The CAPP Demonstration Long-Term Planning Model

Potential Capacity Expansion Planning and Electricity Trading in Central Africa, 2005 – 2025

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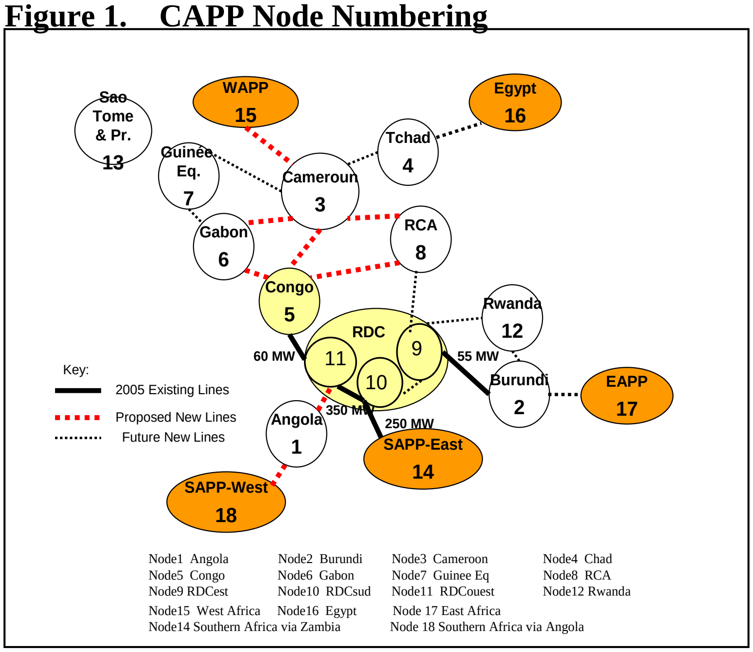
Introduction

A preliminary Central Africa Power Pool (CAPP) Model has been developed that demonstrates the long-term economic and reliability benefits from regional cooperation and integration (Figure 1).

Figure 1. CAPP Node Numbering



This model estimates the amount of savings expected to arise from regional cooperation and integration over a ten year (2005-2015) period, as well as estimating the additional investment CAPP might be expected to make, and revenues it might receive, during the period 2015-2025, if it were asked to provide electricity to the West African Power Pool (WAPP), Egypt, the East African Power Pool (EAPP), and the Southern African Power Pool (SAPP). The model illustrates the strategic importance of new transmission lines across Central Africa to the economic development of the region. The construction of new lines will allow the creation of a single regional market for electricity, rather than separate markets for electricity in each of the countries, with all the attendant gains from electricity trade.

The CAPP cost minimizing model is run in two modes:

(A) Grid Development Mode (or Free-Trade Mode) in which the commodities of electrical energy (MWh) and generation reserve (MW) are free to trade to their CAPP wide cost minimizing levels. <u>This is called Scenario A</u> - the regional approach.

(B) Without Grid Development Mode (or Self-Sufficiency Mode) in which each country's domestic generation capacity is utilized and constructed only to serve the country's energy and reserve needs. <u>This is called Scenario B</u> - the country by country approach.

Summary - Savings From Centralized Operation & Capacity Expansion

Massive cost savings to the CAPP, during the period 2005-2015, are expected if CAPP were to adopt a regional approach to electricity operation and capacity expansion, rather than a country by country approach.

Table 1. Total Costs to CAPP With &Without Grid Development ($ Millions)

	New Gen	***New Trans***	***Fuel***	***O&M***	***Water***	***Unserved Energy***	***Unmet MW***	**TOTAL COST**
Scenario A. With Grid Development - Regional Approach								
2005 – 2015	273	64	84	23	50	0	0	**494**
Scenario B. Without Grid Development – Country y Country Approach								
2005 – 2015	338	40	686	40	43	5	55	**1,207**

Table 1 shows that the savings are achieved in the short run by dispatching regional supplies against regional demand, rather than each country satisfying its own demand from its own capacity, and allowing regional excess capacity to satisfy regional reserve margins, rather than requiring each country to satisfy its own reserve requirements by its own excess capacity. In the long run, the benefits arise from the region jointly planning the expansion of the regional system, rather than each country constructing only enough new capacity to meet its own electricity demand. As the figure indicates, the reduction over the 10 year period is more than 50% - from $1207 millions to $494 millions.

These savings result from a combination of reasons, chief among them the switch to utilizing the excess capacity of the large hydropower plants in the region, rather than continuing to operate and construct the expensive thermal units located in many of the countries. This alone reduces regional fuel costs from $686 to $84 million, a savings of over $600 million. Additional savings arise from reductions in the construction of new capacity ($65 million), reductions in the amount of demand that cannot be met in the region ($5 million), and reductions in the amount of unmet required reserve capacity (unmet MW) in the region ($55 million).

If therefore the countries choose the regional approach, electricity costs would be reduced by over 50% while at the same time improving the quality of that electricity by improving the reliability of the system, the latter effect achieved by eliminating the reserve requirements deficit present in the country by country approach. Because the gains from trade are assumed to be shared equally between buyers and sellers of electricity, all participants, not just exporters, are made better off by the regional approach.

While all countries are better off with trade than without, some countries are made much better off with trade than others. This has to do with the inordinately large share of the gains from trade captured by those who buy from one country, and resell it to others - so called “wheelers” of electricity - when the gains are split equally between buyer and seller.

An examination of the alternative ways to split the gains from trade between producer, wheeler, and consumer will be a critical decision for CAPP as it evolves. The key point to be made here is the enormous magnitude of the total gains to be shared among the participants. The percent reduction in electricity costs for CAPP is the largest the Power Pool Development Group has seen in its history. Undoubtedly this is the result of the large spread both of the costs of generating electricity within the CAPP countries, and of the distribution of available excess capacity within the CAPP countries being concentrated in the low cost countries.

