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MODELING ELECTRICITY TRADE IN SOUTHERN AFRICA
First Year Report to the Southern African Power Pool

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1. Review of the Year

The threefold purposes under which the Southern African Power Pool (SAPP) operate are:

- (i) To co-ordinate and co-operate in the operation of their systems to minimize costs while maintaining reliability,
- (i) To fully recover their costs, and
- (i) To share equitably in the resulting benefits.

The purpose statement in the SAPP Agreement continues: "Among the benefits that will be achieved are reductions in required generating capacity, reductions in regional fuel costs and improved use of hydro-electric energy." [1]

Purdue University contracted with USAID (through EAGER) and the SAPP in 1997 to investigate the potential short-term savings from tight pool operation.

The first year of modeling has concentrated on quantifying the production cost savings within the SAPP through centralized commitment and dispatch. Purposes (i) and (ii) have been given most attention. The limiting bounds for purpose (iii) are being considered.

It was agreed with the SAPP colleagues, at the February 1997 SAPP quarterly meeting in Windhoek, Namibia, that the 1997 modeling should focus on short-term cost savings. Following the Namibia meeting the collection of regional generation and transmission data took a couple of months to compile. Excellent participation has developed between Purdue and the SAPP colleagues from BPC (Botswana), EDM (Mozambique), NamPower (Namibia), Eskom (South Africa), SEB (Swaziland), ZESCO (Zambia), and ZESA (Zimbabwe). It is hoped that the communication will be strengthened with SNEL (Democratic Republic of Congo) and the other utilities in the proposed second year of modeling. SAPP colleagues supplied all the data and confirmed that correct data had been incorporated into the models during the SAPP/Purdue Modeling Workshop, August-September 1997, at Purdue.

National models were designed and operational prior to the 1997 Workshop. Regional models were also created and since the workshop have been further refined. The extra complexities in the regional models as a result of interconnections between the countries (line losses and trade variations) cause this model to have longer running times than the national models.

The magnitudes of national and regional costs have been analyzed using mathematical models specifically designed at Purdue University's State Utility Forecasting Group for the Southern Africa region. Optimum commitment and dispatch for minimum costs have been determined for the SAPP under different trade scenarios.

The models indicated that for an "average" year the production cost savings achievable through harmonization of SAPP generation equipment with existing infrastructure and with HCB will be about \$62 millions. The results from the SAPP national models have been summarized in the "Interim Progress Report." [2] The results in this final report are from the regional models. Two types of regional models have been used. They are the bilateral contracts regional model and the free trade optimal regional model. These will be referred to as the "contract" and "free trade" models.

Figure 1. Summary of Major Variables in the Model

Generation Data
O(t) Op.Cost $
PG(t,z,i)Thermal MW
H(t,z,ih)Hydro MW
fuel(t,z,i) Cost $
D(t,z)DemandMW
FD(z,i)ShutDown cost
FS(z,i)Start Up cost
FDh(z,ih)H.StUp$
MN(z,i),MinU/D time
MNh(z,ih),H.MinU/D t
pt, time
pr, price ($/MWh)

Hydrological
(All flows in cu m/h)
Predicted Water Inflow(z,ih),
q (t,z,ih)Turb discharge
sp(t,z,ih)Water sp spill
st(t,z,ih), Water stor
til, Water travel t
SLL/ELL(z,ih),Start/End lake level

Indexes:
i, Therm Station
ih, Hydro Stat
t, Time-hours
z, Area/country
g, Thermal unit
gh, Hydro unit

Trade & Transmission
CEM(zp,z)Import cost
CEP(z,zp)Export revenue
DLC, Domestic loss coefficient
KL, Line loss coeff
Lst(t,z,zp), Transmission loss
PF(t,zp,z), Power flow

Generation cost Fuel cost + Start-up & shut-down cost + OMLC)

Load balance, Total generation+Losses+Net trade=D(t,z)
===DDemand

Trade, thermal,hydro & PFmax constraints PF,PFmax, PG, H
PG(t,z,i)<PGmax(z,i), . .

Water storage balance (Storage)+(Inflows)-(Discharges)-(Spillage)
= Final storage

Minimize costs

2. Background to the Models

A very brief background to the structure and formulation of the models will help personnel in SAPP who read this report and wish to understand more about the modeling but who could not attend the workshop.

2.1 Model Structure and Policy Details

The models have to work with four areas of data. These are generation, demand, transmission, and hydrology. The major variables in these areas are grouped in Figure 1. Notation is defined in Appendix I. The indices for each thermal station in the region is shown by an "i". In the national models the individual units were given an indice g. In order to keep the model running time to a minimum, the regional models will simultaneously switch all units on and off which are at the same station. A 24-hour time horizon is employed throughout the modeling.

The advantages of increasing the number of hour periods to 168 (one week) or longer was finally decided to be unnecessary with the current short-term modeling. The demand data used for each period in each country D(t,z) was that recorded for the peak day of Eskom's operation (July 24, 1997). A load reduction factor (LRF) of 0.9 has been widely used in order to represent a more average daily load in the region. This value, or a slightly lower one, is considered suitable for South Africa's Eskom [12]. The impact on the gains from using lower reduction factors is discussed later in the report.

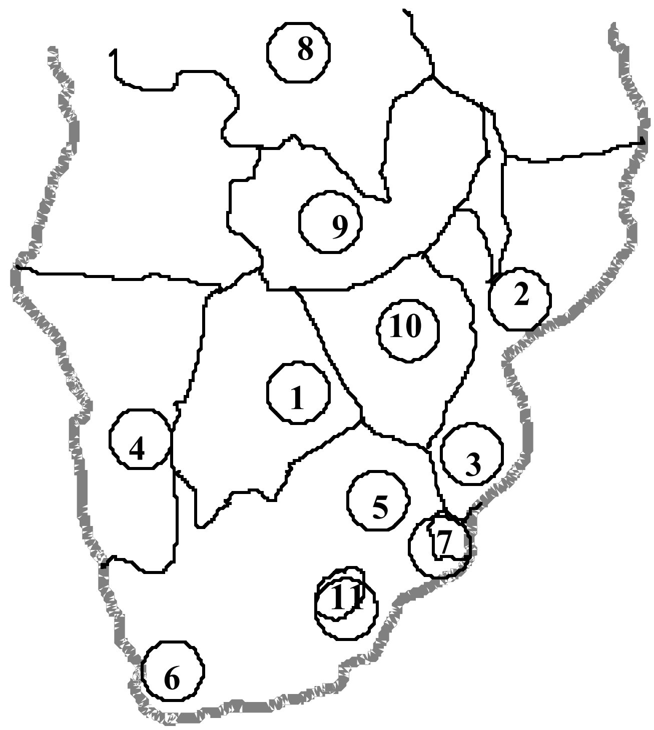
The hydrological data is very significant to the results from the models. The water inflows to the main reservoirs at Cahora Bassa, Kariba, Kafue and Inga and the smaller reservoirs are assumed constant throughout the 24 hour period. Annual water inflows and annual production costs (hydro and thermal) have been obtained using the daily values as an average for the whole year. The demand and hydrological data used in the final analyses for this report are the same ones that were confirmed during the 1997 workshop. This constant supply of water is a major assumption in the short-term model. For a long-term model different formulation will be required [5].

The regional model quantifies the load flows around the region. In the models the major constraints on load flow between countries are the line maximum load capacities, PFmax(t,zp,z), for the free trade regional model and the line contract quantities, PFaverage(t,zp,z), for the existing fixed bilateral trade regional model. Transmission losses on the international interconnectors are determined in the regional models. The generation and demand for each country (z or zp) is taken as at a point. Domestic losses are included as a scalar value of 5% of load. Transmission losses on the long international interconnectors, which join the countries together, are determined by using the individual line characteristics (resistance and reactance).

The regional model is reduced to an eleven node system (Figure 2). Botswana (Bots), Namibia (Nam), Swaziland (Swaz), Democratic Republic of Congo (DRC), Zambia (Zam), Zimbabwe (Zim) and Lesotho (Les) are given a single node each (1,4,7,8,9,10,11, respectively). Mozambique has disconnected systems with Hydro Cahorra Bassa (HCB) feeding directly to South Africa and a minimum of two nodes (2 and 3) NMoz, Northern Mozambique, and SMoz, Southern Mozambique) are necessary. The size of the South Africa system requires that more than one node be given. With two nodes it is possible to reliably represent the trade that is going across its borders (5 and 6, NSA Northern South Africa and SSA, Southern South Africa) and the transfer of power from the Johannesburg distribution area to the Cape Town distribution area.

During the 1997 Workshop it was recommended that $1.5 and $0.5 per MWh be allocated for the operations and maintenance (O&M) costs for the thermal and hydro stations respectively. Labor costs and chemical costs are included in the model but the most suitable values have yet to be generally agreed upon by SAPP colleagues. Operations, maintenance, labor and chemicals (OMLC) are now given a combined value. Thermal stations will have upper and lower OMLC limits of $4.5 and $1.5 per MWh and hydro stations will have upper and lower OMLC limits of $3.5 and $0.5 per MWh.

Figure 2. SAPP's Eleven Nodal Points
(1.Bots, 2. NMoz, 3. SMoz, 4. Nam, 5. NSA, 6. SSA,
7. Swaz, 8. DRC, 9.Zam, 10.Zim, 11.Les)



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2.2 Formulation of the Models

For a detailed understanding of the SAPP modeling it will be necessary to refer to other publications. [3,4,5,6,7] This report will note the objective function that is used and two important constraints taken from among scores of others. Readers should request copies of the other publications from Purdue's Ms. Barbara Beaver (Email: barb@ecn.purdue.edu or fax: 765-494-2351) or from any one of the co-authors listed on the front page of this report if a more thorough understanding of the models is desired (Appendix II).

The objective function (OF) is the most important statement in all of the model. It describes the whole objective of the study, that is to minimize production costs. The general expression is stated in {1a} and the mathematical expression of it is given in {1b}. For the modeling work on the national models, during the 1997 workshop, the OF included the cost of trade. In the regional models this cost has been deleted from the OF so that the expression is strictly production cost minimization.

Minimize (Fuel Cost + Start-up and Shut-down cost +{Trade Cost} + Unserved Energy + Operation, Maintenance,Labor,Chemicals Cost)

{1a}

$$\sum_{t,z,i} fuel(t,z,i)+(Z(t,z,i)*FS(z,i)+(Y(t,z,i)*FD(t,z,i))] \; +$$

$$\sum_{t,z,ih} Zh(t,z,ih)*FSh(z,ih))+Yh(t,z,ih)*FDh(z,ih))] \; +$$

$$\sum_{t,z,zp} [((PF(t,zp,z)*CEM(zp,z))-(PF(t,z,zp)*CEP(zp,z)))] \; +$$

$$\sum_{t,z} UNSER(t,z)+1.5*\sum_{t,z,i} PG(t,z,i)+0.5*\sum_{t,z,ih} H(t,z,ih)$$

{1b}

The load balance equation {2a & 2b} and water balance equation {3a & 3b} are two very important constraints;

Thermal generation + Hydro generation + Trade - Losses = Demand

{2a}

$$\sum_{i} PG(t,z,i) + \sum_{ih} H(t,z,ih) + \sum_{zp} (PF(t,zp,z) - \mathrm{PF(t,z,zp)}) - Domloss(t,z) - Tranloss(t,z) = D(t,z)$$

{2b}

Initial storage + Inflow - Discharge - Spillage = Final storage

{3a}

$$st(t-1,z,ih) + Inflow(t,z,ih) - q(t,z,ih) - sp(t,z,ih) = st(t,z,ih)$$

{3b}

The commercial optimizer GAMS is used with the Purdue models. The results are given in Section 3 below.

