DESIGN OF A POWER PURCHASE TARIFF IN COTE D'IVOIRE
by Wolfgang Mostert

PART I: TARIFF POLICY FOR SALES OF COGENERATED POWER TO THE PUBLIC GRID

The Need for a Tariff Policy

Under the electricity law of 1985, the Government holds a monopoly for electricity transmission and distribution, and had until October 1990 entrusted this monopoly to the public power company, ECCI, under a concession system. In November 1990, the power sector in Côte d'Ivoire was partly privatised:

* The *operational responsibility* for power supply, transmission and distribution was transfered to a private company, the Compagnie Ivorienne d'Electricité, CIE. The CIE signed a 15 year franchise agreement to operate the integrated utility system and pays a lease fee to the Government.

* The EECI has the *technical responsibility for the management of the public assets*. In this function, the EECI undertakes major repairs and rehabilitation and plans investments for system expansion for which it seeks finance. In addition, the EECI is in charge of sector regulation, that is, in supervising the contract between the Government and CIE.

* As part of the financial restructuring of EECI undertaken in February 1993 the *ownership of the assets* of the electricity subsector were transfered to the Caisse Autonome d'Amortissement (CAA) in exchange for a write off for the company.

* The next large investment project in the power sector, the Foxtrott project, involving the development of the Foxtrott natural gas deposit and the implementation of a a 135-150 MW combined cycle power plant will be undertaken as a *boot-project* by a private company set up as a joint-venture between Ivoirean and foreign investors.

The part-privatisation of the power sector does not eliminate the need for public regulation of the sector activities, in particular the fixing of tariffs for cogeneration. The CIE being an integrated power production, transmission and distribution company is a *natural monopoly* due to the latter two activities. Public regulation therefore, has to provide the pressure on performance which otherwise would have come from the forces of competition. If the fixing of cogeneration tariffs was left to the outcome of negotiations between the CIE and the individual cogenerators, the price would not reflect a competitive market situation, as the CIE is in a much stronger bargaining position:

- Whereas the CIE can chose between alternative sources of supply, including its "own" generating capacity, would-be suppliers of cogenerated power to the public grid face a monopolist purchaser interested in maximising his profits.

- Once a cogenerator has invested in cogeneration equipment, it is "sunk costs" with few, if any, alternative applications. Any price higher than the marginal cost of cogeneration to the grid would still be better for the investor than no price at all.

In its search to maximise profits, the CIE would be tempted to exploit its strong bargaining position and negotiate the purchase tariffs down towards the marginal costs of cogeneration. This would lead to average tariffs below the average cost of supply and the cogenerator would make a loss on his investment. Because of this risk, no cogenerator would undertake any investments in capacity directly aimed at supplying the public grid unless the principles for the setting of tariffs are defined a priori in a clear and transparent manner.

Tariff Objectives

The setting of appropriate buy-back tariffs for non-utility produced power (called "cogeneration" in the following[1]) is a difficult exercise subject to compromises between conflicting objectives. In particular, the development of a rate schedule for biomass cogenerated power has to take four considerations into account:

* Economic efficiency as determined by the true resource costs of providing electricity supply, including the existence of externalities such as CO_2 emissions in power production. As in least-cost power planning studies, efficiency or "shadow" prices are the relevant measures.

* Power prices must raise sufficient revenues to meet the financial requirements of both the cogenerator and the utility in order to provide financial incentives for the implementation of economically attractive schemes.

* Fairness and equity considerations must be satisfied, e.g. with regard to how financial surpluses, if any, are appropriated.

* Ease of administration so as to not place an undue burden on utility billing and accounting units.

PART II: THE THEORY OF AVOIDED COST TARIFICATION

Avoided Cost

1 The word cogeneration in its technical sense refers to the combined production of heat and power in a plant.

It will be shown below that the pricing principle, most likely to balance the above considerations, is the one which bases the buy-back rates of cogenerated power on the avoided cost of the utility which holds the concession for the transmission and distribution of power. This principle has become the adopted legislative principle for the pricing of cogenerated power in a number of countries, inter alia, the USA, France, Denmark and Holland[2] . The avoided cost of the utility is the avoided cost of not having to take recourse to the alternative least cost source of supply otherwise available to the utility. As such, the "avoided cost" concept is the mirror image of "marginal cost" pricing [3]:

* The *marginal cost* concept as used in the LRMC approach prices output on the cost of the "last" (costliest) unit produced. To promote better utilization of capacity, and to

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[2] The U.S. Public Utilities Regulatory Policies Act (PURPA) of 1978 defines avoided cost as "the cost which the utility would have incurred had it been required to generate the power though its own (or alternative) means. This principle has been upheld in numerous legislative reviews, most significantly by the U.S. Supreme Court in American Electric power Service Corporation, Consolidated Edison, et al, versus Federal Energy Regulatory Commission, and American Paper Institute versus American Electric Power Service Corporation et al, in May 16, 1983. In the other countries, which do not rely on court and public hearing proceedings to establish regulatory practice, the principle is enshrined in decrees and pricing guidelines.

[3] "Purists" will note a small difference: The computation of avoided costs takes into account the characteristics of the power being supplied (i.e. capacity and capacity factor) whereas the computation of marginal costs assumes that power is supplied at load factor and very small increments.

avoid unnecessary investments to meet peak demands, prices are structured so that they vary according to the marginal costs of serving demands: (a) by different consumer categories, (b) in different seasons, (c) at different hours of the day, (d) by different voltage levels, (e) in different geographical areas; and so on. This ensures that the marginal consumption decisions of the consumers are based on the economic value of future resources required by the power system to meet marginal changes in consumption[4].

* If the tariffs for the purchase of cogenerated power are based on the avoided cost of the utility, they reflect the production costs of the units next in the merit order. Potential cogenerators can see whether they are capable of providing marginal supply at a lower economic and or financial cost than the utility. Cogenerators capable of producing at a lower cost would thus see an incentive to enter the market.

Figure 1 illustrates why the avoided caost principle is capable of satisfying the *economic efficiency goal:* the maximisation of the development and exploitation of economic cogeneration resources - those which supply power at a lower resource cost than the utility.

