WORKING PAPER #1

Review of International Non-discriminatory Grid Access and Bilateral Trading Models to Develop Suitable Proposals for Improving the Regulatory Framework in South Africa

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IMPORTANT NOTICE

Review of International Non-discriminatory Grid Access and Bilateral Trading Models to Develop Suitable Proposals for Improving the Regulatory Framework in South Africa

The objectives are to develop proposals to improve the electricity grid access and wheeling framework and to undertake capacity building for industry stakeholders.

Working Paper #1

This Working Paper provides a summary of the current wheeling framework, key electricity market concepts, a review of the legal / regulatory framework and initial recommendations for options to improve the wheeling framework in South Africa. This is accompanied by a set of supporting background material.

Acknowledgements

CPCS would like to thank those stakeholders consulted during the preparation of this working paper. In preparing this paper, we have consulted with a wide range of sector stakeholders. We have also worked closely with members of a “Wheeling Working Group”, comprised of members from Eskom, SALGA, AMEU and NERSA as observer. However, we reiterate that the views expressed in this paper are those of the authors and not of any of the stakeholders consulted in its preparation. Further, this paper is intended to be a working / living document that contributes to the discussions in the South African sector. This project was funded by the Deutsche Gesellschaft für Internationale Zusammenarbeit (GIZ).

Opinions and limitations

Unless otherwise indicated, the opinions herein are those of the authors and do not necessarily reflect the views of the Wheeling Working Group and/or GIZ.

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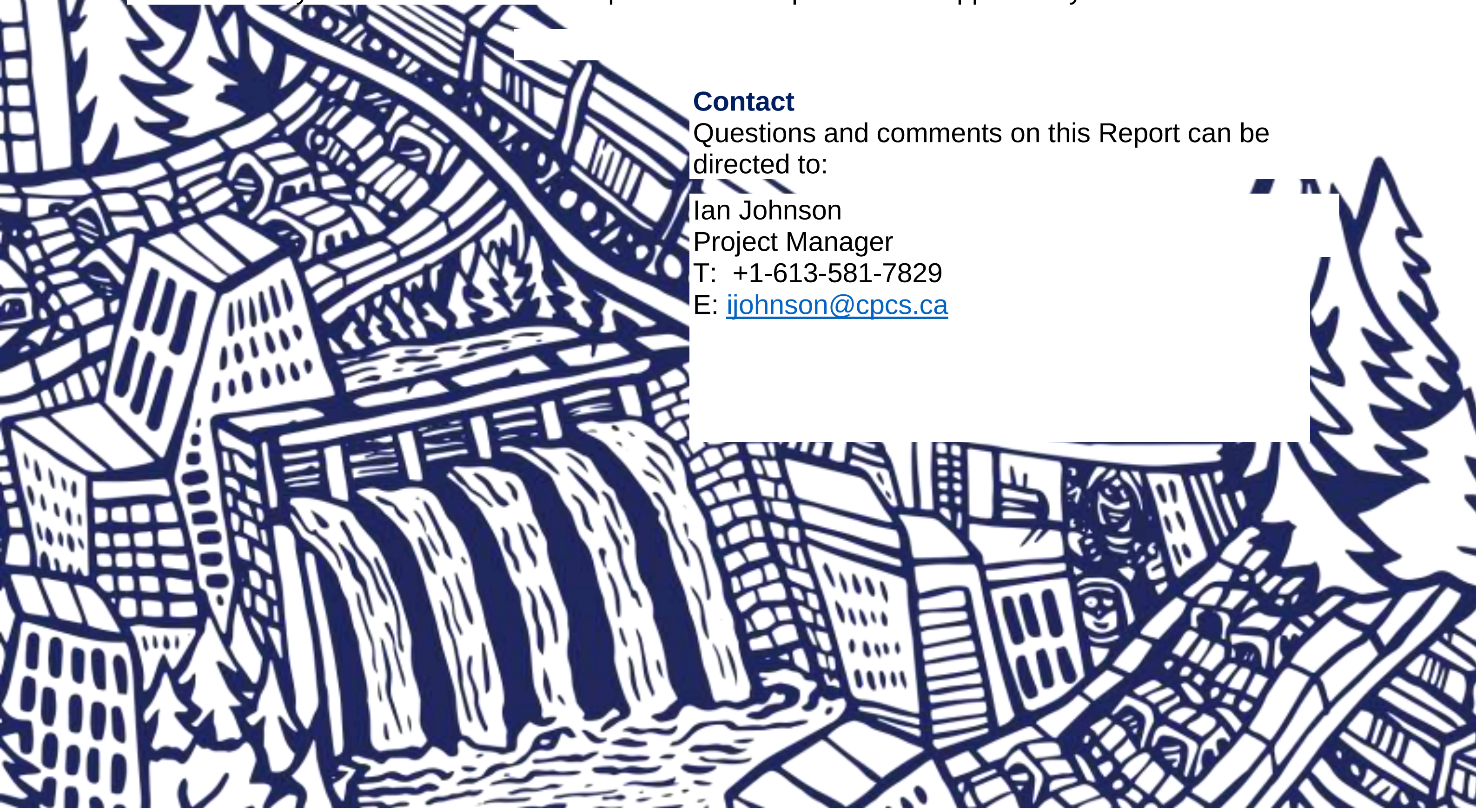

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Acronyms / abbreviations

Acronym	Description
AMEU	Association of Municipal Electricity Utilities
CACM GL	the Capacity Allocation and Management Guideline
CAISO	California Independent System Operator
CCee	The Brazilian wholesale market operator
CCGT	Combined cycle gas turbine
CDCM	Common distribution charging methodology
CfD	Contract for Difference
Client	GIZ
CNe	Chilean National Energy Commission
Consultant	CPCS Transcom Limited (CPCS) and Norton Rose Fulbright
CoCT	City of Cape Town
CPA	Central Purchasing Agency
CUOSA	Connection and use of system agreement
DCUSA	Distribution and connection use of system agreement
DISCO	Distribution and Supply Company (in the South African context these are municipalities)
DMRE	Department of Mineral Resources and Energy
DPE	Department of Public Enterprises
DSR	Demand side response
EB GL	Electricity Balancing Guideline
EDCM	Extra high voltage charging methodology
EIUG	Energy Intensive Users Group
EPP	Energy Pricing Policy
ERA	Electricity Regulation Act (2006)
EU	European Union
FeC	Firm energy certificates
FERC	Federal Energy Regulatory Commission
FTR	Financial transmission rights
GENCO	Generation Company

Acronym	Description
GIZ	Deutsche Gesellschaft für Internationale Zusammenarbeit GmbH (German Development Agency)
GVA	Giga-volt ampere
GW	Gigawatt
IMTT	Inter-Ministerial Task Team
IPP	Independent Power Producer
IRP	Integrated Resource Plan
ISO	Independent System Operator
ITSMO	Independent Transmission System and Market Operator
KPLC	Kenya Power and Lighting Company
LMP	Locational marginal price
MFPFA	Municipal Fiscal Powers and Functions Act
MO	Market Operator
MSB	Modified single buyer
MTREF	Medium - Term Revenue and Expenditure Framework
MW	Megawatt
NERA	National Energy Regulator Act
NERC	North American Electric Reliability Corporation
NERSA	National Energy Regulator of South Africa
NRF	Norton Rose Fulbright South Africa Inc.
NT	The National Treasury of South Africa
NTC	Net Transfer Capacity
ONS	Operador Nacional do Sistema Elétrico
PA	Purchasing agreement
PPA	Power Purchase Agreement
Project Working Group	Eskom, AMEU, SALGA and NERSA as observer
PX	Power Exchange
RED	Regional electricity distributor
REIPPPP	Renewable Energy Independent Power Producer Procurement Program
RFP	Request for Proposal
RMIPPP	Risk Mitigation Independent Power Producer Procurement Programme
RPM	Reliability pricing model

Acronym	Description
RTO	Regional transmission organizations
SAIPPA	South African Independent Power Producer Association
SALGA	South African Local Government Association
SAPP	South African Power Pool
SDAC	Single Day Ahead Coupling
SMP	System marginal price
SO	System Operator
TPA	Third Party Access
TSO	Transmission system operator
UK	United Kingdom
USA	United States of America
VOLL	Value of lost load
WEPS	Wholesale Electricity Pricing Scheme
WP	Working Paper

1 Introduction

This chapter provides a summary of the objectives, background and structure of this report. The structure was agreed with the Client and Project Working Group in December 2020, following the presentation of the CPCS Inception Report.

1.1 Objective of the Working Paper

This Working Paper (WP) was prepared under the authority of the contract signed between the GIZ and CPCS Transcom Limited (CPCS) in September 2020, to provide consultancy services for "Review of International Non-discriminatory Grid Access and Bilateral Trading Models to Develop Suitable Proposals for Improving the Regulatory Framework in South Africa" (Contract No. 18.2101.6-001.00).

The objectives of this WP are three-fold:

- To identify aspects of the current third party access arrangement in South Africa that limit the ability to enter into bilateral contracts between generators and customers.
- To describe key prerequisites for the development of a competitive electricity market including open access to networks, as well as to describe key electricity market concepts, various case studies and lessons for South Africa
- To propose phases of development for developing an improved initial wheeling framework but also for the development of a competitive electricity market in South Africa.

1.2 Background

The electricity sector in South Africa is in a period of great transition for a number of reasons, including the ongoing reorganization of the integrated electricity utility (Eskom) to be gradually unbundled over the next two years, and ongoing efforts to reform the sector and introduce a competitive electricity market.

At the same time, there is a need for expansion in generation capacity to prevent load shedding, and the desire to increase the penetration of renewable electricity generation. In this context, GIZ commissioned this project to develop proposals to improve the so-called wheeling framework and to undertake capacity building for industry stakeholders.

In this context, "wheeling" refers to an open access regime where some generators (IPPs) are allowed to sell directly (or via a trader or a retailer) to what we call "eligible customers" by signing a use of system agreement with the transmission and distribution system operators and paying the transmission and distribution use of system charges for transportation.[1]

Current situation of third party access in South Africa

The Electricity Regulation Act (ERA) of 2006 requires a transmission or distribution licensee to provide non-discriminatory access to the transmission and distribution power systems to third parties to the extent provided for in the licence. This is supported by the Transmission and

[1] Both CPCS and Eskom prefer not to use the word "wheeling." Normally, the buyer would be paying the seller directly for the energy. If meter readings do not match the schedule sent to the TSO, the parties would also pay an imbalance charge. In this type of arrangement municipalities buying directly from non-Eskom generators would also be liable to pay imbalance charges. This means they would need to learn how to contract 24/7 as currently they are receiving what we call "full supply" contract from Eskom.

Distribution Tariff Codes that the regulator, the National Energy Regulator of South Africa (NERSA), approved in 2019. Chapter 3 of this WP presents the current legal/regulatory framework for the electricity sector.

Given the requirements of the law, but without any unbundling, Eskom has nevertheless developed a framework to allow for some non-Eskom generators to contract directly with customers, up to a certain quantity. Under this framework, the non-Eskom generators and the customers must pay the transmission use of system charge and other charges. Under the so-called net billing system, Eskom is crediting an average production cost to their customer accounts (also discussed further in chapter 3).

In theory, customers connected to the distribution network should also be able to contract directly with generators by paying, in addition to the transmission use of system charge, an additional distribution use of system charge. However, we understand that municipalities (which own/operate a number of distribution networks) follow a range of different approaches to defining and calibrating tariffs, have limited capacity (in many cases) to negotiate third party access contracts, and charge additional surcharges that cross-subsidize other municipal revenue streams. Another issue that has recently come to the fore is the ability of municipalities (as public retailers of electricity) to contract directly with IPPs, which was the subject of a recent litigation.[2]

On the regulatory side, NERSA puts itself at the centre of third party access agreements by being the arbiter and approving authority for wholesale energy costs (i.e. the generation component), even when this price is agreed bilaterally between generators / customers (e.g. through a trader).

The current setup has led to a limited number of bilateral agreements between eligible customers and IPPs organised via traders, and changes are necessary to unlock the potential for such contracts to take place. However, the expansion of bilateral contracts increases the importance of accurately scheduling generation and forecasting load, for which there does not currently appear to be any responsibility placed on generators, municipalities or traders as they are not penalized for errors. Given the very limited number of transactions, this has no consequence on real time operations as it does not impose additional burden to the system operator (SO). However, if such bilateral contracts were going to proliferate, the SO would need to use more resources to balance the system in real time to compensate for scheduling errors.

There is also uncertainty around the future electricity market design, which, as we understand, generally seems to be leaning toward the introduction of a competitive wholesale market based on a multi-market model (including bilateral contracts, a day ahead market, and a balancing market). If this is the case, then, the requirements for introducing these markets and increasing the volume of non-Eskom generation without long-term PPAs and sovereign guarantees would be significantly different from those under the current market design based on the single buyer model.[3]

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[2] In 2017, the City of Cape Town ("CoCT") brought an application to the High Court for a declaratory that Ministerial consent is not required for a municipality to procure electricity directly from an IPP, alternatively that if such ministerial consent is so required, section 34 of ERA should be declared to be unconstitutional. The litigation was precipitated by NERSA's refusal to licence an IPP generator to establish new generating capacity to sell electricity directly to CoCT without a Ministerial Determination or consent to a deviation from IRP2010 (as it then was). Before the matter was argued, in his State of the Nation Address in February 2020, State President Ramaphosa announced that municipalities in good financial standing would be able to purchase power direct from IPPs. The case was heard in May 2020, with the Minister of Mineral Resources & Energy arguing chiefly that the CoCT application was premature inasmuch as section 41 of the Constitution and the provisions of the Intergovernmental Relations Framework Act obliged CoCT first to resolve the dispute outside of the courts. In her judgement handed down on 15 August 2020, the presiding judge agreed with this argument and referred the dispute back to the parties to endeavour extra-curial resolution, in the absence of which either party could re-enroll the matter for further hearing by the court. On 16 October 2020, in line with the State President's earlier announcement, amendments to the Electricity Regulations on New Generation Capacity were gazetted, which enable municipalities to generate or procure power from IPPs. This renders the issues between CoCT and the Minister essentially moot.

[3] In reality, it should be called a quasi-Single buyer since there are some transactions occurring between consumers and traders-IPPs as described.

These issues are explored in more detail in this WP.

The importance of considering market design and models

The wheeling of electricity in South Africa that is currently occurring happens through bilateral physical contracts between customers and IPPs (i.e. contracts for the physical production of electricity as opposed to financial contracts). By default, South Africa is therefore effectively operating an electricity market based on bilateral physical contracts negotiated between generators and load.

However, in South Africa there is currently no penalties for customers or generators that are party to these contracts if they deviate from the agreed level of production or consumption. In such a situation (along with the other difficulties discussed in this paper) there will be a limit to the amount of wheeling that can be tolerated in the system.

At the same time, we understand that Eskom is developing proposals for the introduction of new wholesale markets based on bilateral contracts in the future (including the introduction of a day ahead market, which is effectively a one-hour bilateral contract). Also, the South African government could elect to go with a different model in the future.

To inform the discussion and how this model could evolve in future and how it could facilitate wheeling, we have examined other markets where bilateral physical contracts are either not allowed or seldom used (in Section 2.2 and 2.3). This helps to highlight how wheeling is done elsewhere, what lessons can be learned for South Africa and how this could help meet the challenges faced by the sector.

Engagement with stakeholders in the South African electricity sector

CPCS would like to thank those stakeholders consulted during the preparation of this working paper. In preparing this paper, we have consulted with a wide range of sector stakeholders. We have also worked closely with members of a “Wheeling Working Group”, comprised of members from Eskom, SALGA, AMEU and NERSA as observer. However, we reiterate that the views expressed in this paper are those of the authors and not of any of the stakeholders consulted in its preparation. Further, this paper is intended to be a working / living document that contributes to the discussions in the South African sector.

1.3 Organization of the WP

The remainder of this WP is organized as follows:

- **Chapter 2:** sets out key electricity market design concepts that are useful for understanding electricity “wheeling” and the functioning of competitive markets.
- **Chapter 3:** presents the current market structure and the legal/regulatory context for electricity wheeling in South Africa.
- **Chapter 4:** describes Government policy related to sector reforms, as well as the status of ongoing reforms at Eskom.
- **Chapter 5:** summarizes key challenges to increasing wheeling and the development of a competitive market and proposes various actions in a phased approach.

2 Electricity Market Design Concepts and Models

This chapter is presenting the typical prerequisites for the development of a competitive electricity market and the various types of markets that have been developed and implemented internationally over the last 25 years.

2.1 Pre-requisites for open access

Adam Smith, the famous Scottish economist and pioneer of modern free market theory, wrote:

> "*It is not from the benevolence of the butcher, the brewer, or the baker that we expect our dinner, but from their regard to their own interest.*"[4]

The meeting of those two interests – the eating (buying) and butchering/brewing/baking (selling) – and the institutional framework to allow for those interests to thrive are the pre-conditions to a functioning competitive market.

It has been recognized in various papers[5] that unbundling of the electricity value chain is the key prerequisite for the development of competitive electricity markets, with accounting separation between the key functions of the electricity sector at a minimum as a first step. While unbundling in general is a good initial step, unbundling of the system operation function is also often mentioned as a prerequisite for the development of national competitive electricity markets, including for open access to the grid. There is a range of experience globally with unbundling, for instance.

- In Europe, there is now a requirement for legal and ownership unbundling of the transmission and system operation functions. The national markets have been organized around the concept of transmission system operators (TSO) and associated power exchanges (PX) who manage day ahead and other short-term markets.
- In the USA, it has been difficult to legally separate transmission from generation and thus the concept of independent system operator (ISO) has been created. Such a system creates the need for additional agreements and governance between the transmission owners and the ISO and is probably warranted only for larger systems. What is critical is that the system operator be truly independent of ownership and control by market participants—generators, distributors, and suppliers[6].

Eskom management has recognized the potential conflict of interests of not having an independent TSO or ISO, as noted in a keynote presentation by Eskom CEO Andre de Ruyter. In 2020 (an extract of this is shown in the figure below).

[4] Adam Smith, The Wealth of Nations.

[5] For example:

- V. Foster and al, "*Charting the Diffusion of Power Sector Reforms across the Developing World*", 2017,
- Bacon, R., "Taking stock of the impact of power utility reform in developing countries: A literature review", 2018.

[6] See Beatrice Arizu and al, Transmission System Operators – Lessons From The Frontlines, 2002

Figure 2-1: Potential bias from non-independent TSO\ISO

Transmission Grid	System Operator	Market Operator
Potential bias in: • Grid maintenance (preference for maintaining lines connecting Eskom generators) • Outage scheduling (scheduling outages that favour Eskom plant) • Network access (preference for Eskom generators / customers for new connections) • Resource allocation (expanding network in areas supporting Eskom customers or generators)	Potential bias in: • Dispatch instructions (curtailing non-Eskom plant in order to minimise cost impacts on Eskom generators) • Outage scheduling (favouring Eskom generators in determining generator outage plans) • Balancing decisions (allowing Eskom plant to reduce capacity without penalty to avoid costs)	Potential bias in: • Market access (providing smooth access for Eskom generators and retailers to the market and limiting non-Eskom customers or generators) • Information access (providing information to Eskom generators or retailers to give an advantage in the market)

Source: Eskom presentation by Mr Andre de Ruyter, October 15th, 2020

The benefit of unbundling is that autonomous entities with clear responsibilities are created, and conflicts of interests are removed. It can also result in improved network performance (as the network companies are solely interested in the efficient operation of the networks and their regulated income should be dependent on this), efficiency of regulatory activities (as unbundling should bring a greater degree of transparency), and increased competition in generation and retail markets.

The provision of open access – also referred to as third-party access (TPA) – to existing infrastructure has been at the heart of reforms and competitive markets development. TPA has become all the more imperative as a result of the broader shift toward sustainability and digitalisation in the electricity sector globally. The idea of TPA:

- Is borne out of a desire to address the existence of a vertically integrated value chain, where the grid is owned by a producer/retailer.
- Is defined by its key principle, which is to not discriminate among users of the grid (i.e. non-discrimination).
- Requires owners to grant access to parties other than their own customers on commercial terms comparable to those that would apply in a competitive market.
- Is a key instrument to bring competition in generation and retail parts of the value chain.

In any country, the decision to implement TPA tends to mark a seismic shift in the development of its power sector. ***With TPA in place, sectoral opportunities, participants and processes are substantially different from those in the pre-TPA environment***. Therefore, the introduction of a TPA framework requires careful design, detailed planning and a realistic impact assessment for each concerned party.

Open access requires several technical and contractual elements to be in place, in order to allow market participants to have access to the transmission and distribution networks.

The presence of multiple sellers and buyers in the market is also a key prerequisite of a successful open access regime. It also simply means that generation companies (GENCOs), independent suppliers/retailers and eligible consumers must have access to the transmission and distribution networks if they sign a bilateral contract, and that a GENCO should be able to either sell directly to an eligible customer or do so through an independent retailer.

In case of network congestion, there must also be transparent short- and long-term mechanisms in place to alleviate congestion so as to not discriminate against any open market transactions.

Access to the grid by GENCOs, independent retailers and eligible consumers should be guaranteed by a use of system agreement, with the transmission and distribution grid owners as a counterparty. Market players ought to be free to sign bilateral contracts on a short- or long-term basis.

The next section discusses the various types of competitive electricity markets.

2.2 Competitive electricity market models

Competitive market models have different characteristics that affect their suitability for producing competitive prices. The main types of market model to choose from are:

- Mandatory power pool (also called a gross settlement pool).
- Bilateral contract market with residual balancing (which can also be called a voluntary or net pool, or a multi-settlement market).
- Hybrid models, which combine features of the above with some characteristics of non-competitive markets.
- Mandatory self-scheduling day ahead with residual balancing.
- Modified single buyer (e.g. as in Namibia).

Each type of arrangement can be successfully implemented in different circumstances, and their applicability must be assessed for each country.

2.2.1 Centralized mandatory pool

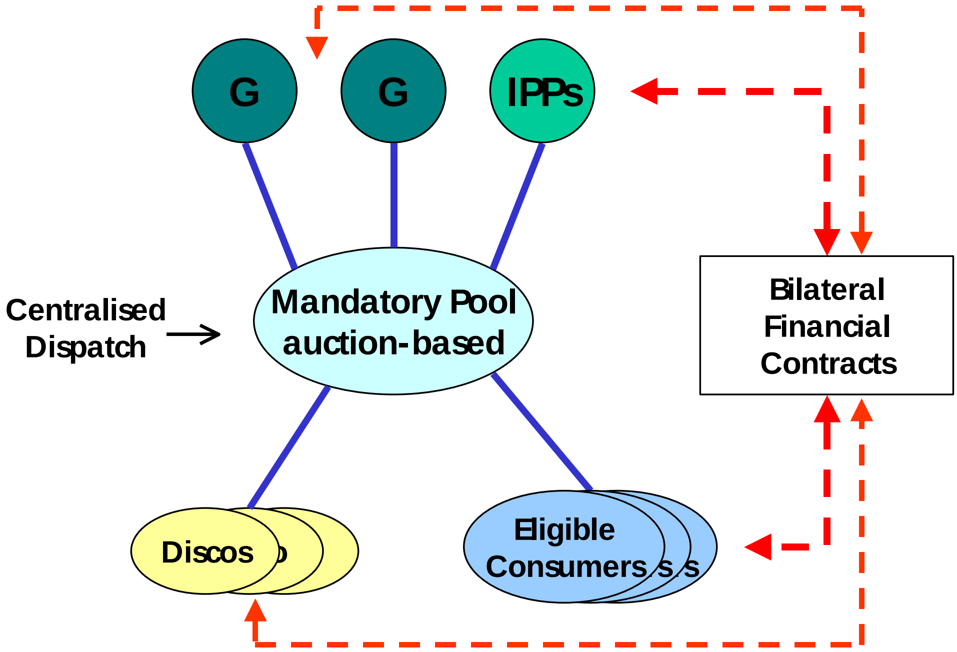
Early electricity market pool designs (e.g. in England & Wales and Latin America) were based on mandatory pools (also called gross pools) with centralised dispatch of all plants (see Figure 2-2 below). In this model, all generators are required to offer their capacity to the system operator by bidding into the pool. Centralised dispatch is carried out on the basis of the offers from generators.

In most markets today, voluntary bilateral contracts are allowed outside the pool. The principal form of contract outside the pool, where permitted, in the voluntary bilateral market is a contract for differences (CfD), which is a financial contract for hedging prices since all physical energy is traded through the pool.

Bidding into the pool is mandatory since centralised dispatch is based on bids. The features of a mandatory pool can be summarised as:

- A pool that is mandatory for all generators and all suppliers.
- Day-ahead bidding by generators into the pool.
- Pool prices determined by the price of the marginal plant that is dispatched.
- Contracts for differences (financial instruments) that allow generators and suppliers to have stable wholesale prices.

Figure 2-2: Mandatory pool



Source: CPCS

When moving from a regulated and vertically integrated structure to a mandatory pool-based structure, there are relatively few changes to the way power is generated, transmitted and distributed.

An important feature of a mandatory power pool arrangement is the fact that dispatch decisions are still made ‘centrally’. This is different from a competitive environment where the decision as to which generator to dispatch will be based on a set of market rules and competitive generator offers, not on a pre-specified merit order.[7]

The idea that generators are centrally dispatched creates a sense of ‘control’ for the SO. This gives participants a degree of comfort that system security, and reliability could be better maintained under a mandatory power pool arrangement than under a trading arrangement such as a bilateral physical contracts market with a voluntary power pool (as an example), in which generators have the capability to dispatch themselves. However, this is an over-simplification, since other market models provide virtually the same degree of control for the SO who can always use resources in real time to manage the system.

In a mandatory pool setup, generators and eligible consumers will face a risky price of electricity in the pool, which will drive them to contract with each other at a fixed price outside the pool. These contracts will usually be a financial contract for difference (i.e. where the generator is paid (or will pay) an additional amount for the difference between a pre-determined strike price and the wholesale market price). Risk-averse players will contract for close to 100% of their energy requirements through CfDs, whereas those with a risk appetite may stay partly or wholly exposed to the pool price. For players with CfDs, their contracts determine the price of electricity, although the actual dispatching of generators is determined by the bids and offers.

The key question in such a market is whether there are enough players for the pool price to be set competitively.[8] If not, it will have to be regulated (e.g. with a price cap). The UK pool was

[7] The merit order is the ranking of capacity and bid prices by generators.

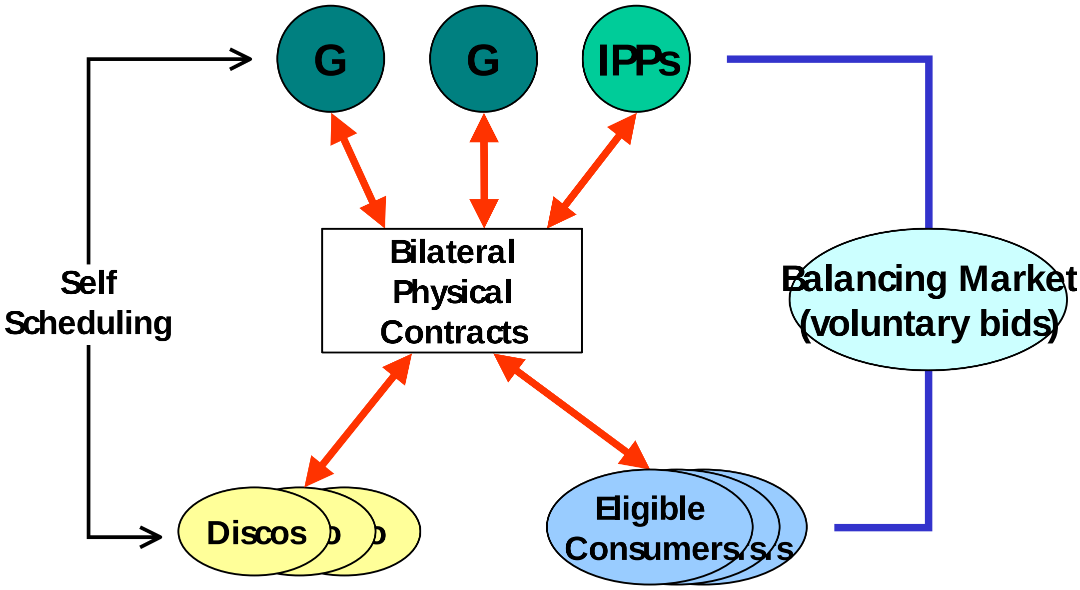
[8] For example, participants bidding into the pool should not be in a position to manipulate prices to their own advantage.

heavily price-regulated for the first six or seven years of its operation, and the regulator has continued to intervene to combat abuse of market power.

