

**Improving the performance of regional electricity markets in  
developing countries: The case of the Southern African Power  
Pool**

by

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**Abstract**

Power pools can reduce the cost of providing electricity and improve system reliability through coordinated use of energy resources. Realizing these benefits requires careful market design supported by technical, economic and institutional analysis of the system as it exists today and as it will likely evolve in the future. In this dissertation, I demonstrate this integrated approach through a detailed study of the design and operation of the Southern African Power Pool (SAPP). I develop a linear programming model of the SAPP system that explicitly represents hourly system operations to conduct this analysis. This model is then adapted through the addition of new input parameters or linear constraints to investigate different market design questions including how to implement bilateral contracts in the wholesale market and allocate costs for regional transmission investments. I also examine the design of regional institutions and their role to promote efficient investments and market behavior.

The primary contributions from this work include a new method to design and incorporate security-motivated bilateral contracts into wholesale markets using Implicit Auctions with Security of Supply Guarantees; a regulatory framework for transmission planning and cost allocation designed specifically for supranational regional markets; a quantitative comparison of transmission pricing methods leading to recommendations to apply Beneficiary Pays for new lines and Average Participations for existing lines; recommended adjustments to transmission regulation to facilitate increased penetrations of renewable energy; and a proposed design for the regional regulator. I also identify several unique features of developing country power systems that may influence market design. Other markets in Africa, Asia and Central America contain similar technical and institutional characteristics that can lead to similar market challenges. The specific market rules and implementation steps developed for the SAPP may not apply in all regions but the integrated approach used in this thesis, combining technical models and institutional analysis to support regulatory decisions, could be generalized to other regional electricity markets.

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## List of Acronyms

ACER	Agency for the Coordination of Energy Regulators
BPC	Botswana Power Corporation
CBA	Cost-benefit analysis
CC	Coordination Centre
CEC	Copperbelt Energy Corporation
CEER	Council of European Energy Regulators
CESUL	Centro-Sul Backbone Transmission Project
CfD	Contract for Differences
CRIE	Comisión Regional de la Interconexión Eléctrica
DAM	Day-ahead market
DRC	Democratic Republic of Congo
EAPP	East African Power Pool
ECOWAS	Economic Community of West African States
EDM	Electricidade de Moçambique
ENE	Empresa Nacional de Electricidade
ENS	Energy non-served
ENTSO-E	European Network of Transmission System Operators for Electricity
EOR	Ente Operador Regional
ERERA	ECOWAS Regional Electricity Regulatory Authority
ESCOM	Electricity Supply Corporation of Malawi
EU	European Union
FC	Financial Contracts
FERC	Federal Energy Regulatory Commission
GMS	Greater Mekong Subregion
GW	Gigawatt
HCB	Hidroeléctrica de Cahora Bassa
IDM	Intra-day market
IEM	Internal Electricity Market
IPP	Independent power producer
ITC	Independent transmission company
km	Kilometer
LEC	Lesotho Electricity Corporation
LHPC	Lunsemfwa Hydro Power Company
MER	Mercado Eléctrico Regional
MERCOSUR	Mercado Común del Sur

MIBEL	Iberian Electricity Market
MO	Market Operator
MORTRACO	Mozambique Transmission Company
MW	Megawatt
NP	Non-operating member
OECD	Organisation for Economic Co-operation and Development
OP	Operating member
OSC	Operations sub-committee
OTC	Over-the-counter
PC	Physical Contracts
PCI	Projects of Common Interest
PIDA	Program for Infrastructure Development in Africa
PJM	Pennsylvania-New Jersey-Maryland Interconnection
PPP	Public Private Partnership
PSC	Planning sub-committee
PT	Physical Transmission
RERA	Regional Electricity Regulators Association
SADC	Southern African Development Community
SAPP	Southern African Power Pool
SEC	Swaziland Electricity Company
SINEA	Sistema de Interconexión Andina
SMD	Standard Market Design
SNEL	Société Nationale d'Électricité
SPC	Special Purpose Company
SPTR	Sistema de Planificación de la Transmisión Regional
TANESCO	Tanzania Electricity Supply Company Ltd
TWh	Terawatt-hour
WAPP	West African Power Pool
ZESA	Zimbabwe Electricity Supply Authority



# 1

## Introduction

There is a clear trend to integrate independent national, state, or local power systems to create supranational or regional electricity entities [295]. These entities are termed “pools”, “interconnections” or “regional markets”, depending on their internal form of organization.

These regional entities offer the potential to significantly reduce the cost of providing electricity and improve system reliability through coordinating the use of energy resources across a larger supply area [290]. Power pools in the United States were the first regional organization of this kind [178]. These were later established as “regional transmission organizations” and true regional markets. The National Electricity Market in Australia [193] and the European Internal Electricity Market (IEM) [106] were directly created as regional markets. The Regional Electricity Market (Mercado Eléctrico Regional, MER) in Central America was also formed during the 1990s. All these markets continue to evolve, as more advanced forms of organization are developed and accepted by member parties. This phenomenon extends to several developing regions of the

world, with countries adopting different integration approaches, presently under the format of regional markets in all cases. Figure 1-1 shows the geographic distribution of regional markets. Some of them have reached an advanced level of maturity and integration (blue), while others are still in the early stages of this process (green). As the figure reveals, the newest markets being proposed are located among developing countries in South America, Africa and Asia.

For these countries, the potential benefits of regional power sector integration are more significant [273]. 1.5 billion people do not have access to grid-connected electricity [134] and many others have unreliable service that constrains income-generating business activities. This is due, in large part, to poor utility performance and underinvestment in generation and transmission infrastructure. In 2015, the World Bank estimates 10% of business sales in low income countries were lost due to electrical outages [78]. By providing reliable and affordable electricity, regional electricity markets could directly impact social and economic development in some of the poorest regions in the world. These impacts can only be realized if the market is designed to encourage efficient use of energy resources and promote investments in necessary regional electricity infrastructure.

Realizing the benefits of regional integration requires careful market design supported by technical, economic and institutional analysis of the system as it exists today and as it will likely evolve in the future. Despite a growing body of literature on regional market design in industrialized regions, very little work focuses on how to design and implement regional

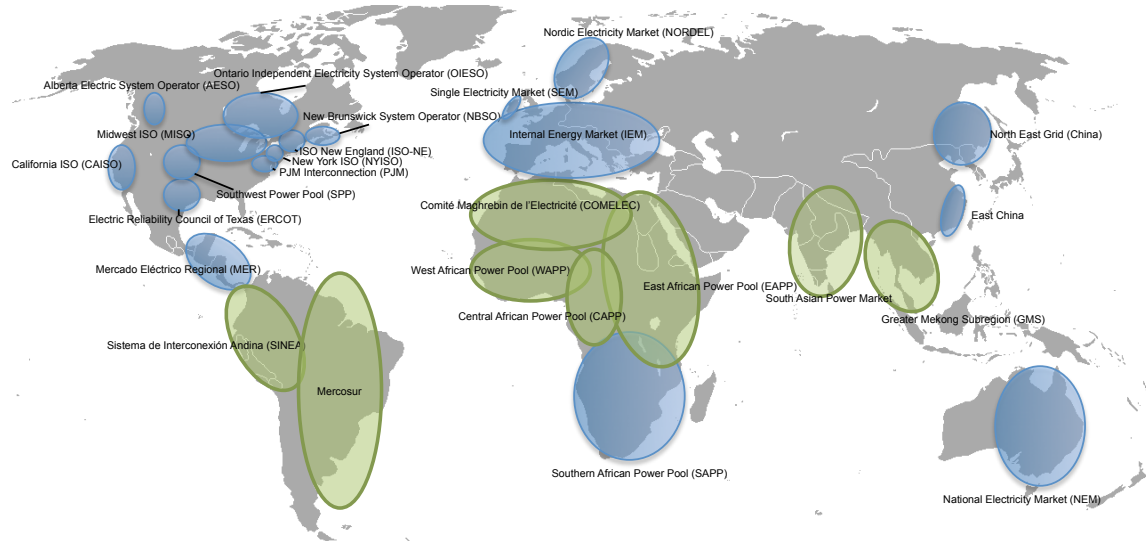


Figure 1-1: Map of regional electricity interconnections around the world. The blue areas indicate markets that exist and green areas are markets in various stages of development.

markets in developing countries using this type of integrated approach [71]. This dissertation aims to fill this gap through a detailed study of the design and operation of the Southern African Power Pool (SAPP). Drawing from lessons learned in other regional markets and principles of power sector regulation, I identify a set of critical market design issues that must be addressed to promote efficient use of energy resources and necessary investments in new infrastructure. I then combine institutional analysis with technically modeling of the SAPP system to evaluate existing market rules against a range of alternative approaches to propose new rules and implementation guidelines to address these critical issues. The proposals include 1.) a new method to design long-term energy contracts and integrate these contracts into the competitive market bidding and dispatch procedures, 2.) rules for planning, approving, and allocating costs for regional transmission lines, 3.) adjustments to transmission reg-

ulation to facilitate increased penetrations of renewable energy, and 4.) the design of the regional regulator including its roles, responsibilities, funding, staffing, and governance. These proposals are selected because they are more likely than existing rules or alternative approaches implemented in other markets to promote efficient market operations and investments in regional markets in developing countries and, specifically, in the SAPP.

The remainder of Chapter 1 provides a brief introduction to regional electricity markets, the class of problems this dissertation aims to address, the SAPP, and the thesis outline.

## **1.1 Introduction to Regional Electricity Markets**

Regional electricity interconnections are composed of multiple local, state, or national power systems that agree to coordinate their operations and planning [218]. Electricity markets are an advanced form of integration whereby electricity suppliers compete to sell power to consumers located anywhere in the region through a process of centralized bidding and coordinated use of the regional transmission network. While each case offers specific objectives and potential benefits, motivations for integrating individual power systems generally include goals to reduce the cost of electricity generation, reduce investment costs, and improve system reliability [71]. By permitting generators to sell to a larger consumer market, regional markets promote better utilization of the most efficient generators and greater efficiency and price reduction through competi-



tion. Countries with excess low-cost electricity supplies can export power to countries with limited or more expensive supplies, allowing the former to earn extra revenues through sales and the latter to reduce their costs of supply and potentially forego new investments. Further investment savings are possible by capturing economies of scale in new generation infrastructure. This is particularly important for developing countries where total demand may be relatively small. Large projects with lower per unit costs that might be deemed oversized and risky for a single country may be economically feasible if it is used by the entire region.

Regional integration can also allow participants to reduce the cost of supplying operating reserves and improve reliability. These reserves are used to ensure the system will be able to meet demand in case of unforeseen events, such as a technical failure, and generally must be sufficient to cover the loss of production from the largest power plant at any given moment plus a fraction of demand. By sharing operating reserves, systems that experience peak demand at different times could reduce the total capacity needed to meet their reserve requirements. Even if the systems experience peak demand at the same time, interconnected systems need only supply sufficient reserves to cover the failure of the largest plant from the entire interconnected system (instead of the largest plant from each system) and the total reserves needed would be less than the sum of each system providing their own. Finally, regional markets can increase system reliability in two ways. First, if countries have different generation resources, regional coordination can diversify the types of fu-

els available for electricity generation and offer some protection from fuel price spikes or droughts. Second, regional markets create a larger support network during major incidents such as the failure of a power plant or transmission line.

To capture these benefits, policy makers, utilities, regulators, and consumers must strike a balance between a local or national mentality and a regional mentality. National and local entities may have to cede some authority to a regional entity responsible for coordinating the regional market and the technical operation of the interconnected system. National regulations may need to be changed to harmonize technical standards and operating rules across the region. The difficulty of shifting from the long-held view of electricity as a strategic national asset to view it as a regional asset subject to regional regulations cannot be underestimated [189]. Conflicting desires to capture the benefits of regional integration and maintain local control over regulations, investments, and operational decisions lead to problems in regional markets all over the world [71].

While the range of issues may vary, international experience suggests there are three critical problems that all regional markets must resolve in order for the market to function efficiently. First, the market rules must be aligned with national concerns about security of supply. Without well-designed market rules, countries may refuse to trade or behave uncompetitively to prioritize supplies for domestic consumers. Second, the regional regulations must incentivize investments in regional infrastructure projects, particularly cross-border transmission. Despite their

significant potential benefits, national and local actors are generally not willing to invest in regional infrastructure projects because the benefits from these projects are often widely dispersed among multiple local or national systems. Regional transmission projects present a particular challenge because they are necessary to facilitate cross-border trade but their benefits can be difficult to assess and widely dispersed. Finally, the region must have effective regional institutions, particularly the regional regulator. Regional institutions, including the regional system operator, market operator and regulator, are responsible for coordinating all activities among market participants. The design of the regional regulator is particularly important because this entity is responsible for developing and enforcing the regulations that govern the market. More information on these four critical issues and experiences in real electricity markets to resolve them are explored in greater detail in Chapter 2.

## **1.2 Regional Markets in Developing Countries**

This dissertation is focused on a subset of regional electricity markets located in developing countries. This section defines which countries and markets are included in this classification and why they represent a unique case separate from regional markets in industrialized countries.

### **1.2.1 Classification of a Developing Country**

The term “developing country” is a classification that is often used but rarely defined. The United Nations uses the term but does not have an

official definition [272]. The International Monetary Fund admits that it does not have “strict criteria, economic or otherwise” for distinguishing between advanced and emerging economies [1]. Recognizing the ambiguous and, at times, arbitrary methods used for classification, the World Bank recently announced it would not longer distinguish between “developed” and “developing” countries in its presentation of country-level data [105].

Given the lack of consensus on how to define “developing country”, this section defines how the term is applied in this dissertation. This term is applied based on the status of a particular country’s electric power industry rather than its broader socio-economic status. Under this scheme, “developing countries” are those where the electric power industry is failing to provide reliable and affordable electricity to all consumers. This class of countries experience the following: difficulty meeting electricity demand due to insufficient generation and transmission infrastructure, difficulty mobilizing financing for new projects, regulatory bodies have not been formed or lack the necessary institutional capacity and independence to set and enforce rules, power supplies are unreliable and customers experience regular outages, and portions of the population do not have access to electricity. While this definition focuses solely on the performance of their respective power sectors, these countries generally overlap with those typically classified as “developing”, “emerging”, or “low-income” based on broader macro-economic indicators.

Developing country markets are, therefore, composed of countries that

can be described as developing, electrically speaking. Examples of these markets already operating include Central America's MER and the SAPP. Other developing country markets that are in the process of being developing or being proposed include the West African Power Pool (WAPP), East African Power Pool (EAPP), Greater Mekong Subregion (GMS), Sistema de Interconexión Andina (SINEA), and Mercado Común del Sur (MERCOSUR).

### **1.2.2 Opportunities and Challenges for Developing Country Markets**

For developing countries, regional electricity markets present a number of distinct opportunities and challenges not present in industrialized markets. First, regional markets could significantly change the investment model for electricity infrastructure. Total demand in many countries is too low to warrant investments in larger, more efficient power plants commonly found in the United States or European countries and utilities often cannot afford to overbuild their systems with large plants that will not be fully used for years [23]. As a result, many countries meet growing demand using technologies such as diesel generators that have higher running costs but can be built in small increments rather than develop domestic resources such as hydropower, gas, or geothermal which may be oversized for a single country and require large up-front investments. In Africa, for example, over fifteen countries use small oil plants for at least 15% of their power generation compared to less than 1% in the United

States and 1.3% in Europe [287]. Regional markets, therefore, offer a unique opportunity for developing countries to develop domestic natural resources and increase generating capacity at lower cost [213].

A second potential opportunity stems from the fact that many developing countries do not have national electricity markets. As a consequence, the often contentious process of harmonizing market rules and regulations across multiple countries can be vastly simplified. New national regulations and practices can be developed alongside regional ones ensuring they are consistent.

Finally, in areas where large portions of the population still lack access to electricity, national governments and utilities could collaborate to expand access to electricity. Both the SAPP and EAPP explicitly include goals to expand electricity access in their governing documents and several inter-utility agreements for cross-border rural electrification strategies exist between neighboring countries in the WAPP [228, 259, 21].

On the other hand, developing country markets also face unique challenges that may influence the design of the regional market. The three problems presented in Section 1.1 exist in all markets but they are felt more acutely in developing country regions where supply is scarce, utilities have difficulty mobilizing financing for new projects, regional infrastructure is underdeveloped, and institutions are weak. The problems are also interconnected and the regional market cannot function effectively unless all are addressed.

When the electricity industry does not have sufficient infrastructure

and fuel to meet demand, concerns about national security of supply become more urgent. Countries may be unwilling to pool their resources or trade if they risk load shedding at home. These concerns must be considered when designing the market rules. Even if countries are willing to trade, trading opportunities may be limited if the cross-border transmission network is underdeveloped. For example, the proposed nine-country EAPP currently exists as three weakly interconnected sub-groups and two isolated countries [259]. Any plans to create a centralized market in this region must start with significant transmission investments to connect the member countries. However, in regions where financial resources are constrained, investments in regional infrastructure may be difficult to achieve and it is increasingly important to properly design methods to plan and allocate costs for new infrastructure to aid with negotiations and reduce risk. Effective regional institutions will play a critical role to address concerns about security of supply and incentivize investments in regional infrastructure. In this area, too, developing countries may need special consideration in the design process because many have limited experience with independent regulators and electricity markets operators.

## **1.3 Motivating Case: Southern African Power Pool**

### **1.3.1 Overview of the Southern African Power Pool**

The Southern African Power Pool presents a compelling case study of regional markets in developing countries because it has been operating

for two decades, allowing time for experiential learning and discovering emergent challenges. This section provides an overview of the SAPP’s structure and design.

The SAPP was created in 1995 between the twelve members of the Southern African Development Community (SADC) and is the only operating regional electricity market in Africa. Its mission is to “provide the least cost, environmentally friendly and affordable energy and increase accessibility to rural communities” [242]. More specifically, the regional market aims to meet the following goals:

- improve security and quality of electricity supply;
- capture economies of scale for larger generation plants through pooling of demand;
- reduced prices to consumers through increased competition among market participants and economies of scale in generation;
- increase power accessibility in rural communities; and
- facilitate the development of regional expertise through training programmes and research.

Table 1.1 lists the current members of the SAPP. All national power utilities and other electricity supply enterprises may participate as members subject to approval by the SAPP Executive Committee and the utility’s host country. Membership is divided between operating and non-operating members. Non-operating members are those that are not connected to the regional transmission network. This currently includes utilities from Angola, Malawi, and Tanzania.



Utility	Status	Abbreviation	Country
Empresa Nacional de Electricidade	NP	ENE	Angola
Botswana Power Corporation	OP	BPC	Botswana
Société Nationale d'Électricité	OP	SNEL	Democratic Republic of Congo
Lesotho Electricity Corporation	OP	LEC	Lesotho
Electricidade de Moçambique	OP	EDM	Mozambique
Hidroeléctrica de Cahora Bassa	IPP	HCB	Mozambique
Mozambique Transmission Company	ITC	MORTRACO	Mozambique
Electricity Supply Corporation of Malawi	NP	ESCOM	Malawi
NamPower	OP	NamPower	Namibia
Eskom	OP	Eskom	South Africa
Swaziland Electricity Company	OP	SEC	Swaziland
Tanzania Electricity Supply Company Ltd	NP	TANESCO	Tanzania
ZESCO Limited	OP	ZESCO	Zambia
Copperbelt Energy Corporation	ITC	CEC	Zambia
Lunsemfwa Hydro Power Company	IPP	LHPC	Zambia
Zimbabwe Electricity Supply Authority	OP	ZESA	Zimbabwe

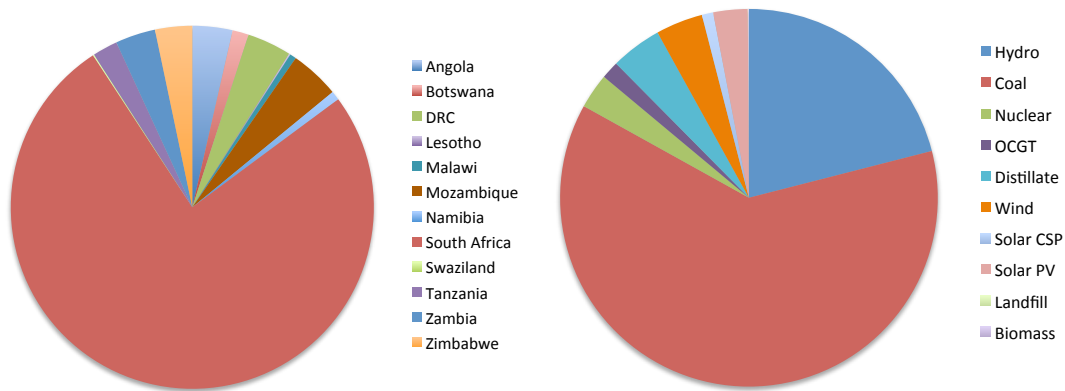
Table 1.1: Members of the Southern African Power Pool (OP, Operating Member; NP, Non-operating Member; ITC, Independent Transmission Company; IPP, Independent Power Producer)

## Supply and Demand

Southern Africa is rich in energy resources. Over 99% of proven coal reserves on the continent are located in SAPP countries, with 96% of this in South Africa. The Congo River in the Democratic Republic of Congo (DRC) accounts for 60% of Africa's hydropower potential. There are additional hydropower resources in Angola, Mozambique, South Africa and Tanzania. Angola and Mozambique also have natural gas reserves. The region also has substantial wind and solar resources. A recent GIS-based survey estimates the annual generation potential for concentrated solar power and solar PV to be 190,000 and 219,000 terawatt-hours (TWh), respectively [124]. Potential generation from wind resources is similarly substantial, estimated to be 145,000 TWh per year [124].

Electricity supplies in the region are characterized by thermal systems

in the coal-rich south and hydropower-based systems in the north. At the beginning of 2015, the SAPP’s installed capacity was 61,859 megawatts (MW) with 76% available to operate. Three quarters of this capacity is located in South Africa (Figure 1-2a) [241]. Coal and hydropower make up most of region’s electricity capacity, accounting for 62% and 20%, respectively (Figure 1-2b) [241].



(a) Distribution of installed generation capacity in the SAPP by host country

(b) Distribution of installed generation capacity in the SAPP by technology

In 2014, regional demand reached 49,562 MW and total consumption was 277 TWh [242]. South Africa is the region’s largest consumer, accounting for nearly 80% of annual consumption. Demand grew by 6.8% in the year 2014 and is forecast to continue growing at an average of 3.1% per annum through 2027 [242].

## Market Design

SAPP members can choose from three trading arrangements:

- Long-term bilateral contracts
- Short-term or over-the-counter (OTC) bilateral contracts
- Day-ahead market (DAM) and intra-day market (IDM) trades

Long-term bilateral contracts are the basis for cross border trading in the SAPP, accounting for over 94% of power traded in the 2014-15 trading year [242]. OTC bilateral contracts are mainly entered into on a needs basis to meet short-term demand. The DAM and IDM are bid-based firm energy markets designed to optimize the use of generation and transmission resources [243]. The SAPP market operator located in Harare, Zimbabwe is responsible for collecting all trading information from bilateral contracts, running the competitive markets, and scheduling power exchanges between control areas. More information on the SAPP's procedures for trade and scheduling is provided in Chapter 3.

### **Market Challenges**

The regional market is faced with a number of challenges that could threaten its success. The biggest challenge is insufficient generation and transmission infrastructure. Years of rapid growth in electricity demand were not matched with necessary investments in new electricity infrastructure. In some countries, national tariffs are kept below cost-reflective levels, resulting in low investment grades for SAPP utilities and limiting their ability to mobilize funds for system upgrades or new projects [161, 27, 120]. In other cases, such as South Africa, political changes in the 1990s stalled new investments from state-owned utilities [147]. As a result of both of these factors, SAPP countries have experienced supply disruptions since 2007 and many countries are only weakly connected, if at all, to the regional network [235]. The region is now strongly promot-

ing energy efficiency and demand-side management programs to relieve supply constraints and reduce load shedding [242].

The second biggest challenge is developing regulatory and policy frameworks that are compatible with the regional market. The SAPP does not have a regional grid code and, as a result, members do not have basic assurances, such as open access to the transmission network, that are necessary to promote competition and facilitate trade [160]. In the absence of a common regulatory and policy framework, some member states have national policies and rules that conflict with the goals of regional integration. For example, in cases of supply constraints or price spikes, some countries have explicit national rules to prioritize domestic demand first, even if this means not meeting contractual export obligations [225].

Inadequate institutional capacity at the national and regional level is third major challenge facing the SAPP. None of the member countries has previous experience with electricity markets at the national level and participants are still undergoing training and certification activities [235]. Regulatory institutions are particularly weak. National and regional regulators are newly formed and need significant training and capacity building [255].

### **1.3.2 Implications for Other Regional Markets**

This dissertation is motivated by the case of the Southern African Power Pool but the proposed solutions are relevant to other developing country electricity markets. Many of these organizations, still in the process of

establishing enabling legislation and regulatory agreements, have similar characteristics to those found in the SAPP. These markets tend to have a single dominant country analogous to South Africa (Egypt in EAPP, Nigeria in WAPP, Columbia in SINEA, and Thailand in GMS) with the potential to significantly influence investments and trade. And, similar to the coal-rich south and hydro-rich north among SAPP countries, resources in these pools are also unequally distributed among member countries. WAPP countries have significant oil and gas resources in the north and west and hydropower in the center and east of the region [294]. Untapped hydropower resources among GMS countries are concentrated in Lao PDR and Myanmar [19]. Resources in east Africa are even more diverse with oil and gas reserves located primarily in Egypt and Sudan, geothermal resources in Kenya and Ethiopia and major hydropower resources located in Tanzania, Ethiopia and Kenya [259].

Many of the market challenges identified in the SAPP, including insufficient generation and transmission capacity, weak national utilities, inconsistent legal and regulatory frameworks and weak regulatory bodies are also cited in other regional developing country markets. Inadequate transmission capacity to facilitate trade is cited as a critical issue among member countries in MERCOSUR [209], WAPP [289], EAPP [67], MER [188] and GMS [30]. Insufficient investments in new generation capacity are also a problem, resulting in supply shortages in some WAPP [72], EAPP [67] and MER [291] countries.

Partly as a result of insufficient generation and transmission capacity,

members of developing country markets experience worse reliability and more electrical outages than industrialized countries. Table 1.2 compares the average number of electrical outages in a typical month and losses in annual sales due to electrical outages in developing country markets to those experienced by OECD countries<sup>1</sup>. Reliability tends to be worse among African countries but all markets experience more outages and economic losses compared to those experienced by high income countries in the OECD. Poor reliability leads to concerns about security of supply and, as in the SAPP, these concerns have prompted countries in other developing country markets to prefer long-term bilateral trade agreements rather than competitive market trading. Trade is expected to continue exclusively through bilateral contracts in MERCOSUR [209], WAPP [22], EAPP [67] and GMS [30] for the coming years. MER has a competitive market but bilateral contracts still play a major role in regional trade and some countries concerned about security of supply continue to prioritize domestic demand over exports [291].

Region	Market	Number of electrical outages in a typical month	Losses due to electrical outages (% of annual sales)
Africa	EAPP	9.8	4.2
	SAPP	6.0	4.9
	WAPP	13.8	6.9
Latin America	MER	2.4	2.2
	MERCOSUR	1.8	1.3
	SINEA	0.8	0.7
Asia	GMS	3.0	1.0
OECD		0.4	0.1

Table 1.2: Comparison of electricity reliability and economic losses due to electrical outages in OECD countries to those in developing country markets [78]

<sup>1</sup>The Organisation for Economic Co-operation and Development (OECD) is an intergovernment organization of 35 mostly high-income countries. The OECD serves as a group of “industrialized” countries for comparison.

Like the SAPP, other developing country markets have weak or inexperienced regulatory bodies. Among GMS members, two countries still lack national regulators and there is no regional regulatory body or cooperation among existing regulators [30]. EAPP and WAPP officials report that regulatory bodies still lack proper skills and training to carry out their responsibilities [67, 282].

Recognizing these similarities, the SAPP is already being used as a model for other newly formed regional power pools on the African continent and in other developing country regions. Delegations from other regional pools visited the SAPP to familiarize themselves with its operations and management [239, 241]. The proposed solutions developed in this dissertation to address pressing challenges in the SAPP could, therefore, directly inform the market design for other developing country markets.

## **1.4 Research Statement**

To better understand how an integrated approach to regional market design can be used to address the unique opportunities and challenges present in developing countries, I develop a package of proposed regulatory measures tailored to the specific case of the SAPP. This dissertation is not designed to be a comprehensive study of every aspect of market design, but focuses on key issues identified as common challenges in regional markets. Specifically, this dissertation addresses the following research questions:

1. How can regional market rules promote efficient use of resources while ensuring security of supply?
2. What institutional arrangements, planning processes and network cost allocation mechanisms are needed to promote necessary investments in regional transmission infrastructure?
3. What should the primary responsibilities of the regional regulator and national regulators be to support the efficient functioning of the market?

Any recommendations must be consistent with sound economic and regulatory theory and include two important elements. First, major regulatory changes are likely to be in place for many years and must be based on a broad, long-term perspective and not designed to solve short-term problems. Second, any workable recommendations should include a discussion of possible transition paths to get from the status quo to the proposed change. In this second element, the proposed solutions may not be fully generalizable to other markets because actual implementation steps will depend on the market being studied.

## **1.5 Thesis Outline**

Chapter 2 provides a literature review on major issues and analytic approaches applied to regional market design in developed and developing country regions. Each of the major issues and recommendations for im-



provement in the SAPP are described and discussed in detail in subsequent chapters.

Chapter 3 presents an analysis of the SAPP's current method to integrate bilateral and market trading and, using an optimization model developed for this thesis, compares this method with alternative approaches. Based on this analysis, I propose a novel method to integrate high levels of security-motivated bilateral contracts with competitive market trades that provides the same level of security of supply for contract holders while maximizing the efficient use of generation and transmission infrastructure. The chapter concludes with a discussion of the impact that increasing penetrations of renewable energy may have on regional security of supply.

Chapter 4 addresses the challenge of developing necessary cross-border transmission investments, focusing on the issues of regional planning and cost allocation. In this chapter, I examine different methods for transmission planning and cost allocation and develop a general regulatory framework for these topics tailored to the specific needs of regional markets. Proposed cost allocation schemes are evaluated using a power system model of the SAPP based on the existing network and three case studies of new transmission projects. The general framework is then applied to the SAPP to develop a set of specific transmission planning and pricing rules that could serve as a feasible alternative to the existing rules. The chapter concludes with recommendations for transmission regulation in regions keen to promote renewable energy.

Chapter 5 examines the design of the regional regulator in international markets and the current status of national and regional regulation in the SAPP. Based on a review of regional regulation in other markets and the SAPP's own institutional capabilities, I propose a new design for the regional regulator.

Finally, Chapter 6 summarizes the findings and presents final conclusions and recommendations for further work.

## 2

# Literature Review

The development of regional power pools, or integrated electricity systems, around the world is motivated by a desire to improve power sector reliability, reduce costs, and promote regional integration [57, 189]. A power pool is defined as “a group of two or more utilities that co-ordinate their operation and planning” and may encompass multiple national, state or local systems [203, 218]. The process of integrating multiple systems poses a number of technical, regulatory, and institutional challenges. Underlying all of these challenges is a conflict between capturing the benefits of integration and maintaining local or national sovereignty.

As experience with regional markets increase, there is a growing body of literature on the critical challenges that these markets face and analytic approaches to assess and resolve these challenges. However, very little work focuses on regional markets in developing countries. This literature gap is significant because developing country regions experience unique challenges not present in other markets. At the same time, interest in regional markets among developing countries is growing and a

number of new markets are being developed or proposed. This chapter demonstrates the need for further study focused on developing country electricity markets. The following sections provide a review the current literature on existing challenges and analytic approaches to regional market design, identify areas where methods used in developing countries can be improved and motivate the focus of the research presented in subsequent chapters.

## 2.1 Critical Topics in Power Pools

International experience with regional markets reveals that transitioning from independent local or national systems to a regional system poses a number of challenges. These challenges can be classified into three categories: market operations, regional infrastructure, and institutions and governance [189, 18, 52, 71]. Operational topics cover the specific details governing how market participants will interact including the market rules, technical standards, contracting formats, and procedures for congestion management and dispatch. Regional infrastructure covers aspects of planning, investment, and development of regional generation and transmission projects. Institutions and governance relates to the structural design of the regional market including the protocols of agreement, design of regional institutions, rules governing how regional and national entities will interact, and harmonization of relevant policies and regulations. In addition to these topics, growing interest in renewable energy presents an emerging challenge that impacts all three previous

topics. The following sections present the critical challenges within each category, drawing heavily from experiences in actual markets around the world in both developed and developing countries. The final section reviews critical challenges unique to developing countries.

### **2.1.1 Market Operations**

Market operations are governed by regulations that define the specific technical and economic operating rules for the market. Developing common standards is necessary to avoid technical failures, remove market distortions, and efficiently manage the regional network [189]. At the same time, the degree of harmonization is largely driven by the governance and institutional structure the region has adopted [86]. Regions with limited political support for integration or weak regional institutions have experienced very little success harmonizing operating rules. The list of possible regulations to harmonize is extensive including technical standards, bidding rules, dispatch procedures, congestion management, and protocols for data collection and information sharing. While they all present challenges, the greatest resistance in international markets comes from efforts to harmonize regulations related to security of supply and transmission pricing.

#### **Security of Supply**

Security of supply refers to ability of the electricity industry to maintain normal electricity supply to consumers by providing adequate infrastruc-

ture and fuel supplies [220]. The vast majority of systems in regional markets were originally designed to be self-sufficient and there was a strong belief among people working in the power sector that security of supply is a national issue [164]. However, greater levels of coordination and communication are now needed to manage increasing levels of cross-border electricity flows and there is a growing awareness that security of supply can no longer be viewed as a national issue for interconnected systems. Large-scale blackouts in Italy (2003), the Northeastern United States (2003), and Northern India (2012) reveal the detrimental outcomes that can result from a lack of coordination [270, 276, 55]. Increased penetrations of renewable energy technologies are also prompting countries to coordinate their supplies to provide a wider network of support if renewable energy resources are unavailable. For example, recent regional preparation and support among European countries allowed them to withstand an estimated sudden drop of 34 gigawatts (GW) of generation output from solar plants during a solar eclipse in 2015 [82].

A current security of supply issue facing many regional markets is ensuring that each control area honors their scheduled cross-border power exchanges. Analyses of MER, SAPP, and Europe's IEM all report that national regulators or system operators intervened in times of scarcity to prioritize domestic demand over contractual export obligations [291, 223, 164, 221, 224]. The problem largely stems from a lack of harmonization among national policies and regulations and weak or insufficient regional regulations. For example, the Iberian Electricity Market (MIBEL) has

two regional regulations that stipulate how export obligations should be treated during scarcity. Article 4.3 in the European Union’s (EU) Security of Supply Directive states that “Member States shall not discriminate between cross-border contracts and national contracts.” [95]. Within MIBEL, the Proceedings of the Common Market specify that in the case of scarcity, missing energy should be evenly distributed among demand regardless of location [248]. At the same time, the two system operators that control MIBEL each have their own national Operating Rules. According to national Operating Procedures, the Spanish system operator must interrupt exports during times of scarcity if they threaten domestic energy security [247]. This regulation is in direct contradiction to the regional regulations. Recently published EU network codes are now attempting to correct this contradiction. EU 2015/1222 stipulates that national system operators can block exports only when regional scarcity conditions are being managed in a coordinated manner with other power systems [89]. The MER is also actively looking to for a solution to this issue. Current proposals focus on redesigning firm contracts with specific instructions as to how the contract should be treated in times of scarcity [221].

### **Transmission Pricing**

A basic regulatory principle of transmission pricing states that transmission costs should be allocated in proportion to the benefit each agent derives from the network [219]. Historically, when there was little cross-

border coordination and trade, national agents were responsible for the cost of the network within their geographic territory because they were the main beneficiaries. As regional markets facilitate more cross-border power trade and coordinated operations, national entities are increasingly benefiting from the use of transmission grids located in other countries and this method of transmission pricing no longer seems fair [189]. This led most regional markets to develop various transmission pricing methods to charge market agents for their use of network facilities both within and outside of their national borders.

Ideally, transmission pricing should be based on establishing a level playing field for competition and promoting efficient use of resources [219]. Under this philosophy these charges should be calculated centrally based on each agent's use of the regional network without considering the local system to which each agent belongs [189]. In practice, implementing a system of harmonized, centrally calculated regional tariffs poses many challenges. First, members would have to agree on a single method for computing transmission tariffs. This is far from trivial because countries and local markets have a variety of different transmission pricing methods [150] and may be reluctant to change their long-established systems. And the best pricing scheme may vary depending on the network topology and location of generators and loads [191]. Second, a central entity must be authorized to calculate and allocate transmission costs to regional agents. Many regions resist creating independent regional institutions with this type of centralized authority. Finally, even if these challenges were re-



solved there is no universal catalog of transmission benefits or generally accepted method to determine how each agent uses the network [265]. If the method is poorly designed, transmission pricing can significantly impact regional competition and trade. For example, applying different transmission charges to domestic and international generators for the same use of the network would discriminate against one type of trade and distort trading behavior. Given these difficulties, regional schemes to compute transmission tariffs in most markets reflect a compromise between promoting economic efficiency and respecting local sovereignty.

Only the MER has a system of centrally computed nodal charges [62, 207]. However, as Olmos (2007) notes, the transaction-based method discriminates between agents trading energy regionally or locally and does not harmonize how charges are allocated among generators and consumers in each country [190]. The IEM has an inter-system compensation scheme whereby each country is compensated for the use that others make of their transmission grid. The Agency for the Coordination of Energy Regulators (ACER) is responsible for monitoring and implementing cost allocation procedures and the the European Network of Transmission System Operators for Electricity (ENTSO-E) collects and distributes payments [90]. While this scheme simplifies the cost calculations and avoids the need to harmonize transmission regulations for all countries, it is far from optimal and many countries think the system is unfair and insufficient. Alternative regional methods are being evaluated [188, 190, 81] and harmonizing transmission tariffs has been identified as

a priority for ACER in the coming year [93, 53]. Some regional markets in the United States use highly detailed nodal pricing schemes. However, each of these markets is only a fraction of the size of other international markets. The United States equivalent to what the IEM is attempting to accomplish would be to expand and harmonize these schemes across all seven Regional Transmission Organizations in the United States. This is proposed by some [151] but no local markets are actively pursuing harmonization.

### **2.1.2 Regional Infrastructure**

Proposals for regional markets all over the world generally to start with a basic economic argument that developing an integrated regional system will save money in capital and operating costs compared with each country developing their own systems independently. For example, power trading in the GMS would allow Lao PDR and Myanmar to develop their vast hydro resources in excess of what domestic customers need. The excess power could be exported to neighboring Vietnam, Thailand, and Cambodia providing an estimated annual savings of \$715 million, mainly due to the substitution of fossil fuel generation with hydropower [19]. Resource sharing, particularly among systems with asynchronous peak demand, can reduce total reserve requirements and the need for investments new peaking capacity. In 2015, the Pennsylvania New Jersey Maryland Interconnection (PJM) estimates that the integrated market reduces the regional reserve margin, saving \$1.1-\$1.4 billion in generation

investments annually [5]. In short-term operations, increased competition among a greater number of market participants can encourage greater efficiency and price reduction. Cross-border trading and market participation in Europe, Central America, southern Africa, and Asia continues to grow steadily since the trade was established, indicating increased levels of competition among regional market participants [19, 93, 241, 274]. PJM recently estimated that competition in the regional market reduces annual production costs by \$525 million [5].

These savings require coordinated planning and management of both generation and transmission infrastructure but international experience suggests that promoting investments in regional infrastructure is a universal challenge. Developing necessary transmission reinforcements, in particular, is one of the most difficult challenges for regional markets. Markets across the United States, Europe, Central America, Asia, Australia, and Africa cite insufficient transmission capacity as a critical barrier to realizing the full benefits of integration [189, 98, 274, 173, 140]. Given the potential savings, there is growing awareness that a new approach is needed for infrastructure planning, financing, and management at a regional level [189].

## **Planning**

Almost all regional markets, regardless of their stage of development, begin with a least-cost expansion plan that optimizes the expansion and use of generation and transmission resources to meet growing regional

electricity demand. Sample studies can be found for Asia [19, 20], Central America [116], Africa [268, 259, 182], Europe [79]. The purpose of these optimization models is to quantify the economic benefits of regional integration and identify projects that are economically efficient for the regional market. However, these potential benefits often go unrealized because regional expansion plans are not implemented at the national level. Studies of developing and industrialized countries alike found a “national bias” in infrastructure planning [86]. The review found that optimized regional expansion plans are not generally mandatory and countries, feeling skeptical and disconnected from the regional planning process, were unwilling to accept them. A recent study of energy policy in EU countries found that, while regional legislation is moving towards greater integration and resource sharing, national legislation is moving in the opposite direction, emphasizing domestic generation and energy security [164].

Given the resistance from national governments to voluntarily adopt regional expansion plans, three new approaches are currently being tested to promote regional infrastructure priorities. The first is to establish high-level mandatory targets. The European Commission uses legislation to set targets for generation adequacy and the future energy mix. The targets are broad enough to provide countries with flexibility in choosing how to comply. For example, one part of the Renewable Energy Directive mandates that 20% of final energy consumption must come from renewable energy sources by 2020 without indicating which technologies or projects should be pursued [96]. Countries can meet the target with their

own resources or through “cooperation mechanisms” with other member countries [91].

The second, more prescriptive mechanism is the promotion of specific “priority projects”. These projects are selected because they offer large potential benefits but, due to their size or distribution of benefits, are unlikely to be developed without external support. The SAPP [234], WAPP [267], and IEM [280] each have a list of such projects. The IEM’s approach is the most developed with transparent criteria and cost-benefit methodology to select each project, termed Projects of Common Interest (PCI). Once selected, PCIs are eligible for special permitting and financial support. IEM members have yet to adopt the TEN-E regulation which outlines the process to identify and complete PCIs [93]. Methods to classify and calculate benefits for a given project vary and there is some debate as to what method should be adopted. Ongoing work in this area includes methods to include environmental benefits [197], market power mitigation [47], and interactions with other projects [180]. Once the benefits are identified, other authors are developing methods to narrow the list to only the most impactful benefits [280] and rank projects according to benefits [34].

