November 29, 2018

**COMMENTS ON THE QUANTUM REPORT**

**EXECUTIVE SUMMARY:**

Quantum prepared a report “Tariff Study in the Electricity Sector in Mozambique,” in November 2017, for the period 2019-22 for the electric utility EDM. The utility regulators asked in August 2018 that comments be prepared on Quantum’s report. The comments in this document are based on a review of the Quantum report. The comments in the document spell out the information that is further required to conduct the assessment.

The report generally does a good job of covering many of the areas. While the report is comprehensive and covers a lot of ground, numerous specific details on assumptions and methodology are required from the authors of the report to make further conclusions on the reasonableness of the recommendations in the report. The regulators need to obtain and analyze data, especially in many of the cost areas, before reaching a conclusion on whether the allowed revenues presented are reasonable and necessary. Also, the regulators need to consider the proposed tariff adjustment mechanisms considered within a year and between years (e.g., fuel and purchased power, inflation, foreign exchange etc.) to see if they are reasonable.

The report recommends an incentive ratemaking regime to be implemented that requires more of a macro review by the regulator and benchmarking to help set allowed revenues and prices for a multi-year period. For a nascent regulator like ARENE which has never reviewed the cost elements of the utility before, it may be premature to rely on an incentive ratemaking approach from day one. The regulator needs to get comfortable that the baseline cost figures are reasonable before simply relying on what the utility provides and simply escalating them for inflation less productivity. At least for a couple of cycles, the regulator needs to review the costs thoroughly and set the baseline level that can be relied on before embarking on incentive rate making approach.

There is generally a tendency among some to quickly call for tariff increases for the sake of achieving “cost reflectivity” in the tariffs. While cost reflectivity is a good goal, before tariffs are raised, especially where consumers cannot afford the already high level of tariffs, the regulators need to seriously examine the utility cost structure to make sure it is efficient and reasonable. Inefficiency can lead to unnecessarily high utility costs and simply raising tariffs to make them cost reflective would not be prudent for the regulators without addressing the inefficiencies and the concomitant high costs.

In this document we provide comments on the report and raise several questions in each section that need to be further addressed. For the sake of ease, all the questions are also listed again in one place in the Annex that is attached.

**INTRODUCTION:**

Overall, the report covers the following areas:

* a financial assessment of the electric utility;
* determines the generation costs of the utility;
* arrives at allowed revenues for each of the major business units (transmission/system market operator, distribution/retail, system operator/dispatch);
* offers a proposal for quarterly adjustment of the tariff to flow through certain costs automatically and for monthly adjustment of the tariff for certain costs;
* assesses alternatives to improve the financial sustainability of the utility;
* provides a simulation of impacts of plans to expand generation;
* reviews existing tariff structure for improvements; and
* offers a design for strategy and a transition period to full implementation of amended tariff structure.

The comments below are organized in six sections. In the first section, general ratemaking concepts and principles are discussed. In the second section, all the cost areas that are built into determining the allowed revenues are discussed. The tariff adjustments within a year and for years 2-4 are discussed in the third section. Rate Design issues are addressed in section four. Specific incentive mechanisms are discussed in section five and miscellaneous issues are discussed in section six. In many of the sections, additional questions are listed that should be directed to Quantum for a response.

**Section A: Overarching Ratemaking Issues**

1. Theory of Regulation and the Role of the Regulator:

Section 3 of the report discusses general history of the theory of regulation including cost of service vs incentive-based regulation and advocates for the latter. However, it should be cautioned that the ground realities including the maturity of the regulatory framework be considered in developing the appropriate regulatory regime and the role of the regulator.

* Utilities in developed countries have maintained books and records of their assets in a specified standard format for decades, generally leading to reliable and dependable data that regulators and other stakeholders can rely on to make decisions.
* The regulatory developments in the advanced countries happened over decades. The regulators have decades of history of examining utility books and records, and an understanding of the various technologies of production and delivery and the cost structure of the industry.
* For the most part, the utilities are investor owned utilities with a profit motive and in the absence of competition, the regulation is tailored to motivate the utility to serve customers and to hold the utility management (and shareholders) accountable for their performance and provide an incentive to them if they do a good job or penalize them for a poor job.
* Private capital is available to utilities and the cost of capital is commensurate with the risk the investors take. Financial institutions and analysts regularly evaluate the financial health of utilities and publish reports that regulators can rely on.
* In some of the emerging economies, including Mozambique, many of these characteristics do not hold true. Utilities are generally owned by the government, not private investors. The regulators do not have decades of experience. The utility cost structures and data are not well established. Private capital is somewhat scarce as the utilities do not have enough credit history and/or are considered very risky. Not much independent financial analysis is conducted by analysts and financial institutions. It is unclear if the utilities are as efficient as they can be, especially as there is no profit motive.

The regulatory regime needs to be established and the role of the regulator defined with this backdrop in mind. Before one can jump to an incentive-based regulation in full force, the regulator needs to have a good understanding of the utility functions and its basic cost structure, have enough good data that they have confidence in, and tools to motivate a utility that has no profit motive. At the same time, they need to generate a regulatory climate to provide enough investor confidence to invest in utility assets.

In the beginning years of regulation, the regulator needs to get a good handle on the utility cost structure, so that the base line costs are well established before plunging into incentive-based regulation where future costs may simply be indexed from a base line level.

1. Allowed Revenue Requirement: Increase in Tariff vs Reducing Costs:

There is generally a tendency among many to quickly call for tariff increases for the sake of achieving “cost reflectivity” in the tariffs. While cost reflectivity is a good goal, before tariffs are raised, especially where consumers cannot afford the already high level of tariffs, the regulators need to seriously examine the utility cost structure to make sure it is efficient and reasonable. Inefficiency can lead to unnecessarily high utility costs and simply raising tariffs to make them cost reflective would not be prudent for the regulators without addressing the inefficiencies and the concomitant high costs.

The areas for examination to evaluate costs include:

* O&M costs: the reduction in O&M costs will directly reduce the need for increased allowed revenues. Numerous areas for further questioning include
  + Labor costs
  + Material and supplies
  + Level of losses
  + Level of overall budgeted and actual past spending compared to the projected spending
  + Need for and reasonableness of various proposed O&M programs/projects
* Regulated Rate Base: Reducing the rate base will reduce the need for increased allowed revenues because the cost of capital on the rate base including the rate of return (financing charges) and depreciation will be lower. The rate base seems have doubled in the last year. A thorough examination of the following are necessary.
  + Recent doubling of the rate base in the report
  + Level of projected capital expenditures, especially in transmission
  + Level of overall budgeted and actual past capital spending compared to the projected spending
  + Need for and reasonableness of various proposed capex programs/projects including justification and benefit/cost analysis for them
  + Development of CWIP
* Rate of Return: the rate of return provided to the investors should be commensurate with the risk the investors take by investing in the company. The more risk reduction features there are in the ratemaking mechanism, the lower the risk for investors. In some government owned utility regimes, the equity cost is considered to the be the same as the cost of debt.
  + Identify the risk reduction features in the ratemaking regime and study whether others can be introduced such as revenue decoupling mechanism, capex reconciliation etc., to help reduce the cost of capital
  + The level of cost of equity in the report appears very high
* Depreciation: there is no discussion on depreciation in the report. An adjustment downwards here will directly reduce the need for increased allowed revenues.
  + Evaluate how depreciation costs are developed and identify areas where they are overstated

Additionally, if there are cash flow problems at a utility, the analysis should examine whether there are structural shifts in the revenues and/or cost elements or if there are only unusual short-term problems but not structural changes. If there are no structural changes, caution should be taken not to overreact and overhaul the existing regulatory mechanism but fix the identified short-term problem in a strategic fashion.