2.3 Trading Constraints

The models have two categories of constraints on trade. They can be classified as technical and policy constraints.

In the regional optimal free trade models the only constraint on trade is the maximum capacity on the international lines between the nodes and the supply, demand and cost conditions at the end of each line. The actual line capacity, PFmax(z,zp), for each interconnector in the regional model is listed in Table 2.3.1.

The bilateral contracts are incorporated into the model with a constraint called the average trade constraint. It is expressed as:

$$\sum_{t} PF(t,z,zp) = TT*average(z,zp)$$

The average(z,zp) term is the amount of fixed trade that has been agreed upon between country z and country zp. Throughout the 24-hour periods of the model this term specifies the average hourly MW on the line. The values used in the instance with HCB for fixed trade are listed in Table 2.3.2 and are the basis of the 24-hour trade volumes in the contract (fixed trade) cases in Figure 3.2.2 and Table 3.2.2.

Table 2.3.1. SAPP International Line Capacities, PFmax(z,zp), with HCB

	Bots	Les	NMoz	SMoz	Nam	NSA	SSA	Swaz	DRC	Zam	Zim
Bots						185					320
Les						80					
NMoz						1400					540
SMoz						250					
Nam							265				
NSA	185	80	1400	250			6000	150			500
SSA					265	6000					
Swaz						150					
DRC										250	
Zam									250		1200
Zim	320		540			500				1200	

Table 2.3.2. SAPP Bilateral Trade Contracts with HCB, average(z,zp) values

	Bots	Les	NMoz	SMoz	Nam	NSA	SSA	Swaz	DRC	Zam	Zim
Bots											
Les											
NMoz						900					430
SMoz											
Nam											
NSA	75	54		85				75			150
SSA					120						
Swaz											
DRC										100*	
Zam											100*
Zim											

* Not specified at the Purdue/SAPP workshop.

3. Results from the Regional Models

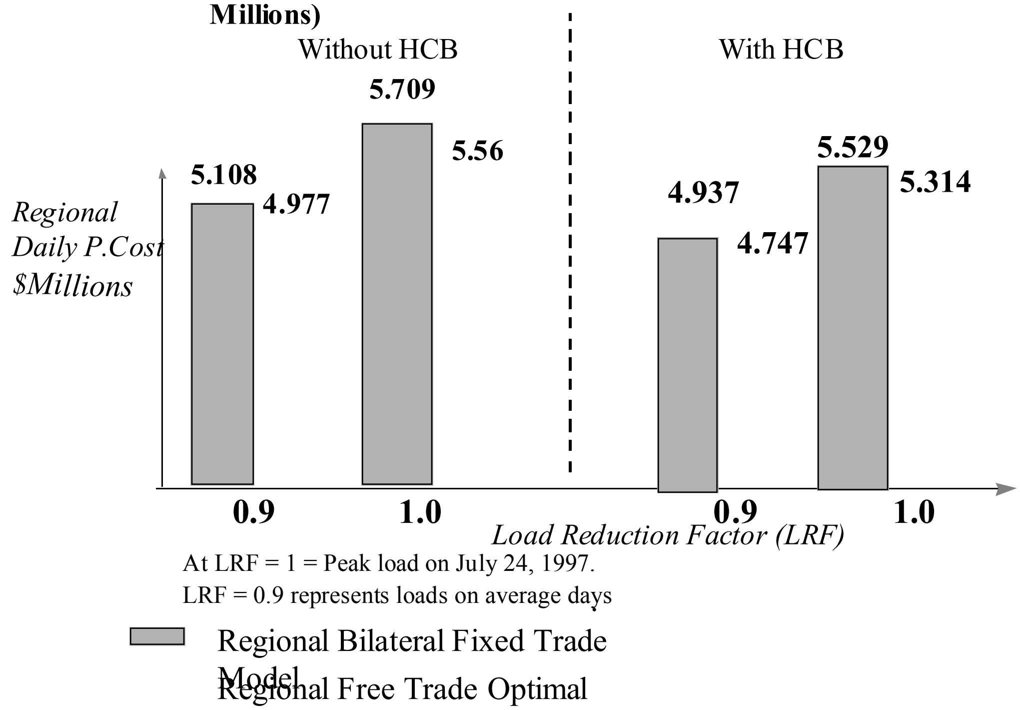
3.1 SAPP Regional Daily Costs

The daily costs for the two types (bilateral fixed trade or optimal free trade) of regional SAPP models are summarized in Figure 3.1.1. OMLC values are 4.5(PG) and 3.5(H) unless stated otherwise.

Figure 3.1.1 also shows the significance of having Hydro Cahora Bassa (HCB) fully operational. Under fixed trade conditions the average (LRF = 0.9, OMLC 4.5 & 3.5) daily costs vary from $5.108 million without HCB to $4.937 million daily with it. At peak load conditions (LRF = 1) these values are higher. With an optimal free trade scenario the average daily costs vary from $4.977 million to $4.747 million for without and with HCB, respectively. The average trade between NSA and SSA was given the value of 3000MW at the 1997 workshop and has been used throughout. A value of 2332MW (derived from the optimal trade), however, with HCB a slightly more reliable and lower daily cost estimate. All dollar values are in US dollars.

The average annual production cost savings without HCB amount to $47.8 million and with HCB they are $69.4 million ($62.4 million when optimal NSA-SSA average trade = 2332MW). The average production cost (LRF = 0.9) savings represent 2.6% of total annual regional costs without HCB and 3.8% with HCB. With lower OMLC costs of 1.5(PG) and 0.5(H) this percentage savings increases up to 4.4% and 6.7% for without and with HCB, respectively. Comparing the current contract scenario without HCB and the free trade scenario with HCB there would be an annual production cost saving of $131.7 millions ((5.108 - 4.747) x 365).

Figure 3.1.1 SAPP Regional Model Daily Production Costs



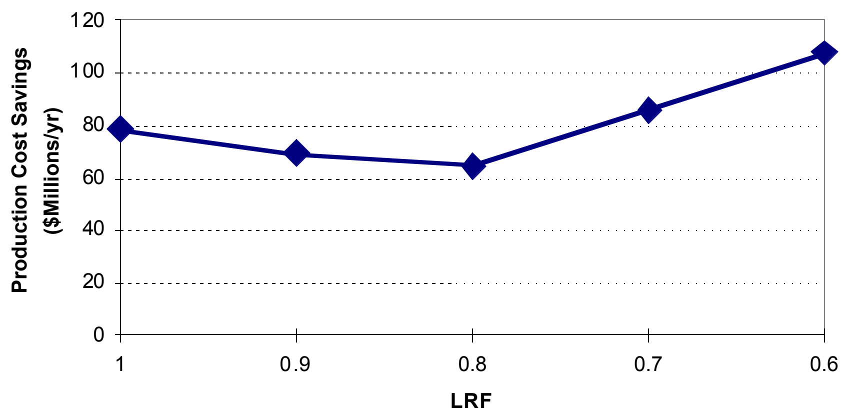
The OMLC and LRF values are not as critical as might be first considered because in assessing reductions in production costs, the absolute values take on less importance. OMLC becomes more important when marginal costing is considered.

A wide range in variation of the OMLC cost has no effect on the savings in production costs because it is not a variable within the optimization. It has no bearing on the commitment and dispatch decisions as it is a constant value for all stations in the regional models.

Table 3.1.1 The Impact of Varying LRF on Cost (with HCB)

LRF	*Contract daily cost*	*Free Trade daily cost*	*Daily Savings ($m/day)*	*Annual Savings ($m/year)*	*Free Trade Total Volume (MWh)*
1.0	5.529	5.314	0.215	78.48	59163
0.9	4.937	4.747	0.19	69.35	61549
0.8	4.352	4.175	0.177	64.61	63782
0.7	3.842	3.607	0.235	85.78	65694
0.6	3.350	3.055	0.295	107.68	66509

Figure 3.1.2 LRF & Production Cost Savings per Year
($ millions/year)



From Table 3.1.1 and Figure 3.1.2, it can be seen that production cost savings are about the same for LRF = 0.9 and 0.75. The increase in savings after LRF = 0.8 is a result of continued increase in trade. The utilities which specify that LRF = 0.7 will produce improved savings than the value of LRF = 0.9 which has been widely used in this report.

3.2 SAPP Regional Trade Quantities

3.2.1 Without HCB

The results from the fixed contracts and free trade regional models are compared, without HCB being operational, in Figure 3.2.1. These results show the relative magnitudes of net trade – exports minus imports -- for each trade scenario (LRF = 0.9 unless stated otherwise).

Table 3.2.1 shows in greater detail the full trade flows between individual countries for the two cases. The upper box describes sources (rows) and destinations (columns) with existing trading, while the middle shows imports/exports if optimal trade were to take place, and the bottom the changes as a result of free trade.

Table 3.2.1 shows that total trade doubles with the move to free trade, increasing from 24 to 48 thousand MWh/day.

Major changes seen in the bottom table are:

- Botswana more than doubles imports.
- South Africa shifts from the largest net exporter to importing slightly more than it exports.
- DRC's exports more than double.
- Zambia's exports almost quadruple.
- Zimbabwe's imports increase 60% to 18,900 MWh/day, and exports go from 0 to 13,650 MWh/day.

Figure 3.2.1 Daily Total Net Trade Without HCB

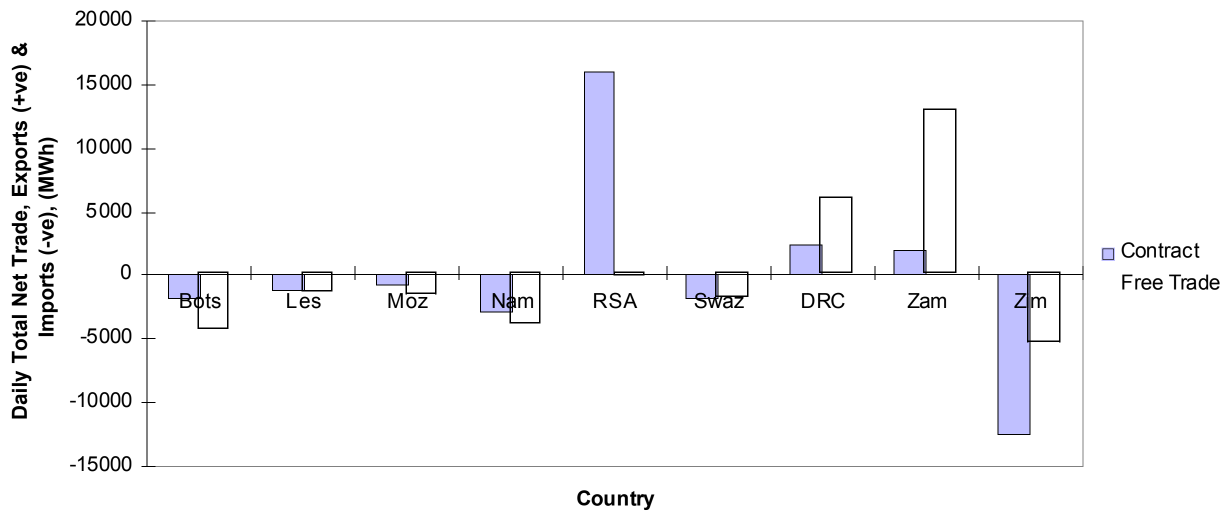


Table 3.2.1 Contract and Free Trade Without Hydro Cahora Bassa (Daily MWh received) (Ftotal, LRF=0.9)