The third approach is to authorize regional entities to oversee national investments or implement them directly. This is mostly used for transmission interconnections rather than generation. In Central America, the regional system operator is responsible for preparing the Regional Transmission System Plan (Sistema de Planificación de la Transmisión Re-

gional, SPTR), an indicative transmission expansion plan [213]. Projects identified in the SPTR and approved by the regional regulator cannot be opposed by national governments. Similarly, ENTSO-E is responsible for developing a EU-wide transmission expansion plan for Europe. Member countries are free to develop their own expansion plans but they must submit them to ACER for review. If ACER finds discrepancies between national and ENTSO-E plans, they are authorized to ask the country to revise their expansion plan. In cases where the country does not comply with ACER's request, ACER can report the issue to the European Commission for further action. The Economic Community of West African States (ECOWAS) uses Special Purpose Companies (SPCs) to design, finance, and own regional transmission and generation projects [73]. An SPC was responsible for the recently completed West African Gas Pipeline and the WAPP Executive Board recently approved a measure to use an SPC for the Coastal Transmission Backbone project [281].

The unique properties of electricity transmission present an additional planning challenge. Transmission facilities cannot be freely designed because investments are discrete (i.e. we cannot build half a line) only a handful of standard voltage levels and configurations are technically feasible. In addition, transmission costs are highly subject to economies of scale. Per unit line costs increase linearly with the line's voltage rating while transfer capacities grow approximately with the voltage squared. Because it is more economic to add transfer capacity in large increments rather than continuously, transmission investments tend to be overbuilt

for the existing system and, as a result, a new line may not be fully utilized for many years. The physical laws governing network flows mean that there is no fixed definition of transfer capacity —any new line can impact the transfer capacities across the entire network. This implies the need for some coordination among network owners.

### **Cost Allocation**

For projects of regional scope, the costs of designing and implementing the project tend to be high while the benefits are often distributed among multiple local or national systems. As a result, there is generally no single market actor willing to invest in such a project because it would only receive a fraction of the benefits [50]. Disagreement on how to allocate costs to finance new infrastructure is a main barrier for developing regional projects [123].

In West Africa, there is no established regional method for transmission tariffs. Consortia of national network owners build cross-border lines, each bearing the cost of construction and operation within their national borders. The costs are currently recovered through a combination of transmission charges included in bilateral power purchase agreement and charges to domestic consumers [31]. This approach is highly flawed because it does not guarantee that costs are being allocated efficiently and projects that are more complex may not be built due to the increasingly difficult negotiation process.

To facilitate negotiations and overcome resistance to regional projects,

other areas use methods to allocate costs among project beneficiaries. The “beneficiary pays” principle was first introduced in Argentina in 1992 [126] and later implemented in other South American countries [163]. Under this method, an independent party allocates costs to market agents in proportion to the benefits they receive from the project using an established methodology.

Beneficiary pays is a simple concept that is difficult to implement in practice. While transmission costs are usually well-defined, benefits are more difficult to quantify. There is no universal catalogue of transmission benefits. Chang et al (2013) developed a comprehensive list of transmission benefits including over thirty possible items [265]. The challenge, as their list demonstrates, is that some benefits (e.g. production cost savings and reduced transmission energy losses) are relatively straightforward to measure but others (e.g. increased market liquidity and reliability during extreme weather events) are difficult to measure and quantify. Further, the nature and magnitude of benefits may change over the lifetime of the line. Network usage is generally accepted as a proxy for how much each agent benefits from the network but here too there is difficulty because there is no universally accepted method to determine how each agent uses the network [188]. Methods to allocate costs among beneficiaries are still being developed [280, 34] and there are ongoing debates regarding who qualifies as a beneficiary and how to quantify different types of benefits (e.g. reliability, economic) [157, 41].

Despite these difficulties, the beneficiary pays idea continues to be



adopted and implemented in other markets. In the United States, FERC Order 1000 states that transmission costs “must be allocated to those within the transmission planning region that benefit from those facilities in a manner that is at least roughly commensurate with benefits” [103]. Order 1000 was purposefully designed to be broad, allowing local markets to develop their own cost allocation methods. As a result, the implementation of the “beneficiary pays” principle varies among local markets in the United States [107]. In the MER, cost recovery for mandatory transmission projects occurs through a combination of transmission usage charges, tolls, and complementary charges. Complementary charges are socialized over the entire region in proportion to each country’s demand and are designed to add any additional revenues necessary to ensure a regulated rate of return for the project developer [188]. In this case, usage and demand serve as proxies for benefits.

Renewable energy policy goals present a new element to the cost allocation debate. If the fraction of the transmission cost assigned to renewable energy plants, particularly those located far from load centers, under existing cost allocation rules is so large as to make the projects uneconomic, the investments may not occur and the policy goals for renewable energy will not be met. Anticipated growth in renewable energy is “pushing the current paradigm of transmission regulation to its limits” [219] and existing markets are now exploring ways to allocate transmission costs in a way that sends efficient economic signals while also meeting technology-specific policy goals.

### 2.1.3 Institutions and governance

The institutional and governance arrangements are the foundation of regional markets. Common legal and regulatory frameworks are necessary to establish the rights and responsibilities of each member utility and the conditions for a level playing field among all participants [203]. Regional institutions (e.g. regional regulator and system operator) coordinate functions related to operations [291], planning, market oversight [208] and dispute resolution [290, 285]. Legally binding agreements between members must also define the roles and responsibilities of regional institutions and interactions between national and regional entities. The following table contains the key elements that must be included in these new institutions and legal documents. While the exact structure and responsibilities may vary depending on the market context, the topics themselves must be addressed to ensure efficient operation of a regional electricity market [57, 189, 291, 290, 66, 273].

Developing and implementing common governance and institutional arrangements is a formidable challenge, particularly in international markets. As Olmos (2013) explains, “the main barriers are political ones” because it requires a change in mindset from a “local mentality” to a “regional mentality”. Each part of the integration process involves powerful stakeholders (e.g. utilities, regulators, system operators, politicians) that may be reluctant to cede power to a regional authority [273]. These challenges are found to be particularly acute in developing countries, where utilities and regulatory institutions are less likely to be independent from

Documents/Institution	Functions and Responsibilities
Protocols of Agreement between governments	<ul style="list-style-type: none"> <li>• Grant permissions for utilities to make cross-border contracts</li> <li>• Guarantee obligations to exchange energy and payments</li> <li>• Define common legal and regulatory framework for cross-border trade</li> <li>• Define responsibilities of local and regional institutions</li> <li>• Authorize regional institutions to fulfill their responsibilities</li> <li>• Define governance procedures between local and regional institutions</li> <li>• Establish procedures for conflict resolution at supranational level</li> </ul>
Protocols of Agreement between operating members	<ul style="list-style-type: none"> <li>• Define ownership of assets</li> <li>• Define common principles of technical planning, operations, and commercial aspects of the integrated system</li> <li>• Define method to fund regional organizations</li> </ul>
Regional regulator	<ul style="list-style-type: none"> <li>• Develop regional regulations to promote efficiency and security of supply at regional level</li> <li>• Enforce regulatory framework</li> <li>• Settle disputes</li> <li>• Monitor regional market</li> </ul>
Coordination center and system operator	<ul style="list-style-type: none"> <li>• Monitor, control, and coordinate the security of power system operation at regional level</li> <li>• Schedule, coordinate, and settle cross-border energy exchanges</li> <li>• Collect and share any necessary information between the members of the regional market</li> </ul>

Table 2.1: Key elements that should be included in the institutional and governance arrangements for a regional electricity market

political influence and major restructuring may be necessary to ensure a fair playing field [66]. In cases where changes must be made to national legal and regulatory frameworks or restructuring is necessary, the process is slow. For example, the development of the MER among six Central American countries took over eighteen years, requiring national utilities to be restructured, national energy policies to be changed, and the development of new regional institutions [213].

### **Political and Member Support**

A key factor consistently cited for the successful development of a regional market is support from utility members and national governments [290, 66, 273]. The World Bank (2011) cites a lack of political willing-

ness to undergo necessary changes as a major factor in the MER's slow progress. Such reluctance can be understood, given the natural skepticism of the concerned countries regarding the unique liberal doctrine preached by the World Bank's staff at the time, regardless of the countries' specific conditions. The EAPP and the GMS appear to be created and almost universally promoted by international development banks rather than regional governments [132, 19]. Not surprisingly, both of these efforts experience very little political support to harmonize policies, sign protocols of agreement, and create regional institutions [30, 24]. Regions that already have a strong central governing body appear to have greater success. All of the members of the IEM are also members of the EU and subject to its laws. Similarly, the developing WAPP is composed of members of the ECOWAS. Both of these regional governing bodies play a key role in harmonizing policies by passing legally binding electricity market directives. The Federal Energy Regulatory Commission's (FERC) experience with the Standard Market Design (SMD) in the United States demonstrates that political support and central governance are not sufficient without support from utility members and local governments. In 2002, FERC proposed the SMD as a single template for United States electricity markets with the goal of moving towards a single North American market [188]. Strong opposition from states and concerns raised after the California power crisis about the ability for liberalized markets to ensure system reliability forced FERC to reduce the SMD to a set of recommendations released as a white paper in 2003 [142].

## **Regional Institutions**

In addition to political support, new levels of coordination among system operators and regulators are needed [127, 153]. In a regional market, systems that had previously operated autonomously must now coordinate their dispatch, network oversight, and market rules with neighboring systems. Studies of regional markets reveal that local concerns about energy security and sovereignty deter systems from ceding complete authority in system operations and regulation to a regional entity [71]. As a result, a variety of designs for regional institutions exist, varying in terms of membership and authority.

The three dominant membership schemes are voluntary associations, representative regional authorities, and independent regional authorities. Voluntary associations typically bring together groups of relevant local stakeholders (e.g. regulators, system operators) to discuss regional challenges. Attempts to achieve regional coordination through voluntary associations are largely unsuccessful. In 2000, European regulators created the Council of European Energy Regulators (CEER) to discuss key regional regulatory issues. At the initiative of these regulators the Florence Forum was created to discuss the implementation of the IEM and to create regulation by voluntary agreement, informally but very effectively. This approach was successful for a few years to overcome the existing gridlock in European cross-border regulation. However, without legal authority over national regulators, this rudimentary form of governance was unable to resolve the subsequent regulatory challenges the IEM presented and a

new authority, ACER, had to be created. Regional regulation within the SAPP is coordinated through a voluntary association called the Regional Electricity Regulators Association (RERA). Similar to CEER, RERA has no legal authority over national regulators and has largely been ineffective at promoting regulatory harmonization [223]. Despite discussions of voluntary associations among GMS countries, no formal bodies have been established and a review of the regulatory framework in each country concluded there was no cooperation among governments, regulators, or system operators [30].

Representative regional authorities are more successful, particularly in fostering coordination among system operators. Under this model, membership to the regional entity is composed of representatives from national regulators and system operators. The IEM is coordinated by an association of national system operators, ENTSO-E [99]. Under this model, ENTSO-E members have a legal mandate to propose binding operational guidelines at the “European level” but also maintain their authority to oversee activities in their local networks. The SAPP goes a step further to coordinate operations. Members are divided into three control areas and one national system operator from each control area is selected to coordinate operations within its zone [245]. In Central America, the Comisión Regional de la Interconexión Eléctrica (CRIE) is responsible for developing and enforcing market rules as well as market oversight [213, 188]. CRIE is composed of one regulator from each member country.

Sharing control between central and local entities does result in a loss

of efficiency compared to a fully centralized model. A lack of centralized dispatch and coordination among local European markets leads to unscheduled flows and underutilization of the regional network. Increased market coupling improved the efficient use of cross-border transmission lines from 60% in 2010 to 76% in 2012 but network usage after the intraday market closes remains low [14]. Some argue that the SAPP should abandon the control area model in favor of a single regional system operator to increase the efficient use of the regional network [223]. CRIE's design, though equitable, can lead to gridlock since members are unlikely to support regional initiatives that are not in their national interest.

The third membership model is the creation of independent regional authorities. In this case, regional system operators and regulators are independent from their national counterparts. Central American countries created a new independent entity, the Ente Operador Regional (EOR), to run the regional market and coordinate with national system operators [213, 279]. To address concerns about national energy security, MER market transactions are conducted between authorized agents selected by national regulators to represent their country at the regional level. Under this method, countries can schedule their own national dispatch first and choose the level of power they wish to buy and sell on the regional market. This design avoids the need to harmonize market rules across the six member countries but could also lead to inefficiencies due to under participation in the regional market compared to a mandatory pool. Oseni and Pollitt (2015) found cross-border trade as a fraction of consumption

was only 2% in Central America compared to 21% in SAPP and 28% among Nordic countries [192]. Recognizing the need for stronger regional regulation, the European Commission created ACER as part of the Third Package [98]. Similar to FERC in the United States, ACER is EU government appointed and independent of the regulators of the member states. Regulatory harmonization among EU countries has been more successful than among states in the United States. While FERC's SMD faltered, the EU developed a Target Model for a single regional market design [93]. As part of the Target Model, ACER is working with ENTSO-E and the European Commission to harmonize security of supply policies, renewable energy programs, transmission pricing, and a binding network code [189, 93, 249].

The authority of regional institutions is defined by the scope of their responsibilities and legislated ability to fulfill those responsibilities. With no legal responsibilities or authority, voluntary associations such as CEER are limited to an advisory role or to a transitory role of voluntary agreement on some limited number of regulations [63]. For other regional institutions, their authority may be limited by regional preferences for local governance. Not unlike countries in the EU, individual states in the United States prefer to pursue their own initiatives with limited direction from the central government. As a result, both FERC and ACER are relatively weak, reflecting a preference in both regions for decision-making at the local level when possible [98, 141].

All regional institutions, even those with significant legal decision-



making authority, require some degree of approval and oversight by local, national, or regional governing bodies. ACER and ENTSO-E have legal mandates to develop proposals for technical, market, and policy issues brought forth by the European Commission. Their proposals, once developed, are subject to approval by the European Commission through a process called “commitology”, which involves the approval of some specified majority of the member states. Similarly, regional regulations in West Africa must be approved by ECOWAS. In Central America, EOR and CRIE have greater authority to choose which topics to address and propose changes. Changes to the regional grid code are developed by EOR and approved by CRIE. However, without a strong central governing body in the region, proposed changes to the existing grid code must be signed by each government [188].

### **Market Concentration**

Once a certain level of maturity was reached after the very first decades of the last century, the majority of power systems around the world began as vertically integrated, mostly publicly owned utilities with one utility performing all generation, transmission, and distribution functions [117]. A wave of liberalization and restructuring efforts in the 1980s and 1990s brought a variety of organizational structures from vertically integrated systems to fully decentralized systems, where each function is performed by a separate utility or group of utilities [153, 144, 25]. In addition to structure, power systems vary along an ownership spectrum from fully

public to fully private ownership.

For regional markets, varying levels of market concentration and restructuring among market participants can impact long-term investment decisions [44], as well as short-term trading decisions and operations [108]. Some minimal level of legislated unbundling and restructuring is normally required to introduce competition in regional markets. Complete unbundling is not feasible in the majority of markets due to resistance from national governments and incumbent utilities. Instead, reforms focus on regulatory measures such as ensuring open access to the transmission network and non-discriminatory dispatch and balancing procedures [246, 49, 219]. In the United States vertically integrated utilities were not required to be unbundled, but FERC Orders 888 and 889 required all transmission owners to provide non-discriminatory access to the network and share network information with market participants [102, 101]. In 1996, the European Commission in its first Electricity Market Directive mandated open access to the network as well as some restructuring among EU members. The Electricity Market Directives 1996 and 2003 required account separation between generation, transmission, and distribution activities and the creation of an independent Transmission System Operator that cannot discriminate in its economic dispatch and balancing operations [97, 94]. Regional legislation in the MER also mandated unbundling between generation, transmission, and distribution accounts to permit the regional regulator to monitor for cross-subsidization between services that would skew competition among market participants.

Instead of trying to mandate non-discriminatory behavior on the part of national system operators, the MER created an independent regional system operator [279].

There is less progress to promote horizontal unbundling and restructuring. Among EU countries, horizontal concentration in generation remains high. In ten member countries the largest generation company has a market share over 66% [93]. Some areas are creating methods to mitigate market power without forcing utilities to unbundle. The Single Electricity Market between the Republic of Ireland and Northern Ireland forces the dominant utility to sign forward financial contracts, termed Directed Contracts [250]. These contracts remove incentives for dominant firms to manipulate the spot price without interfering in short-term market operations [201]. Mitigating market power may not be sufficient to ensure efficient regional trade. In other EU countries, Gebhardt and Hoffler (2013) found that dominant utilities tend to under-participate in cross-border trade . They hypothesize that utilities were willing to forego small profits from cross-border trading to maintain dominant positions in their national markets. The MER tried to open the generation sector to competition by stipulating in regional regulations that any market participant must be allowed to build a generation plant in any country and export produced power to any other market participant. In practice, this is not fully implemented and generation markets in Costa Rica and Honduras are only partially opened [186].

#### 2.1.4 Critical Topics in Developing Country Markets

Many authors argue that developing countries represent a specific class of problem distinguished by characteristics not present in the power sectors of industrialized countries. Pandey (2002) describes how existing modeling tools fail to capture salient features of developing countries including specific socio-economic conditions, supply shortages, and inadequate access to energy services . Following Pandey, other authors [275, 277, 39] also question the suitability of existing planning and policy analysis tools for developing countries and call for new designs.

While some authors question the appropriateness of quantitative modeling tools, others question whether “best practices” for institutional design and reform coming from industrialized countries should be applied to the developing world [135, 88, 87, 258]. Experiences across a range of countries reveal that attempts to force institutional change or regulatory reform without taking the time to develop matching institutional capacity are often ineffective and even counterproductive, resulting in worse outcomes for consumers and utilities [88, 37]. In response, some authors advocate for a “second-best mindset” based on understanding the institutional and governance arrangements of a country to identify feasible reforms and institutional designs suitable to the context [222, 110].

While these authors focus on modeling tools or institutional arrangements for a particular country, a review of regional markets around the world reveals that developing country power pools also face a number of unique challenges not present in other markets. These challenges are re-

lated to weak institutions, difficulty mobilizing financing, and insufficient infrastructure.

### **Weak Institutions**

Low levels of institutional capacity and staff training are cited as significant challenges for regional markets in developing countries [291, 30, 24, 241, 74]. Industrialized countries must focus on creating regional institutions and harmonizing long-standing regulatory frameworks, national grid codes, and market practices. By contrast, in many developing country regions, national institutions are not developed enough to begin working towards these goals. Reviews of developing country markets find that power sector institutions are undeveloped or underdeveloped at the national level, regulatory frameworks are incomplete, and national agents have no experience with market operations. For example, the previously cited analyses from GMS, SAPP, EAPP, and WAPP conclude that some countries still do not have national regulators and those that are established need basic training on things such as tariff design, dispute resolution, and licensing. Insufficient training and experience is not limited to regulators. Only three out of six GMS members have system operators and none of these are independent from other activities. In southern Africa, twenty years after the SAPP was established, the Coordination Centre (CC) continues to organize popular training sessions for SAPP members and system operators covering fundamental topics such as trading principles, bid submission strategies, and power system

economics. ECOWAS reports “the single biggest threat to the Secretariat’s operation is the lack of appropriate human capital to carry out the planned activities and manage the operations” [282]. Difficulties attracting and retaining qualified staff hinder efforts to develop expertise in African power pools [132, 282].

### **Difficulty Mobilizing Financing**

National utilities in developing countries are often characterized as inefficient and unable to mobilize financing for much needed investments [111]. Financial reviews of national utilities in SAPP, EAPP, and WAPP countries reveal that most of these institutions do not have the investment capital or the credit worthiness to qualify as borrowers for large power projects [259, 182, 267]. The reviews conclude that poor governance and management of the power sector contributes to the utilities’ poor financial performance. In many cases, government ministries are involved in both the regulation and operation of the electric utilities. Under this regime, governments intervene in the tariff-setting process to keep tariffs below cost-reflective levels for many years while, at the same time, instructing state-owned utilities to expand service. As a result, national utilities are unable to recover their costs through consumer tariffs.

Some regions are looking to the private sector to fill the investment gap left by national utilities. A survey among governments and utilities conducted as part of the SAPP’s 2009 master plan found that 75% of planned projects must be funded by Public-Private Partnerships (PPPs)

or pure private sector investment because national utilities lack adequate financing [182]. However, the study notes that many countries lack the legal and institutional capacity needed to engage in large PPP projects. Private sector investments also face several challenges. Many countries do not have a regulatory framework for Independent Power Producers (IPPs) to operate in their country. For those that do allow private sector involvement, this is limited by strict rules regarding mandatory contracts with state-owned utilities and the types of investments private sector investors can make. Additionally, studies of African utilities conclude there is a lack of credible off-takers in the region outside of Eskom, South Africa's state-owned utility. Most major projects are too large for other national utilities with smaller domestic markets. Off-taker agreements with multiple utilities may be possible but negotiations can take a long time and there is currently no standardized form of agreement for the region. To date, private sector investment in the energy sector does not meet these needs. Average private sector investments in the poorest seventy-seven countries from 2009-2014 averaged \$3 billion per year [292], far below the \$27 billion per year estimated to meet energy needs in Africa alone [224].

### **Insufficient Infrastructure**

Largely as a result of the first two challenges, recent investments in generation and transmission infrastructure are not sufficient to meet electricity demand. Many developing countries systems face supply constraints and are unable to meet domestic demand several times throughout the year.

In sub-Saharan Africa, customers experience an average of over eight power outages per month, lasting almost five hours each instance [78]. Alby et al (2012) found that 26.4% of companies in low income countries mention electricity as a severe constraint to their business, compared to 4.9% of high income countries. Under these conditions, domestic energy security is a constant concern among system operators, regulators, and policy-makers. Insufficient generation capacity is cited as a key barrier to trade across markets in Asia, Africa, and Central America [291, 19, 224]. In cases where countries do have excess power to trade, these trades are limited by insufficient cross-border transmission capacity and weak national networks [21]. For African countries, their large geographic size poses a barrier to developing a regional transmission grid because interconnections will require extensive investments in long transmission lines. For example, the EAPP Master Plan indicates that over 8,000 km of new transmission lines are needed just to connect all member countries [259]. By comparison, the SIEPAC line, which forms the backbone of the MER's regional transmission network, is only 1800 km long.

## **2.2 Analytic Approaches to Market Design and Analysis**

A variety of analytic tools are used to assess the performance of regional markets and inform market design and planning decisions. These tools range from quantitative decision support models based on optimization



and simulation techniques to qualitative analysis of institutions and policies. Recognizing the benefits of both approaches, new regulatory and planning studies incorporate both technical modeling and social science methods. The following sections present an overview of the range of the techniques that being applied in regional markets and examples of their applications. As the review illustrates, only a limited number of tools are applied to regional markets in developing countries.

### **2.2.1 Decision Support Models**

Mathematical models developed for specific applications are often referred to as decision support systems. Electric utilities, regulators, system operators, and policy-makers use mathematical simulation and optimization models to support planning and operational decisions across a range of time horizons from long-term investment decisions to short-term decisions on market bidding and plant operations. Analysis conducted at the regional level generally focuses on long-term planning and market monitoring.

#### **Long-Term Planning**

Capacity planning models are used to develop scenarios of how the electricity system may evolve over long time periods including investments in new generation and transmission infrastructure, plant retirements and operational changes that may occur in response to changes in demand, regulations, law and technologies [262] . An overview on planning meth-

ods and tools can be found in [28, 176, 125, 146]. Planning models generally use one of the following approaches:

- explore planning decisions using a simplified operations model [10, 131, 75, 45];
- test the operating dynamics for a set of fixed capacity mixes [77, 56];  
or
- combine both approaches sequentially to screen for candidate generation mixes and transmission investments and then check system dynamics for a given mix [154, 165].

For regional markets, planning models are generally used to guide regional transmission planning decisions. These plans were originally based on reliability and economic efficiency criteria. For example, transmission planning by the New York Independent System Operator is based on a Comprehensive Reliability Planning Process and Economic Planning Process [56]. However, diverging policies among regional stakeholders led to modifications in the planning criteria to include policy objectives. While PJM’s Regional Transmission Expansion Plan is designed to identify mandatory additions and improvements “needed to keep electricity flowing”, the planning process also includes relevant state and local policy objectives that have regional planning impacts [210]. Similarly, ENTSO-E’s Ten-Year Network Development Plan includes European energy objectives related to market integration, security of supply, and renewable energy integration [79]. Also in Europe, the ongoing e-Highway 2050 project is a collaborative effort between ENTSO-E and several research

institutions and industrial firms to develop a top-down methodology for the long-term expansion of the European grid to support the EU's overall policy objectives with regard to energy [7].

Regional network planning is also changing in response to growing interest in intermittent renewable energy plants. Faced with unprecedented increases in renewable generation connected to the regional network, researchers in Europe [165, 167] and the Eastern [77] and Midwestern [154] parts of the United States analyzed the linkage between renewable integration and transmission investments. All of these studies required advances in modeling techniques to accommodate very large geographic areas, on the order of 3-4 million square kilometers, multiple operating areas, and temporal variability of wind resources.

### **Market Monitoring**

Power system operation models are also been widely used to assess the efficient functioning of the regional market. These models generally evaluate short-term operations and test for market power or the inefficient use of infrastructure and resources.

Market power is a significant concern in competitive markets and many researchers use simulation and optimization models to assess the potential for or actual abuse of market power. Borenstein et al (2002) used data from the California market over the period of 1998-2002 to simulate market operations and determine the level of market power abuse that contributed to price spikes during California's power crisis. Mod-

eling methods to identify abuses of market power are far from perfect. Mansur (2008) found that many common methods in the literature overestimate the welfare impacts of market power because they fail to include production constraints that individual firms face. Analysts looking into the California crisis debated whether or not the problem stemmed from the exercise of market power [143] or flaws in the design of the regional market [121] or both. Underlying the debate was whether or not the data included in the simulation model and representation of the network and operating constraints were valid. Very little quantitative market power analysis exists at a regional level. One exception is ACER’s work in Europe using market simulations to test the impact of market power and level of market concentration across the IEM [14].

Other operational models analyze the efficient functioning of the market through the use of regional infrastructure. Oseni and Pollitt (2015) compared levels of market integration across regional markets in Europe, Africa, and Central America by analyzing the fraction of cross-border transmission capacity used for trade. However, network use may not indicate if the market is functioning efficiently since not all physically possible cross-border trades may be economically efficient. ACER’s 2014 Market Monitoring Report looked beyond total transmission usage to assess “efficient use” of the network, defined as scheduled cross-border flows that take advantage of price differentials [14]. Expanding the analysis to include both generation and transmission infrastructure, Bushnell and Saravia (2002) simulated operations of the New England market to test

for “efficient use” of infrastructure. The authors found that unit operating constraints for large fossil fuel plants as well as transmission constraints were barriers to the efficient operation of the regional market.

All of these models assume that market participants will pursue all economically efficient arbitrage opportunities for power trade. This condition requires that they have full access to the regional market and act as profit maximizing enterprises. However, in some cases market participants are not always purely profit maximizing, particularly if they are publicly owned, and national restrictions such as quotas or tariffs may interfere with trade. The types of models and simple metrics cited above provide a useful quantitative evaluation of the gap between economically efficient behavior and actual behavior but they may not be able to identify the reasons behind observed outcomes. This may be particularly difficult in regional markets where distorted market behavior could be the result of some combination of ownership, legal, and regulatory structures in member countries.

### **2.2.2 Social Science Methods**

Institutional assessments have been applied to evaluate regional institutions, policies, and regulations. These assessments use social science methods including interviews, surveys, institutional analysis, content analysis, and cross-case comparisons. Additional resources on these methods can found in [297, 113, 226, 32]. The goals for these types of assessments in regional markets typically include one of the following:

- understand the governance and rule-making process for a given organization [122];
- evaluate the performance of a particular rule, policy, or organization [140];
- compare practices across multiple contexts [107]; or
- understand stakeholder preferences and develop proposals in line with these preferences [53, 140];

Surveys and interviews have been applied to define vague concepts and evaluate rules, policies, and organizations. In Australia, stakeholders were interested in assessing the performance of the National Electricity Market but there were no established criteria to measure the market's performance [140]. Further, there was disagreement as to how to interpret the market's objectives stated in the National Electricity Objective. For example, there was no consensus as to what is meant by "the long term interests of consumers". To address this, the authors used stakeholder surveys to create and rank a list of thirteen performance criteria. Once the criteria were established, researchers collected data to score the market's performance. The surveys responses also helped develop a concrete definition of the market's objectives.

In other cases, social science methods are used to better understand the local context in which an institution, regulation, or policy operates and make recommendations that are appropriate for the context. NREL (2011) and Hauteclouque and Rious (2011) used content analysis of existing policies, regulations, and processes to develop recommendations for

the role of FERC in the United States [107] and ACER in Europe [122] to oversee cross-border transmission lines. Glachant et al (2013) applied theoretical work on incentive regulation to existing national regulatory designs to develop a target for regulatory harmonization in Europe. In addition to institutional design, these methods are also applied to regulatory design. CEPA/ACER (2015) interviewed stakeholders in Europe to understand how current transmission pricing practices can negatively impact the efficient functioning of the market. They combined these findings with economic theories on transmission pricing and reviews of national energy policies and regulations to develop and evaluate policy proposals for transmission pricing that are “feasible to implement” in the European market.

### **2.2.3 Hybrid Studies**

Technical models play an important role to transfer technical knowledge into the decision-making and negotiation process but many policy and regulatory decisions require an understanding of the regional context in which these decisions are being made. Similarly, social science methods are useful to understand decision-making processes, preferences, and compare non-quantitative factors, but do not include technical analysis and may not easily identify and communicate tradeoffs between decisions. Recognizing the shortcomings of both approaches, an increasing number of assessments use a hybrid approach that combines decision support models with social science methods.

Bockers et al (2013) used six years of load data among EU countries to model potential economic trades and prices and compare these results to actual trading. Based on a content analysis of national energy policies and regulations, the authors estimated the welfare loss in the regional market due to different support schemes for particular technologies among member states that only applied within their country. PJM's Market Monitoring report combines quantitative modeling and data analysis with qualitative criteria related to market's structure, rules, membership, and participant behavior to develop an overall assessment of the market's competitiveness [173].

Hybrid studies are particularly useful to develop and test proposals for new policies or regulations because they combine rigorous technical representations of the system with an understanding of the market context. In these studies, social science methods are generally used to identify a problem, develop boundary conditions on possible solutions, and offer implementation steps for a given proposal [109]. For example, a key objective of Olmos and Perez-Arriaga's (2007) study on methods to allocate transmission capacity in the IEM was to develop a scheme that is "compatible with the market structures in member states". In this case, the list of possible proposals is constrained to those that are compatible with EU markets. Once the problem is identified and feasible proposals are developed, computer models can test each proposal. This approach was adopted to test methods for capacity mechanisms [164], zonal pricing [263], and transmission pricing and investment strategies [123].



A final role for hybrid studies is to communicate tradeoffs and help in the negotiation process among decision-makers. This is particularly important in regional markets where decisions often involve stakeholders representing multiple local, national, and regional perspectives, each with their own objectives. For example, in the EU there is growing concern that “necessary investments will not take place or not as quickly as needed” in the electricity and gas sectors [92]. In response, the EU has called for a new quantitative policy and project support tool that can “better explain the benefits of a specific project” to the stakeholders affected and create a transparent template for evaluating project risk [92].

#### **2.2.4 Analytic Approaches in Developing Country Markets**

In developing country markets, the range of tools and level of analysis is significantly lower than in other regions. Most technical studies are focused on long-term expansion planning and there are few institutional assessments providing concrete conclusions or recommendations.

##### **Decision Support Models**

The use of technical models in regional markets in developing countries is almost exclusively limited to long-term generation and transmission expansion planning. One exception to this is a grid development study by the Asian Development Bank (2013) to assess the benefits of proposed cross-border lines between six countries in South Asia that could form a South Asian Regional Power Market. The study combined optimal

power flow and investment-planning models to quantify the benefits of each line, based on reduced system costs. It also addressed legal and regulatory changes required in each country to establish open electricity trading but did not test the impact of existing policies on the economic viability of the transmission lines.

All other technical modeling efforts in developing country markets focus on long-term planning. Long-term master plans were created for the SAPP [224, 182, 260, 169], WAPP [224, 268, 170], EAPP [224, 259], and GMS [15, 17]. Notably, consultants, multilateral development banks, or academic groups conducted all of these studies rather than planning authorities within the region. The objective for each study was to compare the costs of regional expansion planning with the total cost of each country developing its own system based on simple least-cost criteria.

Two studies did attempt to go beyond this basic framework and test the impacts of different policy or regulatory scenarios. Purdue University's Long Term Model tested the impact of national trade policies such as limits on imports and exports in the SAPP. The International Renewable Energy Agency's models were designed to estimate cost savings of integrating renewable energy on a regional rather than national basis. For both of these studies, the results were not directly applicable because the policies and scenarios were not based on national policies that existed or were being proposed. Instead, they reflected a range of possible scenarios (e.g. a carbon tax) created by the model developers.

## Social Science Methods

In developing country markets, institutional assessments generally focus on reviewing the historical context in which a market was created and the existing institutional, policy, and regulatory environment in which it operates. These studies generally rely on content analysis, cross-case comparisons, and gap analysis to draw conclusions and make recommendations.

In some cases, the purpose of the study is an overview of the market and no analysis is provided [132]. In others, the analysis does not lead to recommendations. For example, Lovei (2000) provides a good analysis on why structural rules that limit competition in generation (the “single buyer model”) are prevalent in developing countries and how this model could hurt the development of electricity markets [158]. However, the paper does not propose alternative models.

A second group of papers provides recommendations but they are generally vague and difficult to translate into actionable steps. For example, studies on market design and operations in Gulf Countries, Africa, and Central America include recommendations such as “harmonizing tariffs” [291, 76, 70, 168], “greater government cooperation” [70, 161], and “skills development” [70, 120]. These studies do not specify which tariffs should be harmonized, the areas in which greater cooperation is needed, the types of skills that should be developed or a process by which these recommendations could be implemented. The recommendations also do not incorporate the lessons learned from the content analysis to establish a

boundary on what types of reforms are feasible in the region being studied. There are some notable exceptions to this group. A 2008 survey by Mabombo et al. of policy, institutional, and regulatory frameworks among SAPP countries resulted in specific short- and medium-term action items to implement their recommendations [160]. Also in the SAPP region, Zhou (2012) used a gap analysis to assess if national regulations, policies, and strategies are sufficient to meet future energy demand [230]. The results are translated into specific action items for “soft infrastructure”. In both studies, the authors also indicate which regional organization(s) should be responsible for fulfilling each action item.

A number of authors use cross-case comparisons of regional markets from different parts of the world to analyze market performance and develop recommendations. A comparison between regional markets in Africa, Europe, and the United States was used to identify potential issues that African markets may face [271]. The authors do not assess the potential impact of these issues on trade and recommendations for resolving them are weak. For example, they conclude that issues related to transmission access and congestion “will be addressed” once a regional regulator is established in the SAPP but offer no guidance as to how these issues can and should be resolved based on international experience. Consultants studying the WAPP reviewed transmission tariff pricing schemes across seven systems in the United States, Europe, Asia, Africa, and Latin America. This review was combined with the results of a questionnaire on pricing methodologies used by WAPP countries to identify “key points

for discussion” on regional transmission regulation [31]. The study did not provide recommendations for ways to address each discussion point based on their international review. Navarro (2008) provides a good comparison of regional markets only among developing country regions [177]. Based on comparisons of the Nile Basin Initiative, MER, and GMS the author identifies key aspects of developing countries that may require special consideration in the design of the regional market and proposes context-specific recommendations for governance arrangements.

A final group of studies are sponsored by external agencies and focus on assessing the effectiveness of the agency’s support in the regional market, rather than the market itself. A review by the World Bank of its multi-country operations concluded that the organization is meeting its goals of sustainable growth and poverty reduction [137]. Similar assessments by the Asian Development Bank (2008) and SIDA (2011) were conducted in the GMS [30, 16]. The reports do not indicate if the agencies’ goals are aligned with the goals of the regional market. In the case of the Asian Development Bank, the objectives were clearly tied to developing specific infrastructure projects. While these projects are important for the development of a regional market, they do not ensure that a market will be created or function efficiently.

### **Hybrid Studies**

Hybrid studies have only been applied to markets in Latin America. Olmos (2006) combined policy and regulatory analysis with technical mod-

eling to propose rules for transmission regulation in the MER [188]. In Argentina, a technical study was used to assist with project negotiations for a proposed “Fourth Line” from a main generation center in Comahue to a major load center in Buenos Aires [157]. As Littlechild and Sterk (2008) explain, the “much needed” project was initially rejected because technical analysis revealed the costs of the project most likely outweighed its benefits. After concerns about transmission congestion and imbalances in the location of demand and supply centers increased, the line was proposed again a year later and passed after new analysis revealed it was economic.

These types of hybrid studies have not been implemented in African markets but there are several opportunities where they could be useful. In West Africa, the consultant Nexant proposed four possible methods for transmission regulation and pricing in the regional market [183]. The proposals ranged from establishing a single regional transmission company to adopting an inter-TSO compensation scheme similar to what is used in Europe. The authors offered a qualitative review of the tradeoffs and concepts behind each proposal but did not provide quantitative analysis to support their recommendation. Technical analysis could support their work by providing information on how the proposal may impact trade flows and cost allocation among different market agents. In 2010 the Program for Infrastructure Development in Africa (PIDA), a consortium of the African Union, United Nations, and NEPAD, developed a list of priority infrastructure projects in Africa [23]. The PIDA Prior-

ity Projects are important because they provide centralized guidance to national, regional, and multi-lateral efforts to improve Africa's infrastructure. However, the project selection process involved no technical modeling or quantitative analysis. Instead, the projects were chosen based on two days of consultations with representatives from across the continent. Projects were prioritized based on three criteria: 1.) impact on regional integration, 2.) feasibility and readiness, and 3.) development impacts. Without quantitative analysis, assessments about project impacts were based solely on perceptions from stakeholders.

### **2.3 The Gap in Literature and Research Objectives**

Despite the fact that regional markets exist in a variety of sizes, structures, and locations around the world, there are several common challenges that all markets face and which must be addressed in order for the market to function efficiently. These are: 1.) aligning market rules with national concerns about security of supply, 2.) incentivizing investment in regional infrastructure, particularly cross-border transmission, and 3.) designing effective regional institutions, particularly the regional regulator. Markets in developing countries have unique characteristics that are not present in other regions, including significant needs for institutional capacity building, financing, and infrastructure development which exacerbate these challenges. Several authors identified the need for more work focused specifically on developing countries and adopted traditional modeling tools and institutional assessments to the developing country

context. However, these efforts have not been translated into analysis of regional markets. Most of the analytic studies on regional market design and analysis are focused on markets in the United States, Europe, and Latin America.

More work is needed to bring theoretical insights and practical lessons from the regional market literature to developing country markets. The approach taken thus far, based on developing best practices, is limited because it does not provide for specific contextual factors such as a region's institutions, governance arrangements, specialized knowledge, legal frameworks, and preferences. Therefore, this dissertation aims to move beyond least-cost expansion planning and high-level institutional analysis to provide specific recommendations for these four market challenges that are supported by rigorous technical analysis and tailored to meet the specific needs of a developing country market. In meeting these goals, this research aims to expand the literature on market design and regulation in developing countries.



# 3

## Regional Market Design and Security of Supply

Security of supply is a critical concern for regional markets in both developed and developing countries. This chapter examines the impact of high levels of inflexible bilateral trade in southern Africa limit participation in the competitive short-term markets and lead to inefficient use of regional generation and transmission infrastructure. Under the current supply situation, governments and market participants are unlikely to forego their preference for long-term contracts owing to concerns about security of supply and risk mitigation. This chapter provides an evaluation of the current methods to integrate bilateral contracts with competitive market trading and proposes an alternative method based on contracts for differences and implicit auctions. I simulate the impacts on trade flows, generation, system costs, and security of supply with a representative economic dispatch model of the SAPP. The analysis includes proposed steps to implement the alternative method. The chapter concludes with

a discussion on the potential impacts of renewable energy on security of supply and market design.

## 3.1 Background

### 3.1.1 Regional Context

Security of supply is a critical issue in the SAPP. Three of the SAPP's six objectives are related to improving security of supply and regional coordination in developing energy resources. Despite a regional goal of providing a “world class, robust, safe, efficient, reliable and stable interconnected electrical system in the southern African region”, SAPP countries were ranked among the bottom 50 in the world in 2014 for quality of electricity supply according to the World Economic Forum<sup>1</sup> [242, 293]. The largest contributor to poor quality of supply appears to be insufficient investments in new generation. The region has experienced supply shortages since 2007 resulting in interrupted supply for consumers and slower economic growth [288]. In 2015, the capacity shortfall reached 8,247 MW (17% of peak demand).

This situation impacts the level of participation in the regional market and the way in which regional trade is conducted. Instead of trading in the competitive markets, SAPP members prefer firm bilateral contracts for cross-border trade [184]. These contracts provide guaranteed electricity supply for consumers and reduce demand risk for generators. Bilateral

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<sup>1</sup>Namibia is the sole exception with a score of 52 out of 148 countries.

contracts consistently make up over 90% of total cross-border trade in the SAPP<sup>2</sup>. In addition, bilateral contracts are viewed as necessary in the region to obtain financing for investments in new power plants or energy-intensive industries [298].

SAPP officials are trying to promote more trading in the competitive day-ahead and intra-day markets and reduce the share of trades through long-term bilateral contracts [58]. This is motivated by the belief that the competitive markets will allow more opportunities for new entrants to build power plants and compete to sell their power to the region. According to market theory, greater competition among more suppliers and consumers will result in more efficient use of energy resources and lower prices for consumers [54].

