV line south of the Kwanza River, stage 2030. Two 400 kV lines (black and red) vs. three 400 kV lines (blue) south of the Kwanza River.



- For a three-phase fault on the 400 kV line from Caculo Cabaca to Keve in 2025, the system in Angola remains in synchronism with the rest of the SAPP system for both 70 ms and 100 ms fault clearing times.
- By 2030, the system is transiently unstable for a 100 ms fault clearing time unless a third line to the south is added (in this case assuming a second line from Caculo Cabaca to Keve – other alternatives may provide similar results). Although a three-phase fault is normally cleared faster than 100 ms, the stability margin is low for high transfers towards the main load centres in the south supporting export to or via Namibia.

Further, detailed studies of this stability limit should be carried out as part of future planning of the grid in the central and southern parts of Angola, and should obviously be based on accurate models of the existing and planned power plants on the system. Both the requirements for the line, the timing of the project and also the preferred routing is uncertain, and the investment is therefore not included in the following table presenting the system expansion plan for the 400 kV grid in Angola.

Figure 110 Transmission system expansion plan in Angola

TRANSMISSION PROJECTS												
Voltage [kV]	Substation		Distance [km]	Conductor type	Circuits	Tower type		Cost estimate [MUSD]	In service (latest) by year			
	From	To							Comp A	Comp B	Comp C	
400	Cambutas	Bitá	172	2 x Sorbus	1	Y	SgCkt	60	2020	2020	2020	
400	Catete	Bitá	55	2 x Sorbus	1	Y	SgCkt	24	2020	2020	2020	
400	Lauca	Waku Kongo	202	2 x Sorbus	1	Y	SgCkt	71	2020	2020	2020	
400	Waku Kungo	Dango	196	2 x Sorbus	1	Y	SgCkt	66	2020	2020	2020	
400	Dango	Lubango	343	2 x Sorbus	1	Y	SgCkt	107	2020	2020	2020	
400	Viana	Catete	42	2 x Sorbus	1	Y	SgCkt	24	2025	2025	2025	
400	Lubango	Cahama	190	2 x Sorbus	1	Y	SgCkt	67	2025	2022	2022	
400	Lauca	Caculo Cabaca	25	3 x Sorbus	1	Y	SgCkt	20	2022	2022	2022	
400	Lauca ckt. 2	Caculo Cabaca ckt. 2	25	3 x Sorbus	1	Y	SgCkt	14	2022	2022	2022	
400	Caculo Cabaca	Cambutas	75	3 x Sorbus	1	Y	SgCkt	38	2022	2022	2022	
	- line connecting to Zenzo in future, by:									2033	2029	2038
400	Caculo Cabaca	Biopio	390	3 x Sorbus	1	Y	SgCkt	132	2022	2022	2022	
	- line connecting to Keve (also allowing for in-feed from potential power plant)											
400	Biopio	Dango	250	2 x Sorbus	1	Y	SgCkt	79	2025	2025	2025	
400	Biopio	Lubango	250	2 x Sorbus	1	Y	SgCkt	79	2025	2025	2025	
400	Cambutas ckt. 2	Bitá ckt. 2	172	2 x Sorbus	1	Y	SgCkt	54	2025	2025	2025	
400	Tumulo do Cacador	Cambutas	20	2 x Sorbus	1	Y	SgCkt	17	2031	2029	2038	
400	Cahama	Baynes	112	3 x Sorbus	1	V	SgCkt	44	2029	2022	2022	
	- in B and C; the line via Baynes to Kunene is initially used to for trade only - Baynes added in:									2029	2029	2027
	Note: If interconnecting Angola and Namibia early on, a direct link Cahama - Kunene could be an option.											
400	N'zeto ckt.1	Inga (to border) ckt.1	165	3 x Sorbus	1	V	SgCkt	57		2023	2020	
400	N'zeto ckt.2	Inga (to border) ckt.3	165	3 x Sorbus	1	V	SgCkt	51		2023	2020	
400	N'zeto ckt.3	Inga (to border) ckt.3	165	3 x Sorbus	1	V	SgCkt	51		2033	2034	
	N'zeto ckt.3	Kapary/Catete ckt.3	220	3 x Sorbus	1	Y	SgCkt	79		2033	2034	
	SVC at N'zeto								30		2033	2034
	SVC in Luanda area								30		2033	2034
Total investment costs (million USD) by component:								Total:	898	1195	1195	
Note: This estimate applies only to the 400 kV system as may be impacted by the Pool Plan.								PV:	554	709	715	

The overall investment costs on the 400 kV transmission system increases by an estimated ~\$300 m over the planning period – mainly due to the proposed interconnections to DR Congo (costs only to the border included in the above figures). In present value (PV) terms, the increase is ~\$160 m. The timing of the projects differs only slightly between Component B and C, and the present values are therefore almost equal for these two components.

7.2 Botswana

In the Benchmark Case (Component A), Botswana remains an importer throughout most of the study period – with two small 150 MW coalfired units added in 2029 and 2035 plus a CSP plant in 2031. The existing 400 kV transmission lines to South Africa and Zimbabwe are therefore mainly used for import of power.

In Component B, the picture is much the same until 2028 when the link from Victoria Falls to Pandamatenga is added, allowing for additional wheeling from north to south on the interconnected system of Zambia, Zimbabwe and Botswana of about 400 MW. At a modest cost of about \$34 million, it may have been expected that this investment would be part of the least-cost plan earlier on. This project would also seem the least-cost approach to ensure back-up supply to Pandamatenga, and as such would seem a good alternative compared to the Mawana – Pandamatenga line planned in Botswana. However, if the Mawana – Pandamatenga line is dropped, further investment may be required elsewhere to secure a back-up supply to Orapa and Mawana in Botswana. Although the regional importance of this project may seem less than what may have been expected, additional local benefits may therefore justify the project at an earlier stage than 2028.

With additional capacity for import of power, local generation developments in Component B is postponed compared to A with the two coalfired units added in 2031 and 2038 respectively, and the CSP plant dropped from the least-cost plan. Right at the end of the study period (2039) further coalfired generation may be justified along with the addition of the Isang – Watershed connection to South Africa. Although assuming a high incremental transfer capacity from Botswana to South Africa of 700 MW for this project, the high cost of about \$200 million (including 400 kV grid connections from Watershed in South Africa to neighbouring substations at Pluto and Mokoodi) means this project is not viable early on in Component B.

The base case for Component C results in rather different developments in Botswana. To meet the minimum installed capacity requirement, a total of 700 MW coal fired generation is added already by 2022 and a further 700 MW is added towards the end of the study period. Rather than importing power throughout as in A and B, Botswana becomes a net exporter in many years in Component C.

With additional local generation, there is less need for import via the link from Victoria Falls to Pandamatenga in Component B, and the project is postponed from 2028 to 2032 (but the same comment as made above on local benefits still apply and could certainly justify early implementation of the project).

Higher levels of local generation in Component C combined with a general requirement for transfer capacity from north to south on the SAPP system, also means that the Isang – Watershed project is justified earlier on – i.e. by 2031 rather than 2039. As in Component B, earlier implementation may be justified if local grid reinforcement in the area towards Watershed is required regardless of the development of Isang – Watershed. Further studies of this interconnection should look into details of such requirements (including assessment of local demand in the area).

Overall, both the Victoria Falls – Pandamatenga and the Isang – Watershed interconnection projects may provide significant benefits in a regional context. However, in order to justify

an early implementation of these two projects, it is necessary to identify in more detail the local grid requirements and evaluate if these links are part of the least-cost development plans for local supply. In the case of securing the supply to Pandamatenga, this would certainly seem so. Furthermore, it is assumed that the Feasibility Study of the Isang – Watershed project (study not available for the preparation of this Pool Plan) may provide further insight on this issue.

The stability of the system in Botswana in case of loss of the link to South Africa has been tested for wheeling from north to south. Indications are that the transient stability of the power plants in Botswana is not the limiting factor in such a scenario, but rather that the transfer is limited by low steady stage voltages in the Tokwe – Triangle area in Zimbabwe following an outage of the 400 kV line from Phokoje to Matimba, i.e. in future once the Triangle – Nzhelele line is established. The Isang – Watershed line would certainly increase the transfer limit in such a case, and obviously if the Triangle – Nzhelele line is postponed, the Isang – Watershed project may become very attractive – in particular if combined with the Pandamatenga – Victoria Falls line and the other components of the ZIZABONA project.

Figure 111 Transmission system expansion plan in Botswana

TRANSMISSION PROJECTS											
Voltage [kV]	Substation		Distance [km]	Conductor type	Circuits	Tower type		Cost estimate [MUSD]	In service by year		
	From	To							Comp A	Comp B	Comp C
400	Morupule	Orapa	220	3 x Tern	1	Guyed V	SgCkt	78	2019	2019	2019
400	Orapa	Mawana (Maun)	280	3 x Tern	1	Guyed V	SgCkt	93	2019	2019	2019
400	Phokoje	Dukwi	230	3 x Tern	1	Guyed V	SgCkt	81	2019	2019	2019
400	Dukwi	Pandamatenga	289	3 x Tern	1	Guyed V	SgCkt	95	2019	2019	2019
400	Morupule (ckt. 2)	Isang (ckt. 2)	215	3 x Tern	1	Guyed V	SgCkt	68	2019	2019	2019
400	Mawana	Pandamatenga	290	3 x Tern	1	Guyed V	SgCkt	90	2025	2025	2025
400	SVC at Pandamatenga (+100 MVar)							20	2025	2025	2025
400	SVC at Mawana (+100 MVar)							20	2025	2025	2025
400	Pandamatenga	Vic. Falls (to border)	10	3 x Tern	1	Guyed V	SgCkt	6		2028	2032
400	Isang	Watershed (to brdr)	60	3 x Tern	1	Cross Rope	SgCkt	22		2039	2031
400	Serule	Morupule	120	3 x Tern	1	Guyed V	SgCkt	47		2039	2022
Total investment costs (million USD) by Component:								Total:	545	620	620
								PV:	391	409	431

Note: This estimate applies only to the 400 kV system as may be impacted by the Pool Plan.

The total investment costs on the 400 kV transmission system increases by an estimated ~\$75 m over the planning period in Component B and C compared to the Benchmark Case. This includes costs for interconnections from Pandamatenga to Victoria Falls and from Isang to Watershed (costs only to the border included in the above figures) plus an internal line between new coal fired power plant(s) in the Serule area to Morupule. In present value (PV) terms, the increase is a moderate ~\$20 m in Component B as the additional grid investment comes late. In Component C, the present value of costs increases by ~\$40 m.

A sensitivity test for Component C with a 100 MW solar plant added in 2022 and adding coal-fired units in smaller steps than in the base case for Component C, results in less surplus generation in Botswana from around 2027 towards the end of the study period. There are only minor changes in the transmission expansion plan, though. The interconnection from Isang to Watershed in South Africa (BOSA) and the line from Pandamatenga to Victoria Falls in Zimbabwe (part of ZIZABONA) is postponed by three years. As indicated above, local benefits may well justify these links earlier on.

7.3 DR Congo

As commented on in the section on Angola, the interconnection of DR Congo and Angola seems very promising both in Components B and C. Two AC lines from Inga to N'zeto are found to be viable early on to provide import of power from Angola until the development of Inga 3 takes place. At that time, Angola would benefit from import from DRC, meaning that the power flow on the proposed interconnections would shift from high import to DRC early on to high export to Angola towards the end of the study period.

The next major project of regional importance would be the development of Inga 3 and also Inga 4. The base cases of both Components B and C includes the development of Inga 3 and the first units at Inga 4 around 2030-2033. For all practical purposes, this means that the Inga project in these scenarios should be developed in line with the high dam alternative and that the Inga 4 project would possibly be developed in stages over a few years.

Several DC links to support such expansion of the Inga project have been evaluated. Initially, such options also included a possible link to Tanzania. Although indications were that such a project may have been viable, it was decided to leave this option as there are major uncertainties about the market in the EAPP countries and details on a number of generation options in the EAPP area are not known to the study team on the Pool Plan.

As commented on in the Benchmark Case, the Katanga Province in DRC and the Copperbelt and North-Western Provinces in Zambia represents a major load centre in the northern parts of the SAPP system. Local generation capacity is also limited, and some of the local hydropower resources also provide limited firm power during the dry season. An in-feed to this area from a DC link from Inga therefore seems a natural option. Terminating such a link in the Lubumbashi area (as included in the Benchmark Case) may be possible (although the short circuit level may be low). However, such an approach requires that the grid is reinforced between Lubumbashi and the Copperbelt area to achieve high levels of export from Inga. An in-feed in the Copperbelt area is preferable from such a point of view (the fault level on the grid in this area is also higher). The Luano substation provides the best access, and Luano is also a central substation in the system linking back to Kabwe and Leopards Hill as well as towards Solwezi and the 330 kV substations in the North-Western Province of Zambia. A connection to the Luano substation would therefore provide a high capacity for in-feed of power from a DC link from Inga, and the 220 kV lines from Luano back to the Katanga province would also ensure that significant power may be fed back to DRC from Zambia.

An in-feed of up to 2500 MW was considered early on, but found to be excessive in view of system stability (this issue is elaborated further in the section presenting details on Zambia). A 2000 MW scheme Inga - Luano has therefore been included in the PLEXOS simulations - with the option of developing this in stages of 1000 MW. The results indicate that this scheme should be added by 2030/31. The load factor on the DC link varies, but is relatively high - indicating that the 2000 MW capacity is fairly optimal. Further studies on the scheme at a later stage would have to consider in detail the need for temporary overload capability on the DC link to ensure stable operation during different modes of operation of this new scheme in parallel to the existing DC link from Inga to Kolwezi.

A second HVDC link from Inga would be required to evacuate the power from Inga. As South Africa is seen as one of the main markets for power from Inga, a DC link from Inga to

South Africa has therefore been investigated. A link with a capacity of 3000 MW – with the option of developing this in stages of 1500 MW – has been considered. The termination point could be in the central areas of the Gauteng province or possibly at Merensky in the Limpopo Province as proposed in an inter-utility study provided to the study team on the Pool Plan late in June 2017. A 3000 MW in-feed is 50 % higher than the current Songo – Apollo scheme, but is evaluated as feasible in view of the fact that the system in South Africa will be considerably larger in future compared to the time the Songo – Apollo scheme was implemented. Some load shedding would be required for loss of both poles on such a link, but the outage of a single pole should not require such measures – at least not if the DC scheme is designed with some temporary overload on the remaining pole.

The HVDC link from Inga to South Africa is found to be part of the least-cost plan in both Components B and C from 2032/33 – shortly after the HVDC from Inga to Luano discussed above.

As mentioned above, the Pool Plan was provided an inter-utility study on an HVDC link from Inga to South Africa following the dissemination workshop in Johannesburg in June 2017. The inter-utility study presents a solution based on a multi-terminal DC link Inga – Luano – Merensky. Although a multi-terminal solution may present cost savings, the risk of a simultaneous loss of both poles on the link between Inga and Luano must be accounted for. At 5000 MW transfer from Inga as foreseen in this Pool Plan study, such a fault would certainly black-out major parts of the SAPP system. The multi-terminal solution would therefore seem feasible for scenarios with less power from Inga – for instance if only the low dam of Inga 3 is developed. The Pool Plan indicates that further development of Inga beyond the low dam at Inga 3 would be part of the least-cost plan for the region in both Components B and C, and that this is the case even accounting for the higher investment costs of two HVDC schemes from Inga as outlined above.

In addition to the AC link between Inga and Angola and the HVDC links from Inga discussed above, the study has also evaluated reinforcement of the link from the Katanga Province into Zambia. Such a link may be a natural part of development of the hydropower potential on the Luapula River, and it is strongly recommended that further studies of projects on the border river between DRC and Zambia should investigate such options. Furthermore, plans for a link between Kolwezi and Solwezi has been considered earlier on and has also been included as one of the candidates in this study. However, the project has not been selected in any of the base case scenarios for Components B and C. The project may provide significant local benefits though. Depending on how the Gecamines project in Katanga is connected to the grid, a link from Kolwezi to Solwezi in Zambia may possibly form part of reinforcing the grid between Kolwezi and Fungurume – i.e. by routing the interconnection from Kolwezi via Fungurume to Solwezi. An in-feed from DRC to Solwezi may furthermore reduce the need to add a second line from Luano towards the substations in the North-Western Province in Zambia. Such local benefits combined with additional capacity for regional trade may still justify the project even though the project is not part of the least-cost development plan in Components B and C. Timing of the development of Inga and the DC link to Luano that is part of the least-cost plan may also impact on the viability of the Kolwezi – Solwezi interconnection project. As such, the project should definitely be of interest for further studies – in particular to support grid developments in the Katanga, Copperbelt and North-Western Provinces.

The table below summarises the grid investment costs for the Katanga Province as well as the new interconnections from DR Congo in Component B and C. Note the following split of costs on the HVDC links from Inga:

- ❑ For the HVDC from Inga to Zambia:
 - ❑ The costs of the HVDC lines inside Zambia and the converter terminal at Luano are included as part of the grid costs in Zambia
- ❑ For the HVDC from Inga to South Africa:
 - ❑ The costs for the HVDC lines up to the border of South Africa are reported as part of costs in DRC in the table below. Costs for HVDC lines and the converter station in South Africa are part of the grid costs reported in South Africa.

Figure 112 Transmission system expansion plan in DR Congo

TRANSMISSION PROJECTS											
Voltage [kV]	Substation		Distance [km]	Conductor type	Circuits	Tower type		Cost estimate [MUSD]	In service by year		
	From	To							Comp A	Comp B	Comp C
220	Busanga	Nseke	10	2xAster 228	1	Guyed V	SgCkt	17	2020		
220	Busanga	Kolwezi	55	2xAster 228	1	Guyed V	SgCkt	25	2020		
220	Busanga	Kolwezi	55	2xAster 228	1	Guyed V	SgCkt	27	2020		
220	Mambilima	Lubumbashi NR2	200	2xAster 228	1	Guyed V	SgCkt	72	2025	2031	2029
400	Inga ckt.1	N'zeto (to brdr) ckt.1	55	2xAster 228	1	Guyed V	SgCkt	25		2023	2020
400	Inga ckt.2	N'zeto (to brdr) ckt.2	55	2xAster 228	1	Guyed V	SgCkt	22		2023	2020
400	Inga ckt.3	N'zeto (to brdr) ckt.2	55	2xAster 228	1	Guyed V	SgCkt	25		2033	2034
500 DC	HVDC Inga III - Stage I - 1000 MW	HVDC Lubumbashi - Stage I - 1000 MW	1900	4 x Martin	2	Mono-pole lines		1440	2025		
500 DC	HVDC Inga III - 2000 MW	HVDC Luano - 2000 MW	1970	4 x Martin	2	Mono-pole lines		1260		2030	2031
600 DC	HVDC Inga III - 3000 MW	HVDC South Africa - 3000 MW	2800	5 x Martin	2	Mono-pole lines		2110		2033	2032
Total investment costs (million USD) by Component:								Total:	1582	3514	3514
Note: This estimate applies only to the part of the grid as may be impacted by the Pool Plan.								PV:	849	1226	1248

Note: Details on the location the new 500 MW coal plant and how this will be integrated to the grid in Katanga are not known and therefore not included in the above table. The assumption is that the bulk of the power will be fed into Fungurume. Grid connection assumed independent of regional grid integration scenarios.

The significantly higher investment costs in Component B and C are mainly related to the development of Inga and the addition of the DC links to Zambia and South Africa. Costs in Component B and C are almost identical. Considering how the Inga project could be implemented, the staging of the generators for Inga 3 and the first units at Inga 4 would be similar in these two Components. Although total investment costs are more than doubled, the present value (PV) increase by less than 50 % as the expansion of Inga and the DC links comes relatively late in the study period.

7.4 Lesotho

As mentioned in Section 6, the results for Component A indicates that there could be some unserved energy towards the end of the study period. An additional interconnection from South Africa would certainly eliminate such problems. Previous proposals to add a 132 kV line (possibly a double circuit line) from Clarens in South Africa to Khukhune in Lesotho

seem to be reasonable. If the system in South Africa can support such an in-feed in the north-east of Lesotho, it would provide added flexibility and reliability to the present system which basically is supported via links to Maseru further west.

If such an interconnection is terminated at Khukhune, the existing 88 kV at Khukhune should possibly be upgraded to 132 kV. Alternatively, the interconnection should be extended to one of the other planned 132 kV substations in the same area.

The PLEXOS results indicate that the new 132 kV interconnection – at a cost of ~\$20 m – is viable already by 2022 both in Components B and C. Further planning for such development should therefore be considered. The project has no impact on other regional developments as the power requirement is minor compared to the power exchanges elsewhere in SAPP. The least-cost options show that Lesotho will remain an importer throughout the study period, and the domestic generation is almost the same in Components B and C. Further regional integration of SAPP is therefore seen to have no significant impact on grid developments in Lesotho, but could still lower costs of imports.

7.5 Malawi

In Component A, Malawi remains separate from the rest of the SAPP grid and will have to rely on development of domestic resources. Malawi is, and will, for the next few years experience a shortage of generation capacity, and there are relatively high levels of unserved energy.

An interconnection can be built in relatively short time compared to some of the local, least-cost generation options. Adding an interconnection therefore proves to be a very viable option in the further development of the power system in Malawi. As the Tete area in Mozambique has generation surplus and has potential for further development of large power plants, an interconnection from Mozambique to Malawi seems an obvious option. In the medium term, Zambia and Tanzania may also possibly offer support, but a supply from for instance Chipata in Zambia would have much more limited capacity to support growth in Malawi. Similarly, a connection for instance from Mbeya would be very limited in the short term and even if the 400 kV grid in Tanzania is planned to grow in the future, significant investments in the north of Malawi would also be required to support import to Malawi from Tanzania.

For the SAPP Pool Plan, the addition of interconnections from Mozambique has therefore been the key option for power exchange between Malawi and the rest of SAPP. The results demonstrate that the first line should be added as soon as possible, preferably by 2020 in both Components B and C. The reason is that this would reduce the unserved energy significantly.

