Technical Assistance to Regional Electricity Regulators Association of Southern Africa (RERA)

Implementation Plan for the "*Market and Investment Framework for SADC Power Projects*"

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Acronyms

ATI	African Trade Insurance Agency
BPA	Blanket Purchase Agreement
COR	Contracting Officer's Representative
DFI	Development Finance Institution
DoS	Department of State
ENR	Bureau of Energy Resources
FAR	Federal Acquisition Regulations
IPP	Independent Power Producer
IRENA	International Renewable Energy Agency
ISO	Independent System Operator
MCH	Market Clearing House
MO	Market Operator
M&E	Monitoring and Evaluation
NRA	National Regulatory Agencies
PPA	Power Purchase Agreements
PRG	Partial Risk Guarantees
PSP	Private Sector Participation
RERA	Regional Electricity Regulators Association
RIDMP	Regional Infrastructure Development Master Plan
RTO	Regional Transmission Organization
SADC	Southern African Development Community
SAPP	Southern African Power Pool
SoU	State Owned Utility
SOW	Scope of Work
TSO	Transmission System Operator
WBG	World Bank Group

1. INTRODUCTION

The Southern African Development Community (SADC) Heads of State have officially adopted a Regional Infrastructure Development Master Plan (RIDMP) to facilitate the realization of the energy (and other) infrastructure needed to enable the SADC region to achieve regional integration, economic growth and poverty eradication.

The United States Department of State, Bureau of Energy and Resources (State/ENR), through Deloitte, are helping the Regional Electricity Regulators Association (RERA) of Southern Africa to design a "*Market and Investment Framework for SADC Power Projects*" (the *Market and Investment Framework*) to help SADC Member States meet their power sector development goals, and their plans under the RIDMP.

The Market and Investment Framework *w*ill also help RERA to implement the strategic interventions the RIDMP tasks it with. These include harmonizing Member State regulations and legislation to facilitate cross-border power trade, and assisting Member States to make their regulatory frameworks more conducive for energy sector investment. The RIDMP also requires that RERA be raised to an authority in order to make it effective in regulation.

Over 2014 and early 2015, RERA, with Deloitte assistance, developed an initial design for the *Market and Investment Framework*, incorporating the views and feedback of public and private sector stakeholders across the SADC region, including ministries, regulators, utilities and investors[1].

In July 2015, at the 34th Meeting of SADC Ministers Responsible for Energy, Energy Ministers urged SADC Member States to cooperate and support the implementation of the Market and Investment Framework (Decision 13. 9.4.4). They also directed the SADC Secretariat, assisted by RERA and the Southern African Power Pool (SAPP), to facilitate its implementation, and to report back to the SADC Energy Ministers at their next meeting (2016).

Building on work done during Phase I of the assistance State/ENR provided to RERA, this Report presents the *Regional Implementation Plan* necessitated by the Energy Ministers' direction. This *Regional Implementation Plan* also addresses the role of:

- Ministries and government agencies in the implementation of the Market and Investment Framework;
- Regulators as market enablers and overseers of the power sector;
- Regulators in supervising and monitoring public and private power producers;
- Vertically integrated state owned utilities in regional project development;
- The private sector;
- Local authorities;
- Off-takers;

[1] As a result of stakeholder feedback, the name of the Framework was changed from "IPP Framework" to "*Market and Investment Framework for SADC Power Projects.*"

- Development finance and other financial institutions; and,
- The role and use of external and embedded expert advisors.

The Regional Implementation Plan also includes a summary Road Map and accompanying time line for implementation by each of these stakeholder groups, including the key steps they will need to take over time.

1.1. Project Background

SAPP estimates that US$90 billion of investment will be required to provide the SADC region with the electricity services it will require over the next two decades. Much of this capital will have to come from the private sector, as neither the region's utilities nor the region's governments have the necessary budgetary resources to fund this level of investment.

In spite of this need, most of the power sectors in the SADC countries (Member States) have been and will remain, if the status quo continues, starved of capital. This is partly because the investment environment, both at the Member State and regional level, poses too many risks for private sector investors and developers.

Many of these risks can be reduced or mitigated by putting in place a Market and Investment Framework for the SADC Region that provides more comfort and certainty to local, regional, and international investors, supports regional power trade, and improves the operating environment for IPPs, utilities and regulators, and ministries of energy.

Once implemented, the Market and Investment Framework will attract increased private sector participation in the expansion and development of the SADC power sector, and bring other advantages also, including:

- Greater security of energy supply;
- Greater competition for markets resulting in better services;
- More secure and stable power system operation;
- More efficient, more economically viable utilities, as a result of:
    - A more organized system of bi-lateral contracts;
    - A balancing market that properly assigns the risks and costs of non-delivery for energy transactions;
- Reduced Member State reliance on imports of expensive and foreign-controlled energy sources; and,
    - The transfer of some investment risk from Member States and their utilities to the private sector.

The Market and Investment Framework includes a unified market structure (Target Market Model) that will be supported by a New Legal and Regulatory Framework, constituting a body of harmonized legal and regulatory rules that will be applicable in each Member State for all regional projects.

The Market and Investment Framework also includes an Operating Framework to mitigate technical risks that are preventing increased investment; an Institutional Framework, that intends to highlight the institutional support required for the successful implementation of the Market and

Investment Framework; and a Financial Framework, which seeks to enhance the credit worthiness of project structures and power offtake agreements, and generally reduce investment risk for developers.

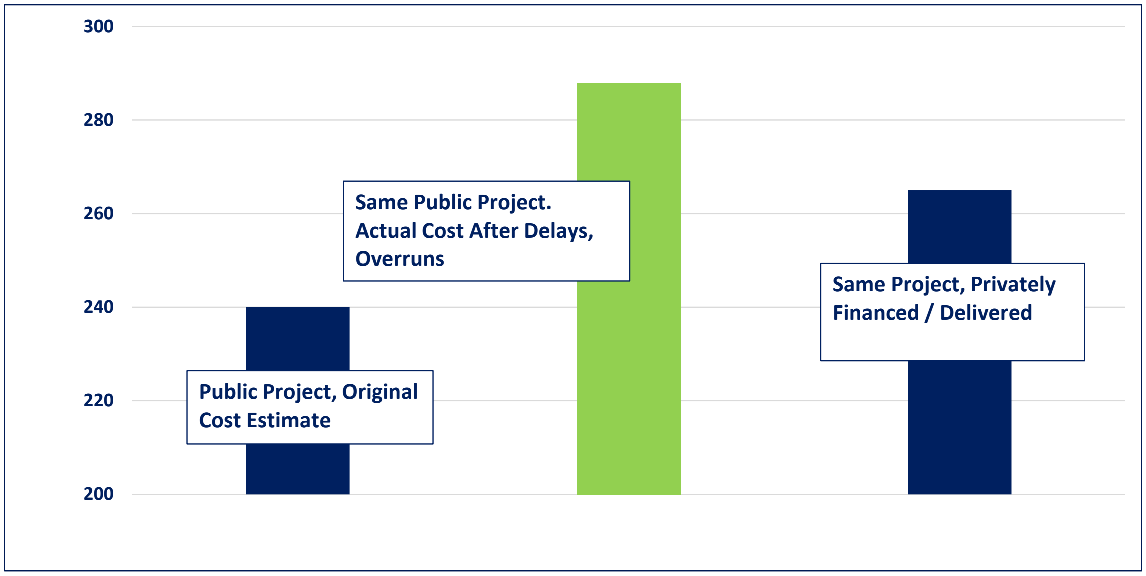
2. POTENTIAL VALUE CREATED BY MARKET AND INVESTMENT FRAMEWORK IMPLEMENTATION

The Market and Investment Framework has the potential to bring multiple benefits to Member States participating in the unified regional market. Primarily, SADC countries will benefit from:

- As highlighted further below, economies of scale from larger (i.e. regional) markets. Access to larger markets will enable investment in larger plants, which in turn are better able to take advantage of economies of scale, and therefore result in lower per unit plant costs (USD/MWh);
- An alternative option to highly constrained public financing for the development of SADC Member State and regional power sector infrastructure;
- An alternative option to 'Government to Government, non-OECD financing' for power sector development, which often has long term costs that have negative consequences for the independence and sustainable development of Member States, and the SADC region.
- Project structures that allow for public/private partnerships, as well as entirely privately owned companies;
- Direct support for SADC's goals by improving energy security, alleviating poverty through increased access to modern energy services, promoting energy investment, and addressing aspects of climate change.
- While a market designed to facilitate commercial activity and trading offers benefits (through economies of scale, increased operational efficiency, etc.), it will also create additional costs (implementation, regulation, market monitoring etc.). However, if the Market and Investment Framework is properly implemented, net benefits will result, meaning lower USD/MWh costs.
- When the costs arising from budget and time overruns[2], and asset under performance, often associated with public power projects are properly accounted for, IPPs can offer lower cost power delivery than the public alternative, in spite of higher financing costs. As illustrated in Figure 2-1, this can result in lower USD/MWh costs, and therefore, lower tariffs.
- Commercial sector discipline could substantially increase the benefits accruing to the SADC power sector further.

[2] Studies (e.g. National Audit Office, UK) show that over 70% of publically funded infrastructure projects run over budget. Privately funded plants, while requiring more expensive financing, are usually delivered on time, and at the pre-agreed cost.

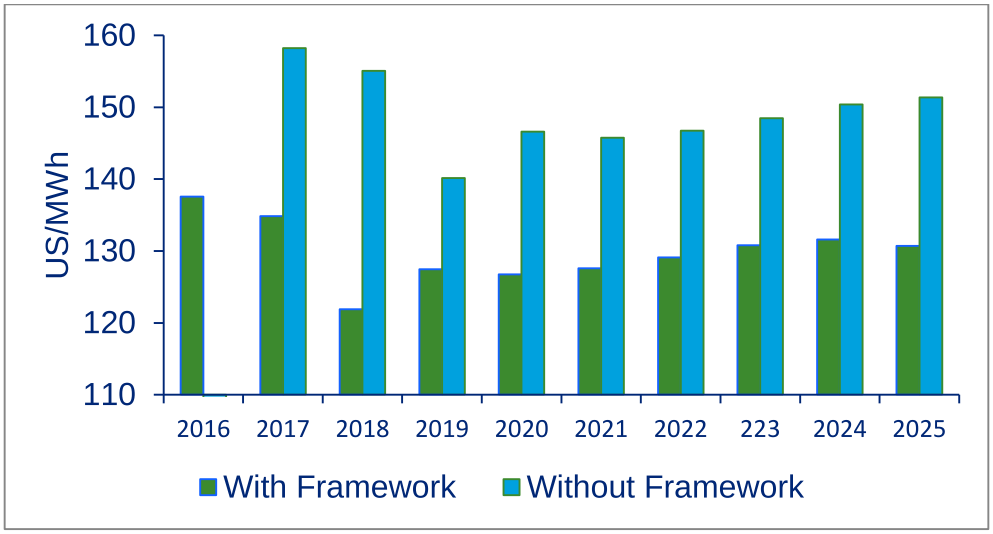
Figure 2-1: Illustrative Comparison of Cost, Public vs Private Delivery of Identical Power Infrastructure Project (US$ Million)



2.1. Potential economies of scale benefits

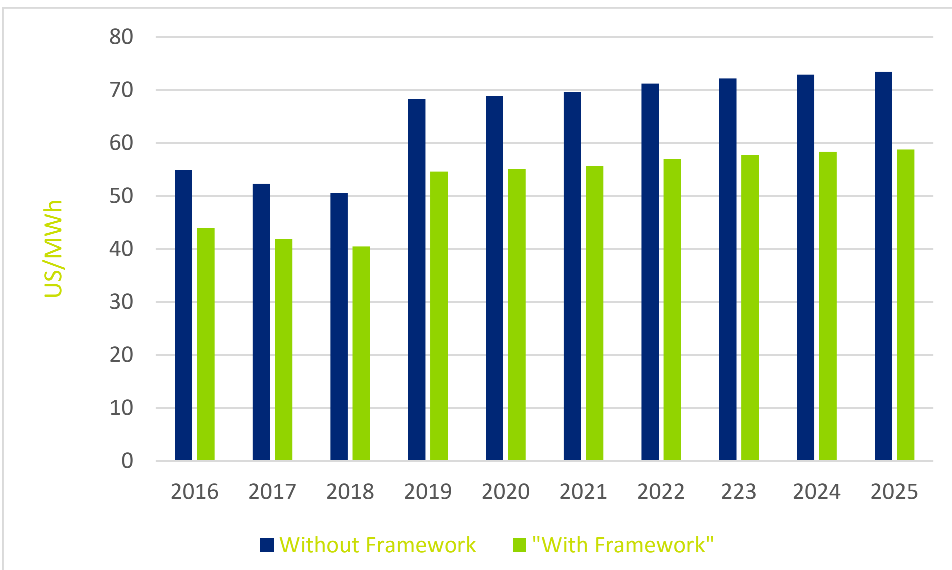
To demonstrate the potential economies of scale benefits of participating in the proposed Market and Investment Framework, presented below are illustrative cost-benefit analyses (CBA) of generation expansion in Angola, which is not yet connected to the SAPP regional grid, and Mozambique, which is. The analysis compares a scenario where Angola and Mozambique expand their generating fleets to serve solely local market load, with a second scenario in which generation expansion is done within the regional context, i.e. larger power plants and systems engaging in significant cross border power sales, facilitated by the Market and Investment Framework. The analyses use information from IRENA's database for Southern African country power systems. Figure 2-2 and Figure 2-3 below illustrate how per unit power cost (US$/MWh) might fall under the second scenario in each country, as a result of economies of scale gain arising from Market and Investment Framework implementation.

Figure 2-2: Unit Power Cost, Market and Investment Framework vs. No Framework, Angola



Source: International Renewable Energy Agency (IRENA) Data; Authors

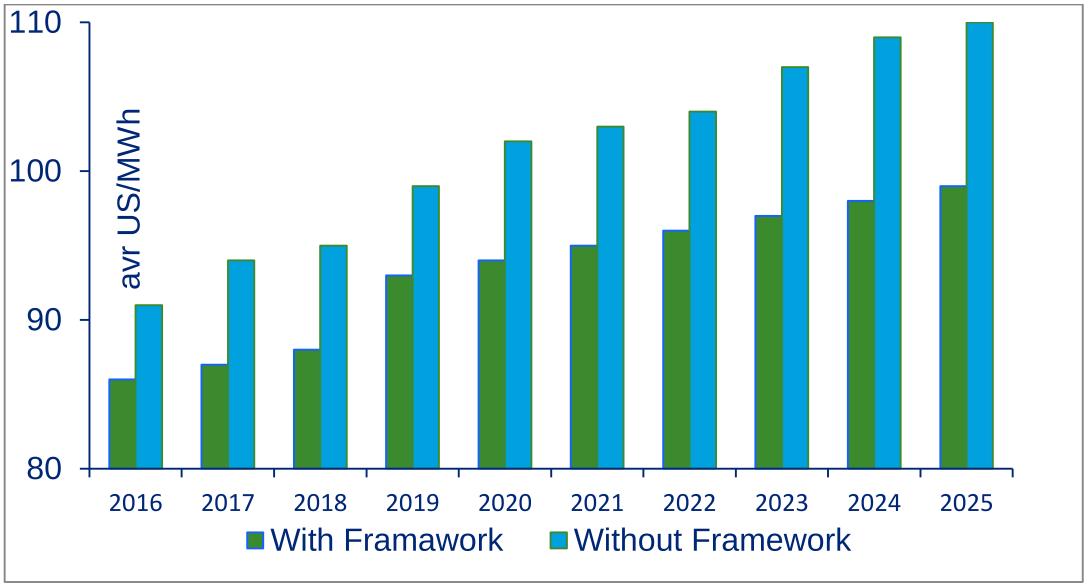
Figure 2-3: Unit Power Cost, Market and Investment Framework vs. No Framework, Mozambique



Source: International Renewable Energy Agency (IRENA) Data, Authors

While the Market and Investment Framework may offer economies of scale gains, its implementation would also create additional costs, such as metering, software, market regulation, market monitoring, and so on. Additional expense would also be created by the added complexity of structuring regional projects to sell power to off takers in different countries, and the additional infrastructure that will be required to connect projects to a regional grid. Figure 2-4 below illustrates the effect of scaling up the Angola example across the whole of SADC region, while also accounting for such additional costs. The analysis assumes that in the absence of the Market and Investment Framework, each country would pursue its own generation projects that will be brought online to meet local demand, other than the relatively small volumes of power that are traded on SAPP, which are modelled to grow as they have historically over the last decade (between 5-10% annually).

