Report 09/01

Cost structure and tariff study for Uganda

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Confidential

Cost structure and tariff study for Uganda

Commissioned by Electricity Regulatory Authority

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List of abbreviations

AGP	Average generation price
ATP	Average transmission price
BSC	Bulk supply cost
BST	Bulk supply tariff
Disco	Distribution company
ERA	Electricity regulatory authority
Genco	Generation company
GoU	Government of Uganda
HCP	Hourly capacity price
HV	High voltage
LV	Low voltage
MAC	Maximum available capacity
MEMD	Ministry of Energy and Minerals Development
MGC	Monthly generation cost
MV	Medium voltage
OCV	Operative Capacity Value
REV	The revised demand forecast used by URU/Transaction Advisors in the tariff model
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
Transco	Transmission company
UEB	Uganda Electricity Board
URU	Utility reform unit
WACC	Weighted average cost of capital

Executive summary

Abstract

We have examined proposals put forward for the setting and regulation of electricity prices in Uganda. The proposals relate to the overall approach to regulation as well as methods for calculating revenue requirement at each level in the industry, allocating these requirements to customer groups and structuring these requirements as tariffs. Our recommendations focus on advice to the electricity regulator in Uganda on how these proposals should be amended before being accepted for implementation.

Background

ECON Centre for Economic Analysis was appointed to undertake the project "Cost Structure and Tariff Study for Uganda". The primary objective of the Project is to support the Ugandan Electricity Regulatory Authority (ERA) in setting tariff controls for the electricity industry in Uganda. The project has been financed by Norwegian Agency for Development cooperation (NORAD) through the Norwegian Water resources and Energy Directorate (NVE).

There is a certain urgency in finalising the regulatory approach and pricing system since existing generation and distribution assets will be leased to private operators. The bidding process for these concessions is expected to take place during the first half of 2001.

Conclusions and recommendations

The recommendations made during the course of this review are collated and summarised below. The minutes of a meeting held in Kampala to discuss these recommendations are included as an Annex to the report.

Regulatory approach

The choice of regulatory system will depend, to a certain extent, on the commitments made in the concessioning process. Since this process has yet to be designed, we suggest that the ERA interact with the Transaction Advisors and the investment bankers, seeking to devise a concessioning approach and regulatory system that appropriately balances risks with incentives. While it is anticipated that the ERA may be required to guarantee a certain return on investment, the ERA should seek to introduce incentives in the price setting process that that operating and investment efficiency is continually improved.

It has been proposed that prices will first be set for 24 months, and thereafter reviews will be held every 36 months. We recommend that this approach be adopted by the ERA.

In between price reviews, prices will be indexed. It has been proposed that a portion of the price will be indexed to the dollar exchange rate and prices adjusted monthly. We suggest that:

- The Shilling component of the tariff should be indexed to Ugandan inflation, and adjustments made on an annual basis.
- The US dollar component of the tariff should not be indexed to US inflation, or any other inflation rate.
- The proportion of the tariff indexed to US dollar should be set at each price review, and not updated annually.

While price reviews will be conducted every 36 months, it appears implicit in the proposals (if a specific rate of return is guaranteed) that prices will be reset annually in response to actual investment levels. If and when the ERA moves to introduce additional incentive elements into the regulatory system, then this automatic indexing to actual investment would fall away and prices should then be set for the three year period based on anticipated investment.

Incentive targets: losses and allowances for operating cost

We recommend that the distribution loss targets included in the tariff model be reset in light of losses experienced in 2000. These revised figures should be used to determine 2001 prices, and as indicative targets in providing information to potential concessionaires. The ERA should reserve the right to reset these targets at each 36 month price control.

With respect to targets for distribution operating costs, we recommend that either the Transaction Advisors revise the gains in the light of anticipated new connections, or inform potential operators that the current figures will be revised to take account of system expansion from 2005 onwards.

The ERA should initiate a comparative study of distribution costs in order to inform the price review to be undertaken in 2002.

Asset values, investment and lease fees

Subject to the Transaction Advisors clarifying the discrepancy between OCV figures in the Lahmeyer report and replacement cost figures used in the pricing model, we recommend that the ERA accept the asset values calculated by Lahmeyer.

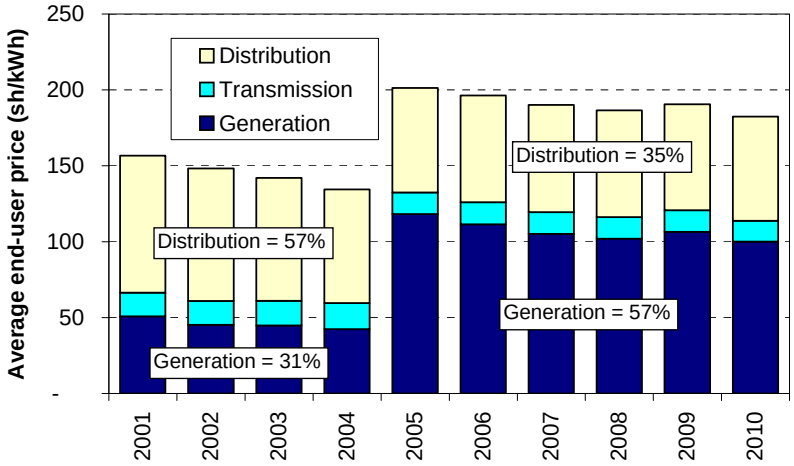
We recommend that ERA adopt the Base rehabilitation investment figures (2001 to 2005) produced by the Transaction Advisors, subject to clarification of the differences in numbers presented in the Lahmeyer report and the figures in the tariff model.

The build-out investment figures for 2005 onwards should be used for indicative pricing, but that the approximate nature of the figures be made known to investors in bidding documents released early 2001. Further, the distribution licence should contain a requirement that the distribution concessionaire prepare a system expansion plan for the period 2005 to 2010.

We recommend that ERA require the GoU to clarify what lease should be charged for generation and distribution assets as soon as possible. The lowest acceptable lease payment will be that required to service UEB's restructured debt.

Average prices

The figure below summarises the trends in average prices. It can be seen that average prices in the early years are around 140-150 sh/kWh. In 2000 they increase to 200 sh/kWh due to the additional costs of Bujagali. Thereafter they decline again as demand increases.



Average generation prices

The generation element of the end-user price starts out at around 50sh/kWh, declining to around 40sh/kWh by 2004. It then increases dramatically in 2005 to 120sh/kWh as a result of the additional costs of Bujagali. Thereafter, prices decline steadily to around 100sh/kWh as load grows.

While the underlying increase in costs from 2005 onwards cannot be avoided, it is possible to phase in the price increase over several years and eliminate the price shock followed by subsequent reductions. We recommend that the Transco introduce increased power supply prices prior to 2005, and not set power supply prices any higher than their expected long-term trend. Revenue from price increases in 2003 and 2004 as well as profits from exports should be used to finance this mechanism. Transco should be required to develop the mechanism required to implement this proposal during the course of 2001.

In the case of other, less predictable, causes of price instability, the ERA should signal that this is an issue to discuss with the distribution concessionaire, and that

the ERA is willing to consider any proposals that the concessionaire may wish to make with regard to improving stability of prices.

Average transmission prices

Transmission prices account for a small portion of end-user prices – only 8-12 per cent. Prices increase slightly over the period 2000 to 2004 as a result of increased investment in preparation for Bujagali. Thereafter, prices decrease as load increases.

The revenue requirement for transmission is calculated as operating costs plus depreciation plus interest on existing debt, thus implicitly assuming that new investment is financed at zero interest. To correct this, we recommend the transmission company be allowed a return on capital in calculating its revenue requirement.

Average distribution prices

Average distribution prices are a function of the calculation of the revenue requirement of distribution. The revenue requirement is made up of:

- ***Depreciation:*** We recommend that UEB provide justification for the use of a 3.5 per cent depreciation rate for distribution assets in its tariff application.
- ***Return on assets:*** For indicative pricing purposes, we recommend that the ERA use an after-tax return level of 15 per cent, until such time as the bidding process results in a specific return.
- ***Operating costs:*** Current levels appear reasonable, but the ERA should initiate a distribution cost study to assist in setting efficiency gain targets for the next price review.
- ***Lease fee:*** As discussed above, the determination of the lease fee is a matter for the GoU, although the ERA should rightly limit the return that the state should earn on its assets.
- ***Taxation:*** We recommend that the pricing model should be adapted to incorporate a suitable level of gearing (i.e. ratio of debt to assets), and the tax calculations adjusted accordingly.

Price structure for generation

While provisionally accepting the proposed method for calculating payments to the Genco, the ERA should express doubts about the workability of the mechanism and the potential for manipulating determination of availability and capability. The implementation of the system should be monitored with a view to amending it, as suggested in section 5.1, in order to reduce the level of oversight and validation required.

For the 2001 price calculations, the proposed method should be revised in the following ways:

- In calculating the Genco revenue requirement for 2001, depreciation plus return on assets/interest charges should be replaced by the expected lease fee for 2002. In fact this approach is consistent with the proposed approach to setting the lease fee, even if the level has not yet been determined.
- Introduce a target availability in the calculation of the Hourly Capacity Price.
- Correctly calculate the payment during instances of reduced availability.

Structure of bulk sales tariff

The method for calculating the BST for 2001 should be accepted with the following conditions:

- The revenue requirement for UEB Transmission is altered to allow UEB Transmission a return on capital.
- There is some justification for the 120:100 ratio of peak to shoulder prices.
- The load profile used to determine off-peak energy consumption is documented.
- The calculation of the Bulk Supply Costs should use a rolling average of export volumes rather than the previous month's export volumes. Alternatively, the Disco should introduce a price stabilising mechanism in its charges to end-users.
- The error in the description of the tariff relating to the calculation of the Bulk Supply Costs should be corrected.

Further, it should be noted that the method for determining the BST will be changed in future in order to implement the gradual increase in prices to accommodate the additional costs of Bujagali, as well as considering the possibility of a maximum demand charge component to the tariff.

End-user price structures

The method for calculating end-user prices for 2001 should be accepted subject to the following conditions:

- The calculation of asset costs (depreciation plus interest charges) should be replaced with the anticipated lease fee for 2002 (see recommendation on generation revenue requirement).
- The existing cross-subsidies in the tariff calculations (from customers paying capacity charges to those not paying capacity charges) should be removed.
- Should the ERA decided to cap domestic (code 10) prices, then any revenue shortfall should be spread across other customer class in proportion to their energy consumption.
- The ratio used to split the overall revenue requirement between MV and LV customers (65:35) should be justified or amended.

- The load profiles used to determine consumption per customer group in each load period should be documented.
- The 20 per cent rural surcharge should be removed.

Connection fees, life-line tariffs and quality of supply

We recommend that the UEB seek to develop and implement a new connection fee policy broadly along the lines described in section 7.4 in collaboration with the new concessionaire, and in the meantime UEB's existing connection fee policy should be applied.

Given the high level of poverty in Uganda, and the high price increase which low income consumers face as a result of the proposed tariffs, we recommend that the ERA exercise some caution in removing life-line tariffs. We suggest that the ERA consult more broadly with stakeholders in the industry, and so understand better the implications of removing or phasing out the existing inclining block system. This consultation should occur during the public hearing on the 2001 price increase.

We recommend that ERA should consider the introduction of a Quality of Service Penalty/Reward Indicator that would be used be used to regulate the quality of supply to customers. Also ERA should indicate a willingness to consider linking electricity prices in rural areas to lower supply quality standards, as a way of bringing down costs and hence prices.

Priorities facing ERA

Task	**Timeframe**
Finalise the tariffs for 2001/2	Immediate
Draft a description of the regulatory framework, including price indexing between reviews, in consultation with URU	Immediate
Consult with stakeholders regarding the removal or reformulation of life-line tariffs.	During 2001
Require and assist UEB Transmission to develop a new approach to setting the BST to phase-in of the additional costs of Bujagali.	During 2001
Initiate comparative study on the costs of distribution.	During 2001/2002
Develop QSI, targets & penalties in consultation with distribution concessionaire	During 2001/2002
Determine the terms of reference, in consultation with the MEMD, for the distribution concessionaire's system expansion	During 2001/2002
Develop a connection fee policy in collaboration with the successful distribution concessionaire.	During 2001/2002

1 Introduction

ECON Centre for Economic Analysis was appointed to undertake the project "Cost Structure and Tariff Study for Uganda" (hereafter referred to as the Project). The primary objective of the Project is to support the Ugandan Electricity Regulatory Authority (ERA) in setting tariff controls for the electricity industry in Uganda. The project has been financed by Norwegian Agency for Development cooperation (NORAD) through the Norwegian Water resources and Energy Directorate (NVE).

The Project commenced on 1 December 2000, and is to be completed by end January 2001 in time for the release of bidding documents to potential operators of UEB generation and distribution assets. The Project is intended to review the tariff work undertaken by the Transaction Advisors to the Utility Reform Unit (URU), and to advise the ERA on how to respond to the proposals put forward.

Focus of the Project

While the ERA will be required to license and regulate generation, transmission and distribution elements of the industry, it has been decided that the Project should focus on end-user price controls. The reasons for this are:

- Generation is to be regulated in a "light-handed" manner, and the Project should focus on the implications for end users of the proposed power sales agreement between UEB Generation and UEB Transmission, and the Bujagali contract.
- Transmission is not to be privatised, and so there is no urgency to come to price controls at this stage. The ERA will address transmission prices in more detail at a later stage, but the Project should examine the implications of transmission costs for end-user prices.
- Distribution and retail are the key elements that ERA is required to regulate. Further, the regulatory approach as well as price controls for the first two years should be determined before the bidding process for the distribution concession is undertaken.

Structure of report

The report is structured in eight chapters:

- Chapter 2 looks at the broad regulatory framework, including the periodic nature of price reviews, price indexing and the nature of incentives in the price control system.
- Chapter 3 examines the current demand situation and reviews the different load forecasts prepared for Uganda. It identifies the load forecasts that will be used by the Project for examining medium-term price trends.
- Chapter 4 deals with asset valuation and investment projections. We comment on the methodology employed by the Transaction Advisors and the way in which the results have been used in the price modelling work. We also look at the question of the lease fee for UEB generation and distribution assets.
- Chapter 5 examines generation and transmission prices. We look at the proposals put forward for tariff structures – both the tariff that the generation concessionaire will charge the transmission company and the tariff that the transmission company will charge the distribution concessionaire. In addition, we examine the implications of these tariffs for end-user prices, looking at the average generation and transmission components of end-user prices.
- Chapter 6 deals with distribution and retail charges, and looks in some detail at the way in which the revenue requirement for distribution is calculated. We also translate this into a unit cost, i.e. an average distribution price, and examine the implications of investment projections for average distribution prices.
- Chapter 7 looks at end-user price structures and reviews the proposals put forward by the Transaction Advisors, as encapsulated in the tariff model provided to us. In addition, the chapter provides our views on rural tariffs, connection fees, lifeline tariffs and pricing concerns with quality of supply.
- Finally, Chapter 8 summarises our conclusions and recommendations, and presents the priorities and tasks facing the ERA. The chapter also recommends a strategy for dealing with the 2001 price application.

2 Regulatory approach

2.1 Price controls

Proposed approach

The proposals as they stand can be summarised as follows (details are presented in the document "2001 UEB Tariff Restructuring"):

- ***UEB Generation – Genco –*** in 2001 will sell power to UEB Transmission – Transco – through a Capacity Price, i.e. a fee expressed as shillings per MW. Essentially, for each MW made available – whether dispatched or not – Transco will pay Genco an amount based on the Capacity Price. Details of this arrangement are presented and discussed in section 5.1.

  From 2002 onwards, we presume that the power sales agreement to be signed between the generation concessionaire and Transco will reflect a similar arrangement, where the Capacity Charge will reflect an appropriate rate of return on investment for the generation concessionaire.

- ***Transco will sell power to UEB Distribution - Disco***, and will set a Bulk Supply Tariff (BST) as a unit energy charge (shillings per kWh) with peak, shoulder and off-peak components. The BST will combine the costs of payments to Genco, transmission services, system operation and transmission losses. Details of this arrangement are presented and discussed in section 5.3.

  From 2002, we presume that the power sales agreement to be signed between the distribution concessionaire and Transco will reflect a tariff calculated in a similar manner.

- ***Disco will set end-user tariffs*** so that the costs of generation and transmission are passed through to end-users, and so distribution and retail prices are reflective of costs. A price formula has been proposed which combines the different cost elements into an average price per consumer category. The Transaction Advisors have proposed specific end-user tariffs for 2001.

  Again, from 2002 we presume that the distribution concessionaire will be required to offer end-use tariffs calculated in the same manner.

Regulation and the award of concessions

Variables in the price calculations

The uncertainties in the pricing approach, at least for beyond 2001, lies in certain parameters underlying the calculation of the revenue requirements:

- What rate of return should be used in calculating the return on concessionaire's investment?
- What level of investment should be used in the price calculations?
- What lease payment does the Government of Uganda (GoU) require for its assets?

Each of these elements may be linked to the design of the concessioning process, which impacts on the form of regulation. The basic options can be briefly stated below.

A guaranteed rate of return

One option, preferred by the Transaction Advisors, is for the GoU and/or the ERA to guarantee a certain rate of return on investment. Part of this guarantee will be a certain approach to indexing of prices to inflation and foreign exchange, as well as allowances for operating costs, and targets for loss reduction and operating efficiency gains.

In this scenario, it seems sensible for the potential operators to compete for the concessions on their required rate of return, together with a commitment to a target or minimum level of investment. The bidder with the lowest requirement will be successful, and this requirement will thereafter be used in price calculations. Prices will then be based on the actual investments made by the concessionaire, with the ERA having to exercise regulatory scrutiny of the prudence of investments.

This option effectively commits the ERA to a "rate of return" type regulatory system, with incentive elements largely restricted to targets on losses and efficiency gains on operational costs.

This approach reduces the risk for investors, but also reduces ERA's ability to include incentive elements in the regulatory system. There will be very few incentives for investment efficiency, and the ERA will be required to monitor investment planning by the concessionaire, possibly on an annual basis. However, by making the rate of return explicit and guaranteed, the updating of prices becomes relatively straight-forward. Regulatory risk is reduced considerably.

Incentive regulation through price caps

An alternative approach is for the ERA to itself identify what an appropriate target rate of return should be. Then, accounting for expected investment, operating costs, consumption, losses and so on, the ERA will be able to set a price cap for a certain time period.

In this case, it would be likely that potential operators bid on the level of lease and/or investment they are willing to make given the price level set by ERA. The bidder with the highest investment/lease commitments would be successful. In this way, while the ERA calculates prices based on a ***target rate of return***, the ***actual return*** received by the concessionaire will be a function of his investment and lease commitments. If he bids an investment/lease below the level used by the ERA in price calculations, he is effectively asking for a higher rate of return than the one used by ERA in the price calculations, and *vice versa*.

This approach increases regulatory risk for investors. Given that the initial price control will only cover a limited amount of time, investors will be reluctant to commit to investments beyond that timeframe. Even if ERA commits to continue using the same rate of return for price calculations for the duration of the concession, the concessionaire will be uncertain what medium to long term investment commitments will be required by the ERA. Hence there will be uncertainty in what the concessionaire's actual return will be in the medium term.

However, if the ERA adopts this approach it will effectively be setting prices based on its own estimate of the investment required to meet certain performance targets. If the concessionaire can meet these targets at lower cost, then the gain (during the price period) can be captured by the concessionaire. This approach thus has powerful incentives to improve investment efficiency. While these efficiency gains will be captured by the investor for the duration of the price period, the ERA may "claw back" gains for customers in the subsequent price reviews.

The implications for ERA

In summary,

- A rate-of-return style regulatory system will be linked to a concessioning process in which bidders compete on their required rate of return, and
- A price-cap style regulatory system will be linked to a concessioning process in which bidders compete on investment/lease payments.

The former approach contains less regulatory risk, but also reduces the ERA's ability to include incentives in regulation. The latter approach increases regulatory risk, but improves incentives.

While a regulator would typically prefer a regulatory system with greater incentives, such a system is also more demanding on regulatory competence. Incentive regulation may only be a realistic option once the ERA has built the required capabilities and established a track record for independence.

Further, from a policy perspective, the GoU is placing great importance on successfully establishing the concessions and obtaining commitment to the investment necessary to accommodate Bujagali. The Transaction Advisors appear to view the country risks in Uganda as so great that any additional regulatory risk may jeopardise the process, or result in very poor terms being bid by potential operators.

The two alternatives presented above are, to a certain extent, extremes. In practice, it is possible to include greater incentives in a rate-of-return style regulation. For example, at a certain stage the ERA could switch to basing prices on projected rather than actual investment. The concessionaire then has incentive to achieve the performance targets with lower investment than projected, while the original guarantee on minimum return still holds. Through periodic price reviews, the efficiency gains resulting from such incentives can be shared between investors and customers.

Recommendation

The issue is difficult to resolve without the advice of the investment bankers, who are yet to recommend the most appropriate process for awarding the concessions. Should the investment bankers concur with the Transaction Advisors, i.e. that a guaranteed rate of return on investment is required, the ERA will effectively be asked to implement rate of return regulation.

Our view is that:

- In principle, ERA's first preference should be an incentive-based regulatory system. However, it may be impractical to implement such an approach in the early years due to limited regulatory capabilities.
- For this reason, and if this approach imposes excessive risks in the Ugandan context, the second preference should be a rate-of-return system, with the intention to introduce investment incentives at the third price review (i.e. for 2006-8 prices).
- The third preference is a rate-of-return regulatory system with a commitment to a specific rate to be used throughout the concession period.

We recommend that the ERA interact with the Transaction Advisors and the investment bankers, seeking to devise a concessioning approach and regulatory system that appropriately balances risks with incentives.

2.2 Price reviews and price indexing

Proposals

The proposals at present are that the initial price control to be set for 2001 will hold for 24 months, and thereafter will be reset every 36 months. We presume that the proposal is that the periodic reviews will reset the parameters used for calculating the Capacity Price, the BST and the end-user tariffs, while the overall framework for arriving at tariffs will remain the same.

Effectively this option allows the successful concessionaires a year to familiarise themselves before a new tariff control is set. In this way, the ERA and the concessionaire will have the opportunity to interact in the setting of prices for 2002 and beyond. This includes setting operational efficiency targets, loss reduction targets and investment commitments for the coming years (if not already fixed in the concessioning process).

In between reviews, it is proposed that prices will be indexed. The proposal is for a portion of the price to be indexed to the Shilling/Dollar exchange rate, and to be reset every month.