Further developments rest on the extent to which Malawi may choose to depend on imports. The transfer limit on the first interconnection is set relatively low at 200 MW. The reason is that a sudden loss of the line would cause a significant frequency drop on the system at the relatively low load levels in Malawi early on. To avoid having to shed load, imports would actually have to be limited to less than 200 MW, but accepting the risk of some load shedding for a few years seems acceptable on such a small system (large parts of the transmission system will not meet the N-1 planning criteria anyway). The least-cost

development plan in Component B includes a second 400 kV interconnection by 2022. In such a development scenario, it would be necessary to add the second line at the same time as the first line to increase the level of reliability (costs of construction would also drop somewhat if the two lines are added at the same time). A double circuit line is not recommended as simultaneous outages of both circuits at high levels of import would likely cause a system collapse.¹²

Component C requires that Malawi's domestic generation capacity should meet local peak demand. The higher investment in domestic generation means that the second interconnection would be viable only in 2028 – six years later than in Component B. At such a stage, it may be reasonable to consider if the second interconnection should provide access to the SAPP market via a second point of interconnection. With the lower levels of import and the further likely development of the local grid, Zambia and Tanzania may certainly be options at this stage. Further evaluation of such a second interconnection at a later stage should therefore naturally consider this issue closely.

For Component B, the PLEXOS simulations indicates that a third interconnection may be viable by 2033.

As the levels of import vary significantly between Components B and C, timing of the local power plants differs and therefore also the development of the 400 kV domestic grid differs somewhat. The internal grid also must be expanded to meet load growth, and the grid solution towards the end of the study period is therefore foreseen to be quite similar in all three Components A, B and C – it is mainly the timing of the different transmission projects that will differ.

Although the proposed interconnections from Malawi are mainly used for import, it should be noted that the lines would also provide an opportunity for export of power at times with high inflow to the hydropower stations. The lines also secure access to a market for the local generation in case the foreseen load growth does not take place. Similarly, should there be delays in development of local generation plants, the interconnections would eliminate or at least reduce the unserved energy that may otherwise have been the result. Furthermore, if Malawi becomes interconnected to the SAPP system, it will be technically feasible to integrate higher levels of intermittent renewable generation (PV plants and wind farms) than would otherwise be the case. The reason is that the larger SAPP system would stabilise the frequency which in a small islanded system would otherwise be more difficult to control (certainly costlier). Overall benefits of adding the proposed interconnections or similar projects are therefore likely to be higher than identified in this Pool Plan Study.

¹² The high import in Component B would require reinforcement of the grid in Mozambique between Songo and Matambo. Component C is as such more realistic and would probably fit better in with generation expansion and associated grid investments in Mozambique.

Figure 113 Transmission system expansion plan in Malawi

TRANSMISSION PROJECTS											
Voltage [kV]	Substation		Distance [km]	Conductor type	Circuits	Tower type		Cost estimate [MUSD]	In service by year		
	From	To							Comp A	Comp B	Comp C
400	Phombeya ckt. 1 only	Nkohma ckt. 1 only	173	2 x Bluejay	1	Y	DbCkt		2017	2017	2017
400	Phombeya string ckt. 2	Nkohma string ckt. 2	173	2 x Bluejay	1	Y	DbCkt	22	2021	2021	2021
400	Nkhoma	Kasungu	200	3 x Tern	1	Y	SgCkt	75	2020	2020	2020
400	Kasungu	New Bwengu	235	3 x Tern	1	Y	SgCkt	86	2023	2023	2023
400	Phombeya	Blantyre West	60	3 x Tern	1	Y	SgCkt	33	2023	2023	2023
400	Phombeya	Mpatamanga	70	3 x Tern	1	Y	SgCkt	33	2023		
400	Mpatamanga	Blantyre West	50	3 x Tern	1	Y	SgCkt	22	2023	2032	2023
400	Nkhoma	Kanengo	60	3 x Tern	1	Y	SgCkt	30	2024	2024	2024
400	New Bwengu	Fufu	55	3 x Tern	1	Y	SgCkt	29	2027	2037	2030
400	Kanengo	Dwangwa	220	3 x Tern	1	Y	SgCkt	81	2028	2028	2028
400	Dwangwa	New Bwengu	250	3 x Tern	1	Y	SgCkt	85	2028	2028	2028
400	Fufu	Coal North	120	3 x Tern	1	Y	SgCkt	49	2030	2038	2031
400	New Bwengu	Coal North	175	3 x Tern	1	Y	SgCkt	61	2030	2038	2031
400	Phombeya	Kholombidzo	15	3 x Tern	1	Y	SgCkt	11	2033	2035	2026
400	Phombeya ckt.1	Matambo (to brdr) ckt.1	100	3 x Tern	1	Y	SgCkt	58		2020	2020
400	Phombeya ckt.2	Matambo (to brdr) ckt.2	100	3 x Tern	1	Y	SgCkt	38		2022	2028
400	Cassapa T	Mpatamanga	15	3 x Tern	1	Y	SgCkt	8		2032	2023
400	Cassapa T	Mpatamanga	15	3 x Tern	1	Y	SgCkt	8		2032	2023
400	Phombeya ckt.3	Matambo (to brdr) ckt.3	100	3 x Tern	1	Y	SgCkt	44		2033	
Total investment costs (million USD) by Component:								Total:	595	717	674
Note: This estimate applies only to the part of the grid as may be impacted by the Pool Plan.								PV:	304	256	280

The overall investment costs on the grid in Malawi increases due to the addition of the interconnections to Mozambique. Integration with SAPP means that some of the investments in local power plants may be postponed, meaning that the present value of grid investment may be somewhat reduced. In Component B the assumption is that the second 400 kV line to Blantyre West is added at the same time as the development of Mpatamanga in 2032. To maintain the reliability of supply to Blantyre West, the second line may be required earlier on as in Component C. If implemented early on as in Component C, the difference in present value (PV) of investment costs in Component B and C would become minor.

A sensitivity test has been carried out for Component C based on less generation from natural gas in Mozambique and further expansion of the hydropower system on the Zambezi River- including the Cahora Bassa North Bank, Lupata and Boroma projects in addition to the Mphanda Nkuwa project which is part of the base case in Component C as well. The results indicate that in such a scenario, it is economical to implement the second 400 kV line from Mozambique to Malawi early by 2021, compared to 2028 in the base case for Component C, and modify the timing of domestic generation projects slightly. This indicates that the second interconnection from Malawi to its neighbours is sensitive to assumptions on timing and costs both of domestic generation projects and import options. To ensure stability of the system and to be able to stay interconnected following common line faults, it is certainly preferable to establish two links early on from a technical point of view.

7.6 Mozambique

Key transmission projects related to further regional integration in Mozambique are the 400 kV lines from Tete (Matambo) to Phombeya in Malawi as discussed above and the development of the STE grid from the Tete area to Maputo – creating a corridor for power transfer from north to south in Mozambique and making it possible to utilise the MOTRACO system for export of power to the region rather than import to the southern parts of Mozambique as has been the case since the MOTRACO system became operational.

These transmission projects would work hand-in-hand with the development of hydropower resources on the Zambezi as well as some coal fired projects early on, and may also facilitate further development of gas fired power plants later on.

The 400 kV lines from the Matambo substation in Tete to Phombeya in Malawi have been discussed above in the section on grid developments in Malawi. Two 400 kV lines (one possibly being linked to for instance Ncondezi if this coal plant is developed) would seem viable relatively early in the study period. The first line should be added by 2020 if possible. The second line is included from 2022 in Component B, and added by 2028 in Component C.

The other key driver for regional trade is the Mphanda Nkuwa hydropower project. The PLEXOS simulations indicate that the project may preferably be developed a bit later than in the plan as presented by EdM. The difference is marginal though – 2027 in Component B and 2028 in C as compared to 2025 in the Benchmark Case, Component A. In line with previous studies of the STE grid, the Pool Plan assumes that the 400 kV AC link between Cataxa and Maputo has to be completed once the new DC link between Cataxa and Maputo is added. There would be at least one 400 kV line from the Tete area to Maputo at the same time as the DC link from north to south is established.

Notably, the 1200 MW coal plant in Tete included in the Benchmark Case as well as the North Bank power station at Cahora Bassa are not part of the least-cost plan in the base cases for Components B and C. The two smaller 300 MW coal plants in the Tete area are still part of the development plan though.

The lower installed capacity in the Tete area, means that the second stage on the HVDC link from Cataxa to Maputo is not part of the plan in Components B and C. This was included from 2032 in the Benchmark Case. Furthermore, the first stage (i.e. rated 1325 MW) is running at a relatively low load factor.

All three Components A, B and C include additional gas fired generation in Mozambique from around 2030. The installed capacity is highest in Component B and relatively much lower in Components C and A. All scenarios assume that significant further generation may be added in the south of Mozambique. If such generation should be developed in the north, the use of the STE grid would be higher, and the second stage on the DC may be required also in Component B and C.

The high and increasing levels of export from Mozambique would require that a new 400 kV line from Maputo to South Africa is added around 2030. The alternative included in this study is based on a line from Maputo to the Marathon substation in South Africa. The line is part of the plan in the base case in Component B by 2030 and two years later in Component C.

The study has also considered upgrading the 330 kV line from Songo to Bindura and Dema in Zimbabwe to 400 kV. This line is designed for 400 kV, but operated at 330 kV. An upgrade would therefore provide additional transfer capacity at relatively low cost. The addition of a second 400 kV line has also been evaluated. Further increasing the transfer capacity between Mozambique and Zimbabwe has also been evaluated by adding a 400 kV link from Inchope in the Beira corridor to Orange Grove outside Mutare in Zimbabwe. None of these projects seem to provide benefits justifying the investment costs except towards the very end of the study period.

However, there are some uncertainties linked to these results. The PLEXOS model does not reflect impedances on parallel paths. The model may therefore at times utilise the links from Zimbabwe to Mozambique, South Africa and Botswana at their full capacity to transfer power from north to south within SAPP. This may actually not be feasible considering actual impedances on the parallel paths from north to south. It is likely that the links from Zimbabwe to South Africa and/or Botswana would be fully loaded while the power flow from Bindura to Songo would still be low. The DC links in Mozambique, i.e. the existing line from Songo to Apollo and the future DC line on the STE backbone grid, may to some extent be used to control wheeling from Zimbabwe via Mozambique to South Africa, but to achieve full control may require the addition of a phase-shift transformer at Songo.

At high levels of generation in the Tete area, the typical power flow on the Songo – Bindura line would be from Mozambique to Zimbabwe, and this line may at such times become a bottleneck for export from Mozambique. System stability and control would also benefit from having two lines between Songo/Tete and Zimbabwe. Historically, outages on this part have proven to be challenging, although with other reinforcements in place, such problems may become less. The reinforcement of the link from Songo to Bindura still seems a promising alternative, and should be further considered in view of possible needs for modifications to the STE grid (see also comments in the section on grid developments in Zimbabwe below).

Furthermore, a transmission line from Songo to Msoro in Zambia has not been found to present a viable option except towards the end of the study period in Component B. Somewhat similar to the Kolwezi – Solwezi project discussed as part of the presentation of results for Zambia and DRC, the local benefits in view of securing back-up supply to the areas east of Pensulo (Msoro and Chipata) may however justify this link at some stage. A link to Chipata from the future 400 kV grid in the Lilongwe area in Malawi may provide similar benefits.

In Components B and C, a third 400 kV line between Maputo and South Africa is required to support the existing two 400 kV lines on the MOTRACO system. This line is required to support export from Mozambique which would otherwise be limited by the thermal capacity on the 275 kV interconnection during outages on the 400 kV system. The need for such export capacity is naturally dependent on generation expansion in Mozambique and in particular the development of projects in the Tete area (not least Mphanda Nkuwa) and the STE backbone grid from Tete to Maputo. Should such developments be postponed, the third line between South Africa and Maputo may be required to support import to the southern areas of Mozambique (and the timing of the project may naturally shift). Such development may also be dependent on the need for upgrade of the 275 kV system in South Africa towards the border areas.

Figure 114 Transmission system expansion plan in Mozambique

TRANSMISSION PROJECTS												
Voltage [kV]	Substation		Distance [km]	Conductor type	Circuits	Tower type		Cost estimate [MUSD]	In service by year			
	From	To							Comp A	Comp B	Comp C	
400	Chimuara (Caia)	Namialo	780	3 x Tern	1	Guyed V	SgCkt	243	2022	2022	2022	
400	Vilanculos	Chibuto	340	4 x Tern	1	Guyed V	SgCkt	145	2022	2022	2022	
400	Chibuto	Matalane	179	4 x Tern	1	Guyed V	SgCkt	80	2022	2022	2022	
400	Matalane	Maputo	44	4 x Tern	1	Guyed V	SgCkt	27	2022	2022	2022	
400	Songo	Matambo	118	4 x Tern	1	Y	SgCkt	80	2021	2020	2020	
	Above line to connect to Cataxa once Mphanda Nkuwa is added							8	2025	2027	2028	
400	Mphanda Nkuwa 1	Cataxa 1	18	4 x Tern	1	Y	SgCkt	26	2025	2027	2028	
400	Mphanda Nkuwa 2	Cataxa 2	18	4 x Tern	1	Y	SgCkt	15	2025	2027	2028	
400	Cataxa ckt. 2	Matambo ckt. 2	64	4 x Tern	1	Y	SgCkt	49	2025			
400	Matambo	Lupata	80	4 x Tern	1	Guyed V	SgCkt	63	2023	2023	2023	
400	Lupata	Chimuara	210	3 x Tern	1	Guyed V	SgCkt	72	2023	2023	2023	
400	Lupata ckt. 2	Chimuara ckt. 2	210	3 x Tern	1	Guyed V	SgCkt	67	2025	2025	2025	
400	Lupata	Inchope	304	4 x Tern	1	Guyed V	SgCkt	182	2023	2023	2023	
400	Inchope	Vilanculos	352	4 x Tern	1	Guyed V	SgCkt	222	2025	2027	2028	
400	Vilanculos ckt. 2	Chibuto ckt. 2	340	4 x Tern	1	Guyed V	SgCkt	215	2025	2027	2028	
400	Chibuto ckt. 2	Matalane ckt. 2	179	4 x Tern	1	Guyed V	SgCkt	115	2025	2027	2028	
400	Matalane ckt. 2	Maputo ckt. 2	44	4 x Tern	1	Guyed V	SgCkt	24	2025	2027	2028	
500	HVDC Cataxa	HVDC Maputo	1276	4 x Martin	1	Bi-pole DC line		740	2025	2027	2028	
500	Increased converter capacity at Cataxa and Maputo							270	2032			
400	Songo	Cahora Bassa North	10	4 x Tern	1	Y	SgCkt	17	2026			
400	Cahora Bassa North	Cataxa	64	4 x Tern	1	Y	SgCkt	34	2026			
400	Songo ckt.2	Matambo ckt.2	118	4 x Tern	1	Y	SgCkt	74		2020	2020	
	Above line to connect to Cataxa once Mphanda Nkuwa is added							8		2027	2028	
400	Matambo ckt.1	Phombeya (to brdr) ckt 1	110	3 x Tern	1	Guyed V	SgCkt	41		2020	2020	
400	Matambo ckt.2	Phombeya (to brdr) ckt 2	110	3 x Tern	1	Guyed V	SgCkt	36		2022	2028	
400	Matambo ckt.3	Phombeya (to brdr) ckt 3	110	3 x Tern	1	Guyed V	SgCkt	36		2033		
400	Maputo	Marathon (to border)	50	3 x Tern	1	Cross Rope	SgCkt	25		2028	2032	
400	Songo	Bindura - Dema upgr.	0	3 x Tern	1	Guyed V	SgCkt	18		2037		
400	Songo ckt. 2	Bindura ckt.2 (to brdr)	125	3 x Tern	1	Guyed V	SgCkt	42		2038		
400	Songo	Msoro (to brdr)	170	3 x Tern	1	Guyed V	SgCkt	61		2040		
400	Inchope	Orange Grove (to brdr)	140	3 x Tern	1	Guyed V	SgCkt	53		2040		
Total investment costs (million USD) by Component:								Total:	2695	2719	2510	
								PV:	1461	1407	1309	

Note: This estimate applies only to the part of the grid as may be impacted by the Pool Plan.

Investment costs for the main transmission grid in Mozambique are presented in the table above. Total investment costs are lower in Component B and C than in the Benchmark Case even though a number of new interconnections are added. The main reason is that the increase in converter capacity that is required by 2032 in the Benchmark Case is not part of the development plan in B and C. The STE backbone grid in Mozambique is also added two or three years later as the Mphanda Nkuwa project is postponed compared to the Benchmark Case. There is therefore a potential reduction in present value of investment costs in the order of \$50 m in Component B and about \$150 m in Component C. The results indicate that it may be possible to modify the STE backbone grid solution or at least reconsider the scheduling of the different components making up the DC and AC link from north to south.

It should be noted that the cost of upgrading the DC converter stations on the DC link from Cataxa to Maputo is not much different from the cost of the series compensation and the SVCs required for the previously proposed solution for the STE project. It may therefore be an alternative to increase the capacity on the DC link and reduce or postpone (or even avoid) the costly compensation on the AC link which is mainly required once the DC is running at full capacity of 2650 MW. Further reduction of the transmission costs in Mozambique may therefore be feasible. Reinforcement of the AC link from Songo via Zimbabwe to South Africa may also support the AC grid in Mozambique – making it possible to adjust the level of series compensation on the AC line in Mozambique (and possibly also avoid having to use 550 kV design of the equipment on this part of the 400 kV system).

Notably, even in the sensitivity test for Component C which includes the Cahora Bassa North Bank and development of Lupata and Batoka in addition to the Mphanda Nkuwa project on the Zambezi River, it is not found economical to increase of the capacity of the DC link on the STE backbone grid in Mozambique from 1,325 MW to 2,650 MW. The third line from the Maputo area to South Africa is added earlier though (2032 vs. 2038).

As commented on above, the surplus capacity in Botswana is less in this sensitivity study for Component C, and as a result the energy flow from northern Mozambique to and via Zimbabwe is higher. Consequently, the reinforcement of the link from Kariba via Alaska towards Harare is also dropped in this case.

This demonstrates (as would be expected) that the interconnectors and the timing of these may easily shift if the generation expansion plans are altered. However the impact is mostly towards the end of the study period. There is therefore ample time to adjust the transmission plans in line with actual developments and further, more detailed input on the cost of the different generation projects.

It should also be noted that a link from the north of Mozambique to Tanzania has been considered. Results from PLEXOS indicated no or minor regional benefits from such a project – linked to the fact that gas fired generation in the border area of the two countries would have similar costs. Due to the long distances to reach load centres in the two countries, high levels of trade would also require major investments on the transmission grid in the area. An interconnection allowing for some local trade across the border may very well be viable. In Mozambique, such a project may save investments in reinforcement of the grid from Tete to the northern provinces in Mozambique and would also allow for some export from local gas fired generation in the north. A link between the northern parts of Mozambique and Malawi may also be of interest in this regard (ref. the previously considered link from Phombeya to Nampula).

7.7 Namibia

In the Benchmark Case (Component A), the transmission grid developments in Namibia were driven by the development of Kudu in 2024 and Baynes by 2029. The timing of the Baynes project is unchanged in the base case for Component B whereas it comes two years earlier in Component C – i.e. by 2027. The development of the Kudu project also remains as an early investment in Component C – i.e. by 2024 as in A – but is postponed until 2037 in Component B.

Furthermore, both Components B and C indicates that a link from Angola to Namibia should be established early on – by 2022 if possible. A second link from Angola to Namibia does not seem viable. As the Baynes project is included by 2027/2029, the preferred line route would seem to be the line route considered for connection of Baynes. Such development early on may seem to depend on some firm commitment on the Baynes projects, and a more direct and shorter route may therefore be the preferred option. Further detailed analyses of the interconnection project should address this issue in detail. The outcome of such studies may be highly dependent on the potential for a second link between the two countries – which may also depend on the development of the proposed link between Angola and DRC.

The main benefit of the first interconnection between Angola and Namibia is related to export of surplus power from Angola. The capacity of the first interconnection between Angola and Namibia is relatively modest at about 250 MW due to steady state voltage constraints during outages on the grid in Angola. Actual developments on the grid in Angola, and the load level in the southern part of the system, is naturally uncertain. Even though the transfer limit has been set relatively low, the project is still found to be economical early on. Actual benefits of the project may therefore be higher than what may seem likely from the simulations in the Pool Plan. Further planning of the interconnection of Angola and Namibia should also investigate the impact of loss of the link at high transfer levels. In this regard, a second link between the two countries may be justified to ensure stability of both the generators at the Baynes project and the entire integrated system of Angola and Namibia. Such studies would require more detail on characteristics of the power plants in Angola than what has been available for this study.

To facilitate the import of power from Angola early on and prior to development of the Baynes project, it would be necessary to upgrade the grid in the northern part of Namibia. The 400 kV system from Kunene to Omburu etc. as planned for the integration of Baynes should therefore be established earlier on than in the Benchmark case.

Further regional integration by adding a second 400 kV line to South Africa is part of the least-cost plan in conjunction with the development of the Kudu project – i.e. by 2024 in Component C, but only in 2037 in Component B. The addition of a second 400 kV line between Namibia and South Africa along the existing 400 kV line from Aries to Kokerboom has been evaluated as an option independent of the development of the Kudu project. The results are that the Kudu project and the second link coincide, and the connection from Kudu to Oranjemund in line with previous studies therefore seems the preferred alternative.

Total investment costs on the main grid in Namibia is slightly higher in Component B than in the Benchmark Case, but almost \$100 m lower in Component C. The change to the grid integration of Kudu is the main reason for the lower costs in Component C as the Kudu project will be linked to South Africa. Part of the grid integration costs for Kudu are therefore seen on the system in South Africa rather than in Namibia. Similar reduction in costs in Component B will also materialise, but the DC link on the Caprivi Strip is upgraded in Component B – bringing the total costs close to the Benchmark Case. Note that the upgrade of the system in the north as planned for connection of the Baynes project has been assumed built early on to allow for trade with Angola from 2022. As a result, the present value of costs increases somewhat both in B and C compared to A.