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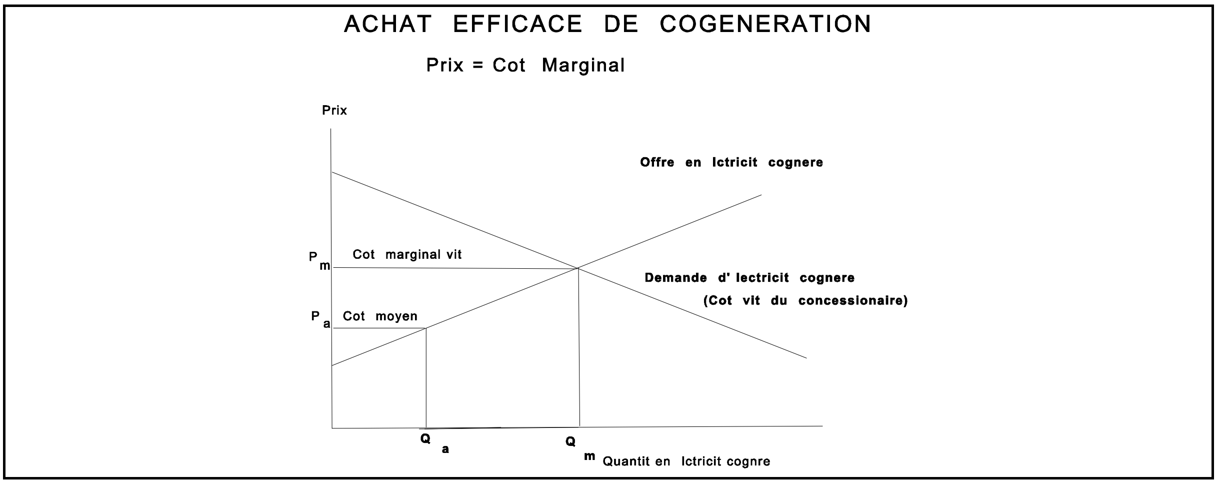
4 In practical application, this pricing principle needs some adjustment. Normally, the marginal cost of supply is higher than the average cost of supply, although also the reverse can be the case, if there are substantial economies of scale to be reaped. Therefore, the application of strict marginal cost pricing would lead to substantial "higher than normal profits" for the utility. These either would have to be taxed away, or retransfered to consumer e.g. by lowering the fixed rates, by introducing "life-line tariffs", or by redistribution the surplus according to the consumer's level of annual consumption.



The utility's (in Côte d'Ivoire, the CIE's) demand for cogenerated power reflects the marginal cost curve of power in its traditional system of power supply (own production plus production from other power companies). The demand curve slopes downward. The highest price will be offered for supply which replaces the highest cost units used to cover peak demand. Since this type of peak demand represents a small fraction of the annual demand for power, only small quantities are demanded. The cost of replaced traditional supply falls as one moves upwards in the merit order towards the low cost base load plants (and their high shares of total supply). The supply curve of cogenerated power on the other hand is upward sloping. The higher the price, the more cogenerators will enter the market as they see that their costs including a reasonable profit margin can be covered.

The economically efficient *market clearing price* is Pm, the utility's *marginal avoided cost* a this level of demand/supply. Any higher price level would lead to the development of cogenerating potential which has higher costs than the utility's alternative sources of supply. Any lower generally applied price level would prevent the implementation and exploitation of some cogenerating potential which has lower costs than the alternative marginal production units of the utility. It can, for example, be seen that it would be unwise to fix the purchase tariff at the level of the *average avoided cost of the utility*. In that case, there is a substantial loss of undeveloped efficient cogenerating potential.

The existence of a diversified cogenerating potential with different cost curves provides the regulating public authorities with an alternative possibility for its tariff policy. Instead of using the market clearing price P_m for all producers, in principle, the full potential for economic cogeneration can also be realised through the fixing of individual prices for each producer on the basis of cost-plus pricing. That is, on the basis of the cogenerator's cost of power supply to the grid including a mark-up to achieve a return on his investment. The latter possibility could be a tempting prospect for a Government eager to share the advantages of lower costs between the cogenerator and the utility and ultimately, through lower average tariffs, with the consumers. Thus, from an *equity point of view*, one may argue for this tarification policy.

However, four arguments can be raised against such a policy:

* Firstly, one may equally argue from an *equity point of view* that tariffs fixed on the individual cost curves of the producers would be considered as unfair by low cost producers, who fail to see why they should be paid less for the same product [5].

* Secondly, from an *administrative point of view,* the transaction costs of developing individual contracts with numerous cogeneration proposers would be considerable. Individual negotiatios would have to take place, and the cost curves for each producer have to be established by the regulating authority on the basis of information provided by a producer who has has every incentive to inflate the estimates. Since electricity is not the sole output of a cogenerator but rather a joint product of a process which simultaneously produces steam and power, the objective cost of generation cannot easily be established. Standard utility measures of cost of generation are not applicable to cogenerators.

* Thirdly, the cogeneration business is not going to be a gold mine under any of the two pricing scenarios. It is unlikely that the cost curves for biomass based cogeneration are substantially below the marginal cost curves of the utility. Under the present low prices for hydrocarbon fuels, it is more likely that most of the physical potential is marginally uncompetitive and needs subsidies to be realised. Thus, the potential cost differences are too small to justify efforts aimed at sharing the "benefits" [6].

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5 Cogenerated power is a non-dispatchable resource of power supply. Therefore, two cogenerators deliver the same product. It is differente with the "pure" power producers who operate on a dispatchable basis. A high cost supplier of power for peak consumption delivers a different product than a low cost supplier of base load which is purchased on "continous" basis.

6 *Bidding systems,* as being developed in some United States jurisdictions, are another way to ascertain the cogeneration supply curve. It can be shown that bidding systems can be devised which are theoretically equivalent to a non-bidding system in which each cogenerator is paid the utility's marginal avoided cost. With these one can capture at least a part of the cogenerator's surpluses for the benefit of the utlitiy's ratepaying customers. However, biddding systems presuppose the existence

of an effective, competitive market for cogenerated power. In the context of the young Ivoirean cogeneration market this is a future possibility.

* Fourthly, in practice, it is unlikely that both methods would be equally effective in realizing the *economic potential* for cogeneration. Whereas power production is the core activity of a utility, it will only be a subsidiary activity for the cogenerator. Unless it is a financially very attractive activity, it is likely that the management of a potential cogenerator would not find it worthwhile to devote scarce management and financial resources to its realization. Thus, one may expect that marginally attractive cogeneration investments will either not be implemented or be postponed. Thus, if a tariff based on the utility's avoided marginal cost makes some cogeneration projects very profitable this should be applauded as a means to accelerate their implementation.

Thus, for *economic efficiency* and *administrative ease* reasons it is recommended to base the tariff on the avoided cost of the utility. *Equity considerations* can be satisfied by varifying the level of the investment subsidy between categories of producers that have different cost levels, e.g. one level for the sugar industry, another level for the palm oil industry.

Marginal Cost and Avoided Cost

There are three broad categories of marginal costs in power production:

* *Marginal capacity costs* which are basically the investment costs of generation, transmission and distribution facilities associated with supplying additional kilowatts.

* *Marginal energy costs* which are the fuel and operating costs of providing additional kilowatt-hours.

* *Marginal customer costs* which are the incremental costs directly attributable to consumers including costs of hook-up, metering and billing.

Relevant operation and maintenance costs (O&M) as well as administrative and general costs (A&G) must be allocated to these basic cost categories [7]. O&M Costs must include salaries, maitenance contracts, lubricants and replacement of parts, and auxiliary equipment of the generating units. O&M costs do not include fuel or any annual fixed charges on plant capital costs such as interest on debt, return on equity, depreciation, amortization and taxes. Furthermore, where appropriate, these elements of LRMC must be structured by time of usage, voltage level, and so on.

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[7] While there are no strict definitions to differentiate between regular maintenance and major rehabilitations, in general terms, any expense that is not related to fuel supply or to the book value of assets is considered an O&M cost.