Table 2. Demonstration of CAPP Transmission & Generation Potential Capacities With the Three Scenarios (MW)

(MW)	Base Year 2005	A. With Grid Development & Regional Integration 2015	B. Without Grid Development. 2015
Transmission Expansion Total	0	1,984	654
Transmission Total	615	2,599	1,269
Generation Expansion Total	0	1400	1,437
Generation Total	3,124	4,524	4,561

Table 2 shows the amount of installed transmission and generation capacity at the end of the 10 year horizon that would result with and without a regional approach to capacity expansion. As expected, the amount of installed transmission capacity with regional sharing of the resources is much greater than without the sharing (2599 MW versus 1269 MW) and the amount of installed generation capacity is less (4524 MW versus 4561 MW).

Summary – Impact of Export Markets

The successful development of the CAPP is totally dependent upon the building of an extensive and long ranging transmission grid. The international DC lines to other regions of Africa (Southern African Power Pool, SAPP, West African Power Pool, WAPP, Egypt, East African Power pool, EAPP) make the development objectives of the newly formed CAPP management committee quite unique. From the outset the CAPP plans to combine improved regional electricity supplies with a major export activity. The ability to export from the Inga site is totally dependent upon the international gird.

Table 3. Cost Impact on the CAPP of SAPP, WAPP, EAPP, and Egypt Export Market Development ($ Millions)

Planning Horizon	***New Gen***	***New Trans***	***Fuel***	***O&M***	***Water***	***Unserved Energy***	***Unmet MW***	**TOTAL COST**
A1. **2005 – 2015**	273	64	84	23	50	0	0	**494**
A2. **2015 - 2025**	7141	1206	2659	192	155	31	696	**12,080**
20 Year TOTAL	7414	1270	2743	215	205	31	*696*	**12,574**

Table 3 shows the cost impact on CAPP if it were to serve additional demand in SAPP, WAPP, Egypt, and EAPP during the period 2015-2025 (Scenario A2). For purposes of illustration, it is assumed that SAPP wants an additional 1750 MW starting in 2015, WAPP 1000MW, EAPP 1000MW, and Egypt 4000MW. Each market is assumed to grow at 5% per year. As Table 3 shows, this additional demand results in CAPP spending $12 Billion dollars over the 20 year period, including over $7 billion in new generating capacity (chiefly in the expansion of the Inga site) and $1.2 billion in new transmission capacity. These very large quantities of electricity exports, from the CAPP, which are dispatched to other regions of the African Continent, initiate huge hydropower expansions, multi-billion investments, and high import revenues, resulting in the pool having a total generating capacity of 18.6GW by 2025 (Table 5).

CAPP Modeling Assumptions

As this is a preliminary demonstration model for the CAPP with little time having been available for the team to provide training in data collection across the region then several important cost and parameter values have been given generic values. These values are very important for a reliable model. In most cases they are the same in each country and in each scenario:

1. The electricity **demand growth rate** will vary from country to county. This rate takes the peak demand and electricity consumption in the base year 2005 and multiplies it to determine the peaks and consumption levels in following years. It is currently given the value of 5% for each CAPP member. The CAPP model is driven by the "typical hour/day/season/year" chronological demand approach as taken by many of the latest commercial models, rather than the load duration curve methodology used in earlier approaches.

2. The **unserved energy** costs are $140/MWh. This value has been estimated by members of Purdue University's State Utility Forecasting Group (SUFG) and was initially used in the SAPP regional model and more recently also used with planners in the WAPP and the Economic Community of West African States (ECOWAS). This is the basic cost of providing electrical power from a distributed generation (DG) source as compared with being integrated into a regional power grid. There are arguments that suggest that the $140/MWh is too small a value and this needs further consideration within the newly formed CAPP. Reasons for this to be higher will depend on the capital and operational costs, technology type, and life span of the DG installation chosen.

3. **Unmet demand** penalty charges of $3Million/MW. This high CAPP penalty charge - a cost in excess of the cost of building Inga 3 - is chosen to illustrate the critical role this value plays in selecting the CAPP least cost generation mix. The combined cost of the Inga 3 project with its required transmission investment is $4.007 Billion and for 1344MW this gives an average capital cost of $2.98Million/MW. In the case of the modeling work with other regions of Africa an unmet demand charge of $2Million/MW has been used but if this value is used with this demonstration CAPP model then unmet demand charges would be chosen instead of building the Inga 3 project. What this says is that a major benefit of the decision to construct Inga will be its beneficial impact on the reliability of the CAPP system There is however no unmet demand in Scenario A1 and only a small amount in Scenario B and therefore has little or no impact on the total cost to the CAPP.

4. Water costs $0.5/MWh. The cost of water can either be assessed from the environmental cost of the changing water levels and downstream flows that arise when water is utilized to generate electricity, or from the opportunity cost of using the finite amount of water in the reservoir r- e.g., the system benefit of using the water at a different time. The amount charged will vary from country to country. In some cases it could be argued to be equivalent to the cost of oil while in others it is assumed to be free. Several years back this topic was discussed with members of the SAPP management committee and after lengthy debate between two charges of $0.5/MWh and $1.5/MWh it was decided to employ the lower value. This value is now also currently being used in WAPP.

5. An annual **hydro MWh production capability** is required for each hydropower station, which depends on the working capacity of each reservoir in the system. Since no values were available at the time of writing this report, values were estimated by taking 70% of the generating capability, which was provided and multiplying this by the number of hours in a year\, in effect assuming that there is enough water in the reservoir each season to allow the generating units to operate 70% of the time. Once the actual working capacity is known for each reservoir, the first task of the team will be to enter these values in the model. The level of water in the reservoir at each hydropower station will provide a known generating production level. The level of water behind each dam will vary seasonally and become dramatically reduced in times of drought. For example with the Inga 3 project of 1344MW the hydro production capability was calculated as 8241GWh (1344 x 8760 x 0.7).