2.2.2 Bilateral contracts model (multi markets)

The second main market type is the bilateral contract model with residual balancing through a voluntary pool. This is sometimes called a net pool (as opposed to a gross pool) since only residual amounts of energy, and not all energy, is traded through the pool. Most of the more recent pool designs have used a voluntary pool (see Figure 2-3 below). All European countries are now using this model as well as India and some other Asian countries.

Figure 2-3: Bilateral market with residual balancing



Source: CPCS

Bilateral physical contracts can be freely negotiated and will be self-scheduled. The ‘pool’ is a balancing market for residual quantities of energy above or below the contracted quantities. Imbalances arise because any generator’s or consumer’s actual metered amount in any time period will never exactly match the contracted amount.

If a participant submits a bid or an offer to the balancing market, the participant’s exposure to the balancing market price is capped at its bid price. This action is voluntary. If the participant does not submit a bid or an offer, the participant’s imbalances will still need to be settled at the balancing market price (this is mandatory!).

The main trading platform is the market for direct physical contracts between parties, shown in the centre of the diagram above. These contracts can take a limitless variety of forms and offer many advantages in terms of flexible trading arrangements. The secondary trading platform is the voluntary pool that balances the market. The contracted parties schedule themselves and centralised dispatch only applies to the accepted offers for increases and decreases in the balancing market.

Advantages of the bilateral market model include:

- Flexibility of contract types to suit the participants.
- Bilateral market is the main trading platform that simplifies and reduces the cost for new participants to enter the market.

- The voluntary balancing market is less susceptible to gaming than a mandatory pool.[9]

One of the other main disadvantages is considered to be the issue of how to ensure the obligation to supply captive regulated markets. One method that has been used (e.g. in Latin America and elsewhere) is to impose an installed capacity obligation on the distribution companies and supply companies (DISCOs) equal or nearly equal to the regulated market size. This would result in non-uniform retail prices across different distribution areas unless a revenue compensation mechanism were put in place. Another way to retain uniform retail prices is for the regulated market to be supplied through a common bulk supply tariff with all energy purchased by a central purchasing agent (single buyer). This is, in fact, the hybrid model discussed next.

2.2.3 Hybrid market model

The third main type of market is a hybrid between the bilateral market and a pool. It is shown in Figure 2-4 below. This market arrangement is in fact the situation in a number of markets that have been partially opened to competition or are on a transition towards a fully competitive bilateral contract market. All European countries (except the UK and Greece who had mandatory pools) initially started with such an approach. In the initial stage of market opening, only eligible consumers could contract with independent suppliers or directly with GenCos. The Namibia's proposed approach could be called a hybrid market model (even if it is referred to as a modified single buyer).

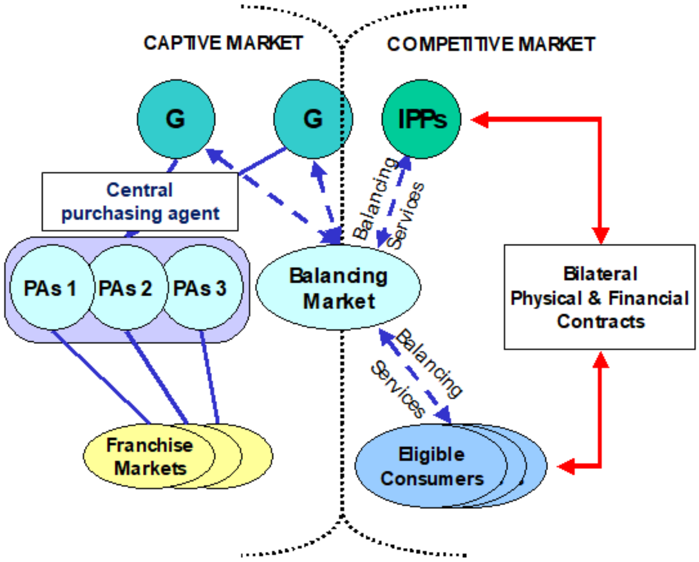
The hybrid market has the following features:

- The regulated market is supplied by generators who either sell to a centralized purchasing agent (a single buyer but only for the regulated market) or are required to bid into a mandatory pool. This part of the market is centrally dispatched.
- The competitive part of the market supplying eligible consumers is based on a bilateral market for physical contracts. The parties in this market schedule themselves and notify their contract positions to the SO.
- The competitive market needs to be balanced via a balancing mechanism or market.

As market increasingly opens and the number of eligible consumers is allowed to grow, the captive market shrinks; this market eventually evolves into a bilateral contract market as in above.

[9] There are various reasons for this including: payment is on pay-as-bid, not the system marginal price (SMP); the balance point in the market is inherently unpredictable and therefore not susceptible to strategic bidding; instead of large players dominating the balancing market the advantage lies will flexible generators. A day ahead market (which often complements bilateral trading) is also subject to potential market power if there are not enough participants.

Figure 2-4: Hybrid market model



Source: CPCS. Note: Franchise market is similar to regulated market; PA = purchasing agreements, similar to bilateral contracts.

If, at the time of partial market opening, no long-term contracts exist between the generators and suppliers providing supply to the regulated (non-competitive) market, the participants in this market segment could be fully exposed to the imbalance price (Section 2.4 explains the issue of balancing in more details) . It therefore seems necessary that a purchasing agent (single buyer) would be in place to carry out the contracting[10] for the regulated market and aim to submit balanced demand and supply positions to the SO. As a dominant and regulated purchasing entity, the purchasing agent could be restricted to trade less freely than participants in the competitive market, including taking account of policies towards security of supply and other requirements arising from public service obligations.

With such a hybrid market where the open and the captive markets are running in parallel for a number of years, it is important for the national regulator to clearly outline how it will verify that regulated customers are still paying cost-reflective tariffs. For example, the public generator as a dominant player should not be able to sell low-cost generation to eligible consumers and sell higher-cost generation to the regulated market. The initial allocation of generation between the open and regulated market as well as guiding principles for the future will be crucial.

In the case of Namibia, the problem has been partially solved by not allowing existing GENCOs to sell to the open market. However, the regulator will still need to regulate the purchases of the DISCOs (public suppliers) even if those will be able to buy 30% of their electricity requirements from new IPPs (Namibia is discussed in more detail below).

Variation of the hybrid market

Variations to the market described above are possible. Through discussions with Eskom, one of the ideas for the future South African market is for the eventual central purchasing agent (CPA) to buy from Eskom generation and resell into a day ahead market.

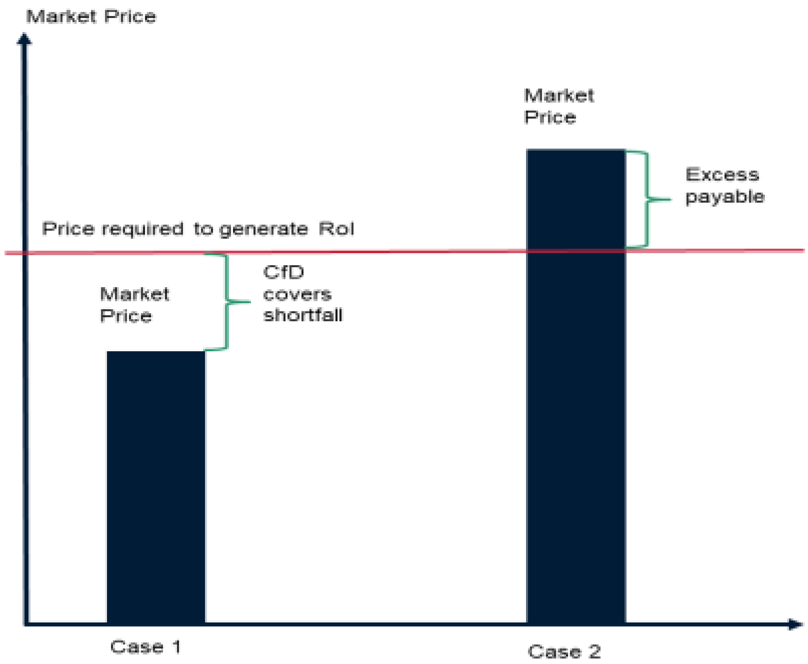
2.2.4 Mandatory self-scheduled day-ahead

Recently, a new model has emerged and is currently under development in a few countries (e.g. Albania). It is based on mandatory bidding in an organised day ahead market run by a power exchange. The difference between this setup and a mandatory pool is that participants self-schedule as opposed to centralised dispatch. In a country with a legacy of long-term power purchase agreement (PPAs), these agreements can be turned into financial contract for

[10] The purchasing agent could also likely initially take over existing long term contract obligations

differences (CfDs) with physical bidding in the day ahead market. This would mean that IPPs would be receiving the same payments under PPAs and CfDs.

Figure 2-5: How a CfD works in reference to a day ahead market price



Source: CPCS

2.3 International case studies on market design

2.3.1 Latin American electricity markets

Most Latin American markets have mandatory pools with contract for differences. Given the importance of security of supply and the development of new generation, most countries have also implemented capacity markets. The auction types for capacity markets differ for each country. We present the case of Brazil and Chile.

Brazil

The country's electricity sector has undergone considerable reforms and has advanced significantly over the past 15 years, evolving from a government-run, tariff-subsidized unsustainable business, comprised of several state-owned inefficient utilities, to a partially competitive environment with both private and government-owned companies, and a relatively independent regulatory agency.

Given the predominance of hydro generation in the country, with huge reservoirs that control multiple river systems distributed over a vast area, there has been a strong tendency towards centralized hydro-thermal coordination for the system's operations and dispatch. ONS[11] is the national independent transmission and system operator, dispatching the system according to a least cost, centralized tight pool. The wholesale energy market operator (CCee) is responsible for spot price setting, contract settlement, and more recently, conducting energy auctions.

ONS uses a multi-stage stochastic optimization model that takes into account the plants' operating characteristics and inflow uncertainties. The least-cost dispatch does not take into account any bilateral contracts or other commercial arrangements and, as a result, determines

[11] Operador Nacional do Sistema Elétrico

the dispatch of every plant in the system and also the short-run marginal cost, which is used as the clearing price in the short-term energy spot "market." In order to hedge against the high price volatility, generators sign bilateral contracts, which are purely financial instruments.

A system based on **mandatory reliability contracts** was introduced in 2004 to incentivize new generation. Its three main rules are:

- First, all loads (captive consumers from distribution companies and eligible consumers) must prove to be 100% covered by energy contracts.
- All contracts, which are financial instruments, should be covered by 'firm energy certificates' (FeC) which are fairly complex and are defined in GWh/year, and are issued by the Ministry of Energy.
- In order to promote the most efficient procurement mechanism for regulated (captive) consumers, the contract obligation scheme for distribution companies operates in tandem with auctions for long-term generation contracts. On the other hand, eligible consumers can procure their energy needs as they please (as long as they remain 100% contracted).

The captive (regulated) customers constitute 70% of the country's load and are supplied by the local distribution companies, which are responsible for procuring energy on their behalf. Eligible customers (i.e., those who may individually procure an electricity supplier) account for the remaining roughly 30% of consumption.

Separate auctions are carried out to procure new energy (greenfield generation) or to renew existing contracts (from existing power plants) in the regulated market. The reason for this separation was a matter of risk allocation between generators and distribution companies (a new plant needs long-term contracts to ensure project financing). In contrast, if long-term contracts are given to existing plants as well, the contract portfolios of the distribution companies would become inflexible and difficult to adjust to an uncertain load growth. Hence, existing plants are offered shorter contracts, typically from a few months to eight years.

The contract auction market is organized by the government as a centralized scheme, carried out jointly to satisfy the total load increase. The objective of the joint auction is to allow smaller distribution companies to benefit from economies of scale in the new energy contracting environment. However, the government does not interfere with the demand forecasts, which are directly declared by distribution companies. Each winning GENCO signs separate (private) bilateral contracts with each of the distribution companies in proportion to their forecasted loads. In other words, this is *not* a typical single buyer model: the government *does not* interfere with the contracts, nor does it provide payment guarantees. It is a fundamentally different scheme of centralized procurement.

In recent years, adjustments have been made to reflect the cost competitiveness of new wind and solar projects. DISCOs have been organizing tenders for 15-20 year PPA (30 for large hydro). The first wind-specific auction was organised in 2009. New energy auctions are now usually carried out twice per year for electricity to be delivered three and five years later (referred to as A-3 or A-5 auction, respectively). A-3 auctions are typically used for wind, solar and small hydro, while A-5 ones for largescale hydro and conventional power. The main goal remains to procure energy contracts (supported by firm energy certificates - FEC10) to back up the distribution companies' load growth. The counterparty of the contract is the distribution company, who passes all costs to regulated consumers.

In March 2019, the Ministry of Mines and Energy unveiled a program including plans for six "new energy" auctions with the Ministry scheduling two per year: the A-4 and A-6 procurement rounds (so named because of the number of years developers have to connect facilities to the grid after signing power supply contracts). Auctions are currently postponed due to the COVID situation. The last A-6 auction was held in October 2019. The Brazilian government allocated 2,979 MW of generation capacity of which 530 MW was solar. The final average solar electricity price was

BRL84.39/MWh ($16.1028 at today's exchange rate) and was the lowest among the competing technologies.

Chile

Chile became the first country in the world to deregulate its power sector in the early 1980's. In the mid 2000's when new generation was needed, the government sought solutions by exploring long-term contracts at a price to be determined by a free bidding process in order to ensure profitable cash flows for investors, thereby stimulating the entrance of new generation. The mandatory bidding pool is complemented by a capacity obligations system.

The Chilean auctions focus on ensuring the security of supply for the regulated market. Free consumers are expected to procure their own supply requirements independently and select their preferred procurement mechanism, which includes energy auctions.

- Distributors must be 100% contracted all the time, at least for the next three years.
- Distributors must contract their needs through auctions, which must be public, open, transparent, and without discrimination.
- Each distributor auctions its consumption requirements according to its own criteria (i.e. auction design is freely decided by each distributor).
- A coordinated group of distributors is permitted to organize a process in order to simultaneously auction their net demand.
- Distributors can auction contracts for up to 15 years at a fixed price (indexed to changes in the main variables).

To ensure system adequacy, generators must give a yearly justification to the National Energy Commission (CNe) of their firm energy necessary to supply all the regulated contracted demand. Generators can use a combination of existing and new plants to justify their capacities. Thus, the general auction process is not divided between existing and new generation auctions, as is the case in Brazilian auctions.

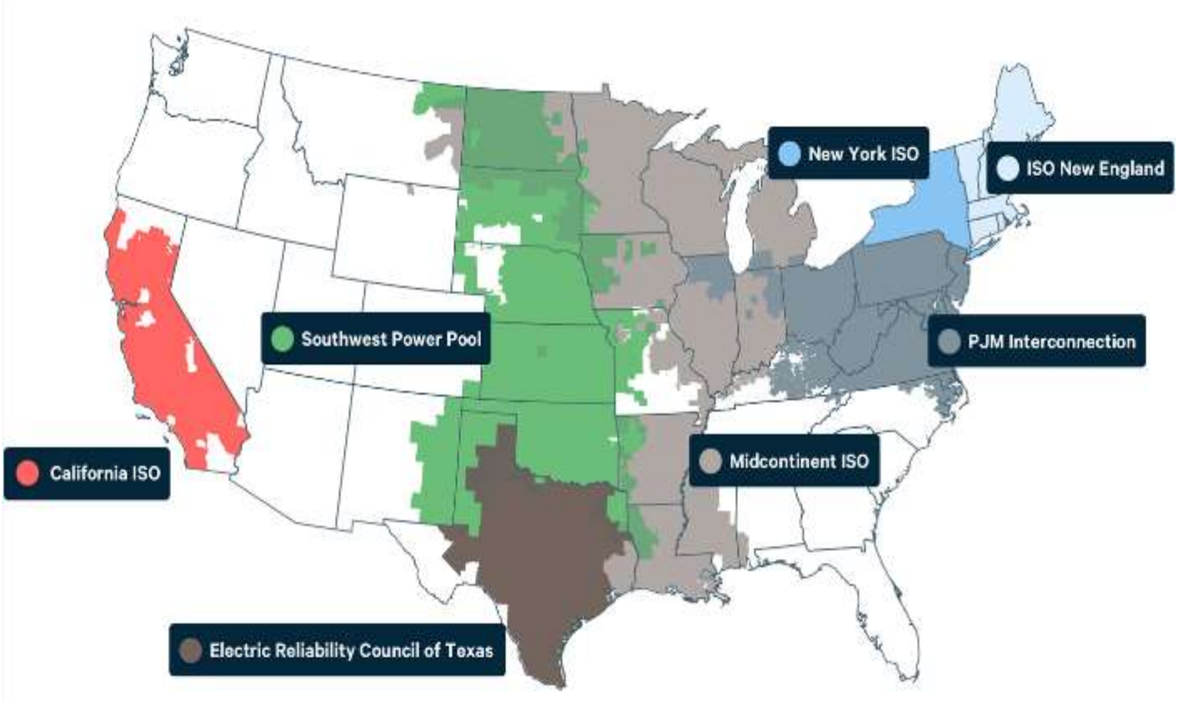
Lessons for South Africa

While Eskom has been working on a self-scheduled European type of market design, South African decision-makers could assess the Latin American experience in bringing new capacity on line via various tendering schemes and obligations on DISCOs (i.e. municipalities) to contract. Given the financial situation of South African municipalities, a capacity payment system for new IPPs would be easier to implement in the short to medium terms than capacity obligations. Capacity markets are more frequently used in Europe as discussed below. However, in any type of market design, for them to be able to procure directly, DISCOs would need to be bankable anyway.

2.3.2 USA regional markets

The most competitive electricity markets in the USA are PJM, New York ISO, New England ISO and California. Following deregulation, regional transmission organizations (RTOs) replaced utilities as grid operators and became the operators of wholesale markets for electricity. These RTOs have evolved over time.

Figure 2-6: Regional transmission organizations in the USA



Source: FERC

Since many RTOs operate wholesale markets that encompass multiple states, they are regulated by the Federal Energy Regulatory Commission (FERC)[12]. FERC has oversight of all wholesale power transactions on the two large interconnected grids: the eastern and western interconnects. Deregulated retail utilities purchase electricity at market-determined wholesale prices and then sell that electricity to customers at market-determined retail prices, given competition from other retailers. RTOs typically run three kinds of markets that determine wholesale prices for these services: energy markets, capacity markets, and ancillary services markets.

Energy markets: day ahead and real time

RTOs typically run two energy markets: the day-ahead and real-time markets. The day-ahead market, which represents about 95% of energy transactions, is based on forecasted load for the next day and typically occurs the prior morning in order to allow generators to prepare for operation. The remaining energy market transactions take place in the real-time market, which is typically run once every hour and once every five minutes to account for real-time load changes that must be balanced at all times with supply

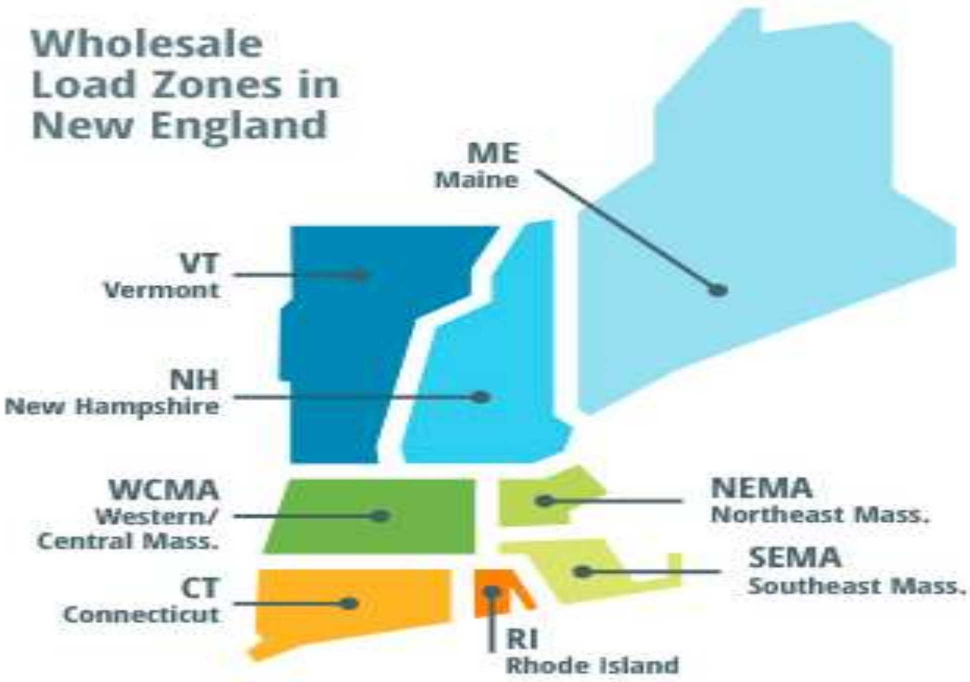
Base wholesale market prices typically reflect the price for power when it is able to flow freely without transmission constraints across the RTO's territory. When that is not possible, RTOs account for congestion on transmission lines by allowing prices to differ in different locations.

For instance, PJM and ISO New England are using nodal pricing to relieve congestion. This leads to clearing prices at various nodes, so PJM also offers financial transmission rights (FTRs). FTRs allow market participants to offset potential losses (hedge) related to the price risk of delivering energy to the grid. FTRs are a financial contract entitling the FTR holder to a stream of revenues (or charges) based on the day-ahead hourly congestion price difference across an energy path.

[12] With the exception of ERCOT, the Texas RTO.

For example, in the ISO New England, pricing in the wholesale electricity marketplace is calculated at individual generating units, about 900 load nodes (specific points on the transmission system), eight load zones (aggregations of load nodes), and the Hub (a collection of locations in central New England where little congestion is evident). The following figure depicts the eight load zones.

Figure 2-7: ISO New England load zones



Source: ISO New England

In summary:

These markets are based on a **centralized dispatch** (security constrained bid-based dispatch using state estimator network model) and comprise:

- Day-ahead hourly markets resulting in locational marginal prices (LMPs) calculated at each bus (node)[13].
- Intra-day adjustment and balancing markets (adjustments, imbalances, 5-minutes)
- Self-scheduling and bilateral contracts are permitted subject to imbalance and congestion charges.
- There are also balancing (real time) markets, and various ancillary services being procured via tenders.
- Given the need for flexibility with deployment of renewables, some ISOs have a "Forward Reserve Market (FRM)"[14] designed to:
  - Acquire commitments from resources ahead of time to provide reserve capacity in real time.
  - Attract investments in resources that provide the least-cost solution for satisfying off-line reserve requirements—typically, fast-start units that run infrequently throughout the year.

[13] Locational marginal pricing (nodal pricing) is discussed in Section 2.4.

[14] This is now being also discussed in Europe – see next section but with a different potential mechanism.

- Competitive FRM auctions are organized twice a year.

Capacity markets

Some USA RTOs run also capacity auctions to provide retailers with a way to procure their capacity requirements while also enabling generators to recover fixed costs, i.e. those costs that do not vary with electricity production, which may not be covered in the energy markets alone.

The capacity market auction works as follows: generators set their bid price at an amount equal to the cost of keeping their plant available to operate if needed. These bids are arranged from the lowest to the highest. Once the bids reach the required quantity that all the retailers collectively must acquire in order to adequately meet expected peak demand plus a reserve margin, the market “clears” (supply meets demand). At this point, generators that “cleared” the market, or were chosen to provide capacity, all receive the same clearing price, which is determined by the bid price of the last generator used to meet demand.

PJM’s capacity market is called a **Reliability Pricing Model (RPM)**. While the Energy Market addresses near-term need, the capacity market prepares for the future. PJM’s capacity market was implemented to secure enough power supplies three years down the road to ensure sufficient supply will be available to meet peak demand. Each year, PJM holds a competitive auction to obtain these future power supplies at the lowest reasonable price. ISO New England and New York ISO have similar schemes.

Variations across States

The structure of wholesale markets varies across regions as well. For example, ERCOT, the RTO of Texas, does not run ***a capacity market*** and instead relies on price signals in the energy market alone to ensure reliability. The California Independent System Operator (CAISO) similarly does not run a capacity market and relies on retailers to ensure resource adequacy to meet the North American Electric Reliability Corporation (NERC) reliability requirements.

Some states have deregulated their wholesale markets but not retail markets. California, for example, is partially deregulated and formed its own RTO, CAISO, which operates the grid and wholesale markets. However, the state does not offer individual customer retail electricity choice, although communities can opt out of the local utility through community choice aggregation under which a company hired by the community buys power in wholesale markets for all residents who do not opt out of this arrangement.

Lessons for South Africa

The USA markets are very complex and do not provide many lessons for South Africa, except for the various examples of capacity markets and forward reserve markets. The use of nodal pricing makes also the markets more complex. During discussion with Eskom, it was said that initially, transmission congestions would be relieved by re-dispatching and not via nodal or zonal pricing.

2.3.3 European common market

All European Union (EU) Member States and some countries in Southeast and Eastern Europe who are not members of the EU, must adhere to various EU regulations on market opening.

Ownership unbundling is now required, and every consumer must choose a supplier (retailer). There are specific guidelines for determining use of system charges and who pays what. While there were mandatory pools 20 years ago (e.g. UK, Greece), all markets now are based on day ahead and other bilateral contracting with balancing markets. National markets must also coordinate with their neighbours with what we call market coupling or implicit auctions[15]. Contrary to US markets, there are no systems that rely on nodal pricing to relieve network congestion.

There is no obligation for market participants to buy and sell their energy on the various European day-ahead markets. However, importantly, although volumes traded in the wholesale markets are, in some cases, only a fraction of the final volume of generated electricity, the wholesale prices serve as the price reference in long-term contracts.

There is currently one pan-European auction at noon for the 24 hours of the next day. All accepted bids are paid the marginal offer. Trading is organized by one or several power exchanges per Member State. A Single Day Ahead Coupling (SDAC), allowing for efficient trade between all European bidding zones in the day-ahead timeframe, has started operating in 2020.

After the day-ahead market is cleared, the intraday market opens. Currently, trading in the intraday market is done via continuous trading (as on a stock exchange) in some countries and via auctions in other countries. Recently, it has been decided that the future intraday European model will consist of a combination of continuous trading with three European-wide auctions at pre-defined times. The governance of power exchanges operating the day-ahead and intraday market, market coupling and cross-zonal intraday market design are described in the Capacity Allocation and Management Guideline (CACM GL).

After trading in the intraday market closes, the balancing mechanism is in place to ensure that supply equals demand in real-time. Each TSO is responsible for the real-time balancing in its control area. The balancing market design at the European level is prescribed in the Electricity Balancing Guideline (EB GL), one of the eight currently existing European electricity network codes and guidelines.

European capacity markets

European market are mostly now all self-scheduled bilateral contract market models. Most used to rely primarily on energy payments only but various capacity schemes have been implemented in recent years. Every capacity scheme is unique, combining different obligations and incentives. A recent paper by Timera Energy has summarized the various European Schemes[16].