### 3.1.2 Scheduling procedures

The SAPP market operator (MO) is responsible for collecting all trading information from bilateral and market trades and scheduling power exchanges between control areas<sup>3</sup>. This process occurs over a series of steps. In the morning the day before trading, parties with bilateral contracts declare their trades and wheeling paths, confirmed by the transmission system operators, to their local control area system operator. The control area operators combine these declarations to calculate the remaining

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<sup>2</sup>The share of bilateral trades fell slightly in the last year, from 98% in 2014 to 94% in 2015.

<sup>3</sup>The SAPP is divided into three control areas, each with its own control area system operator. Eskom serves as the operator for Botswana, Lesotho, southern Mozambique, Namibia, South Africa, and Swaziland; Zimbabwe Electricity Supply Authority (ZESA) is the operator for Zimbabwe and northern Mozambique; and Zambia Electricity Supply Corporation (ZESCO) is the operator for Zambia and the DRC.

cross-border transmission capacity available for market trading. This information, along with information on all self-scheduled bilateral trades, is sent to the SAPP MO.

On the basis of these declarations, the SAPP MO calculates and publishes the remaining transmission capacity available for trading in the DAM. Participants use this information to submit their offers and bids for the DAM. At noon the DAM closes and the SAPP MO publishes the results including traded volumes, power requested, market clearing prices, and any remaining demand and transmission capacity available. Participants can then contest any errors or resubmit their bids to the IDM, which opens immediately when the DAM results are published.

On the day of trading, each control area system operator is responsible for monitoring and correcting intra-control area imbalances of supply and demand. The SAPP CC handles inter-control area imbalances according to procedures described in the SAPP Operating Guidelines [245].

For producers with bilateral contracts, the favorable treatment contracts receive during the dispatch process ensures they will have priority access to the transmission network to sell their power. Contracted consumers also benefit by ensuring they will be able to receive power when supplies are not sufficient to meet all demand. By contrast, DAM and IDM traders face high levels of uncertainty as to whether their bids will be matched in the market and, if matched, whether the trades will be technically feasible as a result of transmission constraints. Historically, <20% of buy and sell bids submitted to the SAPP MO were matched

in the DAM or IDM [253]. Among the offers that were matched, only a fraction was actually traded because of transmission constraints. In the most recent trading year, 88% of energy matched in the DAM or IDM was traded, a significant improvement from only 15% in the 2012-13 trading year [242]. For potential investors, these rules may deter new entrants from building plants and competing in the short-term markets because transmission constraints may prevent them from selling their power.

### **3.1.3 Contract designs**

Bilateral contracts can be designed to include physical or financial obligations. Physical obligations require the physical use of designated infrastructure (e.g. transmission line, power plant) to fulfill the contract. This format puts the greatest constraint on the operation of the system but also guarantees that power will be delivered as promised. Financial contracts, by contrast, only require exchanges of money and do not influence the physical operation of the system. Purely financial contracts are widely considered to be the most efficient format because they incentivize participants to sign contracts consistent with the efficient operation of the system but do not impact system operations. Participants earn money through differences in nodal prices between the points of injection and withdrawal described in the contract. Those that sign financial contracts in the “right” direction (i.e. the same direction that trade would flow under purely least-cost objectives) can earn revenues because the difference in nodal prices will be positive as power flows from low- to high-cost ar-

eas. On the other hand, those who sign contracts in the “wrong” direction could lose money. Financial contracts are widely used across systems in the United States.

The SAPP’s market rules mandate that bilateral contract holders must obtain physical transmission rights for their contracts but can transfer their energy obligations to third parties. In other words, the energy obligation is financial and they are not obligated to meet these contracts with their own power plants if there is a more economic alternative. This rule allows generators to seek the least-cost supply to meet their contractual obligations but it does not encourage efficient use of the transmission network because their reserved transmission capacity will go unused. In practice, SAPP members are reported to treat these contracts as physical energy obligations as well and self-schedule their own generators to meet all contract obligations even if there are lower-cost suppliers available in the market [22].

## **3.2 Problem Statement**

Experience in United States and European markets suggests that bilateral contracts do not have to conflict with market efficiency. In fact, Hogan (1994) argues that bilateral transactions create a need for competitive markets for balancing and economic efficiency and competitive markets need bilateral transactions to provide market stability [127]. However, these transactions are only complementary if commercial bilateral transactions do not influence the least-cost dispatch and delivery of energy –a

condition not met in the SAPP's current market design.

The SAPP CC has two approaches to increase market competition and improve security of supply in the region. The first approach is promoting investments in new generation and transmission infrastructure by identifying and publicizing a list of priority projects. The second approach, supported by regional training and informational programs, is to encourage market participants to shift from bilateral to market trading. New investments are slowly coming online but these are, for the most part, not projects identified as priority projects by the SAPP CC. More importantly, current projections indicate the system will continue to be constrained for many years to come. Even if supply constraints are eased by new infrastructure, it is not clear that members will be willing to abandon long term contracts in favor of market trading. More importantly, however, SAPP members do not need to abandon bilateral contracts to promote efficiency gains from the competitive market. Instead, the SAPP must address the underlying market design flaw that puts bilateral transactions in conflict with the efficient use of generation and transmission infrastructure.

To date, evaluations of bilateral contracts in the SAPP have focused on the level of trade or infrastructure constraints that bilateral contracts impose on market transactions [296, 46]. There has been no study of the impact of the SAPP's market design rules for integrating bilateral and market trading on either market efficiency or security of supply. The analysis presented in this chapter aims to fill this gap by addressing the

following subquestions:

- Under existing rules, what impacts do bilateral contracts have on the efficient functioning of the regional market?
- Under existing rules, what impacts do bilateral contracts have on security of supply for contract holders?
- What are alternative methods to integrate bilateral and market trading to minimize market distortions while ensuring the same level of security of supply for contract holders?
- How can such methods be integrated in practice into the existing market?

### **3.3 Impact of Contract Formats on Market Outcomes**

#### **3.3.1 Model Description**

There exists a wide range of power system optimization and simulation models designed to support planning and operation decisions at incremental time horizons. The most common types are expansion planning, hydro-thermal coordination, unit commitment, economic dispatch, power flow and network stability. An overview of these decision support tools is provided by [194, 214]. Long-term planning models use coarse system representations to inform high-level investment decisions on multi-decade time scales. These decisions are refined using medium and short term models that represent the system in greater detail but have more limited decision spaces.



For any study, the model type should be selected based on the desired planning or operation decisions to optimize or observe and the level of detail required to represent the system. In this case, I am interested in analyzing the technical and economic impacts of different market rules governing bilateral contracts on system operations. Specifically, I am interested in simulating how these contracts impact patterns of generation, power trade and security of supply under different operating conditions. With this in mind, I developed a security-constrained unit commitment and economic dispatch model of the SAPP system.

Unit commitment and economic dispatch models optimize the hourly commitment and output of generation plants to meet demand over a medium period (one week to one year) at lowest cost subject to technical, policy or regulatory constraints formulated as linear equations. The model has multiple nodes to represent generation and demand characteristics in each country. The regional network is represented using a simplified transportation model where each country is represented as a single node. Although this approach simplifies the complexity of physical network to only capture the transfer capacity limits between contiguous countries, it is able to capture the relevant higher-level impacts that bilateral contracts and operating rules may have on trade flows that are of interest for this study. The approach is deterministic, covering the hourly operation over a one week period, and represents the 2015 SAPP system. Non-operating members (Tanzania, Angola, and Malawi) are not included in the model as these countries are not physically connected to

the regional grid.

The complete model formulation can be found in Appendix A.

### 3.3.2 Input Data

#### Generation

Tables 3.1 and 3.2 contain the installed capacity and operating parameters for each country and generator type. To reduce the dimensionality of the problem, individual power plants are grouped by technology. The group “hydro” includes both reservoir and run-of-river plants. Although this incorrectly represents run-of-river plants as dispatchable, these plants only account for <2% of the total hydropower capacity. The parameter, Availability Factor, is used to reduce the maximum capacity of each plant to reflect power consumed for the plant’s own use and periods when it is unavailable because of planned and unplanned outages. For wind and solar technologies, resource availability figures for each country were taken from published results based on [100].

Country	Biomass	Coal	Distillate	Gas	Hydro	Nuclear	Wind	Solar
Botswana		502	70	90				
DRC				14.5	2353			
Lesotho					72			
Mozambique			64	242	2157			
Namibia		120	46.5		330			
South Africa	18	36437	1833	2791	2239	1888	1233	1160
Swaziland					60.5			
Zambia			50	60	2149			
Zimbabwe		1384			750			
<b>Total</b>	<b>18</b>	<b>38443</b>	<b>2063.5</b>	<b>3187.5</b>	<b>10109.5</b>	<b>1888</b>	<b>1233</b>	<b>1160</b>

Table 3.1: 2015 installed capacity in SAPP countries by technology [MW] [242, 211]

In addition to these generators, an additional dummy generator, en-

Technology	Country	Heat rate (MMBTU/MWh)	Variable cost (\$/MWh)	Availability factor (%)	Fuel cost (\$/MMBTU)
Biomass	South Africa	13.3	5.4	50	1.6
Coal	Botswana	12.2	3.4	65	0.5
	Namibia	11.4	1.3	88	0.4
	South Africa	8.3	0.5	82	0.4
	Zimbabwe	11.4	1.3	88	0.7
Distillate	Botswana	13.3	17	80	17.2
	Mozambique	11.8	3	80	12.8
	Namibia	12.3	11	88	17.8
	South Africa	13.1	16.1	73	16.7
	Zambia	11.5	3	80	12.8
Gas	Botswana	11.4	19.9	85	9
	DRC	11.4	19.9	85	9
	Mozambique	11.4	19.9	85	9
	South Africa	27.1	15.6	79	10.6
	Zambia	11.4	19.9	85	11.6
Hydro	DRC		1.51	70	
	Lesotho		1.51	65	
	Mozambique		1.51	65	
	Namibia		1.51	60	
	South Africa		1.51	70	
	Swaziland		1.51	37	
	Zambia		1.51	65	
	Zimbabwe		1.51	61	
Nuclear	South Africa	10.1	0.71	81	

Table 3.2: Techno-economic parameters for generation technologies used in the 2015 economic dispatch model [169, 40]

ergy non-served (ENS), was added to account for hours when supply is not sufficient to meet demand. ENS is assumed to have 100% availability and a variable cost of \$800/MWh. The high variable cost serves as a penalty for not meeting demand.

### Transmission Network

The transmission network includes all existing interconnections between member countries and does not include intra-national networks. Table 3.3 shows the transfer capacities between member countries. All transmission lines are assumed to have energy losses of 2.5%.

Country	Country	Transfer capacity (MW)
Botswana	Zimbabwe	850
Mozambique	Swaziland	1450
	Zimbabwe	500
South Africa	Botswana	800
	Lesotho	230
	Mozambique	3850
	Namibia	750
	Swaziland	1450
	Zimbabwe	70
Zambia	DRC	260
	Namibia	400
	Zimbabwe	1400

Table 3.3: Cross-border transfer capacities in SAPP regional network [6]

## Demand

Hourly demand values for each SAPP country are not publicly available. Therefore, hourly demand is based on a representative week in South Africa at the end of June 2015 [85] (Figure 3-1). This corresponds to the region’s annual peak demand. For other countries, hourly load curves were modelled after those of South Africa and scaled based on their equivalent peak demand. Although imperfect, this simplification is not unrealistic because SAPP countries are reported to have almost no load diversity with demand peaking at almost the same time in each country. In addition, South Africa accounts for nearly 80% of total demand in the region and its demand profile will be the key driver for generation and trade patterns. A shortcoming of this approach is that it does not account for potential differences from different demand sectors (e.g. residential, industrial, commercial) in each country that could change the shape of the demand curve when aggregated at the regional level.

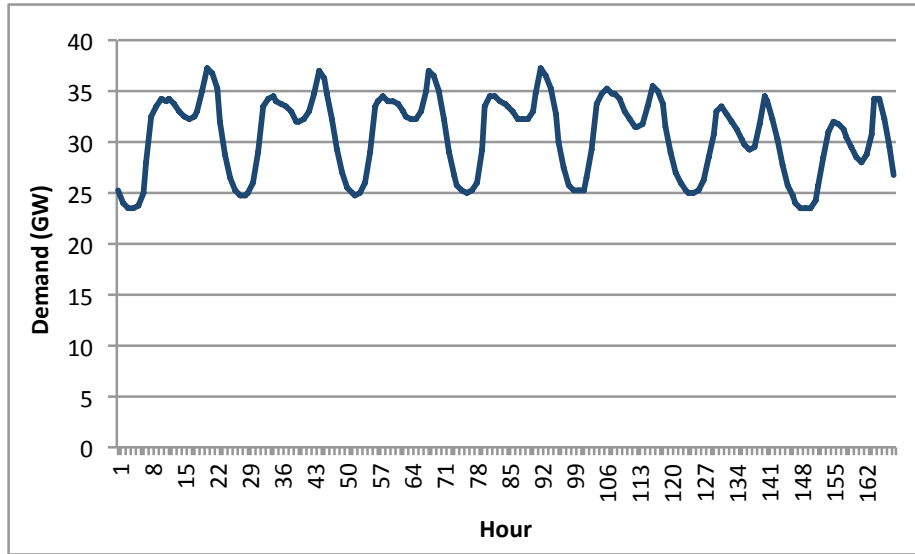


Figure 3-1: Hourly load curve for sample week in June 2015 in South Africa. Demand in all other countries is assumed to follow a similar pattern [85, 242]

## Contracts

Data on bilateral contracts are based on the most recent published information available from the SAPP (Table 3.4). This information only included the co-signers and contracted capacity. Details regarding how the contracts must be fulfilled are proprietary and not publicly available. For this study, all contracts are assumed to be flat (i.e. the co-signers are responsible for delivering/buying the same capacity every hour).

## Case Studies

To compare different methods for treating bilateral contracts, I tested a range of contract designs including physical and financial components (Table 3.5).

Many reported instances of power outages among SAPP members are due to unplanned outages because plants have not been properly main-

Supplier	Consumer	Bilateral contract (MW)
EdM (Mozambique)	SEC (Swaziland)	40
	NamPower (Namibia)	40
	BPC (Botswana)	45
HCB (Mozambique)	Eskom (South Africa)	1370
	ZESA (Zimbabwe)	250
ZESA (Zimbabwe)	NamPower (Namibia)	80
SNEL (DRC)	Eskom (South Africa)	150
	ZESA (Zimbabwe)	100
Eskom (South Africa)	LEC (Lesotho)	100
	EdM (Mozambique)	120
	NamPower (Namibia)	200
	BPC (Botswana)	210
	SEC (Swaziland)	96
	MOZAL (Mozambique)	950

Table 3.4: Bilateral contracts between SAPP members. Utilities in South Africa and Mozambique account for the most bilateral contract activity measured by total capacity (MW) contracted. [58]

Case study	Description
Base case	Assume there are no bilateral contracts. Generation and trade are computed in the short term based purely on least-cost principles. This provides a baseline of maximum efficiency for comparison.
Physical transmission (PT)	Contract holders retain PT rights that can only be used to meet their contract obligations but energy obligations are financial. This reflects the official SAPP policy.
Physical contracts (PC)	Contract holders retain PT rights and have physical obligations to meet energy contracts with their own power plants. This reflects what is generally practiced in the SAPP.
Financial contracts (FC)	Both transmission and generation components are purely financial. This format is commonly viewed as the most efficient way to implement bilateral contracts.
Scarcity	Each of the above scenarios were tested under normal and scarcity conditions.

Table 3.5: Description of alternative methods to format and implement bilateral contracts into the competitive market tested in each case study

tained and suffer technical failures or droughts that reduce output from hydropower plants [242]. These extreme events are represented by the scarcity scenarios. For South Africa and Mozambique, scarcity is simulated as 20% of the country’s generating capacity being unavailable. All other countries have a limited number of power plants or rely heavily on one or two large hydro plants. For these countries scarcity is simulated

as 50% of the country's generating capacity being unavailable.

### 3.3.3 Results

#### System Operations

Figure 3-2 shows the least-cost generation profile over the week for the base case with no bilateral contracts. Generation is dominated by coal in South Africa, accounting for 75% of total output. Hydropower from South Africa, DRC, Mozambique, Zimbabwe, and Zambia is the second largest contributor. The largest producer is South Africa with 85% of total generation.

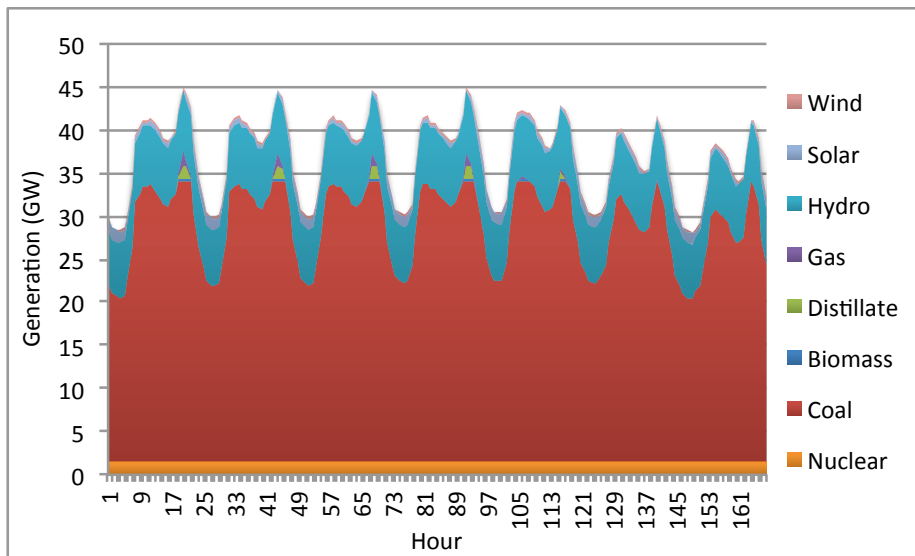


Figure 3-2: Hourly generation profile for the base case over the simulated week of operation

In the base case, there are no bilateral contracts and over 20% of electricity generated is traded in the regional network. A simple way to see whether bilateral contracts could influence efficient operation of the network is to compare the least-cost trades achieved in the base case with the

power exchanges agreed through bilateral contracts (Figure 3-3). The size of the orange arrow indicates the total volume of energy traded. The red arrows indicate the direction of trade for bilateral contracts. Notably, in two cases (circled), bilateral contract exchanges are in the opposite direction from that of the least-cost trading solution. These are potential cases where physical network and generation obligations may lead to inefficiencies in the physical transmission (PT) and physical contract (PC) scenarios and economic losses in the financial contract (FC) scenario.

### *Physical Transmission*

In the PT scenario, total cross-border trade falls by 2%. The reduction is due to the fact that some portion of transmission capacity must be reserved for bilateral trades but this transmission capacity goes unused if these trades are not economic because they would require dispatching higher cost generators. Across individual lines, net trade flows changed by an average of 13% with some lines being used more whereas others are used less owing to contract constraints. Figure 3-4 shows the change in trade flows under the PT scenario compared to the base case. Physical transmission rights cause the largest change in flows across the Namibia-Zambia interconnection. Notably, this line has no bilateral contracts and therefore no additional operating constraints associated with it. The DRC-Zambia interconnection is always fully utilized to transfer low cost hydropower from DRC to its southern neighbors.

Physical transmission rights also cause small changes in generation



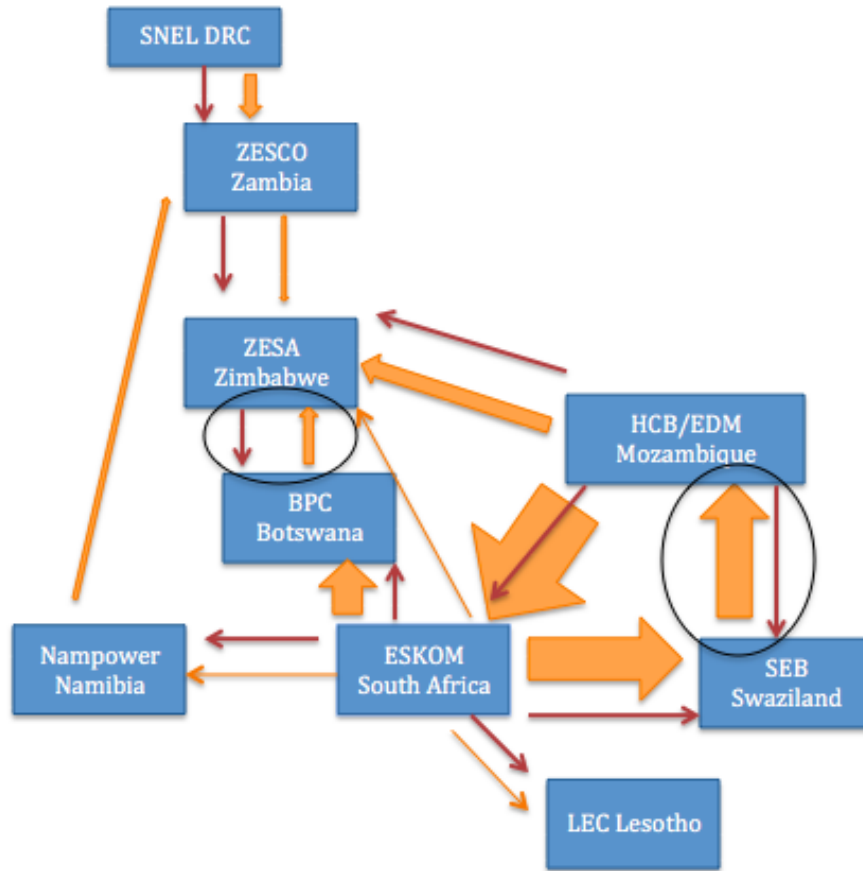


Figure 3-3: Comparison of the optimal trade flows simulated in the base case (orange arrow) with trade flows based on bilateral contracts (red arrow). The size of the orange arrow indicates the total volume of energy traded in the base case. The two cases circled indicate cases where the least cost trading solution is in the opposite direction of the bilateral contract.

output from different countries. Zimbabwe’s imports from Mozambique decrease because Mozambique is exporting more power to South Africa. As a result, total production in South Africa decreases and Zimbabwe experiences a small number of hours with ENS. These changes are small, accounting for <1% of total generation. Figure 3-5 compares the change in total generation in each country compared to the base case. For both South Africa and Zimbabwe, the change accounts for less than 1% of total generation.

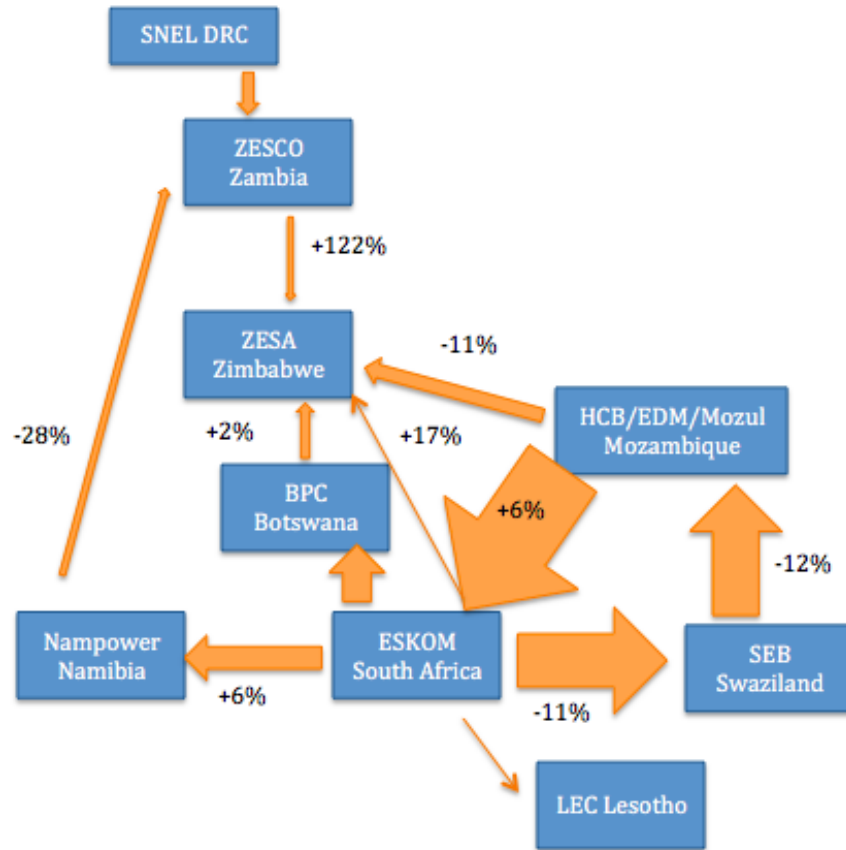


Figure 3-4: Comparison of optimal trade flows under the PT scenario with the base case in a normal operating week. Physical transmission rights introduce constraints on power flows across specific transmission corridors (i.e. Mozambique-Swaziland). These changes impact flows entering and exiting these countries from other parts of the region.

### *Physical Contracts*

The impact on system operations in the PC scenario is larger because this method constrains the use of the transmission network and introduces mandatory generation and import obligations for contract holders. Total cross-border trade falls by 50% compared with the base case and, for the two connections circled in Figure 3-3, trade flows are constrained to go in the opposite direction. Figure 3-6 shows the change in trade flows across

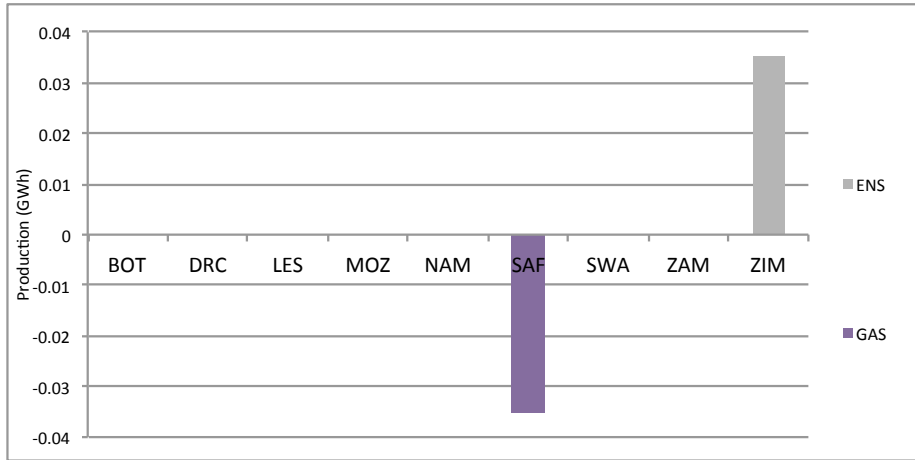


Figure 3-5: Impact of physical transmission rights on generation output in each country compared to the base case. In a normal week, gas generation from South Africa decreases slightly and Zimbabwe experiences a small number of hours of ENS.

each interconnection compared to the base case. Trade across lines that are not contracted (i.e. Namibia–Zambia and South Africa–Zimbabwe) increase whereas trade across lines that are contracted in the apparent wrong direction (i.e. Mozambique–Swaziland) decrease. The average change in trade flows across individual lines is 32%, indicating that physical contracts require significant changes in the efficient operation of the system.

Physical contracts also impose larger changes in generation. Figure 3-7 shows the change in which generators are dispatched to meet demand each hour compared to the base case. Some countries, such as South Africa, have fewer export opportunities because their neighbors now import power from other adjacent countries with which they have bilateral contracts. As a result, total generation in South Africa decreases. Others, such as Zimbabwe, must increase generation to meet contractual obligations. Figure 3-8 shows the change in total production in the PC scenario

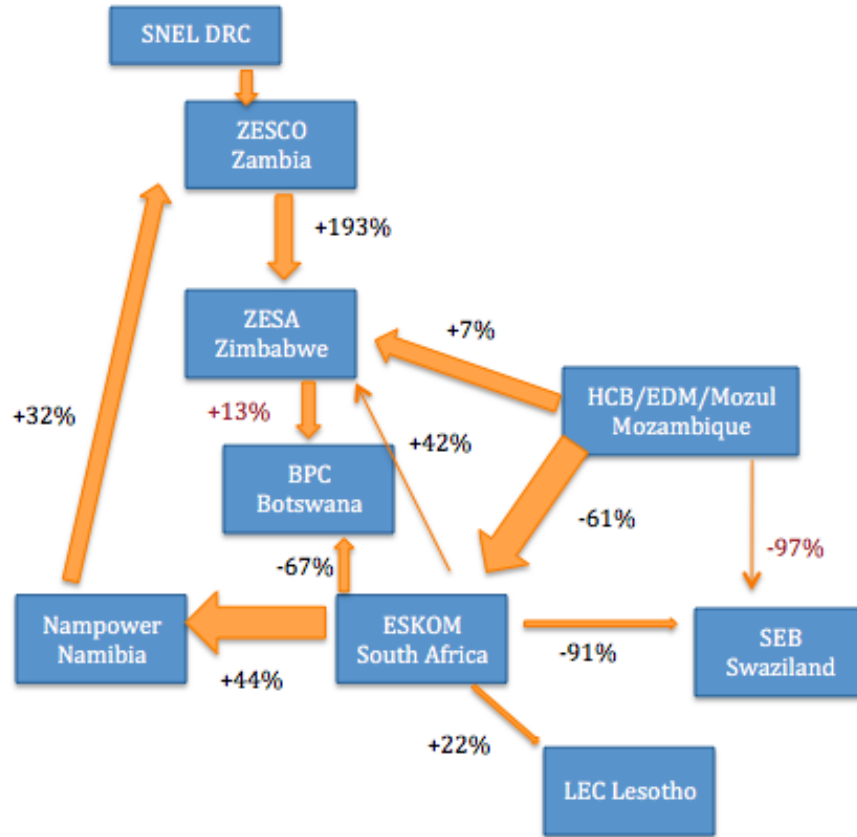


Figure 3-6: Comparison of optimal trade flows under the PC scenario with the base case in a normal operating week. Physical contracts reduce total trade by 50% and, in two cases highlighted in red, cause trade flows to go in the opposite direction as the least cost solution.

compared with the base case. The numbers below the country indicate the percent change in output for each country compared with the base case. For some countries this change is significant. For example, the decrease in generation in Botswana represents a fall of 69% in that country's output.

### *Financial Contracts*

As purely financial instruments, financial contracts have no impact on system operations. Trade flows and economic dispatch remain the same

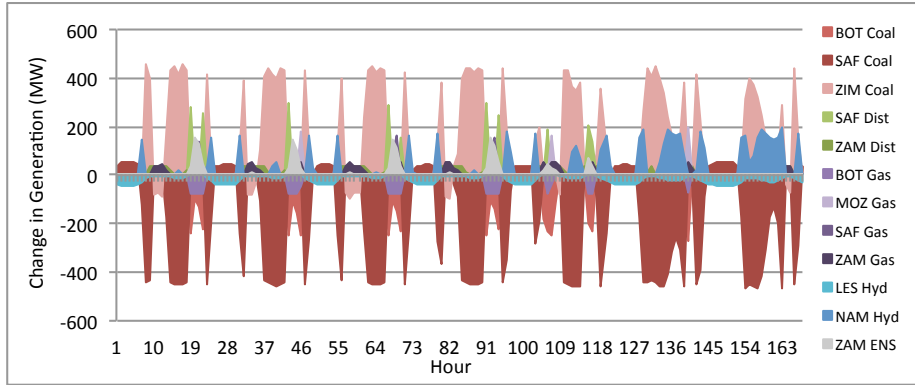


Figure 3-7: Impact of physical contracts on hourly dispatch schedule compared to the base case. Physical contracts force low cost generation from coal plants in Botswana and South Africa to be curtailed during peak hours and replaced by generators with higher variable costs such as coal from Zimbabwe.

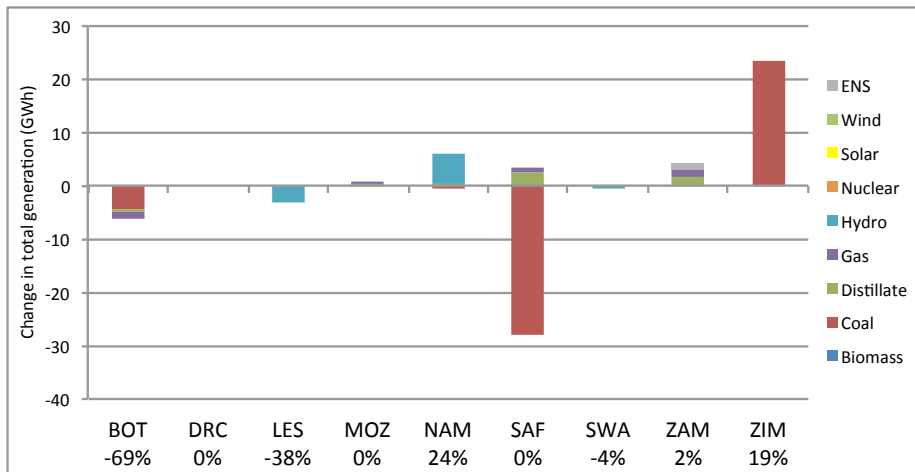


Figure 3-8: Impact of physical contracts on generation output in each country compared to the base case. Physical contracts result in decreased generation in Botswana, Lesotho and South Africa and generation increases in other countries. The numbers below each country indicate the percent change in generation output for that country.

as the base case.

### System Costs

As expected, the base case has the lowest total generation costs. The absence of bilateral contracts allows generation and trade outcomes to be based purely on least-cost criteria. In the PT scenario, total costs only

increase by a small amount, <1% compared with the base case, because only small changes in generation were needed. The more restrictive PC scenario increased total costs by 13% compared with the base case. In this scenario, countries had fewer options to shift generation among countries with lower costs owing to additional constraints on network usage and generation output imposed by bilateral contracts. For example, coal plants in Zimbabwe were forced to produce more to meet Zimbabwe's export obligations, displacing output from lower-cost coal plants in South Africa and Botswana.

The largest source of cost increases for both the PT and PC scenarios is penalties from ENS. In both scenarios, ENS occurred in some countries as a result of additional constraints on the use of transmission and generation assets. Penalties for ENS account for 63% of the cost increase in the PT scenario and 34% of the increase in the PC scenario.

In the FC scenario, system costs remain unchanged because financial contracts do not influence system operations but the contracts do have economic implications for their holders. The revenue from a financial transmission contract is equal to the quantity contracted (MW) times the difference in nodal prices between the injection and withdrawal points. From inspecting Figure 3-3, contracts that require physical transmission rights in the opposite direction of the least-cost power flows (i.e. from Mozambique to Swaziland and Zimbabwe to Botswana) are expected to result in economic losses. Table 3.6 shows the estimated revenues for each bilateral contract over the sample week. The revenues for the con-

tract between Zimbabwe and Namibia is negative due to negative nodal prices differences between Zimbabwe and Botswana, an intermediate link required to complete the transaction. Mozambique and Swaziland also have a bilateral contract in the opposite direction of the least cost power flows but, in this case, the difference in nodal prices is zero between the two countries.

Supplier	Consumer	Bilateral contract (MW)	Contract revenues (\$ million)
EdM (Mozambique)	SEC (Swaziland)	40	0
	NamPower (Namibia)	40	2.85
	BPC (Botswana)	45	6.81
HCB (Mozambique)	Eskom (South Africa)	1370	0
	ZESA (Zimbabwe)	250	37.81
ZESA (Zimbabwe)	NamPower (Namibia)	80	-6.41
SNEL (DRC)	Eskom (South Africa)	150	729.64
	ZESA (Zimbabwe)	100	501.55
Eskom (South Africa)	LEC (Lesotho)	100	0
	EdM (Mozambique)	120	0
	NamPower (Namibia)	200	14.23
	BPC (Botswana)	210	31.76
	SEC (Swaziland)	96	0
	MOZAL (Mozambique)	950	0

Table 3.6: Revenues from financial bilateral transmission contracts between SAPP members. Contract revenues are based on the contracted quantity (MW) and difference in nodal prices. In cases where nodal prices are equal, the revenues are zero. Zimbabwe and Namibia have negative revenues due to negative nodal prices between Botswana and Zimbabwe.

### Security of Supply

The four market designs were run under nine “scarcity” scenarios to simulate supply shortfalls in each individual country. Security of supply is measured as the total ENS over the model period. National energy concerns such as reliance on imports, or other factors such as the time of day or duration of ENS occurrences are not considered.

To analyze how holding a bilateral contract impacts a country’s security of supply, SAPP countries are divided into “importers”, “exporters”, and “neutral” based on the sum of all contracts each country has signed. For example, South Africa has both importing and exporting contracts but is classified as an exporter because it is contracted to export more than it imports. Exporters are DRC, South Africa, and Mozambique. Zambia is the only neutral country. All others are importers.

For both the PT and PC scenarios, imposing bilateral contracts during scarcity conditions increased the total amount of ENS in the region because of increased restrictions on trade. Table 3.7 shows the impact of including different bilateral contract designs on ENS averaged over all scarcity scenarios. Countries with bilateral contracts to export power experienced the highest increases in ENS. Countries with net import contracts experienced fewer hours of ENS compared with the base case.

	Total ENS	Importers	Exporters	Neutral
Base case	27	15	12	0
PT	31	13	17	1
PC	53	2	40	11

Table 3.7: Impact of different bilateral contract designs on the total hours of energy non-served (ENS) experienced by different types of contract holders averaged over all scarcity scenarios

The results of the scarcity tests indicate that bilateral contracts with a physical component (transmission rights and/or generation obligations) can be effective tools at ensuring electricity supplies for power purchasers during scarcity. The greatest protection for importing consumers came from the PC scenario. Complete numerical results for each scenario are included in Appendix C.



### 3.4 Proposed Method: Implicit Auction with Security of Supply Guarantees

The modeling exercise demonstrates that the current practice of treating bilateral contracts as physical obligations for the use of transmission and/or generation assets results in distortions in the least-cost dispatch and trade patterns, increased ENS, and increased costs for the region as a whole. From an economic efficiency perspective, the most efficient contract design is a financial contract, which carries no physical obligation and, therefore, does not negatively impact system operations.

On the other hand, bilateral contracts with physical obligations are effective tools to ensure security of supply for importers during scarcity conditions. This is an important benefit in the SAPP, generation shortages are an ongoing problem in many member countries. As purely financial instruments, financial contracts do not protect importers from load shedding during scarcity. In addition, bilateral contracts are generally viewed to be necessary among project developers and financing institutions for investments in new power plants and energy-intensive industries. As a result, utilities and major consumers are likely to continue relying on them as a key risk mitigation tool.

The regional market would benefit from a new method for integrating bilateral and market trades that incorporates the desirable features of physical and financial contracts. When there is no scarcity the contracts would not interfere with the efficient functioning of the market. With

scarcity, the contracts would offer consumers and investors the same level of risk reduction provided by firm bilateral contracts. Importantly, this method must be compatible with the current market structure and institutional capacities in the SAPP so that it can be feasibly implemented.

### **3.4.1 Description of Proposed Rule**

I propose replacing the existing methods for treating bilateral contracts with an implicit auction with security of supply guarantees. Implicit auctions allocate energy and transmission capacity together through a single market clearing process that jointly considers generation and transmission constraints. As the grid is implicitly taken into account within the dispatch algorithm, implicit auctions maximize the efficient use of the transmission network [114].

Under this method, parties can continue to sign long-term contracts for any desired capacity with a privately negotiated strike price, subject to transmission constraints. However, instead of physical contracts, these contracts will be partly modeled after a contract for differences (CfD), a purely financial instrument with no physical energy or transmission rights. The system operator will consider the contracts only if there is a supply problem. Unlike a traditional CfD that does not account for emergency conditions when consumers are unable to procure their contracted power or generators are unavailable or constrained to be off owing to transmission failures, additional penalty features will be included to ensure that generators and transmission owners with long-term contracts

have an incentive to be available when needed and are responsible for any risk associated with non-compliance.

The outcome of the proposed contract design is:<sup>4</sup>

**In normal conditions:**

- contract holders are fully hedged to consume/produce the contracted quantity at the contract price; and
- contract holders have incentives to respond to actual market prices.

**In scarcity conditions:**

- contract holders are guaranteed the same level of security of supply/income or equivalent compensation that they would receive if contracts were physical; and
- penalties are assigned to the party responsible for the supply shortfall.

### 3.4.2 Implementation Under Normal Conditions

Implicit auctions are difficult to implement in regional markets where multiple system operators are responsible for energy dispatch and network allocation [220]. This is particularly true in international systems that must coordinate system operations across multiple national markets. For large regional markets, a centralized implicit auction may not be feasible owing to the size of the computational problem. In these cases, the problem must be solved in multiple levels.

The SAPP has two characteristics that may relieve some of the difficulties of implementing an implicit auction scheme. First, system operations

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<sup>4</sup>See Appendix B for further discussion of CfDs and mathematical proof of these outcomes

for all member countries are already clustered among three control area system operators and the SAPP is the only competitive market in the region. Therefore, the process to centralize system operations is much simpler than if each country had its own national market and system operator. Second, the regional transmission network only has a limited number of high voltage lines. This allows the SAPP MO to capture the entire regional network with a single model that is computationally tractable.

To implement a centralized implicit auction, several changes must be made to the current market rules. For market participants, all generators and consumers must submit bids to the SAPP MO. Consistent with rational market behavior, these bids should be based on their marginal costs, ignoring the existence of any bilateral contracts. Generators with bilateral contracts will continue to obtain transmission rights for their contracts to ensure their trades are technically feasible but these rights are purely financial rather than physical. Contract holders must continue to notify the SAPP MO of all bilateral contracts but they will no longer be able to self-schedule through their local control area system operator.

Under this scheme, the SAPP MO will be solely responsible for allocating transmission capacity and scheduling generators. Rather than running the competitive market on top of self-scheduled bilateral trades communicated through control area operators, the SAPP MO will collect all bids and run a single security-constrained economic dispatch algorithm. Although the SAPP will continue to collect information on all

bilateral contracts, these contracts will not be considered in the system dispatch unless there is a supply problem. Control area system operators can continue to monitor intra-day balancing, but they will lose authority to schedule day-ahead transactions.

