Kosrae Utilities Authority

Cost of Service and Tariff Study

FinalReport

submitted to: Kosrae Utilities Authority (KUA)

submitted by: KEMA Inc.

1October 2012

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1 Introduction

1.1 Project Background

Kosrae Utilities Authority (KUA) is a vertically integrated utility that supplies electrical power to the State of Kosrae, Micronesia. In the year 2011, KUA served 1,870 customers with a demand of 5,248,361 kWh. The peak load in that year was 1.06 MW.

The company is heavily dependent on external financing (grants) for undertaking investments. Most of the company's assets have been funded by grants from the USA and other states.

KUA's base tariff has not been reviewed and/or adjusted since 1991 and it is opportune to review the tariff in the fore field of possible private sector participation in the electricity industry in the Kosrae State. The review based on the findings will be required to provide recommendations on an appropriate tariff structure and on mechanisms to adjust the tariffs.

In this context KUA has asked DNV KEMA through the Pacific Power Associated (PPA) to undertake a study to review the current base tariff applied by KUA and recommend a tariff structure that balances the interest of consumers and the utility.

This Final Report presents the results of the analysis conducted by DNV KEMA and presents the possible options that KUA could consider to change the existing tariffs. The Draft version of this report has been presented and discussed with KUA and other stakeholders in the week of 25 September 2012. Based on this the draft version was further refined resulting in this Final Report.

1.2 Approach for this Study

During the Inception Phase of this project an assessment was made of the existing tariff policies and procedures as well as of the available data and information. Based on this the following approach was proposed and subsequently carried out after approval by the client:

1. **Tariff Level Analysis:** KUA's financial performance has been modeled and evaluated to evaluate the effectiveness of the existing tariff level. For this purpose KEMA has developed a financial model in the form of a spreadsheet model, which has incorporated capital and operational expenditures and income sources in order to identify financial performance and robustness of the company. Using the model different options to increase tariffs to assure sustainable financial performance of KUA have been evaluated.

2. **Tariff Structure Analysis:** An analysis has been performed to evaluate the existing tariff structure in use by KUA. This has provided insight into the extent to which the existing tariffs can be considered in line with the true costs associated with each customer group i.e. to what extent the tariffs for each customer reflect the true costs of providing supply. From an economic point of view an alignment between costs and tariff is desired as cost reflectiveness helps to promote efficiency. Based on this an alternative tariff structure for KUA has been developed.

1.3 Report Outline

The remaining of this report is structured as follows:

- Section 2 presents an overview on the financial model that has been developed and sets out the underlying modeling assumptions and data. In this chapter also the indicators and targets for evaluating financial performance are presented.

- Section 3 presents the results of the financial analysis that were performed making use of the model developed in Section 2. The gap in financial performance between current and desired tariff levels is assessed and possible tariff increase scenarios discussed.

- Section 4 deals with the tariff structure. A cost allocation analysis is performed to investigate the extent to which the current tariff structure is in line with the actual costs allocated to each customer category. Also here alternative tariff structures are investigated.

- Section 5 closes with the conclusions and presents the recommendations of this study.

2 KUA Rate Setting Model

2.1 General overview of the model

The KUA Rate Setting Model simulates revenues and costs and based on this, derives forecasts for Profit and Loss (P&L), Balance Sheet (BS), and Cash Flow (CF) statements as well as for key financial indicators. The format of these statements is kept the same as the published financial accounts by KUA.

Financial data for the financial years 2009/10 and 2010/11 have been used as the model's starting point. These are inserted as hard data into the model. From there on the financial model simulates the financial statements and indicators for the next 10 years i.e. until financial year 2021/22. This simulation can be performed under the assumption of different scenarios and parameter settings.

The model has been developed as a Microsoft Excel 2010 spreadsheet. A screenshot of the model is shown in Figure 1. After opening the file, the main model interface is automatically started up by displaying the "Cockpit". From here, the user can control the different model assumptions and settings as well as view the main simulation results directly in the form of charts showing the development of the key financial indicators over time.

A simplified outline of the model is presented in Figure 2. Given a certain demand and tariff, the revenues and costs can be projected. Investments have an impact on the capital cost i.e. depreciation and interest costs. From the revenue and cost assumptions the financial statements can be derived in the form of the balance sheet, profit & loss account and the cash flow statement. Finally, the financial ratios can be computed based on which financial performance can be evaluated. The following sections provide a more detailed overview of the main modeling assumptions and the data used.

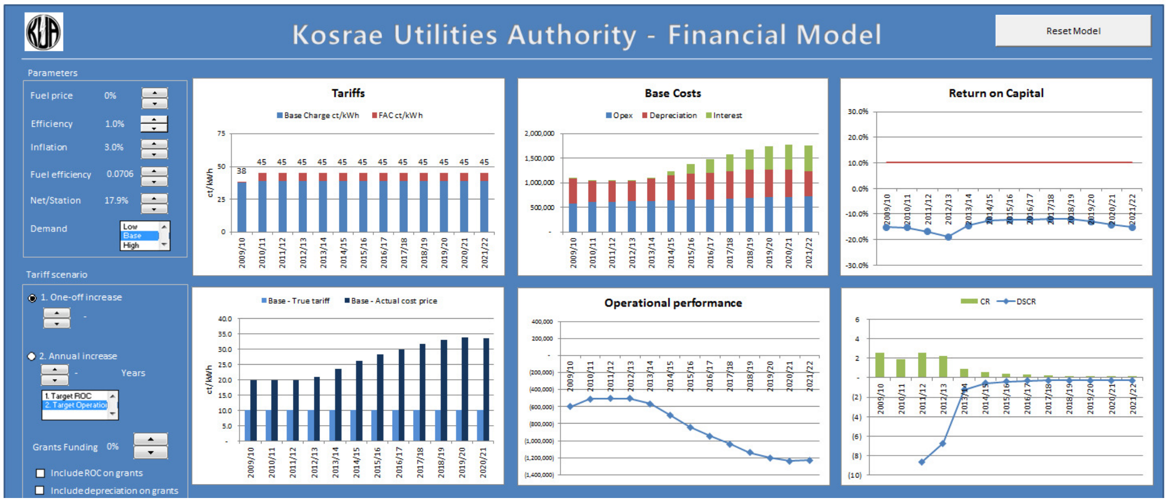


Figure 1. Screenshot of the financial model Cockpit interface

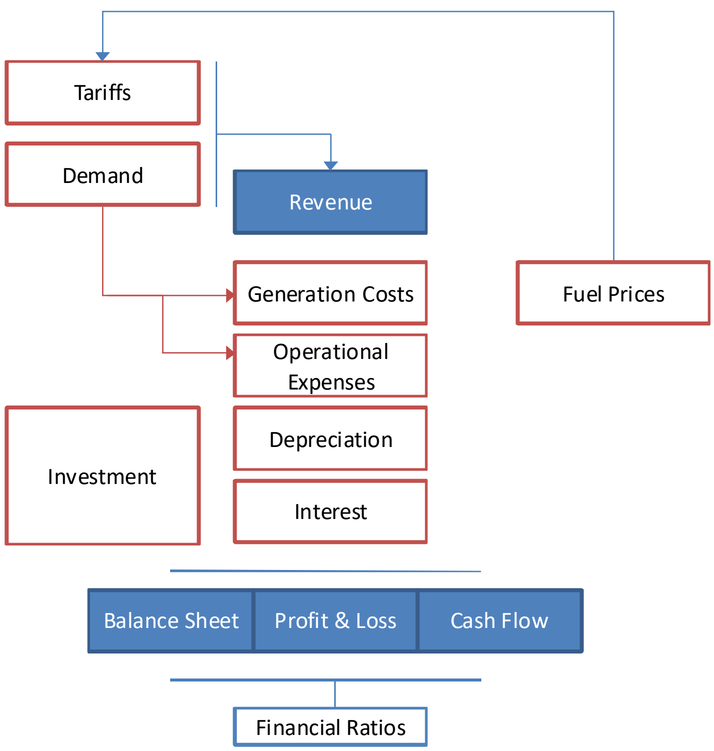


Figure 2. Simplified structure of the financial model

2.2 Model Assumptions

2.2.1 Demand

The number of customers has remained more or less stable in the last few years and stood at 1,870 by the end of 2011. Most customers are supplied via a prepaid meter. Households with 78% form the major part of the customer population.

Table 1 Number of customers supplied by KUA as per December 2011

	Metered	Pre-Paid	Total	Percentage
Residential	224	1,234	1,458	78%
Commercial	55	191	246	13%
Government	32	50	82	4%
Non-Government	26	43	69	4%
Industrial	14	1	15	1%
Total	351	1,519	1,870	100%

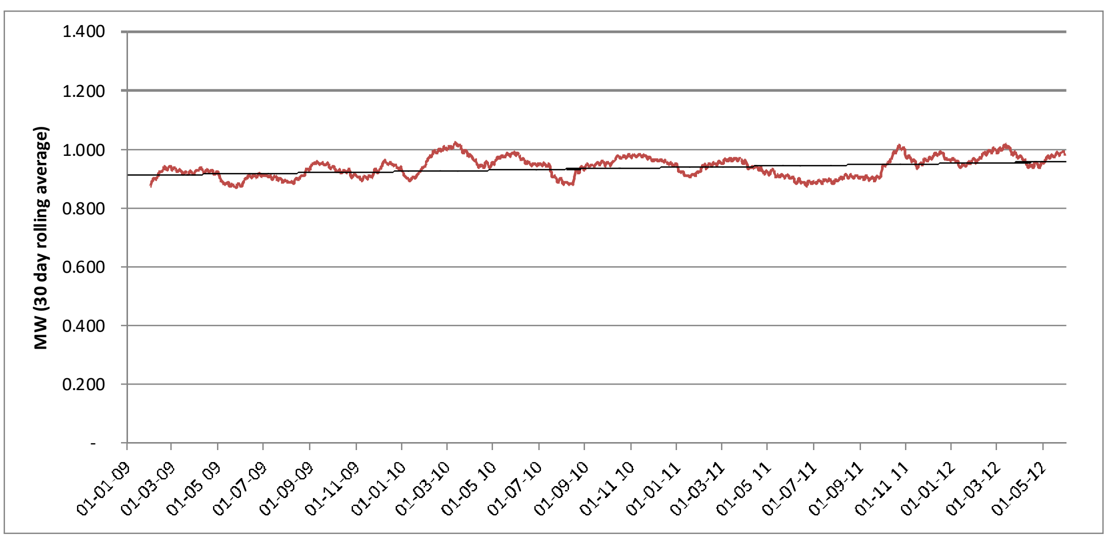


Figure 3 Development in the peak demand from 1 January 2009 – 31 May 2012. Demand shown is the 30 day rolling average based on daily peak demand data.

The system peak load in 2011 was 1.22 MW and the average load factor is around 60%. Peak demand has remained more or less flat in recent years as shown inFigure 3. For the future some new projects on the island are envisaged which will tend to increase demand such as a new hospital. For the immediate coming three years demand however demand will remain flat.

Demand forecast is set at zero-growth under the base case. During the analysis demand variation will nevertheless be included by considering annual increase/decrease levels. For the purpose of analysis a High and Low demand growth scenario have been assumed as well. These correspond to respectively +2% and -2% demand growth.

2.2.2 Tariffs

KUA's existing tariffs consist of two components:

- The Base Tariff, which is adjusted on an annual basis and is intended to cover the base costs of the company including a part of the fuel costs;
- The Fuel Adjustment Charge (FAC), which is adjusted monthly and is intended to cover the fuel costs in excess of the portion covered in the tariff rate.

Base tariffs are increased annually by 1 ct/kWh. This decision was made by the KUA Board in line with the policy to align income and costs in the long-run. The base tariff currently applicable to the period October 2011 – September 2012 are shown inTable 2.

Table 2. Existing base tariff. Prices in USD per kWh.

Block	Tariff 1 Residential	Tariff 2 Commercial	Tariff 3 Government	Tariff 4 Industry
0 - 100 kWh	$ 0.358	$ 0.398	$ 0.423	$ 0.423
101 - 1,000 kWh	$ 0.403	$ 0.413	$ 0.423	$ 0.423
1,001 - 10,000 kWh	$ 0.416	$ 0.423	$ 0.434	$ 0.428
10,001 - 100,000 kWh	$ 0.409	$ 0.414	$ 0.424	$ 0.418
> 100,000 kWh	$ 0.349	$ 0.373	$ 0.383	$ 0.343

As can be seen the tariffs has a mix of a progressive and regressive elements. For residential and commercial customers the initial block contains a relatively low tariff. This suggests a socio-economic policy of cross-subsidizing low consumption customers (which typically also tend to belong to the low-income groups). At higher consumption levels the tariff increases but then decreases again for consumption in excess of 10,000 kWh per month. In practice however no user has ever reached the 10,000 kWh thresholds.

The Fuel Adjustment Charge (FAC) is set on a monthly basis as X ct/kWh according to the following formula:

X= (FC x $0.08) - $0.29

Where FC stands for: Highest purchase costs, in dollars per gallon, of the diesel fuel delivered on the previous month and applied on the current month's kWh.

