

FORMULATION OF A CAPACITY MECHANISM FOR THE SOUTHERN AFRICAN POWER POOL (SAPP) FOR SUSTAINED LONG-TERM SYSTEM ADEQUACY

Jarrad G. Wright

A thesis submitted to the Faculty of Engineering and the Built Environment,
University of the Witwatersrand, Johannesburg, in fulfilment of the requirements
for the degree of Doctor of Philosophy.

University of the Witwatersrand, Johannesburg

Declaration

I declare that this thesis is my own, unaided work, other than where specifically acknowledged. It is being submitted for the degree of Doctor of Philosophy in the University of the Witwatersrand, Johannesburg. It has not been submitted before for any degree or examination in any other university.

Signed on: *8th February 2019*



Jarrad G. Wright

Abstract

Power system adequacy has been historically insufficient in the Southern African Power Pool (SAPP) region with resulting negative effects on economic growth and electrification efforts. Existing domestic regulatory frameworks and opaque long-term bilateral contracting for procuring capacity in the region have been shown to be insufficient in ensuring system adequacy. The concept of an adequacy product in the form of a Capacity Mechanism (CM) introduced into the SAPP region has not yet appeared in the literature. A Capacity Mechanism (CM) for the SAPP region has been proposed and designed as part of this research to address this. A framework has been developed to consider CMs via the combination of a screening assessment, quantitative (model-based) analysis of more favourable CM options and an identification and quantification of key design elements. The developed framework can also be generalised and applied to other jurisdictions where CMs are under consideration. A regional CM which transparently and explicitly values capacity is proposed in the form of a forward-looking annual Capacity Auction that is locationally disaggregated, supplied by all possible supply-side resources with all feasible SAPP market participants included. The CM should be technology agnostic and account for the dual requirement for firm capacity to meet peak demand and firm-energy to meet annual energy requirements considering the dominance of hydro-based capacity in the region when excluding South Africa. There should be a lead-time of 3-4 years with the possibility of long-term auctions for large hydro-based capacity. Strict market monitoring and adherence to performance incentives and penalties will need to be ensured to avoid exercising of market power considering the dominant size of the South African power system. Appropriately mandated institutions to run Capacity Auctions would include the SAPP Co-Ordination Centre as well as a sufficiently mandated regional regulatory body. A further contribution is made in the form of a public domain power system dataset of the SAPP region with sufficient detail to be used in power system operations and planning efforts by future researchers and practitioners.

To, Téhne

To, Tyler

To my parents, family and friends

Acknowledgements

I would like to sincerely thank:

- My supervisor Dr J.M. van Coller for patience, guidance and experienced insight;
- The University and more particularly the School of Electrical and Information Engineering for the opportunity to complete this research and the experience of being a postgraduate in such an inviting environment.
- The Council for Scientific and Industrial Research (CSIR) for assistance with funding; and
- Ad-hoc collaborative discussions and inputs from SAPP Co-Ordination Centre representatives in particular Musara Beta and the late Dr Lawrence Musaba.

JW

Contents

Declaration	ii
Abstract	iii
Acknowledgements	v
Contents	vi
List of Figures	ix
List of Tables	xi
1 Background	1
1.1 Introduction	1
1.2 Hypothesis	3
1.3 Research significance	4
1.4 Research limitations	6
1.5 Thesis Outline	6
2 Literature Survey	9
2.1 Power system adequacy	9
2.2 Generation expansion planning and competitive electricity markets .	17
2.2.1 Competitive electricity markets	17
2.2.2 Generation expansion planning	22
2.3 Energy-only markets (EOMs) and the need for CMs	28
2.3.1 Background	28
2.3.2 Practicalities of electricity markets necessitating CMs	29
2.4 Capacity mechanisms (CMs)	32
2.4.1 Categorisation	32
2.4.2 Characterisation and design elements	37

2.4.3	Performance criteria	43
2.4.4	Capacity mechanisms (CMs) around the world	45
2.4.5	Impact of variable renewable energy sources (RES) on CMs	47
2.5	SADC and SAPP	49
2.5.1	History of SADC and SAPP	49
2.5.2	The SAPP market participants	55
2.5.3	The SAPP size and interconnections	56
2.5.4	Evolution of the SAPP market architecture	60
3	System adequacy and capacity equilibrium	63
3.1	Adequacy metrics: LOLE and LOLP	63
3.2	Capacity equilibrium	71
4	Focus on SAPP market performance	76
4.1	SAPP historical power system adequacy	76
4.2	The existing SAPP energy mix	79
4.3	Historical performance of SAPP markets	84
5	Framework to assess capacity mechanisms (CMs) in the SAPP	88
5.1	Need for a CM in the SAPP	88
5.2	Approach	90
5.2.1	Screening	91
5.2.2	Quantitative assessment	93
5.3	Outcomes and discussion	100
5.3.1	Screening	100
5.3.2	Quantitative assessment	112
5.4	Proposed CM design for the SAPP	125
5.4.1	Definition of the adequacy product	125
5.4.2	Targeting	131
5.4.3	Lead-time	132
5.4.4	Duration	134
5.4.5	Performance incentives and penalties	134
5.4.6	Secondary design elements	134
5.4.7	Summary	135
6	Conclusions and further research	137
6.1	Conclusions	137

6.2	Addressing the hypothesis and research questions	139
6.3	Recommendations for further research	140
References		145
A Published Research		168
B Dataset of the SAPP region		170
B.1	Overview	170
B.2	Supply technologies (existing)	171
B.3	Supply technologies (candidates)	186
B.4	Regional electrical demand	195
B.5	Electrical transmission networks	198
B.6	Fuels for power generation	202

List of Figures

1.1	Thesis outline highlighting chapter flow	8
2.1	Demonstration of two price-inelastic demand scenarios	16
2.2	Optimal capacity in competitive market with three possible suppliers	22
2.3	A simple least-cost generation capacity expansion	26
2.4	Typical categorisation of Capacity Mechanism (CM) types	33
2.5	Global map of pertinent existing and under consideration CMs . . .	45
2.6	Geographical illustration of the Southern African region	51
2.7	The SAPP management and governance structure (2016)	55
2.8	Graphical overview of existing and future SAPP interconnections . .	59
3.1	LOLE/LOLP vs peak demand & capacity (flat demand)	65
3.2	LOLE/LOLP vs peak demand & capacity (sloping demand)	66
3.3	LOLE/LOLP vs peak demand & capacity (representative demand) .	67
3.4	Normalised daily peak Load Duration Curve (LDC) (one year - flat)	68
3.5	Normalised daily peak LDC (one year - sloped)	68
3.6	Normalised daily peak LDC (one year - representative)	69
3.7	LOLE and LOLP vs granular installed capacity (flat LDC)	69
3.8	LOLE and LOLP vs granular installed capacity (sloping LDC) . . .	70
3.9	LOLE and LOLP vs granular installed capacity (representative LDC)	71
3.10	Cost of capacity (sloping demand profile, 1% FOR)	74
3.11	Cost of capacity (sloping demand profile, 5% FOR)	75
4.1	Historical SAPP system adequacy	78
4.2	Historical SAPP system adequacy (excluding South Africa)	79
4.3	SAPP overall/interconnected installed capacity (by country - 2016) .	81
4.4	SAPP overall/interconnected energy mix (by country - 2016)	82
4.5	SAPP capacity & energy mix (by type - 2016)	83
4.6	SAPP capacity & energy mix excluding South Africa (by type - 2016)	83
4.7	SAPP annual historical bilateral electricity trade (2002-2017)	85
4.8	SAPP historical electricity trade (annual)	86

4.9	SAPP historical competitive electricity market trade (monthly) . . .	87
5.1	Framework developed to assess CMs (applied to the SAPP)	91
5.2	Performance of CMs assessed for the SAPP	113
5.3	Expected SAPP supply-demand balance (2016-2020)	115
5.4	Expected evolution of supply-demand balance for CMs considered. .	118
5.5	Reserve margin vs Loss of Load Probability (LOLP) for CMs assessed	119
5.6	Reserve margin ranges for capacity auction in SAPP	120
5.7	Reserve margin ranges for capacity auction in SAPP	121
5.8	Wholesale annual price vs LOLP for CMs assessed	122
5.9	Resulting energy mix from applying a capacity auction in the SAPP	124
5.10	Resulting energy mix from applying a strategic reserve in the SAPP	124
5.11	Demonstration of a capacity auction for SAPP	128
5.12	SAPP capacity auction with existing/newly incentivised capacity . .	130
B.1	Expected electrical energy demand forecast for SAPP (2016-2050) .	196
B.2	Expected electrical peak demand forecast for SAPP (2016-2050) . .	197

List of Tables

2.1	Categorisation of Capacity Mechanism (CM) types	34
2.2	Performance criteria for CM types	44
2.3	The SAPP membership (2016)	56
2.4	SAPP electricity statistics (2016)	58
5.1	Screening rating scale for CM performance	92
5.2	Strategic reserve sizing in selected jurisdictions	100
5.3	Evaluation of CMs for the SAPP	101
5.4	Performance on key adequacy metrics of CMs assessed	120
5.5	Representative parameters for SAPP capacity-auction	129
5.6	Typical lead-times for technologies	133
5.7	Summary of proposed CM for the SAPP	136
B.1	Existing generation capacity in developed dataset of SAPP region .	172
B.2	Expected capacity factors of variable RES	187
B.3	Candidate generation capacity in developed dataset of SAPP region	188
B.4	Transmission interconnectors for SAPP region (existing)	199
B.5	Expected fuel prices included in SAPP dataset (2016-2050)	203

Abbreviations

BRA	Base Residual Auction
CA	Central Authority
CCM	Capacity Credit Market
CEO	Chief Executive Officer
CIGRE	Conseil International des Grands Réseaux électriques
CAISO	California Independent System Operator
CCGT	Combined-Cycle Gas Turbine
CM	Capacity Mechanism
CONE	Cost Of New Entry
COUE	Cost Of Unserved Energy
CRM	Capacity Remuneration Mechanism
CSP	Concentrating Solar Power
DisCo	Distribution Company
DAM	SAPP Day-Ahead Market
DER	Distributed Energy Resources
DRC	Democratic Republic of Congo
DSR	Demand-Side Response
EDNS	Expected Demand Not Supplied
EENS	Expected Energy Not Supplied
EIR	Energy Index of Reliability
EOM	Energy-Only Market
ERCOT	Electric Reliability Council of Texas
EU	European Union
FOM	Fixed Operations and Maintenance

FOR	Forced Outage Rate
FPM-M	SAPP Forward Physical Market (Monthly)
FPM-W	SAPP Forward Physical Market (Weekly)
HL	Hierarchical Level
HVDC	High Voltage Direct Current
IA	Incremental Auction
IDM	SAPP Intra-Day Market
IPP	Independent Power Producer
ITC	SAPP Independent Transmission Company
ISO-NE	Independent System Operator-New England
KKT	Karush-Kuhn-Tucker
LDC	Load Duration Curve
LLD	Load-Limiting Device
LOLP	Loss of Load Probability
LOLE	Loss of Load Expectation
LP	Linear Programming
LRMC	Long-Run Marginal Cost
LSE	Load-Serving Entity
MCP	Market Clearing Price
MENA	Middle-East and North Africa
MO	Market Operator
MT	Medium-term
MTP	SAPP Market Trading Platform
MILP	Mixed-Integer Linear Programming
MISO	Mid-continent Independent System Operator
MoU	Memorandum of Understanding

NEM	National Electricity Market
NERC	North American Electric Reliability Corporation
NP	SAPP Non-Operating Member
NYISO	New York Independent System Operator
OCGT	Open-Cycle Gas Turbine
OECD	Organisation for Economic Co-operation and Development
OB	SAPP Observer
OP	SAPP Operating Member
PDAM	SAPP Post Day-Ahead Market
PJM	PJM Interconnection LLC
PPA	Power Purchase Agreement
PU	SAPP Power Utility
PV	Photovoltaics
QP	Quadratic Programming
REIPPPP	Renewable Energy Independent Power Producer Procurement Programme
RERA	Regional Electricity Regulators Association
RES	Renewable Energy Sources
RPM	Reliability Pricing Model
RSI	Residual Supply Index
Rte	Réseau de transport d'électricité SA
RTO	Regional Transmission Organisation
SADC	Southern African Development Community
SAPP	Southern African Power Pool
SO	System Operator
SP	SAPP Service Provider

STEM	Short-Term Energy Market
TransCo	Transmission Company
TSO	Transmission System Operator
UCAP	Unforced Capacity
UFOR	Unforced Outage Rate
UK	United Kingdom
USA	United States of America
USE	Unserved Energy
VoLL	Value of Lost Load
VOM	Variable Operations and Maintenance

Chapter 1

Background

1.1 Introduction

When a regional power pool in the Southern African region was established in 1995, known as the Southern African Power Pool (SAPP), all countries in the region exhibited vertically integrated electricity sectors (one entity performing all functions in the electricity sector). The SAPP originally aimed for co-operative electricity trade between countries but moved towards establishing competitive electricity trade soon thereafter. Currently, the Southern African region exhibits unique electricity sector arrangements in that it combines countries with some level of unbundling where generation, transmission, distribution and customer services are undertaken by separate entities with those still applying vertically integrated models¹. These entities mostly trade bilaterally with each other with some use of the established competitive SAPP markets. This has been one of the drivers that has prompted this research where there is no ability to transparently and objectively signal the need for capacity in the region to ensure system adequacy.

A key objective of the SAPP has been to facilitate competitive electricity trade between market participants. This has been enabled through the established SAPP market architecture and associated markets (as will be discussed further in Chapter 2). The administrative arrangements and market platforms developed and administered by the SAPP Co-ordination Centre as the existing regional Market Operator (MO) enable the implementation of electricity trade in the region. The mix of vertically integrated and unbundled electricity sectors in the region combined with this regional power pool results in an interesting mix of SAPP market participants. Some

¹ Where all of these functions are undertaken by one entity.

countries are only represented by their vertically integrated SAPP Power Utilities (PUs) whilst others are represented by both vertically integrated PUs, individual Independent Power Producers (IPPs) and/or SAPP Independent Transmission Companies (ITCs).

These electricity market arrangements have also meant a largely country level centrally planned determination of system adequacy requirements and associated least-cost capacity expansion planning. The consequences of this are explored as part of this research. Regional trade of electricity is often only on a bilateral basis between SAPP market participants (with minimal trade on the aforementioned historically co-operative and now competitive SAPP markets). Thus, the required revenues for generation capacity investment in the region have mostly been established on the basis of long-term Power Purchase Agreements (PPAs) between the relevant national PUs and IPPs or built by the national PUs themselves based on the outcomes of cost-optimal capacity expansion plans. The use of existing SAPP markets to underpin generation capacity investment has not yet occurred.

Primarily owing to the realities of imperfect foresight and long-term nature of power system investments (amongst others), there are often times of over-investment and under-investment in electricity markets. In SAPP countries specifically, the primary reasons for this can be linked to significant demand growth in the region and the uncertainty thereof as well as country-specific policy environments where decisions on capacity investments are administratively determined (often delayed or exhibit significant time-overruns) and not based on market forces.

As will be outlined in Chapter 2 and 4, the historically co-operative and now competitive SAPP electricity trading markets have historically been Energy-Only Markets (EOMs) including forward physical markets (month-ahead, week-ahead) and short-term markets (day-ahead and intra-day). Although electricity market theory would suggest that in a restructured energy market environment with competitive EOMs these should provide the necessary price spikes in times of scarcity to incentivise investment and ensure system adequacy, this has not necessarily been the case in practice in a number of jurisdictions around the world (for a number of reasons which will be expanded on in this research). As a result, system adequacy concerns have been raised and discussions around Capacity Mechanisms (CMs) have gained research interest since deregulation began in the 1990s globally with considerable increased interest recently following system adequacy concerns as increasing penetrations of variable Renewable Energy Sources (RES) are being deployed globally.

CMs present themselves in various forms but are fundamentally policy instruments which provide revenue to capacity providers based purely on capacity (independent of energy produced) to ensure sustained system adequacy. In the SAPP specifically, low-trade volumes and liquidity in the competitive EOMs discussed combined with a low price-cap has meant that scarcity has not by any means been able to incentivise capacity investment in the region. This is another driver for interest in the research presented.

For clarity on terminology, in most European markets, CMs are often referred to as *Capacity Remuneration Mechanisms (CRMs)* whilst in the United States of America (USA) and in a number of other jurisdictions the term *capacity market* is often used more generally. This research refers to any policy instrument that values system adequacy as a *Capacity Mechanism (CM)*.

1.2 Hypothesis

In this research, a regional CM introduced into the SAPP market architecture is proposed with the hypothesis that it can incentivise sustained capacity investment in the region as existing country specific electricity market arrangements as well as SAPP competitive markets have not historically exhibited the necessary characteristics to ensure sustained system adequacy. This would be ensured via the transparent and explicit signal to incentivise capacity investment via a CM. In this context, the research hypothesis has been defined via a primary research question and a number of secondary research questions.

The primary research question is:

1. *Can a regional CM be designed for the SAPP to ensure long-term sustained system adequacy considering the existing SAPP market architecture and regional electricity market environment?*

Secondary research questions would then be:

- a. *What would the impact of a regional CM be on the existing SAPP market architecture?*
- b. *What is the most appropriate CM (if any) considering existing implementations of CMs globally?*

- c. *Will a novel CM need to be formulated considering the SAPP market architecture and electricity market environment?*
- d. *Would the formulation of a CM facilitate system adequacy and/or increase electricity trade in the SAPP?*
- e. *What resources should be included in the CM? e.g. technology agnostic or technology specific.*
- f. *What will the impact of increasing levels of variable RES be on the requirement for a CM in the SAPP?*

1.3 Research significance

This research is envisioned to be used as a basis for the necessary stimulation of discussion and action surrounding perpetual under-investment in the electricity sector in the SAPP region while remaining cognisant of the SAPP market architecture and country specific regulatory environments. Sufficient and sustained levels of system adequacy can also further enable electricity access and drive investments necessary for economic growth expected in the region. With CMs integrated into the SAPP, this research aims to show how a sustained level of system adequacy in future can be attained via sufficiently valuing capacity and incentivising capacity investment. Conversely, the impact of an inadequate power system on further investments and economic growth are also clear and are a driving force behind the value of this research.

The research provides a brief historical adequacy assessment of the SAPP as well as an approach for considering forward-looking system adequacy assessments. This provides some valuable insights into the need to ensure a transparent indication of the valuation of capacity in the SAPP region and further drives the necessity for an explicit adequacy product that is a further contribution of this research.

The use of historically co-operative and now competitive SAPP electricity markets to underpin capacity investment has not yet occurred. The introduction of an appropriately designed CM in the SAPP to supplement the revenues that could be obtained from existing competitive markets (or through domestic market arrangements) could enable capacity investment in itself negating the need for long-term PPAs as has historically been the case. With a CM, the supplementary revenue source removes some level of long-term risk inherently present in EOMs. Instead, capacity requirements

can be procured via a CM where the value of capacity is transparently established and revenue explicitly recovered by capacity providers. Energy revenue is then either recovered domestically or via existing SAPP competitive electricity markets as mentioned.

This research could be used for informed policy formulation by responsible national institutions, the development of regulations by regulators, insight into the possible market opportunities for investors as well as increased investment certainty in the SAPP to ensure sustained levels of power system adequacy. This includes incumbent PUs as well as existing and future IPPs.

It develops a framework to assess CMs whilst also finding out what the most appropriate CM for the SAPP would be and the impact it could have on correcting chronically insufficient generation capacity investment in the region. It presents, analyses and recommends what is hypothesised to be the most appropriate CM via a screening, an approach to determining Medium-term (MT) adequacy, a model-based quantitative approach for selected CMs and then presents the key design elements that characterise a preferred CM. This provides a practical indication of what a CM in the SAPP would resemble.

If designed and considered appropriately, the introduction of a CM into the SAPP should ensure sufficient and sustained system adequacy. This will also assist with increased inter-regional electricity trade as a result of sustained system and more specifically if the competitive wholesale electricity markets on the SAPP are used to indicate scarcity and drive capacity investment. There are clear benefits associated with this as a result of the large geographical area of the region and location specific nature of the considerable available resources e.g. hydro, coal, natural gas, biomass, solar and wind.

Although a range of data is available in the public domain for power systems in the SAPP region, these are highly fragmented and largely inconsistent. Thus, a considerable contribution made by this research is the integrated dataset developed and collated for sharing in the public domain. It has sufficient detail to be used for power sector operations and planning research efforts and is summarised in Appendix B.

Increased levels of cheap, zero short-run marginal cost, variable RES like solar Photo-voltaics (PV) and wind introduce an additional dimension to this research. Although not necessarily an explicit focus, these resources pose a particular challenge to power system adequacy. They do not contribute significantly to ensuring adequacy (as

do conventional dispatchable generation technologies). Increased penetration levels of these resources will likely increase the role CMs would need to play to ensure sufficient system adequacy in future. This is applicable globally as well as regionally in the SAPP context.

1.4 Research limitations

The research provides an analytical basis upon which a potential CM could be introduced into the SAPP in future (amongst other aspects considered and discussed). It is fully appreciated that any change and/or addition to the existing electricity market architecture of the SAPP and country-specific market arrangements will entail a significant process involving inputs and decisions at technical, managerial and political institutions and structures. These institutions and structures would enable the enactment of any form of new CM for the region and would need to define and implement enabling cross-border policy, legislation and regulations before a CM, as considered in this research, could actually be implemented. It is acknowledged that this is a limitation of the research as it is envisioned to be a proof-of-concept which can then be used as a basis for further investigation regarding the implementation of CM options to ensure sufficient and sustained levels of system adequacy in the region.

1.5 Thesis Outline

A graphical view of the thesis outline is given in Figure 1.1 and described further below.

Chapter 1 is the current chapter which has provided an introductory background to the research providing the aim and rationale followed by the hypothesis, significance and limitations of the research.

Chapter 2 summarises and evaluates the relevant literature that has been considered as part of the research while providing a critique to reveals the research focus and areas of development filled by this research contribution.

Chapter 3 provides an analytical representation of key concepts defined relating to system adequacy and power system capacity equilibrium.

Chapter 4 is dedicated to providing a summary of historical SAPP market performance to provide further context and motivation for the the research.

Chapter 5 defines and justifies the framework developed and approach as part of this research while linking consistently to the existing literature. This is followed by the research outcomes and significant findings based on the approach whilst analysing, interpreting and synthesising outcomes to argue the contribution the research has made to the existing body of knowledge.

Chapter 6 provides the conclusions which distil the outcomes of the research to succinctly define the contribution made. It also includes recommendations to extend the research further.

Appendix A includes publications published as part of this research.

Appendix B provides a summary of the SAPP dataset and model(s) developed and applied in this research.

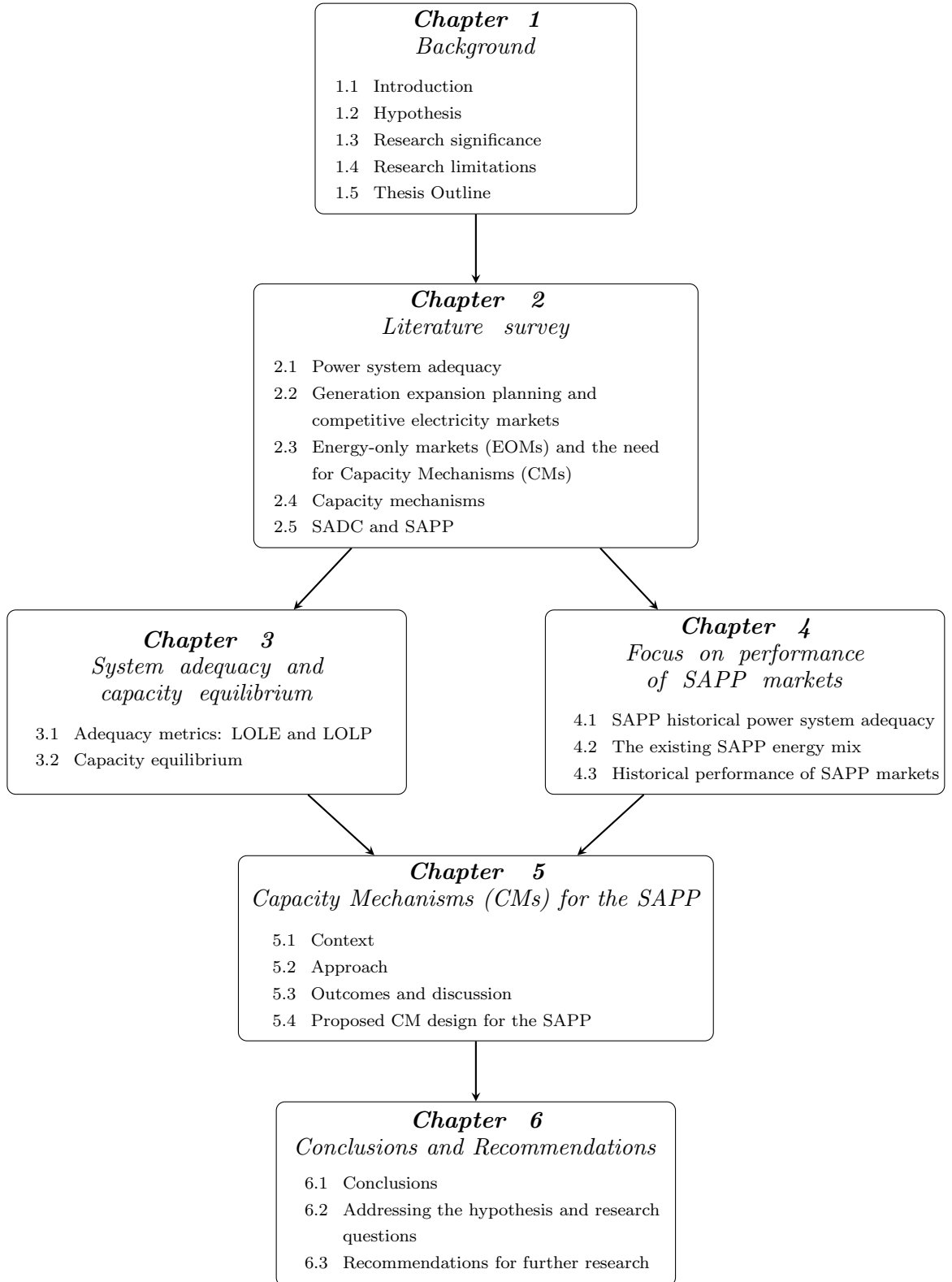


Figure 1.1: Thesis outline highlighting chapter flow

Chapter 2

Literature Survey

2.1 Power system adequacy

As outlined by Billinton in [1], one can consider power system adequacy from the perspective of three functional hierarchies. Hierarchical Level (HL) I includes only generation and the collective ability to meet demand. HL II refers to the ability of both generation and transmission networks to meet demand. Finally, HL III refers to the ability of generation, transmission and distribution networks to meet demand. The focus of this research is on HL I while some consideration is given to other HLs at a superficial level throughout.

CMs link closely to power system adequacy (a component of power system reliability - as will be described). Thus, adequacy forms a key dimension of the technical background for this research and will be expanded upon in the sections that follow.

As is well known and described by Billinton [1] and Kundur [2], power system reliability is usually conceptualised to be made up of two components:

1. **Adequacy:** The existence of sufficient facilities in the power system to satisfy demand. Billinton extensively addresses this component of power system reliability in [1].
2. **Security (resiliency):** The ability of the power system to respond to and recover from unexpected disturbances within the power system or from external disturbances. Kundur extensively addresses this component of power system reliability in [2].

As would be expected, these two concepts are interdependent and only separated for convenience. Adequacy typically relates to a particular steady state of the power system and whether it has sufficient capability to match supply and demand whilst security is the dynamic process of transitioning from one state to another. Both of these states could be adequate/inadequate but the transition may/may not be secure. The more relevant component of reliability applicable to this research is *adequacy*¹.

Adequacy can be defined at an operational level and at a planning level. Both are interdependent but once a planning decision has been made, the operational supply-demand balance becomes an operating consideration i.e. the amount of reserves available to provide system adequacy is defined. The planning level problem is different in that it requires an adequate supply-demand balance to be planned for and decisions on capacity investment made well in advance.

The nature of electricity necessitates that the supply-demand balance is maintained at all times. In order to ensure this for a particular jurisdiction, certain levels of generation, interconnectors (if available) and/or Demand-Side Response (DSR) resources are required over and above instantaneous demand in any period. The reason for this in both the operating and planning domain is that it is impossible for a System Operator (SO) to forecast with complete certainty the exact demand or supply resources that will be available in a future timeframe. This uncertainty has historically been mostly on the demand side but there also exists supply-side uncertainty as generating units may under-deliver or over-deliver in particular time periods or fail unexpectedly². This uncertainty requires a certain margin of additional capacity over and above demand in order to maintain an acceptable level of power system adequacy.

In some jurisdictions, historical practice has been to define and compare power system adequacy via deterministic methods and resulting adequacy metrics, for example, discrete reserve margins (%) and/or absolute capacity reserve margins (MW). However, these approaches have significant weaknesses when considering the inherent probabilistic nature of supply and demand in power systems. These weaknesses include an intense focus on only one period or set of critical periods (while ignoring demand in other periods) as well as minimal consideration for the

¹ For more information on the *security* component of power system reliability, please refer to Kundur [2] (amongst others).

² More recently the introduction and proliferation of variable RES sources in a number of power systems globally has introduced further uncertainty on the supply side.

reliability metrics of individual units as well as inherent penalty associated with unit sizes (specifically larger units in small power systems).

The most appropriate methods for determining system adequacy are probabilistic methods [1, 3, 4]. Most probabilistic methods approach the adequacy problem in a similar manner. That is, supply and demand models are combined to form an appropriate risk model. The most commonly used probabilistic metric in assessing power system adequacy is the Loss of Load Expectation (LOLE) or the Loss of Load Probability (LOLP) metric and has been the widely accepted system adequacy metric for over 50 years [3, 4]. The LOLE (and associated LOLP) is defined in [1] as:

$$LOLE = \sum_{i=1}^n p_i(C_i < L_i) \quad (2.1)$$

where:

- $p_i(C_i < L_i)$ - Probability of loss of load (peak demand exceeds available capacity) at time period i , based on capacity outage probabilities;
- C_i - Available capacity at time period i ;
- L_i - Peak demand at time period i ; and
- n - Total number of periods under consideration.

The LOLP which is essentially a normalised version of the LOLE is expressed as:

$$LOLP = \frac{LOLE}{n} \quad (2.2)$$

Equation 2.1 defines the probability of all combinations of generator forced outages (a capacity outage probability table) convolved into a demand model for particular periods over a particular timeframe (typically daily peak demand over one year) to then produce the LOLE. The LOLE is a mathematical expression of the number of periods (or percentage of periods if LOLP) in which loss of load could be expected. It does not give any insight into the severity of the expected loss of load. This can be obtained by the expected capacity deficit in each time period (known as the Expected Demand Not Supplied (EDNS)) and summed for the overall time period

to obtain the Expected Energy Not Supplied (EENS) when applying the abovementioned model [1]. The concept of LOLE (and LOLP) are further demonstrated in section 3.1.

Although LOLE and LOLP provide some useful insight into the measure of system adequacy, the valuation of system adequacy provides more insight into the valuation of capacity. It can be intuitively understood that the optimal amount of installed capacity (to ensure a pre-defined level of system adequacy) will be a trade-off between the costs of additional supply capacity and the costs of outages that would be experienced as a result of insufficient capacity. This has been mathematically proven in the literature and will be included briefly for reference [1, 5–9]:

$$b_n = b_s + b_c \quad (2.3)$$

where:

b_n = Net benefit of electricity provision (USD/yr);
 b_s = Supplier surplus for electricity (USD/yr); and
 b_c = Consumer surplus for electricity (USD/yr).

Also, consumers net-benefit for electricity can be expressed as follows;

$$b_c = c_o + c_g \quad (2.4)$$

where:

c_o = Cost to consumer when experiencing outages (USD/yr); and
 c_g = Consumer surplus when not experiencing outages (USD/yr).

Therefore;

$$b_n = b_s + (c_o + c_g) \quad (2.5)$$

Optimal electricity supply to consumers would mean an optimisation of the sum of c_o and c_g as supply capacity is increased. Letting q be the available supply capacity, the change in net-benefit of electricity relative to a change in q is obtained as:

$$\frac{db_n}{dq} = \frac{db_s}{dq} + \frac{dc_o}{dq} + \frac{dc_g}{dq} \quad (2.6)$$

As one typically assumes demand is price inelastic, and hence b_s does not change with available supply capacity, $\frac{db_s}{dq}=0$, resulting in:

$$\frac{db_n}{dq} = 0 + \frac{dc_o}{dq} + \frac{dc_g}{dq} \quad (2.7)$$

The cost of outages can be expressed as a function of the $VoLL$ (USD/kWh) and $EENS(q)$ (kWh):

$$c_o = EENS(q) \cdot VoLL \quad (2.8)$$

Meaning that:

$$\frac{db_n}{dq} = VoLL \frac{dEENS(q)}{dq} + \frac{dc_g}{dq} \quad (2.9)$$

As we approach the optimal available supply capacity q , the change in generation costs relative to the change in available supply capacity q , $\frac{dc_g}{dq}$ approaches the cost of a new adequacy provider c_p :

$$\frac{db_n}{dq} = VoLL \frac{dEENS(q)}{dq} + c_p \quad (2.10)$$

If we wish to find the optimal required available capacity, we would need to set $\frac{db_n}{dq} = 0$:

$$0 = VoLL \frac{dEENS(q)}{dq} + c_p \quad (2.11)$$

Therefore;

$$\frac{dEENS(q)}{dq} = -\frac{c_p}{VoLL} \quad (2.12)$$

The term $-\frac{dEENS(q)}{dq}$ is also known as the LOLE (as previously presented) and thus:

$$c_p = LOLE \cdot VoLL \quad (2.13)$$

The cost of new capacity provision c_p is composed of both fixed and variable costs. The fixed cost component of c_p is often referred to as the Cost Of New Entry (CONE) and represents the upper limit for the normalised revenue that a new supplier of capacity would receive to recover fixed investment and operating costs to ensure a pre-defined level of system adequacy (net of energy revenue earned in bilateral PPAs³, EOM and ancillary services markets⁴).

The Value of Lost Load (VoLL), often used interchangeably with the well-known Cost Of Unserved Energy (COUE), is typically determined via detailed economic studies and can be time dependant, be different for a range of consumer classes (residential, commercial, industrial) as well as individual consumers within these classes [5, 10]. The VoLL is the value consumers place on the provision of electricity supply beyond which a consumer would prefer to be curtailed (disconnected). For the sake of this thesis, VoLL is the aggregated normalised value placed on electrical energy for all consumer classes.

Often, the CONE is either based on an existing peaking generator or calculated ex-ante based on the pre-defined system adequacy requirement (LOLE) and VoLL which would adequately incentivise supply capacity investment [11–15]).

An illustration of demand price-inelasticity is given in Figure 2.1. For demand that is price-inelastic snapshots are shown in Figure 2.1(a) and Figure 2.1(b)). From this, it can be appreciated that there will be times when demand is less than the supply (unconstrained) and times when it is more than supply (constrained)⁵. When there is sufficient supply capacity (Figure 2.1(a)), the intersection of the marginal supply cost and consumer value curves results in the system wide marginal price paid to suppliers (in this case, one supplier). When the system is constrained (Figure 2.1(b)), the intersection of these curves is at the previously defined VoLL (VoLL = 7500 USD/MWh). This means that capacity on-line during these times receives VoLL. In addition, consumer surplus is zero while supplier surplus is considerably large and supplier capacity is inherently incentivised.

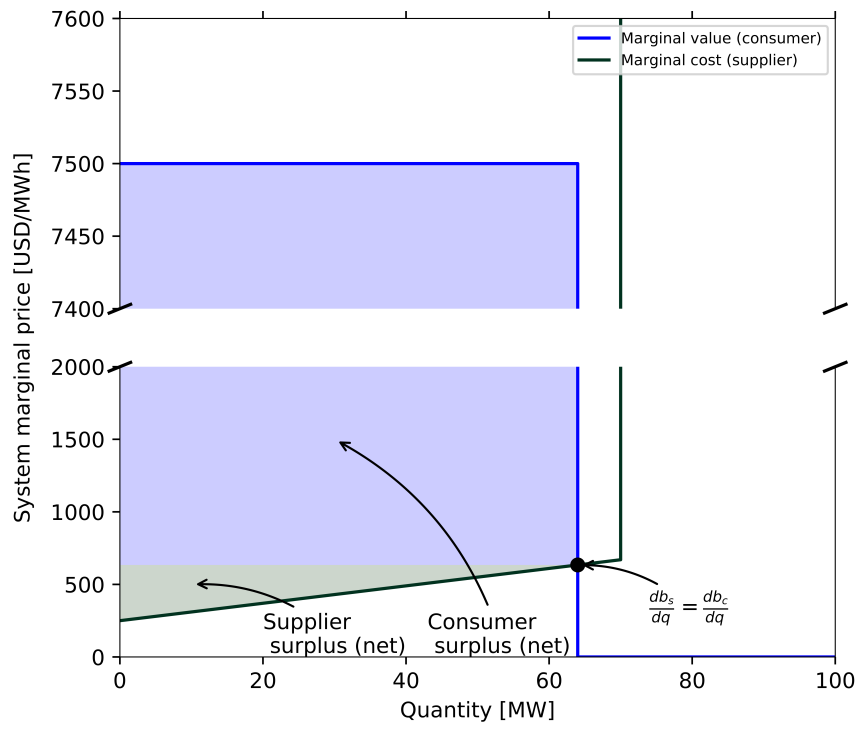
As can be intuitively seen from the previous derivation, LOLE combined with VoLL should be set at appropriate levels (whether via price formation in a competitive energy market during scarcity or in defining adequacy requirements in a centralised capacity expansion planning environment) as this will ensure sufficient levels of

³ If only part of an investment is in a PPA.

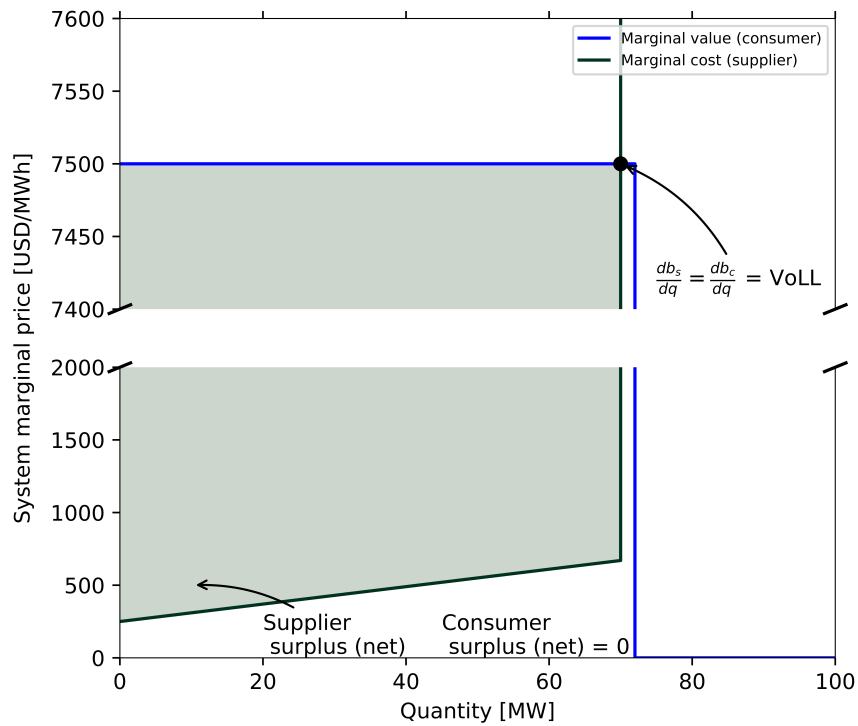
⁴ Energy-Only Markets (EOMs) are discussed further in section 2.3.

⁵ Ideally not too long and defined by the LOLE and resulting Expected Energy Not Supplied (EENS).

capacity investment and associated system adequacy. If set incorrectly, economic inefficiency in the form of over-investment or under-investment are likely to occur resulting in either too much capacity (with the associated costs) or an inadequate power system with high-levels of outages (further illustrated in section 3.2).



(a) Unconstrained



(b) Constrained

Figure 2.1: Demonstration of two price-inelastic demand scenarios highlighting incentivisation for supply capacity under constrained system conditions

2.2 Generation expansion planning and competitive electricity markets

In jurisdictions with competitive wholesale EOMs (no CM), system adequacy is implicitly assumed by the expectation that revenues earned over the investment time horizon in competitive EOMs should be sufficient to ensure existing supply capacity is kept available whilst also incentivising investment in new generation capacity [16].

In jurisdictions where centralised long-term (≥ 20 years) capacity expansion planning is undertaken, the requirement for capacity is explicit with the least-cost planning outcomes and procurement of capacity thereafter explicitly compensating providers of capacity.

As will be described in more detail in section 2.2.1 and 2.2.2 that follow with further detail in section 2.3 thereafter, the driving force behind CMs is the notion that practicalities associated with operating and planning power systems in reality⁶ do not implicitly allow for sustained levels of sufficient system adequacy into the future.

2.2.1 Competitive electricity markets

Assuming a perfectly competitive electricity market, in order to ensure dynamic economic efficiency (long-term efficiency) the net-benefit of electricity provision should be maximised (as previously presented in section 2.1 and extended further here) [9]. In the long-term, a key assumption is that supply capacity can be increased and as a result, with t suppliers with unit fixed costs f_t (inclusive of capacity expansion costs) and variable costs c_t , the cost function $C_t(Q_t, K_t)$ would be:

$$C_t(Q_t, K_t) = c_t Q_t + f_t K_t \quad (2.14)$$

where:

$C_t(Q_t, K_t)$ = Supplier cost function for generator t operating at capacity Q_t (MW)
and with maximum capacity of K_t (MW);
 c_t = Variable cost of supplier t (USD/MWh);

⁶ Whether in competitive wholesale electricity markets or centrally planned markets.

Q_t	= Operating capacity at supplier t (MW);
f_t	= Fixed capacity cost of supplier t (USD/MW-yr);
K_t	= Maximum capacity of supplier t (MW).

Knowing that there is some level of uncertainty in the cost function $C_t(Q)$ and utility function for consumers U_Q , we would prefer to represent these functions with random variables with probability p_s for any state of the system s . Thus, the maximisation of economic welfare would be:

$$\text{Max: } \sum_s p_s \left[U_s \left(\sum_t Q_{ts} \right) - \sum_t C_t(Q_{ts}, K_t) \right] \quad (2.15)$$

Subject to:

$$\begin{aligned} Q_{ts} &\leq K_t && \leftrightarrow p_s \mu_{ts} \\ Q_{ts} &\geq 0 && \leftrightarrow p_s \nu_{ts} \end{aligned} \quad (2.16)$$

where:

$U_s \left(\sum_t Q_{ts} \right)$	= Utility (value) function of a consumer - in this case set as the utility (value) in system state s from the quantity Q_{ts} supplied by supplier t in state s (also expressed as $U_s(Q_s)$);
p_s	= The probability of a state s to occur in the system;
μ_{ts}	= The upper-bound production Lagrange multiplier for supplier t in state s ;
ν_{ts}	= The lower-bound production Lagrange multiplier for supplier t in state s ;

From this, the Karush-Kuhn-Tucker (KKT) conditions of the constrained optimisation defined are:

$$\begin{aligned}
\forall \quad t, s, \mu_{ts}; \quad & \mu_{ts} - \nu_{ts} = \frac{dU_s(Q_s)}{dQ_s} - c_t \\
& \mu_{ts} \geq 0 \\
& \nu_{ts} \geq 0 \\
& \mu_{ts}(K_t - Q_{ts}) = 0 \\
& \nu_{ts}Q_{ts} = 0 \\
& \sum_s p_s \mu_{ts} = f_t
\end{aligned} \tag{2.17}$$

As is well known in competitive markets, at this optimal point long-term (dynamic) economic efficiency is attained. The marginal value of the consumer is equal to the marginal cost of suppliers i.e. $\frac{dU_s(Q_s)}{dQ_s}$ is equal to a common system-wide price P_s . This assumes a perfectly smooth supply function (linear capacity expansion to meet consumer demand). In this outcome, the dispatch of capacity from each supplier to meet consumer demand would be based on a merit-order (suppliers dispatched from lowest to highest variable cost). Typically in competitive EOMs, SOs would obtain marginal supply and demand bid functions and dispatch each accordingly with the resulting marginal system price. The natural equilibrium that would be reached assuming perfect competition and no additional technical constraints would be when each supplier and consumer truthfully reveals their marginal cost of supply and consumption in order for the SO to obtain a dispatch representative of the economic welfare maximisation. The result of this is that consumers and suppliers (or a SO dispatch based on marginal supply and demand bid functions) would set respective quantities of suppliers and consumers to ensure that their marginal value of consuming or marginal cost of producing is exactly equal to the marginal system-wide price P_s .

From the previously provided KKT conditions, one can see that the average gap between the system-wide price P_s and variable costs c_t for each supplier t when the system-wide price is above variable costs would be exactly equal to the fixed cost of

capacity f_t :

$$\begin{aligned}
\sum_s p_s \mu_{ts} &= \sum_{s:P_s > c_t} p_s (P_s - c_t) I(P_s > c_t) \\
&= \sum_{s:P_s > c_t} p_s (P_s - c_t) \\
&= E[(P - c_t) I(P > c_t)] = f_t
\end{aligned} \tag{2.18}$$

where:

$I(x)$ = A boolean expression (1 if *true*, 0 if *false*).

This is a fundamentally important outcome as it provides the basis upon which EOMs can theoretically provide for the optimal investment in capacity K_t of each supplier to ensure dynamic (long-term) economic efficiency. This can be rewritten as follows:

$$\begin{aligned}
E[(P - c_t) I(P > c_t)] &= (E(P|P \geq c_t) - c_t) \cdot \Pr(P \geq c_t) \\
f_t &= (E(P|P \geq c_t) - c_t) \cdot \Pr(P \geq c_t) \\
E(P|P \geq c_t) &= c_t + \frac{f_t}{\Pr(P \geq c_t)}
\end{aligned} \tag{2.19}$$

This is often termed the Long-Run Marginal Cost (LRMC) of generator t where the variable cost c_t is combined with the fixed unit cost of capacity f_t and a discounted probability for when generator t is operating i.e. when the system price P is greater than or equal to the variable cost c_t of generator t (it is being dispatched as part of the merit-order). The interpretation of this when applied to competitive EOMs would be that in order for a supplier to recover all fixed and variable costs, the area underneath the price-duration curve⁷ and above the variable cost of generation c_t would need to be at least equal to the fixed cost f_t of adding capacity from supplier t . Stated alternatively, in the long-term, the optimal capacity to be invested in K_t from all suppliers, consumers pay (and suppliers are paid) exactly their LRMC covering all variable and fixed costs perfectly.

The above is illustrated in Figure 2.2 for three hypothetical suppliers where the optimal combination of capacity investment in each occurs when the area under the

⁷The shape of which is determined by the fixed and variable costs of the optimal capacity from all suppliers

price duration curve (Figure 2.2(b)) and above variable costs of each is exactly equal to the unit fixed costs of each supplier. It can be appreciated from Figure 2.2(c) that in order for a supplier with low variable costs (c_1) to be part of the optimal capacity investment there is a large area available to allow for a high unit fixed costs for investment (f_1) i.e. high overnight investment costs and fixed operations and maintenance costs. Conversely, for a supplier with high variable costs (c_3) as shown in Figure 2.2(e), there is a much smaller area available for unit fixed cost (f_3) in order for it to be part of the optimal investment.

One can notice that for a very short duration (although exaggerated in Figure 2.2(b) for visualisation purposes), the system price spikes to a very high level. This is the VoLL derived in section 2.1. For these periods of time, it is best for the SO to curtail some consumer demand resulting in the marginal system price being equal to the VoLL. This is a natural outcome of the long-term economic equilibrium as it has been shown where if the unitised fixed costs of capacity for capacity suppliers are positive (which they always are), there exists a small proportion of time where it is optimal to curtail the consumer. During this time, the price spikes to the VoLL and all suppliers continue supplying their full capacity i.e. capacity is exhausted and each supplier is receiving the marginal system price of VoLL. This is a different approach to obtaining a similar outcome as derived in section 2.1 where the relationship between this period of time (previously defined as the LOLE and the associated energy - the EENS) is equal to the unitised fixed cost of a marginal supplier less variable costs i.e. the CONE.

During periods of supply capacity scarcity, if the system marginal price is capped below the VoLL (typically as a result of the political sensitivity of consumers or market power concerns), it can also be appreciated that supply capacity will under-recover as a result of the true value associated with supplying demand during these times being lower than expected (the VoLL).

As can also be appreciated from Figure 2.2, if a particular jurisdiction deems the economically optimal outcome unacceptable (risk of load shedding (LOLE) is too high), it can define a strict capacity requirement upfront to ensure that the LOLE and/or capacity reserve margin is improved. This will result in a reduction in prices that should be expected by suppliers as a result of the additional supply capacity shifting the price duration curve. This results in a revenue shortfall implicitly necessitating a payment for capacity as a result of the additional pre-defined capacity requirement over and above the long-term economically efficient outcome previously derived.

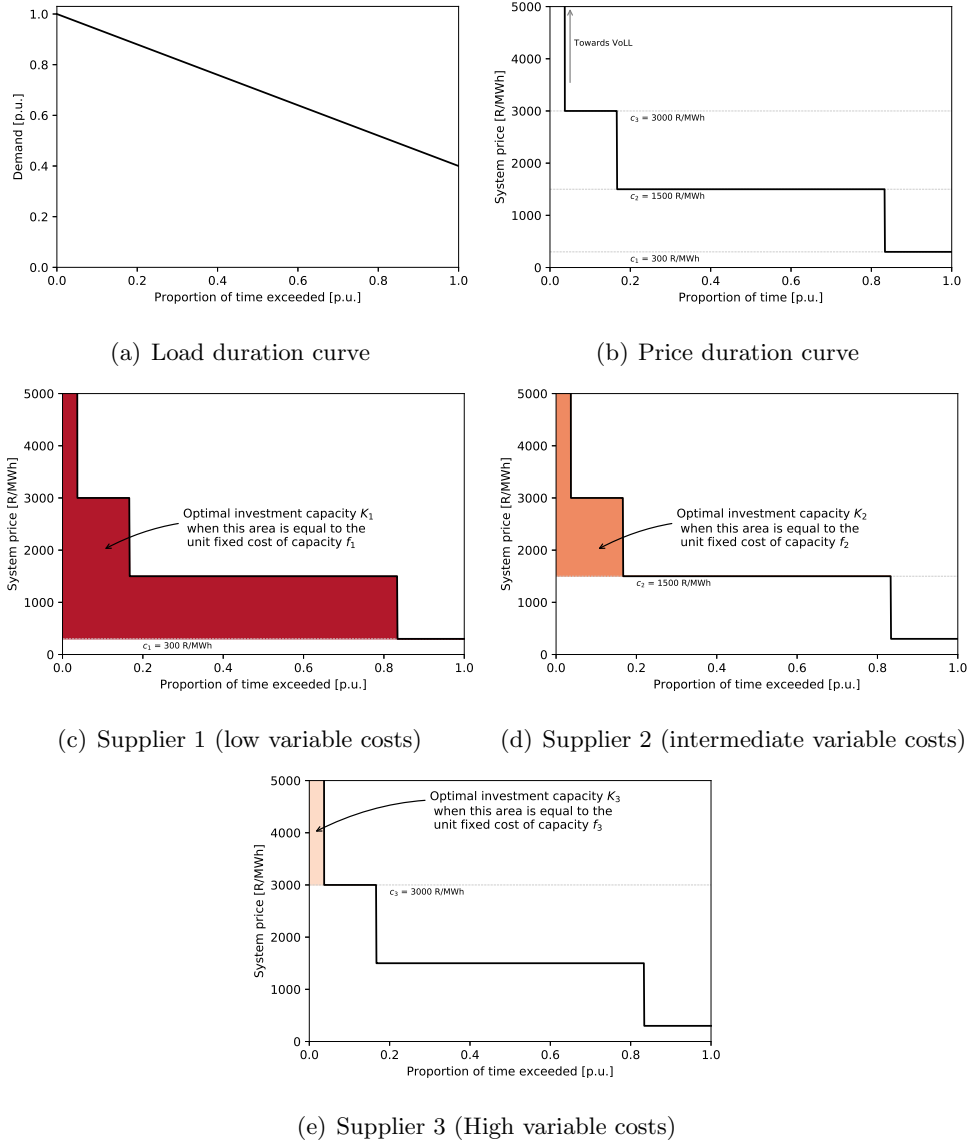


Figure 2.2: Use of price duration curve to obtain optimal capacity in competitive markets with three possible suppliers (combination of capacity investments for all three suppliers results in optimal long-term efficiency)

2.2.2 Generation expansion planning

A brief summary of generation capacity expansion planning is provided in this section. A particular focus is given to HL I (generation only). Although long-term capacity expansion planning outcomes are important and guide policy direction in a number of jurisdictions globally (and in Southern Africa in particular), these are not necessarily the focus of this research. Instead, these outcomes are used as a basis to

assess the value of CMs in the SAPP.

Long-term capacity expansion planning (typically ≥ 20 years) is a complex topic which will be expanded on in this section. Established literature can be found in [5, 17, 18] (amongst others). Due to the significant mathematical computation required to solve the capacity expansion planning problem as a power system grows in size, computerised models have been applied for a number of decades with various tools and platforms available each with varying degrees of capability. Adding to this, recent trends in the economics of variable and non-dispatchable supply side capacity (in particular wind and solar PV) combined with further increased computing capabilities has resulted in a number of new approaches specifically focussed on improved demand mode representation of the capacity expansion planning problem with a number of tools and platforms available either commercially or open-source.

Historically, integrated electricity systems would undertake capacity expansion planning exercises. In this, the optimal generation mix is determined considering technical and economic characteristics of all existing and new supply capacity (and the decommissioning thereof), forecasted demand trajectories, pre-defined levels of system adequacy as well as other necessary/optional constraints e.g. supply-demand balance, supply capacity technical characteristics, CO₂ emissions trajectories. The most common approach to solving the capacity expansion planning problem uses numerical mathematical methods based on optimisation (least-cost is most commonly applied). Typically, a Linear Programming (LP) problem is formulated and solved using the simplex method (with primal and dual variants) or interior point method. In some approaches (probably more common nowadays considering cheap and powerful computing capabilities), the mixed linear and integer nature of the problem formulation means a Mixed-Integer Linear Programming (MILP) problem is formulated and solved (typically using branch and bound algorithms or variants thereof) [19]. In its simplest form, the long-term capacity expansion planning problem can be formulated as follows:

$$Min : \left\{ \begin{array}{l} \sum_y^Y \sum_g^G DF_y \cdot [C_{(g)} \cdot G_{b(g,y)}] + \\ \sum_y^Y \sum_g^G DF_y \cdot FOM_{(g)} \cdot P_{IC(g)} \cdot [U_{(g)} + \sum_{i \leq y}^Y U_{b(g,i)}] + \\ \sum_y^Y \sum_t^T DF_y \cdot [VoLL \cdot USE_{t \in y} + \sum_g^G P_{(g),t \in y} (VOM_{(g)} + HR_{(g)} \cdot F_{(g)})] \end{array} \right. \quad (2.20)$$

subject to:

$$\begin{aligned}
\sum_y^Y \sum_T^t \sum_g^G P_{(g),t \in y} &= \sum_y^Y \sum_t^T \left[D_{t \in y} + USE_{t \in y} \right] && \text{Necessary} \\
\sum_T^t P_{(g),t \in y} &\leq E_{(g)Max} && \text{Necessary} \\
&\dots\dots\dots \\
&\dots\dots\dots \\
P_{(g),t} - P_{(g),t-1} &\leq RR_g && \text{Optional} \\
CO_{2(y)} &\leq \max(CO_{2(y)}) && \text{Optional} \\
\text{Other constraints ...} &&&
\end{aligned}$$

where:

$VOM_{(g)}$ = Generator g variable operations and maintenance costs (USD/MWh).

$G_{b(g,y)}$ = Capacity built of generator g in year y . (MW).

$C_{(g)}$ = Build cost of generator g (USD/MW) if economic life (y_{g-e}) is shorter than the time horizon Y . Otherwise, build cost is typically annualised (USD/MW-yr) if y_{g-e} is more than Y or extends beyond Y once the build decision is made for generator g .