Of the three categories, only the first two are relevant for the avoided cost computations for supplies from cogenerated power. They lead to payments for energy avoided energy costs and capacity costs respectively and to the distinction between SRMC and LRMC:

- The *short run marginal cost (SRMC)* may be defined as the cost of meeting additional electricity consumption (including the cost of shortages) with capacity fixed. The SRMC is only the marginal cost of energy.
- The *long run marginal cost (LRMC)* is the cost of providing an increase in consumption (sustained indefinitely into the future) in a situation where optimal capacity adjustments are possible [8]. To obtain the LRMC, the SRMC is combined with an independent estimate of the marginal cost of capacity [9].

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[8] It may be defined practically as the incremental cost of optimal adjustments in the system expansion plan and system operations attributable to a small increment of demand which is sustained in the future. See for example, Mohan Munasighe, Electric Power Economics, 1990.

[9] It is possible to obtain the marginal cost of capacity and energy simultaneously by using a method known os the **Average Incremental Revenue Requirements (AICR).** The process consists, briefly, of calculating the annual fixed and variable costs of two least cost expansion plans. The first corresponds to a base case load growth, the second to a higher load growth, often obtained by advancing all load levels by one year. Long run capacity and energy costs are then obtained by allocating all incremental fixed costs to the increments of capacity and all variable costs to the increments of energy. Since the least cost expansion plan of the system seeks a compromise between low investment and low operating costs it is inevitable that some of the incremental fixed costs are not solely derived from the need of incremental capacity but result from the need to lower operating costs and thus are not truly energy costs. The AIRC method thus needs to include this correction.

When the system is optimally planned and operated (i.e. capacity and reliability are optimal) SRMC and LRMC coincide. However, given the uncertainties associated with forecasting future demand, fuel prices and generation technologies, the system equilibrium is often unfulfilled by a wide margin - characterised by an excess or a deficit in capacity or by a high cost technology mix. So in general, there will be significant deviations between SRMC and LRMC, and choices must be made on which criterion and methodologies to adopt to estimate an efficient price for cogenerated power purchases.

As always, the presence (SRMC) is easier to establish than the future the (LRMC):

- The identification of avoided energy costs is done rather unambiguously on the basis of the system lambda (although we shall see that the calculation of the opportunity cost of replaced hydropower in a mixed hydro-thermal system takes some analysis)
- In contrast to marginal energy cost calculation there is no universally accepted method for estimating the LRMC for generation capacity. Whereas there is general agreement at a conceptual level, when it comes to estimation, a consensus is lacking. Controversy exists both with regard to the choice of correct reference unit and with regard to the allocation of computed capacity costs to different time periods.

Identification of Avoided Energy Costs

(a) Avoided energy costs at power generation level

Energy payments to cogenerators should be based on the avoided energy costs of the utility. The appropriate cost in any time period is the *system lambda*, familiar to utility dispatchers as the measure of rank order. System lambda is a short run marginal cost composed of (i) the marginal unit in service fuel costs (unit cost of fuels times the marginal heat rate) plus (ii) variable operations and maintenance (O&M) costs. The SRMC of peak period will be the running costs of the machines used last in the merit order to meet incremental peak kilowatt-hour. Similarly, the off-peak energy would usually be the running cost of the least efficient base load or cycling plant used during this period.

A element which has to be taken into account is the fact that system optimization is not done on a single period basis. Some generating capacity not needed during the base load period will be needed for load carrying or spinning reserve the next morning and a shut down would be imprudent. To allow for off-load heat costs which are not avoidable during certain periods, avoided energy costs should be conservatively based not on the least efficient unit in service during the base load or shoulder period period, but on the average unit in service.

The calculated busbar avoided cost (power production measured at the level of generators) needs to be adjusted upwards for station internal consumption, which in 1993 averaged 6.8% for the steam power plants and 0.2% for the gas turbines.

(b) The special case of mixed hydro-thermal systems

In an *all hydro system* the LRMC of *generating capacity* would be based on the cost of increasing peaking capability (i.e. additional turbines, penstocks, expansion of power house, etc.), while *incremental energy* costs would be the costs of expanding reservoir storage [10]. When there is significant spillage of water, e.g. during the rainy season, incremental energy costs would be very small, (e.g. O&M costs only) and at times when demand does not press on capacity, incremental capacity costs may be ignored. However, if the system is likely to be energy constrained and all incremental capacity is needed to generate more energy because the energy shortage precedes the capacity constrained for many years in the future, then the distinction between peak and off-peak costs tends to blur. In an extreme case, because hydro consumed during any period (except when spilling) leads to an equivalent draw-down of the reservoirs, it may be sufficient only to levy a simple kilowatt-hour charge at all times, e.g. by aplying the AIC method to total incremental system costs.

The estimation of marginal costs in *mixed hydro-thermal generating units* depends critically on the mix of generating plants used at different times. An important general guideline is that if hydro is used to replace thermal plant during a rating period, then the running costs of the latter is the relevant incremental energy cost. Also, if the pattern of operation is likely to change rapidly in the future (e.g. shift from gas turbines to peaking hydro as the marginal peaking plant or vice-versa) then the value of the LRMC would have to be calculated as a weigthed average, with the weights depending on the share of future generation by the different types of plant used.

Part a of figure 2 shows the case of a *predominantly hydro system* in which steam turbines are operated continuously during the dry season to supplement hydro. The shaded area I represents thermal plants, area II hydro generation. To minimise the system cost in the long run, the smallest possible amount of thermal capacity must be installed and base loaded to run 24 hours a day during the dry season with stored water meeting peak demands. In this situation, incremental energy must always be supplied by operating the thermal plants. In addition, since thermal costs are fully utilised, the marginal costs of additional capacity divided by the number of hours of operation at full capacity must be added to the marginal fuel costs to obtain marginal energy costs. If changes take plce in the pant mix, weighted averages have to be introduced.