Figure 2-4: Unit Power Cost, Market and Investment Framework vs. No Market and Investment Framework, SADC Region

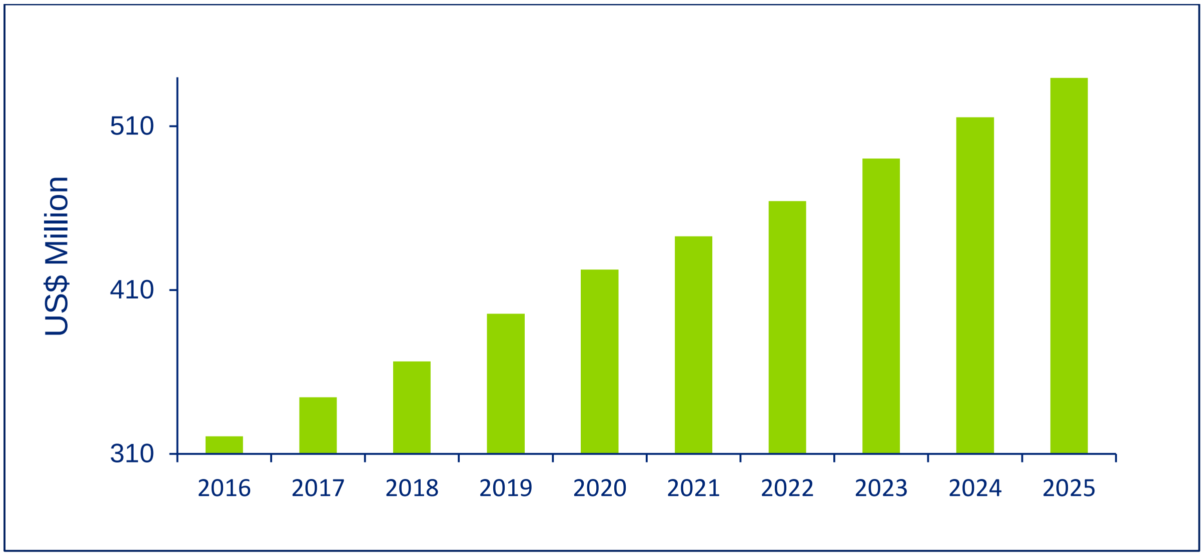


Source: International Renewable Energy Agency (IRENA) Data, Authors

In the analysis shown in Figure 2-4, the average annual power cost (US/MWh) is calculated using the yearly averaged total cost (including O&M, investment cost, generation cost, fuel cost, annual transmission investment cost, annual domestic transmission and distribution cost), forecasted export revenues, and consumption. The '*with IPP Implementation*' scenario also incorporates the associated costs of Market and Investment Framework implementation.

Figure 2-5 demonstrates the potential net benefit for the entire SADC (mainland) region. As shown, net benefits are anticipated to gradually increase after the initial years of Market and Investment Framework implementation as power demand in the region grows, and as investors become more comfortable with project viability.

Figure 2-5: Benefits from Framework Implementation (SADC Region)



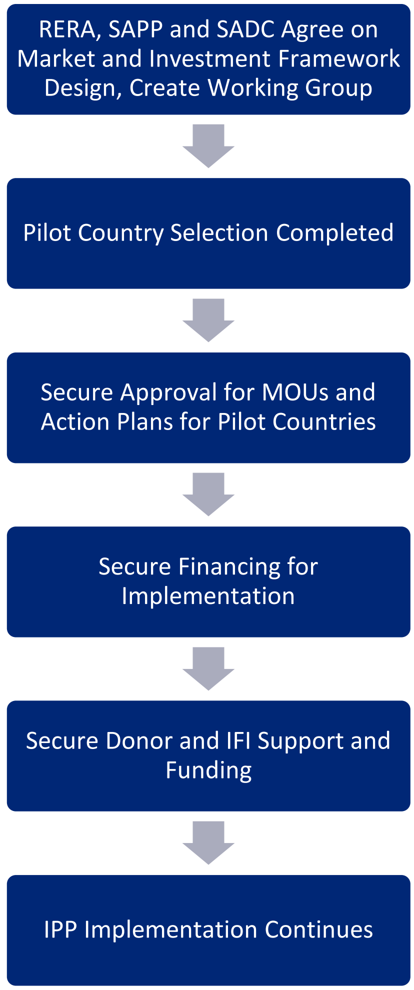
Source: International Renewable Energy Agency (IRENA) Data, Authors

3. IMPLEMENTATION SEQUENCING

Implementation through sequential processes is primarily used when some actions need to technically precede others, and when actions cannot be undertaken simultaneously. The Market and Investment Framework implementation is complex and deep, meaning that not all initiatives can be tackled at once. Moreover, due to system interdependencies, some actions must precede others, and be completed before the latter to be successfully implemented.

Figure 3-1 below shows a high level sequencing of selected activities for the Market and Investment Framework's implementation. This sequencing encompasses the stages RERA anticipates will need to be accomplished for effective implementation to be achieved.

Figure 3-1: Market and Investment Framework Implementation Process



Below we provide more detail on milestones for implementation sequencing.

1. **RERA, SAPP, and SADC agree on Market and Investment Framework Design:** A vital first step in the near term is securing RERA, SAPP and SADC stakeholder agreement on the Market and Investment Framework's design. RERA presented basic elements of the Market and Investment Framework at the SADC energy ministers meeting in August 2015, resulting in agreement, in principle, on its primary tenants. In December 2015, the Deloitte team met with RERA and SAPP to review the Market and Investment Framework and near, mid, and long term steps required for its implementation.
2. **Pilot Country Selection:** With general agreement on the functional design, the next step involves selecting two to three pilot countries where the Market and Investment Framework will be implemented. This is a sensitive matter as the number of countries is limited, and RERA and SAPP will work with Deloitte to design a transparent methodology that will be used to select the pilot countries.
3. **Secure Approval for MoUs and Action Plans**: Upon selection of the pilot countries, the identified countries will need to sign memoranda of understanding and agree to action plans that list the responsibilities of the appropriate agencies and institutions in each of the pilot countries. The recommendations may include specific programs for capacity

building within regulatory agencies, process maps for developing future projects, and adaptation of the existing organizations and processes to address concerns and questions raised by investors and other stakeholders.

4. **Secure Financing for Implementation**: After mapping the processes for implementing the Market and Investment Framework and providing recommendations for the appropriate agencies and institutions, funding sources for program implementation will be needed. Costing implementation and including this figure within the Market and Investment Framework action plan will give a picture of financing needs and is a critical step towards full and effective implementation. A realistic and transparent assessment of existing resources and capacities, as well as needs, is also an important component of effective planning and implementation of the Market and Investment Framework.

   The enactment of new laws and policies is commendable, but without adequate financial, technical, and in-kind support for implementation of the Market and Investment Framework, these laws might not be effectively implemented and the status quo (i.e. insufficient investment) will continue. Additionally, a lack of sustainable funding diminishes the authority and legitimacy of SADC governments and the international community, both of whom have made strong commitments to ending the power deficit in the SADC region.

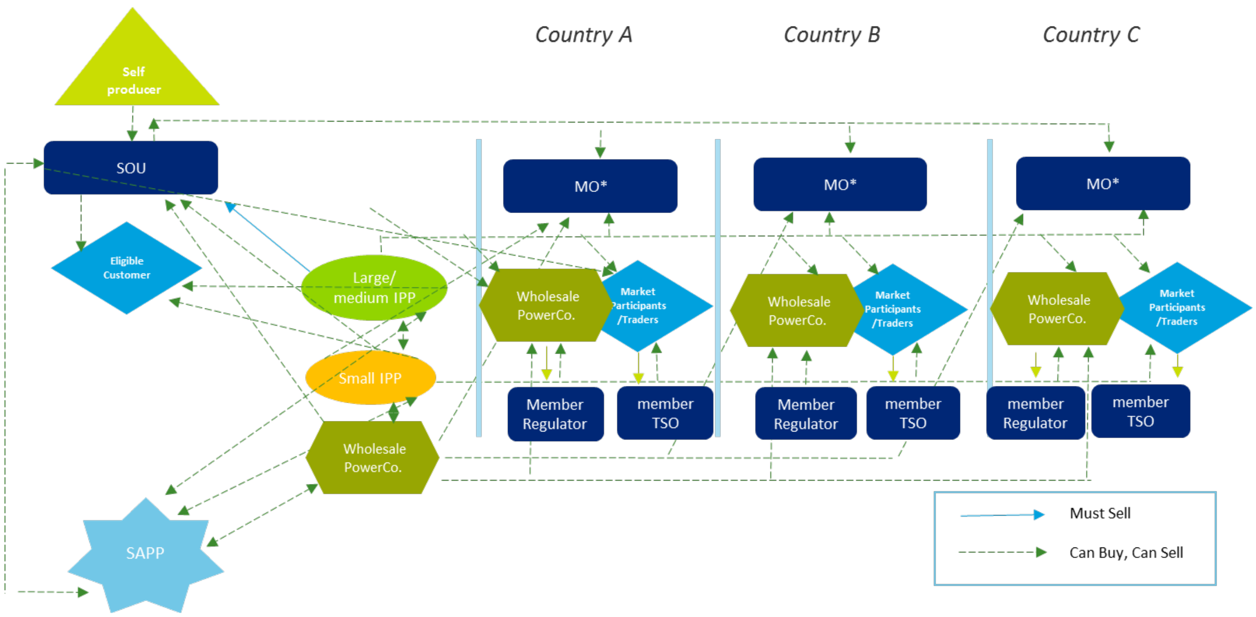
5. **Secure Donor and IFI Support and Funding**: Ideally, the international donor community should provide predictable, long-term, and substantial financial resources, as well as other relevant resources, for Market and Investment Framework implementation, and channel these resources through the appropriate regional stakeholders and institutions. Donors should ideally finance initiatives and projects that are specifically linked to the Market and Investment Framework. Financing must be predictable and timely, and disbursed rapidly when needed.

6. **Framework Implementation Continues:** With funding for the Market and Investment Framework implementation secured, Framework implementation will continue until 2022 when most initiatives are expected to be completed.

4. TARGET MARKET MODEL

The target market model that was designed with significant stakeholder feedback during Phase 1 of this work is best summarized by Figure 4-1 below. In each Member State, there are: the SOU, Small IPPs, Large and Medium IPPs, Off Grid Systems, Self-Producers, Wholesale Power Companies and Eligible Consumers. SAPP, as a Market Service Provider, is also referenced. Below, we present diagrams of the proposed wholesale power trading relationships between these entities, and also describe the phased approach we recommend to implement the trading scenarios included in the fully evolved regional power market. We use six Stages, but more stages or fewer stages are also possible. In these diagrams, we did not include reference to a new institutional set-up, such as including an unbundled transmission system operator (TSO), an independent system operator (ISO) / regional transmission operator (RTO). The steps needed to set up such institutions are covered later in the Report.

Figure 4-1: Wholesale Arrangements in the Target Market Model



The target market model assumes two implementation phases. During Phase 1 the region will have three Market Operators (MO), one for each of SAPP's three synchronized control areas. These are operated by the dominant State Owned Utility (SOU) in South Africa (Eskom), Zambia (ZESCO) and Zimbabwe (ZESA). Phase 2 envisages one regional MO.

The cornerstone of this wholesale market model is the harmonization of a number of codes and rules that will allow for the trade of power within the region. In a simplified regional model, power trade will occur between an exporting country, an importing country, and power will be wheeled through a third country.

Exporting Country: According to the Market and Investment Framework, the first stage in the implementation will include a power plant in one country, such as an IPP, selling a specified proportion of its power to the SoU in the same country, and exporting the remainder to another country. This ensures that the host country that will bear the brunt of the negative externalities caused by physically hosting the power plant can also enjoy the benefits of some of the power produced. Deloitte will work with SAPP, RERA, and the SADC Energy Office to identify countries with resource potential and/or well supported projects that can be leveraged for the implementation of the Market and Investment Framework. Additionally, after pilot countries are identified, RERA and Deloitte will work with as many counterparts as possible to identify a preliminary list of relevant ministries and relevant stakeholders whose buy-in is required to ensure the successful implementation of the Market and Investment Framework. Consequently, RERA and Deloitte will work with the relevant ministries to propose a structure for the functions, responsibilities, policy roles and procedures of the primary identified ministerial and sectoral institutions. The exporting country's institutions will have the following responsibilities:

a. Issuing license to the generator;
b. Issuing license to the transmission company;
c. Licensing the exporter;
d. Ensuring interconnection access;
e. Approving the Power Purchase Agreement (PPA) between the seller and buyer;
f. Approving prices; and,
g. Monitoring market abuses.

Importing Country: In the first stages of the Market and Investment Framework, the power plant from the exporting country can sell both to the SoU of the importing country and to other eligible consumers in the importing country. Both the SoU and the eligible consumers in the importing country can also buy power from SAPP. Given this wholesale trading arrangement, RERA and Deloitte will work with the relevant ministries and governmental agencies in the importing country to identify the relevant key stakeholders whose buy-in is crucial. RERA and Deloitte will then liaise with the importing country's ministries to propose the structure, functions, responsibilities, policy roles and procedures of the institutions. The importing country's institutions will have, among others, the following responsibilities:

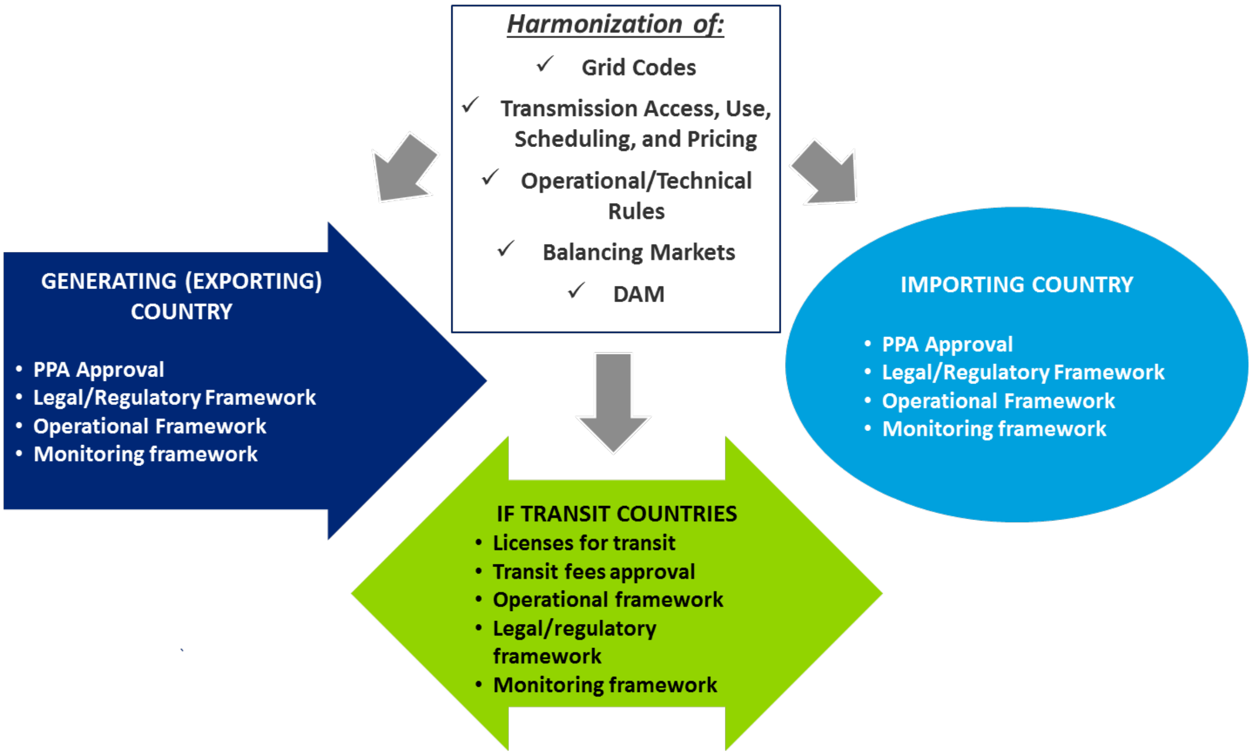
a. Issuing license to transmission licensee and importer;
b. Approving the PPA between buyers and seller;
c. Approving prices if buyer is a supplier to or a captive customer;
d. Approving wheeling charges through all transit countries; and,
h. Approving pass-through of all purchasing costs into regulated tariffs.

Transit Country: Depending on whether the exporting and importing countries share a common border, there may be a need for a third country that will wheel the power from the exporting country to the importing country. As described above, RERA and Deloitte will also work with relevant ministries and sector institutions to develop a roadmap for the implementation of the Market and Investment Framework and will also highlight the functions, responsibilities, policy roles and procedures for the host governments and relevant energy sector stakeholders. At a minimum, the transit country will need to have the following responsibilities:

a. Issuing licenses to the transmission company;
b. Issuing licenses to the importer;
c. Approving wheeling agreements; and,
i. Approving prices if the Transmission Company also supplies captive customers.

Figure 4-2 below shows the codes and frameworks that will need to be harmonized in each of the generating, importing and, where appropriate, the transit countries.