### **3.4.3 Implementation Under Scarcity Conditions**

The SAPP considered implementing CfDs to increase liquidity in the DAM as early as 2011 but did not pursue it because of fears that “there is more exposure for buyers of power when bilateral contracts are cleared through the DAM” [238]. Given these fears and the current supply constraints in the region, a “security of supply guarantee” will be included in the proposed method for market scheduling. This guarantee mandates that, when there is scarcity, members with supply contracts must have the same level of supply (no increase in ENS) as the case where contracts are physical. This may require changes to the least-cost dispatch schedule but does not require that contracts be physically imposed.

The guarantee should be implemented based on a predictable and transparent process by an independent entity. This entity should be the SAPP MO because it is already responsible for organizing the dispatch schedule and is not affiliated with any national utilities or governments. The following steps outline the proposed method for the SAPP MO to handle contingency events:

- Run the security-constrained economic dispatch algorithm to determine the least-cost scheduling of generators.

- If there is ENS, rerun the dispatch model assuming all bilateral contracts are physical contracts. This will provide a baseline level of ENS for participants with bilateral contracts if contractual obligations are honored.
- If consumers with supply contracts are not receiving the same level of supply as the baseline value (i.e. every hour their ENS must not exceed what is achieved in the PC scenario), rerun the dispatch model with a constraint that ENS for these consumers must not exceed their baseline values.
- In extreme cases, such as multiple failures, it may not be possible for all consumers with supply contracts to receive their guaranteed level of supply and the scheduling problem will not have a feasible solution. In this case, the SAPP MO must prioritize which contracts will be imposed. For simplicity and continuity, prioritization should follow the existing scheme already in place in the SAPP where firm contracts are prioritized over non-firm contracts and older contracts are prioritized over newer ones. Following this, the SAPP MO would enforce supply obligations as needed in the dispatch schedule (starting with older, firm contracts) until the economic dispatch problem is feasible. Consumers with contracts that do not receive their guaranteed level of supply will receive a penalty payment from the party responsible for the problem as agreed in the contract.

### 3.4.4 Model Results with Implicit Auctions

The SAPP 2015 model was rerun assuming bilateral and market exchanges were scheduled following the implicit auction method. The mathematical equations used to formulate this scenario are described in Appendix A. Under normal conditions, the proposed method has no impact on generation, trade, network usage, or costs compared with the base case. This means the implicit auction method avoids all the market distortions seen in the previous scenarios when there is no scarcity. The following sections compare how the implicit auction method performs with supply shortages.

#### System Operations

With scarcity, the implicit auction design has a significantly smaller impact on trade flows and production than the PC scenario. Recall, PCs decrease regional trade by an average of 50% (2% for PT rights) during scarcity. By contrast, on average, implicit auctions decrease trade flows by 10% compared with the base case. The impact is higher than the PT scenario because of larger changes needed for all lines connected to Zimbabwe, a net importer, to ensure security of supply for this country. The average change across all lines is only 8% compared with 13% and 32% in the PT and PC scenarios, respectively. Figure 3-9 shows the change in trade flows averaged over all scarcity scenarios compared with the results obtained in the base case during scarcity.

Implicit auctions also require less deviation in generation than the PC

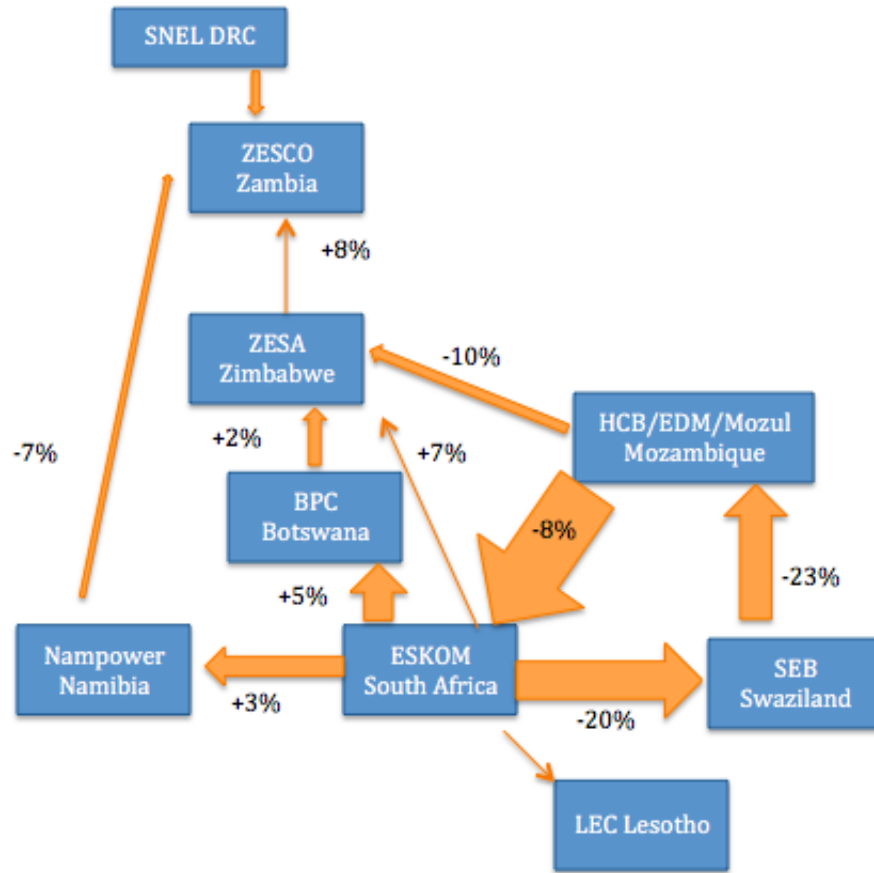


Figure 3-9: Comparison of optimal trade flows under the IA scenario with the base case during scarcity (averaged over all scarcity scenarios). Implicit auctions reduce total trade by 10% compared to the base case but do not require changes in the direction of flows seen in the PT and PC scenarios.

scenario. Figures 3-10 and 3-11 show the changes in generation output in each country averaged over all scarcity scenarios compared to the base case using PCs and implicit auctions, respectively. In both cases, the total ENS in countries with import contracts (i.e. Zimbabwe) is reduced because the contracts guarantee their supply. However, implicit auctions offer the same level of protection with less deviation from the least-cost solution in terms of both the number of countries forced to change their generation output and the magnitude of changes required.



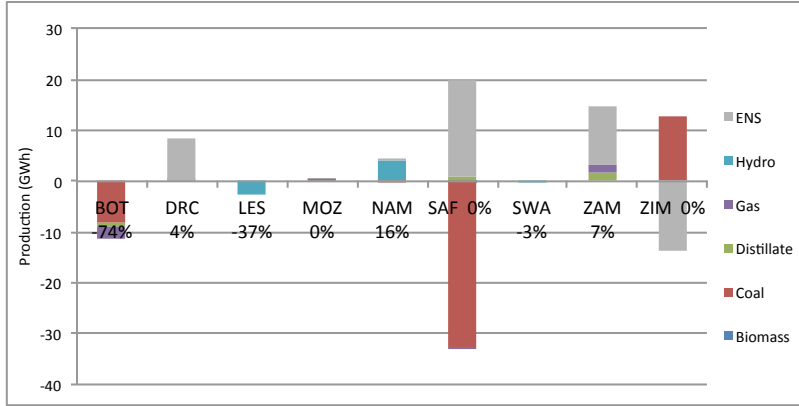


Figure 3-10: Impact of physical contracts on generation output in each country compared to the base case during scarcity (averaged over all scarcity scenarios). ENS increases in South Africa and decreases in Zimbabwe. The numbers below each country indicate the percent change in generation output for that country.

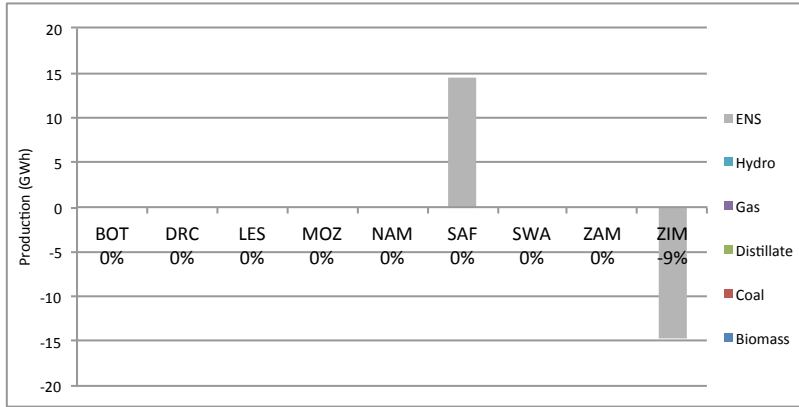


Figure 3-11: Change in generation output in each country compared to the base case under the implicit auctions scheme during scarcity (averaged over all scarcity scenarios). The implicit auctions scheme imposes smaller changes in generation output compared to the PC scenario in the previous plot.

### System Costs

During scarcity, implicit auctions had significantly less impact on system costs than the PT and PC scenarios. The average cost increase over all scarcity scenarios was  $<0.5\%$ . By contrast, PT rights increased system costs by  $<1\%$  in normal conditions and  $8\%$  during scarcity whereas PCs increased costs by  $13\%$  in normal conditions and  $51\%$  during scarcity.

It is important to note that this result holds for the current configuration of bilateral contracts, network capacity, and input parameters tested. In other systems with larger variations in fuel costs, generation technologies, cost of ENS, contracts, or network topology, implicit auctions could increase the total system costs compared with a base case during scarcity by a larger amount if the system operator is forced to redirect power flows and constrain off lower-cost generators to guarantee supplies for contract holders. However, these increases will not exceed those experienced by PT rights or PCs because implicit auctions have fewer constraints on the use of transmission and generation infrastructure to meet demand at lowest cost.

### Security of Supply

Table 3.8 compares the total ENS averaged over all scarcity scenarios for importers, exporters, neutral countries, and the region as a whole. The results show that both importing countries and the region as a whole are better off (less ENS) with implicit auctions compared with the PT and PC scenarios.

	Total ENS	Importers	Exporters	Neutral
Base case	27	15	12	0
PT	31	13	17	1
PC	53	2	40	11
IA	27	0	27	0

Table 3.8: Impact of implicit auctions compared with previous contract designs on total hours of ENS experienced by different types of contract holders averaged over all scarcity scenarios

In Table 3.8, importing countries experience less ENS with implicit

auctions than with PCs. This is due to input assumptions about supply and demand parameters in each country, not the implicit auction method itself. The implicit auction method only requires that ENS in importing countries should not exceed what is achieved with PCs (2 GWh in this case). If, for example, the cost of ENS were very high in exporting countries, the cost-minimizing solution would be to minimize ENS in these countries. In this case, total ENS in importing countries would be 2 GWh (the maximum allowable) and any remaining necessary load shedding would be in exporting or neutral countries.

### **3.5 Renewable Energy and Security of Supply**

Southern Africa has significant renewable energy potential. Falling technology costs and concerns about global climate change have prompted a growing interest in developing these resources. Investments in hydropower, solar, and wind account for over two-thirds of planned capacity additions by 2020 (Figure 3-12).

Anticipated growth in renewable energy has several implications for regional security of supply. First, variable renewable resources can increase the frequency and magnitude of changes in net load that must be met by conventional generators [61]. This has implications for the flexibility needs of the system and the operational modes of other generators. Flexibility is the extent to which a power system can modify electricity production or consumption to maintain balance between supply and demand, measured in capacity over time (e.g. MW per minute) and the

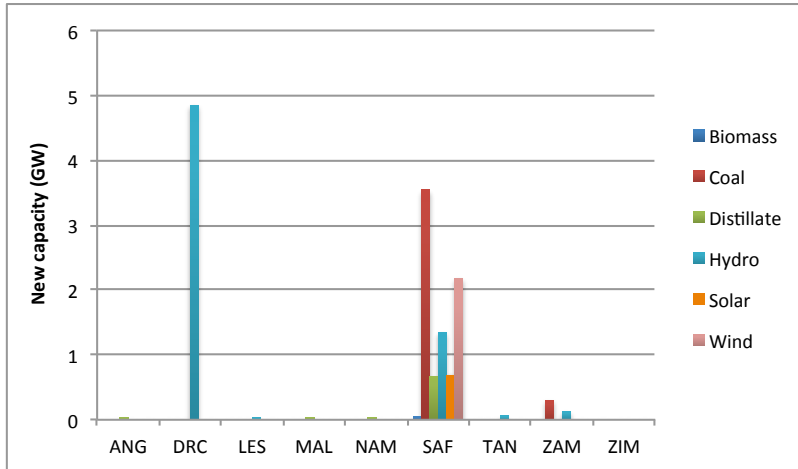


Figure 3-12: Planned generation capacity additions in SAPP countries by 2020 [182, 169, 159]

length of time this change can be sustained. [136]. Quickly dispatchable generators, such as combined-cycle gas turbines or reservoir hydropower plants, are important providers of system flexibility but they are not the only sources. System flexibility can also be provided by responsive demand, battery storage, and the variable generators themselves by curtailing their output. Providing flexibility may require increased ramping and cycling from conventional technologies, reducing their efficiency.

Regional integration could help mitigate these impacts in two important ways. Spreading variable renewables over a larger geographic area can smooth out fluctuations in generation. This can reduce the changes in net load and flexibility requirements for the regional system [198]. Transmission interconnections also represent another potential source of flexibility because they enable systems to share and coordinate flexible resources through trade. Countries with low-cost flexible resources can provide load-following and reserve capabilities to other countries with less

flexible generation technologies.

In the longer term, climate change is expected to cause major variations in Africa's hydrological resources, resulting in increased seasonal and inter-annual variations in water availability [138]. Major planned hydropower investments in DRC, Mozambique and Zambia could increase the security of supply risk for these and other countries that rely primarily on hydropower for their electricity supply. At the same time, reservoir hydropower could play an important role to support higher penetrations of variable renewable technologies by providing system flexibility. By diversifying the energy sources used for power generation, regional coordination can protect individual countries from extreme weather events such as droughts. In fact, this was a motivating factor for creating the SAPP after a severe drought in 1992 threatened power supplies in northern countries [228].

Growth in renewable energy, particularly variable renewable technologies, also has implications for the design of the regional market. First, forecast errors for wind and solar can make it increasingly difficult to anticipate market outcomes. This may increase the importance of the SAPP's Intra-day Market to provide generators an opportunity to adapt to actual system conditions with markets that are closer to real time than the standard day-ahead market. In the future, the SAPP could adopt multiple intra-day auctions or a continuous intraday market [172]. Second, variable renewable generators, when paired with hydropower plants with storage capabilities, could play a role to improve security of supply.

SAPP members can capture this benefit by allowing variable renewable generators to contribute to their Firm Capacity Obligations. These obligations provide an investment incentive for countries to build adequate capacity to meet growing demand but they do not currently provide market incentives for generators to be available during scarcity events. Updating the SAPP's Firm Capacity Obligation to include this criteria would strengthen signals to all generators to be available when needed and allow variable renewable generators to contribute to security of supply alongside conventional generators if they can provide energy when needed.

For now, these issues are not being addressed at the regional level. Variable generation makes up only a small portion of generation in the region and participation levels in the short-term markets remain low. National utilities that own or contract with wind and solar plants aggregate all of their generators into a single bid, thereby internalizing any forecast errors in wind and solar availability. As the penetrations of wind and solar in these countries increase, these utilities may begin to participate more in the Intra-day Markets. System adequacy is also handled at the national, rather than regional, level. The SAPP does have firm capacity obligations for member countries but there are currently no plans for a regional capacity mechanism.

## 3.6 Conclusions

Concerns about security of supply and risk mitigation have prompted SAPP members to rely on long-term bilateral contracts for cross-border trade. The current method for integrating bilateral and market trading introduces inefficiencies in the use of generation and transmission infrastructure, reduces total trade, and increases system costs. At the same time, these contracts play a key role in increasing security of supply during emergencies.

To capture the security of supply benefits of bilateral contracts while minimizing market distortions, I propose a new method of implicit auctions with security of supply guarantees. The implicit auction scheme will require changes in how generators, consumers, and system operators interact with the SAPP MO, but the SAPP is well positioned to implement these changes. Modeling simulations of the method show that during normal conditions, it has no impact on the efficient functioning of the market. During scarcity conditions, the implicit auction scheme offers the same level of protection for countries with import contracts, but with less impact on the least-cost patterns of generation and trade compared with existing methods. These results are indicative of the types of impact that the proposed method may have. Further work is needed to refine the scarcity scenarios used for testing, represent the characteristics of existing bilateral contracts, and describe the demand patterns in each country.

Anticipated growth in renewable energy may soon present new chal-

lenges for security of supply and market design. Regional integration and trade could mitigate variability in wind, solar, and hydropower resources through greater resource sharing. However, these resources may require changes in regional market rules to account for forecast errors and ensure the system has adequate installed capacity. Characterizing the exact impact of renewable energy in the SAPP is an area for further research.



## 4

# Incentivizing Regional Transmission Investments

The transmission network is an essential part of any electricity market because it facilitates power exchanges between network users [246]. At the same time, regional rules for transmission planning and cost allocation necessary to support network investments are among the most contentious issues in regional markets. Insufficient transmission capacity is an urgent issue in the SAPP. Regional officials cite a lack of coordination in the planning process and flawed transmission pricing rules for the lack of investment in transmission infrastructure. In this chapter, I combine principles of transmission regulation with international experience to propose a general regulatory framework for these topics tailored to the specific needs of regional markets. This framework is applied to the SAPP to develop a set of transmission planning and pricing rules that could serve as a feasible alternative to existing rules. Power system simulations of the existing SAPP grid and future investments are used to

evaluate different transmission pricing methods. The chapter concludes with recommendations for transmission regulation in regions keen to promote renewable energy.

## **4.1 Background**

### **4.1.1 Brief Overview of Transmission Planning**

#### **Objectives and principles of transmission planning**

The objective of transmission planning is to identify the most efficient series of possible network investments with the highest social benefit. For regional systems, this generally requires some degree of centralized planning or, at a minimum, coordination among national entities because national planning mandates generally do not include objectives to facilitate cross-border trade or take into account the impact that planned network reinforcements in one area may have on other systems [128, 171]. Even when planning occurs at the regional level, new lines will not be built without approval from local systems on where to locate new lines and how to share costs [189]. Therefore, the planning process must be grounded in principles of sovereignty, transparency, and credibility to obtain the full support from national authorities and avoid disputes [80]. First, the process must honor existing regulations, policy targets and national legislation in the region. Second, the method used for planning and project evaluation should be transparent and agreed upon by all parties. Finally, the party conducting the assessment must be viewed as credible

and fair with sufficient human, technical and financial resources to ensure the process and its results are accepted by all members and reflect as much as possible the most efficient series of investments.

### **Regulatory paradigms for transmission investments**

There are four main approaches to plan and implement new transmission investments [204]. The first and most common model is centralized planning. Under this model, the regional system operator, or some other specialized institution with the experience and technical expertise to identify and evaluate candidate transmission lines, is responsible for planning. The selected specialized institution must seek regulatory approval for any proposed network reinforcements. This typically involves demonstrating the investment is justified based on a cost-benefit analysis (CBA) and conducting any additional studies requested by the regulator to test different uncertainty scenarios and demonstrate the project is superior to other alternatives. If the regulator approves the line, investors are paid a guaranteed remuneration from charges levied on network users. The remuneration could be established by the regulator based on standard prices or set in a pay-as-bid auction among potential investors. A shortcoming of centralized planning is that system operators, driven by concerns about reliability and network congestion, may have an incentive to over-invest in transmission reinforcements above levels that are socially optimal. These investments are generally approved because regulators do not have the same intimate knowledge of the system or technical exper-

tise to contradict proposals from the specialized entity and are wary of being blamed for technical failures that may occur as a result of missing investments they do not authorize.

The second model for network reinforcements is to license a specialized company that will serve as the system operator and own and operate the network. In this case, the regulator sets some minimum performance criteria and the company is responsible for making any necessary network upgrades to meet these criteria. The company is paid a regulated rate based on their costs plus some additional performance-based remuneration. This approach cannot guarantee the investments will be optimal but, rather, that the investments will be sufficient to comply with the minimum standards. The company itself has an incentive to maximize revenues by meeting the performance criteria at the lowest possible cost.

Network reinforcements can also be proposed by coalitions of network users. If the regulator determines the project is beneficial based on some technical and financial criteria, the project can be put to an auction to select a winning bid for construction and maintenance of the line. If there is not enough competition, a specialized entity can build the line and be remunerated based on standard prices set by the regulator. Alternatively, if the coalition of users wants to develop the line for their own use, they can finance and build the line themselves. The coalition can recover some of its costs by charging other agents for using the line according to the same network tariff applied to other lines. This approach could be effective for projects where the beneficiaries can be easily identified and

are concentrated among a few agents willing to form a coalition. However, coalitions of users are unlikely to form around projects where the benefits are widely distributed among many users or difficult to quantify because the marginal benefit to each user would be very small [29, 59, 202].

Finally, private profit-seeking companies can develop new lines, also termed investments at risk or merchant lines, under their own initiative. Because merchant lines are not part of the central planning process, the regulator must ensure any proposed merchant line does not conflict with other planned network reinforcements and is not harmful to the network. Unlike the previous three models, the regulator does not guarantee some level of remuneration for the company. Merchant investors have two main options for earning revenues to recover their investment costs. If the line is expected to benefit a small number of easily identifiable users, the company could negotiate long-term pricing contracts with these users in exchange for building the line [64]. There is a risk of a free rider problem, where some beneficiaries may be unwilling to pay for the line, forcing others to pay a disproportionate share. If the benefits are widely dispersed, the task of identifying and negotiating with all beneficiaries could quickly become infeasible. In the second option, merchant investors in systems with nodal energy prices could try to recover their costs by taking advantage of price differences between the ends of the proposed line. Differences in prices occur most frequently when the transmission network is congested and network constraints prevent some consumers from purchasing power from the lowest cost generators located at another

point in the network. In these cases, the owner of a new merchant line could earn revenues by buying energy at one end of the line where it is less expensive and selling it at the other end where it is more expensive. Note that merchant investors earning revenues from price differentials have a perverse incentive to underinvest so that congestion, and resulting price differentials, remains high. Because merchant investors select projects that maximize private profits rather than social benefit, only those lines with large estimated profit margins have the potential to be built as merchant lines. These investments are unlikely to result in adequate or optimal network investments for the region as a whole.

Table 4.1 summarizes the key features of the four models for transmission investments. The first three categories are also termed regulated lines because the regulator has determined that they are cost effective, according to some criteria, and guaranteed some remuneration. Within each category there are possible variations depending on the regulatory framework in place.

### **Regulatory test**

Regulators should apply a “regulatory test” or set of rules to decide if the construction of a proposed transmission line or set of lines should be authorized. The criteria for passing this test can vary depending on the nature of the project. For regulated lines, the regulatory test is used to identify the most efficient series of possible network additions and assess if a project is economically justified (i.e. the societal benefit provided by

Investment model	Planning	Regulatory approval	Remuneration
Centralized Planning	System operator or other specialized institution	Project is economically justified, technically feasible, and superior to alternatives	Cost-of-service or pay-as-bid
Licensed company	System operator	Investments meet performance criteria	Cost-of-service or Cost-of-service + performance-based incentives
Coalition of users	Network users	Project is technically feasible and socially beneficial	Cost-of-service or pay-as-bid
Merchant lines	Independent transmission company	Project is not detrimental to network and does not conflict with other planned investments	Contracted rate or congestion rents

Table 4.1: Comparison of business models for transmission investments

the line is greater than its cost)[189, 12, 156]. For merchant lines, the test is generally less stringent. The line’s proponents need only demonstrate that it is not detrimental to the network and does not interfere with other anticipated investments already underway.

While the idea of a regulatory test is simple, it can be very difficult to apply in practice. First, estimating the expected benefits from a network investment is challenging. There is no universal catalogue of transmission benefits but Table 4.2 presents a list of the most commonly cited potential benefits that transmission investments can provide [265]. To conduct the regulatory test, regulators must define which benefits will be considered and construct methods to measure and quantify each type of benefit. This can be especially difficult for benefits such as increased market liquidity and storm hardening.

Even if the range of benefits is limited to traditional production cost

Benefit Category	Transmission Benefit
Traditional production cost savings	Savings in fuel & other variable operating costs of generation
Additional production cost savings	Reduced transmission energy losses Reduced congestion due to transmission outages Mitigation of extreme events and system contingencies Mitigation of weather and load uncertainty Reduced cost due to imperfect foresight of real-time system conditions Reduced cost of cycling power plants Reduced amounts and costs of operating reserves and other ancillary services Mitigation of reliability-must-run conditions More realistic representation of system utilization in “Day-1” markets
Reliability and resource adequacy	Avoided/deferred reliability projects Reduced loss of load probability or Reduced planning reserve margin
Generation capacity cost savings	Deferred generation capacity investments Access to lower-cost generation sources
Market	Increased competition Increased market liquidity
Environmental	Reduced emissions of air pollutants Improved utilization of transmission corridors
Public policy	Reduced cost of meeting public policy goals
Employment & economic development	Increased employment and economic activity Increased tax revenue
Other project specific benefits	Examples: storm hardening, increased load serving capability, synergies with future projects, increased fuel diversity & resource planning flexibility, increased wheeling revenues

Table 4.2: Potential benefits of transmission investments [265]

savings, estimating these benefits requires accurate predictions of system dispatch over a number of future years. Any unexpected changes in demand patterns, new infrastructure investments, equipment failures or other unanticipated events can affect the system dispatch. Therefore, the party conducting the assessment must run the test over lots of future scenarios to account for uncertainty. The project should pass the regulatory test in some minimum number of scenarios, defined in advance, to be approved.



## 4.1.2 Brief Overview of Transmission Cost Allocation

### Objectives and principles of transmission charges

The objectives of transmission charges are to guarantee cost recovery for efficient network investments (i.e. those that provide a net benefit to the region) and send efficient locational signals to market agents regarding the cost of installing their facilities in different parts of the grid [189]. Paying the transmission charge should grant the network user access to the entire network. To meet these objectives, the design of the charge should follow four basic principles. These principles, presented in [203], are derived from a combination of microeconomic theory, power system engineering, sound regulatory practice and years of trial and error in actual systems [206].

First, costs should be allocated in proportion to benefits or, equivalently, in proportion to each user's responsibility for requiring the reinforcement ("cost causality"). By allocating charges among beneficiaries or those agents responsible for the investments, the method is both economically efficient and generally accepted as equitable. Further it minimizes potential opposition to the project because the project's beneficiaries will be better off for lines where the expected benefits exceed the costs. Some network users, such as generators located in areas with high prices because network constraints limit imports, may be made worse off with the construction of the new line. In these cases, the regulator can choose whether or not these users should be compensated to avoid opposition.

Second, transmission charges should not depend on commercial trans-

actions. The efficient operation of the power system and actual network flows should be the same regardless of the type of transactions individual users undertake. In other words, demand will be met by the same set of lowest cost generators regardless of the contracts that have been signed between network users<sup>1</sup>. Transmission charges should therefore be based on an agent's benefit from the network rather than his trading agreements. Each agent's benefit from the network depends on his location within the network and the time of day when he is injecting or withdrawing power [188]. Failure to follow this principle could lead to transmission charges that distort market behavior and present unnecessary barriers to trade. This is particularly important in regional markets where some transactions may cross national borders. Charges that only apply to transactions between agents in different countries but not transactions between buyers and sellers within the same country would deter cross-border trade. A more general version of this principle for the context of regional markets is often referred to as the single system paradigm. Under this philosophy, the charges should reflect those that would be achieved if all generators and consumers were located in a single country.

Third, transmission charges should be established ex ante and not updated for a reasonably long time. New power plants or major consumer centers, such as factories, are large, long term investments that cannot easily be relocated, if at all. Therefore, these investors need to know in advance what their transmission charges will be for a reasonably long time

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<sup>1</sup>This requires that the contracts are well-designed and do not influence the physical operation of the power system (see Chapter 3).

(e.g. 10 years) to inform their investment decision. For investments with different potential sites, the transmission charge can also send locational signals as to the best places to build within the network. If the costs are updated regularly based on actual network flows, this would weaken the long term locational signals for generators and consumers and create additional investment risk.

Finally, regulators must pay attention to the format of the transmission charge. Transmission charges can be formatted as a volumetric charge (\$/MWh), capacity charge (\$/MW), lump sum (\$/year), or some combination of these. The format of the charge matters because it can affect the behavior of market agents. For example, generators are likely to include a volumetric charge as part of their variable cost when bidding in the market. This could impact which generators are dispatched through the market clearing process and increase the marginal price of electricity. A capacity charge, by contrast, would be included as part of the generator's fixed costs when making an investment decision.

### **Design of transmission charges in regional markets**

The integration of local markets presents new challenges for the design of transmission charges. The single system paradigm would indicate that the best approach is to apply the same transmission pricing method to all network users to cover the cost of the entire regional network irrespective of national borders. However, this is unlikely to be acceptable when applied to existing national grids because network planning and

investment practices can vary significantly between countries. For example, a study of transmission tariffs in Europe found wide variations between countries in standard per unit costs of transmission components and allocation among generators and consumers [174]. Network users in one country will resist paying a fraction of costs in another country for investments that they believe are inefficient and from which they derive no benefit [200].

One approach to avoid these difficulties, called the License Plate method, charges all network costs within a predefined area to users located within that area. For example, all network costs in Country A would be allocated to network users within Country A. Paying this charge would grant users access to the entire regional network. The License Plate method is appealing because network users are not held responsible for overbuilt systems or inefficient investments in other countries but it is unlikely to be acceptable in practice because the charges do not account for the use that network agents outside of a particular zone make of the transmission facilities within the zone. A major load or supply center located near the border that only hosts a small portion of a transmission line in their country would only be responsible for a small portion of the line's cost even if they are its main beneficiary. Alternatively, lines that transit entire countries may offer very little benefit to local consumers and suppliers but these users could bear most of its cost if most of the line falls in their geographic territory. Further, the cost allocation results could be changed arbitrarily through an administrative decision to move a national border

with no underlying change in system operations.

Given these difficulties, this thesis will follow three further guiding principles on the design of regional transmission charges. First, the charges should only apply to transmission facilities identified as part of the regional network. This avoids the problem of forcing users to pay for network investments in other countries from which they derive no benefit. Second, the transmission charges should be calculated without considering national borders, in accordance with the single system paradigm, but these charges should be aggregated ex post to a single national charge. National officials can then decide how to allocate costs among their respective generators or consumers. Finally, the transmission charge, once paid, will grant the network agent access to the entire regional network.

Before a regional transmission pricing scheme can be implemented, some common method must be developed to calculate network benefits and allocate network costs among beneficiaries. The next section describes the candidate cost allocation mechanisms selected for consideration.

### **Review of cost allocation mechanisms**

Transmission cost allocation involves assigning the costs of a new or existing transmission facility among network users. There is no general consensus on which method to allocate costs is the most suitable and regional markets have adopted a wide range of approaches. This section

reviews the methods that could be implemented under the proposed regulatory principles for regional charges. The review is intended to highlight the best known methods in practice today and is not intended as a comprehensive review of all transmission cost allocation methods that exist or have been proposed.

### *Beneficiary Pays*

Beneficiary Pays attempts to directly allocate network costs to agents in proportion to the benefits they receive from the network. This approach is the best method conceptually and is attractive because it has dimensions of fairness and equity [128]. Under this scheme, the net benefit for each network user is calculated as the difference in benefits with and without the line. The most basic application of beneficiary pays only considers changes in revenues over operating costs for generators and changes in the cost of purchasing electricity for consumers. However, the calculation could be expanded to include a range of other potential benefits that transmission investments could provide (see Table 4.2).

Beneficiary pays has been adopted for cost allocation of new lines in several areas including Argentina, California, Peru and New York [203]. Applying Beneficiary Pays to transmission facilities built years ago also presents some obvious challenges because the “without the line” case does not exist. If the line did not exist, another line may have been built instead or the locations of generators and loads may be different. Simply

removing the line from the existing system will not provide meaningful results and may, in some cases, disrupt operations across the entire system.

In light of the difficulty of defining and measuring the various benefits of transmission lines, many cost allocation methods use network utilization as a reasonable proxy for benefits [199, 206, 227, 278]. Under this approach, network agents that utilize the regional network more would pay a higher transmission charge. In practice, it is not possible to directly measure how much each market agent uses the network. This must be inferred based on values that can be measured, namely, the quantities injected or withdrawn at each node and how much power flows over each line. The remaining cost allocation methods all rely various techniques to approximate network usage as a measure of network benefits.

### *Postage Stamp*

The Postage Stamp method charges all users a flat rate based on the total amount (MW or MWh) injected or withdrawn from the network. The method is easy to implement and does not require detailed data or sophisticated modeling. In addition to its simplicity, proponents argue that it could be useful in cases where the distribution of benefits is likely to vary considerably over the lifetime of the transmission facility [103]. It could also be appropriate for well-developed grids that do not need reinforcements and therefore do not need to send locational signals to potential investors [203]. The Postage Stamp method is used widely in

the local systems in the United States and individual European countries [203].

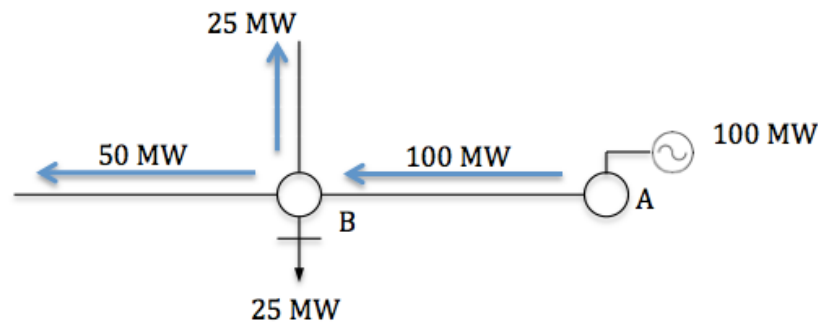
The major shortcoming of the Postage Stamp method is that the charges do not reflect actual network conditions or send locational signals. A generator located in a highly congested area is charged the same rate as a generator that does not contribute to network congestion. Further, agents whose injections or withdrawals only impact flows across a limited number of adjacent lines could be charged the same as agents whose activities impact flows across the entire regional network. As a result, the charges may not reflect actual network usage.

#### *Average Participations*

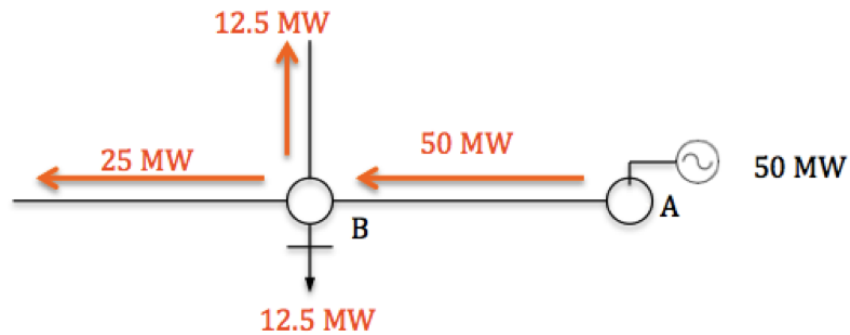
The Average Participations method uses actual patterns of network flows and a simple heuristic to attribute how much each agent uses the network. This method “traces” the injections or withdrawals of each agent through the network by assuming the power branches at each node in proportion to actual power flows experienced on the line. Figure 4-1 illustrates this heuristic by zooming in on two nodes in a larger sample system. The top figure shows the actual network flows and the bottom figure shows how flows from a particular network agent can be attributed to each line according to the Average Participations method. In the Figure 4-1a, 100 MW flows into node B and is divided between consumption at node B (25 MW), and flows exiting through a line to the left (50 MW) and a line going up (25 MW). In other words, 50% of inflows exit through the



line on the left, 25% exit through the line going up and the remaining 25% are consumed at node B. If a generator located at node A injects 50 MW, this power can be traced through the network by assuming it branches in the same proportions (Figure 4-1b).



(a) Actual network flows



(b) Distribution of 50 MW injected at node A through the network

Figure 4-1: Sample application of the Average Participations method. The bottom figure shows how 50 MW of injected power from node A can be “traced” through the network in the same proportion to actual network flows shown in the top figure.

The Average Participations method has been applied in New Zealand, Poland and Central America [188]. While the method cannot be proven because electricity flows do not behave in the simplistic manner assumed here, no counterexamples have been presented to date that show the method leads to incorrect solutions [203].

### *Transits*

The Transits method differs from all other methods reviewed because it is specifically designed to be implemented under a system of compensation payments between transmission system operators and could not be implemented for a single country or local system under a different regulatory framework. Rather than track activity from individual network users, the Transits method uses aggregate national data on load, generation, imports and exports to calculate the total use that agents within a given country make of outside networks and, correspondingly, the use that outside agents make of domestic networks. Each country is then charged for the benefit that its users obtain from regional network facilities and paid for the benefit that outside agents obtain from their network. These charges and payments are aggregated into a single national charge (or payment). Any remaining network costs are allocated to network users within the service area according the same method used for local lines not included in the regional network.

Under the Transits method, countries are compensated for the fraction of its network capacity used to provide wheeling services<sup>2</sup>. One method to approximate wheeling is by examining imports and exports. If a Country A imports 100 MW and exports 80 MW, the Transits method assumes 20 MW is used by domestic consumers and 80 MW is wheeled.

Domestic generation and load data can be used to determine how

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<sup>2</sup>Wheeling means the electricity transits a line in a given service area and is neither injected nor withdrawn in that service area. For example, transactions between Mozambique and Botswana must be wheeled through a third country because they are not adjacent.

much agents within a country use external networks. Because supply and demand must be kept in balance at all times, any period where domestic consumption does not exactly match domestic generation, the country must be using external networks to import or export power. If load exceeds generation, consumers must be using outside networks for imports. Conversely, if generation exceeds load, generators must be using outside networks to transmit excess power. Each country's contribution to cover regional wheeling charges can be calculated in proportion to the difference between its domestic load and generation.

In practice, the Transits method may not fully capture actual network use within and outside a given service area. It assumes internal networks are sufficiently developed such that if 1 MW enters one border of Country A and 1 MW exits another border, the power must have been wheeled. In fact, there may be no physical links between the entry and exit points and it is the load and generators within Country A that are consuming and producing 1 MW at different points of the network. The method also sends no locational signals to individual network agents regarding their benefits from the network because all network activity is aggregated at the national level.

### *MW-mile*

The MW-mile (or MW-km) method is a transaction-based method to allocate costs based on the impact that individual transactions have on network usage [251, 252]. The system operator simulates network flows

in a base case with all transactions included. Then the system operator removes one transaction at a time and calculates the new flows. The difference between this case and the base case is the contribution of that transaction to flows across each line. By repeating this for every transaction, all network flows can be attributed to a particular trade. The total network charge for each transaction is calculated by multiplying its contribution (MW) of flows over a particular transmission line times the line's cost (\$/MW/km) and its length (kilometer, km) for all lines. The underlying assumption behind the MW-mile method is that distance and the configuration of the network between two nodes is a proxy for incurred losses and, by extension, incurred costs. In other words, it should cost more to transfer 1 MW over 100 miles than 1 mile because more energy will be lost in transit.

This method is fundamentally flawed because it depends on commercial transactions that are, as previously discussed, unrelated to the physical operation of the system. Despite this flaw, the method is included as a candidate for comparison because it is widely used. The WAPP recently adopted MW-mile for its regional transmission pricing method [84] and a variant of this method is in place in the SAPP.

Readers interested in more information on various cost allocation methods are directed to [107, 150, 188]. Further reading specifically on utilization based methods can be found in [195, 205].

### 4.1.3 Regional Context

Insufficient transmission capacity is one of the biggest challenges for the SAPP [242, 132]. A lack of transmission interconnections is reported to limit competition in the short-term markets and deter investments in regional generation facilities. Since the DAM opened in 2009, less than 60% of energy matched was actually traded because of transmission constraints [242]. The SAPP’s “central corridor” (comprised of Botswana, Zimbabwe, and Zambia) is known to experience high levels of congestion that limits trade between South Africa and its northern neighbors.

One of the SAPP’s main objectives is to capture economies of scale for larger generation plants with lower per unit costs by pooling demand from multiple countries. Although transmission is not mentioned, it plays a critical role in achieving this goal because these plants cannot evacuate their power without adequate transmission links to load centers around the region. Some of the highest priority generation projects including the Cahora Bassa North Bank Extension in Mozambique (1245 MW) [130], Batoka Gorge in Zambia and Zimbabwe (1600MW) [3] and Inga 3 in DRC (4800 MW) [212] will require extensive transmission investments. The SAPP is trying coordinate network investments by identifying regional priority transmission projects. Table 4.3 lists the primary objectives and current status of these projects.

Of the twelve priority transmission projects, only one has been completed and two are under construction. The majority of projects have not moved past their initial proposals and feasibility studies. Regional offi-

Project Name	Capacity (MW)	Expected Date	Status
Interconnect non-operating members			
WESTCOR (Angola, DRC, Namibia, Botswana, South Africa)	3000	2012	Abandoned
Zambia-Tanzania-Kenya	400	2007	Work in progress on Zambia-Tanzania side. Feasibility study on Tanzania-Kenya side
Mozambique-Malawi	300	2008	Implementation planning
Namibia-Angola	400	2012	Feasibility study
DRC-Angola	600	2016	Feasibility study
Relieve Congestion			
ZIZABONA (Zimbabwe, Zambia, Botswana, Namibia)	600	2008	Implementation planning. SPC established and registered in Namibia
Central Transmission Corridor (Zimbabwe)	300	2008	Feasibility study review
Kafue-Livingstone Upgrade (Zambia)	600	2014	Commissioned 2016
Integrate new generation			
Mozambique Backbone (CESUL)	3100	2017	Implementation planning
2nd Mozambique-Zimbabwe	500	2017	Feasibility study
2nd Zimbabwe-South Africa	650	2008	Feasibility study
2nd DRC-Zambia	600	2009	Construction

Table 4.3: Status of priority regional transmission projects [239, 179]

cials from the SAPP [175, 58, 242], SADC [298], RERA [253] and various international organizations [132, 294, 184] attribute the slow progress to a lack of coordination in the planning process and flawed transmission pricing methods.