Figure 115 Transmission system expansion plan in Namibia

TRANSMISSION PROJECTS												
Voltage [kV]	Substation		Distance [km]	Conductor type	Circuits	Tower type		Cost estimate [MUSD]	In service by year			
	From	To							Comp A	Comp B	Comp C	
400	Kunene	Omatando	190	3 x Tern	1	Cross Rope	SgCkt		2017	2017	2017	
400	Gerus	Otjikoto	174.6	3 x Tern	1	Cross Rope	SgCkt		2017	2017	2017	
400	Auas	Gerus	265	3 x Tern	1	Cross Rope	SgCkt	84	2019	2019	2019	
330	Ruacana	Kunene	20	3 x Tern	1	Cross Rope	SgCkt	31	2020	2020	2020	
400	Kudu ckt.1	Obib ckt.1	50	4 x Tern	1	Cross Rope	SgCkt	30	2024	2037	2024	
400	Kudu ckt.2	Obib ckt.2	50	4 x Tern	1	Cross Rope	SgCkt	22	2024			
400	Obib	Kokerboom	252	4 x Tern	1	Cross Rope	SgCkt	89	2024			
400	Kokerboom	Auas	445.8	4 x Tern	1	Cross Rope	SgCkt	150	2024	2024	2024	
400	Auas	Omburo	200	4 x Tern	1	Cross Rope	SgCkt	72	2024	2024	2024	
400	Omburo	Gerus	140	4 x Tern	1	Cross Rope	SgCkt	53	2024	2024	2024	
400	Baynes	Kunene	180	3 x Tern	1	Y	SgCkt	68	2029	2022	2022	
400	Kunene	Omburu	481.5	4 x Tern	1	Cross Rope	SgCkt	158	2029	2022	2022	
400	Omatando	Otjikoto	275	4 x Tern	1	Cross Rope	SgCkt	93	2029	2022	2022	
400	Kudu	Oranjemund (to brdr)	44	4 x Tern	2	Cross Rope	SgCkt	18		2037	2024	
400	Zambezi	Livingstone (to brdr)	5	3 x Tern	1	Y	SgCkt	18		2035	2039	
350	HVDC on Caprivi Strip - Upgrade of converter capacity								90		2040	
Total investment costs (million USD) by Component:								Total:	850	865	775	
Note: This estimate applies only to the part of the grid as may be impacted by the Pool Plan.								PV:	452	482	477	

An important point to note, is that the timing of the Kudu project seems to be very dependent on other developments in the region.

7.8 South Africa

In the Benchmark Case, South Africa imports significant levels of power and energy from around 2025 although import is partly limited by the capacity of the grid connections to neighbouring countries.

Both Components B and C indicate that significant regional benefits may be achieved by covering higher levels of the demand in South Africa from low-cost generation options throughout SAPP. This would naturally require additional transfer capacity on links to neighbouring countries.

However, South Africa will initially be a net exporter of power, and the new transmission lines are therefore required only when the power flow is reversed on the main interconnections already in place (or committed, like the Nzhelele – Triangle line).

In Component C, the Kudu project in Namibia is part of the least-cost expansion plan by 2024, and a second 400 kV link between South Africa and Namibia is found viable at the same time. This project is included only by 2037 in Component B – indicating that the project is sensitive to development of other regional projects.

Additional cross-border reinforcements will be needed from 2030 onwards. The main driver is the development of Inga in DRC and an HVDC link from Inga to South Africa. As discussed in the section on DRC, the termination point for such a link could be Merensky as proposed by an inter-utility study team for a DC link from Inga via the Katanga/Copperbelt area to South Africa. An alternative termination point could be in an area closer to the major load centre in the Gauteng Province. Such a link may be built via Angola, Namibia and Botswana – possibly allowing for a terminal close to the main hydropower plants on the

Kwanza River in Angola (and technically also DC terminals in Namibia and/or Botswana, but such options would seem costly considering the load level in these two countries).

The maximum capacity for a DC converter station in South Africa on such a DC link from Inga should probably be about 3000 MW to ensure that the system can sustain a sudden loss of one pole without causing massive load shedding on the system in South Africa (system protection schemes handling loss of both poles would be required). A sudden loss of a 1500 MW in-feed is somewhat higher than the current dimensioning fault on the system in South Africa, but is considered acceptable in view of the higher load on the system by 2032/33 when the DC from Inga is part of the least-cost development plan in the base case for Components B and C. Further detailed analyses of such a DC link should also carefully consider the need for temporary overload on the remaining pole in case of DC faults in order to minimise the impact on the AC system.

The development of the Mphanda Nkuwa project and the STE grid in Mozambique – combined with further development of generation projects in Mozambique – may support the demand in South Africa by reversing the power flow on the MOTRACO system. Further potential import from Mozambique indicates that the reinforcement of the MOTRACO system may be viable by 2030/32 by adding for instance a 400 kV line from Maputo to Marathon.

The Isang – Watershed project reinforcing the connection between Botswana and South Africa is also included by 2031 in Component C. In Component B, this link is only added right at the end of the study period as Component B results in somewhat less power from north to south – partly as a result of imports to Tanzania via a DC link from Kabwe to Mbeya. If the grid in South Africa towards the Watershed substation needs to be reinforced regardless of whether the link from Isang to Watershed is added, the inclusion of this project may certainly be viable at an earlier stage than what has been identified in this study.

A second link between South Africa and Zimbabwe does not seem to be viable until right at the end of the study period. This project is also commented on in the section on Zimbabwe. However, this result may be sensitive to other developments on the grid – not least generation expansion in Botswana and the timing of the Isang – Watershed link.

If for instance the link from Songo to Bindura and Dema is reinforced to increase the capability for power evacuation from the Tete area, the second link between Zimbabwe and South Africa would likely be more viable. Staging of the different components on the STE grid in Mozambique may therefore also impact on the possible return on a second link between Zimbabwe and South Africa. The overall costs of grid developments in this area are likely to be quite similar regardless of which project is developed first in this area. It may actually be the commercial arrangements between buyer and seller and wheeling costs that would decide the preferred approach in the end.

The new interconnections increase the costs on the grid in the border areas in South Africa considerably (see table below). The DC link from Inga is the largest cost component, but integration of Kudu and the strengthening of the links to Botswana and Mozambique also adds significantly to the costs. Some of the projects are implemented relatively late in the study period, and the increase in present value (PV) costs are therefore comparably less.

Of importance to note is the fact that the link from Inga is added around 2032/33 in both Components B and C. The Kudu project and the link to Namibia as well as the Isang –

Watershed project seems much more dependent on other regional developments. The development or not of the HVDC link from Kabwe to Mbeya appears to shift the development of these projects in Component B and C.

Figure 116 Transmission system expansion plan in South Africa

TRANSMISSION PROJECTS										
Voltage [kV]	Substation		Distance [km]	Conductor type	Circuits	Tower type	Cost estimate [MUSD]	In service by year		
	From	To						Comp A	Comp B	Comp C
Western area towards Namibia										
400	Aries	Niuwehoop	90		1	Cross Rope SgCkt		2017	2017	2017
400	Niuwehoop	Upington	70		1	Cross Rope SgCkt		2017	2017	2017
400	Ferrum	Niuwehoop	239		1	Cross Rope SgCkt	74	2019	2019	2019
400	Juno	Gromis	260		1	Cross Rope SgCkt	84	2021	2021	2021
400	Mookodi	Hotazel	237		1	Cross Rope SgCkt	75	2021	2021	2021
400	Ferrum	Hotazel	53		1	Cross Rope SgCkt	20	2021	2021	2021
400	Aries	Upington	145		1	Cross Rope SgCkt	53	2022	2022	2022
400	Aries - ckt. 2	Upington - ckt. 2	145		1	Cross Rope SgCkt	45	2023	2023	2023
400	Ferrum	Upington	225		1	Cross Rope SgCkt	67	2023	2023	2023
400	Oranjemund ckt.1	Kudu (to border) ckt.1	1	3 x Tern	1	Cross Rope SgCkt	9		2037	2024
400	Oranjemund ckt.2	Kudu (to border) ckt.2	1	3 x Tern	1	Cross Rope SgCkt	3		2037	2024
400	Oranjemund	Aggeneis	260	3 x Tern	1	Cross Rope SgCkt	79		2037	2024
400	Oranjemund	Gromis	130	3 x Tern	1	Cross Rope SgCkt	44		2037	2024
Northern area towards Botswana and Zimbabwe										
400	Medupi - ckt. 1	Ngwedi - ckt. 1	200		1	Cross Rope SgCkt	68	2018	2018	2018
400	Medupi - ckt. 2	Ngwedi - ckt. 2	200		1	Cross Rope SgCkt	60	2018	2018	2018
400	Tubat	Senakangwedi	60		1	Cross Rope SgCkt	28	2020	2020	2020
400	Tubat	Silimela	50		1	Cross Rope SgCkt	23	2020	2020	2020
400	Masa - ckt. 1	Medupi - ckt. 2	20		1	Cross Rope SgCkt	17	2021	2021	2021
400	Masa - ckt. 2	Medupi - ckt. 2	20		1	Cross Rope SgCkt	12	2021	2021	2021
400	Borutho	Silimela	100		1	Cross Rope SgCkt	39	2022	2022	2022
400	Silimela	Emkhiweni	80		1	Cross Rope SgCkt	34	2022	2022	2022
400	Borutho	Nzhelele	250		1	Cross Rope SgCkt	79	2021	2021	2021
400	Tabor	Nzhelele	170		1	Cross Rope SgCkt	52	2021	2021	2021
400	Nzhelele	Triangle (to border)	60	3 x Tern	1	Cross Rope SgCkt	19	2021	2021	2021
400	Masa	Witkop	220		1	Cross Rope SgCkt	68	2026	2026	2026
400	Watershed	Isang (to border)	165	3 x Tern	1	Cross Rope SgCkt	59		2039	2031
400	Watershed	Pluto	145	3 x Tern	1	Cross Rope SgCkt	48		2039	2031
400	Watershed	Mookodi	180	3 x Tern	1	Cross Rope SgCkt	58		2039	2031
400	Nzhelele	Insukamini (to border)	60	3 x Tern	1	Cross Rope SgCkt	22		2039	2031
600 DC	HVDC Inga III - 3000 MW (from brdr)	HVDC South Africa - 3000 MW	300	5 x Martin	2	Mono-pole lines	540		2033	2032
Eastern area towards Swaziland and Mozambique										
400	Arnot	Gumeni	55		1	Cross Rope SgCkt	59	2022	2022	2022
400	Gumeni	Marathon	92		1	Cross Rope SgCkt	66	2023	2023	2023
400	Marathon	Maputo (to border)	92		1	Cross Rope SgCkt	61		2030	2032
Total investment costs (million USD) by Component:							Total:	1043	1966	1966
Note: This estimate applies only to the 400 kV system as may be impacted by the Pool Plan.							PV:	704	976	1053

7.9 Swaziland

The generation expansion plan for Swaziland in Components B and C remains identical to Component A – meaning Swaziland remains an importer of about 1.0-1.5 TWh annually. The existing 400 kV substation at Edwaleni – with its connections to South Africa and Mozambique – is considered adequate to support the required levels of power exchange. Developments in Swaziland are therefore not considered to have a significant impact on regional developments in SAPP, and the transmission development plan for Swaziland is

not affected by the regional development scenarios in Component B and C, but such developments may have an impact on the costs of imports to Swaziland.

7.10 Tanzania

In Component A, there is potential for some export from Tanzania to other SAPP members via the committed link from Kasama to Mbeya (single 330 kV line from Kasama to Nakonde 400/330 kV substation and 420 kV double circuit line from Nakonde/Tunduma to Mbeya) assuming this project is in place early on and the generation expansion plan in Tanzania is realised. Beyond 2023, this link is mainly used for import to Tanzania in the Benchmark Case.

The Pool Plan has considered several alternatives for increasing the transfer capacity between Zambia and Tanzania. The results early on indicated that the potential for large scale trade was limited. The previously proposed HVDC scheme connecting Kabwe and Tunduma/Mbeya at a rating of 2000 MW in stages of 1000 MW was therefore scaled down to 1500 MW with the option of developing this in stages of 750 MW. An alternative with a second 330 kV line to Nakonde running along the first interconnection was also added.

The transfer limit for the committed interconnection from Kasama to Nakonde/Tunduma and Mbeya is dependent on the load level in the north-eastern grid in Zambia and also support from local generation. The Kalungwishi power plant is important in this respect, but to our knowledge, this project has limited firm capacity – providing most of the energy output in the wet season. Furthermore, in view of the indicative results early on that the viability of additional interconnections between Zambia and Tanzania was poor, it was decided to set the transfer limit at a relatively conservative 200 MW for the committed line.

Neither the second AC link nor the HVDC link are chosen as part of the least-cost development plan in the base case in Component C even though the 200 MW transfer limit set on the committed link is fully utilised in some years. If the actual transfer limit on the committed link can be raised somewhat above 200 MW (for instance by adding SVCs), that would likely be beneficial, but would have a marginal impact on the overall regional developments. It is understood that further detailed studies of this initial development are still on-going. A critical limitation at least for the early operation of this link will be the impact of a sudden loss of the interconnection if carrying power up to 400-500 MW as indicated as a possible transfer limit by the utilities.

The results from Component C indicates that the economic viability of strengthening the interconnection between Tanzania and Zambia beyond the first committed project may be questionable. However, if the system in Tanzania relies more heavily on imports as in Component B, the HVDC link from Kabwe to Mbeya is added in 2030. The HVDC will be running at a relatively modest load factor – in particular during the initial years of operation. Therefore, scaling down the capacity of the interconnection further may be justified. The impact on the overall costs of the Pool Plan if the project is postponed would seem marginal. The justification of the project may therefore hinge on requirements during years with very high or very low output from the hydropower plants in the region and the need for high transfer capacity across borders in such cases. Higher levels of intermittent renewable power may also benefit from stronger regional interconnections.

It is noted that further development of the grid in the EAPP countries and possibilities for trade between EAPP and SAPP may also have a significant impact on the need for and benefits from stronger links between Zambia and Tanzania. Further evaluation of such projects in view of future EAPP-SAPP trade may therefore lead to different conclusions from those drawn above.

In the long term, the 400 kV system in Malawi will also be developed towards the northern parts allowing for interconnection with Tanzania (local generation projects like alternatives on the Songwe River may also support such development). Tanzania and Mozambique may also interconnect at relatively low cost in future when both countries have extended their main grid to the gas fields in the border areas. Due to the distances covered by such transmission lines, the incremental capacity for regional trade is likely to be limited, but the projects may still be of high value locally – not least to ensure back-up supply.

The levels of trade between Tanzania and SAPP as seen in this Pool Plan study, are not seen to have a major impact on grid development costs in Tanzania. The grid expansion plan presented in the latest Master Plan is very ambitious, and there would seem to be a high risk of power imbalances as load grows and the generation system is expanded very rapidly. A link to SAPP may provide valuable support in such a development scenario – providing access to a market for surplus power and imports if generation is lagging behind load growth. Such benefits are likely to be considerably higher than any benefits that may be achieved from adjustment of the investment plan on the transmission system.

7.11 Zambia

According to information from Tanzania and Zambia, the 330 kV line from Kabwe via Pensulo to Kasama will be extended to Nakonde and the 400 kV system in Tanzania will be extended to Mbeya and Tunduma and across the border to a new 400/330 kV substation at Nakonde. This project has been considered as committed and is commented on in the section on Tanzania as well.

The interconnection between Zambia and Tanzania will also interconnect EAPP and SAPP. Integration of the EAPP countries will likely be relatively weak in the medium term. Outages on certain interconnections may therefore create large imbalances on parts of the EAPP system. The interconnected SAPP system is much larger than the system in Tanzania, and if for instance Tanzania is islanded from EAPP due to disturbances on the system, the grid in Tanzania will mainly be balanced by the grid in SAPP once interconnected to Zambia.

Any large power imbalance in Tanzania would in such a case be seen directly on the power exchange between Zambia and Tanzania – i.e. causing a step-change in the power transfer on the planned Kasama – Nakonde – Tunduma – Mbeya link. When setting the transfer limit on the interconnector, such events need to be taken into consideration. The damping of power oscillation on this link may also be critical as the damping of the 0.3-0.4 Hz interarea power oscillation prevalent in the SAPP system will likely be seen also on the link to Tanzania (and EAPP).

As the integration of the EAPP countries becomes stronger, such problems may diminish. However, the relatively weak interconnection from Mbeya to Kabwe may not be able to

maintain synchronism between two areas, and the interconnection of EAPP and SAPP must be studied closely as part of the integration of the two power pools. (In SAPP, a similar limitation is seen on the 220 kV line between Marvel in Zimbabwe and Francistown in Botswana. This link is too weak to keep the system north of the interconnection in synchronism with the system in South Africa if the 400 kV line between Zimbabwe and Botswana is out of service). An asynchronous DC link between Zambia and Tanzania may certainly be preferable from such a point of view, and these and similar technical constraints may justify why the EAPP and SAPP systems should preferably be interconnected via a back-to-back AC-DC-AC solution in the future if an HVDC link is not viable.

The interesting outcome of the Pool Plan is that even if the transfer limit on the committed 330 kV interconnection between Zambia and Tanzania is set conservatively low (due to steady state voltage constraints in the northern parts of the system in Zambia), the addition of a second 330 kV line or a DC link does not seem to be viable in Component C, and is added only by 2030 in Component B. Note also that DC links rated 1,500 MW and 2,000 MW have been considered – in stages of 750 MW as well as 1,000 MW. Even for Component B, the link would be running at a relatively low load factor, and a DC link with a lower rating than 1,500 MW may therefore be a more optimal solution if going ahead with this project.

To maximise the benefit of the committed interconnection from Kasama via Nakonde to Mbeya, it is proposed that detailed studies of the interconnection (understood to be ongoing) should consider the benefits of increasing the transfer limit by installing one or more SVCs along the system. An SVC may also preferably include a power oscillation damper function to ensure that inter-area oscillations are properly damped. The impact of a sudden loss of the interconnection at high transfer levels must be studied in detail. The frequency response on the system in Tanzania may be critical and could therefore limit the maximum transfer.

Furthermore, the transient stability of the SAPP system and in particular the system in Zambia and Zimbabwe may also limit the maximum power exchange between Zambia and Tanzania (certainly early on). Too high load/generation imbalances on the system in Zambia and Zimbabwe are known to cause transient instability and separation of the grid in the west of Zimbabwe or on the link between Zimbabwe, Botswana and South Africa. This limit will increase as the grid is reinforced, but this is certainly an important issue to note in the short term. For further details on this link, please also see comments in the section on Tanzania above.

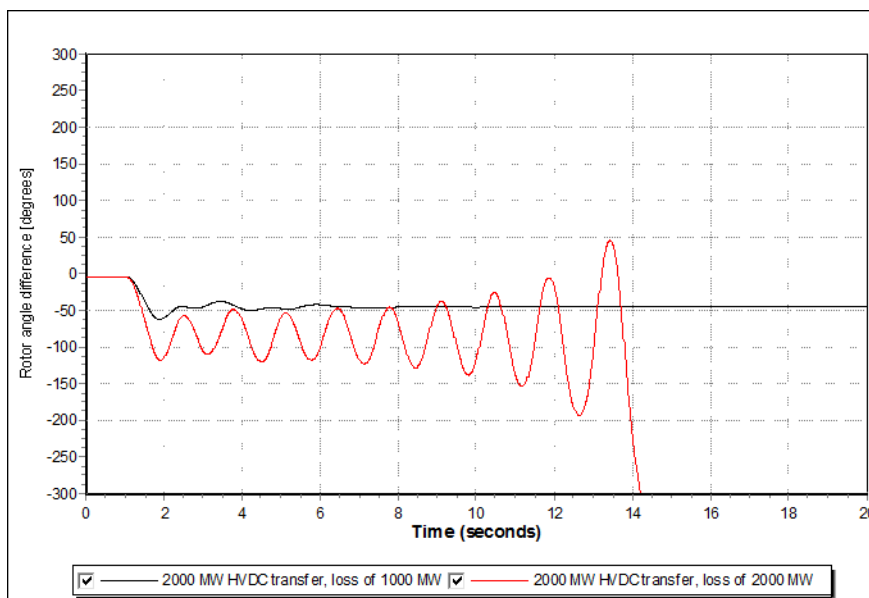
The main regional project that impacts on the system in Zambia is the development of Inga and the addition of an in-feed of power from Inga either in the Katanga Province or in the Copperbelt Province. As discussed above, a DC converter terminal in the Luano area in the Copperbelt seems to provide the best solution from a technical point of view. The fault level in the 330 kV grid in Zambia is also higher than in the eastern grid in the Katanga Province in DRC. At the same time, Luano is a very central substation in the grid in this part of Zambia, and access to this substation seems simpler than for instance at the Kitwe substation.

The stability studies carried out indicate that a 2,000 MW link from Inga to Luano is close to the maximum capacity that can be accepted. The system as developed around stage 2030 – i.e. at the time such a link seems viable in Component B and C, seems to be able to sustain an outage of a single pole on such a DC link. This is demonstrated in the following figure showing that the system is stable for loss of 1,000 MW on a DC link carrying 2,000 MW at

the foreseen load levels by 2030. Loss of both poles would require system protection schemes shedding major loads. This is demonstrated by the undamped oscillation leading to a transient instability following a loss of both poles.

The system response is very dependent on the load level on the system and not least generation dispatch, and therefore transfers across main interconnections between Zambia, Zimbabwe, Botswana and South Africa. Note also that the Pool Plan includes the STE grid in Mozambique prior to the HVDC links from Inga. This part of the system is also contributing to the stability margin on the overall system in view of high transfers from north to south. The maximum in-feed from a DC link from Inga to Luano is therefore dependent on a number of other projects on the grid, and the transfer limit on this DC link is therefore dependent both on timing and in general system reinforcement and expansion – which is linked to load growth in the system.