United Kingdom (UK)

The UK is the most mature of Europe's recent wave of capacity markets having started in 2014. The UK capacity market supports new build plant via capacity contracts up to 15 years in length, with 1-year contracts for existing capacity. Prices around 20 £/kW (24 €/kW) in the first three T-4 auctions supported significant volumes of new build. The last two auctions have cleared at much lower prices (6-8 £/kW) as an overhang of older existing plants is removed. Looking forward, Timera Energy thinks the outlook for UK capacity prices is more constructive as 4GW of nuclear and 8GW of coal capacity are closing by 2024, as well as older combined cycle gas turbines (CCGTs). This underpins a steady requirement for new capacity.

France

The French capacity mechanism followed the design of UK mechanism. Prices have generally been in the 15-20 €/kW region but a recent €0/kW auction for 2019 undermined confidence in the mechanism. The French regulator has indicated it is considering a review of the mechanism. New build plants can tender for contracts for up to seven years, which is shorter than other markets and weakens the case for new build capacity. This partly reflects the fact that France has limited near term new build requirements.

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[15] These concepts are explained in Section 2.4.3

[16] Timera Energy, a Tour of European capacity markets, February 2020.

Ireland

The Irish mechanism was based on the UK model but with two key changes. Firstly, spot price is capped at a pre-defined strike price. Secondly, new build contracts are limited to 10-years. Recent auction prices have been supportive of new build, reaching 46 €/kW. Ireland is closing coal, peat and older gas-fired capacity. However, it is a relatively small market and has some strong locational considerations driving capacity requirements.

Poland

The Polish scheme is based on the UK and has a similar design. However, prices have been significantly higher than in the UK. The first four auctions resulted in a 45-60 €/kW price range, reflecting the need for significant new build. In Poland, 90% of the existing flex fleet is lignite/coal and will be ineligible for capacity support under EU law from 2025.

Italy

Similar to the Irish scheme in design, the Italian mechanism combines a spot price cap with conventional capacity payments. However, unlike the Irish mechanism, new build plant is eligible for up to 15 years of support. All coal plants are excluded from the scheme. Timera Energy noted that the large capacity overhang in Italy is gradually being eroded, particularly in localized regions where coal plant retirement combines with ageing CCGT. The first auction saw prices of 33 €/kW for existing capacity and 75 €/kW for new build (both hitting their respective price caps). This has sparked renewed investor interest in Italy.

Belgium

The proposed Belgian scheme is similar to the Italian scheme and is designed to replace the existing strategic reserve to provide new build price signals. It has taken a long time to develop with several reincarnations. Belgium's outlook is one of the most supportive in Europe for new build, with the whole nuclear fleet scheduled to retire between 2022-2025, removing what is currently 50% of Belgium generation output.

Spain

In Spain, capacity payments used to be made from a central fund for available capacity. Spanish CCGTs have historically received two forms of capacity payment:

(i) an availability payment (~5 €/kW) which was suspended in 2018 as a result of EU state aid review; and

(ii) an investment subsidy (~10 €/kW), with 70% of CCGTs set to lose this from 2020.

The way forward for capacity payments has not yet been resolved by the new Spanish government.

Summary

In summary, capacity payments have become more and more a solution for underpinning system reliability as power markets decarbonize. Each scheme is unique and has its own strengths and weaknesses, but a growing structural requirement for new capacity across the next five years is set to support capacity prices across Europe. Coal and nuclear closures cannot be offset by intermittent renewable generation alone, which underpins the need for investment in new flexible capacity across storage, gas, demand response / management, interconnectors, flexible renewables and hydrogen. Capacity payments will play a key role in delivering that investment.

However, the European Commission is not generally in favour of capacity payments and has said that it is of paramount importance that capacity mechanisms are only introduced if it is necessary, and should be designed to minimize impact on market functioning. Significantly, they also need to ensure that the mechanism is proportionate to the underlying adequacy problem so that the available and expected energy capacity is sufficient to meet demands at all times[17].

Lessons for South Africa

European markets offer flexibility to market participants to trade in various ways: bilateral, via a day ahead, intraday and real time (balancing). The Southern African Power Pool (SAPP) markets are very similar, and thus Eskom is already quite familiar with this market model. A major difference, however, is the fact that South Africa needs even more new capacity than Europe does (though South Africa has not aggressively pursued a transition away from coal as many European countries have).

The emerging European capacity markets can provide lessons for South Africa to both develop a competitive market and bring new generation capacity online to replace coal. The increased renewable penetration in Europe is also forcing changes to market rules and grid codes, especially for reserves and balancing. The fact that so many countries are interconnected facilitates this integration. Through SAPP, the South African TSO will need to work more closely with the neighbouring ones to allow for more reserve sharing and balancing resources to allow for more renewables.

2.3.4 Namibia

The Namibian Modified Single Buyer (MSB) Model is a new market reform for the electricity sector in Namibia. It builds incrementally on the existing Single Buyer Model, i.e. it represents a modification (evolution) of their existing market structure. The MSB draws on global best practice, but it has been designed for Namibia, with the support and involvement of all stakeholders in the Namibian electricity industry.

The model is described in a Detailed Market Design document. The outlined principles for the MSB are fairness, efficiency, simplicity, ease of implementation, and low cost of market operator. Following the principles, the main features of MSB are:

- Partial opening of the electricity market in Namibia by allowing IPPs (named as Eligible Sellers) to sell electricity to eligible customers (Contestable Customers) via bilateral transactions.
- Opening of the market in a stepwise approach outlined in the Market Code to promote competition and choice in a phased and structured way to manage exposure to potential market risks.
- Self-dispatching by eligible generators.
- Unbundling of existing tariffs and development of new products and services to facilitate bilateral transactions and wheeling of energy.
- Allows licensed traders to facilitate transactions between Eligible Sellers and Contestable Customers.
- Allows GENCOs and traders licensees holders to export but no import for the time being.
- Allows NamPower (still operating as a national utility) to build new generation and transmission facilities.
- Allows NamPower to procure power from IPPs but also allows IPPs (if eligible) to sell their power to a Contestable Consumer.
- Positions NamPower to act as the supplier of last resort.

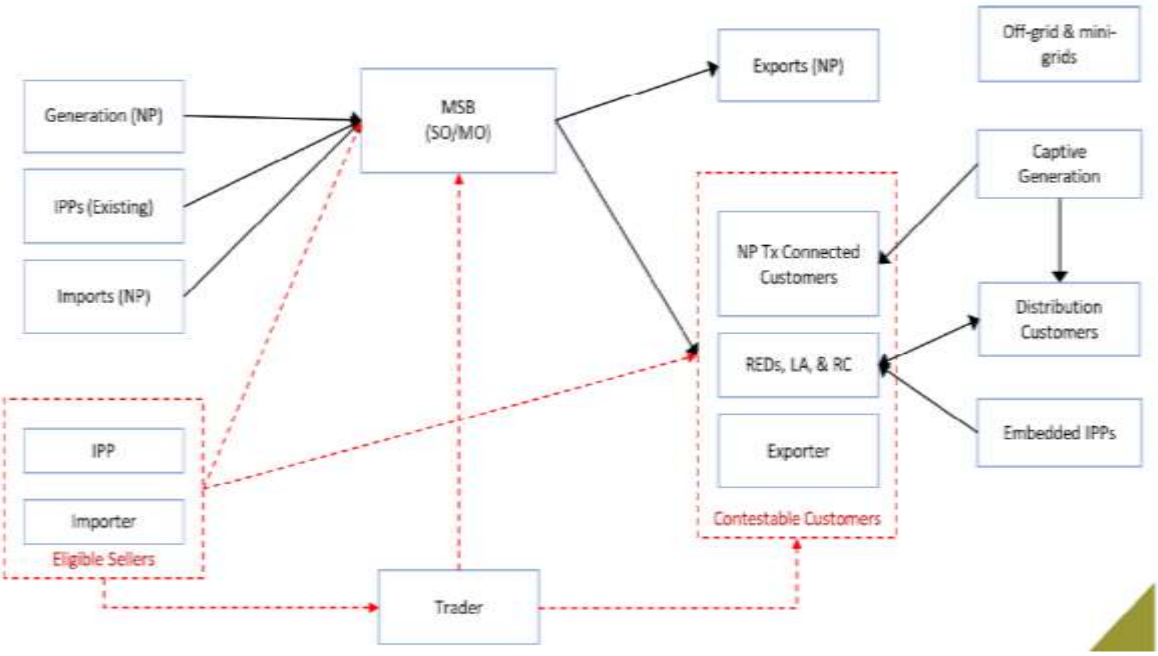
[17] European Commission, https://ec.europa.eu/energy/topics/markets-and-consumers/capacity-mechanisms_en

There is no legal unbundling or privatization of existing utilities. However, MSB will be a ring-fenced entity within NamPower with separate financial statements. MSB will hold licenses for: Market Operation, Imports and Export. MSB will also carry out the following key functions: Market Operations, Planning & Procurement, SAPP Trading and System Operations support.

There is a **limit of 30% of total consumption for discos and eligible consumers** that can be sourced from new IPPs. Regional Electricity Distributors (REDs) will also be able to source 30% of their sales from IPPs. Phase 2 will allow imports (other than via the NamPower MSB) only once Namibia has reached ~80% self-sufficiency of supply.

NamPower will continue to own and operate various generation plants, the transmission system and parts of the distribution system. It will also manage the market and systems operations of the MSB market, subject to the respective licenses. Critically, NamPower will continue to act as the Supplier of Last Resort in the system – a service for which it will be compensated.

Figure 2-8: MSB Phase 1a & 1b trading arrangements



Source: New Energy Consulting, ELECTRICITY SUPPLY INDUSTRY DETAILED MARKET FRAMEWORK, May 2019
Note: RED: regional electricity distributors; LA: local authority; RC: regional council

One of the peculiarities of the Namibian option is the functions MSB will be carried out as described above. An embedded systems operations function will be seconded into MSB to streamline decision-making and facilitate information exchange. It is not clear for us how exactly it will work with the NamPower system operator.

Functioning of the market and tariffs in the Namibia model

Eligible sellers will have to nominate both their export sales and their sales to eligible customers. Their imbalances will be penalized according to two different methodologies.

- For exports, the imbalance prices will be determined using the future SAPP balancing market methodology (NamPower will be liable for all interconnectors' imbalances).
- For sales to eligible consumers, the imbalance prices will be determined with reference to NamPower's approved energy charge to large customers in case the IPP under produces. If the IPP over produces, it will not be compensated.

The default MSB position for Contestable Customer Unsold Energy (i.e. where customers consume less than they nominated on their submitted schedule) is that it will not be compensated. Nevertheless, MSB will have an option, but not an obligation, to purchase Unsold Energy from the Contestable Customer at a predetermined rate (e.g. a rate linked to the Day Ahead Market). If MSB decides to purchase Unsold Energy and to prevent discrimination, the offer to purchase must be available to all Contestable Customers that find themselves in an Unsold Energy situation.

In addition to the development of specific transmission and distribution charges, the IPPs and or the eligible customers will be paying for series of services:

- Balancing (as discussed above)
- Connection
- Losses
- Wheeling service (use of system charge)
- Network capacity reserve charge (if the Generator is seeking a firm wheeling path with "deemed energy" payments)
- Reliability
- Customer service
- Point of supply service
- Levies and VAT

Without going into details, it can be said that some of these charges are not usually present in a typical competitive electricity market. Grid congestion is normally handled quite differently. For example, the capacity reserve charge should be used to give priority access in case of congestion, not to receive deemed energy payments. Above a certain outage threshold, all grid users should receive deemed energy payments. Some of the other charges apply only to certain participants, which is reasonable.

2.4 Key concepts in electricity markets

2.4.1 Scheduling, dispatching and balancing

In the previous section, we reviewed markets that are centralized and some that are decentralized. Self-schedule is a concept of decentralized markets where GENCOs (and potentially load) must provide a schedule to the SO for the next day, (e.g. hour-by-hour). This is compared to a centralized market where software optimizes the dispatch of the system (sometimes because of the utilization of nodal pricing) based on price offers.

The following figure presents the Namibia scheduling notification process by GENCOs as defined in the market rules (see below).

Figure 2-9: Proposed GENCO schedule notification in Namibia

Addendum 9: Example of Generator/Importer Schedule Notification

Revision: 1.0

Name of Eligible Seller: [As printed on license from Regulator]
Identification No of ES: ____________________
License Type: [Generator, Trader or Importer]
Delivery Date: [dd-mm-yyyy]
Published Date [dd-mm-yyyy hh:mm]

Hour	Total Schedule (MW)	Contestable Customer(s) Allocation			
		CC1 ID no. ______	CC2 ID no. ______	CC3 ID no. ______	
		% of Total	% of Total	% of Total	% of Total
00-01					0.0%
01-02					0.0%
02-03					0.0%
03-04					0.0%
04-05					0.0%
05-06					0.0%
06-07					0.0%
07-08					0.0%
08-09					0.0%
09-10					0.0%

Source: Namibia Market Rules

Generators need to prepare a schedule hour-by-hour. A key particularity of the Namibia process is the allocation of the schedule to various customers: exports or national eligible customers. This is due to the two imbalance pricing methodologies noted in the previous section.

Balancing – why it is important to get the price right

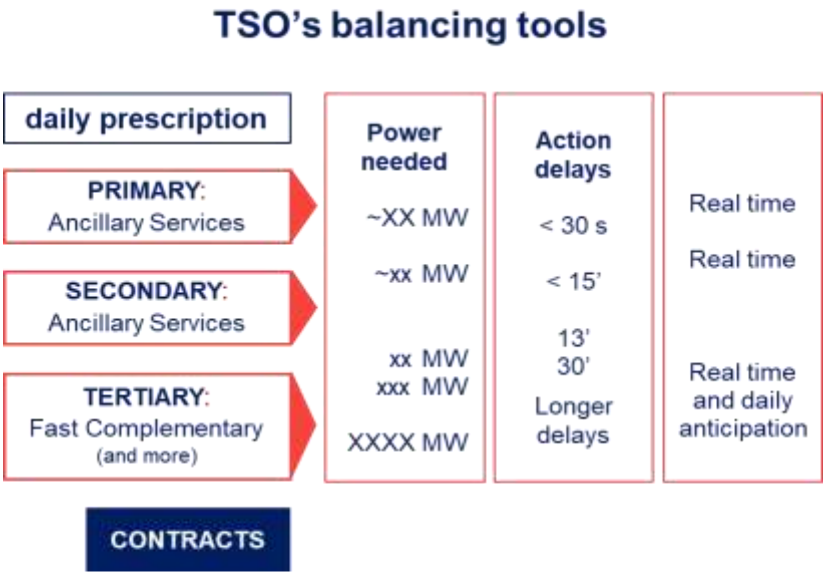
Balancing energy consists of both energy activated in real time under ancillary services (reserves) contracts and energy provided directly to a balancing market[18].

Under a balancing market, the SO activates (in real time) some bids and offers that GENCOs and/or loads proposed the day before. For each hour, the SO might activate more offers to increase output by GENCOs (or to decrease by load), meaning the system is short of energy for that hour. On the other hand, the SO might activate more offers to reduce output by GENCOs (or ask load to increase), meaning in that the system has too much energy for that hour.

Imbalances created by participants in bilateral trading are calculated after real time balancing by the SO occurs (this is the right side of the Figure 2-10 below). Imbalances are the extent to which physical energy has deviated from contracted energy.

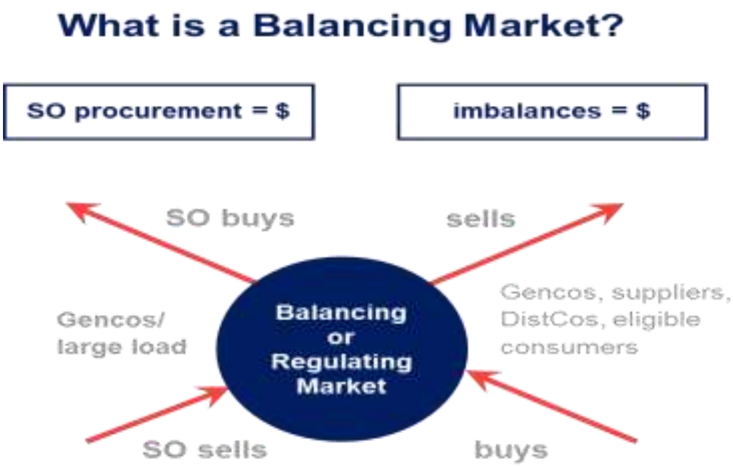
[18] A TSO can sign various type of ancillary services contracts (both in MW and MWh) in addition to using a balancing market bids and offers to balance the system in real time

Figure 2-10: Real-time balancing tools used by the SO



The contracts specify how much energy has been sold[19], which is compared with metered energy generated. If too much has been generated relative to contracts, the generator is said to have 'spilled' energy. If too little has been generated, then the generator will have a shortfall that is 'topped-up' through real-time balancing. For retailers, essentially the same process applies. Contracts are compared with metered offtake[20], and if retailers have over-contracted then they 'spill' the imbalance, otherwise they are in a shortfall position.

Figure 2-11: Representation of a balancing market



Source: CPCS

Spilled (over-contracted) energy accounts are 'cashed out' at the 'spill price' whereas shortfall accounts are cashed out at the 'top-up price'. In a two-price system, top-up price is usually higher since the TSO is asking some generators to increase their generation, while spill price is lower (the TSO actually receiving some payments from GENCOs who are decreasing their

[19] And also bought, since generators can meet their sale obligations either by generating or buying energy from another generator

[20] Or deemed metered offtake. If meter readings are not available for each settlement period, then estimated meter readings taken from profiles can be used.

production[21]). In a one-price system these will be the same within a given settlement period but will vary between settlement periods.

What is the correct way to set imbalance prices?

There is no fully correct methodology for calculating imbalance price(s). The aim is to set prices that are sufficiently high to encourage participants to contract as closely as possible to their demand, while not over-penalising errors (which are largely unavoidable) in order not to discourage new entrants to the market. The methods can be divided into two broad types:

- **Two-price systems:** shortfalls (top-up requirement) are charged differently (higher) than spills.
- **One-price systems:** shortfalls and spills charged at the same price within each trading period (similar to pricing within a mandatory pool).

These two types can be further sub-divided:

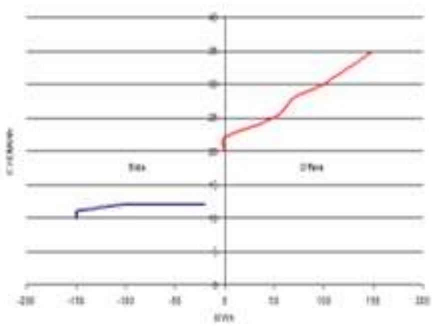
- A single price regardless of whether the participant has spilled or is in shortfall, reflecting the marginal value of imbalance energy in that hour.
- Two prices: one each for top-up or spill.
- Three prices: top-up, spill and an in-between price for a tolerance band.
- Multiple prices: a higher price for larger shortfalls than smaller ones; two prices for the tolerance band; etc.

Prices can also be calculated in different ways. For example, using marginal prices (the highest price at which the TSO had to buy balancing energy and the lowest at which the TSO sold energy) or average prices (e.g. average of the energy bought/sold by the TSO, or separate average prices for energy bought and energy sold by the TSO).

Figure 2-12: One example of imbalance price options

IMBALANCE PRICE OPTIONS

In any hour there is a bid price stack:
Bids and offers stacked in price or 'merit' award



ACCEPTED BIDS & OFFERS

There may be several bids accepted and several offers accepted

		Price	MWh	Cumulative MWh	Average Price
Unit 1	Bid 1	12.00	- 20	- 20	12.00
Unit 2	Bid 1	12.00	- 50	- 70	12.00
Unit 1	Bid 2	12.00	- 30	- 100	12.00
Unit 3	Bid 1	11.00	- 50	- 150	11.67
Unit 3	Bid 2	11.00	-	- 150	11.67
Unit 2	Bid 2	10.00	-	- 150	11.67

		Price	MWh	Cumulative MWh	Average Price
Unit 1	Offer 1	20.00	-	-	
Unit 2	Offer 1	22.00	-	-	
Unit 3	Offer 1	25.00	50	50	25.00
Unit 2	Offer 2	28.00	20	70	25.86
Unit 1	Offer 2	30.00	30	100	27.10
Unit 3	Offer 2	35.00	50	150	29.73

Source: CPCS

[21] The generator would still receive the full payment from his bilateral contracts.

Using the example in Figure 2-12, if we were to assume 2 prices (**marginal**), this would mean that a GENCO out of balance would need to pay $29.73 per MWh if short or would receive $11.67 if it had a long position. A load would receive $11.67 if it consumes less than scheduled or would need to pay $29.73 for the extra consumption.

With an average 2 prices method, the difference between the top-up and the spill would be much less. Usually, systems with hydro would tend to have less harsh penalties as opposed to systems using some form of fuel peakers for balancing.

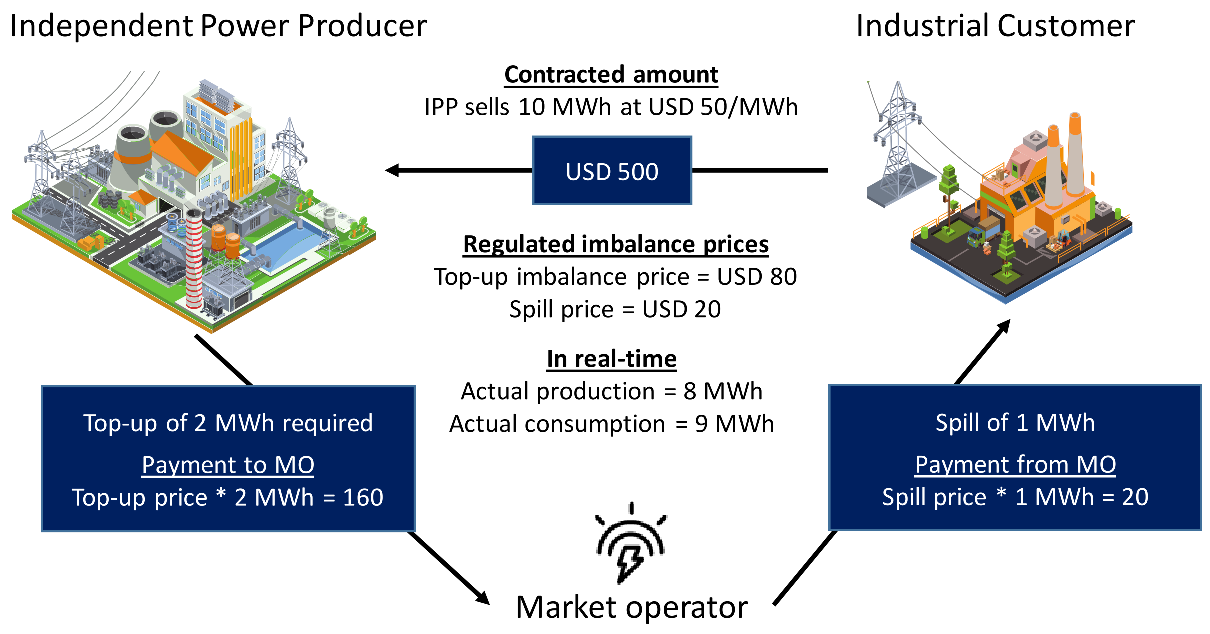
A simple method, which is both sufficiently cost reflective as well as being fair to all participants and encouraging competition, is often to have a single price in each period calculated as the average of the TSO's transactions in the direction of system imbalance (meaning either the average of the TSO's buy-price, or its sell-price, depending on whether the system was short or long). Usually, for each hour, the SO would be buying more or selling more. A well-functioning balancing market would usually have a few consecutive hours of the balancing market being short, then traders would react and then, the balancing market would become long, etc.

However, while balancing markets have been implemented as part of the development of competitive national electricity markets in USA, Europe and elsewhere, no such market has been implemented yet in Africa[22]. Currently, most African utilities are using their own reserves for balancing or contract specifically for ancillary services.

In the absence of a balancing market, a competitive electricity market must nevertheless have some form of balancing mechanism to penalize imbalances. In this case, TSOs and regulatory agencies must agree on regulated imbalance prices which are defined ex ante. The problem with regulated imbalance prices is they will tend to over penalize deviations from schedules to avoid, for example, GENCOs from under producing and load from over consuming. The problem with these penalties is they have no relation with the real status of the system for that hour.

The following figure presents a very simple example of regulated imbalance pricing.

Figure 2-13: Example of regulated imbalance prices



[22] SAPP has introduced an in-between solution where interconnector deviations are penalised based on frequency deviations. SAPP is currently working on developing a regional balancing market.

Source: CPCS

The initial Namibian imbalance prices and lessons for South Africa

In the first phase of the proposed Namibian market, there will be no balancing market. Participants who are out of balance will pay regulated imbalance prices. A tolerance band has been defined for lower and upper limits with no penalties on deviations.

Only negative deviations will attract a balancing payment, i.e. if a generator under-produces or an eligible consumer overconsumes, they will be penalized. However, if a generator overproduces, they will not receive any payment. Similarly, if an eligible consumer/supplier under-consumes, they will still have to pay the full payment to the GENCO (based on the bilateral contract) and will not receive any credit from the market operator (MO). In other words, the spill price is zero.

This system will not favour efficient trading as, normally, the MO should be compensating partly the GENCOs for over production or the eligible consumers/suppliers for under consumption especially if their position is the opposite of the overall system position and thus ‘helping’ the system. It illustrates that it is very difficult to develop efficient regulated imbalance prices.

Lessons for South Africa

In chapter 5, we propose various Phases/Steps for further market opening in South Africa. The first Phase would be a simple improvement of **the current wheeling framework. We propose that Eskom has a transparent bilateral contract to complement the bilateral contracts between the IPP and customers, and to start penalizing imbalances**. If this option is retained, we propose that NERSA develop and approve a regulated imbalance price regime where under-production or a consumer over-consumption is charged at the system marginal price, and over-production or under-consumption receives some form of financial compensation at a price to be defined.

Market rules (market code)

The scheduling process, the imbalances prices calculation method, settlement, how to participate, etc., are usually defined in market rules.[23] Market rules are what we can call the “rules of the game.” They represent a contract between participants and the operator of the market (whom we usually call the market operator). The market rules must go hand-in-hand with the national grid code.

Market rules need to be tailor made to the market model. However, specific chapters linked to day ahead, and balancing market scheduling are usually quite similar. The following figure presents the table of contents of the proposed Namibian market rules.

Figure 2-14: Table of contents of the proposed Namibian market rules

1. Definitions
2. Acronyms and Abbreviations
3. Purpose
4. Governance

5.Overview
   - 5.1 Market Development
   - 5.2 Trading Products and Services
   - 5.3 Market Participants (MP) and Authorisations

[23] Market rules are similar to a market code. The difference is that governance arrangements as a code is issued by the regulator while market rules can be issued by a market operator. The process to amend the rules can also be different.

5.4 Qualifying Requirements to Trade
6. Application of the Rules
7. Network Capacity Management Rules
7.1 Network Access
7.2 Network Capacity Reservation
7.3 Network Capacity Allocation and Congestion
8. Bilateral Trading Nomination Rules
8.1 Market Participant General data
8.2 Market Participant Standing data
8.3 Bilateral Nomination Instructions
8.4 Bilateral Nomination Process
8.5 Bilateral Trading Timelines
9. Balancing Mechanism Rules
10. Metering and Settlements
10.1 Metering
10.2 Services & Charges
10.3 Settlement information
11. Financial Rules and Invoicing
11.1 Clearing Account
11.2 Currency
11.3 Financial Security
11.4 Invoicing and Crediting
11.5 Payment Procedure
11.6 Auditing
12. Addenda

Source: Namibia market rules

2.4.2 Security of supply and the need (or not) for a capacity market

Ultimately, the key objective of public policy regarding competitive electricity markets is to ensure security of supply at the lowest sustainable cost (along with given choices of products to eligible consumers). Governments and regulators are often concerned that an energy-only market might not provide the needed economic signals for the maintenance of installed capacity, and the construction of new capacity as needed (and when it is needed).