The base charge includes an allowance for fuel equal to 29 ct/kWh with surplus fuel costs recouped through the FAC. The 29 ct/kWh corresponds to a fuel price of 3.625 USD/gallon. The FAC thus recovers the costs of fuel in excess of this price. The FAC thus can also be negative in the case that the fuel price is below 3.625 USD/gallon; this situation has in fact occurred e.g. last year. Notably the FAC includes a linkage with the fuel efficiency which is targeted at 0.08 gallon/kWh (or 12.5 kWh/gallon). In the case that a higher efficiency is achieved (more kWh per gallon) the FAC is higher than the actual fuel cost price and hence a surplus can be obtained and conversely.

2.2.3 Fuel Costs

Total fuel costs depend on the total fuel consumption and the price of fuel. The various elements that drive total fuel costs are shown inFigure 4.

Fuel consumption depends on the gross production in kWh, which in turn is driven by demand and generation efficiency.

Based on data for 2011 a performance of 0.0706 gallon/kWh has been adopted. Note that this reflects the gross efficiency i.e. the quantity of electricity produced measured at the terminal of the generating units.

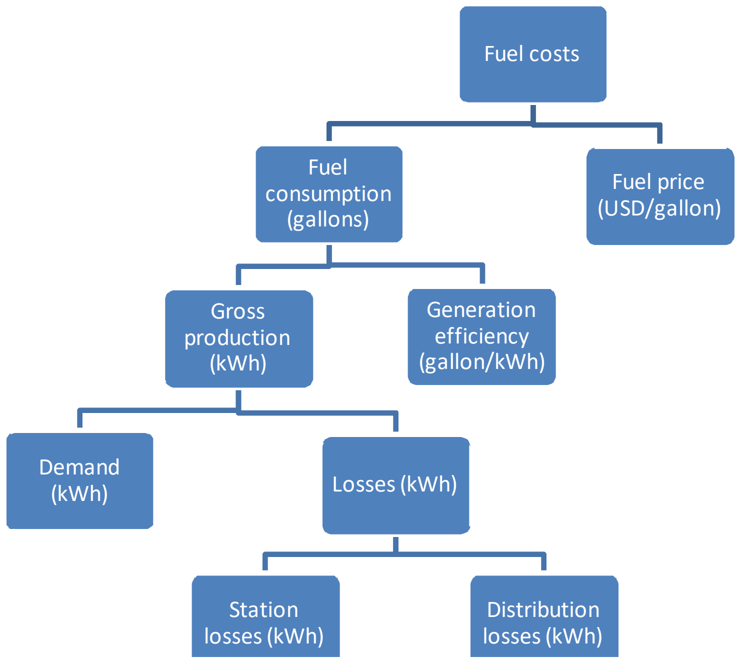


Figure 4 Factors determining fuel costs

Demand follows automatically from the selected demand scenario. All parameters are modeled as variables and can be adjusted in the model to investigate the impact of changes in the production mix and fuel price on prices.

Losses consist of two parts namely station losses and distribution losses. Station losses relate to the energy consumed by the power plant itself in producing the net energy output delivered to the grid. Distribution losses consist of technical and non-technical losses. Technical losses are the losses occurring in the various network assets due to thermal and magnetic phenomena while non-technical losses relate to metering and billing errors. The base assumptions regarding station and network losses together are 17.9% based on data for 2011. In the model it is possible to project a reduced level of losses over time.

Fuel prices for 2011 are taken as the average price incurred by KUA during the financial year 2011 (USD 4.34/gallon[1]). For each subsequent year prices are projected by selecting an oil price scenario. Note further thatall fuel-related costs are included in this price (i.e. lubricants and fuel conditioning). In the case of KUA these form about 2% of the total fuel costs. In the model fuel prices are by default assumed to be fixed but can be increased or decreased as required.

Note that the 0.08 gallon/kWh in the FAC formula considers the net efficiency i.e. the number of gallons used to deliver 1 kWh to the final customer. This number thus includes the gross efficiency (conversion of fuel into electricity at the power plant) and the losses (station and distribution losses). As mentioned earlier the gross efficiency in KUA in 2011 was 0.0706 gallon/kWh. The actual net efficiency was 0.0832 gallon/kWh which is less than the target of 0.08 implied in the FAC formula. This suggests that KUA is making a loss on the FAC front.

Table 3. Fuel consumption versus gross production and sales. Gross efficiency is defined as fuel consumption divided by gross production. Net efficiency is fuel consumption divided by sales.

		2009/09	2009/10	2010/11
Fuel	gallon	420,372	452,628	436,894
Gross Production	kWh	6,022,171	6,504,201	6,188,752
Losses	kWh	852,813	991,475	940,391
Sales	kWh	5,169,358	5,512,726	5,248,361
Gross efficiency	gallon/kWh	0.0698	0.0696	0.0706
Net efficiency	gallon/kWh	0.0813	0.0821	0.0832

[1] Total fuel consumption was 436,894 gallons at a cost of USD 1,894,071. Note that these totals also include the gallon consumption and cost for fuel used for vehicles as well as costs for lubricants and others.

Figure 5 Actual net efficiency of KUA versus target implied by the FAC

2.2.4 Revenue and Grants

Revenue income consists of the following two main components:

1. **Base charge revenue**: This is the revenues earned through the base charge and is the base charge times the kWh sales, summed up for each customer category.

2. **FAC revenue**: The FAC revenue represents the income generated by application of the FAC. This FAC is set in line with the current specification. Note that the FAC can be negative. In practice there will be a one-month lag between actual costs and invoiced surcharge. As the financial model is on an annual basis this lag is ignored.

In addition to the normal revenue income the model also allows the possibility to project **Grant Income**. Grant incomeis assumed to be used for financing of investments. In the model the possibility has been programmed to indicate what percentage of total investment is to be financed through grants (see also section 2.2.7)

2.2.5 Operating Expenses

The starting point for operating expenses (excluding fuel and depreciation which are treated separately) is the historical opex record as observed from the financial accounts. In order to derive the forecast for opex, demand has been adopted as the main opex driver.

In developing opex forecasts one also needs to take into account the fact that opex levels are affected by general inflation trends. Over time, the nominal prices of goods and services procured by KUA will increase and this will have an upward effect on its opex. For inflation a value of 3% has been adopted based on the latest available information for the year 2010.[2]

Operational Efficiency

Productivity improvement is modeled by an annual decrease in the required costs per kWh. The increase in efficiency can come through two fundamental routes. First, productivity can be increased up to the level of so-called best-practice performance. Initially, it is fair to assume that KUA is not as efficient as the most efficient similar sized electric island utilities in the world. These most efficient utilities would determine the so-called productivity frontier. The distance between KUA's actual productivity performance and the frontier is a measure of the efficiency improvement potential that could be achieved. Second, over time, due to ongoing technological improvements, the productivity frontier itself will also shift. That is, even the most efficient utilities will become more efficient over time. This is also referred to as dynamic efficiency improvement.

In order to establish the expected increase opex efficiency, one should take into account that improvement is a continuous process over time rather than a one-off event. For the base case, the assumption is that KUA has potential to improve its efficiency at a level of 1% per annum.

[2] Source: World Bank, http://www.tradingeconomics.com/micronesia/inflation-gdp-deflator-annual-percent-wb-data.html

The opex forecast is dependent on the choice of demand forecast with costs increasing more under the high scenario and vice versa.

2.2.6 Investment and Depreciation

Based on projected capex, depreciation costs and net asset values (book values) for new investments have been computed. The assumption is made that no disposals (capital exits) take place. Investments forecasts have been obtained from KUA's forecasts. A distinction is made between (1) existing investment and (2) new investment.

Table 4 Overview of projected investments by KUA

	USD	Year
A. Conventional energy projects		
1 Upgrading of Lelu distribution system	450,000	2014
2 Replacement of old cables at Okat	100,000	2013
3 Replacement of KUA power plant sybstatio	450,000	2014
4 Replacement of transformer at Okat Dock	50,000	2014
5 Major overhauling gensets 6 and 7	400,000	2013
6 Fuel buffer stock of 30,000 gln	105,000	2013
B. Energy efficiency projects		
1 New 1250 kW genset	1,200,000	2013
2 Replacement of 750 kW backup genset	750,000	2014
3.1 pre-paid kWh meters	250,000	2013
3.2 kW demand meters	50,000	2015
3.3 Public information campaign	30,000	2014
3.4 Feasibility study heat energy	20,000	2015
3.5 LPG dealership	200,000	2015
3.6 Kosrae building code	25,000	2015
3.7 Hybrid drive	50,000	2014
3.8 Public transport policy	750,000	2014
3.9 Manpower effciency improvement	50,000	2015
4 Loss control	30,000	2014
5 Prototype study	40,000	2013
C. Alternative renewable energy		
1 Solar projects	400,000	2013
2 Small hydro plant	1,500,000	2017
TOTAL	6,900,000	

Existing investments are reflected in the balance sheet as per 30 September 2011. The depreciation in 2010/11 is used as the starting point. Depreciation costs for existing investments are projected to slightly decrease over time, reflecting the fact that some assets have been fully depreciated and therefore removed from the net asset base.

New investments are those undertaken after 30 September 2011. New depreciation is derived from the level of projected investments and is computed on the basis of straight-line depreciation. An average depreciation period of 25 years is assumed based on the analysis of depreciation periods and remaining asset lives in KUA's existing asset base.

For the level of new investment a default scenario has been used as provided by KUA. A summary of this plan is Table 4.As can be seen the investments are concentrated in the years 2013 and 2014. To allow a smoother investment profile the assumption has been made that all investment is undertaken in the period 2013/14 till 2018/19 with a concentration in the first two years. The resulting allocation is shown inFigure 6. Note however that an analysis of previous investment figures show much lower levels (USD 36,061 in 2010/11 and USD 114,872 in 2009/10). On this basis for the years 2010/11 and 2011/12 a level of USD 100,000 has been assumed.The total depreciation for existing and new assets is shown inFigure 7.

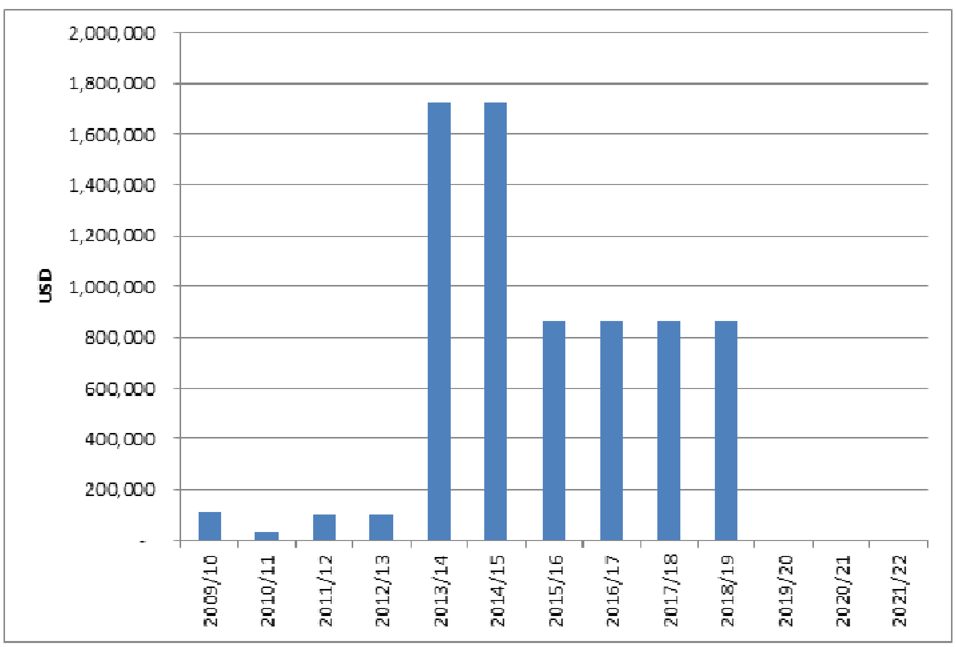


Figure 6 Projected investment based on KUA planning and smoothed over time

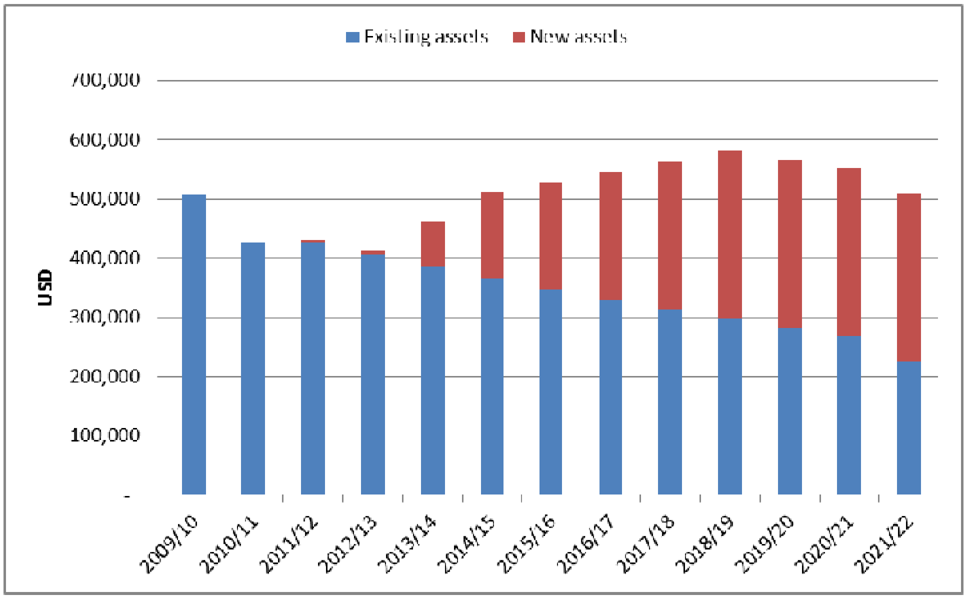


Figure 7 Projected depreciation for existing and new assets

2.2.7 Investment Funding

Financing of new investment is modeled in terms of two options, to be selected by the user.