DF_y = $\frac{1}{(1+DR)^y}$; Discount factor applied in year y based on assumed discount rate (DR)

DR = Discount rate (%) used to discount costs in future years into present values.

$FOM_{(g)}$ = Fixed operational and maintenance costs for generator g (USD/MW/yr).

$P_{IC(g)}$ = Installed capacity of generator g (MW).

$U_{(g)}$ = Number of existing units at generator g .

$U_{b(g,i)}$ = Number of units built at generator g in year i .

$D_{t \in y}$ = System demand in time period t in year y (MW).

$USE_{t \in y}$ = Unserved energy in time period t in year y (MW).

$P_{(g),t \in y}$ = Power generated by generator g in time period t in year y (MW).

$HR_{(g)}$ = Heat-rate of generator g (GJ/MWh).

$F_{(g)}$ = Fuel costs of generator g (USD/GJ).

$E_{(g)Max}$ = Maximum annual energy from generator g in MWh (link to generator availability).

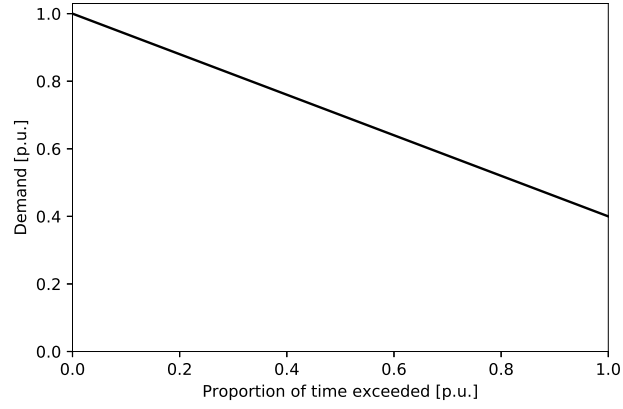
RR_g = Ramp-rate of generator g (MW/min).

As can be seen in its simplest form, the solution to the generation capacity expansion

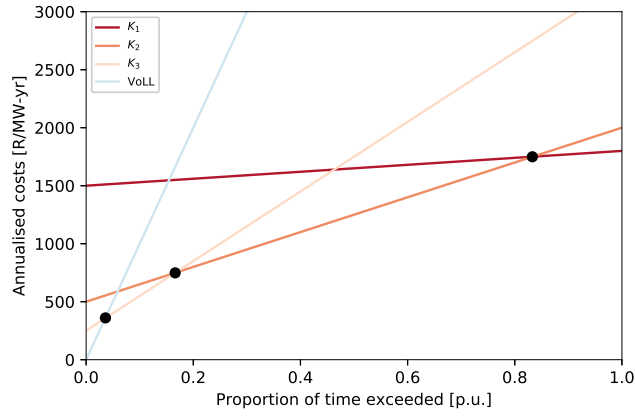
problem determines the optimal existing and new capacity that minimises the net-present value of all costs associated with electricity supply (inclusive of all fixed and variable costs) with some arbitrary discretionary constraints included (as examples). The outcome of the least-cost optimisation presented in equation 2.20 is the natural equilibrium reached between the provision of energy from all existing and new capacity and the cost associated with outages as a function of demand over the long-term time horizon considered.

In the linear-relaxed version of the optimisation, this results in all supply capacity being perfectly compensated for all fixed and variable costs. When integer optimality is considered (as is the case in reality), *'lumpy'* capacity investment requirements result in a deviation from this outcome resulting in a dual variable that reveals the losses that could be expected by a new adequacy provider as a result of a marginal over-investment in capacity (as also demonstrated in Figure 3.10 and Figure 3.11).

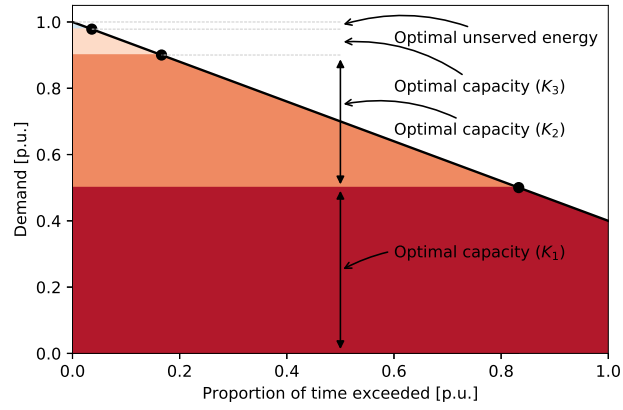
Using the same simple system presented in Figure 2.2 (from the perspective of a competitive energy-only market), the outcome of a cost-optimal capacity expansion is demonstrated in Figure 2.3 inclusive of fixed and variable costs of three investment options (K_1 , K_2 and K_3). As long as the fixed costs of investment (and operations) for any capacity investor are greater than zero, it is always optimal to allow for some level of unserved energy. The intersections of the screening curves in Figure 2.3(b) reveal the points at which the optimal capacity from respective capacity suppliers is found. It should be noted that this analysis is purposefully simplified to demonstrate least-cost optimal outcomes. This is the classical approach taken to least-cost capacity expansion planning but does not consider the chronology of the demand profile and the correlation between variable and non-dispatchable RES as is the case with more recent approaches [20–23].



(a) Load duration curve



(b) Screening curves



(c) Optimal capacity investment

Figure 2.3: A simple least-cost generation capacity expansion using screening curves to obtain the optimal amount of capacity from each adequacy provider (based on fixed and variable costs of each). It is optimal to allow for a small amount of Unserved Energy (USE) as a result of non-zero fixed costs of adequacy providers

In addition to the above, in reality, it may be that the natural economic equilibrium that is reached does not meet necessary pre-defined system adequacy requirements. As a result, jurisdictions typically include additional capacity constraints e.g. an explicit capacity reserve margin or maximum LOLE constraint. This inherently distorts the natural equilibrium previously discussed and results in a dual variable in the optimal solution outcome. This combined with the previously mentioned integer nature of capacity investments are primary driving forces behind the explicit requirement for CMs in the capacity expansion planning context. Similar derivations and outcomes from the perspective of competitive electricity markets have also been provided in section 2.2.1. An example of a capacity constraint that could be added to the previously presented problem formulation is given below:

$$\sum_y^Y \sum_g^G P_{f(g)} \cdot \left[U_{(g)} + \sum_{i \leq y}^Y U_{b(g,i)} \right] - \max(D_{t \in y}) \geq P_{res} - P_{short} \quad (2.21)$$

where:

$P_{short} = \alpha_{short} \cdot P_{res}$; Variable indicating the shortage of capacity reserves allowed (MW). This is typically zero ($\alpha_{short}=0$, a hard constraint on capacity reserve requirements) but can be made a soft-constraint if some level of shortage of capacity reserves is allowed ($\alpha_{short} \geq 0$).

$P_{f(g)}$ = Firm capacity of generator g (MW).

P_{res} = Pre-defined minimum capacity reserve requirement (MW). This can be an explicit capacity requirement (MW), a translation from a capacity reserve margin (% above peak demand) or from a maximum LOLE adequacy requirement (days/yr).

As can be seen in equation 2.21, the explicit capacity constraint requires that the firm capacity from all supply capacity less the peak demand is always greater than or equal to the capacity reserve requirement (with some adjustment for capacity shortage if desired).

The approach presented to ensuring system adequacy (via centralised capacity expansion planning) is still largely dominant in the Southern African region as a result of existing electricity market structures that have largely not followed similar restructuring as other markets globally. Consequentially, required capacity is predominantly procured centrally by the relevant institutions in each country

(electricity trade on local wholesale energy markets does not exist domestically). The SAPP offers a trading platform on which market participants are able to trade energy on wholesale competitive markets. However, market participants are largely limited to national PUs owing to the aforementioned existing national electricity market structures⁸.

In this context, the primary reasons for CMs in the Southern African region are more nuanced than those for CMs globally (as discussed in more detail in section 2.3). Although it is appreciated that it is possible (and has been the case) that energy and capacity have been traded on a bilateral basis historically in the region, there are clear market power concerns that exist (as will be described further in section 2.5), boom-bust cycles (at best) and chronic inadequacy (at worst) that have been experienced historically. Nonetheless, there exists a wholesale electricity market trading platform in the form of the SAPP and a proposed CM therein could act as an enabler for sustained levels of system adequacy into the future. Thus, leveraging on the historical experience gained on the SAPP market platform for the implementation of a CM could allow for a more transparent, effective (ability to avoid shortage), efficient (low-cost in this context) approach to ensure system adequacy across the region by various market participants in future.

2.3 Energy-only markets (EOMs) and the need for Capacity Mechanisms (CMs)

2.3.1 Background

Liberalisation and restructuring of a number of electricity markets globally started in the late 1980s and early 1990s in the UK and Chile and was followed by many others including Argentina, Australia, a number of jurisdictions within the USA as well as a number of European nations. These reformed markets included competitive energy-only wholesale electricity markets supplemented by ancillary services markets in some cases where the focus was on short-term (static) economic efficiency. Long-term system adequacy was assumed to be possible via the inherent market dynamics that would result i.e. adequacy was left to *the invisible hand* of the market. There are a number of examples where this has not necessarily been the case following liberalisation and restructuring historically (in [24], Olsina provides examples of

⁸ More on this will be provided in section 2.5

California (USA), Electric Reliability Council of Texas (ERCOT) (USA), Australia, Spain and Argentina). There is still ongoing debate on whether system adequacy will be sustained into the future in these jurisdictions (and others) and as a result some form of CM is proposed to ensure system adequacy in future [25].

Examples of where EOMs have been applied include the aforementioned Australian National Electricity Market (NEM) [26–28], New Zealand [29], Alberta and Ontario (Canada) [27, 28], ERCOT (USA) [27, 28] and NordPool [27, 28]. Examples where EOMs markets have had to be complemented with CMs are numerous and include a number of countries in almost all regions globally (South America, North America, Europe, Middle-East and Asia - more detail will be provided in section 2.4.4).

The classically accepted and conceptually coherent EOM model should in theory provide for sufficient energy market price spikes (as previously described in section 2.2.1) to keep existing supply capacity available and incentivise capacity investment to ensure acceptable system adequacy in future [7, 9, 30–33]. Price spikes towards the VoLL or some market specific price-cap would occur if a feasible supply-demand curve equilibrium is reached and a scarcity of supply capacity exists. As a result, price spikes should implicitly incentivise capacity investment and new providers of capacity to enter the market (resulting in an increased level of system adequacy). This in turn results in a lower quantum of price spikes and a stabilisation of capacity investment i.e. a natural economic equilibrium is reached. However, in practice, a number of jurisdictions have not exhibited sufficient system adequacy with EOMs (for a number of reasons that will be outlined later) and as a result have put in place CMs of various forms⁹. Thus, it could be argued empirically that EOMs as well as markets which include CMs achieve the desired outcomes of system adequacy. However, there is considerable ongoing discussions on whether this will be the case in future [34–36]. As part of this research, the value of a CM introduced into the existing energy-only SAPP market architecture (combined with country specific regulatory environments) is explored¹⁰.

2.3.2 Practicalities of electricity markets necessitating CMs

The primary drivers for electricity markets coupled with CMs vary but mostly relate to the imperfections and practicalities that present themselves when electricity

⁹ The various forms of CM groupings and jurisdictions that have adopted some form of CM are provided in section 2.4.1 and 2.4.4 respectively.

¹⁰See Chapter 5.

markets operate in practice i.e. the market failure. The electricity market failure that is the "*missing money*" problem occurs when existing supply capacity is unable to recover fixed and variable costs as well as an inability to justify new supply capacity investments to ensure sufficient system adequacy. Key practicalities of electricity markets which drive the requirement for CMs present themselves differently in individual jurisdictions but are typically considered to be:

- **Insufficient short-term Demand-Side Response (DSR) and consumer differentiability** [7, 27, 29, 37–40]. Most consumers are not exposed to real-time energy market prices and as a result do not recognise when there is insufficient supply capacity. In addition, there is also no way for consumer classes (or individual consumers) to be sufficiently differentiated, controlled in real-time and demand reduced at times of supply capacity scarcity (as yet). This may change in future as advanced metering technologies may enable more demand-side responsiveness at scale;
- **Imperfect information with a particular sensitivity to demand uncertainty** (short-term and long-term) [29, 32, 39–44]. The inherent stochastic nature of demand in the short-term (days, weeks, months) necessitates SOs to procure operating reserves (supply capacity over-and above expected demand) to ensure a sufficiently low probability of system collapse. In the medium to long-term, uncertainty associated with the level of demand expected also results in an uncertainty with regards to the quantity of supply that would be needed;
- **Discrete (integer) investment decisions** i.e. "*lumpy*" investments. As demonstrated in Figure 3.10 and 3.11, the discrete nature of capacity investments means that for a pre-defined level of system adequacy (a maximum LOLE/LOLP), slightly more capacity will be invested in than required as a result of the discrete (integer) nature of a capacity investment. This is more important in small power systems where a large capacity addition will mean too much capacity is invested in and as a result there will be an under-recovery of revenue and an explicit requirement for a payment for the capacity invested in (over and above what is ideally required);
- **Non-zero lead-times for new supply capacity investment** [29, 40, 42, 45–47]. This lead-time results in investment cycles where periods of under-capacity result in periods of higher market prices incentivising capacity investment (or decisions by relevant institutions to procure more generation capacity). Once the additional supply capacity is brought on-line more supply capacity is available

resulting in lower market prices and reduced incentive for new capacity investment (or decisions to procure no further new generation capacity). This is likely to be less exaggerated in future as more modular investments with less lead-time as well as Distributed Energy Resources (DERs) become more common.

- **Price-caps** in a number of jurisdictions around the world imposed in energy markets (well below the VoLL) due to concerns around market power, price volatility and consumer exposure to high price spikes [7, 27, 29, 32, 38–40, 48, 49]. Price-caps in energy markets result in an insufficient level of price spikes and thus lower incentivisation for capacity investment. As shown in section 2.5.4, the price-cap on the competitive regional SAPP Day-Ahead Market (DAM) market is only 400 USD/MWh (well below typical VoLL in the order of 7500-15000 USD/MWh);
- **Market power** both in the short-term and long-term [8, 29, 33, 37, 40, 42, 50]. In the short-term, dominant market positions combined with imperfect and asymmetrical information amongst market participants could result in capacity withholding by suppliers which drives up energy prices. In the medium to long-term, intentional under-investment to continually receive price spike revenue or intentional over-investment to keep out new entrants can occur.
- **Regulatory limitations on particular supply technologies** [29]. Some jurisdictions impose constraints on particular technologies for reasons of environmental impact, domestic energy security, job creation and political acceptance by consumers amongst others. This could mean that particular technologies which could be perfectly capable of providing necessary system adequacy are not an option.
- **Risk-averse behaviour by capacity investors** considering the asymmetrical risk of a capacity investment decision [7, 24, 29, 40, 42, 44, 51–53]. Investment in supply capacity is typically capital intensive and once a decision is made to invest it is largely irreversible i.e. a sunk cost. As a result, capacity investors are typically risk averse and would require medium to long-term views of expected energy market prices and/or system adequacy in order to allow for an investment decision. Despite the possibility of sufficient price spikes in an energy-only market, the frequency of these price spikes and volatility thereof (from year to year) as well as possibility of intervention (price-caps) would mean a risk averse capacity investor is unlikely to make an investment decision on this basis.

Whether in a competitive energy-only market environment or a classically centrally planned power system, the combination of any number of the above results in a market failure where there is an under-recovery in necessary revenue (for an existing

capacity supplier) or insufficient incentive to invest (for a new capacity supplier). The result of this is capacity under-investment and reduced system adequacy. The proposed solution to this is an appropriately designed CM where the "*missing money*" is provided for via the CM.

Although the discussion surrounding EOMs relative to the necessity for CMs is quite nuanced, there are strong advocates for energy-only markets including W. Hogan [48], Oren [54], Wolak [55], M. Hogan [56] and Leautier [50]. Authors who have advocated for the need for CMs in recent times are numerous and include amongst others Bhagwat [57–59], Batlle et. al [60, 61], Cramton et. al. [42], de Vries [8], Doorman [62, 63], Joskow [39, 64, 65], Keppler [66], Mastropietro [67–70], Milstein [33], Schwenen [71] and Stoft [38]. A number of publications from Conseil International des Grands Réseaux électriques (CIGRE) have also summarised the discussion around CMs but do not necessarily advocate for or against CMs [29, 72–74].

As part of this research, it is hypothesised that sustained system adequacy can be ensured in the Southern African region by the introduction of an appropriately designed CM into the SAPP market architecture. This would provide suppliers of capacity with an additional revenue stream which supplements the typical energy revenue received in already existing SAPP sub-markets (or in existing domestic energy and capacity purchase arrangements).

2.4 Capacity mechanisms (CMs)

2.4.1 Categorisation

Based on the literature reviewed, there is no commonly accepted approach to categorising CMs. This is primarily as a result of the number of nuanced design elements that constitute the adequacy product that define CMs (see section 2.4.2). However, there have been attempts to categorise pertinent CMs in the literature with a range of authors taking different approaches to this categorisation. A popular approach is one in which CMs are categorised into price-based or volume-based and further split into whether they are targeted or market-wide [75–78]. A graphical representation of this approach and resulting six pertinent CM types is shown in Figure 2.4.

More recently, there has been a preference to classify CMs based on the design elements like what the adequacy product is, how the volume of capacity is determined and the responsible institution(s) for procurement [29, 79]. From the definition of these design elements pertinent CMs can be classified. On this basis, these CM types are categorised as shown in Table 2.1 (similar CM types to those seen in Figure 2.4).

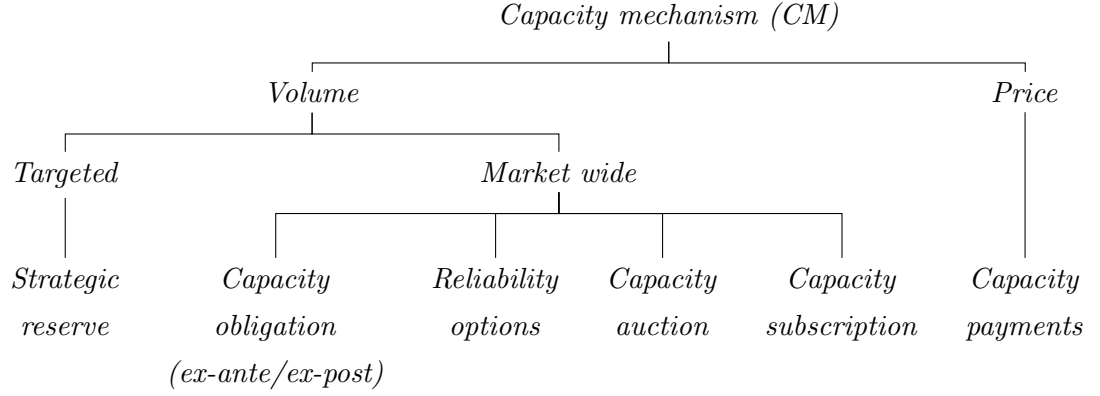


Figure 2.4: Typical categorisation of Capacity Mechanism (CM) types showing two main groups of price-based and volume-based CMs further disaggregated into particular focus (targeted or market-wide)

Table 2.1: Categorisation of Capacity Mechanism (CM) types based on design choices showing different approach defining what the product is, how the product is determined and who is responsible for procurement

CM type	Product definition	Product determination (responsible)	Institution(s) to procure
<i>Strategic reserve</i>	Capacity, sub-set (P)	Volume (CA)	CA
<i>Capacity obligation (ex-ante)</i>	Capacity (P)	Volume (CA)	LSEs
<i>Capacity obligation (ex-post)</i>	Capacity (P)	Volume (LSEs), verified by CA	LSEs
<i>Capacity auction</i>	Capacity (P)	Volume (CA)	CA
<i>Reliability options</i>	Instrument (F)	Volume (CA)	CA
<i>Capacity payment</i>	Capacity (P)	Price (CA)	CA
<i>Capacity subscription</i>	Capacity (P)	Volume (C)	C

LSE = load-serving entity, CA = central authority, C = customers/aggregators,

P = physical, F = financial.

Although the classification of CMs may appear to be distinct as the two very different approaches shown previously have demonstrated (and thus easy to differentiate and test for performance), it is important to note that jurisdictions globally have implemented nuanced variations of CMs (of various types) in order to best fit the jurisdiction within which the CM is considered.

Thus, although the categorisation is useful, it is more important when considering the introduction of a CM that the design elements and performance criteria of the CM itself are considered. Section 2.4.2 provides details on these design elements while section 2.4.3 provides details on the performance criteria that would enable the assessment of CMs in an objective manner. Based on [8, 29, 62, 80], descriptions of the more pertinent fundamental types of CMs previously categorised in Figure 2.4 and Table 2.1 are provided next.

Strategic reserve

Strategic reserves (analogous to operating reserves) are typically implemented alongside an EOM where the SO determines a volume of required capacity (typically on an annual basis) and contracts this capacity with a small amount of adequacy providers (either via auction or bilateral negotiations). Strategic reserves can be supplied by typical supply-side resources as well as Demand-Side Response (DSR). This CM effectively removes a certain amount of capacity from the competitive energy market with compensation provided separately. Costs are recovered by the SO from all consumers (via an uplift). This capacity is dispatched when all other capacity is already operating. Market signals from an EOM still drive capacity investment and resulting system adequacy with this CM in competitive environments.

Capacity obligations (*ex-ante*)

A decentralised approach where a pre-determined volume of necessary capacity is calculated *ex-ante* (before the event and based on future expectations). This is based on expected demand and pre-defined adequacy levels by a relevant central authority with the obligation for this capacity borne by Load-Serving Entities (LSEs) based on demand served in the past. Capacity obligations can include supply and demand side resources. Typically, penalties are applied to resources (*ex-post*) if necessary capacity obligations are not met (incentivising capacity investment). In the SAPP context, the central authority would likely be an overarching regional regulator (Regional Electricity Regulators Association (RERA) - if made an authority) or domestic regulators in each SAPP country. LSEs in a SAPP context would be the SOs of each SAPP nation (currently predominantly the individual national PUs). At a national level, LSEs would be distribution companies (DisCos) within each country. At this stage, for most countries in the SAPP region, this also coincides with the national vertically-integrated PUs.

Capacity obligations (*ex-post*)

A decentralised approach, similar to the previously defined CM but with the fundamental difference being that the responsibility for capacity is calculated and borne by each LSE *ex-ante* following which actual demand is measured and verified by a relevant central authority *ex-post* (after the event and based on actuals). With

this information, the required capacity obligation of the LSE (can include supply and DSR) is calculated based on a pre-defined methodology (and parameters) by a relevant central authority. Penalties are applied (*ex-post*) if LSEs are determined to have procured insufficient capacity relative to their calculated capacity obligation. In the SAPP context, the relevant central authority as well as LSEs would be similar to those described before for the *ex-ante* capacity obligation.

Capacity auctions

An approach where a central authority determines the volume of capacity required based on forecasted demand and takes the responsibility to procure this centrally via a market-based auction. Demand is either fixed or a demand curve is defined (downward-sloping to avoid price volatility) and all adequacy providers (including supply and DSR) bid to provide the required capacity. Often, the CONE (for a reference power generator - typically an Open-Cycle Gas Turbine (OCGT)) or some multiple thereof is used as the upper-limit of the demand curve while the downward sloping portion of the demand curve is determined by the net-CONE (CONE less energy and ancillary services revenue - dependant on jurisdiction). It is common to have the downward-sloping demand curve extending beyond the adequacy target to represent the value of increased system adequacy albeit with diminishing value. Similar to previously outlined CMs, penalties are commonly applied for non-performance when required. The central authority would also be similar to that previously described, such as a regional regulator like RERA.

Reliability (adequacy) options

Strictly speaking, this CM should actually be termed *adequacy options* based on the previous definition of adequacy. It is a slightly different CM type introduced in [81]. It is a financial instrument (an option) tightly linked to the wholesale EOM price. It involves a financial contract backed by the delivery of physical capacity (or firm energy in the case of hydro dominated systems) but only when system adequacy is at risk. The Market Clearing Price (MCP) is used as a proxy to indicate scarcity. The volume is typically determined based on expected demand forecasts and procured by a central authority via auctions on behalf of LSEs and customers. The seller of the reliability options (the central authority) acquires the right to call on physical capacity (supply or DSR) during times of scarcity (when the MCP reaches a pre-defined and agreed strike price - effectively setting a price-cap on the energy

market). The adequacy provider is then paid at this strike price if it provides the required capacity. If the adequacy provider under-performs, it will pay the prevailing MCP for the amount it under-performs by (similarly it will be paid at the MCP for any capacity more than that contracted for). This inherently incentivises capacity performance during times of scarcity.

Capacity subscriptions

Defined conceptually in [62, 63], a decentralised model where customers (and/or aggregators) determine the amount of capacity they would prefer based on individual preferences for system adequacy and the price at which the capacity is provided. Procurement of the capacity is via a capacity market between buyers and sellers of capacity with supply and demand price-elasticity. Demand from a customer/aggregator is capped at the procured amount of capacity preferred by the customer/aggregator with appropriate hardware.

Capacity payments

An ongoing fixed payment (or set of payments) is determined (or negotiated) periodically either *ex-ante* or *ex-post* between a central authority and adequacy providers (existing and/or new, technology agnostic/specific) with the resulting volume procured a function of the supply-demand equilibrium. The costs associated with capacity payments are then typically recovered from LSEs as an uplift. In the SAPP context, the central authority could be an overarching regional regulator (RERA - if made an authority) and would likely be determined in consultation with domestic regulators in each SAPP country.

2.4.2 Characterisation and design elements

Although it is convenient and useful to categorise CMs as shown in the previous section, the design elements that drive the choice of CMs are critical. The intention of any CM is to act as an adequacy product that ensures sustained levels of long-term system adequacy. The manner in which this is achieved is highly dependant on the market environment. As previously discussed (section 2.3), competitive market environments intend scarcity pricing to send the relevant price signals to incentivise efficient capacity investment (as well as keep efficient existing capacity

operational). In the SAPP environment, a hybrid environment exists of vertical integration within countries (with some level of unbundling in selected countries) as well as competitive markets at the regional level via the established competitive SAPP markets (section 2.5.4). Thus, the performance of design elements to assess any CM will be specific to each jurisdiction (or set of jurisdictions) and more specifically, unique to the SAPP. This provided additional impetus for this research and is intended to be a valuable contribution in itself.

In this regard, a range of literature has attempted to define what design elements characterise CMs and the resulting definition of the most appropriate CM for particular jurisdictions. The choice of design elements considered in this research are chosen by considering this existing literature including that of de Vries [8], Batlle [60], Mastropietro [69] and Doorman et. al. [29]. These are presented and justified in the sections that follow. The selection of the most appropriate design elements is elaborated on. The performance of any CM against these design elements is critical for the SAPP specifically as part of this research contribution. These emanate from the design choices made using these design elements as part of the CM design process undertaken in Chapter 5 for the performance of a proposed CM for the SAPP.

Definition of the adequacy product

The definition of what the adequacy product is that will assist in achieving the objective of long-term system adequacy is clearly the most important design element for a CM. Brief definitions of the adequacy product and associated categorisation have been shown in Figure 2.4 and Table 2.1 (section 2.4.1) based on the approaches in [75–78] and [29] respectively (as discussed in section 2.4.1). Thus, this section will not repeat the content but instead provide further details that justify the need to ensure that the adequacy product as a design element is characterised as a function of the type of power system (capacity- or energy-constrained) as well as the critical indicator(s) that reveal scarcity.

The definition of the adequacy product is strongly related to whether the jurisdiction within which it is being considered is capacity-constrained or energy-constrained. An energy-constrained system would be one which is typically hydro-dominated where more than sufficient supply capacity exists but dry-years (or sets of years) can result in scarcity where there exists an inability to meet demand seasonally or annually. Thus, there is insufficient firm-energy to meet demand. A capacity-constrained system is one in which there exists more than sufficient energy on an

annual basis but there exists certain periods during which scarcity is characterised by instantaneous demand exceeding instantaneous supply. This would primarily be as a result of higher than expected demand or lower than expected supply capacity performance¹¹. The distinction between these two types of power systems will then clearly define the resulting choice of the most appropriate adequacy product. Materially, a CM in an energy-constrained system would need to incentivise behaviour that would make adequacy providers manage reservoirs in the most optimal manner that would ensure they deliver the necessary energy during times of scarcity (dry-years). In a capacity constrained system, the CM would need to incentivise adequacy providers to ensure they are available with the necessary capacity at times when scarcity occurs to meet instantaneous demand.

Following on from this is the requirement to define a rule (or set of rules) that determines the critical period(s) that define(s) scarcity. This design element is important as it ensures adequacy providers have an understanding of what to be aware of when there are times of scarcity so that they can ensure they are available when most needed. This scarcity indicator can be determined either by a central authority, by market participants themselves including LSEs or perhaps even individual/aggregated customer demand as technologies enable increased DSR. The period that indicates scarcity could be expected peak demand (in capacity-constrained systems), the wholesale market price (probably best), the annual/seasonal energy demand requirement (in hydro-dominated systems, indicating expected firm energy from hydro-based generators during dry-years) or even the highest level of unavailable capacity. In combination with this is the need to determine the contribution of adequacy providers at these critical times i.e. their *firm capacity/firm energy* contribution. This would be based on a derating of their maximum possible capacity/energy typically considering FORs, maximum energy (in dry-years), fuel-supply limitations or in the case of non-dispatchable resources like wind/solar a statistical expression of expected output during these periods.

Once the critical period has been identified along with the expected contribution from adequacy providers, there is also a need to further define details including the technical capabilities of these providers when called upon during periods of scarcity. This includes the number of activations per year as well as the maximum operation time when activated. This is particularly important when including energy-limited resources like hydro capacity, peaking plants with limited fuel off-take and DSR as adequacy providers.

¹¹Forced Outage Rates (FORs) higher than expected resulting in capacity not available when needed.

Targeting

The targeting of a CM speaks broadly to whether the CM focusses on a specific sub-set of adequacy providers or whether it is market-wide (open to all adequacy providers inclusive of the demand-side). This design element also relates to whether the CM is targeted to existing and/or new-build suppliers of capacity as well as whether certain technologies are excluded (predominantly for jurisdiction specific policy reasons). In some jurisdictions, the exclusion of already existing adequacy providers is based on the rationale that these suppliers have already recovered fixed costs and thus should not require any additional revenue stream (Fixed Operations and Maintenance (FOM) is still to be covered but is typically a small fraction of total fixed costs relative to annualised capital investment costs). A drawback of excluding existing adequacy providers as part of prospective adequacy providers included in the CM is that there is no incentive to be available when needed (in times of scarcity). The choice of targeting in a CM should ideally be market-wide as this would result in the most efficient capacity investments (with minimal distortion, assuming an efficient market).

An important consideration when deciding on targeted adequacy providers, is the inclusion of prospective DSR as an adequacy provider. An historically inelastic demand-side becomes more elastic as it responds to price signals when included and reduces the need for traditional supply-side capacity (more specifically, peaking capacity). Similarly, the inclusion of stationary storage (although still nascent, especially in the Southern African Development Community (SADC) region) can play a similar role by decoupling the instantaneous supply-demand balancing requirement.

There is a distinct need to define who the buyers of capacity would be (or who would be responsible for procuring the capacity on behalf of customers). Similar to the supply-side, the decision on whether all demand should be included or whether a particular sub-set of demand should be included is an important one. The fundamental reason for this is that if a selected sub-set of the demand-side is included only (captive demand), free-riding can occur where large customers do not pay for capacity but benefit from the resulting system adequacy. As a result, procurement is typically undertaken by a central authority (and not decentralised to LSEs). Decentralised approaches do exist in some jurisdictions but it has become more common to adopt a centralised approach to capacity procurement on behalf of end-users. In addition, it is important to appreciate the scale that exists with centralised procurement

while a decentralised approach may exclude particular adequacy providers. Finally, a particular benefit of a decentralised approach to capacity procurement is that it places the responsibility on forecasting of demand directly onto LSEs (who would likely have a much more intimate understanding of the evolution of their respective demand). Combining this with a scheme of performance incentives and penalties for over/under-estimating the required capacity by LSE respectively is a particularly efficient manner in which to ensure long-term system adequacy.

Lead-time

In the context of a CM, the lead-time is the amount of time between which an adequacy provider has committed to delivery of capacity and when the capacity needs to be provided. Clearly, this is more applicable to new-build capacity and is an important design element as long lead-time technologies may be implicitly excluded. In this respect, it could be seen as a fully intended consequence of this design element that these long lead-time technologies are implicitly excluded as they do introduce an increased risk of over-procuring/under-procuring the necessary capacity to meet an uncertain future demand requirement. This is particularly important in the SAPP environment where an increasing and often uncertain demand requirement exists. It can easily be appreciated though that a number of capacity auctions can be held of various volumes with a range of lead-times depending on the technologies available to a particular jurisdiction as well as the expected risk in demand forecast. In the SAPP context, it should be appreciated that although a broad range of technologies may be available across the region, this may not necessarily be the case within particular countries.

Duration

The contract duration is probably the most important of design elements and defines the period over which the contract for capacity is provided for and can range anywhere from less than 1 year to 20 years. Similar to the lead-time, the contract duration can be different for existing and new-entry adequacy providers as there are very different risk-profiles inherent in existing capacity and new-entry capacity. In addition, there is likely going to be a direct relationship between contract duration and lead-time as adequacy providers with longer lead-times will likely be capital intensive and thus require longer contract durations. This eases

financing requirements and hedges against energy market price volatility as well as regulatory uncertainty.

At the extreme, all fixed costs are ideally fully recovered over the contract duration of a CM (as in a PPA with typically durations of ≈ 20 years). Of course, allowing for CM contract durations this long may inherently then default capacity investment back into bilateral PPAs resulting in a lack of transparency and resulting market forces sought after to drive capacity investment and sustained system adequacy with an appropriately designed CM. In addition, contract durations that are too long transfer risk onto LSEs and customers. This results in inefficient capacity procurement if new technologies become more economically viable to invest in or expected demand is not realised. In the SAPP, fast changing technology costs and DSR technologies combined with an increasing demand requirement would require flexibility in CM contract duration.

Performance incentives and penalties

Performance incentives for the actual delivery of capacity when needed as well as penalty schemes for non-delivery were not sufficiently focussed on in historically implemented CM designs. This is the primary reason for the inclusion of this specific design element in a possible CM for the SAPP where one does not exist. In recent times, these have started to become key design elements following experiences in the USA [57] as well as in a number of South American countries [69]. Performance incentives should be sufficient to reinforce the critical requirement to be available at times of scarcity. Penalty schemes can be implicit where under-performance requires an adequacy provider to pay for what was used to replace the unavailable resource during the scarcity condition. They can also be explicit where strong penalties are defined ex-ante and imposed on adequacy providers for under-performance (a multiple of the contract value). This also implicitly means that there will be no need for any further action from the authority procuring the adequacy product as providers will ensure that they only bid what they are truly capable of in times of scarcity.

Secondary design elements

A secondary design element like indexation of CM remuneration to currency exchange rates and fuel prices could also be considered [69]. However, this does shift the

risk to end-users who may not necessarily have the best ability to control them. This is particularly relevant in the SAPP environment and should be carefully considered as a number of currencies exist (but most trade is currently undertaken either in South African Rands or U.S. Dollars).

It will also be necessary to ensure that financial warranties are provided by adequacy providers as collateral for if/when penalties may be imposed for non-performance. These should not be too excessive though to exclude market participants and/or disincentivise investment.

The exercising of market power cannot be overlooked in the design of a CM. This is particularly important knowing that a CM is (by definition) an adequacy product which is provided during times of scarcity when market power is most likely to be exercised. The exercising of market power links closely to the previous discussion on performance incentives and penalties to ensure capacity is made available when needed and the exercising of market power is minimised. In the SAPP, it is also of particular significance where an existing dominant market participant exists (in South Africa via Eskom).

2.4.3 Performance criteria

The design elements presented in section 2.4.2 characterise CMs and enable a distinct grouping (as detailed in section 2.4.1). The relevant performance of CMs against a set of performance criteria to assess their performance is now presented. Following a similar approach that has been customised for the SAPP, these will be used in Chapter 5 to design an appropriate CM for the specific SAPP context.

Based on the original generalised framework in [82], Doorman analysed the peaking capacity problem and resulting CM groupings (section 2.4.1) in [62]. In [8], de Vries also analysed these but on much more specific and focussed performance criteria (also with a specific focus on the European Union (EU)). There is some overlap in this regard but some performance criteria are unique. Table 2.2 presents the performance criteria deemed most pertinent for the SAPP environment and provide a brief description of each.

Table 2.2: Performance criteria and descriptions for pertinent CM types

Performance criterion	Description
<i>Incentive for system adequacy</i>	A clear central performance criterion - the ability to incentivise capacity investment and long-term sustained system adequacy (can be both domestically as well as regionally).
<i>Static efficiency</i>	The well-known welfare criterion where existing available resources are allocated efficiently (marginal cost equals marginal value). Relates to supply-side efficiency, the ability to mitigate against short-term market power and domestic/regional shortages.
<i>Dynamic efficiency</i>	Similar to static efficiency except that dynamic efficiency relates to long-term economic efficiency where new investments and technologies are introduced. Typically, more welfare gains are possible when considering dynamic efficiency (relative to static efficiency) e.g. introduction of DSR, variable RES and storage.
<i>Correctability</i>	The ability to reverse an implemented CM or transition to a different CM if the CM does not perform as expected and/or deliver on performance criteria sufficiently.
<i>Simplicity</i>	Any proposed adequacy product should be as simple as possible but as complex as necessary. If overly complex, lower levels of <i>acceptability</i> and <i>stakeholder equity</i> will exist whilst also likely imposing higher <i>implementation costs</i> .
<i>Implementation costs</i>	Includes the initial costs for setup as well as ongoing transaction costs imposed due to capital investments and human resources. The distribution of costs between market participants is also included.
<i>Acceptability and stakeholder equity</i>	The level of how a proposed CM is accepted by the full range of stakeholders (not just market participants and especially those not strongly represented). Could be expanded to include political and social acceptability within particular countries as well as a larger region. Could also relate to the inclusion of the demand-side (DSR) as well as stakeholders possibly prejudiced due to the exercising of market power.
<i>Invisibility</i>	Closely related to economic efficiency but more specifically an <i>invisible</i> CM would be one in which market participants would be able to adopt their strategies independent of others. Also relates to whether the CM is compatible with the market framework within which it is being considered i.e. centralised (integrated markets) relative to decentralised markets.
<i>Robustness</i>	The ability of the CM to perform in the face of unexpected perturbations/changes e.g. a changing supply mix, scarcity conditions domestically (regional capacity withdrawn for domestic needs), demand forecast uncertainty, hydrological conditions, the exercising of market power.
<i>Timing</i>	The extent to which a particular CM is dependant on the system status (general over- or under-supply conditions) and whether the opportunity for a phase-in is possible.

2.4.4 Capacity mechanisms (CMs) around the world

There are a number of implementations of CMs around the world. Most CMs apply a volumetric scheme while some apply a price-based scheme (see section 2.4.1). Although not necessarily an exhaustive listing or description of all CMs globally, Figure 2.5 and the section which follows attempts to highlight experiences of pertinent CMs globally based on [29] and developed further.

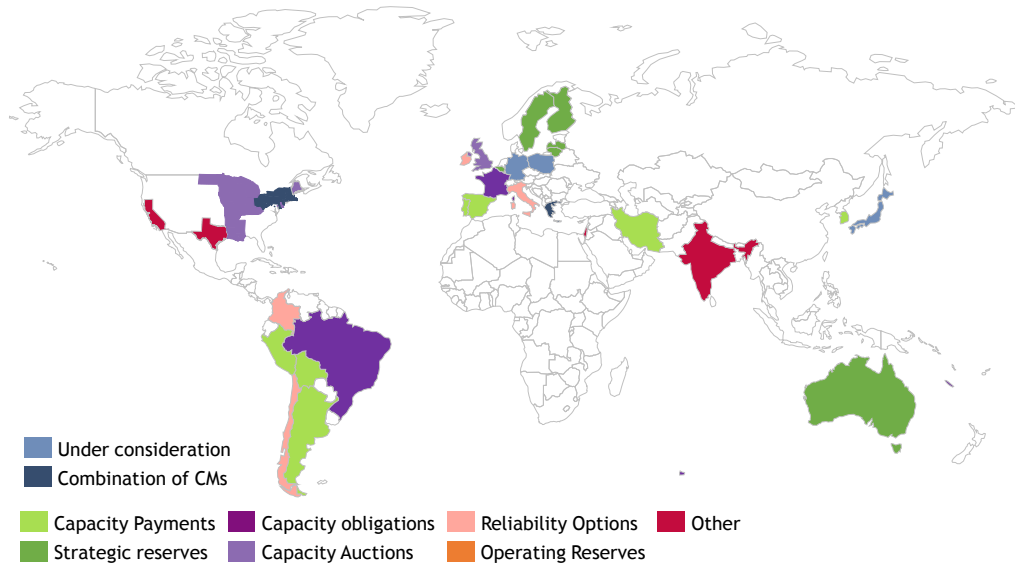


Figure 2.5: Global map of pertinent existing Capacity Mechanisms (CMs) and CMs in the near future (2020) revealing existing and proposed future role of CMs in a range of jurisdictions

Based on the categories of CMs previously discussed in detail (section 2.4.1), a few examples of implementations globally are given.

New Zealand, the Netherlands, Singapore, the Electric Reliability Council of Texas (ERCOT) in Texas USA as well as the NEM in Australia currently apply an EOM approach and do not include any form of CM.

Capacity payments are present in a number of Latin American countries (Chile, Argentina, Peru and Bolivia) [28] as well as in Spain [28], Portugal [83], Ireland [84], South Korea [27] and Iran [10, 28].

Strategic reserves have been applied in Sweden and Finland [29], Belgium (more recently) [85] and more recently revived interest in strategic reserves has been seen

in the Australian NEM [86]. Strategic reserves are also under consideration in Germany [87, 88]. The primary reason for the introduction of strategic reserves in Belgium and Germany is the decision to phase-out nuclear capacity in these countries [89, 90].

Capacity obligations (*ex-ante*) were historically applied in the USA at the PJM Interconnection LLC (PJM) Regional Transmission Organisation (RTO) - known as the Capacity Credit Market (CCM) [29]. Capacity obligations (*ex-post*) have been applied for many years in Brazil and have more recently been applied in France [91].

Capacity auctions are most common in a number of jurisdictions in the USA including PJM, Mid-continent Independent System Operator (MISO) (voluntary) and New York Independent System Operator (NYISO) [92]. A more recently introduced capacity auction is in the United Kingdom (UK) [29].

A hybrid of a capacity auction and reliability options have been applied for many years in Colombia for firm energy (considering significant hydro-based supply capacity) [93, 94] while Independent System Operator-New England (ISO-NE) in the USA apply reliability options (but with different proxies for system scarcity) [29]. In Ireland, reliability options are being proposed to replace existing capacity payments [29].

As can be seen, there is no universal CM but rather a CM (or lack thereof) which will fit best into the particular market and regulatory environment. Administratively determined CMs implicitly attempt to incentivise capacity investment but have been criticised for their subjectivity (not being able to show the true value of capacity) and could result in over- or under-investment. A market based CM whereby market forces explicitly determine the value of capacity has been shown to be a more efficient approach but does also result in some level of capacity price volatility [28]. The complexity of some centralised capacity auctions have also been criticised in the past and thus simplicity and ease of implementation is important [27]. The choice of the most appropriate CM design (if any at all) to best suite the SAPP market is assessed in more detail in Chapter 5.

As demonstrated in [28] for the eastern USA, the locational value of capacity (effect of network congestion), previously omitted from market designs in a number of jurisdictions in the USA was found to be an important design element in the implementation of a CM. This is particularly noteworthy for SAPP where insufficient network interconnection between market participants is well known in addition

to interconnections being largely unmeshed (resulting in binding constraints on electricity trade historically). Again, this is dealt with in more detail in Chapter 5 but as mentioned previously, the focus of this research will be on assessing whether a CM can incentivise investment (whether network congestion exists or not) and thus is not necessarily a definitive focus of this research.

As noted by a number of authors (and as has been the case in most USA jurisdictions applying CMs) [28, 29, 34, 54, 62, 95–99], the participation of the demand-side in the form of DSR will have a direct effect on system adequacy. Thus, DSR adequacy providers need to be considered as part of any CM design where appropriate. The largely price-inelastic demand-side is one of the drivers that necessitates CMs and thus making it more price-elastic may reduce the need for CMs but would not remove it. The primary reason for the demand-side price-inelasticity has been that insufficient information is made available to act accordingly. Recent technological advances are envisaged to extend real-time information and control systems to large and small customers that can enable an increased role for the demand-side in CMs.

2.4.5 Impact of variable renewable energy sources (RES) on CMs

The dominant variable RES (solar PV and wind) are on considerable learning curves and have gone beyond just being competitive relative to alternative technologies [100–103]. They are now the first choice in a number of jurisdictions around the world for new-build capacity and are even displacing existing capacity in others. This economic reality combined with enforced policy decisions is likely to continue to drive further deployment of solar PV and wind in particular in future. The concern going forward has now shifted to integration of variable RES and ensuring system adequacy as the relative economics of these resources are now more than competitive.

Although there has always been a distinct requirement for sufficient levels of system adequacy, this will be amplified in future by increased penetrations of low (almost zero) short-run marginal cost variable RES [69, 92, 104–113]. Variable RES do not necessarily have a high correlation with demand. This results in a relatively low contribution to system adequacy. In addition, the variability introduced into the power system necessitates flexibility of the complimentary supply/demand side resources. Thus, there is a requirement for flexible capacity to supplement these resources and ensure sufficient system adequacy if they are further deployed. The variable nature of these resources also results in a reduced role being played by

traditionally capital intensive base-supply resources¹² while their low-levels of capacity contribution shift the energy mix to flexible adequacy providers and change competitive market outcomes as the supply curve shifts to the right (market price suppression and increased volatility) [34, 92, 111, 114, 115].

In this context, ensuring sufficient system adequacy has become the focus of many jurisdictions globally, resulting in an increased interest in the inclusion of CMs in energy-only market structures especially at high variable RES penetration levels [58, 59, 116–118]. This increased focus on CMs as variable RES penetration increases is also intuitive - as variable RES penetration increases, energy prices will be suppressed in competitive energy markets while the value of capacity in CMs will increase. The balance between the two is critical to ensure economic efficiency and resulting optimal outcomes.

As previously discussed, variable RES (particularly wind and solar PV) are often not considered able to contribute to system adequacy. However, these resources are actually able to contribute capacity albeit at a relatively lower level when compared to conventional supply technologies [69, 92]. Although limited at this stage, a demonstration of this is the most recent PJM Base Residual Auction for 2020/2021¹³ where 6.8 GW of wind capacity and 0.3 GW of solar PV capacity were cleared to provide 0.9 GW and 0.1 GW respectively of the 165.1 GW total capacity cleared i.e. a capacity contribution of 13% and 38% of their installed capacities respectively but still only 0.6% of the total capacity cleared in PJM [119]. PJM is currently one of the only jurisdictions which allow wind and solar PV to participate in capacity auctions. At increased penetration levels, it is likely that these resources will need to be considered as resources that can contribute to system adequacy whether via a risk-adjusted contribution to a CM and/or the provision of any other ancillary services they may be technically capable of providing [120, 121].

The medium-term to long-term planning impacts of increased variable RES penetration are inherently considered as part of this research in the context of the SAPP. However, the detailed operational impacts and integration issues associated with high penetrations of variable RES are not necessarily a focus of this research.

¹² Typically replaced by mid-merit and peaking flexible supply side capacity and DSR.

¹³ A capacity auction type of CM.

2.5 SADC and SAPP

A brief history and overview of the Southern African Development Community (SADC) region as it relates to the history of the SADC and SAPP [122–127], SAPP members [128, 129], geographical context [129], electricity market size and existing legislation which governs SAPP market participants [130–134] is provided in this section. Chapter 4 provides a more detailed analysis of the SAPP historical system adequacy and as well as market performance.

2.5.1 History of SADC and SAPP

The SADC region covers an area of almost 10-million km². This is over twice the area of the EU and is equal to that of the USA and China. The SADC population grew from ≈ 180 -million in 1995 to ≈ 300 -million in 2015 [135]. This equates to an equivalent annual population growth rate of 2.6% for 20 years. During this same period, the world grew at half this rate (1.3%). With the exception of the Sub-Saharan African region with a growth rate of 2.7%, no other region has shown such growth. Regions with the closest level of population growth have been the Middle-East and North Africa (MENA) region (1.8%) and South Asian region (1.6%). This exceptional growth has placed pressure on SADC countries for infrastructure development (specifically electrical energy infrastructure to support economic growth). Demand for electricity in the SADC region grew from just over ≈ 203 TWh in 1996 [136] to ≈ 295 TWh in 2016 [137] i.e. an average annual growth rate of 12.0%. While per capita electricity consumption in Organisation for Economic Co-operation and Development (OECD) countries ranged from ≈ 7400 -8000 kWh/capita (1996-2015), the SADC region per capita electricity consumption ranged from ≈ 50 -1000 kWh/capita in 1996 to ≈ 100 -1750 kWh/capita in 2015 (excluding South Africa) [138]. In addition, the electricity access rate in the region has remained largely unchanged since 2000 where electricity access was at 13.9% of moving to 13.4% in 2015 [139]. With clearly defined goals of electrification, combining these realities with expected considerable economic growth in the developing nations of the SADC region, there is an expectation of considerable increased electrical energy demand in future. This exceptional historical and expected future increase in electrical energy demand has placed and will continue to place pressure on SADC nations for infrastructure development (specifically electrical energy infrastructure).

The member countries of the SAPP are shown in the stylised map in Figure 2.6.

Historically, the mainland SADC region has not been highly electrically interconnected¹⁴ and thus minimal electricity trade took place (selective bilateral contracts between countries only)¹⁵.

The first bilateral contract in the region was established in the 1950s between Zaire (now known as Democratic Republic of Congo (DRC)) and Zambia followed by the interconnection of Zimbabwe and Zambia at Lake Kariba in the 1960s [122]. The Songo-Apollo High Voltage Direct Current (HVDC) link between Mozambique and South Africa followed in 1975. These developments resulted in two separate interconnected power systems (the Northern system and Southern system).

Following the emergence of relative political stability, the region emphasised integrated and co-operative trading of electricity from the rich hydro resources in the Northern system (Congo and Zambezi rivers) and the rich thermal resources in the Southern region (coalfields of Botswana and South Africa and onshore gas fields in Mozambique) would be beneficial for all countries [123]. As a result, in 1995, the Northern and Southern systems were electrically interconnected with the construction of the 400 kV line between Matimba (South Africa) and Insukamini (Zimbabwe) [124]. This created a platform for electricity trading between these two previously disconnected power systems. However, this trading still remained in the form of bilateral contracts updated and renegotiated on a periodic basis. With only this interconnector between the two systems, there was a distinct requirement for better electrical interconnection between Southern African nations as well as an enabling platform that would further promote the trading of electricity. The platform that was established was the Southern African Power Pool (SAPP). Some history and the general governance framework under which it was established and currently operates are outlined next.

¹⁴ More detail on this is provided in section 2.5.3.

¹⁵ A bilateral contract is a mutually agreed upon contract between two parties (a buyer and a seller) typically on a medium to long-term basis to exchange electricity with pre-defined delivery requirements, volumes and prices.

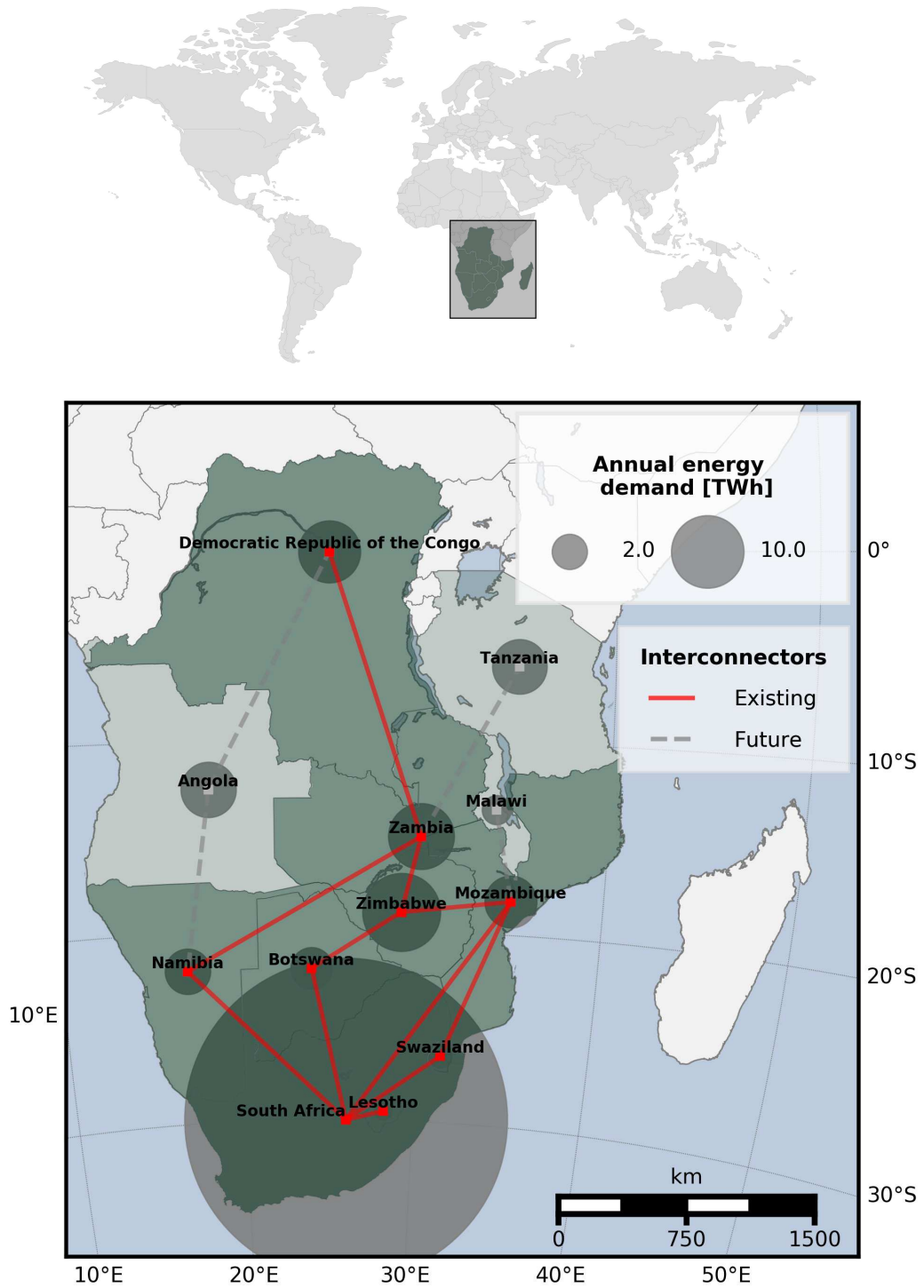


Figure 2.6: Geographical illustration of the Southern African region showing interconnection between SAPP Operating Members (OPs) in dark green (electrically interconnected) and future interconnection SAPP Non-Operating Members (NPs) in light green (not electrically interconnected). Relative power system sizes for each country are also plotted (as domestic energy demand - 2016) with the dominant South African system easily noticeable

Formally, the Lusaka Declaration of 1980 (in Lusaka, Zambia) [125] initiated regional co-operation and development between Southern African states. An update to this (signed in Windhoek, Namibia in 1992) [126] created what is now known as the SADC. There are currently 15 member states of SADC [140]:

- | | |
|--|--------------|
| - Angola | - Botswana |
| - The Democratic Republic of Congo (DRC) | - Lesotho |
| - Madagascar | - Malawi |
| - Mauritius | - Mozambique |
| - Namibia | - Seychelles |
| - South Africa | - Swaziland |
| - Tanzania | - Zambia |
| - Zimbabwe | |

Following on from the formation of the SADC, the SAPP was established in 1995. The SAPP is currently governed via a framework encapsulated in the following:

- Inter-Governmental Memorandum of Understanding (MoU);
- Inter-Utility Memorandum of Understanding (MoU);
- Agreement between Operating Members (OPs);
- SAPP Operating Guidelines; and
- SAPP Market Guidelines

The Inter-Governmental MoU that established the SAPP in 1995 at the SADC summit in South Africa included the majority of the national utilities of each country in the SADC [128]. The 2006 revised Inter-Governmental MoU for the SAPP extended the scope of members to include new entities (as outlined in Section 2.5.2).