### **Assessment of transmission planning in the SAPP**

The SAPP's Transmission Planning Criteria serves as the regional guide for coordinating planning activities. These criteria consist of minimum technical standards and some procedural rules for planning. In practice, the Planning Criteria have not been a useful tool to harmonize transmission planning because the rules are not enforceable and are incomplete and vague in many areas on how regional planning should occur.

First, there is no formal definition of what constitutes a “regional” project and what lines are included in the definition of the regional network [58, 298]. This distinction is important because it may affect which institutions are responsible for planning a new line and how the costs of the line will be recovered.

Second, there is no single authority responsible for developing a regional transmission expansion plan and proposing new lines. Under the Planning Criteria, individual members are responsible for conducting their own transmission planning studies. In cases where a new line may impact other systems, network owners are instructed to conduct joint studies. The guidelines do not specify how system owners should determine if a project impacts another system or the process for conducting joint studies (i.e. What type of information must be shared among members? How will disputes be resolved?). The SAPP Planning Subcommittee (PSC) is nominally responsible for publishing regional planning studies but this unit still lacks the institutional capacity to undertake regional planning activities. The only official Pool Plan was conducted in 2009 by Nexant [182]. Despite endorsements from the SADC and SAPP, the Pool Plan and subsequent lists of SAPP Priority Projects are not endorsed by national governments and have been largely ineffective at guiding investment decisions at the national level [298, 86].

In practice, new lines are planned and developed by various groups including national utilities, private investors and coalitions of network users. Zambia hosts the only private company involved in transmission invest-

ments. The Cooperbelt Energy Corporation (CEC) owns and operates a section of Zambia’s transmission network and is responsible for Zambia’s portion of the upcoming DRC-Zambia upgrade [286]. CEC is generally viewed to be a successful model for catalyzing private sector investment in transmission and, in August 2016, the company was awarded the Iconic Investor Award by the Zambian Development Agency [185]. Coalitions of national utilities are also developing regional transmission projects through the creation of SPVs. The Mozambique Transmission Company (MOTRACO) is jointly owned by the national utilities of Mozambique, Swaziland, and South Africa and was created to supply power from South Africa to an aluminum smelter in Mozambique [8]. The WestCor (now abandoned) and ZIZABONA interconnections are also designed as SPVs.

Third, the region lacks common criteria to approve and prioritize regional projects [4]. For regional generation projects, the SAPP has seven selection criteria and a scorecard to evaluate and rank candidate projects<sup>3</sup> [244]. There is no equivalent assessment criteria for evaluating and ranking candidate transmission projects. The Planning Criteria state that priority transmission projects should be selected based on “least life cycle cost option” and “other parameters as specified by SAPP” implying the application of some type of CBA. In the case of lines designed to improve reliability or network redundancy, the guidelines state that lines should only be selected if the expected reduction in costs from non-served energy exceeds the project’s costs. There are no guidelines on how to evaluate

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<sup>3</sup>Notably, one of the criteria is Access to Transmission, worth 10% of the overall score.



other types of benefits or compare and rank lines that offer different types of benefits. The current list of priority transmission projects are selected based on anticipated generation investments reported by member countries rather than the result of centralized planning and CBA or some other multi-criteria assessment [244]. Even if a regulatory test is designed, there is no regional entity with the authority to conduct the test and approve or reject proposed network reinforcements. This responsibility would generally fall to RERA but it does not have the authority to interfere in investment decisions. Currently, any approval requirements occur at the local level where national regulations may stipulate that projects located within a country's geographic boundary must be approved by a national regulator or relevant ministry.

Fourth, with no regional regulator to allocate network costs among users, all investments are effectively investments at risk with no guarantee that the full cost of the line will be recovered. Investors can recover their costs through regional charges based on the MW-km method (discussed in detail in the next section) and privately negotiated contracts with generators and major load centers. Most investments are developed by national utilities with privately negotiated contracts backed by government guarantees [179]. This negotiation process can take a long time because countries have their own schedules, priorities and differences in capabilities and expertise. Negotiations are also slowed by other issues related to free riders and market power. For example, all north-south power exchanges with South Africa must transit Zimbabwe or Botswana.

Planning officials at Eskom report that intermediate countries have held up negotiations for new north-south reinforcements by refusing to pay for a portion of the line, forcing other parties to abandon the project or cover the costs themselves [283]. This could have serious implications for upcoming large generation projects that depend on South Africa to be the main purchaser of power. The South African government is committed to buy 2500 MW of electricity from the new 4800 MW Inga 3 hydropower project in the DRC [2]. However, this project is unlikely to go ahead without significant network reinforcements through Zambia and Zimbabwe or a new western corridor through Angola and Namibia to enable the DRC to transmit electricity to its southern neighbor.

Finally, regional transmission projects involve a variety of stakeholders (i.e. banks, governments, regional institutions, utilities), but the SAPP does not have a “champion” responsible for their promotion after a project has been deemed beneficial [298]. The SAPP CC is the best candidate to play this role but its planning abilities remain weak and it has no authority to raise funds or support a team to prepare and develop regional projects. In an effort to overcome this challenge, the World Bank recently established a Project Advisory Unit at the SAPP CC to accelerate project implementation [242]. This unit will coordinate with national governments, conduct analytic work and help screen, select, prepare and monitor the implementation of priority projects. Other organizations, including USAID and NEPAD, are also involved in efforts to prepare and package regional projects [234, 23]. Even with this assistance, without a

legislated mandate to coordinate national and regional investments, the SAPP and SADC are still limited in their ability to promote regional projects and can only act as counselors to national governments [166].

### **Assessment of transmission pricing in the SAPP**

The SAPP's transmission pricing method is based on principles of short term, long term, and implementation efficiency [243]. In the short term, transmission prices should not distort efficient day-to-day operations whereby demand is met by the lowest cost generators when it is technically feasible. Long term efficiency means transmission charges should send efficient locational signals for siting new generation and transmission investments. Finally, the design of the charges should not be overly complicated so as to be difficult to implement. The method used to calculate transmission charges should be transparent, simple, unambiguous and politically acceptable by all members.

Originally, the SAPP used the Postage Stamp method for transmission prices but this was abandoned in 2003 in favor of a Partial MW-km method. The SAPP's rules stipulate that these charges only apply to consumers [243]. I refer to this as a "partial" MW-km method because this method only applies to bilateral contract transactions and lines used for wheeling. Transmission charges for DAM and IDM trades are based on the average transmission charge obtained from the MW-km method and shared evenly between buyers and sellers.

This method violates the principles of transmission pricing and the

SAPP's own efficiency principles in several respects. First, the MW-km method is transaction-based, inaccurately assuming actual system operations reflect commercial transactions [150]. Second, market participants receive no signals to promote short term or long term efficiency because their charges are based on those obtained from bilateral contract transactions rather than their own market activity. If the share of DAM and IDM trading increases, these charges may deviate significantly from actual network use. Third, the charges discriminate between buyers with bilateral contracts and those that trade through the market. In the former case, buyers are responsible for the entire network charge and, in the latter, the charges are shared between buyers and sellers. Fourth, the method used to calculate the average charge from the MW-km results is not transparent. It is not clear if the average is equally weighted over all bilateral contracts or if it is weighted based on some characteristic of the transaction (e.g. contract quantity, fraction of network used). Finally, the pricing rules do not guarantee that a transmission owner will be able to recover the cost of the line because charges only apply to the fraction of the line used for wheeling. Any remaining costs must be recovered through privately negotiated charges or national transmission tariffs.

The design of transmission pricing in the SAPP results in charges that are not uniform, predictable or transparent. Some fraction of the cost for new lines is negotiated on an ad hoc basis between parties of bilateral contracts and may vary significantly between countries [223]. This uncertainty, combined with the other flaws in the SAPP's transmission pricing

scheme, may help explain why regional transmission projects expected to offer significant benefits have not been developed in the absence of long-term bilateral contracts with a power purchase agreement (PPA) to guarantee their cost recovery [69]. Financial institutions, concerned with how utilities will recover their investment costs, are weary of financing lines with uncertain revenues from transmission charges.

## 4.2 Problem Statement

There is a general consensus that a fair amount of centralized authority is needed to plan, approve and allocate costs for regional transmission lines [133, 128]. In Europe, ENTSO-E is responsible for regional transmission planning and national utilities pay regional network costs under an Inter-TSO Compensation Scheme. National entities conduct their own network planning but these plans are subject to approval by ENTSO-E and ACER to ensure they are compatible with the regional plan. Network planning in Central America is conducted by the regional system operator and CRIE is responsible for approving lines and allocating their costs among network users according to a method based on Average Participations. Both regional systems use some form of CBA or multi-criteria assessment to select and approve candidate lines.

The SAPP does not have a similar centralized process for developing regional transmission lines or coordinating investments among members. The current strategy to promote regional transmission investments is to publicize priority projects at Investors Roundtable events that bring to-

gether investors, financiers, developers, project owners and contractors [237, 236, 239]. This approach was useful to solicit financing and government support for the upcoming ZIZABONA project [240] but has otherwise not resulted in new transmission investments. Current proposals for changes in transmission regulation are focused on updating the transmission pricing system but are not considering larger coordination issues between national and regional entities.

The following analysis is thus designed to examine the overall regional transmission planning process and develop a comprehensive method for project development and cost allocation that could be a feasible model for developing cross-border transmission projects in the SAPP by addressing the following subquestions:

- How do the existing processes for regional transmission planning and cost allocation influence investment decisions?
- What are alternative models for regional grid expansion that promote efficient investments and allocate costs equitably?
- Is there a class of projects where these approaches could be used more broadly?
- How can such methods be integrated in practice into the existing market?

The chapter is focused on specific topics of regional planning and cost allocation and will not cover other relevant topics including the range of decision-analysis tools used for transmission planning, the iterative transmission modeling process itself, the range of tools and analyses used for the regulatory test, and permitting and siting for new facilities.

## **4.3 Transmission Planning**

### **4.3.1 General framework for investments**

The previous sections outlined a number of regulatory principles and models for the construction of new transmission lines. Most authors agree that centralized grid expansion is the most effective model for developing transmission facilities that are adequate to meet regional needs and also the most beneficial from a regional perspective (see [145, 181, 65, 202, 142]). However, coalitions of users and merchant investors could also play a role to develop new transmission lines, particularly in cases where authority is decentralized, the regional planning process is slow, or public authorities cannot raise funds. Based on these considerations and the regulatory principles and objectives presented above, I propose a reference framework for transmission planning. This framework complements the work from [188] on transmission regulation in regional markets with added features related to the process for distinguishing domestic and regional lines, proposing new lines and the design of the regulatory test. The

features of this reference approach, presented in Table 4.4, can serve as a general framework for developing regional transmission lines in any global market.

The following sections demonstrate how this framework can be applied to the specific context of the SAPP.

### **4.3.2 Proposed transmission planning scheme for SAPP**

#### **Definition of the regional network**

Before discussing expanding the regional network, some process is needed to define the regional network and distinguish between domestic and regional lines. I propose the regional network should include all cross-border lines and some intra-national lines. Intra-national lines can be considered part of the regional network if they are used for regional transactions. This should be measured by simulating network flows under different demand and supply scenarios and calculating the utilization of the line by “external” agents located outside of the area where the line is built. Regional institutions can set a threshold above which the line would be considered part of the regional network. In the MER, for example, regulators calculate the power flows due to regional transactions on each line to estimate the total volume of regional trade in each corresponding country. Any line where regional transactions account for at least 10% of the total volume of regional trade within the country are considered part of the regional network [188]. Otherwise, the line should be considered a domestic line and responsibility for its regulation should be left to



Domestic and regional lines
<ul style="list-style-type: none"> <li>• A transparent procedure must be in place to determine if a proposed line is domestic or regional. This determination should be left to an independent regional institution.</li> <li>• Only local authorities and system operators can participate in the decision-making process for the construction of domestic lines.</li> <li>• Any regulator or system operator affected by a new regional line should be able to participate in the decision making process for its construction.</li> <li>• The regional regulator, or other authorized regional body, should be responsible for identifying any discrepancies between national regional plans and intervening to resolve these discrepancies.</li> </ul>
Proposing new lines
<ul style="list-style-type: none"> <li>• System operators, preferably the regional system operator, should have the primary responsibility to propose new lines because they are best situated with the relevant expertise and technical knowledge to evaluate potential investments.</li> <li>• The regional system operator must take into account proposals by network users in their evaluations and justify the rejection of any proposed lines.</li> <li>• Associations of network users or licensed companies can propose lines if the line is especially relevant for a limited number of them.</li> <li>• Merchant investors can propose lines, subject to special conditions and rules (presented below).</li> </ul>
Regulatory test
<ul style="list-style-type: none"> <li>• All new lines should be subject to regulatory approval according to well-defined criteria. The criteria will depend on the type of line (regulated or merchant).</li> <li>• The regulatory test for regulated lines should determine if a particular reinforcement is justified, measured by its net benefit to the region.</li> <li>• The design of the regulatory test should avoid narrowly defining benefits based on what can easily be measured with sufficient certainty and precision as this can lead to the development of projects whose benefits are easiest to identify rather than those that are most beneficial.</li> <li>• Approval for merchant lines should be less stringent. Merchant investors need only demonstrate that their proposed lines do not coincide with regulated lines under development and are not detrimental to the network.</li> <li>• The regulator should evaluate all projects equally without consideration of the entity promoting them.</li> </ul>
Investment costs
<ul style="list-style-type: none"> <li>• The regulator, through a fixed rate of return or performance index, must guarantee satisfactory remuneration for new regional lines (except merchant lines).</li> <li>• Public tendering for construction under pay-as-bid pricing is recommended when possible as an effective way to obtain a low rate of return that is sufficient for the investor.</li> <li>• The regional regulator is responsible for establishing a method of cost allocation among network users for lines approved as regulated lines.</li> </ul>
Merchant lines
<ul style="list-style-type: none"> <li>• Merchant lines can be a viable option for developing new lines if regulated investments are not expected to take place or the regional planning process is too slow.</li> <li>• For security of supply reasons, the physical operation of the line should be left to the relevant system operator.</li> <li>• The lines should be subject to open access rules under strict non-discriminatory conditions.</li> </ul>

Table 4.4: Features of a global regulatory framework for developing regional transmission lines

national authorities.

The SAPP Operations Sub-Committee (OSC) should determine which lines are included in the regional network subject to approval by RERA. The SAPP CC, control area system operators and national entities can recommend lines to be included in the definition of the regional network. All recommendations must be evaluated by the OSC and, if rejected, the OSC must justify why the line is not included. The OSC should update the definition of the regional network every 3-5 years or upon request by RERA, the SAPP CC, control area system operators or national utilities.

### **Planning process**

The process for developing regional transmission lines must strike a balance between honoring the sovereign authority of member countries and maximizing efficiency from a regional perspective. Ideally, the PSC would be responsible for developing a regional expansion plan and proposing new lines but this unit still lacks the technical training and expertise to conduct regional planning. Further, national entities have thus far resisted efforts to cede planning authority to regional entities and are unlikely to endorse a system of centralized planning. Therefore, I propose both regional and national entities should be responsible for proposing and developing new lines under the supervision of RERA according to the process outlined in the following paragraphs.

First, any entity including the PSC must submit a proposal for the construction of a new line to RERA for approval. This is consistent with

the current practice of allowing national utilities to conduct their own planning studies but the reporting requirement is altered. The Transmission Planning Criteria includes a similar reporting requirement but it is not mandatory and the rule states that all plans must be submitted to the SAPP rather than RERA. Since the SAPP itself is also responsible for proposing regional projects, it is not in a neutral position to evaluate national proposals against its own proposed investments. Therefore, RERA should be responsible for evaluating and approving all planned lines.

Upon receiving the proposal, RERA will submit it to the OSC to determine if the line is domestic or regional according to a predetermined method. If the line is domestic, the regional process ends here and national authorities are responsible for deciding whether to go forward with the project. If the line is regional, the proposing entity must demonstrate through technical analyses that the line meets all technical criteria outlined in the SAPP's Transmission Planning Criteria and does not interfere with other planned lines already under development. RERA can consult with the OSC, PSC or outside consultants to confirm the results of these analyses. Any lines that do not meet these conditions will be rejected by RERA. If the line meets these conditions, the proposing entity can request approval from RERA to move the project forward.

### *Regulated lines*

For regulated lines, the proposing entity could be the SAPP CC, a na-

tional entity, or a coalition of network users. The sponsor must demonstrate that the line is beneficial to the region based on a CBA. This analysis should include multiple scenarios representing uncertainty in demand, fuel prices, and generation output as well as reliability criteria. RERA can request additional technical analysis from the proposing party, the PSC or a third party for any additional scenarios of interest including comparisons with alternative projects. In addition to passing a CBA, RERA must ensure the proposed line does not have any outstanding issues that may prevent it from being completed such as siting and permitting issues, social opposition, overly complex technical design or extensive time to build. If the line meets these requirements, it can be approved by RERA as a regulated line. In cases where proposals overlap, RERA should approve the project with the highest overall performance according to the CBA. Regulated lines should take priority over merchant lines since these are more likely to be optimal from a regional perspective. RERA's approval should be binding and once a project is approved as a regulated line, national entities should not be able to oppose it.

Once approved, construction for regulated lines can be undertaken by the project's sponsor or through a competitive bidding auction. If there is enough competition, competitive bidding is preferable because it avoids the need for RERA to compute benchmarks for the cost of constructing different kinds of lines, since the winning company would be paid according to their bid. If there is not enough competition, RERA can set the remuneration rate based on the project's estimated cost and an

added rate of return for the investor. SAPP members already established a common standard for the cost of transmission assets in the Agreement Between Operating Members that RERA can use to estimate costs [233].

The owner of the line, if not already a member of SAPP, must sign the Inter-Utility Memorandum of Understanding and Agreement Between Operating Members and be approved by the SAPP CC to become a member.

### *Merchant lines*

Merchant lines are relatively rare in the United States and Europe but they could play a large role in the SAPP. National and regional entities have historically been very slow to complete planning and financing activities for new lines and the procedure for regulatory approval proposed above may slow the process further in the first few years as these entities gain experience conducting the necessary analyses to obtain regulatory approval. This means, at least in the near term, merchant investors will continue to have ample opportunities to build new lines.

The current state of the SAPP grid also presents a favorable investment climate for merchant lines. The region has a number of already-identified transmission projects designed to connect specific power plants or large consumers to the regional grid. These projects are fitting candidates for merchant investors because the beneficiaries are easily identifiable and limited in number. In addition, the regional grid is relatively underdeveloped, leaving many profitable opportunities for private

entrepreneurs to earn revenues through price differentials. This revenue stream is less likely to be sufficient to incentivize merchant investors because, in the long-term, reinforcements through regulated lines will begin to eliminate large price differences. Because merchant lines are built under the initiative of private investors, the threshold for regulatory approval is lower. The project's sponsor only needs to demonstrate that the line will have no detrimental effect on the network and does not conflict with planned regulated lines. Similar to regulated lines, the investor must become a member of SAPP by signing the Inter-Utility Memorandum of Understanding, Agreement Between Operating Members and gaining approval by the SAPP CC.

Once built, merchant lines should be subject to two further conditions. First, for security of supply reasons, the physical operation of the line should be left to the relevant system operator. This entity is best positioned to coordinate flows across all lines and maintain all equipment within safe, operable limits. Second, to prevent non-competitive behavior market agents should have open access to the transmission line with regulated payments based on the transmission pricing and cost allocation method used for all other regional lines. Long-term contracts for network rights can be awarded but these should be awarded through transparent market mechanisms under regulatory supervision by RERA.

### *Licensed companies*

Licensed companies operating under performance-based regulation are

possible, but not recommended, models for transmission investments in the SAPP. Transmission performance is generally characterized through metrics such as the volume of losses, congestions, average availability of the line and supply interruptions or shortfalls [83]. However, because multiple agents including generators, consumers, and other transmission owners, are expected to interact with the regulated line, poor performance could often be outside of the company's control. In these cases, the company's remuneration may be at the discretion of RERA. This is unlikely to lead to a predictable and transparent process necessary to incentivize investors. Further, few SAPP utilities have experience with this type of regulation. In fact, the performance contract signed in 2007 between the Government of Mozambique and its national utility EdM overseen by the country's independent regulator represents the first such arrangement in Africa. An alternative option is to combine regulated and performance-based payments. The licensed company could earn regulated rate set by RERA or through an auction plus an additional performance-based penalty or credit based on having higher or lower reliability than a pre-specified target. However, this option would not address the issue that some performance failures are outside of the control of the transmission owner.

### **4.3.3 Final considerations**

A shortcoming of this process is that the investments may not be optimal compared to those resulting from centralized planning. National utilities

will most likely propose new lines that are of greatest benefit to their country and there is a risk of biasing new projects in favor of countries with the best technical expertise and capabilities to organize proposals to RERA. An alternative approach would be to delegate planning responsibilities to the three control area system operators. However, these entities (Eskom - South Africa, ZESA - Zimbabwe, and ZESCO - Zambia) are not independent from member countries and may act in favor of their native country. Further, regional transmission planning cannot be an accumulation of national plans because lines that pass the regulatory test separately may not pass the test when considered in combination with other proposals [189]. By allowing the SAPP's PSC, an entity tasked with optimizing regional rather than national welfare, to propose new lines to RERA, these biases and potential conflicts can be avoided. Proposals from the PSC should reflect the most efficient network investments from a regional perspective and RERA can request analytic support from the PSC or an outside agency to identify potential conflicts and prioritize which lines should be authorized according to the process outlined above.

## **4.4 Transmission Cost Allocation**

### **4.4.1 General framework for cost allocation**

The objectives and principles of transmission pricing and cost allocation are difficult to translate into actual regulations. There is no single scheme for cost allocation that is both technically and economically sound and



easy to implement in a real system for both new and existing lines. In addition, consideration must be paid to several transitional issues. First, the discrete nature and economies of scale associated with transmission investments means many new lines are oversized for existing network users and only a fraction of the line may be used in the near term. For regulated lines, investors must recover the entire cost of the line even if it is not fully utilized. Therefore, some method is needed to allocate the cost of the unused fraction of new transmission lines among network users.

Second, different cost allocation rules may be needed for new and existing lines because the nature and magnitude of transmission benefits will change over the lifetime of the line as patterns of trade, generation, consumption and network topology continue to change. If different cost allocation schemes are used for new and existing lines, some rules are needed to determine when a line no longer qualifies as “new” and should be treated as an existing line. Finally, new investment decisions by network users and transmission owners are based on the set of transmission pricing rules that exist at the time of the investment. If these are changed, the new cost allocation scheme could increase their transmission charges above the level they would have been willing to pay. In these cases, the regulator must decide if and how these users should be compensated.

Based on these considerations, I propose a reference framework for designing transmission cost allocation schemes similar to the framework for transmission planning. The features, presented in Table 4.5 are designed

to serve as a general framework for developing regional transmission lines in any global market.

The following sections apply this framework to the specific case of the SAPP to develop recommendations for a feasible regional transmission cost allocation scheme.

#### **4.4.2 Assessment of transmission cost allocation schemes**

This thesis adopts a regulatory framework for transmission pricing that combines three features. First, network users do not have to pay piecemeal to access different transmission corridors. A single regional transmission charge will grant users access to the entire regional network. Second, the transmission charges will consider a network agent's use of the entire regional network and be implemented through a system of national charges. Third, regional transmission charges only apply to lines identified as part of the regional network. With this framework in place, a method is needed to calculate transmission charges and allocate these charges among network users. As the previous sections indicated, a variety of transmission cost allocations schemes are being proposed or implemented in regional markets around the world. The effectiveness of any cost allocation scheme will depend on its adherence to basic regulatory principles, technical and economic soundness and its compatibility with the institutional design and capabilities of the region. Therefore, any well-designed method should contain the following characteristics: (1) recovers the full cost of the network, (2) allocates costs in proportion

Charges for new and existing lines
<ul style="list-style-type: none"> <li>• Costs for new lines should be allocated to the project's beneficiaries.</li> <li>• A transparent procedure must be in place to determine the fraction of network costs associated with benefits that are widely distributed or difficult to quantify (i.e. reduced emissions, improved market competition) and allocate these costs among network users.</li> <li>• Costs for existing lines should be allocated with a utilization-based method.</li> <li>• To avoid distorting trading behavior, the method should not be transaction-based or based on a user's country of origin.</li> </ul>
Calculation of network charges
<ul style="list-style-type: none"> <li>• Network charges for new lines should be calculated after the CBA is complete (but before investment decisions are made). Otherwise, project beneficiaries may have an incentive to understate their benefits during the regulatory test to reduce their cost responsibility.</li> <li>• Generators and loads located at the same node should be treated as separate entities. Using the net injections/withdrawals between all agents located at the same node is equivalent to assuming there is a transaction between these agents, violating the principle that charges should not be transaction-based.</li> <li>• To obtain political support in international markets, a system of national charges can be applied. Charges for each network user within a given country can be aggregated to a single national charge and each country can decide how to allocate costs among their respective generators and consumers.</li> </ul>
Structure of network charges
<ul style="list-style-type: none"> <li>• Large users that require investments in new transmission facilities to physically connect them to the grid can be charged a shallow connection charge to cover these costs.</li> <li>• All other transmission costs should be recovered through use of system charges calculated using Beneficiary Pays for new lines or a utilization-based method for existing lines.</li> <li>• Use of system charges should be formatted as a fixed capacity charge to avoid distorting system operations.</li> <li>• All network users should be charged using the same method regardless of their trading relationships (i.e. if they engage in bilateral or market trades).</li> </ul>
Transitional issues
<ul style="list-style-type: none"> <li>• Regulated lines resulting from centralized planning or licensed companies require a method to allocate the costs of unused transmission capacity to fully recover their investment costs. Merchant investors or coalitions of users should be responsible for the cost of the unused fraction of the line they propose.</li> <li>• The costs associated with the unused fraction of a new line should be socialized among network users rather than charged in full to the project's current beneficiaries. Socializing these costs to consumers would likely have the least impact on system operations and investment decisions.</li> <li>• For the first few years (around 5), new network users and lines that are made worse off by the pricing scheme can be, but do not need to be, compensated as needed to make them indifferent between the new and previous pricing systems. This compensation should be in the form of a fixed annual payment that decreases each year until no compensation is paid after the transition period ends. Funds for the compensation payments can be socialized among all network users.</li> <li>• The cost allocation scheme for new lines should transition to the allocation scheme for existing lines after the new line has been operating for a reasonable amount of time (10 years). The transition should occur gradually over a number of years (around 5) with the pricing scheme for existing lines accounting for a larger share of the line's remuneration each year.</li> </ul>

Table 4.5: Features of a global regulatory framework for transmission cost allocation

to benefits, (3) avoids interfering with cross-border trade, (4) separates cost allocation from commercial transactions, (5) uses a technically sound method to approximate network benefits and (6) is feasible to implement in a real system.

To identify what method or combination of methods is the best option for regional markets, I apply several transmission pricing methods to the cost allocation problem for the existing SAPP network and three proposed transmission projects and compare their performance using these six criteria. The following sections describe the cost allocation methods chosen for comparison, the power system model, model scenarios and the performance results.

### **Description of cost allocation methods for comparison**

Table 4.6 summarizes the cost allocation schemes selected for comparison. These options are chosen because they represent the methods widely used in existing markets or generally considered to be the most conceptually sound for either new or existing lines. Further, each method can be implemented under a system of national charges by aggregating the charges for each user within a given country or service area to a total service area charge.

#### *Beneficiary pays*

Beneficiary Pays is generally viewed as the best approach to allocate network costs and therefore serves as a basis for comparison with other

Pricing method	Description
Beneficiary pays	Costs are allocated based on expected increases in revenues or decreases in costs that each user obtains as a result of the line.
Average participations	Users are charged based on their contribution to line flows across the entire network.
Postage stamp	Charges are allocated in proportion to each user's injections and withdrawals from the network.
Transits	National charges are based on imports and exports to other systems.
Partial MW-km	Charges for bilateral contracts are calculated according to MW-km method and applied to consumers. Market trades are charged based on the average result from bilateral contracts and shared equally between buyers and sellers.

Table 4.6: Description of transmission pricing methods evaluated in the study

methods. Network costs for each user  $i$ ,  $TC_i$  (million \$), are allocated based on expected increases in revenues for generators (Equation 4.1) or decreases in costs for consumers (Equation 4.2) resulting from the addition of a new line. Plant revenues are calculated as the plant's injection into the network  $P_i$  (MW) times the nodal price where the plant is located. The nodal price represents the value of having one additional unit of energy at that node and can be obtained from the economic dispatch model as the dual variable of the energy balance equation,  $X$ , for that node. For consumers, electricity costs are calculated as the total power withdrawn from the network times the nodal price where the consumer is located.

$$TC_i = P_{i,with} * X_{i,with}^* - P_{i,without} * X_{i,without}^* \forall i \in supply \quad (4.1)$$

$$TC_i = P_{i,without} * X_{i,without}^* - P_{i,with} * X_{i,with}^* \forall i \in load \quad (4.2)$$

### *Average participations*

Among the usage-based pricing methods, Average Participations adheres most closely to the principles of transmission cost allocation and can therefore serve as a basis for comparison with other methods for existing lines. Under Average Participations, the total transmission charge for each network user is equal to their contribution to flows across each line,  $F_{i,l}$  (MW), times the line's cost,  $C_l$  (million \$), (Equation 4.3). Each user's contribution to flows across a particular line  $l$  is based on the heuristic rule for "tracing" injections and withdrawals presented in Section 4.1.2.

$$TC_i = \sum_l F_{i,l} * C_l \quad (4.3)$$

### *Postage stamp*

The Postage Stamp method is selected for comparison because it offers a simple, easy to use method for calculating transmission charges. The total transmission charge is allocated among network users in proportion to their injections or withdrawals from the network (Equation 4.4).

$$TC_i = \sum_l C_l \frac{P_i}{\sum_i P_i} \quad (4.4)$$

### *Transits*

The Transits method is included because it uses a different, top-down ap-

proach to allocate regional network costs. Instead of calculating charges for individual users and then aggregating them to a single national charge, the Transits method assumes each country must pay for network costs within its geographic area plus some payments or compensations for the use that domestic consumers make of external networks and the use that external users make of its own network.

The first step is to calculate how much each country should be compensated for providing wheeling services. Wheeling is measured as the minimum of total imports,  $Im_c$ , and exports,  $Ex_c$ , through a country. Obviously, countries that have zero imports or zero exports cannot provide wheeling services (Equation 4.5).

$$Wheel_c = Min(Im_c, Ex_c) \forall Im_c, Ex_c > 0 \quad (4.5)$$

The total compensations that countries should receive for providing wheeling services is equal to the power flows due to wheeling dividing by the total power flows over the line,  $F_l$ , times the line's cost (Equation 4.6).

$$Comp_c = \sum_l C_l \frac{Wheel_c}{F_l} \quad (4.6)$$

The second step is to determine how much each country must pay for using external networks. This can be approximated by examining the difference between a country's generation,  $G_c$ , and load,  $L_c$  because any imbalance between domestic generation and load must be balanced through

imports or exports using regional lines. The total wheeling payment that must be paid can then be divided among countries in proportion to that country's load imbalance (Equation 4.7).

$$Pay_c = \frac{G_c - L_c}{\sum_c G_c - L_c} \sum_c Comp_c \quad (4.7)$$

Finally, the net charges to each country is equal to the cost of the network within that country plus the sum of that country's compensations and payments (Equation 4.8).

$$TC_c = TC_{national,c} - Comp_c + Pay_c \quad (4.8)$$

#### *Partial MW-km*

Finally, the SAPP's Partial MW-km pricing method combines separate charges for bilateral contracts and market trades. For bilateral contracts, the total charge is equal to the difference in power flows with and without the bilateral transaction times the line's per unit cost. This is represented mathematically in Equation 4.9 where  $F_{all,l}$  is the simulated power flow over line  $l$  when all transactions are included and  $F_{t,l}$  is the simulated power flow when transaction  $t$  is removed.  $Cap_l$  is the carrying capacity (MW) of line  $l$ . As per SAPP rules, these charges only apply to consumers and to lines used for wheeling.

$$TC_{bilat,t} = \sum_l (F_{all,l} - F_{t,l}) \frac{C_l}{Cap_l} \forall l \notin t \quad (4.9)$$

The method to calculate transmission charges for DAM and IDM



trades is more ambiguous. According to the SAPP Market Guidelines, the “total SAPP average transmission charges from bilateral calculations obtained using the MW-KM methodology shall apply to all DAM and PDAM<sup>4</sup> trades” and shared equally between buyers and sellers. Because the rules do not specify how the average charge should be computed or applied to each market transaction, I created a method that could serve as a reasonable interpretation of this rule. First, I calculate the fraction of the network capacity used for bilateral contracts as the sum of power flows due each bilateral transaction divided by the sum of all line capacities in the network. Multiplying this value by the total network cost per unit capacity and length yields the average per unit transmission charge (\$/MW/km) from all bilateral trades (Equation 4.10).

$$AvgTC_{bilat} = \sum_{t,l} \frac{(F_{all,l} - F_{t,l})}{Cap_l} \sum_l \frac{C_l}{Cap_l D_l} \quad (4.10)$$

The total charge allocated to market transactions,  $TC_{mkt}$  (million \$) is equal to capacity of each line used for market transactions times the length of that line and the average transmission charge obtained from bilateral trades (Equation 4.11). The capacity of each line used for market transactions is equal to the total flow over that line minus the flows from all bilateral contracts.

$$TC_{mkt} = AvgTC_{bilat} * \sum_l (F_{all,l} - \sum_t F_{t,l}) * D_l \quad (4.11)$$

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<sup>4</sup>Since these guidelines were published, the Post day-ahead market (PDAM) has been replaced by the Intra-day market (IDM).

Finally, the total charge for market transactions obtained in Equation 4.11 is distributed among all market participants in proportion to their injections into or withdrawals from the network (Equation 4.12).

$$TC_{mkt,i} = TC_{mkt} \frac{P_i}{\sum_i P_i} \quad (4.12)$$

The total transmission charge for consumers equals the sum of charges from their market and bilateral transactions while generators only pay charges associated with their market transactions (Equation 4.13).

$$\begin{aligned} TC_i &= TC_{bilat,t} + TC_{mkt,i} \forall i \in Load, t \\ TC_i &= TC_{mkt,i} \forall i \in Gen \end{aligned} \quad (4.13)$$

### **Selection of new lines for cost allocation**

The transmission pricing schemes selected for comparison are tested for the existing SAPP network and the problem of cost allocation for a new line or group of lines. The new projects are chosen from among the projects identified by the SAPP as priority transmission projects. This list is used because these projects were identified by regional authorities with intimate knowledge of system operations and are therefore most likely to offer net benefits to the region. Projects that are still far from implementation are not considered because there is not enough information on the project's design and costs for analysis. Projects with objectives to interconnect non-operating members are also eliminated because, though these projects most likely offer regional benefits, this is not their primary

objective. These considerations help narrow the list of priority projects from Table 4.3 to three projects: ZIZABONA, CESUL and the 2nd DRC-Zambia line.

In addition to meeting the previous criteria, these projects are useful case studies because they differ significantly in terms of their complexity, costs, objectives and expected beneficiaries. ZIZABONA is a complex project consisting of multiple transmission facilities spread over four SAPP member countries. The benefits are expected to be concentrated among these member countries and South Africa. By contrast, CESUL is located entirely within Mozambique. CESUL is expected to cost at least ten times as much as the other two projects and its financial viability depends critically on the parallel development of two hydropower plants. The project's benefits are expected to be primarily shared between these plants and consumers in Mozambique and South Africa. Finally, the 2nd DRC-Zambia line is very simple technically compared to the previous two and only a fraction of their costs but its benefits are expected to be widely dispersed across the entire SAPP region. The paragraphs below provide a brief overview of each project.

### *ZIZABONA*

The following profile of the ZIZABONA transmission project is based on analysis presented at the SAPP's 2012 Investors Roundtable Meeting [129]. ZIZABONA is a joint venture between the national utilities of Zimbabwe, Zambia, Botswana, and Namibia. The primary objective of

the project is to allow these four member countries to increase trade with each other and the wider SAPP area, South Africa, in particular. The project is expected to ease congestion through the central corridor connecting Zimbabwe and South Africa and, as a result, ease congestion within South Africa between the Matimba power station and Cape Town. ZIZABONA is really a cluster of projects consisting of three transmission lines and five substations. Figure 4-2 shows a schematic of the planned project and Table 4.7 lists the components and their estimated capital costs.

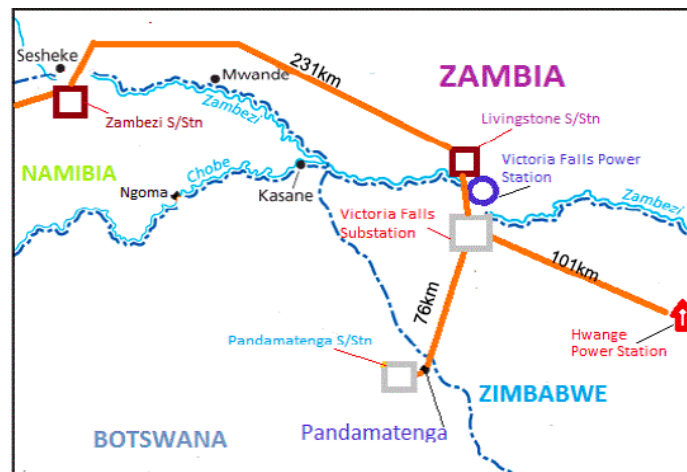


Figure 4-2: Planned ZIZABONA transmission project [129]

Component	Expected Cost \$ '000 (2011 value)
400kV line Hwange -Livingstone (via Vic Falls), 101 km	23,832
400kV line Livingstone - Zambezi, 231 km	54,507
400kV line Vic Falls - Pandamatenga, 76 km	17,933
Hwange Substation extension	10,770
Vic Falls Switching Station	10,187
Livingstone Substation extension (incl. reactor)	13,314
Zambezi Substation extension	12,466
Pandamatenga Substation	19,928
<b>Total Capital Costs</b>	<b>162,936</b>

Table 4.7: Infrastructure components and estimated costs for the ZIZABONA transmission project [129]

Adjusting for current dollar values and other project related costs such as financing and insurance, the total project funding requirement is estimated to be \$223 million. ZIZABONA is being implemented through an SPV domiciled in Namibia under a build-own-transfer (BOT) model whereby the SPV designs and builds the infrastructure and transfers it to the individual entities upon completion. The infrastructure is then “leased back” to the SPV to operate and maintain. The SPV proposes to recover its investment costs through transaction-based use of system charges. These charges will be fixed monthly payments built into long term (20 year) PPAs between Zambia (Zesco) as the seller and South Africa (Eskom), Namibia (Nampower) and Botswana (BPC) as buyers.

#### *Mozambique Backbone (CESUL)*

The Mozambique Center-South (Centro-Sul, CESUL) Backbone Transmission Project is a double transmission line from the Tete Province in the center of the country to the capital Maputo located in the south [4]. The project is designed to evacuate power from the new Mphanda Nkuwa (1500 MW) and Cahora Bassa North Bank (1245 MW) hydropower plants located in the Tete Province. CESUL consists of a 400 kV HVAC line that will connect to substations within Mozambique and a 500 kV HVDC line that will link with South Africa via Maputo (see Figure 4-3) [232].

The project is divided into two phases. Both lines and major substations will be developed in Phase 1 and additional substations for the DC line will be added in Phase 2. Table 4.8 lists the anticipated components

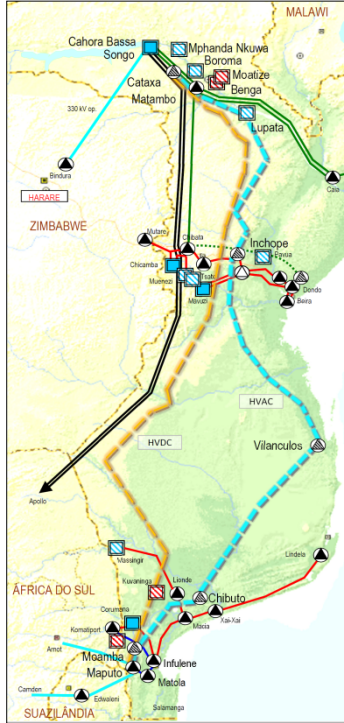


Figure 4-3: Planned CESUL transmission project [60]

and costs for each phase.

	Component	Expected Cost \$ '000
Phase 1	AC transmission line	419,313
	AC substations	366,017
	Other engineering costs	165,452
	DC transmission line	380,566
	DC substations	320,310
	DC other engineering costs	147,787
Phase 2	DC substations	266,000
	DC other engineering costs	53,200
Total Capital Costs		2,118,645

Table 4.8: Infrastructure components and estimated costs for the CESUL transmission project [60]

The estimated cost of CESUL is expected to increase to over \$2.7 billion once other financing-related costs are included [60]. Because CESUL is primarily designed to evacuate electricity from two new hydropower plants, the timely completion of these plants, particularly the Mphanda

Nkuwa plant, is vital to the financial viability of the transmission project. Given the significant size, complexity and large financing requirements for CESUL, the project's promoters advocate that it should be established as an SPV licensed by the government of Mozambique. The license would include terms for a transmission charge methodology but current proposals do not specify what this methodology might be and how it would relate to regional transmission charges [60].

### *2nd DRC-Zambia line*

The primary objective of the 2nd DRC-Zambia transmission line is to eliminate the transmission bottleneck between the two countries and allow DRC to export more hydropower generation to SAPP members through Zambia [257]. The proposed line would increase the existing transfer capacity from 210 MW to 500 MW and is expected to offer "huge potential benefits to the whole region" [286]. The project consists of a 220 kV line from the Luano substation in Zambia to the Karavia substation in DRC [286].