Option 1: Own funding

Under this option financing of new investment is assumed to take place by KUA itself through a mix of equity and long-term debt. A base case of 66% / 33% debt/equity allocation is assumed. This allocation can be changed in the model. For the debt part (66%) an interest rate of 7.5% and a repayment period of 10 years has been assumed. The remainder of the financing requirement is assumed to come from equity (through cash reserves or alternatively short-term loans).

Option 2: Grant funding

The second option is to have all investment financed through external grant funds. Under this option the grant is treated as income under the profit & loss account and hence results in an increase in net assets. The asset obtained through the grant is booked under the assets side of the balance and depreciated annually.

2.2.8 Working Capital

With respect to working capital assumptions are made for the following balance sheet elements:

- Inventories change in proportion to the net asset value
- Receivables and payables change in proportion to tariff revenue

Current loans are used for the financing of working capital. In the modeling the assumption is that changes in current loans are set equal to changes in working capital. Effectively the net effect on the cash flow is thus zero.

2.2.9 Other assumptions

In addition to above some additional assumptions have been made:

- **Cash:** The assumption is that KUA targets to maintain a cash balance of USD 150,000. This value can be changed in the model.
- **Taxes**: Corporate profits are not subject to income tax in the Federated States of Micronesia. There is a gross receipt tax of 3% on revenues. KUA is however specifically exempt from this tax or any other taxes such as taxes on property, operations, or activities imposed by the Government.
- **Exchangerate**: All figures are nominated in United States Dollars.

2.2.10 Summary of Main Model Parameters

A summary of the default values for the main model parameters areshown inTable 5. All default parameters can be adjusted as required in the model.

Table 5 Summary of main model parameters

Model parameter	Default value
Demand growth	Flat
Depreciation period	25 years
Loan interest	7.5%
Loan repayment	10 years
Financing	2/3 (66%) debt
Minimum cash	150,000 USD
Fuel prices	Flat
Efficiency improvement	1% per year
Inflation	3% per year
Fuel efficiency	0.0706 gallon/kWh
Net + Station losses	17.9% of sales

2.3 Financial Targets

A sound financial performance should meet, at least, a revenue requirement enough to ensure full recovery of supply costs and satisfy the basic financial objectives and covenants faced by of the company. The revenue requirement (and therefore tariff requirements) will include the operational and maintenance costs necessary to sustain a continuous supply to customers and the capital costs related to the recovery and remuneration of investments.

Based on the financial performance, it is possible to evaluate and compare the effect of different rate structures on the operational results and long-term sustainability of the company from the financial perspective.

2.3.1 Return on Capital

The required rate of return of any business is the opportunity cost of capital, that is, the return expected in alternative investments with similar risk. This requirement is usually measured in relation to the returns obtained in financial capital markets. The Weighted Average Cost of Capital, WACC, is the most common method used for calculating the minimum rate of return of a business. The WACC is the average of the cost of each component of the capital structure of the company, debt and equity, weighted by their share on total capital. It is therefore the weighted average of the return required by lenders and shareholders of the company, who are the providers of capital. An estimation of the WACC for KUA is carried out in Annex 2 of this report and showed a rate of return of 10% to be appropriate.

2.3.2 Debt Service Coverage Ratio

Another indicator for the ability to borrow is the Debt Service Coverage Ratio (DSCR). The DSCR gives an indication of an organization's excess revenues over debt obligations. The higher, the more funds the company has available to finance its debt obligations (interest and principal payments). Consequently, the better the company is able to attract new debt.

It is computed as (net income + depreciation + interest) / (repayments + interest). Target values are typically a minimum of 1.5 while the desirable level is above 2.0. A lower level implies that there is a risk that excessive level of debt (and consequently high interest and principal payments) can quickly consume any excess revenues.

2.3.3 Current Ratio

Liquidity is the ability of a company to satisfy its short-term obligations with current assets. In contrast to viability, liquidity is a short-term element of financial health. The fact that a company has substantial resources to operate over the long term (viability) could be irrelevant if it does not have the cash or other resources easily convertible to cash to pay its bills in the coming twelve months.

For measure liquidity the Current Ratio is typically used. This indicator is computed by dividing total current assets by total current liabilities. This ratio provides a measure of a business's current assets in proportion to its current liabilities and indicates whether the organization has sufficient cash or other easily convertible assets to cover its obligations due in the next twelve months.

A ratio of less than 1.0 suggests that the firm's liquid resources are insufficient to cover its short-term payments. Moreover a ratio less than 1.0 indicates that fixed assets are being financed partially with short-term debt. This is not considered to be a good management practice. Short-term debts become due quicker than long-term debt, so there is greater risk of non-payment.In practice, a current ratio of 1.2 is generally considered to be desired.

2.3.4 Summary Financial Targets

It should be emphasized that the financial ratios are functionally intertwined, reflecting the logical relationships among the components of the balance sheet, income and cash flow statements. So, for instance, the earnings generated by the company's operations are reflected in the profit margin, return on assets and cash flows, which in turn reveal liquidity and solvency. Therefore, it is convenient to consider the ratios as indicative of the financial position of the company and in the context of their relationships.

Table 6. Expected range of financial indicators

Financial Indicator	Expected Range
Return on Capital (post tax nominal)	≥10%
Debt Service Ratio (DSR)	≥ 1.5
Current Ratio	≥ 1.2

3 Analysis of KUA Tariff Levels

The financial model described in the previous section has been used to perform financial analysis of KUA. A number of scenarios have been investigated and the results are now presented. First an assessment is done of how financial performance will develop in the case of the existing tariffs (Scenario 1). Second, it has been investigated what tariff adjustment would be necessary to bring the financial performance of KUA in line with financial targets (Scenario 2). Finally the practical realities have been taken on board and the possibility of financing (part of) investment through grants is also considered (Scenario 3).

3.1 Scenario 1: Existing Tariffs

As a start the situation has been analyzed where the existing tariffs would remain as they were. The assumption is that all planned investments are undertaken and financed internally by KUA with 66% of the funding from new loans. Furthermore no grants are assumed.

3.1.1 Scenario 1A: No change in tariffs

Figure 8shows the development in tariffs and costs over time.

As can be seen the base charge is frozen at the current level of around 39 ct/kWh. The FAC is also kept constant through assuming no changes in the fuel price. There is a substantial difference between income and costs with the true base charge being at a level lower than the actual base costs. Note here that the true base tariff is defined as the current base charge without the 29 ct/kWh, which is to be allocated to the true FAC.

In terms of costs it can be seen that base costs increase substantially. This is a direct effect of the investment program, resulting in higher depreciation costs as well as higher interest costs from the loans required to fund the investment. In addition there are also interest costs for short-term loans, which are necessary to finance the operational deficit of the company. This also adds to the base costs. As can be seen the operating result is structurally negative, which is a direct effect of tariffs being below costs. Here operating result is defined as the difference between operational costs and operational income.

Having considered the developments in tariffs and costs it is also useful to take a look at how the performance of the company evolves in terms of financial indicators. As can be seen the return on capitalvaries between -10% and -15%, which is much lower than the target of 10%. The debt service ratio is also at an unhealthy level well below the minimum target of 1.5 and remains more or less zero i.e. there is no capacity to pay back the loans and associated interest costs. Finally the current ratio reduces over time very much below the target of 1.2 reflecting the fact that the operational deficit is being financed with current liability (short-term loans) hence diminishing the liquidity of the company.

Figure 8 Simulation results for Scenario 1A: Current Tariffs

3.1.2 Scenario 1B: Annual increase of 1ct/kWh in the Base Charge

There is currently a policy of increasing the base charge by 1 ct/kWh every year. This is shown in Figure 9where it can be seen that the base charge increases gradually each year. In terms of costs there is little difference with the first scenario, except for the fact that interest costs now are somewhat lower. The additional income generated through the 1 ct/kWh results in a lower operational deficit and hence less need for additional current liabilities (and hence lower interest costs).However, in terms of financial performance the overall picture remains more or less the same as under the first scenario. Even though financial performance is a little bit better, in absolute terms performance is still well below the desired target levels. The 1 ct/kWh increase per year essentially has a somewhat delaying effect but does not structurally solve the financial problems.

Figure 9Simulation results for Scenario 1B: Annual base charge increase of 1ct/kWh

3.2 Scenario 2: Tariff Increase for 10% ROC

In order to arrive at a sound financial performance level it will be necessary for KUA to achieve a rate of return in line with its capital costs. Thus, the rate of return on capital will need to be increased from the current -15% region to the target of 10%. This can be achieved through a tariff increase, for which two options have been considered. The first one is an initial one-off increase in tariffs, to be implemented at the start of the financial year 2012/13. The second option is to gradually increase tariffs year by year. Under a one-off increase there is a sudden increase in the tariffs but after that tariffs remain fixed. With a gradual increase the tariff increase is more gradual but the full tariff increase effect takes a longer time to materialize.

3.2.1 Scenario 2A: One-off increase in tariffs

Using the financial model it can be computed that in order for financial performance to be in line with targets an initial increase in the base charge would be needed of around 23 ct/kWh. If such an increase were implemented it can be seen from the financial trends that KUA would iterate towards a return on capital around 10% in the longer run with the debt service ratio above the minimum requirement of 1.5. The current ratio would also be at very good levels and well above the minimum requirements. Note that in practice though the current ratio would likely be lower as surplus cash would be paid out to the shareholder as dividends.

Figure 10 Simulation results for Scenario 2A: One-off tariff increase

3.2.2 Scenario 2B: Annual Tariff Increase

Another possible way to implement a tariff increase is to gradually increase the tariffs year by year until the point that financial indicators are in line with targets. Using the model it has been calculated that this would require an annual increase in the base charge of 2.5 ct/kWh for a period of 10 years.

The financial results show a corresponding increase in performance over time as the tariff is progressively increased. Note that the current ratio nevertheless remains below target levels due to the fact that the gradual tariff increase implies that the operational loss is reduced gradually over time only. Thus in the intermediate there will still be a strong need to attract additional short-term loans to finance the cash flow deficit, which is reflected in an unfavorable current ratio.

Figure 11Simulation results for Scenario 2B: Annual tariff increase

3.3 Scenario 3: Grant-funded Investment

In the previous scenario the necessary tariff increase was computed on the assumption that financial performance needs to be at a 10% rate of return. The question may be put whether this assumption is practical given the economic realities in Kosrae. A one-off tariff increase of 23 ct/kWh would correspond to an increase of around 50%, which may not seem entirely realistic. Similarly, an increase of 2.5ct/kWh for a period of 10 successive years could be challenging to implement in practice.

On the other hand it is a known fact that KUA is very much dependent on grant funding for financing investments. KUA's policy with respect to grants is to book these as income (adding to cash at the asset side and net capital at the liability side) and subsequently using this to finance the assets (transferring from cash to book value at the assets side). Grant-financed investments are thus treated as a normal asset and a depreciation charge is applied to them. Furthermore, given the way how these assets are treated, financial profitability analysis of the company would require these assets to be included in the capital base for judging the rate of return generated by the company. That is, the tariff increase computed under scenarios2 also allows for a return on these grant-funded assets.

Theoretically speaking such a return should be applied as it represents a return on the company's capital. Thus, the company could have used the grant alternatively and earned a return on that investment. Not allowing for a return would thus imply opportunity costs. In practice however the grant is most likely to be conditional on specific investments and alternative applications of the grant amounts are typically not allowed. Then the grant becomes sunk and making allowances for a return would no longer be justified.

3.3.1 Scenario 3A: Break-Even Performance

In this light an alternative scenario has been analyzed where the assumption is that future investment is funded through grants. Furthermore the assumption is that no return is expected on these investments. This means that under this scenario KUA is expected to achieve a break-even outcome with operational income at the same level as operational expenditures. There would be no costs of capital as all capital is financed through grants.

Note that in the operational expenditures an allowance for depreciation on grant-funded assets is included here. This assumes that KUA should make sufficient reservations to be able to replace these assets at the end of their lifetime through own funds rather than being dependent on grants again.

The break-even situation is expected to be achieved through a one-off increase of the tariff.This increase is calculated to be 14 ct/kWh. Note that in the initial year there would be an operational surplus but in subsequent years the tariffs and costs would align again with increasing costs over time.