Using the Inter-Governmental MoU as an enabling framework, the second SAPP document, the Inter-Utility MoU governing the management of the SAPP was enacted in 1995 [141]. The latest version of this was signed in 2007 defining a new structure for the management and operations of the SAPP [134].

The third SAPP document is the Agreement between OPs of the SAPP of which the original was signed in 1995 [131]. This document outlines responsibilities of OPs (members whose transmission systems are interconnected) with respect to standards, operations and pricing in the SAPP. A revised version of this was signed in 2008 [142] and has been under review since 2012 (it is unclear whether a revised version is enacted as yet) [143].

The fourth and fifth SAPP documents within this governance framework are the SAPP Operating Guidelines and SAPP Market Guidelines. The SAPP Operating Guidelines were first developed in 1996 [133] and defined the sharing of costs and responsibilities in the SAPP (including inter-alia standards and guidelines for plant operations, maintenance and safety). This document has been under review [143] and was updated in 2014. At the same time, the newly established SAPP Market Guidelines were also developed and approved.

Another critical component to the ongoing operations of the SAPP was the establishment of the SAPP Co-ordination Center in 2002 in Harare, Zimbabwe [128]. The SAPP Co-ordination Center implements inter alia the SAPP objectives (a regional wholesale market in the SADC), monitors SAPP transactions between members, carries out technical studies to assess the impact of future projects on the SAPP, coordinates training of members and provides SAPP statistics for planning and development in the region [128]. One of the most critical roles that the SAPP Co-ordination Center plays is the regional MO with interfaces to the various SAPP country Transmission System Operators (TSOs).

The governance structure of the SAPP is shown in Figure 2.7 and outlined below [134, 144]:

- **The SADC Directorate of Infrastructure and Services** is made up of ministers and officials from the respective SADC countries and forms the direct link between SADC and the SAPP. Major policy issues are referred from the Executive Committee to this Directorate.
- **The Executive Committee** is made up of Chief Executive Officers (CEOs) of the SAPP members and a representative from the SADC Secretariat. As mentioned above, major policy issues are referred from this Committee to the SADC Directorate of Infrastructure and Services as/when required.
- **The Management Committee** decides on recommendations of Sub-Committees and the SAPP Coordination Center Board.

- The Operating Sub-Committee establishes and updates methods and standards to measure technical performance and operating procedures.
- **The Planning Sub-Committee** establishes and updates common planning and reliability standards, reviews integrated generation and transmission plans, evaluates software and other planning tools, determines transfer capability between systems amongst other aspects of power system operation.
- **The Environmental Sub-Committee** develops Environmental Guidelines for the SAPP amongst other issues in environmental impact of power systems.
- **The Markets Sub-Committee** is responsible for the design and continued development of the SAPP electricity market and determines criteria to authorize this trade.
- **The Coordination Centre** reports to a Co-ordination Center Board consisting of a maximum of two representatives of each national PU.

From this brief outline of the SAPP, any change in policy and/or market structure in SAPP will be a significant process involving inputs and decisions at technical, managerial and political levels from a number of established institutions. Considerations related to enabling the implementation of a CM for the SAPP at the managerial and political level are out of the scope of this research. The research is envisioned to provide a framework to enable the most appropriate CM design and inform decision making in this regard (as detailed in Chapter 5).

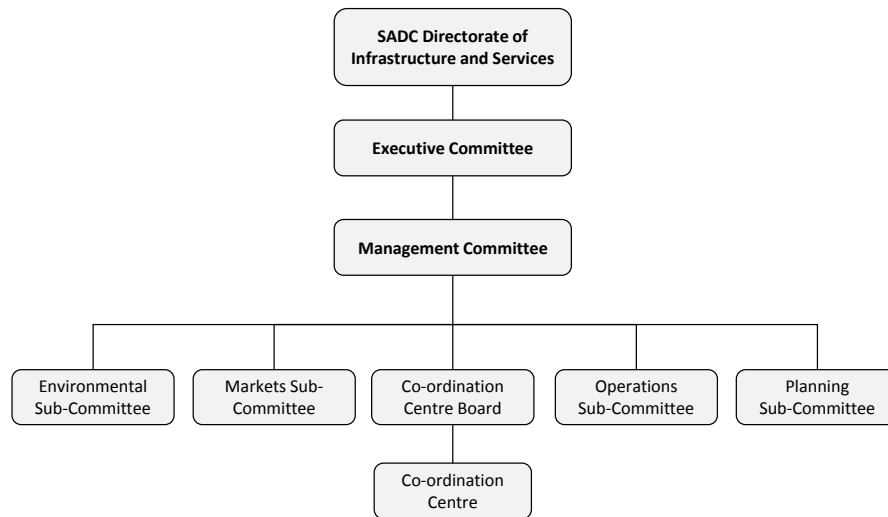


Figure 2.7: The SAPP management and governance structure (2016) demonstrating multiple layers of technical, managerial and political structures to enable implementation of a Capacity Mechanism (CM) in the SAPP

2.5.2 The SAPP market participants

The classes of SAPP membership are as follows [128]:

- SAPP Independent Transmission Company (ITC);
- Independent Power Producer (IPP);
- SAPP Power Utility (PU);
- SAPP Service Provider (SP); and
- SAPP Observer (OB).

As can be seen in Table 2.3 (as of 2016), there are currently 12 member states and 16 members of the SAPP [129]. There are nine SAPP Operating Members (OPs) (national PUs), three SAPP Non-Operating Member (NP) (national PUs), two ITCs and two IPPs.

Table 2.3: The SAPP membership highlighting the 12 member states and 16 members of the SAPP in 2016

Name	SAPP Status	Abbreviation	Country
Botswana Power Corporation	OP	BPC	Botswana
Electricidade de Mocambique	OP	EdM	Mozambique
Electricity Supply Company of Malawi	NP	ESCOM	Malawi
Rede Nacional de Transporte de Electricidade	NP	RNT	Angola
Eskom	OP	Eskom	South Africa
Hidroelectrica de Cahorra Bassa	IPP	HCB	Mozambique
Lesotho Electricity Corporation	OP	LEC	Lesotho
Mozambique Transmission Company	ITC	MOTRACO	Mozambique
Namibia Power Company	OP	Nampower	Namibia
Societe Nationale d'Electricite	OP	SNEL	DRC
Swaziland Electricity Supply Company	OP	SEC	Swaziland
Tanzania Electricity Supply Company	NP	TANESCO	Tanzania
Zambia Electricity Supply Company	OP	ZESCO	Zambia
Copperbelt Energy Corporation	ITC	CEC	Zambia
Lunsemfwa Hydro Power Station	IPP	LHPS	Zambia
Zimbabwe Electricity Supply Authority	OP	ZESA	Zimbabwe

OP = Operating Member

NP = Non-Operating Member

ITC = Independent Transmission Company

IPP = Independent Power Producer

2.5.3 The SAPP size and interconnections

To provide some perspective on the electrical size of the SAPP, a summary of the SAPP demand and energy statistics for 2016 is given in Table 2.4 [129, 137, 145–152]. The graphical overview in Figure 2.8 shows peak demand, domestic energy demand, existing interconnectors (including voltage levels and transfer capacities) as well as future (planned) interconnectors [129, 153]. As can be seen, there is a relatively low-level of interconnection between SAPP countries and although Angola, Malawi and Tanzania are SAPP Non-Operating Members (NPs), there are plans to interconnect in future. South Africa is by far the largest market with domestic demand making up $\approx 77\%$ of the total SAPP energy demand and $\approx 83\%$ of the interconnected SAPP demand (in 2016). The next two biggest markets are Zambia and Angola (4.5% and 4.1% of total and 4.8% and 4.4% of interconnected demand respectively) followed by DRC and Zimbabwe (2.8% and 3.2% of total and 3.4% and 3.0% of interconnected demand respectively). Thus, South Africa is $\approx 20x$ bigger than the next biggest country and 25-35x bigger than the next biggest three market participants. The

market concentration of the SAPP is clear from this with South Africa likely to remain dominant in the region.

Table 2.4: SAPP electricity statistics (2016) highlighting some countries still not interconnected (Angola, Malawi, Tanzania) as well as significant role of South Africa in the region

Country	Utility	Installed capacity [MW]	Net capacity [MW]	Max. demand [MW]	Gen. sent-out [GWh]	Imports [GWh]	System demand [GWh]	Exports [GWh]	Dom. demand [GWh]
Angola	RNT	3 129	2 500	1 869	12 058	0	12 058	0	12 058
Botswana	BPC	927	459	610	2 057	1 679	3 736	0	3 736
DRC	SNEL	2 457	1 076	1 376	8 156	95	8 250	0	8 250
Lesotho	LEC	74	70	150	486	175	661	3	658
Malawi	ESCOM	352	351	326	1 809	0	1 809	0	1 809
Mozambique	EdM	2 724	2 279	1 850	4 956	1 004	5 960	184	5 776
Namibia	Nampower	493	354	667	1 420	3 085	4 505	99	4 406
South Africa	Eskom	48 467	46 202	34 481	228 896	9 703	238 599	13 465	225 134
Swaziland	SEB	70	70	220	123	1 077	1 200	0	1 200
Tanzania	TanESCO	1 366	823	1 051	6 403	0	6 403	0	6 403
Zambia	Zesco	2 734	2 734	2 194	13 004	1 135	14 139	1 080	13 059
Zimbabwe	ZESA	2 045	1 555	1 615	7 388	2 877	10 265	943	9 322
Total	SAPP	64 838	58 473	46 409	286 757	20 830	307 586	15 774	291 812
Total	SAPP (OP only)	59 991	54 799	43 163	266 486	20 830	287 316	15 774	271 542

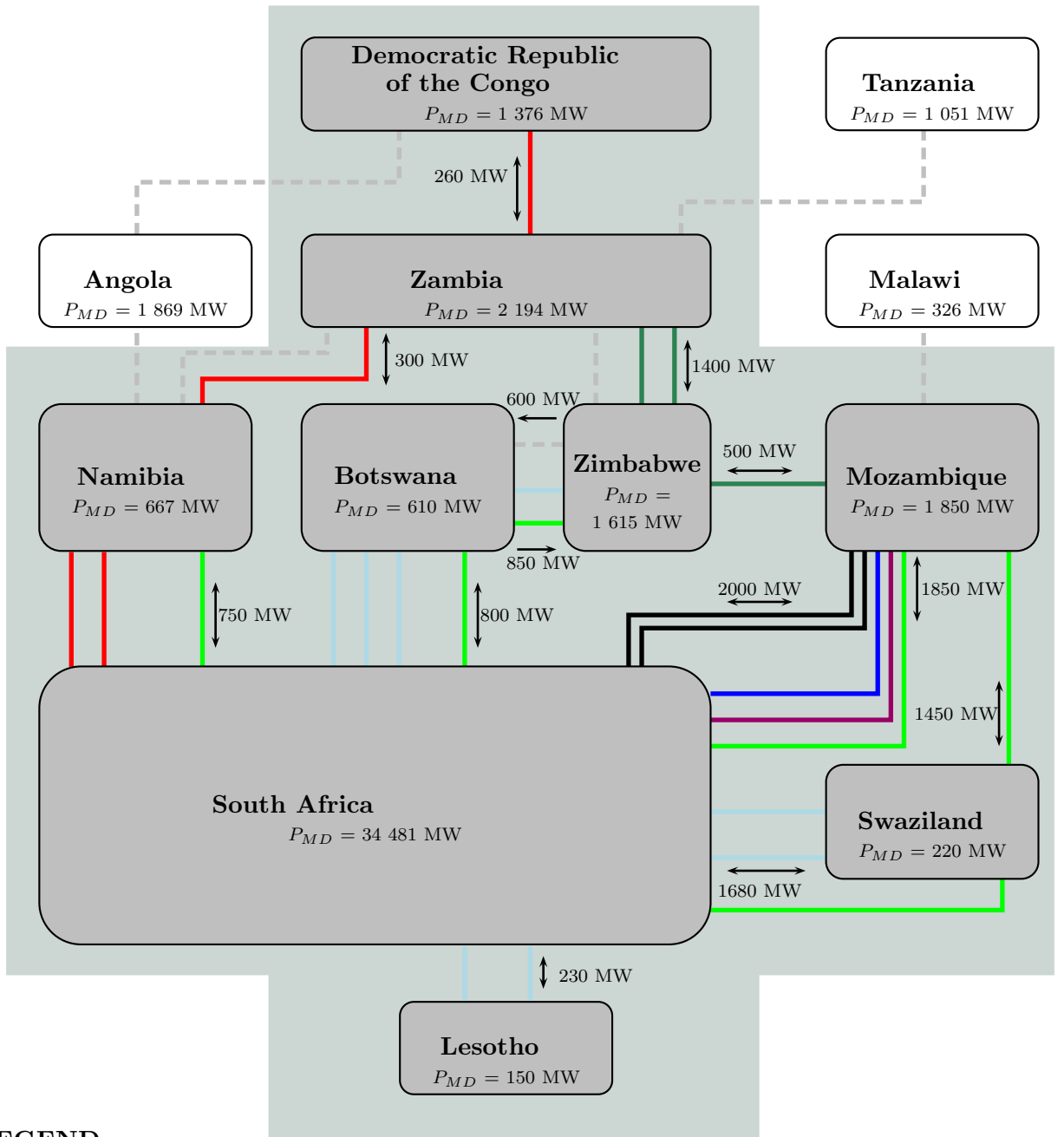


Figure 2.8: Graphical overview of existing and future SAPP interconnections along with maximum demand per country (2016) showing how OP members are interconnected and planned future interconnection of NP members

2.5.4 Evolution of the SAPP market architecture

As outlined in section 2.5.1, the Southern African region has historically traded electricity predominantly through bilateral contracts between SAPP market participants. Following the establishment of the SAPP in 1995, a considerable amount of time passed before any formal sub-markets were formed within the SAPP market architecture (other than already existing and periodically updated bilateral contracts) [122, 154].

Market participation by SAPP market participants is voluntary i.e. a *net-pool*. This means that the use of SAPP markets for trading of electricity is not compulsory as in a *gross-pool*. This is expanded on further in section 4.3 with particular reference to bilateral contracting and competitive electricity market trade in the SAPP.

In 2001, the Short-Term Energy Market (STEM) was established as a collaborative market structure within the SAPP to allow for the trading of electricity on a shorter timeframe between SAPP members¹⁶ (to allow for trading in addition to bilateral contracts).

From 2004 onwards, the SAPP wished to move from the collaborative STEM towards a competitive market where buyers and sellers would compete in the trading of electricity. This was predominantly driven by principles in Nordic power markets and resulted in the establishment of the SAPP Day-Ahead Market (DAM) to replace the STEM in late 2009. The DAM is a firm energy market that trades (via a double sided auction process) hourly energy contracts for the following day inclusive of existing bilateral contracts (cleared first), transmission capacity constraints and wheeling fees¹⁷. It is also locational allowing the market to split with resulting individual MCPs at each node based on transmission constraints in the SAPP Market Trading Platform (MTP).

A SAPP Post Day-Ahead Market (PDAM) was established in 2013 to settle any outstanding imbalances that were still present following DAM trading. The Post-DAM was then discontinued when the SAPP Intra-Day Market (IDM) went live in December 2015 (as discussed next). The SAPP market architecture was further updated recently with a number of new sub-markets established. The sub-markets included in this new SAPP market architecture are enabled for market participants

¹⁶See [122, 154] for more details on the STEM.

¹⁷See [122] for an overview of the SAPP DAM and [132] for more details on the SAPP DAM trading rules.

by the SAPP MTP [155]. An overview of each of the sub-markets in the SAPP market architecture is provided with more detailed information and market performance summaries provided in section 4.3 (the sub-markets below are cleared in this order):

- **Bilateral contracts** (legacy): To meet long-term energy supply-demand balance between market participants (can be firm and non-firm). This sub-market predates the establishment of the SAPP and has been the legacy sub-market within which most electricity trading in the SAPP has occurred. The magnitude of planned volumes and time of delivery are confirmed the day-ahead.
- **SAPP Forward Physical Market (Monthly) (FPM-M)** (since *April 2016*): A sub-market where market participants can trade either an *Off-Peak* product for a single month (same volume and price in *Off-Peak* hours for the month) or a *Non Off-Peak* product for a single month (same volume and price in *Non Off-Peak* hours of the month). This is a sub-market that acts as a bridge between bilateral contracts and the SAPP Forward Physical Market (Weekly) (FPM-W) (outlined next). The magnitude of planned volumes and time of delivery are confirmed the day-ahead following bilateral contracts.
- **SAPP Forward Physical Market (Weekly) (FPM-W)** (since *April 2016*): A sub-market where market participants can trade *Off-Peak*, *Standard* and *Peak* products for a particular week (with the same volume and price for all *Off-Peak*, *Standard* and *Peak* hours of the week respectively). This is a sub-market that acts as a bridge between the FPM-M and SAPP Day-Ahead Market (DAM).
- **SAPP Day-Ahead Market (DAM)** (since *January 2010*): An open and competitive sub-market traded on a day-ahead basis with gate-closure at 12h00 for next delivery day to meet short-term supply-demand balances between SAPP market participants. This is the main market for competitive electricity in the SAPP. The market price-cap on the DAM is 400 USD/MWh.
- **SAPP Intra-Day Market (IDM)** (since *December 2015*): A sub-market where market participants can continuously trade up to one hour prior to delivery. This essentially replaces the previous PDAM. The IDM matches market participants automatically on a first-come first-serve basis if a seller's offer price is less than a buyer's bid price and a seller's volume is lower (or equal to) a buyer's volume.
- **Interchange imbalance energy** as a result of differences between schedules and actuals in a specific hour of operation is currently settled in the SAPP by averaging the system frequency over the dispatch period (1 hour) and requiring a rate to be paid as a function of the frequency deviation from nominal (50 Hz).

This is currently linked to the average and highest generation cost in the SAPP but there are proposals to link this deviation to the DAM MCP.

The historical and still continued dominance of bilateral contracts in electricity trade in the SAPP hampers the ability to trade on the competitive SAPP sub-markets (the DAM, IDM, FPM-M and FPM-W). The primary reasons for this being the combined effect of bilateral contracts having priority over trade on competitive SAPP sub-markets and the resulting preference of buyers to have supply certainty during scarcity events. However, as shown by Rose et al. in [156], if bilateral contracts change the least-cost outcome in the SAPP region that this deviation would reduce overall electricity market efficiency and increase relative electricity costs. This is explored further in Chapter 4.

Chapter 3

System adequacy and capacity equilibrium

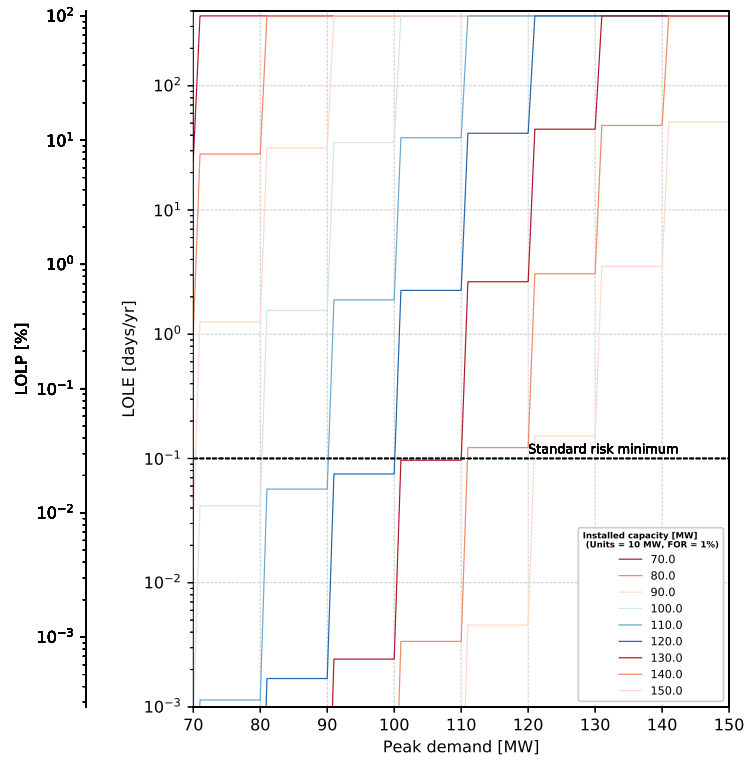
3.1 Adequacy metrics: Loss of Load Expectation (LOLE) and Loss of Load Probability (LOLP)

The probabilistic approach to ensuring system adequacy was summarised in section 2.1 where the definitions of LOLE and LOLP were provided. As mentioned, the LOLE provides a measure for the number of periods (or percentage of periods if LOLP) in which loss of load could be expected based on particular characteristics of capacity supply and demand. This can be better understood by considering a some examples to demonstrate the approach.

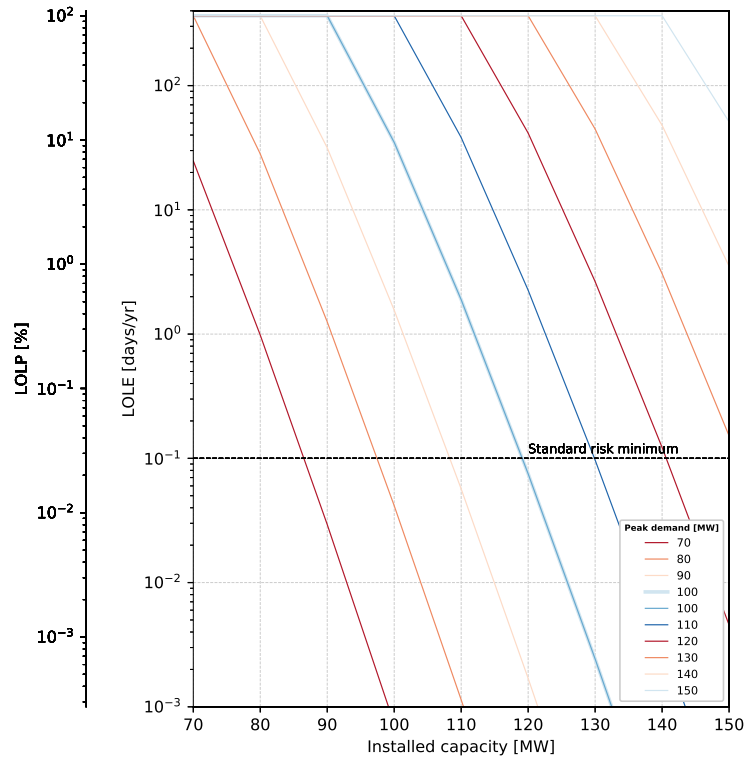
Figures 3.1-3.3 show LOLE and LOLP for a range of system peak demands shown in Figure 3.4-3.6 respectively (for a period of one year) for a range of installed capacity (in increments of 10 MW with $FOR = 1\%$). As shown for reference, a standard maximum risk level (based on engineering judgement) applied by North American Electric Reliability Corporation (NERC) in the USA is for LOLE to be no more than one (1) day in ten (10) years i.e. 0.1 days/yr and resulting LOLP $\approx 0.027\%$ [157]. A range of standard maximum LOLE and resulting LOLP levels are applied across Europe ranging from 0.07-0.4 days/yr [5, 11]. To illustrate this in the outcomes presented, Figure 3.1(a) shows that in order to maintain an acceptable LOLE for a system with a peak demand of 100 MW, one would need to invest in 12 x 10 MW (120 MW) of supply capacity. This results in a LOLE of 0.075 days/yr (LOLP of 0.02%). As a result of the size of the discrete capacity investments (10 MW

at a time), for the same 100 MW peak demand assumption, a sloping as well as representative demand profile would still require 120 MW installed capacity. It is also not possible to have a LOLE of exactly 0.1 days/yr. However, if one considers Figure 3.1(b)-3.3(b), an interpolation would show that one would ideally need 114-118 MW of installed capacity to ensure a an exact LOLE of 0.1 days/yr (depending on demand profile).

Focussing on the 100 MW peak demand scenario, if one were to assume that more granular investments were possible, the LOLE and LOLP as a function of installed capacity for a range of capacity investment options (1-10 MW) is given in Figures 3.7-3.9. For example, for the sloping demand profile (Figure 3.5) and a predefined maximum LOLE of 0.1 days/yr, increased granularity in supply capacity options results in less installed capacity required e.g. 1 MW investment sizes require only 103 MW while 3 MW investment size require 108 MW and as was shown previously, at least 120 MW is required for investment sizes of 10 MW.

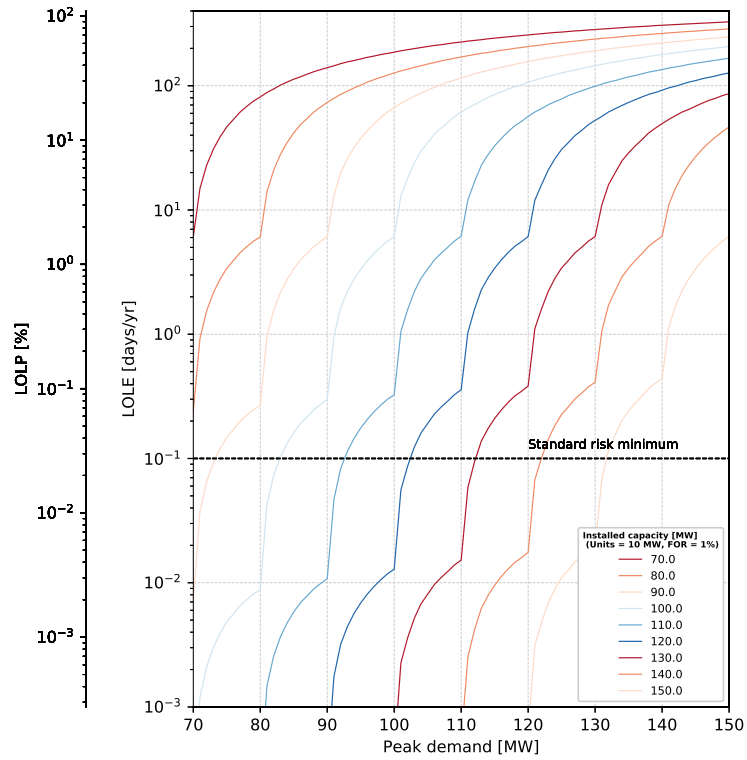


(a)

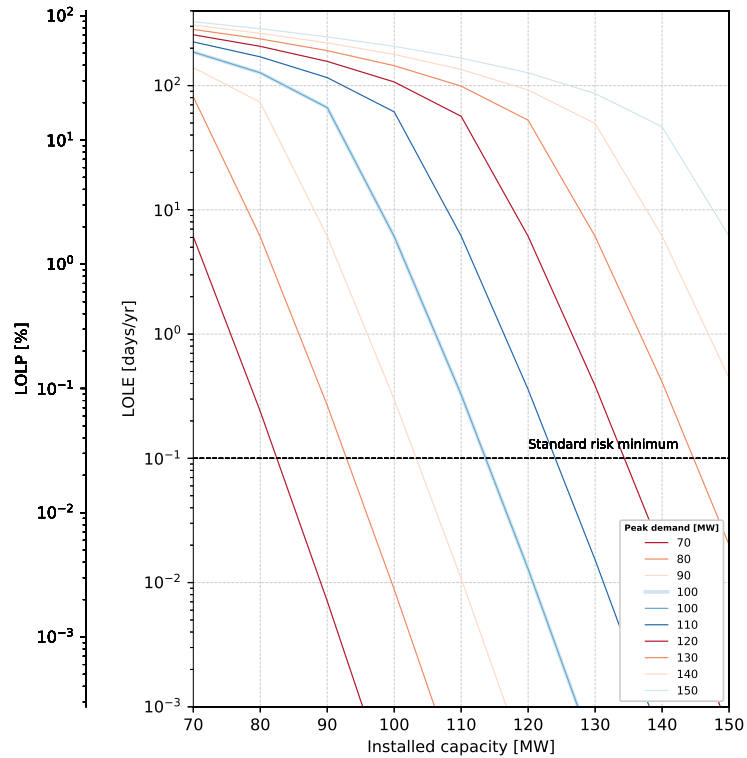


(b)

Figure 3.1: LOLE and LOLP 3.1(a) as a function of system peak demand (flat LDC) for a range of installed capacity (discrete investments) and 3.1(b) as a function of installed capacity range of peak demand (LDC in Figure 3.4)

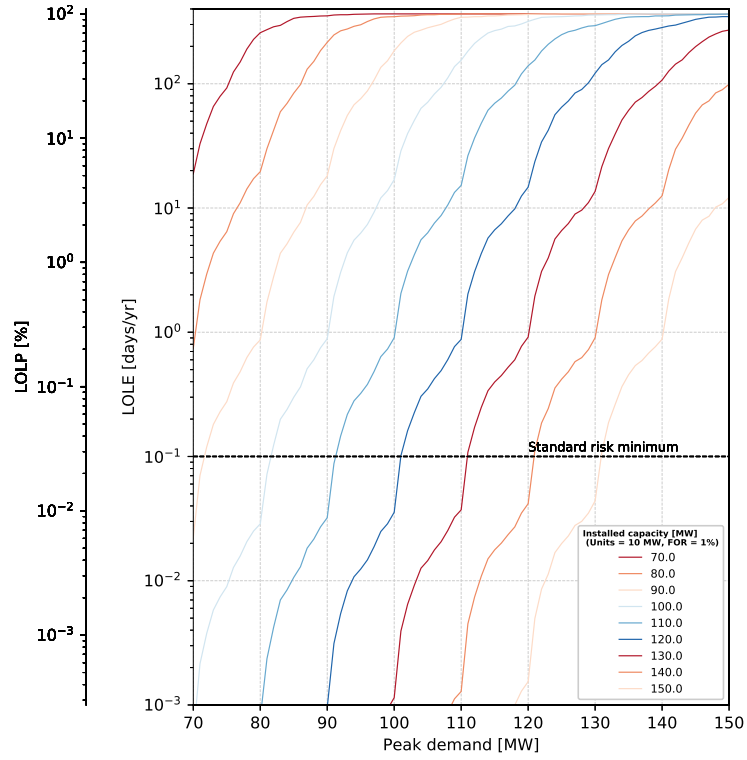


(a)

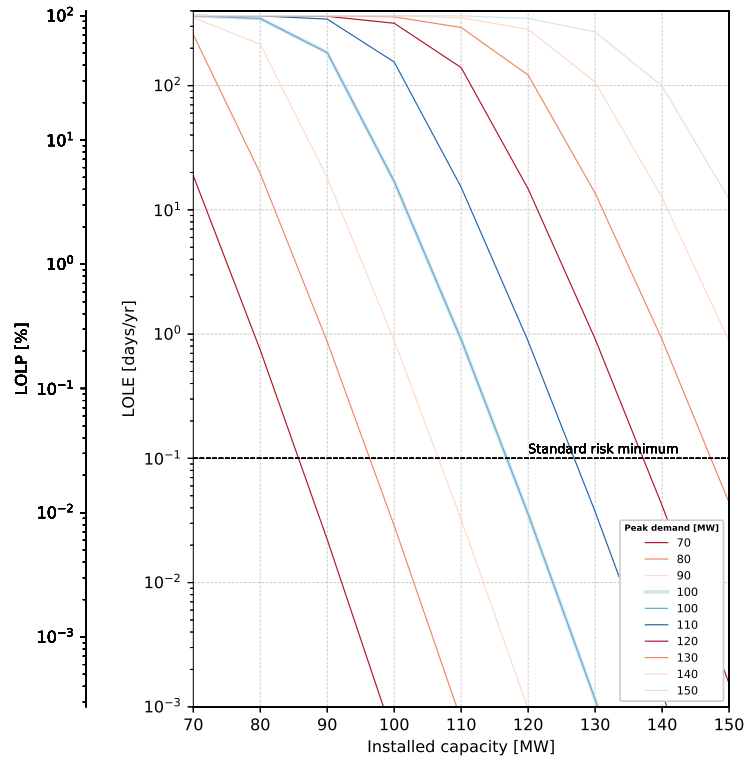


(b)

Figure 3.2: LOLE and LOLP 3.2(a) as a function of system peak demand (sloped LDC) for a range of installed capacity (discrete investments) and 3.2(b) as a function of installed capacity for range of peak demand (LDC in Figure 3.5)



(a)



(b)

Figure 3.3: LOLP and LOLE 3.3(a) as a function of system peak demand (representative LDC) for a range of installed capacity (discrete investments) and 3.3(b) as a function of installed capacity for range of peak demand (LDC in Figure 3.6)

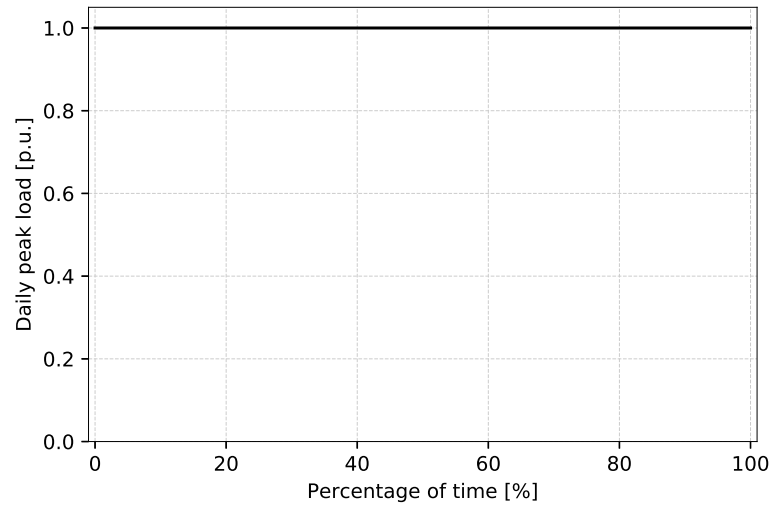


Figure 3.4: Normalised daily peak LDC (one year - flat), applied for system shown in Figure 3.1

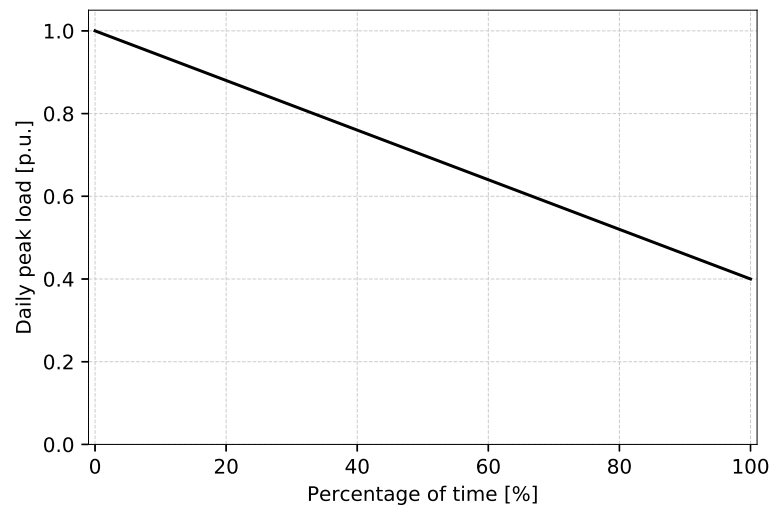


Figure 3.5: Normalised daily peak LDC (one year - sloped), applied for system shown in Figure 3.2

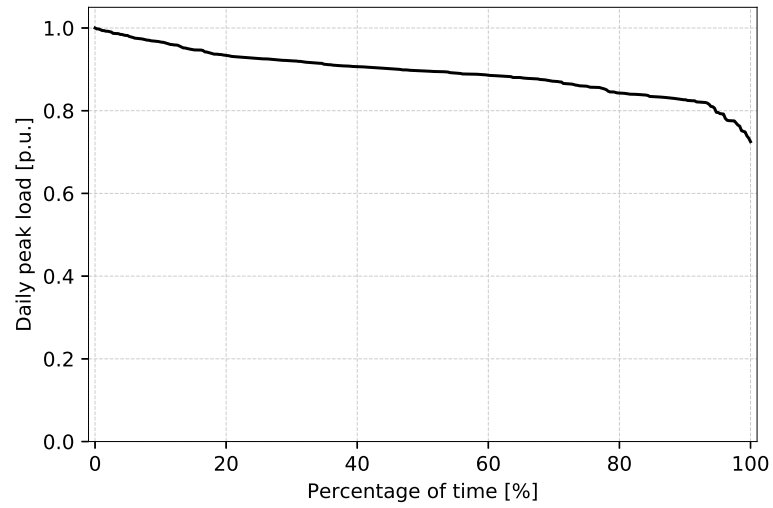


Figure 3.6: Normalised daily peak LDC (one year - representative), applied for system shown in Figure 3.3

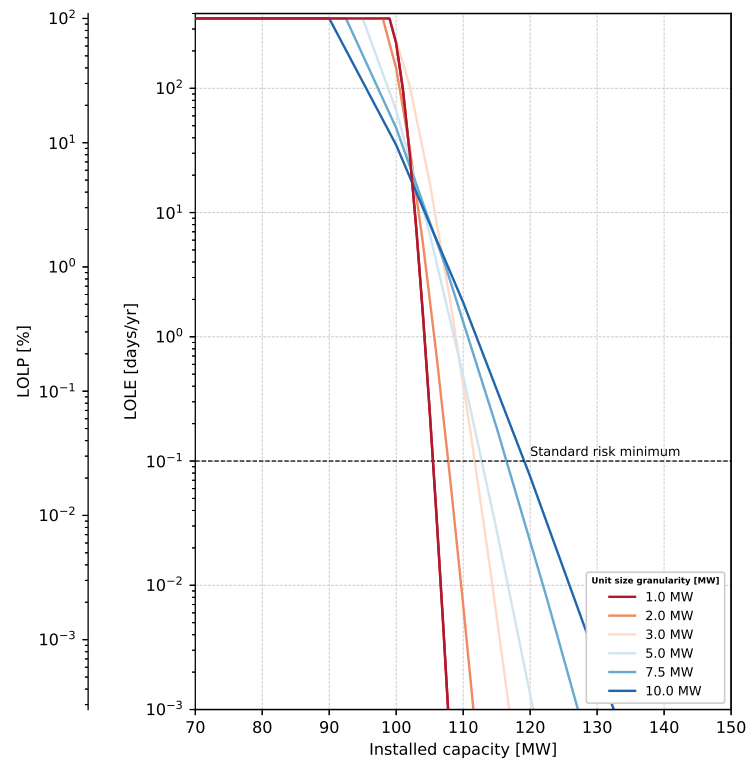


Figure 3.7: LOLE and LOLP as a function of installed capacity for a range of investment granularities (100 MW peak demand with flat LDC in Figure 3.4)

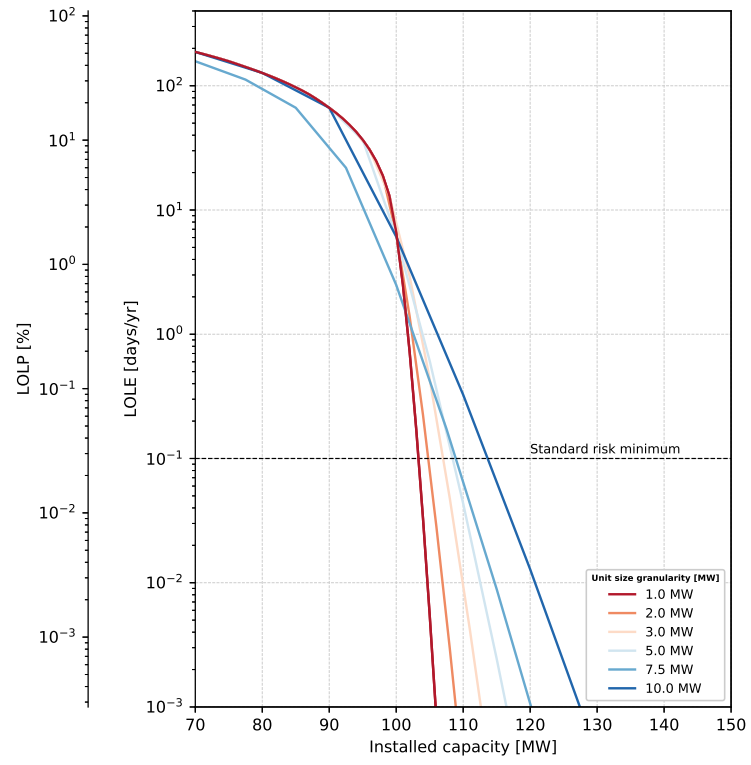


Figure 3.8: LOLE and LOLP as a function of installed capacity for a range of investment granularities (100 MW peak demand with sloping LDC in Figure 3.5)

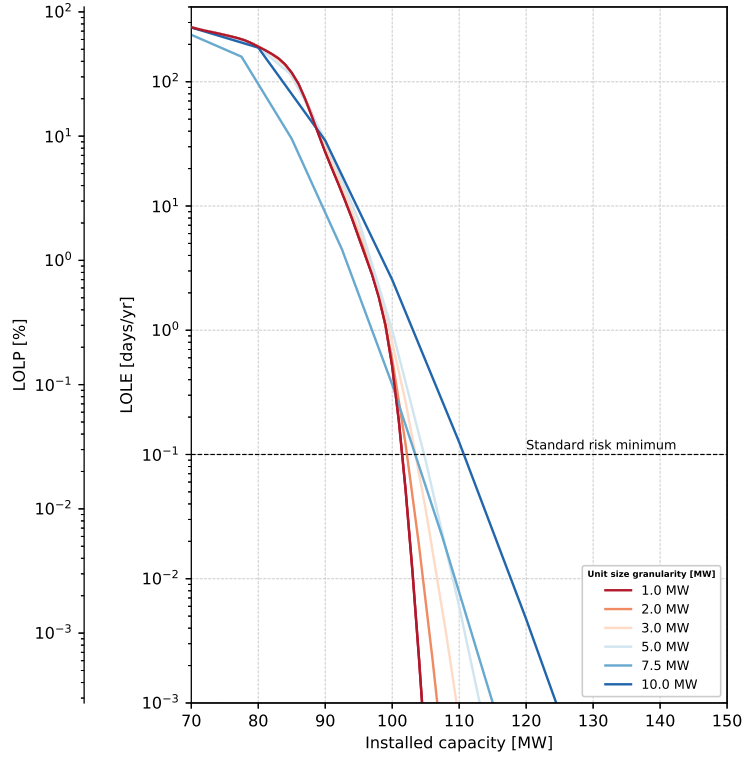


Figure 3.9: LOLE and LOLP as a function of installed capacity for a range of investment granularities (100 MW peak demand with representative LDC in Figure 3.6)

3.2 Capacity equilibrium

To illustrate capacity equilibrium in a power system, with one supplier of capacity, the optimal supply capacity to be invested in will be shown for the sloping demand profile previously presented (assuming a 100 MW peak demand). The previously determined installed supply capacity for this demand profile has been shown for a range of investment size options (Figure 3.8). As a maximum risk level has already been defined (LOLE of 0.1 days/yr) and calculated the EENS as a function of installed capacity, it is possible to calculate the CONE if we define a VoLL.

Assuming a representative example of $\text{VoLL} = 7500 \text{ USD/MWh}^1$ combined with the LOLE of 0.1 days/yr, one would obtain a CONE of 18 USD/kW-yr. Relative to reference new-build frame heavy-duty OCGTs with typically the lowest upfront

¹ This has recently been estimated for South Africa in equivalent South African Rand terms as $\approx 82.50 \text{ R/kWh}$ (82500 R/MWh) [145].

investment costs resulting in an estimated annualised cost of $\approx 90\text{--}120$ USD/kW-yr², a CONE of 18 USD/kW-yr is clearly considerably lower than necessary for investment in capacity at times of scarcity. The associated VoLL would mean a required VoLL of 37 000–50 000 USD/MWh to sufficiently fund the investment in the required capacity to meet peak demand (OCGT).

Using this information, one is able to calculate the total costs of capacity (and the associated capacity equilibrium) as the sum of c_0 and c_g as a function of installed capacity. This obtains exactly the same required supply capacity as before when total cost of capacity (c_t) is minimised. It should be noted that for simplicity sake, c_g is assumed to be only made up of the fixed costs associated with providing capacity from the peaking capacity provider mentioned. In reality, various providers of capacity along with their associated fixed costs and expected reliability metrics (including Forced Outage Rate (FOR))) can be optimised to provide the necessary capacity to ensure sufficient system adequacy at least-cost. These would also need to be supplemented with the variable costs of each capacity provider resulting in a least-cost optimal capacity mix that ensures the desired system adequacy (more detail on this is provided in section 2.2).

The costs for providing capacity for the various unit sizes previously defined are shown in Figure 3.10 (assuming 1% FOR) verifying previous outcomes i.e. optimal supply capacity for 1 MW unit sizes is 104 MW, for 3 MW unit sizes is 108 MW and 10 MW unit sizes is 120 MW. The asymmetrical nature of this outcome is well known [158] and reveals the reasons for most jurisdictions globally opting to rather invest in more supply capacity than less as the cost of under-investment is significantly higher for small changes in supply capacity and demand than the costs of over-investment. The results also reveal the reason for small power systems opting for the smallest unit sizes possible³. It can also be appreciated that assuming a similar CONE for a peaking capacity provider that a higher VoLL would result in the c_t curves in Figure 3.10 shifting to the right as a result of more value being given to the cost of outages c_o and thus a requirement for more capacity to be built until least-cost optimum is reached.

An indication of the effect of a higher FOR is presented in Figure 3.11 where a 5% FOR is considered (compared to previously considered 1% FOR). This necessitates

² Including capital and fixed operations and maintenance costs [145].

³ Smaller units would typically cost more than larger units though so there is also a more detailed optimisation to be undertaken in this regard (the results presented here assume the same costs across all unit sizes for simplicity).

an increased supply capacity to ensure least-cost supply relative to that which was previously presented (Figure 3.10). For example, for 1 MW unit sizes there is now a requirement for 111 MW of capacity (previously only 104 MW was required). Similarly, for 3 MW unit sizes there is a requirement for 117 MW of capacity (relative to 108 MW previously) and for 10 MW unit sizes there is now a requirement for 140 MW of capacity (relative to 120 MW previously). This is an important result to keep aware of considering the historical performance of supply capacity in the Southern African region. That is, relatively high FOR resulting in considerable differences between installed capacity and operating capacity available to meet demand.

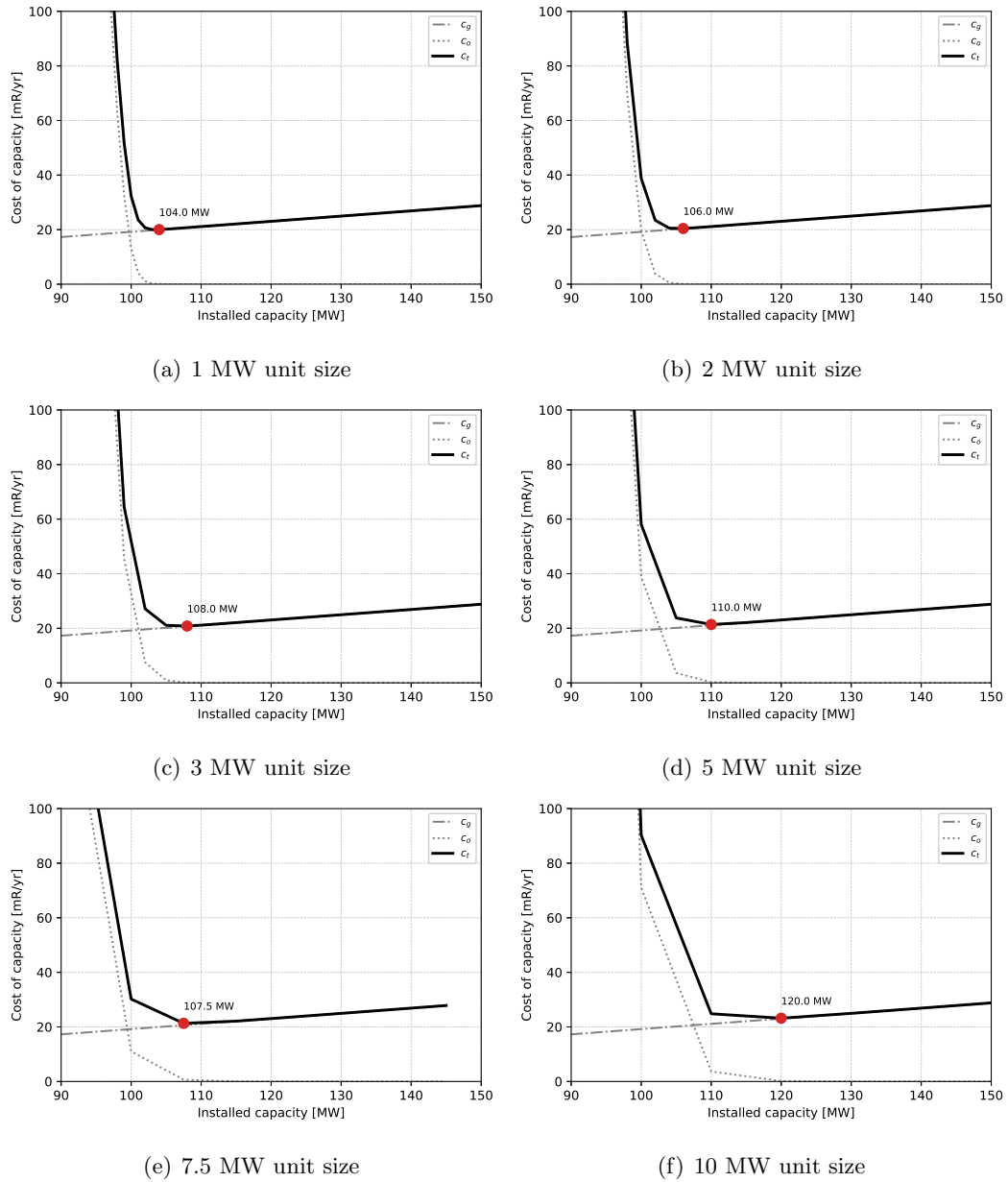


Figure 3.10: Total cost of capacity (c_t) as the sum of generation cost (c_g) and outage costs (c_o) (1% FOR, sloping demand profile - Figure 3.8)

3. SYSTEM ADEQUACY AND CAPACITY EQUILIBRIUM

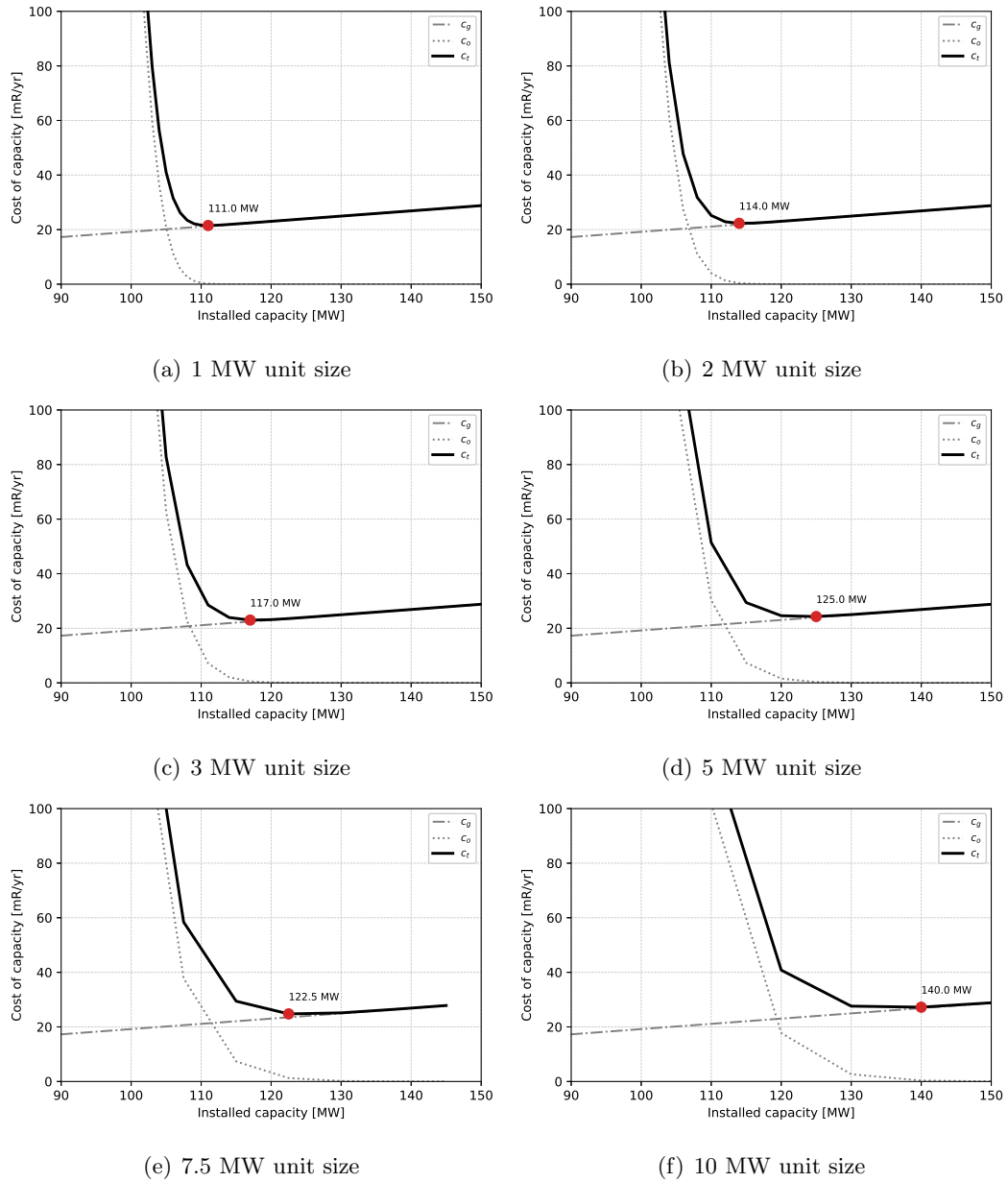


Figure 3.11: Total cost of capacity (c_t) as the sum of generation cost (c_g) and outage costs (c_o) (5% FOR, sloping demand profile of 100 MW peak demand - Figure 3.5)

Chapter 4

Focus on SAPP market performance

4.1 SAPP historical power system adequacy

An assessment of historical capacity adequacy in the SAPP is summarised in Figures 4.1 and 4.2 (predominantly based on the data in [129, 142–144, 159–167]). Based on this, the proxy used for the assessment of system adequacy is the annual operating supply capacity relative to annual peak demand. A benchmark of a 20% reserve margin is used as a demonstrative metric for system adequacy¹. This is further disaggregated into the total SAPP in Figure 4.1(a) and the interconnected SAPP in Figure 4.1(b). Due to the significant size of the South African power system, Figure 4.2 considers both the total SAPP capacity in Figure 4.2(a) and the interconnected SAPP capacity in Figure 4.2(b). Since 2004, the SAPP peak demand has been growing at an average rate of 2.2% per year (including South Africa) and at 5.2% (excluding South Africa). Similarly, the interconnected SAPP has seen average peak demand growth of 2.0% (including South Africa) and 4.2% (excluding South Africa).