The portion of the price indexed to the Dollar is proposed to include everything except the operating and maintenance costs. The ratios as contained in the tariff model are presented in Table 2.1. The increase in 2005 is due to the Bujagali contract which is set in US dollar terms.

Table 2.1 Proportion of costs indexed to US dollar exchange rate

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Generation	77%	76%	76%	76%	94%	94%	95%	95%	95%	95%
Transmission	64%	65%	67%	70%	72%	73%	73%	73%	73%	72%
Distribution	32%	34%	35%	36%	23%	25%	26%	28%	28%	30%
Total	56%	56%	58%	59%	73%	74%	74%	75%	76%	77%

Comment

One area of uncertainty in the proposal as it stands is the question of indexing prices to inflation. Although not explicitly mentioned, we presume that the non-dollar portion of the price will be indexed to Ugandan inflation. The uncertainties to be resolved in this issue is what index for inflation should be used, and how frequently adjustments should be made.

Secondly, it is not explicit whether the US dollar portion of the tariff should be linked to both shilling/US$ exchange rates as well as US inflation. The Transaction Advisors suggested in discussion that the potential operators may request such an adjustment in their proposals or in subsequent negotiations.

It is our view that it is inappropriate to index the US dollar portion of the tariff to US inflation. The reason for this is that the revenue requirement calculations, as structured in the tariff model, are effectively based on a nominal return on investment. As long as the return is based on actual investment made or expected (which reflects any inflation in international prices), then there is no need to adjust for inflation rates in the price indexing system.

Thirdly, there is a question of price adjustments in response to actual investment levels where a specific rate of return is guaranteed. It is not explicit in the proposals whether prices would be adjusted annually to reflect any deviations from expected investment, or whether adjustments would only be made at the 36 month intervals. In the latter case, prices for the next period would have to be increased/decreased to reflect any under/over recovery from the previous price period.

Recommendations

We recommend that:

> ***The Shilling component of the tariff should be indexed to Ugandan inflation, and that consequent price adjustments should be made on an annual basis. The Transaction Advisors should be requested by URU to propose an appropriate index to use.***
>
> ***The US dollar component of the tariff should not be indexed to US inflation, or any other inflation rate.***
>
> ***For simplicity and clarity, the proportion of the tariff indexed to US dollar should be set at each price review, and not updated annually.***
>
> ***If a specific rate of return is guaranteed, price adjustments should be made annually in response to the actual investment (i.e. one year lag with reconciliation adjustments). If and when the ERA moves to introduce additional incentive elements into the regulatory system, then this automatic indexing to actual investment would fall away.***

2.3 Price stability

In the proposals as they stand, there is the risk that there will be considerable instability in prices. Instability arises from the following:

- Foreign exchange risks are passed through to customers, with price adjustments every month. A sudden devaluation in the shilling will result in a price shock.
- As will be explored in more detail in section 5.1, the costs associated with Bujagali are also passed through to end-users. Consequently, it is likely that there will be a large increase in power supply prices in 2005, to be followed by steady price decreases over the coming years as demand grows.
- Sudden improvements in availability at Nalubale (formerly Owen Falls) will also result in higher payments to the Genco, and so will impact on the BST.
- At present exports vary considerably from month to month. As will be discussed in section 5.4, this will cause instability in the level of the BST from month to month.
- Hydrology risks are also passed through to end-users. Price calculations have been based on average river flows – annual variations may result in price variations where the system is energy constrained.
- Lastly, the risks of lower than expected demand growth will also impact prices. However, this is not likely to lead to sudden price shocks.

While all players in the industry, including customers, benefit from price stability, there is a cost associated with mechanisms to provide stability. If the cost

structure changes suddenly, and prices are to respond more slowly to this change, there will be a need to finance such a transition, with associated costs and risks.

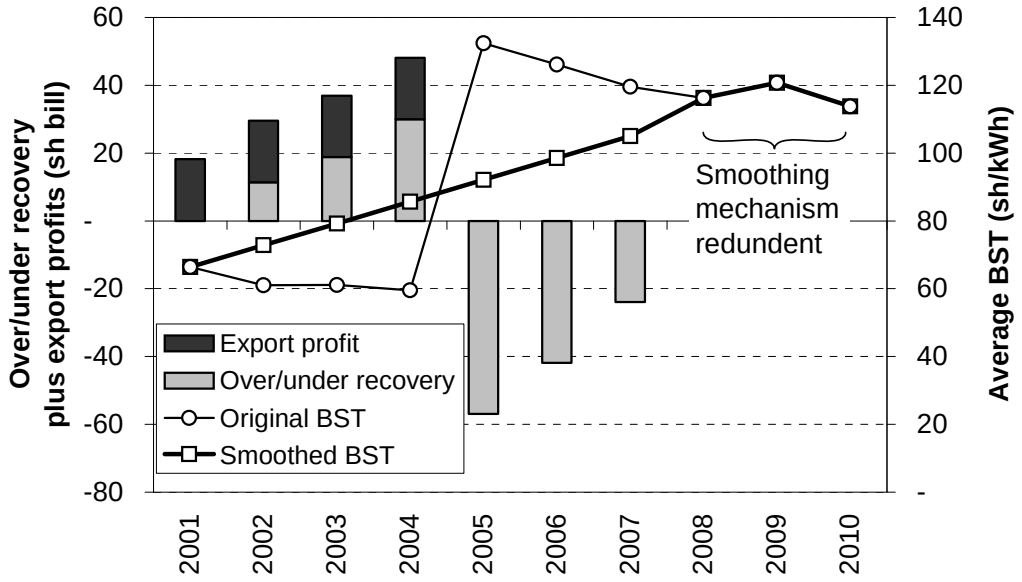
The Transaction Advisors proposals at present do not include any mechanisms to support price stability, with the exception to a reference to "a normalisation adjustment" to distribution tariffs where generation availability changes significantly. There are at present no details on what this adjustment entails, except that it is to be "developed and agreed with ERA".

Recommendations

It is useful to distinguish between:

- Price effects that are in response to predictable step changes in cost structure (e.g. Bujagali)
- Price effects that are a result of an underlying instability or seasonal variation in a particular variable (e.g. monthly variations in exports)
- Price effects that are in response to unpredictable step changes in cost structure (e.g. sudden shilling depreciation)

Figure 2.1 Smoothing the price impacts of Bujagali



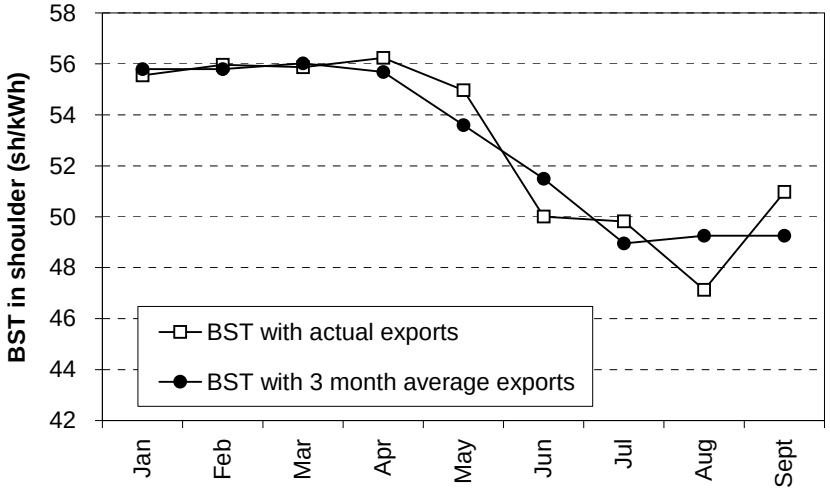
Recommendations

In the case of price increases associated with Bujagali, we recommend that the Transco introduce increased power supply prices prior to 2005, and not set power supply prices any higher than their expected long-term trend. Revenue from price increases in 2003 and 2004 as well as profits from exports can be used to finance this mechanism. This is illustrated in the figure below. Transco should be required to develop the mechanism required to implement this proposal during the course of 2001.

In the case of price variations associated with instability in monthly export volumes, the Transaction Advisors should be requested to modify the algorithm for calculation of the BST to reflect a rolling average of export levels rather than the previous month's exports. Alternatively, the Disco should introduce a smoothing mechanism into the way it sets end-user power supply prices.

In the case of other, less predictable, causes of price instability, the ERA should signal that this is an issue to discuss with the distribution concessionaire, and that the ERA is willing to consider any proposals that the concessionaire may wish to make with regard to improving stability of prices.

Figure 2.2 Smoothing the price effects of variation in exports



2.4 Loss reduction and efficiency targets

Two areas of incentives included in the current proposals are targets related to loss reduction and efficiency gains in operating costs.

Proposals

The tariff model includes estimates for these parameters, as shown in Table 2.2.

Table 2.2 Incentive targets

	Losses (% of energy)				**Change in operating expenses**		
	Trans-mission technical	Dist-ribution technical	Distribu-tion non-technical	Bad-debts	Gen-eration	Trans-mission	Dist-ribution
2000	5.0%	15%	20.0%	6.9%			
2001	4.8%	14%	17.6%	6.9%	5.0%*	5.0%*	5.0%*
2002	4.6%	13%	15.2%	6.1%	0.0%	0.0%	0.0%
2003	4.4%	12%	12.8%	5.3%	-5.0%	-2.5%	-5.0%
2004	4.2%	11%	10.4%	4.6%	-4.0%	-2.0%	-4.0%
2005	4.0%	10%	8.0%	3.8%	-3.2%	-1.6%	-3.2%
2006	4.0%	10%	7.6%	3.0%	-2.6%	-1.3%	-2.6%
2007	4.0%	10%	7.2%	3.0%	-2.0%	-1.0%	-2.0%
2008	4.0%	10%	6.8%	3.0%	-2.0%	-1.0%	-2.0%
2009	4.0%	10%	6.4%	3.0%	-2.0%	-1.0%	-2.0%
2010	4.0%	10%	6.0%	3.0%	-2.0%	-1.0%	-2.0%

* This is to reflect an inflation adjustment to 2001 terms, net of efficiency gains, from 2000 to 2001.

Losses

UEB's total losses in 1999 were almost 40 per cent of generation, and close to 30 per cent in 2000. The loss breakdown is estimated at 0.1 per cent for generation, 5 per cent for transmission and 35 per cent for distribution of which 15 per cent is estimated to be technical losses and 20 per cent commercial losses (including theft and other non-metered consumption). This level of distribution losses is very high even in the context of other similar vertically integrated state-owned electricity utilities in Africa, as may be seen from comparative statistics for other African utilities in the table below.

Table 2.3 Total losses in selected African countries

Country	Total Losses
Botswana	9.5%
Ghana (ECGonly)	26.0%
Kenya	18.4%
Malawi	17.0%
Mozambique	15.1%
South Africa	12.3%
Swaziland	14.5%
Tanzania	11.2%
Uganda	34.5%
Zambia	9.6%*
Zimbabwe	10.8%

* The figures for Zambia is low due to the high proportion of energy consumed in the copper industry.

One explanation for the high level of losses in Uganda is the relatively low proportion of large industrial consumers supplied a high voltage. However, one would still not expect losses to exceed the following levels:

- Transmission 2-4%
- Distribution (including both technical and commercial)..... 6-10%
- Total losses (excluding generation losses) 8-14%

As has already been discussed above, commercial losses in Uganda are very high at present. In principle, this component of losses is the easiest to reduce, since it can normally be achieved with relatively low capital investment. In well managed utilities in industrialised countries, commercial losses would generally be expected to be less than 1 per cent. However, experience shows that in developing countries, even in well managed utilities, non technical losses tend to be higher, say 2-3 per cent.

Comment on loss targets

The transmission loss factors appear reasonable, but it should be possible to reduce them to say 2-3 per cent, given adequate investment in new capacity. We support the proposal that the ERA should set target loss factors and provide incentives to meet these that would encourage investment.

Loss targets in distribution appear generous. Demand and supply data for 2000 given to us by UEB indicate that total losses for 2000 will be in the region of 28-30 per cent. The total loss target for 2001 is 35 per cent of energy generated - considerably higher than losses in 2000.

We believe that the distribution technical loss factors are at the high end of what could be expected given the proposed investment in rehabilitation of the distribution network over the period to 2005. The assumption is that once the

rehabilitation is completed, the technical losses will stabilise at 10 per cent. This, in turn, assumes that there will be sufficient investment in the network to meet load growth from new connections and increases in consumption of existing consumers. While this may be reasonable, we believe it may not provide adequate incentive to the Disco to invest in the network. The ERA may wish to consider the introduction of stricter distribution loss targets to incentivise investment in the network to reduce technical losses below 10 per cent.

The proposed commercial loss factors indicate a reduction from 20 per cent to 8 per cent by 2005, falling to 6 per cent in 2010 and 4 per cent by 2015. Again, it should be possible for the Disco to meet, or better these figures. There is a strong incentive for the Disco to reduce commercial losses provided it is allowed by the ERA to share the benefits with consumers.

At present UEB collects only about 81 per cent of revenue billed. It should be possible to substantially improve the collection rate by the implementation of new systems, updating of the consumer register, prompt disconnection for non-payment, etc. These improvements should be achievable within a comparatively short timescale, e.g. 1-2 years. Incentives to achieve improvements in the collection rate are similar to those for the reduction of distribution commercial losses and the lease arrangements should be structured to ensure such incentives are included.

Comment on operating costs

In the case of distribution costs, there is no recognition that costs may in fact increase with increasing numbers of connections from 2005 onwards. The marginal operating and maintenance costs of new connections is difficult to determine, and to a large extent depends on whether new customers are connecting to existing grids and supply areas, or whether new supply areas are being opened up. The latter may imply significant new customer service costs.

Recommendations

With the exception of distribution costs from 2005 onwards, these figures appear reasonable to us. However, the ERA should note that the figures need not necessarily represent appropriate regulatory targets for the companies.

While the matter does not significantly affect the 2001/2 price control, the ERA should devise an appropriate strategy for setting regulatory targets for losses and efficiency gains for 2004 onwards. This may require some benchmarking and dialogue with the concessionaires.

We recommend that the distribution loss targets included in the tariff model, and used to set the 2001 tariff, be reset in light of losses experienced in 2000. These revised figures should be used to determine 2001 prices, and as indicative targets in providing information to potential concessionaires. The ERA should reserve the right to reset these targets at each 36 month price control. ***(Continues next page…)***

With respect to targets for distribution operating costs, we recommend that either the Transaction Advisors revise the gains in the light of anticipated new connections, or inform potential operators that the current figures will be revised to take account of system expansion from 2005 onwards.

The ERA should initiate a comparative study of distribution costs in order to inform the price review to be undertaken in 2002.

3 Demand & export scenarios

3.1 Current status of demand

UEB produce monthly and annual statistics on supply and demand. There have been system capacity constraints, so that supply is less than unconstrained demand at peak times. Load shedding takes place during peak hours, and export is constrained.

Power

Installed capacity is reported in Table 3.1. This is likely to be more than the actual capacity due to low availability at Nalubale (formerly Owen Falls). The 80 MW increase in installed capacity reported in the table is the two 40 MW units installed at Kiira (formerly Owen Falls Extension) in June and August 2000 respectively.

Table 3.1 Installed capacity, MW

	December 1999	**September 2000**
Nalubale and Kiira	180	260
Maziba	1	1
Thermal	2	2
Total	183	263

Source: UEB Operational Statistics, September 2000.

Maximum demand (unconstrained) is established by UEB using load flow studies, and reported to be 260 MW, including exports, for both 1999 and 2000[1]. A comparison of maximum demand with installed capacity in 1999, shows at least 77 MW unserved demand at peak hours. Installed capacity is just sufficient to meet maximum demand from September 2000, but restrictions on generation availability still causes some load-shedding at peak hours.

The main export agreement is with Kenya. UEB's contractual obligations are given in Table 3.2. As UEB is not obliged to export at peak hours, exports should

[1] Source: UEB Operational Statistics 1999 and September 2000.

be non-coincident with Uganda peak demand. Nevertheless, UEB statistics show cases where Ugandan demand is load shed while exports continue.[2]

Table 3.2 UEB export obligations to Kenya, MW

Time-period	Export obligation
11 pm to 5 am	30
5 am to 6 pm	10
6 pm to 11 pm (peak hours)	0

Energy

Energy consumption is reported in UEB's operational statistics as energy billed. The numbers for 1999 and 2000[3], in Table 3.3, show a quite substantial increase in energy billed. This is made possible by generation capacity added in June and August 2000.

Table 3.3 Energy billed in 1999 and 2000, GWh

	1999	2000	Increase
Uganda	702	853	22%
Exports	174	260	49%
Total	876	1 113	27%

Source: UEB Operational Statistics, September 2000 (consumption for October to December 2000 estimated).

Energy supplied is reported in Table 3.4[4]. The difference between energy supplied and energy billed is system losses, including both theft and technical losses. The increase in energy billed from 1999 to 2000 (27 per cent) is larger than the increase in energy supplied (16 per cent), and this is due to a reduction in losses over this period.

[2] One such example is Tuesday 7 November 2000, UEB Load diagram with generation and demand including exports.

[3] To estimate consumption for the full 12 months of 2000, we have used actual figures up to September 2000, and assumed consumption in October, November and December 2000 is equal to that of September.

[4] Energy supplied for 2000 has been estimated by assuming the supply in November and December to be equal to that of October.

Table 3.4 Energy supplied in 1999 and 2000, GWh

	1999	2000	Increase
Nalubale and Extension	1 341	1 532	14%
Thermal power	1	1	0%
Purchase from Mubuku	12	15	32%
Imports from Rwanda	1	1	11%
Total	1 355	1 549	14%
Total losses	35%	28%	

Sources: UEB Operational Statistics September 2000 and UEB Power System Summary of October 2000

End-use consumption and customer numbers

Table 3.5 reports end-use consumption according to customer category. For 1999 actual numbers are reported, while the numbers for 2000 are estimated based on actual consumption until October. The two categories Industrial and General account for a large portion of the estimated growth from 1999 to 2000.

Table 3.5 End-use consumption in Uganda, GWh

	Customer numbers (1999)	1999	2000	Increase
Domestic	145 313	307	319	4%
Commercial	18 031	107	129	21%
Industrial	58	163	205	26%
General	583	122	199	63%
Street Lighting	237	2	2	0%
Total	164 222	702	853	21%

Source: ECON/UEB

Customer numbers are reported in Table 3.5. The number of active customers in September 2000 was 127 624. This is not comparable with the total 1999 number as the latter includes all customers served during the full year.

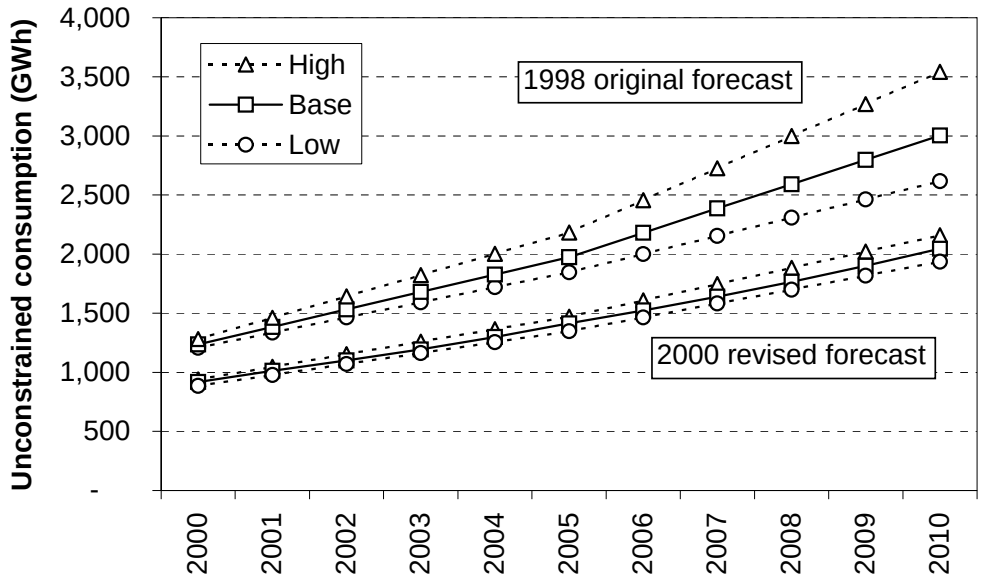
3.2 Demand projections

A set of demand forecasts were prepared by EdF in 1998, and revised in 2000. Each set contains a Low, Base and High forecast. A brief summary of the approach and assumptions used in the forecasts is presented in Annex A.

The figure below compares the 1998 and 2000 projections. It can be seen that the 2000 revised forecast is considerably lower (25-30 per cent lower) than the original forecasts, as it takes into consideration consumer responses to anticipated price increases and lower than originally forecast economic growth rates. It should be noted however that the revised forecasts only accommodated price increases at the start of the period (60 per cent, which is similar to the price hikes proposed for 2001), but not in 2005 when Bujagali comes on line. Thus, if demand reacts to price hikes due to Bujagali, then the revised forecasts may still over-estimate

demand from 2005 onwards. For the period 2000 to 2004, demand is effectively constrained by limited supply capacity and energy, and this means that both forecasts produce the same actual consumption over this period. Thereafter, the 2000 forecasts predict significantly lower consumption.

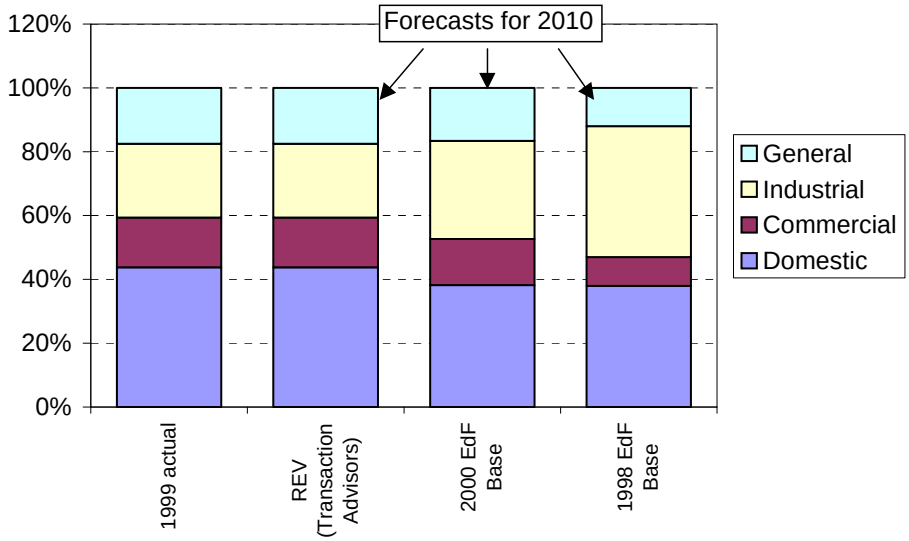
Figure 3.1 Comparison of 1998 and 2000 EdF demand forecasts



In the pricing model developed by the Transaction Advisors, a revised version (REV) of the 1998 Low forecast was used. This forecast was developed by reducing the starting point of the (unconstrained) forecast to 1999 actual (constrained) levels. The result is close to the EdF 2000 High forecast.