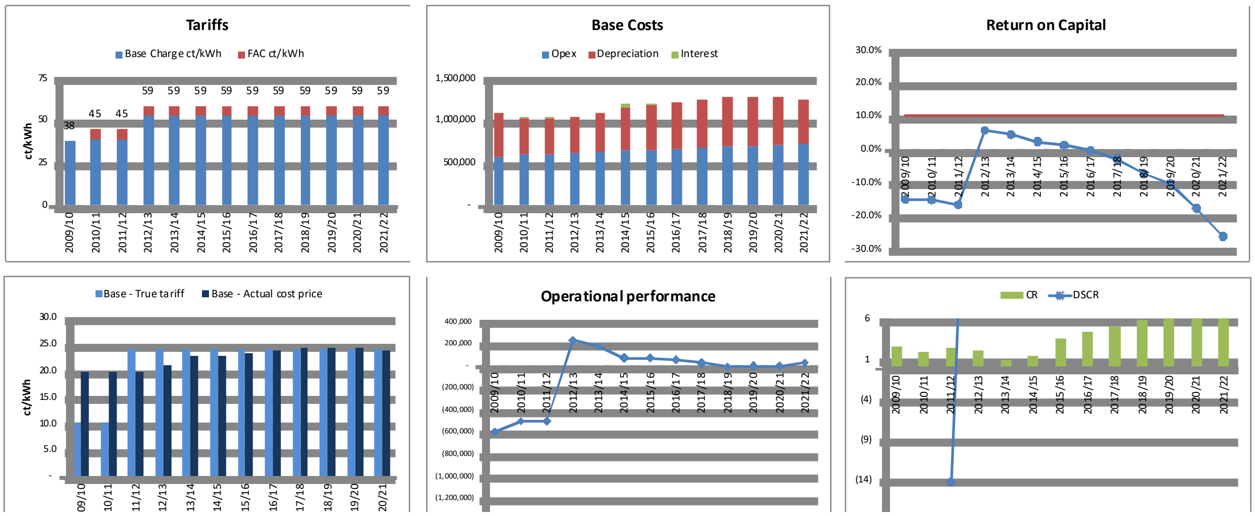


Figure 12 Simulation results for Scenario 3A: Break-even performance

3.3.2 Scenario 3B: Break-Even Performance / No grant depreciation

The previous scenario can be taken even further by also assuming that no depreciation allowance should be made for grant related investment. This is an important consideration as choosing so would imply that renewal of assets would also only be possible through new grants.

The necessary tariffs increase in this case is 9 ct/kWh. KUA would then have sufficient operational income to sustain its operations. However, KUA would not have any resources to undertake capital projects on its own. In other words the company would be able to operate in a normal operational manner but also be entirely dependent on external grants for any investment.

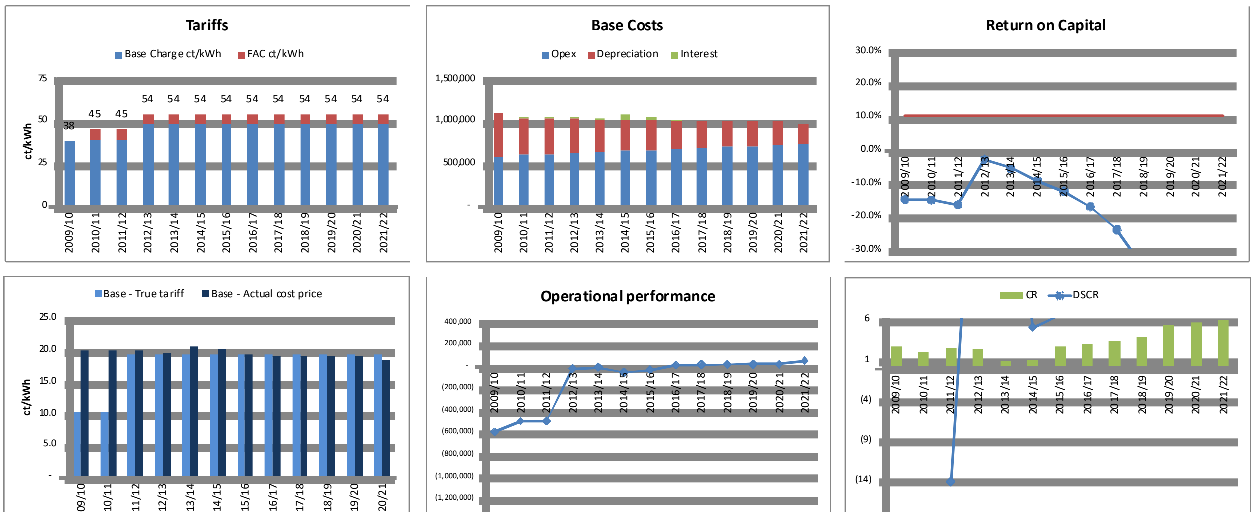


Figure 13 Simulation results for Scenario 3B: Break-even performance / No grant depreciation

3.4 Summary of Scenario Results

In this section three main scenarios have been evaluated. The main results are summarized in the Table 7.

Under scenario 1 the impact of existing tariffs on financial performance was reviewed. It was seen that maintaining the current tariffs (or even the 1/ct/kWh increase per annum) will result in a financially serious situation for KUA. Not only will financial targets not be achieved, but the company will also not be able to undertake the projected investments on its own. Furthermore there remains a structural difference between operation income and operational expenditures. This deficit results in a continuous diminishing of the net assets and eventually technical bankruptcy.

Under scenario 2 the requirement of financial sound performance, as defined in achieving a 10% return was investigated. It was revealed that to bring about a sudden turn in financial events a tariff increase of 23 ct/kWh would be necessary. If this was to be done, then KUA would be able to generate sufficient income to undertake all projected investments on its own (based on a 60/40 debt/equity financing structure) and to achieve excellent financial performance. Alternatively the one-off increase can be substituted by an annual increase of 2.5 ct/kWh during a period of 10 years.

Finally under scenario 3 the strict financial requirements were relaxed and the possibility of funding of investment through external grants was also considered. In this case KUA would be mainly focusing on the operational side of the business. To assure operational balance between tariffs and costs it was computed that an increase of 14 ct/kWh would be needed. Alternatively if it were decided that future investment should also be (indefinitely) dependent on grants, then the tariff increase could be limited to 9 ct/kWh. This could possibly also be substituted by an annual tariff increase during a number of consecutive years.

Table 7 Summary of scenarios analyzed using the financial model

Scenario	Assumptions	Necessary Tariff increase	Financial impact
1A	Existing tariffs	n/a	Financial performance well under targets
1B	Existing tariffs + 1 ct/kWh increase	n/a	Slight improvement but still financially well under targets
2A	10% rate of return	23 ct/kWh one-off increase	10% rate of return
2B	10% rate of return	2.5 ct/kWh during 10 years	10% rate of return but only after some time
3A	Investments dependent on grants	14 ct/kWh one-off increase	Operational break-even but allowance for depreciation
3B	Current + Replacement investments dependent on grants	9 ct/kWh one-off increase	Operational break-even, no allowance for depreciation

4 Analysis of KUA Tariff Structure

4.1 Cost Allocation Analysis

4.1.1 Introduction

This chapter presents the results of the cost allocation analysis that was carried out for KUA. The main purpose of this is to obtain information about the true costs per customer group as compared to the currently implied costs by the existing tariff structure.

The purpose of the cost allocation analysis is to identify to what extent certain customer groups contribute to the costs of KUA. From a theoretical economic point of view tariffs should be set at a level such that they reflect the marginal cost of supply. That is, the price paid for each additional unit of consumption should be equal to the additional costs incurred by the utility due to the additional consumption. This results in an economically efficient income as customers are provided with the right price signals.

In practice this marginal cost analysis approach however is not possible to be applied here due lack of data (absence of demand growth) and the small size of KUA. Due to this it was agreed that the cost allocation analysis would be based on the so-called embedded cost analysis. Here, rather than marginal costs we consider the already incurred costs with the company, and try to allocate these costs to the various customer groups.

In carrying out the cost allocation analysis three steps need to be carried out namely (1) Functionalization, (2) Cost Classification, and (3) Allocation to Customers. These are discussed in the following sections.

4.1.2 Functionalization

First the three main functions within the electricity supply chain need to be identified namely (1) Generation, (2) Network, and (3) Supply:

- **Generation** costs are related to the function of producing the electricity; this would entail the costs associated with the power plant (including station/auxiliary losses).

- **Network** costs are those costs incurred in the network system (note that KUA only has distribution and no transmission) and would include the costs associated with the investment and maintenance of these assets as well as the technical and non-technical losses.

- **Supply** costs are those costs not associated with the technical product (electricity) but the costs associated with metering and billing and service to customers.

For carrying out the cost functionalization use was made of cost data from KUA's accounting systems. In this system the costs are allocated to the following cost centers:

1. ADM: Administration

2. CSM: Customer service and metering

3. DST: Distribution

4. PRO: Production

5. P&E: Planning and engineering

The five cost centers have been rearranged into the three functions (Generation, Network, Supply) based on the following criteria:

- Cost of DST and PRO are directly allocated to Network and Generation, respectively;

- Cost of CST has been allocated to Supply;

- Costs of ADM have been allocated to the three functions on a pro rata basis;

- Cost of P&E have been allocated to Network and Generation on a pro rate basis.

Note that fuel costs related to vehicles have been allocated to the respective function except for the fuel costs for production, which has been allocated between Generation and Network. In the KUA accounting system currently no distinction is made between fuel costs related to plant consumption, net energy output, and distribution losses. Rather all fuel costs are currently allocated to PRO and were re-allocated on the basis of losses information.

Table 8 Energy losses information used for allocating fuel costs

	MWh	Allocated to
Gross plant production	6,022	
Station consumption	300	Generation
Feed into network	5,722	Generation
Losses in network	552	Network
Total Sales (inc streetlights)	5,170	

The Table 9 shows an overview of the costs incurred by KUA for the financial year2010/11 and the allocation to the generation, network, and supply functions.

Table 9. Allocation of expenses to the three functions

Results of Functionalization (USD)

	Generation	Network	Supply	Total
Fuel - Production	1,711,265	172,691	-	1,883,956
Fuel - Vehicles	2,408	4,241	3,465	10,114
Depreciation	212,337	211,235	3,046	426,617
Salaries and Wages	202,963	96,464	70,304	369,731
Administrative and general	88,617	34,844	20,568	144,028
Repairs and maintenance	49,931	31,672	1,825	83,428
Total	**2,267,521**	**551,146**	**99,208**	**2,917,874**

4.1.3 Classification

The next step is to classify the costs identified under the functionalization step into different cost components. These represent the services supplied by KUA which, in principle, should also be charged for as separate “products”:

- **Capacity Component (kVA):** These represent the costs incurred by KUA related to provide a system capable of meeting all capacity requested by its customers. Simply stated these are the costs of setting up and maintaining a system such that the potential demand of all customers could be satisfied. These costs are fixed costs i.e. do not change as a function of consumption (in the short-term at least).
- **Energy Component (kWh):** Energy costs vary directly with kWh production and are mainly related to the fuel and associated costs. Notably these costs are not only driven by consumption but also the level of losses i.e. the network losses and station consumption.
- **Connection Component:** These costs vary as a function of the number customers and include costs associated with providing the connection i.e. customer services, metering, and billing.

For the allocation all fuel related costs have been allocated to the energy component while all other costs are allocated to the demand component. For supply, all costs are allocated to the customer component. The Table 10 shows the result of this allocation.

Table 10. Allocation of costs to demand, energy, and customer components

Results of Classification (USD)

	Capacity	Energy	Connection	Total
Generation	556,255	1,711,265	-	2,267,521
Network	378,455	172,691	-	551,146
Supply	-	-	99,208	99,208
Total	**934,710**	**1,883,956**	**99,208**	**2,917,874**

The interpretation of the classification table should be that KUA is incurring costs in three areas (generation, network, supply) while providing three types of services (capacity, energy, connection) to its customers. In principle each of these three services should be priced separately with customers paying:

- A fee for capacity based on the size of their connection (kVA)
- A fee for energy based on their actual consumption (kWh)
- A fee for connection based on the number of connections (#)

4.1.4 Allocation

4.1.4.1 Determination of allocation factors

The final step is to allocate the costs identified above to the various customer categories. The basis on which allocation is to take place per product isshown inTable 11.

Table 11. Allocation basis per customer category

Allocation Factors

Allocation of:	Capacity	Energy	Connection
Allocation basis:	Non-Coincidental Peak (kW)	Sales (kWh)	Nr of Customers
Residential	597	2,015,675	1,458
Commercial	245	1,424,550	246
Government	153	889,943	82
Non-Government	77	446,874	69
Industrial	54	311,349	15
Total	**1,125**	**5,088,390**	**1,870**

Allocation of energy and connection costs can be done on the basis of energy sales and number of customers, respectively. For the allocation of capacity costs the peak demand for the particular customer group is generally used. In this case the non-coincidental peak has been used. Demand information at the level of customer categories is currently not being collected within KUA and therefore had to be synthesized. The process followed for this is explained next.

Although demand information per customer category is not available, KUA does measure the total system peak demand data. The data consists of half-hour peak data measured at the power plant (see Annex 1 for overview of the data). Here a sample of 10 weekdays in 2011 and 2012 was used to construct an average daily demand profile. This average load profile is assumed to be a good representation of the behavior of customer demand in the KUA system during an average day. The resulting daily demand profile is shown inFigure 14. In the Figure the typical development in demand over the day is clearly visible. There are two peaks with the first occurring between 11 and 12 pm and the second around 7:30 pm.