6. Fuel costs in the model are assumed to be $50/MWh to $60/MWh. In some cases where the thermal power plants are getting quite old and the location of the power plant is a considerable distance in the interior then these costs are likely to be much higher resulting from lower operating efficiencies and fuel shipment costs.

7. Reserve margins for all thermal and hydropower stations in the CAPP are 19% and 10% respectively. When the model was originally constructed for the Southern Africa utilities these parameters were set at a national system level. Over the past couple of years the values have been changed to being station specific in response to requests from the West African utilities where one hydropower station and reservoir can operate at a significantly different level of reserve than another. The CAPP electricity and long-term capacity expansion model also has a functionality for drought scenarios and this might be needed with future more detailed pool planning. In other regions the level of reserve margin for hydro schemes is known to be much higher than the existing 10% in the CAPP model and this value will also need further consideration when planning for a more detailed CAPP model. A common method of choosing the reserve margin for a utility system will be through selecting the largest unit in the system and calculating its' load carrying potential as a percentage of the total system load carrying potential.

8. Forced and unforced outage rates for power stations are set at minimal values of 4% and 2%. These are relatively low values and when the comprehensive data collection takes place within the CAPP these values will need to be determined for each station in the CAPP. The model consistently uses the MW power capability and never uses the name plate MW.

9. The development of the CAPP grid and **capital investment in new transmission** lines is the most cost effective investment for promoting the benefits from power pooling and so the costs of new transmission lines will be very critical numbers in future CAPP pool planning. In this demonstration model the costs of building new transmission lines and expanding load carrying capabilities on existing lines is $0.1Million/MW for the shorter lines and $0.3Million/MW for the longer DC lines. Capital costs should be recalculated as soon as the lengths and full technical specifications of each of the proposed lines are known.

10. The power losses along each transmission line are incorporated into the model by means of **transmission line loss factor**s. Throughout the CAPP model the **value of 5%** is used, regardless of length. These loss factors should be recalculated as soon as the lengths and full technical specifications of each of the proposed lines are known. Each line in the model is also given a forced outage rate of 2% to allow for accidents.

11. Generic capital costs for new thermal power stations are used in the model. For the proposed new gas turbines the cost that is is $300,000/MW and the cost for combined cycle is $500,000/MW, both numbers representative of current worldwide costs

12. Capital costs for new hydro stations were taken from the data collected at the initial CAPP Meeting in early 2005.

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CAPP Generation Expansion Pool Plan and Electricity Trading Scenarios

This demonstration CAPP model illustrates the consequences from two very different scenarios considered over a 10 year planning horizon. The two scenarios demonstrate the orders of magnitude of the economic benefits from (A), a regional integration policy having joint cooperative and collective planning for regional transmission and generation operation and capacity expansion and (B) capacity expansion and operation on an individual country by country basis with no international grid.

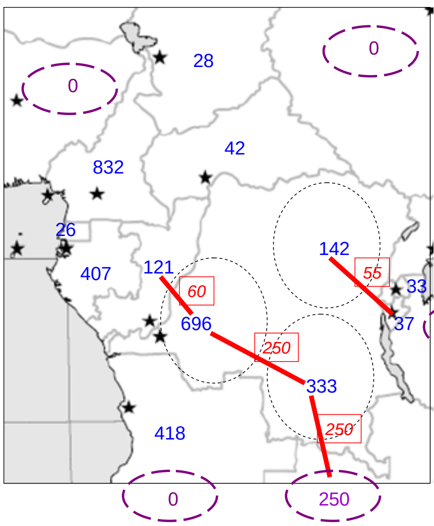


Figure 2

CAPP 2005

Existing Generation & Transmission Lines (MW)

CAPP Total 2005 Generation Capacity in Model = 3,124MW

Original Total Transmission on 4 Lines = 615MW

Key:
250 Generating Capacity
250 Transmission Capacity
0 External Node & Demand

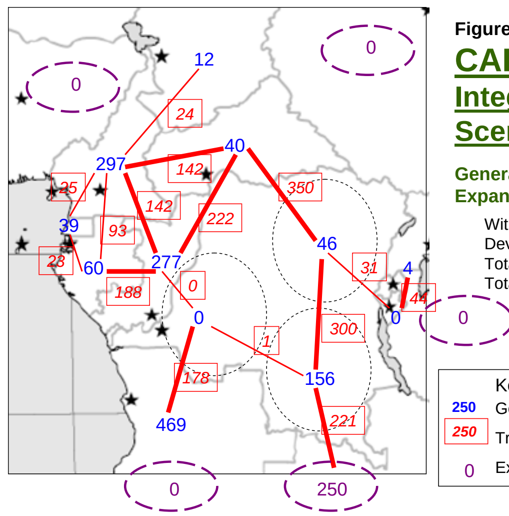


Figure 3

CAPP 2015 Integrated Grid Scenario A1

Generation & Transmission Expansions (MW)

With first 10 years of Grid Development:
Total Trans Cap. = 2,599MW
Total Gen. Cap. = 4,524MW

