Electricity Supply Cost of Service Study – LEWA Lesotho

Final Report

Support Provided by African Development Bank

Prepared for: LEWA

Final Version: August 2018

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LIST OF ACRONYMS

AfDB	African Development Bank
AIC	Average Incremental Cost
BoS	Bureau of Statistics
CoSS	Cost of Service Study by MRC
CoSST	CoSS Tariff model
GDP	Gross Domestic Product
GoL	Government of Lesotho
HV	High Voltage
LDC	Load Duration Curve
LEC	Lesotho Electricity Company
LEWA	Lesotho Electricity & Water Authority
LRAC	Long Run Average Cost
LRMC	Long Run Marginal Cost
LV	Low Voltage
MAED	Model for Analysis of Energy Demand (International Atomic Energy Agency)
MD	Maximum Demand
MEM	Ministry of Energy & Meteorology
O&M	Operation & Maintenance
OPEX	Operating Expenditure
RE	Renewable Energy
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SAPP	Southern African Power Pool
STC	CoSS Technical Committee
T&D	Transmission & Distribution
TOR	Terms of Reference
UAF	Universal Access Fund

1 INTRODUCTION

This is the final report of the Cost of Service Study (CoSS) carried out during the second half of 2017 by the MRC Group for LEWA supported by the AfDB.

The overall objectives of the CoSS are summarised in the Terms of Reference (TOR) of the CoSS as:

"The objectives of the study are twofold: firstly, to set electricity tariffs to promote economic efficiency of production and consumption, and ensure financial viability of the electricity sector while taking into account social and equity considerations and secondly to provide a basis of strategy formulation for the gradual transition from financial-cost based tariffs to economic cost reflective tariffs, setting targeted life-line tariffs and associated subsidy mechanism, while maintaining consumer economic cost-based tariffs."

The TOR require that these objectives be delivered through nine tasks and a separate report was prepared for each of these tasks as shown in Table 1 below.

Table 1: CoSS Tasks and Deliverables

Task No	Description	Date submitted	No pages
1	Review of Structure and Conduct of the Power Sector including the Legal and Regulatory Framework – identifying inconsistencies and weaknesses for determination of tariffs	26/6/2017	35
2	Electricity Demand Forecasts – historic demand, existing forecasts and a revised projection	24/07/2017	33
3	Determination of Medium to Long-Term Development Programs – gather data on existing generation, transmission and distribution, SAPP, evaluate costs for new generation, transmission and distribution, prepare financial model for least cost expansion and present scenarios.	30/8/2017	55
4	Determination of Economic Cost of Supply and Structure and Levels of Tariffs – evaluate marginal costs by voltage level, characterise demand by consumer type, model economic cost and use model to establish economic cost by capacity and energy and by consumer type.	11/9/2017	45
5	Life-Line Tariff Mechanism – gather data on poor households use of electricity and define basic needs, review affordability of electricity among poor households and recommend lifeline tariff and process for subsidy.	10/11/2017	22
6	Review of Financial Performance of LEC and Preparation of Projections – review LEC cost structure, benchmark costs and indicate areas for improvement, review current tariffs structure and levels as compared to economic tariffs, propose trajectory for bringing tariffs to cost-reflective levels indicating the resultant impacts on LEC financial viability.	7/12/2017	97
7	Transmission Wheeling Charges – provide a methodology for the determination of transmission wheeling charges.	7/12/2017	24

Task No	Description	Date submitted	No pages
8	LEWA Tariff Determination Methodology – review LEWA Tariff Methodology and propose alternative approaches, prepare manual for the financial model and a capacity building plan.	10/1/2018	16
8a	Model (Excel Spreadsheet with 20 worksheets) and Manual	10/1/2018	54
9	Tariff Adjustment Roll-Out Strategies – propose strategies for tariff adjustment to economic levels including the introduction of a life-line tariff	10/1/2018	23

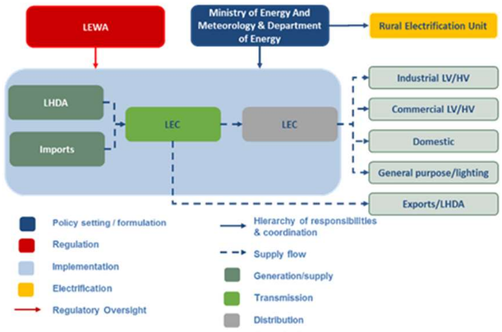
This report summarises the key data sources, assumptions, analyses/methodologies and results of these nine deliverables. This final report executive summary and the individual task reports, model and model manual are provided as the "CoSS package". The Task reports have been updated to reflect comments received from the STC. All tables and figures in the remainder of this executive summary are provided in full in the respective ask reports.

2 Overview of the Power Sector

2.1 Institutional Market Structure

The relationship between the key institutional elements of the power sector in Lesotho is shown in Figure 1. These are discussed in the following subsections.

Figure 1: Overview of key structural elements in the power sector and the connections[1]



2.2 Functioning of the Sector

Lesotho has established electrification targets in its "Vision 2020" of 2005: 35% of population having access to electricity by 2015 and 40% by 2020. A number of detailed strategic objectives are included in the National Strategic Development Plan 2012-2017. The Lesotho Energy Policy 2015-2025 is an overarching sector document that guides specific sector policies development and implementation.

The Act N .12 of 2002 (Lesotho Electricity Authority Act as amended in 2006 and 2011) establishes the Lesotho Electricity Authority to regulate and supervise activities in the electricity sector and to make provision for the restructuring and the development of the electricity sector and for connected matters. The LEWA has created and also manages the Universal Access Fund (UAF), which disburses

[1] Not intended to present hierarchies.

money in order to subsidise the capital costs of electrification in the country. The fund is resourced through an electrification levy charged by LEC. The tariff regime traditionally known as “Cost of Service” or “Rate of Return (ROR) regulation” has been applied in Lesotho up to now.

In 2000, principally to improve access to electricity, the Government of Lesotho (GoL) embarked on a restructuring of the electricity supply industry which included the privatisation of LEC through the sale of a majority shareholding to a strategic investor. The privatisation did not take place and LEC has continued to operate under the ownership of Government and under the guidance of its Board whose members are selected by the Ministry of Energy and Meteorology (MEM).

Historically the major barrier to deployment of Renewable Energy (RE) technologies in Lesotho has been the lack of finance and lack of economically viable technologies. The technologies are becoming increasingly viable but barriers still exist principally centred on a lack of knowledge and understanding of the opportunities for RE exploitation in Lesotho.

There is potential for building new generation capacity from hydro, solar and wind. The National Strategic Development Plan has identified hydropower development as a key focus area for electricity generation for both local consumption and export. A high level pre-feasibility study for Generation Planning was carried out in 2012 of a number of small and medium hydro projects Identified with approximate estimates on the costs and capacities possible. However, there are no detailed studies or costings and no specific Government plan for new generation development.

There is an Electrification Master Plan carried out by Danish Consultants COWI in 2006 with a planning period to 2020. It is principally concerned with electrification through grid extension. A new Electrification Master plan is currently underway. The terms of reference include a significant component considering non-grid connected development.

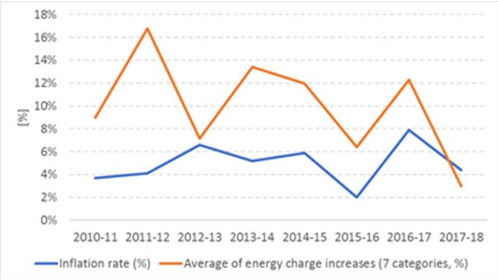
2.3 CURRENT TARIFF STRUCTURE

Retail tariffs in Lesotho have risen steadily over the past 8 years and, until the 2017/18 tariff review, at a rate above inflation – Figure 2. The 2017/18 tariffs were increased by an average of 3% which is the first time tariffs have increased at a rate below the current rate of inflation (4.4%, April 2017[2]) for about 10 years[3].

[2] Lesotho Bureau of Statistics.

[3] In 2006/2007 the tariff levels were reduced by the regulator

Figure 2 - Average increase in energy charges and Lesotho inflation rate 2010-2017.



Source: Lesotho BoS Data Portal (April figure for year in which tariff took effect).

LEC has not declared operational losses during the last 8 years. Customer tariffs are low by regional standards but this is balanced by the very low purchase tariff LEC pays to Muela hydro for more than half its electricity. There is thus evidence that the average level of tariff may not be orders different from cost reflective.

2.4 Sector Issues in the Context of a Cost of Service Study

Early in the project we identified the following significant issues in Lesotho that have an impact on the CoSS analysis:

1. The "cost of service" regime in Lesotho generally guarantees that the operator will recover its costs, and that the cost of capital would be low, due to the low risk of the business. However international experience has shown that the frequency of the reviews reduces incentives for productive efficiency and raises regulatory costs.
2. The cost of service study depends on an analysis of relevant data. As in many countries the data available in Lesotho may not be sufficient for an unequivocal set of conclusions.
3. The inability to pay for electricity that has been recorded in BoS surveys compromises any attempt to bring tariffs to cost-reflective levels immediately.
4. Government may need to establish a more definite policy on the importance of security of supply (reliance on imports to meet demand). The CoSS model will assist Government to understand the cost implications of any plans for additional generation in Lesotho.

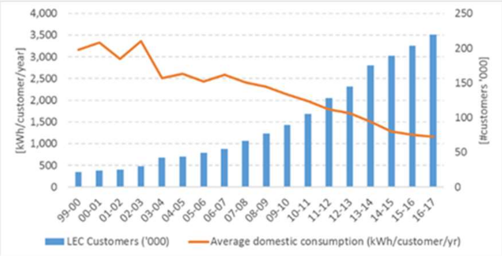
3 Electricity Demand Forecasts

A first step for electricity system development modelling in Lesotho is to develop a projection of electricity demand expected to be met by LEC transmission and distribution networks during the period up to 2030.

3.1 Analysis of Current Demand

The analysis of the recent electricity demand provided by LEC (energy purchases, energy sales and peak demand) from 2000 until 2016 showed that since 2001/02 the peak demand has increased by 93% (83.5 MW to 161.0 MW) and total consumption by 186% (257.9 GWh to 737.3 GWh).

Figure 3: LEC customer numbers and average consumption per domestic customer 2000 to 2016



A key driver for this increase in demand has been the connection of new customers. Figure 3 shows how the LEC customer base has increased by almost a factor of 10 from around 25,000 in 2001/02 to approaching 210,000 in 2016/17 although average consumption per household has decreased by over 60% during the same period (2,951 kWh/year to 1,157 kWh/year).

Daily load curves for industrial and commercial customers have been derived from half hourly meter readings data covering the period 2016-2017.[4] These profiles have been used to derive an average daily load profile by customer tariff category.

3.2 Derivation of a Demand Forecast

In this study the International Atomic Energy Agency Model for Analysis of Energy Demand (MAED) was used to compute final consumption forecasts. MAED uses analytical bottom up variables together with their constituents and their drivers. Its inputs include GDP, population, electrification rates and energy usage per economic sector. The forecast is made on three possible scenarios:

- The **most likely scenario** in which the recent rate of about 15,000 new connections per year[5] is maintained until 2020 and then scaled back from 2020 onwards. The resulting household electrification rates for the on-grid households are 44% in 2020, 51% in 2025 and 54% in 2030. This scenario assumes the continuation of the long-term average GDP growth rate of 4%.
- The **low economic growth scenario** defines a lower bound for economic development. Low growth might occur for a number of reasons, such as, unstable socio-economic and political environments, and low levels of internal and foreign investment.
- The **high economic growth scenario** assumes an economic growth rate of 5.68% which is the average GDP growth rate of the highest 5 years in the last 19 years.

The final consumption results produced by MAED were converted to a projection for gross system demand by applying transmission and distribution losses and an appropriate system demand profile, both derived from LEC data. Figure 4 shows the total gross energy demand and total gross system maximum demand for the three scenarios relative to the final consumption.

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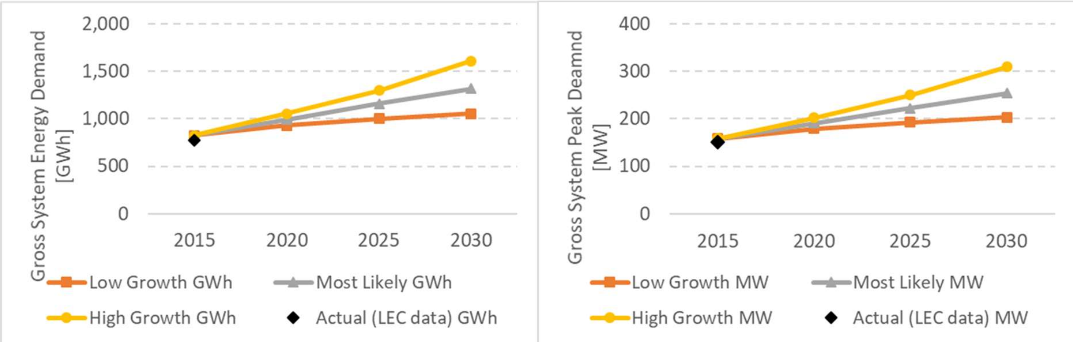
[4] LEC does not currently have equivalent data for residential, general purpose and street lighting.

[5] Of this total, 10,000 new connections are assumed in Urban and Peri-Urban areas with the remaining 4,000 in rural areas.

Figure 4: Projections for Gross Energy Demand and System Peak demand derived from MAED Final Consumption results



4 DETERMINATION OF LONG-TERM DEVELOPMENT FORECASTS

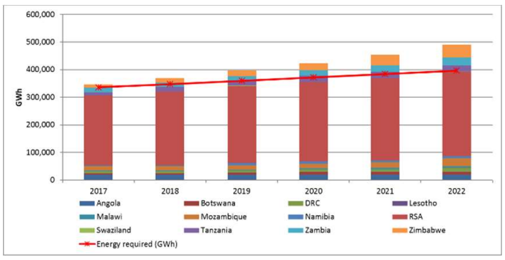
4.1 EXISTING DEVELOPMENT PLAN

LEC is responsible for initiatives to resolve short term power deficits, particularly in currently isolated parts of the network at Mafeteng and Semonkong.[6] LEC's network development plan consists of a total capital expenditure of US$193 million (2.513 billion loti) for projects expected to be commissioned over the period 2018-2024. The projects consisting of line (US$112.5m) and other upgrades (e.g., substations etc), total US$80.2m. A number of these transmission and distribution upgrades are needed to keep pace with the demand growth – for example to reinforce the network to increase power supply to the Letseng mines – whereas others are for expanding the network to improve security and quality of supply. Where appropriate, data from the LEC development plan has been integrated into the development plan model for this study.

4.2 POTENTIAL DEVELOPMENTS IN SAPP

Figure 5 shows the consultants' estimate of production from existing and potential new generation in SAPP to 2022 against the total energy forecast. Projections beyond 2022 are more uncertain, however assuming a similar rate of growth in new capacity then the analysis suggests that there will be ample generation in the SAPP system and Lesotho can continue to import capacity and energy as required. The development plan modelling explores the uncertainty in these plans, along with associated availability and costs of imported power.

Figure 5: Estimate of maximum production from in SAPP 2017- 2022 (GWh)



[6] Projects include two (2) solar plants (Mafeteng 40 MW and Semonkong 10 MW), a wind plant (Semonkong 20 MW) and a hydro project (upgrade Mantsonyane 10 MW).

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4.3 Development Plan Modelling

The development plan objective is to find the optimal capacity expansion in response to demand growth, existing asset retirements, and resource and modelled policy constraints. The electricity demand forecast is represented as a load-duration curve (LDC).[7] Of critical importance is the accurate representation of monthly peak load, which is captured in the LDC peak block.

Generation planning considers the peak demand condition and energy demand plus (optionally) reliability standards and other constraints[8]. The generation expansion provides the cost of new generation investment and expected despatch costs at peak and year-round.

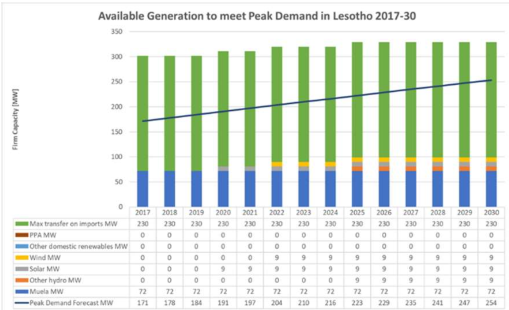
The transmission expansion plan provides the cost of new investment to enhance the reliability of the existing networks and meet the peak demand condition at transmission level derived in the electricity demand forecast. The distribution expansion provides the cost of new distribution investment. Candidates for transmission and distribution investment are included in the model and are defined for lines, substations transformers, switchgear and other upgrades.[9]

To address uncertainties in model input data, three major variations have been modelled:

- **Base Case:** the least-cost option where reliance on imports to meet demand growth is maintained with no constraints on the volumes that can be imported from SAPP.
- **Self-reliant supply:** To address the uncertainty surrounding the expansion plans for SAPP and the subsequent availability of imported power, a case where reliance on imports is greatly reduced and, if possible, eliminated entirely by 2030.
- **Trading in SAPP:** An alternative evolution of contracting with SAPP participants whereby LEC instead participates fully in the developing SAPP market.

The analysis indicates that costs are relatively similar in the base case and the self-reliant scenarios due to the investment cost of new generation being somewhat offset by the production cost savings in later years as generation from renewables displaces imports. The NPV of adopting a strategy to achieve security of supply through generation in Lesotho is similar to that of the base case. However, it requires a very significant additional capital expenditure of more than US$0.5 billion.

Figure 6: Projected installed and peak capacity to meet peak demand 2017-30 (base case).



	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Max transfer on imports MW	230	230	230	230	230	230	230	230	230	230	230	230	230	230
PPA MW	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Other domestic renewables MW	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind MW	0	0	0	0	0	9	9	9	9	9	9	9	9	9
Solar MW	0	0	0	9	9	9	9	9	9	9	9	9	9	9
Other hydro MW	0	0	0	0	0	0	0	0	9	9	9	9	9	9
Muela MW	72	72	72	72	72	72	72	72	72	72	72	72	72	72
Peak Demand Forecast MW	171	178	184	191	197	204	210	216	223	229	235	241	247	254

[7] The LDC is equivalent to the load-over-time curve sorted in order of decreasing power.

[8] Model constraints include, for example, reliability requirements, technology investment limits, plant availability (year-round and at peak demand) and renewable generation resource availability.

[9] For example, costs associated with feasibility studies or customer compensation for through/close to community routing (although these costs are expected to be low relative to the main upgrades and are not associated with construction lead times or interest during construction).

5 Economic Costs and Tariffs

The estimation of Economic Cost of Supply in the CoSST model is carried out through a Building Blocks Approach where the costs of each segment (generation - transmission – distribution – supply) are added:

- **Generation costs:** computed as pass through costs to end users. The "pass through" mechanism is the formula and methodology for generation rates or prices to be passed through to tariffs.
- **Transmission and distribution costs:** computed with a rolling forward model of the networks Asset Base, whereby the value is updated each year as new capital expenditure is added and depreciation is deducted. The model also considers OPEX, administration and commercial costs. LEC does not currently separate all its transmission and distribution cost data so splitting factors were derived from available data.
- **Supply costs:** Total OPEX for T&D has been split into Network OPEX and Supply OPEX assuming that Supply OPEX represents 10% of the total in LV and 5% of the total in HV.

5.1 Incremental Cost of Supply by Voltage Level

The most efficient and sustainable policy for pricing electricity is to set its price equal to its long-run marginal cost of supply, which ensures the utility company is able to meet its costs in the long term. Table 2 shows the long-run marginal cost (LRMC) of generation and Average Incremental Costs (AIC) of transmission and distribution at each level (the difference is the impact of losses) in the base case development program.

Table 2: Summary of LRMC of generation, AIC of transmission and supply

Delivery point at voltage level	LRMC of Generation (M/kWh)	Transmission network LRMC (M/kWh)	Distribution Network LRMC (M/kWh)	Transmission network & supply OPEX (M/kWh)	Distribution network & supply OPEX (M/kWh)	Total (M/kWh)
Generation	1.473	-	-	-	-	**1.473**
Transmission	1.584	0.302	-	0.101	-	**1.987**
Distribution	1.810	0.346	0.186	0.116	0.421	**2.878**

5.2 Economic Cost of Supply by Voltage Level

A summary of the per year economic cost of supply is shown in Table 3. The analysis applies the LRAC generation tariff when calculating the costs of generation component. If on the other hand, the LRMC of generation tariff is used to calculate the generation cost then the allowable revenue us somewhat higher – Table 4.

Table 3: Summary of Economic Cost of Supply based on LRAC generation tariff

	2018/19	2019/20	2020/21
Return of Capital (Depreciation)	109,800,000	115,333,919	119,776,967
Return on Capital	233,494,440	249,607,665	261,776,703
OPEX	289,766,305	316,581,510	339,225,320
Total Cost Generation (using LRAC of generation tariff)	591,782,718	613,443,912	635,105,107
Total Required Revenue	**1,224,843,464**	**1,294,967,006**	**1,355,884,097**

Table 4: Economic Cost of Supply based on LRMC generation tariff

	2018/19	2019/20	2020/21
T & D Costs - Total	633,060,746	681,523,094	720,778,991
Total Cost Generation for Demand and Energy losses (using LRMC tariff)	1,362,390,022	1,412,257,978	1,462,125,935
Total Required Revenue	**1,995,450,768**	**2,093,781,072**	**2,182,904,925**

5.3 Classifying And Allocating Economic Costs

Generation costs have been allocated according to the energy consumption of each customer category. In practice this means the same unit cost of power generation has been applied to all customers. This is consistent with the fact that there is no time-discrimination applied to end-user tariffs and therefore all consumers should contribute the same per-unit amount to generation costs.

Transmission and distribution capital and OPEX costs are allocated based on the criteria of coincidental peaks at system peak. That is, each customer category is responsible for its contribution to the system peak. This is so because network investments are mostly linked to network capacity, which in turn is dimensioned to be able to supply the peak demand in the system. Network OPEX costs are mostly fixed and can be considered directly proportional to the system size, and therefore also linked to the system's peak demand. Therefore, the burden that each customer category imposes in the network system costs is proportional to its contribution to that peak demand.

Supply OPEX is allocated proportional to the number of customers as supply activities (meter reading, billing, collection and customer complaint management) are not related with the size of the system, but rather to the number of delivery points or customers the company needs to serve.

5.4 Tariff Categories

The definition of customer categories has a very relevant impact on tariff levels and their adequacy to reflect economic costs of supply. The current set of customer categories were evaluated and, aside from the introduction of a life-line tariff (see section 6), we have not identified any immediate need for LEWA to change customer categories.

Table 5: Current tariff structure

Category	Description
Domestic	For the supply of electricity to premises used solely for private residential purposes.
General Purpose	For the supply of electricity to premises used solely for primary and secondary schools and churches.

Category	Description
Street Lighting	For the lighting of public areas (streets).
Commercial LV	For customers using electricity entirely or predominantly for purpose other than industrial and regularly having a maximum demand of 50kVA
Industrial LV	For customers using electricity entirely or predominantly for industrial purposes and regularly having a maximum demand in excess of 25kVA
Commercial HV	For major non-industrial customers it may be desirable or essential for a supply to be given at medium voltage or high voltage.
Industrial HV	For major industrial customers it may be desirable or essential for a supply to be given at medium voltage or high voltage.

5.5 Economic Tariffs By Consumer Category

Table 6: Economic Tariffs by Customer Categories (no subsidies or levies included, 2017 real)

		Economic Tariffs 2018 - 2020 (LRMC Generation)	Economic Tariffs 2018 - 2020 (LRAC Generation)	Economic Tariffs 2018 - 2020 (LRAC Generation, no fixed charges)
Domestic				
Fixed Charge	M/month	6.96	6.96	-
Energy Charge	M/kWh	2.897	1.945	2.016
Maximum Demand Charge	M/kVA	-	-	-
General Purpose				
Fixed Charge	M/month	6.96	6.96	-
Energy Charge	M/kWh	2.535	1.583	1.595
Maximum Demand Charge	M/kVA	-	-	-
Street Lighting				
Fixed Charge	M/month	6.94	6.94	-
Energy Charge	M/kWh	2.705	1.753	1.759
Maximum Demand Charge	M/kVA	-	-	-
Commercial LV				
Fixed Charge	M/month	6.95	6.95	-
Energy Charge	M/kWh	1.682	0.731	0.731
Maximum Demand Charge	M/kVA	285.82	285.82	285.82
Industrial LV				
Fixed Charge	M/month	6.96	6.96	-
Energy Charge	M/kWh	1.683	0.731	0.731
Maximum Demand Charge	M/kVA	254.24	254.24	254.24
Commercial HV				
Fixed Charge	M/month	3,681.80	3,681.80	-
Energy Charge	M/kWh	1.780	0.773	0.797
Maximum Demand Charge	M/kVA	149.81	149.81	149.81
Industrial HV				
Fixed Charge	M/month	3,673.14	3,673.14	-

		Economic Tariffs 2018 - 2020 (LRMC Generation)	Economic Tariffs 2018 - 2020 (LRAC Generation)	Economic Tariffs 2018 - 2020 (LRAC Generation, no fixed charges)
Energy Charge	M/kWh	1.782	0.774	0.785
Maximum Demand Charge	M/kVA	150.36	150.36	150.36

6 LIFE-LINE TARIFF MECHANISM

The need for a lifeline tariff to meet basic needs of the poorest households in Lesotho has also been evaluated. Lifeline tariffs are common in the developing world especially in Africa to provide the poorest households with affordable electricity.

The CoSS analysis has shown a strong case for the introduction of a lifeline tariff in Lesotho. A majority of households connected to the grid would be considered fuel poor if paying for their usage at current tariff levels. The evidence of a rapidly decreasing consumption for newly connected customers is presented and this further supports the conclusion that a lifeline tariff is needed for low consumption households. This is reinforced by surveys that have been carried out over many years which point to the fact that most households in Lesotho use electricity only for lighting.

Thus tariff reform should address not only the issue of access and cost-reflectivity but affordability as well. Globally in both developing and developed countries affordability has been addressed by various subsidy mechanisms and consumption targeted lifeline tariffs has been found to be the most effective.

A lifeline tariff for households that consume less than 50kWh/month would adequately address the basic energy necessities of poor households in Lesotho and lead to an improvement in the standard of living. An important additional benefit would be a reduction in the use of biomass which contributes to the degradation of the environment and CO2 emissions. However, in 2016 a large number, in fact a majority of grid connected households (57%) used less than the 50kWh/month threshold. Thus if subsidised tariffs were charged on the basis of this threshold it would lead to an over-elevated tariff for the fewer higher consumption households. The analysis concludes that it would be more realistic to adopt a lower threshold of 30kWh/month which would have provided subsidised electricity to about 25% of households in 2016.

The analysis shows that a lifeline tariff of 0.5 to 0.6 M/kWh would ensure that customers on or below the poverty line could reasonably afford to pay for electricity and we therefore propose a lifeline tariff be set at 0.5 M/kWh.

We note that public education and consultation with key stakeholders, is critical for success of the lifeline tariff. In planning a tariff reform, it is important to clearly outline the goals and objectives, identify main stakeholders and interest groups, and develop strategies to address their concerns. Convincing the population that there is a credible commitment to compensate the vulnerable groups is essential for the success of introducing a lifeline tariff.

7 BENCHMARKING OF LEC

The study included a review of LEC's cost structure benchmarking with other comparable utilities. There is no perfect comparability to LEC as there is no country or power system identical to that of Lesotho. Comparing utilities from different countries is not an exact science and it needs to be understood that the economic framework, regulatory conditions and consumption profiles are specific to each country. Nevertheless, this benchmarking analysis has maximized comparability through careful selection of companies, KPIs and by providing guidance in the interpretation of each benchmark result.

This study adopted two separate benchmarking exercises that utilize different peer groups:

1. A **regional analysis** - utilities from other countries that have a similar regulatory framework (vertically integrated utilities) as Lesotho, that also participate in SAPP and in which distribution and retail activities are operated by the same company.
2. A **best international practices analysis for operational expenditure** - distribution utilities from well established markets, whose density values and composite indexes are similar to those of LEC. This analysis was used to **derive an OPEX improvement target for LEC.**

7.1 Regional Analysis

The regional benchmarking analysis concluded:

- Loss levels and energy intensity in Lesotho are comparable with its African peers but still far away from International Best Practices.
- SAIDI and SAIFI figures have worsened in the recent years and, despite some improvement during 2016, are still below 2014’s values.
- In general, LEC’s operational figures are better than in the rest of its African peers.
- LEC’s figures suggest some level of excessive staff costs: despite a good evolution of connections by employee in recent years, the level of labour costs over total sales seems high. Consumption levels amongst newly connected customers have been falling significantly in recent years limiting sales and hence worsening this ratio, while ensuring relatively high salaries within LEC guarantees its ability to retain high-skilled workers.
- The ratio of OPEX per MWh is expected to fall due to reduced O&M requirements given the new infrastructure already deployed and expected to be deployed in the short term. We have thus derived an efficiency goal for LEC.
- LEC financial indicators are generally more in line with international norms than those of its regional peers.

7.2 International Analysis: OPEX Efficiency Target

To establish a credible operational expenditure efficiency improvement target for LEC the study compared LEC to international utilities. For the Networks part of the business, operational performance is affected by two major variables: the customer density on the network and average consumption by customer. The study used a composite index of these as a basis for the comparison. The target resulting from the comparative analysis is a total reduction of unit costs of 15.8% by 2035.

For the Commercial part of the business operational performance is related to invoicing activities, customer care, and advertising, which are costs that are proportional to the number of customers. The comparison therefore used a density value of customers per kilometre of line. The target resulting is a yearly reduction of 2% for commercial costs.

7.3 Economic Tariffs with OPEX Improvements

The economic tariffs for the OPEX improvement cases (excluding customer levies and electrification levies) are shown in Table 7. The adjustments are reflected through changes in the energy charges.

Table 7: Economic Tariffs (excluding levies) for efficiency improvement scenarios

Tariff	Current 2017/18	Table 6	No improvement	High improvement	Intermediate improvement
Energy Charges	**M/kWh**	**M/kWh**	**M/kWh**	**M/kWh**	**M/kWh**
Domestic	1.347	1.945	1.878	1.842	1.855
General Purpose	1.522	1.583	1.529	1.500	1.511
LV Commercial	0.206	0.731	0.731	0.731	0.731
HV Commercial	0.186	0.773	0.773	0.773	0.773
LV Industrial	0.206	0.731	0.731	0.731	0.731
HV Industrial	0.186	0.774	0.774	0.774	0.774
Street Lighting	0.764	1.753	1.693	1.661	1.673
Demand Charges	**M/kVA**	**M/kVA**	**M/kVA**	**M/kVA**	**M/kVA**
LV Commercial	306.302	285.818	275.983	270.741	272.671
HV Commercial	262.239	149.811	144.656	141.909	142.921
LV Industrial	306.302	254.245	245.496	240.834	242.551
HV Industrial	262.239	150.355	145.182	142.425	143.440
Fixed Charges	**M/month**	**M/month**	**M/month**	**M/month**	**M/month**
Domestic	0	6.97	6.97	6.97	6.97
General Purpose	0	6.96	6.96	6.96	6.96
LV Commercial	0	6.95	6.95	6.95	6.95
HV Commercial	0	3,681.80	3,681.80	3,681.80	3,681.80
LV Industrial	0	6.96	6.96	6.96	6.96
HV Industrial	0	3,673.14	3,673.14	3,673.14	3,673.14
Street Lighting	0	6.93	6.93	6.93	6.93

Six cases for a tariff trajectory and financial performance of LEC were analysed. The analysis demonstrated that tariffs can be set in many ways with LEC still anticipated to achieve financial viability and recovery of allowed revenue. The main driving factors for the tariff decision are:

1. The level of tariff increase customers would be willing to accept / afford; and
2. The availability to raise finance to fund the portion of the network and generation expansion program that the cash flow will not support.

From the analysis of the six scenarios the following conclusions can be drawn:

- Adjusting tariffs to cost reflective immediately, results in dramatic changes to customer tariffs.
- Including a full return on capital results in tariffs that it may be considered too high for LEC customers (unaffordable for many domestic customers and holding back economic development for commercial customers).
- A cross-subsidised lifeline tariff could be introduced with moderate impact on other customers.
- A smooth transition to a cost reflective average tariff could be achieved with modest tariff changes but this would not correct imbalances between tariff categories.

- A transition over three years to fully cost reflective and including a lifeline tariff, though still excluding returns on capital, was shown to be feasible with important tariff changes that it may be possible to introduce in Lesotho.

7.4 Recommended Performance Indicators

Table 8: Recommended performance indicators, technical, operational, and financial

Technical KPIs	Description
Energy losses (%)	It is the ratio of electricity losses during the year over total electricity wheeled. It gives the electricity losses as a percentage of the overall electricity wheeled in the transmission system.
SAIFI	It is the average number of times per year that supply to a customer is interrupted.
SAIDI (hours)	It is the average amount of time per year that supply to a customer is interrupted
Energy intensity (MWh/km)	Capital energy efficiency of a company infrastructure.
Operational KPIs	**Description**
Energy wheeled per employee (MWh/employee)	It is the ratio of total electricity wheeled during the year to the number of employees. It gives the amount of electricity per employee.
Customers per employee	It gives the number of customers per employee
Network Length per employee	It gives the Km per employee, to relate staff numbers with the need to manage a network of a certain size
Salaries to Sales Ratio (%)	Total operating salaries expenditure of the utility over the total net sales recorded for the year.
OPEX versus Energy Wheeled	Total transmission OPEX over the total volume of energy wheeled. It gives an expenditure figure per MWh of transported power.
OPEX over Total Revenues	This ratio provides an idea about gross profit of the company (which percentage of its revenues is devoted to OPEX)
OPEX per grid km	Total transmission OPEX over the total Km of transmission lines. It gives an expenditure figure per km of lines.
Assets Efficiency	The figure uses gross value of assets, so does not take into account depreciation
Revenue Collection Ability USD/kWh	It represents the ability of a company to obtain revenues from its sales (hence it covers both tariff levels and collection rates).
Financial KPIS	**Description**
Working ratio	It measures the ability to recover Op. Costs from annual revenue.
Working ratio with depreciation	Same ratio but accounting for depreciation, to reflect asset value evolution.
Working ratio with depreciation and net interest	As the previous, but including net financing costs
Net operating margin	It provides the percentage of revenue that is left for the company after accounting for all expenses
Current ratio	It measures the company's ability to repay s/t and l/t obligations

Accounts receivable collection period	Number of average days that it takes a company to collect its accounts receivables (i.e. to make them liquid)
Accounts payable disbursement period	Number of average days that it takes a company to pay its debtors
Return on equity	Measures Net Income as a percentage of shareholders equity (i.e. the profitability of the money invested by shareholders)
Return on net fixed assets	It measures how efficiently a company is using its net fixed assets.
Debt to assets	This leverage ratio provides an indicator of financial risk exposure by the company (the higher the ratio, the higher the exposure)

8 Tariff Determination and Roll-out Plan

8.1 Regulatory Options

Cost Plus or Incentive Based Regime?

There are two distinct cases commonly defined for utility tariff regulation: Cost plus and Incentive Based. The regulatory framework and tariff methodology in Lesotho is Cost Plus. A switch to incentive-based regulation is not recommended. The current cost-plus regulatory regime will remain appropriate for Lesotho for the foreseeable future.

Yearly or Multi Year?

The computation of economic costs and tariffs reported in Deliverable 5 is based on a Multi-Year tariff regime for which a number of benefits are identified. The length of the tariff period (3 years) is in line with international experience.

Allowance for Return on Assets?

The **Cost-Plus** tariff regime includes an allowance for the provision of a reasonable rate of return on assets. This is designed to enable the utility to raise capital and invest in the improvements and additions to its assets required to meet customer demand and growth. Up to now tariffs in Lesotho have not included an element designed to provide a return on assets. Furthermore, the Government of Lesotho has funded the majority of asset improvements and additions. The CoSS is tasked to develop cost-reflective tariffs which by definition include a return on assets element. However, to mitigate tariff shock to customers we recommend a gradual introduction of a full return on capital over 3 to 6 years.

8.2 Recommended Approach

Tariff Regime

The recommended tariff regime is to retain the existing cost of service system, extend it to three years, provide a minor review process for bulk supply variations in cost annually, and propose a relatively small bonus payment to LEC management be allowed (at LEC's Board's discretion to apply) as a regulatory cost for the achievement of specific improvements in operating efficiency.

Specific Proposals

Specific proposals were discussed and agreed as appropriate at the December review meetings in Maseru and included:

1. Tariffs should rise to cost reflective levels excluding return on capital over the three-year review period – i.e., covering bulk costs, operating expenditure and depreciation. An operational efficiency improvement of about 0.9% per year in network OPEX and 2.0% per year in commercial OPEX should be assumed in estimating the operating expenditure.
2. A fixed charge tariff for credit metered customers would be included.
3. Tariffs will be rebalanced amongst tariff categories over the three-year tariff review period. However the General Purpose tariff (which needs to be reduced by 27% to be cost reflective) would be maintained constant in the expectation that rising costs would lead to it becoming cost reflective in due course.
4. Gradual rebalancing of capacity and energy tariffs for industrial and commercial customers over a suitable path would take place.
5. LEC need to demonstrate that they are including the lowest possible Bulk Supply costs in calculating the revenue requirement.
6. LEC need to consider the technical and commercial implications for the introduction of time of use tariffs for large customers to better match demand and supply timings[10].

8.3 Introducing the Lifeline Tariff

Meeting of STC in December 2017 – Lifeline and Universal Access Fund

We took part in discussions with the Study Technical Committee in December and we noted the following:

Lifeline Tariff Definition

The introduction of a lifeline tariff is to be considered, though it was proposed that the lifeline tariff level must at least cover bulk supply costs – i.e. about 60% of the allowable revenue if returns on capital are excluded. The subsidy required to make up the LEC deficit resulting from the lifeline block tariff being lower than cost reflective would be paid by an uplift in all other tariffs.

Universal Access Fund

As noted in the Background section 2.3 of the Deliverable 6 it is also necessary to review the continuing collection of the Universal Access Fund levy from existing customers. The discussions with the STC in December suggested that the introduction of the lifeline block tariff would need to consider the discontinuing of the UAF levy and we agree with that conclusion. It would be unfair and unreasonable to continue to collect a levy from existing customers to fund the extension of the grid to new customers that are likely to be mainly low consumption poorer households also availing of the lifeline block cross-subsidy from existing customers. However it is also our understanding that there is probably a need for a change in law before LEC can discontinue the collection of the UAF levy.[11]

Legal Status

The legal and regulatory basis for the life-line tariff comes from the Regulators' mandate i.e. LEA Act itself and is supported by provisions of the Lesotho Energy Policy 2015-2025.

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[10] Countries in Africa that have TOU tariffs for industrial customers include: Burkina Faso, Cameroon, Cote D'Ivoire, Ethiopia, Senegal, South Africa (since 1992 and including commercial and some residential), and Uganda.

[11] The levy collection can be repealed only by a determination contained in an act that has the same legal status as the Legal Notice no 83/2011 that established that the UAF levy be collected in 2011.

Guidelines for Introducing a Lifeline Block Tariff

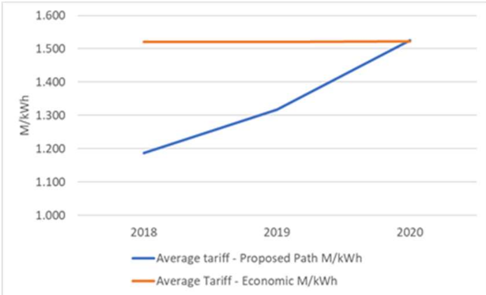
A lifeline block tariff can be introduced without change to the law – i.e. within the current LEWA regulations. LEWA needs to instruct LEC that in the next tariff review they need to include a lifeline block tariff. This will be a tariff that applies to the first 30 kWh per month for all domestic customers. The tariff applying to domestic customers for consumption above 30 kWh in a month will be renamed the standard domestic tariff.

LEWA and LEC should ensure that awareness campaigns are rolled out nationally to educate communities on the introduction of the Lifeline Block Tariff.

8.4 Recommended Tariff Option

In the recommended option tariffs are increased gradually towards the economic level. If this plan is adopted, then LEC are expected to under-recover against the revenue requirement in years 1 and 2 of the price control but by year 3, the tariffs reach the economic level including Return on Capital. This is demonstrated at the average tariff level in Figure 7.

Figure 7: Recommended average tariff pathway relative to the economic tariff level



To establish fully cost-reflective economic tariffs the most significant change required in customer tariffs is the rebalancing of energy and maximum demand tariffs for industrial and commercial customers.

Increases in domestic and street lighting tariffs are also required. The overall increase in domestic is 13.4% per year although the introduction of a lifeline block tariff means this increase is portioned as a 52% reduction at the lifeline block level (1.347 to 0.650 M/kWh) and a 34% increase in the standard domestic tariff (1.347 to 1.804 M/kWh). The street lighting tariff is increasing by 31.6% per year and there is no increase in General Purpose.

The combined effect of a low tariff for the first 30 kWh of monthly consumption with the remaining consumption at the standard domestic tariff is that typical customer bills increase by modest amounts. The impact on domestic bills in the first year is presented in Figure 8 below, showing that low consumption-level customers would see a 17% reduction, average consumption-level customers a 13% increase and high consumption level customers a 24% increase.

The resulting tariffs are as shown in Table 9. The Table also shows in the first column the current tariffs (no levies or VAT) and in the final column the resulting economic tariffs to provide a basis for comparison.[12]

[12] Note that the discrepancies between the 2020/21 energy charges and the economic energy charges is due to the economic energy charges being set at a flat rate over the period (so that the NPV of the summed differences between total expected income and total costs is zero – further explanation of this is provided in the Task 4 (deliverable 5) and Task 6 (deliverable 7) reports) whereas the 2020/21 energy charges are set to recover exactly the economic costs in that year with no consideration of previous years.

Table 9: Tariff pathway for recommended option

Tariff	Current 2017/18	2018/19	2019/20	2020/21	Economic Tariffs
Energy Charges	**M/kWh**	**M/kWh**	**M/kWh**	**M/kWh**	**M/kWh**
Lifeline Block	1.347	0.650	0.650	0.650	1.925
Standard Domestic	1.347	1.804	2.088	2.404	1.925
General Purpose	1.522	1.523	1.523	1.524	1.524
LV Commercial	0.206	0.320	0.498	0.774	0.731
HV Commercial	0.186	0.306	0.502	0.823	0.773
LV Industrial	0.206	0.320	0.498	0.774	0.731
HV Industrial	0.186	0.306	0.502	0.824	0.774
Street Lighting	0.764	1.006	1.323	1.741	1.674
Demand Charges	**M/kVA**	**M/kVA**	**M/kVA**	**M/kVA**	**M/kVA**
LV Commercial	306.302	294.763	283.659	272.973	272.973
HV Commercial	262.239	214.284	175.099	143.079	143.079
LV Industrial	306.302	283.483	262.364	242.819	242.819
HV Industrial	262.239	214.543	175.522	143.599	143.599
Fixed Charges	**M/month**	**M/month**	**M/month**	**M/month**	**M/month**
Domestic	0	0	0	0	0
General Purpose	0	0	0	0	0
LV Commercial	0	6.952	6.952	6.952	6.952
HV Commercial	0	3681.801	3681.801	3681.801	3681.801
LV Industrial	0	6.962	6.962	6.962	6.962
HV Industrial	0	3673.140	3673.140	3673.140	3673.140
Street Lighting	0	6.945	6.945	6.945	6.945

Table 10 shows an excerpt from the projected financials for LEC under this scenario – performance improves throughout the period. This is due to tariffs being below the economic level in the first and second year of the price control before reaching the economic level in year 3.

The applied increases mean LEC is expected to have sufficient income (1,017.7 Mil) to cover bulk supply costs (513.7 M mil), OPEX (263.3 M mil) and depreciation (115.9 M mil) in 2018 with a remaining income allowing a profit after tax of 45.7 M mil in 2018.

Table 10: Projected income statement for full balancing of MD and energy charges (Mm)

LEC Statement of Comprehensive Income	2018	2019	2020
Total Revenue	1,017.7	1,158.5	1,375.8
Gross profit	449.1	589.3	788.6
Profit/(Loss) before tax	60.9	172.6	350.4
Profit/(Loss) after interest and tax	45.7	129.5	262.8

Under this scenario, funding is required in order for LEC to meet its network expansion goals and also invest in the amount of generation expected in the base case (e.g., the 10 MW Solar Park at Semonkong). The table below shows an excerpt from the projected cash flow and highlighted bold the level of funding[13] in order to maintain a minimum of 50 M million cash in bank balance. The table shows an income from commercial loans and capital grants totalling 399.2 M mil.

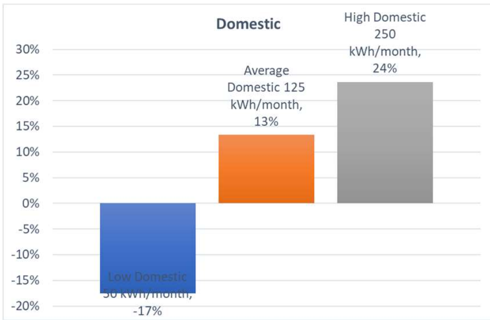
Table 11: Summary of projected cash flow for LEC in recommended tariff option

Cash Flow	2018 M m	2019 M m	2020 M m
Opening Cash	**112.9**	**50.0**	**50.0**
Add receipts			
from commercial loans & capital grants	**244.8**	**154.4**	**0.0**
Income from tariffs & levies	81.6	81.7	83.8
Other income	81.6	81.7	83.8
Less payments			
For power purchase	-513.7	-512.2	-526.2
Salaries, Wages and OPEX	-458.6	-421.1	-398.7
CAPEX	-513.7	-512.2	-526.2
Other payments			
Closing cash	**50.0**	**50.0**	**68.1**

Of key importance is the impact of these changes on consumer bills, particularly with the introduction of a lifeline block tariff for domestic and rebalancing of MD and energy charges for industrial and commercial. Using actual data for 2016 from LEC these impacts are demonstrated in the figures below.

Figure 8 shows that for a low consumption domestic customer a 17% reduction in bills can be expected in 2018. For average consumers a 13% increase and for higher consumers a 24% increase.

Figure 8: Impacts on domestic customer bills for a low, average and high consumer under tariff study option 1



The left most plot in Figure 9 considers three types of LV industrial customer who all consume the same amount of energy per month (20,529 kWh/month) but consume varying levels of maximum demand (ranges witnessed in the 2016 data from LEC). It shows that an average kVA/month and average kWh/month consumption customer (orange bar) can expect a modest 1% increase in their bill but a below average kVA/month (same energy) would see an increase. For HV industrial (right plot in Figure 9) the average customer (328,079 kWh/month, 641 kVA/month) would expect a 5% increase.

Figure 10, left plot, considers three types of LV commercial customer who all consume the same amount of energy per month (24,176 kWh/month). It shows that an average kVA and average energy consumption customer (orange bar) can expect a 7% increase in their bill. For HV commercial (right most plot in Figure 10) the average customer would expect a 2% increase.

[13] Assumed that funded is 50% commercial loans and 50% capital grant. See deliverable 7 report for assumptions on commercial loan properties.

Figure 9: Impacts on LV and HV industrial customer bills for a low, average and high kVA consumer (each consuming same energy kWh/month) under tariff study option 1

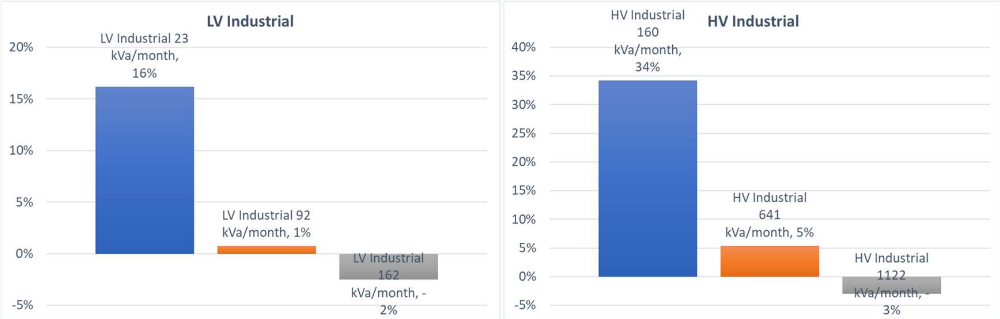
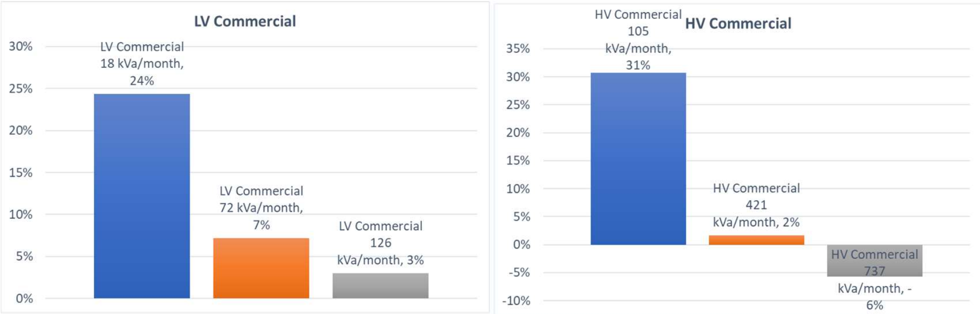


Figure 10: Impacts on LV and HV commercial customer bills for a low, average and high kVA consumer (each consuming same energy kWh/month) under tariff study option 1



9 CONCLUSIONS

The individual reports on the specific tasks of the CoSS can be referred to for the detailed conclusions of the study. This section draws the following overall conclusions:

1. Lesotho can introduce fully cost-reflective tariffs with relatively modest increases (some reductions) in the majority of customer bills.
2. A lifeline tariff is needed to cushion the impact of the introduction of cost-reflective tariffs.
3. The proposed lifeline tariff is for the first tranche of consumption per month for domestic customers. The resultant loss of revenue on those units delivered can be recovered from non-domestic customers as well as domestic customers consumption above the life-line level, by modest increases in tariff above cost-reflective levels.
4. The CoSS has developed and delivered a model that can be used in future tariff determinations by LEWA.

There are a number of issues on which government decision is required:

1. Whether LEC should earn a return on capital and the level to be set at and implications of moving LEC gradually towards bankability;
2. Introduction of a lifeline tariff and level, design and subsidy recovery; and
3. Changes in legal and regulatory environment such as the discontinuation of the UAF.

Electricity Supply Cost of Service Study – LEWA Lesotho

Review of Power Sector – Deliverable 2

Support Provided by African Development Bank

Prepared for: LEWA

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CONTENTS

LIST OF ACRONYMS

BoS	Bureau of Statistics
CMS	Continuous Multi-Purpose Household Survey
DoE	Department of Energy
EdM	Electricidad du Mozambique
LEP	Lesotho Energy Policy 2015-2025
GoL	Government of Lesotho
IBR	Incentive Based Regulation
IPP	Independent Power Producer
LEC	Lesotho Electricity Corporation
LEWA	Lesotho Energy and Water Authority
LHDA	Lesotho Highlands Development Authority
LREBRE	Lesotho Renewable Energy-Based Rural Electrification Project
MEM	Ministry of Energy and Meteorology
NUL	National University of Lesotho
RoR	Rate of Return
REU	The Rural Electrification Unit
SV	Solar Photovoltaic
SAPP	The Southern African Power Pool
SE4ALL TAF	EU Technical Assistance Facility for the "Sustainable Energy for All" Initiative (SE4ALL) - Eastern and Southern Africa
WB	World Bank

1 INTRODUCTION

The report provides a review of the power sector in Lesotho.

The market for electricity in Lesotho is characterised by the country's small size, the relative poverty of its population of about 2 million and the low level of electrification of that population. Of the estimated 500,000 households about 200,000 are connected to grid electricity.

The Lesotho electricity sector is characterized by

- A single large hydro power generating plant that meets about half the power demand and about two-thirds energy demand;
- Imports from Eskom and EdM via the Southern African Power Pool (SAPP) to meet the remaining demand; and the terms are established through bilateral agreements between LEC and EDM/ESKOM with SAPP having no part in those contracts.
- The majority of connections are concentrated in the urban areas with little grid supply to rural areas.

The sector is explored in the remainder of the report.

Section 2 provides an overview of the key institutions of the power sector with discussion on their roles, responsibilities and relationships between them. Section 3 details the key policies, their objectives and progress with a focus on power sector privatisation, electrification through the Universal Access Fund and tariff regulation through Cost of Service regulation. Section 4 provides a summary of the existing power system including generation performance to date. Section 5 looks at the level of current on-grid demand and number of customers. Section 6 looks at the costs of supply through tariffs levels and recent tariff review data. Finally, Section 7 concludes with the identification of inconsistencies and weaknesses in the existing structure and recommendations on how these inconsistencies can be resolved.

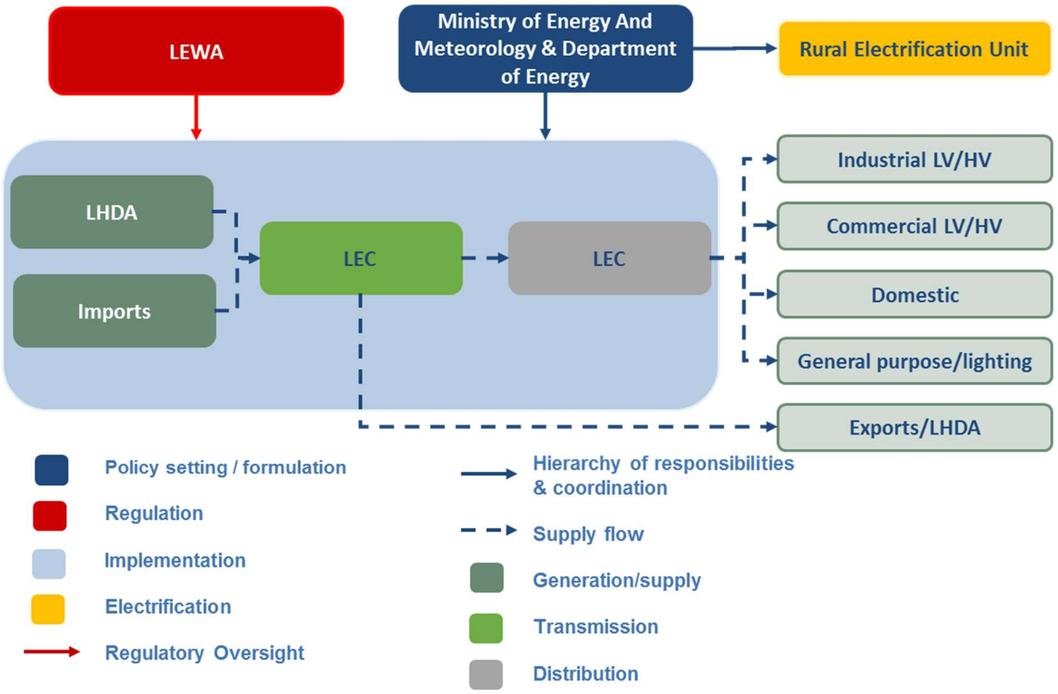
Figure 1: Map of Lesotho

2 Institutional Market Structure

2.1 Key Structural Elements

The relationship between the key institutional elements of the power sector in Lesotho is shown in Figure 2. These are discussed in the following subsections.

Figure 2: Overview of key structural elements in the power sector and the connections[1]



2.2 Ministry of Energy & Meteorology

The Ministry of Energy and Meteorology (MEM) is traditionally organized with a Minister heading the Ministry. The Minister is seconded by a Principal Secretary (PS) who is politically chosen, assisted by a Deputy Principal Secretary, a non-political appointee. The Ministry has two main Departments as the name already suggests.

2.3 Department of Energy

The Department of Energy (DoE) was established in the then Ministry of Water, Energy and Mining)[2] in 1985.

[1] Not intended to present hierarchies.

[2] The DoE is now part of the Ministry of Energy and Meteorology (MEM). Up to 2015 MEM also included water, but that is now a separate independent ministry.

It has three technical divisions: Planning, Renewable Energies and Project Monitoring. There is also administration which has Human Resource, Accounts and support staff

The **Planning Division** has two sections; Planning and Information (Statistics). As the name suggests this division deals with planning and information related to energy issues

The **Renewable Energies Division** has three sections namely Bioenergy, Solar/Wind and Energy conservation.

The **Project Monitoring Division** (Conventional Energies) has two sections: namely Electricity and Petroleum.

2.4 The Rural Electrification Unit

The Rural Electrification Unit (REU) was established in May 2004 to implement five Electricity Access Pilot Projects and with the broader remit to address electrification issues outside the service territory. It was intended to be part of the DoE, although in reality is not a formally constituted institution.. Thus it was established as a project within the Department of Energy with the intention that it would test delivery models for provision of electricity outside the service area using different technologies and also to test the institutional arrangement required for efficient provision of electricity particularly in the rural areas. The original plan was that it would utilise both grid and isolated means for electrification but the main effort has been on grid extension and generally very little on off-grid solutions.

The Government of Lesotho is currently being assisted by SE4ALL TAF team engaged by EU to review the mandates of energy institutions in the country. Preliminary findings are pointing towards restricting REU to off-grid energy solutions and making LEC the single party responsible for dealing with grid-connected electricity.

2.5 Lesotho Highlands Development Authority

The Lesotho Highlands Development Authority (LHDA) was established in 1986 to manage Lesotho's portion of the Lesotho Highlands Water Project, a joint water supply and hydropower project with South Africa. This project brought about the construction of the Katse Dam situated on the Maliba Matso River and the accompanying 72 MW Muela hydropower station to utilise the dam for electricity generation (see section 4.1.1). LHDA obtained a licence to generate at Muela from LEWA in 2006.

2.6 Lesotho Electricity Company

The Lesotho Electricity Company (LEC), which started operation in 1969, is a government-owned electricity company responsible for the electricity networks and the electricity customer interface (connections, billing and payment). LEC operations were licensed by LEWA in 2006. The electricity transmission and distribution networks comprise the main LEC assets valued at M2.66bn.[3]The

[3] As at 31 March 2016. The 2015/16 audited accounts show transmission, distribution and generation as accounting for around 85% of the value of LEC's asset base.

company has a debt: equity ratio of about 2% with equity (M2.71bn) consisting of about 14% in capital grants[4].

Transmission, distribution and supply to grid-connected customers are monopolies of LEC in defined service territories.

LEC undertakes connection efforts inside its service territory, being responsible for electrification within 3.5 km distance of the existing distribution network. LEC undertakes connection efforts outside of its territory only upon provision of subsidies (see section 3.5).. Hence, the country is split into two areas. The Service Territory, currently defined as a "*3.5 km buffer around the existing LEC distribution infrastructure*" and the remaining rural and remote area where 70% of Basotho population lives. The service territory is therefore naturally expanding as the grid is extended.

2.7 Lesotho Electricity and Water Authority

The Lesotho Electricity Authority (since 2013 Lesotho Electricity and Water Authority – LEWA) was established in 2004 as regulator of the electricity sector on the basis of the Lesotho Electricity Authority Act 2002 (see section 3.3).[5] The creation of the regulator was a consequence of the Lesotho Utilities Sector Reform Project (2002-2007), financed by the World Bank and the African Development Bank with a small contribution of the European Union.

The precise duties of LEWA are set out in section 21(1) of the Lesotho Electricity Authority Act, 2002 (LEWA Act)[6]. In summary, its mandate entails four main activities:

- Licensing (all participants in energy supply activities need a license to operate that is issued by LEWA);
- Tariff Approval;
- Monitoring Licensees' performance and technical standards (e.g., Quality of Service and Supply Standards); and
- Resolution of complaints or conflicts.

LEWA gets funding from licensed electricity operators (licence fees) and a levy on electricity customer tariffs (the "customer levy" – see section 6.3.2).

[4] The 2015/16 LEC Annual report indicates a vehicle financing loan with Nedbank Lesotho and Standard Lesotho Bank which is repayable over a period of 48 and 60 months respectively at a variable rate of 3% below prime and a Subsidiary loan payable over a period of 25 years with effect from September 2014 at a 2% pa.

[5] The Lesotho Electricity Authority was established through the Act. No. 12 of 2002. In 2007 the Government decided that the Lesotho Electricity Authority (LEA) should be transformed to be a multi-sector regulatory body assuming additional powers to regulate urban water and sewerage services in the country. LEWA officially started regulating both electricity and urban water and sewerage services sector on May 1, 2013.

[6] Ensure the operation and development of a safe, efficient and economic electricity sector in Lesotho; protect the interests of all classes of consumers of electricity as to the terms and conditions and price of supply; ensure, so far as it is practical to do so, the continued availability of electricity for use in public hospitals, and centres for the disabled, aged and sick; ensure the availability of health and safety guidance in relation to electricity supply to the public; ensure the financial viability of efficient regulated electricity undertakings; ensure the collection, publication and dissemination of information relating to standards of performance by licensed operators and on the electricity sector in Lesotho for use by the industry, consumers and prospective investors; participate, in consultation with the Minister, in regional and international matters relating to the regulation of electricity in Lesotho.

3 Functioning of the Sector

3.1 Energy Sector Objectives

Lesotho has established electrification targets in its “Vision 2020” of 2005: 35% of population having access to electricity by 2015 and 40% by 2020.

In the current **National Strategic Development Plan 2012-2017** the following strategic objectives are included:

- Increase clean energy production capacity to attain self-sufficiency and export income by:
  - Evaluating renewable power generation options and negotiate financing arrangements to expand national generation capacity.
  - Explore opportunities and negotiate regional power pool linkages.
  - Develop small-scale electricity generation models that are viable for communities, where connection to the national power grid is not cost-effective.
- Expand electricity access to industry, commercial centres, households and other institutions by:
  - Maintaining the existing power generation infrastructure.
  - Extending transmission and distribution networks and increasing connectivity rates through community initiatives and by reviewing the tariff policy and terms for connections.
  - Evaluating the rural electrification programme for technical and cost efficiency and implement recommendations.
- Increase energy conservation, security and distribution efficiency of alternative sources by:
  - Raising awareness and promoting the use of energy efficient technologies.
  - Developing and disseminating guidelines for specific industries and types of firms to increase energy conservation/efficiency.
  - Promoting appropriate technology for biofuel use.
  - Promoting forest/tree planting and regeneration of other important biofuel species.
  - Undertaking research to assess market and distribution efficiency of other sources of energy.
  - Developing and implementinga medium- to long-term energy security strategy, including alignment with land and mining rehabilitation policy.
  - Promoting research in solar and other potential niche renewable energy markets.

There is an **Electrification Master Plan** carried out by Danish Consultants COWI in 2006 with a planning period to 2020. It is principally concerned with electrification through grid extension. It consciously excludes the approximately 50% of the population that lived in such dispersed areas that grid connection would not at that time be considered viable. The SE4ALL EU TAF project has prepared terms of reference for a new Electrification Master plan that is scheduled to be conducted in the second half of 2017 under an existing EU framework agreement. The terms of reference include a significant component considering non-grid connected development so that the whole population can now to be catered for.

A high level pre-feasibility study for **Generation Planning** was carried out in 2012 of a number of small and medium hydro projects Identified with some very rough estimates on the costs and capacities possible.

3.2 Lesotho Energy Policy 2015-2025

The Lesotho Energy Policy 2015-2025 (LEP) is aligned to national planning documents and it represents the "*vehicle providing guidance and strategic direction for the energy sector programs and activities*". Launched in September 2015, it is an overarching sector document that guides specific sector policies development and implementation.

The LEP addresses several challenges facing the sector and, in parallel, outlines strategies to meet critical needs, giving direction. It targets three distinct, yet supportive functions (policy design to provide strategic framework of operation, implementation of policy and regulation of policy) and it reviews institutional responsibilities from policy design to regulation of single policies, including a proposal of a model for the energy sector governance. Annex 1 of the LEP proposes a viable model for Lesotho which can be summarised as follows:

- The DoE is mandated to coordinate, monitor and evaluate the programs and activities within the energy sector as well as to coordinate the engagement of all stakeholders. In this role, the DoE is the primary party responsible for implementing the Energy Policy and formulating short / medium and long-term actions that are in line with it. Moreover, DoE is solely responsible for resource assessment, supervision and enactment of Master Planning, data base management, monitoring and funding.
- LEWA regulates the electricity industry as Authority independent from the Government, without operating as a policymaker. It's up to the DoE to guide the whole sector setting policy goals.
- Distinction is made between the three constituencies for electrification: urban areas / rural areas / off grid areas where:
    - LEC undertakes electrification efforts in "urban areas"
    - LEC undertakes electrification efforts in "rural areas" (grid extension).
    - An Agency-like Entity to be created that shall take care of "off-grid areas"
- The current REU activities (see section 0) need to be divided up. Grid extension projects in rural areas to be the responsibility of LEC and off grid projects being promoted by a separate organization.

3.3 Key Sector Legislation

The existing legal and regulatory framework pre-exists Lesotho's Energy policy 2015-2025, and various laws and regulations are not integrated into a unified coherent system. Thus the legal framework is uncertain and it would help to consolidate and integrate the various laws and regulations into a unified national Energy Law. Bottlenecks holding back an increase in investment in the energy sector of

Lesotho appear to arise more from considerations of governance, policy implementation and uncertain regulatory framework, rather than financing itself. The Consultants' review of the sector found out-dated Acts still in force, missing regulations, overlapping functions (e.g. REU and LEC), non-definition of competencies (e.g. REU) (explain), and a lack of coordination of different bodies (e.g. LEWA and DoE for the UAF) involved in the decision-making processes.

The Act N .12 of 2002 (Lesotho Electricity Authority Act as amended in 2006 and 2011) establishes the Lesotho Electricity Authority to regulate and supervise activities in the electricity sector and to make provision for the restructuring and the development of the electricity sector and for connected matters. The main laws and regulations related to the exploitation and use of Lesotho's energy resources are summarised inTable 1 and Table 2 below.

Table 1 - Key Sector Legislation

Legislation	Overview
Fuels and Services Control Act 1983	Empowers the Minister responsible for energy affairs to be in control of fuel supply, regulation (pricing and licensing). Practically, the application of the Act has been limited to petroleum fuels.
Lesotho Electricity Authority (LEA) Act (2002)	Establishes the Lesotho Electricity Authority as regulator for electricity sector.
LEA Amendment Act (2006)	Amends LEA Act (2002) regarding composition of Board, funding, powers to enter and use land for regulated activities, and acquisition of land required for regulated activities
LEA Amendment Act (2011)	Amends LEA Act (2002) to give the Authority power to regulate Lesotho's water and sanitation sector and renaming the regulator as the Lesotho Electricity and Water Authority (LEWA)

Source: DoE

Table 2 - Key Regulations

Regulation	Purpose
Petrol or Distillate Fuel Levy, 1985	Empowers the Minister to impose levy on petroleum products.
Liquefied Petroleum Gas (Trade and Handling) 1997	Regulate the trade and handling of liquefied petroleum gas
Fuel and Services Control (Importation of Petroleum Products), 1999	Regulation of imports of petroleum products in the Country.
Lesotho (Petroleum Fund), 2009	Finance petroleum fuels projects and other energy projects on loan basis.
Electricity Price Review and Structure Regulations (2009)	Regulates reviews of tariff structure and prices
License Fees and Levies Regulations (2009)	Regulates funding Regulator activities via licensing fees and customer levies
Resolution of Disputes Rules (2010)	Regulates dispute resolution between licensees and between licensees and customers
Universal Access Fund Rules (2011)	Establishes a fund for electrification and sets administrative rules
Application for Licenses Rules (2012)	Sets procedures and requirements for license applications and exemptions

Source: DoE

The existence of a clear legal and regulatory framework for the sector plays a fundamental role in boosting investors' confidence in Lesotho and attracting private sector operators. Therefore, a comprehensive framework for the entire Energy sector is required to create a solid, coherent and effective system.

3.4 Attempts at Privatisation

In 2000, principally to improve access to electricity, the Government of Lesotho (GoL) embarked on a restructuring of the electricity supply industry which included the privatisation of LEC through the sale of a majority shareholding to a strategic investor.

As a preparatory step to privatisation, GoL recruited a private sector management team, known as the Interim Management Task Force (IMTF) to prepare LEC for privatisation and operate it until the strategic investor took over. The IMTF commenced its activities on 1 February 2001. At the end of the IMTF contract GoL entered into a caretaker management contract with the same management contractor to continue to run LEC until the privatisation was completed.

A Sales Advisory Group was appointed in December 2001 to assist the Government with the privatisation process. The objectives of the privatisation were summarised as:

Table 3 - Priorities of the electricity sector privatisation process in Lesotho

Priorities	Description
1st priority	▪ Maximise future investments to stimulate access to electricity, which in turn will stimulate GDP growth and alleviate poverty.
2nd priority	▪ Minimise future tariffs, within the constraints of LEC self-sufficiency. ▪ Introduce efficient commercial, financial, technical and operational business practices. ▪ Ensure safe and secure electricity provision. ▪ Reduce the financial burden on the State. ▪ Improve customer service.
3rd priority	▪ Maximise sale proceeds.

Bidding documents were issued to five prequalified companies in July 2004, however, following several extensions to the submission deadline, just two companies submitted bids. Of these two, neither bid conformed entirely to the Tender Rules and consequently, in June 2005, the GoL declared the Tender a failure.

A Re-Tender was conducted soon after using the original Tender Rules but with some exceptions intended to make the deal more attractive to potential Bidders. Despite four of the five prequalified companies expressing an interest, only two bids were submitted. As a result of a combination of non-compliance issues in one of the bids and the determination that the other company was not a suitable bidder, the attempt to privatise ended in 2006.

The IMTF company ceased providing management services to LEC sometime after 2006 and LEC has continued to operate under the ownership of Government and under the guidance of its Board whose members are selected by the Ministry of Energy and Meteorology (MEM).

3.5 The Universal Access Fund

The LEWA has created and also manages the Universal Access Fund (UAF). A brief description of how the UAF works is provided in the box below.

In 2001, LEWA set up (Legal notice 83/2011) a Universal Access Fund (UAF). The main purpose of the UAF is to support the grid extension in rural areas and disburse money in order to subsidize the capital costs of electrification in the country. The UAF is replenished via a "electrification levy" on tariffs for customers connected.

UAF Mode of Operation

1. **LEWA** sets up the UAF and administers the levy on the LEC tariffs
2. An electrification levy added to tariff by **LEC** is the funding source of the UAF
3. The **UAF** finances the grid extensions
4. **REU** is mandated to extend the grid out of the Service Territory
5. REU contracts **LEC** for these works

Rules of the UAF:

- The government identifies projects and prioritizes them. It also identifies the Implementation Agency for the projects. Currently REU is the unit charged with implementation.. Only green field projects are eligible for funding..
- The Board of LEWA declares how much is available to spend.
- The REU needs to provide the supporting documentation (e.g. costs, number of households to be connected, tendering process and documents, etc). LEWA approves these documents. If available funds in the UAF are insufficient, the Ministry of Energy can decide to pay the balance or to find donors to take this part.
- The REU is in practice in charge of the tendering process, the implementation of the project and monitoring.
- LEWA pays the contractors directly in line with the contract and the monitoring process. There is no transfer of cash to LEC. Money sits with LEWA, LEC instructs LEWA to pay contractors directly.

LEWA is currently involved in the management of the UAF which disburses money in order to subsidise the capital costs of electrification in the country.

LEWA manages a Universal Access Fund for subsidizing capital costs of electrification projects. The fund resources are coming from an electrification levy charged by LEC (see section 6.3.2). Connections in the LEC area usually cost on average M4000. LEC charges customers M2000 and spreads the cost over subsequent monthly bills.

Despite the tariff levies, the GoL still contributes a high proportion of the costs for electrification. For instance, according to LEC's 2015-16 Annual report, GoL contributed M101.8 million for electrification of 23 villages while UAF contributed M20.5 million for electrification of 3 villages.

This approach is likely to be changed following the implementation of recommendations recently made by the SE4ALL TAF team for the setting up of a new financing facility. It is unlikely that LEWA will retain responsibility for a fund that is collecting and disbursing the access levy.

3.6 Renewable Energy

Historically the major barrier to deployment of Renewable Energy (RE) technologies in Lesotho has been the lack of finance and lack of economically viable technologies. The technologies are becoming increasingly viable but barriers still exist principally centred on a lack of knowledge and understanding of the opportunities for RE exploitation in Lesotho.

There is potential for building new generation capacity from hydro, solar and wind. The National Strategic Development Plan has identified hydropower development as a key focus area for electricity generation for both local consumption and export. However, there are no detailed studies or costings and no specific Government plan for new generation development. There is a RE regulatory framework developed by LEWA. There is also an approved Solar Photo Voltaic (PV) code of practice developed by DoE in collaboration with NUL.

The high upfront costs of RE can make it unaffordable for rural households. Energy needs for cooking, space heating and sanitation are not available to most households in Lesotho. RE has limited value for large energy needs related to cooking and heating. Rural households therefore continue to use firewood, shrubs, dung cakes and crop residues for the bulk of their energy needs.

The majority of rural households are inaccessible by road, which tends to significantly increase costs for renewable energy service providers.

Arrangements for service and maintenance of Solar Home Systems (SHS) and other renewable energy systems are unclear or non-existent. A significant number of SHS are not working, the key issues being the failure of the electronic components and absence of maintenance.

Due to the moderate climate, there is a strong need for water heating. Electric water heaters are currently the preferred choice of heating, but solar water heaters have also been introduced, although with mixed results due to low quality products.

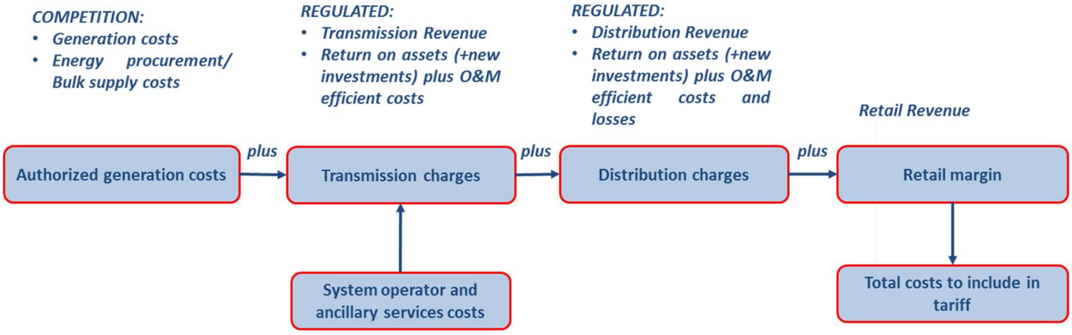
3.7 Tariff Regulation

3.7.1 Cost of Service Regulation

The tariff regime traditionally known as “Cost of Service” or “Rate of Return (ROR) regulation” has been the dominant approach for the definition of public service tariffs that involve natural monopolies. Under this approach, the regulated service company is allowed to charge tariffs that cover its reasonable operating costs and ensure a fair rate of return on its capital. If the company faces relevant changes in its costs, it can require the regulator to re-set tariffs. LEWA broadly follows this approach closely scrutinizing LEC costs. For example, in the recent tariff review LEWA noted the significant LEC salary increase of 10% above inflation.

This methodology generally guarantees that the operator will recover its costs, and that the cost of capital would be low, due to the low risk of the business. However international experience has shown that the frequency of the reviews reduces incentives for productive efficiency (in which every efficiency improvement should be rapidly transferred to a price decrease) and raises regulatory costs. This may be the case in Lesotho.

Figure 3 – Summary of components of cost of service



3.7.2 ALTERNATIVES TO COST OF SERVICE

Incentive Based Regulation (IBR) was introduced in Latin America in the late 1980s (Chile, Argentina) and England at the beginning of the 1990s as an alternative to ROR, in an attempt to overcome its limitations. Under an IBR approach, the regulator must define a maximum regulatory constraint (price or total revenue) to be applied by the operator, based on efficiency criteria, without taking directly into consideration the real situation of the company. Moreover, prices are set for a certain tariff period (4 to 5 years), so the regulated company would have the incentives to reduce its costs during that period, as every cost reduction would represent additional earnings compared to the starting point situation. International experience shows that this kind of regulation provides better incentives to productive efficiency.

First, price cap regulation tends to encourage increased sales by the utility since prices, but not quantities, are constrained under the scheme. This incentive, in some circumstances, may be inconsistent with energy efficiency goals to reduce consumption. Price or revenue cap approaches may potentially be less suitable in cases where the regulated firm has high fixed costs and faces volatility in revenues beyond its control. A pass-through mechanism of non-manageable costs is critical.

Revenue Caps are a kind of IBR, similar to price caps except that revenue is adjusted to reflect changes in the number of customers or demand. The incentive provided to a regulated firm to reduce costs under a revenue cap is similar to that provided by a price cap. However, revenue caps differ from price caps in reducing both the incentive and the risk associated with sales. This pricing feature of revenue caps has been criticized since it may also encourage the utility to raise its prices, thus reducing sales to stay within the revenue cap, and maximizing profits. Other theoretical criticisms maintain that price caps are more efficient in setting relative prices, and that pricing in general under revenue caps is more variable.

4 EXISTING POWER SYSTEM

4.1 GENERATION

4.1.1 CURRENT ON-GRID GENERATION MIX

The only significant generation capacity in Lesotho is the 72 MW Muela hydro project owned and operated by LHDA which is part of the Lesotho Highlands Water Project.

This is a reliable resource commissioned in 1998 with an expected reliable life of at least 40 years. Monthly energy production (GWh) and peak load [MW] data 1998-2016 for Muela is shown in Figure 4. The data shows that peak production is around July/August period with lowest production during February. This is further illustrated by isolating data for 2016 – Figure 5.

Figure 4 – Monthly energy production and peak load data for Muela hydro 1998-2016

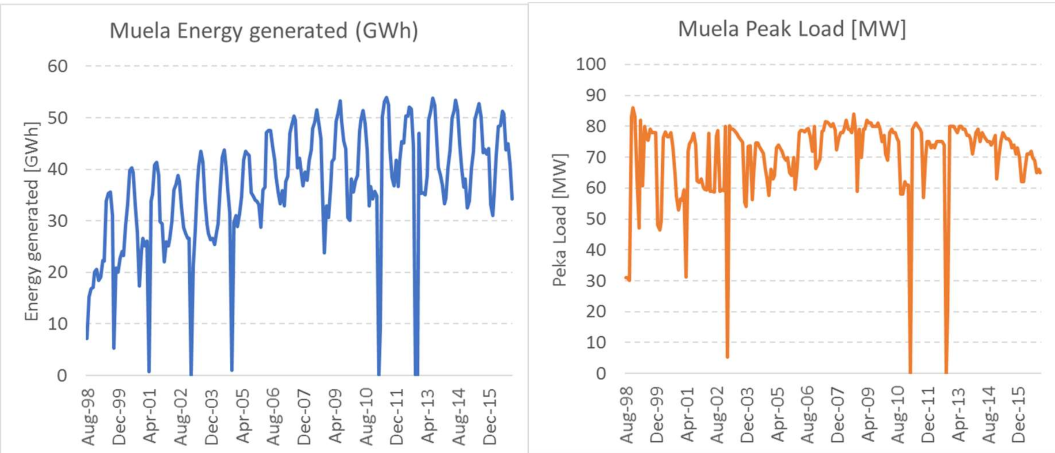
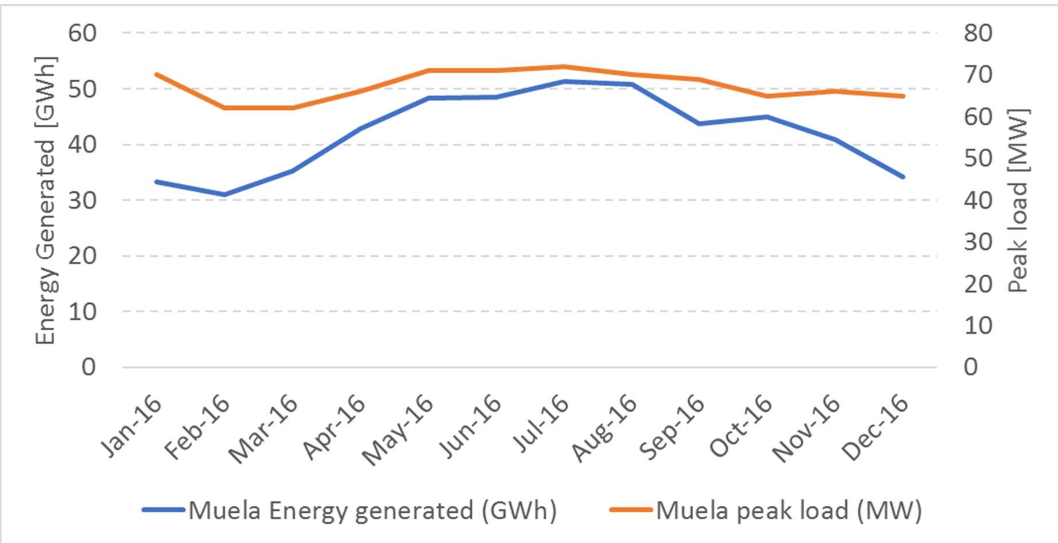


Figure 5 - Monthly energy production and peak load data for Muela hydro 2016



Source: LDHA http://www.lhda.org.ls/Phase1/

LEC purchases about 66% of its energy needs from Muela when meeting on-grid demand.[7]

In addition to Muela, there are four mini-hydro plants owned and operated by LEC. The 2 MW Mantsonyane plant is connected to the main grid, however since February 2016 a technical problem has hampered operation.[8] Similarly the mini off-grid hydro at Tlokoeng, and Tsoelike are not operating and have effectively been decommissioned. Only the Semonkong plant is operational, which consists of a 180 kW hydro turbine and 400kW diesel generator that is also not connected to the main grid.

Finally, Lesotho also has a small proportion of solar photovoltaic (PV) generating capacity:

- A 280 kW solar installation at Moshoeshoe I International Airport is used to serve the airport's demand with any excess power exported to the grid; and
- Off-grid 2.4 kW solar installation in Roma at the National University of Lesotho.

4.1.2 Off-grid Generation

Negligible off-grid power has been developed in Lesotho, although attempts were made to introduce solar home systems in 2013 though the implementation of the Lesotho Renewable Energy-Based Rural Electrification Project (LREBRE). The total cost of the project was $7.3 million and was to be co-financed by GoL and the Global Environment Facility. A core objective of the project was to achieve 1000 solar home systems annually in the Mokhotlong, Thaba-Tseka and Qacha's Nek districts.

The results were disappointing and by the end of the project, in that only 1,537 systems were installed with at least half of the systems either not in operation or providing inadequate service due to technical issues experienced soon after installation.

There are considerable opportunities in Lesotho for the private sector to provide services. There are approximately 1,000,000 people living in households that may be ideally suited to solar home systems. There are also villages where grid-connection is probably uneconomic but which may be connectable through exploitation of renewable energy resources to establish mini-grids. The DoE with support from the Atkins SE4ALL TAF team is embarking on a process to develop Off-Grid Energy. Recently there is a project funded by GEF aimed at establishing isolated mini Grids and energy service centres

4.2 The Southern African Power Pool

LEC is part of the South African Power Pool (SAPP). SAPP has twelve member countries.

The high voltage grid in Lesotho is connected to SAPP via two 132kV circuits at Maseru (Tweespruit to Maseru, 90 MW[9]) and Butha Buthe (Clarens to Butha-Buthe). SAPP rate the aggregate interconnector capacity as 230 MW.[10]

Other parts of Lesotho are separately connected to SAPP at Qacha's Nek. In a period around 2008 shortages of generation capacity in South Africa led to shortages of supplies to Lesotho. In recent

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[7] Technical losses in Lesotho are in the region of 10-15%.

[8] "Generation", Lesotho Electricity Company (Pty) Ltd, accessed February 16, 2017, available <https://www.lec.co.ls/generation>

[9] http://www.sapp.co.zw/transfer-limits.

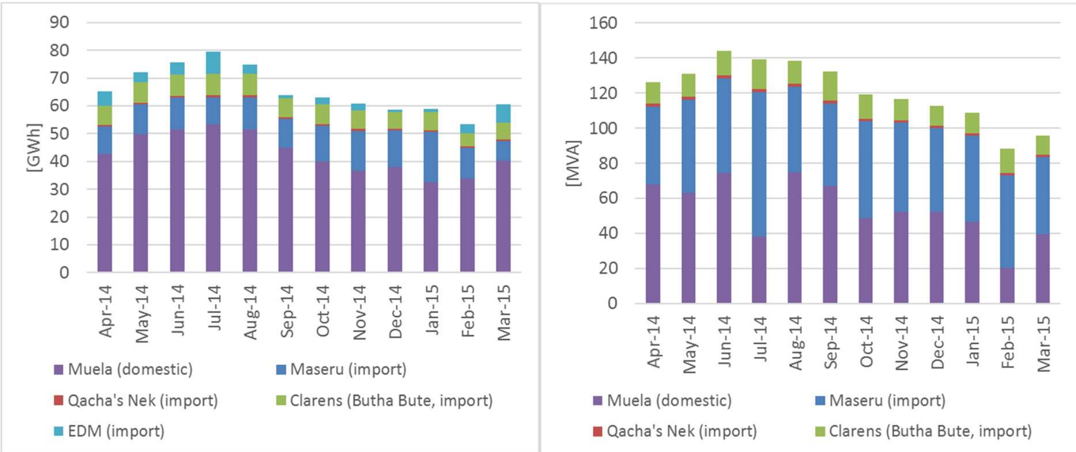
[10] SAPP Annual report for 2016.

years there has been ample generation in the SAPP system[11] and Lesotho has been able to import capacity and energy as required.

Lesotho has signed international agreements that enable interconnection with the SAPP grid. In addition, it has bilateral agreements for the purchase of energy from EdM (Electricidad du Mozambique) and Eskom (South Africa). Both contracts are short-term and can be cancelled.

In the absence of sufficient domestic sources of generation to meet its energy needs, LEC purchases about 35% of its energy needs through imports when meeting on-grid demand.

Figure 6 – LEC bulk purchases by intake point April 2014 – March 2015



4.3 POTENTIAL FOR ON-GRID GENERATION EXPANSION

Drawing on the Lesotho Generation Master Plan of 2010 a recent study by World Bank (WB) and the DoE[12] found there to be good potential for expanding the domestic generation capability to reduce the reliance on imports. In all 11 potential sites were reported with a total combined capacity of 88 MW - Table 4.

[11] Analysis of the SAPP website

[12] World Bank and Department of Energy. "Scaling-Up Renewable Energy in Low Income Countries Program (SREP) Investment Plan for Lesotho." Options study, March 2017.

Table 4 – Potential small hydro power plant sites in Lesotho as reported in the WB/DoE study.

Site	Installed Capacity (MW)	Annual Generation (GWh)
Hlotse	6.5	39.7
Phuthiatsana	5.4	18.87
Khubelu	14.6	64.26
Polihale	19.3	83.89
Tsoelike	17.7	69.86
Makhaleng 1	2	15
Makhaleng 2	1.4	6.15
Makhaleng 3	8.9	39.4
Makhaleng 4	9.1	58.3
Quthing 1	0.63	2.31
Quthing 2	2.4	9.61
Total	**87.93**	**407.35**

There are also 6 solar parks proposed across the Maseru, Leribe, Mafeteng and Mohale's Hoek districts totalling 50 MW and the WB/DoE study found that the good solar resource in the country provides potential for up to 239 MW (or 737 GWh) of solar park installations across the 10 administrative districts.[13]

There are not currently any operational wind power plants and those under development (e.g., the 35.7MW wind park at Lets'eng) have stalled. However, the WB/DoE study estimated that country's wind resource provides potential for up to 2,077 MW (5,157 GWh).

4.4 Transmission and Distribution

The electricity network in Lesotho is shown in Figure 7.

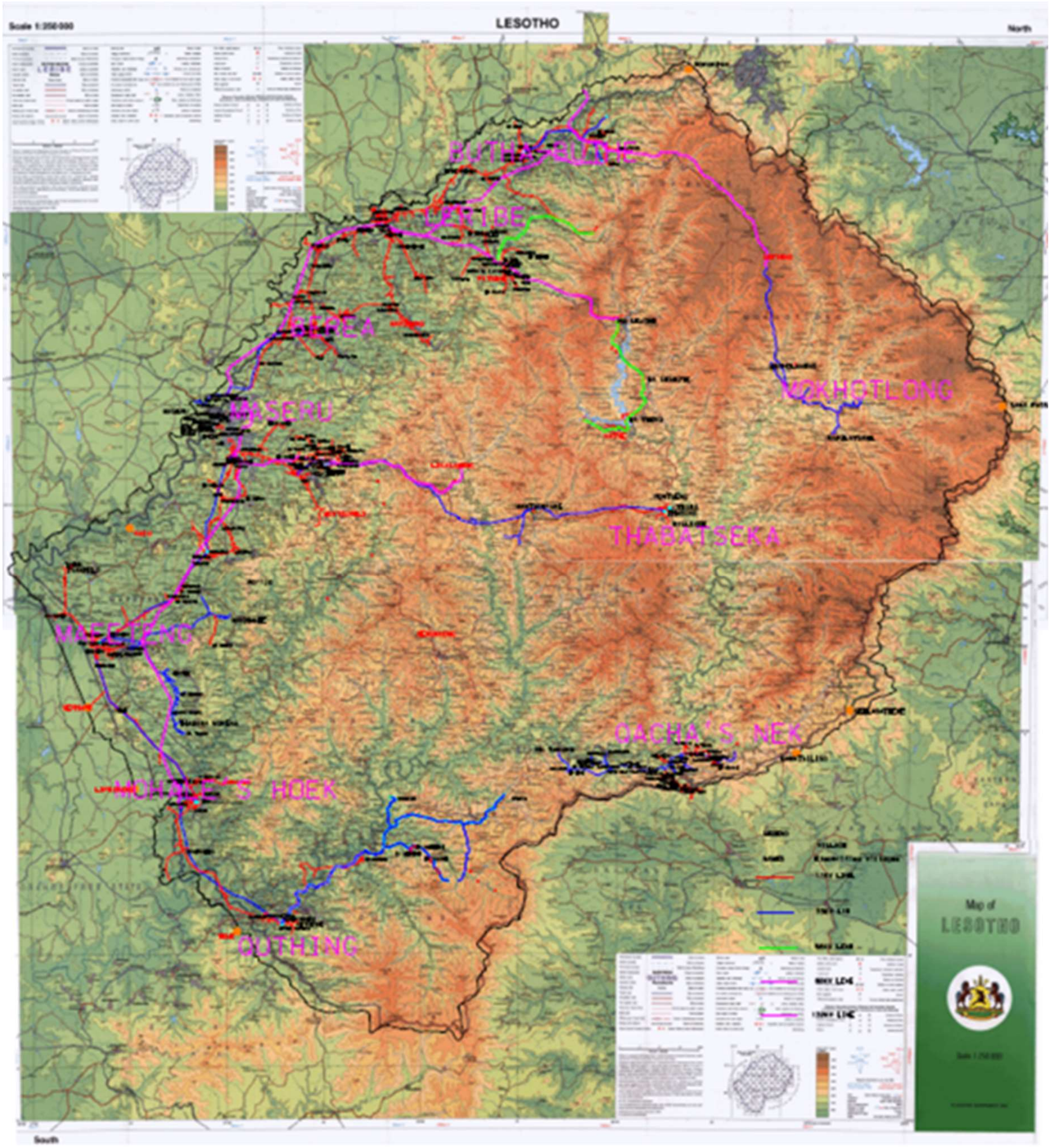
The 2016 census confirms that the population of Lesotho is divided 70% in the Lowlands to the West and 30% in the Highlands – central and East. The over 200,000 LEC customers account for a connected population of between 800,000 and 900,000 and the majority (70%) of these are in the Lowlands. Transmission Lines at 132 kV and 33 kV traverse the lowlands area. Over the past 10-15 years LEC has rolled out the grid (principally at 33kV and lower) in the Lowlands area to provide connections to 180,000 new customers.

The COWI Electrification Master Plan of 2006 identified settlements that it would be viable to connect to the grid. The population in these settlements was 66% of the Lowlands population and 22% of the Highlands population and amounted to approximately half the people of Lesotho. The remaining half

[13]World Bank and Department of Energy. "Scaling-Up Renewable Energy in Low Income Countries Program (SREP) Investment Plan for Lesotho." Options study, March 2017

were not considered by that plan to be economically connectable. Since 2006 about 700,000 of the Lowlands connectable population (about 150,000 households) have been connected by LEC.

Figure 7 – The electricity network in Lesotho



5 DEMAND CURRENTLY MET

On-grid demand is easily met in Lesotho by imports from the large SAPP pool. LEC electrification has connected 10 to 15,000 customers per year over the past 15 years (Table 5). The SE4ALL TAF team believe this rate of electrification may now start to decline as the remaining unconnected population become increasingly uneconomic to connect to the grid. Stand-alone solar home systems may now be rolled out across Lesotho. There are already indications that the remaining unelectrified population is becoming increasingly uneconomic to connect (Figure 8) This suggests that other delivery models may have to be considered.

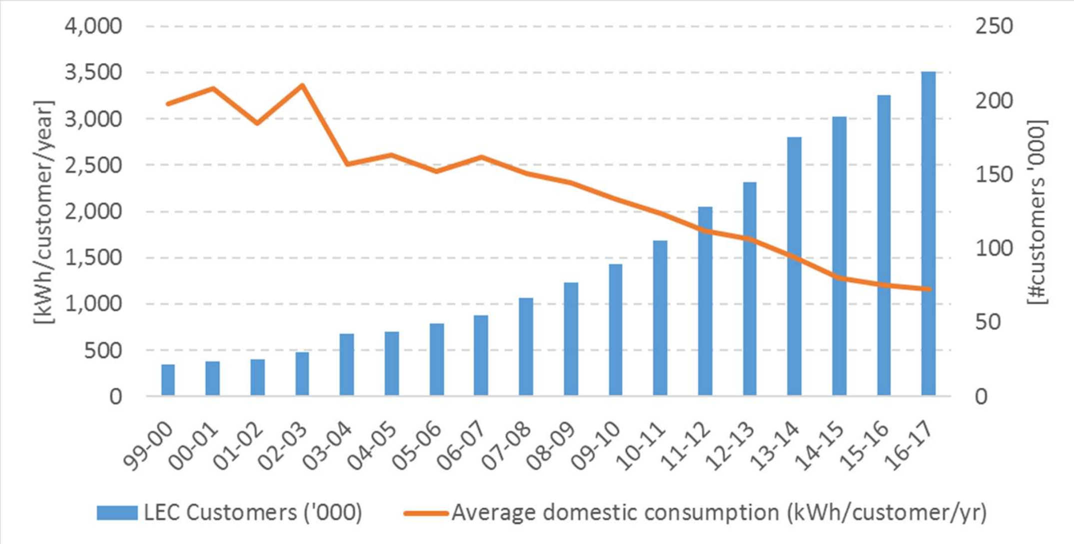
Despite the considerable electricity infrastructure development in the country since the year 2000 with a ten-fold increase in customers, electricity access is still of the order of 39% of households, with most of these being located in urban areas in the western lowlands. Currently LEC has just over 200,000 customers, 450 of which are industrial/commercial. Growth in the LEC customer population is shown in Table 5. As shown, the majority of customers are pre-paid.

This data along with average consumption is presented in Figure 8.