Figure 4-2: Regulatory Tasks of Member State Regulators under the New Legal and Regulatory Framework



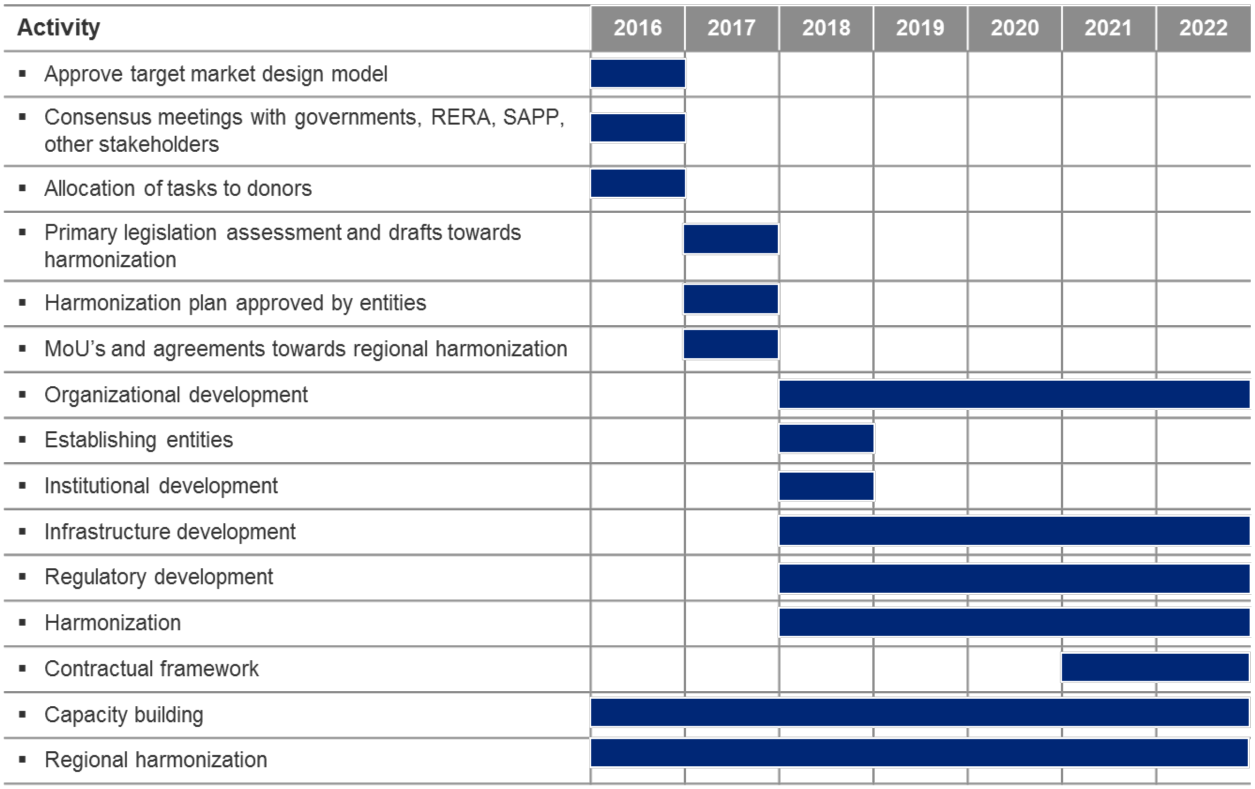
Each of the countries in the Market and Investment Framework will have roles and responsibilities that will enable the effective implementation of the Market and Investment Framework. In particular, each country in the Market and Investment Framework will need to provide for:

- Strategy development and capacity building;
- Organizational design and development;
- Regulatory accounting and tariffs;
- Primary legislation, and market rules and procedures;
- Regulation and contractual framework;
- Engineering and infrastructure improvements; and,
- Harmonization of trading mechanisms.

4.1. Implementation Schedule

The figure below is an illustrative timeline of the implementation of the target market model. The timeline also shows some of the associated activities.

Figure 4-3: Target Market Model Implementation Timeline



The implementation process starts with securing approval for the target market model design. This design is the result of significant rounds of feedback from SADC regulators and utilities, and was presented during the SADC energy ministers meeting in 2015, but the pilot countries still need to provide definitive ministerial approval and support to the Market and Investment Framework process. Following this, consensus meetings with governments, RERA, SAPP, and other stakeholders will also need to be held. This will be followed by the allocation of tasks to donors to complete the activities that need to be held in 2016 and 2017. The timeline ends with the regional harmonization of the regulatory framework in 2022.

In the target market model, the SADC Member States will need to harmonize the following:

1. Power sector laws for market structures;
2. Legal and Regulatory frameworks related to power trade and transmission access, use, and scheduling;
3. Institutional structure for administering policy and laws;
4. Operational structure for power delivery and technical issues;
5. Role of an independent national regulator for each state under priorities and laws; and,
6. Approved market model design.

As Market and Investment Framework implementation gets underway, SAPP and RERA will need to request key stakeholders to:

- Agree to coordinate all activities on the Market and Investment Framework in a special working group;

- Speak with one common voice on the Market and Investment Framework;
- Provide feedback on proposed draft documents/process;
- Provide financial support, if feasible, on certain aspects of the IPP initiative;
- Agree on deadlines and conditions with the Pilot Country governments; and,
- Create a joint implementation agreement.

5. IMPLEMENTATION OF REGULATORY FRAMEWORK

Regulatory independence, licensing, tariff setting, network access, service quality, transparency, and stakeholder participation have all been cited as barriers to increased private investment and regional trade in SADC. The SADC Region would benefit from a harmonized regulatory environment. Some of the identified bottlenecks preventing this include:

1. **Licensing:** Lack of coordination in terms of types of licenses, content of licenses, and of recognition of licenses across borders;
2. **Metering:** Insufficient extent of metering and/or standards for metering;
3. **Cross-border Disputes**: Lacking process for resolution of cross border disputes;
4. **Tariffs:** Lack of harmonized approach to tariffs, particularly – transmission and lack of cost reflectivity of tariffs;
5. **Transmission Losses:** Incoherent approach to coverage of transmission losses (or their cost);
6. **Grid Access:** Lack of common rules for connecting to the networks (including connection charging principles and Third Party Access to the networks;
7. **Congestion Management:** Lack of consistent regional rules for managing the congestions;
8. **Grid Codes:** Lack of a regional Grid Code and regulatory approval of the regional grid code; and
9. **Planning Coordination:** Lack of regular mechanism for coordinating and updating regional Transmission and Generation Development Plans.

We provide more information on each of the bottlenecks below.

5.1. Licensing

The first bottleneck related to the legal and regulatory framework is licensing requirements. There is a lack of coordination in terms of types of licenses, the contents of licenses, and the recognition of licenses across borders.

5.1.1. Proposed General Approach

- Identify the types of licenses relevant to cross border electricity generation, transmission and trade;
- Collect relevant rules for issuing licenses currently in use in SADC; and,
- Collect relevant types (templates) of licenses currently in use in SADC.

5.1.2. Forecast Milestones

- Merger of national license requirements for developing the regional license;
- Develop a template regional license(s) – NRAs would have to agree on their respecting the regional license(s) nationally - no extra national requirements/licensing.

5.1.3. Alternatively:

- Agree on cross-border respecting licenses issued in other SADC countries

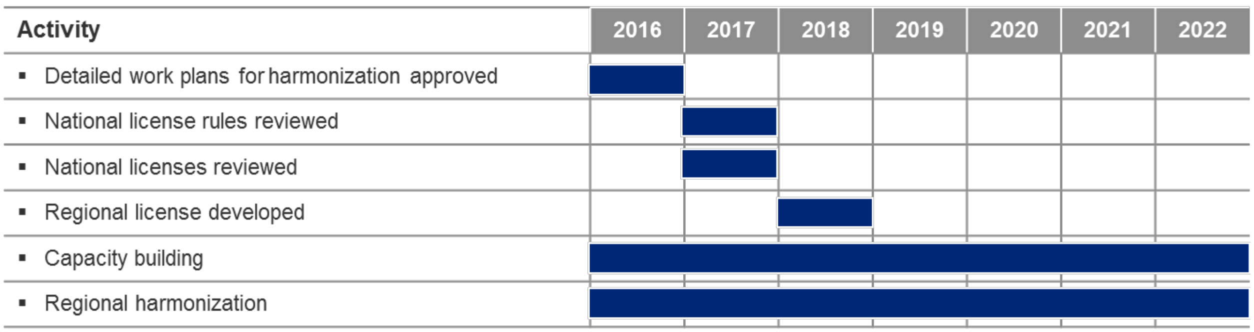
5.1.4. Involved Parties

- RERA and National Regulatory Agencies (NRAs); and,
- Ministries in charge of energy matters (only to the extent that they are involved in licensing at all).

5.1.5. Implementation Path

Figure 5-1 below shows an implementation timeline for harmonizing the licensing rules and procedures in the region.

Figure 5-1: Licensing Implementation Timeline



The implementation path begins with developing detailed work plans for harmonization and securing approval from all stakeholders. This is anticipated to be completed in 2016. Following the approval of the detailed work plans, national licenses and national license rules will be reviewed in 2017, followed by the development of regional licenses in 2018. Accompanying all these activities is capacity building of all entities that will be involved in the regional harmonization.

5.2. Metering

The second bottleneck is the insufficient extent of metering and metering standards in the region. Without adequate metering, power trade in the region will remain constrained as there will not be the required infrastructure to determine the power being traded, sold, or wheeled in any particular jurisdiction. In order to alleviate the metering bottleneck, and harmonize metering and metering standards in the region, the Deloitte team proposes the following.

5.2.1. Proposed Approach

- Collect the information concerning the rules and standards for metering requirements currently used by different parties;
- Choose the best regional example or the best international standard.

5.2.2. Forecast Milestones

- Roadmap and steps necessary for harmonizing the metering systems, metering replacement plans.

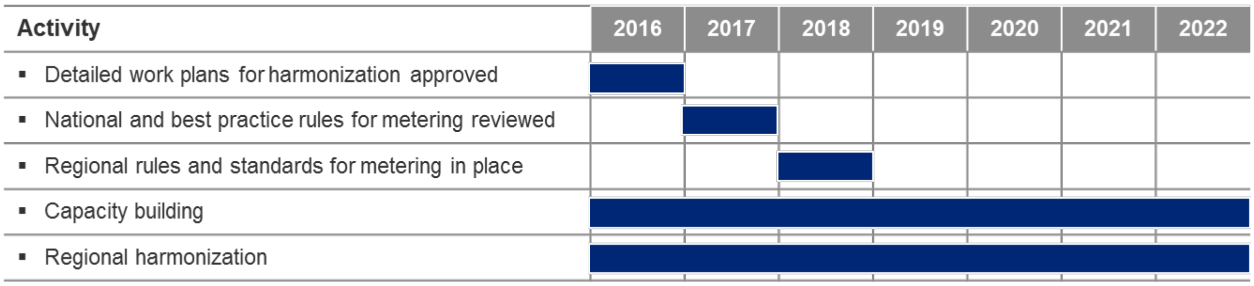
5.2.3. Involved Parties

- Relevant transmission network owners (i.e. whomever is responsible in a certain country for conducting connections to the national network);
- RERA and National Regulatory Agencies;
- SAPP.

5.2.4. Implementation Path

Figure 5-2 below shows the implementation timeline for harmonizing the metering procedures in the region.

Figure 5-2: Metering Implementation Timeline



As is the case with the licensing implementation, the implementation path begins with developing detailed work plans for harmonization and securing approval from all stakeholders. This is anticipated to be completed in 2016. Following the approval of the detailed work plans, national and best practice rules for metering will be reviewed in 2017, followed by the implementation of regional rules and standards for metering in 2018. As before, all these activities require capacity building in all entities that will be involved in the regional harmonization.

5.3. Cross Border Disputes

Another area posing significant barriers to increase cross border power trade is the lack of process for the resolution of cross border disputes. In the economic sphere, utility regulators usually spend most of their time addressing issues of market access, pricing, and service quality. Regulators and service providers often take different views on how to set tariffs, how to enforce obligations related to Quality of Service, and what penalty is appropriate for a given infraction. Conflicts also frequently arise between regulated companies or between service providers and users, for example, on matters such as right of access to networks, or on interconnection or wheeling charges. These issues are multiplied as the number of countries and regulators increase.

Various regulatory governance models have been developed to resolve conflicts and reduce regulatory risks for private investors. Approaches typically range from placing detailed regulatory mechanisms in legal instruments, such as licenses and contracts (with possible appeals to the judiciary bodies of the state) to establishing specialized bodies to make regulatory decisions on the basis of pre-established rules and processes. The following is the methodology we recommend for implementing dispute resolution related to regional supply and trade among service providers in other countries;

5.3.1. Proposed General Approach

- Identify if any of the SADC countries has already a well-developed process for addressing the disputes;
- Tailor dispute resolution practices to regional dimensions.

5.3.2. Forecast Milestone

- Developed Regional dispute resolution procedures, compatible with the existing process before the SADC Tribunal.

5.3.3. Involved Parties

- RERA and National Regulatory Agencies;
- National Anti-monopoly tribunals;
- SADC Tribunal.

5.3.4. Implementation Path

Figure 5-3 below shows the implementation timeline for harmonizing the cross border resolution procedures in the region.

Figure 5-3: Cross Border Dispute Resolution Timeline

Activity	2016	2017	2018	2019	2020	2021	2022
▪ Detailed work plans for harmonization approved	■						
▪ National and best practice rules for dispute resolution reviewed		■					
▪ Regional rules and standards for dispute resolution in place				■			

The implementation path begins with developing detailed work plans for harmonization and those being approved by all stakeholders in 2016. Following the approval of the detailed work plans, national and best practice rules for dispute resolution will be reviewed in 2017, followed by the implementation of regional rules and standards for dispute resolution in 2019.

5.4. Tariffs

The lack of harmonized approaches to tariffs, particularly transmission tariffs, and the lack of cost reflectivity, is a major stumbling block to the implementation of the Market and Investment Framework. Without a harmonized approach to tariffs, private investors will have to master the intricacies of tariffs and tariff setting in each of the countries in the region where their power will be wheeled and sold. To help eliminate the diversity in tariff rates and tariff setting, the following is proposed:

5.4.1. General Approach

- Compare transmission tariff rules (use-of-system charging) currently used by all the parties;
- Assess compatibility with the best international solutions concerning tariffs facilitating market opening and tailor transmission tariff rate design to regional market design goals.

5.4.2. Forecast Milestones

- Roadmap for different stages of utilities' unbundling (functional, standards of conduct, accounting, legal)
- Roadmap for gradual market opening (releasing from regulated electricity tariffs for end-users) and TPA based on regulated transmission tariffs for the biggest consumers;
- Cost of service study of transmission activities;
- Development of regional transmission tariff rules and of a regional transmission tariff.

5.4.3. Involved Parties

- RERA and National Regulatory Agencies;
- SAPP;
- Ministries in charge of energy matters (only to the extent that they are involved in tariff approvals at all).

5.4.4. Implementation

Figure 5-4 below shows the implementation timeline for harmonizing the tariffs and tariff methodology procedures in the region.

Figure 5-4: Transmission Tariffs Harmonization Timeline

Activity	2016	2017	2018	2019	2020	2021	2022	2023	2024
▪ Detailed work plans for harmonization approved	■								
▪ Regional rules and standards for metering in place			■	■					
▪ Complete cost of service study for regional transmission tariff						■			
▪ Updates to regional transmission tariff rules implemented								■	

Following the approval of the detailed work plans in 2016, regional rules and standards for transmission tariffs are expected to be in place by 2019. This would be followed by the completion of a cost of service study for regional transmission tariff in 2022. Updates to the regional transmission tariffs are expected to be implemented in 2022.

5.5. Transmission Losses

There are incoherent approaches to the coverage of and recuperation of transmission losses. Accordingly, to harmonize the treatment of transmission losses, the following will be considered.

5.5.1. Proposed General Approach

- Identify best framework for treatment of transmission losses taking into account the market design (EU rules may constitute an example).

5.5.2. Forecast Milestones

- Regional Transmission Loss Management and Reimbursement Rules;
- Building from scratch rather than choosing some regional practice is probably the way forward.

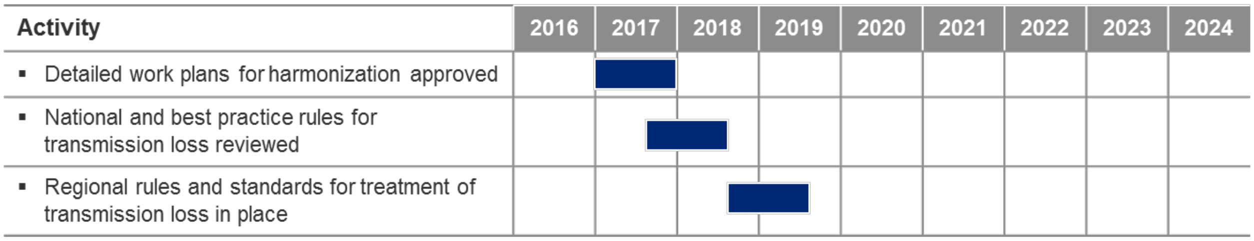
5.5.3. Involved Parties

- Relevant transmission network owners (i.e. whomever is responsible in a certain country for conducting connections to the national network);
- RERA and National Regulatory Agencies;
- SAPP.