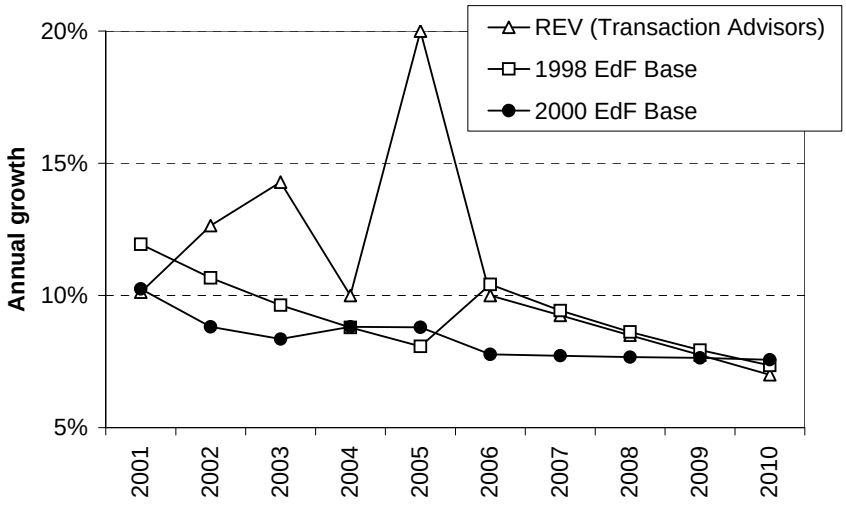
The REV forecast assumes the same growth rate across all customer groups, whereas EdF modelled different growth rates across different customer groups. The result is that under the REV forecast, the structure of demand remains constant, whereas under the EdF forecast it changes with time.

Figure 3.2 Projected structure of demand in 2010 under different forecasts



The 2000 revised forecasts prepared by EdF have growth rates declining slowly from 10 per cent to 7.5 per cent per annum. The original 1998 forecasts had higher growth rates, particularly after 2005. The REV forecast has particularly high growth rates from 2001 to 2005, and thereafter kept to the original 1998 growth rates. Comparisons are presented in the figure below. It is possible that the REV forecast presents constrained rather than unconstrained demand, thereby explaining the large changes in demand growth from year to year.

Figure 3.3 Annual growth rates in unconstrained demand for different forecasts



Comparing actuals with forecasts for 2000

Before studying the different forecasts of unconstrained demand in Uganda for 2000, it is helpful to look at the estimates of maximum demand. The EdF revised forecast has estimated the maximum demand to be 236 MW in 2000. This does not take account of exports as this is assumed to be non-coincident with peak load

in Uganda. The UEB Operational Statistics give 260 MW as the system maximum demand. In August and September the reported maximum supply was about 245 MW, indicating that the EdF forecast may be slightly conservative (by 6 per cent).

Table 3.6 compares forecasts of unconstrained energy consumption for 2000 with estimates of the actual consumption (see Table 3.3). During most of 2000 there have been considerable constraints on the system, and some constraints still remain. Therefore, unconstrained energy demand must be above 937 GWh. A rough estimate of the constraints at peak hour is given by UEB[5]: 60 MW January to June, 30 MW in July and August and 10 MW thereafter. Assuming 2 hours of full constraint at peak load, this will give roughly 28 GWh of suppressed demand in year 2000, and so an estimate of unconstrained demand for 2000 of approximately 965 GWh.

Table 3.6 Forecasts of unconstrained Ugandan demand 2000

Transaction Advisers' REV Forecast (unconstrained)	790 GWh
EdF Revised Base Forecast (unconstrained)	918 GWh
UEB Energy Billed (constrained extrapolated to 12 months)	937 GWh
UEB Energy Billed (unconstrained extrapolated to 12 months)	965 GWh

Both the EdF Base and REV forecasts appear to underestimate actual demand for 2000, by 5 per cent and 18 per cent respectively. The Transaction Advisers recalibrated unconstrained demand to be equal to constrained demand in 1999. This explains the low REV forecast for 2000. As mentioned earlier, the EdF forecasts underestimate maximum demand by 6 per cent. If this underestimation applies to the full load curve, then this explains the difference between EdF forecast and UEB numbers.

Despite this discrepancy, the EdF forecasts revised in 2000 are the latest available, and appear reasonable, well researched and fully documented. We recommend that these forecasts should be used for price forecasts by the ERA. We have used these forecasts in the results presented in Chapters 5 and 6.

It should be noted that for the period 2001 to 2005, it is not relevant which forecast is used, since all forecasts are effectively constrained by capacity limitations.

3.3 Export projections

The EdF forecasts looked only at projections of Uganda demand, and not at exports. The Transaction Advisors prepared their own forecast of exports, partly based on changing maximum demand on exports to Kenya, and partly on changing load factor of exports. It is further assumed that exports are non-coincident with Ugandan peak demand and hence do not contribute to constraints.

[5] Interview with UEB Genral Manager, Services 20th December 2000.

Table 3.7 Export assumptions used by Transaction Advisors

	2001 to 2004	**2005 onwards**
Maximum demand	65 MW	90 MW
Load factor	57%	74%
Energy exported	321 GWh	583 GWh

Given that power supply prices will be sensitive to the level of exports, we have also proposed Low and High export scenarios, in addition to that presented by the Transaction Advisors. The scenarios are only differentiated from 2005 onwards as supply constraints before this limit the volume of exports possible. This is summarised in Table 3.8. In order to achieve the projected exports, existing transmission facilities to Kenya must be expanded.

Table 3.8 Export scenarios used for price projections in Chapters 5 and 6

	2001 to 2004	**2005 onwards**
Max export demand Low	65 MW	65 MW
Max export demand Base	65 MW	90 MW
Max export demand High	65 MW	115 MW
Load factor	57%	74%
Energy exported Low	321 GWh	422 GWh
Energy exported Base	321 GWh	583 GWh
Energy exported High	321 GWh	747 GWh

4 Asset values & investment

4.1 Asset valuation

An asset valuation was carried out in 2000[6] to asses the investment requirement for rehabilitation of UEB's transmission and distribution system up to 2010. An engineering based asset valuation was also carried out as part of the same study.

Assets were divided into groups and an inventory established for each group. The age, remaining life and replacement values were established according to established international practice. Remaining useful asset lives were determined according to the ages of the assets and the adopted physical lives. A sample of assets were inspected to assess their condition and where their physical life-span had already been reached, their expected remaining lives. Replacement values were determined using international market prices and an "operative capacity value" (OCV) established for each asset. OCV is based on current replacement costs and does not consider future earnings of the assets.

Asset lives were adopted based on the expected useful lives of the assets under the conditions prevailing in Uganda.

A summary of the assets values determined in the study is presented in Table 4.1, under Lahmeyer report. As can be seen from the table, the numbers from the asset valuation report do not match numbers in model. The Transaction Advisors claim this is because Lahmeyer analysis excluded certain assets and they made adjustments to reflect this.

Exchange rate of sh1505/$ used for asset values, and sh1800/$ for investments.

[6] Transmission & Distribution Needs Assessment & and Engineering Based Depreciated Cost Valuation of UEB Operational Fixed Assets, Hagler Bailly, October 2000

Table 4.1 Lahmeyer asset values and figures used in the tariff model (figures in US$ mill, using exchange rate of sh1505/dollar)

	Gross assets/replacement			***Net assets/OCV***		
	Gen	Trans	Dist	Gen	Trans	Dist
Tariff model						
1999 (opening)	165m	148m	295m	93m	47m	94m
2000 (opening)	166m	149m	297m	89m	45m	89m
2001 (opening)	396m	164m	336m	315m	56m	121m
Lahmeyer report	524m	161m	225m	307m	38m	76m

Implications for prices

These values affect the price calculations in two ways:

Firstly, for the 2001 prices, while UEB still operates the system, the new asset values result in a higher depreciation component to the revenue requirement. This increase in depreciation from 2000 to 2001 is shown for the three groups in Table 4.2, and is particularly large for generation and distribution.

Secondly, for prices from 2002 onwards, the new asset values may guide the GoU in setting a lease fee for the assets. However, if lease fees are determined through the bidding process, or set equal to UEB loan commitments, then the asset values for generation and distribution will be irrelevant for pricing purposes. In fact, it has been proposed that lease fees will be set equal to depreciation of revalued assets plus interest obligations on existing debt. In this way, asset values will influence the depreciation element of lease fees.

Table 4.2 Increase in depreciation: 2000 to 2001 (sh mill)

Year	**Generation**	**Transmission**	**Distribution**
2000	5 818	5 155	10 295
2001	14 912	6 171	22 190
Increase	150%	20%	116%

Given that UEB is not required to replace existing assets, there seems little rationale to increase depreciation allowances in 2001. As we will see in section 6.1, the unit cost of distribution increases by 8 per cent from 2000 to 2001, only to decrease again by 11 per cent by 2003. Price stability will be promoted by replacing depreciation plus return on assets in the revenue requirement of generation and distribution with the expected lease fee in 2002, or the full loan obligations of UEB (i.e. principal plus interest payments).

Recommendations

The Transaction Advisors have revalued UEB assets. In order to do so, they have calculated the replacement cost of the assets, estimated their remaining useful life, and thus calculated what is termed an "operative capacity value" (OCV) for the assets.

Subject to the Transaction Advisors clarifying the discrepancy between replacement cost and OCV figures in the Lahmeyer report and those used in the pricing model, we recommend that the ERA accept the asset values calculated by Lahmeyer.

For the calculation of 2001 generation and distribution prices, we recommend that depreciation and return on assets in the revenue requirement be replaced by the expected lease fee for 2002.

4.2 Investment projections

The investment projections cover the rehabilitation and strengthening of the transmission and distribution systems during the period 2001 to 2005 and "build-out investment projections for the period 2005 to 2010. The rehabilitation proposals were based on a condition assessment of the transmission lines. The rehabilitation requirements cover the replacement of poles on some of the transmission lines. Rehabilitation needs for the distribution system were based on sample inspections to assess the general condition of the network. The results were then used to estimate the extent of the work required which then costed using unit rates applicable in Uganda. The projected investment on rehabilitation was then phased over the five-year period, as follows:

2001	5%
2002	35%
2003	20%
2004	20%
2005	20%

The transmission and distribution needs and asset valuation study also covered rehabilitation and investment estimates for switchgear, control and protection equipment for the power stations and control centre.

The build-out investment requirements were based on an empirical approach. The Transaction Advisor's estimated the investment needs for the 6-year period 2005 to 2010. The basic assumption is that:

- if demand grows at 3 per cent per year, then investment in transmission should be 3 per cent of the current replacement value of the transmission system, and

- if demand grows at 3 per cent per year, then investment in distribution should be 4 per cent of the current replacement value of the distribution system.

No justification was provided for the proposed method other than it was based on the consultant's experience. The method proposed by the consultant was used to estimate the build-out investment requirements for transmission and distribution. However, the numbers in the consultant's report do not match numbers in tariff model. It is not clear why this is so.

The REV demand scenario used by the Transaction Advisors was based on the 1998 Low demand growth, and so the Low investment scenarios were used. However, since distribution investment is based more on numbers of customers connected than demand growth, it seems more appropriate to use the Base investment projections. In later work in this report, we have used the Base investment projections.

Also, it is noted that there is an overlap, in 2005 between the rehabilitation period and the build-out period. Very heavy investment is required in this year when rehab is on-going and the build-out has started.

We recommend that a system expansion plan should be conducted by the concessionaire to firm-up the distribution investment requirements from 2005 onwards and this should be included as a condition of the distribution licence.

Table 4.3 Investment projections in tariff model and Laymeyer report (US$ mill), for Base scenario

	Generation		**Transmission**		**Distribution**	
	Lahmeyer	Model	Lahmeyer	Model	Lahmeyer	Model
2001	0.6	0.7	1.6	10.2	1.7	15.3
2002	1.0	1.6	2.0	15.9	12.2	15.1
2003	0.6	0.9	30.9	30.8	8.2	9.4
2004	0.6	0.9	30.9	30.8	7.0	7.8
2005	1.2	1.5	14.1	16.0	32.2	34.1
2006	0.6	0.6	11.9	12.0	24.1	25.2
2007	0.6	0.6	11.9	12.0	24.1	25.2
2008	0.6	0.6	11.9	12.0	24.1	25.2
2009	0.6	0.6	11.9	12.0	24.1	25.2
2010	0.6	0.6	11.9	12.0	24.1	25.2

Implications for prices

Investment projections influence prices in two ways:

- Firstly, the depreciation on new assets will be built into the revenue requirement of generation, transmission and distribution.

- Secondly, the allowed return on investment will also influence the revenue requirements of the different businesses.

It should be noted that the tariff model currently makes use of the Low investment projections, since the REV demand forecast is based on the 1998 EdF Low forecast. However, since the costs of distribution investment are related to customer numbers rather than load growth, using the Low figures is inconsistent with the customer number projections, and the Base projections should rather be used. The results presented in Chapters 5 and 6 make use of the Base projections rather than the Low.

Recommendations

The Transaction Advisors have assessed the status of UEB's infrastructure, and costed the necessary rehabilitation and strengthening required. They recommend that this investment be made over the period 2001 to 2005, and that this will be an obligation on the generation and distribution concessionaires. Presumably, UEB transmission will also be obliged to invest the required amount in transmission infrastructure.

We recommend that ERA adopt the Base rehabilitation investment figures (2001 to 2005) produced by the Transaction Advisors, subject to clarification of the differences in numbers presented in the Lahmeyer report (and provided to investors at the October London briefing) and the figures in the tariff model.

The Transaction Advisors have estimated the costs of the "build-out" from 2005 onwards using a rule-of-thumb. This is clearly an approximate assessment, and unit costs of electrification experienced in South Africa suggest that the estimate may lie on the conservative side (see section 6.2).

It should be noted that this matter only concerns price controls for 2005 onwards, and does not affect the 2001 price, nor controls until 2005.

We recommend that the build-out investment figures for 2005 onwards be used for indicative purposes at present, but that the approximate nature of the figures be made known to investors in bidding documents released early 2001.

Further, the distribution licence should contain a requirement that the distribution concessionaire prepare a system expansion plan for the period 2005 to 2010. The targets for this expansion, and the terms of reference for the study, should be developed collaboratively between the ERA and the MEMD. The plan should be costed and submitted by mid-2004 at the latest. Once the ERA has independently verified the cost estimates, these should be used for price setting from 2005 onwards.

4.3 Lease price for UEB assets

There is some uncertainty in what the lease fee to UEB should be for its distribution and generation assets.

Lease options

The options are to charge a lease fee equal to:

1. Depreciation of existing assets and any other assets acquired by UEB plus a return on these assets.
2. Depreciation of existing assets and any other assets acquired by UEB plus a proportionate share of UEB's existing interest obligations[7].
3. A proportionate share of UEB's total debt servicing obligations, including interest charges and principal repayments.
4. A sum as bid by the concessionaire during the bidding process.

There is further uncertainty relating to the current status of UEB's loan book, with the possibility of capital restructuring and write-off of debt. We understand that the GoU is looking at this option.

We examine these options for generation and distribution assets in more detail in sections 5.2 and 6.1.

Recommendation

Given that UEB is not required to replace existing assets (except for transmission), there seems little reason for UEB to base the lease fee on the depreciation of revalued assets. For generation and distribution, setting a lease fee which includes this component will result in positive cash flows over the coming years. We have been assured that Government's intention in this process is not to realise rent from the electricity industry. If this is the case, and if Government wishes to return as much of the economic surplus to customers as possible, then lease fees should be set to service existing and future loan commitments of UEB plus any administrative costs associated with the concession.

We recommend that ERA require the GoU to clarify what lease should be charged as soon as possible. Given that the introduction of private returns to capital, as well as the backlog of investment required, will tend to increase prices, the ERA should recommend to Government to set the lease payment at moderate levels. The lowest acceptable lease payment will be that required to service UEB's restructured debt.

[7] The tariff model is intended to allocate UEB's existing debt to the three groups generation, transmission and distribution in proportion to the book value of assets. However, the model as given to us recalculates the proportional split every year, whereas it is more likely that UEB's debt will be allocated in 2001, and the split will remain fixed from that point on. This point was raised with the Transaction Advisors and the model should be amended to reflect the more realistic approach.

5 Generation & transmission prices

5.1 Principles of generation pricing

Proposals

Under the proposed tariff, UEB Generation (Genco) will be allowed to charge a tariff based on "available" capacity at Nalubale (previously Owen Falls) and Kiira (previously Owen Falls Extension). The installed capacity at Nalubale is 180 MW (10 units of 18 MW each) and at Kiira (2 units of 40 MW under construction and up to a further 3 units of 40 MW possible).

Each year Genco will develop a budget of operating costs, for approval by the ERA. In addition, Genco will be allowed to earn a return on new investments.

Genco will establish the Maximum Actual Capacity (MAC) of each unit by demonstrating the available capacity for each unit at least once per month.[8]

The total agreed annual operating budget, plus return on investment, will be converted to a Monthly Generation Cost (MGC) - presumably 12 equal monthly amounts - and Genco will then calculate an Hourly Capacity Price (HCP) for each month, where:

HCP = MGC / (MAC for all units * hours in the month) ..... (i)

It is proposed that Genco should be paid the HCP multiplied by the MAC for each 24-hour period that the unit can be shown to be available during that month, regardless of whether or not it is generating.

If a unit is not available, or is only partially available (due to either forced or planned outage), for any time during the 24-hour period, then:

- the HCP applicable to that unit for that 24-hour period shall be reduced by 50 per cent, and

[8] It is not clear to whom the availability capacity should be demonstrated – would it be the ERA, UEB transmission, or another authority?

- payment will only be made for complete hours that the unit is available, based on the 50 per cent HCP multiplied by the ratio of the actual unit capacity to the Maximum Actual Capacity (MAC).

The payments to Genco will be passed on to the end users through the Bulk Supply Tariff (BST). The BST recommended by the Transaction Adviser includes a unit (kWh) energy charge, with time-of-day components (i.e. peak, shoulder and off-peak).

The BST will be calculated annually by the Single Buyer – UEB Transmission (Transco) – based on an analysis of system loads. The tariff will be subject to approval by the ERA.

Comment

The algorithm as outlined above will only allow the Genco to achieve its full revenue requirement if availability is 100 per cent for every hour of the year. Both planned and unplanned outages mean that this is unrealistic. This can be corrected by setting a target availability and altering equation (i) to read:

HCP = MGC / (MAC for all units * hrs in month * target availability) ..... (ii)

There appears to be an error in the calculation of the payment for capacity at reduced capability. At present it is expressed as:

Payment = 50% * HCP * (Actual unit capacity / MAC) ..... (iii)

This gives a result in units of shilling/MW instead of shilling. The formula should read:

Payment = 50% * HCP * Actual unit capacity ..... (iv)

The penalty for reduced generating unit availability is seemingly arbitrary, i.e. 50 per cent of the normal per MW capacity payment. This figure does not appear to be supported by any documentation or analysis.

"Policing" of generating unit availability will be a critical aspect of the proposed generating pricing, since all risks to Genco (and other generators), other than generating unit availability, will be passed through to the single buyer (Transco). It is not clear how this will be handled. In the short term, this should not present a serious problem, as the system is capacity constrained (at peak). However, it remains a problem for off-peak hours, and will become increasingly important during peak periods once there is spare/reserve capacity on the system.

Risk is also a major issue in the present proposals. All generation risk (except that linked to reduced availability) is passed through to Transco. This risk is passed through to the distribution company by Transco, who in turn passes it through to customers. We have two concerns: first, can the ERA accept this risk pass-through and, secondly, will the distribution concessionaire accept it? The Transaction Advisors are aware of this, and believe that the Single Buyer should not be allowed to pass through all the risks. On the other hand if Transco is not allowed

to do so, it will be effectively bankrupted. We examine the risks associated with surplus capacity once Bujagali is installed in section 5.2 below.

A second element of risk relates to occasions when transmission lines are out of service. If these transmission faults result in unserviced demand, should end-users still be liable for the full take-or-pay costs of generation? The current proposals implictly suggest that they would do so, although they do not explicitly address this issue.

Whilst the method selected, and described above, is certainly straightforward we have doubts about the workability of the proposals. On the one hand it is easy enough to verify power supply predicated on a maximum demand and energy tariff by metering which is both accurate and can be readily verified. On the other hand, we foresee difficulties with the selected method for the following reasons:

- All the payments will depend on the "availability" of generating units and, more than that, on the capability of units when they are available. Our concern is that there may be a lot of scope for "manipulating" the rules.
- Verification will be difficult. Who will do it? It almost certainly requires an independent authority respected by both Genco and Transco. It seems unlikely that the ERA would undertake this role, nor have the resources to do it. In other parts of the world, for example in Peru and Colombia, there have been problems in the verification of “available” capacity. In Colombia, the “available” capacity calculated for the coming year is determined using the level of the reservoirs at the end of the rainy season. The operation is then simulated and on the assumption that the next year will be a “critical” hydrological year and the available capacity from each hydro station calculated accordingly. It seems that some of the hydro producers are cheating on the information supplied and the procedures are being revised and penalties introduced.

Recommendations

An alternative approach might be for Transco to notify the Genco, on a monthly or even daily basis, of its required maximum demand during peak hours (or even its required demand on an hourly basis), with the proviso that the required demand must be less than the installed maximum capacity. Payment to the Genco would then be:

- If the Genco is able to meet the required demand, then the Transco is obliged to pay the Genco its full revenue requirement.
- If the Genco is not able to meet the required demand due to reduced availability, then a penalty is incurred and only a portion of the revenue requirement is paid.
- If actual demand is greater than the requested supply, and the Genco is able to meet this demand, then a premium is paid to reward this.
- Similarly, if actual demand is less than the requested supply, a premium should also be paid to the Genco in order that the Transco faces a disincentive to consistently request more than it requires.

It may also be possible to adapt this approach to include energy payments in addition to capacity payments.