Figure 117 Rotor angle on power plants in Katanga (vs South Africa) following loss of power transfer on HVDC Inga - Luano



Further detailed feasibility studies of such a DC link would be required to optimise the rating of such a scheme. Such optimisation will also have to consider details on parallel operation with the existing DC link from Inga and the need for or benefits of temporary overload capability on the proposed link. The results indicate that the Inga 3 and first units of the Inga 4 project may be part of the least-cost plan around 2030, and the HVDC link from Inga to Luano should be added by 2030/31 in Component B and C. In most years after the Inga - Luano link is added, the link is running at load factors in the range of 50 - 80 %, being fully loaded only in 2-3 years. A somewhat lower rating than the indicative 2000 MW may therefore be optimal.

With the in-feed of power from Inga into the Copperbelt area, the power flow on the system will change significantly. As a result, the load on the interconnectors from Zambia to other neighbouring utilities increases. As discussed above, the HVDC Kabwe - Mbeya is added in 2030 in Component B, but not in Component C. Component C includes reinforcement of the link from Kariba North to Alaska by 2033 instead (not part of Component B as more power

is transferred to Tanzania instead). The further reinforcement from Alaska via Chakari and Selous to Dema should be added at the same time.

It may be suspected that the overall costs for the Pool Plan is not much different whether developments are based on adding the DC link Kabwe – Mbeya or the reinforcement of Kariba – Alaska – Chakari – Selous – Dema around this time.

Further additional transfer capacity from Zambia may include upgrade of the link to Namibia, but only towards the end of the study period. In Component B, the Livingstone – Sesheke/Katima Mulilo line is added in 2035 and the DC link on the Caprivi Strip is upgraded in 2040. Similar investment may be viable in Component C, but a few years later. Further investment in incremental capacity in the link between Zambia and Namibia in the medium term would therefore seem to hinge on whether there are local benefits that are not necessarily addressed in detail in the Pool Plan study.

A transmission link from Mozambique to Zambia – i.e. from Songo to Msoro – has not been found to be part of the least-cost development plan except towards the end of the study period in Component B. Likewise, the Solwezi – Kolwezi project (also discussed as part of the presentation of results for DRC) does not seem to provide benefits that justify inclusion on the least-cost development plan. As discussed as part of the presentation for DRC and Mozambique above, both projects may provide local benefits that could justify development earlier on. For the Solwezi – Kolwezi project, this may be related to stabilising local generation and possibly also postponement of other grid investments that may be required without the interconnection. In case of the grid east of Pensulo, there are local benefits in view of securing back-up supply to the Msoro and Chipata substations. In this area, a link from Chipata to a substation on the future 400 kV grid in the Lilongwe area in Malawi may provide similar benefits and should naturally be considered an alternative (providing benefits also to Malawi).

Note that the cost estimates presented in the table below are based on the assumption that all new lines in Zambia will be designed for 400 kV even though operating at 330 kV initially. Double circuit lines are used on some connections. Further planning of these links should carefully consider the risk of double circuit faults on such connections.

Figure 118 Transmission system expansion plan in Zambia

TRANSMISSION PROJECTS												
Voltage [kV]	Substation		Distance [km]	Conductor type	Circuits	Tower type		Cost estimate [MUSD]	In service by year			
	From	To							Comp A	Comp B	Comp C	
330	Maamba	Muzuma	46	2 x Bison	2	Y	DbCkt		2016	2016	2016	
330	Livingstone	Muzuma	159	2 x Bison	1	Guyed V	SgCkt		2017	2017	2017	
330	Muzuma	Kafue Town	189	2 x Bison	1	Guyed V	SgCkt		2017	2017	2017	
330	Kafue West	Lusaka West	42	3 x Bison	1	Guyed V	SgCkt	24	2018	2018	2018	
400	Livingstone	Hwange (to border)	10	3 x Bison	1	Guyed V	SgCkt	32	2020	2020	2020	
330	Kasama	Nakonde	200	3 x Bison	1	Guyed V	SgCkt	69	2019	2019	2019	
330	Pensulo	Mansa	294	3 x Bison	1	Guyed V	SgCkt	100	2019	2019	2019	
330	Kabwe	Pensulo	298	3 x Bison	1	Guyed V	SgCkt	95	2019	2019	2019	
330	Livingstone	Muzuma	159	3 x Bison	2	Y	DbCkt	93	2019	2019	2019	
330	Muzuma	Lusaka West	239	3 x Bison	2	Y	DbCkt	133	2019	2019	2019	
330	Luano SVC (+/- 100 MVA)								25	2019	2019	2019
330	Kalumbila (+/- 100 MVA)								25	2019	2019	2019
330	Kasama (+/- 150 MVA)								30	2020	2020	2020
330	Lusaka West	Kabwe	100	3 x Bison	1	Guyed V	SgCkt	35	2020	2020	2020	
330	Kafue Gorge Lower	Kafue Gorge	15	3 x Bison	1	Guyed V	SgCkt	19	2021	2021	2021	
330	Kafue Gorge Lower	Kafue West	57	3 x Bison	1	Guyed V	SgCkt	23	2021	2021	2021	
330	Kafue Gorge Lower	Lusaka West	100	3 x Bison	1	Guyed V	SgCkt	35	2021	2021	2021	
330	Batoka	Livingstone	22	3 x Bison	2	Y	DbCkt	32	2023	2023	2023	
330	Luano	Lumwana	262	3 x Bison	1	Guyed V	SgCkt	88	2024	2024	2024	
330	Kansanshi	Kalumbila	140	3 x Bison	1	Guyed V	SgCkt	53	2024	2024	2024	
330	Muzuma	Mumbwa	270	3 x Bison	1	Guyed V	SgCkt	90	2025	2025	2025	
330	Mumbwa	Luano	300	3 x Bison	2	Y	DbCkt	164	2025	2025	2025	
330	Devil's Gorge	Muzuma	130	3 x Bison	2	Y	DbCkt	86	2025	2025	2025	
330	Lusaka West	Kabwe	100	3 x Bison	1	Guyed V	SgCkt	41	2030	2030	2030	
330	Pensulo ckt.2	Kasama ckt.2	381	3 x Bison	1	Guyed V	SgCkt	122				
330	Kasama ckt.2	Nakonde ckt.2	200	3 x Bison	1	Guyed V	SgCkt	70				
500 DC	HVDC Inga III - 2000 MW (from brdr)	HVDC Luano - 2000 MW	60	4 x Martin	2	Mono-pole lines		250		2030	2031	
500 DC	HVDC Kabwe - 1500 MW	HVDC Nakonde/ Mbeya - 1500 MW	800	4 x Martin	2	Mono-pole lines		790		2030		
400	Kariba North	Alaska (to border)	10	3 x Bison	1	Y	SgCkt	23			2033	
400	Msoro	Songo (to border)	90	3 x Bison	1	Y	SgCkt	57		2040		
400	Livingstone	Zambezi (to border)	195	3 x Bison	1	Guyed V	SgCkt	60		2035	2039	
350	HVDC on Caprivi Strip - Upgrade of converter capacity								0		2040	
Total investment costs (million USD) by Component:								Total:	1291	2447	1624	
Note: This estimate applies only to the 400 kV system as may be impacted by the Pool Plan.								PV:	855	1286	967	

7.12 Zimbabwe

Further regional integration as in Component B and C would postpone major coal fired generation projects in Zimbabwe (except for the Hwange 7&8 project which is committed). The Lusulu, Gokwe North and also the Southern Energy projects therefore fall outside the study horizon or are included only late in the 2030s.

However, the Batoka project seems very promising and is part of the development plan by 2023 in all three main Components - the timeline may be short for such early implementation though. The Devil's Gorge project is not part of the least-cost expansion plan in Components B and C until 2032/33. Similar postponement of local generation projects is seen also in Zambia, but the addition of the DC link from Inga to Luano in 2030/31 also has an impact on power flows in Zimbabwe. Compared to the Benchmark Case (Component A), there is a higher flow of energy from north to south on the grid in the long term.

The result of the above changes is that the link from Victoria Falls to Pandamatenga in Botswana is added in 2028 in Component B and by 2032 in Component C. As discussed

under developments in Botswana, an earlier completion of this project may be viable when looking at local requirements for back-up supply to Pandamatenga. The corridor is therefore certainly of interest for further investigation and possible inclusion in the short to medium term (noting also that the link may support power flow from south to north).

In Component C, high flows from north to south mean that a 400 kV link from Kariba via Alaska, Chakari and Selous to Dema is added by 2033 (Alaska – Chakari based on upgrade from 330 kV to 400 kV operation of the second line planned for Alaska – Sherwood, and also upgrade from 330 kV to 400 kV of the line planned for Selous – Dema). These developments are clearly linked to the addition of the DC link from Inga to Luano which results in higher flow from north to south. In Component B, a DC link from Zambia to Tanzania is added in conjunction with the DC link from Inga to Luano, and the reinforcement of Kariba – Alaska and further towards Dema is not viable within the study period.

The second 400 kV line between Zimbabwe and South Africa (i.e. Insukamini – Nzhelele as evaluated in this study) is not part of the least-cost plan until right at the end of the study period. This is so even when assuming a relatively conservative transfer limit on the existing system from north to south following the completion of the Triangle – Nzhelele line and also accounting for the fact that this limit will be reduced in future as the load grows in the southern part of Zimbabwe.

Connecting the north and south bank at Batoka increases the transfer capacity from north to south at a relatively low cost. Such a link is also likely to be required to ensure that the plant remains stable following outages on the 400 kV grid. This is illustrated in the following graphs showing that the damping of power oscillations are greatly improved in the medium term if adding this link, and that there is a risk the plant may drop out of synchronism without such a link as the system is expanded in future. Note that this simulation is based on a generic model for the plant and that further studies will be required once more details on the actual design of the plant are available.

Figure 119 Outages on 400 kV system connecting Batoka, stage 2025, Without and with link between North Bank and South Bank (requires autotransformer)

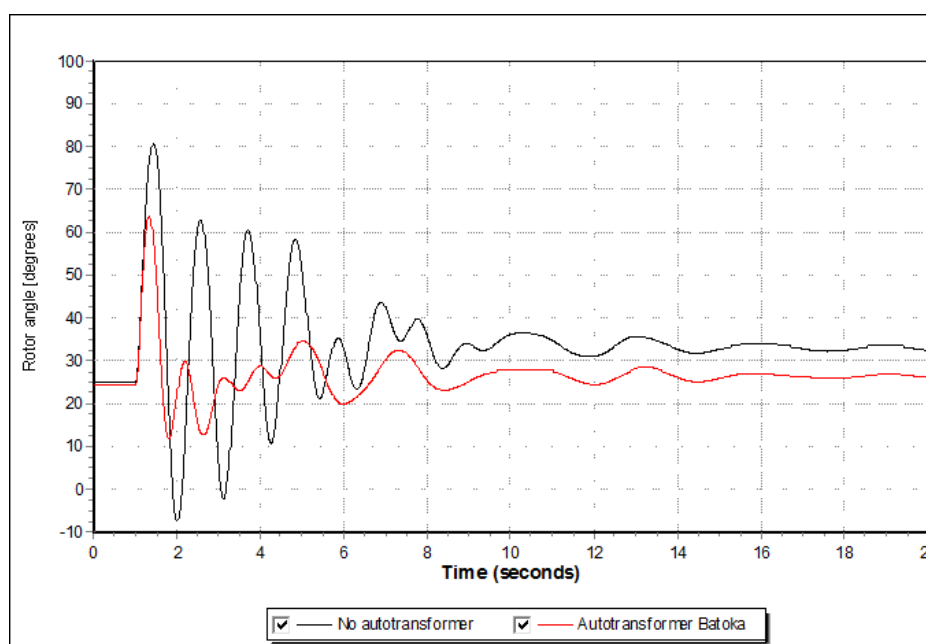
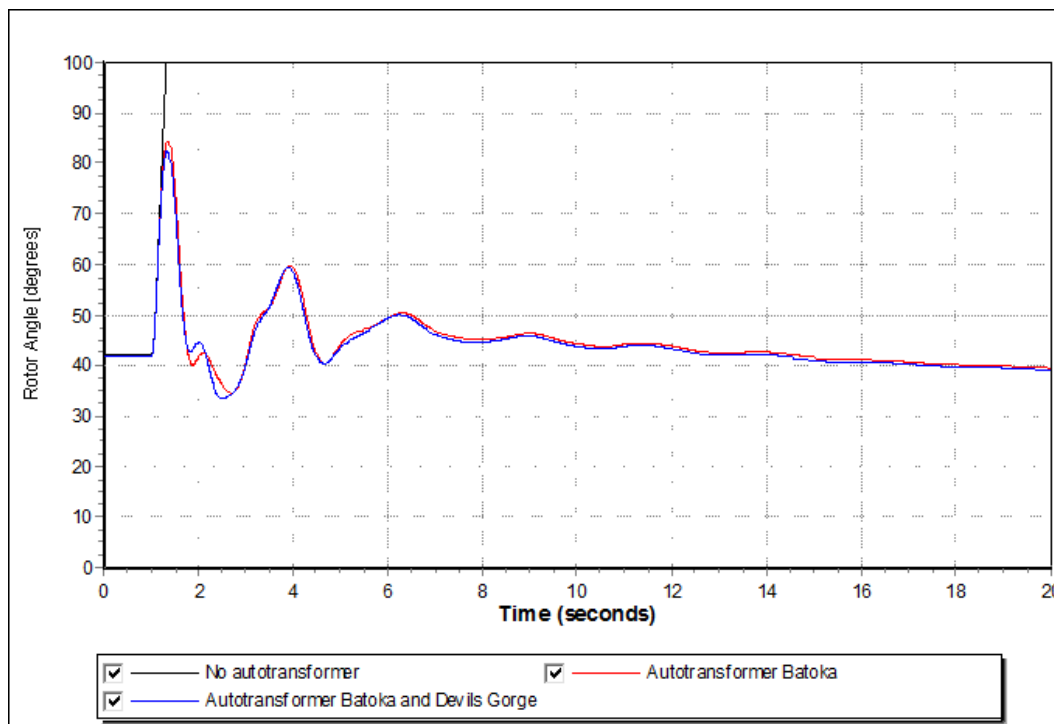


Figure 120 Outages on 400 kV connecting Batoka, beyond 2030 with DC Inga – Luano, Without and with link between North Bank and South Bank at Batoka and Devils Gorge.



It is proposed that the north and south banks at Devils Gorge should also be linked, although the results indicate that this is not critical as long as the link at Batoka Gorge is established.

It is also important to note that a link between the north and south bank at Batoka would ensure that the western parts of the main grid in Zambia and Zimbabwe would remain interconnected during an outage on the link from Livingstone to Victoria Falls.

The need for reinforcement of the system between Kariba and Alaska would also be reduced through linking the north and south bank at Batoka. However, the main problem in the grid south/east of Kariba is an outage of one of the three lines between Kariba South and Alaska at high levels of generation in Kafue and Kariba, combined with high levels of wheeling from north to south. An outage of one of the three lines to Alaska presents a thermal limit on this boundary in the grid.

Furthermore, linking Batoka north and south may be important in supporting the planned ZIZABONA project. As commented on elsewhere in this report: A “triangle” configuration with three lines Livingstone – Hwange, Livingstone – Pandamatenga and Pandamatenga – Hwange would ensure that the three countries would remain interconnected in this area for single line faults. The plans to link the three countries via a substation at Victoria Falls means that an outage of Livingstone – Victoria Falls would separate the western part of the grid in Zambia from Zimbabwe (and Botswana) – in which case a link from north to south at Batoka may be important.

Similarly, a “triangle” configuration of this part of the ZIZABONA project would ensure that the western part of the grid in Zimbabwe and the northern part of Botswana would

remain interconnected to the neighbouring systems following single circuit faults. Modifying this part of the ZIZABONA system is therefore strongly recommended.

Adding a link between the northern and southern bank at Batoka would partly solve this problem if Batoka South is connected to Victoria Falls as in current plans presented by ZETDC. Outages between Victoria Falls and Hwange and Pandamatenga may still be challenging though, and a triangle configuration would still seem to present benefits. Likewise, it should be considered carefully if Batoka South should be connected to Hwange rather than Victoria Falls. If the ZIZABONA project is developed in line with the plans to have a central connection point at Victoria Falls and Batoka South is connected to this substation and not Hwange, an outage of the 400 kV line between Hwange and Victoria Falls would mean that Hwange and Batoka is only connected via long lines to the Sherwood-Chakari area.

Similarly, the banks on either side of the power plant at Devil's Gorge should also be linked as part of development of this project. This would provide additional capacity for power exchange between the two countries at a very low cost.

It is also important to note that although the energy simulations in PLEXOS recognises transfer limits between the countries, the model as established for the preparation of the Pool Plan does not reflect the actual flow on parallel paths in line with the impedances on the different parts of the grid. The DC links may also partly be used to control flow on parallel paths on the grid. This is not modelled in PLEXOS either. Careful examination of the PLEXOS results reveal that power from north to south on the central part of the SAPP system at times may result in power flow from Zimbabwe to Mozambique on the Bindura - Songo line. This happens at the same time as the links from Zimbabwe to South Africa and Botswana are running at or close to the maximum transfer limit.

Such operation may require that a phase-shift transformer is installed for instance at Songo to control the power flow on the parallel path north to south in Zimbabwe and Mozambique. The impedances on the system may otherwise result in excessive flow on the lines from Zimbabwe to South Africa and/or Botswana. An alternative could be to advance the investment on a second link from Zimbabwe to South Africa like for instance the Insukamini - Nzhelele interconnection considered in this Pool Plan (i.e. the link included in 2032 in Component C and 2038 in B). Costs of bringing in this project earlier on would be relatively small compared to the power flows that may be seen on the line.

Similarly, and depending on generation dispatch and load level in this area of the SAPP grid, the existing 330 kV line (400 kV design) between Songo and Bindura may become a bottle-neck for export at high levels of generation in the Tete area. A phase-shift transformer at Songo may also prove to be beneficial in such a case, but upgrading of the Songo - Bindura - Dema link to 400 kV in combination with a second 400 kV line plus a second link between Zimbabwe and South Africa may be a good solution to provide capacity for increased regional trade in such a scenario. Although these projects (reinforcement of the link Songo - Bindura - Dema and a second direct link from Zimbabwe to South Africa) do not feature among the early projects for consideration in the least-cost development plan as identified in the base case of Components B and C, these two projects should still be considered carefully as candidates for further integration of the SAPP system. The second line between Songo and Bindura would also basically remove the problem of the northern part of the grid in Mozambique being separated from Zimbabwe and the central part of the SAPP system for any single circuit fault.

It is also noted that developments as outlined above may provide additional transfer capacity from north to south both prior to development of the STE scheme and also once the STE scheme is in place (both initial and future stages). Furthermore, the need for forced generator tripping at Mphanda Nkuwa as may be required for outages on the STE scheme in Mozambique, would likely be reduced.

As for the Benchmark Case (Component A), an SVC in the Tokwe-Triangle area would seem required to ensure safe operation of the interconnection with South Africa from Triangle to Nzhelele (although not included in the investment plan shown below).

The total investment costs on the main grid in Zimbabwe will increase as a result of regional integration by up to \$250 m. Costs in Component C are marginally higher than in B. It is noted that Component B includes reinforcement of the link from Songo whereas Component C includes reinforcement of the link from Zambia towards the end of the study period. These projects are clearly sensitive to other regional developments. As commented on above, benefits of a stronger connection from Songo to Bindura and Dema are likely to be underestimated, and this project should be seen in conjunction with developments in Mozambique – not least modifications to the STE grid in Mozambique.

Figure 121 Transmission system expansion plan in Zimbabwe

TRANSMISSION PROJECTS											
Voltage [kV]	Substation		Distance [km]	Conductor type	Circuits	Tower type		Cost estimate [MUSD]	In service by year		
	From	To							Comp A	Comp B	Comp C
400 ^{*)}	Bindura	Mutorashanga	80	3 x Bison	1	Guyed V	SgCkt	35	2018	2018	2018
400 ^{*)}	Sherwood	Alaska	160	3 x Bison	1	Guyed V	SgCkt	58	2018	2018	2018
400	Hwange	Livingstone (to border)	104	3 x Bison	1	Guyed V	SgCkt	36	2020	2020	2020
400	Hwange	Southern Energy	20	3 x Bison	1	Guyed V	SgCkt	42	2019	2019	2019
400	Southern Energy	CASECO	70	3 x Bison	1	Guyed V	SgCkt	23	2019	2019	2019
400	CASECO	Insukamini	160	3 x Bison	1	Guyed V	SgCkt	61	2019	2019	2019
400	CASECO	Sherwood B	294	3 x Bison	1	Guyed V	SgCkt	124	2019	2019	2019
400 ^{*)}	Insukamini	Marvel	42	3 x Bison	1	Guyed V	SgCkt	21	2019	2019	2019
330	Sherwood B SVC (+/- 150 MVA)							30	2019	2019	2019
400	Orange Grove	Triangle	300	3 x Bison	1	Guyed V	SgCkt	101	2021	2021	2021
400	Triangle	Nzhelele (to border)	215	3 x Bison	1	Guyed V	SgCkt	65	2021	2021	2021
400 ^{*)}	Selous	Dema	95	3 x Bison	1	Guyed V	SgCkt	40	2022	2022	2022
400	Batoka	Vic. Falls	30	3 x Bison	1	Guyed V	SgCkt	25	2023	2023	2023
400	Batoka	Chakari	400	3 x Bison	2	Guyed V	SgCkt	161	2023	2023	2023
400	Devils Gorge	I/O Batoka-Chakari	25	3 x Bison	2	Guyed V	SgCkt	19	2026	2026	2026
400	Gokwe	Selous	236	3 x Bison	2	Guyed V	SgCkt	97	2030	2030	2030
400	Gokwe	Sherwood B	225	3 x Bison	1	Guyed V	SgCkt	74	2030	2030	2030
400	Victoria Falls	Pandamatenga (brd)	66	3 x Bison	1	Guyed V	SgCkt	22		2028	2039
400	Kariba North (from brdr)	Alaska	170	3 x Bison	1	Guyed V	SgCkt	69			2032
400	Alaska	Chakari	Upgrade	3 x Bison	1	Guyed V	SgCkt	6			2032
400	Chakari	Selous	60	3 x Bison	1	Guyed V	SgCkt	40			2032
400	Selous	Dema	Upgrade	3 x Bison	1	Guyed V	SgCkt	23			2032
400	Songo	Bindura/Dema	Upgrade	3 x Bison	1	Guyed V	SgCkt	43		2037	
400	Songo ckt.2	Bindura ckt.2	130	3 x Bison	1	Guyed V	SgCkt	55		2038	
400	Orange Grove	Inchope (to border)	20	3 x Bison	1	Guyed V	SgCkt	9		2040	
400	Insukamini	Nzhelele (to border)	280	3 x Bison	1	Guyed V	SgCkt	90		2038	2039
^{*)} These lines may be operated at 330 kV initially.											
Total investment costs (million USD) by Component:								Total:	1013	1232	1264
								PV:	663	720	736
Note: This estimate applies only to the 400 kV system as may be impacted by the Pool Plan.											