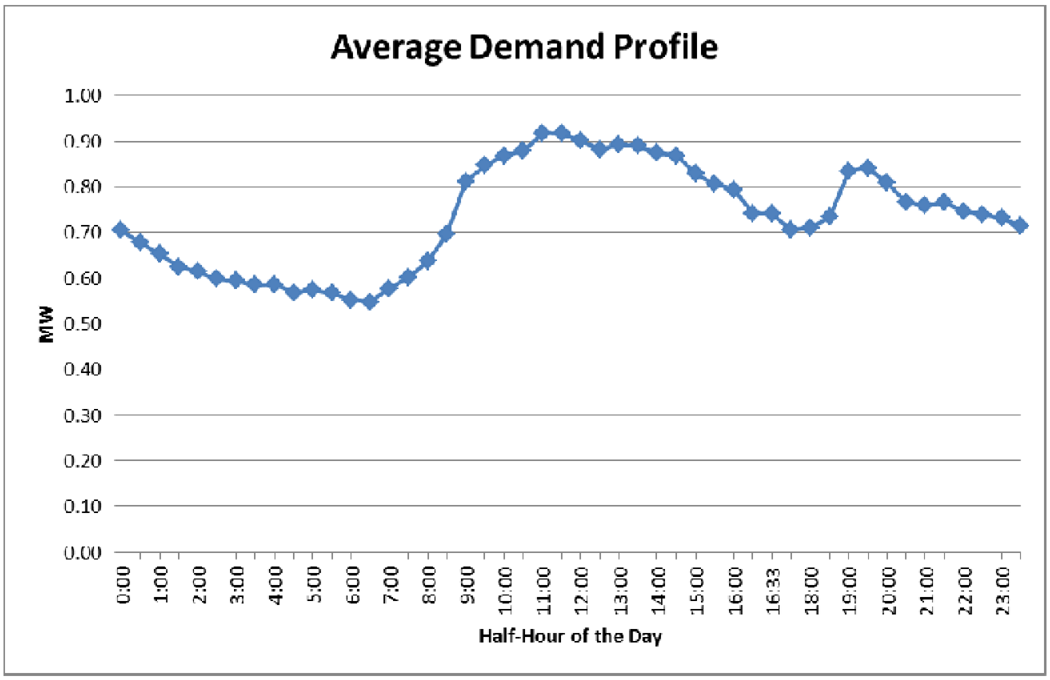


Figure 14 Average demand profile constructed on the basis of metered data

For the cost allocation information is required on the peak demand per each customer group. This information acts as a way to allocate the demand related costs to the various customer groups. As KUA did not have information about the load profile for domestic and non-domestic customer types this was estimated on the basis of typical load profiles from the DNV KEMA database. Three customer categories were identified based on aggregation of the customer categories normally distinguished with in KUA. This is shown inFigure 15.

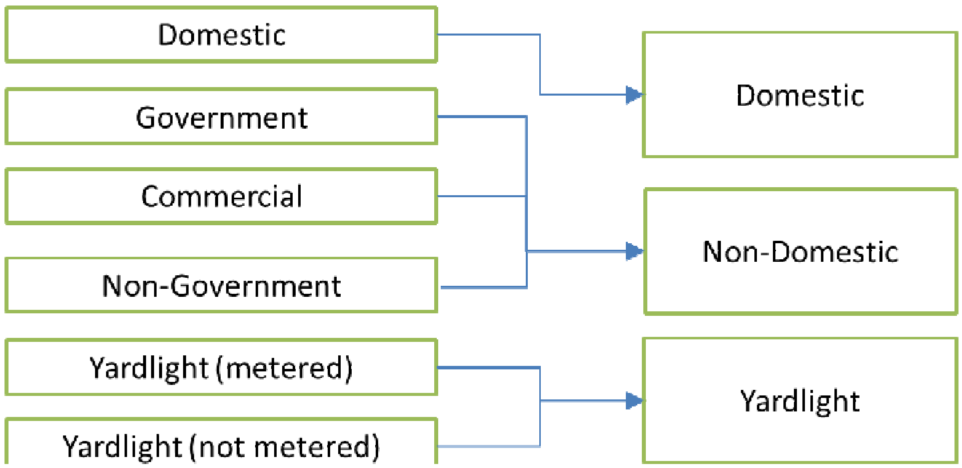


Figure 15 Allocation applied in estimation of demand profiles

The government, commercial and non-government categories were aggregated into a single category (non-domestic) as it would not appear possible to derive accurate load curves for each category separately. At the same time it seems that these categories tend to have more or less the same demand pattern during the day which closely resembles a commercial demand profile.

For domestic and non-domestic typical load profiles from the DNV KEMA database were used as a starting point. For yard lights the load profile used was based on the known information that lights are turned on between 6 pm and 6 am i.e. a load factor of 50%.

The standard load profiles together with the yard light profile were aligned with the actual load data in two steps. First by fine-tuning the standard load profiles to bring these in line with the demand times as observed in the KUA system. This involved the horizontal shifting and compression of the typical demand curves to match the normal times observed in Kosrae with regard to sun-rise, sun-set, and working hours. The second step was to vertically align the demand profiles to assure that total actual measured demand matches the synthesized demand as much as possible. This was done through the minimization of the quadratic difference between the actual demand curve and the synthesized demand curve.

Figure 16 shows the resulting match between the average load profile and the synthesized load profile. As can be seen there are some differences due to errors in the estimation but generally there is a good match between projected and actual profile the total deviation being slightly more than 1%. From the load profile information the non-coincidental peak demand for each customer class was finally derived, as shown in Table 11.

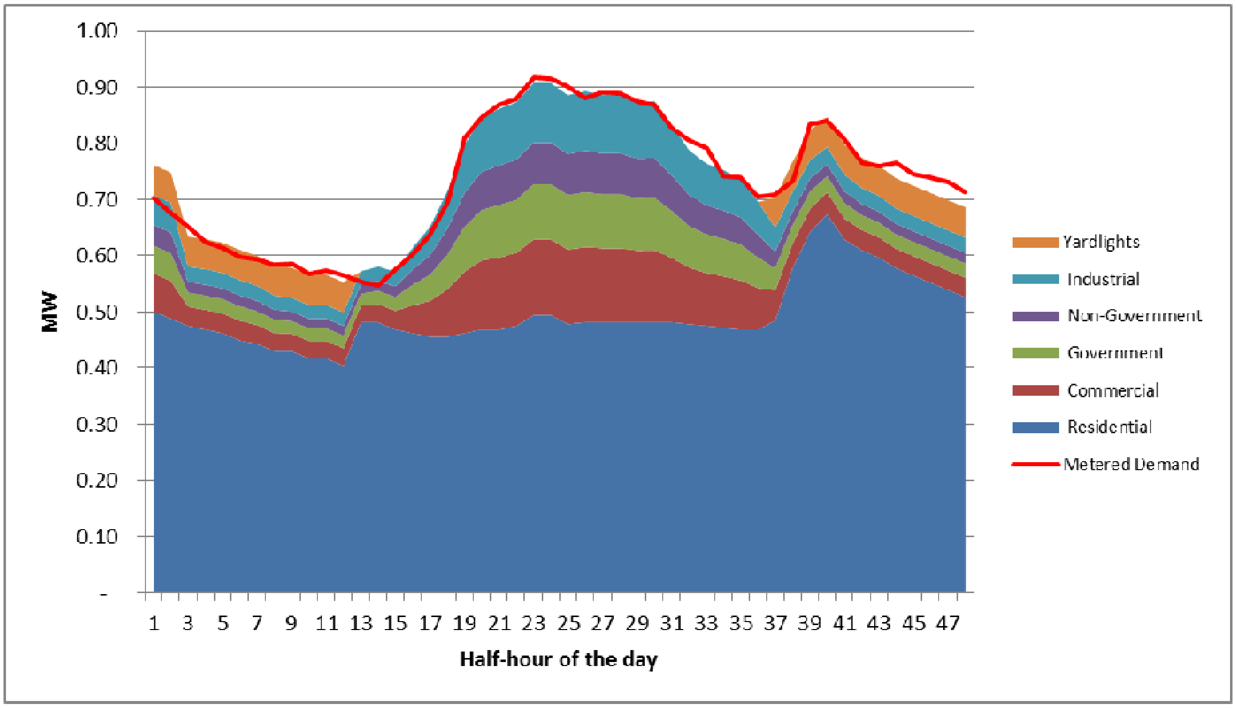


Figure 16. Match between the average demand profile based on metered data and the constructed profile using the synthesized load profiles per customer class.

4.1.4.2 Allocation to Customer Categories

The information regarding sales and quantities can be used to perform the allocation from the cost classification towards the customer classes. This computation isshown inTable 12. Here, each cost category is allocated to each customer class whereby allocations are done on the basis of the non-coincidental peak, total sales, and number of customers for respectively the demand costs, energy costs, and customer costs.

Table 12. Cost allocation results

Result of Allocation (USD)

		Demand	Energy	Customer
Generation	Residential	295,167	677,887	-
	Commercial	121,044	479,087	-
	Government	75,618	299,295	-
	Non-Government	37,971	150,287	-
	Industrial	26,455	104,709	-
Network	Residential	200,820	68,408	-
	Commercial	82,354	48,347	-
	Government	51,448	30,203	-
	Non-Government	25,834	15,166	-
	Industrial	17,999	10,567	-
Supply	Residential	-	-	77,350
	Commercial	-	-	13,051
	Government	-	-	4,350
	Non-Government	-	-	3,661
	Industrial	-	-	796

Finally the costs can be allocated to the various customer categories by summing up the respective costs per generation, network, and supply components. The results areshown inTable 13. As can be seen the costs of residential customers are around 65.5 ct/kWh, which is about 25% higher than the other categories, whose costs are around 51 to 52 ct/kWh. This can be explained by the less favorable demand profile for these customers. This is in line with what is generally observed elsewhere. Note further that the costs for the other customer categories are very similar. In larger power systems one would tend to notice more variation in costs. In the KUA system however the customers are much more homogenous in terms of demand profile and hence also tend to have similar costs per kWh.

Table 13. Final results

Final Results (USD)

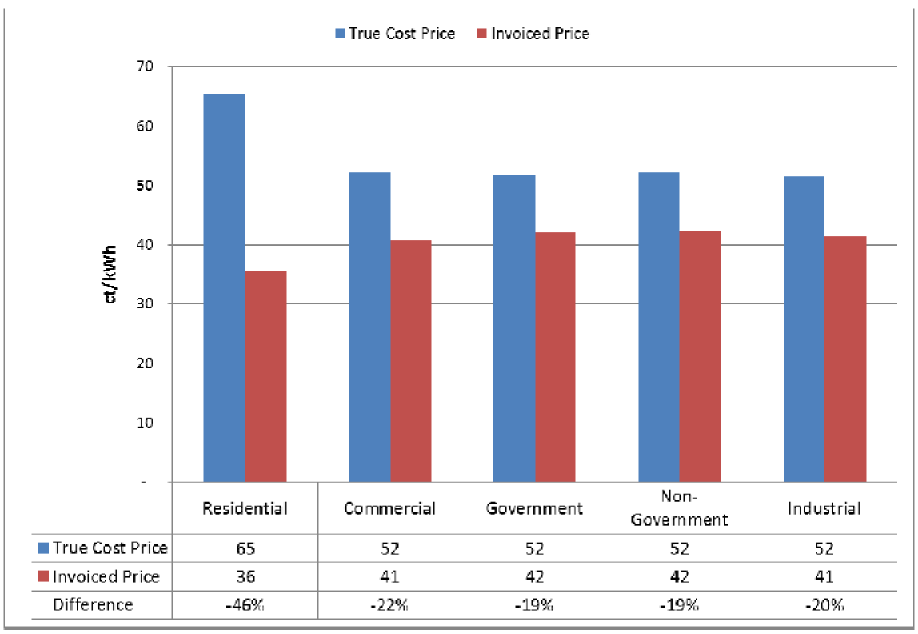
	Demand	Energy	Customer	Price (ct/kWh)
Residential	495,987	746,295	77,350	65.5
Commercial	203,397	527,434	13,051	52.2
Government	127,066	329,498	4,350	51.8
Non-Government	63,805	165,453	3,661	52.1
Industrial	44,454	115,276	796	51.6
Total	**934,710**	**1,883,956**	**99,208**	

4.2 Analysis of Existing KUA Tariffs

In the previous section the results of the cost allocation analysis were presented. In this section the results of this allocation can be compared with the actual tariffs in place.

4.2.1 Existing Tariffs versus Cost Allocation

The average cost per customer based on the cost allocation analysis can be compared with the actual price. As the cost allocation is based on 2010/11, the applicable base and fuel charges for that period have been used as derived from the financial statements.



	Residential	Commercial	Government	Non-Government	Industrial
True Cost Price	65	52	52	52	52
Invoiced Price	36	41	42	42	41
Difference	-46%	-22%	-19%	-19%	-20%

Figure 17. Comparison of average cost per customer group and average price paid in 2010.

