Ghana Power Sector Financial Restructuring and Recovery Study

16 October 2009

Reliance Restricted

Final Report

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Confidential

Reliance Restricted

16 October 2009

The Project Coordinator
Ministry of Energy
P. O. Box ST 40, Stadium Post Office
Accra, Ghana

Dear Sir,

Final Report - Ghana Power Sector Financial Restructuring and Recovery Study

In accordance with our contract dated 1 June 2009, we have pleasure in submitting this Final Report (Main Report) under the **Ghana Power Sector Financial Restructuring and Recovery Study**.

Purpose of our report and restrictions on its use

This report was prepared in accordance with our contract and is solely for the purpose of presenting our findings and recommendations and should not be relied upon for any other purpose. Because others may seek to use it for different purposes, this report should not be quoted, referred to or shown to any other parties unless so required by court order or a regulatory authority, without our prior consent in writing. In carrying out our work and preparing our report, we have worked solely on the instructions of the Ministry of Energy and for the Ministry of Energy's purposes.

Our report may not have considered issues relevant to any third parties. Any use such third parties may choose to make of our report is entirely at their own risk and we shall have no responsibility whatsoever in relation to any such use. This report should not be provided to any third parties without our prior approval and without them recognising in writing that we assume no responsibility or liability whatsoever to them in respect of the contents of our report.

Scope of our work

Our work in connection with this assignment is of a different nature to that of an audit. Our report to you is based on inquiries of, and discussions with, key management personnel of MoE, MoFEP, World Bank, VRA, ECG, GRIDCO, PURC and the Energy Commission. We have not sought to verify the accuracy of the data or the information and explanations provided by the key management personnel. We however assessed the reasonableness of key information provided by the utility companies for the purposes of our analysis and projections.

In view of the limited time available for this assignment and the challenges we have encountered in getting vital information, our activities have been limited in scope and time and we wish to emphasize that a more detailed review may reveal material issues that this review has not. Our focus has therefore been on those issues which are most material to the development of a credible plan for financial recovery of the three utility companies.

We wish to emphasise that we appreciate all the assistance we have received in this all important assignment and look forward to continued work relationship in the near future.

Yours faithfully

Djabanor Narh

PARTNER

Abbreviations

BPO	Billing Processing Officer
BSP	Bulk Supply Point
BST	Bulk Supply Tariff
CBA	Collective Bargaining Agreement
CCGT	Combined Cycle Gas Turbine
CIE	Compagnie Ivoirienne d' Electricité
CRO	Customer Relations Officer
DCO	District Commercial Officer
DO	Disconnection Officer
DSC	Distribution Service Charge
EC	Energy Commission
ECG	Electricity Company of Ghana
EMBA	Executive Masters in Business Administration
EUT	End User Tariff
FOB	Free On Board
GDP	Gross Domestic Product
GIMPA	Ghana Institute of Management & Public Administration
GOG	Government of Ghana
GWh	Giga Watt Hour
GRIDCO	Ghana Grid Company
HIPC	Highly Indebted Poor Countries
HND	Higher National Diploma
HRIS	Human Resource Information System
IPP	Independent Power Producer

Abbreviations

IT	Information Technology
KPI	Key Performance Indicators
KWh	Kilo Watt Hour
LC	Letter of Credit
LCO	Light Crude Oil
LCU	Loss Control Unit
LI	Legislative Instrument
MAED	Model for Analysis of Energy Demand
MBA	Masters in Business Administration
MoE	Ministry of Energy
MoFEP	Ministry of Finance and Economic Planning
MW	Mega Watt
NED	Northern Electricity Department
NSLT	Non Special Load Tariff
NPV	Net Present Value
OCGT	Open Cycle Gas Turbine
OLM	Oracle Learning Management
OTA	Oracle Training Administrator
PPE	Property, Plant and Equipment
PURC	Public Utilities Regulatory Commission
SEC	State Enterprises Commission
SLT	Special Load Tariff
TAPCO	Takoradi Power Company Limited
TICO	Takoradi International Company Limited

Abbreviations

TOR	Terms of Reference
TSC	Transmission Service Charge
VRA	Volta River Authority
WAGP	West Africa Gas Pipeline
WAPCO	West Africa Power Company
WAPP	West African Power Pool
WASP	Wien Automated System Planning
WEM	Wholesale Electricity Market

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Executive summary

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2. Summary of key findings and recommendations

Overview of assignment

Ernst & Young was appointed in June 2009 by the Ministry of Energy (MoE) and Ministry of Finance and Economic Planning (MoFEP) of the Government of Ghana (GoG) to undertake a review of the financial status of the three state-owned power utilities, VRA, GRIDCo, and ECG and propose a financial restructuring and recovery program. This report documents the key results of our exercise and specifically addresses the following areas:

A. Our assessment of the policy, legal and regulatory framework governing the power sector in Ghana, highlighting the gaps and inconsistencies which are impacting on the operation of the utilities;

B. Our operational and financial analysis of the utilities including a detailed assessment of the current debt position of the utilities and financial projection for the next ten years; and

C. Recommendations for financial restructuring and recovery, including a program (action plan) with the timings and responsibilities for the stakeholders to implement those recommendations.

As part of this analysis, we undertook a detailed financial modelling exercise of the utilities, producing the set of pro forma financial statements for the business units of each utility and an overview of the main operational and business processes (in Appendices A, and E). Upon adoption of the recommendations in this report, it is intended that lending agencies such as the World Bank, other Multilateral Funding Agencies as well as commercial lenders will be able to recommence their support for the utilities, as appropriate, subject to their own assessments of the implementation of the recommended action plan.

Summary of Key findings and recommendations

Key findings

The utilities have been in a position of financial distress for some years. This has been largely due to an increase in the cost of producing electricity because of the combination of rising cost fuel costs and increased reliance on thermal generation as end user demand continues to grow. The regulated price of electricity has not increased in line with these increased production costs.

This inability to cover total costs, and in some years even operating costs, has most severely impacted VRA because the Bulk Supply Tariff has not increased in line with the costs to produce wholesale electricity. ECG and GRIDCo have been less affected because the generators have been unable to pass on their increased costs. The operating costs for ECG and GRIDCo, comprising largely of the cost of their electricity (BST), has therefore been broadly in line with their revenues, neither of which has increased on a per-unit basis in the last few years. However, due to allowed losses being less than actual losses, both ECG and GRIDCo nevertheless face decreasing profitability.

In the absence of a clear framework for tariff-setting, as well as uncertainty in projecting commodity prices and economic parameters, long term financial forecasts are subject to uncertainty. We have therefore projected the revenue shortfall for the utilities based on their projected costs (including investment costs) for the next ten years (out to 2018) and assuming the end user regulated price of electricity remains at the current level. Using these assumptions, it is projected that there will be a shortfall of GH¢30.3bn over the next ten years.

Our review of the operational performance of the utilities finds that the management of the large debt and other obligations has been managed well in spite of the uneconomic position of the companies. Without increases in the revenue for the utilities (VRA in particular) restructuring of the existing debts will not result in appreciable benefit or savings.

Our review of the existing policy and legal framework, which provides the basis for the different roles played by government as shareholder, policy maker and regulator, has found that it results in conflicting and competing interests which adversely affect the ability of the utility companies to operate commercially. There is a need to safe-guard the credibility of the Regulators by making them financially autonomous. In the opinion of the Regulators, financial independence will vest them with the credibility and true autonomy they require to perform their functions.

Summary of Key findings and recommendations

It was noted that the government's role as a sovereign is sometimes confused with its role as shareholder of a private limited liability company. This result in a situation where government may sometimes omit to perform the obligations that, for example, a private sector shareholder will.

Key recommendations

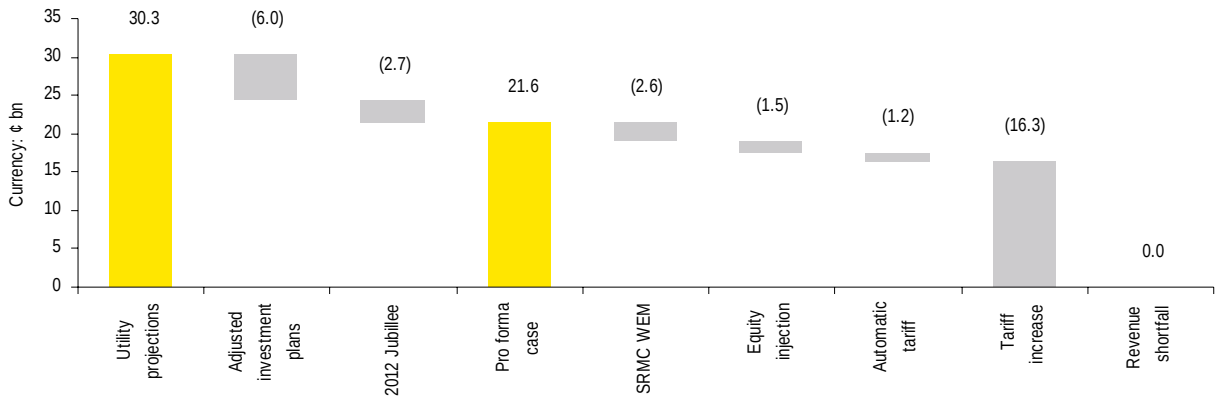
The projections for the utilities indicate that increased revenue or recapitalisation (through equity or refinancing) cannot be pursued alone; both must be implemented together. There is a relationship between the two; if more capital is injected into the sector, tariffs may not need to increase so much, while if tariffs are increased significantly, the capital injection required may be lower. Action without addressing the governance and regulatory framework inadequacies will not result in the full realisation of the potential benefits of these measures.

In the absence of GoG policy or financial constraints, and assuming the objective of placing the utilities on a standalone commercial basis in the shortest timeframe possible, we have assumed a direct GoG equity injection of GH¢1.25bn together with a 51% increase in end user tariffs in 2010. The chart below outlines the recommended sequence of options, based on the assumed current and future operating cash flows and debt positions of the utilities.

Summary of Key findings and recommendations

Recommended options

Source: EY Analysis



In summary:

- Utility projections would result in an estimated GH¢30.3bn shortfall in revenue from existing electricity tariff levels;
- A pro forma case has been developed by reducing investment plans, chiefly those of VRA, plus assuming gas arrives from indigenous sources in 2012 with a projected GH¢21.6bn shortfall;
- An assumed WEM pricing reduction, a GH¢1.25bn GoG direct equity injection and an automatic tariff adjustment mechanism resulting in a tariff increase peaking at 51% in 2010 is projected to eliminate the revenue shortfall for the sector.

The projected shortfall elimination may be achievable by a lower level of GoG equity investment if alternative equity options outlined previously are implemented. However, this would likely result in higher end user tariff increases, due to longer implementation times, and increased complexity in designing intercompany transfers. Specifically, the other factors which could reduce the required level of government equity investment include:

- Revised utility investment plans for the 10 year forecast, with refined estimates of the Regulated Asset Base and asset replacement cost component of future tariffs;

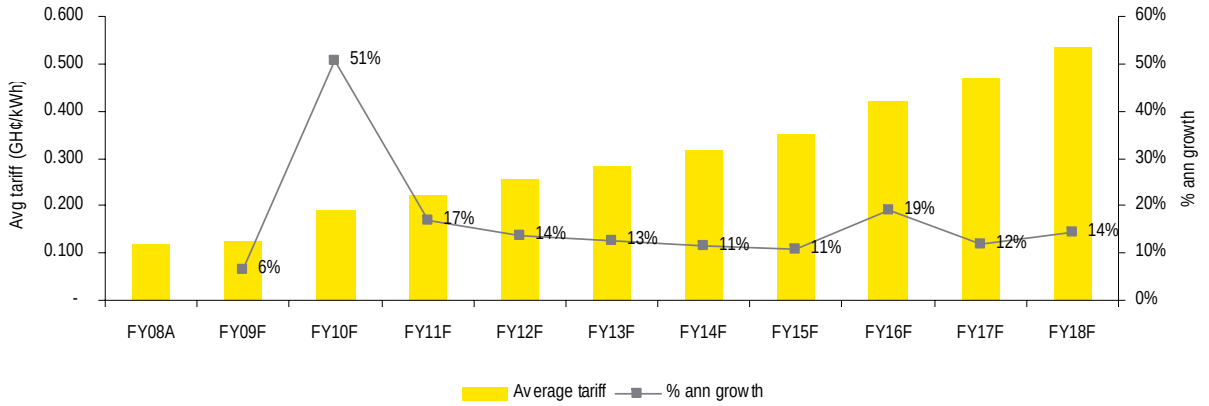
Summary of Key findings and recommendations

- Use of third parties for equity provision, through debt for equity swaps and/or asset sales;
- Higher levels of sustainable debt and gearing levels may be possible in discussions with MLAs and commercial lenders;
- Profit in some companies could be more effectively used to reduce the revenue requirement and hence target equity level for others, for example using VRA Hydro and ECG profits to support VRA thermal debt repayment.

The resulting average tariff increase projection for the 10 year forecast period is shown below. The 51% peak in tariff increases in 2010 reduces to a 17% annual tariff increase in 2012, falling to 11% by 2015. These tariff increases are driven by assumed increases in utility operating and investment costs. The key underlying assumptions are oil/gas prices and the cost of capital, with any changes to those impacting the required revenue increase.

Projected annual average tariff increases

Source: EY Analysis



Action plan

A summary timeline for the recommended timing and sequence of actions is shown on the next page; the full list of recommendations is summarised in the following section. As indicated, the first task is the consideration by GoG of the affordability of the required equity investment of GH¢1.25bn. If only part of this can be funded by GoG in the near term, alternative capitalisation strategies can be pursued. In particular, it may be possible to develop a plan with a staged injection of GoG equity and tariff increases, which if implemented as part of a longer term strategy could allow the refinancing of the high cost working capital and letters of credit facilities which presently constrain the ability of the utilities to invest in the businesses. We recommend in any case that a privatisation strategy is considered, for some or all state-owned assets which could potentially eliminate the need for direct GoG subvention in the medium to long term. The specific tasks in the summary action plan are detailed in the following section. The key questions to be addressed immediately are the appropriate level of tariffs and capital raising strategy to be implemented, whereupon further work can be undertaken to implement these measures.

Equally important is the need to implement the recommended legal and governance amendments to relevant legislation and working practices, as detailed in the following sections. This is key to underpinning any recapitalisation with a long term and sustainable framework within which private sector investment can begin to replace GoG subvention.

There are a large number of complex interdependencies of the recommended restructuring and recapitalisation activities summarised in the action plan. In order to ensure the sector's long term stability, the first three tasks (definition of GoG equity investment, proposed tariff increase and HIPC strategy), must be undertaken within an overarching strategy which takes account of the uncertainties around value and risk. It is important that the tasks within the plan are executed in a measured and sequential manner in order to manage these risks and any potential adverse impact of them. A more detailed discussion of the action plan recommendations is on page 182 of this report.

Summary of Key findings and recommendations

ACTION PLAN - POWER SECTOR FINANCIAL RESTRUCTURING AND RECOVERY STUDY

Area	Task	Responsibility	2009 Q1	2009 Q2	2009 Q3	2009 Q4	2010 Q1	2010 Q2	2010 Q3	2010 Q4	2011 Q1	2011 Q2	2011 Q3	2011 Q4	2012 Q1	2012 Q2	2012 Q3	2012 Q4
Finance	1. Define GoG equity investment	MoFEP																
	2. Propose required tariff increase	ECG, VRA, GRIDCO																
	3. Develop HIPC strategy	MoFEP																
	4. Implement working capital management programme	MoFEP																
	5. Undertake asset valuation	PURC																
	6. Swap GoG debt for equity	MoFEP																
	7. Divestment/IPO readiness assessment	MoFEP, MoE																
	8. Develop divestment/IPO strategy	MoFEP, MoE																
	9. Market sounding of strategy	MoFEP																
	10. Inject GoG/third party equity	MoFEP																
	11. Carve out assets for divestment/IPO	MoFEP																
	12. Implement divestment stream	MoFEP																
	13. Implement IPO stream	MoFEP																
Policy	1. Approve interim tariff increase	PURC																
	2. Implement automatic tariff adjustment	PURC																
	4. Finalise gas sector master plan	MoE																
	4. Finalise power sector master plan	MoE																
	5. Modify WEM design	EC																
	6. Transitional WEM arrangments	EC																
	7. Implement WEM	GRIDCo																
	8. Undertake tariff structure review	PURC																
	9. Develop RAB replacement and expansion policy	PURC																
	10. Revaluation of RAB	PURC																
Technical / operational	1. Review partly completed generation plants and prioritise for financial support	EC/GoG																
	2. Review techniques and tools for generation investment planning	EC																
	3. Review techniques and tools for operational planning and dispatch	GRIDCO																
	4. Consider introduction of more condition-based maintenance	GRIDCO																
	5. Review and prioritise transmission investment plans	GRIDCO																
	6. Review effectiveness of prepayment metering	ECG																
	7. Targeted roll-out of pre-payment metering	ECG																
	8. Strengthen loss control units	ECG																
	9. Address back log of cases for investigation	ECG																
	10. Update technical and commercial loss reduction study	ECG																
	11. Implement findings of loss reduction study	ECG																
	12. Review and prioritise distribution investment plans	ECG/NED																
Legal / Governance	1. Legislative changes	MoFEP, MoE																
	2. Governance improvements	MoFEP, MoE, SEC																
	3. Executive arrangements for Rights of Way	MoFEP, MoE, ECG, NED, GRIDCO																
	4. GRIDCO/VRA separation	VRA, GRIDCO																
	5. Abrogation of non-performing PPAs	MoE, MoFEP, ECG																

Summary of Key findings and recommendations

Subject		Findings/ Recommendations
1 Increase operating cash flows, and reduce debtor days		
– Earning Before Interest, Taxation, Depreciation and Amortisation (EBITDA)		► EBITDA seeks to measure performance to demonstrate earnings exclusive of interests or finance costs, taxes and other non cash expenses (ie depreciation, amortisation). The performance of the three utilities in terms of EBITDA has been mixed over the review period with VRA being the hardest hit. **EBITDA** *Currency: GHC'000* / Dec06A / Dec07 / Dec08UA EBITDA VRA (108,901) (259,598) (57,078) ECG 59,475 55,044 115,694 GRIDCO 17,941 ► VRA has consistently reported negative EBITDA mainly resulting from the poor performance of the Thermal business. Thermal generation costs were 23 times that of hydro for 2006 and 18 times for both 2007 and 2008. This is mainly as a result of the combined effect of high fuel prices and the high comparative cost of repair and maintenance of the thermal plants. ► Under the current tariff regime, VRA's operating expenses are not covered by the revenues currently generated. ECG and GRIDCO appear to be performing better because as mentioned earlier VRA's operating costs are not pushed to them. However their performance does not place them in a position to adequately meet future operating, financing and investment costs. There is therefore insufficient operating cash-flow. We recommend that regulated revenues are increased to provide sufficient operating cash flow, at a minimum, to VRA.
– Working capital management		► Overall, the working capital ratios i.e. the ratio of Current Assets to Current Liabilities for the three utilities is quite satisfactory. As at 31 December 2008, VRA's was 1.6:1, ECG's was 1.86:1, and GRIDCO's was 1.73:1. The ideal ratio for most companies is 2:1. However the fact that a critical component of current assets for the companies ie receivables from customers, tended to be consistently high year on year, meaning that receivables have not been easily translated into cash, the working capital position is weakened. On average debtor days for all three utilities exceeded 185 days (6 months). As ECG and NED fail to properly bill and collect amounts due from their customers, ECG and NED are unable to pay VRA as and when their debts fall due. Consequently, the companies most affected by the debtor day challenges are VRA and GRIDCO. The urgency for the improvement of the recovery of receivables especially by ECG and NED cannot be

Subject		Findings/ Recommendations
		overemphasised to ensure that the operations of the utilities do not grind to a halt. To assist ECG and NED to address the problems with their working capital management, as a first step, ECG and NED need to review their working capital management processes (from the billing stage to the collections stage). The review should take cognisance of the suggested improvements relating to working capital management highlighted in Section C: Recommendations for Financial Restructuring and Recovery. The suggested improvements relate to four (4) key areas of working capital management namely corporate, accounts receivable, inventory and accounts payable.
2 Allow PURC to raise its own funds and reintroduce automatic tariff adjustment		
– Institutional		The Public Utilities Regulatory Commission (PURC) although set up as a regulator charged with the mandate of economic and service regulation has no financial autonomy. PURC is currently funded via budgetary allocations from the GoG. As with most GoG funded institutions, PURC does not receive the required funds that it needs to undertake its planned programmes and activities due to GoG funding constraints. Additionally, there are delays in disbursement which hinders the timely execution of planned activities. PURC's effectiveness as a regulator is therefore limited due to funding constraints. It is recommended that the PURC be allowed to raise its own funds, e.g. through licence fees or levies on electricity and water sales, to be able to carry out its functions effectively and independently. Such fees or levies should however be passed on to the final consumer.
– Tariff setting mechanism		The PURC needs to be strengthened to enable it set tariffs in an independent manner We recommend the introduction of a regular tariff setting process characterised by: ► Major tariff reviews, at a fixed interval of between two and four years, to establish base tariffs. The average base tariffs would be set to recover the net present value of projections of efficiently incurred operating and investment costs during the four year tariff period together with projections of the change in the (regulatory) asset base during the tariff period. ► Automatic adjustment of base tariffs for uncontrollable cost changes in the "tariff period" between major tariff reviews. We propose that the adjustment allows for changes in: – Fuel and energy purchase prices – Fuel and energy purchase mix – Local and foreign inflation – Exchange rate changes

Subject		Findings/ Recommendations
		– Forecast error in sales volumes – Forecast error in customer mix ► The difference in costs of service between NED and ECG should be considered in the tariff mechanism. One option would be to set a transfer payment from ECG to NED during the four year tariff period such that after the transfer ECG and NED are both expected to exactly cover their projected costs.
3 Update the system and commercial losses benchmark		
– Review of the extent of transmission and distribution losses		The benchmark levels of transmission and distribution losses allowed for in the current tariff were established following analysis that dates back to 2000. Losses have increased considerably since then. This means the regulated level of losses which is below the actual level. As a result the regulated tariff is lower than the true cost to serve customers. A new study is required to evaluate appropriate levels for transmission and distribution losses. The PURC should then review the regulated level of transmission and distribution losses and consider adjusting the regulated tariff as a result
4 Legal and regulatory framework		
– Delineation of multifaceted role of Government		The existing policy and legal framework provides the basis for the different roles played by government as shareholder and policy maker. The government through the Ministry of Finance is the sole shareholder in VRA and ECG and also makes policy directly or on the recommendation of the Energy Commission (EC). Although the government does not directly play the role of regulator, the government per the existing legal and regulatory framework appoints the members of the PURC and EC and consequently determines who the persons acting for and on behalf of the regulator are. This multifaceted role sometimes results in conflicting and competing interests which adversely 'affects the ability of the utility companies to operate commercially. Accordingly, there is the need to delineate the multifaceted roles of government. To enhance the independence of the Regulators there must be the legislative changes that: ► Mandate the Regulators to generate their own revenue for their operations. In the Case of the EC for example, grants and revenue generated from licensing fees (whose use are currently restricted) should be applied towards the operations of the EC. ► Vests the Regulators with power to prescribe the terms and conditions of their staff.

Subject		Findings/ Recommendations
		► Regulate any form of support they may receive from government. It was noted that government has on occasion intervened in the setting of commercially realistic tariffs through a purported absorption of the increase for life-line consumers. To address this it is recommended that: ► There should be the prescription of clear rules and guidelines and /or legislative formula for the absorption by government (if at all) of proposed tariff increases. ► The absorption of such tariff increases should be done outside the tariff so that consumers who can afford the cost of electricity at higher tariffs (and who are not the target of the government "subsidy") do not benefit to the detriment of the utility. To delineate the role of government as shareholder there is the need for clear legislative provision on timelines for government's capitalisation or recapitalisation of incorporated and converted companies (namely GRIDCO and ECG).
– Corporate governance of Utilities		Generally standards and benchmarks to be met by the Board of all the three (3) utilities should be established in accordance with the law and in line with best practice. Specific details relating to VRA, GRIDCO and ECG are as follows: **VRA** The criteria for appointments to the Authority which were provided for in the original VRA Act, of 1961, Act 46 were removed pursuant to the Volta River Authority (Amendment) Act, 2005, Act 692. The amendment vests the government being the appointing authority with the legal right to appoint persons whose competency and expertise may not necessarily advance the objects of the Authority. It is important that the criteria detailing the required competencies for the operation of the Authority are reintroduced into the law. Additionally, it may be necessary to make changes to ensure the inclusion of key members of management (aside the Chief Executive) to the Board of the Authority. **ECG, GRIDCO** ► The conversion of corporations pursuant to the Statutory Corporations (conversion to companies) Act, 1993 vests the assets and liabilities in the successor companies but not rights typically vested in statutory corporations. Significantly, ECG cannot access Rights of Way and some land reservations which they could hitherto do under the Land (Statutory way leaves) Act 1961, Act 186, i.e. for the purposes of construction, installation and maintenance of work. Consequently, the ECG has to both

Subject		Findings/ Recommendations
		negotiate to acquire land and pay compensation to land owners for the use of their property. GRIDCO as a company incorporated in Ghana can also not exercise Rights of Way. It is recommended that whilst ECG and GRIDCO being private limited liability companies should factor the cost of compensation payments in their budgets, being providers of utility whose tariffs are set by the PURC (and not open market forces) the government may facilitate (through Executive Instruments) the acquisition of Rights of Way for ECG and GRIDCO's network expansion. ► The standard provisions of the regulations of GRIDCO and ECG must be reviewed to improve their governance generally and their robustness to meet the challenges of the proposed restructuring and prepare to participate in the WEM.
– Impact of specific legislation on the operation of the Utilities (VRA, ECG and GRIDCO)		*Public Procurement Act, 2003, Act 663* The application of the Procurement Act, 2003, Act 663 to procurement by the utilities does not advance the primary objective of value for money that the Procurement Act is inter alia intended to achieve. This is largely attributable to the capacity challenge of some members of the Tender Committees of the utilities to appreciate the specific issues related to such procurement. It is therefore recommended that: ► The procurement of operating and specialised equipment undertaken by VRA should not be subject to the application of the Act. To ensure that the principles of transparency and accountability which the Act seeks to safe-guard are not lost, it is recommended that the VRA submit detailed procurement rules for the approval of the Public Procurement Authority. A similar exemption was effected for MiDA under Act 709. The procurement of other equipment should continue to be subject to the Public Procurement Act. ► ECG and GRIDCO being limited liability companies and required to be self-financing institutions should be completely excluded from the application of the Procurement Act. This is because these entities are not using "public funds" as defined under the Act but are "private" companies. *VRA: Impact of Water Resources Commission Act 1997, Act 522 on the cost of Hydro Power Generation* The Water Resource Commission (WRC) grants water right for inter alia the use of water for power generation and water transportation through the issue of permits. It is important that as part of the WEM this element of cost of production is factored in by VRA and other hydro power generators in the future.

Summary of Key findings and recommendations

Subject		Findings/ Recommendations
		Provision of Subsidies By Government It would appear that currently the ECG and GRIDCO being fully commercial agencies should not receive government subvention. It is therefore important that legally any financial support that is provided by government to ECG and GRIDCO is properly described as equity investment made by a shareholder and the necessary documentation completed with the appropriate agencies.
– Whole Sale Energy Market		Pursuant to Section 25 of the Energy Commission Act, the EC passed the Electricity Regulations 2008 LI 1937. The Regulations are aimed as to facilitating the wholesale electricity trading regulate the national interconnected transmission system, and provide ancillary services in accordance with the Energy Commission Act, LI 1937, the Wholesale Energy Market, electricity market rules, and the National Electricity Grid Code. The Regulations also provide for the establishment of an independent Electricity Market Oversight /panel to supervise the administration and operation of the Wholesale Energy Market Based on the acceptance of the Financial Model, it will be necessary to consider legislative arrangements if any that has to be put in place for the transition to the WEM in 2012.
- Levies on Rural Electrification		The Electricity (Special Levies) Act, 1995, Act 497 imposes special levies towards rural electrification and lighting of public places and related matters. The Act provides a special levy payable by a consumer of electricity as additional charge towards the cost of rural electrification and towards the provision of lights on streets, roads and similar public places. It was found that these charges are unable to meet the cost of rural electrification and lighting. However, because these charges are fixed by law, they can only be changed by an amendment by Parliament. Additionally, these charges are to be collected by the ECG and the VRA and the mechanism for the joint collection and apportionment of the charge is unclear. It is recommended that: ► Instead of fixed charges, the amount payable by consumers towards rural electrification should be a percentage of the charges for power consumed ► The apportionment of charges collected by ECG and VRA should be clear ► The legislation should be amended to indicate which portion (in the case of ECG) should be for installation of street lights and which portion for the consumption of power.
- PPAs executed by ECG		We noted that ECG has signed eight (8) Power Purchase Agreements (PPAs) with various Independent Power Producers (IPPs) with two others being negotiated. It is expected that a total of seven thousand (7,000) GWh of power including will become available to ECG.

Subject		Findings/ Recommendations
		The PPAs are structured on take or pay clauses which means that ECG will be obligated to pay the capacity charges even when the energy is not used by ECG. Therefore if the entire seven thousand (7,000) GWh of power becomes available then ECG may not have (at present capacity) the ability to take and distribute all that power since demand is estimated at six thousand (6,000) GWh. We understand that the agreements with the underlisted companies have been earmarked by the ECG to be abrogated: ► Cirnergex Solutions ► Tropical Energy Resources Ltd ► TransTema Power ► Rare Ventures ► Lushann Int Power Development Ltd Based on the review of the agreements, we are of the opinion that the agreements earmarked for abrogation can be terminated under any of the following circumstances: ► That the Conditions Precedent (CPs) have not been fulfilled and the period for doing so have not been waived or extended. ► Expiration of the agreement. For example the TransTema agreement. ► That event of default have occurred We have provided below a summary of the key issues and recommendations related to the Canadian Energy Solutions Agreement which is estimated to generate a maximum of 660 mw of power. The power generated are subject to take or pay clauses. However, ECG's off-take obligation is based on energy actually generated and received. The seller has the obligation to supply and deliver the power and consequently execute an interconnection agreement with GRIDCO. Therefore ECG's obligation to pay for the power only arises where the power generated is delivered. In the circumstances the ECG must undertake the following: ► Consider whether ECG's can take and distribute (and therefore earn income) the energy to be generated under this PPA particularly in the face of the proposed abrogation of some of the PPAs. If it is determined

Summary of Key findings and recommendations

Subject		Findings/ Recommendations
		that the energy generated will be required and will not expose ECG to the payment obligations above, ECG's capacity then there is no need to terminate. ► If ECG's potential liability is higher than its expected installed capacity by the projected Commercial Operations Date of the IPP then it will be safer to terminate immediately since the potential liability will be much lower now. However, in view of the fact that the liquidated damage ECG will incur is based on the cost incurred (prior to the COD), plus two months wind down period) after termination, it is possible to estimate actual potential liability now and compare it to the future liability and take a decision to terminate or not based on the potential liability of ECG/GOG.

A: Business operating environment analysis

3. Legal and regulatory overview

Evaluation of Regulatory/Policy Environment and impact on operations of the Utilities

This section sets out:

- Our assessment of the policy, legal and regulatory framework governing the power sector in Ghana. The assessment is based on the review of the draft National Energy Policy, relevant legislation (see Appendix C) and internal rules governing the operations of the utilities as well as comments raised on the Inception report. The purpose of the assessment is to achieve the following:
  - Provide an understanding of the regulatory environment in which the utilities in the power sector operate;
  - Provide an analysis of concerns and gaps in the existing legal framework that may adversely affect the work of the Regulators and the governance and financial sustainability of the applicable entities; and
  - Make recommendations on legal and regulatory interventions that may be required to provide the enabling legal and regulatory environment to improve the governance of the utilities and Regulators and achieve the financial sustainability of the utilities.
- Accordingly, this section provides the following:
  - Overview of the legal and regulatory issues in the power sector in Ghana with a specific focus on the following:
    - Multifaceted role of government
    - Corporate governance of Utilities
    - Tariff Setting
    - Provision of subsidies by government
    - Wholesale Energy Market (WEM)
    - Impact of specific legislation on the operation of the utilities
    - Impact of the public Procurement Act, 2003, Act 663
  - Matters arising which may require legislative and/ or administrative interventions that may be considered.

Overview of Power Sub-Sector Policy

The overall objectives of the power sub-sector policy under the Draft Energy Policy, 2009 (yet to be approved by Cabinet) is to achieve:

- An installed power generation capacity of 5,000 megawatts (MW) by 2015; and
- Universal access to affordable electricity by 2020.

In pursuance of these objectives, the government has identified the following constraints which pose significant challenges to the attainment of these objectives:

- The sustenance and expansion of power generation capacity;
- The rehabilitation of transmission and distribution infrastructure;
- The acquisition of long term reliable and cheaper fuels the West Africa Gas Pipeline and domestic resources for the operation of thermal power plants;
- Increase access to electricity by consumers especially in the rural areas;
- Attainment of full cost recover for electricity services;
- Reduction of power system losses and waste; and
- Attraction of sustainable investments to build the necessary infrastructure for the production, transmission and distribution of electricity.

In furtherance of the power sub-sector policy objectives and to address the challenges outlined above, the Policy direction of government seeks to focus on the following:

- Increase in generation capacity from 2000 MW to 5000MW through private sector investment in:
  - the rehabilitation, expansion and completion of on-going and existing power plants;
  - the construction of new power plants;
  - the completion of the Bui dam; and
  - support for the development of small and medium scale hydro projects.
- The development of a safe and reliable electricity transmission network using commercial and domestic capital resources

- Acquisition by the distribution utilities of funding and investments from the domestic capital markets
- Enhancement of institutional and human resource capacity
- Regulatory reforms intended to create:
  - A competitive electricity market; and
  - An enabling environment for the participation of independent power producers for the development of new power plants through Public Private Partnership arrangements.
- Efficient pricing of power through:
  - Uniform electricity tariffs
  - Cost recovery
  - The continued provision of life-line tariffs and special rates for productive activities which have economic benefits
  - Implementation of the WEM.

Legislative & Regulatory overview of Power Sector – Multifaceted Role of Government

The Role and Mandate of Government as Policy Maker and Regulator

The existing policy and legal framework provides the basis for the different roles played by government as shareholder policy maker and regulator. The government makes policy directly or on the recommendation of the Energy Commission (EC). Although the government does not directly play the role of regulator, the government appoints the members of the Public Utilities and Regulatory Commission (PURC) and EC and consequently determines the individuals who act for and on behalf of the regulators. The government through the Ministry of Finance is the sole shareholder in the utilities. This multifaceted role sometimes results in conflicting and competing interests which adversely 'affects the ability of the utility companies to operate commercially. These interests it appears are prioritized by the government depending on which interests the government seeks to advance at a particular time. It appears that invariably political considerations weigh heavily in decision making. For example, the Government of Ghana "absorbed"' PURC approved tariff increases in the past, but reimbursed the utilities late which affected their cash flow.

Ghana's power sector consists of a deregulated wholesale and regulated retail market. The Ministry of Energy (MOE) has the oversight responsibility for the sector. The EC and the PURC regulate the sector,

and the Ministry of Finance and Economic Planning (MoFEP) is the final recourse for the payment of debts by the utilities and trustee for holding government shares in GRIDCO and ECG.

The functions of MOE, MoFEP, the EC the PURC are provided below:

- Ministry of Energy (MOE):
  - Development and implementation of energy sector policy in Ghana; and
  - Ministerial oversight over the Energy Commission.

- MoFEP
  - Representative of government as shareholder in State Owned enterprises
  - Formulation and implementation of fiscal and financial policies
  - Mobilisation and allocation of resources
  - Management of public finances and expenditure
  - Preparation and implementation of the annual budget

- Energy Commission (EC)
  - Recommendation of national policies for the development and utilisation of indigenous energy resources;
  - Recommendation of national policies for the development and utilization of indigenous energy resources;
  - Advice to the Minister of Energy on national policies for the efficient, economical, and safe supply of electricity, natural gas, and petroleum products;
  - Preparation, review and periodic update of indicative national plans to ensure that all reasonable demands for energy are met;
  - Establishment of a comprehensive data base for national decision making on the extent of development and utilisation of energy resources available to the nation;

- Receipt and assessment of applications, and grant of licenses for the transmission, wholesale supply, distribution, and sale of electricity and natural gas;
- Establishment and enforcement, in consultation with the PURC, standards of performance for public utilities engaged in the transmission, wholesale supply, distribution and sale of electricity and natural gas;
- Promotion of uniform rules of practice for the transmission, wholesale supply, distribution and sale of electricity and natural gas; and
- Monitoring compliance with the Energy Commission Act and Regulations pursuant to the Act.

► Public Utility Regulatory Commission (PURC):

- Provision of guidelines on rates to be charged for the provision of utility services;
- Examination and approval of rates for the provision of utility services;
- Protection of the interest of consumers and providers of utility services;
- Monitoring standards of performance for provision of services;
- Initiation and conduct of investigations into standards of quality of service given to consumers;
- Promotion of fair competition among public utilities;
- Conduct of studies on the economy and efficiency of public utilities;
- Make such valuation of property of public utilities where necessary for the purposes of the Commission; and
- Collection and compilation of data on public utilities for the performance of its functions.

Government as Shareholder

It was noted that the government's role as a sovereign is sometimes confused with its role as shareholder of a private limited liability company. This results in a situation where government may sometimes omit to perform the obligations that for example a private sector shareholder will. This state of affairs is exacerbated by the fact that there are no special provisions (except the Companies Act) that regulate the operations of companies incorporated by the government and/or converted from statutory corporations.

- **Capitalisation and Recapitalisation of Utilities:** It is important to have a clear legislative position on the provision of capital to GRIDCO and ECG since these are private limited liability companies. Essentially, the Government of Ghana, being the sole shareholder is required by the Companies Act to provide adequate capital for these entities and/or invite other investors to participate in these entities through the provision of the requisite equity.

  For example, there are no specific provisions save that provided for in the Companies Act, 1963, Act 179 that regulates how government owned companies are to be capitalised and recapitalised respectively. It appears that the assumption is made that as private companies limited by shares, the government being the shareholder will determine and provide the capitalisation or recapitalisation required for these companies in accordance with the Companies Act and the regulations of the companies.

  Whereas the minimum capitalisation for wholly owned Ghanaian or foreign companies and jointly owned foreign/Ghanaian companies, are prescribed in the Ghana Investment Promotion Centre Act, 1994, Act 478,there is no clear legislative position on the capitalisation of companies owned by government.

  It is obvious that there is the need to salvage the financial situation and in the case of ECG, recapitalisation may be required whilst in the case of GRIDCO (a new entity) capitalisation may be required.

  It appears that in the absence of a clear legislative provision on the quantum / timelines for government's capitalisation or recapitalisation of incorporated and converted companies, the capitalisation or recapitalisation may not materialise or be provided at a time when the financial position of the companies have already been impaired. To delineate the role of government as shareholder there is the need for:

  – A clear legislative position on the provision of capital to GRIDCO and ECG.
  – Clear legislative provision on timelines for government's capitalisation or recapitalisation of incorporated and converted companies (namely GRIDCO and ECG).

  In the case of VRA, Section 22 of the Volta River Development Act, Act 46 of 1961 as amended which establishes the Authority has clear provisions on VRA's ability to borrow and invest. It provides as follows:

  – In order to enable the Authority to meet an expenditure of a capital nature, including provision for working capital, for the performance of its functions under this Act, and in particular for the financing

of its operations the Authority may borrow the sums that it requires, on the terms and in the currencies that may be agreed between it and the lender.

– The Authority may charge its assets, undertakings and revenues with the repayment of the money borrowed together with interest on that money and may issue debentures, bonds on any other securities in order to secure the repayment of the money so borrowed together with interest on that money and may do any other thing necessary in connection with or incidental to the borrowings are authorised by this section.

– The President may prescribe the maximum sums of money which the Authority may borrow.

Governance of Regulators

At the inception stage, concerns were raised about perceived overlaps in the functions of the roles of the PURC and the EC. Based on separate discussions with the EC and the PURC, the two Regulators stated that in their opinion, there are no overlaps in the roles that they perform. They stated that in accordance with the Energy Commission Act and the PURC Act, the PURC and the EC collaborate to prescribe standards of performance for the utilities. From subsequent discussions with the utilities, it appears that the concern is rather with the fact that they have to deal with more than one Regulator on different aspects of their operations which makes compliance cumbersome.

Based on discussions with the EC and the PURC, we noted hat the governance provisions in their establishment Acts did not lead to any interference by government. The concern raised was the need to safe-guard the credibility of the regulators by making them financially autonomous. Currently, the day to day operations of the EC and the PURC are funded from the Consolidated Fund. In the case of the EC for example, it is significant to note that, although the Energy Fund established pursuant to sections 41 and 42 of the Energy Commission Act includes internally generated funds, the EC is by law mandated to use such revenue solely for the promotion of energy efficiency, the use of renewable energy services, human resource development and related purposes. In the opinion of the Regulators, financial independence will vest them with the credibility and autonomy they require to perform their functions.

It was also found that because staff of the EC and PURC are appointed in accordance with public service terms and conditions which are generally not attractive, the regulators find it difficult to retain professionals with the expertise required for their operations.

Governance of Power Sector Utilities

The electric energy sector is dominated by VRA as the generator, GRIDCO as the transmitter and ECG as the distributor. The State Enterprises Commission is mandated pursuant to the State Enterprises Commission Act, Act 1987, Act 170 to monitor the governance of the utilities.

Role of the State Enterprises Commission

We noted the comment by the Ministry of Finance and Economic Planning on the corporate governance challenges outlined in the Inception Report to the effect that the challenges are not unique to the utilities and need to be addressed generally. The role of the State Enterprises Commission (SEC) is significant since the VRA, GRIDCO and ECG are all under its purview. The Consultant has therefore provided a summary of some of the key corporate governance functions to be performed by the SEC. The SEC is mandated to oversee the operations of state-owned corporations and companies through:

- The promotion efficient and profitable operation of companies
- Advice the government on the criteria for the establishment of new state enterprises
- Advice to the government on the appointment and removal of chief executive officers and board members
- Ensure the payment of dividends to the government
- Make recommendations applications made by corporations and companies to the MOFEP for credit, government guarantees, financing or capital expenditure and investment plans.
- Approve investments to be made by companies and corporations

The SEC's role in checking the governance of the utilities did not appear to be high.

Financial Reporting under the Financial Administration Act, 2003, Act 654

The Financial Administration Act, 2003, Act 654 also prescribes the financial reporting obligations of persons representing government on the Board of state owned enterprises.

Section 72 of the Financial Administration Act, 2003, Act 654 places a mandatory responsibility on the Directors of Companies appointed by the government to submit a report on the operations of the company to the Minister of Finance. Section 72 provides as follows:

- Directors of companies appointed by the Government shall submit a report (in a form to be determined by the Minister of Finance) on the operations of the company to the Minister of Finance and the sector Minister at the end of June and December each year.
- The directors appointed by the Government shall forward to the sector Minister a copy of the audited financial statements of the company within one (1) month after the publication of the audited financial statements of the company.
- Subject to any provision on the removal of directors from a board, where the directors fail to comply with the reporting obligations the directors shall be removed from the board.

In practice, it appears this provision is overlooked and we did not find any example of a government appointee to the board being held accountable for non-compliance with the provision. Its impact on the financial operation of the companies has to be taken into account in the financial restructuring. For example, it would imply that if private equity is introduced into any of the companies, the expenditure related to meeting twice yearly reporting to the government must be factored into the expenses of the entity unless it is treated as an expense to be borne by GoG (as a distinct shareholder) and not the company's expense.

Below is a summary of the specific corporate governance issues relevant to each of the three (3) utilities.

The Volta River Authority (VRA)

- **Mandate:** The mandate of the VRA set out under section 10 of the VRA Act, 1961, Act 46 as amended by the Volta River Development Amendment Act, 2005, Act 692 and described as the "primary functions of the Authority" are the following:

  - The generation of electric power for general individual, commercial and domestic use;
  - The provision of facilities and assistance for the development of the Volta Lake;
  - Transportation of goods and passengers; and
  - The development of the lake and area for the health and well being of the inhabitants and people living adjacent to the lake.

- **Rules:** The governance of VRA is regulated by the VRA Act and standing Orders of the VRA pursuant to section 7 of the Act and may be altered or revoked by a resolution of the Authority.

Legal and regulatory overview

- **Governing Body:** The VRA Act unlike other Acts setting up Authorities and Commissions does not specifically provide for a Board. Under the Act, the members of the Authority (i.e. the governing council) are synonymous with the Authority. The Act requires that the Board should be composed of a nine (9) member board comprised of the Chief Executive, a Chairperson and seven (7) other persons all appointed by the President. Currently, VRA has its full complement of representation as prescribed in the Act. With the exception of the Chief Executive all Board Members are non- executive positions. The Authority is assisted in its business by the following committees:
  - Finance Committee
  - Engineering and Operations Committee
  - Investment and Subsidiaries Committee
  - Compensation and Industrial Relations Committee

- **Decision Making:** The Standing Orders provide that voting shall be by show of hands with the chairman having a casting vote. The Board has general approval limits for the Board/the CEO/Deputy CEO. The Authority employs written opinion papers to make decisions on matters which cannot be deferred to the next board meeting of the Authority. The Standing Orders do not have any specific provisions to cover matters to be decided by ordinary, special resolution or unanimous decision.

- **Conduct of Meeting:** The Standing Orders prescribe inter alia rules for the conduct of meetings (ordinary, extraordinary and emergency), preparation, action and custody of minutes in accordance with standard practice.

- **Conflict Of Interest:** The Act requires members of the Authority to declare their interest in any contract or transaction and to excuse themselves from participating in any deliberation in respect of such contract or transaction. The Standing Orders prescribe detailed provisions on conflict of interest. Significantly, members of the Authority are required not only to declare their financial interest in any matter but interest relating to their wives, family members, business partners or associates.

- **Execution of Contracts:** The Standing Orders prescribe that contract shall be entered into by the Authority in accordance with approval limits or resolutions of the members of the Authority.

Ghana Grid Company Limited (GRIDCO)

GRIDCO is a wholly owned state private company limited by shares incorporated by GoG pursuant to the Volta River Development Amendment Act, 2005, Act 692, which ceded the transmission function of the VRA to the Ghana Grid Company (GRIDCO). The Company is regulated by the Companies Code 1963, Act 179 and its Regulations, which are the standard regulations provided under the Companies Code. GRIDCO currently does not have any Standing Orders that regulate the conduct of GRIDCO. The mandate of GRIDCO under its regulations is the following:

- Carry out the business of economic dispatch and transmission of electricity facilities of wholesale suppliers to bulk customers or distribution utilities in Ghana and West Africa without discrimination;

- To acquire by purchase or otherwise, construct, establish, manage, maintain and otherwise deal with all transmission facilities, works, buildings, conveniences and other systems necessary to transmit electric energy;

- Undertake metering and billing of all power transfers in the national interconnected system;

- Carry out general commercial activities related to the safe and reliable operation of the transmission system and the economic dispatch of electric energy.

Governing Body: It was noted that at the time of reviewing the corporate documents of GRIDCO, the directors of the company registered with the Registrar of Companies consisted of an ex- Minister and a deceased minister of the erstwhile NPP government. The Board has since been constituted and we have been informed that the necessary returns for the change of directors have been filed with the Company Registry.

It is significant to note that the Volta River Authority (Amendment) Act divests VRA of its transmission function but does not make provision for how the assets to be ceded (in this case to GRIDCO) are to be treated in VRA's accounts.

The legal documentation for the transfer of assets from VRA to GRIDCO (if this has not been done) must be completed as a matter of urgency.

- **Right Of Way:** It is significant to note that as a private company limited by shares, GRIDCO cannot exercise the Right Of Way prescribed under the Statutory Way Leaves Act, 1963, Act 186 to i.e. to enter land for the purposes of construction, installation and maintenance of works. Consequently, eventhough

GRIDCO can negotiate with and pay compensation to land owners whose land it requires for the expansion of its transmission network, the assistance of government in accessing land for GRIDCO is recommended.

Electricity Company of Ghana Limited (ECG) formerly known as the Electricity Corporation of Ghana was established in 1967 pursuant to the Electricity Corporation of Ghana Decree of 1967 (NLCD 125) and Executive Instrument No. 59 dated June 29,1967 which vested all assets and liabilities of the former Electricity Department in the corporation. ECG was converted into a private limited liability company pursuant to the Statutory Corporations (Conversion to Companies) Act, 1993 (Act 461) to take over the assets and operations of the Corporation.

Currently, the regulations of the ECG prescribe the objects of ECG as follows:

- To purchase, take over or acquire the undertaking and business previously carried on by the Electricity Corporation of Ghana as well as its goodwill, assets, properties, rights, debts, liabilities and obligations;
- To transmit, supply and distribute electricity;
- To purchase electrical energy in bulk (from the Volta River Authority) or any other supplier for distribution;
- To construct, reconstruct, install, assemble, repair, maintain, operate or remove, sub-transmission lines; distribution lies, transformer stations, electrical appliances, fittings and installations; and
- Other activities incidental to the attainment of the above objectives.

The governance of ECG is regulated by the Companies Code, Standardised Regulations and its Standing Orders. With the exception of the provisions on the execution of contracts which are not provided for, the Standing Orders of ECG are modelled on the same lines as the VRA.

It is significant to note that although the Statutory Corporations (conversion to companies) Act, 1993, Act 461 vests the assets and liabilities of the Electricity Corporation of Ghana to ECG some rights vested in public corporations are not transferred. Significantly, the Land (Statutory Way Leaves) Act 1961, Act 186, under which Rights Of Way are created by Executive Instrument to enter land for the purposes of construction, installation and maintenance of works by a public utility and to pay compensation for loss or damage is no longer exercisable by ECG. We noted that this change has affected the ability of the ECG to expand its network because owners of land now have a bargaining power in determining whether to sell their land and at what cost.

Tariff Setting

The PURC's mandate in respect of economic regulation is:

- To develop a tariff setting mechanism which is fair and predictable;
- To ensure transparency in the tariffs based on efficient production costs; and
- To provide opportunity for utilities to earn a fair risk adjusted returns.

In accordance with Section 16 of the PURC Act, the PURC fixes rates for electricity based on its Electricity Rate Setting Guidelines. The Guidelines prescribe rules for:

- The deregulated market (which is based on whole sale market transactions on the basis of power sale and purchase contracts; and
- The regulated market for residential (including lifeline customers) /non residential customers and SLT-LV customers based on a categorization of users determined by the levels of consumption prescribed by the PURC in consultation with the distribution utility on a periodic basis.

Pursuant to section 16(3) of the Act, the guidelines take into account the interests of the consumer and investors, the cost of production of the service and the assurance of the financial integrity of the utility. We noted from our discussions with the PURC that government's purported absorption of increases in electricity tariffs fixed by the PURC, in some circumstances, has had the effect of broadening the life-line net to include beneficiaries who did not otherwise fall into this category. It was found that in reality, the government only purported to absorb but in reality never reimburse the utilities in cash. It has been recommended that the absorption of tariff increases by government should be done outside tariff so that consumers who can afford the cost of electricity at higher tariffs and who are not the target of the government "subsidy" do not benefit to the detriment of the utility.

Provision of Subsidies by Government

The Subvented Agencies Act, 2006, Act 706 Act provides for governmental subventions for state agencies and mechanisms for the settlement of interagency debts.

The Act also defines a subvented agency as a public agency which receives public funds. The law clarifies five (5) categories of subvented agencies. In respect of a partially subvented agency, the State Enterprises

Commission (SEC) shall examine and initiate action for the conversion of the partially subvented agency into a fully commercial entity where the State Enterprises Commission determines that it is viable to do so.

- **Category 1** – an agency which ceases to receive subvention. Such an agency under the law may either be closed down or have its subvention withdrawn, the agency shall be subject to a conversion under the statutory corporations, (conversion to Companies) Act, 461.

- **Category 2** – Public agencies which provide a core government function and for which full subvention is provided by the government.

- **Category 3** – An agency which operates in the public interest and has the capacity to perform a commercial function for which partial subvention is provided by the government.

- **Category 4 -** Public agencies shall continue to operate under the Ministry responsible for it and be answerable to that Ministry.

- **Category 5** - Fully commercial agencies which shall not receive subvention.

It would appear that currently the ECG and GRIDCO being fully commercial agencies should not receive government subvention.

Whole Sale Electricity Market (WEM)

Pursuant to Section 25 of the Energy Commission Act, the Energy Commission may on an application by a public utility grant the public utility a wholesale supply license to operate facilities and installations for the wholesale supply of electricity or natural gas. A licensed public utility licensed shall be authorised by the licence to produce electricity or natural gas for supply to distribution companies; and bulk customers. A wholesale supply license may be granted subject to specified conditions including “a condition that charges for its services to distribution companies shall be subject to the approval of the Public Utilities Regulatory Commission”.

Pursuant to Section 56 of the Energy Commission Act, the Electricity Regulations, 2008 LI 1937 was passed to provide amongst other key activities the establishment and regulation of Wholesale Electricity Market (WEM). The WEM is defined under the Regulation as “an electricity market established by market

rules approved by the Energy commission for bulk trading of electricity, ancillary services or any other related electricity supply product or service". The Regulations prescribes the composition of the WEM as:

- The Spot Market defined under the Regulations as "the real-time market that comprises an hourly auction of electricity by a generator to meet the projected demand".
- Bilateral contracts excluding electricity generated from the Akosombo and Kpong hydro electric dams.

The WEM is to facilitate wholesale electricity trading and the provision of ancillary services in the national interconnected transmission system. A utility is mandated under the law to operate and administer the WEM in accordance with the Energy Commission Act, the Regulations (i.e. rules developed by the Energy Commission to govern the Wholesale Energy Market) Electricity market rules, and the National Electricity Grid Code. The Regulation identifies the participants of the wholesale electricity market as whole electricity suppliers, electricity distribution utilities licensed by the Energy Commission and bulk customers of electricity.

The requirement under the Regulations for the approval by the PURC under section 25 of the Energy Commission Act for the charges of suppliers of electricity to be subject to the approval of the Public Utilities Regulatory Commission may need to be reconciled with the definition of a WEM under LI 1736 as an electricity market approved by "market rules".

Pricing for the WEM

The Regulations provide that transmission charges in the WEM shall be uniform throughout the country. Whilst the spot market price shall be based on the system marginal cost of supply and merit – order dispatch (defined under the Act as "the ranking in order of which a generation plant shall be used, based on the ascending order of price in correlation with the amount of electricity that will be generated").

Oversight of Wholesale Market

The Regulations provide that the Energy Commission shall establish an independent Electricity Market Oversight panel to supervise the administration and operation of the WEM. The functions of the panel include settlement of disputes and ensuring compliance with rules and standards by the wholesale utilities companies. Significantly, the Panel shall be appointed by the Minister of Energy and shall consist of the Executive Secretaries of the Energy Commission and the PURC, the Chief Executive Officer of the Energy Commission and the PURC, the head of systems operations/control of the utility, two representatives nominated by wholesale suppliers, a representative each of the distribution licences and bulk customers, the administrator of the Panel and a person with expertise in the Wholesale Energy Market. It may be important to consider whether the composition of the Oversight Panel will impact positively on the regulation

of the Wholesale Energy Market. Upon acceptance of the Financial Model, it may be necessary to consider the legislative arrangements if any that have to be put in place for the transition to the WEM which is scheduled to commence in January 2012.