The 2nd DRC-Zambia line is estimated to cost around \$35 million and is being implemented as a joint venture between DRC's national utility, SNEL, and Zambia's CEC. Each company is responsible for financing and building the portion of the line within its national borders. SNEL is financing its 92 km portion of the line with funding from the World Bank and CEC is using debt financing for the 53 km section in Zambia [257]. For the existing DRC-Zambia line, investment costs were recovered

through charges negotiated in SNEL’s PPAs with Eskom and ZESA. CEC had a revenue sharing agreement with SNEL and also earned revenues through wheeling charges. Investment costs for the new line are expected to be recovered through a similar arrangement but information on the final agreements is not publicly available. BPC, ZESA and Eskom are all reported to be potential buyers [286].

### **Model Description**

The choice of power system model developed to compare the various cost allocation schemes is driven by the cost allocation methods themselves. The Postage Stamp and Beneficiary Pays methods only require information on injections and withdrawals at each node<sup>5</sup>. The Transits, Average Participations and Partial MW-km methods require additional information on the power flows across each line to determine the total amount of imports and exports (for Transits), apply a heuristic “tracing” rule (for Average Participations) and determine the contribution of each transaction to flows over a particular line (for Partial MW-km). Because the Partial MW-km method is transaction-based, the model also needs the capability to define a series of transactions and remove one transaction at a time.

Based on these considerations, I opted to use the same economic dispatch model described in Section 3.3.1. This model takes in system conditions related to demand, supply, and transmission capacities and

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<sup>5</sup>Beneficiary Pays also requires nodal prices but this can be derived from the equation used to determine injections and does not require additional modeling.



outputs the least-cost schedule of generators and power flows to meet demand in each hour. The input parameters can be easily adapted to provide snapshots of how the system may operate at different times of year and under different demand and supply scenarios. In addition, because it was originally developed to test the impact of bilateral contracts on market transactions (see Chapter 3), the model already includes bilateral transactions that can be added or removed for the Partial MW-km method.

A shortcoming of this model is the limited representation of the regional network and absence of intra-national networks. Each country is represented as a single node with all generators and load aggregated as a single generator and single load per country. For cost allocation schemes that include locational signals, these signals will be very weak because all charges are necessarily aggregated at the national level. However, the simplified network representation is driven by inadequate data rather than the model design itself. As more data become available, the same economic dispatch model could be updated to include greater detail.

### **Input data**

This analysis uses the same input parameters to characterize the SAPP system presented in Section 3.3.2 plus additional parameters related to the regional transmission network. Table 4.9 lists the transfer capacities, costs and distances for all existing lines as well as proposed lines included in the three new projects.

	Country	Country	Transfer capacity (MW)	Cost (\$ million)	Distance (km)
Existing lines	Botswana	Zimbabwe	850	74	200
	Mozambique	Swaziland	1450	43	200
		Zimbabwe	500	37	170
	South Africa	Botswana	800	102	300
		Lesotho	230	4	35
		Mozambique	3850	249	350
		Namibia	750	74	170
		Swaziland	1450	68	200
	Zambia	Zimbabwe	70	6	50
		DRC	260	22	142
Namibia		400	27	172	
ZIZABONA	Zambia	Zimbabwe	600	24	101
		Namibia	600	55	231
	Zimbabwe	Botswana	600	18	76
CESUL	Mozambique	Mozambique (AC)	900	419	1340
		Mozambique (DC)	2650	381	1275
2nd DRC-Zambia	DRC	Zambia	290	35	142

Table 4.9: Transmission line parameters for the SAPP network [257, 286, 129, 182, 6]

All bilateral transactions are assumed to remain the same as those presented in Chapter 3. For the assessment with new projects, any anticipated bilateral transactions associated with the project are also included. Only ZIZABONA has information on potential bilateral contracts that may be tied to the project. Analysis presented at the Investors Roundtable presentation assumes anchor transactions between ZESCO and Nampower (100 MW) and ZESCO and Eskom (200 MW) [129].

## Modeling Results

### *Existing network*

Figure 4-4 compares the allocation of costs obtained by each transmission pricing method for the existing SAPP network. As the figure shows, the results can vary significantly between different methods.

By assuming each country pays for their own network plus some com-

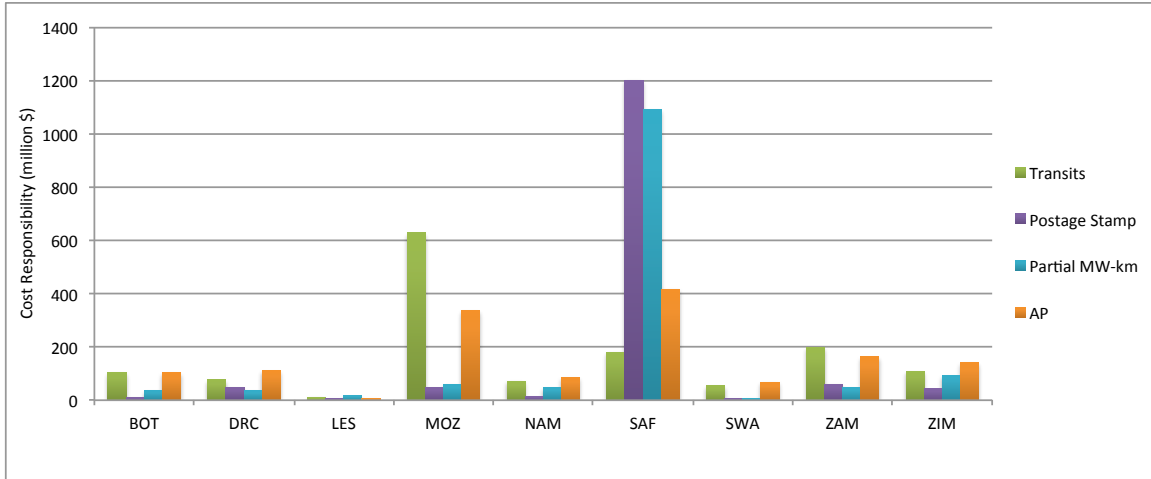


Figure 4-4: Comparison of network cost allocation results obtained from different transmission pricing methods for the existing regional network (AP - Average Participations)

pensations or payments based on net imports and exports, the Transits method obtains the closest results to those obtained from Average Participations. Differences in the two methods stems from the fact that Transits only approximates cost causality in proportion to total network use rather than the use of individual lines. This simplification can impact an agent’s cost responsibility because it does not account for the fact that some lines are more expensive than others. For example, a user responsible for 30% of power flows across a line will face very different charges if the line costs \$1 or \$1,000. The cost allocation results for Mozambique and South Africa demonstrate the impact of this simplification among SAPP users. In the simulated period, Mozambique is responsible for 30% of total energy imbalances in the region and is therefore responsible for 30% of total wheeling charges (in addition to its own network costs). These charges are applied to cover wheeling payments to South Africa and Namibia. Namibia has several expensive interconnections, including

one with South Africa that is the second most expensive in the region. However, the AP results indicate that Mozambique only contributes to flows across a small number of mostly inexpensive adjacent lines and only marginally impacts flows across lines connected to Namibia. As a result, the charges calculated using AP are less than those obtained with the Transits method. Similarly, the Transits method underestimates South Africa's cost responsibility because it does not account for the fact that South Africa contributes to flows across many of the most expensive lines in the regional network.

The Partial MW-km and Postage Stamp methods diverge the most compared to Average Participations. Under these methods, the majority of charges are levied on South Africa because it is the biggest consumer and producer and, therefore, has the biggest share of injections and withdrawals. In addition, under the Partial MW-km method South African consumers are responsible for most of the charges associated with bilateral contracts because they hold many of the supply contracts.

### *ZIZABONA*

Figure 4-5 compares the allocation of costs under different pricing methods for the ZIZABONA project. Comparing the results obtained from Beneficiary Pays to those obtained from other pricing methods, several problems are immediately apparent. First, the results obtained for the Transits, Postage Stamp, and Partial MW-km methods are largely in-

dependent of how each agent benefits from the new lines. Both Postage Stamp and Partial MW-km overcharge South African consumers and producers compared to how much these agents are expected to use of benefit from the ZIZABONA lines.

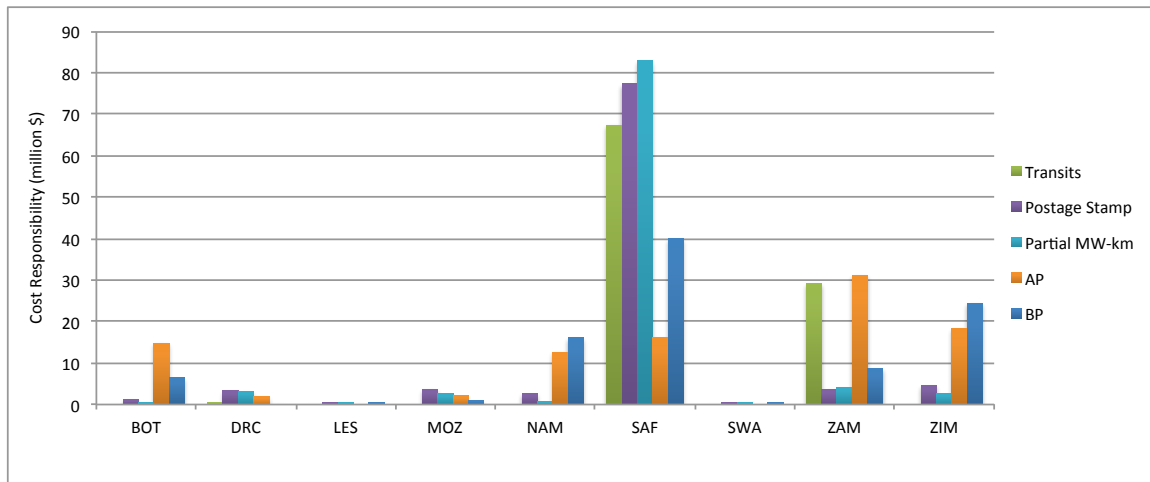


Figure 4-5: Comparison of network cost allocation results obtained from different transmission pricing methods for the ZIZABONA project (BP - BeneficiaryPays)

The Transits method can only capture changes in net compensations between countries and not how each country benefits from the project. The biggest change is in South Africa because the ZIZABONA project reduces the total power wheeled through South Africa reducing the total compensations it will receive. This results in higher overall network payments for South Africa. Zambia’s network costs increase to cover its portion of the ZIZABONA project but these increases are not matched by increased compensations from other countries because wheeling through Zambia is not expected to increase. Most other countries are expected to pay or receive the same compensations with and without the project.

Average Participations also diverges from Beneficiary Pays in some in-

stances, revealing the shortcomings of using network usage as a proxy for economic benefits. For example, under Average Participations, South African load pays nothing for the ZIZABONA project because, by “tracing flows” into South Africa, domestic users are not expected to use the lines. However, the Beneficiary Pays analysis reveals that these consumers are benefiting through lower nodal prices during peak hours. This is possible because the new lines allow increased trade among other countries, reducing South Africa’s exports and allowing lower cost generators to meet domestic load. In other cases (i.e. Botswana, Zambia), Average Participations allocates costs to users that are not benefitting economically from the project because their costs or revenues remain the same with and without the line.

### *CESUL*

The cost allocation results for the CESUL project are presented in Figure 4-6. Based on Beneficiary Pays, the biggest beneficiaries are generators in Mozambique and consumers in South Africa. Consumers in four other countries are also expected to benefit slightly and are thus responsible for a small fraction of the project’s cost.

The Postage Stamp and Partial MW-km methods only coincide with Beneficiary Pays in cases where the biggest beneficiaries also, by chance, account for the largest portion of injections and withdrawals into the network. This is the case for consumers in South Africa who are expected to benefit from the lower-cost power the CESUL lines will carry from hy-

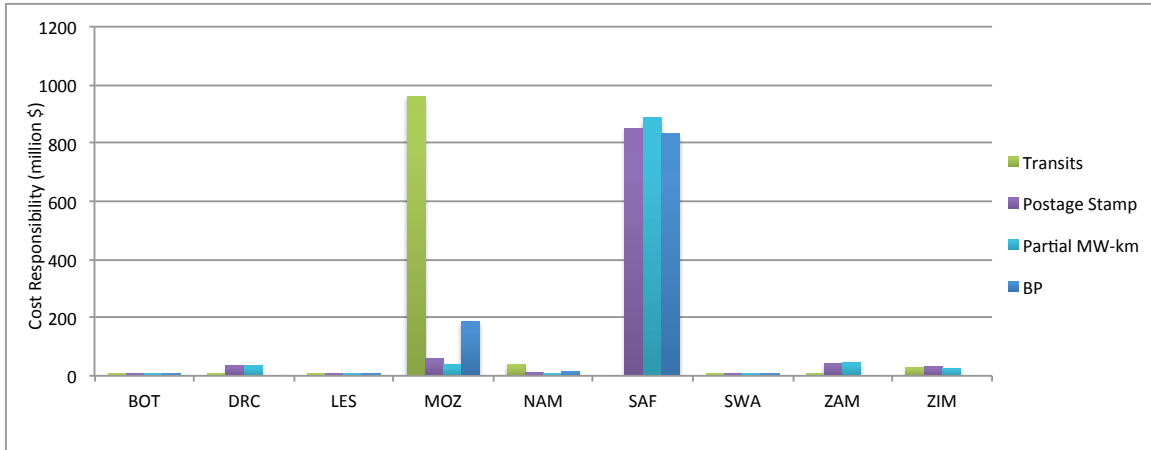


Figure 4-6: Comparison of network cost allocation results obtained from different transmission pricing methods for the CESUL project

dropower plants in Mozambique to the South African border. If, however, the CESUL project was not located near the largest regional consumer, the results from these methods may not correspond. Despite the fact that South Africa is using the CESUL lines to import power for domestic consumption or wheeling, Mozambique is responsible for most of the project's costs under the Transits method. South Africa's net payments actually decrease because it is wheeling power to neighboring countries using its network rather than using domestic generators to produce power for export. Countries that import power wheeled through South Africa are benefiting from lower power costs but are not increasing the amount they must compensate other countries because their total volume of imports and exports remains largely unchanged.

Average Participations could not be applied in this case because the model does not include intra-national networks and, as a result, it was not possible to trace flows along the CESUL lines. Average Participations could be used for projects such as this one in the future if more network

data become available.

*2nd DRC-ZAM line*

The results for the 2nd DRC-ZAM line are shown in Figure 4-7. Under the simulation assumptions, the economic benefits are expected to be shared primarily between DRC and Zambia.

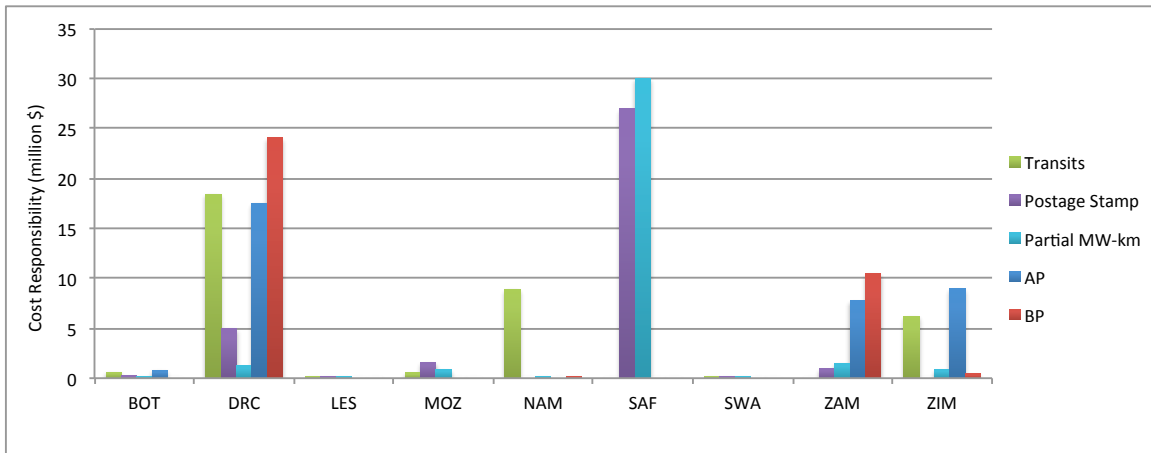


Figure 4-7: Comparison of network cost allocation results obtained from different transmission pricing methods for the 2nd DRC-ZAM line

The Average Participations method provides a close approximation to Beneficiary Pays but it assigns some costs to load in Zimbabwe for using the line even though, according to Beneficiary Pays, these users receive no economic benefits from the line. Similarly, Transits assigns costs to Zimbabwe and Namibia because these countries are making greater use of the regional network by importing more power. However, they are expected to receive only small economic benefits from the DRC-ZAM line. As in the previous cases, the Postage Stamp and Partial MW-km results are primarily driven by factors unrelated to the line in question resulting in cost allocation results that diverge significantly from Beneficiary Pays.



Complete numerical results for each scenario are included in Appendix D.

### Assessment of the Simulation Results

Each method presents some advantages but also some challenges and shortcomings for regional transmission pricing. According to sound regulatory practice, a well-designed method should (1) fully recover cost of the network, (2) allocate costs in proportion to benefits, (3) not deter cross-border trade, (4) separate cost allocation from commercial transactions, (5) use a technically sound method to approximate network benefits and (6) be feasible to implement in a real system. This section evaluates the performance of each method according to these criteria. The results are summarized in Table 4.10.

Method	Cost recovery	Beneficiary pays	Doesn't distort trade	Non-transaction based	Technically sound	Feasible
Beneficiary pays	✓	✓	✓	✓	✓	partial
Average participations	✓	partial	✓	✓	✓	✓
Postage stamp	✓	✗	✓	✓	✗	✗
Transits	✗	✗	✗	✓	✗	✗
Partial MW-km	✗	✗	✗	✗	✗	✗

Table 4.10: Assessment of cost allocation methods based on their compatibility with regulatory principles, technical and economic soundness and ease of implementation (✓ - meets the criteria; ✗ - does not meet the criteria; 'partial' - meets the criteria with minor flaws)

#### *Cost Recovery*

The Partial MW-km and Transits methods do not ensure the full recovery of network costs because these methods are designed, using different approaches, to only recover costs for the use that third parties make of

regional transmission lines. All other network costs are assumed to be recovered through transmission charges levied on domestic network users or negotiated privately between parties with bilateral transactions. Leaving some portion of network costs to the discretion of local authorities or private negotiations can lead to inefficiencies and uncertainty for both network users and network owners. Network agents may face large uncertainties as to what their total transmission charge will be if a fraction of their charges must be negotiated privately as part of a bilateral trade agreement. If this fraction of the line's cost is expected to be large, this could deter or distort investment decisions away from projects that offer the greatest benefit.

*Allocates costs in proportion to beneficiaries*

Only the Beneficiary Pays method adequately allocates costs in proportion to economic benefits for new lines. For existing lines where economic benefits are difficult to quantify because there is no counterfactual case without the line in question, network usage can be used as a proxy for benefits. In this case, the Average Participations method is the best usage-based method to allocate costs.

By narrowly defining network benefits according to imports and exports in each country without, the Transits method leads to charges that may not reflect actual benefits. The results for the existing SAPP network and CESUL project demonstrate how the Transits method could allocate charges to countries, such as Mozambique, far in excess of the

country's actual benefits.

The Postage Stamp method cannot provide useful information on how much a network agent actually uses the regional network because it only measures net injections and withdrawals with no locational information. A country that is only weakly connected to the region may be responsible for a large fraction of the regional network costs if it is the largest producer or consumer. In the model simulations, the Postage Stamp method consistently levied most of the network charges on South Africa because it is the largest producer and consumer regardless of South Africa's actual network use.

Finally, charges in the Partial MW-km method fail to reflect beneficiaries because they are based on bilateral transactions between network agents and these transactions are independent from actual system operations and network use. For market trades, the charges are allocated according to the Postage Stamp method, whose shortcomings have already been discussed.

#### *Avoid interfering with cross-border trade*

The Transits and Partial MW-km methods could both interfere with cross-border trade. By charging countries in proportion to their imports and exports, the Transits method incentivizes countries to meet all demand with domestic generation and avoid overbuilding generation capacity for export. If imports and exports are necessary, the country can minimize transmission charges by maintaining a balance between net

imports and exports.

The Partial MW-km method distorts trade because users are charged differently depending on if they trade through the market or through bilateral contracts. Consumers with bilateral contracts are responsible for the entire network charge associated with their contract while those who trade through the market share their network costs with generators.

### *Non-transaction based charges*

All of the methods avoid distortions due to transaction-based charges except the Partial MW-km method. As previously discussed, this method bases some charges on transactions and uses different methods to calculate charges based on the type of transaction (market or bilateral).

### *Soundness of the method*

Any usage based method necessarily depends on some assumptions to approximate network benefits or cost causality since it cannot be measured directly in an indisputable way [188]. The Partial MW-km method uses line length as a proxy for cost causality based on the assumption that it generally costs more to deliver one unit of energy over a longer distance because energy losses increase with distance. However, this method only accounts for the length of the line and not actual network conditions such as whether or not the line is congested or the transaction eases network congestion. Further, the method to allocate costs to market participants is not technically sound. The allocation of costs is based in proportion to

each user’s injections and withdrawals but does not reflect each agent’s patterns of use or location in the network and therefore cannot capture the benefit each user receives from the network.

The Postage Stamp and Transits methods use high-level approximations of network use that do not reflect the technical operation of the system. The underlying assumption behind the Postage Stamp method is that network use rises proportionally to the amount injected or withdrawn. However, as the modeling results illustrate, this assumption could be easily disputed when the method is applied only to regional lines. The Transits method assumes internal networks are sufficiently developed such that any power entering and existing different points in national grid are wheeled. In fact, there may be no physical links between the entry and exit points.

The Average Participations method is based on a simple heuristic that assumes power flows from an individual user can be traced through the network in proportion to actual flows. By tracing the flows based on historic flows, Average Participations avoids some of the spurious assumptions present in other methods. This method does lead flows to “die off” sooner with the majority of the impact on adjacent or nearby lines compared to some other methods but, absent a way to measure electrical usage directly, we cannot prove that this is correct or incorrect. Average Participations has been used in many real systems and has not been shown to have strange results to date. However, the modeling results demonstrate that network usage is not always an accurate proxy for

network benefits.

Beneficiary Pays avoids the challenges associated with trying to approximate benefits based on electrical usage and measures economic benefits directly through increases in revenues for generators and decreases in costs for consumers. To the extent that these are the only benefits of interest, Beneficiary Pays is the best option. However, this approach may fail to capture other important benefits that drive investments decisions but are difficult to measure and quantify.

#### *Ease of implementation*

Finally, any transmission pricing method must be feasible to implement. This means the method should not rely on data that will be difficult to obtain or computer models that are overly detailed and cannot be solved at the regional level. In addition, the method should be transparent and predictable to ensure the results are deemed fair and minimize potential appeals by members.

The SAPP's Partial MW-km method is one of the more difficult methods to implement. It requires detailed system information to model the economic dispatch problem as well as information on all bilateral transactions. It also suffers from transparency and predictability problems because the method to calculate costs for market trades is not clearly explained and some fraction of the network's cost is always left to be recovered through private negotiations or national network charges.

Postage Stamp is relatively simple to compute and only requires data

on network costs and the power injected and withdrawn from each user. When applied only to regional lines, the method is not sound because generation and load that are weakly connected to the regional network may have to pay for a disproportionate share of network costs. This could be resolved if the method is applied to recover the cost of all domestic and regional networks, but this is unlikely to be politically acceptable for two reasons. First, different approaches to estimate network costs in different countries would lead to conflicts in estimating the overall cost of all domestic and regional lines. Second, it could require network users to pay for inefficient investments in domestic networks in other countries from which they derive no benefit.

The Transits method also avoids the need for detailed network information or system modeling. The central authority responsible for allocating costs only needs data on national consumption, generation, imports and exports. However, the case studies reveal shortcomings of the Transits method. Countries with the most imports and exports were responsible for the largest fraction of a project's cost regardless of whether or not they are expected to use or benefit from the project. Further, there is no error-proof way to define a "transit" because there is no indisputable way to attribute power flows to individual agents. Therefore, any attempt to assign responsibility for power flows to agents within or outside a given country could be contested.

Average Participations is also relatively simple to implement and compute. If the regional network is large and complex, the problem can be

broken into smaller subproblems without sacrificing detail. The method is transparent and does not include the ambiguity or assumptions that leave some of the other methods open to dispute. For the existing network, the authority calculating charges needs injections and withdrawals from each network agent and snapshots of actual network flows. Several snapshots sufficient to represent the system throughout the entire year are needed. For new lines, the case studies show that network usage is not always a good proxy for economic benefit and Average Participations may be more appropriate for existing lines.

Beneficiary Pays provides a method to allocate costs for new lines that is generally accepted as fair. Like all other methods, the calculation for new lines requires system information on load growth as well as power plant and network characteristics to model anticipated system operations and estimate future revenues and costs. Beneficiary Pays may be difficult to apply if the anticipated benefits cannot easily be monetized or are difficult to measure (i.e., reliability, environmental, storm hardening, market liquidity). As already mentioned, Beneficiary Pays is not appropriate for existing lines.

#### **4.4.3 Proposed transmission pricing scheme for the SAPP**

Based on the assessment of different transmission pricing methods and the general regulatory framework for transmission pricing and cost allocation, this section proposes a new transmission pricing scheme for the SAPP.



## Regulated charges for new and existing lines

The SAPP should replace the current system of Partial MW-km pricing and privately negotiated transmission charges for a centralized system of transmission pricing for lines that are deemed part of the regional network and approved by RERA as regulated lines. For new lines, these charges should be calculated using Beneficiary Pays. Rather than attempt to quantify and monetize all possible transmission benefits, the evaluation should account for the most significant benefits that are relevant for the SAPP. These benefits are presented in Table 4.11.

Beneficiary	Description
Consumers	Production cost savings
	Reduced energy losses
	Reduced loss of load probability
	Improved reliability during system contingencies and extreme weather events
	Reduced costs of providing operating reserves
Generators	Avoided cost of alternative reliability or generation capacity projects
	Increased energy sales
	Reduced maintenance costs due to plant cycling

Table 4.11: Transmission benefits to include in the Beneficiary Pays assessment for new transmission projects in the SAPP

These benefits should be estimated using a combination of power flow and unit commitment models to capture anticipated system operating conditions. Power flow models are useful to estimate network losses, congestions and ensure the transmission network remains within safe operating limits under different system contingencies such as the unexpected loss of a line or power plant. Unit commitment models can identify impacts on production costs, plant cycling, trade flows and other system operating conditions. Because future system conditions are uncertain, sensitivity analysis should be used for both models to account for uncer-

tainty in future demand, fuel costs, commissioning dates for new projects, project costs, extreme weather conditions, plant or line failures and policy changes. Note that these analyses should not impose additional data requirements because these data are already needed for the CBA to determine if the project qualifies as a regulated line.

The PSC should be responsible for conducting these evaluations with oversight from RERA. The number of scenarios to test and parameters for the sensitivity analysis should be pre-determined by the PSC but RERA can request additional simulations or additional technical support from a third party. The charges determined through Beneficiary Pays should be in place for a reasonable amount of time, around ten years. This will help reduce risk for network investors concerned about recovering their investment costs and also reduce uncertainty for network users because they will know in advance what their network charges will be.

After a line has been commissioned for many years, the magnitude, distribution and nature of its benefits may change. Rerunning the Beneficiary Pays analysis cannot provide meaningful results because there is no viable scenario without the line. Therefore, the SAPP should adopt the usage-based method of Average Participations to approximate network benefits and allocate costs for existing lines. I recommend the analysis be conducted by the OSC rather than the PSC because this entity is involved with day-to-day system operations that serve as the basis for calculating charges in Average Participations. If, for reasons of consistency, RERA or SAPP members prefer to have the same entity conduct

the analysis for both new and existing lines, the PSC can conduct the assessment. The analysis should be based on actual power flows from the most recent year of operation.

To avoid discontinuities, the charges for new and existing lines should transition over a period of five years. After a line has been commissioned for ten years, or some other reasonably long time established in the regulations by RERA, Average Participations should be used to calculate a fraction of the network charge (e.g., 80% of the charge from Beneficiary Pays and 20% from Average Participations). The fraction of charges set by Average Participations will increase each year while the fraction set by Beneficiary Pays will decrease until, after five years, all charges are set by Average Participations. To avoid uncertainty, the charges over the entire transition period should be established in advance by RERA based on analysis from the OSC.

Merchant lines or lines built and financed by coalitions of network users for their own use can recover their costs through privately negotiated contracts with network users. Because insufficient transmission capacity is an ongoing constraint for market trading and potential investments in new generation plants, these lines should be subject to open access rules for regulatory approval. In this case, the owners can also earn revenues calculated with the same system of regulated payments used for other regional lines. However, for projects developed under private initiative, these payments are not guaranteed to recover the entire cost of the line.

## **Design of network charges**

Once the charges are calculated, they should be distributed among member countries as a single national charge aggregated by RERA. National authorities are then responsible for allocating this charge among their respective network users. This method is recommended because it avoids the need to harmonize transmission cost allocation regulations among all member countries and is, therefore, more likely to be politically acceptable by SAPP members. Because the Beneficiary Pays and Average Participations methods are applied before the charges are aggregated, the resulting national charges will avoid estimation errors seen with other methods, such as Transits, that only look at gross national activity and miss interactions among individual network users.

To avoid distorting system operations, the network charges from RERA should be in the form of a fixed annual charge. National entities have discretion to allocate these costs using a method of their choosing, but capacity charges are recommended. Similar to regional charges, the design of national charges should as much as possible allocate costs to beneficiaries, avoid basing charges on commercial transactions and be in place for a reasonably long time. In addition, the same method should be used to allocate costs associated with national and regional networks to avoid distorting regional trade. In cases where large users require investments in new transmission facilities to physically connect them to the grid, national entities can also consider charging these users a shallow connection charge to cover these costs.

The regulated charge should be sufficient to cover the initial investment cost plus a rate of return. If there is sufficient competition, it is preferable to obtain the regulated rate through a competitive auction. Otherwise, RERA can set the rate of return for network investments and can adjust the rate or return as needed to incentivize investments.

#### **4.4.4 Implementation**

The proposed transmission pricing methods will require updates to the SAPP's governing documents and endorsement by member governments and utilities. The Inter-Governmental Memorandum of Understanding and Inter-Utility Memorandum of Understanding should be updated to grant RERA authority to set regional transmission charges. The new process should be outlined in an updated version of the Agreement Between Operating Members. The updated document will replace the existing Partial MW-km method with the new cost allocation process, outline the roles and responsibilities for RERA and the SAPP sub-committees to implement the new transmission pricing system, and set out all reporting requirements for SAPP members.

#### **4.4.5 Final Considerations**

Allocating costs in proportion to beneficiaries should help eliminate potential objections because only those network users that benefit from the line will be charged. While it is not possible to perfectly characterize all the benefits a network reinforcement could provide, "uncertainty

about benefits does not mean ignorance about benefits” [284] and it is still preferable to use the results obtained from Beneficiary Pays and Average Participations because these align most closely with the regulatory principles and objectives of transmission cost allocation. As the regional system continues to evolve, the Beneficiary Pays method could be adopted to suit new system conditions. For example, the SAPP does not have regional environmental or energy policy goals but, if these are created, the evaluation could be updated to include reduced environmental costs and costs of meeting public policy goals.

## **4.5 Transmission Regulation for Policy-Driven Renewable Energy Investments**

Southern Africa is increasingly interested in promoting development in renewable energy resources at both large and small scales. Major hydropower projects in DRC, Zambia and Mozambique are being promoted by the SAPP and member countries as priority energy projects. National governments are also interested in promoting utility-scale wind and solar plants. South Africa’s Renewable Energy IPP has procured over 6,400 MW of renewable energy capacity from 102 IPP projects and the government aims to increase this to 17,800 MW by 2030 [68, 9]. Many renewable energy projects may require significant investments in transmission infrastructure because resources are located far from major load centers and the rules for planning, approving and allocating costs for

new lines can play a key role to enable or deter renewable investments. Therefore, special care must be taken to design transmission regulation for policy-driven energy investments. The following paragraphs outline some recommendations to regulate this type of investment.

First, if a proposed line is not economically justified but it is needed to meet policy goals to promote renewable energy, the regulator could still authorize the line to be built as a regulated line. The additional cost of developing the line could be socialized among electricity consumers or go to the state budget where it could be allocated through the same method used to cover the costs of other public policy initiatives. It is important to note that failure to pass a CBA does not imply the transmission line will not improve overall social welfare. Rather, the benefits associated with meeting public policy goals may be difficult to quantify and are not accounted for in a traditional CBA assessment.

Second, if the network charges allocated to a renewable energy development is too high, the project could be uneconomic. To meet policy goals, regulators may need to reduce the transmission cost responsibility for renewable generators. Importantly, the transmission charges should still include locational signals to incentivize investors to build renewable energy plants in locations that have good energy resources but are not too far from load centers. For a given line, the regulator can use the beneficiary pays principle to allocate the costs of the line to generators and consumers in proportion to their expected benefits and send locational signals to potential investors. Regulators could then reallocate costs to

consumers until enough renewable energy projects are viable to meet the policy goal.

Finally, if renewable energy projects are not competitive enough to meet policy goals, policy makers may use some form of subsidy to promote renewable development. In this case, the transmission cost allocation should be carefully coordinated with this subsidy to avoid oversubsidizing renewable projects and distorting investment decisions. For example, if a price mechanism such as a feed-in-tariff, premium or investment subsidy are offered to renewable generators, these subsidies should be included when estimating network benefits. Failure to include these subsidies could underestimate the expected benefits and, under a beneficiary-pays approach, the expected cost responsibility that should be allocated to a renewable generator for network investments. If, after the subsidies are accounted for, there are still not enough viable renewable energy projects to meet policy goals because of transmission costs, the subsidy could be increased or a fraction of the network costs could be shifted to consumers.

Currently, these considerations are only relevant for national governments and regulators because the SAPP has no regional renewable energy policy. However, they could be applied at the regional level if the SADC or SAPP members choose to develop regional energy targets.



## 4.6 Conclusions

The SAPP needs significant investments in cross-border transmission capacity to facilitate trade, relieve congestion and connect new generation projects. Needed investments have failed to materialize due to a lack of coordinated planning and flawed transmission pricing rules.

I recommend the regional network should be developed based on proposals from any SAPP member or the SAPP PSC under the supervision of the regional regulator. Regulated lines should be approved only if the reinforcement is justified, measured by its net benefit to the region, superior to alternative proposals and does not have any outstanding technical or non-technical issues that may prevent it from being built. If approved, the regional regulator must guarantee satisfactory remuneration for new regulated lines through a fixed rate of return or bid-based auction.

Network costs should be allocated in proportion to the benefit each user obtains from the network and avoid basing charges on commercial transactions. To accommodate differences in national transmission planning and tariff practices, I propose three additional guiding principles for the application of regional network charges: (1) a single payment should grant the network user access to the entire regional network, (2) charges should be implemented through a system of national charges allowing each country flexibility to allocate charges to network users according to a method of its choosing, and (3) regional transmission charges only apply to lines identified as part of the regional network.

Based on simulations of different network cost allocation methods,

the SAPP's MW-km method is found to be technically or economically unsound and may distort regional trade. This method should be replaced with Beneficiary Pays for new lines and Average Participations for existing lines. Beneficiary Pays uses a technically sound method to allocate the full network cost among beneficiaries without introducing market distortions. For existing lines, network usage provides a valuable proxy for network benefits and Average Participations is the best usage-based method tested.

Finally, southern Africa is increasingly interested in promoting renewable energy investments but many of the best sites would require significant transmission investments because they are located far from major load centers. Countries could allow regulated network reinforcements needed to meet policy goals even if they are not economically justified. The additional cost of developing the line could be socialized among electricity consumers or go to the state budget. If renewable energy subsidies are provided, the allocation of transmission costs should be carefully coordinated with this subsidy to avoid over-subsidizing renewable projects and distorting investment decisions.

# 5

## Regional Regulation

Regional markets require some minimum level of regulatory harmonization to protect the system from technical failures and guarantee members can compete on equal terms. Responsibility for developing common standards typically falls to a regional regulator or similar regional body. The effectiveness of this institution to harmonize regulations necessary to promote the efficient use of regional resources and avoid technical failures depends critically on its design. The SAPP was created in an environment with very little regulatory oversight and, as new problems and more complex trading arrangements have emerged, there is increasing awareness that a stronger regional regulatory body is needed. This chapter examines the design of regulatory institutions in the SAPP and proposes an alternative design for the regional regulator that fits the region's institutional capabilities, existing governance structures and the needs of the regional market. The proposal also includes recommendations for the regulatory responsibilities of other national and regional institutions and how these entities should interact with the regional regulator.

## 5.1 Background

### 5.1.1 Brief Overview of Power Sector Regulation

#### Role of regulation

The role of electricity regulation is to balance the interests of consumers and utilities and promote greater efficiency in the supply of electricity [35]. Regulators must protect consumers from opportunistic behavior on behalf of utilities while also protecting utilities and investors from capricious government policies [36]. For electric utilities, regulation should promote necessary investments and operational decisions to meet existing and future demand at lowest cost with acceptable levels of reliability. When directed to meet other policy goals, utilities should also be encouraged to do so in the most cost-effective manner [171]. For consumers, regulation should encourage greater consumption efficiency through a system of prices and charges that exposes consumers to the incremental costs they impose of the system.

Regulation of the power sector is justified by two features of the industry [266]. First, electricity is considered an essential service for public wellbeing. Electric utilities have a broad range of users that overlap with the voting population, which means the sector tends to be highly politicized and vulnerable to administrative interference in the absence of independent oversight [155]. Second, the technical and economic features

of the industry present large barriers to entry that limit open competition in some sectors, particularly transmission and distribution [152]. The characteristics of electricity infrastructure, namely, significant economies of scale, long construction times, and resource locations that cannot be replicated or relocated, limit the number of new entrants in the power industry and, in the case of transmission and distribution, result in natural monopolies. These conditions warrant the need for regulatory oversight to promote efficient outcomes in the public interest that the market may fail to reach on its own.

### **Principles for effective regulation**

Previous authors identify a number of principles for effective utility regulation [38, 36, 11, 35, 87]. Most common among these are: independence, transparency, consistency, accountability, targeting and proportionality.

Independence refers to political independence and independence from stakeholder interests [135, 35]. Political independence ensures the regulator is protected from short-term political influence through measures such as separate budgets, autonomy in the management of staff and protections from arbitrary removal for political reasons [87]. This is particularly important in countries where electric utilities are state owned, posing potential conflicts of interest between the government's role as owner and regulator [35]. Regulators are also vulnerable to regulatory capture from stakeholders, where regulated entities seek to use regulations to their advantage [261]. For example, industry players may seek regulations that

minimize their compliance costs and maximize their gains by arguing for lower service standards, higher subsidies or tariffs and restricted permitting for competing firms. Information asymmetries between regulators and utilities increase the threat of regulatory capture since utilities are better informed about their costs and technologies than regulators. To minimize this threat, regulators should be subject to restrictions regarding their relationship with regulated utilities during and after their service on the regulatory body.

The decision-making process should be transparent, consistent and accountable [11, 38]. Transparency means regulators should follow clear, simple procedural rules and information should be made available in a timely manner. This ensures all decisions can be subject to public scrutiny. Consistency is important to minimize uncertainty for regulated entities. For example, potential investors may choose not to build a new power plant if the method for setting tariffs is unpredictable. To minimize uncertainty, the logic, analysis and legal basis for all decisions should be consistent over time for all regulated entities and compatible with other regulations and laws. Regulators should be able to provide clear justifications for their decisions. In cases where parties disagree with the decision, a process should be in place for public comment and formal appeals. Holding regulators accountable for their decisions can help improve the credibility and quality of regulatory decisions.

Finally, regulatory decisions should be targeted to specific objectives and proportional to the risks posed by inaction [38]. Berg et al (2000)

recommend regulators should interfere as little as possible in private decision making when carrying out their responsibilities [36]. Rather than try to micromanage utility decisions, the emphasis should be on providing incentives to promote desirable outcomes, leaving the regulated entities flexibility to decide how to achieve these outcomes [149]. These incentives should focus on specific problems and be systematically reviewed to test if they are still necessary and effective [38]. Proportionality means regulatory actions should be appropriate to the perceived risk and justify the costs of compliance. The UK's Better Regulation Task Force recommends regulators should "think small first" because regulation can have disproportionate and unintended consequences on different industry stakeholders [38].

### **Design of effective regulators**

The principles for effective regulation can be incorporated into the regulatory process through careful design of the regulatory institution. Basic features that must be considered in the design process are the regulator's jurisdiction and authority, division of responsibilities with relevant ministries, decision-making structure, process to select key personnel, funding and appeals process [264].

Electricity regulators are generally responsible for the following activities [35]:

- Establish the level and structure of network charges and end-user tariffs

- Define standards for quality of service, operating rules and system safety
- Design market rules and oversee market behavior and operations
- Enforce national laws and regulations
- Grant entry through licenses and authorizations
- Resolve disputes
- Report to relevant government entities

For each function, the regulatory body needs sufficient legal authority to carry out these responsibilities. The regulator's jurisdiction can cover multiple sectors or focus solely on the electricity sector. Arguing in favor of multi-sector agencies, Smith (1997) notes that these agencies can reduce overhead costs by sharing resources (i.e. office facilities and professional personnel) and reduce the risk of industry and political capture [258]. Further, as gas companies are now entering the power sector and power and water companies are, in some countries, entering the telecommunications sector, the lines between industries are becoming blurred. Multi-industry agencies can avoid economic distortions by promoting consistent rule-making across sectors. On the other hand, multi-industry agencies may lack of industry-specific expertise. In addition, sector-specific agencies allow for experimentation with different regulatory approaches (i.e. cost of service, performance-based regulation) to learn which approaches work best in different settings [36].

