**Technical Support for Continued Support on Regional Market Framework Implementation to the Regional Electricity Regulators Association of Southern Africa (RERA)**

Rules for Managing Congestion

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**September 7, 2018**

This work was funded by the U.S. Department of State, Bureau of Energy Resources, Power Sector Program. This work does not necessarily reflect the views of the United States Government.

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Acronyms

|  |  |
| --- | --- |
| DOS | U.S. Department of State |
| ENRESI | Bureau of Energy ResourcesElectricity Supply Industry |
| GPS | Global Positioning System |
| MIF | Market and Investment Framework |
| RERA | Regional Electricity Regulators Association of Southern Africa |
| SADC | Southern Africa Development Community |
| SAPPSAPP CCSAPP ABOMSAPP OG | Southern Africa Power PoolSAPP Coordination CenterSAPP Agreement Between Operating MembersSAPP Operating Guidelines |
| SAPP IUMOUTSO | SAPP Inter Utility Memorandum of UnderstandingTransmission System Operator |

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# Executive Summary

Work under *Technical Support for Continued Support on Regional Market Framework Implementation to the Regional Electricity Regulators Association of Southern Africa (RERA)* is funded by the United States Department of State (DOS) through the Bureau of Energy Resources (ENR) Power Sector Program (PSP). This work will continue support to RERA, as well as three selected pilot countries – Zambia, Namibia, and Botswana – to develop tools and procedures identified by the Market & Investment Framework (MIF) and the Framework Roadmap. The primary objective is to make further progress with specific generation and transmission projects, as identified by the Southern Africa Power Pool (SAPP) and RERA and to increase SAPP membership and participation in the regional electricity market.

The regional transmission capacity needed to facilitate an increase in cross border power trading in the Southern African region is highly constrained, unreliable, and does not offer redundancy. This is mainly due to the lack of investment in new transmission infrastructure and maintenance of existing capacity. Recognizing the importance of a robust transmission system in meeting electricity demand and allowing the market to operate competitively and efficiently, it is important to develop standards and rules that harmonize the effective use of the interconnected SAPP system.

This report provides one component of such harmonized standards – Rules for Managing Congestion.

Given the critical importance of understanding the current rules SAPP and its members use to manage congestion on the SAPP interconnected transmission system, the Deloitte Team sought to review existing internal SAPP agreements, guidelines, rules, and procedures before proposing improved rules based on international leading practices.

During the course of this project, the Deloitte Team conducted a sustained effort to secure a non-disclosure agreement (NDA) with SAPP (through RERA), in order to obtain the internal documents that the SAPP Coordination Center (SAPP CC) uses to guide procedures for managing congestion and addressing contingencies on the interconnected SAPP transmission system, primarily:

* Agreement Between Operating Members (ABOM);
* Operating Guidelines (OG); and
* DAM Book of Rules (DBOR).

However, the Deloitte Team was unable to secure the required NDA after repeated attempts. As a result, this report provides an overview of the various approaches to congestion management used worldwide that provide for private sector participation and promote information sharing to facilitate the growth of the energy market.

# review of international leading practices in congestion management

In reviewing international leading practices for the management of congestion on interconnectors, the Deloitte Team reviewed the following reports/publications:

* [*Merchant Interconnectors*](http://www.electricitypolicy.org.uk) by David Newbery of EPRG, 2006;
* *Interconnector Congestion Management* report, published by System Operator of Northern Ireland (SOIN), which addresses congestion management on the Moyle Interconnector linking the Northern Ireland and the GB transmission system in Scotland;
* *Congestion Management Guidelines* by Nordic Energy Regulators (NordREG), 2007; and
* *Capacity Allocation and Congestion Management Guidelines,* developed by National Grid.

This review reflects a consensus that the global liberalization of electricity systems and markets has led to a substantial change in the manner in which national electricity systems manage interconnectors. Whereas in the past only a few large, vertically integrated electricity companies were involved in international energy exchanges, now power producers, large consumers, distribution companies, and a growing number of electricity traders use interconnectors for international trade. As a result, the demand for interconnector capacity has rapidly increased.

Initially, interconnectors were constructed for the purpose of improving stability of the interconnected electricity system and enabling mutual support between countries. Liberalization has changed the function of interconnectors; they are increasingly regarded as a means to foster international trade and to link markets that otherwise have too little competition.