5.5.4. Implementation Path

Figure 5-5 below shows the anticipated implementation timeline for the harmonization of the transmission losses treatment.

Figure 5-5: Transmission Losses Treatment Harmonization Timeline



Following the approval of the detailed work plans in 2017, national and best practice rules for transmission losses will be reviewed in 2018, followed by the implementation of the regional rules and standards of treatments of transmission losses treatments in 2019.

5.6. Grid Access

The lack of common rules for connecting to the networks, including connection charging principles and third party access to network is another bottleneck in the effective implementation of the Market and Investment Framework. In order to effectively ameliorate the grid access bottleneck, we propose the following.

5.6.1. Proposed General Approach

- Collect information concerning the following relevant practices currently used by SADC countries:
- Transmission connection procedures and studies;
- Transmission connection charging principles;
- Thresholds and procedure for Third party access (by eligible customers).

5.6.2. Forecast Milestones

- Realistic roadmap for gradual market opening and TPA for the largest customers;
- Connection procedures;
- Connection charging rules;
- Choosing the best regional/international examples is likely to be the best way forward in the end of the day.

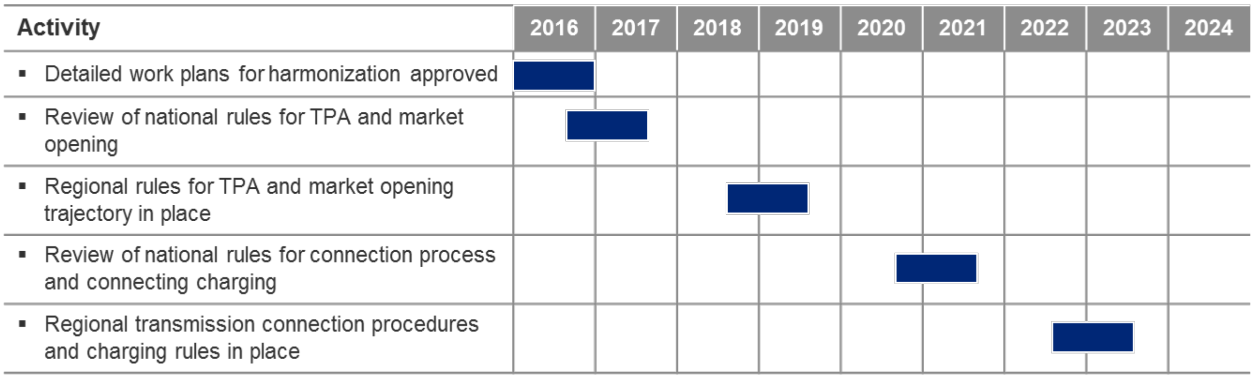
5.6.3. Involved Parties

- Relevant transmission network owners (i.e. whomever is responsible in a certain country for conducting connections to the national network);
- RERA and National Regulatory Agencies;
- SAPP.

5.6.4. Implementation

Figure 5-6 below shows the anticipated implementation timeline for the harmonization of grid access.

Figure 5-6: Grid Access Harmonization Timeline



The grid access harmonization process will begin with the development and approval of the detailed work plan in 2016. This is followed by the review of national rules for third party access and market opening in 2017. Following the review, regional rules for third party access are anticipated to be in place by 2019, followed by the review of national rules for connection process and connection charges in 2021. The process will conclude with the implementation of transmission connection procedures and charging in 2022.

5.7. Congestion Management

The lack of consistent regional rules for managing congestion is also another bottleneck in the Market and Investment Framework implementation. The Market and Investment Framework will need to develop and implement mechanisms to manage transmission congestion. Additionally, the planning and expansion processes undertaken by the regional entities must encourage operating and investment actions for preventing and relieving congestion.

5.7.1. Proposed General Approach

- Collect information concerning the rules for approving and scheduling transmission services and managing the congestion, which is an issue in SADC countries;
- Identify best framework for treatment of grid congestion taking the market design into account (EU rules may constitute an example).

5.7.2. Forecast Milestones

- Regional Grid Congestion Management Rules developed;
- Building from the scratch rather than choosing some regional practice is probably the way forward.

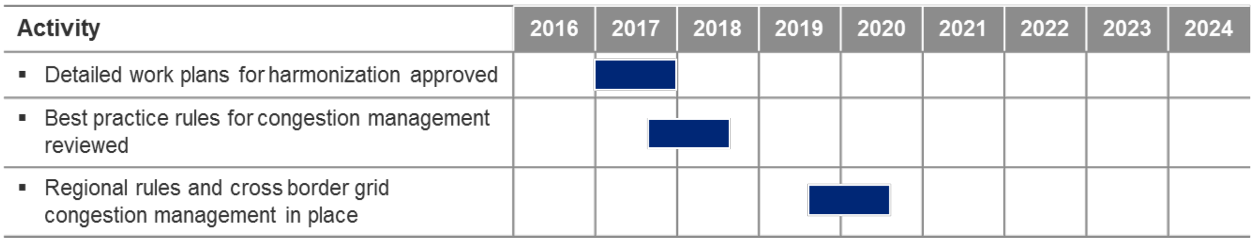
5.7.3. Involved Parties

- Relevant transmission network owners (i.e. whomever is responsible in a certain country for conducting connections to the national network);
- RERA and National Regulatory Agencies;
- SAPP.

5.7.4. Implementation Path

Figure 5-7 below shows the anticipated implementation timeline for the harmonization congestion management methodologies and processes.

Figure 5-7: Harmonization of Congestion Management Methodologies



The harmonization process of congestion management will begin with the development and approval of detailed work plans in 2017. This is followed by the review of best practice rules for congestion management in 2018, followed by the implementation of the rules in 2020.

5.8. Grid Codes

The lack of a regional grid code, and the lack of regulatory approval for a regional grid code, present significant challenges to the successful implementation of the Market and Investment Framework. The grid code, as the primary technical document regulating the grid, provides procedures for both system planning and operational purposes, and covers both normal and exceptional circumstances. It should be followed by all Market Participants. It is, however, a living, working document that will be, from time to time, subjected to changes and/or revisions as the power sector evolves.

The Grid Code will define the rules and regulations for various Market Participants for accessing and using the transmission grid. The main objectives of the Grid Code will be to:

- Establish the obligations of the TSO/SOU, Transmission Companies, and grid users—Generators (including IPPs), directly-connected customers (such as Eligible Customers) and Other Users —for accessing and using the transmission grid;
- Define obligations, responsibilities, and accountabilities of all parties towards ensuring open, transparent, non-discriminatory, and economic access and use of the transmission grid while maintaining its safe, reliable, and efficient operation;
- Define minimum technical requirements for all participants;
- Set out the information exchange obligations of all participants.

The proposed Grid Code will not replace or substitute any existing dispatch rules, procedures and manuals. Rather, it will provide a general framework for their revision to ensure the safe, secure, and reliable operation of each national transmission grid as the Market and Investment Framework develops. It will work in conjunction with other legal and regulatory documents that may exist within SADC countries, such as national laws on electricity, market rules, regulatory guidelines issued by the regulatory authorities, and interconnection capacity auctioning and allocation procedures.

5.8.1. Proposed General Approach

- Collect grid codes currently used by all the SADC parties;

5.8.2. Forecast Milestones

- Regional Grid Code developed;
- Merger of national solutions for coming up with the regional GC, rather than choosing the best regional example may prove to be the best way forward incorporating unique national circumstances.

5.8.3. Involved Parties

- Relevant transmission network owners (i.e. whomever is responsible in a certain country for conducting connections to the national network);
- RERA and National Regulatory Agencies;
- SAPP

5.8.4. Implementation Path

Figure 5-8 below shows the anticipated implementation timeline for the harmonization grid codes in the SADC region.

Figure 5-8: Harmonization of Grid Codes

5.9. Planning Coordination

Finally, the lack of regular mechanics for coordinating and updating regional transmission and generation development plans constrains the Market and Investment Framework Implementation. While the SADC energy ministers meet regularly to decide on a prioritized list of transmission and generation projects, it is not clear whether there is an established methodology for coordinating these projects. On an ongoing basis, the following is proposed.

5.9.1. Proposed General Approach

- Establish framework for coordination of long term development plans at the regional level for:
  - Generation Development Planning and regular updating;
  - Transmission Development Planning and regular updating;
  - Consumption forecasting and regular updating.

5.9.2. Forecast Milestones

- Establish parties responsible for submission and timelines for information collection
- Regional rules for updating all three elements relevant for planning developed;

- Merger of national solutions for coming up with the regional Grid Code, rather than choosing the best regional example may prove to be the best way forward; EU TYNDP coordination process used by ACER or rules of ECSEE market may constitute examples.

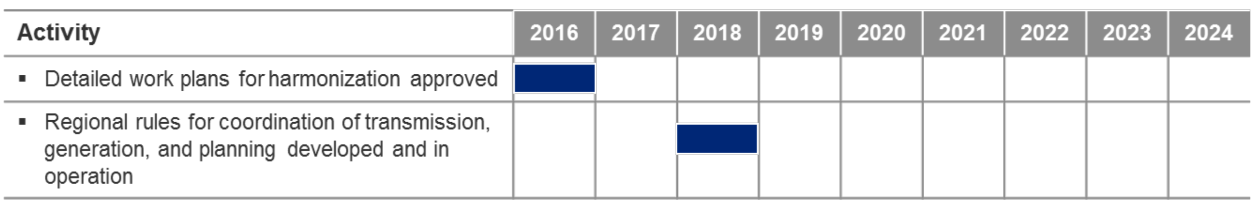
5.9.3. Involved Parties

- Relevant transmission network owners (i.e. whomever is responsible in a certain country for conducting connections to the national network);
- RERA and National Regulatory Agencies;
- SAPP
- Ministries in charge of energy matters (to the extent that they are involved into generation planning or discussions regarding IPPs)

5.9.4. Implementation Path

The figure below shows the anticipated implementation timeline for planning coordination in the SADC region.

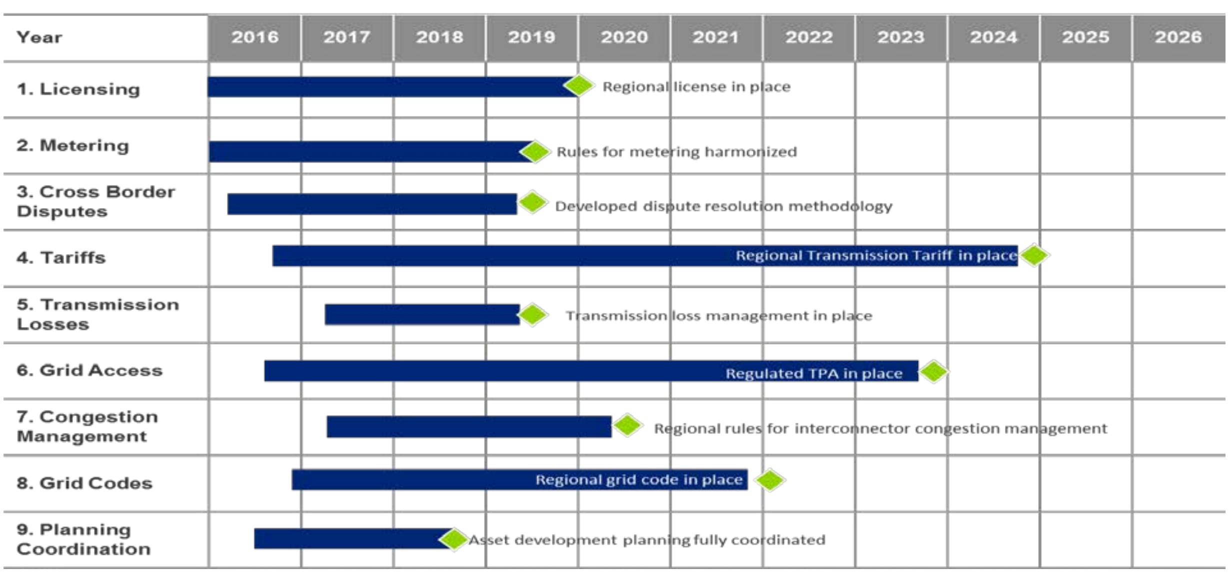
Figure 5-9: Planning Coordination Timeline



5.10. Schedule Summary

Figure 5-10 below summarizes, the implementation schedule of the harmonization of the regulatory environment.

Figure 5-10: Regulatory Environment Harmonization Timeline



6. IMPLEMENTATION OF INSTITUTIONAL FRAMEWORK

As shown by the scarcity of projects brought to financial closure and completion across SADC outside of South Africa, market forces alone are currently insufficient to encourage project development. There is a need for national and regional institutions to lead, coordinate, supervise, and foster the processes required to encourage private and public investment in power projects. These institutions would also be responsible for governing the market in an appropriate manner. Key institutions in this regard are RERA and SAPP, whose current and anticipated roles and responsibilities are discussed throughout this report.

SADC Member States have already taken important and significant steps to laying the institutional foundations for cross border trade, for a regional power market, and, therefore for the envisaged Market and Investment Framework. Most notable are the establishment and long term operation of SAPP, and the creation of RERA itself, along with agreement that the latter be raised to an authority in order to make it effective in regulation. Additionally, many Member State energy ministries are publically committed to pursuing a regional strategy, as indicated by their desire for SAPP to identify, promote and procure priority regional generation and transmission projects.

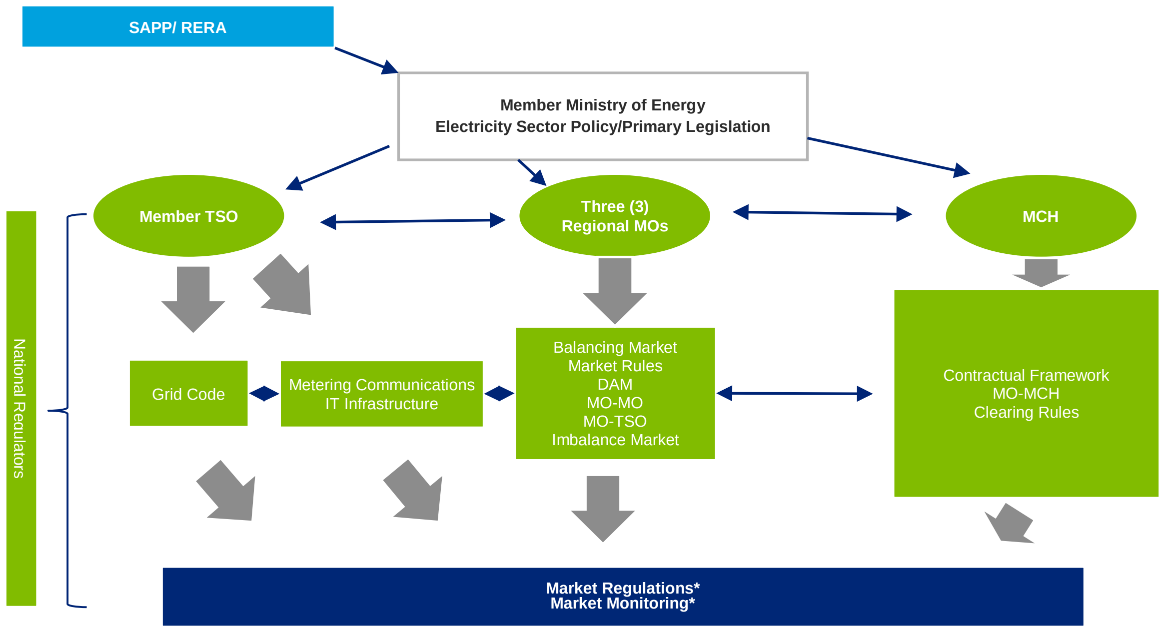
However, challenges with regard to institutional set up persist. In the section below, we highlight some of the more significant challenges that are a cause for concern for potential private and public investors in the SADC power markets. Solutions to regulation and governance challenges are covered in detail within the New Legal and Regulatory Framework, which is a primary component of the Market and Investment Framework. Below, we highlight some of the other issues, such as procurement, and system and market operation.

The target institutional model that RERA and Deloitte suggest (shown in Figure 6-1a and Figure 6-1b below) shows the relationships between various institutions in the SADC region, as well as some of their anticipated functions. The model is designed to be implemented in two phases:

1) During the first phase, Figure 6-1a, three national MOs should be considered, along with member TSOs. The MOs are envisaged to operate the three control areas / zones currently characterizing the SAPP power system, and will coordinate the Balancing Market and DAM, as well as being responsible for adopting and monitoring Power Market rules. The functions of the above market entities will be defined by the Member State Ministry of Energy, through adopted legislation.
2) The second phase of the institutional model envisages creation of a single, regional MO, Figure 6-1b. This institution will oversee the three national MOs and overall regional market performance.