Key:
250 Generating Capacity
250 Transmission Capacity
0 External Node & Demand

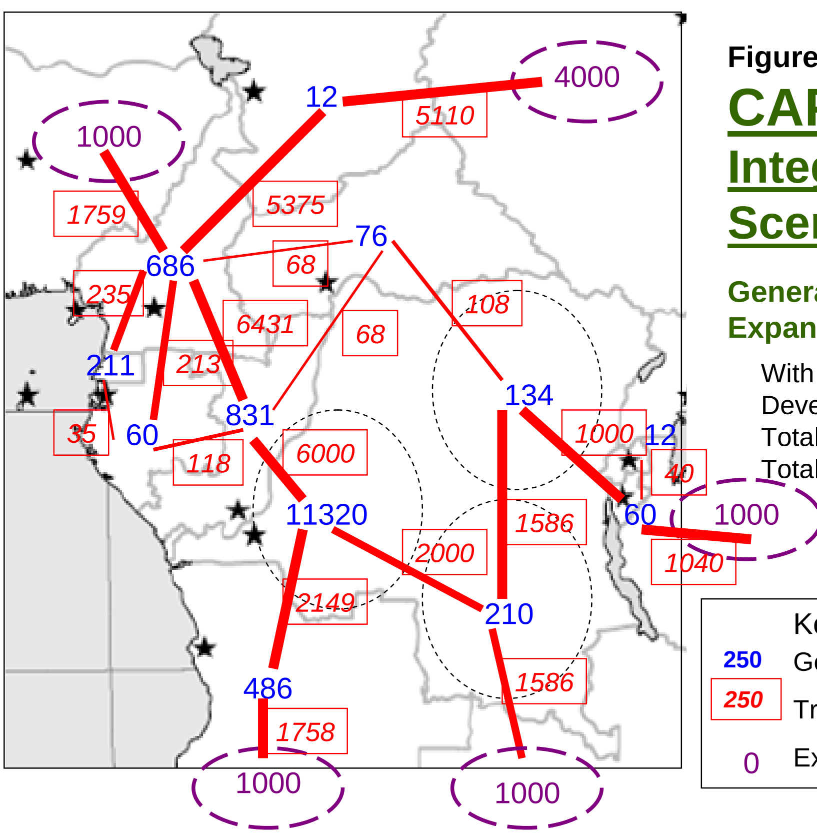


Figure 4

CAPP 2025 Integrated Grid Scenario A2

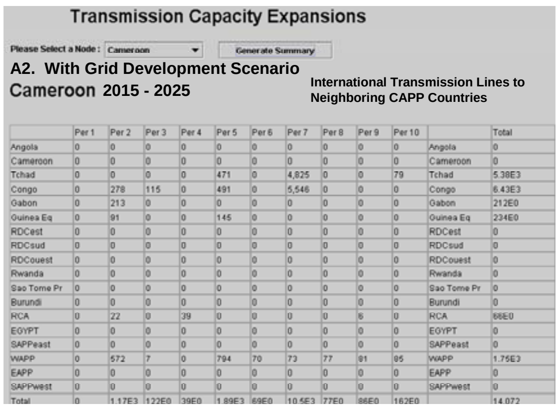
Generation & Transmission Expansions (MW)

With second 10 years of Grid Development:
Total Trans Cap. = 39,278MW
Total Gen. Cap. = 18,622MW

Key:
250 Generating Capacity
250 Transmission Capacity
0 External Node & Demand

The growth of the CAPP grid and generation capabilities are illustrated, in Figures 2, 3 and 4 (and Tables 4 and 5), for a fully cooperative and integrated planning approach (Scenario A). By 2025 the CAPP interconnected international grid provides an effective means of providing power from the hydro potential of the River Congo to CAPP consumers and other African power pools. Significant interest in the further development of the Inga site has been expressed by leaders from all over Africa and this new grid will enable it to become a reality. The $1.27 Billion international transmission lines investment (Table 1) is vital and yet it only represents about 10% of the total investment costs over during the 20 year the planning horizon.

Figure 7. Transmission Expansions In Cameroon



Transmission Capacity Expansions

Please Select a Node : Cameroon | Generate Summary

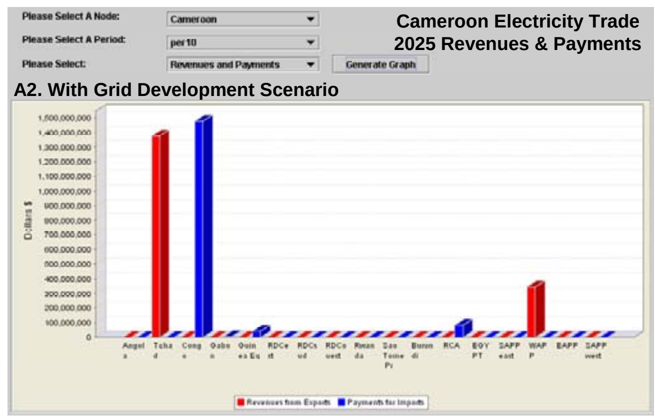
A2. With Grid Development Scenario

Cameroon 2015 - 2025

International Transmission Lines to Neighboring CAPP Countries

	Per 1	Per 2	Per 3	Per 4	Per 5	Per 6	Per 7	Per 8	Per 9	Per 10		Total
Angola	0	0	0	0	0	0	0	0	0	0	Angola	0
Cameroon	0	0	0	0	0	0	0	0	0	0	Cameroon	0
Tchad	0	0	0	0	471	0	4,825	0	0	79	Tchad	5.38E3
Congo	0	278	115	0	491	0	5,546	0	0	0	Congo	6.43E3
Gabon	0	213	0	0	0	0	0	0	0	0	Gabon	212E0
Guinea Eq	0	91	0	0	145	0	0	0	0	0	Guinea Eq	234E0
RDCest	0	0	0	0	0	0	0	0	0	0	RDCest	0
RDCsud	0	0	0	0	0	0	0	0	0	0	RDCsud	0
RDCouest	0	0	0	0	0	0	0	0	0	0	RDCouest	0
Rwanda	0	0	0	0	0	0	0	0	0	0	Rwanda	0
Sao Tome Pr	0	0	0	0	0	0	0	0	0	0	Sao Tome Pr	0
Burundi	0	0	0	0	0	0	0	0	0	0	Burundi	0
RCA	0	22	0	39	0	0	0	0	6	0	RCA	66E0
EGYPT	0	0	0	0	0	0	0	0	0	0	EGYPT	0
SAPPeast	0	0	0	0	0	0	0	0	0	0	SAPPeast	0
WAPP	0	572	7	0	794	70	73	77	81	85	WAPP	1.75E3
EAPP	0	0	0	0	0	0	0	0	0	0	EAPP	0
SAPPwest	0	0	0	0	0	0	0	0	0	0	SAPPwest	0
Total	0	1.17E3	122E0	39E0	1.89E3	69E0	10.5E3	77E0	86E0	162E0		14,072