There are a number of market-based methods used to manage congestion on interconnectors: explicit auctioning, market splitting, implicit auctioning, counter trading, and re-dispatching.

This report provides a detailed explanation of each method. Annex A provides quantitative examples of how each method is implemented.

## Explicit Auctioning

Explicit auctioning is based on the difference in price between two countries, which corresponds to the “economic rent” available from the use of an interconnector. Generally, if the price in country B is higher than the price in country A, generators in country A will seek to bid for access to the market in country B as they will receive a higher price.

The first example provided in Annex A depicts a simple winner takes all auction. Other auction design possibilities are available, which might lead to different outcomes, for example:

* Restrictions can be placed on the proportion of capacity held by each generator; and
* The lowest bid can determine prices for capacity instead of generators paying “prices as bid.”

**Common Features of Explicit Auctioning:**

* Auctions can be prone to gaming. Some generators may not require interconnector capacity at all but still try to bid up the price to damage their competitors. This is particularly true if the exporting country has spare capacity and marginal costs are low;
* Depending on the design of the auction, the Transmission System Operators (TSOs) will tend to collect the economic rents available. If these are split evenly between the two connected countries to reduce network charges then the difference in final electricity prices will probably not be significantly eroded;
* Auctions require two separate transactions for potential exporters, which may also be a disincentive;
* Auctions do not require a common balancing method in the two countries, whereas alternatives do require significant harmonization of balancing rules; and
* TSO rents can be used for expansion but the amounts collected are unlikely to give a clear signal of the optimal amount of capacity increase.

## Market Splitting and Implicit Auctioning

Under this system, the TSO fixes the price for using the interconnector based on a comparison of electricity prices offered by the generators. Each generator in both countries nominates an amount it wishes to supply into the combined market and the lowest price it is willing to offer electricity into the market.

An implicit auction is similar to market splitting. With this method, the TSO levies a surcharge on the prices offered by generators in Country A who wish to sell in Country B such that the prices push enough of these bids out of the market. Provided that the TSO knows the details of all prices offered, they can calculate the required surcharge.

**Common Features of Market Splitting and Implicit Auctioning:**

* Market splitting and implicit auctions are much less prone to gaming since the generators are not bidding for economic rents from higher prices in one market. They simply try to sell at a common system price;
* Customers in the high cost country and TSOs will share economic rents under market splitting. Final electricity prices will be closer together than for explicit auctions. No economic rents are available to generators;
* These methods do not require two separate transactions by exporters but they do require a common balancing mechanism in both countries; and
* TSO rents can be used for expansion but, as with explicit auctions, the amounts collected are unlikely to give a clear signal of the optimal amount of capacity increase.

## Counter Trade and Re-Dispatching

As with market splitting, the first step for generators in both countries is to nominate an amount they wish to supply into the combined market and the lowest price they are willing to offer. The TSO then calculates the unconstrained system price to supply the total system demand and buy and sell electricity to balance demand in each country. In this approach, there is no market splitting and the system price applies to all generation in both zones.

Under re-dispatching, there are no bids but the TSOs must assess the extent to which the nominations of generators are in excess of the available capacity and decide, on some basis, which generators will be constrained.

Often TSOs carry out re-dispatching depending on the nature of the terms under which generators have access to the constrained part of the network. In particular, some generators have non-firm access and are constrained. Other generators with firm access are entitled to compensation if their output is not transported. TSOs, therefore, seek to avoid constraints on these transactions.

Generally, TSOs now consider such arrangements discriminatory and typically base re-dispatching on economic precedence, which requires some knowledge of the cost structure of each generator’s output. Given that the TSO is likely to be reliant on generators for this information, such an approach to re-dispatching becomes almost identical to counter trading.

For both counter trading and re-dispatching, the TSO incurs a cost rather than income from this type of arrangement, with the amount depending on the nature of the connection agreements with generators.