As can be observed there is a general mismatch between the true cost price derived from the cost allocation and the actual price paid. This mismatch has two dimensions. First, it can be observed that all customer classes pay a price that is below the actual cost level. Second, it appears that residential customers pay a proportionally lower price with the gap between priceand cost in the order of 46%. For the other categories the difference is lower at round 20% but nevertheless still substantial.

4.2.2 Progressive structure of Tariffs

The cost allocation analysis shows that the existing tariff structure seems to have the intention for domestic customers to be subsidized by the other groups. However, overall the price level is well below the actual costs for all customer groups with all groups paying a price lower than it should be from a cost perspective.

4.2.3 Absence of Demand Tariff

Another observation to be made is that the current tariff structure of KUA consists only of kWh charges. That is, there are no fixed or demand fees e.g. in terms of a fixed amount per month or per kVA of connected capacity. As was observedin the cost allocation analysis there are considerable demand related costs, which are more or less fixed in the short term. Given that KUA's income only varies with kWh sales, this creates risks to KUA as there is a mismatch between costs and income. Demand can be influenced by different factors but most importantly by fluctuations in the fuel price. Higher fuel prices will tend to reduce demand and therefore income for KUA. In particular taking into account the recent uncertainty regarding oil prices this issue is very important to consider.

A more elaborate tariff structure containing fixed and demand related fees can help to deal with this issue. At the same time, such a structure will also create reallocations in the average price per customer. In particular for customers with relatively low consumption the introduction of a fixed tariff will lead to a relatively high increase in the electricity bill. The trade-off between the reduction in financial risks and possible adverse socio-economic aspects should therefore be considered in the design of a new tariff structure.

4.2.4 Introduction of renewable sources

The issue of renewable (non-diesel) generating options is currently being considered by KUA. In this light it should be noted that the current formulation of the FAC does not allow the integration of non-diesel related production costs to be included into it. The FAC formula explicitly refers to "diesel fuel price" and the price for such fuel, while it is true that the costs of alternative energy sources i.e. renewables would not vary with the diesel fuel price. There would thus be a discrepancy between the applicable FAC and the actual energy costs (being the sum of diesel and non-diesel generation).

In the case that the costs of renewables would be below the costs of diesel, the FAC could potentially act as a mechanism to offset the tariff deficit that KUA is currently facing. In this case, the FAC would still be set on the basis of the diesel gallon price, but the actual underlying costs would be lower. This approach however is not recommendable as it will not be transparent and result in potential confusion at the side of customers. Furthermore the absence of a causal link between tariffs and costs can lead to adverse effects in case that diesel prices increase or decrease substantially.

The current formulation of the FAC does not allow renewable energy costs to be incorporated. At the same time inclusion of (renewable) energy purchase costs is desired and these costs should be reflected in the tariff structure. There are two main ways to do this depending on the variability in costs. If the costs of purchased energy are more or less fixed and do not change over time, this could be could be considered part of the base charge. The disadvantage of this would be that if in future renewable costs were to be changed (either increased or decreased) then this would need to be reflected in the base charge, which is less flexible to change as opposed to the FAC.

If costs of purchased energy tend to fluctuate then they could be recouped through a separate charge (e.g. Renewable Energy Charge). A more practical solution however is to combine the costs of fuel and renewable energy into one single Energy Charge. In this case the energy charge would vary periodically as a function of diesel prices but this change would be dampened due to the inclusion of the renewable energy (purchase) costs.

4.3 Development of Alternative Tariff Structure

The previous analysis showed two main issues with the current KUA tariffs. First, the financial analysis revealed that current tariff income levels are insufficient to allow KUA to achieve financial adequate performance in either the sense of earning a return on investment as well as to be operationally break even. Second, the cost analysis showed that there is a discrepancy between the tariff level per customer group and the true costs that should be allocated to that group.

4.3.1 Base Charge

The base charge reflects the operational costs of the company (i.e. excluding fuel and renewable energy costs) and is fixed for a predefined period of time (e.g. 5 years).Base costs are more or less fixed and are therefore to be recouped through a fixed charge i.e. a charge that does not vary as a function of actual consumption. This amount should in principle be related to the connected capacity of the customer (i.e. kVA based). Due to the small scale of the customer base it would seem more practical however to introduce a fixed amount per month, defined in absolute dollar terms rather than per installed kVA. Furthermore the customer costs, which are also fixed, could be incorporated into the same charge.

Based on the findings from the cost allocation analysis presented in the previous section the fixed component per customer category can be computed. The results areshown inTable 14. Note that these numbers here are based on the base costs only and do not include an allowance of 29 ct/kWh for fuel costs (as currently is the case).

Table 14 Derived fixed charges per month per customer category

	Current Tariffs	Scenario 2A	Scenario 3A	Scenario 3B
	0 ct/kWh increase	23 ct/kWh increase	14 ct/kWh increase	9 ct/kWh increase
	Fixed Charge (USD/month)			
Residential	16.96	55.22	40.25	31.93
Commercial	37.95	123.55	90.05	71.44
Government	69.12	225.04	164.03	130.13
Non-Government	42.17	137.30	100.07	79.39
Industrial	130.10	423.61	308.76	244.95

4.3.2 Energy charge

The energy charge is intended to cover the costs of fuel and renewable energy and would be adjusted periodically (e.g. monthly) on the basis of actual costs. As discussed the current FAC does not allow costs of renewable energy to be passed through in the tariffs in a clear way. Therefore an Energy Charge is proposed, which would be able to accommodate a mix of diesel produced electricity and renewable energy.Additional renewable energy costs would be added as a lump sum and spread over the total sales to derive the energy charge. The relative share in total production would be used as weighting factors.

The formulation for the Energy Charge would be as follows:

The Energy Charge is set as the weighted value of the FAC and the Renewable Energy Purchase costs. Weighting takes place according to the share in the total electricity production.

Under the energy charge any change in fuel prices (USD/gallon) would still be reflected in the energy charge, but limited to the percentage of generation that was done using diesel generation. In the extreme case where all energy is produced using renewables, the energy charge would be independent from fuel price fluctuations i.e. remain flat over time.

The Energy Charge computation is contained in the rate setting model and can be used to peridically compute the value.

4.3.3 Impact on monthly bill

The introduction of a fixed charge has the effect that the monthly bill for the base charge part now becomes independent of actual consumption. Consumption levels would only have an impact on the level of the energy charge. The difference between a situation without a fixed charge (Table 15) and where a fixed charge is introduced (Table 16) have been compared in terms of the impact on the monthly bill for a customer.

Table 15 Existing tariff structure used for comparison purposes. Note: FAC excludes 29 ct/kWh which have been allocated to the base charge.

	Base Charge (USD/kWh)				FAC (USD/kWh)
	0-100kWh	101-1,000kWh	1,001-10,000kWh	10,001-100,000kWh	All kWh
1. Residential	0.358	0.403	0.416	0.409	0.057
2. Commercial	0.398	0.413	0.423	0.414	0.057
3. Government	0.423	0.423	0.434	0.424	0.057
4. Industrial	0.423	0.423	0.428	0.418	0.057

Table 16 Alternative tariff structure with fixed charge and separation base and energy charge. Note: the 29 ct/kWh have been taken out of the base charge and brought into the energy charge.

Scenario:	Scenario 1A	Scenario 2A	Scenario 3A	Scenario 3B	All scenarios
Tariff increase:	0 ct/kWh increase	23 ct/kWh increase	14 ct/kWh increase	9 ct/kWh increase	
	Fixed Charge (USD/month)				Energy Charge (USD/kWh)
1. Residential	16.96	55.22	40.25	31.93	0.347
2. Commercial	37.95	123.55	90.05	71.44	0.347
3. Government	69.12	225.04	164.03	130.13	0.347
4. Industrial	42.17	137.30	100.07	79.39	0.347

To analyze the impact of the introduction of the fixed charge in principle, it is helpful to first consider Scenario 1 where this charge is introduced but no tariff increase applied. That is, a rebalancing of the tariffs takes place but the average tariff for all customer groups combined remains the same. As can be observed inFigure 18the introduction of a fixed charge results in a price increase for consumers with relatively low consumption. Conversely, customers with higher consumption tend to pay a lower price.

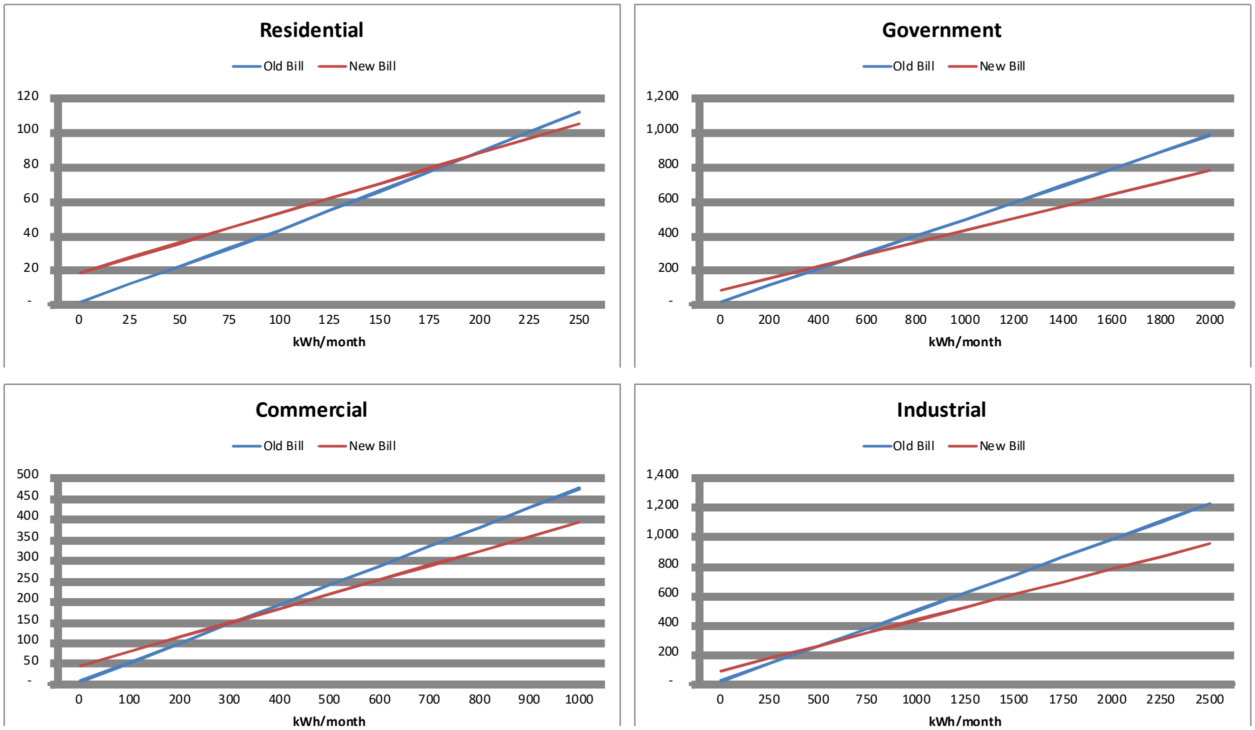


Figure 18 Effect on the monthly bill per customer category after introduction of a fixed charge and no tariff increase (Scenario 1A)

As can be observed the introduction of a fixed charge has the effect that customers with relative low consumption tend now to pay more as compared with the case where the tariffs were energy-related only. As can be observed this impact is particularly relevant to residential customers. Here, all customers with a consumption level less than 190 kWh per month would pay a higher monthly bill. For commercial customers the break-even point is at 321 kWh per month and for government and industrial this is 520 kWh per month.

The next Figures show the effect on monthly bills resulting from the introduction of a fixed charge under different tariff increase scenarios. As expected the break-even point varies with the level of the tariff increase. If the tariff increase is higher then the fixed charge is also higher and consequently the break-even point also increases. A summary of the break-even points areshown in

Table 17. The Table also shows the average consumption per customer category.