In theory, the division of responsibilities between the ministry and regulator is as follows: the ministry sets policies and laws under which



the power sector will operate and develop and the regulator is responsible for implementing these rules [135]. In practice, the lines between these entities can be blurred and there can be overlap. In some cases the ministry itself is responsible for regulatory oversight and rule-making. The ministry can establish an independent regulatory body to assist and advise their decisions but it retains final decision-making authority. Other countries have created new independent regulatory bodies that operate separately from the ministry. Within each approach, there are variations including the number of regulators that make up the body, the scope of regulatory authority, protocols for the rule-making process, and the level of discretion given to the regulatory entity [264].

For those countries that grant the regulator decision-making authority, the decision-making process can vary depending on the structure of the regulatory entity. Many regulatory commissions are composed of several appointed members and headed by a high-level appointed regulator that serves as the chairman [36]. The United Kingdom has one commissioner responsible for decisions while regulatory commission in Canada and the island of Ireland have seven members. Most systems fall somewhere in the middle with three (Orissa in India) or five (Argentina, Mexico and FERC) members. An odd number of commission members is recommended to avoid ties in majority voting. The chairman and members can take hands-on managerial roles to lead preparatory work and due-diligence before voting or rely on outside consultants for these tasks. The latter model may be more appropriate in cases where members only work part-time

with the commission.

The processes to select key personnel and fund the regulatory agency's activities are key design issues to promote independence and consistency. Commissioners and staff should be appointed based on professional and personal criteria rather than political connections. In addition to personal characteristics such as integrity, independent reasoning and resistance to pressure, desirable skills include training in economics, finance, public administration and engineering [35, 36]. Regulators should be protected from arbitrary removal during their term and the legal mandate should define the length of appointment term and whether or not appointments are renewable [87]. Longer appointments give regulators time to become familiar with the sector but also present greater opportunities for regulatory capture. Many commissions have staggered terms to ensure continuity of decision-making. Members can be appointed by the legislative branch, the executive branch or a combination of these. For example, appointments can be made by the executive branch and approved by the legislature. To promote independence, commissioners should have autonomy to recruit and manage permanent staff. The commission can also rely on expert consultants and fixed-term contracts with experts to keep permanent staff numbers small.

Commissions should have an independent budget approved by the government or parliament [35]. Governments should provide initial funds required to hire necessary staff, compensate consultants, and acquire office space, furniture and equipment. To minimize short-term politi-

cal pressure, these funds should be made available on time and when needed. Over time, the agency could fund itself completely or in part through other sources including levies added to consumer bills, licensing fees, penalties and special fees for hearings [36]. Governments can limit the size of the agency's budget to control costs.

Finally, rules and procedures must be in place to allow concerned parties the opportunity to express their views in a public forum or appeal decisions [87]. Stakeholder input can be obtained before a decision is made through formal consultations, workshops, position papers and hearings. After decisions are made, the regulator should provide timely and detailed justifications of the decision. If concerned parties wish to appeal the decision, the legal mandate should establish acceptable grounds for appeals, the appellate body responsible for decisions and deadlines for decisions.

In considering all of these design elements, the final design of the regulatory body should be appropriate for the institutional arrangements in the country or region [135, 87, 88, 258]. Institutional arrangements are the legislative, executive and judicial institutions, customs, social interests and administrative capabilities of a particular country [155]. These arrangements can impact both the quality of regulation and its effectiveness. For example, a survey of telecommunications regulation across different countries found that countries with weak administrative capabilities were not able to effectively enforce complex regulatory systems [155]. Similar evidence on the relationship between a country's institu-

tional characteristics and investments have been found in the power sector [37]. This may explain why some countries leave regulatory responsibilities to the relevant ministry rather than create an independent regulator or delay industry restructuring to unbundle utility activities. Experiences with electricity sector reforms in Zambia, India and Lebanon demonstrate that these “good enough governance” approaches may produce better results than attempts to undertake complete reforms [110].

### **5.1.2 Regulation in Regional Electricity Markets**

A key challenge of regional integration is harmonizing regulatory practices among member countries. Each independent system likely has its own rules governing the technical operation of the system and functioning of the local market. If these regulations are incompatible, regional integration could result in technical failures and market distortions [290]. Harmonizing all regulations at the regional level is not generally feasible because many countries have long-standing regulatory frameworks that can differ significantly and national regulators and policymakers are generally reluctant to cede authority to regional bodies. Nor is complete harmonization necessarily desirable because the specific structure and institutional context of some countries may warrant variations in regulatory design.

Rather than force complete harmonization, a more feasible approach

to regional regulation is the organizing principle of subsidiarity, whereby decisions should be left as much as possible to local authorities. Under this philosophy, the regional regulator's bailiwick includes harmonizing only those rules necessary for the efficient functioning of the market [290]. This includes establishing common technical, planning, operational and market rules. For example, common operating guidelines are needed for things such as voltage and frequency stability and procedures for coordination among system operators to manage real-time operations. The transmission network poses a particular challenge for regional markets because network flows are highly interdependent [127]. Therefore, a common method must be established to coordinate regional transmission planning, calculate and allocate interconnection capacity on the regional network and charge network users in a manner that does not distort economically efficient trades. The basic features of the market (e.g., gate closure times, bid formats) must be harmonized and, ideally, coordinated through a common trading platform where the regional regulator can monitor for market transparency and abuses of market power [189]. The list of possible areas where regulatory harmonization is needed will depend on the region being studied and may change over time. For example, European countries interested to promote renewable energy have adopted a range of renewable support mechanisms. The IEM is now looking into harmonizing these mechanisms as well as capacity instruments across member countries to facilitate more efficient use of regional resources and avoid distorting investment decisions [63, 164].

The responsibility for developing and enforcing common regional regulations rests with a regional regulatory body, which can take a variety of different forms. As discussed in Chapter 2, the three main membership models are voluntary associations, representative regional authorities and independent regional authorities. Europe's CEER is an example of a voluntary association of local regulators. Central America's CRIE and Europe's ACER are representative groups composed of regulators from member countries. FERC in the United States is an independent regulatory authority whose members are not affiliated with local regulatory bodies. The WAPP recently established its own independent regulatory body, the ECOWAS Regional Electricity Regulatory Authority (ERERA). International regulatory commissions tend to have more members than their national counterparts to allow each member state to be represented.

There are also three main approaches to establishing the regional regulator's rule-making authority. The first group has no authority to make regional regulations and mostly serves as an advisor to national and regional entities. CEER is one such organization<sup>1</sup>. The second approach allows the regional regulator to design and enforce rules subject to approval by a regional governing body. Under the third approach, regional regulators have rule-making authority in areas where they have legally mandated jurisdiction. CRIE and ERERA do not have to seek approval from governments to pass new regulations. Similarly, FERC's rule-making pro-

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<sup>1</sup>CEER continues to operate as an influential association with no legally established mandate but regional regulation in the IEM was transferred to ACER in 2011.

cess does not require approval from the federal government [104]. ACER's authority includes all three approaches. It can issue non-binding opinions and recommendations to national regulators, transmission system operators and EU institutions, draft framework guidelines upon request by the European Commission that must be approved by the European Commission to come into force and, in specific cases related to cross-border infrastructure, issue binding individual decisions [13].

Similar to the design of national regulators, the approach adopted for a regional market will depend on the region's institutional capabilities and norms. For example, regions with an established process of centralized decision-making through central governing bodies such as the European Commission may prefer a regulatory framework that includes approval from the central governing body. On the other hand, regions with no central governing body or weak central governance may prefer to establish a regional regulatory entity with its own rule-making powers. Similar considerations apply to the composition of the regulatory body. Voluntary associations or representative authorities may not be appropriate in areas with limited regulatory experience at the national level.

### **5.1.3 Regional Context**

When the SAPP was created, the region enjoyed excess generation capacity, all activities were conducted by a single utility in most countries and cross-border trade was limited in volume and only conducted through bilateral contracts. The regional market is now more complex and its

problems are more pressing. Market trading is conducted through short-term markets in addition to long-term bilateral trade, prompting the need for new market rules and operating procedures to integrate the various types of trade. Countries are opening their doors to private sector participation, giving rise to a host of new concerns including access to the regional grid, tariff setting, licensing and coordinated planning [254]. Insufficient generation and transmission capacity are now critical issues, but efforts to develop regional infrastructure projects are slowed because there is no regional regulatory or policy framework for regional planning or cost allocation for new projects.

The SAPP was created in a weak and uncoordinated regulatory environment. For the first ten years of operation, the SAPP had no regional regulator. RERA was established in 2002 but was not operational until 2005 [256]. For the first five years of SAPP operations, only four countries had national regulators. Today, ten of the twelve SAPP members have regulatory bodies. Under this environment, SAPP utilities, predominantly vertically-integrated state-owned companies, and the SAPP Coordination Centre itself became accustomed to operating under a mode of self-policing and there are significant information asymmetries between the newly formed regulatory bodies and the utilities they oversee [253].

## **5.2 Problem Statement**

Improved regional regulation is a key component of the SAPP's regional objectives to develop and enforce common regional supply standards



and harmonize relationships between members [242]. Despite significant changes in the SAPP's regulatory environment in the last ten years, very little progress has been made to develop common regulatory frameworks. Experience with similar regulatory associations with no rule-making authority suggests that RERA's design may not be adequate to achieve the SAPP's objectives and support the continued development of the regional market.

The following analysis aims to evaluate the design of the SAPP's regional regulator considering the needs of the regional market and the institutional context in which this body must operate. Specifically, this chapter addresses the following subquestions:

- Is the current design of the regional regulator effective and consistent with the region's institutional capabilities?
- What are alternative designs for regional institutions to support effective regional regulation?
- What should be RERA's responsibilities and does it have the necessary authority, resources and independence to fulfill these responsibilities?
- What should be the primary regulatory responsibilities of the SAPP's other regional and national institutions?

## 5.3 Analysis of Regulation in Southern Africa

### 5.3.1 National Regulation

Government ministries were traditionally responsible for power sector regulation among SAPP countries. Ministerial regulation has the benefit of avoiding conflicts between public policy and regulatory objectives but it also introduces political interference in regulatory decisions. This is most notable in the tariff-setting process. Responding to political pressure, consumer tariffs across the regional are kept artificially low [161]. High levels of public ownership among utilities complicates the regulatory process because the government is responsible for oversight and running the company being overseen. In some countries, utilities are able to directly influence the setting and enforcement of standards for quality of service, operations and system safety [148].

In the last ten years, efforts to improve the credibility of electricity regulators led to a shift away from ministerial regulation to the adoption of an independent regulator (Table 5.1). The responsibilities and authority granted to these institutions varies considerably among SAPP countries. In Angola, Mozambique, and Namibia the regulators do not have rule-making and enforcement authority but serve as advisors to the ministry [118, 119, 139]. In South Africa, the national regulator can issue licenses, set tariffs, and oversee the industry but the ministry retains the authority to set standards, define licensing rules and mandate restructuring. In addition, the ministry can hold licenses and enter into contracts

itself [216]. Regulation in Botswana is still conducted by the ministry but it has proposed to develop an independent regulatory agency [187]. In DRC, the ministry sets regulatory standards but the utility is tasked with monitoring its own performance [215].

Country	Regulator	Regulatory model
Angola	Institute for Electricity Sector Regulation	Ministry agency
Botswana	Botswana Energy & Water Regulation (under development)	Independent
DRC	Ministry of Mines, Energy and Hydrocarbons/SNEL	Ministry/Utility
Lesotho	Lesotho Electricity Authority	Independent
Malawi	Malawi Energy Regulatory Authority	Independent
Mozambique	National Electricity Council	Ministry
Namibia	Electricity Control Board	Ministry
South Africa	National Energy Regulator of South Africa	Ministry/Independent
Swaziland	Energy Regulatory Authority	Independent
Tanzania	Energy and Water Utilities Regulatory Authority	Independent
Zambia	Energy Regulatory Board	Independent
Zimbabwe	Energy Regulatory Authority	Independent

Table 5.1: Comparison of national regulatory bodies in SAPP countries

Despite new regulatory frameworks in ten SAPP countries, national regulatory bodies have yet to take on their full responsibilities. This is due, in part, to insufficient training and expertise. RERA reports that significant training is needed among national regulators for fundamental tasks such as tariff design [253]. In fact, several years after the SADC called for all countries to establish cost-reflective tariffs, only Tanzania and Namibia have reformed their tariff process and met this goal [299]. For the time being, national regulators are reported to “accommodate rather than enforce” rules with utilities [223].

### 5.3.2 Regional Regulation

The SAPP and RERA operate under the governing body of the SADC<sup>2</sup>. The SAPP CC currently serves as the de facto regulator, translating SADC inter-governmental agreements into market and operating rules that govern the functioning of the regional market. The SAPP CC is responsible for developing and enforcing the Operating Guidelines, Agreement Between Operating Members, Day-Ahead Market Book of Rules, Market Guidelines, Generation Planning Criteria and Transmission Planning Criteria. RERA was established in 2002 by the SADC to facilitate harmonized electricity policies, legislation, and regulations and increase information sharing and capacity building among SAPP members. As a regional association it has no rule-making authority and can only act in an advisory role to national governments, regulators and the SAPP CC.

This arrangement was well-suited to the regulatory environment at the time because most utilities and the SAPP CC itself were not accustomed to strong regulatory oversight and trading relationships were simple, limited to long-term bilateral arrangements. However, as the number of SAPP members increased and trading relationships became more complex with the creation of the day-ahead and intra-day markets, SADC officials felt greater regulatory oversight was needed. In 2008, they commissioned RERA to establish common guidelines to reduce regulatory uncertainty or inconsistencies that may impede cross-border trade. The resulting nine Guidelines for Regulating Cross-Border Trading are

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<sup>2</sup>The SADC Government Ministers and Officials are responsible for policy matters to promote increased development of regional infrastructure. SADC laws are binding for all member states and this body serves as the primary forum for regional policymaking [231].

RERA's main contribution to establishing a regional regulatory framework to date. The guidelines do not propose specific rules but present high-level principles that regulators should follow for activities such as licensing, approving trade contracts and setting network charges [217].

RERA is currently designed to bring together national regulators to tackle pressing regional issues under the guidance of a permanent regional regulator. Because RERA does not have legal authority, any solutions must be approved by the SADC and enforced by the SAPP CC. This approach has been unsuccessful to achieve the SADC and SAPP objectives for harmonized policies, legislation and regulations for two key reasons. First, national regulators in SAPP countries are newly formed and inexperienced [69]. Instead of bringing together national regulators to address regional problems, RERA staff are training national regulators on their basic roles and responsibilities. This could be viewed as a short-term problem since these institutions could quickly gain experience and knowledge. The larger barrier to RERA's effectiveness is cultural. Regional stakeholders report that formal hierarchies are important in SAPP countries and doubt that the "regulation by consensus" model that was useful during the early stages of the IEM could work in southern Africa [223]. They argue that RERA needs to become an "authority" sanctioned by the SADC to be influential in regional decision-making.

The design of RERA as a voluntary association that national regulators do not have to join leads to other problems that limit the institution's effectiveness. First, RERA has very limited resources. The association

employs one permanent regulator and two support staff. References to work by “RERA” really refer to activities from these three individuals. Regulatory bodies from ten SAPP countries are members of RERA but national institutions are unwilling to allow their engineers and regulators to spend time on RERA projects until it gains legal status as an authority [223]. Second, RERA’s informal status precludes it from conducting many of the key functions that should fall to the regional regulator. RERA’s responsibilities do not include dispute resolution, market monitoring, licensing or approving tariffs. Under existing arrangements, utilities resolve disputes among themselves and the SAPP CC is responsible for licensing and market monitoring. There is also uncertainty about the roles and responsibilities of national regulators and their relationship with RERA [253].

One area of focus where RERA is successful is developing regulatory training programs for national regulators. In the wave of reforms that brought newly formed national regulatory bodies, some inexperienced national regulators were reported to make unpredictable or non-credible decisions. These decisions exacerbated some of the very problems independent regulators were supposed to fix such as cost recovery, losses and security of supply [69]. RERA has taken responsibility for addressing these issues and recently signed a memorandum of understanding to undertake all regulator training for the SADC region [255].

Recognizing the need to grant RERA more authority, the SAPP CC and national governments have endorsed a proposal to transform RERA

from an association to a regulatory authority. For the proposal to move forward, RERA staff must present their case during one of the biannual meetings of the SADC Council of Ministers for approval [241].

## **5.4 Proposed Design of RERA**

RERA is well-regarded as a credible leader on power sector regulation but it does not have sufficient authority or resources to fulfill its responsibilities. Further, some activities that should be overseen by the regional regulator are assigned to other entities or not conducted at all. Given the pressing challenges the SAPP is now facing, the region would benefit from a redesign of RERA to broaden its responsibilities and enhance its authority.

### **5.4.1 Jurisdiction and authority**

RERA should become a regional authority sanctioned by the SADC to develop regional regulations for the electric power sector. RERA's jurisdiction could be expanded to include other energy-related sectors such as petroleum and gas but greater coordination in these areas does not appear to be a priority for the region. The SADC's Protocol on Energy, under which RERA was created, only emphasizes increasing regional integration and trade for electricity and the Regional Infrastructure Master Plan focuses on electricity infrastructure projects, rather than refineries and pipelines [298]. RERA's legal mandate should grant it authority to undertake the following activities:

- Define standards for quality of service, operating rules and system safety
- Design market rules and oversee market behavior and operations
- Grant entry to regional market through licenses
- Authorize regional transmission projects
- Establish the level and structure of network charges for lines that belong to the regional network
- Resolve regional disputes
- Conduct regulatory training
- Report to SADC
- Other activities as directed by the SADC

For activities that may require changes in national laws and regulations, RERA's rule-making authority should be subject to approval from the SADC. Activities that should require SADC approval include establishing a regional grid code, defining market rules and procedures for market oversight and establishing regional transmission regulation. The Operating Guidelines created by the SAPP CC should be replaced by a more comprehensive regional grid code that defines standards for quality of service, operating rules and system safety. Similarly, the Day Ahead Market Book of Rules and Market Guidelines should be replaced by market rules that govern all types of regional transactions and define RERA's authority to oversee the regional market. Finally, the Transmission Planning Criteria should be replaced by a regional transmission planning and cost allocation regulatory framework that establishes methods to define



the regional network, apply the regulatory test, calculate transmission charges and allocate network costs<sup>3</sup>. These activities can be conducted by the SAPP CC or an external consultant subject to RERA's approval or developed by RERA itself.

With regional regulations in place, RERA should have individual authority to make binding decisions for specific activities including decisions to authorize regional transmission projects, allocate network costs and issue licenses. The SAPP CC itself should be licensed by RERA as a market and system operator and subject to RERA oversight. RERA should also continue to play a leading role in training regulators. The SADC can direct RERA to address other issues as it deems necessary.

#### **5.4.2 Decision-making structure and interaction with ministries**

To account for the interests of all member countries, RERA decisions should be taken by a Commission composed of one representative from each country and one non-voting representative selected by the Energy Thematic Group of the SADC. Each member will have one vote and decisions should be adopted on the basis of majority. Before voting takes place, the Commission should solicit input from interested parties through formal consultations, workshops, position papers or hearings. The schedule for these activities should be published at least thirty days in advance to allow stakeholders sufficient time to present their views. After the vote is taken, the Commission should publish the results along with a detailed

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<sup>3</sup>Recommendations for these rules in the SAPP are presented in Chapter 4.

justification of the decision.

Requiring SADC approval for regional rules will appeal to the region's preference for formalized authorities and be consistent with the well-established SADC approval process for other regional policies and legislation. A benefit of this process is that government ministers responsible for approving SADC laws are also responsible for enforcing them in their home countries, increasing the likelihood that national governments will comply with SADC decisions. The regulatory hierarchy created by this system, with regional regulations at the highest level and national regulations subservient, would permit some flexibility and innovation at the national level so long as national regulations are compatible with regional rules. This is unlikely to cause the conflicts experienced in other regional markets, like the IEM, because most national regulatory frameworks in the SAPP are still in their infancy. SAPP countries can develop national rules alongside regional ones, ensuring they are compatible.

### **5.4.3 Selection of key personnel and funding**

Representatives to the regulatory Commission will preferably be selected from national regulatory bodies but this may not be ideal in the near term because some countries do not have national regulators and others still lack experience. In light of this, members should be allowed to be selected based on experience with other relevant organizations such as ministries, utilities, academia as long as they have the necessary expertise in the power sector. Members should serve staggered, fixed terms,

between three and seven years is recommended, with the option to renew their term one time. The option to renew terms may be especially important in RERA's early years as members gain experience with the regional market and become familiar with acceptable investment and service levels for different technologies. All members should be subject to approval by the SADC Council of Ministers. In addition to professional expertise, qualified candidates should not have conflicts of interest with public or private parties that may prevent them from acting independently. For example, candidates selected based on experience with government ministries or utilities should no longer be active with these organizations.

To fulfill its enhanced role, RERA needs significantly more staff and resources. RERA's legal mandate should include the ability to collect fees to fund its operations, hire permanent qualified staff and contract with engineers and national regulators to work on RERA projects. Possible sources of funds include fees for membership, licensing, and training activities as well as funds from the SADC budget. RERA should have authority to hire and manage its own permanent staff and contracted consultants at competitive salaries to guarantee its ability to attract and retain qualified personnel.

#### **5.4.4 Appeals process**

Concerned parties should have an opportunity to appeal decisions by the RERA Commission in cases where the Commission has binding decision-making powers. The SADC has a Tribunal responsible for ensuring ad-

herence to regional laws and adjudicating disputes that could serve as the appellate body for appeals [229]. However, this body appears to be highly politicized and has been suspended since 2010 after several rulings against the Zimbabwean government. There are talks underway to reestablish the Tribunal with a narrower mandate, but it is not clear when it will be active again.

Given the uncertain future of the SADC Tribunal, I recommend RERA should establish a separate Board of Appeals. The Board of Appeals should consist of an odd number of members, three to five are recommended, nominated by the SADC Council of Ministers. Members should be current or former senior staff from national regulatory bodies or other relevant institutions in the energy sector committed to act independently and in the region's interest. Membership could be part-time or full-time depending on regional needs. Any legal person, regulatory entity, utility or government representative from a member country should be able to lodge an appeal against a decision taken by RERA. Because RERA's decisions are governed by higher level regulations already approved by the SADC Commission, I recommend the grounds for overrule should be narrowly defined to errors of factual data or cases where the law was not appropriately followed. The Board of Appeals will rule based on a majority decision and a justification for its decision should be publicly available.

## 5.5 Other Regional Institutions

In addition to RERA, other regional and national institutions play an important role in the regulation of the regional market. This section considers the responsibilities of these institutions and how they should interact with RERA.

First, RERA's authority does not cover all aspects of power sector regulation and the majority of regulatory activities should remain with national regulators including setting end-user tariffs, enforcing national laws and regulations, granting licenses to domestic utilities and reporting to their respective governments. In addition, if RERA becomes a regulatory authority, national regulators will have an additional responsibility to enforce regional regulations and provide data or perform analysis as requested by RERA.

In cases where newly formed national entities need more training and experience before undertaking these responsibilities, alternative regulatory models can be implemented [69]. For example, some authors recommend regulation by contract [33] or outsourcing specific regulatory functions such as dispute resolution or technical support to independent consultants [269] for state-owned companies. Brown et al (2006) proposes that recommendations from outside consultants should be enacted unless the minister (or relevant authority) provides a publicly available written justification explaining its rejection [48]. The exact model can be adapted to suit the country context and domestic competencies. These alternative models for power sector regulation can coexist alongside an independent

regulatory agency and could help improve the credibility and quality of regulatory decisions at the national level.

Second, the SAPP CC should transition from its current role as de facto market regulator to a regulated entity under RERA's supervision. As the market and system operator, any Member wishing to participate in cross-border trade must coordinate with the SAPP CC. However, some note that the SAPP CC does not have sufficient monitoring power to ensure contracted transactions adhere to their schedules or enforce sanctions for non-competitive behavior [58]. Under the proposed regulatory model, all Members are subject to reporting and monitoring procedures established by RERA and approved by the SADC. The SAPP CC or member utilities would then be able to report cases of non-compliance to RERA and this entity will have authority backed by the SADC to investigate and issue sanctions if necessary.

Finally, the SADC will provide the legal and political legitimacy for RERA's authority and decisions. After the SADC Ministers approve RERA's new designation as a regulatory authority, this body should be involved in approving membership to the regulatory Commission and approving, when necessary, the Commission's decisions. The SADC should have the authority to review RERA's work plan and request RERA work on specific tasks identified by the Council of Ministers as priorities. This arrangement will facilitate political support among Member governments for RERA's activities.

## 5.6 Conclusion

Some degree of regulatory harmonization is necessary in regional markets to prevent technical failures and promote open and fair competition among market participants. The SAPP's regional regulator is nominally responsible for harmonizing energy policies and regulations but a review of the regulatory environment in the region shows this entity does not have sufficient authority or resources to fulfill these responsibilities. RERA's current design as a voluntary association is not compatible with the region's institutional capacities or cultural norms.

This chapter proposes an alternative regulatory model whereby RERA becomes a regulatory authority sanctioned by the SADC. Under the proposed model, RERA has broader responsibilities and authority but, consistent with regional rule-making in other sectors, decisions that impact national laws and regulations must be approved by the SADC. A new Commission responsible for regulatory decisions should be formed as well as a Board of Appeals to decide cases where stakeholders appeal decisions by the Commission. The proposal also includes recommendations to select key personnel, fund RERA's activities and allocate responsibilities with other regional and national institutions. The proposed design of regulatory decision-making and regulatory institutions in the SAPP should enable more effective rule-making to support the continued development of the regional market.





# 6

## Conclusions

There is a clear trend in the electric power sector to create supranational or regional electricity entities or power pools. This phenomenon extends to several developing regions of the world and many of the newest markets being proposed are located among developing countries in South America, Africa and Asia. Power pools present an opportunity to reduce the cost of providing electricity and improve system reliability through coordinated use of energy resources. Realizing these benefits requires careful design of market rules and regional institutions based on an integrated approach that includes technical, economic and institutional analysis of the system as it exists today and as it will likely evolve in the future. This integrated approach has not been widely applied in the design of regional markets in developing countries where investment needs and institutional capabilities can vary considerably compared to power pools in industrialized countries. As a result, levels of regional trade and coordinated resource development remain low in many developing country power pools. In this dissertation, I demonstrate how this integrated approach can be applied

to a developing country market through a detailed study of the design and operation of the SAPP.

## 6.1 Contributions

From a study of regional markets in various global settings I identified three common challenges that must be addressed to realize the benefits of regional integration. These challenges are: 1.) aligning market rules with national concerns about security of supply, 2.) promoting investment in regional infrastructure, particularly cross-border transmission, 3.) designing effective regional institutions, particularly the regional regulator. To explore how an integrated approach to market design can be applied in a developing country market, I analyzed each of these challenges in the SAPP. I developed a linear programming model of the SAPP system that explicitly represents hourly system operations over a sample operating week to conduct this analysis. This model was then adapted through the addition of new input parameters or linear constraints to investigate different methods of implementing bilateral contracts in the wholesale market and allocating costs for regional transmission investments. In addition to optimization-based analyses, I examined the role of different regional institutions to implement market rules based on principles of sound regulatory practice and the institution's own capabilities.

The primary contributions from this work include a new method to design and incorporate security-motivated bilateral contracts into wholesale markets through a method I refer to as Implicit Auctions with Security of

Supply Guarantees (Chapter 3); a regulatory framework for transmission planning and cost allocation designed specifically for supranational regional markets (Chapter 4); a quantitative comparison of different transmission pricing methods leading to recommendations to apply Beneficiary Pays for new lines and Average Participations for existing lines (Chapter 4); recommended adjustments to transmission cost allocation rules to facilitate increased penetrations of renewable energy (Chapter 4); and a proposed design for the regional regulator (Chapter 5).

I also identify several unique features of developing country power systems that may influence market design. The specific market rules and implementation steps developed for the SAPP may not apply in all developing country markets, but the analysis tools and regulatory frameworks described in this thesis could be generalized to other regional markets.

## **6.2 Findings**

In undertaking this work, I was motivated by the case of the SAPP where, after two decades of operation, the market continues to experience substantial reliability problems and low levels of regional trade in the competitive market. The SAPP's challenges raise several important questions about the design of regional markets. For example, how do security of supply concerns stemming from insufficient generation and transmission capacity impact trading behavior? How can countries that have poor access to project financing promote necessary investments in regional

generation and transmission infrastructure? What role can regional institutions play to promote efficient trade and investment decisions?

The SAPP represents one example of a regional market where the market's performance is impacted by insufficient generation and transmission infrastructure, poor access to project financing among utilities and weak or unexperienced regional institutions. Other developing country markets including the WAPP, EAPP, MER and GMS contain similar technical and institutional characteristics that can lead to similar market challenges.

### **6.2.1 Impact of Bilateral Trade on System Operations and Security of Supply**

Bilateral contracts play a unique role in supply-constrained power systems to reduce risks for consumers and generators. Under the SAPP's current method of treating bilateral contracts as physical obligations, consumers have guaranteed supply when generation capacity is insufficient to meet demand and generators have priority access to scarce transmission capacity to sell their power. However, the modeling results show this design introduces additional constraints on the use of generation and transmission infrastructure resulting in increased system costs, increased instances of non-served energy for the region as a whole and reduced regional trade. By granting bilateral contracts priority access to the transmission network, these rules may discourage investments in new generation plants if these entities cannot gain access to transmission capacity to sell their

power, further exacerbating regional supply problems. It may also prioritize less efficient transactions agreed a long time ago over more efficient ones selected based on better knowledge of the existing operating conditions.

The market inefficiencies can be reduced if generators meet their supply obligations through third party generators when it is economic to do so but this still leaves some inefficiency in the use of network capacity. Treating bilateral contracts as purely financial instruments, as is widely done in the United States and Europe, promotes the efficient use of generation and transmission but these instruments do not reduce risks for contract holders when supply cannot meet demand and are, therefore, unlikely to be adopted in supply-constrained regions.

The proposed method of Implicit Auctions with Security of Supply Guarantees combines the favorable features of financial and physical contracts. It minimizes market distortions by implementing the contracts through a minimum guarantee on the level of supply for contract holders rather than a physical obligation on the use of specific generation and transmission infrastructure. Modeling simulations of the Implicit Auctions method show that, during normal conditions, bilateral contracts have no impact on the least-cost solution for dispatch and trade. During scarcity, contract holders are protected from increased outages with fewer impacts on generation, trade and costs compared to the SAPP's existing rules. The proposed method will require changes in how generators, consumers and system operators interact with the SAPP MO but the SAPP

is well-positioned to incorporate these changes. The regional network is not so large that it cannot be solved as a single optimization problem and system operations are already partially centralized through three control area operators.

### **6.2.2 Promoting Regional Transmission Investments**

Some degree of centralized planning is needed to develop regional transmission facilities necessary for regional trade. The SAPP PSC does not currently have the resources to undertake network planning and SAPP members have expressed reluctance to cede planning authority to a regional entity. Therefore, I propose the regional network should be developed based on proposals from any SAPP member or the SAPP CC under the supervision of the regional regulator. The regional regulator should approve new regulated lines only if the reinforcement is justified, measured by its net benefit to the region, superior to alternative proposals and does not have any outstanding technical or non-technical issues that may prevent it from being built.

The regional regulator must guarantee satisfactory remuneration for new regulated lines through a fixed rate of return or bid-based auction. The regulator is also responsible for allocating the costs of the line among network users. The method for cost allocation should (1) fully recover the cost of the network, (2) allocate costs in proportion to benefits, (3) avoid interference with cross-border trade, (4) separate network charges from commercial transactions, (5) use a technically sound method to approxi-

mate network benefits, and (6) be feasible to implement in a real system. Once calculated, I propose the following three guiding principles for the application of network charges: (1) a single payment should grant the network user access to the entire regional network, (2) after calculating each network agent's use of the entire regional network, charges should be implemented through a system of national charges allowing each country flexibility to allocate charges to network users according to a method of its choosing, and (3) regional transmission charges only apply to lines identified as part of the regional network.

Based on these criteria, I recommend the method of Beneficiary Pays for new lines and Average Participations for existing lines. The power system simulations reveal Beneficiary Pays fully recovers network costs by allocating costs to beneficiaries according to a technically sound method and avoids market distortions. However, it is not appropriate for existing lines and may be difficult to apply if anticipated benefits cannot easily be monetized or measured. For existing lines, network usage should be used as a proxy for benefits. Average Participations is the best usage-based method tested. The SAPP's MW-km transmission pricing method is found to be unsound economically and technically and may distort regional trade.

### **6.2.3 Design of the Regional Regulator**

Regional markets require some minimum level of regulatory harmonization to protect the system from technical failures and guarantee members

can compete on equal terms. The regional regulator or a similar regional body should be responsible for developing necessary common standards. This entity's responsibilities should include, at a minimum, (1) defining operating rules, (2) overseeing market behavior, (3) issuing licenses to participate in the regional market, (4) authorizing regional transmission projects, (5) establishing network charges and (6) resolving disputes. Effective regional regulation depends heavily on the design of the regional regulator including its membership, authority, funding and an appeals process. This design should be based on principles of (1) independence, (2) transparency, (3) consistency, (4) accountability, (5) targeting and (6) proportionality.

The SAPP's regional regulator, RERA, is an example of an ineffective regulatory body. RERA lacks sufficient resources to fulfill its responsibilities and has no legal mandate to create and enforce rules. To overcome these barriers, I propose RERA should be changed from an association to a regional authority, sanctioned by the SADC. RERA should have direct rule-making authority for a limited number of specific activities such as authorizing regional transmission projects, allocating network costs and issuing licenses. Other decisions that require changes to legislation or policies among member countries should require approval by the SADC. This is consistent with regional governance norms in other sectors. A new RERA Commission and Board of Appeals can serve as a guarantee that representatives from all countries are involved in RERA's decisions and stakeholders have an opportunity to appeal decisions.



#### 6.2.4 Implications for Other Developing Country Markets

Many of the design proposals developed for the SAPP could be feasible options for other developing country markets. The WAPP and EAPP are both supply-constrained regions that trade exclusively through bilateral contracts. These power pools are in the process of implementing wholesale markets and are likely to face similar challenges promoting market trading over security-motivated bilateral trades because of security of supply concerns. Implicit Auctions with Security of Supply Guarantees could provide a feasible way to encourage market trading without eliminating the desirable security of supply benefits that bilateral contracts provide.

Transmission pricing and cost allocation is a contentious issue in all supranational markets and one of immediate concern for power pools currently under development. The WAPP recently announced its plan to adopt the flawed MW-km method for regional transmission pricing and the EAPP is in the process of evaluating different methods. The proposed methods of Beneficiary Pays and Average Participations present technically and economically sound alternative that could be implemented in any regional market. Beneficiary Pays would require some agreement on what benefits will be included in the calculation and how these benefits will be measured. Average Participations requires historic data on actual network flows, injections and withdrawals. For large networks, the problem can be broken into subproblems without loss of detail or accuracy.

The design of the regional regulator is another issue of immediate

concern for newly formed power pools. The WAPP's regulator is newly established and the scope of its responsibilities is still being defined. The EAPP and GMS have yet to establish regional regulators and, similar to the SAPP in its early years, some member countries have no experience with independent regulators or the regulatory process is subject to high levels of political influence. The regulatory principles and minimum list of rules that must be harmonized presented in this thesis are applicable for all of these regions. To avoid political influence, the recommendations for the selection of key personnel, funding, interactions between national and regional entities and the appeals process could be applied to these regions as well. The jurisdiction, authority and decision making process may vary between regions based on differences in institutional capabilities, governance arrangements and cultural norms but the principles presented in this thesis can serve as design guidelines.

### **6.3 Future Work**

This thesis has increased my understanding of how to improve the design of regional electricity markets in developing countries. At the same time, this research gives rise to opportunities for further work that could improve or complement the findings presented in this thesis.

First, the analysis of the SAPP could be improved with more technical and institutional data. Specifically, the power system models could be improved if provided with more detailed data on the regional and national transmission networks, characteristics of existing bilateral contracts, wa-

ter availability, plant outages and historic patterns of network flows, generation and consumption. In some countries, I relied on secondary sources for information on national energy policies and regulatory frameworks because these documents are still in development or not publicly available. There is also some uncertainty as to how the SAPP implements some of its market rules, particularly the rules for transmission pricing applied to market trades.

Given greater system detail, future work can also examine the emerging topic of renewable energy integration. Planned investments in hydropower, wind and solar resources could dramatically change the generation mix in the SAPP and the ways conventional technologies are operated. Regional integration could unlock increased system flexibility through trade and protect hydro-based systems from supply shortages during droughts. At the same time, increased variability in net load and market prices may warrant changes in the design of the regional market. Intra-day markets and capacity mechanisms may play an increasingly important role in a regional system with high penetrations of variable renewable energy.

Finally, further research should apply the approach taken in this thesis to other regional markets. Regional markets in east Africa, west Africa, India and south east Asia are all in early stages of developing institutional and governance arrangements and market rules. The insights and lessons from this thesis can inform the design of markets in these regions.



# Appendix A

## SAPP 2015 Model Formulation

The mathematical formulation for the security-constrained economic dispatch model is presented below. As a matter of nomenclature, all input parameters are designated with the letter  $p$  before the name and decision variables with the letter  $v$ .

### Indices

$p$	Period
$c$	Country
$g$	Generation technology
$l_{c,c}$	Interconnections between countries
$t$	Types of power trade (bilateral, market)

### Input Parameters

$pD_{p,c,t}$	Demand	[MW]
$pBC_{c,c}$	Bilateral contracts	[MW]
$pCap_{c,g}$	Generation capacity	[MW]
$pAvailFactor_{c,g}$	Availability factor	[%]
$pHF_{c,g}$	Heat Rate	[MMBTU/MWh]
$pRenewCF_{p,g,c}$	Capacity factor for wind and solar	[%]
$pVC_{c,g}$	Variable cost	[\$/MWh]
$pFC_{c,g}$	Fuel cost	[\$/MMBTU]
$pTx_{c,c}$	Transfer capacity	[MW]
$pLoss$	Line losses	[%]

### Decision Variables

$vConCap_{c,p,g}$	Connected capacity (synchronized to the grid)	[MW]
$vGeneration_{c,p,g,t}$	Generation	[MW]
$vGxCost_{c,p}$	Generation cost	[\$]
$vResBilDemand_{p,c}$	Bilateral demand that must be met by the market	[MW]
$vTrade_{c,c,p,t}$	Electricity trade	[MW]

The index  $t$  is used to distinguish between wholesale market and bilateral transactions. For countries with bilateral contracts to purchase power, total demand is composed of bilateral demand (based on the quantity of contracts signed) and market demand. Similarly, generation and trade are divided between bilateral and market. For countries with no contracts, the bilateral component for demand, generation, and trade is always zero.

### Objective function

The objective function is minimization of all generation costs over the simulated week. Generation costs consist of: (i) running costs for units synchronized to the regional grid but not necessarily producing power, (ii) fuel costs, and (iii) variable operation and maintenance costs.

$$\begin{aligned}
 & \text{Min} \sum_{c,p,g} vConCap_{c,p,g} * pVC_{c,g} + \\
 & \sum_t vGeneration_{c,p,g,t} * (pHR_{c,g} * pFC_{c,g} + pVC_{c,g})
 \end{aligned} \tag{A.1}$$

### Constraints

The dispatch schedule is subject to constraints on the available capacity of each technology, transfer capacity between countries, and requirements that supply must meet demand in every period.

### *Available Capacity*

The total capacity available to be dispatched is less than the total installed capacity because power plants use some portion of their power internally and must go offline occasionally for maintenance. For wind and solar plants, output also depends on the resource availability, which may vary throughout the day. The parameters  $pAvailFactor$  and  $pRenewCF$  take on values between 0 and 1 to account for the fraction of installed capacity available in each period. For example, solar plants may have a  $pRenewCF$  value of 0.8 during the day, indicating that a 100W plant could generate up to 80W during this time and a value of 0 at night when there is no sunlight. For all non-renewable plants, the value of  $pRenewCF$  is set to 1.

$$vConCap_{c,p,g} \leq pCap_{c,g} * pAvailFactor_{c,g} * pRenewCF_{p,g,c} \quad (A.2)$$

A plant must be running and synchronized to the grid to produce power. Therefore, total generation in any hour cannot exceed the connected capacity during that time.

$$\sum_t vGeneration_{c,p,g,t} \leq vConCap_{c,p,g} \quad (A.3)$$

### *Transfer Limits*

Total power trade is limited by the physical transfer capacity between

countries. For bilateral trade, the maximum allowable trade is limited by the capacity of the contract,  $pBC$ . Any remaining transfer capacity not used for bilateral trade can be used for market trading.

$$0 \leq vTrade_{c,c,p,Bil} \leq pBC_{c,c} \quad (A.4)$$

$$pBC_{c,c} - pTx_{c,c} \leq vTrade_{c,c,p,Mkt} \leq pTx_{c,c} - pBC_{c,c} \quad (A.5)$$

### *Supply Demand Balance*

The supply demand balance equations are divided into two parts: bilateral and market. Bilateral demand comes from capacity that countries have contracted to receive or provide. Any residual bilateral demand not met by domestic generation or bilateral trade is captured by the variable  $vResBilDemand$ .

$$vResBilDemand_{p,c} = pD_{p,c,Bil} + \sum_{l(c,cf)} vTrade_{c,cf,p,Bil} * pLoss - \sum_{l(ci,c)} vTrade_{ci,c,p,Bil} * pLoss - \sum_g vProduction_{c,p,g,Bil} \quad (A.6)$$

The market energy balance equation requires that total supply must equal demand in all periods. Supply can take the form of domestic market generation, energy non-served (ENS), and market imports. Demand comes from market demand plus any residual bilateral demand and energy exports.



$$\begin{aligned}
\sum_g vGeneration_{c,p,g,Mkt} &= pD_{p,c,Mkt} + vResBilDemand_{p,c} + \\
\sum_{l(c,cf)} vTrade_{c,cf,p,Mkt} * pLoss &- \sum_{l(ci,c)} vTrade_{ci,c,p,Mkt} * pLoss
\end{aligned} \tag{A.7}$$

### *Contract Scenarios*

In the base case, all bilateral contracts,  $pBC$ , are assumed to be “0” and all bilateral demand, trade, and generation values are also “0”. As a result, all transfer capacity is available for market trading (Equation A.5) and the balance equation for bilateral contracts (Equation A.6) is not binding.