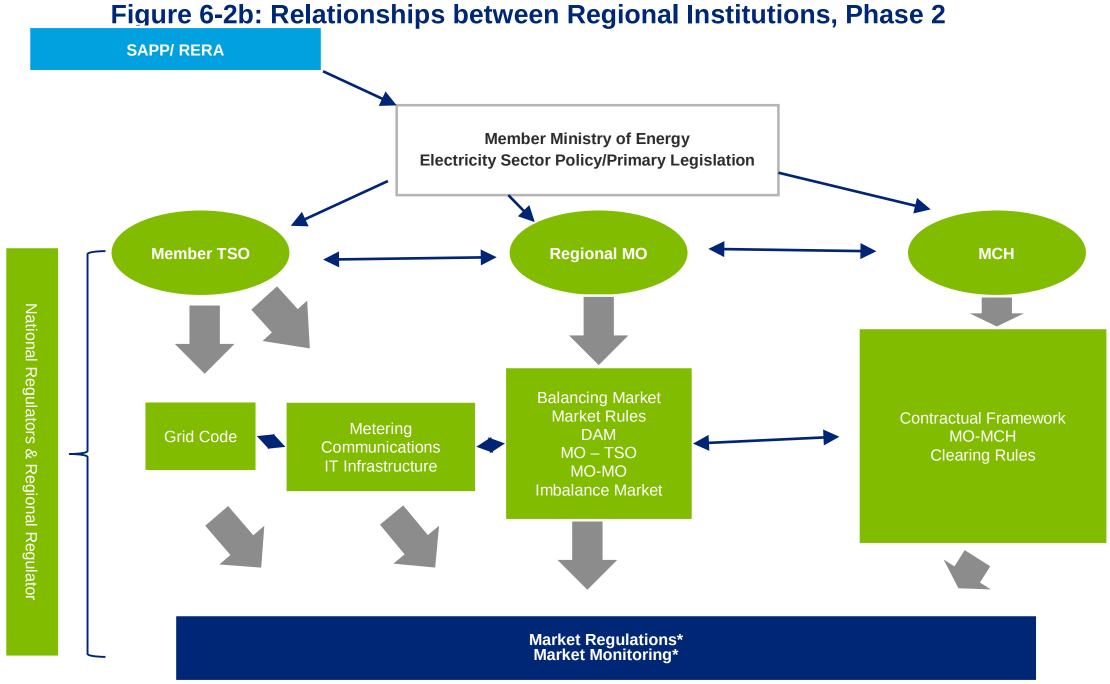
The proposed institutional phases will target an efficient power market with well-defined market regulations and efficient monitoring.

Figure 6-1a: Relationships between Regional Institutions, Phase 1



The various regional institutions will be responsible for the functioning of the market model and its further monitoring through contractual frameworks. Each country's Ministry of Energy will be the responsible entity for creating and adopting a sound energy policy for implementation. The Ministry will be the body to approve the functions of the domestic TSO and the MO (in case the MO is within the considered country zone). The Market Clearing House (MCH) will be a solid financial institution responsible for market clearing rules, and will have a contractual framework developed with the three regional MOs. TSOs and the MOs will have clearly defined unbundled functions to perform in the market: The TSO will coordinate metering, coordinate IT communications, and ensure technical guidelines are in place, while the MO will handle Balancing/DAM market operations, as well as the implementation of Market Rules.

Figure 6-2b: Relationships between Regional Institutions, Phase 2



6.1. Roles within the Implementation Plan

The following roles are envisioned for the following entities.

Role of RERA

- Facilitate the adoption of the Legal/Regulatory, Financial, Operational, and Institutional frameworks required to implement the Market and Investment Framework
- Facilitate cross-border agreements and MoUs with the stakeholder institutions and Member States for adoption of regulations
- Lead development and roll out of the Market and Investment Framework

Role of SAPP

- Continue to operate the regional power exchange
- Serve as the regional MO coordinator for the three newly established MOs
- Harmonize with Eskom

Role of SADC

- Continue to set regional energy policy

Role of Member State Governments

- Develop, approve and implement strategy/policies and master plans
- Develop and adopt power market laws that harmonize power markets in Member States
- Oversee/facilitate Market and Investment Framework implementation

Role of Regulatory Authorities

- Provide independent regulatory services for each Member State
- Harmonize regulatory rules towards regional trade

Role of TSOs

- Unbundled and separate TSO for each member state that owns and operates transmission assets
- Responsible for grid code, transmission plan, etc.
- Operational harmonization between the states

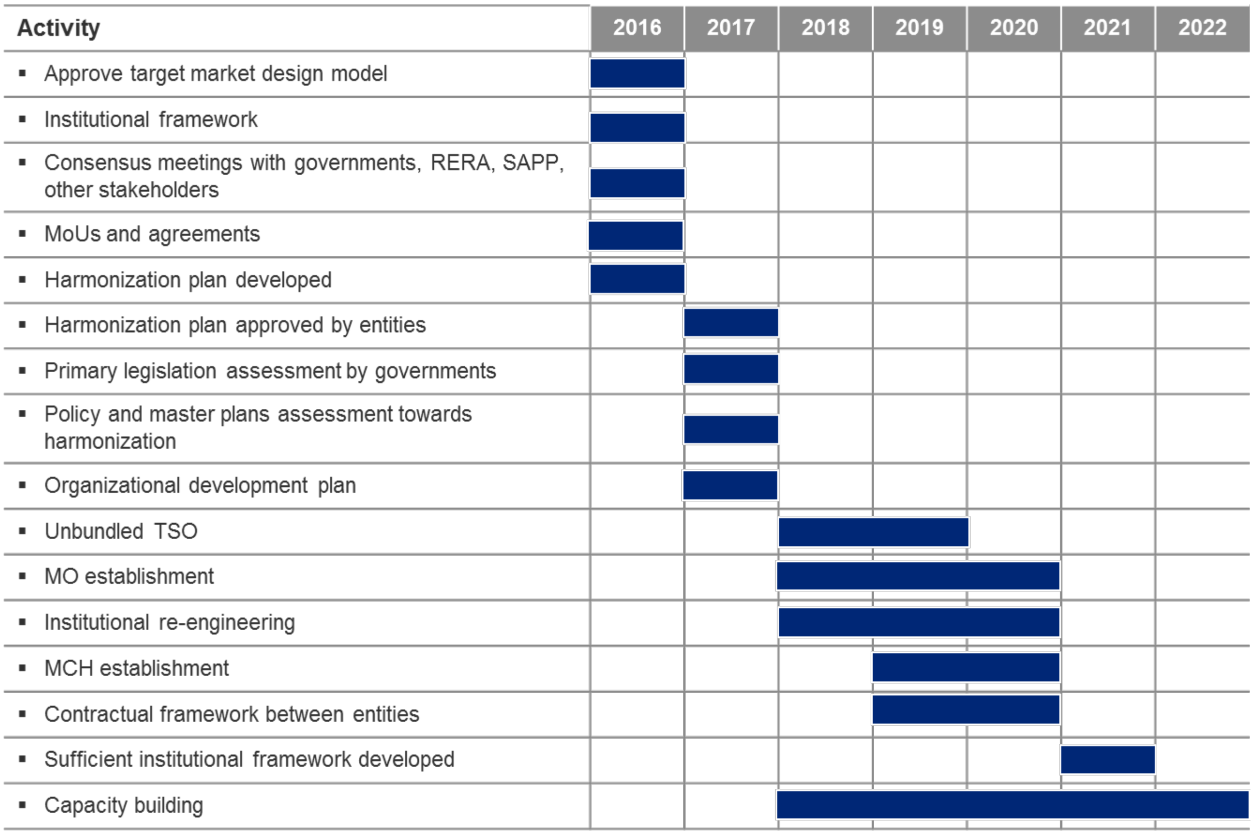
Role of Market Operator

- Operates and monitors the market
- Serve as the MCH
- Manage energy balancing and settlement services

Timeline

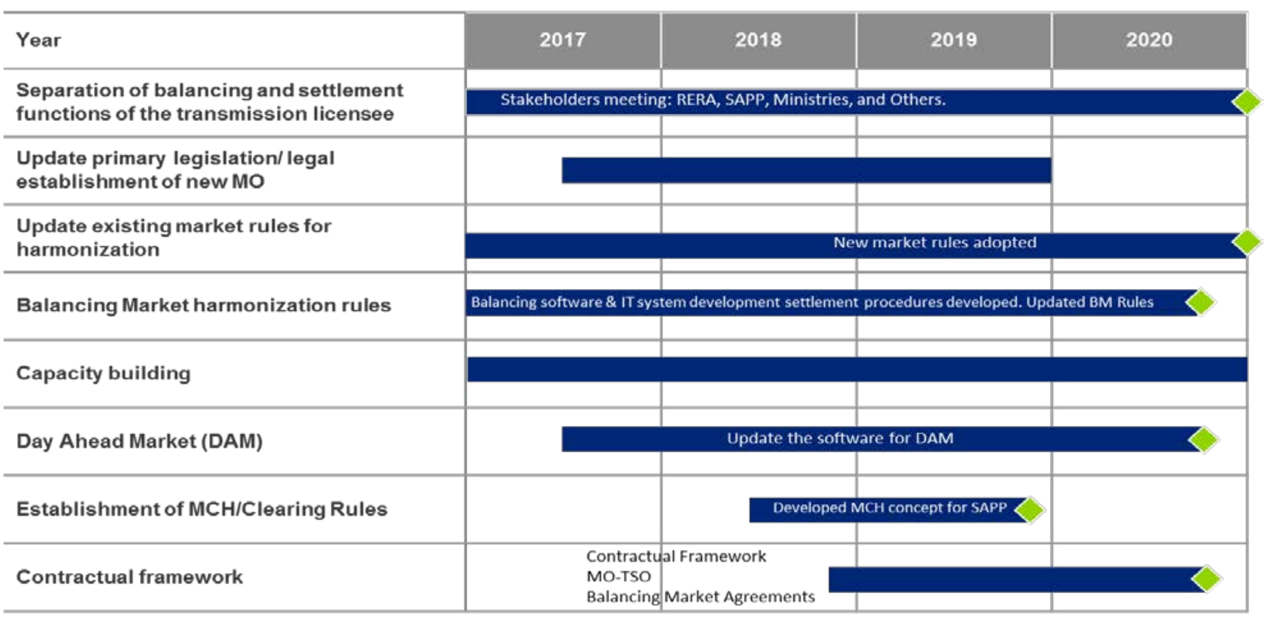
The following Figure 6-2 shows the activities and associated timelines for the implementation of the Institutional Framework.

Figure 6-3: Institutional Framework Implementation Timeline



In addition, in implementing the institutional framework, one of the major tasks is the development and establishment of the MO. Figure 6-3 below shows the activities involved in the creation and establishment of the MO.

Figure 6-4: MO Establishment Timeline



In the process of implementing the institutional framework, SAPP and RERA will also need to ask the key stakeholders to perform the following:

- Agree to coordinate all activities on the trading mechanism in a special working group;
- Speak with one common voice on the electricity trading mechanism;
- Provide feedback on proposed draft documents/process;
- Provide financial support, if feasible, on certain aspects of the Market and Investment Framework / initiative;
- Agree on deadlines/conditions with the Member State governments; and,
- Possibly create a joint Implementation Agreement.

7. IMPLEMENTATION OF OPERATING FRAMEWORK

Significant operational risks also confront SADC power project developers, many of which are described in some detail in the Recommended Market Model Report, issued by RERA/Deloitte and ENR in September 2015. Examples of such challenges include transmission congestion management, a lack of harmonization between Member State grid codes, technical legislation, planning, metering, and communications; dispatch and curtailment issues; inadvertent power flows and draw; and ineffectual monitoring of compliance and adherence to rules that do exist.

Such risks can be mitigated through the development and application of a set of technical documents and contracts intended to ensure the safe, secure, and reliable operation of the regional SAPP grid, and to provide Market Participants and Market Service Providers with clear, transparent, and predictable rules to support regional power trading activity.

We refer to these elements collectively as the Operating Framework within the Market and Investment Framework. The Operating Framework includes a Transmission Tariff Design, a Regional Grid Code, Processes for Managing Inadvertent Power Flows, Common Approaches to Grid Connection Procedures & Requirements, Connection Charging Methodologies, Dispatch Rules & Agreements, Transaction Scheduling, Transmission Approval Processes, Network Congestion Management Rules, TSO/TSO Agreements, and other areas.

The Operating Framework contains the following components and structural changes.

Non-discriminatory access to the regional and national transmission systems: Non-discriminatory access to the regional and national transmission systems is a cornerstone of the Operating Framework under the proposed Market and Investment Framework. This will require the development of:

- A physical and/or financial rights transmission tariff that supports the electricity market design and provides non-discriminatory services, as well as just and reasonable rates.
- A system and processes to sell and approve transmission services (property rights) under the terms of service of the transmission tariff. This includes a methodology for grandfathering legacy loads and legacy generation such that transmission services are provided under the new regime, but no changes are required to existing agreements.
- A system and processes to schedule the use of approved transmission service transactions. This will require SAPP to further develop its Operating Guidelines, primarily restricting sections 1.G Interchange Scheduling and Appendix 1.D Transfer Capability around transmission services.
- Settlement, risk and billing processes for payment of transmission services.
- A non-discriminatory methodology to manage transmission capacity shortages among transmission service customers and the cost responsibility for relieving transmission constraints.
- Study agreements for the connection of new generation and loads. These include system impact studies, facility studies, and cost allocation procedures for generation and load interconnection facilities as well as for any necessary system upgrades from the facility studies.

- Transmission loss repayment factors and procedures for the scheduling of transmission line losses.

Technical Documents to provide reliable and predictable transmission services and grid operations:

- A Regional Grid Code: A grid code provides standardized rules and procedures that govern the technical aspects of connecting to the transmission system, and the operation of the transmission system, in both normal and emergency operations. It includes planning and operating standards for the transmission and generating assets and the system, the functions of the TSOs, connection conditions, compliance process, operating code, balancing code, data registration code, standards for metering, communications, control, relay protection, equipment ratings, operating reserves, and frequency control. SAPP's Operating Guidelines contain a substantial amount of the operations and operations planning information for a regional grid code. SAPP also has compliance requirements for some of its guidelines and penalties / sanctions for non-compliance. However, these areas will need to be expanded.
- Interconnection Agreements: These describe the operating and maintenance procedures and cost assignments for the facilities that are used to interconnect SADC Member States.
- Connection Agreements: These are pro forma agreements that describe the operating and maintenance procedures and cost assignments for the facilities used to interconnect generation and / or load facilities to the transmission system.
- Standards of Conduct for the TSOs: These are needed for Phase 2 development where the systems are functionally separated.

7.1. Operational Framework Implementation Plan Steps

Below are some of the milestone tasks required for the effective implementation of the Operating Framework. In addition to highlighting the required tasks, we provide background information on the importance of the tasks and factors to take into consideration.

7.2. Obtain Agreement on the Development of a Type of Transmission Tariff System

7.2.1. Proposed General Approach

- Provide information on the types of transmission tariff rate designs and recommendations for specific designs.

7.2.2. Involved Parties

- SAPP
- RERA
- National Utilities

7.2.3. Background

Any transmission tariff design work should be reflected in the objectives of the transmission system tariff. Some commons objectives are listed below.

- **Objective 1: Stability –** The transmission tariff rate design and its service offerings need to be predictable and supportive of the electricity market design. This allows users of the transmission system to understand their risks and to make appropriate investment decisions. Stability in the rates of the service offerings and their terms reduces the uncertainty on project value by minimizing unexpected operational costs.
- **Objective 2: Non-discrimination –** The transmission tariff is an exclusive offer for transmission service. There are no other rates, terms, or conditions that can be offered or negotiated among the parties. New transmission services customers should not face charges or terms of services that are different from those of existing users (including the transmission providers' own generation and network customers) and vice-versa, and thus the tariff should not create undue barriers to entry. The objective is to facilitate the cost efficient expansion of the generation and transmission systems by eliminating the preferential rights of existing users, and allowing new efficient generators to replace older ones. The non-discrimination principle works both ways and ensures that legacy generation will be treated fairly with new, more efficient resources.
- **Objective 3: Recovery of Costs –** The tariff rates must provide for complete recovery of the transmission providers' revenue requirement in order to cover all incurred expenses.
- **Objective 4: Energy Transmission Efficiency Incentive –** The tariffs should provide appropriate signals to promote the most economical siting of generation and large industrial loads. The tariff rate design should inform the users of the cost imposed to the system, allowing them to make decisions on the placement of new loads, the retirement of inefficient and obsolete generators and the optimal location of new power plants.
- **Objective 5: Simplicity of Rates –** The charges should be conceptually simple and transparent and must allow all users to estimate the expected payments. Users should be able to easily understand the rationale for the methodology used in rate design.
- **Objective 6: Consistency with Other Charges Faced by the Users –** The transmission tariff design should be consistent, as much as possible, with other fuels' transportation charges, to promote economically appropriate decisions on the location of generation facilities.