In a market without long-term PPAs, a new generator needs to convince prospective lenders that the investment risk can be evaluated and that it is reasonably low. However, future energy market revenues are inherently uncertain, and thus expectations of revenue might not be sufficient to ensure that new investment is timely. In turn, under-investment (or late investment) can lead to very high prices in an energy-only market. In addition, prices in energy markets are usually volatile (even going negative in Europe lately at certain hours).

A capacity payment mechanism aims to calm the volatility while ensuring supply adequacy. There is no best solution to designing such a mechanism. Various forward capacity markets have thus been put in place to establish more revenue streams with greater certain for investments in new capacity that will be needed at a future date. As shown in the case studies above, some wholesale markets rely on capacity markets to ensure reliability while others still rely only on energy price signals. The best capacity market for a particular country is a function of the specific conditions of that country.

We can distinguish two main types of capacity markets:

- **Capacity obligations**:
  - Impose an obligation to contract for capacity, including a reserve margin on suppliers / customers, or just the reserve margin on a central buyer.

- Generators (and DSR[24]) compete to provide capacity.
- Auctions may be used.

- **Capacity payments:**
  - Make additional payment (above energy market price) to qualifying capacity.
  - Administered payment or set through auctions.

The various case studies above highlight these two types: Capacity obligations: Brazil and USA and capacity payments: Chile, Argentina, Peru, UK, France, Ireland, Italy, etc.

It is easy to implement a capacity payment in a mandatory pool type of market given that capacity is clearly visible. In a bilateral contract market model where generators self-schedule, capacity is less visible. It is however being done in Europe. Capacity obligations are possible in both market models and require generators to commit capacity ex ante (these obligations are regulated by certificates).

Among the criteria for designing and evaluating capacity market alternatives[25] are:

- Capacity adequacy/reliability of the system
- Efficient price signals for long-term investments
- Price stability
- Susceptibility to gaming
- Fairness
- Simplicity

Recent viewpoints on capacity markets in the context of high penetration of renewables

A new discussion has also emerged as renewable generators become a larger portion of the grid's resources, and complications may arise with the existing wholesale market structure. The argument goes that renewable energy sources not requiring fuel inputs to run are able to offer bids of $0 into the energy and capacity markets (if they are allowed to participate in capacity markets). As these sources make up a larger portion of the grid over time, these $0 bids can significantly reduce wholesale prices for energy and capacity and could discourage long-term investment for all resources.

However, this argument fundamentally misunderstands how wholesale energy pricing is formed. Pricing in energy-only markets are set to account not only for fuel costs, but all long-run fixed and operating costs. These may be recovered when markets become constrained and prices become very high. With more renewables, this will concentrate the periods in which thermal plants must recover costs and so prices may become "peakier", but this does not inherently undermine the concept of pricing by kilowatt-hour.

As a recent article by ECA consulting points out, political concerns about price spikes are not new, but consensus is also lacking both on the need for dedicated capacity markets to address these concerns and their appropriate structure even if recently, the balance of policy maker views has swung more in favour than against capacity markets.[26]

ECA tried to envisage what would happen in systems with 100% renewables with storage. In that case, such a system would move from a capacity-constrained to an energy-constrained one. This is similar to hydro-dominated systems where capacity may be plentiful but the availability

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[24] Demand Side Response.

[25] See Hamish Fraser, Capacity payment mechanisms: how to pick the one that's right for you, in The line in the Sand-the shifting of boundary between markets and regulation in network industries, edited by S Potts Voll and M. King, 2007

[26] ECA Consulting, Viewpoint, renewable energy's dirty little secret: power market cost reflectivity can handle intermittency, 2017.

of energy is dependent on water inflows and storage. Pricing is formed effectively through a repeated game that incentivizes an efficient level of market entry for long-run cost recovery[27].

The impact of wind and solar on market design is much more keenly felt on balancing/ancillary services markets. Yet even here, market models already in operation provide most of the cost reflective price signals required even if some changes have been made or are contemplated. This is discussed in the bow below.

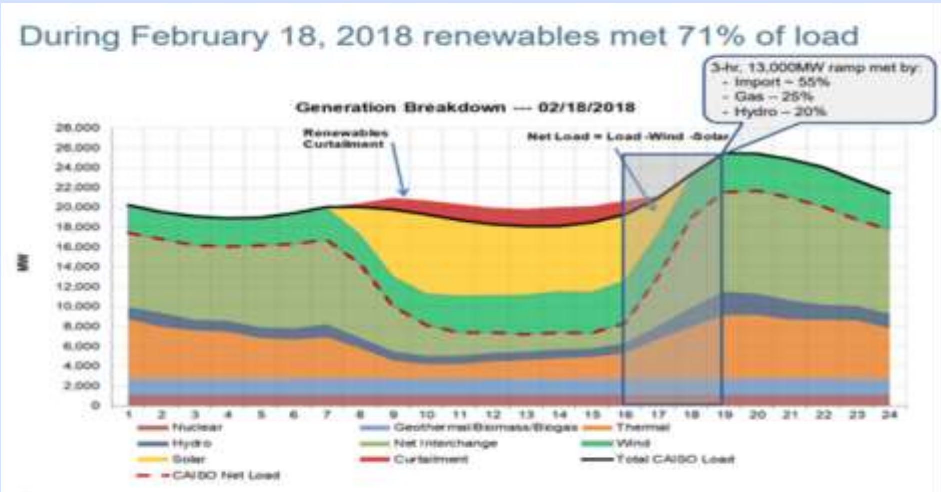
Figure 2-15: Impacts and approaches to dealing with high renewable penetration in balancing and ancillary services markets

An innovative idea being considered in Europe is the implementation of a shortage price function in the balancing markets. Currently, in the rare event that balancing reserves are depleted, administrative curtailment has to take place. During those rare moments, the balancing energy price should spike very high, to the Value of Loss Load (VOLL). It is exactly these price spikes that are crucial for flexible resources (''peakers'' or other technologies) to recuperate their investment costs.

However, these price spikes are infrequent and highly unpredictable (and not liked by politicians). What a shortage price function does is to provide a signal when the real-time balancing reserves are near depletion. More precisely, a "**scarcity price adder**" is calculated that equals zero when there are more than enough reserves but which rises gradually to equal VOLL when the reserves are very near to depletion. This scarcity price adder is then added on top of the balancing energy price (paid to those providing balancing energy) and/or the imbalance price (paid by participants having imbalances).[28] A variant of such a system is already implemented in various USA markets.

The well-known duck curve in California (shown in Figure 2-16 below) also highlights the potential need for new ancillary markets dedicated to securing the required ramping services (as recently implemented both in the Californian and the mid-continent systems and planned for the new Irish market).

Figure 2-16: Example of the California duck curve



Source: California ISO

Ancillary services provided for system-related reasons; namely frequency and voltage control, are the clearest area where changes in technology composition are threatening the cost reflectiveness of electricity markets. These costs are currently socialized in most markets through use of system charges. The UK National Grid ESO tendered last year 12.5 giga-volt ampere (GVA) seconds of inertia for more than 328 million sterling.[29] This inertia will be provided by pumped storage hydro and eventually by flywheels.[30]

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27 Idem

28 This issue is currently discussed among market design experts in Europe, see https://fsr.eui.eu/evolution-of-electricity-markets-in-europe-where-are-we-going/

29 The equivalent of inertia provided by 5 coal-fired plants

30 See Financial Times, Electricity grid operators search for inertia to power a greener future, December 6th 2020.

In conclusion to the article discussed above, ECA wrote that integration of the costs imposed into imbalance pricing by high renewable energy penetration to retain cost reflectiveness will need consideration and create additional market complexity, but this remains a minor issue in relation to overall revenues.[31] However, ECA concludes that rapid change also affects the ability of markets to find new equilibria around long-run costs and capacity markets may provide some security against this threat.

Lessons for South Africa

South Africa will have to balance the pros and cons of a capacity market when finalizing its market design. However, as recommended in Section 5.2, in the short to medium terms, the current system of tendering for new capacity will probably need to partly continue. While new IPPs would have the possibility to sell into a future day-ahead market or sign bilateral contracts with eligible consumers, there could be a default option to sign long-term PPAs with the future TSO or central purchasing agent. After a few more rounds of tendering under the current system, the system could be replaced by some form of capacity payment.

2.4.3 Congestion management

In competitive national electricity markets, market rules usually allow for de facto access to the grid combined with a system of transmission, distribution and other charges to use the systems. These rules, or code, can also be combined with open access regulations developed by national regulators.

Market rules must include a specific section on how long-term and short-term grid congestion would be relieved, and the SO needs to follow these congestion management rules. As part of this, the SO must usually publish the Net Transfer Capacity (NTC) between congested areas as an indicator of the amount of capacity that is available for commercial exchange. In case of congestion, the SO may curtail individual transactions. The methods used in practice to curtail are:

- First-come-first-served
- Pro rata, %-utilization
- Market-based solutions such as Auctions and Secondary trading

A simple method used to relieve congestion is a simple transmission right allocation based on a first come, first serve approach. This is not common in more advanced competitive markets given the probable lack of transparency. Another method is the selling of explicit transmission rights. Auctions can be organized on a yearly and monthly basis to allocate the transmission capacities to participants.[32] This method has been particularly popular in Europe for the allocation of interconnection transmission rights by the two corresponding TSOs.

Network constraints can also be solved by the SO using nodal, zonal pricing or methods most suitable for relieving short term congestion such as re-dispatching, counter trading and market splitting. These are discussed below.

Nodal and zonal pricing

One way to relieve long-term congestion is the implementation of nodal or zonal pricing. The way it works is the market is split into different market areas (zones) or even individual nodes

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[31] ECA, op. cit.

[32] In mandatory pools, financial transmission rights are usually sold; Market using nodal pricing such as PJM also sell FTRs to hedge between zones.

(e.g. HV busbars). There is then a simultaneous calculation of optimal generation and network dispatch resulting in potentially different prices in/at every zone/node. PJM in the USA (which has more than 2,000 busses updated every five minutes) and New Zealand have nodal pricing systems while Norway and some other European markets have zonal systems. Zonal / nodal pricing is only possible if all exchanges are handled via a central market and system operator. The following figure illustrates the components of nodal (locational pricing).

Figure 2-17: Nodal pricing

Locational marginal price = **Generation marginal cost** + **Transmission congestion cost** + **Cost of marginal losses**

Source: CPCS

Nodal pricing is theoretically ideal as prices are cost-reflective, but it is extremely complex to compute and very sensitive to hypotheses on transmission, generation, and demand. Zonal pricing is less flexible in handling congestion because it introduces an additional (computational) constraint in the market clearing procedure, namely that all prices in one region shall be equal. However, zonal pricing appeals more to traders and may increase the liquidity in hedging instruments since it is easier to hedge between large zones than between multiple nodes.

When congestion is not persistent, SOs can use re-dispatch, counter trading or, if a day ahead exists, what we call market splitting.

Re-dispatching

With this method, the SO re-dispatches generators on both sides of the constraint. It requires prices to modulate generators up and down. The cost of this re-dispatch is then invoiced to participants. If a balancing market exists, the SO can also use it for solving internal transmission constraints.

Counter trading

With this method, the SO engages in purchase and sales transactions with system users on both sides of the constraint. This means that congestions are handled in two steps: first a uniform price (called system price) is computed as if the capacity of the grid is infinite. Production for each generator is determined where the submitted supply curve intersects with the system price.

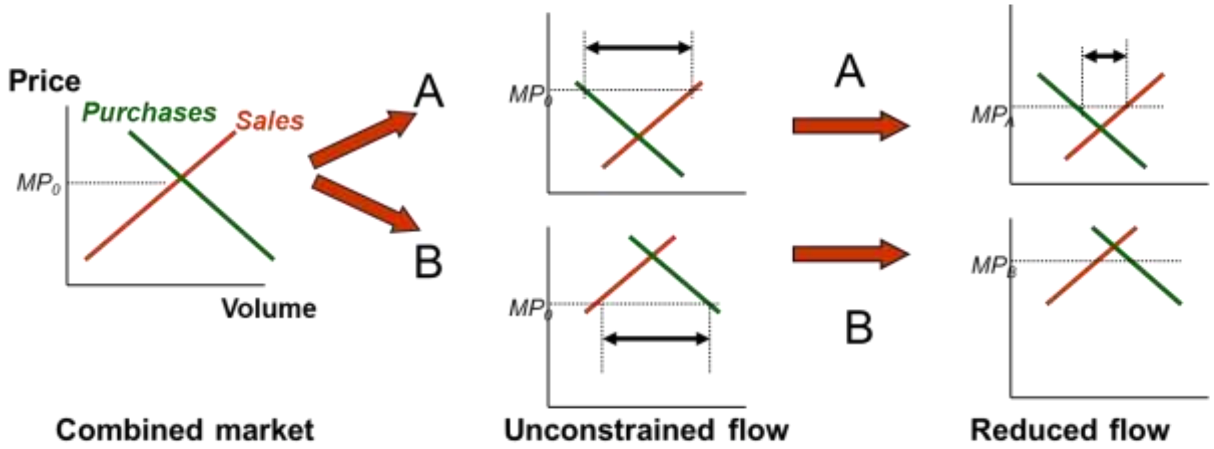
With counter trading, the SO will pay for increased production to get the volume needed. Consumers pay the system price so the system operator will sell the power with a net loss. A system of counter trading needs a very strong grid with limited congestions. In a system with significant congestions, the operation of such a system may be very costly to the system operator and in turn lead to high tariffs.

Both re-dispatching and counter trade methods create (substantial) additional costs for the system operator that have to be recovered from system users.

Market splitting

Market splitting requires a market operator (Px) that has a monopoly on any congested capacities. The market may be split into several market areas (zones). The way it works is that the market price on the surplus (deficit) side of constraint is artificially reduced (increased) to reduce the flow between these areas.

Figure 2-18: Market splitting method



Summary on congestion management

Regardless of the method used to relieve congestion, it must be described in the market rules.

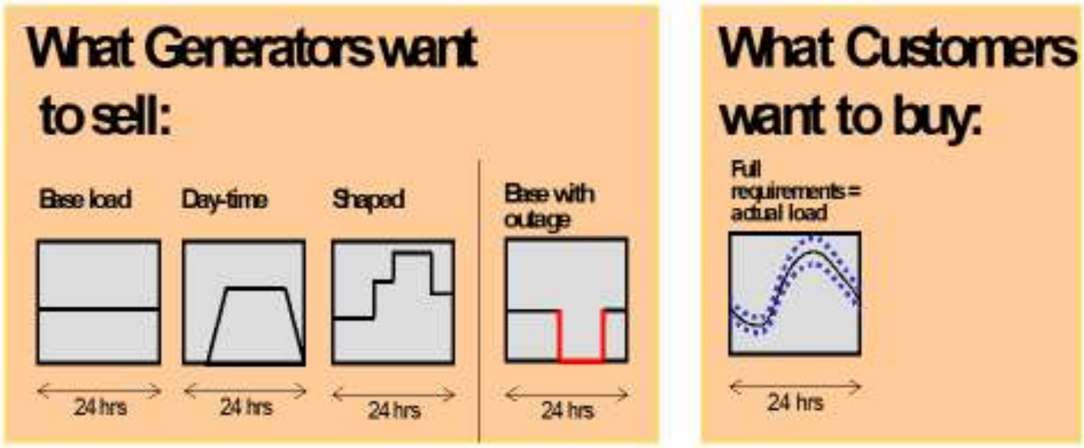
The proposed method for handling congestion in Namibia is not common and mixes congestion with issues of grid reliability. It proposes a deemed payment in return for a monthly capacity reserve charge. Those paying that charge will also have priority access. The Namibian market rules mention that the MO will develop more specific rules later on.

Through discussions with Eskom, we were told that the draft market code envisions re-dispatching as the first method to relieve congestion. This has to be put in a context where future generation is likely to be located in very different locations from the existing large coal fired plants. Eskom has embarked on a large transmission lines construction program for the system to be able to evacuate future renewable energy projects. In this context, it is difficult to assess where network congestion is likely to happen in the future.

2.4.4 Role of wholesale retailer and independent retailer (suppliers)

GENCOs, especially renewables, are not able to supply the full load required by customers at all times (an illustrative example is shown in the figure below). In markets with independent retailers, a retailer will buy various types of energy contracts to aggregate generation, package them and resell them to its customers (as demonstrated in the figure below) The retailer will also take the balancing risk (i.e. will be responsible for paying imbalance penalties).

Figure 2-19: Role of retailers



Source: CPCS

Currently, Eskom is providing what we call a "full supply contract" to municipalities, which means municipalities simply get the energy they need from Eskom and are not responsible for imbalances between load and generation. One energy trader, which contracts between customers and IPPs, is currently active in the market as well but is also not responsible for imbalances.

In the future, if balancing responsibility is shifted to other non-Eskom entities, then the fundamental allocation of risk in the sector will change. This applies to IPPs, energy traders and municipalities.

For instance, if the retail arm of municipalities buys (at least partly) from IPPs they will need to manage their customers' load carefully. The municipalities may therefore be likely to buy their expected load from retailers rather than directly from GENCOs. The role of trader as we currently understand it in South Africa would also change in this context as retailers become key intermediates between IPPs and consumers.

3 Review of Current Arrangements in South Africa and Key Challenges

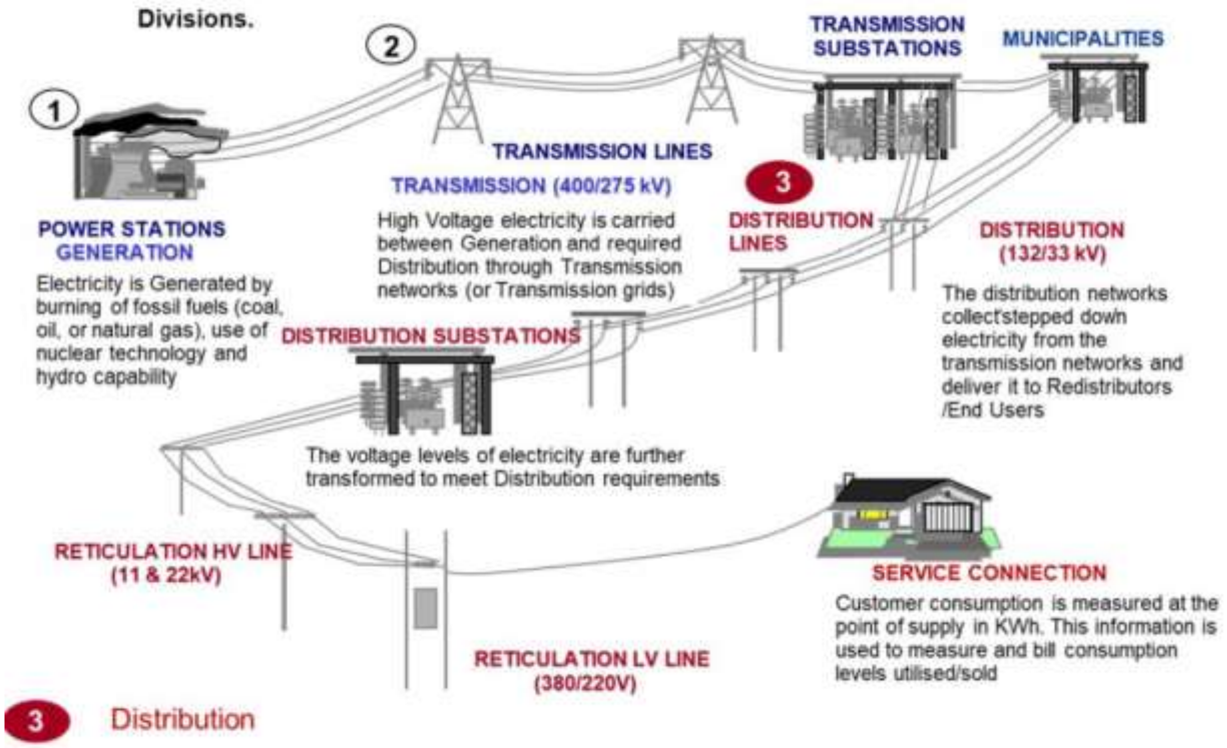
This chapter sets out the current industry structure and the general requirements for wheeling agreements between customers/generators at different network levels. It then reviews the legal / regulatory framework for wheeling, and considers particular challenges under the current framework / arrangements being implemented across the sector.

3.1 Industry structure

The electricity value chain in South Africa is dominated by the vertically integrated state-owned enterprise Eskom. Municipalities also play a key role in many areas in the operation of distribution networks. Outside of these entities, there are also a number of IPPs that generate electricity (but are not owned by Eskom) based on long-term PPAs, and a few energy traders that facilitate financial transactions between IPPs and some customers. Overseeing the sector is the energy regulator NERSA and the Government policymaking body, the Department of Mineral Resources and Energy (DMRE).

A simplified depiction of the value chain and key players is shown in the figure below and discussed further in the subsequent sections.

Figure 3-1: Representation of the electricity value chain



Source: DMRE (2019) "ROADMAP FOR ESKOM IN A REFORMED ELECTRICITY SUPPLY INDUSTRY"

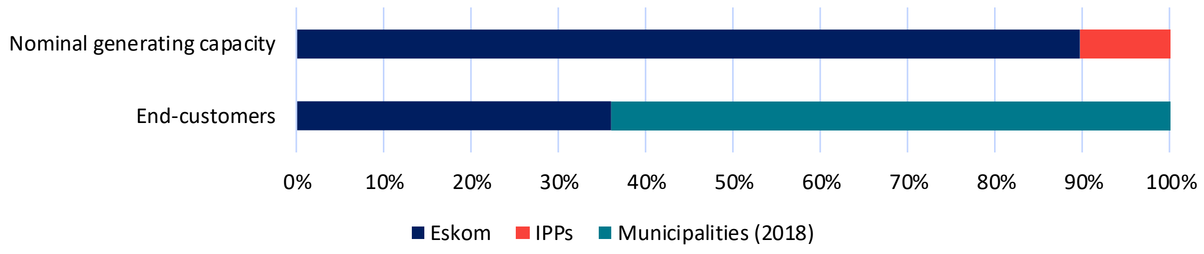
3.1.1 Eskom and its functions

Eskom is a vertically integrated utility, which means it provides services across the entire electricity value chain. Eskom:

- Owns and operates all the high-voltage electricity transmission network.
- Owns and operates the majority of electricity generation and about 60% of the distribution network.[33]
- Is the electricity retailer for a large share of end-customers connected at low-voltage levels, in addition to the majority of customers connected to the high-voltage transmission network.
- Is responsible for real-time balancing of the electricity system.

Eskom currently owns the majority of generation capacity in the country and supplies about 35% of end-customers (as shown in the figure below).

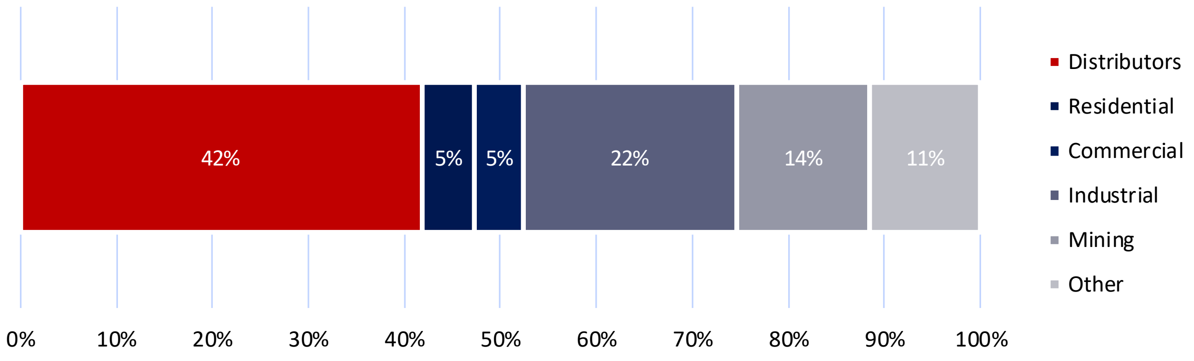
Figure 3-2: Eskom's market share in generation and end-customers



Source: CPCS analysis based on Eskom and StatSA data

Eskom sells about 42% of its electricity to distributors, with the majority of its remaining electricity either being sold to industrial/ commercial/ mining operations (which are more likely to be connected to the high-voltage network). Only about 5% of its electricity sales go to its residential end-customers. As such, Eskom is highly dependent on sales to municipal networks.

Figure 3-3: Eskom's customer profile (based on GWh of sales)



Source: CPCS analysis of Eskom data

33 https://journals.sagepub.com/doi/pdf/10.1177/2399654418778590#:~:text=Eskom%20is%20responsible%20for%2060,third%20of%20South%20Africa's%20customers.

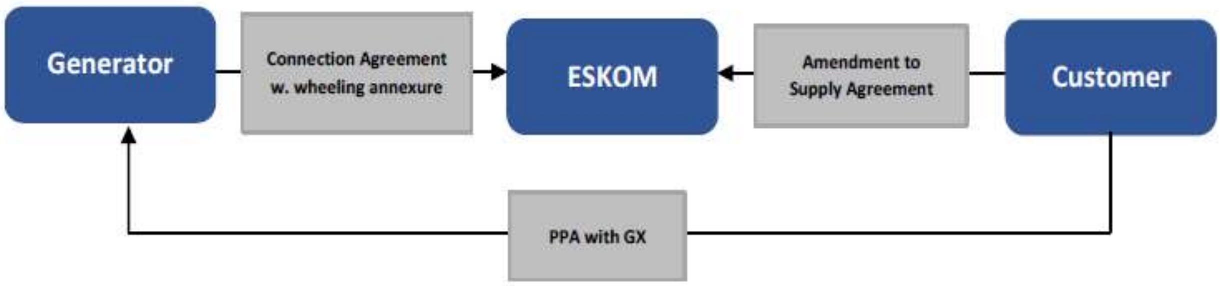
Wheeling for customers connected to the Eskom network

For end-customers connected to the Eskom network, the process for entering into a wheeling agreement between the generator and supplier requires the following agreements to be in place:[34]

- The generator must obtain a generation license from NERSA. These are reportedly difficult to obtain for some projects due to the requirement for projects to be fully developed and have a signed PPA in place. The PPA is between the generator and the off-taker / trader and will typically stipulate that the off-taker / trader must take so-called 'grid risk' (i.e. for unscheduled outages of the network) and may require the off-taker / trader to pay 'deemed energy' payments where the generator is not able to export to the network through no fault of its own.[35]
- A signed connection and use of system agreement ("CUOSA") with Eskom (plus payment of connection fees), with a 'wheeling annexure'. The CUOSA stipulates who between the off-taker / trader and Eskom ultimately takes 'grid risk'.
- An amendment to the customer's existing supply agreement with Eskom, which will allow the off-taker's electricity bill to be adjusted to take account of wheeled energy.

This is shown graphically in the figure below.

Figure 3-4: Agreements when wheeling between an IPP / customer both connected to Eskom network



Source: Presentation "SALGA: Legal Framework and Wheeling of Electricity "

According to AMEU, a separate wheeling agreement would also be required between the generator and Eskom.[36] Based on Eskom's publicly available guidance, this is not a requirement and it is unclear what such an agreement would include. Perhaps this references the CUOSA (with wheeling attachment) that Eskom does require with the generator.

3.1.2 Municipalities and their structure

Municipalities operate low voltage networks across South Africa and act as the electricity retailer for customers connected to their networks. Municipalities buy their energy from Eskom, or

[34] As noted in Eskom's documents including "Process and pricing for the third party transportation of energy (wheeling) over Eskom networks due to a bilateral trade (Information Brochure) September 2012" and "Eskom wheeling framework 5 September 2019" presentation.