7.13 Key findings – Main transmission corridors

The key findings on the main transmission corridors have already been presented in Section 5.3, together with an accompanying map. This ordering was to enable readers to have a preview of the transmission planning framework before getting into the detailed country-by-country analyses.

Now that the full supporting analysis for the findings have been presented, readers are encouraged to return to Section 5.3, as it contains the conclusions of the analysis and discussions in Sections 6 and 7.

8 Environmental and social impact using RIAM

8.1 GIS database and RIAM

The Geographic Information System (GIS) developed for this project has been utilized to structure and collate diverse geospatial data and to present thematic mapping. In addition, the GIS has been integrated with the Rapid Impact Assessment Matrix (RIAM) tool adapted for SAPP to allow for environmental and social screening of transmission and generation options at a regional level and preliminary impact assessment. The RIAM tool is provided in a Microsoft Excel Spreadsheet environment making it easily accessible and useable for SAPP.

The GIS consists of two distinct databases in a standard format for integration within tools such as QGIS, ArcGIS, MapWindow or Geomean, etc. The aim of the databases is to provide SAPP specific as well as open source data in an easy-to-use environment where users can interrogate and report on existing generation, transmission and demand information and secondly, analyse the impact of planned developments in terms of indicative environmental and social impacts.

The first set of data consists of data on generation and transmission infrastructure. The second set of data consists of a standardized reporting framework (2,500m x 2,500m grid) populated with thematic data such as physical, biological, ecological and socio-economic attributes. These data have been used to indicate the impact of planned developments (transmission corridors or power generation infrastructure) on the physical/chemical, biological/ecological and sociological/cultural environments in combination with the RIAM process.

The GIS incorporating the RIAM has been designed to be utilized at a national and regional scale at this stage. However, as additional and higher resolution datasets are acquired more accurate analysis at an individual project level will be possible.

The environmental sensitivity map developed for the SAPP region (Figure 122) which integrates the GIS and the RIAM is the primary tool for visualizing, analysing and planning development from an environmental and social perspective. Potential projects have been overlaid onto the environmental sensitivity map to give a preliminary indication of the likely impacts of significance associated with their implementation and relocation/re-routing undertaken to minimize any negative impacts as far as possible.

The advantage of a GIS and RIAM approach to environmental planning is that it is highly flexible and may be adapted as new data is captured and as strategic priorities change. The various generation projects and interconnector and transmission lines of national importance which have been modelled within PLEXOS have also been assessed utilizing the GIS and RIAM. The analysis for both transmission and generation is presented in the annex volume (Annex A4), utilizing a map based approach to show:



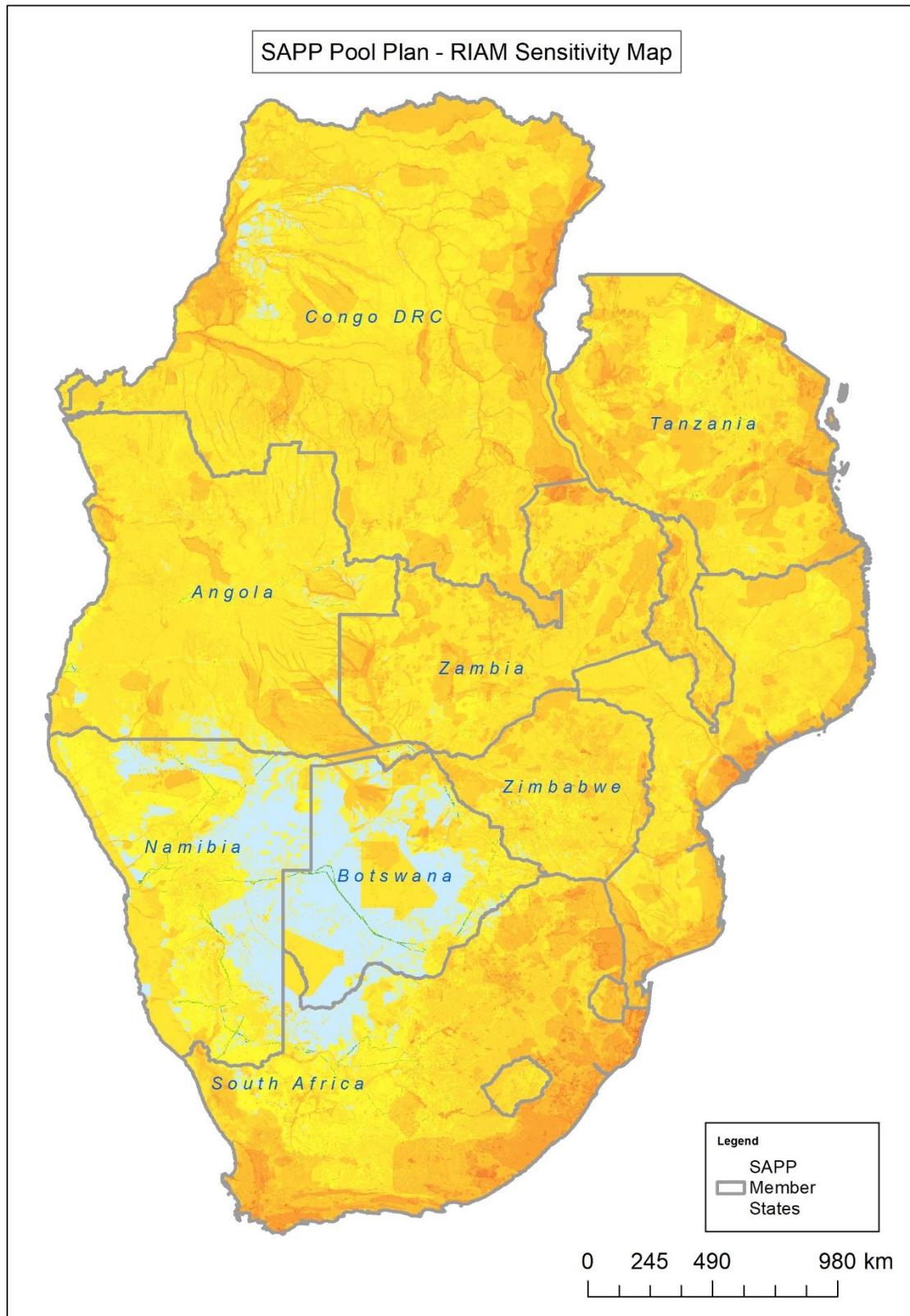
- ❑ Transmission corridors refined so as to potentially minimize impacts on the most sensitive areas and avoid defined no-go areas
- ❑ Generation projects screened and illustrated in relation to their environmental sensitivity and potential impact context

The following table illustrates the quantitative scoring system used .

Table 40 RIAM Range Value		
Environmental Score (ES)	Range Value (RV)	Description of Range Band
108 to 72	5	Major positive change/impact
71 to 36	4	Significant positive change/impact
35 to 19	3	Moderate positive change/impact
10 to 18	2	Positive change/impact
1 to 9	1	Slight positive change/impact
0	0	No change
-1 to -9	-1	Slight negative change/impact
-10 to -18	-2	Negative change/impact
-19 to -35	-3	Moderate negative change/impact
-36 to -71	-4	Significant negative change/impact
-72 to -108	-5	Major negative change/impact

Source: GeoTerraImage, 2016

Figure 122 Map of SAPP RIAM Sensitivity Analysis



8.2 Transmission Line Route Corridors

The alignment of the transmission corridors was carried out using the national parks and RIAM sensitivity maps to provide an alignment which seeks to mitigate against negative impacts (or enhance benefits) in the following areas (range values in brackets):

- ❑ Physical / Chemical
 - Water Bodies (-2)
 - Erosion Potential (-2)

- ❑ Biological / Ecological
 - Wetlands (-4)
 - High Vegetation (-3)
 - Protected Areas (-5)
 - Biodiversity Hotspots (-5)

- ❑ Socio-Economic / Cultural
 - Settlements (-2)
 - High Population Density (-1)
 - Historical / Cultural (-4)
 - Tourist Sites (-4)
 - Cultivated Land (-2)
 - Developments (3)
 - Tribal/Customary Land (-4)

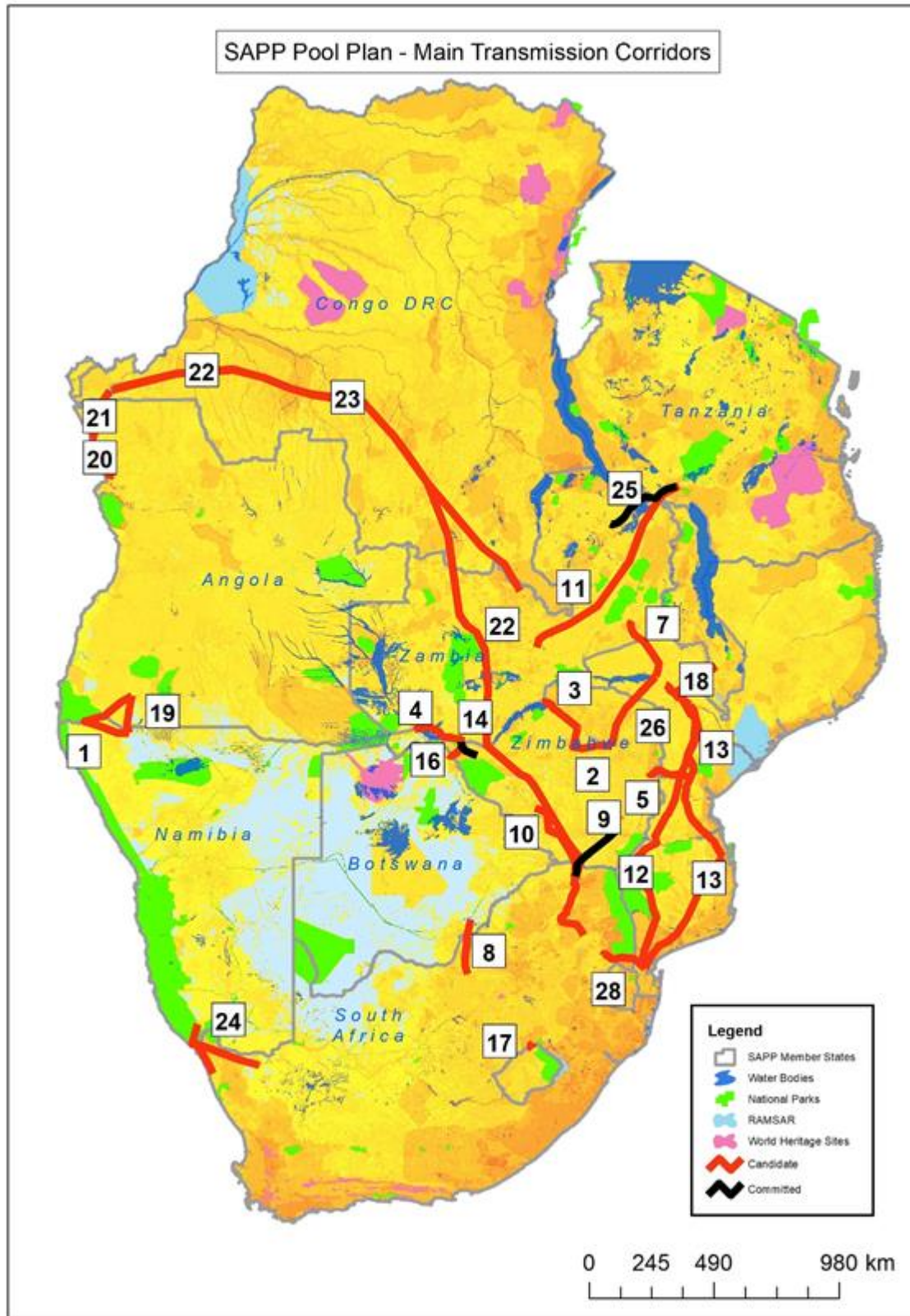
- ❑ National Park

For each interconnector or transmission corridor a map has been generated illustrating the alignment in combination with the RIAM Sensitivity Map as well as the location of the National Parks. A table is also provided which illustrates a summary of all the spatial data variables integrated into the 2.5 km by 2.5km grid cells.

For planning purposes, National Parks have been defined as “no-go” areas for major transmission line corridors. As the GIS database is expanded additional parameters may be added as no-go criteria if deemed appropriate.

Figure 123 gives the overview of the transmission lines assessed.

Figure 123 Map of main regional transmission corridors environmental sensitivity



8.3 Power Generation Facilities

The regional power generation facilities have been screened relative to their context and potential for significant impact if developed and the results appear in Figure 124. The screening process considers plant location in the assessment; however, the different types of generation will result in differing profiles at a project level. Hydropower generation facilities may have extensive downstream and reservoir impacts while thermal generation facilities may have more localized direct impacts but diffuse impacts in relation to GHGs etc.

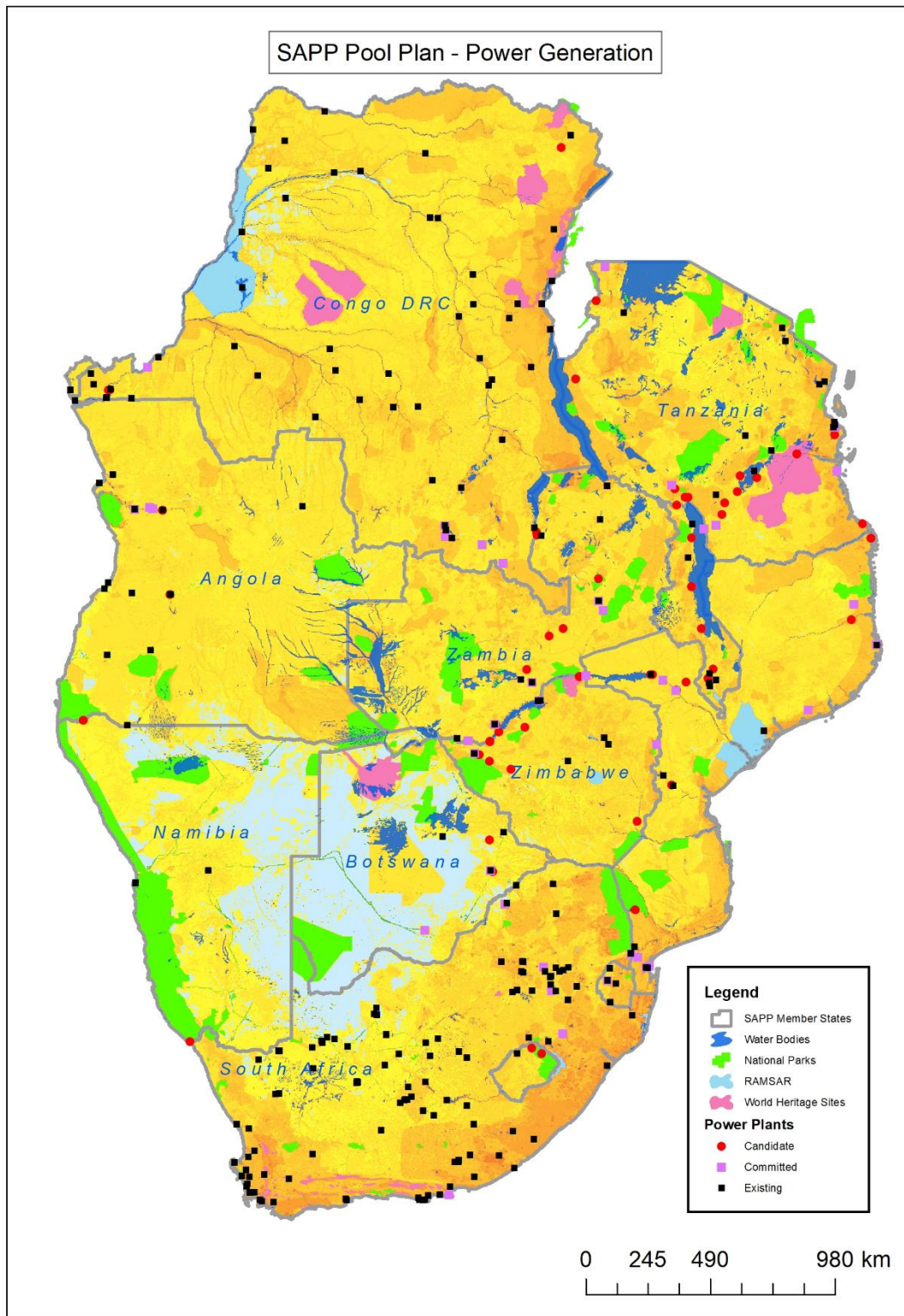
As for the transmission lines, National Parks have been defined as no-go areas and used to largely screen out projects affecting these areas at this level. (see Annex A5 for Mupata Gorge HPP example). As can be seen from Figure 124, only 3 generation facilities appear to be inside National Park boundaries (Table 41). However, the location information for these has been derived from open-source data thus there may be an accuracy issue that can be redressed by the owners of these facilities.

Table 41 Generation projects in National Parks

Country	Name	Capacity	Technology	Status
Angola	Caculo Cabaça	2,160 MW	Hydro	Committed
Lesotho	Letseng wind	65 MW	Renewable	Candidate
Zambia	Mambilimba Falls	326 MW	Hydro	Candidate

Source: National power sector master plans

Figure 124 Map of regional power generation facilities environmental sensitivity



8.4 Conclusions

A pre-requisite for the GIS-based approach to be successful is the establishment of a reliable, representative and current database of both spatial and associated non-spatial attribute information. This is a key necessity to establish both location and thematic map data in order to create a functional GIS platform for analysis and impact assessment.

The GIS database established now contains spatial information of the main primary energy sources, developmental "no-go" areas (currently defined as National Parks), thematic environmental and social data and planned regional generation and transmission infrastructure. The GIS database forms the basis of the RIAM assessment which indicates environmental sensitivity and linked to that the potential significance of impacts associated with development.

The outcome of the preliminary screening process shows that:

- ❑ As a result of an iterative process to define transmission line corridors none of the proposed routes directly impacts on a no-go area
- ❑ Direct impacts associated with generation facilities do not affect no-go areas except possibly in 3 cases

It is anticipated, therefore, that from a preliminary planning perspective there are no constraints to development with the scenarios proposed. However, screening will be followed by more detailed environmental and social studies at a project level which could potentially change the picture and some projects which may pass initial screening with the datasets available now could be ruled out later.

To minimize the risk of controversial projects passing initial screening it is recommended that SAPP continue to develop the GIS database with the ambition to increase the scale of resolution to reduce the uncertainties introduced by data deficiency.

9 Sensitivity tests

9.1 Component A sensitivity tests

Two sensitivity tests were requested for Component A, the first (SA1) being to limit “committed” plants to those already under construction or which have reached financial closure, the second (SA2) being to use in addition the “low” demand forecast. The results are shown in Table 42.

Table 42 Results of Component A sensitivity tests

Component A sensitivity tests	Component A	SA1 - Restricted committed	SA2 - Res committed + low demand
Investment costs (\$ b)	155.3	124.7	95.0
Short-term operational costs (\$ b)	124.7	127.8	107.9
Unserviced energy cost (\$ b)	11.5	13.9	6.1
SAPP total (\$ b)	291.5	266.4	209.0
Installed capacity (GW)	143.4	129.2	100.1

Absolute differences	Component A	SA1 - Restricted committed	SA2 - Res committed + low demand
Investment costs (\$ b)	155.3	-30.6	-60.3
Short-term operational costs (\$ b)	124.7	3.1	-16.8
Unserviced energy cost (\$b)	11.5	2.4	-5.4
SAPP total (\$ b)	291.5	-25.0	-82.5
Installed capacity (GW)	143.4	-14.2	-43.3

% differences	Component A	SA1 - Restricted committed	SA2 - Res committed + low demand
Investment costs (\$ b)	155.3	-19.7%	-38.8%
Short-term operational costs (\$ b)	124.7	2.5%	-13.5%
Unserviced energy cost (\$b)	11.5	21.2%	-47.0%
SAPP total (\$ b)	291.5	-8.6%	-28.3%
Installed capacity (GW)	143.4	-9.9%	-30.2%

Transmission investment	Component A	SA1 - Restricted committed	SA2 - Res committed + low demand
Investment costs (\$ m)	1,100	890	681
Absolute difference (\$ m)	1,100	-210	-420
Relative difference (%)	1,100	-19%	-38%

9.1.1 SA1 – Restricted committed projects list

As discussed in Section 2.4, the modelling team was requested to retain the “committed” status of all projects defined as such by the utilities in the base Component A, but the resulting list of committed projects is lengthy, leaving little room within which the optimisation algorithm can look for least cost investment strategies. Restricting the committed project list should therefore allow lower cost solutions to be found, and indeed sensitivity test SA1 is \$27.5 b less expensive than the NPV of the base Component A, equivalent to a 10% saving.

This arises from reduced investment costs, because only 129 GW of installed capacity is needed by 2040 as compared with 143 GW in the base case. Operational costs are actually a bit higher, indicating that it is optimal to build less capacity but then operate it at higher load factors, in particular thermal plant which increase the operational costs (the proportion of energy supplied by hydro drops from 24% to 23%).