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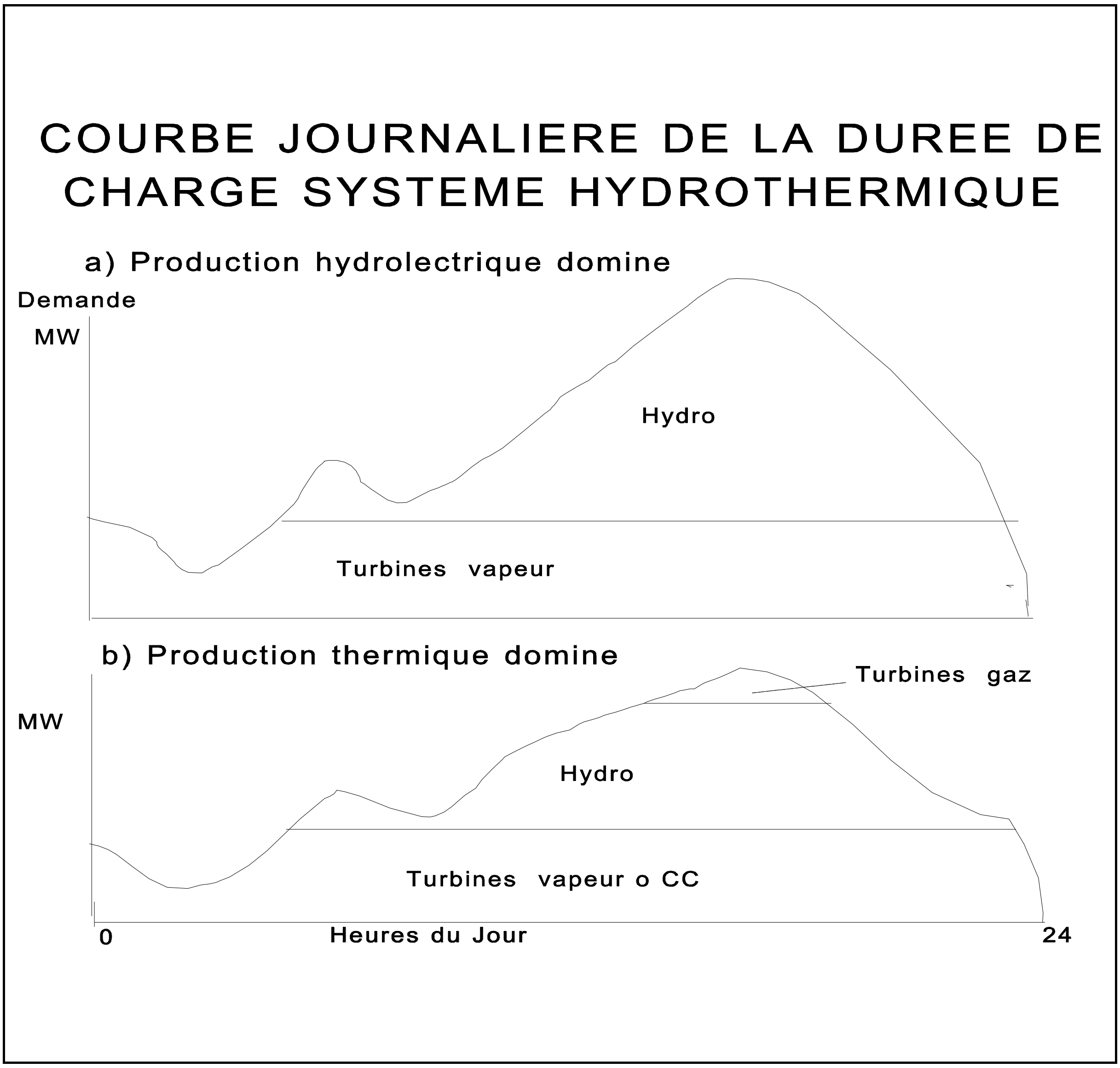
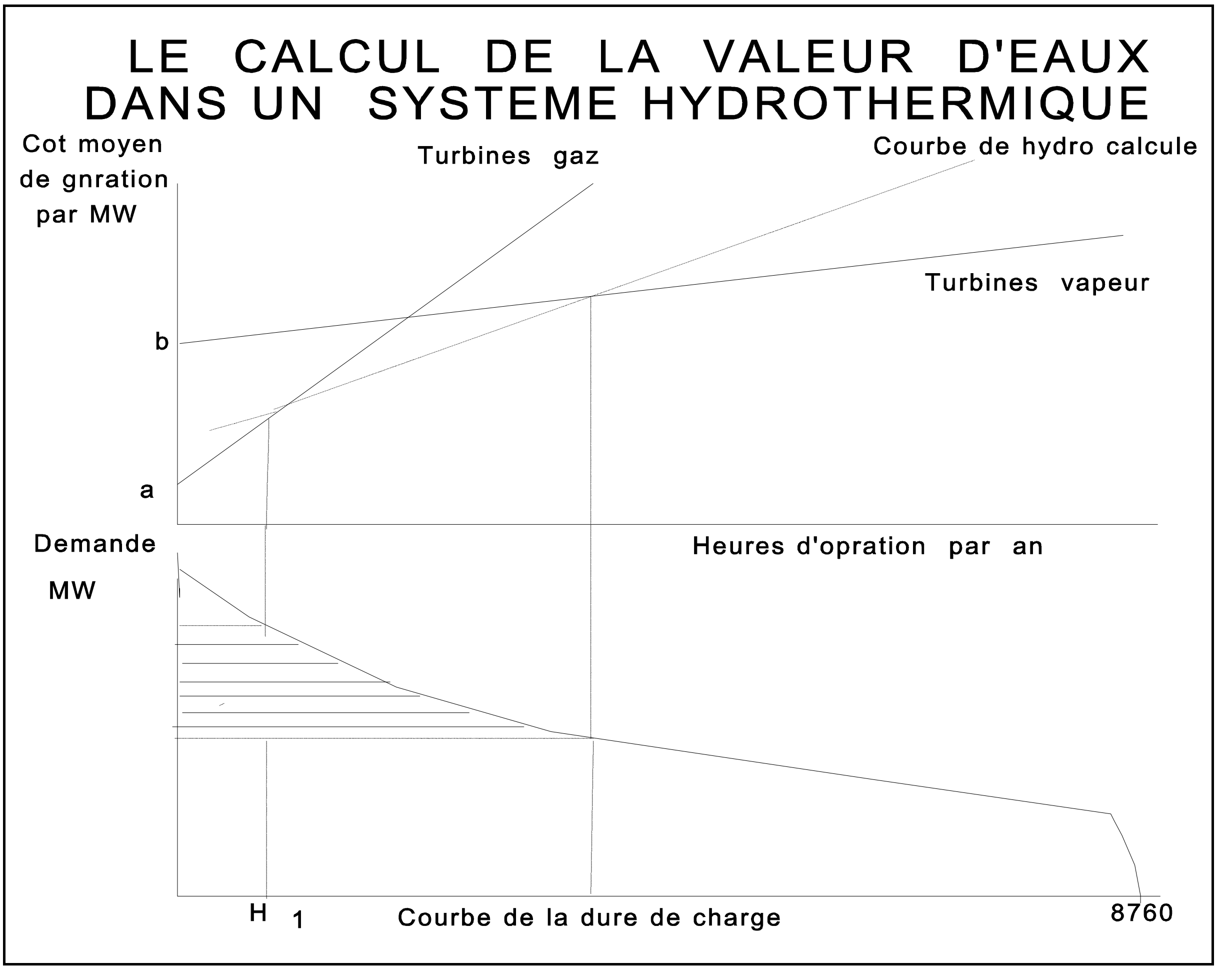
10 See Munasinghe, Power Economics, 1990



In the *thermal dominant case shown in part b of figure 2*, all available water is used and thermal generation is required throughout the year. The typical daily pattern of generation is shown in figure. Base load steam plants represented by area I would be run continuously during the 24 hour period; gas turbines represented by area III would be required to meet peak demand. All the water collected during the year would be used to supplement the thermal generation on a daily basis by filling up area II.

A general *principle for determining the value of water used in a mixed system* is shown geometrically in figure 3. The *gas turbines* with relatively low capital (point A on the y-axis) and high operating costs (the slope of the curve) are used for peaking duty. The *steam turbines* having higher capital and lower operating costs are operated as base load plants. Since the water is used between these two plants, an imputed value would be given by the broken line. The position of this line would usually be determined by conditions of operation that would seek to ensure that all available water in storage would be used up during the year. The intermediate slope of the line indicates that the cost per kWh of energy lies between the



energy costs of peaking and baseload plants.