[35] Usually in an open market, this has to be paid by the transmission owner beyond a certain level of outage hours in which the level of kWh not sold are not compensated. Ultimately, where the offtaker is obliged to pay the IPP for deemed energy, and Eskom refuses to accept financial consequences for network outages beyond the agreed annual 'float' for which it in any event has no liability, presently the best that the offtaker can do is insure against its deemed energy payment obligations through business interruption insurance. However, in an open market, it seems commercially unfair that a network operator should not be responsible for the consequences of failure to make the network available for 3rd party access and wheeling. This will have to change.

[36] AMEU presentation from 2019 "Legal Framework and Wheeling of Electricity"

certain IPPs in exceptional cases.[37] Municipalities can also set local policies on environmental stewardship, e.g. a number of the larger metros have made commitments to be carbon neutral by 2050.[38]

Municipalities "reticulate" power to their customers. While there is much debate about the exact nature of the rights given to municipalities under the constitution, reticulation is defined in the Electricity Regulation Act 2006 (amended in 2008) as the "*trading or distribution of electricity and includes services associated therewith*".[39]

Practically speaking, we understand that this involves the ownership, operation and maintenance of distribution assets (132kV and below), the purchasing of bulk supplies from Eskom, plus meter reading / billing / collection of payments from end-customers. Municipalities also provide access to their networks when customers choose to contract directly with IPPs or traders.

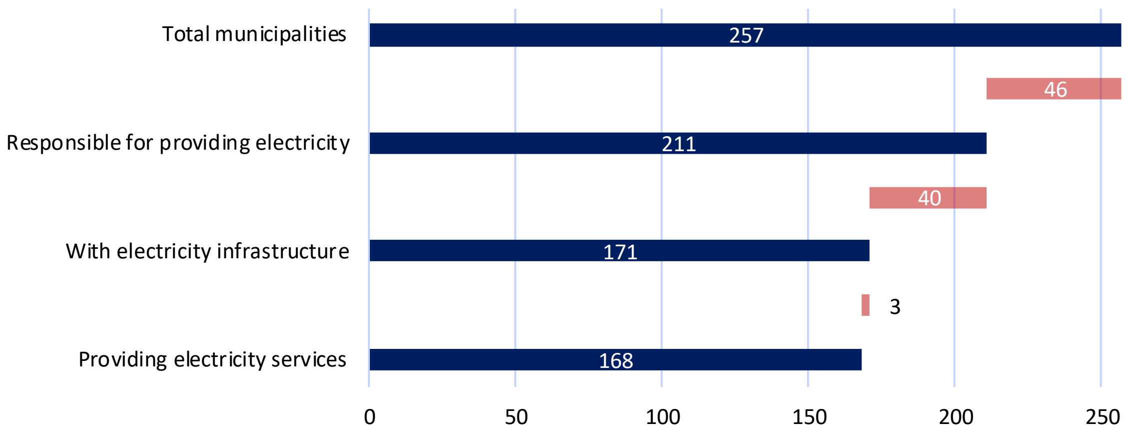
Profile of municipalities

Municipalities are split into three different categorizations:

- Metropolitan municipalities. The eight biggest cities in South Africa belong to this category.
- Local municipalities. There are 205 in this category. Local municipalities are geographic sub-components of (and share executive/legislative powers with) Districts.
- District municipalities. These consist of a number of municipalities. Out of the municipalities shown in the figure above.

According to Government statistics, there are 257 municipalities in South Africa, 211 of which are responsible for providing electricity services, 171 of which have the infrastructure to do so, and 168 of which actually provide the services.[40] [41] This is shown in the figure below. In addition, we understand that Eskom in practice distributes, or co-distributes, electricity with 90 municipalities.[42]

Figure 3-5: Municipalities in South Africa



[37] For example, the City Power PPA with the coal-fired Kelvin Power Station, or the City of Cape Town PPA with the Darling experimental wind farm. These arrangements are not the norm, but are specific to particular power production circumstances.

[38] As noted by Sustainable Energy Africa's Wheeling Discussion Paper (2020)

[39] ERA 2006, Section 1

[40] Only one District municipality is responsible for electricity service provision.

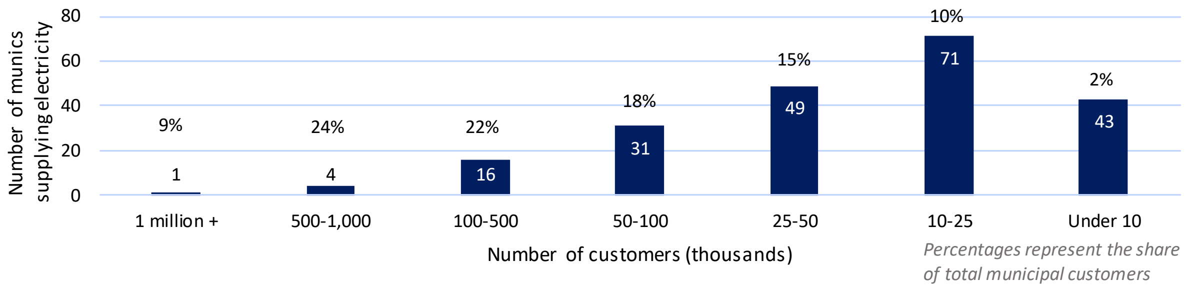
[41] The DPE's "Roadmap for Eskom in a Reformed Electricity Supply Industry" (2019) states that 188 municipalities are licensed by NERSA to distribute electricity to customers. This is slightly higher than the number of municipalities providing these services as quoted by StatSA.

[42] The exact nature of the "co-distribution" relationship is not described by the DPE's 2019 Roadmap.

Source: CPCS analysis of StatSA data

As shown below, there are a relatively small number of these municipalities represent the majority municipally supplied end-customers and the majority of municipalities are relatively small (e.g. with less than 50,000 customers). For instance, the 21 largest municipalities supply over 50% of municipal customers, while the smallest 163 municipalities supply less than 30%.

Figure 3-6: Relative size of municipalities supplying electricity



Source: CPCS analysis of StatSA data

Municipalities face many difficulties, as explored in depth by the 2018 report by the *Inter-Ministerial Task Team: Advisory Panel on Electricity Reticulation and Distribution*. It was noted in the report that in 2018, only 7% of municipalities were functioning well, 31% were functioning reasonably well, and 62% were dysfunctional. The reasons for dysfunctionality were explored further in that report, but in short included both internal and external factors such as:[43]

> *"infrastructure that is in serious need of expansion, upgrading and repair; poor skills in key delivery areas; poor financial and revenue management; poor budgeting and unfunded budgets; poor internal controls and cash flow management inefficiencies; tariff structures that are not cost reflective; poor billing and poor debt management processes; and leakages in the system (funds not used for municipal business), corruption and inefficient procurement process."*

These reasons are not the focus of this report, but rather serve as useful background for understanding some of the difficulties in expanding the volume of wheeling over municipal networks, or having municipalities to procure energy directly.

Wheeling for customers connected to municipality networks

Municipalities have a supply agreement with Eskom (since municipalities are customers of Eskom) and a supply agreement with their own end-customers. For end-customers connected to the municipal networks, the process for entering into a wheeling agreement between the generator and customer requires the following to be in place:

- The generator must obtain a generation license from NERSA (except for some instances related to small-scale generation[44]).
- A signed connection and use of system agreement between the generator and Eskom, with a wheeling annexure. If the generator is connected to the municipal network, then this agreement is between the generator and the municipality.
- Where the end-customer is connected to the municipality's distribution network, a separate 'last mile' 'wheeling agreement' between the municipality and the off-taker / trader for the

[43] Report by IMTT Advisory Panel Electricity Reticulation and Distribution (2018)

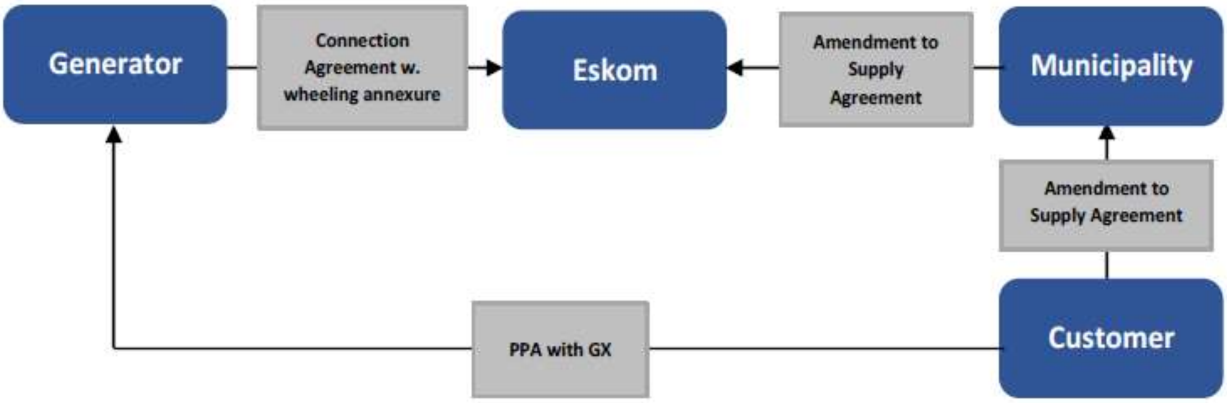
[44] As set out by amendments to Schedule 2 of the ERA made in 2017.

use of the municipal-owned and operated distribution network for the wheeled electrical energy.[45]

- An amendment to the customer's existing supply agreement with the municipality, which will allow the off-taker's electricity bill to be adjusted to take account of wheeled energy.
- An amendment to the municipality's existing supply agreement with Eskom, which will allow the municipality's bulk supply electricity bill to be adjusted to take account of wheeled energy. This is not required if the generator is connected to the municipal network.

This is shown graphically in the figure below.

Figure 3-7: Agreements when wheeling between an IPP connected to Eskom network and a customer connected to a municipal network



Source: Presentation "SALGA: Legal Framework and Wheeling of Electricity "

In practice, there is not a standard approach to wheeling agreements or use of system charges across municipalities (this is discussed further in Section 3.2). Given the large number of municipalities and high level of dysfunctionality, this lack of standardization and consistency in application of the regulatory framework creates a barrier to entering into bilateral contracts with municipalities and/or their customers.

3.1.3 Energy traders

Recently, the sector has seen the development of energy traders. Energy traders are licenced entities that buy electricity from IPPs and sell this energy to end-users connected to the high-voltage or low voltage networks. At this time there is only one energy trader operating in the market, PowerX, although we understand another proposed trader (Energy Exchange South Africa) is also seeking a license to trade electrical energy.

In practice, traders are an intermediary between willing sellers and willing buyers. They enter into PPAs with generators, pay the networks (i.e. Eskom and municipalities) for the use of their systems, and sell electricity to customers. In order to execute trades, energy traders must:

- Obtain an energy trading license from NERSA.
- Enter into a PPA with generators for the supply of electricity. These must also be supplied to NERSA.
- Enter into agreements with customers for the purchase of electricity. These must also be supplied to NERSA.
- Enter into a wheeling agreement with the network operators. This includes Eskom and municipalities if either the generator or customers are connected to their respective networks.

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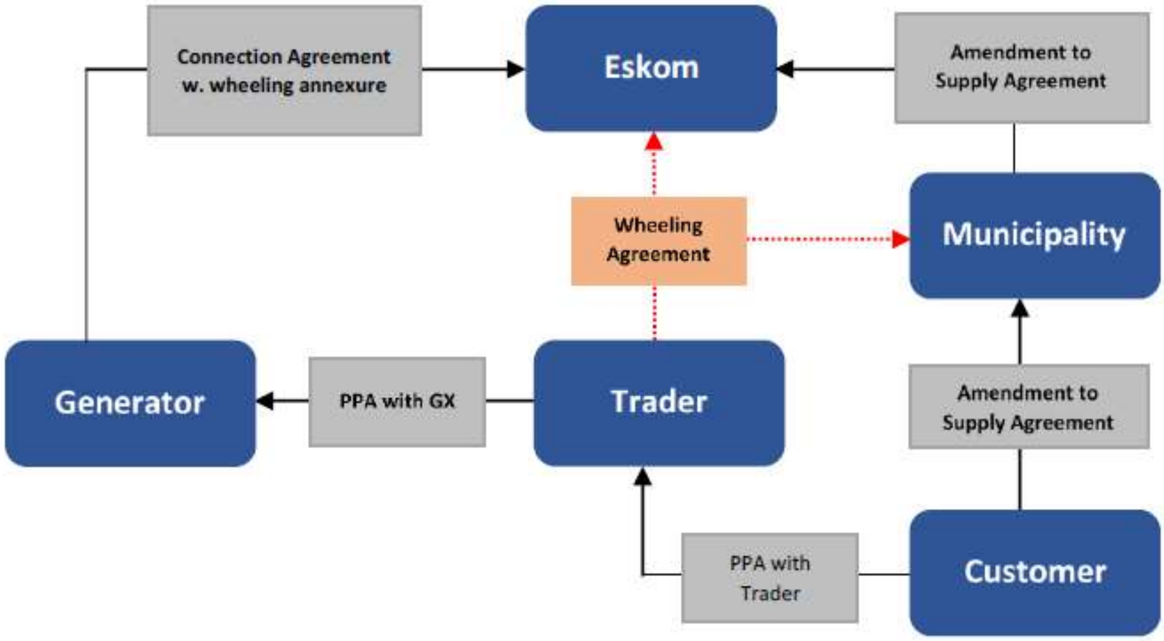
[45] This is dealt with in more detail under Section 3.2.3 below.

In addition to the above requirements, the same amendments to connection / use of system agreements and supply agreements as described in the previous sections is required. This is demonstrated in the figure below.

Figure 3-8: Agreements when for a trader facilitating wheeling between an IPP connected to Eskom network and a customer connected to a municipal network



Source: Presentation "SALGA: Legal Framework and Wheeling of Electricity "

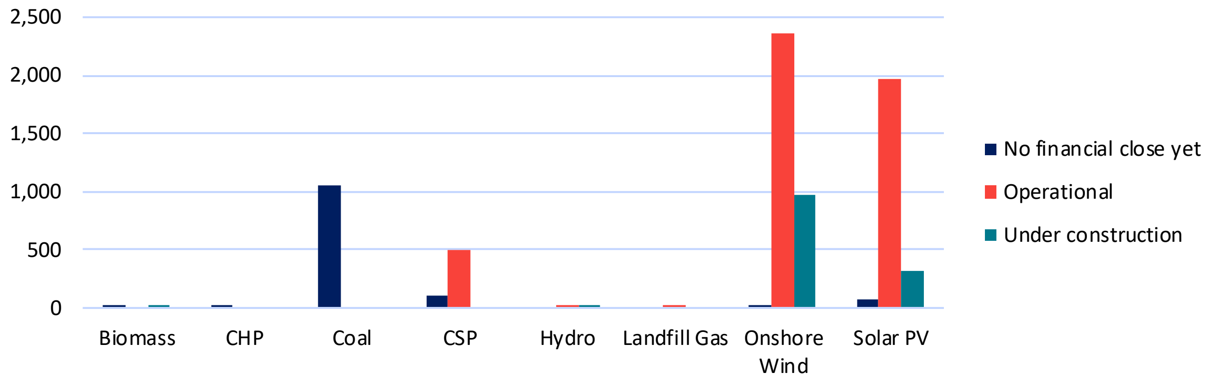
3.1.4 IPPs

There are a number of IPPs that provide electricity to the grid, the majority of which have been procured under the Government's Renewable Energy Independent Power Producer Procurement Programme (REIPPPP), which began in 2011 and has facilitated the expansion of IPPs that exploit renewable energy sources.

As demonstrated below, there are 4.8 GW of operational IPPs (mainly wind and solar PV) procured under the REIPPP[46] in operation with another 2.6 GW under construction or working toward financial close. Another bidding round for the procurement of 'emergency' IPP new generating capacity is currently underway under the Risk Mitigation IPP Procurement Programme, with bids submitted in late December 2020. Bidding Round 5 of REIPPPP has been issued in April 2021. The Coal Base Load IPP Procurement Programme is on hold.

[46] And the small project procurement programme.

Figure 3-9: REIPPPP generators in operation and development (in MW)



Source: CPCS analysis of data from the Independent Power Procurement Office[47]

REIPPPP is run by the Independent Power Procurement Office (IPP Office), which sits under DMRE. Procurement through REIPPPP is done in line with ministerial determinations for capacity, which reflect the 2019 Integrated Resource Plan (IRP). All IPPs awarded under the REIPPPP sign 20-year power purchase agreements (PPAs) with Eskom. As such, these IPPs are not “wheeling” energy to end-customers at this time.

IPPs can be developed to wheel energy to end-customers, outside of the REIPPPP. For example, this is the case for the Bio2Watt project, which supplies the BMW plant in City of Tshwane, and is the ambition for some municipalities such as Cape Town to contract directly with IPPs to buy green power. There are also a number of other IPPs, including the Darling Wind Farm, Bethlehem Hydro, etc.

All new IPP procurement, whether through REIPPPP or not, must be done in accordance with the allocation of capacity under the IRP, and consent to deviation has been given by the Minister where the allocable capacity under the IRP has been used up.[48] Under a competitive market, integrated resources planning would continue but would become more indicative. The current IRP process would need to be changed. This is discussed in various sections all along the report.

3.1.5 Electricity currently being wheeled

In 2020, wheeling of electricity represented a negligible share of the energy flowing over the network at just over 1% (shown in the figure below), equal to about 2.5 TWh or an average of 280 MW. This small amount of wheeling includes projects such as the Bio2Watt project which supplies the BMW plant in City of Tshwane (and has use of system agreements with Eskom and City of Tshwane) and trades facilitated by electricity traders (PowerX).

NERSA has recently approved the generation licence for a project commissioned by Amazon to provide 28 GWh per year to proposed data centres from a solar farm (with 10 MW of capacity) in the Northern Cape.[49] While this is a recent welcome development that could expand the

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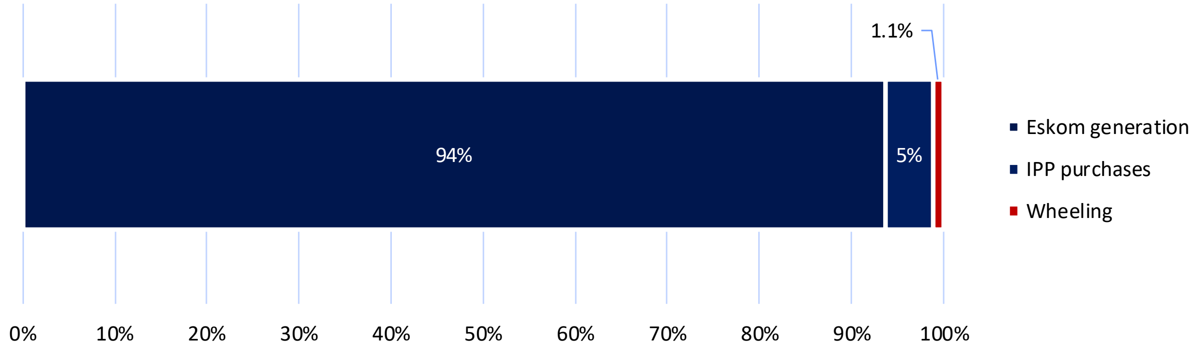
[47] https://www.ipp-projects.co.za/ProjectDatabase

[48] Unlike IRP 2019, IRP 2010 had no allocable capacity outside of the Ministerial Determinations. Consequently, IPPs wishing to develop independent projects to supply electricity direct to offtakers had to apply to the Minister for, and receive, a consent to deviation from IRP 2010, before NERSA would consider any application for a generation licence for the relevant facility. By early-2019, scores of applications representing some 3,500MW of new generating capacity had been lodged with the then Minister of Energy Jeff Radebe. In May 2019, shortly before the re-amalgamation of the Department of Mineral Resources and the Department of Energy into DMRE under Minister Gwede Mantashe, Minister Radebe approved a so-called ‘blanket’ consent to deviation for 500MW of new generating capacity. There was no direction as to which of the 3,500MW applied for would be covered by this. The entire process became moot upon the promulgation of IRP2019, which allocated 200MW per year for so-called ‘Embedded Generation’ (which formed the bulk of the applications pending before the erstwhile Minister).

[49] https://africabusinesscommunities.com/news/nersa-approves-flagship-energy-wheeling-project-for-amazon-in-south-africa/

aggregate share of the wheeling market, the overall contribution of third party bilateral contracts for electricity provision remains negligible compared to overall demand.

Figure 3-10: Electricity wheeling contribution to overall supply (2020)



Source: CPCS analysis of Eskom data

3.1.6 Various industry structure challenges

The structure of the South African electricity sector presents a number of challenges to the development of a coherent and supportive environment for bilateral contracts between generators and customers.

- There are a large number of municipalities that operate autonomously, many of which have few customers. In addition, bankability and governance of municipalities is a real concern.
  - Bankable bilateral contracts will not be possible between most municipalities and generators for the short to medium term. The alternative is for bilateral contracts to be between end-customers and generators.
  - The lack of capacity and standardization of agreements across municipalities (which is a function of the number and size of municipalities) is a barrier to establishing bilateral contracts between end-customers and generators. This is discussed further in Section 3.2.
  - It seems that only a few municipalities have sufficient internal capacity and knowledge to work on developing approaches to wheeling (e.g. Cape Town).
  - There appears to be resistance by municipalities to simply use the distribution use of system tariff methodology approved by NERSA; many see wheeling as an additional service on which a surcharge could be applied.
- Energy traders could help expand the number of IPPs and customers that willingly enter into supply agreements, but this sector is in its infancy in South Africa. Removing barriers to expanding the role of traders in the market should be considered. The role of trader will also change in the future as players will become liable for imbalances; the role of trader will become more of a retailer role.
- The requirement for IPP procurement to follow capacity allocations as set out by ministerial decisions, based on the IRP, could be restraining the development of new IPPs. If the generation market is to be competitive, generation should be able to compete on equal footing for capacity. Even in the short-term before a real competitive market is developed, this consent should not be necessary for IPPs who want to sell directly to consumers.
- Eskom retains a dominant position in the generation market, and any new IPPs procured through the REIPPPP have obligations to Eskom under their 20-year PPAs. This means that there are relatively few existing generators that could enter into wheeling agreements. This means that, in the short-term, increasing the amount of wheeling would require new IPPs to come into the market.

Given all these challenges, wheeling is likely to only realistically increase in a material way with major changes to the electricity market. However, there are still some initial steps that could be taken by Eskom and others to allow more transactions in the short term as described in Section 5.2.

3.2 Legal/regulatory framework

The electricity sector regulatory framework has been in a state of flux since the publication of the Energy White Paper in 1998. The framework for private sector participation was created with the enactment of the Electricity Regulation Act, 2006 (ERA) – in line with the White Paper. However, a 2007 cabinet decision designated Eskom as the Single Buyer of (most) new generation and the 2011 electricity regulation on new generation replaced the market concept for renewable power development in favour of an IPP Procurement Programme.

3.2.1 Responsibilities of policy makers and regulators

The primary responsibilities of policy makers and regulators find first expression in the 1998 Energy White Paper, specifically the Ministerial foreword to that document (the White Paper is discussed in more detail in Chapter 4).

This being settled policy with respect to the electricity sector, Government has had the obligation to create frameworks for the implementation of this policy, including the promulgation of primary and subordinate legislation to procure these policy objectives, and to pursue initiatives that promote such objectives.

It is the responsibility of all spheres of government (national, provincial, and local) to implement such policy. It is the responsibility of regulators (notably NERSA in this instance) to regulate and enforce the policy that is expressed in legislation and regulations.

Specific legislative steps have included the promulgation of ERA and the National Energy Regulator Act No. 40 of 2004 (**NERA**), and the various regulations promulgated thereunder.

Specific initiatives under this overarching legislation and the policy objectives of the White Paper have included:

- the promulgation of the Integrated Energy Plans (the latest in 2016), which govern the overall objectives across the entire South African energy sector;
- the promulgation of the Integrated Resources Plans of 2010 and 2019, which govern the overall objectives for the procurement of new generating capacity in the South African electricity sector;
- the initiative for the rationalization of regional municipal and Eskom distribution assets to create Regional Electricity Distributors (REDs),[50] which would provide for regional distribution of electricity (since aborted, for political reasons);
- the initiative to create an Independent System Market Operator as a state-owned entity which would provide an independent system operation to ensure safe, secure and efficient operation of an integrated power system and the trading of electricity at wholesale level (since aborted, for political reasons).

[50] For example, RED1 would comprise comprise 39 local municipalities, 16 district management areas and one metropolitan area (Cape Town) stretching from the SA border with Namibia in the north to the Plettenberg Bay area in the east. It would consist of an amalgamation of the distribution infrastructure and services of all involved local governments and the distribution assets of Eskom.

3.2.2 ERA

The starting point for evaluation of the current situation is the Electricity Regulation Act (**ERA**), in particular the role of NERSA and DMRE, and the provisions of the transmission and distribution licences that are provided for under ERA.

The express objectives of ERA are to:[51]

- Achieve the efficient, effective, sustainable and orderly development and operation of electricity supply infrastructure in South Africa;
- Ensure that the interests and needs of present and future electricity customers and end-users are safeguarded and met, having regard to the governance, efficiency, effectiveness and long-term sustainability of the electricity supply industry within the broader context of economic energy regulation in South Africa;
- Facilitate investment in the electricity supply industry;
- Facilitate universal access to electricity;
- Promote the use of diverse energy sources and energy efficiency;
- Promote competitiveness and customer and end-user choice; and
- Facilitate a fair balance between the interests of customers and end-users, licensees, investors in the electricity supply industry, and the public.

ERA expressly mandates NERSA (established under NERA) with extensive functions and powers in the regulation and administration of the South African electricity sector. The preamble of ERA notes that NERSA serves as the custodian and enforcer of the national electricity regulatory framework. In particular, section 4 of ERA stipulates that NERSA must perform the following functions:

- consider applications for licenses and may issue licenses for the operation of generation, transmission or distribution facilities, the import and export of electricity, and electricity trading;
- regulate prices and tariffs;
- register persons who are required to register with NERSA where they are not required to hold a licence;
- issue rules designed to implement the national government's electricity policy framework, the Integrated Resource Plans and ERA itself;
- establish and manage monitoring and information systems and a national information system, and coordinate the integration thereof with other relevant information systems; and
- enforce performance and compliance with ERA, and take appropriate steps in the case of non-performance.

In addition, in terms of ERA, NERSA must:

- mediate disputes between generators, transmitters, distributors, customers or end users;
- undertake investigations and inquiries into the activities of licensees; and
- perform any other act incidental to its functions.

[51] Section 2

Notably, in the present context, in issuing a generation licence, NERSA "may facilitate the conclusion of an agreement to buy and sell power between a generator and a purchaser of that electricity."[52]

As to be expected, the Minister of Mineral Resources and Energy is given wide-ranging functions, responsibilities, and powers for the maintenance and development of the South African electricity sector in accordance with the objects of ERA. To this end, amongst other things:

- The Minister may, following consultation with NERSA, determine that certain activities do not require to be licensed, but may require to be registered with NERSA.
- The Minister may consider, and approve, any application for deviation from any applicable integrated resource plan.
- The Minister may prescribe the particulars that are to be included in any application to NERSA for any licence, and may prescribe the procedures to be followed for the variation, suspension, removal, or addition of any conditions to any licence, and the procedure for the revocation of any licence.
- The Minister may make regulations pertaining to service delivery agreements between municipalities and external service providers for the reticulation of electricity in compliance with Chapter 8 of the Municipal Systems Act.
- The Minister may, in consultation with NERSA, determine the necessity for new generating capacity, the type of energy sources from which such new capacity is to be procured, the persons to whom electricity generated by such new generating capacity may be sold, and the requirements of the tendering process and private sector participation.
- The Minister is given the authority to issue regulations over a wide ranging conspectus of matters and issues.[53]

As to transmission and distribution specifically, ERA expressly stipulates:

- Transmission and distribution licenses may impose the duty or obligation on the license holder to transmit or distribute electricity (Section 14(1)(m)).
- A determined framework for the setting of tariffs (Section 15(1)). Specifically, in this regard, the setting or approval of prices, charges, and tariffs must follow the following principles:
  - An "efficient" licensee must be enabled to recover the full cost of its licensed activities, including a reasonable marginal return.
  - There must be incentives for continued improvement of the technical and economic efficiency with which services are to be provided.
  - Undue discrimination between customer categories must be avoided.
  - The licensee must give end-users proper information regarding the costs their consumption imposes on the licensee's business.