**Common Features of Counter Trading and Re-Dispatching:**

* Under counter trading, the TSO passes all economic rents to customers in the high-cost country. Instead of collecting rents, the TSO incurs a loss of revenue as a result of the constraint. This gives a clear economic signal to the TSO about the severity of the constraint. High constraint costs are a signal to upgrade the network;
* Counter trading removes the difference in final electricity prices in the two regions. If TSOs recover the constraint costs evenly from system users, the system price that emerges is likely to be between the two prices under market splitting;
* Counter trading requires a common balancing mechanism in both countries, whereas in theory, re-dispatching merely requires knowledge of generator’s costs. However, in practice there is little difference between counter trading and re-dispatching on the basis of economic precedence;
* These methods provide no funds to the TSO to upgrade the network; and
* If the TSO does not base re-dispatching on economic precedence, the access terms granted to different generators will determine the distribution of rents. If some generators have firm access, they will tend to collect all the economic rent arising from cost differences between the two countries, and there will be less price equalization.

# USING EXAMPLES TO EXPLAIN Approaches to CONGESTION MANAGEMENT

The simplified examples below are intended to demonstrate the effects of capacity allocation methods and their impact on the market prices of electricity in interconnected countries.

## Assumptions

Two countries, A and B, both have demands of 1,000MW.

Country A has three generating stations with the following characteristics:

 **Capacity Unit price/$/MWh**

Gen a 400 25

Gen b 400 30

Gen c 500 40

The price prevailing in country A is therefore $40/MWh since this is the marginal cost required to generate the 1,000MW to supply the demand and 300MW of surplus capacity at $40/MWh.

Country B also has three generating plants

 **Capacity Unit price/$/MWh**

Gen a 700 30

Gen b 200 45

Gen c 200 50

This leads to a price of $50/MWh in country B and a surplus capacity of 100MW at $50/MWh.

As the price ($40/MWh) of the 300MW surplus capacity in Country A is lower that the marginal cost ($50/MWh) in country B, it can be used to reduce prices in Country B.

Available transmission capacity between Countries A and B is 150MW. As a result, the interconnector is constrained as 300MW, based on lower cost, wants to be transferred from A to B.

Examples of various ways of dealing with the issue of congestion and scarce capacity are below.

## Examples

### Explicit Auctioning

The difference in price between the two countries corresponds to the “economic rent” available from the use of the interconnector, i.e. $10/MWh.

As there is 300MW of spare capacity in Country A, the generators will be keen to bid for access to the Country B market since they will receive up to $50/MWh instead of $40/MWh.

The most likely outcome, therefore, is that capacity in the interconnector is bid up to a price close to $10/MWh. Gen c in Country A would probably be prepared to bid the highest amount, as it has unused capacity (say $9/MWh). They will then offer electricity into Country B at $49/MWh, and the generation set in Country B becomes:

 **Capacity Unit price/MWh**

Gen a 700 30

Gen b 200 45

Gen c (A) 50 49

Gen c 200 50

Following the use of the interconnector, the price in Country B will be reduced but only to $49/MWh.

### Market Splitting

Under the market splitting approach, the bids would be as follows:

**Capacity Unit price/MWh**

Gen a (A) 400 25

Gen b (A) 400 30

Gen a (B) 700 30

Gen c (A) 500 40

Gen b (B) 200 45

Gen c (B) 200 50

The TSO would then calculate the prevailing system price under unlimited interconnector capacity, which would be equal to $40/MWh since, at that price, the required 2,000MW is available.

However, this implies export of 300MW from Country A, and there is insufficient capacity. The TSO then recalculates the price in each market considering the interconnector and its constraints.

In Country A, with exports, demand is now 1,150MW given the generation set of:

**Capacity Unit price/MWh**

Gen a (A) 400 25

Gen b (A) 400 30

Gen c (A) 500 40

This has no effect on the price, which stays at $40MWh.

For Country B however, demand is still calculated at 1,000 MW, but the imported generation amount is added to the generation set as follows:

**Capacity Unit price/MWh**

Gen a (B) 700 30

Gen c (A) 150 40

Gen b (B) 200 45

Gen c (B) 200 50

The price in Country B would then fall to $45/MWh as Gen b becomes the marginal producer and Gen c would no longer be required.

The TSO would receive a rent equal to $5 on each unit of electricity transmitted through the connector. This is because whatever the price in Country B, generators only receive the system price of $40/MWh. This means the TSO buys at electricity in Country A at $40 and sells into Country B for $45.