As can be seen, considering the interconnected SAPP in Figure 4.1(b), an adequate regional power system has not been realised for any of the years considered until the most recent three years (2014–2016). This is primarily as a result of large coal-fired stations as well as a pumped-storage station under-construction in South Africa being partially commissioned (and will continue to be commissioned in the near future). When considering the interconnected SAPP without South Africa in Figure 4.2(b), not only has there been a perpetual inadequate power system

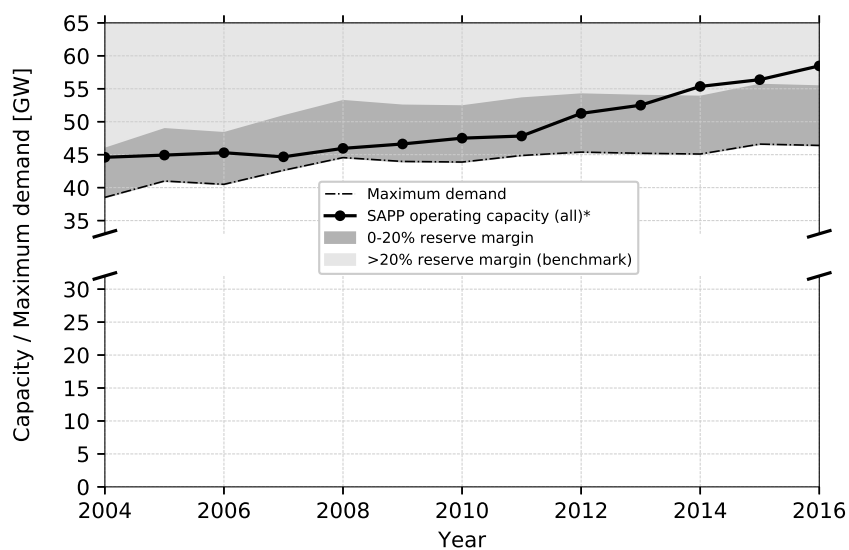
¹ Insufficient data is available to determine the historical LOLP/LOLE (this would be a more rigorous approach if data is made available).

but there have been extended periods (2004-2011) with insufficient absolute supply capacity. The interconnected SAPP without South Africa has demonstrated system inadequacy in all of the years considered. The high level of demand growth can also be clearly noted. This is expected to continue into the future as significant economic growth is expected from the developing nations in the Southern African region. Concomitant with this is an associated demand uncertainty. An example of this is in South Africa where demand forecast expectations have been consistently proven to be uncertain [102, 103, 168–171]. This is then exacerbated by the chronic lack of timely investment in capacity to meet this demand when it is realised.

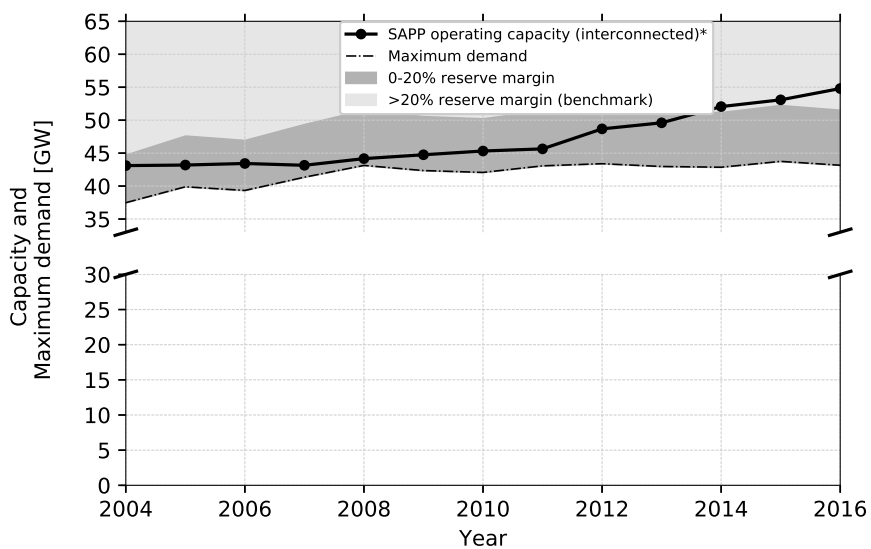
Another significant outcome from the analysis is a distinct investment cycle over the period considered as can be seen in Figure 4.1 and 4.2 (particularly noticeable in Figure 4.2). Although more data would be useful to further assess whether this has been an ongoing phenomenon in the SAPP region (even prior to interconnection and the SAPP)², the clear investment cycle is noticeable. As previously discussed in section 2.3.2, one of the primary drivers for electricity markets coupled with CMs is to minimise investment cycles.

Relative to other jurisdictions around the world where CMs have been considered historically, similar conditions typically existed (or exist currently). Examples include a number of countries in Latin America in the late 2000s (Argentina, Brazil), a number of European countries whose high capacity reserve margins dropped significantly following deregulation [60] as well as in North American jurisdictions [172]. CMs have also come into focus again in more recent times predominantly due to increased deployment of variable RES and policy driven decommissioning of existing generation capacity.

²Additional data is not available in the public domain.

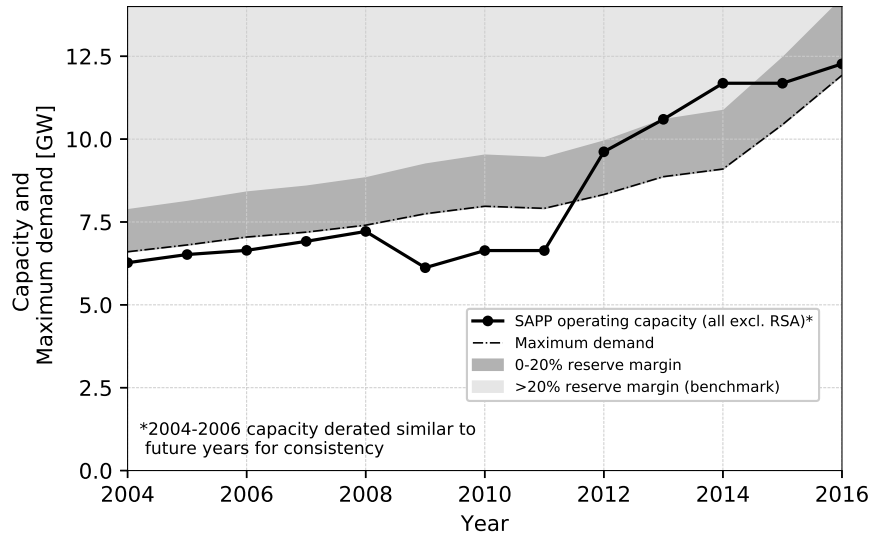


(a)

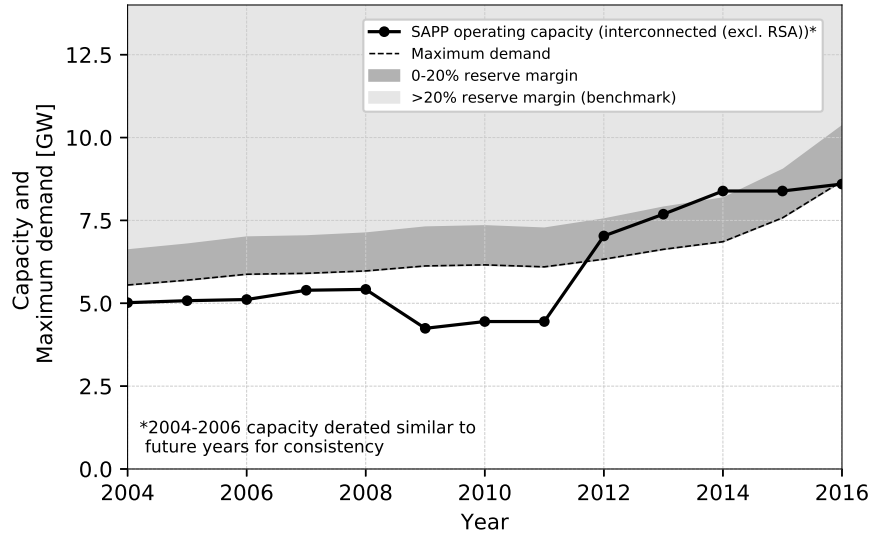


(b)

Figure 4.1: Historical system adequacy of 4.1(a) all of SAPP and; 4.1(b) interconnected SAPP for the period 2004-2016 showing marginal levels of system adequacy combined with over/under supply cycles



(a)



(b)

Figure 4.2: Historical adequacy of 4.2(a) all of SAPP excluding South Africa and; 4.2(b) interconnected SAPP excluding South Africa for the period 2004-2016 showing exaggerated and consistent lack of system adequacy combined with over/under supply cycles

4.2 The existing SAPP energy mix

Utilising the dataset developed as part of this research (see Appendix B), a model was implemented using the PLEXOS modelling platform [173]. The primary ra-

tionale behind utilising this platform is the advanced unit commitment and economic dispatch capabilities available that would enable a representative environment to understand the SAPP energy mix.

The classical unit commitment and economic dispatch problems are numerical in nature and are chronological optimisations that are typically formulated as MILP problems³ and implicitly consider all relevant fundamental technical and economic characteristics of all supply technologies to meet changing power system demand requirements [174, 175]⁴. For MILP problems, the most popular mathematical algorithm applied is the branch-and-bound algorithm (and variations thereof) where the classical 'divide and conquer' technique is applied and complemented by LP algorithms like the Simplex Method (with primal and dual variants) or Interior Point Method (Barrier Method) [19]. These are the algorithms applied in the PLEXOS modelling platform to solve the unit commitment and economic dispatch problem.

Over and above fundamental technical characteristics like number of units and maximum capacity of generators, the more advanced technical characteristics included as part of the production cost analysis undertaken as part of this research include efficiency (heat-rate), minimum-up/down time, ramp-up/down rates, Unforced Outage Rate (UFOR) and Forced Outage Rate (FOR)⁵. Financial characteristics of generation capacity that have been included are fuel costs, Variable Operations and Maintenance (VOM), Fixed Operations and Maintenance (FOM).

A production-cost run including unit-commitment and economic dispatch of the SAPP region was executed for 2016 using this model and summaries of country specific installed capacity and estimated energy shares for 2016 are shown in Figure 4.3 and Figure 4.4 respectively. In order to better appreciate the relative sizes of each SAPP countries' power systems, South Africa is purposefully shown separately for ease of visualisation but also to demonstrate the dominance of the South African power system in the region. The estimated energy mix for 2016 is based on production-cost model outcomes for 2016 based on the technical and economic characteristics of generation capacity in all SAPP countries (see Appendix B for details).

As seen in Figure 4.3, South Africa constitutes 76% of the overall SAPP installed capacity and 82% of the interconnected installed capacity. The next biggest countries

³ Discrete nature of generating units being either on/off makes the unit commitment problem integer.

⁴ Typically on an hourly basis but any relevant time period can be considered.

⁵ See Appendix B.

by installed capacity are Mozambique, Zambia, DRC and Zimbabwe with between $\approx 2\text{-}4\%$ of total installed capacity each. The estimated energy share is similar to the share of installed capacity. When excluding South Africa, it can be seen that Angola, DRC, Mozambique and Zambia contribute similarly to the overall generation mix at $\approx 15\text{-}20\%$ each while Mozambique, DRC and Zambia dominate in the interconnected energy mix with each contributing $\approx 20\text{-}30\%$.

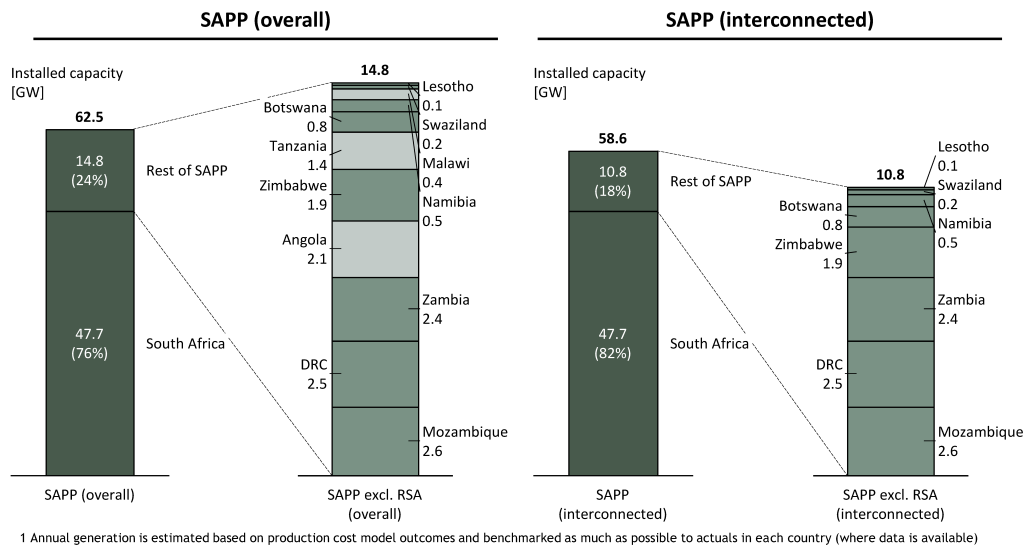


Figure 4.3: SAPP overall and interconnected installed capacity (by country - 2016) showing the dominance of the South African power system

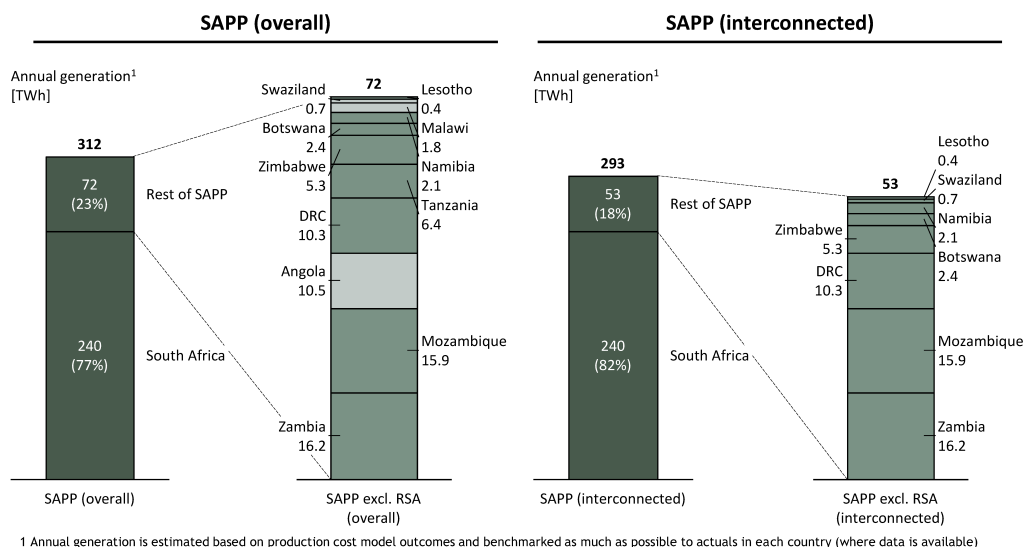
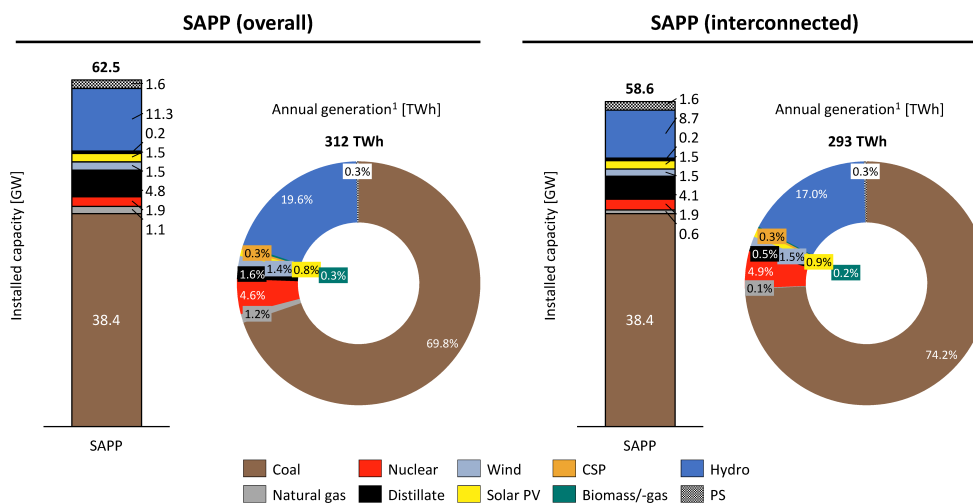


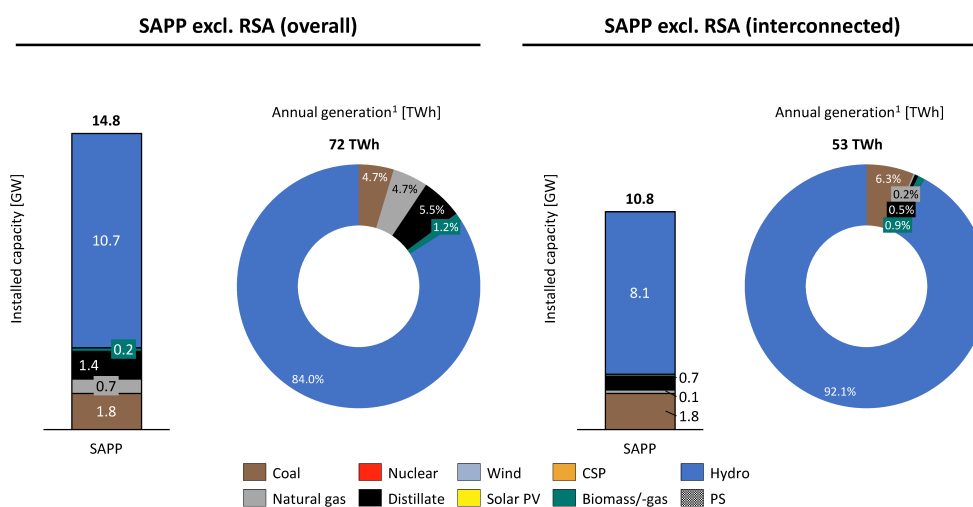
Figure 4.4: SAPP overall and interconnected estimated energy mix (by country - 2016) showing dominance of the South African power system whilst also showing how Mozambique, Zambia and DRC generation dominate in the interconnected SAPP

By technology, the SAPP installed capacity in 2016 as well as estimated energy mix are shown in Figure 4.5 (including South Africa) and in Figure 4.6 (excluding South Africa). The dominance of South African coal capacity and generation in the overall SAPP mix is clear (Figure 4.5). However, when removing South Africa, it is clear that hydro-based generation capacity dominates the remaining SAPP (Figure 4.6). There are small changes when considering the overall SAPP and interconnected SAPP where coal plays a slightly larger relative role in the interconnected SAPP while natural gas, distillate fuelled generators as well as hydro play a slightly smaller role. When excluding South Africa, the role of hydro-based generation increases in the interconnected SAPP relative to the overall SAPP while natural gas and distillate play a noticeably smaller role (primarily as a result of Tanzania not being interconnected as yet).



¹ Annual generation is estimated based on production cost model outcomes and benchmarked as much as possible to actuals in each country (where data is available)

Figure 4.5: SAPP installed capacity (by generation type) and estimated energy mix (2016) showing dominance of coal (predominantly in South Africa)



¹ Annual generation is estimated based on production cost model outcomes and benchmarked as much as possible to actuals in each country (where data is available)

Figure 4.6: SAPP installed capacity excluding South Africa (by generation type) and estimated energy mix (2016) showing dominance of hydro-based generation capacity

4.3 Historical performance of SAPP markets

Although a full set of data is not available for SAPP bilateral trades, based on available data from previous SAPP Annual Reports [129, 143, 144, 159, 160, 166, 167], the volumes traded in SAPP bilateral contracts are shown in Figure 4.7. Although these do vary year-on-year depending on specific regional conditions, there was a maximum of $\approx 19\,000$ GWh of bilaterally traded energy in 2005 ($\approx 8.1\%$ of the interconnected SAPP demand). From this, bilateral contract volumes appear to have been decreasing. More recently, down to $\approx 6\,100$ GWh (in 2015 - $\approx 2.9\%$ of the interconnected SAPP demand). This is notable considering the context of competitive electricity markets introduced into the SAPP (as will be discussed). It is also of relevance that as a result of SAPP market participants being predominantly vertically integrated utilities and the existence of network congestion in the SAPP, bilateral trading has historically resulted in a relatively small role for both co-operative and competitive electricity trade. This is evident in the data presented and can be seen in the relative scale of historical competitive electricity trade volumes in the SAPP. It has also been brought into focus by Rose in [156].

Based on available data from previous SAPP Annual Reports [129, 142–144, 159–167] and SAPP Monthly Market Performance Reports [176], SAPP historical electricity trade (annual) excluding bilateral trading is shown in Figure 4.8 with differentiation between co-operative and competitive electricity trade (transition from STEM to DAM). Bilateral contracts had been complemented by the collaborative SAPP Short-Term Energy Market (STEM) between 2001–2007. The SAPP STEM traded with volumes of between ≈ 70 – 740 GWh annually during this period.

Since the STEM was replaced by the competitive SAPP Day-Ahead Market (DAM) which effectively went live at the beginning of 2010 increasing year-on-year trade volumes have been realised in almost all years. As can be seen in Figure 4.8, the DAM has increased trade volumes year-on-year since its inception and has become the major competitive electricity market in the SAPP. The DAM was supplemented by the IDM in December 2015 followed by the SAPP Forward Physical Market (Weekly) (FPM-W) and SAPP Forward Physical Market (Monthly) (FPM-M) both which went live in April 2016. Significant increases in trade volumes on the DAM have been realised since 2015 where trade shifted from 71 GWh (in 2014) to 451 GWh (in 2015) and 924 GWh (in 2016). Although absolute competitive electricity trade volumes increased in 2017, a slight decrease in DAM trade volumes occurred in 2017 mostly due to increased competitive trade volumes in other markets established

(IDM, FPM-W and FPM-M). Notably, this has been offset in 2017 as DAM trade volumes doubled from 761 GWh in 2016 to 1537 GWh.

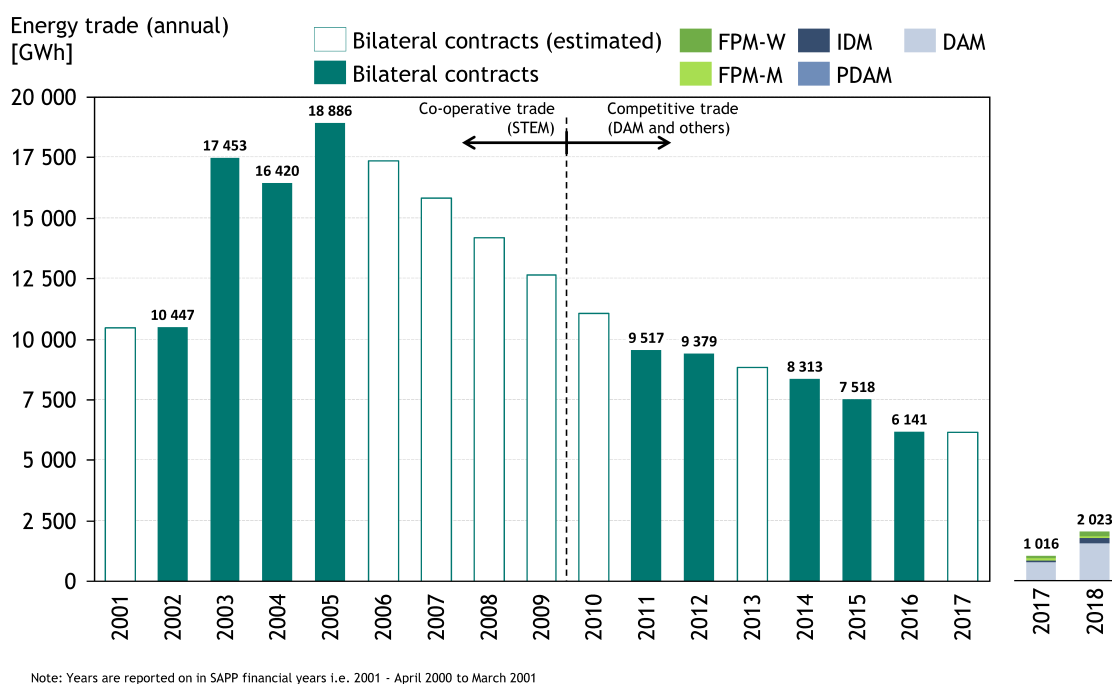


Figure 4.7: SAPP historical annual bilateral electricity trade (estimated where data is not available). Bilateral electricity trade has historically dominated SAPP electricity trade volumes

The increased interest by SAPP market participants in SAPP competitive electricity markets and the introduction of additional competitive electricity markets (as previously described) has driven further competitive electricity trade volumes. The monthly trade volumes (along with average MCP) for the DAM, IDM, FPM-W and FPM-M are shown in Figure 4.9 where the clear upward trend in trade volumes is even more noticeable. The MCP on the DAM (and other markets) trended downwards in 2017 (likely as a result of the considerable increase in trade volumes). Despite this downward trend in the very recent past, the DAM has become a market within which a stabilised reference price for electricity (the DAM MCPs) has been established over more than five years and has started to prove itself as a market where increased trading and investment could be incentivised for existing and future market participants.

It is appreciated that although these increases in competitive electricity trade volumes mean there is a larger role being played by these markets in SAPP, they are still relatively small in volume compared to SAPP bilateral trades (Figure 4.7) and the

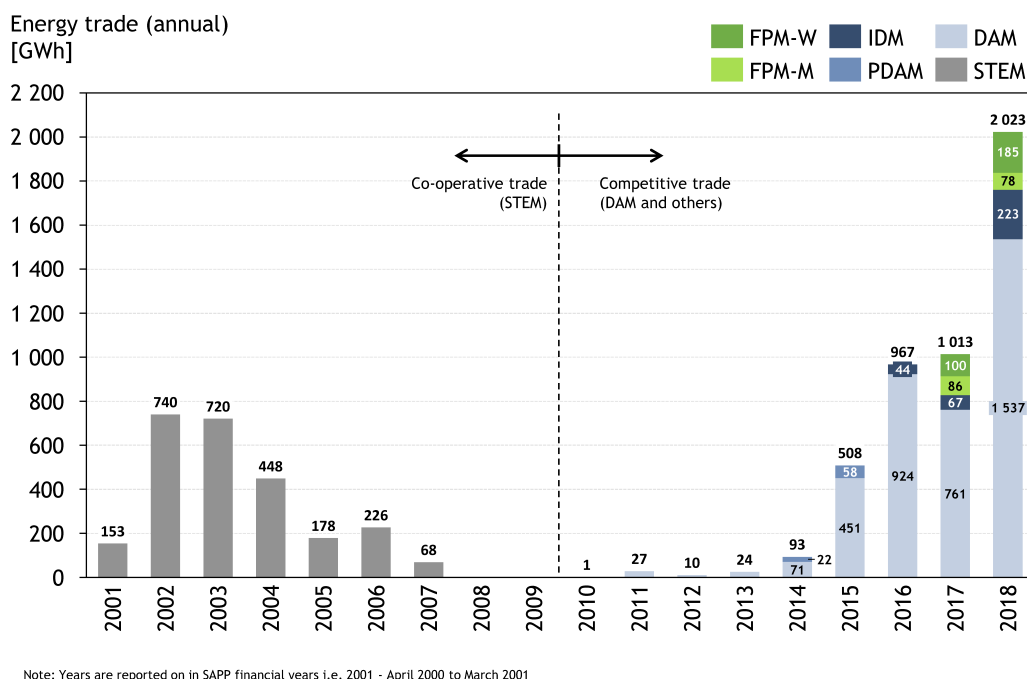
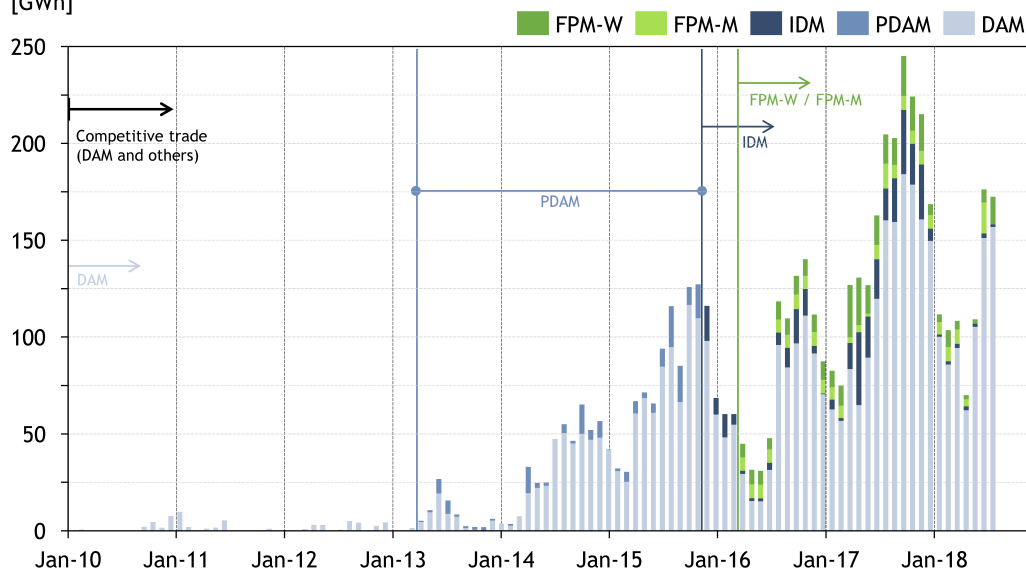
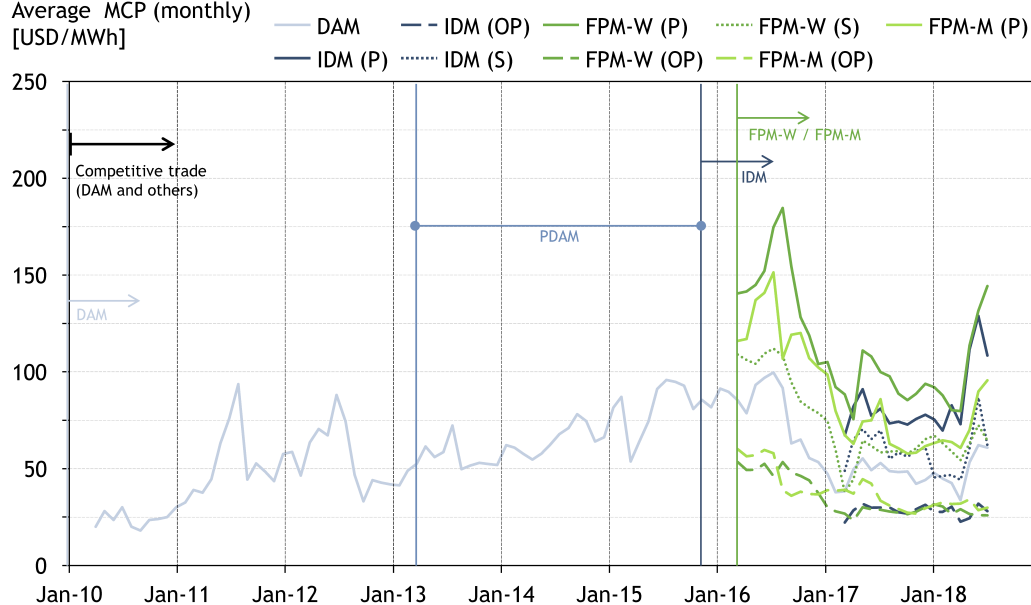


Figure 4.8: SAPP historical electricity trade (annual). The increase in competitive electricity market trade in SAPP is demonstrated by the first half of the 2017/18 year already having almost as much trade as there was in the full 2016/17 year

overall SAPP interconnected electricity demand. Bilateral contracts still dominate trading (but to a lesser extent in recent years) while most domestic demand is met by domestic supply in SAPP countries. A concerted effort is necessary to ensure that these competitive markets play a larger role in electricity trade in the region using the established reference prices for electricity in future as this assists in providing transparent price signals to potential capacity investors along with the associated interaction that will occur with any proposed CM.

Competitive energy traded (monthly)
[GWh]

(a) Historical monthly competitive energy traded on SAPP

Average MCP (monthly)
[USD/MWh]

Note: S - Standard, P - Peak, OP - Off-Peak
 1 No data on MCP for PDAM available; 2 No data for IDM MCP until Apr-2017

(b) Historical monthly Market Clearing Prices (MCPs) of competitive electricity markets on SAPP

Figure 4.9: SAPP historical monthly competitive electricity market trade showing 4.9(a) dominance of DAM (as expected) as well as growing competitive electricity trade in the region; and 4.9(b) Historical Market Clearing Prices (MCPs) for SAPP competitive electricity markets showing stabilised reference prices for electricity in the region

Chapter 5

Framework to assess capacity mechanisms (CMs) in the SAPP

5.1 Need for a CM in the SAPP

Complementing previous discussion on the need for CMs, an identification of the market failures in the SAPP is outlined in this section in order to provide the motivation for the introduction of an appropriately designed CM for the SAPP.

At a system operations level, most countries within the SAPP (and associated SAPP market participants) aim to implement and ensure a pre-defined level of operating reserves. As detailed in section 2.5 and 4.3, trading on the SAPP is undertaken by market participants at this system operations level utilising the previously described markets available as part of the SAPP market architecture¹.

At a systems planning level, national and regional level capacity expansion planning has been undertaken periodically in the past for the SAPP region. Nationally, domestic market participants are involved in these planning processes with the resulting capacity expansion outcomes ranging from being highly prescriptive on market participants to merely indicative. Regionally, most SAPP market participants are deeply involved in this via the structures put in place governing the SAPP (mostly via formal SAPP structures like the SAPP Planning Sub-Committee and SAPP Markets Sub-Committee amongst others). However, the regional level

¹Existing markets for energy trading as presented in section 2.5.4 and 4.3 include bilateral trading, SAPP Forward Physical Market (Monthly) (FPM-M), SAPP Forward Physical Market (Weekly) (FPM-W), SAPP Day-Ahead Market (DAM) and SAPP Intra-Day Market (IDM).

capacity expansion planning is in no way binding on any market participant. As a result, fragmented and ad-hoc approaches to ensuring system adequacy are applied and implemented. In addition, centrally determined administrative and bureaucratic processes often hamper and delay timely electrical infrastructure investments. More specifically, investments in capacity to ensure sustained system adequacy both domestically and regionally are not made timeously.

The dominance of particular SAPP market participants as demonstrated in section 4.2 would also increase the potential for gaming and skewing of outcomes. Although not yet demonstrated explicitly as part of this research, this is a well-known and well understood concern in energy markets globally [71, 177, 178] and in the SAPP [179, 180].

This has resulted both in a lack of sustained system adequacy as well as a lack of harmonisation across the region. There is a distinct need to ensure that capacity is available when and where needed in the region to ensure a pre-defined level of sustained system adequacy is achieved in future. The previously noted persistent lack of system adequacy and investment cycles (section 4.1) are not sustainable and need to be sufficiently addressed.

These are important characteristics of the SAPP status-quo as this research proposes an adequacy product which is able to value system adequacy and react to the inherent market forces that would drive adequacy needs at a regional level.

When capacity is needed in vertically integrated regulatory frameworks (as is the case in most SAPP member countries), the aforementioned centrally determined procurement processes dominate. Capacity is paid for implicitly as part of a regulated price determination (for vertically integrated PUs) or included in long-term PPAs for IPPs (contracting with the vertically integrated PUs in each country).

On the other end of the electricity market design spectrum, in a deregulated market environment where energy is traded as the only primary product (EOMs), scarcity pricing is meant to provide the necessary incentives for new market entry and also keep existing capacity operational to provide capacity when needed (see section 2.3).

The SAPP region combines the above-mentioned vertically integrated frameworks with a set of competitive wholesale markets at a regional level (as discussed in detail in section 2.5.4 and 4.3). These are mostly traded on by the vertically integrated PUs with low-levels of participation by other market participants (IPPs and/or ITCs).

As discussed in detail in section 2.3, in either of these market environments, research has been undertaken and policy direction prioritised towards implementing CMs which when appropriately designed should bring sufficient capacity to market (via an adequacy product) to ensure the required level of long-term sustained system adequacy.

The above understanding reveals the inherent market failures that currently exist in the SAPP which motivate for the introduction of a CM. These include prescriptive limitations on particular supply technologies (and associated administratively determined capacity expansion), implicit assumptions surrounding future demand (and the uncertainty thereof), non-zero lead times of capacity investments and market dominance.

With this context, the sections which follow develop a framework to assess CMs whilst also finding out what the most appropriate CM for the SAPP would be and the impact it could have on correcting chronically insufficient capacity investment in the region.

5.2 Approach

The approach taken in this research is the development of a framework for the assessment of CMs in the SAPP. This is shown graphically in Figure 5.1. It includes an initial screening of CM types based on a range of performance criteria. Following this, a Medium-term (MT) assessment of system adequacy in the SAPP is undertaken to better understand expected system adequacy in the near future. Finally, a quantitative (model-based) assessment of selected and favourable CMs is undertaken. A specific proposed design of a preferred CM for the SAPP is then established which outlines the pertinent design elements that would characterise the CM for the SAPP.

This provides a contribution in the form of the framework developed to consider CMs in the SAPP whilst also quantitatively analysing selected preferred CMs. Finally, on the basis of these outcomes, a proposed CM is designed considering previously presented design elements that characterise CMs in order to provide a practical indication of what a CM in the SAPP would resemble.

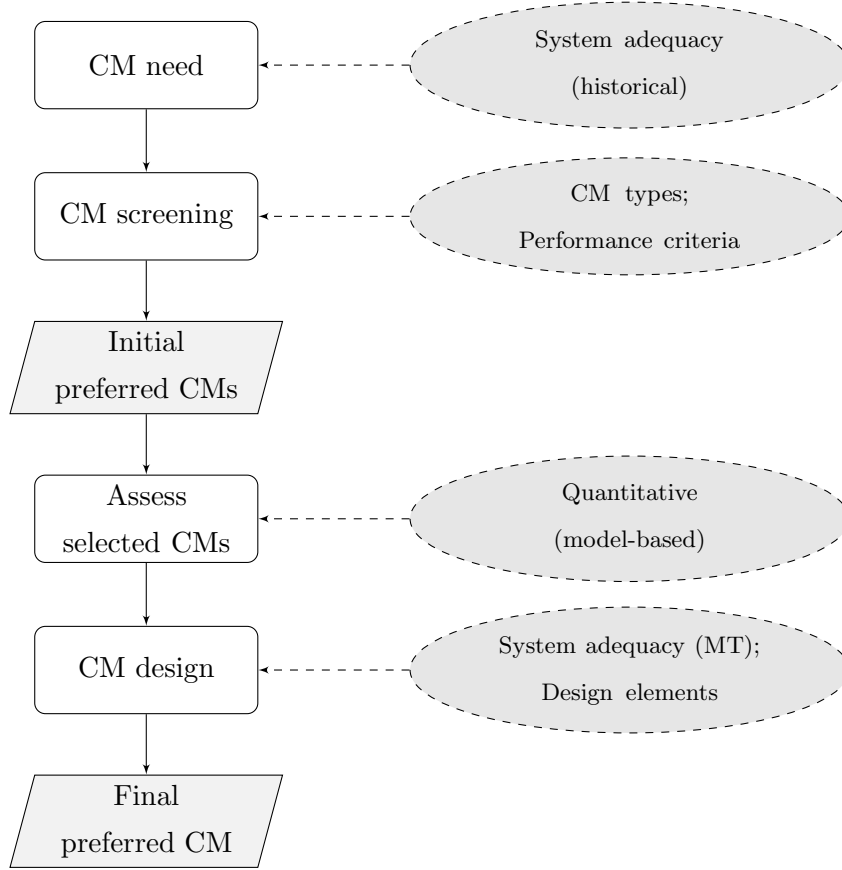


Figure 5.1: Framework developed to assess CMs. This is a dominant contribution of this research and is applied to SAPP but can be generically applied to any jurisdiction.

5.2.1 Screening

The screening is based on the approach initially developed by Doorman in [62] further expanded by de Vries in [8] but is modified for the purposes of this research providing an additional contribution to the knowledge in the SAPP. The modified approach applied to the SAPP environment assesses the performance of the range of CM types (as well as the EOM² previously presented in section 2.4.1) against a set of pre-defined performance criteria as characterised in section 2.4.2.

The screening is a modification and improvement in that it groups some performance criteria (as will be shown) and includes an additional performance criterion which warrants special mention and consideration - *transparency*. Transparency is included

² The EOM can be interpreted in the SAPP context as the *status-quo* where no CM is introduced and capacity is not explicitly valued).

to represent two important dimensions. These are, how clearly a particular CM values capacity (the *transparency* of the price signal) and how *transparent* the process is to procure the necessary capacity product (to all market participants).

The screening applies a relative comparison of the performance of CM types against the performance criteria on a linear scale as presented in Table 5.1. No scoring on a performance criteria means it is not relevant (as shown). This is important as it then does not penalise a CM type for on this basis but instead removes it from the screening assessment performed. A scoring of one (1) means the CM type performs poorly in achieving a particular performance criteria, two (2) means it performs satisfactorily, three (3) means it has good performance while four (4) means it is excellent (the best performing).

It is important to note at this stage that the scoring given to CM types on each performance criteria should be made on a relative basis. That is, only if a CM type on a particular performance criterion is notably differentiable from another CM is it scored differently on the rating scale. This provides for a general understanding and appreciation of the performance of CMs relative to each other when applied in the SAPP environment.

Table 5.1: Screening rating scale for CM performance

Description	Rating	Scoring
<i>Not relevant</i>		-
<i>Poor</i>		1
<i>Satisfactory</i>		2
<i>Good</i>		3
<i>Excellent</i>		4

From this screening, a numerical value is assigned to each performance criterion. All performance criteria scoring is summed and an aggregated scoring of each CM type is obtained (based on the simple linear scale of CM performance presented).

This can be further modified by considering weightings w_n for each performance criterion c_{mn} . These weightings are by default equal to unity (1) and equal for each performance criterion. However, these can be adjusted by a weighting factor

w_n to capture the importance of a particular performance criterion relative to another. It is also clear that it would be preferable to determine the weightings for each performance criterion *ex-ante* to ensure that an objective assessment can be undertaken.

In more definitive terms, the performance of CM m as expressed by P_{CM_m} is:

$$P_{CM_m} = \frac{\sum_n c_{mn} \cdot w_n}{\sum_n a_{mn} \cdot w_n} \quad (5.1)$$

where:

- P_{CM_m} = Relative performance index of CM m ;
- c_{mn} = Performance criterion n scoring for CM m ;
- w_n = Weighting of performance criterion n ;
- a_{mn} - Binary variable (0/1) indicating if performance criterion n scoring for CM m is relevant ($a_{mn} = 1$) or not ($a_{mn} = 0$).

The relative performance of a CM (P_{CM_m}) is an index which can be normalised (between 0 - 1) and gives an objective indication of how each CM type performs relative to other CMs. The application of weighting factors is important as it allows for an assessment of what could be deemed a performance criterion would be more important or less important (or could be completely removed). This is very relevant for the SAPP environment where the value and relevance of a proposed CM may be prioritised towards particular performance criteria e.g. *system adequacy, implementation cost, acceptability and stakeholder equity*.

It can also be appreciated that this screening approach as well as the CM framework to assess CM can be generalised and applied to other jurisdictions where persistent lack of system adequacy exists or where CMs are already under consideration.

5.2.2 Quantitative assessment

A dataset of the SAPP region has been developed as part of this research³ to assess selected CMs as part of the quantitative assessment steps described in Fig-

³ See Appendix B.

ure 5.1. The platform utilised to implement this SAPP dataset as a set of models is PLEXOS [173]. Although the model is inclusive of all SAPP market participants (NPs and OPs), the focus of this quantitative assessment for CMs is on the interconnected SAPP market participants (OPs only). If NPs are interconnected in future (as is planned), the approach would be identical with the only difference being the inclusion of these market participants as the relevant data is already available in the dataset developed and provided. Although not the focus of this research, power system networks have also been considered to the level of existing interconnectors (predominantly between countries) to allow for a representative understanding of existing and future power-flows.

Transfer limits of existing interconnectors between countries are scaled linearly with the expected size of the power system to the end of the time horizon. As the focus was on the impact of a CM on the SAPP and how it can assist with system adequacy, the optimal expansion of transmission interconnectivity was not a direct consideration.

Medium-term (MT) outlook

An assessment of the Medium-term (MT) system adequacy in the interconnected SAPP is used to define and better understand adequacy requirements into the near future for the SAPP. The assessment is undertaken utilising the previously mentioned developed dataset of the SAPP region. For the purposes of this research, the medium-term is considered to be 5 years ahead. That is, the period under consideration is 2016-2020.

System adequacy of the SAPP is represented by the two metrics introduced and extensively discussed in Chapter 2. These are - reserve margin and Loss of Load Probability (LOLP).

In the model developed, reserve margin is calculated in the typical manner by considering the peak interconnected system demand in each year and firm generation capacity available in that year (existing and new-build) and calculating an index:

$$P_{res} = \frac{P_{f(g)} - L}{L} \quad (5.2)$$

LOLP is calculated in the classical manner as presented in section 2.1 using convolution of supply capacity outages (using FOR) and compared to the LDC of the period under study (annually in this case).

Capacity providers on the supply-side include all existing, committed and under-construction supply capacity commissioned (and decommissioned) as planned in the MT in the SAPP. Technical properties considered include firm generation capacity and key reliability performance parameters including technology specific FOR and UFOR (see Appendix B).

On the demand-side, interconnected system demand is forecasted five (5) years ahead across the SAPP region (see Appendix B). The expected demand is then parametrised between 0.8-2.0 of what is expected in each year. This allows for the necessary insight into the MT adequacy outlook of the SAPP region as a function of expected demand forecasted.

The MT adequacy assessment is also a contribution to the requirement to assess adequacy by a Central Authority (CA) when determining the volume of capacity to procure as part of a CM. This is common across a number of CMs including a strategic reserve, capacity auction, reliability options and a capacity payment. Similarly, if desired, the MT assessment approach could be further geographically disaggregated into country level adequacy assessments. From this, the determination of capacity requirements can be better understood down to each specific country within the SAPP.

Selected CMs for further consideration

As part of the CM framework defined (see Figure 5.1), once the screening and medium-term system adequacy assessment is completed, initially preferred CMs are established. The performances of these pertinent CMs are prioritised for the quantitative (model-based) assessment performed.

The preferred CMs identified for the SAPP as part of this research are a strategic reserve and capacity auction. Capacity obligations would be similarly represented (as a result of the implementation of capacity obligations likely being via capacity auctions). The resulting focus on these CM types is to provide an indication of their expected performance in specific dimensions based on the outcomes from the screening component of the framework (section 5.2.1 and 5.3.1). However, it is

not intended to provide a full investigation into the most appropriate parametrised settings for these capacity auctions. Although, these do provide some indication of the relative performance of these CMs which proves useful in informing the proposed CM design for the SAPP.

The uncertainty considered as part of the model-based approach (demand forecast and annual hydro energy constraints) are incorporated via applying a Monte-Carlo approach in which 20 simulation runs considered⁴.

The choice of the minimum reserve margin (for the capacity auction) and absolute amount of strategic reserve is not intended to be extensively parametrised and establish optimised settings for these largely administratively determined parameters as part of this research. They are chosen purely to be representative of cases to test the effects that each of these CMs would have on system adequacy in the SAPP.

The comparison of the relative performance of these two CMs is primarily based on the ability to ensure sustained system adequacy under uncertainty i.e. resulting actual reserve margin, level of shortage expected (USE) and average annual wholesale price.

Demand forecast and hydrological inflow uncertainty

As demand uncertainty has been identified as one the key market failures motivating for the need for a CM, this has been considered as part of the quantitative (model-based) assessment. Although a particular demand forecast with some degree of uncertainty is considered as part of the approach for the SAPP, the demand forecast can be adjusted depending on expectations of market participants. The assumed demand forecast considered in this research is intended to be representative of the expected demand growth in the region (time horizon to 2050)⁵.

On this basis, the demand in the interconnected SAPP is assumed to grow by an average of 1.8% from the present to the end of the time horizon. Excluding South Africa, the interconnected SAPP is assumed to grow at an average of 3.3% per year. Demand uncertainty is accounted for by a normally distributed random variable with mean reversion applied to the expected demand forecast ($\sigma = 2.5\%$ ⁶, $a = 0.1$ ⁷).

⁴ In order to make run-time tractable in light of computation limitations - the number of model runs have been limited.

⁵ Based on historical information published by SAPP on an annual basis (as shared with SAPP by OPs and NPs [129]).

⁶ σ = Standard deviation.

⁷ a = Mean reversion.

The development of stochastic representations of hydro inflows and expected energy capabilities of hydro-based generation capacity in the SAPP region is not necessarily the focus of this research. However, energy limits are applied to hydro-based generators based on average annual energy capabilities (references provided in Appendix B). The uncertainty associated with these annual energy limitations is accounted for via a random variable similar to that applied for the expected demand forecast. However, for this variable, higher levels of uncertainty as well as longer periods of mean reversion are considered ($\sigma = 50\%$, $a = 0.1$).

Transfer limits of existing interconnectors between countries are scaled linearly with the expected size of the power system to the end of the time horizon. As the focus was on the impact of a CM on the SAPP and how it can assist with system adequacy, the optimal expansion of transmission interconnectivity was not a direct consideration.

Capacity auction

For a capacity auction, a pre-defined adequacy requirement range of 10-20% minimum reserve margin is considered. This could also be dimensioned on the basis of an equivalent maximum LOLP and would have a similar effect but as mentioned, a case study based approach is considered for this research. The chosen reserve margin is representative and although jurisdiction dependant, typically accepted ranges for minimum capacity reserve margins are 15-20%. This has been demonstrated via historical empirical experience and is further discussed below. Cost-based offers of capacity by existing as well as new-build capacity providers is considered as part of this research (no game-theoretic bidding is assumed).

At this stage it is important to note that in order to remain conservative on capacity requirements, the assessment does not assume any firm capacity contribution (capacity credit) from either solar PV or wind. This will clearly not be the case as both solar PV and wind could make contributions to system adequacy (and be included in a CM design in future) with some pre-defined derating of their installed capacity. There are a number of approaches to appropriately incorporate variable RES into CM design to achieve an understanding of their likely firm capacity contribution [181–185]. As mentioned previously, PJM already considers wind and solar PV as capacity providers as part of its CM - the Reliability Pricing Model (RPM). A recent outcome of this being that PJM cleared 6.8 GW of wind and 0.3 GW of solar PV to provide 890 MW and 125 MW respectively of the total 165.1 GW of capacity cleared for delivery in 2020/21 i.e. wind is derated to 13% of

installed capacity and solar PV to 38% of installed capacity in PJM [119].

Using the approach described in section 5.2.2 (and as will be shown in the outcomes provided in section 5.3.2), a 20% reserve margin choice actually results in a notably high LOLP in the interconnected SAPP. That is, higher than the typically accepted standard risk level (1 day in 10 years). Thus, it is conservatively a representative level of acceptable system adequacy but could possibly even be considered to be too low.

In most jurisdictions in the USA, reference reserve margins levels range from 11-20% [186]. In PJM specifically (in northeast USA), installed reserve margins of 15-20% have been recommended historically [187–189]. In order to incentivise investment to ensure this level of system adequacy, PJM introduced a capacity auction called the RPM in 2007/2008 (includes two components known as the Base Residual Auction (BRA) and Incremental Auctions (IAs) [190, 191]. Expected reserve margins for the delivery year as part of RPM BRAs since 2008/09 have ranged from 17-23% (on a system with peak demand of 130-170 GW⁸).

ERCOT (also in the USA) recently calculated an economically optimal reserve margin of 9-12% [14]. When imposing a maximum LOLE standard of 1 day in 10 years, this went up to 13-16% and as a result placed an implicit additional payment for capacity above what may be deemed economically optimal in the existing EOM [14]. Even with the tight and declining reserve margin experienced in recent years in ERCOT, system adequacy has been maintained via a range of measures but there is ongoing discussion and consideration being given to some form of CM if sufficiently high price spikes in the EOM do not provide the necessary impetus to incentivise new capacity investment [192, 193].

In the UK, on a power system with peak demand of 50-53 GW, reserve margins ranged from $\approx$ 6-11% between 2014-2018. This resulted in security of supply concerns being raised and prompted debate surrounding the need for a CM. In 2014, a capacity auction was established (amongst other electricity market reforms) [194]. The first UK capacity auction was run in 2014 with first delivery expected in 2018 [195]. The adequacy standard applied is guided by National Grid and is a LOLE of 3 hours per year. This is very similar to the typical 1 day in 10 years LOLE i.e. 2.4 hours per year. In the first capacity auction in 2014, 49.3 GW of capacity was secured for delivery in 2018 [196], the 2015 auction secured 46.3 GW for delivery in 2019 [197] and the 2016 auction secured 52.4 GW for delivery in

⁸ The considerable increase is as a result of additional control areas joining PJM over time.

2020 [198].

Strategic reserve

A strategic reserve is typically dimensioned based on a pre-defined level of acceptable system adequacy using an acceptable LOLP [85, 199]. For a strategic reserve in the SAPP, an initial absolute amount of strategic reserve of 2000 - 10000 MW is considered for introduction by 2020. This then scales linearly with the expected peak demand forecast in the interconnected SAPP i.e. with power system size. In this research, the strategic reserve is bid as a cost-based provider of capacity. It is also considered as a separate provider of reserves (not able to participate in providing energy) until operating reserves fall below a threshold (20%), following which it is allowed to be called upon to provide energy i.e. a technical trigger. The interconnected SAPP peak demand in 2020 is expected to be ≈ 52 GW resulting in a 2000 -10000 MW strategic reserve being ≈ 4 -19% of peak demand⁹.

Selected strategic reserves implemented in other jurisdictions are shown in Table 5.2. The Belgian strategic reserve established 850 MW (2014/15), 1535 MW (2015/16) and 750 MW (2016/17) [85]. Belgian peak demand is 12-13 GW resulting in the strategic reserve being 6-13% of peak demand. The German strategic reserve is intended to be 5% of peak demand of 80-82 GW (≈ 4000 MW) [80, 87, 88]. The Swedish strategic reserve has ranged from 750-1750 MW (cap is 2000 MW) with a peak demand of 26-28 GW resulting in a strategic reserve of up to 7-8% of peak demand [200]. In Finland, strategic reserve plants have an installed capacity of 1230 MW with Finnish peak demand of 13-15 GW resulting in a strategic reserve of 8-10% [201].

⁹ Interconnected SAPP peak demand in 2016 was ≈ 42 GW

Table 5.2: Size of a strategic reserve implemented in selected jurisdictions (with representative SAPP strategic reserve range shown)

Country/region	Peak demand [GW]	Strategic reserve (absolute) [MW]	Strategic reserve (relative) [%]
Belgium	12-13	850-1 535	6-13%
Germany	80-82	4 000	5%
Sweden	26-28	750-1 750 ¹	3-8%
Finland	13-15	1 230	8-10%
<i>SAPP</i>	<i>53</i>	<i>2000-10000</i>	<i>4-19%</i>

¹ Up to a 2000 MW cap.

5.3 Outcomes and discussion

5.3.1 Screening

Utilising the approach described previously (section refsec:ApproachScreening), the screening assessment for the pertinent CM types is undertaken in this section for the SAPP environment. This is summarised in Table 5.3. The basis upon which this screening is made and the relative performance of each CM is justified in the sections which follow. As described in section 5.2.1, it is important to note that the comparison is made on a relative basis.

Table 5.3: Evaluation of CMs for the SAPP against pre-defined performance criteria

Capacity Mechanism (CM) type	Performance criteria									
	System adequacy	Static/dynamic efficiency	Correctability	Simplicity	Implementation costs	Acceptability and stakeholder equity	Invisibility	Robustness	Timing	Transparency
<i>Energy-Only Market (EOM) - SAPP status-quo</i>										
<i>Strategic reserve</i>										
<i>Capacity obligation (ex-ante)</i>										
<i>Capacity obligation (ex-post)</i>										
<i>Capacity auction</i>										
<i>Reliability options</i>										
<i>Capacity payment</i>										
<i>Capacity subscription</i>										

○ - Not relevant (0); - Poor (1); - Satisfactory (2); - Good (3); - Excellent (4)

System adequacy

From the screening in Table 5.3, the reasoning behind the SAPP status-quo performing poorly for this performance criterion is clear based on previous discussions in sections 2.3 and 4.1. Briefly, it was shown amongst other reasons that the primary drivers for the need to supplement EOMs with CMs include inherent demand-side inelasticity (lack of Demand-Side Response (DSR)), imperfect information (particularly demand forecast uncertainty), long lead-times for new supply capacity investment and to a lesser extent price-caps. This translates to the minimal use of DSR in the SAPP other than in South Africa [202], price-caps placed on the main competitive wholesale market (the DAM) as well as centrally determined capacity expansion decisions (not necessarily linked to expected demand or market conditions) often delaying necessary capacity investments (as previously shown). This also leads to the previously described investment cycles in the region.

Reliability options would likely perform poorly in ensuring system adequacy in the SAPP. Although, it is appreciated that reliability options have been considered one of the best CM types globally [81, 203–205] as they have been applied successfully in a number of other jurisdictions (section 2.4.4). They send a clear pricing signal to capacity providers via the wholesale energy market to provide capacity during times of scarcity whilst incentivising performance during these times by penalising the capacity provider if they do not perform. However, a key pre-requisite for this is a liquid competitive wholesale electricity market. This does not yet exist in the SAPP (as was shown previously in section 4.3) and thus the reason for this CM type performing worse than others (in the specific SAPP context).