(c) Power loss reduction and quality credit

Whereas the thermal power plants are concentrated in the Abidjan area, the biomass cogeneration plants in the sugar and palm oil industry are spread across the local demand centres. This aspect, the nearness of their output to the local customers of power demand has two beneficial impacts on the national interconnected power system - they *reduce line losses* for the transport of power from the central power plants to the customers in the local region and they *improve the quality of the local power*.

The line losses are governed by several factors: a) the distance to remote power plants; b) partial overloading of substations and O/H lines; and c) lack of proper power factor correction equipment, especially in the rural areas. Since measurements are not taken throughout the system, the exact amount of losses is subject to some uncertainty. Based on the 1991 ESMAP report on the line losses and assumed line losses on the transport of cogenerated power to local demand of 2% the net avoided line losses can be estimated at 13%, which have to be given as credit to the price of cogenerated power:

LINE LOSSES IN THE CIE SYSTEM, 1991

Transmission losses	5.4%
Distribution losses	9.6%

Total losses	15.0%
Cogeneration line losses	2.0%
Net Avoided System Losses:	13.0%

The 15% line losses in CIE's system relate to the annual energy losses. There is no documentation on the capacity losses during peak hours, but keeping in mind that the instant capacity losses are proportional to the square of the current and the proportion between the peak and minimum loads is in the magnitude of 2:1, the capacity loss will under peak conditions be substantial.

A further aspect in the consideration of local power generation is the distribution of *reactive power* in CIE's system. Reactive power creates voltage drops and line and substation losses. Furthermore, generating capacity used to produce reactive power cannot be utilized to produce active power to the same extent. For these reasons it is always in the interest of a utility to keep the reactive power component as low as possible. This is done in various ways, either with restrictions and penalty payments embedded in the tariff system or by means of power factor correction equipment (capacitors) placed as close to the consumers as possible. Cogenerated power improves the frequency in the local net and reduces the eefect of reactive power. While this aspect is not unimportant, it is difficult to quantify in practice. No attempt has been made in this report.

Avoided Capacity Costs

Whereas the rationale for the energy credit is intuitively accepted by all parties, the computation of capacity credits for cogenerated power is often subject to a certain degree of controversy. Capacity credits are derived from : (a) the costs imposed on the electric system due to marginal increases in peak demand, and (b) the cogenerators effective load carrying capacity. The discussions concern both the correct estimation of capacity costs (choice of method) as well as the load carrying capacity of cogenerated power. Finally, also the allocation of capacity costs to different time periods is open for discussion.

(a) Methods for determining capacity costs

Several methods plus variants are commonly employed to estimate utility system capacity costs. However, although they approach the subject from different angles, several of them will - depending on circumstances - yield similar estimates of LRMC. In the methods listed below, for example:

- As long as the designated plant refers to plants currently under construction or to the next new project as the proxy unit, the proxy unit method becomes very similar to the LRAIC approach.
- If the next plant in the optimal expansion plan is a peaker plant, the peaker plant variant of the proxy unit mehod, the LRAIC (next plant only) and the component method will all give the same results. This will be the case when the utility's generating mix is not substantially different from the least-cost mix and the reserve margin is just adequate. Under such conditions, the "next unit" will indeed be a peaker

and the system optimization method should also elect to advance the peaker.

Costs of Bulk Purchase Method

Where inter-utility power trading is common, the cost of acquiring capacity on a contractual basis from a neighbouring utility is sometimes taken as a measure of avoided cost.

Long Run Average Incremental Method (LRAIC)

The LRAIC is calculated as the present discounted value of generation capacity investments contained in the utility's least cost expansion plan. It can be based on either

- All plant in resource plan
- Current investments
- Marginal investments

The figures are adjusted upwards for the annual availability factors of the plants.

The *incremental revenue requirement variant* requires use of sophisticated optimization expansion planning models. Estimates of "marginal cost" developed by this method are weigthed averages of capacity costs of a diverse mix of marginal as well as inframarginal plant types: peaking, intermediate and base load. The mixing is a conceptual flaw, it is contrary to the notion of marginal capacity cost, ie the cost of meeting a marginal increment of demand on-peak.

Proxy Unit Method

The proxy unit approach uses the fixed (cost/installed kW) and variable costs of a single "representative" resource (which may or may not be in the utility's resource plan) and assumes that these costs represent the utility's long-run avoided costs. The proxy unit can either be (i) a "generic representative" unit based on other real life investment costs of plants with a capacity of x MW; (ii) a peaker plant, (iii) the next plant under construction; or (iv) the next new project.

Under the *next plant variant*, it is assumed that the 1 kW load increment will de met by appropriately advancing forward which ever power plant is planned to come on-line next. Its annualized cost can be used to establish the LRMC after assigning credit for any fuel savings as a result of having more fuel-efficient plant. The *fuel saving adjustment* is done by noting how the additional capacity from such a unit will have the effect of displacing generation of all more expensive units higher up in the stacking order , e.g x hours of coal, y hours of lignite, z hours of gas turbines. The annual fueld savings that should be credited against the annualized capacity cost are given by the mulitplying the hours with the fuel savings per hour.

An example of the *"generic representative unit" variant* is seen in the 1991 ESMAP report "REPUBLIQUE DE COTE D'IVOIRE: ETUDE DU RENDEMENT DU RESEAU ELECTRIQUE":" Les couts marginaux á long terme pour la puissance sont basé sur l'implantation d'un <u>cycle combiné de 150 MW</u> au <u>coût</u> de 29,7 milliard de FCFA. En utilisant un facteur de réduction de capacité de 8%, une vie économique de 25 ans et un coût de capital de 10% on arrive á un coût marginal de puissance de 23,710 FCFA/kW et par année. Ce coût doit être majoré de 22,7%

- soit 0,7% pour les services auxiliaires,
- 2% pour l'entretien et l'exploitation, et
- 20% á titre de réserve tournante et d'indisponibilités

Le résultat est donc de 29,092 FCFA par kW par année au niveau de la production". Adding 80% to obtain the 1994 post devaluation price, this gives a cost of 52,365 FCFA per kW-year.

The *peaker plant variant* is rationalized on the basis that the *least cost means of securing capacity is a peaking unit*, and the *reason any other type of generation is built is to derive the energy savings* [11]. The annualized cost of such a unit - adjusted for reserve margin and losses, and appropriately discounted to today from the year needed - is the marginal cost of generation capacity. The following equation captures this calculation:

"marginal generation capacity cost" (cents/coincidel KW/year) =
K * ((1+rm)/(1-SL)) where
K = annualized cost of peaking unit (cents/kW/yr)
RM = planning reserve margin (%)
SL = station losses (%)

This cost (in constant prices) is subsequently discounted from the first year in the future when the reserve margin constraint (or the loss-of-load probability criterion) is binding, and adjusted upward for incremental fixed O&M operating expenses, as well as any downstream losses up to the point of delivery. This cost can be allocated to different rating periods e.g. on the basis of the contribution of each rating period to the annual LOLP. The approach is valid if the system reliability level is below its optimum level, as is believed to hold for the CIE system.