Contract without HCB

from-to	*Bots*	*Les*	*NMoz*	*SMoz*	*Nam*	*RSA*	*Swaz*	*DRC*	*Zam*	*Zim*	*Σ*
Bots											0
Les											0
NMoz										720	720
SMoz											
Nam											
RSA	1800	1296		1536	2880		1800			6600	15912
DRC									2400		2400
Zam										5304	5304
Zim											
Σ	1800	1296	0	1536	2880	0	1800	0	2400	12624	24336

Free Trade without HCB

from-to	*Bots*	*Les*	*NMoz*	*SMoz*	*Nam*	*RSA*	*Swaz*	*DRC*	*Zam*	*Zim*	*Σ*
Bots											0
Les											0
NMoz										960	960
SMoz											0
Nam											0
RSA	342	1286		1619	4010		1820				9077
DRC									6000		6000
Zam										18939	18939
Zim	3940					9710					13650
Σ	4282	1286	0	1619	4010	9710	1820	0	6000	19899	48626

Changes as a Result of Free Trade (without HCB)

from-to	*Bots*	*Les*	*NMoz*	*SMoz*	*Nam*	*RSA*	*Swaz*	*DRC*	*Zam*	*Zim*	Increase in Exports
Bots											0
Les											0
NMoz						0				+240	240
SMoz											0
Nam											0
RSA	-1458	-10		+83	+1130		+20			-6600	-6835
DRC									+3600		3600
Zam										+13635	13635
Zim	+3940					+9710					13650
Increase in Imports	2482	-10	0	83	1130	9710	20	0	3600	7275	24290
Increase in Imports - Increase in Exports											

3.2.2 The Shift to HCB

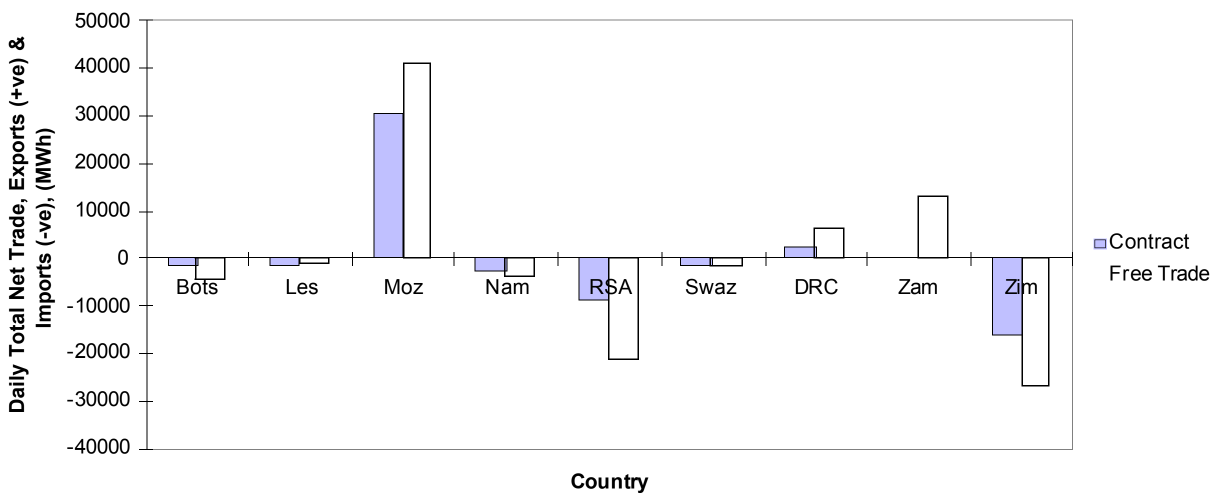
A comparison of Figures 3.2.1 and 3.2.2 show that there is a very different trade scenario when HCB is fully operational. First, as might be expected, the presence of low-cost hydro results in total trade almost doubling under either the contract or free trade scenarios. Trade volume increases also increase, from 24,290 MWh/day without HCB to 34,176 MWh/day with HCB.

Mozambique becomes the dominant exporter in the region, while South Africa becomes a net importer, rather than dominating exports without HCB. Zimbabwe remains a net importer with HCB fully operational; the availability of HCB more than quadruples their net imports under the free trade scenario.

3.2.3 The Impact of Free Trade with HCB

A comparison of the upper and middle boxes of Table 3.2.2 show that with the switch to free trade, total trade volume increases almost 70%, from 49,632 MWh/day to 83,798 MWh/day.

Figure 3.2.2 Daily Total Net Trade with HCB



Major country-by-country changes with the switch to free trade shown in the bottom box are:

- Botswana's imports more than double.
- Mozambique's exports increase over 30%.
- Namibia increases imports over 30%.
- South Africa's exports decrease slightly, while exports increase over 50%.
- DRC exports more than double.
- Zambia exports increase almost 700%.
- Zimbabwe's imports nearly double, while exports increase from 0 to 5000 MWh/day.

Table 3.2.2 Contract and Free Trade With Hydro Cahora Bassa
(Daily MWh received) (Ftotal, LRF=0.9)

Contract with HCB

from-to	*Bots*	*Les*	*NMoz*	*SMoz*	*Nam*	*RSA*	*Swaz*	*DRC*	*Zam*	*Zim*	Σ
Bots											0
Les											0
NMoz						21600				10320	31920
SMoz											0
Nam											0
RSA	1800	1296		1536	2880		1800			3600	12912
DRC									2400		2400
Zam										2400	2400
Zim											0
Σ	1800	1296	0	1536	2880	21600	1800	0	2400	16320	49632

Free Trade with HCB

from-to	*Bots*	*Les*	*NMoz*	*SMoz*	*Nam*	*RSA*	*Swaz*	*DRC*	*Zam*	*Zim*	Σ
Bots											0
Les											0
NMoz						29570				12960	42530
SMoz											0
Nam											0
RSA	2619	1286		1618	4012		1820				11355
DRC									6000		6000
Zam										18939	18939
Zim	1652					3322					4974
Σ	4271	1286	0	1618	4012	32892	1820	0	6000	31899	83798

Changes as a Result of Free Trade (with HCB)

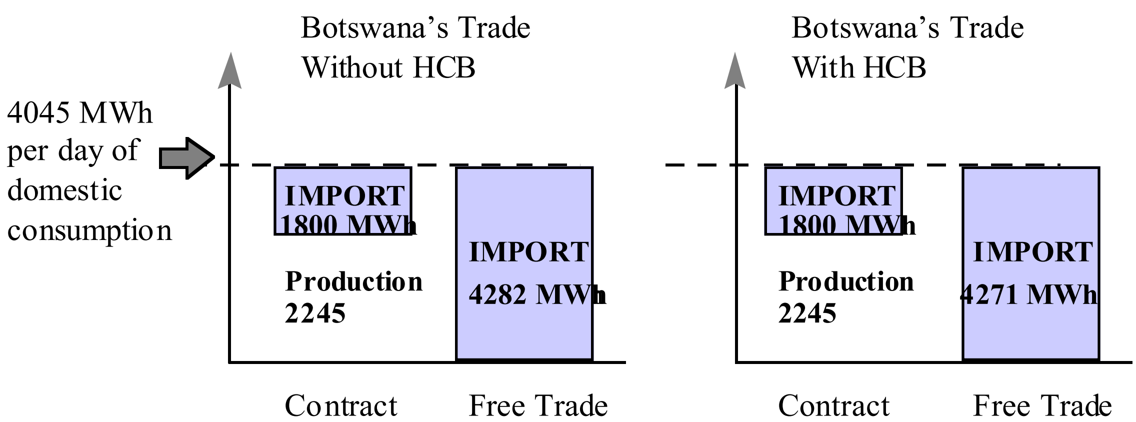
from-to	*Bots*	*Les*	*NMoz*	*SMoz*	*Nam*	*RSA*	*Swaz*	*DRC*	*Zam*	*Zim*	Increase in Exports
Bots											0
Les											0
NMoz						+7970				+2640	10610
SMoz											0
Nam											0
RSA	+819			+82	+1132		+20			-3600*	-1547
DRC									+3600		3600
Zam										+16539	16539
Zim	+1652					+3322					4974
Increase in Imports	2471	0	0	82	1132	11292	20	0	3600	15579	34176
Increase in Imports - Increase in Exports	2471	0	-10610	82	1132	12840	20	-3600	-12969	10605	

4. Individual Country Analyses

4.1 Botswana's Trade

For Botswana the data provided (all in MWh per day) indicates that greater economic efficiency will be achieved for the country by importing all of its demand requirement, although there is some indication that the data entered into the model for Botswana's avoided costs are too high. The gains to Botswana depend upon how the gains from trade are to be distributed among the countries.

Figure 4.1 Botswana's Trade Scenarios

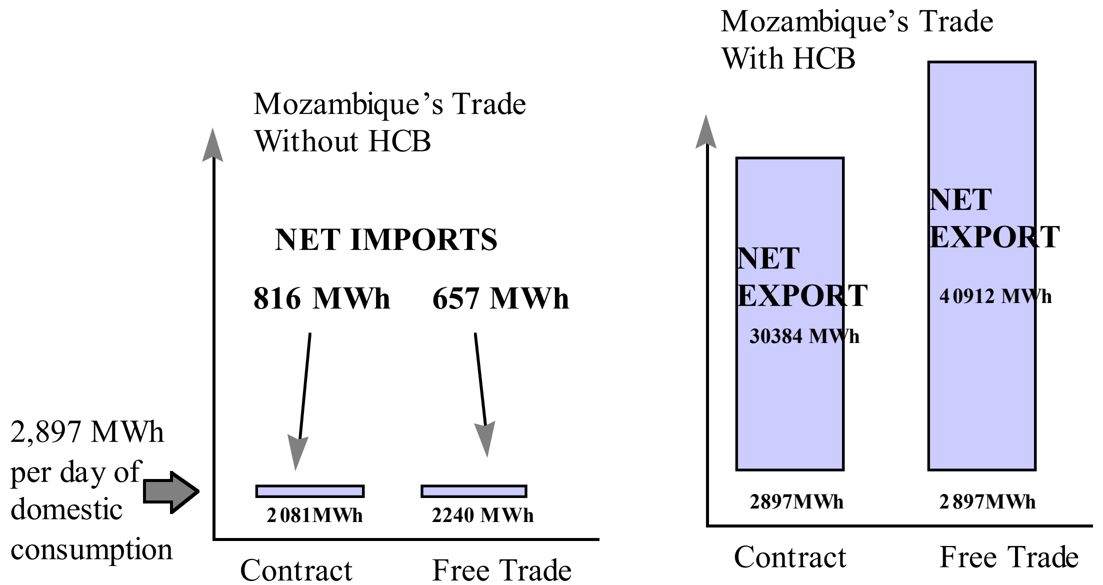


4.2 Mozambique's Trade

With optimal conditions the hydro-power in Mozambique is used to its maximum. This means that production costs increase in the hydro dominated countries of Mozambique, Zambia and the DRC as the demand for hydro-power is increased. Without HCB the SMoz node imports more from NSA under optimal conditions and so in this instance the production cost decreases. With HCB NMoz exports more when optimal and so production costs increase.

In Mozambique the cost of having fixed trade with HCB is more than the cost of having free trade without HCB, owing to the high increases in generation. These increases although very high must also be balanced with the very high increases in revenue from the great increase in export trade. The increased costs can then be easily justified. The magnitude of the revenue will depend on the agreed trading prices.