Impact of Specific Legislation on the Operation of the Power Sector Utilities

Impact of the Public Procurement Act, Act 663 on the operations of VRA, ECG and GRIDCO

The Public Procurement Act 2003, Act 663 was identified at the Inception Stage as a key legislation affecting the core operations of the utilities. The utilities were of the opinion that the application of the Procurement Act, 2003, Act 663 impeded their ability to procure expeditiously and sometimes hampered their operations. This was attributed for example to the inability of members of the Tender Committees of these agencies to appreciate the specific issues related to the power sector and the low thresholds provided in the Act. We noted that currently the ECG and the VRA pursuant to the Procurement Act, apply to the Public Procurement Authority for exemptions from the application of the Act on a case by case. It is therefore recommended that:

- The procurement of operating and specialised equipment should not be subject to the application of the Public Procurement Act. This can be done pursuant to section 16(2)(c) of the Procurement Act where subject to the approval of the Public Procurement Authority it can be established that public sector procurement procedures are not suitable, considering the strategic nature of the procurement. Specialised equipment shall include equipment that has to be specially designed to fit VRA's specifications or which requires the grant of patent rights for its use. To ensure that the principles of transparency and accountability which the Act seeks to safe-guard are not compromised, it is recommended that the VRA submit detailed procurement rules for the approval of the Public Procurement Authority. A similar exemption was effected for MiDA under Act 709. Other equipment (i.e. non-specialised equipment and equipment not used for operation should however continue to be subject to the Public Procurement Act.
- ECG and GRIDCO, being limited liability companies and required to be self-financing institutions, should be completely excluded from the application of the Procurement Act. This is because these entities are not using "public funds" as defined under the Act but are "private" companies.

Impact of the Financial Administration Act, 2003, Act 654

The requirement of financial reporting by government appointments on state owned companies under the Financial Administration Act is significant to note and has been addressed under the sub section on mandate/governance of the power sector utilities.

Electricity Company of Ghana – recovery and payment of overdue debts

The Electricity Supply and Distribution (Standards of Performance) Regulations 2008, provide for the performance levels for electric supply and distribution in accordance with the provisions of the Electricity supply and Distribution (Technical and Operational) Rules, 2005 (LI 1816). Under the L.I. *"where a supplier (ECG/NED) fails to bill a customer for a period of 12 months, the supplier cannot recover the cost of the service"*. Under clause 9 of the LI, the cost of the service can only be recovered when it is established that the delay in the billing occurred without negligence on the part of the supplier or due to the customer's actions. In such circumstances the supplier shall recover the accrued cost of service by:

- giving the customer the option to pay the shortfall by an instalment payment plan; and
- not charging interest on the amount.

We understand that the intention of this provision is to ensure that electricity power suppliers do not burden the end-user with their rate collection inefficiencies particularly in respect of the ECG's delay in billing clients for the use of electricity prior to a change over to the pre-paid metering system. In practice, several factors affect the ability of ECG to ensure that it has not gone against the provision. There has been some controversy regarding the proper legal application of this provision between the PURC and ECG. The impact of this provision vis-à-vis ECG's change over to a nationwide pre-paid meter system must be factored into any financial modelling or restructuring arrangement.

- **Illegal Connections** – This has been identified as one of the causes of ECG's financial problems. LI 1816 sets out electrical installation standards and the penalties for illegal connections. The Law prescribes that an electrical installation should be carried out by a qualified certified electrician certified by the electricity distribution utility or a member of the Ghana Electrical Contractors Association or similar body recognized by the utility. Additionally, applications for electricity installations are to be accompanied by an Installation Completion Certificate approved by the electricity supplier. An illegal electrical installation shall be disconnected in accordance with the Public Utilities (Termination of Service) Regulations, 1999(LI 1651) which provides that a public utility may disconnect an illegal connection without notice to the consumer. The Consumer shall also be liable to a fine or a term of imprisonment or both and shall also be liable for the cost of damage to the supplier's equipment. It is recommended that enforcement should be enhanced.

- **Rural Electrification** – The Electricity (Special Levies) Act, 1995, Act 497 imposes special levies towards rural electrification, lighting of public places and related matters. The Act provides a special levy payable by a consumer of electricity as additional charge towards the cost of rural electrification and towards the provision of lights on streets, roads and similar public places. It was found that charges fixed in the law are unable to meet the cost of rural electrification and lighting. However, because these charges are fixed by law, they can only be changed by an amendment by Parliament. Additionally, although the law prescribes that these charges are to be collected by the ECG and the VRA the mechanism for the joint collection and apportionment of the charge is unclear. It is recommended that the following amendments be made to the Electricity 1995, Act 497 (Special Levies Act:
  - Instead of fixed charges, the amount payable by consumers towards rural electrification should be a percentage of the charges for power consumed;
  - The apportionment of charges collected by and between ECG and VRA should be clear; and
  - There should be a clear prescription on which portion of the revenue accruing to ECG should be applied to the installation of street lights and lighting of streets and public places.

Volta River Authority - West Africa Gas Pipeline Treaty

Ghana is a co-signatory to the West African Gas Pipeline Treaty in 2004 ("Treaty"). The West African Gas Pipeline Act (WAGP) 2004, Act 681 was enacted to incorporate the provisions of the Treaty into domestic law. The following Acts do not apply to the operations of the WAGP Company, buyers, shippers and contractors:

- The Energy Commission Act/Regulations
- The Ghana Investment Promotion Centre (GIPC) Act, 1994, Act 478 and;
- The Foreign Exchange Act

Part six of the WAGP Act, 2006, Act 723 sets out VRA's additional mandate outside that provided under its establishment Act. This additional mandate includes the payment of dividends, distributions or other monies due to government from Ghana's investment in the Project held in trust by the VRA for the government Additionally, VRA may charge any of its assets of revenues as security for the performance of its payment obligations under the Act. From the financial statements, the government's debt related to the WAGP is reflected in VRA's balance sheet, although the principal and interest payments are made by the government.

Water Resources Commission Act on the Cost of Hydro Power Generation

The establishment of the WEM has brought attention, to the need to consider the cost of water resources in the generation of hydro power. The Water Resources Commission (WRC) established pursuant to the Water Resources Commission Act, 1996, Act 522 regulates the management of the use of water resources which includes natural lakes.

Significantly, the WRC grants water right through the issue of permits which confers the right to use water for specified purposes including power generation and water transportation. Regulation 20 of the Water Use Regulations, 2001, LI 1662, sets the raw water charge at 0.60 (old Ghana Cedis) per KWh of power generated. It is important that this element of cost of production be factored in by VRA, Bui and other hydro power generators in the future.

Recommendations

Following our review of relevant legislation, documentation and follow up discussions, we have provided below a summary of proposed changes that will need to be considered.

Delineation of multifaceted role of government

- Independence of Regulators - Legislative changes will be required to vest the Regulators with the autonomy which their establishment Acts sought to achieve The proposed legislative changes must ensure the following:
  - Financial autonomy where the regulators generate their own funds for their operations;
  - Remove government subventions; and
  - Vest in the Regulators the power to prescribe the terms and conditions of their staff outside the civil service rules.

- Government Role As Shareholder - to delineate the role of government as shareholder there is the need for:
  - The enhancement of role of the SEC in checking the governance of state owned companies;
  - Drafting of tailored company regulations that address the specific objectives to be pursued by ECG and GRIDCO and prescribe government's role as shareholder;
  - A clear legislative position on the capitalisation requirements of companies owned by government; and

– Clear legislative provision on timelines for government's capitalisation and recapitalisation requirement recapitalisation of incorporated and converted companies.

Corporate governance of the Utilities

- **VRA** - The criteria for appointments to the Board of the Authority which was provided for in the original VRA Act, of 1961, Act 46 and removed pursuant to the Volta River Authority (Amendment) Act, 2005, Act 692 should be reintroduced. The Board should include other members of management in addition to the Chief Executive.
- **ECG/GRIDCO** – To the extent that ECG and GRIDCO remain companies under the Companies Code, 1963, Act 179, it is important to ensure that they comply with the provisions of the Act regarding corporate governance. For example, the Government of Ghana as the sole shareholder is by virtue of Act 461, represented by the Minister of Finance who holds the shares in trust on behalf of the Government and people of Ghana. However, there is no evidence that any shareholders meetings are ever held pursuant to which returns are filed at the companies registry in compliance with the Act. Without an adequate mechanism to ensure this is done, the two (2) entities may remain in breach of the corporate governance rules of the Companies Code. Even though this issue is not peculiar to the utility agencies only, it may be necessary as part of the financial restructuring to ensure that corporate governance is made in compliance with the law.

Wholesale Electricity Market (WEM)

Transitional legislative arrangements may need to be made to enable government meet the scheduled date (2012) for the commencement of the WEM.

The Disposal of VRA's Assets (and its acquisition by GRIDCO)

From the records, the books of VRA will show that until the establishment of GRIDCO, the assets of VRA included some buildings, transformers and transmission lines which were part of VRA but have now been transferred to GRIDCO. The legal mechanisms for regularising this transfer of assets and whether or not VRA will earn monetary value for the "disposal" of these assets (to GRIDCO) will have to be taken care of as part of the financial restructuring.

Completion of decoupling – the relevant of agreements to complete the decoupling of VRA and GRIDCO operations particularly legal documentation on the allocation of transmission losses should be finalised.

Absorption of tariff increases by Government

Prescription of clear rules and guidelines for the absorption by government of proposed margins on tariff increases. Consequently when government makes an intervention there should be a legislative formula by which the amount due can be shown in the books of the utility company. Such a legislative formula will regulate how the government fulfils its public service obligations if and when the government decides to absorb any cost in future in order that the decision may be "depoliticized". Additionally, the absorption of such tariff increases should be done outside the tariff so that consumers who can afford the cost of electricity at higher tariffs (and who are not the target of the government "subsidy") do not benefit to the detriment of the utility.

Recovery and payment of ECG's oversight

At the moment we do not recommend any legislative intervention in the controversy surrounding the interpretation of LI 1816. Clearly, the client has the right to refuse to pay the bill only where the default was occasioned by ECG. Whilst it may appear "unfair" at the moment to the ECG, a full implementation of the prepaid meter programme of ECG will affect the operative effect of that provision. For now it acts as a check on ECG's efficiency and should be maintained.

There is the need for enhanced enforcement of the power of the ECG to disconnect illegal connections and to follow through with the prosecution of offenders to serve as a deterrent.

Public Procurement

The Public Procurement Act governs the procurement of all procurement financed wholly or partly using public funds except where the Minister of Finance decides that it is in the national interest to use a different procedure or where the procurement is undertaken using foreign funds and the funding agreements specify the procurement procedure to be employed. Under the Act, a procuring entity can on an application to the Procurement Authority request for a waiver from the use of the Procurement Act. We recommend the following:

- In the case of VRA, since it is still a statutory corporation set up by an Act, there should be a permanent exclusion of its specialised procurement from the application of the Public Procurement Act. The ambit of specialised procurement can be spelt out in consultation with the Public Procurement Authority.

- In respect of the ECG and GRIDCO since these are limited liability companies, and are self-financing institutions, should be completely excluded from the application of the Act. This is because these

entities are not using “public funds” as defined under the Act but are “private” companies and the shares held by the Government is not enough to bring the companies within the ambit of Act 179.

Rural Electrification

It is recommended that the Electricity (Special Levies) Act, 1995, Act 497 should be amended as follows:

- Instead of fixed charges, the amount payable by consumers towards rural electrification should be a percentage of the charges for power consumed.
- The apportionment of charges collected by ECG and VRA should be clear.
- The legislation should be amended to indicate which portion (in the case of ECG) should be for installation of street lights and which portion for the consumption of power.

Power Purchase Agreements (PPAs) executed by ECG

We noted that ECG has signed eight (8) PPAs with various Independent Power Producers (IPPs) and that two (2) other PPAs are being negotiated.

It is expected that a total of seven thousand (7,000) GWh of power will become available to ECG. The PPAs are structured on take or pay clauses which means that ECG will be obligated to pay the capacity charges even when the energy may not necessarily be consumed by ECG. Therefore if the entire 7,000 GWh of power becomes available then ECG may not have (at present capacity) to take and distribute all that power since demand is estimated at six thousand (6,000) GWh.

The agreements with the underlisted companies have been earmarked by the ECG to be abrogated:

- Cirnergex Solutions
- Tropical Energy Resources Ltd
- TransTema Power
- Rare Ventures
- Lushann Int Power Development Ltd

Altogether, if these agreements are abrogated, ECG's expected off-take obligation will be reduced by 568 mw.

We have provided in Appendix D a summary of the key issues provided in the agreement and the ability of ECG to abrogate these agreements. We have provided below our views on the legal strategy to adopt for the agreements that ECG wants to proceed with i.e. Canadian Energy Solutions and Shenzhen Energy Group.

► Canadian Energy Solutions

The PPA executed between ECG and the Canadian Energy Solutions Agreement is estimated to generate a maximum of 660 MW of power.

The power generated is subject to take or pay clauses. However, ECG's off-take obligation is based on energy actually generated and received. The seller has the obligation to supply and deliver the power and consequently execute an interconnection agreement with GRIDCO. Therefore ECG's obligation to pay for the power only arises where the power generated is delivered. In order for ECG to minimize its exposure, ECG must undertake the following:

- Consider whether ECG's can take and distribute (and therefore earn income) the energy to be generated under this PPA particularly in the face of the proposed abrogation of some of the PPAs.If it is determined that the energy generated will be required and will not expose ECG to the payment obligations above, ECG's capacity, then there is no need to terminate.
- If ECG's potential liability is higher than its expected installed capacity by the projected Commercial Operations Date (COD) of the IPP then it will be safer to terminate immediately since the potential liability will be much lower now. However, in view of the fact that the liquidated damage ECG will incur is based on the cost incurred (prior to the COD), plus two months wind down period) (after termination), it is possible to estimate actual potential liability now and compare it to the future liability and take a decision to terminate or not based on the potential liability of ECG/GOG.

► Shenzhen Energy Group

Under the PPA between ECG and Shenzhen Energy Group, a total of 123MW is to be generated. The power generated is subject to take or pay clauses. However the PPA becomes effective and consequently ECG's off-take obligation is based on the fulfilment of the following pre-conditions:

- The execution of the Natural Gas Supply and Purchase Contract between Shenzhen and the Gas Supplier; and
- Inclusion by PURC of the energy supplied into the generation mix.

We are not aware that these preconditions have been fulfilled. We understand that ECG has recommended the following approaches to deal with any surplus energy that may be generated:

- Establishment of a Special Purpose Vehicle to trade in the surplus power produced by the IPPs to identified markets in and outside Ghana;
- A halt on negotiations with potential IPPs; and
- An assessment by the PURC of the impact of the operations of thermal/renewable energy on energy tariffs.

It is recommended that these alternative approaches should also inform the government's final decision on the PPAs.

B: Operational and financial analysis

4. Historical financial statements analysis
5. Overview of debt
6. Forecasting Analysis
7. Sensitivities
8. Tariff setting Methodology
9. Extent and causes of system losses
10. Review of key operational processes
11. Organisational and Human Resource Review

Historic financial statement

This section provides historic financial statement analysis for all three utility companies:

- Volta River Authority (VRA)
- Electricity company of Ghana Limited (ECG)
- Ghana Grid Company Limited (GRIDCO)

1. VRA historical financial statement analysis

Historical financial statements analysis

Introduction

The Volta River Authority (VRA), historically, was involved in the generation and transmission of hydroelectric and thermal power as well as the distribution of power to the three Northern regions through the Northern Electricity Department (NED). In 2008, the Ghana Grid Company Limited (GRIDCO) was incorporated as a separate legal entity to takeover the operations of power transmission previously handled by VRA.

Our analysis of VRA's historic financial statement has been made under three major sub sections:

1.1 VRA Combined Business

All VRA business being both core and non core.

1.2 VRA Core Business

VRA's core business for the purpose of this study has been defined as

- Hydro generation- which refers to energy generated from the hydro plant in Akosombo and Kpong;
- Thermal generation- which refers to energy generated from VRA's thermal plants in Tema and Takoradi; and
- Northern Electricity Department (NED) which distributes electricity to five areas; Northern Region, Upper East Region, Upper West Region, Sunyani and Techiman.

For the purposes of this study, the hydro and thermal operations were separated to facilitate analysis by business units.

1.3 VRA Non- Core Business

Non-core business of VRA for this study has been defined as all subsidiaries and other non core operations of VRA.

1. VRA historical financial statement analysis

► The table below provides details of VRA's subsidiaries within 2006 and 2008.

Company	Principal activities	Number of shares	VRA's Interest
Akosombo Hotels Limited	Hospitality	1,000	100
Volta Lake Transport Company Limited	Transportation	3,000	100
Takoradi Power Company Limited	Power generation/ Gas supply	5,000	100
Kpong Farms Limited	Farming	2,000	100
Volta Telecommunications Company Limited	Telecommunications	5000	100

Aside the overall analysis of the impact of these companies on VRA as a whole, we have also analysed the individual financial statements of the subsidiaries under the VRA non core section except for three (3) subsidiaries namely: Volta Telecommunication Company Limited (Voltacom); Takoradi Power Company Limited (TAPCO); and Kpong Farms Limited. Reasons are provided below:

- In 2008 VRA's interest in Volta Telecommunication Company Limited (Voltacom ie the Fibre Optic) was sold as part of the sale of GoG's interest in Ghana Telecommunication Company Limited to Vodafone.
- TAPCO was formed to take over the management of the Takoradi Thermal Plant and is only an investment vehicle. The take over has however not been carried out and the Thermal Department currently manages the Takoradi Thermal Plant. The investment in the TAPCO shown in the financial statements of VRA is the government's investment in the West African Gas Pipeline Project for which VRA serves as a conduit.
- Kpong Farms Limited has been out of operation and on the government divestiture list for a number of years now.

The other non-core operations comprise:

- Real estate and guest houses;
- Hospitals at Akosombo, Akuse, Accra and Aboadze; and
- Schools ie. VRA International Schools at Akosombo, Akuse and Aboadze.

1. VRA historical financial statement analysis

Source of Information for analysis and basis for separation into core and non core activities

- The information used for the analysis of the combined business are extracts from the audited financial statements of VRA for the years ended 2006 and 2007 as well as unsigned audit report for 2008.
- Information used for the core businesses:
  - Hydro and Thermal was from a segmental report provided by VRA's Finance department.
  - NED- audited financial statements and report for 2006 and 2007 and draft financial statements and reports for 2008.
- Information used for the non core business was as follows:
  - Akosombo Hotels Limited- audited financial statements and report for 2006 and 2007 and draft financial statements and reports for 2008.
  - The Volta Lake Transport Company Limited- audited financial statements for 2006 and 2007. No financial statement was presented for 2008.
  - Segmental information on real estate, hospital and schools.

1.1 VRA Combined Business

Balance sheet VRA

Currency: GHC'000	Notes	Dec06A	Dec07A	Dec08A
Non-current Assets				
Property, plant and equipment		1,725,295	1,816,752	1,858,664
Long term investments		112,967	130,807	154,500
		1,838,262	1,947,559	2,013,164
Current Assets				
Stocks		48,406	97,176	98,239
Debtors		244,826	184,873	406,227
Other current assets		17,597	46,557	119,160
		310,829	328,606	623,626
Current Liabilities		212,950	290,323	402,177
Net Current Assets		97,879	38,283	221,449
		1,936,141	1,985,842	2,234,613
Non-current liabilities				
Debt		426,955	309,884	289,583
		1,509,186	1,675,958	1,945,030
Financed By				
Investment by the Republic of Ghana		37	18,329	18,329
Income surplus / (deficit) account		(101,410)	(94,996)	78,971
Capital surplus		1,594,699	1,646,402	1,715,362
Debt contingency fund reserve		15,860	17,016	21,816
Rep of Ghana contribution to (WAPCO)			89,207	110,552
		1,509,186	1,675,958	1,945,030
Ratios				
Non current asset turnover		0.24	0.20	0.34
Working capital		1.46	1.13	1.64
Debtor days		203	171	190
Total debts to shareholders funds (excluding WAPCO)		31%	26%	27%

Source: Audited Financial Statements

Ref: Lead BS - Section Lead - Lead Schedules

Balance sheet overview

Property, Plant and Equipment (PPE)

PPE of VRA are classified under five main headings namely: Dam power house and civil works, Generation Plant and Machinery, Transmission and Power distribution network (currently Power distribution network), Land, Buildings and Townships, and Motor vehicles.

The Dam power house and civil works includes the dam, the spillway and machinery such as the turbines, generators, transformers etc. Transmission and power distribution assets comprises of transmission and distribution lines, substations, transformers and consumer metres. Generation plant and machinery made up of the Akosombo Generation Plant, the Kpong Hydro Generation Plant, and the Takoradi Thermal Plant.

- In 2008, all Transmission assets which formed 17% of the Net Book Value (NBV) of VRA's PPE as at 2007 was transferred to GRIDCo. Despite the transfer of the Transmission assets to GRIDCo, overall, NBV of VRA's PPE has seen an increment of 2.3% between 2007 and 2008. Additions to PPE however accounted for less than 0.5% of the movement between 2007 and 2008. The increase was mainly a consequence of the indexation of US Dollar denominated assets to obtain the carrying values in Ghanaian Cedis in the period where the Ghanaian Cedi weakened by 25%[1] against the US Dollar from year end 2007 to year end 2008. VRA has a policy of carrying out physical revaluation of all PPE every five years (the most recent being in 2006), and the use of the replacement method of accounting for PPE by applying yearly indexation of US dollar denominated assets to the Ghanaian cedi equivalent.

Point of view

The policy adopted by VRA to index its US dollar denominated PPE and revalue in Ghanaian cedi terms may fall under the Ghana National Accounting Standard's (GNAS) Allowed Alternative Treatment of "carrying PPE at a revalued amount being the fair value at the date of the revaluation less any accumulated depreciation". However this treatment is subject to another GNAS requirement "PPE should be periodically reviewed to assess whether the recoverable amount has declined below the carrying amount"

The possibility exist therefore that if the US dollar dominated assets are not periodically assessed as to whether the amount being recalculated and carried on the balance sheet for PPE is recoverable, their PPE value may be overstated.

- As at 31 December 2008, capital work-in-progress worth GH¢164 million consisted of the T1 Gas Conversion project, T2 Thermal Project, 126 MW Tema Thermal Power Plant, 330 KV Aboadze-Volta Line and the West Africa Power Pool Projects.

[1] BOG statistical bulletin. December 2008

1.1 VRA Combined Business

Property Plant and Equipment	2006	2007	2008
	GH¢'000	GH¢'000	GH¢'000
Dam Power House & Civil Works	43%	42%	53%
Transmission and Power distribution	34%	33%	17%
Generation Plant & Machinery	18%	42%	22%
Land, buildings, machinery & motor vehicles	6%	25%	18%

Source: VRA company information

Ref: Other(New 1) - Section - Other

- Return on revalued Assets (i.e. PPE), a measure of how efficiently PPE is used to generate revenue, showed a positive movement from 24% in 2006 to 34% in 2008. This is mainly due to:
  - The indexation of the US dollar denominated assets; and
  - Ann increase in revenue as a result a 40% increase in bulk tariffs by the PURC.

- The table on the left is a break down of assets as a percentage of total PPE for the years 2006 to 2008. Comparisons for 2006 and 2007 include transmission assets transferred to GRIDCo in 2008.

Long term Investment	2006	2007	2008
	GH¢'000	GH¢'000	GH¢'000
Rep. of Ghana- TAPCO Investment in WAPCO	79%	77%	73%
Debt contingency fund investment	14%	13%	14%
Equity shares in subsidiaries	4%	5%	8%
Others	3%	4%	5%

Source: VRA company information

Ref: Other(New 1) - Section - Other

Long Term Investment

Long term investment for VRA has been fairly stable over the period. The investment composition, in percentage terms, is shown on the adjacent table:

A brief description of VRA's long term investment is provided below:

- GoG's capital contribution to the West African Power Company (WAPCo)- GoG owns 16.3% interest in WAPCo. VRA's subsidiary TAPCO was used as a conduit for the project and GoG's contributions over the period has been captured as an investment.
- Debt contingency fund investment - This investment represents a US dollar Escrow account held with Ghana International Bank (GIB) London and Standard Chartered Bank (SCB) London to be used by VRA to meet its debt service obligations during years of operational difficulties. This has been made to satisfy VRA's financial covenants with IDA and EIB. No draw down has been made in the past five years.
- Equity investment in VRA's subsidiaries ie Akosombo Hotels Limited, Kpong farms Limited, Volta Lake Transport Company and TAPCO.
- Other long term assets relates to loans given to VRA staff spanning over 5 years.

Point of view

Of the Long term investment of GHC154m on the Balance sheet as at 31 December 2008, the only components attributable to VRA that can be sold for a consideration is their equity interest in subsidiaries which has a book value of GHC 5.76million and other long term assets of GHC 4.29 million.

1.1 VRA Combined Business

Power Sales Debtors	2006	2007	2008
	GH¢'000	GH¢'000	GH¢'000
Communaute Electrique du Benin	28,774	3,449	17,319
Electricity Corporation of Ghana (ECG)	88,774	75,831	99,033
Emergency plant	-	14,018	13,624
Trans. Power Sales - Ashanti Goldfields	3,733	5,252	14,944
Billiton Bogosu Gold Limited	1,646	5,956	18,698
Goldfields Ghana Limited	1,458	2,875	12,684
Power Sales Prestea Gold Resources	7,406	8,162	9,785
Newmont Ghana Gold Limited	2,975	8,240	17,651
NED Power Customers	28,237	38,781	53,584
Total	163,003	162,563	257,324
% of total trade debtors	72%	95%	92%

Source: VRA Management information

Current liabilities	2006	2007	2008
	GH¢'000	GH¢'000	GH¢'000
Trade creditors	73%	47%	27%
Other trade creditors and related companies	3%	8%	18%
Sundry creditors	5%	3%	3%
Accruals	-	1%	-
Current portion of long term loan	6%	11%	7%
Bank overdrafts	1%	5%	-
Short term loans	11%	24%	45%

Source: VRA Management information

Current Assets

- On average, the composition of current assets over the period under review was as follows; debtors (58%); stocks (21%); and 13% cash and short term investments.
- VRA's major trade debtors along with the respective amounts owed in the respective years are shown on the adjacent table.
- Analysis of current assets showed that the debtors' collection period over the three years under review was 6 months on average. This indicates that services rendered and billed stood as unpaid for 6 months on average.
- Sundry debtors constituted a very minor part of total debtors until it shot up from GH¢3million in 2007 to GH¢119 million in 2008. The main cause of the sharp increase was due to the sale of the Volta Telecommunications Company Limited by GoG to Vodafone for GH¢45.7 million and an amount owed to VRA by GoG in relation to light crude oil worth GH¢52 million.
- Cash balances and short term investments increased by 165% from 2006 to 2007 and by 156% from 2007 to 2008. Two main reasons accounted for this:
  - In 2007 the government issued sovereign bonds earmarked for certain specific projects in the energy sector including the Thermal 1 Power Plant (Generation), systems transmission line reinforcement projects, substations upgrade etc. Some of the funds were transferred to VRA's account at the end of 2007 causing a large cash balance at year end.
  - During the energy crises in 2007, a large amount of crude oil had to be purchased monthly for thermal generation. In order to pay off creditors, VRA had to build up cash reserves in their accounts. Short term investments comprised mainly of fixed deposits and treasury bills.

Current Liabilities

The table on the left shows a break down of current liabilities in percentage terms. Further analysis of current liabilities is provided below:

- Trade creditors

Trade creditors decreased significantly from 73% in 2006 to 27% in 2008. The main reason being the conversion of Letters of Credit to short term loans resulting from VRA's inability to comply with the terms of LC's. Consequently, short term debt increased from 11% in 2006 to 45% in 2008.

1.1 VRA Combined Business

Trade creditors	Purpose	2006	2007	2008
		GH¢'000	GH¢'000	GH¢'000
Compagnie Ivoirienne d'electricite de Cote d'Ivoire	Purchase of Electricity	31,873	49,205	15,144
SAE Power Lines SRL	Electrical contractors	4,865	176	3,870
Sahara Energy Resource Limited	Crude oil purchases	53,116	27,590	20,623
Takoradi International Company	Purchase of Electricity	13,161	13,006	5,671
Tsakos	Transporters of fuel	2,137	1,655	1,725
General Electric - Canada	Suppliers of Equipment	8,747	3,973	3,698
Total		113,899	95,607	50,732
% Major Trade Creditors to Total Trade Creditors		73.28	70.29	47.29

Source: VRA Management information

A break down of major trade creditors of VRA have been outlined below:

► Other trade creditors and amounts owed to related companies

Amounts owed to related companies as at 2008, mainly comprise 41% GRIDCO, 27% Ministry of Energy, and 12% TAPCO. Break down is shown below.

Related companies	GH¢'000	Comments
GRIDCO	29,294	This is an accounting number which will be offset by expenses incurred by VRA on GRIDCO
Ministry of Energy	19,428	Power sales from the Emergency plants and offset is in corresponding receivables
TAPCO	8,283	TICO dividends to TAPCO

Short term loans	2006	2007	2008
	GH¢'000	GH¢'000	GH¢'000
Stanbic	2,763	30,680	9,817
Ecobank	13,020	11,222	11,358
Barclays	722	-	-
Merchant Bank	5,200	23,689	2,103
Ghana International bank	4,605	4,799	6,067
Ghana Commercial Bank	-	-	60,480
Zenith Bank	-	-	25,482
Standard Chartered Bank	-	-	64,342
Total	26,310	70,390	179,649

► Short term loans

A number of commercial banks have provided short term facilities to VRA over the past three years.

As at 31 December 2008 a total of GH¢180 million was the short term debt position of VRA (2007: GH¢70 million, 2006: GH¢26 million). The relevant banks and the amounts provided are in the adjacent table.

See further details on VRA loans at Section named “Overview Debt profile”

► Current portion of long term loans

Also, the portion of long term loans which becomes due in 2009 is GH¢29 million.

Working capital movement

► Overall, the working capital ratio i.e., the ratio of current assets to current liabilities for the combined business of VRA on average was 1.6:1. In view of the bad debtor days position of VRA’s customers, VRA is unable to easily convert debtors to cash, the ratio of 1.6:1 therefore could indicate that VRA can hardly pay its current debts as and when they fall due.

1.1 VRA Combined Business

Income statement VRA Combined business

Currency: GHC'000	Notes	Dec06A	Dec07	Dec08UA
Sale of electricity		429,272	382,803	616,591
Other income		11,707	12,195	63,613
		440,979	394,998	680,204
Purchase of electricity		(267,611)	(293,027)	(351,271)
Fuel handling and usage		(138,981)	(170,393)	(205,798)
Salaries and related expenses		(52,498)	(66,767)	(72,001)
Exchange fluctuation gain / (loss) on foreign debt		(16,145)	(20,943)	(34,003)
Other operating expenses		(74,645)	(103,466)	(74,209)
		(549,880)	(654,596)	(737,282)
EBITDA		(108,901)	(259,598)	(57,078)
Depreciation		(67,677)	(66,044)	(60,896)
Interest and commitment charges		(16,341)	(23,519)	(23,292)
Taxation		-	-	-
EBT		(192,919)	(349,161)	(141,266)
Government Assistance		41,457	307,383	264,032
Net profit /(loss) after tax		(151,462)	(41,778)	122,766

Source: Audited Financial Statements 2005 - 2007

Ref: Lead PL - Section Lead - Lead Schedules

Non-Current Liabilities

Long term liabilities made up on average about 63% of total liabilities from 2006 to 2008. VRA has contracted a number of long term loans from various international lenders.

See further details on VRA loans at Section named "Overview Debt profile".

Capital Investment

- GoG injected an amount of GH¢18.3 million through equity in the draught year 2007. Before that year equity capital of VRA was only GH¢0.037 million. No injection of capital has been made since then. This not withstanding VRA's total debt to shareholders funds indicates a lowly geared position for all the years under review.

Income Statement overview

- Sources of Revenue from core activities is made up of: hydro and thermal generation and distribution; as well as non core activities, made up lake transport, real estate and training school. Revenue is also generated from the sale of power purchased from Takoradi International Company (TICO) and Compagnie Ivoirienne d'Electricité (CIE).
- Revenue from power purchases from TICO and CIE on average make up about 25% of total revenue whiles the related cost make up about 45% of total cost. This is due to the high cost of purchasing thermal energy and the fact that tariffs on power do not take cognisance of sources of energy.
- Overall, revenue fell by 11% from 2006 to 2007 as a result of a nine month load shedding exercise which ended in September 2007. The total power generated from both hydro and thermal sources in 2007 was 6,704 GWh while that of 2008 was 8,173 GWh.
- In 2008, even though the transmission operation of VRA was hived off with the establishment of GRIDCO, revenue increased by 61%. This can be partly attributed to:
  - a the full year of power supply to meet demand
  - a 40% increase in bulk tariffs by the PURC to GH¢0.0692/KWhfrom GH¢0.0494/KWh in 2007.

  Revenue from power transmission before it was transferred to GRIDCO contributed on average about 17% of the total revenue of VRA for 2006 and 2007. The separation of GRIDCO from VRA has not significantly affected the financial performance of VRA.

1.1 VRA Combined Business

- Operating costs for VRA have tended to exceed its revenue. The trend over the three years in percentage terms has been as follows:

	Between 2006 & 2007	Between 2007& 2008
	%	%
Purchase of electricity	9	20
Fuel handling and usage	23	21
Salaries and related expenses	27	8
Exchange fluctuation gain / (loss) on foreign debt	30	62
Other operating expenses	39	-28

- VRA has consistently reported negative EBITDA - a measure of performance to demonstrate Earnings exclusive of interests or finance costs, taxes and other non cash expenses (ie depreciation, amortisation) throughout the historic period under review. 2007 recorded the worst EBITDA due to the energy crisis in that year.
- Under the current tariff regime, the operating expenses are not covered by the revenues currently generated. The resulting shortfall between Revenue and Expenditure has mainly been funded through Government assistance through subsidies and suspension of HIPC debt repayment. In view of the revenue-expenditure gap, Government assistance increased from GH¢41.5million in 2006 to GH¢307million in 2007 and GH¢264million in 2008.
- Also the company has been relying on short term loans for Operating expenses (OPEX). These short term loans have arisen in light of the inability of VRA to fulfil term on Letters of Credit (LC) and, as such, agreeing with commercial banks involved to convert the LC's to short term loans.

Further analysis of the Balance sheet of VRA has been done under its core and non core businesses on pages 54 to 63.

Also our summary findings following a review of key business processes relating to key operating costs identified above are outlined on pages 142 – 144.

1.2 VRA Core businesses

Balance sheets of Hydro and Thermal

GH¢'000	FY06A	FY07A	FY08MA	FY06A	FY07A	FY08MA
		HYDRO			THERMAL	
PPE	890,824	900,837	1,149,465	208,411	282,837	309,957
Long Term Investments				82,735	101,283	122,628
Total Fixed assets	890,824	900,837	1,149,465	291,146	384,120	432,585
Current Assets						
Stock	2,443	3,637	4,241	39,438	89,910	89,938
Debtors	183,252	115,102	327,313	33,207	31,368	36,366
Cash and other investments	10,327	29,990	97,454	1,872	8,206	10,964
Total CA	196,022	148,729	429,008	74,517	129,484	137,268
Current Liabilities						
Trade Creditors and accruals	95,256	88,361	98,200	61,309	68,901	73,147
Short term debt	2,101	7,197	6,386	35,269	96,402	202,364
Total CL	97,357	95,558	104,586	96,578	165,303	275,511
Non Current Liabilities						
Long term debt	38,242	30,448	30,567	182,144	120,796	188,957
Total Net Assets	850,481	863,192	1,112,512	110,728	253,195	126,961
Ratios						
Non current assets turnover	0.36	0.27	0.43	0.28	0.27	0.17
Working capital	2.01	1.56	4.01	0.77	0.78	0.50
Debtor days	209	172	244	150	112	183

Source: Segment report of VRA

Ref: Finance Charges - Section FS - Financial Statement Analysis

Balance sheet overview of Hydro and Thermal

The balance sheet overview of the VRA's core business has been analysed for Hydro and Thermal, then NED separately.

Property, Plant and Equipment (PPE)

- From the adjacent table, Property Plant and Equipment for hydro increased by 29% from 2006 to 2008 while that of thermal increased by 49% during the same period. There were insignificant additions during the period. The increment came as a result of yearly indexations/revaluations of assets in line with company policy and to correspond with movements in the US dollar/ GH¢ exchange rates.
- The return on revalued Assets (ie PPE)- a measure of how efficiently PPE is used to generate revenue showed that for hydro it averaged 35% for the 3 years under review while that for thermal was 24%. This appears to indicate that the assets for thermal are being used to generate less revenue compared to that of hydro. This may be in line with the fact that hydro generation is less expensive than thermal.

Current Assets

- The separation of trade debtors between hydro and thermal was based on power sales of the businesses. Trade debtors make up on average 82% of total current assets for hydro and 32% for thermal. Over the three year review period, average debtor collection period for hydro is 208 days and that for thermal is 148 days. The long collection period for hydro coupled with the fact that debtors make up about 82% of current assets may indicate cashflow constraints.
- Stocks make up about 62% of total current assets for thermal and only 1.6% for Hydro. With respect to thermal, the high stock holding relates to stocks of fuel for thermal power generation.

1.2 VRA Core businesses

Current Liabilities

- For thermal, trade creditors and accruals increased by about 19% from 2006 to 2008. Short term debt relating to overdrafts and short term facilities made up about 37% of total current liability in 2006, 58% in 2007 and sharply increasing to 73% in 2008. This is a result of the conversion of LC's to short term loans discussed in detail under the current liabilities section of VRA combined business.
- The working capital ratio for hydro in 2006 was 2:1 and 4:1 in 2008, which implies theoretically that the currents assets of the hydro business covered its current obligation 2 times in 2006 and 4 times in 2008. In the case of thermal, the working capital over the period under review is well under par; 2008's ratio of 0.5:1 being the worst. The current liabilities under the thermal generation far exceeded the current assets by 1:0.5. The 1:0.5 position as at 2008 is indicative of the inability of the Thermal operation to settle its liabilities as and when they fell due. Apparently, Hydro's "good working capital position" is being used to support the poor state of the working capital of the thermal business.

Non-Current Liabilities

- Long term debts contracted for the thermal business exceeded that contracted for Hydro in excesses of 618% in 2008 (2006: 476%; 2007:396%). As at 31 December 2008 a total amount GH¢ 198 has been granted to VRA mainly by the European Investment Bank (for Akosombo Retrofit),European Development fund (for Kpong hydro project); International Development Agency (for Takoradi Thermal Power Plant), the Kuwait Fund (for Takoradi Thermal Power)
- Also an amount of GH¢ 40 million was also contracted in the form of medium term loans from Standard Chartered Bank and Ghana Commercial Bank.

The purpose of these loan facilities was mainly for capacity expansion of the Akosombo Dam and the Takoradi Thermal Power Plant.

See further details on VRA loans at Section named "Overview Debt profile"

1.2 VRA Core businesses

Income statements- Hydro and Thermal

	HYDRO			THERMAL		
Currency: GHC, 000	Dec06A	Dec07A	Dec08MA	Dec06A	Dec07A	Dec08MA
Revenue	319,528	244,091	488,846	80,518	102,168	72,565
Expenses						
Salaries and related expenses	5,034	6,562	7,623	4,822	9,637	14,205
Fuel & handling				138,981	170,393	205,798
Repairs & maintenance	127	869	808	20,309	11,333	16,815
Exchange Fluctuation	2,326	3,671	6,172	11,077	12,294	23,894
Operating expenses	962	483	1,165	4,868	3,255	4,529
EBITDA	311,079	232,506	473,078	(99,805)	(105,042)	(192,676)
Depreciation	(30,592)	(25,119)	(26,093)	(19,398)	(6,012)	(10,608)
Interest, bank charges and commitments	(2,354)	(4,123)	(4,228)	(20,343)	(57,005)	51,286
Taxation			10,000			13,233
Operating profit /(Loss)	278,133	203,264	452,757	(139,546)	(168,059)	(241,337)
Government Assistance to OPEX	41,457	73,835	4,705	-	233,548	259,327
Net profit /(Loss)	319,590	277,099	457,462	(139,546)	65,489	17,990

Ref: Lead CF - Section Lead - Lead Schedules

Income statement overview

It can be seen from the adjacent table that historically, thermal generation has contributed to the overall loss position of VRA over the period. This analysis excludes the impact of the purchase of electricity from TICO and CIE.

- Thermal generation costs were 23 times that of hydro for 2006 and 18 times for both 2007 and 2008. This is mainly as a result of the combined effect of high fuel prices and the high comparative cost of repair and maintenance of the thermal plants.
- Revenue from hydro dropped by 24% from 2006 to 2007 due to the low water level of the hydro plant and this led to a corresponding 27% increase in thermal revenues as a result of the reliance on thermal energy. Power generation from hydro sources increased from 3,727GWh in 2007 to 6,191GWh in 2008 while that from thermal sources decreased from 2.977GWh in 2007 to 1,982GWh in 2008 as a result of the increased power generation from hydro sources in 2008.
- The ensuing revenue-expenditure gap for thermal has been greatly subsidised over the years with government assistance mainly in the form of write offs of fuel purchased for the thermal plants by government on behalf of VRA. Also it appears that profits made from the hydro generation have been used to subsidise the high cost of thermal generation.
- Interest and commitment charges refer to the interest on long term facilities to support the company.

1.2 VRA Core businesses

NED – Balance Sheet

Currency: GH¢000	Dec06A	Dec07A	Dec08A
Non current assets	NED	NED	NED
Property Plant & Equipment	229,491	231,555	262,675
Long term investments/ Capital work-in-progress	2,798	6,956	7,435
Total Non Current assets	*232,289*	*238,511*	*270,110*
Debtors	27,840	37,918	40,667
Cash and Bank	4,147	6,790	8,590
stocks	6,525	3,630	4,060
short term investment	1,222	1,464	1,663
Total Current assets	39,734	49,802	54,980
Total Assets	272,023	288,313	325,090
Current liabilities			
Creditors and accruals	62,500	75,988	116,596
Others	-	-	-
Short term loan	-	-	-
	62,500	75,988	116,596
Net current assets	(22,766)	(26,186)	(61,616)
Net assets	209,523	212,325	208,494
Non current liabilities	-	-	-
Net assets after long term obligations	209,523	212,325	208,494
Financed by:			
VRA Investment account	20,358	20,358	20,358
Income surplus/ (Deficit)	(62,631)	(78,370)	(93,869)
\Capital surplus	282,005	270,337	251,796
	209,523	212,325	208,494
Ratios			
Fixed asset turnover (revenue/fixed assets)	12	15	20
Current ratio (current assets/current liabilities)	0.64	0.66	0.47
Debtor days (trade debtors/revenue * 365)	362	390	359

Source: Audited financial statements

Balance sheet overview of Northern Electricity Department (NED)

Assets

- From the adjacent table, Property Plant and Equipment for NED increased by 14% from 2006 to 2008. PPE comprises of Distribution lines, Substations, Transformers, Consumer metres, Motor vehicles and other equipment. PPE additions during the period were negligible. The increment came as a result of yearly indexations/revaluations of US denominated assets in line with VRA's policy.
- Turnover as a percentage of NBV of PPE for NED improved marginally from 12% in 2006 to 15% in 2007 and ended up at 20% in 2008.
- Debtor days[2] trend for NED indicate the challenges faced by the company in the collection of debts due to them from customers. The number of days it takes debtors to pay NED moved from 362 days in 2006 to, 390 days in 2007 and declined slightly to 359 days in 2008. This serious position means that nearly all revenue made by NED in a year is not collected by the year end. For Power Sales Debtors to reduce, NED has to achieve a collection rate of over 100%. Any performance below 100% results in an increase in the power sales debtors' balance. In 2008, a collection rate of 73% was achieved.

Current liabilities

- On average 90% of current liabilities of NED are due to VRA. It is apparent that NED does not enter into agreements with creditors directly. Rather it makes use of the central procurement services of VRA for supplies.
- The working capital ratio ie, the ratio between current assets and current liabilities improved from 0.64:1 in 2006 to 0.66:1 in 2007 and then declined to 0.47:1 in 2008. This indicates that over the past three years NED has been unable to pay its main creditors (in this case VRA) as and when the debts fall due.
- A provision of bad debts for both specific debtors and general debtors as at 31 December 2008 was GH¢13million which forms 25% of the debtors balance for the same period.

[2] Debtor days was computed as power sales debtors as a percentage of revenue * 365. No information was obtained on the portion of revenue attributable to the prepaid meters. However we assume that revenue from prepaid metered customers will not be material and will not materially alter the debtor days.

1.2 VRA Core businesses

NED – Income statements

Currency: GH¢000	Dec06A	Dec07A	Dec08A
	NED	NED	NED
Revenue	28,532	35,437	53,957
Other income	694	1,107	1,223
Total income	29,226	36,544	55,180
Operating expenses	(26,090)	(31,009)	(50,219)
Salaries & Related	(11,108)	(14,290)	(17,194)
EBITDA	(7,972)	(8,755)	(12,233)
Depreciation	15,047	16,681	19,089
Interest expense	-	-	-
Taxation	-	-	-
Loss for the year	(23,019)	(25,436)	(31,322)

Source: Audited financial statements

Ref: Lead PL - Section Lead - Lead Schedules

Income statement review of NED

- Total income from NED showed a steady growth of 25.04% between 2006 and 2007 and rose to 51% in 2008. The significant increase was due to a major increase in End user tariffs (EUT) in November 2007 from GH¢0.094 KWh to GH¢0.128 KWh constituting about 35% increment in EUT. A break down of the percentage of total income generated from some customer categories is shown below:

Customers	2006	2007	2008
Residential	54.67%	45.37%	45.26%
Non-residential	29.03%	38.64%	36.20%
High voltage	8.22%	7.68%	8.50%
Low voltage	5.71%	5.27%	7.82%

- There was a corresponding increase in total expenditure of 18.63% from 2006 to 2007 and an increase of 39.56% from 2007 to 2008. This mainly was due to the
  - An increase in the Bulk Supply Tariff (BST) of 36% from 5.34cents in May 2006 to 7.28 cents in November 2007.
  - Company-wide salary adjustments of 20% in 2007 and 25% in 2008.
  - Depreciation of property, plant and equipment increased marginally by 10.86% in 2007 and 14.44% in 2008. The increase in the depreciation charged was caused by the revaluation of PPE at current replacement cost.

1.3 VRA non core businesses

Balance sheet overview –Non core

An analysis of the balance sheets of all non core businesses of VRA (Real Estate, hospital, schools, Akosombo Hotels Limited, Volta Lake Transport Company Limited) is presented below. This analysis excludes the following VRA subsidiaries: Volta Telecommunication Company Limited; Takoradi Power Company Limited and Kpong Farms Limited.

Balance sheets for all Non core businesses

Currency: GH¢000	Dec06A	Dec07A	Dec08UA	Dec06A	Dec07A	Dec06A	Dec07A	Dec08UA	Dec06A	Dec07A	Dec08UA	Dec06A	Dec07A	Dec08UA	2006	2007	2008
Non current assets	AH Limited	AH Limited	AH Limited	VLTC Ltd	VLTC Ltd	Real estate	Real estate	Real estate	Health & safety	Health & safety	Health & safety	Schools	Schools	Schools		Total non-core	
Property Plant & Equipment	1,967	3,338	3,589	4,406	3,377	80,218	90,699	105,875	1,328	1,350	1,599	4,515	4,288	4,201	92,434	103,052	115,264
Long term investments/ Capital work-in-progress	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Non Current assets	*1,967*	*3,338*	*3,589*	*4,406*	*3,377*	*80,218*	*90,699*	*105,875*	*1,328*	*1,350*	*1,599*	*4,515*	*4,288*	*4,201*	92,434	103,052	115,264
Current assets	821	893	1,022	887	1,171	241	211	432	316	380	1,283	389	409	655	2,654	3,064	3,392
Total Assets	2,788	4,231	4,611	5,293	4,548	80,459	90,910	106,307	1,644	1,730	2,882	4,904	4,697	4,856	95,088	106,116	118,656
Current liabilities																	
Creditors and accruals	895	1,056	1,608	324	702	5,090	4,439	3,351	2,317	1,606	1,390	1,049	1,024	845	9,675	8,827	7,194
Others	-	-	-	213	329	650	1,572	2,945	296	568	1,222	134	363	743	1,293	2,832	4,910
Short term loan	64	64	200	813	851	-	-	-	-	-	-	-	-	-	877	915	200
	959	1,120	1,808	1,350	1,883	5,740	6,011	6,296	2,613	2,174	2,612	1,183	1,387	1,588	11,845	12,574	12,304
Net current assets	(138)	(227)	(786)	(463)	(712)	(5,499)	(5,800)	(5,864)	(2,297)	(1,794)	(1,329)	(794)	(978)	(933)	(9,191)	(9,510)	(8,912)
Non current liabilities	-	-	-	(247)	(227)	-	-	-	-	-	-	-	-	-	(247)	(227)	-
Net assets	1,829	3,111	2,803	3,696	2,438	74,719	84,899	100,011	(969)	(444)	270	3,721	3,310	3,268	82,,996	93,314	106,352

Ref: Lead BS - Section Lead - Lead Schedules

Balance Sheet Analysis – VRA Non Core Businesses

- In 2008, the real estate, health and safety and schools contributed 5.55% (2007: 4.95%, 2006: 4.68%) to the total non current assets of VRA.
- Current assets of the real estate, health and safety and schools was 0.38% of VRA's total current assets in 2008 (2007: 0.3%, 2006: 0.3%).

1.3 VRA non core businesses

- Current liabilities of the non core businesses constituted 2.6% of VRA's total current liabilities in 2008 (2007:3.3%, 2006: 4.5%).

Detailed analysis of each of the non-core businesses is taken in turn as follows:

Akosombo Hotels Limited (AHL)

- Fixed asset turnover, a measure which gives an indication of how well a company is using its non current assets to generate income showed that AHL's fixed asset turnover decreased from 55% in 2006 to 35% in 2007 and further declined to 33% in 2008. A contributory factor to the decline in the ratio was the increase in the value of total non current assets by 69.71% as a result of the revaluation of assets in 2007 without a corresponding increase in revenue. An increase of 7.53% in 2008 as a result of additions to non current assets also contributed to the decline on the ratio in 2008.
- The current ratio for the Akosombo Hotels deteriorated progressively from 0.86:1 in 2006 to 0.80:1 in 2007 and finally to 0.57:1 in 2008. This indicates that the AHL may not be able to meet its obligations when they fall due.
- The major components of current liabilities for the Akosombo Hotels Limited are shown below:

	2006	2007	2008
Electricity and water payable	44.33%	48.25%	40.93%
VRA current account (hotel)	18.80%	25.93%	23.02%
VRA current account (Dodi)	12.96%	12.85%	19.53%

- There was a short term loan of US$200,000 granted by VRA to the Akosombo Hotels Limited to facilitate some on-going refurbishment works. The amount is to be repaid within twelve (12) months after the final drawdown. As at the end of 2008 GH¢199,741 of the loan had been used.

Volta Lake Transport Company Limited

- The fixed asset turnover improved greatly from 39% in 2006 to 61% in 2007. The value of non current assets decreased by 23.36% in 2007 and revenue increased by 20.37% resulting in the increase of 61% in 2007.
- The current ratio deteriorated from 0.66:1 to 0.62:1. This is inadequate and the result may be that the Volta Lake Transport Company Limited may not be able to pay for current liabilities as they fall due.
- Debtor days also deteriorated significantly from 99 to 167 days. No reason could be attributed to this.

1.3 VRA non core businesses

- The Volta Lake Transport Company Limited has loans of GH¢0.02 million from the Volta River Authority (VRA), GH¢0.09 million from GoG and GH¢0.28 million from DANIDA (originally obtained from KFW but taken over by GoG). Accrued interest on long term loans amounted to GH¢0.46 million as at 31 December 2007. VRA confirmed that it would not demand repayment of amounts due it before 2006 until the Volta Lake Transport Company Limited is in a position to repay without having an adverse effect on its ability to continue operations. It also assured the company of financial support as when required to enable it meet its obligations. The company also has overdraft facilities for both 2006 and 2007.

1.3 VRA non core businesses

Income statement overview –Non core businesses

Currency: GH¢000	Notes	Dec06A	Dec07A	Dec08UA	Dec06A	Dec07A	Dec06UA	Dec07UA	Dec08UA	Dec06UA	Dec07UA	Dec08UA	Dec06UA	Dec07UA	Dec08UA	2006	2007	2008
		AH Limited	AH Limited	AH Limited	VLTCL	VLTCL	Real estate	Real estate	Real estate	Health & safety	Health & safety	Health & safety	Schools	Schools	Schools		Total non-core	
Revenue		1,075	1,153	1168.721	1,697	2,043	554	565	684	724	1,012	2,033	894	1,090	1,037	4,945	5,864	4,923
Other income		33	34	40	98	118	-	-	-	-	-	-	-	-	-	131	153	40
Total income		1,108	1,188	1,209	1,796	2,162	554	565	684	724	1,012	2,033	894	1,090	1,037	5,076	6,016	4,963
Operating expenses		736	873	884	1,112	1,289	7,069.00	6,533	8,951	3,233.00	1,242	2,950	614	518	786	12,763	10,455	13,571
Salaries & Related		364	363	450	834	952	9,471	12,634	13,627	4,299	5,694	6,417	2,795	3,904	4,911	17,763	23,547	25,405
EBITDA		1,100	1,236	1,334	1,946	2,241	16,540	19,167	22,578	7,532	6,936	9,367	3,409	4,422	5,697	30,526	34,002	38,976
Depreciation		166	134	181	1,015	1,037	2,694	2,180	2,380	93	122	131	258	182	204	4,227	3,655	2,896
Interest expense		6	-	-	38	53	-	-	-	-	-	-	-	-	-	-	-	-
Taxation		1	1	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Loss for the year		(166)	(184)	(308)	(1,204)	(1,169)	(18,680)	(20,782)	(24,274)	(6,901)	(6,046)	(7,465)	(2,773)	(3,514)	(4,864)	(29,723)	(31,696)	(36,911)

Source: Financial statements

Ref: Lead PL - Section Lead - Lead Schedules

Income statement analysis – VRA Non-Core Businesses

- The non-core businesses contributed 0.55% of VRA's total income in 2008 (2007 0.68%, 2006: 0.49%). Total income for the non-core businesses actually increased steadily from 2006 to 2008. Total income increased by 23% from 2006 to 2007 and further increased by 41% from 2007 to 2008.
- The total expenditure incurred by the non-core departments of VRA in 2008 was 5.7% of VRA's total expenditure (2007:5.2%, 2006:5.7%).The major component of expenditure being salaries and this formed 3.55% of total VRA expenditure in 2008 (2007:3.51%, 2006:3.10%).

Detailed income statement analysis of VRA's non-core businesses is provided below:

Akosombo Hotels Limited

- There was an increase in total income for the Akosombo Hotels Limited in the last two years. In 2008, total income increased by 1.77 % and in 2007 by 7.18%.