Figure 8. Electricity Trade Revenues Example: Cameroon 2025



Figures 4, 7 and 8 illustrate the geographic importance of Cameroon in the future CAPP grid. Several new lines pass through this node and it becomes an important wheeling partner among CAPP member states. Figure 1 illustrates Cameroon at the center of six other nodes and Figure 7 shows the size of the line expansions on these nodes. CAPP free trading policy generates large electricity trade revenues and in the case of Cameroon the total revenues exceed $1 Billion (Figure 8), but it also has similar trading payments. As the years progress Cameroon becomes a more and more significant wheeling country (Appendix 3) based on the huge exports from the Inga site. Total CAPP country to country transmission line expansions are summarized in Table 4.

The great asset of huge water flows in the River Congo makes the hydropower potential of the region very attractive for a clean and cheap energy source to promote development and bring in major revenues. The majority of new hydropower in the model takes place in the second decade in the Democratic Republic of Congo, DRC, when implementing the free trade and centrally coordinated construction policy. Over 11GW of hydropower is added to the DRC in the 20 year planning period (Table 5). Enormous development potential can take place with the export earnings from this type of scenario demonstrated by Scenario A2.

Table 4. CAPP Existing and Future Transmission Load Carrying Capability Expansions 2005-2025 (MW)

Line ID **Node Numbers** **Country Interconnections**	**2005 (MW)**	**Future Transmission (MW)**		
		Scenario A CAPP Integrated Grid		**Scenario B** No Grid Integration except to SAPPwest
		A1. **2015**	A2. **2025**	**2015**
1. 1-11, Angola - DRCwest	0	178	2,149	0
2. 1-18, Angola - SAPPwest	0	0	1,758	0
3. 2-9, Burundi - DRCeast	55	31	1,000	0
4. 2-12, Burundi - Rwanda	0	44	40	0
5. 2-17, Burundi - EAPP	0	0	1,040	0
6. 3-4, Cameroon - Chad	0	24	5,375	0
7. 3-5, Cameroon - Congo	0	142	6,431	0
8. 3-6, Cameroon - Gabon	0	93	213	0
9. 3-7, Cameroon - Eq.Guinea	0	25	235	0
10. 3-8, Cameroon - RCA	0	142	68	0
11. 3-15, Cameroon - WAPP	0	0	1,759	0
12. 4-16, Chad - Egypt	0	0	5,110	0
13. 5-6, Congo – Gabon	0	188	118	0
14. 5-8, Congo – RCA	0	222	68	0
15. 5-11, Congo – DRCwest	60	0	6,000	284
16. 6-7, Gabon – Eq.Guinea	0	23	35	0
17. 8-9, RCA – DRCeast	0	350	108	0
18. 9 -10, DRCeast – DRCsouth	0	300	1,586	0
19. 9-12, DRCeast – Rwanda	0	0	0	0
20. 10-11, DRCsouth – DRCwest	250	1	2,000	149
21. 10-14, DRCsouth - SAPPeast	250	221	1,586	221
Transmission ExpansionTotal	**0**	**1,984**	**36,679**	**654**
Transmission Total MW	**615**	**2,599**	**39,278**	**1,269**

Scenario A – CAPP With Grid Development and Regional Integration

A1. 2005 to 2015

- The base year is 2005.
- Yearly generation expansions take place optimally (cost minimization) and are driven by the annual CAPP electricity demand growth rate of 5% (same value at each node/country).
- The demand and generation in the base year 2005 is summarized in Appendices 1a, 1b, and Figure 2.
- SAPPeast (250MW in 2005) is the only external node allowed demand.
- Transmission expansions are permitted to optimally take place between all nodes/countries.
- Smaller hydro schemes have minimum lead times of 3 and 4 years.

- The large hydros at node 11 (RDCouest) have 6 year minimum lead times.
- The generation and transmission capacity expansions for the period 2005 to 2015 are summarized in Tables 2, 3, 4 and 5.
- The costs for this first decade of Scenario A are shown above in Table 1.
- The model structure is illustrated in Appendix 4.

A2. 2015 to 2025

- All details are the same as in A1 except that major "external" electricity demands commence in 2015 for the "external nodes" SAPPeast (1000MW), SAPPwest (1000MW) WAPP (1000MW), EAPP (1000MW), and Egypt (4000MW).
- The costs for this second decade of Scenario 2 are listed in Table 3.