Figure 4.2 Mozambique's Trade Scenarios (Combined North and South Nodes)

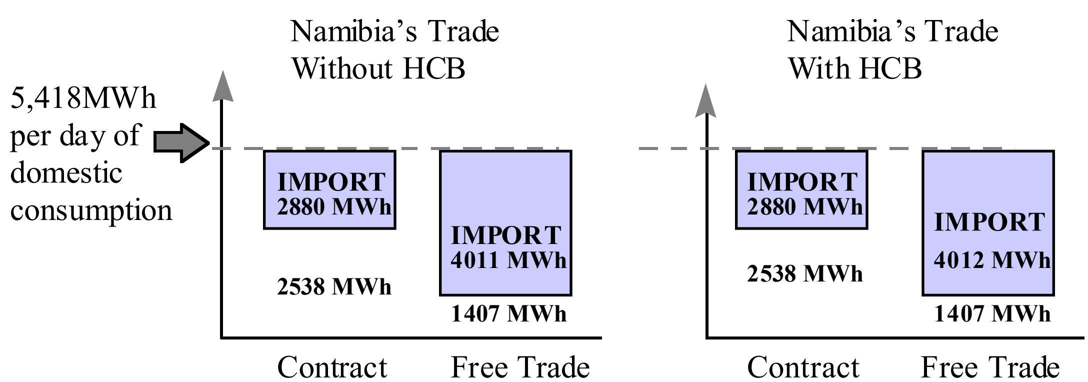


(White blocks are production to meet domestic demand - all numbers in MWh per day)

4.3 Namibia's Trade

Under optimal free trade conditions the model shows that Namibia will import more electricity from the SSA node. The real value of savings to Namibia, from reduced production costs, will depend on trading prices.

Figure 4.3 Namibia's Trade Scenario

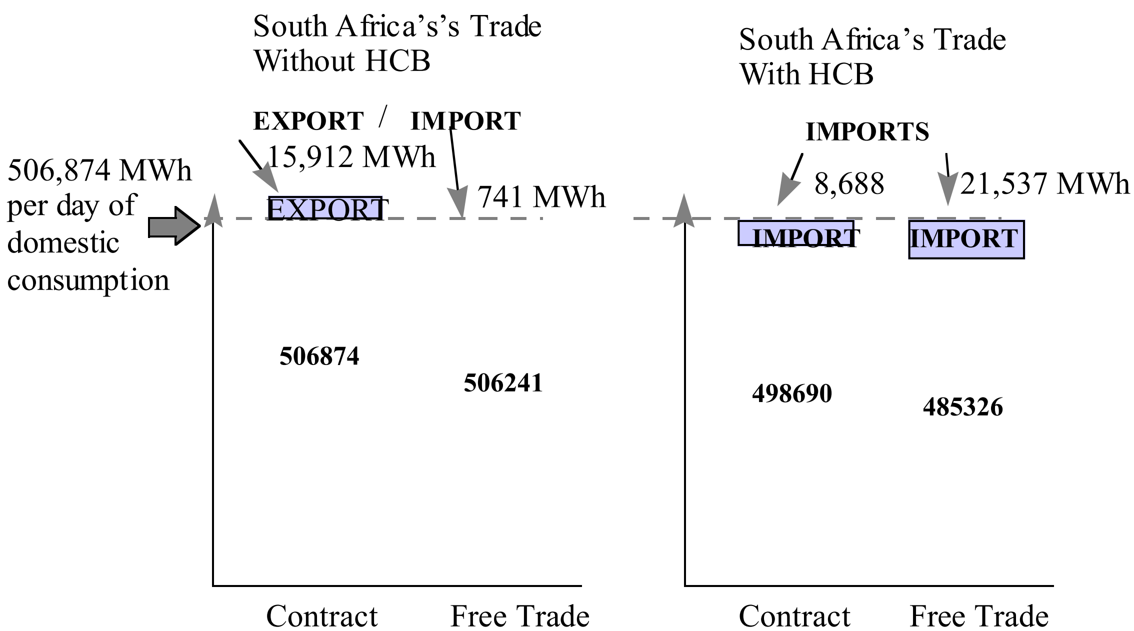


(White blocks are production to meet domestic demand - all numbers in MWh per day)

4.4 South Africa's Trade

The biggest single country production cost saving is to be seen in South Africa (Figure 4.4). When viewed across the two regional scenarios (with and without HCB) the overall gains become much higher than those obtained from looking at a single scenario. In the case of South Africa the difference in the country production cost, determined from the fixed contract and no HCB scenario and then the optimal with HCB, amount to over $124 million annually. (Cost at Contract and no HCB - Cost with Free Trade and with HCB). The Republic of South Africa has the largest changes in trade quantities but it has the smallest percentage change because of its vast size compared to the other SAPP members

Figure 4.4 South Africa's (RSA's) Trade Scenarios

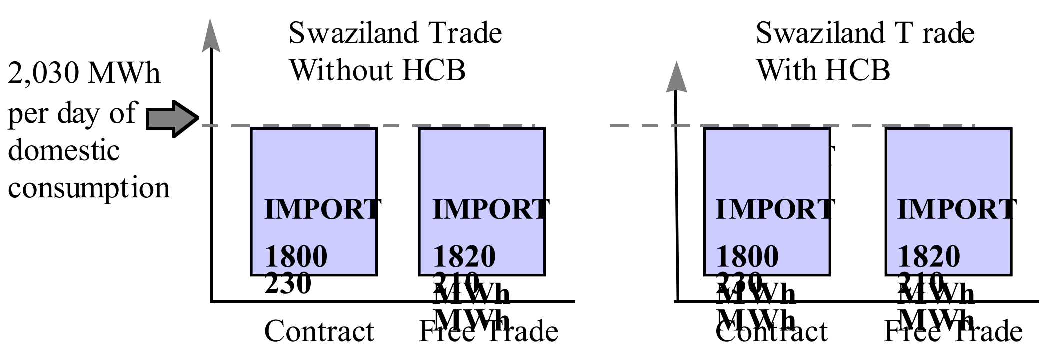


(White blocks production to meet domestic demand - all numbers are MWh per day)

4.5 Swaziland's Trade

In both the contract and free trade scenarios the models show Swaziland using its hydro power for most of the day. Only in the contract scenario does its thermal stations get switched on (five hours each day dispatching 4 MW).

Figure 4.5 Swaziland's Trade Scenarios

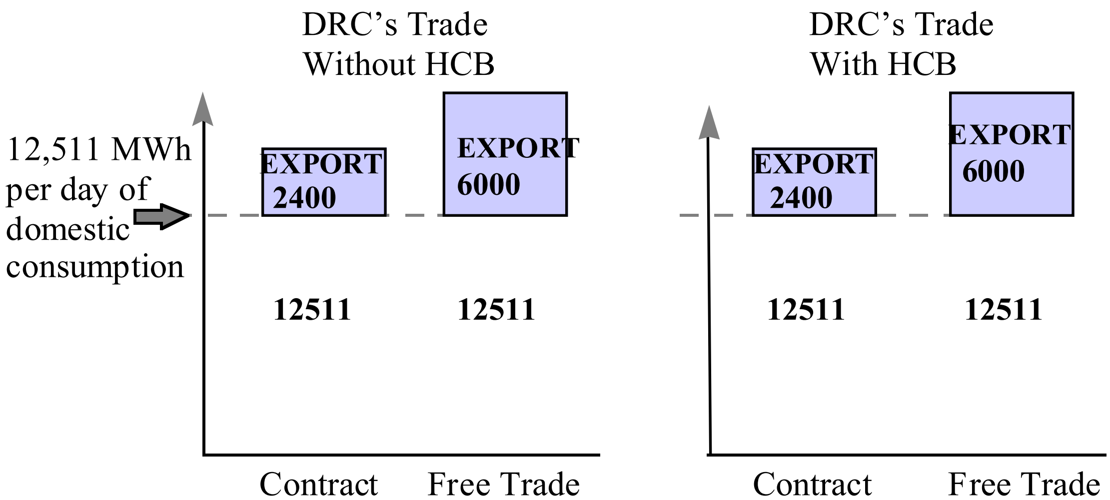


(White blocks are production to meet domestic demand - units MWh per day)
areinareMWMWh//daypedaday)

4.6 Democratic Republic of Congo's Trade

The DRC's exports increase by 150% when free trade exists in the SAPP. The full implementation of HCB has no affect on this country's trade.

Figure 4.6 Democratic Republic of Congo's (DRC's) Trade Scenarios

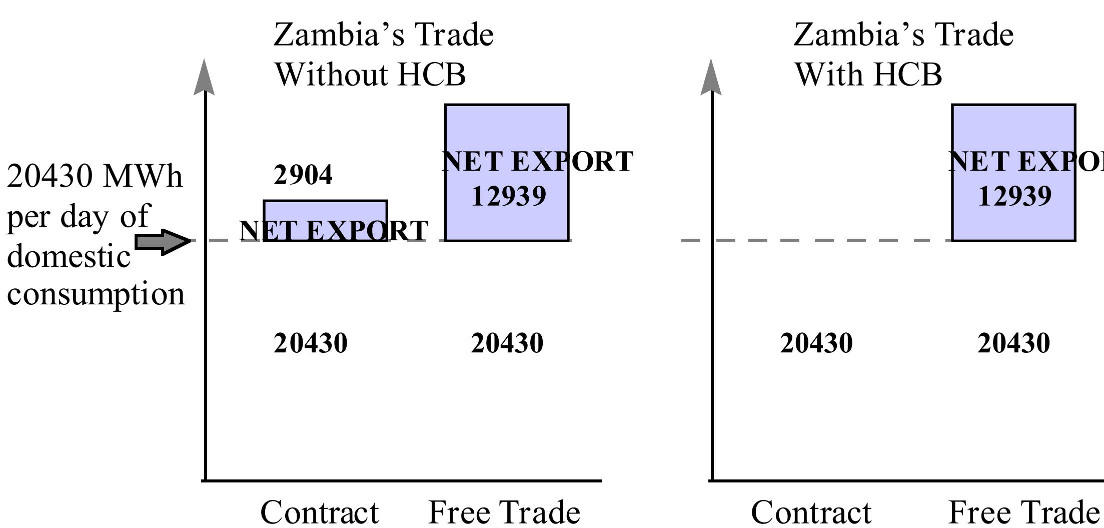


(White blocks are production to meet domestic demand - all numbers in MWh per day)

4.7 Zambia's Trade

Zambia's exports increases by 345% with the free trade scenario and no HCB. They increase almost 700% with HCB. Equitably structured trade prices in SAPP will determine the magnitude of the actual gains.