Sensitivity SA1 produces a scenario that is not greatly different, at least in aggregate terms, to Component C. The installed capacity by 2040 is only 1 GW different, and the total NPV difference is also relatively small (including unserved energy NPV of SA1 is \$266 b, corresponding NPV of Component C is \$259 b). There are larger differences at the country level, however, with South Africa for example building 6,750 MW of new coal capacity that does not feature in Component C, while only 5,000 MW is developed at Inga in DRC as compared with nearly 12,000 MW in Component C.

Sensitivity SA1 retains the other main constraint of Component A that no new interconnectors are constructed beyond those that are already under construction in the region. The figures in the bottom panel of Table 42 are for investments in the STE project in Mozambique, which is an internal line but one which is built in order to facilitate exports and make it possible for Mozambique to invest in large generation projects which offer economies of scale, notably Mphanda Nkuwa. In Component C, major new transmission interconnectors can be chosen and it is the expansion of electricity trade in the region which drives down both investment and operational costs. This theme is explored further in the economic analysis (Section 10).

9.1.2 SA2 – Restricted committed projects and low demand forecast

The second sensitivity test retains the flexibility implied by the restricted committed project list, but brings in a more radical change in assumptions, namely significantly lower demand forecasts. As expected, the total costs fall dramatically (from \$292 b to \$209 b, a reduction of 28%). A much lower level of capacity (100 GW) is required to meet the lower demand, so investment costs fall by 39% while operational costs decrease by 14%.

The details of the changes that take place at the individual country level are given below for the low demand Component C sensitivity (SC5). These results show the value of the flexibility introduced by prioritising investment in transmission corridors that allow for a deferment or cancellation of expensive generation investment. Countries are then able to maximise the use of existing capacity within the region.

9.2 Component C sensitivity tests

9.2.1 Overview of the sensitivity tests

The table below provides an overview of the sensitivity tests which were carried out on Component C. There are 4 sensitivity tests which use the base demand forecast, and a final sensitivity which tests the effect of low demand materialising.

Table 43 Component C sensitivity tests (including unserved energy)

Component C sensitivity tests	Comp C	SC1 - Delay	SC2 - Dry C	SC3 - SA import cap	SC4 - High renewables	SC5 - Low demand
Investment costs (\$ b)	121.0	118.9	121.3	126.6	139.9	86.6
Short-term operational costs (\$ b)	124.7	128.5	130.2	125.1	116.4	107.1
Unserved energy cost (\$ b)	13.0	13.0	24.4	13.0	13.0	6.1
SAPP total (\$ b)	258.6	260.4	275.9	264.7	269.3	199.8
Installed capacity (GW)	129.6	127.5	132.5	132.0	157.2	95.4

Absolute differences	Comp C	SC1 - Delay	SC2 - Dry C	SC3 - SA import cap	SC4 - High renewables	SC5 - Low demand
Investment costs (\$ b)	121.0	-2.0	0.3	5.7	18.9	-34.4
Short-term operational costs (\$ b)	124.7	3.8	5.5	0.4	-8.3	-17.6
Unserved energy cost (\$ b)	13.0	0.0	11.4	0.0	0.0	-6.9
SAPP total (\$ b)	258.6	1.8	17.2	6.0	10.7	-58.9
Installed capacity (GW)	129.6	-2.1	2.8	2.4	27.6	-34.2

% differences	Comp C	SC1 - Delay	SC2 - Dry C	SC3 - SA import cap	SC4 - High renewables	SC5 - Low demand
Investment costs (\$ b)	121.0	-1.7%	0.2%	4.7%	15.7%	-28.4%
Short-term operational costs (\$ b)	124.7	3.0%	4.4%	0.3%	-6.6%	-14.1%
Unserved energy cost (\$ b)	13.0	0.0%	88.2%	0.0%	0.0%	-53.0%
SAPP total (\$ b)	258.6	0.7%	6.7%	2.3%	4.1%	-22.8%
Installed capacity (GW)	129.6	-1.6%	2.2%	1.8%	21.3%	-26.4%

Transmission investment	Comp C	SC1 - Delay	SC2 - Dry C	SC3 - SA import cap	SC4 - High renewables	SC5 - Low demand
Investment costs (\$ m)	3,283	2,487	3,342	2,854	2,665	1,222
Absolute difference (\$ m)	3,283	-796	59	-429	-617	-2,061
Relative difference (%)	3283	-24%	2%	-13%	-19%	-63%

Source: PLEXOS model

What is immediately evident from the table is that the impact of the sensitivity experiments is quite limited for the sensitivities where the base demand is used. The impact ranges between \$1.8 b and \$10.7 b, equivalent to between 0.7% and 4.1% of the total costs of Component C. By contrast, as was the case in the Component A sensitivities, introducing low demand has a marked impact on the level of capacity that is required and hence on the investment costs.

The following bullets summarise the 5 sensitivity tests:

- ❑ SC1 tests the impact of a delay in implementing large regional investment projects, specifically Inga. The impact is an increase in total costs of only \$1.8 b (0.7%).
- ❑ SC2 tests the impact of climate change that results in 'dry' conditions which impact on the availability of energy from hydro stations. Impact is an increase in total costs of \$17.2 b (6.7%), a large portion of this (\$11.4 b) being the costs of additional unserved demand.
- ❑ SC3 tests the impact of South Africa imposing an import cap of 2,800 MW. Impact is an increase in total costs of \$6.0 b (2.3%).
- ❑ SC4 tests the impact of SAPP countries implementing a policy of high renewables, matching the level posed in the 2013 IRENA report. Impact is an increase in total costs of \$10.7 b (4.1%).
- ❑ SC5 tests the impact of low demand. As was the case in SA2, the impact of low demand is very significant, resulting in a reduction in total costs of \$59 b (22.8%).

The sensitivity tests are described in more detail in the sub-sections below.

9.2.2 SC1 – Delays in implementing major projects

SC1 assumptions

A potentially significant risk that countries could face in pursuing a regional integration strategy is that there may be delays in building the large generation projects which are to supply low-cost energy exports. In Component C, the largest single project is the Inga hydropower plant in DRC, so a delay in completion of the various components of Inga was chosen as the basis for this sensitivity test. Inga 3 BC (low dam) is delayed by 5 years, from 2031 to 2036, while Inga 3 HC (high dam) and Inga 4, which are commissioned over the period 2032-2034 in Component C, are postponed in the sensitivity test until after 2040.

SC1 results

At a regional level, 2 GW less capacity is installed than in the base case Component C. Investment cost is \$2 b less, but short-term operational costs are \$4 b higher. This is due to a reduction of 6.4 GW of hydro capacity being replaced with an additional 3 GW of coal and 1.3 GW of natural gas capacity, which require higher operational costs than hydro power.

At a country level, the most notable change comes in the reduction of 5.6 GW of capacity in DRC. A total of 6.8 GW of hydro capacity is lost due to Inga changes, with some smaller hydro plants adding an alternative 1.2 GW of capacity. This decrease is countered by sizeable increases in capacity towards the end of the plan period in South Africa (3.2 GW) and Mozambique (1.4 GW). The additional capacity in South Africa comes from coal plants, while Mozambique sees the construction of a 1,375 MW CCGT NG plant that would not have otherwise been constructed.

The main impact on transmission investments is the postponement of the HVDC link from Inga to Luano in Zambia from 2031 to 2036 and that the link from Inga to South Africa is postponed beyond 2040, whereas the DC link from Zambia to Tanzania is added in 2035. As a result, more AC interconnections are added in the medium to long term as well – notably an upgrade of Songo – Bindura – Dema and also a second 400 kV line on this link. Furthermore, Livingstone – Zambezi – Gerus is reinforced/upgraded and Insukamini – Nzhelele is added to increase transfer capacities in the central area of SAPP.

Details of the capacity changes across all the countries in this sensitivity test are given in Table 44 below.

Table 44 Country breakdown of capacity differences in SC1 (delay)

Country	Component C (MW)	Sensitivity SC2 (MW)	Difference (MW)	Major projects
Angola	10,272	10,272	0	
Botswana	2,046	1,610	-436	Large coal reduced by 700 MW, but some greenfield coal added
DRC	15,468	9,842	-5,626	Reduction in Inga capacity partly offset by other hydros
Lesotho	355	355	0	
Malawi	4,232	4,232	0	
Mozambique	8,681	10,056	1,375	CCGT gas projects
Namibia	1,515	1,515	0	
South Africa	58,392	61,592	3,200	Large coal +3,000 MW
Swaziland	492	492	0	
Tanzania	14,870	14,319	-551	Stiegler's gorge II not chosen, partly offset by other hydro and gas projects
Zambia	8,017	8,017	0	
Zimbabwe	5,287	5,237	-50	Gokwe North chosen in preference to generic coal
SAPP	129,627	127,539	-2,088	

Source: PLEXOS model

9.2.3 SC2 – Dry climate

SC2 assumptions

Long run climate change models for Southern Africa provide a variety of different future rainfall / run-off outcomes. Some projections envisage higher hydrological flows than those assumed in the base Component C, while others foresee lower hydrological flows. High flow outcomes of climate change would obviously come as a bonus to the region, enabling greater use to be made of hydropower and reduced operational costs of thermal power. The opposite case of low hydrological flows, forcing reduced use of hydropower, constitutes an important risk for regional integration.

Therefore, the significant sensitivity to be tested in the Pool Plan is the 'dry climate' case. The hydrological data needed was made available by the team conducting a parallel SAPP study – *Climate Change Impact on Load and Hydropower*, conducted under the DFID-sponsored Climate Resilient Infrastructure Development Facility (CRIDF). The approach in the CRIDF project was to use average weekly temperatures and Representative Concentration Pathways (RCP), extracted from NASA Earth Exchange Global Daily Downscaled Projections (NEX-GDDP) dataset, and from these to estimate average monthly rainfall data per country and impacts on hydropower generation. The main CRIDF deliverable is the SAPP Climate Resilient Scenario Planning Tool.

The hydrological assumptions used in PLEXOS for both the base and dry climate cases were the result of consultation with the CRIDF team. The dry hydrology case reflects the most adverse (i.e. the driest) scenario out of 21 possible scenarios produced in the CRIDF study.

SC2 results

In the dry climate sensitivity, installed capacity under dry climate conditions is 3 GW higher in 2040 than in Component C, but investment costs overall are almost the same due to lower capital cost (largely thermal) plant being chosen. The higher cost of this sensitivity test arises from a higher proportion of energy being supplied from thermal generators (natural gas and coal).

It is interesting to note that some different projects are selected. Cahora Bassa North, for example, appears as a chosen generator in this scenario (1,275 MW from 2027) whereas this project was not selected in Component B or C. Details of the capacity changes in this sensitivity test are given in Table 45 below.

Table 45 Country breakdown of capacity differences in SC2 (dry climate)

Country	Component C (MW)	Sensitivity SC2 (MW)	Difference (MW)	Major projects
Angola	10,272	10,465	193	CCGT +600 MW, 2 small hydro projects deselected
Botswana	2,046	1,610	-436	Morupule B 5&6 chosen in preference to larger Greenfield Coal
DRC	15,468	15,708	240	Busango Hydro selected

Country	Component C (MW)	Sensitivity SC2 (MW)	Difference (MW)	Major projects
Lesotho	355	355	0	-
Malawi	4,232	4,232	0	-
Mozambique	8,681	11,301	2,620	Cahora Bassa North +1,245 MW CCGT +1,375 MW
Namibia	1,515	1,515	0	-
South Africa	58,392	58,392	0	-
Swaziland	492	492	0	-
Tanzania	14,870	15,138	268	Various small projects net change
Zambia	8,017	8,017	0	
Zimbabwe	5,287	5,237	-50	Gokwe North chosen in preference to generic coal
SAPP	129,627	132,402	2,835	

Source: PLEXOS model

The main impact on transmission grid investments is that the second link to Malawi is added early on (2021 compared to 2028) to secure supply in Malawi. Some of the other AC lines are also required earlier on to support trade. Notably, the link from Zambia to Namibia (including the HVDC converter stations) is upgraded by 2032.

9.2.4 SC3 – South Africa IRP cap on imports

SC3 assumptions

This sensitivity seeks to anticipate a possible import restriction being introduced in South Africa's Integrated Resource Plan (IRP). For this test, Eskom recommended that the import limit be set at 2,800 MW.

To impose a restriction that, at any given instant, the total import over all of South Africa's interconnectors should not surpass 2800 MW proved difficult to impose as a 'hard' constraint in PLEXOS. It was implemented instead as a 'soft' constraint, whereby a violation does not make the model infeasible, but causes penalization instead (similar to the approach adopted for unserved energy). This approach mimics what would happen in reality because in real-world system operation it would be preferable to overshoot the limit slightly in some hours in the year, instead of shedding the load in South Africa, while on average maintaining the limit.

SC3 results

Following this restriction, total capacity in the region is increased by 2 GW at an additional discounted cost of \$6 b. Within this, coal capacity is increased by 5.7 GW while natural gas and hydro power are both reduced, by 2.4 GW and 1.1 GW respectively.

At a country breakdown, the restriction on SA imports leads to South Africa investing in an additional capacity of 6.2 GW (coal). The main reduction in exporter capacity due to this change is in Mozambique, which reduces capacity by 3 GW compared with the standard Component C case. This reduction comes from the Mozambique CCGT NG plant. Full details of the changes in capacity are given in Table 46 below.

Table 46 Country breakdown of capacity differences in SC3 (SA import cap)

Country	Component C (MW)	Sensitivity SC3 (MW)	Difference (MW)	Major projects
Angola	10,272	10,265	-7	CCGT +600 MW, 2 small hydro projects deselected
Botswana	2,046	1,974	-72	Morupule B 5&6 chosen in preference to larger Greenfield Coal
DRC	15,468	15,468	0	-
Lesotho	355	355	0	-
Malawi	4,232	4,232	0	
Mozambique	8,681	5,681	-3,000	CCGT NG - 2,125 MW
Namibia	1,515	1,515	0	-
South Africa	58,392	64,592	6,200	Large coal +6,000 MW, medium coal +200 MW
Swaziland	492	492	0	-
Tanzania	14,870	14,372	-498	Various small projects net change
Zambia	8,017	7,801	-216	Lusiwasi Lower Hydro +84 MW Generic coal - 300 MW
Zimbabwe	5,287	5,267	-20	Gokwe North chosen in preference to generic coal (600 MW)
SAPP	129,627	132,014	2,387	

Source: PLEXOS model

With less import to South Africa in the medium to long term, a number of the AC lines supporting trade in the central corridor in SAPP are postponed beyond 2040. The DC links from Inga to Zambia and South Africa are still part of the plan - although postponed one year compared to the base case for Component C, see also the summary table in Section 5.3.

9.2.5 SC4 High renewables

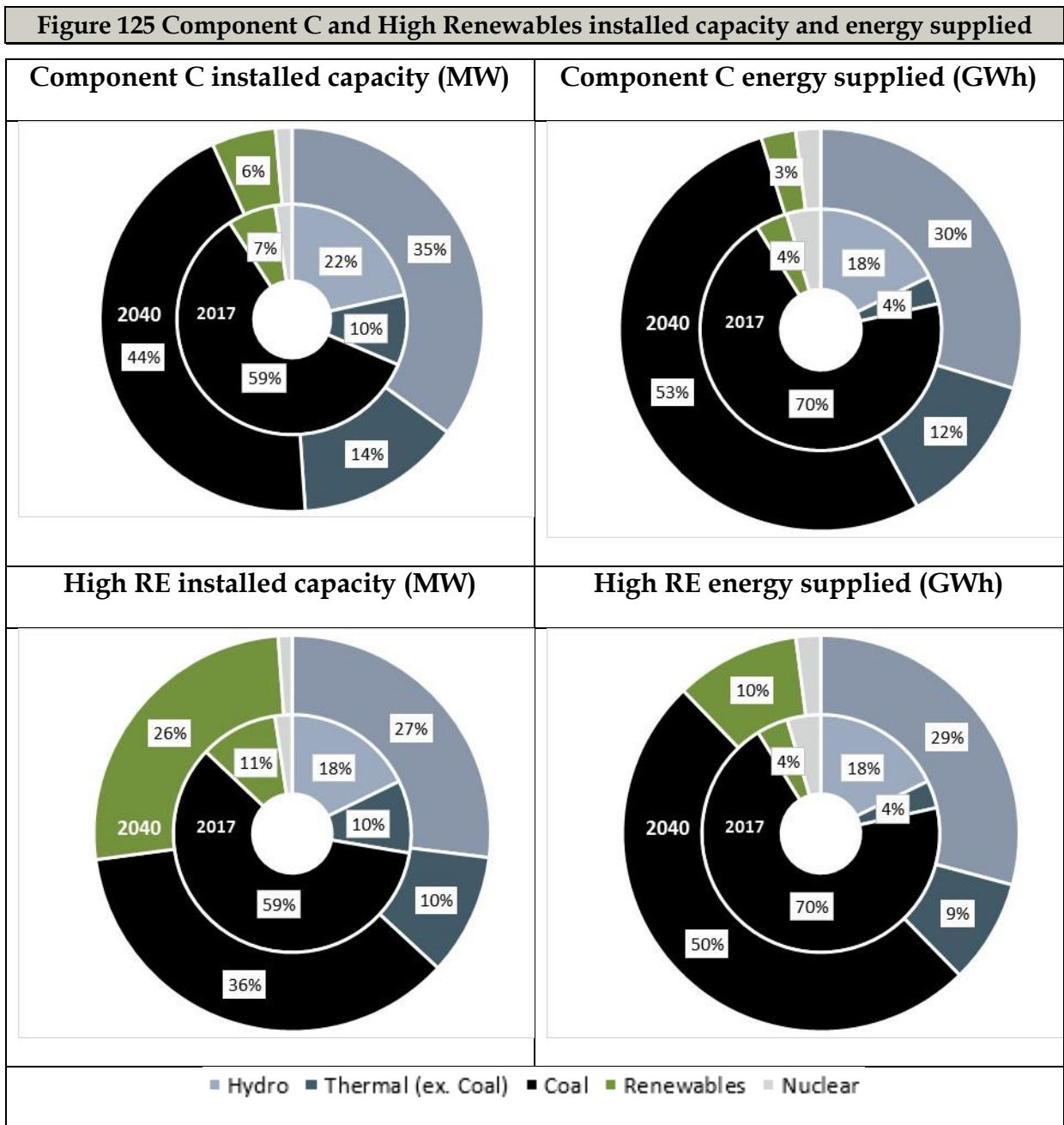
SC4 assumptions

The extent to which renewables might be adopted in SAPP has been documented in a 2013 report published by the International Renewable Energy Agency (IRENA) *Southern African Power Pool: Planning and Prospects for Renewable Energy*. This report was adopted as a reference point in determining the extent to which a policy by SAPP members to adopt renewables in preference to lower cost types of generation would change the generation mix by 2040.

An important departure in this sensitivity test was the introduction of renewable investment options which were not always included in the utility power master plans. Furthermore, to attain the levels of renewables in the IRENA report, renewable projects were treated as being committed. The generation mix is therefore policy-driven, not the result of a choice by the PLEXOS algorithm.

SC4 results

The graphs in Figure 125 below show installed capacity and energy generated for Component C and the High Renewables sensitivity.



In Component C, renewables play an almost static role in the generation mix. The important changes that take place between 2017 and 2040 are an increase in hydro and natural gas generation, with a declining share for coal-fired generation.

Giving renewables a much bigger role results in further decline in the importance of coal. Gas and hydro proportions are also reduced. It is important to note, however, that the installed capacity graphs do not take account of non-dispatchability. Technologies like wind and solar PV have limited dispatchability and hence contribute only a fraction of their installed MW to firm capacity.

This is also reflected in the energy graphs, which show that the contribution of renewables to energy is relatively small. For example, the proportion of renewable energy supplied in the 2040 high renewables case is only 10%, far less than the fraction of renewables in the nominal installed capacity mix (26%).

The High Renewables sensitivity envisaged installed renewables capacity growing from 8 GW in 2017 to close to 41 GW in 2040. Table 47 below provides details of the renewable technologies that are involved. Pumped storage has been treated as part of renewables rather than hydro because it is a relatively untried technology within SAPP. The next biggest components are wind and solar PV, while the other technologies (biomass, solar CSP, geothermal; and biogas) playing much smaller roles.

Table 47 Technologies in the High Renewables sensitivity test

Technology	MW in 2017	MW in 2040
Pumped storage	2,912	2,912
Wind	2,810	18,287
Solar PV	1,902	17,976
Biomass	61	727
Solar CSP	400	700
Geothermal	0	200
Biogas	18	18
Total	8,103	40,819

Source: PLEXOS model

All of the pumped storage is in South Africa. Wind and solar PV capacity is developed in almost all countries, while new biomass capacity is in Angola, Malawi, South Africa, Swaziland and Tanzania. The country with the highest proportion of energy from renewables in 2040 is Lesotho (24% - solar PV and wind), followed by South Africa (5% from a variety of renewable technologies) and Malawi (2.4% - biomass).

The level of energy trade is less in this scenario, and a number of the interconnectors that are part of the investment plan on medium to long term for the base case in Component C, are therefore not part of the least-cost expansion plan in this case. This impacts particularly on the need for reinforcement of the central corridor in SAPP, see also the summary table in Section 5.3. The DC links from Inga to Zambia and South Africa are still part of the development plan though, but postponed by one or two years.

9.2.6 SC5 – Low demand

SC5 assumptions

As discussed in Section 2.2, the assumptions used in the low demand forecast vary by country. In some countries, these include lower initial levels of unmet demand, slower growth in demand per capita and less of an increase in electrification rates than under the base forecast. Detailed discussion of the demand forecast assumptions is given in Annex A1.

SC5 results

At a regional level, a total of 34 GW less capacity is constructed than in the base case for Component C, at a discounted cost of \$59 b less. This reduction in costs comes from the lower installed capacity and lower short-term operational and unserved energy costs. Half of the reduced capacity comes from a reduction in hydro (18 GW), but there is also less coal (7 GW) and natural gas (8.6 GW), with small reductions in diesel (125 MW) and renewable (505 MW) capacity.