Table 5. CAPP Generation Capacity Expansions 2005-2025 (MW)

Node	**Node Name**	**Total** (MW)	Scenario A **With Grid Integration** Total Expansion MW		Scenario B **Without Integration** Total Expansion MW
		2005	**2015**	**2025**	**2015**
1	**Angola**	418	469	486	368
2	**Burundi**	37	0	60	12
3	**Cameroon**	832	297	686	224
4	**Chad**	28	12	12	4
5	**Congo**	121	277	831	433
6	**Gabon**	407	60	60	60
7	**Guinee Eq**	26	39	211	0
8	**RCA**	42	40	76	38
9	**DRCeast**	142	46	134	76
10	**DRCsouth**	333	156	210	210
11	**DRCwest**	696	0	11,320	0
12	**Rwanda**	33	4	12	12
13	**Sao Tome Pr**	9			
14	*SAPPeast Demand*	*250*	*250*	*1000*	*250*
15	*WAPP Demand*	*0*	*0*	*1000*	*0*
16	*Egypt Demand*	*0*	*0*	*4000*	*0*
17	*EAPP Demand*	*0*	*0*	*1000*	*0*
18	*SAPPwest Demand*	*0*	*0*	*1000*	*0*
	Generation Expansion Total	**0**	**1400**	**14,098**	**1,437**
	Generation Total MW	**3,124**	**4,524**	**18,622**	**4,561**

Scenario B – CAPP Without Grid Development and Regional Integration

2005 to 2015

- The base year is 2005.
- Only the 4 existing transmission lines (2-9, 5-11, 10-11, 10-14) are allowed to expand. All of the other future transmission lines are not considered.

- Yearly generation expansions take place optimally (cost minimization) and are driven by the annual CAPP electricity demand growth rate of 5% (same value at each node/country, Appendix 1).
- The demand and generation in the base year 2005 is summarized in Appendices 1a, 1b, and Figure 4.
- SAPPeast (250MW in 2005) is the only external node allowed demand.
- Transmission expansions are permitted to optimally take place between all nodes/countries.
- Smaller hydro schemes have minimum lead times of 3 and 4 years.
- The large hydros at node 11 (RDCouest) have 6 year minimum lead times.
- The generation and transmission capacity expansions for the period 2005 to 2015 are summarized in Tables 2, 3 and 4.
- The costs for this first decade of Scenario B are shown in Table 1 and the line and generation expansions are illustrated in Figure 5, Appendix 2.

Conclusions and What Next

Resulting from cooperation and dialogue among the CAPP member utilities and government energy ministries the CAPP structure has been created. Continuing with this approach in developing the regions' electricity markets a preliminary CAPP demonstration modeling exercise has been commissioned. The exercise has demonstrated the modeling capabilities, orders of magnitudes in cost savings to be expected by CAPP, and capacity expansions for new lines and hydropower in Central Africa. CAPP has potential for providing improved reliability to its' own consumers and also can have a very significant and positive impact on energy trade across the African continent.

The future following steps, in modeling the CAPP infrastructure, can give helpful support to the regional planners as they start to look towards more projects and feasibility and technical studies for specific new lines and stations.

- CAPP modeling activities will quantify the economic impact of each new project for each nation in a regional context.

- Provision is needed for the first CAPP Comprehensive Electricity Data Set. Without this data then the CAPP modeling work will have no significant foundation. Nominally at least a 12 month training and data collection period will be required for this. Final validation could take longer depending on the resources allocated for this essential activity.

- Following this demonstration modeling exercise for Central Africa the building of a CAPP Regional Model is recommended.

- Several modeling issues will be of future interest during the CAPP development including:

  (a) Alternative ways for splitting up the gains from trade between producers, wheelers, and consumers.
  (b) Revenues earned and cost savings made by each CAPP member in an integrated pool setting.
  (c) Effects of water flows in the Congo Basin on new major hydropower installations.
  (d) Role of distributed generation (DG) in the vast area of CAPP in which transmission costs to smaller towns and villages is hard to economically justify.
  (e) Impacts of growth in SAPP, WAPP, Egypt and EAPP on the CAPP.

- The creation of a CAPP Modeling, Policy Analysis and Planning Team, composed entirely of CAPP personnel, is recommended which will take possession of the proposed CAPP Regional Model, provide the latest data inputs and acquire the technical modeling skills to strengthen the region's own planning skills.

April 11, 2005

Appendix 1

Appendix 1a. CAPP Demand Summary for Base Year 2005

Node	**Node Name**	**Peak MW Demand in 2005**	**Total Demand in 2005** (GWh)	**Annual Demand Growth Rate** Percentage Growth 2005-2015 (MW)
1	**Angola**	407	2,497	
2	**Burundi**	37	129	
3	**Cameroon**	570	3500	
4	**Chad**	15	90	5%
5	**Congo**	91	563	
6	**Gabon**	187	1148	
7	**Guinee Eq**	4	26	*Note that in 2005: DRC exports 1700GWh. (a) 250GWh go to Congo. (b) 1450GWh go to RSA.*
8	**RCA**	38	103	
9	**DRCeast**	105	645	
10	**DRCsouth**	245	1505	
11	**DRCwest**	350	2150	
12	**Rwanda**	29	168	
13	**Sao Tome Pr**	8	13	
14	*SAPP-East*	*250 - 1000*	*1,450 - 6,132*	
15	*WAPP*	*1000*	*6,132*	
16	*Egypt*	*4000*	*24,528*	
17	*EAPP*	*1000*	*6,132*	
18	*SAPP-West*	*1000*	*6,132*	
	Totals	**2,086**	*(10,086 with all external nodes)*	

Appendix 1b. CAPP Peak Demand in 2005 and 2015 Assuming an Annual Growth in Demand of 5%

Country	Peak Demand 2005	Peak Demand 2015	GWh 2015
Angola	407	663	4,065
Burundi	37	60	370
Cameroon	570	928	5,693
Chad	15	24	150
Congo	91	148	909
Gabon	187	305	1,868
Guinee Eq	4	7	40
RCA	38	62	380
DRCeast	105	171	1,049
DRCsouth	245	399	2,447
DRCwest	350	570	3,496
Rwanda	29	47	290
Sao Tome Pr	8	13	80
SAPPeast	250	407	2,495
Totals	**2,086**	**3,805**	