Figure 4.7 Zambia's Trade Scenarios

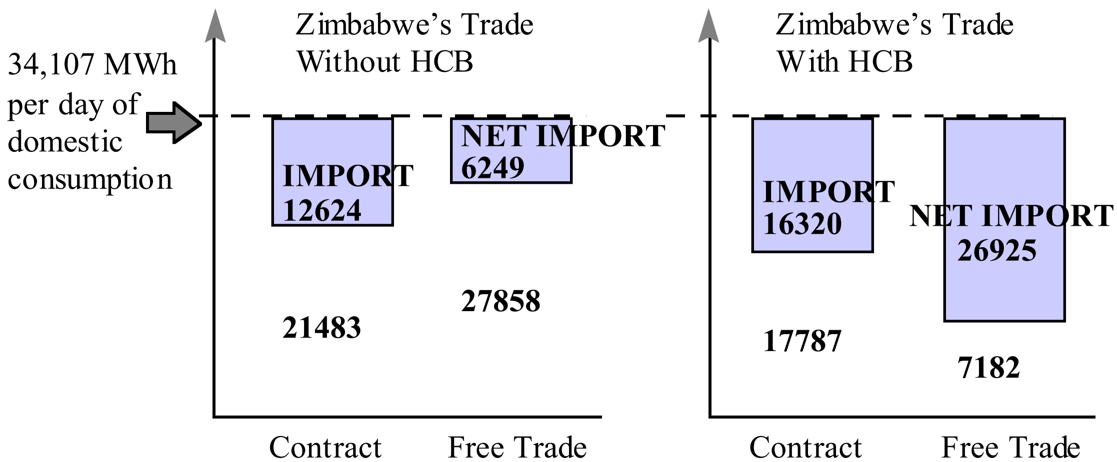


(White blocks are production to meet domestic demand - all numbers in MWh per day)

4.8 Zimbabwe's Trade

Zimbabwe's production costs, in this short-term model, do increase when changing from a fixed contract scenario to a free trade one when there is no HCB. They significantly decrease when HCB is fully operational. The savings to be made from free trade are over $44 million per year when taken across the extremes of the two scenarios.

Figure 4.8 Zimbabwe's Trade Scenarios



(White blocks are production to meet domestic demand - all numbers in MWh per day)

5. Dividing Up The Gains From Free Trade: A Case Study with HCB in Place

Free trade always results in reduced generation costs for the countries involved -- e.g., the combined cost of meeting the total electricity demands of all countries will decrease when compared to the total cost with no, or limited, trade.

Table 5.1 shows the incremental trades which arise between nations when free trade is allowed.

How shall these gains from these trades – estimated to be in the $50 to 80 million a year range -- be shared among the countries? Economists and others have been discussing this type of problem for hundreds of years, at both the normative level -- e.g., how <u>should</u> the gains be split? -- and the positive level -- e.g., how <u>will</u> they be split?

While ultimately the SAPP members themselves must decide this vital issue, the modeling system can be used to trace the consequences for each country, if a particular plan is adopted.

In all plans, the split is governed by the price paid by the importer. For instance, if the avoided cost of the importer is $10/MWh, and the marginal cost of generation by the importer is $6/MWh, then a sale price of $8/MWh would divide the $4/MWh gain from trade equally between importer and exporter – e.g., Importer Gain from Trade/MWh = Avoided cost - import price

= \$10/MWh - \$8/MWh = \$2/MWh

Exporter Gain from Trade/MWh = Import revenue - generation cost

= \$8/MWh - \$6/MWh = \$2/MWh

While many plans are possible, they tend to fall into two groups – those that would arise if SAPP members continued their present practice of bilateral negotiated trades, or those that would arise if a more centralized trading mechanism were used, where all power was traded at a uniform price.

Table 5.2 summarizes the dollar values and percent shares of the gains from trade for import and export nations for three possible sharing mechanisms (all assume HCB is in place).

Case 1: Bi-lateral trade, e.g., a price negotiated for each trade such that each party to a specific trade would share the benefits equally for that trade.

Case 2: Power exchange trade, with the single price for all exports throughout SAPP set to divide up the gains from trade equally between all importers and all exporters.

Case 3: Power exchange trade, with the single price set to clear the market for traded power – e.g., the price is equal to the marginal cost of the most expensive power source (in the region) dispatched for exports, or, alternatively, the least expensive cost avoided by import nations. Economists prefer this option, since it that the correct market signals are sent to all participants as they contemplate increasing or decreasing electricity production/consumption and, more importantly, making new investments in generating and transmission capacity.

Table 5.2 shows that while there is very little difference between the two single price power exchange cases, a major shift in the split in favor of the import nations takes place when the gain from each trade are not pooled, but are split equally between the participants, trade by trade.

Appendix III to this report explains in greater detail how these numbers were derived.

Finally, when considering the alloation of the gains from trade, it should be emphasized that there are many ways of allocating such gains, including methods which allow the wheeler to share in the negotiations. The three methods presented in this report are as examples only. Which of the many options is adopted by SAPP will be determined by the bargaining process much the way it is done in the United States.

The only hope is that in the inevitable scramble to improve their country's position, the gains themselves are not diminished.

Table 5.1. Changes as a Result of Free Trade (with HCB)

(All volumes MWh received)

From:	To: Bots.	Les.	N Moz.	S Moz.	Nam.	S.A.	Swaz.	DRC	Zam.	Zim.	Increase in Exports
Botswana											0
Lesotho											0
N Mozamb.						+7970				+2640	10610
S Mozamb.											0
Namibia											0
RSA	+819			+82	+1132		+20			-3600*	-1547
DRC									+3600		3600
Zambia										+16539	16539
Zimbabwe	+1652					+3322					4974
Increase in Imports	2471	0	0	82	1132	11292	20	0	3600	15579	21150
Increase in Imports - Increase in Exports	2471	0	-10610	82	1132	12840	20	-3600	-12969	10605	34176

* With free trade, Zimbabwe decreases imports from South Africa, causing South Africa's total exports to decrease by 1557 MWh, rather than increase. South Africa's net change in trade is an increase of 12,840 MWh.

Table 5.2. Gains Comparison (all with HCB)

Country	Case #1	Case #2	Case #3
	Unique Price for Each Trade	Single Price for All Trade	
Importing Countries:		Price set to split gains equally	Price = MC
Botswana	2235 (1%)	9050 (4.5%)	9480 (5%)
S. Mozambique	143 (0.1%)	500 (0.5%)	520 (0.3%)
Namibia	15719 (8%)	35170 (19%)	35370 (19%)
South Africa	43893 (23%)	33020 (18%)	35250 (18%)
Swaziland	622 (0.3%)	1250 (0.5%)	1300 (0.7%)
Zimbabwe	61995 (32%)	15790 (8%)	17630 (9%)
	124607 (65%)	95000 (50%)	100000 (52%)
Exporting Countries:			
N Mozambique	28633 (15%)	32970 (18%)	31170 (16%)
DRC	82 (0.1%)	12180 (6%)	11560 (6%)
Zambia	38556 (20%)	49850 (26%)	47650 (25%)
	67271 (35%)	95000 (50%)	90000 (47%)

(All % are % of total trade values of $190,000/day)

6. Wheeling Issues

Where is wheeling in this free trade model? Unfortunately, the model, as it is presently constituted, has no way of distinguishing between simple wheeling, and the wheeler buying from the source country and reselling to the final destination country. The incremental trades identified in Table 5.2 could arise from either contracting mechanism.

For instance, Table 5.1 shows that Zambia increased its imports from DRC by 3600 MWh/day, and increased its exports to Zimbabwe by 16,539 MWh/day. Zambia's avoided cost is actually higher than DRC's marginal cost, something that would normally preclude a trade between DRC and Zambia; Zambia might go ahead with the purchase, knowing it can make up the loss through resale to Zimbabwe, whose avoided costs are higher than DRC's marginal generating costs.

Alternatively, DRC could contract directly with Zimbabwe, paying only a wheeling charge to Zambia. As we have pointed out elsewhere, the contracting mechanisms used to buy and sell power are in the hands of SAPP members; all the model can do is to suggest the magnitude of the gains possible, and trace out the consequences of a few simple frequently suggested pricing rules for the electricity traded.

7. The Implications of the Short-Term Analysis for SAPP[◊]

While the values for the monetary gains to be obtained from freer short-term trade, collectively for all SAPP members, and individually under the set of pricing arrangements, are in themselves interesting, they are, after all, based on data and assumptions which are estimates of true values.

Perhaps what is most important is not their magnitude but what they suggest as to the future directions of SAPP with regards to capitalizing on the existence of these untapped, very short-run trading opportunities.

Up to this point, most trade within the region has been on the basis of long-term contracts. Some have an element of flexibility, with import and export levels being adjusted 24 hours in advance, but the prices for such arrangements are fixed in advance. Developing the collective model for a period as short as one day has brought into focus the potential benefits of short-term trading arrangements in a market environment where prices and quantities would be negotiated over a short time period. The implications of this will require a change of thinking within SAPP, which *inter alia* will require coming to terms with:

- sales and purchases being made at an operational level within utilities, not requiring the sanction and endorsement of senior management as is the case for long-term formal contracts;
- prices for short-term trade (supply prices and wheeling charges) being much lower than those for long-term contracts (reflecting the underlying economic reality that short-run marginal costs are very much lower than long-run costs, which ultimately include the costs of expanding capacity).

Drawing on perceptions arising from the field visits and the results of the short-term model, the immediate proposal for fostering short-term trade is that the Coordination Center maintain a bulletin board on the Internet documenting offers of supply, wheeling capacity and upcoming demand requirements. The debate over wheeling charges for the more conventional contracts highlights that the transmission aspects of trading arrangements need to be carefully handled. The suggested practical requirements to make this operational are:

- once an offer of wheeling has been contracted by a utility, payment to the utility owning the transmission line should be made;
- if the purchasing utility subsequently does not require the capacity, it can be resold to another utility wanting to purchase power via the transmission network.

Once established, this system could allow traders to operate. Futures purchases and options could also come to play a role. Finally, these market arrangements need not be limited to wheeling but could also extend to generation and distribution.

[◊] This section is provided courtesy of Dr. Peter Robinson.

8. Capacity Expansion Opportunities Suggested by the Short-Term Model

One side benefit of the type of mathematical model used to calculate the least cost pattern of trade for SAPP is that the analyst gets as part of the solution the reductions in total SAPP-wide generating costs if small increases in generation and transmission capacity were made available.

An analysis of these values – termed "shadow prices," since they indicate what one would be willing to pay to relax a capacity constraint in the system – gives some tantalizing hints as to the likely results of year two's project, which examines the issue of how best to expand SAPP capacity.

First, the analysis indicates that with electricity demands at their present levels (LRF = 0.9), and with no derating of generation plants:

- The maximum benefits from increasing the capacities of existing thermal plants never exceeds $1.68/MWh for any hour, and average approximately $1.35/MWh over the 24-hour period. This value is well below capital cost/MWh for plants in the U.S., which range from $9/MWh for a 250 MW combined cycle (capacity factor 85%, all in investment cost $480/MW, CRF = 15%) to $18/MWh for a 2-unit 550 MW pulverized coal plant (capacity factor 85%, all in investment cost $810/KW, CRF = 14%).

- The maximum benefits from increasing the capacities of existing hydro generation capacity average over the 24-hour period approximately $4.50/MWh. This may well be in the range of cost for a new turbine installed at an existing hydro station, but is certainly less than the full cost of constructing a new reservoir and generating station.

- The benefit for increased transmission capacity is positive for only two links: DRC to Zambia, with an average of $4.00/MWh over the 24 hours, and Mozambique to Zimbabwe, which averages about $1.20/MWh over the 24-hour period. All other links shadow prices are zero with present demands – e.g., they are not binding constraints in the cost minimizing pattern of trade.

While these shadow prices can only be considered as rough indications of the value of additional generation and transmission capacity, they are useful measures of the immediate value of new capacity.

Obviously, as demand grows, these shadow prices will increase, justifying the construction of new plant and transmission equipment.

With regard to capacity expansion, the message is clear from the model: any argument which suggests an immediate need for additional thermal generating capacity and, to a lesser extent, hydro-generating and transmission capacity, should be examined very carefully, since it appears that such expansions in the short run may not be economically justified, if SAPP members take advantage of all the economic trading opportunities suggested by the model.