7.2.4. Task 1: Financial Rights versus Property Rights Transmission Tariff Design

The SADC Community's energy protocol[3] expresses the need for a coordinated approach on strategy formulation, planning and development of energy resources in the region. The Market and Investment Framework achieves this by proposing to develop a sophisticated arrangement that creates an enabling and attractive investment climate. This is intended to foster confidence for private investment in needed new power generation resources in the SADC community. The framework does this by creating rules and processes that govern both state and privately owned electricity transactions, enforcement mechanisms, and a predictable and reliable operating environment. A proposed regulatory and legal framework is intended to assure investors that their

[3] Protocol on Energy In the Southern African Development (SADC) Community, 2006-11-01

generation assets and transactions and those of the incumbent utilities will be treated fairly through effective and non-prejudicial enforcement regulatory processes.

A transmission tariff is one of the fundamental aspects that is needed to create a climate for investor confidence and is the essential building block for creating a competitive electricity market and for developing new needed transmission resources. The transmission tariff contains the rates, terms and conditions for transmission service, the rights and responsibilities of the Transmission Provider, Transmission System Operator, market participants, and various schedules that define the revenues that are collected for its operations and how those revenues are distributed. Transmission is a monopoly and in order to ensure non-discriminatory access, non-discriminatory operations and just and reasonable pricing, its activities and offerings need to be regulated.

New IPP generation may serve national needs, but can also serve the electricity needs in other and perhaps distant SADC community countries. The transmission tariff provides for the connection of new generation resources and for space on the transmission system to deliver its output. Consequently, the transmission tariff must provide for the potential to develop new transmission facilities and for its pricing to recover the transmission provider's costs.

There are two fundamental transmission tariff arrangements: those based upon financial rights and those based upon physical property rights.

Transmission tariffs using financial rights arrangements tend to have a single transmission planner and a single transmission system operator and use congestion pricing outcomes to justify new transmission development. In these systems, all generator offers at and below the market clearing price are granted transmission access. However, transmission congestion may limit a low priced generator's output and congestion payments is made to those generators that are constrained off or down. Accumulated congestion charges are used in business cases to justify investment to eliminate transmission constraints.

Transmission tariffs based upon physical rights can have multiple planners and multiple operators and new transmission facilities are paid for by applying cost causation principles among the users of the transmission system. Transmission customers pay for the right to use physical space on the transmission system. In order to be able to schedule their power, their transmission reservation must exist and the schedule must be no greater than the reserved transmission capability. Congestion is eliminated by curtailing transactions with the greatest impact upon a transmission constraint. This threshold is typically set at about 5%. Consequently a large amount of schedules need to be curtailed to relieve relatively small overloads. As electricity markets develop, these transmission loading relief procedures are usually replaced with generator re-dispatch schemes.

Because the proposed Market and Investment Framework recommends that national utilities maintain control over and be responsible for the planning and operation of their transmission systems, a transmission tariff system using physical rights will be the best fit.

7.2.5. Task 2: Transmission Tariff: Proposal for a Rate Design

7.2.5.1 Proposed General Approach

- Review various potential transmission tariff rate design methodologies.
- Develop analyses that demonstrates how the rate design would function within the electricity market design.
- Develop examples of various rates for the various designs and how revenues would be distributed to the transmission providers and costs allocated to transmission system users.

7.2.5.2 Involved Parties

- RERA
- Utilities

7.2.5.3 Background

The rate design of the transmission tariff will be a primary concern to the transmission provider in that it ideally recovers costs and that the application of appropriate cost causation principles ensures that transmission system users are not being subsidized. The rate design will also be of great interest to the electricity market designer and regulatory authority to ensure that the rate design achieves the desired and most efficient market outcomes.

The simplest transmission tariff rate design is to develop a pro forma transmission tariff with common service and pricing conditions that could be offered by all national transmission system systems. Pricing would apply national transmission rates to transmission services. This would result in pancaked rates for transmission services, paying multiple transmission charges when transactions cross national boundaries. Pancaked rates are seen as undesirable by electricity market designers and market operators as they discourage the development of remote, efficient, and renewable resources such as hydro-electric facilities.

Regional transmission tariffs overcome pancaked rates. There are a number of rate designs in use. These tend to be developed as a compromise between the needs of the transmission providers and the goals of the electricity market. The transmission tariff rate design is also a staged development that changes as the electricity market becomes more competitive.

The transmission tariff rate design needs to be determined by the utilities and the regulatory authority. This is usually a very lengthy process.

7.2.5.3.1 Background: Market design and Tariff Rate Design

The rates may, or may not be distance sensitive. Some common approaches that could be used in the SADC region are:

- Postage stamp pricing – average pricing – distance insensitive
- Nodal pricing – somewhat distance sensitive
- MW/Mile (or MW/km) – distance sensitive
- License-plate – zonal rates – distance insensitive
- Some hybrid – zonal-highway: a combination of license-plate for local zone rates for generation serving national loads, and a distance insensitive postage stamp for a highway rate for the regional transactions.

1. **Postage Stamp Pricing:** The postage stamp system is the simplest rate design. For transporting a given amount of electrical energy over the grid, a fixed price per energy unit is charged, independent of the distance or the voltage level. In its simplest form, the postage tariff is independent of the point of injection, where the electricity accesses the transmission system, and the point of withdrawal. Pricing is also not a function of time. The methodology is extremely simple to implement.

   In general, the postage stamp pricing system does not give the correct incentives to suppliers or users of electrical energy for siting future investments or for an efficient use of the grid in the short term. Furthermore, this pricing system does not give TSO any incentive to improve the transport efficiency of the present system, nor for future investments to improve or extend the system. Revenue distribution is often based upon a system's pro rata share of the total of the regional transmission system's revenue requirement. Because postage stamp pricing charges the average transmission service rate, then customers that are located in low priced transmission zones, subsidize those customers located in high-prices transmission zones.

2. **Nodal Pricing:** Nodal pricing is designed to take into consideration the actual price of transmission service given congestion. It is used in regional electricity markets where generation resources are dispersed and the market operator dispatches generation based upon a locational marginal price. The locational marginal price is the actual generator marginal offer plus transmission system losses and the opportunity cost of transmission constraints.

   Nodal pricing requires complex up-to-date models for the transmission system and economic dispatch and complex settlement programs. The approach is to set a generation dispatch in a model based upon a transmission system model that is up-to-date with all current limits, outages and generator-to-load schedules, load bids and generator offers. Generation dispatch is based upon the generator offers and is limited by transmission constraints using a constrained economic dispatch algorithm. The model outputs an operating schedule for each generator and load and spot prices. Generators are paid the spot price at their node including the marginal cost of losses and constraints.

3. **MW-Mile or MW-Km:** The method tries to establish a connection between transmission service pricing and the physical impact of generation-to-load deliveries on the regional transmission system. Revenue requirement cost recovery allocation is based upon the engineering concept that generator size and location are the primary drivers of design and construction of the interconnected transmission system. MW-Mile allocates costs among users by calculating a transmission payment for each generation-to-load schedule and where generators self-schedule to loads, those generators allocation in proportion to its calculated impact on the regional transmission system.

   A generator's system impact is calculated by determining the spread of power-flows from the generator into the transmission network. The spread of power-flows is calculated as the difference in MW flow observed on each line in the region when the results of two computer simulations are compared, one with a base case, and another with the generator load increased by 1 MW to supply a specific load. This study is done for all source and sink pairs in the regional transmission system, and a matrix of power transfer distribution factors is calculated for all possible source sink pairs. The MW impact on each line is multiplied by that line's length to get a MW-mile value. These values for all lines in the region are summed to arrive at a total MW-mile value for the generator. Adjustments to the MW-mile value are made to recognize line cost differentials, transformers, and transmission interface restrictions or congestion.

Each generator's payment responsibility is the total regional transmission costs multiplied by a factor. The factor equals that generator's MW-mile value divided by the sum of the MW-mile values for all the generators or a matrix value that allocated the generator schedule to specific loads. The generators pay these amounts into a regional fund. For a generator, this payment becomes a cost component similar to a fixed charge cost component to be recovered in its sales of power, whether to native load customers or to wholesale buyers. The regional transmission fund receipts are distributed to all transmission owners on the basis of their revenue requirements.

The controversy against MW-Mile is that it makes it very expensive to trade over long distances and thereby limits competition. MW-Mile is, essentially, a pancaked rate, and it is argued that pancaked charges do not reflect real system costs.

Example: Generator A sells to load A in region A, while generator B sells to load B in region B. With this arrangement, both pay transmission charges for only one region. Under a MW-Mile charging system, if generator A sells to load B and generator B sells to load A, they will both have to pay an additional transmission service because the distance of the transaction has increased. The problem is this extra charge represent does not really represent the use of the system. The four parties do not use any more transmission system resources if the trades were rearranged. There is no cost to altering the trades in this way. Since the generators produce the same amount of power (assuming the trades were for the same amount of power) and the loads consume the same amount of power, all of the physical activity of the system remains unchanged. The same power will flow on the same lines.

Pancaking and distance sensitive rates have two problems. First, they discourage trades at a distance. Second, the discouragement increases exponentially as more and more regional boundaries are crossed. While MW-Mile schemes eliminate the second problem, they still retain the fundamental problem of discouraging competition. MW-Mile is a distance sensitive scheme that simply smooths pancaked rates.

Because distance-sensitive pricing schemes use absolute changes, and do not look at the net impacts, where certain generators may actually reduce the costs to use the grid, an appealing fix for this problem is to use net MW-Miles. This removes the unfairness of charging traders who reduce flow, and eliminates the market power problem. The “net MW-Mile” approach is the same as the absolute approach except that a trade which reduces a flow on a line by 100 MW has its MW-Miles on this line counted as negative instead of positive.

The net MW-Mile approach is the same method that is used to calculate transmission line losses in most regional systems. Consider the loss charge from flowing power from A to B and the loss charge from B to A—they are equal and opposite. If flowing one way increases losses, then flowing the other way decreases losses. Unfortunately, the net MW-Mile charge has the property that if the charge from A to B is positive, then the charge is applied. If the from B to A is negative, the charge is not applied. Once again the charge is imposed only on trades that increase the power-flow levels on lines and not on all trades regardless of their effect.

MW-Miles charges also cause dispatch inefficiencies and are not be used unless they provide some offsetting benefit. MW-Mile systems are extremely complex both in terms of implementation and in terms of their economic incentives. Because MW-Mile transmission rates are usually quite high, the tariff is often highly discounted and relegated to selling surplus transmission capacity rather than spurring needed transmission investment.

4. **License Plate Pricing:** License-plate pricing is a zonal pricing system. Essentially, the revenue requirement of a subset of the regional transmission system is the only rate paid for transmission services. For example, for a transaction from Angola to South Africa, only South Africa's transmission rate would be applied and would be paid by the load (if all of South Africa's transmission system was a single transmission rate zone).
   This approach is called "Licence Plate" because it is equivalent to the automobile licence plate tariff applied to car owners in each country, state or province, depending on the rate applicable to where the car owner resides. The driver can drive around the entire region without having to pay any extra licensing charges.

   A transmission customer only pays the specific, licence plate network or point-to-point rate and connection charges payable to recover the revenue requirement of the host transmitter to whose system has the point of withdrawal.

   License-plate pricing is the current pricing scheme used by most RTOs and ISOs in North America. However, is it thought of as a transitional pricing mechanism to avoid initial cost shifting when developing regional markets where individual transmission tariff existed and there are multiple regulators that have jurisdiction in part of the regional transmission system and can maintain authority over national transmission service rates.

   Each transmission owner that participates in the regional transmission tariff collects transmission network service charges and point-to-point charges from customers connected to its transmission system on the basis of a "per transmitter" ("Licence Plate") tariff as approved by a regulator. "Licence Plate" pricing methodology has been seen as the only viable approach at the early stages of electricity market development since transmitters participating in a regional tariff come under the jurisdiction of different regulators. The "Licence Plate" approach is considered to be transitory until respective regulators can agree on a uniform tariff structure cross national boundaries.

   The electricity transactions involving transmission systems that are not a part of the regional tariff pay transmission service charges on the basis of a "Point-to-Point" Tariff. This tariff is nominally set at the average system rate of the region, but it may be discounted from time to time. Revenue distribution is based on a pro rata share of the systems percentage of the total regional transmission revenue requirement.

License-plate pricing has similar attributes to postage-stamp pricing in that it is distance insensitive and results in correct generation dispatch signals and permits a high level of competition in the market-place.

Without special provisions in the tariff, license-plate pricing is a substantial disincentive to transmission expansion. For example, if there is a generator located in Angola with the sole purpose of delivering power to South Africa, and requires a transmission expansion in Zimbabwe to do so, license-plate pricing will place the burden on the Zimbabwe customers to pay for the transmission expansion, from which they obtain no benefit. The transmission tariff must have provisions that require the transmission customer to pay for the all the system upgrades in order to obtain the approval for the transmission service to be able to deliver its power.

5. **Highway-Zonal Hybrid Rate Design:** The Highway- Zone rate design separates the rate components based on how portions of the transmission system are used. The methodology segments the transmission system, and associated revenue requirements, into a regional 'highway' system and local 'zonal' systems, and assesses charges to transactions based on usage of these respective segments. System segmentation is based on voltage level and flow impact analyses of cross-regional transactions.

   The regional "highway" rate is a single, postage stamp rate obtained by pooling the costs of all zones' highway facilities that provide transfer capability above a prescribed threshold. The local "zonal" rates are based on the non-highway facility costs within each zone (a license-plate rate). Thus, this compromise structure recovers a portion of each owner's revenue requirement through a postage stamp rate (highway) and a portion through license plate rates (zonal). Zonal rates are further split into supply and load zonal rates:

   - Supply zonal rates are based on the costs of the facilities in the generation zone. New and existing generators in a zone pay the same zonal charges.
   - Load zone rates also vary depending on the load density within a pricing zone. There are generally higher rates in zones with low load density.

   The overriding objectives of the pricing scheme is to develop a regional transmission rate design that eliminates "pancaking", minimizes inequitable cost shifting and revenue erosion, and applies the traditional rate design principles for cost causation and matching payment to usage. The Highway-Zone rate design methodology is premised upon taking the positive attributes of both license plate and postage stamp pricing and applying them in a way that both allocates revenues based upon system usage and sends accurate price signals to the market.

   The Highway-Zone transmission rate methodology strikes a balance between traditional rate methodologies. It promotes economic efficiency through the accurate price signals allowed by postage stamp highway rate, while maintaining a level of usage-based cost recovery through zonal rates determined through local- zone embedded costs. In an effort to produce transmission pricing that adequately compensates the transmission owners for their investment and offers simple cost causation pricing to the market place, the Highway-Zone provides regulators with more certainty that the capital required for installation of new infrastructure will be available when such facilities are sited and approved in the future.

7.2.6. Task 3: Transmission Tariff - Determination of a Uniform Rate Case Methodology for the Transmission Tariff

7.2.6.1 Proposed General Approach

- Provide selection support to RERA and the utilities on the methodology that transmission owners will use when making their transmission tariff rate applications to the regulatory authority.

7.2.6.2 Involved Parties

- RERA
- Utilities

7.2.6.3 Prerequisite

- Transmission providers possess adequate systems to track and determine their cost of operations.

7.2.6.4 Background

In a regional transmission tariff, rates, and revenue distribution are based upon the revenue requirement of the individual transmission providers. Consequently, a common approach to develop the revenue requirement is required.

A transmission tariff is an exclusive offer of service. The tariff is publically available and is a contractual offering that defines the rates and services provided to all users of the system. There is no capability to develop other deals. The regulated transmission tariff system is designed to allow the Transmission Providers to collect an approved income. This is usually set by the regulatory authority to be the Transmission Provider's "Revenue Requirement". The rate is designed such that it recovers the company's approved fixed and variable costs (operation, maintenance, and administration) plus what is judged by the regulator to be a reasonable rate of return on equity.

This Revenue Requirement can be based on actual historic costs (embedded), on a prospective cost of service study that looks at future year's revenue requirements (embedded plus marginal) or on marginal costs. Alternative methodologies are Rate of Return Regulation which is incentive based or on pre-defined efficient operation, maintenance, administrative and investment costs (Price Cap Regulation). In determining the required revenues, some of the studies performed include:

1. **Marginal Cost Studies:** Used primarily to design rates that promote economic efficiency and mirror competitive generation market pricing.
2. **Embedded Cost Studies:** Used to try to achieve equity by allocating existing costs among customers on a cost-causation basis.

3. **Prospective Costs Studies**: Used to allocate existing and expected future costs among customers on cost-causation basis.