Appendix 2

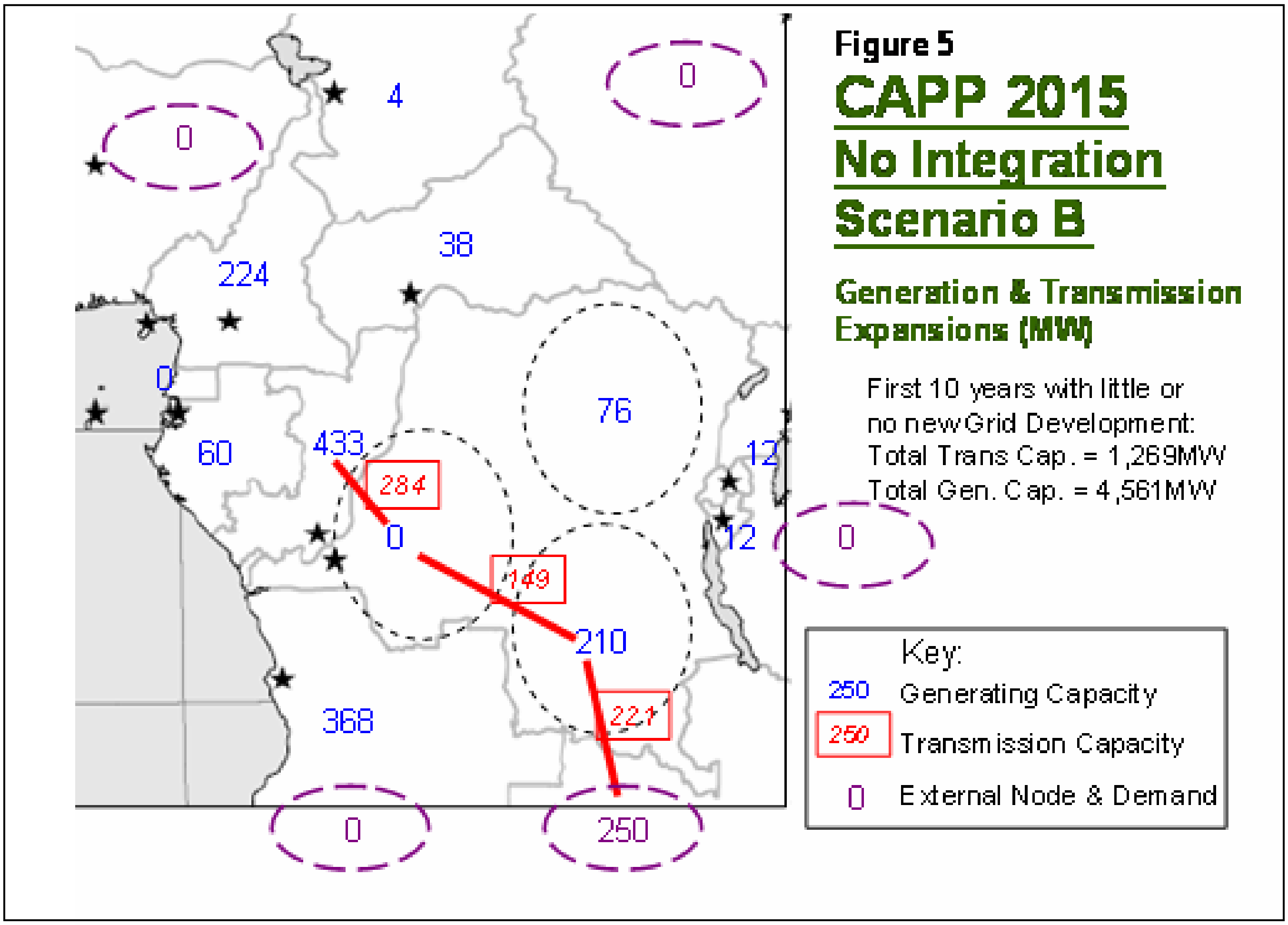


Figure 5
CAPP 2015
No Integration
Scenario B
Generation & Transmission Expansions (MW)
First 10 years with little or no new Grid Development:
Total Trans Cap. = 1,269MW
Total Gen. Cap. = 4,561MW
Key:
250 Generating Capacity
250 Transmission Capacity
0 External Node & Demand
0
4
0
38
224
0
76
60
433
284
12
0
0
12
149
210
368
221
0
250