There are almost no plants selected in the low demand case that are not in the original Component C case. The two plants that are selected in this sensitivity test - Botswana Coal Green field and Botswana Morupule B 5&6 - are chosen as alternatives to the higher capacity Botswana Coal plant, which is not chosen in this sensitivity test, resulting in a net reduction of 654 MW of coal capacity in Botswana by 2040. These results show that under the low demand, large projects may be deselected in favour of constructing smaller projects earlier.

At a country level, all countries have a lower capacity in the low demand case, with the exception of South Africa and Swaziland which are unchanged. The largest reductions in capacity are seen in the DRC and Tanzania, which construct nearly 12 GW and 11 GW less under the low demand case respectively. The table below highlights which countries have the greatest reduction in capacity compared with the base case, as well as key projects which remain unbuilt in this sensitivity test.

Table 48 Country breakdown of capacity differences in SC5

Country	Component C (MW)	Sensitivity SC5 (MW)	Difference (MW)	Major projects not selected
Angola	10,272	8,950	1,322	-
Botswana	2,046	1,392	654	-
DRC	15,468	3,704	11,764	Inga 3 – 7,942 MW Inga 4 – 3,712 MW
Lesotho	355	245	110	-
Malawi	4,232	1,094	3,138	Coal 300 – 1,900 MW Small hydro projects – 747 MW
Mozambique	8,681	6,556	2,125	CCGT NG – 2,125 MW
Namibia	1,515	1,215	300	-
South Africa	58,392	58,392	0	-

Country	Component C (MW)	Sensitivity SC5 (MW)	Difference (MW)	Major projects not selected
Swaziland	492	492	0	-
Tanzania	14,870	3,888	10,982	Future CCGT – 5,640 MW Local and small coal -1,500 MW Stiegler’s Gorge I/II – 2x1,048 MW
Zambia	8,017	5,617	2,400	Maamba Coal – 1,200 MW Local coal – 600 MW Devil's Gorge - 600 MW
Zimbabwe	5,287	3,837	1,450	Devil's Gorge – 600 MW
SAPP	129,627	95,382	37,080	

Source: PLEXOS model

As further development at Inga is not part of the plan for this low growth scenario, the DC links to Zambia and South Africa are naturally dropped as well. It may have been expected that this would result in additional AC interconnections to support regional trade, however, a number of the projects included in the base case in Component C are postponed and some are even dropped; see the summary table in Section 5.3 for details.

9.3 Concluding observations on the sensitivity tests

The sensitivity tests involving the base demand indicate that Component C, the Realistic Regional Integration case, is robust in the face of the risk factors and policy changes analysed – delays in implementing major projects, dry climate change, South Africa imposing a cap on imports and a policy of high renewables being implemented. The impact of these changes for the SAPP region as a whole is quite limited, but there are significant changes for individual countries, Mozambique being a case in point. The interconnectedness of the region is illustrated by impacts popping up in rather unexpected places when a sensitivity scenario is introduced.

If the lower demand forecast were to materialise, member states would be able to delay investment plans, which would reduce the pressure to raise the enormous level of financing required for the base Component C. Projects such as Devil’s Gorge, Maamba Coal II, Inga 3, Inga 4 and Stiegler’s Gorge are no longer selected within the 2040 planning horizon. The results of the sensitivity test also show that under the low demand large projects may be deselected in favour of constructing smaller projects earlier, as is illustrated by the example of coal projects in Botswana. Strengthening of transmission corridors remains necessary and provides the flexibility needed to cope with major demand variations.

9.4 An alternative Component C

In addition to the five sensitivity tests just described, in response to a number of comments and suggested additions from the utilities at the draft Final Report stage, an alternative

version of Component C was developed. The changes which were introduced for four of the countries are summarised as follows¹³:

- ❑ Botswana
 - ❑ Changed the Francistown diesel back to 90 MW.
 - ❑ Removed the decommissioning date for Orapa diesel-fuelled unit.
 - ❑ Changed the Morupule B power to 300 MW total.
 - ❑ Added the 100 MW Solar PV power plant.
 - ❑ CSP not available from 2017.

- ❑ DRC
 - ❑ Updated Kyimbi to 41 MW maximum from 2025.
 - ❑ Updated Mobayi, 30.4 MW from 2022.
 - ❑ Inga 3 no changes, 20 units x 240 MW = 4,800 MW.
 - ❑ Nzongo (misreported as Zongo) was already 150 MW. Name changed in Excel.
 - ❑ Kolwezi, Likashi and Lubumbashi PVs all reduced to 100 MW from previous 200 MW each.

- ❑ Mozambique
 - ❑ Beloluane removed from the model (set to 0 units).
 - ❑ Nacala also removed from the model. In the last revision the number of engine units was changed from 11 to 18 1 MW units, but in this run set as 0 units from the start of the simulations.
 - ❑ CDM 1 diesel unit removed from the model (also set to 0 units).
 - ❑ Luis Cabral, similar to CDM 1. Set to 0 units.
 - ❑ Tavene – set to 0 units.
 - ❑ Inhambane – set to 0 units.
 - ❑ Temane and Temane 2 engines – both set to 0 units.

¹³ Further detail is provided via the original utility and World Bank comments, which are provided, with responses, in Annex A9 in the separate volume of annexes. New units that have not existed in the main Scenario C model have been highlighted on the Generation Units Database sheet in the Excel results file.

- ❑ All the plants above with 0 units donot appear in the report tables, but are in the model and the corresponding Excel reporting sheets in order to avoid cross-referencing problems.
- ❑ Added Temane 100 MW gas fired power plant, as well as Lupata 600 MW and Boroma 200 MW. These had all been in the model at some point, but had then been removed.
- ❑ Swaziland
 - ❑ Added the Lavumisa 5 MW solar PV.
 - ❑ Corrected the name of Lubombo coal fired plant to Lubhuku.

In relation to the full list of generation plants and the total demand that is to be satisfied, these are quite modest changes, and as expected the overall NPV for this scenario is only marginally different (-0.3%) to the original Component C – see Table 49 below. Generation, transmission and short-term O&M costs are all slightly lower, but this is partially offset by a small difference in the cost of unserved energy.

Table 49 Comparison between original and alternative Component C

Component C sensitivity tests	Component C	Alt Component C
Investment costs (\$ b)	121.0	120.8
Short-term operational costs (\$ b)	124.7	124.1
Unserved energy cost (\$ b)	13.0	13.7
SAPP total (\$ b)	258.6	258.6
Installed capacity (GW)	129.6	129.9

Absolute differences	Component C	Alt Component C
Investment costs (\$ b)	121.0	-0.2
Short-term operational costs (\$ b)	124.7	-0.6
Unserved energy cost (\$ b)	13.0	0.7
SAPP total (\$ b)	258.6	0.0
Installed capacity (GW)	129.6	0.3

% differences	Component C	Alt Component C
Investment costs (\$ b)	121.0	-0.1%
Short-term operational costs (\$ b)	124.7	-0.5%
Unserved energy cost (\$ b)	13.0	5.7%
SAPP total (\$ b)	258.6	0.0%
Installed capacity (GW)	129.6	0.2%

Transmission investment	Component C	Alt Component C
Investment costs (\$ m)	3,283	3,219
Absolute difference (\$ m)	3,283	-64
Relative difference (%)	3283	-2%

Despite the limited impact for the SAPP region as a whole, there are changes at the country level. The country differences between the original and alternative Component C are presented in Table 50. Countries such as Botswana experience a big change in energy balance, with a significant reduction in exports in last part of the study period.

Table 50 New generation capacity by 2040 - original and alternative Component C

MW in 2040		Component A		Component C		Alternative C		Alt C - original C	
		New Gen	% thermal	New Gen	% thermal	New Gen	% thermal	New Gen	
1	Angola	10,428	29%	8,303	10%	8,303	10%	0	0%
2	Botswana	582	83%	1,400	100%	882	89%	-518	-11%
3	DRC	21,806	2%	17,664	3%	17,407	3%	-257	0%
4	Lesotho	275	0%	275	0%	275	0%	0	0%
5	Malawi	4,203	64%	3,882	59%	3,882	59%	0	0%
6	Mozambique	5,910	49%	6,060	71%	7,480	50%	1,420	-21%
7	Namibia	1,225	76%	1,000	70%	1,000	70%	0	0%
8	South Africa	20,133	92%	11,958	86%	11,958	86%	0	0%
9	Swaziland	132	0%	432	69%	432	69%	0	0%
10	Tanzania	15,010	69%	14,602	74%	14,302	76%	-300	2%
11	Zambia	4,007	15%	5,269	35%	5,269	35%	0	0%
12	Zimbabwe	4,680	54%	3,770	44%	3,720	43%	-50	-1%
SAPP		88,391	48%	74,615	47%	74,910	45%	295	-2%

Source: PLEXOS model; figures include new generation planned for commissioning in 2017.

The biggest change at the country level is once again in Mozambique. The North Bank of Cahora Bassa peaking hydropower project (1,245 MW) is chosen in the alternative Component C, together with a small increase in gas; the impact of the large hydropower project is to reduce the proportion of thermal in new capacity in Mozambique from 71% to 50%. Four other countries reduce capacity: less coal in Botswana, reduced solar PV in DRC, reduction in both thermal and hydro in Tanzania and removal of a small gas project in Zimbabwe.

It is significant that Cahora Bassa North Bank, which has low capital costs, is introduced without any increase in transmission investments in Mozambique. Evidently sufficient capacity is freed up on the STE lines in the alternative Component C for Cahora Bassa North Bank to be a least cost choice. The scale of STE investments is nearly twice that of Cahora Bassa North Bank, but the STE investments are the same in the two variants of Component C.

Similar conclusions can be drawn to those given for the sensitivity cases which have been analysed. Component C provides a robust Pool Plan for the countries to follow, but changes in assumptions and the playing out of uncertainties may result in significant changes occurring at the national level. Mozambique is particularly vulnerable, and operates as what can be described as a 'buffer country' that absorbs the changes in regional balances, whether these arise from the sensitivity test assumptions or the alternative Component C.

Related transmission issues are discussed in Section 7. Full country level details for the alternative Component C are available in the Generation Annex Tables, which is a separate Excel file.

10 Real Options and Economic Analysis of transmission corridors

10.1 Introduction to ROA

Real options analysis (ROA) provides the ability to analyse the increased flexibility in dealing with uncertainties that some scenarios will offer to SAPP members. It is important to highlight at the outset that in the ROA section of this report the extended net present values (NPV_{ext}, which is defined below) are the discounted values of benefits minus costs and hence the option with the largest NPV_{ext} is the preferred one. Elsewhere in the report, NPV refers to the discounted value of costs only, and hence the preferred option is the one with the lowest NPV.

ROA is an important departure to allow risk to be assessed in a way that is internal to the evaluation process and is not simply investigated through sensitivity tests. During the planning process, where conditions are uncertain, the classic discounted cash flow method may fail to value flexibility associated with investment decisions. Investments that provide flexibility in the future to respond to new information that is presently uncertain may increase their value. Therefore, planning decisions are also evaluated through the Real Options approach, as the static NPV analysis may undervalue projects by suppressing the value of flexibility embedded within many options.

A Real Option is the right but not the obligation to take a pre-defined action, at a predetermined cost, for a predetermined period in time to react to changing market conditions. An illustration of Real Options embedded in projects is depicted in Table 51 below.

Table 51 Real Options embedded in projects

Action	Description
Option to expand	<i>The project could be designed with capacity in excess of the expected level of output. Management then has the option (but not the obligation) to expand output if circumstances show that it will be profitable.</i>
Time to develop/ Staged investment	<i>The project is designed to allow staged investments. Management has the option to re-evaluate and/or abandon each stage.</i>
Option to alter operating scale	<i>In response to changing market conditions the firm can decide to alter its operating scale (up or down) or temporarily shut down. (e.g. expand, shut down, restart)</i>
Option to abandon	<i>If market conditions decline the management may decide to abandon the project</i>
Option to switch inputs or outputs	<i>If prices or demand change, management can change product mix (product flexibility) or switch inputs (process flexibility)</i>
Option to defer	<i>Management has opportunity to wait to invest, and can see if markets warrant further investment.</i>
Growth options	<i>An early investment opens up future growth opportunities in the form of new products or processes, access to markets, or strengthening of core capabilities</i>

Action	Description
Option to contract	<i>The project is engineered such that output can be contracted in future should conditions turn out to be unfavourable. Forgoing these future expenditures constitutes option exercise.</i>
Multiple Interacting Options	<i>Projects involve a collection of various options – both put and call types. Values can differ from the sum of separate option values because they interact.</i>

The aim of Real Options Analysis is to develop numerical techniques to “keep score” and assist in the decision-making process. It uses the extended NPV (NPVext) defined as follows:

$$NPV_{ext} = \text{Passive NPV of extended cash-flows} + O \text{ (value of Real Options management)}$$

Projects with higher NPVext are more likely to generate higher profits. The analysis focuses on the development of interconnectors with uncertainties related to demand and availability of primary energy resources. The first step is to determine risk factors associated with each project and to identify potential mitigating measures. For example, staged investments could mitigate risks associated with demand uncertainties, but this would come with extra costs. Essentially, the investment decision depends on a trade-off between the economies of scale associated with the larger scheme versus the value of a wait-and-see strategy associated with the smaller scheme. Hence, the benefits of a staged investment on each project are assessed to determine if they outweigh the extra costs.

In more detail, to estimate the option value of interconnection the following steps are taken:

- ❑ **Identify projects to analyse with Real Options** - List the identified interconnector projects, determine risk factors associated with each project and identify potential mitigating measures. The two main real options were the option to proceed with staged investments and the option to abandon a project. These options would be reactions to demand uncertainties or uncertainties related to availability of primary energy resources.
- ❑ **Analyse benefits and costs of each project under alternative market conditions** - Develop possible pathways for each project using decision trees that take into account alternative states of uncertain conditions, decisions corresponding to alternative states and possible outcomes. Probabilities are assigned to each pathway using judgmental values based on professional experience and statistical analysis.
- ❑ **Evaluate projects with Real Options analysis** - Calculate the options value through the Extended Net Present Value (NPVext) of each project and compare the outcomes. The NPV values are not the conventional ‘most likely only’ calculations, but are the result of applying a Real Options value approach, that involves exploring a number of different scenarios and applying probabilities as weights to obtain the NPVext.

The projects that were selected to analyse with Real Options, the major corresponding risks and the concepts to mitigate those risks are presented in Table 52 below.

Table 52 Interconnectors analysed with Real Options

Interconnector project 1	
P_DRC-South Africa I (600 kV HVDC) and P_DRC-South Africa II (600 kV HVDC)	
Location:	<i>DRC (Inga) – South Africa (Gauteng)</i>
Major risks:	<ol style="list-style-type: none"> 1. <i>Lower (than forecasted) demand in SA</i> 2. <i>Inga development</i>
Real Options Concept:	<p><i>Concept 1: DRC-South Africa I (600kV HVDC) and DRC-South Africa II (600 kV HVDC) (No option to expand or abandon the project)</i></p> <p><i>Concept 2: Development of DRC-South Africa I (600 kV HVDC) (No option to expand or abandon the project)</i></p> <p><i>Concept 3: Development of DRC-South Africa I (600 kV HVDC) with an option to expand in later years by developing DRC-South Africa II (600 kV HVDC) (Option to expand or abandon the second phase of the project)</i></p>
Interconnector project 2	
DRC-Angola I (400 kV HVAC) and DRC-Angola II (400 kV HVAC) and DRC-Angola III (400 kV HVAC)	
Location:	<i>DRC (Inga) – Angola (N'zeto)</i>
Major risks:	<ol style="list-style-type: none"> 1. <i>Lower (than forecasted) demand</i> 2. <i>Thermal generation in Angola has to run at higher CF</i>
Real Options Concept:	<p><i>Concept 1: Development of DRC-Angola I (400 kV HVAC) (No option to expand or abandon the project)</i></p> <p><i>Concept 2: Development of DRC-Angola I (400 kV HVAC) and DRC-Angola II (400 kV HVAC) (No option to expand or abandon the project)</i></p> <p><i>Concept 3: Development of DRC-Angola I (400 kV HVAC) and DRC-Angola II (400 kV HVAC) and DRC-Angola III (400 kV HVAC) (No option to expand or abandon the project)</i></p> <p><i>Concept 4: Development of DRC-Angola I (400 kV HVAC) with an option to expand in later years by developing DRC-Angola II (400 kV HVAC) and further on DRC-Angola III (400 kV HVAC) (Option to expand or abandon the second and/or third phase of the project)</i></p>

10.2 Interconnector project 1 - DRC-South Africa I (600 kV HVDC) and DRC-South Africa II (600 kV HVDC)

The DRC-South Africa interconnectors are mainly designed to transfer electricity from DRC (Inga) to South Africa (Gauteng). In Component C, the operation of the interconnectors is forecast to commence in 2031 when Inga 3 will be developed. The capacity requirement for the interconnectors depends mainly on the evolution of the demand in South Africa and on the development of Inga 3. Hence, we analysed the operation of the interconnectors under multiple market conditions including low demand forecast in South Africa, base demand forecast in South Africa, Inga developed at the time it is planned and Inga developed with a

5 year delay. The probabilities that were assigned for each state are 60%, 40%, 60% and 40%, respectively.

The concepts that were analysed with Real Options are:

- ❑ **Concept 1** - DRC-South Africa I (600 kV HVDC) and DRC-South Africa II (600 kV HVDC) developed in the same year
- ❑ **Concept 2** - Development of DRC-South Africa I (600 kV HVDC) only
- ❑ **Concept 3** - Development of DRC-South Africa I (600 kV HVDC) with an option to expand in later years by developing DRC-South Africa II (600 kV HVDC)

Concepts 1 and 2 do not allow for any flexibility to adapt to changing market conditions, but Concept 3 will be developed in full if market conditions are favourable. Initially, DRC-South Africa (600 kV HVDC) is developed with an option to expand in later years if demand increases as foreseen or if excess generation will be available for exports.

Concept 3 comes with higher costs as it would be cheaper to develop all three stages at once (as is the case in Concept 2). To create the conditions to be able to expand the project in later years will require additional capital costs at the beginning of the project (Option costs). However, Concept 3 protects the investor from the down state of the market.

The value of real options derives from the fact that when investing in risky assets, we can learn from observing what happens in the real world and adapt our behaviour to increase our potential upside from the investment (expand the project) and to decrease the possible downside (abandon expansions). If the transmission line was developed to support the base case demand forecast (Concept 2) and in reality the low case demand prevails then the project would be underutilised.

The capital costs for the development of each concept are presented in Table 53. Concept 2 has the lowest capital costs with only one DC line being developed. Concept 1 costs are slightly higher and Concept 3 has the highest capital costs. Even though the assets developed under Concept 1 and Concept 3 (if all stages are developed) are the same, Concept 3 has higher capital costs to create the option to develop stage 2 at a later date and when market conditions will be favourable. Of course, there is also the option to abandon stage 2 of the project if market conditions do not require the second line.

Table 53 Costs for the development of DRC-South Africa interconnectors

Concept	Capital costs	Operating costs	Export limit	Import limit
	\$ million	% of capital costs	MW	MW
Concept 1	2,600	2.5	3,000	3,000
Concept 2	2,330	2.5	1,500	1,500
Concept 3				
Stage 1	2,330	2.5	1,500	1,500
Stage 2	320	2.5	3,000	3,000

The costs and benefits of each concept were analysed as it was explained above. The NPVext for each concept (C) is depicted in the table below.

Table 54 Results for ROA analysis of DRC-South Africa interconnector

Concept	Scenario	Angola's thermal generation	Capacity MW	Probability		NPVext - individual scenario	NPVext - probability weighted	NPV ext	
				Demand	Generation				
Concept 1	Base case	Inga as planned	3,000	40%	40%	690	110	147	
	Base case	Inga developed 5y later	3,000	40%	60%	3	1		
	Low case	Inga as planned	3,000	60%	40%	493	118		
	Low case	Inga developed 5y later	3,000	60%	60%	-228	-82		
Concept 2	Base case	Inga as planned	1,500	40%	40%	-228	-37	-374	
	Base case	Inga developed 5y later	1,500	40%	60%	-377	-90		
	Low case	Inga as planned	1,500	60%	40%	-205	-49		
	Low case	Inga developed 5y later	1,500	60%	60%	-549	-198		
Concept 3	Base case	Inga as planned	3,000	(expand in 2033)	40%	40%	670	107	12
	Base case	Inga developed 5y later	3,000	(expand in 2033)	40%	60%	-16	-4	
	Low case	Inga as planned	3,000	(expand in 2033)	60%	40%	474	114	
	Low case	Inga developed 5y later	1,500	(Do not expand)	60%	60%	-569	-205	

The figures point to a clear conclusion - that the first Concept is superior to either Concept 2 or Concept 3. It is thus best to build both of the 600 kV HVDC lines in the same year. The option offered by Concept 3 of building the second line at a later date when some of the uncertainty has been resolved has small positive NPVext. Overall, upside benefits seem to be much higher than possible downside losses.

10.3 Interconnector project 2 - DRC-Angola

The DRC-Angola interconnectors aim to connect DRC (Inga) with Angola (N'zeto) to enable trade between the two countries and the region as a whole. The commissioning of DRC-Angola I (400 kV HVAC) and DRC-Angola II (400 kV HVAC) is planned in 2020. From 2020 to 2030 the interconnectors are mainly transferring electricity from Angola to DRC and after the development of Inga 3 the interconnectors are mainly used to transfer electricity from Inga to Angola. A third interconnector is planned in 2034 (DRC-Angola III (400 kV HVAC)) to enable further trade from Inga to Angola.

The main factors of uncertainty for the development of these interconnectors are the evolution of demand in DRC and the available generation from thermal power plants in Angola. Multiple scenarios have been developed to replicate the market conditions under different states. The scenarios constitute combinations of low demand, base demand, optimised operation of thermal power plants in Angola and operation of thermal power plants in Angola with minimum capacity factors. The operation of the transmission lines was simulated under the alternative states of the market.