The cost studies are simply tools that can be used in rate design. As such, regulators do not usually mechanically apply the cost studies to determine rates, nor are the studies seen as the only ratemaking consideration. Cost studies must be of sufficiently high quality and reliability to be used in the ratemaking process, and the overall reliability of the studies must be weighed against all legitimate rate design goals to determine the extent of their use.

The accepted approach is to group similar customers into classes. Costs are then allocated to each customer class based on the principle of "cost causation". The cost of the portion of the system required to service a customer class, which is "used and useful" for that customer class, is allocated to that class. This follows from the need for fairness so that customer classes pay for the cost of the service provided and do not unduly subsidize another class. The overall objective is that rates are "just and reasonable", without "undue discrimination", and based on the "revenue requirement."

7.2.7. Task 4: Transmission Tariff - Tariff Administration

7.2.7.1 Proposed General Approach:

- Advise on the processes and administration that will be required to approve transmission service requests. This will require some systems to post available transfer capability and study tools to evaluate transmission service requests, and to release unused transfer capability for non-firm uses.

7.2.7.2 Involved Parties

- SAPP
- RERA
- Utilities

7.2.7.3 Background

Assuming a physical rights transmission tariff is adopted, a tariff administration role is required for the evaluation and sale of transmission services. Because of the need for specialized tools and expertise, this is usually best accomplished as a regional function. In order for the tariff administrator to evaluate transmission service requests, the individual transmission providers will need to calculate and have a system to post their available transfer capability.

Transfer capability of a transmission system is determined through a power flow study of the unutilized capability of the system at a given time and depends on a number of factors such as the system generation dispatch, system load level, load distribution in network, power transfer between areas and the limit imposed on the transmission network due to thermal, voltage, and stability considerations. The transmission tariff will contain language as to what is required to post the components for available transfer capability of various transmission paths and the regional grid code or, alternatively, regional operating guides needed to define the study process and scope. The transfer capability usually has a number of components, such as reliability margins and capacity benefit margins that need to be determined. SAPP would likely be the best organization to develop the operating guides for determining the various capacity components. A system will be required to post the capabilities and decrement them appropriately as transmission service is sold.

The tariff administrator will require power flow simulation capabilities and standardized models. The regulator will also need to provide guidance on managing legacy contracts. Legacy loads, existing contracts, and legacy generation resources arrangements need to be grandfathered such that transmission service is provided under the transmission tariff but no changes are required to the existing agreements until they expire. The unique aspects of these situations need to be documented as they may be treated differently than standard transmission services but provided with transmission service reservations to allow for scheduling and congestion management activities.

7.2.8. Task 5: Operations - Interchange Transaction Scheduling Processing, Systems and Administration

7.2.8.1 Proposed General Approach

- Provide information and advice on a system for the scheduling of transactions under transmission reservations for market participants

7.2.8.2 Involved Parties

- Utilities
- SAPP
- RERA

7.2.8.3 Background

Under a transmission tariff arrangement, only point-to-point transactions that have a transmission tariff reservation can be scheduled. Designated network resources[4] are exempt from this requirement as the resources are integrated.

Some form of transaction scheduling software is used to describe the transactions, to facilitate their electronic approval for scheduling by the balancing authorities, and used to develop curtailment reductions in the congestion management processes when transmission loading relief curtailments are required.

Before being allowed to flow, scheduled interchange must be approved. The transaction is evaluated to ensure it is balanced and valid (Balancing Authority and Transmission Service

[4] Designated network resources are defined as any designated generating resource owned, purchased or leased by a Network Customer under the Network Integration Transmission Service Tariff. Network Resources do not include any resource, or any portion thereof, that is committed for sale to third parties or otherwise cannot be called upon to meet the Network Customer's Network Load on a non-interruptible basis, except for purposes of fulfilling obligations under a Commission approved reserve sharing program

Provider validation of sources and sinks, transmission arrangements, loss arrangements, reliability-related services, etc.).

The transaction scheduling systems are also used for financial tracking and validation of energy transactions for monthly billing. These systems are commercially available and SAPP would be the best organization to develop the necessary operating guidelines for the scheduling of transactions.

7.2.9. Task 6: Transmission Tariff - Settlement and Billing

7.2.9.1 Proposed General Approach

- Provide information and advice on: a system, processes and staff for the settlement and billing of transmission reservations for transmission providers.

7.2.9.2 Involved Parties

- Utilities

7.2.9.3 Background

Transmission tariff services need to be billed and revenues distributed to transmission providers. Billing systems will need to be developed and resourced. Because of the need for specialized tools and expertise, billing is accomplished as a regional function.

Depending upon the transmission tariff rate design transmission providers may be paid from revenue pools. If so the transmission providers will often require that all funds be protected through a trustee relationship. If so, a contractual mechanism between the providers will need to be developed regarding how payments are made and how shortages are handled.

7.2.10. Task 7: Operations - Transmission Congestion Management

7.2.10.1Proposed General Approach

- Provide information and advice on: a system, processes, and resourcing for the non-discriminatory management of transmission congestion for transmission providers.

7.2.10.2 Involved Parties

- Utilities
- SAPP
- RERA

7.2.10.3 Background

If a physical rights transmission tariff methodology is used, then transmission congestion, that is, violations of transmission asset transfer capacity, ampacity, or voltage limits, should be an abnormal event caused from maintenance outages or sudden unexpected losses of facilities. It should not occur within the course of planned operations.

Congestion events should be abnormal occurrences because the approval of transmission service requests should have been evaluated against reliable values and operating conditions for available transfer capability and these should already contain components that allow for some variation in expected conditions. Since all interchange transactions must be approved in advance and all must have valid transmission reservations to be scheduled, all users of the transmission system should have approved transmission reservations and should not be transferring power in amounts greater than their reservations.

However, if transmission congestion does occur, transmission constraints need to be relieved without intentional delay. Usually the most effective method to relieve congestion is to re-dispatch generation. For simple situations, re-dispatch can be accomplished with some operating studies that identify effective re-dispatch sources followed by the development of re-dispatch contracts and operating protocols.

If generation re-dispatch options or their resources are unavailable, the default transmission congestion relief methodology is transmission loading relief. This requires that all scheduled transactions including generation-to-load plans are modeled in a power flow program. Transmission loading relief is accomplished by identifying the impact of transactions and generator-to-load schedules on the constraint and ordering curtailments based upon the pro rata impact of the use of the constraint. Non-firm service is interrupted before firm service and shorter duration service is interrupted before longer duration services. Long term firm service and firm loads are curtailed non-discriminatorily. Because of the need for specialized tools and expertise, this is usually performed as a regional function.

Systems also need to be developed to assure reliably planned operations by requiring that planned operations for all generation, loads, and transaction schedules be evaluated the day ahead of the operating day. To do so, systems submit their forecasted hourly loads, and planned operations, including maintenance outages to a central operator who runs a power flow program and assesses the operations against a set of contingencies. If overloads are identified in advance then planned operations can be modified to prevent potential transmission violations or operating guidelines developed to take appropriate and timely actions. Again, this is a regional function.

7.2.11. Task 8: Transmission Tariff - Study Agreement for Generation and Load Connection, Service, and Cost Allocation

7.2.11.1 Proposed General Approach

- Provide template agreements for system impact and facility study agreements for service to new generation, loads and for new transmission service transfer capability and how costs are allocated.
- Provide information to RERA on how they might structure orders with regards to cost allocation of new facilities.

7.2.11.2 Involved Parties

- Utilities
- RERA

7.2.11.3 Background

To obtain connection to the transmission system or obtain new transmission service, a transmission customer must submit a request. If new facilities are required, then the transmission provider will conduct studies to determine those facilities and the cost allocations between the customer and the existing customers.

Once the transmission customer has agreed to the scope of the study the transmission, provider will provide a cost estimate and study agreement for execution. The studies for interconnection and new service are usually broken into two parts: a relatively inexpensive evaluation study, then a detailed facilities study should the customer wish to proceed further.

The facilities study identifies the costs allocation for the new facilities. The process for calculating and allocating these costs must be established in advance to provide ex-ante certainty. The facilities study breaks down the facilities into those required by the customer, those for the interconnection, and any required system upgrades. Cost allocation is based upon an appeal to a number of principles that need to be fleshed out by the regulator. In general, transmission costs must be allocated in a manner that is roughly commensurate with benefits, and those who receive no benefit, either at present or in likely future scenarios, must be not be allocated cost. Cost responsibility can become quite complex and requires regulatory oversight.

7.2.12. Task 9: Transmission Tariff - Transmission Line Loss Repayment Procedures

7.2.12.1 Proposed General Approach

- Provide information on various methods used to repay transmission line losses due to transaction and generation-to-load schedules.

7.2.12.2 Involved Parties

- Utilities
- RERA

7.2.12.3 Background

Transmission line losses that occur from scheduling transactions and for generation-to-load schedules need to be repaid. There are a number of methodologies that are in use and are dependent upon the complexity of the electricity market and the tools that have been developed or loss repayment.

The simplest method is for the transmission providers to perform studies and develop average system loss factors and to post those values. The transmission customer then uses the loss factors when it schedules its transactions. For example, if the system loss factors were 3% and the transmission customer was scheduling 100 MWs, they would schedule 103 MW at the point of injection and 100 MWs at the point of withdrawal. The wheeling system would be compensated in real-time for its transmission line losses. The transmission reservation must be large enough to allow the loss deliveries.

Another method is to charge marginal losses. The marginal losses are determined day ahead when the operation plans are submitted for evaluation. As marginal losses over collect losses by approximately 2 times, a loss repayment system also needs to be developed.

Another methodology is to calculate the transmission line losses that occurred as a result of operations a week later, and develop net loss repayment schedules for all participants in the region.

7.2.13. Task 10: Development of a Regional Grid Code

7.2.13.1 Proposed General Approach

- Provide a draft of a regional grid code developed from the SADC countries individual support documents and identify areas where development is necessary.

7.2.13.2 Involved Parties

- Utilities
- RERA
- SAPP

7.2.13.3 Background

The Regional Grid Code is envisioned as the primary technical document regulating the grid. It provides procedures for both system planning and operational purposes and covers both normal and exceptional circumstances. The Grid Code also sets out the operating procedures and principles governing the relationship between the transmission system operator, power pool, and all users of the system and specifies day-to-day procedures for both planning and operational purposes and covers both normal and exceptional circumstances.

Typically a Grid Code usually has sections dealing with:

1. **Planning Code:** how the system is planned
2. **Connection:** minimum technical, design and operational criteria which must be complied with to connect with the transmission system;
3. **Compliance Processes:** compliance requirements and penalties or sanctions for non-compliance;
4. **Operating Code:** co-ordination of the outage planning process, operating procedures, scheduled and planned actions, and unexpected occurrences such as faults, safety clearances, certain aspects of contingency planning; reporting of operations and events and the procedures for the establishment of system tests;
5. **Balancing Code:** procedures and requirements for system frequency control and inadvertent control

The proposed Grid Code will not replace or substitute any existing dispatch rules, procedures and manuals. Rather, it will provide a general framework for their revision to ensure the safe, secure, and reliable operation of each national transmission grid as the Market and Investment Framework develops. It will work in conjunction with other legal and regulatory documents that may exist within SADC countries, such as national laws on electricity, market rules, regulatory guidelines issued by the regulatory authorities, and interconnection capacity auctioning and allocation procedures.

7.2.14. Task 11: Interconnection Agreements

7.2.14.1 Proposed General Approach

- Develop template interconnection agreements.

7.2.14.2 Involved Parties

- Utilities
- RERA

7.2.14.3 Background

Interconnection agreements describe the operating and maintenance coordination and procedures and cost assignments for the facilities that are used to interconnect the SADC countries transmission systems. These agreements define metering and control requirements, dispute resolution, etc.

7.2.15. Task 12: Connection Agreements

7.2.15.1 Proposed General Approach

- Develop template connection agreements.

7.2.15.2 Involved Parties

- Utilities
- RERA

7.2.15.3 Background

Connection agreements describe the operating and maintenance coordination and procedures and cost assignments for the facilities that are used to connect generation and loads to the transmission system. These are pro-forma agreement forms between generators and transmission providers. They are aimed at decreasing the administrative and legal complexity of reaching agreement on individual transmission service contracts, thereby simplifying the contracting process for all generators, including small-scale distributed generation.

These agreements define minimum operational standards, operating protocols, equipment standards, safety switching procedures, communication protocols, maintenance coordination, metering and control requirements, dispute resolution, etc.

7.2.16. Task 13: Standards of Conduct

7.2.16.1 Proposed General Approach

- Develop draft template standards of conduct for the functionally unbundled transmission operator and the compliance processes.

7.2.16.2 Involved Parties

- RERA

7.2.16.3 Background

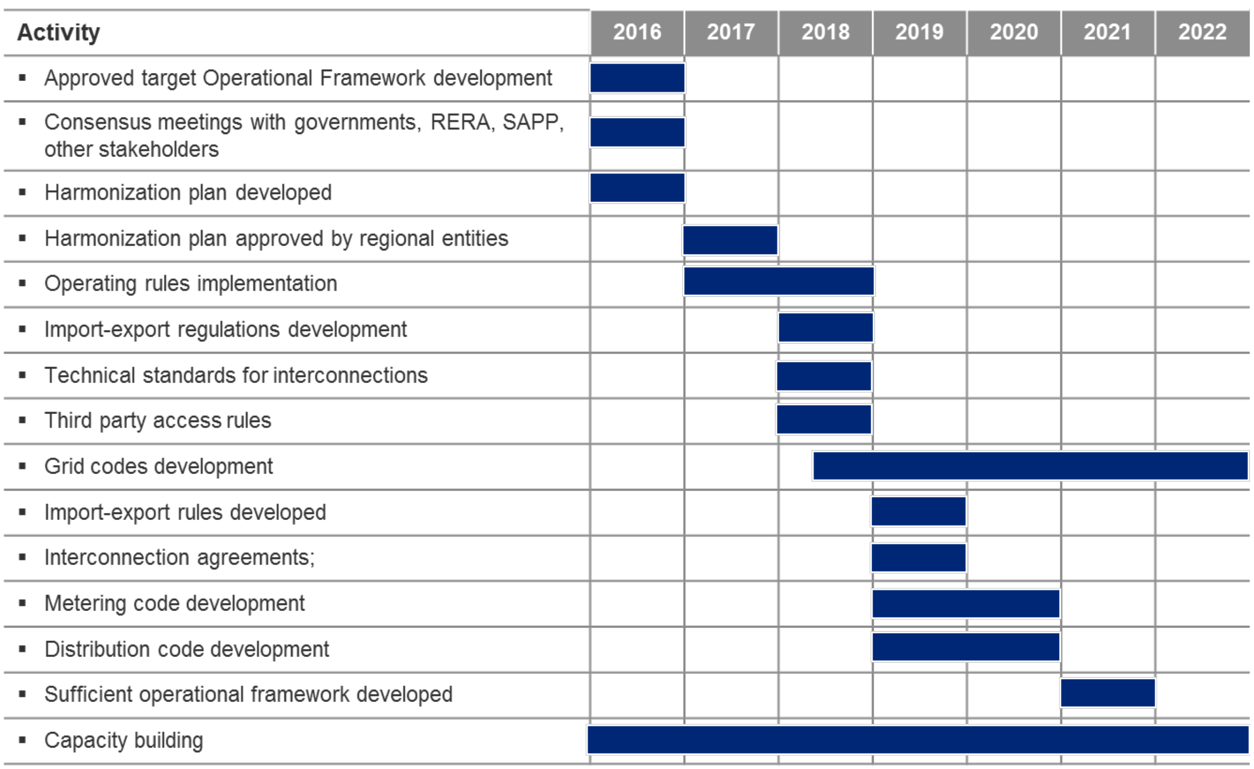
Stage 2 of the Market and Investment Framework calls for functionally unbundling of transmission and generation. To obtain non-discriminatory treatment of non-state-owned assets by the affiliated transmission system operator, a standard of conduct is usually implemented along with penalties for non-compliance as determined by the regulatory authority.

The standard of conduct is a document that the utility implements at its highest levels of the corporation. It requires that the corporation adopt practices such that transmission function and marketing function employees can operate independently of each other, that prohibit the passing of transmission function information to marketing function employees, and that mandates that the corporation comply with posting requirements to help detect any instances of undue preference due to the improper disclosure of transmission function information.

To assure compliance with the standards of conduct organization, a compliance officer function is usually developed.

Timeline

Figure 7-1: Operational Framework Development Timeline



8. IMPLEMENTATION OF FINANCIAL FRAMEWORK

While each of the issues we have raised above result in a lack of funding being made available to project developers, these issues are generally related to broader enabling environment issues. In this next section, we now focus more specifically on project level financing, and the different funding needs at each stage of the project development cycle.

The availability of financing, and its affordability, for power projects within SADC will depend upon the extent to which investors are confident that revenues derived from project investments are secure over the life of their project contracts, which can often stretch to 20 or 30 years. The lack of a legal and regulatory environment that is supportive of cross-border trade and operational and technical barriers, such as those described above, undermine this confidence as PPA and other power sales payments are put at risk. In the next section, we look at some of the financial risks that currently concern potential SADC developers, and also briefly introduce some possible solutions and mitigation techniques. Due to these risks and the potential impact on investments, the SADC energy sector has remained capital starved, in spite of a booming global IPP market.