While this approach needs further development (particularly in determining the penalties and premiums), it has the advantage that it does not require monitoring of availability or capability. Instead, payment of the revenue requirement is automatic if the Genco is able to meet the requested supply. A penalty is only incurred if available capacity fails to meet the requested supply – an event that is easily recorded.

It is appreciated that this alternative power supply pricing proposal does not match what, we understand, has already been agreed for Bujagali. This could lead to problems in securing a concessionaire for Genco, if the risks associated with the operation of Genco are different from Bujagali.

Given that the finalisation of 2001 tariffs is imminent, we recommend that the Transaction Advisors recommendations be provisionally accepted, conditional on including a target availability in the HCP formula and correcting the error in the calculation of payment for reduced capacity.

Nevertheless, the workability of this system should be evaluated during 2001, and consideration given to other approaches, as suggested above.

5.2 Implications of generation prices for end-users[9]

The Disco will pay a bulk supply tariff (BST) reflecting the costs of generation and transmission, and will pass this cost through in end-user prices. We examine the level of this pass-through under different scenarios. This section will deal with the generation component of the BST, and section 5.4 will deal with the transmission component. We refer to the generation pass-through component as the Average Generation Price (AGP), and this is the average price for generation that end-users must pay. The AGP reflects the average costs of generation, as well system losses. That is, it is calculated as the cost of generation divided by the quantity of energy actually sold.

We have defined a set of scenarios to illustrate the sensitivity of the AGP to different conditions and policies. The results illustrate the sensitivity of prices to the following parameters:

- ***Load growth scenarios***: We use the revised EdF Low, Base and High forecasts.
- ***Exports:*** We test the level of the AGP under different export scenarios (see Table 3.8), again testing Low, Base and High estimates for future exports.

[9] The results presented here are based on information provided in December 2000. Data and prices may have been updated since then.

- ***Hydrology risks:*** There are different estimates of the hydrology of the Nile River, with the 40 year average flow being substantially higher than the 100 year average. We test different flow estimates.
- ***Lease fee for Nalubale & Kiira:*** There is uncertainty on the level of the future lease fee. We test two cases: where the lease fee is based on a rate of return for UEB's assets, and where the lease is designed to service UEB generation's debt obligations.
- ***Cost of surplus capacity:*** The power sales agreements with Nalubale and Bujagali are essentially take-or-pay agreements. Proposals at present allow the single buyer to pass-through all these costs to the Disco, who in turn reflects them in end-user prices. We test two cases:
    (i) ***Customers bear costs***: where the single-buyer passes through all costs to the Disco, and
    (ii) ***Single Buyer bears costs***: where the Disco only pays for his actual requirements plus a 10 per cent reserve.
- ***Foreign exchange risks:*** Since a portion of costs is indexed to the dollar, a real devaluation will result in price increases. We test the case of a real depreciation of the Uganda shilling against the US dollar.

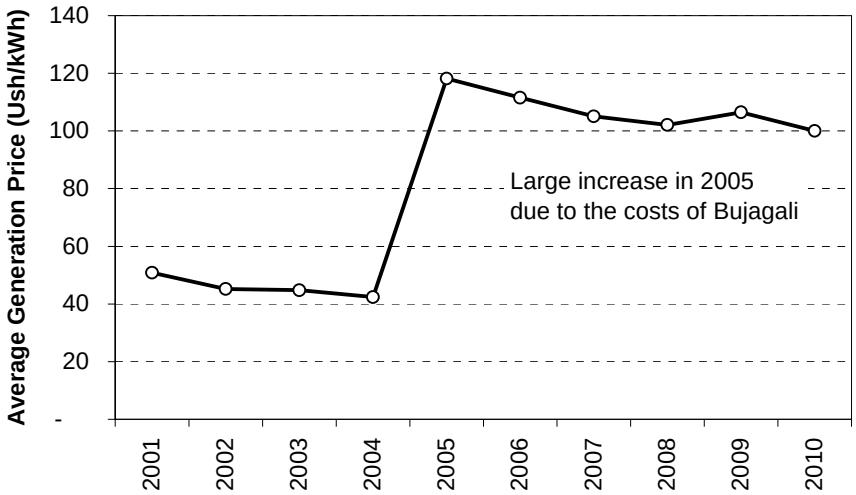
Base scenario results

The Base scenario uses the following assumptions:

- Demand — EdF Base Revised
- Export — Base assumptions (see Table 3.8)
- Hydrology — Start with 40 yr data & converge to 100 yr data in 50 yrs.
- Lease fee — Based on depreciation plus 6 per cent return on UEB assets
- Risk of surplus — Disco takes risk
- Forex — No depreciation of sh relative to US$

The results are shown in Figure 5.1. It can be seen that the AGP varies between 50 and 45sh/kWh from 2000 to 2004, and then increases dramatically. Thereafter the AGP declines steadily to 100 sh/kWh. The large increase in 2005 is due to the costs of Bujagali, which has significantly higher unit costs than Nalubale and Kiira. The steady decline thereafter is the result of load growth, effectively spreading the costs of Bujagali over a larger consumption base.

Figure 5.1 Average Generation Price (to end-consumers) under Base scenario

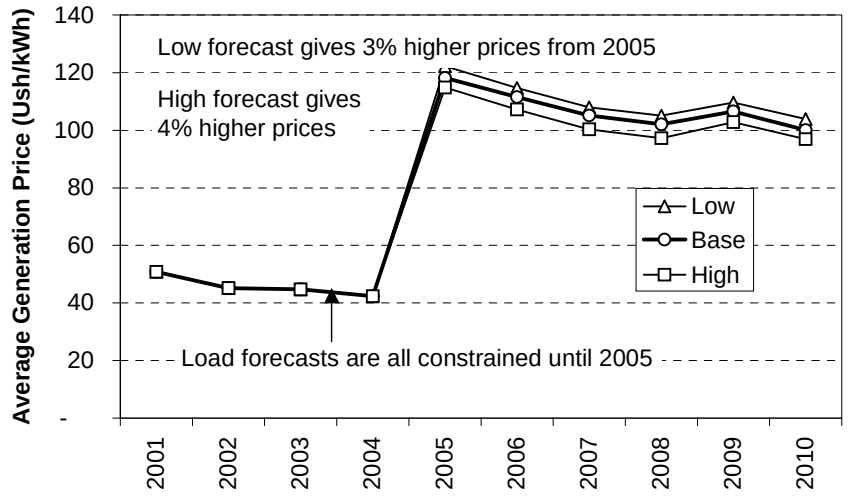


Sensitivity to load growth

The figure below shows the sensitivity of the AGP to different load forecasts. The forecasts used are the EdF revised Low, Base and High forecasts.

Since supply is constrained until 2005, all three forecasts give the same result until 2005. This is because actual consumption is the same in all three scenarios. Thereafter, the Low and High load forecasts give prices that are 3 per cent higher and 4 per cent lower respectively. The High load forecast gives lower prices since the take-or-pay element of generation is spread over a larger consumption base, and vice versa for the Low forecast.

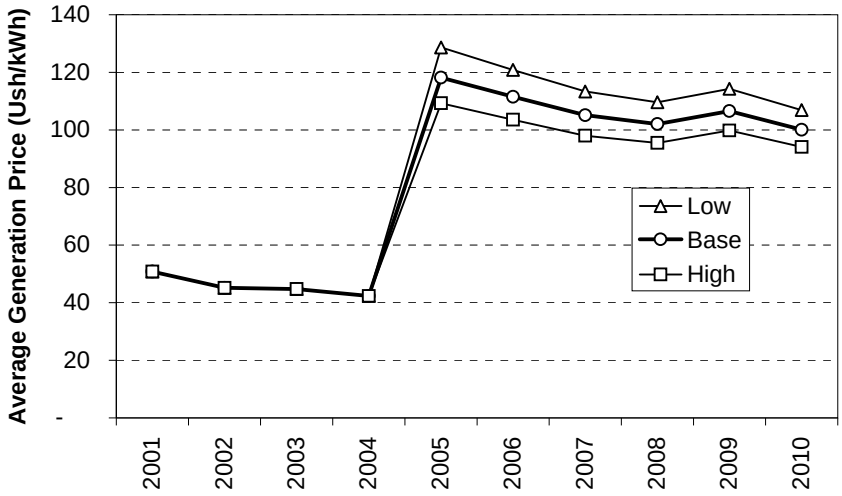
Figure 5.2 Sensitivity of Average Generation Price to load growth



Sensitivity to exports

The steep increase in prices in 2005 is due to the costs of Bujagali. There is an "overshoot" in the years 2005 – 2007 due to the fact that Bujagali introduces an element of surplus capacity that must be paid for by end-users. Increasing exports will reduce this risk. The figure below shows prices under different export assumptions. The export scenarios only differ from 2005 onwards, and so differences in prices only emerge from this date onwards.

Figure 5.3 Sensitivity of Average Generation Price to export assumptions

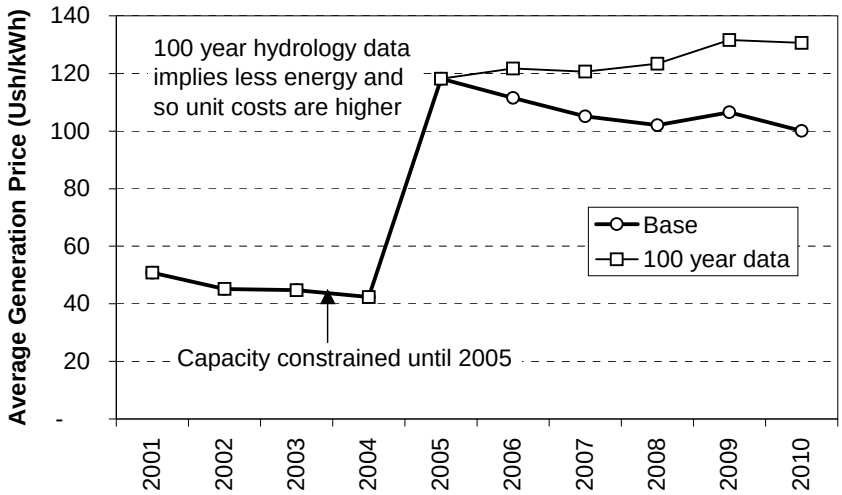


Sensitivity to hydrology assumptions

There are competing hydrological data sets. The 40 year data set suggests that Nile river flows average at around 1100m^3/s whereas the 100 year data gives an average of around 800m^3/s. The base case assumption, as used by the Transaction Advisors, is to start with the 40 year data and converge to the 100 year data in 50 years. We have also tested the case of using only the 100 year data, and compare the results in the figure below.

It can be seen that the 100 year data implies greater constraints on energy production. Once capacity constraints are resolved, the 100 year data implies that there are energy constraints from 2006 onwards. This means that the fixed costs of generation are spread over a reduced load base, resulting in higher prices from this point on. The difference in prices becomes significant towards the end of the period tested here.

Figure 5.4 Sensitivity of Average Generation Price to hydrology assumptions



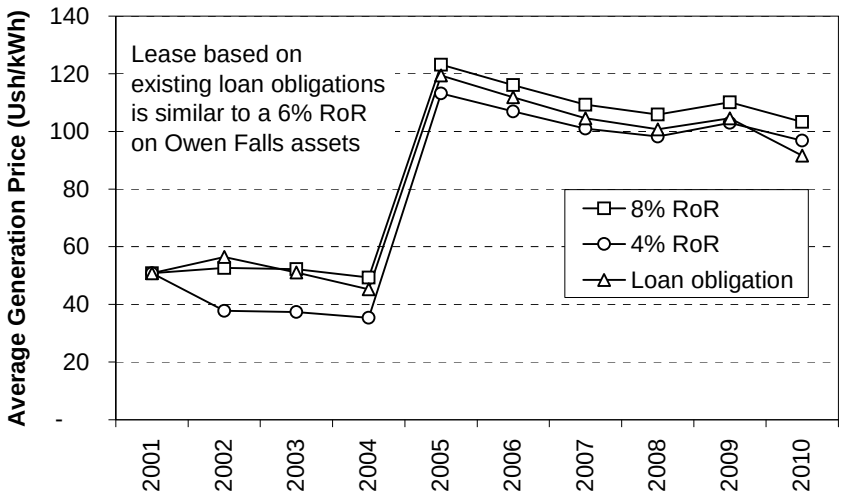
Sensitivity to lease fee

As discussed earlier, there is some uncertainty as to the lease fee for Nalubale and Kiira assets. The proposals for calculating the lease fee are to either charge a lease which will earn UEB Generation a certain return on its revalued assets, or to charge a fee sufficient to service existing interest and debt repayment obligations (i.e. UEB Generation's proportion of UEB's debt).

The figure below compares the results using a 6 per cent return on assets (the base case), an 8 per cent return, and a lease to cover debt obligations. It can be seen that the loan obligation method gives results similar to an 8 per cent return in the period 2001 to 2004, and thereafter similar to a 6 per cent return. From 2010 onwards, the debt obligation method gives the lowest prices since debt is largely paid off by this time.

If UEB's debt is restructured or a portion written off, the lease fee based on debt will be lower than the results shown.

Figure 5.5 Sensitivity of Average Generation Price to method of setting lease fee



Costs of surplus capacity

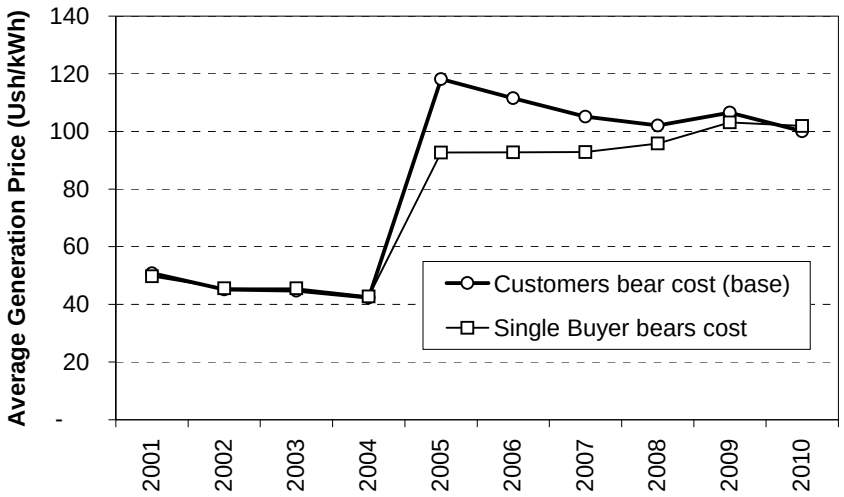
The payments to generators are capacity charges, and are essentially take or pay agreements. There is a risk, once Bujagali is introduced, that there will be surplus capacity, which must be paid for. At present the proposal is for this risk to be passed through to end-users in the form of higher generation prices.

To determine the effect of this, we test two scenarios:

- ***Customers bear costs***: this is the proposed system, in which the Single Buyer passes costs onto the Disco, who then passes them on to customers.
- ***Single Buyer bears costs***: in this case, the Disco only pays for capacity sufficient to meet his requirements plus a 10 per cent reserve.

The figure below illustrates these two cases. It can be seen that where the single buyer bears the costs, the impact of Bujagali on end-users is softened considerably in the years 2005 – 2007. Prices still increase dramatically, but approximately double rather than triple. In addition, prices are more stable thereafter, rather than declining by 20 per cent over the following three to five years.

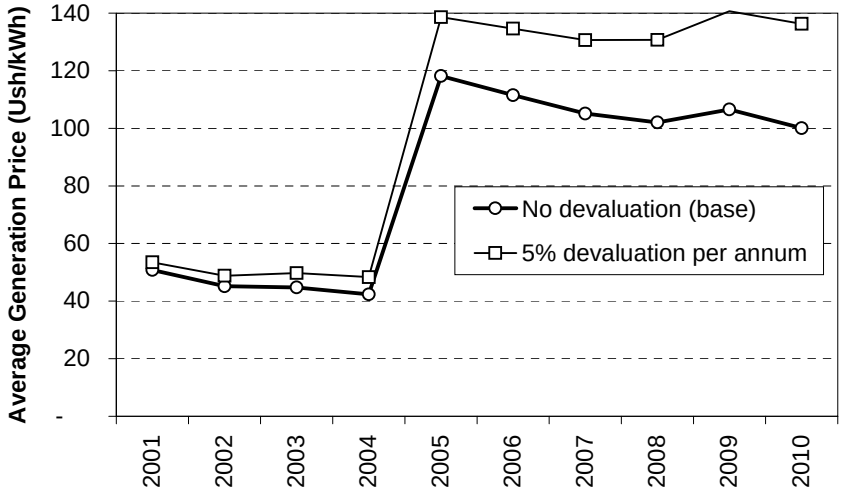
Figure 5.6 Dealing with the costs of surplus capacity



Sensitivity to currency devaluation

A large portion of the AGP will be indexed to the US dollar, implying higher prices in shilling terms if there is a (real) devaluation. The figure below compares the base case (no devaluation) with a 5 per cent real devaluation per annum. This is a cumulative effect of a 45 per cent real devaluation by 2010. The impact of currency devaluation is magnified from 2005 onwards since the Bujagali contract is denominated in dollars.

Figure 5.7 Sensitivity to currency devaluation



5.3 Principles of pricing bulk power

Proposals

As discussed in section 5.1 above, Transco as the Single Buyer purchases power from the Genco based on available generating capacity. Transco sells energy to UEB Distribution (Disco) under a Bulk Supply Tariff (BST). The proposed tariff is made up of peak, shoulder and off peak components.

The costs included in the BST are:

- power supply payments to generators;
- transmission services – comprising direct costs (approved by ERA) plus depreciation of assets and existing interest obligations;
- reconciliation adjustments – required to reconcile its bulk supply costs with revenues received from Disco, and approved by ERA;
- export contribution – the difference between the export sales revenue and the average bulk supply cost.

Bulk Supply Costs (BSC) are then calculated as:

BSC = (Power supply + Transmission costs) * (Sales to Disco / Total sales)
+ reconcilation adjustments, if any
+ export contributions, at discretion of ERA ..... (v)

Each year Transco will define the peak (not to exceed 8 hours per day), shoulder and off-peak periods. Loss factors will be calculated for each period based on actual measurements of generation and consumption for the previous month. In practice, ERA should establish loss factor targets as an incentive for Transco to improve its operating efficiency.

The BST price during the shoulder period will be the total Bulk Supply Costs divided by the sum of energy sales to Disco plus exports.

The peak period price will be the shoulder price multiplied by a peak period factor proposed by Transco and approved by ERA. A factor of 1.20 has been proposed.

The off-peak price will be determined by the total bulk supply costs less the revenues from the peak and shoulder periods divided by the energy consumed during the off-peak period. The tariff model makes use of load profile information in which 22 per cent of energy is consumed off-peak.

Exports will be sold on long term contracts and may generate windfall profits, or losses, in hard currency. The proposals suggest that windfall profits may be used to support the connection of rural consumers through the Rural Electrification Fund.

The BST, as presently proposed allows all risks to be passed through to consumers. It is not clear however whether this includes export power risk. It is

stated in the proposed transmission tariff that any profits or losses from exports should be retained in a special account. The ERA would be informed about the status of the account on a monthly basis and the contribution (profit or loss) from exports may, at the discretion of the ERA, be included in the Bulk Supply Costs.

Comment

We believe there is an error in the algorithm described above. Equation (v) should read:

BSC = (Power supply + Transmission costs)
+ reconcilation adjustments, if any
+ export contributions, at discretion of ERA ..... (vi)

This is because the BST during the shoulder is determined as:

BST (shoulder) = BSC / (Sales to Disco + Exports) ..... (vii)

Although Transco will be allowed to cover the financing costs of existing debt in its revenue requirement, there is no provision for self-financing of new investment, and implicitly assumes that new investment will be financed at zero interest rates. There may be a problem therefore in funding needed new investment in the transmission system.

There is considerable variation in exports from month to month. As discussed in section 2.3, using a rolling average of exports rather than the previous month's exports will help reduce this instability.

Under the proposed BST, all consumers with the same consumption pattern pay the same price for their energy regardless of where they are located on the system. In other words, there are no location-specific transmission prices. Thus, rural consumers remote from the generation sources will be subsidised by consumers close to generation, e.g. consumers in the Greater Kampala area. It is not uncommon for national bulk supply tariffs to be adopted in developing countries with large rural populations, and hence this approach is consistent with practices elsewhere.

Lastly, with an five hour peak period (18.00 to 23.00), the Disco does not see good price signals concerning the costs of peak demand during constrained supply. Further, peak prices are set at 120 per cent of shoulder prices – a ratio that appears arbitrary without any justification. This in turn reduces the incentives for the Disco to provide appropriate price signals to its customers, or to invest in demand side management programmes. It may be useful to consider a maximum demand charge in the BST, effectively giving the Disco the incentive to manage the maximum demand on the system, thereby contributing to relieving supply constraints. Examples of such interventions include the use of tariffs for interruptible supply and load management technologies.

Recommendations

While the proposed BST mechanism should be adopted for 2001, the calculation of the BST should be amended in the following ways:

- ***The calculation of the revenue requirement for transmission should allow a return on future investment, thereby facilitating a degree of self-financing and supporting the raising of new debt.***
- ***The error in the calculation of the Bulk Supply Costs in equation (v) should be corrected (substituted by equation vi).***
- ***The use of monthly export volumes should be replaced by a rolling average of export volumes to improve price stability.***
- ***Load profile information used to calculate the prices in the off-peak period should be documented.***

As discussed in section 2.3, the Transco should be tasked with the responsibility to devise a revised BST algorithm in order to introduce the price increases associated with Bujagali over several years, and to limit the price "overshoot".

In revising the BST, the Transco should give consideration to the inclusion of a maximum demand charge element in order to improve price signals.

5.4 Implications of transmission prices for end-users

In the same way that we have examined the generation component of end-user prices, we also examine the transmission component. We refer to the transmission element of end-user prices as the Average Transmission Price (ATP).[10]

We test various sensitivities, and these relate to:

- ***Load***: As with the AGP, we test sensitivity of the ATP to the three revised EdF load forecasts.
- ***Exports***: As with the AGP, we test sensitivity of the ATP to three sets of export assumptions.
- ***Return on assets***: We test setting the ATP so that income is sufficient to meet a target rate of return on revalued assets (6 per cent and 8 per cent), or meeting loan obligations only.
- ***Currency devaluation***: Since a portion of the ATP is indexed to the dollar, we test a 5 per cent annual real devaluation in the shilling.

[10] The results presented here are based on information provided in December 2000. Data and prices may have been updated since then.