Four concepts were examined with Real Options Analysis for the development of the interconnectors:

- ❑ **Concept 1** - Development of DRC-Angola I (400 kV HVAC) (No option to expand or abandon the project)
- ❑ **Concept 2** - Development of DRC-Angola I (400 kV HVAC) and DRC-Angola II (400 kV HVAC) (No option to expand or abandon the project)
- ❑ **Concept 3** - Development of DRC-Angola I (400 kV HVAC) and DRC-Angola II (400 kV HVAC) and DRC-Angola III (400 kV HVAC) (No option to expand or abandon the project)
- ❑ **Concept 4** - Development of DRC-Angola I (400 kV HVAC) with an option to expand in later years by developing DRC-Angola II (400 kV HVAC) and further on DRC-Angola III (400 kV HVAC) (Option to expand or abandon the second and/or third phase of the project)

The capital and operating costs for the development of each concept is depicted in Table 55. To reap the benefits of the third line in Concepts 3 and 4, the grid between N'zeto and Luanda would need to be reinforced as well. These costs were also considered in the analysis.

The total capital costs for the development of Concept 4 are \$309 m. This is \$23 m higher than Concept 3 and it represents the extra costs required to create the flexibility to develop the project in stages.

Table 55 Costs for the development of DRC-Angola interconnectors

Concept		Capital costs	Operating costs	Export limit	Import limit
		\$ million	% of capital costs	MW	MW
Concept 1		68	2.5	300	300
Concept 2		137	2.5	1,100	1,100
Concept 3		286	2.5	1,900	1,900
Concept 4	Stage 1	76	2.5	300	300
	Stage 2	76	2.5	1,100	1,100
	Stage 3	157	2.5	1,900	1,900

The value of interconnectors comes principally from balancing the capital and operating costs of new interconnectors with wholesale price differentials between the interconnected markets. In reality the value for interconnectors can also come from the provision of ancillary services, from the provision of services to the System Operator, capacity contributions and others. Here, for simplicity, we analyse the added value of each interconnector through wholesale price differentials. We estimate the NPVext of interconnectors at each point in time as:

$$NPV_{ext} = NPV [(Wholesale\ costs\ at\ point\ 1\ at\ time\ i - Wholesale\ costs\ at\ point\ 2\ at\ time\ i) * Energy\ volume\ traded\ through\ the\ interconnector\ at\ time\ i] - NPV [Capital\ costs\ at\ time\ i] - NPV[Operating\ costs\ at\ time\ i] - Option\ costs$$

The variability of the underlying parameters (demand and generation) affects wholesale costs and traded volumes at each point in time. Wholesale prices and traded volumes under different market conditions were obtained from PLEXOS simulations. The results were analysed to develop the optimum pathway for Concept 4 and to calculate the NPVext of each concept. We have assumed that there is a 60% probability for demand to grow in Angola as it was foreseen in the low case demand forecast, 40% as foreseen in the base case demand forecast and; 70% probability for power plants to operate without any constraints in Angola and 30% probability for power plants to operate with minimum capacity factors.

The following table presents the results for ROA analysis of DRC-Angola interconnectors. The results show that Concept 4 can offer the highest benefits. This concept allows development to maximise upside potential while decreasing possible losses under the down side of the market. Concept 1 has the lowest NPVext as the maximum potential for trade is restricted by the capacity of the line. Concepts 2 and 3 stand in the middle.

Concept four suggests that DRC-Angola I (400 kV HVAC) and DRC-Angola II (400 kV HVAC) should be developed as early as possible to enable power exports from Angola to the region. During the latter years of the study the flow in these two lines is reversed and they are mainly used to export power from Inga 3 to Angola. Overall, lines I and II have high utilisation rates during the planning horizon under all alternative scenarios. The benefits these two lines would offer do not seem vulnerable to demand fluctuations or to the simulated generation uncertainties.

The benefits of DRC-Angola III (400 kV HVAC) are uncertain and depend on simulated market condition. The development of DRC-Angola III (400 kV HVAC) could provide additional benefits in some states of the market, but it does not maximise the benefits in all scenarios. For example, under the base case demand forecast with thermal plants in Angola operating with least cost principles (Scenario 1), the third transmission line would generate significant benefits especially from 2034 onwards. The analysis shows that from 2034 additional capacity is required to export energy from Inga 3 to Angola and the third line should be developed.

However, the third line has very low utilisation rates under the low demand forecast case with thermal power plants in Angola operating at higher capacity factors (Scenario 4). In this case the benefits of line III are uncertain and the analysis shows that the line should not be developed.

The real options analysis suggests that DRC-Angola I (400 kV HVAC) and DRC-Angola II (400 kV HVAC) should be developed in 2020 (following the indicated commissioning date of least cost plan) and an option to expand the capacity of those lines with the addition of DRC-Angola III (400 kV HVAC) should be available. If market conditions prove to be favourable, then the third line should be developed as well.

Table 56 Results for ROA analysis of DRC-Angola interconnectors

Concept	Scenario	Angola's thermal generation	Capacity MW	Probability		NPVext – individual scenario	NPVext – probability weighted	NPV ext	
				Demand	Generation				
Concept 1	Base case	Optimised by PLEXOS	300	40%	70%	308	86	271	
	Base case	CF set at higher rates	300	40%	30%	281	34		
	Low case	Optimised by PLEXOS	300	60%	70%	273	115		
	Low case	CF set at higher rates	300	60%	30%	201	36		
Concept 2	Base case	Optimised by PLEXOS	1,100	40%	70%	599	247	845	
	Base case	CF set at higher rates	1,100	40%	30%	648	113		
	Low case	Optimised by PLEXOS	1,100	60%	70%	897	569		
	Low case	CF set at higher rates	1,100	60%	30%	1,349	217		
Concept 3	Base case	Optimised by PLEXOS	1,900	40%	70%	882	168	1,146	
	Base case	CF set at higher rates	1,900	40%	30%	941	78		
	Low case	Optimised by PLEXOS	1,900	60%	70%	1355	377		
	Low case	CF set at higher rates	1,900	60%	30%	1,207	243		
Concept 4	Base case	Optimised by PLEXOS	1,900	(expand line II and III in 2020)	40%	70%	856	240	1,149
	Base case	CF set at higher rates	1,900	(expand line II and III in 2020)	40%	30%	915	110	
	Low case	Optimised by PLEXOS	1,900	(expand line II and III in 2020)	60%	70%	1,329	558	
	Low case	CF set at higher rates	1,100	(expand line II in 2020; do not expand to line III)	60%	30%	1,340	241	

10.4 Economic analysis of transmission corridors

As shown in Section 3.1, the costs of the regional inter-connectors which have been identified are a small proportion (~3%) of total capital costs, but it is through the construction of these interconnectors that the significant reductions in overall NPV take place. From this viewpoint, net transmission investment in Component C of \$2.2 b has the effect of:

- ❑ reducing the required installed capacity from 143 GW in the benchmark case to 130 GW, thereby reducing generation investment costs by \$34 b;
- ❑ reducing the short-term operational costs (fuel and O&M costs) by \$3 b.

The overall reduction in NPV of costs is \$36 b (including the cost of unserved energy). On the basis of these figures, the benefit:cost ratio of the transmission interconnectors built in

Component C (at a cost of \$3.3 billion) over and above those in Component A (at a cost of \$1.1 billion) has a high value of 16.4.

This high figure reflects in part the somewhat artificial assumption that was made in Component A that the long list of committed plants supplied by the utilities had to be adhered to. As was noted in relation to sensitivity test SA1, the relaxation of that constraint brings down the total costs significantly (from \$294 b to \$266 b, including unserved energy). A more relevant measure of the benefit:cost ratio of transmission interconnectors may be obtained from comparing the additional transmission investment costs in C, which in relation to SA1 is \$2.4 b, with the total cost saving of \$7.8 b. The resulting **benefit:cost ratio of the transmission interconnectors is then 3.3**. This is still a high number, but is arguably a more relevant one to use for assessing the economic impact or transmission interconnector investments.

The terms of reference for the Pool Plan study called for separate economic analysis of each of the major transmission corridors identified in Component B, including calculation of indicators such as the benefit-cost ratio (BCR) and economic internal rate of return (EIRR). However in response to the TOR, the following observations are pertinent:

- ❑ The economic analysis and the real options analysis is of more value in relation to Component C rather than Component B.
- ❑ Absolute measures such as NPV are more relevant for comparative purposes (NPV) than relative measures mentioned in the TOR (BCR, EIRR).

The cost-benefit analysis of individual interconnectors cannot be done independently of the system-wide optimisation, because the economic value of a particular interconnector derives from its role in the entire generation-transmission system. It was therefore agreed that assessing the value of an individual inter-connector would be done by removing the interconnector whose value is to be assessed, rerunning PLEXOS and noting the implication on the NPV.

The results of this analysis are reported in this section. Three of the main interconnector corridors that have been identified in the Pool Plan are shown in Table 57 below. The line with the largest capacity (Inga-South Africa) has a high absolute value of over \$9 b, representing a 3.5% increase in costs which would be imposed were that line to be removed, but in the case of Inga-DRC the additional unserved energy gives a higher absolute value of \$16 billion (6.2% increase in costs), most of which is the discounted cost of induced unserved demand (\$13 billion).

The high cost of unserved energy results in Inga-Angola having by far the highest benefit:cost ratio (136.6). The line itself is short and the direct costs are therefore relatively modest, and having the line in place allows unserved energy to be minimised in Angola. In the other two cases, induced additional unserved energy is either zero or not significant. The benefit:cost ratio is higher for Inga-South Africa (8.7) than for Inga-Zambia (1.7): higher avoided costs in the South African case greatly outweigh the cost of the long, high capacity Inga-South Africa transmission line.

Table 57 Effect of removing key transmission links

Transmission projects	Capacity lost	NPV of total costs (incl. UE costs)	Cost of line removal (\$m)	NPV of costs transmission investment (\$m)	Benefit:cost ratio	Induced unserved energy in 2040
Component C		\$ 259 b				
Inga-Zambia removed	2,000 MW	\$ 262 b	\$ 1,215 m (0.5%)	\$ 719 m	1.7	0 GWh
Inga-Angola removed	1,600 MW	\$ 273 b	\$ 16,114 m (6.2%)	\$ 118 m	136.6	7,921 GWh
Inga- South Africa removed	3,000 MW	\$ 269 b	\$ 9,067 m (3.5%)	\$ 1,048 m	8.7	311 GWh

Source: PLEXOS model, unserved energy costed at \$1,000/MWh or \$1m/GWh (see Section 2.9)

These high-level calculations above do not capture the full benefits of investing in the regional interconnectors. These projects will also provide significant local benefits to the countries involved, through supporting local transmission grid development.

11 Conclusions, priority projects, recommendations and lessons learnt

11.1 Conclusions

The Realistic scenario captures most of the regional integration benefits

The net present value of the total costs of meeting projected demand for electricity in each SAPP country is the main indicator that has been used in the Pool Plan study to rank the different components. Total costs include investment costs (overnight capital costs discounted from the year of commissioning) and short-term operational costs (fuel and O&M costs).

The NPVs of the total costs of Components A, B and C are \$283 b, \$241 b and \$246 b respectively. The assumptions incorporated in Component A, the **Benchmark Case**, are such that there can only be limited regional integration, whereas Component B, the **Full Integration Case**, allows full exploitation of regional trade and investment reduction opportunities. Component B would require certain countries to rely heavily on SAPP partners for electricity supplies, while operating some existing, or even newly built, thermal power stations at very low load factors. From several points of view, these features of the Full Regional Integration case could be unacceptable to member states.

Component C requires all countries to install sufficient domestic capacity by 2040 to meet their maximum demand (the SAPP Security Criterion) and also requires large thermal power plants to operate at or above minimum capacity levels. Trading opportunities are still available, so that countries do not necessarily use their capacity installed under the Security Criterion to meet their energy needs, but instead purchase energy from the lowest cost source that is available. Component C is thus justifiably described as the **Realistic Integration Case**.

As can be seen from the NPV figures, Component C is only slightly more expensive than Component B (\$5 b or 2% of the costs of B), while still providing significant savings in relation to Component A (\$37 b or 13% of the costs of A). A major conclusion of the Pool Plan study is that **the imposition of the 'realism' constraints on the idealised full integration case involves only a limited cost, which does not significantly dilute the benefits of regional power sector integration.**

The short-term operational costs are similar across the 3 components (\$128 b, \$123 b and \$125 b respectively). The costs of transmission investments are much higher in the regional integration scenarios (\$1.1 b, \$3.6 b and \$3.3 b respectively), but transmission investments are dwarfed in each of the components by the generation investment costs. It is therefore the **magnitude of installed capacity** that is needed to meet the (same) demand (143 GW, 127 GW and 130 GW respectively), and hence the associated generation investment costs (\$155 b, \$117 b and \$121 b respectively), which constitute the main driver of the overall cost differences between the components.

Over the planning horizon, an important shift occurs in the main elements of the installed **generation mix**, from 59% coal, 10% other thermal and 22% hydro in 2017 to (in the case of Component C) 44% coal, 14% other thermal and 35% hydro in 2040 (Component B has slightly lower coal and higher other thermal, the growth in this being mainly natural gas). As discussed in the next section, the higher installed capacity in hydro is provided mainly by large projects on the Zambezi and Congo rivers, with associated transmission investments being needed to evacuate the power. The proportion of energy supplied by hydro (24% in 2017 rising to 29%/30% in B/C in 2040) is lower than the proportion of installed hydro capacity. The relatively small change in the proportion of energy derived from hydropower stations is part of what accounts for levels of short-term operational costs being not significantly different across the three components.

SAPP member countries will share in the benefits of pursuing the realistic regional integration approach. The main exporting countries in the Plan are DRC and Mozambique, both of which have the potential to make the export of electricity into a major foreign exchange earner. Mozambique is, however, quite vulnerable to changes in regional balances arising from the resolution of uncertainties, including those examined in the sensitivity tests, higher installed capacity being needed in Mozambique if Inga is delayed or dry climate conditions materialise, or reduced capacity if South Africa imposes an import cap or lower demand eventuates across the region. Most of these variations would be achieved through changed levels of CCGT investment, but Cahora Bassa North Bank is also a variable, appearing in the least cost solution in the dry climate scenario but not in other sensitivity test scenarios.

The Realistic Regional Integration scenario is robust

The sensitivity tests involving the base demand forecasts indicate that Component C, the Realistic Regional Integration case, is robust in the face of the risk factors and policy changes analysed. While the impact for the SAPP region as a whole is quite limited, there are significant changes for individual countries.

If the lower demand forecast were to materialise, member states would be able to delay investment plans, which would reduce the pressure to raise the enormous level of financing required for the base Component C. Projects such as Devil's Gorge, Maamba Coal II, Inga 3, Inga 4 and Stiegler's Gorge are no longer selected within the 2040 planning horizon.

Component C is also robust in the face of one of the major new interconnectors being removed. Without changing investments elsewhere, the analysis in Section 10.4 shows that total costs, including the cost of unserved energy, would increase by a maximum of only 6.2%. This figure is for removal of the Inga-Angola line, but this line has by far the highest benefit:cost ratio amongst those tested, due to the fact that the line itself is short and the costs are therefore relatively modest.

These high level calculations do not capture the full benefits of investing in the regional interconnectors. These projects will also provide significant local benefits to the countries involved through supporting local transmission grid development.

Transmission interconnector projects are to be prioritised

As was made clear in Section 10.4, the underlying economics point to priority being given to the building of the regional interconnectors identified during the study. The transmission investment costs in Components B and C are only about 3% of total investment, yet it is through the interconnector investments, and key internal transmission investments such as the STE project in Mozambique, that the countries are able to share generation capacity and this makes it possible to achieve significant cost savings via reduced generation investment, with small savings also accruing from reduced operational costs.

The underlying economics of regional transmission projects is reinforced by the Real Options Analysis in Section 10. This demonstrates that, for the largest of the interconnector projects, there are no savings to be made from staging the investments. Even in the face of reduced demand or delay in implementing the capacity expansions at Inga, the ROA shows that the HVDC line from Inga to Gauteng should be built to its full capacity from the outset.

In the formal modelling, the timing of interconnectors may easily shift if the generation expansion plans are altered. However, a further important advantage of transmission interconnectors is that they typically play an important role in strengthening internal transmission networks. Adding these advantages provides further justification for undertaking interconnector investments early.

11.2 Prioritisation of generation and transmission projects

Investment project options for the Pool Plan were selected by the countries, with the technical team screening out those which would breach social and environmental norms and adding generic projects to allow greater flexibility in the choice of generation options as the study period progressed. The selection of projects is made through the process of minimising investment, operational and unserved energy costs to meet demand, subject to fulfilment of the SAPP security and reliability criteria for each country.

The prioritisation of the selected projects could be tackled through a formal multi-criteria approach, with scores being assigned to different project attributes. Within the context of this study, the prioritisation focusses on key projects of regional significance. These have to be developed in a timely fashion if the benefits of reduced costs of electricity supply (as compared with the inward-looking orientation of the Benchmark Case) are to materialise for the SAPP members.

The **priority generation projects** are shown in Table 58 below (the Angolan projects in the earlier table in Section 3.2 are already committed).

Table 58 Key generation projects in the SAPP Pool Plan

Generation projects	Countries	Capacity and commissioning dates
Batoka	Zambia and Zimbabwe	2,400 MW in 2023
Mphanda Nkuwa	Mozambique	1,500 MW in 2028
Devil's Gorge	Zambia and Zimbabwe	1,200 MW in 2032
Inga 3&4	DRC	4,800 in 2030, 9,426 MW in 2032, rising yearly to 11,654 MW in 2034
Stiegler's Gorge	Tanzania	1,048 MW in 2036 2,096 MW in 2039

In respect of transmission, the analysis in Section 10.4 gave some measure of the value of each of the HVAC / HVDC interconnectors from Inga that are envisaged to be developed in Component C. Together with the STE project in Mozambique, these are the **transmission priority projects** shown in Table 59 below, with Component C commissioning dates. The Inga line with the largest capacity (Inga-South Africa) has a high value (as reflected by a benefit:cost ratio of 8.7). The removal of Inga-Angola would result in significantly increased unserved energy costs and hence that line has an even higher benefit:cost ratio (136.6). The third line studied, Inga-Zambia, has a more modest but still high benefit:cost ratio of 1.7.

Table 59 Key transmission projects in the SAPP Pool Plan

Transmission projects	Characteristics	Capacity and commissioning dates
Inga-Angola	3 x 400 kV HVAC	1,100 MW in 2020 (2 lines) 1,600 MW in 2034 (with third line)
Inga-Luano (Zambia)	500 kV HVDC	2,000 MW in 2029
Inga-Limpopo (Gauteng) (SA)	600 kV HVDC	3,000 MW in 2032
STE (Mozambique)	2 x 400 kV HVAC 500 kV HVDC	Phased development over 2023-2028

The transmission investments are made primarily to evacuate power from the priority generation projects, but also, in the case of Angola-DRC, to supply power in the reverse direction in the early part of the planning period.

11.3 Recommendations

The Realistic Regional Integration Case is recommended as the SAPP Pool Plan 2017

Component C, the Realistic Regional Integration case, has been shown to deliver significant cost reduction benefits while meeting the test of being suitable for guiding the national masterplans of the individual SAPP members.

The Executive Committee of SAPP has endorsed Component C as the SAPP Pool Plan 2017.

Incorporate 2017 Pool Plan perspectives into national power development plans

As previously noted, the SAPP Pool Plan is an indicative rather than a prescriptive plan. In this regard, what is important is for countries to take regional integration opportunities identified in the Pool Plan into account, while at the same time pursuing their own domestic planning goals, such as ensuring that installed generation capacity is at least as large as national maximum demand.

SAPP recommends that the Pool Plan 2017 be taken as a reference point by member states for on-going power system planning and investment decision-making in the Southern African region.

Advance the implementation of the priority transmission and generation projects

The third recommendation, related to the first two, is that the key generation and transmission projects discussed in Section 11.2 and summarised in Table 58 and Table 59 be subject of detailed feasibility and/or financing studies to ensure timely implementation according to the commissioning dates identified in Component C.

Feasibility studies of hydropower projects are required to confirm key assumptions on several of the projects seen as candidates in the Pool Plan. This is important to arrive at correct levels of investment costs for such projects and also to ensure that energy output and production profiles are correctly reflected in the PLEXOS model. It is seen as very important that the outcome of such studies be made available for future updates of the Pool Plan.

As regards the transmission interconnectors, as already noted in the Conclusions, the underlying economics of regional trade, bolstered by consideration of national grid reinforcement, provide strong justification for their early development. Having grid interconnector capacity available also provides the opportunity for flexible solutions to be found as uncertainties are resolved over the course of the planning horizon.

The key projects are currently at different stages of the project cycle and have different implementation dates. The practical details will need to be worked out on a case-by-case basis. However, an important general point is that early attention should be given to the preliminary preparatory work that needs to be done, such as inter-governmental Memoranda of Understanding, before cross-border projects can proceed to the stage of detailed preparatory technical work, and beyond to financing and implementation.

11.4 Lessons learnt

A number of lessons have emerged from the process of formulating the SAPP Pool Plan 2017:

- ❑ **Data:** it is necessary to improve data collection and create functional and systematically updated databases in utilities which are mirrored at the SAPP Coordination Centre. This would lay the basis for a much more efficient regional planning process in the future.



- ❑ ***Demand forecasts:*** Changes in demand forecasts have the biggest impact on generation investments. More frequent and detailed reviews of demand forecasts are therefore necessary, at both country and regional level. It would also be beneficial if there is harmonisation across the region of the methodologies and to have more realistic assumptions for the key drivers used for demand forecasting.

- ❑ ***Training:*** Continuous training of staff in demand forecasting, collection and management of data and use of GIS and other planning tools is essential for conducting project feasibility studies and updating the SAPP Pool Plan.

ANNEXES – see Separate Volume and Excel file for A3

- A1 Demand forecast report**
- A2 Demand forecast summary tables**
- A3 Generation plan annexes**
- A4 GIS and RIAM Analysis**
- A5 Mupata Gorge screening using RIAM**
- A6 Input files for Transmission Modelling**
- A7 Overview of power flow on interconnectors**
- A8 TOR Compliance Table**
- A9 Matrix of comments on Draft Final Report and responses in Final Report**