It should be noted that it is NERSA, as the Regulator defined under ERA, that has the power and authority to regulate these tariffs, as part and parcel of its overall role as custodian and enforcer of the regulatory framework provided for in ERA (Section 3). As such, NERSA has the authority to determine connection and use-of-system fees, applying the principles set out above.

[52] Section 34(3)(b). It is important to note that NERSA may "facilitate", not "regulate". Thus, it is not open to NERSA to determine of itself the commercial terms between such parties where they have agreed between themselves to such terms. For example, where the generator and the offtaker have agreed in their PPA an energy rate that is substantially below the norm, it is not for NERSA to determine that such rate is inappropriate or unacceptable, thereby rejecting such terms and thus refusing to issue a generation licence.

[53] Section 35(4).

- Transmission and distribution licensees must, to the extent stipulated in the relevant license, provide for **non-discriminatory access by third parties** to transmission and distribution power systems (Section 21(3)).
- Transmission and distribution license conditions for such third-party access may relate to circumstances in which access must be allowed or may be refused, the strengthening and upgrading of the transmission and distribution networks in order to be able to provide for such access, compliance with codes, rules, and practices made by the Regulator, and fees to be charged for the use of the transmission and distribution systems (Section 21(4)).
- The Regulator may, in consultation with transmission and distribution licensees, municipalities that reticulate electricity, and other interested and affected parties as necessary, make guidelines, codes of conduct, and/or rules relating to, amongst other things, the relationship between licensees, customers, and end-users, the use of transmission and distribution power systems, and any other ancillary matter appropriate for the implementation of the ERA (Section 35).

With specific reference to the question of open access to the South African electricity network, from the above it can be seen that the legislative framework already exists in the primary law. However, as is further highlighted below, the main challenge to access and wheeling by independent third parties is the failure/refusal/neglect by municipalities to implement their obligations as stipulated in their distribution licenses in a standard and compliant manner.

This point will be discussed more comprehensively below. However, for the purposes of ERA, it is important to note the following:

- Section 2(f) expressly stipulates that one of the main objects of the legislation is to promote competitiveness and customer and end-user choice. This is in full alignment with policy set out in the 1998 White Paper.
- Section 21 expressly stipulates that:
    - a licensee may not discriminate between customers or classes of customers regarding, amongst other things, access to the relevant distribution and/or transmission network;
    - such access must be provided on the conditions as set out in the relevant transmission and/or distribution license.
- In our view, section 21 imposes a general positive obligation on municipal distribution licensees to provide non-discriminatory access to networks for the purposes of wheeling services, this being in full alignment with the main object stipulated in section 2(f).
- Alongside this obligation imposed by section 21, there are other obligations imposed on municipal distribution licensees through various policy instruments issued by NERSA, which are binding on municipalities. In this regard:
    - Section 27 expressly stipulates that a municipality must exercise its executive authority and perform its duties by, amongst other things, executing its reticulation function in accordance with relevant national energy policies.

The question arises as to what changes, if any, will be required to ERA for the implementation of Eskom's proposed 'unbundling' and restructure. It should be noted that this presently does not have any implications for ERA regarding open access and wheeling, inasmuch as the position is determined by the transmission/distribution license provisions as discussed. Nor, for as long as Eskom Transmission remains a division within Eskom Holdings SOC, is there any impact (contractually speaking) on existing PPAs with IPPs or on future PPAs where the Minister might determine that Eskom Transmission (as a division of Eskom Holdings SOC) is the designated buyer of electricity generated from determined new generating capacity.

However, as indicated, this does not affect the basic premise regarding Eskom's and municipalities' obligation to afford third parties open access to their networks for the purposes of wheeling electricity, unless the provisions of license conditions are changed contrary to the express requirements of ERA. An example of an appropriate framework established to promote competition, competitiveness, and open access is the further development of regulation of the electricity sector in Kenya during 2019, which is discussed in the case study below, and which indicates possible legislative and regulatory changes required.

Figure 3-11: Case study: legislative design in Kenya for open access

The Kenyan energy sector has undergone significant market reform since the 1990s. The shift towards market liberalization in Kenya was informed by global trends of unbundling vertically integrated utilities in order to promote competition and enhance energy security in the country.

Various legislative instruments including the Electric Power Act (1977) and the Energy Act (2006) guided these reforms in the Kenyan energy sector. The Electrical Power Act served as the empowering framework for the unbundling of Kenya's vertically integrated utility Kenya Power and Lighting Company (KPLC). As a result, Kenya has three separate companies for generation, transmission and distribution. The Energy Act (2006) established an independent energy regulator to facilitate competition in the market and set out the licensing requirements for electricity generation, transmission and distribution.

The new Energy Act (2019), which repealed the Energy Act (2006), goes even further in promoting competition and energy efficiency in the sector by:

- widening the scope of functions of the Energy and Petroleum Regulatory Authority including and facilitating competition, access and utilization of facilities by third parties in consultation with the Competition Authority;[54]
- stating expressly that transmission licensees have a duty to provide non-discriminatory access to its transmission system for use by any licensee or eligible customer on payment of fair and reasonable transmission or wheeling charges as shall be prescribed in regulations made in terms of the Act;[55]
- stating expressly that distribution licensees have a duty to provide non-discriminatory open access to its distribution system for use by any licensee, retailer or eligible customer upon payment of use of system charges as shall be prescribed in regulations made under the Act and compliance with such minimum requirements of the distribution licensee; [56]
- stating expressly that each distribution licensee or retailer shall upon application, make available net metering services to any electricity consumer that the licensee serves; and

While the previous law established an independent transmission company (transco), the 2019 law established an independent System Operator responsible for matching consumer's requirements or demand with electrical energy availability or supply, maintaining electrical power system security and arranging for the dispatch process.[57]

3.2.3 Constitutional and other rights and obligations of municipalities

It bears referencing the current debate between municipalities and Eskom as to the averred 'exclusive right' of municipalities to 'reticulate' electricity within their municipal boundaries, to the exclusion of Eskom.

We have reviewed the September 2018 report of the Inter-Ministerial Task Team Advisory Panel on this issue, as well as (on a confidential basis) the opinions procured by SALGA / IMTT from Senior Counsel on the constitutional framework of electricity reticulation and distribution. We also have had an opportunity to consider the litigation brought by the City of Cape Town for an order declaring its competence to generate and procure electricity in accordance with its constitutional responsibilities to provide a secure electricity supply, without first procuring a

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[54] Section 10 (m) and (BB) of the Kenyan Energy Act (2019).

[55] Section 136(1)(c) Kenyan Energy Act (2019).

[56] Section 140(1)(d) Kenyan Energy Act (2019).

[57] Section 138(1) of the Kenyan Energy Act (2019).

Section 34 determination from the Minister, insofar as this might be relevant to the issues at hand in this working paper.

We understand that Eskom persists with its view diametrically opposed to that given by Senior Counsel for SALGA and as adopted by IMTT. It is likely that the question ultimately will require determination by the Constitutional Court. That said, we believe the issue to be irrelevant to the question of open, non-discriminatory, and economically-fair access by third parties to transmission and distribution networks for the purposes of wheeling electricity.

Nowhere in the IMTT Advisory Panel report nor the opinion of Senior Counsel is it contended that the applicability of ERA or the jurisdiction of NERSA is ousted by the constitutional principle contended for. Indeed, to the contrary as far as we can see, the constitutional point contended for is averred to fit hand-in-glove with ERA. For example, municipalities cannot make the argument for reticulation as provided for under ERA without logically accepting that the ERA applies.

So said, it is not open for one to pick and choose the legislated provisions that suit one's agenda or purpose. The ERA applies in its totality.

In this regard, we have noted anecdotally from our consultations with stakeholders that at least two municipalities contend for something quite different. In the first instance, the municipality in question refuses to enter into a wheeling agreement, indicating that it will only do so if it is shown that it is under a legal obligation to conclude such an agreement. In the second instance, the municipality in question is willing to enter into a wheeling agreement, but demands a wheeling tariff that is not commercially justifiable or sustainable.

It is understood that these positions have been taken for the following reasons:

- Reluctance on the part of the relevant municipality to relinquish customers, which will take place in the event that end-users conclude PPAs with IPPs/traders.
- Electricity tariffs are seen as a means of subsidizing local government operations on a general basis.
- Wheeling tariffs should recover the full surplus that the municipality would have derived from supplying electricity to a customer to whom the electricity is now to be wheeled over the municipal network.

In our view, such positions could be considered to be unlawful under the current regulatory framework. A municipality is not entitled to refuse to enter into a wheeling agreement with third parties, nor is it entitled to impose excessive wheeling tariffs to recover surpluses that it would otherwise have recovered by supplying electricity directly to the end user. As stated in section 3.2.2 above, ERA contains specific provisions in respect of obliging open access.

There are also other instruments embodying national energy policy, which oblige municipalities to provide wheeling services, including the Grid Code. The 2008 Electricity Pricing Policy and the 2012 3rd Party Access Rules (**2012 Third Party Network Charges Rules**) also contain such obligations (discussed further in 3.2.5 and 3.2.6 below).

With respect to the Grid Code:

- Clause 4(1) of the RSA Distribution Code (v6) states that a distributor shall make capacity available on its networks and provide open and non-discriminatory access for the use of this capacity to all customers including Embedded Generators, and that, in exchange for such service, the Distributor is entitled to fair compensation through electricity tariffs as described in the Tariff Code.

- Clause 4.4.1(1) of the Tariff Code (RSA Distribution Code Tariff Code (v6.0)) restates this principle in almost identical terms - that a distributor shall make capacity available on its networks and provide open non-discriminatory access with the use of this capacity to all South African Customers (loads) and Embedded Generators, in exchange for which service the Distributor is entitled to a fair compensation through electricity tariffs. The Tariff Code is discussed further in Section 3.2.9.

In our view, the cumulative effect of these provisions in ERA as it presently stands, the Grid Code, the 2012 Third Party Network Charges Rules, and the 2008 Electricity Pricing Policy, make it clear that a refusal by municipal electricity distribution licensees to enter into wheeling arrangements with third parties other than for technical or safety requirements would be unlawful.

3.2.4 Municipal tariffs

As stated in section 3.2.2, ERA confers upon NERSA the power to regulate prices and tariffs. Section 4(a) (ii) specifically states that “the Regulator must regulate prices and tariffs

With respect to the regulatory framework and tariffs for third party access to networks, although this is dealt with in more detail elsewhere in this report, it bears outlining the legal position here. In this regard:

- The starting point would be section 229 of the Constitution. It should be noted that there is a distinction between fees for services provided by municipality and surcharges on those fees for such services. Municipalities are vested with an original constitutional power to impose surcharges on fees for services, subject to the express stipulation that such power may not be exercised in a way that materially and unreasonably prejudices national economic policies.
- The distinction between fees for services and surcharges on those fees is carried forward into the Local Government (Municipal Systems) Act No. 32 of 2000 (“**Municipal Systems Act**”) and the Municipal Fiscal Powers and Functions Act No. 12 of 2007 (“**MFPFA**”). In particular:
  - Section 74(2)(d) states that, in respect of the tariff policy for the levying of fees for municipal services, tariffs must reflect the costs reasonably associated with rendering the service, including capital, operating, maintenance, administration and replacement costs and interest charges.
  - Section 74(2)(f) states that, in appropriate circumstances, a surcharge on the tariff or a service may be provided for.
  - Section 75A(2) through (4) regulates procedures for the imposition of tariffs and fees, but not surcharges. Surcharges are dealt with under MFPFA.
  - Section 9(2) and (3) deal with such surcharges, which are defined as charges in excess of the municipal base tariff that a municipality may impose on fees for a municipal service. The municipal base tariff is defined as the fees necessary to cover the actual cost associated with rendering a municipal service
- Accordingly, this local government legislation distinguishes between fees for municipal electricity services and surcharges on those fees. With respect to the former, the legislation obliges municipalities to impose fees that will cover the cost of such services, including a reasonable rate of return if so authorized by NERSA, and vests in municipalities a discretionary financial power to impose additional surcharges that provide a source of additional revenue. Municipal distribution licenses should therefore be constructed in accordance with this framework.

In summary:

- There is a primary distinction between fees for electricity distribution services (which should cover the cost of providing those services, including a reasonable rate of return) and surcharges on those fees which are designed to raise a surplus for a municipality.
- Such fees and surcharges are to be considered separately by the municipality on an annual basis.
- Fees are fixed by NERSA under section 15(2) of ERA
- When NERSA fixes municipal tariffs, it may not provide for a tariff that includes a surplus (disguised surcharge).
- When a municipality fixes municipal surcharges, in the absence of norms and standards under the MFPFA, section 229(2)(a) of the Constitution obliges it to fix a surcharge that does not "materially and unreasonably prejudices national economic policies." These surcharges are regulated by the Minister of Finance, not NERSA.

As will be discussed below, the 2008 Pricing Guidelines, 2012 Third Party Network Rules together with the 2008 Electricity Pricing Policy further reiterate the regulatory and policy frameworks discussed above in respect of prices charged by municipalities.

3.2.5 Energy pricing policy and the 2008 pricing guidelines

The 2008 Electricity Pricing Guidelines (**Electricity Pricing Guidelines**) essentially are a guide issued by NERSA indicating the methodology followed in establishing tariffs. In regulating tariffs, NERSA seeks to enable an efficient distributor of electricity to recover the full costs of licensed activities, and in addition, a reasonable return and margin as required by section 16 of ERA.

Tariffs for large municipalities are approved by NERSA on an annual basis and on a multi-year basis in respect of Eskom. In respect of large municipalities, NERSA approves a percentage guideline increase as well as municipal tariff benchmarks. The percentage guideline increase is developed based on the determinations made in respect of Eskom. The municipal tariff benchmarks have been developed based on five tariff categories and their corresponding average consumption levels. The tariff categories of customers: commercial / business; industrial / manufacturing customers; agricultural / rural customers; schools / hostels / places of worship.

In respect of wheeling arrangements, such transactions involve a financial reconciliation on Eskom's bill in respect of the energy purchased between the generator and buyer which includes use of system charges associated with the delivery of the energy.

In respect of the bi-lateral agreements entered into between municipalities and customers, as stated in the section above, the Constitution draws a distinction between municipalities charging fees for services and surcharges. We are of the view that municipalities are not entitled to impose excessive wheeling tariffs that it would have otherwise recovered by supplying electricity directly to customers.

The 2008 Electricity Pricing Policy expressly provides the following:

- Clause 2.6 obliges network owners to permit customers to have access to and use of the networks provided that such customers are not in arrears in payment of all relevant charges as approved by NERSA from time to time, and that such access would not violate any technical or safety requirements
- Clause 2.6 further provides that the full cost to operate a network should be reflected in the various connection and use of system charges, and that no additional charges are required to facilitate the wheeling of electricity between two parties unless such wheeling would result in incremental costs.
- Clause 2.6 further expressly provides that, if wheeling parties are affected by network constraints causing congestion, NERSA is obliged to develop a mechanism which would

allocate network capacity between interested parties, which mechanism must be fair, non-discriminatory and transparent.

Accordingly, the municipality is not entitled to seek to levy a surcharge on electricity services for wheeling unless incremental costs will be incurred.

Moreover, in particular, customers entering into wheeling agreements should not be paying any retail element associated with energy procured from another source.

While the Electricity Pricing Guidelines (not being a regulation) do not have force of law, a failure to adhere to the guideline may result in any tariff determination being judicially reviewed for want of administrative fairness and failure to pass the 'rationality' test.

3.2.6 2012 Third Party Access Rules

Pursuant to its obligations under Section 35 of the ERA, the Regulator has published "Regulatory Rules on Network Charges for Third Party Transportation of Energy" (**2012 Third Party Network Charges Rules**), ostensibly to regulate the pricing of network access and transportation of electricity across transmission and distribution systems.

The 2012 Third Party Network Charges Rules set out in detail the objective of use-of-system charges, specifically the promotion of non-discriminatory access, prices reflective of the cost of providing services based on relative utilization of the network, non-discrimination, transparency, and revenue recovery by service providers to be sufficient to sustain the transmission/distribution businesses and allow for appropriate expansion of networks.

- Clause 3 of the 2012 Third Party Network Charges Rules expressly stipulates that the objectives of the use-of-system charges are, amongst other things, the promotion of non-discriminatory access, being the ability of customers to contract independently with independent power producers and use of the transmission and distribution networks to generators.
- As to the principles pertaining to use-of-system charges, clause 6 of the 2012 Third Party Network Charges Rules expressly stipulates that any load customer shall be free to conclude bilateral arrangements with any third-party generator that is not Eskom nor a municipality.

These rules included the methodologies for developing transmission and use of system charges but as NERSA developed new transmission and distribution tariff codes, the methodologies described in the 2012 rules are now obsolete. The 2012 rules do not describe how parties could actually access the grid and the type of contracts they should sign with transmission and distribution owners (what is usually called a transmission/distribution use of system agreement). The rules also do not discuss how the transmission owner(s) would relieve grid congestion.

As will be noted under the recommendations set out in this report, the 2012 Third Party Network Charges Rules should be substantially amplified from a tariff framework to include a framework for the non-discriminatory access by third parties to the Eskom transmission network and the Eskom and municipal distribution networks. These revised rules would need to be complimentary to a market code, which would include for example, the rules for scheduling for each of the markets: day ahead, balancing, imbalance pricing methodology, specific congestion management rules, various charges that the TSO could invoice, etc.

3.2.7 Licensing

As highlighted above, section 15 of ERA sets out the tariff principles applicable to transmission and distribution licenses issued by NERSA. These principles are reinforced by clauses 5.2.4 and 5.2.5 of the typical municipal distribution license, which stipulate that NERSA shall determine the prices at which the licensee shall supply electricity to its consumers, and that the licensee is not permitted to charge any consumers with other tariffs other than specified in the attached schedule (as revised from time to time) without NERSA's approval. Pursuant to this framework, the typical municipal distribution license expressly requires the municipality to maintain separate, ring-fenced accounts in respect of the electricity distribution business affairs from its other affairs so that, amongst other things, the cost of providing electricity services can be measured accurately.

Similarly, the Eskom transmission and distribution licences expressly stipulate that Eskom as a licensee must provide for non-discriminatory access by third parties to the transmission and distribution power systems, and that it may not discriminate between customers, classes of customers, or end-users, regarding access, tariffs, prices, or conditions, except where objectively justifiable and identifiable differences have been approved by the Regulator.

The City of Cape Town distribution licence issued in 2010 contains similar provisions.

However, the typical municipal distribution licence issued in 2007 does not contain similar express provisions pertaining to non-discriminatory access. In our view, this obligation is to be imputed by virtue of the express provisions of section 21(2) of ERA, and the efficacy and applicability of section 21(2) is not negated simply because the provision is not expressly referenced in the municipal distribution licence. It is understood that certain municipalities contend that, inasmuch as their distribution licences do not expressly reference this obligation, they are not so obliged. In our view, such position is without merit. The express obligation under section 21(2) not to discriminate as regards access cannot be ignored and must be given effect to unless and until such provision in ERA is repealed.

Indeed, the fact that the Eskom distribution licence and the City of Cape Town distribution licence contain these provisions are probably reflective of the fact that such licences were issued in 2010, when the idea of 3rd party network access was coming to the fore given the impetus in IPP development. This clearly was not an issue of major relevance in 2007, when the typical municipal distribution licence was issued.

However, to avoid confusion that may arise from the application of the provisions of section 21(3) of ERA, and to avoid any contention by Eskom or the City of Cape Town that they are being discriminated against, it is strongly recommended that NERSA amend the municipal distribution licenses to include such express stipulation similar to that as set out in the Eskom and the City of Cape Town distribution licenses.

Tariffs for transmission and distribution are expressly stipulated in licence conditions as being "as approved by the Regulator".

3.2.8 Use of system tariff methodologies (T&D tariff codes)

Use of system charges are fees that are levied for the use of the electricity network. This is different to other charges, e.g. for the generation of electricity or for the retailing of electricity.[58] In the context of South Africa, users of the network are either end-customers, municipalities (who off-take from Eskom's network, but currently buy generation and transmission as a bundled tariff) or energy traders (who purchase electricity from IPPs and pay for its transportation to end-customers).

Use of system charges are therefore the price paid to the network owner for the use of their system in transporting and distributing electricity. These charges should send a price signal to network users that reflects the cost of providing network services to different customer types, in

[58] Electricity retailing is not an established concept in the South African market. Electricity retailers buy wholesale electricity from generators, pay for its transportation across the network, then charge a mark-up on top of this to end-customers (e.g. to cover billing, meter reading, collection, retail margins, etc.). This latter part is the retail charge. We can also make a distinction between the retail function to final customers which eventually should be unbundle from the network function and wholesale retail similar in part to the current trading function.

order to incentivise network users to make economically efficient decisions. Therefore, a pre-requisite for developing transmission and distribution tariffs is a solid understanding of the cost structure of the business (i.e. cost to serve) and cost drivers. Once this is understood, costs can then be transformed into tariffs (i.e. prices) to be charged to customers for using the network.

Methodologies to calculate these charges can be complex and difficult to implement. South Africa has relatively well developed guidance that covers the principles for calculating use of system charges. These are defined in the following documents:

- The Distribution Tariff Code, which is a sub-chapter of the Distribution Grid Code.
- The Transmission Tariff Code, which is a sub-chapter of the Transmission Grid Code.

NERSA also publishes a "Cost of Supply Framework" which sets out high-level principles for rate setting and makes specific reference that tariffs should be developed in line with the principles and formulas in the Distribution Tariff Code.

Additionally, there is guidance available in the NRS-058 guidelines developed by a Working Group (including Eskom, NERSA, and municipalities) on behalf of the Electricity Suppliers Liaison Committee. These guidelines set out the process for developing a robust cost allocation between different customer categories, which can then be used to develop tariffs.

Distribution Tariff Code

The Distribution Tariff Code sets out the principles and guidelines for developing unbundled tariffs charged by companies operating the distribution network to its customers. As there is no separate concept of an energy "retailer" in South Africa (other than traders) the retail component of tariffs is also considered in this document.

This code embodies the principles of non-discriminatory charging for grid access in a number of ways, including:

- Stating that "open nondiscriminatory access for the use of [network] capacity" is necessary by all licensed distributors.
- By requiring unbundled tariffs to be provided where retail tariffs are not applicable (Section 4.2.2). In other words, separate distribution network charges must be provided where a full supply contract is not in place (i.e. where a customer is provided energy by a third party).
- To allow for cost reflective tariffs, costs must be unbundled into separate energy purchase, network (transmission purchases and distribution costs) and retail /service components.
- Stating that cost reflective tariffs should be calculated and that all tariff rates should be based on NERSA-approved regulated revenue requirements.
  - All tariffs should be based on a cost of service study.
  - Tariffs should allow for the recovery of regulated revenues.
  - Subsidies can be applied on top of cost reflective tariffs subject to approval by NERSA, and should be shown separately. Levies for non-electricity revenues (e.g. for other services provided by municipalities) may never be embedded in the regulated tariff and must be shown separately on the bill.
- However, there is some inconsistency in the Tariff Code as it states tariffs cannot be charged based on customer specific assets or services. This is inconsistent with the concept of cost reflectivity since, if customer-specific assets can be identified then costs related to these assets, by definition, are related to that specific customer

As set out in the Code, NERSA is responsible for approving all tariffs and tariff calculation methodologies.

The Distribution Code then goes further in its "Appendix 1 –Guideline to designing tariffs" on the approach and formulae that should be adopted for designing tariffs, and refers to NRS-058 as the approach that should be adopted for unbundling and allocating costs.

The appendix of the Distribution Code also provides a detailed description of the process for developing tariffs, including separate distribution use of system tariffs. It summarizes the relevant cost drivers and cost elements that relate to different tariff elements, as shown in the figure below.

Figure 3-12: Rate Components as set out in the Distribution Tariff Code

	Energy costs	Admin costs	Customer service costs	Network capital costs	Network O & M costs	Network overheads	Energy losses or geographic differentiation
R/customer/day based on std sizes	✗	✔	✔	✗	✗	✗	✗
Single c/kWh	✔	✗	✗	✗	✔	✔	✔
TOU c/kWh	✔	✗	✗	✗	✔	✔	✔
TOU seasonal c/kWh	✔	✗	✗	✗	✔	✔	✔
Seasonal c/kWh	✔	✗	✗	✗	✔	✔	✔
R/kVA – annual utilised capacity	✗	✗	✗	✔	✗	✔	✗
R/kVA – monthly capacity (could include TOU signals)	✗	✗	✗	✗	✔	✔	✗

Source: Distribution Tariff Code Version 6.1

Overall, the Distribution Tariff Code provides the fundamental requirements for developing unbundled distribution use of system charges in a consistent and theoretically robust manner. It is also a requirement for licensees to develop tariffs that are consistent with this code.

However, the code stops short of mandating an approach a specific methodology to calculating use of system tariffs by stating "*[Appendix 1] is a guideline for tariff design. Each distributor shall publish its own methodologies once approved by the NERSA.*" **Therefore, distribution licensees are allowed (under this Code) to develop their own methodologies for approval by NERSA**.

This could create significant divergences in approach (and tariff levels[59]) due to the large number of municipalities, compared to a system whereby a single methodology is imposed. An example of a system with a mandated use of system methodology is Great Britain which is governed by a single multi-party contract. This is summarized in the figure below.

Figure 3-13: Distribution tariff code in Great Britain

The Distribution Connection and Use of System Agreement (DCUSA) is a multi-party contract between licensed electricity distributors, suppliers and generators in Great Britain concerned with the use of the electricity distribution system. It sets out a range of information on governance, relationships between stakeholders, technical parameters and charging.[60] The DCUSA replaced numerous bi-lateral contracts, giving a common and consistent approach to the relationships between parties in the electricity industry.

59 There are very large cost differences among SA discos and thus very large differences in retail tariff to customers. Some countries have national uniform pricing policies where some discos subsidize others via a fund mechanism.

60 https://www.dcusa.co.uk/dcusa-document/

However, unlike in South Africa, the DCUSA sets out specific methodologies that must be used for calculating charges for the use of the electricity distribution network. This is split between:

- The Common Distribution Charging Methodology (CDCM), which applies to customers connected at voltages lower than 22kV. This covers most of the customers in Great Britain.
- The Extra high voltage Charging Methodology (EDCM) covering the calculation of site specific charges for customers connected to the extra high voltage network (above 22kV).

The DCUSA includes formulae and rules on the calculation of tariffs. Alongside the legal text of the DCUSA, DCUSA Ltd (the company established, owned, and funded by parties to the DCUSA to administer the governance of the DCUSA) publishes standardized charging models for the CDCM and EDCM.[61] Each distribution network then populates a copy of these models to produce use of system tariffs. This ensures that the tariff structure and calculation methodology is standardized across all networks.