Base scenario results and sensitivities to load forecasts

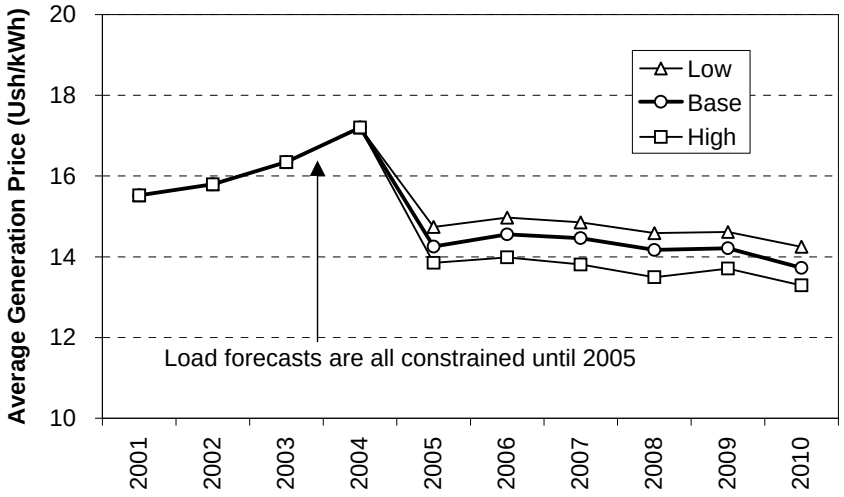
We describe first a base case scenario. This is where load and exports are set to the base cases, there is a 6 per cent return on revalued assets, and no devaluation of the shilling. The results are shown in Figure 5.8, together with the sensitivities to different load forecasts.

It should firstly be noted that transmission prices are significantly lower than generation prices. The ATP in the period 2001 to 2004 is approximately 25 per cent of the BST. From 2005 onwards, it is approximately 12 per cent of the BST.

Prices increase slightly over the period 2001 to 2004 (by 2sh/kWh) as a result of increased investment in transmission in preparation for the introduction of Bujagali. Thereafter, prices decrease as demand increases once supply constraints have been removed, and stay constant at around 14sh/kWh.

Lower and higher load forecasts imply relatively small increases/decreases to the ATP, as shown in Figure 5.8.

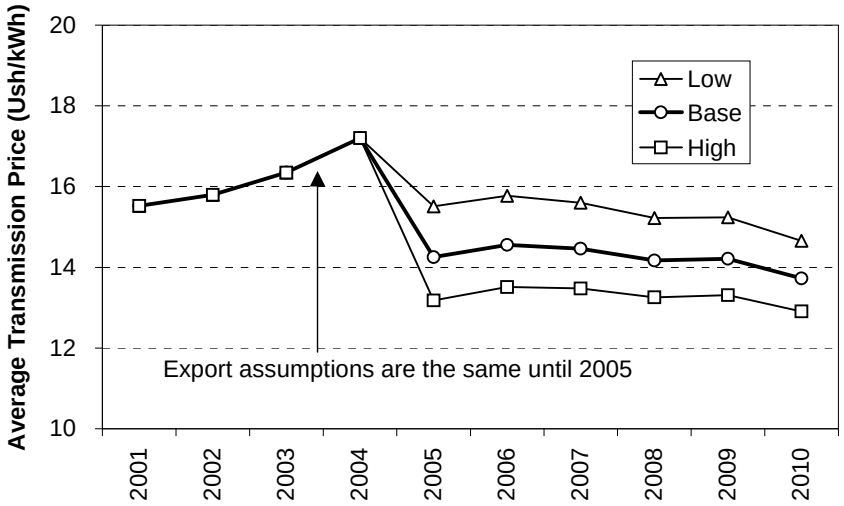
Figure 5.8 Sensitivity of Average Transmission Prices to load forecasts



Sensitivity of Average Transmission Price to exports

Figure 5.9 presents the sensitivity to export assumptions. The different export assumptions affect transmission prices by ±1sh/kWh.

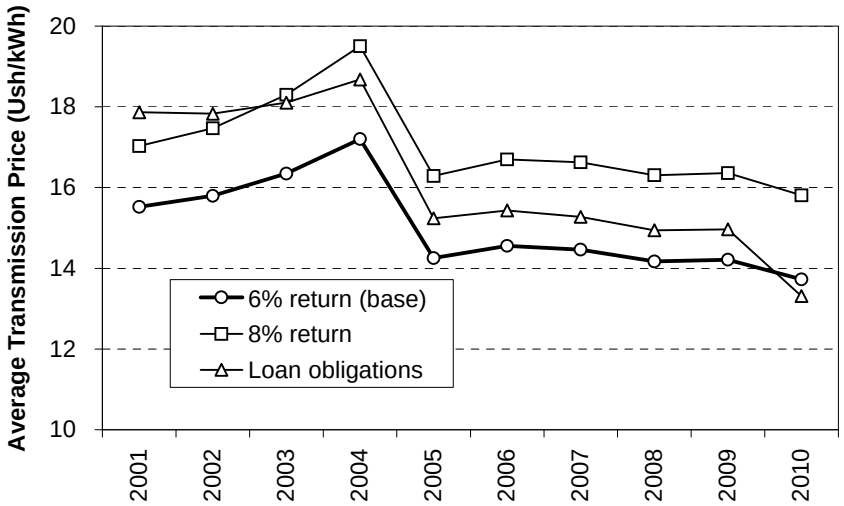
Figure 5.9 Sensitivity of Average Transmission Prices to export assumptions



Sensitivity of Average Transmission Price to return on assets

It is uncertain what return UEB Transmission will be allowed on its assets. We have tested different approaches to this, testing various returns as well as setting return adequate to meet loan obligations. The results for a 6 per cent and an 8 per cent return are shown in the figure below, as well as the case of meeting loan obligations. This last approach is similar to a 7 per cent return on revalued assets. There is a difference of approximately 2sh/kWh between the 6 per cent and 8 per cent return.

Figure 5.10 Sensitivity of Average Transmission Prices to return on assets

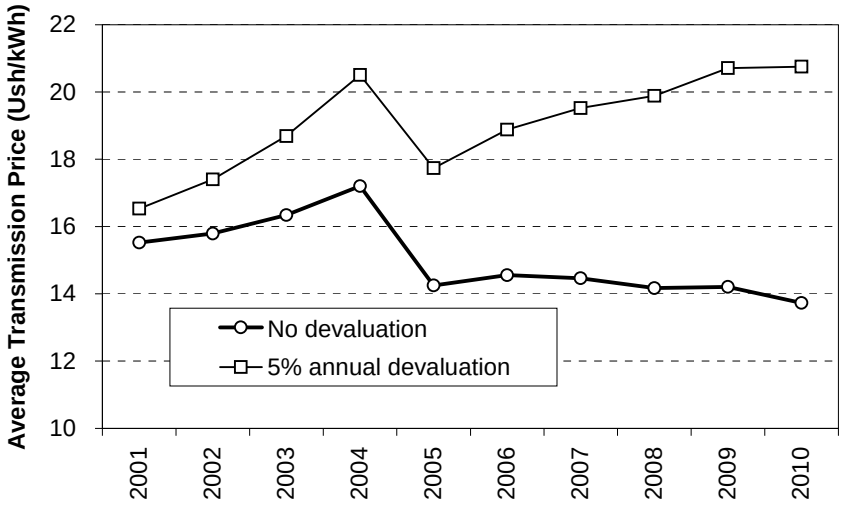


Sensitivity of Average Transmission Price to currency devaluation

A portion of the transmission tariffs will be indexed to the dollar, and so currency devaluation will increase prices. We test the case of a 5 per cent real annual

devaluation, as shown in Figure 5.11. By 2010, prices will have increased by 60 per cent above the case of no real devaluation.

Figure 5.11 Sensitivity of Average Transmission Prices to currency devaluation



6 Distribution prices

The chapter will look mainly at the proposals for constructing the costs of distribution. Chapter 7 will look at the way these distribution costs, as well as generation and transmission costs are translated into end-user tariffs.

6.1 Distribution revenue requirement

Distribution prices are based on the revenue requirement for distribution. The allocation of this to individual tariff categories is described and discussed in Chapter 7.

While UEB Distribution still operates the distribution system, the revenue requirement is made up of the following parts:

- Operating costs
- Depreciation of UEB's distribution assets
- Return on UEB's distribution assets
- Taxation.

Once the concessionaire operates the system, the revenue requirement for purposes of pricing is comprised of:

- Operating costs
- Depreciation of the concessionaire's assets
- Return on the concessionaire's assets
- Lease fee to UEB distribution
- Taxation.

Operating costs

Operating costs for 2001 are taken to be UEB's budgeted figure of sh35,144 mill. Thereafter operating costs are expected to be reduced in real terms in line with estimates presented in Table 2.2.

By 2005 total operating costs should have declined by 12 per cent in real terms. If demand grows and non-technical losses reduced, the cost per unit sold will have decreased even further. Using EdF revised load forecasts, the unit operating costs

would have reduced by 42-46 per cent by 2005 and 64-67 per cent by 2010 (the range relates to Low and High load forecasts). Similarly, operating costs per customer connected would have decreased by 31-37 per cent in 2005 and 54-62 per cent in 2010.

Table 6.1 Projected real reduction in O&M costs per kWh sold and per customer connected

	2005			2010		
Revised EdF forecast	Low	Base	High	Low	Base	High
Reduction in cost per kWh sold	42%	44%	46%	64%	65%	67%
Reduction in cost per customer	31%	33%	37%	54%	58%	62%

As expressed in section 0, it is our view that this decline in costs per connection is optimistic. If the system is to be expanded into new areas of supply, rather than just densified in existing areas, then it is likely that there would be upward pressure on costs.

We have recommended in section 0 that either the Transaction Advisors revise the gains in the light of anticipated new connections, or note to potential operators that the current figures will be revised to take account of system expansion from 2005 onwards.

Lease fee

As described in section 4.3, there is some uncertainty in what the lease fee to UEB should be for its distribution and generation assets[11]. The options are to charge a lease fee equal to:

1. Depreciation of existing assets and any other assets acquired by UEB (as opposed to those acquired by the concessionaire), plus a return on these assets.

2. Depreciation of existing assets and any other assets acquired by UEB (as opposed to those acquired by the concessionaire), plus a proportionate share of UEB's existing interest obligations[12].

3. A proportionate share of UEB's total debt servicing obligations, including interest charges and principal repayments.

4. A sum as bid by the successful concessionaire during the bidding process.

[11] URU has proposed to Government that option 2 in this list be adopted, with some restructuring of UEB's debt.

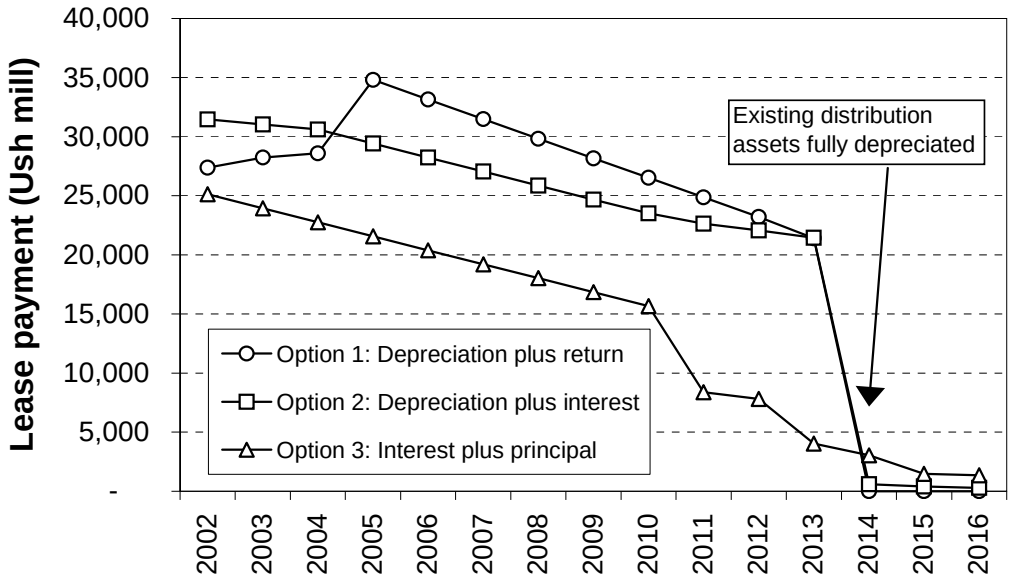
[12] The tariff model is intended to allocate UEB's existing debt to the three groups generation, transmission and distribution in proportion to the book value of assets. However, the model as given to us recalculates the proportional split every year, whereas it is more likely that UEB's debt will be allocated in 2001, and the split will remain fixed form that point on. This point was raised with the Transaction Advisors and the model should be amended to reflect the more realistic approach.

There is further uncertainty relating to the current status of UEB's loan book, with the possibility of capital restructuring and write-off of debt.

The figure below compares the lease fee using the first three different methods (method 1 uses an 8 per cent return), and making use of the data provided on UEB's existing loan book. It can be seen that options 1 and 2 generate broadly similar results, but that option 3 results in a considerably lower lease payment. Naturally, if some of UEB's debt is written off, then option 3 will result in an even lower lease, and option 2 will also be reduced.

The tariff model at present implements option 2. We should point out that implicit in this option (as well as option 3) is the assumption that investments by UEB Distribution in 2001 will be financed either by equity, or at zero interest rate. Both are unlikely scenarios, and the calculation should reflect a financing cost for assets acquired in 2001. Option 2 does, at least, generate a positive cash flow (the difference between the lease and the loan obligations), allowing some self-financing.

Figure 6.1 Lease payments for UEB distribution assets under different options (Option 1 uses an 8% return)



It should be noted that the lease fee, at least under options 1 and 2, is a function of existing asset values. Section 4.1 has addressed the asset valuation methodology used by the Transaction Advisors and concluded that the approach and assumptions employed are acceptable.

The determination of the lease fee is a matter for the GoU, although the ERA should rightly limit the return that the state should earn on its assets. Since it is clear that the Government has no desire to earn a high rate of return, we have recommended in section 4.3 that the ERA should simply require the GoU to clarify what lease fee it requires over the time frame of the lease.

Depreciation

The depreciation calculation is based on a rate of 3.5 per cent as a weighted average for all distribution assets. UEB currently uses the rates for different categories of assets shown in Table 6.2

Table 6.2 UEB's depreciation rates for assets

	Years	Rate	Replacement value[13]
Distribution sub-stations	35	2.5%	$27.0 m
MV lines	50	2.0%	$95.1m
LV lines	35	3.3%	$83.2 m
Services	25	4.0%	$24.6 m

Using the replacement values and depreciation rates in the Table, the weighted average depreciation rate of UEB's distribution assets should be 2.74 per cent. This is significantly lower than the 3.5 per cent per annum used by the Transaction Advisors, and would reduce the depreciation component of the revenue requirement (and lease fee) by 22 per cent. This would lower the overall revenue requirement by 4.3 per cent.

We recommend that the Transaction Advisors provide justification for the use of a 3.5 per cent depreciation rate for distribution assets, or propose a new rate with adequate justification.

It should be noted that the algorithm in the tariff model for calculating depreciation does not allow assets purchased in 2000 and 2001 to be depreciated over their full lives. Thus, the model shows that UEB's distribution assets are fully depreciated by 2014, even though assets purchased in 2000 and 2001 should have a life of 28 years. However, given that new assets are only a small proportion of existing assets, this simplification does not materially affect the pricing results.

As discussed in section 4.1, since UEB distribution is not required to replace any of its existing assets, there is no clear rationale for basing 2001 prices on the depreciation of revalued assets. The effect is to increase prices in 2001 and then to decrease them in 2002 once the concession and new lease arrangements are in place.

We recommend that the 2001 (generation and distribution) prices be based on the lease fee to be charged for 2002 onwards rather than the depreciation of revalued assets plus a return/interest obligation.

[13] The replacement values for MV and LV distribution lines are taken from the Excel spreadsheet provided with the Lahmeyer report. The total of $230m does not agree with the $194.5m given in the executive summary report by Lahmeyer.

Return on assets

The concessionaire's return on assets is calculated by multiplying the net book value of assets by the return requirement.

In the model a return requirement of 20 per cent has been used. It is not evident whether this is a WACC (weighted average cost of capital) or a cost of equity. Not much significance should be attributed to this value, since the Transaction Advisors expect that the bidding for the concession will directly set the rate of return.

Annex II provides an assessment of what might be a useful indicative rate of return to use in pricing calculations. Our conclusion is that, given the proposed automatic indexing of prices to inflation and exchange rates, a suitable after-tax return on equity is in the order of 8-14 per cent. If target debt to equity is 1:1, and with interest rates at 23 per cent (see Annex II), then the after-tax WACC should be 12-15 per cent.

Another consideration is whether the return element should be based on actual investment or anticipated (targeted) investment. In the case of a guaranteed return on investment, the return element would be adjusted annually to reflect the previous year's investment. However, as discussed in section 2.1, the ERA may wish at some stage to introduce incentive elements to investment, and calculate the return on anticipated rather than actual investment. At each price review, the return on actual historical investment would be recalculated, and the level of future anticipated investment would be reset, taking account of any evidence of improved investment efficiency.

For indicative pricing purposes, we recommend that the ERA use an after-tax return level of 15 per cent, until such time as the bidding process results in a specific return.

Taxation

Since the return requirement is expressed as an after-tax return, it is necessary to add tax to the revenue requirement.

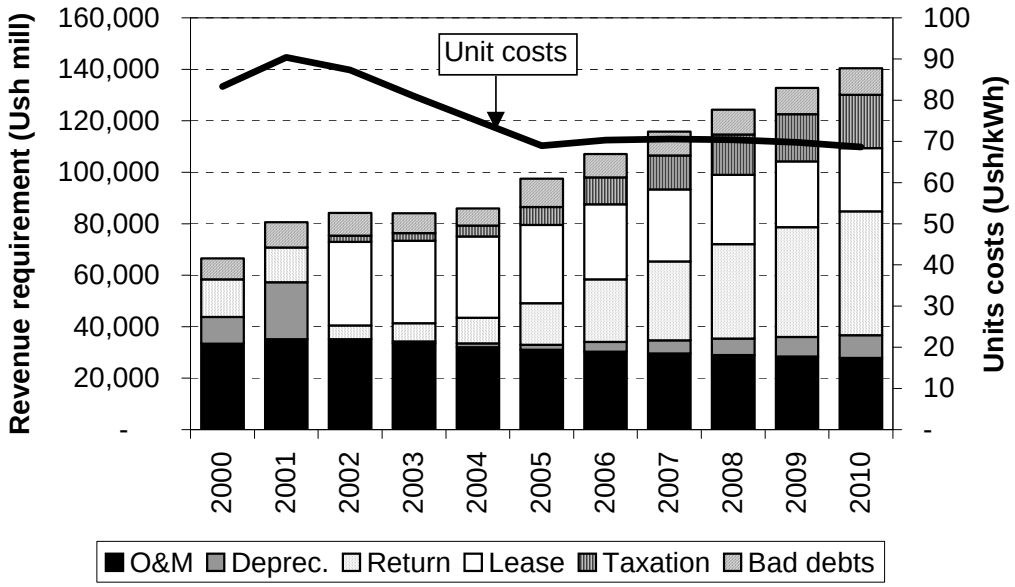
At present the model calculates the tax obligation as 30 per cent of the return. This overstates the tax obligation since a portion of the capital invested will be debt financed, and interest is tax-deductible.

We recommend that the pricing model should be adapted to incorporate a suitable level of gearing (ratio of debt to total assets), and the tax calculations adjusted accordingly.

The total revenue requirement

The figure below[14] shows the build up of the distribution revenue requirement, as projected by the Transaction Advisors[15]. The costs use the Base investment forecast for new investment in distribution.[16]

Figure 6.2 Composition of revenue requirement



The results should be treated as indicative, since a number of factors will act to change the results. These factors include altering the depreciation rate, losses, finalising the lease fee (linked to UEB debt restructuring), return allowances, adjusting operating costs to reflect the increase in customer numbers, currency devaluation, adjusting the taxation calculations, and of course growth rates in consumption.

The increase in costs from 2000 to 2001 is due to the revaluation of UEB's assets, and the consequent increase in depreciation. Thereafter, costs remain approximately constant until 2005. At this point the additional costs associated with the build-out are envisaged to commence in this year. Unit costs, on the other hand, decline by approximately 30 per cent in real terms and then stay more or less constant.

[14] The results presented here are base on information provided to us in December 2000. Data and prices may have been updated since then.

[15] An adjustment has been made to allocate a portion of UEB's existing interest obligations over the entire period to Distribution based on net asset values in 2001. This issue is discussed under the discussion of the lease fee.

[16] The Transaction Advisors used the Low investment forecast for distribution.

6.2 Impact of investment

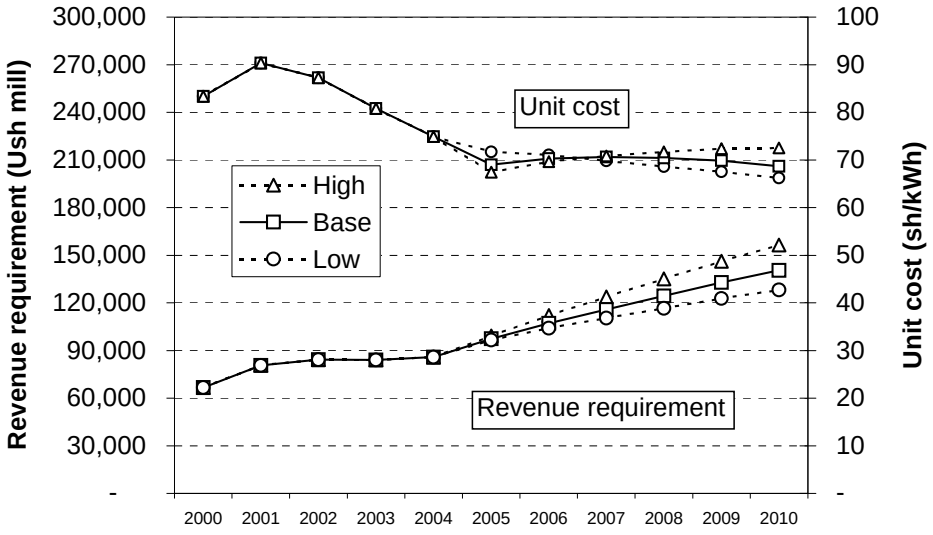
It has been seen in Figure 6.2 that from 2005 onwards, the increase in revenue requirement is largely driven by the investment costs associated with the build-out.