On capacity payments, this is probably the simplest CM type but due to the fact that it is indirect (it sets a price to then induce capacity investment and not a direct volume of capacity), it will perform worse than the other CMs which target capacity directly [54]. It could be argued that capacity payments (in their simplest form) are merely a subsidy to keep existing capacity online without obligating that capacity to be available when needed to ensure adequacy (this is a significant disadvantage of capacity payments). In the SAPP context, if a capacity payment were to be implemented, it would likely not be very effective in ensuring system adequacy primarily due to the above described reasons which may then also encourage gaming. Dominant capacity providers could strategically withhold and/or remove capacity resulting in the capacity payment being increased (as it is administratively determined rather than market driven).

Although a strategic reserve targets capacity as the adequacy product, it is not as good as a capacity auction or capacity obligation (ex-ante) in ensuring system adequacy as it would explicitly set-aside a pre-defined amount of capacity in a targeted manner by a CA (typically the TSO) and implicitly assume that the EOM comprised of the remaining capacity would ensure system adequacy. This has not been the case historically around the world and as was shown in previous discussions for the SAPP in sections 2.3 and 4.1. The activation of strategic reserves is either based on a direct scarcity price (unlikely to be the case in the SAPP for now and in the near future) or on a particular set of power system conditions in the region. Thus, existing TSOs in the region would need to set aside a particular amount of capacity (removed from normal operations) and have this capacity on standby for when tight supply-demand conditions exist. The DAM as well as other competitive SAPP markets are unlikely to be representative of these scarcity conditions as yet. Strategic reserves also have the effect of removing old, inefficient capacity from the supply mix (and having it on standby for very rare occasions) to be replaced by more efficient and cheaper new capacity. In addition, a strategic reserve does not necessarily remove the concerns surrounding overall system adequacy more generally as there will still remain the risk of under-investment due to the lack of a transparent price signal that values capacity explicitly within the market.

Capacity auctions are deemed to provide a good contribution to system adequacy considering the direct focus on obtaining a volume of capacity for system adequacy. They have been shown to be very effective in promoting system adequacy in a number of jurisdictions and could work quite well in the SAPP. The defined volume of capacity (locationally dependant) would be auctioned periodically on a forward-looking basis with qualifying existing SAPP participants (section 2.5.2) as well as prospective new SAPP participants (licensed by domestic regulatory requirements) bidding either existing or new capacity. The required volume would be based on pre-defined and agreed-upon adequacy requirements regionally which would then likely filter down to domestic adequacy requirements. The capacity auction would clear with a uniform price per pre-defined location and all capacity providers paid at the marginal price. This would provide a market-based and explicit price signal to capacity providers on a forward-looking basis for system adequacy in the region based on the inherent supply-demand balance. Depending on the contract duration provided, this would ease financing requirements for new-entrants as fixed-costs would be explicitly paid for via success in the capacity auction. Although the price signal will then incentivise system adequacy, the forward-looking basis of capacity auctions means that the capacity requirement does need to be known ex-ante. Thus,

a risk exists of over-investment if this is determined with insufficient accuracy.

One of the best performing CMs for the SAPP for ensuring system adequacy are likely capacity obligations, more specifically, *ex-post* capacity obligations. Although the capacity obligations (*ex-ante*) variant is similar, the key difference is that the calculation of the pre-defined adequacy requirement is determined (by definition) before the capacity is needed by a central authority. This leads to a risk of over/under-investment in capacity as uncertainty in the expected demand would be larger. Capacity obligations (*Ex-post*) inherently place the responsibility for procuring capacity on LSEs (who best understand their capacity requirements). The key difference being that if insufficient capacity is procured (as has been the case historically), sufficiently strong pre-defined penalties are imposed on LSEs by the central authority. This inherently incentivises LSEs to ensure sufficient capacity is procured or face penalties.

Capacity subscriptions would likely perform best as end-users (directly or via aggregators) choose their level of system adequacy based on pre-defined preferences following which a Load-Limiting Device (LLD) limits their consumption¹⁰. On the supply-side, a market for adequacy would need to be established for capacity providers to provide capacity during scarcity and end-users would buy this capacity. The explicit preference for capacity by end-users and the valuation thereof makes a capacity subscription very attractive for ensuring system adequacy.

Static and dynamic economic efficiency

Economic efficiency occurs when the maximum output occurs for a given set of inputs (labour, fuel, land, equipment) [206, 207]. The difference between static and dynamic efficiency is that static efficiency considers only existing resources while dynamic efficiency considers the use of new and improved technologies or labour practices in the determination of economic efficiency.

The SAPP status-quo has been shown to perform acceptably historically as the typically centrally planned power systems of the region have mostly guided supply-side investments. There are some cases of administratively determined investments as well as a lack of dynamic efficiency where new technologies have not been invested

¹⁰ The necessary functionality of a LLD could easily be integrated into a smart-meter while consumers preferences can be determined based on a few pre-defined selected preferences (whether fixed or via learning end-user reactions to load-limitations).

in despite the economic efficiencies that could be gained (e.g. only South Africa uses DSR actively and minimal investment in variable RES thusfar (despite significant cost reductions)¹¹). The use of the competitive SAPP markets that have been established has also thusfar been minimal despite commitments in the region to promote electricity trade and competitive use of the resources available in the region.

Capacity payments determined by a central authority in the SAPP would allow for some level of risk to be removed for capacity investors by ensuring a well-defined revenue stream (depending on the contract duration). It is unlikely that capacity payments would promote economic efficiency though. Similarly, no adjustments to capacity payments made as a function of system adequacy result in an inherent inefficiency where capacity payments are being made even if they are not needed (during times of excess supply) [208, 209]. In addition, difficulty in determining the optimal level of capacity payment (as well as whether it should be technology agnostic) combined with uncertainty in demand would also mean that economic efficiency would be difficult to attain under this CM. In addition, gaming may occur where if targeted capacity payments are made to certain providers whilst others are excluded, existing capacity excluded from these capacity payments would close and new capacity built that is eligible for capacity payments (even if not required).

The removal of particularly expensive supply-side resources as a strategic reserve could prove to be helpful by incentivising investment in capacity that increases economic efficiency but this would need to be balanced with the realities of chronic shortages in the region that would clearly reduce economic efficiency (as has been experienced historically). In addition, if strategic reserves are activated out-of-market (without market participants knowing) or activated and paid too little when activated, economic efficiency would clearly be lower as it would be more efficient to have the strategic reserve in the market as opposed to set-aside as a strategic reserve. When strategic reserves are dispatched by the SO (during times of scarcity), the impact of market power would typically also clearly be mitigated as dominant market players would not be in a position to create further scarcity. Of course, this assumes the SO is independent from generation (which is not necessarily the case in the SAPP). Thus, this economic benefit may not accrue to end-users.

Capacity obligations are rated quite highly on this performance criterion. Capacity auctions also rate similarly in this regard with the only difference being a centralised determination and procurement of the adequacy requirement in the capacity auction while capacity obligations are procured by LSEs. However, in the *ex-ante* variant

¹¹ This may change in the near future but has not been the case as yet

of capacity obligations the volume of capacity needs to be determined beforehand and by a central authority without relying directly on the market (or LSEs) to determine the volume required. Depending on the lead-time (which could be in the order of years depending on the supply technologies being incentivised under this CM), this may also result in over- and under-investment cycles. With the *ex-post* capacity obligation, adjustments can be made much closer to the time by LSEs which incentivises investments in short lead-time new technologies (e.g. DSR), which improves dynamic economic efficiency. In the SAPP context, it will be important to ensure that a regional approach to this is taken to leverage on the resources that the region has available (for higher economic efficiency) and to enforce penalties for under-procurement of capacity by LSEs.

Reliability options would inherently be the most economically efficient CM as they explicitly use the wholesale market price to send the appropriate pricing signals to capacity suppliers and end-users by hedging against exposure to high prices and volatility. However (as mentioned previously), this requires a liquid short-term competitive wholesale market such as the DAM. This is not currently the case but may change in future upon which reliability options could be reconsidered. Reliability options will also provide a regional indication of scarcity if designed accordingly.

The natural self-rationing characteristic of the capacity subscription CM make it a very economically efficient CM [63]. It has the ability to differentiate between end-users adequacy preferences by allowing each end-user, or aggregator, to define their adequacy preferences. No other CM allows for this. This CM also promotes dynamic efficiency by promoting the introduction of new technologies (LLDs) and inherently a more active and elastic demand-side.

Correctability

It would be relatively easy to stop procuring strategic reserve by a TSO, if necessary, as it would most likely come from existing capacity that is not efficient to provide energy in any case (or for DSR to not be required anymore). The capacity obligation CM types as well as capacity auctions are not as easy to correct as a result of the institutions, established processes, reliability measures as well as long-term investments made would prove difficult to reverse. They are not necessarily the worst performing as a transition between capacity obligation types as well as to a capacity auction would be relatively easy. Capacity payments could easily be reversed,

especially if fixed and not able to change depending on expected system adequacy. However, this would not be helpful in ensuring investor incentivisation or long-term adequacy as it creates regulatory uncertainty. If a capacity subscription was pursued, the investment by end-users (and aggregators) as well as capacity suppliers and TSOs in the necessary technology and communication capabilities would not be easily reversed. This makes the capacity subscription the least correctable CM type.

Simplicity

The SAPP status-quo is familiar with SAPP market participants and is thus clearly the simplest option¹². Similarly though, capacity payments (if static) and strategic reserve CM types are easily understandable for all market participants and would thus perform best on the simplicity criterion. Owing to the fact that the introduction of new approaches to ensuring system adequacy is overseen by a central authority, the capacity obligations as well as capacity auction CM types would likely be seen as less simple and less easy to understand. On reliability options, the introduction of a financial instrument would be very novel in the SAPP market environment and would likely not be very well understood initially. This would take some time for familiarisation and is thus not a favourable short-term option. It would result in lower levels of participation by market participants in an adequacy product trying to fulfil a critical role in the region - ensuring system adequacy. The complexity associated with a capacity subscription CM type would likely also result in a similar effect as that for reliability options. The difference being that it requires all market participants to be actively involved and has also not been applied in any jurisdiction globally.

Implementation costs

The implementation cost for strategic reserves would be minimal considering that existing TSOs in the SAPP region would easily be able to procure the necessary capacity based on previous experience (mostly via bilaterally negotiated strategic reserves and/or emergency supply capacity). Capacity obligations as well as capacity auctions would be similar in implementation costs as a result of administrative

¹² The passive *do-nothing* approach where the status-quo for attempting to ensure system adequacy continues.

costs for determining pre-defined system adequacy requirements as well as monitoring whether LSEs have met their obligations or whether capacity providers have performed as necessary. Capacity payments would impose similar implementation costs for similar reasons to that of capacity obligations (especially if they are not static). Reliability options perform slightly worse on this criterion as a new market would need to be established (albeit using the already existing MTP). Capacity subscriptions would clearly be the most expensive CM type to implement as a result of the considerable technology deployment required by a number of market participants that does not currently exist.

Acceptability and stakeholder equity

Acceptability and stakeholder equity are a tightly linked performance criteria and thus considered together. The broad definition of acceptability (Tables 2.4.3) is not the focus of this research, but acceptability by market participants is considered. More specifically, market participants would include end-users (small), end-users (large), generators (IPPs, PUs), TSOs and domestic/regional regulators. It can be appreciated that it would be very difficult to objectively determine the acceptability of a particular CM without canvassing market participants accordingly. However, a reasonable estimation can be made in this regard considering the likely effects of each CM on market participants. With the exception of reliability options and capacity subscriptions, the CMs types would be deemed similarly acceptable if considered across this spectrum of market participants. Examples of acceptability would include the country-level system adequacy dimension, the ceding of system adequacy responsibility to a central authority (regionally) and the related acceptable levels of domestic system adequacy relative to imports.

Invisibility

The previously discussed existing approaches to ensuring system adequacy in the SAPP region (the status-quo) are prescriptive and administratively determined (via centralised capacity expansion planning). Thus, these are implicitly visible and do not incentivise market participants to act independently. A strategic reserve is similar in this regard as it is a pre-determined centrally procured volume of capacity with the only difference being that does not necessarily need to be prescriptive of the type of capacity being procured.

The *ex-ante* capacity obligation CM centrally enforces system adequacy and is thus not invisible. Similarly, *ex-post* capacity obligations also impose adequacy requirements onto LSEs. However, *ex-post* capacity obligations allow LSEs to determine how to achieve the necessary adequacy levels and is thus slightly better than the *ex-ante* variant.

Owing to the fact that capacity auctions balance the supply and demand of capacity via forward-looking auctions for capacity, they could be considered invisible. However, they do still require an administrative determination of forecasted demand by a central authority which would determine the demand curve. This makes them less invisible.

Capacity payments are similar to reliability options in that they set a price for capacity and the volume is then determined by the market response. Thus, they are less visible than some of the other CMs but do still require the determination of the capacity payment level by an authority and thus there is some level of visibility still present.

Reliability options are invisible in the sense that system adequacy is determined purely by scarcity prices on the wholesale energy market. This is likely to be the DAM if implemented in the SAPP. Capacity subscriptions are similar in that once the market for capacity is setup, market participants define their requirements for supply and demand of capacity which naturally defines a supply-demand equilibrium without any external influence.

Robustness

CMs that would be very robust would be those which naturally balance supply and demand and do not rely on any form of intervention. The SAPP status-quo has been shown to be quite unresponsive to unexpected changes and thus performs poorly on this performance criterion. The most robust CMs would be capacity subscriptions and reliability options as they would naturally react to conditions of scarcity (e.g. if demand is higher or lower than expected or if poor hydrological conditions emanate). However, for reliability options, this does assume that capacity investments in the SAPP region are made on the basis of scarcity prices on the wholesale energy market (which is not currently the case). Thus, if capacity subscriptions were to be implemented, they would perform the best. These would include capacity subscriptions and reliability options. Capacity payments would also perform well

on the robustness criterion if the capacity payment is dynamic i.e. if they changed based on pre-defined system adequacy conditions. Capacity obligations implemented with a number of auctions with differing lead-times would allow for finer control and possible adjustments to unexpected events making them quite robust.

Timing

Considering the sustained periods of system inadequacy in the SAPP historically, the dependence on when a particular type of CM should be introduced or not is one of the most important performance criterion. This criterion becomes more important when the region is inadequate and has an immediate need for capacity. Thus, each CM type is assessed on this basis.

Strategic reserves are relatively quick to implement and would thus score highly. Considering that the SAPP already has established competitive electricity trading markets (albeit with relatively low trade volumes for now), the existing MTP could be used to implement reliability options but this would take some time to implement and would not address an immediate capacity requirement as some time would be required to familiarise market participants. Capacity obligations as well as capacity auctions would be quite familiar to market participants and could thus be implemented quicker than reliability options but markedly slower than a strategic reserve. Capacity subscriptions would not be very timely as there is no experience in any jurisdiction globally as yet and would thus take significant time before system adequacy would be addressed.

Transparency

In the context of CMs, transparency criterion is made up of two important components. These are described briefly below:

- *Fundamental data transparency:* This is a component of transparency that captures the broad requirement for relevant fundamental technical and market power system data and information to be shared on public platforms. This will allow any and all market participants as well as broader stakeholders to make more informed decisions in both operations and planning. More specifically in the context of CMs, the fundamental data and information required to inform prospective capacity

investors where and when opportunities exist is critical to make the most informed decision whilst also lowering investment risk.

- *CM valuation transparency*: Any CM type that transparently reveals to market participants the value of capacity should score highly on this performance criterion.

It is clear that the the latter component of transparency is more directly related to the choice of CM while the former is more general in nature. Increased transparency and resulting liquidity of CMs with appropriate market monitoring, likely by a regional regulator or the SAPP Co-Ordination Centre as the existing regional MO, will allow for the removal of concerns surrounding market power.

Capacity payments would perform well on transparency as there is a transparent signal to capacity providers revealing what capacity is valued at and informed decision making can be undertaken as a result. Due to the fact that most strategic reserves are procured bilaterally in the SAPP, there is not much transparency provided to market participants regarding what the value of capacity is to the power system. Of course, if procured via a centralised auctioning process, this would become public knowledge and thus improve the performance of capacity payments on this criterion. Capacity obligations *ex-ante* would most likely be more transparent than *ex-post* primarily due to the fact that *ex-ante* capacity obligations would be procured centrally and likely via auctions, thus removing concerns surrounding market power that may occur if *ex-post* is chosen (where bilateral negotiations may be a preferred mechanism for capacity procurement). Capacity auctions would perform similarly to *ex-ante* capacity obligations. Reliability options as well as capacity subscriptions would inherently be transparent as price-based valuation of capacity is implicit in these CMs.

Performance of CMs assessed for the SAPP

Using the previously defined approach (section 5.2.1) and the performance of each CM from Table 5.3, a demonstration of weightings applied is considered as follows:

1. Default - $w=1$ for all;
2. System adequacy ($w=3$), $w=1$ for others;
3. Implementation cost ($w=3$), $w=1$ for others; and
4. Acceptability and stakeholder equity ($w=3$), $w=1$ for others.

The relative performance indices for the above demonstrative assessments are shown in Figure 5.2. The best performing CMs are capacity obligations (*ex-post*), capacity auctions and strategic reserves. This is primarily due to good performance on system adequacy, simplicity, implementation costs as well as acceptability and stakeholder equity. As expected, the status-quo performs the worst regardless of weightings applied to performance criteria. This is primarily as a result of it not being able to ensure system adequacy, low-levels of robustness, invisibility and lack of transparency.

It is important to note that the assessment of the performance of CM types is subjective. Thus a final decision on the most appropriate CM can only truly be definitively settled once the detailed design elements are defined for each CM type, in addition to all market participants' interests being considered as well as broader stakeholders previously mentioned. Nonetheless, the screening undertaken as part of this research is intended to provide a demonstrative application of the presented CM framework developed but should not be construed as conclusive on which CM type is best suited for the SAPP environment. However, it does provide an indication of which CM types would likely perform well in the SAPP environment and is thus a valuable and useful contribution.

If a fully consultative process is envisioned in future on the role CMs could play in the SAPP region, it will be critical for the weightings applied to the assessment to be considered and decided upon by all market participants - *ex-ante*. This will avoid gaming to skew outcomes by market participants with particular preferences for CMs or the status-quo.

5.3.2 Quantitative assessment

Medium-term outlook

As outlined in section 5.2.2, in order to obtain an indication of the expected requirement for capacity in the interconnected SAPP region, a medium-term assessment of the supply-demand capacity balance is undertaken. This adequacy outlook for the SAPP region is shown in Figure 5.3 (from 2016-2020).

The historical system adequacy assessment undertaken in section 4.1 is verified with this more detailed adequacy assessment by looking forward to 2020 whilst also parametrising expected demand (considering this uncertainty). In 2016 (for

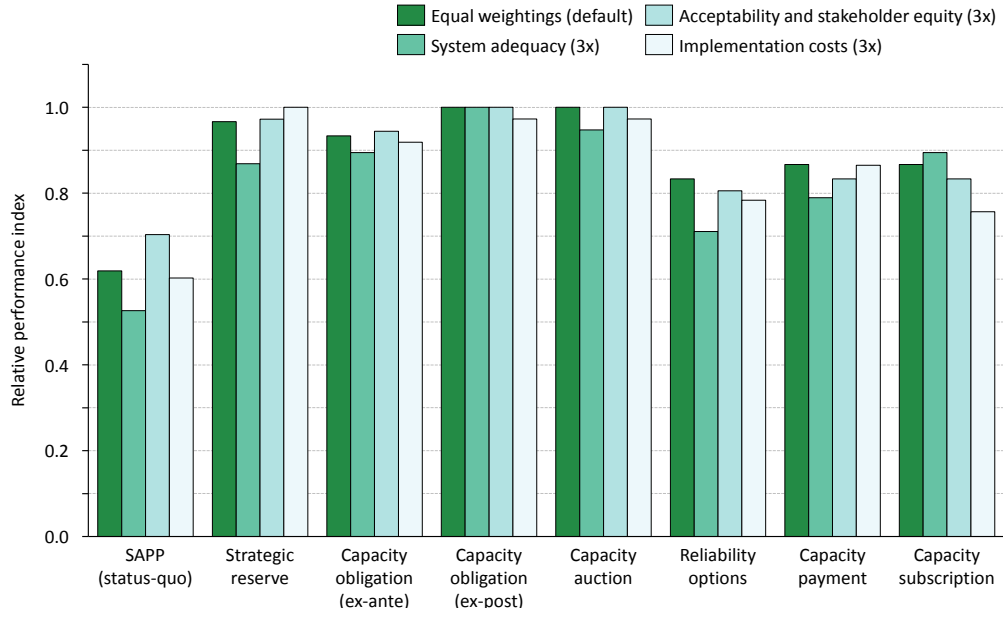


Figure 5.2: Performance of CMs assessed for the SAPP with default weightings of performance criteria as well as increased weightings applied to three performance criteria ($w=3$)

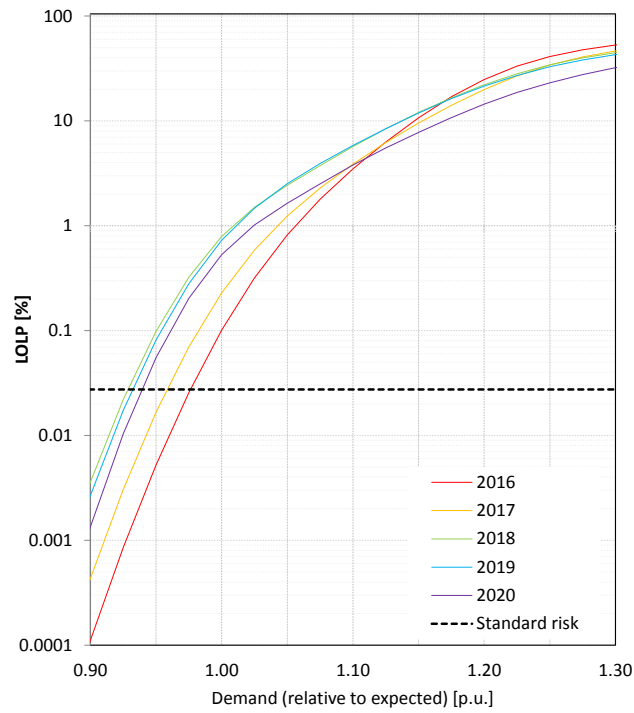
demand and supply capacity reliability performance expected), it is clear that there is an excess supply for the 2016-2020 period when using the previously defined 20% reserve margin as a metric for system adequacy. However, when considering the LOLP metric which inherently includes the reliability performance for each power station¹³, the SAPP region is not necessarily in an excess supply situation¹⁴. On this basis, in none of the years from 2016-2020 will there be sufficient supply if LOLP is the adequacy metric.

Only if demand is lower than expected (0.93-0.97 of expected demand for 2016-2020) will the LOLP be acceptable. The reserve margin at these points is 30-35%. This is an important finding as it links to the previously discussed typical reserve margin considered acceptable mentioned previously and in section 5.2.2 of 20% . At this point, it is important to note that some countries within the SAPP are likely to exhibit sufficient levels of system adequacy whilst others exhibit lower levels of adequacy to 2020 as the sharing of capacity across available interconnector capacity would allow for a more adequate interconnected SAPP power system (relative to the adequacy of stand-alone countries or countries not yet interconnected).

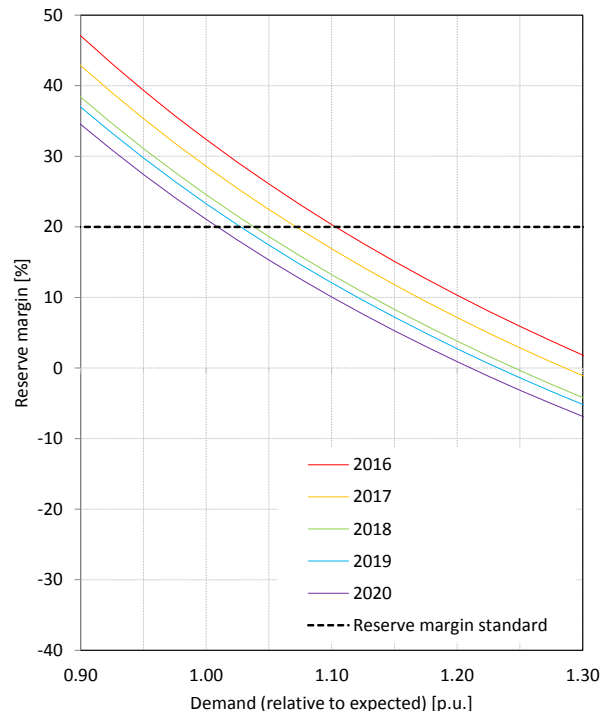
¹³ Based on assumed Unforced Outage Rates (UFORs) and Forced Outage Rates (FORs) given in Appendix B.

¹⁴ Relative to the 0.1 days/yr LOLE and resulting 0.027% LOLP metric previously defined

Combining this forward-looking medium-term assessment of system adequacy with the historical assessment of system adequacy (section 4.1) provides some valuable insight into the need to ensure a transparent indication of the need for system adequacy in the SAPP region. This also further drives the necessity for an explicit adequacy product. This adequacy product (in the form of a CM) is discussed throughout but in particular in the outcomes of this section and is further explored in section 5.4 to design a proposed CM for the SAPP.



(a) Loss of Load Probability (LOLP) as a function of expected demand (logarithmic scale)



(b) Reserve margin as a function of expected demand (linear scale)

Figure 5.3: Expected SAPP supply-demand balance (2016-2020) assuming only existing & under construction supply capacity as a function of normalised expected demand. Differences notable as a result of deterministic nature of reserve margin metric relative to stochastic LOLP

Selected CMs for further consideration

A comparison of the selected CMs as part of the framework developed is presented in this section by applying the approach described in section 5.2.2.

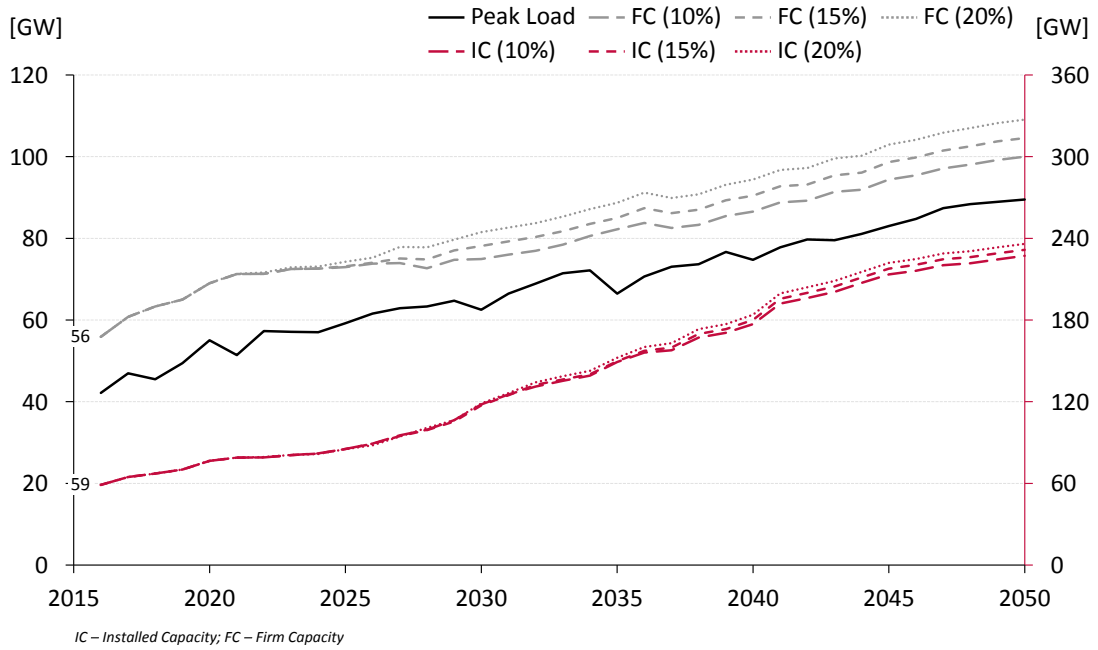
The average capacity supply-demand balances for the assessed CMs following the previously described approach are shown in Figure 5.4. The deployment of high levels of variable RES results in a significant deployment of installed capacity (right axis) while firm capacity from dispatchable capacity providers of various technologies provides system adequacy.

The capacity auction results in a higher reserve margin relative to the strategic reserve across the full range considered. This can be better appreciated when considering how LOLP and reserve margin relate for the capacity auction and strategic reserve as shown in Figure 5.5. It is clear that even if an improved reserve margin may be realised in the face of demand uncertainty that an acceptable LOLP may still not exist (when LOLP is less than the typical standard - 1 day in 10 years). This is similar across both CMs assessed. However, a key difference between the capacity auction and strategic reserve is how many instances of combined low reserve margin and relatively high LOLP exist. This is summarised in Table 5.4. As can be seen, the capacity auction performs well on reserve margin but not necessarily as well on LOLP. A strategic reserve performs better on the LOLP metric and similarly to the capacity auction on reserve margin. When combining these two metrics (the lower right corner of Figure 5.5), it seems that the strategic reserve would perform better. However, it is important to note that this only occurs for the extreme of an initial 10 GW strategic reserve ($\approx 19\%$ of expected interconnected SAPP peak demand in 2020) and significantly higher than most jurisdictions globally that have already implemented a strategic reserve (see section 5.2.2 for further discussion on this). More specifically, the 5 GW strategic reserve (10% of expected 2020 peak demand) has a LOLP of less than the typical standard 27% of the time and has a reserve margin better than the reference reserve margin 51% of the time i.e. similar to the capacity auction performance. As will be discussed, there are also cost implications of holding such significant quantities of strategic reserve set aside and not providing energy during normal operations.

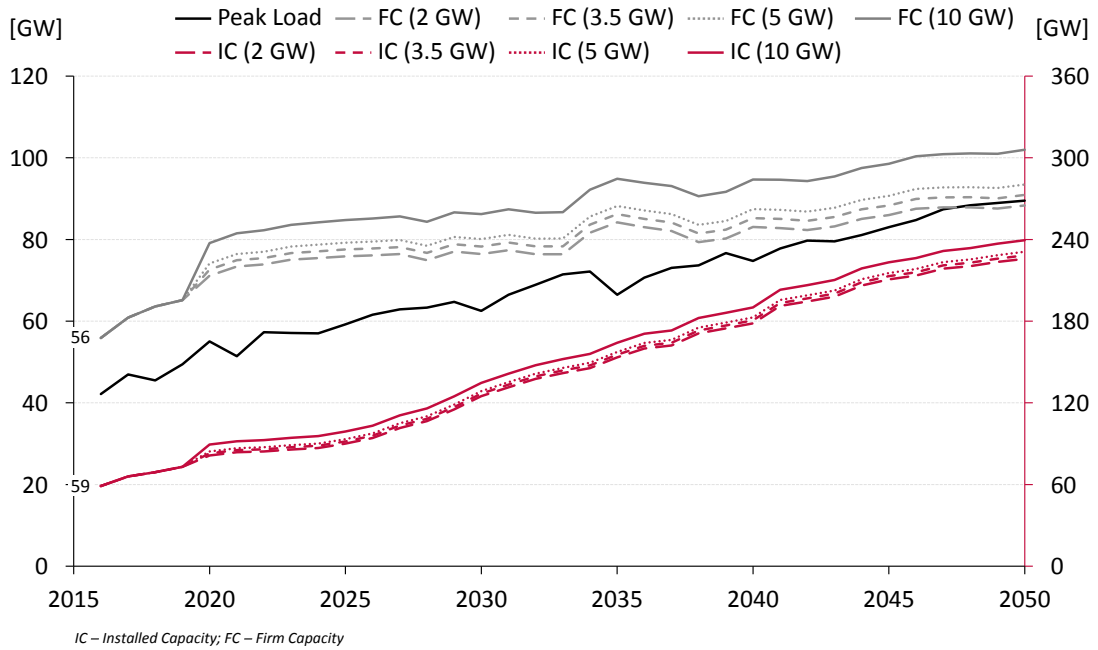
On this, summaries of how the reserve margin evolves from the beginning to end of the study time horizon for the capacity auction and strategic reserve are provided in Figure 5.6 and 5.7 respectively. Although the starting point in 2016 is one in which a relatively high reserve margin is noted, the expected increased demand in the SAPP

quickly erodes this until the capacity auction arrests this around the reference reserve margins set (10-20%). The strategic reserve does not do this but instead establishes a set absolute amount of capacity to set-aside and only use when critically needed (see section 5.2.2). As a result, this allows for a relatively high reserve margin when initially implemented (in 2020). This continues to drop though as the expected demand increases (even though the strategic reserve scales linearly with expected demand). The primary reason for this being that it is optimal for capacity to only invest enough to ensure the supply-demand equilibrium is maintained (including USE and VoLL) but no more than this.

The costs associated with providing system adequacy for the capacity auction and strategic reserve considering demand uncertainty are summarised in Figure 5.8. From this, it is clear that there is a cost implication for increased sustained system adequacy but to differing degrees. Aside from a strategic reserve introducing distortions by purposefully setting aside capacity from the market, only a considerably large strategic reserve size of up to 10 GW could provide a similar level of system adequacy to a capacity auction of the range considered (but would be priced slightly higher). The trend in Figure 5.8(a) for the capacity auction is also clearly moving downwards as (yet saturating) as system adequacy increases. Thus, there is an optimal capacity auction level at which beyond it would start to cost more to incentivise additional capacity even as increased system adequacy is attained. This optimal point seems to be around the 20% reference reserve margin considered in this assessment. This is verified by the previous discussion in section 5.2.2 on existing capacity auctions in a number of jurisdictions globally where this seems to be the typical range where reserve margins settle once capacity auctions are put in place.

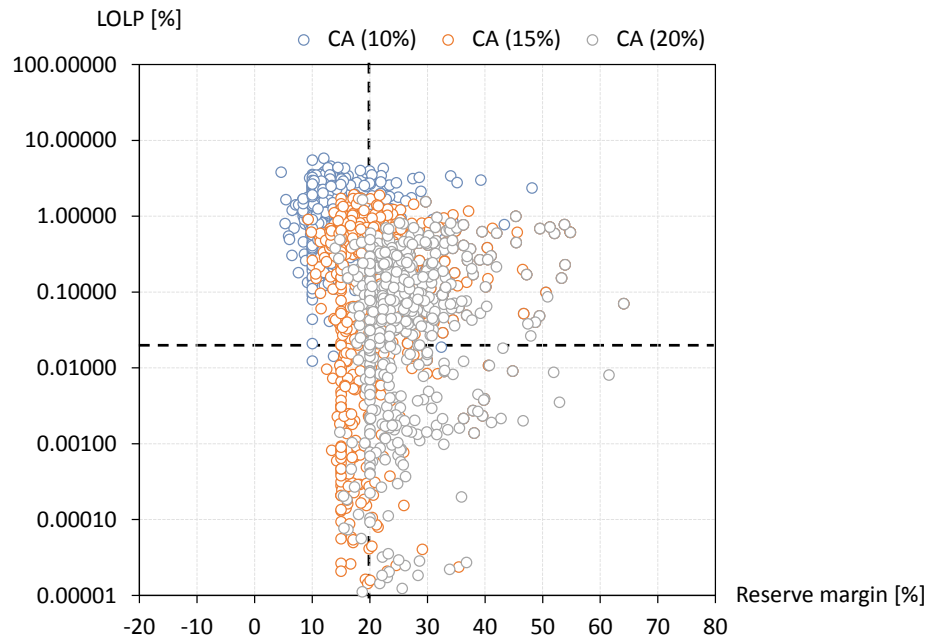


(a) Capacity auction (10-20% reserve margin reference)

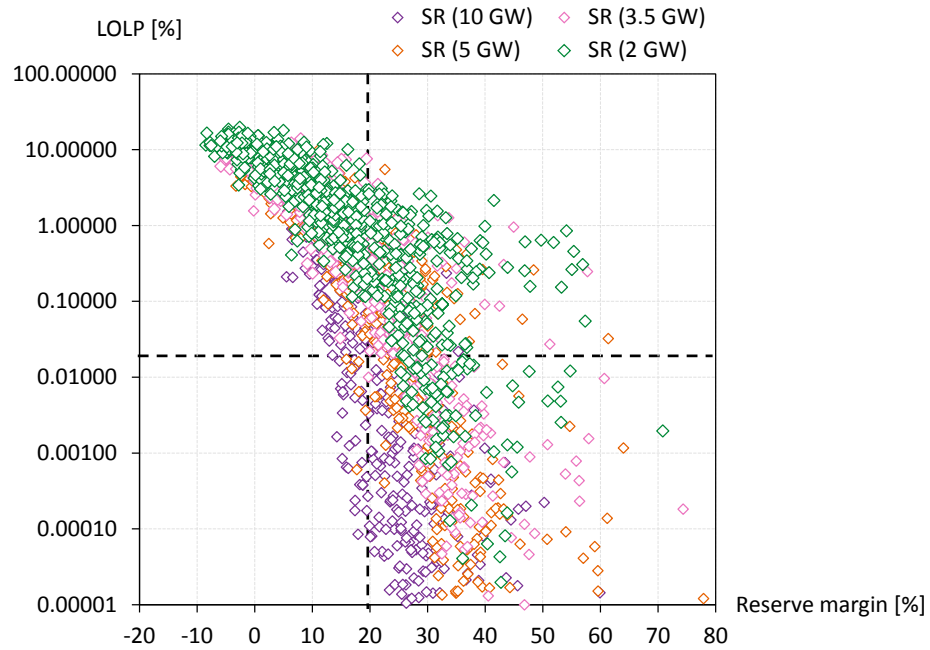


(b) Strategic reserve (2-10 GW absolute initial size)

Figure 5.4: Average expected evolution of supply-demand-balance for the SAPP for two CMs considered 5.4(a) capacity auction and; 5.4(b) strategic reserve. Note the difference in installed capacity (right axis) relative to firm capacity as a result of high-penetrations of variable RES being deployed while other supply (of various technologies) is still deployed



(a) Capacity auction (10-20% reserve margin reference)



(b) Strategic reserve (2-10 GW absolute initial size)

Figure 5.5: Reserve margin vs LOLP revealing how these two key system adequacy parameters relate for the interconnected SAPP for 5.5(a) capacity auction and; 5.5(b) strategic reserve. A reference reserve margin (20%) and LOLP (1 day in 10 years i.e. 0.027%) are included for information

Table 5.4: System adequacy performance for CMs assessed for the interconnected SAPP considering demand uncertainty (based on Figure 5.5)

CM type	$LOLP \leq \text{Ref}^1$ [% of instances]	$P_{res} \leq \text{Ref}^1$ [% of instances]	Combined [% of instances]
Capacity auction	3-54	37-86	0-27
Strategic reserve	12-69	40-77	1-52

¹ Reference for LOLP is 0.027% (1 day in 10 years); Reference for reserve margin is 20%

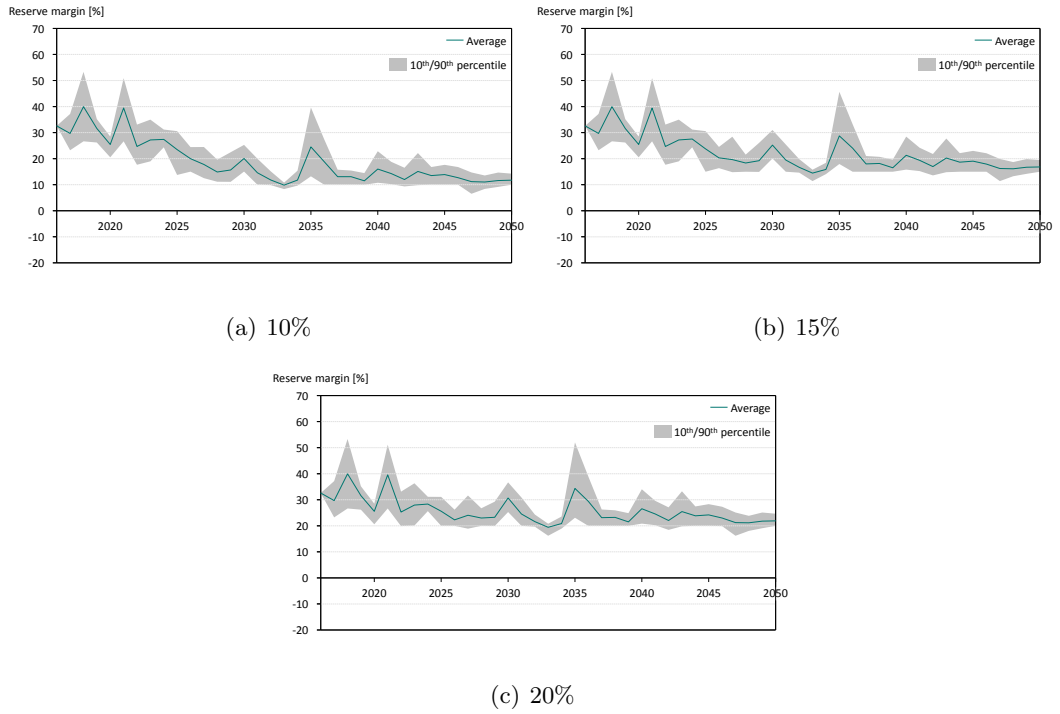


Figure 5.6: Realised reserve margins for a range of capacity auctions in SAPP (10-20% reference reserve margins)

5. FRAMEWORK TO ASSESS CAPACITY MECHANISMS (CMS) IN THE SAPP

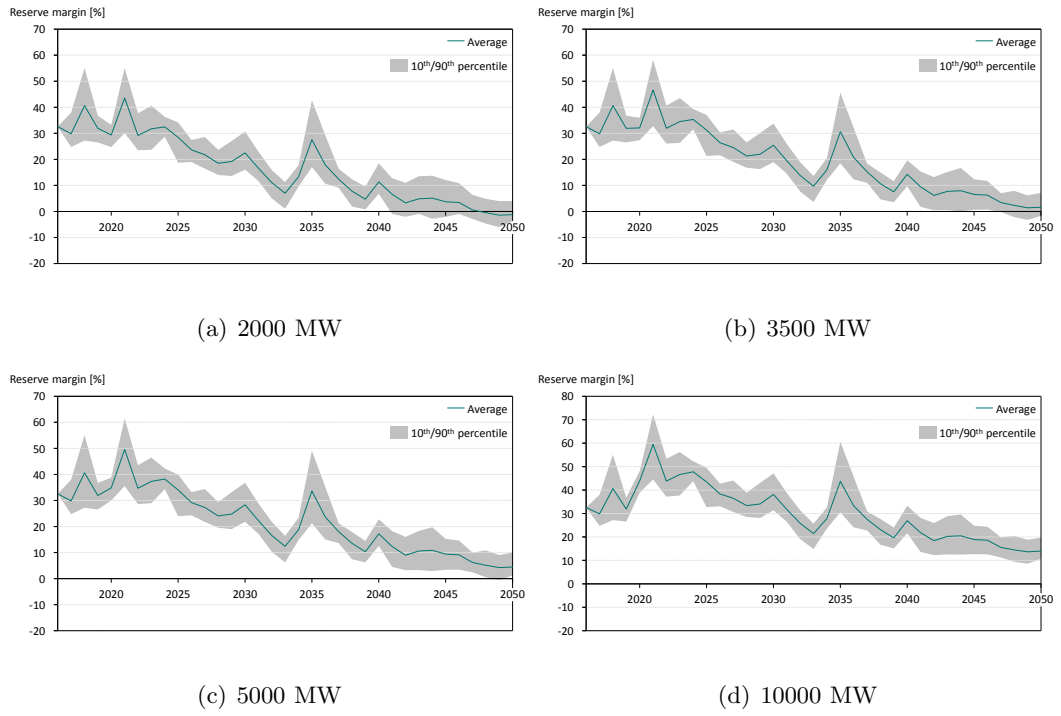
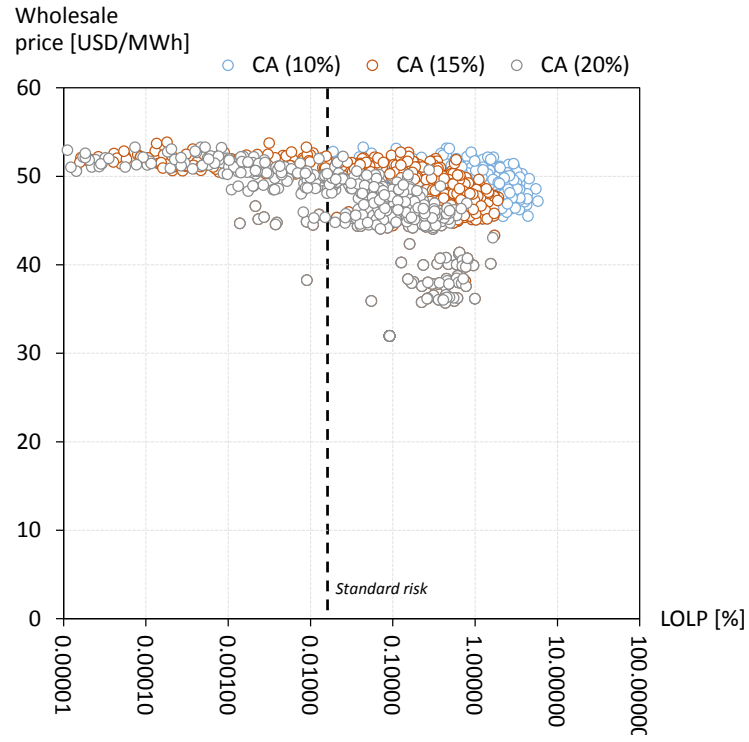
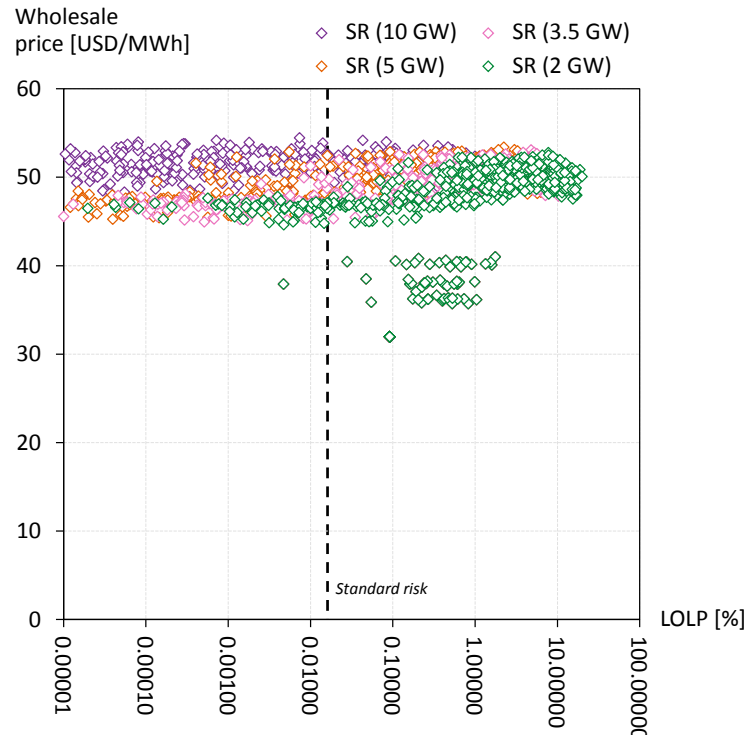


Figure 5.7: Realised reserve margins for a range of strategic reserves in SAPP (2000-10000 MW)



(a) Capacity auction



(b) Strategic reserve

Figure 5.8: Wholesale annual price vs LOLP for CMs assessed in the interconnected SAPP for 5.8(a) capacity auction and; 5.8(b) strategic reserve

Investment in supply capacity technologies is relatively consistent whether a capacity auction or strategic reserve is considered. The resulting energy mix from capacity auction outcomes is provided in Figure 5.9 for the two extremes tested (10-20%). Similar is provided for strategic reserve in Figure 5.10 for the range considered. Easily observable and understandable differences is the additional capacity as part of the capacity auction when higher reference reserve margin levels are considered i.e. 20% vs 10%. The strategic reserves sets aside the additional capacity but this has very minimal impact on the overall energy mix as it is used very rarely and only for very short durations to avoid USE. When additional capacity as part of a capacity auction is cleared, this is mostly driven by relatively cheap to build capacity like OCGTs and Combined-Cycle Gas Turbines (CCGTs). The strategic reserve also sets aside similar types of capacity but also considers capacity that is due to decommission as an option for strategic reserve provision.

Although not necessarily a focus but nonetheless an important and interesting natural outcome is the deployment of significant amounts of variable RES (solar PV and wind) through the time horizon. As mentioned, this is largely insensitive to the CM considered, demand or hydrological uncertainty considered. It is also interesting to note that the majority of the deployment of variable RESs is in South Africa while the rest of the interconnected SAPP still deploys solar PV (and some wind capacity) but most new-entrant capacity is hydro-based generation capacity (as expected). This is combined with natural gas and distillate fuelled OCGTs and CCGTs. On this, the deployment of this relatively cheap to build capacity to ensure system adequacy is driven naturally as a result of significant levels of variable RES mentioned and provides what is typically referred to as *back-up* capacity to ensure system adequacy. This is already starting to be seen in a number of jurisdictions globally including those in the USA like PJM [119, 210], the UK [196, 198, 211] Ireland [212] and Australia [213].

Finally, it is important to introduce an appreciation of a key limitation of the model-based approach presented. That is, it does not capture agent-based and game-theoretic behaviour. More specifically, capacity suppliers' bidding strategies as well as exercising of market power. This may become important considering South Africa's market dominance. This could be considered in further research and has been demonstrated in some other jurisdictions and model-based simulation approaches [117, 214–217].

5. FRAMEWORK TO ASSESS CAPACITY MECHANISMS (CMS) IN THE SAPP

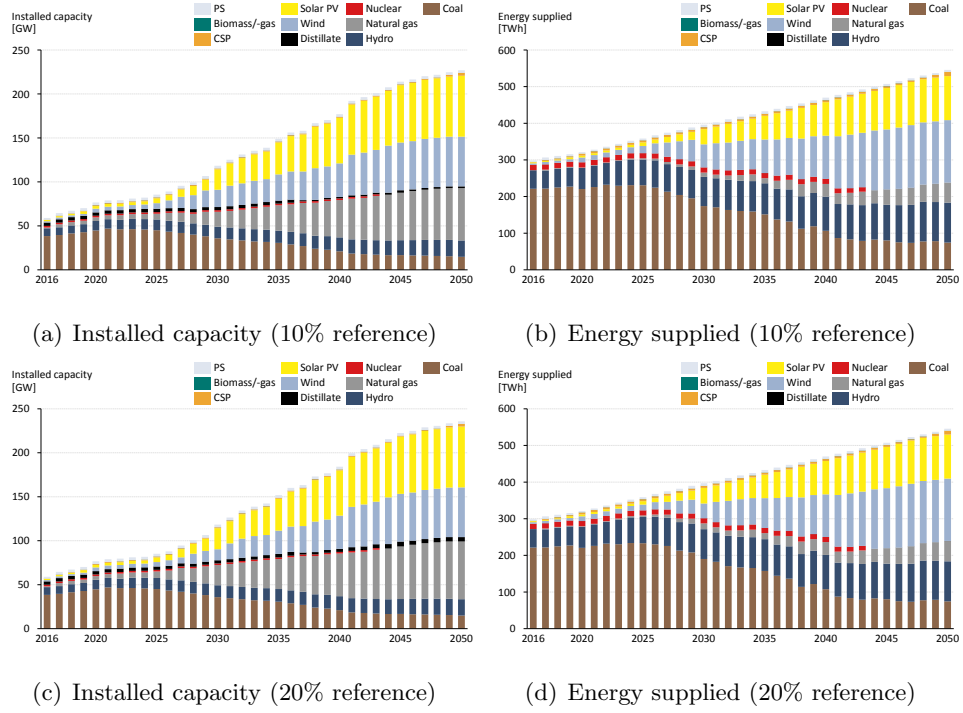


Figure 5.9: Resulting energy mix from applying a capacity auction in the SAPP revealing only slightly different new capacity and energy mixes

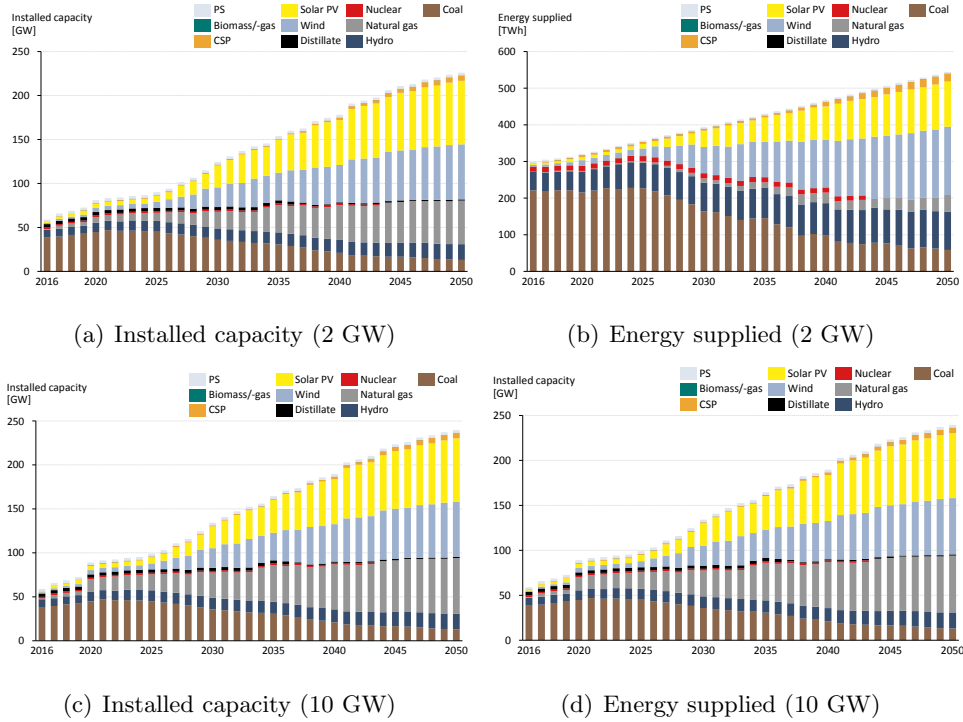


Figure 5.10: Resulting energy mix from applying a strategic reserve in the SAPP revealing only additional capacity as expected (no change in energy mix)

5.4 Proposed CM design for the SAPP

Using the design elements presented in section 2.4.2, the screening in section 5.3.1 and quantitative assessments from section 5.3.2 - a CM for the SAPP is proposed and characterised in this section. This is the final step in the CM framework introduced in Figure 5.1 and is intended to provide an indication of the design element choices available for the SAPP when considering the introduction of the proposed CM.

5.4.1 Definition of the adequacy product

Discussion on firm energy

Although the capacity product (for capacity adequacy) has been extensively discussed as part of this research, this concept can be clearly translated to providing an annual firm energy product (for energy adequacy) with the intention of ensuring system adequacy in power systems that are energy-constrained i.e. hydro-dominated power systems. It can also just as easily still be appreciated that this does not mean that ensuring system adequacy via sufficient capacity being available to meet peak demand does not also exist simultaneously. All that it means is that the focus of the adequacy product shifts from that of ensuring sufficient capacity to that of ensuring sufficient energy.

As already demonstrated clearly in section 4.2, when excluding South Africa, the SAPP is currently a hydro-dominated power system and could thus exhibit notable risks as a result of variations in temporal and spatial rainfall patterns in future as a result of climate change impacts and resulting hydro-based generation capacity constraints [218, 219]. This has been more clearly demonstrated recently in the SADC region where a recent period of notably decreased rainfall patterns occurred (beyond the typical well-known inter-annual and inter-decadal variations) and resulted in limited production from hydro-based generation capacity in the SADC region [220]. Similar experiences have also been noted in other developing countries like Colombia where hydro-based generation capacity also dominates ($\approx 80\%$) [94] and Brazil ($\approx 70\%$) [221].