Source: CPCS analysis

Transmission Tariff Code

The Transmission Tariff Code has similar statements to the Distribution Tariff Code in terms its objectives to provide open and non-discriminatory access: "*NTC transmission tariffs shall be designed in pursuit of the following objectives: Open access to the transmission services at equitable, non-discriminatory prices to all customers…*"[62] It also embodies the principles of cost reflectivity and revenue recovery (as does the Distribution Code).

The Code sets out the four categories of charges (Network Charge, Connection Charge, Losses Charge, and Reliability services Charge) that can be levied and specifies that revenue recovery is split 50:50 between generators and load.

Unlike the Distribution Code, the Transmission Tariff Code includes a calculation procedure for each tariff component to be followed (whereas the Distribution Code contains "guidelines" in its Appendix).

3.2.9 Challenges: current implementation by Eskom

Eskom publishes its tariffs on its website.[63] Eskom has a range of tariffs available depending on the category of customer. These are built up based on a combination of charges for energy, use of the electricity network (separate transmission and distribution use of system charges), administrative charges, subsidy charges, and adjustments for network losses. Eskom does not have a separate retail charge – it has administrative and service charges, but these appear to be levied whether or not Eskom is generating electricity for customers.

When a customer enters into a wheeling agreement with a non-Eskom generator:

- Eskom uses a net billing framework whereby it charges customers for the full cost of energy (i.e. as if Eskom is supplying all electricity) and then credits the customer account for the wheeled energy (excluding losses) and the affordability subsidy charge.[64]
- Eskom then levies an additional administration charge for undertaking this reconciliation.
- We understand that under normal circumstances,[65] Eskom does not allow "banking" of credits where the amount of energy generated exceeds the amount consumed at the customer's metering point – i.e. customers are not allowed to go into credit, or carry credits over from month-to-month.

[61] https://www.dcusa.co.uk/publications/

[62] The South African Grid Code Transmission Tariff Code Version 10

[63] https://www.eskom.co.za/CustomerCare/TariffsAndCharges/Pages/Tariffs_And_Charges.aspx#:~:text=On%209%20March%202020%2C%20the,implemented%20on%201%20July%202020.

[64] Note: Eskom does not allow generators or load connected at low voltage to enter into wheeling agreements.

[65] Although banking can be agreed with Eskom, which would also attract an additional Administration Charge.

In parallel, the customer will pay the generator the agreed upon price of the electricity provided (which is currently also regulated by NERSA, which is totally uncommon for open market transactions), as per their bilateral contract.

Figure 3-14: Challenges with the Eskom net billing arrangement

- This system creates an additional cost to Eskom, which is charged as an additional administrative charge to customers on their bill. Based on Eskom's published rates, this charge is relatively small, ranging from R 3.7 to R 148 per day depending on the voltage at which customers are connected.[66] This means that Eskom effectively treats wheeling as an additional service, on top of its normal practices
- This could be seen as discriminatory as: (1) customers who do not wheel energy do not pay this charge (i.e. there is an additional cost to wheeling compared to purchasing from Eskom); and (2) Eskom continues to make a retail margin on the component of energy supplied by third parties (i.e. Eskom does not deduct any retail component from customer bills).

Typically, generators/customers should also pay an imbalance charge if the metered production and consumption is different from the schedule sent the day ahead for actual production and consumption. Eskom has not imposed any imbalance charges under the current net billing system (except for the implicit penalty that customers may face due to the inability to go into credit on their bills).

- At this stage, given the relatively small amount of electricity contracted under this framework, this does not pose a burden on the system in real time.
- However, if the number of bilateral contracts between non-Eskom generators and customers grows then the lack of an imbalance charge would become an issue as the total amount of imbalances might require Eskom SO to carry out more actions in real time.
- While the restriction on going into credit and banking energy provides some incentive to customers to not under-consume compared to the amount agreed in their PPAs with generators, it does not provide any incentive to be in balance.

Therefore, there is a limit to the extent to which wheeling contracts can proliferate under this framework, before Eskom will require imbalance charges to be introduced. Introducing imbalance charges would fundamentally change the risk allocation for market participants.

3.2.10 Challenges: implementation by municipalities

Tariffs for customers connected to municipal networks are developed by municipalities and approved by NERSA, and published on NERSA's website.[67] Municipal tariffs do not have a common structure and there can be materially different levels of charges for neighbouring municipalities. In addition to this, other than a couple instances it does not appear that municipalities have (or at least do not publish) use of system, or wheeling, charges for customers wishing to enter into bilateral contracts with a non-Eskom generator.[68]

Therefore, what we observe is that municipalities do not have a standard structure for charges nor do they have a standard methodology for calculating use of system charges. This means that municipalities are left to develop their own methodology and determine their own use of system charges. This should be done in line with the relevant regulations and distribution tariff Code (discussed above)[69].

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[66] WEPS NLA Administration Charge, Eskom 2020/21 SCHEDULE OF STANDARD PRICES FOR ESKOM TARIFFS

[67] For example, see the approved tariffs for 2018/19 here: http://www.nersa.org.za/Admin/Document/Editor/file/News%20and%20Publications/Publications/Current%20Issues/NERSA%20Approved%20Municipal%20Electricity%20Tariffs%202018_2019.pdf

[68] In NERSA's publication of tariffs only the City of Cape Town, Stellenbosch and City of Tshwane publish "wheeling" charges and even these are vastly different (and it is not clear how they are implemented in practice from this document).

[69] We can even argue that NERSA methodology should not be a guideline but mandatory; this would not prevent different use of distribution charge between discos but at least, a transparent one for potential open market participants to understand.

Very few municipalities have published an approach to third party access and use of system charges, with the notable exception of a couple metropolitan networks as highlighted in Figure 3-15 below.

Figure 3-15: Example of approaches to wheeling by metros

City of Cape Town[70]

The City of Cape Town has calculated use of system charges (shown in the table below), which it proposes to apply to all customers regardless of whether they are supplied by Eskom or a trader. Where the customer is in deficit (i.e. the IPP production is less than customer consumption) then the City supplies the remainder at the regulated electricity tariff (i.e. the rate applicable to municipal customers). Where customers are in surplus (i.e. consumption is less than IPP production), the City proposes to buy the surplus energy at a set rate which we understand that the City of Cape Town is thinking about using the lesser of WEPS and REIPPP bid price (minus green benefit),[71] which means that the City allows a form of "banking" (unlike Eskom).

Figure 3-16: Wheeling use of system charges (2019/20 high demand season)[72]

Service Charge	R/day	115.71
Peak	c/kWh	100.22
Standard	c/kWh	53.19
Off-peak	c/kWh	43.88
Demand charge	R/kVA	-
Network access charge	R/kVA NMD	-

In addition to the above, we understand that the City of Cape Town also has an independent retail arm, whereas most other municipalities do not.[73]

City of Ekurhuleni[74]

Annexure D24 of the City of Ekurhuleni's Medium - Term Revenue and Expenditure Framework (MTREF)[75] sets out their policy for wheeling of energy. This policy describes the eligibility criteria (which is limited to certain voltages and tariff classes[76]) and the agreements that are required for wheeling over the municipal network (it also requires the consumer to provide a copy of the agreement between the generator, trader and customer to the City). The policy states that customer accounts will be credited for wheeled energy – this implies that the billing approach is a 'net billing' arrangement like Cape Town and Eskom. The City's policy does not allow for banking, so any IPP production in excess of customer consumption is not credited.

In addition to the lack of a standardized approach to use of system charges, municipalities are left to develop their own policy toward third party access, but in practice it appears that very few actually publish a policy.

This can make negotiation for third party access to municipal networks difficult, especially where no policy exists. It can also create divergences in the terms of access, e.g. for customer eligibility, which appears to be defined by municipalities. For instance, the City of Cape Town allows for

[70] Sources: http://resource.capetown.gov.za/documentcentre/Documents/Bylaws%20and%20policies/Tariff%20Policies.pdf, http://www.cityenergy.org.za/uploads/resource_501.pdf

[71] SEA (2020) "*Wheeling Discussion Paper, A guide for municipal electricity distributors*"

[72] http://resource.capetown.gov.za/documentcentre/Documents/Financial%20documents/Electricity%20Consumptive%20Tariffs.pdf

[73] CPCS interview with AMEU (October 23 2020)

[74] https://www.ekurhuleni.gov.za/council/by-laws-policies/policies/budget-related-policies/4805-annexure-d24-policy-for-the-wheeling-of-electricity-new/file.html

[75] Full name "*Reviewed Integrated Development Plan (IDP), Medium - Term Revenue and Expenditure Framework (MTREF), And Built Environment Performance Plan (BEPP): 2020/2021 To 2022/23*"

[76] This is interesting and realistic but in practice, illegal under the current legal framework where all customers are in theory, eligible

wheeling at the medium and high-voltage levels (11kV and higher) whereas the City of Ekurhuleni allows for customers above 6.6kV to wheel energy.

We understand that many municipalities have not developed use of system charges for various reasons, such as:[77]

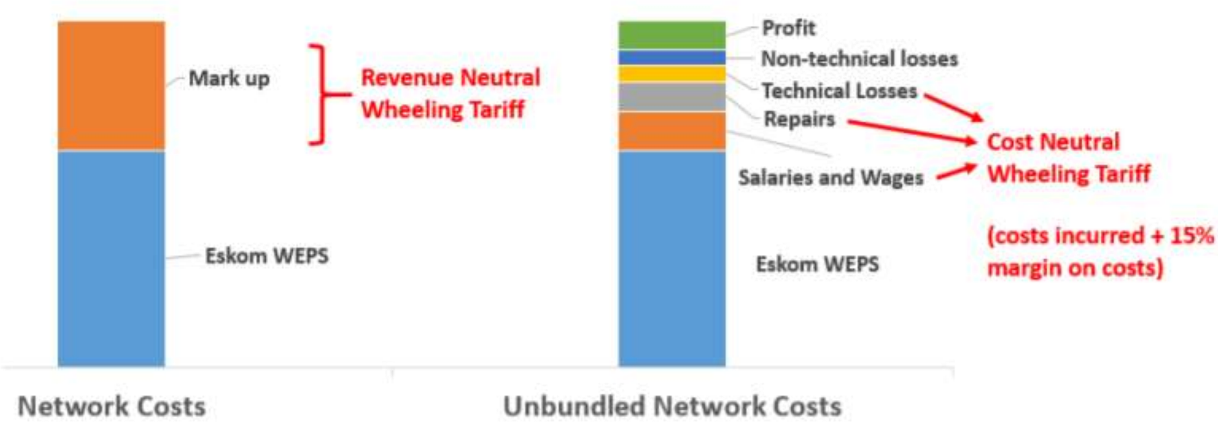
- The lack of understanding on the cost of supply and accounting separation. Understanding the cost of supply requires cost of supply studies which should be carried out regularly, but are often not carried out due to lack of funds (though we understand that the cost of these studies is recoverable through tariffs).
- The lack of a clear understanding of the current framework and how to contract with IPPs.
- The complexity of calculating use of system charges.
- The perception that municipalities will lose customers and hence revenue.

To encourage more bilateral contracts with customers in municipal networks it would be helpful to:

- Have a national phased approach to eligibility as discussed in the next section. This should include a standard use of system agreement / standard amendments to supply agreements.
- Have transparent cost reflective unbundled use of system charges for each municipality, based on a standardized approach and tariff structure if possible.

Previous work by SEA[78] noted that, while the EPP requires municipalities to calculate unbundled cost reflective use of system charges, most municipalities do not have up to date cost of service studies (though we understand there is work underway on this). As a result, municipalities have developed a "*revenue neutral*" approach whereby the energy costs (represented by the Eskom WEPS price) is deducted from customer bills (as shown in the figure below). This is effectively the same as the Eskom net billing approach.

Figure 3-17: Revenue neutral versus cost neutral tariffs



Source: SEA (2020), Wheeling Discussion Paper

The SEA paper notes that revenue neutral does not provide the best price signals but argues that it can still be "fair". However, as with the Eskom net-billing approach, this ignores the retail component of charges which should also be deducted.

[77] Source: Discussion with industry stakeholders and previous reports, including SEA (2017) "*Sustainable energy solutions for South African local government, A practical guide*"
[78] SEA (2020) "*Wheeling Discussion Paper, A guide for municipal electricity distributors*"

3.2.11 Other challenges: balancing issues, lack of phasing and definition of eligibility criteria

According to the law, all customers are de facto eligible and could, in theory, choose their retailer (supplier) of energy. As we have seen in the above sections, there are various obstacles for customers to practically buy power at lower cost and/or choose a specific retailer. We have also seen that at least two municipalities have effectively developed their own eligibility criteria which is theoretically illegal but could make sense if the approach was standardized across all South Africa.

This lack of phasing in market opening and the lack of definition/criteria to determine who could actually buy their power directly from a retailer or GENCO is a problem. Most competitive markets around the world have been developed gradually, including the recent case of Namibia, which is planning its opening in various phases as shown in the figure below. Such a phasing approach usually leads to a more efficient development of the market without various disputes.

Figure 3-18: Namibian market opening phases

Phases	1a (1st Sep 2019 – June 2021)	1b (July 2021 – June 2026)	2 (July 2026)
Contestable purchases National Cup	• 30% of total national purchases	• 30% of total national purchases	• As determined by Regulator
Contestable purchases Customer Supply Point Cap	• 30% of total customer purchases • For distributors this volume is reduced by 30% of the purchases by >1MVA connected customers	• As determined by Regulator	• As determined by Regulator
Contestable Customers	• Tx connected	• Tx connected • Dx connected (>1MVA) • Dx connected (<1MVA) as determined by Regulator	• Tx connected • Dx connected (>1MVA) • Dx connected (<1MVA) as determined by Regulator
IPPs	• Licensed • Tx or Dx connected • Capacity ltd by sales to Contestable Customers	• Licensed • Tx or Dx connected • Capacity ltd by sales to Contestable Customers	• Licensed • Tx or Dx connected • Capacity ltd by sales to Contestable Customers
Exporters	• Licensed • No size limit	• Licensed • No size limit	• Licensed • No size limit
Traders	• On application and approval by Regulator; Licensed • No trading volume limit	• Licensed • No trading volume limit	• Licensed • No trading volume limit
Importers	• Not allowed	• Not allowed	• Licensed • Capacity ltd by sales to Contestable Customers

Source: Namibia, market design document, 2019

Eligibility criteria

The concept of eligible consumer criteria is usually defined based on the size of the industrial sector, as well as the availability of generation (current and future). This topic is complex and several critical questions need to be answered to define eligibility, for example:

- Include or exclude self-supplied demand?
- Can eligibility be lost if consumption falls below a threshold?
- Can potential eligible customers opt to remain under the regulated tariff or can they go back to the regulated tariff if they opt to sign a non-regulated contract?
- Eligibility is an amount of energy consumption/demand per year (MWh/year) or load per year (MW/year) or some model combination?
- How will embedded generation be treated in the context of market opening and whether embedded generators will be eligible consumers?

- How will the demand of an eligible consumer be established, i.e. accumulated (multi-site) or distributed (single-site)?
- Is eligibility to be considered as a one-time award or it is a moving target, i.e. can eligibility be lost if consumption falls below threshold?
- Is eligibility to be considered as a mandatory status at certain threshold or eligibility is a status to be awarded by consumer choice, i.e. can potential eligible customers opt to remain or not under the regulated tariff?
- If eligibility is mandatory, what incentives are to be established for potential eligible consumers to get awarded with the status?

Regarding the phasing of additional market opening, there is a need for sufficient years between each new phase of eligibility for the system to cope. Usually, the national regulator can decide with a certain level of discretion. This phasing approach to eligibility works especially well with the hybrid market model.

There is also the issue of the eligibility of the municipalities. We discussed above their poor financial situation rendering them not bankable as well as their lack of knowledge about load forecasting, procurement, etc. While there is a recent court case involving Cape Town, a practical approach would be to allow municipalities to contract only a small % of their expected load in the initial years and increasing over time. This is the approach taken in Namibia.

3.2.12 Other challenges: New IPP bankability

The IPP market in South Africa is in constant development and expansion. For example, DMRE presently is engaged in the procurement of 2,000 MW of dispatchable new generating capacity from a range of energy source technologies, for the purpose of ensuring energy security in the short term. This procurement is under the so-called Risk Mitigation Independent Power Producer Procurement Programme (RMIPPP). Twenty-eight projects have been submitted in the Bid Submission phase of the procurement and eight Preferred Bidders with a combined capacity of 1,845 MW have been appointed. a further three Eligible Bids with a total capacity of 150 MW are subject to satisfactory value for money proposition in line with the provisions in the Request for Proposal. Appointed projects will be required to achieve commercial operation by no later than 31 December 2022. Eskom is the designated off-taker under a template PPA.

In addition, DMRE has issued the fifth round under REIPPPP in April 2021. In this context, if the South African decision makers decide to implement a competitive electricity market where IPP will be selling energy into the market (with an associated capacity market or not), there will need to be an announcement far ahead to prepare the developers and organize various capacity building workshops.

Even if a decision is taken and communicated way ahead of time, there might still be a need for a default buyer option to reassure some lenders. Competitive electricity markets can provide a relief valve for long-term contracts. Short-term electricity markets are inherently more volatile and lenders will need to adapt and learn how to price these new merchant risks.

3.2.13 Potential required changes in the legal/regulatory framework

The relevant legislation and regulations make it clear that network owners (i.e. licensed distributors) may not refuse access to the grid for wheeling electricity, provided such access does not violate any technical or safety requirements. The market model remains a quasi-single buyer one with a good system for tendering new generation. It is possible to revise the regulatory framework to increase the level of direct contracting between consumers, traders and IPPs but this will always remain marginal if there is not a fundamental review of the overall legal/regulatory framework and market model.

That said, the current framework for wheeling could be strengthened in the following manner:

- The 2012 Third Party Network Charges Rules should be amplified and adjusted to be more reflective of its actual documentary title ("2012 Third Party Access Rules") as opposed to being a tariff document. Such Third Party Access Rules should:
  - Stipulate expressly the distributor's obligation to afford non-discriminatory access in accordance with section 21 of ERA.

    Provide expressly for the appropriate tariff framework, taking cognizance of what is set out above with respect to section 15 of ERA, the Grid Code, the 2008 Pricing Policy, the Tariff Code, and the requirements under the Municipal Systems Act and MFPFA.
- Municipal distribution licenses should be amended to include the non-discrimination provisions of section 21(2) of ERA, to eliminate potential confusion and misdirection arising from the provisions of section 21(3) of ERA in the absence of such express inclusion in the municipal distribution license.
- Standardize the approach to wheeling across municipalities, including the definition of eligibility criteria, use of system tariff methodologies, and use of system agreements.
- Make the distribution tariff methodology, as set out in the Distribution Code, a requirement rather than a "guideline" and unbundle the retail component of tariffs from other components.
- Investigate eligibility further, including the legal basis for defining eligibility under the current framework (as noted, the legislation requires open access as long as it does not violate any technical or safety requirements) and the potential to have a phased approach to eligibility.
- Implement a billing system for levying use of system charges at Eskom, which does not require "netting" to be undertaken. In so doing, remove the additional service charge levied for wheeling.
- Develop an imbalance pricing regime as well as the market code which will govern competitive markets in the future. The market code would go hand-in-hand with third party access regulation and would include for example, the rules for scheduling for each of the markets: day ahead, balancing, imbalance pricing methodology, specific congestion management rules, various charges that the TSO could invoice, etc. It is understood that Eskom is already developing such as code but we did not get a copy for review.

Furthermore, for the introduction of a real competitive electricity market, there will also be a need to amend the electricity law to reflect the chosen market model, steps of implementation, etc. It would probably need to reflect on how the current tendering system for new generation based on an initial Integrated Resources Plan would eventually be replaced by a market-based system with a transitory arrangement where a central purchasing agent could be created to deal with some stranded assets and be potentially a default off-taker. Alternatively, there could also be pure market system with capacity and energy markets to support new IPP generation.

Notionally, this might require legislative adjustments similar to those brought about in Kenya in 2019, in particular as regards the establishment of an independent SO. South Africa was well advanced along this path with the ISMO Bill until it was terminated in 2014. The ISMO Bill may require resurrection and review. More importantly, legislative adjustments to ERA and the regulations promulgated thereunder will be required in order to facilitate competition in generation and retail (supply) as opposed to discretionary regulation by NERSA in accordance with so-called policy guidelines (e.g. NERSA being involved in bilateral contracts approval). Furthermore, the discretion as to new generation capacity vested in the Ministry of Mineral Resources and Energy (DMRE) may have to be removed in order to allow IPPs to compete in capacity (possibly) and energy markets.

4 Proposed Sector Reforms in South Africa

This chapter provides the policy background, summarizes some of the previous attempts at reforming the sector, discusses the ongoing unbundling of Eskom, and sets out what we know about the proposed market model for the future of the sector.

4.1 Government policy

4.1.1 Energy Policy White Paper

An Energy Policy White Paper was published by the Department of Minerals and Energy in 1998 (22 years ago), which was then the first white paper for the sector since 1986 (12 years previous). There have been no further white papers published by Government since.

The White Paper was designed to "clarify government policy regarding the supply and consumption of energy for the next decade." This came on the back of the end of apartheid and the desire for increased democratisation in various economic sectors. The White Paper had a number of recommendations specifically for the electricity distribution sector, including:[79]

- **Restructuring the distribution sector.** This envisaged consolidating the numerous distributors, many of whom had less than 1,000 customers and many of which were not financially viable (e.g. in some cases failing to pay Eskom for bulk supplies). It envisaged five financially viable Regional Electricity Distributors (REDs) would be created, which would be achieved by setting up a transitional structure for companies.

  In the restructured industry, the White Paper envisaged that industrial customers would be able to choose their supplier but did not envisage free choice of supplier for all customers at least in the short-term.
- **Reforming electricity pricing**. This included a range of proposed measures including rationalizing the number of tariffs/tariff structures, implementing cost reflective tariffs that reflect the revenue requirement a cost structure of utilities, establishing transparent subsidies for vulnerable customers / cross-subsidies, and minimizing cross-subsidies. NERSA would be in charge of regulating domestic electricity prices.
- **Encouraging the entry of "non-utility generation" in the market.** The purpose of this policy was to encourage new environmentally friendly generation to be deployed and to encourage more generators to enter the industry ***"in order to develop a competitive power market***". To enable this, the White Paper required Eskom to publish NERSA-approved tariffs for the purchase of independently generated electricity costs (i.e. use of system tariffs). It noted that NERSA would be responsible for finalizing the details of the methodology for calculating such tariffs[80].
- **Considering the potential for an alternative market structure in South Africa**. The White Paper stated that the "*Government will initiate a comprehensive study on future market structures for the South African electricity supply industry*" but that the actual implementation

[79] The White Paper covered a much broader range of topics than those enumerated here. We have focussed on those that are most relevant to the third party electricity purchases.

[80] This could be characterized as competition for the market and not IN the market and contradict the previous objective of letting industrial consumers to contract directly with IPPs.

of any market restructuring would come after the re-organization of networks. **Therefore, there was no vision for the future market structure presented.**

- **Restructuring of Eskom into separate generation and transmission companies,** in line with Government Policy on rationalizing State-owned assets.
- **Ensuring a sound sector governance structure is in place.** This includes:
  - Providing guidelines on the regulatory philosophy to be adopted by NERSA, through the passing of a new piece of legislation. Government also noted the need to increase the capacity of NERSA to deal with future sector challenges.
  - Strengthening the capacity of the Department of Mineral and Energy, which carries the responsibility for the development of Government policy in the electricity sector, in order to deal with future objectives of restructuring the distribution sector, introducing competition in the sector, etc.

4.1.2 Managed Liberalization and The Farm Inn Agreement[81]

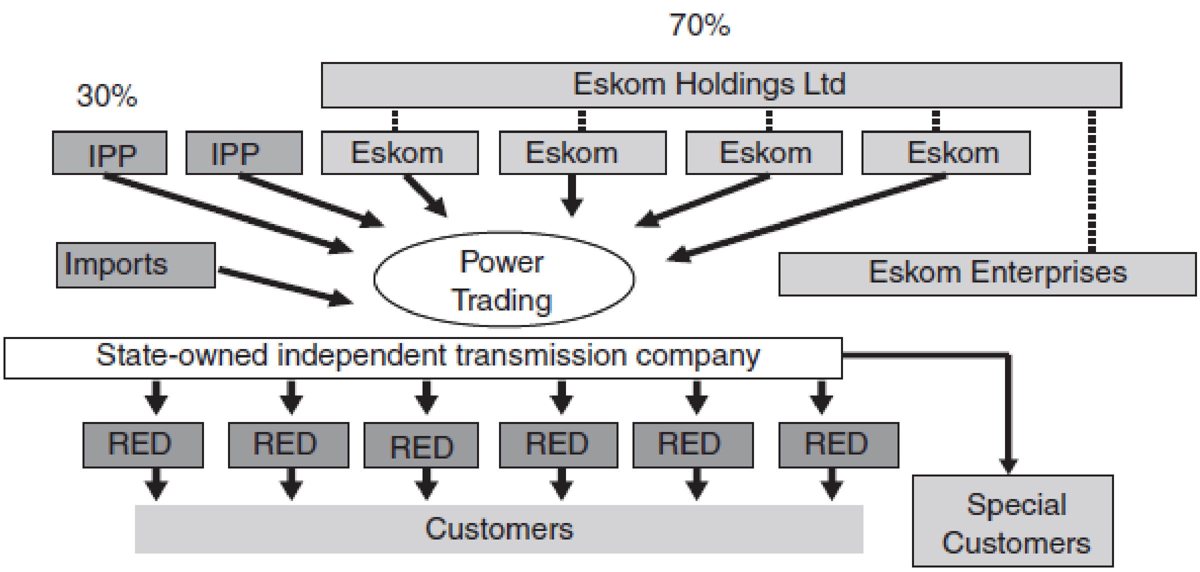
Following the 1998 White Paper, in May 2001, the Cabinet approved proposals for the reform of the sector through a "managed liberalization" process, the key elements of which were:

- Restructure the generation industry with Eskom retaining at least 70% of capacity, with the remainder being privatized.
- Unbundle Eskom to create a separate state-owned transmission company with ring-fenced system operation and market operation functions.
- Establish a **"multi-market model**" for the electricity market in which transactions between generators/traders/customers can take place on multiple platforms including bilateral contracts, a power exchange and a balancing mechanism.
- Develop a regulatory framework that facilitates the participation of IPPs.

The envisaged form of the market is set out below.

[81] Key source for this section is "The Political Economy of Power Sector Reform in South Africa" by Anton Eberhard (2004)

Figure 4-1: Market structure envisaged by Cabinet in 2001



Source: Anton Eberhard (2004), The Political Economy of Power Sector Reform in South Africa

Following this , the Farm Inn Summit took place in October 2001 and resulted in the Farm Inn Agreement which was signed in March 2002. In this agreement, the Department for Minerals and Energy, the Department of Public Enterprises (DPE), SALGA, NERSA and Eskom agreed on the broad next steps for sector reform and on the formulation of a "restructuring committee" chaired by DPE. This included the ring-fencing of Eskom's generation and transmission businesses.

Initial work was undertaken by this restructuring committee to implement the proposed reforms and development of this competitive market. However, this was not endorsed by senior Government officials and ministers and therefore never got off the ground. Subsequently, there was a follow-up Farm Inn Summit where significantly delayed target dates were set for reform.