1.3 VRA non core businesses

- Total expenditure increased by 8.24% in 2007 and 10.55% in 2008.
- The major expenditure items that impacted on the non-core businesses costs during the review period are: salaries and related expenses, electricity and water usage; and depreciation. Analysis of the major items showed that salaries and related expenses fell by 33% in 2007 and increased by 24% in 2008. The decrease in 2007 in expenditure was attributed to the loss of a managerial staff by key finance staff. It was further explained that in 2008, the collective bargaining agreement was completed and this resulted in an increase in salaries and related expenses for 2008 by 15%. The agreement however took effect from 2007 for which year a cost of living allowance (COLA) of 10% had been paid out.
- Following a similar trend in salaries and related expenses, expenditure on electricity and water usage fell, this time by 21.43% in 2007 and then increased by 22.28% from 2007 to 2008. Depreciation followed a similar trend decreasing in 2007 by 19.22% and then increasing by 34.85% in 2008. Factors attributed to this trend by key finance staff include revaluation of PPE and rehabilitation of a marine vessel in 2008 at a cost of GH¢408,678 which resulted in an increase in the depreciation charge almost 8 times.

Volta Lake Transport Company Limited

2008 financial statements for the Volta Lake Transport Company Limited were not available for review. Analysis of the 2006 and 2007 financial statements showed that:

- Revenue increased by 20.37% in 2007 and total expenditure by 10.72%.
- The largest component of total expenditure in 2006 was depreciation which formed 34.29%. Salaries and wages made up 28.16% of the company's total expenditure in 2006. In 2007, depreciation made up 31.63% while salaries and wages was 29.04% of total expenditure. Although in absolute terms both depreciation and salaries and wages increased, in relation to total expenditure there was a decrease.

2. ECG historic financial statement analysis

Historical financial statements analysis

Introduction

Electricity Company of Ghana is a wholly owned Government of Ghana company authorised to carry on the following business:

- Purchase or otherwise acquire the undertaking and business previously carried on by the Electricity Corporation of Ghana, as well as its goodwill, assets, properties, rights, debts, liabilities and obligations;
- Transmit, supply and distribute electricity;
- Purchase electricity in bulk from the Volta River Authority or any other supplier for distribution;
- Construct, reconstruct, install, assemble, repair, maintain, operate or remove sub-transmission lines, distribution lines, transformer stations, electrical appliances, fittings and installations; and
- Carry out any other activities incidental or conducive to the attainment of the objects specified above

Source of Information for analysis

- The information used for the analysis are extracts from the audited financial statements of ECG for the years ended 2006 and 2007 as well as unsigned audit report for 2008.
- Interviews and discussions with the acting Finance Director and other officials of ECG

2. ECG historic financial statement analysis

ECG Balance sheet

Currency: GH¢, 000	Notes	Dec06A	Dec07A	Dec08A
Non-current Assets				
Property, plant and equipment		854,629	933,986	1,171,1978
Current Assets				
Stocks		48,800	68,000	135,852
Debtors		147,503	171,412	258,033
Other current assets (including cash and Bank balances)		42,465	45,461	74,156
		238,768	284,873	468,041
Current Liabilities				
Creditors and accruals		163,589	202,352	243,457
provision for corporate tax				8,361
Current portion of long term loans		9,365	5,754	7,749
		172,954	208,106	259,567
Net Current Assets		65,814	76,767	208,474
Total assets less current liabilities		920,443	1,010,753	1,379,671
Deferred credit/ (Deferred Expenditure)		43,747	86,232	161,778
Government grant		37,031	43,491	44,541
Long term loans		63,932	52,389	71,689
		144,710	182,112	278,008
Net Assets		775,733	828,641	1,101,664
Financed by				
Republic of Ghana		5	5	5
Government Equity		8,063	8,063	8,064
Income surplus		75,858	97,336	161,265
Revaluation surplus		691,805	723,237	932,330
		775,733	828,641	1,101,664
Ratios				
Return on Revalued Assets Employed		7%	8%	11%
Debtor collection days		208 days	203 days	185 days
Working capital ratio		1.38	1.37	1.86
Total debt to shareholders funds		9.45	7.02	7.21

Source: Audited Financial Statements 2006-2008

Ref: Lead BS - Section Lead - Lead Schedules

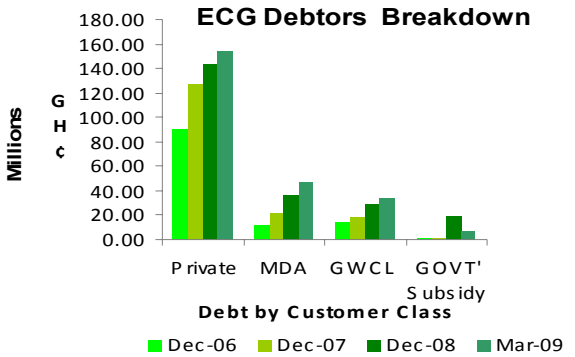
Balance sheet review

Property, Plant and Equipment

- From the adjacent table, it is apparent that PPE of ECG has increased marginally over the period 2006 to 2008. Increases in capital expenditure mainly resulted from the following:
  - An expansion of the Distribution Network system which led to a 46% in PPE increase between 2006 and 2008.
  - The Company also replenished its fleet of motor vehicles for operations with very few disposals in the year 2008 resulting in the net increase in the Motor Vehicles Balance by about 142% from 2007 to 2008.
  - ECG embarked on an extensive roll out of prepayment meters in the Accra West Region as a measure to decrease amounts owed by customers and curtail bad and doubtful debts. This accounted for the 74% increase in the Meter asset balance during the period under review and a corresponding increase of 99% in stocks (mainly stock of electrical parts of the prepayment meters and general electrical stock).
- Return on revalued assets (ie, PPE),a measurement that reflects the productivity and efficiency of property, plant, and equipment in generating revenue, has not been impressive, but however showed an improving trend from 7% in 2006 to 11% in 2008.

Current Assets

- The debtor's balance of 2008 was 51% more than that of year 2007 in line with a corresponding increase of 42% in revenue over the same period.
- A break down of debtors at year ended 2006, 2007 and 2008 is shown below. On the average, 77% of ECG's trade debtors relates to private customers. The remaining 23% which relates to MDA's and other government agencies is managed by a Cross Debt Clearing House (CDCH) system (under the auspices of the Ministry of Finance & Economic Planning) for reconciling and settling interagency debts. The



2. ECG historic financial statement analysis

Debtor days' analysis for private customers

GH¢,000	Dec06A	Dec07A	Dec08A
Revenue			
SLT	107,519	129,954	228,929
NSLT	172,914	203,345	319,142
Debtors			
SLT	32,440	4,822.	73,008
NSLT	83,794	118,295	135,692
Debtor days			
SLT	110	135	116
NSLT	177	212	155

Source: Management information 2006-2008

Ref: Turnover and Expenditure Gap - Section FS - Financial Statement Analysis

agencies involved are the Ghana Water Company Limited (GWCL), VRA, ECG and the MDAs.

- The private customers are made up of Special Load Tariff (SLT) and Non-Special Load Tariff (NSLT) customers.
- It is apparent from the adjacent table that even though the NSLT customers contribute more to Revenue, they also tie down ECG by holding on for an extended period before making payment. The debtor days in excess of 100 days indicates how ECG is struggling to collect its receivables from private customers. This may also suggest inefficiencies in billing, collection, and or existence of potential bad debts.
- ECG's policy on provision for bad and doubtful debts of 10% per annum has not been revised in the past 5 years. Additionally, no specific provision or write off of debts has been done over the last 10 years.

  From analysis of a schedule of debtors per regional boundary provided, it can be surmised that about 53% of the total outstanding debts relates to customers in Accra and its environs whiles 22% represents Ashanti region customers and the remaining 25% is spread across the remaining four regions. There is a proposal to write off bad debts currently under consideration which dates back to 1999. This, when approved, will result in a write off of about 55% of all outstanding debt exceeding two years old.
- Sundry debtors also increased by 74% in 2008. This resulted from an increase in the minimum Life Line Levy from 50 units to 150units in November 2007 as well as delays in setting-off debts. Life Line Levy is the Government's support for low income earners to enable them to gain access to electricity.

Current Liabilities

- A break down of current liabilities of ECG from 2006 to 2008 is as follows:

	2006 GH¢ '000	2007 GH¢ '000	2008 GH¢ '000
VRA power purchases	95,774	90,478	128,891
Independent power producers	-	15,140	11,913
Trade creditors	10,706	15,437	21,204
Other creditors	50,879	73,759	71,366
Interest creditors	-	1,211	3,773
Emergency power producers	5,387	5,387	5,387
Counterpart fund	720	769	754
Accrued expenses	108	155	153
Staff welfare fund	16	16	16
Total	163,589	202,352	243,457

Further analysis of the above is provided:

VRA Power purchases

This represents the amounts that ECG owed to VRA for the purchase of power. On average, about 52% of the total creditor's balance of ECG relates to amounts owed to VRA.

Arrears due to Independent power producers (IPP)

- Amounts owed to the independent power producer as at 31 December 2008 represents 5% of the total creditors and accruals balance.
- In the year 2008, one of the IPPs namely Trans Tema Company was paid off leaving only one IPP namely Tema Reserve Power Plant unpaid as at 31 December 2008 leading to a reduction in the total balance by 21%.
- The Company's Officials explained that the balance relating to Emergency Power Producers should actually be written off their books as the supplier has been paid off. However, a proposal is yet to be approved for this amount to be written off.

Trade and other creditors

Trade and other creditors made up 40% of the total trade creditors on average over the period under review.

Amongst the major trade creditors are suppliers of vehicles, materials, electricals, cables, meters etc. such as Japan Motors and Trading Company, Pfisterer Limited, Reroy Enterprise, Nexans Kabel Metal, Matelec, Aandatta Limited, Electrometer Company Limited.

Also, amongst other creditors are the following:

	Purpose	2006 GH¢ '000	2007 GH¢ '000	2008 GH¢ '000
Output VAT		21,737	21,442	36,026
British Engineering Services	Material supplier	2,338	4,839	4,940
Power Factor Surcharge	Uneconomical use of electricity surcharge	4,826	5,182	4,767
Jacobsen Electro AS	Construction work	4,721	7,623	773
Customer deposit	deposits	5,723	6,655	-
Total		39,345	45,741	46,506
%age of total other creditors		77%	62%	65%

Working capital movement

Overall, the Working capital ratio ie the ratio of current assets to current liabilities for ECG was 1.38:1 in 2006, 1.37:1 in 2007 and 1.86:1 in 2008. This indicates that ECG can barely pay its current debts as and when they fall due. This fact is corroborated by the bad debtor days position over the period buttresses the liquidity or cashflow problems being faced by ECG.

Non Current Liabilities

Long term loans

As at 31 December 2008 ECG had contracted several long term loans from the International Development Agency (IDA), the Nordic Development Fund (NDF), Caisse Française de Développement (CFD), the Swedish International Development Cooperation Agency (SIDA). Also, ECG is indebted to Chirano Gold Mine Company Limited for an investment in the construction of 31km of 33KV overhead line and upgrading of ECG's Primary Sub-station at Asawinso.

As at 31 December 2008, loans due but not paid as well as accrued interest for some of the loans above ie, IDA, NDF, SIDA, and CFD qualified under the HIPC arrangement and as a result were cancelled by GoG.

See further details on ECG loans at Section named "Overview Debt profile"

Deferred credit:

This relates to customer and government contributions to assets. The customer contribution is the cost of connection from the customer's house to the nearest source of electricity (service connection). This is made up of projects the government carried out in deprived areas, rural electrification, and the upgrade of substations in overloaded urban areas, meters, cables and poles. The sharp increases over the period of 97% between 2006 and 2007; and 87% between 2007 and 2008 is mainly due to an increase in Government's support for developmental projects due to the power crises in 2007. GoG contribution in 2008 was GH ¢ 73.5 million.

2. ECG historic financial statement analysis

Income statement ECG

GH¢,000	Dec06A	Dec07A	Dec08A
Revenue			
Sale of Electricity	287,479	348,689	598,445
Public lighting levy	151	224	324
Other income	44,091	40,179	21,845
Total Revenue	331,721	389,092	620,614
Expenditure			
Purchased Power	(223,413)	(261,330)	(405,491)
Distribution, Operation/Maintenance	(8,866)	(10,161)	(13,993)
Staff Costs	(26,725)	(39,518)	(46,277)
Other Operating, Administrative and General Expenses	(6,711)	(19,483)	(19,411)
Foreign Exchange Translation Loss	(6,531)	(3,556)	(19,748)
EBITDA	59,475	55,044	115,694
Depreciation of Property, Plant & Equipment	(57,962)	(58,876)	(77,161)
Loan Interest	(4,943)	(4,825)	(5,090)
Net profit/ (Loss) before tax	(3,430)	(8,657)	33,443
Provision for company tax @ 25%			(8,361)
Net profit/ (Loss) after tax	-	-	25,082

Source: Audited Financial Statements 2006-2008

Ref: Turnover and Expenditure Gap - Section FS - Financial Statement Analysis

Income statement review

- Revenue arises mainly from sale of electricity, levies for public lighting and other income. Other income is on average 15% of total revenue.
- Revenue increased by 17% from 2006 to 2007 and increased sharply by 42%from 2007 to 2008. Reasons for this trend are listed below:
  - The decrease in supply from VRA due to the load shedding exercise during the first 3 quarters of 2007. There was a slight decrease in the volume of sales between 2006 and 2007. This was from 3,978GWh to 3,909GWh, representing a decrease of 2%. However in 2008, the volume of sales increased by 10% to 4,316GWh.
  - In November 2007, PURC increased the EUT from GH¢0.094 KWh to GH¢0.128 KWh constituting about a 35% increment.
- Other income for ECG comprises mainly of reconnection fees, interest and dividends received, stock price adjustment (the difference between the standard ruling price of stock and the invoice price), interest and dividends (interest earned on fixed deposits, treasury bills and from ECG's investment in Nexans Kable Metal). Other income fell by 9% from 2006 to 2007 and 46% from 2007 to 2008. The main reason for the sharp decrease in 2008 was that no funds were received from GoG in respect of electricity reimbursables (ie income provided by the government to ECG in order to absorb increases in tariffs) which in previous years was received. Towards the end of 2007, GoG;s decision to cushion the effect of tariff adjustment was revised such that the effect of tariff adjustments may be borne by the end user.
- There was a progressive increase in expenditure over the period under review from a 17% low between 2006 and 2007 to a steep jump of 55% in 2008. The steep increase mainly came about as a result of:
  - Increases in Bulk Supply Tariff (BST) of about 36%.
  - Increase in staff cost from GH¢27 million in 2006 to GH¢ 40 million in 2007 (a 48% increment). In 2008 there was a 17% increment in staff cost which officials attributed to a 10% increase in salaries during the year.
  - There was also a 37% increase in other administrative expenses from the year 2007 to 2008.

Under the current tariff regime, revenues barely cover the operating expenses. GoG support through subsidies and HIPC loan forgiveness in total decreased from GH¢ 38 million in 2006 to GH¢27million in 2007 and subsequently increased to GH¢ 85 million in 2008. GoG support for ECG has mainly been in respect of CAPEX.

3. GRIDCO Historic Financial analysis

GRIDCO 2008 Balance Sheet

Currency: GH¢'000	Dec08UA
Non-current Assets	
Property, plant and equipment	400,249
Long term investments	871
	401,120
Current Assets	
Trade and other receivables	40,214
Cash and bank balances	2,576
Inventories	359
	43,149
Current Liabilities	
Creditors	78
Borrowings	24,884
	24,962
Net Current Assets	18,187
Total assets less current liabilities	419,307
Non current liabilities	
Deferred credit	34,519
Borrowings	48,386
	82,905
	336,402
Financed By	
Investment by the Republic of Ghana	252,004
Income surplus account	4,828
Capital surplus	79,570
	336,402
Fixed asset turnover	19
Current ratio	1.73
Debtor days	194
Gearing	22%

Source: Unaudited Financial Statements

Ref: Lead BS - Section Lead - Lead Schedules

Balance sheet overview

Assets

- Property, Plant and Equipment (PPE) for GRIDCO comprises of Transmission assets ie transmission lines, transmission substations and transformers and some capital work-in-progress (CWIP). The CWIP relates mainly to three Substation upgrade projects, Kumasi- Obuasi transmission projects, SCADA rehabilitation projects, Head office extension.
- 99% of GRIDCO's accounts receivable is due from VRA for power transmitted to VRA's customers. GRIDCO has done a lot of work and is on the verge of commencing the billing of its own customers directly rather than receiving their revenue through VRA.

Debtor days

- This gives an indication of how quickly cash is being collected from debtors and for GRIDCO, debtor days is 194 days. This is rather high and suggests that GRIDCO has most of its revenue locked up by its key debtor- VRA for a good portion of the year and this could result in cash flow problems.

Current Liabilities

- Amounts due to VRA formed 28.69% of the creditors balance as at 31 December 2008. A list of other trade creditors forming 40% of the creditors balance is listed below:

	2008 GH¢
Chavern Ltd	1,132.11
Ghana Water Company	3,140.49
Mikes International Gh. Ltd.	1,005.50
MTN Ghana Ltd	1,550.00
Staff claims	3,321.93
Stephenopp Ent.	4,944.00
The Potter's Touch Ltd	1,076.69
Vansaaddo Ent	5,150.00
St Thomas Hotel	7,496.91

3. GRIDCO Historic Financial analysis

- The working capital ratio for GRIDCO as at 31 December 2008 was 1.73:1. This indicates that GRIDCO's current assets cover its current liabilities by 1.73 times. This coupled with the fact that debtors of GRIDCO take substantial period of time to pay indicates that GRIDCO would barely be able to pay its creditors as and when due.

Non current liabilities

- Deferred credit relates to sovereign bonds by GoG issued between 2007 and 2008 to VRA but related to transmission projects. This was transferred to GRIDCO as part of the separation. GoG issued these bonds with no terms.
- Also some loans relating to Transmission assets were transferred to GRIDCO during the separation of the transmission business of VRA to GRIDCO. 86% of the debts fall due after ten (10) years and 13.9% fall due within three (3) to five (5) years. See further details on GRIDCO loans at Section named "Overview of Debt Profile"

Investment by the Republic of Ghana

- The investment by the Republic of Ghana was derived as a balancing figure. It does not indicate actual injection of capital. GoG has not as yet injected any equity capital since GRIDCO became a limited liability company.
- GOG support through subsidies and HIPC loan forgiveness in total was GH¢ 7 million in 2008. This was in support of CAPEX.

3. GRIDCO Historic Financial analysis

Income statement GRIDCO

Currency: GH¢'000	Dec08U
Revenue	
Transmission income	74,703
Other income	2,041
	76,744
Staff cost	(11,591)
operating expenses	(47,212)
EBITDA	17,941
Depreciation	15,836
Finance cost	1,644
Taxation	-
Net loss for the year	461

Source: Undudited Financial Statements 2008

Ref: Lead PL - Section Lead - Lead Schedules

Income Statement overview

- Revenue consists of transmission income and income from wheeling power. 98% of revenue is as a result of transmission services rendered to customers of VRA. Transmission service charge attributable to GRIDCO is 0.90 cents KWh and this has not been reviewed since 1998.
- 75% of operating expenses are attributed to VRA for common cost. This represents GRIDCO's portion of VRA's apportionment of costs relating to central services and other non core business.

Overview of Debt

Introduction

This section provides the debt profiles of all three utility companies:

- Volta River Authority (VRA) showing the separate profiles of Hydro, Thermal, and NED;
- Electricity Company of Ghana Limited (ECG);and
- Ghana Grid Company Limited (GRIDCO)

VRA Hydro

Summary of outstanding VRA Hydro loans

Loan name	Currency	31/12/08 balance (in original currency)	Amount (in GH¢)	Remaining term (years)	Interest Rate
IDA 2109 GH	EU€'000	3,509	5,643	5	8.00%
EIB-3	SDR'000	24,321	26,951	27	3.00%
European Dev Fund (EDF)	GH¢'000	4,359	4,359	2	n/a
Total			36,953		

Source: Debt Information Ghana Power Sector Companies spreadsheet

Ref: VRA Hydro Loans - Section DR - Debt Restructuring

Summary of outstanding Bui Damn loans

Loan name	Currency	31/12/08 balance (in original currency)	Amount (in GH¢)	Remaining term (years)	Interest Rate
Bui Damn Chinese loan	US$'000	270,000	n/a	20	2.30%
Buyers credit	US$'000	291,680	n/a	17	6.33%
GoG contribution	US$'000	60,000	n/a	n/a	n/a
Total		621,680	-		

Source: Debt Information Ghana Power Sector Companies spreadsheet

Ref: VRA Hydro Loans - Section DR - Debt Restructuring

VRA Hydro: Overview

- The table adjacent shows a summary of the outstanding Hydro loans
- There are 3 hydro loans which are designated for the Akosombo Hydro project (IDA and EIB loans) and its retrofit, and the Kpong Hydro project (EDF loan).
- The loans are all from multilateral lenders (the European Development Fund, EIB and the World Bank IDA) and carry an average unweighted interest rate of 5.5% and an average unweighted remaining term of 11 years.
- There is an outstanding loan balance of approximately GH¢37m.

Bui Damn

- The table adjacent shows a summary of the outstanding Bui Damn loans
- Currently these loans are on the balance sheet of the Bui Damn Authority. It is planned that these loans will be transferred to VRA but this requires an act of parliament.
- The loans carry an average unweighted interest rate of 4.32% and an average unweighted remaining term of 19 years.

There is an outstanding loan balance of approximately US$622m as at 31 December 2008.

VRA Thermal

Summary of outstanding VRA Thermal loans

Loan name	Currency	31/12/08 balance (in original currency)	Amount (in GH¢)	Remaining term (years)	Interest Rate
IDA 2682 GH	SDR'000	104,974	116,328	5	8.00%
Kuwait Fund/Government of Ghana	KUD'000	3,637	18,534	6	3.50%
BADEA	US$'000	1,739	2,110	19	4.00%
Kuwait Fund - 330kV	KUD'000	820	4,177	35	3.00%
IDA - 4092	SDR'000	5,849	6,482	37	1.00%
(i) Standard Chartered Bank (Receivable Backed Medium Term loan)	US$'000	10,069	12,218	2	4.97%
Ghana Commercial Bank	US$'000	22,718	27,566	3	19.50%
Letters of credit / credit lines	GH¢'000	181,140	181,140	2	n/a
Total			368,555		

Source: Debt Information Ghana Power Sector Companies spreadsheet

Ref: VRA Thermal Loans - Section DR - Debt Restructuring

Summary of outstanding letters of credit/credit lines for VRA Thermal

Loan name	Currency	31/12/08 balance (in original currency)	Amount (in GH¢)	Remaining term (years)	Interest Rate
Stanbic Bank	US$'000	8,090	9,817	1	3.97%
Ecobank	US$'000	9,362	11,360	1	19.25%
Standard Chartered Bank	US$'000	53,026	64,342	1	2.00%
Merchant Bank	GH¢'000	2,103	2,103	1	21.50%
Ghana Commercial Bank	US$'000	49,843	60,480	1	16.50%
Zenith Bank	US$'000	21,000	25,482	1	5.50%
Ghana International Bank	US$'000	5,000	6,067	1	1.00%
Bank overdraft	GH¢'000	489	489	1	20.00%
Ecobank	GH¢'000	1,000	1,000	1	0.37%
Total			181,140		

Source: Debt Information Ghana Power Sector Companies spreadsheet

Ref: VRA Thermal Loans - Section DR - Debt Restructuring

VRA Thermal debt: overview

- The table adjacent shows a summary of the thermal loans
- There are 7 thermal loans which are designated for the Takoradi Thermal Power facility and its refurbishment, and other thermal capex. The letters of credit/credit lines were taken out to finance working capital for crude oil purchases for the thermal plant. These letters of credit are discussed in greater detail below.
- The Kuwait Fund 330kV loan is a GRIDco loan but is held on VRA's balance sheet as GRIDco cannot support it.
- The average unweighted remaining term of the loans is 13.6 years and the average unweighted interest rate of the loans is 6.28% (excluding the letters of credit).
- There is an outstanding loan balance of approximately GH¢367m.

Letters of credit

- The table adjacent shows the outstanding letters of credit/credit lines for VRA Thermal
- The nine short term loans, with a total outstanding balance of GH¢181m were raised because VRA was unable to finance its crude oil supply using the thermal loans.
- The average unweighted remaining term of these loans is 1 year and they have an average unweighted interest rate of 10.1%.
- VRA could not meet the required cash cover on letters of credit so these were converted to short term loans or promissory notes raised by the Ghanaian Government.
- These credit lines must be kept open as a requirement of the suppliers.
- In our model we have assumed that the letters of credit roll over to short term debt after maturity with an interest rate of 5% all in.

Government of Ghana serviced debt

- In addition to the above loans is included GoG payment to the WA Gas pipeline fund. VRA is the eventual beneficiary of the pipeline and the Government is yet to decide whether to transfer this expenditure to the VRA as its equity or long term loans
- The table below summarises this loan.

VRA Thermal

Government of Ghana serviced debt

Loan name	Currency	31/12/08 balance (in original currency)	Amount (in GH¢)	Interest Rate
GOGHA-WA Gas Pipeline	US$'000	118,107	143,311	0.0%
Total		118,107	143,311	

Source: Debt Information Ghana Power Sector Companies spreadsheet

Ref: VRA Thermal Loans - Section DR - Debt Restructuring

VRA- NED

Summary of outstanding NED loans

Loan name	Currency	31/12/08 balance (in original currency)	Amount (in GH¢)	Remaining term (years)	Interest Rate
Kuwait Fund - 339	KUD'000	339	1,730	35	4.23%
Saudi Fund (GoG re-lent to VRA in Subsidiary Loan Agreement)	US$'000	158	192	2	6.00%
Total			1,922		

Source: Debt Information Ghana Power Sector Companies spreadsheet, Gridco Final Financial statement spreadsheet

Ref: NED loans - Section DR - Debt Restructuring

NED debt overview

- The table adjacent shows a summary of NED loans
- There are two loans in NED, the Saudi Fund loan (re-lent through the Ghanaian Government) is for the purpose of the Northern Electrification & System Reinforcement Project (NE&SRP), and the Kuwait fund loan is for Rural Electrification.
- There is an outstanding loan balance of GH¢1.9m.
- Covenant information was only available for the Saudi Fund loan. The main requirement is that the Ghanaian Government agrees that no external debt will take priority over this loan via a lien on governmental assets. If any such lien is to be created as security for external debt, the lien will ipso facto and at no cost to the Fund equally and rateably secure payment of principal, accrued interest and other charges on the loan, and an express provision will be made to this effect.
- The average unweighted interest rate is 5.12% and the average unweighted remaining term is 18.5 years.

ECG Debt overview

Summary of outstanding ECG loans

Loan name	Currency	31/12/08 balance (in original currency)	Amount (in GH¢)	Remaining term (years)	Interest Rate
IDA 2467	SDR'000	25,484	28,240	6	7.60%
IDA 2682 DSUP	SDR'000	17,454	19,342	17	8.00%
IDA 4356-GH	US$'000	8,574	10,404	n/a	n/a
NDF 80	SDR'000	6,507	7,212	25	1.25%
SCADA 2ND BULK SUPL.	US$'000	125	152	2	0.88%
KFW NO. 9866070GH	EU€'000	4,263	6,856	20	3.00%
CGH1012 01A (Credit Facility agreement between ECG and CFD (Caisse Francaise De Development)	US$'000	2,611	3,168	11	5.00%
SCADA PROJECT	US$'000	2,380	2,889	4	0.00%
CHIRANO	US$'000	969	1,175	15	2.50%
Total			79,438		

Source: Debt Information Ghana Power Sector Companies spreadsheet, Gridco Final Financial statement spreadsheet

Ref: ECG Loans - Section DR - Debt Restructuring

ECG debt: overview

- The adjacent table provides a summary of the outstanding ECG loans
- ECG has 11 loans, from a variety of sources. Several of the World Bank IDA loans (2061, 2467 and 3456-GH) have been lent to the Ghanaian Government then on to ECG to finance its projects. The loan from NDF (Nordic Development Fund) is to finance an extension of electricity from the national power grid to small urban centres and rural areas.
- Several of the loans including accrued interest (IDA 2061, IDA 2467, NDF 80, KFW NO.9866070GH, and CGH1012 01A) were cancelled under the HIPC agreement on 31 December 2007.
- The average unweighted interest rate for the ECG loans is 5.47%. The average unweighted remaining term is 11 years.
- There is an outstanding loan balance of GH¢79m.

GEDAP

- There are several loans in ECG relating to GEDAP, summarised in the table below:

GEDAP loans

Loan name	Currency	31/12/08 balance (in original currency)	Remaining term (years)	Interest Rate
IDA CREDIT 14356	SDR'000	6,240	20	5.00%
IDA GRANT	SDR'000	n/a	20	5.00%
ACGF GRANT	US$'000	6,658	20	5.00%
AFDB LOAN	US$'000	n/a	20	5.00%

Source: GEDAP loan information

Ref: Debt Restructuring (DR8) - Section DR - Debt Restructuring

- We understand that the Ghana Energy Development Access Project ('GEDAP") is a joint programme funded principally by the World Bank and Africa Development Bank as well as a number of other development funds.
- The majority of the programme (70%) relates to projects to be implemented by ECG to develop rural electrification, reinforcement of distribution network and electricity access. In addition to development grants and soft loans ECG is contributing 9% of the total costs with 1% contribution from GoG.
- In our model projections we have assumed these development projects have been funded by secured facilities [terms of these loans are outstanding]. In addition, two grants provided by the IDA (US$ 20.2m) and AFDB (US$15m) in relation to this programme have been amortised over the life of the assets they relate to. [nb - louise hasn't done this yet, but is working on it]

ECG Debt overview

Short term debt

- ECG has ¢137m outstanding in short term supplier credit from VRA (GH¢124.8m) and independent power producers (GH¢11.9m).
- In the absence of any restructuring plan, in our base case financial model we have assumed these debts flow to creditors on the balance sheet.

GRIDCO- Debt Overview

Summary of outstanding GRIDCO loans

Loan name	Currency	31/12/08 balance (in original currency)	Amount (in GH¢)	Remaining term (years)	Interest Rate
IDA No. 1628 GH	SDR'000	837	927	28	4.00%
IDA 1759 GH	SDR'000	4,914	5,446	28	8.23%
IDA 2467	SDR'000	20,729	22,971	6	7.60%
Agence Franceaise - Techiman-Wa	GH¢'000	11,117	11,117	10	1.60%
Agence Franceaise - Techiman-SAWLA	GH¢'000	5,072	5,072	12	1.60%
Agence Franceaise - Burkina	GH¢'000	1,825	1,825	2	2.80%
SIDA - Bulk supply point	US$'000	847	1,028	2	0.88%
Newmont and others	US$'000	16,968	20,589	8	8.00%
Tarkwa Phase IV	US$'000	1,356	1,645	4	0.00%
Total			70,620		

Source: Debt Information Ghana Power Sector Companies spreadsheet

Ref: Gridco Loans - Section DR - Debt Restructuring

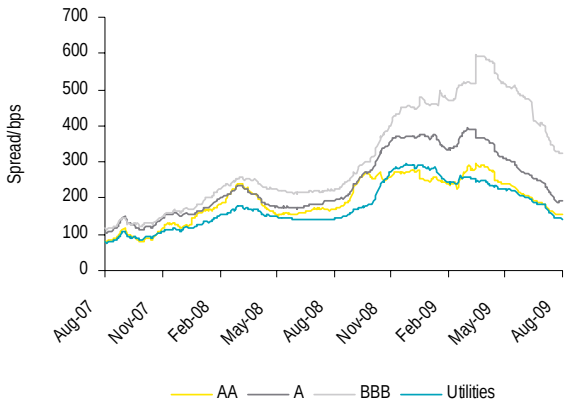
GRIDCO debt overview

- The table adjacent shows a summary of the outstanding GRIDCO loans
- There are 9 outstanding GRIDCO loans, 7 of which are from Multilateral or Bilateral lenders, for the purpose of capital expenditure on the transmission network.
- GRIDCO, was separated from VRA during FY08 and the accounts for 2008 were reconstructed. The loans were tied to the assets it was straightforward to transfer them across to GRIDCo balance sheet.
- The average unweighted interest rate on the GRIDCO loans is 3.86% and the average unweighted remaining term is 11 years.
- There is an outstanding loan balance of GH¢71m, as at 31 December 2008.

Credit issues and broader considerations

Graph 1: iBoxx £ Corp 15+ years spread over 15 year UK benchmark

Source: Datastream



Graph 2; High Yield US BB-B Utilities and Energy over 10 year US benchmark

Source: Datastream

International pricing benchmarks

- The recent credit cycle has been impacted by the cost and availability of credit. It can be seen from graph 1 that the credit crisis has caused credit spreads to widen, however the overall cost of debt has been partially offset by a fall in swap rates. We recognise we are looking at Sterling benchmarks, but are making the comparison as it is reflective of the credit crisis.
- The extent to which the cost of debt has increased has been dependent on the credit rating of the issuer. Debt issued by lower rated entities has increased in price by a much greater extent than higher grade debt.
- Credit spreads are beginning to tighten; however, there is still significant divergence in pricing depending on the credit rating of the issuer. This highlights the importance of strong credit being able to access funding.
- Utilities have faired better than many other sectors during the credit crisis. This is due to many utilities having high credit ratings as they are viewed as a stable asset class. This is driven by the value being supported by a large fixed asset base and cash flows being underpinned by customer group supply contracts. As a result the sector has low volume volatility risk and makes a safe choice for long term lending.
- When we look at the price of debt for utilities with a similar credit rating to the Republic of Ghana (graph 2) we see a marked increase in the cost of debt during the credit crisis. This has decreased over recent months however USD bonds in this sector can be expected to yield approximately 10% which is 650bps above the current US 10 year benchmark rate. This indicates that lower rated entities are exposed to more volatile as well as higher pricing.
- When considering financing options international pricing benchmarks should be considered as they can provide an indication of the pricing of a debt instrument issued by the company. It must be appreciated though that these trends and pricing levels are indicative only and are based on data from developed markets.
- The market appetite for the specific type of debt needs to be sufficient to support a successful issuance. This appetite will be affected by the size, tenor, terms and pricing of an issue. In order for an issue to be successfully placed at a value enhancing price the characteristics of the issue must be evaluated in light of current market appetite. Any characteristics of a proposed issue that are not aligned to the desires of the market would make the issuance harder to place.
- The pricing of any individual issuance will depend on the facets of the particular security. Given the circumstances the company is in, these could be wide ranging and have a significant impact on price.

Long term considerations

- With regulatory stability and sufficient return for capital providers, the availability of capital to meet the investment requirements of the sector can be achieved. Investment in long term economic return assets are most efficiently financed through long term debt and equity.

Long Term Debt

- Access to long term (and commercially provided) debt is best facilitated through the international capital markets and international bank markets. Debt quantums for any given project in the sector are material.
- A dependency to access such debt availability is an investment grade credit rating. The majority of western energy utilities typically attract and are structured to a rating of A-/A3. We recognise GoG's long term foreign currency rating is B+; however, it is of course possible that the sector could attract credit ratings in excess of the sovereign's threshold rating. The international benchmark ratings for the sector are essentially the sweat spot for attracting the debt quantums and tenors required to get optimal capital into projects and utility companies.
- Such a rating allows the issuance of listed security bonds through the public markets – these are very liquid instruments and the utilities companies are of the most active issuers. The year to date amount of bond issued by the power sector globally was over US$140bn. The power sector ranks only behind national governments and banks in terms of amount issued.
- The power sector is not anticipated to attract an investment grade credit rating for many years, but consideration to a credit rating as part of the sector reforms should be prevalent. The sector may be able to consider the issuance of higher yielding non investment grade bonds in due course, perhaps to emerging market investors.
- An improving credit profile (perhaps evidenced through credit ratings, but not necessarily) from stable regulation and improved sector economics, will also open up the international banking markets. Whilst the banking market is not the natural "home" for long term capital needed by the sector, it will always be a key part of providing short to medium term finance which can then be refinanced into longer maturities.

Investor Communication

- It is more important than ever that borrowers of capital take very seriously the professionalism and transparency of investor reporting and communication strategies. This is all part of the investment necessary to open up access to credit.

Recommendations

- ► Access to capital required to support sector is dependent on:
  - – Stable regulation and reform; and
  - – Credit profile.
- ► This report addresses our broader recommendations on sector return and regulation. This is critical for access to capital required to support the sector, and must be seen as a key dependent for restructuring debt.
- ► For the sector to break free of the current debt constraints it must have sufficient tariffs or subsidies to service all operating costs, debt service, capital expenditure and equity return.
  - – Over the longer term, we believe it is important that the sector to sustain itself without government or multilateral support mechanisms and eventually targeting an investment grade credit rating

This is key to driving such a credit rating which will enable funding diversification and optionality that is important to the success of the sector in tapping the capital which will be required.

- ► The credit profile of the sector is heavily influenced by the actions of the stakeholders.

Explicit government support through shareholding:

- – Permitting flexible dividend policies.
- – Subordinating and write off of existing public sector debt.
- – Clear government decision to guarantee debt now and in future.
- – Supporting tariff increases.

Implicit government support through shareholdings:

- – Appointment and approval of certain staff/Regulators.
- – Influencing objectives and business plans.
- – Facilitating access to feedstock and pricing control.
- ► The longer term debt strategy for the sector can only be defined when the broader structural reform is defined, scoped out and agreed. We recommend that following this, the following measures are core to the debt plans;
  - – Capex: Utilisation of international project finance markets, ensuring that contractual flow is optimised. This is likely to involve bank financing, multilateral financing and capital markets.

Credit issues and broader considerations

- Debt forgiveness: Government and multilaterals should be asked to support further debt forgiveness programs.
- Local bank market: Tapping the local banking market for operational and cash flow financing (leaving larger debt programmes to the international markets).
- Local/regional private placements: The sector should examine private placement options across sub-Saharan Africa.
- Multilaterals: Multilaterals will continue to support the sector as the Republic of Ghana continues to develop. Significant consideration and planning should be put into communication plans for multilaterals during the period of sectoral reform.
- Export credit agencies: The ECA's will be supportive of their national exporters (ever more so since the economic downturn). ECA financing offers the opportunity to lock in certain debt packages as investment continues delivering a lower cost of financing for capital investment programmes.
- International banking markets: Likely to offer less capital optionality until the credit rating of the Republic of Ghana improves and hits investment grade. There is potential to issue some higher yielding capital markets debt.
- Government loans: The Ghanaian government could raise debt centrally and make that available to the sector participants at agreed rates.
- Government guarantees: An extension of government guarantees will make capital more readily available.

► The shorter term debt strategy is significantly more restrictive, as flexibility for capital access can only emerge when the sector is reformed and the credit profile improves.

- Debt forgiveness: Agreeing with multilateral creditors and governments to forgive or reschedule debt obligations.
- Debt subordination (most likely from GoG but perhaps also from multilaterals) will provide optionality for new capital providers or those being asked to recommit to existing credit lines.
- Government and/or multilateral guarantees: Extending the recourse to stronger centralised credits to make available additional credit lines.
- Pan sector excess cash flow utilisation – to the extent that surplus cash flows in an annualised period become available, it would be possible to apply such cash flows to debt service in other parts of the sector. Whilst this creates additional intercompany (inter sector) debtor / creditor positions which must be subsequently unwound, it does provide cash flexibility during reform implementation.

Credit issues and broader considerations

– Local private placement markets: Tapping local private placement credit providers who may be interested in the provision of capital.

– Government liquidity loans: GoG lending on commercial terms to the companies when working capital constrains arise.

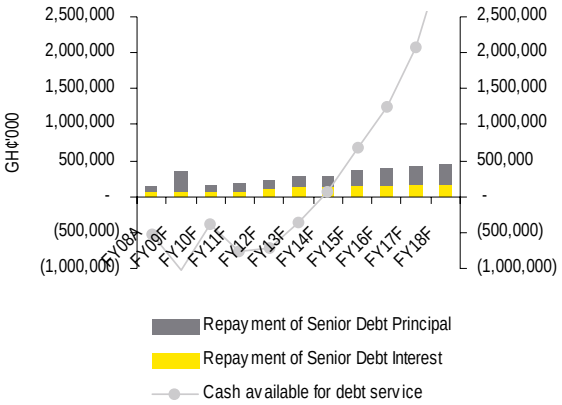
– Banking market access:

  Local: the local banking market remains a key source of finance especially on refinancing debt in the short term. All stakeholders should work together with the lenders to facilitate this and roll over current debt position

  International: International banks could play a role to the extent that debt with them is rolled over, or to the extent that any new borrowing is part of longer term structural reform in the sector. International lenders may be persuaded to re-enter the sector if structural reforms are implemented.

Short term debt service

Source: EY Analysis



Short term debt recommendations

The chart on the left and the table overleaf show the projected debt principle and interest payments made in total and by each of the businesses individually as well as the projected cash available for debt service under the adjusted investment scenario and assuming the tariff increases outlined in our recommendations and an equity investment of GHC1.25bn..

The following description of the overall debt position of each business includes specific recommendations on managing the short term debt servicing challenges facing the businesses. The description has been updated from the Draft Final report, where the projected revenue shortfall was met entirely by tariff increases, to a combination of a (smaller) tariff increase profile and equity injection has been used, resulting in lower overall costs for the sector.

Credit issues and broader considerations

Summary debt position by business

Currency: ¢ 000	FY08A	FY09F	FY10F	FY11F	FY12F	FY13F	FY14F	FY15F	FY16F	FY17F	FY18F
VRA Thermal											
Repayment of Senior Debt Interest	41,758	40,695	28,153	22,096	19,645	18,567	19,204	20,792	22,562	24,533	26,729
Repayment of Senior Debt Principal	67,787	257,987	73,502	61,588	47,240	26,515	4,182	4,473	4,789	5,133	5,509
Cash available for debt service	(7,667)	(401,114)	(371,695)	(630,442)	(733,687)	(818,949)	(1,010,691)	(1,251,278)	(1,566,274)	(1,908,446)	(2,362,021)
VRA Hydro											
Repayment of Senior Debt Interest	1,388	1,260	1,234	1,179	38,796	42,955	44,972	64,113	66,104	67,446	67,918
Repayment of Senior Debt Principal	6,390	6,518	2,527	2,958	2,217	39,639	46,776	105,784	122,642	142,239	165,028
Cash available for debt service	(193,539)	(153,166)	(148,334)	(111,315)	66,509	400,640	882,635	1,483,962	2,171,286	3,019,667	4,068,687
GRIDCo											
Repayment of Senior Debt Interest	4,736	10,035	16,247	22,887	30,001	28,568	26,467	24,755	22,802	21,463	20,058
Repayment of Senior Debt Principal	10,643	12,376	14,333	21,027	28,746	39,211	33,881	36,598	29,519	30,968	31,159
Cash available for debt service	(49,996)	(52,257)	55,538	66,281	85,219	146,041	191,722	244,871	295,768	352,008	401,090
ECG											
Repayment of Senior Debt Interest	5,460	10,480	12,081	14,266	20,203	27,295	35,178	41,300	39,654	37,434	35,053
Repayment of Senior Debt Principal	8,036	9,113	12,635	15,721	18,850	27,174	27,034	39,190	50,659	53,782	57,159
Cash available for debt service	(145,790)	(210,120)	63,268	(67,114)	(123,202)	(142,120)	(78,941)	58,586	128,936	305,972	843,014
NED											
Repayment of Senior Debt Interest	313	1,689	4,042	6,895	9,814	12,624	15,734	16,694	15,900	14,971	13,996
Repayment of Senior Debt Principal	270	346	1,092	2,971	5,563	8,666	12,229	16,814	19,594	20,597	21,654
Cash available for debt service	(127,573)	(200,254)	27,304	(27,784)	(4,889)	49,799	91,006	152,912	206,533	303,662	442,304
Total											
Repayment of Senior Debt Interest	53,655	64,159	61,757	67,323	118,459	130,010	141,554	167,654	167,022	165,848	163,753
Repayment of Senior Debt Principal	93,127	286,340	104,088	104,266	102,617	141,205	124,102	202,859	227,203	252,719	280,510
Cash available for debt service	(524,565)	(1,016,911)	(373,920)	(770,374)	(710,050)	(364,590)	75,733	689,052	1,236,249	2,072,863	3,393,074

Source: EY Analysis

Ref: Debt - Section CH - Charts

Overview of total debt position

All five businesses in aggregate have historically, and for 2010 at least, had insufficient cash available for debt service. This has led to either debt being written off under the HIPC program, or debt being rescheduled or rolled over in either working capital or letter of credit facilities, often at high rates of interest.

On the aggregated basis, this position may be reversed by 2014 if tariffs are increased sufficiently and equity is injected in the business to reduce the most expensive short term debt costs. However, this masks large differences in the debt carrying capacity of businesses. GRIDCo, thanks to it's lower initial debt burden, could have sufficient cash to service debt by 2010. It is assumed that the combination of

tariff increases and equity injection allow the businesses to access commercial borrowing to cover the shortfall in revenues to meet debt obligations in the short term. This assumptions has not been tested in the market and would be subject to individual company negotiations with lenders which ma result in higher or lower costs associated with the commercial funding to bridge the funding gap to 2014.

VRA Thermal

Although in aggregate the total businesses as well as VRA are capable of servicing debts at a point in the future, VRA thermal is not projected on a standalone basis to be able to generate enough cash to service debts in the forecast period. Even though VRA thermal investment plans have been reduced significantly in this scenario, the level of debt burdening the business is such that on a standalone basis it is unable to service them and relies heavily on working capital and other facilities to roll over the debt on an ongoing basis in the forecast period.

In 2009, VRA thermal is projected to comprise 90% of all the debt in the businesses, and 65% of interest payable. As the current level of BST is insufficient to cover operating costs, there is a significant increase in short term debt as the business seeks to roll over these obligations.

Much of the challenge facing VRA thermal on a standalone basis arises from the allocation of the majority of existing debt in the sector to that business. For example, GRIDCo's WAPP loans have been unable to be transferred from VRA's balance sheet due to GRIDCo's undercapitalisation. Further, the VRA hydro business has much less allocated debt on its assets when the businesses are carved out from each other.

The combination of equity injection and BST increase allows VRA Consolidated to reduce the overall costs of these working capital and other facilities. However, VRA Thermal as a standalone business would not be able to support its current debt obligations without the sale of assets or additional equity injections.

VRA Hydro

On a consolidated basis, VRA thermal and hydro are projected, from about 2014, to be able to generate enough cash combined to service debts, largely due to the windfall profits accruing to VRA hydro from the commencement of the WEM.

GRIDCO

On the basis that GRIDCO's revenues can increase to cover its operating costs and debts, it is projected that by 2010 the business will be able to service debts, including funding ongoing investment in transmission grid expansion (albeit at a lower rate than the business currently forecasts).

Credit issues and broader considerations

ECG

Under the tariff increase and equity injection scenario considered here, ECG is projected to be able to service debts sustainably from 2015. Although end user tariffs increase substantially, and ECG is projected to make an operating profit from 2012, the profits are somewhat offset by a rise in BST to allow VRA to meet its debt service obligations.

NED

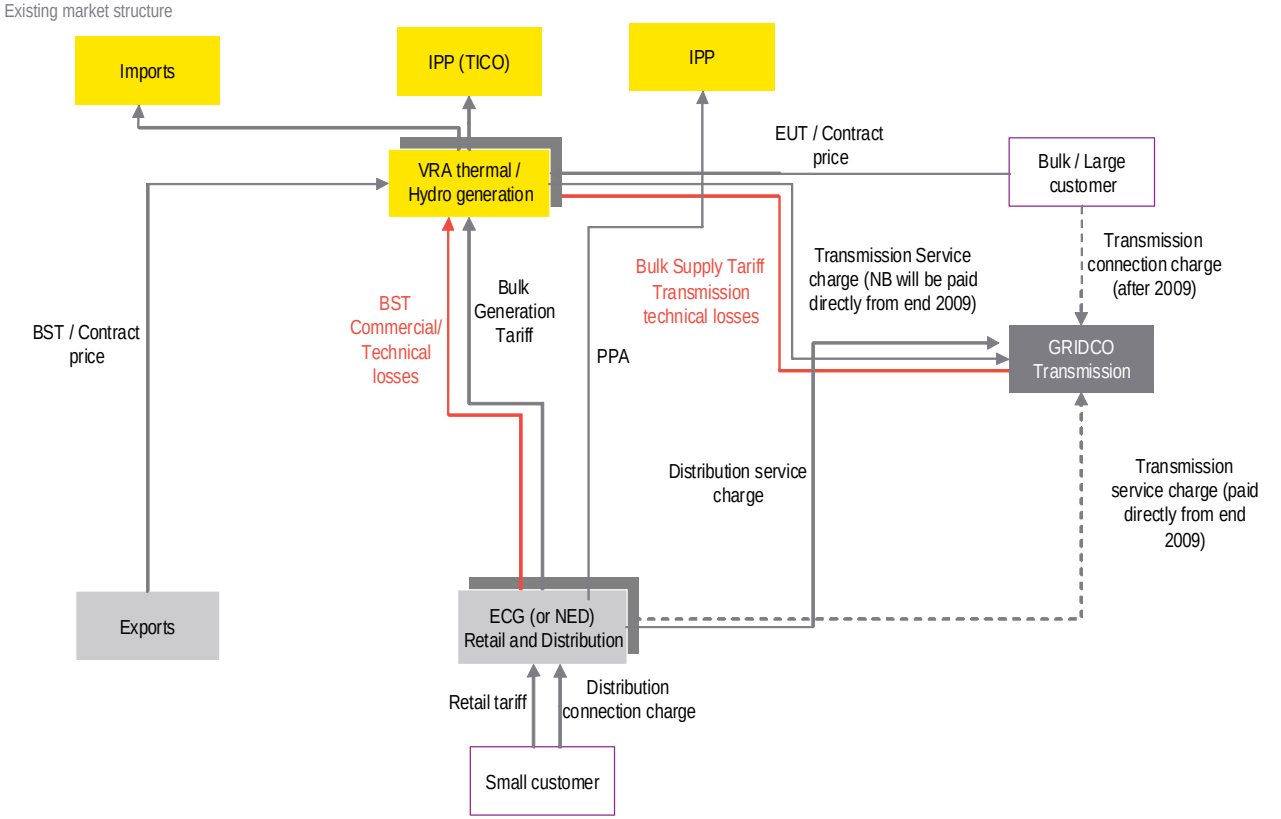
Significant ongoing investment by NED in the projection period results in a shortfall in cash to fund the associated debt repayments. NED is therefore only able to meet these obligations if it remains integrated into the VRA thermal and hydro business.

Introduction

Model structure

► The projected financial statements have been developed using an integrated financial model of the Ghanaian electricity sector. The model produces ten year (2008-2018) pro-forma financial statements for each of VRA (divided into four business units: VRA Thermal, VRA hydro, NED and VRA non-core), ECG and GRIDCO, under Appendix A. The diagram below summarises the flow of funds as modelled for the existing market structure.

Existing market structure



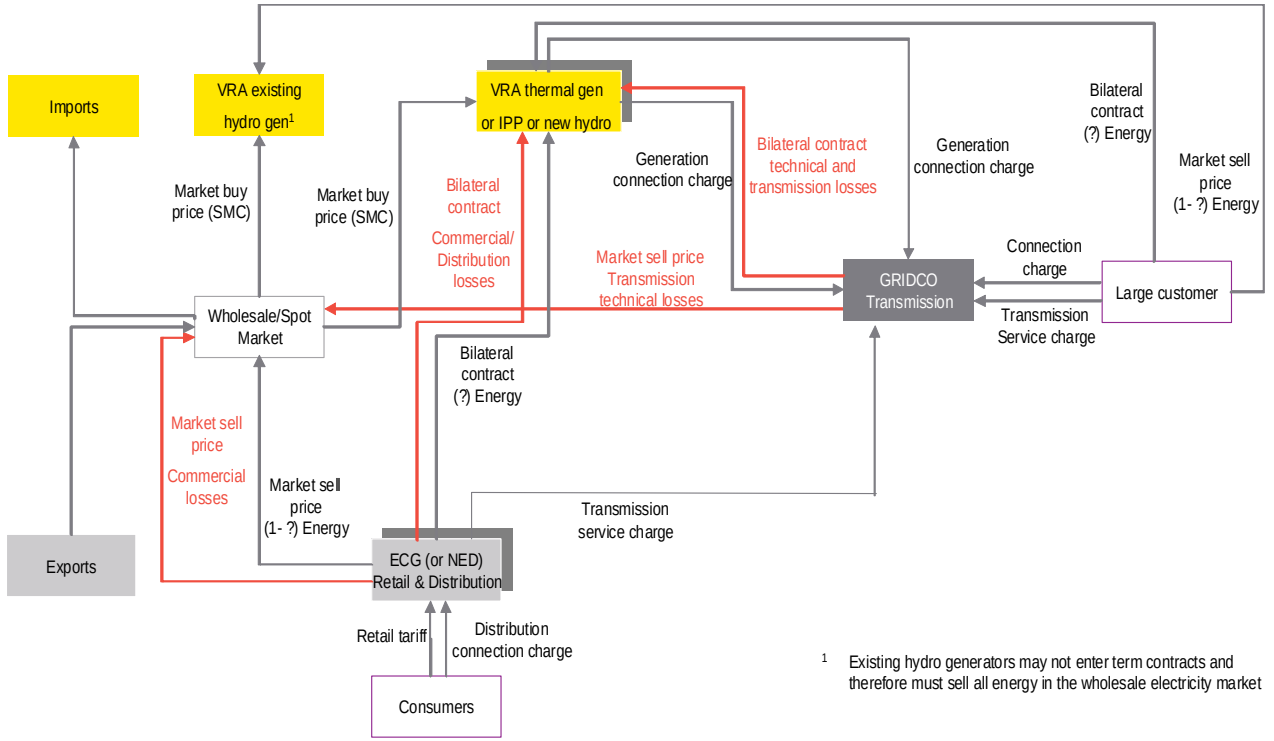
► The model is integrated in that it captures the inter- and intra-company payment transfers. For example, the cost of purchasing electricity from VRA for ECG is set as a cost for ECG and a corresponding

Forecasting methodology

revenue for VRA. Changes in the revenue requirement for VRA therefore translate as higher input costs to ECG, who in turn faces a higher revenue requirement. In this way, the overall system revenue requirement is aggregated sequentially for each of the companies' projected financial statements.

- The Ghanaian electricity sector is currently undergoing a restructuring. The market is expected to transition to a Wholesale Electricity Market (WEM) over the coming years. The financial projections take account of the restructured market according to the flow diagram below from 2012.

Wholesale market structure



[1] Existing hydro generators may not enter term contracts and therefore must sell all energy in the wholesale electricity market

- The major features of the new wholesale market are that eligible customers (which include large customers as well as the distribution companies ECG and NED) will be able to contract directly with Independent Power Producers (IPPs) for the bulk of their power, and purchase any shortfall in their

energy from a wholesale spot market which will be operated by GRIDCO as the system operator. Further assumptions are described in subsequent sections.