For example, here there appears to be a temporary problem that has arisen in 2016 and 2017 because there was significant increase in the energy purchase costs and there was no automatic mechanism to raise the tariff to cover the increased cost to the utility. This led to financial pressure on the company, requiring a high level of borrowing to finance capex, and thus led to high leverage and poor coverage ratios. The pass through of prudent supply costs on a more real time basis would be a decent remedy to address the identified problem.

1. Price Cap Mechanism:

In Section 3, the report advocates separating costs that are manageable (controllable by the utility) and those that are not and providing separate ratemaking treatment for each category accordingly. Typically, the costs that are not manageable will be passed through to the customer if they are prudently incurred. Whereas, for costs that are manageable, there could be performance expectations of the utility in those areas and the utility would be held accountable to achieve the performance through incentive/penalty mechanisms.

The report advocates the use of ‘price cap’ as the primary regulatory mechanism. While this is a regulatory incentive mechanism that is widely used, the additional feature that is also used in many other regulatory regimes is the use of ‘revenue decoupling mechanism.’ There are advantages and disadvantages to both. Under a price cap mechanism, the prices are essentially locked in (more precisely ‘capped’) for a given period, say one year, for all the manageable costs. However, it does not adjust revenues for changes in sales. Whether the sales are higher or lower than projected, the price does not change[[1]](#footnote-1). If the weather is hotter than forecasted level or the economy picks up more than forecasted level, the sales (and concomitant revenues and profits) to the utility can go up. The reverse is also true. If the weather is cooler than normal or the economy slows down compared to forecast or there is more conservation by customers or increased customer owned generation, sales (and revenues and profits) could be lower than forecasted. So, essentially the utility has an incentive to sell more and a disincentive to pursue conservation or encourage customer owned generation. It also has an incentive to cut costs compared to forecasts, as the resulting savings will accrue to its bottom line.

In a “Revenue Decoupling Mechanism (RDM),” the allowed revenues are reconciled to actual sales revenues. So, if the sales go up more than forecasted for any reason, the company receives more revenues than allowed and will return the excess revenues to the customer as a refund, and vice-versa. The benefit of having a revenue cap mechanism is it takes away a major risk element to the utility; i.e., sales fluctuations, which may not be perfectly predictable. Sales typically are linked to weather, economy, and customer conservation and self-generation initiatives. In some countries that are tight on supplies, sales are primarily a function of available capacity and energy from various available supply sources.

By eliminating this risk variable, the overall risk of the utility should reduce, thus reducing cost of capital to the utility. The utility would still have an incentive to be efficient and productive as the resulting cost savings would still accrue to the utility. The con is that it may take away the utility incentive to attract new customers and sell more energy. But that can be addressed through a separate incentive mechanism where the company is rewarded for adding customers beyond forecast level. Also, the customer price is technically not fixed any more.

1. Outer Year Rates:

The report recommends the use of a price cap mechanism with inflation index (less productivity plus externality) adjustments in the outer years. However, this requires confidence in the base line data to begin with. If the base line data is poor and the confidence in the accuracy of data is low, then there is a likelihood of extending any mistakes in the base year into outer years. Until there is more experience and confidence with underlying data, it would be prudent for the regulators to thoroughly review upfront the projected revenues and costs in the outer years as well. In addition, there should be continuous monitoring by the regulators on a periodic basis (say quarterly) through reporting requirements from the utility on the actual utility revenues and costs and the variances from budget levels, so corrective actions can be taken.

It is recommended for at least the first two iterations the regulators perform a detailed examination of the utility cost structure to ensure the expenses are reasonable and the utility is spending capital and O&M efficiently and following the prescribed tariff determination guidelines. Once there is a comfort level that the baseline data is good and can be relied on, then one can engage in longer term rate making using price cap or other incentive mechanisms.

1. Conversion from Debt to Equity:

The report recommends converting some of the existing debt into equity to improve the financial coverage ratios. This appears to be a reasonable step to take given the current financial health of the utility. Going forward, regulators should provide guidance on the ideal amount of debt vs equity the utility is supposed to have.

**Section B: Allowed Revenue Requirement Elements**

1. Tariff Increase Level:

The study projects an increase from the current level of tariff in 2017 of 6.54 MT/kWh to go up to 7.63 MT/kWh and to 8.84 MT/kWh in 2018 and 2019, respectively. See the graph below from the report (page 16). That is an increase of 35% in just two years. If exports are excluded, the increase is not 35% but 54% (see table on page 18). Although the inflation was high in 2016 (19.2%) and 2017 (15.3%), it is expected to drop to a lower level of 6.7% in 2018 and 5.7% in 2019[[2]](#footnote-2). Compared to these inflation levels, the tariff increases seem high, especially when many customers cannot afford power to begin with. The regulators need to analyze all the underlying causes for the increase in rates to ensure they are as efficient and low as possible[[3]](#footnote-3).

2019 COS 16%

Mid-2018

Current 2017 (Aug/17)

**2019 COS**

**Mid-2018**

**Current 2017 (Aug/17)**

**16%**

6.54

7.63

8.84

10.00

9.00

8.00

7.00

6.00

5.00

4.00

3.00

2.00

1.00

-

|  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- |
|  |  |  |  |  |  |  |  |
| **KPI** | **Units** | **2017** | **2018** | **2019** | **2020** | **2021** | **2022** |
| **Average Tariff**  **(excluding**  **Exports)** | **USD/MWh** | **88.14** | **111.55** | **136.02** | **136.10** | **134.89** | **140.58** |
| **Export Tariff** | **USD/MWh** | **58.56** | **53.00** | **53.57** | **52.50** | **62.50** | **70.00** |
| **Average Tariff**  **(including**  **Exports)** | **USD/MWh** | **82.01** | **95.42** | **111.20** | **117.59** | **125.13** | **125.39** |
| **Gross Profit per Unit** | **USD/MWh** | **19.51** | **38.36** | **55.81** | **60.82** | **67.09** | **59.52** |

1. Sales Projection:

Having an accurate sales projection is important to set proper tariffs in an efficient and equitable manner. If a price cap mechanism is used, the accuracy of sales forecast becomes even more important. If sales are projected low, the average tariff is set a high level to achieve the allowed revenues. The utility would always have an incentive to project low sales. If the actual sales turn out to be higher than forecast, the utility keeps the incremental profit margin. However, if an RDM mechanism is used, the accuracy of sales forecast is important, but the adverse impact on customer is not much if the actual sales turn out to be higher than forecast. The utility simply would return the incremental revenue back to the customer as a refund.

The utility is projecting a healthy increase in sales for the residential customers, from 1,624 GWh in 2017 to 3,058 GWh in 2022, or about 13% annual growth rate. This seems consistent with the growth rate in the number of residential customers from 1.35 million in 2017 to 2.7 million in 2022.

Similarly, the load of MT customers is increasing from 1,128 GWh in 2017 to 1323 GWh in 2022, or about 3% annual growth rate. This is consistent with the growth rate in the number of MT customers. Finally, the commercial customer category load is growing from 408 GWh in 2017 to 639 GWh in 2022, or about 9.5% annual growth rate. The customer number is growing at about 11% annually.