- **The Energy Policy White Paper is now 22 years old.** Since that time, the energy landscape in South Africa, and globally, has changed significantly. At the time of publishing the White Paper, South Africa had a surplus of energy, whereas it is now suffering from energy deficits and load shedding. It is clear that the vision of the Energy Policy White Paper of "*adequate, reliable, and low cost electricity to serve the people and industries of South Africa*" has not been fully realized.
- **The White Paper did not cover what the future market structure should look like**, but did put the responsibility on the Department of Minerals and Energy to further develop policy around how to achieve further competition in the sector.
- The rationalization of the distribution sector was not successful and the re-organization of Eskom is still ongoing. Electricity pricing has been reformed but there is still a lack of consistency in pricing among municipal distributors and questions as to the level of cost reflectivity and cross-subsidization present in distribution tariffs. We understand that work is currently being done on establishing cost of service across some municipalities.
- The Farm Inn Agreement envisioned a multi-market model but was not described in details nor implemented (discussed below).
- Given the present realities in the sector and changes in energy landscape since 1998, **a refreshed Policy Paper that includes a detailed market design complementing the current Eskom unbundling would be a sensible undertaking.**

4.1.3 Roadmap for Eskom and a reformed industry structure

More recently, a "Roadmap for Eskom in a Reformed Electricity Supply Industry" was published by DPE in 2019. This paper sets out key steps to "transform" Eskom and set it on a path to provide sustainable electricity to all South Africans. It highlights key challenges for Eskom resulting from governance and operational misdemeanors over the past decade, which have led to multiple Government bailouts. These include:

- an unsustainable debt burden and a culture of non-payment from municipalities;
- poor governance and a gap in necessary skills/capacity;
- poor operational performance; and
- a vertically integrated business model that is no longer fit for purpose and lacks transparency.

The paper proposes a range of measures to address financial sustainability, including debt restructuring, operational improvements, debt collection, and the need for Eskom's regulated tariffs to allow for the recovery of efficient costs. In particular, the Roadmap proposes to unbundle Eskom into separate generation, transmission and distribution businesses (as per the figure below).

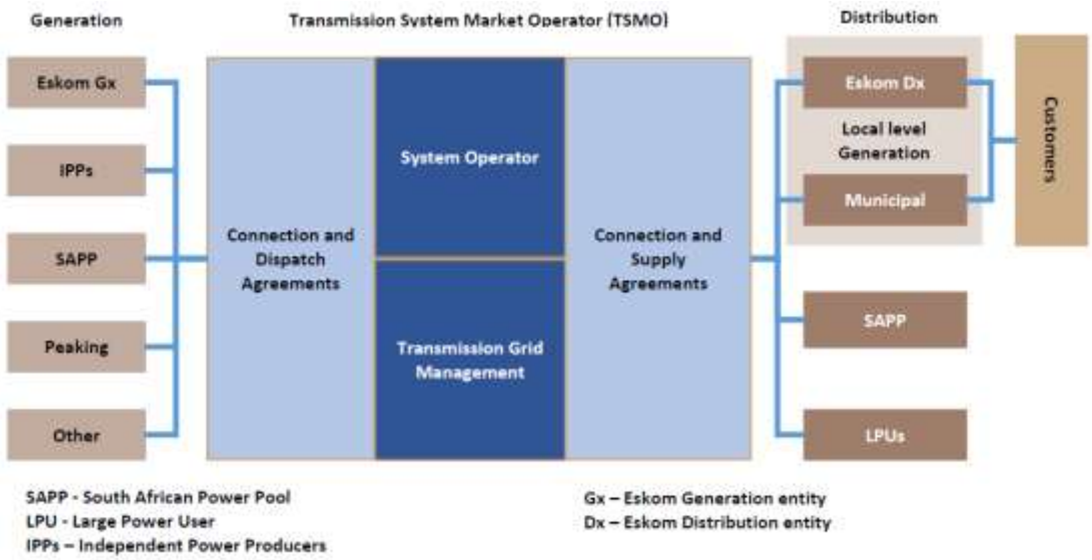
Figure 4-2: Roadmap for Eskom unbundling

Source: DPE (2019), Roadmap for Eskom in a Reformed Electricity Supply Industry

The unbundling of Eskom is in line with the 1998 White Paper, though goes further by elaborating the type of separation and isolating the distribution business as a separate business unit (in the White Paper, distribution was envisaged to be owned by REDs).

The reformed industry envisaged by the Roadmap is shown below.

Figure 4-3: Reformed electricity sector



Source: DPE (2019), Roadmap for Eskom in a Reformed Electricity Supply Industry

The description of the reformed sector does not discuss the specifics of the long-term model for the electricity market. However, it does:

- State that the new transmission system and market operator would be a single buyer and central purchasing agent, e.g. one of the main roles of the entity will be buying electricity from generators and selling to distributors (including Eskom Distribution).

  In the short term, each generation plant will be envisaged to have their own PPA with the transmission entity but will thereafter “transition to an open-market model.”
- Note that “The [transmission entity] will be empowered to introduce additional markets and products if necessary, such as, a reserves market.” This suggests it will be Eskom Transmission tasked with developing and implementing the “open-market model.”
- State that an internal trading system will be implemented (followed by legal contracting), and that market rules/structures will need to be clarified in future.
- Highlight that the transmission business will be required to provide grid access on a non-discriminatory basis to Eskom generation and IPPs. NB: this is no different to the current legal requirements of Eskom.

Status of Eskom Unbundling

Eskom has started divisionalisation, as the first state towards its restructured end state. Functional separation of transmission is scheduled for March 2021 while legal separation is scheduled for December 2021. The following figure shows more details about the initial market model and the role of the future ITSO.

Figure 4-4: Future role of the ITSO

	Create Eskom Subsidiary (Dec 21)	Capacitate Eskom Subsidiary (Dec 22)	Create ITSO (TBC)
	Eskom TSO (Phase 1)	**Eskom TSO (Phase 2)**	**Independent TSO**
Legal Status	• Eskom Subsidiary (TSO)	• Eskom Subsidiary (TSO)	• Independent governance (ITSO)
Market	• Eskom internal • Eskom based market rules	• Eskom Internal • External (based on legal position) • Eskom based market rules	• Fully operational external Market • NERSA approved rules
Contracts and Pricing	• Divisional contracts • Current Pricing	• Divisional contracts–amended • Unbundled Pricing	• External contracts • Unbundled Pricing
Balance Sheet	• Assets transferred - status quo • Loans estimated • Due diligence	• Assets transferred - refined • Loans transferred & agreed	• Assets transferred • Loans Transferred & agreed • Due diligence done prior
Operations: Processes and Systems	• Reliance on Eskom systems and processes (SLAs) • Initial MO systems in place	• Limited reliance on Eskom, further ring-fencing done • Sensitive systems secured • Service contracts for Eskom enterprise systems	• Fully ring-fenced processes and systems • Segregated IT capability
Staff	• Eskom staff seconded	• Staff transferred (Sec 197)	• Staff transferred (S197)
Regulatory / License	• Eskom License • Current Regulatory framework	• Eskom License • Current Regulatory framework	• New License • Revised Regulatory framework

Source, Eskom, CEO Presentation, Nedbank conference, October 15th 2020.

In section 5.2, we based our detailed recommendations based on this initial plan.

4.1.4 Operation Vulindlela

Operation Vulindlela is a Government initiative initiated by the President and led by NT. Its purpose is to support the implementation of the Economic Reconstruction and Recovery Plan, by accelerating priority structural reforms to revive the country's economy.

The initiative's focus is on speeding up priority reforms, many of which have been in the pipeline for years but have not yet been implemented. In the electricity sector, key areas of focus are:

- Increasing the role of IPPs.
- Unbundling Eskom.
- Improving availability of Eskom generation.
- Improving institutional inefficiencies in municipalities.

Through this programme, the NT is trying to push reforms by providing information and support that will help empower reform makers and hold them to account. Encouraging third party access and bilateral contracting for electricity is directly in line with the objectives of Operation Vulindlela, since having a transparent and open grid access framework will help (though may not solve) electricity shortages that constrain economic growth.

While a Steering committee oversees the overall reforms as part of the operation Vulindlela, it was clear through discussions with NT that DMRE is the Ministry responsible to develop further and finalize an updated detailed market design that would complement the Eskom reform process discussed in the previous section. While the road map for Eskom unbundling is straightforward, the details about the market are not very clear. It envisions a single buyer model but would also allow for traders – this could be called a hybrid model (as per chapter 2) especially with the potential introduction of a central purchasing agent. As repeated many times, these details would need to be presented in a **Market design policy paper.**

4.2 Eskom's proposed market model and market code

A high level market design has been developed by Eskom and has been presented to stakeholders but it has not been officially approved by DMRE. Furthermore, more details will need to be developed and included in what we call a **market design paper**. The following figure was presented in a recent conference[82].

Figure 4-5: Future market design as envisioned by Eskom

Just based on this presentation, it is difficult to determine exactly how the capacity market would work as well as the CPA. These are some of the market design issues that need to be confirmed. We could also add the issue of potential market power of Eskom if it was going to be able to freely bid into a day ahead and a balancing market given its size[83]. We discussed as well the probable need to have default options for new IPP financing instead of moving directly from long term PPAs with sovereign guarantees to relying on market prices only.

Based on discussions with Eskom, we understand as well that a draft market code explaining the rules for these markets has already been prepared but we have not reviewed it.

[82] Nedbank Conference, October 15th 2020

[83] The initial balancing arrangements could combine regulated bids and offers from Eskom with free bids and offers by other participants. Such arrangements have been implemented in some Southeast European countries in the mid 2000.

5 Summary of Key Challenges for Wheeling

This chapter summarizes the key challenges facing the sector and sets out a potential road map for increasing the level of competition in the sector, including considering potential changes to the existing wheeling framework that could be implemented ahead of more radical changes to the design of the market.

5.1 Summary of key challenges

The South African electricity sector faces various current challenges:

- Low operational efficiency of the recent new large coal fired plants leading to load shedding.
- Municipalities facing large financial difficulties and defending their rights to develop their own distribution tariffs.
- Eskom facing also large financial difficulties.
- The legal framework, which allows implicitly for consumers to contract directly but with no clear regulatory framework.
- Ongoing unbundling of Eskom after many years of failing to do so.
- The need to decarbonize the sector, to move to smaller renewable generation units and to add **16,000 MW** of new capacity over the next 10 years[84]

On the other hand, the sector has managed to develop a program for developing South Africa's renewable energy resource potential. According to the South African IPP Office[85] more than 6,000 MW of electricity has been procured from 112 renewable energy IPPs since the first REIPPPP bidding round.[86] Furthermore, approximately 4,276 MW of electricity generation capacity from 68 IPP projects to date has been connected to the national grid. In terms of current procurement, the DMRE released a request for proposals (RFP) for the Risk Mitigation Independent Power Producer Procurement Programme (RMIPPP) with the bid submission date at the end of 2020. RMIPPP sought the procurement of 2,000-3,000 MW, including from renewable energy sources. Eight Preferred Bidders with a combined capacity of 1,845 MW have been appointed. A further three Eligible Bids with a total capacity of 150 MW are subject to satisfactory value for money proposition in line with the provisions in the Request for Proposal. In addition, the fifth REIPPPP bidding window has been issued in April 2021, seeking to procure 2,600 MW new generation capacity from renewables.

In terms of the current framework for wheeling, there are many pieces that could be retained (e.g. Distribution and Transmission Tariff Codes) and which support (at least in theory) open and non-discriminatory access to the network (e.g. as required under ERA). However, there are many roadblocks that remain, such as a lack of standardization in tariffs, eligibility criteria, use of system agreements, practical difficulties engaging with municipalities, interference by NERSA in bilaterally agreed prices, out of date rules on third party access, a lack of policy guidance on future markets, etc.

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[84] See Eskom CEO Presentation, Nedbank workshop, October 15th 2020

[85] Independent Power Producer Office "Independent Power Producers Procurement Programme: An Overview" June 2020.

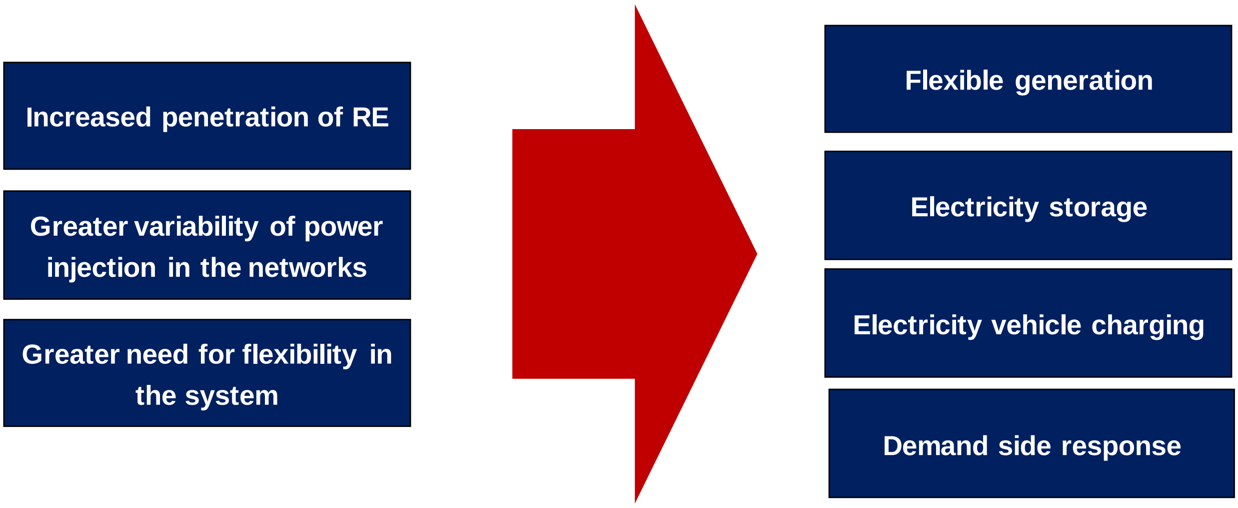
[86] The bidding rounds that have concluded in respect of REIPPPP are: bidding window 1, 2,3,3.5,4 smalls BW1 and BW2.

While facing the above challenges, the sector faces additional ones for the development of a competitive electricity market:

- Completing the current process of Eskom unbundling.
- Agreeing on a detailed market design including how the market will work at the beginning and the eventual additional phases. This should actually already include the way to change (in full or partly) future DMRE Bidding Windows to rely on a capacity and energy market and/or or a default option for IPPs to sign with a new government counterpart but without sovereign guarantee.
- The need to assess and develop a mechanism to deal with potentially stranded assets.
- The need to have municipalities to improve their financial health to become bankable and thus being able to at least, procure partially from IPPs their expected load.
- Revising the electricity act and the overall regulatory framework.
- The need for a champion reformer / Steering group to drive the overall reform process
- The need to develop detailed market rules (market code)
- The need to implement various new functions, IT systems, etc.
- Lack of knowledge of key aspects of competitive electricity markets and how it differs from current modes of operation (e.g. key function of load forecasting and importance of the retail function) among stakeholders.

The various challenges specific to South Africa are also compounded by the overall changes facing all electricity systems and their search for flexibility, in the context of deeper penetration of intermittent renewables. As mentioned by Professor Anton Eberhard in a recent conference[87], there has been more changes in the electricity sector in the last five years than in the previous 30. These changes will need to be anticipated as well in South Africa.

Figure 5-1: Key Characteristics of future electricity systems



Most of these resources are or will be connected to the distribution grids, thus the utmost importance of fixing the problems of the various municipalities.

[87] Presentation by A. Eberhard, Nedbank conference, October 15th 2020

5.2 Phases of development for an improved wheeling framework and the development of a competitive electricity market

Based on our analysis of the South African industry structure and challenges, and international case studies, we propose various phases of development going forward. These phases rank from less to more complex both in terms of actions to be developed and political economy issues.

We consider that these phases could be developed realistically over a 5-7 years' time horizon. Alternatively, with a champion steering committee (yet to be created), the timeframe could possibly be reduced to 3-4 years.

The following figure shows a potential roadmap in phases to improve the current wheeling framework but also to gradually develop a competitive electricity market, most likely similar to the European self-scheduled bilateral contract market model or alternatively a more centralized dispatch system similar to most Latin American countries (if stakeholders decide that it might be more suitable to the peculiarities of the South African situation).[88] Each phase and task is then discussed in more detail below.

Figure 5-2: Roadmap for improved wheeling framework and the development of a competitive electricity market

Task	Phase		
	1: Short-term (≤ 1 year)	2: Medium-term (1-3 years)	3: Medium-term (3-5 years)
A	Short term actions to improve current wheeling system	Finalize Eskom unbundling and creation of an independent market and system operator / creation of a CPA?	Increased liquidity in the markets, DISCOs able to procure higher % of their expected load
B	Eskom unbundling (already on going)	Finalize the financial recovery plan for munics, build knowledge on procurement / supply / load, implement national methodologies for use of system charging	
C	Development of market design paper to further define and confirm the current Eskom plan and draft final market code	Revision to the legal-regulatory framework	
D		Implementation of day ahead and balancing market / revise mechanism for new generation	

[88] We understand that the NT will be contracting this year a consultant to assess various market models, carry out some simulations and recommend a best option for South Africa.

Phase 1 A Short-term actions to improve the current wheeling framework

Timeframe: could be implemented from January 2022.

Eskom and NERSA can immediately start working on the improvements to the current wheeling framework so there could be more open market contracts (at least for consumers connected at high voltage levels). Among the key actions are:

- Revision to current rules for settlement of bilateral contracts between IPPs-traders and direct consumers (no netting from Eskom).
- Removing the interposition of NERSA in setting prices in bilateral contracts.
- Revision to trader licensing to reflect open market conditions.
- Development by Eskom and approval by NERSA of regulated imbalance prices.
- Development of initial market rules (or simplified market code) / harmonization with grid code.
- Eskom to charge directly for use of system charges, rather than implementing the current netting system.
- Insertion by NERSA into municipal distribution licenses the express obligation stipulated in section 21(3) of ERA.
- Issue of grid risk – beyond a certain level of accepted outages hours, Eskom should be liable to compensate parties if their grid is not available;
- Given the need for new capacity, IPPs who want to sell to the open market should not need to have a prior consent to be able to contract directly.
- Substantially amplify the **2012 Third Party Network Charges Rules** to include a detailed framework and process for the non-discriminatory access by third parties to the Eskom transmission network and the Eskom and municipal distribution networks.

Establish an appropriate tariff framework to be included in such amplified rules, taking cognizance of section 15 of ERA, the Grid Code, the 2008 Pricing Policy, the Tariffs Code, and the requirements under the Municipal Systems Act and MFPFA.

We understand that some of the above changes would require some changes in Eskom IT systems, but given that the unbundling process is ongoing, it would not take too long for Eskom to be able to invoice separately for use of system charges (transmission and distribution) to GENCOs/traders and consumers (who contract and settle directly their bilateral contracts but would need to pay Eskom charges). In summary, Eskom (Transmission) would calculate the imbalance prices for each participant and would also invoice for:

- Transmission use of system tariff (to GENCOs and/or traders/consumers)
- Transmission constraints (if any)
- Transmission Losses (possibly)
- Other ancillary services
- Special levy (if needed)

In addition to having to approve regulated imbalance prices, NERSA would need to refrain from having to approve bilateral contracts prices. Changes to the traders and IPPs licenses would also be needed.

While we recommended in section 3.2.13 for municipalities to follow the NERSA guidelines for use of system charges, we understand that this issue of municipalities not using the NERSA transmission and distribution tariff code methodologies would not be solved initially. Materially increasing the amount of wheeling through municipalities' networks will probably take more time to take effect.

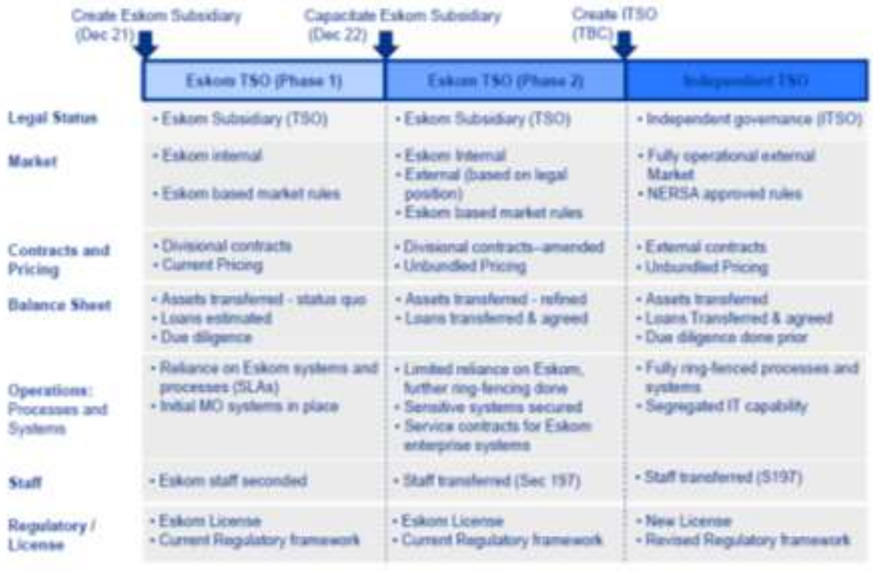
These recommended changes will nevertheless facilitate some additional open market transactions between IPPs, traders and consumers. However, it is clear that for a real competitive market to develop, major additional reforms will be needed as described below.

Phase 1 B Eskom legal unbundling of TSO

Timeframe: January 2022

Functional separation of transmission is scheduled for March 2021 while legal separation is scheduled for December 2021. The following figure shows more details about the initial market model and the role of the future ITSO.

Figure 5-3: Future role of the ITSO



Create Eskom Subsidiary (Dec 21) | Capacitate Eskom Subsidiary (Dec 22) | Create ITSO (TBC)

	Eskom TSO (Phase 1)	Eskom TSO (Phase 2)	Independent TSO
Legal Status	• Eskom Subsidiary (TSO)	• Eskom Subsidiary (TSO)	• Independent governance (ITSO)
Market	• Eskom internal • Eskom based market rules	• Eskom Internal • External (based on legal position) • Eskom based market rules	• Fully operational external Market • NERSA approved rules
Contracts and Pricing	• Divisional contracts • Current Pricing	• Divisional contracts–amended • Unbundled Pricing	• External contracts • Unbundled Pricing
Balance Sheet	• Assets transferred - status quo • Loans estimated • Due diligence	• Assets transferred - refined • Loans transferred & agreed	• Assets transferred • Loans Transferred & agreed • Due diligence done prior
Operations: Processes and Systems	• Reliance on Eskom systems and processes (SLAs) • Initial MO systems in place	• Limited reliance on Eskom, further ring-fencing done • Sensitive systems secured • Service contracts for Eskom enterprise systems	• Fully ring-fenced processes and systems • Segregated IT capability
Staff	• Eskom staff seconded	• Staff transferred (Sec 197)	• Staff transferred (S197)
Regulatory / License	• Eskom License • Current Regulatory framework	• Eskom License • Current Regulatory framework	• New License • Revised Regulatory framework

Source, Eskom, CEO Presentation, Nedbank conference, October 15th 2020.

What we propose in Phase 1 A is in agreement with the proposed Phase 1 of unbundling with some slight modifications to the regulatory framework, as described above. By December 2022, it is planned that the TSO will be ring-fenced but it would still be too early to launch a full competitive market. The final Phase of unbundling (an independent ITSO) has no specific date. In Our Phase 2A, we have a tentative date of mid 2023 along with the opening of a day ahead and balancing market (Phase 2 C).

Phase 1C Development of market design paper to further define and confirm the current Eskom market design plan and finalization of a draft market code

Timeframe: Mid 2022

The Government would develop a market design paper, which would confirm the objectives of the reform and present in details the market design (who can sell to whom and the various type of markets: day ahead, balancing, etc.). The paper would:

- Confirm the creation of a central purchasing agent (CPA) and describe its role and how it would operate.
- Confirm or not the need for a capacity market and how it would work.

- Describe the potential regulatory changes required (e.g. how participants selling in both the regulated and the open markets would be regulated, etc.).
- Describe the various steps of market implementation, including potential phases (if any) – the most important aspects being the general eligibility criteria and % that municipalities could contract directly, as well as who could import and export. As an example, from January 2023, large industrial consumers could contract directly and municipalities could buy 30% of the expected load directly or more depending on the readiness level.

Based on the market design paper, Eskom TSO would finalize the draft market code and submit it for approval to NERSA. This would need to be done in parallel with a review of the legal/regulatory framework.

This phase should include a large capacity building program for various stakeholders

Phase 2 A - Finalize Eskom unbundling and creation of an independent market and system operator/ creation of a CPA?

Timeframe: Mid to late 2023.

The end restructured state for ESKOM TSO is the creation of an ITSO but with no timeline**.** We think it could be possibly realized by mid to late 2023 given the previous steps are all taken and there are no delays in the Eskom unbundling. As mentioned by many stakeholders, the overall reform process will need to be carried out by a Steering committee composed of key Ministries with DMRE taking a more active role.

Phase 2 B Finalize the financial recovery plan for municipalities, build knowledge on procurement / supply / load, implement national methodologies for use of system charging

Timeframe: Mid to late 2023

There are various initiatives including Operation Vulindlela to improve the financial health of the municipalities. To be able to procure power directly, municipalities will need to be bankable and pay their bills in time. They will need as well to learn to do load forecasting and plan their supplies accordingly.

Currently, Eskom is selling municipalities what we call full supply contracts. In the future, the municipalities will need to contract with various GENCOs for various type of products to meet their load, buy or sell into the short-term markets (day-ahead, possibly intra-day) and if their schedules do not match the meters, they would be subject to imbalance prices. These will be radical changes. In addition, most of the current and future changes in the electricity sector are affecting municipalities directly as pointed out in Section 5.1, for example electric vehicle charging, the deployment of decentralized generation, DSM, storage, etc.

We understand also that there are various court cases related to municipalities rights, some being discussed in this report. Practically, for a national competitive market to function efficiently and consumers to select freely their retailers, there will be a need for a uniform distribution use of system charge methodology and of course, no specific surcharge for so-called wheeling as non-discrimination between transactions should be the core principle of the market.

Phase 2 C – Revision to the legal/regulatory framework

Timeframe: end of 2022

The development of such a market model would need various legal and regulatory changes. There will probably be a need for changes to the Electricity (ERA) law to clarify the eventual market model and the role of the various participants.

This may require substantial legislative adjustments, including:

- Resurrection and review of the ISMO Bill, to establish a truly independent system and Market Operator;
- Amendments to ERA and the regulations promulgated thereunder in order to facilitate competition in generation and retail (supply) as opposed to discretionary regulation by NERSA in accordance with so-called policy guidelines;
- Amendment to ERA to remove the discretion as to new generation capacity presently vested in the Minister of Mineral Resources and Energy, in order to allow market forces to determine whether or not such capacity is to be introduced in order to meet market demand (e.g. introduction of energy and possibly, capacity markets).

There will also be a need to revise the 2012 access rules, changing the various licenses, the generation tariffs (partly for GENCOs selling into both markets), the development of a wholesale supply tariff (for the CPA), and possibly to the transmission and distribution tariff code to reflect the market design.

Phase 2 D Implementation of day ahead and balancing market / revise mechanism for new generation

Timeframe: Mid to late 2023

If there are no delays in the previous steps, a day-ahead market and a balancing mechanism (or market) could start operating by mid to late 2023. It is not clear at this point, who would be the participants and/or if a future CPA would be required to bid into the day ahead market. Given Eskom ownership of all hydro, it is possible that its bids and offers in a balancing market would need to be regulated. A modified balancing market could be developed combining some free bids and offer and some regulated ones. The resulting price(s) in each hour would still be the results of a market process and not known in advance.

To assure a smooth transition (independently or not if a capacity market is implemented), the TSO (or CPA) could be a default off-taker for a specified number of years. IPPs would have the choice to sell into the organized markets, contract bilaterally with municipalities, Eskom distribution, eligible consumers or sell long-term to the CPA. The PPAs would need to be structured the same way as bilateral contracts and be subject to imbalance payments

Phase 3A – Increased liquidity in the markets; discos able to procure higher % of their expected load

Timeframe: Post 2025.

At some later point, there will be more liquidity in the various markets and the default buying option for new generation would be abolished. New IPPs would be selling only into the markets. Municipalities would then be able to contract up to 100% of their load.

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