8.1 Extensions of the Model – Optimizing System Expansion[◊]

The model developed so far has demonstrated the potential benefits from increasing electricity trade in the region to be tens of millions of dollars per annum. However, the savings from joint optimization of investment planning is expected to be at least an order of magnitude higher (hundreds of millions of dollars per annum). The short-term model is thus not just an end in itself, but a building block towards a long-term model. This ideally would allow optimization of investments over say 25 years, while also

[◊] This section is also provided courtesy of Dr. Peter Robinson.

minimizing costs of generation commitment over the medium-term (day-to-day) and of dispatch over the short-term (hour-by-hour). Through the State Utility Forecasting Group and associated academic research, Purdue has developed practical models incorporating these aspects and allowing for the formal treatment of uncertainty.

Taken collectively, SAPP presently has considerable excess capacity, most of which is located in South Africa. In relation to the 1996 maximum demand of 30 785 MW, net available capacity was 41 604 MW, giving a margin of 35%. By the year 2000, if the economic projections made in Tables 8.1A & 8.1B materialize, demand will have grown to 38 064 MW. On present plans, capacity will be expanded to a total of 46 000 MW by 2000, giving a margin in that year of 21%. Most of the planned increase is in South African capacity, with plants presently in cold storage or mothballed being revived and brought into production.

Having a long-term regional investment planning model could well reduce the costs of the present capacity expansion plans up to the year 2000, and certainly into the next century when economic growth is expected to eliminate the excess, including mothballed capacity. The potential to develop economically efficient hydro-generation in countries such as Democratic Republic of the Congo, Zambia, Zimbabwe and Mozambique may even make it attractive for ESKOM to leave some thermal plants mothballed and instead import environmentally benign power from the north in the next millennium.

Emphasizing regional supply options in investment planning shifts the focus from generation to transmission. The results of the short-term model already indicate where transmission investments should be directed, by showing which lines are loaded to capacity under optimal trading arrangements. Significant projects for promoting trade in SAPP are those which increase capacity of key interconnectors at a reasonable cost. The prime case is the DRC-Zambia interconnector, where for an estimated US$40 million, the interconnector capacity could be increased from 250 MW to 500 MW, allowing much higher exports of power from Inga on the Congo River to the rest of SAPP at a capital outlay around one seventh the cost of installing new generation capacity.

Table 8.1A SADC & Southern African Power Pool – GDP & Capacity Growth Rates

1996-2000	Real Growth Rates '91-'95 % p.a.	'96-'00 % p.a.	Improvement % p.a.	Real Growth 95-96 % p.a.
South Africa	0.8%	4.2%	3.4%	3.1%
Zimbabwe	0.6%	5.0%	5.4%	6.6%
Zambia	-0.6%	6.0%	6.6%	6.4%
Tanzania	4.2%	5.0%	0.8%	
Namibia	4.6%	6.0%	1.4%	
Botswana	4.4%	6.0%	1.6%	
Mozambique	5.8%	6.5%	0.7%	6.4%
Angola	-0.4%	5.0%	5.4%	12.5%
Malawi	1.6%	5.0%	3.4%	9.7%
Swaziland	2.5%	6.0%	4.0%	3.2%
Lesotho	6.9%	12.2%	5.3%	14.1%
SADC tot/w av	1.2%	4.5%	3.4%	3.6%
-excluding SA	2.4%	5.6%	3.7%	5.5%

Table 8.1B SADC & Southern African Power Pool – GDP & Capacity Growth Rates

	Maximum Demand 1996 MW	2000 MW	Annual Average Growth	Elec: GDP Elasticity 1996-2000 Average	Underlying
South Africa	26382	32116	5.0%	1.20	
Zimbabwe	1667	2026	5.0%	1.00	
Zambia	1028	1258	5.2%	0.86	1.20
Tanzania **	412	568	8.4%	1.67	?
Namibia	321	655	19.5%	3.25	1.00
Botswana **	222	296	7.5%	1.25	1.00
Mozambique	192	351	16.3%	2.50	
Angola	181	291	12.6%	2.52	?
Malawi	164	214	6.9%	1.38	?
Swaziland	140	177	6.0%	1.00	
Lesotho	76	112	10.2%	0.83	?
SADC tot/w av	30785	38064	5.4%	1.21	
-excluding SA	4403	5948	7.8%	1.39	

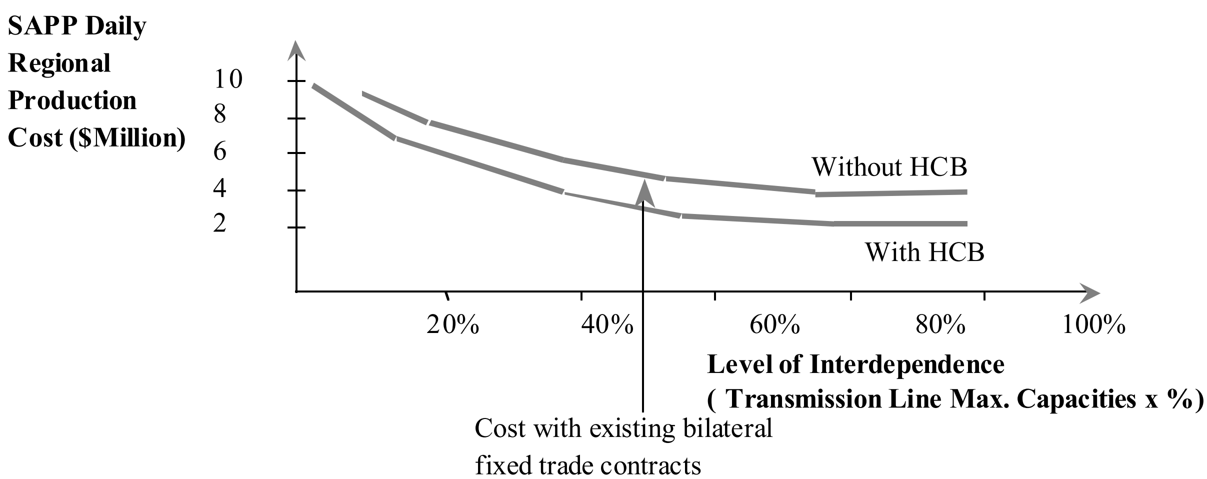
Sources: SADC- FISCU study
Modified with SAPP- PSC

9. Summary and Recommendations

The first year of modeling has evaluated the savings in production costs by employing a more free trade policy as compared to the existing fixed contracts policy. The year has also demonstrated the importance of quantitative modeling to policy makers and planning engineers in the SAPP. It has seen built up a most valuable regional generation and transmission data bank. The partnership between staff in the SAPP and at Purdue during 1997/98 has made it possible to achieve the objectives set out in the first year proposal for evaluating short-term gains [8].

The production cost savings for SAPP with a short-term tree trade scenario will save the region in the range of $48 to $131 millions each year. Equitable distribution of these savings will now be determined from the trade prices agreed among the SAPP members. The short-term work can indicate upper and lower limits to these prices so that there is a consistent win-win situation for each utility.

Figure 9.1. SAPP Trade Frontier – Optimal Regional Model with and without Hydro Cahora Bassa



At the start of the first year of modeling the discussion of loose and tight power pools took place [9]. The quantitative results can now be assessed. A trade frontier diagram is shown in Figure 9.1. It can be seen that the current level of trade already provides very high levels of savings. Over the next few years a total swing towards a tight pool is not likely but savings can be made by introducing a trade prices bulletin board which will restructure towards a tighter structure and so move further along the trade frontier to gain some further degree of savings. (Modeling the interdependence in Figure 9.1 is the totally free trade scenario with the PFmax being multiplied by the percentage factor. The further reduction in line capacities reflects the increase in national independence.) The difference in regional production cost savings, by including or not including HCB, is clearly summarized by this figure.

Future data requirements for the short-term model are that a regional LRF should be agreed upon as well as an OMLC cost. Alternatively, the model could be modified with each country specifying its own LRF value while maintaining the peak load day (Eskom's of July 24, 1997) in the data file. When the long-term model is constructed, then further regional water inflow data will be needed. The OMLC costs also include no capital recovery factor and these will need to be resolved for the long-term modeling that is proposed for the second year of modeling.

With regard to capacity expansion, the message is clear from the model: any argument which suggests an immediate need for additional thermal generating capacity and, to a lesser extent, hydro-generating and transmission capacity, should be examined very carefully, since it appears that such expansions in the short run may not be economically justified, if SAPP members take advantage of all the economic trading opportunities suggested by the model.

Finally, it should be emphasized that there are many ways of allocating the gains from trade, including methods which allow the wheeler to share in the negotiations. The three methods presented in this report are as examples only. Which of the many options is adopted by SAPP will be determined by the bargaining process much the way it is done in the United States.

The only hope is that in the inevitable scramble to improve their country's position, the gains themselves are not diminished.

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Appendix I
Notation

C(z)	-	Operating cost of area or country z.
CEM(z,zp)	-	Cost of imports to area z from area zp ($/MWh).
CEP(zp,z)	-	Revenue from exports from area zp to area z ($/MWh).
Cost(z)	-	Production costs of country.
DLC(z)	-	Domestic loss coefficient for area z
Domloss(t,z)	-	Domestic loss in z at time t.
D(t,z)	-	Load at z in time t.
ELL(z,ih)	-	Ending level of lake ih in country z (m).
Fuel(t,z,i)	-	Fuel cost ($/MWh in time t in country z at station i).
FD(z,i)	-	Thermal station i shut-down cost ($).
FDh(z,ih)	-	Hydro station ih shut-down cost. ($)
FS(z,i)	-	Thermal station i start-up cost ($).
FSh(z,ih)	-	Hydro station ih start up cost.($)
g	-	Thermal generation unit index, g = 1,---,M.
gh	-	Hydro generation unit index, gh = 1---Mh.
H(t,z,ih)	-	Hydro station ih's power production.
i	-	Thermal station index.
ih	-	Hydro station index.
Inflow(z,ih)	-	Predicted water inflow in country z at ih (cubic meters/h).
j	-	Pumped storage unit index, j = 1---,J.
KL	-	Multiplicative constant of a system's real power losses.
LRF	-	Load Reduction Factor
Ls(z,t)	-	Estimated country real power losses at time t.
M	-	Number of thermal stations.
Mh	-	Number of hydro stations.
MN(z,i)	-	Minimum-up/down time of thermal station i in country z.
MNh(z,ih)	-	Minimum-up/down time of hydro station ih in country z.
PFex(t,z)	-	Power flow exported from area z in time t.
PFim(t,z)	-	Power flow imported from area z in time t.
PFmax(z,zp)	-	Maximum power that can be transported from area z to area zp.
PG(t,z,i)	-	Thermal power production(MW) or energy production (MWh) of a station.
PGmax(z,i)	-	Thermal power production upper limit for i (MW).
PGmin(z,i)	-	Thermal power production lower limit for i (MW).
PH(j)	-	Pumped Storage total production (MW).
PF(t,z,zp)	-	Power flow in a transmission line from area z to area zp (MW).
q(t,z,ih)	-	Turbine water discharge at time t of hydro station ih (cubic meters/h).
qw(t,j,ih)	-	Water discharge per unit time from j.
qmin	-	Minimum turbine water discharge of a hydro station (cubic meters/h).
qmax	-	Maximum turbine water discharge of a hydro station (cubic meters/h).
Sp(t,z,ih)	-	ih's water spill through raceway (cubic meters/h).
SLL(z,ih)	-	Starting level of lake ih in country z (m).
spmax(z,ih)	-	Maximum water spill through raceway from hydro station ih (cu. m/h).
st(t,z,ih)	-	Water storage at time t. (cubic meters).
stmax(ih)	-	Maximum storage of a hydro plant (cubic meters).
stmin(ih)	-	Minimum storage of a hydro plant (cubic meters).
t	-	Time index (hour), t = 1,---,TT.
Til	-	Water traveling time of hydro plant il to its immediate down stream hydro plant, j.
Tranloss(t,z)	-	Transmission loss in z at time t.
U(t,z,i)	-	Thermal station i's commitment binary variable (0,1).
Uh(t,z,ih)	-	Hydro station ih's commitment binary variable (0,1).
UNSER(t,z)	-	Unserved energy in time t for area z (MWh).
z, zp	-	Area, country or zone index.