Component Method

The component method simultaneously develops detailed, time-differentiated avoided energy and capacity costs for each year of expected service life of the cogeneration unit. *Avoided capacity costs* are estimated by determining, for each year, the least-cost capacity option available to the utility. This is done by running a *probabilistic production cost simulation model* with expected cogenerator output modeled as a cost-free resource or as a reduction in load. The least-cost option is often a peaking unit or a capacity purchase, but may also be a load management program, a baseload plant net of fuel savings it provides in non-peak hours, or any other resource which could provide low-cost capacity in peak hours. The cost of the least-cost option is annualized using the appropriate economic carrying charge. These figures should be adjusted by the availability factor of the capacity being installed,

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11 For example, the California Public Utilities Commission began in 1979 to use the annualized cost of a combustion turbine to approximate the value of reliability improvement (an addition to system capacity).

Differential Revenue Requirement Method

The differential revenue requirements method is an ideal way of assessing the value of cogeneration to the national power system without any reference to its own production cost. It assumes an amount of cogeneration capacity operating with given characteristics and calculates the utility's total generation cost with and without that cogeneration capacity over a period of years. The present value of the difference in total generation costs between the two cases is the lump sum of avoided cost for the hypothesized block of cogenerated power. They can then be divided into (i) energy and (ii) capacity components.
Since this method requires a sophisticated simulation model which was not at the disposal of the mission, this approach has not been used.

True Short-run Marginal Cost Method

This method costs capacity in terms of the value of reliability to consumers. The method is used by the SIE's simulation model to establish the system lambda of the hydropower plants. True SRMC is the sum of a) the additional running costs, and b) the change in the value of system reliability caused by producing one more unit of output with existing capital equipment. The latter value "b" is called the *marginal expected curtailment cost (MECC)*. It is the total welfare loss resulting from an outage times the probability of that outage occuring.

The true SRMC method may be operationalized by exploiting the *electric system optimal reliability marginality condition*. It states that the value of the benefit to the consumer of the marginal reduction in expected curtailment cost should be equal to the utility's adjusted marginal cost of additional system reliability (capacity addition) [12]. It can be stated as:

[12] The least cost expansion plan to meet the demand forecast is generally determined assuming some (arbitrary) target level of system reliability, e.g. loss-of-load-probability (LOLP), reserve margin, etc. Thus, the marginal costs depend on the target reliability level.

(OC-L) * LOLE = MCC/a

Where:

OC	=	Outage cost per unit of unserved energy (FCFA/kWh)
L	=	Operating cost per unit energy for the marginal capacity addition (Lambda) = marginal fuel and variable O&M costs (FCFA/kWh).
LOLE	=	Optimal Loss of Load Expectation = cumulative duration of loss of load over a period (i.e., one year) (hours/year).
MCC	=	Marginal Cost of Capacity = annual cost per unit capacity (FCFA/kW-year)
a	=	Availability factor of the capacity being added (between 0 and 1)

When examining the situation of a particular power sector, one can encounter three possibilities:

MECC = MCC/a illustrating optimal capacity of the system
MECC > MCC/a illustrating the existence of undercapacity
MECC < MCC/a showing the existence of overcapacity

When capacity is of optimal size the MECC is, by definition, the *cost of a peaker plant* on the electrical generation system. Due to the lumpiness of capital investment, rapid demand growth and funding constraints, MECC and hence true SRMC in Côte d'Ivoire will generally vary above this optimal level.

Estimation of OC:

Three analytical approaches are available for *outage cost estimation*:

However, economic theory suggests that reliability should also be treated as a variable to be optimized, and both price and capacity (or reliability) levels should be optimized simultaneously. The optimal price is the marginal cost price, while the optimal reliability level is achieved when the marginal cost of capacity additions are equal to the expected value of economic cost savings to consumers due to electricity supply shortages averted by those capacity increments. (See Munasinghe, 1990)

(a) *Willingness to pay* for planned electricity consumption. It can be established through "revealed preferences" interviews or be refered from the cost of the first best alternative, such as e.g. the cost of running diesel water pumpsets instead of electric water pumpsets. This estimate should be considered the lower bound: the fact that many industries do in fact purchase back-up diesels indicates that their willingness to pay for reliability meets or exceeds this figure. In addition, purchase of an autogenerator is a long run adaptation which likely understates short-run willingness to pay since short run unplanned demand responses are normally much less elastic than long-run consumption adjustments.

(b) Cost of maintaining a *back-up source of power. The 300 kW diesel autogenerators commonly found in the agroindustry in Côte d'Ivoire are the most relevant form of* *BACK-UP POWER.*

(c) *Cost of loss of production* due to unreliability of supply of electricity, an intermediate good in the production of goods and services

(b) Allocation of capacity costs by time period

The allocation of system capacity costs to different time periods on the basis of *accounting costs* is usually quite arbitrary:

- One method attempts to identify peaking, intermediate and base load generation plant and then alocates these costs to the peak, shoulder and off-peak periods.
- Another method uses the probability of contribution to the peak based on the number of hours in each rating period in which demand exceeds some arbitrary threshold level divided by the total number of hours in the year. None of these are based on LRMC.

With an appropriate choice of the peak period, structuring the LRMC-based tariffs by time of day generally leads to the conclusion that peak consumers should pay both capacity and energy costs, whereas offpeak consumers should pay only energy costs [13]. The logic is that peak period users, who are the cause of capacity additions, should bear responsibility for (i) the capacity costs as well as (ii) fuel, operating and maintenance costs, while off-peak

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[13] Although the simplification is often made, it is not correct to define the change in the utility's capacity costs as capacity related and the change in the running costs as energy-related. It is usually the case that a portion of a utility's capital costs are avoided energy costs because they enable the utility to avoid operating resources with higher running costs. Thus, a utility invests in a baseload plant with high fixed costs per kilowatt both to meet peak demands and to save fuel. If capacity costs of base load units are included in the capacity cost calculations to peak period consumers, then it is important to net out potential fuel savings due to displacement of less efficient plant by these new base load units.

consumers only pay the latter costs. However, if there are substantial outage costs outside the peak period, then the optimal marginal capacity costs may be allocated among the different rating periods in proportion to the corresponding marginal outage costs.

(c) One-part of two part tariff

Typically, the capacity charge for consumers during the peak period is converted into an equivalent kilowatt-hour charge and added to the energy charge; whereas it is leveled as a seperate capacity charge for off-peak periods. At the generation level the issue has more to do with project financing and risk management than with economics and is therefore a matter of negotiation. Under the project financial regime in Cote d'Ivoire it is unlikely that a two-part tariff would facilitate better financing of the plant (for reducing overall income risk). Since a one part tariff based on energy delivered may be simpler for the CIE to administer, it is recommended to use a one-part tariff; the avoided cost calculation used in thereport are based on it.

(d) Load carrying capacity of cogenerated power

The existence of cogenerated power capable of "exporting" to the grid reduces the loss-of-load-probability of the latter. However, if its supply is completely stochastic, the percentage wise reduction in the LOLP is low, and little capacity will be saved in expansion plans. Thus, the degree to which cogenerated power capacity can effectively replace capacity in the CIE system, depends on its load carrying capacity (the "firmness" of capacity), that is, the seasonal and technical availability of the plant. In the palm oil industry, the cogenerated delivers power to the grid throughout the year subject only to the technical availability of the plant, which can be estimated at 80%. In the sugar industry, however, bagasse cogenerated surplus power is only available during the four to five months of the campaign season, that is from .... to .... . During the season, the technical availability of the plant may be as high as 95%, as routine maintenance can be scheduled to take place outside this period. But from the point of view of the CIE, the problem is that outside the campaign season the capacity is only available for internal consumption. This means, that the CIE needs to have capacity available to satisfy demand during this period.