Table 5 - LEC customer numbers 2012-2017 (financial years)

Years	2012-13	2013-14	2014-15	2015-16	2016-17
Number of Special Domestic Consumers	*5*	*5*	*5*	*5*	*5*
General Purpose Special	*30*	*26*	*24*	*24*	*24*
Commercial	*204*	*241*	*235*	*241*	*240*
Industrial	*150*	*190*	*197*	*216*	*218*
LHDA	*9*	*9*	*9*	*9*	*11*
Pre-paid Domestic	*135,986*	*166,032*	*178,618*	*192,833*	*207,584*
Pre-paid General Purpose	8,312	8,774	9,501	10,363	11,217
Street Lights		128	133	133	133
Total Number of Consumers	**144,696**	**175,405**	**188,722**	**203,824**	**219,432**
Annual Increase	16,517	30,709	13,317	15,102	15,608
Annual Growth from previous year %	12.9%	21.2%	7.6%	8.0%	7.7%

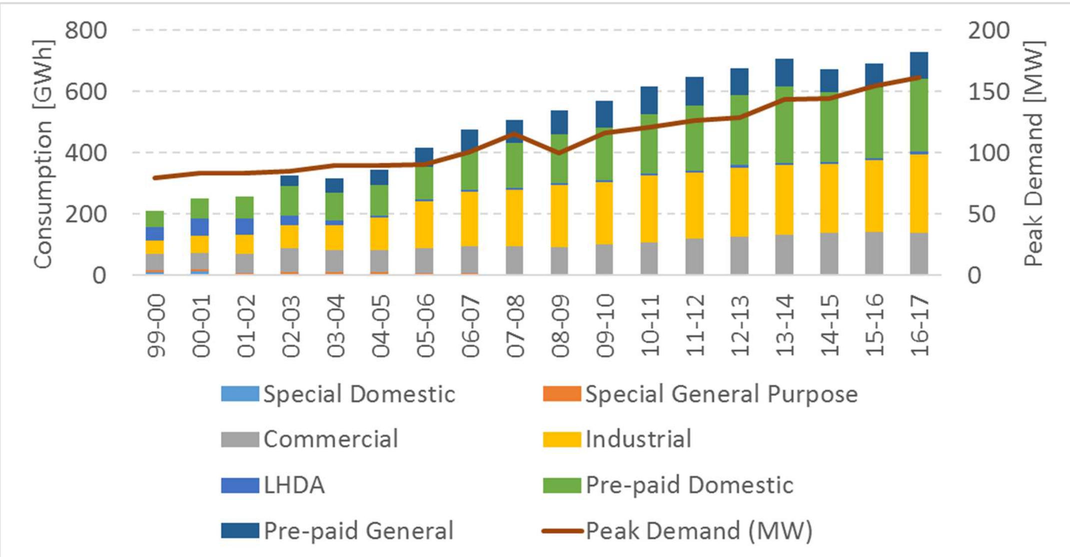
Figure 8 - LEC customer numbers and average consumption 2000 to 2016



The average consumption figures have fallen to close to a third of the figure in 2000 indicating the extremely low consumption of new customers that have been connected recently. The results suggest it is likely that a high proportion of the population not yet connected to the network would not be economically connectable.

Despite a fall in average consumption, peak demand has been increasing –Figure 9. This graph also shows the breakdown of customer consumption showing that much of the demand is from Industrial and pre-paid domestic customers.

Figure 9 – On-grid peak demand in Lesotho 2000 to 2016 (MW)[14]



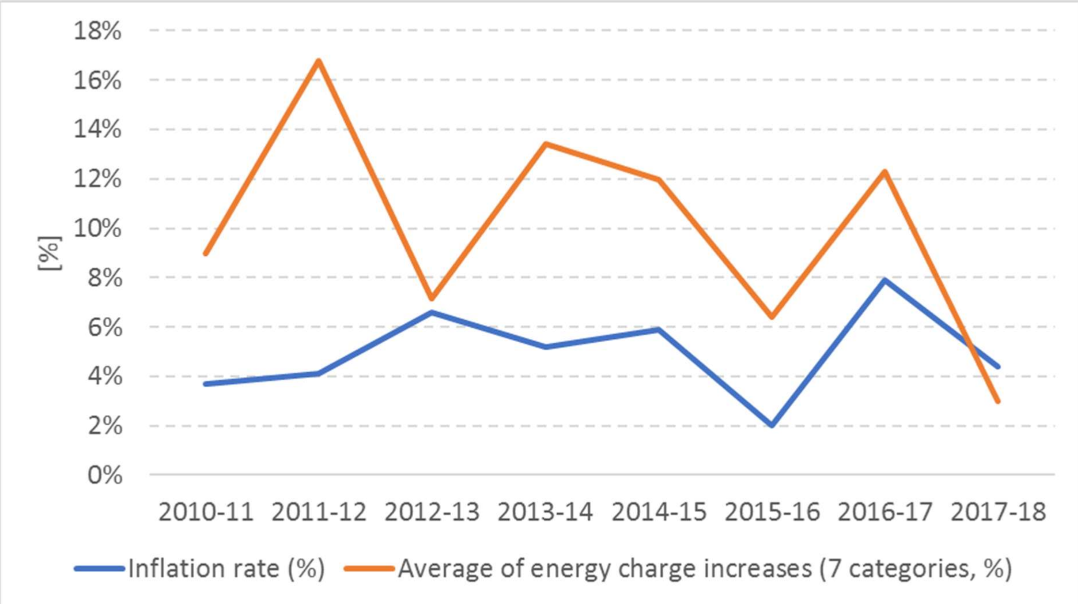
[14] Note that consumption from Street Light customers was only present in the 2016-17 (2.3 GWh) data and is not included in the graph.

6 Cost of Supply

6.1 History of Tariff Levels

Retail tariffs in Lesotho have risen steadily over the past 8 years and, until the 2017/18 tariff review, at a rate above inflation - Figure 10. The 2017/18 tariffs were increased by an average of 3% which is the first time tariffs have increased at a rate below the current rate of inflation (4.4%, April 2017[15]) for about 10 years[16].

Figure 10 - Average increase in energy charges and Lesotho inflation rate 2010-2017.



Source for inflation rates: Lesotho BoS Data Portal (April figure for year in which tariff took effect).

Figure 11 – LEWA approved Per cent increases in retail energy charges by tariff category

	Industrial HV	Industrial LV	Commercial HV	Commercial LV	General Purpose	Domestic	Street Lighting
2009-10	36.8%	34.3%	36.8%	34.3%	11.5%	17.7%	24.5%
2010-11	10.3%	10.0%	10.3%	10.0%	6.4%	7.7%	7.9%
2011-12	16.9%	16.8%	16.9%	16.8%	16.8%	16.8%	16.6%
2012-13	6.9%	6.9%	6.9%	6.9%	7.6%	7.6%	7.3%
2013-14	12.6%	12.8%	12.6%	12.8%	14.6%	14.5%	14.0%

[15] Lesotho Bureau of Statistics.
[16] In 2006/2007 the tariff levels were reduced by the regulator

	Industrial HV	Industrial LV	Commercial HV	Commercial LV	General Purpose	Domestic	Street Lighting
2014-15	11.8%	11.9%	11.8%	11.9%	12.2%	12.1%	11.9%
2015-16	7.0%	6.9%	7.0%	6.9%	5.6%	5.6%	5.7%
2016-17	12.3%	12.3%	12.3%	12.3%	12.4%	12.4%	12.2%
2017-18	2.7%	2.8%	2.7%	2.8%	3.5%	3.4%	3.3%

Figure 12 – Retail energy charges (M/kWh) 2008-2017 (financial years) by tariff category

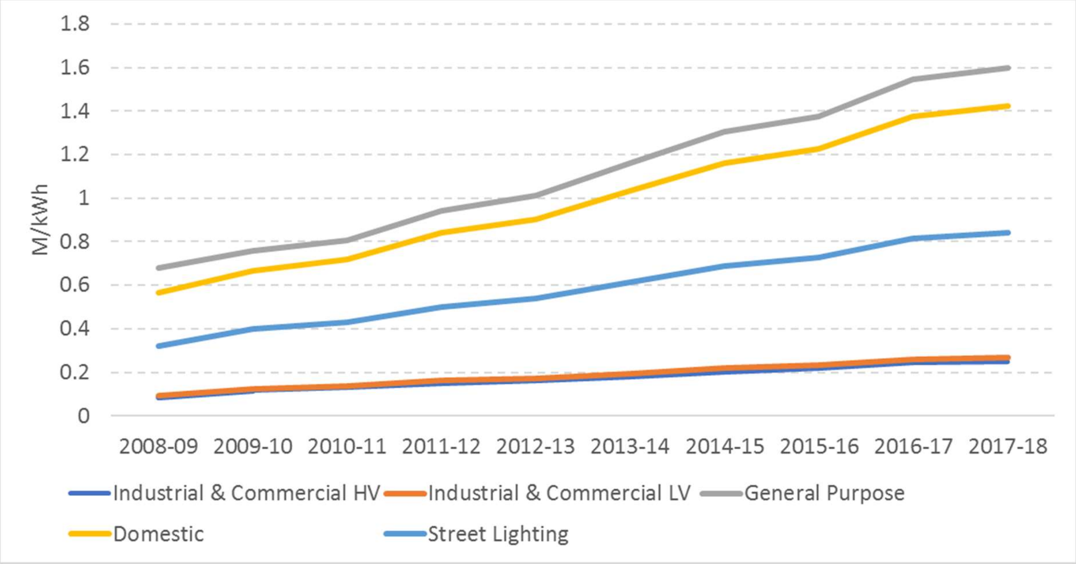
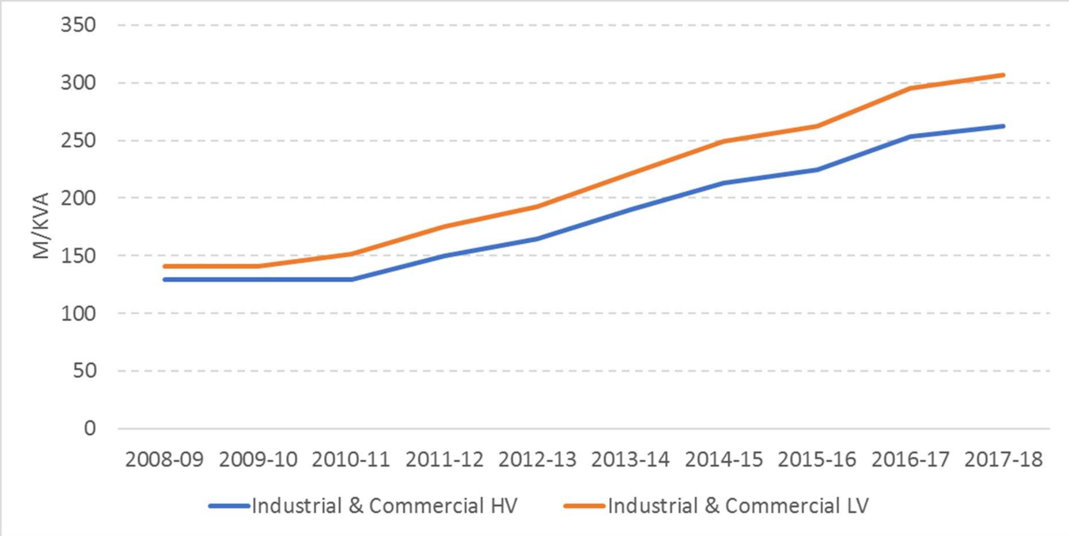


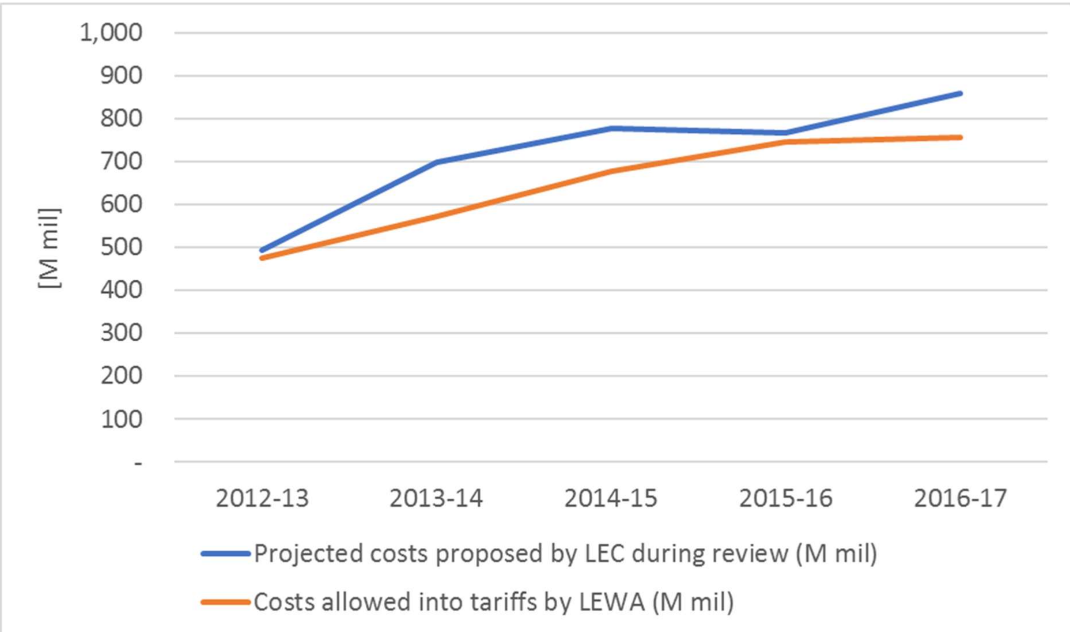
Figure 13 – Maximum Demand charges (M/kVA) 2008-2017 (financial years) for commercial and industrial customers



6.2 LEC Revenue Requirement

LEC has not declared operational losses during the last 8 years. However, it is understood that there is doubt as to whether the treatment of capital expenditure in assessing its revenue requirement has been correct. Moreover, around 90% of the costs proposed by LEC in their tariff applications have been accepted by LEWA - Figure 14. Thus the overall tariff may not be orders different from cost-reflective.

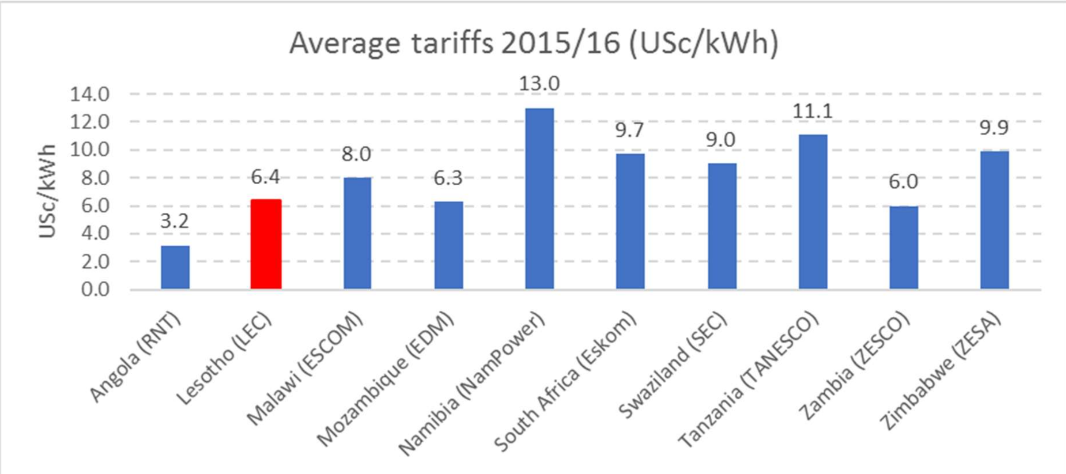
Figure 14 – Total proposed and allowed costs in LEC tariff applications 2012 to 2017 (financial years)



Source: LEC Tariff Determination Reports.

Another way to review if the overall tariff is cost reflective is to compare or benchmark with tariffs elsewhere. The tariffs are low by regional standards. For instance, SAPP found the average tariff in Lesotho to be one of the lowest in the SAPP region – Figure 15.

Figure 15 - Average electricity tariffs 2015/2016 in the SAPP region (USc/kWh)



Source: SAPP Annual report for 2016.

This may be compensated by the very low purchase tariff LEC pays to Muela hydro for more than half its electricity –Table 6.[17]Thus providing further evidence that the average level of tariff may not be orders different from cost reflective.

Table 6 – Summary of LEC's power purchase costs for the period covering April 2014 – March 2015.

	Average Tariff (total of energy and MVA charges) (M/kWh)	Costs of purchases as % of total purchase costs	Energy purchased as % of total energy purchases
Muela	0.117	22.7%	65.5%
Eskom*	0.748	64.5%	29.2%
EdM	0.814	12.8%	5.3%

** Total of Maseru, Qacha's Nek and Clarens (Butha Bute).*

[17]Furthermore since the SAPP comparison was published, LEWA have implemented tariff rises of 12% and 3% in 2016/17 and 2017/18 tariff reviews, respectively, and we estimate the average tariff in Lesotho to now be around 7-8 USc/kWh.

Table 7 – Breakdown of LEC Allowed Revenue Requirement for 2016-17

Cost Item	LEWA approved costs in 2016/17 tariffs (Maloti)	% of total allowed costs
Cost of sales		
Bulk Purchases	367,158,878	48.6%
Repairs and maintenance	31,409,071	4.2%
Diesel and oil	1,726,000	0.2%
Operating Expenditures		
Labour	147,951,504	19.6%
Depreciation	100,005,205	13.2%
Other expenses	88,010,761	11.7%
LEA License	4,815,870	0.6%
Sub-total (Cost of sales and operating expenditures)		
Return on Asset	0	0.0%
Financing costs	14,240,023	1.9%
LEC's Total Allowed Revenue (excl. levies)	**755,317,312**	

6.3 Subsidies and Levies

6.3.1 Apparent Cross-Subsidization in Tariffs

Figure 12 demonstrates that industrial and commercial tariffs are orders of magnitude lower than the domestic and general purpose tariffs. It is unlikely that the industrial and commercial cost-reflective tariff would be this low so it seems likely that there may be a cross-subsidization from domestic and general purpose customers to industrial and commercial customers.

The industrial and commercial customers also pay a maximum demand tariff which is significant, however our analysis of 2016/17 tariff determination indicates that it may compensate fully or in part for the low energy tariff. Table 8 demonstrates that the revenue per kWh (last column) is higher for general purpose domestic relative to industrial HV and commercial LV and HV.

Table 8–Expected recovery of LEC allowed revenue for 2016/17

Customer Categories	Proposed LEC Energy Charge (net of levies) (M/kWh)	Proposed Maximum Demand Charge (M/kVA)	Forecasted Energy Sales (kWh)	Forecasted Maximum Demand (kVA)	Total Revenue to LEC (M)	Revenue M / kWh
Industrial HV	0.180	253.04	196,378,283	415,879	140,505,570	0.715
Industrial LV	0.199	295.55	45,333,528	196,483	67,085,951	1.480

Customer Categories	Proposed LEC Energy Charge (net of levies) (M/kWh)	Proposed Maximum Demand Charge (M/kVA)	Forecasted Energy Sales (kWh)	Forecasted Maximum Demand (kVA)	Total Revenue to LEC (M)	Revenue M / kWh
Commercial HV	0.180	253.04	88,306,126	225,327	72,877,383	0.825
Commercial LV	0.199	295.55	56,725,901	172,878	62,375,087	1.100
General Purpose	1.469		76,571,039		112,465,262	1.469
Domestic	1.299		229,827,908		298,639,537	1.299
Lighting	0.738		1,855,385		1,368,522	0.738
Total			**694,998,170**		**755,317,312**	

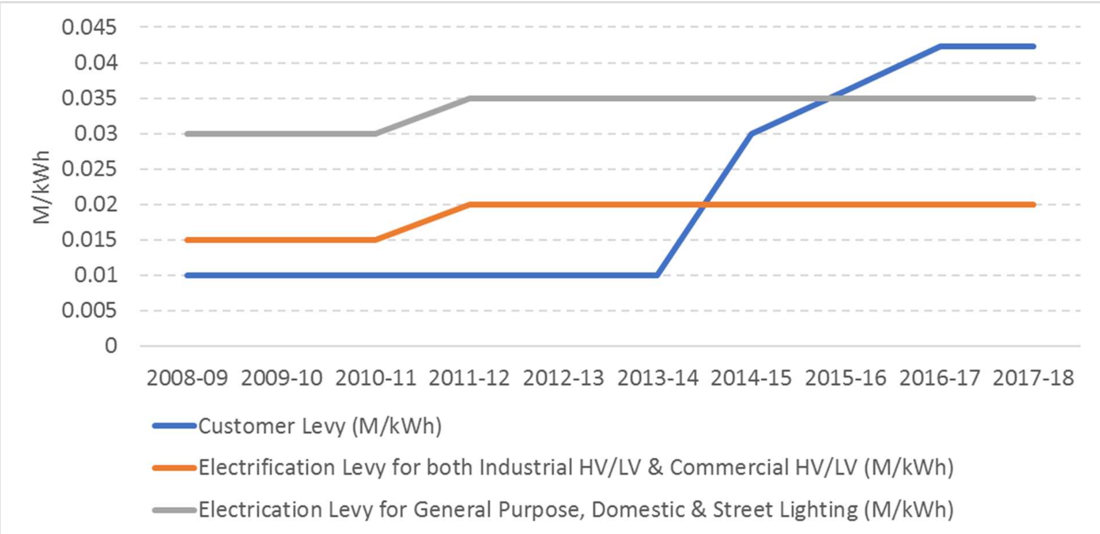
6.3.2 Tariff Levies

The tariffs presented in Figure 12 include a number of levies:

- A Customer Levy for funding LEWA;
- An Electrification Levy for both Industrial HV/LV and Commercial HV/LV; and
- An Electrification Levy for General Purpose, Domestic and Street Lighting. Both are for funding the UAF (see section 3.5).

Values for the levies on tariffs are shown inFigure 16.

Figure 16 – Levies in retail energy charges (M/kWh)



6.4 Indicators of Ability to Pay

The Bureau of Statistics (BoS) Continuous Multi-Purpose Household Survey(CMS)[18] study found that of those customers with electricity connection the majority reported they were unable to pay. The relevant table is as follows:

Table 9 - Percentage Distribution of Household Ability to Buy or Pay for Utility by Urban/Rural Residence, CMS 2013/2014-3rd Quarter.

	Response	Residence		
Utility		Urban	Rural	Total
Electricity	Yes (%)	9.3	2.1	4.3
	No (%)	49.2	14.5	25.3
	N/A (%)	41.5	83.4	70.4
	Total surveyed	**132,921**	**296,107**	**429,028**

There are analyses that demonstrate that the costs of light and telephone charging where a household has no electricity supply are higher than the costs of grid-connected electricity, which would suggest an ability to pay amongst newly connected households.

[18] 3rd Quarter (February to April) 2013/14.

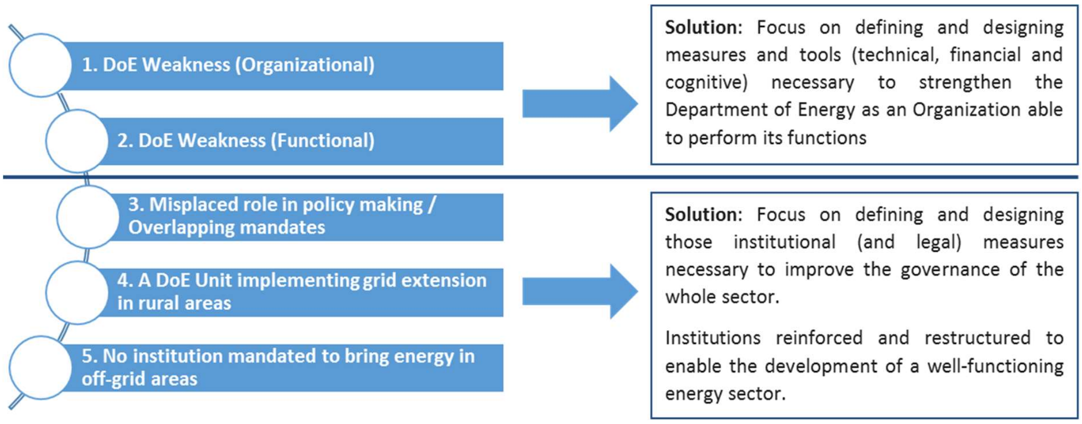
7 Conclusions and Recommendations

7.1 Legal and Regulatory

The main legal and regulatory inconsistencies or weaknesses identified in this review are that the mandates for the key players in the energy sector are not defined thereby clear lines of responsibility are not ensured.

The EU Technical Assistance Facility for the "Sustainable Energy for All" Initiative (SE4ALL) - Eastern and Southern Africa Report “Lesotho in the energy sector - Mandate revision and DoE coordinator function strengthening” identified the main problems affecting the energy sector as shown in the figure below.

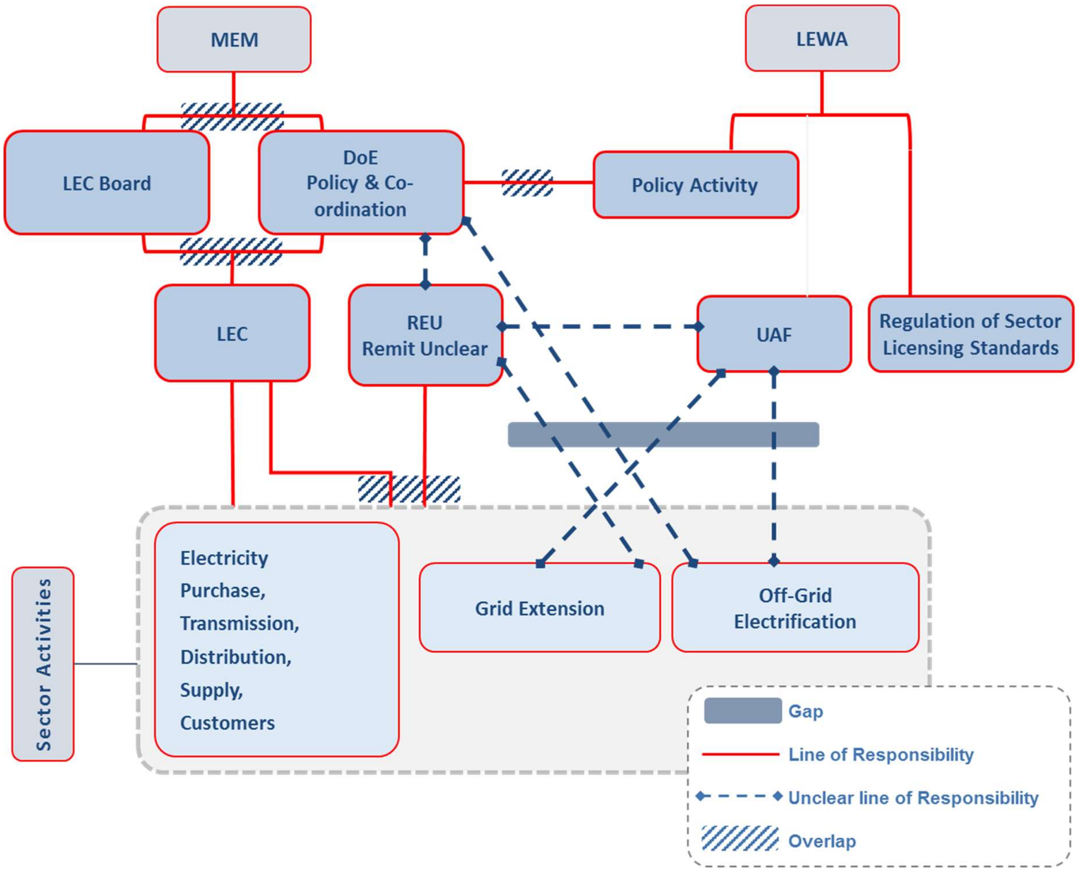
Figure 17 – Identified weaknesses in the DoE and potential solutions



The Long-Term EU TAF team identified gaps in the energy sector governance - Figure 18. They have recommended lines of responsibility are clarified and are assisting with a revision of mandates that will remove overlaps, fill gaps and clarify lines of responsibility. The EU TAF Report ES-0075 presented the following recommendations:

- Revise the model of the Energy Policy 2015-2025 and develop sectoral consensus.
- Implement the legislative changes required to establish mandates as defined by the new energy sector model.
- LEC is solely responsible for national grid management and extension.
- Transfer the REU grid-extension-related activities to LEC.
- Create an Agency-like Entity that shall take care of energy solutions in off-grid areas.
- Create a Financing mechanism for Rural Energy Access within an Energy fund.

Figure 18 - Overlaps and Gaps in Energy Sector Governance in Lesotho



Work on Translating the Energy Policy 2015-2025 into Legislation is crucial. In the short term, consolidation and integration of various laws and regulations into a unified national Energy Law should be pursued. More precisely, a new Energy Law should clarify the underlying concept of the energy sector reform and the power market reform strategy in Lesotho. Two main concepts should be clarified, namely:

- Competition for the market: this describes the situation where new market players attempt to enter the market.
- Retail market competition: this relates to the concept that competition exists also in the retail market. In practice this means that some customers should be allowed to contract their electricity supply directly with IPPs or other suppliers (including, auto-generators, and renewable generators, etc.).

Different options are available to Lesotho to reform its power sector. A major aspect of improving the power sector is the requirement, amongst other things, to ensure that relevant investments are made in all segments of the industry. Positive issues have been identified in the current framework of Lesotho, which create good conditions for the development of an adequate and reliable electricity sector in the country well-aligned with the regional context:

- the power system is *de facto* not vertically-integrated, and there is no vested interest between generation on one side and distribution and supply on the other side
- Lesotho has a goal to move from a single domestic plant, single resource generation to multiple domestic plant generation portfolio and multiple resource bases involving IPPs. A template for Standardized Power Purchase Agreement for renewable electricity has been developed by LEWA.
- There is interest in the GoL to take up generation options in Lesotho to reduce or eliminate dependence on imported supplies. There are a number of generation options under consideration. Some of these are small in relation to the demand and it is thought may not impact significantly on costs, although the purpose of this study is to make that determination. There is interest from SREP (Scale-up Renewable Energy Programme) to provide resources for medium scale wind parks and solar parks. .

7.2 In the Context of a Cost of Service Study

The weaknesses and proposed improvements described above do not impact significantly on the sector's ability to move positively towards cost reflective tariffs. However, there are six significant issues in Lesotho that do affect the project:

- The "cost of service" regulatory regime applied by LEWA was designed to regulate a private sector utility. The failure of the privatisation of LEC in 2006 means that the regulator is now regulating a public sector utility where the incentives for performance improvement are not so strongly perceived by management.The "cost of service" regime in Lesotho generally guarantees that the operator will recover its costs, and that the cost of capital would be low, due to the low risk of the business. However international experience has shown that the frequency of the reviews reduces incentives for productive efficiency (in which every efficiency improvement should be rapidly transferred to a price decrease) and raises regulatory costs.

- The cost of service study accuracy, dependability and ultimately credibility depend on an analysis of detailed and relevant data on demand, expansion plans, costs etc. As in many countries the data available in Lesotho may not be sufficient for an unequivocal set of conclusions.
- The inability to pay for electricity that has been recorded in BoS surveys compromises any attempt to bring tariffs to cost-reflective levels immediately.
- The roll out of the grid to dispersed parts of Lesotho over the past 15 years has been impressive. However, the significant reduction in average consumption demonstrates that the consumers now being connected bring a lot less income to LEC than long-standing consumers that are mainly in urban areas. And it is certain that connections of dispersed households will cost significantly more as the populations served become more and more remote. Thus there is a growing divergence of cost-reflectivity between long time connected urban households and the newly connected mainly rural and certainly dispersed households. A truly cost reflective regime might attempt to address this discrepancy perhaps by a further split of customer categories. However this would be politically difficult anywhere and especially in Lesotho where the roll out of grid connected electricity has been a political promise for 20

years. Nevertheless the difference in cost-reflective tariff between urban and dispersed rural is also important to establish as it is a significant input into the Government's understanding of the most economic way to electrify its dispersed population.

- Following the identification of the opportunities, needs and costs of a lifeline tariff there will need to be a specific lifeline tariff policy established by Government. The COSS will provide important inputs to this policy-making.
- Government may also need to establish a more definite policy on the importance of security of supply (reliance on imports to meet demand). The COSS model will assist Government to understand the cost implications of any plans for additional generation in Lesotho.

Electricity Supply Cost of Service Study – LEWA Lesotho

Load Forecast Report – Deliverable 3

Support Provided by African Development Bank

Prepared for: LEWA

Final Version: August 2018

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Contents

LIST OF ACRONYMS

BoS	Bureau of Statistics
COSST	Cost of Service Study Tariff model developed by MRC
GDP	Gross Domestic Product
GoL	Government of Lesotho
HH	Households
IAEE	International Atomic Energy Agency
LEC	Lesotho Electricity Company
LEWA	Lesotho Energy and Water Authority
LHDA	Lesotho Highlands Development Authority
MAED	Model for Analysis of Energy Demand
NEMP	National Electrification Master Plan
SE4ALL	Sustainable Energy for All
TAF	Technical Assistance Facility

1 INTRODUCTION

This report is the third deliverable of the Electricity Cost of Service Study being carried out by the MRC Group for LEWA supported by the African Development Bank. The objective of this report is to present a projection of electricity demand expected to be met by the Lesotho Electricity Company transmission and distribution networks during the period up to 2030 that will form a basis to project the expansion of the power generation, transmission and distribution and retail activities in the subsequent tasks of this study.

This report is organised as follows:

- Section 2 provides a review of historical demand for the period 2000-2016.
- Section 3 provides a review and analysis of historical consumption over the past ten years by consumer category with a discussion of the causalities of the growth patterns.
- Section 4 considers an already developed forecast from the National Electrification Master Plan of 2007 and a discussion of its relevance today.
- Section 5 discusses the model applied in this forecast study. This includes a description of the modelling used to develop the forecast - an analytical bottom up approach to project the overall magnitudes of electricity demand (GWh/year) to 2030 using assumptions for GDP, population and anticipated electrification rates for urban and rural households – and the steps taken to calibrate final consumption and peak demand to LEC data.
- Section 6 describes the three scenarios for demand modelled.
- Section 7 presents the MRC Group forecasts for national demand.
- Finally, Section 8 presents conclusions.

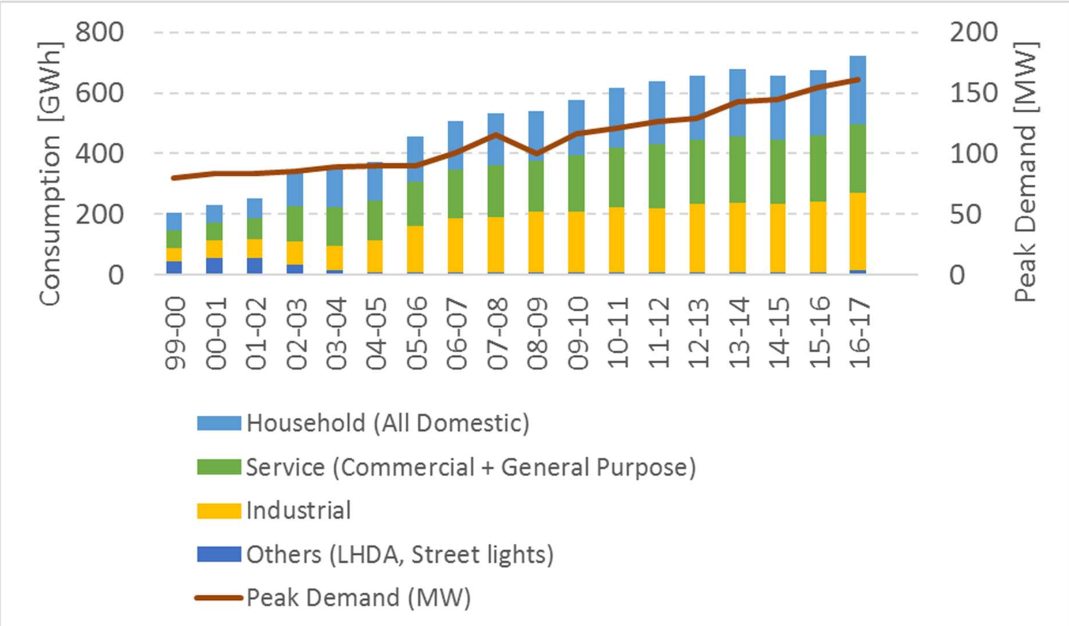
The demand forecast is critical in the computation of medium to long-term development programs, economic tariffs and the design of the roll-out strategies.

2 CURRENT DEMAND

The analysis of the recent electricity demand provided by LEC (energy purchases, energy sales and peak demand) from 2000 until 2016 is shown in Figure 1.[1] The graph shows that overall consumption[2] and peak demand have increased over the period (the graph shows a dip in consumption during 2014-15 but it has since continued to grow). More precisely, since 2001/02 the peak demand has increased by 93% (83.5 MW to 161.0 MW) and total consumption by 186% (257.9 GWh to 737.3 GWh).

A key driver for this increase in demand has been the connection of new customers. Figure 1 shows how the LEC customer base has increased by almost a factor of 10 from around 25,000 in 2001/02 to approaching 210,000 in 2016/17 although average consumption per household has decreased by over 60% during the same period (2,951 kWh/year to 1,157 kWh/year).

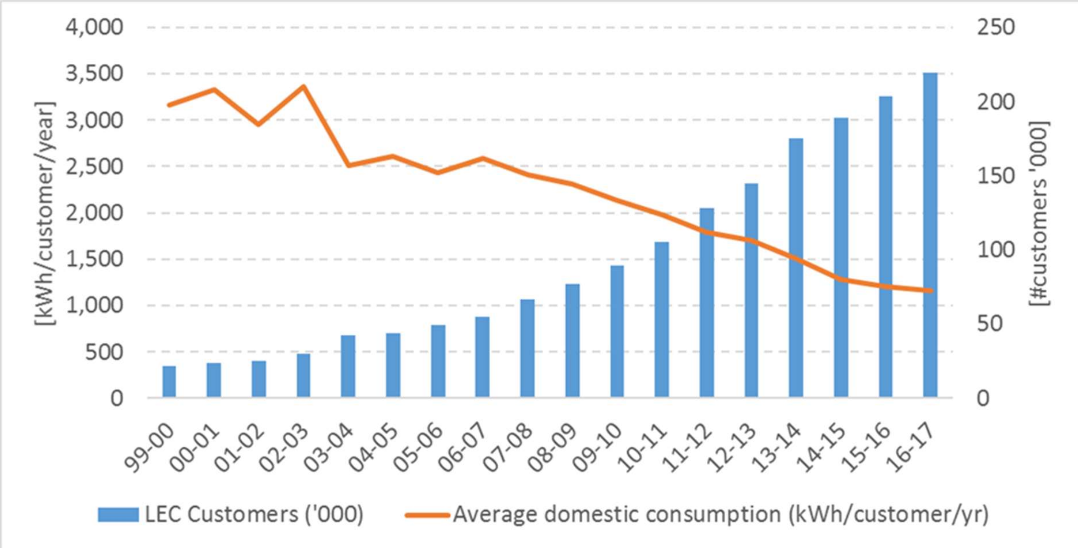
Figure 1: Energy sales (consumption)and peak demand [MW] in Lesotho 1999/00 to 2016/17



[1] Data provided by LEC was in financial years April-March.

[2] We consider energy sales as a good proxy for actual consumption.

Figure 2: LEC customer numbers and average consumption per domestic customer 2000 to 2016



This data has been used to calibrate the demand forecast, which is discussed in Section 5.2.

2.1.1 Daily Load Curves and Seasonal Profiles

Daily load curves for industrial and commercial customers have been derived from half hourly meter readings data covering the period 2016-2017. LEC does not currently have equivalent data for residential, general purpose and street lighting.

Figure 3 shows daily load curves for typical work days for five Commercial HV customers (there are around 40 commercial HV customers in total). It demonstrates how activity from some commercial activities have more demand during business hours on weekdays with a flat and lower profile at weekends. There are similar weekday profiles in summer and winter, although the absolute values of demand are higher in winter.

Figure 4 shows daily load curves for typical work days for two Commercial LV customers (there are around 200 commercial LV customers in total). It demonstrates that these profiles are similar between weekdays and weekends and within seasons.

Figure 5 shows daily load curves for typical work days for six Industrial HV customers (there are around 45 industrial HV customers in total). It demonstrates that these profiles are quite flat and on the whole winter demand is lower than summer.

Figure 6 shows daily load curves for typical work days for five Industrial LV customers (there are around 175 industrial HV customers in total). It demonstrates that these profiles have a similar shape throughout the year with winter demand higher than summer. There is also a distinct drop around the middle of the day most likely coinciding with staff lunch breaks.

Figure 3: Daily load curves and seasonal variations for 5 commercial HV customers of LEC (LEC data)

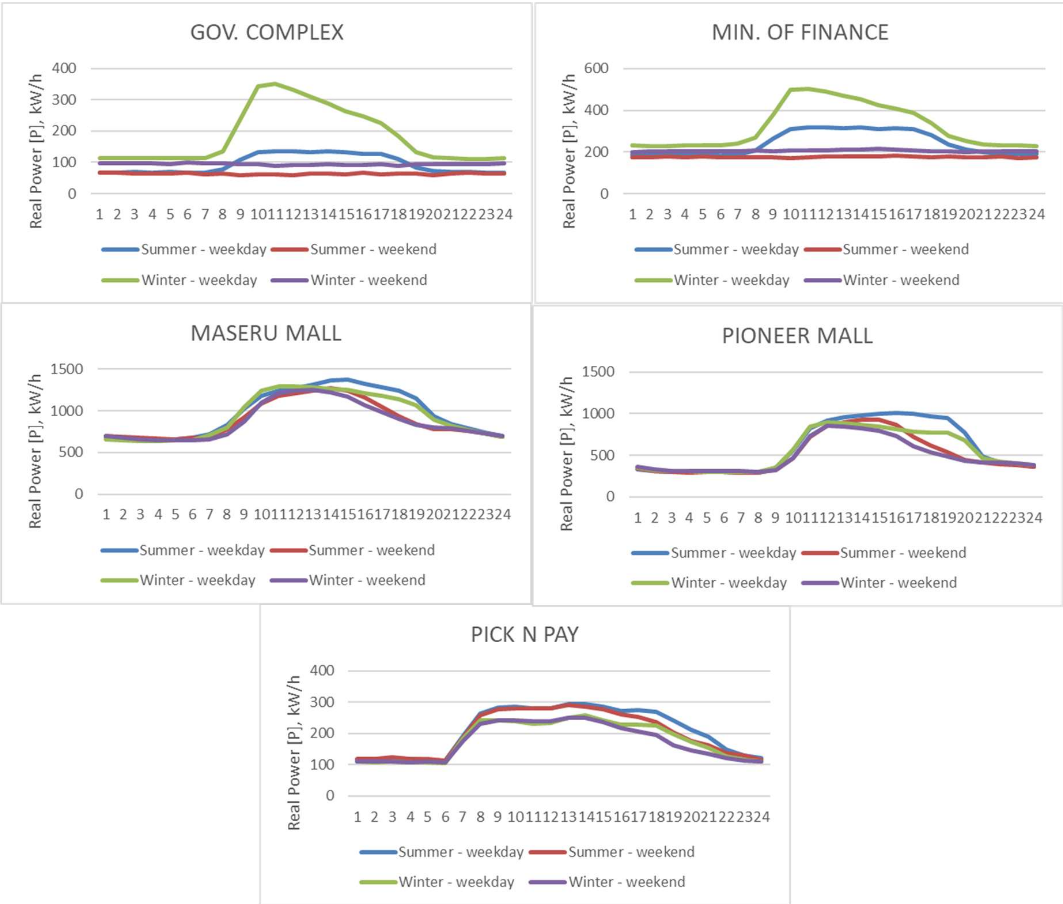


Figure 4: Daily load curves and seasonal variations for 2 commercial LV customers of LEC (LEC data)

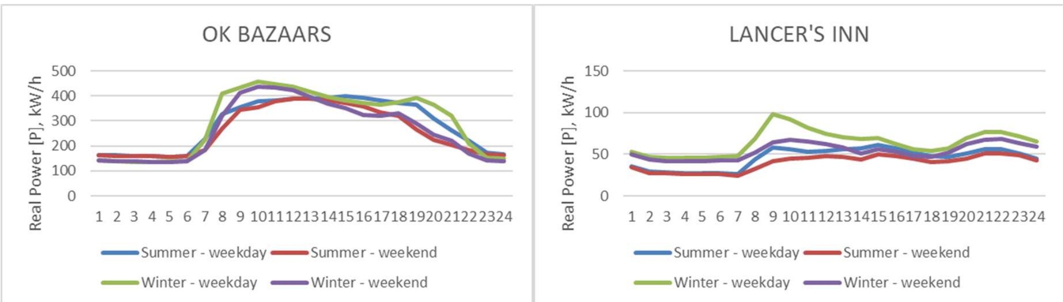


Figure 5: Daily load curves and seasonal variations for 6 industrial HV customers of LEC (LEC data)

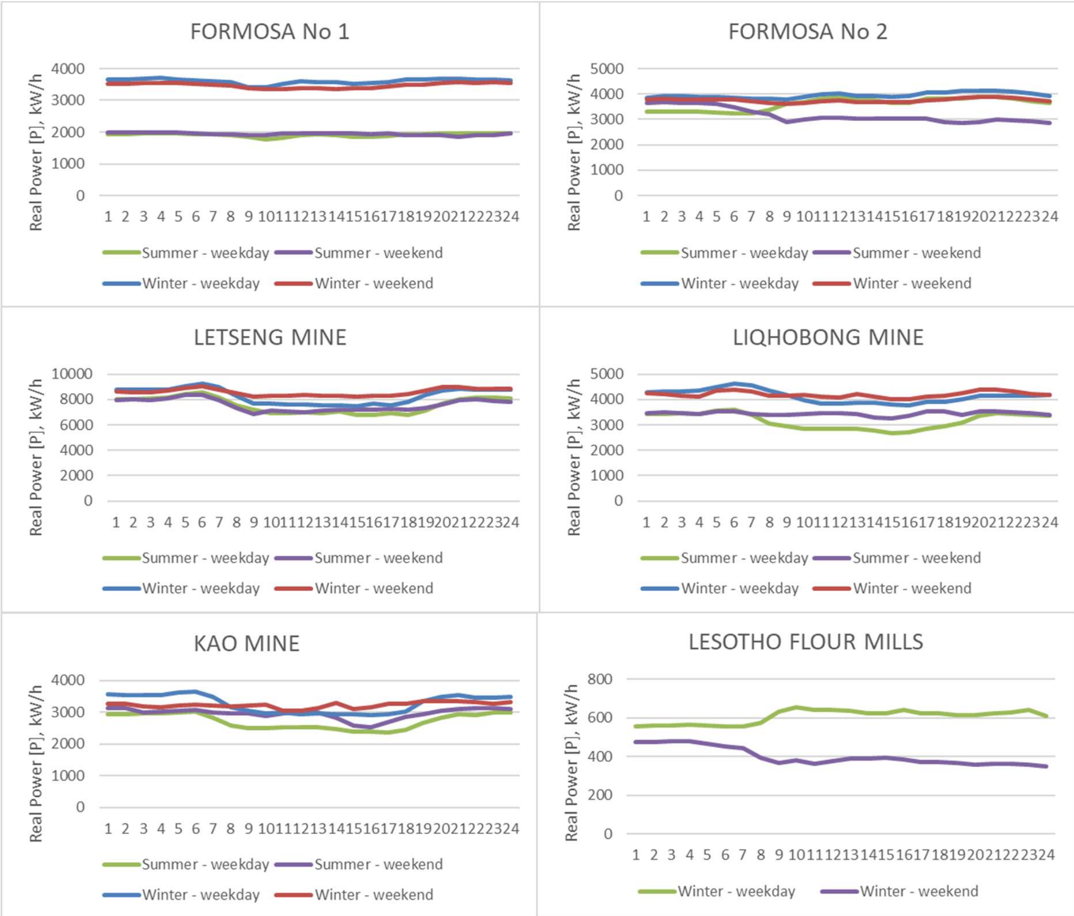
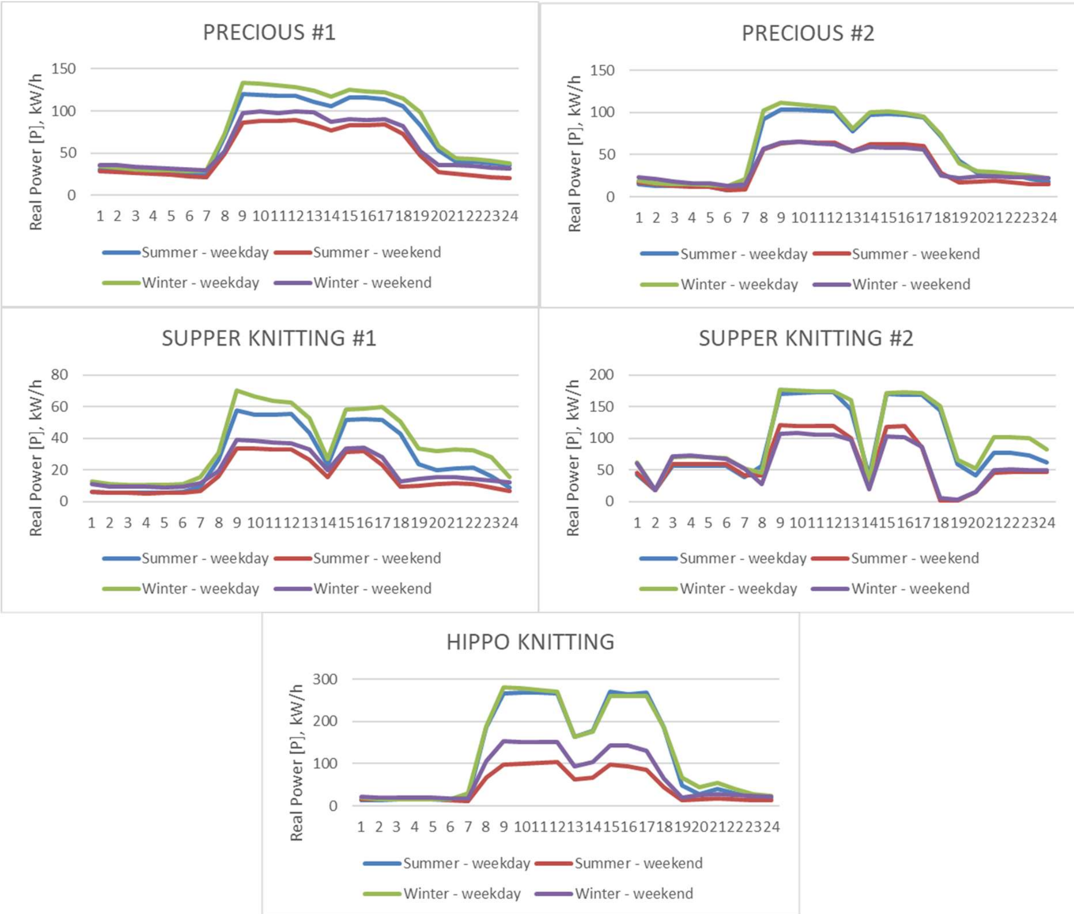


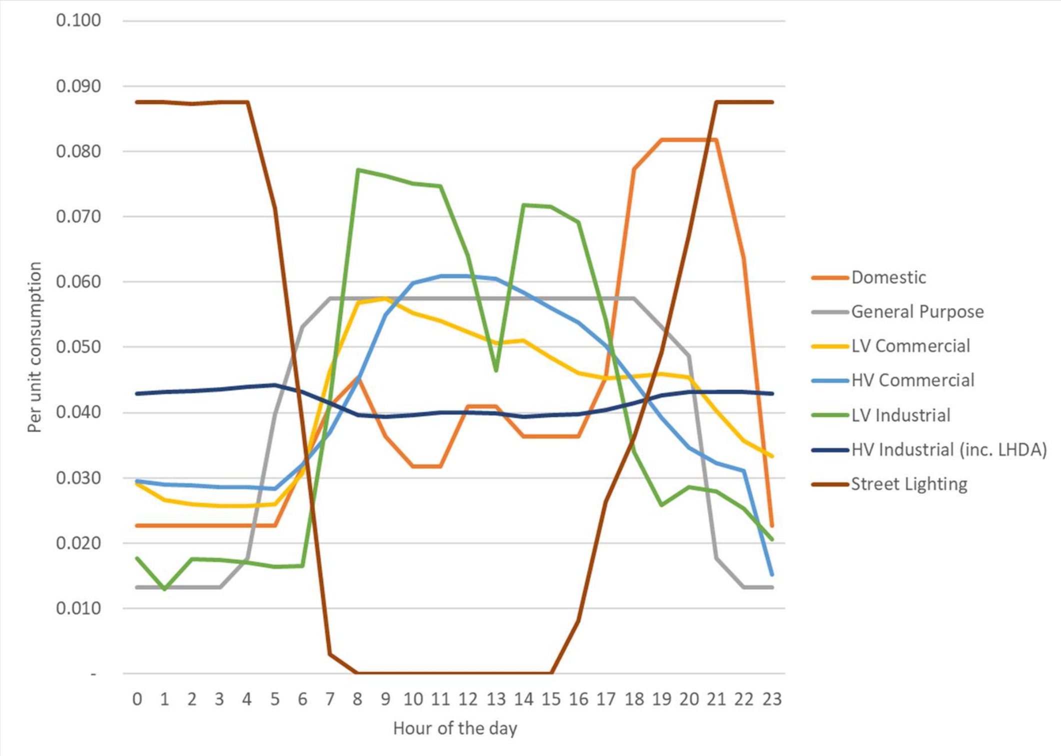
Figure 6: Daily load curves and seasonal variations for 5 Industrial LV customers of LEC (LEC data)



These profiles have been used to derive an average daily load profile for inclusion in the calculation of economic costs and tariffs in (task 4) deliverable 5. These are shown in Figure 7. Note that the street light profile has been derived from publicly available data[3] and general purpose and domestic is obtained from other models already developed by LEWA.[4]

[3] US national grid data: https://www9.nationalgridus.com/niagaramohawk/business/rates/5_load_profile.asp
[4] Obtained from the "Lesotho Demand Module v3.2a (2011-2012).xls" file provided by LEWA

Figure 7: Standard Load Profiles used in the costs allocation in task 4 (deliverable 5)



2.1.2 System Load factor

Figure 8 shows a plot of the system load factor for 2015, 2016 and 2017 (up to 1/9/2017). The average system load factor is 59% in 2015 and 2016 and 64% in 2017 (partial year). The plot shows how Lesotho's maximum demand occurs in sometime over the winter months June-July (31st July 2015, 28th July 2016, 29th June 2017) with minimums over the November – February period.

Figure 8: System load factor 2015-2017 (LEC data)

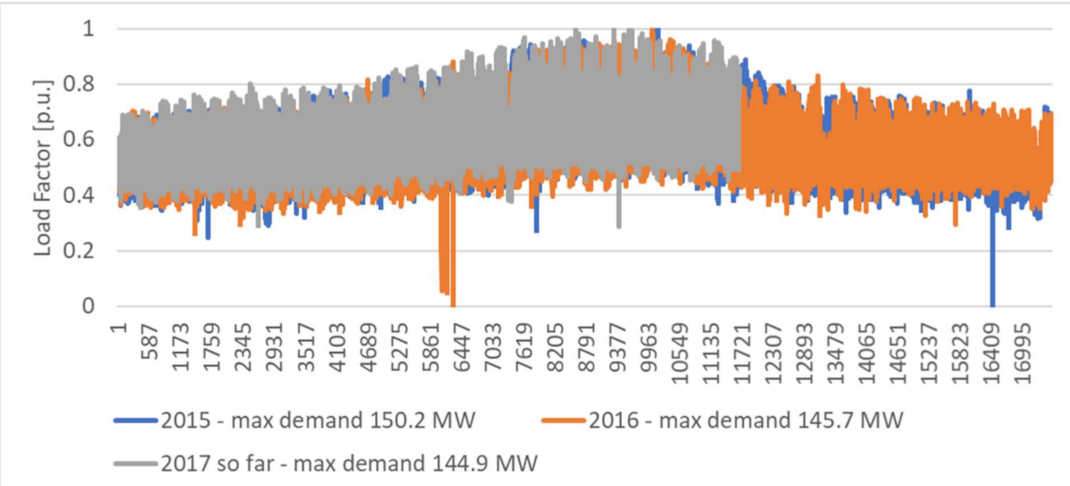
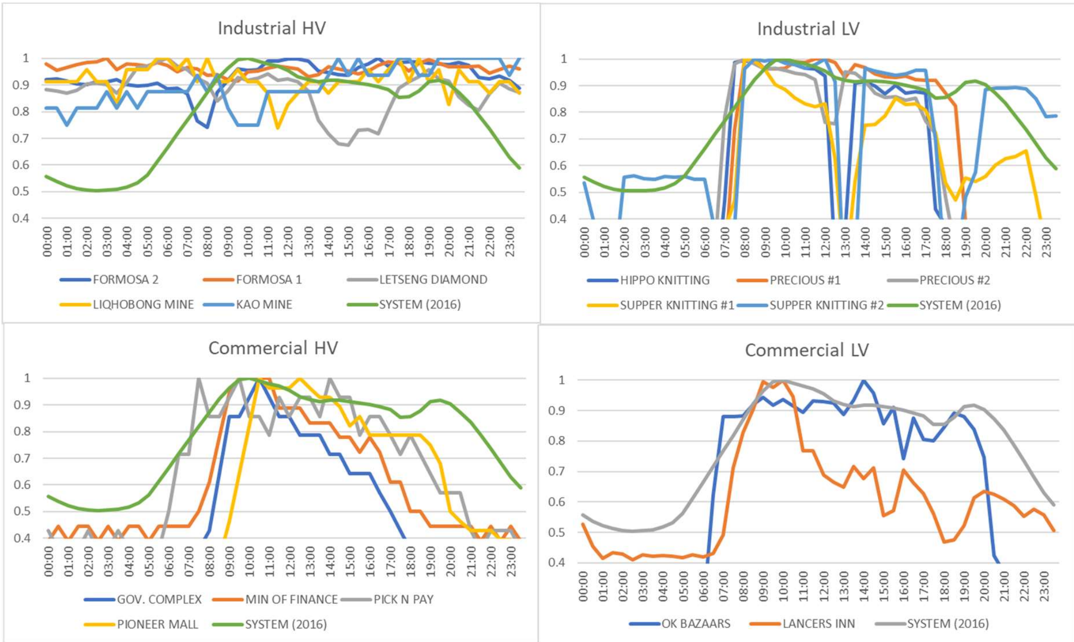


Figure 9 shows the daily load profile for the Industrial HV (5 customers), Industrial LV (5 customers), Commercial HV (4 customers) and Commercial LV (2 customers) against the system peak profile in 2016. The profile is calculated half-hourly as the load in the half hour as a proportion of the maximum demand for the day. The plots show that in 2016, the peak load occurred at 10:00am and on the whole, the peak load for Industrial HV customers tended not to coincide with the system peak whereas for other customers a coincidence with peak did occur.

Considering the Maximum Demand charges for these customers which are currently[5] 306.3 M/month for Commercial LV and Industrial LV and 262.2 M/month for Commercial HV and Industrial LV, this analysis suggests maximum demand charges that are higher for LV customers than HV customers is justified - the absolute values of the figures will be determined as part of the economic costs and tariffs analysis in task 4 (deliverable 5).

Figure 9: Customer load. profiles (half hourly load as % of daily maximum) during the system maximum demand in 2016 (31/7/2016)



2.1.3 DIVERSITY OF CONSUMPTION

Table 1 shows the diversity of consumption by consumer category with % diversity shown in Table 2. The figures show that consumption is quite diverse although domestic and industrial make up the main share. The proportion of domestic consumption has been reducing in recent years whilst the proportion from industrial has increased.

[5] 2017/18 Tariffs.

Table 1: Consumption by consumer category 2012-2017 (LEC data)

	2012/13	2013/14	2014/15	2015/16	2016/17
Domestic[1]	236,946	247,807	233,770	238,147	245,835
General Purpose[2]	89,295	90,799	77,791	79,785	89,568
Commercial	123,410	229,093	133,728	137,911	141,934
Industrial	231,676	134,410	232,950	241,872	263,735
Street Lighting	4,009	3,310	1,497	1,654	2,336
Total Consumption	**685,335**	**705,420**	**679,736**	**699,369**	**743,408**

[1] Domestic (pre-paid + credit) plus LEC staff.
[2] For the supply of electricity to premises used solely for primary and secondary schools and churches.

Table 2: Percentage of consumption by consumer category 2012-2017

	2012/13	2013/14	2014/15	2015/16	2016/17
Domestic	34.6%	35.1%	34.4%	34.1%	33.1%
General Purpose	13.0%	12.9%	11.4%	11.4%	12.0%
Commercial	18.0%	32.5%	19.7%	19.7%	19.1%
Industrial	33.8%	19.1%	34.3%	34.6%	35.5%
Street Lighting	0.6%	0.5%	0.2%	0.2%	0.3%
Total	**100%**	**100%**	**100%**	**100%**	**100%**

3 Historical Developments

This section provides a review and analysis of historical consumption over the past ten years by consumer category. For the available data, we explore the causalities of the growth patterns, including the main determinants of the growth such as, GDP growth rate, incomes, and tariffs. The objective is to provide a sound basis of moving into the future as to the relevance of the key parameters that could influence future demand.

Figure 10 gives the total electricity consumption provided by LEC over the period April 2007 to March 2017. It can be observed from the graph that electricity consumption is dependent on seasonal weather variations, with yearly peak occurring between June and August (during or slightly after winter).

In 2013, electricity consumption reached a peak high of 71,738 MWh, which is approximately a 42% increase from the 2007 peak of 50,589 MWh. However, the annual peak declined by 8% from 2013 to 2014 and then increased by approximately the same percentage to 70,809 MWh in 2016.

Figure 10: Total monthly electricity consumption (MWh) April 2007 to April 2017

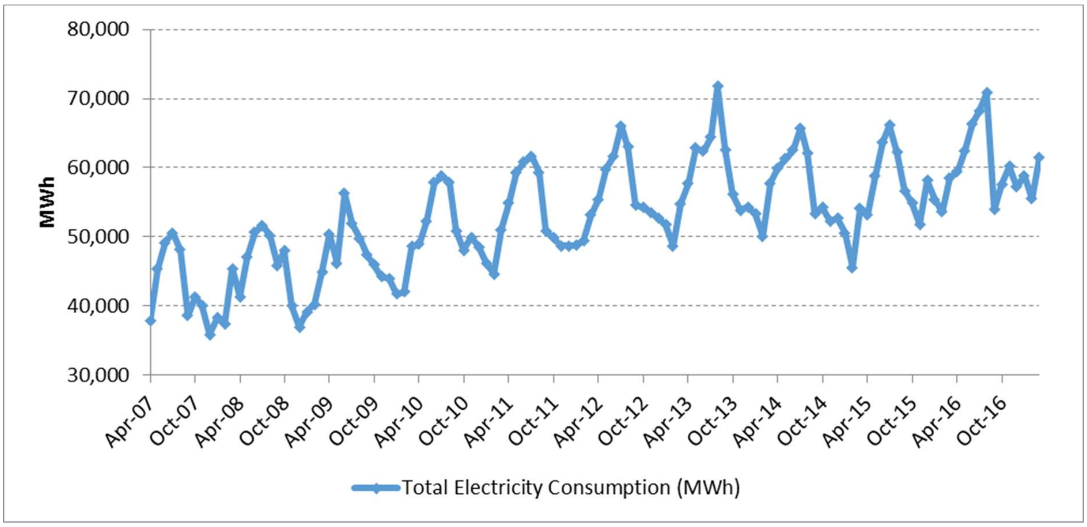


Figure 11 and Figure 12 depict the relationship between total electricity consumption and national income (using real GDP as a proxy), and their growth rates, respectively from 2007 to 2016.

It can be seen from Figure 11 that both the total electricity consumption and GDP have been showing a general upwards trend since 2007. For example, electricity consumption increased by 31% from 507,713 MWh in 2007/2008 to 731,873 MWh in 2016/2017 while GDP has increased by 40% (from M8,945 million to M12,482 million) over the same period. Furthermore, Figure 12 shows a positive correlation between the annual growth rates of electricity consumption and GDP, with the average growth rate of 4.5% for both variables over the period under consideration.

These trends could imply a causal relationship between GDP and electricity consumption in Lesotho, whereby growth in electricity consumption is positively correlated with growth in GDP. However, as already shown in Figure 2, average consumption per domestic customer has been reducing in recent years. The result adds an important nuance to the consumption growth pattern in Lesotho whereby the trend of growth in overall consumption is not reflected on an individual customer basis. The explanation for this phenomenon is due to LEC connecting on average 15,878 new customers per year over the 10 year period[6] whose consumption is relatively low.

[6] Data proved to the Consultant by LEC.

Figure 11: Total electricity consumption (blue, left axis) and real GDP (orange, right axis) 2007/8 to 2016/17

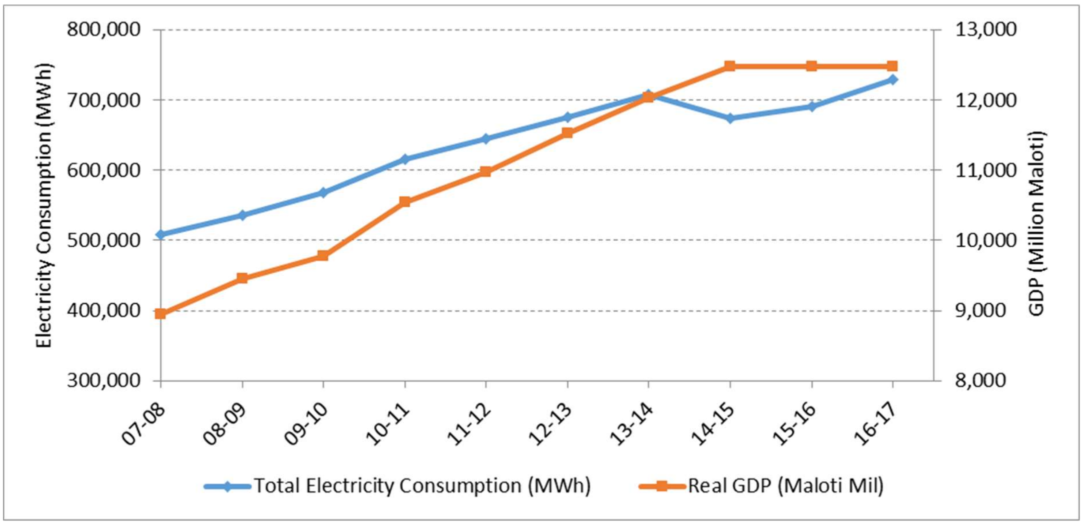
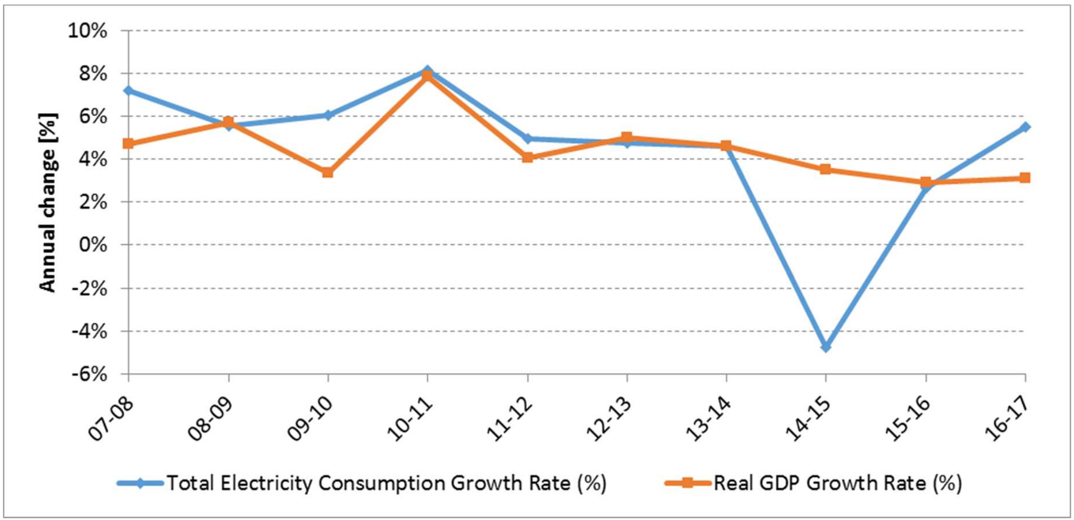


Figure 12: Per cent annual growth rates of electricity consumption and real GDP 2007/8 to 2016/17



The trends in average electricity consumption per each customer category (domestic, general purpose, and commercial and industrial at both low voltage (LV) and high voltage (HV)) and real energy (or maximum demand charges[7]) are plotted from Figure 13 to Figure 16.

Total electricity consumption for **domestic customers** has seemingly increased despite steady increases in tariffs (Figure 13, left) however as already discussed average consumption per customer

[7] The energy charges include both customer and electrification levies but exclude value-added tax. The consumer price index has also been used to calculate the real energy tariffs, with 2010 being the base year.

is reducing (Figure 13, right). This could imply a causal relationship, whereby new domestic customers are limiting their usage due to affordability. This assertion will be explored later on in the study when developing a lifeline tariff.

There is a similar picture for **general purpose customers** (Figure 14), although electricity consumption for this category was trending upwards till 2013/14 until it fell sharply in 2014/15 before increasing again in the subsequent years.

Total electricity consumption for **commercial and industrial customers** has experienced an upward trend from 2007/8 to 2016/17 (Figure 15, left). Average consumption per customer has been relatively stable for commercial customers (Figure 15, right) whereas average consumption per industrial customer was increasing until 2014/15 at which point there was a sharp decrease – this reduction in production from the energy sector may provide an explanation for the down turn in consumption growth in that year (Figure 12). In 2010 real terms, energy charges for these customers have been increasing, while maximum demand charges for both commercial and industrial LV and HV have trended downwards during the years before the 2010/11 tariff year and then increased steadily till 2016/17. The largely observed positive correlation between electricity consumption and real energy (or maximum demand) charges for industrial and commercial customers seems to imply that electricity prices are playing a less significant role in terms of influencing electricity consumption in Lesotho from these sectors.

Figure 13: Domestic electricity consumption (left) and average consumption per domestic customer (right) and real energy charges (both) 2007 to 2016

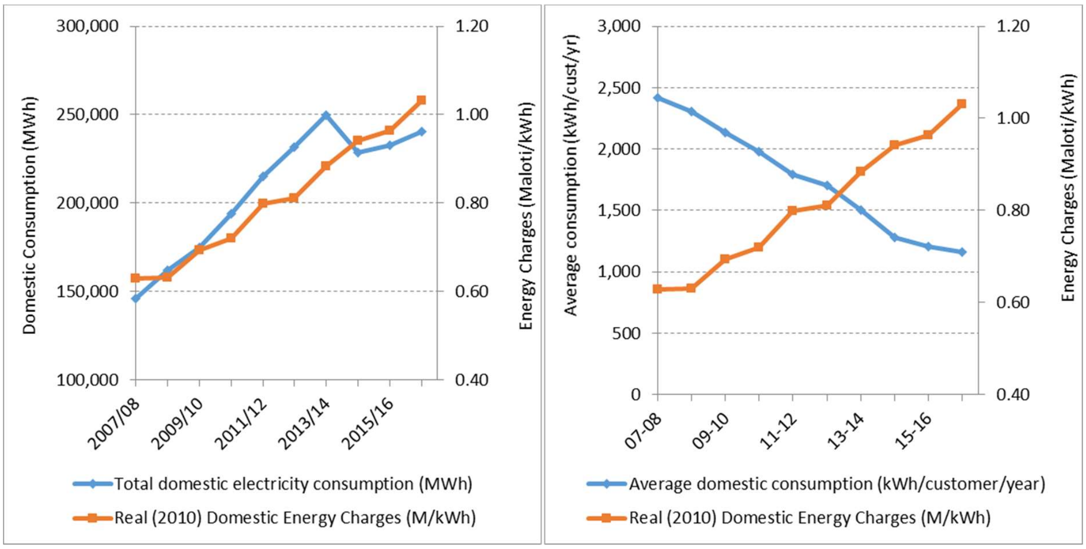


Figure 14: General Purpose (GP) electricity consumption (left) and average consumption per GP customer (right) and real energy charges (both) 2007 to 2016

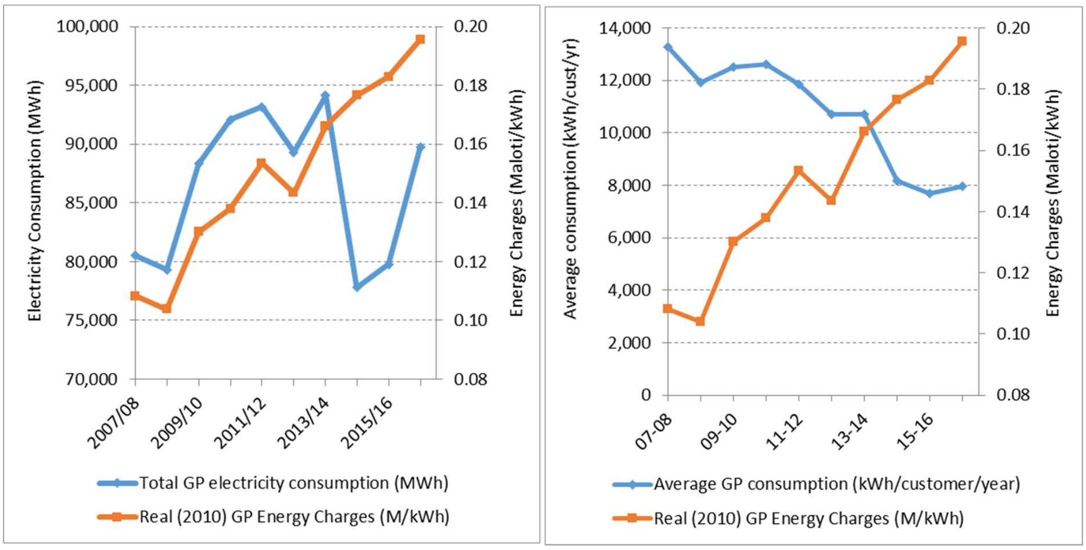


Figure 15: Commercial and Industrial electricity consumption (left) and average consumption per customer category (right) and real energy charges (both) 2007 to 2016

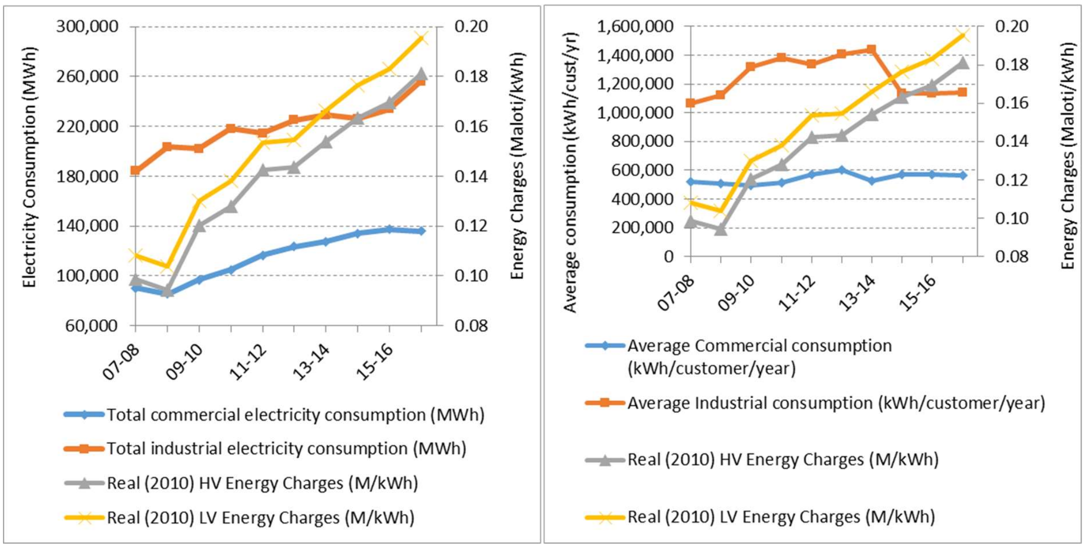
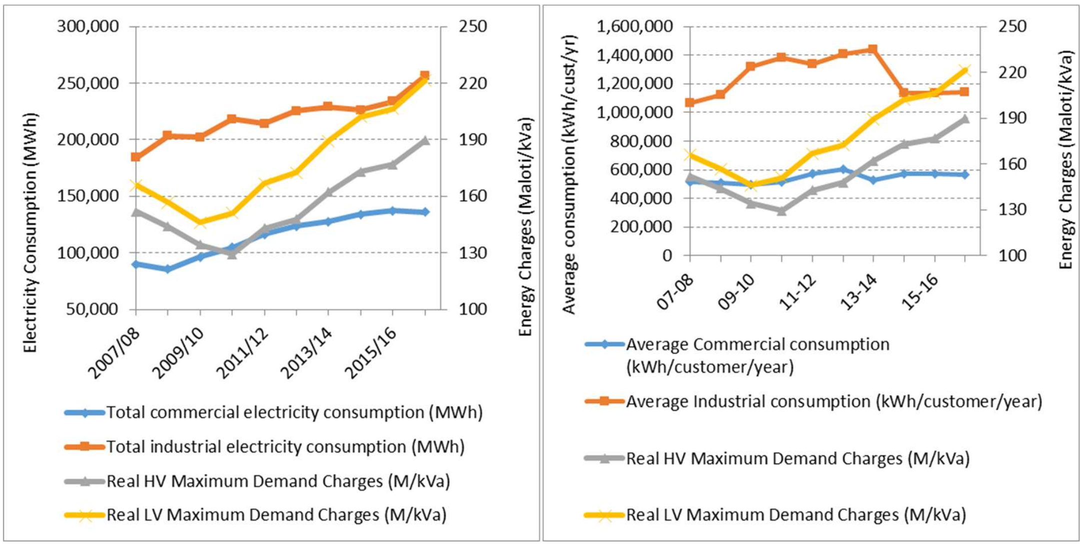


Figure 16: Commercial and Industrial electricity consumption (left) and average consumption per customer category (right) and real maximum demand charges (both) 2007 to 2016



4 EXISTING DEMAND FORECASTS

The 2007 National Electrification Master Plan (NEMP) included a demand forecast from 2005 to 2020. The NEMP forecasts for energy and peak demand are shown in Figure 17. A key driver of the NEMP forecast was meeting the GoL electrification rates targets of 35% by 2015 and 40% by 2020.

A comparison of the forecasted and actual main parameters and key drivers are depicted in Table 3. The comparison for 2010 shows that the realized peak demand (120 MW forecast versus 121 MW actual) and electrification rates (20% targeted versus 19% actual) were close to the forecast. Other parameters show less alignment, such as total energy consumption (i.e., energy sales in the LEC data) which was higher than forecast.

The comparison for 2015 shows how almost all parameters forecast are below reality apart from one key value – the electrification rate. The comparison shows how LEC, in connecting a significant number of new customers (Figure 2) have surpassed the target of 35%. The lower than anticipated level of demand in combination with this high electrification rate is most likely explained by the declining consumption per household noted in section 2. This implies that the model assumed a constant average household consumption or even an increasing trend, which would be expected under normal conditions with a normal growth of customer numbers in a normal urban/rural mix and normal economic growth in electricity consumption through acquisition of additional electrical appliances. For Lesotho, the higher household electrification rates do not result in constant average household consumption, probably the result of a focus of resources on rural electrification and little or no external support for urban densification expansion which was expected in the NEMP study.

This comparison therefore indicates that the growth rates in energy and peak demand and household consumption applied in the NEMP are not appropriate for this study.

Figure 17: Energy demand (left) and peak demand (right) forecast 2005-2020 from the NEMP

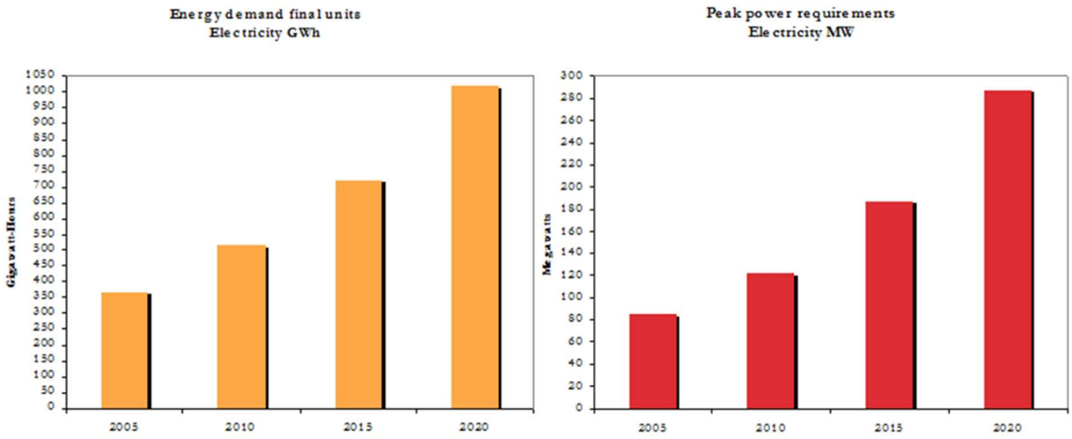


Table 3: Comparison of the NEMP forecast with the actual data

	2010 NEMP Forecast	2010 Actual Data	2015 NEMP Forecast	2015 Actual Data	2020 NEMP Forecast
Energy Consumption (GWh)	500	614.9	725	691.4	1,000
Peak Demand (MW)	120	121	190	154.2	290
Implied On-grid Electrification Rate (%)	20	19	35	36	40
	(Target)	(Estimate)	(Target)	(Estimate)	(Target)
Annual Average Consumption per Household (kWh/year)	Not Stated	1,980.7	Not Stated	1,207.6	Not Stated

Source: Actual electrification rates derived from number of domestic customers (LEC data for financial years 2010/11 and 2015/16) and estimates for population, number of households and capita per households from the 2017 SE4ALL TAF study – see section 5.1.

5 Application of the MAED Model

The revised demand forecasts in this study are carried out using the International Atomic Energy Agency (IAEA) Model for Analysis of Energy Demand (MAED). This model is ideal as the Department of Energy in Lesotho has trained personnel of the major energy stakeholders in the country to use it. This will facilitate the speedy appreciation from the relevant stakeholders on how the results were obtained. Moreover, future forecasts could then be easily obtained by any interested party without incurring expenses for both the software and expertise.

MAED uses analytical bottom up variables together with their constituents and their drivers. Its inputs include GDP, population, electrification rates and energy usage per economic sector. The identified major shortcomings of the NEMP forecast, namely, constant/increasing average household consumption are addressed in this model.

The MAED model forecasts medium- to long-term energy demand based on the following:

- Socio-economy
- Technology
- Demography

The model presents a framework for evaluating the impact on energy demand by changes in the overall macroeconomic picture of the country as well as the standard of living of the population. The energy demand is disaggregated into various end-use categories and each category is affected by assumptions on a number of variables, such as demography (urban/rural population, population growth rate, potential/active labour force), GDP (total GDP and GDP structure by main economic sectors), energy intensities for industry (agriculture, construction, manufacturing and mining), modes of transportation (freight/passenger, intra/inter-city) and household usages (space heating/cooling, cooking, water heating and appliances). The total energy demand is combined into the following energy consumer sectors:

- Industry (includes Agriculture, Construction, Mining and Manufacturing)
- Transportation
- Service
- Household

The first year of the model projection is typically calibrated to outturn data. This requires collection, verification, and in the case of Lesotho, estimation, of certain model input data. Once the base year has been calibrated, then scenarios for the future evolution of the system can be computed. The scenarios are typically based on expectations about the overall macroeconomic picture but there is scope for focusing on more detailed factors such as consumption efficiency and the penetration of different energy sources in the supply mix (e.g., biomass, solar, fuel, and thermal), however the affordability of these energy sources is not taken into consideration.

The model computes total energy demand and there are options for how different types of end-use demand are met. For example, biomass and electricity compete for cooking purposes. The model derives the end-user demand, in terms of useful energy and then converts useful energy into final energy where penetration and efficiency of all energy sources, including electricity are taken into consideration.

Excerpts from the input assumption table in MAED for this application are provided in Annex A. These assumptions include Lesotho specific information where available and in the absence of such information the Consultant’s own judgment and/or the default values of MAED.

The final energy demand output is given in terms of GWyr. The final output page contains the following sections:

- Final Energy Demand by Energy Form
- Final Energy Demand per Capita and per GDP
- Final Energy Demand by Sector

Table 4: Example of final energy demand by energy form output table from MAED

Item	Unit	2010	2015	2020	2025	2030
Traditional fuels	GWyr	1.892	2.100	2.317	2.557	2.830
Modern biomass	GWyr	0.000	0.000	0.000	0.000	0.000
Electricity	GWyr	0.071	0.080	0.092	0.104	0.119
District heat	GWyr	0.000	0.000	0.000	0.000	0.000
Soft solar	GWyr	0.000	0.000	0.000	0.000	0.000
Fossil fuels	GWyr	1.722	1.857	2.046	2.258	2.495
Motor fuels	GWyr	0.187	0.205	0.223	0.242	0.263
Coke & steam coal	GWyr	0.000	0.000	0.000	0.000	0.000
Feedstock	GWyr	0.000	0.000	0.000	0.000	0.000
Total	GWyr	3.872	4.242	4.678	5.161	5.706

Table 5: Example of final energy demand per capita and per GDP output table from MAED

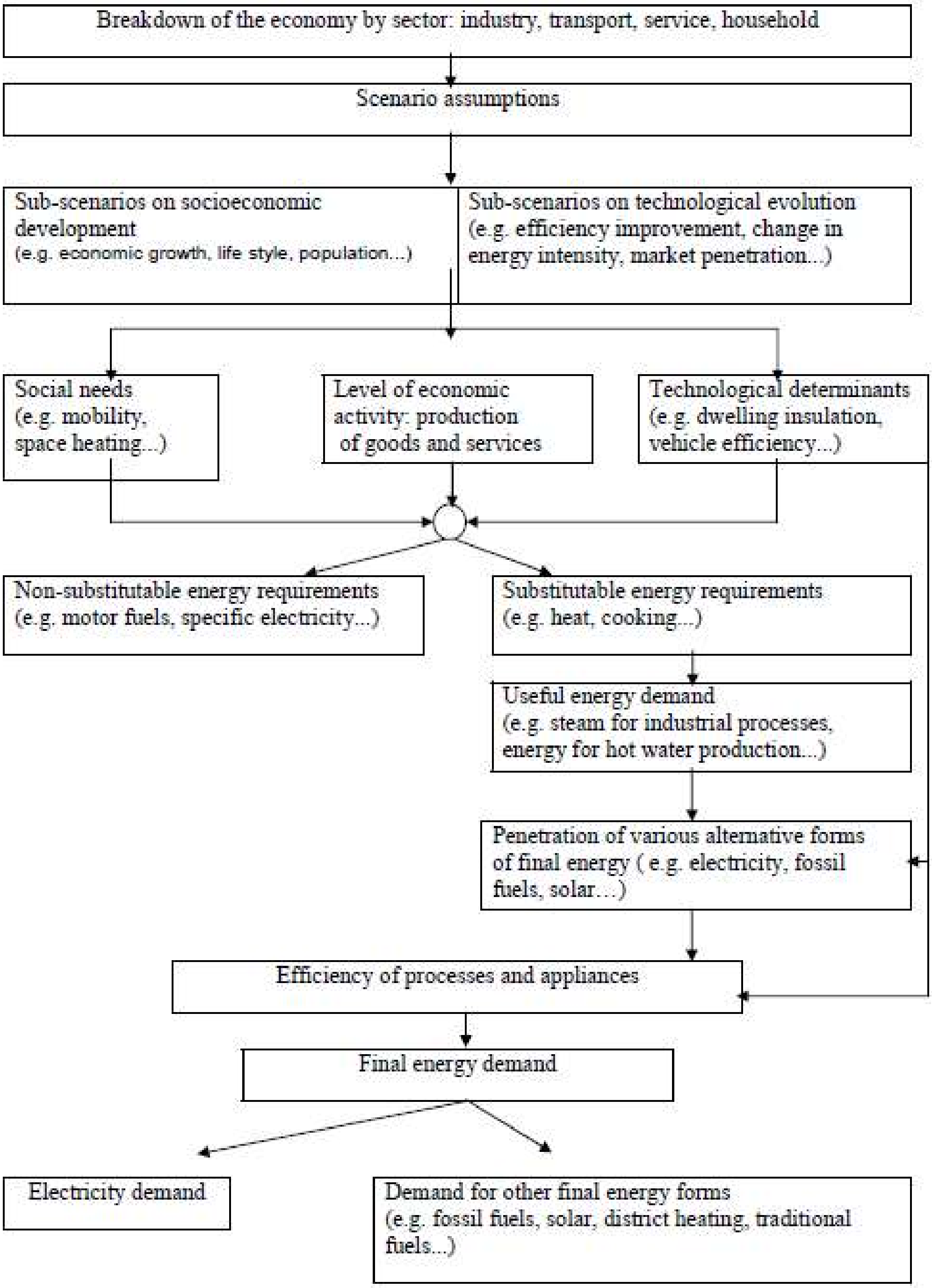
Item	Unit	2010	2015	2020	2025	2030
FE per capita	[MWh/cap]	17.037	17.410	18.156	19.052	20.110
FE per GDP	[kWh/US$]	19.836	17.862	16.191	14.681	13.340

Table 6: Example of final energy demand by sector output table from MAED

Item	Unit	2010	2015	2020	2025	2030
Industry	GWyr	0.396	0.418	0.509	0.619	0.753
Manufacturing	GWyr	0.365	0.379	0.461	0.561	0.683
ACM	GWyr	0.032	0.039	0.047	0.058	0.070
Transportation	GWyr	0.158	0.170	0.180	0.189	0.198
Freig. transp.	GWyr	0.001	0.001	0.002	0.002	0.003
Pass. transp.	GWyr	0.157	0.168	0.178	0.187	0.196
Household	GWyr	1.893	2.037	2.156	2.269	2.377
Service	GWyr	1.424	1.617	1.834	2.084	2.378
Total	GWyr	3.872	4.242	4.678	5.161	5.706

The output of interest in this setting is electricity demand only, however Table 4 shows MAED can also produce total energy demand for all sectors. An overview of how electricity demand is derived from the aggregate energy demand is shown in Figure 18.

Figure 18: Diagram describing how useful and final energy demand is constructed in MAED



Source: MAED Manual (copied directly)

In this application, the MAED model has been set-up to produce results for 2010, 2015, 2020, 2025 and 2030 with linear interpolation between the intervening years. Each modelled year was broken down into three periods of 4 months during which climatic patterns in Lesotho are reasonably constant, namely Jan-Apr, May-Aug and Sep-Dec.

Note that the 13 years horizon for the demand forecast was considered carefully during the early stages of the project and we selected 2030 as a realistic target date for the analysis and agreed this with LEWA. A principal factor in this decision is the uncertainty that has been introduced this year as to the future grid roll-out methodology. An electrification master plan is currently underway which is considering fundamental changes to the way the unconnected population will get electricity supply. There are likely to be significant reductions in grid expansions with a major switch to off-grid solar home and mini-grid solutions. It is also clear there are no committed supply expansion candidates in Lesotho (see deliverable 4). On both counts it would therefore be misleading to project beyond 2030 and we recommend that such a projection is not delivered in Lesotho. However, in principle, the MAED model can be extended to 2045 if required.

2010/11 year in the LEC data presented in section 2 is used as the 2010 base year. This allows enough overlap of the actual data with the forecast data to check the validity of the model computations. When comparing consumption between the actual data for consumption (Figure 1) and the forecasted values, the LEC customers are classified as electricity consumers in MAED as follows:

- **Household -** represents consumption from LEC Special Domestic and Pre-paid Domestic customers;
- **Industrial** - represents consumption from LEC Industrial customers;
- **Service** - represents consumption from LEC Commercial, Special General Purpose & Pre-paid General Purpose, LHDA and street lighting customers; and
- **Transport** – not used

5.1 Model Assumptions

The MAED model allows for **electrification rates** to be defined separately for urban and rural dwellings.

The current rate of new connections being undertaken by LEC is on course to achieve or surpass the 2020 target of 40% electrification. Our analysis suggests that at this level of electrification would involve a reasonable number of rural households that are typically low consumers and are also widely scattered. Connecting these customers would perpetuate the declining average consumption per household (Figure 2). Such an approach to electrification would therefore result in marginal increases in overall on-grid consumption and peak demand, unless there is significantly higher growth in the Services and Industrial sectors.

The 2016 population census by the BoS revealed a trend of population urbanisation over the last ten years. More precisely, the percentage distribution of household population by Urban, Peri-urban and Rural Residence has changed from 24% Urban, 76% Rural in 2006 to 34% Urban, 8% Peri-urban and 58% Rural in 2016. The modelling therefore adopted grid access for 82% of urban households by 2020 with less significant increases in rural grid access thereafter. The model also adopted a distribution of households of 34% urban in 2020, rising to 40% by 2030. As a result, it is assumed in the model that Lesotho will achieve total household electrification rates of 44% in 2020, 50% in 2025 and 54% in 2030.

The number of new connections per year is expected to continue at the recent rate of around 15,000 until 2020. Of this total, 10,000 new connections are assumed in Urban and Peri-Urban areas with the remaining 4,000 in rural areas. These rural connections will not be funded by LEC, rather via GoL funds or Universal Access Funds. This split broadly reflects anecdotal evidence from LEC that a high portion (around 8-10k) of new connections are from applicants in urban areas. Noting again the decline in average consumption per domestic customer (Figure 2) this suggests that consumption from urban as well as rural households is in decline. This decline would imply there is little economic justification for continuing at this rate and therefore after 2020 the number of new connections is scaled back - Table 7. Note that the model uses actuals for the number of new residential connections added by LEC in the 2015/16 and 2016/17 financial years[8] and assumes new committed connections of 14,000 for 2017/18.[9]

Table 7: Number of new customer connections per (financial) year assumed in the modelling

	Actual			Forecast		
	2015/16	2016/17	2017/18	2018-19	2020-24	2025-30
New domestic customer connections (per yr)	14,215	14,751	14,000	14,361	11,374	8,421
Of which Urban				*10,842*	*9,937*	*7,489*
Of which Rural				*3,519*	*1,437*	*932*

The actual **population** figure for 2006[10] together with the anticipated % growth rate from the United Nations World Population Review[11] are applied.

The **Gross Domestic Product** (GDP) growth rate used in the model is the average long run growth rate of 19 years (2000 – 2018). This is made up of actual values for 2000 to 2014 and the Central Bank of Lesotho projections for 2015-2018. The Central Bank of Lesotho (CBL) Economic Outlook 2015-2018 and 2016-2018 indicates:

- Lesotho's economic growth is estimated to be 3.5% in 2016, 4.3% in 2017 and 4.2% in 2018 (4% is applied in the MAED model).
- This improvement in economic activities is expected to be supported by:
    - Strong growth in the diamond mining industry as a result of the beginning of production processes (in the fourth quarter of 2016) at Liqhobong mine and the achievement of full production capacity at Letseng and Kao mines. To facilitate this growth the model developed for deliverable 4 includes the associated network upgrades to allow this demand to be served.
    - Positive growth prospects in the building and construction sector mainly due to the advancement in infrastructure development (including construction of road to Polihali Dam and accommodation facilities, as well as provision of power supply and telecommunication services) during the implementation of the second phase of the Lesotho Highlands Water Project (LHWP). Again, the system expansion model includes the associated network upgrades.