Question:

* Why are the sales levels lower in 2017 compared to 2016 even though the customer numbers are higher?
* Are the projections of increased number of customers realistic? How does it compare with the past growth rate?
* Page 4 of the report states that the utility is currently connecting 118,000 new customers per year, but the World Bank has estimated that the country needs between 300,000 and 400,000 new customers in addition to those connected. There is no further discussion on this topic. What is the status of this effort and what effort is the utility taking to increase access? Has it been accounted for in the sales forecast and in the allowed revenue computations in the report?
* In emerging economies, sometimes the sales depend on available generation supply and imports. Are there any issues associated with potential supply that could reduce the sales compared to forecast?

1. Losses: Page 14 and page 36

Losses are expected to drop from 25.9% in 2017 to 18.9% in 2022. Even though this is an impressive projected drop, it is unclear if this projected improvement will really happen. From 2013, the loss level has been on an increasing trend. There is no discussion on the reasons for the deterioration in loss levels. Even if the projected improvement happens, the level it is still high compared to other South African countries. See World Bank study (Figure 10, Page 45)[[4]](#footnote-4): the actual loss level for Sub Saharan African countries is 15%, and the ideal benchmark reference level is 10%. Reducing losses translates directly to lower costs and rate for customers. For example, a 10% improvement means that effectively 10% more sales are available for spreading costs, thus reducing per unit costs to customers.

Questions:

* What are the root cause reasons for the high loss levels?
* Has the utility considered taking steps to reduce losses? What are they? What are the implementation problems the utility is facing?
* Have losses been accounted for in sales properly?
* What steps can be taken to achieve the World Bank study results for the benchmark reference level or at least the average loss level in the region?
* Are there any incentive mechanisms that can be implemented to motivate the utility?

1. WACC (starting on page 39):

The WACC is used to determine the financing costs on the Regulated Asset Base (RAB). The WACC is the weighted average cost of debt and equity used in the capital structure to finance the assets. The utility investors need to be compensated commensurate with the risk they take in making the investment. Too high a return level probably would be welcomed by the investors but would cost consumers too much money unfairly and unnecessarily. Too low a return level will probably be welcomed by consumers but may not provide enough return to investors to attract capital for the utility. Hence finding the optimal level is important. This is a critical variable that affects the allowed return. The higher the WACC, the higher the financing costs, and hence higher the allowed revenues. As the WACC is applied to the entire rate base, even a small change in the WACC level will affect the allowed revenues quite a bit. Hence getting this variable value right is important for the regulator and the utility.

Quantum used a standard framework for determining the WACC. The cost of debt is typically the actual cost of debt for the utility, whereas the cost of equity needs to be estimated to determine the equity investor return expectations. For the cost of debt, Quantum used 5.41% as shown in the table below. The tax rate used is 32%. The leverage assumption is 56% debt and 44% equity. For computing the equity return, Qantum used the standard Capital Asset Pricing Model. The CAPM has three inputs: risk free return, beta, and market risk premium. Quantum used 4.79% and 6.39% for risk free return and market risk premium estimates, respectively. For an asset beta, it used 0.287. With the given leverage ratio, this asset beta translates to an equity beta of 0.535. They also add a country risk premium of 8.88%. This results in a required nominal equity return of 17.08% after tax and 9.58% nominal WACC after tax.

On a real basis (net of inflation), the WACC is estimated at 7.22% after tax and 10.61% before tax.

|  |  |
| --- | --- |
| Cost of Capital - WACC | December  2016 |
|  |  |
| Equity Cost of Capital |  |
| Risk free rate | 4.79% |
| Asset Beta | 0.287 |
| Capital structure (D/E) | 127.27% |
| Tax income rate | 32.0% |
| Beta equity | 0.535 |
| Average market return | 11.17% |
| Market risk premium | 6.39% |
| Country risk premium | 8.88% |
|  |  |
| CAPM | 17.08% |
|  |  |
| Cost of Debt | 5.41% |
| WACC nominal after tax | 9.58% |
| D/A | 56.00% |
| USA Inflation | 2.20% |
| WACC real before taxes | 10.61% |
| WACC real after taxes | 7.22% |

Questions:

* What is the source for the assumptions for -
  + cost of debt,
  + asset beta
  + risk free rate
  + market risk premium and
  + inflation?
* How was the leverage ratio precisely derived? What is an optimal leverage ratio for the utility?
* Why should a country risk premium be added for a utility that is government owned and financed?
* The recent NERSA decision arrived at a real WACC before tax of 6.9% (see table 42 of South African regulator decision in 2018 in the ESKOM rate filing)[[5]](#footnote-5). This compares to the 10.61% being recommended by Quantum. Explain the differences between the two utilities to justify why a significant premium should be paid to EDM?
* In some government owned utilities, equity cost is considered the same as the cost of debt. What are the pros/cons of using cost debt for equity as well?

If country premium is not added, it seems that the real after-tax WACC would be 3.4%, and pre-tax real WACC would be 5%

Inflation rate forecast for 2019 is 6%. (<https://tradingeconomics.com/mozambique/forecast>), so the risk-free rate appears be below inflation.

1. Rate Base (Page 17 and starting on Page 43):

It is good that third party funded assets are excluded from the rate base for both depreciation and rate of return calculations. Page 17 states “Only EDM's own assets have been considered for the calculation of the regulatory asset base on which depreciation cost and return on assets are determined, i.e. assets resulting from donations or executed with contributions from third parties have been excluded.”

Quantum identified the net assets as of December 2017 and then projected future net assets until 2022 on which rate of return and depreciation will be applied. The table on page 44 shows the following net asset base.

##### Net Asset Base (MT Millions) – Existing assets at Dec/16

|  |  |  |  |  |  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
| **Activity** | **2017** |  | **2018** |  | **2019** |  | **2020** |  | **2021** |  | **2022** |  |
| Generation |  | 635 |  | 592 |  | 550 |  | 508 |  | 466 |  | 427 |
| Transmission |  | 10,917 |  | 10,059 |  | 9,282 |  | 8,586 |  | 7,911 |  | 7,264 |
| Distribution |  |  |  |  |  |  |  |  |  |  |  |  |
| HV & MV Voltage |  | 9,967 |  | 8,611 |  | 7,291 |  | 6,045 |  | 4,877 |  | 3,836 |
| Low Voltage |  | 6,645 |  | 5,740 |  | 4,861 |  | 4,030 |  | 3,251 |  | 2,558 |
| Customer Services |  | 1,138 |  | 1,020 |  | 902 |  | 789 |  | 678 |  | 566 |
| General Services |  | 1,989 |  | 1,714 |  | 1,457 |  | 1,234 |  | 1,027 |  | 828 |
| Non-regulated Services |  | 1 |  | 0 |  | 0 |  | 0 |  | 0 |  | 0 |
| **Total RAB** |  | **31,290** |  | **27,736** |  | **24,342** |  | **21,193** |  | **18,210** |  | **15,479** |
| Donated assets |  | 17,212 |  | 15,256 |  | 13,390 |  | 11,657 |  | 10,017 |  | 8,515 |
| **Total Net Fixed Assets** |  | **48,502** |  | **42,992** |  | **37,732** |  | **32,850** |  | **28,227** |  | **23,994** |

Then they added Construction Work in Progress and capital expenditures to arrive at the final Regulated Asset Base. The table below from page 48 shows the final RAB.