The calculation of the investment requirements has been discussed in section 4.2. While the costs of rehabilitation and strengthening (required over the period 2001 to 2005) were comprehensively investigated, the Transaction Advisors employed a "rule of thumb" to calculate the anticipated investment in the build-out. This rule was that for every 3 per cent increase in customer numbers, a 4 per cent increase in the 2005 replacement value of the assets was required.

This formula equates to an average cost of approximately US$700 per connection. The programme assumes a programme of 12,000 new connection per annum rising to 20,000 per annum by 2010. South Africa's electrification programme has had investment costs of approximately US$450 per connection in urban areas and US$600 in rural areas. The large scale of South Africa's electrification programme (450,000 per annum) has helped to bring costs down, and so the figure used of US$700 per connection may be viewed as a reasonable comparison with rural electrification costs in South Africa. However, this figure may overstate the costs if a large number of connections come from urban areas and densification of existing networks.

The Transaction Advisors projected Low, Base and High investment costs for the build-out from 2005, each corresponding to the EdF Low, Base and High load forecasts. Figure 6.3 shows the sensitivity of distribution costs to these scenarios. While the revenue requirement changes significantly with scenario (by ±10%), the unit cost is much less affected, simply because increased costs are off-set by increased sales.

Figure 6.3 Sensitivity of distribution costs to demand and investment scenario



Given the uncertainties in the costs of the build-out, it is also useful to look at the impact of changes in assumptions on costs per connection. If capital costs of build-out vary by ±10%, the revenue requirement and units cost will change by approximately ±5% by 2010.

Given the uncertainties in the investment required to implement the build-out, we have recommended in section 4.2 that one of the conditions of the concessionaire's licence be that a network expansion plan be undertaken. The ERA should, in consultation with the MEMD, set the targets for such an expansion, and require the concessionaire to plan and cost it. The cost estimates resulting from such a study, once verified by the ERA, will be used for subsequent price controls.

7 End-user price structures

7.1 Proposed prices

In the tariff model, the spreadsheet "Tariff Calculations B" calculates the revenue requirement for different components of the business. The spreadsheet "Tariffs 2001 Calc" then converts these into a set of end-user tariffs. Our discussion here is based on our analysis of this latter spreadsheet, as there is currently no documentation of the method employed.

There are four categories of end-user tariffs:

- Code 10: Small general service taking from the LV distribution network
- Code 20: Large general service taking from the LV distribution network
- Code 30: Industrial users taking from the HV distribution network
- Code 50: Streetlighting

End-users are charged both a power supply charge (for the costs of bulk supply, transmission services and losses), and a distribution charge.

The elements of the tariff include a standing charge (sh/month), a demand charge (sh/kVA) and two energy charges (sh/kWh) – for power supply and distribution charges. The distribution charge is broken into regular and off-peak rates for codes 20 and 30. Only codes 20 and 30 include a demand charge.

Table 7.1 presents the proposed tariffs. The figures below are taken from the spreadsheet as provided by the Transaction Advisors[17], with one alteration made in discussion with Mr Jim Tasillo[18].

[17] The document "2001 UEB Tariff Restructuring" as provided to us had no details filled in section "4 Proposed 2001 UEB Tariff Schedule"

[18] This alteration was to allocate UEB's interest payments to generation, transmission and distribution in proportion to net asset values in 2001. This alteration should not have affected the price calculations and revenue requirement for 2001.

Table 7.1 Proposed tariffs for 2001

	Standing charge	Demand charge	Power supply	Distribtn Regular	Distribtn Off-peak	Effective ave price
	sh/month	sh/kVA	sh/kWh	sh/kWh	sh/kWh	sh/kWh
Code 10	1 000	N/a	64.0	76.9	N/a	145
Code 20	10 000	10 000	61.4	76.9	38.4	181
Code 30	15 000	10000/8000*	33.9	36.4	23.2	102
Code 50	4 000	N/a	60.4	68.3	N/a	133

* sh 10000/kVA is charge for the first 2000kVA and sh 8000/kVA thereafter.

Table 7.2 compares the proposed prices with existing prices. Increases are particularly steep for domestic and LV industrial consumers, who face increases of over 50 per cent.

Table 7.2 Proposed price increases, 2001

Category	Old code	New code	Old tariff	New tariff	Increase
Domestic	1	10	84	145	72%
Commercial	2	10	122	143	17%
LV industrial	4.1 & 4.2	20	119	181	52%
HV industrial	3.1 & 3.2	30	97	102	5%
Streetlights	5	50	129	133	3%

7.2 Methodology

The methodology for calculating these tariffs, as we can detect from an examination of the spreadsheet model, is described below.

Standing charges and demand charges

These elements of the tariff are retained at existing levels.

Power supply

The power supply price for each customer group is calculated as the average of peak, shoulder and off-peak elements of the BST, weighted by the proportion of energy consumed by that group in each time period. The power supply price is also adjusted for losses to that customer group.

The weights are derived from the load profiles per customer group. The proportion of energy used in each time period per customer group is presented below. The source of this data is not documented.

Table 7.3 Load profile information for customer groups

	Codes 10 & 20	Code 30	Code 50	Code 22 & 32
Peak	37.5%	35%	60%	0%
Shoulder	56.0%	65%	40%	0%
Off-peak	6.5%	0%	0%	100%
TOTAL	100%	100%	100%	100%

Note: Codes 22 and 32 are codes for energy consumed by codes 20 and 30 in off-peak periods

Distribution charges

Distribution charges are calculated in the following manner (and illustrated in Figure 7.1):

- The total revenue requirement for distribution is allocated to MV and LV networks according to the proportion 65:35. These form the basis for the calculation of MV and LV distribution charges.
- ***MV distribution charges:***
  - A net revenue requirement for MV networks is calculated as the gross revenue requirement for MV less revenue from standing charges and demand charges from customers on MV networks.
  - A net MV revenue requirement during the peak period is defined as the product of the net revenue for MV and the proportion of energy consumed during the peak period, multiplied by 120 per cent.
  - A net MV revenue requirement during the shoulder period is defined as the product of the net revenue for MV and the proportion of energy consumed during the shoulder period, multiplied by 100 per cent.
  - A net MV revenue requirement during the off-peak period is defined as the remaining revenue required.
  - The net MV revenue requirements per period are then allocated to all customer groups taking power in proportion to the energy they consume.
  - The revenue requirements per time period are then added to yield a revenue requirement per customer group. This monetary amount is then divided by the sum of energy billed per customer group to give an MV charge for that group.
- ***LV distribution charges:***
  - Similarly, a net revenue requirement for LV networks is calculated as the gross revenue requirement for LV less revenue from standing charges and demand charges from customers on LV networks.
  - Similarly, a net LV revenue requirement during peak, shoulder and off-peak is defined in the same manner as for MV
  - The revenue requirements per time period are then added to yield a revenue requirement per customer group. This monetary amount is then

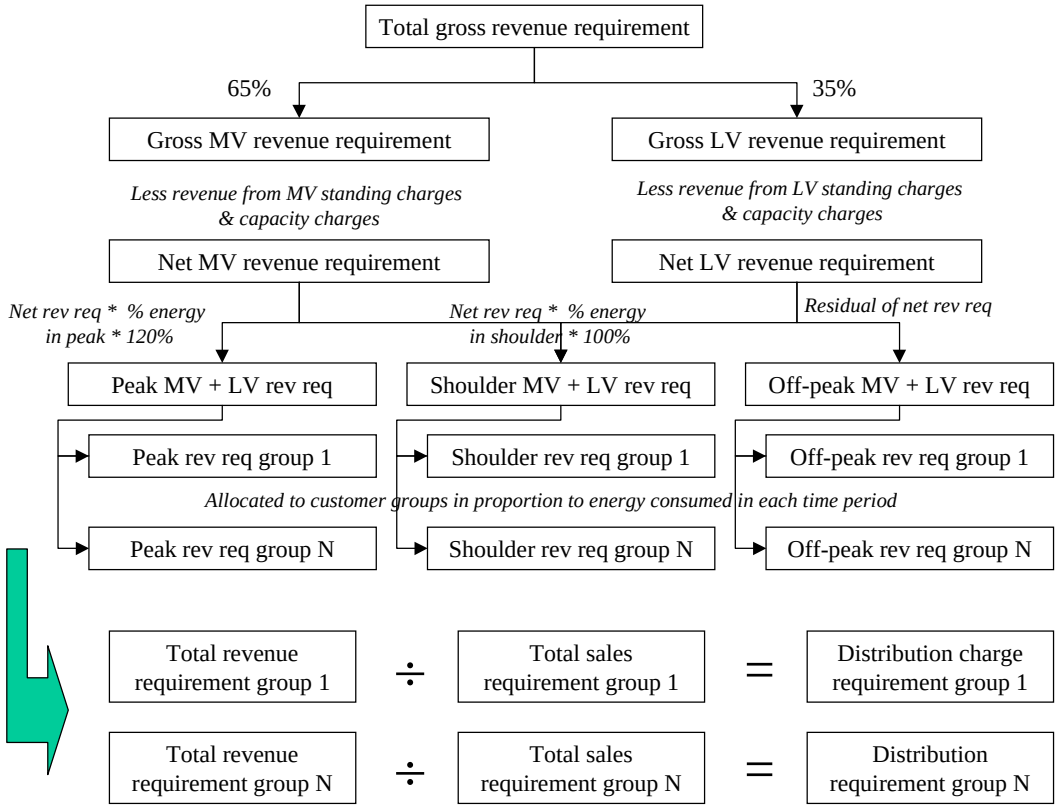
divided by the sum of energy billed per customer group to give an LV charge for that group.

- Finally, the distribution charge for customers taking power on MV networks is defined as their MV charge. The distribution charge for customers taking power on LV networks is defined as the sum of their MV and LV distribution charges.

The parameters driving this algorithm are

- the overall revenue requirement from distribution,
- the 65:35 allocation of costs to MV and LV networks
- the 120 per cent and 100 per cent factors applied to the allocation of costs to peak and shoulder time periods
- technical and commercial losses in MV networks (5 per cent and 4.1 per cent respectively)
- technical and commercial losses in LV networks (12 per cent and 18 per cent respectively)
- the load profiles and energy consumption of the individual customer groups.

Figure 7.1 Illustration of calculation of distribution charges



It should be noted that the revenues from standing charges and demand payments are not credited to specific customer classes. This effectively means that those customers paying demand charges are subsidising those who do not. Thus, distribution fees paid by code 10 customers are subsidised by the demand charges

paid by code 20 customers. This explains why the effective average tariff for code 20 is higher than code 10. Removing these cross subsidies would result in the effective average prices as shown below.

Table 7.4 Revised distribution charges for 2001

	Code 10 sh/kWh	**Code 20** sh/kWh	**Code 30** sh/kWh	**Code 50** sh/kWh
Revenue from standing & demand charges	4.0	44.9	40.7	3.9
Original average price	145	181	102	133
Revised average price	165	158	67	150
Change	13%	-13%	-35%	13%

The cross-subsidy mechanism incorporated in the existing method should be removed. The ERA should consider whether any cross-subsidies to domestic consumers should be implemented in end-user price structures. If so, the ERA should set the maximum effective tariff to domestic customers, and require the revenue shortfall to be spread across other customers groups in proportion to their energy consumption.

In the implementation of this algorithm, we note that LV customers are also required to bear a portion of the cost of revenue losses due to MV customers. This is an error, but only introduces a slight bias to the results.

Total distribution commercial and technical losses are taken equal to those in the supply and demand assumptions underlying the forecasts. It is further assumed that 64 per cent of the technical losses, and 77 per cent of the commercial losses occur at the LV level.

The ratio 65:35 to determine the cost allocation to MV and LV appears arbitrary. Using information from the Lahmeyer report, the ratio of replacement value of transformers and MV lines to LV lines and service connections is approximately 50:50.

With the exception of the cross-subsidy mechanism currently in the end-user price structure, we recommend that ERA accept the methodology employed. In addition, we suggest that the ERA should require:

- ***Documentation of load profiles per customer group.***
- ***Justification for the 65:35 allocation of revenue requirement to MV and LV networks.***
- ***Some justification for the 120 per cent factor applied to peak price.***

7.3 Rural prices

Proposed approach

It is proposed that rural tariffs should contain a 20 per cent surcharge, and that revenue from this surcharge should be allocated to Government's Rural Electrification Fund. It is not evident what the definition of rural is, and who would be liable for paying it.

The rationale for this proposal is that:

- Such a surcharge provides rural customers with a signal that they impose higher costs.
- The distribution concessionaire should be provided with a financial incentive to serve rural customers.
- Developers of off-grid projects and independent line extensions may be reluctant to initiate projects close to the grid, fearing that they will not be able to compete with grid tariffs.

Comments

There will be practical difficulties in implementing this proposal, with regard to defining rural consumers.

The price signal proposed is approximate, and not related to actual costs of serving rural customers. The economic efficiency gains from improved price signals are likely to be small.

Since the revenue from the surcharge is allocated to the RE Fund, the proposal does not provide the grid concessionaire with any additional incentive to serve rural customers.

While sharing costs across rural and urban customers (within a customer class) may tend to lower prices in rural areas, we are not convinced that the proposal as it stands will encourage off-grid and independent grid developers. We would prefer appropriate signals to be provided through more open grid planning and through a revised connection fee policy (see below).

The proposal suggests that rural consumers should contribute to raising funding for rural electrification through the application of this surcharge. In most countries where rural electrification has been subsidised or cross-subsidised, it has been typical that all consumers contribute to the costs. Without such an approach, rural electrification is unlikely to be promoted. Given Government's wish to see an extensive build-out of the distribution network, we suggest that it is appropriate that all customers contribute to the cost of this.

Finally, Government is considering applying a rural electrification levy on bulk supply of electricity. Implementing this levy and the rural surcharge proposal would result in two rural taxes on electricity.

Recommendations

We recommend that the proposal for a 20 per cent surcharge on rural consumers should be rejected by the ERA. In its place, the ERA should seek to implement a new connection fee policy, as described below.

7.4 Connection fees

There is a range of options for a connection fee policy. These are:

- Charge a nominal connection fee, and build the costs of connection into the general revenue requirement and tariff
- Charge a nominal connection fee, and build the costs of connection into a special premium on new customers.
- Charge a cost-reflective connection fee (possibly amortised into monthly payments), but exclude these assets from the return calculation on assets.

It is possible to combine elements from the above options into a connection fee policy.

We recommend that the ERA seek to develop a connection fee broadly on the following lines:

- For customers within a certain distance of existing transformers and LV lines (preferably defined as the limit of the concession area), charge a nominal connection fee as a strategy to densify existing networks. The costs of connection should be included in the investment costs of the distribution company, and so form part of the overall revenue requirement.
- Similarly, for customers within a certain distance of transformers and LV lines built under the planned build-out programme, charge a nominal connection fee. The capital costs of the build-out should then be included in the investment element of the revenue requirement, as is already treated in the tariff model.
- For customers beyond the limit, the distribution company should be permitted to charge a connection or amortised line-extension fee to that customer or group of customers. This fee should cover the additional cost of extending the network beyond the specified distance. In principle, assets funded in this manner should not form part of the asset base for calculation of the concessionaire's return. Similarly, independent grid and off-grid developers should be able charge line extension fees on the same basis.

The advantages of this policy are firstly that it encourages connections in areas where infrastructure already exists. Secondly, it permits a certain amount of cross-subsidisation from existing to new customers, thereby promoting electrification, whilst simultaneously protecting existing customers from expensive electrification projects. Thirdly, it helps level the playing field between the grid concessionaire and independent developers, since all will be charging line extension fees for projects outside the concessionaire's service area. Finally, the plan for the build-

out, which we propose as a requirement of the licence, should give independent investors, and customers, an indication of the higher priority electrification areas.

We recommend that the UEB seek to develop and implement a policy broadly along the lines described above in collaboration with the new concessionaire, and in the meantime UEB's existing connection fee policy should be applied.

7.5 Life-line tariff options

The proposals at present do away with a life-line or poverty tariff. The existing system of an inclining block tariff is designed to offer low rates to customers with very low consumption. This is effectively a cross-subsidy to low-income customers.

As a general policy, we recommend that cross-subsidies be directed at promoting new connections, rather than subsidising existing customers. Such a policy is effectively contained in our proposals for connection fees, in which new customers within a certain limit of existing lines and those within the planned build-out, are cross-subsidised by existing customers.

We suggest that the ERA consult with stakeholders during the 2001 price hearings regarding the implications of removing or phasing out the existing inclining block system.

7.6 Prices and quality of supply

Distribution and Quality of Supply Codes have been prepared which set out a basic framework. The codes set out minimum standards. They do not tackle the basic issues of penalties for poor supply quality and customer satisfaction. It is understood these will be developed for discussion with the distribution concessionaire. However, the codes do need to be developed further in order to make them suitable instruments to assist the ERA in the regulation of the distribution service to the benefit of electricity consumers in Uganda.

What are the available options? The first requirement is have a realistic set of supply quality and customer service targets which are achievable. These should be back up by incentives that may take two basic forms:

- a system of fines for breaching standards, or
- a system that links prices to service quality.

A possible advantage of the second option is that it could have the flexibility to allow the utility to offer lower standards in rural areas at a lower price.

Consideration is given to:

- The development of a Quality of Service Penalty/Reward Indicator (QSI), for inclusion in the distribution tariff formula to be used by the ERA in the periodic adjustment of tariffs;
- The range and level of performance that the distribution concessionaire should be obliged to deliver during the period of transition;
- The institutional issues that need to be considered in developing the capabilities of the parties to meet the regulatory and utility reporting requirements.

One of the conditions set down in the Electricity Tariff Code is that: "The Licensee must set reasonable tariffs consistent with maintaining a high level of quality and reliability."

In order to deliver the appropriate supply quality and reliability, the ERA may wish to consider introducing a Quality of Service Indicator (QSI) that will include factors such as consumer satisfaction, reliability of supply etc.

Quality of Service Penalty/Reward Indicator (QSI)

The QSI might include a combination of a simplified system availability target and a weighted basket of several measurable parameters. Thus, the QSI could incorporate two parts: a customer satisfaction index, and a system performance index. In setting the QSI, it would be important to exclude guaranteed standard payments from these indices.

The ERA may wish to employ an independent customer survey to monitor customer satisfaction as a basis for the customer satisfaction index. We do not have access to data that allows us to assess the key areas of current customer concern. Typically these may include the reliability of the metering cycle, the speed of crediting payments to accounts, and the speed of providing meters.

The ERA is likely to be determined partly by the recognition that UEB does not have the collection mechanisms in place to provide information of an adequate quality and coverage. It is considered that these should be put in place as part of the customer satisfaction survey study. Once the customer satisfaction index is established, its weighting within the QSI needs to be determined. This should be done in consultation with the distribution concessionaire.

The ERA should consider adopting overall system performance, measured by availability (hours lost/customer-year) levels, as the initial basis of the control for the system performance index. No penalties would be paid unless system performance is worse than pre-defined levels. Values would be specified for the first few years until better system performance data has been collected.

The determination of the value weighting of the system performance index within the QSI would need to be established by the ERA.

Customer service targets

Given the strategic importance of programmes to reduce non-technical losses, it is recommended that supplementary targets in associated areas be also set by the ERA. For this purpose, it is proposed that the ERA may wish to establish a few key customer service/commercial targets, including:

- Number of customers who have paid for a connection and are not connected after 21 days;
- Number of customers without meters or cut-outs (for any reason);
- Number of meters issued and not in the billing system;
- Percentage of meters not read in the current month;
- Number of customers with zero meter readings for more than 2 months.

Another important commercial parameter is the number of days of receivables outstanding. Targets for this parameter are best set in discussion with the distribution concessionaire. These targets should be challenging, but nonetheless realistic.

System performance targets

Initiatives should be put in place to improve the quality of information relating to system performance monitoring. Targets of reductions in customer outage hours lost should be agreed between the ERA and the distribution concessionaire. This target is likely to be demanding but should be a key business target. The concessionaire should establish system improvement plans to achieve these targets and as better data becomes available the targets will need to be refined.

It is important that targets set by the ERA for system performance should be demanding yet realistic.

Examples of regulatory approach to quality of supply

Ghana has already taken the step of planning to steer the pricing of distribution services by the use of a quantified Quality of Performance Index. This index is to be a compound of measures of system performance and customer satisfaction combined with valuations of loss of supply (hours) and of the costs of customer dissatisfaction.

The Index therefore requires measurement of system performance and customers' satisfaction - improvements to the performance reporting scheme and surveys of customer satisfaction are now underway. Until these systems are fully in place, short-term targets and measurement mechanisms are to be used. It is unlikely that the impact of the index will be to vary rewards or penalties by more than a few percentage points of revenue, although this is seen as a notable risk to distribution business profitability and therefore a strong incentive to business efficiency.

In South Africa, similar target performance measures have been used for several years in the consideration in pricing of customers' supplies.

In the UK there is now a commitment by the Electricity Regulator to implement a stronger linkage between pricing controls a performance level. Again, factors of system performance efficiency and customer satisfaction are being measured and valued, and standard penalties for a range of under-performance are being levied.

Technical indicators of system performance

System Average Interruption Duration Index (SAIDI)

This index is defined as the system average interruption duration for customers connected per year. Utilities attempt to lower this index as much as possible.

$$SAIDI = \frac{\text{Total Customer-Hours of Interruptions}}{\text{Total Customers Served}}$$

System Availability

This index is defined as the percentage of the year for which the average customer has a supply available. It implicitly presumes that the supply will provide adequate voltage, capacity and frequency characteristics, and is an overall measure of the ability of the distribution business to satisfy customer supply needs. Utilities attempt to increase this index as much as possible.

$$\text{SYSTEM AVAILABILITY} = [1- (SAIDI / 8760)] *100$$

System Average Interruption Frequency Index

This index is defined as the average number of interruptions per customer connected per year. Utilities attempt to lower this index as much as possible.

$$SAIFI = \frac{\text{Total Customer Interruptions}}{\text{Total Customers Served}}$$

Institutional strengthening

The institutional aspects of the supply quality and system performance monitoring should be considered and capability strengthened both in the utility and in the ERA, through appropriate training and staff recruitment.

There is a need to develop skills in the management of regulatory affairs, particularly with regard to dealing with the ERA. Experience from other countries indicates that the managers of the unbundled utility companies will need to be supported by teams able to integrate advice on tariff formulation, financial affairs, and operational functions (billing, revenue protection/collection), engineering, and customer care) to ensure that business strategies are managed consistently. To ensure effectiveness, this support function needs to have some degree of formal independence from the main core functions of the companies.