The objective of the modelling is to determine the quantum of additional revenue required to make each company a self financing entity. We define self financing entities as ones with a positive return on invested capital over the forecast period. Within that definition we also expect each business to have cashflows at such a level as to sustain debt and equity investors in the business with conservative assumptions in relation to financial strength. So in addition to an Average Return on Invested Capital (ROIC) over the ten year period, ratios such as Debt Service Cover Ratio (DSCR) are projected to recover to sustainable levels of 1.5x.

The required revenue to meet these return and debt obligations is estimated for each of the businesses. The calculation scales the projected revenue from existing average consumer tariffs and other sources of revenue to a level which meets the constraints described above. The scaling is done in the following sequence:

1. VRA thermal + VRA Hydro generation tariff scaled to meet financial metrics targets
2. Revenue shortfall for VRA non-core added to 1
3. GRIDCO transmission tariff scaled to meet financial metrics targets (using 1 as cost inputs)
4. NED average consumer tariff scaled to meet financial metrics targets (using 1 & 3 as cost inputs)
5. ECG average consumer tariff scaled to meet financial metrics targets (using 1 & 3 as cost inputs)

The projected financial statements have been developed using an integrated financial model of the VRA hydro business ("the Model") which has been developed by Ernst & Young for the purposes of this analysis. The financial statements summary analysis presented here summarise the pro forma financial statement for the period 2009-2018 in the Appendix A.

All assumptions presented here have been provided by or agreed with VRA, ECG and GRIDCO management. A reconciliation exercise has been undertaken against the management forecasts. Although VRA management do not report VRA hydro as a separate business unit, reconciliation has been achieved at BU level for the VRA thermal and hydro level.

The analysis presented on the following pages details the financial components and analysis as follows:

- Forecast volume of electricity sales by over the forecast period, (including the addition of the Bui hydroelectric dam to VRA Hydro in 2012).

Forecasting methodology

- Forecast revenue with an electricity sales price based on the operation of the wholesale electricity market (WEM) by 2010. This endows a windfall profit on VRA hydro due to the increase of electricity price to the system marginal price. It is assumed that all VRA hydro electricity is sold into the WEM at the system marginal price and that no additional revenue is received.
- Cost of sales including fuels costs, salaries operation and maintenance costs. This includes any efficiency gains, which are separately categorised.
- Assumptions on the depreciation of assets and taxation are described.
- The existing and planned future debt for the business are described in line with the investment plant outlined by management, with adjustment
- The chief components and ratios of the cash flow, profit & loss and balance sheet in the base case are presented.

Market Assumptions

Sensitivities to the base case assumption of oil price, exchange rate and interest rates illustrate the potential impact on the financial viability of the business.

The inflation and foreign exchange assumptions provided by the Ministry of Finance and Economic Planning used over the forecast period are shown below.

Inflation assumptions

	2009	2010	2011	2012	2013	2014
Foreign Inflation (%)	0.7%	2.5%	3.0%	3.3%	3.5%	3.5%
	1.01	1.03	1.03	1.03	1.04	1.04
Foreign Indexation (US$000)	1.01	1.03	1.06	1.10	1.14	1.18
Local Inflation (%)	19.6%	12.0%	10.0%	13.0%	15.0%	15.0%
	1.20	1.12	1.10	1.13	1.15	1.15
Local Indexation (GH¢000)	1.20	1.34	1.47	1.66	1.91	2.20

Source: VRA

Ref: Inflation - Section BS - Balance Sheet Analysis

- The GH$/ USD and EURO/ GH$ exchange rates are calculated based on the above inflation projections and are as follows:

Exchange rates

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
GH¢000 : US$000	1.41	1.67	1.81	1.95	2.16	2.40	2.66	2.96	3.29	3.65
GH¢000 : GH¢000	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00

Source: VRA

Ref: Foreign Exchange - Section BS - Balance Sheet Analysis

The fuel price projections are as follows:

Fuel prices

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
LCO import (USD/bbl)	67	77	82	82	82	82	82	82	82	82
Gas price (USD/mmBtu)	7.05	5.51	5.51	5.51	5.51	5.51	5.51	5.51	5.51	5.51

Source: VRA

Ref: Foreign Exchange - Section BS - Balance Sheet Analysis

Revised investment plans

The utilities investment projections are shown below.

Utilities investment plans

Currency: ¢ 000	FY08A	FY09F	FY10F	FY11F	FY12F	FY13F	FY14F	FY15F	FY16F	FY17F	FY18F
VRA Thermal	43,185	300,130	68,942	137,000	3,969	4,442	-	-	-	-	-
VRA Hydro	264,997	12,130	64,598	50,052	38,628	-	-	-	-	-	-
NED	40,171	36,973	62,516	76,701	80,876	81,372	93,424	40,735	114,879	53,873	151,927
VRA Non-core	-	-	-	-	-	-	-	-	-	-	-
ECG	57,878	146,443	50,730	67,509	172,539	210,303	244,947	191,092	222,718	256,125	-
GRIDCo	50,259	236,058	548,154	414,025	193,139	15,367	-	-	-	-	-
	456,490	731,734	794,941	745,288	489,152	311,484	338,372	231,827	337,597	309,998	151,927
Adjusted Investment											
VRA Thermal	43,185	9,253	32,657	3,558	3,969	4,442	-	-	-	-	-
VRA Hydro	264,997	12,130	64,598	50,052	38,628	-	-	-	-	-	-
NED	40,171	36,973	62,516	76,701	80,876	81,372	93,424	40,735	114,879	53,873	151,927
VRA Non-core	-	-	-	-	-	-	-	-	-	-	-
ECG	57,878	146,443	50,730	67,509	172,539	210,303	244,947	191,092	222,718	256,125	-
GRIDCo	50,259	141,602	172,740	192,116	214,601	-	-	-	-	-	-
	456,490	346,401	383,241	389,937	510,614	296,117	338,372	231,827	337,597	309,998	151,927

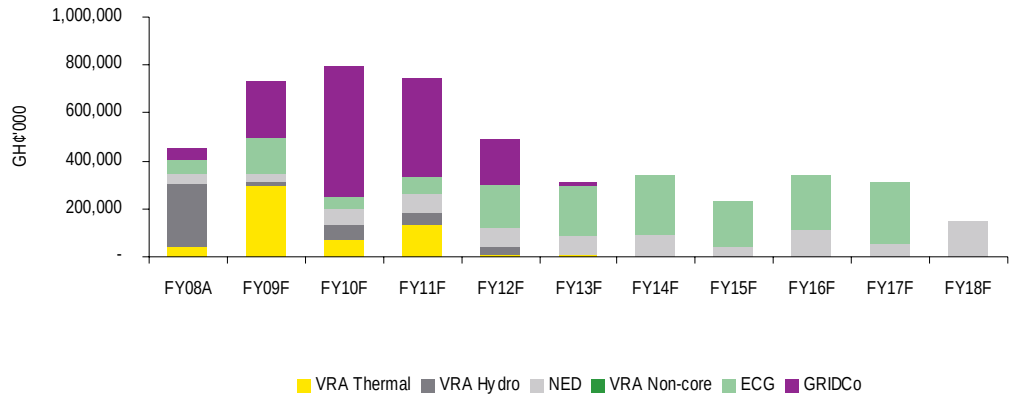
Source: Utilities investment plans (excl Bui)

Ref: Investment plans - Section CH - Charts

Forecasting methodology

Utility investment projections

Source: ECG, VRA and GRIDCo



In the graph, investment is projected to increase substantially to over GH¢730m pa in 2009 from just GH¢456m in 2008, a 60% increase. This high level of investment further increases to about GH¢795m in 2010 and subsequently decreases over time. For the five year period (2009 – 2013), approximately GH¢3.1bn in total is projected to be invested by the three utilities. Given the poor creditworthiness of the companies, it is considered unlikely that funds could be raised to this level. Notwithstanding the heavily indebted state of the companies at the moment, there is also a question as to whether the utilities would in fact be able to absorb such a step change in investment levels. The numbers of contractors, staff and projects under management would increase by as much as 60% as well, with the operational capacity of the utilities (including the newly formed GRIDCO) in excess of its current levels.

EY have consequently raised a number of observations concerning the investment plans provided by the utilities as follows:

- Funding has not yet been identified for much of the investment. Of that funding identified, much is from GoG. The Ministry has requested that where not linked to specific concessionary loans, GoG contribution is reduced to zero. On that basis, over 50% of the projected investment is unfunded and has therefore been removed from the investment plan.
- GH¢318m of VRA investment is associated with the Kpone Thermal Power Project (KTPP) which is scheduled for spend in 2009. However, we understand that financing for this project has not yet been

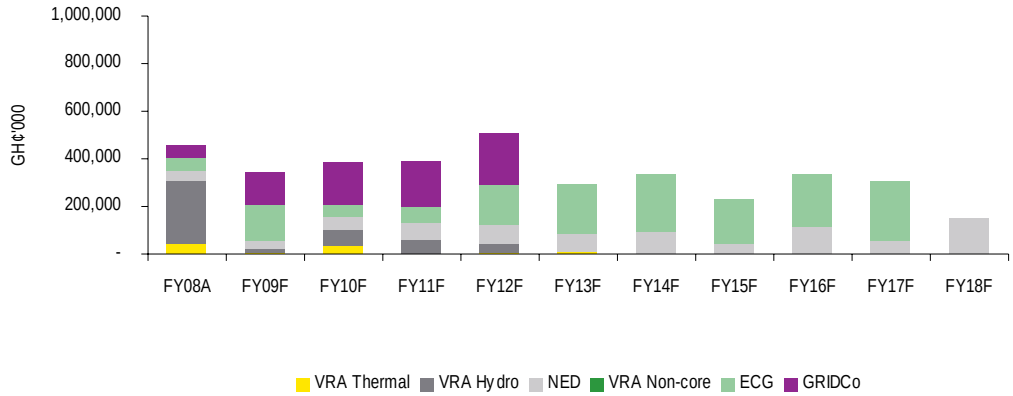
approved as at August 2009. We have therefore developed an alternative investment scenario where the VRA Kpone plant is replaced by the Sunon-Asogli IPP, with the gas contracted with VRA to be transferred. We have correspondingly adjusted the energy balance.

- Some of the VRA investment is in the provision of WAPP transmission capacity. This investment has not been transferred to GRIDCO as the company is at too early a stage to support the debt associated with those investments. However, GRIDCO forecast considerable investment also in the WAPP, with the potential for duplication.

In summary, EY have developed a lower utility investment scenario to be in line with historical investment levels of GH¢456b pa, as shown below:

Adjusted utility investment projection

Source: EY Analysis



- This would be in line with the currently known levels of funding available to the sector through concessionary loans. However, it is not known what impact this would have on the projected supply and demand for power. It is expected that the investment plans would have resulted in lower cost of supply or increased demand than otherwise, and the relationship between them is not known. For example,

targeted efficiency improvements could not be achieved without investment. It is recommended that forecast supply demand balance be revised in light of this lower investment plan.

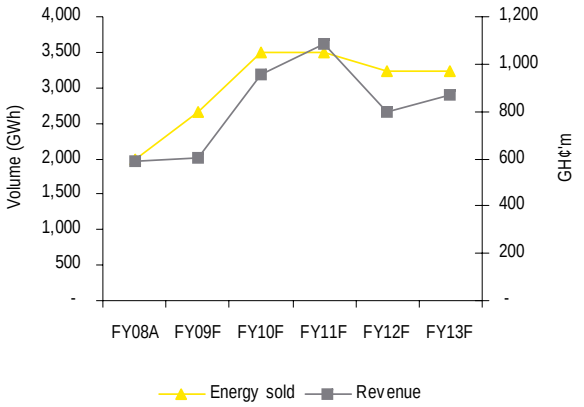
We present overleaf detailed analysis of forecasting relating to: VRA (Thermal, Hydro, NED, Non Core); ECG and GRIDCO under the following heading:

- Trading assumptions
- Capital Investment
- Capital Viability

1.1 Financial projection for VRA Thermal

VRA thermal sales volume and revenue projections

Source: VRA Management Forecasts



Trading Assumptions

Electricity sales

The chart opposite shows the revenue and volumes of electricity sales from the thermal plants in VRA. This includes revenues from the following thermal power plants:

Thermal power plants

Symbol	Name	Owner	Fuel	Capacity (MW)
T1	TAPCO	100% VRA	LCO, converting to gas in 2012	2x110 OCGT = 220MW 110 MW Steam turbine in place requires repair.
T2	Tico	10% VRA 90% Private	LCO, converting to gas in 2013	2x110 OCGT = 220MW 110 MW ST expansion in 2013
TT1	Tema 1	100% VRA	LCO, converting to gas in 2012	126MW
TT2	Tema 2 (Siemens)	100% VRA	Diesel	50MW
Mines plant	MRP = Mines reserve Plant	100% VRA (mines built then transferred)	Diesel	80MW
Barge	Osagyefo Barge	Balkan Energy	Diesel, converting to gas in 2011	125MW, possible CCGT in future, not planned
Osonor	TOPL - Tema Osonor Power Ltd	Gecad MoE PPA	LCO, converting to gas in Jun 2010	126MW
Alstom	KTPP - Kpone Thermal Power Plant	100% VRA	Not operating. Diesel or gas	2x110MW OCGT Partially built, requires $70m to complete
T3	Takoradi 3 Magellan	MoE with Canadian funding ECG PPA	Diesel or gas	Planned 110MW OCGT online 2012
Osonor + VRA expansion	TOPL - Tema Osonor Power Ltd	Gecad VRA	LCO, converting to gas in Jun 2010	110MW Steam Turbine onto existing 110MW OCGTs owned by VRA and TOPL in 2014

Source: VRA company information

Ref: Other(New 1) - Section OT - Other

Takoradi Thermal power plant is already operational as a simple cycle oil fired plant, and was converted to a combined cycle plant in 2008. It has been forecast to generate 1840GWh of electricity from 2010 onwards, with lower volumes in 2009, per the energy supply balance shown on the following page.

VRA Thermal has a 10% equity holding in Takoradi International Company (TICO) from which it purchases power which it sells on to customers. The Mines reserve plant has been assumed to operate within VRA thermal. While it is forecasted by VRA to be required to generate electricity during the forecast period, it is projected to cease generation beyond 2011.

► Projected volume transmitted

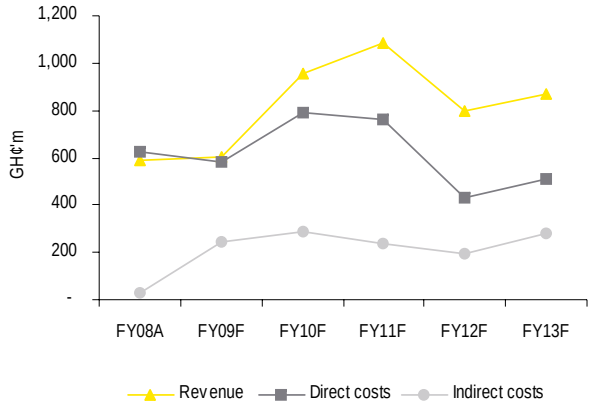
VRA management provided forecast accounts for the period 2009-2016. An energy flow forecast for the period 2009-2016 was also provided. An alternative projected energy generation forecast has been

1.1 Financial projection for VRA Thermal

developed for the reduced investment scenario. As it is understood that funding is not available for the investment in Kpone power plant, the forecast energy production has been replaced with energy from the Senzchen plant, assuming that the WAGP gas held by VRA will be on-sold.

Revenue, direct and indirect costs

Source: VRA Management forecasts



► Revenue projections

In order to determine the projected revenue requirement, the existing sources of revenue are projected to continue at current levels. By deducting the projected operating, investment and financing costs described in the following sections, a revenue requirement is determined for the base case. This base case revenue requirement is then recalculated under different scenarios to determine the potential impact in the revenue shortfall of alternative restructuring options, described in Section C.

The existing regulated Bulk Generation Tariff (in local currency), as determined by PURC assuming a 50% share of thermal and hydro generation, has been assumed until WEM introduction in 2012 to apply to all VRA thermal electricity produced. The Bulk customers of VRA are assumed to all transfer to VRA thermal in 2012 when the WEM rules do not allow hydro to contract directly.

It is understood that the basis for the PURC BGT tariff determination is under review, particularly on the indexation to fuel prices and the assumed thermal-hydro mix. It is recommended that these adjustments are implemented as they will have a material impact on the revenue projections of VRA, which are not projected in this analysis. Existing tariff levels and revenue sources have been assumed, and an estimate made of the revenue shortfall arising from that average tariff level, based on the projected costs.

► Forecast direct costs

– Power purchases

VRA thermal is projected to purchase electricity under PPAs from the TICO. VRA paid an energy charge component of 0.255 US$/kWh in 2008, which is projected to reduce to 0.040 US$/kWh in 2013 as the plant is converted to combined cycle and runs on gas from the West Africa gas pipeline by 2013.

– Fuel costs

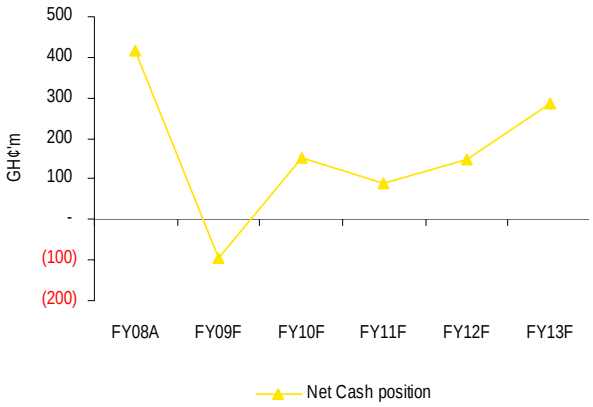
Fuel costs have been projected for the power plants which are assumed to be fully owned and operated by VRA Thermal.

Fuel costs have been based on assumptions of fuel costs for gas and oil provided by VRA in addition to efficiencies for combined cycle or simple cycle turbines. The table above shows the date, if any conversion of each power plant to combined cycle and to run on gas. The impact of the delay of WAGP and introduction of indigenous gas are considered in the scenarios described later.

1.1 Financial projection for VRA Thermal

Net cash position

Source: EY Analysis



Capital investment

As discussed in previous sections, all of the utilities have projected significant increases in capital spending in the forecast period. These investment plans are unlikely to be realised, as they will be constrained by either the limited level of external funding available or the future debt carrying capacity of the companies (at current tariff levels).

Adjusted capital investment programs are being developed by the companies, but are not available at time of writing. Therefore adjustments have been made to all company's investment projections in order to be consistent with historic levels of investment, and falling within existing funding commitments available to the companies. Further work is required in order to optimise these investment projections, especially concerning the impact, if any, on supply and demand energy balances. The management and adjusted investment program projections in 2009 real terms are summarised below.

Capex plans

Currency: ¢ 000	FY08A	FY09F	FY10F	FY11F	FY12F	FY13F	FY14F	FY15F
Management forecasts	275,700	47,500	77,000	2,000	2,000	-	-	-
Adjusted forecasts	8,500	22,500	2,000	2,000	2,000	-	-	-

Source: Management forecasts

Ref: VRA Thermal Capex - Section FC - Forecast

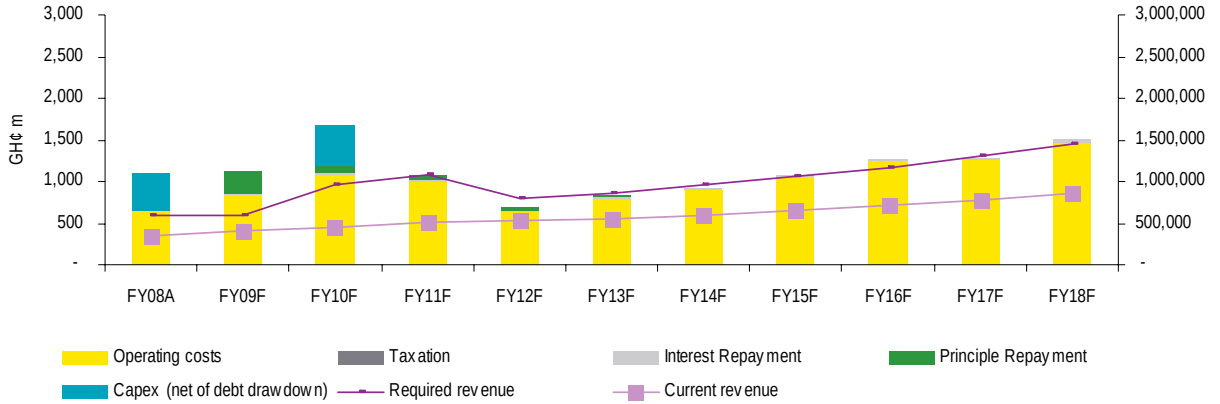
1.1 Financial projection for VRA Thermal

Company viability

The graph below shows the revenue requirements against the operating costs under the pro-forma case described above. The revenue requirements increase significantly above operating costs in FY10 in order to facilitate payment of the interest and principal associated with the adjusted (lower) investment plan, and increase again beyond 2012 in line with gas tariff indexation of WAGP and Jubilee gas.

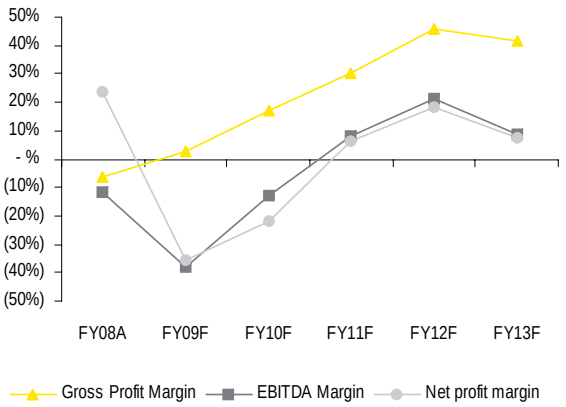
Projected revenue requirement

Source: EY Analysis



Profit margins

Source: EY Analysis

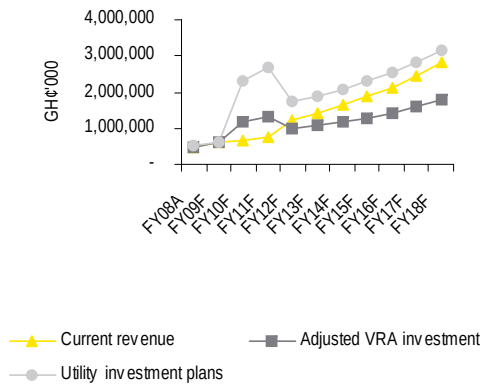


The graph on the left shows the five-year projected gross profit margin, net profit margin and EBITDA margin for the third scenario described above ie, forecasting VRA Thermal with reduced energy production and a correspondingly lower investment plan. This is the scenario which is used to populate the pro forma financial statements under the Appendix A. It also forms the basis for the adjusted generation tariff which flows into the ECG, NED and bulk supply customers.

1.1 Financial projection for VRA Thermal

Revenue requirements

Source: EY Analysis



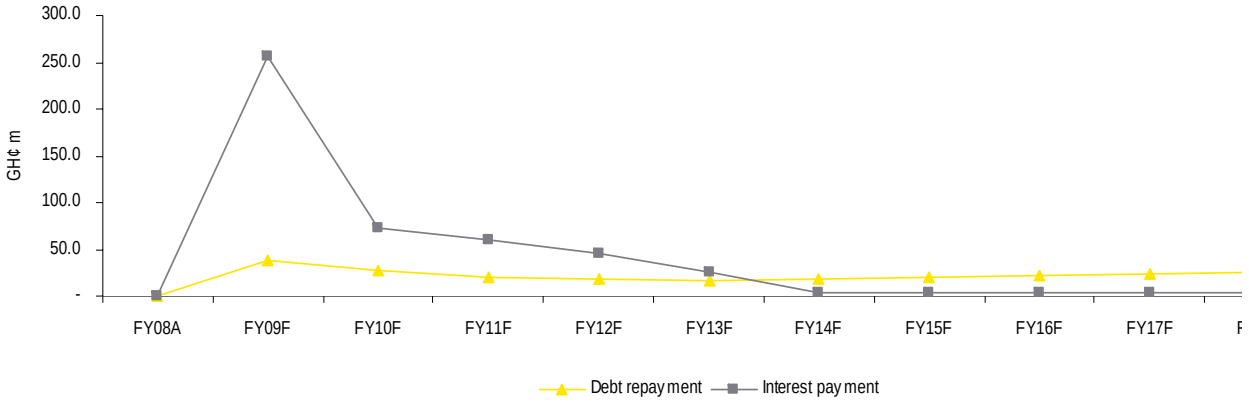
The graph on the left shows VRA Thermal's projected revenue requirement under three scenarios:

- Existing tariff revenue, using management generation forecasts, at the current level of BGT;
- Adding operating costs and the reduced generation investment program and scaling revenue to meet all operating and debt costs, which will increase the revenue requirement for VRA Thermal by about 40%; and
- Adding generation operating costs and investment plans as forecast by VRA described above will increase the revenue requirement for VRA Thermal by approximately two times.

The graph below also shows the projected debt and interest repayment profile for VRA Thermal. This projection will require further optimisation when VRA Thermal develops a revised investment plan, which will incorporate a funding drawdown schedule and analysis on the potential impact of reduced investment on the energy balance.

Debt repayment profile

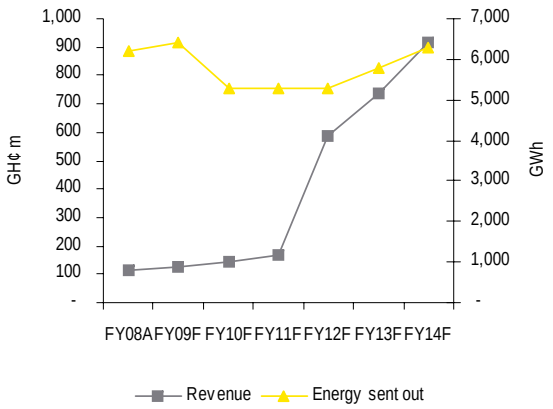
Source: EY Analysis



1.2 Financial projections for VRA Hydro

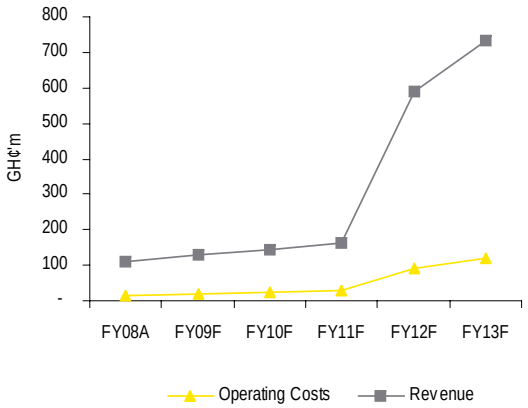
VRA Hydro output and revenues

Source: VRA Management forecasts, EY Anlaysis



Revenues and operating costs

Source: VRA Managements forecasts, EY Analysis



Trading Assumptions

Financial projections for VRA Hydro

1. Forecast volume of electricity sales

- The graph on the left shows the forecast revenue from electricity sales for VRA hydro. This is based on the 1020MW Akosombo and 160MW Kpong Hydro Plants with water levels producing average electricity output of 4,415 and 885 GWh for each of the next ten years.
- The Bui dam is assumed to be commissioned in 2012 and produce electricity at the design output of 1000GWh pa. There is assumed to be no impact on output from the Akosombo dam other than in 2011 when the upper lake above Bui is being filled and output from Akosombo reduces The Bui dam is assumed to be transferred to VRA Hydro on completion. It is currently a wholly owned government entity. It is assumed the business is transferred to VRA at book value.

2. Forecast electricity revenue

- It is assumed that the WEM is operational from 2012. Prior to that date, it is assumed that VRA Hydro supplies ECG and NED only – all existing PPAs with VRA are assumed to be allocated to the VRA Thermal business. The price of electricity sold to ECG and NED prior to the WEM becoming operational in 2012 is set by PURC at US cents 1.5/kWh. Once the WEM begins in 2012, all hydroelectric power is assumed to be sold at the system marginal price. We have assumed that the SMP is equal to the short run marginal cost of the highest priced thermal generator on the system[3]. For 2012-14 onwards this is assumed to be OCGT gas-fired plant, on the assumption that the WAGP remains operational. From 2012 it is assumed that the Jubilee field is priced at the same level as the WAGP, and the marginal plant becomes a CCGT with 55% thermal efficiency. Beyond 2015, further gas from the Ghana territorial waters is assumed to come online, at prices increasing over time to ensure sufficient returns for the oil and gas investors.

[1]Energy Commission

1.2 Financial projections for VRA Hydro

3. Cost of sales

Operating expenses have been assumed to include:

– Salaries and related expenses (Existing VRA Hydro);

– Other operating costs (Existing VRA Hydro);

– Bui operating costs

VRA provided an allocation of the 2008 accounts split by VRA Thermal and VRA hydro. Salaries and related expenses for the VRA hydro business are estimated at GHC 7,623,000 while other operating costs are estimated at GHC 1,973,000. These costs are projected to inflate over time at local inflation.

Bui is assumed to transfer to VRA hydro upon completion in 2012. The operating costs for Bui are projected to be in the same ratio to output as the existing VRA assets. They are projected to inflate at local inflation for the remainder of the forecast period.

4. Depreciation and tax

► The depreciation assumptions by the asset classes for VRA hydro are shown in the following table.

Depreciation assumptions

Currency: ¢ 000	NBV (01/01/2008)	Additions in FY08	Low	High
Dam	751,321	181,392	0.67%	2.20%
Generating Plants	139,171	67,124	2.20%	4.00%
Marine Assets	8,304	349	12.50%	12.50%
Vehicles, Computer & Others	1,346	(404)	10.00%	25.00%
Capital Works in Progress	695	166	0.00%	0.00%
Total	900,837	248,627		

Source: VRA

Ref: VRA Hydro - Section BS - Balance Sheet Analysis

► It is assumed that tax is incurred at the Ghana corporate rate of 25%. Windfall profits are taxed at this rate, and no assumptions have been provided for how the excess revenue in VRA hydro has been allocated.

1.2 Financial projections for VRA Hydro

Capital investment

► The table below shows the investment program for VRA Hydro.

VRA Hydro investment plan

Currency: US$000	2009	2010	2011	2012	2013	2014
Kpong Dam Downstream Shoreline Protection	-	1,500	1,500	1,000	-	-
Major Retrofit of Kpong GS	-	2,000	33,000	25,000	18,000	-
Total	-	3,500	34,500	26,000	18,000	-

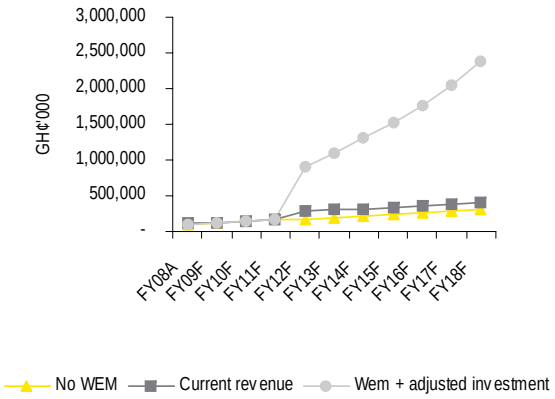
Source: VRA

Ref: Investment Category - Section BS - Balance Sheet Analysis

1.2 Financial projections for VRA Hydro

Revenue requirement

Source: EY Analysis



Company viability

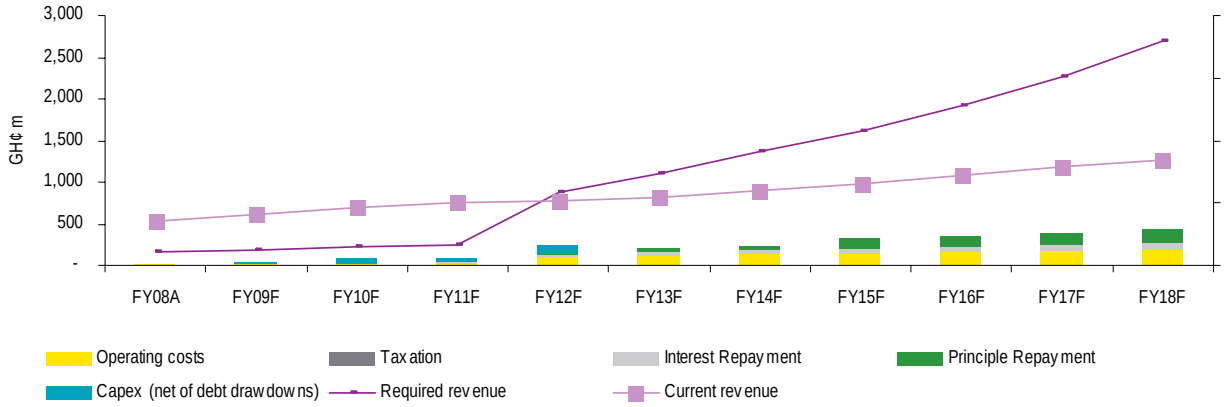
The graph on the left shows VRA Hydro's projected revenue requirement under three scenarios:

- Existing tariff revenue, using management generation and investment forecasts, at the current level of BGT for the entire forecast period and assuming no Wholesale Electricity Market (WEM);
- Adding the investment forecasts VRA Thermal assets from 2012, which increases the revenue requirement further; and
- Adding the impact of the WEM introduction in 2012, which increases the revenue in that year as described above because it is assumed that the revenue will increase for the existing assets by some 150%. The resultant higher profit projected to accrue to VRA Hydro under the WEM operation is used to offset the losses and debt requirement of VRA thermal under the VRA Consolidated accounts, on the assumption that the businesses are not separated.

The graph below shows the revenue requirements against the operating costs under the base case described above. The revenue increases significantly above operating costs in FY12 as a result of the WEM and the higher revenue earned by VRA hydro.

Projected revenue requirement

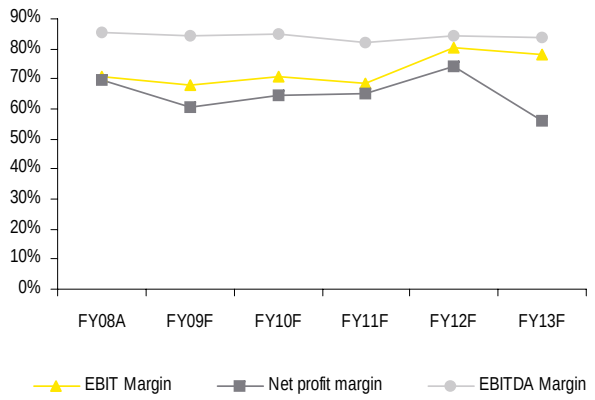
Source: EY Analysis



1.2 Financial projections for VRA Hydro

Profit margins

Source: EY Analysis

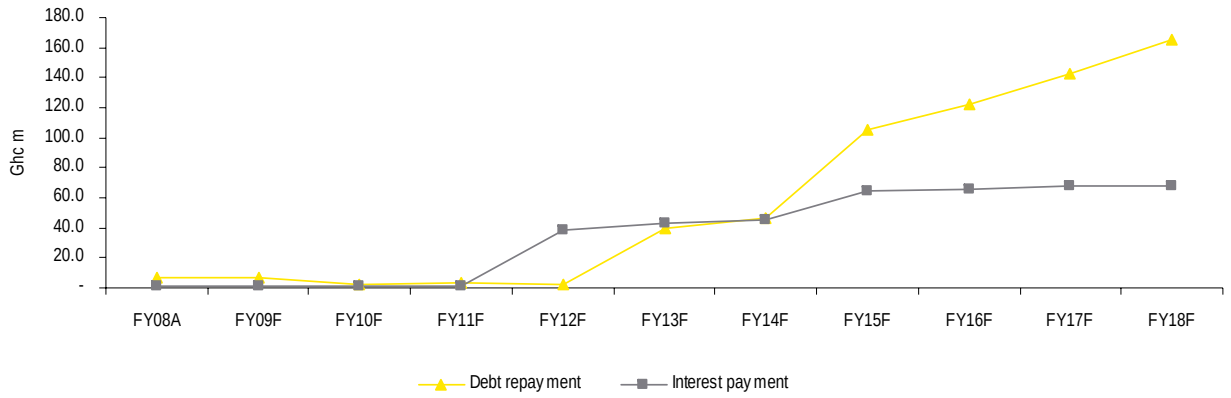


The graph on the left shows the five-year projected EBIT margin (gross profit margin), net profit margin and EBITDA margin for the third scenario described above ie, forecasting VRA Hydro with both the WEM and Bui hydro revenue added to existing revenue. This is the scenario which is used to populate the pro forma financial statements under Appendix A. It also forms the basis for the adjusted generation tariff which flows into the ECG, NED and bulk supply customers.

The graph below shows the projected debt and interest repayment profile for VRA Hydro. This projection will require further optimisation when VRA Hydro treatment of super profits is agreed, and a revised investment plan is developed, which will incorporate a funding drawdown schedule and analysis on the potential impact of reduced investment on the energy balance.

Debt repayment profile

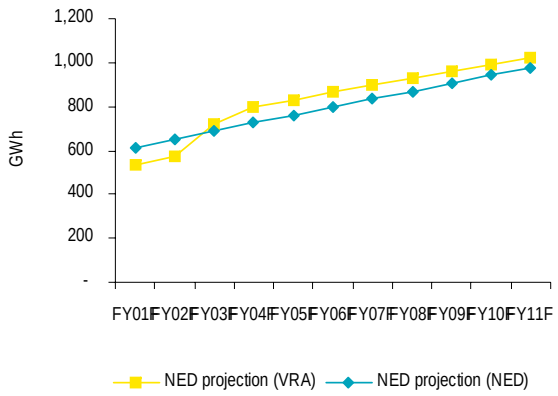
Source: EY Analysis



1.3 Financial projections for VRA NED

NED demand projection

Source: NED, VRA



Trade assumptions

Projected volume transmitted

NED management provided forecast accounts for the period 2009-2018. Both VRA and NED provided an energy flow forecast shown at left. The NED energy differed from the VRA projections by about 10% each year of the forecast. Because the VRA projections were consistent with their energy balance, the NED projections we adjusted accordingly.

Forecast electricity revenue

- NED sells electricity to end users at the regulated PURC price of 0.132GH¢/kWh. A lower tariff of 0.00008GH¢/kWh is applied to street lighting, volumes for which are projected separately.

Cost of sales

Operating expenses have been provided by NED management and include:

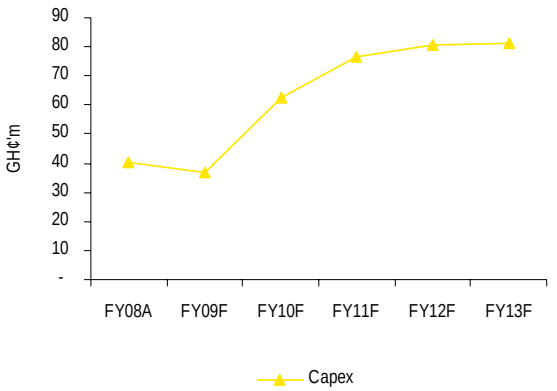
- Purchased power
- Transmission service charge
- Increase/(decrease) in bad debts
- Salaries and related expenses
- Material expenses
- Repairs and maintenance
- Other working costs

No adjustments have been made to projected operating costs, other than the price of purchased power which is at the level of the scaled tariff required for VRA to be self-financing.

1.3 Financial projections for VRA NED

NED Investment projection

Source: NED



Depreciation and tax

- The depreciation assumptions by the asset classes for NED are shown in the following table.

Depreciation assumptions

Categories	Additions / Disposals in FY08	NBV (31/12/2008)	Low	High
Distribution Network	30,622	216,218	2.50%	4.00%
Consumer Connection	4,398	45,688	4.00%	5.00%
Vehicles, Computers and others	123	768	10.00%	25.00%
Capital Works in Progress	4,917	7,435		
Total	40,059	371,179		

Source: NED

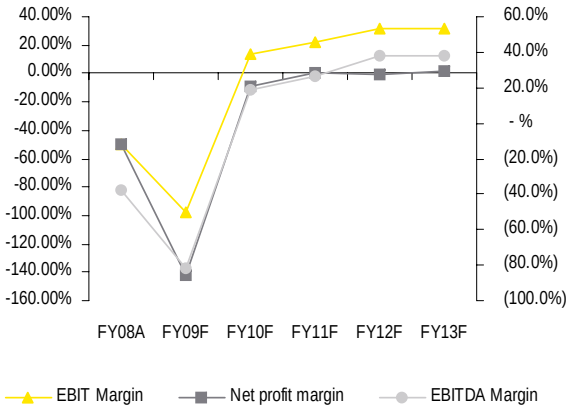
Ref: NED Depreciation - Section BS - Balance Sheet Analysis

- It is assumed that tax is incurred at the Ghana corporate rate of 25%.
- The projected NED investment is shown on the left. No adjustment has been made as it is understood the funding has been or will be put in place.

1.3 Financial projections for VRA NED

NED profit margins

Source: Management information



Company viability

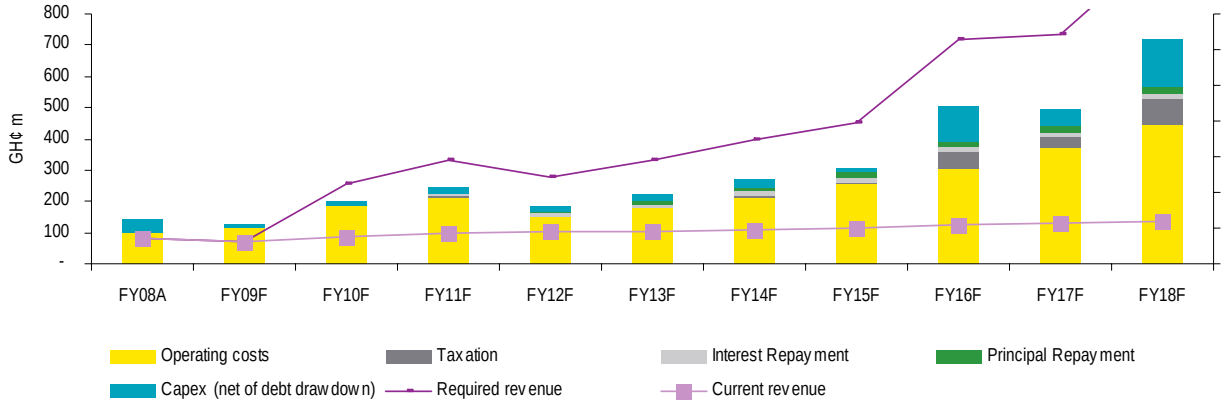
The graph on the left shows the five-year projected gross profit margin, net profit margin and EBITDA margin for NED. This is the scenario which is used to populate the pro forma financial statements under Appendix A.

The graph below shows NED's projected revenue requirement under two scenarios against the operating costs:

- Existing tariff revenue, using management sales forecasts, at the current level of end user tariffs and BGT for the entire forecast period;
- Adding the investment projection and expected generation costs required to cover the all in operating and financing costs of VRA. .

Projected revenue requirement

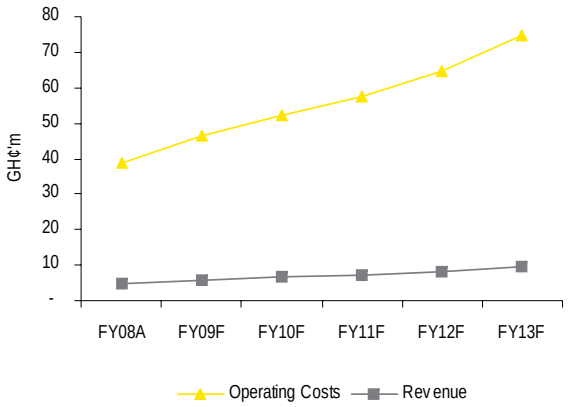
Source: Management Information



1.4 Financial projections for VRA Non-Core

Forecast revenues and operating costs

Source: Management information



Trading Assumptions

- For the purpose of this report, we have assumed the non core businesses as being:
  - Real Estate;
  - Health and Safety;
  - Schools;
  - Hotels; and
  - Lakes.
- The analysis presented on the following pages details the financial components and analysis as follows:
  - Forecast revenue for the five VRA non core businesses listed above.
  - Cost of sales including salaries, materials and hospital costs, and operation and maintenance costs.
  - Assumptions on the depreciation of assets and capital investment programme.

Forecast revenue

- The forecast revenue for VRA non core businesses is shown in the graph on the left. These forecasts were calculated by using as a basis the revenues earned by each business for the year ending 31 December 2008 and inflating these by the local Ghanaian indexation forecast for the next ten years.

The five non core businesses earned the following revenues for the year ending 31 December 2008:Revenues from VRA Non core*Currency: ¢ 000*	Real Estate	Health & Safety	Schools	Hotels	Lake	Total
Sales	684	2,033	1,037	1,169	0	4,923
Other Income	0	0	0	40	0	40
Total	684	2,033	1,037	1,209	0	4,963

Source: XXX

Ref: Forecast Revenue - 2008 - Section BS - Balance Sheet Analysis

1.4 Financial projections for VRA Non-Core

Operating costs

- The forecast operating costs for VRA non core businesses is shown in the table below. These forecasts were calculated by using as a basis the cost of sales for each business for the year ending 31 December 2008 and inflating these by the local Ghanaian indexation forecast for the next ten years.
- The five non core businesses had the following operating costs for the year ending 31 December 2008:

Currency: ¢ 000	Real Estate	Health & Safety	Schools	Hotels	Lake	Total
Salaries & Related	13,627	6,417	4,911	450	-	25,405
Materials & Hospital Costs	406	1,740	30	-		2,176
Transport & Travel	646	343	118	-	-	1,107
Operating Expenses	3,973	748	547	427	-	5,695
Repairs & Maintenance	1,089	52	73	132	-	1,346
Administration & General Expenses	1,022	55	18	123	-	1,218
Electricity & Water Usage	1,815	12	-	202	-	2,029
Total	22,578	9,367	5,697	1,334	-	38,976

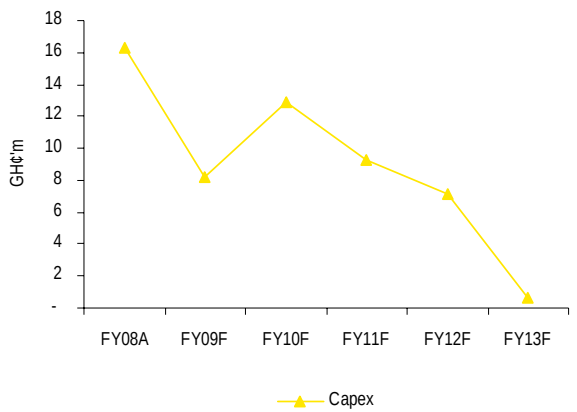
Source: VRA

Ref: Cost of Sales - 2008 - Section BS - Balance Sheet Analysis

1.4 Financial projections for VRA Non-Core

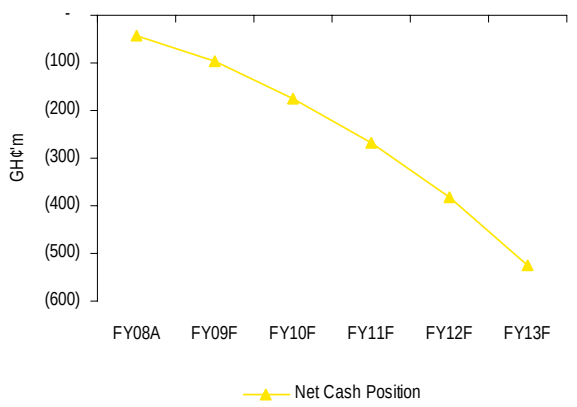
Forecast capex (nominal)

Source: Management information



Net cash position

Source: Management information



Capital Investment

The capex projection on the top left shows the investment program outlined below. The fixed asset projection includes the investment program outlined below. No adjustment has been made to this investment.

VRA non-core investment projection

Additions in US$000	3,150	117	-	-	-
Additions in GH¢000	337	401	408	447	215

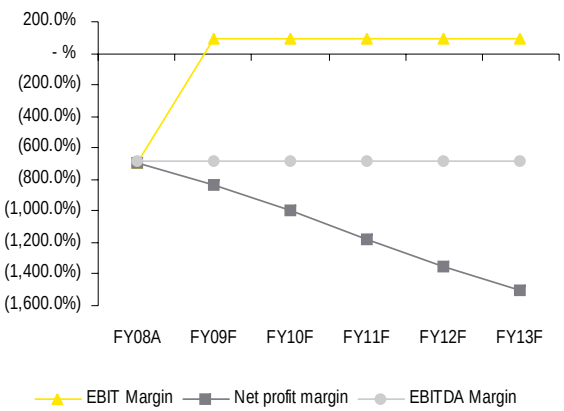
Source: VRA

Ref: Capex - Section BS - Balance Sheet Analysis

1.4 Financial projections for VRA Non-Core

VRA Non core profit margins

Source: Management information



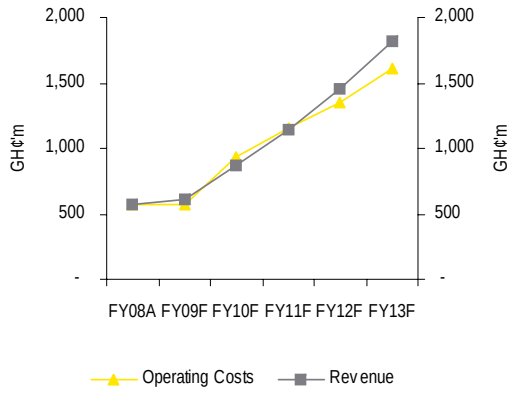
Company viability

- The graph on the left shows the VRA non core gross profit margin, net profit margin and EBITDA margin. It is projected that the company will experience large cash outflows and losses over the forecast period and will not contribute positively to the consolidated accounts.

2. Financial projections for ECG

ECG operating costs and revenue

Source: ECG, EY analysis



Trading Assumptions

Forecast volume of electricity sales and forecast revenue

- The table below shows the forecast volume of annual electricity sold by ECG for the 10-year period to 31 December 2018. This is based on:
  - ECG's annual forecasts for electricity demand; less
  - ECG's projections for distribution losses over the same period.

Energy forecast

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
ECG Demand (GWh)	5,700	6,062	6,389	6,801	7,206	7,620	8,046	8,486	8,939	9,408	9,892
Distribution Losses (GWh)	1,382	1,516	1,502	1,496	1,477	1,448	1,408	1,443	1,520	1,599	1,682
Energy Sold (GWh)	4,318	4,547	4,888	5,305	5,729	6,172	6,638	7,043	7,420	7,809	8,210

Source: ECG

Ref: ECG - Section BS - Balance Sheet Analysis

- The forecast electricity price is shown in the graph on the left. The end-user tariff has been assumed to be GH¢ 0.13/kWh for the projected 10-year period. This tariff has been derived by adding up the bulk generation tariff of GH¢ 0.06/kWh charged by VRA Hydro, the non-uplifted transmission tariff of GH¢ 0.009/kWh charged by GRIDCO and the uplifted distribution service tariff of GH¢ 0.0628/kWh charged by ECG.

Other sources of revenues

- Public lighting levy: An end-user tariff of GH¢ 0.00008/kWh has been assumed to be levied on electricity sold to derive the annual public lighting levy revenues. The table below shows the projected revenue for public lighting levy income over the 10-year period for ECG:

Other revenue

Currency: ¢ 000	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Energy Sold	4,318	4,547	4,888	5,305	5,729	6,172	6,638	7,043	7,420	7,809	8,210
Levy	0.00008	0.00008	0.00008	0.00008	0.00008	0.00008	0.00008	0.00008	0.00008	0.00008	0.00008
End User Tariff (Local Currency)	0.00008	0.00008	0.00008	0.00008	0.00008	0.00008	0.00008	0.00008	0.00008	0.00008	0.00008
Revenue (Nominal)	345	364	391	424	458	494	531	563	594	625	657

Source: ECG

Ref: ECG - Other Revenue - Section BS - Balance Sheet Analysis

2. Financial projections for ECG

Operating expenses

- Operating expenses have been assumed to include:
  - Purchase of power;
  - Transmission service charge;
  - Bad debts increase/decrease;
  - Distribution Operation and Maintenance;
  - Transport;
  - Staff costs; and
  - Other administrative expenses
- Purchase of power relates to the power purchased in the pre wholesale market. An average bulk generation tariff was applied to the forecast volumes of power purchased until 2012 at a tariff which is set to the level required by VRA and/or IPPs to recover full operating and investment costs.
- The transmission service charge is incurred which relates to the costs incurred for the transmission of ECG power purchased. An average transmission charge was applied to the forecast volumes of power transmitted/ purchased at a level which allows GRIDCO to recover its full costs. .
- Finally, the projections for the other costs were calculated using as a basis the 2008 figures provided by the ECG management. These costs were thereafter inflated by the local Ghanaian inflation and foreign exchange assumptions provided by Ministry of Finance.

2. Financial projections for ECG

Depreciation and tax

► The depreciation assumptions by the asset classes for ECG are shown in the following table.

Categories	NBV (01/01/2008)	Revaluations in FY08	Additions in FY08	Disposals in FY08	Depreciation in FY08	NBV (31/12/2008)	Low	High	Average
Sub-T Network	181,406	57,987	3,454	-	(12,832)	230,015	2.50%	4.00%	3.30%
Distribution Network	516,994	165,587	23,595	(291)	(52,831)	653,054	2.50%	4.00%	3.30%
Land, Building & Capital Works	62,461	9,390	3,601	-	(1,783)	73,669	2.50%	2.50%	2.50%
General Tools	1,666	533	39	-	(444)	1,794	12.50%	12.50%	12.50%
Fixtures & Fittings	4,223	1,350	1,824	-	(1,421)	5,976	12.50%	12.50%	12.50%
Meters	32,904	10,445	14,896	(27)	(4,205)	54,013	5.00%	5.00%	5.00%
Software	1,742	557	58	-	(466)	1,891	25.00%	33.33%	29.20%
Motor Vehicles	6,548	2,093	10,411	-	(3,179)	15,873	10.00%	25.00%	17.50%
Total	807,944	247,942	57,878	(318)	(77,161)	1,036,285			

Source: XXX

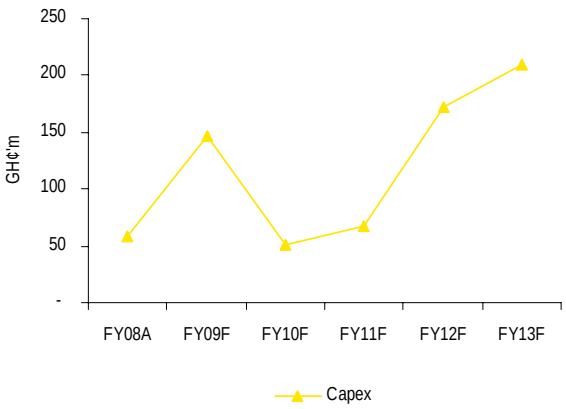
Ref: ERG - Section BS - Balance Sheet Analysis

It is assumed that tax is incurred at the Ghana corporate rate of 25%.