With this in mind, the adequacy product that characterises the proposed CM should be inclusive of the fact that the SAPP region can be capacity constrained and energy constrained simultaneously. Thus, the adequacy product should effectively

incentivise an adequate combination of capacity (for capacity adequacy) and firm annual energy (for energy adequacy). As a result, the CM should incentivise the availability of capacity when needed to meet peak demand whilst also incentivising appropriate hydro-reservoir management to ensure sufficient energy when needed considering inherent uncertainty associated with hydro-inflows.

CM for the SAPP

The preferred CM would be that of annual forward-looking capacity auctions or capacity obligations (*ex-post*). Strategic reserves could also be considered favourable but the lack of transparency would not allow for the transparent valuation of adequacy in the region. The familiarity in the region with administratively determined centralised procurement of supply capacity would also make either capacity auctions or capacity obligations (*ex-post*) CM types preferable. The implicit regional approach to ensuring system adequacy would result in capacity sharing that then promotes regional electricity trade and integration.

The critical period indicator (when capacity needs to be available) may change over time as the energy mix in the region changes. As a result, the appropriate indicator of scarcity for the CM may also need to change in future. With capacity auctions, a very transparent forward-looking signal for system adequacy is provided. The price at which the capacity auction clears explicitly reveals the value of capacity. In this regard, capacity auctions may be more preferable relative to capacity obligations (*ex-post*). Capacity obligations (*ex-post*) could also run auctions but these would not necessarily need to be public and thus would not be as transparent as a capacity auction.

In Brazil, firm energy auctions are run annually driven by obligations to be met by LSEs where one auction is run to meet existing energy (to be delivered in the next year) and one auction is run to meet new energy (to be delivered in 3-5 years) [222]. Thus, this is a forward looking capacity obligation (*ex-ante*) CM type as previously discussed but is applied specifically to provide system adequacy via firm energy commitments ¹⁵. Similarly, in Colombia, a forward energy auction is adopted and run 3-4 years before expected delivery [93, 94].

A representative capacity auction supply-demand curve equilibrium is shown in

¹⁵Suppliers are asked to bid annual price/quantity pairs and cleared based on total energy demand declared by LSEs in a classical supply-demand curve intersection.

Figure 5.11. The points at which the capacity auction supply- and demand-curves intersect provide the amount of capacity or firm energy (CP) and the clearing price (PC) that would be paid to system adequacy providers. The capacity auction demand-curve is parametrised to demonstrate how the amount of capacity (or firm energy) would change depending on the pre-defined demand for capacity or firm energy needed. The knee-point of the demand curve is P_{res} and is the amount of capacity (or firm energy) that would at least be needed to ensure a pre-defined system adequacy (informed by a LOLP standard, a reserve margin or absolute amount of capacity or firm energy). The maximum amount paid would be the CONE multiplied by a factor (a) to incentivise capacity investment¹⁶. The downward sloping demand for capacity (or firm energy) is then defined by a multiple (b) of the previously mentioned P_{res} to allow for some level of additional capacity (or firm energy) to be procured but with decreasing price paid i.e. capacity (or firm energy) becomes less valuable as more is cleared.

Using some representative choices for these administratively set parameters as shown in Table 5.5, the supply-demand curve equilibrium of a prospective capacity auction for the SAPP is shown in Figure 5.12. In Figure 5.12(a), only existing capacity in the SAPP is assumed. The equilibrium reached is one in which 58.3 GW of capacity is cleared at a price of 150 USD/kW-yr (the maximum possible price). The combination of this maximum capacity clearing price being reached and only 58.3 GW of capacity clearing (relative to a peak demand of 52.8 GW i.e. 10.4% reserve margin) would then incentivise new capacity to be built with lower capacity costs. This is represented in Figure 5.12(b) where a notional 6.5 GW of capacity bids into the capacity auction at 100 USD/kW-yr. This shifts the supply curve to the right and results in a new supply-demand equilibrium where 65.1 GW of capacity is cleared (reserve margin of 23.3%) with a resulting price of 118 USD/kW-yr i.e. additional capacity is cleared even beyond P_{res} but at a lower clearing price. Finally, with even further new notional new capacity bid into the capacity auction (8.5 GW), the supply-curve is further pushed to the right. This results in some of the new capacity not being cleared, the new supply-demand equilibrium being 65.5 GW (reserve margin of 24.1%) and a lower clearing price of 100 USD/kW-yr i.e. more capacity is cleared but this capacity is even less valuable.

A similar effect demonstrated on supply above would be noted if a lower demand is assumed (either as a result of a lower demand forecast or a lower system adequacy requirement), the demand-curve shifts to the left (as demonstrated in Figure 5.11)

¹⁶ Typically based on a reference capacity provider like a regionally referenced or country specific OCGT.

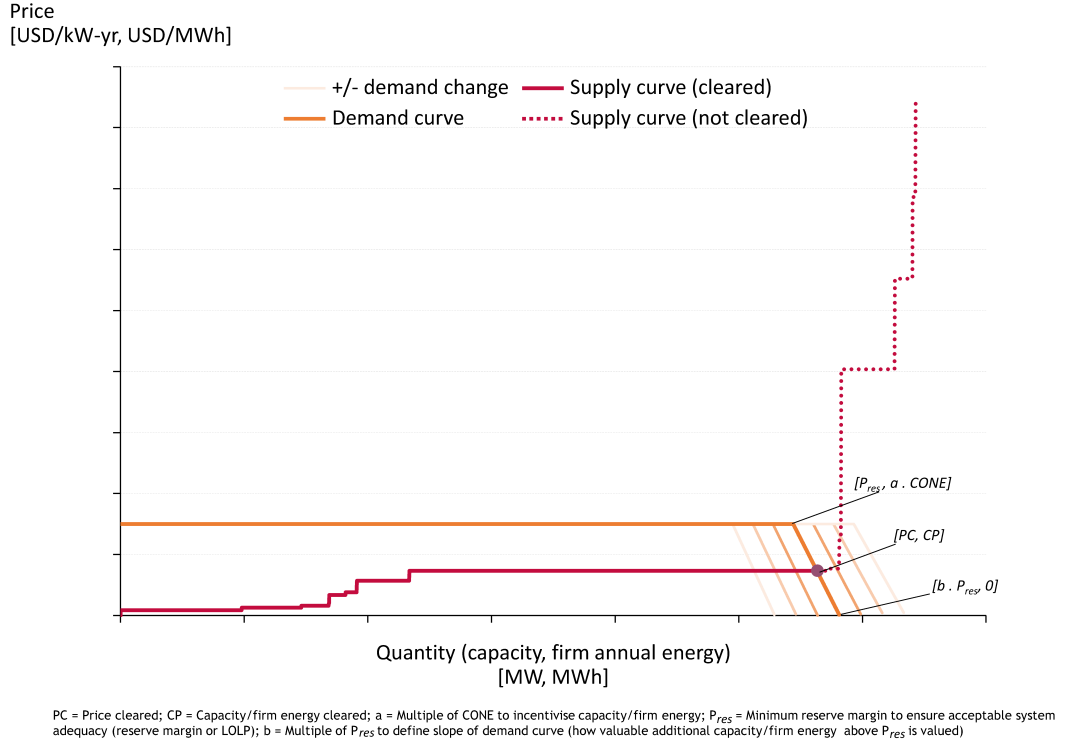


Figure 5.11: Demonstration of a capacity auction supply-demand curve equilibrium as part of the proposed capacity auction for SAPP. The quantity being procured as part of the capacity auction could be capacity to meet peak demand or firm energy (in the case of hydro-dominated systems like in the SAPP). A demonstration of demand uncertainty (+/- demand change) is also shown.

and would also result in less capacity being procured as well as a possibly lower clearing price.

In the SAPP, existing cheap hydro-based capacity in the region (with very low FOM) would make up the first ≈ 10 GW of capacity that would be offered by suppliers while existing OCGTs, engines and some coal supply would provide an additional ≈ 10 GW following the large South African coal fleet (adds ≈ 35 GW). More expensive capacity providers thereafter would include biomass, Concentrating Solar Power (CSP), new coal, new hydro and new nuclear capacity.

It can also be appreciated that the capacity auction described and presented here could also be made locational (as is the case, for example, in PJM [190, 191]). The capacity auction would then most likely become one in which firm energy is procured in countries that are hydro-dominated whilst capacity is procured in others which are not. This is not necessarily explored further as part of this research but is

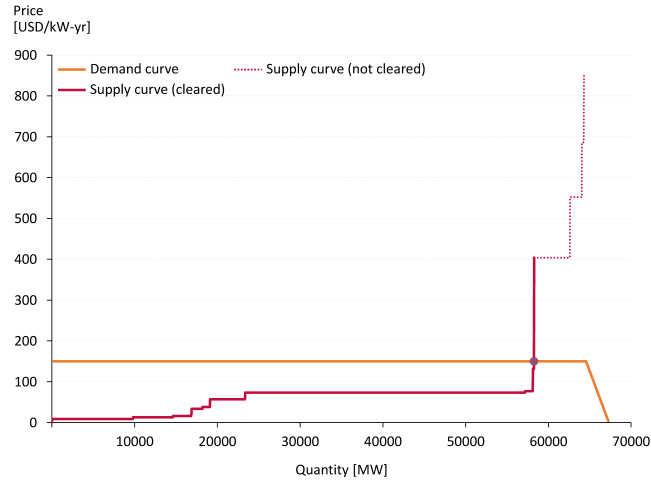
recommended for further research (see section 6.3).

Due to the high level of uncertainty associated with the demand forecast in the SAPP region, the downward gradient of the capacity demand curve should generally be made gradual to ensure stable revenues for more adequacy providers (when demand is over-estimated or under-estimated). The exact gradient of the capacity demand curve as well as the upper-limit thereof will need to be defined with detailed investigations in future but the suggested (see section 6.3).

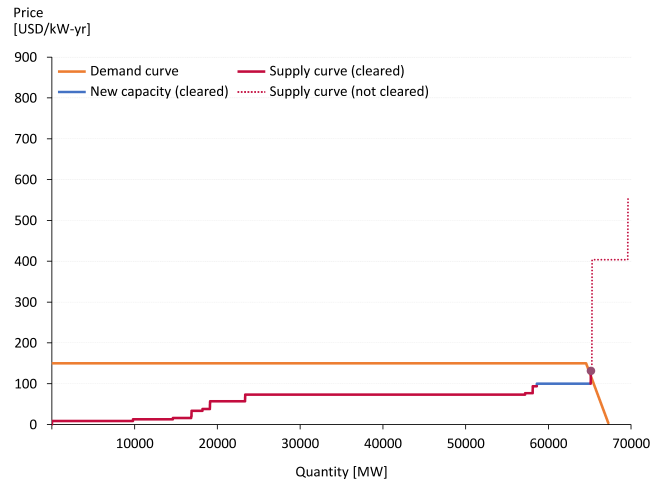
Table 5.5: Representative parameters for SAPP capacity auction run (capacity is the focus of this representative example (not firm energy))

Parameter	Unit	Setting
Peak demand ¹	$[GW]$	52.8
P_{res}	$[GW]$	63.4
$CONE$	$[USD/kW-yr]$	100
a	$[p.u.]$	1.5
b	$[p.u.]$	1.05

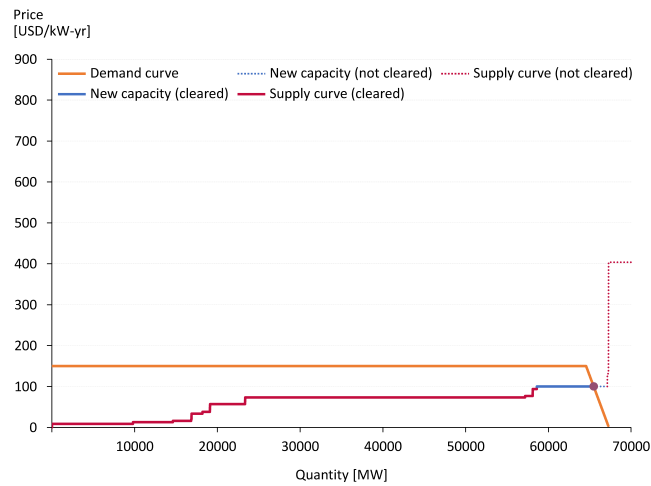
¹ *Interconnected SAPP only*



(a) Existing supply capacity)



(b) Existing and new incentivised supply capacity)



(c) Existing and further new incentivised supply capacity

Figure 5.12: SAPP capacity auction supply-demand curves 5.12(a) with existing SAPP capacity, 5.12(b) with representative newly incentivised capacity and 5.12(c) with even further new incentivised supply capacity (some not cleared).

The ideal indicator of scarcity would be the competitive wholesale electricity market price. At this stage, for the SAPP, it is unlikely that this will be indicated by the existing short-term energy markets (FPM-M, FPM-W, DAM, IDM) as a result of the lack of liquidity and trade volumes. However, considering that the DAM has been continually increasing in liquidity and is becoming more of a transparent reference price to which levels of scarcity could be indicated, it may prove useful to consider this as a reference for scarcity in future. More particularly, it may be that reliability options could be considered at this stage as a CM of choice. However, this would be highly dependant on very different domestic electricity market structures in the region (unbundling and market liberalisation would need to be pursued). With a transparent outlook provided for increased competitive electricity trade by market participants, the additional trade on the DAM to establish further liquidity and capacity investment linked to DAM price levels would also enable long-term sustained system adequacy. Of course, with reliability options, a natural capacity equilibrium will be reached where no further capacity will be invested in as DAM prices reduce to the point where it would not be viable to invest further.

The determination of the system adequacy requirement should be based on a pre-defined methodology agreed to by all market participants. An initial assessment of this is offered as part of this research where either LOLP or reserve margin could be used as the relevant metrics for defining system adequacy (section 5.3.2). In addition, a pre-defined methodology to determine the capacity contribution from all possible capacity providers (supply-side and demand-side) should also be agreed upon. The central authority tasked with the responsibility for calculating these parameters would also need to be agreed upon. In the SAPP, it is proposed that this is RERA, as an appointed institution representing the regulators of each SAPP country. Considering the existing capabilities and mandate of the SAPP Co-Ordination Centre as the regional MO, it should be the implementing agency for running a capacity auction for the SAPP.

5.4.2 Targeting

With considerably large as well as considerably small market participants in the SAPP (see section 2.5.3), a centralised process where the principles of stakeholder equity can be promoted would work best. This would also avoid market dominance and possible gaming as market monitoring could be more easily managed by a central authority. Thus, a capacity auction would be preferred, albeit with a locational component considering existing interconnector limitations in the region.

A harmonised CM across all countries' power systems in the SAPP would level the playing field for all adequacy providers in all countries. This is an important consideration in light of what the EU experience. A range of electricity market environments exist with country-specific proposals and implementations of CMs resulting in a lack of harmonisation [223]. Any proposed CM in the EU needs to be compliant with State Aid Guidelines where aid is only provided for capacity availability [224]. An important consideration for the SAPP is whether during times of scarcity a resource outside a particular country will provide the necessary capacity (as part of a CM) or will the country cut exports to deal with scarcity domestically. This has not yet been agreed upon or finalised in the EU but proposals have been made [225]. In any case, this would implicitly mean that domestic resources would likely be seen to be more available under scarcity conditions while resources via interconnectors would need to be appropriately derated. This is currently the case in the UK capacity auction [226].

A technology agnostic market-wide capacity auction is preferred that values adequacy contributions based on pre-defined approaches to determining the capacity contribution that an adequacy provider is capable of providing when needed e.g. how much of a coal-fired power plant, natural gas OCGT, hydro-based power plant, wind or DSR provider's installed capacity can be provided relative to their installed capacity. This should be pre-determined and verified by the relevant central authority before an adequacy provider can bid into the capacity auction.

The buyers of capacity will be the individual LSEs of each country i.e. the national PUs. It is proposed that the SAPP Co-Ordination Centre as the regional MO co-ordinate the capacity auction on the basis of information shared with it from the SOs (or relevant departments) of each national PU. If large customers are sufficiently licensed to trade internationally by their domestic regulatory frameworks, then these large customers would also provide the necessary information to the SAPPs Co-Ordination Centre to enable capacity auctions.

5.4.3 Lead-time

There is an important balance to be obtained in the lead-time chosen. A lead-time that is too short will exclude certain new-build technologies from being included in the capacity auction. A lead-time that is too long risks over-estimating or under-estimating demand. It could also be possible to mitigate this risk by defining a range of capacity auctions of differing volumes depending on the supply technologies

available in the SAPP and level of demand uncertainty.

A summary of the typical lead-times of predominant technologies considered as candidates in the SAPP region are summarised in Table 5.6 (based on [227]). As can be seen, there is a distinct grouping of short lead-time technologies like OCGTs (or engines), CCGTs (or engines), DSR, biomass/gas, small hydro, solar PV and wind. Other long lead-time technologies would include coal, nuclear and large hydro.

As shown previously, the only long lead-time technology that is included in the outcomes of the quantitative assessment is large hydro. Thus, specific auctions with lead-times in the order of 8-10 years could be considered for this technology if deemed economically efficient (and accordingly risk-adjusted for expected demand). Otherwise, a capacity auction with a lead-time in the order of 3-4 years is proposed. Of course, the capacity auction should be inherently technology agnostic but if a particular lead-time is chosen this may preclude certain technologies from participating.

Table 5.6: Typical lead-times for predominant technologies considered in the SAPP region

Technology	Typical lead-time
	[years]
Hydro (small, < 250 MW)	2 - 4
Hydro (large, > 250 MW)	6 - 10
Coal (small, < 250 MW)	4 - 6
Coal (large, > 250 MW)	8 - 10
Nuclear	8 - 10
OCGT (or engines)	2
CCGT (or engines)	3
Solar PV	2
Wind	3 - 4
Biomass	3 - 5
Biogas	1 - 2
DSR	1

5.4.4 Duration

Once the lead-time ends, the responsibility for a capacity provider to be available to provide capacity begins. The duration of this contract is typically differentiated between new-entrants and existing capacity.

Due to the range of technologies that would likely be available in the SAPP, it is proposed that when capacity is pre-qualified by the central authority, that it specifies the contract duration it would prefer. On this basis and on the bids provided by capacity providers, the central authority would clear the capacity auction as normal but at the next iteration include capacity that was cleared previously with its associated contract durations. This would be similar to what is already applied in the UK [196].

5.4.5 Performance incentives and penalties

Although a detailed design of the proposed CM will be required before penalties and performance incentives can be well-defined, it should be a matter of principle that market monitoring with performance and penalties strongly enforced by the relevant institutions(s) be defined upfront e.g. SAPP Co-Ordination Centre as the existing regional MO in partnership with an institution like RERA as a central authority.

Any penalties applied for non-performance should be applied with a reasonable understanding of the capabilities of the capacity provider i.e. pre-qualifications should allow for a reasonable understanding of the capabilities of a capacity provider beforehand (firm capacity and/or firm-energy). On the other hand, cumulative penalties and the limitation thereof should be considered to ensure a capacity provider is sufficiently penalised but not so much so that it removes their capability to operate and provide capacity in future. Finally, a good approach to penalising non-performance is that of derating a capacity provider following non-performance. This derating should then be used for future capacity auctions.

5.4.6 Secondary design elements

The proposed CM should leverage on the already existing MTP which SAPP market participants are already familiar with. This will also reduce the costs of implementation and assist in obtaining stakeholder participation. This will also allow

for increased transparency. In this regard, transparent stakeholder consultation (including more than just market participants) and a phasing period is critical to ensure any unintended consequences of the CM are minimised to ease correctability. A good example of this is the current EOM applied in Alberta that is transitioning to a CM (from 2017-2021) [228].

5.4.7 Summary

Table 5.7 provides a brief summary of the proposed CM design for the SAPP based on the previous design elements provided.

Table 5.7: Summary of proposed CM for the SAPP

Design element	Description
<i>Adequacy product (definition)</i>	- Medium-term: Annual forward-looking capacity auction (locationally differentiated). - System adequacy: Pre-defined agreed upon methodology (forward looking LOLP/reserve margin). - Capacity and firm energy need (hydro-dominated SAPP when excluding South Africa). - Critical period indicator may change as the energy mix changes (transparent forward-looking signal for adequacy). - Long-term (possible): Reliability options based on competitive DAM wholesale electricity market price.
<i>Targeting</i>	- Technology agnostic market-wide (pre-determined and verified by central authority). - Avoid market dominance with a centralised process (large/small providers). - Market monitoring managed by a central authority. - Harmonised CM across all countries (level playing field). - Capacity sharing with derating across interconnectors. - Buyers: Individual LSEs of each country via SAPP Co-Ordination Centre.
<i>Lead-time</i>	- Not too short (exclude technologies), not too long (demand uncertainty risk). - Large hydro: 8-10 years. - All others: 3-4 years.
<i>Duration</i>	- Option to differentiate between existing/new entrants. - Otherwise, capacity provider specifies duration (once pre-qualified).
<i>Performance incentives and penalties</i>	- Principles: Market monitoring with performance/penalties strongly enforced. - Penalties based on known capabilities (firm capacity/firm energy). - Derate based on poor previous performance.
<i>Secondary design elements</i>	- Leverage existing MTP (reduce implementation costs, increase participation). - Transparent stakeholder consultation. - Phasing (avoid unintended consequences).

Chapter 6

Conclusions and further research

6.1 Conclusions

A Capacity Mechanism (CM) for the Southern African Power Pool (SAPP) region has been proposed and designed with the objective of ensuring sustained system adequacy. As part of this research contribution, a framework to consider CMs is developed combining a screening assessment, quantitative (model-based) analysis of more favourable CM options, Medium-term (MT) system adequacy assessment and resulting proposed CM design. The framework provided can also be generalised and applied to other jurisdictions where CMs are under consideration.

The research has been primarily driven by a distinct need to better appreciate demand uncertainty and shift away from opaque long-term bilateral contracting arrangements as well as existing domestic regulatory frameworks driven by administrative and bureaucratic processes to procuring capacity in the region. It has been shown that historically these approaches have not provided sufficient system adequacy. As a result, this research is an attempt at removing or minimising the risks, delays and cost implications of these approaches.

The concept of a CM being introduced into the SAPP region has not yet appeared in the literature and with the framework provided as well as the proposed simple, transparent, robust and implementable CM this research provides a valuable contribution. With the application of the developed framework, it has been demonstrated that a regional CM which transparently and explicitly values capacity can ensure sustained system adequacy. A forward-looking annual capacity auction that is locationally disaggregated, supplied by all possible supply-side resources with all

feasible SAPP market participants is proposed to fulfil this objective. The CM should be technology agnostic and account for the dual requirement for firm capacity as well as firm energy owing to hydro-dominated systems in some jurisdictions in the SAPP region. It should consider a lead-time of 3-4 years for all technologies with the possibility of long-term auctions for large hydro-based capacity. Strict market monitoring and adherence to performance incentives and penalties will need to be ensured to avoid possible exercising of market power considering the existing dominant size of the South African power system. Notably, principles surrounding cross-border participation need to be strictly monitored and adhered to while taking the regional nature of the proposed CM into consideration. This is of particular importance in times of domestic shortages to promote regional integration and stakeholder equity. Another important outcome of this research is that although a particular CM is proposed, it does not necessarily perform best on all performance criteria considered. As detailed in the research, other CMs do perform better on some performance criteria but the proposed CM performs best overall.

The proposed utilisation of the existing SAPP Market Trading Platform (MTP) can also provide a platform that incentivises participation by market participants to incentivise capacity investment. The market-based mechanism inclusive of all existing and future market participants ensures necessary transparency. The appropriately mandated institution(s) to run the capacity auctions would include the SAPP Co-Ordination Centre as the existing regional Market Operator (MO) as well as a regional regulatory body like the Regional Electricity Regulators Association (RERA) with sufficient mandate.

The impact of high levels of variable Renewable Energy Sources (RESs) (solar PV and wind) have been found to be more focussed on South Africa considering its dominant size whilst significant available hydro resources in the rest of the SAPP region could be deployed further for ensuring system adequacy. With most variable RES being deployed in South Africa, there is a notable shift from short-run variable costs (based on thermal fuels) to up-front capital costs for new investments in future. Combined with the relatively small contribution of variable RES to system adequacy, this further drives the need for an explicit valuation of capacity in the region and more generally for CMs to be considered as explicit adequacy products to ensure system adequacy in future.

Although not necessarily a focus, a further valuable contribution is made in the form of a public domain SAPP power system dataset developed as part of this research with sufficient detail to be used in power sector operations and planning research

efforts by future researchers and practitioners.

This research lays the foundation into a research domain that has not been extensively pursued in the region and is desperately needed. It addressed a specific aspect of the research domain where long-term system adequacy can be enabled by the application of an appropriately designed CM.

Further research into a range of topics should be pursued including cross-border effects of CMs, political impacts on CMs, constrained access to capital and the associated cost of capital, investigations into increased demand-side participation (as well as stationary storage), stochastic hydrological considerations (and hydro-thermal co-ordination), further investigations into high penetration zero-marginal cost variable RES scenarios, further regional energy market integration and related market structures and an assessment of acceptability and stakeholder equity when implementing CMs in the SAPP.

6.2 Addressing the hypothesis and research questions

Addressing the hypothesis and research questions directly reveals that this research has shown that a designed and proposed regional CM that is simple, transparent, robust and implementable in the form of a forward-looking annual capacity auction that is locationally disaggregated can ensure system adequacy in the SAPP in future. It has defined the need for a CM based on historical inadequacy in the region and requirement to shift away from the existing opaque domestic administrative, bureaucratic processes and contracting arrangements to procuring capacity. In addition, the framework developed as part of this research can be generalised and applied to other jurisdictions considering CMs.

Some distinct details of the CM include the requirement to be technology agnostic, account for the need for system adequacy via capacity investment and have lead-times in the order of 3-4 years (with the possibility of longer lead-times for hydro-based capacity). With market power being a possible concern, market monitoring and adherence to performance incentives and penalties is critical and should be overseen by sufficiently mandated institutions.

Discussion and review of the existing literature as it relates to annual firm-energy requirements (in hydro-dominated power systems) has been provided. A firm-energy auction that is analogous to the classical capacity auction CM (for hydro-dominated

systems) is worth noting and is included as part of recommendations for further research. Conceptually, the capacity auction CM proposed for the SAPP would then be a slightly slightly modified version of a pure capacity auction as it would include an auction or set of auctions for two distinct products (one for firm annual energy in hydro-dominated jurisdictions and one for capacity in others in the SAPP).

The use of the existing SAPP MTP to implement the annual capacity auction would be a preferred option considering familiarity by market participants which will then also inherently incentivise increased participation. Integration of the CM with existing competitive markets on the SAPP would not necessarily need to be explicit at this stage and could be implemented independently. However, if increased levels of competitive trade occurs, the use of an alternative CM type (reliability options) could be considered. The direct link between price-spikes on these competitive markets implemented on the MTP and the need for capacity would be an ideal indicator for scarcity and thus incentivise capacity investment.

As mentioned, variable RESs will impact South Africa more than the rest of the SAPP region as a result of wind and solar resources in South Africa as well as significant hydro resources in the rest of the region. Combining the derated contribution from variable RESs to system adequacy with the shift from high variable costs (driven by thermal fuels) to up-front capital costs for capacity and energy requirements, there will be a distinct need to value capacity more explicitly in future and thus a requirement for an adequacy product like the proposed CM to ensure system adequacy.

6.3 Recommendations for further research

Cross border effects of CMs

There is an opportunity to further explore the cross-border effects of CMs in the SAPP considering existing low-levels of interconnectivity. Although network infrastructure was not necessarily a focus of this research (transmission infrastructure in particular), improved interconnectivity in the SAPP region could have a noticeable impact on the generation mix for the region but will not necessarily change the need for a CM. What would be an important topic for future research would be the harmonisation of CMs between various SAPP jurisdictions if different CMs were adopted. A number of researchers have considered this recently but in very

well interconnected power systems [40, 117, 229–231] with a particular focus on Europe [15, 230, 232–234] and the USA [57]. If individual jurisdictions opt for different CMs as opposed to an integrated CM across the SAPP region, there will be a distinct need to assess the effects of this. This has been an area of particular interest in the EU considering the numerous market zones that exist, interconnected nature of the region and objectives of the EU internal energy market model [57, 230, 235, 236]. A secondary component of research in this direction could include a measure of the explicit locational value of capacity. This could be based on an assessment of the value of capacity in the region with existing interconnectors in the SAPP relative to one in which completely unconstrained networks are considered.

Political impacts on CMs

A possible multi-disciplinary research topic could include non-technical aspects of CM implementation in the SAPP e.g. the inclusion of political considerations not necessarily considered implicitly as part of this research. This was pursued to some extent as part of a capacity expansion planning exercise in [237] but has not been undertaken specifically for CMs in any jurisdiction based on the reviewed literature. More specifically, a proposed topic could include an extension of the screening approach taken in this research to include an interview and/or survey-based canvassing of key decision makers, market participants as well as broader stakeholders in the region.

Increased detail of developed SAPP dataset

The model used in this research is based on the dataset developed and it is purposefully simplified and aggregated in order to focus on the research hypothesis and establish key conclusions and implications for long-term system adequacy in the SAPP region. Future research could consider a more detailed model including more granular representation of supply capacity, network expansion opportunities as well as intra-country network constraints. As an example, integrated generation-transmission expansion could be considered for the possibility of SAPP Non-Operating Members (NPs) becoming interconnected in future and existing limited transmission capacity expanded realistically to further increase electricity trade and promote regional adequacy. Further detailed investigations into the possibility of increased trading volumes on competitive wholesale electricity markets in the SAPP within the context of CMs could also prove valuable (specifically if reliability options are considered).

Hydro-thermal co-ordination and the impact on CMs

The risk associated with hydro-based power systems where energy constraints present themselves based on hydrological conditions has been considered at a high-level as part of this research. However, detailed stochastic approaches to determine the firm energy contributions of hydro capacity within the SAPP were not considered. This could be a worthwhile research contribution and is highly recommended.

Impacts of high variable RES penetration and new storage

High variable RES penetration scenarios were not the focus of this research but implicitly an outcome considering their existing and expected economic characteristics. Combined with the fast-moving technology cost declines and performance improvements seen in stationary storage (other than pumped storage and hydro reservoirs) [238–244]. This could be a focus of future research. The likely proliferation of variable RES into the SAPP in future will necessitate the inclusion of flexibility into regional power markets (this could be comprised of storage) including the CM or associated markets for both existing and potential future generation capacity. Authors who have recently considered this are numerous with a number of approaches proposed [108, 109, 111, 245–249]. In addition, the deployment of storage in the region (whether utility-scale or distributed) will become an important dimension to consider as it relates to the provision of system adequacy. This was not a focus of this research but an interesting future research topic where it was shown in [250] for the Dutch power system how storage deployment would decrease the requirement for CMs as the instantaneous supply-demand balance is decoupled and the demand-side becomes more price-elastic.

The role of the demand-side (Demand-Side Response (DSR)) for CMs in SAPP

On electricity demand elasticity, the demand-side is likely to become more price-elastic in future with the advent of smart-metering and the associated ability to control demand at a more granular scale (not just for large customers). Aggregators could have a large role to play in this domain by providing a service to customers considering their willingness to change demand at times of peak (decreasing the requirement for peaking capacity).

This links closely to the capacity subscription CM type as discussed in this research and introduced in [62, 63] but which has not yet been implemented in any jurisdiction. Further exploration of this CM in the SAPP region via a practical

implementation at a pilot-scale would be an interesting and valuable research contribution. This could have the potential to transform the need for utilising the existing MTP and shift the focus from large centralised capacity procurement to decentralised capacity procurement in future. In this regard, the use of blockchain as an enabling technology in power systems is still quite nascent [251] but seems to exhibit significant potential for enabling of transactions down to the individual customer level [252]. Blockchain could be considered as a platform for buying and selling of CM contracts at scale and would be a very novel application of the technology relevant to CMs whilst inherently including the demand-side and making it more responsive. To name a few examples of the use of blockchain - in Germany a demonstration of decentralised home storage systems for redispatching of the power system is being pursued [253], in the USA at commercial-scale where *transactive energy* is the focus [254] and in Australia with multiple applications envisioned [255]. The sustainability of the use of blockchain as a technology in itself would need to be considered if pursuing research in this regard as highlighted in [256, 257] especially if pursued at scale.

Access to capital and the cost of capital

Access to capital in the SAPP is assumed to be unconstrained with the cost of capital assumed consistent across all technologies and countries in the region. This research does not try to focus on whether increased access to capital or the related cost of capital will promote capacity investment, change the choice of CM or the resulting energy mix (and resulting system adequacy).

Future research could explore this with constrained capital access and cost of capital across supply/demand choices and network infrastructure to improve interconnectivity. It is highly likely that a constrained capital access and capital cost environment would have an impact on system adequacy. Country-specific capital access and cost of capital for various reasons including institutional capacity, political instability/policy positions would imply an inherent requirement to ensure acceptable system adequacy via considerable power imports from the SAPP region. This may be possible but would likely need considerably increased investment in network infrastructure improving interconnectivity and allowing unconstrained flow of power throughout the region (still requiring access to capital at a reasonable cost).

Acceptability and stakeholder equity

This research did not explicitly focus on an objective assessment of stakeholder

equity and acceptability. Thus, an area of future research would include an intentionally designed survey of SAPP market participants to assess acceptability and stakeholder equity of any proposed CM in the region.

References

- [1] R. Billinton and R. A. Allen. *Reliability Evaluation of Power Systems*. New York: Plenum Press, 1996.
- [2] P. Kundur. *Power System Stability and Control*. McGraw-Hill, 1994.
- [3] R. Billinton. “Bibliography on the application of probability methods in power system reliability evaluation: 1987-1991.” In *Institute of Electrical and Electronics Engineers: Winter Power Meeting*. New York, 1966.
- [4] R. Billinton and K. Chu. “Early evolution of LOLP: Evaluating generating capacity requirements [History].” *IEEE Power and Energy Magazine*, vol. 13, no. 4, pp. 88–98, 2015.
- [5] IAEA. “Expansion Planning for Electrical Generating Systems: A Guidebook - Technical Report Series No. 241.” Tech. Rep. 241, International Atomic Energy Agency (IAEA), 1984. URL http://www-pub.iaea.org/MTCD/publications/PDF/TRS1/TRS241_Web.pdf.
- [6] S. Jonnavithula and R. Billinton. “Cost-benefit analysis of generation additions in system planning.” *IEE Proceedings - Generation, Transmission and Distribution*, vol. 145, no. 3, pp. 288 – 292, 1998.
- [7] S. Stoft. *Power System Economics : Designing Markets for Electricity*. Wiley-IEEE Press, 2002.
- [8] L. De Vries. *Securing the public interest in electricity generation markets: The myths of the invisible hand and the copper plate*. Phd, Delft University of Technology, 2004.
- [9] D. R. Biggar and M. R. Hesamzadeh. *The Economics of Electricity Markets*. Wiley - IEEE, 2014.
- [10] M. Hasani-Marzooni and S. H. Hosseini. “Dynamic analysis of various investment incentives and regional capacity assignment in Iranian electricity market.” *Energy Policy*, vol. 56, pp. 271–284, 2013.
- [11] The Australian Energy Market Commission (AEMC). “AEMC Reliability Panel: Comprehensive reliability review.” Tech. Rep. December, The Australian Energy Market Commission (AEMC), 2007.

- [12] J. P. Pfeifenberger, K. Spees, K. Carden, and N. Wintermantel. “Resource adequacy requirements: Reliability and economic implications.” Tech. Rep. September, The Brattle Group and Astrape Consulting, 2013. URL http://www.brattle.com/system/publications/pdfs/000/004/984/original/Resource_Adequacy_Requirements_Pfeifenberger_Spees_FERC_Sept_2013.pdf?1392303166.
- [13] Commission for Energy Regulation (CER). “Capacity requirement and annual capacity payment sum for calendar year 2014: Consultation paper.” Tech. rep., Commission for Energy Regulation (CER), 2013. URL www.allislandproject.org.
- [14] S. A. Newell, K. Spees, J. P. Pfeifenberger, I. Karkatsouli, N. Wintermantel, and K. Carden. “Estimating the economically optimal reserve margin in ERCOT.” Tech. rep., The Brattle Group Inc., 2014. URL <http://www.brattle.com/news-and-knowledge/publications/estimating-the-economically-optimal-reserve-margin-in-ercot>.
- [15] D. Newbery. “Security of supply, capacity auctions and interconnectors.”, 2015.
- [16] A. B. Jaffe, F. A. Felder, and H. Lighting. “Should electricity markets have a capacity requirement? If so, how should It be priced?” *The Electricity Journal*, vol. 9, no. 10, pp. 52–60, 1996.
- [17] H. G. Stoll. *Least-cost electric utility planning*. Wiley, 1989.
- [18] A. Mazer. *Electric Power Planning for Regulated and Deregulated Markets*. Wiley-IEEE Press, 2007.
- [19] F. S. Hillier and G. J. Lieberman. *Introduction to Operations Research*. New York: McGraw-Hill Higher Education, 7th ed., 2001.
- [20] J. H. Merrick. “On representation of temporal variability in electricity capacity planning models.” *Energy Economics*, vol. 59, pp. 261–274, 2016.
- [21] K. Poncelet, H. Hoschle, E. Delarue, A. Virag, and W. D’haeseleer. “Selecting representative days for capturing the implications of integrating intermittent renewables in generation expansion planning problems.” *IEEE Transactions on Power Systems*, vol. 32, no. 3, pp. 1936–1948, 2016.
- [22] S. Pfenninger. “Dealing with multiple decades of hourly wind and PV time series in energy models: A comparison of methods to reduce time resolution and the planning implications of inter-annual variability.” *Applied Energy*, vol. 197, pp. 1–13, 2017.
- [23] International Renewable Energy Agency (IRENA). “Planning for the renewable future: Long-term modelling and tools to expand variable renewable power in emerging economies.” Tech. rep., International Renewable Energy Agency (IRENA), 2017.

- [24] F. Olsina. *Long-term dynamics of liberalized electricity markets*. Phd, National University of San Juan, 2005. URL web.ing.puc.cl/~power/paperspdf/Olsina.pdf.
- [25] F. P. Sioshansi and W. Pfaffenberger. *Electricity Market Reform: An International Perspective*. Elsevier, 2006.
- [26] P. Simshauser. “The dynamic efficiency gains from introducing capacity payments in the National Electricity Market.” *Australian Economic Review*, vol. 41, no. 4, pp. 349–370, 2008.
- [27] J. Pfeifenberger, K. Spees, and A. Schumacher. “A comparison of PJM’s RPM with alternative energy and capacity market designs.” Tech. Rep. September, The Brattle Group (for PJM Interconnection L.L.C.), 2009. URL https://sites.hks.harvard.edu/hepg/Papers/2009/BrattleRPMComparisonWhitepaper_Sept09.pdf.
- [28] C. Batlle and P. Rodilla. “A critical assessment of the different approaches aimed to secure electricity generation supply.” *Energy Policy*, vol. 38, no. 11, pp. 7169–7179, 2010.
- [29] G. Doorman, J. Barquin, L. Barroso, C. Batlle, A. Cruickshank, C. Dervieux, R. Flanagan, J. Gilmore, J. Greenhalg, H. Höschle, P. Mastropietro, A. Keech, M. Krupa, J. Riesz, B. LaRose, S. Schwenen, G. Thorpe, K. D. Vos, L. de Vries, and J. Wright. “Capacity mechanisms: needs, solutions and state of affairs.” Tech. rep., CIGRE WG C5.17 (TB647), 2016.
- [30] M. Caramanis, R. Bohn, and F. Schweppe. “Optimal spot pricing: Practice and theory.” *IEEE Transactions on Power Apparatus and Systems*, vol. 101, pp. 3234–3245, 1982.
- [31] F. Schweppe, M. Caramanis, R. Tabors, and R. Bohn. *Spot Pricing of Electricity*. Springer US, Kluwer Academic Publishers, 1988.
- [32] D. Kirschen and G. Strbac. *Fundamentals of Power System Economics*. John Wiley and Sons Inc., 2004.
- [33] I. Milstein and A. Tishler. “The inevitability of capacity underinvestment in competitive electricity markets.” *Energy Economics*, vol. 34, no. 1, pp. 62–77, 2012.
- [34] J. Riesz and I. Macgill. “100% renewables in Australia: Will a capacity market be required?” In *Solar Integration Workshop*. London, England, 2013.
- [35] International Energy Agency (IEA). “Re-powering Markets: Market design and regulation during the transition to low - carbon power systems.” Tech. rep., International Energy Agency (IEA), 2016. URL <http://www.iea.org/publications/freepublications/publication/REPOWERINGMARKETS.pdf>.

- [36] U.S. Department of Energy. “Staff report on electricity markets and reliability staff report to the Secretary on Electricity Markets and Reliability.” Tech. rep., U.S. Department of Energy, 2017. URL https://energy.gov/sites/prod/files/2017/08/f36/StaffReportonElectricityMarketsandReliability_0.pdf.
- [37] P. Cramton and S. Stoft. “A capacity market that makes sense.” *The Electricity Journal*, vol. 18, no. 7, pp. 43–54, 2005.
- [38] P. Cramton and S. Stoft. “The convergence of market designs for adequate generating capacity.”, 2006. URL <http://dspace.mit.edu/handle/1721.1/45053>.
- [39] P. L. Joskow. “Capacity payments in imperfect electricity markets: Need and design.” *Utilities Policy*, vol. 16, no. 190, pp. 159–170, 2008.
- [40] P. Cramton, A. Ockenfels, and S. Stoft. “Capacity market fundamentals.” *Economics of Energy & Environmental Policy*, vol. 2, no. 2, 2013.
- [41] D. W. Bunn and E. R. Larsen. “Sensitivity of reserve margin to factors influencing investment behaviour in the electricity market of England and Wales.” *Energy Policy*, vol. 20, no. 5, pp. 420–429, 1992.
- [42] P. Cramton and A. Ockenfels. “Economics and design of capacity markets for the power sector.” *Zeitschrift für Energiewirtschaft*, vol. 36, no. 2, pp. 113–134, apr 2012.
- [43] S. He, L. Xiao, G. Liu, and M. Zeng. “Capacity mechanism analysis based on dynamic simulation of generation investment.” In *IEEE International Conference on Service Operations and Logistics, and Informatics*, pp. 265–269. 2013.
- [44] A. Ousman, N. Hary, V. Rious, and M. Saguan. “The impact of investors’ risk aversion on the performances of capacity remuneration mechanisms.” *Energy Policy*, vol. 112, pp. 84–97, 2018.
- [45] D. W. Bunn and E. R. Larsen. “Assessment of the uncertainty in future UK electricity investment using an industry simulation model.” *Utilities Policy*, vol. 4, no. 3, pp. 229–236, 1994.
- [46] A. Ford. “Cycles in competitive electricity markets: a simulation study of the western United States.” *Energy Policy*, vol. 27, pp. 637–658, 1999.
- [47] S. Arango and E. Larsen. “Cycles in deregulated electricity markets: Empirical evidence from two decades.” *Energy Policy*, vol. 39, no. 5, pp. 2457–2466, 2011.
- [48] W. W. Hogan. “On an ”Energy Only” electricity market design for resource adequacy.” Tech. rep., Harvard University, 2005. URL https://ferc.gov/EventCalendar/Files/20060207132019-Hogan_Energy_Only_092305.pdf.

- [49] D. Newbery. “Missing money and missing markets: Reliability, capacity auctions and interconnectors.” *Energy Policy*, vol. 94, pp. 401–410, 2015.
- [50] T. O. Leautier. “The visible hand: Ensuring optimal investment in electric power generation.” *IAEE Energy Journal*, vol. 37, no. 4, pp. 89–109, 2016.
- [51] G. Meunier. “Risk aversion and technology mix in an electricity market.” *Energy Economics*, vol. 40, pp. 866–874, 2013.
- [52] A. O. Abani, N. Hary, M. Saguan, and V. Rious. “Risk aversion and generation adequacy in liberalized electricity markets : benefits of capacity markets.” In *13th International Conference on the European Energy Market (EEM)*. Porto, Portugal, 2016.
- [53] M. Petitet, D. Finon, and T. Janssen. “Capacity adequacy in power markets facing energy transition: A comparison of scarcity pricing and capacity mechanism.” *Energy Policy*, vol. 103, pp. 30–46, 2017.
- [54] S. Oren. “Capacity payments and supply adequacy in competitive electricity markets.” In *Symposium of Specialists in Electric Operational and Expansion Planning*. 2000.
- [55] F. Wolak. “What’s wrong with capacity markets?”, 2004. URL stoft.com/metaPage/lib/WolaK-2004-06-contract-adequacy.pdf.
- [56] M. Hogan. “Follow the missing money: Ensuring reliability at least cost to consumers in the transition to a low-carbon power system.” *The Electricity Journal*, vol. 30, no. 1, pp. 55–61, 2017.
- [57] P. C. Bhagwat, L. J. de Vries, and B. F. Hobbs. “Expert survey on capacity markets in the US: Lessons for the EU.” *Utilities Policy*, vol. 38, pp. 11–17, 2016.
- [58] P. C. Bhagwat, J. C. Richstein, E. J. Chappin, and L. J. de Vries. “The effectiveness of a strategic reserve in the presence of a high portfolio share of renewable energy sources.” *Utilities Policy*, vol. 39, pp. 13–28, 2016.
- [59] P. C. Bhagwat, K. K. Iychettira, J. C. Richstein, E. J. Chappin, and L. J. D. Vries. “The effectiveness of capacity markets in the presence of a high portfolio share of renewable energy sources.” *Utilities Policy*, vol. 48, pp. 76–91, 2017.
- [60] C. Batlle and I. J. Pérez-Arriaga. “Design criteria for implementing a capacity mechanism in deregulated electricity markets.” *Utilities Policy*, vol. 16, no. 3, pp. 184–193, 2008.
- [61] C. Batlle, P. Mastropietro, and P. Rodilla. “The system adequacy problem : Lessons learned from the American continent.”, 2014. URL http://www.iit.upcomillas.es/~batlle/Docs/2013ThesystemadequacyproblemLessonslearnedfromtheAmericancontinent_Batlleetal.pdf.

- [62] G. Doorman. *Peaking capacity in restructured power systems*. Phd, Norwegian University of Science and Technology, 2000. URL <http://www.diva-portal.org/smash/get/diva2:125349/FULLTEXT01.pdf>.
- [63] G. Doorman. “Capacity subscription: Solving the peak demand challenge in electricity markets.” *IEEE Transactions on Power Systems*, vol. 20, no. 1, pp. 239–245, 2005.
- [64] P. Joskow. “Competitive electricity markets and investments in new generation capacity.”, 2006. URL <https://economics.mit.edu/files/1190>.
- [65] P. Joskow and J. Tirole. “Reliability and competitive electricity markets.” *RAND Journal of Economics*, vol. 38, no. 1, pp. 60–84, 2007.
- [66] J. H. Keppler. “Rationales for capacity remuneration mechanisms: Security of supply externalities and asymmetric investment incentives.” *Energy Policy*, vol. 105, pp. 562–570, 2017.
- [67] P. Mastropietro, I. Herrero, P. Rodilla, and C. Batlle. “A model-based analysis on the impact of explicit penalty schemes in capacity mechanisms.” *Applied Energy*, vol. 168, pp. 406–417, 2015.
- [68] Paolo Mastropietro, Pablo Rodilla, and Carlos Batlle. “National capacity mechanisms in the European internal energy market: Opening the doors to neighbours.” *Energy Policy*, vol. 82, pp. 38–47, 2015.
- [69] P. Mastropietro. *Regulatory design of capacity remuneration mechanisms in regional and low-carbon electric power markets*. Phd, Universidad Pontificia Comillas, 2016. URL <http://kth.diva-portal.org/smash/record.jsf?pid=diva2:918381&dswid=2966>.
- [70] P. Mastropietro, P. Rodilla, and C. Batlle. “Performance incentives in capacity mechanisms: conceptual considerations and empirical evidence.” *Economics of Energy & Environmental Policy*, vol. 6, no. 1, pp. 149–163, 2017.
- [71] S. Schwenen. “Market design and supply security in imperfect power markets.” *Energy Economics*, vol. 43, pp. 256–263, 2014.
- [72] H. Hoshle and G. Doorman on behalf of CIGRE WG C5.17. “Capacity mechanisms : Results from a world wide survey.” In *CIGRE Session 2016*, pp. 1–9. 2016.
- [73] CIGRE WG C5.71 TB500. “Impacts of infrastructure investment resulting from electricity market designs.” Tech. rep., CIGRE, 2012.
- [74] CIGRE WG C5.10 TB565. “Regulatory incentives for capital investments in electricity.” Tech. Rep. December, CIGRE, 2013.
- [75] The Agency for the Cooperation of Energy Regulators (ACER). “Capacity remuneration mechanisms and the internal market for electricity.” Tech. rep.,

2013. URL www.acer.europa.eu/...of.../crmsandtheiemreport130730.pdf.
- [76] K. Iychettira. *Orchestrating investment in an evolving power sector: An analysis of capacity markets*. Masters, Delft University of technology, 2013. URL <http://repository.tudelft.nl/view/ir/uuid:b96aaa13-96fc-488b-be96-24c627c12be6/>.
- [77] B. Caldecott and J. McDaniels. “Stranded generation assets : Implications for European capacity mechanisms , energy markets and climate policy.”, 2014.
- [78] L. Hancher and A. de Houteclocque. *Capacity mechanisms in EU energy markets: Law, policy, and economics*. Oxford University Press, 1st ed., 2015.
- [79] FERC Staff Report. “Centralized Capacity Market Design Elements.” Tech. rep., 2013. URL <https://www.ferc.gov/CalendarFiles/20130826142258-StaffPaper.pdf>.
- [80] K. Neuhoff, J. Diekmann, F. Kunz, S. Rüster, W. P. Schill, and S. Schwenen. “A coordinated strategic reserve to safeguard the European energy transition.” *Utilities Policy*, vol. 41, pp. 252–263, 2016.
- [81] C. Vázquez, M. Rivier, and I. J. Pérez-Arriaga. “A market approach to long-term security of supply.” *IEEE Transactions on Power Systems*, vol. 17, no. 2, pp. 349–357, 2002.
- [82] H. A. Averch. *Private markets and public intervention: A primer for policy designers*. University of Pittsburgh Press, 1991.
- [83] World Economic Forum (WEF) in collaboration with Bain & Company. “The future of electricity: Attracting investment to build tomorrow’s electricity sector.” Tech. Rep. January, World Economic Forum (WEF), Davos, 2015. URL http://www3.weforum.org/docs/WEFUSA_FutureOfElectricity_Report2015.pdf.
- [84] V. Di Cosmo and M. Á. Lynch. “Competition and the single electricity market: Which lessons for Ireland?” *Utilities Policy*, vol. 41, pp. 40–47, 2016.
- [85] H. Hoshle and K. de Vos. “Implementation of a strategic reserve in Belgium: Product design and market rules.” In *CIGRE Session 2016*. 2016.
- [86] Australian Energy Market Operator (AEMO). “Electricity statement of opportunities for the National Electricity Market (NEM).” Tech. Rep. September, Australian Energy Market Operator (AEMO), 2011. URL http://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/NEM_ES00/2017/2017-Electricity-Statement-of-Opportunities.pdf.
- [87] Bundesministerium für Wirtschaft und Energie (BMWi). “Ein Strommarkt für die Energiewende.” Tech. rep., 2015. URL <https://www.>

- bmwi.de/Redaktion/DE/Publikationen/Energie/weissbuch.pdf?__blob=publicationFile&v=33.
- [88] Bundesministerium für Wirtschaft und Energie (BMWi). “An electricity market for Germany’s energy transition: White Paper by the Federal Ministry for Economic Affairs and Energy.”, 2015. URL <https://www.bmwi.de/Redaktion/EN/Artikel/Energie/strommarkt-2-0.html>.
 - [89] A. Henry. “Quelle énergie pour un développement durable?”, 2005. URL <http://www.plan.be/admin/uploaded/200605091448115.WP0514fr.pdf>.
 - [90] Bundesministerium für Wirtschaft und Energie (BMWi). “Overview of legislation governing Germany’s energy supply system.” Tech. rep., Bundesministerium für Wirtschaft und Energie (BMWi), 2017. URL www.bmwi.de/overview-of-legislation.
 - [91] Réseau de transport d’électricité (Rte). “French Capacity Market.” Tech. rep., Réseau de transport d’électricité (Rte), Paris, 2014.
 - [92] T. Jenkin, P. Beiter, R. Margolis, T. Jenkin, P. Beiter, and R. Margolis. “Capacity payments in restructured markets under low and high penetration levels of renewable energy capacity payments in restructured markets under low and high penetration levels of renewable energy.” Tech. Rep. February, National Renewable Energy Laboratory (NREL), 2016. URL <https://www.nrel.gov/docs/fy16osti/65491.pdf>.
 - [93] P. Cramton and S. Stoft. “Colombia firm energy market.” In *40th Hawaii International Conference on System Sciences*. 2007.
 - [94] S. Zapata, M. Castaneda, E. Garces, C. Jaime, and I. Dynner. “Assessing security of supply in a largely hydroelectricity-based system : The Colombian case.” *Energy*, vol. 156, pp. 444–457, 2018. URL <https://doi.org/10.1016/j.energy.2018.05.118>.
 - [95] W. Jiekang and L. Jiayu. “Capacity payments in competitive electricity markets-a bilateral trade model.” In *International Conference on Power System Technology (PowerCon)*, pp. 21–24. 2004.
 - [96] C.-k. Han, D. Hur, J.-m. Sohn, and J.-k. Park. “Assessing the impacts of capacity mechanisms on generation adequacy with dynamic simulations.” *IEEE Transactions on Power Systems*, vol. 26, no. 4, pp. 1788–1797, 2011.
 - [97] J. Stede. “Demand Response in Germany: Technical potential, benefits and regulatory challenges.”, 2016. URL https://www.diw.de/documents/publikationen/73/diw_01.c.532827.de/diw_roundup_96_en.pdf.
 - [98] J. Riesz, J. Gilmore, and I. Macgill. “Assessing the viability of energy-only markets with 100% renewables : An Australian National Electricity Market case study.” *Economics of Energy & Environmental Policy*, vol. 5, no. 1, pp. 105–130, 2016.

- [99] Y. Liu. “Demand response and energy efficiency in the capacity resource procurement: Case studies of forward capacity markets in ISO New England, PJM and Great Britain.” *Energy Policy*, vol. 100, no. 2016, pp. 271–282, 2017.
- [100] IRENA (International Renewable Energy Agency). “The power to change: Solar and wind cost reduction potential to 2025.” Tech. rep., International Renewable Energy Agency (IRENA), 2016. URL http://www.irena.org/DocumentDownloads/Publications/IRENA_Power_to_Change_2016.pdf.
- [101] International Renewable Energy Agency (IRENA). “Renewable energy auctions: Analysing 2016.” Tech. rep., International Renewable Energy Agency (IRENA), 2017. URL https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2017/Jun/IRENA_Renewable_Energy_Auctions_2017.pdf.
- [102] J. G. Wright, T. Bishof-Niemz, J. Calitz, C. Mushwana, R. van Heerden, and M. Senatla. “Report: Formal comments on the Integrated Resource Plan (IRP) Update Assumptions, Base Case and Observations 2016.” Tech. rep., Council for Scientific and Industrial Research (CSIR), Pretoria, 2017.
- [103] J. G. Wright, T. Bischof-Niemz, J. Calitz, C. Mushwana, R. van Heerden, and M. Senatla. “Presentation: Formal comments on the Integrated Resource Plan (IRP) Update assumptions, Base Case and observations 2016.” Tech. rep., Council for Scientific and Industrial Research (CSIR), Pretoria, 2017. URL https://www.csir.co.za/sites/default/files/Documents/20170331CSIR_EC_DOE.pdf.
- [104] M. Cepeda and D. Finon. “How to correct for long-term externalities of large-scale wind power development by a capacity mechanism?” *Energy Policy*, vol. 61, pp. 671–685, 2013. URL <http://dx.doi.org/10.1016/j.enpol.2013.06.046>.
- [105] Samil Succar. “Distributed generation’s future impact on the U.S. capacity markets.”, 2014. URL <http://www.icfi.com/insights/white-papers/2014/distributed-generations-future-impact-us-capacity-markets>.
- [106] T. P. Tangerås. “Equilibrium supply security in a multinational electricity market with renewable production.”, 2017. URL <http://www.eprg.group.cam.ac.uk/wp-content/uploads/2017/04/1707-Text.pdf>.
- [107] A. Mills and R. Wiser. “Changes in the economic value of variable generation at high penetration levels: A pilot case study of California.” Tech. rep., Ernest Orlando Lawrence Berkeley National Laboratory, 2012. URL <https://emp.lbl.gov/sites/all/files/lbnl-5445e.pdf>.
- [108] M. Milligan, B. A. Frew, A. Bloom, E. Ela, A. Botterud, A. Townsend, and T. Levin. “Wholesale electricity market design with increasing levels of renewable generation: Revenue sufficiency and long-term reliability.” *The Electricity Journal*, vol. 29, no. 2, pp. 26–38, 2016.