Recommendations

We recommend that ERA should consider the introduction of a Quality of Service Penalty/Reward Indicator that would be used be used to regulate the quality of supply to customers. ERA should carry our an independent survey to establish levels of customer satisfaction Demanding yet realistic customer service and system performance targets should be established in conjunction with the distribution concessionaire.

Also ERA should indicate a willingness to consider linking electricity prices in rural areas to lower supply quality standards, as a way of bringing down costs and hence prices.

8 Conclusions and recommendations

8.1 Summary of recommendations

The recommendations made during the course of this review are collated and summarised below.

Regulatory approach

Rate-of-return or incentive regulation

There is a direct trade-off between risk and incentives in regulation. A rate-of-return regulatory system, with pass-through of most costs will reduce risks, but also blunt incentives for efficiency. The choice of regulatory system will depend, to a certain extent, on the commitments made in the concessioning process. Since this process has yet to be designed, we suggest that the ERA interact with the Transaction Advisors and the investment bankers, seeking to devise a concessioning approach and regulatory system that appropriately balances risks with incentives.

Price reviews and indexing

It has been proposed that prices will first be set for 24 months, and thereafter reviews will be held every 36 months. We recommend that this approach be adopted by the ERA.

In between price reviews, prices will be indexed. It has been proposed that a portion of the price will be indexed to the dollar exchange rate and prices adjusted monthly. We suggest that:

- The Shilling component of the tariff should be indexed to Ugandan inflation, and that consequent price adjustments should be made on an annual basis. The Transaction Advisors should be requested by URU to propose an appropriate index to use.
- The US dollar component of the tariff should not be indexed to US inflation, or any other inflation rate.

- For simplicity and clarity, the proportion of the tariff indexed to US dollar should be set at each price review, and not updated annually.

While price reviews will be conducted every 36 months, it appears implicit in the proposals (if a specific rate of return is guaranteed) that prices will be reset annually in response to actual investment levels. If and when the ERA moves to introduce additional incentive elements into the regulatory system, then this automatic indexing to actual investment would fall away and prices should then be set for the three year period based on anticipated investment.

Price stability

There is a high risk given existing proposals that prices will be unstable. A particular problem is the high price rise associated with the introduction of the Bujagali power station. We recommend that the Transco introduce increased power supply prices prior to 2005, and not set power supply prices any higher than their expected long-term trend. Revenue from price increases in 2003 and 2004 as well as profits from exports should be used to finance this mechanism. Transco should be required to develop the mechanism required to implement this proposal during the course of 2001.

In the case of price variations associated with instability in monthly export volumes, the Transaction Advisors should be requested to modify the algorithm for calculation of the BST to reflect a rolling average of export levels rather than the previous month's exports.

In the case of other, less predictable, causes of price instability, the ERA should signal that this is an issue to discuss with the distribution concessionaire, and that the ERA is willing to consider any proposals that the concessionaire may wish to make with regard to improving stability of prices.

Incentive targets

We recommend that the distribution loss targets included in the tariff model be reset in light of losses experienced in 2000. These revised figures should be used to determine 2001 prices, and as indicative targets in providing information to potential concessionaires. The ERA should reserve the right to reset these targets at each 36 month price control.

With respect to targets for distribution operating costs, we recommend that either the Transaction Advisors revise the gains in the light of anticipated new connections, or inform potential operators that the current figures will be revised to take account of system expansion from 2005 onwards.

The ERA should initiate a comparative study of distribution costs in order to inform the price review to be undertaken in 2002.

Asset values, investment and lease fees

Asset values

Subject to the Transaction Advisors clarifying the discrepancy between replacement cost and OCV figures in the Lahmeyer report and those used in the pricing model, we recommend that the ERA accept the asset values calculated by Lahmeyer.

Investment projections

We recommend that ERA adopt the Base rehabilitation investment figures (2001 to 2005) produced by the Transaction Advisors, subject to clarification of the differences in numbers presented in the Lahmeyer report (and provided to investors at the October London briefing) and the figures in the tariff model.

The build-out investment figures for 2005 onwards should be used for indicative pricing, but that the approximate nature of the figures be made known to investors in bidding documents released early 2001.

Further, the distribution licence should contain a requirement that the distribution concessionaire prepare a system expansion plan for the period 2005 to 2010. The targets for this expansion, and the terms of reference for the study, should be developed collaboratively between the ERA and the MEMD. The plan should be costed and submitted by mid-2004 at the latest. Once the ERA has independently verified the cost estimates, these should be used for price setting from 2005 onwards.

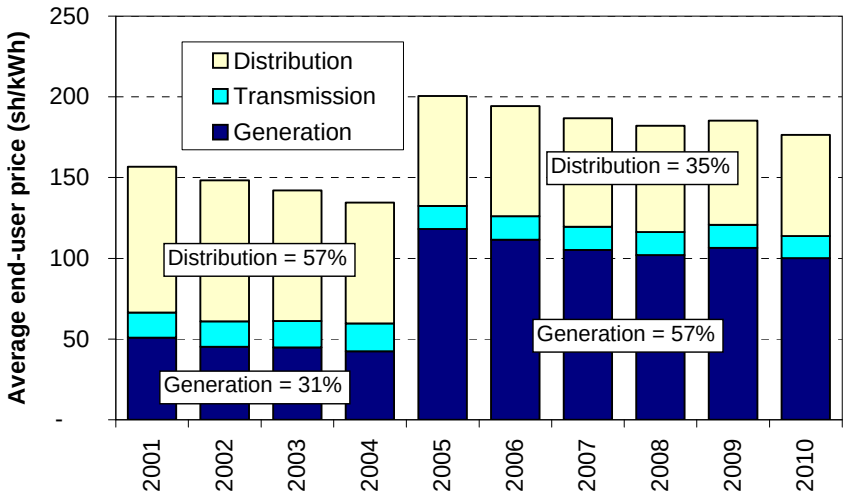
Lease fees

We recommend that ERA require the GoU to clarify what lease should be charged as soon as possible. Given that the introduction of private returns to capital, as well as the backlog of investment required, will tend to increase prices, the ERA should recommend to Government to set the lease payment at moderate levels. The lowest acceptable lease payment will be that required to service UEB's restructured debt.

Price levels

The figure below shows the components of average end-user prices. Over the period 2001 to 2004, distribution and retail account for the majority of total costs, whereas from 2005 onwards, generation does. This is due to the steep increase in generation costs as a result of Bujagali, which results in an average end-user price increase in 2005 of 50 per cent.

Figure 8.1 Build-up of end-user prices



Average generation prices

The generation element of the end-user price starts out at around 50sh/kWh, declining to around 40sh/kWh by 2004. It then increases dramatically in 2005 to 120sh/kWh as a result of the additional costs of Bujagali. Thereafter, prices decline steadily to around 100sh/kWh as load grows.

While prices show some sensitivity to factors such as load growth, exports and lease fee, the step increase in prices in 2005 overshadows these other effects. An important feature of the price increase in 2005 is the "overshoot" due to surplus capacity once Bujagali has been introduced. Passing these costs through to end-users means that prices increase by close to three-fold, and then decline significantly thereafter. If the Single Buyer absorbs the costs of surplus capacity, then the "overshoot" will be eliminated.

It is possible to design methods to improve price stability. While the underlying increase in costs from 2005 onwards cannot be avoided, it is possible to phase in the price increase over several years and eliminate the price shock followed by subsequent reductions. As outlined above under "price stability", we recommend that the Transmission company increase bulk supply prices prior to 2005, and use the income generated to cover the costs of surplus capacity in the years 2005 – 2007. We also recommend that profits from exports over the period 2000 to 2004 could also be used to cushion the impact of price increases in 2005.

Average transmission prices

Transmission prices account for a small portion of end-user prices – only 8-12 per cent. Prices increase slightly over the period 2000 to 2004 as a result of increased investment in preparation for Bujagali. Thereafter, prices decrease as load increases.

Our concern with the current method for calculating the revenue requirement of transmission is that investment is implicitly assumed to be financed at zero interest. The revenue requirement is simply calculated as operating costs plus depreciation plus interest on existing debt.

While the GoU may be able to raise capital at extremely low interest rates, this approach does not allow the transmission company to develop an independent commercial orientation, nor to self-finance a portion of its investment requirements. We recommend an alternative method where the transmission company is allowed a return on capital in calculating its revenue requirement, with a reasonable return level being equal to its expected cost of debt in the coming years.

Average distribution prices

Average distribution prices are a function of the calculation of the revenue requirement of distribution. The revenue requirement is made up of:

- ***Depreciation:*** We recommend that the Transaction Advisors provide justification for the use of a 3.5 per cent depreciation rate for distribution assets, or propose a new rate with justification.
- ***Return on assets:*** For indicative pricing purposes, we recommend that the ERA use an after-tax return level of 15 per cent, until such time as the bidding process results in a specific return.
- ***Operating costs:*** Current levels appear reasonable, but the ERA should initiate a distribution cost study to assist in setting efficiency gain targets for the next price review.
- ***Lease fee:*** As discussed above, the determination of the lease fee is a matter for the GoU, although the ERA should rightly limit the return that the state should earn on its assets. Since it is clear that the GoU has no desire to earn a high rate of return, we have recommended above that the ERA should simply require the GoU to clarify what lease fee it requires over the time frame of the lease.

  We recommend that the 2001 prices be based on the lease fee to be charged for 2002 onwards rather than the depreciation of revalued assets plus a return/interest obligation.
- ***Taxation:*** We recommend that the pricing model should be adapted to incorporate a suitable level of gearing, and the tax calculations adjusted accordingly.

Price structures

Power sales agreement between Genco and Transco

The current proposal for fixing the tariff between the Genco and the Single Buyer (Transco) will not achieve revenue sufficient to meet the Genco's requirement unless 100 per cent availability is attained. We propose that the method set a target availability level so that the full revenue requirement is obtained should this

target be reached. This availability level should be based on historical levels, with an adjustment for anticipated improvements in operations.

The logical error in the description of the payment for cases where availability is less than 100 per cent should be corrected.

Given that the finalisation of 2001 tariffs is imminent, we recommend that the Transaction Advisors' recommendations be provisionally accepted, conditional on including a target availability in the HCP formula and correcting the error in the calculation of payment for reduced capacity.

Nevertheless, the workability of this system should be evaluated during 2001, and consideration given to other approaches, as suggested in section 5.1.

Bulk sales tariff

The proposals for calculating the BST at present assume full pass through of generation costs with consequent steep price increases in 2005, followed by real price decreases. As discussed above, we suggest that the Single Buyer seek to introduce the price increases due to Bujagali over several years, and to set prices no higher than the long-term expected level. This mechanism should be financed from price increases prior to 2005 as well as profits from exports.

Price variations caused by monthly variations in exports (in the calculation of the Bulk Supply Costs) should be smoothed by using a rolling average of monthly exports rather than the previous month's exports.

The BST is divided into peak, shoulder and off-peak rates, with the peak rate being 120 per cent of the shoulder rate. This ratio is arbitrary but designed to introduce the principle of cost-reflect prices, and the ERA should initiate a discussion on how to set this ratio. Given that the Ugandan electricity system will be capacity constrained over the period 2001 to 2004, and again from 2007/8 onwards, it may be desirable to introduce a maximum-demand charge in the BST, thereby giving the Disco incentives to introduce demand-side management (DSM) programmes.

End-user price structures

End-user prices are structured as standing charges plus energy charges for codes 10 and 50, and standing charges plus capacity charges plus energy charges for codes 20 and 30. Standing charges and capacity charges are retained at existing levels, and the energy charges calculated to obtain the residual revenue requirement. The revenue requirement is divided between HV and LV networks according to the ratio 65:35, and the energy charge is calculated based on load profiles per customer group and the ratio between price periods of the BST.

The revenue from standing charges and capacity payments is subtracted from the overall revenue requirement (at each voltage level), effectively implying that customers paying capacity charges cross-subsidise those who do not, most noticably between codes 20 and 10. The ERA should decided whether cross-

subsidies are acceptable, and if not to require the Transaction Advisors to modify the algorithm appropriately. If cross-subsidies to domestic consumers are a policy, we suggest that the ERA set the maximum effective tariff for domestic customers, and the consequent revenue shortfall be spread evenly across other customer groups in proportion to their energy consumption.

With the exception of the cross-subsidy mechanism currently in the end-user price structure, we recommend that ERA accept the methodology employed. In addition, we suggest that the ERA should require:

- Documentation of load profiles per customer group.
- Justification for the 65:35 allocation of revenue requirement to MV and LV networks.
- Some justification for the 120 per cent factors applied to peak period prices.

Life-line tariffs, rural surcharge, connection fees and quality of supply

We recommend that the proposal for a 20 per cent surcharge on rural consumers should be rejected by the ERA. In its place, the ERA should seek to implement a new connection fee policy, broadly along the lines described in section 7.4 in collaboration with the new concessionaire. In the meantime UEB's existing connection fee policy should be applied.

Given the high level of poverty in Uganda, and the high price increase which low income consumers face as a result of the proposed tariffs, we recommend that the ERA exercise some caution in removing life-line tariffs. We suggest that the ERA consult more broadly with stakeholders in the industry, and so understand better the implications of removing or phasing out the existing inclining block system.

We recommend that ERA should consider the introduction of a Quality of Service Penalty/Reward Indicator that would be used be used to regulate the quality of supply to customers. ERA should carry our an independent survey to establish levels of customer satisfaction Demanding yet realistic customer service and system performance targets should be established in conjunction with the distribution concessionaire.

Also ERA should indicate a willingness to consider linking electricity prices in rural areas to lower supply quality standards, as a way of bringing down costs and hence prices.

8.2 Dealing with the 2001/2 price application

Generation tariffs

In calculating the Genco revenue requirement for 2001, depreciation plus return on assets/interest charges should be replaced by the expected lease fee for 2002.

While provisionally accepting the proposed method for calculating payments to the Genco, the ERA should express doubts about the workability of the mechanism and the potential for manipulating determination of availability and capability. The implementation of the system should be monitored with a view to amending it in order to reduce the level of oversight and validation required.

The proposed method should be (immediately) revised to:

- Introduce a target availability in the calculation of the Hourly Capacity Price.
- Correctly calculate the payment during instances of reduced availability.

Bulk supply tariff

The method for calculating the BST for 2001 should be accepted with the following conditions:

- The revenue requirement for UEB Transmission is altered to allow UEB Transmission a return on capital.
- There is some justification for the 120:100 ratio of peak to shoulder prices.
- Documentation is presented of the load profile used to determine off-peak energy consumption.
- The calculation of the Bulk Supply Costs should be amended to reflect a rolling average of export volumes rather than the previous month's export volumes, or the distribution company be tasked with smoothing end-user prices.
- The error in the description of the tariff relating to the calculation of the BSC should be corrected[19].

Further, it should be noted that the method for determining the BST will be changed in future in order to implement the gradual increase in prices to accommodate the additional costs of Bujagali, as well as considering the possibility of a maximum demand charge component to the tariff.

End-user prices

The method for calculating end-user prices for 2001 should be accepted subject to the following conditions:

- The calculation of asset costs (depreciation plus interest charges) should be replaced with the anticipated lease fee for 2002, and the GoU should determine this lease fee as soon as possible in order to allow this.

[19] The line "Bulk Supply Costs…shall be equal to the sum of: (1) the total costs of Power Supply and Transmission Services multiplied by the ratio of sales to UEB Distribution to total sales by UEB Transmission, (2)…" should be replaced by "Bulk Supply Costs…shall be equal to the sum of: (1) the total costs of Power Supply and Transmission Services, (2) …".

- Justification for a 3.5 per cent depreciation rate for distribution assets should be provided, particularly important if depreciation expenses influence the lease fee set by GoU.
- The distribution loss figures should be reset in light of actual losses experienced in 2000.
- The existing cross-subsidies in the tariff calculations (from customers paying capacity charges to those not paying capacity charges) should be removed.
- Should the ERA decided to cap domestic (code 10) prices, then any revenue shortfall should be spread across other customer class in proportion to their energy consumption.
- The ratio used to split the overall revenue requirement between MV and LV customers (65:35) should be justified or amended.
- The load profiles used to determine consumption per customer group in each load period should be documented.
- The 20 per cent rural surcharge should be removed.

8.3 Priorities facing ERA

The key priorities facing the ERA are presented in the table below.

Table 8.1 Key priorities facing the ERA

Task	Timeframe
Finalise the tariffs for 2001/2	Immediate
Draft a description of the regulatory framework, including price indexing between reviews, in consultation with URU as the concessioning process is designed.	Immediate
Consult with stakeholders regarding the removal or reformulation of life-line tariffs.	During 2001
Require and assist UEB Transmission to develop a new approach to setting the BST in order to allow a phase-in of the additional costs of Bujagali.	During 2001
Initiate a study of the costs of distribution.	During 2001/2002
Develop QSI, targets & penalties in consultation with distribution concessionaire	During 2001/2002
Determine the terms of reference, in consultation with the MEMD, for the system expansion plan to be undertaken by the successful distribution concessionaire	During 2001/2002
Develop a connection fee policy in collaboration with the successful distribution concessionaire.	During 2001/2002

Annex I:
Review of EdF demand forecasts

This appendix will give a very brief overview of the load forecast studies prepared by Electricité de France (EdF) for the World Bank[20].

EdF did the first forecast study in 1998. The load forecast covered the period from 2000 to 2020. This forecast was then revised and updated in 2000. The methodical approach was kept the same, and the revision focused on some changes in assumptions and base data. The focus of this section is the 2000 revised forecasts.

The starting point of the EdF study was Kennedy & Donkin's Hydro Power Master Plan for Uganda and the Lahmeyer study of UEB assets and needed investments.

Methodology

The load forecasts are based on a set of assumptions and smoothed historical data from the period 1994-1999. Monte Carlo simulations with 10 000 iterations are used to create a probability distribution for the load forecasts.

The forecasts are given for:

- Base - the estimated average.
- Low - the lower 20 per cent cut-off point on the Monte Carlo results
- High - the upper 20 per cent cut-off point

All three categories are reported as:

- Energy requirements without losses, with losses (and co-generation)
- Peak load.

Key variables and assumptions

The forecasts are calculated from the variables given below. In establishing the total demand, the study relies on the number of customers within the nine different classes of consumers. Specific consumption is defined for each class. A key element for forecast of residential consumption (domestic) is increase in income and related move of consumers through the income classes. Typically a high-income urban customer has much higher consumption than a low-income rural consumer. Different growth rates are applied to the different income classes to give relatively detailed demand information.

[20] The documents are EdF (September 1998), *OPTIMISATION STUDY – LOAD FORECAST* and EdF, (October 2000), *UGANDA LOAD FORECAST REVIEW (Up-date 2000)*

Projected variables:

- General:
  - Monetary GDP growth and Industrial product growth for each year
  - Technical and non-technical losses (linear decrease until 2010 and 2008 respectively, then constant thereafter)
  - Load factor (linear increase 2000 - 2020)
- For the residential sector:
  - Number of new connections for 2000 and growth rate 2000 - 2020
  - Of the estimated 40 000 customers disconnected due to non-payment and theft, 20 000 are assumed to return in 2001
  - Average electricity demand for each type of consumer
  - Maximum share of household income dedicated to electricity
  - Nominal electricity tariff increase for residential sector in 2000
  - 25 per cent annual phase-in of consumption (relative to normal use in income category)
- Non-residential sector:
  - Real electricity tariff increase for non-residential sector in 2000
  - Price elasticities, and income elasticities related to GDP or Industrial Product (respectively for commercial /general sector and industrial sector).

Key changes from 1998

The base value in the revised forecast was reduced according to observations of actual use. Lower growth was used than earlier expected, together with UEB implementing a policy of disconnecting connections to consumers not paying, are the main reasons mentioned.

There are also generally reduced assumptions on economic growth due to recent macroeconomic observations.

Direct or indirect price elasticities are included. This is particularly important as tariffs are assumed by EdF to rise sharply in 2000 to meet cost recovery levels and accumulated inflation of about 60 percent. The tariff increase is unevenly distributed between the industrial and residential sectors, so that industry carries a larger portion of the burden (non-domestic prices are assumed to rise by 73 per cent and domestic prices by 50 per cent). This price increase is assumed to be a once-off price rise at the start of the period, and is comparable with the price hikes proposed for 2001. However, the forecast does not take account of price increases associated with the introduction of Bujagali, and hence may overestimate demand from 2005 onwards.

In the 1998 study consumers were expected to reach mature consumption level immediately. The update use a more plausible phase-in over four years, i.e. that

25 per cent of mature consumption level is added each year according to the stepwise nature of acquisition of electrical appliances and so on.

As a result of the above-mentioned changes, the 2000 revised Base forecasts are reduced and closer to the 1998 Low level. This seems also to be a more realistic assessment of demand growth (see section 3.2).

The EdF forecasts in this report

This report has used the *EdF 2000 Base* for the Base demand projection. It is complemented with export projections as described in section 3.3 to give complete demand. We did not have access to the EdF Excel spreadsheets, and thus had to do a linear interpolation between the values of the years presented in the report (2000, 2005, 2010).

The EdF Base forecast differs somewhat from demand used in the tariff model by the Transaction Advisers. Unconstrained demand in the tariff model is below EdF Base in the period 2000-2005 due to a constraint on new connections in the tariff model. After 2005 the Tariff Model has a higher demand caused by a strong catch-up effect as the constraint is lifted. For constrained demand the two projections are equal prior to 2005, but then the tariff model calculates a higher growth rate. It should be noted that the Transaction Advisors have not yet been instructed to use the revised EdF forecasts, but may be required to do so by the URU.

Annex II
Cost of capital for pricing purposes

General comments

A key element in the required rate of return is the risk premium. The GoU can influence the risks that the bidders perceive. It then needs to weigh several considerations. On the one hand it wants the potential contractor to carry much of the risk of operating the distribution system and to have strong incentives to carry out investments in expanding the net in a cost efficient way. On the other hand it should realize that the contractor might perceive the risk as higher than the government does, so that the government will have to pay a premium for the risk relief.

Risks arise from factors such as uncertainty in inflation and exchange rates, regulatory and political risk, as well as market risks related to sales growth and payment levels.

To reduce the risk premium that the GoU will have to pay it can design the tariff mechanism so that the return to be made on invested capital to a large extent is decided by cost-plus calculations. The mechanism can allow the contractor to bring forward a high share of the cost of loans, or the costs can be calculated from some multiplier of the interest rate paid on a financial benchmark, such as treasury bills. For foreign loans a correction for changes in the exchange rate may also be included. The bidding process will then be limited mainly to the return on equity, and even here the GoU should allow for changes in the exchange rate to reduce the risk premium that the concessionaire otherwise will add to compensate for the uncertainties about the future of the Uganda shilling.