Table 17 Break-even consumption level per customer category under different scenarios

Scenario	1A	2A	3A	3B	Average Consumption (kWh/month)
Tariff increase	0 ct/kWh	23 ct/kWh	14 ct/kWh	9 ct/kWh	
Residential	190	528	396	322	115
Commercial	321	1,017	744	593	483
Government	520	1,639	1,215	978	904
Industrial	520	1,667	1,225	978	1,730

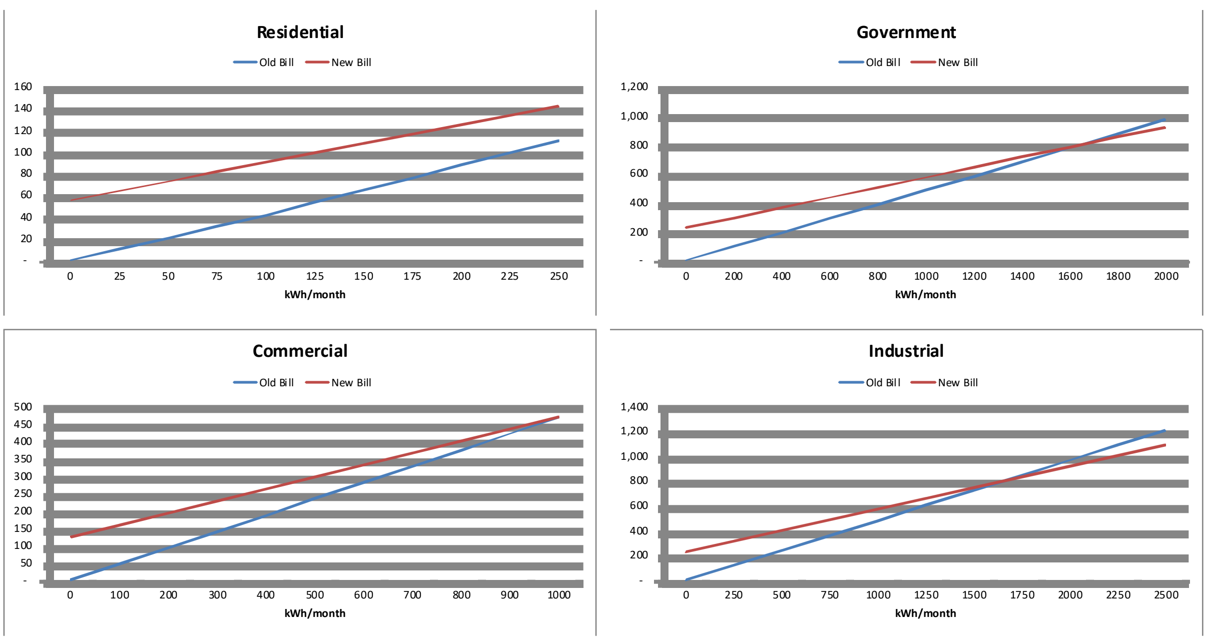


Figure 19 Effect on the monthly bill per customer category after introduction of a fixed charge and achieving a 10% rate of return (Scenario 2A- 23 ct/kWh increase)

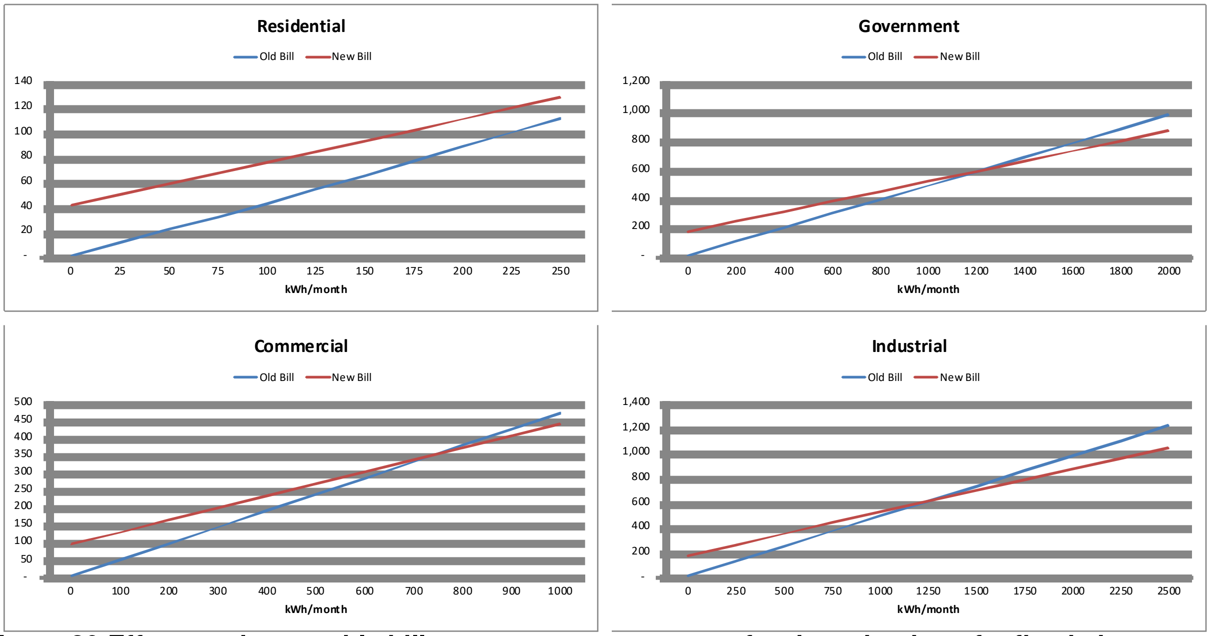


Figure 20 Effect on the monthly bill per customer category after introduction of a fixed charge and achieving operational break-even (Scenario 3A – 14 ct/kWh increase)

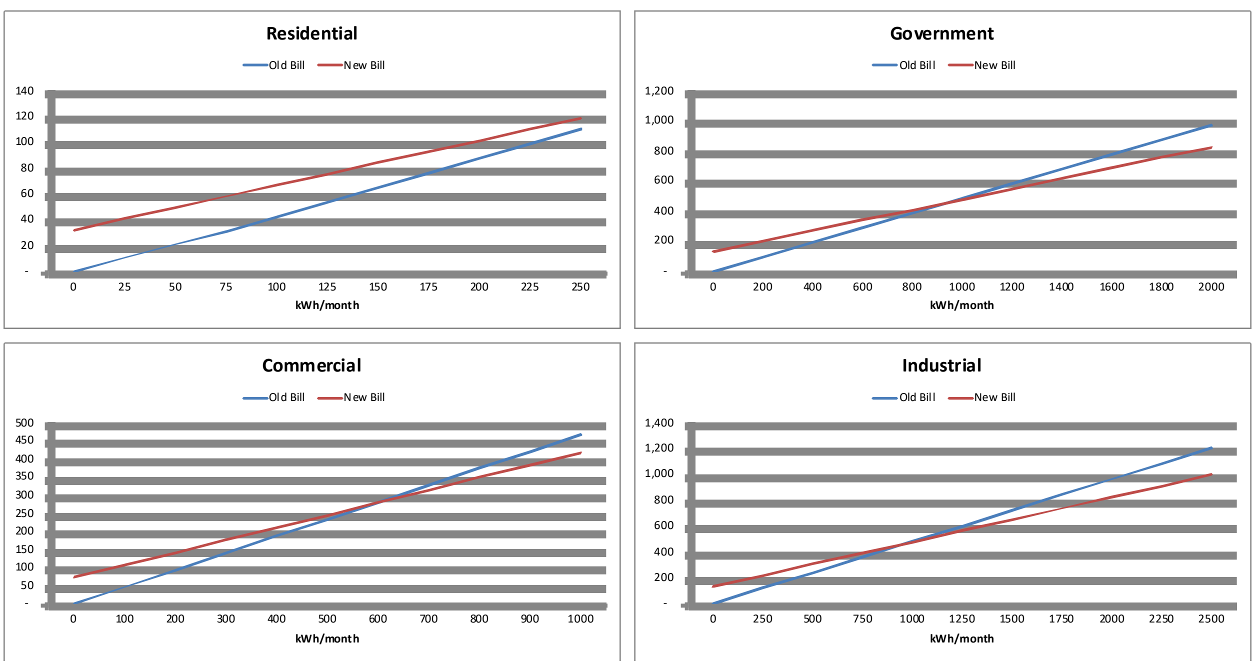


Figure 21 Effect on the monthly bill per customer category after introduction of a fixed charge and achieving operational break-even without depreciation allowance (Scenario 3B – 9ct/kWh increase)

5 Conclusions and Recommendations

5.1 Conclusions

The purpose of this project was to perform a review of KUA's tariffs and develop recommendations on an appropriate tariff structure and on mechanisms to adjust the tariffs. This task was approached from two main perspectives (1) the tariff level, and (2) the tariff structure. The following conclusions can be drawn based on the analysis performed.

5.1.1 Tariff Level Analysis

KUA's financial performance has been evaluated. For this purpose a financial model was developed as described in Section 2. This model was applied in Section 3 to evaluate the existing tariffs and to compute the necessary tariff adjustment under different scenarios.

Analysis showed that existing tariffs in use by KUA are below costs and if not increased will result in (further) serious financial impact for KUA. After this it was computed what kind of tariff increase would be necessary to bring financial performance to an adequate level. Here, "adequate" can be interpreted in different ways, each resulting in a different necessary tariff increase:

- If KUA were to be financially sound with a rate of return of 10% implying the company having full ability to independently undertake all investment, then the necessary tariff increase would be 23 ct/kWh.

- If KUA were to remain dependent on external grants for financing investment the criteria would be assurance of a balance between operational income and expenses. In that case the necessary tariff increase would be 14 ct/kWh (with ability to independently renew these investments in future) or 9 ct/kWh (with future renewals also being dependent on grants).

5.1.2 Tariff StructureAnalysis

In Section 4 the analysis of the existing tariff structure was undertaken. This analysis helped to assess the degree of alignment between the true costs and the tariff paid per type of customer. From an economic point of view an alignment between these two is desired as cost reflectiveness helps to promote efficiency.

The costs per customer category within the KUA customer base was computed in three steps namely functionalization, classification, and allocation. Using this method the costs incurred by KUA for each group was computed. This was compared to the actual tariff paid by customers. Comparisons showed that there is a misalignmentfor all customer groups. Overall customers pay a price that is lower than actual costs (which is in line with the conclusions from the tariff level analysis). The mismatch is particularly visible for domestic customers.

The misalignment can be taken away by introducing a fixed charge, which better aligns the costs and tariff per customer group. The disadvantage of this however is that rebalancing in the monthly bill will take place. Customers with low consumption will then be paying a higher bill and vice versa.

5.2 Recommendations

The main conclusion from the analysis is that an adjustment in KUA's tariffs will be necessary. The issue therefore is not whether or not such an adjustment should take place, but rather the way in which this should come. This ultimately will be a policy decision by KUA. In order to accommodate this process the following decision trees can be useful.