[8] Derived from customer number information provided by LEC.
[9] Derived from LEC expansion plan data. Data not available at time of SE4All TAF study.
[10] 2006 Population Census for Lesotho.
[11] http://worldpopulationreview.com/countries/lesotho-population/

- Good performance of the electricity and water sector following the establishment of the Lesotho Energy Policy and the completion of the Metolong Dam project.

A summary of the key modelling assumptions is shown in Table 8.

It is important to note that the MAED model is employed to provide a very broad-brush estimate of electricity demand for the purposes of an input to the development planning. The key focus in this analysis has been the proper representation of the reducing average household consumption. A fuller analysis would have considered the impact of, for example, improvements in consumption efficiency on electrical demand. However, it was decided that due to the relatively small size of the Lesotho power system and the lack and uncertainty in the data, the consultants can see no benefit in developing a model that considers a wide range of behavioural changes in the modelling.

Table 8: Summary of modelling assumptions

	2010	2015	2020	2025	2030
GDP (US$bn)	1.71	2.08	2.53	3.08	3.75
GDP growth (%)		4%	4%	4%	4%
Population (mil)	1.991	2.135	2.258	2.373	2.486
Urban					
Urban population (%)	25.5%	34.0%	37.0%	39.0%	40.0%
Population (mil)	0.508	0.726	0.835	0.926	0.994
Capita/Household (HH)	2.98	2.98	2.98	2.98	2.98
Electrification (%)	54.1%	72.0%	82.0%	90.0%	95.0%
HH with Grid Access (LEC customers) ('000)	92.0	175.1	229.5	279.1	316.5
Rural					
Population (mil)	1.484	1.409	1.422	1.448	1.492
Capita/Household	4.42	4.42	4.42	4.42	4.42
Electrification (%)	1.8%	5.5%	11.0%	13.0%	14.0%
HH with Grid Access (LEC customers) ('000)	6.1	17.5	35.4	42.6	47.2
Total					
Households (mil)	0.506	0.562	0.601	0.638	0.670
LEC residential customers ('000)	98.1	192.6	264.9	321.7	363.7
Electrification (%)	**19.4%**	**34.3%**	**44.0%**	**50.5%**	**54.2%**

5.2 Model Calibration

The calibration was applied to the 2010 and 2015 model years.

To calibrate the overall peak demand and energy consumption by sector (households, industrial and commercial) for 2010 and 2015 presented in Figure 1, the energy intensities of each sector were adjusted until the consumption for each sector was similar to the actual data.

For example, in order to accurately forecast electricity consumption for households, adjustments were made to the levels of electricity penetration in both cooking and space heating for both 2010 and 2015. This followed the observed trend of declining average consumption per household which also addressed the shortcoming of the NEMP forecast. The declining household consumption was extrapolated to subsequent years.

Thus the **average electricity consumption per household** for 2010 and 2015 was aligned with the historic data as shown in Figure 2. This was achieved by setting the **electricity penetration into space heating for urban dwellings** to 0.31% in 2010 and 0.21% in 2015. Furthermore, the **electricity penetration levels into cooking for urban dwellings** were assumed to be 37.8% in 2010 and 30.7% in 2015.

Inputs pertaining to the energy intensities of the service and industrial sectors for 2010 and 2015 were set to result in values for electricity consumption that are closer to the actual. These intensities were then extrapolated to subsequent years.

The results of this calibration are shown in Table 9.

Table 9: Summary of the Main Parameters assessed in the model calibrations

	2010		2015	
	Actual Data	**Calibrated Modelled Data**	**Actual Data**	**Calibrated Modelled Data**
Household Consumption (MWh)	193,836	184,444	232,880	244,375
Annual Average Consumption per Household (kWh)	*1,998*	*1,877*	*1,207*	*1,267*
Industrial consumption (MWh)	217,964	221,952	233,767	236,944
Service consumption (MWh)	203,068	212,973	224,765	223,460
Total Consumption (GWh)	**614,868**	**619,369**	**691,412**	**704,779**

5.3 Gross System Demand

MAED is used to project total electrical energy consumption. The corresponding gross system demand projections are then derived from these energy figures. This calculation is described below and forms part of the Cost of Service Study Tariff (COSST) model.

5.3.1 Losses

Our analysis of energy purchase and final consumption data provided by LEC indicates that aggregate transmission and distribution losses have been around 14% with an increasing trend in recent years – Table 10.[12]

Table 10: Aggregate losses derived from energy purchase and sales data from LEC

Data item		2012	2013	2014	2015	2016
Energy purchases	MWh	756,788	800,012	786,362	804,180	885,589
Energy sales	MWh	676,078	707,148	673,281	691,412	737,308
Aggregate Losses	%	10.7%	11.6%	14.4%	14.0%	16.7%

Data on the disaggregation of losses was not available so an estimate of 7% transmission and 8% distribution was applied, which aggregate to 14.4%.[13]

The final consumption figures produced by MAED are grossed up to provide total system gross energy demand by applying a 14.4% loss factor.

5.3.2 Profiling Demand

Using actual 30-min interval chronological system load data for 2015 provided by LEC the total gross energy demand can be transformed into an hourly load profile. The hourly load is the average of each half hourly loads within the hour. The per unit load in each hour is the ratio of the load to the average load across the 8760 hourly loads in one year:

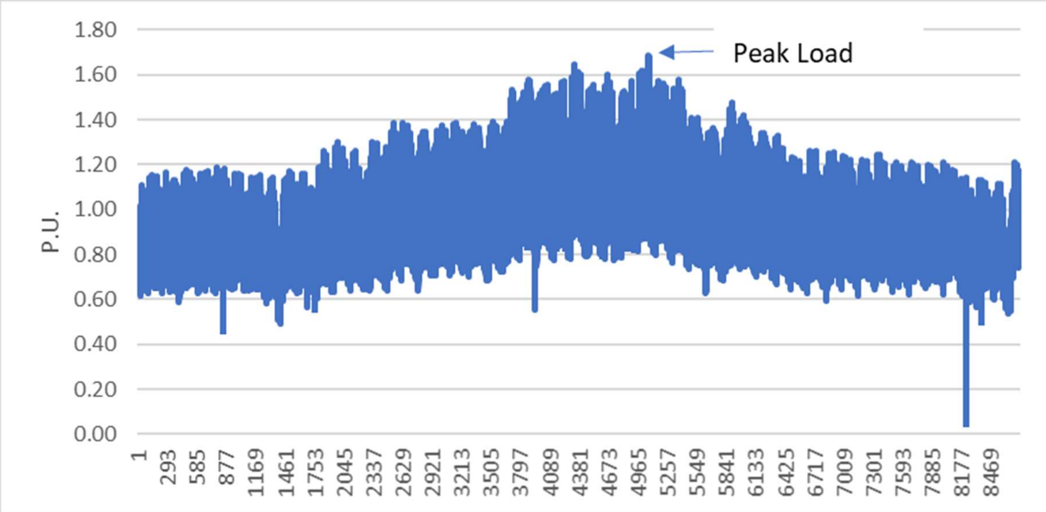
$$p.u.load_t = \frac{Hourly\ load_t}{\frac{\sum_{i=1}^{8760} Hourly\ load_i}{8760}}$$

This profile is shown in Figure 19. This profile is used for the duration of the planning horizon. This is, however an input to the COSST model and can be adjusted – it is included in the Load Profiles sheet of the COSST model (see model manual).

[12] Note that the majority of customers are on pre-payment meters so it seems reasonable to assume that energy sales is a good representation of actual consumption.

[13] Aggregate losses = [Transmission Losses] + (1-[Transmission Losses])* [Distribution Losses] = 7%+(1-7%)*8% = 14.4%.

Figure 19: Per unit load profile derived from 2015 system load profile



5.3.3 System Peak Load

The maximum per unit load coefficient is multiplied by the average system load (final consumption adjusted for losses) to determine the gross peak demand. Based on the 2015 load profile data this is 1.68 and is indicated in Figure 19:

$$Peak\ load\ [MW] = \frac{Final\ Consumption\ [MWh]}{8760} \times \frac{1}{(1 - 14.4\%)} \times 1.68$$

This approach assumes that the evolution of peak demand is driven by the same underlying parameters as final consumption and, for example, there are no measures in place to reduce peak demand growth relative to the overall energy demand growth.[14]

6 Model Scenarios

The forecast is made on three possible scenarios for the evolution of on-grid final energy consumption out to 2030.

The **most likely scenario** in which the recent rate of about 15,000 new connections per year is maintained until 2020 and then scaled back from 2020 onwards and the resulting total household electrification rates for the on-grid households are 44% in 2020, 51% in 2025 and 54% in 2030.[15]

[14] For instance, the System Operator might procure services to provide demand-side response at times of high system load in order to reduce overall production costs.

[15] A higher rate of electrification is actually expected to take place through alternatives to on-grid supply, for instance by mini-grid and stand-alone renewable energy solutions that are significantly more economic than grid connection for the majority rural and dispersed population not yet connected.

This scenario assumes the continuation of the current average economic growth rate in all sectors of the economy with no changes (e.g. national policies) that may affect this trend. This scenario assumes the continuation of the long-term average GDP growth rate of 4%.

The analysis considers two alternative scenarios for GDP growth:

The **low economic growth scenario** defines a lower bound for economic development. The average GDP growth rate of the lowest 5 years in the last 19 years (2000-2018), of 2.19%, is used. Low growth might occur for a number of reasons, such as, unstable socio-economic and political environments, and low levels of internal and foreign investment.

The **high economic growth scenario** assumes an economic growth rate of 5.68% which is the average GDP growth rate of the highest 5 years in the last 19 years. This scenario is expected to influence factors that result in higher energy consumption, even for households, hence the levels of electricity usage intensities in both cooking and space heating are adjusted upwards.

Table 11: Assumed GDP and GDP growth in the model scenarios

	2010	2015	2020	2025	2030
Most likely					
GDP (US$bn)	1.71	2.08	2.53	3.08	3.75
GDP growth (%)		4.0%	4.0%	4.0%	4.0%
Low economic growth					
GDP (US$bn)	1.71	2.08	2.32	2.58	2.88
GDP growth (%)		4.0%	2.2%	2.2%	2.2%
High economic growth					
GDP (US$bn)	1.71	2.08	2.74	3.61	4.76
GDP growth (%)		4.0%	5.7%	5.7%	5.7%

The scenarios are used to forecast possible situations from 2020 using the calibrated modelled data for 2010 and 2015.

7 Forecasting Results

In all scenarios demand is expected to rise. Figure 20 shows energy consumption. Average household consumption falls in all scenarios -Figure 21.

With the **most likely scenario**, the peak demand is expected to increase from 154.2 MW in 2015 to 211 MW in 2030, while average household consumption will fall from 1,205 kWh/customer/year in 2015 to 1009 kWh/year in 2030.

The steep decline in average consumption per household experienced since 2000 is reduced to a more gradual decrease from around 2015 in the model. This levelling off in the decline in consumption is the result of the modelled reduction in electrification explained in Section 5.1.

Should Lesotho realise a **high economic growth** both the peak and average consumption are expected to rise further to 258 MW and 1,218 kWh/customer/year by 2030, respectively.

Figure 20: Model projections for Final Energy Consumption

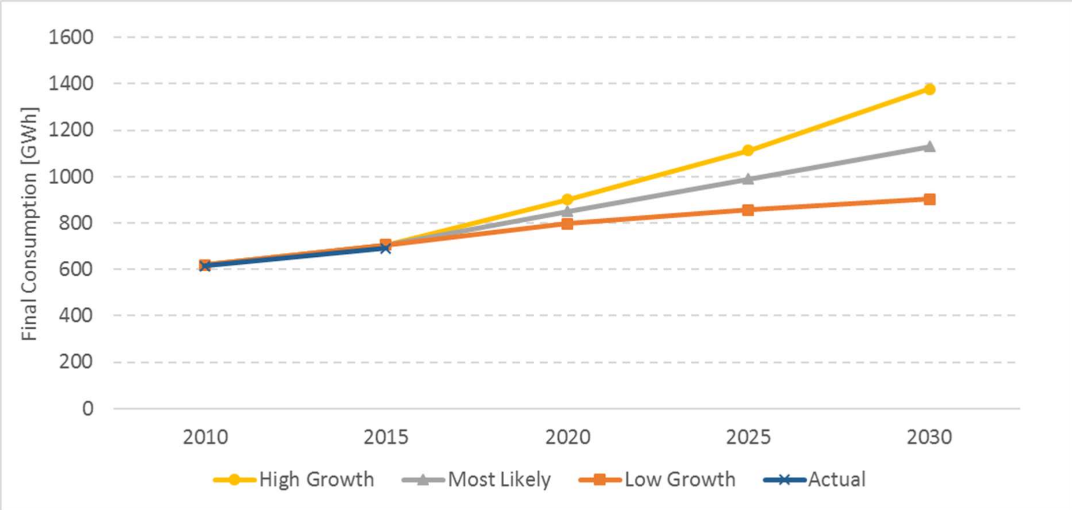


Figure 21: Annual Average Household Consumption from on-grid customers (kWh/year)

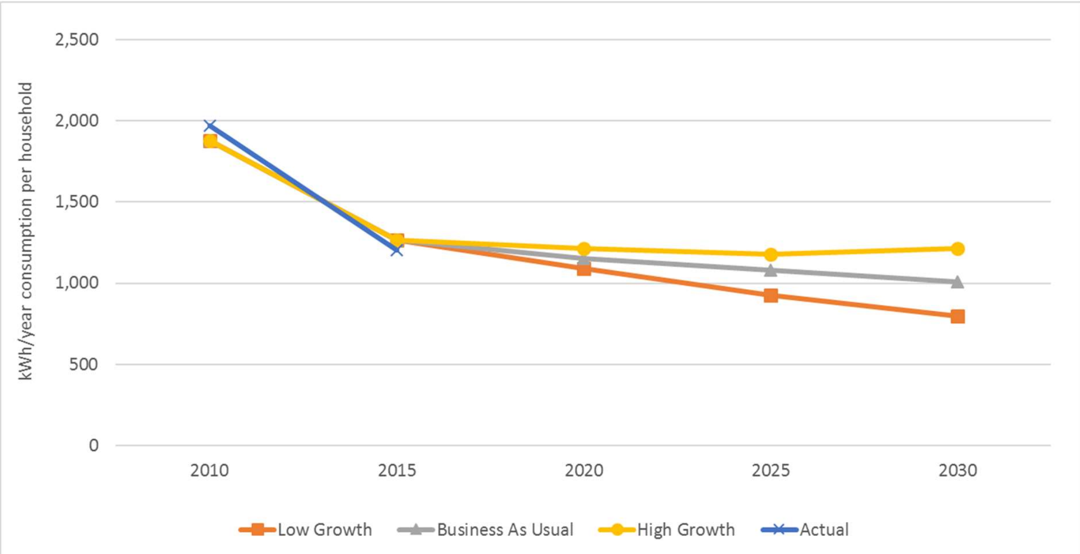


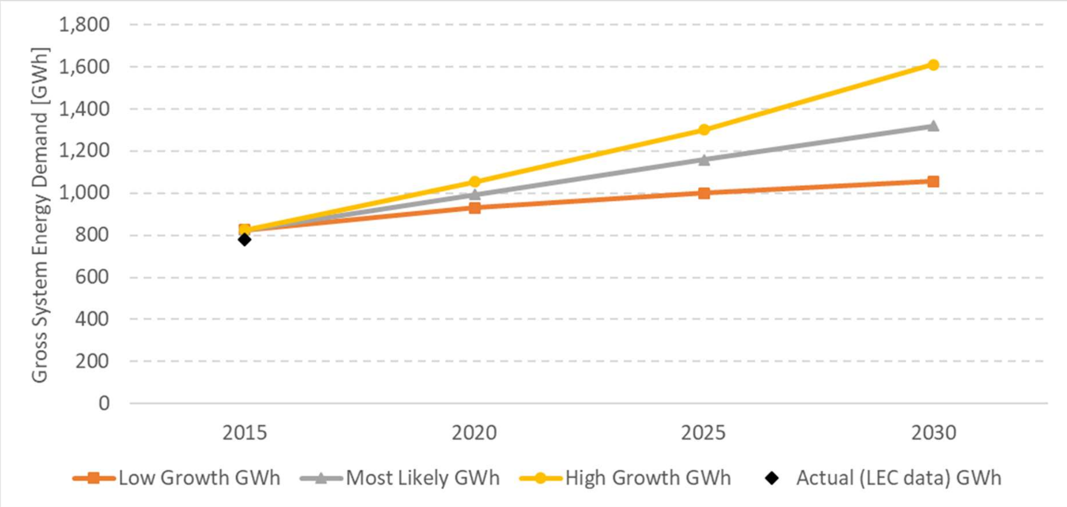
Table 12: Summary of the model forecasting results

	2020			2025			2030		
	Low GDP Growth	Most likely	High GDP Growth	Low GDP Growth	Most likely	High GDP Growth	Low GDP Growth	Most likely	High GDP Growth
Annual Consumption from households (MWh)	289,288	306,204	322,278	298,221	348,430	379,364	289,903	367,521	442,735
Annual Average Consumption per Household (kWh/cust/yr)	*1,091*	*1,155*	*1,215*	*926*	*1,082*	*1,178*	*796*	*1,009*	*1,216*
Annual Consumption from industry (MWh)	264,087	288,318	312,370	294,299	350,783	411,749	327,968	426,781	542,747
Annual Consumption from services (MWh)	242,903	254,755	266,519	263,511	291,139	320,960	285,650	333,982	390,704
Total final energy consumption (MWh)	**796,277**	**849,277**	**901,167**	**856,031**	**990,352**	**1,112,073**	**903,520**	**1,128,284**	**1,376,185**

7.1 Gross System Energy Demand

Figure 22 shows the total gross energy demand for the three scenarios relative to the final consumption.

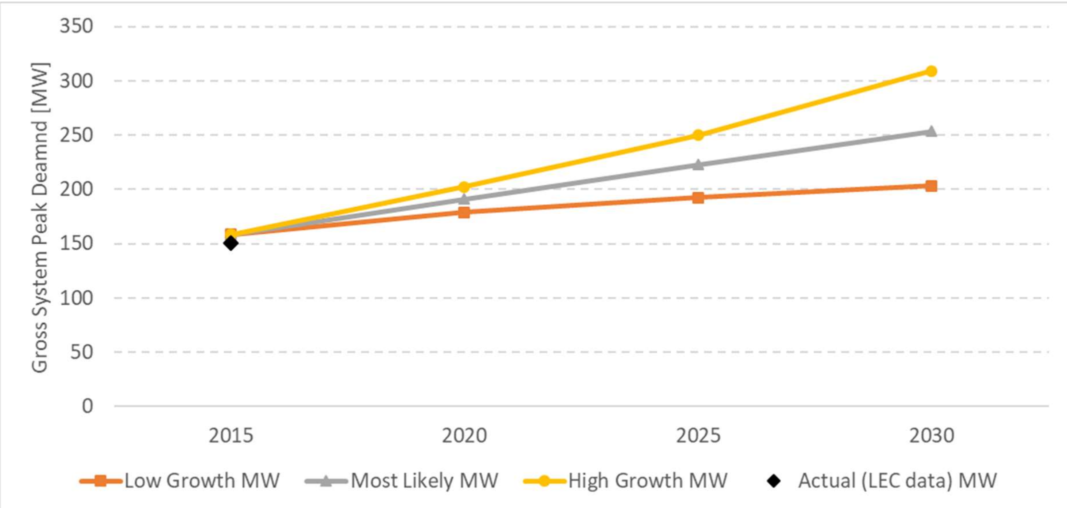
Figure 22: Projections for Gross Energy Demand derived from MAED Final Consumption results



7.2 System Peak Load

Figure 23 shows the total gross system maximum demand for the three scenarios relative to the final consumption.

Figure 23: Projections for Gross Energy Demand derived from MAED Final Consumption results



8 Discussions and Conclusions

The most likely scenario for on-grid final energy consumption represents total household on-grid electrification rates of 44% in 2020, 50% in 2025 and 54% in 2030.

In all scenarios, despite average consumption per household reducing and a reduction in the rate of new connections, overall residential demand is expected to increase. Demand from industrial and service sectors also increases in all scenarios with the rate of increase shown to be sensitive to the assumed rate of GDP growth.

In order to provide inputs for the subsequent deliverables of the study, the demand forecast will need to include an electricity demand forecast classified by zone and type of use (industrial, household and service), peak demand and load profiles for the different customer groups. Since the demand forecast includes an implicit view on the network expansion and in turn newly connected customers, this is expected to inform the task of determining the medium- and long-term network development program. This step will be undertaken as part of deliverables four and five.

9 ANNEX A: MAED MODEL INPUT TABLES AND DATA

Table 1 Demography

Item	Unit	2010	2015	2020	2025	2030
Population*	[million]	1.991	2.135	2.257	2.373	2.485
Pop. gr. rate*	[%p.a.]		1.402	1.124	1.005	0.931
Urban pop.	[%]	25.500	25.500	25.500	25.500	25.500
Capita/hh	[cap]	2.980	2.980	2.980	2.980	2.980
Households	[million]	0.170	0.183	0.193	0.203	0.213
Rural pop.	[%]	74.500	74.500	74.500	74.500	74.500
Capita/hh	[cap]	4.420	4.420	4.420	4.420	4.420
Households	[million]	0.336	0.360	0.380	0.400	0.419
Potential lf	[%]	64.000	64.000	64.000	64.000	64.000
Participating lf	[%]	65.000	65.000	65.000	65.000	65.000
Active lf	[million]	0.828	0.888	0.939	0.987	1.034
Share of lc. pop.	[%]	22.000	22.000	22.000	22.000	22.000
Pop. inside lc	[million]	0.438	0.470	0.497	0.522	0.547

GDP formation

Table 2-1 Total GDP and GDP structure by main economic sectors

Item	Unit	2010	2015	2020	2025	2030
GDP*	[10^9 US$]	1.710	2.080476463	2.531217727	3.079613394	3.746820575
GDP gr. rate*	[%p.a.]		4.000	4.000	4.000	4.000
GDP/cap	US$	858.9	974.7	1121.4	1297.8	1507.5
Agriculture	[%]	7.804	7.804	7.804	7.804	7.804
Construction	[%]	5.555	5.555	5.555	5.555	5.555
Mining	[%]	4.413	4.413	4.413	4.413	4.413
Manufacturing	[%]	16.277	16.277	16.277	16.277	16.277
Service	[%]	61.850	61.850	61.850	61.850	61.850
Energy	[%]	4.101	4.101	4.101	4.101	4.101

Table 2-7 GDP formation by sector/subsector (absolute values)

Item	Unit	2010	2015	2020	2025	2030
Agriculture	[10^9 US$]	0.133	0.162	0.198	0.240	0.292
Construction	[10^9 US$]	0.095	0.116	0.141	0.171	0.208
Mining	[10^9 US$]	0.075	0.092	0.112	0.136	0.165
Manufacturing	[10^9 US$]	0.278	0.339	0.412	0.501	0.610
Service	[10^9 US$]	1.058	1.287	1.566	1.905	2.317
Energy	[10^9 US$]	0.070	0.085	0.104	0.126	0.154
Total GDP	[10^9 US$]	1.710	2.080	2.531	3.080	3.747

Table 2-8 GDP formation by sector (per capita):

item	Unit	2010	2015	2020	2025	2030
GDP/cap	US$	858.865	974.673	1121.384	1297.797	1507.477
Agriculture	US$	67.026	76.063	87.513	101.280	117.643
Construction	US$	47.710	54.143	62.293	72.093	83.740
Mining	US$	37.902	43.012	49.487	57.272	66.525
Manufacturing	US$	139.797	158.648	182.528	211.242	245.372
Service	US$	531.208	602.835	693.576	802.687	932.374
Energy	US$	35.222	39.971	45.988	53.223	61.822

Table 2-9 GDP formation by sector/subsector (growth rates):						
Item	Unit	2010	2015	2020	2025	2030
Agriculture	[%]		4.000	4.000	4.000	4.000
Construction	[%]		4.000	4.000	4.000	4.000
Mining	[%]		4.000	4.000	4.000	4.000
Manufacturing	[%]		4.000	4.000	4.000	4.000
Service	[%]		4.000	4.000	4.000	4.000
Energy	[%]		4.000	4.000	4.000	4.000
Total GDP	[%]		4.000	4.000	4.000	4.000
GDP/cap	[%]		2.562	2.844	2.965	3.041

Energy intensities for Industry

Table 3-1 Energy intensities of Motor fuels

Item	Unit	2010	2015	2020	2025	2030
Agriculture	[kWh/US$]	0.268	0.268	0.268	0.268	0.268
Construction	[kWh/US$]	0.068	0.068	0.068	0.068	0.068
Mining	[kWh/US$]	1.285	1.285	1.285	1.285	1.285
Manufacturing	[kWh/US$]	0.425	0.425	0.425	0.425	0.425

Table 3-2 Energy intensities of Electricity specific uses

Item	Unit	2010	2015	2020	2025	2030
Agriculture	[kWh/US$]	0.013	0.009	0.009	0.009	0.009
Construction	[kWh/US$]	0.183	0.163	0.163	0.163	0.163
Mining	[kWh/US$]	0.808	0.908	0.908	0.908	0.908
Manufacturing	[kWh/US$]	0.292	0.192	0.192	0.192	0.192

Table 3-3 Energy intensities of Thermal uses

Item	Unit	2010	2015	2020	2025	2030
Agriculture	[kWh/US$]	0.020	0.011	0.011	0.011	0.011
Construction	[kWh/US$]	0.018	0.018	0.018	0.018	0.018
Mining	[kWh/US$]	0.686	0.686	0.686	0.686	0.686
Manufacturing	[kWh/US$]	6.836	5.836	5.836	5.836	5.836

Useful energy demand in Industry

Table 4-1 Useful energy demand for Motor fuels

Item	Unit	2010	2015	2020	2025	2030
Agriculture	GWyr	0.004	0.005	0.006	0.007	0.009
Construction	GWyr	0.001	0.001	0.001	0.001	0.002
Mining	GWyr	0.011	0.013	0.016	0.020	0.024
Manufacturing	GWyr	0.014	0.016	0.020	0.024	0.030
Total	GWyr	0.029	0.036	0.044	0.053	0.064

Table 4-2 Useful energy demand for Electricity speci

Item	Unit	2010	2015	2020	2025	2030
Agriculture	GWyr	0.000	0.000	0.000	0.000	0.000
Construction	GWyr	0.002	0.002	0.003	0.003	0.004
Mining	GWyr	0.007	0.010	0.012	0.014	0.017
Manufacturing	GWyr	0.009	0.007	0.009	0.011	0.013
Total	GWyr	0.018	0.019	0.023	0.029	0.035

Table 4-3 Useful energy demand for Thermal uses

Item	Unit	2010	2015	2020	2025	2030
Agriculture	GWyr	0.000	0.000	0.000	0.000	0.000
Construction	GWyr	0.000	0.000	0.000	0.000	0.000
Mining	GWyr	0.006	0.007	0.009	0.011	0.013
Manufacturing	GWyr	0.217	0.226	0.274	0.334	0.406
Total	GWyr	0.224	0.233	0.284	0.345	0.420

Table 4-4 Total useful energy demand in Industry

Item	Unit	2010	2015	2020	2025	2030
Agriculture	GWyr	0.005	0.005	0.007	0.008	0.010
Construction	GWyr	0.003	0.003	0.004	0.005	0.006
Mining	GWyr	0.024	0.030	0.037	0.045	0.054
Manufacturing	GWyr	0.240	0.249	0.303	0.369	0.449
Total	GWyr	0.271	0.288	0.351	0.427	0.519

Factors for Manufacturing

Shares of useful thermal energy demand in Manufacturing

Table 7-1

Manufacturing	Unit	2010	2015	2020	2025	2030
Steam generation	[%]	79.266	77.266	77.266	77.266	77.266
Furnace/direct heat	[%]	0.734	0.764	0.764	0.764	0.764
Space&water heating	[%]	20.000	21.970	21.970	21.970	21.970

Useful thermal energy demand in Manufacturing

Table 7-2

Manufacturing	Unit	2010	2015	2020	2025	2030
Steam generation	GWyr	0.172	0.174	0.212	0.258	0.314
Furnace/direct heat	GWyr	0.002	0.002	0.002	0.003	0.003
Space&water heating	GWyr	0.043	0.050	0.060	0.073	0.089
Total	GWyr	0.217	0.226	0.274	0.334	0.406

Useful energy demand in Urban Household sector

Table 14-1 Basic data for useful energy demand in Urban Household sector

Item	Unit	2010	2015	2020	2025	2030
Dwellings	[million]	0.170	0.183	0.193	0.203	0.213
Share of dw. requiring SH	[%]	100.000	100.000	100.000	100.000	100.000
Degree-days	[days°C]	1775.000	1775.000	1775.000	1775.000	1775.000

Tables 14-2 Dwelling factors for space heating and air conditioning, Urban Household

Item		2010	2015	2020	2025	2030
Share of Malaene	[%]	41.100	41.100	41.100	41.100	41.100
Share of Family house	[%]	58.900	58.900	58.900	58.900	58.900
Dw. size. Malaene	[sqm]	30.000	30.000	30.000	30.000	30.000
Dw. size. Family house	[sqm]	100.000	100.000	100.000	100.000	100.000
Area h. Malaene	[%]	75.000	75.000	75.000	75.000	75.000
Area h. Family house	[%]	55.000	55.000	55.000	55.000	55.000
H. los. R. Malaene	[Wh/sqm/°C/h]	16.000	16.000	16.000	16.000	16.000
H. los. R. Family house	[Wh/sqm/°C/h]	15.000	15.000	15.000	15.000	15.000
Dw. AC. Malaene	[%]	0.000	0.000	0.000	0.000	0.000
Dw. AC. Family house	[%]	3.000	3.000	3.000	3.000	3.000
Spc. req. AC. Malaene	[kWh/dw/yr]	0.000	0.000	0.000	0.000	0.000
Spc. req. AC. Family house	[kWh/dw/yr]	7254.000	7254.000	7254.000	7254.000	7254.000

Table 14-3 Dwelling factors for cooking, hot water and appliances, Urban Household

Item	Unit	2010	2015	2020	2025	2030
Cooking	[kWh/dw/yr]	*900.377*	*900.377*	*900.377*	*900.377*	*900.377*
Dw with hot water	[%]	*30.000*	*30.000*	*35.000*	*45.000*	*45.000*
HW per cap	[kWh/cap/yr]	*180.154*	*180.154*	*180.154*	*180.154*	*180.154*
Electr. cons. for appliances	[kWh/dw/yr]	*800.910*	*800.910*	*800.910*	*800.910*	*800.910*
Electr. penetration	[%]	*54.087*	*95.000*	*100.000*	*100.000*	*100.000*
FF for lighting	[kWh/dw/yr]	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*

Table 14-4 Calculation of useful energy demand in Urban Household sector

Item	Unit	2010	2015	2020	2025	2030
Space heating	GWyr	0.525	0.563	0.595	0.626	0.656
Water heating	GWyr	0.003	0.003	0.004	0.006	0.006
Cooking	GWyr	0.018	0.019	0.020	0.021	0.022
Air conditioning	GWyr	0.002	0.003	0.003	0.003	0.003
Elec. for appliances	GWyr	0.008	0.016	0.018	0.019	0.019
FF for lighting	GWyr	0.000	0.000	0.000	0.000	0.000
Total	GWyr	0.557	0.604	0.640	0.674	0.706

Table 14-5 Penetration of energy forms into space heating, Urban Household

Item		2010	2015	2020	2025	2030
Traditional fuels	[%]	4.933	4.933	4.933	4.933	4.933
Modern biomass	[%]	0.000	0.000	0.000	0.000	0.000
Electricity	[%]	0.312	0.212	0.162	0.112	0.062
(thereof: heat pump)	[%]	0.000	0.000	0.000	0.000	0.000
District heat	[%]	0.000	0.000	0.000	0.000	0.000
Soft solar	[%]	0.000	0.000	0.000	0.000	0.000
Fossil fuels	[%]	94.8	94.9	94.9	95.0	95.0

Table 14-6 Efficiencies and other factors for space heating, Urban Household

Item		2010	2015	2020	2025	2030
Eff. Trad. fuels	[%]	30.612	30.612	30.612	30.612	30.612
Eff. Mod. biomass	[%]	1.000	1.000	1.000	1.000	1.000
Eff. Fossil fuels	[%]	88.861	88.861	88.861	88.861	88.861
COP heat pumps	[ratio]	1.000	1.000	1.000	1.000	1.000
Solar share	[%]	1.000	1.000	1.000	1.000	1.000

Table 14-7 Penetration of energy forms into water heating, Urban Household

Item		2010	2015	2020	2025	2030
Traditional fuels	[%]	0.000	0.000	0.000	0.000	0.000
Modern biomass	[%]	0.000	0.000	0.000	0.000	0.000
Electricity	[%]	100.000	100.000	100.000	100.000	100.000
(thereof: heat pump)	[%]	0.000	0.000	0.000	0.000	0.000
District heat	[%]	0.000	0.000	0.000	0.000	0.000
Soft solar	[%]	0.000	0.000	0.000	0.000	0.000
Fossil fuels	[%]	0.0	0.0	0.0	0.0	0.0

Table 14-8 Efficiencies and other factors for water heating, Urban Household

Item		2010	2015	2020	2025	2030
Eff. Trad. fuels	[%]	1.000	1.000	1.000	1.000	1.000
Eff. Mod. biomass	[%]	1.000	1.000	1.000	1.000	1.000
Eff. Fossil fuels	[%]	1.000	1.000	1.000	1.000	1.000
COP heat pumps	[ratio]	1.000	1.000	1.000	1.000	1.000
Solar share	[%]	1.000	1.000	1.000	1.000	1.000

Table 14-9 Penetration of energy forms into cooking, Urban Household						
Item		2010	2015	2020	2025	2030
Traditional fuels	[%]	8.673	8.673	8.673	8.673	8.673
Modern biomass	[%]	0.000	0.000	0.000	0.000	0.000
Electricity	[%]	37.798	30.740	27.240	16.740	13.240
Soft solar	[%]	0.000	0.000	0.000	0.000	0.000
Fossil fuels	[%]	53.5	60.6	64.1	74.6	78.1

Table 14-10 Efficiencies and other factors for cooking, Urban Household						
Item		2010	2015	2020	2025	2030
Eff. Trad. fuels	[%]	21.053	21.053	21.053	21.053	21.053
Eff. Mod. biomass	[%]	1.000	1.000	1.000	1.000	1.000
Eff. Fossil fuels	[%]	76.754	76.754	76.754	76.754	76.754
Solar share	[%]	1.000	1.000	1.000	1.000	1.000

Table 14-11 Penetration into air conditioning by technology, Urban Household						
Item		2010	2015	2020	2025	2030
Electricity	[%]	100.000	100.000	100.000	100.000	100.000
Non-electric	[%]	0.00	0.00	0.00	0.00	0.00

Table 14-12 Efficiencies for air conditioning, Urban Household						
Item		2010	2015	2020	2025	2030
COP electric AC	[ratio]	2.500	2.500	2.500	2.500	2.500
COP non-electric AC	[ratio]	2.500	2.500	2.500	2.500	2.500

Useful energy demand in Rural Household sector

Table 15-1 Basic data for useful energy demand in Rural Household sector						
Item	Unit	2010	2015	2020	2025	2030
Dwellings	[million]	0.336	0.360	0.380	0.400	0.419
Share of dw. requiring SH	[%]	100.000	100.000	100.000	100.000	100.000
Degree-days	[days°C]	1775.000	1775.000	1775.000	1775.000	1775.000

Tables 15-2 Dwelling factors for space heating and air conditioning, Rural Househol						
Item		2010	2015	2020	2025	2030
Share of Mudhouse/hut	[%]	100.000	100.000	100.000	100.000	100.000
Dw. size. Mudhouse/hut	[sqm]	20.000	20.000	20.000	20.000	20.000
Area h. Mudhouse/hut	[%]	100.000	100.000	100.000	100.000	100.000
H. los. R. Mudhouse/hut	[Wh/sqm/°C/h]	6.300	6.300	6.300	6.300	6.300
Dw. AC. Mudhouse/hut	[%]	0.000	0.000	0.000	0.000	0.000
Spc. req. AC. Mudhouse/hut	[kWh/dw/yr]	0.000	0.000	0.000	0.000	0.000

Table 15-3 Dwelling factors for cooking, hot water and appliances, Rural Household						
Item	Unit	2010	2015	2020	2025	2030
Cooking	[kWh/dw/yr]	*4792.217*	*4792.217*	*4792.217*	*4792.217*	*4792.217*
Dw with hot water	[%]	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*
HW per cap	[kWh/cap/yr]	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*
Electr. cons. for appliaces	[kWh/dw/yr]	*250.771*	*250.771*	*250.771*	*250.771*	*250.771*
Electr. penetration	[%]	*1.816*	*5.497*	*10.000*	*12.000*	*15.000*
FF for lighting	[kWh/dw/yr]	*140.806*	*140.806*	*140.806*	*140.806*	*140.806*

Table 15-4 Calculation of useful energy demand in Rural Household sector

Item	Unit	2010	2015	2020	2025	2030
Space heating	GWyr	0.206	0.220	0.233	0.245	0.257
Water heating	GWyr	0.000	0.000	0.000	0.000	0.000
Cooking	GWyr	0.184	0.197	0.208	0.219	0.229
Air conditioning	GWyr	0.000	0.000	0.000	0.000	0.000
Elec. for appliances	GWyr	0.000	0.001	0.001	0.001	0.002
FF for lighting	GWyr	0.005	0.005	0.006	0.006	0.006
Total	GWyr	**0.395**	**0.423**	**0.448**	**0.471**	**0.493**

Table 15-5 Penetration of energy forms into space heating, Rural Household

Item		2010	2015	2020	2025	2030
Traditional fuels	[%]	73.063	73.063	73.063	73.063	73.063
Modern biomass	[%]					
Electricity	[%]					
(thereof: heat pump)	[%]					
District heat	[%]					
Soft solar	[%]					
Fossil fuels	[%]	**26.9**	**26.9**	**26.9**	**26.9**	**26.9**

Table 15-6 Efficiencies and other factors for space heating, Rural Household

Item		2010	2015	2020	2025	2030
Eff. Trad. fuels	[%]	30.612	30.612	30.612	30.612	30.612
Eff. Mod. biomass	[%]	1.000	1.000	1.000	1.000	1.000
Eff. Fossil fuels	[%]	94.558	94.558	94.558	94.558	94.558
COP heat pumps	[ratio]	1.000	1.000	1.000	1.000	1.000
Solar share	[%]	1.000	1.000	1.000	1.000	1.000

Table 15-7 Penetration of energy forms into water heating, Rural Household

Item		2010	2015	2020	2025	2030
Traditional fuels	[%]	0.000	0.000	0.000	0.000	0.000
Modern biomass	[%]	0.000	0.000	0.000	0.000	0.000
Electricity	[%]	0.000	0.000	0.000	0.000	0.000
(thereof: heat pump)	[%]	0.000	0.000	0.000	0.000	0.000
District heat	[%]	0.000	0.000	0.000	0.000	0.000
Soft solar	[%]	0.000	0.000	0.000	0.000	0.000
Fossil fuels	[%]	100.0	100.0	100.0	100.0	100.0

Table 15-8 Efficiencies and other factors for water heating, Rural Household

Item		2010	2015	2020	2025	2030
Eff. Trad. fuels	[%]	1.000	1.000	1.000	1.000	1.000
Eff. Mod. biomass	[%]	1.000	1.000	1.000	1.000	1.000
Eff. Fossil fuels	[%]	1.000	1.000	1.000	1.000	1.000
COP heat pumps	[ratio]	1.000	1.000	1.000	1.000	1.000
Solar share	[%]	1.000	1.000	1.000	1.000	1.000

Table 15-9 Penetration of energy forms into cooking, Rural Household

Item		2010	2015	2020	2025	2030
Traditional fuels	[%]	67.450	67.450	67.450	67.450	67.450
Modern biomass	[%]					
Electricity	[%]	0.038	0.038	0.038	0.038	0.038
Soft solar	[%]					
Fossil fuels	[%]	32.5	32.5	32.5	32.5	32.5

Table 15-10 Efficiencies and other factors for cooking, Rural Household

Item		2010	2015	2020	2025	2030
Eff. Trad. fuels	[%]	21.053	21.053	21.053	21.053	21.053
Eff. Mod. biomass	[%]	1.000	1.000	1.000	1.000	1.000
Eff. Fossil fuels	[%]	91.228	91.228	91.228	91.228	91.228
Solar share	[%]	1.000	1.000	1.000	1.000	1.000

Table 15-11 Penetration into air conditioning by technology, Rural Household

Item		2010	2015	2020	2025	2030
Electricity	[%]	100.000	100.000	100.000	100.000	100.000
Non-electric	[%]	0.00	0.00	0.00	0.00	0.00

Table 15-12 Efficiencies for air conditioning, Rural Household

Item		2010	2015	2020	2025	2030
COP electric AC	[ratio]	2.500	2.500	2.500	2.500	2.500
COP non-electric AC	[ratio]	2.500	2.500	2.500	2.500	2.500

Useful energy demand in Service sector

Table 17-1 Basic data for useful energy demand in Service sector

Item	Unit	2010	2015	2020	2025	2030
Labour force in SS	[%]	60.000	60.000	60.000	60.000	60.000
Floor area per emp.	[sqm/cap]	8.000	8.000	8.000	8.000	8.000
Labour force in SS	[million]	**0.497**	**0.533**	**0.563**	**0.592**	**0.620**
Floor area of SS	[million sqm]	**3.976**	**4.262**	**4.507**	**4.738**	**4.963**

Table 17-2 Factors for space heating and air conditioning

Item		2010	2015	2020	2025	2030
Share of area req. SH	[%]	75.000	75.000	75.000	75.000	75.000
Area actually heated	[%]	80.000	80.000	80.000	80.000	80.000
Specific SH req.	[kWh/sqm/yr]	1873.534	1873.534	1873.534	1873.534	1873.534
Air cond. floor area	[%]	80.000	80.000	80.000	80.000	80.000
Specific cooling req.	[kWh/sqm/yr]	45.200	31.534	31.534	31.534	31.534

Table 17-3 Useful energy demand for space heating and air conditioning

Item		2010	2015	2020	2025	2030
Total area heated	[million sqm]	**2.385**	**2.557**	**2.704**	**2.843**	**2.978**
Space heating	GWyr	**0.510**	**0.547**	**0.578**	**0.608**	**0.637**
Air conditioning	GWyr	**0.016**	**0.012**	**0.013**	**0.014**	**0.014**

Energy intensities for end-uses other than space heating and

Table 17-4 Energy intensities of Motor fuels

Item		2010	2015	2020	2025	2030
Service	[kWh/US$]	0.000	0.000	0.000	0.000	0.000

Table 17-5 Energy intensities of Electricity specific uses

Item		2010	2015	2020	2025	2030
Service	[kWh/US$]	0.054	0.054	0.054	0.054	0.054

Table 17-6 Energy intensities of Other thermal uses

Item		2010	2015	2020	2025	2030
Service	[kWh/US$]	2.154	2.154	2.154	2.154	2.154

Useful energy demand for end-uses other than space heating

Table 17-7 Useful energy demand of Motor fuels

Item		2010	2015	2020	2025	2030
Service	GWyr	0.000	0.000	0.000	0.000	0.000

Table 17-8 Useful energy demand of Electricity specific uses

Item		2010	2015	2020	2025	2030
Service	GWyr	0.007	0.008	0.010	0.012	0.014

Table 17-9 Useful energy demand of Other thermal uses

Item		2010	2015	2020	2025	2030
Service	GWyr	0.260	0.316	0.385	0.468	0.570

Table 17-10 Total useful energy demand in Service sector

Item		2010	2015	2020	2025	2030
Space heating	GWyr	0.510	0.547	0.578	0.608	0.637
Air conditioning	GWyr	0.016	0.012	0.013	0.014	0.014
Motor fuels	GWyr	0.000	0.000	0.000	0.000	0.000
Electricity spec. uses	GWyr	0.007	0.008	0.010	0.012	0.014
Other thermal uses	GWyr	0.260	0.316	0.385	0.468	0.570
Total	GWyr	0.793	0.884	0.986	1.102	1.235

Electricity Supply Cost of Service Study – LEWA Lesotho

Determination of Medium to Long Term Development Programs – Deliverable 4

Support Provided by African Development Bank

Prepared for: LEWA

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Contents

LIST OF ACRONYMS

BoS	Bureau of Statistics
COSS	Cost of Service Study by MRC
GDP	Gross Domestic Product
GoL	Government of Lesotho
HPP	Hydro Power Plant
IAEE	International Atomic Energy Agency
LEC	Lesotho Electricity Corporation
LEWA	Lesotho Energy and Water Authority
LHDA	Lesotho Highlands Development Authority
LHWP	Lesotho Highlands Water Project
LDC	Load Duration Curve
LRMC	Long-Run Marginal Cost
MAED	Model for Analysis of Energy Demand
NEMP	National Electrification Master Plan
PPA	Power Purchase Agreement
SE4ALL	Sustainable Energy for All
SAPP	The Southern African Power Pool
SREP 2017	Renewable Energy Options Study Scaling-Up Renewable Energy Program: Investment Plan for Lesotho (March 2017)
TAF	Technical Assistance Facility

1 Introduction

This report provides the fourth deliverable of the Electricity Cost of Service Study being carried out by the MRC Group for LEWA supported by the African Development Bank. The objective of this report is to present the approach, assumptions and results of the analysis that projects the development of power generation, transmission and distribution to 2030.

This report is organised as follows: Section 2 reviews LEC's existing system development plan, this is followed by Section 3 exploring potential developments in SAPP. Section 4 provides a general description of the modelling methodology applied. Section 5 lists the data sources for the specific application and Section 6 describes the results.

The development programs presented in this report are key inputs to the following stages of the cost of service study. It is therefore essential that the approach and data used in the analysis as presented here are understood and agreed by the Study Technical Committee (STC), such that the STC validate our approach and agree to the input data used in time to enable the development programs to serve as key confirmed inputs to the computations of economic tariffs and the proceeding analyses.

To align with the reporting, data workbooks have been developed to distinguish between data for generation, transmission and distribution. This workbook has been formatted clearly to allow for any updates or inputs resulting from new data or future studies. This workbook will be made fully available to the STC if required.

A least cost expansion plan is necessarily an assessment of the least cost of all investments required to meet the demand projection - that is investments involved in each of generation, transmission and distribution. The modelling for least cost expansion therefore is a single model involving these three elements that has been constructed considering a disaggregated approach to deriving expansion plans for generation, transmission and distribution. It was expected in the study scope that the work would be reported in three separate expansion program reports on generation, transmission and distribution. Having now undertaken the analysis we consider that separate reports would confuse the interactions and overlaps that the model has revealed and that therefore a single report covering all developments to be more logical and more useful.

2 Existing Development Plan

We have examined all available data on development plans for generation, transmission and distribution. We have established that LEC has a grid network (transmission and some distribution) development plan to 2030.

Our understanding is that this grid development is driven by demand projections due to natural growth, GoL initiatives towards increasing access to electricity (e.g., the National Electrification Master Plan for Lesotho, 2007 and hence to maintain the current connection rate of around 15,000 new connections per year) and improving security and quality of supply of the network.

The following subsections discuss assumptions adopted for the plan.

2.1 Demand Projections

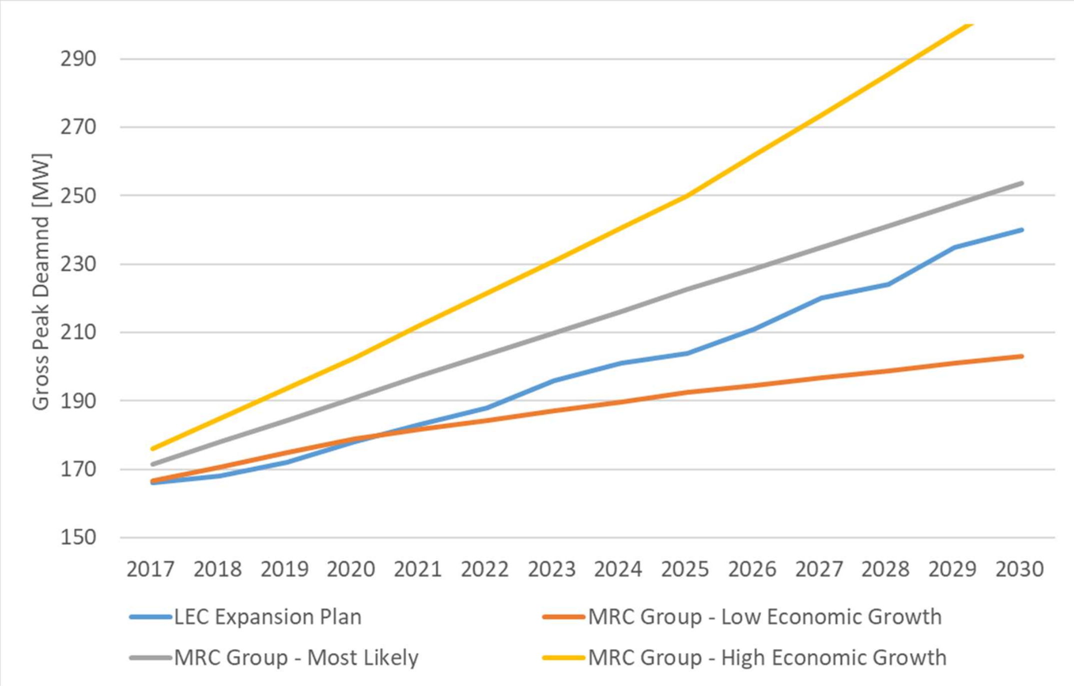
Figure 1 shows LEC's assumption for system gross peak MW per year used in their development plan. This is compared to the three gross peak demand forecasts (most likely, low and high growth) from the MRC Group projection from deliverable 3.[1]

The comparison demonstrates that the peak demand projection is somewhat different to the most likely demand projection from deliverable 3. An energy demand projection for LEC's development plan was not provided and so a comparison in energy terms could not be undertaken.

As presented in the deliverable 3 report the most likely scenario for on-grid final energy consumption is based on on-grid electrification rates of 44% in 2020, 50% in 2025 and 54% in 2030. Furthermore, despite average consumption per household reducing and a reduction in the rate of new connections, overall residential demand is expected to increase. Demand from industrial and service sectors also increases in all scenarios with the rate of increase shown to be sensitive to the assumed rate of GDP growth.

[1] The figures shown include two adjustments relative to Figure 6 of the deliverable 3 report: 1) the raw demand from MAED is scaled to account for an assumed value of aggregate transmission and distribution losses (around 14%, the MAED figures used for deliverable 3 did not include losses); and 2) the 2010 system load profile used for the demand calibration is replaced with the more recently made available 2015 system load profile.

Figure 1: Gross Demand projection from LEC's development plan 2017-30



2.2 Generation Development

LEC has indicated that the DoE is responsible for planning the development of new long-term generation. However, LEC is responsible for initiatives to resolve short term power deficits and has provided the list of such projects as shown in Table 1.

Table 1: New generation projects and timings included in LEC's development plan

Technology	Location	Capacity (MW)	Planned construction start	Expected commissioning	LEC expected cost (US$/kW)
Solar	Mafeteng	40	2019	2020	750
Solar	Semonkong	10	2019	2020	1,000
Wind	Semonkong	20	2019	2022	1,250
Wind	Mphaki	50	2021	2022	1,600
Hydro	Upgrade Mantsonyane	10	2022	2025	4,000
Hydro	Senqu HPPs (cascades)	500	2021	2030	2,000
Total		**630**			

It is not clear how LEC have estimated the 500 MW hydro power capacity associated with the Senqu River system cascade as this does not correspond with the hydro power potential identified in the

2009 SSI Lesotho Generation Master Plan. The potential identified in that study is shown in Table 2 - showing 54.63 MW of potential on the Senqu River system.[2]

Table 2: Hydro power potential identified in the 2009 SSI Lesotho Generation Master Plan

Site	River	Cascade	Installed Capacity (MW)	Annual Generation (GWh)
Hlotse HPP	Holtse	Holtse	6.5	39.7
Phuthiatsana HPP	Phuthiatsana	Phuthiatsana	5.4	18.87
Khubelu HPP	Khubelu	Senqu	14.6	64.26
Polihale HPP	Polihale	Senqu	19.3	83.89
Tsoelike HPP	Tsoelike	Senqu	17.7	69.86
Makhaleng 1 HPP	Makhaleng	Makhaleng	2	15
Makhaleng 2 HPP	Makhaleng	Makhaleng	1.4	6.15
Makhaleng 3 HPP	Makhaleng	Makhaleng	8.9	39.4
Makhaleng 4 HPP	Makhaleng	Makhaleng	9.1	58.3
Quthing 1 HPP	Quthing	Senqu	0.63	2.31
Quthing 2 HPP	Quthing	Senqu	2.4	9.61
Total			**87.93**	**407.35**
Total Senqu river			**54.63**	

The solar and wind plants listed in Table 1 were also identified in the Renewable Energy Options Study Scaling-Up Renewable Energy Program: Investment Plan for Lesotho (March 2017) (SREP 2017). For comparison, the potential capacity identified in this plan was 290 MW for solar (LEC listed 50 MW) and 432.7 MW for wind (LEC listed 70 MW).

Our analysis of the assumed capex costs of these technologies indicate that they are low relative to international standards for the region. For example, the SREP 2017 study anticipated capex costs for solar in the range 1,620-2,730 US$/kW where as LEC have indicated 750-1,000 US$/kW. For wind SREP anticipated capex costs of 2,500 US$/kW where as LEC have indicated 1,250-1,600 US$/kW. A further discussion on this is given in section 5.6.

2.3 Transmission and Distribution Development

LEC's network development plan consists of a total capital expenditure of US$193 million (2.513 billion loti) for projects expected to be commissioned over the period 2018-2024. The projects consisting of

[2] The SSI Master Plan also included an 1,800 MW pumped storage project at Quthing. Pumped storage capacity at this scale would only be justified at a regional level which is beyond the scope of this study. It is therefore not included.

line upgrades are shown in Table 3 (US$112.5m) with other upgrades (e.g., substations etc, total US$80.2m) are included in Table 36 (Annex B).

A number of these transmission and distribution upgrades are needed to keep pace with the demand growth – for example to reinforce the network to increase power supply to the Letseng mines – whereas others are for expanding the network to improve security and quality of supply.

Table 3: New power lines as part of LEC's development plan

From	To	Voltage	Total cost (Maloti m)	Total cost (US$m)	Cost ($/km)
Mphaki	Sekake	33kV	29.0	2.23	44,615
St Agnes	Maputsoe	33kV	24.0	1.85	36,923
Maputsoe	Mapoteng	33kV	29.0	2.23	55,769
Thaba Tseka	Mokhotlong	33kV	44.0	3.38	45,128
Morija	Kolo	33kV	18.0	1.38	46,154
Botshabelo	Ha Makhoathi	33kV	9.0	0.69	46,154
Hlotse	Buth-Buthe	33kV	15.0	1.15	46,154
Katse	ThabaTseka	66kV	53.0	4.08	81,538
Muela	Khukhune	132kV	24.0	1.84	230,769
Khukhune	Ha Belo	132kV	53.0	4.08	163,077
Liqhobong	Lemphane	132kV	53.0	4.08	163,077
Letseng	Mothae	33kV	9.0	0.69	46,154
Mazenod	Qacha's Nek	132kV	338.0	26.00	161,491
Mazenod	Thetsane	132kV	53.0	4.08	163,077
Mt Moorosi	Mosi	132kV	147.0	11.31	161,538
Lejone	Polihali	132kV	168.0	12.92	161,538
Polihali	Mokhotlong	132kV	7.0	0.54	67,308
Letseng	Mokhotlong	132kV	126.0	9.69	161,538
Khukhune	Letseng	132kV	158.0	12.15	162,051
Letseng	Liqhobong	132kV	105.0	8.08	161,538
Total			**1462.0**	**112.46**	

Where appropriate, data from the LEC development plan has been integrated into the development plan model developed for this deliverable. There is more discussion on this in Data Sources - Section 5.

3 Potential Developments in SAPP

Lesotho is part of the South African Power Pool (SAPP).

The high voltage grid in Lesotho is connected to SAPP via two 132kV circuits at Maseru and Clarens. SAPP rate the aggregate interconnector capacity as 230 MW.[3] Remoter parts of Lesotho are separately connected to SAPP at Qacha's Nek and Thaba Seka.

An important consideration for the development plan is to establish whether there is ample generation in the SAPP system and Lesotho can continue to import capacity and energy as required.

Since the inception of SAPP in 1995, new entrant capacity has increased by on average 1,290 MW per year with a significant increase in the level of interconnection between member countries.[4] Table 4 shows the breakdown of current installed and operating capacity in SAPP and projected new generating capacity entry over the next 5 years.[5]

Table 4: Current installed and operating capacity in SAPP and projected new generating capacity entry over the next 5 years

SAPP country	Existing		New Capacity					
	Installed (MW)	Operational (MW)	2017	2018	2019	2020	2021	2022
Angola	2,210	1,772	2,571	200				
Botswana	927	459	120		300	300		
DRC	2,442	1,066	150			360		1500
Lesotho	74	70	20					
Malawi	352	351	36	12	132	340	310	100
Mozambique	2,724	2,279		100			900	1900
Namibia	501	354			800			
RSA	42,710	35,563	999	2,169	2,169	1,446	1,446	1,528
Swaziland	70	55			12			
Tanzania	1,380	823	900	1,040	250	1000		
Zambia	2,206	2,175	15	113	300	790	930	1200
Zimbabwe	2,045	1,555	120	540	630	600	2,210	1,200
Total	**57,641**	**46,522**	**4,931**	**4,174**	**4,593**	**4,836**	**5,796**	**7,428**

SAPP also provide a projection for peak demand (MW) and an "energy forecast" (GWh) to 2025. This forecast provides an estimate of total energy requirements (demand including losses) for the SAPP region.[6] This is shown in Table 5 and Table 6, respectively.

[3] SAPP Annual report for 2016.

[4] SAPP Annual report for 2016.

[5] Current capacity taken from SAPP website and projection for new capacity from *"Meeting growing power demands through Southern African regional integration"*, SAPP, SAREE/IRENA Workshop, Windhoek, Namibia, April 2017: www.irena.org/eventdocs/SAPP.pdf

[6] SAPP Annual report for 2016 with an adjustment to Eskom data. A comparison of the 2016 SAPP figures for RSA (41,755 MW peak demand) with the equivalent data from Eskom (34,122 MW peak demand, Source: Eskom Integrated Report, 2017, p54) indicates that the peak and energy forecasts look high. Consequently, the Eskom portion of the projection was pro-rated down so that the peak and energy figures aligned with the Eskom Integrated Report for 2016/17 year.

Table 5: SAPP forecast for peak demand (MW) 2017-22 (with adjustments to RSA data to align with Eskom reporting)

Participant	Country	2017	2018	2019	2020	2021	2022	2023	2024	2025
ENE	Angola	1,872	1,987	2,109	2,226	2,347	2,472	2,601	2,734	2,871
BPC	Botswana	854	877	902	924	959	1,030	1,055	1,091	1,111
SNEL	DRC	3,503	3,592	3,685	3,783	3,886	3,994	4,107	4,225	4,350
LEC	Lesotho	154	160	167	175	182	190	198	207	215
ESCOM	Malawi	459	503	522	541	560	577	594	611	629
EDM	Mozambique	768	795	822	876	939	1,007	1,079	1,157	1,240
NamPower	Namibia	656	748	759	771	783	795	806	818	830
Eskom	RSA (adjusted)	35,167	36,178	37,181	38,211	39,439	40,638	41,843	43,007	44,344
SEC	Swaziland	287	293	300	304	308	311	315	319	323
TANESCO	Tanzania	2,088	2,522	2,698	2,881	3,067	3,274	3,498	3,743	4,017
ZESCO	Zambia	3,314	3,392	3,472	3,552	3,652	3,752	3,852	3,952	4,052
ZESA	Zimbabwe	2,795	2,895	3,053	3,174	3,270	3,384	3,515	3,640	3,751
	Total	51,917	53,942	55,670	57,418	59,392	61,424	63,463	65,504	67,733

Table 6: SAPP energy forecast (GWh) 2017-22 (with adjustments to RSA data to align with Eskom reporting)

Participant	Country	2017	2018	2019	2020	2021	2022	2023	2024	2025
ENE	Angola	10,658	11,316	12,008	12,674	13,364	14,077	14,812	15,568	16,345
BPC	Botswana	5,919	6,247	6,744	6,848	6,949	7,049	7,147	7,243	7,336
SNEL	DRC	21,719	22,270	22,847	23,455	24,093	24,763	25,463	26,195	26,970
LEC	Lesotho	674	703	733	765	797	832	867	905	944
ESCOM	Malawi	2,761	2,866	2,973	3,081	3,190	3,284	3,380	3,479	3,581
EDM	Mozambique	4,695	4,869	5,042	5,389	5,777	6,193	6,639	7,117	7,629
NamPower	Namibia	4,289	4,496	4,663	4,838	4,966	5,143	5,338	5,579	5,767
Eskom	RSA (adjusted)	228,311	234,927	242,200	249,586	257,245	265,019	272,885	280,757	289,002
SEC	Swaziland	1,624	1,658	1,698	1,720	1,743	1,760	1,783	1,805	1,828
TANESCO	Tanzania	14,456	15,336	16,276	17,363	18,476	19,718	21,057	22,526	24,160
ZESCO	Zambia	19,384	19,553	19,760	19,968	20,177	20,387	20,597	20,809	21,021
ZESA	Zimbabwe	14,688	15,975	17,381	18,629	19,481	20,160	20,938	21,684	22,346
	Total	324,149	335,794	347,489	359,711	371,975	384,032	396,251	408,778	421,912

Figure 2: Estimate of maximum production from existing and potential new generation in SAPP 2017- 2022 against total energy requirements forecast (GWh)

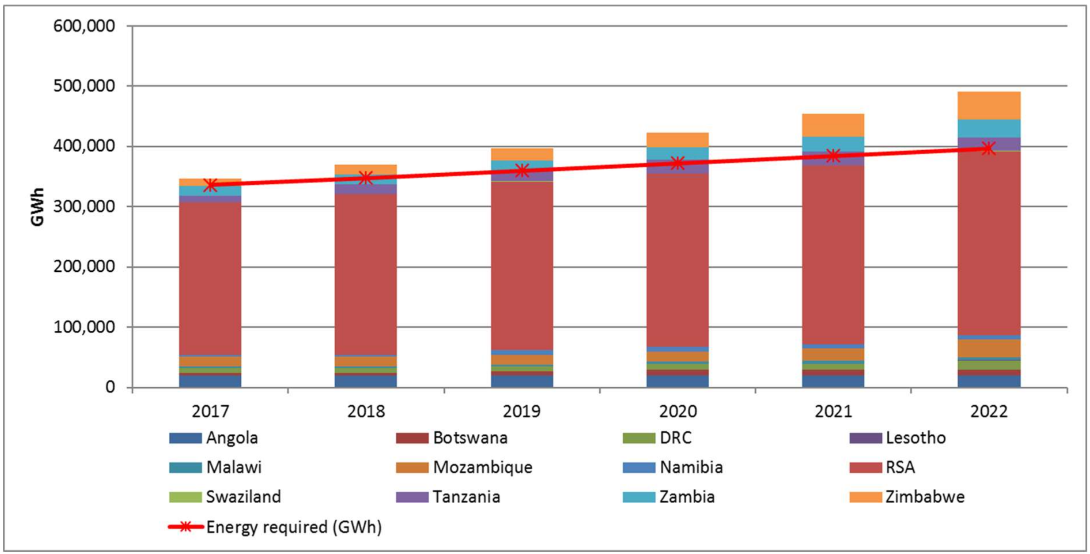


Figure 3: Estimate of operating capacity from existing and potential new generation in SAPP 2017-2022 against the forecasted peak demand (MW)

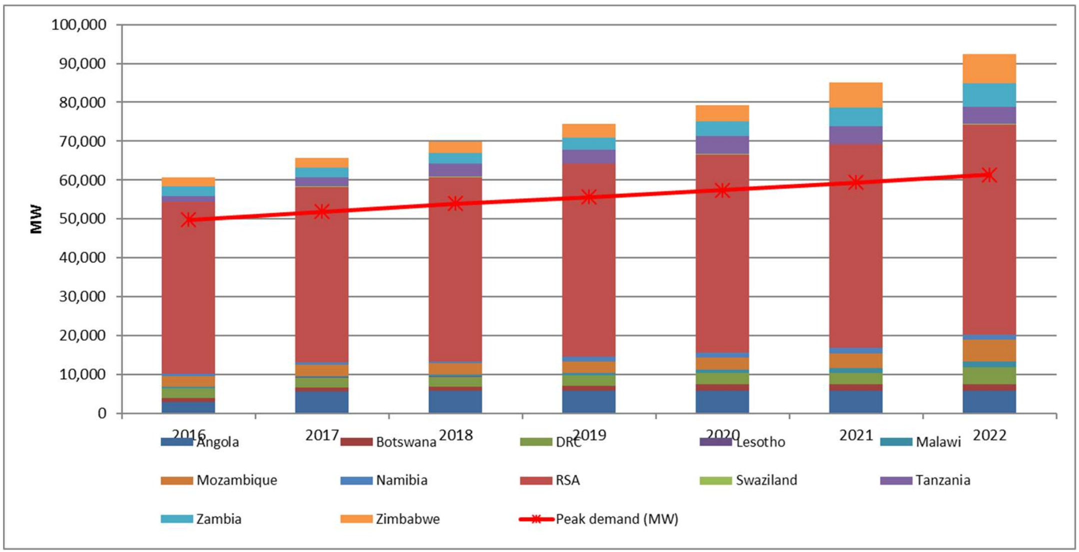
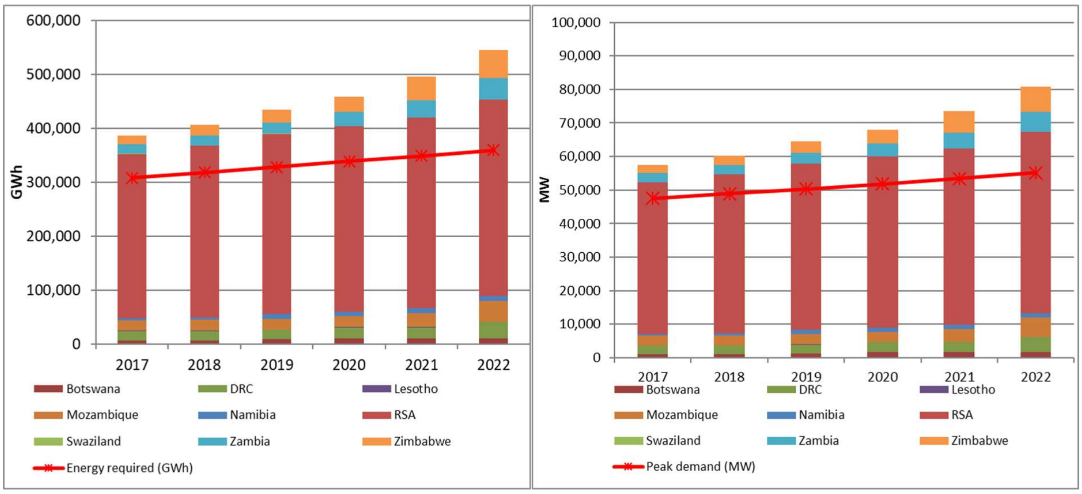


Figure 2 shows the consultants estimate of production from existing and potential new generation to 2022 against the total energy forecast. Figure 3 shows the projection of installed operational capacity and peak demand. The aggregate new capacity in Table 2 is distributed by technology based on the potential capacity by technology identified in a 2013 IRENA Study for the SAPP region.[7] Capacity factors used to derive production from new generation are estimated using the same study. The graph indicates that there is sufficient generation to meet the energy forecast and, in fact a surplus in later years. Projections beyond 2022 are more uncertain, however assuming a similar rate of growth in new

[7] SAPP: Planning and Prospects for Renewable Energy, IRENA 2013, Appendix C. www.irena.org/DocumentDownloads/Publications/SAPP.pdf

capacity then the analysis suggests that there will be ample generation in the SAPP system and Lesotho can continue to import capacity and energy as required. **It is important to note here, however, that there is significant uncertainty surrounding the validity of these expansion plans for the region. Furthermore, the non-operating members of SAPP, namely ENE (Angola), ESCOM (Malawi) and TANESCO (Tanzania) are unlikely to be interconnected into SAPP until about 2025, and thereafter. The adjustment to Figure 2 and Figure 3 of this is shown in Figure 4. It is therefore essential to explore the uncertainty in these plans, along with associated availability and costs of imported power, as part of the modelling work undertaken in this CoSS**.

Figure 4: Impact in SAPP of maximum production (left) and operating capacity (right) of excluding ENE (Angola), ESCOM (Malawi) and TANESCO (Tanzania) from the SAPP projection. Note the energy required and peak demand have also been adjusted.



Although the outlook for energy availability is good, it is worth noting that SAPP does currently suffer from tight reserve margins. For example, in 2016 SAPP had an installed capacity of 61,894 MW of which 46,959 MW was operational. Peak demand including operating reserve requirements was 52,542 MW meaning there was a shortfall of 5,593 MW.[8] However, it is hoped that with the commissioning of new capacity over the coming years the margin will increase.

[8] SAPP Annual report for 2016.

4 Methodology

The MRC team have selected and implemented the most appropriate approach for development plan modelling. This section 3 details the overall broad methodology which has been applied, with more specific and detailed information covered in section 5.

In the absence of an existing model from LEC, one has been developed. We have proposed to use an MS-Excel based modelling approach. This model includes all necessary functionality and the complexity of the model is reasonable, with transparency achieved. The box-out below reviews the functionality, complexity and transparency in more detail.

Figure 5: Review of the functionality, complexity and transparency of the developed model

The developed model applies principles of dynamic optimisation programming while recognising that the **complexity** of the expansion model is typically proportional to (1) the system being represented (2) the accuracy and uncertainty of the data; and (3) the capabilities of the intended users. The model is implemented to calculate three disaggregated parts of the expansion plan:

1. the net present value (NPV) of the generation cost of meeting the forecast demand subject to the operational and cost characteristics of generation and interconnection and any supply reliability criteria;
2. the net present value (NPV) of the transmission cost of meeting the forecast demand and generation background; and
3. the net present value (NPV) of the distribution cost.

The sum of these NPV metrics is taken as a proxy for total system costs and is used to rank possible development plans to determine the least cost option. This approach applies many of the principles of dynamic optimisation programming but instead of implementation being in a "black-box" complex mathematical software we instead give priority to transparency and usability and the developed model therefore does not consider all possible futures instantaneously but is an approach that is aligned with the perceived simpler nature of the Lesotho power system and limited number of outcomes over the planning horizon. The MS Excel model developed therefore allows for the computation of a single development plan at a time but has been developed to enable efficient testing of alternative scenarios and sensitivities.

The **functionality** includes a representation of existing on-grid supply (including interconnection with SAPP) and its utilisation to meet demand. The model includes a computation of per year disaggregated generation, transmission and distribution system costs over the planning horizon to meet the forecast demand including expansion of supply as required. The key model inputs are accessible and user-adjustable bearing in mind the objective to allow for testing a coherent set of sensitivities within the context of the prevailing policies in the Lesotho power sector (e.g., options for electrification of rural customers). The model allows for straight-forward viewing of key system indicators such as total costs, installed capacity, production by technology/source, volumes and timings of new investments and any anticipated unserved energy.

The advantage of **transparency** is that the model can be more easily explained to individuals who were not involved in its development. The modelling tool can be handed over at the end of the project and can allow LEWA to maintain an up to date least cost development plan for transmission, distribution and generation. Furthermore, the model calculations and assumptions are available and therefore all aspects of the model can be reviewed and audited.

This section provides explanatory notes on the methodological approach adopted by the consultants – an important guide to how the model functions and therefore to the source of the results. This section will also be useful for knowledge transfer when the model is taken over by LEWA.

4.1 Disaggregated System Planning

Simply put, the 2017-30 planning objective of this deliverable is to find the optimal capacity expansion in response to demand growth (including transmission and distribution losses), existing asset retirements (generation, transmission and distribution) and resource and modelled policy constraints (e.g., any goal to reduce reliance on imported power or meet a target reliability criterion). Over-supply can lead to stranded assets and consumers over-paying for capacity that is never used, under-supply can lead to consumers experiencing frequent load shedding (or worse, blackouts).

4.2 Generation Expansion

Disaggregated generation planning should be done to meet the peak demand condition plus (optionally) the cost of supply reliability standards (modelled as an implicit target capacity planning margin) and other constraints[9]. The generation expansion provides the cost of new generation investment and expected despatch costs.

To calculate the NPV of future generation costs a discount rate needs to be applied. This could be considered as the **social discount rate**. It is necessary to use one social discount rate, which will apply to all elements of the total generation cost function (i.e., variable, fixed, and investment costs) to provide the net present value of costs across the planning horizon. The costs are all in present discounted value terms (e.g., 2017 real). The degree of discounting reflects the time value of money. The mathematical description of the generation costs function is provided in Annex A. The model is set up to include two historic years to allow for, where possible, calibration and validation of outputs. The time horizon of the model is therefore 2015-30 although the model can include up to 2035. The years 2015 and 2016 are not included in the total system cost equation. The model years represent financial years in order to line up with the tariff review periods (e.g., April – March).

The LRMC of generation can be determined following increments of load at the peak demand condition. The LRMC calculations for the base case expansion plan presented here are also included in Task 4 (deliverable 5) for the calculation of economic costs and tariffs.

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[9] Model constraints include, for example, reliability requirements, technology investment limits, plant availability (year-round and at peak demand) and renewable generation resource availability.

4.2.1 Reliability Criterion

Power generation adequacy represents the ability of generators to meet the aggregate power and energy requirements of all consumers at all times. To ensure a given level of generation adequacy in the planning process, the model includes a calculation to verify that the sum of expected available capacity of all generators (including expected import availability) and interconnectors at system peak demand to be sufficiently high to give an acceptable level of security of supply risk. This is termed the "security" constraint.

The model security constraint is based on a peak de-rated capacity margin, which is the capacity margin adjusted to take account of the expected capability of generation to contribute to peak demand if needed.[10] Specific expected availabilities can be applied to each type of generation technology in the model. In simple terms, each generator's capacity is scaled by its expected contribution to meeting the peak demand to give a de-rated capacity. These de-rated states are summed, and the total de-rated margin over peak demand is calculated. For example, if there are two units, each rated at 10 MW with expected availability at peak of 90%, then the total de-rated capacity is given by 0.9*10 + 0.9*10 = 18 MW. If the expected peak demand is 15 MW, then the expected de-rated margin is 18/15 – 1 = 0.2 (or 20%). The use of de-rated margin is preferable when calculation of an absolute level of risk is difficult, and it provides a robust alternative[11] to the full capacity margin.

The security margin is reported as part of model outputs.

If an absolute level of risk was to be determined, then this can be done considering the system Loss of Load Probability (LOLP). The greater the installed capacity, the smaller the number of load shedding hours and lower the LOLP. This reduces the cost of unserved energy, although it increases the cost of serving load (cost of additional capacity). The Value of Loss Load (VOLL) and total fixed costs of the most expensive peaking generator can be used to determine the optimal level of reliability, or duration of load shedding, from the point of view of society.

There is currently no LOLP-based reliability standard for Lesotho but in a developing economy, such as that of Lesotho, where economic productivity is of low energy intensity, the unserved energy criterion could be set at about 3 days per year of total black-out, which is a LOLP of about 0.8%. On the same basis the VOLL could be set US$ 0.75-1.0/kWh. This is something that could be considered in a future analysis once reliability standard is implemented and the VOLL confirmed[12] but the optimal level of unserved energy based on the LOLP is not considered in this application.

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[10] For example, conventional generators suffer from the risk of being unavailable due to a mechanical fault and renewable generators suffer from the risk of low availability due to resource uncertainty, which is also correlated with the availability of other renewable generators of the same fuel type.

[11] Mathematically there is more to de-rated margins than the description given here; the "optimal" level of de-rated margin depends on the mix and amount of capacity and level and uncertainty of the forecast peak demand, however detailed calculation of optimal de-rated margins is beyond the scope of this project.

[12] The issue with the VOLL discussed at great length by market designers, is what is the VOLL exactly? In theory, the inelasticity of demand means VOLL is typically very high and there is a willingness of consumers to pay up to the VOLL when there is a shortage to avoid disconnection without notice. Depending on its use, electricity is valued very differently. For example, a hospital will place a much higher value on its energy supply than a domestic user running a washing machine. Furthermore, the load centers are highly integrated, with currently no method of disaggregation within a region. Therefore, it is largely impossible to provide different levels of reliability within a geographical region and defining a single VOLL figure remains a contentious issue.

4.2.2 Generation Investment (Located in Lesotho)

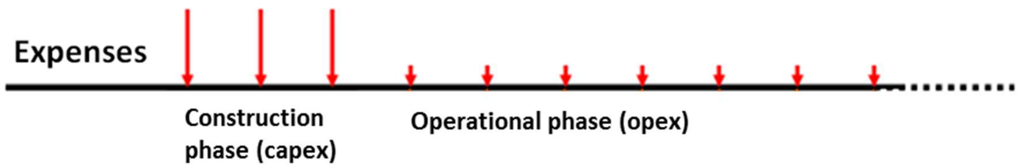
Candidates for generation investment are defined for hydro, solar, wind and biomass. The candidates are given an (inputted) entry year, construction period (years), capacity minimum investment size[13] and number of years over which the investment can occur. The capacity minimum investment size multiplied by the number of years must be less than the maximum MW limit on the total investment in the technology.

Lifetime operating expenditures are discounted to the first year of the analysis to reflect the real cost of a project. Capital costs are discounted assuming constant expenditure during construction (a uniform per year capital expenditure across the construction period, which is not user-adjustable). In the event that the lifetime of the asset exceeds the optimisation horizon, capital expenditures are scaled down to take into account the residual value of the investment (see Annex A).

Each candidate technology can be assigned a different risk profile or discount rate, which is reflected in the capital expenditure element of the project only. Different discount rates represent investor views of the risks and potential returns associated with those technologies. More precisely, an "additional capex" input is derived; this reflects the difference in interest accumulated across the construction period (more if for a project with a high risk perception, and less if lower). The derivation of additional capex is provided in Annex A.

Figure 6 summarises how expenditure is modelled as capital and operation expenditures. Note that this does not include generator revenues or costs incurred by LEC through the purchase of this power through PPAs for new generation as the model objective is to minimise total system costs. In this type of model, for this deliverable, we do not represent the optimisation of an investor's portfolio of generation or any "non-rational" investment drivers (like asymmetrical attitudes to risk). Instead, each investment is made on purely rational economic grounds to minimise the overall cost of supply.

Figure 6: Expenditure associated with candidate projects



Investment costs for assets that exist at the start of the simulation (e.g., Muela) are not considered, instead the cost of these plants is captured through production costing at market despatch (see section 4.9).

There are no wind or solar plants operating in the initial years of the model, but candidates for investment in these technologies are considered. The long-term representation of weather dependant renewable sources wind and solar and any new hydro is based on availability factors of power generation during the year.

The wind, solar and hydro potential in Lesotho while known to be significant and potentially economic is not well defined. There is a lack of overall resource data and little specific project identification even

[13] Investment in new generation and transmission are typically made in "lumps" proportional to the size of the power system. For example, wind plants are relatively small "lumps" of investment (e.g., 5 or 10 MW at a time), but transmission networks are more "lumpy".

at a rudimentary pre-feasibility study level. The model therefore assumes that the wind, solar and new hydro energy availability factor for new plants is the same in each load duration curve block (i.e., a uniform availability across the year). The model includes a separate peak capacity availability factor for calculating the contribution of this generation to the reserve requirement for security of supply, if applied.

When more detail becomes available on the resource characteristics and when specific projects and locations are defined, expansion planning may need to add the capability to consider the daily, weekly and monthly variability of renewable resources and their interdependency with fluctuations in demand. The consultant considers that modelling these interdependencies would only have a small impact on the results, likely to be secondary to the significant uncertainties associated with the resources characteristics and the estimated costs of their development.

The energy availability factors, times the capacity, times the block duration, provides the maximum production (e.g., MWhs) that can contribute to meeting demand in each load block including the peak demand condition.

The model assumes that any new power plant built will not retire before the end of the planning horizon in 2030 and therefore any decommissioning costs do not apply.

The model also considers pseudo-generating units not located in Lesotho that follow the structure of imports from SAPP – these are discussed in section 4.8.

4.3 Transmission Expansion

Disaggregated transmission planning should be done to meet the peak demand condition plus (optionally) the cost of supply reliability standards (e.g., system secured up to an N-1 loss of equipment event). The transmission expansion provides the cost of new transmission investment. Similarly to generation expansion modelling, to calculate the NPV of future generation costs a discount rate needs to be applied. The mathematical description of the transmission costs function is provided in Annex A.

The LRMC of transmission for the base case expansion plan presented here are also included in Task 4 (deliverable 5) for the calculation of economic costs and tariffs.

4.3.1 Transmission Investment

Candidates for transmission investment are included in the model. Candidates for transmission expansion are defined for lines, substations transformers, switchgear and other upgrades.[14]

Large-scale generation projects (e.g., hydro) may require transmission investment to accommodate them. These investments could involve local works (i.e., to connect the generation plant directly to the grid) or wider works to alleviate deeper bottlenecks on the network located far from the additional generation that might arise due to the transporting of additional power.

[14] For example, costs associated with feasibility studies or customer compensation for through/close to community routing (although these costs are expected to be low relative to the main upgrades and are not associated with construction lead times or interest during construction).

For large complex power systems, it is common that the decision to undertake wider works may be contingent on multiple generation projects and so, from a least cost perspective, the decision to invest would need to take into consideration the timing and location of multiple rather than single generation projects. Consideration of these combinatorial decisions would add complexity to the model.

Given the relatively small footprint of the Lesotho power network, it seems reasonable to assume that wider works with these contingent decision processes are not applicable and any transmission investment needed to realise the full benefits of new generation investment would be part of the same investment decision. To address this the capex for new generation should be inputted including the cost for transmission development needed to accommodate these additions and the separately defined candidates for network development are pertaining to demand (new connections and existing) growth only. The data used for these costs is described in Section 5.2, 5.6 and 5.7.

4.3.2 Largest Loss of Infeed

In addition to planning to ensure an overall security margin, most reliable power systems also plan to limit the power infeed loss risk. Whereby following a fault or outage of a transmission circuit no loss of power infeed shall occur where the loss of power infeed would be the sum of the registered capacities of the generating units disconnected from the system following the secured event (e.g., circuit outage).

In Lesotho, although there are no network security or planning standards in place, it is our understanding from LEC that the transmission expansion plan has been determined to ensure improved reliability of the network and we therefore believe, given time, the network will have sufficient spare capacity so that the system is secured against a loss of a single piece of equipment (e.g., an N-1 circuit outage event), although this is unlikely to be achieved during the next few years but, if the necessary funding is available, could be an achievable target for 2030.

4.4 Distribution Expansion

Disaggregated distribution planning should be done to meet the peak demand condition. The distribution expansion provides the cost of new distribution investment. Similarly, to calculate the NPV of future distribution costs a discount rate needs to be applied. The mathematical description of the distribution costs function is provided in Annex A.

The LRMC of distribution for the base case expansion plan presented here are also included in Task 4 (deliverable 5) for the calculation of economic costs and tariffs.

4.4.1 Distribution Investment

Candidates for distribution investment are also included. Candidates for distribution expansion are defined for lines, substations transformers, switchgear and other upgrades.[15]

[15] For example, costs associated with feasibility studies or customer compensation for through/close to community routing (although these costs are expected to be low relative to the main upgrades and are not associated with construction lead times or interest during construction).

4.5 Total System Costs

The disaggregated generation, transmission and distribution expansions plans described above can be combined to give the total costs of the expansion program. This is calculated as the net present value (NPV) of total system costs over the entire planning horizon. These "total system costs" are[16]:

- the cost of new generation investment and expected despatch costs – from the generation expansion program;
- the cost of new transmission network investment – from the transmission expansion program; and
- the cost of distribution network investment (including cost of new connections) - from the distribution expansion program.

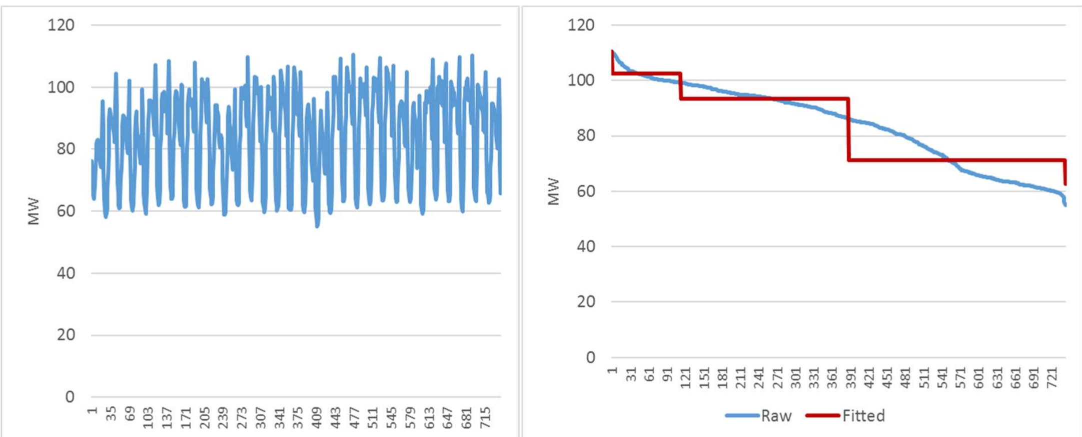
4.6 Demand

Demand is represented as a load-duration curve (LDC). The LDC is equivalent to the load-over-time curve sorted in order of decreasing power.

In general, the duration of the LDC ranges from one day or week to a whole year and can be used to reveal hourly, weekly/weekend and seasonal variations. Typically, the higher the number of LDCs used, the more detailed representation of load will result but at the expense of higher computation times. In this application, monthly load duration curves to capture seasonal variability are applied.

The LDC is represented by a discrete number of blocks as shown in Figure 7. Block heights vary by period according to demand growth assumptions. The model repeats each month's block structure – including the system peak demand (first block) - across all periods. Therefore, it is important that the sum of the block durations across all stages equals 8,760 hours.

Figure 7: Illustrative transformation to a load duration curve and fitted blocks



These blocks capture the different load levels ranging from peak to off-peak load.

[16] The risk of unserved energy in Lesotho due to, for example, the unavailability of imported power is not included in the cost function.

Of critical importance for the generation planning is the accurate representation of **monthly peak load**, which is needed for the generation planning to meet the peak demand condition (see section 4.2.1) and to determine the level of security of supply risk.

Given the inevitable uncertainties associated with modelling demand and production costs a number of years into the future, the consultant considers that modelling the load with a finer granularity than monthly would not improve the credibility of the development plan results.

The model uses year periods and monthly stages, with each month having four load blocks to represent the combinations of demand (absolute peak, peak, standard, off-peak). The load blocks represent variation within each month.

4.7 MUELA HYDRO

The only significant generation capacity in Lesotho is the 72 MW Muela hydro project owned and operated by LHDA which is part of the Lesotho Highlands Water Project (LHWP).

Monthly energy production of Muela is constrained to a maximum available energy by month (based on historic data, see section 5.5). The model assumes that Muela will not retire before the end of the planning horizon in 2030.

According to the Power Agreement between LHDA and LEC *"The objective of the operating regime will be to operate the Facility efficiently and economically in such a way as to ensure that its Output is available to minimise the cost to Lesotho of electricity from Eskom"*[17] Given that energy management is an objective of the Power Agreement, the model includes functionality for energy management as described in the following box-out.

Figure 8: Description of available water management functionality in the developed model

The model includes the ability for water management at Muela hydro power plant by considering maximum available energy by month (a proxy for water resource availability).

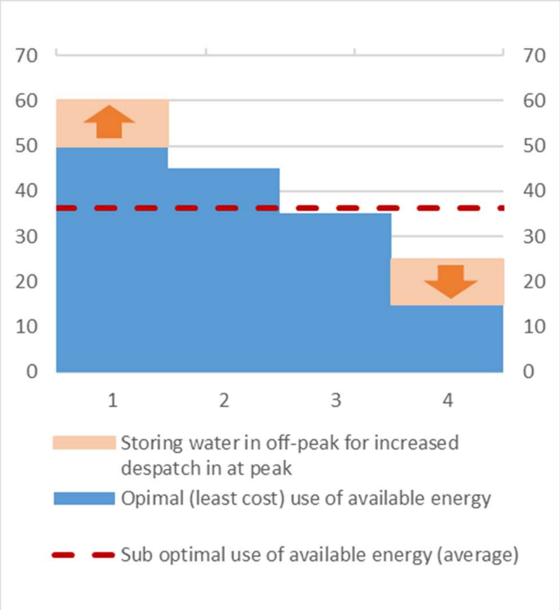
The model can optimise the use of the available energy resource within the load-blocks created in each month. More precisely, energy cannot be stored and moved between months, only between blocks within a month. The maximum production is limited by the output capacity multiplied by the assumed availability, in this case 72MW per hour.

Energy management by effective use of storage to minimize system costs is illustrated in Figure 9. The areas containing arrows shows water being stored during off-peak and moved to peak periods (or alternatively, running the plant at full load in peak periods to the detriment of its availability on off-peak periods). By generating in times of highest system production cost (i.e., highest import prices), the value of the stored energy is maximised.

The sum of energy production over all blocks in each month must be less than or equal to the maximum available energy by month.

[17] Annex B, clause 4.2.

Figure 9: Representing hydroelectric generation (storage) using load blocks



4.8 INTERCONNECTION WITH SAPP

The current status and possible developments of the generation mix in SAPP was discussed in section 3.

Lesotho has signed international agreements that enable interconnection with the SAPP grid. In addition, it has bilateral agreements for the purchase of energy from EdM (Electricidad du Mozambique) and Eskom (South Africa). The model has been developed to allow for a credible representation of these bilateral agreements. The main features of these agreements are described in the table below.

Table 7: Main features of agreements

	Energy charge	Maximum Demand charge	Wheeling charges	Admin. charges	Comments
Eskom	Yes	Yes	Yes	Yes	• Contracting via the Schedule of Standard Prices, issued annually • Applicable tariff per interconnector: o Maseru - Megaflex tariff, low season, high season variability o Clarens - Nightsave Urban Large tariff; and o Qacha's Nek is on the Nightsave Rural tariff • Energy charges vary – low season/ high seasons and time of use (peak, standard, off-peak) • Example charges: o Dx Netwk Demand Charge, R/kVA/m

	Energy charge	Maximum Demand charge	Wheeling charges	Admin. charges	Comments
					○ Tx Network Charge, R/kVA/m ○ Dx Netwk Access Charge, R/kVA/m ○ Urban LV Subsidy Charge, R/kVA/m ○ Ancillary/Reliability Service Charge, c/kWh ○ Administrative charge, R/day ○ Service charge, R/day ○ Control Area Charge, M/month ○ Wheeling (EDM S - LEC), c/kWh
EdM	Yes	No	No	No	• Based on long-term PPA – seems LEC have scope to renegotiate prices • Energy-only charges • Profile for firm power – LEC has to consume according to this profile even if not least cost

To capture the structure of import prices, separate energy prices are defined for each peak, standard and off-peak load block. There is also the ability to consider demand (kVA) and fixed usage/rental charges, maximum import limits per year (MWh) and contribution to the reserve requirement (MW). These prices can be based on the expected max amount of capacity to be realised in SAPP (e.g., as discussed in section 3) and the anticipated generation mix therein. The resulting costs for importing power may be considered as the cost of generation by pseudo-generating units and are considered as part of the production cost element of total system costs. The volume of power imported is a decision of the market despatch module which is described in section 4.9.

The model also considers possible developments in SAPP market arrangements. For example, we are aware that SAPP is trying to develop a Day Ahead Market for electricity and while this is still modest in terms of the total volume, it is increasing in volume and in the number of active participants. The model is able to take into account the effects of trading in a spot regional market by allowing prices for imports (pseudo-generating units) to be adjusted.

4.9 System Despatch

The model simulates production costing to meet the anticipated demand based on variable short-run production costs (based on marginal costs) of new generation resources and power purchase agreements with existing suppliers.

The input characteristics of solar, wind and new hydro plants provide variable short-run production costs. The bilateral agreements with Muela, Eskom and EdM and/or SAPP wholesale prices provide costs using imported power.

For each monthly load duration curve (consisting of 4 blocks) the despatch module seeks to minimize the cost of meeting the demand by creating a “supply curve” of available generation (MWhs) ordered by despatch price lowest to highest.[18]

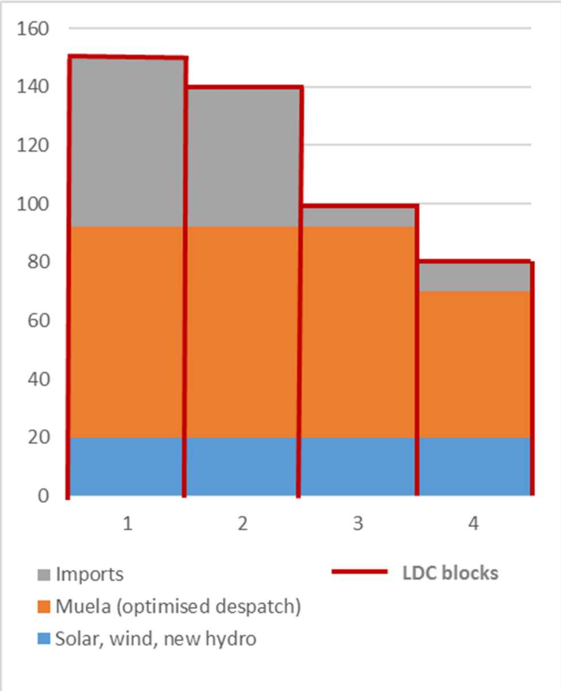
[18] For simplicity, the despatch considers only the active energy charges for Eskom when ordering prices.

This assumes that any newly built generation (e.g., wind, solar, new hydro) is despatched subject to its energy availability limits and with zero or very low short-run marginal costs.

Muela is despatched up to the maximum available energy such that as much energy as possible is used in the peak and standard blocks[19] and imports (pseudo-units) from SAPP meet any remaining load (these sources incur the highest cost if called upon).

An illustrative example of this is shown in Figure 10, where solar, wind and new hydro are despatched at maximum, with Muela dispatched at maximum capacity generating in block 1-3 (higher demand) at the expense of lower dispatch in block 4 (off-peak).

Figure 10: Illustrative example of optimal (least cost) filling of load duration curve blocks with available generation



The model does not consider costs associated with circumstances where demand exceeds available supply. Instead the model assumes adequate elasticity of demand and load shedding would result.

4.10 Policy Objectives

The model is capable of internalising investment decisions in response to policies promoting off-grid electrification solutions and/or initiatives to limit reliance on imported power.

The former policy objective is captured though the inputted demand – this has already been determined from the outputs of deliverable 3.

[19] An assumption of this approach is that energy prices for imports will be highest in peak, followed by standard, followed by off-peak. And that all import energy prices are higher than charges for calling on Muela.