The drawback of cost plus calculations is that the contractor loses incentives for cost efficiency and may have incentives to over-invest. However, there obviously has to be some procedure for the regulator to approve investment so that the concessionaire will be able to secure loans. Further the need for equity to maintain gearing at an acceptable level may also serve as an incentive invest prudently.

It is common for companies to calculate with an ex-ante return on equity capital of 15 percent and more. However, this high rate is rarely achieved ex-post, and is clearly explained by a need to compensate for uncertainty and risk. Part of that uncertainty is nominal, and if this part of the uncertainty is reduced through indexing to inflation and exchange rate, there should not be a need for contractors to ask for this high rate. On the other hand, Uganda is an emerging market where the perceived political risk is still high, and this will call for a country-specific risk premium. Still, it is difficult to justify rates of 15 percent or more after-tax return-on-equity, about two times the return on treasury bills, given the indexing mechanisms suggested.

Some estimates

As a starting point we quote from Siggel and Semogerere (2000)[21]:

> *The cost of capital is measured by four components. First, the financial social opportunity cost is taken to equal the shadow interest rate applied to the total value of fixed and non-fixed assets at purchase prices. The shadow interest rate is computed as the mean of two estimates. Both are based on the assumption of strong international mobility of capital. The first is the international rate LIBOR[22] (6.1 per cent in 1997), augmented by an inflation differential between Uganda and the OECD average of 5.4 per cent, resulting in 11.5 per cent. This approach has been criticised as being unrealistic. One can indeed argue that the shadow interest rate should include a margin accounting for the underdeveloped state of the financial sector and low savings, implying costs and a risk factor that exceed those of high-income countries. Unfortunately, we were unable to find data measuring these factors. An alternative approach, based on the international interest parity condition, is to add to the LIBOR the expected rate of depreciation of the shilling. Using the actual exchange rate of 1998 as the expected one, we obtain an expected rate of depreciation of 14.5 per cent and a shadow interest rate of 20.6 per cent. We consider the rates of 11.5 per cent and 20.6 per cent as lower and upper bounds (used in sensitivity analysis) and adopt the mean of 16 per cent as the shadow rate for our computations of the shadow cost of capital.*
>
> *In contrast, the market opportunity cost of capital is equal to the capital stock times a market interest rate, which is taken to equal the average lending rate of 21.5 per cent, based on IMF statistics (IFS, various years). The difference between these two interest rates constitutes the main capital cost distortion and is the second component. The third component is the annual depreciation as reported by the firms; it is treated as undistorted for simplicity. The fourth component is a capital price distortion, due to the payment of import duties on imported capital goods. Only a few firms have reported this distortion, and even where reported, it represents a negligible proportion of total costs. We also do not attach much importance to this distortion, because we focus on present policy distortions. Duties on capital goods represent a policy distortion of the past, i.e. of the time when major investments were made.*

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21 *Uganda's Policy Reforms, Industry Competitiveness and Regional Integration: A comparison with Kenya,* African Economic Policy Discussion Paper Number 24 from the United States Agency for International Development, Bureau for Africa, Office of Sustainable Development, Washington, DC, June 2000 by Eckhard Siggel, Concordia University and CRÉFA, and Germina Ssemogerere, Makerere University, Uganda.

22 London Inter-Bank Offered Rate (deposit rate in the inter-bank market).

Then we try to update the numbers in this quote. The one year LIBOR for US$ at the end of 2000 was about 5.9 percent, and the inflation rate in Uganda was down to 4.2 percent which implies a differential to the OECD average of only 2.2 percent. So a low estimate of the shadow cost of capital in Uganda is about 8 percent. Using the expected rate of currency depreciation as a proxy for risk factors that exceed those of high-income countries is not an obvious procedure any longer as the Ugandan shilling is not as obviously over-valued as it was in 1997, and the inflation rate is down. Instead we suggest arbitrarily adding 6 percent to the low estimate to define a high estimate. A mean estimate of the social opportunity cost of capital is then 11 percent. This is significantly lower than the estimate of 16 percent that is quoted above, and it reflects both the improvement in macroeconomic management and the correction that has taken place in the exchange rate.

This number can be compared to the market average lending rate that the IMF *International Statistics* report to be about 23 percent during 2000, up somewhat compared to 1997 in spite of the general improvements in economic fundamentals. This reflects the tight fiscal and monetary policies, the discount rate is up from 14 percent in 1997 to about 25 percent in 2000.

Another approach might to look at actual returns on foreign direct investment (FDI). Some numbers are given in *Foreign Direct Investment in Africa: Performance and Potential* (UNCTAD/ITE/IIT/Misc. 15). Table 3 quotes rates for US FDI in Africa (not including South Africa) between 25 and 35 percent. However, these high numbers are explained by a distortion related to an under-evaluation of the capital stock, therefore they cannot be considered relevant.

Conclusion

There has been a considerable improvement in the Ugandan economy in recent years, but it is presently in strict readjustment process that is accompanied by very high interest rates. Our advice is that the presently high interest rates should not be taken as indicative of the opportunity cost of capital in Uganda. With tariff mechanisms that take away most of the risks related to taxation, inflation and exchange rate there should be no need to pay more than about 10–11 percent rate of return on concessionaire equity. Borrowed funds could be compensated at cost, or could be included into a WACC calculation based on prevailing interest rates to calculate a return for pricing purposes on an annual basis.

Annex III
Principles of tariff structure

This annex will outline the principles for an optimal tariff structure and thereafter comment on tariff structure for Uganda.

When power systems are deregulated, it is common to distinguish conceptually between the grid as a natural monopoly on the one hand and generation and retailing which are exposed to competition on the other. When evaluating the Ugandan pricing system, particularly in looking at end-user prices, it may however be useful to turn back to the "old" perspective, and consider generation, transmission, distribution and retailing as one *total power system*.

From an economic point of view, a natural goal is to maximise the social surplus of this system, which is to maximise the consumer's utility of consumption minus the costs of generation and transmission. Although obvious, it is important to point out that patterns of production and consumption influence the short and long run costs of the total power system. Similarly, changes in the localisation of production and consumption influence the demand for transmission capacity.

Optimal tariff structure

The main features of an optimal tariff structure are that consumers receive correct signals about marginal cost of increased consumption and that producers receive correct signals about marginal willingness to pay for increased production. In an efficient market system, there is no need for regulation; market prices will reflect both the marginal cost and willingness to pay. However, power systems are subject to market failures, which normally implies distorted prices or that market prices do not exist at all (as in the Ugandan case).

Price signals and cost reflective tariffs

The economically optimal structure of tariffs has two main characteristics

- All agents should pay the costs they impose on the system, i.e. short-run marginal costs, losses and direct costs associated with connection or network strengthening.
- Supplementary charges, meant to cover costs not included in the first bullet point, are designed to minimise influence on the behaviour of the agents and in particular not to reduce the use of the system.

The value chain is generation, transmission, distribution and retail. The end-user prices should reflect the sum of the marginal cost in all parts of the value chain.

The costs of transmission and distribution of electricity are mainly fixed and there exist economies of scale. Economies of scale imply that marginal cost is below average cost. Marginal cost pricing is therefore not sufficient to cover the total

cost. There is a need for elements in the tariff system to cover the difference between the average and the marginal cost.

Transmission - Nodal pricing

In an optimal designed power system, the prices in each hour and in each node should reflect the marginal cost of tapping out (or feeding in) electricity. In a country with an advanced power system including a high degree of information availability, the system operator should be able to calculate the optimal price at each node. The node prices are then the relevant wholesale prices to be included in the end-user price. An optimal node price system will reflect the variations in load, and will implicitly represent a peak load pricing system. Transmission losses and congestion prices will also be reflected in the node prices.

Distribution - Need for supplementary charges

Distribution charges should in principle also be based on marginal cost pricing. But to overcome the problem of economies of scale, the larger part of the distribution tariff is supplementary charges.

Normally distribution charges are set as average price on energy delivered. This gives no incentives to organise consumption to optimise the available capacity. It could increase efficiency to introduce peak load pricing, since the main cost driver is the maximum load. But hourly metering and peak load pricing requires installation of necessary metering devices, which may be too costly, compared with actual demand. Thus such pricing is applicable only to larger customers.

Tariff structure for Uganda

For Uganda the challenge is to find a set of second best rules that maximise the social surplus, given all relevant restrictions. What is efficient in a first best world is not necessarily efficient in a second best situation.

Key relevant features of the Ugandan power system are:

- single buyer model and effectively no market;
- few generators, with capacity based PSAs;
- excess demand, but possible excess capacity after 2005;
- many small consumers.

Power supply element of end-user prices

The single buyer's PPAs with the producers are not related to demand, since payment is based only on available capacity (MW). That price is not a marginal cost price, and an obvious problem is that consumers will bear the costs of any excess capacity. There will be full cost pass-through so that the single buyer gets all costs reimbursed through payments from the Disco.

Proposed contracts between single buyer and Disco are energy charges. An obvious problem with a price only related to energy, is that the network owner

does not face any incentive to reduce the maximum load. The structure of peak, shoulder and off-peak prices will contain some incentives to do so, but the proposed eight hour peak period is possibly too long for the Disco to design effective price signals in its own pricing system. An alternative could then be to reduce the time period of the peak, and increase the price paid during this period.

The Disco may face limitations in transfering a time-of-use BST into a time-of-use end-user price due to metering costs or other limitations. This restricts hourly metering and peak load pricing to larger industrial customers. Industrial consumers could also be given other economic incentives to cut demand in stressed situations in the power system, including interruptible tariffs, i.e. a price discount for the right to load shed during stressed periods.

Smaller customers equipped with simple metering technology could pay flat energy tariffs based on an estimated load profile (as the current price emthod currently employs). This, combined with peak load pricing for large consumers, would typically result in higher prices to residential consumers. A solution such as this does have efficiency gains compared to the case of flat energy tariffs for all customers.

Transmission element of end-user tariffs

The transmission costs are the sum of energy losses, capital cost related to fixed investments and operating & maintenance costs. All costs are passed on to end-users.

There are principally no restrictions to use nodal pricing in Uganda. Still some technical limitations may exist on metering and dispatch, but this does not necessarily justify average pricing that would reduce incentives.

Capacity restrictions in the transmission network could cause a need to introduce some sort of congestion pricing in power supply. Network owners tapping power in stressed part of the power system should pay more than others.

Distribution element of end-user tariffs

The distribution costs are the sum of energy losses, capital cost related to fixed investments and operating and maintenance costs. Normally the distribution network is the most costly part.

Supplementary charges to compensate for high portion of fixed costs should normally be levied on energy, not on maximum load. This is based on long term equilibrium without many of the restrictions relevant for Uganda.

A key issue is the allocation of distribution costs to different voltage levels. The split is normally related to how costs actually are allocated between the different levels. It is difficult to comment on the proposed split in Uganda, which is largely an accounting issue relating to asset values.

It could however be rational to deviate from the cost allocation based on cost considerations due to Ramsey pricing considerations. The principle is that actors with low elasticity of demand should carry the large part of the fixed costs. However, Ramsey pricing could be in conflict with social and political goals. Ramsey pricing would normally give higher prices for residential consumers relative to industrial consumers. This would be regressive, particularly in Uganda due to the low level of income for many residential consumers.

Annex IV: Minutes of meeting

MINUTES OF MEETING		
Meeting:	Tariff adjustments for 2001	
Venue:	URU Board Room	
Time:	2:30 pm	Date: 22 January 2001
Invited:	ERA, URU, UEB, NVE, Transaction Advisors, ECON	

Attendance

B Dramadri (ERA - chair), Kasangaki (ERA), D Okumu (UEB), J Wright (URU), T Sherwood (PA Consulting), E Nyirinkindi (URU), P Mare (UEB), S Zimbe (UEB), R Bjelland (NVE), M Davis (ECON).

Italic text refers to ECON's draft report, if not otherwise stated.

1 Finalisation of 2001 UEB tariff application

1.1 Generation revenue requirement

In calculating the Genco revenue requirement for 2001, depreciation plus return on assets/interest charges should be replaced by the expected lease fee for 2002.

URU informed the meeting that it has been proposed to Government that the lease fee should be comprised of depreciation of revalued assets plus interest on outstanding UEB debt. This formulation is used for setting the 2001 tariff, and so is consistent with the recommendation.

URU further informed the meeting that it has proposed to Government that UEB's debt be restructured to reflect Government's debt terms, rather than the terms at which Government has on-lent to UEB. If accepted, this will reduce the lease fee from the current anticipated level.

1.2 Calculation of Generation tariff

The proposed method should be revised to:

- *Introduce a target availability in the calculation of the Hourly Capacity Price.*

This proposal was accepted by the meeting, and UEB was tasked with proposing a target availability to ERA.

- *In the description of the generation price , replace the phrase (2001 UEB Tariff Restructuring, pA-3):*

  "If a unit is on outage or reduced capability…. Payment will be made only for all full (60 minute) hours (of the 24) that the unit is available, by applying the reduced Capacity Price (50 per cent of the normal rate per MW) to the ratio of the actual unit capacity in each hour to the Maximum Actual Capacity of the unit" with the phrase

  "If a unit is on outage or reduced capability…. Payment will be made only for all full (60 minute) hours (of the 24) that the unit is available, by applying the reduced Capacity Price (50 per cent of the normal rate per MW) to the actual unit capacity in each hour of the unit"

This was accepted by the meeting, and PA Consulting will effect the recommendation in the draft of the price description.

1.3 Transmission revenue requirement

"The revenue requirement for UEB Transmission should be altered to allow UEB Transmission a return on capital".

This recommendation was accepted by the meeting, and Mr Sherwood noted that the recommendation had already been implemented.

It was noted that the impact on the 2001 tariff will be minimal since UEB's investments in 2001 will be small. Nevertheless, P Mare was requested to estimate the level of investment to be made in 2001 and to provide an assessment of an appropriate (commercial) cost of finance to use in calculating the return.

1.4 Calculation of Bulk supply Tariff

The method for calculating the BST for 2001 should be accepted with the following conditions:

- *There is some justification for the 120:100 ratio of peak to shoulder prices.*
- *Documentation is presented of the load profile used to determine off-peak energy consumption.*

It was noted that this should be addressed through documentation submitted as part of the price application by UEB.

- *The calculation of the Bulk Supply Costs should be amended to reflect a rolling average of export volumes rather than the previous month's export volumes.*

This recommendation was accepted and a rolling average of three months exports was suggested as suitable.

- *The error in the description of the tariff relating to the calculation of the BSC should be corrected in the following manner:*

  The phrase "Bulk Supply Costs…shall be equal to the sum of: (1) the total costs of Power Supply and Transmission Services multiplied by the ratio of sales to UEB Distribution to total sales by UEB Transmission, (2)…" should be replaced by

  "Bulk Supply Costs…shall be equal to the sum of: (1) the total costs of Power Supply and Transmission Services, (2) …".

The recommendation was accepted and PA Consulting will amend the description of the Bulk Supply Tariff.

1.5 Distribution revenue requirement

The method for calculating the distribution revenue requirement should be accepted subject to the following conditions:

- *The calculation of asset costs (depreciation plus interest charges) should be replaced with the anticipated lease fee for 2002.*

It was noted that this issue is the same as item 1.1 and will be handled in the same way.

- *Justification for a 3.5 per cent depreciation rate for distribution assets should be provided.*

UEB was requested to provide documentation regarding its depreciation rate in its tariff application.

1.6 Calculation of end-user prices

The distribution loss figures should be reset in light of actual losses experienced in 2000.

This recommendation was accepted by the meeting, and it was suggested that UEB's technical and non-technical losses (30 per cent) experienced in 2000 would be a suitable target for the 2001 price calculation.

Regarding an allowance for bad debts, it was noted that the allowance in the tariff calculation may be too demanding. However, given that Government outstanding bills should be settled soon, this will bring down the level of provision for bad debts. UEB was requested to confirm that the level of 6.9 per cent in the tariff calculation was reasonable.

The existing cross-subsidies in the tariff calculations (from customers paying capacity charges to those not paying capacity charges) should be removed.

PA Consulting (via phone call with Mr J Tasillo) noted that the tariff model did not include these cross-subsidies and so no adjustment was necessary. ECONwill conform with this and respond to ERA.

Should the ERA decided to cap domestic (code 10) prices, then any revenue shortfall should be spread across other customer class in proportion to their energy consumption.

It was noted that ERA supported Government's policy to remove cross-subsidies and so this recommendation was not relevant.

The ratio used to split the overall revenue requirement between MV and LV customers (65:35) should be justified or amended.

The load profiles used to determine consumption per customer group in each load period should be documented.

It was noted that UEB's tariff application should include appropriate documentation.

The 20 per cent rural surcharge should be removed.

The meeting agreed to remove the 20 per cent rural surcharge.

1.7 Tariff application documentation

The meeting should decide on what documentation should be submitted to ERA in order to finalise the 2001 tariff application. It is suggested that this should include:

- *Redrafted document "2001 UEB Tariff Restructuring"*
- *Excel spreadsheets "Loan analysis", "UEB Proforma accounts", "Supply & Demand A", "Tariff Calculations B", "Tariffs 2001 Calc"*

This was noted by the meeting, and Mr Sherwood provided the spreadsheets immediately after the meeting.

The process for the tariff approval process was discussed. UEB will submit the tariff application by the end of January, and will include a target date for when it would wish to implement the tariff increase. ERA will then try to conduct its review process, if possible, to fit with this schedule.

2 Asset values and investment projections

2.1 Asset values

Subject to the Transaction Advisors clarifying the discrepancy between replacement cost and OCV figures in the Lahmeyer report and asset values used in the pricing model, we recommend that the ERA accept the asset values calculated by Lahmeyer.

Mr T Sherwood noted that the differences in figures can be ascribed to UEB's non-operational asset which were not included in the Lahmeyer report.

2.2 Investment projections

We recommend that ERA adopt the Base rehabilitation investment figures (2001 to 2005) produced by the Transaction Advisors, subject to clarification of the differences in numbers presented in the Lahmeyer report and the figures in the tariff model.

Mr T Sherwood indicated that the latest version of the model was consistent with the Lahmeyer report.

The build-out investment figures for 2005 onwards should be used for indicative pricing, but that the approximate nature of the figures be made known to investors in bidding documents released early 2001.

Further, the distribution licence should contain a requirement that the distribution concessionaire prepare a system expansion plan for the period 2005 to 2010. The targets for this expansion, and the terms of reference for the study, should be developed collaboratively between the ERA and the MEMD. The plan should be costed and submitted by mid-2004 at the latest. Once the ERA has independently verified the cost estimates, these should be used for price setting from 2005 onwards.

This recommendation was accepted by the meeting.

3. Regulatory approach

3.1 Rate-of-return or incentive regulation

We suggest that the ERA interact with the Transaction Advisors and the investment bankers, seeking to devise a concessioning approach and regulatory system that appropriately balances risks with incentives.

Mr Bjelland informed the meeting that NVE will support ERA to draft a description of the regulatory approach to be included in the bidding documentation to be released to operators.

3.2 Price reviews and indexing

It has been proposed that prices will first be set for 24 months, and thereafter reviews will be held every 36 months. We recommend that this approach be adopted by the ERA.

In between price reviews, prices will be indexed. It has been proposed that a portion of the price will be indexed to the dollar exchange rate and prices adjusted monthly. We suggest that:

- *The Shilling component of the tariff should be indexed to Ugandan inflation, and that consequent price adjustments should be made on an annual basis. The Transaction Advisors should be requested by URU to propose an appropriate index to use.*
- *The US dollar component of the tariff should not be indexed to US inflation, or any other inflation rate.*
- *For simplicity and clarity, the proportion of the tariff indexed to US dollar should be set at each price review, and not updated annually.*

These recommendations will be reflected in the description of the regulatory approach to be presented by ERA in bidding documentation.

3.3 Incentive targets: losses and allowances for operating cost

We recommend that the distribution loss targets included in the tariff model be reset in light of losses experienced in 2000 [see item agenda 1.6 above]. These revised figures should be used to determine 2001 prices, and as indicative targets in providing information to potential concessionaires. The ERA should reserve the right to reset these targets at each 36 month price control.

With respect to targets for distribution operating costs, we recommend that either the Transaction Advisors revise the gains in the light of anticipated new connections, or inform potential operators that the current figures will be revised to take account of system expansion from 2005 onwards.

The description of the regulatory approach will reflect these recommendations.

The ERA should initiate a comparative study of distribution costs in order to inform the price review to be undertaken in 2002.

Mr Bjelland informed the meeting that this recommendation will be incorporated into the NVE/ERA workplan.

3.4 Future alterations to BST

A particular problem is the high price rise associated with the introduction of the Bujagali power station. We recommend that the Transco introduce increased power supply prices prior to 2005, and not set power supply prices any higher than their expected long-term trend. Revenue from price increases in 2003 and 2004 as well as profits from exports should be used to finance this mechanism. Transco should be required to develop the mechanism required to implement this proposal during the course of 2001.

URU expressed the opinion that this was an interesting recommendation and deserved further development. Questions of practicality were raised. It was noted that ERA would investigate a possible price smoothing mechanism in 2001.

Given that the Ugandan electricity system will be capacity constrained over the period 2001 to 2004, and again from 2007/8 onwards, it may be desirable to

introduce a maximum-demand charge in the BST, thereby giving the Disco incentives to introduce demand-side management (DSM) programmes.

This recommendation was noted but not discussed.

3.5 Connection fees, life-line tariffs and quality of supply

We recommend that the UEB seek to develop and implement a new connection fee policy …. in collaboration with the new concessionaire, and in the meantime UEB's existing connection fee policy should be applied.

The options for connection fee policy were discussed by the meeting, and it was agreed that the issue should be pursued once the distribution concessionaire has been appointed.

Given the high level of poverty in Uganda, and the high price increase which low income consumers face as a result of the proposed tariffs, we recommend that the ERA exercise some caution in removing life-line tariffs. We suggest that the ERA consult more broadly with stakeholders in the industry, and so understand better the implications of removing or phasing out the existing inclining block system.

The ERA noted that it supported the policy to remove cross-subsidies, but would expect to hold public hearings on the 2001 price increase before they were implemented.

We recommend that ERA should consider the introduction of a Quality of Service Penalty/Reward Indicator that would be used to regulate the quality of supply to customers. Also ERA should indicate a willingness to consider linking electricity prices in rural areas to lower supply quality standards, as a way of bringing down costs and hence prices.

The recommendation was noted as a medium-term matter.