Appendix II
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Appendix III
Dividing Up the Gains from Free Trade: A Case Study with HCB

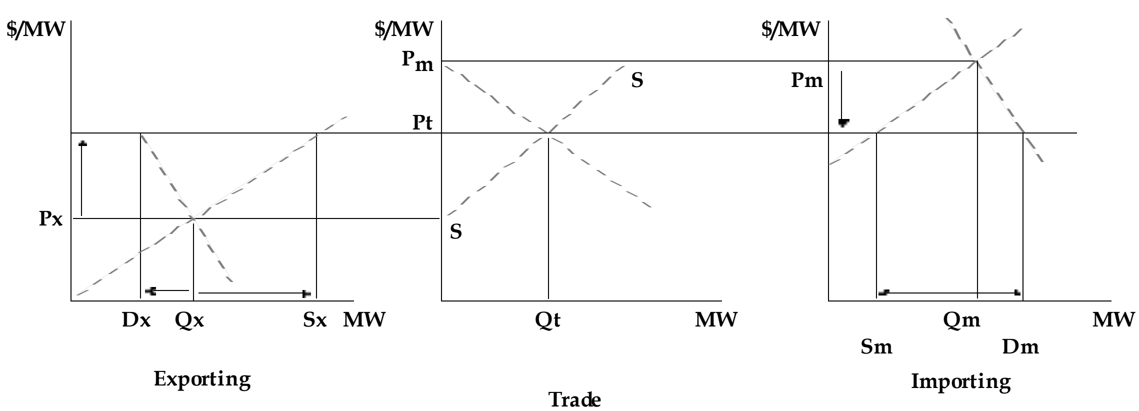
Free trade always results in reduced generation costs for the countries involved -- e.g., the combined cost of meeting the total electricity demands of all countries will decrease when compared to the total cost with no, or limited, trade.

How shall these gains from trade be shared among the countries? Economists and others have been discussing this type of problem for hundreds of years, at both the normative level -- e.g., how should the gains be split? -- and the positive level -- e.g., how will they be split? Consider now a few methods, from many possibilities, of how to share gains.

1. **Sharing of Gains from Trade: Method 1 -** Set a single export price equal to the marginal cost of imports

Economists argue that the transaction price per MWh -- e.g., the price paid by the importer which governs the split -- should be set equal to the marginal cost of the most expensive MWh generated by the exporting nation to meet the export demand, plus the marginal cost of transmitting the electricity, or, equivalently, the least expensive avoided cost among import nations. This assures that the social welfare is maximized, and that the price of electricity paid by the importer is equal to it's marginal cost, which in turn assures that the correct market signals are sent to all participants as they contemplate increasing or decreasing electricity production/consumption and, more importantly, making new investments in generating and transmission capacity.

A1. Trade Diagram

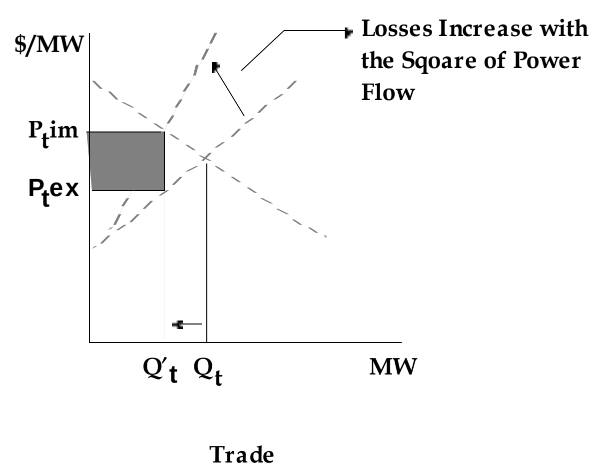


The export/import model used by economists to support this argument allows for trade to take place between regions with differing generating costs until the rising cost of producing for export demand meets the falling price import regions are willing to pay for imports. The methodology can be illustrated using a three-panel diagram showing the fundamental economics of trade. This is illustrated in Figure A1. The panel on the left represents the supply and demand schedules for the low-cost, exporting region, and the panel on the right represents the supply and demand schedules for the higher cost, importing region. This general model allows for electricity demand in both countries to adjust to changes in electricity prices as trade takes place; thus, it is a long-run model. The special case of interest to SAPP – the case of demands fixed in the short run – will be considered shortly. The middle panel shows derived schedules for excess demand of the importing region and excess supply of the exporting region.

Px is the price in the exporting region before trade, i.e., where supply and demand cross in the region. At that price, consumers want to purchase exactly the amount producers want to sell (Qx). However, if higher prices were to prevail, then suppliers would offer additional production. At the same time, consumers would be willing to purchase less. Hence, there is excess supply at prices higher than Px in the amount of the difference between the points along the demand curve and the points along the supply curve. The situation will be reversed in the importing region. There will be excess demand when prices are lower than Pm. The curves in the middle panel are constructed by tracing out the excess supply schedule from the exporting region rising from Px and excess demand schedule from the importing region falling from Pm. Assuming no transaction costs (i.e., losses and transmission fees), the equilibrium price with trade will be equal to Pt and Quantity Qt will be traded (i.e., produced by the exporting region and sold to consumers in the importing region). Quantity consumed in the exporting region will decline, from Qx to Dx, as prices rise. Quantity produced will increase from Qx to Sx. Quantity consumed in the importing region will increase, from Qm to Dm as prices fall. Quantity produced will decline from Qm to Sm. If any trade restrictions are present, a wedge is driven between the price received by the exporting region and the price paid by the importing region. Thus, in Figure A2, if the fraction of transmission losses were C, the exporting region would receive P_t^{ex}, while the importing region would pay P_t^{im} per MWh, and

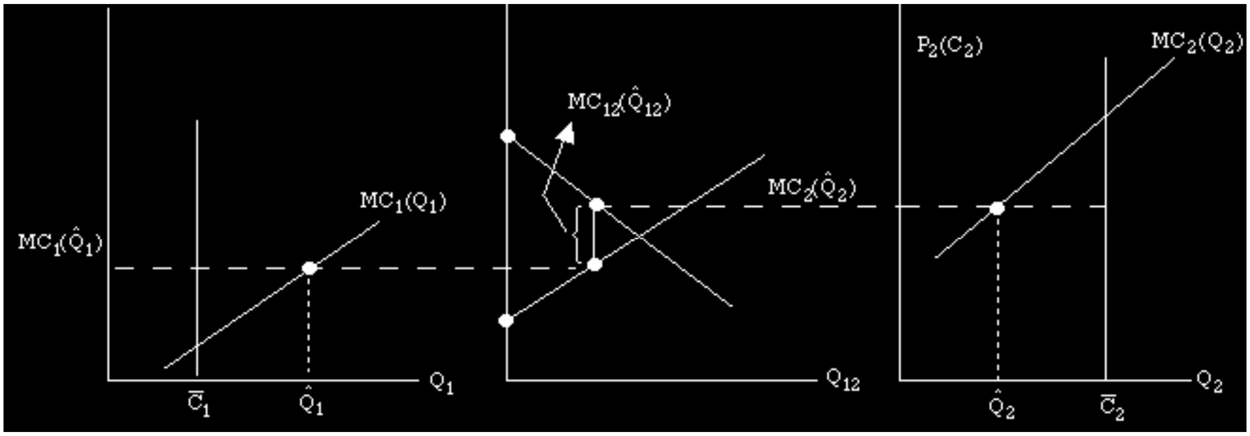
$P_t^{im} = P_t^{ex} * (1+C)$ and trade would be reduced to Q_t' rather than Q_t.

Figure A2. Trade with Increasing Losses



The special case considered in this analysis is to assume all domestic demands are unaffected by the price changes in electricity. Thus, in Figure A3, exports increase until the rising marginal cost of generation in the export country, $MC_1(Q_1)$, plus the marginal cost of transmission plus loss, $MC_{12}(Q_{12})$, equals the falling avoided cost of the import nation, $MC_2(Q_2)$,.

Figure A3.



Note that the price paid by importers is equal to the marginal (lowest) cost avoided by the importer, or equivalently, the marginal (largest) cost of producing electricity plus the marginal cost of transmission.

Applying this logic to the SAPP case with HCB in place, the data indicate that the lowest avoided cost among the import nations is \$7.04/MWh. Unfortunately, there is some ambiguity as to the exact value that should be used, which should be cleared up in the near future. Thus, the \$7.04/MWh should be considered a provisional value which may be adjusted in later reports.

How shall the gains from trade be allocated, if this marginal cost pricing rule is used?

Columns 1 and 2 in Tables A1 and A2 summarize the changes in imports and exports, and Column 3 in Table A1, the costs avoided by import nations, and in Column 3 of Table A2 the costs incurred by export nations. The totals for each table indicate that by importing an additional 27,160 MWh/day, importing nations avoid a total of \$290,930/day in generation costs, while the export nations spend \$100,920/day to generate this amount (including losses). The aggregate gain from trade is then \$190,000/day; how this shall be split depends on the price/MWh paid for imports by the import nations.

Using the marginal cost pricing logic of economists, the price paid by all importers should be equal to the lowest marginal avoided cost/MWh among the importing nations -- \$7.04/MWh.

Column 4 of Table A1 shows each country's payments for their imports when the price is set at \$7.04/MWh, the marginal cost of exports, while Column 4 of Table A2 shows each exporting country's share of these payments. Finally, Column 5 is each country's savings, or gains, from trade, when this export pricing method is used. In Table A1, the savings are the decrease in daily production costs, Column 3, less the payments for imports, Column 4.

In Table A2, Column 5 is each country's increased profit, or gain, from trade -- the difference between the increased revenues in Column 4 and increased costs in Column 3.

Note that using this pricing rule, the total gains from trade of \$190,000/day are divided up 53% to importers, 47% to exporters.

Note also that the gains from trade are <u>not</u> proportional to the import or export share in Column 2 -- for instance, South Africa has 10 times the increase in exports as Namibia, but roughly the same gains from trade. The reason is that the gains from trade are determined not only by the price paid per MWh by the importing nation, but also the magnitude of the generation costs avoided by the importing nation. Thus, the reason Namibia has such a higher gain from trade than would be expected looking just at their share of the increase in imports is because the costs avoided by Namibia per MWh are much larger than for South Africa.

The same explanation holds for why exporter profits from trade are not directly proportional to a country's level of exports.

IF this method of allocating the gains from trade is used, Namibia and South Africa are the major gainers among the import nations, while Mozambique and Zambia are the major gainer export nations.

Method #1: Price imports are marginal cost of production plus marginal cost of transmission.