- [109] J. Riesz and M. Milligan. “Designing electricity markets for a high penetration of variable renewables.” *Wiley Interdisciplinary Reviews: Energy and Environment*, vol. 4, no. 3, pp. 279–289, 2015.
- [110] T. Ackerman, E. M. Carlini, B. Ernst, F. Groome, A. Orth, J. O’Sullivan, M. del la Torre Rodriguez, and V. Silva. “Integrating variable renewables in Europe: Current status and recent extreme events.” *IEEE Power and Energy Magazine*, vol. 13, no. 6, pp. 67–77, 2015.
- [111] B. A. Frew, M. Milligan, G. Brinkman, A. Bloom, K. Clark, and P. Denholm. “Revenue sufficiency and reliability in a zero marginal cost Future.” In *15th Wind Integration Workshop*, December. 2016.
- [112] H. Auer and R. Haas. “On integrating large shares of variable renewables into the electricity system.” *Energy*, vol. 115, no. 3, pp. 1592–1601, 2016.
- [113] M. Liebreich. “Six design principles for the power markets of the future – A personal view from the Chairman of the Advisory Board (Bloomberg New Energy Finance).” Tech. rep., Bloomberg New Energy Finance (BNEF), 2017. URL <https://data.bloomberglp.com/bnef/sites/14/2017/05/Liebreich-Six-Design-Principles-for-the-Power-Markets-of-the-Future.pdf>.
- [114] F. A. Felder. “Examining electricity price suppression due to renewable resources and other grid investments.” *The Electricity Journal*, vol. 24, no. 4, pp. 34–46, 2011.
- [115] T. Traber and C. Kemfert. “Gone with the wind? - Electricity market prices and incentives to invest in thermal power plants under increasing wind energy supply.” *Energy Economics*, vol. 33, no. 2, pp. 249–256, 2011. URL <http://dx.doi.org/10.1016/j.eneco.2010.07.002>.
- [116] M. Shah, J. M. Valenzuela, H. A. Mora Beltran, K. M. Porst, A. Hasselager, S. Friis-Jensen, M. Vingaard, F. Wigand, S. Tiedemann, L. Bird, O. Zinaman, and J. Logan. “Clean restructuring: Design elements for low-carbon wholesale markets and beyond.” Tech. rep., 21st Century Power Partnership, 2016. URL <https://www.nrel.gov/docs/fy16osti/66105.pdf>.
- [117] P. C. Bhagwat, K. Iychettira, and L. J. De Vries. “Cross-border effects of capacity mechanisms in interconnected power systems.” In *International Conference on the European Energy Market, EEM*. Dresden, Germany, 2017.
- [118] J. Blazquez, R. Fuentes-Bracamontes, C. A. Bollino, and N. Nezamuddin. “The renewable energy policy paradox.” *Renewable and Sustainable Energy Reviews*, vol. 82, no. April 2017, pp. 1–5, 2018. URL <http://dx.doi.org/10.1016/j.rser.2017.09.002>.
- [119] PJM Interconnection LLC. “Capacity market (RPM): 2020/2021 RPM Base Residual Auction results.”, 2017. URL <http://www.pjm.com/markets-and-operations/rpm.aspx>.

- [120] International Energy Agency (IEA). “Getting wind and sun onto the grid: A manual for policymakers.” Tech. rep., International Renewable Energy Agency (IRENA), 2017. URL https://www.iea.org/publications/insights/insightpublications/Getting_Wind_and_Sun.pdf.
- [121] C. Loutan, P. Klauer, S. Chowdhury, S. Hall, M. Morjaria, V. Chadliev, N. Milam, C. Milan, and V. Gevorgian. “Demonstration of essential reliability services by a 300-MW solar photovoltaic power plant.” Tech. Rep. March, CAISO, First Solar, NREL, 2017. URL <http://www.nrel.gov/docs/fy17osti/67799.pdf>.
- [122] L. Musaba. “The development of the SAPP competitive electricity market.” In *IEEE Power Engineering Society Inaugural Conference and Exposition in Africa*, pp. 11–15. Durban, South Africa, 2005.
- [123] B. Graeber, R. Spalding-Fecher, and B. Gonah. “Optimising trans-national power generation and transmission investments: A Southern African example.” *Energy Policy*, vol. 33, no. 18, pp. 2337–2349, 2005.
- [124] M. Coetzee. “The operational experience of the first 400 kV feeder in the Southern African power pool.” In *1996 IEEE AFRICON 4th Africon conference in Africa*, pp. 48–51. Stellenbosch, South Africa, 1996.
- [125] SADCC. “Southern Africa: Toward economic liberation. A declaration by the governments of independent states of Southern Africa made at Lusaka on the 1st April 1980.”, 1980. URL <http://www.sadc.int/english/key-documents/declaration-and-treaty-of-sadc/>.
- [126] SADC. “Towards a Southern African development community - A declaration made by the Heads of state or government of Southern Africa at Windhoek.”, 1992. URL <http://www.sadc.int/english/key-documents/declaration-and-treaty-of-sadc/>.
- [127] The Infrastructure Consortium of Africa. “Regional power status in African power pools report.” Tech. rep., The Infrastructure Consortium of Africa, 2011. URL http://www.icafrica.org/fileadmin/documents/Knowledge/Energy/ICA_RegionalPowerPools_Report.pdf.
- [128] T. J. Hammons. *Electricity infrastructures in the global marketplace*. Intech, 2011.
- [129] Southern African Power Pool (SAPP). “SAPP Annual Report.” Tech. rep., SAPP, 2016.
- [130] SADC Energy Ministers. “Southern African Power Pool Inter-Governmental Memorandum of Understanding.”, 2006.
- [131] Southern African Power Pool. “Southern African Power Pool Agreement between Operating Members.” Tech. rep., Southern African Power Pool (SAPP), 1995. URL www.sapp.co.zw.

- [132] Southern African Power Pool. “Southern African Power Pool (SAPP) Day Ahead Market (DAM) Book of Rules.” Tech. rep., Southern African Power Pool, 2009. URL www.sapp.co.zw.
- [133] Southern African Power Pool. “Southern African Power Pool Operating Guidelines.” Tech. Rep. August, Southern African Power Pool, 1996.
- [134] Southern African Power Pool. “Southern African Power Pool Inter-Utility Memorandum of Understanding.”, 2005. URL <http://www.sadc.int/documents-publications/show/1024>.
- [135] World Bank Group. “Population, total.”, 2015. URL <http://data.worldbank.org/indicator/SP.POP.TOTL>.
- [136] Southern African Power Pool (SAPP). “SAPP Annual Report.” Tech. rep., SAPP, 1996. URL [http://www.sapp.co.zw/docs/SAPPReport\(1995-1997\).pdf](http://www.sapp.co.zw/docs/SAPPReport(1995-1997).pdf).
- [137] Southern African power Pool (SAPP). “Demand and Supply.”, 2016. URL <http://www.sapp.co.zw/demand-and-supply>.
- [138] World Bank Group. “Electric power consumption (kWh per capita).”, 2014. URL <https://data.worldbank.org/indicator/EG.USE.ELEC.KH.PC>.
- [139] International Energy Agency (IEA). “Energy Access Outlook 2017: From poverty to prosperity.” Tech. rep., International Energy Agency (IEA), 2017. URL https://www.iea.org/publications/freepublications/publication/WE02017SpecialReport_EnergyAccessOutlook.pdf.
- [140] Southern African Development Community (SADC). “MEMBER STATES.”, 2012. URL <http://www.sadc.int/member-states/>.
- [141] Southern African Power Pool (SAPP). “Southern African Power Pool Inter-Utility Memorandum of Understanding.”, 1995.
- [142] Southern African Power Pool. “SAPP Annual Report.” Tech. rep., SAPP, 2009. URL www.sapp.co.zw.
- [143] Southern African Power Pool. “SAPP Annual Report.” Tech. rep., SAPP, 2012. URL www.sapp.co.zw.
- [144] Southern African Power Pool. “SAPP Annual Report.” Tech. rep., SAPP, 2015. URL <http://www.sapp.co.zw/docs/SAPPAnnualReport-2015.pdf>.
- [145] Department of Energy (DoE). “Integrated Resource Plan Update: Assumptions, Base Case Results and Observations (Revision 1).” Tech. Rep. 40445, Department of Energy (DoE), 2016. URL <http://www.energy.gov.za/IRP/2016/Draft-IRP-2016-Assumptions-Base-Case-and-Observations-Revision1.pdf>.

- [146] Botswana Power Corporation (BPC). “Botswana Power Corporation (BPC): Annual Report.” Tech. rep., Botswana Power Corporation (BPC), 2016. URL https://www.bpc.bw/about-us/AnnualReports/2016BPC_AnnualReport.pdf.
- [147] Electricidade de Mocambique (EdM). “Relatorio anual de estatistica.” Tech. rep., Electricidade de Mocambique (EdM), 2013. URL http://www.edm.co.mz/index.php?option=com_docman&task=doc_download&gid=181&Itemid=68&lang=en.
- [148] Namibia Power Corporation (Nampower). “2016 Annual Report.” Tech. rep., Namibia Power Corporation (Nampower), 2016. URL <http://www.nampower.com.na/Media.aspx?m=Annual+Reports>.
- [149] Swaziland Electricity Company (SEC). “Swaziland Electricity Company (SEC): Annual Report 2015/16.” Tech. rep., Swaziland Electricity Company (SEC), 2016. URL <http://www.sec.co.sz/documents/annualreports/20152016.pdf>.
- [150] Ministry of Energy and Minerals (United Republic of Tanzania). “Power system master plan - 2016 Update.” Tech. rep., Ministry of Energy and Minerals (United Republic of Tanzania), 2016. URL <http://www.ewura.go.tz/wp-content/uploads/2017/01/Power-System-Master-Plan-Dec.-2016.pdf>.
- [151] Energy Regulatory Board (ERB). “Energy Sector Report.” Tech. rep., Energy Regulation Board (ERB), 2016. URL <http://www.erb.org.zm/downloads/esr2016.pdf>.
- [152] Zimbabwe Power Company (ZPC). “Zimbabwe Power Company (ZPC): Annual Report 2016.” Tech. rep., Zimbabwe Power Company (ZPC), 2016. URL <http://www.zpc.co.zw/data/media/00000050/ANNUAL-REPORT-PAGES-CURVES.pdf>.
- [153] Southern African Power Pool (SAPP). “SAPP Transfer Limits (2017).”, 2017. URL <http://www.sapp.co.zw/transfer-limits>.
- [154] L. Musaba and P. Naidoo. “Towards developing a competitive market for regional electricity cross border trading: the case of the Southern African power pool.” In *IEEE Power Engineering Society General Meeting*. Denver, USA, 2004.
- [155] Southern African Power Pool (SAPP). “SAPP Market Trading.”, 2017. URL <http://sappmarket.com/>.
- [156] A. Rose, R. Stoner, and I. Pérez-Arriaga. “Integrating market and bilateral power trading in the South African Power Pool.” Tech. rep., United Nations University (UNU-WIDER), 2016. URL https://www.wider.unu.edu/sites/default/files/wp2016-132_0.pdf.

- [157] North American Electric Reliability Corporation (NERC). “Standards: Reliability Standards.”, 2013. URL <http://www.nerc.com/pa/stand/Pages/ReliabilityStandardsUnitedStates.aspx?jurisdiction=UnitedStates>.
- [158] L. de Vries and P. Heijnen. “The impact of electricity market design upon investment under uncertainty: The effectiveness of capacity mechanisms.” *Utilities Policy*, vol. 16, no. 3, pp. 215–227, 2008.
- [159] Southern African Power Pool (SAPP). “SAPP Annual Report.” Tech. rep., SAPP, 2004. URL www.sapp.co.zw.
- [160] Southern African Power Pool (SAPP). “SAPP Annual Report.” Tech. rep., SAPP, 2005. URL www.sapp.co.zw.
- [161] Southern African Power Pool. “SAPP Annual Report.” Tech. rep., SAPP, 2006. URL www.sapp.co.zw.
- [162] Southern African Power Pool. “SAPP Annual Report.” Tech. rep., SAPP, 2007. URL www.sapp.co.zw.
- [163] Southern African Power Pool. “SAPP Annual Report.” Tech. rep., SAPP, 2008. URL www.sapp.co.zw.
- [164] Southern African Power Pool. “SAPP Annual Report.” Tech. rep., SAPP, 2010. URL www.sapp.co.zw.
- [165] Southern African Power Pool. “SAPP Annual Report.” Tech. rep., SAPP, 2011. URL www.sapp.co.zw.
- [166] Southern African Power Pool. “SAPP Annual Report.” Tech. rep., SAPP, 2013.
- [167] Southern African Power Pool. “SAPP Annual Report.” Tech. rep., SAPP, 2014.
- [168] Department of Energy (DoE). “Integrated Resource Plan for Electricity 2010-2030.” Tech. rep., Department of Energy (DoE), 2011. URL http://www.doe-irp.co.za/content/IRP2010_promulgated.pdf.
- [169] Department of Energy (DoE). “Integrated Resource Plan for Electricity (IRP update 2013).” Tech. Rep. November, Department of Energy (DoE), 2013. URL www.doe-irp.co.za/content/IRP2010_updatea.pdf.
- [170] J. Holloway, P. Mokilane, S. Makhanya, T. Magadla, and R. Koen. “Forecasts for electricity demand in South Africa (2014-2050) using the CSIR sectoral regression model.” Tech. Rep. January, Council for Scientific and Industrial Research (CSIR), 2016. URL <http://www.energy.gov.za/IRP/2016/IRP-AnnexureB-Demand-forecasts-report.pdf>.

- [171] R. Koen, J. Holloway, P. Mokilane, S. Makhanya, and T. Magadla. “Forecasts for electricity demand in South Africa (2017-2050) using the CSIR sectoral regression model.” Tech. rep., Council for Scientific and Industrial Research (CSIR), 2017. URL <http://www.energy.gov.za/IRP/irp-update-draft-report2018/CSIR-annual-elec-demand-forecasts-IRP-2015.pdf>.
- [172] S. Newell, K. Spees, J. Pfeifenger, R. Mudge, M. DeLucia, and R. Carlton. “ERCOT investment incentives and resource adequacy.” Tech. rep., 2012. URL <http://www.power-eng.com/content/dam/pe/online-articles/documents/2012/June/BrattleERCOTResourceAdequacyReviewJune2012.pdf>.
- [173] Energy Exemplar. “PLEXOS Integrated Energy Model.”, 2017. URL www.energyexemplar.com.
- [174] J. Grainger and J. William Stevenson. *Power System Analysis*. McGraw-Hill, 1st ed., 1994.
- [175] A. J. Wood and B. F. Wollenberg. *Power generation, operation and control*. John Wiley & Sons, Inc., 2nd ed., 1996.
- [176] Southern African Power Pool (SAPP). “SAPP Monthly Market Performance Report.” Tech. rep., SAPP Co-ordination Centre. URL <http://www.sapp.co.zw/mreports.html>.
- [177] J. Teirilä. “Market Power in the Capacity Market? The Case of Ireland.”, 2017. URL http://www.eprg.group.cam.ac.uk/wp-content/uploads/2017/07/1712-Text_COMP.pdf.
- [178] M. Chaigneau and S. Lannez. “Forward capacity markets: Maintaining system reliability in Europe.” In *9th International Conference on the European Energy Market (EEM)*, pp. 1–8. 2012. URL http://ieeexplore.ieee.org/xpls/abs_all.jsp?arnumber=6254643.
- [179] G. A. Chown. *The Economic Analysis Of Relaxing Frequency Control*. P.h.d., University of Witwatersrand, 2007. URL <http://wiredspace.wits.ac.za/bitstream/handle/10539/5326/GChownPhDThesisfinal.pdf?sequence=1&isAllowed=y>.
- [180] V. C. Jaunky. “Divergence in technical efficiency of electric utilities: Evidence from the SAPP.” *Energy Policy*, vol. 62, pp. 419–430, 2013.
- [181] A. Keane, M. Milligan, C. J. Dent, B. Hasche, C. D’Annunzio, K. Dragoon, H. Holttinen, N. Samaan, L. Söder, and M. O’Malley. “Capacity value of wind power.” *IEEE Transactions on Power Systems*, vol. 26, no. 2, pp. 564–572, 2011.
- [182] F. Ueckerdt, R. Brecha, and G. Luderer. “Analyzing major challenges of wind and solar variability in power systems.” *Renew. Energy*, vol. 81, pp. 1–10, 2015. URL <http://dx.doi.org/10.1016/j.renene.2015.03.002>.

- [183] C. Dent, R. Sioshansi, J. Reinhart, A. Wilson, S. Zachary, M. Lynch, C. Bothwell, and C. Steele. “Capacity value of solar power: Report of the IEEE PES task force on capacity value of solar power.” In *International Conference on Probabilistic Methods Applied to Power Systems (PMAPS)*, Beijing, China. 2016.
- [184] H. Holttinen, J. Kiviluoma, M. Milligan, and B. Frew. “Assessing capacity value of wind power.” In *Proceedings of WIW2017 workshop*. 2017.
- [185] E. Zhou, W. Cole, and B. Frew. “Valuing variable renewable energy for peak demand requirements.” *Energy*, vol. 165, pp. 499–511, 2018. URL <https://linkinghub.elsevier.com/retrieve/pii/S0360544218317638>.
- [186] North American Electric Reliability Corporation (NERC). “2018 Summer Reliability Assessment.” Tech. rep., 2018. URL https://www.nerc.com/pa/RAPA/ra/ReliabilityAssessmentsDL/NERC_SRA_05252018_Final.pdf.
- [187] PJM Interconnection LLC. “2010 PJM Reserve Requirement Study.” Tech. rep., 2010. URL <https://www.pjm.com/~media/documents/reports/2010-pjm-reserve-requirement-study.ashx>.
- [188] PJM Interconnection LLC. “2012 PJM Reserve Requirement Study.” Tech. rep., 2012. URL <https://www.nrc.gov/docs/ML1419/ML14190B177.pdf>.
- [189] PJM Interconnection LLC. “2017 PJM Reserve Requirement Study.” Tech. rep., 2017. URL <https://www.pjm.com/-/media/committees-groups/committees/pc/20171012/20171012-item-03a-2017-pjm-reserve-requirement-study.ashx>.
- [190] PJM Interconnection LLC. “Capacity Market (RPM).”, 2018. URL <https://pjm.com/markets-and-operations/rpm.aspx>.
- [191] PJM Interconnection LLC. “PJM Manual 28: PJM Capacity Market (Revision: 40).” Tech. rep., 2018. URL <https://pjm.com/-/media/documents/manuals/m18.ashx?la=en>.
- [192] Raul Bajo-Buenestado. “Welfare implications of capacity payments in a price-capped electricity sector: A case study of the Texas market (ERCOT).” *Energy Economics*, vol. 64, no. 272-285, 2017.
- [193] M. Soni and G. Gulen. “The Impacts of Raising the Energy Price Cap in ERCOT.” *The Electricity Journal*, vol. 26, no. 7, 2013.
- [194] National Grid ESO. “Winter Outlook.”, 2018. URL <https://www.nationalgrideso.com/insights/winter-outlook>.
- [195] National Grid. “National Grid EMR Electricity Capacity Report.” Tech. rep., 2016. URL https://www.emrdeliverybody.com/Lists/LatestNews/Attachments/47/ElectricityCapacityReport2016_Final_080716.pdf.

- [196] National Grid. “Final auction results: T-4 capacity market auction, 2014 (2018/19).” Tech. rep., National Grid, 2014. URL https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/389832/Provisional_Results_Report-Ammendment.pdf.
- [197] National Grid. “Provisional auction results: T-4 capacity market auction, 2015 (2019/20).” Tech. rep., 2015. URL <https://www.emrdeliverybody.com/CapacityMarketsDocumentLibrary/EarlyAuction17-18ProvisionalResults.pdf>.
- [198] National Grid. “Provisional auction results: T-4 capacity market auction, 2016 (2020/21).” Tech. rep., 2016. URL <https://www.emrdeliverybody.com/CapacityMarketsDocumentLibrary/EarlyAuction17-18ProvisionalResults.pdf>.
- [199] A. Bublitz, C. Fraunholz, F. Zimmermann, and D. Keles. “Capacity remuneration mechanisms in Europe.” Tech. rep., REFLEX (Karlsruhe Institute of Technology), 2016. URL http://reflex-project.eu/wp-content/uploads/2016/12/REFLEX_PB_Capacity_remuneration.pdf.
- [200] THEMA Consulting Group. “Capacity adequacy in the Nordic electricity market.” Tech. rep., 2015. URL http://www.nordicenergy.org/wp-content/uploads/2015/08/capacity_adequacy_THEMA_2015-1.pdf.
- [201] FinGrid. “Reserve power plants.”, 2018. URL https://www.fingrid.fi/en/electricity-market/reserves_and_balancing/reserve-power-plants/.
- [202] V. Smith, I. Tshwagong, M. Ntusi, V. Smith, and C. Masike. “Ancillary services technical requirements for 2017/18 - 2021/22.” Tech. rep., Eskom Holdings SOC Limited, 2016. URL http://www.eskom.co.za/Whatweredoing/AncillaryServices/Documents/TechReqAncillary2017_18.pdf.
- [203] C. Vasquez, C. Batlle, M. Rivier, and I. Perez-Arriaga. “Security of supply in the Dutch electricity market : the role of reliability options.” Tech. rep., Instituto de Investigacion Tecnologica - Universidad Pontifica Comillas Madrid, Madrid, 2003. URL http://www.hks.harvard.edu/hepg/Papers/Vazquez.Batlle.Rivier.PerezArriaga_Secutiry_Supply_Dutch.pdf.
- [204] M. Bidwell. “Reliability options : A market-oriented approach to long-term adequacy.” *The Electricity Journal*, vol. 18, no. 5, pp. 11–25, 2005.
- [205] C. Batlle, C. Vázquez, M. Rivier, and I. J. Pérez-Arriaga. “Enhancing power supply adequacy in Spain: Migrating from capacity payments to reliability options.” *Energy Policy*, vol. 35, no. 9, pp. 4545–4554, 2007.
- [206] T. Rothwell, G. Gomez. *Electricity Economics: Regulation and Deregulation*. Wiley Inter-Science, 2003.
- [207] S. Borenstein. “The economics of fixed cost recovery by utilities.”, 2016. URL <http://ei.haas.berkeley.edu>.

- [208] D. Hach and S. Spinler. “Capacity payment impact on gas-fired generation investments under rising renewable feed-in — A real options analysis.” *Energy Economics*, vol. 53, pp. 270–280, 2014.
- [209] F. Olsina, R. Pringles, C. Larisson, and F. Garcés. “Reliability payments to generation capacity in electricity markets.” *Energy Policy*, vol. 73, pp. 211–224, 2014.
- [210] PJM Interconnection. “PJM’s Evolving Resource Mix and System Reliability.” Tech. rep., 2017. URL <http://www.pjm.com/~media/library/reports-notices/special-reports/20170330-pjms-evolving-resource-mix-and-system-reliability.ashx>.
- [211] National Grid. “Provisional auction results: T-4 capacity market auction, 2018 (2021/22).” Tech. rep., 2018. URL <https://www.emrdeliverybody.com/CapacityMarketsDocumentLibrary/EarlyAuction17-18ProvisionalResults.pdf>.
- [212] Eirgrid and SONI. “All -Island Generation Capacity Statement 2016-2025.” Tech. rep., 2016. URL http://www.eirgridgroup.com/site-files/library/EirGrid/Generation_Capacity_Statement_20162025_FINAL.pdf.
- [213] Australian Energy Market Operator (AEMO). “2018 Electricity Statement of Opportunities.” Tech. Rep. August, 2018. URL https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/NEM_ES00/2018/2018-Electricity-Statement-of-Opportunities.pdf.
- [214] N. Y. Dahlan. “Agent-based modeling for studying the impact of capacity mechanisms on generation expansion in liberalized electricity market.” *Journal of Electrical Engineering and Technology*, vol. 10, no. 4, pp. 1461–1471, 2015.
- [215] S. E. Kerckhoffs. *Influence of capacity markets on the development of electrical energy storage: An Agent-Based simulation study into the long term effects of a capacity market on electrical energy storage*. Masters, Delft University of Technology, 2015. URL <https://repository.tudelft.nl/islandora/object/uuid:f4437f73-779c-4ec2-b282-8e339c30c816/datastream/OBJ1/download>.
- [216] D. Keles, A. Bublitz, F. Zimmermann, M. Genoese, and W. Fichtner. “Analysis of design options for the electricity market: The German case.” *Applied Energy*, vol. 183, pp. 884–901, 2016.
- [217] D. Lara-arango, S. Arango-aramburo, and E. R. Larsen. “Towards long-term economic welfare in deregulated electricity markets : Testing capacity mechanisms in an experimental setting.” *The Electricity Journal*, vol. 30, no. 6, pp. 53–71, 2017.

- [218] SADC. “SADC Regional Vulnerability Assessment and Analysis Synthesis Report 2015.” Tech. Rep. October, SADC, 2015. URL https://www.sadc.int/files/1715/3114/9162/2018_SADC_RVAA_Synthesis_Report__060718.pdf.
- [219] C. L. Davis-Reddy and K. Vincent. *Climate Risk and Vulnerability: a Handbook for Southern Africa*. 2nd ed., 2017. URL <http://linkinghub.elsevier.com/retrieve/pii/B9780128014776000034>.
- [220] R. Spalding-Fecher, B. Joyce, and H. Winkler. “Climate change and hydropower in the Southern African Power Pool and Zambezi River Basin: System-wide impacts and policy implications.” *Energy Policy*, vol. 103, pp. 84–97, 2017.
- [221] F. Almeida Prado, S. Athayde, J. Mossa, S. Bohlman, F. Leite, and A. Oliver-Smith. “How much is enough? An integrated examination of energy security, economic growth and climate change related to hydropower expansion in Brazil.” *Renewable and Sustainable Energy Reviews*, vol. 53, pp. 1132–1136, 2016. URL <http://dx.doi.org/10.1016/j.rser.2015.09.050>.
- [222] H. Rudnick and L. Barroso. “South American reform lessons—twenty years of restructuring and reform in Argentina, Brazil, and Chile.” *IEEE Power and Energy Magazine*, vol. 3, pp. 49–59, 2005.
- [223] G. Hawker, K. Bell, and S. Gill. “Capacity Markets and the EU Target Model – a Great Britain Case Study.” In *CIGRE Session 2016*, pp. 1–15. 2016.
- [224] European Commission. “Guidelines on State aid for environmental protection and energy 2014-2020.”, 2014. URL [http://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX:52014XC0628\(01\)](http://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX:52014XC0628(01)).
- [225] P. Mastropietro, P. Rodilla, and C. Batlle. “The need for non-performance penalties in capacity mechanisms: Conceptual considerations and empirical evidence.”, 2015. URL http://www.iit.comillas.edu/batlle/Publications/2015Capacitymechanismsandperformanceincentives_Mastropietroetal.pdf.
- [226] Ofgem. “Consolidated version of the Capacity Market Rules.” Tech. rep., 2018. URL https://www.ofgem.gov.uk/system/files/docs/2018/07/annex_c_-_schedule_showing_amendments_to_the_capacity_market_rules.pdf.
- [227] Electric Power Research Institute (EPRI). “Power generation technology data for Integrated Resource Plan of South Africa: Technical Update.” Tech. Rep. August, Electric Power Research Institute (EPRI), 2015. URL http://www.energy.gov.za/IRP/irpfiles/Tech_Data_for_Integ_Plan_of_South_Africa_July_08_2010_Final.pdf.
- [228] Alberta Electric System Operator. “Capacity market transition.” URL <https://www.aeso.ca/market/capacity-market-transition/>.

- [229] M. Cepeda, M. Saguan, D. Finon, and V. Pignon. “Generation adequacy and transmission interconnection in regional electricity markets.” *Energy Policy*, vol. 37, no. 12, pp. 5612–5622, 2009.
- [230] P. C. Bhagwat, J. C. Richstein, E. J. Chappin, K. K. Iychettira, and L. J. De Vries. “Cross-border effects of capacity mechanisms.” In *11th International Conference on the European Energy Market (EEM)*, pp. 33–47. Krakow, Poland, 2014.
- [231] H. Hoschle, C. D. Jonghe, D. Six, and R. Belmans. “Influence of non-harmonized capacity mechanisms in an interconnected power system on generation adequacy.” In *19th Power Systems Computation Conference*. 2016.
- [232] L. J. De Vries. “Generation adequacy: Helping the market do its job.” *Utilities Policy*, vol. 15, no. 1, pp. 20–35, 2007.
- [233] D. Grubb, M. Newbery, D. Newbery, and M. Grubb. “The final hurdle?: Security of supply, the capacity mechanism and the role of interconnectors.” Tech. rep., University of Cambridge: Energy Policy Research Group, 2014.
- [234] V. V. Vadlamudi and G. Doorman. “Interconnector participation in capacity mechanisms: A new derating approach.” In *14th International Conference on the European Energy Market (EEM17)*. Dresden, Germany, 2017.
- [235] R. Meyer and O. Gore. “Cross-border effects of capacity mechanisms : Do uncoordinated market design changes contradict the goals of the European market integration?” *Energy Economics*, vol. 51, pp. 9–20, 2015.
- [236] H. Höschle, H. L. Cadre, and R. Belmans. “Inefficiencies caused by non-harmonized capacity mechanisms in an interconnected electricity market.” *Sustainable Energy, Grids and Networks*, vol. 13, pp. 29–41, 2017.
- [237] P. A. Trotter, R. Maconachie, and M. C. Mcmanus. “The impact of political objectives on optimal electricity generation and transmission in the Southern African Power Pool.” *Journal of Energy in Southern Africa*, vol. 28, no. 3, pp. 27–42, 2017.
- [238] U.S. Trade and Development Agency. “South Africa Energy Storage Technology and Market Assessment: Objective 2.2 Deliverable (Economic Assessment).” Tech. rep., 2016. URL https://www.idc.co.za/images/2017/eskom/USTDA_PublicVersion.pdf.
- [239] Lazard. “LAZARD’s Levelised Cost of Storage Version 3.0.” Tech. rep., Lazard, 2017. URL <https://www.lazard.com/media/450338/lazard-levelized-cost-of-storage-version-30.pdf>.
- [240] Benoit Decourt, R. Debarre, S. Alias, and P. Gahlot. “FactBook: Electricity Storage Gaining Momentum.” Tech. rep., A.T. Kearney Energy Transition Institute, 2017.

- [241] Australian Energy Market Operator (AEMO). “Initial operation of the Hornsdale Power Reserve Battery Energy Storage System.” Tech. rep., 2018. URL <http://energylive.aemo.com.au/Innovation-and-Tech/-/media/45ACDCBA73CE46A585ACBFFB132EF9B0.ashx>.
- [242] International Renewable Energy Agency (IRENA). *Electricity Storage and Renewables : Costs and Markets To 2030*. 2017. URL http://www.irena.org/-/media/Files/IRENA/Agency/Publication/2017/Oct/IRENA_Electricity_Storage_Costs_2017.pdf.
- [243] O. Schmidt, A. Hawkes, A. Gambhir, and I. Staffell. “The future cost of electrical energy storage based on experience rates.” *Nature Energy*, vol. 6, p. 17110, jul 2017. URL <http://www.nature.com/articles/nenergy2017110>.
- [244] A. Eller and D. Gauntlett. “Energy storage trends and opportunities in emerging markets.” Tech. rep., International Finance Corporation (IFC) - World Bank Group, 2017. URL <https://www.ifc.org/wps/wcm/connect/ed6f9f7f-f197-4915-8ab6-56b92d50865d/7151-IFC-EnergyStorage-report.pdf?MOD=AJPERES>.
- [245] M. Milligan, B. Frew, E. Zhou, D. J. Arent, M. Milligan, B. Frew, and E. Zhou. “Advancing system flexibility for high penetration renewable integration.” Tech. Rep. October, NREL, 2015. URL <https://www.nrel.gov/docs/fy16osti/64864.pdf>.
- [246] P. N. Christiansen. *Equilibrium modeling of a power market with a capacity market designed to promote flexible capacity*. Ph.D. thesis, Norwegian University of Science and Technology, 2016.
- [247] I. Filipiak. “Capacity market in Poland – evaluation of the proposed solution.” In *14th International Conference on the European Energy Market (EEM)*. Dresden, Germany, 2017.
- [248] H. Höschle, C. De Jonghe, H. Le Cadre, and R. Belmans. “Electricity markets for energy, flexibility and availability — Impact of capacity mechanisms on the remuneration of generation technologies.” *Energy Economics*, vol. 66, pp. 372–383, 2017.
- [249] M. Wierzbowski and I. Filipiak. “Enhanced operational reserve as a tool for development of optimal energy mix.” *Energy Policy*, vol. 102, no. 2016, pp. 602–615, 2017.
- [250] S. Kerckhoffs. “The influence of capacity markets and electrical energy storage on the Dutch electricity market.” Tech. rep., Faculty of Technology, Policy and Management, Delft University of Technology, Delft, 2013. URL <https://repository.tudelft.nl/islandora/object/uuid%3Af4437f73-779c-4ec2-b282-8e339c30c816>.

- [251] S. Chen and C.-c. Liu. “From demand response to transactive energy : state of the art.” *Journal of Modern Power Systems and Clean Energy*, vol. 5, no. 1, pp. 10–19, 2017.
- [252] M. Mylrea and S. N. G. Gourisetti. “Blockchain for smart grid resilience: Exchanging distributed energy at speed, scale and security.” *2017 Resilience Week (RWS)*, pp. 18–23, 2017. URL <http://ieeexplore.ieee.org/document/8088642/>.
- [253] TenneT and Sonnen. “Europe’s first blockchain project to stabilize the power grid launches: TenneT and sonnen expect results in 2018 - TenneT.”, 2018. URL <https://www.tennet.eu/news/detail/europes-first-blockchain-project-to-stabilize-the-power-grid-launches-tennet-and-sonnen-expect-res/>.
- [254] LO3Energy. “Exergy.”, 2017. URL <https://exergy.energy/>.
- [255] Power Ledger. “Power Ledger.”, 2017. URL <https://powerledger.io/>.
- [256] D. Malone and K. O’Dwyer. “Bitcoin Mining and its Energy Footprint.” *25th IET Irish Signals & Systems Conference 2014 and 2014 China-Ireland International Conference on Information and Communities Technologies (ISSC 2014/CICT 2014)*, pp. 280–285, 2014. URL <http://digital-library.theiet.org/content/conferences/10.1049/cp.2014.0699>.
- [257] H. Vranken. “Sustainability of bitcoin and blockchains.” *Current Opinion in Environmental Sustainability*, vol. 28, pp. 1–9, 2017. URL <http://dx.doi.org/10.1016/j.cosust.2017.04.011>.
- [258] FICO. “Xpress Optimization Suite.”, 2017. URL <http://www.fico.com/en/products/fico-xpress-optimization-suite>.
- [259] International Renewable Energy Agency (IRENA). “Southern African Power Pool: Planning and Prospects for Renewable Energy.” Tech. rep., International Renewable Energy Agency (IRENA), 2013. URL http://www.irena.org/DocumentDownloads/Publications/GA_ECOWAS_Solar_Web.pdf
<http://www.irena.org/DocumentDownloads/Publications/SAPP.pdf>.
- [260] R. Spalding-Fecher, M. Senatla, F. Yamba, B. Lukwesa, G. Himunzowa, C. Heaps, A. Chapman, G. Mahumane, B. Tembo, and I. Nyambe. “Electricity supply and demand scenarios for the Southern African Power Pool.” *Energy Policy*, vol. 101, pp. 403–414, 2017.
- [261] C. Taliotis, A. Shivakumar, E. Ramos, M. Howells, D. Mentis, V. Sridharan, O. Broad, and L. Mofor. “An indicative analysis of investment opportunities in the African electricity supply sector - Using TEMBA (The Electricity Model Base for Africa).” *Energy for Sustainable Development*, vol. 31, pp. 50–66, 2016.

- [262] S. Bofinger, B. Zimmermann, A.-K. Gerlach, D. T. Bischof-Niemz, and C. Mushwana. “Wind and Solar PV Resource Aggregation Study for South Africa.” Tech. rep., CSIR, Fraunhofer IWES, Eskom, SANEDI, DTU, 2016. URL <https://www.csir.co.za/csir-energy-centre>.
- [263] G. Andresen, J. Hörsch, T. Brown, M. Schlott, and D. Schlachtberger. “Atlite.”, 2017. URL <https://github.com/FRESNA/atlite>.
- [264] G. B. Andresen, A. A. Søndergaard, and M. Greiner. “Validation of Danish wind time series from a new global renewable energy atlas for energy system analysis.” *Energy*, vol. 93, pp. 1074–1088, 2015.
- [265] S. Saha, S. Moorthi, X. Wu, J. Wang, S. Nadiga, P. Tripp, D. Behringer, Y.-T. Hou, H.-y. Chuang, M. Iredell, M. Ek, J. Meng, R. Yang, M. P. Mendez, H. van den Dool, Q. Zhang, W. Wang, M. Chen, and E. Becker. “NCEP Climate Forecast System Version 2 (CFSv2) Selected Hourly Time-Series Products.”, 2011.

Appendix A

Published Research

Academic articles that contributed part of this research are listed below:

- **Wright, J.G.** van Coller, J. *Long-term system adequacy in the Southern African Power Pool (SAPP) based on a review of historical capacity balances and electricity trade: A case for Capacity Mechanisms*, Journal of Energy in Southern Africa (JESA), 2018 [Submitted manuscript]
- **Wright, J.G.** van Coller, J. *A capacity mechanism framework to incentivise generation capacity in the Southern African Power Pool (SAPP)*, Utilities Policy, 2018 [Submitted manuscript]

Conference articles and industry related publications that contributed to this research are listed below:

- **Wright, J.G.** and Van Coller, J. “*A review of SAPP markets and a proposal for a novel market structure to incentivise generation investment in Southern Africa*,” in 25th Southern African Universities Power Engineering Conference (SAUPEC), 2017.
- Doorman, G. Barquin, J. Barroso, L. Batlle, C. Cruickshank, A. Dervieux, C. Flanagan, R. Gilmore, J. Greenhalg, J. Höschle, H. Mastropietro, P. Keech, A. Krupa, M. Riesz, J. LaRose, B. Schwenen, S. Thorpe, G. Vos, K. De Vries, L. **Wright., J.G.** “*Capacity mechanisms: needs, solutions and state of affairs*,” *CIGRE WG C5.17 (TB647)*, 2016.
- Bowker, D. Cruickshank, A. Balkwill, A. Keech, A., Nozdryn-Plotnicki, M. Clarke, B. Stevens, D. Urrego, L. Libratti, S. Haarla, L. Surendran, R. Domergue, S.

- Naidoo, R. Laurita, R. Asano, H. Sato, Y. Furusawa, K. Tsukamoto, Y. Hastings, M. Beta, M. Yang, D. Giesbertz, P. Macdonald, G. Dumas, J. la Grange, J. Steven, R. Eggleston, J. Taccoen, A. Baker, T. Cary, T. **Wright, J.G.** Murphy, P. Barroso, L. “*WG C5.12: Generator Market Power Mitigation Measures in Electricity Markets (TB 580)*,” 2014.
- **Wright, J. G.** “*Over the Transmission Hurdle: Assessing electrical transmission constraints for the Southern African Power Pool (SAPP) in PLEXOS*,” Johannesburg, South Africa, 2014.

Appendix B

Dataset of the SAPP region

B.1 Overview

In the spirit of this research being open and available for researchers and practitioners, the dataset developed is shared accordingly as part of this research contribution. This section provides an overview of the contents therein. Please note that the full dataset is available upon request.

An assumed simplified transportation model with each node represented on a country-by-country basis (similar to that of the MTP network model used for SAPP competitive electricity market trading). The transfer limits of existing interconnectors between countries are scaled linearly with the expected size of the power system to the end of the time horizon¹. Planned interconnectors are also included in the dataset but not used at this stage in the models developed (see section B.5).

The demand-side is modelled considering present demand in the region at a national level with a demand forecast to the end of the assumed time horizon (see section B.4).

The supply-side is modelled in detail with available public domain data and is presented in section B.2 for existing capacity and B.3 for future supply candidates in the SAPP region.

The quantitative assessments performed are undertaken by implementing the previously mentioned SAPP dataset in PLEXOS [173]. The platform is based on optimisation and provides a mathematical programming environment based on numerical

¹Assumed to be 2050.

optimisation to optimise systems in the short-term², medium-term³ and long-term⁴ in an integrated manner. It is tightly integrated with a number of commercial (and open-source) mathematical solvers capable of solving Linear Programming (LP) and Mixed-Integer Linear Programming (MILP) problems. The commercial solver utilised in this research is Xpress-MP [258].

B.2 Supply technologies (existing)

Existing supply capacity in the SAPP region is based on [259] supplemented by [156, 237, 260, 261], the most recent SAPP Annual Report [129] and national SAPP Power Utilities (PUs) Annual Reports (where available). For South Africa, the basis is [102, 103, 145]. For plants considered small, these are aggregated accordingly (as will be shown). Where decommissioning dates are not known, typical lifetimes for particular technologies are assumed (as will be shown). Key technical characteristics of supply technologies are based on [102, 103] and summarised in this section.

A listing of the existing supply capacity in the SAPP region along with key technical and economic characteristics is provided in Table B.1. Please note that the full dataset is published as part of this research and is available upon request.

² Minutes/hours/days.

³ Months/years.

⁴ Many years.

Table B.1: Existing generation capacity in developed dataset of SAPP region (overleaf)

Name	Units	Max Capacity [MW]	Firm Capacity [MW]	Decom. Date	Capacity Factor (ave) [%]	Fuel	Tech	Heat Rate [GJ/ MWh]	VOM [USD/ MWh]	FOM [USD/ kW-yr]	MUT/ MDT [Hrs]	Ramp up/ramp down rate [MW/min]	Reliability (UFOR/ FOR) [%]
ANG-E-Eng-Angola	1	200.0	200.0	-	-	Diesel	Engine	8.70	5.54	33.4	0.5/0.5	40/40	0.6/3.4
ANG-E-H-Bengo	1	17.8	17.8	-	50	Water	Hydro	-	1.51	8.7	-/-	-/-	7.9/5.9
ANG-E-H-Biopia	4	3.6	3.6	-	50	Water	Hydro	-	1.51	8.7	-/-	-/-	7.9/5.9
ANG-E-H-Cambambe I	4	65.0	65.0	-	60	Water	Hydro	-	1.51	8.7	-/-	-/-	8.9/2.7
ANG-E-H-Cambambe II	4	175.0	175.0	-	60	Water	Hydro	-	1.51	8.7	-/-	-/-	-
ANG-E-H-Capanda	4	130.0	130.0	-	66	Water	Hydro	-	1.51	8.7	-/-	-/-	8.9/2.7
ANG-E-H-Chicapa	4	4.0	4.0	-	65	Water	Hydro	-	1.51	8.7	-/-	-/-	7.9/5.9
ANG-E-H-Gove	4	15.0	15.0	-	33	Water	Hydro	-	1.51	8.7	-/-	-/-	7.9/5.9
ANG-E-H-Huambo	1	19.0	19.0	-	50	Water	Hydro	-	1.51	8.7	-/-	-/-	7.9/5.9
ANG-E-H-Huila	1	41.1	41.1	-	50	Water	Hydro	-	1.51	8.7	-/-	-/-	8.9/2.7
ANG-E-H-Lauca	6	340.0	340.0	-	50	Water	Hydro	-	1.51	8.7	-/-	-/-	-
ANG-E-H-Lomaum	1	50.0	50.0	-	33	Water	Hydro	-	1.51	8.7	-/-	-/-	8.9/2.7
ANG-E-H-Mabubas	4	6.4	6.4	-	33	Water	Hydro	-	1.51	8.7	-/-	-/-	7.9/5.9
ANG-E-H-Matala	3	13.6	13.6	-	50	Water	Hydro	-	1.51	8.7	-/-	-/-	7.9/5.9
ANG-E-OCGT-Angola	5	50.0	50.0	-	-	NG	OCGT	18.00	0.19	12.7	2/2	5.0/5.0	2.2/4.7
BOT-E-Coal-Morupule 5&6	2	150.0	150.0	2048	-	Coal	St	9.73	4.18	38.0	8/8	3.0/3.0	8.1/4.5
BOT-E-Coal-Morupule A	4	33.0	33.0	2047	-	Coal	St	12.00	0.86	56.7	8/8	0.7/0.7	4.5/6.9
BOT-E-Coal-Morupule B	4	150.0	150.0	2044	-	Coal	St	10.91	4.18	38.0	8/8	3.0/3.0	5.6/3.6
BOT-E-Eng-Francistown	1	70.0	70.0	-	-	Diesel	Engine	8.78	0.19	33.4	1/1	14.0/14.0	0.6/3.4

NG: Natural Gas; St: Steam Turbine

Name	Units	Max Capacity [MW]	Firm Capacity [MW]	Decom. Date	Capacity Factor (ave) [%]	Fuel	Tech	Heat Rate [GJ/ MWh]	VOM [USD/ MWh]	FOM [USD/ kW-yr]	MUT/ MDT [Hrs]	Ramp up/ramp down rate [MW/min]	Reliability (UFOR/ FOR) [%]
BOT-E-OCGT-Orapa	1	90.0	90.0	-	-	Diesel	OCGT	10.29	0.19	12.7	2/2	9.0/9.0	2.2/4.7
DRC-E-Eng-DRC Engines	15	10.0	10.0	-	-	Diesel	Engine	8.78	5.54	33.4	1/1	0.2/0.2	0.6/3.4
DRC-E-H-Inga 1	6	58.5	58.5	-	77	Water	Hydro	-	1.51	8.7	-/-	-/-	8.9/2.7
DRC-E-H-Inga 2	8	178.0	178.0	-	77	Water	Hydro	-	1.51	8.7	-/-	-/-	8.9/2.7
DRC-E-H-Koni & Nseke	1	290.0	290.0	-	55	Water	Hydro	-	1.51	8.7	-/-	-/-	8.9/2.7
DRC-E-H-Mwadingusha	1	68.0	68.0	-	34	Water	Hydro	-	1.51	8.7	-/-	-/-	8.9/2.7
DRC-E-H-Nzilo	1	108.0	108.0	-	60	Water	Hydro	-	1.51	8.7	-/-	-/-	8.9/2.7
DRC-E-H-Sanga & Zongo	1	83.0	83.0	-	12.8	Water	Hydro	-	1.51	8.7	-/-	-/-	7.9/5.9
LES-E-H-LES Small	1	2.0	2.0	-	65	Water	Hydro	-	1.51	8.7	-/-	-/-	7.9/5.9
LES-E-H-Muela	3	24.0	24.0	-	65	Water	Hydro	-	1.51	8.7	-/-	-/-	7.9/5.9
MAL-E-Eng-Lilongwe Mzuzu Blantyre	1	46.0	46.0	-	-	Diesel	Engine	8.78	5.54	33.4	1/1	9.2/9.2	0.6/3.4
MAL-E-H-Kapichira I	2	32.0	32.0	-	84	Water	Hydro	-	1.51	8.7	-/-	-/-	8.9/2.7
MAL-E-H-Kapichira II	2	32.0	32.0	-	84	Water	Hydro	-	1.51	8.7	-/-	-/-	8.9/2.7
MAL-E-H-Nkula A	3	8.0	8.0	-	59	Water	Hydro	-	1.51	8.7	-/-	-/-	7.9/5.9
MAL-E-H-Nkula B	5	20.0	20.0	-	39	Water	Hydro	-	1.51	8.7	-/-	-/-	7.9/5.9
MAL-E-H-Tedzani I	2	10.0	10.0	-	81	Water	Hydro	-	1.51	8.7	-/-	-/-	7.9/5.9
MAL-E-H-Tedzani II	2	10.0	10.0	-	81	Water	Hydro	-	1.51	8.7	-/-	-/-	7.9/5.9
MAL-E-H-Tedzani III	2	26.0	26.0	-	63	Water	Hydro	-	1.51	8.7	-/-	-/-	7.9/5.9

NG: Natural Gas; St: Steam Turbine

Name	Units	Max Capacity [MW]	Firm Capacity [MW]	Decom. Date	Capacity Factor (ave) [%]	Fuel	Tech	Heat Rate [GJ/ MWh]	VOM [USD/ MWh]	FOM [USD/ kW-yr]	MUT/ MDT [Hrs]	Ramp up/ramp down rate [MW/min]	Reliability (UFOR/ FOR) [%]
MAL-E-H-Wovwe Mini Hydro	3	1.3	1.33	-	25	Water	Hydro	-	1.51	8.7	-/-	-/-	7.9/5.9
MOZ-E-Eng-Aggrekko	1	224.0	224.0	-	-	NG	Engine	8.78	5.54	33.4	1/1	22.0/44.8	0.6/3.4
MOZ-E-Eng-Nacala	6	16.7	16.7	2018	-	Diesel	Engine	8.78	5.54	33.4	1/1	3.3/3.3	0.6/3.4
MOZ-E-Eng-Ressano Garcia	7	17.1	17.1	2044	-	NG	Engine	8.78	5.54	33.4	1/1	3.4/3.4	0.6/3.4
MOZ-E-Eng-Temane	1	5.0	5.0	2046	-	NG	Engine	8.78	5.54	33.4	1/1	1.0/1.0	0.6/3.4
MOZ-E-H-Cahora Bassa	5	415.0	415.0	-	85	Water	Hydro	-	1.51	8.7	-/-	-/-	8.9/2.7
MOZ-E-H-Chicamba	2	19.0	19.0	-	16	Water	Hydro	-	1.51	8.7	-/-	-/-	7.9/5.9
MOZ-E-H-Corumana	1	16.6	16.6	-	21	Water	Hydro	-	1.51	8.7	-/-	-/-	7.9/5.9
MOZ-E-H-Mavuzi 1-3	3	14.0	14.0	-	75	Water	Hydro	-	1.51	8.7	-/-	-/-	7.9/5.9
MOZ-E-H-Mavuzi 4-5	2	5.0	5.0	-	75	Water	Hydro	-	1.51	8.7	-/-	-/-	7.9/5.9
MOZ-E-OCGT-Maputo 1	1	12.0	12.0	2046	-	Diesel	OCGT	10.29	0.19	12.7	2/2	1.2/1.2	2.2/4.7
MOZ-E-OCGT-Maputo 2	1	32.0	32.0	2046	-	Diesel	OCGT	10.29	0.19	12.7	2/2	3.2/3.2	2.2/4.7
MOZ-E-OCGT-Maputo 3	1	22.0	22.0	2046	-	Diesel	OCGT	10.29	0.19	12.7	2/2	2.2/2.2	2.2/4.7
MOZ-E-OCGT-Temane	1	11.2	11.2	2046	-	Diesel	OCGT	10.29	0.19	12.7	2/2	1.1/1.1	2.2/4.7
NAM-E-Coal-Van Eck	4	30.0	30.0	2027	-	Coal	St	12.00	4.18	56.7	8/8	0.6/0.6	4.5/6.9
NAM-E-Eng-Anixas	3	7.5	7.5	-	-	Diesel	Engine	8.78	5.35	33.4	1/1	1.5/1.5	0.6/3.4
NAM-E-Eng-Paratus	4	10.0	10.0	-	-	HFO	Engine	8.78	5.35	33.4	1/1	1.2/1.2	0.6/3.4

NG: Natural Gas; St: Steam Turbine

Name	Units	Max Capacity [MW]	Firm Capacity [MW]	Decom. Date	Capacity Factor (ave) [%]	Fuel	Tech	Heat Rate [GJ/ MWh]	VOM [USD/ MWh]	FOM [USD/ kW-yr]	MUT/ MDT [Hrs]	Ramp up/ramp down rate [MW/min]	Reliability (UFOR/ FOR) [%]
NAM-E-H-Ruacana	4	86.8	86.8	-	66	Water	Hydro	-	1.51	8.7	-/-	-/-	8.9/2.7
NAM-E-Wind-Ombepo	1	5.0	0	2034	-	Wind	Wind	-	-	165.0	-/-	-/-	-
RSA-E-Biogas-REIPPPP3 Landfill Gas	1	18.0	18.0	-	-	Biogas	Engine	12.30	9.04	154.0	1/1	3.6/3.6	5.0/10. 0
RSA-E-Biomass- REIPPPP3 Biomass	1	16.5	16.5	-	70	Bagasse	St	14.24	5.24	131.0	8/8	0.3/0.3	6.0/4.0
RSA-E-Biomass- REIPPPP4 Biomass	1	25.0	25.0	-	70	Bagasse	St	14.24	5.24	131.0	8/8	0.5/0.5	6.0/4.0
RSA-E-Coal-Arnot	6	370.0	370	2021-2029	-	Coal	St	13.40	6.33	73.2	8/8	2.1/2.0	6.9/4.5
RSA-E-Coal-Camden	8	190.0	190	2020-2023	-	Coal	St	14.28	6.33	73.2	8/8	1.1/1.0	6.9/4.5
RSA-E-Coal-Duvha	6	580.0	580.0	2030-2034	-	Coal	St	12.69	6.33	73.2	8/8	3.3/4.0	8.1/4.5
RSA-E-Coal-Grootvlei	6	180.0	180.0	2025-2028	-	Coal	St	14.50	6.33	73.2	8/8	0.9/0.3	6.9/4.5
RSA-E-Coal-Hendrina	10	190.0	190.0	2019-2026	-	Coal	St	13.95	6.33	73.2	8/8	1.1/1.1	6.9/4.5
RSA-E-Coal-Kelvin A	6	30.0	30.0	2016	-	Coal	St	12.37	6.33	73.2	8/8	0.6/0.6	6.9/4.5
RSA-E-Coal-Kelvin B	7	60.0	60.0	2016	-	Coal	St	12.37	6.33	73.2	8/8	1.2/1.2	6.9/4.5
RSA-E-Coal-Kendal	6	640.0	640.0	2037-2043	-	Coal	St	12.39	6.33	73.2	8/8	1.8/2.0	8.1/4.5
RSA-E-Coal-Khanyisa	2	153.0	153.0	2051	-	Coal	St	10.79	14.98	49.2	8/8	3.1/3.1	4.8/3.7
RSA-E-Coal-Komati	9	100.0	100.0	2023-2028	-	Coal	St	14.90	6.33	73.2	8/8	0.5/0.6	5.6/3.6
RSA-E-Coal-Kriel	6	480.0	480.0	2025-2029	-	Coal	St	12.93	6.33	73.2	8/8	3.6/0.5	7.6/4.9
RSA-E-Coal-Kusile	6	723.0	723.0	-	-	Coal	St	9.81	6.33	478.4	8/8	7.2/7.2	7.8/3.3

NG: Natural Gas; St: Steam Turbine

Name	Units	Max Capacity [MW]	Firm Capacity [MW]	Decom. Date	Capacity Factor (ave) [%]	Fuel	Tech	Heat Rate [GJ/ MWh]	VOM [USD/ MWh]	FOM [USD/ kW-yr]	MUT/ MDT [Hrs]	Ramp up/ramp down rate [MW/min]	Reliability (UFOR/ FOR) [%]
RSA-E-Coal-Lethabo	6	590.0	590.0	2034-2040	-	Coal	St	11.57	6.33	73.2	8/8	5.9/2.0	8.1/4.5
RSA-E-Coal-Majuba I	3	610.0	610.0	2045	-	Coal	St	12.39	6.33	73.2	8/8	1.7/2.5	8.1/4.5
RSA-E-Coal-Majuba II	3	670.0	670.0	2048	-	Coal	St	11.60	6.33	73.2	8/8	1.9/2.5	8.1/4.5
RSA-E-Coal-Matimba	6	620.0	620.0	2036-2041	-	Coal	St	12.99	6.33	73.2	8/8	3.0/3.2	8.1/4.5
RSA-E-Coal-Matla	6	580.0	580.0	2028-2033	-	Coal	St	12.69	6.33	73.2	8/8	2.5/2.5	8.1/4.5
RSA-E-Coal-Medupi	6	722.0	722.0	-	-	Coal	St	9.81	6.33	478.4	8/8	7.8/7.2	7.8/3.3
RSA-E-Coal-Secunda	12	50.0	50.0	-	-	Coal	St	12.75	14.98	49.2	8/8	1.2/1.2	4.5/6.9
RSA-E-Coal-Thabametsi	4	140.0	140.0	2051	-	Coal	St	10.79	14.98	49.2	8/8	2.8/2.8	4.8/3.7
RSA-E-Coal-Tutuka	6	580.0	580.0	2034-2038	-	Coal	St	9.47	6.33	73.2	8/8	3.2/3.2	8.1/4.5
RSA-E-CSP-REIPPPP1-KaXu Solar 3h	1	100.0	50.0	2045	-	Solar	CSP	-	0	1046.4	-/-	-/-	-/-
RSA-E-CSP-REIPPPP1-Khi Solar One 6h	1	50.0	25.0	2046	-	Solar	CSP	-	0	1277.2	-/-	-/-	-/-
RSA-E-CSP-REIPPPP2-Bokpoort 9h	1	50.0	25.0	2046	-	Solar	CSP	-	0	1393.2	-/-	-/-	-/-
RSA-E-CSP-REIPPPP35-Kathu 6h	1	100.0	50.0	2047	-	Solar	CSP	-	0	1187.3	-/-	-/-	-/-
RSA-E-CSP-REIPPPP35-Redstone Solar 9h	1	100.0	50.0	2047	-	Solar	CSP	-	0	1384.8	-/-	-/-	-/-