##### Net Asset Base (MT Millions)

Function 2017 2018 2019 2020 2021 2022

Generation 9,365 10,460 9,902 9,344 8,786 8,231

Transmission 14,060 13,918 17,096 25,571 38,233 47,627

Distrib. HV & MV 23,057 24,997 25,199 25,869 26,217 26,046

Distrib. LV 15,372 16,664 16,800 17,246 17,478 17,364

Cust. Services 1,290 1,681 2,002 2,296 2,547 2,745

General Services 1,990 1,714 1,457 1,235 1,028 829

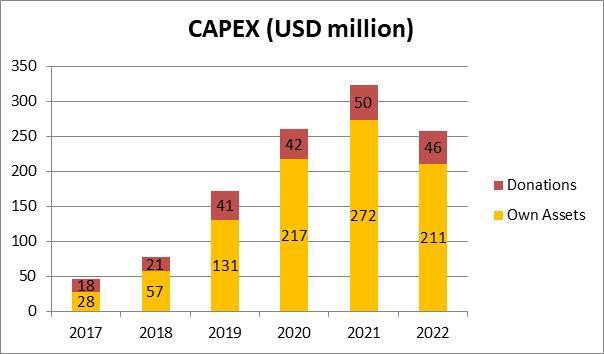
|  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- |
| **Total** | **65,134** | **69,434** | **72,456** | **81,562** | **94,289** | **102,843** |

Questions:

* Why is the RAB (net of third party funded assets) more than doubling from MT 31,290 million in 2017 (table on page 44) to MT 65,134 in 2017 (table on page 48) by the inclusion of CWIP and capital expenditures?
* Is depreciation accounted for in reducing the net asset base on which return is being applied? Show the specific derivation of the net asset base figures.
* What are the specific projects built into CWIP and capital expenditures?
* Are all those capital projects needed, and needed in this time frame?
* Is there an analysis showing the benefits and costs for each of the major capital projects?
* Were the capital budgets and major projects approved by the utility Board of Directors?
* Were rate impacts on customers considered when the capital budgets were adopted?
* How does the capital budgeting process at the utility work? What is the vision, what are the goals and how is the process laid out? What is the role of the management and the role of the Board in the capital budgeting decision making and oversight process?
* What is the planning period? How are projects designated and prioritized? How is the budget arrived at? How does the capital budgeting decision-making process at the utility work?
* Are there control systems in place to minimize abuse and inefficiency in spending?

1. Capital Expenditures: (page 17 and page 47)

Capex is increasing significantly in the coming years. Page 17 (and page 47) graph shows capex increasing from $50 million USD in 2017 to $322 million USD in 2021. That is an increase of over 6x in a four-year period, about 60% annual growth rate. Collectively almost $1.1 billion USD is planned to be spent in six years, with over 80% of the funding from utility sources and the remainder from donations. That is nearly 68 billion MT in spending over the six years or about 10.1 billion MT on average per year. To provide a perspective, the average annual revenue requirement for local market customers during this period is about 45 billion MT (per table on page 52). A detailed examination is necessary to ensure that this capex funding level is needed and is needed in this time frame.



##### Net Asset Base (MT Millions) – CAPEX

|  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- |
| **Activity** | **2017** | **2018** | **2019** | **2020** | **2021** | **2022** |
| Generation | 479 | 455 | 430 | 406 | 381 | 356 |
| Transmission | 436 | 1,293 | 5,389 | 14,701 | 28,177 | 37,489 |
| Distribution  HV & MV Voltage | 587 | 2,030 | 4,306 | 6,975 | 9,244 | 10,867 |
| Low Voltage | 392 | 1,353 | 2,870 | 4,650 | 6,162 | 7,244 |
| Customer Services | 152 | 661 | 1,100 | 1,506 | 1,870 | 2,179 |
| General Services | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total RAB** | **2,047** | **5,793** | **14,095** | **28,237** | **45,834** | **58,135** |
| Donated assets | 1,327 | 2,700 | 5,243 | 7,882 | 10,987 | 13,653 |
| **Total Net Fixed Assets** | **3,374** | **8,493** | **19,338** | **36,120** | **56,821** | **71,788** |

Questions:

* Even if it is deemed that these capital projects are needed in this time frame, realistically, can the utility perform the work?
* Anytime budgets are ramped up significantly in a short period of time, there is a high likelihood of introducing inefficiency and corruption in the execution. What steps are being taken and what control systems are in place to minimize such problems?
* Also, what inflation estimates were used in the projections? If the estimates by the utility were made in 2016 when the inflation was high, given the new current inflation projected estimates, are the old capex funding projections still valid?
* It appears that over 2/3 or more of the capex is related to transmission additions. Is there any analysis showing the costs and benefits for each of the major transmission projects?
* What are the past capex budget level and actual spending level, by year and by business unit, for the past five years?
* If there are variances between the budget and actual levels, what were the reasons for the variances?
* What is the oversight process at utility to monitor variances and take corrective actions?
* Should capex be reconciled after the fact? There are pros/cons of reconciliation, but it would help reduce the risk to the utility if there is uncertainty in forecasting the spending levels.

1. O&M Expenses: (page 49)

The O&M costs consist of personnel, contractors, other costs and bad debt cost, per Quantum report (page 50). Based on the table below (page 50), the costs are increasing by over 50% during this period. There is no baseline data for the years before 2017 to assess what the magnitude of the increase has been from the past levels. Also, no breakdown of the O&M is provided to assess the reasonableness of various inputs that went into this summary figures, and how the costs were allocated to various business units. The World Bank report (cited before) points out the level of overstaffing at utilities in Africa. Per Table 11 of the report, the utility has 3,763 employees whereas the optimal size should be 2,837 employees. Using this benchmark approach, this implies that there are over 900 (or 25%) excess employees at the company. In addition, the WB report states that the average employee compensation among utilities in Africa (excluding South Africa) is $13,000 USD per year, whereas the employees at this utility earn on average $17,000 USD (or over 30%). These two effects are additive and increase the costs to customers significantly.

##### Operating Expenditures (MT Millions)

|  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- |
| Function | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 |
| Generation | 909 | 1,340 | 1,932 | 1,932 | 1,932 | 1,932 |
| Transmission | 299 | 310 | 320 | 331 | 342 | 354 |
| Distrib. HV & MV | 1,198 | 1,238 | 1,281 | 1,324 | 1,370 | 1,416 |
| Distrib. LV | 1,198 | 1,238 | 1,281 | 1,324 | 1,370 | 1,416 |
| Cust. Services | 2,176 | 2,464 | 2,813 | 3,193 | 3,579 | 3,970 |
| General Services | 589 | 610 | 632 | 655 | 676 | 695 |
| **Total** | **6,368** | **7,200** | **8,259** | **8,760** | **9,269** | **9,783** |

Questions:

* What is the breakdown of the various O&M expenses?
* How are the O&M costs allocated to various business units?
* What is the past O&M budget and actual spending level, by year and by business unit, for the past five years?
* If there are variances between budget and actual, what were the reasons for the variances?
* What is the oversight process at utility to monitor variances and take corrective actions?
* What are the major drivers for increase in O&M expenses in each of the years going forward?
* What efficiency, productivity steps has the company taken to reduce O&M costs?
* How does the company respond to the report from the World Bank on staffing levels?
* What is the basis for using a bad debt level of 1%? This seems rather low.

1. Fuel and Purchased Power Costs (page 51):

The fuel and power purchase costs are almost doubling over the period from 2017 to 2022 although the supply quantity (GWh) is only increasing by 50%. From the tables on pages 51 and 52, shown below, the bulk of the costs are caused by the IPP thermal units although they account for only 40% of the supply mix. It appears that these are very high priced IPP thermal contracts (about $115 USD/MWh). Clearly, more exports would help to raise revenues and offset costs for local customers. The total revenue requirement table on page 52 shown below indicates supply costs are nearly half the total revenue requirement. One of the areas to reduce costs would be supply costs but one should review the IPP contracts to see if there are opportunities to do so.