Table A1. Free Trade Impact on Importing Countries with HCB

Country	Col. 1 Increase in Imports (MWh)	Col. 2 % Total	Col. 3 Decrease in Daily Production Costs x 1000	Col. 4 Share of Payment x 1000	Col. 5 Savings from Trade x 1000
Botswana	(Deleted)	(Deleted)	(Deleted)	(Deleted)	9.48
Les					-
S. Moz.					0.52
Nam					35.37
RSA					35.25
Swaz					1.3
Zim					17.63
TOTAL	27,160	100%	290.93	191.3	100

Table A2. Free Trade Impact on Exporting Countries (with HCB)

Country	Col. 1 Increase in Net Exports (MWh)	Col. 2 % Total	Col. 3 Increase in Daily Production Costs x 1000	Col. 4 Share of Receipts x 1000	Col. 5 Profits from Trade x 1000
N. Moz.	(Deleted)	(Deleted)	(Deleted)	(Deleted)	31.17
DRC					11.56
Zam					47.65
TOTAL	27,149	100%	100.92	191.3	90

2. **Sharing of Gains from Trade: Method 2A -** Set the price so as to split the gains from trade equally between importers and exporters

Frequently, a much simpler method of equitably and efficiently dividing up the gains is employed -- that of giving each side half of the difference between the total generating costs avoided by the importing nation and the incremental generation costs incurred by the exporting nation.

Thus, if Country A saved 10 million by importing X MWh from Country B, and Country B incurred 5 million in additional generating expense as a result of the export, Country A would pay Country B 7.5 million for the X MWh. In this way, Country A's net revenues go up by 2.5 million, as do Country B's.

There are at least two ways of splitting the gains from trade:

Method #2A: Lump all the avoided costs of importers together, all the marginal costs of exporters together, split the aggregate difference, determine the aggregate bill the importers are to pay the exporters (exporter incremental generation costs plus one-half the gain from trade), and pro-rate the aggregate bill among the importers according to each importing country's percentage of total imports, and pro-rate the aggregate revenues according to each exporting country's percentage of total exports.

Method #2B: For each power flow between areas, determine which country generated and which consumed the power, determine the avoided costs and marginal costs for the transaction, and split the gains from trade for this transaction between importer and exporter. This approximates the results if bi-lateral bargaining between individual buyers and sellers were to take place for each transaction, with each transaction taking place at it's own unique price.

The results of Method #2A are shown in the tables below; only the case with HCB in place will be analyzed. Table A3 shows, as before, for each country, whose imports increase with free trade:

Column 1: The daily MWh import increase
Column 2: The percent it represents of the total increase
Column 3: The avoided generation costs

Likewise, Table A4 shows, as before, for each country whose exports increase with free trade:

Column 1: The daily MWh export increase
Column 2: The percent of total exports it represents
Column 3: The increase in generation costs

Method #2A: Split gains equally between import and export nations, using SAPP average avoided and marginal costs.

Table A3. Free Trade Impact on Importing Countries with HCB

Country	Col. 1 Increase in Imports (MWh)	Col. 2 % Total	Col. 3 Decrease in Daily Production Costs x 1000	Col. 4 Share of Payment x 1000	Col. 5 Savings from Trade x 1000
Botswana	(Deleted)	(Deleted)	(Deleted)	(Deleted)	9.05
Les					-
S. Moz.					0.50
Nam					35.17
RSA					33.02
Swaz					1.25
Zim					15.79
TOTAL	27,160	100%	290.93	196.1	95

Table A4. Free Trade Impact on Exporting Countries (with HCB)

Country	Col. 1 Increase in Net Exports (MWh)	Col. 2 % Total	Col. 3 Increase in Daily Production Costs x 1000	Col. 4 Share of Receipts x 1000	Col. 5 Profits from Trade x 1000
N. Moz.	(Deleted)	(Deleted)	(Deleted)	(Deleted)	32.97
DRC					12.18
Zam					49.85
TOTAL	27,149	100%	100.92	195.9	95

From Tables A3 and A4, we see that by importing 27,160 MWh/day, importers avoid a total of 290,930 in domestic generation costs, while exporters spend 100,920 per day to generate this amount (including losses).

The aggregate gain from trade is then $190,000 per day, to be split equally between importers and exporters. This means that importers as a whole will pay exporters as a whole the exporter's generation costs ($100,920 per day) plus one-half of the gains from trade (95,000) or $195,920 per day.

Equivalently, a single price to be paid by importers to exporters is determined, equal to the aggregate generation costs/MWh of all exports, plus the average of the aggregate avoided costs/MWh -- e.g.,

$$\text{price paid / MWh} = \frac{\$100{,}920}{2{,}716{,}000} + \frac{\dfrac{290{,}930}{2{,}716{,}000} - \dfrac{100{,}920}{2{,}716{,}000}}{2}$$

$$= \$3.72 + \frac{10.71 - 3.72}{2} = \frac{10.71 + 3.72}{2} = \$7.22 \text{ / MWh}$$

IF this price is used for all import/export transactions, the gains from trade -- $190,000/day -- are split equally -- $95,000 each -- between importers and exporters, as is shown in the Column 5 total rows of Tables A3 and A4.

Column 4 of Table A3 gives each importing country's share of this bill, based on their percentage share of total imports, shown in Column 2.

Column 5 is each importing country's share of half the gains from trade resulting from this approach, e.g., the difference between columns 1 and 4.

Columns 4 and 5 of Table A4 show the same calculations for the exporting countries.

A comparison of the allocation of the gains from trade resulting from this method with the marginal cost pricing method previously described shows there is very little difference between the two. This is no surprise, since the marginal cost price -- $7.04/MWh -- is very close to the single price which would split the gains 50/50 --$7.22/MWh.

3. Sharing of Gains from Trade: Method 2B

Method #2B: Share the gains from trade arising from each specific export between each transaction's export and import countries.

As was mentioned, an alternative way of dividing up the gains from trade is to divide up the gains from each trade that takes place between nations based on the costs avoided by importers and incurred by exporters for that particular trade.

Table A5 shows the changes in trade which take place with a shift to free trade on a country-by-country basis. The export countries are listed in the rows, and the import countries are in the columns. For example, as a result of moving to free trade, Botswana increased exports to Zimbabwe by 1652 MWh/day. The column and row sums for each country are then their increases in imports (column sum) and increases in exports (row sum). In addition, net increases in imports -- e.g., imports minus exports -- are given in the last row. These are the same as the numbers contained in Tables A1 through A4 for each country.

For each transaction in Table A5, this approach would determine:

- A unique avoided cost, based on the importing country avoided cost.
- A unique marginal cost, based on the marginal cost of the country likely to have generated the power.
- A unique gain from trade to be split equally between the importing and exporting country.

For example, considering the Botswana/Zimbabwe example, suppose, as a result, Botswana was able to avoid $\$X_1$ of generation costs, while Zimbabwe incurred $\$X_2$ generation costs (including losses) meeting this increased export demand for their power. Then, if the gains from trade for this transaction were to be split equally between the two countries, Botswana would pay $\$X_2 + \frac{\$X_1 - \$X_2}{2} = \frac{\$X_1 + \$X_2}{2}$ to Zimbabwe, and Botswana's gain from the trade would be the difference between the costs it avoided, and what it paid for the power -- e.g.,

$$\text{Botswana Gain} = \$X_1 - \frac{\$X_1 + \$X_2}{2} = \frac{\$X_1 - \$X_2}{2}$$

Zimbabwe's gain from the trade would be the difference between the revenues it receives from the sale, and the generation costs:

$$\text{Zimbabwe Gain} = \frac{\$X_1 + \$X_2}{2} - \$X_2 = \frac{\$X_1 - \$X_2}{2}$$

Equivalently, a unique price for the transaction would be determined, equal to Zimbabwe's marginal cost of generating the power plus the average of Botswana's avoided cost and Zimbabwe's marginal cost -- e.g.,

Table A5. Changes in Trade (with HCB)
(All volumes MWh received)

From:	To: Bots.	Les.	N Moz.	S Moz.	Nam.	RSA	Swaz.	DRC	Zam.	Zim.	Increase in Exports
Botswana											0
Lesotho											0
N Mozamb.						+7970				+2640	10610
S Mozamb.											0
Namibia											0
RSA	+819			+82	+1132		+20			-3600*	-1547
DRC									+3600		3600
Zambia										+16539	16539
Zimbabwe	+1652					+3322					4974
Increase in Imports	2471	0	0	82	1132	11292	20	0	3600	15579	34176
Increase in Imports - Increase in Exports	2471	0	-10610	82	1132	12840	20	-3600	-12969	10605	

* With free trade, Zimbabwe decreases imports from South Africa, causing South Africa's total exports to decrease by 1557 MWh, rather than increase. South Africa's net change in trade is an increase of 12,840 MWh.

$$\text{price paid / MWh} = \frac{\$X_2}{1652} + \frac{\frac{\$X_1}{1652} - \frac{\$X_2}{1652}}{2} = \frac{\$X_2 + \$X_1}{(2)\ (1652)} = \bar{P}_{BZ}$$

and that price would govern the split:

$$\text{Botswana Gain} = \$X_1 - \left(\bar{P}_{BZ}\right)1652 = \frac{\$X_1 - \$X_2}{2}$$

$$\text{Zimbabwe Gain} = \left(\bar{P}_{BZ}\right)1652 - \$X_2 = \frac{\$X_1 - \$X_2}{2}$$

Table A6 shows the gains from trade that result from this method of allocation, compared to the previous one.

Note that unlike the previous cases this method allocates roughly 2/3 of the gains from trade to importers, and 1/3 to the export nations. This is not a general result: different combinations of avoided and marginal costs could have produced a higher share of the gains to export nations.

It is instructive to compare the changes in the gains distribution which arise when this method, rather than the single price method, is used.

Returning to the Botswana/Zimbabwe case, the difference in the gains from trade for the two countries under the two systems reduces to comparing the gains when calculated:

(a) Using the individual transaction -- i.e.,

$$\text{Botswana Gain} = \$X_1 - \left(\frac{\$X_2 + \$X_1}{(2)(1652)}\right)1652 = \$X_1 - (\bar{P}_{BZ})(1652)$$

$$\text{Zimbabwe Gain} = \left(\frac{\$X_2 + \$X_1}{(2)(1652)}\right)1652 - \$X_2 = (\bar{P}_{BZ})(1652) - \$X_2$$

Table A6. Gains Comparison

Country	Single Price for All Trade	Unique Price for Each Trade
Importing Countries:		
Botswana	9050	2235
S. Mozambique	500	143
Namibia	35170	15719
South Africa	33020	43893
Swaziland	1250	622
Zimbabwe	15790	61995
	95000	124607
Exporting Countries:		
N Mozambique	38860	28633
DRC	11620	82
Zambia	44500	38556
	95000	67271

(b) Using the universal single price of the first method -- i.e.,

$$\text{Botswana Gain} = \$X_1 - \left[\frac{\overline{\$X}_M + \overline{\$X}_A}{(2)(\overline{Q})}\right]1652 = \$X_1 - (\overline{P})(1652)$$

$$\text{Zimbabwe Gain} = \left[\frac{\overline{\$X}_M + \overline{\$X}_A}{(2)(\overline{Q})}\right]1652 - \$X_2 = (\overline{P})(1652) - \$X_2$$

where $\overline{X}_M$, $\overline{X}_A$, and $\overline{Q}$ are, respectively, the sum of all SAPP export country marginal costs, import country avoided costs, and total SAPP exports.

A comparison of the two shows that if P_{BZ} is greater than $\overline{P}$, Botswana is worse off using the individual price and Zimbabwe better off by its use. To generalize:

(a) If the average of the two costs per MWh for two countries is higher than the average of the aggregate marginal and avoided costs for all of SAPP, the export nation is better off, and the import nation worse off using the individual, rather than the collective, price.

(b) The opposite is true if the individual price is less than the collective price.