NG: Natural Gas; St: Steam Turbine

Name	Units	Max Capacity [MW]	Firm Capacity [MW]	Decom. Date	Capacity Factor (ave) [%]	Fuel	Tech	Heat Rate [GJ/ MWh]	VOM [USD/ MWh]	FOM [USD/ kW-yr]	MUT/ MDT [Hrs]	Ramp up/ramp down rate [MW/min]	Reliability (UFOR/ FOR) [%]
RSA-E-CSP-REIPPPP3-Karoshhoek 6h	1	100.0	50.0	2047	-	Solar	CSP	-	0	1187.3	-/-	-/-	-/-
RSA-E-CSP-REIPPPP3-Xina 6h	1	100.0	50.0	2046	-	Solar	CSP	-	0	1187.3	-/-	-/-	-/-
RSA-E-CSP-REIPPPP4-Expedited 9h	9	50.0	25.0	2049	-	Solar	CSP	-	0	847.6	-/-	-/-	-/-
RSA-E-Eng-Sasolburg	18	9.7	9.7	-	-	NG	Engine	8.78	5.35	33.4	1/1	1.9/1.9	6.9/4.6
RSA-E-H-Gariep	4	90.0	90.0	-	10	Water	Hydro	-	1.51	8.7	-/-	-/-	8.9/2.7
RSA-E-H-REIPPPP2-Mini_Hydro	1	14.3	14.3	-	65	Water	Hydro	-	0	8.7	-/-	-/-	7.9/5.9
RSA-E-H-REIPPPP4-Mini_Hydro	1	5.0	5.0	-	65	Water	Hydro	-	0	8.7	-/-	-/-	7.9/5.9
RSA-E-H-REIPPPP4-Mini_Hydro Expedited	1	5.0	5.0	-	65	Water	Hydro	-	0	8.7	-/-	-/-	7.9/5.9
RSA-E-H-Vanderkloof	2	120.0	120.0	-	10	Water	Hydro	-	1.51	8.7	-/-	-/-	8.9/2.7
RSA-E-Nuc-KoebergU1	1	930.0	930.0	2043	-	Uranium	Nuclear Fission	11.11	2.94	76.6	12/12	18.6/18.6	6.0/2.1
RSA-E-Nuc-KoebergU2	1	930.0	930.0	2043	-	Uranium	Nuclear Fission	11.11	2.94	76.6	12/12	18.6/18.6	6.0/2.1
RSA-E-OCGT-Acacia	3	57.0	57.0	2025	-	Diesel	OCGT	11.52	0.19	12.7	2/2	3.4/3.4	2.2/4.7

NG: Natural Gas; St: Steam Turbine

Name	Units	Max Capacity [MW]	Firm Capacity [MW]	Decom. Date	Capacity Factor (ave) [%]	Fuel	Tech	Heat Rate [GJ/ MWh]	VOM [USD/ MWh]	FOM [USD/ kW-yr]	MUT/ MDT [Hrs]	Ramp up/ramp down rate [MW/min]	Reliability (UFOR/ FOR) [%]
RSA-E-OCGT-Ankerlig	9	148.0	148.0	2036	-	Diesel	OCGT	11.52	0.19	12.7	2/2	9.0/9.0	2.2/4.7
RSA-E-OCGT-Avon	4	167.5	167.5	2045	-	Diesel	OCGT	11.52	0.19	12.7	2/2	10.0/10.0	6.9/4.6
RSA-E-OCGT-Dedisa	2	167.5	167.5	2045	-	Diesel	OCGT	11.52	0.19	12.7	2/2	10.0/10.0	6.9/4.6
RSA-E-OCGT-Gourikwa	5	148.0	148.0	2036	-	Diesel	OCGT	11.52	0.19	12.7	2/2	9.0/9.0	2.2/4.7
RSA-E-OCGT-Port Rex	3	57.0	57.0	2025	-	Diesel	OCGT	11.52	0.19	12.7	2/2	3.4/3.4	2.2/4.7
RSA-E-OCGT-Secunda SSF	5	50.0	50.0	-	-	NG	OCGT	11.52	0.19	12.7	2/2	5.0/5.0	6.9/4.6
RSA-E-PS-Drakensberg	4	250.0	250.0	-	-	Water	PS	-	0	15.9	-/-	-/-	8.9/2.7
RSA-E-PS-Ingula	4	333.0	333.0	-	-	Water	PS	-	0	15.9	-/-	-/-	8.9/2.7
RSA-E-PS-Palmiet	2	200.0	200.0	-	-	Water	PS	-	0	15.9	-/-	-/-	8.9/2.7
RSA-E-PS-Steenbras	3	60.0	60.0	-	-	Water	PS	-	0	15.9	-/-	-/-	3.0/2.4
RSA-E-PV-REIPPPP1- Solar PV	1	627.0	0	2039	-	Solar	PV	-	0	550.6	-/-	-/-	-/-
RSA-E-PV-REIPPPP2- Solar PV	1	417.0	0	2039	-	Solar	PV	-	0	328.8	-/-	-/-	-/-
RSA-E-PV-REIPPPP3- Solar PV	1	435.0	0	2041	-	Solar	PV	-	0	176.5	-/-	-/-	-/-
RSA-E-PV- REIPPPP4_Add-Solar PV	1	318.0	0	2043	-	Solar	PV	-	0	93.5	-/-	-/-	-/-

NG: Natural Gas; St: Steam Turbine

Name	Units	Max Capacity [MW]	Firm Capacity [MW]	Decom. Date	Capacity Factor (ave) [%]	Fuel	Tech	Heat Rate [GJ/ MWh]	VOM [USD/ MWh]	FOM [USD/ kW-yr]	MUT/ MDT [Hrs]	Ramp up/ramp down rate [MW/min]	Reliability (UFOR/ FOR) [%]
RSA-E-PV- REIPPPP4_Exp-Solar PV	1	591.0	0	2043	-	Solar	PV	-	0	93.5	-/-	-/-	-/-
RSA-E-PV-REIPPPP4- Solar PV	1	415.0	0	2043	-	Solar	PV	-	0	131.3	-/-	-/-	-/-
RSA-E-Wind-REIPPPP1- Wind	1	646.0	0	2034	-	Wind	Wind	-	0	402.8	-/-	-/-	-/-
RSA-E-Wind-REIPPPP2- Wind	1	560.0	0	2034	-	Wind	Wind	-	0	317.4	-/-	-/-	-/-
RSA-E-Wind-REIPPPP3- Wind	1	788.0	0	2034	-	Wind	Wind	-	0	232.0	-/-	-/-	-/-
RSA-E-Wind- REIPPPP4_Add-Wind	1	686.0	0	2039	-	Wind	Wind	-	0	165.4	-/-	-/-	-/-
RSA-E-Wind- REIPPPP4_Exp-Wind	1	681.0	0	2039	-	Wind	Wind	-	0	165.4	-/-	-/-	-/-
RSA-E-Wind-REIPPPP4- Wind	1	676.0	0	2039	-	Wind	Wind	-	0	184.1	-/-	-/-	-/-
RSA-E-Wind-Sere	2.3	46.0	0	2034	-	Wind	Wind	-	0	184.1	-/-	-/-	-/-
SWA-E-Biomass-RSSC Bagasse	1	65.0	65.0	-	50	Bagasse	St	9.47	2.13	131.0	8/8	1.3/1.3	4.2/5.8

NG: Natural Gas; St: Steam Turbine

Name	Units	Max Capacity [MW]	Firm Capacity [MW]	Decom. Date	Capacity Factor (ave) [%]	Fuel	Tech	Heat Rate [GJ/ MWh]	VOM [USD/ MWh]	FOM [USD/ kW-yr]	MUT/ MDT [Hrs]	Ramp up/ramp down rate [MW/min]	Reliability (UFOR/ FOR) [%]
SWA-E-Biomass-Ubombo Bagasse	1	40.0	40.0	-	50	Bagasse	St	9.47	2.13	131.0	8/8	0.8/0.8	4.2/5.8
SWA-E-H-Edwaleni 1	4	2.5	2.5	-	37	Water	Hydro	-	1.51	8.7	-/-	-/-	7.9/5.9
SWA-E-H-Edwaleni 2	1	5.0	5.0	-	37	Water	Hydro	-	1.51	8.7	-/-	-/-	7.9/5.9
SWA-E-H-Ezulwini	2	10.0	10.0	-	37	Water	Hydro	-	1.51	8.7	-/-	-/-	7.9/5.9
SWA-E-H-Maguduza	1	5.6	5.6	-	34	Water	Hydro	-	1.51	8.7	-/-	-/-	7.9/5.9
SWA-E-H-Maguga	2	9.9	9.9	-	44	Water	Hydro	-	2.13	8.7	-/-	-/-	7.9/5.9
TAN-E-Biomass-Kagera Sugar	2	2.5	2.5	-	50	Bagasse	St	14.24	2.13	131.0	8/8	0.1/0.1	4.2/5.8
TAN-E-Biomass- Kilombero Sugar I	2	3.0	3.0	-	50	Bagasse	St	14.24	2.13	131.0	8/8	0.1/0.1	4.2/5.8
TAN-E-Biomass- Kilombero Sugar II	1	2.8	2.8	-	50	Bagasse	St	14.24	2.13	131.0	8/8	0.1/0.1	4.2/5.8
TAN-E-Biomass-Mtibwa Sugar	1	13.0	13.0	-	50	Bagasse	St	14.24	2.13	131.0	8/8	0.3/0.3	4.2/5.8
TAN-E-Biomass-Mufindi Paper Mills	1	30.0	30.0	-	50	Bagasse	St	14.24	2.13	131.0	8/8	0.6/0.6	4.2/5.8
TAN-E-Biomass-Sao Hill Timber		10.0	10.0	-	50	Bagasse	St	14.24	2.13	131.0	8/8	0.2/0.2	4.2/5.8

NG: Natural Gas; St: Steam Turbine

Name	Units	Max Capacity [MW]	Firm Capacity [MW]	Decom. Date	Capacity Factor (ave) [%]	Fuel	Tech	Heat Rate [GJ/ MWh]	VOM [USD/ MWh]	FOM [USD/ kW-yr]	MUT/ MDT [Hrs]	Ramp up/ramp down rate [MW/min]	Reliability (UFOR/ FOR) [%]
TAN-E-Biomass- TANWAT	1	2.7	2.7	2030	50	Bagasse	St	14.24	2.13	131.0	8/8	0.2/0.2	4.2/5.8
TAN-E-Biomass-TPC	1	17.0	17.0	2029	50	Bagasse	St	14.24	2.13	131.0	8/8	0.1/0.1	4.2/5.8
TAN-E-Eng-Aggreko Tegeta	32	1.5	1.5	2013	-	Diesel	Engine	8.78	5.54	33.4	1/1	0.3/0.3	0.6/3.4
TAN-E-Eng-Aggreko Ubungo	32	1.5	1.5	2013	-	Diesel	Engine	8.78	5.54	33.4	1/1	0.3/0.3	0.6/3.4
TAN-E-Eng-IPTL	10	10.3	10.3	2021	-	HFO	Engine	8.78	5.54	33.4	1/1	2.1/2.1	0.6/3.4
TAN-E-Eng-Nyakato	6	10.0	10.0	2032	-	HFO	Engine	8.78	5.54	33.4	1/1	2.0/2.0	0.6/3.4
TAN-E-Eng-Symbion Arusha	6	8.5	8.5	2014	-	HFO	Engine	8.78	5.54	33.4	1/1	1.7/1.7	0.6/3.4
TAN-E-Eng-Symbion Dodoma	6	8.5	8.5	2013	-	HFO	Engine	8.78	5.54	33.4	1/1	1.7/1.7	0.6/3.4
TAN-E-Eng-Tegeta	5	9.0	9.0	2028	-	NG	Engine	8.78	5.54	33.4	1/1	1.8/1.8	0.6/3.4
TAN-E-Eng-Zuzu	1	7.0	7.0	2014	-	Diesel	Engine	8.78	5.54	33.4	1/1	1.4/1.4	0.6/3.4
TAN-E-H-Hale	2	10.5	10.5	-	51	Water	Hydro	-	1.51	8.7	-/-	-/-	7.9/5.9
TAN-E-H-Kidatu	4	51.0	51.0	-	57	Water	Hydro	-	1.51	8.7	-/-	-/-	8.9/2.7
TAN-E-H-Kihansi	3	60.0	60.0	-	33	Water	Hydro	-	1.51	8.7	-/-	-/-	8.9/2.7
TAN-E-H-Mtera	2	40.0	40.0	-	54	Water	Hydro	-	1.51	8.7	-/-	-/-	8.9/2.7

NG: Natural Gas; St: Steam Turbine

Name	Units	Max Capacity [MW]	Firm Capacity [MW]	Decom. Date	Capacity Factor (ave) [%]	Fuel	Tech	Heat Rate [GJ/ MWh]	VOM [USD/ MWh]	FOM [USD/ kW-yr]	MUT/ MDT [Hrs]	Ramp up/ramp down rate [MW/min]	Reliability (UFOR/ FOR) [%]
TAN-E-H-Nyumba Ya Mungu	2	4.0	4.0	-	53	Water	Hydro	-	1.51	8.7	-/-	-/-	7.9/5.9
TAN-E-H-Pangani Falls	2	34.0	34.0	-	52	Water	Hydro	-	1.51	8.7	-/-	-/-	8.9/2.7
TAN-E-OCGT-Kinyerezi I	4	37.5	37.5	2035	-	NG	Engine	10.29	0.19	12.7	2/2	3.8/3.8	2.2/4.7
TAN-E-OCGT-Songas I	2	21.0	21.0	2023	-	NG	Engine	10.29	0.19	12.7	2/2	2.1/2.1	2.2/4.7
TAN-E-OCGT-Songas II	3	40.0	40.0	2024	-	NG	Engine	10.29	0.19	12.7	2/2	4.0/4.0	2.2/4.7
TAN-E-OCGT-Songas III	1	40.0	40.0	2025	-	NG	Engine	10.29	0.19	12.7	2/2	4.0/4.0	2.2/4.7
TAN-E-OCGT-Symbion Ubungo	5	24.0	24.0	2013	-	Diesel	Engine	10.29	0.19	12.7	2/2	2.4/2.4	2.2/4.7
TAN-E-OCGT-Ubungo I	12	8.5	8.5	2026	-	NG	Engine	10.29	0.19	12.7	2/2	0.9/0.9	2.2/4.7
TAN-E-OCGT-Ubungo II	3	35.0	35.0	2031	-	NG	Engine	10.29	0.19	12.7	2/2	3.5/3.5	2.2/4.7
ZAM-E-Coal-Maamba I	2	150.0	150.0	2047	-	Coal	St	8.11	0.96	20.0	8/8	3.0/3.0	2.2/4.7
ZAM-E-Eng-Ndola Energy HFO	1	50.0	50.0	2043	-	HFO	Engine	8.78	5.54	33.4	1/1	10.0/10.0	0.6/3.4
ZAM-E-Eng-ZESCO	1	12.0	12.0		-	Diesel	Engine	8.78	5.54	33.4	1/1	2.4/2.4	0.6/3.4
ZAM-E-H-Chishimba	1	6.2	6.2	-	51	Water	Hydro	-	1.51	8.7	-/-	-/-	8.9/2.7
ZAM-E-H-Ithezi Thezi	1	120.0	120.0	-	-	Water	Hydro	-	1.51	8.7	-/-	-/-	0.6/3.4
ZAM-E-H-Kafue Gorge	6	150.0	150.0	-	-	Water	Hydro	-	1.51	8.7	-/-	-/-	0.6/3.4
ZAM-E-H-Kafue Gorge Lower	3	250.0	250.0		67	Water	Hydro	-	1.51	8.7	-/-	-/-	8.9/2.7

NG: Natural Gas; St: Steam Turbine

Name	Units	Max Capacity [MW]	Firm Capacity [MW]	Decom. Date	Capacity Factor (ave) [%]	Fuel	Tech	Heat Rate [GJ/ MWh]	VOM [USD/ MWh]	FOM [USD/ kW-yr]	MUT/ MDT [Hrs]	Ramp up/ramp down rate [MW/min]	Reliability (UFOR/ FOR) [%]
ZAM-E-H-Kariba NB	4	180.0	180.0	-	64	Water	Hydro	-	1.51	8.7	-/-	-/-	8.9/2.7
ZAM-E-H-Kariba NBE	2	180.0	180.0	-	-	Water	Hydro	-	1.51	8.7	-/-	-/-	0.6/3.4
ZAM-E-H-Lunsemfwa	1	56.0	56.0	-	44	Water	Hydro	-	1.51	8.7	-/-	-/-	7.9/5.9
ZAM-E-H-Lunzua	1	14.8	14.8	-	45	Water	Hydro	-	1.51	8.7	-/-	-/-	8.9/2.7
ZAM-E-H-Lusiwasi	1	12.0	12.0	-	60	Water	Hydro	-	1.51	8.7	-/-	-/-	7.9/5.9
ZAM-E-H-Mulungushi	1	32.0	32.0	-	70	Water	Hydro	-	1.51	8.7	-/-	-/-	7.9/5.9
ZAM-E-H-Musonda	1	5.0	5.0	-	-	Water	Hydro	-	1.51	8.7	-/-	-/-	0.6/3.4
ZAM-E-H-Victoria Falls	3	36.0	36.0	-	-	Water	Hydro	-	1.51	8.7	-/-	-/-	0.6/3.4
ZIM-E-Coal-Bulawayo	3	30.0	30.0	2050	-	Coal	St	12.00	6.33	56.7	8/8	0.7/0.7	4.5/6.9
ZIM-E-Coal-Harare 1	1	21.0	21.0	1970	-	Coal	St	12.00	6.33	56.7	8/8	0.4/0.4	4.5/6.9
ZIM-E-Coal-Harare 2	3	12.5	12.5	-	-	Coal	St	12.00	6.33	56.7	8/8	0.3/0.3	4.5/6.9
ZIM-E-Coal-Harare 3	2	30.0	30.0	2050	-	Coal	St	12.00	6.33	56.7	8/8	0.6/0.6	4.5/6.9
ZIM-E-Coal-Hwange Ext	2	300.0	300.0	2060	-	Coal	St	9.73	6.33	56.7	8/8	6.0/6.0	7.6/4.9
ZIM-E-Coal-Hwange I	4	120.0	120.0	-	-	Coal	St	12.00	6.33	56.7	8/8	2.4/2.4	5.6/3.6
ZIM-E-Coal-Hwange II	2	220.0	220.0	-	-	Coal	St	12.00	6.33	56.7	8/8	4.4/4.4	4.5/6.9
ZIM-E-Coal-Munyati	2	100.0	60.0	-	-	Coal	St	12.00	6.33	56.7	8/8	1.2/1.2	4.5/6.9
ZIM-E-H-Kariba South	6	125.0	-	-	64	Water	Hydro	-	1.51	8.7	-/-	-/-	8.9/2.7
ZIM-E-H-Kariba South Ext	2	150.0	150	-	47	Water	Hydro	-	1.51	94.0	-/-	-/-	8.9/2.7
ZIM-E-PV-Gwanda	1	100.0	0	-	-	Solar	PV	-	0	94.0	-/-	-/-	-/-

NG: Natural Gas; St: Steam Turbine

Name	Units	Max Capacity [MW]	Firm Capacity [MW]	Decom. Date	Capacity Factor (ave) [%]	Fuel	Tech	Heat Rate [GJ/ MWh]	VOM [USD/ MWh]	FOM [USD/ kW-yr]	MUT/ MDT [Hrs]	Ramp up/ramp down rate [MW/min]	Reliability (UFOR/ FOR) [%]
ZIM-E-PV-Insukamini	1	100.0	0	-	-	Solar	PV	-	0	94.0	-/-	-/-	-/-
ZIM-E-PV-Munyati	1	100.0	0	-	-	Solar	PV	-	0	8.7	-/-	-/-	-/-

NG: Natural Gas; St: Steam Turbine

B.3 Supply technologies (candidates)

For candidate supply technologies in the dataset, most data specifically related to the economic parameters of technologies is taken from [259] and supplemented by [145, 260]. Key technical characteristics of supply technologies are based on [102, 103] and summarised in this section.

Feed-in times series for variable RES for South Africa (solar PV and wind) is based on [262] which uses a 5 km x 5 km spatial resolution and 15-minute temporal resolution. For the rest of the SAPP region, the time series for solar PV at a national level are generated using *Atlite* [263] based on the original work in [264]. *Atlite* is not yet very well configured for the Southern African region yet and thus the time series generated are a first approximation at this stage considering the minimal information available for the region (other than South Africa as previously mentioned). Thus, knowing that wind feed-in times-series are still very uncertain (more so than solar PV by some margin) and thus wind time-series from *Atlite* are not used at this stage. Instead, the wind feed-in time-series for South Africa is assumed for all other countries for now where wind is considered an expansion candidate. For some background, the re-analysis weather data used in *Atlite* to generate the time-series is based on the *NCEP CFSv2* dataset (with a $0.2^\circ \times 0.2^\circ$ spatial resolution) [265]. The time series also does not have any exclusion areas as yet and is fully inclusive of the entire land-mass of each country. The time-series is averaged for the period 2012-2015. Each grid cell is weighted based on resource available i.e. a grid cell with twice the resource will contribute twice as much to the time-series. For solar PV, solar PV is configured to be north-facing and tilted at the latitude it is located at. The relative capacity factors of the generated time series for each SAPP country is summarised in Table B.2.

A listing of the assumed candidate supply capacity in the SAPP region along with key technical and economic characteristics is provided in Table B.3. As previously mentioned, that the full dataset is published as part of this research and is available upon request.

Table B.2: Annual country level expected capacity factors of variable RES (solar PV and wind) based on generated time series

Country	Solar PV [%]	Wind ¹ [%]
Angola	20.0	-
Botswana	20.8	35.1
DRC	19.1	-
Lesotho	21.2	35.1
Malawi	20.4	35.1
Mozambique	18.8	35.1 ²
Namibia	21.8	35.1
South Africa	20.3	35.1
Swaziland	17.2	-
Tanzania	19.8	35.1
Zambia	20.2	35.1
Zimbabwe	20.1	35.1

¹ Assumed similar for all countries; ² Mozambique south only

Table B.3: Candidate generation capacity in developed dataset of SAPP region (overleaf)

Name	Max Units Built	Max Capacity [MW]	Firm Capacity [MW]	Build Cost (Present/ 2030) [USD/ kW]	Technical/ Economic Life	Capacity Factor Ave [%]	Fuel	Tech	Heat Rate [GJ/ MWh]	VOM [USD/ MWh]	FOM [USD/ kW-yr]	MUT/ MDT [Hrs]	Ramp up/ramp down rate [MW/min]	Reliability (UFOR/ FOR) [%]
ANG-N-CCGT NG	1000	125	125	710	30	-	NG	CCGT	8.57	1.73	13.1	-/-	-/-	6.4/2.4
ANG-N-Eng-Diesel small	1000	10	10	-	30	-	Diesel	Engine	8.78	5.54	33.4	-/-	-/-	-/-
ANG-N-H-Generic	15	200	1560	2665	50	50	Water	Hydro	-	1.51	8.7	-/-	-/-	-/-
ANG-N-OCGT-NG	1000	100	100	647	30	-	NG	OCGT	10.29	0.19	12.7	2/2	10.0/10.0	3.5/2.4
ANG-N-PV-Solar Generic	>10000	1	0	572/461	25	-	Solar	PV	-	-	16.0	-/-	-/-	-/-
BOT-N-CCGT-Diesel	1000	125	125	710	30	-	Diesel	CCGT	8.57	1.73	13.1	3/3	6.3/6.3	6.4/2.4
BOT-N-Eng-Diesel small	1000	10	10	1009	30	-	Diesel	Engine	8.78	5.54	33.4	1/1	-/-	-/-
BOT-N-OCGT-Diesel	1000	100	100	647	30	-	Diesel	OCGT	10.29	0.19	12.7	2/2	10.0/10.0	3.5/2.4
BOT-N-PV-Solar Generic	>10000	1	0	572/461	25	-	Solar	PV	-	-	16.0	-/-	-/-	-/-
BOT-N-Wind-Wind	1200	1	0	869	20	-	Wind	Wind	-	-	40.0	-/-	-/-	-/-
DAM-N-OCGT-NG	10000	100	100	647	30	-	NG	OCGT	11.52	0.19	12.7	2/2	10.0/10.0	3.5/6.9
DRC-N-CCGT-Diesel	1000	125	125	710	30	-	Diesel	CCGT	8.57	3.67	13.1	3/3	6.3/6.3	6.4/2.4
DRC-N-Eng-Diesel small	1000	10	10	1009	30	-	Diesel	Engine	10.90	5.54	33.4	1/1	2.0/2.0	-/-
DRC-N-H-Grand Inga	78	500	928	3591	50	76	Water	Hydro	-	1.51	8.7	-/-	-/-	-/-
DRC-N-H-Inga III	12	100	100	3591	50	76	Water	Hydro	-	1.51	8.7	-/-	-/-	-/-
DRC-N-OCGT-Diesel	1000	100	100	647	30	-	Diesel	OCGT	10.90	0.19	12.7	2/2	10.0/10.0	3.5/2.4
DRC-N-PV-Solar Generic	>10000	1	0	572/461	25	-	Solar	PV	-	-	16.0	-/-	-/-	-/-
LES-N-Eng-Diesel small	1000	10	10	1009	30	-	Diesel	Engine	10.29	5.54	33.4	1/1	2.0/2.0	-/-
LES-N-H-Lesotho_Muela II	1	110	110	1938	50	9	Water	Hydro	-	1.51	8.7	-/-	-/-	-/-

NG: Natural Gas; St: Steam Turbine

Name	Max Units Built	Max Capacity [MW]	Firm Capacity [MW]	Build Cost (Present/ 2030) [USD/ kW]	Technical/ Economic Life	Capacity Factor Ave [%]	Fuel	Tech	Heat Rate [GJ/ MWh]	VOM [USD/ MWh]	FOM [USD/ kW-yr]	MUT/ MDT [Hrs]	Ramp up/ramp down rate [MW/min]	Reliability (UFOR/ FOR) [%]
LES-N-H-Lesotho_Oxbow	1	80	80	1938	50	59	Water	Hydro	-	1.51	8.7	-/-	-/-	-/-
LES-N-PV-Solar Generic	5500	1	0	551/444	25	-	Solar	PV	-	-	16.0	-/-	-/-	-/-
LES-N-Wind-Letseng	1	65	0	837	20	-	Wind	Wind	-	-	40.0	-/-	-/-	-/-
LES-N-Wind-Wind	110	1	0	869	20	-	Wind	Wind	-	-	40.0	-/-	-/-	-/-
MAL-N-Biomass-Biomass	35	125	125	5890	30	50	Bagasse	St	14.24	5.24	131.0	8/8	6.3/6.3	4.2/5.8
MAL-N-Coal-Coal	1000	150	150	3388	30	-	Coal	St	10.79	11.68	49.2	8/8	3.0/3.0	7.6/4.9
MAL-N-Eng-Diesel small	1000	10	10	1009	30	-	Diesel	Engine	8.78	5.54	33.4	1/1	2.0/2.0	-/-
MAL-N-H-Generic	11	50	100	1450	50	62	Water	Hydro	-	1.51	8.7	-/-	-/-	-/-
MAL-N-PV-Solar Generic	>10000	1	0	572/461	25	-	Solar	PV	-	-	16.0	-/-	-/-	-/-
MAL-N-Wind-Wind	1150	1	0	869	20	-	Wind	Wind	-	-	40.0	-/-	-/-	-/-
MOZ-N-CCGT-MozC NG	1000	125	125	710	30	-	NG	CCGT	8.57	3.67	13.1	3/3	6.3/6.3	6.4/2.4
MOZ-N-CCGT-MozN NG	1000	125	125	710	30	-	NG	CCGT	8.57	3.67	13.1	3/3	6.3/6.3	6.4/2.4
MOZ-N-CCGT-MozS NG	1000	125	125	710	30	-	NG	CCGT	8.57	3.67	13.1	3/3	6.3/6.3	6.4/2.4
MOZ-N-Coal-Coal	10	150	150	3388	30	-	Coal	St	10.79	11.68	49.2	8/8	3.0/3.0	7.6/4.9
MOZ-N-Eng-MozC NG small	1000	10	10	1009	30	-	NG	Engine	8.78	5.54	33.4	1/1	2.0/2.0	6.4/2.4
MOZ-N-Eng-MozN NG small	1000	10	10	1009	30	-	NG	Engine	8.78	5.54	33.4	1/1	2.0/2.0	6.4/2.4
MOZ-N-Eng-MozS NG small	1000	10	10	1009	30	-	NG	Engine	8.78	5.54	33.4	1/1	2.0/2.0	6.4/2.4

NG: Natural Gas; St: Steam Turbine

Name	Max Units Built	Max Capacity [MW]	Firm Capacity [MW]	Build Cost (Present/ 2030) [USD/ kW]	Technical/ Economic Life	Capacity Factor Ave [%]	Fuel	Tech	Heat Rate [GJ/ MWh]	VOM [USD/ MWh]	FOM [USD/ kW-yr]	MUT/ MDT [Hrs]	Ramp up/ramp down rate [MW/min]	Reliability (UFOR/ FOR) [%]
MOZ-N-H-HCB North Bank	2	430	430	907	50	85	Water	Hydro	-	1.51	8.7	-/-	-/-	-/-
MOZ-N-H-MozC generic	2	500	500	1375	50	29	Water	Hydro	-	1.51	8.7	-/-	-/-	-/-
MOZ-N-H-MozN generic	7	500	500	1590	50	83	Water	Hydro	-	1.51	8.7	-/-	-/-	-/-
MOZ-N-OCGT-MozC NG	1000	100	100	647	30	-	NG	OCGT	10.29	0.19	12.7	2/2	10.0/10.0	3.5/2.4
MOZ-N-OCGT-MozN NG	1000	100	100	647	30	-	NG	OCGT	10.29	0.19	12.7	2/2	10.0/10.0	3.5/2.4
MOZ-N-OCGT-MozS NG	1000	100	100	647	30	-	NG	OCGT	10.29	0.19	12.7	2/2	10.0/10.0	3.5/2.4
MOZ-N-PV-MozC Solar Generic	>10000	1	0	572/461	25	-	Solar	PV	-	-	16.0	-/-	-/-	-/-
MOZ-N-PV-MozN Solar Generic	>10000	1	0	572/461	25	-	Solar	PV	-	-	16.0	-/-	-/-	-/-
MOZ-N-PV-MozS Solar Generic	>10000	1	0	572/461	25	-	Solar	PV	-	-	16.0	-/-	-/-	-/-
MOZ-N-Wind-MozS Wind	1500	1	0	869	20	-	Wind	Wind	-	-	40.0	-/-	-/-	-/-
NAM-N-CCGT-NG	1000	125	0.1	710	30	-	NG	CCGT	8.57	3.67	13.1	3/3	6.3/6.3	6.4/2.4
NAM-N-Eng-NG small	1000	-	-	1009	30	-	NG	Engine	8.78	5.35	33.4	1/1	-/-	-/-
NAM-N-H-Baynes	1	360	360	1778	50	55	Water	Hydro	-	1.51	8.7	-/-	-/-	-/-
NAM-N-OCGT-NG	1000	100	100	647	30	-	NG	OCGT	10.29	0.19	12.7	2/2	10.0/10.0	3.5/2.4
NAM-N-PV-Solar Generic	>10000	1	0	572/461	25	-	Solar	PV	-	-	16.0	-/-	-/-	-/-
NAM-N-Wind-Wind	20000	1	0	869	20	-	Wind	Wind	-	-	40.0	-/-	-/-	-/-

NG: Natural Gas; St: Steam Turbine

Name	Max Units Built	Max Capacity [MW]	Firm Capacity [MW]	Build Cost (Present/ 2030) [USD/ kW]	Technical/ Economic Life	Capacity Factor Ave [%]	Fuel	Tech	Heat Rate [GJ/ MWh]	VOM [USD/ MWh]	FOM [USD/ kW-yr]	MUT/ MDT [Hrs]	Ramp up/ramp down rate [MW/min]	Reliability (UFOR/ FOR) [%]
RSA-N-Biogas-Biogas Generic	1000	5	5	1009	30	-	Biogas	Engine	12.00	4.1	153.6	1/1	1.0/1.0	4.2/5.8
RSA-N-Biomass-Biomass	1000	25	25	5890	30	70	Bagasse	St	14.24	5.24	131.0	8/8	0.5/0.5	4.2/5.8
RSA-N-CCGT-NG	1000	125	125	710	30	-	NG	CCGT	7.40	3.67	13.1	3/3	6.3/6.3	6.9/4.6
RSA-N-Coal-large	1000	750	750	2807	30	-	Coal	St	9.81	6.33	73.2	8/8	15.0/15.0	4.8/3.7
RSA-N-Coal-medium	1000	150	150	3338	30	-	Coal	St	10.79	6.33	49.2	8/8	3.0/3.0	4.8/3.7
RSA-N-CSP-Solar CSP 12h	>10000	1	0	6804/4042	30	-	Solar	CSP	-	-	91.0	-/-	-/-	8.0/-
RSA-N-CSP-Solar CSP 3h	>10000	1	0	4569/2714	30	-	Solar	CSP	-	-	81.0	-/-	-/-	8.0/-
RSA-N-CSP-Solar CSP 6h	>10000	1	0	5635/3347	30	-	Solar	CSP	-	-	85.0	-/-	-/-	8.0/-
RSA-N-CSP-Solar CSP 9h	>10000	1	0	5888/3807	30	-	Solar	CSP	-	-	87.0	-/-	-/-	8.0/-
RSA-N-Eng-NG small	1000	10	10	1009	30	-	NG	Engine	8.78	5.54	33.4	1/1	2.0/2.0	-/-
RSA-N-Nuc-Nuclear	10000	1359	1359	4784	60	-	Uranium	Nuclear Fission	10.57	2.94	76.6	12/12	27.2/27.2	3.0/6.0
RSA-N-OCGT-NG	10000	100	100	647	30	-	NG	OCGT	11.52	0.19	12.7	2/2	10.0/10.0	3.5/6.9
RSA-N-OCGT-NG_SR	10000	100	100	647	30	-	NG	OCGT	11.52	0.19	12.7	2/2	10.0/10.0	3.5/6.9
RSA-N-PV-Solar PV Generic	>10000	1	0	572/461	25	-	Solar	PV	-	-	16.0	-/-	1.0/1.0	-/-
RSA-N-Wind-Wind Generic	>10000	1	0	869	20	-	Wind	Wind	-	-	40.0	-/-	-/-	-/-

NG: Natural Gas; St: Steam Turbine

Name	Max Units Built	Max Capacity [MW]	Firm Capacity [MW]	Build Cost (Present/ 2030) [USD/ kW]	Technical/ Economic Life	Capacity Factor Ave [%]	Fuel	Tech	Heat Rate [GJ/ MWh]	VOM [USD/ MWh]	FOM [USD/ kW-yr]	MUT/ MDT [Hrs]	Ramp up/ramp down rate [MW/min]	Reliability (UFOR/ FOR) [%]
SWA-N-Coal-Lubhuku Coal	6	50	50	2624	30	-	Coal	St	9.73	6.33	49.2	8/8	1.0/1.0	6.9/4.5
SWA-N-Eng-Diesel small	1000	10	10	1009	30	-	Diesel	Engine	8.78	5.54	33.4	1/1	2.0/2.0	-/-
SWA-N-H-Lower Maguduza	2	6	6	4620	50	34	Water	Hydro	-	1.51	8.7	-/-	-/-	8.9/2.7
SWA-N-H-Ngwempisi	4	30	30	4620	50	50	Water	Hydro	-	1.51	8.7	-/-	-/-	8.9/2.7
SWA-N-PV-Lavumisa	1	5	0	551/444	25	-	Solar	PV	-	-	16.0	-/-	-/-	-/-
SWA-N-PV-Solar Generic	3250	1	0	572/461	25	-	Solar	PV	-	-	16.0	-/-	-/-	-/-
TAN-N-Biomass-Biomass	1000	85	85	5890	30	50	Bagasse	St	14.24	2.13	131.0	8/8	1.7/1.7	4.2/5.8
TAN-N-CCGT-NG	1000	115	115	710	30	-	NG	CCGT	8.57	3.67	13.1	3/3	5.8/5.8	6.4/2.4
TAN-N-Coal-Local	42	100	100	3100	30	-	Coal	St	9.73	6.33	49.2	8/8	2.0/2.0	6.4/2.4
TAN-N-Geothermal- Geothermal	12	50	50	4632	50	-	Geo.	St	-	-	1200.0	8/8	1.0/1.0	-/-
TAN-N-H-Generic	35	100	85	2410	50	50	Water	Hydro	-	1.51	8.7	-/-	-/-	8.9/2.7
TAN-N-OCGT-NG	1000	100	50	647	30		NG	OCGT	10.29	0.19	12.7	2/2	5.0/5.0	3.5/2.4
TAN-N-PV-Solar Generic	>10000	1	0	572/461	25		Solar	PV	-	-	16.0	-/-	-/-	-/-
TAN-N-Wind-Wind Generic	12000	1	0	869	20		Wind	Wind	-	-	40.0	-/-	-/-	-/-
ZAM-N-CCGT-Diesel	1000	125	125	-	30		Diesel	CCGT	8.57	3.67	13.1	3/3	6.3/6.3	6.4/2.4
ZAM-N-Coal-Maamba II	2	150	150	2500	30		Coal	St	8.11	0.96	20.0	8/8	3.0/3.0	6.6/2.4

NG: Natural Gas; St: Steam Turbine

Name	Max Units Built	Max Capacity [MW]	Firm Capacity [MW]	Build Cost (Present/ 2030) [USD/ kW]	Technical/ Economic Life [yr]	Capacity Factor Ave [%]	Fuel	Tech	Heat Rate [GJ/ MWh]	VOM [USD/ MWh]	FOM [USD/ kW-yr]	MUT/ MDT [Hrs]	Ramp up/ramp down rate [MW/min]	Reliability (UFOR/ FOR) [%]
ZAM-N-Eng-Diesel small	1000	10	10	1009	30		Diesel	Engine	8.78	5.54	33.4	1/1	2.0/2.0	-/-
ZAM-N-H-Generic	20	100	100	2750	50	62	Water	Hydro	-	1.51	8.7	-/-	-/-	-/-
ZAM-N-OCGT-Diesel	1000	100	100	647	30		Diesel	OCGT	10.29	0.19	12.7	2/2	20.0/20.0	6.5/2.4
ZAM-N-PV-Solar Generic	>10000	1	0	572/461	25		Solar	PV	-	-	16.0	-/-	-/-	-/-
ZAM-N-Wind-Wind Generic	4500	1	0	869	20		Wind	Wind	-	-	40.0	-/-	-/-	-/-
ZIM-N-Biomass- Chisumbanje	1	90	90	5890	30	50	Bagasse	St	14.24	2.13	131.1	8/8	1.8/1.8	4.2/5.8
ZIM-N-CCGT-Lupane NG	6	50	50	710	30		NG	CCGT	8.57	3.67	13.1	3/3	2.5/2.5	-/-
ZIM-N-Coal-Local	13	200	200	1144	30		Coal	St	9.73	6.33	20.0	8/8	4.0/4.0	7.6/4.9
ZIM-N-Eng-NG small	10000	10	10	1009	30		NG	Engine	8.78	5.54	33.4	1/1	2.0/2.0	-/-
ZIM-N-H-Batoka Gorge	6	200	200	1563	50	85	Water	Hydro	-	1.51	8.7	-/-	-/-	-/-
ZIM-N-PV-Solar Generic	>10000	1	0	572/461	25		Solar	PV	-	-	16.0	-/-	-/-	-/-
ZIM-N-Wind-Wind Generic	4000	1	0	869	20		Water	Wind	-	-	40.0	-/-	-/-	-/-

NG: Natural Gas; St: Steam Turbine

B.4 Regional electrical demand

The existing demand at a country level has been established for 2016 based on the latest SAPP Annual Report [129] and SAPP website [137] complemented by a range of country-specific sources [129, 137, 145–152]. These have been provided in Table 2.4 of section 2.5.3.

The expected demand forecasts (at a country level⁵) for the SAPP are based on information from the latest SAPP Annual Report [129] but normalised to 2016 peak and electrical energy demand (as discussed above). The growth expectations are then indexed until 2025 (as no further data is available⁶). Following this, growth is assumed to continue at the average rates of previous years to the end of the time horizon (2050).

Based on this information, the demand forecasts for energy and peak demand are summarised in Figure B.1 and B.2 respectively. As previously mentioned, that the full dataset is published as part of this research and is available upon request.

⁵ Except for Mozambique where the northern, central and southern power systems are represented explicitly

⁶ With the exception of South Africa where the low-growth demand forecast has been assumed based on [145]

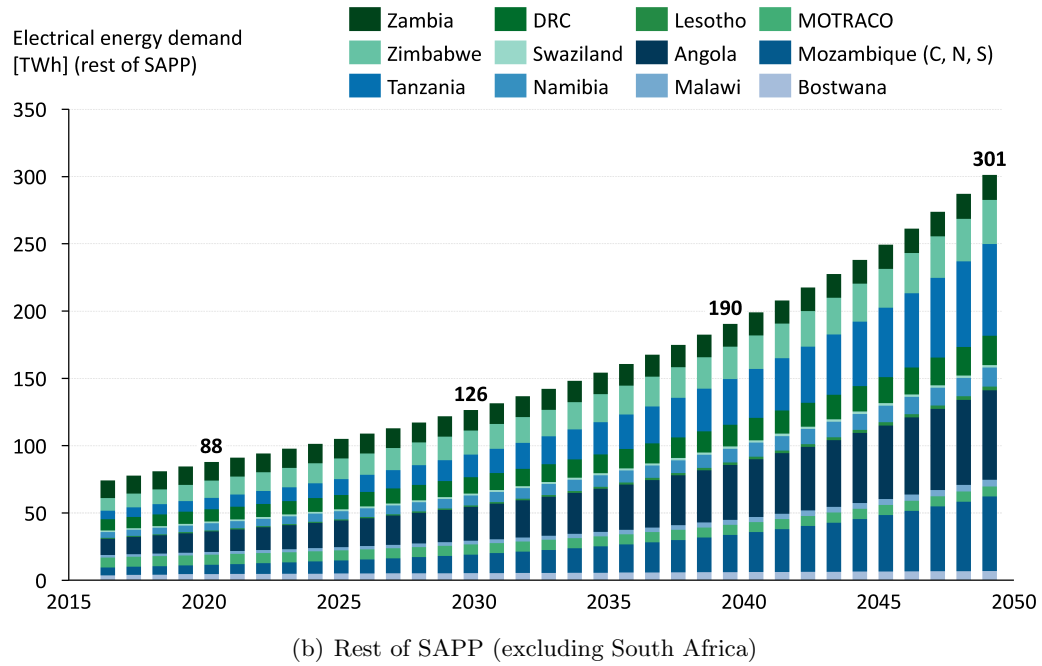
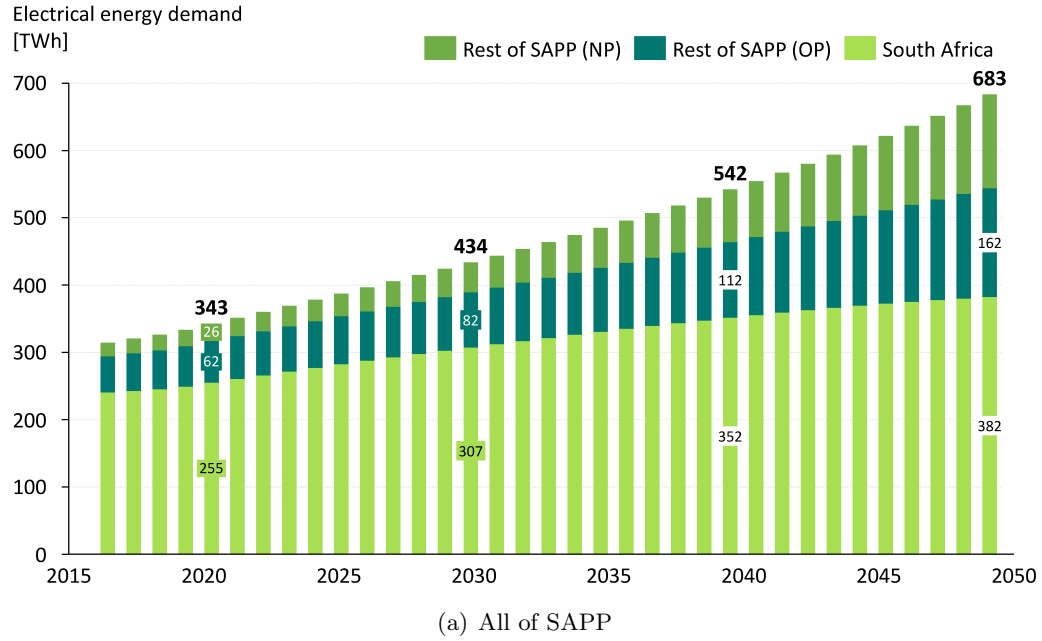


Figure B.1: Expected electrical energy demand forecast for SAPP (2016-2050) B.1(a) for the entire SAPP highlighting the size of South Africa and B.1(b) showing the expected growth for the rest of the SAPP region

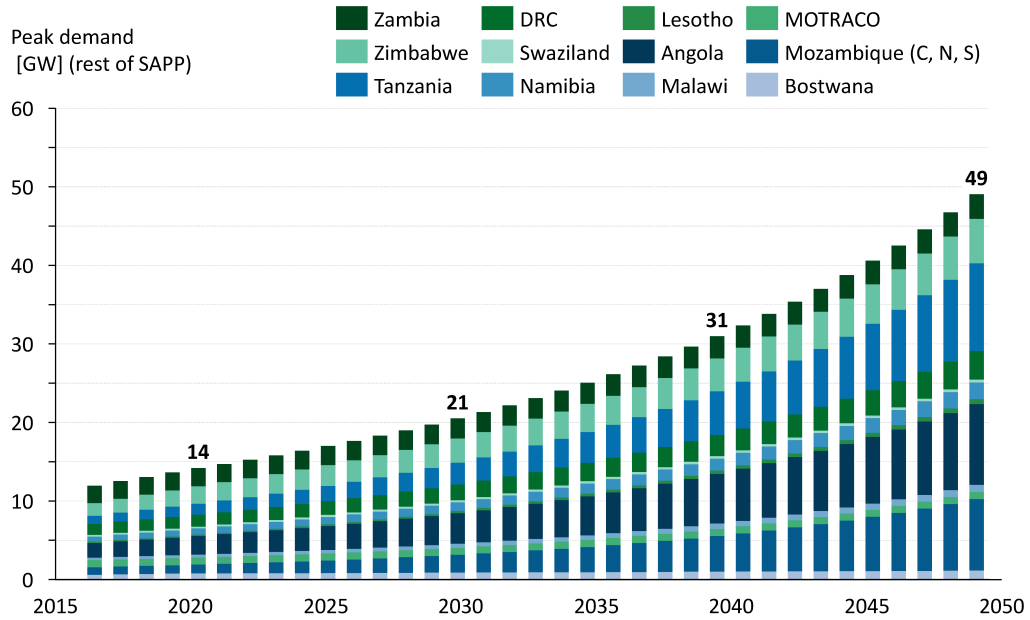
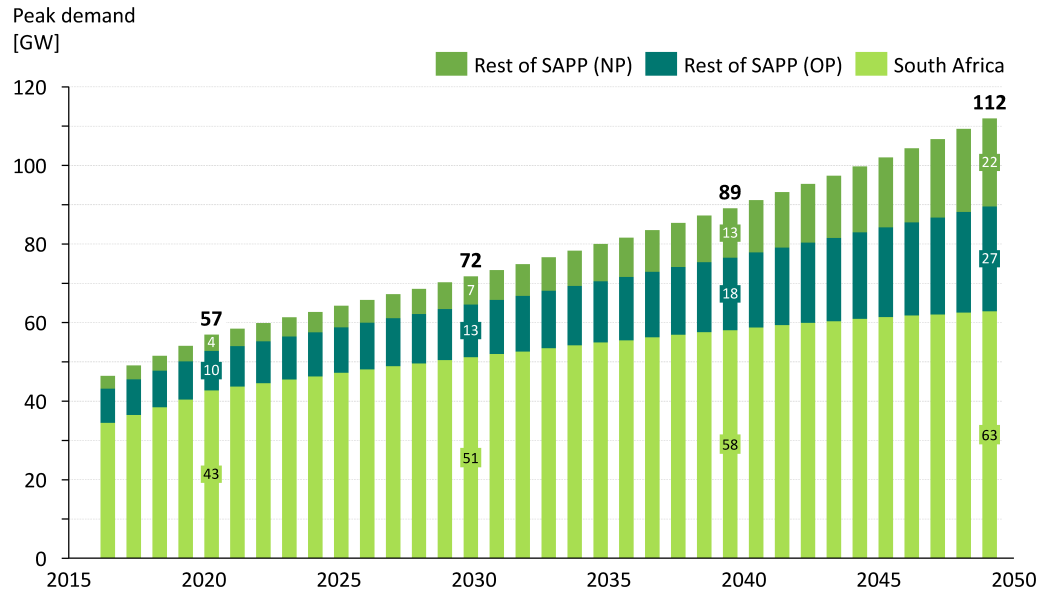


Figure B.2: Expected electrical peak demand forecast for SAPP (2016-2050) B.2(a) for the entire SAPP highlighting the size of South Africa and B.2(b) showing the expected growth for the rest of the SAPP region

B.5 Electrical transmission networks

The dataset includes inter-country transmission networks that are existing as well as possible future interconnections. These are based on [129, 153]. A summary of the technical characteristics of existing transmission lines is provided in Table B.4. Other selected planned transmission lines have also been included in the dataset but not provided for brevity. As previously mentioned, that the full dataset is published as part of this research and is available upon request.

Table B.4: Transmission interconnectors for SAPP region (existing) - overleaf

Name	Transfer Limit (Max/Min) [MW]	Resistance [p.u.]	Reactance [p.u.]	Reliability (FOR) [%]
E_Botswana-South Africa I (132kV HVAC)	82/-82	0.0386	0.1928	0.75
E_Botswana-South Africa I (400kV HVAC)	190/-190	0.0466	0.5590	0.56
E_Botswana-South Africa II (132kV HVAC)	82/-82	0.0618	0.3090	0.75
E_Botswana-South Africa III (132kV HVAC)	82/-82	0.0619	0.3095	0.75
E_Botswana-Zimbabwe I (220kV HVAC)	200/-200	0.0226	0.1581	0.77
E_Botswana-Zimbabwe I (400kV HVAC)	220/-220	0.0319	0.3829	0.57
E_DRC-DRCs I (500kV HVDC)	560/-560	0.0105	0	3.27
E_DRCs-Zambia I (220kV HVAC)	247/-247	0.0203	0.1419	0.56
E_DRCs-Zambia I (330kV HVAC)	333/-333	0.0157	0.1569	0.57
E_Lesotho-South Africa I (132kV HVAC)	45/-45	0.0376	0.1882	0.29
E_Lesotho-South Africa II (132kV HVAC)	45/-45	0.0376	0.1882	0.29
E_MozC-Zimbabwe I (110kV HVAC)	38/-38	0.1337	0.5349	0.29
E_MozN-MozC I (110kV HVAC)	50/-50	0.1284	0.5137	1.71
E_MozN-South Africa I (533kV HVDC)	1800/0	0.0035	0	2.61
E_MozN-Zimbabwe I (330kV HVAC)	220/-220	0.0248	0.2477	0.73
E_MozS-MozS-MOTRACO I (400kV HVAC)	500/-500	0.0000278	0.0003341	0.03
E_MozS-MozS-MOTRACO II (400kV HVAC)	500/-500	0.0000278	0.0003341	0.03
E_MozS-MozS-MOTRACO III (400kV HVAC)	500/-500	0.0000278	0.0003341	0.03
E_MozS-South Africa I (110kV HVAC)	67/-67	0.0912	0.3647	0.34
E_MozS-South Africa I (275kV HVAC)	133/-133	0.0429	0.3865	0.33
E_MozS-South Africa I (400kV HVAC)	1100/-1000	0.0046	0.0553	0.68

Name	Transfer Limit (Max/Min [MW])	Resistance [p.u.]	Reactance [p.u.]	Reliability (FOR) [%]
E_MozS-Swaziland I (400kV HVAC)	1100/-1100	0.0022	0.0266	0.34
E_Namibia-South Africa I (220kV HVAC)	195/-195	0.0233	0.1630	1.27
E_Namibia-South Africa I (400kV HVAC)	380/-380	0.0145	0.1734	1.04
E_South Africa-Swaziland I (132kV HVAC)	76/-76	0.0439	0.2194	0.18
E_South Africa-Swaziland I (400kV HVAC)	1100/-1100	0.0030	0.0355	0.32
E_South Africa-Zimbabwe I (132kV HVAC)	15/-15	0.3106	1.5531	0.11
E_Zambia-Namibia I (220kV HVAC)	180/-180	0.0289	0.2026	0.88
E_Zambia-Zimbabwe I (330kV HVAC)	214/-214	0.0005	0.0050	0.03
E_Zambia-Zimbabwe II (330kV HVAC)	214/-214	0.0005	0.0050	0.03

B.6 Fuels for power generation

For ease of reference, the price of fuels for power generation is based on [145, 259] and is summarised in Table B.5. As previously mentioned, that the full dataset is published as part of this research and is available upon request.

Table B.5: Expected fuel prices included in SAPP dataset (2016-2050)

Country	Period	Diesel [USD/GJ]	Natural gas [USD/GJ]	Coal [USD/GJ]	Uranium [USD/GJ]	Bagasse [USD/GJ]	Biogas [USD/GJ]
Angola	2016	14.7	5.7	-	-	-	-
	2030-2050	17.7	6.9	-	-	-	-
Botswana	2016	16.9	-	1.2	-	-	-
	2030-2050	20.4	-	1.5	-	-	-
DRC	2016	14.7	7.4	-	-	-	-
	2030-2050	17.7	8.9	-	-	-	-
Lesotho	2016	16.9	-	-	-	-	-
	2030-2050	20.4	-	-	-	-	-
Malawi	2016	16.9	-	-	-	-	-
	2030-2050	20.4	-	-	-	-	-
Mozambique	2016	14.7	5.7	2.0	-	-	-
	2030-2050	17.7	6.9	2.4	-	-	-
Namibia	2016	14.7	7.4	4.6	-	-	-
	2030-2050	17.7	8.9	5.5	-	-	-
South Africa	2016	21.6	10	1.1	0.6	2.5	11.8
	2030-2050	26.1	12.1	1.3	0.6	2.5	11.8
Swaziland	2016	16.9	-	3.0	-	2.5	-
	2030-2050	20.4	-	3.6	-	2.5	-
Tanzania	2016	14.7	5.7	-	-	2.5	-
	2030-2050	17.7	6.9	-	-	2.5	-
Zambia	2016	16.9	-	3.0	-	-	-
	2030-2050	20.4	-	3.6	-	-	-
Zimbabwe	2016	-	5.7	2.0	-	-	-
	2030-2050	-	6.9	2.4	-	-	-