##### Supply (MWh)

|  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- |
| Item | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 |
| Own generation (Thermal) | 0 | 153,300 | 613,200 | 613,200 | 613,200 | 613,200 |
| Own generation (Non-Thermal) | 339,264 | 466,976 | 490,560 | 490,560 | 490,560 | 490,560 |
| HCB | 3,423,000 | 4,139,100 | 4,577,100 | 4,577,100 | 4,577,100 | 4,577,100 |
| Other IPP (Thermal) | 2,655,183 | 2,570,981 | 2,477,556 | 2,477,556 | 2,477,556 | 3,966,756 |
| Other IPP (Non-Thermal) | 1,156 | 47,621 | 156,471 | 156,471 | 156,471 | 156,471 |
| Imports | 87,000 | 60,904 | 60,177 | 59,450 | 58,723 | 32,996 |
| **Total energy** | **6,505,603** | **7,438,882** | **8,375,064** | **8,374,337** | **8,373,610** | **9,837,083** |

##### Fuel & Energy Purchase Costs (MT Millions)

|  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- |
| Item | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 |
| Own generation (Thermal) | 0 | 2,660 | 4,894 | 4,954 | 5,014 | 5,076 |
| Own generation (Non-Thermal) | 0 | 33 | 34 | 34 | 35 | 36 |
| HCB | 2,371 | 3,290 | 3,783 | 3,858 | 3,935 | 4,014 |
| Other IPP (Thermal) | 18,339 | 17,743 | 16,864 | 17,202 | 17,546 | 28,252 |
| Other IPP (Non-Thermal) | 2 | 949 | 1,941 | 1,980 | 2,019 | 2,059 |
| Imports & Wheeling | 571 | 638 | 752 | 753 | 755 | 503 |
| Exports | -4,406 | -6,270 | -7,953 | -5,711 | -4,133 | -8,946 |
| **Total** | **16,876** | **19,043** | **20,314** | **23,069** | **25,171** | **30,995** |

##### Revenue Requirement for local market (MT Millions)

|  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- |
| Item | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 |
| Total Var. Own Gen & PPA Cost | 16,876 | 19,043 | 20,314 | 23,069 | 25,171 | 30,995 |
| Generation Fixed Costs | 2,399 | 3,048 | 3,886 | 3,800 | 3,722 | 3,645 |
| Transmission | 2,864 | 2,900 | 2,936 | 3,553 | 5,052 | 7,064 |
| Distrib. HV & MV | 1,958 | 2,083 | 2,219 | 2,259 | 2,320 | 2,347 |
| Distrib. LV | 3,627 | 3,874 | 4,144 | 4,218 | 4,332 | 4,377 |
| Cust. Services | 4,205 | 4,456 | 4,732 | 4,819 | 4,948 | 5,010 |
| General Services | 2,786 | 3,135 | 3,566 | 4,043 | 4,533 | 5,024 |
| **Total** | **34,715** | **38,539** | **41,798** | **45,763** | **50,078** | **58,461** |

Questions:

* The supply and purchase costs are not broken down in granular detail. What is the fixed cost and variable cost breakdown for owned generation assets, and output levels, for the last five years?
* What are the unit prices for the IPP contracts? It would be helpful to see, especially for the thermal IPP contracts, how the energy and capacity costs are structured in the contract.
* Are there opportunities to reduce the IPP costs?
* Are there increased opportunities to export power?

1. Overall Revenue Requirement (page 52):

The overall revenue requirement increases by over 70% from 2017 to 2022, driven primarily by generation and transmission costs. It would also be helpful to see the build up of the revenue requirement by cost component (return, depreciation, O&M, taxes) to get a better feel for the cost drivers.

From the data above, it appears that the overall tariff increase is influenced by increases in various cost components; the blank elements need to be filled in; data is not readily available.

|  |  |  |  |  |
| --- | --- | --- | --- | --- |
|  | 2018 | 2019 | 2020 | 2021 |
| Tariff % increase | 16 | 16.5 | 5.7 | 6.4 |
| O&M Expense % increase | 13 | 15 | 6 | 6 |
| Fuel and Energy Purchase % increase | 13 | 7 | 14 | 9 |
| Depreciation |  |  |  |  |
| Net Regulated Asset Base |  |  |  |  |
| Cost of Capital |  |  |  |  |

Questions:

* What is the buildup of the revenue requirement for 2018-2022, by year, using various cost components – return (debt, equity), depreciation, O&M, taxes, other levies, etc.
* Similarly, what is the historical composition for 2016 and 2017 of the same costs?
* What are the changes from 2016, 2017 to the projected levels and are they reasonable?
* Are there opportunities to reduce costs in any of those elements going forward?

**Section C: Adjustments in Years 2-4**

Two types of adjustments to costs are proposed in years 2-4. The first deals with non-fuel costs and the second deals with fuel related variable costs. In general, this approach is reasonable to segregate costs in this manner and update for adjustments in years 2-4.

1. Non-fuel Adjustment Factor (Page 55) – It accounts for inflation and foreign exchange fluctuations of the non-fuel costs. In addition, it adjusts for productivity factor (X) and other external reasons (Z). It is applied on a quarterly basis.

###### NFAI = NFAF ± X ± Z



A factor of 45% for operational costs is used for adjusting for inflation (i.e., 45% of the cost structure is susceptible to inflation), and a factor of 55% is used for FX. There is no discussion on the X and Z factors.

Questions:

* It is unclear how the 45% and 55% are arrived at. Which specific costs are affected by inflation and which specific costs are affected by the FX?
* Are these numbers based on historic values?
* How stable or volatile are these percentages from year to year?
* What is the base to which these percentages apply?
* What are the specific benchmark indices to use for inflation and FX adjustments?
* What productivity factor (X) is imputed and what is the basis?
* What externality factor (Z) is imputed and what is the basis?

1. Fuel and Purchased Power Adjustment:

This mechanism allows for the monthly pass through of fuel and PPA costs and appears reasonable. It accounts for regulator expectations on generator heat rates and system losses. The fuel costs are adjusted for target vs actual heat rate. If the actual heat rate is worse than the target, the utility is penalized and vice-versa. A fuel cost forecast is made for the next month to provide a price signal to consumers to allow them to modify their usage, but the forecast is based simply on two-month old actual fuel cost data.

Questions:

* It makes sense to reduce the fuel costs when the heat rate is worse than the target level. But if the actual heat rate is better than the target, should the generator be paid more? This is an incentive rate making issue with arguments on both sides. On the one hand, incentives, if structured properly, generally motivate a company to perform better, and then the resulting efficiency and cost savings can be captured for consumer benefit in a future period. On the other hand, should consumers pay extra for improved efficiency and if so, should be there a limit on it? Also, there would be questions about setting the proper targets for implementing the mechanism so there is no gaming by the utility.
* How good are the heat rate numbers? Is there enough historical data to make an assessment? What would be considered as an optimal heat rate that should be set as a target? What improvements would the company to have to make to achieve the optimal heat rate and what would it cost? Do the benefits justify the costs?
* The goal of providing customers the fuel price estimate for the next month (X) to send a forward-looking price signal is good. But using two-month old (X-2) actual data may defeat that purpose. For example, if the historic month is a low-price month and that is simply used for estimating next month’s price, consumers will consume more given the low-price signal. But the actual price next month may be much higher than the estimate that is based on historical data, defeating the purpose of the estimate. A forecast-month based fuel price needs to be explored to send a better forward-looking price signal to consumers.