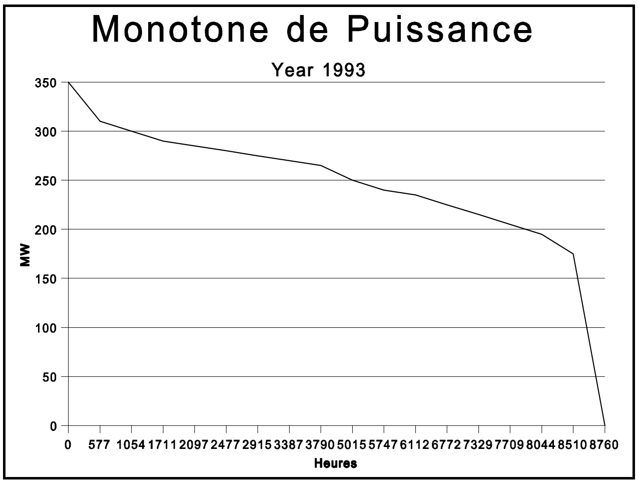
The traditional view would assign full capacity credit to the "firm" plant of the plam oil industry (the yearly availability factors of the CIE units and the palm oil units may be said to be equivalent); and zero capacity to the "non-firm" bagasse cogeneration plant. However, the absolute distinctions between firm and non-firm or between peak and non-peak are artificial in a world of uncertainty. Through a combination of plant failures and demand uncertainty there is a finite probability of demand being curtailed at any time of the day and year. With capacity subject to random failure, demand characteristics alone do not indicate when the system is under stress. Therefore, all time periods should be responsible for some portion of the capacity costs and corresponding credits to cogenerators.

The estimation of *peak responsibility* as a measure of the relative need for generating capacity at different time periods may be estimated according to the time period's contribution to the *annual expected unserved energy (EUE)*. The resulting graphical representation, when normalized so that the area under the curve equals unity, is known as the *capacity responsibility curve*. The probabilistic costing model of the CIE used in its system planning and the establishment of the merit order for hydropower plants can derive such a curve for CIE's system. But is was not made known to the mission.

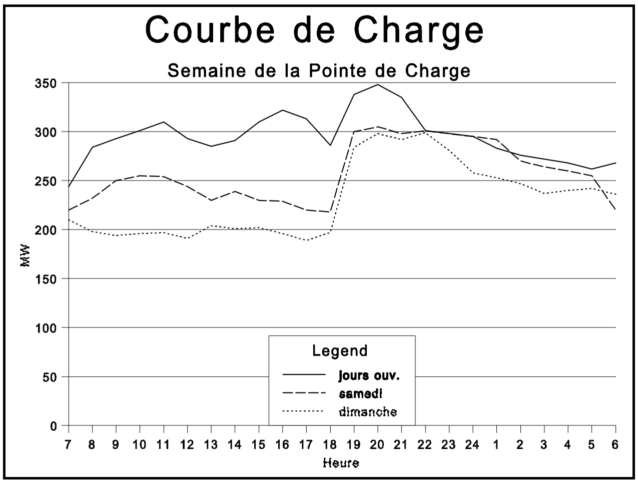
PART IV: THE POWER SECTOR IN COTE D'IVOIRE

Characteristics of Power Demand and Supply in Côte d'Ivoire

The *interconnected system* of the power sector in Côte d'Ivoire is served by an installed capacity of 904 MW. 604 MW are supplied by *hydro units* located in the interior of the country, while 300 MW are supplied by *thermal power plants* located near Abidjan which accounts for 70% of national demand. The *isolated grids* are served by diesel units totalling 4 MW.



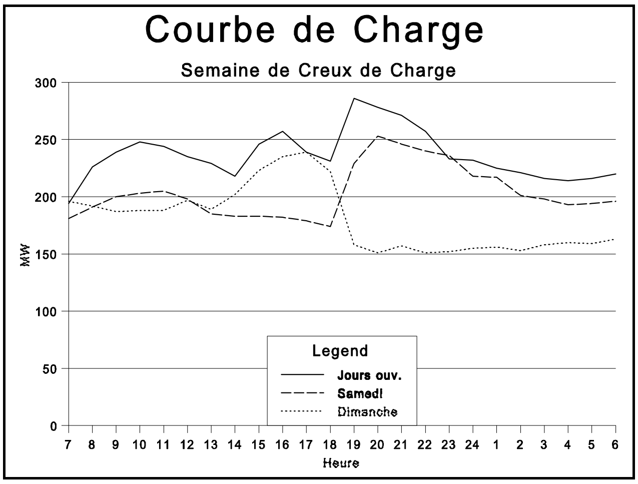
Peak demand in the interconnected system amounted to 350 MW in 1993. Demand has stagnated for a number of years due to the economic crisis. With installed capacity being more than double the level of peak demand, the power system is clearly not *capacity constraint*. However, due to water shortages caused by low precipitation during the 1980s, the system is *energy constraint*. Inspite of its large nominal capacity, hydro power could cover no more than 52% of electricity demand in 1991, the oil fired thermal power plants 30% (with the 86 MW coming from four gas turbines installed for operation during peak demand being operated almost in base load), while imports from the Volta River Authority (VRA) in Ghana covered the remaining 18% of demand.



Demand is marked by large daily (1:2) and seasonal differences (1:1.25) between the peak and trough demand. Since the utility's marginal unit in service may change hourly and seasonally, it is customary to define various rating periods for assignment of SRMCs and associated energy credits. In Côte d'Ivoire, the SIE operates with three rating periods:

* The *"Heures Creuses"* tariff for consumption between 24 hours and 7 hours
* The *"Heures Pointes"* tariff for consumption between 18.30 and 22 hours
* The "Heures Pleines" tariff for supplies outside these hours

The rational for the rating periods is evident from a look at the two daily load curves shown in figur 5 (from week 16 in 1993) and figur 6 (from week 34 in 1993).



The four tables in *Annex A* show the *economic loading order* for March 1994. It is seen that the thermal power units have the lowest economic cost of around 17 FCFA/kWh; that the first tranche of the Buyo hydropower plant is the next cheapest source of base load (apart from the rather insignificant contributions from SIR) with a cost of about 25 FCFA/kWh; that the gas turbines are the intermediate load plants (about 32 FCFA/kWh); whereas the remaining hydropower plants make up the peak load with costs ranging from 36 to 55 FCFA/kWh. That the gas turbines are lower cost that the hydropower plants, shows the impact of the water shortage - the cost of the hydropower units is a computed cost based on LOLP and an estimated cost of 400 FCFA per unserved kWh of industrial demand (supply interruptions caused by load shedding). As the LOLP depends on both demand and supply (availability of water) patterns, the computed cost of hydropower kWhs changes from week to week.