The latter can be modelled explicitly in the form of constraints (e.g., constraints on the use of imports), or implicitly (e.g., a cost for imports that is more expensive that the cost associated with building and operating new generation). The use of explicit constraints serves as a powerful policy indicator as the difference between the total system costs with or without the constraints determines the cost of the policy over the planning horizon.

4.11 OUTPUTS

The model objective function calculates the NPV of the generation, transmission and distribution system costs. It is important to note that this value will not include any subsidy or external (such as off-grid solution) costs. Subsidies act as a reduction in costs for the model (e.g., generation that is subsidised on output will be seen as a cost saving whenever it is despatched) and the NPV of subsidy cost must be added to the objective function, if a "true" total system cost estimate is required. That said, total system costs are extremely difficult to estimate with any accuracy and are largely meaningless when considered in isolation. Therefore, we suggest that the relative change in objective function value, along with key model outputs, is used to assess the impact of changes in inputs between scenarios.

Generation, transmission and distribution capacity development is an output of the model, as is generation despatch. These outputs are summarised by generator type. Investment costs by year are also reported.

Security margins are reported, plus outputs of the long-run marginal costs for generation, transmission and distribution. These calculations are reported in Task 4 (deliverable 5) report where the economic costs and tariffs are derived. Also available is the average and long-run system marginal cost, which is the aggregation of generation, transmission and distribution results.[20] The long-run marginal cost is given by the NPV of total annual system cost (NPV_{sys}, see Annex A) divided by the NPV of annual increases in energy produced.

4.12 INFLATION AND CURRENCY

All figures (inputs, parameters and outputs) from the modelling will be presented in real 2017 terms. The model currency is loti and any cost inputs or outputs in foreign denomination (e.g., US$) are converted at an inputted exchange rate.

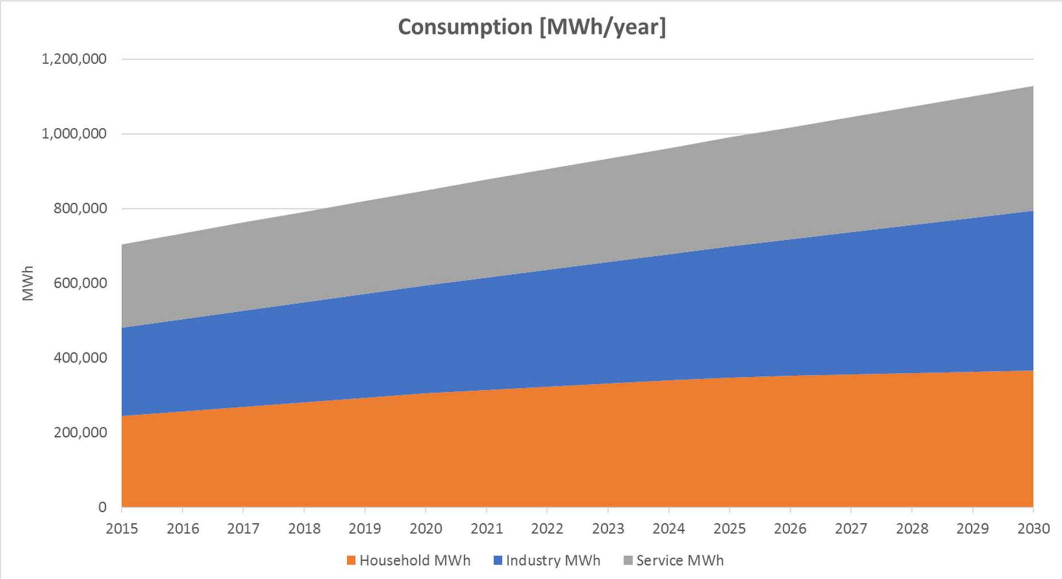
[20] The marginal (or opportunity) cost is the change in total cost when the amount produced changes by one unit. It applies to both the demand and supply side of a market. The marginal cost of supply is derived from the production cost function. This could be short-run, where the cost of producing an additional unit is incurred by increasing output from existing facilities. Or it could be long-run where new facilities must be built in order to produce the additional unit.

5 Data Sources

5.1 Demand Projection

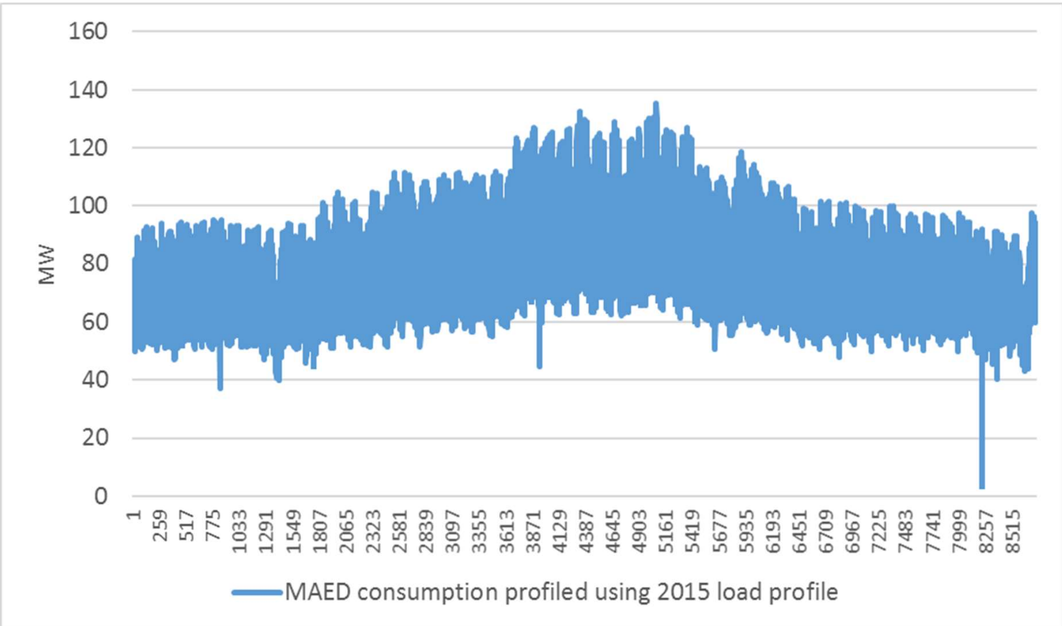
The demand projections in the model are derived from deliverable 3. Figure 11 illustrates the total demand for the projection period 2015 to 2030.

Figure 11: Annual consumption 2015-2030



This demand is profiled using the 2015 load profile - Figure 12.

Figure 12: Example chronological load profile calibrated to 2015 load profile



The NPV of total system costs includes the cost of new connections, (which are set by voltage level). Consequently, the annual consumption for household, industry and service sectors from the MAED model (Figure 11) is broken down into consumption by tariff category based on analysis of 2014 to 2016 (3 years) consumption data provided by LEC. The proportioning is shown in Table 8.

Table 8: Allocation of MAED demand (columns) to LEC tariff categories (rows) based on analysis of 2014 to 2016 annual consumption data (kWh) by tariff category provided by LEC.

	Industry	Household	Service
Domestic	0.0%	100.0%	0.0%
General Purpose	0.0%	0.0%	37.1%
LV Commercial	0.0%	0.0%	25.3%
HV Commercial	0.0%	0.0%	36.8%
LV Industrial	17.7%	0.0%	0.0%
HV Industrial	82.3%	0.0%	0.0%
Street Lighting	0.0%	0.0%	0.8%
Total	**100.0%**	**100.0%**	**100.0%**

The overall allocation of the gross energy demand to customer categories is shown in Table 9 and Table 10.

Table 9: Demand (final consumption) by tariff category kWh for each year 2017-30 in the development plan

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Domestic	269,106	281,472	293,838	306,204	314,649	323,094	331,540	339,985	348,430	352,248	356,067	359,885	363,703	367,521
Gen Purpose	87,541	89,863	92,185	94,507	97,207	99,906	102,606	105,305	108,005	111,183	114,362	117,541	120,720	123,898
LV Comm.	59,633	61,214	62,796	64,378	66,216	68,055	69,894	71,733	73,572	75,737	77,903	80,068	82,233	84,399
HV Comm.	86,860	89,164	91,468	93,771	96,450	99,128	101,807	104,486	107,164	110,318	113,472	116,626	119,780	122,934
LV Indust.	45,485	47,300	49,115	50,930	53,136	55,343	57,550	59,757	61,964	64,649	67,334	70,018	72,703	75,388
HV Indust.	212,009	220,469	228,929	237,388	247,674	257,961	268,247	278,533	288,819	301,334	313,849	326,363	338,878	351,393
Street Light	1,944	1,995	2,047	2,099	2,158	2,218	2,278	2,338	2,398	2,469	2,539	2,610	2,681	2,751
Total	**762,578**	**791,478**	**820,377**	**849,277**	**877,492**	**905,707**	**933,922**	**962,137**	**990,352**	**1,017,939**	**1,045,525**	**1,073,111**	**1,100,698**	**1,128,284**

Table 10: Demand (final consumption) by tariff category % for each year 2017-30 in the development plan

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Domestic	33.9%	33.6%	33.3%	33.0%	32.2%	31.6%	30.9%	30.3%	29.7%	29.1%	28.5%	27.9%	27.3%	26.8%
General Purpose	11.7%	11.7%	11.7%	11.7%	11.7%	11.7%	11.8%	11.8%	11.8%	11.8%	11.9%	11.9%	11.9%	11.9%
LV Commercial	8.0%	8.0%	8.0%	7.9%	8.0%	8.0%	8.0%	8.0%	8.1%	8.1%	8.1%	8.1%	8.1%	8.1%
HV Commercial	11.6%	11.6%	11.6%	11.6%	11.6%	11.6%	11.7%	11.7%	11.7%	11.8%	11.8%	11.8%	11.8%	11.8%
LV Industrial	6.1%	6.2%	6.2%	6.3%	6.4%	6.5%	6.6%	6.7%	6.8%	6.9%	7.0%	7.1%	7.2%	7.3%
HV Industrial	28.4%	28.7%	29.0%	29.3%	29.8%	30.3%	30.8%	31.2%	31.6%	32.1%	32.6%	33.0%	33.4%	33.8%
Street Lighting	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%
Total	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**

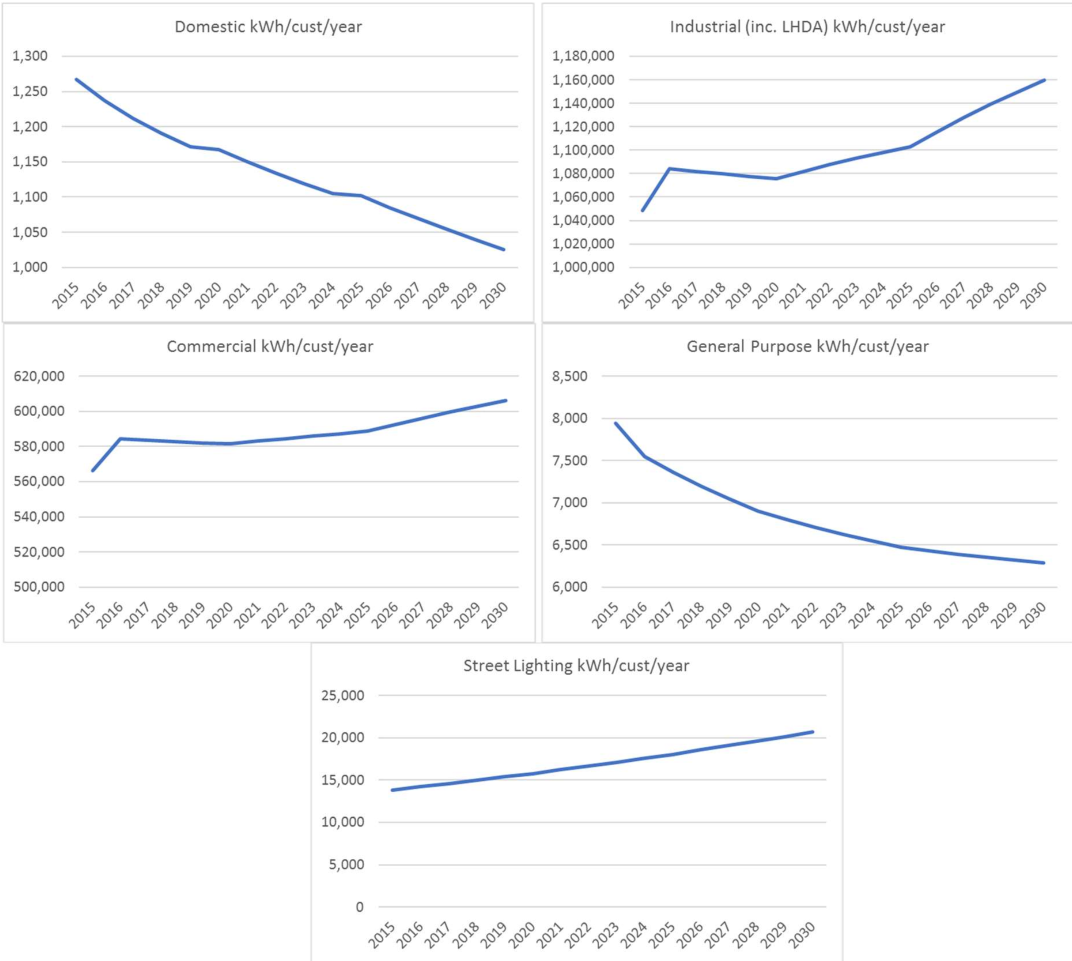
Table 11: Number of new connections by tariff category for each year 2017-30 in the development plan

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Domestic	14,500	14,361	14,361	11,374	11,374	11,374	11,374	11,374	8,421	8,421	8,421	8,421	8,421	8,421
Gen Purpos	600	600	600	600	600	600	600	600	600	600	600	600	600	600
LV Comm.	4	4	4	4	4	4	4	4	4	4	4	4	4	4
HV Comm.	3	3	3	3	3	3	3	3	3	3	3	3	3	3
LV Industrial	9	9	9	9	9	9	9	9	9	9	9	9	9	9
HV Industrial	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Street Lighting	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	**15,117**	**14,978**	**14,978**	**11,991**	**11,991**	**11,991**	**11,991**	**11,991**	**9,038**	**9,038**	**9,038**	**9,038**	**9,038**	**9,038**

The number of new residential (domestic) connections per year by tariff category is taken directly from the MAED model. For other customer types (industrial, commercial, general purpose) the number of new connections per year continues at the level experienced in recent years and remains fixed at that level for the whole planning horizon. These are shown in Table 11.

The combination of energy demand and existing and new customer numbers provides the consumption per tariff category shown in Figure 13. Note that the trend of decreasing demand per residential is consistent with the results of deliverable 3. Furthermore, the trend of increasing consumption per customer for industrial seems reasonable given the expected growth in demand from the Letseng mines.

Figure 13: Consumption per customer by LEC customer type



5.2 COST OF NEW CONNECTIONS

Data on cost of new connections was not available by customer tariff category. Our estimate is based on personal communication with LEC personal. The figure applied was 4,500 M/connection (for all types on connection and in all years of the planning horizon). This figure does not include the cost of extending the distribution system (e.g., lines and substations), these costs are covered in section 5.7.

A customer capital contribution of 2,000 M/connection is assumed for new urban connections, leaving a balance of 2,500 M/connection to be funded by LEC - Table 12.

Table 12: Cost per urban customer connection used in the development plan model (source: personal communication with LEC, April 2017)

Customer type	Total M/connection	Funded by LEC M/connection	Customer capital contribution M/connection
Domestic	4,500	2,500	2,000
General Purpose	4,500	2,500	2,000
LV Commercial	4,500	2,500	2,000
HV Commercial	4,500	2,500	2,000
LV Industrial	4,500	2,500	2,000
HV Industrial	4,500	2,500	2,000
Street Lighting	4,500	2,500	2,000

The cost per connection of new rural domestic connections is assumed not to be funded by LEC, rather via GoL funds or Universal Access Funds. This cost is therefore excluded from the total system cost and in turn not passed through to end-user tariffs. The breakdown of domestic connections assumed in the modelling is shown in Table 13.

Table 13: Number of new domestic connections in the development plan

Customer type	2018-19	2020-24	2025-30
Domestic customer connection (per yr)	14,361	11,374	8,421
Of which Urban	*10,842*	*9,937*	*7,489*
Of which Rural	*3,519*	*1,437*	*932*

5.3 Losses

The model allows for transmission and distribution losses to be specified separately and by year. Our analysis of energy purchase and final consumption data provided by LEC indicates that aggregate transmission and distribution losses have been around 14% with an increasing trend in recent years Table 14.[21]

Table 14: Aggregate losses derived from energy purchase and sales data from LEC

Data item		2012	2013	2014	2015	2016
Energy purchases	MWh	756,788	800,012	786,362	804,180	885,589
Energy sales	MWh	676,078	707,148	673,281	691,412	737,308
Aggregate Losses	%	10.7%	11.6%	14.4%	14.0%	16.7%

Data on the disaggregation of losses was not available so an estimate of 7% transmission and 8% distribution was applied, which aggregate to 14.4%.[22]

[21] Note that the majority of customers are on pre-payment meters so it seems reasonable to assume that energy sales is a good representation of actual consumption.

[22] Aggregate losses = [Transmission Losses] + (1-[Transmission Losses])* [Distribution Losses] = 7%+(1-7%)*8% = 14.4%.

5.4 Gross Demand Projection

The peak demand used in the generation planning is shown in Figure 14.

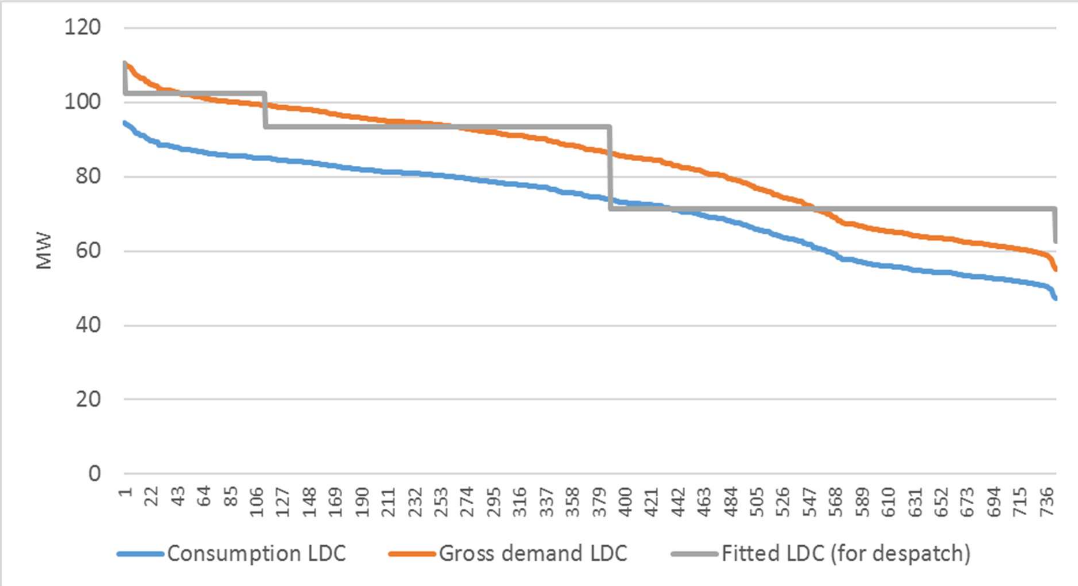
Figure 14: Peak demand condition 2017-30

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Peak Demand Forecast MW	171	178	184	191	197	204	210	216	223	229	235	241	247	254

The demand projection is transformed to a consumption load duration curve (LDC) for representative months of the year. This LDC is scaled up to account for transmission (7%) and distribution (8%) network losses to produce a gross demand LDC and the 4 blocks for the fitted LDC. An example for one month is shown in Figure 15.

Note that the absolute peak block (left most block) is one hour duration, the peak block is 112 hours, standard 275 hours and off-peak 343 hours. Total duration 730 hours.

Figure 15: Process of transforming energy consumption to a fitted LDC for despatch



5.5 EXISTING SOURCES OF SUPPLY

5.5.1 MUELA

Historic production data for Muela was obtained from LHDA for 2015 and 2016. This was averaged to provide the maximum monthly production for each month 2017-30. Based on the upcoming scheduled outage in October and November 2018 announced by LHDA, availability is reduced to zero in these months (but the reduction in energy availability is compensated by pro rating up energy availability in other months of the year because LHDA is committed to maintain the annual water supply volumes delivered to RSA) and a 6 year cycle of this maintenance is assumed.[23]

Tariffs charged to LEC by LHDA for procuring power from Muela in the development plan are based on the formulas in Annex C of the power agreement between LHDA and LEC.

It is widely accepted within the STC that the Muela tariffs do not reflect the true cost of the Muela development – operational costs, depreciation, debt service and a realistic return on equity. The tariffs appear to be low by international standards though this might be because of low levels of debt service required by the significant level of concessionary finance utilised in its implementation, and/or that some or all of the debt has now been retired. However, in the absence of any robust data on the cost-reflective tariff for Muela, the model anticipates that the current tariffs will continue for the duration of the planning horizon.

[23] The last maintenance at Muela took place in 2012.

Table 15: Maximum production and procurement data used for Muela

	Unit	2015	2016	Applied for 2017-2030 projection
Capacity	MW	72	72	72
Peak Availability	%	100%	100%	100%
Generation cap				
April	MWh	43,566	42,988	43,277
May	MWh	49,843	48,996	49,420
June	MWh	51,858	48,720	50,289
July	MWh	53,878	51,495	52,687
August	MWh	50,923	50,987	50,955
September	MWh	43,800	44,192	43,996
October	MWh	44,195	45,373	44,784*
November	MWh	43,140	41,154	42,147*
December	MWh	44,154	34,253	39,204
January	MWh	33,244	33,489	33,367
February	MWh	31,011	34,758	32,885
March	MWh	35,320	38,484	36,902
Total	**MWh**	**524,932**	**514,889**	**519,911**
Applicable Charges				
GDP Deflator for June 1992		246.9	246.9	246.9
GDP Deflator for June Current		325.1	325.1	325.1
Indexation factor	p.u.	1.317	1.317	1.317
Indexation correction factor	p.u.	0.0125	0.0125	0.0125
Indexation factor	p.u.	1.329	1.329	1.329
Base Energy Charge	M/kWh	0.05	0.05	0.05
Effective Energy Charge (indexed)	M/kWh	0.06	0.06	0.06
Base Demand Charge	M/kVa	22.63	22.63	22.63
Effective Demand Charge	M/kVa	30.08	30.08	30.08
Base Fixed Charge	M/month	625,000	625,000	625,000
Effective Fixed Charge (indexed)	M/kWh	830,767	830,767	830,767

** Assumed to have zero availability in October & November in 2018, 2024 and 2030 for maintenance. In these years production in other months is adjusted in order to achieve same level of overall availability in the year of 519,911 MWh.*

5.5.2 Imports – Pseudo Units

Tariffs for procuring power are derived from considering the structure of imports. The most relevant document to establish this structure is the Schedule of Standard Prices for Eskom Tariffs.[24] Maseru is on the Megaflex tariff, Clarens in on the Nightsave Urban Large Tariff and Qacha's Nek is on the Nightsave Rural tariff. Our analysis of changes in tariffs over the 3 years 2015/16 to 2017/18 showed that increases in tariffs have been on average around 2% above South African inflation - Table 16.

Table 16: Import supply costs 2013-2016 (LEC data).

Supply sources & entry points (M/kWh)	2013/14	2014/15	2015/16	2016/17
EDM	0.68	0.81	1.36	1.39
CLARENS	0.56	0.61	0.68	0.74
MASERU	0.80	0.81	0.95	0.90
QACHAS'NEK	0.92	0.99	1.11	1.20

LEC also procures power from EdM – Table 17.

Table 17: Tariff for procuring power from EdM used in the development plan

EdM tariffs		2015/16	2016/17	2017/18
Peak	U$c/kWh	13.57	13.57	13.50
Standard	U$c/kWh	10.71	10.55	10.50
Off-peak	U$c/kWh	8.46	8.55	8.50

To represent the structure of imports with maximum flexibility the model includes 13 pseudo generating units. This is based on the fact that the Maseru interconnection over which power traded on SAPP flows has up to three price structures (peak, standard, off-peak) for high a low season (3x2 = 6). A further four pseudo units are used to represent the Clarens and Qacha's Nek import contracts agreed with Eskom (low and high season prices) and three pseudo generating units are included to allow for a representation of additional imports structures (e.g., for procuring power from EdM).

The projected prices 2017-30 applied in the planning model are based on the structure of imports and anticipated capacity mix in SAPP. The pseudo unit prices for a selection of years are shown in Table 18, prices increase by around 2% per year. Estimates of additional import charges for wheeling power over the Eskom network that will arise if/when purchasing power from import sources and time of use assumption are shown in Table 33 in Annex B.

Table 18: Pseudo generating unit parameters to represent the structure of imports.[25]

Pseudo-Generator Parameters	Unit	2017	2020	2025	2030
P-UNIT1-EM-L-Peak	c/kWh	87.39	92.74	102.39	113.05
P-UNIT2-EM-L-Standard	c/kWh	60.14	63.82	70.46	77.80

[24] Available on Eskom website.

[25] These parameters can be derived for a combination of thermal efficiency, fuel cost, and other production costs of typical generating candidates for base-load, mid-merit and peaking generators that provide a credible representation of generation supply sources for imported power. An additional data table is included in Annex B (Table 38).

Pseudo-Generator Parameters	Unit	2017	2020	2025	2030
P-UNIT3-EM-L-Off-Peak	c/kWh	38.15	40.49	44.70	49.35
P-UNIT4-EM-H-Peak	c/kWh	267.90	284.30	313.89	346.56
P-UNIT5-EM-H-Standard	c/kWh	81.15	86.12	95.08	104.98
P-UNIT6-EM-H-Off-Peak	c/kWh	44.06	46.76	51.62	57.00
P-UNIT7-EC-L-PSOP	c/kWh	50.20	53.27	58.82	64.94
P-UNIT8-EC-H-PSOP	c/kWh	64.62	68.58	75.71	83.59
P-UNIT9-EQN-L-PSOP	c/kWh	54.55	57.89	63.91	70.57
P-UNIT10-EQN-H-PSOP	c/kWh	70.18	74.48	82.23	90.79
P-UNIT11-Ed-Peak	U$c/kWh	13.50	13.50	13.50	13.50
P-UNIT12-Ed-Standar	U$c/kWh	10.50	10.50	10.50	10.50
P-UNIT13-Ed-Off-Peak	U$c/kWh	8.50	8.50	8.50	8.50

The model also assumes a distribution of supply source consistent with the annual purchases in 2016/17 will be maintained for the duration of the planning horizon. This distribution is 23% Clarence, 68% Maseru and 3.1% Qacha's Nek. The model has been developed to allow defined constraints on per year volumes that can be procured from each pseudo unit, but this has not been applied to the scenarios considered in this report.

The data shows that costs have increased significantly in recent years and it may be that more economic options exist to LEC than maintaining these agreements. Furthermore, it is important to note that there is significant uncertainty surrounding the validity of the SAPP region expansion plans. It is therefore essential to explore the uncertainty in these projected prices and sensitivity to this is presented in section 6.1.2.

One such option might be to participate in SAPP markets. Table 19 shows average prices in the Day Ahead Market (DAM) for the Lesotho (LES) node in SAPP (same as prices in the Republic of South Africa Node (RSAN) node). Trading in SAPP is fairly modest in terms of the total volume, however the table shows that prices have been reducing and may become a more economic procurement option than LEC's current bilateral arrangements.

Table 19: Average DAM prices in SAPP 2015-17. Source: www.sappmarket.com (US$/MWh converted to Loti at the average exchange rate for the year, see section 5.8)

DAM, M/kWh	2015/16	2016/17	2017/18 so far
Weekday	1.335	1.059	0.801
Saturday	1.293	1.041	0.815
Sunday	0.963	0.738	0.489

5.6 Candidate Generation (Located in Lesotho)

We have used the following sources for new generation costs and operating characteristics:

- Renewable Energy Options Study Scaling-Up Renewable Energy Program (SREP): Investment Plan for Lesotho (March 2017) for new generation costs. This is a comprehensive study assessing the resource availability for solar and wind together with an assessment of the economics; and

- Lesotho Power Generation Master Plan, Final Milestones Report, Volume 1, Part 1.1 Hydro Power Generation Option.

If large-scale generation projects (e.g., hydro) are to be considered in Lesotho then the transmission investment needed to accommodate this must be part of that expansion project and it would be modelled as part of the same investment decision. This means capex includes cost for transmission expansion needed to accommodate these additions, which we assume that the SREP study includes.[26]

Note that the capex costs for the generation projects included in LEC's development plan (Table 1) are in the Consultant's view not as current as SREP and the projects have not been studied in any detail yet. Consequently the SREP costs are considered the most authoritative and used in the analysis.[27]

The development plan includes as a **committed project** the upgrade of Mantsonyane hydro (10 MW) and as candidate project the solar (10 MW) and wind (20 MW) at Semonkong indicated by LEC. Both these plants pertain to areas of the network that are currently isolated from the main grid. The capex for these plants is aligned with the capex for the technology shown in Table 20.

The discount rate for these technologies is set equal to the model social discount rate (see section 5.8). The economic lifetime of hydro is 40 years, wind and solar 20 years.

A summary of the candidate generation data is shown in Table 20 and Table 37 in Annex B.[28] Note that the cost data in the SREP report is in US$. This is converted to Lesotho Maloti at the prevailing exchange rate in the year that the investment is made.

[26] The SREP report indicates that the cost assumptions are for grid connected projects and projects located further than 20km from a transmission line were excluded.

[27] The SREP 2017 study anticipated capex costs for solar in the range 1,620-2,730 US$/kW. The midpoint of this range (2,175 US$/kW) is applied in this analysis.

[28] The capacity factors (35%) for wind and solar are based on study averages and when more detail becomes available on the resource characteristics and when specific projects and locations are defined these assumptions could be revised in the future.

Table 20: Candidate generation data

Technology	Earliest Commissioning Year	Construction (years)	Minimum capacity size per year (MW)	Total available capacity identified (MW)	Discount rate	Economic life (years)	Peak availability rating	Capacity factor	CAPEX ($/kW)	OMFix ($/kW/yr)	OMVar ($/kWh)
Hydro	2022	3	47	94	6.5%	40	90.0%	55.7%	3,500	175	0.00
Solar	2020	2	10	290	6.5%	20	10.0%	35.1%	2,175	16	0.00
Wind	2020	2	10	433	6.5%	20	10.0%	35.0%	2,500	32	0.00
Biomass	2021	3	10	16,706	6.5%	25	80.0%	70.0%	3,750	115	0.02

5.7 Transmission and Distribution (Disaggregated)

Operating cost of existing transmission and distribution network are based on 2016/17 LEC Annual report. When extrapolating values for total OPEX we have assumed that the current operating efficiency rates of LEC are kept constant for the three-year period. This efficiency rate has been formulated by keeping constant the opex costs as a percentage of assets book value (9.6%) as shown in Table 21. It is important to note that a more thorough projection of these costs is expected to be undertaken for deliverable 7 – financial performance of LEC.

Table 21: LEC operational costs used in the development plan analysis.

OPEX (M mil)	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23
Transmission	77.88	87.01	95.06	101.86	106.82	113.74
Distribution	181.47	202.75	221.52	237.36	248.92	265.04
Total costs	**259.35**	**289.77**	**316.58**	**339.23**	**355.74**	**378.78**

The list of network upgrades discussed in section 2.3 are included as candidate network upgrades. This network development is expected to happen over a number of years and serve demand growth until 2030. As already noted the transmission and distribution upgrades identified by LEC are needed to keep pace with the demand growth – for example to reinforce the network to increase power supply to the Letseng mines – and to increase system reliability. A summary of the total cost of the projects is shown in Table 22.

The model assumes that these investments are carried out over the period 2018-2025 and that per year capex to 2025 does not exceed USD$15m / year except for the line Lejone – Polihali. This line, at a cost of USD$12.9m (for Phase II of the LHWP), will not be funded by LEC and is therefore excluded from the per year capex restriction. This leaves USD$179.7m (M2.345 billion) to be funded by LEC.[29]

Table 22: Summary network investment candidates for transmission and distribution

Transmission and distribution Total capex (disaggregated)	Raw Capex		Including IDC	
	US$m	M mil	US$m	M mil
Transmission				
Line	48.4	630.1	52.8	686.6
Substation	29.4	382.3	31.7	412.5
Other	5.2	70.8	5.3	73.4
Distribution				
Line	64.0	831.9	69.7	906.5
Substation	38.8	504.7	41.9	544.5
Other	6.8	93.5	7.1	96.9
Total	192.6	2513.2	208.6	2,720.4
IDC = Interest during construction estimated assuming a 1-2 year construction period (discount rate 6.5%).				

[29] We note that LEWA indicated that the investment associated with connecting Qacha's Nek to the main grid of around USD$40 million would not be accepted unless LEC could make a convincing case. In the modelling, these investments are given an earliest start time of 2024 and so will not be included in end-user tariffs for the upcoming price controls.

The discount rate for network development projects is set equal to the model social discount rate (see section 5.8). The economic lifetime of new investments is assumed to be 35 years.

5.8 OTHER DATA

Data on forex has come from the CBL - Table 23.

Table 23: US$ to loti exchange rate assumption

General Parameters	Unit	2015	2016	2017	Applied for 2018-2030 projection
Exchange Rate (US$)	Maloti/US$	13.94	14.06	14.54	13.00

The social discount rate is set at 6.5%, this is a figure applied by MRC Group in other development plan modelling but it may be that CBL or the STC has data that can verify this figure as appropriate[30].

[30] The discount rate was set at 6.5% in line with MRC Group common practice for economic analyses in Sub-Saharan Africa. This figure is also supported by a Mercados study carried out in 2013 in which WACC estimates for four distinct financing options for power sector development in Botswana ranged from 2.5% to 10.4%. It may be argued that the discount rate should be selected to reflect actual cost/value of capital and to provide a median value that bridges between the costs associated with different financing options. The median value in the Botswana analysis is close to 6.5%. From the Lesotho perspective the 2007 NEMP load forecast analysis used 6% and the recent SREP options study uses 5%, which are of a similar order.

6 Modelled Scenarios and Results

6.1 Proposed Model Scenarios

There are some significant uncertainties as to the direction of development of the power sector in Lesotho. In particular there are ongoing deliberations about:

- The reliance on imports versus developing more generation capacity in country
- The possibility of replacing some or all of existing bilateral electricity import contracts (Eskom and EdM) with direct purchasing from the SAPP market.

To enable the cost of service evaluation to consider these possibilities three major variations to a base case have been modelled so that the report considers 4 scenarios as follows:

6.1.1 Base Case

In this case reliance on imports to meet demand growth is maintained with no constraints on the volumes that can be imported from SAPP via existing contracts with Eskom and EdM. The case also assumes as in the deliverable 3 that Government adopts a policy for a significant proportion of electrification to be met by off-grid solutions reducing the grid connections rate from its current level of 15,000/year to 4,000/year.

6.1.2 Scenario 1: Self-Reliant Supply

To address the uncertainty surrounding the expansion plans for SAPP and the subsequent availability of imported power, a “self-reliant” generation case where reliance on imports is greatly reduced and, if possible, eliminated entirely by 2030. This is a gradual change due to the time lag for new capacity to be commissioned and the requirement to plan the system to meet the peak demand condition - imports will contribute the capacity margin in the interim.

6.1.3 Scenario 2: Trading on SAPP

An alternative evolution of contracting with SAPP participants whereby the current bilateral contracts with EdM and Eskom are cancelled and LEC instead participates fully in the developing SAPP market (e.g., the Day-Ahead and Forward Physical markets). In this scenario prices achieved for imported power are based on a simple average of the current trends in SAPP prices - Table 24. More precisely it is assumed that the SAPP trading takes place on the Maseru and Clarens interconnectors but Qacha’s NeK continues to purchase from Eskom on the Nightsave Rural Tariff. The Eskom wheeling charge and control area charge (Table 33, Annex B) are assumed to still apply.

Table 24: Average SAPP spot market prices used in scenario 2

DAM, M/kWh	2015/16	2016/17	2017/18 so far	Average for most recent available 12 months	Applied for 2017-2030 projection
Peak	2.010	1.584	1.150	1.533	1.533
Standard	1.524	1.275	0.949	1.188	1.188
Off-peak	0.882	0.616	0.472	0.590	0.590

6.2 Results

The key output for comparing system development programs in the model is the disaggregated discounted cost of generation, distribution and transmission[31] Table 25 shows the ranking of the modelled cases.

Table 25: Comparison of disaggregated system costs in tested scenarios

Scenario	Cost Rank	Discounted generation costs 2017 - 2030 (M mil)	Discounted transmission costs 2017 - 2030 (M mil)	Discounted distribution costs 2017 - 2030 (M mil)	Total discounted system costs 2017 - 2030 (M mil)	Increase in costs relative to base case (%)
Base case	1	6,565	2,371	2,823	11,757	0.00%
Self-reliant Supply	2	6,702	2,371	2,823	11,896	1.18%
Trading on SAPP	3	6,812	2,371	2,823	12,005	2.11%

The relative closeness of results in the base case and the self-reliant scenario is due to the investment cost of new generation being somewhat offset by the production cost savings in later years as generation from zero short-run cost renewable technologies displaces imports in the system despatch. However, these results are sensitive to the choice of social discount rate, construction lead times of new generation and tariffs for imported power.

6.2.1 LRMC and SRMC

Table 26 shows the long-run marginal cost (LRMC) of generation, transmission and distribution at each level (the difference is the impact of losses). The impact of these results in tariffs will be analysed in deliverable 5.

[31] As already noted, the total system costs are extremely difficult to estimate with any accuracy and are largely meaningless when considered in isolation. Therefore, we suggest that the relative change in (disaggregated) objective function values is used to assess the impact of changes in inputs between scenarios

Table 26: Summary of LRMC of generation, transmission and supply

Delivery point at voltage level	LRMC of Generation (M/kWh)	Transmission network LRMC (M/kWh)	Distribution Network LRMC (M/kWh)	Transmission network & supply OPEX (M/kWh)	Distribution network & supply OPEX (M/kWh)	Total (M/kWh)
Generation	1.473	-	-	-	-	**1.473**
Transmission	1.584	0.302	-	0.101	-	**1.987**
Distribution	1.810	0.346	0.186	0.116	0.421	**2.878**

The short-run marginal cost (SRMC) of generation can be determined by simulation of the variable costs of generation (or pseudo-units for imports) in the least-cost system despatch for the given demand condition. The model allows for this computation to take place at the maximum demand condition and also for standard and off-peak demand levels. The SRMC for the maximum demand and other conditions is shown in Table 27.

Table 27: SRMC based on a simulation of variable costs of the plants in the least-cost despatch

Demand condition		2017	2018	2019	2020	2021	2022	2023
Maximum demand	High Season	1.85	1.76	1.76	1.76	1.76	1.76	1.76
Standard	High Season	0.76	0.77	0.79	0.81	0.82	0.84	0.86
Off-peak	High Season	0.51	0.52	0.53	0.54	0.55	0.56	0.57
Maximum demand	Low Season	0.75	0.77	0.79	0.80	0.82	0.83	0.85
Standard	Low Season	0.57	0.58	0.59	0.61	0.62	0.63	0.64
Off-peak	Low Season	0.42	0.43	0.44	0.45	0.46	0.47	0.48

The continued use of imported power at the assumed prices seems reasonable when considering the costs of the alternative sources of supply located in Lesotho relative to import prices. Table 28 shows the levelized costs for the individual generation candidates (i.e., total discounted variable, fixed and amortized investment costs for the project divided by total discounted output) in the model alongside the weighted average pseudo unit import prices. The results demonstrate that the weighted average price for imports 2017-2020 (see Section 5.5[32]) is far below the estimated levelized cost for new candidate generators in Lesotho and is therefore least cost. However, the increase in import prices assumed in the modelling means that by 2030 imports start to look less economic relative to generation candidates in Lesotho. The data used for the calculation is shown in Table 38 in Annex B.

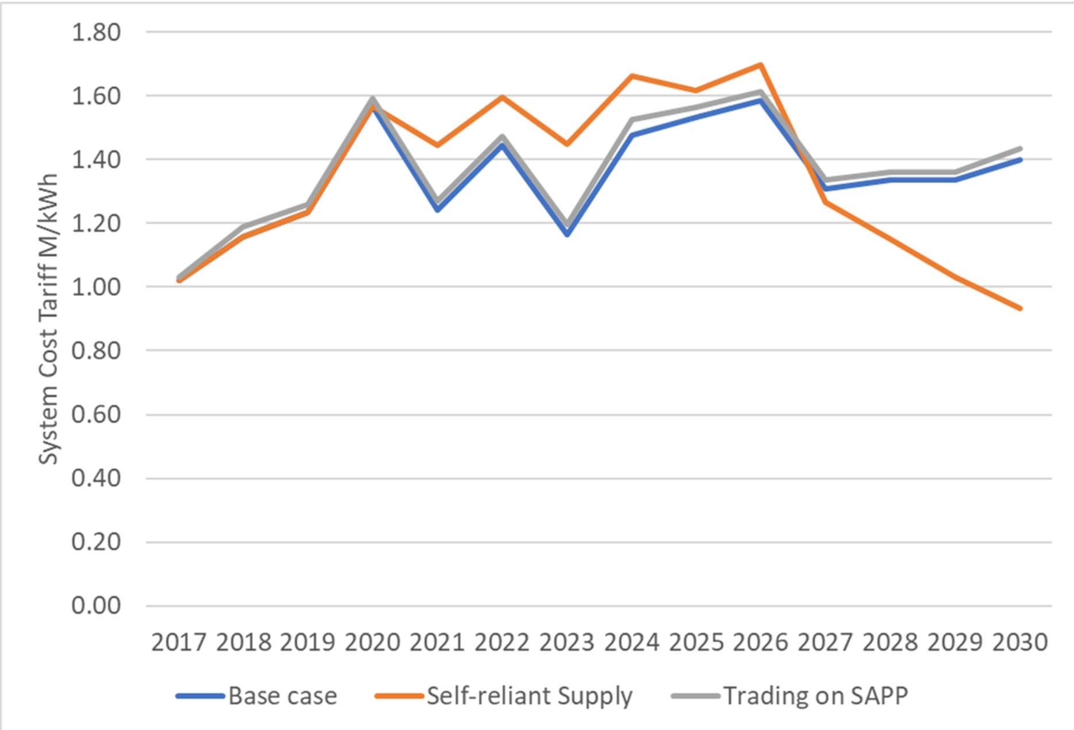
[32] The distribution on the weighted average price is 23% Clarence, 68% Maseru and 3.1% Qacha's Nek.

Table 28: Comparison of levelised cost of new generation technologies located in Lesotho against pseudo-unit import prices (2017 real)

Discount rate:		5.5%	6.5%	7.5%	8.5%	9.5%	10.5%
Hydro	\$/MWh	78.58	86.70	95.00	103.47	112.10	120.89
Solar	\$/MWh	81.78	88.66	95.84	103.31	111.06	119.08
Wind	\$/MWh	80.55	86.84	93.42	100.26	107.36	114.70
Gas	*\$/MWh*	*81.04*	*82.65*	*84.33*	*86.08*	*87.90*	*89.79*
Weighted average (pseudo unit) imports	\$/MWh	62.8 (2017) 74.6 (2020) 89.1 (2030)					

A representative system cost is shown in Figure 16. It is important to note that the unit costs shown here provide the yearly breakdown of the total generation, transmission and distribution costs (cost of new investment in generation and transmission and distribution network and despatch costs) divided by the total energy demand in the year (i.e., production net of losses). Capital expenditure for new investment (including interest during construction) is allocated to the year in which the project is commissioned. In a small system this inevitably results in spikes in the system unit cost when significant investments take place. End-user tariffs would deal with this differently – capex would be recovered through return of capital (depreciation) over many years and the impact on tariffs would be less marked. Translation of the selected development plan into long-run marginal costs and end-user tariffs will be part of deliverables 5 and 9.

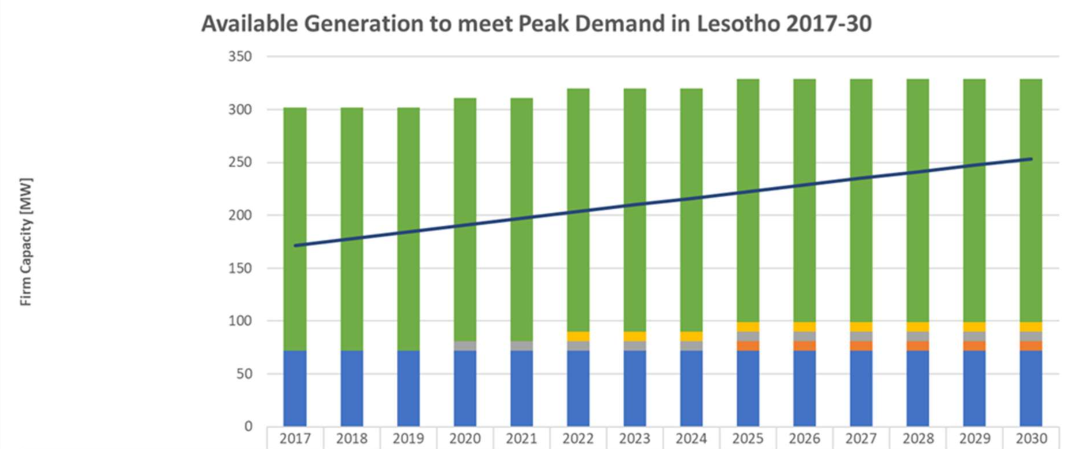
Figure 16: Representative system unit cost



6.2.2 Installed Capacity

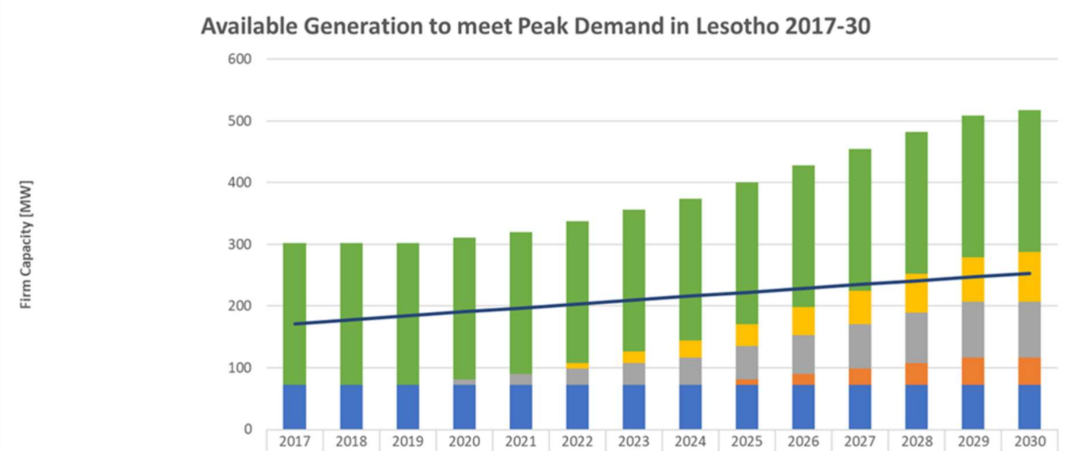
The per year installed capacity available to meet peak demand forecast is shown in Figure 17 and Figure 18. Note that new generation is de-rated by the peak availability factors shown in Table 20. Given that the installed capacity is the same for scenario 2 as the base case, there is just one variant on the installed capacity to present.

Figure 17: Projected installed and available at peak capacity to meet peak demand 2017-30 for base case and scenario 2.



	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Max transfer on imports MW	230	230	230	230	230	230	230	230	230	230	230	230	230	230
PPA MW	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Other domestic renewables MW	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind MW	0	0	0	0	0	9	9	9	9	9	9	9	9	9
Solar MW	0	0	0	9	9	9	9	9	9	9	9	9	9	9
Other hydro MW	0	0	0	0	0	0	0	0	9	9	9	9	9	9
Muela MW	72	72	72	72	72	72	72	72	72	72	72	72	72	72
Peak Demand Forecast MW	171	178	184	191	197	204	210	216	223	229	235	241	247	254

Figure 18: Projected installed and available at peak capacity to meet peak demand 2017-30 for scenario 1 – self-reliant.



	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Max transfer on imports MW	230	230	230	230	230	230	230	230	230	230	230	230	230	230
PPA MW	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Other domestic renewables MW	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind MW	0	0	0	0	0	9	18	27	36	45	54	63	72	81
Solar MW	0	0	0	9	18	27	36	45	54	63	72	81	90	90
Other hydro MW	0	0	0	0	0	0	0	0	9	18	27	36	45	45
Muela MW	72	72	72	72	72	72	72	72	72	72	72	72	72	72
Peak Demand Forecast MW	171	178	184	191	197	204	210	216	223	229	235	241	247	254

6.2.3 Generation Planting Program

Table 29 shows the per year generation planting for the Base case and Self-reliant scenarios.

Table 29: New capacity additions by technology type for Base case and Self-reliant

MW	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Base Case														
Wind									10					
Solar				10										
Hydro						10								
Self-reliant														
Wind						10	10	10	10	10	10	10	10	10
Solar				10	10	10	10	10	10	10	10	10	10	
Hydro									10	10	10	10	10	

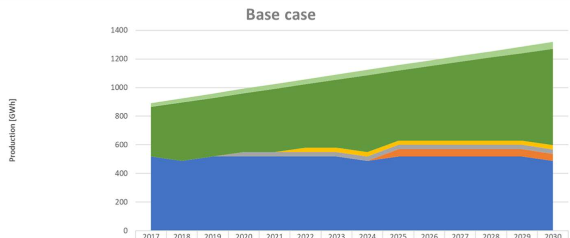
6.2.4 PRODUCTION

The per year production by fuel type is shown in Figure 19. The dips in Muela production reflect the impacts of the 6 year maintenance cycle whereby the increases in energy availability in April-August (to offset zero availability in October and November) results in an energy cap for the month that exceeds the maximum generation capability (i.e., 72MW generating per hour). Consequently, production in these months is below the energy availability limit and there is a corresponding reduction in annual production relative to a non-maintenance year. During these years the volume of imports from Eskom increases.

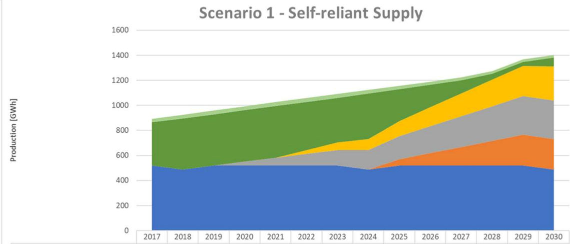
Results for the base case suggest continuing the volume of purchases from EdM is not economic – the model recognises that Eskom is lower cost relative to EdM and so purchases from EdM only during peak periods when the Megaflex tariff is expensive.

For scenario 2 - Trading on SAPP - the EdM Standard price is more economic than trading on SAPP from 2025 and the volume of EdM imports increases.

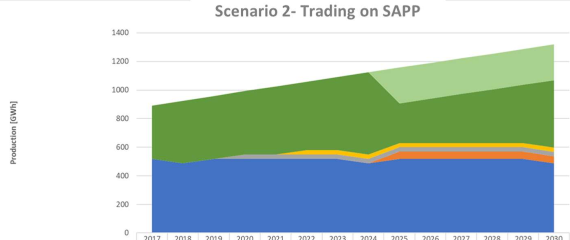
Figure 19: Energy production by source for each scenario and year 2017-30



	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
of which EDM	27	29	31	31	33	34	36	38	38	40	42	43	45	47
of which Eskom	345	409	408	410	442	444	475	538	490	520	550	581	611	674
PPA GWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Other domestic renewables GWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind GWh	0	0	0	0	0	30	30	30	30	30	30	30	30	30
Solar GWh	0	0	0	31	31	31	31	31	31	31	31	31	31	31
Other hydro GWh	0	0	0	0	0	0	0	0	49	49	49	49	49	49
Muela GWh	520	487	520	520	520	520	520	487	520	520	520	520	520	487



	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
of which EDM	27	29	31	31	32	32	31	31	28	26	24	21	19	20
of which Eskom	345	409	408	410	412	384	357	362	254	179	104	48	33	71
PPA GWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Other domestic renewables GWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind GWh	0	0	0	0	0	30	61	91	121	151	182	212	242	272
Solar GWh	0	0	0	31	62	92	123	154	185	216	246	277	308	308
Other hydro GWh	0	0	0	0	0	0	0	0	49	98	147	196	245	245
Muela GWh	520	487	520	520	520	520	520	487	520	520	520	520	520	487



	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
of which EDM	0	0	0	0	0	0	0	0	250	250	250	250	250	250
of which Eskom	371	438	439	442	475	478	511	576	278	310	342	374	407	472
PPA GWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Other domestic renewables GWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind GWh	0	0	0	0	0	30	30	30	30	30	30	30	30	30
Solar GWh	0	0	0	31	31	31	31	31	31	31	31	31	31	31
Other hydro GWh	0	0	0	0	0	0	0	0	49	49	49	49	49	49
Muela GWh	520	487	520	520	520	520	520	487	520	520	520	520	520	487

6.2.5 Capital Expenditure

The per year capex requirements in generation, network expansion and new connections is shown in Figure 20 with totals shown in Table 30. Comparable figures for network expansion only (i.e., not including generation capex) is shown in Table 31.

Table 30: Total capex expenditure and capex per customer in the development plan scenarios

Scenario	Total capex 2017-30 (M mil)	Total capex 2017-30 (US$ mil)	Average capex per customer per year (loti)	Average capex per customer per year (US$)
Base case	4,277	328	1,034	79
Self-reliant Supply	11,267	866	2,567	197
Trading on SAPP	4,277	328	1,034	79

Table 31: Total capex expenditure and capex per customer in the development plan scenarios excluding generation capex

Scenario	Total capex 2017-30 (M mil)	Total capex 2017-30 (US$ mil)	Average capex per customer per year (loti)	Average capex per customer per year (US$)
All scenarios	3,208	246	899	69

The change in the LEC asset base value is shown Table 32. The scenario shows a significant increase in the asset base.

Table 32: Changes in LEC asset T+D base for all scenarios (Maloti mil)

Scenario	Opening asset base (2017)	Closing asset base (2028)	% change
All scenarios	2,594	4,062	57%

Figure 20: Capital expenditure by source for each scenario and year 2017-30

7 CONCLUSIONS

Three broad conclusions can be drawn:

- The base case represents the economic optimum for Lesotho – continue reliance on Eskom and EdM to meet the gap between Muela generation and demand.
- From an economic perspective adopting a strategy to achieve security of supply through generation projects in Lesotho is not hugely worse than the base case in NPV terms. However, it requires a very significant additional capital expenditure of more than US$0.5 billion.
- The relative closeness of the NPV of total system cost results suggests that whatever scenario is selected, the cost reflective tariffs will overall be similar (although the allocation amongst tariff categories could well alter significantly). This is particularly the case for the next three years as achieving security of supply through generation projects in Lesotho and the phasing out of imports would not be realised until beyond 2020.

Our intention now is to take the base case forward to the computation of the economic tariffs and the design of the roll-out strategies. This will take on board the policy implications emerging from this analysis including:

- Renegotiate or enhance bulk power purchasing agreements to minimize power purchase pass through costs. Most notably, the analysis suggests that LEC should reduce contracted supply from EdM as in most periods[33] its prices are substantially higher than ESKOM.[34]
- Use Muela to minimize power purchase costs by operating, as far as is possible within its water supply obligations, to maximise generation during peak hours (when import purchase prices are highest).[35]
- SAPP is trying to develop a Day Ahead Market for electricity and while this is still modest in terms of the total volume and average prices are higher than current tariffs with Eskom, it is increasing in volume and in the number of active participants. It may be that as SAPP develops there are opportunities for LEC to source firm supply from SAPP at lower cost than current options.

There is a perceived lack of incentive for LEC to improve its performance in these areas and there is scope to make the governance of LEC more effective to achieve progress in each of these three areas. Options for enhancing the effectiveness of LEC governance are described in the Task 9 (deliverable 10) report.

We also note that initiatives to promote the development of top priority domestic generation sources and lowering of costs should be pursued to meet demand over the medium to long-term. The analysis presented here can combine with studies such as the SREP Investment Plan for Lesotho, November

[33] Analysis indicates that EdM maybe be less expensive than ESKOM only in peak periods, however LEC have contracted an offtake profile for firm power with volumes across the day.

[34] It appears that this is based on a decision by LEC that it needs the EdM contract to prevent an over-reliance on ESKOM.

[35] We believe LHDA has an obligation in its contract with LEC to do this. We also believe it is technically feasible as the delivery of the contracted daily water supplies to RSA can be achieved with varying levels of flow throughout the day.

2017 (from which candidate generation cost data is taken see section 5.6) to provide a coherent and least-cost investment schedule for Lesotho.

8 ANNEX A: ADDITIONAL MATERIAL ON THE METHODOLOGY

This Annex provides additional detail on the modelling methodology.

8.1 COST FUNCTIONS OF THE MODEL

The generation cost functions of the model is given by:

NPV generation costs = $NPV_{gen} = \sum_{p=1}^{P} \frac{1}{(1+r)^{p-1}} \cdot \left(\sum_g \left(CV_{p,g} + CF_{p,g} + IC_{p,g} + SV_{p,g}\right) + UE_p\right)$,

The transmission cost function of the model is given by:

NPV transmission system costs = $NPV_{trans} = \sum_{p=1}^{P} \frac{1}{(1+r)^{p-1}} \cdot \left(\sum_{tl} \left(CF_{p,tl} + IC_{p,tl}\right)\right)$,

The distribution cost function of the model is given by:

NPV total system costs = $NPV_{dist} = \sum_{p=1}^{P} \frac{1}{(1+r)^{p-1}} \cdot \left(\sum_{l} \left(CF_{p,dl} + IC_{p,dl}\right)\right)$,

General components:

p (lower case) is the index of the period (e.g., 1 to 40 years);

r Is the NPV discount rate (p.u.) (see below); and

Generation components (indicated by suffix g):

$CV_{p,g}$ Total variable costs in period p of generator g (Maloti). This includes generator production (fuel) and variable O&M costs.

$CF_{p,g}$ Total O&M fixed costs in period p of generator g (Maloti). This includes fixed costs by generator.

$IC_{p,g}$ Total investment costs in period p of generator g (Maloti). This includes capex costs for generators. Note that the "true" capex cost may be pre-processed to adjust for technology-specifc discount rates or region-specific costs (see below), however the model cost function only "sees" the adjusted value input into the model.

$SV_{p,g}$ The salvage values of assets whose operating life extend beyond the horizon (usually only considered if significant).

UE_p The cost of unserved energy (if considered).

Transmission components (indicated by suffix tl):

$CF_{p,dl}$ Total O&M fixed costs in period p of line dl (Maloti). This includes any fixed costs for the line, fixed connection charges for generation **and connecting new customers and transmission level**. The cost of new connections is modelled as a fixed per connection costs so does not attract any technology specific discount rate and has no associated amortization).

$IC_{p,dl}$ Total investment costs in period p of transmission line l (Maloti).

Distribution components (indicated by suffix dl):

$CF_{p,dl}$ Total O&M fixed costs in period p of line dl (Maloti). This includes any fixed costs for the line, fixed connection charges for generation **and connecting new customers at distribution level**. The cost of new connections is modelled as a fixed per connection costs so does not attract any technology specific discount rate and has no associated amortization).

$IC_{p,dl}$ Total investment costs in period p of distribution line dl (Maloti).

It is important to note that the NPV of total system costs function does not include any residual investment costs that would occur after the end of the simulated planning horizon. This is because only fixed (investment costs and operational) costs that would be incurred during those years of the plant lifetime falling within the planning horizon are included. However, the impact on the total cost of an asset of capital repayment that extends beyond the simulation period is modelled by means of an adjustment that is described in more detail below.

The annualised cost is based on straight line depreciation – distributing the capital cost payments (including any additional interest above the model discount rate) over an amortisation period. If considering the entire economic lifetime of the asset, this amortisation period is the economic lifetime of the asset, and the present value of this stream of payments is captured by the annuity factor:

$$AnnLife_g = \frac{r \cdot (1+r)^{Amort_g}}{(1+r)^{Amort_g} - 1}, \qquad \forall\, g$$

where $\mathrm{Amort_g}$ is the amortisation time (or economic lifetime, years) of plant g, and r is the discount rate. To obtain the total investment cost discounted to the first year of operation, this annuity factor is multiplied by the following three calculations:

1) The accumulation of interest during construction:

$$Int_{g,r} = \frac{1}{Const_g} \cdot \sum_{i=0}^{Const_g - 1} (1+r)^{Const_g - i}, \qquad \forall\, g$$

where $\mathrm{Const_g}$ is the construction time of plant g (years). This ensures that capital expenditure is discounted to the first year of operation;

2) The capital expenditure ($\mathrm{CAPEX_g}$, Maloti/MW); and

3) The volume of investment ($\mathrm{inv_{g,p}}$, MW).

This gives the total investment cost discounted to the first year of operation:

$$IC_{g,p} = Int_{g,r} \cdot \frac{AnnLife_g}{AnnRem_{g,p}} \cdot \left(CAPEX_g\right) \cdot inv_{g,p}. \qquad \forall\, g, p$$

$\mathrm{AnnRem_{g,p}}$ is the annuity factor with amortisation period equal to the remaining simulation time horizon (this value could be greater or equal to the full annuity factor):

$$AnnRem_{g,p} = \frac{r \cdot (1+r)^{Rem_{g,p}}}{(1+r)^{Rem_{g,p}} - 1},$$

where $\mathrm{Rem_{g,p}}$ is the number of years of operation that fall within the simulation time horizon accounting for lead time for construction, $\mathrm{Const_g}$ ($\mathrm{Rem_{g,p}}$ could be less than or equal to the full amortisation period). So $\mathrm{AnnLife_g}/\mathrm{AnnRem_{g,p}}$ is the ratio of the full economic lifetime to the shortened annuity ($\mathrm{AnnLife_g} \leq \mathrm{AnnRem_{g,p}}$). This scales down the investment cost on account of the capital repayment on the asset being lower than its full economic lifetime. For the avoidance of doubt, $\mathrm{AnnRem_{g,p}}$ is the annuity factor of the investment cost across the remaining simulation time horizon only, rather than the full economic lifetime.

For example, if investment in plant A with an economic lifetime if 25 years occurs at the start of 2025 and the planning horizon ends in 2030, then $Rem_{g,p}$is equal to 6 years. The remaining 21 years of residual costs will not be considered.

The value $IC_{g,p}$ forms part of the overall objective function. Within the model objective function, $IC_{g,p}$ is then discounted by year (resulting in the same present value).

To crystallize this concept, consider the following example:

Generator A's characteristics:

- Economic life of ten years;
- Build time of three years; and
- Capital expenditure 500 £/MW;

Model characteristics:

- Planning horizon 2017-25; and
- Discount rate 0.065.

The model is deciding whether to invest in 100 MW of generator A's capacity to come online at the start of 2020.

The model calculates the following:

1. Interest accumulated during construction factor:

   $$Int_{g,r} = \frac{1}{Const_g} \cdot \sum_{i=0}^{Const_g - 1} (1+r)^{Const_g - i} = \frac{1}{3} \cdot \sum_{i=0}^{2-1} (1+0.065)^{3-i} = 1.136;$$

2. Years of operation falling within the planning horizon: $\mathrm{Rem_{g,p}}$ = 6 years;
3. Generator annuity factor with amortisation period equal to the full economic lifetime: $AnnLife_g = \frac{r \cdot (1+r)^{Amort_g}}{(1+r)^{Amort_g} - 1} = \frac{0.065 \cdot (1+0.065)^{10}}{(1+0.065)^{10} - 1} = 0.139;$
4. Generator annuity factor with amortisation period equal to the remaining simulation time horizon:

   $$AnnRem_{g,p} = \frac{r \cdot (1+r)^{Rem_{g,p} - 1}}{(1+r)^{Rem_{g,p}} - 1} = \frac{0.065 \cdot (1+0.065)^{5-1}}{(1+0.065)^{5} - 1} = 0.241$$

5. Total investment cost included in the objective function discounted to the first year of operation:

   $$IC_{g,p} = Int_{g,r} \cdot \frac{AnnLife_g}{AnnRem_{g,p}} \cdot (CAPEX_g) \cdot inv_{g,p} = 1.136 \cdot \frac{0.131}{0.194} \cdot (500) \cdot 100 = £32{,}835$$

Note that ratio $\mathrm{AnnLife}_g/\mathrm{AnnRem}_{g,p}$ = 0.578 scales down the investment cost on account of the capital repayment on the asset until 2025 is lower than its full economic lifetime (reached at the end of 2029). Thus, if the model decides to invest in 100 MW of generator A's capacity in 2020, 32,835 Maloti contributes to the total system costs (the objective function). If all years of operation were to fall within the planning horizon (i.e., point 2 above = 10 years), then

$$IC_{g,p} = Int_{g,r} \cdot \frac{AnnLife_g}{AnnRem_{g,p}} \cdot \left(CAPEX_g\right) \cdot inv_{g,p} = 1.136 \cdot 1 \cdot (500) \cdot 100 = £56{,}786,$$

i.e., in this example 56,786 - 32,835 = 23,951 Maloti is excluded as a result of some years of generator A's economic life occurring after 2025.

8.2 Representing Technology Discount Rates

Investors will see different levels of risk in each technology. Therefore they will expect different discount rates to apply to different technologies. For example, a higher discount rate may apply to wind compared to hydro. The discount rate setting by technology is done outside the model in pre-processing, and is seen in the model as an increase (or decrease) in the capital cost of the investment depending on whether the **technology discount rate** is higher (or lower) than the social discount rate.

In the model, a higher capital cost with the social discount rate is economically equivalent to the normal capital cost with a technology-specific discount rate.

Discount rates specific to each technology are applied within the capex term. Within the model, a pre-processing step calculates an additional capex element, which is economically equivalent to the discount rate.

When taking account of different discount rates, the procedure to calculate the additional capex is:

1. Calculate the accumulation of interest during construction factor (shown above but repeated here) under the social discount rate, r (this is what the model will do):

$$Int_{g,r} = \frac{1}{Const_g} \cdot \sum_{i=0}^{Const_g-1} (1+r)^{Const_g-i},$$

   Where *u* is the discount factor: *u=1/(1+r)* and $Constr_g$ is the construction period (years) for generator *g*, i.e., the assumption is that capital costs occur uniformly across the construction period.

2. Calculate the accumulation of interest during construction factor under the technology (or generator) specific discount rate, r_g (this is what the model would do if the generator specific discount rate was applied as the social discount rate):

$$Int_{g,r_g} = \frac{1}{Const_g} \cdot \sum_{i=0}^{Const_g-1} (1+r_g)^{Const_g-i},$$

3. The "additional capex" (£/MW) is the uplift difference between the accumulation values multiplied by the capex (£/MW):

$$AdCAPEX_g = CAPEX_g \left(\frac{Int_{g,r_g}}{Int_{g,r}} - 1\right)$$

So if the technology discount rate is higher relative to the social discount rate, this result will be positive, and it will be negative if the opposite is true. The principle behind this calculation is to account for the differences in the investment costs between the two discount rates so that the value entered into the model is coherent with respect to the subsequent discounting that will occur under point 1. The AdCAPEX term forms part of the overall investment cost (IC), which like all other costs is in turn discounted to the first year of the planning horizon. This ensures that all costs are reported in present value year terms (i.e., 2017).

This process insures that the additional (lower) investment cost incurred as a result of a higher (lower) technology specific discount rate (r_g) relative to the model discount rate (r) is internalised by the model.

This different discount rates can only be applied to the construction phase of the project appraisal, and all operational costs will be discounted at the social rate. We consider this to be a reasonable approach as given that the bulk of risk is contained in the investment phase.

9 Annex B: Additional Data Tables

Table 33: Additional charges for procuring power wheeled over Eskom network used in the development plan

Eskom Parameters	Unit	2016	2017	2020	2025	2030
Maseru						
Dx Netwk Demand Charge	R/kVA/m	9.39	9.60	10.19	11.25	12.42
Tx Network Charge	R/kVA/m	6.99	7.14	7.58	8.37	9.24
Dx Netwk Access Charge	R/kVA/m	5.07	5.18	5.50	6.07	6.70
Urban LV Subsidy Charge	R/kVA/m	12.50	12.78	13.56	14.97	16.53
Ancillary/Reliability Service Charge	c/kWh	0.33	0.34	0.36	0.40	0.44
Administrative charge	R/day	111.24	113.69	120.65	133.21	147.07
Service charge	R/day	3,483.16	3,559.79	3,777.68	4,170.86	4,604.97
Control Area Charge	M/month	2,409.94	2,409.94	2,409.94	2,409.94	2,409.94
Wheeling (EDM S - LEC)	c/kWh	0.21	0.21	0.21	0.21	0.21
Clarens						
Demand Charges, Low season						
Demand Charge	R/kVa/m	26.68	27.27	28.94	31.95	35.28
Demand Charges, High season						
Demand Charge	R/kVa/m	190.88	195.08	207.02	228.57	252.36
Dx Netwk Demand Charge	(R/kVA/m)	9.39	9.60	10.19	11.25	12.42
Tx Network Charge	(R/kVA/m)	6.94	7.09	7.52	8.31	9.17
Dx Netwk Access Charge	(R/kVA/m)	5.07	5.18	5.50	6.07	6.70
Administrative charge	R/day	80.11	81.87	86.88	95.92	105.91
Service charge	R/day	177.75	181.66	192.78	212.84	235.00
Environmental levy	R/kWh	0.04	0.04	0.04	0.05	0.05
Qacha's Nek						
Demand Charges, Low season						
Demand Charge	R/kVa/m	119.28	119.28	126.58	139.76	154.30
Demand Charges, High season						
Demand Charge	R/kVa/m	226.05	226.05	239.89	264.85	292.42
Dx Network Demand Charge	R/kWh	0.20	0.20	0.22	0.24	0.26
Dx Network Access Charge	(R/kVA/m)	10.75	13.47	14.30	15.78	17.43
Ancillary/Reliability Service Charge	c/kWh	0.36	0.37	0.39	0.43	0.48
Administrative charge	R/day	72.13	73.72	78.23	86.37	95.36
Service charge	R/day	151.81	166.23	176.40	194.76	215.03
Connection charge rebate	fixed	-3,353.45	-3,353.45	-3,558.71	-3,929.10	-4,338.04
Residual connection charge	fixed	20,850.00	20,850.00	22,126.19	24,429.10	26,971.70

Table 34: Time of use assumptions for the interconnectors with SAPP

Time of Use			
Time	Weekday	Saturday	Sunday
0	Off-Peak	Off-Peak	Off-Peak
1	Off-Peak	Off-Peak	Off-Peak
2	Off-Peak	Off-Peak	Off-Peak

3	Off-Peak	Off-Peak	Off-Peak
4	Off-Peak	Off-Peak	Off-Peak
5	Off-Peak	Off-Peak	Off-Peak
6	Standard	Off-Peak	Off-Peak
7	Peak	Standard	Off-Peak
8	Peak	Standard	Off-Peak
9	Peak	Standard	Off-Peak
10	Standard	Standard	Off-Peak
11	Standard	Standard	Off-Peak
12	Standard	Off-Peak	Off-Peak
13	Standard	Off-Peak	Off-Peak
14	Standard	Off-Peak	Off-Peak
15	Standard	Off-Peak	Off-Peak
16	Standard	Off-Peak	Off-Peak
17	Standard	Off-Peak	Off-Peak
18	Peak	Standard	Off-Peak
19	Peak	Standard	Off-Peak
20	Standard	Off-Peak	Off-Peak
21	Standard	Off-Peak	Off-Peak
22	Off-Peak	Off-Peak	Off-Peak
23	Off-Peak	Off-Peak	Off-Peak

Table 35: Pseudo-generator parameters

Pseudo-Generator Parameters	Fuel type	Construction (years)	Economic life (years)	Operating life (years)	Capacity factor	CAPEX ($/kW)	OMFix ($/kW/yr)	OMVar ($/MWh)	Thermal Efficiency (%)	Gas price - USD/ MMBTu	Coal price - USD/ MWh	LRMC (2017) $/MWh	LRMC (2017) USc/kWh	LRMC (2017) c/kWh
P-UNIT1-EM-L-Peak	Gas	2	25	25	33%	850	30	5	35%	2.5		67.22	6.7	87.39
P-UNIT2-EM-L-Standard	Gas	2	25	25	77%	1101	17.5	3.5	36%	2.5		46.26	4.6	60.14
P-UNIT3-EM-L-Off-Peak	Coal	3	30	30	38%	*	42.1	4.6	41%		5	16.82	1.7	21.87
P-UNIT4-EM-H-Peak	Gas	2	25	25	7%	850	30	5	35%	2.5		206.08	20.6	267.90
P-UNIT5-EM-H-Standard	Coal	3	30	30	85%	3636	42.1	4.6	41%		5	62.42	6.2	81.15
P-UNIT6-EM-H-Off-Peak	Gas	2	25	25	82%	978	11	3.5	55%	2.5		33.89	3.4	44.06
P-UNIT7-EC-L-PSOP	Gas	2	25	25	75%	978	11	3.5	55%	3		38.62	3.9	50.20
P-UNIT8-EC-H-PSOP	Gas	2	25	25	86%	1101	17.5	3.5	36%	3		49.71	5.0	64.62
P-UNIT9-EQN-L-PSOP	Gas	2	25	25	61%	978	11	3.5	55%	3		41.96	4.2	54.55
P-UNIT10-EQN-H-PSOP	Gas	2	25	25	53%	850	30	5	35%	2.5		53.98	5.4	70.18
P-UNIT11-Ed-Peak	Gas	2	25	25	12%	1101	17.5	3.5	36%	2.5		135.00	13.5	175.50
P-UNIT12-Ed-Standar	Hydro	3	40	120	48%	3500	175	5	-			105.00	10.5	136.50
P-UNIT13-Ed-Off-Peak	Hydro	3	40	120	56%	3500	175	0	-			85.00	8.5	110.50

* Fully amortized (i.e., no capex to be recovered in power tariff)
Source, various including MRC Group generation database and "*Capital Cost Estimates for Utility Scale Electricity Generating Plants*" EIA, November 2016

Table 36: Other network upgrades part of LEC's system expansion plan

Description	Total cost (Maloti m)	Total cost (US$m)
Substations at Ha Mofoka, Ramabanta, Semonkong, Ha Mosi and Ha Mpiti	206.0	15.85
Electrification of Villages at Ha Ramabanta, Semonkong, Ha Mosi and Ha Mpiti	160.0	12.31
Secure Line Route (compensation estimated at M1.2m for 50 Households)	60.0	4.62
Maseru South Substation	25.0	1.92
Mapoteng Substation	20.0	1.54
Mokhotlong Substation	25.0	1.92
Kolo 33/11kv substation	20.0	1.54
Ha Makhoathi 33/11kV Substation	25.0	1.92
ThabaTseka Substation	25.0	1.92
Thetsane Substation	62.0	4.77
Ha Mofoka Switching Station	22.0	1.69
Upgrading of Khukhune to 132kV	22.0	1.69
Ha Ramabanta Substation	45.0	3.46
Semonkong Substation	45.0	3.46
Ha Mosi Substation	45.0	3.46
Ha Mpiti B Substation	49.0	3.77
Ha Belo Substation	45.0	3.46
Lemphane Substation	23.0	1.77
Mothae Substation	20.0	1.54
Metolong to St Agnes 33kV line, Civil & electrical works at both Metolong & St. Agnes	22.2	1.52
Mazenod 132/33kV 40MVA Transformer, 132kV & 33kV electrical equipment, NECRT, civil & structural works and connection of 2nd 132kV circuit between Mabote and Mazenod	31.0	2.13
Maputsoe 2 x 20MVA 33/11kV Transformer, upgrading of protection, and cabling	16.3	1.16
Construction of Litsoeneng 2nd 33/11kV 5MVA TRF, civil works & switchroom and electrical work.	13.3	0.92
Feasibility study of 132 KV Mazenod-Semonkong – Qacha's nek line	3.8	0.26
New switchroom SW12 switching station to address load growths Limkokwin, Lerotholi Polytechnic up to Mashoeshoe 2	0.5	0.04

Description	Total cost (Maloti m)	Total cost (US$m)
New switchgear at SW12 to address load growths Limkokwin, Lerotholi Polytechnic up to Mashoeshoe 2	4.7	0.37
New Switching Station at Ha Foso to address loads in the northern part of Maseru	9.3	0.72
Replacement of mini-sub & 3 way RMU that limit capacity at Palace of Justice, Hills View, Husteds, CTC, Alliance, Sefika HS & Cenez Rd	2.9	0.21
Hlotse System improvement projects (Pole-mounted transformers upgrading/additional and extensions of MV lines completed at Pela-Tsóeu Ha Ntsoakele, Sebothoane Ha Mafa, Mohobollo, Ha 'Mathata and Ha Makakamela)	0.3	0.02
Upgrade conductor that limit capacity between Phuthiatsana & Mapoteng (Mapoteng feeder from Maputsoe System improvement)	0.5	0.04
Upgrade conductor that is limiting capacity between Hololo & Ha Molapo (Botha-Bothe System improvement)	1.4	0.10
Determine 132 kV line route from Mazenod to Thetsane	0.6	0.04
Installed 2 x RMU at Masowe and Matukeng	0.3	0.02
	1051.2	**80.15**

Table 37: Capacity and cost assumptions for candidate generation plants

Technology	Name	Region	Capacity (MW)	Min Capex (US$/kW)	Max Capex (US$/kW)	Omfix (US$/kW)
Solar Park	Maseru	Maseru	20.0	1,620	2,730	16.0
Solar Park	Hlotse - 1	Leribe	2.0	1,620	2,730	16.0
Solar Park	Mafeteng - 1	Mafetang	2.0	1,620	2,730	16.0
Solar Park	Maputsoe	Leribe	1.0	1,620	2,730	16.0
Solar Park	Mohales Hoek - 1	Mohale's Hoek	5.0	1,620	2,730	16.0
Solar Park	Neo 1	Mafetang	20.0	1,620	2,730	16.0
Solar Park	Tsupane Gate	Mafetang	10.0	1,620	2,730	16.0
Solar Park	Mafetang – 2	Mafetang	10.0	1,620	2,730	16.0
Solar Park	Makadinyane	Maseru	20.0	1,620	2,730	16.0
Solar Park	Lithabaneng	Maseru	20.0	1,620	2,730	16.0
Solar Park	Matbang	Berea	10.0	1,620	2,730	16.0
Solar Park	Maputsoe – 2	Leribe	10.0	1,620	2,730	16.0
Solar Park	Semonkong	Maseru	10.0	1,620	2,730	16.0

Technology	Name	Region	Capacity (MW)	Min Capex (US$/kW)	Max Capex (US$/kW)	Omfix (US$/kW)
Solar Park	Potential in Berea	Berea	22.0	1,620	2,730	16.0
Solar Park	Potential in Leribe	Leribe	31.0	1,620	2,730	16.0
Solar Park	Potential in Maseru	Maseru	5.0	1,620	2,730	16.0
Solar Park	Potential in Mokhotlong	Mokhotlong	5.0	1,620	2,730	16.0
Solar Park	Potential in Quthing	Quthing	5.0	1,620	2,730	16.0
Solar Park	Potential in Butha-Buthe	Butha-Buthe	7.0	1,620	2,730	16.0
Solar Park	Potential in Mafeteng	Mafeteng	51.0	1,620	2,730	16.0
Solar Park	Potential in Mohale’s Hoek	Mohale’s Hoek	29.0	1,620	2,730	16.0
Solar Park	Potential in Thaba-Tseka	Thaba-Tseka	5.0	1,620	2,730	16.0
Wind	Wind Park at Letseng*	Mokhotlong	35.7	2,500	2,500	32.0
Wind	Wind Park at Semonkong*	Maseru	15.0	2,500	2,500	32.0
Wind	Wind Park at Oxbow**	Butha-Buthe	0.0	2,500	2,500	32.0
Wind	Bokong	Thaba-Tseka	11.6	2,500	2,500	32.0
Wind	Hlakametsa	Butha-Buthe	324.0	2,500	2,500	32.0
Wind	Mokhotlong	Mokhotlong	11.6	2,500	2,500	32.0
Wind	Nyane	Thaba-Tseka	11.6	2,500	2,500	32.0
Wind	Poqa	Mohale’s Hoek	11.6	2,500	2,500	32.0
Wind	Mphaki	Quthing	50.0	2,500	2,500	32.0
Wind	Thabana Morena	Mafeteng	11.6	2,500	2,500	32.0
Total			**782.7**			

Table 38: Data used in levelised cost of generation technologies calculation

Technology	Construction (years)	Economic life (years)	Operating life (years)	Capacity factor	CAPEX ($/kW)	OMFix ($/kW/yr)	OMVar ($/kWh)	Thermal Efficiency (%)
Hydro	3	40	120	55.7%	3,500	175	0.00	-
Solar	2	20	20	35.1%	2,175	16	0.00	-
Wind	2	20	20	35.0%	2,500	32	0.00	-
Gas-fired*	2	25	25	62.5%	1,092	6	65.75**	36.5%

* Based on data from MRC Group generation cost database for a gas turbine generator in the region
** Includes an estimate of fuel opex costs (i.e., short-run production costs)

Electricity Supply Cost of Service Study – LEWA Lesotho

Determination of Economic Costs and Tariffs – Deliverable 5

Support Provided by African Development Bank

Prepared for: LEWA

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Contents

Figures and Tables

List of Acronyms

AIC	Average Incremental Cost
CAPEX	Capital Expenditures
CAPM	Capital Assets Pricing Model
COSS	Cost of Service Study
GoL	Government of Lesotho
HV	High Voltage
LEC	Lesotho Electricity Corporation
LEWA	Lesotho Energy and Water Authority
LRAC	Long Run Average Cost
LRMC	Long Run Marginal Cost
LV	Low Voltage
RAB	Regulatory Asset Base
SRMC	Short Runa Marginal Cost
ToR	Terms of Reference
T&D	Transmission and Distribution
UAF	Universal Access Fund
WACC	Weighted Average Cost of Capital

1 INTRODUCTION

This report is the fifth deliverable of the Electricity Cost of Service Study (COSS) being carried out by the MRC Group for LEWA supported by the African Development Bank. The objective of this report is to present the approach, assumptions and results of the modelling analysis undertaken for the determination of economic costs and tariffs for LEC for a three years tariff period beginning in 2018.

The general objective of this task (Task 4 of the COSS) is to provide LEWA with electricity tariff structure and charges for all customer categories, based on the economic cost of service to customers in each tariff category. This analysis has been undertaken following the standard principles of tariff setting:

- To ensure **transparency and simplicity** within the tariff structure and its underlying cost allocation principles;
- To develop **efficient** price signals to consumers to guide short-run and long-run consumption decisions to encourage efficient consumption patterns;
- To develop charges which are just and reasonable and **non-discriminatory**;
- Improve the economic viability of power producers to ultimately **facilitate wholesale competition** without creating artificial barriers for any electric power generator or supplier; and
- Establish tariff design rules that provide **consistent** incentives for efficient location of new generators and efficient expansion of the distribution and transmission network.

According to requirements of the Terms of Reference (ToR), which adhere to best practices in power sector tariff design, the overall economic cost of supply for each consumer category/class should be the sum of costs incurred in delivering electricity to the customers of that specific category in the four distinct areas of generation, transmission, distribution and supply. This overall economic cost of supply to each consumer category is then the basis for determining an appropriate cost reflective tariff structure and level.

The assessment and definition of the Tariff Regime most appropriate for Lesotho is finalised in Task 8 (Deliverable 9). However, it is important to note that the tariff regime influences the economic cost of supply computation and in turn the resultant tariff structure and charges to be proposed:

Tariff Regime (regulatory) → (Approach for) Economic Cost of Supply → Tariff Structure and Charges

The approach taken when calculating the Economic Cost of Supply is to use actual capital and operating expenditures of LEC as a "**Cost Plus" Reference Case** for tariffs. However, the analytical model developed in this task (which is an extension to the model developed for task 3) and reported in Section 6 can be readily adjusted to reflect assumptions corresponding to an alternative regulatory regime.

This report is organized as follows:

- **Section 2** provides the relevant theory and principles underpinning tariff regimes and the calculation of the economic cost of supply.

- **Section 3** analyses alternative tariff regimes under which Economic Cost of Supply can be computed, identifying benefits and drawbacks on the utilities behaviour and performance obtained from international experience. This section also describes some key assumptions that need to be made on the tariff regime in order to undertake the tariff design exercise. These assumptions will be confirmed with LEWA during Task 8.
- **Section 4** presents the so-called **Building Blocks Approach for computing the Economic Cost of Supply of LEC** that constitutes the starting point for the Tariff Model.
- Finally, **Section 5** presents the structure, specifications and results of a **stylized Tariff Design Model** which extends the expansion plan model developed for deliverable 4. As required in the ToR, Economic Cost of Supply is expressed as (a) capacity cost (cost/kw/year) and energy cost (cost/kWh/year), and (b) as a composite (average) and monomic cost/kWh. The main result is the determination *for each main class of consumer category, using the applicable characteristics, the appropriate structure and level of tariff reflecting the economic cost of supply to the category.*

The tariff design exercise requires consideration of consumer characteristics (e.g., typical load profiles, energy and load loss rates, consumption seasonality). For this project these are based on a combination of available information from LEC and the Consultant's experience in other countries with similar power systems to that of Lesotho, and with similar consumer classification and patterns of consumption.

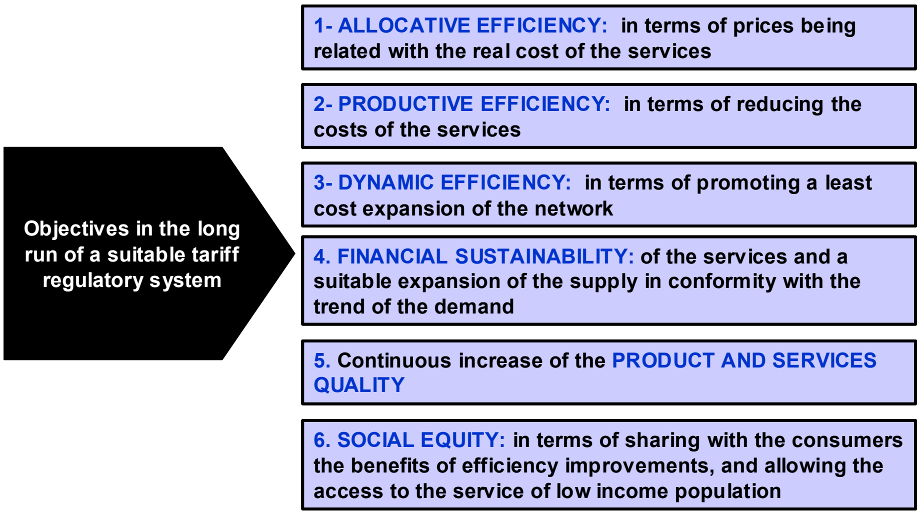
It is important to note that all economic costs and tariff charges computed in this report are expressed in real terms, real Maloti of 2017. Tariff charges in real terms computed in this report (Deliverable 5) will require along the three years tariff period adjustments to reflect inflation (in the share of internally procured goods and services) and to exchange rates (in the share of imported goods). Those intra-period adjustment criteria and formulation will be included in the tariff regime to be proposed in Task 8 (Deliverable 9).

The determination of the economic costs and tariffs presented in this report are key inputs to the following stages of the cost of service study. It is therefore essential that the approach and data used in the analysis as presented here are understood and agreed by the Study Technical Committee (STC), such that the STC validate our approach in time to enable the economic costs and tariffs to serve as confirmed inputs to the remaining project tasks.

2 Tariff Regime Objectives

The objective of a regulatory tariff regime is to set electricity tariffs at a level which promotes **economic efficiency** of production and ensures **financial viability** of the sector. From an economic and social point of view, the fundamental principles typically acknowledged when determining efficient cost reflective tariffs may be summarized as shown below in Figure 1:

Figure 1: Economic Principles for Tariff Setting



Thus an efficient tariff design should be based on economic efficiency, financial viability and social equity. These concepts are described in the following sub-sections.

2.1 Economic Efficiency

Economic efficiency in tariff design requires tariffs to be linked to the economic cost of meeting a consumer's demand. These costs vary typically by voltage level, seasonally (summer and winter), time-of-day, service area and type of consumer (load profile).

The three key economic aspects of economic efficiency are considered below.

a) Allocative efficiency: definition of a cost reflective tariff structure

Future costs should be efficiently allocated within diverse tariff categories using cost responsibility as the driving criteria, thereby promoting **allocative efficiency**. However, the need for simplicity and fairness may be such that socialization of costs, implying homogeneous rating of diverse groups, sometimes prevails over economically efficient allocation.

From a theoretic point of view, the Long Run Marginal Costs (LRMC)[1] of providing the service should be the basis for the tariff system.

[1] The LRMC represents the cost of producing an additional unit of product (in this case electricity) considering all factors (including power purchase, operational expenditure and capital expenditure) of production as variable costs.

b) Productive efficiency: Rate of Return and IBR systems

Productive efficiency means delivering the good (in this case electricity) or service at the minimum cost. In this setting, the principle of productive efficiency means identifying the efficient cost of electricity supply. The efficient cost of supply may be higher or lower than the actual cost. If lower, it may indicate that electricity can be produced at a lower cost than currently. Understanding any difference between efficient and actual costs is critical to developing a suitable suite of tariffs.

c) Dynamic efficiency: rate of return and expansion of supply

In order to guarantee the financial sustainability of the business and expansion of supply, tariffs applied by the utility must provide a reasonable rate of return on assets for an efficiently operated company. With that purpose, a fair rate of return that is similar to that of other activities having similar or comparable risk at the local and international level must be set for the regulated business. Well known, international methodologies such as the ***Capital Asset Pricing Model (CAPM)*** and ***Weighted Average Cost of Capital (WACC)*** are generally employed for this purpose.

2.2 Financial Viability

Financial viability means that tariff design must ensure that the total revenue to be produced by the tariffs will cover economic and efficient costs of supply, taxes, investments and reasonable rates of return. This is critical to ensure that the company can meet its financial sustainability under the set of tariffs that result from the policy.

In systems subject to economies of scale (as is the case for electricity networks), Long Run Marginal Cost (LRMCs) are not necessarily equal to Long Run Average Costs (LRACs) (see 6.3.1).[2] Thus for a scale of operations that varies from the most productively efficient, allowable revenues derived from the LRMCs may not be enough to guarantee financial sustainability of the firm. An example of this would be when a period of intense investment (or unexpectedly low demand growth) results in surplus capacity relative to demand and a significant time lag before any new capacity enters the system. In a situation of surplus capacity, allowable revenue derived from the LRMC of supply would reduce (the LRMC of generation would fall as future year increments of demand could be met without having to build any new capacity). It therefore may be some time before new capacity enters again and during this time the allowable revenues derived from LRMC of generation (although being the correct price signal from an investment perspective) may not be enough to ensure financial sustainability of the utility.

Furthermore, increasing demand can often only be met by quantum levels of investment – e.g. a new transmission line to a rapidly growing mining load. With modest demand increases the new line will need to be included in investment plans, the LRMC projections will increase but as demand has only

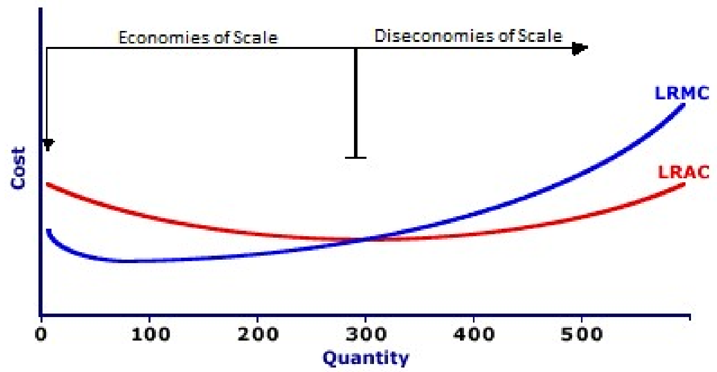
[2] To develop this understanding it is helpful to consider two things:

- The **Marginal Cost** (MC) which is the increment in total cost by producing an additional unit of output; and
- The **Average Cost** (AC) which is the total of average variable and average fixed costs divided by the number of units produced.

In systems subject to economies of scale, the AC curve is decreasing – for every additional unit of output the costs increase by the additional variable costs incurred (as the fixed costs are already sunk). There will, however, be a point when the quantity produced results in diminishing returns for the firm meaning the AC increases for the additional quantity (i.e., diseconomies of scale). The marginal cost is derived solely from variable costs so is increasing with the quantity produced. The point where the two curves meet provides the lowest AC or efficient scale for the firm. This relationship between MC and AC to find the productive efficiency in theory extends to the long-run as shown in Figure 2.

risen by a modest increment, revenues will not increase sufficiently to meet the utility's significant additional capital service costs that are associated with the new line. For a period until the line is fully utilized the utility will therefore receive insufficient revenue to make it financially whole.

Figure 2: Relationship between LRMC and LRAC in system with economies of scale



In addition, an important determinant of the financial position of the firm is the form of regulation, which will affect the amount of systematic risk faced by the firm. The level of systematic risk faced will be higher in general for incentive-based regulation when compared to rate of return regulation (see section 3.1). The firm should receive appropriate compensation for systematic risk through its cost of capital, more specifically via the beta parameter in the cost of equity capital. However, regardless of the cost of capital, under highly powered incentive regimes, greater variability in revenue will be evident. Greater variability of revenue affects the financial position of the firm by creating a disconnect between revenues and costs.

2.3 Social Equity

Social equity is a non-technical ingredient that forms part of a tariff scheme. It is associated with the ability of low income consumers to purchase electricity. Meeting social objectives usually requires subsidies to some consumer groups. Subsidies distort tariff economic signals and need to be analysed and assigned carefully, to minimize distortions in consumption patterns that may compromise economic efficiency.

In any tariff system, there are elements of subsidy or cross-subsidy. These can include:

- **Explicit (or implicit) subsidies** between the company and other sectors in the economy, where revenue does not cover the full cost of supply.
- **Cross-subsidies** that can take various forms:
    - Cross-subsidization between tariff categories;
    - Regional subsidies, for example between low cost (urban) and high cost (rural) customers; and
    - Cross-subsidization between high income and low-income customers, for example a Life Line Tariff regime.

Subsidies will arise because the cost to supply customers is not homogenous. Moreover, it does not make sense economically, or practically, to eliminate all cross-subsidies.

Typical examples in the case of Lesotho are:

- Life Line tariffs for low income (consumption) customers, which result in either cross-subsidies from high income (consumption) customers or that rely on exogenous direct subsidies.
- A national uniform tariff as in Lesotho, which is maintained for policy and equity reasons. It will necessarily result in some cross-subsidies from urban areas to rural areas, especially where customers are connected to the distribution network in extremely remote areas.

Those cross-subsidy cases illustrate two important issues:

- The necessity for key aspects of subsidy policy to be devised at a policy (Governmental) level,
- The necessity for direct and cross-subsidies to be understood by all parties and measured where possible.

Subsidies are not included in the calculation of the economic cost of supply and tariffs. These will be addressed in later tasks.

3 REGULATORY TARIFF REGIME ASSUMPTIONS

The computation of the Economic Costs and Tariffs depends in part on the regulatory tariff regime adopted. The tariff regime for Lesotho will not be fully defined until Task 8 (Deliverable 9), however to allow for the computation of economic costs and tariffs, some assumptions are needed to allow the model construction. These are described in the next sub-sections.