2. Financial projections for ECG

Capital investment (nominal)

Source: Management information

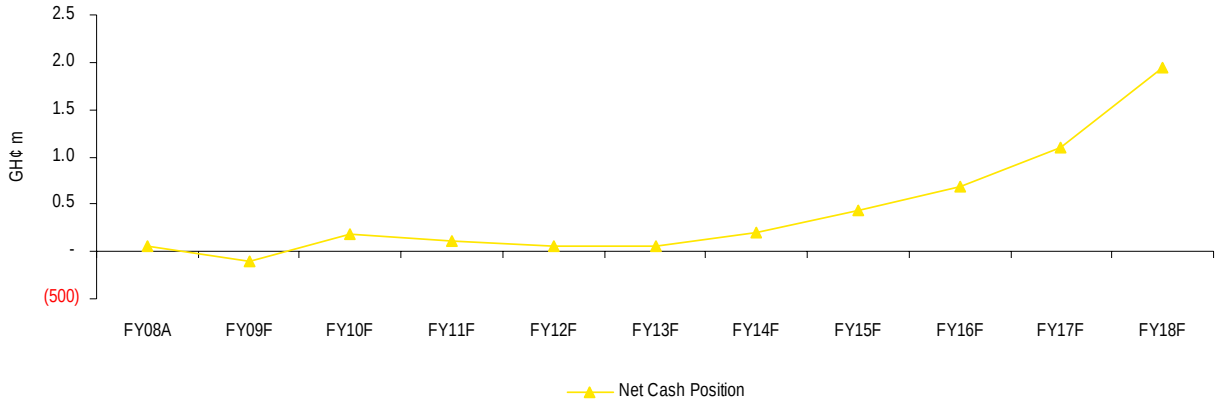


Capital Investment

An adjusted capital investment plan was received from ECG management and has been incorporated into the projections. It is understood that the investment projections are fully funded. The resultant net cash position for ECG is shown in the graph below:

Net cash position

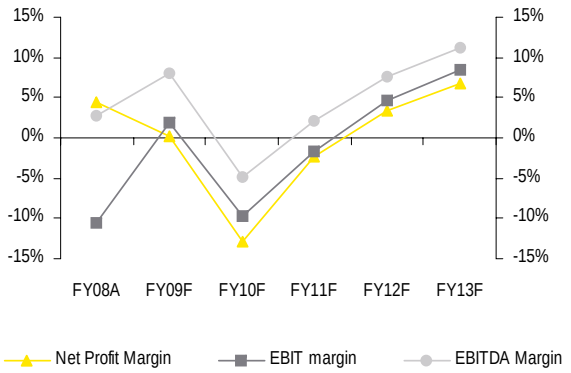
Source: EY Analysis



2. Financial projections for ECG

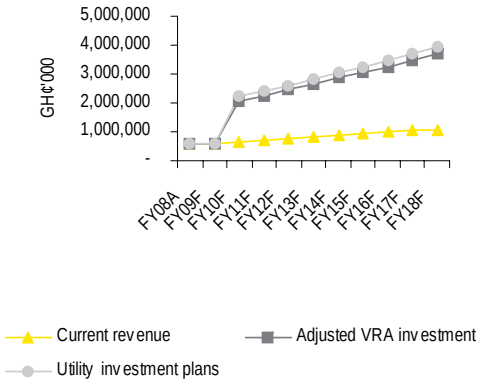
ECG profit margins

Source: EY Analysis



ECG Revenue requirement

Source: EY Analysis



Company viability

- The graph on the left shows ECG gross profit margin, net profit margin and EBITDA margin. Although the company experiences positive cash flows over the 10-year period projection and profits up until the year ending 31 December 2010, it witnesses decreased profitability as from 2011. This is due to increasing operating expenses, notably in relation to the charges paid for power purchased and distributed.

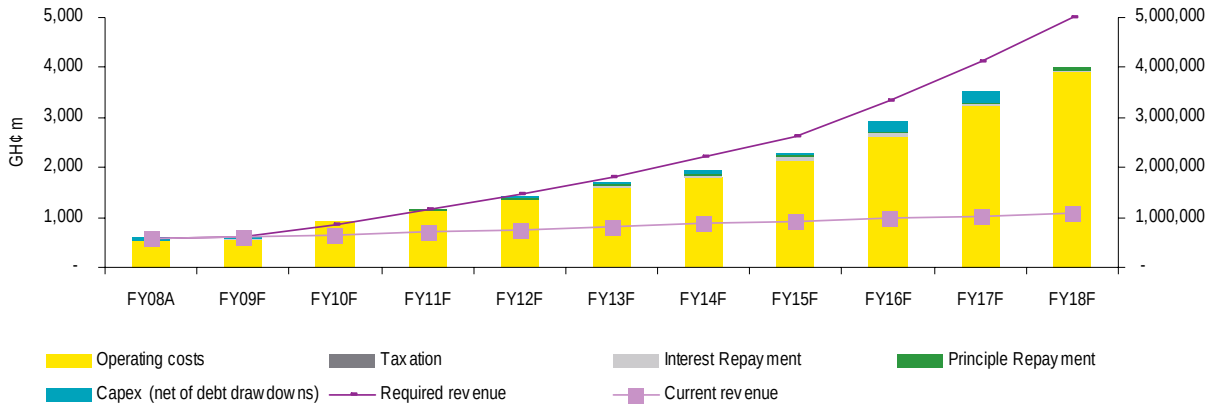
The graph on the bottom left shows ECG's projected revenue requirement under three scenarios:

- Existing tariff revenue, at the current level of end user tariff for the entire forecast period;
- Adding the impact of the increased capex and opex costs of the VRA thermal power project investments; and
- Replacing the VRA projected thermal investment with the PPAs in place with Scenhzen and the Candian plant. .

The graph below shows the revenue requirements against the operating costs under the base case described above. The revenue increases significantly in future largely due to inflation of fuel prices in local currency.

Projected revenue requirement

Source: EY Analysis

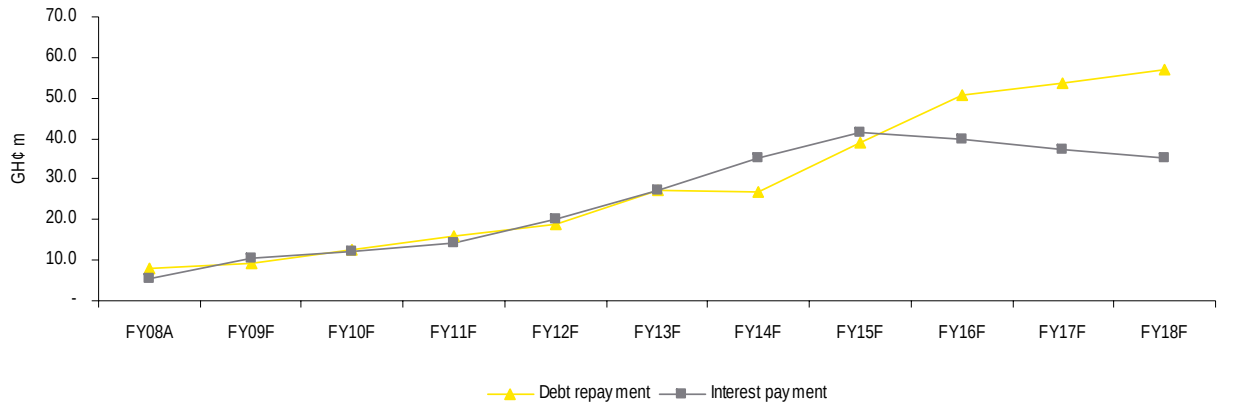


2. Financial projections for ECG

The graph below shows the projected debt and interest repayment profile for ECG.

Debt repayment profile

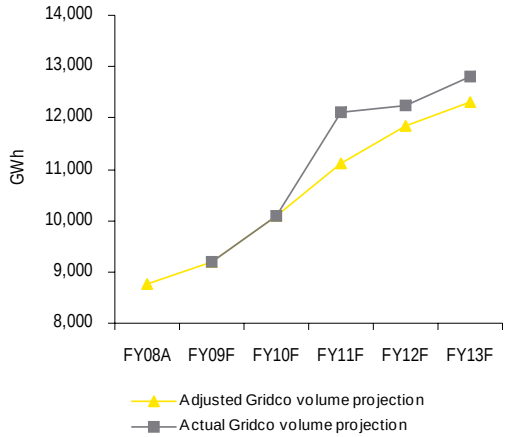
Source: ECG, EY Analysis



3. Financial projections for GRIDCo

Projected energy transmitted

Source: GRIDCo, VRA



Trade Assumptions

Projected volume transmitted

GRIDCO management provided forecast accounts for the period 2009-2011. An energy flow forecast for the period 2009-2016 was also provided. The energy projection was consistent with VRA projections for 2009 (when adjustment was made for system losses) and 2010, but diverged thereafter, as shown on the diagram at left. The divergence is due to an annual growth assumption by GRIDCO in 2012 of 20%, which is not consistent with historical annual growth rates of up to 10%.

Therefore adjustment was made to the GRIDCO energy forecast used to derive revenues. For the period 2012-2018 the transmitted energy forecast was derived from the VRA energy balance projections, and is shown in the diagram at left to 2013 as the adjusted GRIDCO volume projection. The CEB Wheeled energy is shown separately as it is projected to have a different US denominated tariff, as described later. The projected energy balance used as the basis for the GRIDCO transmission tariff for the 10-year period to 31 December 2018 is shown below:

Basis for transmission tariff

GWh	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Total Domestic	8,043	8,746	9,465	10,126	10,596	11,138	11,703	12,298	13,110	13,811
VALCO	12	12	12	12	12	12	12	12	12	12
CEB (Contractual Supply)	509	500	500	500	500	500	500	500	500	500
CEB (Additional VRA Supply)	302	500	814	814	814	814	814	814	814	814
SONABEL	5	5	5	66	66	67	68	68	69	70
Basis for Transmission tariff	8,871	9,763	10,796	11,518	11,988	12,531	13,097	13,692	14,505	15,207
CEB (Wheeled)	313	313	313	313	313	313	313	313	313	313
Adjusted GRIDCO volume projection	9,184	10,076	11,109	11,831	12,301	12,844	13,410	14,005	14,818	15,520

Source: GRIDCO, EY Analysis

Ref: GRIDCO - Section BS - Balance Sheet Analysis

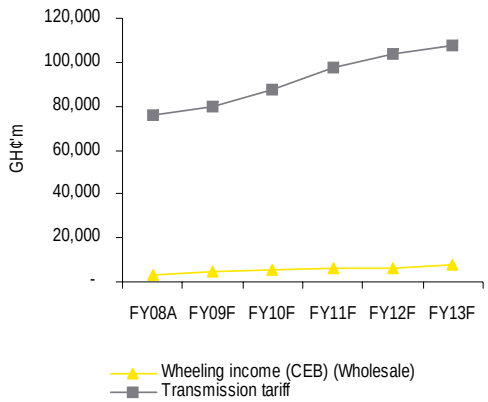
Revenue projections

- In order to determine the projected revenue requirement, the existing sources of revenue are projected to continue at current levels. By deducting the projected operating, investment and financing costs described in the following sections, a revenue requirement is determined for the base case. This base case revenue requirement is then recalculated under different scenarios to determine the potential impact in the revenue shortfall of alternative restructuring options, described in Section C.

3. Financial projections for GRIDCo

GRIDCO existing tariff revenue projection

Source: GRIDCo, EY Analysis



- The existing regulated transmission tariff of GH¢ 0.009/kWh, as determined by PURC, has been assumed for the forecast period to apply to all domestic electricity transmitted. It is understood that the basis for the PURC tariff determination is under discussion with GRIDCO, including how to compensate GRIDCO for interconnection costs (ie, connection of new generators and large users) as well as the benchmark for transmission losses (see next section). Although all of these will have a material impact on the revenue projections or GRIDCO, at this time no estimates are available for the impact on revenues. Therefore, existing tariff levels and revenue sources have been assumed, and an estimate made of the revenue shortfall arising from that average tariff level, based on the projected costs.
- In addition to the regulated transmission tariff which GRIDCO applies to energy transmitted for domestic consumption, additional revenue is earned by wheeling (transporting) energy for the CEB. The tariff is subject to bilateral negotiation between GRIDCO and CEB, and we understand is not subject to regulation by PURC. Following discussions with GRIDCO, a wheeling tariff of US$ 0.010/kWh has been assumed in the projected revenue, inflated in line with the foreign exchange assumptions provided by the Ministry of Finance for this study. The graph on the left shows the projected domestic tariff and wheeling tariff revenue over the 10-year projection period for GRIDCO.

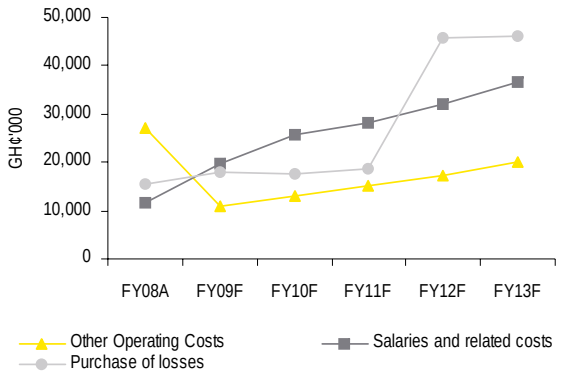
Operating expenses

- Operating expenses have been assumed to include:
  - Purchase of losses;
  - Salaries and related costs;
  - Other operating costs
- Purchase of losses relates to the GRIDCO's projections for transmission losses (referred above in section 1). The financial projections provided by GRIDCO management do not include transmission losses. We understand that this is because VRA currently collect transmission losses from customers on GRIDCO's behalf. As at August 2009, contracts are about to be put in place between GRIDCO and bulk customers, and expected to come into effect from 1 Jan 2010. The contracts with contract GRIDCO for transmission services, including the payment of transmission losses. VRA will, after that, date no longer collect transmission losses on GRIDCO's behalf. We have therefore adjusted the VRA 2008 and 2009 projections to remove transmission losses, and included it in GRIDCO projected costs. It is then added to other costs used to estimate the required revenue. Losses as a percentage of energy entering the transmission system are projected by GRIDCO to fall over the forecast period from 3.27% in 2009 (up from 2008 level of 3.07%) to 2.5% by 2018, as per the following table.

3. Financial projections for GRIDCo

GRIDCo operating costs

Source: GRIDCo, EY Analysis



Projected transmission losses

GWh	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Energy entering Transmission	9,168	9,804	10,548	11,818	12,291	12,838	13,422	14,036	14,874	15,598
Transmission system use losses	300	295	312	301	304	308	325	343	369	390
Total energy entering distribution	8,868	9,509	10,237	11,517	11,988	12,530	13,097	13,692	14,505	15,207
Losses as % energy entering Transmission	3.27%	3.01%	2.95%	2.54%	2.47%	2.40%	2.42%	2.45%	2.48%	2.50%

Source: GRIDCO, EY Analysis

Ref: GRIDCO - Section BS - Balance Sheet Analysis

- An average cost of purchasing energy lost on the transmission grid was applied to the forecast volumes of transmission losses. This energy purchasing cost was assumed to be the average Bulk Generation Tariff (BGT) up until 31 December 2011, which is set at the price of wholesale electricity which provides VRA with its projected revenue requirement (i.e. above the current level of BGT of GH¢ 0.0602/kWh). This price is sensitised between the base case and other scenarios. From 1 Jan 2012, the Wholesale Electricity Market (WEM) is projected to be operational, and GRIDCO is expected to purchase power for transmission losses either under bilateral contract or from the wholesale market directly. As no cost projections are available, a conservative assumption has been made that energy is purchased at the system marginal price of the WEM.
- Forecasts for "Salaries and related costs" and for "Other operation costs" were provided by GRIDCO in its Business Plan up until 31 December 2011, and have not been adjusted. For the remainder of the forecast period (2012-2018), these costs are projected to increase in line with inflation.

Depreciation and tax

- The depreciation assumptions by the asset classes for GRIDCO are shown in the following table.

GRIDCO depreciation assumptions

Categories	NBV (01/01/2008)	Additions / Disposals in FY08	Depreciation in FY07	NBV (31/12/2008)	Low	High	Average
Transmission	300,458	75,322	(9,314)	366,466	2.20%	4.00%	3.10%
Other Land, Buildings & Townships	5,204	(660)	(130)	4,414	2.50%	2.50%	2.50%
Vehicles, Other Equipment & Misc. Assets	341	18	(60)	299	10.00%	25.00%	17.50%
Total	306,003	74,680	(9,504)	371,179			

Source: GRIDCO

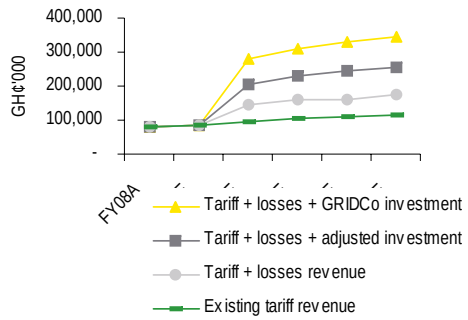
Ref: GRIDCO Depreciation - Section BS - Balance Sheet Analysis

- It is assumed that tax is incurred at the Ghana corporate rate of 25%.

3. Financial projections for GRIDCo

Projected revenue requirement scenarios

Source: GRIDCo, EY Analysis



Capital Investment

As discussed in previous sections, all of the utilities have projected significant increases in capital spending in the forecast period. These investment plans are unlikely to be realised, as they will be constrained be either the limited level of external funding available or the future debt carrying capacity of the companies (at current tariff levels). Adjusted capital investment programs are being developed by the companies, but are not available at time of writing. Therefore adjustments have been made to all company's investment projections in order to be consistent with historic levels of investment, and falling within existing funding commitments available to the companies. Further work is required in order to optimise these investment projections, especially concerning the impact, if any, on supply and demand energy balances. The management and adjusted investment program projections are summarised below.

	FY08A	FY09F	FY10F	FY11F	FY12F	FY13F
Management	61,035	219,680	284,660	183,480	89,420	6,270
Adjusted	61,035	100,000	100,000	100,000	100,000	-

Source: GRIDCO, EY Analysis

Ref: GRIDCO Investments - Section BS - Balance Sheet Analysis

Company viability

The graph on the top left shows GRIDCO's projected revenue requirement under four scenarios:

- Existing tariff revenue, using management forecasts, the current level of BST and the current level of transmission tariffs. No transmission losses are included in GRIDCo revenue or costs and there is zero capital investment;
- Adding transmission losses to the existing tariff will increase the revenue requirement for GRIDCo by about 20%;
- Adding transmission losses plus the adjusted (lower) investment plan described above will increase the revenue requirement for GRIDCo by over 200%; and
- Finally, adding transmission losses plus the GRIDCo management (higher) investment plan described above will increase the revenue requirement for GRIDCo by approximately 300%.

3. Financial projections for GRIDCo

The revenue requirement for all four scenarios is shown in the following table:

Projected GRIDCo revenue requirements

Currency: ¢ 000	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Existing tariff revenue	84,164	93,141	103,026	110,212	115,369	121,373	127,757	134,600	143,619	151,897
Tariff + losses revenue	84,164	112,231	124,134	132,732	138,808	145,874	153,364	161,371	171,979	181,630
Tariff + losses + adjusted investment	84,164	201,236	222,552	237,734	248,096	260,107	272,757	286,194	304,210	320,259
Tariff + losses + GRIDCo investment	84,164	280,392	310,080	331,116	345,289	361,700	378,938	397,204	421,808	443,548

Source: GRIDCo, EY Analysis

Ref: GRIDCo - Section BS - Balance Sheet Analysis

As discussed in previous sections, all of the utilities have projected significant increases in capital spending in the forecast period. These investment plans are unlikely to be realised, as they will be constrained be either the limited level of external funding available or the future debt carrying capacity of the companies (at current tariff levels). Adjusted capital investment programs are being developed by the companies, but are not available at time of writing. Therefore adjustments have been made to all company's investment projections in order to be consistent with historic levels of investment, and falling within existing funding commitments available to the companies. Further work is required in order to optimise these investment projections, especially concerning the impact, if any, on supply and demand energy balances. The management and adjusted investment program projections are summarised below.

Capital investment

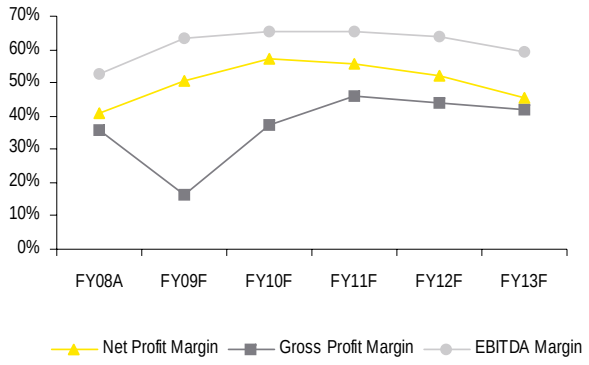
Currency: US$000	FY08A	FY09F	FY10F	FY11F	FY12F	FY13F
Management	61,035	219,680	284,660	183,480	89,420	6,270
Adjusted	61,035	100,000	100,000	100,000	100,000	-

Source: GRIDCo, EY Analysis

Ref: Real GRIDCo Investments - Section BS - Balance Sheet Analysis

Base case projected margins

Source: EY Analysis



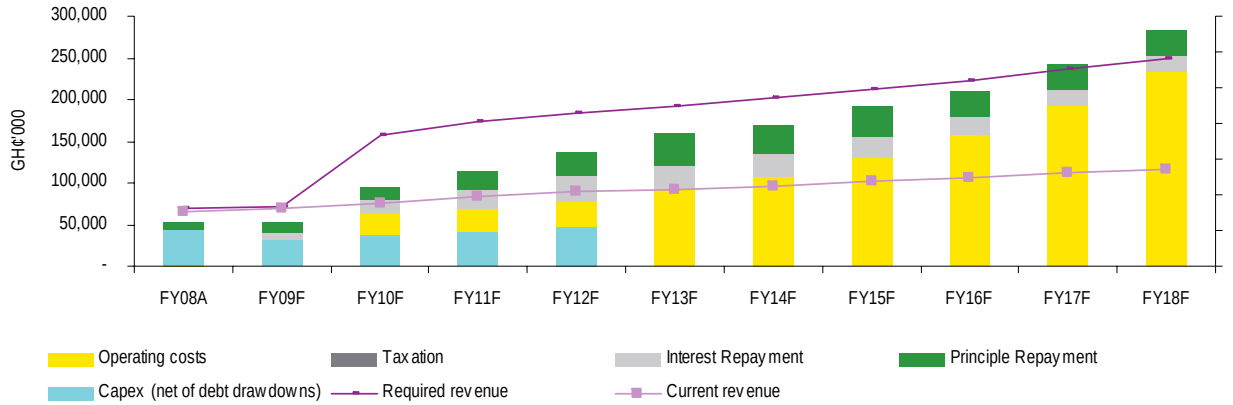
The graph on the left shows the five-year projected gross profit margin, net profit margin and EBITDA margin for the third scenario described above ie, forecasting GRIDCo with transmission losses plus the adjusted (lower) investment plan. This is the base case scenario which is used to populate the pro forma financial statements in the Appendices. It also forms the basis for the transmission tariff which flows into the ECG, NED and bulk supply customers.

3. Financial projections for GRIDCo

The graph below shows the revenue requirements against the operating costs under the base case described above. The revenue requirements increase significantly above operating costs in FY10 in order to facilitate payment of the interest and principle associated with the adjusted (lower) investment plan, as well as increased operating costs owing to inclusion of transmission losses in GRIDCo's revenue requirement.

Projected revenue requirements

Source: EY Analysis



3. Financial projections for GRIDCo

The graph below also shows the projected debt and interest repayment profile for GRIDCO. This projection will require further optimisation when GRIDCO develop a revised investment plan, which will incorporate a funding drawdown schedule and analysis on the potential impact of reduce investment on the energy balance.

Debt repayment profile

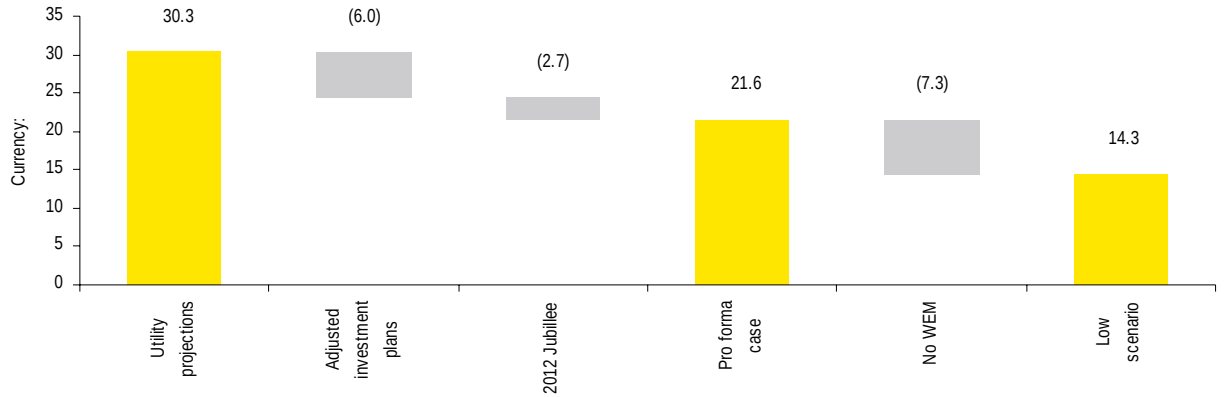
Source: Management Information

Projected revenue requirement sensitivities

► The total revenue requirement for all three companies is shown below for the base case.

Projected revenue shortfalls for electricity sector

Source:



► The impact of changes to input assumptions are shown in the diagram as a positive or negative impact as follows:

- Base case, assuming the utilities investment plans, debt assumptions, energy balances, WEM introduction in 2012 and no Jubilee gas (as assumed by VRA). Total NPV of the revenue shortfall of the sector over 10 years is GH¢30.3bn.
- Historical investment plans shows the impact of assuming a reduced level of investment by the companies as described previously. Investment levels are reduced for the 2009-2013 period from $2bn to $200m pa. to be in line with historical levels of capital investment. This reduces the NPV of the revenue shortfall of the sector over 10 years by GH¢6.0bn.
- VRA assume in the base case that the Jubilee gas does not arrive. However, the plans for Jubilee gas are increasingly probable meaning a reduced cost of generation may be possible when volumes

Trading sensitivities

arrive available for the power sector from 2012. Assuming a price in line with the WAGP, gas would reduce the NPV of the revenue shortfall of the sector over 10 years by GH¢2.7bn. This scenario forms the basis for the pro forma accounts in Appendix A.

- Under the draft WEM market rules, the hydro generators at VRA will earn a windfall profit as they receive the system marginal price which is higher than the hydro component of the BST currently paid under the regulated tariff model. This windfall causes the sector revenue requirement to increase. Assuming hydro receives a lower price in line with the existing BST level reduces the NPV of the revenue shortfall of the sector over 10 years by GH¢7.3bn.

- These sensitivities in total are estimated to result in a reduction of the revenue requirement of the sector by some GH¢16bn, with a total projected revenue shortfall of GH¢14.3bn.

Tariff setting methodology

Introduction

- Given the limited time, we have not been able to conduct a regulatory study but have used interviews and documents reviews to make recommendations on "the mechanism for determining suitable and affordable rates towards financial recovery". Our focus has been on outlining a mechanism which we believe will ensure timely *average* tariff changes rather than on a mechanism to allocate these average tariff changes across customer classes.
- We begin this section by summarising the historical tariff setting approach, which has comprised periodic major tariff reviews to establish base tariffs with or without automatic adjustment of base tariffs for uncontrollable cost changes in the "tariff period" between major tariff reviews. We then note issues arising concerning the establishment of base tariff and the automatic adjustment mechanism. Finally we set out our suggestions for the tariff setting mechanism.

Historical Tariff Setting Approach

- From our discussions with the PURC, we understand that the history of tariff setting can be thought of in the following periods:
  - Before 2000, when tariff increases were made following reviews at the request of the utilities but these increases were offset by exchange rate depreciation leading to a large real fall in tariffs
  - 2000 – 2006, when tariff increases in a transition period allowed recovery towards economic levels by around 2003, an automatic adjustment mechanism sought to compensate for changes in fuel costs, hydro/thermal mix, and exchange rate thereafter;
  - 2007 – date, when the automatic adjustment mechanism was discontinued and, again, tariff increases were made following reviews at the request of the utilities.
- In broad terms, we understand the PURC has followed the process described in its document "Electricity rate setting guidelines" dated December 1999. Accordingly, the PURC sought to provide adequate revenue to ensure the financial viability of the power utilities while providing incentives for the utilities to operate efficiently by allowing recovery of the PURC's estimates of the costs of a reasonably efficient utility (standard costs) rather than recovery of the actual costs of the utility. These incentives were provided by, in the case of:
  - Generation, setting a fixed capacity charge (GH¢/kW/month) and energy charge (GH¢/kWh) for the bulk generation tariff intended to cover the capital, fixed operating costs and variable operating costs of the generation business respectively. As far as we could ascertain, these generation charges reflected the PURC's estimates rather than actual costs.

- Transmission, setting a fixed transmission service charge (TSC) ((GH¢/kW/month) and fixed transmission energy loss (%) allowance intended to cover the capital and operating costs and loss purchase costs of the transmission business respectively assuming reasonably efficient operation. To encourage efficiency:
  - the TSC was set to recover an annuity of standard investment costs and standard operating costs of the transmission system rather than an annuity of the actual investment costs and actual operating costs of the transmission system; and
  - the transmission energy loss allowance was set to recover the costs of standard losses rather than the costs of actual losses.
- Distribution/retail, setting a fixed distribution service charge (DSC) ((GH¢/kW/month for each voltage level) and fixed distribution energy loss (%) allowance for each voltage level. This is intended to cover the capital and operating costs and loss purchase costs of the distribution/retail business respectively, assuming reasonably efficient operation and allowing ECG and NED to charge an average end user tariff expressed in GH¢/kWh. This comprises the sum of the bulk generation charges, transmission service charge and distribution service charge all expressed in GH¢/kWh. As for transmission, to encourage efficiency:
  - the DSC was set to recover an annuity of standard investment costs, and standard operating costs, of the distribution system rather than an annuity of the actual investment costs and actual operating costs of the distribution system; and
  - the distribution energy loss allowance was set to recover the costs of standard losses rather than the costs of actual losses

► During the automatic adjustment period, the:

- Generation energy charge was adjusted to reflect changes in generation mix (hydro, oil-fired OCGT and oil-fired CCGT), oil prices and exchange rate.
- Transmission service charge was adjusted to reflect changes in exchange rate (but its value remained constant in USc/kWh[4]).
- Distribution service charge was adjusted to reflect changes in exchange rate.
- End User Tariffs (EUTs) were adjusted to reflect changes in the sum of generation, transmission and distribution charges.

[4] Indeed, we understand that the transmission service charge has remained fixed at 0.09USc/kWh from 1998 to date.

Issues with Base Tariffs

- We note the following issues with the establishment of the base tariffs:
  - The values of certain key parameters, such as allowed technical and commercial losses, were determined from studies which were not updated and became outdated.
  - The EUT which applied to ECG was applied to NED also despite significant differences in the costs of service between ECG and NED. In effect, VRA's generation business was forced to provide a transfer to NED.

Issues with automatic adjustment mechanism

- We understand that the previous mechanism for automatic adjustment was discontinued mainly because the PURC wished the utilities to request tariff reviews and hence be required to provide more information but also because there were a number of issues with the mechanism. As examples,

  Concerning all utilities:

  - the values of certain key parameters, such as allowed technical and commercial losses, were determined from studies which were not updated and became outdated
  - the mechanism did not allow for new investment within the "tariff period"
  - the mechanism was based on projections but did not allow for forecasting error in some material uncontrollable factors, particularly sales volumes

  Concerning ECG:

  - the asset base used to establish the initial DSC was undervalued
  - the mechanism did not allow for changes in the costs of purchase of energy losses when the generation and transmission charges changed as a result of the mechanism
  - the mechanism did not allow for changes in customer mix, such as a tendency for reduced consumption in higher charge blocks of the residential tariff following EUT increases.

  Concerning VRA, the mechanism did not adjust appropriately for generation mix as, for example, it did recognise imports or power purchases from TICO.

Recommended tariff setting mechanism

- In an environment such as Ghana where factors outside of the control of the utilities can cause large changes in costs, we favour a tariff setting methodology based either on annual major tariff reviews or on less frequent periodic major tariff reviews to establish base tariffs with automatic adjustment of base tariffs for uncontrollable cost changes in the "tariff period" between major tariff reviews. In the Ghanaian environment, we favour the latter approach because we consider that major reviews are likely to be costly and contentious and to encourage unnecessary political interference. We consider that a two to four year tariff period would be appropriate.
- At major tariff reviews, we propose that the PURC establishes base tariffs using the building block approach which has become common internationally. Under such approach, the average base tariffs are set to recover the net present value of projections of efficiently incurred operating and investment costs during the tariff period together with projections of the change in the (regulatory) asset base during the tariff period (in other words, tariffs recover operating and investment expenditure during the period plus the value of assets at the start of the period less the value of assets at the end of the period which will be paid for in tariff periods)[5].
- Given the policy decision to maintain geographically uniform tariffs, either the uniform EUT is set sufficiently high to cover NED's costs of service and ECG enjoys a surplus or, more plausibly, the EUT is set at a lower level and NED receives a payment to recognise the difference between the uniform EUT and its costs of service. In principle, to minimise the EUT, tariffs might be set so that revenues received nationally exactly cover the combined ECG and NED costs of service and ECG might provide the transfer to NED such that after the transfer ECG and NED both exactly cover their costs.
- Between major tariff reviews, we propose that the PURC implements an automatic tariff adjustment mechanism which adjusts average base tariffs for the following uncontrollable changes:
  - Fuel and energy purchase prices
  - Fuel and energy purchase mix
  - Exchange rate changes

[5] Tariffs would be set such that the NPV of expected tariff revenue equalled

$$\sum_{t=1}^{t=n} \frac{OPEX_t + CAPEX_t}{(1+ROR)^t} + \frac{RAB_0}{(1+ROR)^0} - \frac{RAB_n}{(1+ROR)^n}$$

where $OPEX_t$ and $CAPEX_t$ are projected cash operating costs and capital expenditure in year t, RAB_0 and RAB_n are the projected regulatory asset base values at the start and end of the tariff period n and ROR is the allowed rate of return.

- Local and foreign inflation
- Forecast error in sales volumes
- Forecast error in customer mix

► We have not focused on affordable rates as we understand these relate mainly to maintenance of the existing subsidised tariff for low consumption users (taken as a proxy for low income users) which would not be impacted by our suggestions on average rates. However, in implementing the regime, the PURC will need to check that any cross-subsidy from other customer categories is not excessive. (We note that the 50kWh/month limit for the lifeline tariff is more generous than some others in the region).

Extent and causes of system losses

Introduction

- Our understanding is that the benchmark levels of transmission and distribution losses allowed for in the current tariff were established following analysis that dates back to 2000. Clearly, a thorough new study is required to evaluate appropriate levels for transmission and distribution losses. We note that transmission technical losses can be estimated more accurately than distribution technical losses as it is practical and usual to model the actual transmission system but it is impractical to model the actual distribution system. In this section, for GRIDCO and for ECG, we review historical losses and their causes, we note planned initiatives to reduce losses and we suggest indicative loss projections for the financial analysis.

Historical transmission losses

	2002	2003	2004	2005	2006	2007	2008
Transmission losses					3.5%	3.2%	3.6%

Source: 2006 and 2007 data VRA Annual Report and Accounts 2007; 2008 data from GRIDCO 2008 Energy Statistics

Transmission Losses

- We show historical transmission losses (as a percentage of energy entering the transmission system less energy use in substations) in the table on the left. While some transmission losses may be non-technical (eg, due to inaccurate metering of bulk supply customers or non-payment by these customers), in practice, we understand almost all transmission losses are technical losses which reflect the location of generation and bulk supply points.

Projected transmission losses

	2009				2010	2012
Investment	Base	Second Kumasi - Obuasi	Aboadze-Volta	Accra 3rd Bulk Point	Sunon Asogli	Bui
Losses after date	3.8%	3.5%	3.0%	2.7%	1.6%	0.2%

Source: Consultant's estimates using GRIDCO data

- We show our projection of transmission losses as a percentage of energy entering the transmission system in the table on the left. We have derived these projections as follows:
  - We discussed with GRIDCO the investments which it considers would make significant impacts on transmission losses.
  - We asked GRIDCO to conduct load flow analysis under conditions of peak demand to determine the peak MW losses with the system configured as it would be before and after each of the investments.
  - We also asked GRIDCO to estimate the annual energy losses (GWh) with the system configured as it would be before and after each of the investments. To do so, we understand that it used a loss load factor of 61.3% derived from an empirical relationship[6] between the loss load factor and the system load factor of 75.9%.
  - We used the data to estimate the percentage change in annual energy losses (GWh) occasioned by each of the investments.

[6] The relationship is $LLF = \mu LF + (1-\mu)\ [LF]^{1.8}$ where LLF and LF are the loss load factor and load factor respectively and μ is an empirical parameter chosen as 0.2 to reflect the load profile on the transmission network.

Extent and causes of system losses

Historical distribution losses

%	2002	2003	2004	2005	2006	2007
NED Energy losses	29.10	31.40	30.10	27.30	25.50	20.20
ECG Energy losses	26.04	25.65	26.54	25.44	24.26	24.03

Source: VRA Annual Report and Audited Accounts 2007, ECG Annual Report and Audited Accounts 2007

- We note that this approach leads to an unrealistic level of transmission energy losses in the later years particularly after the commissioning of Bui in 2012. Accordingly, we have used the projections on page 122 for the analysis in this report.

Distribution Losses

- We show historical distribution losses, as a percentage of energy entering the distribution system, for ECG and NED in the table on the left. For ECG and NED, we estimate that technical losses were around 10% and 12% respectively throughout the period. Accordingly, for ECG, non-technical losses have been little reduced during the period, whereas, for VRA, non-technical losses have been reduced during the period.
- We base these estimates of technical losses on our brief review of the most recent analysis of distribution losses, the study by Power Planning Associates "Distribution Planning and Technical Losses – Technical losses" dated November 2000[7]. PPA estimated peak period technical power losses and annual technical energy losses for each of five regions together with the all Ghana averages for the year 1999. It concluded that the all Ghana average technical energy loss was some 10.5%, which was not substantially different from the estimate of 9.9% made by other consultants in 1995, and that urban 33kV lines and LV feeders were the network components for which loss levels were significantly above economic levels while 33kV/11kV transformer and 11kV feeder loss levels were reasonable. It also concluded that the NED technical energy loss was 12.8%. In reaching these conclusions, PPA used load flow analysis for 33kV, 33kV/11kV and 11kV feeders based on the system models used for preparing the ECG distribution master plan (and its own models for NED), statistical analysis of 33kV/LV and 11kV/LV transformers and load flow analysis for a number of representative LV feeders to estimate peak power losses (MW) and used an empirical relationship between peak power losses and energy losses to derive energy losses. PPA also suggested that, for Accra, where energy losses exceeded 12%, a target level of 7-8% energy losses might be achievable in say seven years through sustainable investment and good system management.
- PPA noted that the important causes of technical losses in Ghana were overloaded 33kV and LV feeders. It suggested that these could be addressed, in the case of:
  - 33 kV feeders, which were often inadequate for the short term demand growth, by replacement with higher capacity, and hence lighter loaded, new lines.
  - LV feeders by appropriate choice of phase balancing, reconductoring and feeder length reduction.

[7] We understand that there is a companion analysis of non-technical losses which we have not seen. However, the technical volume indicates that, for the year 1999, non-technical losses were estimated for all Ghana and for NED respectively as 14.5% and 17.4% of energy entering the distribution system.

Extent and causes of system losses

- The causes of commercial losses include:
    a. Illegal connections, such as from informal traders and kiosks.
    b. Metering problems, such as under recording of consumption.
    c. Billing issues, such as failure to prepare the correct bill.
    d. Unmetered and unrecorded street lighting. Street lighting is being installed in an uncontrolled manner. Problems include:
        i. Unknown new lights. MPs often use the common fund to install lighting and customers install lights themselves as they consider that the public lighting levy entitles them to street lights.
        ii. Consumption exceeding the estimated amount because timers do not work or because higher wattage light fittings are used.
    e. Collection issues, such as non-payment of bills.
- We note that 30% of ECG's investment plan for the period 2008 – 2017 is in respect of technical loss reduction/voltage improvement projects and commercial/revenue improvement projects. Components include:

Technical loss reduction / voltage improvement projects

- Procurement of 11kV and LV materials to support expansion and maintenance;
- High voltage distribution serving smaller areas with smaller transformers (rather than large areas with larger transformers);
- Shunt capacitor compensation; and
- Secondary (33kV/11kV) substation metering.

Commercial/revenue improvement projects

- Extension of pre-payment metering;
- Replacement faulty meters; and
- Rural network automation (to reduce outage time).

- We show our projection of distribution losses as a percentage of energy entering the distribution system for ECG in the table on the left. In the absence of recent analysis, we have derived these projections by assuming that:

Projection of distribution losses as a percentage of energy entering distribution system for ECG

Year	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Technical (%)	10.5	10.0	9.5	9.0	8.5	8.0	7.5	7.5	7.5	7.5
Non-technical (%)	14.5	13.5	12.5	11.5	10.5	9.5	9.5	9.5	9.5	9.5
Total (%)	25.0	23.5	22.0	20.5	19.0	17.5	17.0	17.0	17.0	17.0

Extent and causes of system losses

Projection of distribution losses as a percentage of energy entering distribution system for NED

Year	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Technical (%)	12.8	12.3	11.8	11.3	10.8	10.3	10.0	10.0	10.0	10.0
Non-technical (%)	7.2	6.2	5.2	5.0	5.0	5.0	5.0	5.0	5.0	5.0
Total (%)	20.0	18.5	17.0	16.3	15.8	15.3	15.0	15.0	15.0	15.0

- The base year total distribution energy losses, of some 25% of energy entering the distribution system, comprise technical losses of 10.5% and non-technical losses of 14.5%;
- Technical losses will fall linearly from 10.5% to 7.5% at 0.5% pa and will level out thereafter; and
- Non-technical losses will fall linearly from 14.5% to 9.5% at 1.0% pa and will level out thereafter.

► We show our projection of distribution losses as a percentage of energy entering the distribution system for NED in the table on the left. We have received projections of energy losses from NED which show a linear loss reduction path, with losses falling from 20% in 2008 to 10% in 2018, and we have also reviewed its financial projections which show a different loss reduction path, with losses falling from 18.8% in 2009 to 16% in 2013 and levelling out thereafter. For the purposes of our financial projections we have relied on the PPA report to inform our projection of NED technical and non-technical losses reductions. We have projected as for ECG, but with assumed base year technical and non-technical losses of 12.8%[8] and 7.2% respectively being reduced by 0.5% pa and 1% pa respectively and levelling out at 10% and 5% respectively.

Methodology for pricing transmission system losses

► Our proposal has been informed by a review of the "Transmission System Pricing Study" dated November 2000 by Acres Management Consulting in its report Background, knowledge that GRIDCO has prepared draft terms of reference for a new study of transmission pricing and our discussions with stakeholders which indicate that GRIDCO will need to purchase generation in the spot market or under bilateral contract to cover transmission losses.

► At the outset we note that the transmission service charge (TSC) together with the transmission interconnection charge will need to recover all GRIDCO's operational costs together with a reasonable return on capital invested. We anticipate that GRIDCO's cost of purchasing transmission losses will be recovered through its TSC.

► We have briefly reviewed the methodology proposed by Acres Management Consulting for establishing the transmission charges in its report dated November 2000 "Transmission System Pricing Study". We recognise the merits of the approach which leads to the calculation of locationally varying transmission loss charges. However, as noted in our Inception Report, we consider that locationally varying transmission charges are not necessary at present and, in any event, the Electricity Regulations, 2008 which establish the wholesale electricity market (WEM) (LI 1937) explicitly prohibit locationally varying

[8] PPA suggested that technical and non-technical losses in 1999 were 12.8% and 17.4% respectively. Our discussions suggest that technical losses may have changed little but non-technical losses have reduced considerably since then though collection remains a problem.

transmission charges in the WEM. Accordingly, we have focused on a much simpler approach which leads to an average benchmark transmission loss percentage.

Summary of Proposal- Methodology for pricing transmission system loses

- We understand that the price of purchase in respect of transmission losses will be the WEM price (or a bilateral contract price related to that expected in the WEM) and, accordingly, we focus on estimation of the quantity of transmission losses for the purposes of fixing transmission tariffs. In summary, our proposal determines the projected transmission loss percentage, for a number of representative load levels for each year within the tariff review period, by simulation of system operation ("load flow studies") and establishes the benchmark transmission loss percentage as an appropriately weighted average of the representative projected transmission loss percentages. Obviously, the estimate may be more accurate but the modelling becomes more onerous depending on factors that are taken into account in making the weighted average, e.g. the number of:
  - Time periods[9]
  - Demand scenarios[10]
  - Load levels associated with each demand scenario
  - Generation and transmission configurations associated with each load level
- We suggest a [one year] time period, a single demand scenario, [1] load levels and a single generation and transmission configuration associated with each load level.

Steps

- We set out below our suggested methodology for determining the benchmark transmission loss percentage for the purposes of fixing transmission tariffs. The steps are as follows:

  a) Establish (say) [21] system load levels separating the range between projected transmission system peak demand and projected transmission system minimum demand in the time period (say) [one year] (under base case demand growth assumptions) into [20] equal intervals. The transmission system demand should be expected transmission network demand including expected exports after allowing for any generation embedded in the distribution networks.

[9] We understand that there is little seasonality in the demand pattern but there is fairly steady load growth through the year. Accordingly, there is no need for time periods shorter than one year to capture seasonality though these may be warranted to capture load growth.
[10] We understand that the industry uses a base case load growth scenario and high and low demand growth scenarios.

b) Determine the [20] representative system load levels which are the mid-points of the load ranges separated by the [21] system load levels at (a) above together with the number of hours of the [year] in the relevant load range through examination of the projected annual transmission system load duration curve.

c) Allocate the [20] system load levels at (b) above to demand at each bulk supply point. As it is derived from a load duration curve, each of the representative system load levels includes many different demand configurations. To simplify modelling, some judgement is needed to ascribe a unique load pattern for each of the [20] system load levels. We understand that VRA previously conducted, and GRIDCO now conducts, its operational analysis for three load levels (peak load, 80% of peak and 60% of peak). We suggest that the BSP demand configurations for these system load levels could be used as the basis for allocation of demand for other system load levels. For example, for load levels close to peak demand, the demand would be allocated pro-rata to peak demand.

d) Determine a generation pattern (including imports) which is expected to supply each of the load levels at (c) above given the expected transmission configuration for that load level in the relevant [year]. This generation pattern should reasonably reflect merit order dispatch as adjusted to meet any known transmission constraints (eg the need to run out-of-merit thermal generation for system stability) in the relevant [year].

e) Conduct a load flow study with each of the [20] load and corresponding generation patterns from (c) and (d) above. For load level *i*, the required generation expressed in MW will be G_i and the demand expressed in MW will be D_i leading to transmission losses of $G_i - D_i$. This load level and associated loss level will be representative of H_i hours in the relevant [year]. Aggregating over all [20] load levels, the average transmission system energy loss percentage is given by $100[\sum_i (G_i - D_i)H_i]/[\sum_i D_i H_i]$ in the relevant [year].

– Repeat the above steps for each [year] in the tariff review period.

Extent and causes of system losses

Issues Arising

- We have suggested this approach in the interests of simplicity. We recognise however that it has some drawbacks, particularly:
  - The judgements necessary to determine the generation, transmission and BSP demand configuration associated with each transmission system load level.
  - The loss of accuracy from assuming a single generation, transmission and BSP demand configuration is associated with a particular system load level.
  - The implicit assumption that the price at which losses will be purchased does not vary with load level though, given the extent of hydro storage, this may not be material.
  - The impact of forecasting errors particularly concerning system demand.
- We see little merit in more complex modelling as this will simply raise more potentially contentious issues (eg, what probability to associate with particular generation, transmission and BSP demand configurations if more than one configuration is associated with a particular system load level) without necessarily improving the accuracy of the estimate. However, we do see merit in correcting for the impact of forecast error through an automatic adjustment formula.

Review of key operational processes

Introduction

- In this section, we set out the conclusions from our high level review of a sample of the key business and operational processes to identify inefficiencies and bottlenecks. We stress that our suggestions are based on limited interviews and analysis and will need to be further analysed and validated by the utilities. We have examined the following business and operational processes which our experience suggests have the largest impact on the costs and revenues of the utilities.
  - Generation and transmission investment planning
  - Fuel and procurement and power purchase
  - Operational planning and despatch
  - New customer connection
  - Meter reading, billing and cash collection
  - Dealing with non-payment
  - Identification of illegal connections.

- We summarise these processes in Appendix E and based on our brief review, we make the following observations:
  - Generation and transmission investment planning. We suggest the Energy Commission considers using optimisation techniques rather than simulation techniques to identify the indicative generation expansion plan.
  - Project implementation. We note that funding constraints and disbursement delays have caused significant delays in project implementation and led to adoption of techniques such as contractor financing which have other disadvantages (eg leading to higher costs and lack of standardisation as the contractor is sometimes tied to purchase particular equipment). We consider it essential to restore financial viability so that the utilities can make optimum project choices without regard to potential funding constraints or disbursement delays.
  - Hedging. We suggest that VRA considers whether it should hedge against oil price and/or exchange rate movements. We understand that both oil and gas will be procured in US$ with prices based on the spot oil price. Specifically, we understand that oil will be procured under short-term contracts with pricing based on the spot oil price and that gas will be procured under a long-term contract with a proportion of the base price indexed in line with the oil price.

- Load scheduling and despatch. We suggest that GRIDCO considers more rigorous use of hydro/thermal despatch optimisation software to inform despatch. We consider that estimation of, and use of, the water value (opportunity cost of use of hydro generation) at each reservoir will help achieve least cost despatch.
- Maintenance planning. We suggest GRIDCO considers the use of more condition-based maintenance planning as we understand GRIDCO often plans transmission maintenance on a time basis rather than a condition basis.
- Spares procurement. We suggest a review of the public procurement requirements be considered for the utilities. The utilities must follow the Public Procurement Act 2003 which focuses on competitive tendering for purchases and does not make adequate allowance for the special requirements of the utilities for swift, and sometimes sole sourced, procurement. Often the utilities find that suppliers are not willing to respond to competitive requests for relatively small quantities leading to delay[11] while the utilities seek approval for sole sourcing.

Non-technical loss reduction:

- Pre-payment metering. We suggest that ECG conducts a review of the impact of the introduction of pre-payment meters before rolling the programme out to lower density areas.
- Customer identification. We support the recommendation in the Strategic National Energy Plan 2006-2020 prepared by the Energy Commission to associate payment for consumption with a unique customer identifier (eg social security number) rather than only with the address of the relevant meter to avoid customers absconding with unpaid bills.
- Unmetered electricity. We suggest that legislative measures are introduced to ensure that street lighting can be connected only by the relevant distribution utility.
- Monitoring. We suggest that Loss Control Units are strengthened to allow more pro-active monitoring and to deal with the backlog of cases identified for investigation.
- Deterrence. We suggest that fees for reconnection are increased.

► During our interviews concerning business processes, we asked both VRA and GRIDCO whether they faced particular co-ordination difficulties arising from their separation. While certain transitional issues were raised, we uncovered no material on-going issues. Issues raised include:

[11] Delays have been exacerbated by funding issues as some sole suppliers require payment in advance. Such delays have resulted in poor thermal plant availability as components must be sole sourced from GE which requires payment in advance.

The requirement to implement service agreements so that for example:

- VRA continues to operate and maintain equipment in the generation sub-station at a power plant now owned by GRIDCO
- GRIDCO operates and maintains shared SCADA systems
- Traditional funding for GRIDCO
- The need to amend arrangements for return of customer contributions towards transmission equipment. Specifically, we understand that certain large customers have constructed or funded transmission connection equipment and have been reimbursed by agreed reductions in their bulk supply tariff over a relatively short period. Reimbursement through reductions in the transmission service charge alone would require reductions over a longer period which is unlikely to be acceptable.

Organisational and Human Resource Review

This section covers the organisation of VRA and ECG's work, organizational culture issues, staffing and general human resource management practices in the organization. It specifically focuses on key areas which include organization of work, organizational culture issues, staffing, training and development, recruitment, performance management, succession planning, career management and manpower planning.

VRA- Organisational and HR Review

Introduction

The Human Resource Department of VRA is a functional component of the organization with equal responsibility of ensuring that organizational set goals and objectives are achieved. They perform this by ensuring that they are strategically placed to offer management the necessary advice on all human resource issues. Their strategic efforts are guided by the department's HR Business Plan for 2009-2011. VRA has a well documented Module of Human Resource Policies and Procedures which covers all the key policies and procedures necessary to effectively manage human resource for results.

From our interactions, observations and the review of documentation, VRA is on track with the implementation of the key strategies outlined in their strategy document. VRA are currently working on four projects namely Performance Management, Reward System, Manpower Auditing and Human Resource Information System – which are in line with what has been set out in their strategy document and they intend to start implementation of recommendations before the third quarter of this year.

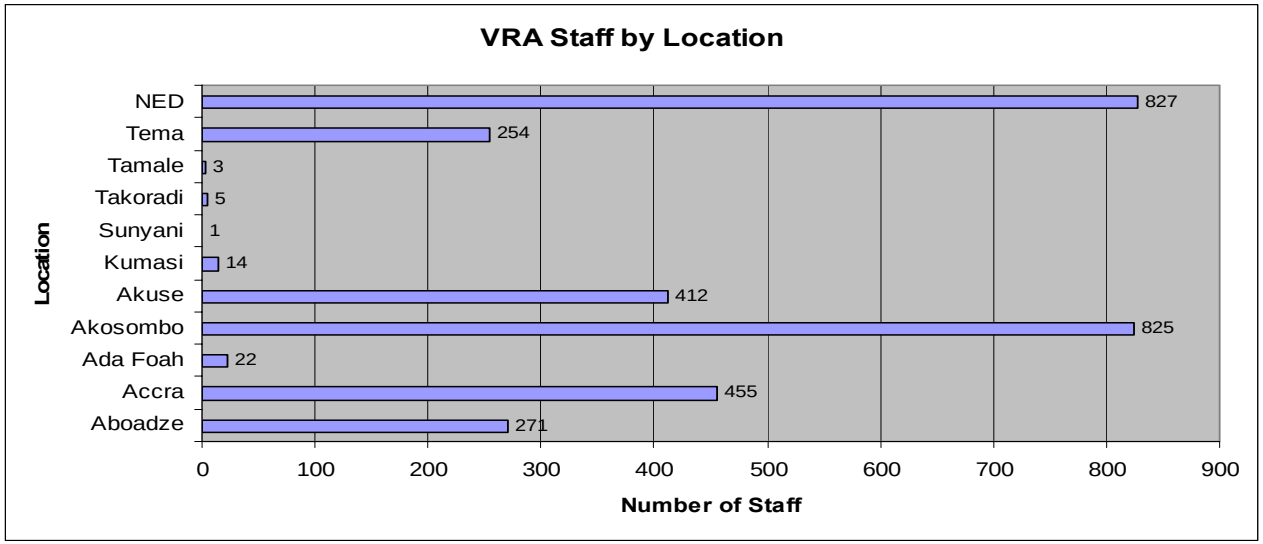
Organisational Structure

VRA refers to its current organizational structure as "Transitional Structure" since it is in the process of the restructuring of the organization. In view of the changing market place, and the competitive nature being introduced by the IPPs, VRA needs to review its organisational structure to ensure its in line with its renewed strategic intent.