**Section D: Rate Design**

The report recommends primarily the use of marginal costs to set tariff energy rates and the use of network access charges as a supplement to ensure the company covers the needed revenue requirement. The design also takes into consideration the alternatives consumers have, especially larger consumers, to bypass the utility and engage in self generation if the utility tariffs are set too high. The tariff energy rates constructed are on an inclining basis, i.e., higher blocks of consumption are charged progressively higher rates, supporting conservation goals. The large customers are also assessed demand charges to reflect the demand they impose on the system.

Typically, designing rates follows several principles, initially articulated by Professor Bonbright.

Some of the key principles are:

* Rate attributes: simplicity, understandability, public acceptability, and feasibility of application and interpretation
* Effectiveness of yielding total revenue requirements
* Revenue (and cash flow) stability from year to year
* Stability of rates themselves, minimal unexpected changes that are seriously adverse to existing customers
* Fairness in apportioning cost of service among different consumers
* Avoidance of “undue discrimination”
* Efficiency, promoting efficient

Viewed against these principles, the Quantum recommendations appear to focus heavily on efficiency goals. The rate design structure would also yield the needed revenue requirement to the utility. Stability of the rates from year to year may depend on the variability of several adjustment formulas in the ratemaking mechanisms. It is unclear though if the proposed structure is simple or easy to develop and administer.

Questions:

* There is no discussion on how the revenue requirement was apportioned among different customer classes first (domestic/residential, commercial, agricultural and large higher voltage customers)? What principles were used?
* There are no seasonal or time-of-use rates proposed. Why not?
* System capacity is typically designed to meet peak loads. Those who use more on peak are likely imposing higher costs on the system. How is this addressed in the tariff design?
* There is no explicit discussion on pass through of variable costs (fuel and purchased power). From the tables on pages 73 and 74, it appears the same value has been used for all kWh? Those who use more on peak will lead to a higher supply cost causation requiring higher cost generation units to be utilized (or from high priced imports) for energy? How is that reflected in the tariff?
* How were various marginal costs determined in the non-fuel part of the tariff?
* How stable are the marginal costs over time? How difficult is this exercise to repeat?
* How were thresholds for different usage tiers (0-100 kWh, 100-300 kWh, 300- 500 kWh and above 500 kWh) selected for differentiating rates?
* How are prepaid customer rates developed? It appears that they are higher than the post-paid customer rates. Why would customers want to prepay? Is it because they would escape any reconciliation charges?

**Section E: Various Performance Based Incentives**

1. KPIs for Reliability: Page 6

The performance levels for reliability, SAIFI and SAIDI are deteriorating. Incentive/penalty mechanisms are needed to improve the performance. A root cause analysis by the utility is necessary to identify and address weaknesses causing the deterioration.

Questions:

* What are the reasons for the deterioration in service quality?
* What measures are needed to bring the performance to benchmark levels?
* What incentive or penalty mechanisms should be utilized?

1. Zesco Payment Delays: Page 6:

The main driver of the huge increase in the Days Sales Outstanding observed in 2015 and 2016 is the account receivable created by Zesco Ltd. If Zesco payment pattern is causing pressure on the utility working capital needs, steps need to be taken to improve Zesco payment habits. The steps could include incentives or penalties to modify and improve Zesco behavior.

Questions:

* What are the reasons for Zesco delayed payments?
* What measures has the utility taken in the past to improve Zesco performance?
* What incentive/penalty mechanisms would be helpful to fix the problem?

**Section F: Miscellaneous**

1. Leverage Ratio:

Page 16 of the Quantum report states that the revenue requirement and the tariff calculated through the cost of service study is the same regardless of the level of capitalization of the debt the utility has with the government.

This statement is unclear. Typically, the cost of debt is lower than the cost of equity as the risk undertaken by investors in debt is lower than the risk undertaken by equity investors. Suggesting that even if debt is converted into equity, the cost of capital does not change is theoretically not correct, unless one uses the same cost for both debt and equity. The WACC computed in the report uses different costs for debt and equity, the cost of equity being higher than the cost of debt.

ANNEX

Cover Letter

To: EDM/Quantum

From: ARENE

Date:

Dear XX

Quantum prepared a report “Tariff Study in the Electricity Sector in Mozambique,” in November 2017, for the period 2019-22 for the electric utility EDM. We have reviewed the report and have several questions we need answers from you to help us understand the report better. The questions are listed below. We would like you to respond to these questions in 10 business days. Please submit the responses as you develop them instead of waiting for 10 days. If you require more time for any questions, please advise accordingly. In addition, we also want to discuss with you at a mutually convenient time the general philosophy of the use of price cap mechanism for a nascent regulatory system like ours.

If you have any questions, please do not hesitate to contact me.

Regards,

XXX

**Allowed Revenue Requirement Elements**

1. Tariff Increase Level:

The study projects an increase from the current level of tariff in 2017 of 6.54 MT/kWh to go up to 7.63 MT/kWh and to 8.84 MT/kWh in 2018 and 2019, respectively. That is an increase of 35% in just two years. If exports are excluded, the increase is not 35% but 54% (see table on page 18). Although the inflation was high in 2016 (19.2%) and 2017 (15.3%), it is expected to drop to a lower level of 6.7% in 2018 and 5.7% in 2019[[6]](#footnote-6). Compared to these inflation levels, the tariff increases seem high.

Questions:

* 1a) Please explain the primary drivers for the increase in costs.
* 1b) Please explain what steps you have taken to ensure that the cost levels are as efficient and low as possible.

1. Sales Projection:

The utility is projecting an increase in sales for the residential customers, from 1,624 GWh in 2017 to 3,058 GWh in 2022, or about 13% annual growth rate. This seems consistent with the growth rate in the number of residential customers from 1.35 million in 2017 to 2.7 million in 2022. Similarly, the load of MT customers is increasing from 1,128 GWh in 2017 to 1323 GWh in 2022, or about 3% annual growth rate. This is consistent with the growth rate in the number of MT customers. Finally, the commercial customer category load is growing from 408 GWh in 2017 to 639 GWh in 2022, or about 9.5% annual growth rate. The customer number is growing at about 11% annually.

Questions:

* 2a) Why are the sales levels lower in 2017 compared to 2016 even though the customer numbers are higher?
* 2b) Are the projections of increased number of customers realistic? How does it compare with the past growth rate? Please provide historical annual growth rate for the last five years in terms of number of customers and usage levels, by customer category and by year.
* 2c) Page 4 of the report states that the utility is currently connecting 118,000 new customers per year, but the World Bank[[7]](#footnote-7) has estimated that the country needs between 300,000 and 400,000 new customers in addition to those connected. There is no further discussion on this topic. What is the status of this initiative and what effort is the utility taking to increase access? Has it been accounted for in the sales forecast and in the allowed revenue computations in the report?
* 2d) Are there any issues associated with availability of potential supply (and/or imports) that could reduce the sales levels compared to forecast?

1. Losses: Page 14 and page 36

Losses are expected to drop from 25.9% in 2017 to 18.9% in 2022. However, from 2013, the loss level has been on an increasing trend. There is no discussion on the reasons for the deterioration in loss levels. Even if the projected improvement happens, the level is still high compared to other South African countries. See World Bank study (Figure 10, Page 45)[[8]](#footnote-8): the actual loss level for Sub Saharan African countries is 15%, and the ideal benchmark reference level is 10%. Reducing losses translates directly to lower costs and rates for customers.