### Implicit Auction

In an implicit auction, provided that the TSO knows the details of all prices offered, they can calculate exactly the required surcharge. In the example, the appropriate surcharge is something a little over $5. This would relegate Gen c in Country A behind Gen b in Country B in the market, resulting in the following outcomes.

***Country A***

**Capacity Unit price/MWh**

Gen a 250 25

Gen b 400 30

Gen c 350 40

***Country B***

**Capacity Unit price/MWh**

Gen a (A) 150 30

Gen a 700 30

Gen b 150 45

Markets split in the same way; however, the successful exporter is now the lowest cost generator in Country A rather than the marginal producer. As with market splitting, generator a in Country A receives the system price of $40/MWh with the TSO gaining $5/MWh as economic rent.

### Re-Dispatching

Under re-dispatching, generators in both countries nominate an amount they wish to supply into the combined A&B market and the lowest price they are willing to offer.

The bids would be as follows:

**Capacity Unit price/MWh**

Gen a (A) 400 25

Gen b (A) 400 30

Gen a (B) 700 40

Gen c (A) 500 40

Gen b (B) 200 45

Gen b (C) 200 50

The TSO then calculates the unconstrained system price, which would be $40/MWh since at that price the required 2,000MW is available.

### Counter Trading

In this method, the TSO must buy and sell electricity to balance demand in each country. Thus, in Country B, the TSO needs to buy in 150MW of capacity. The lowest price at which that capacity will be available is from Gen b at a cost of $45/MWh. In Country A the TSO will need to sell back 150MW to generators, the highest price offered will be $40 by generator c. The resulting output in the two countries will be as follows:

***Country A***

 **Capacity Unit price/MWh**

Gen a (A) 400 25

Gen b (A) 400 30

Gen c (A) 200 40

***Country B***

Gen a (B) 700 30

Gen c (A) 150 40

Gen b (B) 150 45

In this approach there is no market splitting and the system price of $40/MWh applies to all generation in both zones. However, the TSO will suffer a cost of $5/MWh for each transaction that is constrained.

# ObservationS

All of the mechanisms discussed above have the potential to improve the allocation of generation resources. However, the outcome in terms of price differences between different countries, and the allocation of rents between different market players gives varying signals to market players; this will affect the dynamic performance of the market in terms of pressures on market players to become more efficient.

## Price Signals to Generators

A single system price gives the clearest signal to generators as to whether their facilities are economic or not at the level of the combined market. Different prices in different markets enable an inefficient plant to continue operations.

* Counter trading/re-dispatching (economic precedence) is likely to give the clearest signal in this regard;
* Market splitting/implicit auctions are the next preferred method; and
* Explicit auctions, which market actors may manipulate, or re-dispatch methods based on different conditions of access, are less likely to deliver more uniform electricity prices. The greater excess capacity exists, the more tendency exists in explicit auctions to drive price for interconnector capacity to high levels.

## Price Signals to TSOs Concerning Upgrading

Both counter trading and market splitting provide a clear signal of the extent to which capacity is insufficient. With market splitting, this is reflected by the differences in price prevailing between countries. For counter trading, the costs directly incurred by TSOs in balancing the markets provide a clear indicator of the cost of constraints.

Under auctioning, large price differences may persist as long as capacity is insufficient. As more capacity becomes available, the price of capacity and the differences between countries will fall abruptly to zero, providing a clear signal of the extent to which capacity is inadequate.

# NEXT STEPS

This report on international leading practices for congestion management provides the SAPP, its members, market participants, and the SAPP Markets Subcommittee with an understanding of the benefits and drawbacks of a number of methods used for managing congestion around the world. The information serves to help inform the SAPP CC, should it make a critical decision to change or review current practices.

Upon receipt of this overview of congestion management approaches, RERA should consult with the SAPP and the three pilot countries, and test the application of the varying methods on power trade scenarios on the planned ZIZABONA interconnection project.

Suggestions for possible enhancements or expansions may flow from these consultations, which will be considered and incorporated into a final document establishing Rules for Managing Congestion. Following RERA’s approval, the Rules will then be presented to the SADC Directorate of Infrastructure and Services, which will consider and table it to the SADC Energy Ministers for possible adoption and use across Southern Africa.