In the physical transmission (PT) rights scenario, all existing bilateral contracts are included. These contracts must have reserved transmission capacity (Equations A.4 and A.5 are active) but any technology located in any country can meet bilateral demand.

In the physical contracts (PC) scenario, all existing bilateral contracts are included and the contract holders must meet these contractual obligations with their own generators. Two additional constraints are included to impose this rule. The first constraint mandates that domestic generators within countries with export obligations must produce enough to meet these obligations and the second mandates that bilateral trade between countries must match their contracted exchanges.

$$\sum_{g,t} vGeneration_{c,p,g,t} \geq \sum_{cf} pBC_{c,cf} \quad (\text{A.8})$$

$$vTrade_{c,c,p,Bil} = pBC_{c,c} \quad (\text{A.9})$$

The implicit auctions scenario does not explicitly include bilateral contracts. Similar to the base case, all bilateral contracts are assumed to be “0”. Instead, this scenario contains a new constraint on the maximum allowable ENS a country with a purchase contract can experience in any period.

$$\sum_t vGeneration_{c,p,ENS,t} \leq pBaseENS_{c,p} \quad (\text{A.10})$$

The parameter  $pBaseENS$  is equal to the ENS a country with a purchase contract experienced under the PC scenario. Equations A.8 and A.9 are not active in this scenario.

# Appendix B

## Contracts for Differences (CfDs)

In a CfD, participants agree to exchange a contracted quantity,  $q_c$ , at a fixed price,  $P_c$ , known as the contract or strike price. The market clearing price,  $P_m$ , serves as the reference price. The monetary result of the contract is that the buyer pays the seller  $q_c(P_c - P_m)$ . Note that when the strike price is less than the market price, this value is negative and the seller actually pays the buyer.

### Traditional CfD Design

With traditional CfDs, if buyers purchase some quantity  $q$  from the market at price  $P_m$  they will pay the market price for what they consume plus the contract price (Equation B.1).

$$qP_m + q_c(P_c - P_m) \tag{B.1}$$

Sellers earn income from selling some quantity  $q$  of power to the mar-

ket and the CfD. Their net revenues include this income minus their generation costs (the quantity produced times their variable cost,  $VC$ ) (Equation B.2).

$$qP_m + q_c(P_c - P_m) - qVC = q_cP_c + (q - q_c)P_m - qVC \quad (\text{B.2})$$

If buyers buy exactly their contracted quantity,  $q_c$ , their resulting costs would be

$$q_cP_m + q_c(P_c - P_m) = q_cP_c \quad (\text{B.3})$$

Similarly, if sellers produce exactly  $q_c$ , their net revenue would be

$$q_cP_m + q_c(P_c - P_m) - q_cVC = q_c(P_c - VC) \quad (\text{B.4})$$

In both cases, the final costs/revenues are independent of the market price,  $P_m$ . In other words, buyers and sellers with a CfDs are fully hedged to consume and produce exactly the contracted quantity.

Although contract holders are fully hedged to consume their contracted quantity, ignoring the market price could reduce the efficient functioning of the market. If contract holders held strictly to this rule, sellers would be willing to produce even if the market price fell well below their variable cost of generation or buyers would continue buying power even if the market price skyrocketed. Fortunately, with CfDs, both parties to respond to market price signals as if the contracts do not exist.

If, for example, the market price rose above  $P_c$ , buyers could continue to consume  $q_c$  and pay  $q_cP_c$ . However, according to Equation B.1, they

would be better off reducing their consumption,  $q$ , as much as possible and pay  $qP_m + q_c(P_c - P_m)$ . Note that the second term is negative, meaning the seller would be paying the consumer. On the other hand, if the market price increases above  $VC$ , sellers have an incentive to produce as much as possible. From Equation B.2, generators could earn an additional  $P_mVC$  for each incremental unit sold over the contracted quantity,  $q_c$ .

If the market price falls below  $P_c$  and  $VC$ , buyers and sellers would have the opposite reaction. Buyers could increase their consumption and pay  $P_m$  for each additional unit consumed over the contracted quantity. As this price is less than the value the consumer was willing to pay in the contract, consumers are most likely willing to buy more at this price. By contrast, sellers would lose  $VC - P_m$  for every unit sold. In this case, they are better off shutting down generation and collecting payments from the CfD.

Ignoring the equations or the specific example of electric power systems, these results reflect our intuition about how consumers and producers respond to market prices. When the market price is high, consumers will try to consume less whereas producers want to sell more. When the market price falls, consumers are willing to buy more whereas fewer producers will find it profitable to sell. With CfDs, consumers and producers have an incentive to respond to market prices as if the contracts did not exist.

## **Proposed contract design during scarcity**

Financial contracts, such as CfDs, are sufficient for cases where there is sufficient generation and transmission capacity for consumers to buy and generators to sell  $q_c$ . For example, if a generator breaks down, it cannot hedge against market prices by selling power but it can purchase power from the market to cover its contractual obligations. The generator would be fully exposed to the market price,  $P_m$ , and its net revenues (from Equation B.2) are  $q_c(P_c - P_m)$ . Note that if the market price is higher than the strike price, the generator is exposed to a potential loss. For transmission owners, if the contracted transmission capacity is not available but consumers are still able to receive  $q_c$  and generators are still able to sell  $q_c$  through alternative network paths, the transmission owner is not subject to any penalty as both the generator and the consumer are fully hedged against market prices.

This framework breaks down when contracted generation or transmission capacity is not available and there are no alternative supplies or network paths to guarantee consumers are able to buy and generators able to sell  $q_c$ . This situation is a reality in supply-constrained systems like the SAPP. In these cases, the party responsible for creating the problem must pay some compensation to the contract holders. Under the proposed implicit auction scheme presented in Chapter 3, CfDs must include a per-unit fine for generators,  $FG$ , that are not available when needed and transmission rights contracts must include a per-unit fine for transmission owners,  $FT$ , that are not available when needed. These fines

will be applied only if the outage results in the consumer being unable to consume  $q_c$  or the generator being unable to sell  $q_c$ .

If the generator is not available, they must pay the consumer the penalty cost for every unit not supplied,  $FG(q_c - q)$ . Similarly, if the transmission line is not available, the transmission owner is subject to a fine to both the consumer and producer for any foregone consumption or revenues that result from the line being down. This amounts to a penalty of  $FT(q_c - q)$  to the consumer and  $(q_c - q)(P_c - VC)$  to the generator.

The following tables outline the monetary outcome of the proposed contracts under different scenarios for consumers and producers.

	Payment by consumers	
	Able to consume $q_c$	Unable to consume $q_c$
Generator/Transmission available	$qP_m + q_c(P_c - P_m)$	Impossible case
Generator unavailable	$qP_m + q_c(P_c - P_m)$	$qP_m + q_c(P_c - P_m) - FG(q_c - q)$
Transmission unavailable	$qP_m + q_c(P_c - P_m)$	$qP_m + q_c(P_c - P_m) - FT(q_c - q)$

	Revenues for producers	
	Able to sell $q_c$	Unable to sell $q_c$
Generator/Transmission available	$q_c P_c + (q - q_c)P_m - qVC$	Impossible case
Generator unavailable	$q_c(P_c - P_m)$	$q_c(P_c - P_m) - FG(q_c - q)$
Transmission unavailable	$q_c P_c + (q - q_c)P_m - qVC$	$qP_m + q_c(P_c - P_m) - (q_c - q)(P_c - VC)$





# Appendix C

## SAPP 2015 Model Results

Scenario	Country	BIO	COA	DIST	GAS	HYD	NUC	SOL	WIN	ENS
Base	BOT		7.3	0.4	1.5					
	DRC					236.2				
	LES					7.9				
	MOZ			0.9	3.5	304.4				
	NAM		5.8	0.6		17.7				
	SAF	0.2	4,570	12.1	5.9	263.3	256.9	107.6	41.5	
	SWA					3.8				
	ZAM			0.7	0.8	234.7				
	ZIM		46.7			76.9				
PT	BOT		7.3	0.4	1.5					
	DRC					236.2				
	LES					7.9				
	MOZ			0.9	3.5	304.4				
	NAM		5.8	0.6		17.7				
	SAF	0.2	4,570	12.1	5.9	263.3	256.9	107.6	41.5	
	SWA					3.8				
	ZAM			0.7	0.8	234.7				
	ZIM		46.7			76.9				
PC	BOT		2.9							
	DRC					236.2				
	LES					4.9				
	MOZ			1.0	4.1	304.4				
	NAM		5.6	0.7		23.5				
	SAF	0.2	4,542	14.6	6.7	263.3	256.9	107.6	41.5	
	SWA					3.6				
	ZAM			2.3	2.0	234.7				1.6
	ZIM		70.0			76.9				

Table C.1: Generation (GWh) by country and technology for each contract scenario under Normal operating conditions

Scenario	Country	BIO	COA	DIST	GAS	HYD	NUC	SOL	WIN	ENS
Base	BOT		11.8	1.0	2.5					
	DRC					225.0				18.0
	LES					7.4				
	MOZ			1.6	6.3	297.6				
	NAM		6.7	1.2		19.1				
	SAF	0.3	4,523	26.4	26.5	257.5	251.2	105.2	40.5	89.9
	SWA					3.6				
	ZAM			1.2	1.5	221.6				
ZIM		68.3			72.6				43.8	
PT	BOT		11.8	1.0	2.5					
	DRC					225.0				52.6
	LES					7.4				
	MOZ			1.5	6.2	297.6				
	NAM		6.7	1.2		18.9				0.2
	SAF	0.3	4,523	25.9	26.2	257.4	251.2	105.2	40.5	104.3
	SWA					3.6				
	ZAM			1.2	1.5	221.6				0.5
ZIM		66.1			72.6				29.3	
PC	BOT		3.8	0.1	0.4					
	DRC					225.3				95.5
	LES					4.7				
	MOZ			1.6	6.5	297.6				
	NAM		6.5	1.2		23.1				4.0
	SAF	0.3	4,491	27.1	26.2	257.5	251.2	105.2	40.5	261.6
	SWA					3.4				
	ZAM			2.9	3.0	221.6				11.5
ZIM		81.1			72.6				9.8	
IA	BOT		11.8	1.0	2.5					
	DRC					225.3				18.0
	LES					7.4				
	MOZ			1.6	6.3	297.6				
	NAM		6.7	1.2		19.1				
	SAF	0.3	4,524	26.4	26.5	257.5	251.2	105.2	40.5	110.6
	SWA					3.6				
	ZAM			1.2	1.5	221.6				
ZIM		68.3			72.6				0.1	

Table C.2: Generation (GWh) by country and technology for each contract scenario averaged over all scarcity scenarios

Scenario	From	To	Base	PT	PC	IA
Normal	DRC	ZAM	44	44	44	44
	MOZ	SAF	270	328	120	289
	MOZ	SWA	-135	-186	7	-134
	MOZ	ZIM	60	54	70	40
	NAM	ZAM	19	23	63	21
	SAF	SWA	163	215	22	162
	SAF	ZIM	7	9	8	10
	SAF	NAM	86	90	124	88
	SAF	BOT	114	115	38	130
	SAF	LES	14	14	17	14
	ZAM	ZIM	15	19	63	17
	ZIM	BOT	-35	-35	48	-51
Scarcity	DRC	ZAM	35	39	44	35
	MOZ	SAF	299	331	117	290
	MOZ	SWA	-157	-188	7	-139
	MOZ	ZIM	50	49	69	42
	NAM	ZAM	18	23	60	22
	SAF	SWA	186	217	22	168
	SAF	ZIM	7	7	7	9
	SAF	NAM	82	87	120	86
	SAF	BOT	108	103	36	125
	SAF	LES	14	14	17	14
	ZAM	ZIM	-7	2	59	-3
	ZIM	BOT	-35	-30	49	-52

Table C.3: Total cross-border trade (GWh) for each contract scenario under normal and scarcity conditions (averaged over all scarcity scenarios)

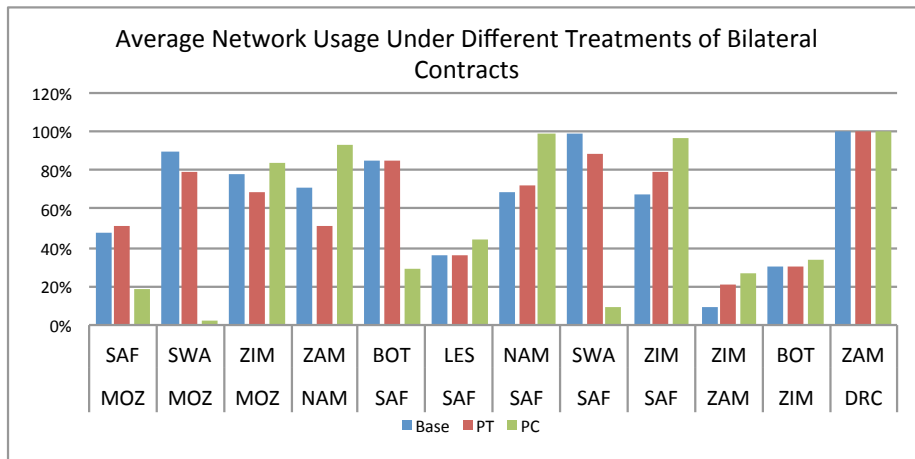


Figure C-1: Comparison of the average capacity factor (%) for each transmission interconnection under different methods of implementing bilateral contracts in a normal week. The PC scenario causes the largest change in the use of specific transmission lines.

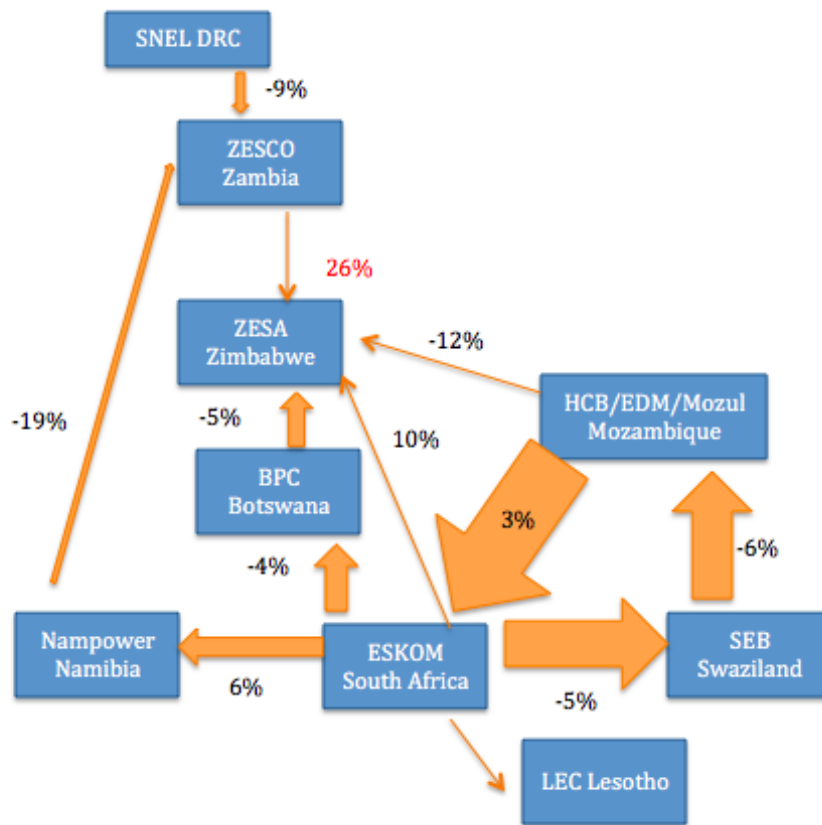


Figure C-2: Comparison of optimal trade flows under the PT scenario with the base case during scarcity (averaged over all scarcity scenarios). During scarcity, the impact of physical transmission rights on power flows is more pronounced, averaging 16% compared to the base case, and in one case the direction of flows is forced to reverse.

Scenario	Base	PT	PC	IA
Normal	29.2	29.3	33.1	29.2
Scarcity	82.6	89.6	124.7	82.3

Table C.4: Total operating costs (\$ million) for each contract scenario under normal and scarcity conditions (averaged over all scarcity scenarios)

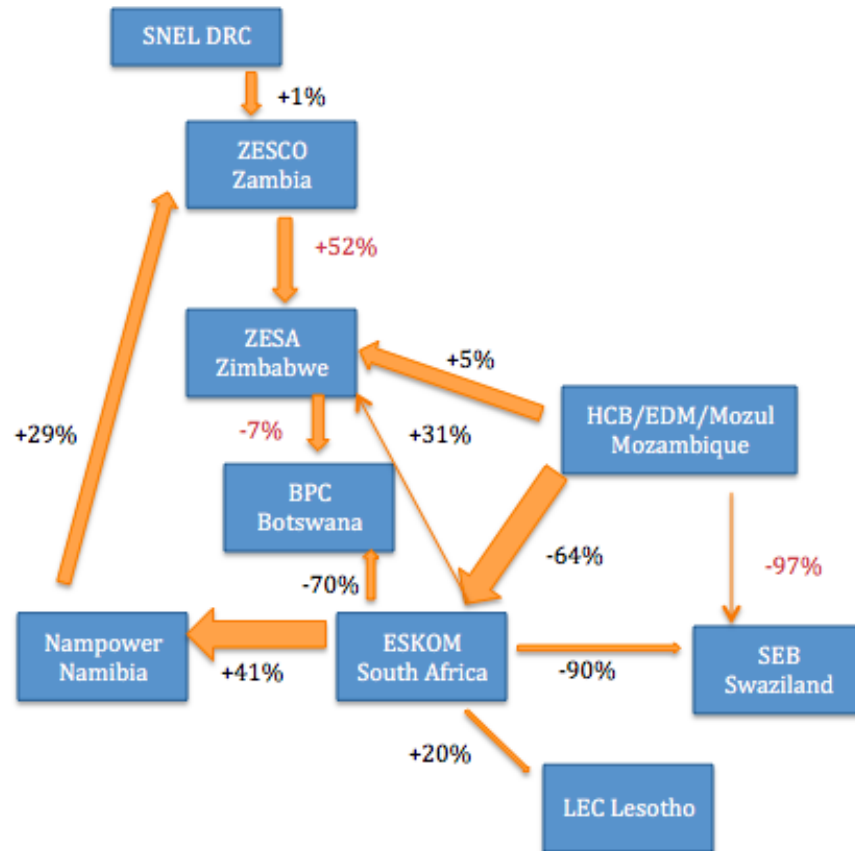


Figure C-3: Comparison of optimal trade flows under the PC scenario with the base case during scarcity (averaged over all scarcity scenarios). Physical contracts force flows to change significantly, including changing direction in three interconnections, compared to the base case.

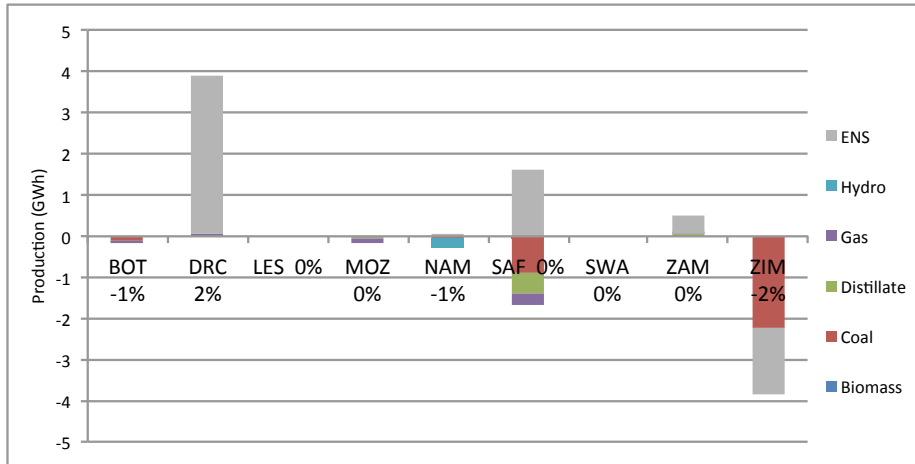


Figure C-4: Impact of physical transmission on generation output in each country compared to the base case during scarcity (averaged over all scarcity scenarios). Physical transmission rights increase ENS in DRC when there is scarcity in this country and decrease, on average, generation from South Africa and Zimbabwe.

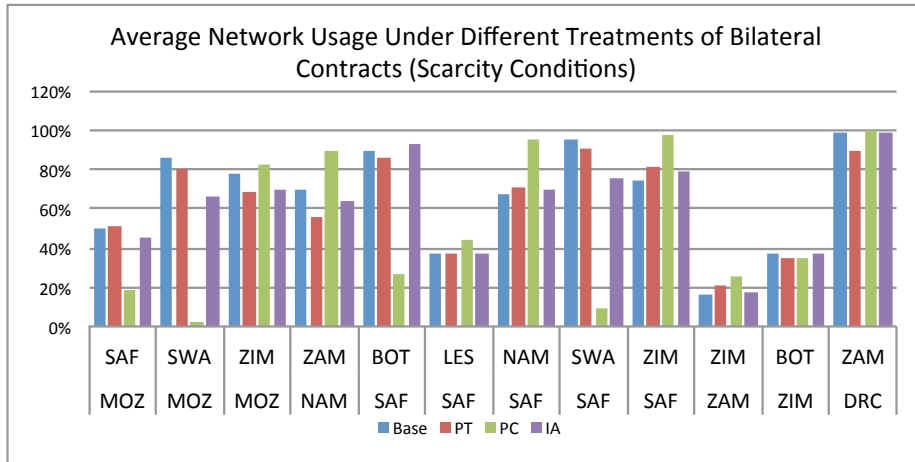


Figure C-5: Comparison of the average capacity factor (%) for each transmission interconnection under different methods of implementing bilateral contracts during scarcity (averaged over all scarcity scenarios). The PC scenario causes the largest change in the use of specific transmission lines.

# Appendix D

## Transmission Cost Allocation Model

### Results

Country	Wheeling (MW)	National Net Load (MW)	Compensations To Pay (\$ million)	Compensation To Receive (\$ million)	Domestic Network Cost (\$ million)
BOT	0	522	57	0	48
DRC	0	-260	29	0	48
LES	0	101	11	0	0.3
MOZ	0	-1158	129	0	499
NAM	392	350	38	81	115
SAF	637	-644	60	299	418
SWA	0	172	19	0	35
ZAM	371	281	33	22	189
ZIM	272	613	58	32	83

Table D.1: Average wheeling, net load, and inter-country compensation payments calculated using the Transits method applied to the existing SAPP network. Note: payments are calculated based on hourly results obtained for imports, exports, generation and consumption rather than average values.

Country	Average Hourly Injection (MW)	Average Hourly Withdrawal (MW)	Injections/Withdrawals as Fraction of Regional Injections/Withdrawals (%)
BOT	16	538	1
DRC	1424	1164	3
LES	31	132	<1
MOZ	1843	685	3
NAM	200	550	1
SAF	31739	31095	84
SWA	22	194	<1
ZAM	1435	1716	4
ZIM	839	1453	3

Table D.2: Patterns of injections and withdrawals used to calculate network costs for the existing network using the Postage Stamp method. South Africa accounts for 84% of injection and withdrawals in the region. Note: the Postage Stamp method is applied to hourly values for injections and withdrawals rather than average values.

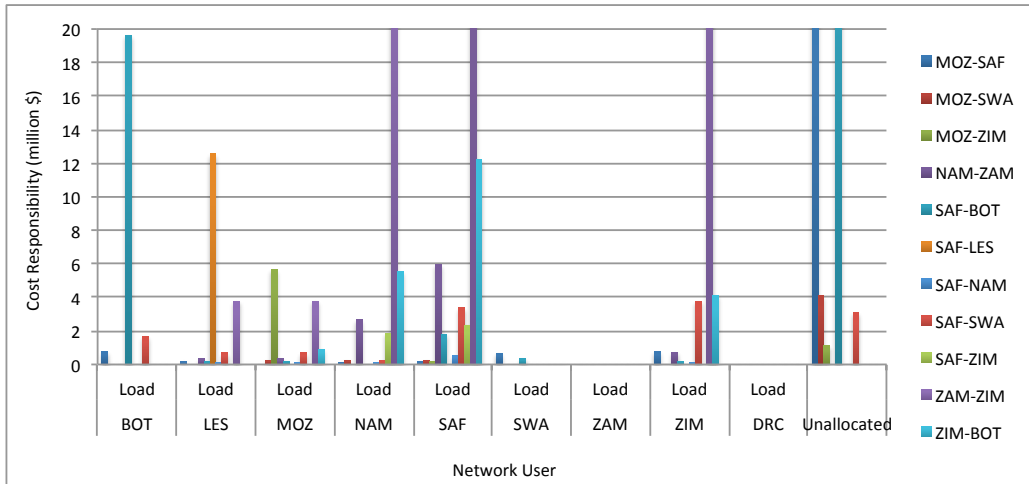


Figure D-1: Cost responsibility for each interconnection among network users with bilateral contracts using the MW-km method. MW-km only accounts 24% of regional network costs and 17% of these charges are unallocated because the lines are not used for wheeling. The remaining regional network costs must be recovered through charges to short-term market trades, national network charges, or privately negotiated contracts.



Line	Fraction of line capacity attributed to bilateral contracts (%)	Fraction of line costs recovered from MW-km (%)	Average charge obtained from MW-km (\$/MW/km)
BOT-SAF	100	53	191
BOT-ZIM	32	32	219
LES-SAF	7	100	543
MOZ-SAF	43	7	59
MOZ-SWA	3	9	127
MOZ-ZIM	50	3	285
NAM-SAF	5	<1	262
NAM-ZAM	18	24	388
SAF-SWA	12	17	103
SAF-ZIM	7	56	1786
ZAM-ZIM	9	100	132
DRC-ZAM	0	0	0
Total	29	24	105

Table D.3: Results of MW-km method used to determine average charge for short-term market trades. Across the regional network, bilateral contracts accounted for 29% of network flows and MW-km charges recovered 24% of network charges.

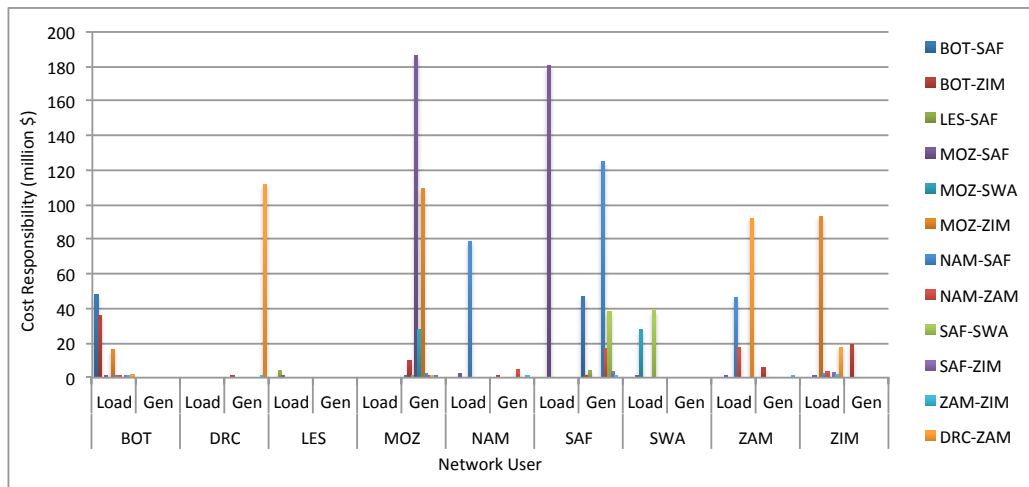


Figure D-2: Cost responsibility for each interconnection among network users using the Average Participations (AP) method. AP fully recovers the cost of the regional network and costs allocation tends to be “localized” such that users are primarily responsible for lines connected to or directly adjacent to their host country.

Country	Transits	Postage Stamp	Partial MW-km	Average Participations
BOT	105	11	36	105
DRC	77	49	35	112
LES	12	3	19	5
MOZ	628	49	60	338
NAM	71	14	48	86
SAF	180	1200	1,093	416
SWA	54	4	4	68
ZAM	199	60	47	164
ZIM	110	43	92	141

Table D.4: Results of national transmission charges (\$ million) for the existing network under different transmission cost allocation methods

Country	Wheeling (MW)	Change in wheeling with ZIZABONA (MW)	National Net Load (MW)	Change in net load with ZIZABONA (MW)
BOT	0	0	482	-40
DRC	0	0	-260	0
LES	0	0	101	0
MOZ	0	0	-1135	-23
NAM	515	123	247	-103
SAF	580	-57	4370	5014
SWA	0	0	172	0
ZAM	469	98	298	17
ZIM	507	235	485	-128

Table D.5: Impact of ZIZABONA project on wheeling and net load in each country. The largest changes in net load and wheeling take place in the four host countries and South Africa.

Country	Average Hourly Injection (MW)	Change in Injections with ZIZABONA (MW)	Change in Injections as Fraction of Regional Change (%)
BOT	55	30	7
DRC	1424	0	0
LES	31	0	0
MOZ	1843	0	0
NAM	306	106	20
SAF	31492	-247	46
SWA	22	0	0
ZAM	1411	-24	4
ZIM	959	120	22

Table D.6: Impact of ZIZABONA project on patterns of injections in each country. Most of the changes occur from reduced generation in South Africa matched by increased injections in other countries that host the ZIZABONA lines.

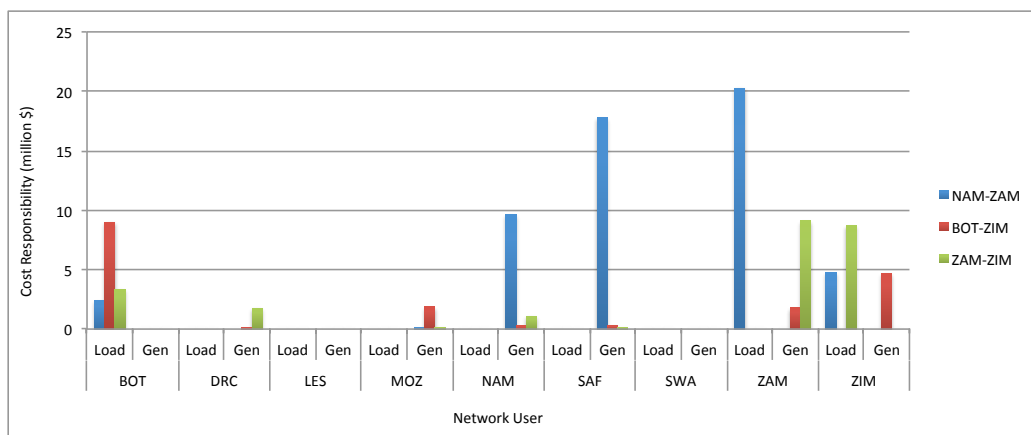


Figure D-3: Cost responsibility for each segment of the ZIZABONA project using the Average Participations (AP) method.

Country	Average nodal price without ZIZABONA (\$/MWh)	Average nodal price with ZIZABONA (\$/MWh)	Average change in nodal price (\$/MWh)
BOT	5.3	46.0	40.7
DRC	8.6	8.6	0
LES	42.6	39.8	-2.8
MOZ	43.3	40.5	-2.8
NAM	44.0	134.0	90.0
SAF	43.3	40.5	-2.8
SWA	43.3	40.5	-2.8
ZAM	147.0	134.0	-13.0
ZIM	9.9	46.0	36.1

Table D.7: Impact of ZIZABONA project on nodal prices in each country. Note: this represents average changes. The Beneficiary Pays calculation uses actual hourly differences in nodal prices.

Country	Transits	Postage Stamp	Partial MW-km	Average Participations	Beneficiary Pays
BOT	0	1	1	15	6
DRC	0	3	3	2	0
LES	0	0	0	0	0
MOZ	0	4	3	2	1
NAM	0	3	1	13	16
SAF	67	77	83	16	40
SWA	0	0	0	0	0
ZAM	29	4	4	31	9
ZIM	0	5	3	18	24

Table D.8: Results of national transmission charges (\$ million) for the ZIZABONA project under different transmission cost allocation methods

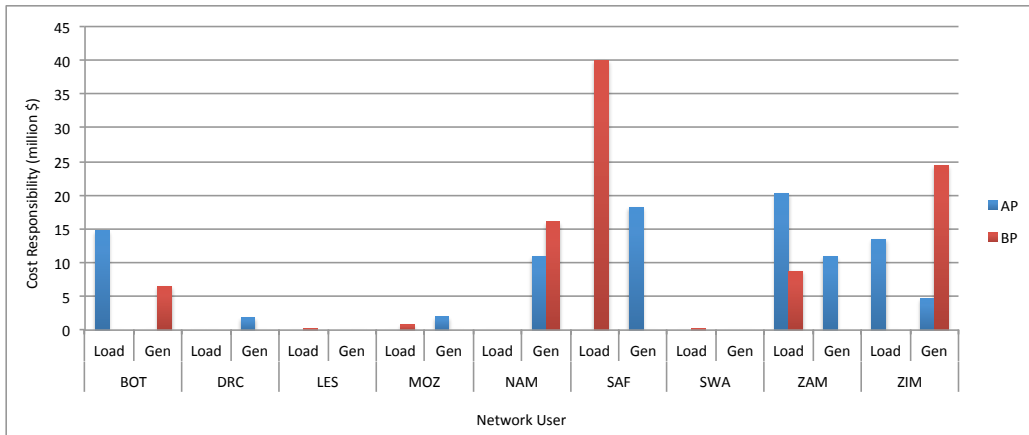


Figure D-4: Comparison of cost responsibility for the ZIZABONA project using the Average Participations (AP) and Beneficiary Pays (BP) methods. Total charges under both methods are similar at the national level but there are differences in how each method allocates charges among different user groups within each country.

Country	Wheeling (MW)	Change in wheeling with CESUL (MW)	National Net Load (MW)	Change in net load with CESUL (MW)
BOT	0	0	522	0
DRC	0	0	-265	5
LES	0	0	101	0
MOZ	0	0	-1843	-685
NAM	392	0	353	3
SAF	1253	616	39	683
SWA	0	0	172	0
ZAM	371	0	282	1
ZIM	261	-11	639	26

Table D.9: Impact of CESUL project on wheeling and net load in each country. The largest changes in net load and wheeling take place in Mozambique and South Africa.

Country	Average Hourly Injection (MW)	Change in Injections with CESUL (MW)	Change in Injections as Fraction of Regional Change (%)
BOT	16	0	0
DRC	1424	0	0
LES	31	0	0
MOZ	2551	708	50
NAM	198	-2	<1
SAF	31056	-683	48
SWA	22	0	0
ZAM	1435	0	0
ZIM	816	-23	2

Table D.10: Impact of CESUL project on patterns of injections in each country. The CESUL project allows increased generation and export from Mozambique to displace generation from neighboring South Africa.

Country	Average price without CESUL (\$/MWh)	Average price with CESUL (\$/MWh)	Average change in nodal price (\$/MWh)
BOT	5.3	5.0	-0.3
DRC	8.6	8.6	0
LES	42.6	39.8	-2.8
MOZ	43.3	40.3	-3.0
NAM	44.0	41.1	-2.9
SAF	43.3	40.3	-3.0
SWA	43.3	40.3	-3.0
ZAM	147.0	147.0	0
ZIM	9.9	9.9	0

Table D.11: Impact of CESUL project on nodal prices in each country. Note: this represents average changes. The Beneficiary Pays calculation uses actual hourly differences in nodal prices.

Country	Transits	Postage Stamp	Partial MW-km	Beneficiary Pays
BOT	3	8	4	1
DRC	2	36	34	0
LES	0	2	1	3
MOZ	961	60	37	188
NAM	39	10	6	14
SAF	0	850	887	831
SWA	0	3	1	5
ZAM	9	44	46	0
ZIM	29	31	27	0

Table D.12: Results of national transmission charges (\$ million) for the CESUL project under different transmission cost allocation methods

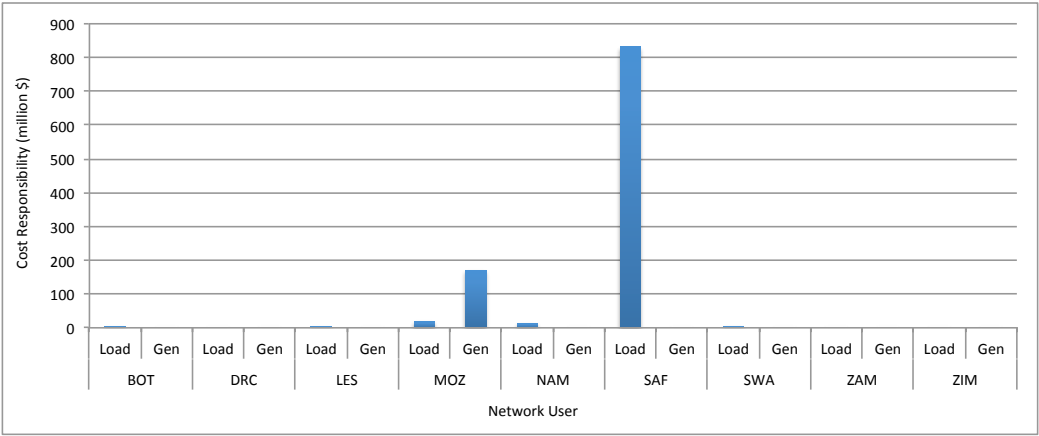


Figure D-5: Cost responsibility for the CESUL project using the Beneficiary Pays method. Consumers in South Africa are anticipated to be the primary beneficiaries through reduced electricity costs. Generators in Mozambique and, to a lesser extent, consumers in Mozambique and Namibia also benefit.

Country	Wheeling (MW)	Change in wheeling with DRC-ZAM (MW)	National Net Load (MW)	Change in net load with DRC-ZAM (MW)
BOT	0	0	522	0
DRC	0	0	-470	-210
LES	0	0	101	0
MOZ	0	0	-1135	23
NAM	335	-57	407	57
SAF	668	31	-610	34
SWA	0	0	172	0
ZAM	496	125	309	28
ZIM	274	2	706	93

Table D.13: Impact of DRC-ZAM project on wheeling and net load in each country. With the new line, generation and exports increase in DRC and are wheeled through Zambia to the rest of the region where generation in multiple countries decreases.

Country	Average Hourly Injection (MW)	Change in Injections with DRC-ZAM (MW)	Change in Injections as Fraction of Regional Change (%)
BOT	16	0	0
DRC	1629	205	50
LES	31	0	0
MOZ	1843	0	0
NAM	145	-55	13
SAF	31706	-33	8
SWA	22	0	0
ZAM	1408	-27	7
ZIM	749	-90	22

Table D.14: Impact of DRC-ZAM project on patterns of injections in each country. The DRC-ZAM line allows increased generation and export from DRC to displace generation from Namibia, South Africa, Zambia and Zimbabwe.

Country	Average nodal price without DRC-ZAM (\$/MWh)	Average nodal price with DRC-ZAM (\$/MWh)	Average change in nodal price (\$/MWh)
BOT	5.3	5.3	0
DRC	8.6	105.8	97.2
LES	42.6	42.6	0
MOZ	43.3	43.3	0
NAM	44.0	44.0	0
SAF	43.3	43.3	0
SWA	43.3	43.3	0
ZAM	147.0	106.2	-40.8
ZIM	9.9	7.6	-2.3

Table D.15: Impact of DRC-ZAM project on nodal prices in each country. Note: this represents average changes. The Beneficiary Pays calculation uses actual hourly differences in nodal prices.

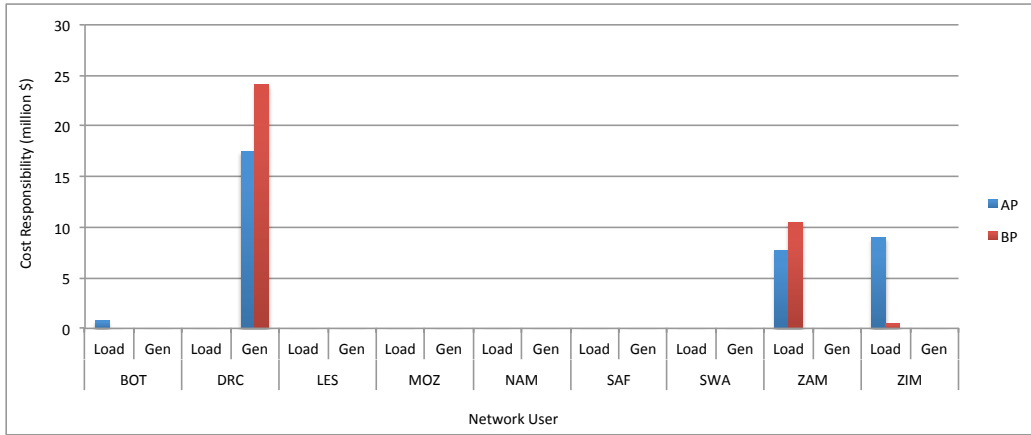


Figure D-6: Comparison of cost responsibility for the DRC-ZAM line using the Average Participations (AP) and Beneficiary Pays (BP) methods. Both methods identify the same set of project beneficiaries with small differences in the magnitude of anticipated benefits.

Country	Transits	Postage Stamp	Partial MW-km	Average Participations	Beneficiary Pays
BOT	1	0	0	1	0
DRC	18	5	1	18	24
LES	0	0	0	0	0
MOZ	1	2	1	0	0
NAM	9	0	0	0	0
SAF	0	27	30	0	0
SWA	0	0	0	0	0
ZAM	0	1	2	8	10
ZIM	6	0	1	9	0

Table D.16: Results of national transmission charges (\$ million) for the DRC-ZAM line under different transmission cost allocation methods



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