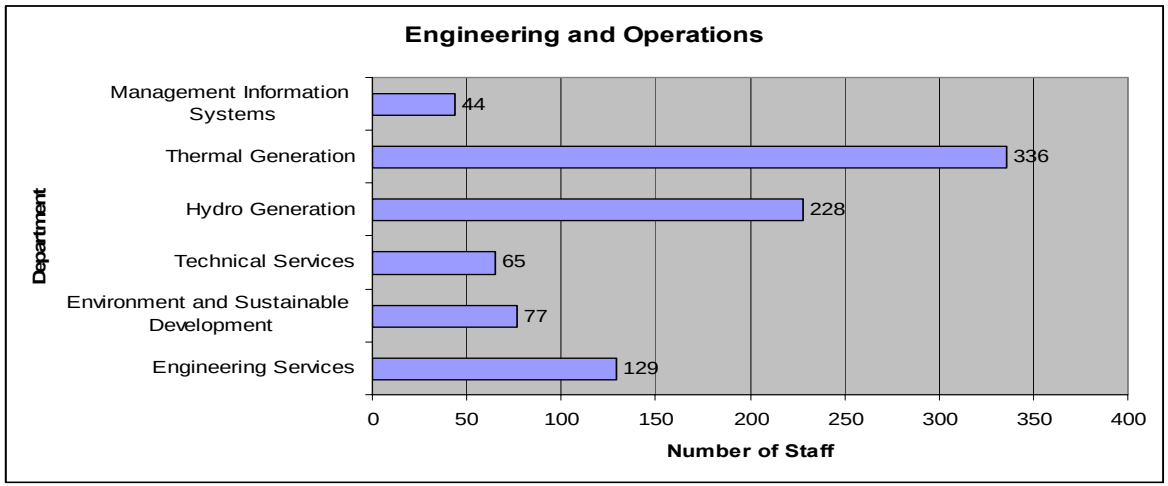
Staffing

We noted that VRA has a staff strength of 3,078. The graph on the following page shows the distribution of staff by location. Akosombo and NED (representing the northern sector locations) have the highest (about 800) number of staff whilst Ada Foah, Kumasi, Sunyani and Tamale together have less than 50 employees.

VRA- Organisational and HR Review

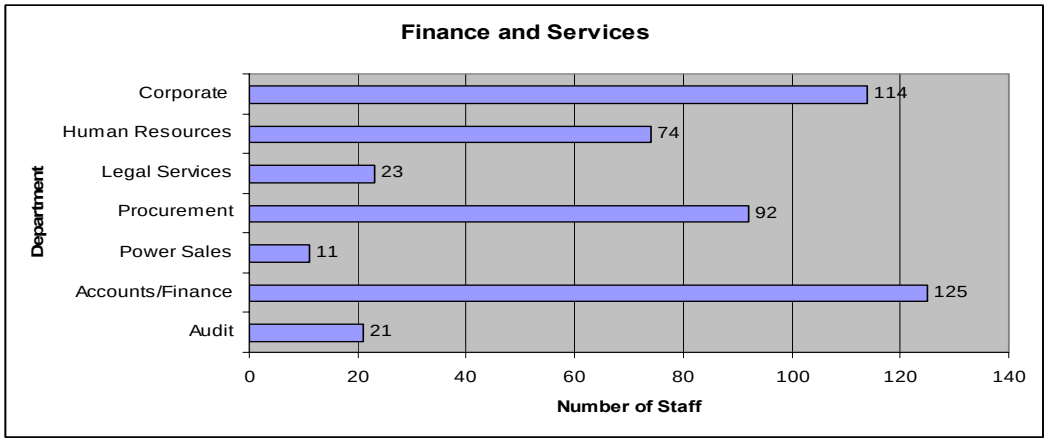


Staff of engineering and operations form 28.5% (879) of the total number of staff for VRA. Of this number, majority (564) are in thermal and hydro generation (which are core to VRA's operations). Engineering Services department together with special engineering projects also have 129 staff, representing 15% of the total number of staff in engineering and operations. Special engineering has one person responsible for its activities.

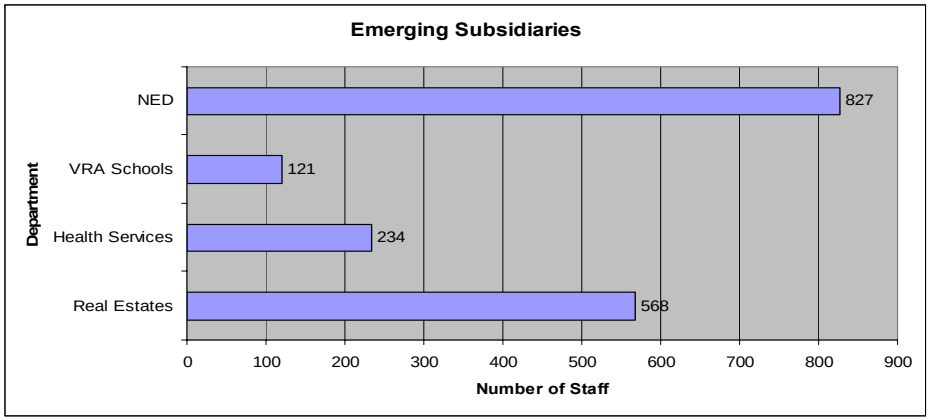


The above analysis excludes NED

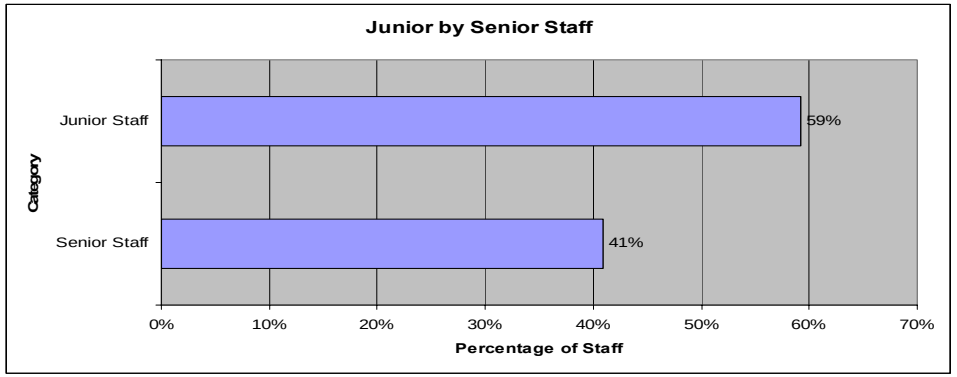
The Accounts and Finance departments together have 125 staff representing 28% of the total number of staff in Finance and Services. Corporate which covers both the corporate office and corporate service also has 114 representing 25%. Procurement Department has a staff strength of 92 representing 21% of VRA total staff. 108 staff (25%) are distributed among the remaining service providers.



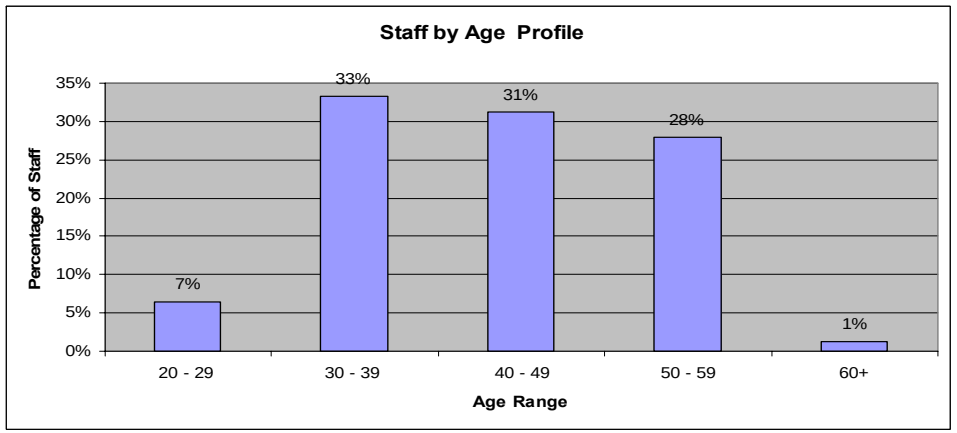
When the plan of moving NED from engineering and operations to emerging subsidiaries (as shown in VRA's organisational structure in Appendix F) is implemented, the graph below depicts how staffing for the various departments will be for emerging subsidiaries. This non-core area of VRA's operations will have 1750 staff, representing 57% of VRA's staff strength. This will bring the ratio of core to non-core staff to 0.7:1.



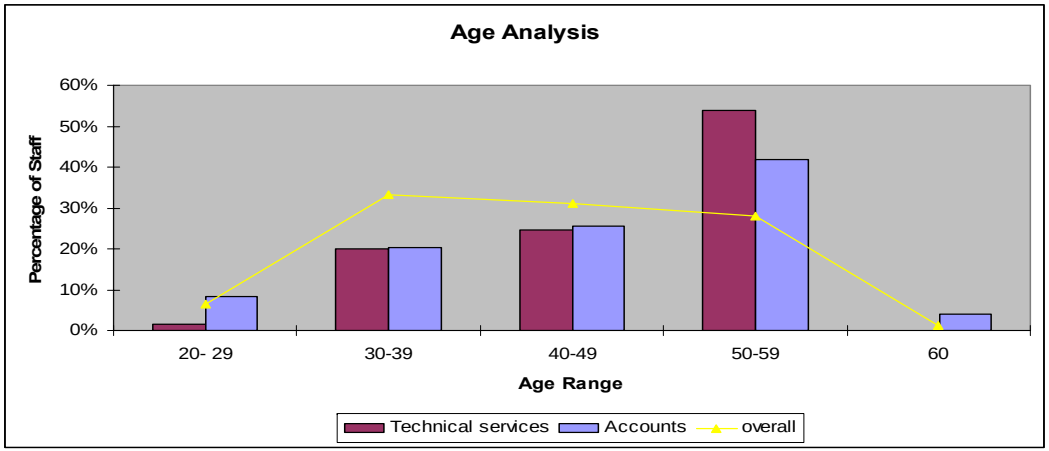
41% (1262) staff are categorised as senior staff with 59% (1827) being junior staff. The ratio of senior staff to junior staff is 1:1.4. The number of senior staff includes about 700 HND holders who were absorbed into the senior staff category when the Authority implemented government's policy on placement for graduates from the polytechnics.



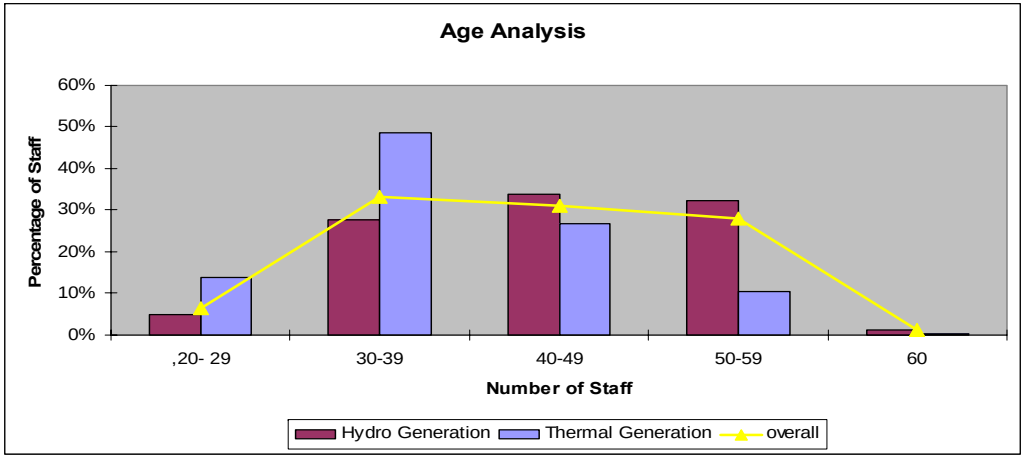
Our review showed that 39 staff representing 1% of the total staff strength would be due for retirement within the next 1 year. Majority (64%) of staff are in the 30 and 49 age range with 35% being in the 20-29 and 50-59 age ranges.



The Technical and the Accounts Departments currently have the highest number of staff in the 50-59 age range - over 50% of technical staff and 42% of accounts staff will retire over the next 10 years. The percentage of technical staff retiring over the next 10 years is about twice the overall organizational average for retirees over the same period.



It is generally assumed that people over 40 years tend to stay longer in organizations however those below 40 years tend to change jobs frequently. Though, young people exhibit high levels of energy and enthusiasm, they also tend to use the organizations as training centres and leave for other jobs once they acquire the needed knowledge and skills. If the Thermal Department experiences these trends, then it may have a high staff turnover due to the large population (63%) of staff who are between 20 and 39 years. The average of staff between 30 and 59 in the Hydro Generation Department is (31%) and this is the same as the overall (VRA's) average for the same group of staff. This suggests that the overall age combination of staff in VRA is reflected in the department.



Span of Control

The Chief Executive supervises four (4) Deputy Chief Executives in addition to the head of the Audit Department. The span of control of the Deputy Chief Executives is between three (3) and eight (8). Of the eight departments supervised by the Deputy Chief Executive Operations, five (5) are located outside the head office – Accra. To a large extent, head office functions such as human resource, accounts and finance are replicated in the other locations. Though, policies are owned at the head office level, implementation is decentralized with the necessary in-built checks and balances.

Our interactions however showed that these processes could be enhanced to achieve the objective of decentralizing decision making. This is also confirmed by the HRD's decision to pursue the establishment of clear responsibility/authority levels to promote timely decision making in the next three (3) years.

Organisational Culture

One of the key objectives and strategies identified in the Human Resources Business Plan for 2009-2011 is to re-orient the Authority's organizational culture to support a new direction/new operating environment. The identified activities for this strategy are to pursue the establishment of clear responsibility/authority levels to promote timely decision making; develop Code of Ethics/Code of Business Conduct and educate staff on new core values to ensure that the desired behaviours and attitudes are established and shared by

all staff. Education on the values is carried out during junior and senior staff meetings. Additionally, organizational culture issues have been made a vital part of all orientation programmes for new staff.

Manpower Planning

The Authority no longer does one-on-one recruitment in case of attritions – retirements, deaths, resignations etc. Zero (0) based forecasting is done yearly where every department justifies its manpower requirements. No unused funds are carried over to the next year since the department's circumstances may have changed. A Manpower Audit Team is currently going round the offices and departments analyzing staffing and workload.

Recruitment

Recruitment is linked to a department's budget. All staff requisitions are matched against the department's current establishment before authorization is given to ensure that corporate manpower limits are adhered to. VRA's recruitment policy further spells out criteria for staff selection, appointments, selection process, re-engagement of staff, probation, induction and internal transfers. Internally advertised positions serve as avenues for career progression for staff as well as opening for placement of staff who have acquired certain required competencies after joining the Authority.

Performance Management System

Performance Management is currently being changed as part of the overall institutional transformation exercise. There are efforts to move away from competency based appraisal to output/result based system. The following challenges associated with the system were shared with us:

- The current process does not align to strategy execution - targets are set at different times of the year which does not align with strategy execution.
- The tool has a host of competency requirements which is usually applied to all staff – competencies are not customized for the different grades and job groups.
- Subjectivity in ratings, hence the system has become unpopular among staff.
- There was no appraisal committee to validate the process by dealing with appraisal issues such as disagreements between appraisers and appraisees.

It is intended that the new system will have organizational objectives and targets drilled down to all the units and individuals and also address all the challenges raised above.

Training and Development

In addition to the training needs identified through the appraisal system, training officers assist departments with their training needs identification. Training plans are included in the overall departmental plans and defended by heads of departments at the corporate level before the approved plans are forwarded to the Training School for implementation. This is done in concert with the organization's scheme of service. Although training evaluations are undertaken by participants immediately after the programme, training impact assessments are not regularly done. Generally, the school uses internal staff as training officers and due to low levels of motivation for them; it is difficult to attract the needed numbers. Another area of concern is the slow pace of transforming the Training School to a Training Centre of Excellence for West Africa. This is intended to commercialize the school and also serve a larger clientele.

Career Management

Currently careers are managed by employees themselves and by managers in an informal manner. Specifically, the Authority supports staff by granting loans for self initiated programmes and also grants study leave without pay to staff who pursue relevant courses. There are about 70 staff who have pursued bachelor's and master's programmes and have submitted their certificates for consideration by management. There are no vacancies for all these staff currently and the Authority is finding ingenious ways to address this problem.

Succession Planning

Though, there is a policy on succession planning in the Module of Human Resource Policies and Procedures, implementation has been ineffective due to the frequent change of the leadership. Apart from the difficulty of planning for the top hierarchy jobs, succession plans for other management positions have also not been effectively pursued.

VRA- Organisational and HR Review

Below is a summary of the issues discussed on VRA's human resource management.

Dimension	Status	Comment
Strategic Alignment of the Function		Has an HR Business Plan for 2009-2011 which is guiding the work of the department
Effective Management of HR		Has a well organized HR Department and well documented HR policies
Human Resource Management Policies and Procedures		Updating policies
Manpower Planning		Manpower audit in progress
Recruitment & Selection Policy		There is an elaborate staff resourcing policy and implementation
Performance Management System		Project in progress to improve the current system
Training and Development Policies		In place but identification of training needs to be improved
Succession Planning		Not effectively done
Career Development		Though the Authority supports staff by granting loans for self initiated programmes, it needs to be more structured.

Areas Requiring Attention (Levels of Attention)

High Medium Low

Recommendations

Organisational Structure

As part of the VRA's organisational structure review, we recommend that cognisance is taken of the future position of NED and the separation of the Transmission Department (now GRIDCo) on the general operations of VRA.

We recommend the framework below is adopted for the organisational structure review:

- Determine the Strategic Intent of the VRA
- Understand key business processes, existing structure and related challenges
- Formulate and detail accountabilities
- Develop structural options for VRA based upon design parameters
- Detail the chosen structure in terms of role descriptions for the unique roles
- Design the grade and designation structure

Staffing

Immediate steps should be taken to develop and implement a succession plan for the Technical Department in order to ensure that there is gradual transition and continuity of work in the department. [refer to section on succession plan).

We recommend that, significant efforts should be made to ensure that the high fliers amongst the large number of young employees in the department are retained. Effective ways of motivating them should be explored and adopted for implementation. We recommend the following to motivate staff:

- the performance management system being developed should recognize and reward the high performers
- it is important to ensure that staff personal goals are aligned to VRA's goals
- training and development should be effective
- there should be effective career management

Span of Control

The current process of strategically re-organizing the Authority's operations by either merging departments or hiving them off to form complete autonomous companies needs to take the reductions in the span of control into consideration. For example the span of control of the Deputy Chief Executive Officer, Engineering and Operations could reduce to six (6) when NED's status changes to become either a department under Emerging Subsidiaries or it becomes an autonomous company.

Organizational Culture

We recommend that a structured approach and process is developed and instituted to help revive desired ways of doing things. This approach should recognize the complexities of corporate culture such as dealing with the unseen elements identified in everyday interactions between employees.

Manpower Planning

We recommend that in addition to the ongoing manpower audit, VRA adopts manpower management as a strategic approach to the management of staff. This requires a holistic approach of managing recruited employees, training, motivating them, helping them update their work knowledge and maintaining the attrition rate to a minimum.

Training and Development

The following guidelines should inform the review of the training and development function of VRA;

- Training Needs identification and analysis; prioritisation and development of a training plan
- Calendar development and management; detailed list of training programmes, timelines, duration, cost and employee coverage
- Coordination and delivery of training programmes
- Training effectiveness measurement; assessment of training interventions using feedback at various levels.

Career Management

We recommend that VRA adopts the following approach to career management;

- Ensure the grade structure design considers the impact on career management

- Develop a career management framework and define career paths
- Establish linkages of career management system with other HR processes such as training and performance management.

Additionally, the following practices would support an effective career management programme:

- Develop a system that collates information on employees;
- Departmental training and development policy or strategy; and
- Effective performance assessment/management system and regular update of job descriptions.

Succession Planning

As captured in the HR Department's Business Plan for 2009 – 11 to consolidate Manpower, Succession Planning, it is important that succession plans for key positions are put in place to ensure continuity in the performance of critical roles at in the Authority. We recommend the following steps to develop and implement an effective succession plan:

- Define the process – lay out objectives, activities and timelines
- Identify the needs of VRA – identify the skills and competencies needed for key positions
- Assess talent – identify possible candidates who may be ready now or in the future
- Engage people – actively involve people in their development
- Track data – track the process of filling critical positions
- Measure performance – continuously track the overall results of the succession

ECG- Organisational and HR Review

Introduction

The Human Resource Division of ECG is responsible for effectively managing the organization's human resource. Though the Division does not have its own HR strategic plan, the subject of staff productivity and organizational culture are captured in ECG's Strategic Plan (2007-2011) and this is used to guide the activities of the department.

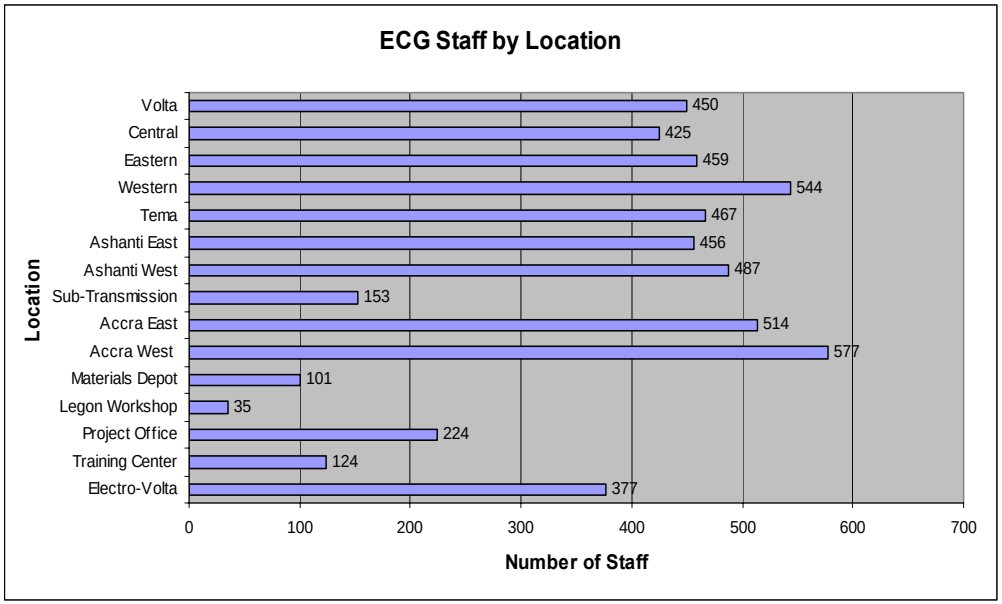
ECG does not have a complete document of all human resource management policies. The policies are found in either the Senior Staff Manual or the Collective Bargaining Agreement (CBA) for the different categories of staff. We were however informed that a committee will soon be set up to develop a comprehensive HR policy document for the organization.

Organisational Structure

The organization of ECG's work largely reflects how it operates. Currently, work is coordinated under eight (8) broad directorates namely Engineering, Operations, Finance, Legal, Audit, Human Resource, Customer Services and Materials. These are further subdivided into the following sub functions:

- **Engineering** – Design, Premises, Urban Projects, Rural Projects and Planning
- **Operations** – Operations, Maintenance, Protection and Control and Sub-Transmission
- **Finance** – Financial Accounting, Treasury and Management Accounting
- **Legal** – Litigation Services, Way Leaves & Contract and Board Secretariat
- **Audit** – Financial Audit, Operations & Compliance Audit
- **Human Resources** – Personnel, Manpower Planning & Training and Training Centre
- **Customer Services** – Billing & Revenue, Sales & Marketing, Data Processing, Regions, MIS/Organisation, Metering & Technical Service and Revenue Protection
- **Materials & Transport** – Materials and Transport

These directorates are headed by Directors and the Divisions by Divisional Heads. Field operations are undertaken through nine (9) area divisions namely Accra East, Accra West, Tema, Ashanti East, Ashanti West, Eastern, Volta, Central Western and Sub-Transmission. Each area is headed by a Regional Director who is responsible for activities in the districts within their region. The distribution of staff at the head office and the regions is shown in the graph overleaf:



The graph shows the distribution of staff by location. Currently, Accra West has the highest (577) number of staff with the Legon Workshop having the least (35) staff.

Creation of IT and CPM&E Divisions

There have been plans in place for the last three (3) years to create two (2) new directorates - Information Technology (IT) to centralize all IT-related functions which are currently being housed in the Engineering and Operations Directorates; and Corporate Planning Monitoring and Evaluation (CPM&E) to elevate the management of planning and M&E to directorate level.

Span of Control

The span of control at the head office ranges from two (2) to seven (7) for Directors; and about five (5) for the regions. The Managing Director currently supervises eight (8) directorates and two (2) divisions which will increase to ten (10) directorates and (2) divisions when the IT and CPM&E directorates are created. The Director of Customer Services supervises seven (7) Divisions including nine (9) regional offices. In our view, though some of the jobs are homogeneous, there are other heterogeneous areas which widen the

span of control, and this does not facilitate effective decision-making, communications and organizational flexibility between head office and the regions.

Although, the operations of the ECG are decentralized as part of its efforts to improve service delivery to the customer, financial decision making is centralized. Hence regional and district heads are unable to take critical decisions in real time without recourse to the head office, this leads to significant delays in service delivery.

A thorough review of the organizational structure is required to ensure that the structure is aligned with ECG's current strategic intent.

Organisational Culture

As part of ECG's strategy to enhance its organizational culture, the organization's culture has been analyzed recently in a comprehensive document "Action Plan for Building the Desired Organizational Culture" which was issued in February 2009. The following recommendations were made in the document:

- Re-examine of ECG's core values to afford management the opportunity to examine and evaluate the utility's overriding beliefs;
- Communicate of ECG's values to ensure that the agreed values will be shared by all staff;
- Establish responsibility for the desired organizational culture (role modelling) to ensure that the Managing Director and his team own and drive all efforts towards the achievement of the desired organizational culture;
- Implement 'role modelling values' as a key criterion for appointment and continuing employment at director, divisional manager and equivalent district managers levels at ECG to ensure that people with the desired attitudes and behaviours are recruited into the organization ;
- Re-design reward package to motivate employees who live ECG's values; and
- Conduct a yearly values survey to provide input for regular reviews to ensure that ECG's desired ways of doing things is maintained.

We followed up on the progress of the implementation of the above recommendations and our interactions revealed that specific activities such as the re-examination of ECG's Core Values have been completed and approval granted for communication of these values to all staff. This is however yet to be done due to the change of the Managing Director and Board of Directors. All the other recommendations are outstanding.

Staffing

The staff strength of ECG as at March 2009 was 5,393. This excludes 74 fixed term (contract) staff. Since December 2007, the permanent workforce has increased from 4978 to 5393 representing an 8% increase. Fixed term staff, however, have reduced by about 79% - from about 350 to 74. This is due to a wholesale conversion of the employment status of fixed term staff to permanent staff during the last quarter of 2008. The conversion also partly accounts for the increase in the number of permanent staff. The table below presents staff distribution by location and job group.

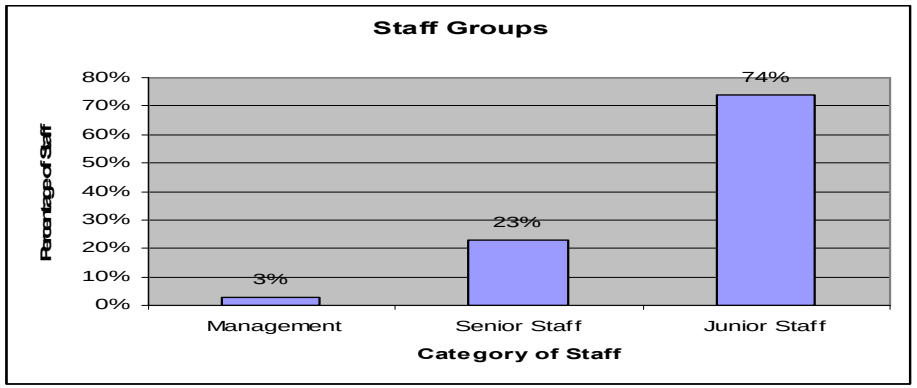
ECG

Distribution of ECG Staff

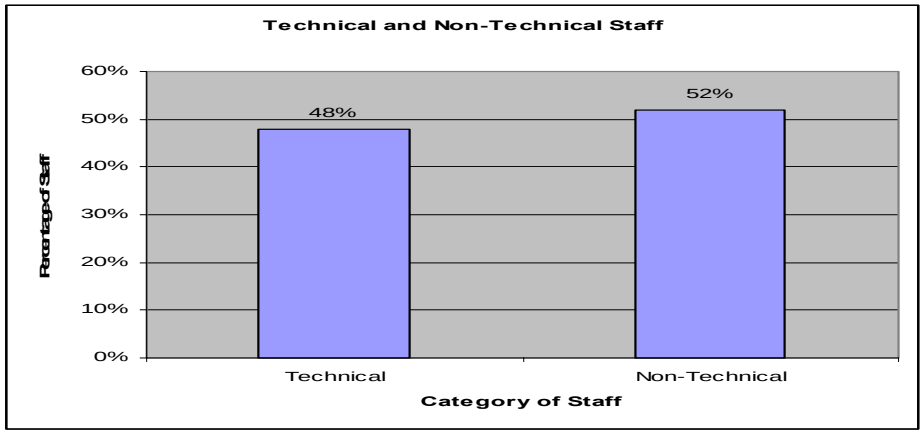
Location	Electro-Volta	Training Center	Project Office	Legon Workshop	Materials Depot	Accra West	Accra East	Sub-Transmission	Ashanti West	Ashanti East	Tema	Western	Eastern	Central	Volta	Total
Job Group																
Mgt	55	2	29	0	3	11	10	5	9	8	8	8	6	7	4	**165**
Elect. Eng.	20	0	47	1	0	9	6	11	8	7	5	7	6	2	4	**133**
Tech. Eng.	21	0	27	7	0	31	46	43	47	44	51	59	41	33	47	**497**
Works Supt.	0	0	0	0	0	7	11	3	4	2	0	3	8	4	6	**48**
HR Officers	11	2	2	0	1	2	2	1	2	4	1	2	1	1	1	**33**
Accounts	28	1	3	0	6	26	27	2	16	12	23	8	14	15	15	**196**
Audit	17	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**17**
Other Snr. Staff	46	4	17	0	17	25	30	1	19	22	22	25	14	22	17	**281**
Junior Technical																
Artisan	18	89	18	6	0	199	109	34	111	93	102	102	74	91	102	**1148**
Tradesman	5	0	7	11	1	53	57	10	61	72	56	74	67	59	41	**574**
Non Technical																
Clerical	71	11	34	4	31	157	143	7	124	127	119	125	121	99	125	**1298**
Drivers	48	2	32	1	12	45	41	25	33	36	40	44	41	38	35	**473**
Daily Rated																
Watchman	12	5	5	2	15	4	15	5	27	22	32	58	42	32	33	**309**
Labourer	25	8	3	3	15	8	17	6	26	7	8	29	24	22	20	**221**
Total	**377**	**124**	**224**	**35**	**101**	**577**	**514**	**153**	**487**	**456**	**467**	**544**	**459**	**425**	**450**	**5393**
Fixed Term	47	0	2	0	1	14	4	0	1	0	2	0	0	1	2	74

Source - 1st Quarter Manpower Inventory Chart (January - March 2009)

About two-thirds (74%) of ECG's current staff are in the junior staff category. The ratio of senior staff to junior staff is 1:3. 165 representing (3%) of staff are in management.



The ratio of technical to non-technical staff is 1:1. In real terms, the number of technical staff is about 250 more than the technical staff. For the purpose of this analysis, technical staff comprises management, electrical and technical engineers, works superintendent and junior technical staff. HR, Accounts, Audit, non-technical, daily rated and staff who fall under 'other staff' have all been categorized as non-technical staff.



Manpower Planning

The current ECG manpower planning approach is based on the following factors: staff attrition, creation of district offices, review of directorates and corporate expansion. Specifically, the manpower budget is drawn by all regions according to their needs, and is defended at a manpower budget defence session. The manpower budget is then incorporated into the corporate budget after a review by the Director of Manpower and Training & Development and final approval sought from the Board before implementation. The Establishment List is reviewed every 2-3 years and this is normally based on the number of staff retiring, resigning etc.; creation of new district offices and reviews of directorates.

Recruitment

A recruitment policy has been drafted but has not yet been approved. Currently, the Board appoints Directors; the Managing Director appoints Managers and Senior Staff with the Director of HR appointing Junior Staff. Each division consolidates its plans/requests which are discussed and agreed annually as part of the manpower planning process. Implementation of this policy is dependent on the manpower budget/allocation.

Performance Management

A consultant was recently contracted to help streamline the performance management system for Management while another one is being reviewed internally for senior and junior staff. The major challenge with the system is goal/objective/target setting for staff. Currently, senior staff and managers draw their targets from the strategic plan with the junior staff targets being largely based on personal attributes. Measuring only personal attributes does not help in measuring total performance of staff. Areas of measurement need to cover both functional and personal attributes.

Training

Presently, ECG implements the following four (4) types of training programmes:

- Implant programme – The various directorates prepare inputs which are collated into specialized and generalized programs based on corporate policies.
- Foreign programme – these are collated from the Directorates and quotas are given to the various directorates.

- Open courses – these are courses that are advertised in the press. If the need meets corporate objectives and is identified by a member of staff, training is allowed.
- Staff facilitated – these are facilitated in-house by staff with the requisite experience.

There is also on-the-job training, job rotation and induction training to augment the four (4) programmes. The organization also sponsors 10 employees every year to attend the MBA and EMBA programs at GIMPA and also junior staff to undertake bachelor courses. Although training needs analysis is performed yearly and it is not effective. ECG's Corporate Training Policy was reviewed about two (2) years ago but the recommendations have not yet been approved for implementation.

Career Development

Currently, careers are managed as follows: by employees themselves, by managers in an informal manner, within the framework of HR policies and guidelines, as part of general systems designed to enhance competency and evaluate potential. Specifically, appointments and training programmes are used to develop staff careers. This is not very effective because training needs are not effectively identified and performances not effectively measured to determine how staff should be developed.

Succession Planning

There is no effective succession planning process in place. A process has been under discussion for a period but no decision has been taken yet.

ECG- Organisational and HR Review

Below is a summary of the issues discussed on ECG's human resource management.

Dimension	Status	Comment
Strategic Alignment of the Function		Has some HR strategies incorporated in the overall Strategic Plan (2007-2011)
Effective Management of HR		Has a well organized HR Department but needs to improve on documentation of policies
Human Resource Management Policies and Procedures		There are no separately documented HR policies & procedures except what are captured in the CBA and Senior Staff Conditions of Service. A Committee to be set up to undertake this exercise.
Manpower Planning		Manpower budgets are used. Additional manpower requirements are met with the recruitment of contract staff
Recruitment & Selection Policy		There is a policy in place
Training and Development Policies		In place but under review; Training needs sourced from the Performance Appraisal System which is not very effectively done
Career Development		Needs to be improved.
Succession Planning		Not in place
Performance Management System		Needs improvement to make it more effective

Areas Requiring Attention (Levels of Attention)

High Medium Low

Recommendations

Organisational Structure

There is the urgent need to review the organisational structure to ensure that it is in line with the renewed strategic intent and the tenets of the power sector reform. The review needs to take into consideration the SBU concepts detailed in the PWC Report (2008). This process is critical in addressing challenges with the span of control, performance management system as well as any workforce rationalisation interventions which are required to improve the technical staff to customer and technical staff to non-technical staff ratios. We recommend the following steps for the organisational structure review:

- Determine the Strategic Intent of the ECG
- Understand key business processes, existing structure and related challenges
- Formulate and detail accountabilities
- Develop structural options for ECG based upon design parameters
- Detail the chosen structure in terms of role descriptions for the unique roles
- Design the grade and designation structure

Span of Control

In our view, though the execution and reporting on some jobs are similar, there are others which are generally different. Supervision of a large number of jobs which are different in terms of performance and reporting widens the span of control of a manager, and this may not facilitate effective and flexible decision-making between head office and the regions. There is the need to reorganize the organizational structure to improve ECG's span of control.

There is the need to decentralize the expenditure and control system so that decisions can be taken at the operational level within approved budgets. The internal audit function has to be strengthened to support the revised expenditure and control procedures. This process will facilitate timely decision making with appropriate controls.

We would also like to comment that these organizational and decision making issues are likely to be effectively addressed when ECG's operations are re-organized. Consultancy assignments by Kwame Asante & Associates and ECG's Change Management (2000), Development Management Associates (2007) and PWC (2008) have proposed different business models, all aimed at re-organizing ECG's operations. Presently, no firm decision has been taken on how ECG should operate to ensure effective and efficient performance.

We would like to highlight the potential benefits of ECG operationalising the Strategic Business Units (SBU) concept (PWC, 2008):

- Business operations would be made more market responsive and efficient, and are more likely to result in better profitability
- Greater transparency and accountability can be ensured leading to better commitment to ECG's respective values
- Effective service delivery
- Rationalised or reduced burden of head office costs on business fortunes would result in an improvement in the profit or loss line of ECG.

Organisational Culture

We recommend that the current Board and Managing Director ensure that this process is sped up to facilitate the cultivation of the right work attitudes and attributes by staff to support ECG achieve its mission of providing quality electricity services to support economic growth and development in Ghana. Specifically, there is the need to ensure that the newly identified core values are communicated to all staff and steps taken to identify behavioural descriptors of the values and re-design ECG's reward system.

Human Resource Policies and Procedures Manual

We recommend that the following HR Processes and Policies are covered in the proposed comprehensive HR Policies and Procedures Manual:

- ► Employee code of conduct – guidelines on code of conduct for employees and broad procedure for disciplinary action
- ► Office Conduct – details on work hours, attendance and grievance redress procedure
- ► Recruitment – selection process, probation, confirmation policy and employee induction process
- ► Performance Management System – brief details of the performance management process
- ► Compensation Administration – details of policy around payroll processing
- ► Business related expenses – details of the level-wise / grade-wise business related expense entitlements
- ► Promotion – details on promotion criteria within ECG

- Transfer – details on entitlement limits on relocation expenses available with an employee upon transfer of services from one location to the other
- Training and Development –details on the training and development process
- Leave – details on list of permissible leave and each type of permissible leave
- Separation and Exit Management – details on the various modes of separation from the ECG and the exit management procedure

Manpower Planning

Manpower management should be ECG's strategic approach to the management of staff. This requires a holistic approach of managing recruited employees, training, motivating them, helping them update their work knowledge and maintaining the attrition rate to a minimum. We recommend that as part of ECG's response to the power sector restructuring, and efforts to ensure that there is a balance in the Establishment for all job functions, a thorough workload analysis is undertaken in addition to the regular manpower budget defence to enhance efficiency in staffing levels. Workload analysis will provide a specification of the manpower required to complete specific functions/activities. It will help ECG understand what your people are doing, when they are doing it, what skill level is required and what the critical interactions between people and systems are.

Recruitment

There is the need for the Executive to review the draft recruitment policy and approval given for implementation. This will ensure that the right processes are followed to recruit the right people at the right time. The following recruitment process is recommended for ECG; understand the business and operating plan, existing recruitment plan, cultural and ethical parameters; prepare detailed job descriptions and competencies ; define policies around sourcing, selection, offer and on boarding; develop process flow maps for recruitment process along with timelines; and design recruitment tracker and success factors for the recruitment process.

Performance Management

There should be a holistic review of the performance management system for ECG to ensure that a uniform and reliable system is put in place for all staff to help the organization measure performance effectively. As a matter of urgency, the current system should be extended to cover junior staff since they form the majority

(74%) of ECG staff. As part of this exercise, Directors and Managers should work together to explore ways that targets can be effectively set and agree areas of measurement of performance for the junior staff.

It should also be ensured that the overall appraisal process is one that is accountability-based and has at its centre instruments/forms that are capable of measuring performance as objectively as possible. The system should also serve as a control mechanism for aligning the actions of individual staff to the organization's goals, values and objectives. Additionally, due to the staff strength of ECG, managing performance will be more effective and less cumbersome if the system is automated. The following approach is recommended when the performance management system is being reviewed for all staff; establish a common understanding of ECG's strategy and goals; cascade organisation goals to departments/positions; select performance measures; develop individual performance targets; and monitor and measure performance

Training and Development

Recommendations from the Draft Training Policy should be reviewed for implementation. We further recommend that the Manpower, Training and Development Division puts measures in place to ensure that training needs are effectively identified. To assess the ECG's training needs, its policy direction is expected to drive all aspects of the Training Needs Assessment of the utility. The underlying policy themes should drive the training plan or reflect the prioritization process that is used to decide on training programmes. Competency requirements should take cognizance of a number of issues including job requirements and performance trends.

An effective performance management system can also support in this area. Additionally, due to the limited financial resources available to ECG, it is crucial that training programmes and beneficiaries are tightly matched to ensure that the needed benefits are reaped by ECG.

The following guidelines should inform the review of the training and development function of ECG:

- Training Needs identification and analysis; prioritisation and development of a training plan
- Calendar development and management; detailed list of training programmes, timelines, duration, cost and employee coverage
- Coordination and delivery of training programmes
- Training effectiveness measurement; assessment of training interventions using feedback at various levels.

Career Management

We recommend that ECG adopts the following approach to career management;

- Ensure the grade structure design considers the impact on career management
- Develop a career management framework and define career paths
- Establish linkages of career management system with other HR processes such as training and performance management.

Additionally, the following practices would support an effective career management programme:

- Develop a system that collates information on employees;
- Departmental training and development policy or strategy; and
- Effective performance assessment/management system and regular update of job descriptions.

Succession Planning

We recommend the following steps to develop and implement an effective succession plan:

- Define a process – lay out objectives, activities and timelines
- Identify the needs of ECG – identify the skills and competencies needed for key positions
- Assess talent – identify possible candidates who may be ready now or in the future
- Engage people – actively involve people in their development
- Track data – track the process of filling critical positions
- Measure performance – continuously track the overall results of the succession

C: Recommendations for Financial restructuring and Recovery

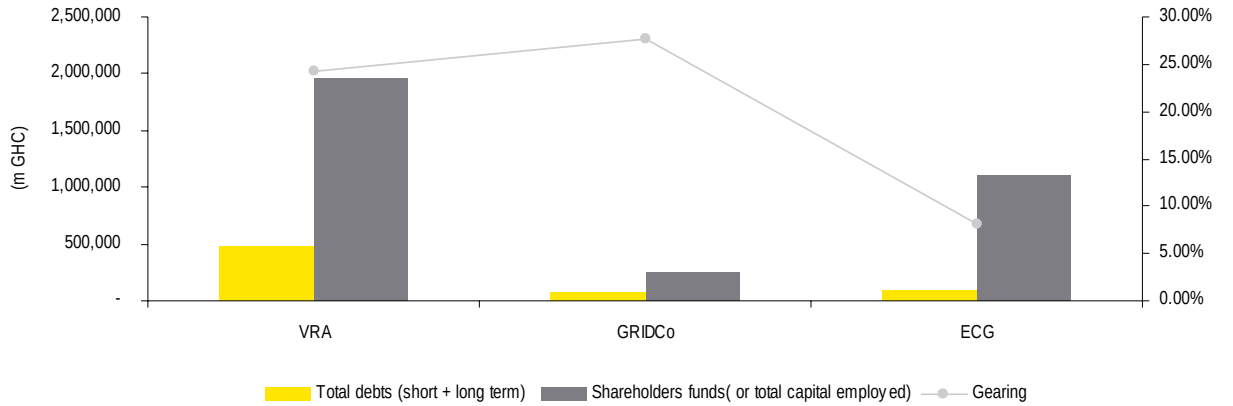
Balance sheet restructuring

We consider here a number of options for financial restructuring of the utilities. In the previous section we outlined the projections which have been developed to estimate the revenue shortfall of each of the companies, which amounts to GH¢ 3bn over the next 3 years in the base case. We also analysed the impact of separating the businesses as required by our terms of reference, including the impact a sale of VRA Thermal would have on the remainder of the VRA business.

We revert in this section to the base case where the individual businesses are modelled separately as shown below.

Electricity company capitalisations

Source: Company annual reports 2008



Each of the utilities appears to have low gearing primarily due to large revaluation surplus balances. The revaluation surpluses have arisen from the indexation of US dollar denominated assets to the Ghanaian cedi. In spite of the apparent low gearing of the utilities, their ability to raise commercial debt is significantly hampered. Large scale recapitalisation of the sector is therefore required. Sources of funds could include some or all of:

- End user tariff increases
- Equity injection from GoG
- Equity injection from external parties

- Asset sales
- New long term debt facilities
- Increased exports

End user tariff increases

Any restructuring of the sector to attract private sector investment can only be feasible if tariffs can be expected by investors to increase to be fully cost reflective in future. Therefore, the first step which must be agreed by GoG is a robust and credible program to increase end user electricity tariffs in Ghana. Without this, none of the following options will be in itself effective in reducing GoG required funding for the sector. The recommendations on the governance of the sector discuss in more detail the steps required to ensure a robust and credible tariff increase within the existing regulatory framework.

Equity injection from GoG

There are a number of options available to GoG in injecting equity into the businesses as follows:

- Direct equity investment. Were funds available to GoG, a direct equity injection could be made. This would amount to an equity injection requirement in GRIDCO of over GH¢100m, VRA of GH¢750m and ECG of GH¢400m. The total amount of GH¢1.25bn would need to be funded either from GoG central funds or an asset sale (see later).
- Debt for equity swap. A large portion of the debt in each company is in the form of Subsidiary Loan Agreements with GoG. If GoG could undertake to repay these debts and convert them into equity in the utilities, it would significantly enhance the cash flow position and ability to borrow of the utilities. This swap could be implemented in a short timeframe, potentially under six months.

Equity injection from external parties

If GoG choose not to inject equity into the businesses, there are other options by which additional equity may be contributed by external parties.

- Introduce a cornerstone investor, which could either be a strategic or financial investor. In either case, the sale of an initial stake is generally seen as a precursor to a full sale of the relevant business.
  - Strategic investor: would generally buy a cornerstone stake (25 to 30% for example) and assume operational control. Such investors would usually require a pre-emption right to acquire full ownership

if GoG ever sought to dispose of its remaining holding. Introducing a strategic investor may be of benefit if the existing management lack sufficient quality and experience to transform the business in anticipation of the transition to a WEM, or the company in its current state is unsuitable for the public markets by way of an Initial Public Offering (IPO).

- Financial investor: would generally buy a cornerstone stake in anticipation of an IPO (or similar transaction). A financial investor is likely to require a commitment from GoG to an IPO or similar transaction to enable it to monetise some or all of its initial investment. Whilst a financial investor would be unlikely to assume operational control, it may seek to influence strategy, but would also enable the company to de-leverage its balance sheet ahead of an IPO and add credibility when approaching the public market. Such a placement offers GoG greater discretion and control in selecting one or a small group of investors, and at a lower cost than an IPO.

- Float 100% or a smaller percentage of the businesses to institutional and retail investors. It is not uncommon for the vendor to retain a stake in the floated business, but not to the extent that it creates the perception of an "overhang" as this can impact post float share price performance. A float would enable access to additional capital to repay debt, fund expansion and meet capital expenditure requirements, assuming the funds raised remain with the company. However, capital from the public markets may not be accessible if any funds raised are to be retained by GoG, leaving the company/s overleveraged with little balance sheet headroom to raise further debt or equity capital to grow the business. In this regard, a pre-emptive debt for equity swap, as discussed above, may enhance the outcomes of the float and enable GoG to retain some or all of the float proceeds. This would also allow the businesses to seek new equity from the market once it has established a track record, or issue bonds/raise bank debt given the improvements to the balance sheet (see below). In assessing the "IPO readiness", the following non exhaustive list of issues will be important; growth (Ghanaian GDP, electricity sector and company itself), scale of the business, corporate structure, use of proceeds, corporate governance, and accounting/information systems. The relative attractiveness of the various entities will need to be assessed to ensure the best IPO candidate is floated first to establish credibility in the market. There are options available when considering a float:

  - Ghana Stock Exchange: In addition to any financial return, a successful local listing is likely to contribute to the ongoing development of the domestic capital market, and retain ownership of critical national assets and infrastructure in the hands of Ghanaians. Furthermore, it will enhance the depth and liquidity of the local stock market. An assessment would be required to determine whether any of the companies meet the eligibility requirements to list on the exchange, their suitability to list at the current time, and the appetite and available capital of local institutional and retail investors to absorb the shares issued.

Balance sheet restructuring

- Global Stock Exchange: There are a number of examples where businesses have listed on a global exchange, such as London. The larger global exchanges often attract cross-border listings due to the deeper pools of capital, possibility of a higher valuation driven by the liquidity, access to a highly sophisticated investor base with an appetite for emerging markets and the ability to enhance the profile and credibility of the IPO candidate. However, listing on a global exchange will decrease the share of equity capital market activities taking place in Ghana. An analysis of the most suitable global exchange and an assessment of eligibility (when measured to against the admission criteria), IPO readiness and the appetite and support of foreign investors would be required prior to committing to this course.
- Global Depository Receipts (GDRs): GDRs have been commonplace amongst emerging market issuers, as investors seek to diversify and access the higher returns that may be available in these markets. GDRs are a security representing a company's publicly traded equity. They are created when a broker buys the stock, delivers it to a Custodian Bank, which issues the GDRs. They effectively allow a company to list domestically and sell their shares internationally, without having to go through the full listing process on a foreign exchange. For the issuing company, GDRs may contribute to a more diversified investor base, with the potential for greater liquidity and an enhanced profile in global markets, and represent a flexible mechanism for raising capital.

Balance sheet restructuring

Case Study: Ken Gen IPO (2006)

Kenyan Government objectives

- Divest commercial activities, and increase accountability of government enterprises
- Raise IPO funds for reinvestment in other Government programmes
- Develop domestic capital market
- Encourage share ownership by Kenyans

Float structure

- Offered 30% of Ken Gen in total, with 25% allocated to public, and 5% to employees

Preparation

- Started to prepare well ahead of IPO, initially focused on balance sheet restructuring
- Introduced legislation support privatisation and IPO
- Built committed team early in the process
- Implemented appropriate governance framework and policies to guide operations, and 5-year business plan
- Subsequently undertook intensive operational, financial and legal due diligence
- Raised profile through road shows and meetings with foreign and domestic institutional investors

Impact

- Largest IPO on Nairobi Stock Exchange
- Attracted 275,000 applicants from across the country, and oversubscribed by a factor of more than 2x
- Reinvigorated market by encouraging first time shareholders
- Improved public awareness of capital markets generally, and share ownership specifically.

Asset sales

The sale of assets would enable GoG to avoid funding the ongoing business as well as making available equity for possible re-investment in the other companies in the sector. The options available are:

- Sale of individual assets. These include:
  - Sale of hydroelectric power stations at Akosombo, Kpong and/or Bui. We are projecting that these assets will become more profitable in the new wholesale electricity market, particularly the plants at Akosombo, Kpong. Based on our understanding of the WEM, the un-contracted hydro plant will be paid the system marginal price which is expected to be initially an oil fired OCGT. We estimate that at $60/bbl oil prices this is 16.0US$c/kWh, compared to a PURC regulated price for hydro of 1.5US$c/kWh. The Bui dam is, however, under a long term PPA with ECG which seems to be under-recovering on costs, and therefore unless the PPA price was renegotiated or some other form of subsidy provide, this asset would not be profitable to sell. The sale of these hydro assets to a private investor may be opposed by the public in Ghana. However, an IPO may be a more acceptable method of selling some or all of the hydro assets of VRA.
  - Sale of thermal power stations owned by VRA and Kpone (110MW OCGT) and Tema (220MW OCGT). These stations require significant investment to continue operations, and upgrade from open cycle to combined cycle. Passing this investment requirement to the private sector would reduce the revenue requirement for the utilities provided by GoG in the near term, although passing the assets to the private sector will result in higher returns and therefore a higher cost of electricity from these stations. The sale of these assets would take a 12-18 months period to complete. Purchasers would place additional value on the assets if they were packaged with either a long term offtake PPA agreement or a Gas Supply Agreement. Without these guarantees, the value of the assets may make them uneconomic to sell.
- Outright sale of one or more of the businesses. The sale could be for all or part of the business, and be in the form of a private or public sale i.e., IPO. Of the three business, GRIDCO seems the least indebted and closest to financial viability although the transmission tariff is not yet at a fully cost reflective level, and would need to happen before sale of some of all of the business.
- Sale of carbon credits. The future plans to construct hydro electric and gas OCGT and CCGT plant will result in carbon emission reductions than would otherwise be the case. It may therefore be possible to gain carbon credit financing which could reduce the lifetime cost of these assets and hence reduce the revenue requirement for the sector. It is recommended that this possible additional funding option be further explored."
- Sale of current assets such as the debtor book or accounts receivable. The debtor book is significant and growing. Furthermore, little headway seems to be made by the utilities in recovering aging debts. A

private investor may be able to expend more time and effort in recovering the monies due by debtors. The debtor book would be sold at a discount in order to reflect the expected success rate of the private investor. The transaction could be executed in a relatively short timeframe e.g. under 6 months provided a buyer could be found. The sale of accounts receivables would similarly entail a private investor

New long term debt facilities

- The ability to raise new long term debt from commercial banks will be in large part dictated by the success or otherwise of the tariff increase and injection of equity into the utilities. In principle, however, should those perquisites be met, commercial debt should become increasingly available to the sector at more cost effective rates and margins. A track record in paying down debt on time and can be built up in coming years to place the sector on a better footing with lenders.

Increased exports

- As discussed earlier, there is a possibility of an excess of supply over demand in 2011/12 and beyond if the IPPs currently contracted by ECG are constructed. In this case, an obvious use of the excess power not consumed within Ghana would be via exports to surrounding countries within the West Africa Power Pool, including Togo, Benin, Cote d'Ivoire and Nigeria. This would be dependant on the introduction of domestic natural gas, and diversion of sufficient quantities to the power sector. We understand the MoE is currently developing a natural gas sector master plan which will address, among other thing, the amount of gas to be allocated to the power sector. There is consideration being given to the development of an indigenous petrochemical industry, which if progressed would potentially reduce the availability of gas to fuel power exports. Furthermore, there is a need to invest to be able to export the power, both in transmission capacity and generation unit upgrades (to CCGT). There is considerable uncertainty over the potential prices and volumes which could be achieved. For these reasons, the prospects of increased exports by the utilities will not impact significantly on the ability of the sector to restructure.