3.1 COST PLUS OR INCENTIVE BASED REGIME?

When computing economic tariffs is it is necessary to consider the basis for establishing costs in the estimation of the economic cost of supply. There are two distinct cases:

- Considering actual capital and operational expenditures of LEC, associated with the current managerial and operational status of the company, with tariffs computed therefore assuming a "**Cost Plus**" tariff regime; or
- Considering efficient costs and expenditures (capital and operational), associated with a performance improvement scenario with tariffs computed therefore assuming an **"Incentive Based"** tariff regime.

Historically, the tariff regime traditionally known as **"Cost Plus"** or **"Rate of Return (ROR)"** regulation has been the dominant approach for the definition of public service tariffs that involve natural monopolies such as electricity supply in Lesotho. Under this approach, the regulated service company can charge tariffs that cover its reasonable operating costs and ensure a fair rate of return on its capital. If the company faces relevant changes in its costs, it can require the regulator to re-set tariffs.

This methodology generally guarantees that the operator will recover its costs, and that the cost of capital would be low, due to the low risk of the business. However, international experience (particularly in the United States) has shown that the frequency of the reviews reduces incentives for productive efficiency and raises regulatory costs[3]. It also may be considered that this approach has developed incentives to over-invest in capacity and service quality[4].

"Incentive Based" Regulation (IBR) was introduced in Latin America in the late 1980s (Chile, Argentina) and England at the beginning of the 1990s in an attempt to overcome the limitations of ROR. Under an IBR approach, the regulator must define a maximum regulatory constraint (price or total revenue) to be applied by the operator, based on efficiency criteria, without taking directly into consideration the real financial situation of the company. Moreover, prices are set for a certain tariff period (4 to 5 years), so the regulated company would have the incentive to reduce its costs during that period, as every cost reduction relative to the revenue requirement based on efficiency criteria would result in additional earnings compared to those expected in the tariff.

International experience shows that this kind of regulation provides better incentives to productive efficiency, even though in practice, price or revenue cap estimations have several common aspects with ROR regulatory approach. This is because in setting the regulatory constraint the regulator must consider, at least as a reference, the real financial situation of the regulated firm.

The economic theory underlying tariff regulation (as presented in Section 2) was developed in the context of private ownership or autonomous management of network and generation assets. The

[3] Due to information asymmetry issues.

[4] Averch, H. and Johnson, L. 1962. *Behavior of the firm under regulatory constraint*. American Economic Review 52.

incentive-based regulatory framework relies on the company having an economic incentive to maximize profits. Shareholders have an economic incentive to maximize return on their investment, and management must have incentives passed through into their contracts.

When a utility is in public ownership, incentive based regulation does not function in the same way. There are no shareholders, so there is no direct economic incentive on management to minimize costs, unless precise corporate and governance rules give place to those incentives. Without careful design, conventional approaches to incentive based regulation in tariffs will not be effective in a publicly owned utility.

For this task, the computation of economic costs and tariffs is based on taking a “first pass” view of LEC costs assuming opex costs as a percentage of gross assets book value remains constant across the tariff period, and therefore setting a tendency towards an incentive based regime. However, this efficiency criteria will be reviewed in Task 6 during the LEC benchmarking exercise. The relative effectiveness of applying a conventional tariff regime approach under the public ownership status of LEC will be reviewed in Task 8 (tariff determination) and Task 9 (Roll-out strategy) and additional measures may be considered, for example the approach may be complemented with internal governance and additional incentive measures for LEC.

3.2 Price Cap or Revenue Cap?

Price cap regulation sets a cap on the price the firm can charge. It is often argued that the application of a price cap approach to regulated companies may entail some potential disadvantages:

- It tends to encourage increased sales by the utility since prices, but not quantities, are constrained under the scheme. This incentive, in some circumstances, may be inconsistent with energy efficiency goals to reduce consumption and in turn may induce extensive on-grid expansion plans, that may result in clear inefficiencies.
- Price (or revenue indeed) cap approaches may potentially be less suitable in cases where the regulated firm has high fixed costs and faces volatility in revenues beyond its control. A pass-through mechanism of non-manageable costs is critical.

Revenue cap regulation is a kind of IBR. It is like price cap except that revenue is adjusted to reflect changes in the number of customers or demand. The incentive provided to a regulated firm to reduce costs under a revenue cap is like that provided by a price cap. However, revenue caps differ from price caps in reducing both the incentive and the risk associated with sales. This pricing feature of revenue caps has been criticized since it may also encourage the utility to raise its prices, thus reducing sales to stay within the revenue cap, and maximizing profits. Other theoretical criticisms maintain that price caps are more efficient in setting relative prices, and that pricing in general under revenue caps is more variable.

To overcome the inherent problems with a pure price or revenue cap, in some cases a ***Hybrid Revenue Cap*** has been proposed as a solution. The advantage of a hybrid revenue cap over the above methods is that it gives the regulator more flexibility to design a formula that best reflects the firm’s (exogenous) cost drivers. This should lower the risk that the regulated company will suffer windfall losses or enjoy windfall gains because of shocks (e.g., demand “shocks”) that are beyond the company’s control.

For the case of Lesotho, the computation of economic costs and tariffs is based on Revenue Cap regulation. This is to avoid the potential disadvantages of Price Caps mentioned above – i.e., to avoid encouraging an inefficient level of on-grid investment. This approach is also consistent with the Charging Principles for Electricity and Water and Sewage Services (2012).[5] .

3.3 Yearly or Multi Year?

The length of tariff period will be finalised as part of Task 8.

For this task, the computation of economic costs and tariffs in Lesotho is based on a Multi-Year tariff regime, with a three-year period. The choice of multi-year is to avoid the tariff fluctuations and volatility that are present in a Single-Year regime, in addition to the institutional and procedural efforts that Single-Year regime may generate.

The length of the tariff period (3 years) is in line with international experience (3 to 5 years), as a minimum period to effectively mitigate the tariff volatility. In general terms the tariff period length is the result of trade-off between mitigation of volatility (the longer the period, less volatility) and the efficiency gains retained by the operator (the longer the period, higher efficiency gains kept by the utility and not transferred to the customer).

The justification for the multi-year tariff period will be explored further in task 8 (deliverable 9).

3.4 Return on Assets and WACC

As discussed in section 3.1, the **Cost-Plus** tariff regime includes an allowance for the provision of a reasonable rate of return on assets.

For this task, the computation of economic costs and tariffs is based on rate of return via Weighted Average Cost of Capital (WACC). In the "**Cost Plus" Reference Case** presented here a return on asset calculation is included in the tariffs for the existing and new asset base.

It is important to note, however, that the regulatory mechanisms for including a return on assets in the allowable revenue were developed in the context of private ownership and as LEC is a wholly government-owned state utility, return on assets is arguably a matter of public policy and may therefore be subject to different criteria. We have provided our recommended value for WACC below and it can be seen that we have adopted a compromise value between the extremes of commercial private sector capital and long term low cost Government/donor capital. A low return on capital would make electricity more affordable, potentially boosting economic growth. A high return on capital would give LEC a greater capacity to raise commercial finance and be more independent of Government funding. A key factor in reviewing the return on capital expected by LEC is the policy on the future funding of capital investment in electricity supply. If Government expects LEC to secure sufficient revenue in the future to fund all its required investments then realistic commercial returns on capital will need to be allowed.

The treatment of return on assets will be finalised in Task 8 (deliverable 9).

Furthermore, the return on asset calculation requires a rate of WACC to be applied. In fact, a WACC is needed for three components of the economic cost of supply calculation:

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[5] This regulation states at section 5 that "*For network businesses (electricity transmission and distribution and water and sewerage other than licensed water treatment plants and sewage treatment plants) requesting multi-year tariffs, licensees will normally be expected by the Authority to request a revenue-cap formulae".*

- The Long-Run Marginal Cost and Long-Run Average Cost of Generation – see section 6.3.1;
- The Long Run Marginal Cost of the network (Average Incremental Cost) – see section 6.4.3; and
- The Return on Asset calculation.

The real post-tax WACC is defined as follows:

$$WACC = \frac{d}{d+e} r_{debt}(1-t) + \frac{e}{d+e} r_{equity},$$

where:

d = the market value of LEC's debt,

e = the market value of LEC's equity,

$\frac{d}{d+e}$ = the debt ratio,

$\frac{e}{d+e}$ = the equity ratio,

r_{debt}= the real cost of debt.

r_{equity}= the real cost of equity, and

t = the corporate tax rate, in the case of Lesotho 25%.

The **debt/equity ratio** is calculated based using the 2015/16 audited accounts. The **cost of debt** is obtained in the same way. LEC has a modest level of long-term loans, mainly for vehicle financing from Standard Lesotho Bank at 3% below prime. The prime rate is assumed at 11.5% (CBL data, 2016) giving a debt rate of 8.5%. It is important to note that LEC has obtained the majority of its network funding to date through capital grants and consequently the debt ratio is low. Furthermore, anecdotal evidence from LEC has indicated that securing financing for network and generation investment has been and continues to prove a challenge as there is no appetite from the commercial sector for this type of lending.

Table 1: Debt cost calculations for LEC

Debt cost calculations	
Debt cost	**8.5%**
From LEC 2015/16 audited accounts:	
Total equity	2,708,060,563
Total equity and liabilities	2,966,128,708
Equity ratio	**91.3%**
Debt ratio	**8.7%**

The Capital Asset Pricing Methodology (CAPM) can be used to calculate the **cost of equity** component of the WACC. This aligns with the approach laid out in the *Charging Principles for Electricity and Water and Sewerage Services*. The assumptions for this calculation are shown in Table 2.

Table 2: Equity cost calculations using CAPM

Equity cost calculations	
A. Risk-free rate: Lesotho Government 10yr bond (Prospectus for Lesotho Government bonds)	10.0%
B. Assumed Market return (Consultant's analysis of performance of FTSE/JSE 40 Top Index)	12.5%
C=B-A. Market premium	2.5%
D. Country risk premium	1.0%
E. Typical 'Beta' for electricity network business (Based in industry norm)	0.8
F=A+D+ExC. Cost of Equity (via CAPM)	**13.0%**

The CAPM analysis results in a cost of equity of 13%. However, again considering that LEC has relied on capital grants from the GoL, on which no return is expected (although there is an associated opportunity cost for Lesotho of investing government funds in the electricity sector at the expense of other opportunities) it is arguably the case that the cost of equity from an LEC revenue requirement point of view is 0%. However, from a sector sustainability point of view it may be advantageous to consider some level of equity cost. As a result, we have assumed a mid-point of 6.5% cost of equity in the analysis.

Drawing all this together results in a real post-tax rate of 0.085*.087*(1-0.25) + 0.065*.913 = 6.5% as follows and pre-tax of 8.7%, which aligns with the 6.5% discount rate used in deliverable 4.

4 Lesotho Perspective

From the perspective of Lesotho, the tariff regime objectives and assumptions discussed in section 2 and 3 have relevant implications when proposing a future tariff regime (Deliverable 9). The main questions that arise can be summarized through the following:

Table 3: Tariff Regime objectives in the Lesotho perspective

Tariff Regime Objective	Best practice strategy from international experience	How can it be reached in the case of Lesotho?
Allocative efficiency	Cost reflective tariffs, with a forward-looking perspective	• Tariff rates structure based on proper allocation (see section 6.4) of long run marginal costs per voltage level (transmission-HV and distribution-MV)
Productive efficiency	Incentive based tariff regimes	• Prudent review of LEC actual costs for required revenue computation – explored more in task 6 (deliverable 7) when LEC benchmarking undertaken. • Internal governance and incentive mechanisms in LEC – explored more in task 9 (deliverable 10) where options for improving governance of LEC are presented.
Dynamic efficiency	Guarantying a fair rate of return to investors (based on WACC)	• Using a realistic WACC adapted to the fact that the sector will continue financing its future expansion with capital grants and public funding from the GoL – tariff computations undertaken assuming a mid-point of 6.5% cost of equity in the analysis.
Financial viability	Adjusting long-run marginal costs tariffs when computing revenue requirements	• Adjusting LRMC of generation to LRAC (in the Lesotho case lower than

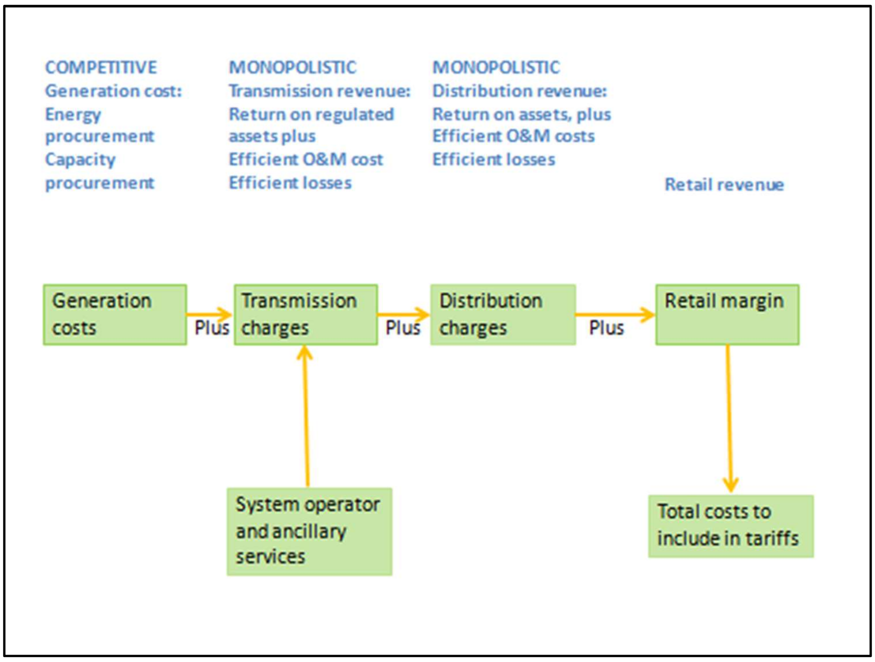
Tariff Regime Objective	Best practice strategy from international experience	How can it be reached in the case of Lesotho?
		LRMC) to maintain a balance between financial viability for generation and the level of generation costs pass through to user tariffs (section 6.3.1 (4) and 6.8) • Adjusting LRMC of the Transmission and Distribution segments to align with required revenues – the revenue requirement computations include a financial mark-up applied to the LRMC of transmission and distribution (section 6.5).
Social equity	• Explicit subsidies from public funds or other sectors of the economy • Cross subsidies among tariff categories	• Life line tariffs funded through cross subsidies from other tariff categories – this is explored more in task 5 (deliverable 6) where a life-line tariff is proposed.

5 Economic Cost of Supply: Building Blocks Approach

The estimation of Economic Cost of Supply in the electricity industry is often carried out through a sequential approach (generation - transmission – distribution – supply) by which the costs of each segment of the industry (being it unbundled or not) are added to the aggregated costs of the previous segments. This is often referred to as a Building Blocks Approach.

The following diagram represents a typical Building Blocks Approach for economic cost of supply computation:

Figure 3: Components of electricity supply chain and building blocks approach



5.1 Generation Costs

In systems where generation has been separated from the remainder of the sector generation costs will depend on the wholesale market and bilateral agreements for the purchase of energy. In the tariff structure for such an unbundled system, generation costs of energy are typically transferred to end users (pass through) with formulae that usually make utilities neutral to bulk costs.

The “pass through” mechanism is the formula and methodology for generation rates or prices to be passed through to tariffs. In this way payments by customers of the distribution company allow it to recover the costs / prices paid to power suppliers in exchange for energy supply. For efficiency and sustainability, the following criteria are normally taken into account in the design of a “pass through” mechanism:

- Cost reflectiveness, but at the same time promote economic efficiency and efficient commercial management of the distributors.
- Attributed between consumers in a fair and transparent way.
- Simplicity of formulation.

- Flexibility, which means the ability of the bulk supply regime to adjust as changes are introduced in the power sector; and
- Financial viability, particularly in delivering the revenues required to recover the cost of the generation and the necessary capacity investments for expansion of the generation system.

In Lesotho, the regulatory rules allow for the automatic pass through to tariffs of unspecified costs. The current pass through charging principle for Lesotho is outlined in the Guidelines for implementation of Pass-through Mechanism (2011):

"The Bulk Supply Tariff (BST) shall be calculated, at the beginning of each tariff year on the basis of the forecasted price conditions and then any difference between expected and actual revenues for the months or year shall be compensated in the following year's BST or as may be found appropriate by the Authority during the year. This is because generators prices will vary from one month to another and from one year to another. Furthermore, the capacity and energy demand along each month or year will usually differ from forecasted values."

There is no explicit "pass through" formula to consider generation costs into tariff computation and so **transparency** could be improved, although the updated version does allow **flexibility**. The approach and formulation mechanism adopted for the computation of generation charges in Section 6.3, provides a "pass through" formula for transferring actual generation costs to final tariffs.

5.2 Ancillary Services and System Operator Costs

It is recommended that the following reserves should be paid by consumers on a MWh basis as part of the bulk generation tariff:

- Spinning Reserves;
- Non-Spinning Reserves;
- Voltage Control and Reactive Power Regulation; and
- Black-Start Capability.

System Operator costs include investment and operational costs to operate the generation system and the transmission network in an efficient way.

In the case of LEC, ancillary services costs are included in the tariff schedule for procuring power from Eskom and so form part of generation costs building block. It is therefore not necessary (for the purpose of determining end-user tariffs) to add ancillary costs separately from power acquisition costs already transferred to tariffs.

5.3 Transmission and Distribution (T&D) Costs

Given that LEC does not separate its transmission and distribution records, the analysis firstly computes a combined estimation for T&D costs. The resultant T&D costs consider:

- **Capital costs**, including
    - The Regulatory Asset Base (RAB), as the starting value of assets in operation. It is assumed that the value of the LEC asset base with a reduction to exclude generation assets is included in the RAB.

  - Fixed investment and working capital, derived from the distribution expansion plan provided by LEC and integrated into the expansion program from task 3 (CAPEX)[6],
  - The rate of return on the investment (to cover both the cost of debt and the cost of equity) as discussed in section 3.4.
  - The assets rates of depreciation. It is assumed in the modelling that existing assets depreciate at the same rate as historically according to LEC audited accounts. New assets depreciate at 3.7% per year.[7]

  A Financial Approach is adopted, with a rolling forward model of the annual Asset Base[8], which means that the value of the Asset Base is updated each year as new capital expenditures are added and depreciation is deducted.

- **Operation and maintenance costs (OPEX)**. These costs may be considered as actual or efficient, depending on the regulatory practice (see section 3.1).
- **Administrative and commercial costs**: meter reading, billing, collection, information and working capital. These costs may be considered as actual or efficient, depending on regulatory practice.
- **Network losses at each voltage level.** These costs may be considered as actual or efficient, depending on the regulatory practice.
- **Connection costs to LEC,** which will ultimately be separately considered in the proposed connection and capital contribution policy.

Note that assets funded through capital contributions are not recognized to yield return on capital and return of capital (depreciation) to LEC as they have been funded by third parties. But LEC will be entitled to receive income to recover OPEX costs for the operation and maintenance of those assets.

We note that the Charging Principles for Electricity and Water and Sewage Services (2012) indicates that *"the required revenue shall normally be based on forecasts of reasonable operating costs plus a rate of return on net re-valued fixed assets – the regulatory asset base (RAB)"* and the principles described above are consistent with this requirement. Furthermore, the regulation indicates that when designing tariffs, transmission, distribution and supply, tariffs and charges should be distinguished by voltage level. Therefore, in addition to the combined T&D costs computation an attempt is made to allocate costs to transmission (HV) and distribution (LV) based on the application of splitting factors – see section 6.4.1.

5.4 Supply Costs

Usually, in cases in which distribution (network operation and maintenance) and supply activities are merged (as is the case of LEC), normal service costs (supply margins) are embedded into normal administrative and commercial costs of the distribution network. The developed model makes this assumption but still separately includes readily identifiable supply costs, which are directly linked to the provision of key supply activities (commercial cycle management and customer care service).

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[6] Including development projects' interests during construction.

[7] The average rate of depreciation for generation, transmission and distribution assets in the LEC audited accounts 2011-15.

[8] An alternative approach would be the Latin American one in which Allowed Revenue is computed for the initial year of the tariff period, on an optimized asset base, and prices estimated as average costs of this optimized network.

By separately identified service costs the model allows for the application of different cost allocation and charging rules to these costs from the rules applied to other network costs. Furthermore, it allows the supply costs (and associated margin on the costs of purchased services) to be separately computed which is consistent with the approach to calculating the required revenue outlined in section 6 of Charging Principles for Electricity and Water and Sewage Services (2012).

6 Calculation of Economic Tariffs: Unbundled Charges

This section presents the methodology applied to the design and calculation of electricity tariffs based on economic costs of supply. It describes in detail the conversion of economic costs of supply (as presented in the previous section) into generation charges and network charges, which in turn feed into end-user final tariff components. As already discussed, the final recommendation for the methodology to be applied will be presented in Task 8 – LEWA Tariff Determination Methodology.

The resulting tariffs, are purely cost-reflective (representing the economic cost of supply to different customer types), which means they are free of any kind of subsidy (direct or external). Cost reflective tariffs are therefore the result obtained from the objective application of the tariff calculation methodology; they are a base case for evaluating affordability issues and a starting point for the introduction of subsidies should these be considered necessary. Final tariffs can then be computed that incorporate the adopted subsidy regime as applicable.

The Economic Costs of Supply model uses the output from the Development Programs (Long Term Expansion) estimated in Task 3 (Deliverable 4) as a key input to the tariff design analysis.

6.1 Tariff Categories

The definition of customer categories has a very relevant impact on tariff levels and their adequacy to reflect economic costs of supply. We have evaluated the current set of customer categories and we have also analysed the possibility of designing new ones, either modifying the definition of the existing ones or adding previously non-existent categories.

Ideally, customer categories should be designed to simultaneously be representative of the underlying supply cost structure and the electricity usage structure. In practice, there are implementation constraints that complicate re-configuration of existing customer categories, notably:

- Availability of historical data with a level of disaggregation compatible with proposed new customer categories, to enable calculation of the new rates,
- Inertia or reluctance of customers to accept new customer categories (customer category redefinition is not necessarily neutral for customers), and
- Availability of systems (such as commercial cycle management) and metering infrastructure compatible with the proposed new customer categories and tariff components.

In the absence of clear benefits from changing customer categories definition, the above listed constraints deter the regulator from abruptly redefining tariff groups. This should be understood as a barrier or transition cost, but not an insurmountable obstacle.

In the case of Lesotho, we have not identified any immediate need for LEWA to change customer categories in the short term, therefore for this task no adjustments are made to the current categories.

Nevertheless, it may be suitable to create new tariffs in the following cases:

- A new lifeline tariff category for domestic consumers, to create the opportunity to apply social measures to the cost of electricity for low income households who cannot afford the economic (subsidy free) cost of their electricity supply. This will be evaluated and discussed with LEWA in deliverable 6 – Life-Line Tariff.

- In case in the future it is decided to implement time discriminating tariffs (such as time-of-day tariffs for example). At which point, it will be mandatory to install systems and metering equipment that support the required time discrimination.

For reference, the current customer categories are:

Table 4: Current customer categories

Category	Voltage Level	Description
Domestic	LV	For the supply of electricity to premises used solely for private residential purposes.
General Purpose	LV	For the supply of electricity to premises used solely for primary and secondary schools and churches.
Street Lighting	LV	For the lighting of public areas (streets).
Commercial LV	LV	For consumers using electricity entirely or predominantly for purpose other than industrial and regularly having a maximum demand of 50kVA measured during any 30-minute period in the course of a meter reading period.
Industrial LV	LV	For consumers using electricity entirely or predominantly for industrial purposes and regularly having a maximum demand in excess of 25kVA measured during any 30 minute-period during the course of a meter reading period.
Commercial HV	HV	For major non-industrial consumers it may be desirable or essential for a supply to be given at medium voltage or high voltage.
Industrial HV	HV	For major industrial consumers it may be desirable or essential for a supply to be given at medium voltage or high voltage.

6.2 Tariff Structure

There are five distinct charges that can be applied through a tariff structure:

1. For energy supplied
2. For maximum demand taken in a specific period (typically monthly)
3. A fixed component for making the connection available
4. A charge that varies with time of day
5. A charge for reactive power consumption

In the context of this project the first three charges are applicable: charges for energy supplied, for maximum demand taken, and for making electricity available (a fixed element) (see Table 5). Time of day variations and charges for the use of reactive power are included in tariff structures in many systems but these are not currently applicable in Lesotho because the metering systems are not in place.

Charges for energy supplied are the simplest form of charging. A customer's consumption of electricity determines the payment it must make. This form of charging is typically applied to domestic customers, whether on credit metering or pre-payment. This form of charging is particularly applicable where customers have low usage as it has relatively low metering costs.

Charges for maximum demand are made where customers may have significant capacity requirements that will impact on the electricity supply system. Maximum demand charges are typically applied to commercial and industrial customers. However, in this case energy charges are also relevant so a two-part tariff is normally applied. Metering is therefore more complex and expensive.

The tariffs for energy and maximum demand can be made cost-reflective by allocating energy specific costs to the energy charge and capacity-specific costs to the maximum demand charge. In Lesotho we will show that commercial and industrial customers are currently under-charged for energy and over-charged for maximum demand. We will also show how correcting this imbalance will impact customers: high load factor customers (e.g., a factory operating 24 hours per day) incurring significant payment increases while low load factor customers (e.g., a welding workshop) would see bills reduce.

A fixed element is widely applied to electricity supply charging. There are significant costs associated with electricity supply that are independent of the level of consumption and are incurred by the utility even if the customer does not use electricity. A charge that reflects this reality is a necessary component in a tariff regime that is cost-reflective. Including a fixed charge is becoming increasingly relevant with the rapid development of self-generation (mainly roof-mounted solar panels). A number of new industrial and commercial consumers in the USA for example produce approximately the same amount of energy as they consume but use the utility's grid connection extensively as the energy they produce depends on daytime and sunshine. If the utility only charged for energy or capacity it would receive a very non-cost-reflective revenue for the fixed costs associated with providing that service to that customer. Fixed charges are not currently applied in Lesotho.

The logic behind analysing the most suitable tariff structure is similar to the one presented above for the redesign of customer categories. On the one hand, it is desirable to reflect in a tariff, components that are driven by the same factors that drive costs, but on the other hand, constraints affecting ease of calculation, implementation and social acceptance hinder drastic changes to the tariff structure.

The current tariff structure is shown in Table 5.

Table 5: Current tariff structure

Category	Monthly Fixed Charge	Monthly Energy Charge	Monthly Maximum Demand Charge
Domestic	NO	YES	NO
General Purpose	NO	YES	NO
Street Lighting	NO	YES	NO
Commercial LV	NO	YES	YES
Industrial LV	NO	YES	YES
Commercial HV	NO	YES	YES
Industrial HV	NO	YES	YES

6.2.1 Tariff Components

Considering the tariff components listed in Table 5, **the Consultant recommends introducing a fixed charge for all customer categories.** The reasons behind this recommendation are:

- There are a number of fixed costs that are unrelated to energy consumption and peak demand, so the cost driver matching principle is best met if those fixed costs are recovered through a fixed charge. An example of such fixed cost is the supply costs (metering, billing, managing customer complaints, etc).
- The foreseeable development across the world of distributed generation and self-generation has the potential to noticeably change energy flows in most electricity systems including that in Lesotho. The role of the interconnected electricity network is therefore likely to slowly mutate from being the main channel for delivering electricity to becoming a back-up to local or on-site generation. As this happens the energy volumes delivered by the utility are likely to reduce significantly and the fixed costs of maintaining the network to become proportionally higher. Thus again it can seen that matching cost drivers with tariff drivers requires consideration of introducing a fixed charge. Moreover there is the opportunity given by this cost of service review to introduce the concept of a fixed charge, improving the tariff structure flexibility so that in future costs could be transferred into the fixed charge as the role of the network changes. The fixed charges could be applied in a relatively modest way initially.
- A fixed component is easy to calculate and to apply. It is calculated as cost per connection per billing period, so all variables are already known and minor adjustments to the metering and billing systems are required.

The main disadvantage to the implementation of a fixed charge is that consumers dislike paying charges that are still payable even if their electricity consumption in that billing period was zero. However given the reasons listed above, it is recommended to introduce the concept now at a low tariff level, rather than wait until important changes in the usage of the electricity network make it essential but by which time the system is likely to require the implementation of a more significant fixed charge.

The application of maximum demand charges to energy-intensive consumers (commercial and industrial) as a tariff component is reasonable, as 1) their individual consumption is proportional to the cost of supplying them, and 2) they are in a position to control and adjust their peak demand to minimise their peak consumption or to accept the associated financial costs.

In the current state of the Lesotho power sector and in particular given the categories and metering devices already in place, it does not seem appropriate at this stage to create time-of-use electricity tariffs for end-users. As the system develops and as systems and equipment capable of time-wise discrimination are available, implementing time-of-use tariffs will provide a straightforward method to send adequate price signals to end-users.

Thus, the new recommended tariff structure would be as shown in Table 6.

Table 6: Recommended tariff structure – changes to the current pricing structure highlighted in bold

Category	Fixed Charge	Energy Charge	Maximum Demand Charge
Domestic	**YES**	YES	NO
General Purpose	**YES**	YES	NO
Street Lighting	**YES**	YES	NO
Commercial LV	**YES**	YES	YES
Industrial LV	**YES**	YES	YES
Commercial HV	**YES**	YES	YES
Industrial HV	**YES**	YES	YES

6.2.2 Cost Drivers

Tariffs should be driven, as much as possible, by the same cost drivers they are meant to represent. Therefore, this objective is met if:

- **fixed charges** should be a fixed amount per year (expressed in a fixed amount per billing period for practical purposes),
- **energy charges** should be driven by the units of active energy consumed (kWh) as those are the driver behind most variable costs, and
- **maximum demand charges** are driven by the sizing parameter for system capacity, which is peak demand, expressed in kVA to account for the impact of reactive energy wheeling needs.

The current tariff drivers are therefore adequate with the addition of the fixed charge.

Customer numbers (linked to income from fixed charges) and energy demand (linked to income from energy charges) forecasts were directly obtained from the Demand Forecast (Deliverable D3).

Growth rates for energy demand were also obtained from the Demand Forecast. Maximum Demand by customer category was projected applying these growth rates to historical 2016 values as shown in Table 7 below.

Table 7: Maximum demand forecast used in the computation of economic cost of supply and tariffs (2016 data is actual as provided by LEC)

	Year	2016 (Actual)	2017	2018	2019	2020
LV Commercial	kVA	176,878	177,588	182,298	187,009	191,719
HV Commercial	kVA	225,327	231,466	237,605	243,745	249,884
LV Industrial	kVA	196,483	204,649	212,815	220,981	229,147
HV Industrial (inc. LHDA)	kVA	397,804	414,337	430,870	447,403	463,937

6.3 Generation Charges

6.3.1 Generation Costs

Generation costs are the addition of fixed generation costs (unrelated to production/dispatch levels) and variable generation costs (directly proportional to energy produced).

Fixed and variable generation costs for each year are those representative of the total system's generation assets (as per the least cost expansion plan) and their expected power output levels (as per the despatch model, also linked to the least cost expansion plan).

Imports should be treated in the same way as generation costs, as they are a bulk supply cost to be passed through to end-user tariffs.

The aforementioned power generation cost can be easily translated into a short-run marginal cost (SRMC) and a long-run marginal cost (LRMC) for power generation during the forecast period.

(1) Short Run Marginal Cost (SRMC) of Generation

The SRMC is representative of the current power generation mix and only takes into account the marginal variable costs required to supply an extra energy unit.

As discussed in the Task 3 (Deliverable 4) report, the SRMC of generation can be determined by simulation of the variable costs of generation (or pseudo-units for imports) in the least-cost system despatch for the given demand condition. The model allows for this computation to take place at the maximum demand condition and also for standard and off-peak demand levels. The SRMC for the maximum demand and other conditions is shown in Table 8.

Table 8: Simulation of SRMC based on a simulation of variable costs of the plants in the least-cost despatch

Demand condition		2017	2018	2019	2020	2021	2022	2023
Maximum demand	High Season	1.85	1.76	1.76	1.76	1.76	1.76	1.76
Standard		0.76	0.77	0.79	0.81	0.82	0.84	0.86
Off-peak		0.51	0.52	0.53	0.54	0.55	0.56	0.57
Maximum demand	Low Season	0.75	0.77	0.79	0.80	0.82	0.83	0.85
Standard		0.57	0.58	0.59	0.61	0.62	0.63	0.64
Off-peak		0.42	0.43	0.44	0.45	0.46	0.47	0.48

(2) Long Run Marginal Cost (LRMC) of Generation

The Long Run Marginal Cost (LRMC) of generation represents the incremental cost of supplying an extra energy unit when all factors of production are variable. Therefore, it includes both fixed (including capital expenditure) and variable costs of the generating plant. It results from dividing the NPV difference in power generation costs for the investment horizon (in this case 2017-2030) by the NPV difference in power generation during the same period – i.e., the increment in cost for an increment in load, which is most costly at system peak.

A calculation of the generation LRMC can be derived from the task 3 (deliverable 4) model in the Determination of Medium to Long Term Development Programs. The simulated LRMC of generation in the model over the planning horizon is 1.473 Maloti/MWh.

To obtain the LRMC of power generation expressed at the end-user level (so as to evaluate its contribution to the overall cost transferred to tariffs) we simply need to multiply by the loss factors:

$$LRMC_{HV\ output} = LRMC_{generator\ output} \cdot \left(\frac{1}{1 - HV_{energy\ loss\ factor}}\right)$$

$$LRMC_{LV\ output} = LRMC_{generator\ output} \cdot \left(\frac{1}{1 - HV_{energy\ loss\ factor}}\right) \cdot \left(\frac{1}{1 - LV_{energy\ loss\ factor}}\right))$$

Since we have an input of 12.5% loss factor in the LV network and 7% loss factor in the HV network the resulting LRMC expressed at delivery points in each voltage level are as shown in the following table:

Table 9: LRMC of generation at the end-user level

System level	LRMC of generation
Generation	1.473
Transmission (HV)	1.584
Distribution (LV)	1.809

(3) Long Run Average Cost (LRAC) of Generation

As shown in section 2.2, financial viability of generation expansion is guaranteed by the Long Run Average Cost (LRAC), computed by dividing the NPV of power generation costs for the investment horizon (2017-2030) by the NPV of total power generation output (in MWh) for the same period. Whether or not the utility finds itself above or below the balanced production level and therefore finds itself subject to either economies of scale or diseconomies of scale as shown in Figure 2, LRAC gives a suitable price signal (financially sustainable) for tariff setting.

A calculation of the generation LRAC can be derived from the task 3 (deliverable 4) model in the Determination of Medium to Long Term Development Programs. The NPV 2017-30 of power generation costs is 6,595.7 million Maloti[9] and the NPV of power generation output is 10,307.1 GWh, thus the power generation LRAC of generation is 0.640 Maloti/kWh (4.92 USDc/kWh).[10]

To obtain the LRAC of power generation expressed at the end-user level (so as to evaluate its contribution to the overall cost transferred to tariffs) we simply need to multiply by the loss factors:

$$LRAC_{HV\ output} = LRAC_{generator\ output} \cdot \left(\frac{1}{1 - HV_{energy\ loss\ factor}}\right)$$

$$LRAC_{LV\ output} = LRAC_{generator\ output} \cdot (\frac{1}{1 - HV_{energy\ loss\ factor}}) \cdot (\frac{1}{1 - LV_{energy\ loss\ factor}}))$$

Since we have an input of 12.5% loss factor in the LV network and 7% loss factor in the HV network the resulting LRAC expressed at delivery points in each voltage level are as shown in the following table:

Table 10: LRAC of generation at the end-user level

System level	LRAC of generation
Generation	0.640
Transmission (HV)	0.688

[9] This figure includes existing generation, new plants and imports.

[10] In theory, any surplus obtained by LEC between the LRAC received through tariffs (639.92 M/MWh) and actual purchasing costs (as for example 140.0 M/MWh payment to Muela) should fund the necessary capacity investments for an adapted expansion of the generation system.

System level	LRAC of generation
Distribution (LV)	0.786

(4) Use of LRMC or LRAC in Tariffs

The computed LRMC is 130% higher than the LRAC needed to finance the generation system expansion. The decision about which value (LRAC or LRMC) to include in the costs chain for tariff setting is a policy decision. Considering LRMC as the generation costs component for tariff setting would have a significant impact on average tariff levels (more than 60% with respect to LRAC case), as is presented in Section 6.8.

6.3.2 Costs Allocation

Generation costs in Lesotho are largely the combination of payments to LHDA for generation from Muela and payments for bulk supplies from Eskom and EdM. The details of these generation costs are provided in the Deliverable 4 (Task 3) report. The EdM payments relate mainly to energy supply. There are maximum demand charges payable to Muela and Eskom.

It may also be noted, as was considered in Deliverable 4, that there is a potential impact of unserved energy on the LRMC of generation. There is currently no Loss of Load Probability (LOLP)-based reliability standard for Lesotho but in a developing economy, such as that of Lesotho, where economic productivity is of low energy intensity, the unserved energy criterion could be quantified.[11] The application of such a value in this analysis was not considered, though it is something that could be considered in a future analysis once a reliability standard is implemented. It may be noted that the incorporation of such an analysis could reduce tariffs by reducing levels of imports and/or generation investments included in the tariff analysis.

Regardless of source, generation costs can be broken down into two categories:

- Fixed – independent of energy delivered; and
- Variable – proportional to energy delivered.

The allocation of the fixed and variable generation costs to tariff charges is as follows:

Fixed generation costs are mainly driven by peak demand needs, to cover the maximum expected load with a certain security margin. Thus, in theory they should be allocated to tariff categories according to some measure of contribution to peak demand and security margin level requirements the costs of which are in turn transferred to a maximum demand charge or to a fixed charge. However, transferring all these fixed costs would in practice lead to excessively high fixed charges in the end-user tariffs, hardly acceptable by the general public, therefore we recommend following **the common practice of "energizing" a significant share of these fixed costs, that is, to recover them through the energy charge in tariffs** (this is the case in a diverse range of systems such as in Ghana, Tanzania,

[11] In deliverable 4 we argue that it could be set at about 3 days per year of total black-out, which is a LOLP of about 0.8%. On the same basis its value could be set US$ 0.75-1.0/kWh.

Nigeria, Spain, Italy, Turkey, Peru, Mexico). Such contribution to the energy charge is simply calculated by dividing the fixed costs by the projected energy demand including the loss factor.

Variable generation costs are recovered via variable charges, and their main driver is the energy output, therefore we recommend allocating variable generation costs in proportion to energy demand (including losses) and to recover them through the energy charge. This contribution to the energy charge is simply calculated as the total variable generation costs associated with the projected generation level (total demand plus losses plus exports minus imports) divided by that projected generation level in kWh. In other words, it is a direct pass-through of the unit generation cost.

Thus, the computation of generation charges in the end-user tariffs for year "y" is as follows:

1) The cost responsibility of each customer category is calculated as the sum of fixed generation cost and variable generation costs to that category by:

   a. First, dividing total fixed generation costs (FGC^y) into four components:

      i. Fixed Generation Costs to cover LV demand ($FGCD\_LV^y$)

$$FGCD\_LV^y = FGC^y \cdot \frac{\sum_i EC_i^y}{EL^y + \sum_j EC_j^y}$$

Where:

- "i" represents each customer category connected at LV and "j" represents each tariff category of LV and HV,
- "EC" represents Energy Consumption (in kWh),
- "EL" represents total energy losses (in kWh), including both energy losses at LV and at HV.

      ii. Fixed Generation Costs to cover LV energy losses ($FGCL\_LV^y$)

$$FGCL\_LV^y = FGC^y \cdot \frac{EL\_LV^y}{EL^y + \sum_j EC_j^y}$$

Where:

- "j" represents each tariff category of LV and HV,
- "EC" represents Energy Consumption (in kWh),
- "EL_LV" represents energy losses at the LV level (in kWh),
- "EL" represents total energy losses (in kWh), including both energy losses at LV and at HV.

      iii. Fixed Generation Costs to cover HV demand ($FGCD\_HV^y$)

$$FGCD\_HV^y = FGC^y \cdot \frac{\sum_k EC_k^y}{EL^y + \sum_j EC_j^y}$$

Where:

- "k" represents each customer category connected at HV and "j" represents each tariff category of LV and HV.

- "EC" represents Energy Consumption (in kWh)
- "EL" represents total energy losses (in kWh), including both energy losses at LV and at HV.

iv. Fixed Generation Costs to cover HV energy losses ($FGCL\_HV^y$):

$$FGCL\_HV^y = FGC^y \cdot \frac{EL\_HV^y}{EL^y + \sum_j EC_j^y}$$

Where:

- "j" represents each tariff category of LV and HV,
- "EC" represents Energy Consumption (in kWh),
- "EL_HV" represents energy losses at the HV level (in kWh),
- "EL" represents total energy losses (in kWh), including both energy losses at LV and at HV.

b. Second, allocating each fixed generation cost component to each tariff category in proportion to the selected cost allocation factor:

i. For each customer category "i" at LV:

$$FGC_i^y = FGCD\_LV^y \cdot CAFD\_LV_i + FGCL\_LV^y \cdot CAFL\_LV_i + FGCL\_HV^y \cdot CAFL\_HV_i$$

Where:

- CAFD_LVi represents the cost allocation factor for demand at LV applicable to customer category "i",
- CAFL_LVi represents the cost allocation factor for energy losses at LV applicable to customer category "i",
- CAFL_HVi represents the cost allocation factor for energy losses at HV applicable to customer category "i".

ii. For each customer category "k" at HV:

$$FGC_k^y = FGCD\_HV^y \cdot CAFD\_HV_k + FGCL\_HV^y \cdot CAFL\_HV_k$$

Where:

- CAFD_HVk represents the cost allocation factor for demand at LV applicable to customer category "k",
- CAFL_HVk represents the cost allocation factor for energy losses at LV applicable to customer category "k",

c. Third, calculating variable power generation costs (VGC) in year "y" as the product of the unit variable generation cost (in currency units per kWh) times the energy required to supply each consumers category. The latter includes the energy demand of the customer category itself plus its proportional responsibility for energy losses at its voltage level and higher voltage levels. Thus:

i. For each customer category "i" at LV:

$$VGC_i^y = VGC^y \cdot \left[EC_i^y + EL\_LV^y \cdot \frac{EC_i^y}{\sum_i EC_i^y} + \left(EC_i^y + EL\_LV^y \cdot \frac{EC_i^y}{\sum_i EC_i^y}\right) \cdot \frac{EL\_HV^y}{EL^y + \sum_j EC_j^y}\right]$$

Where:

- "i" represents each customer category connected at LV and "j" represents each tariff category of LV and HV,
- "EC" represents Energy Consumption (in kWh)
- "EL" represents total energy losses (in kWh), including both energy losses at LV and at HV,
- "EL_HV" represents energy losses at the LV level (in kWh),
- "EL_HV" represents energy losses at the HV level (in kWh).

ii. For each customer category "k" at HV:

$$VGC_k^y = VGC^y \cdot \left[EC_k^y + EL\_HV^y \cdot \frac{EC_k^y}{EL^y + \sum_j EC_j^y}\right]$$

Where:

- "k" represents each customer category connected at HV and "j" represents each tariff category of LV and HV,
- "EC" represents Energy Consumption (in kWh)
- "EL" represents total energy losses (in kWh), including both energy losses at LV and at HV,
- "EL_HV" represents energy losses at the HV level (in kWh).

6.4 Network Charges

This section describes in detail the steps followed in the Tariff Model (in Excel) to convert input data (cost and demand) into tariff components (charges).

The Economic Costs of Supply model uses the output from the Development Programs (Long Term Expansion) estimated in Task 3 (Deliverable 4) as a key input to the analysis of network charges, according to the following Table 11:

Table 11: Network Expansion Plan – RAB, CAPEX and OPEX

	Units	2017	2018	2019	2020
Initial RAB value					
LV	Mmill	1,141.79	1,151.85	1,281.72	1,386.65
HV	Mmill	1,452.19	1,438.19	1,515.74	1,575.17
CAPEX					
LV	Mmill	56.67	180.50	159.15	134.39
HV	Mmill	42.93	136.72	120.55	101.80
Depreciation					
LV	Mmill	46.62	50.63	54.21	57.16
HV	Mmill	56.93	59.17	61.12	62.62

	Units	2017	2018	2019	2020
TOTAL T&D OPEX					
LV	Mmill	181.35	202.62	221.37	237.20
HV	Mmill	78.00	87.15	95.21	102.02
OPEX - Network					
LV	Mmill	163.22	182.35	199.23	213.48
HV	Mmill	74.10	82.79	90.45	96.92
OPEX - Supply					
LV	Mmill	18.14	20.26	22.14	23.72
HV	Mmill	3.90	4.36	4.76	5.10

Initial RAB values were obtained from the Asset Register as of 31st March 2017 and brought forward as: Closing RAB = Opening RAB + CAPEX – Depreciation.

When extrapolating values for total OPEX for LEC shown in Table 11 we have assumed that the current operating efficiency rates of LEC are kept constant for the three-year period. This efficiency rate has been formulated by keeping constant the opex costs as a percentage of assets book value (9.6%). Note that the efficiency of LEC will be explored in task 6 (deliverable 7).

It is assumed that existing assets depreciate at the same rate as historically according to LEC audited accounts. New assets depreciate at 3.7% per year (average rates for T&D assets).

Total OPEX for the T&D business have been split into Network OPEX and Supply OPEX assuming that Supply OPEX represents 10% of the total in LV and 5% of the total in HV.

The CAPEX transferred to tariffs (and shown as inputs to the tariff model in the table above) are only those CAPEX funded by LEC, therefore it excludes investments funded through capital contributions and from the UAF. In any case, the OPEX associated with operating those assets is still part of the OPEX recognised as LEC's and transferred to tariffs.

Energy losses were used as inputs to the model at 12.5% for LV network and 7% for the HV network, resulting overall in 14.4% energy loses in the system.

The computed transmission and distribution costs are shown in Table 12 and Table 13. Transmission charges for an efficiently operated LEC are explored in task 6 (benchmarking) and task 7 (wheeling charges). These charges are presented in 2017 real terms and so would need to be subjected to the applicable indexation factors. Those intra-period adjustment criteria and formulation will be discussed in the tariff regime to be proposed in Task 8 (Deliverable 9).

Table 12: Transmission network and supply charges

Transmission	Units	2018	2019	2020
Depreciation - HV Assets	M mil	59.17	61.12	62.62
Return on Capital - HV Assets	M mil	128.02	133.96	138.23
Network OPEX - HV	M mil	82.66	90.31	96.77
Supply OPEX - HV	M mil	4.35	4.75	5.09
Total	M mil	274.21	290.15	302.71

Transmission	Units	2018	2019	2020
Consumption	MWh	791,478	820,377	849,277
Transmission – HV (total)	M/kWh	0.346	0.354	0.356

Table 13: Distribution network and supply charges

Transmission	Units	2018	2019	2020
Depreciation - LV Assets	M mil	50.63	54.21	57.16
Return on Capital - LV Assets	M mil	105.47	115.65	123.54
Network OPEX - LV	M mil	182.48	199.37	213.63
Supply OPEX - LV	M mil	20.28	22.15	23.74
Total	M mil	358.85	391.38	418.07
Consumption	MWh	791,478	820,377	849,277
Distribution - LV (total)	M/kWh	0.453	0.477	0.492

6.4.1 Functional Allocations

It is necessary to associate costs to specific functions and facilities. This task comprises the discrimination of costs to the following categories:

- Distribution Voltage Lines (LV or HV),
- Distribution Substations (HV/HV, HV/LV, LV/LV),
- Meters, and
- Services.

Costs (CAPEX and OPEX) are linked to the category they stem from. In order to transfer this kind of discrimination to the tariff computation model, new investments are split into HV and LV taking as splitting rule the statistics from the asset register for CAPEX and the relative contribution to peak demand for OPEX. This assumption has enabled us to distinguish CAPEX and OPEX by voltage level and, through the application of cost classification and allocation, to associate them with tariff categories and the tariff charges applied to each (see below in Table 14).

Table 14: Splitting factors used in the distribution of CAPEX and OPEX by voltage level

Relative weights: T and D over total (T+D). Obtained from Net book values in March 2017		
LV (Distribution)	%	56.90%
HV (Transmission)	%	43.10%
Relative weights: T and D as per weight in average peak demand in 2017		
LV (Distribution)	%	69.92%
HV (Transmission)	%	30.08%

The key data source for the allocation of costs to functions is the network expansion plan and the OPEX projections developed to match projected future electricity demand (energy and number of customer connections).

6.4.2 Classifying and Allocating

There are three types of cost to be allocated, specific, shared and common:

- **Specific Costs.** These costs are directly related to specific customers or customer categories. They are easy to allocate and primarily depend on cost estimations. **Specific costs are directly allocated to each customer (simple cost analysis).**

- **Shared Costs.** These costs are those not specifically related to one client but still costs that can be fairly allocated, and cost responsibility identified, based on cost studies and load profiles. **Shared costs are often forced to be referred to capacity demand[12] and are allocated based on Long Run Marginal Costs for each voltage level and load profile allocation (inside each voltage level).**

  - LRMC per voltage level: HV and LV

  - Cost responsibility analysis **inside each voltage level**

    Once the LRMC for each voltage level is defined, it is necessary to further breakdown these costs into charges for each tariff category group within that voltage level. This breakdown is carried out by analysis of averages based on a load profiling survey, which identifies the share in total costs of each customer category. If there is no load profile survey, allocation may be carried out with the use of "special purpose" referential load profiles (see Section 6.4.4).

    To assess cost responsibility for small customers, who (generally) are not billed using Time of Use (TOU) metering equipment, the estimation of the aggregated load profile of the tariff category reflects participation in peak and off-peak periods.

- **Common costs allocation:** These costs are those not specifically related to one client and also that cannot be fairly (nor efficiently) allocated to a service or customer group. **Common costs are often distributed to groups of customers based on case specific rules, not necessarily efficient.** Being general costs, they are not naturally linked to specific uses (overhead, headquarter costs, cleaning services, etc.), so an exogeneous sharing assumption is required. In the case of Lesotho, as we will detail later on, we have opted to apply proportional mark-ups to the LRMC items to ensure full cost recovery, and therefore have common costs allocated in direct proportion to shared costs. In practice, this means that the network costs in the tariffs (represented by the network capacity LRMC) will be scaled up or down adjusting its value so that the overall allowed revenues are recovered.

6.4.3 Network Costs and Supply Costs

Supply Costs are a direct pass-through of the allowed operating expenses associated to the provision of commercial cycle management and customer service at the utility. That is, the separately identified components of the required supply margin.

[12] Most shared costs are fixed network costs, and the network is dimensioned to cope with the peak demand it needs to supply. Therefore, once invested, it is a fixed cost directly linked to a capacity need.

Network costs are obtained by computing the Long Run Marginal Cost of the network and adding on top of it the allowed network operating expenses.

(1) Long-Run Marginal Cost of Transmission and Distribution (Disaggregated)

Long Run Marginal Cost of transmission and distribution (disaggregated) is calculated, by voltage level, following the Average Incremental Cost proxi[13] applied to the 3-year tariff calculation period (so the Net Present Values -NPV- are calculated on values from y=1 to y=3) and an average useful life of 30 years.

- LRMC of the network (AIC) at the LV level:

$$LRMC_{LV}^{TP} = AF \cdot \frac{NPV_{y=1}^{y=TP}(CAPEX\_LV^{y})}{NPV_{y=1}^{y=TP}(\Delta PC\_LV^{y})}$$

Where:

  - AF is the Annuity Factor, that is the factor that, multiplied by a certain initial total amount (NPV of CAPEX in this case) gives the equivalent fixed annual amount of money that, applied over the useful life of the asset, adds up to the recovery of the initial total amount plus the interests over time, valued at the relevant WACC. AF is calculated as:

$$AF = \frac{WACC}{1-[1+WACC]^{UL}}$$

    Being WACC the relevant applicable WACC and UL the asset's useful life (in years), that takes the value of 30 in this case.
  - "NPV" means net present value, calculated discounting annual values at the relevant WACC,
  - "CAPEX_LV" is the total network CAPEX forecast at the LV level,
  - "ΔPC_LV" represents year-on-year variations in peak consumption of LV customer categories (in kW).

- LRMC (AIC) at the HV level:

$$LRMC_{HV}^{TP} = AF \cdot \frac{NPV_{y=1}^{y=TP}(CAPEX\_HV^{y})}{NPV_{y=1}^{y=TP}(\Delta PC\_HV^{y})}$$

Where:

  - AF is the Annuity Factor, that is the factor that, multiplied by a certain initial total amount (NPV of CAPEX in this case) gives the equivalent fixed annual amount of money that, applied over the useful life of the asset, adds up to the recovery of the initial total amount plus the interests over time, valued at the relevant WACC. AF is calculated as:

[13] Long Run Marginal Cost (LRMC) is a theoretic definition that requires a differential increments expansion of the system that is impossible to apply in real systems, on which discrete capacity increases are verified. This is why Average Incremental Cost (AIC) is considered as a reasonable approximation to LRMC.

$$AF = \frac{WACC}{1 - [1 + WACC]^{UL}}$$

Being WACC the relevant applicable WACC and UL the asset's useful life (in years), that takes the value of 30 in this case (typical reference value for useful life for network assets).

- "NPV" means net present value, calculated discounting annual values at the relevant WACC,
- "CAPEX_HV" is the total network CAPEX forecast at the HV level,
- "ΔPC_HV" represents year-on-year variations in peak consumption at the HV voltage level, calculated as the sum of HV and LV customer categories (in kW).

Then, the LRMC is decomposed into its two components: the one that represents the repayment of the principal of the initial amount and the other that represents the annual fixed interest to repay the return on the initial amount (linked to Return of Capital) at the relevant WACC.

Return of Capital and Return on Capital for each customer category are obtained by multiplying the relevant LRMC component (in currency units per kW) by the average peak demand (in kW) of that category each year and applying to that the selected cost allocation criterion (as we will see in the next section).

Using an average useful life of 30 years and a post-tax real WACC of 6.50%, the Long Run Average Incremental Cost for each network voltage level is:

- HV network: 3,860.58 M/kW
- LV network: 7,853.58 M/kW

But these are forward looking average incremental costs, to ensure full cost recovery (and correct any under- or over-recovery of allowed revenues) for the utility we should apply a financial mark-up to them (as we describe in section 6.4.2), the Average Incremental Costs resulting after the mark-up adjustment are:

- HV network: 920.38 M/kW,
- LV network: 1,872.34 M/kW.

In this case, post-adjustment Average Incremental Costs are lower than pre-adjustment because the unitary cost of investments to supply future increments in demand is higher than that required in the past.

These costs can be "energized", that is, expressed in per kWh supplied to end-users rather than in per incremental kW of peak demand supplied. This facilitates interpreting their contribution to the overall average economic cost of supply. The energized network Average Incremental Costs (post-adjustment) for the initial year would be:

- HV network: 0.302 M/kWh (per kWh delivered at HV level) or 0.345 M/kWh (per kWh delivered at LV level),
- LV network: 0.186 M/kWh (per kWh delivered at LV level).

Further explanation and a worked example is provided in Annex 1. Please note that on top of the Average Incremental Costs, we should add OPEX to ensure full cost recovery:

- HV network and supply OPEX: 0.101 M/kWh (per kWh delivered at HV level) or 0.116 M/kWh (per kWh delivered at LV level). This results from dividing the total HV Network OPEX of 87.15

million Maloti by the energy demand at the HV level 860.31 MWh (481.85 MWh for LV end-users, 68.83 MWh for LV losses and 309.63 MWh for HV end-users) for year 2018.

- LV network and supply OPEX: 0.421 M/kWh (per kWh delivered at LV level). This results from dividing the total LV Network OPEX of 202.62 million Maloti by the energy demand at the LV level 481.85 MWh for year 2018.

6.4.4 Costs Allocation

Network charges are the result of dividing the total cost to be recovered for each cost item and for each tariff category (that is, the cost responsibility of each tariff category for each cost item) by the magnitude of the tariff driver for that cost item and that tariff category.

The following table lists the cost responsibility criterion applied to allocate responsibility over costs items to each customer category (that is, their share of the burden on the system):

Table 15: Cost allocation criteria

Cost Item	Cost allocation criterion
Fixed Generation Costs for Demand	Energy consumption
Variable Generation Costs for Demand	Energy consumption
Fixed Generation Costs for Energy Losses	Energy consumption
Variable Generation Cost for Energy Losses	Energy consumption
Network Return of Capital - LV	Coincidental peaks at peak
Network Return of Capital - HV	Coincidental peaks at peak
Network Return on Capital - LV	Coincidental peaks at peak
Network Return on Capital - HV	Coincidental peaks at peak
Network Common OPEX - LV	Coincidental peaks at peak
Network Common OPEX - HV	Coincidental peaks at peak
Supply OPEX - LV	Per customer
Supply OPEX - HV	Per customer

Generation costs, both fixed and variable, have been allocated according to the energy consumption of each customer category. In practice this means the same unit cost of power generation has been applied to all customers. This is consistent with the fact that there is no time-discrimination applied to end-user tariffs and therefore all consumers in the country should contribute the same per-unit amount to power generation costs.

Network Capital and OPEX costs are allocated based on the criteria of coincidental peaks at system peak. That is, each customer category is responsible for its contribution to the system peak. This is so because network investments are mostly linked to network capacity, which in turn is dimensioned to be able to supply the peak demand in the system. Network OPEX costs are mostly fixed and can be considered directly proportional to the system size, and therefore also linked to the system's peak demand. Therefore, the burden that each customer category imposes in the network system costs is proportional to its contribution to that peak demand. To apply this criterion we considered standard load profiles by customer category based on actual data for industrial and commercial customers provided by LEC and data for domestic and general purpose consumers used by LEWA in its demand forecasts[14] in the past.

Supply OPEX, are assumed to be proportional to the number of customers. Supply activities (meter reading, billing, collection and customer complaint management) are not related with the size of the system, but rather to the number of delivery points or customers the company needs to serve.

The results of applying the Coincidental Peaks at Peak methodology to the load profiles of each customer category (shown in the graph below) are as follows:

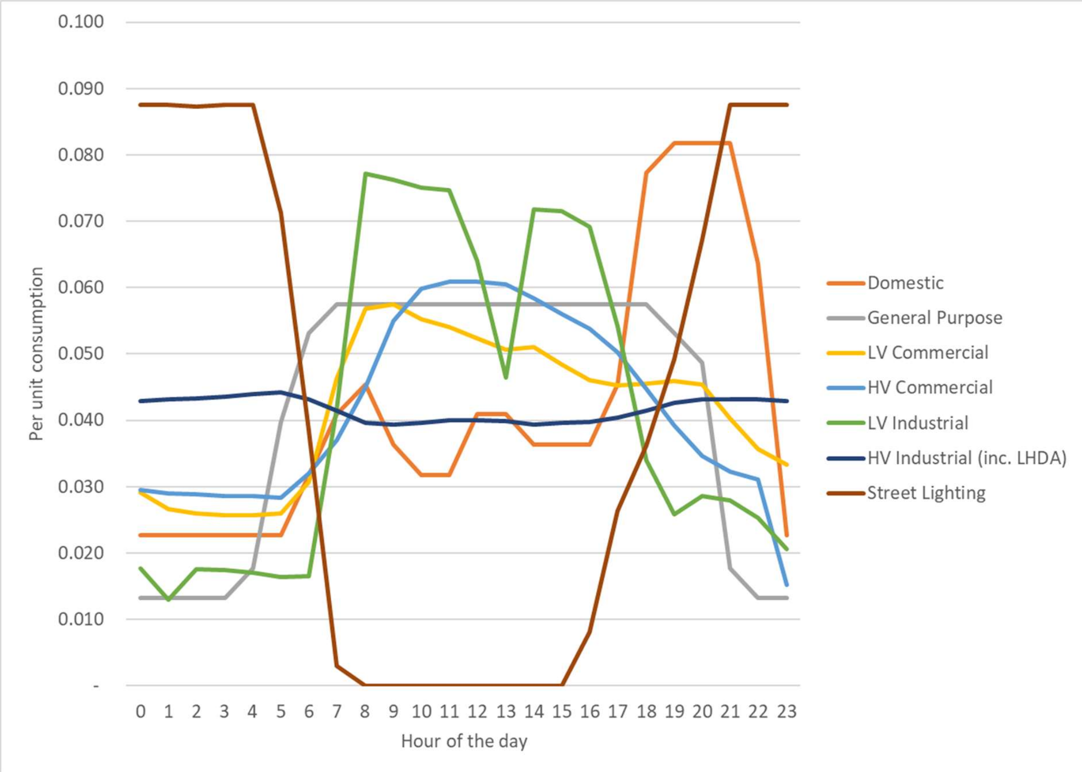
Table 16: Cost Allocation Factors using Coincidental Peaks at Peak

Customer Category	LV Factor	HV Factor	HV only Factor
Domestic	65.26%	48.29%	0.00%
General Purpose	14.39%	10.65%	0.00%
LV Commercial	9.79%	7.24%	0.00%
HV Commercial	0.00%	8.84%	34.00%
LV Industrial	10.28%	7.61%	0.00%
HV Industrial (inc. LHDA)	0.00%	17.16%	66.00%
Street Lighting	0.27%	0.20%	0.00%
Total	***100.00%***	***100.00%***	***100.00%***

Where the “LV Factor” indicates responsibility over LV network costs, the “HV Factor” indicates responsibility over HV network costs and the “HV only Factor” indicates cost responsibility for HV network costs among customer categories directly connected at HV.

[14] Obtained from the “Lesotho Demand Module v3.2a (2011-2012).xls file.

Figure 4: Standard Load Profiles used in the costs allocation derived from LEC data



And, in line with the cost drivers and the practical implementation considerations described in sections 6.2 and 6.2.2, each cost item is recovered through different tariff charges for each customer category as shown in Table 17. The detail on the allowed revenues (costs) allocated to each tariff category for each component is included in Annex 2.

Table 17: Cost drivers and tariff charges

	Domestic	General Purpose	Street Lighting	Commercial LV	Industrial LV	Commercial HV	Industrial HV
Fixed Generation Costs for Demand	Energy Charge	Energy Charge	Energy Charge	Energy Charge	Energy Charge	Energy Charge	Energy Charge
Variable Generation Costs for Demand	Energy Charge	Energy Charge	Energy Charge	Energy Charge	Energy Charge	Energy Charge	Energy Charge
Fixed Generation Costs for Energy Losses	Energy Charge	Energy Charge	Energy Charge	Energy Charge	Energy Charge	Energy Charge	Energy Charge
Variable Generation Cost for Energy Losses	Energy Charge	Energy Charge	Energy Charge	Energy Charge	Energy Charge	Energy Charge	Energy Charge
Network Return of Capital - LV	Energy Charge	Energy Charge	Energy Charge	Maximum Demand Charge	Maximum Demand Charge	Maximum Demand Charge	Maximum Demand Charge
Network Return of Capital - HV	Energy Charge	Energy Charge	Energy Charge	Maximum Demand Charge	Maximum Demand Charge	Maximum Demand Charge	Maximum Demand Charge
Network Return on Capital - LV	Energy Charge	Energy Charge	Energy Charge	Maximum Demand Charge	Maximum Demand Charge	Maximum Demand Charge	Maximum Demand Charge
Network Return on Capital - HV	Energy Charge	Energy Charge	Energy Charge	Maximum Demand Charge	Maximum Demand Charge	Maximum Demand Charge	Maximum Demand Charge
Network Common OPEX - LV	Energy Charge	Energy Charge	Energy Charge	Maximum Demand Charge	Maximum Demand Charge	Maximum Demand Charge	Maximum Demand Charge
Network Common OPEX - HV	Energy Charge	Energy Charge	Energy Charge	Maximum Demand Charge	Maximum Demand Charge	Maximum Demand Charge	Maximum Demand Charge
Network Directly Allocated OPEX	Energy Charge	Energy Charge	Energy Charge	Energy Charge	Energy Charge	Energy Charge	Energy Charge
Network Service OPEX - LV	Fixed Charge	Fixed Charge	Fixed Charge	Fixed Charge	Fixed Charge	Fixed Charge	Fixed Charge
Network Service OPEX - HV	Fixed Charge	Fixed Charge	Fixed Charge	Fixed Charge	Fixed Charge	Fixed Charge	Fixed Charge

In simple terms, the contribution of any cost item to any tariff charge is simply the total cost to be recovered from that cost item for each customer category divided by:

- The energy consumption of that customer category (in kWh) for energy charges,
- The maximum demand of that customer category (in kVA) for maximum demand charges,
- The number of customers in that customer category and by 12 for fixed charges[15].

[15] The division by 12 is just to obtain the monthly fixed charge from the annual cost amount.

In practice, an additional step is required, because the regulatory regime sets the multi-annual tariff values so that they remain constant in real terms during the whole tariff period. It is therefore necessary to obtain the weighted average value of each tariff charge that is output for each year of the three-year period so that the utility is projected to recover all of its allowed costs. This is done to avoid abrupt tariff changes within the tariff period. This is achieved by calculating charges not just as a simple division of cost by tariff driver, but as the division of the net present value of costs by the net present value of tariff drivers over the years in the tariff period:

- Each contribution to the **fixed charge** of each tariff category is calculated as:

$$Fixed\ Charge_{c,tc}^{TP} = \frac{NPV_{y=1}^{y=TP}\left(Cost\ Item\ _c^y\ \right)}{NPV_{y=1}^{y=TP}\left(\#Cust_{tc}^{y}\right)}$$

Where:

- "c" represents each cost item,
- "tc" represents each tariff category,
- "y" represents each year used in the calculation,
- "TP" represents the number of years in the tariff period (3 in our case),
- "#Cust" represents the number of customers.

- Each contribution to the **energy charge** of each tariff category is calculated as:

$$Energy\ Charge_{c,tc}^{TP} = \frac{NPV_{y=1}^{y=TP}\left(Cost\ Item\ _c^y\ \right)}{NPV_{y=1}^{y=TP}\left(EC_{tc}^{y}\right)}$$

Where:

- "c" represents each cost item,
- "tc" represents each tariff category,
- "y" represents each year used in the calculation,
- "TP" represents the number of years in the tariff period (3 in our case),
- "NPV" means net present value, calculated discounting annual values at the relevant WACC,
- "EC" represents the energy consumption (in kWh).

- Each contribution to the **maximum demand charge** of each tariff category is calculated as:

$$Maximum\ Demand\ Charge_{c,tc}^{TP} = \frac{NPV_{y=1}^{y=TP}\left(Cost\ Item_{c}^{y}\ \right)}{NPV_{y=1}^{y=T}\ \left(MD_{tc}^{y}\right)}$$

Where:

- "c" represents each cost item,
- "tc" represents each tariff category,
- "y" represents each year used in the calculation,
- "TP" represents the number of years in the tariff period (3 in our case),
- "MD" represents the maximum demand (in kVA).

The final aggregate tariff charge for each tariff category is the sum of all cost item contributions to that particular tariff charge.

6.5 FINANCIAL MARK-UP

As discussed in Section 2.2, in industries where economies of scale are important such as electricity transmission and distribution, Long Run Marginal Costs may be different to Long Run Average Costs, and recovery of LRMC in tariffs may not therefore guarantee financial viability of the utility.

More specifically, the application of pure Long Run Marginal Cost (LRMC) method to set tariffs for shared costs (and implicitly also common costs as they are proportional to the former), leads to the utility under-recovering historical sunk costs as the LRMC is lower than the LRAC.

By contrast when the network is not fully utilised and incremental costs are above LRAC, recovering LRMC could give rise to excess returns.

To ensure full cost recovery, and thus long term financial sustainability, tariffs need to be adjusted to correct such an under- or over- recovery. This can be achieved by applying a mark-up to tariffs. The mark-up, can be the result of either:

a) A regulatory model that derives tariff mark-ups on the basis that the NPV of income over the tariff period (in this case three years) matches precisely the allowed revenue, or

b) An actual financial model of the utility that derives tariff mark-ups based on some financial criteria (e.g., based on a minimum cashflow).

The resultant mark-ups are typically similar in both cases however we are applying approach a) to the LRMC of HV and LV network on the basis that it is in theory easier for the regulator to apply and the additional accuracy that approach b) provides is not justifiable when compared to the level of additional complexity needed in the modelling.

Since the mark-up is applied to the LRMC and not to the total tariff, the price signal contained in the LRMC is preserved. That is, the customer categories that consume more at the time of the system peak, and therefore contribute to a higher share of the projected need to increase investments required in the sector, will have to pay higher tariffs.

Therefore, the resulting end-user tariffs, after the mark-up adjustment, ensure that the regulated utility fully recovers its estimated revenues (fixed and variable costs, including financing costs) throughout the tariff period[16]. The unadjusted and adjusted LRMC for Transmission (HV) and Distribution (LV) network are shown in Table 18. The adjustment factor is 0.238.

Table 18: Unadjusted and adjusted LRMC for Transmission (HV) and Distribution (LV) network

		Unadjusted	Adjusted
Distribution (LV) LRMC	M/kW	3,861	920
Transmission (HV) Capacity LRMC	M/kW	7,854	1,872
Distribution LRMC (Return of Capital Component)	M/kW	1,203	287
Transmission LRMC (Return of Capital Component)	M/kW	2,448	584
Distribution LRMC (Return on Capital Component)	M/kW	2,657	634
Transmission LRMC (Return on Capital Component)	M/kW	5,406	1,289

6.6 Summary of Economic Cost of Supply

In summary, the system requires the following costs to supply future demand (all energized) shown in Table 19. The peak losses applied to generation, transmission and distribution are shown in Table 21.

Table 19: Summary of economic cost of supply based on LRMC of generation

Delivery point at voltage level	LRMC of Generation (M/kWh)	Transmission network LRMC (M/kWh)	Distribution Network LRMC (M/kWh)	Transmission network & supply OPEX (M/kWh)	Distribution network & supply OPEX (M/kWh)	Total (M/kWh)
Generation	1.473	-	-	-	-	**1.473**
Transmission	1.584	0.302	-	0.101	-	**1.987**
Distribution	1.810	0.346	0.186	0.116	0.421	**2.878**

The same calculation using the LRAC of generation is shown in the following table:

Table 20: Summary of economic cost of supply based on LRAC of generation

Delivery point at voltage level	LRAC of Generation (M/kWh)	Transmission network LRMC (M/kWh)	Distribution Network LRMC (M/kWh)	Transmission network & supply OPEX (M/kWh)	Distribution network & supply OPEX (M/kWh)	Total (M/kWh)
Generation	0.640	-	-	-	-	**0.640**
Transmission	0.688	0.302	-	0.101	-	**1.091**
Distribution	0.786	0.346	0.186	0.116	0.421	**1.854**

[16] Taking into account the time value of money, using the relevant WACC as discount factor.

Table 21: Summary of peak losses applied to generation, transmission and distribution

			2018/19	2019/20	2020/21
	Generation				
A	Generation Sent-out	kWh	925,067,351	958,927,859	992,788,367
	Transmission				
B	Energy injected at HV	kWh	925,067,351	958,927,859	992,788,367
C	Energy Losses at HV	%	7.0%	7.0%	7.0%
D=BxC	Energy Losses at HV	kWh	64,754,715	67,124,950	69,495,186
E	Energy Consumed at HV	kWh	309,632,741	320,396,266	331,159,791
	Distribution				
F=B-D-E	Energy Injected at LV	kWh	550,679,895	571,406,642	592,133,390
G	Energy Losses at LV	%	12.5%	12.5%	12.5%
H=FxG	Energy Losses at LV	kWh	68,834,987	71,425,830	74,016,674
F-H	Energy Consumed at LV	kWh	481,844,908	499,980,812	518,116,716
C+G	Total Losses	kWh	133,589,701	138,550,780	143,511,859
(C+G)/A	Total Losses	%	14.4%	14.4%	14.4%

6.7 Summary of Allowed Revenue

A summary of the per year allowed revenue corresponding to the economic cost of supply is shown in Table 22. The analysis applies the LRAC generation tariff when calculating the costs if generation component. Also shown is the anticipated income from tariffs, which due to the goal to keep tariffs flat over the three year price control, may be above or below the allowed revenue but the NPV of the differences (at the pre tax nominal WACC of 8.67%) is zero.

Table 22: Allowed revenue corresponding to the Economic Cost of Supply based on LRAC generation tariff

	2018/19	2019/20	2020/21
Return of Capital (Depreciation) - LV Assets	50,627,932	54,212,853	57,161,015
Return of Capital (Depreciation) - HV Assets	59,172,068	61,121,066	62,615,952
Return on Capital - LV Assets	105,470,706	115,647,237	123,542,419
Return on Capital - HV Assets	128,023,734	133,960,428	138,234,284
Common OPEX LV System	182,479,252	199,366,027	213,625,883
Common OPEX HV System	82,661,002	90,310,517	96,770,067
Directly Allocated	0	0	0
Service OPEX LV System	20,275,472	22,151,781	23,736,209
Service OPEX HV System	4,350,579	4,753,185	5,093,161
Total Cost Generation for Demand (using LRAC of generation tariff)	506,322,912	524,810,412	543,297,912
Total Cost Generation for Energy Losses (using LRAC of generation tariff)	85,459,806	88,633,500	91,807,195
Total Required Revenue	**1,224,843,464**	**1,294,967,006**	**1,355,884,097**
Anticipated Tariff Income (under flat tariffs)	*1,244,056,488*	*1,290,939,428*	*1,337,572,636*

	2018/19	2019/20	2020/21
Difference (NPV @pre-tax nominal WACC = 0)	*19,213,024*	*-4,027,578*	*-18,311,461*

The allowance for generation costs accounts for around 48% of the allowed revenue (Table 23) and includes a surplus above actual purchasing costs resulting from the LRAC approach – in theory, this surplus should fund the necessary capacity investments for expansion of the generation system. For example, the allowable revenue for generation in 2018/19 is 10% above the anticipated costs LEC will incur for power purchase[17] - Table 24. Overall the allowance for generation costs is 17% above anticipated LEC costs for the period.

Table 23: Proportions of allowed revenue corresponding to the Economic Cost of Supply

	2018/19	2019/20	2020/21
Generation	48.3%	47.4%	46.8%
Total Network Opex	23.7%	24.4%	25.0%
Depreciation	9.0%	8.9%	8.8%
Return on Asset	19.1%	19.3%	19.3%
Total	**100.0%**	**100.0%**	**100.0%**

Table 24: Comparison of Allowed Revenue for Generation costs with expected LEC Bulk Purchase costs

	2018/19	2019/20	2020/21	3 Year Period
Generation component of Allowable Revenue - LRAC	591,782,718	613,443,912	635,105,106	1,840,331,736
Expected LEC Bulk Purchase costs	513,746,383	512,206,778	526,183,169	1,552,136,330
Difference	*15.19%*	*19.76%*	*20.70%*	*18.57%*
Surplus (in theory, to fund new generation Investments)	78,036,335	101,237,134	108,921,937	288,195,406

If on the other hand, the LRMC of generation tariff is used to calculate the generation cost then the allowable revenue us somewhat higher – Table 25.

Table 25: Allowed revenue corresponding to the Economic Cost of Supply based on LRMC generation tariff

	2018/19	2019/20	2020/21
T & D Costs - Total	633,060,746	681,523,094	720,778,991
Total Cost Generation for Demand and Energy losses (using LRMC tariff)	1,362,390,022	1,412,257,978	1,462,125,935
Total Required Revenue	**1,995,450,768**	**2,093,781,072**	**2,182,904,925**

[17] Recalling from deliverable 4 that Muela is expected to be out on maintenance for a portion of 2018, which will in turn increase import costs.

6.8 RESULTING END-USER TARIFFS AND CONCLUSIONS

The end-user tariffs resulting from the above described exercise and applying the LRAC tariff to calculate economic costs are shown in the following table:

Table 26: Resulting Tariff Charges with generation charges computed based on LRAC

COST REFLECTIVE TARIFFS (BEFORE SUBSIDY ADJUSTMENT) (Real 2017 Maloti)					
			2018	2019	2020
Domestic					
	Fixed Charge	M/month	6.96	6.96	6.96
	Energy Charge	M/kWh	1.94	1.94	1.94
	Maximum Demand Charge	M/kVA	-	-	-
General Purpose					
	Fixed Charge	M/month	6.96	6.96	6.96
	Energy Charge	M/kWh	1.58	1.58	1.58
	Maximum Demand Charge	M/kVA	-	-	-
Street Lighting					
	Fixed Charge	M/month	6.94	6.94	6.94
	Energy Charge	M/kWh	1.75	1.75	1.75
	Maximum Demand Charge	M/kVA	-	-	-
Commercial LV					
	Fixed Charge	M/month	6.95	6.95	6.95
	Energy Charge	M/kWh	0.73	0.73	0.73
	Maximum Demand Charge	M/kVA	285.82	285.82	285.82
Industrial LV					
	Fixed Charge	M/month	6.96	6.96	6.96
	Energy Charge	M/kWh	0.73	0.73	0.73
	Maximum Demand Charge	M/kVA	254.24	254.24	254.24
Commercial HV					
	Fixed Charge	M/month	3,681.80	3,681.80	3,681.80
	Energy Charge	M/kWh	0.77	0.77	0.77
	Maximum Demand Charge	M/kVA	149.81	149.81	149.81
Industrial HV					
	Fixed Charge	M/month	3,673.14	3,673.14	3,673.14
	Energy Charge	M/kWh	0.77	0.77	0.77
	Maximum Demand Charge	M/kVA	150.36	150.36	150.36

Below are the economic tariffs in the LRMC of generation is applied to calculate the economic tariffs:

Table 27: Resulting Tariff Charges with generation charges computed based on LRMC

COST REFLECTIVE TARIFFS (BEFORE SUBSIDY ADJUSTMENT) (Real 2017 Maloti)					
			2018	2019	2020
Domestic					
	Fixed Charge	M/month	6.96	6.96	6.96

COST REFLECTIVE TARIFFS (BEFORE SUBSIDY ADJUSTMENT) (Real 2017 Maloti)					
			2018	2019	2020
	Energy Charge	M/kWh	2.90	2.90	2.90
	Maximum Demand Charge	M/kVA	-	-	-
General Purpose					
	Fixed Charge	M/month	6.96	6.96	6.96
	Energy Charge	M/kWh	2.53	2.53	2.53
	Maximum Demand Charge	M/kVA	-	-	-
Street Lighting					
	Fixed Charge	M/month	6.94	6.94	6.94
	Energy Charge	M/kWh	2.70	2.70	2.70
	Maximum Demand Charge	M/kVA	-	-	-
Commercial LV					
	Fixed Charge	M/month	6.95	6.95	6.95
	Energy Charge	M/kWh	1.68	1.68	1.68
	Maximum Demand Charge	M/kVA	285.82	285.82	285.82
Industrial LV					
	Fixed Charge	M/month	6.96	6.96	6.96
	Energy Charge	M/kWh	1.68	1.68	1.68
	Maximum Demand Charge	M/kVA	254.24	254.24	254.24
Commercial HV					
	Fixed Charge	M/month	3,681.80	3,681.80	3,681.80
	Energy Charge	M/kWh	1.78	1.78	1.78
	Maximum Demand Charge	M/kVA	149.81	149.81	149.81
Industrial HV					
	Fixed Charge	M/month	3,673.14	3,673.14	3,673.14
	Energy Charge	M/kWh	1.78	1.78	1.78
	Maximum Demand Charge	M/kVA	150.36	150.36	150.36

The reason as to why the fixed monthly charges for HV commercial, and HV Industrial are so high is explained in the table below. Of the total allowed revenue (Table 22) the Service OPEX costs (LV and HV) are allocated to fixed charges (as shown in Table 17). These are then allocated to the customer categories in the relevant voltage level as (LV or HV costs allocated to LV or HV customers) on a per customer basis (as shown in Table 15). An illustrative computation showing the components for domestic, HV commercial and HV industrial fixed charges is shown in Table 28.

Table 28: Components for domestic, HV commercial and HV industrial fixed charges

		TOTAL	Domestic	HV Commercial	HV Industrial
Number of customers (3-year average)					
LV	#	263,483	249,846	-	-
HV	#	107	-	50	57
Number of customers					
LV	%		94.8%	-	-

		TOTAL	Domestic	HV Commercial	HV Industrial
HV	%		-	46.7%	53.3%
Allocation to customer categories					
Network Service OPEX LV	M	20,275,472	19,226,082		
Network Service OPEX HV	M	4,350,579		2,032,981	2,317,598
Service OPEX allocated to fixed charges	**M**		**19,226,082**	**2,032,981**	**2,317,598**
Service OPEX allocated to fixed charges	%		94.8%	46.7%	53.3%
NPV Service OPEX allowed revenue	*#*		*53,020,274*	*5,606,405*	*6,391,302*
NPV customer numbers	*#*		*634,378*	*127*	*145*
Fixed charge	**M/mon.**		**6.41**	**3,388.30**	**3,388.30**
Fixed charge (based on NPV to achieve uniform charge)	*M/mon.*		*6.96*	*3,681.80*	*3,673.14*

The following table presents an initial comparison between the current tariffs and the obtained cost reflective ones shown above in Table 26:

Table 29: Comparison of Current Tariffs and Cost Reflective Tariffs

			2017 (Current)	2018-20 (Cost Reflective)
Domestic				
	Fixed Charge	M/month	--	6.96
	Energy Charge	M/kWh	1.347	1.94
	Maximum Demand Charge	M/kVA		
General Purpose				
	Fixed Charge	M/month		6.96
	Energy Charge	M/kWh	1.522	1.58
	Maximum Demand Charge	M/kVA		
Street Lighting				
	Fixed Charge	M/month		6.94
	Energy Charge	M/kWh	0.764	1.75
	Maximum Demand Charge	M/kVA		
Commercial LV				
	Fixed Charge	M/month		6.95
	Energy Charge	M/kWh	0.2061	0.73
	Maximum Demand Charge	M/kVA	306.3	285.82
Industrial LV				
	Fixed Charge	M/month		6.96
	Energy Charge	M/kWh	0.2061	0.73
	Maximum Demand Charge	M/kVA	306.3	254.24
Commercial HV				
	Fixed Charge	M/month		3,681.80
	Energy Charge	M/kWh	0.1861	0.77

			2017 (Current)	2018-20 (Cost Reflective)
	Maximum Demand Charge	M/kVA	262.24	149.81
Industrial HV				
	Fixed Charge	M/month		3,673.14
	Energy Charge	M/kWh	0.1861	0.77
	Maximum Demand Charge	M/kVA	262.24	150.36

To facilitate the comparison with the current tariff rates, we have simulated a Cost Reflective Tariff schedule without fixed charges:

Table 30: Comparison of Current Tariffs and Cost Reflective Tariffs (without fixed charge) without levies

		2017 (Current without levies)	2018-20 (Cost Reflective, without levies)	Increase
Domestic				
Energy Charge	M/kWh	1.347	2.02	49.7%
Maximum Demand Charge	M/Kva			
General Purpose				
Energy Charge	M/kWh	1.522	1.60	4.8%
Maximum Demand Charge	M/Kva			
Street Lighting				
Energy Charge	M/kWh	0.7644	1.76	130.1%
Maximum Demand Charge	M/Kva			
Commercial LV				
Energy Charge	M/kWh	0.2061	0.73	254.7%
Maximum Demand Charge	M/Kva	306.3	285.82	-6.7%
Industrial LV				
Energy Charge	M/kWh	0.2061	0.73	254.9%
Maximum Demand Charge	M/Kva	306.3	254.24	-17.0%
Commercial HV				
Energy Charge	M/kWh	0.1861	0.80	328.5%
Maximum Demand Charge	M/Kva	262.24	149.81	-42.9%
Industrial HV				
Energy Charge	M/kWh	0.1861	0.78	321.7%
Maximum Demand Charge	M/Kva	262.24	150.36	-42.7%

From the table above, it can be said that cost reflective energy charges are substantially higher than current ones. At the same time, and with the exception of Commercial LV, cost reflective demand charges (in categories with such a charge) are lower than current demand charges.

The reason for such imbalances may be differences in cost drivers and allocation assumptions between the ones currently and historically made by LEWA and the ones included in our tariff model. To get conclusions on this issue requires further research on the current LEWA tariff model and a cross comparison with our tariff model.

To skip those eventual differences on the cost allocation factors used in our model or in LEWA model, we have simulated tariff revenues with both tariff schedules, so as to identify cross subsidies directly on tariff revenues. The obtained results are represented in the following table:

Table 31: Difference between Cost Reflective Tariff Revenues and Current Tariff Revenues for the period 2018-2020 (Maloti mil)

	2018	2019	2020
Domestic			
Energy Charge	188.34	196.61	204.88
Maximum Demand Charge	-	-	-
Subtotal for Domestic	188.34	196.61	204.88
Rev. Difference/Rev. Current Tariff	+49.68%		
General Purpose			
Energy Charge	6.56	6.73	6.90
Maximum Demand Charge	-	-	-
Subtotal for Domestic	6.56	6.73	6.90
Rev. Difference/Rev. Current Tariff	+4.80%		
Street Lighting			
Energy Charge	1.98	2.04	2.09
Maximum Demand Charge	-	-	-
Subtotal for Domestic	1.98	2.04	2.09
Rev. Difference/Rev. Current Tariff	+130.07%		
Commercial LV			
Energy Charge	32.13	32.96	33.79
Maximum Demand Charge	-3.73	-3.83	-3.93
Subtotal for Domestic	28.39	29.13	29.86
Rev. Difference/Rev. Current Tariff	+41.48%		
Industrial LV			
Energy Charge	24.85	25.80	26.76
Maximum Demand Charge	-11.08	-11.50	-11.93
Subtotal for Domestic	13.77	14.30	14.83
Rev. Difference/Rev. Current Tariff	+18.38%		
Commercial HV			
Energy Charge	54.51	55.92	57.33
Maximum Demand Charge	-26.71	-27.40	-28.09
Subtotal for Domestic	27.80	28.52	29.24
Rev. Difference/Rev. Current Tariff	+35.23%		

	2018	2019	2020
Industrial HV			
Energy Charge	132.01	137.07	142.14
Maximum Demand Charge	-48.21	-50.06	-51.91
Subtotal for Domestic	83.80	87.02	90.23
Rev. Difference/Rev. Current Tariff	+54.41%		

Table 24 shows that, irrespective of different tariff charges structure, the average level of cost reflective tariffs is clearly above current tariff levels. This finding requires further analysis on two issues:

- Generation LRAC considered for energy charges is higher than the simple projection of current procurement costs, because it includes future generation capacity investments that would be executed beyond this tariff period (2022-2025). The inclusion of those investments in the required revenues for the period 2018-2020 means a sort of investment pre-funding that is a typical tariff policy decision to be taken by LEWA.
- The share of non-reimbursable capital grants in the financing of new investments is a very sensitive variable for the resulting tariff level. Table 23 shows that return on assets represents 18% of required revenues, and a decrease on the effective rate of return (due to capital grants) may represent a significative decrease in average tariff levels.

These findings and considerations will be reconsidered and recomputed in Task 8, to propose a definitive tariff regime and recommended tariff schedule going forward. However in the context of this deliverable the following comments are worth mentioning:

The ToR of the study calls for setting consumer tariffs to reflect economic cost, and this is only fully achieved by adopting the significantly higher tariffs resulting from adopting the LRMC rather than the LRAC approach. Although it may be noted as discussed in section 2.2 that over time tariffs associated with LRMC will eventually align with those determined using the LRAC approach. In Deliverable 7 we further explore the impacts on consumer tariffs, and LEC's resultant profitability. Deliverable 7 also addresses ways to lower the levels of the economic-cost based tariffs to assure the minimum level of utility financial viability, while at the same time maintaining the economic structure of the tariffs to provide the right incentive signals to induce change of consumer behavior. In Deliverable 9 we show ways to attain economic pricing with tariff rises spread over a number of years. In this context we would comment that if economic tariffs are attained over a number of years it may provide sufficient time for efficiency improvement benefits (also considered in detail in Deliverable 7) to accrue to both consumers and the utility.

7 Annex 1 - Additional Explanation on Energisation of Capacity Charges

Table 32 below shows how the capacity charges in the Average Incremental Costs can be "energized". As can be seen from the table in the rows marked D and H the **cost responsibility** is related to the peak demand of the customers at the voltage level (in this case split into LV and HV).

The energised tariff (M/kWh, row O) is calculated as the cost responsibility (row G + row K) of the customer type divided by the **energy injected at net of losses** at the relevant voltage level (row N).

The derivation of peak demand of the customers at the voltage level is derived by multiplying the per day hourly load curve per unit value (Figure 4) by the average daily demand (kWh) to get a daily load profile (Figure 5). The maximum of these provides the peak demand (kW). This analysis is summarised in Table 33. Note that the peak demand figures (97,361 kW for LV and 41,568 kW for HV) in Table 33 correspond to the peak demand figures in rows D and H in Table 32.