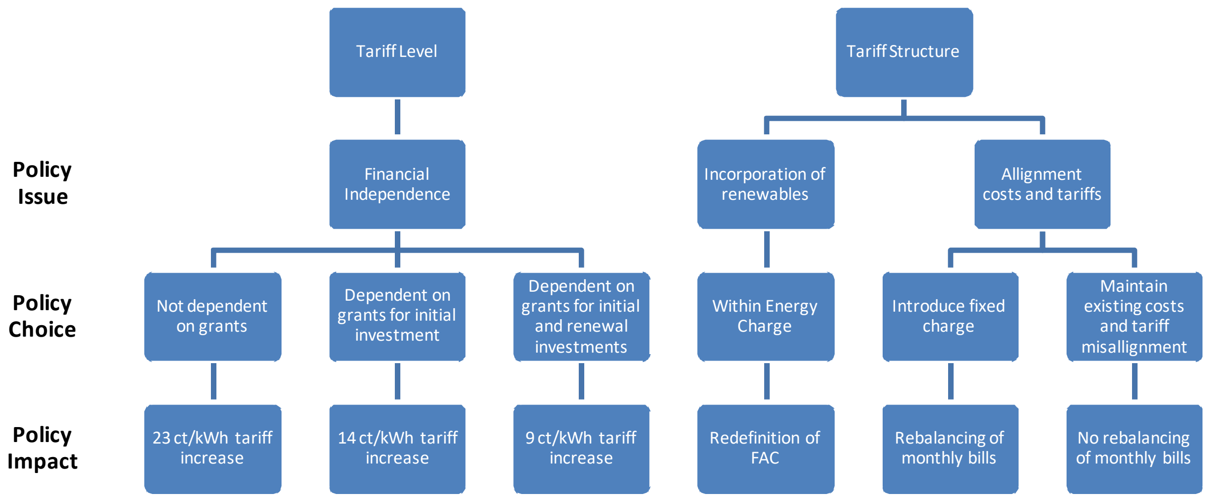


Figure 22 Overview of impact of different policy choices and their impact

Annex 1: Demand data used for deriving load profiles

Metered MW peak per half-hour period

			Thu	Fri	Mon	Tue	Wed	Wed	Thu	Fri	Mon	Tue
	From	**To**	14-06-12	15-06-12	18-06-12	19-06-12	20-06-12	14-12-11	15-12-11	16-12-11	19-12-11	20-12-11
1	0:00	0:30	0.64	0.69	0.73	0.64	0.67	0.65	0.64	0.66	1.04	0.68
2	0:30	1:00	0.62	0.67	0.65	0.61	0.66	0.62	0.58	0.66	1.02	0.68
3	1:00	1:30	0.61	0.64	0.63	0.61	0.62	0.59	0.57	0.61	1.00	0.64
4	1:30	2:00	0.60	0.62	0.63	0.61	0.60	0.57	0.57	0.61	0.82	0.61
5	2:00	2:30	0.59	0.62	0.62	0.59	0.60	0.59	0.57	0.60	0.77	0.60
6	2:30	3:00	0.58	0.60	0.61	0.59	0.57	0.56	0.48	0.60	0.80	0.60
7	3:00	3:30	0.57	0.61	0.60	0.59	0.58	0.55	0.41	0.60	0.83	0.60
8	3:30	4:00	0.56	0.59	0.59	0.57	0.57	0.57	0.42	0.58	0.79	0.61
9	4:00	4:30	0.56	0.59	0.58	0.57	0.56	0.58	0.45	0.60	0.76	0.61
10	4:30	5:00	0.56	0.59	0.58	0.57	0.58	0.57	0.45	0.56	0.62	0.60
11	5:00	5:30	0.56	0.56	0.60	0.58	0.58	0.57	0.50	0.58	0.61	0.60
12	5:30	6:00	0.55	0.54	0.61	0.59	0.58	0.57	0.46	0.57	0.59	0.61
13	6:00	6:30	0.56	0.54	0.57	0.54	0.58	0.58	0.46	0.51	0.59	0.59
14	6:30	7:00	0.57	0.57	0.58	0.55	0.58	0.56	0.43	0.52	0.55	0.57
15	7:00	7:30	0.59	0.60	0.61	0.59	0.62	0.55	0.47	0.54	0.61	0.59
16	7:30	8:00	0.59	0.62	0.63	0.62	0.63	0.57	0.60	0.57	0.60	0.60
17	8:00	8:30	0.63	0.60	0.66	0.69	0.62	0.61	0.60	0.60	0.69	0.67
18	8:30	9:00	0.62	0.65	0.80	0.66	0.69	0.72	0.69	0.70	0.65	0.78
19	9:00	9:30	0.78	0.88	0.85	0.76	0.76	0.77	0.74	0.75	0.75	1.07
20	9:30	10:00	0.91	0.93	0.88	0.80	0.85	0.77	0.81	0.81	0.80	0.90
21	10:00	10:30	0.92	0.90	0.90	0.83	0.87	0.89	0.80	0.83	0.84	0.90
22	10:30	11:00	0.93	0.93	0.91	0.91	0.87	0.82	0.84	0.85	0.87	0.85
23	11:00	11:30	1.03	0.92	0.95	0.89	0.93	0.88	0.84	0.88	0.85	1.00
24	11:30	12:00	1.02	0.92	0.92	0.95	0.93	0.92	0.91	0.94	0.67	0.98
25	12:00	12:30	0.96	0.94	0.97	0.94	0.96	0.87	0.89	0.84	0.70	0.94
26	12:30	13:00	0.94	0.91	0.93	0.94	0.95	0.86	0.88	0.86	0.62	0.92
27	13:00	13:30	0.95	0.93	0.95	0.95	0.97	0.87	0.84	0.84	0.68	0.93
28	13:30	14:00	0.95	0.94	0.93	0.93	0.93	0.89	0.80	0.88	0.72	0.92
29	14:00	14:30	0.95	0.94	0.92	0.91	0.93	0.85	0.84	0.81	0.69	0.90
30	14:30	15:00	0.92	0.94	0.90	0.90	0.95	0.84	0.83	0.80	0.70	0.90

31	15:00	15:30	0.85	0.79	0.89	0.91	0.97	0.78	0.83	0.80	0.64	0.82
32	15:30	16:00	0.84	0.80	0.85	0.90	0.83	0.78	0.83	0.75	0.66	0.82
33	16:00	16:04	0.80	0.80	0.76	0.90	0.82	0.75	0.75	0.76	0.81	0.78
34	16:04	16:33	0.66	0.76	0.75	0.75	0.75	0.69	0.77	0.71	0.82	0.76
35	16:33	17:30	0.66	0.74	0.83	0.80	0.70	0.73	0.69	0.67	0.81	0.77
36	17:30	18:00	0.65	0.68	0.73	0.63	0.69	0.74	0.68	0.70	0.78	0.78
37	18:00	18:30	0.66	0.69	0.72	0.62	0.66	0.78	0.69	0.76	0.75	0.77
38	18:30	19:00	0.63	0.73	0.79	0.64	0.74	0.80	0.69	0.68	0.78	0.85
39	19:00	19:30	0.78	0.85	0.87	0.78	0.81	0.84	0.81	0.84	0.89	0.86
40	19:30	20:00	0.76	0.82	0.85	0.79	0.86	0.80	0.80	1.04	0.86	0.83
41	20:00	20:30	0.79	0.79	0.79	0.79	0.83	0.77	0.80	0.82	0.87	0.83
42	20:30	21:00	0.76	0.76	0.78	0.77	0.80	0.73	0.76	0.74	0.79	0.78
43	21:00	21:30	0.77	0.74	0.77	0.77	0.76	0.73	0.76	0.72	0.83	0.75
44	21:30	22:00	0.74	0.73	0.79	0.70	0.75	0.73	0.76	0.70	0.99	0.76
45	22:00	22:30	0.71	0.71	0.77	0.70	0.74	0.70	0.75	0.69	0.95	0.74
46	22:30	23:00	0.68	0.70	0.74	0.69	0.74	0.67	0.74	0.68	1.04	0.72
47	23:00	23:30	0.69	0.71	0.72	0.66	0.72	0.68	0.69	0.68	1.04	0.72
48	23:30	0:00	0.64	0.71	0.72	0.65	0.70	0.65	0.67	0.66	1.04	0.70

Annex 2: Cost of Capital

The standard methodology to determine the cost of capital of a business is the Weighted Average Cost of Capital, WACC. The WACC is the average of the cost of debt and the cost of equity, the two components of the capital structure of the company, weighted by their share on total capital. It is, therefore, the weighted average return required by the lenders and shareholders of the company, that is, by its providers of capital. The WACC is also used for regulated businesses, since it allows the companies to earn the normal rate of return that is expected in competitive markets.

In order to derive the WACC for a particular company, a significant amount of data is necessary. For the specific case of KUA it should be noted that most of these data were not available, in particular due to the absence of mature financial markets in Micronesia. Therefore a number of assumptions had to be made in order to arrive at a reasonable estimation for the WACC.

WACC Formula

The general formulas used to calculate the WACC can be expressed as follows:

$$WACC = w_d \,.\, k_d + w_e \,.\, k_e$$

$$w_d = D/(D+E),\ w_e = E/(D+E)$$

Where:

- k_d: cost of debt
- k_e: cost of equity
- D: value of firm's debt
- E: value of firm's equity

This is the so-called nominal WACC since it is computed in nominal terms.Note that as corporate taxes are not applicable to KUA no adjustments for this need to be made in the WACC (i.e. the pre-tax and post-tax WACCs are the same).

For the purposes of this analysis, we will estimate KUA's WACC in nominal terms and referred to in USD dollars. The following sections describe the criteria and calculation of the different components of the WACC.

Capital Structure and Cost of Debt

Most firms use both debt and equity to fund their business and the relationship between these two sources of funds provides the firm's capital structure ratios or gearing ratios or leverage ratios. The analysis of a firm's capital structure is essential to evaluate its long-term risk and return prospects. Since debt carries fixed-interest and repayment commitments, a highly geared firm (i.e. a firm with large fraction of debt in its invested capital) has greater chances of failing on its financial commitments and being forced into bankruptcy. As such, highly leveraged firms are more vulnerable to business downturns than those with lower debt to worth positions. Also, for the same reason, the returns for equity shareholders (who are the residual claimants in the company) become more volatile and risky as gearing increases. Finally, a high level of gearing may also have implications for the extent to which a company may have access to additional capital.

One indicator of the amount of leverage used by a business is the Gearing Ratio. This ratio indicates the level of debt in proportion to total capital (debt + equity). A high gearing indicates an extensive use of leverage i.e. a large proportion of financing provided by creditors. A low gearing, on the other hand, indicates that the business is making little use of leverage.

Currently the level of long-term debt in KUA's books is equal to zero. This implies a debt level of 0%, which would not be observed in normal circumstances. The present situation could be explained by the fact that KUA currently is primarily dependent on grants for financing investments. Furthermore it may seem that the current financial performance of the company would make it more difficult to attract commercial loans.

At the same time the purpose of the WACC computation is to estimate KUA's costs of capital assuming a normal mode of business i.e. sufficiently high income to finance investments through a considerable degree of own funding. Generally, a gearing of 2/3 is considered to be appropriate. That is, 2/3 of the investment would be financed by external capital sources (loans) and 1/3 through own funds (equity). For the purpose of WACC computation this number of 2/3 will therefore be assumed.

An evaluating of past interest payments and considering future expected developments the average debt cost is estimated at 7.5%. Consequently a value of k_d = 7.5% will be used as debt cost for the present calculation.

Cost of Equity

There are several approaches to estimate the cost of equity. The most common method used in the business and regulatory practice is based in the Capital Asset Pricing Model or CAPM. The CAPM states that in efficient markets investors should be compensated for the systematic risk they take, that is, the risk non diversifiable through portfolio diversification. In simple terms, the risk-adjusted return is composed of a risk free rate of return and an equity risk premium. The equity risk premium ERP can be higher or lower than the average market return, depending on the correlation between the returns of the specific investment and the returns of the capital market as a whole.

The general formula for the cost of equity according to the CAPM methodology is:

$$k_e = R_f + \beta.[E(R_m) - R_f]$$

Where R_f: Risk-free rate of return

$E(R_m)$: Expected rate of return of the market

β: beta, measure of systematic risk of the equity investment

$E(R_m)$ – Rf: market risk premium

The Beta (β) parameter is a measure of the sensitivity of the business to the general economic cycles, being positive when the business return moves in the same direction of the market and negative if it moves in the opposite way. A Beta value equal to 1 indicates that the business follows the cycles of the economic activity as reflected in the average market returns, and should earn this same rate of return. Business with risk lower than the average have a Beta less than 1 and require lower rates of return.

The calculations of k_e depend on data availability and the specific conditions of the business. For KUA, there is no market information available in the context of a national or regional financial market. Therefore an indirect approach should be followed by considering the risk-free risk in the United States and adding a specific country risk premium to recognize additional risks introduced by investing in the local business environment.

The risk free-rate in the United States is around 4.5% based on long-term analysis of the returns[3]. The additional risks for an investor investing in Micronesia rather than the US could in principle be derived from an analysis of the country sovereign credit rating, as published by agencies such as Standards & Poor's or Moody's. However, Micronesia currently does not have such a rating and this approach therefore is not possible.

An alternative but crude way to estimate the market risk in Micronesia compared to the US would be look at the spread between the interests on corporate loans between the two countries. Conveniently both countries use the United States Dollar as legal currency. Nevertheless we should stress that this method provides only a very rough indication in the absence of other data.

The logic here is that a business operating in Micronesia would incur a certain interest rate that would be in line with the risk profile for that company. The same would hold for the US. By taking the spread between these two interest rates, an idea can be developed about the difference in perceived risks between a business in Micronesia and the US. Again we should note that in the absence of data this provides only a rough estimation.

For the analysis data was used as published by the World Bank[4] as shown in the following Table.

	2008	2009	2010	2011	Average
Micronesia	14.4	15.4	15.1	14.4	14.8
UnitedStates	5.1	3.3	3.3	3.3	3.8
Spread	9.3	12.1	11.8	11.1	11.1

[3]Source: http://pages.stern.nyu.edu/~adamodar/New_Home_Page/datafile/ctryprem.html

[4]http://data.worldbank.org/indicator/FR.INR.LEND

As can be seen the spread is on average 11.1%. This has been accordingly used as a (rough) approximation for the country risk for Micronesia.

Beta

The beta parameter can be inferred from historical data of a publicly quoted company. Alternatively, as not all companies are listed in stock markets, or data is not available, the beta estimation is made by comparison with companies with similar risk profile, like for example electric utilities in the case of KUA. To account for differences in financial leverage and therefore in financial risk taken, the equity betas (β_e) comparative companies are "unleveraged" to estimate the unleveraged of true beta of the operative assets, or asset beta (β_a). The relationship between both types of beta is the following:

$$\beta_e = \beta_a\,[1+(D/E)(1-\tau)]$$

Equity betas can be observed in the market and various financial information providers publish information on equity betas. For those companies for which such data are not available, the beta of other companies doing similar business could be taken. Regulators worldwide calculate the equity beta based on international studies. The following table provides an overview of the results.

Country & Regulator	Regulated Company	Equity Beta
Netherlands (DTe)	Distribution Companies	0.47 – 0.74, 2007 – 2009; 0.45 – 0.85, 2004 – 2006;
Belgium (CREG)	Gas distribution network	1.0, 2005
UK (Ofgem)	Electricity distribution	1.0, 2005 – 2010 1.0, 2000 – 2005
Australia (ACCC)	Electricity Transmission Operator	1.0, 2006 – 2010
Jamaica (OUR)	Electricity transmission/distribution	0.87, 2004
State of Victoria (ORG)	Electricity distribution	1.0, 2006 – 2010 1.0, 2000 – 2005

Source: Homepage and reports of the respective regulating authorities.

In line with the international observations for regulated electricity companies for the present calculation an equity beta of 1.0 is used.

WACC estimation

The application of the different parameters selected and the WACC calculations are summarized in the following table. The estimated forward-looking WACC for KUA is estimated at aound10%.

Parameter / Value		Reference
Tax rate	0.0%	Corporate tax rate
Debt Ratio, Wd	66.7%	Assumed capital structure
Cost of Debt, kd	7.50%	Company's financing cost
Post-tax Cost of Debt, Kd*(1-T)	**7.50%**	
Equity Ratio, We	33.3%	Assumed capital structure
Risk-free rate, Rf	4.5%	US Government long-term bonds
Market risk premium, E(Rm)	11.2%	Corporate interest spread
Equity Beta, Be	1.00	Leveraged beta
Cost of Equity, Ke	**15.70%**	**CAPM**
WACC, post tax nominal	**10.23%**	