Balance sheet restructuring

Suggested Working capital improvements

Corporate

- Stronger corporate focus on cash management through key metrics, individual incentivisation and training
- More robust and accurate cash flow forecasting
- Segmented approach to customer/suppliers/stock
- Deployment of more integrated systems

Accounts payable

- Payment frequency
- Early payments and other system housekeeping
- Payment terms (capex and opex) and payment practice rules
- Joint procurement approach for cost and cash
- Invoice and goods timing
- Rebate management
- Invoice trigger point
- Use of centralised, processes and functions

Inventory

- Accuracy of demand forecasting
- Raw material, finished goods, packaging coverage and root cause review
- Slow moving and obsolescence procedures
- Re-ordering assumptions (safety stock, order quantities, lead times)
- Flexible/vendor managed supply arrangements
- Seasonal inventory requirements and procedures

Balance sheet restructuring

Accounts receivable

- Overdue debtor management, escalation policy and dispute resolution
- Credit limits and credit management
- Accuracy and speed of order processing
- Invoice processing frequency and unbilled receivables
- Terms of trade and early payment discounts
- Rebate management (consistency and appropriateness)
- Pricing and promotions management
- Increased pre-payment/direct debit penetration

Recommendations and Action Plan

The recommendations are summarised in the Action Plan on page 8, and are described in more detail as follows.

Financial

1. Define GoG equity investment MoFEP

The first three tasks are interdependent and are indicated as occurring simultaneously in Q409, although practically they will occur iteratively firstly at a GoG policy level in order to determine the optimum balance acceptable to the GoG and other stakeholders. There is a complex interconnection between any tariff increase, equity injection and treatment of the HIPC debt relief program. They will need to be considered holistically as each impact on the levels of the others. The projections presented in this report are our recommended combination in the absence of policy and funding constraints, which exist in practice but are not taken into account in this work. Many other combinations of tariff, equity and debt relief exist, and it is for the GoG and stakeholders to agree the most practical combination in order to restructure the businesses.

The first task is therefore for GoG to superimpose the policy and funding constraints on the recommendations in this report in order to optimise a practical solution. It is estimated that this task can be complete by the end of 2009, and is a critical underpinning of the entire restructuring program. As described in the balance sheet restructuring options previously, there are a number of options open to the GoG should a direct equity injection at the level of GHC1.25bn not be possible. Should the level of equity available to GoG be less than the level projected here, GoG will need to consider what level is achievable and how much would need to be realised through other options described previously such as asset sales, debt for equity swaps (including the HIPC program), or potentially even cornerstone private investors.

2. Propose required tariff increase Utilities

Having set the level of equity which GoG can afford to inject in the sector, the required tariff level would need to be estimated. Given the level of recapitalisation from GoG, as well as taking into account the level, if any, of asset sales or third party equity, it will then be the utility's task to make a rate case to the PURC in order to attain the levels of revenue which can sustain both the recapitalised businesses and the level of debt which can be serviced as a result. An important input into the projected tariff level is the cost of capital, which is critically dependant on both Tasks 1 and 3 running simultaneously to this one; level of equity investment and HIPC strategy.

3. Develop HIPC strategy MoFEP

The MOFEP will, in considering the potential equity investment level in Task 1 and resultant tariff level in Task 2, need to consider also the treatment of the IFI debt forgiveness program currently implemented by GoG for the utilities. A significant amount of value accrues to the utilities through this program, which at

current tariff levels allows the utilities to maintain operations and access short term commercial debt for working capital purposes (albeit with government underwriting). Explicitly treating this HIPC program as a source of revenue or equity is required in order to remove this implicit public subsidy, as well as allow the regulator to ascertain the correct level of fully-cost reflective tariffs, including their cost of capital, which the utilities should earn revenue against. Setting the government policy on the levels of forgiveness of debt will, in combination with the level of equity injected, drive the require level of tariffs and allow certainty and investment via commercial sources of funding to be achieved in the medium term.

4. Implement working capital management programme Utilities

As described in the previous section, there is a considerable opportunity for the utilities to achieve value through the implementation of working capital management programs. We recommend that these programmes are initiated immediately at the utilities as they do not require any external intervention. Programmes already in place should be integrated into a wider working capital management program, and utilising best practice from international utilities. We recommend that recent improvements in working capital management, including but not limited to improved levels of tariff recovery, achieved by NED management act as a template for such programs to be implemented across the other utilities.

5. Undertake asset valuation PURC

A key underpinning in the estimation of long term sustainable levels of tariffs is the value of the utility's assets (the Regulated Asset Base) and appropriate signalling for their efficient replacement, maintenance and upgrading. This is achieved through the pass-through of appropriate levels of capital depreciation via tariffs. The balance of efficient capital utilisation by the utilities and affordable tariffs which provide value for money for consumers is the role of the PURC. We recommend that the valuation of the existing asset base for the utilities is undertaken from Q110, and estimate it will take approximately six months to undertake and agree on a value. This revaluation is also recommended to be undertaken on a regular basis (such as every 4-5 years) in future, in order to ensure that the utilities are responding appropriately to the investment signals being set for them. We understand that this valuation study is already being started by the PURC.

6. Swap GoG debt for equity MoFEP

Based on the agreed level of equity investment by GoG in task 1, tariff level in task 2 and HIPC strategy in task 3, we recommend that the first tranche or equity investment be implemented via a debt for equity swap. We recommend that the recapitalisation of the sector be undertaken in a number of steps, and recognise the constraints on the availability of GoG cash to inject into the utilities in the immediate future. These steps are to, firstly (by Q1 2010), in this Task 6, implement a debt for equity swap to reflect the HIPC strategy considered in Task3. Following this transfer of liabilities by the GoG, as appropriate, the next step is the injection of equity by GoG in Task 10. We recognise that this may take more time to implement than a debt for equity swap, and recommend it is undertaken in the context of a long term strategy considering the

ownership of the utilities by the GoG (Tasks 7, 8 and 9). We make this recommendation on the basis that this is the most rapid way for GoG to place the utilities on a firm financial footing in advance of further tranches of equity via, as appropriate, direct cash injection, asset sales etc.

7. Divestment/IPO readiness assessment MoFEP + MoE

We recommend that a long term strategy be developed relating to the continuing GoG ownership of the utilities, especially in the context of the planned Wholesale Electricity Market. In order to inform this strategy (Task 8) an assessment is required on the readiness of each of the utilities and assets for divestment options, including potentially (in the long term) IPO. The assessment will allow the GoG to consider the most appropriate timeframe for any divestment strategy. Our action plan recommends that potential divestments, if any, be achieved over a 3-4 year period. This timetable may be accelerated depending on the types of assets or businesses considered for divestment and the readiness assessment will inform GoG on the specific options available to it, in the context of the levels of equity GoG plan to invest as determined in Task 1.

8. Develop divestment/IPO strategy MoFEP

Setting a clear long term GoG power sector strategy is important in order to facilitate increasing private sector involvement in the power sector. We recommend that such a strategy is developed in close consultation with the private sector. We recommend that a first draft of this task is completed by Q3 2010, taking into account the preceding tasks concerning tariffs, level of equity investment and divestment readiness assessment.

9. Market sounding of strategy MoFEP

We recommend that the GoG strategy is market sounded with the private sector as well as power sector stakeholders. Adjustment of the strategy may be necessary in light of this market sounding, and we recommend that the GoG consider making adjustments on the timing or structure of the strategy in order to facilitate effective and timely. We recommend a period of three months during Q4 2010 in order to adequately test the strategy with investors. In particular, discussions with lenders concerning the levels of investment and debt which can be sustained by the utilities will be particularly crucial in setting the relative levels of capital injection and ongoing revenues from regulated or market based tariffs.

10. Inject GoG/third party equity MoFEP

On the completion of the strategy for the GoG investment in the power sector in Task 9, the final step in the recapitalisation program is the actual injection of the agreed amount of GoG equity, coupled with the commencement of the implementation of any divestment/IPO strategy. We recommend that the injection of GoG equity by completed by Q1 2011. However, the benefit of the recapitalisation and tariff recovery program is expected to have been realised through the market sounding and consultation process

described in the preceding tasks – all of which have the objective of making the financing of the sector for commercial lenders a more transparent and accessible process.

11. Carve out assets for divestment/IPO MoFEP

Should divestment of some or all GoG power sector assets, including a possible IPO, be considered necessary in order to recapitalise the sector, it will be necessary to undertake a carve out of the assets in order to facilitate the divestment process. Depending on the complexity of the assets being divested, the process may take shorter or longer than the two years indicated in 2011 and 2012. We recommend that the form and commercial/contractual structure of the assets being divested be defined during the market sounding stage in Task 9.

12. Implement divestment stream MoFEP

Should a divestment/IPO strategy be adopted, we recommend the dual-running of a divestment and IPO preparation program. Should divestment of some or all GoG power sector assets, including a possible IPO, be considered necessary in order to recapitalise the sector, it will be necessary to undertake a carve out of the assets in order to facilitate the divestment process. Depending on the complexity of the assets being divested, the process may take shorter or longer than the two years indicated in 2011 and 2012. We recommend that the form and commercial/contractual structure of the assets being divested be defined during the market sounding stage in Task 9.

13. Implement IPO stream MoFEP

The requirements for an IPO, particularly concerning the length of time of stable profitability, will necessarily mean that any IPO process will be achievable only well beyond the three year program of the action plan considered here. However, the benefits to end consumers of reliable power supply from well capitalised and profitable businesses is considered achievable by the end of the action plan period, and this can be accelerated and strengthened by a long term IPO strategy which can increase still further the private sector participation in the sector.

<u>Policy</u>

1. Approve interim tariff increase PURC

The tariff increase proposed by the utilities in Q4 2009, will require approval by PURC, subject to adjustment and/or clarification.

2. Implement automatic tariff adjustment PURC

We recommend the reinstatement of the automatic adjustment mechanisms as well as period reviews of the tariff methodology to ensure that the indices and correlations used in computing end user tariffs remain relevant to the utilities and the power sector.

3. Finalise gas sector master plan MoE

We understand that a gas sector master plan is under development by the MoE to consider the impact of the newly discovered offshore gas reserves. We recommend that this is finalised by Q1 2010 in order to inform other tasks such as the power sector master plan and divestment/IPO strategy.

4. Finalise power sector master plan MoE

We understand that a power sector master plan is under development by the MoE to consider the impact of the wholesale electricity market and increased private participation in the sector. We recommend that this is finalised by Q1 2010 in order to inform other tasks such as the gas sector master plan and divestment/IPO strategy.

5. Modify WEM design EC

We recommend that the Energy Commission continues in the critical task of designing a practical Wholesale Electricity Market. We recommend the modification of the market rules currently being drafted to avoid market distortions and minimise any potential increases in power prices for end users.

6. Transitional WEM arrangements EC

We recommend that the Energy Commission develops a transitional set of Wholesale Electricity Market arrangements.

7. Implement WEM GRIDCO

Implementation of the WEM should be undertaken in compliance with GoG power sector policy and we recommend that it takes account of the recommendations in the power sector strategy.

8. Undertake tariff structure review PURC

Periodic reviews of the structure of end users tariffs, and we recommend the first to be undertaken in 2010.

9. Develop RAB replacement and expansion policy PURC

In the context of a full cost recovery system of end users tariffs, as well as a revalued asset base, the PURC should develop the policy under which utilities will expect to be governance in future tariff estimates

10. Revaluation of RAB PURC

We recommend a revaluation of the Regulated Asset Base in undertaken by PURC as soon as practical, and we understand such a study is currently being commissioned.

Legal

1. Legislative changes MoFEP, MoE

We recommend the following legislative changes are implemented in accordance with our action plan timeline:

- Amendment of establishment Acts - Independence of Regulators
- Drafting of tailored company regulations - Government's Role as Shareholder
- Legislative provision on requirements and timelines for capitalisation and recapitalisation of inc and converted companies
- Transitional legislative arrangements - Commencement of WEM in 2012
- Public Procurement Act - Specialised Procurement relating to VRA
- Public Procurement Act - Exclusion of GRIDCO and ECG from application of Act 663
- Amendment of Electricity (Special Levies) Act, 1995

2. Governance improvements MoFEP, MoE, SEC

We recommend the:

- reintroduction of criteria for appointments to the Board of VRA into VRA (Amendment) Act, 2005.
- compliance by GRIDCO and ECG to the provisions of the Companies Code, 1963, Act 179, and
- the enhancement of SEC's role in strengthening governance of the utilities.

3. Executive arrangements for Rights of Way MoFEP, MoE, ECG, NED, FRIDCO

It is recommended that as private limited liability companies, ECG and GRIDCO should factor the cost of compensation payments in their budgets, and the government may facilitate (through Executive Instruments) the acquisition of Rights of Way for ECG and GRIDCO's network expansion.

4. GRIDICO/VRA Separation VRA, GRIDCO

The legal mechanisms for regularising transfer of assets and whether or not VRA will earn monetary value for the "disposal" of these assets (to GRIDCO) has to be addressed. The relevant agreements to complete

the decoupling of VRA and GRIDCO operations particularly legal documentation on the allocation of transmission losses need to be finalised.

5. Abrogation of non-performing PPAs MoE, MoFEP, ECG

We recommend that action is taken based on the key issues identified in the agreements and the ability of ECG to abrogate the agreements as provided in Appendix D.

Appendices

Appendix A - Pro forma financial statements

Income statement - VRA Consolidated

VRA Consolidated – Forecast Income Statement

Currency: ¢ 000	FY08A	FY09F	FY10F	FY11F	FY12F	FY13F	FY14F	FY15F	FY16F	FY17F	FY18F
Revenue	713,426	724,792	1,201,129	1,397,091	1,642,449	1,898,832	2,224,910	2,538,610	3,080,310	3,475,850	4,158,082
Total opex	(744,962)	(933,129)	(1,199,495)	(1,133,626)	(840,782)	(1,044,970)	(1,197,389)	(1,392,051)	(1,604,803)	(1,676,089)	(1,935,095)
Operating profit	(31,536)	(208,337)	1,634	263,465	801,667	853,863	1,027,521	1,146,559	1,475,507	1,799,761	2,222,987
Depreciation	(44,464)	(53,781)	(54,384)	(59,823)	(62,972)	(84,614)	(85,759)	(86,985)	(85,244)	(86,125)	(85,153)
EBIT	188,033	(262,118)	(52,750)	203,642	738,695	769,249	941,761	1,059,574	1,390,263	1,713,635	2,137,834
Financing Costs											
Senior Debt Interest	(34,559)	(32,424)	(21,373)	(17,457)	(54,548)	(59,140)	(63,454)	(83,530)	(84,700)	(85,084)	(84,549)
Financing charges	(7,280)	(9,600)	(10,490)	(11,203)	(12,255)	(13,616)	(15,129)	(16,810)	(18,678)	(20,753)	(23,059)
Interest on cash balances (overdraft)	-	11,742	(39,895)	(1,920)	(7,583)	21,587	74,007	141,808	218,778	316,933	444,463
Gain/(loss) on Foreign Exchange	-	(13,409)	(22,260)	(17,083)	(12,634)	(150,331)	(160,162)	(172,574)	(179,788)	(185,909)	(190,508)
Profit Before Tax	146,193	(305,809)	(146,768)	155,980	651,676	567,749	777,022	928,469	1,325,875	1,738,822	2,284,181
Tax	-	-	-	-	-	-	-	-	-	-	-
Profit After Tax	146,193	(305,809)	(146,768)	155,980	651,676	567,749	777,022	928,469	1,325,875	1,738,822	2,284,181
Dividends	-	-	-	-	-	-	-	-	-	-	-
Retained Profit	146,193	(305,809)	(146,768)	155,980	651,676	567,749	777,022	928,469	1,325,875	1,738,822	2,284,181
Asset Revaluation Reserve	308,182	-	-	-	-	-	-	-	-	-	-
Retained Profit & Reserves	454,375	(305,809)	(146,768)	155,980	651,676	567,749	777,022	928,469	1,325,875	1,738,822	2,284,181

Source: Management information

Ref: VRA Con P&L - Section VR - Volta River Authority

Balance sheet - VRA Consolidated

VRA Consolidated – Balance Sheet

Currency: ¢ 000	FY08A	FY09F	FY10F	FY11F	FY12F	FY13F	FY14F	FY15F	FY16F	FY17F	FY18F
Current Assets											
Cash	146,774	-	-	-	269,842	925,082	1,772,606	2,734,729	3,961,664	5,555,790	7,590,922
Debtors	413,362	559,075	665,018	809,949	899,526	1,003,967	1,134,587	1,276,375	1,469,529	1,679,272	1,920,909
Stock	85,697	99,588	101,229	103,207	105,570	108,376	111,691	115,592	88,231	104,929	124,788
Fixed Assets											
Total fixed Assets	1,867,064	1,879,819	1,998,105	2,077,904	3,479,667	3,481,548	3,489,621	3,443,819	3,473,668	3,441,416	3,508,190
Long term investment	122,628	122,628	122,628	122,628	122,628	122,628	122,628	122,628	122,628	122,628	122,628
Total Assets	2,635,526	2,661,109	2,886,980	3,113,687	4,877,232	5,641,601	6,631,133	7,693,143	9,115,720	10,904,035	13,267,438
Current Liabilities											
Creditors and accurals	199,182	247,594	327,294	316,308	230,746	286,206	330,318	386,383	448,829	478,815	558,075
Overdraft	-	498,693	23,999	94,784	-	-	-	-	-	-	-
Current portion of long term loans	263,791	75,760	65,142	52,413	71,944	59,997	123,721	143,508	164,276	188,314	27,010
Non-current Liabilities											
Senior Debt	210,833	183,152	183,152	211,403	235,060	1,507,744	1,660,852	1,765,525	1,823,215	1,836,702	1,832,171
Total Liabilities	673,806	1,005,199	627,838	698,565	1,810,435	2,007,055	2,219,565	2,353,106	2,449,807	2,499,300	2,578,522
Net Assets	1,961,719	1,655,910	2,259,142	2,415,122	3,066,798	3,634,546	4,411,569	5,340,037	6,665,913	8,404,735	10,688,916
Owners Equity											
Share Capital	18,329	18,329	768,329	768,329	768,329	768,329	768,329	768,329	768,329	768,329	768,329
Retained Profits	143,251	(162,558)	(309,326)	(153,346)	498,329	1,066,078	1,843,100	2,771,569	4,097,444	5,836,266	8,120,447
Revaluation reserve	1,689,587	1,689,587	1,689,587	1,689,587	1,689,587	1,689,587	1,689,587	1,689,587	1,689,587	1,689,587	1,689,587
WAPCo	110,552	110,552	110,552	110,552	110,552	110,552	110,552	110,552	110,552	110,552	110,552
	1,961,719	1,655,910	2,259,142	2,415,122	3,066,798	3,634,546	4,411,569	5,340,037	6,665,913	8,404,735	10,688,916

Source: Management information

Ref: VRA Con BS - Section VR - Volta River Authority

Cash flow statement - VRA Consolidated

VRA Consolidated – Cash Flow Statement

Currency: ¢ 000	FY08A	FY09F	FY10F	FY11F	FY12F	FY13F	FY14F	FY15F	FY16F	FY17F	FY18F
Cash Inflow											
Sales Revenue	713,426	724,792	1,201,129	1,397,091	1,642,449	1,898,832	2,224,910	2,538,610	3,080,310	3,475,850	4,158,082
Increase in Debtors	(228,489)	(145,713)	(105,943)	(144,931)	(89,577)	(104,441)	(130,620)	(141,788)	(193,154)	(209,744)	(241,637)
Change in stock	576	(13,891)	(1,641)	(1,977)	(2,363)	(2,806)	(3,316)	(3,901)	27,362	(16,699)	(19,859)
Increase in Creditors	(6,488)	48,412	79,700	(10,986)	(85,562)	55,460	44,112	56,065	62,445	29,986	79,260
Total revenue	479,025	613,600	1,173,244	1,239,197	1,464,947	1,847,044	2,135,087	2,448,987	2,976,963	3,279,394	3,975,846
Cash Outflow											
Operating costs	(744,962)	(933,129)	(1,199,495)	(1,133,626)	(840,782)	(1,044,970)	(1,197,389)	(1,392,051)	(1,604,803)	(1,676,089)	(1,935,095)
Operating Cash Flow	(265,936)	(319,529)	(26,251)	105,571	624,165	802,075	937,698	1,056,936	1,372,160	1,603,305	2,040,751
Taxation	-	-	-	-	-	-	-	-	-	-	-
Net Cash Flow	(265,936)	(319,529)	(26,251)	105,571	624,165	802,075	937,698	1,056,936	1,372,160	1,603,305	2,040,751
Capex and drawdowns											
Project Capital Costs	(56,511)	(66,535)	(172,670)	(139,622)	(1,464,735)	(86,495)	(93,832)	(41,182)	(115,093)	(53,873)	(151,927)
Senior Debt Drawdown	181,140	34,670	71,380	60,195	1,333,374	64,361	70,068	30,552	-	-	-
Equity Drawdown	-	-	750,000	-	-	-	-	-	-	-	-
Long term investment	(21,345)	-	-	-	-	-	-	-	-	-	-
sub-total	388,661	(31,866)	648,710	(79,427)	(131,361)	(22,135)	(23,764)	(10,631)	(115,093)	(53,873)	(151,927)
Net cash flow after investing activities	122,725	(351,395)	622,459	26,144	492,804	779,940	913,934	1,046,305	1,257,067	1,549,432	1,888,824
Cash Balance b/f	32,411	146,774	(498,693)	(23,999)	(94,784)	269,842	925,082	1,772,606	2,734,729	3,961,664	5,555,790
Cash Flow Available For Debt Service	155,136	(204,620)	123,766	2,144	398,021	1,049,782	1,839,016	2,818,911	3,991,796	5,511,096	7,444,613
Repayment of Senior Debt Interest	(1,701)	(42,024)	(31,863)	(28,659)	(66,803)	(72,756)	(78,583)	(100,340)	(103,378)	(105,837)	(107,608)
Repayment of Senior Debt Principal	(6,660)	(263,791)	(76,007)	(66,349)	(53,793)	(73,531)	(61,833)	(125,650)	(145,532)	(166,402)	(190,546)
Interest on cash balances	-	11,742	(39,895)	(1,920)	(7,583)	21,587	74,007	141,808	218,778	316,933	444,463
Cash Balance c/f	146,774	(498,693)	(23,999)	(94,784)	269,842	925,082	1,772,606	2,734,729	3,961,664	5,555,790	7,590,922

Source: Management information

Ref: VRA Con CF - Section VR - Volta River Authority

Income statement - VRA Thermal

VRA Thermal –Forecast Income Statement

Currency: ¢ 000	Notes	FY08A	FY09F	FY10F	FY11F	FY12F	FY13F	FY14F	FY15F	FY16F	FY17F	FY18F
Revenue												
	Wholesale market	-	-	-	-	-	-	-	-	-	-	-
	ECG BST revenues	267,415	318,721	402,689	371,794	-	-	-	-	-	-	-
	NED BST revenues	52,277	59,127	111,804	130,282	-	-	-	-	-	-	-
	Bulk customers	205,296	222,660	440,608	583,760	800,145	866,467	953,514	1,055,257	1,163,151	1,307,695	1,448,033
	Other income	63,613	-	-	-	-	-	-	-	-	-	-
	VRA Hydro subsidy	-	-	-	-	-	-	-	-	-	-	-
	Total revenues	588,601	600,507	955,102	1,085,837	800,145	866,467	953,514	1,055,257	1,163,151	1,307,695	1,448,033
Operating Expenses		-	-	-	-	-	-	-	-	-	-	-
	Fuel, heating and usage	(265,902)	(287,975)	(459,295)	(543,800)	(160,675)	(183,343)	(210,771)	(242,306)	(278,561)	(320,245)	(368,170)
	Purchase of electricity	(358,986)	(297,234)	(332,995)	(216,863)	(273,892)	(324,943)	(358,581)	(429,419)	(518,739)	(444,074)	(575,176)
	Salaries and related expenses	(14,205)	-	-	-	-	-	-	-	-	-	-
	O&M	(16,815)	-	-	-	-	-	-	-	-	-	-
	Other	-	-	-	-	-	-	-	-	-	-	-
	Recurrent direct expenditure	-	(242,558)	(286,828)	(234,286)	(193,150)	(280,926)	(337,733)	(393,176)	(442,475)	(501,256)	(534,491)
	Total Opex	(655,908)	(827,767)	(1,079,118)	(994,949)	(627,717)	(789,211)	(907,085)	(1,064,901)	(1,239,774)	(1,265,574)	(1,477,837)
		-	-	-	-	-	-	-	-	-	-	-
Operating profit		(67,306)	(227,260)	(124,016)	90,888	172,428	77,255	46,429	(9,644)	(76,623)	42,121	(29,803)
	Government assistance	264,032	-	-	-	-	-	-	-	-	-	-
	Depreciation Expense	(16,065)	(19,222)	(18,586)	(20,344)	(19,006)	(17,832)	(16,814)	(15,443)	(14,200)	(13,073)	(12,049)
		-	-	-	-	-	-	-	-	-	-	-
EBIT		180,661	(246,481)	(142,602)	70,544	153,422	59,423	29,615	(25,087)	(90,824)	29,048	(41,852)
Financing Costs		-	-	-	-	-	-	-	-	-	-	-
	Senior Debt Interest	(32,858)	(29,475)	(16,097)	(9,382)	(5,938)	(3,560)	(2,748)	(2,723)	(2,696)	(2,667)	(2,635)
	Financing charges	(7,280)	(9,600)	(10,490)	(11,203)	(12,255)	(13,616)	(15,129)	(16,810)	(18,678)	(20,753)	(23,059)
	Interest on cash balances (overdraft)	-	83,211	(19,300)	30,627	18,062	29,641	56,923	73,559	82,620	86,088	95,970
	Gain/(loss) on Foreign Exchange	-	(13,348)	(18,548)	(13,263)	(8,740)	(5,201)	(3,359)	(3,598)	(3,846)	(4,105)	(4,372)
Profit Before Tax		140,523	(215,694)	(207,036)	67,322	144,552	66,686	65,301	25,341	(33,425)	87,611	24,052
Tax		-	-	-	-	-	-	-	-	-	-	-
Profit After Tax		140,523	(215,694)	(207,036)	67,322	144,552	66,686	65,301	25,341	(33,425)	87,611	24,052
Dividends		-	-	-	-	-	-	-	-	-	-	-
Government assistance		-	-	500,000	-	-	-	-	-	-	-	-
Retained Profit		140,523	(215,694)	292,964	67,322	144,552	66,686	65,301	25,341	(33,425)	87,611	24,052
Asset Revaluation Reserve		43,185	-	-	-	-	-	-	-	-	-	-
Retained Profit & Reserves		183,708	(215,694)	292,964	67,322	144,552	66,686	65,301	25,341	(33,425)	87,611	24,052

Source: Management informaiton

Ref: VRA Thermal P&L - Section VR - Volta River Authority

Balance sheet- VRA Thermal

VRA Thermal Forecast balance sheet

Currency: ¢ 000		FY08A	FY09F	FY10F	FY11F	FY12F	FY13F	FY14F	FY15F	FY16F	FY17F	FY18F
Current Assets		-	-	-	-	-	-	-	-	-	-	-
	Cash	416,054	-	153,133	90,310	148,207	284,614	367,795	413,098	430,438	479,850	502,105
	Debtors	47,250	145,896	206,102	285,827	260,372	224,336	249,530	280,543	314,980	356,449	403,247
	Stock	85,697	99,588	101,229	103,207	105,570	108,376	111,691	115,592	88,231	104,929	124,788
	Short term investments	-	-	-	-	-	-	-	-	-	-	-
		-	-	-	-	-	-	-	-	-	-	-
Fixed Assets		-	-	-	-	-	-	-	-	-	-	-
	Total Fixed Assets	309,957	299,989	314,060	297,274	282,238	268,847	252,033	236,590	222,390	209,317	197,268
	Long term investment	122,628	122,628	122,628	122,628	122,628	122,628	122,628	122,628	122,628	122,628	122,628
		-	-	-	-	-	-	-	-	-	-	-
Total Assets		981,586	668,101	897,151	899,246	919,014	1,008,801	1,103,678	1,168,451	1,178,666	1,273,173	1,350,036
		-	-	-	-	-	-	-	-	-	-	-
		-	-	-	-	-	-	-	-	-	-	-
Current Liabilities		-	-	-	-	-	-	-	-	-	-	-
	Creditors and accruals	161,620	203,967	265,902	245,162	154,674	194,467	223,512	262,399	305,489	311,846	364,149
	Overdraft	-	96,500	-	-	-	-	-	-	-	-	-
	Current portion of long term loans	256,926	72,141	59,212	44,632	23,639	992	1,123	1,272	1,440	1,632	1,805
		-	-	-	-	-	-	-	-	-	-	-
Non-current Liabilities		-	-	-	-	-	-	-	-	-	-	-
	Senior Debt	173,772	121,918	105,499	75,592	62,290	68,244	68,644	69,041	69,423	69,770	70,104
		-	-	-	-	-	-	-	-	-	-	-
		-	-	-	-	-	-	-	-	-	-	-
Total Liabilities		592,318	494,527	430,613	365,386	240,603	263,703	293,279	332,712	376,351	383,247	436,059
		-	-	-	-	-	-	-	-	-	-	-
		-	-	-	-	-	-	-	-	-	-	-
Net Assets		389,268	173,574	466,538	533,860	678,412	745,098	810,399	835,740	802,315	889,925	913,977
		-	-	-	-	-	-	-	-	-	-	-
		-	-	-	-	-	-	-	-	-	-	-
Owners Equity		-	-	-	-	-	-	-	-	-	-	-
GoG Equity		8,877	8,877	508,877	508,877	508,877	508,877	508,877	508,877	508,877	508,877	508,877
Retained Profits		(166,751)	(382,444)	(589,481)	(522,159)	(377,607)	(310,921)	(245,620)	(220,279)	(253,704)	(166,093)	(142,041)
Revaluation reserve		436,590	436,590	436,590	436,590	436,590	436,590	436,590	436,590	436,590	436,590	436,590
WAPCo		110,552	110,552	110,552	110,552	110,552	110,552	110,552	110,552	110,552	110,552	110,552
		389,268	173,574	466,538	533,860	678,412	745,098	810,399	835,740	802,315	889,925	913,977

Source: Management information

Ref: VRA Thermal BS - Section VR - Volta River Authority

Cash flow statement- VRA Thermal

VRA thermal forecast cash flow statement

Currency: ¢ 000	FY08A	FY09F	FY10F	FY11F	FY12F	FY13F	FY14F	FY15F	FY16F	FY17F	FY18F
Cash Inflow											
Sales Revenue	588,601	600,507	955,102	1,085,837	800,145	866,467	953,514	1,055,257	1,163,151	1,307,695	1,448,033
Increase in Debtors	(3,889)	(98,646)	(60,205)	(79,726)	25,455	36,036	(25,194)	(31,013)	(34,437)	(41,468)	(46,798)
Change in stock	576	(13,891)	(1,641)	(1,977)	(2,363)	(2,806)	(3,316)	(3,901)	27,362	(16,699)	(19,859)
Increase in Creditors	31,938	42,347	61,935	(20,740)	(90,488)	39,793	29,045	38,887	43,090	6,357	52,303
	617,226	530,317	955,189	983,394	732,749	939,490	954,049	1,059,230	1,199,165	1,255,885	1,433,680
Cash Outflow	-	-	-	-	-	-	-	-	-	-	-
Operating costs	(655,908)	(827,767)	(1,079,118)	(994,949)	(627,717)	(789,211)	(907,085)	(1,064,901)	(1,239,774)	(1,265,574)	(1,477,837)
Operating Cash Flow	(38,682)	(297,449)	(123,928)	(11,555)	105,032	150,278	46,964	(5,671)	(40,609)	(9,689)	(44,157)
Taxation	-	-	-	-	-	-	-	-	-	-	-
Net Cash Flow	(38,682)	(297,449)	(123,928)	(11,555)	105,032	150,278	46,964	(5,671)	(40,609)	(9,689)	(44,157)
Capex and drawdowns	-	-	-	-	-	-	-	-	-	-	-
Project Capital Costs	-	(9,253)	(32,657)	(3,558)	(3,969)	(4,442)	-	-	-	-	-
Senior Debt Drawdown	181,140	6,940	24,493	2,669	2,977	3,332	-	-	-	-	-
sub-total	445,172	(2,313)	491,836	(890)	(992)	(1,111)	-	-	-	-	-
Net cash flow after investing activities	406,490	(299,763)	367,907	(12,445)	104,039	149,168	46,964	(5,671)	(40,609)	(9,689)	(44,157)
Cash Balance b/f	9,563	416,054	(96,500)	153,133	90,310	148,207	284,614	367,795	413,098	430,438	479,850
Cash Flow Available For Debt Service	416,054	116,291	271,407	140,688	194,350	297,374	331,578	362,124	372,489	420,749	435,693
	-	-	-	-	-	-	-	-	-	-	-
Repayment of Senior Debt Interest	-	(39,075)	(26,586)	(20,585)	(18,193)	(17,176)	(17,877)	(19,533)	(21,374)	(23,420)	(25,694)
Repayment of Senior Debt Principal	-	(256,926)	(72,388)	(60,419)	(46,013)	(25,226)	(2,829)	(3,051)	(3,296)	(3,566)	(3,864)
	-	-	-	-	-	-	-	-	-	-	-
Interest on cash balances	-	83,211	(19,300)	30,627	18,062	29,641	56,923	73,559	82,620	86,088	95,970
	-	-	-	-	-	-	-	-	-	-	-
Cash Balance c/f	416,054	(96,500)	153,133	90,310	148,207	284,614	367,795	413,098	430,438	479,850	502,105

Source: Management information

Ref: VRA Thermal CF - Section VR - Volta River Authority

Income statement- VRA Hydro

VRA Hydro forecast income statement

Currency: ¢ 000	FY08A	FY09F	FY10F	FY11F	FY12F	FY13F	FY14F	FY15F	FY16F	FY17F	FY18F
Revenue											
Wholesale market generation	-	-	-	-	589,797	692,540	821,028	974,574	1,159,594	1,383,155	1,654,033
Direct ECG revenues (current regime)	56,823	67,725	61,119	56,430	-	-	-	-	-	-	-
Direct NED revenues (current regime)	11,108	12,564	16,969	19,774	-	-	-	-	-	-	-
Bulk customer revenues	43,623	47,313	66,875	88,602	-	-	-	-	-	-	-
Bui management fee	-	-	-	-	-	-	-	-	-	-	-
Bui revenue	-	-	-	-	-	41,781	92,943	103,270	114,745	127,494	141,660
Total revenues	111,554	127,601	144,963	164,806	589,797	734,321	913,971	1,077,844	1,274,339	1,510,649	1,795,693
Operating Expenses	-	-	-	-	-	-	-	-	-	-	-
Recurrent direct expenditure	(8,431)	(9,905)	(11,311)	(17,808)	(20,690)	(35,073)	(37,957)	(41,095)	(44,512)	(48,236)	(51,411)
Central services	(7,820)	(10,034)	(10,476)	(11,872)	(59,764)	(69,885)	(80,651)	(90,620)	(96,053)	(107,108)	(113,053)
Bui opex	-	-	-	-	(11,651)	(13,399)	(15,409)	(17,720)	(20,378)	(23,435)	(26,950)
VRA Thermal subsidy	-	-	-	-	-	-	-	-	-	-	-
Total opex	(16,251)	(19,938)	(21,788)	(29,679)	(92,105)	(118,357)	(134,017)	(149,435)	(160,943)	(178,778)	(191,413)
Operating profit	95,303	107,663	123,175	135,127	497,692	615,965	779,954	928,409	1,113,396	1,331,870	1,604,280
Depreciation Expense	(16,369)	(21,026)	(20,990)	(22,580)	(23,621)	(43,321)	(42,400)	(41,513)	(40,659)	(39,835)	(39,038)
EBIT	78,934	86,637	102,186	112,546	474,071	572,644	737,555	886,896	1,072,737	1,292,036	1,565,243
Financing Costs	-	-	-	-	-	-	-	-	-	-	-
Senior Debt Interest	(1,388)	(1,260)	(1,234)	(1,179)	(38,796)	(42,955)	(44,972)	(64,113)	(66,104)	(67,446)	(67,918)
Financing charges	-	-	-	-	-	-	-	-	-	-	-
Interest on cash balances (overdraft)	-	(8,027)	(4,092)	(656)	5,189	26,358	60,428	114,237	177,589	258,891	361,197
Gain/(loss) on Foreign Exchange	-	-	(3,043)	(3,095)	(3,109)	(144,280)	(155,884)	(167,984)	(174,871)	(180,651)	(184,895)
Profit Before Tax	77,545	77,349	93,816	107,616	437,355	411,767	597,127	769,035	1,009,351	1,302,830	1,673,626
Tax	-	-	-	-	-	-	-	-	-	-	-
Profit After Tax	77,545	77,349	93,816	107,616	437,355	411,767	597,127	769,035	1,009,351	1,302,830	1,673,626
Dividends	-	-	-	-	-	-	-	-	-	-	-
Government assistance	-	-	-	-	-	-	-	-	-	-	-
Retained Profit	77,545	77,349	93,816	107,616	437,355	411,767	597,127	769,035	1,009,351	1,302,830	1,673,626
Asset Revaluation Reserve	264,997	-	-	-	-	-	-	-	-	-	-
Retained Profit & Reserves	342,542	77,349	93,816	107,616	437,355	411,767	597,127	769,035	1,009,351	1,302,830	1,673,626

Source: Management informaiton

Ref: VRA Hydro P&L - Section VR - Volta River Authority

Balance sheet- VRA Hydro

VRA Hydro forecast balance sheet

Currency: ¢ 000	FY08A	FY09F	FY10F	FY11F	FY12F	FY13F	FY14F	FY15F	FY16F	FY17F	FY18F
Current Assets											
Cash	-	-	-	64,862	329,480	755,345	1,427,959	2,219,860	3,236,138	4,514,964	6,122,143
Debtors	318,310	349,751	357,984	367,151	476,761	617,093	696,972	781,618	870,415	977,061	1,105,526
Total Fixed Assets	1,149,465	1,140,569	1,184,177	1,211,649	2,560,790	2,517,469	2,475,069	2,433,556	2,392,897	2,353,062	2,314,025
Total Assets	1,467,775	1,490,321	1,542,161	1,643,662	3,367,031	3,889,907	4,600,000	5,435,035	6,499,450	7,845,088	9,541,694
Current Liabilities	-										
Creditors and accurals	4,004	4,913	5,369	7,313	22,695	29,164	33,023	36,822	39,657	44,052	47,165
Overdraft	100,339	51,145	8,196	-	-	-	-	-	-	-	-
Current portion of long term loans	6,518	2,527	2,958	2,217	39,639	46,776	105,784	122,642	142,239	165,028	2,437
Non-current Liabilities	-										
Senior Debt	30,434	27,908	27,993	28,870	1,262,079	1,359,584	1,409,683	1,455,026	1,487,658	1,503,281	1,685,739
Total Liabilities	141,296	86,492	44,516	38,401	1,324,414	1,435,523	1,548,490	1,614,489	1,669,554	1,712,361	1,735,341
Net Assets	1,326,479	1,403,829	1,497,645	1,605,262	2,042,617	2,454,384	3,051,510	3,820,546	4,829,896	6,132,726	7,806,353
Owners Equity	-	-	-	-	-	-	-	-	-	-	-
GoG Equity	8,877	8,877	8,877	8,877	8,877	8,877	8,877	8,877	8,877	8,877	8,877
Retained Profits	64,605	141,955	235,771	343,387	780,743	1,192,509	1,789,636	2,558,671	3,568,022	4,870,852	6,544,479
	1,326,479	1,403,829	1,497,645	1,605,262	2,042,617	2,454,384	3,051,510	3,820,546	4,829,896	6,132,726	7,806,353

Source: Management information

Ref: VRA Hydro BS - Section VR - Volta River Authority

Cash flow statement- VRA Hydro

VRA Hydro forecast cash flow statement

Currency: ¢ 000	FY08A	FY09F	FY10F	FY11F	FY12F	FY13F	FY14F	FY15F	FY16F	FY17F	FY18F
Cash Inflow											
Sales Revenue	111,554	127,601	144,963	164,806	589,797	734,321	913,971	1,077,844	1,274,339	1,510,649	1,795,693
Increase in Debtors	(214,716)	(31,442)	(8,232)	(9,168)	(109,610)	(140,332)	(79,879)	(84,646)	(88,797)	(106,646)	(128,465)
	-	-	-	-	-	-	-	-	-	-	-
Increase in Creditors	4,004	909	456	1,945	15,382	6,469	3,859	3,799	2,836	4,395	3,113
	(99,157)	97,068	137,187	157,583	495,569	600,458	837,951	996,997	1,188,377	1,408,398	1,670,341
Cash Outflow	-	-	-	-	-	-	-	-	-	-	-
Operating costs	(16,251)	(19,938)	(21,788)	(29,679)	(92,105)	(118,357)	(134,017)	(149,435)	(160,943)	(178,778)	(191,413)
Operating Cash Flow	(115,408)	77,130	115,399	127,904	403,464	482,101	703,934	847,562	1,027,435	1,229,619	1,478,928
Taxation	-	-	-	-	-	-	-	-	-	-	-
Net Cash Flow	(115,408)	77,130	115,399	127,904	403,464	482,101	703,934	847,562	1,027,435	1,229,619	1,478,928
Capex and drawdowns	-	-	-	-	-	-	-	-	-	-	-
Project Capital Costs	-	(12,130)	(64,598)	(50,052)	(1,372,761)	-	-	-	-	-	-
Senior Debt Drawdown	-	-	-	-	1,269,740	-	-	-	-	-	-
sub-total	-	(12,130)	(64,598)	(50,052)	(103,021)	-	-	-	-	-	-
Net cash flow after investing activities	(115,408)	64,999	50,801	77,851	300,443	482,101	703,934	847,562	1,027,435	1,229,619	1,478,928
Cash Balance b/f	22,848	(100,339)	(51,145)	(8,196)	64,862	329,480	755,345	1,427,959	2,219,860	3,236,138	4,514,964
Cash Flow Available For Debt Service	(92,561)	(35,339)	(343)	69,655	365,305	811,581	1,459,279	2,275,521	3,247,295	4,465,758	5,993,892
	-	-	-	-	-	-	-	-	-	-	-
Repayment of Senior Debt Interest	(1,388)	(1,260)	(1,234)	(1,179)	(38,796)	(42,955)	(44,972)	(64,113)	(66,104)	(67,446)	(67,918)
Repayment of Senior Debt Principal	(6,390)	(6,518)	(2,527)	(2,958)	(2,217)	(39,639)	(46,776)	(105,784)	(122,642)	(142,239)	(165,028)
	-	-	-	-	-	-	-	-	-	-	-
Interest on cash balances	-	(8,027)	(4,092)	(656)	5,189	26,358	60,428	114,237	177,589	258,891	361,197
	-	-	-	-	-	-	-	-	-	-	-
Cash Balance c/f	(100,339)	(51,145)	(8,196)	64,862	329,480	755,345	1,427,959	2,219,860	3,236,138	4,514,964	6,122,143

Source: Management information

Ref: VRA Hydro CF - Section VR - Volta River Authority

Income statement-NED

NED forecast income statement

Currency: ¢ 000	FY08A	FY09F	FY10F	FY11F	FY12F	FY13F	FY14F	FY15F	FY16F	FY17F	FY18F
Revenue											
End user tariff	70,488	60,999	221,578	287,419	242,239	286,237	343,846	389,893	624,862	636,854	890,606
Other income	1,206	1,442	1,615	1,776	2,007	2,308	2,655	3,053	3,511	4,038	4,643
Total revenue	71,694	62,441	223,193	289,195	244,246	288,545	346,501	392,946	628,372	640,892	895,249
Total opex	(97,212)	(110,513)	(175,170)	(201,641)	(151,746)	(179,342)	(213,641)	(255,067)	(307,310)	(368,347)	(445,540)
	-	-	-	-	-	-	-	-	-	-	-
Operating profit	(25,518)	(48,072)	48,023	87,554	92,500	109,203	132,860	137,879	321,063	272,545	449,709
Depreciation expense	(8,573)	(9,961)	(11,007)	(12,962)	(16,331)	(19,528)	(22,700)	(26,265)	(26,708)	(29,632)	(30,569)
	-	-	-	-	-	-	-	-	-	-	-
EBIT	(34,091)	(58,033)	37,016	74,592	76,169	89,675	110,161	111,614	294,354	242,912	419,140
	-	-	-	-	-	-	-	-	-	-	-
Senior Debt Interest	(313)	(1,689)	(4,042)	(6,895)	(9,814)	(12,624)	(15,734)	(16,694)	(15,900)	(14,971)	(13,996)
Financing charges	-	-	-	-	-	-	-	-	-	-	-
Interest on cash balances (overdraft)	-	(25,394)	(44,764)	(2,545)	(1,221)	6,419	22,609	40,090	63,842	99,431	146,727
Gain/(loss) on foreign exchange	-	(61)	(669)	(725)	(785)	(850)	(919)	(992)	(1,071)	(1,153)	(1,241)
Profit Before Tax	(34,404)	(85,176)	(12,459)	64,427	64,349	82,620	116,116	134,017	341,225	326,219	550,631
	-	-	-	-	-	-	-	-	-	-	-
Tax	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-
Profit After Tax	(34,404)	(85,176)	(12,459)	64,427	64,349	82,620	116,116	134,017	341,225	326,219	550,631
	-	-	-	-	-	-	-	-	-	-	-
Dividends	-	-	-	-	-	-	-	-	-	-	-
Government assistance	-	-	250,000	-	-	-	-	-	-	-	-
Retained Profit	(34,404)	(85,176)	237,541	64,427	64,349	82,620	116,116	134,017	341,225	326,219	550,631
	-	-	-	-	-	-	-	-	-	-	-
Asset Revaluation Reserve	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-
Retained Profit & Reserves	(34,404)	(85,176)	237,541	64,427	64,349	82,620	116,116	134,017	341,225	326,219	550,631

Source: Management information

Ref: NED P&L - Section NE - NED

Balance sheet- NED

NED forecast balance sheet

Currency: ¢ 000	FY08A	FY09F	FY10F	FY11F	FY12F	FY13F	FY14F	FY15F	FY16F	FY17F	FY18F
Current Assets											
Cash	-	-	-	-	32,094	113,043	200,448	319,208	497,157	733,636	1,095,757
Debtors	46,579	61,965	99,295	155,169	160,357	160,197	185,393	211,118	280,573	341,668	407,429
Fixed Assets	-										
Total Fixed Assets	270,109	297,121	348,630	412,369	476,914	538,758	609,483	623,953	712,124	736,364	857,722
Total Assets	316,688	359,086	447,925	567,538	669,365	811,998	995,324	1,154,279	1,489,853	1,811,669	2,360,908
Current Liabilities	-	-	-	-	-	-	-	-	-	-	-
Creditors and accruals	23,954	27,231	43,163	49,686	37,391	44,191	52,642	62,850	75,723	90,763	109,784
Overdraft	126,968	223,820	12,723	6,106	-	-	-	-	-	-	-
Current portion of long term loans	346	1,092	2,971	5,563	8,666	12,229	16,814	19,594	20,597	21,654	22,767
Non-current Liabilities	-										
Senior Debt	6,627	33,326	77,911	130,598	183,375	233,025	287,198	299,148	279,621	259,121	237,594
Total Liabilities	157,895	285,469	136,767	191,953	229,432	289,445	356,654	381,592	375,942	371,538	370,146
Net Assets	158,793	73,617	311,157	375,584	439,933	522,553	638,669	772,686	1,113,912	1,440,131	1,990,762
Owners Equity	-										
Share Capital	576	576	250,576	250,576	250,576	250,576	250,576	250,576	250,576	250,576	250,576
Retained Profits	158,217	73,041	60,582	125,009	189,358	271,977	388,093	522,110	863,336	1,189,555	1,740,186
	158,793	73,617	311,157	375,584	439,933	522,553	638,669	772,686	1,113,912	1,440,131	1,990,762

Source: Management information

Ref: NED BS - Section NE - NED

Cash flow statement- NED

NED forecast cash flow statement

Currency: ¢ 000	FY08A	FY09F	FY10F	FY11F	FY12F	FY13F	FY14F	FY15F	FY16F	FY17F	FY18F
Cash Inflow											
Sales Revenue	71,694	62,441	223,193	289,195	244,246	288,545	346,501	392,946	628,372	640,892	895,249
Increase in Debtors	(8,661)	(15,386)	(37,330)	(55,874)	(5,188)	160	(25,196)	(25,725)	(69,455)	(61,095)	(65,760)
Increase in Creditors	(52,034)	3,277	15,932	6,523	(12,295)	6,800	8,451	10,208	12,873	15,040	19,021
	10,999	50,332	201,794	239,844	226,764	295,505	329,756	377,429	571,790	594,836	848,510
Cash Outflow											
Operating costs	(97,212)	(110,513)	(175,170)	(201,641)	(151,746)	(179,342)	(213,641)	(255,067)	(307,310)	(368,347)	(445,540)
Operating Cash Flow	(86,214)	(60,181)	26,625	38,203	75,018	116,163	116,115	122,361	264,480	226,489	402,970
Taxation	-	-	-	-	-	-	-	-	-	-	-
Net Cash Flow	(86,214)	(60,181)	26,625	38,203	75,018	116,163	116,115	122,361	264,480	226,489	402,970
Capex and drawdowns											
Project Capital Costs	(40,171)	(36,973)	(62,516)	(76,701)	(80,876)	(81,372)	(93,424)	(40,735)	(114,879)	(53,873)	(151,927)
Senior Debt Drawdown	-	27,730	46,887	57,526	60,657	61,029	70,068	30,552	-	-	-
sub-total	(40,171)	(9,243)	234,371	(19,175)	(20,219)	(20,343)	(23,356)	(10,184)	(114,879)	(53,873)	(151,927)
Net cash flow after investing activities	(126,385)	(69,424)	260,996	19,028	54,799	95,820	92,759	112,178	149,602	172,617	251,043
Cash Balance b/f	-	(126,968)	(223,820)	(12,723)	(6,106)	32,094	113,043	200,448	319,208	497,157	733,636
Cash Flow Available For Debt Service	(126,385)	(196,392)	37,176	6,305	48,693	127,914	205,802	312,626	468,809	669,773	984,679
	-	-	-	-	-	-	-	-	-	-	-
Repayment of Senior Debt Interest	(313)	(1,689)	(4,042)	(6,895)	(9,814)	(12,624)	(15,734)	(16,694)	(15,900)	(14,971)	(13,996)
Repayment of Senior Debt Principal	(270)	(346)	(1,092)	(2,971)	(5,563)	(8,666)	(12,229)	(16,814)	(19,594)	(20,597)	(21,654)
	-	-	-	-	-	-	-	-	-	-	-
Interest on cash balances	-	(25,394)	(44,764)	(2,545)	(1,221)	6,419	22,609	40,090	63,842	99,431	146,727
	-	-	-	-	-	-	-	-	-	-	-
Cash Balance c/f	(126,968)	(223,820)	(12,723)	(6,106)	32,094	113,043	200,448	319,208	497,157	733,636	1,095,757

Source: Management information

Ref: NED CF - Section NE - NED

Income statement- VRA Non Core

VRA Non core forecast income statement

Currency: ¢ 000	FY08A	FY09F	FY10F	FY11F	FY12F	FY13F	FY14F	FY15F	FY16F	FY17F	FY18F
Revenue											
Sales	4,923	5,886	6,592	7,251	8,194	9,423	10,836	12,462	14,331	16,481	18,953
Other income	40	48	53	59	66	76	88	101	116	133	153
Total revenue	4,963	5,933	6,645	7,310	8,260	9,499	10,924	12,563	14,447	16,614	19,106
Salaries & Related	(25,405)	(30,375)	(34,020)	(37,422)	(42,287)	(48,630)	(55,925)	(64,313)	(73,960)	(85,054)	(97,812)
Material & Hospital Costs	(2,176)	(2,601)	(2,914)	(3,205)	(3,622)	(4,165)	(4,790)	(5,508)	(6,334)	(7,285)	(8,377)
Transport & Travel	(1,107)	(1,323)	(1,482)	(1,630)	(1,842)	(2,119)	(2,436)	(2,802)	(3,222)	(3,706)	(4,261)
Operating expenditure	(5,695)	(6,809)	(7,626)	(8,388)	(9,479)	(10,901)	(12,536)	(14,416)	(16,579)	(19,065)	(21,925)
Repairs & Maintenance	(1,347)	(1,610)	(1,803)	(1,983)	(2,241)	(2,577)	(2,964)	(3,409)	(3,920)	(4,508)	(5,184)
Administration & General Expenses	(1,218)	(1,457)	(1,632)	(1,795)	(2,028)	(2,332)	(2,682)	(3,085)	(3,547)	(4,079)	(4,691)
Electricity & Water Usage	(2,029)	(2,426)	(2,717)	(2,989)	(3,377)	(3,884)	(4,466)	(5,136)	(5,907)	(6,793)	(7,812)
Total opex	(38,977)	(46,601)	(52,194)	(57,413)	(64,877)	(74,608)	(85,799)	(98,669)	(113,469)	(130,490)	(150,063)
	-	-	-	-	-	-	-	-	-	-	-
Operating profit	(34,014)	(40,668)	(45,548)	(50,103)	(56,616)	(65,109)	(74,875)	(86,106)	(99,022)	(113,876)	(130,957)
Depreciation	(3,457)	(3,572)	(3,801)	(3,936)	(4,014)	(3,933)	(3,846)	(3,763)	(3,676)	(3,586)	(3,498)
	-	-	-	-	-	-	-	-	-	-	-
EBIT	(37,471)	(44,240)	(49,349)	(54,039)	(60,631)	(69,042)	(78,721)	(89,869)	(102,698)	(117,461)	(134,455)
	-	-	-	-	-	-	-	-	-	-	-
Financing Costs	-	-	-	-	-	-	-	-	-	-	-
Senior Debt Interest	-	-	-	-	-	-	-	-	-	-	-
Financing charges	-	-	-	-	-	-	-	-	-	-	-
Interest on cash balances (overdraft)	-	(8,394)	(19,515)	(34,867)	(53,498)	(76,626)	(104,691)	(140,204)	(185,002)	(241,213)	(311,499)
Gain/(loss) on foreign exchange	-	-	-	-	-	-	-	-	-	-	-
Profit Before Tax	(37,471)	(52,635)	(68,864)	(88,906)	(114,129)	(145,668)	(183,412)	(230,073)	(287,700)	(358,675)	(445,954)
	-	-	-	-	-	-	-	-	-	-	-
Tax	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-
Profit After Tax	(37,471)	(52,635)	(68,864)	(88,906)	(114,129)	(145,668)	(183,412)	(230,073)	(287,700)	(358,675)	(445,954)
	-	-	-	-	-	-	-	-	-	-	-
Dividends	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-
Retained Profit	(37,471)	(52,635)	(68,864)	(88,906)	(114,129)	(145,668)	(183,412)	(230,073)	(287,700)	(358,675)	(445,954)
	-	-	-	-	-	-	-	-	-	-	-
Asset revaluation reserve	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-
Retained Profit and reserves	(37,471)	(52,635)	(68,864)	(88,906)	(114,129)	(145,668)	(183,412)	(230,073)	(287,700)	(358,675)	(445,954)