Questions:

* 3a) What are the root cause reasons for the high loss levels?
* 3b) Has the utility considered taking steps to reduce losses? What are they? What are the implementation problems the utility is facing?
* 3c) Have losses been accounted for in sales properly?
* 3d) Even though this is an impressive projected drop, it is unclear if this projected improvement will really happen. What gives you confidence that the goal can be accomplished?
* 3d) What steps can be taken to achieve the World Bank study results for the benchmark reference level or at least the average loss level in the region?
* 3e) Are there any incentive mechanisms that can be implemented to motivate the utility?

1. WACC (starting on page 39):

Quantum used the standard framework for determining the WACC. For the cost of debt, Quantum used 5.41%. The tax rate used is 32%. The leverage assumption is 56% debt and 44% equity. For computing the equity return, Qantum used the Capital Asset Pricing Model with 4.79% and 6.39% for risk free return and market risk premium estimates, respectively. For an asset beta, it used 0.287. With the given leverage ratio, this asset beta translates to an equity beta of 0.535. They also added a country risk premium of 8.88%. This results in a required nominal equity return of 17.08% after tax and 9.58% nominal WACC after tax. On a real basis (net of inflation), the WACC is estimated at 7.22% after tax and 10.61% before tax.

Questions:

* 4a) What is the source for the assumptions for -
  + cost of debt,
  + asset beta
  + risk free rate
  + market risk premium and
  + inflation?
* 4b) How was the leverage ratio precisely derived? What is an optimal leverage ratio for the utility?
* 4c) Why should a country risk premium be added for a utility that is government owned and financed?
* 4d) The recent South African regulator NERSA decision arrived at a real WACC before tax of 6.9% (see table 42 of NERSA decision in 2018 in the ESKOM rate filing)[[9]](#footnote-9). This compares to the 10.61% being recommended by Quantum. Please explain the differences between the two utilities to justify why a significant premium should be paid to EDM?
* 4e) In some government owned utilities, equity cost is considered the same as the cost of debt. What are your views on using cost of debt for equity as well?

1. Regulated Asset Base (Page 17 and starting on Page 43):

Questions:

* 5a) Why is the RAB (net of third party funded assets) more than doubling from MT 31,290 million in 2017 (table on page 44) to MT 65,134 in 2017 (table on page 48) by the inclusion of CWIP and capital expenditures?
* 5b) Is depreciation accounted for in reducing the net asset base on which return is being applied? Show the specific derivation of the net asset base figures.
* 5c) What are the specific projects built into CWIP and capital expenditures?
* 5d) Please explain whether all those capital projects are needed, and if so, needed in this time frame?
* 5e) Is there an analysis showing the benefits and costs for each of the major capital projects?
* 5f) Were the capital budgets and major projects approved by the utility Board of Directors?
* 5g) Were rate impacts on customers considered when the capital budgets were adopted?
* 5h) How does the capital budgeting process at the utility work? What is the vision, what are the goals and how is the process laid out? What is the role of the management and the role of the Board in the capital budgeting decision making and oversight process?
* 5i) What is the planning period? How are projects designated and prioritized? How is the budget arrived at? How does the capital budgeting decision-making process at the utility work?
* 5j) Are there control systems in place to minimize abuse and inefficiency in spending?

1. Capital Expenditures: (page 17 and page 47)

Capex is increasing significantly in the coming years. Page 17 (and page 47) graph shows capex increasing from $50 million USD in 2017 to $322 million USD in 2021. That is an increase of over 6x in a four-year period, about 60% annual growth rate. Collectively almost $1.1 billion USD is planned to be spent in six years, with over 80% of the funding from utility sources and the remainder from donations. That is nearly 68 billion MT in spending over the six years or about 10.1 billion MT on average per year.

Questions:

* 6a) Even if it is deemed that these capital projects are needed in this time frame, realistically, can the utility perform the work?
* 6b) Anytime budgets are ramped up significantly in a short period of time, there is a high likelihood of introducing inefficiency and corruption in the execution. What steps are being taken and what control systems are in place to minimize such problems?
* 6c) Also, what inflation estimates were used in the projections? If the estimates by the utility were made in 2016 when the inflation was high, given the new current inflation projected estimates, are the old capex funding projections still valid?
* 6d) It appears that over 2/3 or more of the capex is related to transmission additions. Is there any analysis showing the costs and benefits for each of the major transmission projects?
* 6e) What are the past capex budget level and actual spending level, by year and by business unit, for the past five years?
* 6f) If there are variances between the budget and actual levels, what were the reasons for the variances?
* 6g) What is the oversight process at utility to monitor variances and take corrective actions?
* 6h) Should capex be reconciled after the fact to help reduce the risk if there is uncertainty in forecasting the spending levels?

1. O&M Expenses: (page 49)

The O&M costs consist of personnel, contractors, other costs and bad debt cost, per Quantum report (page 50). Based on the table on page 50, the costs are increasing by over 50% during this period. There is no baseline data for the years before 2017 to assess what the magnitude of the increase has been from the past levels. Also, no breakdown of the O&M is provided to assess the reasonableness of various inputs that went into this summary figures, and how the costs were allocated to various business units. The World Bank report (cited before) points out the level of overstaffing at utilities in Africa. Per Table 11 of the WB report, the utility has 3,763 employees whereas the optimal size should be 2,837 employees. Using this benchmark approach, this implies that there are over 900 (or 25%) excess employees at the company. In addition, the WB report states that the average employee compensation among utilities in Africa (excluding South Africa) is $13,000 USD per year, whereas the employees at this utility earn on average $17,000 USD (or over 30%). These two effects are additive and increase the costs to customers significantly.

Questions:

* 7a) What is the breakdown of the various O&M expenses?
* 7b) How are the O&M costs allocated to various business units?
* 7c) What is the past O&M budget and actual spending level, by year and by business unit, for the past five years?
* 7d) If there are variances between budget and actual, what were the reasons for the variances?
* 7e) What is the oversight process at utility to monitor variances and take corrective actions?
* 7d) What are the major drivers for the increase in O&M expenses in each of the years going forward?
* 7e) What efficiency, productivity steps have the company taken to reduce O&M costs?
* 7f) How does the company respond to the report from the World Bank on staffing levels?
* 7g) What is the basis for using a bad debt level of 1%? This seems rather low.

1. Fuel and Purchased Power Costs (page 51):

The fuel and power purchase costs are almost doubling over the period from 2017 to 2022 although the supply quantity (GWh) is only increasing by 50%. From the tables on pages 51 and 52, the bulk of the costs are caused by the IPP thermal units although they account for only 40% of the supply mix. The total revenue requirement table on page 52 shows that supply costs are nearly half of the total revenue requirement.

Questions:

* 8a) The supply and purchase costs are not broken down in granular detail. What is the fixed cost and variable cost breakdown for owned generation assets, and output levels, for each of the last five years?
* 8b) What are the unit prices for the IPP contracts? Please describe, especially for the thermal IPP contracts, how the energy and capacity payments are structured in the contract.
* 8c) Are there opportunities to reduce the IPP costs?
* 8d) Are there increased opportunities to export power?

1. Overall Revenue Requirement (page 52):

The overall revenue requirement increases by over 70% from 2017 to 2022, driven primarily by generation and transmission costs. It would also be helpful to see the build up of the revenue requirement by cost component (return, depreciation, O&M, taxes) to get a better feel for the cost drivers.