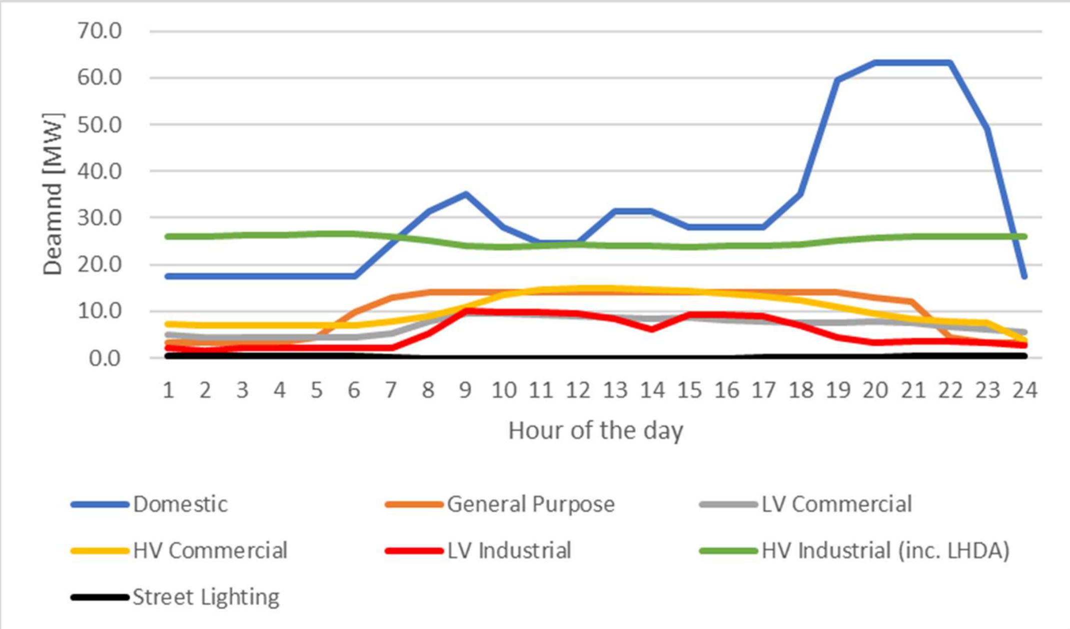
Table 32: Explanatory calculation of energising AIC

			HV (Transmission)	LV (Distribution)
	Return of Capital Component			
A	Capacity LRMC	M/kW	583.5	286.8
	Return on Capital Component			
B	Capacity LRMC	M/kW	1,288.8	633.5
	Total			
A+B	Capacity LRMC	M/kW	1,872.3	920.4
C	Total Peak Demand	kW	138,929.0	97,361.5
	Cost responsibility			
	LV Customers			
D	Share of Peak Demand at voltage level	kW	97,361	97,361
E=AxD	Return of Capital Component	M	56,812,472	27,927,275
F=BxD	Return on Capital Component	M	125,481,241	61,682,743
G=E+F	Total Cost responsibility	**M**	**182,293,713**	**89,610,018**
	HV Customers			
H	Share of Peak Demand		41,568	-
I=AxH	Return of Capital Component	M	24,255,535	-
J=BxH	Return on Capital Component	M	53,573,001	-
K=I+J	Total Cost responsibility	**M**	**77,828,536**	-
	Energisation of capacity charges			
L	Energy injected at voltage level	kWh	925,067,351	550,679,895
M	Losses at voltage level	M/kWh	64,754,715	68,834,987
N	Energy net of losses at voltage level	kWh	860,312,636	481,844,908
O=(G+K)/M	Energised LRMC at stated voltage level	M/kWh	0.302	0.186
P	Losses at lower voltage level	%	12.5%	-
Ox(1/(1-P))	Energised LRMC at LV level	M/kWh	0.346	0.186

Table 33: Consumption, average demand and peak demand figures for 2018/19

	Consumption kWh/year	Average Demand kWh/day	Peak Demand kW/day
LV			
Domestic	281,472,173	771,157	63,095
General Purpose	89,863,296	246,201	14,162
LV Commercial	61,214,319	167,710	9,630
LV Industrial	47,299,711	129,588	9,997
Street Lighting	1,995,409	5,467	479
LV TOTAL	**481,844,908**	**1,320,123**	**97,361**
HV			
HV Commercial	89,163,880	244,285	14,885
HV Industrial (inc. LHDA)	220,468,861	604,024	26,683
HV TOTAL	**309,632,741**	**848,309**	**41,568**

Figure 5: Daily demand profiles by customer type for 2018/19



8 Annex 2 – Detailed allocation of allowed revenues to tariff categories

Table 34: Detailed allocation of Allowed Revenues to the Domestic tariff category

Domestic	2018/19	2019/20	2020/21
Fixed Generation Costs for Demand	-	-	-
Variable Generation Costs for Demand	181,155,236.96	187,973,642.60	194,792,048.24
Fixed Generation Costs for Energy Losses	-	-	-
Variable Generation Cost for Energy Losses	25,879,319.57	26,853,377.51	27,827,435.46
Network Return of Capital - LV	18,098,131.66	18,893,234.30	19,688,336.94
Network Return of Capital - HV	36,817,040.00	38,434,517.77	40,051,995.55
Network Return on Capital - LV	39,973,194.71	41,729,331.38	43,485,468.05
Network Return on Capital - HV	81,317,493.77	84,890,003.65	88,462,513.52
Network Common OPEX - LV	119,086,650.70	130,107,024.53	139,413,060.30
Network Common OPEX - HV	39,918,566.03	43,612,662.03	46,732,101.54
Network Directly Allocated OPEX	-	-	-
Network Service OPEX - LV	19,226,081.68	21,005,278.64	22,507,702.32
Network Service OPEX - HV	-	-	-
Subtotal Domestic	***561,471,715.06***	***593,499,072.41***	***622,960,661.92***

Table 35: Detailed allocation of Allowed Revenues to the General Purpose tariff category

General Purpose	2018/19	2019/20	2020/21
Fixed Generation Costs for Demand	-	-	-
Variable Generation Costs for Demand	56,833,432.80	58,972,556.15	61,111,679.51
Fixed Generation Costs for Energy Losses	-	-	-
Variable Generation Cost for Energy Losses	8,119,061.83	8,424,650.88	8,730,239.93
Network Return of Capital - LV	4,062,241.25	4,167,200.48	4,272,159.71
Network Return of Capital - HV	8,263,819.79	8,477,338.42	8,690,857.04
Network Return on Capital - LV	8,972,238.87	9,204,061.47	9,435,884.06
Network Return on Capital - HV	18,252,230.88	18,723,827.71	19,195,424.55
Network Common OPEX - LV	26,266,436.98	28,697,154.05	30,749,746.85
Network Common OPEX - HV	8,804,668.64	9,619,459.71	10,307,501.24
Network Directly Allocated OPEX	-	-	-
Network Service OPEX - LV	1,007,144.23	1,100,346.16	1,179,049.53
Network Service OPEX - HV	-	-	-
Subtotal General Purpose	***140,581,275.25***	***147,386,595.03***	***153,672,542.42***

Table 36: Detailed allocation of Allowed Revenues to the LV Commercial tariff category

LV Commercial	2018/19	2019/20	2020/21

Fixed Generation Costs for Demand	-	-	-
Variable Generation Costs for Demand	38,714,581.13	40,171,738.66	41,628,896.20
Fixed Generation Costs for Energy Losses	-	-	-
Variable Generation Cost for Energy Losses	5,530,654.45	5,738,819.81	5,946,985.17
Network Return of Capital - LV	2,762,166.87	2,833,535.09	2,904,903.30
Network Return of Capital - HV	5,619,077.71	5,764,262.11	5,909,446.52
Network Return on Capital - LV	6,100,775.27	6,258,405.67	6,416,036.06
Network Return on Capital - HV	12,410,810.77	12,731,478.37	13,052,145.97
Network Common OPEX - LV	17,860,160.83	19,512,954.38	20,908,638.07
Network Common OPEX - HV	5,986,834.00	6,540,860.40	7,008,702.02
Network Directly Allocated OPEX	-	-	-
Network Service OPEX - LV	16,544.62	18,075.67	19,368.56
Network Service OPEX - HV	-	-	-
Subtotal LV Commercial	***95,001,605.64***	***99,570,130.17***	***103,795,121.87***

Table 37: Detailed allocation of Allowed Revenues to the HV Commercial tariff category

HV Commercial	2018/19	2019/20	2020/21
Fixed Generation Costs for Demand	-	-	-
Variable Generation Costs for Demand	*56,547,837.27*	*58,513,566.23*	*60,479,295.19*
Fixed Generation Costs for Energy Losses	-	-	-
Variable Generation Cost for Energy Losses	*11,826,071.89*	*12,258,945.03*	*12,691,818.16*
Network Return of Capital - LV	-	-	-
Network Return of Capital - HV	*8,685,636.18*	*8,910,053.60*	*9,134,471.02*
Network Return on Capital - LV	-	-	-
Network Return on Capital - HV	*19,183,893.27*	*19,679,562.18*	*20,175,231.10*
Network Common OPEX - LV	-	-	-
Network Common OPEX - HV	*7,308,314.27*	*7,984,631.51*	*8,555,740.31*
Network Directly Allocated OPEX	-	-	-
Network Service OPEX - LV	-	-	-
Network Service OPEX - HV	*2,032,980.85*	*2,221,114.53*	*2,379,981.98*
Subtotal HV Commercial	***105,584,733.73***	***109,567,873.07***	***113,416,537.75***

Table 38: Detailed allocation of Allowed Revenues to the LV Industrial tariff category

LV Industrial	2018/19	2019/20	2020/21
Fixed Generation Costs for Demand	-	-	-
Variable Generation Costs for Demand	30,279,878.20	31,419,566.43	32,559,254.67
Fixed Generation Costs for Energy Losses	-	-	-
Variable Generation Cost for Energy Losses	4,325,696.89	4,488,509.49	4,651,322.10
Network Return of Capital - LV	2,867,444.50	2,977,472.76	3,087,501.01
Network Return of Capital - HV	5,833,244.05	6,057,074.60	6,280,905.15

Network Return on Capital - LV	6,333,301.11	6,576,319.62	6,819,338.13
Network Return on Capital - HV	12,883,838.21	13,378,210.91	13,872,583.61
Network Common OPEX - LV	18,767,419.73	20,504,171.75	21,970,753.26
Network Common OPEX - HV	6,290,952.67	6,873,122.46	7,364,729.46
Network Directly Allocated OPEX	-	-	-
Network Service OPEX - LV	15,467.30	16,898.65	18,107.35
Network Service OPEX - HV	-	-	-
Subtotal LV Industrial	***87,597,242.66***	***92,291,346.68***	***96,624,494.72***

Table 39: Detailed allocation of Allowed Revenues to the HV Industrial tariff category

HV Industrial	**2018/19**	**2019/20**	**2020/21**
Fixed Generation Costs for Demand	-	-	-
Variable Generation Costs for Demand	141,529,962.28	146,449,859.46	151,369,756.65
Fixed Generation Costs for Energy Losses	-	-	-
Variable Generation Cost for Energy Losses	29,598,718.36	30,682,128.82	31,765,539.27
Network Return of Capital - LV	-	-	-
Network Return of Capital - HV	15,569,898.87	16,167,339.85	16,764,780.82
Network Return on Capital - LV	-	-	-
Network Return on Capital - HV	34,389,107.72	35,708,670.70	37,028,233.68
Network Common OPEX - LV	-	-	-
Network Common OPEX - HV	14,184,537.72	15,497,186.18	16,605,638.00
Network Directly Allocated OPEX	-	-	-
Network Service OPEX - LV	-	-	-
Network Service OPEX - HV	2,317,598.17	2,532,070.56	2,713,179.45
Subtotal HV Industrial	*237,589,823.12*	*247,037,255.57*	*256,247,127.88*

Table 40: Detailed allocation of Allowed Revenues to the Street Lighting tariff category

Street Lighting	**2018/19**	**2019/20**	**2020/21**
Fixed Generation Costs for Demand	-	-	-
Variable Generation Costs for Demand	1,261,983.01	1,309,482.11	1,356,981.22
Fixed Generation Costs for Energy Losses	-	-	-
Variable Generation Cost for Energy Losses	180,283.29	187,068.87	193,854.46
Network Return of Capital - LV	137,290.78	140,838.07	144,385.36
Network Return of Capital - HV	279,290.72	286,506.97	293,723.22
Network Return on Capital - LV	303,233.03	311,067.89	318,902.75
Network Return on Capital - HV	616,867.13	632,805.59	648,744.06
Network Common OPEX - LV	498,583.42	544,722.73	583,684.57
Network Common OPEX - HV	167,128.18	182,594.36	195,654.60
Network Directly Allocated OPEX	-	-	-

Network Service OPEX - LV	10,234.58	11,181.70	11,981.48
Network Service OPEX - HV	-	-	-
Subtotal Street Lighting	***3,454,894.14***	***3,606,268.30***	***3,747,911.73***

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Electricity Supply Cost of Service Study – LEWA Lesotho

Lifeline Tariff Report – Deliverable 6

Support Provided by African Development Bank

Prepared for: LEWA

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Contents

LIST OF ACRONYMS

BOS	Bureau of Statistics
HBS	Household Budget Survey
IBT	Increasing Block Tariff
LEC	Lesotho Electricity Company
LEWA	Lesotho Energy and Water Authority
PPP	Purchasing Power Parity
VDT	Volume Differentiated Tariff
WASCO	Water and Sewage Company of Lesotho

1 INTRODUCTION

This report is the sixth deliverable of the Electricity Cost of Service Study being carried out by the MRC Group for LEWA supported by the African Development Bank. The objective of this task is to evaluate a lifeline tariff to meet basic needs of the poorest households in Lesotho. It will determine the level of electricity requirement, define the applicable basic needs, evaluate the linkage between household incomes and expenditure on electricity. It will propose a lifeline tariff level, consumption threshold and method of application and evaluate the differential between the lifeline tariff and the economic cost of supply to the applicable customers. Finally, it will make proposals for the implementation of the lifeline tariff subsidy.

This report is organised as follows:

This introduction is followed by a section on the background and theory for the setting of lifeline tariffs. Section 3 describes the regional and international experience where lifeline tariffs have been implemented including the identification of the reasons subsidy systems have been withdrawn. Section 4 considers the options for designing a tariff system that includes a lifeline tariff component. Section 5 looks at the basic needs required by the poorer households in Lesotho and Section 6 proposes a level of consumption below which a lifeline tariff would apply. Section 7 presents an analysis of the application of a lifeline tariff structure while Section 8 sets out the study conclusions. The various references used are listed in the final Section 9.

The analysis of a potential lifeline tariff system for electricity supply in Lesotho is a key input to the overall cost of service study and the conclusions set out in this report will form an important input to the remaining elements of the overall study, including in particular the strategy for rolling out economic tariffs in deliverable 10.

2 Background

As noted above in the Introduction this task of the COSS is to evaluate a lifeline tariff to meet basic needs of the poorest households in Lesotho. Lifeline tariffs are common in the developing world especially in Africa to provide the poorest households with affordable electricity. The consumption levels of the poorest households are sensitive to price and fall if prices are not affordable. A cost of service study seeks to allocate cost reflective tariffs to the various consumer groups and can lead to setting unaffordable tariffs for poor households. The analysis of a potential lifeline tariff system for electricity supply in Lesotho is therefore a key input to the overall cost of service study.

The following two subsections consider price sensitivity (section 2.1) and cost recovery versus affordability (section 2.2). In the third subsection (section 2.3) we draw attention to the specific levy charged to existing customers, for the Universal Access Fund.

2.1 Price Sensitivity

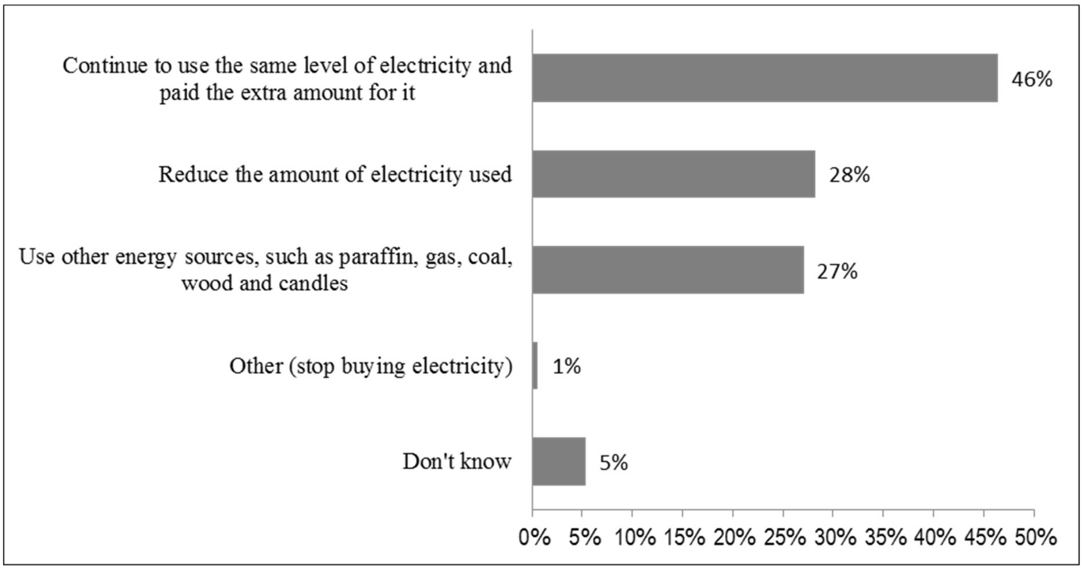
The most efficient and sustainable policy for pricing electricity is to set its price equal to its long-run marginal cost of supply, this leaves the utility company better able to cover its long-run costs. Reforming tariffs to this policy often leads to steep increases in electricity prices [Audinet, 2002; Karekezi, 2002b]. The challenge with large increases in price is that in the long run, demand for electricity is responsive to changes in price as shown by the global survey of electricity demand in more than 450 studies for more than 60 countries carried out since 1950s [Vagliasindi, 2012]. Even more crucial, for low income countries, tariff reforms should balance social stability, affordability, fairness, energy efficiency as well as cost recovery especially because the poor make up the majority of the population [Sun, 2013]. More so because most electric utilities are constructed with public funding, the expectation is that everyone is entitled to utilize electricity, to meet basic needs at least, at an affordable price [Hosier, 1993]. This is crucial in the none-industrialised nations where the bulk of consumption is by households. For example, in Tanzania, the household sector accounts for nearly 80% of the total final energy consumption [Hosier, 1993]. In Lesotho the highest annual consumption is normally by the pre-paid domestic customers, occasionally the industrial consumption matches it or is slightly more.

The biggest challenge is that throughout Africa, the poor constitute a significant domestic group [Hosier, 1993]. With the growing rate of poverty and the limited development in low-income countries, the cost of energy services is increasingly becoming prohibitive for low-income households and informal sector enterprises which are often the largest source of employment for low-income urban residents [Karekezi, 2002a]. Low income households are more likely to reduce electricity consumption when faced with increases. For example, in Armenia 80% of the households partly substituted their electricity consumption with other energy sources following an electricity price increase while in Kyrgyz Republic consumption by the poorest households reduced by 15-25% [Gassmann, 2012]. On average, a 10% increase in electricity tariffs reduces electricity consumption with 1.5 per cent [Gassmann, 2012].

Findings from the study by Mpholo et al. (2017) revealed that although majority of the households (75%) surveyed in three rural villages in Lesotho perceived the prevailing electricity price to be high, almost half of the total households indicated that they have continued to use the same amount of electricity regardless of the previous price hike and they will continue to do so even if the electricity price increases in the future, as shown in Figure 1.

The analysis of price responsiveness presented in Figure 1 implies that the majority (55% of the sample) of households will reduce consumption and in turn exacerbate the already declining average household consumption depicted in Figure 2. This is not desirable in a country where low income levels mean that demand for electricity is already below the level that ensures good health and adequate participation in society [Price, 2009]. This implies that the prolonged steady decline of average household electricity consumption in Lesotho (see Figure 2) that almost certainly results from the decline in the consumption of newly connected customers (see Figure 3)[1] could be exacerbated if prices continue to rise.

Figure 1: Household frequency distribution by reaction to electricity price increase in the future. Extracted from [Mpholo et al., 2017]



[1] It may be worth explaining that figures 2 and 3 present a similar story in two quite different ways. Figure 2 presents average consumption by all domestic customers which has been falling steadily from year to year. Figure 3 is a more detailed analysis for the year 2016 only, of the actual consumption in 2016 of the customers that have been connected in each previous year. Thus for example from figure 3 the consumption for customers that were connected during 2014 was about 140 kWh per month in 2016, whereas the average consumption of all customers in 2014 from figure 2 was about 2800 kWh per year or about 230kWh per month.

Figure 2: LEC customer numbers and average consumption per domestic customer 2000 to 2016

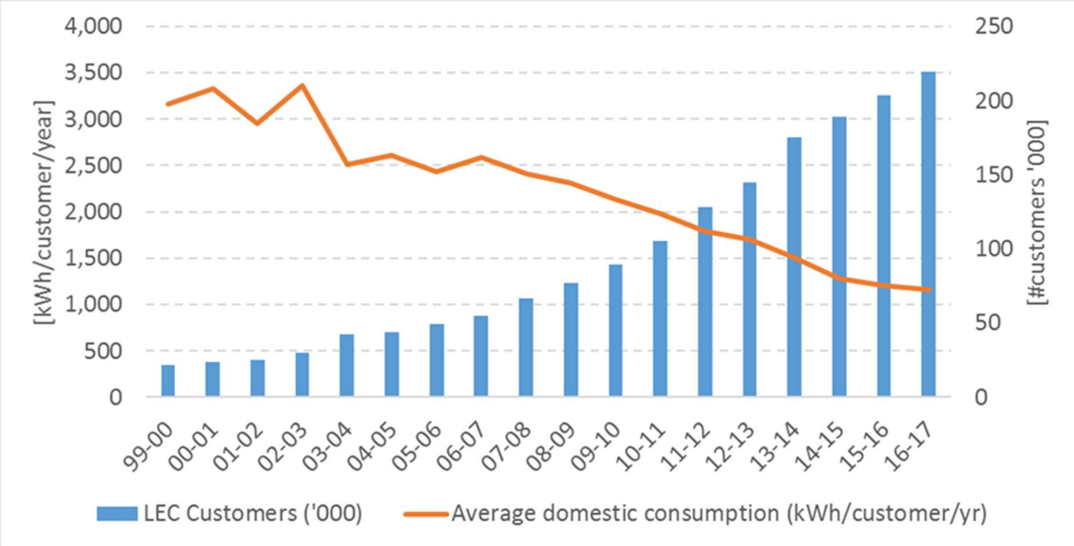
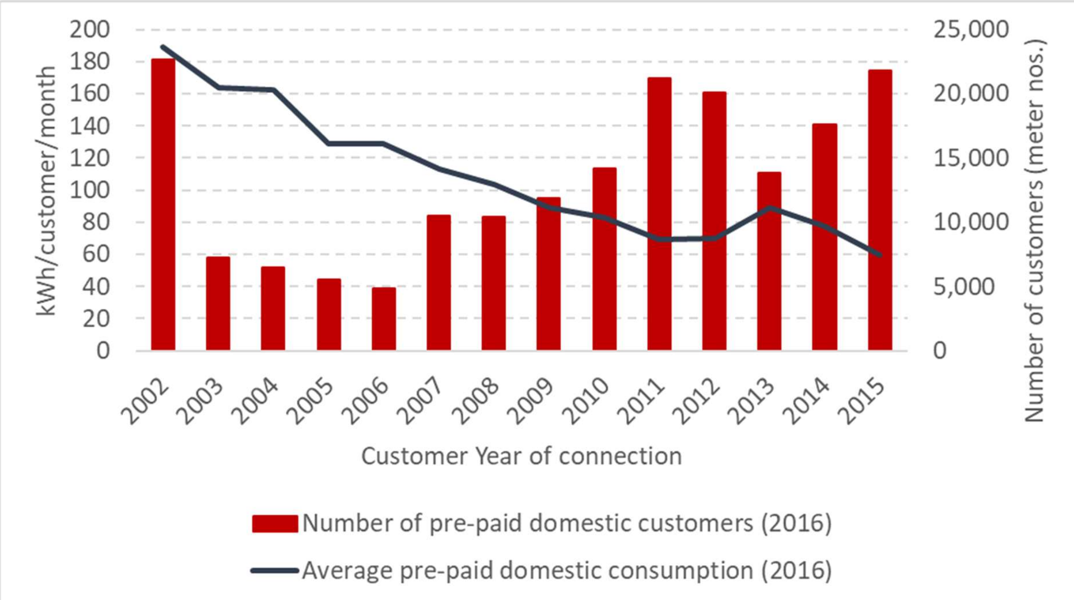


Figure 3 Average pre-paid domestic consumption in 2016 by customer year of connection



2.2 Cost Recovery Versus Affordability

The balance between cost recovery and affordability/equity can be hard to strike. Chad, Mozambique, Rwanda, and Uganda have done well on cost recovery but poorly on affordability and equity, while South Africa, the Democratic Republic of Congo, Tanzania, and Zambia have fared well on the social objectives but have not been able to achieve cost recovery. Nevertheless, some countries' experiences, such as the progress in Kenya, indicate that it is possible to make substantial progress in both cost recovery and affordability [International Monetary Fund, 2013].

How does a country identify, target and help the poor? Income and consumption expenditure are normally considered good indicators. The distribution of income in most countries in Africa shows that most households are poor [Karekezi, 2002a]. Lesotho, with a population slightly above 2 million as of 2016, is considered to be among the poorest countries in the world. According to the World Bank (2015), Lesotho ranked ninth out of 30 world's poorest countries in terms of poverty gap or depth (recorded to be 29.5% in 2010/2011, see Figure 4). Poverty "depth" is a measure of how far poor people are from poverty line. Using the 2010/2011 HBS, the study found that Lesotho has an estimated national headcount poverty rate of 57%, with 61% and 40% of the people living in rural and urban areas, respectively, considered to be poor (see Figure 4 and Table 1). This relatively high level of poverty in Lesotho has generally remained unchanged when compared to the 2002/2003 poverty rates.

Figure 4: Poverty headcount and poverty gap US$1.25 of 30 poorest countries in the world. Extracted from [World Bank, 2015]

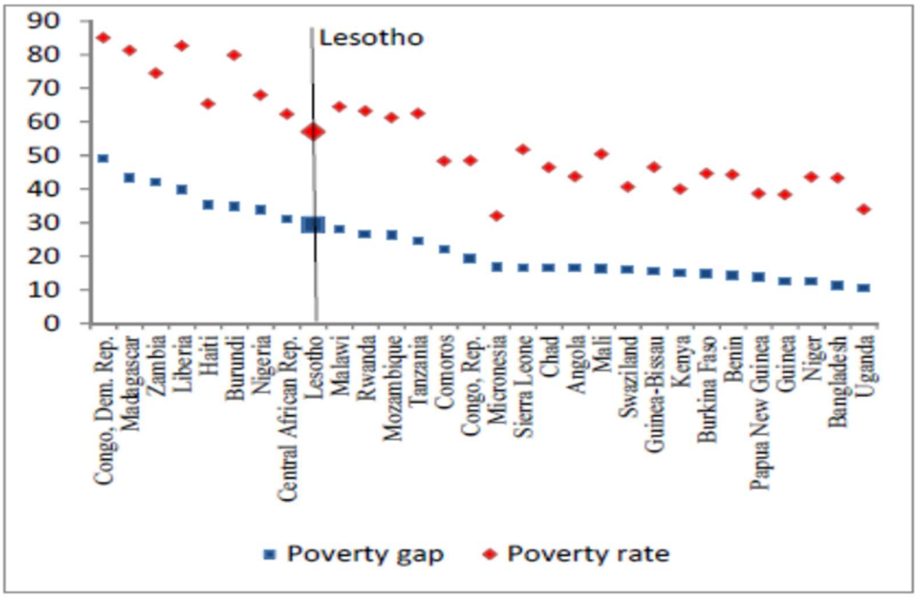


Table 1: Lesotho's poverty rates by urban/rural area in 2002/03 and 2010/11. Adapted from [World Bank, 2015]

	National poverty rate (%)			Extreme poverty rate (%)			$1.25PPP/day poverty rate		
	2003	2010	Change	2003	2010	Change	2003	2010	Change
Lesotho	56.6	57.1	0.5	34.0	35.1	1.1	55.3	55.8	0.5
Urban	39.0	39.6	0.6	20.3	20.4	0.1	37.1	38.5	1.4
Rural	60.9	61.2	0.3	37.4	38.5	1.1	59.8	59.9	0.1

The high poverty levels imply that a majority of the population in Lesotho spends a much higher proportion of their income to meet their energy needs compared to higher income groups. According to the results of Mpholo et al. (2017), electricity users in the surveyed rural villages spend about 26% of their total household expenditure per month on energy sources - Table 2. Globally, household's expenditure of more than 10% on energy sources is considered to be energy poor – thus being unable to afford energy sources. Specifically, **World Bank considers more than 5% expenditure just on electricity to be energy poor** [Kojima, 2016]. Hence the 9% expenditure on electricity in the sampled population suggests that households face electricity poverty.

Table 2: Household Energy Spending as a Share of Monthly Total Spending. Adapted from [Mpholo et al., 2017]

Energy Sources	Share of Monthly Total Spending	
	Electricity Users	Non-electricity Users
Coal	0.00 (SD = 0.01)	0.00 (SD = 0.00)
Electricity	0.09 (SD = 0.11)	0.00 (SD = 0.00)
Firewood	0.02 (SD = 0.05)	0.06 (SD = 0.12)
Gas	0.07 (SD = 0.09)	0.08 (SD = 0.14)
Diesel/Petrol (for generator)	0.00 (SD = 0.00)	0.00 (SD = 0.01)
Paraffin	0.07 (SD = 0.11)	0.06 (SD = 0.07)
Solar	0.00 (SD = 0.00)	0.00 (SD = 0.00)
Others	0.01 (SD = 0.04)	0.01 (SD = 0.03)
All Energy Sources	0.26 (SD = 0.19)	0.21 (SD = 0.18)

The World Bank and a number of countries classify access to basic electricity services as a social good and/or a basic need [Audinet, 2002; Dube, 2003; Louw, 2008]. To ensure that all consumers can utilize a limited quantity of energy to meet the basic needs, a targeted subsidised, or "lifeline" tariff, is normally implemented [Hosier, 1993]. This support needs to be targeted and limited to avoid subsidising users who are able to pay (i.e., not energy poor).

2.3 Universal Access Fund (UAF)

LEWA set up in 2011 (Legal notice 83/2011) a Universal Access Fund which disburses money in order to subsidize the capital costs of electrification in the country, with a focus on the rural areas. This is a Fund set up to support grid extension in rural areas. LEC are required to charge a levy on consumption by its existing connected customers. This levy is the source of funding for the UAF.

The UAF levy has contributed a small but important source of funding for the grid extensions that have taken place in recent years – approximately 10% of the capital expenditure involved in grid extension has come from the UAF levy[2].

The introduction of a lifeline tariff policy with a subsidy from the non-poor customers that enables non-economic tariffs to be charged to poor customers must also consider whether it is fair and reasonable to continue to charge such a UAF levy. The 2015/2025 Energy Policy has signalled a shift towards a greater emphasis on off-grid solutions for providing access to the rural population that is not yet connected nor within the LEC service territory, and this is therefore expected to reduce LEC's capital investment requirements for grid extension.

[2] Source SE4ALL EU TAF analysis

3 Regional and International Experience

3.1 Widespread Application in Developing Countries

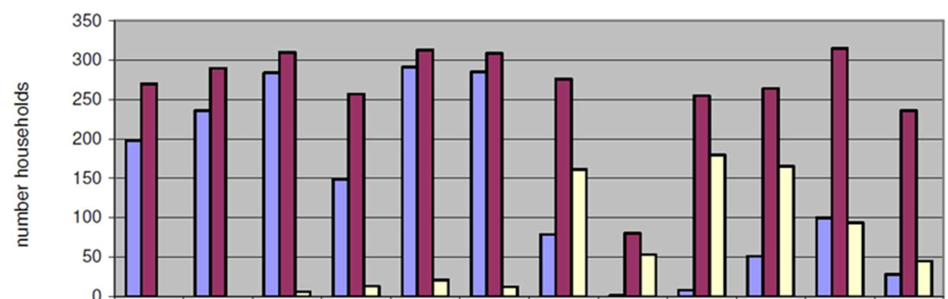
Lifeline tariffs are applied to the household sector in many developing countries including India, Cambodia, Vietnam, Ivory Coast, South Africa, Costa Rica, Gabon, Nigeria, Uganda, Zambia, Ghana, Kenya, Zimbabwe [Audinet, 2002; Dube, 2003]. In a survey of utilities in Asia, the Asian Development Bank found that the majority of utilities in their sample (20 out of the 32) used lifeline tariff structures [Lin, 2012]. They have been implemented even in many developed countries or regions, such as the United States, Japan, Korea, Malaysia and China's Hong Kong, Taiwan, and so on [Lin, 2012].

The lifeline tariffs try to address the challenge of energy affordability (households spending >10% of their expenditure on energy) and improve standards of living [Sun, 2013]. Available evidence indicates that, globally, electricity in most cases displays a regressive pattern, with the bottom (low consumption) quintile of users consuming electricity as a portion of their income that is up to 3 times that of the top quintile [Fankhauser, 2007; Vagliasindi, 2012]. The affordability challenge is clearly indicated by the large proportion of African low income electrified households that still have a large prevalence of fuelwood, paraffin and candle usage [Louw, 2008].

3.2 Lesotho Studies

In a 2007 GTZ survey in Lesotho, shown in Figure 5, only one household out of 80 electrified in the survey area used electricity while others relied on other forms of energy with the majority citing electricity as being too expensive.

Figure 5: Number of households using different fuels. Extracted from [GTZ, 2007]



	Dung	Shrubs	wood	crop residue	paraffin	candles	gas	electric	Gen set	car battery	Dry cells	Solar
Number user hh	198	236	284	149	291	285	79	1	8	51	100	28
Available?	270	290	310	257	313	309	276	80	255	264	315	236
Too expensive	0	0	6	13	21	12	161	53	180	165	94	45

The situation has not improved since 2007. The 2012 Sustainable Energy for All report and the 2017 survey by Mpholo et al. confirmed the predominance of biomass and petroleum as energy sources for cooking and space heating even for households with electricity - Table 3 and Table 4. On the other hand, a relatively high proportion of electricity use by those connected to the grid was attributed to lighting and media access, while the use of solar PV energy for lighting was almost insignificant -Table 5.

Table 3: Household Energy Use for Cooking. Adapted from [Mpholo et al., 2017]

Energy Sources	Mean Responses	
	Electricity Users	Non-electricity Users
Coal	1.05 (SD = 0.21)	1.03 (SD = 0.17)
Electricity	1.92 (SD = 1.09)	1.00 (SD = 0.00)
Firewood	2.55 (SD = 1.22)	2.98 (SD = 1.10)
Gas	2.74 (SD = 1.25)	2.09 (SD = 1.26)
Diesel/Petrol (for generator)	1.00 (SD = 0.00)	1.00 (SD = 0.00)
Paraffin	2.25 (SD = 0.98)	2.36 (SD = 1.09)
Solar	1.01 (SD = 0.08)	1.00 (SD = 0.00)
Others (cow dung, corn cobs/stover)	1.52 (SD = 0.96)	1.77 (SD = 1.12)

Notes: The scale is 1 (never), 2 (sometimes), 3 (often) and 4 (always); SD = Standard Deviation.

Table 4: Household Energy Use for Space Heating. Adapted from [Mpholo et al., 2017]

Energy Sources	Mean Responses	
	Electricity Users	Non-electricity Users
Coal	1.08 (SD = 0.38)	1.06 (SD = 0.32)
Electricity	1.28 (SD = 0.71)	1.00 (SD = 0.00)
Firewood	2.11 (SD = 1.23)	2.22 (SD = 1.29)
Gas	1.08 (SD = 0.41)	1.05 (SD = 0.34)
Diesel/Petrol (for generator)	1.00 (SD = 0.00)	1.00 (SD = 0.00)
Paraffin	2.52 (SD = 1.15)	2.05 (SD = 1.39)
Solar	1.00 (SD = 0.00)	1.00 (SD = 0.00)
Others (cow dung, corn cobs/stover)	1.33 (SD = 0.83)	1.65 (SD = 1.11)

Notes: The scale is 1 (never), 2 (sometimes), 3 (often) and 4 (always); SD = Standard Deviation.

Table 5: Household Energy Use for Lighting. Adapted from [Mpholo et al., 2017]

Energy Sources	Mean Responses	
	Electricity Users	Non-electricity Users
Coal	1.00 (SD = 0.00)	1.00 (SD = 0.00)
Electricity	3.89 (SD = 0.46)	1.00 (SD = 0.00)
Firewood	1.00 (SD = 1.00)	1.04 (SD = 0.25)
Gas	1.00 (SD = 0.00)	1.00 (SD = 0.00)
Diesel/Petrol (for generator)	1.01 (SD = 0.08)	1.00 (SD = 0.00)

Energy Sources	Mean Responses	
	Electricity Users	Non-electricity Users
Paraffin	1.89 (SD = 0.89)	3.10 (SD = 1.28)
Solar	1.04 (SD = 0.27)	1.16 (SD = 0.62)
Others (cow dung, corn cobs/stover)	1.51 (SD = 0.62)	2.24 (SD = 1.25)

Notes: The scale is 1 (never), 2 (sometimes), 3 (often) and 4 (always); SD = Standard Deviation.

3.3 Affordability

Access without affordability may not mean much. Data from a survey of households in Bulgaria and Turkey showed a high proportion of respondents who reported no electricity consumption. A check against the ownership of electricity appliances in Turkey confirmed the government's claim of universal access but despite that over a quarter of all households, and half the poorest households, declared no electricity consumption. In Bulgaria the figures are lower by 10% overall but constitute nearly a third of the poorest decile [Price, 2009]. Hence, being connected to a grid does not imply usage of electricity, and especially so by the poor households. In Zimbabwe, without subsidies the moderately poor and the extremely poor would need to transfer at least 14% from their other expenditure towards meeting the additional energy costs [Dube, 2003]. In Bangladesh, 10–15% of consumers remain disconnected on an on-going basis, in some areas disconnection levels are as high as 20% [Winkler, 2011]. Thus the burden of a removal of subsidies falls more heavily on the extremely poor households.

Experience has shown that lifeline tariffs need to be targeted and limited to avoid subsidising energy users who are able to pay. South Africa has a lifeline tariff consumption threshold level of 50 kWh. This has been found to reduce the energy burden of the poor by one-third [Winkler, 2011]. The threshold was arrived at because 56% of the connected households in the South Africa consume an average of less than 50 kWh/month, and this is expected to meet the needs for lighting, media access, limited water-heating and basic ironing or cooking [Davidson, 2004; Winkler, 2011]. The situation in Lesotho for 2016 is similar, as shown in Table 6. Around 57% of customers use an average that is less than 50 kWh. Moreover, 25% uses less than 30 kWh.

Table 6: Summary of electricity usage data of LEC customers (2016)

Annual Monthly Consumption (kWh)	No. of Pre-Paid Customers	Percentage (%)
x < 30	**64,259**	**30**
30 <= x < 50	29,814	14
50 <= x < 100	64,051	30
x > = 100	54,562	26
Total	**212,686**	**100**

3.4 CONSUMPTION THRESHOLD AND TARIFF LEVEL

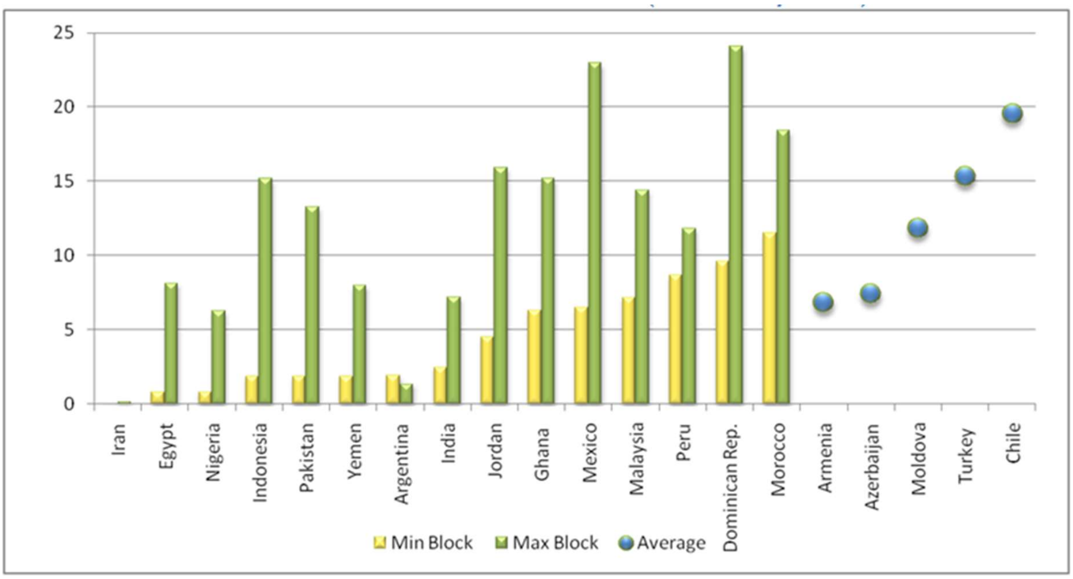
In South Africa basic electricity (50 kWh) is defined as adequate energy for 2 lamps for 6 hr/night; one radio for 10 hr/day; and one 1.6 kW hot-plate for 0.7 hr/day [Davidson, 2004]. Table 7 gives a snapshot of lifeline tariff thresholds in selected countries while Figure 6 shows the difference between the lifeline tariff and the highest residential tariff in different countries. In Ethiopia the lifeline tariff is around 46% of the long-run marginal cost [Kebede, 2006]. In Nigeria, the lifeline tariff (50 kWh) is charged at 4 Naira/kWh while the highest residential block is charged at over 35 Naira/kWh, moreover, the tariff regulation states that the lifeline tariff is not to be increased until at least 2025 while all other tariff blocks will rise [Nigerian Electricity Regulatory Commission, 2015]. In Zimbabwe in 2014, the lifeline (50 kWh) was charged at \$0.02/kWh while the highest block was charged at \$0.15/kWh, making the lifeline tariff to be 13% of the highest residential tariff [Zimbabwe Energy Regulatory Authority, 2014]. This is implemented even for pre-paid customers.

Table 7: A snapshot of basic electricity consumption levels for lifeline tariffs in selected countries

Country	Life-line/First Block Tariff Limit (kWh)
Nigeria	50
Uganda	15
Zambia	300
Ghana	300
South Africa (minimum)	50
Zimbabwe	50
Brazil	30
Bangladesh	100
Taiwan	40
Kenya	50

Sources: References given at the end of the report

Figure 6: Increasing Block Tariffs (IBTs) across sample countries (cents US/kWh). Extracted from [Vagliasindi, 2012], Fig 22 p25/34



Of particular interest in South Africa is that there were some households with electrical appliances that were used only with the introduction of the lifeline tariff. In some communities, about 30% of households have added lights in previously non-electrified rooms. Some households started using appliances they owned but were not able to use before the programme was implemented [Davidson, 2004; Winkler, 2011]. The additional costs of the lifeline tariff leakage to the non-poor inherent in consumption targeting are normally accepted by the population and politicians [Gassmann, 2012]. Lifeline tariffs are generally found to perform better as a means to help low income households, than universal subsidies and treasury cash transfers [Vagliasindi, 2012].

3.5 Implementation Considerations

In considering the introduction of a lifeline tariff it is important to understand why lifeline tariff or other forms of electricity subsidy have been withdrawn or scrapped in other countries. The following are the main motivations behind scrapping subsidies:

- ***Uprising of the un-electrified population and political pressure***: Government loans and/or grants to utility companies are seen as unfair because the entire national population is responsible for such funding while the minority of the population have access to the electricity supply that it is financing. Muela power station in Lesotho is a case in point, whose benefit is enjoyed by the connected few. Basically only the well-off section of the population, which happens to be connected to the grid, benefits from electricity utility funding [Hosier, 1993; Karekezi, 2002b; Lin, 2012].
- ***Equity amongst the poor***: The electrified poor pay a lifeline tariff (very low cost) for basic energy needs while the un-electrified poor pay far more for lower quality fuels such as wood [Karekezi, 2002a].
- ***Regressive****:* Household survey evidence from nine African countries suggests that poorer households consume directly a much smaller share of the total electricity supplied [International Monetary Fund, 2013; Lin, 2012; Vagliasindi, 2012].
- ***Subsidies provided from the public funds****:* Issues of opportunity costs come up; funds could better be utilised elsewhere to help everyone. For example, in Nigeria, the government used the fact that fuel subsidies ($9.3 billion, or 4.1 percent of GDP in 2011) exceeded capital expenditure to call for reform [International Monetary Fund, 2013].
- ***Reforms to cost reflective tariff***: For example, in Bulgaria, reforms raised the level of the tariffs to long run marginal costs hence lifeline tariffs that were introduced in 2001 were abolished in 2007. This raised the expenditure for all households, the rich in absolute terms, and the poor proportionally to income. Although Bulgaria claims universal access, this resulted in no electricity consumption by nearly a third of the poorest decile [Price, 2009].
- ***Allocative and productive inefficiencies and financial unsustainability***: Tariff reforms are meant to increase efficiencies in the sector, subsidies are perceived to do the opposite and may result in the arrangement being unsustainable [Gassmann, 2012].
- ***Complex implementation***: To be effective, subsidy programs should adopt simple and transparent targeting criteria [Vagliasindi, 2012].

4 Lifeline Tariff Design Options

4.1 Cross subsidies

The costs (or lost revenue by the utility) as a result of the application of the lifeline tariff can be recovered through cross-subsidisation in the tariff structure. For example, in a tariff structure that is fully cost-reflective the introduction of a lifeline tariff would require some of the other tariffs to be higher than their cost-reflective level so that the income lost to the utility from the application of the lifeline tariff is recovered from other tariff category consumers.

In some cases, industrial and commercial customers provide the cross-subsidies to the households. However, this kind of cross-subsidisation can have long-term negative economic implications - in Kenya industries cited high electricity tariffs as a principal reason for closure and relocation [Karekezi, 2002b]. Therefore, it may have fewer drawbacks if the cross-subsidisation is done between low- and high-income households rather than industrial customers [Lin, 2012]. Moreover, reasonably high tariffs are found to restrain electrical waste and promote energy efficiency in higher income households [Sun, 2013]. This might be a challenge in Lesotho where a high proportion of households are fuel poor. The small higher income population could be over-burdened and hence reduce their consumption below what was planned in the tariff setting and in turn reduce utility revenues [Louw, 2008].

To be effective and practical, tariff reforms need to benefit a large majority of the population, not only the utility company. If this principle is not followed then tariff reviews may lead to unrest, such as in Ghana, and protracted political debates, such as in Uganda. There have been instances of regulatory approved increases being reversed and alternative measures, such as the introduction of subsidies being implemented. Therefore, experience has shown that it helps to be pro-active and consider all possible measures when reforming tariffs to address fuel poverty.

4.2 Increasing Block Tariffs (IBT)

The most common system for introducing a lifeline tariff is based on consumption. This type of regime is called **Increasing Block Tariffs** (IBTs), where consumers face higher unit prices on higher blocks of consumption [Borenstein, 2012; Fankhauser, 2007; Lin, 2012; Winkler, 2011]. The first block is normally considered as the lifeline tariff. Multiple blocks are often used for household customers with higher blocks being more than the cost-reflective level.

In Lesotho there is currently one domestic tariff. We believe it will be relatively straightforward to introduce one additional tariff (lifeline) for all domestic customers and to adjust the pre-paid metering analysis software to charge all customers at the lifeline rate up to the agreed threshold and then the higher rate for consumption above the lifeline threshold level. All households consuming more than the lifeline threshold level will be subsidising the lifeline households with the amount of subsidy directly proportional to the level of consumption.

4.3 Volume Differentiated Tariffs (VDT)

If the IBT structure is designed so that block prices increase too slowly with higher volumes, cost recovery is compromised even for higher blocks, and better-off households benefit from the subsidies.

An alternative design is the so-called **Volume-Differentiated Tariff**s (VDTs) where kWh consumption above a threshold leads to a higher price on all consumption. The VDT structure is an effective method to efficiently target lifeline blocks, thus reducing costs associated with subsidy schemes for the poorest, for example, Cape Verde [International Monetary Fund, 2013]. This requires progress in metering, which could be a challenge. Regardless of the pricing mechanism, correct calibration of block sizes and associated price levels requires a good knowledge of consumption patterns.

Theoretically, the larger the gaps between incomes, the more blocks should be set to ensure the efficiency of income redistribution. However, considering the administrative costs, the common structure usually consists of three to six blocks [Lin, 2012]. This would require a significant increase in complexity for LEC where all domestic customers are currently on one tariff. There would be a need for a major revision of administrative systems to accommodate such a structure.

4.4 Selection of IBT Structure for Lesotho

The IBT system is the most commonly applied particularly in the developing world and may be relatively straightforward to introduce in Lesotho. The VDT system is more common in the developed world and would require significant investment to introduce it in Lesotho. The IBT system is there recommended for Lesotho.

5 Definition of Basic Needs Consumption

Drawing on the case of South Africa where basic electricity is defined as meeting the following needs [Davidson, 2004; Winkler, 2011]:

1. Lighting - 2 lamps for 6 hr/night;
2. Media access - one radio for 10 hr/day; and
3. Limited water heating, basic ironing and/or basic cooking - one 1.5 kW hot-plate for 0.7 hr/day.

These requirements can be used to compute the level of **basic needs consumption[3] per month** of approximately **50 kWh** broken down as follows:

- Lighting: 2 x 11W (energy efficient lights) x 6hr/night x 30 days = 3.96kWh/month;
- Radio: 3W x 10hr/day x 30 days = 0.9 kWh/month; and
- Cooking/water heating/ironing: 1.5 kW x 1hr/day x 30 days = 45 kWh/month.

The most significant portion of the 50kWh/month is the third item – limited water heating, basic ironing and/or basic cooking. Considering this item in the case of Lesotho, other than for the obvious reason that people **need** to eat on a daily basis, cooking is a vital component of the basic electricity needs definition. Over 80% of households in Lesotho use unhealthy smoky biomass to cook and its supply is dwindling from year to year which affects both the quality of life (collection time can be up to 8 hours) and the environment. Lesotho's energy usage is dominated by biomass energy and 90% of total energy consumption is utilised by households [Letsela, 2003; ProBEC, 2009; Dasappa S., 2011;

[3] One notable shortcoming of using consumption as a gauge is that a poor family with many members may consume more and hence not qualify for the lifeline tariff. This is a real challenge considering that normally low income households tend to have more family members.

Taele 2012] and so there is good reason to encourage cleaner forms of energy for cooking and space heating.

Using the electricity usage data of LEC customers for 2016 shown in Table 6, introducing lifeline tariff to households which consume less than 50 kWh implies subsidising the majority of grid connected households (57%). The analysis presented in Table 8 shows that such a level would require a significant portion of total domestic consumption to be subsidized.

Table 8: Volume of subsidized energy sales for domestic customers for 30 and 50/kWh definition of basic needs electricity

Basic Needs consumption	30kWh/month	50 kWh/month
Residential customers within basic needs band (Table 6)	64,259	94,073
Residential customers outwith basic needs band	148,427	118,613
Total basic needs consumption (kWh/month)	1,927,770	4,703,650
Average domestic consumption (kWh/month) (Figure 2)	101	101
Total consumption - all domestic customers (kWh/month)	21,586,788	21,586,788
Total subsidised domestic consumption under IBT (%)	29.6%	49.3%
Total subsidised domestic consumption under VDT (%)	8.9%	21.8%

Furthermore, since the framework developed by the Sustainable Energy for All initiative to define and measure access to energy considers 30kWh/month to be the ideal subsistence level for grid electricity [Kojima, 2016] then this could be considered an effective compromise for Lesotho - it relates only to 30% of households hence 75% of households could manage to shoulder the subsidy. This figure is also consistent with the WorldBank's 2016 analysis of energy affordability in Africa [Kojima, 2016].

6 Definition of Lifeline Tariff Level

Taking the 30kWh/month as basic electricity, and considering the Worldbank's criteria that *"Electricity is affordable if 30 kWh a month costs no more than 5 percent of household income"* [Kojima, 2016] an analysis of whether the current domestic tariff is affordable can be performed:

- The current domestic tariff is M1.424/kWh and so 30kWh/month costs M42.77/month.
- The latest Household Budget Survey (BOS, 2014) shows the poverty line to be an income of M246.60/month in 2011, adjusting this to 2017 money gives M330.47/month.
- The current cost of 30 kWh/month is approximately 13% of this amount, which indicates the current tariff is unaffordable for a poverty line household.
- Therefore, to meet the 5% criteria, the lifeline tariff should be no higher than M0.55/kWh.

The BOS survey also shows that 94% of households had an average income of M404.43/month, adjusting this to 2017 money gives M541.98/month. The table below shows for a range of tariff levels, the required level of income for a household not to be electricity poor with the poverty line (0.5 M/kWh) and household average income (0.9 M/kWh) tariff levels highlighted in bold.

Table 9: Analysis of required income not to be fuel poor for 30 kWh/month consumption

Tariff level	Cost	Required gross income not to be electricity poor (5% of income)
M/kWh	M/month	M/month
0.5	**15**	**300**
0.6	18	360
0.7	21	420
0.8	24	480
0.9	**27**	**540**
1.0	30	600
1.1	33	660

A lifeline tariff level of 0.5 to 0.6 M/kWh in 2017 appears to best address the energy needs of households on or below the poverty line.

7 Tariff Structure Design Analysis

This section presents an analysis considering the implementation of an additional tariff category for lifeline customers in addition to the existing seven tariffs. We propose to name the new tariff category the Lifeline-Block Domestic Tariff and to differentiate the non-lifeline domestic tariff more clearly to rename it as the Standard Domestic Tariff.

The analysis presented in Section 6 indicates that the lifeline tariff should be below the current level of domestic tariff. Introducing a lower tariff will have a financial impact on LEC and the analysis presented below in Table 10 quantifies the impact and presents some possible mitigation strategies using and IBT or VDT structure for a Lifeline-Block Domestic Tariff at 0.5 M/kWh and 0.9 M/kWh.

The analysis assumes only domestic customers are permitted to have their first 30kWh/month of consumption charged at the Lifeline-Block Domestic Tariff rate.

Table 10: Analysis of IBT and VDT tariff structures for 0.5M/kWh and 0.9 M/kWh Lifeline-Block Domestic Tariff.

	Lifeline - 0.5 M/kWh		Lifeline - 0.9 M/kWh	
	IBT	VDT	IBT	VDT
Current structure				
Current Domestic tariff (M/kWh)	1.424	1.424	1.424	1.424
Total domestic consumption (kWh/year)	240,400	240,400	240,400	240,400
Income from Domestic sales (M mil)	342.3	342.3	342.3	342.3
New tariff structure with lifeline				
Lifeline-Block Domestic Tariff (M/kWh)	0.500	0.500	0.900	0.900
Standard Domestic Tariff (M/kWh)	1.856	1.522	1.669	1.480

Number of Lifeline customers (consuming <= 30kWh/month)	64,259	64,259	64,259	64,259
Number of Domestic non-lifeline customers	148,427	148,427	148,427	148,427
Income from domestic sales under new tariff structure				
Lifeline customers - up to 30kWh/month (M mil)	11.6	11.6	20.8	20.8
Non-lifeline domestic customers - first 30kWh/month (M mil)	26.7	n/a	48.1	n/a
Standard Domestic - cross-subsidy for lifeline customers (M mil)	**21.4**	**21.4**	**12.1**	**12.1**
Standard Domestic – non-lifeline customer - remaining consumption (M mil)	282.7	309.4	261.3	309.4
Total income from Domestic sales (M mil)	**342.3**	**342.3**	**342.3**	**342.3**

Note that this analysis is for one tariff year (2017 tariffs) and the tariff and revenue implications will be different for different revenue requirements. This analysis is intended to demonstrate that there is an impact on other tariffs and the 0.5M/kWh range 0.9 M/kWh provides an indication of the order of magnitude increases in the standard domestic tariff if the cross subsidy is to be recovered through tariffs only

The results of these cases are shown in Table 10 and the cross subsidy required to make LEC whole for the lifeline tariff consumption is highlighted red. The amount remains the same in the IBT and VDT cases - principally because the 64,259 lifeline tariff customers (i.e., those consuming below 30kWh/month, Table 6) pay the same amount in both cases so there is no more consumption to subsidise in the IBT relative to the VDT case. The domestic tariff band above lifeline – Standard Domestic Tariff – is higher in the IBT case relative to VDT but the non-lifeline domestic customers do not on average pay more because they get charged for the first 30kWh/month of their consumption at lifeline levels.

For the same levels of lifeline-block domestic tariffs an example of where all tariff categories (i.e. including commercial and industrial etc) provide cross-subsidy is shown in Table 11. Unsurprisingly with more customer categories cross-subsidising the burden on domestic customers from the increase in tariffs to offset LEC's revenue loss is reduced.

Table 11: Lifeline tariff analysis with all customer cross-subsidisation

	Lifeline - 0.5 M/kWh		Lifeline - 0.9 M/kWh	
	IBT	VDT	IBT	VDT
Lifeline-Block Domestic Tariff (M/kWh)	0.500	0.500	0.900	0.900
Standard Domestic Tariff (M/kWh)	1.789	1.479	1.631	1.455
Required uplift on all other tariffs for cross-subsidisation of lifeline tariff (%)	4.5%	3.8%	2.5%	2.2%

8 DISCUSSIONS AND CONCLUSIONS

The analysis has shown a strong case for the introduction of a lifeline tariff in Lesotho. A majority of households connected to the grid would be considered fuel poor if paying for their usage at current tariff levels. The evidence of a rapidly decreasing consumption for newly connected customers as presented in section 2.2 further supports the conclusion that a lifeline tariff is needed for low consumption households. This is further reinforced by the referenced surveys that have been carried out over many years which point to the fact that most households in Lesotho use electricity only for lighting.

Thus tariff reform should address not only the issue of access and cost-reflectivity but affordability as well. Globally in both developing and developed countries affordability has been addressed by various subsidy mechanisms and consumption targeted lifeline tariffs has been found to be the most effective.

A lifeline tariff for households that consume less than 50kWh/month would adequately address the basic energy necessities of poor households in Lesotho and lead to an improvement in the standard of living. An important additional benefit would be a reduction in the use of biomass which contributes to the degradation of the environment and CO_2 emissions. However, in 2016 a large number, in fact a majority of grid connected households (57%) used less than the 50kWh/month threshold. Thus if subsidised tariffs were charged on the basis of this threshold it would lead to an over-elevated tariff for the fewer higher consumption households. The analysis presented in section 6 concludes that it would be more realistic to adopt a lower threshold of 30kWh/month which would have provided subsidised electricity to about 25% of households in 2016.

The analysis presented in section 6 has shown that a lifeline tariff of 0.5 to 0.6 M/kWh would ensure that customers on or below the poverty line could reasonably afford to pay for electricity and we therefore propose a lifeline tariff be set at 0.5 M/kWh. Section 4.4 concluded that the IBT structure would be preferable in Lesotho.

The analysis in Section 7 is for one tariff year (2017 tariffs) and the tariff and revenue implications will be different for different revenue requirements. The analysis has demonstrated the impact on other tariffs and provided an indication of the order of magnitude increases in the standard domestic tariff if the cross subsidy is to be recovered through tariffs only.

We note that public education and consultation with key stakeholders, is critical for success of the lifeline tariff. In planning a tariff reform, it is important to clearly outline the goals and objectives, identify main stakeholders and interest groups, and develop strategies to address their concerns. Convincing the population that there is a credible commitment to compensate the vulnerable groups is essential for the success of introducing a lifeline tariff. This will be a key focus of Task 9 (Deliverable 10) – Roll out strategies.

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Review of Financial Performance of LEC and Preparation of Projections– Deliverable 7

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Contents

List of Acronyms

BoS	Bureau of Statistics
CAPEX	Capital Expenditure
CMS	Continuous Multi-Purpose Household Survey
DoE	Department of Energy
EdM	Electricidad du Mozambique
EDM	Electricidade de Moçambique
EEPCo	Ethiopian Electric Power Corporation
Eskom	Eskom Holdings SOC Limited South Africa
GoL	Government of Lesotho
GRIDCo	Ghana Grid Company Limited
IBR	Incentive Based Regulation
IMF	International Monetary Fund
IPP	Independent Power Producer
KETRACO	Kenya Electricity Transmission Company Limited
KPI	Key Performance Indicator
KPLC	Kenya Power Limited Company
L/M/H-V	Low. Medium and High Voltage
LEC	Lesotho Electricity Corporation
LEP	Lesotho Energy Policy 2015-2025
LEWA	Lesotho Energy and Water Authority
LHDA	Lesotho Highlands Development Authority
LREBRE	Lesotho Renewable Energy-Based Rural Electrification Project
MEM	Ministry of Energy and Meteorology
NamPower	Namibia Power Corporation
O&M	Operation and Maintenance
OPEX	Operating Expenditure
P&A	Process and Activity
PPI	Power Purchase Index (purchasing power by country compared to US) https://data.worldbank.org/indicator/PA.NUS.PPPC.RF
REU	The Rural Electrification Unit

RoR	Rate of Return
RU	Reference Utility
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SAPP	The Southern African Power Pool
STEG	Société Tunisienne de l'Electricité et du Gaz
SV	Solar Photovoltaic
TANESCO	Tanzania Electric Supply Company
TSO	Transmission system Operator
UETCL	Uganda Electricity Transmission Company Limited
WB	World Bank
WEMMIN	Ministry of Water, Energy and Mining
ZESCO	Zambia Electricity Corporation

1 INTRODUCTION

This is the seventh deliverable of the Cost of Service Study (COSS) for Electricity Supply by LEC in Lesotho being carried out for LEWA supported by the AfDB. It reports on the analysis undertaken to address the terms of reference for Task 6 of the COSS. Task 6 includes two main elements: a review of LEC's cost structure benchmarking with other comparable utilities and a review of LEC tariffs structure and levels with a proposal for adjusting these over time to achieve economic cost-based tariffs in Lesotho. The second part of Task 6 also includes a forecast of the financial performance of LEC during the tariff adjustment period which demonstrates the link between tariff levels and LEC financial performance.

1.1 BENCHMARKING

Given that size (e.g., number of employees, energy sales volumes) and business structure differ among utilities, the benchmarking exercise use uses relative metrics (ratios) to allow credible comparisons to be made.

The benchmarking exercise has been structured around three main areas of performance:

- **Technical Standards** relates to the technical performance of the utility, focusing on the evolution of network losses, both for transmission and distribution, on the levels of reliability of supply (duration and frequency of interruptions by customer) and power intensity of the grid.
- **Operational Efficiency** relates to managerial operations of the company, such as O&M costs, current sales or bad debt, and relates them to structural data of the company (number of employees, length of the network, volumes of served energy). In this section, a forecasted growth path has been included for LEC's OPEX.
- **Financial Stability** reviews the financial performance of the company[1].

This report includes a comprehensive definition of different conceptual approaches towards benchmarking and presents a comprehensive set of performance metrics. These metrics provide a conceptual reference framework for benchmarking that, provided the necessary data can be made available by LEC, LEWA could use in the future to assess LEC's performance.

Finally, we recommend OPEX efficiency improvements to be achieved by LEC according to efficiency levels that are being achieved in other parts of the world by comparable (in terms of composite index) companies. These efficiency targets are explained in Section 6.8.2 while our final recommendations can be found in Section 8.

1.2 FINANCIAL PERFORMANCE

The second step in this deliverable is to use the recommended efficiency improvements arising from the benchmarking and define a basis for financial viability of LEC. As LEC income depends on the tariff regime this analysis also takes into consideration the economic costs and tariffs from Task 4. As LEC

[1] The results that come from this analysis would be typically used in presentations to prospective investors where private sector involvement was being sought.

financial performance is also a function of capital expenditure this analysis also draws from the CAPEX set out in the expansion program from Task 3.

1.3 STRUCTURE OF THE REPORT

For convenience the report has been divided into two parts:

- Part 1 – Benchmarking in Sections 2 to 8, and
- Part 2 – LEC Financial Performance and Tariff Scenarios in Sections 9 to 12.

A summary of the content of the sections is as follows:

<u>**Part1**</u>

- **Section 2, Methodology**: this section presents why benchmarking is useful and how a benchmarking analysis should be carried out.
- **Section 3, Ratio Selection**: in this section, the ratios to be employed for the analysis are presented, categorised and explained.
- **Section 4, Peer Selection**: in this section, we explain the selection of the power utilities against which LEC's performance will be compared.
- **Section 5, Technical Benchmarking**: technical ratios identified in section 3 are displayed and compared in this section.
- **Section 6, Operational Benchmarking**: operational ratios identified in section 3 are displayed and compared in this section. Moreover, a forecasted evolution for OPEX, based on this benchmarking, is also provided.
- **Section 7, Financial Situation and Benchmarking**: on one hand, this section analyses current financial situation of LEC in depth; on the other, it displays and compares the financial ratios presented in section 3. It also includes a subsection devoted to analysing current structure of power tariffs in Lesotho, their recent evolution and their level of adequacy.
- **Section 8, Main Results Benchmarking**: the conclusions reported in sections 2 to 7 are summarized and presented in this section.

<u>**Part2**</u>

- **Section 9, Financial Performance Analysis**: a report on the analysis of current and historic financial performance of LEC that considers the impact of the OPEX efficiency improvements identified in Part 1.
- **Section 10, Financial Model Description**: a description of the model developed for projecting LEC financial performance during the three-year tariff review period.
- **Section 11**, **Financial Analysis Results:** describing the results of six tariff trajectories for the three-year tariff review period.
- **Section 12, Conclusions and Proposed Tariff Trajectory:** conclusions of the financial performance analysis and an initial proposal for a tariff trajectory.

Part1 - Benchmarking

2 Available Methodologies

2.1 Top-down Benchmarking

One available benchmarking approach is the so called **top-down benchmarking** method. This method is based on ranking a selected company against similar peers, and to determine whether its performance levels can be deemed reasonable if compared to others.[2]

The electricity sector in Lesotho is relatively small and there is no scope for a national (i.e., within Lesotho) benchmarking as there is only one transmission and distribution company. Nevertheless, partial similarities can be found with international and regional firms that share similarities with LEC.

The top-down method has limitations because of the fundamental uniqueness of every utility and hence the **difficulty in finding representative comparisons**. Thus, the provision of basic infrastructure services is strongly related to the local conditions of the area where those services are provided. Some processes are more related to those local conditions than to the service's "technical specificities". In addition, some countries have extremely specific characteristics (demography, culture and other idiosyncrasies) that are reflected in the provision of basic infrastructure services.

Recent relevant regulatory cases in developing countries have shown that top-down benchmarking methodologies alone do not allow for homogenous comparison. Therefore, "efficient" benchmarks determined by such methods are difficult to apply. As a result, this approach is predominantly applied in developed countries, where services are provided in a mature and stable sector and results obtained are generally consistent, because benchmarking is applied considering reasonably comparable companies.[3]

2.2 Bottom-up Benchmarking

The alternative is to apply a **bottom–up benchmarking** methodology that attempts to overcome the above-mentioned constraints and limitations. This method has been developed for setting prices of services provided by companies under Incentive Based Regulation (IBR) approaches, applied in several reforming Latin American countries. This alternative methodology is known as the **"Reference Utility (RU)" approach** and consists of a "company specific" design that creates an ideal efficient utility which provides the regulated services under the same conditions existing for the real one ("economically adapted" to the local conditions of the area where services are provided).

RU is a company specific approach intended to overcome the limitations of traditional benchmarking and the effects of information asymmetry. It was first developed in Chile during the 1980s and can be used to determine both efficient operating expenditures and levels of technical performance. It is a form of benchmarking based on engineering cost estimates considering specific conditions of service provision, rather than econometric estimates. This model disaggregates the activities performed by the company under study and assigns a theoretical cost for each activity on the basis of International

[2] This way, a set of meaningful KPIs (Key Performance Indicators) are selected and acceptable ranges for each of them are described in terms of international best practices. Then the company under study is compared against them to determine in which areas they should increase operational efficiency. An example of selected KPIs can be found within section 3 while a table of acceptable ranges can be found within Section 77.1.

[3] For example, in a country with a number of distribution companies operating under the same regulatory, policy and market regime the companies could be reasonably benchmarked against one another using the top-down method.

Best Practices and efficient prices. Then, all the performance of the regulated company is compared against those efficient levels set by regulation. The company will be rewarded for savings against the efficient level established (usually under a shared profit rule, i.e. 50% of the savings are retained while the remainder is shared with customers), while penalties will be included for cases of underperformance (either in the form of future reductions in allowed costs due to over-spending or in the form of penalties). This type of model considers not only the activities to be performed, but also the conditions of the local market in which activities are performed (levels of collection, power purchase indexes for final consumers, local supply prices, labour costs, efficient procurement regulations for contractors, etc.). As such, it is more understandable (i.e., less of a "black box") to most regulators and other sector stakeholders. This approach can be applied to both network and generation activities.

As already indicated, RU is a "bottom-up" approach. Each and every process and activity (P&A) necessary for efficient service provision meeting predefined requirements on availability and quality is identified and precisely described. International experience and references and conditions on availability and quality defined by the competent authorities are considered in order to define frequency of execution of those P&As, and required human and material resources. For every P&A the required human and material resources for its efficient execution are defined in physical terms and then valued considering prices of representative supply markets. This means that a "benchmark" is built at the level of each P&A and the overall benchmark, representative of efficient performance, is obtained by adding the individual values in a "bottom-up" process.

This approach enables detailed analysis of every specific condition of the service, in particular relevant aspects of the assets' starting condition, local conditions for execution of certain processes and activities, and market prices of representative supplies.

2.3 Choice of Methodology

The application of the bottom up benchmark model described above requires a deep analysis of the utility's infrastructure and asset base and technical and management processes. The data needed to undertake such an analysis would include as a minimum for the current and previous years (e.g., at least five years) the following:

- Number of customers by voltage level.
- Peak load by voltage level.
- Energy consumption by voltage level.
- Number of transformers, listed type (HV/MV, MV/LV) and capacity (MVA).
- Number of MV/MV sub-stations.
- Underground and Overhead km of lines listed by voltage level.
- Registered load in MV/LV substations (MW).
- Local salaries (if possible, in two or more levels according to workers' capabilities).
- Transport costs.
- General administrative costs.

This data was requested from LEC during the data collection phase of the study but was not available. As a result, the bottom-up method could not be applied.

As a general point, increasing information requirements for LEC to provide to LEWA would enable LEWA to have a clearer view of LEC's situation, making it easier to monitor its performance and to accurately determine its financial and operating needs. We recommend, therefore, that LEWA periodically (i.e., annually) request the above data from LEC.

Given the lack of sufficiently disaggregated and time indexed data, we consider that the most realistic option is **to develop an overall benchmarking method** based on three performance areas (technical, operational and financial) described in section 1.1, together with an historical analysis of LEC performance. The results shall serve as a source of information for the LEWA in its rate setting activity - a regularly updated tool.[4]

The method is sub-divided into two different benchmarking exercises

1. A **regional analysis** - In Section 4 we detail how we have attempted to select utilities from other countries for this benchmarking exercise that have a similar regulatory framework (vertically integrated utilities) as Lesotho, that also participate in SAPP and in which distribution and retail activities are operated by the same company, thereby ensuring maximum possible comparability. Performance benchmark averages, calculated among the selected companies, are also presented. This exercise provides an idea of how LEC is behaving with respect to relevant players in its regional market (SAPP). More detail on our choice of peer utilities is provided in section 4.
2. A **best international practices analysis for operational expenditure** - In Section 6.8 OPEX cost indexes are compared using a broader database which includes distribution utilities from well established markets, whose density values and composite indexes are similar to those of LEC (see section 6.8 for a detailed description of both variables).

The international benchmarking exercise provides quantitative assessments of the efficient frontiers for equivalent companies thereby enabling us to derive goals for LEC in terms of OPEX/MWh and OPEX/Customers. The regional exercise is only employed to compare LEC with its neighbouring power companies, but does not result in the derivation of efficiency goals since companies are not the most similar and their performances are not necessarily efficient.

To supplement these purely comparative approaches, and where the data was available, an analysis of LEC's performance over time is included. This has merits in that the area where the services are provided is consistent, although this has its limitations because the network is inevitably evolving and there also could be institutional inefficiencies that have remained unimproved for some years.

[4] That may for example assist in dialogues with other regulators.

3 Ratio Selection

Key Performance Indicators have been selected taking into account the following characteristics:

- **Adapted to the study purpose**. The indicators chosen are representative of the overall study purpose: they try to cover the most important drivers for tariff setting, including performance levels and cost structures, without neglecting the important differences between utility performance in developing countries as compared to those in the developed world.

- **Comprehensive but not excessive.** It is important to avoid "duplication" of inputs or defining more than one indicator for each of the aspects to be examined - each indicator should measure one particular aspect of the activity performed, unless it adds relevant additional insight or facilitates interpretation of the information. Thus, we selected indicators of the utility performance that provide enough information to give a complete picture of the overall efficiency in performing its operations. Nevertheless, in certain occasions multiple related indicators are acceptable in case they show different aspects of the relationships between drivers and outcomes.

- **Quantifiable (measurable).** The indicators are expressed in figures that can be computed using objective and precise formulas. The parameters (to be used in the formulas) have clear definitions, keeping subjective interpretation to a minimum.

- **Feasible to calculate**. We selected indicators on the basis that the necessary information for their calculation is available. In some cases, indicators considered as best practice in other environments are not ideal for LEC because of differences in the availability, type or format of the input data required. A practical example of this principle is the decision of presenting peers' company data as they are, that is, for instance keeping power distribution and retail activities bundled when there is not enough data to split them.

- **To be recurrent.** Basic data and selected Key Performance Indicators (KPIs) have to be replicated periodically, so as to allow not only cross-section assessment (several systems at a certain point in time), but the evolution path along time for the Lesotho system.

Considering these five criteria, we have selected a set of performance indicators that can be classified in three groups:

- Technical performance indicators, related to the effectiveness of technical and engineering practices to maintain the grid in satisfactory condition to provide the service. The main indicators are energy and power losses, and reliability of service.
- Operational performance indicators, related to the efficiency of the operation and maintenance activities of the grid, and associated commercial activities.
- Financial performance indicators, that reflect how the company transforms its technical and operational performance into satisfactory results for existing and potential investors.

There are a number of ratios that can be considered and the availability of information is a key factor determining their selection. The following table summarizes the indicators we chose for benchmarking LEC's performance:

Table 1 – Selected Ratios for Performance Benchmark

Technical KPIs	Formula	Description	Feature demonstrated
Energy losses (%)	$\frac{Electricity\ losses}{Total\ electricity\ wheeled}$	It is the ratio of electricity losses during the year over total electricity wheeled. It gives the electricity losses as a percentage of the overall electricity wheeled in the transmission system.	These indicators show how effective from the technical point of view are the current routines and practices for grid operations and maintenance, and thereby also an indication of the effectiveness of the associated investments in O&M
SAIFI	$\frac{Sum\ of\ customers\ interruptions}{Total\ number\ of\ customers}$	It is the average number of times per year that supply to a customer is interrupted.	
SAIDI (hours)	$\frac{Sum\ of\ all\ interruption\ duration}{Total\ number\ of\ customers}$	It is the average amount of time per year that supply to a customer is interrupted	
Energy intensity (MWh/km)	$\frac{Total\ electricity\ wheeled}{Total\ Km\ of\ transmission\ lines}$	Capital energy efficiency of a company infrastructure.	This is an indicator of structural demand density – an efficiency measure (though not strictly a performance indicator)
Operational KPIs	**Formula**	**Description**	
Energy wheeled per employee (MWh/employee)	$\frac{Total\ electicity\ wheeled}{Total\ number\ of\ employees}$	It is the ratio of total electricity wheeled during the year to the number of employees. It gives the amount of electricity per employee.	These indicators reflect in physical and monetary terms the efficiency in managing human resources - it is most influenced by management and operational organization and routines
Customers per employee	$\frac{Total\ number\ of\ customers}{Total\ number\ of\ employees}$	It gives the number of customers per employee	

Network Length per employee	$\frac{Total\ Km\ of\ lines}{Total\ number\ of\ employees}$	It gives the Km per employee, to relate staff numbers with the need to manage a network of a certain size	
Salaries to Sales Ratio (%)	$\frac{Total\ salaries\ expenditure}{Net\ total\ sales}$	Total operating salaries expenditure of the utility over the total net sales recorded for the year.	
OPEX versus Energy Wheeled	$\frac{Total\ Operating\ Expenditure}{Total\ MWh\ wheeled}$	Total transmission OPEX over the total volume of energy wheeled. It gives an expenditure figure per MWh of transported power.	These indicators reflect the efficiency of the management of the operational expenses of the company, taking as reference physical assets (grid km), the traded product (MWh) and monetary income (revenues)
OPEX over Total Revenues	$\frac{Total\ Operating\ Expenditure}{Total\ Revenues}$	This ratio provides an idea about gross profit of the company (which percentage of its revenues is devoted to OPEX)	
OPEX per grid km	$\frac{Total\ Operating\ Expenditure}{Total\ km\ of\ transmission\ lines}$	Total transmission OPEX over the total Km of transmission lines. It gives an expenditure figure per km of lines.	
Assets Efficiency	$\frac{Gross\ Value\ of\ Fixed\ Assets}{Peak\ Demand}$	The figure uses gross value of assets, so does not take into account depreciation	This indicator represents the efficiency in CAPEX and assets management activities, very relevant in electricity transmission and distribution - a highly capital-intensive industry.
Revenue Collection Ability USD/kWh	$\frac{Revenue\ from\ sales\ (USD)}{Total\ Sales\ (kWh)}$	It represents the ability of a company to obtain revenues from its sales (hence it covers both tariff levels and collection rates).	This indicator reflects the capacity of the company to transform its technical and operational management into income (measures the average price of sales)
Financial KPIS	**Formula**	**Description**	
Working ratio	$\frac{\text{Operating Expenses}}{\text{Total revenue}}$	It measures the ability to recover Op. Costs from annual revenue.	These indicators reflect the efficiency in managing the cost structure of the company, and therefore its capacity to generate gross operating margin
Working ratio with depreciation	$\frac{\text{Operating Expenses} + \text{Depreciation}}{\text{Total revenue}}$	Same ratio but accounting for depreciation, to reflect asset value evolution.	

Working ratio with depreciation and net interest	$\frac{\text{Op. Expenses } + \text{ Depreciation } + \text{Net Finance C.}}{\text{Total revenue}}$	As the previous, but including net financing costs	
Net operating margin	$\frac{\text{Net Profit}}{\text{Total revenue}}$	It provides the percentage of revenue that is left for the company after accounting for all expenses	This indicator shows whether the company is able to generate a positive operational margin, and hence that it is operationally viable
Current ratio	$\frac{\text{Current assets}}{\text{Current liabilities}}$	It measures the company's ability to repay s/t and l/t obligations	Those are indicators of the financial liquidity of the company, that is, its capacity to cover its current liabilities with its current assets
Accounts receivable collection period	$\frac{\text{Accounts receivable} * 365}{\text{Total revenue}}$	Number of average days that it takes a company to collect its accounts receivables (i.e. to make them liquid)	
Accounts payable disbursement period	$\frac{\text{Accounts payable} * 365}{\text{Operating expenses}}$	Number of average days that it takes a company to pay its debtors	
Return on equity	$\frac{\text{Total revenue } - \text{Operating Expenses}}{\text{Equity}}$	Measures Net Income as a percentage of shareholders equity (i.e. the profitability of the money invested by shareholders)	Return indicators that show how beneficial the company is for existing investors and how attractive the company is for potential investors - vital if the company needs to raise finance for system expansion to meet demand.
Return on net fixed assets	$\frac{\text{Total revenue } - \text{Operating Expenses}}{\text{Assets}}$	It measures how efficiently a company is using its net fixed assets.	
Debt to assets	$\frac{\text{Debt}}{\text{Assets}}$	This leverage ratio provides an indicator of financial risk exposure by the company (the higher the ratio, the higher the exposure)	Debt must be under control so as not to put at risk an otherwise good operational and management performance

4 Peer Selection

4.1 Peer Selection Process

Generally speaking, benchmark validity can be maximized through careful selection of peer companies according to the following criteria:

- Geographical proximity and legal/regulatory similarity. In terms of legal and regulatory conditions, the most comparable companies are other vertically integrated utilities, although no legal and regulatory framework is the same as that of Lesotho.
- Size: measured through different magnitudes. There are economies of scale, economies of density and aspects of the technology used (generation mix) that impact comparability. Selecting similar sized companies (in terms of energy volumes or customer bases) allows for a comparison of the company's performance against businesses that operate under similar scale-related technical and economic conditions.
- Developing / Developed economy: a number of technical operational and investment aspects are strongly related to the country/system being a developing country or a developed economy.[5]

As noted earlier there is no perfect comparability to LEC as there is no country or power system identical to that of Lesotho. Comparing utilities from different countries is not an exact science and it needs to be understood that the economic framework, regulatory conditions and consumption profiles are specific to each country. Nevertheless, this benchmarking analysis has maximized comparability through careful selection of companies, KPIs and by providing guidance in the interpretation of each benchmark result.

Selecting a broad range of peers, with varied characteristics, improves the significance of the exercise although findings must be interpreted accordingly. If the analysis is based on a small number of indicators only then isolated features of the grid could be identified and misinterpreted. For example, low levels of OPEX/MWh could be interpreted as operational efficiency, however the level of quality of service or customer satisfaction should also be considered since low levels of OPEX/MWh may only reveal underinvestment in operational procedures. This potential misinterpretation is therefore overcome by combining the analysis of SAIDI and SAIFI figures with an analysis of OPEX levels.

As noted in section 2.3 we have adopted two separate benchmarking exercises that utilize different peer groups:

1. A **regional analysis** (see section 4.2 below) - utilities from other countries for this benchmarking exercise that have a similar regulatory framework (vertically integrated utilities) as Lesotho, that also participate in SAPP and in which distribution and retail activities are operated by the same company.

[5] Such as electrification rate, the need for new distribution network, the level of consumption per customer, the rates of technical and non-technical (theft) losses, etc.

2. A **best international practices analysis for operational expenditure** (see section 4.3 below) distribution utilities from well established markets, whose density values and composite indexes are similar to those of LEC (see section 6.8 for a detailed description of both variables).

4.2 Regional Benchmark: Peer Selection

During the last two decades, most African countries have commenced power sector reform under the influence of international donor organizations such as the IMF, with the aim of improving financial stability and attracting international investors to facilitate an adequate level of infrastructure development. Most reforms involved various stages of unbundling of the incumbent power company, first by means of corporatization of the public utility and then by opening different segments of the power delivery chain to competition.

This has led to the existence of separate Transmission System Operators (TSOs) in some countries, that have sole responsibility for transmission operations, management and development of the network. In this group, we can find Egypt, Kenya, Nigeria, Uganda and Algeria.

However, in most cases, the utility has been corporatized but retains its role as a vertically integrated utility, allowing for the introduction of private investors at some points of the value chain. Usually, the introduction of private investors first took place in the generation segment, while transmission and distribution assets remain under Government ownership. In this group we can find Botswana, Ethiopia, Libya, Morocco, South Africa, Tanzania, Tunisia, and Zambia, which still need to start effective unbundling of the sector, while Mozambique, Kenya and Namibia have already undertaken partial unbundling (not yet completed).

SAPP members are relevant to LEC given its plans to keep relying on imports for a significant share of total consumption and also because problems in networks directly connected to LEC's (Eskom) or exporting to the country (EDM) will have an impact on LEC's ability to maintain Quality of Service indicators. Furthermore, some members of this market have similar sizes in terms of volumes. However, the sample does not provide completely comparable companies (see Table 2 for a description of each company).

Apart from peak demand and generation capacity, another feature that makes countries comparable is the type of commercial relations they have (recently, LEWA encouraged LEC to start taking an active role within the SAPP market so as to reduce the cost of power imports).

The following Table offers a brief summary of the SAPP members, obtained from SAPP annual reports.

Table 2 – Main Characteristics of SAPP Power Systems[6]

Country Member	Company	Peak	Installed Capacity	Sales (GWh)	Number of Customers	Revenues USDM	MWh/kM2
Angola	ENE	1,599	2,210	3,427	251,952	513.4	2.7
Botswana	BPC	610	692	3,118	251,773	216	5.4
DRC	SNEL	1,317	2,442	7,584	746,902	309.6	3.2

[6] Although more up-to-date figures for Lesotho are available, we reflected those published by SAPP in order not to mix several sources in the same table.

Country Member	Company	Peak	Installed Capacity	Sales (GWh)	Number of Customers	Revenues USDM	MWh/kM2
Lesotho	LEC	150	72	488	58,900	31.5	16.1
Malawi	ESCOM	326	351	1,476	204,955	90	12.5
Mozambique	EDM/HCB	880	2,308	2,380	1,010,780	N/A	3.0
Namibia	NamPower	629	501	3,648	3,449	31	4.4
South Africa	ESKOM	34,481	46,963	224,446	4,653,750	13649	183.8
Swaziland	SEC	227	70.6	1,018.6	97,000	114.4	58.7
Tanzania	TANESCO	935	1,143	3,770	932,285	277.3	4.0
Zambia	ZESCO	2,287	2,029	10,688	418,651	350	14.2
Zimbabwe	ZESA	1,589	1,600	7,367	579,006	469	18.9

Source: SAPP Annual Reports

The rest of companies included in the study include large generation segments in their costs structure whereas LEC sources power from either LHDA, Eskom or EDM (transmitted using Eskom network). The rest of the companies considered are vertically integrated utilities acting as monopolies, so we deem reasonable to consider that the power purchase cost for Lesotho is comparable to the generation cost for the rest of them. Otherwise, the comparison would be biased in favour of LEC, given that the rest of companies would include costs devoted to generation while LEC would only include costs devoted to T&D activities (this potential bias disappears when power purchase costs are included for LEC).

However, not all utilities from countries in the region can be reasonably compared to Lesotho, and including all of them would require a significant amount of effort which would not be reflected in significant results, even more considering the lack of available data in many of them (i.e., in many cases, data are available for some years only, which does not allow to create a trend in time). For example,

- Operators in large and scarcely populated countries like Namibia, Mozambique, Tanzania, DRC, Botswana and Angola will tend to have different network structures than those with higher power consumption per Km^2.
- NamPower, in Namibia, only serves a very limited number of large customers, which makes its case less comparable.
- ENE (Angola), EDM (Mozambique), SNEL (DRC) and Eskom (South Africa) have excess capacity (opposite to Lesotho) and are much larger power systems.
- Tanesco (Tanzania), ZESCO (The Zambia) and ZESA (Zimbabwe) could also be employed for the comparison, but after an initial research of public data, and given the lack of comparable information, it was decided not to consider them.

Therefore, we have selected those systems in the region which are most comparable to Lesotho.

- SEC (Swaziland): similar demographic (density data are comparable in both countries, with values around 75 hab./km2[7]) and geographical situation (small land-locked countries

[7] According to World Bank data, Lesotho presents a density of 73 and Swaziland, 78. (http://wdi.worldbank.org/table/WV.1)

surrounded by the RSA), similar power system (import-dependent, with high levels of interconnection).

- The two SAPP member companies currently exporting power to Lesotho (EDM and Eskom) will also be included. Although RSA's power system is much bigger than Lesotho's it is included as representing the regional context.[8] There technical KPIs are relevant since they may directly affect LEC's ability to maintain Quality of Service levels.
- BPC (Botswana): Similar customer base size (both around 250 k consumers).
- Escom (Malawi): Similar sized customer base, non-operating member of SAPP.

4.3 International Benchmark: Peer Selection

The international benchmarking exercise considers operational expenditure only.

The database used for OPEX indexes (both in terms of OPEX/MWh or OPEX/Customer) is composed of distribution utilities from other countries with well-established power markets and regulations and is based on companies whose density and composite indexes (see section 6.8) are comparable to those of LEC. The companies included are shown in Table 8 and Table 9 in Section 6.1.8.

The figures derived from this exercise are included as OPEX goals for LEC in our financial model (Part 2 of this report).

[8] Given the level of interconnection of both systems, whatever happens to transmission infrastructure on the RSA will affect technical KPIs in Lesotho: e.g. plant availability in places close to the border will affect Eskom's ability to honour its exporting contracts, reducing exporting flows or stopping them; while transmission infrastructure failure on Eskom's side of the network will have a similar effect.

5 TECHNICAL PERFORMANCE BENCHMARKING

The Technical Performance Benchmarking exercise has been hampered by the lack of reliable public data for some of the companies under study. In the case of system interruptions figures (SAIFI and SAIDI) the group of peers has been enlarged to introduce other international references, given that only Eskom published public data on the issue.

5.1 NETWORK LOSSES

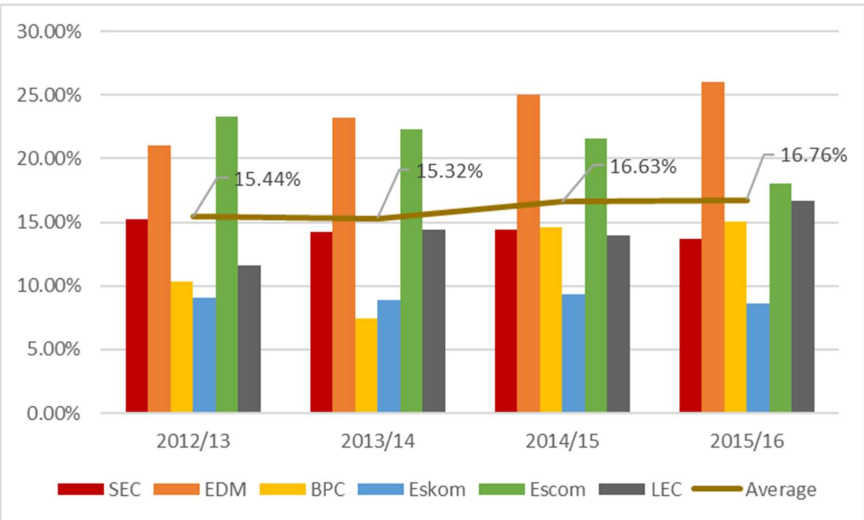
Regarding total losses from the network, Figure 1 presents final values (including losses in the transmission and distribution grid, and technical and non-technical losses) for all the countries considered.

Both EDM and Escom present high figures, ranging around 22%, although with opposite trends: EDM has steadily increased its losses from 21% to 26%, while Escom has decreased them from 23.3% to 18%. Both countries have developed programs to counteract the effects of non-technical losses (theft).

LEC and SEC present very similar loss levels, close to 14%[9] but, again with opposite trends: SEC has decreased them from 15% to 13.7%, while Lesotho has experienced a high increase from 11.6% in 2013 to 16.7% in 2017. Botswana has experienced a similar trend, reaching 15% in 2017, while Eskom presents much lower and stable figures around 9%.

As goal for the future, LEC should try to reach Eskom levels (below 10%). If this goal was reached, the costs incurred in term of network losses could be halved.

Figure 1: Network Energy Losses (Aggregate T+D losses)



Source: Own elaboration based on annual reports

[9] Note that the Task 4 (deliverable 5) report indicated transmission losses at 7% and distribution losses at 12.5%. The overall loss level of 14% is consistent with this breakdown once consumption at the transmission level (i.e., HV commercial and HV Industrial) has been accounted for – see section 6.6 of Task 4 report for a worked example.

5.2 SYSTEM AVERAGE INTERRUPTION DURATION INDEX (SAIDI)

$$\frac{\text{Sum of all interruption duration}}{\text{Total number of customers}}$$

As mentioned, very few data on SAIDI figures is publicly available. Table 3 displays the information that we have obtained for the selected peer companies. We also present in this section some SAIDI figures for more developed European or North American systems, which should be regarded as goals to which Lesotho’s system should converge in the long-term. In the medium to short-term, a reasonable goal would be to converge to Eskom n figures.

Table 3– SAIDI (minutes)

Country	2009	2010	2011	2012	2013	2014	2015	2016
South Africa	54.4	52.6	45.8	41.9	37	36.2	38.6	39
Namibia				40.37	17.14	17.14		
Mozambique		30	45	44				
Lesotho				41.19	88.71	107.88	171.79	131.83

Source: Global Electricity TSO Profiles Report 2015, Global Transmission Research; ESKOM Annual Reports

In the case of Lesotho, SAIDI figures have worsened in recent years: initially (2012) they were at levels comparable to those of Eskom but are now three times higher than South Africa’s (albeit with a slight improvement during 2016).

As for international Standards, European countries present SAIDI numbers around 5 minutes, reaching lower levels in countries as the UK (1.1), while in the USA numbers move in the range between 2.5 and 3.

The South African case shows a constant improvement in network conditions: a 28% decrease was achieved during the period 2009-16. Other examples of mature and developed networks would be Australia (3.3) and Canada (6.5).

European and American standards seem too demanding for LEC’s standards, but Eskom figures, below 50 minutes and decreasing, should be considered as a target.

5.3 SYSTEM AVERAGE INTERRUPTION FREQUENCY INDEX (SAIFI)

$$\frac{\text{Sum of customers interruptions}}{\text{Total number of customers}}$$

A similar approach has been adopted for SAIFI figures, shown in Table 4 below.

Table 4– SAIFI

Country	2009	2010	2011	2012	2013	2014	2015	2016
South Africa	24.7	25.3	23.7	22.2	20	21	20	20
Namibia				33.75	28.67	32.25		

Mozambique	77	78	57	46				
Lesotho				20	33.33	44.41	47.91	34.75

Source: Global Electricity TSO Profiles Report 2015, Global Transmission Research; ESKOM Annual Reports

Again, Eskom achieved a decrease of 19% during the eight-year period, while figures for Namibia show an irregular path. EDM's figures show a sharp decrease between 2009 and 2012 (-40%), but the lack of actual data and the increases in losses (reference Figure 1) and load shedding experienced by the country in recent years[10] seem to point to a deterioration in performance rather than any improvement.

Lesotho again presents a significant worsening of its figures: in 2012 SAIFI levels were comparable to those of Eskom. In addition, and in the same way as for the SAIDI performance, SAIFI numbers improved during 2016. Both figures are closely related, and its evolution can perhaps be explained by the large volumes of recently connected customers imposing extra pressure on network maintenance.

As for International Standards, the number of average interruptions per customer is slightly above 1 in the USA and the UK, around 2.5 in Europe and Australia and around 3.5 in Canada.

Again, for SAIFI numbers, European and American standards seem too demanding for LEC's standards. Eskom figures were comparable at the beginning of the period and represent a target for future years.

5.4 Energy Intensity

$$\frac{Total\ electricity\ wheeled}{Total\ Km\ of\ transmission\ lines}$$

Figure 2 presents the energy intensity of each of the peer group grids. The lack of available data (namely, length of networks), prevents this benchmark from being a comprehensive comparison. Only Eskom and SEC offer periodical data on the matter, while there are some data for EDM and Botswana for year 2013/14.

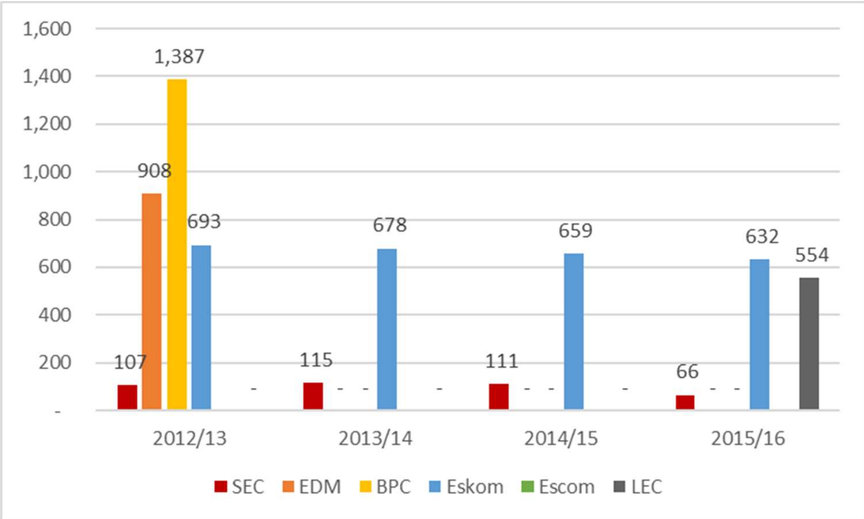
There are two explanations for low levels of energy intensity on the grid:

- Low geographical concentration of population in the area;
- Poor technical performance in the system (design of the grid is poorly adapted to actual needs and main lines are unable to accommodate actual flows within production and consumption areas).

In the case of Eskom, we can see that energy intensity per km of network has decreased constantly since 2013. This is the result of network expansion in combination with no demand growth (lower in 2016 than in any of the previous years under study). In the case of SEC, the trend is not clear, with a sharp decrease in 2016, after commissioning of almost 8,000 km of new transmission lines.

[10] "*In January 2015, floods damaged the line to this region, cutting power to 350,000 EdM customers (and 2 million people altogether) for a period of four weeks. Even under normal operation the line to the north east is overloaded, resulting in load shedding in the region of over four hours per day. The development of a second line to the north east is key to improving security of supply for existing customers and for providing the transmission capacity required to meet demand from new customers as access to power in the region is increased*". Mozambique Energy Sector Policy Note, p. 25; Report No: ACS17091, document of the World Bank.

Figure 2: Energy Intensity (energy wheeled vs network length)



Source: Own elaboration based on annual reports

In the case of Lesotho, only 2016 figures are available for network length. Its figures are comparable to those of Eskom , but the lack of a historical series for this indicator prevent analysis of its trend over time.

6 Operational Performance Benchmarking

6.1 Energy Wheeled per Employee

$$\frac{Total\ electricity\ wheeled}{Total\ number\ of\ employees}$$

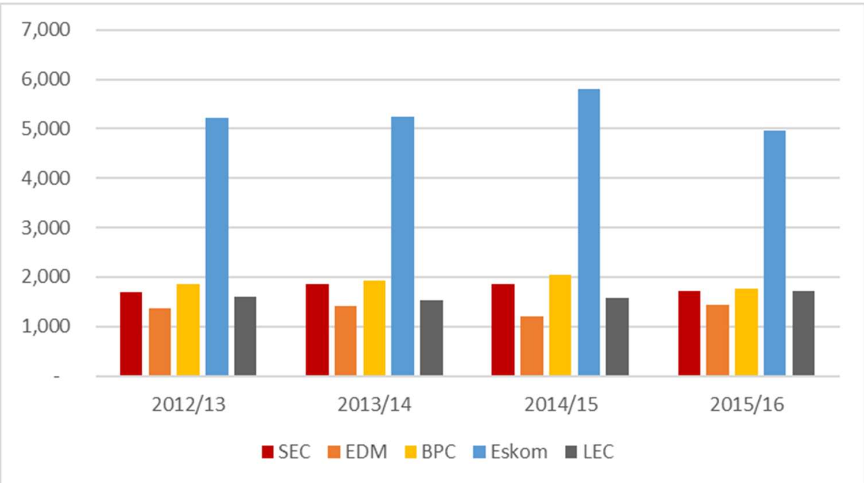
Figure 3 presents this ratio for the peer group countries. Figures for Eskom demonstrate its different status as a much larger network in a larger economy leading to significant economies of scale. Thus, it has almost 6 million customers currently connected to the grid and universal access to electricity is forecasted to be achieved by 2025 so its network is significantly larger than in the rest of African countries in the peer group. The numbers and loads of industrial customers are also significantly higher, further increasing power flows.

As for the remaining countries in the peer group, figures range between 1.3 and 2.4 GWh/employee, and trends are not clear: figures increase or decrease year-on-year. Fluctuations can be caused by changes to staffing (e.g. increases of working staff in SEC) or by changes to the volume of energy wheeled (e.g. EDM). To this regard, it must be noted that EDM had to introduce load shedding schemes during 2016.

In the case of LEC, figures have increased for the last three years and are comparable to the rest of peer group countries.

If network expansion so allows, LEC should try to increase its figures towards Eskom numbers, although different demographic density figures may make it difficult to reach comparable levels.

Figure 3: Energy Wheeled per Employee



Source: Own elaboration based on annual reports

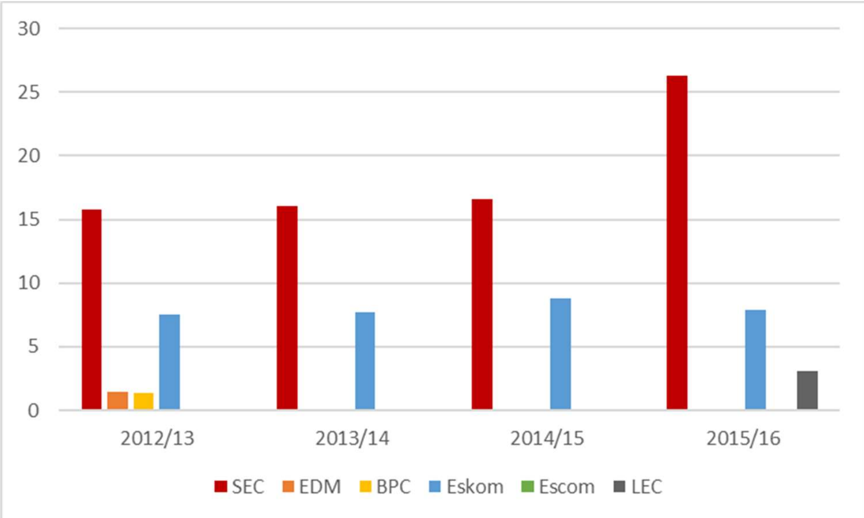
6.2 Network length per employee

$$\frac{Total\ Km\ of\ lines}{Total\ number\ of\ employees}$$

Again, the lack of data on network length limits the value of a benchmark for this operational ratio. The only figures available for EDM and BPC suggest an inefficient staffing policy, with very reduced km figures for each employee. In the case of Eskom, per year values of the metric are around 8 km per employee, while SEC showed values around 16 km per employee until last year, when the commissioning of the new lines led to an increase to 26 km per employee - Figure 4.