Appendix 3

Generation Capacity Expansions

Please Select a Node : RDCouest | Generate Summary

A2. With Grid Development Scenario 2015 - 2025

RDCouest

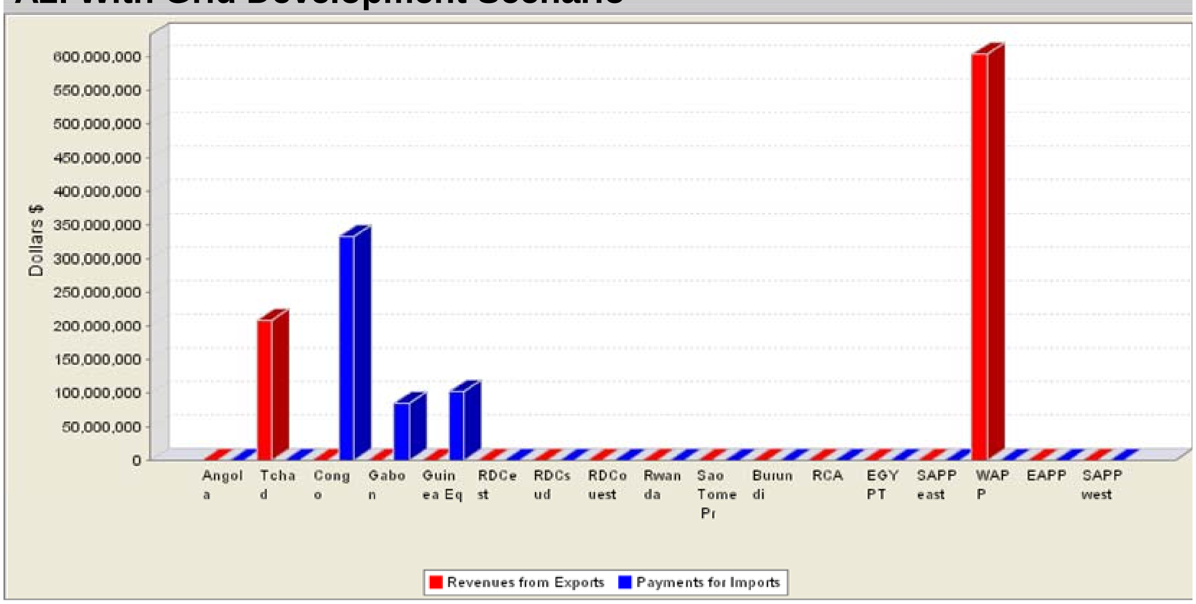
Major Expansion Commissioned at Inga in Period 5, 2020

	Period 1	Period 2	Period 3	Period 4	Period 5	Period 6	Period 7	Period 8	Period 9	eriod 10	Total
Old Thermal	0	0	0	0	0	0	0	0	0	0	0
Comb Cycle	0	0	0	0	0	0	0	0	0	0	0
Small Coal	0	0	0	0	0	0	0	0	0	0	0
Large Coal	0	0	0	0	0	0	0	0	0	0	0
Gas Turbine	0	0	0	0	0	0	0	0	0	0	0
Old Hydro	0	0	0	0	0	0	0	0	0	0	0
New Hydro	0	0	0	0	1,344	0	9,313	210	221	232	11,320
IPP Tier 1	0	0	0	0	0	0	0	0	0	0	0
IPP Tier 2	0	0	0	0	0	0	0	0	0	0	0
Total	0	0	0	0	1.34E3	0	9.31E3	209E0	220E0	232E0	11,320

Please Select A Node: Cameroon
Please Select A Period: per5
Please Select: Revenues and Payments | Generate Graph

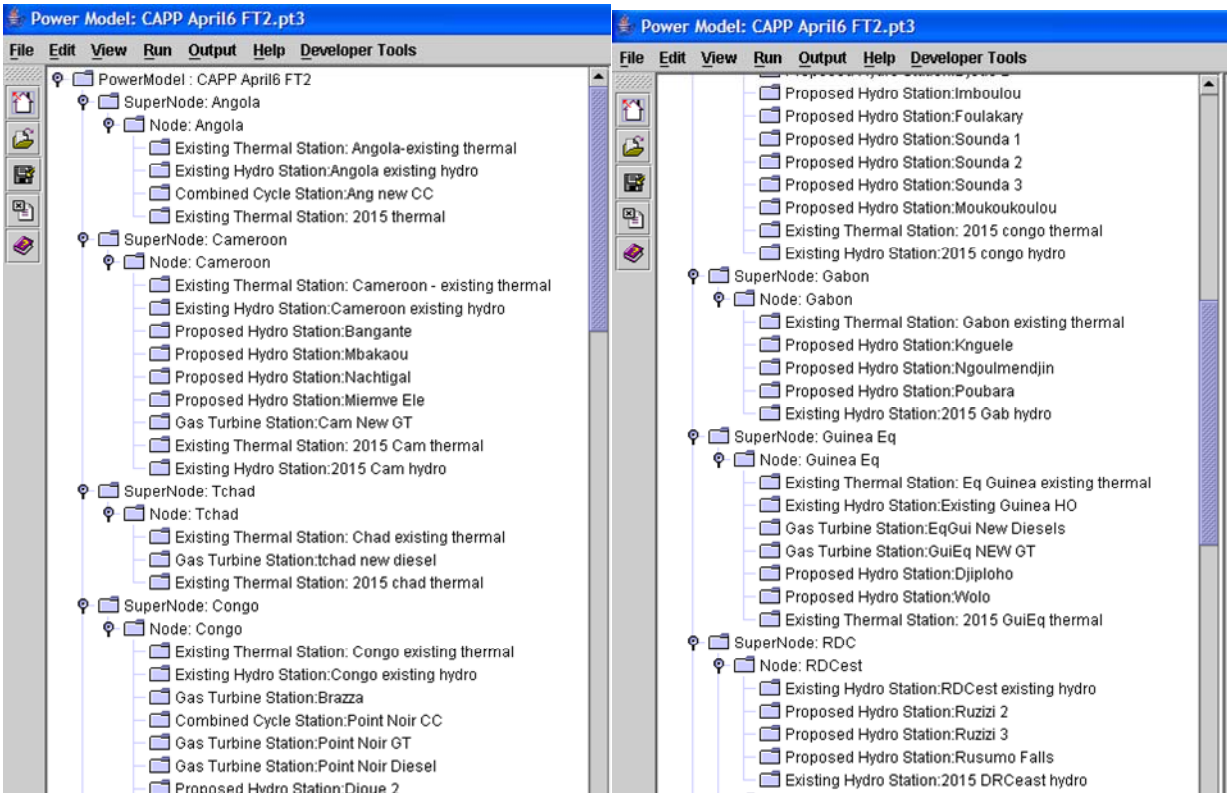
Cameroon Electricity Trade
2020 Revenues & Payments

A2. With Grid Development Scenario



April 11, 2005

Appendix 4
CAPP Demonstration Model Inputs



CAPP Demonstration Model Inputs