The Future Structure of the Power Sector and the Role of Cogeneration

The power sector is undergoing a major reorganization physically as well as administratively. Due to growing demand in Ghana, power imports from Ghana will go down, and the next major power project will be a boot project by a private consortium gas which will invest in the development of the Foxtrott gas field and a combined cycle power plant which is going to use gas from the field. As a result of this, the *mixed hydro-thermal power system* will change from being *predominantly hydro* to being *predominantly thermal* based.

PART V: COMPUTATION OF AVOIDED COST TARIFFS IN COTE D'IVOIRE

(a) Computation of SIE's Avoided Energy Costs

In Cote d'Ivoire this would be the fuel and operating costs of gas turbines, adjusted by the appropriate peak load factors at each voltage level.

Dividing through by (1-0.) and (1-0.) gives an "heures creuses" avoided energy cost of .. FCFA/kWh.

"heures Pleines" Avoided Energy Cost

Avoided energy costs in the "heures pleines" period were estimated in two ways:

(a) For a thermal-dominated, mixed hydro-thermal grid as in Côte d'Ivoire, extra generation requires extra use of water. The marginal energy cost is then the marginal value of water in the hydro dam. After Munasinghe (1990), the imputed value of water may be estimated as the slope of the interiod solution (least cost) line connecting the linear programming representations for baseload (steam) and peaking (gas turbine) energy.

(b) The CIE's marginal thermal plant during this period is ...

"Heures pointes" avoided energy costs

During the period, an increase in demand would be met by increased gas turbine generation. At times when an increase in demand would be met by increased generation from peaking hydro plant, the costs are the opportunity costs of hydro foregone at other times or of demand not served. On CIE's system, all such other times will be peak times and the opportunity cost will again be the cost of gas turbine generation.

Avoided peak energy economic costs are estimated in table .. at FCFA/kWh when adjusted for internal station consumption and an on-peak transmission loss reduction credit of .%.

(b) Estimation of CIE/EECI Capacity Costs

i) Costs of Bulk Purchase Method

The CIE purchases electricity supplies from the VRA in Ghana at a price of US$ 0.051/kWh, or 30.6 FCFA/kWh at an US$ exchange rate of 600. Adjusting for line losses, this gives an avoided cost of 36 FCFA/kWh.

The VRA contract does not distinguish between the provision of energy and capacity. Thus it cannot be used to compute a separate capacity credit. While the VRA purchases are the relevant alternative marginal source of suppply in the short term, they are not relevant for the evaluation of the cogeneration projects. Demand for power is increasing at more than 10% per year, and is expected to outstrip available supply in Ghana in about three years. Thus from 1997 onwards, VRA is no longer a potential source of supply except for emergency situations.

(b) Proxy Unit Method

(c) Long Run Average Incremental Method (LRAIC)

In the case of the Côte d'Ivoire, there are no current investments underway. "All plant" in the resource plan would refer to both stage 1 (the two gas turbines) and stage 2 (the steam plant) of the Foxtrott project. "Marginal investments" would refer to the annual cost of CIE peaking capacity only. They can be calculated as .. and ... FCFA/kw-year respectively, net of any fixed O&M charges and asjusted for their annual availability factor of 80 and 87% respectively.

(d) Component Method

The cost of gas turbine peaking capacity to the CIE is easily calculated from the figures of the Foxtrott project.

These figures should be adjusted by the availability factor of the capacity being installed, which by CEA norms for this type of plant is 87%. The marginal cost of capacity for CIE is thus calculated as .. FCFA/kW-year on a present value basis if construction phasing is not taken into account.

vi) True Short-run Marginal Cost Method

The *cost of loss of production* estimate used in the CIE's simulation model for system planning amounts to 400 FCFA/kWh.

<u>Estimation of L:</u>

In the component method methdology example, the lambda, L, for a gas turbine plant using HVO has been calculated as FCFA/kWh.

<u>Estimation of LOLE:</u>

The *loss of load expectation estimates* used by the CIE model are unknown to the mission.

But we will for illustrative reasons assume that the cumulative duration os loss of load amounts to 5% per year, that is, to 438 hours [14].

Result:

Substituting the estimated values into the marginality condition we obtain:

for OC = FCFA/kWh we have MECC = FCFA/kW-year
for OC = FFCFA/kWh we have MECC = FCFA/kW-year

Summary

The three estimates for the economic value of capacity to the CIE are summarised in table ..:

Table : CIE AVOIDED CAPACITY COSTS

Estimation Methodology	Value: FCFA/kW-year
LRAIC Gas Turbine Peaker Bulk Purchase True SRMC	

Load carrying capacity of cogenerated power

Table : Conversion of Capacity Credit into Energy Payment

	Annual capacity responsibility	Hours per year	Capacity payment of ..FCFA/kW rolled into FCFA/kWh payment
Heures pointes	60%		
Heures pleines	40%		

In the financial and economic calculations made by the mission team the latter method has been chosen. It is obviously relatively favourable to bagasse cogenerated power, as it is not

14 Note that "loss of load probability" LOLP = LOLE/period = LOLE/8760 hours when LOLP is expressed as the expected fraction of the time period when the system experiences loss of load. What should not be used as an indication of LOLP are engineering views which measure the fraction of days over a specified period in which daily peak demand exceeds available system capacity.

firm throughout the season.

Capacity credit

In the absence of more precise information, some simplifying qualified guesses have been made to show the principles of calculation. They can be changed by national experts during supplementary calculations:

* Concerning the *hourly capacity responsibility curve*, it has been assumed that the "heures creuses" have zero capacity responsibility from the side of production; that 40% of the capacity responsibility is attributable to the "heures pleines" and the 60% to the "heures pointes".

* Concerning the *annual capacity responsibility*, that is, the seasonality of EUE, it has been assumed that the dry season (the months ... to ...) accounts for 70% of the yearly capacity responsibility and the wet season for 30%.

For the palm oil industry, the annual capacity is of no interest, as the boilers are supposed to operate throughout the year. The sugar industry plants will only export power during the months of ... and ..., that is, during ..% of the dry season which mulitplied by the 95% availability factor provides the dry season availability of bagasse cogenerated power. The product of the dry season availability of the sugar plants and the seasonal capacity responsibility (..%*..%) is the estimated fraction of yearly avoided capacity costs which should be credited to bagasse cogenerated power in the Côte d'Ivoire.

The appropriate annual bagasse power capacity credit is ..% * FCFA (the peaker capacity cost, see justification below) = ..FCFA/kW-year; the palm oil industry capacity credit is 0.8 * ..FCFA = ... FCFA.

In the traditional two-part tariff structure, the above would be given as capacity payments to the two types of cogenerators. The alternative is to roll the capacity payments into the peak ("heures pointes") and shoulder ("heures pleines") energy prices based on the respective 40/60% contributions of EUE and the respective yearly hours of operation.

The sensitivity of the assumptions has been tested for the Toumangie palm oil project. The result is shown in the table below.

	Financial IRR	Economic IRR	Investors Current / Constant IRR
Base Case	9.6%	5.9%	81%/76%
Investment + 20%	4.9%	0.9%	36%/32%
No loss of fertilizer	10.4%	7.0%	88%/83%
O&M 10% of investment instead of 5%	1.0%	-5.3%	negative
No real increase in fuel price	7.3%	5.2%	74% / 69%