Questions:

* 9a) What is the buildup of the revenue requirement for 2018-2022, by year, using various cost components – return (debt, equity), depreciation, O&M, taxes, other levies, etc.
* 9b) Similarly, what is the historical composition for 2016 and 2017 of the same costs?
* 9c) What are the key changes from 2016, 2017 levels to the projected levels?
* 9d) Are there opportunities to reduce costs in any of those elements going forward?

**Adjustments in Years 2-4**

Two types of adjustments to costs are proposed in years 2-4. The first deals with non-fuel costs and the second deals with fuel related variable costs.

1. Non-fuel Adjustment Factor (Page 55)

It accounts for inflation and foreign exchange fluctuations of the non-fuel costs. In addition, it adjusts for productivity factor (X) and other external reasons (Z). It is applied on a quarterly basis. A factor of 45% for operational costs is used for adjusting for inflation (i.e., 45% of the cost structure is susceptible to inflation), and a factor of 55% is used for FX. There is no discussion on the X and Z factors.

Questions:

* 10a) It is unclear how the 45% and 55% percentages are arrived at. Which specific costs are affected by inflation and which specific costs are affected by the FX?
* 10b) Are these numbers based on historic values?
* 10c) How stable or volatile are these percentages from year to year? Please provide historical percentages for each of the last five years.
* 10d) What is the base to which these percentages apply?
* 10e) What are the specific benchmark indices to use for inflation and FX adjustments?
* 10f) What productivity factor (X) is imputed and what is the basis?
* 10g) What externality factor (Z) is imputed and what is the basis?

1. Fuel and Purchased Power Adjustment:

This mechanism allows for the monthly pass through of fuel and PPA costs. The fuel costs are adjusted for target vs actual heat rate. If the actual heat rate is worse than the target, the utility is penalized and vice-versa. A fuel cost forecast is made for the next month to provide a price signal to consumers to allow them to modify their usage, but the forecast is based simply on two-month old actual fuel cost data.

Questions:

* 11a) It makes sense to reduce the fuel costs when the heat rate is worse than the target level. But if the actual heat rate is better than the target, should the generator be paid more? Should consumers pay extra for improved efficiency and if so, should be there a limit on it?
* 11b) What are the targets for implementing the mechanism?
* 11c) Please provide historical average heat rate data for each of the last five years?
* 11d) What would be considered as an optimal heat rate that should be set as a target? What improvements would the company have to make to achieve the optimal heat rate and what would it cost? Do the benefits justify the costs?
* 11e) The goal of providing customers the fuel price estimate for the next month (X) to send a forward-looking price signal is good. But using two-month old (X-2) actual data may defeat that purpose. For example, if the historic month is a low-price month and that is simply used for estimating next month’s price, consumers will consume more given the low-price signal. But the actual price next month may be much higher than the estimate that is based on historical data, defeating the purpose of the estimate. A forecast-month based fuel price would send a better forward-looking price signal to consumers. Do you have tools to develop and send a forward-looking price signal?

**Cost Allocation and Rate Design**

The report recommends primarily the use of marginal costs to set tariff energy rates and the use of network access charges as a supplement to ensure the company covers the needed revenue requirement. The design also takes into consideration the alternatives consumers have, especially larger consumers, to bypass the utility and engage in self generation if the utility tariffs are set too high. The tariff energy rates constructed are on an inclining basis, i.e., higher blocks of consumption are charged progressively higher rates, supporting conservation goals. The large customers are also assessed demand charges to reflect the demand they impose on the system.

Questions:

* 12a) There is no discussion on how the revenue requirement was apportioned among different customer classes first (domestic/residential, commercial, agricultural and large higher voltage customers)? What principles were used?
* 12b) There are no seasonal or time-of-use rates proposed. Why not?
* 12c) System capacity is typically designed to meet peak loads. Those who use more on peak are likely imposing higher costs on the system. How is this addressed in the tariff design?
* 12d) There is no explicit discussion on pass through of variable costs (fuel and purchased power). From the tables on pages 73 and 74, it appears the same value has been used for all kWh? Those who use more on peak will lead to a higher supply cost causation requiring higher cost generation units to be utilized (or from high priced imports) for energy? How is that reflected in the tariff?
* 12e) How were various marginal costs determined in the non-fuel part of the tariff?
* 12f) How stable are the marginal costs over time? How difficult is this exercise to repeat?
* 12g) How were thresholds for different usage tiers (0-100 kWh, 100-300 kWh, 300- 500 kWh and above 500 kWh) selected for differentiating rates?
* 12h) How are prepaid customer rates developed? It appears that they are higher than the post-paid customer rates. Why would customers want to prepay?
* 12i) How complex is the proposed structure to develop and administer?

**Various Performance Based Incentives**

1. KPIs for Reliability: Page 6

The performance levels for reliability, SAIFI and SAIDI are deteriorating.

Questions:

* 13a) What are the reasons for the deterioration in service quality?
* 13b) What should be considered as optimal benchmarks?
* 13c) What measures are needed to bring the performance to benchmark levels?
* 13d) What are the benefits and costs of improving service quality?
* 13c) What incentive or penalty mechanisms would you recommend be utilized to motivate the utility to improve service in a cost effective manner?

1. Zesco Payment Delays: Page 6:

The main driver of the huge increase in the Days Sales Outstanding observed in 2015 and 2016 is the account receivable created by Zesco Ltd. If Zesco payment pattern is causing pressure on the utility working capital needs, steps need to be taken to improve Zesco payment habits.

Questions:

* 14a) What are the reasons for Zesco delayed payments?
* 14b) What measures has the utility taken in the past to improve Zesco performance?
* 14c) What incentive/penalty mechanisms would be helpful to fix the problem?

**Miscellaneous**

1. Leverage Ratio:

Page 16 of the Quantum report states that the revenue requirement and the tariff calculated through the cost of service study is the same regardless of the level of capitalization of the debt the utility has with the government.

Question:

This statement is unclear. Typically, the cost of debt is lower than the cost of equity as the risk undertaken by investors in debt is lower than the risk undertaken by equity investors. The WACC computed in the report uses different costs for debt and equity, the cost of equity being higher than the cost of debt.

1. Of course, there are other factors that could affect the effective total price paid by the customer, after the fact, such as capex reconciliations, excess earning sharing, and supply cost pass throughs, etc.  [↑](#footnote-ref-1)
2. https://www.statista.com/statistics/507333/inflation-rate-in-mozambique/ [↑](#footnote-ref-2)
3. Data on historical tariffs are not available readily to see whether they kept pace with inflation and other cost increases or not. Until we do a further analysis, it is premature to draw conclusions on the reasonableness of the increase. [↑](#footnote-ref-3)
4. World Bank Study dated August 2016: “Financial Viability of Electricity Sectors in Sub-Saharan Africa

   Quasi-Fiscal Deficits and Hidden Costs,” by *Chris Trimble, Masami Kojima, Ines Perez Arroyo and Farah Mohammadzadeh* [↑](#footnote-ref-4)
5. http://www.nersa.org.za/ [↑](#footnote-ref-5)
6. https://www.statista.com/statistics/507333/inflation-rate-in-mozambique/ [↑](#footnote-ref-6)
7. World Bank Study dated August 2016: “Financial Viability of Electricity Sectors in Sub-Saharan Africa

   Quasi-Fiscal Deficits and Hidden Costs,” by *Chris Trimble, Masami Kojima, Ines Perez Arroyo and Farah Mohammadzadeh.* [↑](#footnote-ref-7)
8. Ibid. [↑](#footnote-ref-8)
9. http://www.nersa.org.za/ [↑](#footnote-ref-9)