Eskom's values are much lower than SEC's given that the former includes a much larger generation segment, while SEC relies heavily on imports. The contrast between Eskom's relatively high energy per employee and its relatively low network length per employee can be explained both by this generation factor and also by the more advanced economy in South Africa that leads to a much higher mean level of consumption.

Figure 4: Network Length vs. Employees



Source: Own elaboration based on annual reports

Again, in the case of LEC, only 2016 figures are available for network length, so little can be said on this indicator. However, numbers (3 km) are significantly lower than those of SEC and Eskom.

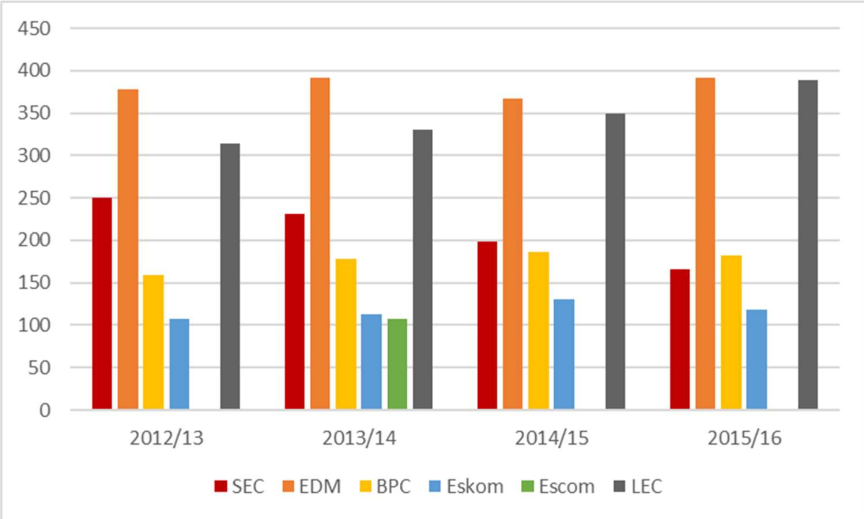
Apart from the number of employees involved in the generation segment, this figure may reflect the degree of quality of service present in the system: networks with a low number of employees per km may not be properly maintained and monitored, leading to higher losses and interruption numbers.

6.3 CUSTOMERS PER EMPLOYEE

The ratio between customers and number of employees is relatively low in Eskom due to its large number of employees in the generation segment, although figures have been increasing. EDM has the highest ratio amongst the peer group countries, in a market with a high number of customers (around 1.5 M) and a not so large generation segment (EDM currently suffers from capacity deficit). The ratio has grown in recent years as the number of employees has increased at a lower rate than final customers. It must be also noted that EdM is not the only producer in the country: there are IPPs connected to gas-fired generation units with 275 MWs of capacity and a private supplier (Aggreko) has also offered temporary capacity up to 65 MW in cases of emergency.

By contrast in Swaziland the ratio has steadily worsened (-33%), which may suggest some over-staffing in the company.

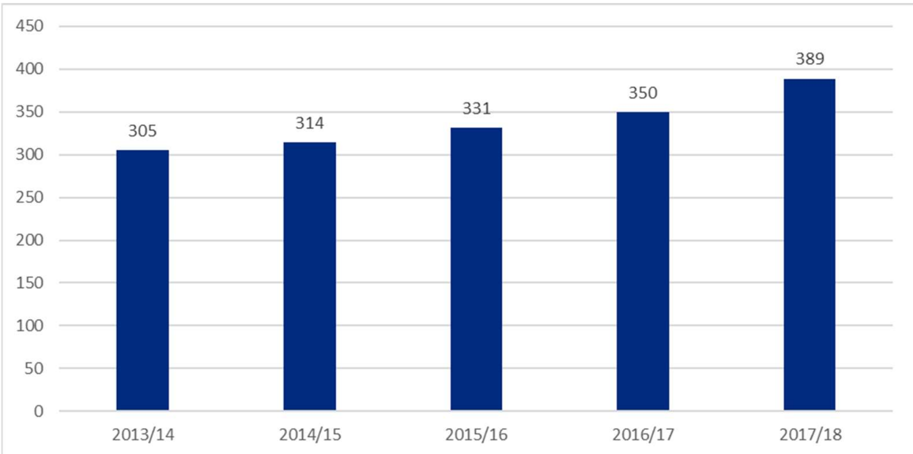
Figure 5: Customers vs number of employees



Source: Own elaboration based on annual reports

The LEC ratio (see Figure 6 below), as estimated by LEWA in its yearly tariff studies, has increased by 27% from the beginning of the period, from 305 until 389, very close to the target figure established by LEWA (400 connections per employee). Figures for LEC are then comparable to those of EDM but, despite the improvement, it must be borne in mind that LEC is the only company without a generation segment (only transmission and distribution).

Figure 6: Evolution of Connections per employee in LEC (2013-2018)



Source: LEWA

6.4 Operating Expenditure

$$\frac{Total\ Operating\ Expenditure}{Total\ MWh\ wheeled}$$

Figure 7 presents the ratios of total OPEX against total energy volumes wheeled for the peer group countries. The figure is expressed in USD/kWh. Exchange rate variations have masked, at least partially, the general trend in which OPEX has increased significantly faster than energy volumes sold in all the African countries in the group.

The case of Mozambique is the most significant with energy wheeled increasing by 23% while OPEX increased by 175%. In South Africa, OPEX increased by 65% since 2013, while energy consumption was slightly reduced (-1%), while in Malawi, OPEX costs doubled against a 14% increase in consumption (2015 figures). The case of LEC is not the most extreme: OPEX increased by 32% while demand grew by 10%.

All in all, and taking exchange rate into consideration, Eskom, Escom and LEC belong to the group with low OPEX/MWh, while SEC, BPC and EDM have much higher figures.

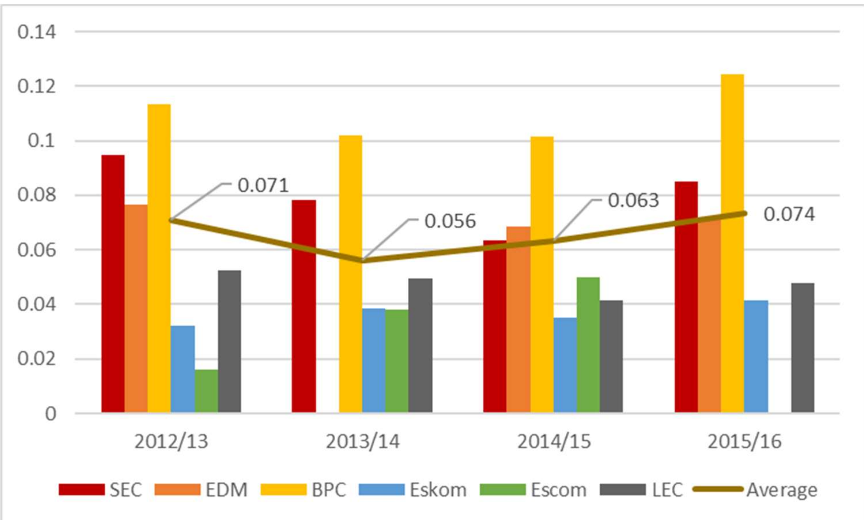
Low OPEX costs per MWh may indicate a low investment in maintenance of the network; lack of suitable levels of refurbishment, poor maintenance of existing assets, increases in time required for repairs, low availability of repair teams in the area, etc. Where low OPEX per MWh is the result of such low O&M investment it usually leads to poor quality of service so a check for such underinvestment is to review this ratio together with the number/duration of interruptions.

To avoid this type of negative effect, regulation must be clear about minimum acceptable service levels to be achieved by utilities, imposing penalties when the thresholds are not met.

In the case of LEC OPEX/MWh is expected to decrease in the future, as the network is periodically replaced with new elements that require less O&M costs (this feature has already started and is foreseen to increase in the future).

Further benchmarking analyses of opex is presented in section 6.8.

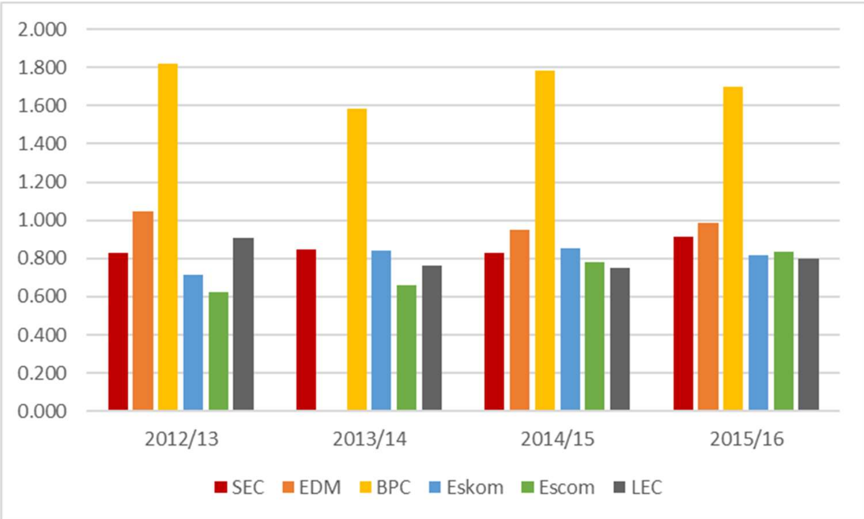
Figure 7: Total OPEX vs energy wheeled (USD/MWh)



Regarding the ability of the company to generate revenues from its OPEX (i.e. Total OPEX/Total Revenues) most companies in the peer group present values of around 80%, which offers a gross margin of 20% over sales. It is striking to see the figures of BPC, where OPEX represents up to 1.6 times total revenue. Such a situation is possible only because final prices are heavily subsidized in Botswana and the company receives a Government subsidy each year to account for that difference.

Decreases in this ratio would allow LEC to be more profitable and to spare money for other issues (such as increasing quality of service or decreasing losses).

Figure 8: Total OPEX/Total Revenue



6.5 SALARIES TO SALES

Figure 9 below considers staff costs incurred by each of the peer group companies (converted to USD) and divided by total sales (measured in MWh). Hence it provides a measure of labour costs for each unit sold. The results show no pattern although they are comparable between the companies.

LEC and SEC have the second highest values (1.4 USc and 1.8 USc), while Eskom has much lower unit labour costs (around 0.9 USc). The trend for LEC is unclear, but its staff costs have increased by 31% since 2013 against an increase of 5.3% in total sales.[11] These figures locate LEC as one of the highest in the peer group.

SEC is similar: it is not clear whether a trend exist or not, but Labour costs have increased significantly since the beginning of the period.

This evolution suggests that LEC may be spending too much on wages with respect to total sales and that figures around 1 USc/kWh should be achieved in the future.[12]

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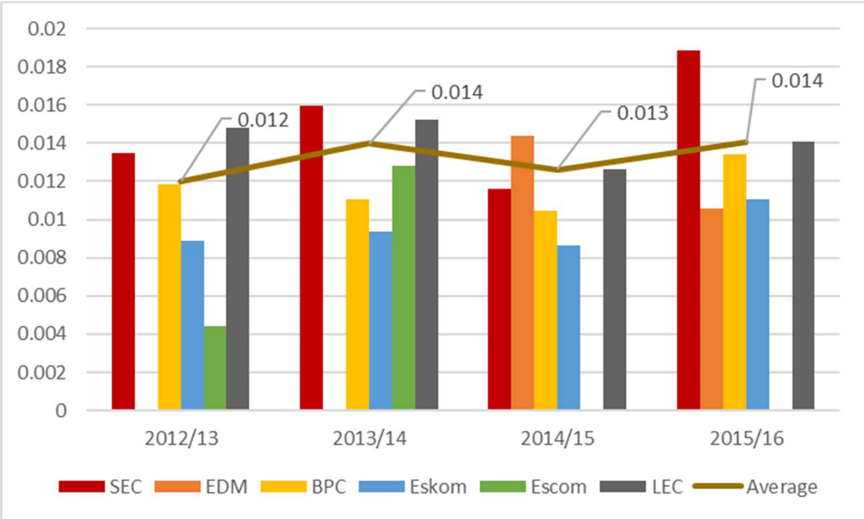
[11] The figure does not show such a big increase since staff costs are measured in Maloti and the graph presents figures in USD.

[12] It is worth noting that LEC staff enjoy a number benefits outside the monthly salary, such as free electricity with the amount linked to position in the organization (e.g., 1200 kWh/month for a mid-level engineer). Any unused electricity is accumulated towards the staff member's retirement benefit. Detailed information on the electricity allowances for staff members was not available but it can be expected that if the monetary value of these benefits were added to the salaries when computing

Figure 9: Salaries to Sales ratio (USD/kWh)



Source: Own elaboration based on annual reports

6.6 Assets Capital Efficiency

$$\frac{Gross\ Value\ of\ Fixed\ Assets}{Peak\ Demand}$$

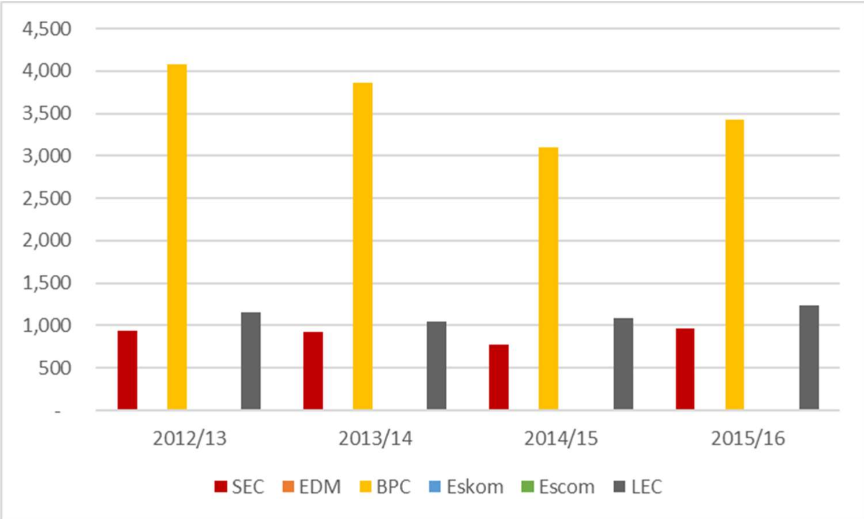
Figure 10 below presents the capital efficiency for each of the companies under study, measured as the Gross Asset Value to peak demand. Gross Asset Value was not available for Eskom, EDM and Escom. LEC and SEC present values of around 1,000 USD/kW, while BPC has much higher values (from 4,000 to 3,500 USD/kW).

The ratio uses gross value of assets, so does not take into account depreciation and reflects purchasing efficiency only. However, it must be borne in mind that both LEC and SEC depend on capacity imports to cover half of their peak requirements, which lowers the figures significantly. BPC is currently planning to export power to other SAPP members[13], although BPC has significant inoperative capacity due to several technical difficulties with recently installed coal-fired plant capacity, and currently imports power from Eskom.

salaries to sales ratio then the LEC values in Figure 9 would be higher. This reinforces the point that there is room for improvement by LEC in this area.

[13] Projects Moruple 5 and 6, to become operational in June 2018. Botswana Power Corporation Annual Report 2016, p. 16.

Figure 10: Capital Efficiency (Gross Asset Value to Peak Demand ratio)



Source: Own elaboration based on annual reports

As in the case of OPEX/MWh, this ratio shall be considered together with Quality of Service ratios, given that low investment levels in peak generation may imply very low levels of system reliability. Thus, pursuing improvements in purchasing efficiency should only take place if quality of service indicators are also acceptable.

Since these figures only offer a regional perspective, we have included observations from two of the largest Spanish distribution utilities: Iberdrola Distribución and Union Fenosa Distribución, covering 38.8% and 13.6% of all power customers in the country. We have considered these two figures as indicative figures for efficient companies, given that sector liberalization took place in 1997 in Spain and ever since distribution companies have been governed by an Incentive Based regulation completed with strict quality of service constraints. Investment controls to which both companies are subject are referred to a Reference Utility Model, in which all investment and operational costs of the company are set against an ideal model and considering target loss ratios, as mandated by European regulations.

The following table presents CAPEX efficiency figures for both companies for years 2013/14. Numbers should not be taken as a target, but can provide an idea of efficient CAPEX expenditures per Peak kW. All figures considered, an average of 593 USD/kW is achieved against LEC's number of 1,238 USD/kW.

Table 5– Capital Efficiency of International Companies (USD)

	2014	2013
Iberdrola Distribución	612.85	508.41
Unión Fenosa Distribución	646.84	605.28

Source: Own elaboration based on annual reports

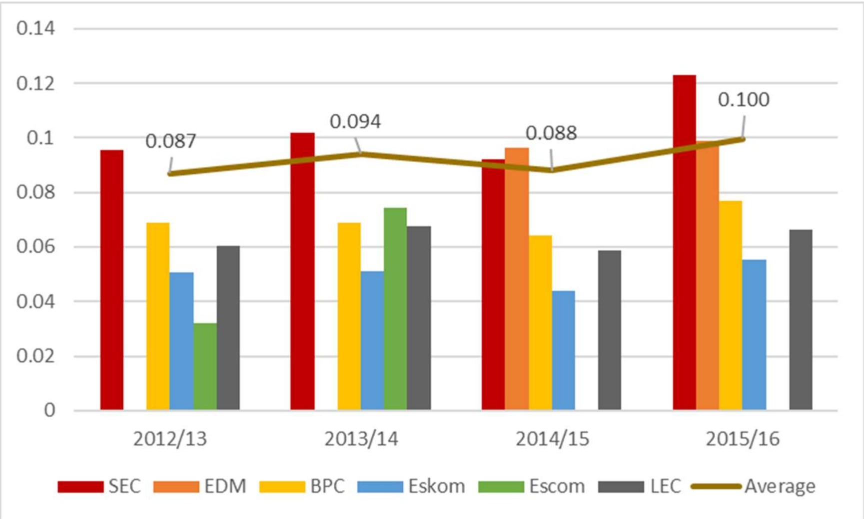
6.7 Revenue Collection

$$\frac{Revenue\ from\ sales\ (USD)}{Total\ Sales\ (kWh)}$$

The revenue collection ability measures the capacity of each company to obtain revenues with the sale of power. It measures both the success in collecting billed energy as well as the comparative level of final prices, thereby revealing the ability of the company to monetize its production (hence, the higher the number, the better for the company).

Amongst the African countries in the peer group, EDM and SEC present the highest unit revenues, while LEC and Eskom remain below average for the whole period. The effect of the national currencies' depreciation with respect to USD is also to be considered when analysing this trend: In all cases in which data are available, sales stagnated or increased less than 5% per year for the period while revenues for sales, measured in national currencies, increased between 42% and 113% depending on the country.

Figure 11: Revenue Collection Ability (USD/kWh)



Source: Own elaboration based on annual reports

6.8 Operational Expenditure: International Analysis

Regarding OPEX, a special separate analysis was carried out in order to derive a credible operational expenditure efficiency improvement target to be included in the financial and tariff analysis.

Data on operational expenses by Department was provided by LEC. Given the lack of comparable data for the African countries included in the peer group, we undertook a similar exercise with alternative utilities, both Transmission and Distribution companies, from South America, Asia and Europe.

As a general rule, technical indicators depend to a great extent on the topology of the network (derived from geographical conditions of the landscape and from demographic patterns). Lesotho is a country with a very specific geographical configuration, in which most of the population is concentrated in a small portion of the country. Useful comparisons with other utilities must therefore consider operational indicators in conjunction with technical performance as explained in section 4.1.

First, the data provided by LEC was arranged by Departments: the Engineering and Corporate Functions Departments were allocated to the Networks aspect of the business, while the remaining Departments were allocated to the Commercial side - Table 6. Thus we have allocated costs to the two main functions of the company: operator of the grid and as retailer to final customers.

Table 6 - Assumed split of network and commercial department expenditure

Department	Expenditure (2016)
Engineering	38,678,890
Corporate	110,240,102
Networks - total	**148,918,991**
Commercial - total	**100,886,313**

In the case of Networks, resulting operating expenses were compared with total energy wheeled (MWh) and network length.

In the case of the Commercial Department, total OPEX was compared against number of customers and energy sold. Figures shown in Table 7 are expressed in USD factored by the Power Purchase Index (PPI) as published by the World Bank.[14] The PPI compares purchasing power of 1 USD for each of the countries with respect to the US, so that countries with higher cost of living standards than that of the US present figures below one. All the cases analysed have a lower cost of living standard than in the US. The OPEX numbers are multiplied by the PPI to make their comparison more realistic.

Table 7– Operational Ratios by Department (USD)

	Networks	Commercial
OPEX/km	21,528.22	
OPEX/Energy (USD/MWh)	38.87	31.37
OPEX/Customers (USD/cust)	n.a.	106.25
km/staff	4	n.a.
Energy/staff	2,387	5,235
Customers/staff		1,546

Source: Own elaboration based on annual reports

6.8.1 Efficiency Frontier

For indicators directly linked to OPEX in the financial model (US$/MWh for distribution and US$/customer in retail), we have considered a group of peers more comparable with LEC based on a suitable density indicator. As we noted in section 2.3, for these indicators to be analysed and improvement targets established for LEC, there is limited value in considering only Regional peers, so

[14] https://data.worldbank.org/indicator/PA.NUS.PPPC.RF

for this analysis we include a broader database. This broader database includes distribution companies from countries in which “yardstick competition” has been implemented for at least the past ten years (Chile, Brazil, Turkey), and furthermore, companies that have reached a reasonable level of operational efficiency.

The idea, for both areas of the business (networks and commercial), is to derive an **Efficiency Frontier** using all available observations and to determine what is the current position of LEC compared to that frontier.

Efficiency Frontier - Networks

For the Networks Part of the business, we consider that operational performance is significantly affected by two major variables:

- The composition of the network and, more specifically, by customer density, and
- Average consumption by final customer.

We have therefore constructed a **composite index** including both metrics (with relative weights of 50% each) to select most comparable peers to LEC. The figure was derived using the following formula:

$$Composite\ Index\ = \left(\frac{\#\ Customers}{Line - Km}\right) * 0.5 + \left(\frac{Total\ Consumption}{\#\ Customers}\right) * 0.5$$

This index covers the two main factors affecting networks costs, as it takes into account the density of customers per km-length of the grid (first element of the equation), and their average consumption (second element of the equation). Both factors are quite relevant for infrastructure dimensioning and also directly affect the level of customers service (measured in terms of frequency and duration of interruptions).

As of 2016, LEC’s composite index stood at 70.32:

$$LEC\ Composite\ Index\ = \left(\frac{219{,}482}{1{,}599}\right) * 0.5 + \left(\frac{743{,}408}{219{,}482}\right) * 0.5$$

The following table shows all the companies considered in the analysis. From these we selected peers with similar composite values for the Distribution segment to derive the target OPEX efficiency.

Table 8– International Comparable Peers for Networks

Country	Company	Allowed Distribution OPEX (USD/MWh)	Customers (#)	Energy sold (MWh/Year)[15]	Total Network (Km)	Composite Index
Brazil	CHESP	79.27	25,837	68,964	2,456	27
Brazil	FORCEL	77.90	5,620	23,632	483	39
Brazil	CELTINS	62.38	290,598	862,152	21,936	30
Colombia	EADE	77.54	445,000	858,000	4,094	70
Brazil	CFLCL	51.64	297,960	971,264	21,003	33
Brazil	CLFM	50.74	35,877	174,746	1,225	54
Brazil	CENF	45.05	80,468	302,903	1,882	51
Brazil	DMEPC	42.76	55,041	285,610	1,198	64

[15] Total energy wheeled would be a more accurate measure, but figures were not available, so total energy sold has been considered as a proxy.

Country	Company	Allowed Distribution OPEX (USD/MWh)	Customers (#)	Energy sold (MWh/Year)[15]	Total Network (Km)	Composite Index
Brazil	EEVP	42.18	139,720	603,531	6,108	46
Brazil	CPEE	40.31	44,340	265,669	3,261	55
Brazil	CNEE	39.50	84,291	382,501	1,974	58
Brazil	CELB	39.32	130,899	475,935	4,117	45
Brazil	CEMAT	37.86	717,900	3,457,295	76,550	43
Brazil	CFLO	79.27	25,837	68,964	2,456	27
Brazil	COCEL	77.90	5,620	23,632	483	39
Brazil	CELPA	62.38	290,598	862,152	21,936	30
Brazil	CSPE	77.54	445,000	858,000	4,094	70
Argentina	EDES	51.64	297,960	971,264	21,003	33
Brazil	CELPE	50.74	35,877	174,746	1,225	54
Brazil	EFLUL	45.05	80,468	302,903	1,882	51
Brazil	CAIUÁ	42.76	55,041	285,610	1,198	64
Brazil	COELCE	42.18	139,720	603,531	6,108	46
Brazil	ENERSUL	40.31	44,340	265,669	3,261	55
Brazil	ENERGIPE	39.50	84,291	382,501	1,974	58
Chile	FRONTEL	39.32	130,899	475,935	4,117	45
Argentina	EDERSA	37.86	717,900	3,457,295	76,550	43
Argentina	EDEN	37.69	40,597	211,338	947	63
Brazil	EEB	37.53	30,231	184,330	1,594	58
El Salvador	EEO	36.91	1,203,789	4,199,316	23,295	54
Brazil	COSERN	36.86	59,388	350,384	3,196	56
Brazil	CEEE	33.74	140,000	587,000	3,777	52
El Salvador	CLESA	35.18	2,432,306	7,523,074	103,596	36
Colombia	ESSA	34.40	4,065	49,141	183	108
Turkey	Baskent	31.12	183,013	807,687	6,632	49
Philippines	Decorp	30.98	2,043,717	5,917,687	76,251	37
Philippines	Meralco	30.37	647,225	2,770,053	42,958	42
Bolivia	CRE	29.24	433,812	1,804,680	19,969	44
Chile	EMELECTRIC	28.32	205,000	360,000	19,229	19
Italy	Whole country (Enel - 87%)	25.99	140,431	770,500	7,795	53
Brazil	CJE	25.62	275,100	1,754,000	16,798	59

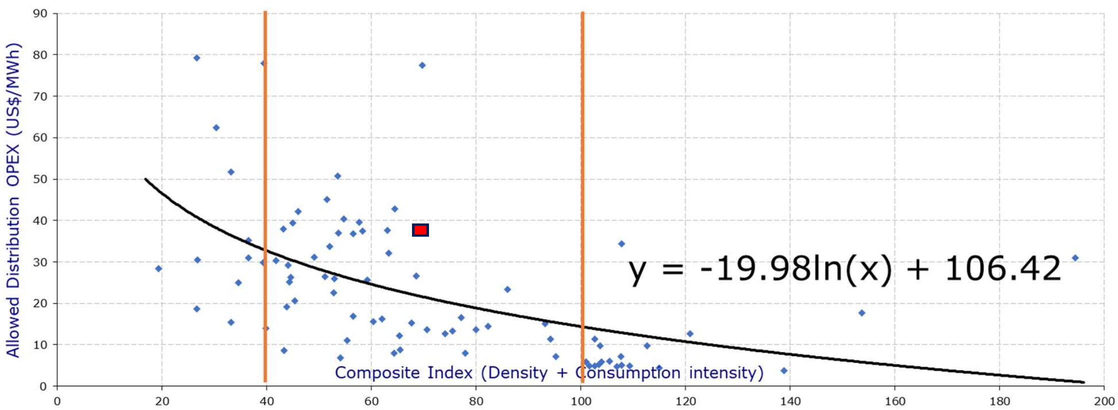
Country	Company	Allowed Distribution OPEX (USD/MWh)	Customers (#)	Energy sold (MWh/Year)[15]	Total Network (Km)	Composite Index
El Salvador	DELSUR	26.64	100,455	693,609	3,770	69
Chile	CGE	30.52	168,760	321,811	7,330	27
Brazil	LIGHT	25.07	779,700	2,939,139	27,510	44
El Salvador	DEUSEM	22.52	1,282,035	6,363,788	49,008	53
UK	SSE Hydro	25.01	229,312	538,733	7,270	35
Chile	EMELARI	29.86	419,000	1,081,000	11,210	39
Chile	EDELAYSE	26.34	2,951,380	9,965,603	83,670	45
Philippines	Cepalco	32.04	83,224	226,754	1,001	63
Brazil	AES SUL	30.99	4,562,466	27,563,056	15,606	195
Chile	ELECDA	26.47	215,779	1,042,487	8,604	51
Chile	SAESA	19.10	121,492	613,200	17,801	44
El Salvador	CAESS					
Chile	EMELAT	17.76	25,843	442,515	772	154
Brazil	ELETROPAULO	20.62	237,209	803,888	6,518	45
Chile	ELIQSA	16.81	610,000	2,740,000	14,777	57
Argentina	EDESUR	16.60	3,375,294	19,841,959	55,916	77
Turkey	Ayedas	18.62	44,213	70,161	1,584	27
UK	WPD S West	9.72	709,201	8,508,000	46,221	104
UK	WPD S Wales	15.60	53,820	180,548	802	60
Brazil	PIRATININGA	15.49	24,000	78,100	1,683	33
Bolivia	ELECTROPAZ	23.35	111,081	730,858	1,666	86
UK	SP Manweb	15.24	1,011,770	7,335,139	52,280	68
Turkey	Sedas	14.51	117,750	493,800	1,209	82
Argentina	EDESAL	14.03	229,000	862,000	11,807	40
UK	CE NEDL	16.29	450,850	1,631,229	6,822	62
UK	SP Distribution	13.69	70,631	368,400	1,224	71
Argentina	EDESA	12.71	5,286,579	32,582,055	36,913	121
Peru	EDELNOR	12.59	60,458	290,504	847	74
Argentina	EDELAP	11.44	2,096,673	12,891,000	23,256	94
UK	CN West	15.13	1,965,156	8,165,594	16,394	93
UK	ENW	7.16	1,488,592	14,943,000	49,824	95
UK	EDFE EPN	7.09	1,070,179	12,354,000	34,945	108

Country	Company	Allowed Distribution OPEX (USD/MWh)	Customers (#)	Energy sold (MWh/Year)[15]	Total Network (Km)	Composite Index
UK	EDFE SPN	11.33	1,176,301	10,235,249	17,799	103
UK	CN East	13.27	291,620	910,542	2,884	76
UK	CE YEDL	6.03	1,464,592	16,554,000	48,562	106
UK	SSE Southern	12.17	1,275,360	7,889,941	40,042	65
Colombia	EEPPM	8.76	109,700	797,000	7,482	65
Peru	LUZ DEL SUR	5.82	1,550,686	16,306,000	39,178	104
UK	EDFE LPN	5.80	1,967,920	20,966,000	62,363	101
Colombia	CODEMSA	8.59	214,735	817,200	8,310	43

Source: Own elaboration based on annual reports

The average OPEX/MWh of the whole group of peers stands at 27.18 USD/MWh, well below LEC's figure of 38.87 (see Table 7). The best-fit equation that delimits the efficiency frontier is shown in the following Figure 12. For LEC's composite index of 70.32 the efficient cost level is 21.44 USD /MWh, well below current level of LEC. The red square in Figure 12 represents the current position of LEC amongst its peers.

Figure 12: Efficient Frontier for Networks (red square shows LEC current values)



Source: Own elaboration

In the case of network costs, the lower the composite index, the higher the efficient costs may be: i.e. companies facing lower density and average consumption figures tend to have higher OPEX costs. To reflect the imprecise nature of the selection of a composite index we compared OPEX costs for a range of composite indexes of ± 30 points around the LEC figure. For a composite index of 50 the frontier OPEX is 28.25 USD/MWh. We consider this as an ambitious target for LEC given the developed-world nature of most of the peer companies used in the analysis. We therefore propose this as the target for the High Efficiency Scenario. The lowest end of this range (composite index of 40) yields a frontier OPEX figure of 32.72 USD/MWh, which we propose as an intermediate target for LEC.

Efficiency Frontier - Commercial

A similar procedure is applied to the Commercial part of the business but commercial costs are related to invoicing activities, customer care, advertising, all costs that are proportional to the number of customers rather than to their average consumption. Thus we use the **Density Value** to derive the Efficient Frontier where the Density Value is measured as the number of customers divided by total length of the network:

$$Density\ Value\ = \left(\frac{\#\ Customers}{Line - Km}\right)$$

As of 2016, LEC's density value stood at 137:

$$LEC\ Density\ Value\ = \left(\frac{219{,}482}{1{,}599}\right)$$

For comparing commercial performance it is more difficult to find comparable peers, since in many cases figures are not disaggregated and/or the retail segment has been liberalized so figures are not directly comparable. Hence, we have considered data from all distribution companies of the available sample:

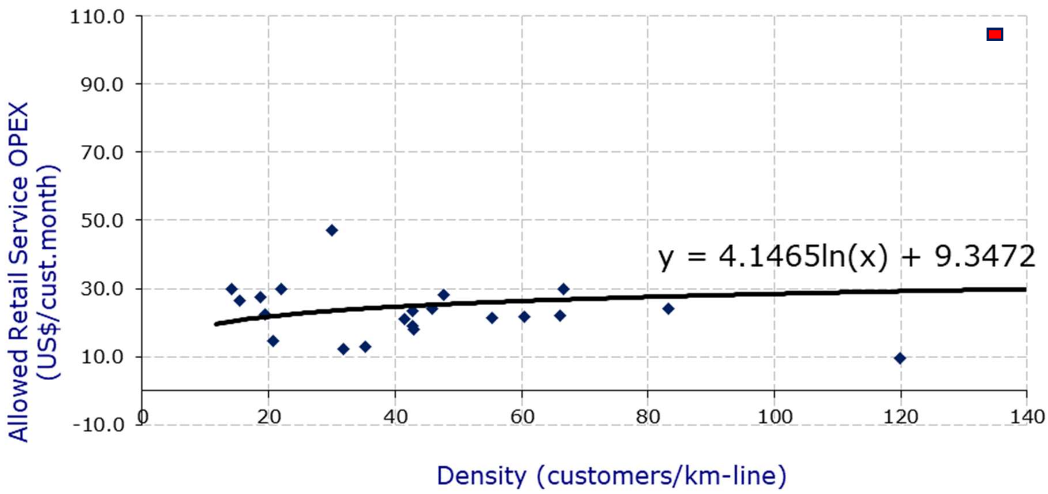
Table 9– International Comparable Peers for Commercial

Country	Company	Allowed retail Service OPEX (US$/customer)	Customers (#)	Energy sold (MWh/Year)	Total Network (Km)	Density (cust/km-line)
Italy	ENEL	47.2	36,301,487	294,923,000	1,207,341	30
Brazil	ESELSA	29.9	968,151	5,943,807	44,105	22
Brazil	CFLCL	29.7	297,960	971,264	21,003	14
Brazil	CEB	28.1	659,439	3,622,303	13,839	48
Brazil	CELESC	27.5	1,875,838	13,651,949	100,443	19
Brazil	COPEL	26.5	3,095,487	18,053,330	201,310	15
Brazil	DMEPC	24.3	55,041	285,610	1,198	46
Brazil	CENF	23.6	80,468	302,903	1,882	43
Brazil	AES SUL	22.3	1,011,770	7,335,139	52,280	19
Brazil	PIRATININGA	22.2	1,176,301	10,235,249	17,799	66
Brazil	LIGHT	21.9	3,375,294	19,841,959	55,916	60
Brazil	BANDEIRANTE	21.6	1,340,207	9,239,379	24,254	55
Brazil	CPFL	21.2	3,098,776	19,236,628	74,814	41
Philippines	Cepalco	29.7	111,081	730,858	1,666	67
Brazil	CNEE	19.2	84,291	382,501	1,974	43
Brazil	CFLO	18.0	40,597	211,338	947	43
Philippines	Decorp	24.0	83,224	226,754	1,001	83
Brazil	COELBA	14.5	3,109,867	9,015,135	149,909	21
Turkey	Baskent	13.1	2,951,380	9,965,603	83,670	35
Turkey	Sedas	12.3	1,275,360	7,889,941	40,042	32

Source: Own elaboration based on annual reports

Using all the observations available, we can derive the Efficient Frontier - Figure 13. If we consider LEC's density figure of 137 (x-axis) a figure of 29.74 USD/Customer is achieved, in the middle of a range between 28.72 and 30.56 USD/customer (if a ±30 points range is considered). These values are far below the value presented by LEC (106.25 USD/Customer), which suggests that OPEX costs per customer should be sharply decreased by LEC. The Red square in the figure presents current LEC's level.

Figure 13: Efficient Frontier for Commercial



Source: Own elaboration

6.8.2 Deriving an OPEX Improvement for LEC

In terms of OPEX improvement, some reference scenarios can be proposed, with the purpose of reflecting them in the subsequent financial analysis. Their feasibility has to be realistically analysed with LEWA and LEC, and in particular, their path has to be monitored and followed up along the successive tariff periods.

Networks

For the Networks part of the business, the value corresponding to a company with a composite index of 70.32 stands at **21.44 USD/MWh**, well below LEC's figure of 38.87. We argued in the previous section for a high target of 28.25 USD/MWh This figure can be considered as the most ambitious improvement goal: to reduce OPEX devoted to networks operation by 27% by year 2035. This will be considered as the High efficiency scenario.

Two other scenarios will also be considered for OPEX: Business as Usual scenario, in which current OPEX/MWh will be maintained, and an Intermediate Scenario. A less exacting intermediate target is justified taking into account the recent trend of falling consumption for newly connected customers, which will in time lead to a lower composite index for LEC and therefore reduce its target for OPEX cost/MWh.

So, for our intermediate scenario as noted in the previous section we have considered that instead of reaching 28.25 USD/MWh, **LEC will reach 32.71 USD/MWh**, which is the value for companies with a composite index of 40 (instead of current value of 70.32). Total reduction of unit costs in this scenario reaches 15.8% by 2035.

It must be reminded that, as shown in Figure 7, LEC's OPEX/MWh decreased between 2012 and 2014/15 to increase in 2015/16. Current levels are still below those of 2012/13.

The three paths considered for OPEX imply the following improvement rates.

Table 10– Networks OPEX Growth Rate Scenarios

	BAU	High Efficiency	Intermediate
2017	0.00%	-1.44%	-0.83%
2018	0.00%	-1.46%	-0.84%
2019	0.00%	-1.48%	-0.85%
2020	0.00%	-1.50%	-0.86%
2021	0.00%	-1.53%	-0.86%
2022	0.00%	-1.55%	-0.87%
2023	0.00%	-1.57%	-0.88%
2024	0.00%	-1.60%	-0.89%
2025	0.00%	-1.62%	-0.89%
2026	0.00%	-1.65%	-0.90%
2027	0.00%	-1.68%	-0.91%
2028	0.00%	-1.71%	-0.92%
2029	0.00%	-1.74%	-0.93%
2030	0.00%	-1.77%	-0.94%
2031	0.00%	-1.80%	-0.94%
2032	0.00%	-1.83%	-0.95%
2033	0.00%	-1.87%	-0.96%
2034	0.00%	-1.90%	-0.97%
2035	0.00%	-1.94%	-0.98%

Source: Own elaboration

Commercial

For the Commercial activity, the BAU scenario will consider that current commercial costs remain on comparable levels (no unit cost reduction).

We do not consider possible that LEC can fully achieve a complete progression towards efficient values so for a High Efficiency scenario we assume that LEC reduces the gap between LEC OPEX/customer and the frontier value by 75% - bringing its OPEX unit cost down to 48.87 USD/customer in 2035. This path is a reduction of 54% in LEC's OPEX/customer.

For an intermediate path we assume that LEC is only able to achieve a 50% reduction in the gap, reaching a final value of 68 USD/customer in 2035 (36% reduction in OPEX/customer). We propose that this scenario, with yearly reduction rates around 2% for commercial costs, represents a realistic target for LEC.

The following growth rates apply for the commercial activity.

Table 11– Commercial OPEX Growth Rate Scenarios

	BAU	High Efficiency	Intermediate
2017	0.00%	-2.84%	-1.90%
2018	0.00%	-2.93%	-1.93%
2019	0.00%	-3.01%	-1.97%
2020	0.00%	-3.11%	-2.01%
2021	0.00%	-3.21%	-2.05%
2022	0.00%	-3.31%	-2.09%
2023	0.00%	-3.43%	-2.14%
2024	0.00%	-3.55%	-2.18%
2025	0.00%	-3.68%	-2.23%
2026	0.00%	-3.82%	-2.28%
2027	0.00%	-3.97%	-2.34%
2028	0.00%	-4.14%	-2.39%
2029	0.00%	-4.31%	-2.45%
2030	0.00%	-4.51%	-2.51%
2031	0.00%	-4.72%	-2.58%
2032	0.00%	-4.96%	-2.65%
2033	0.00%	-5.21%	-2.72%
2034	0.00%	-5.50%	-2.80%
2035	0.00%	-5.82%	-2.88%

Source: Own elaboration

Hence, considering the relative weights of both departments, Networks and Commercial, we can derive total unit OPEX costs growth rate evolution scenarios until 2035. Note that all rates refer to 2016 real values, so inflation must also be taken into account.

With all the assumptions considered, our best estimate is that LEC needs to reach OPEX annual reduction rates averaging -1.47% (the Intermediate Scenario).

Table 12– Total OPEX Growth Rate Scenarios

	BAU	High Efficiency	Intermediate
2017	0.00%	-2.005%	-1.263%
2018	0.00%	-2.051%	-1.282%
2019	0.00%	-2.100%	-1.301%
2020	0.00%	-2.151%	-1.321%
2021	0.00%	-2.205%	-1.342%
2022	0.00%	-2.262%	-1.364%

	BAU	High Efficiency	Intermediate
2023	0.00%	-2.322%	-1.387%
2024	0.00%	-2.386%	-1.410%
2025	0.00%	-2.455%	-1.435%
2026	0.00%	-2.527%	-1.460%
2027	0.00%	-2.605%	-1.487%
2028	0.00%	-2.689%	-1.514%
2029	0.00%	-2.778%	-1.543%
2030	0.00%	-2.875%	-1.573%
2031	0.00%	-2.980%	-1.605%
2032	0.00%	-3.094%	-1.638%
2033	0.00%	-3.219%	-1.672%
2034	0.00%	-3.356%	-1.708%
2035	0.00%	-3.507%	-1.747%

Source: Own elaboration

7 FINANCIAL PERFORMANCE BENCHMARKING

The financial health of LEC is essential so that it has the ability to finance the large investment requirements that are required to sustain the sector's ability to meet growing demand, repay debt and make timely payments for power purchases from third parties within a framework of sector financial viability.

Domestic and international investors, together with commercial lending institutions, will provide capital to the sector provided that the rates of return compare favourably with alternative uses of their funds. If LEC is unable to demonstrate sound financial management, the rates available to LEC will be considerably higher than standard industry averages, hindering its ability to finance its operations in a cost-effective way.

Operational and technical benchmarks are system-specific: comparison among them is not straight forward since the demographic distribution and morphology of each country will result in different network configurations, each of them reflecting the features of the areas they serve.

On the other hand, financial sustainability of a firm is a metric that is largely independent of the country or the sector in which a company operates. Accountancy models have been developed worldwide to assess whether a firm is financially sustainable over time. The sustainability of the company is measured by its ability to reap profits from the revenues it produces, how its capital is structured and its control of cashflows (payment and collection performance), none of which are directly related to type of business of the company.

As a consequence, International Best Practices have been developed regarding financial health of companies, which allow us to derive a range of acceptable values for each of the ratios proposed in section 3 (which was not possible for technical and operational benchmarks).

The table below shows the financial indicators computed for LEC and their acceptable ranges according to international best practices, based on the consultant's experience.

Table 13– Financial indicators (definitions)

Ratio	Formula	Acceptable Range
Working ratio	$\frac{\text{Operating Expenses}}{\text{Total revenue}}$	60-80%
Working ratio with depreciation	$\frac{\text{Operating Expenses} + \text{Depreciation}}{\text{Total revenue}}$	70-90%
Working ratio with depreciation and net interest	$\frac{\text{Operating Expenses} + \text{Depreciation} + \text{Net Finance costs}}{\text{Total revenue}}$	<100 %
Net operating margin	$\frac{\text{Net Profit}}{\text{Total revenue}}$	>5%
Current ratio	$\frac{\text{Current assets}}{\text{Current liabilities}}$	>1
Accounts receivable collection period	$\frac{\text{Accounts receivable} * 365}{\text{Total revenue}}$	20-40
Accounts payable disbursement period	$\frac{\text{Accounts payable} * 365}{\text{Operating expenses}}$	30-80

Ratio	Formula	Acceptable Range
Return on equity	$\frac{\text{Total revenue } - \text{Operating Expenses}}{\text{Equity}}$	8-20%
Return on net fixed assets	$\frac{\text{Total revenue } - \text{Operating Expenses}}{\text{Assets}}$	5-10%
Debt to assets	$\frac{\text{Debt}}{\text{Assets}}$	30%

7.1 LEC'S CURRENT FINANCIAL SITUATION

Before comparing LEC to the peer group, the evolution of its own figures will be compared against the table of acceptable values presented above. Figures in red are outside the acceptable ranges.

Table 14– Financial Diagnosis of LEC

Ratio	2012/13	2013/14	2014/15	2015/16
Working ratio	90%	76%	75%	80%
Working ratio with depreciation	105%	89%	87%	91%
Working ratio with depreciation and net interest	105%	89%	87%	92%
Net operating margin	0%	9%	11%	8%
Current ratio	55%	113%	137%	149%
Accounts receivable collection period	42	37	34	35
Accounts payable disbursement period	75	54	68	43
Return on equity	3%	9%	7%	5%
Return on net fixed assets	3%	8%	7%	5%
Debt to assets	2%	2%	3%	3%

The financial health of LEC has clearly improved since 2013/14, when most of the KPIs were outside of acceptable ranges.

The percentage of Debt is quite low (Equity finances 91% of total assets), which makes LEC not so attractive for private investors. Normal standards in the industry range around 30%, what suggests that LEC could increase its debt levels to finance better infrastructure or small-scale generation projects to increase security of supply and reduce costs.

Table 15 and Table 16 present summaries of the LEC income statement and Balance sheet respectively.

Table 15 - Income Statement (Million Maloti)

Ratio	2011/2012	2012/13	2013/14	2014/15	2015/16
Electricity Sales	411,721,019	447,681,229	530,797,439	636,711,727	676,412,058
Total Revenues	445,572,103	487,234,158	591,138,773	689,121,788	728,310,627
Power Purchase Costs	-183,388,278	-260,519,210	-278,279,816	-298,941,464	-353,331,930
Other Income	3,868,401	20,634,685	4,407,935	11,634,421	9,157,928
Gross Profit	262,183,825	226,714,948	312.858957	390,180,324	374,978,697
Admin. & General Overheads	-236,568,207	-249,284,301	-248,089,292	-299,792,990	-312,031,232
Finance Income	3,005,589	354,907	-336,977	2,913,218	4,309,668
Finance Costs	-803,863	-822,282	-543,241	-4,140,350	-1,163,963
Profit/Loss Before Taxes	31,686,745	-2,402,043	68,297,382	100,794,623	75,251,098
Tax	-7,992,696	646,052	-17,096,497	-25,236,707	-18,866,416
NET PROFIT	23,694,049	-1,755,991	51,200,885	75,557,916	56,384,682

Source: LEC Audited Accounts

Although demand has not increased significantly during the period (+5.38%), total revenues have increased by 64% (what reflects the sharp increase in tariffs presented in section 5 and also the revenues collected by means of connection fees). In the same period, total O&M overheads increased by 92% (further disaggregation of costs has not been provided by LEC). The combination of both trends provides an increase of 42% in the gross profit.

As for Administration and General Overheads Expenses, this item also grows significantly (+32%). A 42% increase in salaries and wages stands out as the main contributor to the increase in Admin costs over the period.

All in all, annual profits over the period have experienced a 137% increase, despite the decrease experienced in 2016 (affected by the step increase that year of O&M costs).

Table 16 – Balance Sheet Statement

Ratio	2012/13	2013/14	2014/15	2015/16
CAPITAL EMPLOYED	**1,811,536,138**	**1,906,668,158**	**2,837,589,845**	**2,966,128,708**
Total Non-Current Assets	1,701,192,054	1,709,953,019	2,576,412,812	2,731,820,321

Ratio	2012/13	2013/14	2014/15	2015/16
Current Assets	110,344,084	196,715,139	261,177,033	234,308,387
FINANCED BY:				
Share Premium	*599,210,049*	*599,210,049*	*599,210,049*	*599,210,049*
Capital Grant	*201,511,596*	*268,142,003*	*364,901,810*	*473,442,571*
Revaluation Reserve	*525,631,252*	*525,631,252*	*1,257,212,775*	*1,257,212,775*
Retained Income	*191,140,016*	*242,340,900*	*324,105,309*	*378,194,169*
Total Equity	1,517,493,913	1,635,325,204	2,545,430,943	2,708,060,564
Non-Current Liabilities	91,598,843	96,772,424	101,646,375	100,807,483
Current Liabilities	202,443,382	174,570,530	190,512,527	157,260,661
Total Equity and Liabilities	**1,811,536,138**	**1,906,668,158**	**2,837,589,845**	**2,966,128,708**

Source: LEC

As mentioned, the capital structure of LEC is characterised by the high proportion of Equity as its source of funding (including Capital grants), and by contrast the very low values for both Non-Current and Current Liabilities. The increase in Equity experienced in 2015 lead to a 51% increase in Non-Current Assets.

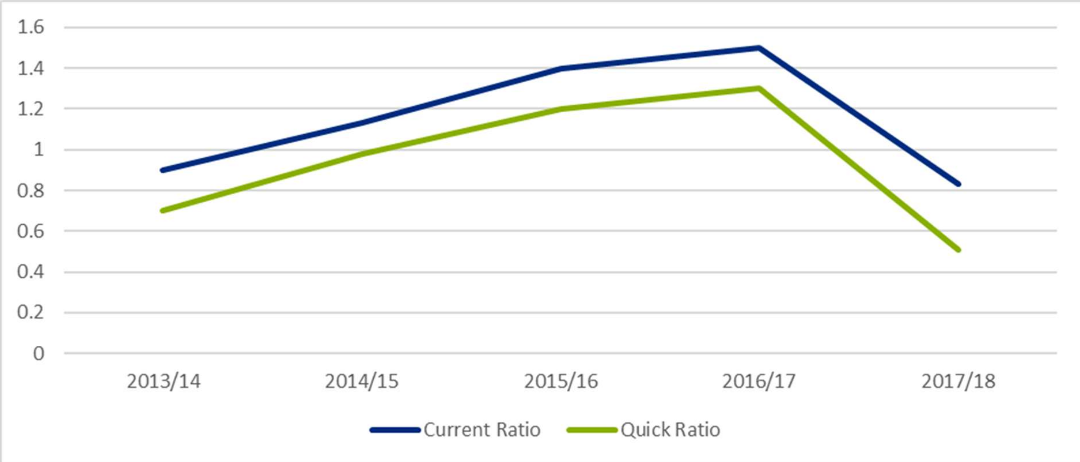
Regarding non-current Assets and Liabilities, LEC has significantly improved its situation and currently, Current Assets are 49% larger than Current Liabilities.

Note that LEC underwent a revaluation in 2014/15. This was undertaken by an independent consultant. When benchmarking LEC on the financial indicators involving assets (Table 13) the revalued asset base is used.

Yearly, within its tariff review exercise, LEWA computes the evolution of two liquidity Ratios for LEC, the Current and the Quick Ratio in order to appraise LEC's performance. The former determines whether the company has enough current assets to cover its coming payments commitments (current liabilities).

Figure 14 below presents the evolution of both ratios as computed by LEC and its forecast evolution for 2017/18. Both figures show a significant worsening of LEC's position.

Figure 14: Liquidity Ratios Evolution 2013-2018

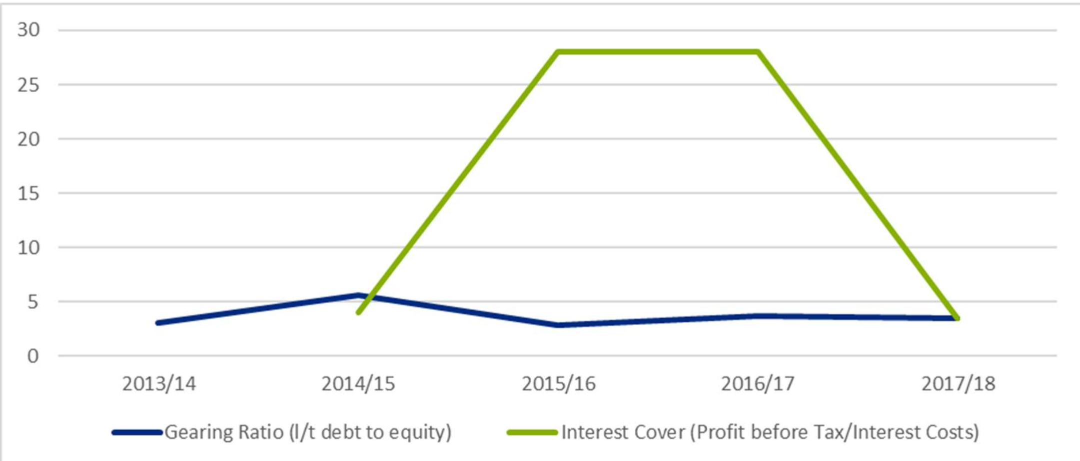


Source: LEWA

Apart from the Liquidity ratios, LEWA computes the Gearing and the Interest cover ratios. The former measures long-term debt over equity, while the latter provides the relationship between Profit before taxes and Interest costs for that year. The gearing ratio for 2016 stood at 3.7% while projections for 2017 stand at 3.5%.

Given the low figures of the gearing ratio, the Interest cover ratio was extraordinarily high in 2016 at 28, although it is projected for 2017 to come down to 3.5. However, in both cases the level is above the recommended level (3 times).

Figure 15: Debt Ratios Evolution 2013-2018



Source: LEWA

7.2 Tariff System in Lesotho

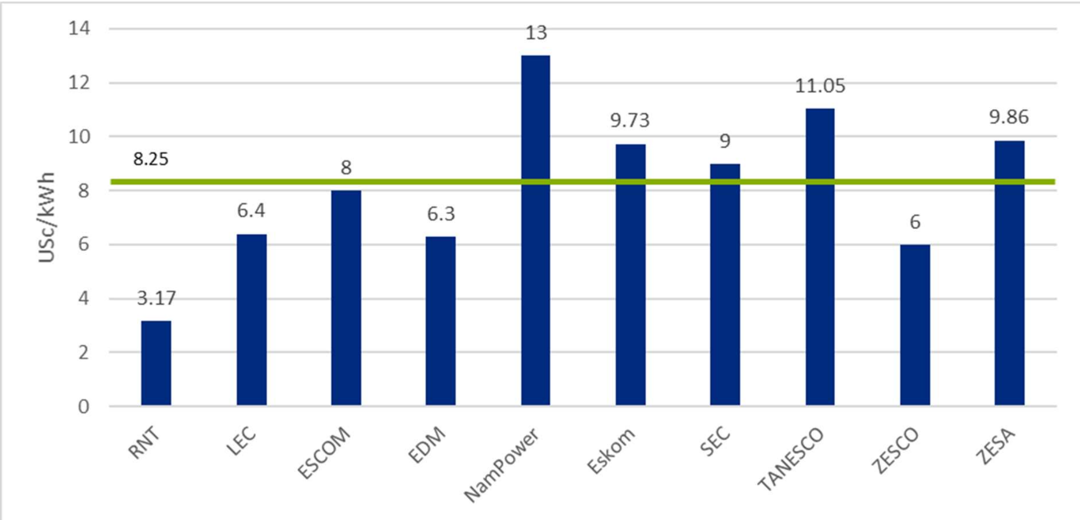
In this subsection, we report our analysis of the structure and evolution of customer tariffs in Lesotho. As for any utility tariff structures and levels are vital to LEC since they will determine whether the company is able to collect all the revenues required to face its supply costs, to provide an attractive level of profitability to investors and to maintain financial health while at the same time ensuring that final consumers pay for the costs they represent to the system and do not pay excessive prices.

If tariffs are below cost-reflectivity, the company will not be able to survive in the long-run, and shall be subsidized (like in the case of Botswana) or service will fall below acceptable levels. On the other hand, excessive tariffs will allow the company to become profitable, but at the expense of hampering economic development through unnecessary costs being imposed on the productive segments of society and domestic customers.

Cost reflective tariffs intend to reflect the whole cost incurred generating, transmitting and distributing power to final customers, but some countries (e.g. Botswana) subsidize power consumption by providing direct grants to the power company after under recovery. Apart from generation costs (based on coal or hydro for most countries in SAPP), physical characteristics of the T&D networks[16] can result in significant tariff differences among the countries under study.

The following figure presents the average final tariff for each power utility, measured in USc/kWh.

Figure 16: Average Tariffs in SAPP Countries[17]



Source: SAPP Annual Report 2016

Countries can be grouped into three main groups: Namibia and Tanzania have the highest final tariffs (>11 USc/kWh); a second group, composed by Eskom, SEC, Zimbabwe and Escom range between 8 and 10 USc/kWh; while in the third group all countries present tariffs lower than 6.5 USc/kWh (Lesotho, Mozambique, Zambia and the extreme case of Angola, with only 3.17 USc/kWh).

The current tariff determination in Lesotho depends on yearly reviews of LEC's allowed revenue implemented by LEWA. LEC first proposes a level of allowed revenue, then LEWA reviews it and subjects the application to a public consultation process involving the most relevant stakeholders

[16] For example, highly dispersed populations in poorly developed regions such as the Highlands of Lesotho with long lines supplying small loads will see cost reflective tariffs much higher than densely populated urban populations in well-developed regions such as Johannesburg/Pretoria.

[17]RNT stands for "REDE NACIONAL DE TRANSPORTE DE ELECTRICIDADE" the TSO from Angola.

(representatives from the consumers' side and LEC). After the process has been completed, LEWA issues its final decision on tariffs for the next year.

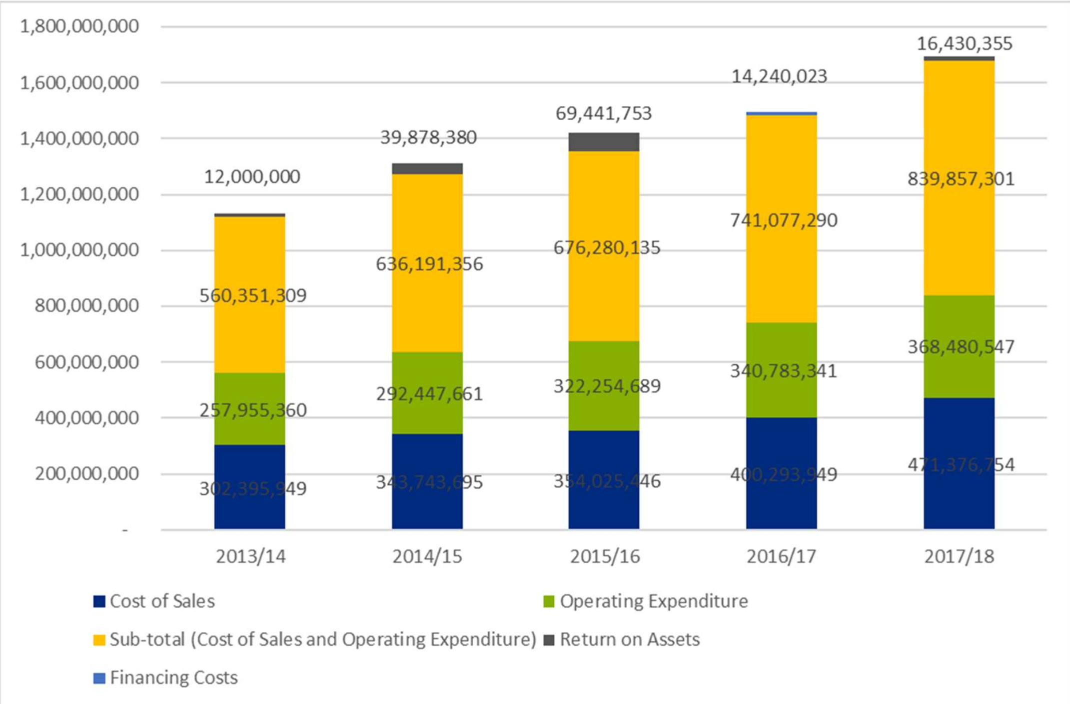
According to present regulation in Lesotho, LEC's cost shall be disaggregated into the four following categories:

- Imported Power Costs (including Muela Hydropower Plant)
- Expenditure Costs
    - Generation, fuel and lubricants (Semonkong facility)
    - Maintenance and repairs
    - LEWA licence fee
    - Operating Expenses
    - Staff Remuneration
- Depreciation Costs
- Return on assets (based on net value of assets financed solely by LEC).

an important risk on the stability of the system, is the high level of dependency on imports and their exposure to exchange rate risks: the devaluation of the South African Rand with respect to the USD has led to a significant recent increase in the cost of imports from Mozambique (nominated in USD).

Figure 17 illustrates the breakdown of allowed revenue at LEC based on its audited financial accounts, forecasts for sales revenues and demand and a clear cost allocation basis.

Figure 17:Evolution of Allowed Revenues by category



Source: LEWA

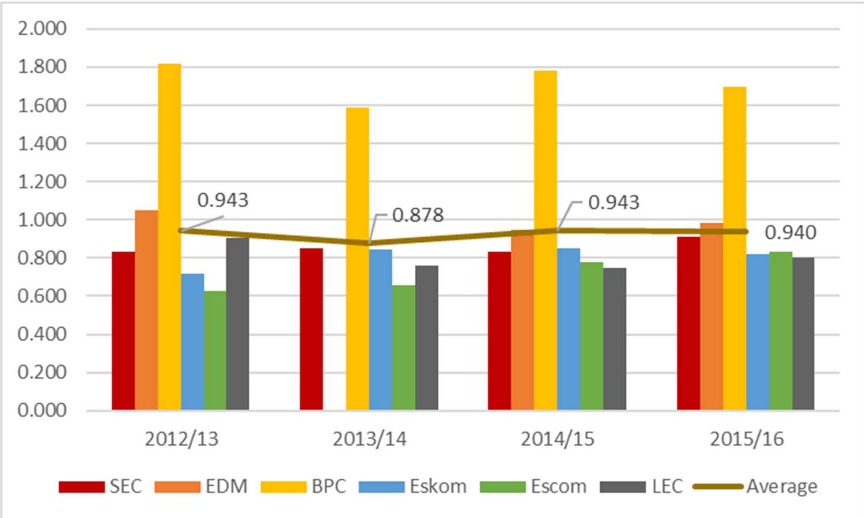
7.3 Regional Benchmarking

7.3.1 Working Ratio

Figure 18 shows the working ratio for the peer group countries and shows that all the countries under study with the exception of BPC and EDM have working ratios within acceptable levels (60-80%). Although with some differences over the years, SEC, Eskom, LEC and Escom present similar ratios.

In the case of BPC, operating expenses represent between 150% and 180% of its total revenues. Such a situation is possible since power prices are heavily subsidized by the Government and BPC receives a yearly grant to face its actual costs. The case of EDM is less pronounced, with ratios between 1 and 0.94, but still out of the acceptable ratio (EDM has presented losses for the last two years).

Figure 18: Working Ratio

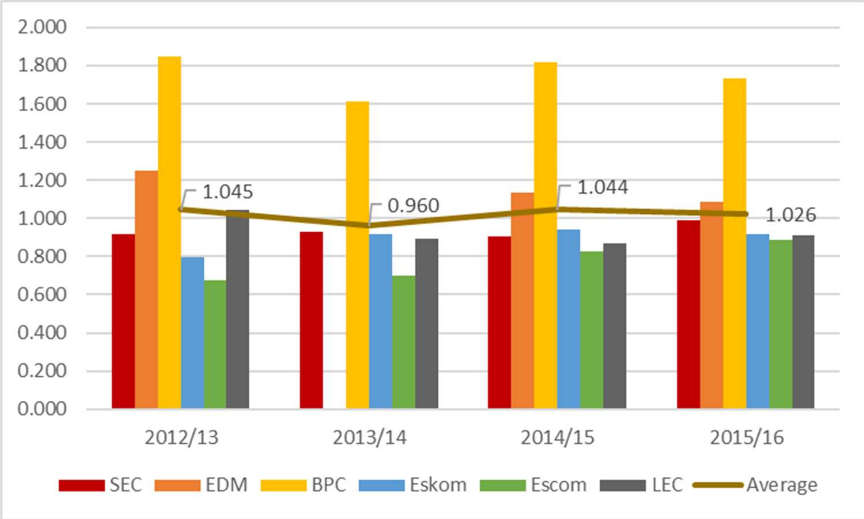


Source: Own elaboration based on annual reports

7.3.2 Working Ratio with Depreciation

If depreciation is taken into account, figures worsen for some countries. Only LEC and Escom present values within acceptable levels (in 2016, LEC is a little bit above, with 91%). SEC and Eskom present slightly higher values than acceptable, but the four countries are still comparable. Both EDM and BPC see their results deteriorate and are well outside the acceptable range.

Figure 19: Working Ratio with Depreciation



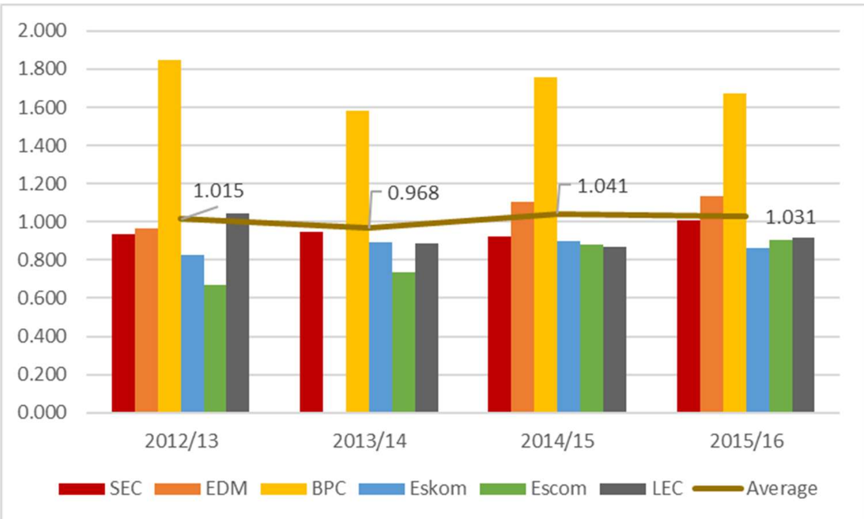
Source: Own elaboration based on annual reports

7.3.3 Working Ratio With Depreciation and Net Interests

If Net Interests are included in the ratio, Escom, Eskom and LEC go back to acceptable levels (below 1), while SEC stands at the margin. Figures for these four countries are quite similar.

The metric improves with the addition of net interest for both BPC and EDM but are still outside the acceptable range, although only slightly for EDM (1.08 in 2016).

Figure 20: Working Ratio with Depreciation and Net Interests



Source: Own elaboration based on annual reports

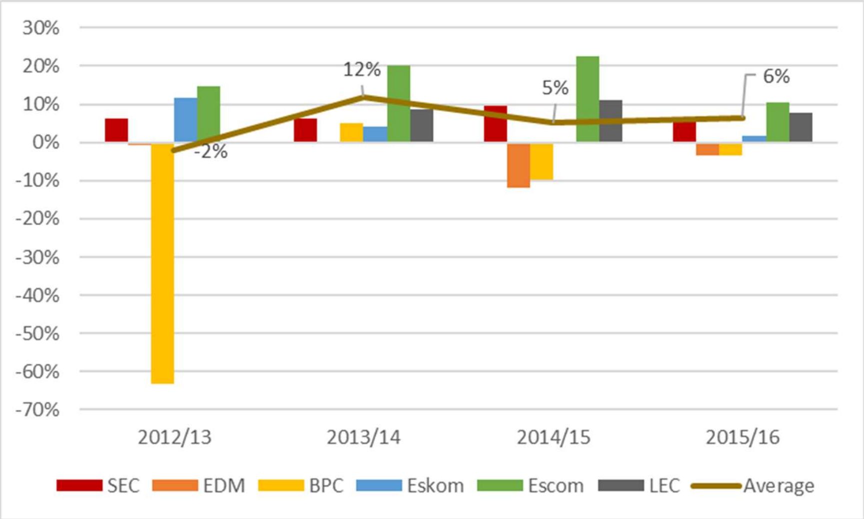
7.3.4 Net Operating Margin

Regarding Net Operating Margin, BPC only achieved positive numbers for 2014/15, while EDM's figures are negative for all years that have data (no data for 2014/15).

SEC, LEC and Escom had acceptable levels (with the exception of LEC for 2012/13). Escom presents very high figures for this ratio when compared to its African peers.

Regarding South Africa, although it started the period with a 12% Net operating Margin, its figures have significantly decreased and net Margin has fallen below acceptable levels for the last three years.

Figure 21: Net Operating Margin

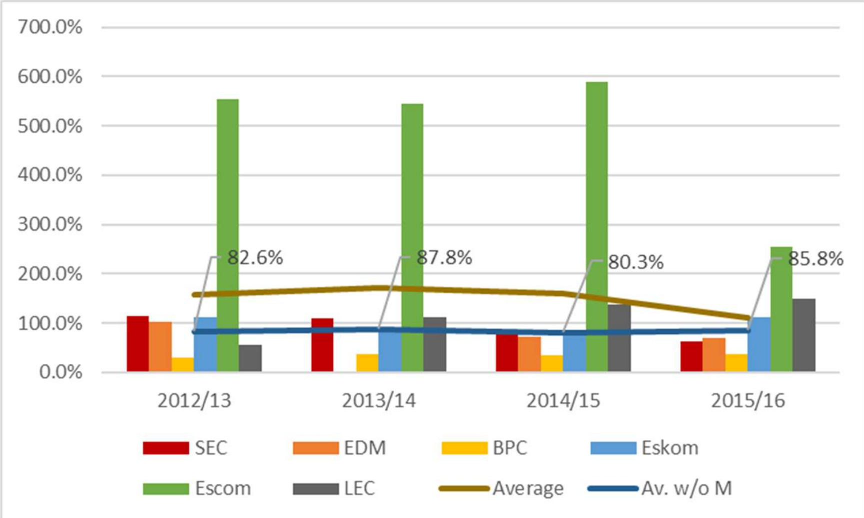


Source: Own elaboration based on annual reports

7.3.5 Current Ratio

Regarding the Current Ratio, Eskom, LEC and Escom present healthy figures at the end of the period (though Eskom was below the acceptable level earlier for two years). The rest of the countries had ratios below acceptable levels (especially in the case of BPC). Ratios for both SEC and EDM have deteriorated significantly over the period.

Figure 22: Current Ratio



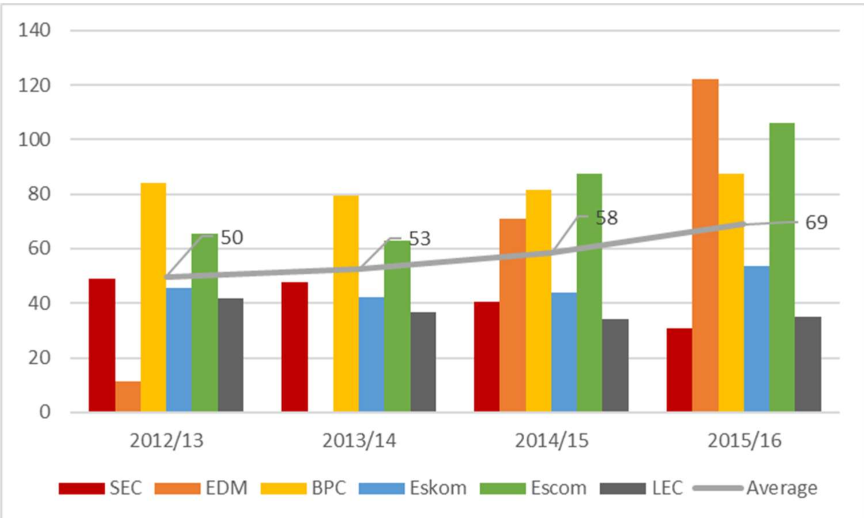
Source: Own elaboration based on annual reports

7.3.6 Accounts Receivable Collection Period

If we take a look into the collection period for accounts receivable, large regional differences appear: only SEC and LEC present acceptable levels at the end of the period.

Eskom begins with almost acceptable levels but the collection period rises to 54 days by 20016/17. The rest of countries have collection periods which are too long, especially in the case of EDM, whose receivable account represents one third of its total revenues and has increased significantly in the last two years.

Figure 23: Accounts Receivable Collection Period



Source: Own elaboration based on annual reports

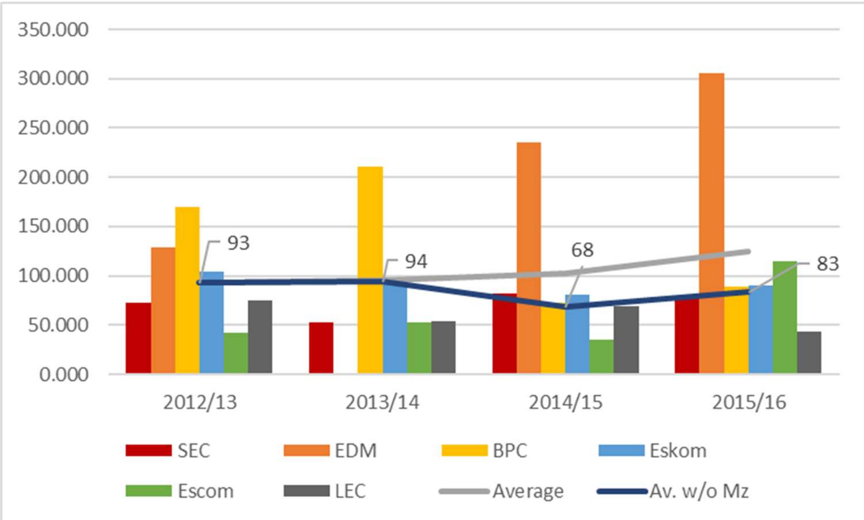
7.3.7 Accounts Payable Disbursement Period

A similar situation can be found for the Payables Disbursement Period: EDM's account has skyrocketed in the last two exercises, reaching 83% of its total Operating Expenses in 2016. This has led to an average disbursement period of 300 days.

SEC and LEC again present acceptable values for the whole period, while BPC and Eskom stay slightly above recommended levels (below 80 days) after a big reduction.

Escom presented acceptable levels until 2016, when the receivables account almost doubled with respect to 2015, reaching 114 days.

Figure 24: Accounts Payable Disbursement Period



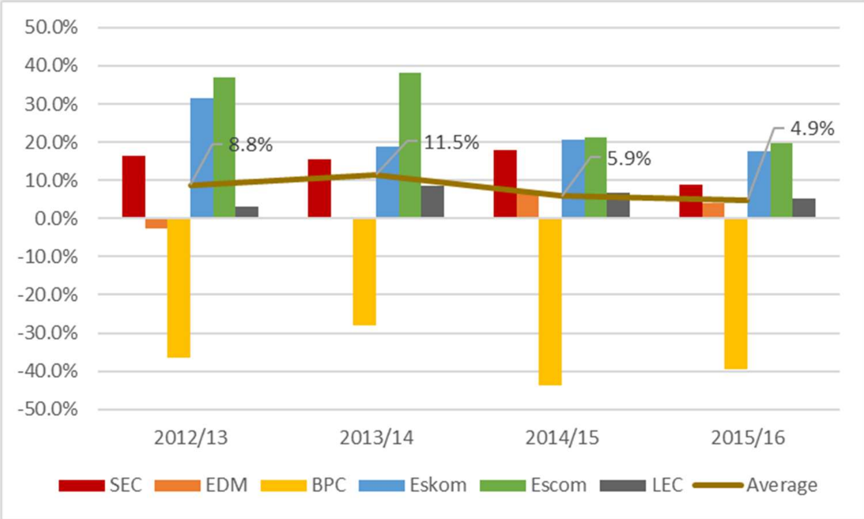
Source: Own elaboration based on annual reports

7.3.8 Return on Equity

Regarding Return on Equity, all figures are negative for BPC, while figures remain below acceptable levels for EDM and LEC.

Escom and Eskom present the best results, although both have experienced a significant decrease. SEC is also within tolerable ranges (although in all three cases results have decreased since the beginning of the period).

Figure 25: Return on Equity

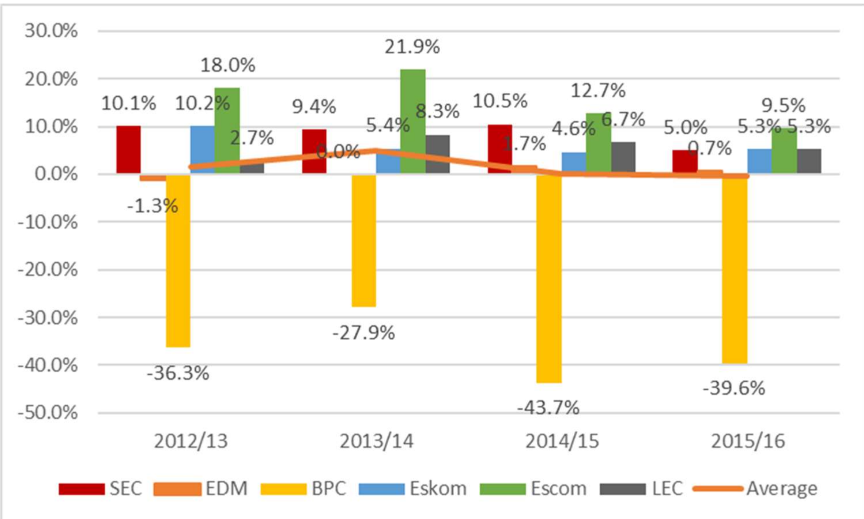


Source: Own elaboration based on annual reports

7.3.9 Return on Net Fixed Assets

Regarding return on net fixed assets, large differences appear: again, BPC presents negative values in all periods, with heavy losses that result in values out of range. EDM also presents negative values at the beginning of the period and very small values afterwards (close to zero profitability). In both cases, figures are out of the acceptable range of values for this KPI. The rest all comply with the minimum level (except LEC in the first year) but all figures decrease throughout the period and seem to converge to the limit value (5%). Only Escom presents higher values at the end of the period.

Figure 26: Return on Net Fixed Assets



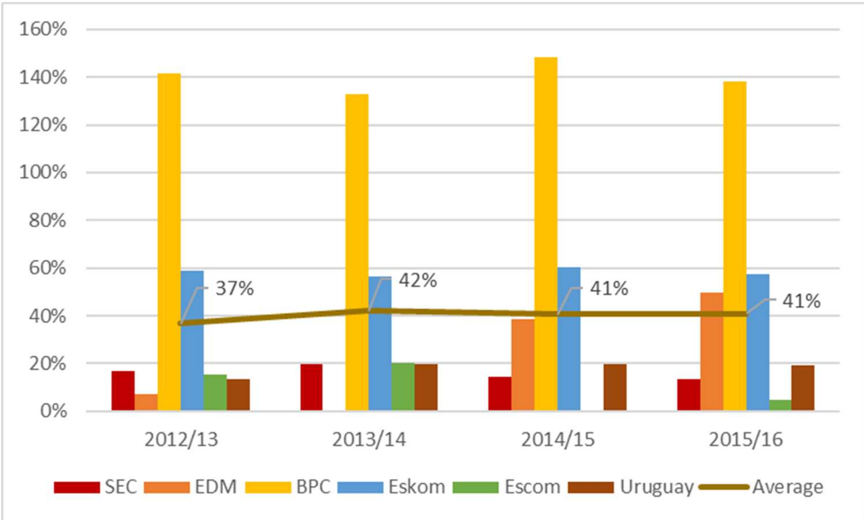
Source: Own elaboration based on annual reports

7.3.10 Debt to Assets

LEC, SEC and Escom present very small Debt to Assets ratios, well below industry standards (30%). In the case of LEC, the ratio is low since investments have been funded by means of capital grants instead of commercial loans. EDM has significantly increased its share over the period and currently stands at 50%, while Eskom has maintained stable levels around 58%.

BPC, on the other hand, has maintained its unsustainable debt levels between 133% and 148%.

Figure 27: Debt to Assets



Source: Own elaboration based on annual reports

8 Summary of Results and Conclusions

LEC is performing well in most areas when compared to most of the regional peers included in the study, although significant improvements would be required to reach international standards.

In this summary the results have been grouped according to the type of KPI involved: technical operational and financial. The summary of the operational results are further subdivided into separate conclusions for the regional (comparing LEC with other vertically integrated utilities present in the SAPP) and international benchmarking exercises (to derive OPEX goals for LEC).

Technical Indicators

- Loss levels and energy intensity in Lesotho are comparable with its African peers but still far away from International Best Practices.
- SAIDI and SAIFI figures have worsened in the last years and, despite some improvement during 2016, are still below 2014's values.
  - Network reliability improvements are required - by appropriate investments in line and substation maintenance and/or investments in monitoring and dispatch software.
  - LEC's levels are still far from International best practices and imposing European or North American reference levels on LEC would not be reasonable.
  - Levels similar to those of Eskom may be taken as a target (less than 50 minutes in the case of SAIDI and values around 20 for SAIFI). Matching the better Eskom performance may help to take into account the negative impact on LEC performance of disruptions in the RSA system that may affect bulk supply to LEC.
  - The ability of LEC to timely deliver investments in this regard will determine its future SAIDI and SAIFI levels.

Regional Operational Indicators

- The lack of data on network length and disaggregated data on operational expenses (for most years) limits the value of the conclusions of the regional part of the study.
- However, this analysis has now provided LEWA with base levels against which it can compare LEC's performance within the SAPP environment.
- In general, LEC's operational figures are better than in the rest of its African peers.
- LEC's figures suggest some level of excessive staff costs: despite a good evolution of connections by employee in recent years, the level of labour costs over total sales seems high. However as noted in deliverable 5 consumption levels amongst newly connected customers have been falling significantly in recent years limiting sales and hence worsening this ratio, while ensuring relatively high salaries within LEC guarantees its ability to retain high-skilled workers.
- As stated in deliverables 3 and 4, the ratio of OPEX per MWh is expected to fall due to reduced O&M requirements given the new infrastructure already deployed and expected to be deployed in the short term. We have thus derived an efficiency goal for LEC.

International Benchmarking and OPEX reduction targets

- Opex figures from the international database should be considered as targets together with their current level of quality of supply (much higher than the rest of countries considered for the regional study).
- Our current database, with detailed data for international peers, has allowed us to derive targets for LEC on the basis of comparable systems (comparable in terms of density and average consumption levels).
- Using this data we have derived an efficiency frontier that allows us to determine LEC's position against the companies included in the database (after taking into account density).
    - In the commercial part of the business OPEX per customer in Lesotho is well above the efficient costs found for international utilities and targeting important OPEX efficiency improvements seems justified.
    - OPEX per MWh for the Networks part of the business is also much higher than efficient costs for the International Data base, but numbers are more comparable than for the Commercial part of the business.
- Given the current trend in Lesotho for newly connected customers to have well below average consumption, LEC will need to include important cost reduction programs in order to improve its current figures for both the commercial part of the business.
- For the network part of the business figures are expected to decrease for two reasons:
    - newly constructed infrastructure requires lower O&M expenditure, and
    - further access to electricity in rural areas that the grid has not yet reached, is expected to be implemented by means of off-grid systems.
- The consultant expects LEC to be able to reduce its total OPEX costs at an average annual level of 1.49%. This figure is taken forward into the financial analysis in part 2 of this report.

Financial Indicators

- LEC financial indicators are generally more in line with international norms than those of its regional peers.
- Financial KPIs present a good evolution in recent years and only two KPIs raise concerns: low levels of working ratio and low return on equity.
- The presence of Equity in its capital structure is quite high, while debt presents very low levels.

Data Gathering Requirements

LEC's annual financial accounts are audited and provide a complete explanation of costs incurred by the business. However, they are not yet split into the transmission, distribution and supply side segments and consequently, this benchmarking exercise has needed to make some assumptions in this regard (e.g., see section 6.8).

We would recommend, therefore, that accounting templates are developed to allow the financial information to be split out and subsequently gathered and monitored at each tariff review period for the network (transmission and distribution) and commercial (supply) parts of LEC.

A similar split of technical data is also recommended and an outline of the data requirements for this was provided in Section 2.3.

Part 2 - Financial Performance

9 FINANCIAL PERFORMANCE ANALYSIS

The next step in this deliverable is to use the recommended efficiency improvements from Section 6.8.2 and define a basis for financial viability of LEC. As LEC income depends on the tariff regime this analysis must also take into consideration the economic costs and tariffs from Task 4. As LEC financial performance is also a function of capital expenditure this analysis also draws from the capex set out in the expansion program from Task 3.

Task 4 indicated that current tariffs (excluding customer levies and electrification levies) are on average around 40% below the economic level.[18] Data from LEC's audited accounts – presented in Figure 28 - shows a profitable business, although LEC has relied significantly on capital grants to fund its investment program – a total of M 273.2 Mil over the five financial years analysed. Furthermore, any new customer is required to contribute to the cost of being connected.[19]

Figure 28: LEC's statement of comprehensive income for 5 years of most recent audited accounts (financial years)

Statement of Comprehensive Income	2011/12 M m	2012/13 M m	2013/14 M m	2014/15 M m	2015/16 M m
REVENUE					
Energy sales	411.7	447.7	530.8	636.7	676.4
Connection fees	34.0	39.7	44.2	52.6	51.3
Miscellaneous other revenue	-0.1	-0.1	16.1	-0.2	0.6
TOTAL REVENUE	**445.6**	**487.2**	**591.1**	**689.1**	**728.3**
Costs					
Cost of sales	-183.4	-260.5	-278.3	-298.9	-353.3
TOTAL O&M OVERHEADS	**-183.4**	**-260.5**	**-278.3**	**-298.9**	**-353.3**
Gross profit	**262.2**	**226.7**	**312.9**	**390.2**	**375.0**
Other income					
Rent of LEC houses	0.1	0.1	0.1	0.1	0.1
Other income	3.8	20.5	4.3	11.6	9.1
Total	**3.9**	**20.6**	**4.4**	**11.6**	**9.2**
Administration & General Overheads					
Salaries & wages	-100.9	-109.6	-119.6	-136.9	-143.6
Additional Management	0.0	0.0	0.0	0.0	0.0
Vehicle costs	-8.1	-8.6	-8.3	-9.1	-8.3
Insurances	-3.1	-3.4	-3.2	-3.8	-4.5
Depreciation	-53.3	-69.0	-76.8	-82.8	-82.1
Operating expenditure	-71.2	-58.7	-40.1	-67.2	-73.6
Interest Paid	0.0	0.0	0.0	0.0	0.0
Retirement benefit obligations					
TOTAL A&G OVERHEADS	**-236.6**	**-249.3**	**-248.1**	**-299.8**	**-312.0**
PROFIT/LOSS before finance income and costs	**29.5**	**-1.9**	**69.2**	**102.0**	**72.1**
Finance income	3.0	0.4	-0.3	2.9	4.3

[18] Calculated as expected total income from tariffs (energy and demand charges) divided by expected total consumption.

[19] Assumed to be 2000 M/connection – see task 3.

Statement of Comprehensive Income	2011/12 M m	2012/13 M m	2013/14 M m	2014/15 M m	2015/16 M m
Finance costs	-0.8	-0.8	-0.5	-4.1	-1.2
PROFIT/LOSS before tax	**31.7**	**-2.4**	**68.3**	**100.8**	**75.3**
Exceptional Items	0.0	0.0	0.0	0.0	0.0
Taxation	-7.9	0.6	-17.1	-25.2	-18.8
PROFIT/LOSS after interest and tax	**23.8**	**-1.8**	**51.2**	**75.6**	**56.4**
Dividends	0.0	0.0	0.0	0.0	0.0
Comprehensive income for the year	**23.8**	**-1.8**	**51.2**	**75.6**	**56.4**

The statement of financial position shows the level of capital grant along with the evolution of the LEC asset base.

Figure 29: LEC's statement of financial position income for 5 years of most recent audited accounts

Statement of Financial Position	2011/12 M m	2012/13 M m	2013/14 M m	2014/15 M m	2015/16 M m
ASSETS					
Non-current assets					
Property, plant and equipment	1,560.9	1,665.9	1,662.7	2,514.3	2,655.9
Deferred taxation	24.2	35.3	47.27	62.1	76.0
Total non-current assets:	**1,585.0**	**1,701.2**	**1,710.0**	**2,576.4**	**2,731.8**
Current Assets					
Inventories	30.5	32.3	26.20	27.8	28.9
Trade debtors and other receivables	43.5	55.7	59.34	64.8	70.2
Sundry debtors	1.6	0.3	1.53	0.6	1.0
Others	0.0	0.0	0.00	0.0	0.0
Cash and cash equivalents	41.1	22.0	109.7	167.9	134.2
Total current assets	**116.7**	**110.3**	**196.7**	**261.2**	**234.3**
Total assets	**1,701.7**	**1,811.5**	**1,906.7**	**2,837.6**	**2,966.1**
CAPITAL AND LIABILITIES					
Equity attributable to equity holder of the company					
Share capital and reserves	0.0	0.0	0.0	0.0	0.0
Share premium	599.2	599.2	599.2	599.2	599.2
Capital grant	200.2	201.5	268.1	364.9	473.4
Loan redemption provision	0.0	0.0	0.0	0.0	0.0
Revaluation reserve	525.6	525.6	525.6	1257.2	1257.2
Retained income	193.0	191.2	242.3	324.1	378.0
Total equity	**1,518.0**	**1,517.5**	**1,635.3**	**2,545.4**	**2,707.9**
Non-current Liabilities					
Retirement benefit obligations	32.0	37.5	43.0	47.7	53.1
Long-term loans	9.8	54.1	53.8	57.9	47.8
Deferred tax	0.0	0.0	0.0	0.0	0.0
Total Non-current Liabilities	**41.8**	**91.6**	**96.8**	**105.6**	**100.9**
Current Liabilities					
Creditors and Provisions	73.1	73.1	26.3	40.9	62.7
Other creditors	17.9	17.9	40.4	56.5	6.4
Accruals	5.4	5.4	16.9	22.1	24.6

Statement of Financial Position	2011/12 M m	2012/13 M m	2013/14 M m	2014/15 M m	2015/16 M m
Trade and other payables balancing figure	0.0	41.3	0.0	0.0	0.0
Taxation	25.5	36.0	65.1	40.1	36.1
Overdraft (bank credit line)	1.4	6.8	2.8	2.7	1.0
Security deposits	13.9	17.5	18.9	20.1	21.2
Current portion of long-term borrowings	4.7	4.5	4.2	4.3	5.4
Total current liabilities	**141.9**	**202.4**	**174.6**	**186.6**	**157.3**
Total equity and liabilities	**1,701.7**	**1,811.5**	**1,906.6**	**2,837.6**	**2,966.1**

These figures are taken forward into the financial modelling as opening values for the business.[20]

10 FINANCIAL MODEL DESCRIPTION

A financial model of LEC has been constructed to assess the financial viability of the company. The model is capable of projecting financial performance out to 2030, although for consistency with Task 4, the focus here is on the 3-year period 2018-20.

The model **inputs** are summarised in Table 17-Table 19. Table 17 also refers to data linked to previous tasks of the project.

Table 17: Inputs to the Financial Modelling feeding through from previous CoSS tasks

Financial Modelling Input Data	Unit	Task	2018/19	2019/20	2020/21
Transmission Losses	%	Task 4	7%	7%	7%
Distribution Losses	%	Task 4	12.5%	12.5%	12.5%
Aggregate T + D Losses	%	Task 3	14%	14%	14%
Energy Consumption	MWh	Task 2	791,478	820,377	849,277
Maximum Demand	kVa	Task 4	1,063,589	1,099,138	1,134,686
Customer Numbers	#	Task 3	249,607	264,586	276,577
New connections	#	Task 3	14,978	11,991	11,991
Cost of connections - funded by LEC	M	Task 3	2,500	2,500	2,500
Cost of connections - customer contribution	M	Task 3	2,000	2,000	2,000
Capex - transmission	M mil	Task 3	136.7	120.6	101.8
Capex - distribution	M mil	Task 3	180.5	159.1	134.4
Capex - new generation*	M mil	Task 3	141.4	141.4	162.5
Power Purchase - Muela	M mil	Task 3	65.70	72.95	72.95
Power Purchase - Eskom	M mil	Task 3	397.58	385.40	398.05
Power Purchase - EDM	M mil	Task 3	50.47	53.86	55.19

* Investment in 10 MW Solar Park at Semonkong (2 years construction, commissioned in 2020) and Wind plants at Mphaki (2 years construction, commissioned in 2022) is assumed to be undertaken by LEC.

[20] Audited accounts for the 2016/17 financial year were not available at the time of model implementation so this year (along with 2017/18) have been simulated using tariffs and LEC costs from the LEWA determinations documents and available information on investments undertaken during this time. The projection for the year 2018/19 onwards is of primary interest here as that is the earliest that any tariff changes will take effect.

Table 18: Inputs to the Financial Modelling not yet shown in other CoSS tasks

Financial Modelling Input Data	Unit	Value	
VAT	%	5.0%	
Corporation tax	%	25.0%	
Allowed Collection Losses	%	0%	
Allowed Transmission Losses	%	7%	
Allowed Distribution Losses	%	12.5%	
Asset Register Categories (Task 4)		**2017 opening value**	**Depreciation rate applied**
Land	Maloti	56,177,671	0.0%
Auxiliary Buildings	Maloti	70,567,497	2.0%
Generation	Maloti	28,585,536	3.7%
Transmission	Maloti	1,368,488,415	3.7%
Distribution	Maloti	1,031,281,225	3.7%
Network Management Systems	Maloti	27,452,650	3.7%
Plant & machinery	Maloti	11,772,956	13.2%
Office Equipment	Maloti	3,220,284	18.7%
Telecom Equipment	Maloti	435,177	18.7%
ICT - Software	Maloti	5,105,685	18.7%
Motor Vehicles	Maloti	21,796,252	27.8%

As shown in Table 18, no allowance is made for collections losses in the tariff modelling on the basis that most customers are on pre-payment meters and those on post-paid (e.g., industrial and commercial) have a good payment record.[21] However, a modest ongoing debtors amount of 2% of industrial and commercial billings is included in the financial modelling when assessing the financial viability of LEC.

The split of network and commercial opex efficiency improvements amongst the categories in the accounts is shown in Table 19. This is based on maintaining the historical proportions of total opex[22] and therefore the same recommended efficiency improvements are reflected across all opex categories.[23]

Table 19: Allocation of network and commercial opex with efficiency improvements to the categories for the financial modelling (replicating audited account categories)

Financial Modelling Input Data	Unit	2018/19	2019/20	2020/21
BAU				
Operating expenditure	M mil	96.23	100.70	104.69
Salaries & wages	M mil	160.22	167.67	174.30
Vehicle costs	M mil	0.00	0.00	0.00
Insurances	M mil	8.93	9.34	9.71
High efficiency				
Operating expenditure	M mil	93.76	96.81	99.27

[21] Anecdotal evidence from LEC staff indicated that post-paid industrial and commercial customers pay in full, albeit with a lag of up to six months (at which point they pay off debts in bulk).
[22] Based on 2016/17 data.
[23] Should the realised split of efficiency improvements be different to the split assumed in the modelling, the impact on the financial modelling results (statement of comprehensive income, financial position, etc) is minimal.