Securing financing requires sponsors and host governments to identify and mitigate the risks inherent in energy project development, from a project's pre-feasibility stages through to commercial operation. To mitigate risks, different approaches and mechanisms should be put in place to increase developer and investor / lender confidence in the reliability of the power project's long term revenue forecasts. This, in turn, is dependent on variables such as the ability of a tariff mechanism to account for changes in costs over the duration of the project contracts, the dependability and enforceability of the PPA, and the ability of the offtaker to pay its bills on time and in full. The Market and Investment Framework will help to create mechanisms that address these issues, and thereby increase the probability and reliability of a power project's revenue forecasts.

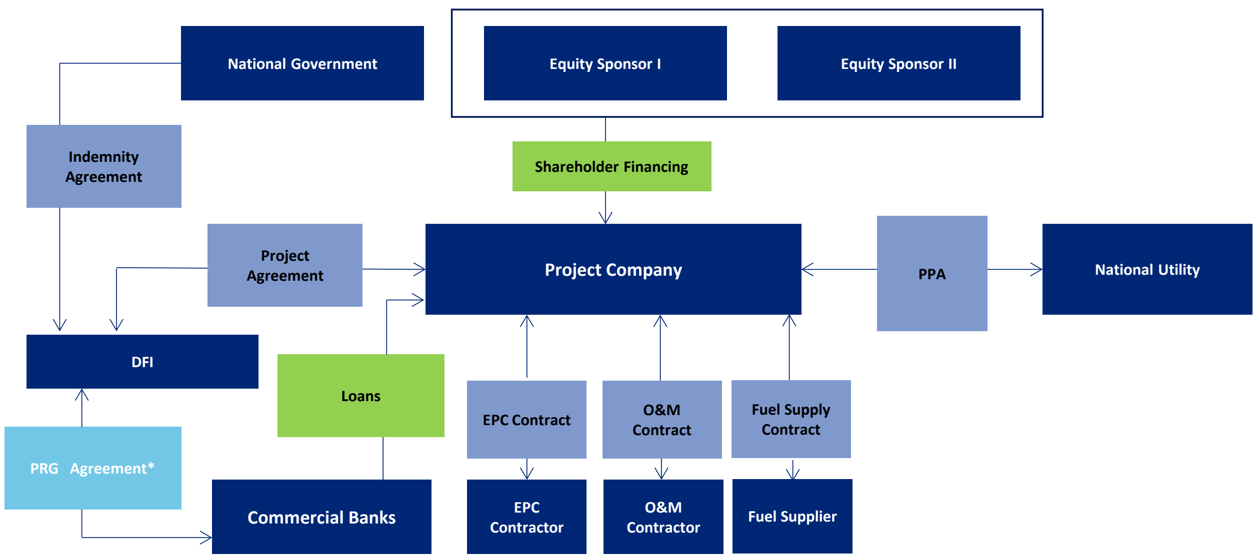
In addition to the New Legal and Regulatory Framework and the Operating Framework discussed above, there is a need to develop a robust Financing Framework in order to reduce or mitigate the risks that are keeping private investment out of regional projects. Below, we discuss each of these potential financing solutions and their application to regional IPPs in the Southern Africa region as they relate to the Market and Investment Framework. These solutions will become tenets of the regional Financing Framework.

- **Sovereign Guarantees** – Sovereign guarantees are a government's guarantee to fulfill payment to investors. Given the lack of formal credit ratings in some SADC countries, a guarantee may not have a lot of value; however, we promote the use of sovereign guarantees, where available and worthwhile. We also note that sovereign guarantees can be difficult to implement in multi-country IPPs, as each individual country may be asked to accept joint liability for payment performance of multiple offtakers procuring energy services from an IPP. Sovereign guarantees also restrict country-level IMF borrowing capacities, so are used sparingly in Africa. However, many IPPs will demand them.

- **Payment Default Coverage** - A limited number of private insurers have begun offering short-term payment default coverage for bankable IPPs in Africa. These include African Trade Insurance Agency (ATI), funded through the World Bank Group (WBG), which is based in Nairobi. ATI may provide short term guarantees (3 – 6 months) on offtaker payments under an agreed PPA, which creates additional comfort for financial partners in the creditworthiness of an IPP. Securing default coverage insurance is easier when experienced developers, DFIs, and other partners are engaged during project development stages. For regional IPPs in Southern Africa, default coverage insurance is most likely to be available when a single offtaker with reasonable credit standing and repayment history will be procuring the majority of energy (75% or greater) from a planned IPP.

- **Partial Risk Guarantees (PRGs)** – PRGs are available through the WBG and AfDB, and cover private lenders against the risk of a government entity failing to perform its obligations with respect to an IPP. PRGs ensure payment in the case of default resulting from the nonperformance of contractual obligations undertaken by governments or their agencies in private sector projects. PRGs have been approved on African energy projects that provide short-term payment guarantees, similar to the payment default coverage discussed above. Most recently, this included an AfDB PRG for US$184 million to support Nigeria's energy privatization program and to provide 3-month payment coverage for the national offtaker (the NBET) on PPA agreements with private generation companies in Nigeria. PRGs can cover other risks relating to government performance including, changes in law, obstruction of an arbitration process, changes in tariff laws, and failure to issue licenses, approvals, and consents in a timely manner. Figure 7-1 below shows an IPP project structuring example that illustrates the protection offered by a PRG on a potential regional IPP project. The protection is usually afforded only to lenders, and not to equity investors.

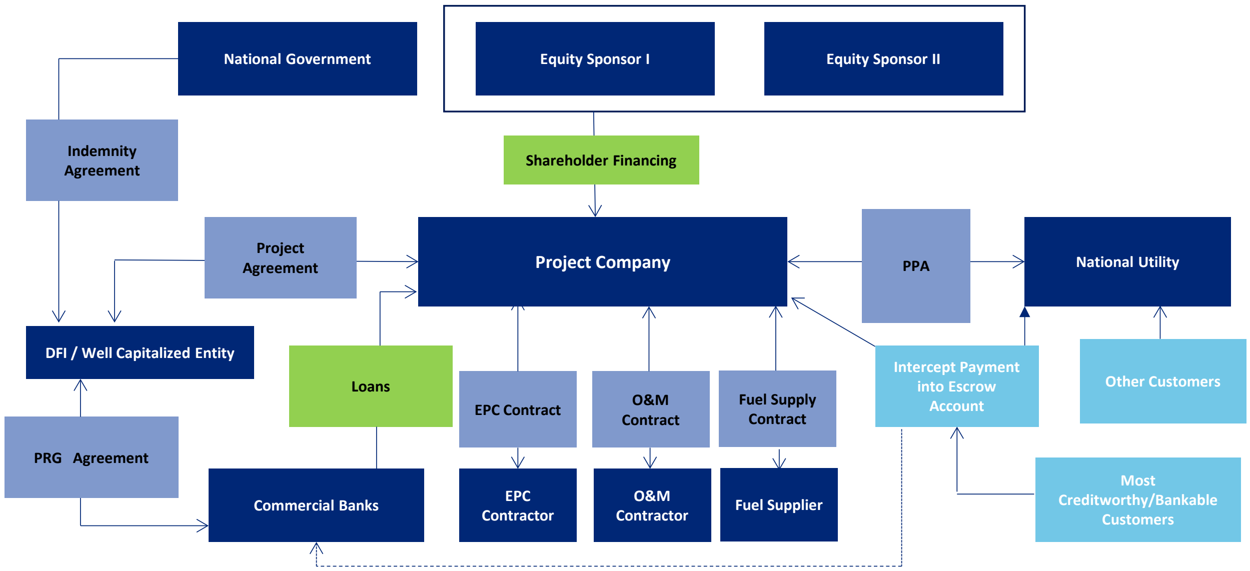
Figure 8-1: Partial Risk Guarantee Structure



PRGs typically cover risks such as political force majeure, changes in law, currency convertibility and a government's failure to fulfill its payment obligations relating to the PPA or other project contracts.

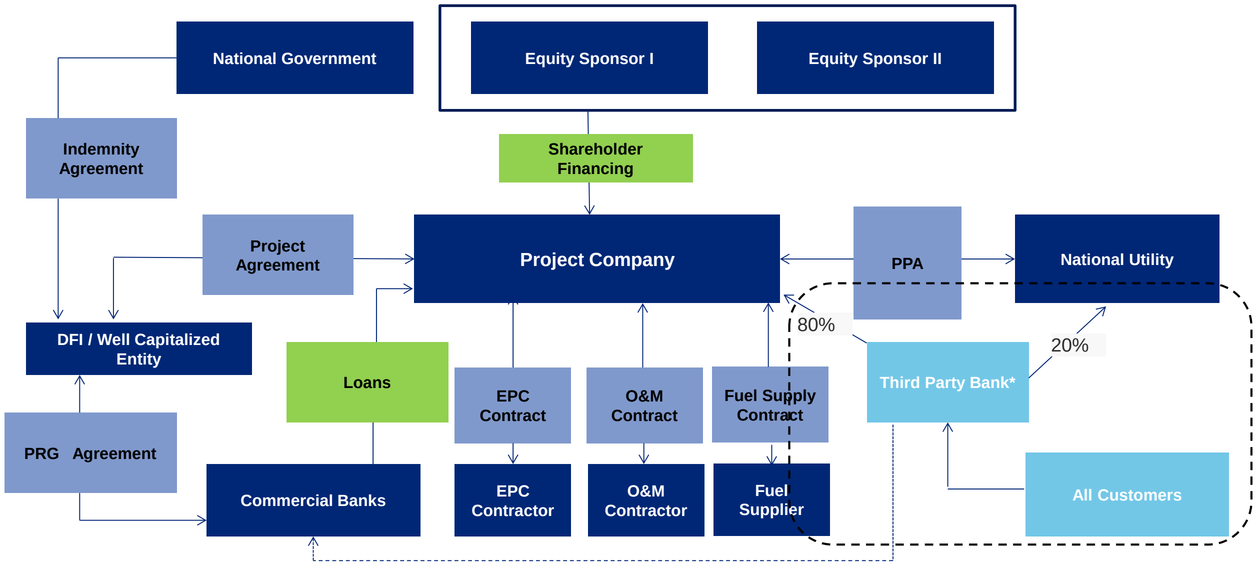
- **Intercept Payments** - A further project structure we will include in the Financing Framework is for certain creditworthy customers to make payments directly to a project SPV, or in certain cases to lenders, bypassing the offtaker with these payments. Intercept structures, as shown in Figure 7-2, are most commonly used where larger industrial or commercial customers are expected to purchase a significant share of the energy to be generated by an IPP. Financing sources may decide that the end-customer is a better credit risk than an energy sector offtaker, and thereby require that partial or full payments for energy services be made through this structure. The logistics and administrative costs of intercept structures limit their application to IPPs involving one major or several significant customers. This structure does nevertheless present a viable alternative in Southern Africa, given the creditworthiness of select large energy users who may procure electricity directly from a new IPP in the region.

Figure 8-2: Intercept Payment Structure



- **Direct Payment into Escrow Account(s)** – Similar to the intercept payment structure described above, another approach to be included in the Financing Framework will be payments into an escrow account managed by a third party, such as a lending bank. All customers deposit their bill payments into this account, with the utility receiving its share only after debt has been paid. Cahora Bassa in Mozambique, wherein the Government of Mozambique used private debt finance to fund its purchase of the hydro plant from Portugal, uses a project structure similar to this.

Figure 8-3: Customer Payment into Escrow Account



* Payment can also be made directly into the lending bank's account

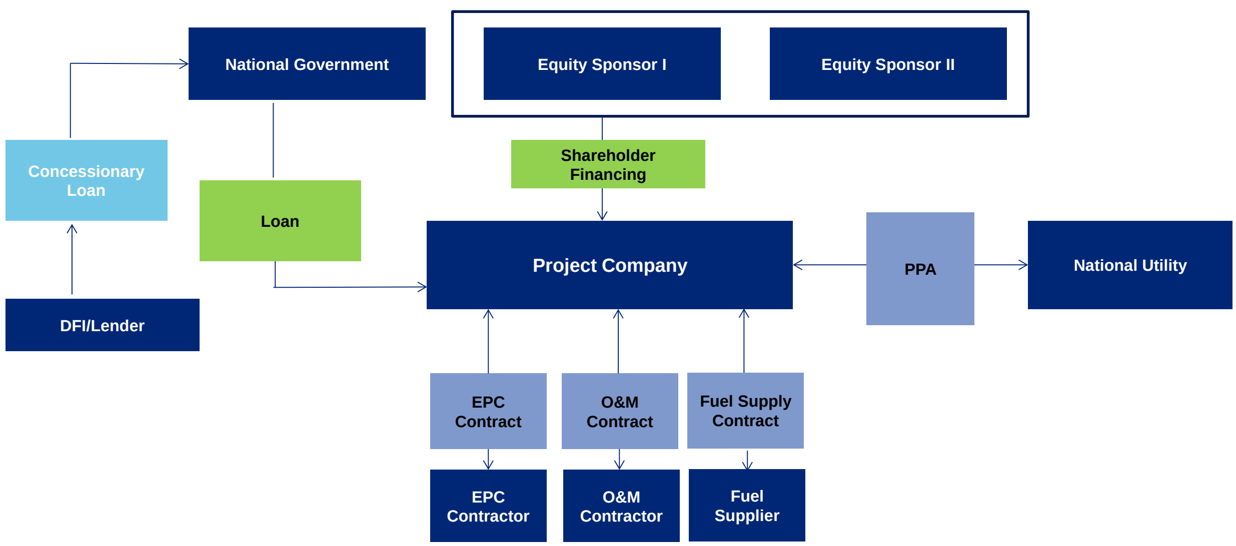
- **Political Risk Insurance –** Political risk insurance is a common protection sought by private investors and lenders, especially involving countries with limited experience developing IPPs. This product is offered by development finance institutions (DFIs) including the WBG's MIGA and OPIC, with participation from private insurance companies depending on the IPP project. Political insurance can protect against uncontrollable events that restrict an IPP's ability to meet its financial obligations, including war, sabotage, civil unrest, and other events referred to as force majeure in the PPA. These conditions are negotiated closely prior to the PPA signing. This insurance can also provide coverage against political or legislative changes that impair an IPP's repayment capacity, including changes to tax laws, currency inconvertibility, or new regulatory policies that materially harm project revenues. Political risk insurance is available to both equity investors and lenders on qualified projects.

- **Performance Bonds -** Also known as a contract bond, performance bonds are issued by an insurance company or a bank to guarantee satisfactory completion of a project by the EPC contractor or developer awarded the project. Governments will usually require a bid bond from private developers during the tender process. When the IPP project is awarded to a specific bidder or developer, a payment and performance bond will then be required as a security of job completion. If the developer fails to complete the IPP project according to the specifications laid out in the PPA, financing partners are guaranteed compensation for any monetary loss up to the amount of the performance bond. Terms of the bond may include failure to complete the project on-time, significant cost overruns, or material defects that would all limit the IPPs ability to generate the revenue projected to repay loans (or investments). Commercial banks, DFIs, and host governments on Southern African IPP projects may all require developers to post performance bonds at the time of finalizing a PPA and commencing with project construction.

- **Currency Swaps –** Experienced private developers typically require that payments for energy services under a PPA be made in hard currency or converted at the time of payment based on an agreed exchange rate format. To this extent, the offtaker rather than the developer bears the currency or exchange rate risk on a regional IPP project, since tariff customers pay for energy in local currency. When multiple local currencies are involved, especially inconvertible currencies, exchange rate risks are increased. Governments in the SAPP region should pay careful attention to currency exchange formulas in PPAs prior to agreeing on terms and conditions. Long-term currency swaps are available in limited cases where IPPs collect revenues in one currency and repay loans in another. Countries that have inflationary conditions or currencies subject to frequent devaluations can end up paying significantly higher costs for procured energy when payments must be converted to dollars, euros, or other global currencies based on current market exchange rates.

- **DFI On-Lending** - A further option that can be explored is DFI on-lending, wherein a DFI such as the World Bank or another development finance institution lends directly to a SADC government, which then lends those funds to a project. This scheme puts the repayment obligation on the government rather than the project, and therefore mitigates some of the political risk, as shown below.

Figure 8-4: DFI On-Lending



- **Bulk Energy Buyer** - A further possible solution to the poor bankability of many of SADC's largest offtakers across SADC that has been referenced in past reports is the creation of an independent, creditworthy bulk energy buyer, an approach that has been used elsewhere, such as in India and Nigeria. Such a bulk buyer could be capitalized using a variety of sources, including local governments, DFIs, and the private sector. The bulk buyer could enter into PPAs with IPPs, and have its own back to back agreements with SOUs and other less creditworthy offtakers.