Source: Management information

Ref: Non core P&L - Section VR - Volta River Authority

Balance sheet- VRA Non Core

VRA Non- Core forecast balance sheet

Currency: ¢ 000	FY08A	FY09F	FY10F	FY11F	FY12F	FY13F	FY14F	FY15F	FY16F	FY17F	FY18F
Current Assets											
Cash	-	-	-	-	-	-	-	-	-	-	-
Debtors	1,223	1,462	1,637	1,801	2,035	2,341	2,692	3,096	3,560	4,094	4,708
Fixed Assets											
Balance c/f	137,533	142,140	151,238	156,612	159,725	156,474	153,036	149,720	146,258	142,672	139,174
Total Assets	138,756	143,602	152,875	158,413	161,761	158,815	155,727	152,815	149,818	146,766	143,882
Current Liabilities	-	-	-	-	-	-	-	-	-	-	-
Creditors and accruals	9,604	11,483	12,861	14,147	15,986	18,384	21,141	24,313	27,960	32,154	36,977
Overdraft	41,972	97,575	174,335	267,492	383,130	523,453	701,021	925,011	1,206,067	1,557,496	1,995,743
Current portion of long term loans	-	-	-	-	-	-	-	-	-	-	-
Non-current Liabilities											
Senior Debt	-	-	-	-	-	-	-	-	-	-	-
Total Liabilities	51,577	109,057	187,195	281,639	399,116	541,837	722,162	949,323	1,234,027	1,589,650	2,032,720
Net Assets	87,179	34,544	(34,320)	(123,226)	(237,355)	(383,023)	(566,435)	(796,508)	(1,084,209)	(1,442,884)	(1,888,838)
Owners Equity											
Share Capital	-	-	-	-	-	-	-	-	-	-	-
Retained Profits	87,179	34,544	(34,320)	(123,226)	(237,355)	(383,023)	(566,435)	(796,508)	(1,084,209)	(1,442,884)	(1,888,838)
	87,179	34,544	(34,320)	(123,226)	(237,355)	(383,023)	(566,435)	(796,508)	(1,084,209)	(1,442,884)	(1,888,838)

Source: Management information

Ref: Non core BS - Section VR - Volta River Authority

Cash flow statement- VRA Non Core

VRA Non core cash flow statement

Currency: ¢ 000	FY08A	FY09F	FY10F	FY11F	FY12F	FY13F	FY14F	FY15F	FY16F	FY17F	FY18F
Sales Revenue	4,963	5,933	6,645	7,310	8,260	9,499	10,924	12,563	14,447	16,614	19,106
Increase in Debtors	(1,223)	(239)	(175)	(164)	(234)	(305)	(351)	(404)	(464)	(534)	(614)
Increase in Creditors	9,604	1,879	1,378	1,286	1,839	2,398	2,758	3,171	3,647	4,194	4,823
	13,344	7,573	7,848	8,432	9,865	11,592	13,331	15,330	17,630	20,274	23,315
	-	-	-	-	-	-	-	-	-	-	-
Cash Outflow	-	-	-	-	-	-	-	-	-	-	-
Operating costs	(38,977)	(46,601)	(52,194)	(57,413)	(64,877)	(74,608)	(85,799)	(98,669)	(113,469)	(130,490)	(150,063)
	-	-	-	-	-	-	-	-	-	-	-
Operating Cash Flow	(25,633)	(39,028)	(44,346)	(48,981)	(55,011)	(63,016)	(72,469)	(83,339)	(95,840)	(110,216)	(126,748)
	-	-	-	-	-	-	-	-	-	-	-
Taxation	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-
Net Cash Flow	(25,633)	(39,028)	(44,346)	(48,981)	(55,011)	(63,016)	(72,469)	(83,339)	(95,840)	(110,216)	(126,748)
	-	-	-	-	-	-	-	-	-	-	-
Capex and drawdowns	-	-	-	-	-	-	-	-	-	-	-
Project Capital Costs	(16,340)	(8,179)	(12,900)	(9,310)	(7,128)	(681)	(408)	(447)	(215)	-	-
Senior Debt Drawdown	-	-	-	-	-	-	-	-	-	-	-
Equity Drawdown	-	-	-	-	-	-	-	-	-	-	-
sub-total	(16,340)	(8,179)	(12,900)	(9,310)	(7,128)	(681)	(408)	(447)	(215)	-	-
	-	-	-	-	-	-	-	-	-	-	-
	(41,972)	-	-	-	-	-	-	-	-	-	-
Cash Balance b/f	-	(41,972)	(97,575)	(174,335)	(267,492)	(383,130)	(523,453)	(701,021)	(925,011)	(1,206,067)	(1,557,496)
	-	-	-	-	-	-	-	-	-	-	-
Cash Flow Available For Debt Service	(41,972)	(89,180)	(154,820)	(232,625)	(329,632)	(446,827)	(596,330)	(784,807)	(1,021,065)	(1,316,283)	(1,684,244)
Interest due	-	-	-	-	-	-	-	-	-	-	-
Debt repayment	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-
Interest on cash balances	-	(8,394)	(19,515)	(34,867)	(53,498)	(76,626)	(104,691)	(140,204)	(185,002)	(241,213)	(311,499)
	-	-	-	-	-	-	-	-	-	-	-
Cash Balance c/f	(41,972)	(97,575)	(174,335)	(267,492)	(383,130)	(523,453)	(701,021)	(925,011)	(1,206,067)	(1,557,496)	(1,995,743)

Source: Management information

Ref: Non core cash flow - Section VR - Volta River Authority

Income statement- ECG

ECG forecast income statement

Currency: ¢ 000	FY08F	FY09F	FY10F	FY11F	FY12F	FY13F	FY14F	FY15F	FY16F	FY17F	FY18F
Revenue											
End user tariff	570,018	600,138	856,282	1,137,202	1,452,258	1,806,334	2,201,546	2,612,167	3,332,766	4,119,369	4,975,096
Public lighting levy	345	364	391	424	458	494	531	563	594	625	657
Customer contribution	3,692	6,767	6,837	6,970	7,187	7,514	7,973	8,581	9,361	10,346	11,576
Total revenue	574,056	607,269	863,510	1,144,596	1,459,903	1,814,342	2,210,050	2,621,311	3,342,720	4,130,339	4,987,328
Purchased power	(411,233)	(387,030)	(650,572)	(837,479)	(1,028,076)	(1,244,978)	(1,388,960)	(1,677,773)	(2,082,856)	(2,584,805)	(3,190,636)
Transmission service charge	(51,300)	(54,558)	(115,845)	(123,314)	(130,647)	(138,154)	(145,877)	(153,850)	(162,080)	(170,575)	(179,343)
Increase/(decrease) in bad debts	(5,700)	(6,001)	(8,563)	(11,372)	(14,523)	(18,063)	(22,015)	(26,122)	(33,328)	(41,194)	(49,751)
Distribution Operation & Maintenance	(13,993)	(17,614)	(21,209)	(25,321)	(30,897)	(38,282)	(47,347)	(57,772)	(69,992)	(84,710)	(102,424)
Transport	(6,354)	(7,998)	(9,630)	(11,497)	(14,029)	(17,383)	(21,499)	(26,233)	(31,781)	(38,464)	(46,507)
Staff Costs	(46,277)	(56,326)	(64,202)	(70,622)	(79,803)	(91,773)	(105,539)	(121,370)	(139,576)	(160,512)	(184,589)
Other Administrative Expenses	(23,123)	(29,107)	(35,048)	(41,843)	(51,057)	(63,261)	(78,240)	(95,468)	(115,662)	(139,983)	(169,255)
Total opex	(557,979)	(558,634)	(905,069)	(1,121,448)	(1,349,032)	(1,611,895)	(1,809,477)	(2,158,587)	(2,635,274)	(3,220,242)	(3,922,505)
	-	-	-	-	-	-	-	-	-	-	-
Operating profit	16,077	48,635	(41,558)	23,148	110,870	202,447	400,573	462,724	707,446	910,097	1,064,823
Depreciation expense	(77,161)	(37,542)	(41,591)	(41,442)	(42,530)	(50,149)	(58,976)	(69,146)	(75,609)	(82,924)	(91,524)
	-	-	-	-	-	-	-	-	-	-	-
EBIT	(61,085)	11,092	(83,149)	(18,294)	68,341	152,298	341,597	393,578	631,837	827,172	973,299
Senior Debt Interest	3,462	(10,995)	(12,578)	(14,746)	(20,664)	(27,737)	(35,599)	(41,700)	(40,031)	(37,788)	(35,381)
Financing charges	-	-	-	-	-	-	-	-	-	-	-
Interest on cash balances (overdraft)	-	5,267	(8,950)	14,275	8,562	5,005	5,023	16,408	34,845	54,550	88,221
Gain/(loss) on foreign exchange	-	(4,130)	(7,209)	(6,684)	(6,734)	(6,574)	(5,959)	(6,172)	(6,341)	(6,453)	(6,487)
Profit Before Tax	(57,622)	1,235	(111,887)	(25,449)	49,505	122,992	305,062	362,114	620,310	837,482	1,019,652
	-	-	-	-	-	-	-	-	-	-	-
Tax	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-
Profit After Tax	25,082	1,235	(111,887)	(25,449)	49,505	122,992	305,062	362,114	620,310	837,482	1,019,652
	-	-	-	-	-	-	-	-	-	-	-
Dividends	-	-	-	-	-	-	-	-	-	-	-
Government assistance	-	-	400,000	-	-	-	-	-	-	-	-
Retained Profit	25,082	1,235	288,113	(25,449)	49,505	122,992	305,062	362,114	620,310	837,482	1,019,652
	-	-	-	-	-	-	-	-	-	-	-
Asset Revaluation Reserve	247,941	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-
Retained Profit & Reserves	273,023	1,235	288,113	(25,449)	49,505	122,992	305,062	362,114	620,310	837,482	1,019,652

Source: Management informaiton

Ref: ECG P&L - Section EC - ECG

Balance sheet- ECG

ECG forecast balance sheet

Currency: ¢ 000	FY08A	FY09F	FY10F	FY11F	FY12F	FY13F	FY14F	FY15F	FY16F	FY17F	FY18F
Current Assets											
Cash (Including short term investments)	65,832	-	178,437	107,029	62,564	62,792	205,101	435,566	681,875	1,102,758	1,950,632
Debtors	258,033	266,217	329,357	398,618	476,312	563,648	661,153	762,491	940,250	1,134,325	1,345,493
Stock	135,852	171,010	205,914	245,836	299,976	371,677	459,680	560,902	679,543	822,434	994,418
Fixed Assets											
Total Fixed Assets	1,036,283	1,145,184	1,154,323	1,180,391	1,310,401	1,470,555	1,656,526	1,778,473	1,925,581	2,098,782	2,007,259
Total Assets	1,639,238	1,725,005	2,015,854	2,083,406	2,304,565	2,628,288	3,144,933	3,705,635	4,403,491	5,344,501	6,496,023
Current Liabilities	-	-	-	-	-	-	-	-	-	-	-
Creditors and accruals	242,443	110,289	190,960	239,548	289,095	345,264	383,619	457,760	561,379	689,094	842,644
Overdraft	-	111,876	-	-	-	-	-	-	-	-	-
Current portion of long term loans	9,450	12,988	16,093	19,240	27,584	27,464	39,641	51,133	54,279	57,682	-
Non-current Liabilities											
Senior Debt	79,026	180,000	209,164	247,240	355,796	492,633	642,662	741,020	693,082	641,852	648,339
Total Liabilities	537,575	622,107	624,843	717,843	889,498	1,090,229	1,301,812	1,500,400	1,577,946	1,681,473	1,813,343
Net Assets	1,101,664	1,102,898	1,391,012	1,365,563	1,415,067	1,538,059	1,843,121	2,205,235	2,825,545	3,663,028	4,682,680
Owners Equity											
Stated Capital	5	5	5	5	5	5	5	5	5	5	5
Government Equity	8,064	8,064	408,064	408,064	408,064	408,064	408,064	408,064	408,064	408,064	408,064
Revaluation Surplus	932,330	932,330	932,330	932,330	932,330	932,330	932,330	932,330	932,330	932,330	932,330
Income Surplus	161,265	162,500	50,613	25,164	74,669	197,660	502,723	864,837	1,485,147	2,322,629	3,342,281
	1,101,664	1,102,898	1,391,012	1,365,563	1,415,067	1,538,059	1,843,121	2,205,235	2,825,545	3,663,028	4,682,680

Source: Management information

Ref: ECG BS - Section EC - ECG

Cash flow statement- ECG

ECG forecast cash flow statement

Currency: ¢ 000	FY09F	FY10F	FY11F	FY12F	FY13F	FY14F	FY15F	FY16F	FY17F	FY18F
Cash Inflow										
Sales Revenue	607,269	863,510	1,144,596	1,459,903	1,814,342	2,210,050	2,621,311	3,342,720	4,130,339	4,987,328
Increase in Debtors	(8,184)	(63,140)	(69,261)	(77,694)	(87,336)	(97,505)	(101,337)	(177,760)	(194,075)	(211,168)
Change in stock	(35,159)	(34,904)	(39,922)	(54,139)	(71,701)	(88,003)	(101,222)	(118,641)	(142,892)	(171,983)
Increase in Creditors	(132,154)	80,671	48,588	49,548	56,168	38,355	74,142	103,619	127,715	153,550
Increase in prepayments	644	(5,229)	(3,709)	(3,782)	(4,304)	(2,857)	(5,731)	(8,038)	(9,960)	(12,021)
	432,416	840,909	1,080,292	1,373,836	1,707,169	2,060,040	2,487,163	3,141,901	3,911,129	4,745,706
Cash Outflow										
Operating costs	(558,634)	(905,069)	(1,121,448)	(1,349,032)	(1,611,895)	(1,809,477)	(2,158,587)	(2,635,274)	(3,220,242)	(3,922,505)
	-	-	-	-	-	-	-	-	-	-
Operating Cash Flow	(126,218)	(64,160)	(41,156)	24,803	95,274	250,563	328,575	506,627	690,886	823,201
	-	-	-	-	-	-	-	-	-	-
Taxation	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-
Net Cash Flow	(126,218)	(64,160)	(41,156)	24,803	95,274	250,563	328,575	506,627	690,886	823,201
	-	-	-	-	-	-	-	-	-	-
Capex and drawdowns										
Project Capital Costs	(146,443)	(50,730)	(67,509)	(172,539)	(210,303)	(244,947)	(191,092)	(222,718)	(256,125)	-
Disposal of fixed assets	-	-	-	-	-	-	-	-	-	-
Government and customer contributions	299	1,672	3,189	5,209	7,845	11,022	14,597	18,719	23,639	29,516
Government grant	-	-	-	-	-	-	-	-	-	-
Senior Debt Drawdown	109,832	38,048	50,632	129,405	157,727	183,711	143,319	-	-	-
Equity Drawdown	-	400,000	-	-	-	-	-	-	-	-
sub-total	(36,311)	388,989	(13,689)	(37,926)	(44,731)	(50,215)	(33,176)	(203,999)	(232,487)	29,516
	-	-	-	-	-	-	-	-	-	-
Net cash flow after investing activities	(162,530)	324,830	(54,845)	(13,123)	50,543	200,348	295,399	302,628	458,399	852,717
Cash Balance b/f	65,832	(111,876)	178,437	107,029	62,564	62,792	205,101	435,566	681,875	1,102,758
	-	-	-	-	-	-	-	-	-	-
Cash Flow Available For Debt Service	(96,697)	212,954	123,593	93,906	113,108	263,140	500,499	738,194	1,140,275	1,955,474
	-	-	-	-	-	-	-	-	-	-
Repayment of Senior Debt Interest	(10,995)	(12,578)	(14,746)	(20,664)	(27,737)	(35,599)	(41,700)	(40,031)	(37,788)	(35,381)
Repayment of Senior Debt Principal	(9,450)	(12,988)	(16,093)	(19,240)	(27,584)	(27,464)	(39,641)	(51,133)	(54,279)	(57,682)
	-	-	-	-	-	-	-	-	-	-
Interest on cash balances	5,267	(8,950)	14,275	8,562	5,005	5,023	16,408	34,845	54,550	88,221
	-	-	-	-	-	-	-	-	-	-
Cash Balance c/f	(111,876)	178,437	107,029	62,564	62,792	205,101	435,566	681,875	1,102,758	1,950,632

Source: Management information

Ref: ECG CF - Section EC - ECG

Income statement- GRIDCO

GRIDCO forecast income statement

Currency: ¢ 000	FY08A	FY09F	FY10F	FY11F	FY12F	FY13F	FY14F	FY15F	FY16F	FY17F	FY18F
Transmission tariff	75,942	79,842	177,016	195,737	208,831	217,354	227,191	237,453	248,251	262,985	275,710
Wheeling income (CEB) (Wholesale)	5,653	4,321	5,272	5,863	6,549	7,476	8,597	9,887	11,370	13,075	15,036
Total revenues	81,595	84,164	182,288	201,600	215,380	224,829	235,788	247,339	259,621	276,060	290,746
Operating expenses	-	-	-	-	-	-	-	-	-	-	-
Purchase of losses	-	-	(24,872)	(26,255)	(29,120)	(35,425)	(43,538)	(55,728)	(71,245)	(92,490)	(118,505)
Salaries and related costs	(11,591)	(19,728)	(25,646)	(28,211)	(31,878)	(36,660)	(42,159)	(48,482)	(55,755)	(64,118)	(73,736)
Other Operating Costs	(27,027)	(10,935)	(12,926)	(15,315)	(17,306)	(19,902)	(22,887)	(26,321)	(30,269)	(34,809)	(40,030)
Total opex	(38,619)	(30,663)	(63,444)	(69,781)	(78,304)	(91,987)	(108,584)	(130,530)	(157,269)	(191,417)	(232,270)
Operating profit	42,976	53,501	118,844	131,819	137,076	132,843	127,205	116,809	102,352	84,643	58,476
Depreciation Expense	(9,487)	(10,736)	(14,789)	(19,681)	(25,024)	(30,899)	(29,939)	(29,010)	(28,110)	(27,238)	(26,393)
EBIT	33,489	42,765	104,055	112,138	112,052	101,944	97,265	87,799	74,242	57,405	32,083
Financing Costs	-	-	-	-	-	-	-	-	-	-	-
Senior Debt Interest	(4,736)	(10,035)	(16,247)	(22,887)	(30,001)	(28,568)	(26,467)	(24,755)	(22,802)	(21,463)	(20,058)
Financing charges	-	-	-	-	-	-	-	-	-	-	-
Interest on cash balances (overdraft)	515	(11,508)	(15,148)	7,613	16,465	24,429	42,530	64,677	89,206	117,756	148,610
Gain/(loss) on foreign exchange	-	(7,280)	(4,866)	(3,895)	(3,868)	(3,411)	(2,331)	(1,779)	(1,006)	(1,081)	(1,159)
Profit Before Tax	29,269	13,941	67,794	92,969	94,648	94,394	110,997	125,942	139,640	152,617	159,476
Tax	-	-	-	-	-	-	-	-	-	-	-
Profit After Tax	29,269	13,941	67,794	92,969	94,648	94,394	110,997	125,942	139,640	152,617	159,476
Government assistance	-	-	100,000	-	-	-	-	-	-	-	-
Retained Profit	29,269	13,941	167,794	92,969	94,648	94,394	110,997	125,942	139,640	152,617	159,476
Asset Revaluation Reserve	-	-	-	-	-	-	-	-	-	-	-
Retained Profits & Reserves	29,269	13,941	167,794	92,969	94,648	94,394	110,997	125,942	139,640	152,617	159,476

Source: Management information

Ref: GRIDCO P&L - Section GR - NED

Balance sheet- GRIDCO

GRIDCO forecast balance sheet

Currency: ¢ 000	FY08F	FY09F	FY10F	FY11F	FY12F	FY13F	FY14F	FY15F	FY16F	FY17F	FY18F
Current Assets											
Cash	-	-	38,064	82,324	122,146	212,648	323,383	446,032	588,778	743,048	905,295
Debtors	44,679	45,312	69,490	74,249	77,645	79,973	82,673	85,520	88,546	92,596	96,215
Stock	360	146	172	204	231	265	305	351	403	464	533
Fixed Assets											
Total Fixed Assets	346,775	477,640	635,591	808,025	997,602	966,704	936,765	907,755	879,645	852,407	826,014
Total Assets	391,814	523,098	743,317	964,803	1,197,623	1,259,590	1,343,126	1,439,657	1,557,373	1,688,516	1,828,058
Current Liabilities	-	-	-	-	-	-	-	-	-	-	-
Creditors and accruals	9,516	7,555	15,633	17,194	19,295	22,666	26,756	32,164	38,752	47,166	57,233
Overdraft	57,542	75,740	-	-	-	-	-	-	-	-	-
Current portion of long term loans	12,376	14,333	21,027	28,746	39,211	33,881	36,598	29,519	30,968	31,159	32,747
Non-current Liabilities											
Senior Debt	57,833	156,982	270,377	389,612	515,220	484,750	450,483	422,744	392,781	362,703	331,115
Total Liabilities	137,267	254,610	307,036	435,553	573,726	541,298	513,837	484,426	462,501	441,028	421,095
Net Assets	254,547	268,487	436,281	529,250	623,898	718,292	829,289	955,231	1,094,871	1,247,488	1,406,964
Owners Equity											
Investment by GoG	252,004	252,004	352,004	352,004	352,004	352,004	352,004	352,004	352,004	352,004	352,004
Income Surplus Account	(77,027)	(63,086)	4,708	97,677	192,324	286,719	397,716	523,657	663,298	815,914	975,390
Capital Surplus	79,570	79,570	79,570	79,570	79,570	79,570	79,570	79,570	79,570	79,570	79,570
Debt Contingency Fund Reserve	-	-	-	-	-	-	-	-	-	-	-
	254,547	268,487	436,281	529,250	623,898	718,292	829,289	955,231	1,094,871	1,247,488	1,406,964

Source: Management information

Ref: GRIDCO BS - Section GR - NED

GRIDCO forecast cash flow statement

Currency: ¢ 000	FY08A	FY09F	FY10F	FY11F	FY12F	FY13F	FY14F	FY15F	FY16F	FY17F	FY18F
Cash Inflow											
Sales Revenue	81,595	84,164	182,288	201,600	215,380	224,829	235,788	247,339	259,621	276,060	290,746
Increase in Debtors	(44,679)	(633)	(24,178)	(4,759)	(3,395)	(2,328)	(2,700)	(2,846)	(3,026)	(4,051)	(3,619)
Change in stock	(233)	214	(27)	(32)	(27)	(35)	(40)	(46)	(53)	(60)	(70)
Increase in Creditors	9,516	(1,960)	8,078	1,561	2,100	3,371	4,090	5,408	6,588	8,414	10,067
	46,199	81,785	166,160	198,371	214,058	225,838	237,138	249,855	263,130	280,363	297,125
Cash Outflow	-										
Operating costs	(38,619)	(30,663)	(63,444)	(69,781)	(78,304)	(91,987)	(108,584)	(130,530)	(157,269)	(191,417)	(232,270)
Operating Cash Flow	7,580	51,122	102,716	128,590	135,754	133,851	128,554	119,325	105,862	88,946	64,854
Taxation	-	-	-	-	-	-	-	-	-	-	-
Net Cash Flow	7,580	51,122	102,716	128,590	135,754	133,851	128,554	119,325	105,862	88,946	64,854
Capex and drawdowns	-										
Project Capital Costs	(50,259)	(141,602)	(172,740)	(192,116)	(214,601)	-	-	-	-	-	-
Senior Debt Drawdown	-	106,201	129,555	144,087	160,951	-	-	-	-	-	-
sub-total	(50,259)	(35,400)	56,815	(48,029)	(53,650)	-	-	-	-	-	-
Net cash flow after investing activities	(42,678)	15,722	159,531	80,561	82,104	133,851	128,554	119,325	105,862	88,946	64,854
Cash Balance b/f	-	(57,542)	(75,740)	38,064	82,324	122,146	212,648	323,383	446,032	588,778	743,048
Cash Flow Available For Debt Service	(42,678)	(41,821)	83,791	118,625	164,428	255,997	341,202	442,708	551,894	677,724	807,902
	-	-	-	-	-	-	-	-	-	-	-
Repayment of Senior Debt Interest	(4,736)	(10,035)	(16,247)	(22,887)	(30,001)	(28,568)	(26,467)	(24,755)	(22,802)	(21,463)	(20,058)
Repayment of Senior Debt Principal	(10,643)	(12,376)	(14,333)	(21,027)	(28,746)	(39,211)	(33,881)	(36,598)	(29,519)	(30,968)	(31,159)
	-	-	-	-	-	-	-	-	-	-	-
Interest on cash balances	515	(11,508)	(15,148)	7,613	16,465	24,429	42,530	64,677	89,206	117,756	148,610
	-	-	-	-	-	-	-	-	-	-	-
Cash Balance c/f	(57,542)	(75,740)	38,064	82,324	122,146	212,648	323,383	446,032	588,778	743,048	905,295

Source: Management information

Ref: GRIDCO CF - Section GR - NED

Appendix B- Energy forecast

Projected system energy supply

GWh	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
VRA Hydrogeneration											
- Akosomdo Hydro Plant	6,196	5,402	4,415	4,415	4,415	4,415	4,415	4,415	4,415	4,415	4,415
- Kpong Hydro Plant	-	1,029	885	885	885	885	885	885	885	885	885
- Bui Hydro Plant	-	-	-	-	-	500	1,000	1,000	1,000	1,000	1,000
Total Hydro Production	6,196	6,431	5,300	5,300	5,300	5,800	6,300	6,300	6,300	6,300	6,300
VRA Thermal Generation											
- Takoradi Thermal Simple Cycle	153	-	-	-	-	-	-	-	-	-	-
- Takoradi Thermal Combined Cycle	721	960	1,840	1,840	1,840	1,840	1,840	1,840	1,840	1,840	1,840
- Mines Reserve Plant	41	2	263	263	-	-	-	-	-	-	-
- Tema Thermal Plant I (Simple Cycle)	-	683	745	745	745	745	745	745	745	745	745
- Tema Thermal 2 Power Plant (Combined Cycle)	-	-	335	335	-	-	-	-	89	335	335
- Takoradi 3 Thermal Power Plant	-	-	-	-	894	483	-	369	894	894	894
- Kpone Thermal Power Plant (KT1PP)	-	-	-	-	645	-	-	-	-	592	1,316
- Kpone Thermal Power Plant (KT2PP)	-	-	-	-	-	-	-	-	-	-	-
Total Thermal Production	915	1,646	3,182	3,182	4,123	3,067	2,584	2,953	3,567	4,405	5,129
Total VRA Generation	7,111	8,077	8,482	8,482	9,423	8,867	8,884	9,253	9,867	10,705	11,429
VRA Thermal JV											
- TICO - T2 Simple cycle	1,063	1,020	1,402	1,402	1,402	1,402	1,402	1,402	1,402	1,402	1,402
- TICO Expansion	-	-	-	-	-	701	701	701	701	701	701
Total Thermal JV production	1,063	1,020	1,402	1,402	1,402	2,102	2,102	2,102	2,102	2,102	2,102
Imports											
- CIE	275	151	-	-	-	-	-	-	-	-	-
Total VRA Demand	8,448	9,248	9,884	9,884	10,825	10,970	10,987	11,356	11,970	12,808	13,531
IPP PPAs											
- 200MW Sunon-Asogli Shenzen Energy Group	-	-	-	-	-	-	-	-	-	-	-
- 126 MW OSONOR Plant	-	-	-	745	745	745	745	745	745	745	745
- Osagyefo barge	-	-	-	-	329	657	657	657	657	657	657
- OSNOR & VRA expansion	-	-	-	-	-	-	530	745	745	745	745
- Canadian Energy Solutions Consortium (GH) Ltd	-	-	-	-	-	-	-	-	-	-	-
Total PPAs	-	-	-	745	1,073	1,402	1,931	2,146	2,146	2,146	2,146
Total Energy Sent Out	8,448	9,248	9,884	10,628	11,898	12,371	12,918	13,502	14,116	14,954	15,678

Source: VRA

Ref: Supply - Section BS - Balance Sheet Analysis

Adjusted energy supply projection

GWh	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
VRA Hydrogeneration											
- Akosomdo Hydro Plant	6,196	5,402	4,415	4,415	4,415	4,415	4,415	4,415	4,415	4,415	4,415
- Kpong Hydro Plant	-	1,029	885	885	885	885	885	885	885	885	885
- Bui Hydro Plant	-	-	-	-	-	500	1,000	1,000	1,000	1,000	1,000
Total Hydro Production	6,196	6,431	5,300	5,300	5,300	5,800	6,300	6,300	6,300	6,300	6,300
VRA Thermal Generation											
- Takoradi Thermal Simple Cycle	153	-	-	-	-	-	-	-	-	-	-
- Takoradi Thermal Combined Cycle	721	960	1,840	1,840	1,840	1,840	1,840	1,840	1,840	1,840	1,840
- Mines Reserve Plant	41	2	263	263	-	-	-	-	-	-	-
- Tema Thermal Plant I (Simple Cycle)	-	683									
- Tema Thermal 2 Power Plant (Combined Cycle)	-										
- Takoradi 3 Thermal Power Plant	-										
- Kpone Thermal Power Plant (KT1PP)	-										
- Kpone Thermal Power Plant (KT2PP)	-	-	-	-	-	-	-	-	-	-	-
Total Thermal Production	915	1,646	2,102	2,102	1,840	1,840	1,840	1,840	1,840	1,840	1,840
Total VRA Generation	7,111	8,077	7,402	7,402	7,140	7,640	8,140	8,140	8,140	8,140	8,140
VRA Thermal JV											
- TICO - T2 Simple cycle	1,063	1,020	1,402	1,402	1,402	1,402	1,402	1,402	1,402	1,402	1,402
- TICO Expansion											
Total Thermal JV production	1,063	1,020	1,402	1,402	1,402	1,402	1,402	1,402	1,402	1,402	1,402
Imports											
- CIE	275	151	-	-	-	-	-	-	-	-	-
Total VRA Demand	8,448	9,248	8,804	8,804	8,541	9,041	9,541	9,541	9,541	9,541	9,541
IPP PPAs											
- 200MW Sunon-Asogli Shenzen Energy Group	-		1,077	1,077	1,077	1,077	1,077	1,077	1,077	1,077	1,077
- 126 MW OSONOR Plant	-	-	-	745	745	745	745	745	745	745	745
- Osagyefo barge	-	-	-	-	329	657	657	657	657	657	657
- OSNOR & VRA expansion	-	-	-	-	-	-	530	745	745	745	745
- Canadian Energy Solutions Consortium (GH) Ltd	-	-	-		1,207	851	368	738	1,351	2,189	2,913
Total PPAs	-	-	-	745	2,280	2,253	2,300	2,884	3,498	4,336	5,059
Total Energy Sent Out	8,448	9,248	8,804	9,549	10,821	11,294	11,841	12,425	13,039	13,877	14,601

Source: VRA, EY Analysis

Ref: Supply - Section BS - Balance Sheet Analysis

Appendix D- List of Laws reviewed and ECG PPAs to be abrogated

Appendix D: List of Laws Reviewed

No.	Name of Law
1	1992 Fourth Republican Constitution
2	Volta River Authority Act 1961, Act as amended
3	Volta River Authority (Amendment) Act, 2005, Act692
4	Financial Administration Act, 2003, Act 654
5	Public Procurement Act, 2003 Act 663
6	Statutory Corporations (Conversion to Companies) Act 1993, Act 461
7	Energy Commission Act, 1997, Act 541
8	West Africa Gas Pipeline Project Agreement
9	West Africa Gas Pipeline Treaty
10	West Africa Gas Pipeline Act, 2004, Act 681
11	Loans Act, 1970, Act 335
12	Lenders and Borrowers Act
13	Sub vented Agencies Act, 2006, Act 706
14	Insolvency Act , Act 708
15	Divestiture of State Interests (Implementation) Law, 1993, PNDCL 326
16	Companies Code, 1963, Act 179 as amended
17	Internal Revenue Act, 2000, Act 592 as amended
18	Ghana Investment Promotion Centre Act, 1994, Act 478
19	Technology Transfer Regulations, 1992, LI 1547
20	Civil Service Law, 1993, PNDCL 327
21	Public Utilities Regulatory Commission Act, Act 538
22	Electricity Supply and Distribution (Technical and Operational Rules)2002, LI 1720
23	Electricity Supply & Distribution (Standards of Performance) , 2008, LI 1816
24	Energy Commission Act
25	Public Utilities(Complaints Procedure) Regulations, 1999, LI 1665
26	State Enterprises Commission Act, ….....
27	Water Resources Commission Act , 1996, Act 522
28	Water Use Regulations 2001 LI 1692
29	Bui Power Authority Act, 2007, Act 740.
30	Electricity (Special Levies) Act, 1995, Act 497

List of ECG PPAs to be abrogated

Company	Date of Contract	Energy to be generated (GWh)	Term /Renewal	Conditions Precedent (CPs)	Liabilities /Event s of default	Commencement /Status	Comments
Tropical Resources	27th November, 2007	50	15 years renewable every 5 years	• Coming into force of a raw material contract between the seller and Tema Metropolitan Authority • Completion of interconnection network between the Seller's Plant and ECG's Dawhenya Primary substation • Financial close	ECG can terminate the agreement where the aggregate energy supplied to ECG is less than 85% of the anticipated annual energy (i.e. the aggregate of net electrical output of the plant within a calendar year) over a 60 day period.	2nd February, 2009 Construction yet to commence	The agreement will be deemed not effective in the absence of the fulfillment of the CPs The events of default based on which ECG can terminate have not kicked in as the construction is yet to commence ECG can terminate the agreement
Trans Tema Power	22nd August, 2007	50	1 ½ renewable every quarter		ECG can terminate the agreement in the following circumstances: • Assignment /transfer of agreement without ECG's consent • Failure of seller to make payments required under the agreement within 14 day • Restructuring/winding up of seller • Supply of less than 85% of the dependable capacity(i.e. 50MW continuous supply from the plant) the net electrical output (i.e.	4th August, 2007 Expired	The agreement has terminated on the expiration of the term

List of ECG PPAs to be abrogated

Company	Date of Contract	Energy to be generated (GWh)	Term /Renewal	Conditions Precedent (CPs)	Liabilities /Event s of default	Commencement /Status	Comments
					the power measured in KWh at the delivery point) to ECG over a period of30 days		
Rare Ventures	14th April, 2008	36	15 years renewable every 5 years	• Coming into force of a raw material contract between the seller and Shama Ahanta East Metropolitan Assembly • Completion of interconnection network between the Seller's Plant and ECG's Primary substation at Takoradi • Financial close	ECG can terminate the agreement where the aggregate energy supplied to ECG is less than 85% of the anticipated annual energy(i.e. the aggregate of net electrical output of the plant within a calendar year) over a 60 day period and this failure is not cured within 35 days.	1st October , 2008 Construction yet to commence	The agreement will be deemed not effective in the absence of the fulfillment of the CPs The events of default based on which ECG can terminate have not kicked in as the construction is yet to commence ECG can terminate the agreement
Lushann Int Power	20th May,2008	380	20		Where any of the CPs have not been waived or any extensions granted within 2 years of the date of the agreement(may 20, 2009), the agreement shall be deemed to be terminated and neither party shall have any liability to the other (except liabilities related to confidentiality)	19th May, 2010 Construction yet to commence	ECG can terminate the contract in May 2010 if any of the CPs have not fulfilled.

Appendix E- Key business processes

Appendix E- Key business and operational processes

In this Appendix, we describe the key business and operational processes we have briefly reviewed. In the case of distribution business processes we describe the process as conducted by ECG.

Generation investment planning

- Since the sector reform, the Energy Commission has been responsible for indicative generation planning which it last reported in its "Strategic National Energy Plan 2006-2020". We understand that the Energy Commission is currently updating that plan using the well known MAED[12] demand forecasting tool and the WASP generation planning optimisation tool. GRIDCO will use the Energy Commission's demand forecast and indicative generation investment plan to develop its transmission investment plan.
- Previously, when VRA was responsible for generation investment planning and also included both generation and transmission, long range investment planning was focused on generation and transmission master plan studies conducted infrequently. In broad terms:
  - On an ad hoc basis, VRA developed generation and transmission master plan covering 20 years. These plans were developed by simulation of the system considering projected demand, existing plants and a range of candidate generation plants. New plants were chosen with the aim of minimising the total costs of investment, operation and unserved energy to the time horizon, the:
    - 1976 master plan indicated Kpong hydro;
    - 1984 master plan indicated thermal;
    - 2001 master plan indicated thermal but also considered Bui noting that it was by far the most economic hydro project remaining in Ghana but was not competitive with LCO fuelled thermal plant given the prevailing long term oil price forecasts (US$18/bbl at 2000 price levels)

[12] The Model for Analysis of Energy Demand which uses scenario-based simulation rather than an econometric approach to project demand. It outputs final energy demand in each energy sector based on inputs, such as economic growth, demographics, energy intensity and efficiency, for a particular forecast scenario. It also includes a module that transforms the daily system load profile into the load duration curve needed for power system expansion analysis by WASP and similar models.

- Prior to construction of new plant, VRA conducted a feasibility study which tested the need for the plant and revisited the assumptions used in the relevant master plan. Feasibility studies conducted since the last master plan include those for:
  - Tema Thermal 1;
  - Tema Osonor
- Demand forecasts were conducted every three years based on econometric trend analysis (projecting based on GDP and price) together with adjustment for large customers. Central, low and high forecasts were prepared. As an example of accuracy, the 2000 forecast predicted for 2006 the demand level that was actually achieved in 2008.
- The most recent master plan was developed using a simulation model purchased from Acres – Generation Simulation (GenSim). This model comprises three components:
  - Planning module which allows the user to simulate the system using projected annual load duration curves and existing plant to the time horizon:
    - to identify the first year in which the planning standards are breached (the planning standards are 5 days/year loss of load probability and 0.1% annual loss of energy expectation)
    - to select manually a candidate plant which is expected to be the lowest costs to allow the planning standard to be met. To this end, candidate plants are ranked using screening curves which show projected unit costs against plant load factor to identify the lower cost options;
    - to include the candidate plant and repeat the steps above until the planning standards are not breached in any year
  - Operating module which allows the user to simulate the system more accurately using projected monthly load duration curves and the existing plant and the candidate plants.
  - Economic module which calculates the NPV of investment, operating and unserved energy costs to the time horizon.
- This model is not an optimising model: it relies on the user identifying appropriate candidate plant and selecting those which are expected to lead to the least cost.

- Noteworthy points are:
  - Thermal candidates
    - Have a minimum capacity of 100MW given thermal efficiency considerations and the size of annual demand increment which is some 250GWh/50MW
    - Have been assumed to run on gas since 2005
  - Experience leads to the following sequence of generation candidates:
    - Steam turbine to convert any combustion turbines to combined cycle when the load factor on the combustion turbine exceeds about 20%
    - Combustion turbine
- However, there are IPP plants which are under construction which did not feature on a master plan, eg the Shenzen group plant, which emerged as a response to the energy crisis.

Fuel oil procurement

- Since its use of oil has increased, VRA has replaced ad-hoc purchases and delivery with:
  - Oil purchases under a framework contract. The framework contract commenced on 1 June 2004 and has recently expired and VRA will be retendering shortly. The contract included supply FOB Nigeria and payment based on spot prices plus a margin. It also included a minimum contract volume over the contract life.
  - Time charter of a tanker of some 400 000 barrel capacity to deliver oil from the Nigerian loading point to Takoradi and, since 2009, Tema.
- Broadly speaking, the fuel procurement process was as follows:

- At the start of the year, VRA determined its expected LCO and gas purchases based on the Annual Supply Plan
- VRA informed the oil company of its expected volumes (now about 8-10 cargoes each year) and delivery timings
- VRA confirmed the quantity, timing and delivery point about one month before delivery
- The oil company procured LCO from Nigeria and loaded it onto the chartered tanker. The contract required VRA to make payment based on the average of the Platt's Brent crude spot rates[13] for the loading date and the successive four days and a margin for the oil company. The loading took place after issue of three month letter of credit (LC). A LC was used to allow time to get funds in place and to check the quantity and quality of the delivered oil;
- The shipper delivered the fuel directly to storage tanks
    - at Takoradi which has storage of about 600,000 barrels; or
    - at Tema refinery where it was held prior to cleaning and delivery to clean tanks at power station. At Tema, unlike at Takoradi, there is a charge for using the mooring facility.
- A sub-contractor checked the delivered fuel quality prior to payment.

Operational planning and despatch

► The operational planning process takes place in four timescales as follows:

- Annual. The Annual Supply Plan covers one calendar year. It sets out monthly generation (MWh) on each plant and imports from Cote d'Ivoire. It is the output of a planning analysis that determines water usage over two succeeding years, based on the Akosombo reservoir level at 1 November, taking a fairly conservative view of hydro inflows in the first year (when the reservoir level is normal, a hydro inflow that will be exceeded with 70% probability, and when the reservoir level is low, a more conservative hydro inflow) and an average view of hydro inflows in the second year (a hydro inflow

[13] We have been told that the Brent crude spot rate was used rather than a Nigerian spot rate, such as that for Bonny light, as the Brent crude market was considered to be more liquid. The Brent crude FOB spot rate and the Bonny light FOB spot rate move together with a small differential.

that will be exceeded with 50% probability equivalent to some 30 Million Acre Feet inflow)[14]. The plan uses available hydro and necessary thermal to ensure that there is no load shedding projected in the two years. We understand that VRA has recently purchased a new model, Vista, which uses a dynamic programming algorithm to optimise hydro/thermal despatch over a three year time horizon though we are uncertain whether this model has yet been used for development of the Annual Supply Plan. Previously, the plan was developed using a simple spreadsheet.

  - Monthly. The monthly plan covers each remaining month in the calendar year. It sets out monthly generation (MWh) on each plant and imports from Cote d'Ivoire. It is used to adjust for changes in hydro inflows and thermal availability during the year. The adjustments seek to bring the Akosombo level back to its target level by 1 November;
  - Weekly. The weekly plan covers the peak demand (MW) for each day of the week ahead. It sets out MW on each plant and imports from Cote d'Ivoire;
  - Daily. The daily plan covers the demand (MW) in each hour of the day with demand forecast based on preceding day. It sets out MW on each plant and imports from Cote d'Ivoire and indicates the expected reserve/deficit in each hour.

- Real time despatch is relatively simple as the thermal units at both Takoradi and Tema are GE Frame 9E units with similar efficiencies and fuel prices. GRIDCO operates the Akosombo generators in regulating mode. GRIDCO does not carry separate spinning reserve as the hydro units can reach full load in 10s. The despatch order is:
  - Must run thermal at Takoradi. Two units must run to improve voltage stability. If the steam turbine is unavailable, the units operate in open cycle mode, otherwise the units operate in combined cycle mode;
  - Hydro to meet the hydro MWh in the daily plan
  - Other thermal plants except the Tema mines reserve plant
  - Tema mines reserve plant

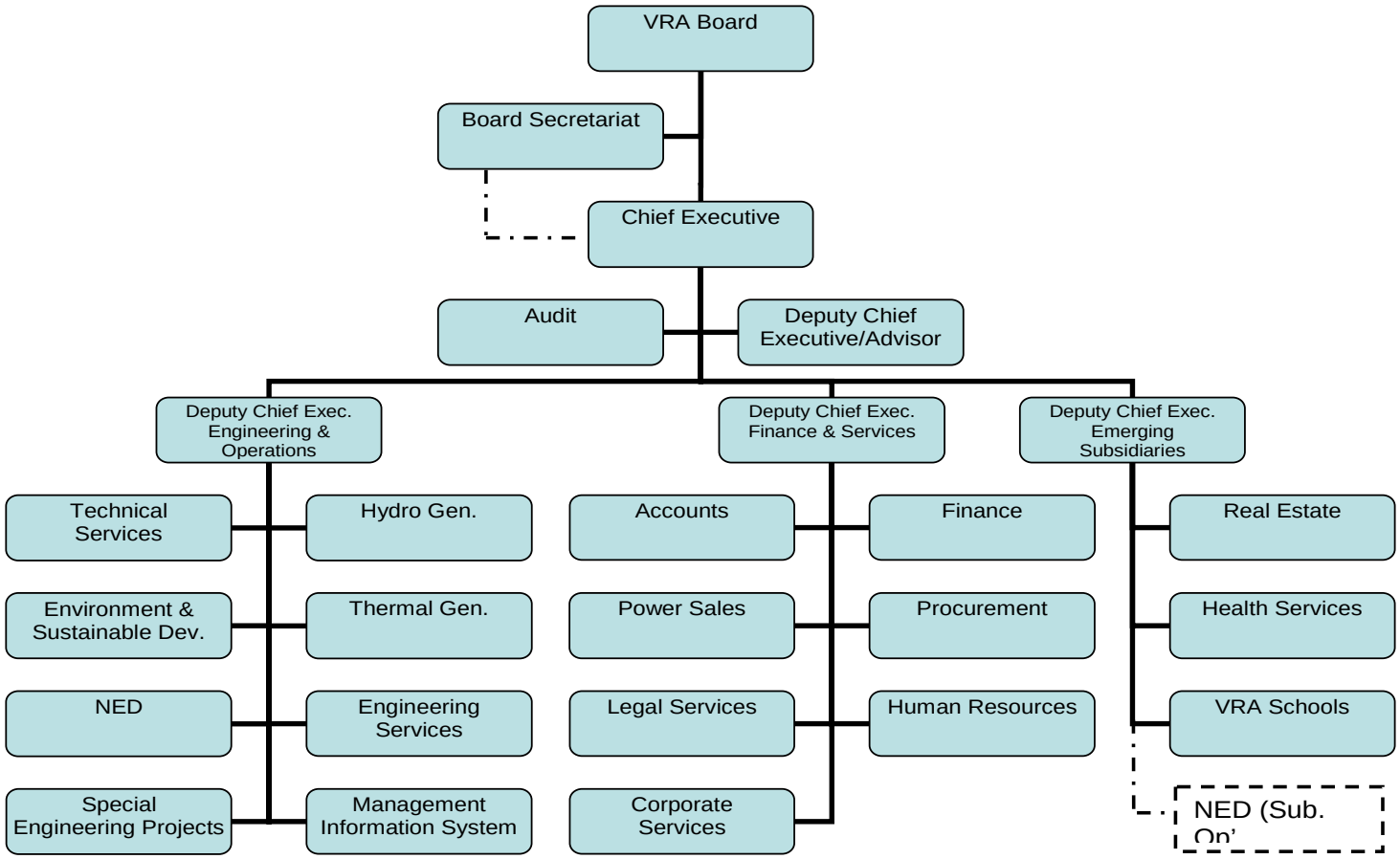
- Noteworthy points are:

[14] Hydro inflow is highly variable. Historical inflows have varied between 6 Million Acre Feet (MAF) and 78MAF with an average of 30MAF. Akosombo provides multi year storage: its level can vary between a high level of 278 feet set by spill and a low level of 240 feet set by cavitation on the turbines; if the level is 267 feet, it can run for two years at full load with no inflow.

- We are unsure that hydro/thermal despatch is fully optimised by use of appropriate models in the planning process which estimates the opportunity cost of hydro (sometimes known as the water value) for use in despatch.
- We understand that despatch does not always follow the plans. For example, on occasions, the reservoirs have been overdrawn because of unwillingness to pay (perceived) high prices of thermal generation or lack of funds to pay for fuel.

Appendix F- Human Resource

VRA Organisational Structure



VRA Staff Count by Department and Location

Staff Count by Department and Location

VRA											
COUNT OF STAFF BY DEPARTMENT AND LOCATION											
Location / Department	Aboadze	Accra	Ada Foah	Akosombo	Akuse	Kumasi	Sunyani	Takoradi	Tamale	Tema	Total
Engineering Services				12	116						**128**
Environment and Sustainable Development			18	59							**77**
Technical Services		8		51	6						**65**
Hydro Generation				138	90						**228**
Thermal Generation	158	8				14		3		153	**336**
Management Information Systems		35		4	2			1		2	**44**
Special Engineering Projects										1	**1**
Audit		21									**21**
Accounts	9	47		19	6					16	**97**
Finance		28									**28**
Power Sales		11									**11**
Procurement		3		14	8					67	**92**
Legal Services		23									**23**
Human Resources	3	39		9	23						**74**
Corporate Services	2	50		17	2		1		1	6	**79**
Corporate Office		34			1						**35**
Real Estates	51	137	4	229	136				2	9	**568**
Health Services	32	11		187	4						**234**
VRA Schools	16			86	18			1			**121**
NED											**827**
Total	**271**	**455**	**22**	**825**	**412**	**14**	**1**	**5**	**3**	**254**	**3089**

Source: VRA's Human Resource Department. Data as at May 2009

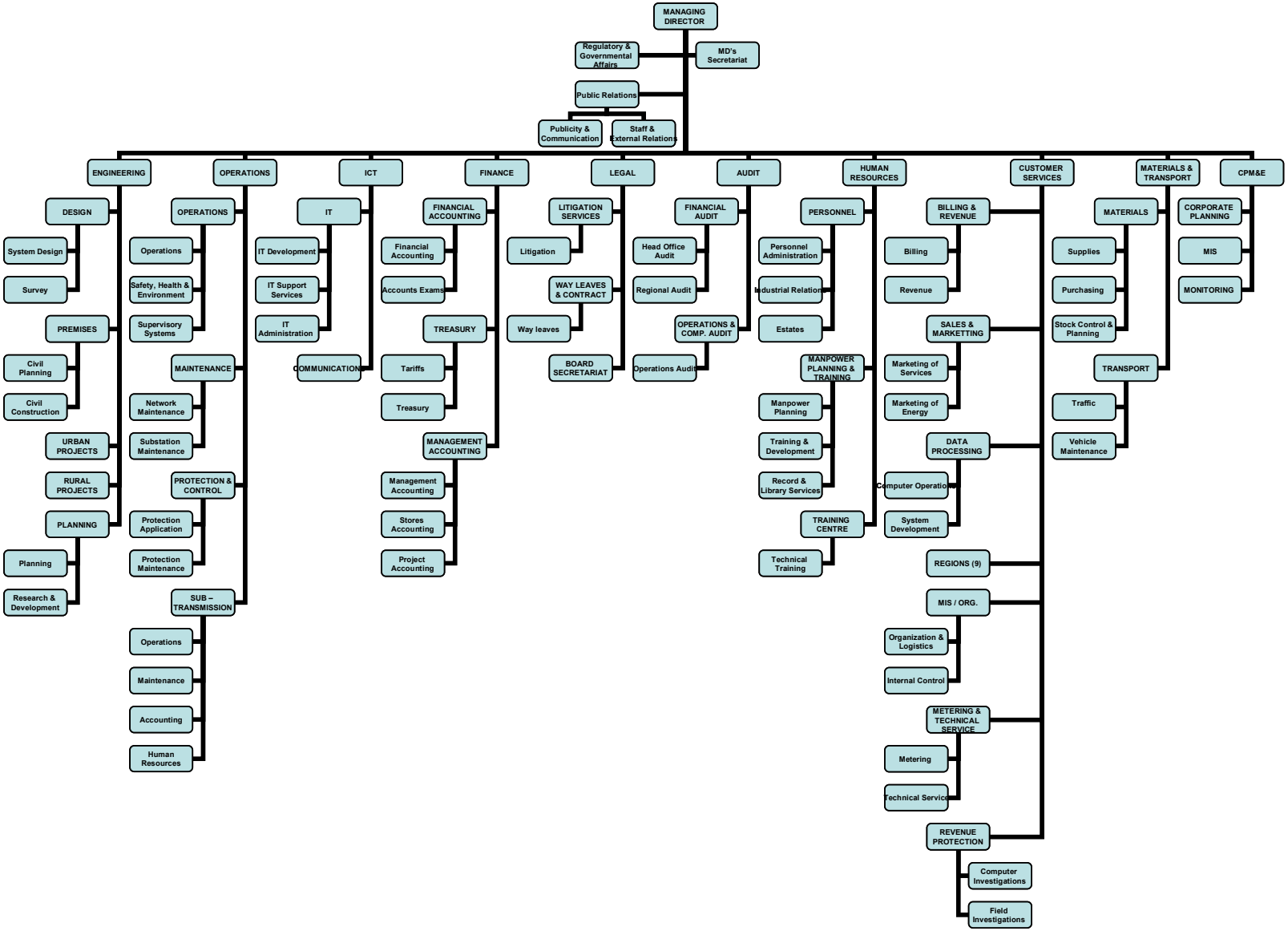
VRA Staff Age Distribution by Department

VRA Staff Age Distribution by Department

AGE DISTRIBUTION BY DEPARTMENT

Age Range / Department	20- 29	30-39	40-49	50-59	60	TOTAL
Engineering Services	20	38	37	40	1	136
Environment & Sust. Development	1	16	34	24	2	77
Technical services	1	13	16	35		65
Hydro Generation	11	63	77	73	3	227
Thermal Generation	46	160	88	34	1	329
Management Information System	2	11	20	11		44
Special Engineering project		1	1			2
Audit	1	4	8	8		21
Accounts	8	20	25	41	4	98
Finance		6	12	8	1	27
Power Sales	1	2	5	3		11
Procurement	5	25	34	27	1	92
Legal		6	12	5		23
Human Resources	3	18	23	28	3	75
Corporate Services		18	27	33		78
Corporate Office	1	5	14	14	1	35
Real Estate	16	131	188	221	11	567
Health Services	11	70	77	72	3	233
VRA Schools	4	28	47	38	3	120
NED	70	390	217	145	5	827
Total	201	1025	962	860	39	**3087**

ECG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Regulatory & Governmental Affairs
MD's Secretariat
Public Relations
Publicity & Communication
Staff & External Relations
ENGINEERING
DESIGN
System Design
Survey
PREMISES
Civil Planning
Civil Construction
URBAN PROJECTS
RURAL PROJECTS
PLANNING
Planning
Research & Development
OPERATIONS
OPERATIONS
Operations
Safety, Health & Environment
Supervisory Systems
MAINTENANCE
Network Maintenance
Substation Maintenance
PROTECTION & CONTROL
Protection Application
Protection Maintenance
SUB – TRANSMISSION
Operations
Maintenance
Accounting
Human Resources
ICT
IT
IT Development
IT Support Services
IT Administration
COMMUNICATION
FINANCE
FINANCIAL ACCOUNTING
Financial Accounting
Accounts Exams
TREASURY
Tariffs
Treasury
MANAGEMENT ACCOUNTING
Management Accounting
Stores Accounting
Project Accounting
LEGAL
LITIGATION SERVICES
Litigation
WAY LEAVES & CONTRACT
Way leaves
BOARD SECRETARIAT
AUDIT
FINANCIAL AUDIT
Head Office Audit
Regional Audit
OPERATIONS & COMP. AUDIT
Operations Audit
HUMAN RESOURCES
PERSONNEL
Personnel Administration
Industrial Relations
Estates
MANPOWER PLANNING & TRAINING
Manpower Planning
Training & Development
Record & Library Services
TRAINING CENTRE
Technical Training
CUSTOMER SERVICES
BILLING & REVENUE
Billing
Revenue
SALES & MARKETTING
Marketing of Services
Marketing of Energy
DATA PROCESSING
Computer Operation
System Development
REGIONS (9)
MIS / ORG.
Organization & Logistics
Internal Control
METERING & TECHNICAL SERVICE
Metering
Technical Service
REVENUE PROTECTION
Computer Investigations
Field Investigations
MATERIALS & TRANSPORT
MATERIALS
Supplies
Purchasing
Stock Control & Planning
TRANSPORT
Traffic
Vehicle Maintenance
CPM&E
CORPORATE PLANNING
MIS
MONITORING