Financial Modelling Input Data	Unit	2018/19	2019/20	2020/21
Salaries & wages	M mil	156.10	161.18	165.28
Vehicle costs	M mil	0.00	0.00	0.00
Insurances	M mil	8.70	8.98	9.21
Intermediate				
Operating expenditure	M mil	92.31	94.54	96.12
Salaries & wages	M mil	153.70	157.39	160.04
Vehicle costs	M mil	0.00	0.00	0.00
Insurances	M mil	8.56	8.77	8.92

The model allows for the testing of 3 major areas:

1. Selection of opex efficiency improvement case – BAU, high or intermediate;
2. Testing a range of tariff scenarios – for example a switch to economic levels or gradual increases; and
3. The inclusion or exclusion of the Increasing Block Tariff lifeline tariff mechanism proposed in Task 5.

Historically LEC have funded capex through two means 1) the income from the depreciation part of the allowed tariffs and 2) capital grant and donor funding. It is likely that for the selected tariff pathway LEC's capital expenditure will require financing. On that basis, the model also computes **funding requirements** based on a minimum cash in bank level, below which funding is pursued. This level is set at 50 M mil.[24] The funding requirement can be met either through commercial loans (for an inputted prime rate, margin over prime and loan tenure), capital grant or a combination of the two.

Interviews with LEC's finance and engineering departments highlighted a difference of opinion within LEC on how they will fund future capex. The engineering department were clear that it would be through commercial loans. The finance department were clear that this would not be possible because of unwillingness (inability) of commercial banks to lend on major capital projects of LEC.[25] Given this uncertainty in the sector on where capex will be sourced, the model assumes that any funding requirement is met through 50% capital grant and 50% commercial loan. Loans are given a 10 year term and the cost of debt is set at 8.5% to be consistent with the WACC derived in Task 4.

The model has been designed so that it can be used to also test gradual increases in tariffs because large immediate step changes of tariff may be politically and socially unacceptable. To do this when testing different scenarios, the model ensures that the NPV over the 3-year tariff period of the summed differences between the total income in each year and the revenue requirement in the corresponding year is zero:[26]

$$\sum_{i=1}^{3} \frac{1}{(1+r)^i}[Anticipated\ tariff\ income_i - Required\ Revenue_i] = 0$$

Designing tariffs to achieve this NPV balance is a common approach applied to tariff setting when switching to economic levels is not feasible and instead a gradual increase is preferred. This typically

[24] The audited accounts show cash in bank ranging from M 22-168 mil in recent years - **Figure 29**.

[25] LEC have some modest long-terms loans for vehicle financing.

[26] For example, allowing the user to manually select changes in tariff levels for the first two years of the price control with the third year used as a "balancing year".

results in under-recovery (income from tariffs below costs) in the early years of the price control which are offset by over-recovery (income from tariffs above costs) in later years.

The **key outputs** of the model are an income statement, cash flow and statement of financial position. For ease of interpretation by LEC and LEWA these have been constructed to follow the same structure as the audited accounts presented in the previous section.[27]

11 Financial Analysis Results

This section presents six cases for a tariff trajectory and reports the financial performance of LEC associated with each. It is, however, important to note that the model is flexible and allows for testing any number of combinations of tariffs beyond the handful presented here. Apart from the sensitivity presented in Section 11.1, **all cases are run with the intermediate opex scenario** (see section 6.8.2).

Note that for all scenarios customer levies and electrification levies are held constant in real terms throughout the period. Income from these levies is included in total revenue but is also added as a cost and payment in the cash flow so does not impact the differences between scenarios in LEC's key financial performance indicators.

The six tariff trajectory cases reported are as shown in Table 20 below.

Table 20 – Tariff Trajectory Cases Considered

Scenario (Section reference):	11.1	11.2	11.3	11.4	11.5	11.6
Full economic cost based tariffs from year 1	yes	yes	no	no	no	no
Based on full return on capital	yes	no	no	no	no	no
Modest tariff changes per year	no	no	yes	yes	no	no
Lifeline tariff applied	no	no	no	yes	yes	yes
Economic cost based tariffs by year 3	no	no	no	no	yes	yes
Economic cost based tariffs by year 3 - Tariffs increased early for viable business in year 1	no	no	no	no	no	yes

These have been carefully selected to show the range of options available and that the model is a flexible tool for investigating those options. The main variables studied are:

- The impact of moving immediately to full economic tariffs – section 11.1
- The possibility to reduce that impact by relaxing the requirement to achieve full returns on capital – section 11.2.
- The options for achieving cost reflectivity on the overall tariff without major tariff changes through a smooth transition and by not seeking to rebalance tariffs between tariff categories – section 11.3.
- The option of introducing a lifeline tariff – sections 11.4 - 11.6.

[27] Note that it was not possible to obtain detailed cash flow movements from LEC and in the absence of this data an approximation of receipts and payments was made based on the cash and bank figure appearing in the LEC statement of financial position in combination with costs and revenues appearing on the income statements. This approach was rolled forward and used in the projection.

- The options of achieving full cost reflectivity over the three year tariff period - two variants, the second with higher tariff rises in the first two years to ensure financial viability of LEC – sections 11.5 to 11.6.

The analyses are considered in detail in the following subsections.

11.1 Economic Cost-Based Tariffs

A logical first step in the analysis would be to assess the financial viability of LEC in a scenario where the economic tariffs were adopted immediately. Table 21 shows the Revenue Requirement from Task 4.

Table 21: LEC revenue requirement derived from Task 4 with adjustment for opex efficiency improvement (intermediate) from Task 6 (section 6.1.8)

Required Revenue	2018	2019	2020
Return of Capital (Depreciation)	109.8	115.3	119.8
Return on Capital	233.5	249.6	261.8
Operating Expenses	289.8	316.6	339.2
Less reduction for opex efficiency improvement	*-26.4*	*-44.7*	*-60.4*
Cost of Generation for Demand	506.3	524.8	543.3
Cost of Generation for Energy Losses	85.5	88.6	91.8
Total Revenue Requirement	**1198.4**	**1250.3**	**1295.5**

Table 22 shows the corresponding adjustment to the revenue requirement after the proposed efficiency improvements. This change impacts only on operating expenses, other items remain as shown in Table 21.

Table 22: LEC revenue requirement for efficiency improvement scenarios

Required Revenue	2018	2019	2020
Operating Expenses - BAU	270.29	282.85	294.04
Total Revenue Requirement	1,205.4	1,261.2	1,310.7
Operating Expenses - High	259.28	265.52	269.99
Total Revenue Requirement	1,194.4	1,243.9	1,286.6
Operating Expenses - Intermediate	263.35	271.90	278.83
Total Revenue Requirement	1,198.4	1,250.3	1,295.5

The economic tariffs for these cases (excluding customer levies and electrification levies) are shown in Table 23. The adjustments are reflected through changes in the energy charges.

Table 23: Economic Tariffs (excluding levies) for efficiency improvement scenarios (constant 2018/19-20/21)

Tariff	Current 2017/18	Task 4	BAU	High	Intermediate
Energy Charges	**M/kWh**	**M/kWh**	**M/kWh**	**M/kWh**	**M/kWh**
Domestic	1.347	1.945	1.878	1.842	1.855
General Purpose	1.522	1.583	1.529	1.500	1.511
LV Commercial	0.206	0.731	0.731	0.731	0.731

Tariff	Current 2017/18	Task 4	BAU	High	Intermediate
HV Commercial	0.186	0.773	0.773	0.773	0.773
LV Industrial	0.206	0.731	0.731	0.731	0.731
HV Industrial	0.186	0.774	0.774	0.774	0.774
Street Lighting	0.764	1.753	1.693	1.661	1.673
Demand Charges	**M/kVa**	**M/kVa**	**M/kVa**	**M/kVa**	**M/kVa**
LV Commercial	306.302	285.818	275.983	270.741	272.671
HV Commercial	262.239	149.811	144.656	141.909	142.921
LV Industrial	306.302	254.245	245.496	240.834	242.551
HV Industrial	262.239	150.355	145.182	142.425	143.440
Fixed Charges	**M/month**	**M/month**	**M/month**	**M/month**	**M/month**
Domestic	0	6.97	6.97	6.97	6.97
General Purpose	0	6.96	6.96	6.96	6.96
LV Commercial	0	6.95	6.95	6.95	6.95
HV Commercial	0	3,681.80	3,681.80	3,681.80	3,681.80
LV Industrial	0	6.96	6.96	6.96	6.96
HV Industrial	0	3,673.14	3,673.14	3,673.14	3,673.14
Street Lighting	0	6.93	6.93	6.93	6.93

The results of switching to economic tariff level in the intermediate opex scenario are summarized in Table 24. The change in the performance indicators reviewed in Section 7.3 income statement, cash flow, statement of financial position and for this case are provided in Annex A - 14.1.

Table 24: Summary of projected financial performance for Economic Cost-Based Tariffs with intermediate opex

M mil	2018/19	2019/20	2020/21
Total Income[1]	1,280.7	1,326.2	1,373.3
EBITA	328.2	354.8	367.8
Retained Income for the Year	242.9	263.1	272.5
Funding requirements[2]	0.0	20.0	0.0

[1] Includes income from tariffs, levies, VAT, and connection charges

[2] To ensure closing cash in bank >= M50 mil

The results show a financially viable company – the retained profits broadly align with the Return on Capital component of the tariffs (about 18% of the revenue requirement) plus a surplus obtained from power purchase costs being below allowed generation costs.[28]

This strong financial position means that LEC in this scenario could fund the majority of the expansion program from income from tariffs with M 20.0 mil of funding over the 3-year period required to maintain a closing cash in bank position on M 50 mil.

[28] Recall from Task 4 that the generation revenue requirement derived from LRMC may be higher than out-turn power purchase costs incurred by LEC. LEC may use this additional income to fund new investments in generation.

11.2 Economic Cost-Based Tariffs – Excluding Return on Capital

The regulatory mechanisms for including a return on assets in the allowable revenue were developed in the context of private ownership and as LEC is a wholly government-owned state utility, return on assets is arguably a matter of public policy and may therefore be subject to different criteria.

On that basis we have included a case where the revenue requirement is adjusted to remove the return on capital (RoC) component in combination with the intermediate opex scenario.

Table 25: LEC revenue requirement derived from Task 4 with Return on Capital removed with intermediate opex

Required Revenue	2018	2019	2020
Return of Capital (Depreciation)	109.8	115.3	119.8
Return on Capital	**0**	**0**	**0**
Operating Expenses	263.3	271.9	278.8
Cost of Generation for Demand	506.3	524.8	543.3
Cost of Generation for Energy Losses	85.5	88.6	91.8
Total Revenue Requirement	**964.9**	**1000.7**	**1033.7**

Table 26: Economic Tariffs with RoC removed from Revenue Requirement (and intermediate opex)

Tariff	Current 2017/18	Economic (no RoC 2018/19 – 2020/21	% increase
Energy Charges	**M/kWh**	**M/kWh**	
Domestic	1.347	1.339	-0.6%
General Purpose	1.522	1.090	-28.4%
LV Commercial	0.206	0.731	254.5%
HV Commercial	0.186	0.773	315.6%
LV Industrial	0.206	0.731	254.7%
HV Industrial	0.186	0.774	315.8%
Street Lighting	0.764	1.207	57.9%
Demand Charges	**M/kVa**	**M/kVa**	
LV Commercial	306.302	196.809	-35.7%
HV Commercial	262.239	103.157	-60.7%
LV Industrial	306.302	175.068	-42.8%
HV Industrial	262.239	103.532	-60.5%
Fixed Charges	**M/month**	**M/month**	
Domestic	0	6.97	
General Purpose	0	6.96	
LV Commercial	0	6.95	
HV Commercial	0	3,681.80	
LV Industrial	0	6.96	
HV Industrial	0	3,673.14	
Street Lighting	0	6.95	

Table 27: Summary of projected financial performance for Economic Cost-Based Tariffs with RoC removed and intermediate opex

M mil	2018/19	2019/20	2020/21
Total Income	1,041.9	1,078.2	1,116.1
EBITA	89.4	106.8	110.6
Retained Income for the Year	63.8	70.0	66.0
Funding requirements	222.3	239.5	224.9

The results show a profitable company – retained profits are anticipated to be at a similar level to those seen historically although funding of M 686.6 mil is required - Table 28. The change in the performance indicators, income statement, cash flow, statement of financial position and for this case are provided in Annex A - 14.2.

Table 28: Projected cash flow for Economic Cost-Based Tariffs excluding Return on Capital Scenario

Cash Flow	2018/19 M m	2019/20 M m	2020/21 M m
Opening Cash	**112.9**	**50.0**	**50.0**
Add receipts			
from commercial loans	111.1	119.7	112.4
from capital grants	111.1	119.7	112.4
Domestic, GP, street lighting and other customers	523.0	544.5	565.6
Industrial and commercial customers	479.2	495.4	511.5
Levies from customers	57.7	59.8	61.9
From connection fees	22.9	21.1	21.1
Catch-up payments	0.0	0.0	0.0
Security deposits	1.0	0.8	0.8
Less payments			
For power purchase	-513.7	-512.2	-526.2
LEC Generation - O&M	0.0	0.0	-2.1
Salaries, Wages and Opex	-263.3	-271.9	-278.8
Licence Fees to LEWA	-33.5	-34.7	-35.9
Electrification levy to REU	-21.4	-22.2	-23.0
Tax	-19.6	-21.3	-23.3
VAT	-50.7	-52.6	-54.5
Loan repayments including interest	-8.1	-25.0	-43.3
capital expenditure - new connection (LEC funded)	-28.6	-26.4	-26.4
capital expenditure - customer contribution	-22.9	-21.1	-21.1
capital expenditure - network	-265.7	-232.2	-188.7
capital expenditure - generation	-141.4	-141.4	-162.5
Closing cash	**50.0**	**50.0**	**50.0**

The key changes in the statement of financial position associated with the loans and capital grants are shown in Table 29.

Table 29: Key changes in LEC financial statements associated with loans and capital grants

Summary results	2018/19	2019/20	2020/21
Equity (balance sheet)			
Capital grant	660.5	780.3	892.7
Non-current Liabilities (balance sheet)			
Long-term loans (including pre-existing loans)	152.0	260.5	352.6

11.3 Smoothed Energy Tariff Trajectory

The changes to tariffs required to move immediately to fully cost reflective tariffs as shown in sections 3.1 and 3.2 above, are quite sharp– particularly for commercial and industrial customers. It may, therefore be preferable to introduce a tariff plan where the change from current levels is more gradual.

Table 30 presents an alternative case with no balancing between tariff categories, smoother changes in energy tariffs, **maximum demand charges remaining at current levels for the duration of the tariff plan** and a fixed charge. In this scenario LEC receives revenue that is equivalent over the three-year period to that provided by a cost reflective tariff regime with the Return on Capital component removed. The outcome is that by the end of the 3-year period Domestic and General Purpose tariffs are above their economic level and others are below. Once again, the intermediate opex scenario is assumed.

Table 30: Sculpted Tariff scenario

Tariff	Current 2017/18	2018/19	2019/20	2020/21	Economic Tariffs (RoC removed)
Energy Charges	**M/kWh**	**M/kWh**	**M/kWh**	**M/kWh**	**M/kWh**
Domestic	1.347	1.374	1.401	1.497	1.339
General Purpose	1.522	1.553	1.584	1.692	1.090
LV Commercial	0.206	0.227	0.249	0.266	0.731
HV Commercial	0.186	0.205	0.225	0.241	0.773
LV Industrial	0.206	0.227	0.249	0.266	0.731
HV Industrial	0.186	0.205	0.225	0.241	0.774
Street Lighting	0.764	0.841	0.925	0.988	1.207
Demand Charges	**M/kVa**	**M/kVa**	**M/kVa**	**M/kVa**	**M/kVa**
LV Commercial	306.302	306.302	306.302	306.302	196.809
HV Commercial	262.239	262.239	262.239	262.239	103.157
LV Industrial	306.302	306.302	306.302	306.302	175.068
HV Industrial	262.239	262.239	262.239	262.239	103.532
Fixed Charges	**M/month**	**M/month**	**M/month**	**M/month**	**M/month**
Domestic	0	6.97	6.97	6.97	6.97
General Purpose	0	6.96	6.96	6.96	6.96
LV Commercial	0	6.95	6.95	6.95	6.95
HV Commercial	0	3,681.80	3,681.80	3,681.80	3,681.80
LV Industrial	0	6.96	6.96	6.96	6.96
HV Industrial	0	3,673.14	3,673.14	3,673.14	3,673.14

Tariff	Current 2017/18	2018/19	2019/20	2020/21	Economic Tariffs (RoC removed)
Street Lighting	0	6.95	6.95	6.95	6.95

Table 31: Per year increases in energy charges in Sculpted Tariff scenario (final year used as balancing year)

Tariff	2018/19	2019/20	2020/21
Energy Charges	**% increase**	**% increase**	**% increase**
Domestic	2.0%	2.0%	6.8%
General Purpose	2.0%	2.0%	6.8%
LV Commercial	10.0%	10.0%	6.8%
HV Commercial	10.0%	10.0%	6.8%
LV Industrial	10.0%	10.0%	6.8%
HV Industrial	10.0%	10.0%	6.8%
Street Lighting	10.0%	10.0%	6.8%

The results of the smoothed increase to energy charges scenario are summarized in Table 32. The change in the performance indicators, income statement, cash flow, statement of financial position and for this case are provided in Annex A - 14.3.

The results show a profitable company, although less so than in the Economic-cost Tariff scenario – retained profits increase gradually and funding of M 671.9 mil over the 3-year period is required to fund the expansion program. Interestingly, by applying gradual changes in tariffs the funding requirements are at a very similar level to economic cost-base case presented in section 11.2 as are the revenues and collected sales (cash flow).

Table 32: Summary of projected financial performance for Smoothed Increases with intermediate opex

M mil	2018/19	2019/20	2020/21
Income	1,015.6	1,071.0	1,155.0
EBITA	63.1	99.5	149.6
Retained Income for the Year	44.1	63.8	94.5
Funding requirements	246.9	240.6	184.4

In this scenario cross-subsidy from domestic and general purpose to industrial and commercial will be present for the 3 years. This is demonstrated by comparing the revenues in the economic case presented in the previous subsection against the smoother tariff scenario - Table 33.

Table 33: Comparison of LEC revenues (income statement) in Economic cost-based tariffs excluding Return on Capital and smoothed tariffs

Excerpt from Income Statement	2018 M m	2019 M m	2020 M m
Economic Cost-Based Tariffs – Excluding Return on Capital			
Sales - domestic, GP, street lighting and other	523.0	544.5	565.6
Sales - industrial and commercial	489.0	505.5	521.9
Total	**1,012.04**	**1,049.94**	**1,087.58**

Excerpt from Income Statement	2018 M m	2019 M m	2020 M m
Smoothed Tariffs			
Sales - domestic, GP, street lighting and other	576.1	610.7	675.5
Sales - industrial and commercial	408.3	431.6	453.0
Total	**984.43**	**1,042.31**	**1,128.47**

11.4 Smoothed Energy Tariff Trajectory – Including Lifeline Tariff

To align with the outputs of Task 5 a case where an increasing block lifeline tariff is introduced is presented. In this analysis the 64,259 LEC customers identified as consuming below 30 kWh / month are considered lifeline and the life-line block tariff of 0.5 M/kWh for consumption below 30 kWh / month is introduced for all domestic customers.

Table 34 shows the energy charges for this scenario. It shows how the standard domestic energy charge increases relative to the smoothed tariff scenario without lifeline (section 11.3). This increase is needed to compensate for lower revenues from the first 30 kWh of consumption.

Maximum demand and fixed charges are the same as in the smoothed energy increases case (section 11.2) although lifeline customers pay an energy charge only.

Table 34: Energy charges in the Sculpted Tariff with lifeline scenario

Tariff	Current 2017/18	2018/19	2019/20	2020/21	Economic Tariffs (RoC removed)
Energy Charges	**M/kWh**	**M/kWh**	**M/kWh**	**M/kWh**	**M/kWh**
Lifeline-Block Domestic	-	0.5	0.5	0.5	1.339
Standard Domestic	1.347	1.650	1.698	2.082	1.339
General Purpose	1.522	1.553	1.584	1.904	1.090
LV Commercial	0.206	0.227	0.249	0.300	0.731
HV Commercial	0.186	0.205	0.225	0.271	0.773
LV Industrial	0.206	0.227	0.249	0.300	0.731
HV Industrial	0.186	0.205	0.225	0.271	0.774
Street Lighting	0.764	0.841	0.925	1.112	1.207

The results of this scenario are summarized in Table 35. In this case, the introduction of life-line customers requires M 84.6 mil (USD$ 6.5 mil) subsidy. This is recovered through tariffs as a cross-subsidy on all customer category energy charges.

Table 35: Summary of projected financial performance for Sculpted Increases with lifeline with intermediate opex

	2018/19	2019/20	2020/21
Income	995.4	1,050.1	1,219.1
EBITA	42.9	78.7	213.6
Retained Income for the Year	28.9	47.5	141.4
Funding requirements	267.2	257.9	118.1

The change in the performance indicators, income statement, cash flow, statement of financial position and for this case are provided in Annex A - 14.4.

The smoothed energy tariff increases for all customers apart from domestic are the same as in the previous scenario. Therefore, the recovery of the lost revenue due to the creation of 64,259 lifeline customers is delayed until 2020/21. This is reflected in 1) a larger energy charge increase (20%) in 2020/21 relative to the case without lifeline (7%, Table 31); and 2) an increase in the difference between the low profits in early years and larger profits in later years relative to the smoothed tariff without lifeline scenario (Table 32 vs Table 35).

The funding requirements in this scenario are M 643.1 mil over the 3-year period, which is broadly the same as the case without lifeline tariffs although more funding is required upfront.

11.5 Gradual Changes By Tariff Category And Removal of Cross-Subsidy – Including Lifeline Tariff

In both the smoothed energy tariff increase scenarios, the cross subsidies between tariff categories were not eliminated during the three-year review period. Thus the energy charges for domestic and general purpose and maximum demand charges for industrial and commercial were still above the economic cost-based level for these categories by the end of the period.

In this scenario the individual tariff categories for energy (and maximum demand) are gradually increased (decreased) over the three-year period to achieve the economic level within that category and so cross-subsidy between categories is eliminated completely by the end of the period - Table 36.

Table 36: Gradual changes scenario

Tariff	Current 2017/18	2018/19	2019/20	2020/21	Economic Tariffs (RoC removed)
Energy Charges	**M/kWh**	**M/kWh**	**M/kWh**	**M/kWh**	**M/kWh**
Domestic	1.347	1.611	1.620	1.622	1.339
General Purpose	1.522	1.362	1.219	1.090	1.090
LV Commercial	0.206	0.314	0.479	0.730	0.731
HV Commercial	0.186	0.299	0.481	0.772	0.773
LV Industrial	0.206	0.314	0.479	0.730	0.731
HV Industrial	0.186	0.299	0.481	0.773	0.774
Street Lighting	0.764	0.890	1.037	1.207	1.207
Demand Charges	**M/kVa**	**M/kVa**	**M/kVa**	**M/kVa**	**M/kVa**
LV Commercial	306.302	264.311	228.076	196.809	196.809
HV Commercial	262.239	192.146	140.788	103.157	103.157
LV Industrial	306.302	254.196	210.954	175.068	175.068
HV Industrial	262.239	192.378	141.129	103.532	103.532
Fixed Charges	**M/month**	**M/month**	**M/month**	**M/month**	**M/month**
Domestic	0	6.97	6.97	6.97	6.97
General Purpose	0	6.96	6.96	6.96	6.96
LV Commercial	0	6.95	6.95	6.95	6.95
HV Commercial	0	3,681.80	3,681.80	3,681.80	3,681.80
LV Industrial	0	6.96	6.96	6.96	6.96

Tariff	Current 2017/18	2018/19	2019/20	2020/21	Economic Tariffs (RoC removed)
HV Industrial	0	3,673.14	3,673.14	3,673.14	3,673.14
Street Lighting	0	6.95	6.95	6.95	6.95

Table 37: Per year increases in energy charges in Gradual Changes Scenario with intermediate opex

Tariff	2018/19	2019/20	2020/21
Energy Charges	**% increase**	**% increase**	**% increase**
Domestic	-0.2%	-0.2%	-0.2%
General Purpose	-10.5%	-10.5%	-10.5%
LV Commercial	52.4%	52.4%	52.4%
HV Commercial	60.7%	60.7%	60.7%
LV Industrial	52.5%	52.5%	52.5%
HV Industrial	60.7%	60.7%	60.7%
Street Lighting	16.5%	16.5%	16.5%

As Table 38 shows, the delay in reaching the economic level means LEC are unable to achieve profitability until 2020/21 and in fact would make a loss in 2018/19 and 2019/20. The change in the performance indicators, income statement, cash flow, statement of financial position and for this case are provided in Annex A - 14.5. Table 65 shows a negative net operating margin in 2018/19 and 2019/20. Unlike the other scenarios presented, LEC would also not be anticipated to recover the Revenue Requirement and would under-recover by M 195.0 Mil (in NPV terms) - Table 39.

The amount of funding required also increases substantially to M 865.5 mil over the 3-year period - Table 38.

Table 38: Summary of projected financial performance for Sculpted Increases with lifeline and intermedaite opex

M mil	2018/19	2019/20	2020/21
Income	944.0	988.7	1,096.3
EBITA	-8.5	17.3	90.8
Retained Income for the Year	-12.9	-0.2	46.0
Funding requirements	318.0	313.3	234.2

Table 39: Anticipated Recovery of LEC revenue requirement for Gradual Increases with Lifeline

Required Revenue	2018/19	2019/20	2020/21
Total Revenue Requirement	964.9	1000.7	1033.7
Anticipated income from Tariffs (Tariff design)	860.6	905.1	1010.6
Difference (NPV @pre-tax nominal WACC = -195.0)	-104.4	-95.6	-23.1

11.6 Gradual Changes and Removal of Cross-Subsidy - scenario in 11.5 adjusted to Ensure Revenue Recovery

To rectify the under recovery of revenue issue in the scenario presented in the previous subsection, this section presents a case for tariffs where the gradual changes in energy charges are increased to avoid the M 218.1 Million under-recovery. Tariffs for this scenario are shown in Table 40. The change in the performance indicators, income statement, cash flow, statement of financial position and for this case are provided in Annex A - 14.6. This scenario also removes the cross subsidy.

Table 40: Gradual changes scenario with energy charges pro-rated up to achieve revenue recovery

Tariff	Current 2017/18	2018/19	2019/20	2020/21	Economic Tariffs (RoC removed)
Energy Charges	**M/kWh**	**M/kWh**	**M/kWh**	**M/kWh**	**M/kWh**
Domestic	1.347	1.609	1.618	1.619	1.339
General Purpose	1.522	1.292	1.137	1.000	1.090
LV Commercial	0.206	0.362	0.578	0.923	0.731
HV Commercial	0.186	0.349	0.590	0.998	0.773
LV Industrial	0.206	0.362	0.578	0.923	0.731
HV Industrial	0.186	0.349	0.590	0.999	0.774
Street Lighting	0.764	0.946	1.123	1.334	1.207
Demand Charges	**M/kVa**	**M/kVa**	**M/kVa**	**M/kVa**	**M/kVa**
LV Commercial	306.302	306.302	245.526	196.809	196.809
HV Commercial	262.239	262.239	164.475	103.157	103.157
LV Industrial	306.302	306.302	231.568	175.068	175.068
HV Industrial	262.239	262.239	164.773	103.532	103.532
Fixed Charges	**M/month**	**M/month**	**M/month**	**M/month**	**M/month**
Domestic	0	6.97	6.97	6.97	6.97
General Purpose	0	6.96	6.96	6.96	6.96
LV Commercial	0	6.95	6.95	6.95	6.95
HV Commercial	0	3,681.80	3,681.80	3,681.80	3,681.80
LV Industrial	0	6.96	6.96	6.96	6.96
HV Industrial	0	3,673.14	3,673.14	3,673.14	3,673.14
Street Lighting	0	6.95	6.95	6.95	6.95

Table 41: Per year increases in energy charges in Gradual Changes Scenario with energy charges pro-rated up to ensure revenue recovery

Tariff	2018/19	2019/20	2020/21
Energy Charges	**% increase**	**% increase**	**% increase**
Domestic	-0.3%	-0.2%	-0.2%
General Purpose	-15.2%	-12.0%	-12.0%
LV Commercial	75.5%	59.7%	59.7%
HV Commercial	87.4%	69.2%	69.2%
LV Industrial	75.5%	59.8%	59.8%
HV Industrial	87.4%	69.2%	69.2%
Street Lighting	23.7%	18.8%	18.8%

Tariff	2018/19	2019/20	2020/21
Demand Charges			
LV Commercial	0.0%	-19.8%	-19.8%
HV Commercial	0.0%	-37.3%	-37.3%
LV Industrial	0.0%	-24.4%	-24.4%
HV Industrial	0.0%	-37.2%	-37.2%

Table 42: Summary of projected financial performance for Gradual changes to ensure revenue recovery scenario with intermediate opex

M mil	2018/19	2019/20	2020/21
Income	1,023.5	1,051.2	1,184.7
EBITA	71.0	79.8	179.2
Retained Income for the Year	50.0	49.2	116.1
Funding requirements	240.3	263.0	154.6

11.7 Summary of Results

Table 43 summarises the scenarios tested in the analysis.

Table 43: Summary of Financial Planning Scenarios

Scenario (Section reference):	11.1	11.2	11.3	11.4	11.5	11.6
Full economic cost based tariffs from year 1	yes	yes	no	no	no	no
Based on full return on capital	yes	no	no	no	no	no
Modest energy tariff changes per year	no	no	yes	yes	no	no
Changes to current maximum demand charges	yes	yes	no	no	yes	no
Introduction of fixed charge	yes	yes	yes	yes	yes	yes
Lifeline tariff applied	no	no	no	yes	yes	yes
Economic cost based tariffs by year 3	no	no	No	no	yes	yes
Economic cost based tariffs by year 3 - Tariffs increased early for viable business in year 1	no	no	No	no	no	yes
Average 2018 energy tariff increase (%)	185.2%	167.1%	7.7%	7.7%	35.3%	49.9%
Average 2018 max demand tariff increase (%)	-30.6%	-49.9%	0.0%	0.0%	-21.0%	0.0%
Standard Domestic 2018/19 (M/kWh)	1.855	1.339	1.428	1.650	1.611	1.609
Average 2019 energy tariff increase (%)	0.0%	0.0%	7.7%	7.7%	33.2%	37.9%
Average 2020 energy tariff increase (%)	0.0%	0.0%	6.8%	20.2%	33.2%	37.8%
Lifeline-Block Domestic Tariff 3 yrs subsidy (M mil)	n/a	n/a	n/a	84.6	74.5	74.4
LEC funding requirement 2018-20 (M mil)	20.0	686.6	671.9	643.1	865.5	657.8

12 Conclusions and Proposed Tariff Trajectory

The financial analysis presented here has demonstrated that tariffs can be set in many ways with LEC still anticipated to achieve financial viability and recovery of allowed revenue. The main driving factors for the tariff decision are:

1. The level of tariff increase customers would be willing to accept / afford; and
2. The availability to raise finance to fund the portion of the network and generation expansion program that the cash flow will not support.

We have reported six scenarios in section 3 from which we draw the following conclusions:

- Adjusting tariffs to cost reflective immediately, results in dramatic changes to customer tariffs
- Including a full return on capital results in tariffs that it may be considered too high for LEC customers (unaffordable for many domestic customers and holding back economic development for commercial customers)
- A cross-subsidised lifeline tariff could be introduced with moderate impact on other customers.
- A smooth transition to a cost reflective average tariff could be achieved with modest tariff changes but this would not correct imbalances between tariff categories.
- A transition over three years to fully cost reflective and including a lifeline tariff, though still excluding returns on capital, was shown to be feasible with important tariff changes that it may be possible to introduce in Lesotho.

The model can be used to evaluate other options and a further analysis of this will be included in the final deliverable 10. Feedback on these options will be sought during workshops and training sessions in Lesotho and will be used to finalise our recommendations.

In particular the recommended significant switch from majority capacity charging to majority energy charging for commercial customers will see large changes to the published tariffs. We can use the model to calculate the impact of these changes on typical customers and the impact will be significant but potentially acceptable as the increase in energy charges will be offset by the decrease in capacity charges. However such a switch from largely capacity to largely energy charging will inevitably lead to major changes in payments due from customers at the extremes. Thus customers with a high demand and low consumption will see significant increases in payments, while customers with modest demand and high consumption will be comparatively better off and may even see a fall in payments.

For this deliverable 7 we recommend the scenario described in section 11.6 – a gradual adjustment over three years to economic tariffs (excluding return on capital) for all tariff categories and including a lifeline tariff from the first year. The increase in tariffs over the three-year period by definition leads to a third-year tariff that is higher than cost-reflective. There is therefore a possibility that tariffs could be reduced somewhat in the first year of the next three-year period. Alternatively the opportunity could be taken to set tariffs in the second three-year period with further modest increases to provide a return on capital.

13 ANNEX A - ADDITIONAL PERFORMANCE DATA FROM LEC

Table 44– Financial indicators

Ratio	2011/12	2012/13	2013/14	2014/15	2015/16
Current Ratio	0.8	0.5	1.1	1.4	1.4
Quick Ratio	0.6	0.4	1.0	1.2	1.3
Debtor Days	37	42	46	34	51
Creditor Days	135	142	85	67	75
Return on Investment	2.09%	-0.16%	4.50%	3.96%	2.78%
Debt to Equity ratio	0.65%	3.56%	3.29%	2.12%	1.76%
Cost-to-Income	94.25%	104.63%	89.04%	86.88%	91.36%
Employee cost/ Total cost	42.66%	43.95%	48.22%	45.66%	46.03%
ROC	5.29%	-0.40%	11.40%	16.82%	12.56%

Source: LEC

14 ANNEX B - INCOME STATEMENT, CASH FLOW AND STATEMENT OF FINANCIAL POSITION OF MODELLED SCENARIOS

14.1 ECONOMIC COST-BASED TARIFFS

Table 45: Anticipated Recovery of LEC revenue requirement for the Economic Tariff Scenario

Required Revenue	2018/19	2019/20	2020/21
Total Revenue Requirement	1198.4	1250.3	1295.5
Anticipated income from Tariffs (Tariff design)	1202.7	1248.0	1293.0
Difference (NPV @pre-tax nominal WACC = 0)	4.2	-2.3	-2.5

Table 46: Projected performance indicators for Economic Cost-Based Tariffs

2015 (Actuals)	Ratios for benchmarking against peers	2016	2017	2018	2019	2020
0.80	Working Ratio	0.81	0.80	0.65	0.64	0.63
0.91	Working Ratio with Depreciation	0.93	0.91	0.74	0.73	0.73
0.91	Working Ratio with Depreciation and Net Interests	0.93	0.92	0.75	0.74	0.74
7.7%	Net Operating Margin	5.2%	6.3%	19.0%	19.8%	19.8%
1.49	Current Ratio	1.14	1.60	0.94	0.88	0.93
35.2	Accounts receivable collection period	32.3	33.1	27.3	29.5	31.6
43.3	Accounts payable disbursement period	99.2	97.4	94.2	91.3	89.1
5.4%	Return on Equity	5.9%	6.5%	14.2%	14.1%	13.7%
5.3%	Return on net Fixed Assets	5.7%	6.4%	13.7%	13.5%	13.2%
1.9%	Debt to Assets	1.8%	1.7%	1.4%	1.2%	1.0%

Table 47: Projected Statement of Comprehensive Income for Economic Cost-Based Tariffs Scenario

Statement of Comprehensive Income	2018 M m	2019 M m	2020 M m
REVENUE			
Energy sales - domestic, GP, street lighting and other	694.4	722.2	750.1
Energy sales - industrial and commercial	334.8	346.2	357.5
Demand charges	206.9	213.8	220.6
Fixed charges - domestic, GP, street lighting	21.9	23.2	24.2
Fixed sales - industrial and commercial	4.8	5.0	5.2
Customer levy	35.2	36.4	37.7
Electrification levy	22.5	23.3	24.2
less VAT included in billings	-59.9	-62.2	-64.4
less VAT included in levies	-2.7	-2.8	-2.9
Connection fees	22.9	21.1	21.1
Miscellaneous other revenue	0.0	0.0	0.0
TOTAL REVENUE	**1,280.7**	**1,326.2**	**1,373.3**
% increase on previous year	36.7%	3.6%	3.5%
Costs			

Power purchased - Muela	-65.7	-72.9	-72.9
Power purchased - Eskom	-397.6	-385.4	-398.0
Power purchased - EDM	-50.5	-53.9	-55.2
Power purchased - IPPs	0.0	0.0	0.0
LEC Generation - O&M	0.0	0.0	-2.1
Licence Fees to LEWA	-33.5	-34.7	-35.9
Electrification levies	-21.4	-22.2	-23.0
TOTAL O&M OVERHEADS	**-568.7**	**-569.1**	**-587.2**
% increase on previous year	16.0%	0.1%	3.2%
Gross profit	**712.1**	**757.1**	**786.1**
Other income			
Total	**0.0**	**0.0**	**0.0**
Administration & General Overheads			
Salaries & wages	-156.1	-161.2	-165.3
Additional Management	0.0	0.0	0.0
Vehicle costs	-8.7	-9.0	-9.2
Insurances	-4.8	-4.9	-5.1
Depreciation	-115.9	-125.8	-134.8
Operating expenditure	-93.8	-96.8	-99.3
Interest Paid	0.0	0.0	0.0
Retirement benefit obligations	-4.6	-4.6	-4.6
TOTAL A&G OVERHEADS	**-383.9**	**-402.3**	**-418.3**
PROFIT/LOSS before finance income and costs	**328.2**	**354.8**	**367.8**
Finance income	0.0	0.0	0.0
Finance costs	-4.3	-4.0	-4.5
PROFIT/LOSS before tax	**323.9**	**350.8**	**363.3**
Exceptional Items	0.0	0.0	0.0
Taxation	-81.0	-87.7	-90.8
PROFIT/LOSS after interest and tax	**242.9**	**263.1**	**272.5**

Table 48: Projected Cashflow statement for Economic Cost-Base Tariffs Scenario

Cash Flow	2018 M m	2019 M m	2020 M m
Opening Cash	**112.9**	**65.4**	**50.0**
Add receipts			
from commercial loans	0.0	10.0	0.0
from capital grants	0.0	10.0	0.0
Domestic, GP, street lighting and other customers	716.2	745.4	774.3
Industrial and commercial customers	535.6	553.7	571.7
Levies from customers	57.7	59.8	61.9
From connection fees	22.9	21.1	21.1
Catch-up payments	0.0	0.0	0.0
Security deposits	1.0	0.8	0.8
Less payments			

For power purchase	-513.7	-512.2	-526.2
LEC Generation - O&M	0.0	0.0	-2.1
Salaries, Wages and Opex	-263.3	-271.9	-278.8
Licence Fees to LEWA	-33.5	-34.7	-35.9
Electrification levy to REU	-21.4	-22.2	-23.0
Tax	-19.6	-81.0	-87.7
VAT	-62.7	-65.0	-67.4
Loan repayments including interest	-8.1	-8.1	-9.6
capital expenditure - new connection (LEC funded)	-28.6	-26.4	-26.4
capital expenditure - customer contribution	-22.9	-21.1	-21.1
capital expenditure - network	-265.7	-232.2	-188.7
capital expenditure - generation	-141.4	-141.4	-162.5
Closing cash	**65.4**	**50.0**	**50.4**

Table 49: Projected Statement of Financial Position for Economic Cost-Based Tariffs Scenario

Statement of Financial Position	2018 M m	2019 M m	2020 M m
ASSETS			
Non-current assets			
Property, plant and equipment	3,175.6	3,470.9	3,734.7
Deferred taxation	76.0	76.0	76.0
Total non-current assets:	**3,251.5**	**3,546.8**	**3,810.7**
Current Assets			
Inventories	28.9	28.9	28.9
Trade debtors and other receivables	95.9	107.2	118.8
Sundry debtors	1.0	1.0	1.0
Others	0.0	0.0	0.0
Cash and cash equivalents	65.4	50.0	50.4
Total current assets	**191.2**	**187.1**	**199.1**
Total assets	**3,442.7**	**3,733.9**	**4,009.8**
CAPITAL AND LIABILITIES			
Equity attributable to equity holder of the company			
Share capital and reserves	0.0	0.0	0.0
Share premium	599.2	599.2	599.2
Capital grant	549.4	559.4	559.4
Loan redemption provision	0.0	0.0	0.0
Revaluation reserve	1,257.2	1,257.2	1,257.2
Retained income	724.8	987.9	1,260.4
Total equity	**3,130.6**	**3,403.7**	**3,676.2**
Non-current Liabilities			
Retirement benefit obligations	67.0	71.6	76.2
Long-term loans	40.9	47.1	42.3
Deferred tax	0.0	0.0	0.0
Total Non-current Liabilities	**107.9**	**118.7**	**118.5**
Current Liabilities			
Creditors and Provisions	69.2	69.2	69.2

Other creditors			
Accruals	24.6	24.6	24.6
Trade and other payables balancing figure			
Taxation	81.0	87.7	90.8
Overdraft (bank credit line)	1.0	1.0	1.0
Security deposits	24.3	25.1	26.0
Current portion of long-term borrowings	4.3	4.0	3.6
Total current liabilities	**204.3**	**211.5**	**215.1**
Total equity and liabilities	**3,442.8**	**3,733.9**	**4,009.9**

14.2 Economic Cost-Based Tariffs – Excluding Return on Capital

Table 50: Anticipated Recovery of LEC revenue requirement for the Economic Tariffs with RoC removed

Required Revenue	2018/19	2019/20	2020/21
Total Revenue Requirement	964.9	1000.7	1033.7
Anticipated income from Tariffs (Tariff design)	963.8	999.9	1035.8
Difference (NPV @pre-tax nominal WACC = 0)	-1.1	-0.7	2.1

Table 51: Projected performance indicators for Economic Cost-Based Tariffs with RoC removed

2015 (Actuals)	Ratios for benchmarking against peers	2016	2017	2018	2019	2020
0.80	Working Ratio	0.81	0.80	0.80	0.78	0.78
0.91	Working Ratio with Depreciation	0.93	0.91	0.91	0.90	0.90
0.91	Working Ratio with Depreciation and Net Interests	0.93	0.92	0.92	0.91	0.92
7.7%	Net Operating Margin	5.2%	6.3%	6.1%	6.5%	5.9%
1.49	Current Ratio	1.14	1.60	1.21	1.26	1.33
35.2	Accounts receivable collection period	32.3	33.1	33.2	35.5	37.7
43.3	Accounts payable disbursement period	99.2	97.4	94.2	91.3	89.1
5.4%	Return on Equity	5.9%	6.5%	6.7%	7.2%	7.2%
5.3%	Return on net Fixed Assets	5.7%	6.4%	6.3%	6.6%	6.4%
1.9%	Debt to Assets	1.8%	1.7%	1.4%	1.2%	1.0%

Table 52: Projected Statement of Comprehensive Income for Economic Cost-Based Tariffs Scenario with RoC removed from revenue requirement

Statement of Comprehensive Income	2018 M m	2019 M m	2020 M m
REVENUE			
Energy sales - domestic, GP, street lighting and other	501.2	521.3	541.4
Energy sales - industrial and commercial	334.8	346.2	357.5
Demand charges	149.4	154.3	159.2
Fixed charges - domestic, GP, street lighting	21.9	23.2	24.2
Fixed sales - industrial and commercial	4.8	5.0	5.2
Customer levy	35.2	36.4	37.7
Electrification levy	22.5	23.3	24.2
less VAT included in billings	-48.0	-49.8	-51.5
less VAT included in levies	-2.7	-2.8	-2.9
Connection fees	22.9	21.1	21.1

Miscellaneous other revenue	0.0	0.0	0.0
TOTAL REVENUE	**1,041.9**	**1,078.2**	**1,116.1**
% increase on previous year	11.2%	3.5%	3.5%
Costs			
Power purchased - Muela	-65.7	-72.9	-72.9
Power purchased - Eskom	-397.6	-385.4	-398.0
Power purchased - EDM	-50.5	-53.9	-55.2
Power purchased - IPPs	0.0	0.0	0.0
LEC Generation - O&M	0.0	0.0	-2.1
Licence Fees to LEWA	-33.5	-34.7	-35.9
Electrification levies	-21.4	-22.2	-23.0
TOTAL O&M OVERHEADS	**-568.7**	**-569.1**	**-587.2**
% increase on previous year	16.0%	0.1%	3.2%
Gross profit	**473.2**	**509.1**	**528.9**
Other income			
Total	0.0	0.0	0.0
Administration & General Overheads			
Salaries & wages	-156.1	-161.2	-165.3
Additional Management	0.0	0.0	0.0
Vehicle costs	-8.7	-9.0	-9.2
Insurances	-4.8	-4.9	-5.1
Depreciation	-115.9	-125.8	-134.8
Operating expenditure	-93.8	-96.8	-99.3
Interest Paid	0.0	0.0	0.0
Retirement benefit obligations	-4.6	-4.6	-4.6
TOTAL A&G OVERHEADS	**-383.9**	**-402.3**	**-418.3**
PROFIT/LOSS before finance income and costs	**89.4**	**106.8**	**110.6**
Finance income	0.0	0.0	0.0
Finance costs	-4.3	-13.4	-22.6
PROFIT/LOSS before tax	**85.0**	**93.3**	**88.0**
Exceptional Items	0.0	0.0	0.0
Taxation	-21.3	-23.3	-22.0
PROFIT/LOSS after interest and tax	**63.8**	**70.0**	**66.0**
Dividends	0.0	0.0	0.0
Comprehensive income for the year	**63.8**	**70.0**	**66.0**

Table 53: Projected Cashflow statement for Economic Cost-Base Tariffs with RoC removed from Revenue Requirement Scenario

Cash Flow	2018 M m	2019 M m	2020 M m
Opening Cash	**112.9**	**50.0**	**50.0**
Add receipts			
from commercial loans	111.1	119.7	112.4
from capital grants	111.1	119.7	112.4

Cash Flow	2018 M m	2019 M m	2020 M m
Domestic, GP, street lighting and other customers	523.0	544.5	565.6
Industrial and commercial customers	479.2	495.4	511.5
Levies from customers	57.7	59.8	61.9
From connection fees	22.9	21.1	21.1
Catch-up payments	0.0	0.0	0.0
Security deposits	1.0	0.8	0.8
Less payments			
For power purchase	-513.7	-512.2	-526.2
LEC Generation - O&M	0.0	0.0	-2.1
Salaries, Wages and Opex	-263.3	-271.9	-278.8
Licence Fees to LEWA	-33.5	-34.7	-35.9
Electrification levy to REU	-21.4	-22.2	-23.0
Tax	-19.6	-21.3	-23.3
VAT	-50.7	-52.6	-54.5
Loan repayments including interest	-8.1	-25.0	-43.3
capital expenditure - new connection (LEC funded)	-28.6	-26.4	-26.4
capital expenditure - customer contribution	-22.9	-21.1	-21.1
capital expenditure - network	-265.7	-232.2	-188.7
capital expenditure - generation	-141.4	-141.4	-162.5
Closing cash	**50.0**	**50.0**	**50.0**

Table 54: Projected Statement of Financial Position for Economic Cost-Based Tariffs Scenario with RoC removed from revenue requirement

Statement of Financial Position	2018 M m	2019 M m	2020 M m
ASSETS			
Non-current assets			
Property, plant and equipment	3,175.6	3,470.9	3,734.7
Deferred taxation	76.0	76.0	76.0
Total non-current assets:	**3,251.5**	**3,546.8**	**3,810.7**
Current Assets			
Inventories	28.9	28.9	28.9
Trade debtors and other receivables	94.7	104.8	115.3
Sundry debtors	1.0	1.0	1.0
Others	0.0	0.0	0.0
Cash and cash equivalents	50.0	50.0	50.0
Total current assets	**174.6**	**184.7**	**195.2**
Total assets	**3,426.2**	**3,731.6**	**4,005.9**
CAPITAL AND LIABILITIES			
Equity attributable to equity holder of the company			
Share capital and reserves	0.0	0.0	0.0
Share premium	599.2	599.2	599.2
Capital grant	660.5	780.3	892.7
Loan redemption provision	0.0	0.0	0.0
Revaluation reserve	1,257.2	1,257.2	1,257.2

Statement of Financial Position	2018 M m	2019 M m	2020 M m
Retained income	545.7	615.7	681.7
Total equity	**3,062.6**	**3,252.4**	**3,430.8**
Non-current Liabilities			
Retirement benefit obligations	67.0	71.6	76.2
Long-term loans	152.0	260.5	352.6
Deferred tax	0.0	0.0	0.0
Total Non-current Liabilities	**219.0**	**332.1**	**428.8**
Current Liabilities			
Creditors and Provisions	69.2	69.2	69.2
Other creditors			
Accruals	24.6	24.6	24.6
Trade and other payables balancing figure			
Taxation	21.3	23.3	22.0
Overdraft (bank credit line)	1.0	1.0	1.0
Security deposits	24.3	25.1	26.0
Current portion of long-term borrowings	4.3	4.0	3.6
Total current liabilities	**144.6**	**147.1**	**146.3**
Total equity and liabilities	**3,426.2**	**3,731.6**	**4,005.9**

14.3 Smoothed Energy Tariff Trajectory

Table 55: Anticipated Recovery of LEC revenue requirement for Smoothed Increases

Required Revenue	2018/19	2019/20	2020/21
Total Revenue Requirement	964.9	1000.7	1033.7
Anticipated income from Tariffs (Tariff design)	937.6	992.7	1074.7
Difference (NPV @pre-tax nominal WACC = 0)	-27.4	-8.0	41.0

Table 56: Projected performance indicators for Smoothed Tariffs

2015 (Actuals)	Ratios for benchmarking against peers	2016	2017	2018	2019	2020
0.80	Working Ratio	0.81	0.80	0.82	0.79	0.75
0.91	Working Ratio with Depreciation	0.93	0.91	0.94	0.91	0.87
0.91	Working Ratio with Depreciation and Net Interests	0.93	0.92	0.94	0.92	0.89
7.7%	Net Operating Margin	5.2%	6.3%	4.3%	6.0%	8.2%
1.49	Current Ratio	1.14	1.60	1.25	1.25	1.22
35.2	Accounts receivable collection period	32.3	33.1	33.5	34.7	35.0
43.3	Accounts payable disbursement period	99.2	97.4	94.2	91.3	89.1
5.4%	Return on Equity	5.9%	6.5%	5.9%	7.0%	8.3%
5.3%	Return on net Fixed Assets	5.7%	6.4%	5.5%	6.4%	7.5%
1.9%	Debt to Assets	1.8%	1.7%	1.4%	1.2%	1.0%

Table 57: Projected Statement of Comprehensive Income for Smoother Tariffs Scenario

Statement of Comprehensive Income	2018 M m	2019 M m	2020 M m

REVENUE			
Energy sales - domestic, GP, street lighting and other	554.2	587.6	651.3
Energy sales - industrial and commercial	92.4	105.1	115.9
Demand charges	311.1	321.5	331.9
Fixed charges - domestic, GP, street lighting	21.9	23.2	24.2
Fixed sales - industrial and commercial	4.8	5.0	5.2
Customer levy	35.2	36.4	37.7
Electrification levy	22.5	23.3	24.2
less VAT included in billings	-46.6	-49.4	-53.5
less VAT included in levies	-2.7	-2.8	-2.9
Connection fees	22.9	21.1	21.1
Miscellaneous other revenue	0.0	0.0	0.0
TOTAL REVENUE	**1,015.6**	**1,071.0**	**1,155.0**
% increase on previous year	8.4%	5.4%	7.9%
Costs			
Power purchased - Muela	-65.7	-72.9	-72.9
Power purchased - Eskom	-397.6	-385.4	-398.0
Power purchased - EDM	-50.5	-53.9	-55.2
Power purchased - IPPs	0.0	0.0	0.0
LEC Generation - O&M	0.0	0.0	-2.1
Licence Fees to LEWA	-33.5	-34.7	-35.9
Electrification levies	-21.4	-22.2	-23.0
TOTAL O&M OVERHEADS	**-568.7**	**-569.1**	**-587.2**
% increase on previous year	*16.0%*	*0.1%*	*3.2%*
Gross profit	**447.0**	**501.8**	**567.8**
Other income			
Total	**0.0**	**0.0**	**0.0**
Administration & General Overheads			
Salaries & wages	-156.1	-161.2	-165.3
Additional Management	0.0	0.0	0.0
Vehicle costs	-8.7	-9.0	-9.2
Insurances	-4.8	-4.9	-5.1
Depreciation	-115.9	-125.8	-134.8
Operating expenditure	-93.8	-96.8	-99.3
Interest Paid	0.0	0.0	0.0
Retirement benefit obligations	-4.6	-4.6	-4.6
TOTAL A&G OVERHEADS	**-383.9**	**-402.3**	**-418.3**
PROFIT/LOSS before finance income and costs	**63.1**	**99.5**	**149.6**
Finance income	0.0	0.0	0.0
Finance costs	-4.3	-14.5	-23.6
PROFIT/LOSS before tax	**58.7**	**85.0**	**125.9**
Exceptional Items	0.0	0.0	0.0
Taxation	-14.7	-21.3	-31.5
PROFIT/LOSS after interest and tax	**44.1**	**63.8**	**94.5**
Dividends	0.0	0.0	0.0
Comprehensive income for the year	**44.1**	**63.8**	**94.5**

Table 58: Projected Cashflow statement for Smoothed Tariffs Scenario

Cash Flow	2018 M m	2019 M m	2020 M m
Opening Cash	**112.9**	**50.0**	**50.0**
Add receipts			
from commercial loans	123.5	120.3	92.2
from capital grants	123.5	120.3	92.2
Domestic, GP, street lighting and other customers	576.1	610.7	675.5
Industrial and commercial customers	400.2	422.9	443.9
Levies from customers	57.7	59.8	61.9
From connection fees	22.9	21.1	21.1
Catch-up payments	0.0	0.0	0.0
Security deposits	1.0	0.8	0.8
Less payments			
For power purchase	-513.7	-512.2	-526.2
LEC Generation - O&M	0.0	0.0	-2.1
Salaries, Wages and Opex	-263.3	-271.9	-278.8
Licence Fees to LEWA	-33.5	-34.7	-35.9
Electrification levy to REU	-21.4	-22.2	-23.0
Tax	-19.6	-14.7	-21.3
VAT	-49.4	-52.2	-56.4
Loan repayments including interest	-8.1	-26.9	-45.3
capital expenditure - new connection (LEC funded)	-28.6	-26.4	-26.4
capital expenditure - customer contribution	-22.9	-21.1	-21.1
capital expenditure - network	-265.7	-232.2	-188.7
capital expenditure - generation	-141.4	-141.4	-162.5
Closing cash	**50.0**	**50.0**	**50.0**

Table 59: Projected Statement of Financial Position for Smoother Tariffs Scenario

Statement of Financial Position	2018 M m	2019 M m	2020 M m
ASSETS			
Non-current assets			
Property, plant and equipment	3,175.6	3,470.9	3,734.7
Deferred taxation	76.0	76.0	76.0
Total non-current assets:	**3,251.5**	**3,546.8**	**3,810.7**
Current Assets			
Inventories	28.9	28.9	28.9
Trade debtors and other receivables	93.1	101.7	110.8
Sundry debtors	1.0	1.0	1.0
Others	0.0	0.0	0.0
Cash and cash equivalents	50.0	50.0	50.0
Total current assets	**173.0**	**181.6**	**190.7**
Total assets	**3,424.5**	**3,728.5**	**4,001.4**
CAPITAL AND LIABILITIES			

Statement of Financial Position	2018 M m	2019 M m	2020 M m
Equity attributable to equity holder of the company			
Share capital and reserves	0.0	0.0	0.0
Share premium	599.2	599.2	599.2
Capital grant	672.9	793.2	885.4
Loan redemption provision	0.0	0.0	0.0
Revaluation reserve	1,257.2	1,257.2	1,257.2
Retained income	526.0	589.8	684.2
Total equity	**3,055.3**	**3,239.3**	**3,426.0**
Non-current Liabilities			
Retirement benefit obligations	67.0	71.6	76.2
Long-term loans	164.4	272.5	343.5
Deferred tax	0.0	0.0	0.0
Total Non-current Liabilities	**231.3**	**344.1**	**419.7**
Current Liabilities			
Creditors and Provisions	69.2	69.2	69.2
Other creditors			
Accruals	24.6	24.6	24.6
Trade and other payables balancing figure			
Taxation	14.7	21.3	31.5
Overdraft (bank credit line)	1.0	1.0	1.0
Security deposits	24.3	25.1	26.0
Current portion of long-term borrowings	4.3	4.0	3.6
Total current liabilities	**138.0**	**145.1**	**155.8**
Total equity and liabilities	**3,424.6**	**3,728.5**	**4,001.4**

14.4 Smoother Energy Tariff Trajectory – Including Lifeline Tariffs

Table 60: Anticipated Recovery of LEC revenue requirement for Smoothed Increases with Lifeline

Required Revenue	2018/19	2019/20	2020/21
Total Revenue Requirement	964.9	1000.7	1033.7
Anticipated income from Tariffs (Tariff design)	912.0	966.5	1133.4
Difference (NPV @pre-tax nominal WACC = 0)	-53.0	-34.2	99.7

Table 61: Projected performance indicators for Smoothed Tariffs

2015 (Actuals)	Ratios for benchmarking against peers	2016	2017	2018	2019	2020
0.80	Working Ratio	0.81	0.80	0.84	0.81	0.71
0.91	Working Ratio with Depreciation	0.93	0.91	0.96	0.93	0.82
0.91	Working Ratio with Depreciation and Net Interests	0.93	0.92	0.96	0.94	0.85
7.7%	Net Operating Margin	5.2%	6.3%	2.9%	4.5%	11.6%
1.49	Current Ratio	1.14	1.60	1.30	1.30	1.11
35.2	Accounts receivable collection period	32.3	33.1	34.1	35.4	33.3
43.3	Accounts payable disbursement period	99.2	97.4	94.2	91.3	89.1
5.4%	Return on Equity	5.9%	6.5%	5.2%	6.3%	10.2%
5.3%	Return on net Fixed Assets	5.7%	6.4%	4.9%	5.8%	9.1%

2015 (Actuals)	Ratios for benchmarking against peers	2016	2017	2018	2019	2020
1.9%	Debt to Assets	1.8%	1.7%	1.4%	1.2%	1.0%

Table 62: Projected Statement of Comprehensive Income for Smoother Tariffs with Lifeline Scenario

Statement of Comprehensive Income	2018 M m	2019 M m	2020 M m
REVENUE			
Energy sales - domestic, GP, street lighting and other	533.0	565.7	704.0
Energy sales - industrial and commercial	92.4	105.1	130.4
Demand charges	311.1	321.5	331.9
Fixed charges - domestic, GP, street lighting	21.9	23.2	24.2
Fixed sales - industrial and commercial	4.8	5.0	5.2
Customer levy	35.2	36.4	37.7
Electrification levy	22.5	23.3	24.2
less VAT included in billings	*-45.6*	*-48.4*	*-56.7*
less VAT included in levies	*-2.7*	*-2.8*	*-2.9*
Connection fees	22.9	21.1	21.1
Miscellaneous other revenue	0.0	0.0	0.0
TOTAL REVENUE	**995.4**	**1,050.1**	**1,219.1**
% increase on previous year	*6.3%*	*5.5%*	*16.1%*
Costs			
Power purchased - Muela	-65.7	-72.9	-72.9
Power purchased - Eskom	-397.6	-385.4	-398.0
Power purchased - EDM	-50.5	-53.9	-55.2
Power purchased - IPPs	0.0	0.0	0.0
LEC Generation - O&M	0.0	0.0	-2.1
Licence Fees to LEWA	-33.5	-34.7	-35.9
Electrification levies	-21.4	-22.2	-23.0
TOTAL O&M OVERHEADS	**-568.7**	**-569.1**	**-587.2**
% increase on previous year	*16.0%*	*0.1%*	*3.2%*
Gross profit	**426.7**	**481.0**	**631.9**
Other income			
Total	**0.0**	**0.0**	**0.0**
Administration & General Overheads			
Salaries & wages	-156.1	-161.2	-165.3
Additional Management	0.0	0.0	0.0
Vehicle costs	-8.7	-9.0	-9.2
Insurances	-4.8	-4.9	-5.1
Depreciation	-115.9	-125.8	-134.8
Operating expenditure	-93.8	-96.8	-99.3
Interest Paid	0.0	0.0	0.0
Retirement benefit obligations	-4.6	-4.6	-4.6
TOTAL A&G OVERHEADS	**-383.9**	**-402.3**	**-418.3**
PROFIT/LOSS before finance income and costs	**42.9**	**78.7**	**213.6**
Finance income	0.0	0.0	0.0

Statement of Comprehensive Income	2018 M m	2019 M m	2020 M m
Finance costs	-4.3	-15.3	-25.2
PROFIT/LOSS before tax	**38.5**	**63.3**	**188.5**
Exceptional Items	0.0	0.0	0.0
Taxation	-9.6	-15.8	-47.1
PROFIT/LOSS after interest and tax	**28.9**	**47.5**	**141.4**
Dividends	0.0	0.0	0.0
Comprehensive income for the year	**28.9**	**47.5**	**141.4**

Table 63: Projected Cashflow statement for Smoothed Tariffs with lifeline Scenario

Cash Flow	2018 M m	2019 M m	2020 M m
Opening Cash	**112.9**	**50.0**	**50.0**
Add receipts			
from commercial loans	133.6	129.0	59.0
from capital grants	133.6	129.0	59.0
Domestic, GP, street lighting and other customers	554.9	588.8	728.2
Industrial and commercial customers	400.2	422.9	458.1
Levies from customers	57.7	59.8	61.9
From connection fees	22.9	21.1	21.1
Catch-up payments	0.0	0.0	0.0
Security deposits	1.0	0.8	0.8
Less payments			
For power purchase	-513.7	-512.2	-526.2
LEC Generation - O&M	0.0	0.0	-2.1
Salaries, Wages and Opex	-263.3	-271.9	-278.8
Licence Fees to LEWA	-33.5	-34.7	-35.9
Electrification levy to REU	-21.4	-22.2	-23.0
Tax	-19.6	-9.6	-15.8
VAT	-48.4	-51.2	-59.6
Loan repayments including interest	-8.1	-28.5	-48.1
capital expenditure - new connection (LEC funded)	-28.6	-26.4	-26.4
capital expenditure - customer contribution	-22.9	-21.1	-21.1
capital expenditure - network	-265.7	-232.2	-188.7
capital expenditure - generation	-141.4	-141.4	-162.5
Closing cash	**50.0**	**50.0**	**50.0**

Table 64: Projected Statement of Financial Position for Smoother Tariffs with Lifeline Scenario

Statement of Financial Position	2018 M m	2019 M m	2020 M m
ASSETS			
Non-current assets			
Property, plant and equipment	3,175.6	3,470.9	3,734.7
Deferred taxation	76.0	76.0	76.0
Total non-current assets:	**3,251.5**	**3,546.8**	**3,810.7**

Statement of Financial Position	2018 M m	2019 M m	2020 M m
Current Assets			
Inventories	28.9	28.9	28.9
Trade debtors and other receivables	93.1	101.7	111.1
Sundry debtors	1.0	1.0	1.0
Others	0.0	0.0	0.0
Cash and cash equivalents	50.0	50.0	50.0
Total current assets	**173.0**	**181.6**	**191.0**
Total assets	**3,424.5**	**3,728.5**	**4,001.7**
CAPITAL AND LIABILITIES			
Equity attributable to equity holder of the company			
Share capital and reserves	0.0	0.0	0.0
Share premium	599.2	599.2	599.2
Capital grant	683.0	811.9	871.0
Loan redemption provision	0.0	0.0	0.0
Revaluation reserve	1,257.2	1,257.2	1,257.2
Retained income	510.8	558.3	699.7
Total equity	**3,050.2**	**3,226.7**	**3,427.1**
Non-current Liabilities			
Retirement benefit obligations	67.0	71.6	76.2
Long-term loans	174.5	290.6	327.1
Deferred tax	0.0	0.0	0.0
Total Non-current Liabilities	**241.4**	**362.2**	**403.3**
Current Liabilities			
Creditors and Provisions	69.2	69.2	69.2
Other creditors			
Accruals	24.6	24.6	24.6
Trade and other payables balancing figure			
Taxation	9.6	15.8	47.1
Overdraft (bank credit line)	1.0	1.0	1.0
Security deposits	24.3	25.1	26.0
Current portion of long-term borrowings	4.3	4.0	3.6
Total current liabilities	**132.9**	**139.6**	**171.4**
Total equity and liabilities	**3,424.6**	**3,728.5**	**4,001.7**

14.5 Gradual Changes By Tariff Category and Removal of Cross-Subsidy – Including Lifeline Tariff

Table 65: Projected performance indicators for Gradual Change Scenario

2015 (Actuals)	Ratios for benchmarking against peers	2016	2017	2018	2019	2020
0.80	Working Ratio	0.81	0.80	0.89	0.86	0.79
0.91	Working Ratio with Depreciation	0.93	0.91	1.01	0.98	0.92

2015 (Actuals)	Ratios for benchmarking against peers	2016	2017	2018	2019	2020
0.91	Working Ratio with Depreciation and Net Interests	0.93	0.92	1.01	1.00	0.94
7.7%	Net Operating Margin	5.2%	6.3%	-1.4%	0.0%	4.2%
1.49	Current Ratio	1.14	1.60	1.40	1.46	1.37
35.2	Accounts receivable collection period	32.3	33.1	35.8	37.3	37.1
43.3	Accounts payable disbursement period	99.2	97.4	94.2	91.3	89.1
5.4%	Return on Equity	5.9%	6.5%	3.5%	4.5%	6.7%
5.3%	Return on net Fixed Assets	5.7%	6.4%	3.3%	4.0%	5.9%
1.9%	Debt to Assets	1.8%	1.7%	1.4%	1.2%	1.0%

Table 66: Projected Statement of Comprehensive Income for Gradual Changes Tariffs Scenario

Statement of Comprehensive Income	2018 M m	2019 M m	2020 M m
REVENUE			
Energy sales - domestic, GP, street lighting and other	507.2	513.7	521.1
Energy sales - industrial and commercial	133.0	218.0	357.1
Demand charges	242.4	196.1	159.2
Fixed charges - domestic, GP, street lighting and other	21.9	23.2	24.2
Fixed sales - industrial and commercial	4.8	5.0	5.2
Customer levy	35.2	36.4	37.7
Electrification levy	22.5	23.3	24.2
less VAT included in billings	*-43.1*	*-45.3*	*-50.6*
less VAT included in levies	*-2.7*	*-2.8*	*-2.9*
Connection fees	22.9	21.1	21.1
Miscellaneous other revenue	0.0	0.0	0.0
TOTAL REVENUE	**944.0**	**988.7**	**1,096.3**
% increase on previous year	*0.8%*	*4.7%*	*10.9%*
Costs			
Power purchased - Muela	-65.7	-72.9	-72.9
Power purchased - Eskom	-397.6	-385.4	-398.0
Power purchased - EDM	-50.5	-53.9	-55.2
Power purchased - IPPs	0.0	0.0	0.0
LEC Generation - O&M	0.0	0.0	-2.1
Licence Fees to LEWA	-33.5	-34.7	-35.9
Electrification levies	-21.4	-22.2	-23.0
TOTAL O&M OVERHEADS	**-568.7**	**-569.1**	**-587.2**
% increase on previous year	*16.0%*	*0.1%*	*3.2%*
Gross profit	**375.3**	**419.6**	**509.1**
Other income			
Total	**0.0**	**0.0**	**0.0**
Administration & General Overheads			
Salaries & wages	-156.1	-161.2	-165.3
Additional Management	0.0	0.0	0.0
Vehicle costs	-8.7	-9.0	-9.2
Insurances	-4.8	-4.9	-5.1
Depreciation	-115.9	-125.8	-134.8
Operating expenditure	-93.8	-96.8	-99.3

Statement of Comprehensive Income	2018 M m	2019 M m	2020 M m
Interest Paid	0.0	0.0	0.0
Retirement benefit obligations	-4.6	-4.6	-4.6
TOTAL A&G OVERHEADS	**-383.9**	**-402.3**	**-418.3**
PROFIT/LOSS before finance income and costs	**-8.5**	**17.3**	**90.8**
Finance income	0.0	0.0	0.0
Finance costs	-4.3	-17.5	-29.5
PROFIT/LOSS before tax	**-12.9**	**-0.2**	**61.3**
Exceptional Items	0.0	0.0	0.0
Taxation	0.0	0.0	-15.3
PROFIT/LOSS after interest and tax	**-12.9**	**-0.2**	**46.0**
Dividends	0.0	0.0	0.0
Comprehensive income for the year	**-12.9**	**-0.2**	**46.0**

Table 67: Projected Cashflow statement for Gradual Changes Tariff Scenario

Cash Flow	2018 M m	2019 M m	2020 M m
Opening Cash	**112.9**	**50.0**	**50.0**
Add receipts			
from commercial loans	159.0	156.6	117.1
from capital grants	159.0	156.6	117.1
Domestic, GP, street lighting and other customers	529.0	536.9	545.3
Industrial and commercial customers	372.6	410.7	511.1
Levies from customers	57.7	59.8	61.9
From connection fees	22.9	21.1	21.1
Catch-up payments	0.0	0.0	0.0
Security deposits	1.0	0.8	0.8
Less payments			
For power purchase	-513.7	-512.2	-526.2
LEC Generation - O&M	0.0	0.0	-2.1
Salaries, Wages and Opex	-263.3	-271.9	-278.8
Licence Fees to LEWA	-33.5	-34.7	-35.9
Electrification levy to REU	-21.4	-22.2	-23.0
Tax	-19.6	0.0	0.0
VAT	-45.8	-48.1	-53.5
Loan repayments including interest	-8.1	-32.3	-56.2
capital expenditure - new connection (LEC funded)	-28.6	-26.4	-26.4
capital expenditure - customer contribution	-22.9	-21.1	-21.1
capital expenditure - network	-265.7	-232.2	-188.7
capital expenditure - generation	-141.4	-141.4	-162.5
Closing cash	**50.0**	**50.0**	**50.0**

Table 68: Projected Statement of Financial Position for Gradual Changes Tariffs Scenario

Statement of Financial Position	2018 M m	2019 M m	2020 M m
ASSETS			
Non-current assets			
Property, plant and equipment	3,175.6	3,470.9	3,734.7
Deferred taxation	76.0	76.0	76.0
Total non-current assets:	**3,251.5**	**3,546.8**	**3,810.7**
Current Assets			
Inventories	28.9	28.9	28.9
Trade debtors and other receivables	92.5	100.9	111.4
Sundry debtors	1.0	1.0	1.0
Others	0.0	0.0	0.0
Cash and cash equivalents	50.0	50.0	50.0
Total current assets	**172.4**	**180.8**	**191.3**
Total assets	**3,424.0**	**3,727.7**	**4,001.9**
CAPITAL AND LIABILITIES			
Equity attributable to equity holder of the company			
Share capital and reserves	0.0	0.0	0.0
Share premium	599.2	599.2	599.2
Capital grant	708.4	865.0	982.1
Loan redemption provision	0.0	0.0	0.0
Revaluation reserve	1,257.2	1,257.2	1,257.2
Retained income	469.0	468.8	514.8
Total equity	**3,033.9**	**3,190.3**	**3,353.4**
Non-current Liabilities			
Retirement benefit obligations	67.0	71.6	76.2
Long-term loans	199.9	342.0	432.8
Deferred tax	0.0	0.0	0.0
Total Non-current Liabilities	**266.9**	**413.6**	**509.0**
Current Liabilities			
Creditors and Provisions	69.2	69.2	69.2
Other creditors			
Accruals	24.6	24.6	24.6
Trade and other payables balancing figure			
Taxation	0.0	0.0	15.3
Overdraft (bank credit line)	1.0	1.0	1.0
Security deposits	24.3	25.1	26.0
Current portion of long-term borrowings	4.3	4.0	3.6
Total current liabilities	**123.3**	**123.8**	**139.6**
Total equity and liabilities	**3,424.0**	**3,727.7**	**4,002.0**

14.6 Gradual Changes and Removal of Cross Subsidy to Ensure Revenue Recovery

Table 69: Anticipated Recovery of LEC revenue requirement for Gradual Change to ensure Revenue Recovery Scenario

Required Revenue	2018/19	2019/20	2020/21
Total Revenue Requirement	964.9	1000.7	1033.7
Anticipated income from Tariffs (Tariff design)	940.1	967.6	1099.0
Difference (NPV @pre-tax nominal WACC = 0)	-24.8	-33.1	65.3

Table 70: Projected performance indicators for Gradual Change to ensure Revenue Recovery Scenario

2015 (Actuals)	Ratios for benchmarking against peers	2016	2017	2018	2019	2020
0.80	Working Ratio	0.81	0.80	0.82	0.80	0.73
0.91	Working Ratio with Depreciation	0.93	0.91	0.93	0.92	0.85
0.91	Working Ratio with Depreciation and Net Interests	0.93	0.92	0.93	0.94	0.87
7.7%	Net Operating Margin	5.2%	6.3%	4.9%	4.7%	9.8%
1.49	Current Ratio	1.14	1.60	1.24	1.31	1.21
35.2	Accounts receivable collection period	32.3	33.1	33.6	36.2	35.9
43.3	Accounts payable disbursement period	99.2	97.4	94.2	91.3	89.1
5.4%	Return on Equity	5.9%	6.5%	6.1%	6.3%	9.1%
5.3%	Return on net Fixed Assets	5.7%	6.4%	5.7%	5.8%	8.2%
1.9%	Debt to Assets	1.8%	1.7%	1.4%	1.2%	1.0%

Table 71: Projected Statement of Comprehensive Income for Gradual Changes Tariffs to ensure revenue recovery scenario

Statement of Comprehensive Income	2018 M m	2019 M m	2020 M m
REVENUE			
Energy sales - domestic, GP, street lighting and other	500.3	505.6	511.9
Energy sales - industrial and commercial	154.6	266.5	459.0
Demand charges	311.1	221.4	159.2
Fixed charges - domestic, GP, street lighting and other	21.9	23.2	24.2
Fixed sales - industrial and commercial	4.8	5.0	5.2
Customer levy	35.2	36.4	37.7
Electrification levy	22.5	23.3	24.2
less VAT included in billings	*-47.0*	*-48.4*	*-55.0*
less VAT included in levies	*-2.7*	*-2.8*	*-2.9*
Connection fees	22.9	21.1	21.1
Miscellaneous other revenue	0.0	0.0	0.0
TOTAL REVENUE	**1,023.5**	**1,051.2**	**1,184.7**
% increase on previous year	*9.3%*	*2.7%*	*12.7%*
Costs			
Power purchased - Muela	-65.7	-72.9	-72.9
Power purchased - Eskom	-397.6	-385.4	-398.0
Power purchased - EDM	-50.5	-53.9	-55.2
Power purchased - IPPs	0.0	0.0	0.0

Statement of Comprehensive Income	2018 M m	2019 M m	2020 M m
LEC Generation - O&M	0.0	0.0	-2.1
Licence Fees to LEWA	-33.5	-34.7	-35.9
Electrification levies	-21.4	-22.2	-23.0
TOTAL O&M OVERHEADS	**-568.7**	**-569.1**	**-587.2**
% increase on previous year	*16.0%*	*0.1%*	*3.2%*
Gross profit	**454.9**	**482.1**	**597.4**
Other income			
Total	**0.0**	**0.0**	**0.0**
Administration & General Overheads			
Salaries & wages	-156.1	-161.2	-165.3
Additional Management	0.0	0.0	0.0
Vehicle costs	-8.7	-9.0	-9.2
Insurances	-4.8	-4.9	-5.1
Depreciation	-115.9	-125.8	-134.8
Operating expenditure	-93.8	-96.8	-99.3
Interest Paid	0.0	0.0	0.0
Retirement benefit obligations	-4.6	-4.6	-4.6
TOTAL A&G OVERHEADS	**-383.9**	**-402.3**	**-418.3**
PROFIT/LOSS before finance income and costs	**71.0**	**79.8**	**179.2**
Finance income	0.0	0.0	0.0
Finance costs	-4.3	-14.2	-24.3
PROFIT/LOSS before tax	**66.7**	**65.6**	**154.9**
Exceptional Items	0.0	0.0	0.0
Taxation	-16.7	-16.4	-38.7
PROFIT/LOSS after interest and tax	**50.0**	**49.2**	**116.1**
Dividends	0.0	0.0	0.0
Comprehensive income for the year	**50.0**	**49.2**	**116.1**

Table 72: Projected Cashflow statement for Gradual Changes to ensure revenue recovery Scenario

Cash Flow	2018 M m	2019 M m	2020 M m
Opening Cash	**112.9**	**50.0**	**50.0**
Add receipts			
from commercial loans	120.1	131.5	77.3
from capital grants	120.1	131.5	77.3
Domestic, GP, street lighting and other customers	522.2	528.7	536.1
Industrial and commercial customers	461.1	483.0	611.0
Levies from customers	57.7	59.8	61.9
From connection fees	22.9	21.1	21.1
Catch-up payments	0.0	0.0	0.0
Security deposits	1.0	0.8	0.8
Less payments			

Cash Flow	2018 M m	2019 M m	2020 M m
For power purchase	-513.7	-512.2	-526.2
LEC Generation - O&M	0.0	0.0	-2.1
Salaries, Wages and Opex	-263.3	-271.9	-278.8
Licence Fees to LEWA	-33.5	-34.7	-35.9
Electrification levy to REU	-21.4	-22.2	-23.0
Tax	-19.6	-16.7	-16.4
VAT	-49.8	-51.3	-57.9
Loan repayments including interest	-8.1	-26.4	-46.5
capital expenditure - new connection (LEC funded)	-28.6	-26.4	-26.4
capital expenditure - customer contribution	-22.9	-21.1	-21.1
capital expenditure - network	-265.7	-232.2	-188.7
capital expenditure - generation	-141.4	-141.4	-162.5
Closing cash	**50.0**	**50.0**	**50.0**

Table 73: Projected Statement of Financial Position for Gradual Changes Tariffs to ensure revenue recovery scenario

Statement of Financial Position	2018 M m	2019 M m	2020 M m
ASSETS			
Non-current assets			
Property, plant and equipment	3,175.6	3,470.9	3,734.7
Deferred taxation	76.0	76.0	76.0
Total non-current assets:	**3,251.5**	**3,546.8**	**3,810.7**
Current Assets			
Inventories	28.9	28.9	28.9
Trade debtors and other receivables	94.4	104.2	116.7
Sundry debtors	1.0	1.0	1.0
Others	0.0	0.0	0.0
Cash and cash equivalents	50.0	50.0	50.0
Total current assets	**174.2**	**184.1**	**196.6**
Total assets	**3,425.8**	**3,730.9**	**4,007.3**
CAPITAL AND LIABILITIES			
Equity attributable to equity holder of the company			
Share capital and reserves	0.0	0.0	0.0
Share premium	599.2	599.2	599.2
Capital grant	669.5	801.0	878.3
Loan redemption provision	0.0	0.0	0.0
Revaluation reserve	1,257.2	1,257.2	1,257.2
Retained income	531.9	581.1	697.3
Total equity	**3,057.9**	**3,238.6**	**3,432.0**
Non-current Liabilities			
Retirement benefit obligations	67.0	71.6	76.2
Long-term loans	161.0	280.6	336.1
Deferred tax	0.0	0.0	0.0
Total Non-current Liabilities	**228.0**	**352.2**	**412.3**

Statement of Financial Position	2018 M m	2019 M m	2020 M m
Current Liabilities			
Creditors and Provisions	69.2	69.2	69.2
Other creditors			
Accruals	24.6	24.6	24.6
Trade and other payables balancing figure			
Taxation	16.7	16.4	38.7
Overdraft (bank credit line)	1.0	1.0	1.0
Security deposits	24.3	25.1	26.0
Current portion of long-term borrowings	4.3	4.0	3.6
Total current liabilities	**140.0**	**140.2**	**163.0**
Total equity and liabilities	**3,425.8**	**3,731.0**	**4,007.3**

Electricity Supply Cost of Service Study – LEWA Lesotho

Transmission Wheeling Charges – Deliverable 8

Support Provided by African Development Bank

Prepared for: LEWA

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Figures and Tables

LIST OF ACRONYMS

CAPEX	Capital Expenditures
CoSS	Cost of Service Study
HV	High Voltage
LEC	Lesotho Electricity Corporation
LEWA	Lesotho Energy and Water Authority
LV	Low Voltage
RAB	Regulatory Asset Base
SAPP	South African Power Pool
T&D	Transmission and Distribution
TUoS	Transmission Use of System

1 INTRODUCTION

This report is the eighth deliverable of the Electricity Cost of Service Study (COSS) being carried out by the MRC Group for LEWA supported by the African Development Bank. The objective of this report is to define a suitable methodology for wheeling charges computation in Lesotho, and its implications on third party transmission access, with particular consideration of the regional SAPP context.

We explore mechanisms for third party access that will be suitable in the immediate trading arrangements, and assess the robustness of such mechanisms for the future development of arrangements in SAPP.

Expected results

- A methodology for the calculation of transmission wheeling charges and why this is the most appropriate for Lesotho and its interconnection and hence interaction with SAPP
- Understanding of the technical and economic drivers of transmission wheeling charges

This report is organized as follows:

- Section 2 summarizes the main findings from international experience on open access to transmission networks
- Section 3 presents the main methodologies for transmission wheeling charges determination, and summarizes some illustrative country examples
- Section 4 applies the previous conceptual framework to the specific case of Lesotho, based on the results of Task 4 (Deliverable 5)
- Section 5 analyses the implication of transmission wheeling charges determination under a regional trade environment, summarizing the case of Nord Pool and presenting in more detail the case of SAPP.
- Finally, in the same section, we analyse the implications of the proposed wheeling charges methodology for Lesotho in relation to SAPP cross border trading arrangements and market structure.

2 OPEN ACCESS AND WHEELING CHARGES - INTERNATIONAL EXPERIENCE.

Open access to the power grid is an important prerequisite for introducing competition to electricity markets and thereby increasing their efficiency. For most practical purposes, open access can be defined as the possibility for any party selling or buying electricity, subject to transparently formulated system-security constraints, to make use of the transmission and distribution (T&D) systems without discrimination. Such usage being made against payment of adequate Wheeling Rates for accessing and using these systems.

Open access can be defined in a narrow sense (minimal open access) or in a broader sense (full open access).

The first step leading to a minimal open access regime is establishing the legal principle that all generators have the right to access the grid to sell capacity and energy, and the wholesale buyers of electricity have the right to contract with the generators. The institutional requirements for minimal open access include transparent rules, procedures, and protocols for grid and market operations, and a financially disinterested, competitively neutral system operator.

Non-discriminatory access for wholesale market participants is a prerequisite for a full open access regime. However it is not the only requirement. The distinction between full open access and minimal open access relates to a number of additional issues, such as market design, congestion management, price signals, demand-side response, and the level of transparency of information about real-time grid conditions. For instance, while market participants may have access to the grid for using its services, their ability to offer services may be limited or denied. This may be due to the lack of transparency and system operation practices limiting the ability of market participants to fully engage in the commerce of a range of electricity services. Therefore, the grid may be open to some transactions but closed to others and would not then be considered as having full open access.

2.1 Benefits and Challenges of Open Access to Transmission Networks

A review of international experience since the initial electricity restructuring processes in the 80's, reveals a set of relevant benefits, challenges and barriers related to open access to transmission networks[1].

2.1.1 Benefits of Open Access

The main identified benefits of Open Access are the following:

- Creates and expands competition, allowing a rich variety of power supply contracts.
- Facilitates a greater exchange of electricity flows among different areas of a country and among different countries in a region.
- Creates opportunities for more productive utilization of the capacity of captive power generators (self-generators).
- Similarly, contributes to greater supply diversification through small distributed generation connecting to the power grid at the distribution-voltage level.
- Reliability of power supply also improves with open access, especially in cases where the incumbent utility cannot ensure an uninterrupted power supply.

2.1.2 Challenges and Barriers to Open Access

In terms of challenges and barriers for open access to a transmission network, the following are the main examples derived from international experience:

[1] *International Experience with Open Access to Power Grid – Synthesis Report*. ESMAP Knowledge Series 016/13. A summary of representative country cases is presented and analyzed: Brazil, Perú, Philippines, Turkey, USA and India.

- Transmission must be unbundled from generation and supply to ensure a level playing field for generators. This level of vertical unbundling is required even for a minimal open access regime, in the form of ownership separation, or at least accounts separation.
- It is not sufficient just to have a legal framework in place, there is also a need for an actual institutional governance structure to enforce open access. In particular, System Operation independence is a necessary condition to enhance institutional governance.
- Open access introduces new challenges to long term optimum transmission planning, because it becomes more plural and participative, with a higher diversity of agents.

3 Determination of Transmission Wheeling Charges

Opening up the electricity market in ways that are transparent will encourage competition in activities such as power generation and electricity supply to end consumers. To enable this to proceed in the future and to avoid distortions in pricing at a later stage, it is important to establish a charging methodology for wheeling that has the potential to be applied to all electricity transactions.

Key aspects of wheeling charge design, and transmission pricing more generally, concern:

- The revenue needs of the transmission service (Revenue Requirements) and the basis on which revenues are recovered, i.e. the size of the asset base and its associated valuation, and the possible inclusion of charges related to congestion and/or network losses;
- How the transmission allowed revenue is allocated among the system users (Pricing Methodologies). The way in which costs are allocated to the users of the transmission and distribution services, i.e. whether any distinction is drawn between charges faced by generators and consumers, or whether charges are differentiated on the basis of locational factors.

3.1 Revenue Requirements for the Management of Transmission Common Network

Transmission pricing requires an evaluation of the annual revenue requirements for the management of the transmission common network. Revenues need to be sufficient for the transmission companies to recover all the costs of providing, operating, maintaining, and planning the transmission network. The revenue shall also include a reasonable rate of return on the investments in the fixed assets.

The annual revenue requirements of the transmission grid include the following components:

1) Network operating and maintenance expenses
2) Current annual depreciation
3) Return on investments in assets in operation
4) System Operation expenses (balancing, settlement)
5) Ancillary Services provision

3.1.1 Network Operation and Maintenance Expenses

Network operation and maintenance expenses are expenses related to keeping the transmission network in acceptable technical condition to provide the transmission service with no capacity restrictions, at minimum cost and adequate quality. It is usually composed of salaries, materials, and subcontracted services.

Operation and maintenance costs are most readily recovered by allowing a predetermined margin on the capital costs of equipment to cover an appropriate amount on an annual basis to cover the O&M costs of each asset. Annual allowances vary from utility to utility, but typical figures in the range 2%-5% of the capital cost per annum are applied to cover O&M costs for the system as a whole. This needs to be sufficient to cover the costs of operating the centralized control functions within the transmission operator business, as well as the maintenance requirements of the individual assets themselves.

3.1.2 Capital Costs

It should be noted that the revenue requirement items (2 O&M) and (3 depreciation) are related to the fixed assets of the transmission grid. There are alternative methods to establish the value of the fixed assets which will result in different levels of revenue requirements: (a) embedded cost; (b) replacement cost methods and (c) long run marginal costs.

The embedded cost method values the fixed assets based on the historical (original) costs. The original costs of the assets are recorded on the accounting books and these figures are not changed over time. Annual depreciation expenses are computed based on the original costs of gross assets. The rate of return is based on the original costs minus the cumulative depreciation.

The replacement cost method will periodically (yearly) revalue the fixed assets based on the current cost to replace them (net of accumulated depreciation). In this case the annual revenue of the transmission company is computed as the current replacement cost multiplied by the capital recovery factor, which depends on the authorized return on assets and the life of the asset.

Depending on the pricing methods, the long run marginal cost of the network assets may be used as the basis for developing transmission service charges. It is the cost necessary to expand the grid to meet the demand. Although this method is extensively used for distribution assets, where there are identifiable patterns of expansion, its use in transmission is ambiguous and introduces the need of arbitrary decisions about incremental costs allocation.

3.1.3 System Operation Expenses and Ancillary Services

Wheeling charges shall include all system costs. The charges to be applied to a particular wheeling transaction shall include all related costs, and not only purely “network” costs. There are a number of other services that will be continued to be provided by Transmission Operator which needs to be taken into account. Among them system balancing and operation and ancillary services (frequency regulations, reserves, reactive power control, black start, etc.). All these costs need to be taken into account in the determination of the wheeling charges.

3.2 PRICING METHODOLOGIES

Pricing methodologies deal with the second issue in transmission pricing, that is, the allocation of revenue requirements among users of the transmission system.

Usually transmission tariffs have several components:

a) **Charges for the use of Transmission Common Network**, or Wheeling Charges. These are charges related to costs associated with transmission lines and embedded transformers, as well as equipment for operation and compensation of lines. The costs of services such as **System Operator Expenses** and, in some cases, **Ancillary Services provision** are also recovered through the Wheeling Charges.

b) **Connection charges**, related to the assets used to connect users to the grid.

c) **Network losses,** that can be recovered through nodal energy prices or separately (as explained in Section 3.2.3)

d) **Congestion charges** (associated with the cost of generation dispatched out of merit because of transmission constraints). In systems with nodal prices, these charges are incorporated to the nodal prices difference. But in single price systems, they are billed as an up-lift to the energy or transmission tariff.

3.2.1 USE OF COMMON NETWORK (TUOS)

The core of a Wheeling Charges system is the allocation of the costs associated with the use of a Common Network. This is the major problem in transmission pricing, as it is impossible to trace energy within a transmission system and so also not possible to identify the specific assets utilized by parties in a transaction. Several approaches are currently used to address the problem as follows:

Postage stamp

Allowed transmission revenue is allocated among users either in proportion to their peak demands and installed capacities, or in proportion to their energy production and consumption. Postage stamp schemes are easy to implement and are an adequate solution for allocation of incurred (sunk or non-avoidable) costs. Tariffs based on postage stamp methodology are implemented as access charges, where users connected to the grid are charged on the basis of the power or energy they inject/withdraw. However, the disadvantage is that location information is lost, i.e., a cheaper generator which is located far away will receive an incentive to enter the system because the high network reinforcement cost needed to connect it will be shared among all users. Therefore, when postage stamp is used it is convenient that network expansions be funded by sponsors or beneficiaries of the new facilities. Furthermore access charges based on maximum power withdrawn for recovery of sunk and non-avoidable costs are currently used in several pools in the USA, but the tendency is that cost of expansions is still allocated to beneficiaries. For example this is the approach set out in the Standard Market Design developed by the FERC[2]. Postage stamp is used in USA, Colombia, Spain, Peru and Bolivia.

Contract Path Method

In the past several years, most transmission services in the United States have been contracted through bilateral bulk power transactions. The transmission service charges are based on a contract path method. This method assumes a reasonable (hypothetical) path between the receipt and delivery points. This approach is simple and easy to administer, and enables the transmission providers to recover their costs. However, the choice of the path is subjective and open to alternative paths, and may result in inefficiency and potentially discriminatory practices.

Long Run Marginal Cost (LRMC)

In theory the ideal approach is the allocation of costs proportional to the marginal contribution of each user to the cost of an ideal transmission network constructed to match supply and demand. However LRMC cannot be properly defined in a transmission system because: (1) of the lumpiness of transmission investments; (2) there are not fixed and undisputable patterns for development of the grid that allow defining marginal costs precisely and with no margin of doubt for each user.

Furthermore, evaluating LRMC caused by the individual transactions can be difficult. Multiple transactions occurring simultaneously create problems in assessing which investment cost relates to which individual transaction, and therefore the extent to which users should contribute to new investments. This is particularly so where new beneficiaries connect to the system at a later date. The sensitivity of future investment programs to assumptions on future system use means that transmission prices can be rather unstable

[2] Federal Energy Regulatory Commission - the United States federal agency that regulates the transmission and wholesale sale of electricity and natural gas in interstate commerce.

Therefore, although in theory LRMC is the best method for transmission pricing, in practice results are poor as LRMC cannot be properly defined. Simplified (highly) approaches to LRMC are used in Brazil and Panama.

Extent of Use Allocation is proportional to the “utilization” of each transmission line which is attributed to each user or node. Because it is based on the concept of usage, it is intuitively perceived to be “fair” by most economic agents. However in contrast to other transportation activities, it is not possible to estimate the “use” of a transmission system without introducing arbitrary and ambiguous definitions. As electricity is not traceable in a grid, it is not possible to define what assets are used in a particular transaction. Therefore, “use” cannot be measured. Nevertheless, several methods based on “extent of use” have been developed and are used in some countries. “Marginal Use” and “Average Use” are the most common methods, although our experience is that these methods produce unrepresentative prices. This method is used (with different implementation in each case) in Argentina and Chile.

There is not a method that can be considered as the standard solution, or the most efficient for transmission pricing, and international experience shows that suitable solutions depend on the system topology and also how evolved are the pricing systems and models of the network.

3.2.2 Connection charges

Connection charges are paid by every user directly connected to the transmission grid. The charge is usually levied per kW connected. Consumers pay according to the maximum annual load, and generators according to their installed capacity.

The connection charge (CC) is computed annually, and includes costs related to capital cost of connection assets (transformers, switchyard equipment, other substation equipment, etc.), O&M expenses associated to these assets, and indirect administrative costs.

3.2.3 Losses and Congestion

The most efficient method for dealing with congestion and losses is through a system of nodal energy prices.

In theory, social welfare (and consequently economic efficiency) is maximized when energy is priced taking into consideration losses and congestion, not only marginal generation costs A nodal energy prices system is based on this approach.

A nodal pricing like the above will result in under-recovery of fixed costs, as pricing is a function of marginal costs. This does not allow for the recovery of the significant existing fixed costs that characterize transmission networks, which lead to average total costs exceeding short-run marginal costs. For these costs to be more fully recovered, it is necessary to move to a system of ‘second-best’ pricing in which economic efficiency is sacrificed for prices that allow the network operator to recover all their costs, including variable and fixed costs.

Furthermore, if this method is used[3], part of the required revenues are collected by the System Operator through locational prices, and are made up of the difference between payments from consumers and payments to generators. Thus the difference between the required revenues and locational prices revenues is collected using one of the methods for computation of TUOS described above (normally Postage Stamp or LRMC).

But if a single price method is adopted, usual methodologies are:

- To compute losses as the difference between energy injected and withdrawn. Losses are priced at the single bus marginal cost and allocated to users of the transmission system based on total production/demand. This computation is performed on an hourly basis.
- Congestion cost is computed as the difference between variable cost of an unconstrained (theoretical) dispatch, and the cost of actual dispatch. Usually this difference is used to pay out-of-merit generation, and allocated to consumers as an up-lift to energy price.

3.3 Country Cases

3.3.1 Ireland

EirGrid is the independent system operator for the Republic of Ireland (RoI) and SONI (System Operator Northern Ireland) is the system operator for Northern Ireland (NI). A system operator agreement exists between the two TSOs and ensures the required coordination between the two. NI and RoI together are referred to as All Island.

SEMO (Single Electricity Market Operator) is responsible for the operation of the centralised gross pool/wholesale market. Electricity is marketed through market clearing mechanisms. Generators are paid the System Marginal Price (SMP) plus the capacity component for that half an hour and constraint payments for the differences between market schedule and system dispatch. Suppliers who buy energy will pay the SMP for each half an hour along with capacity costs and system charges.

According to the All Island transmission methodology, the transmission costs are allocated at 25:75 split with generators paying 25% and demand paying 75% of the transmission related costs.

The All Island transmission tariffs have been designed to recover a maximum of 30% of allowed revenue from a locational element which apportions the share of the cost that a generator uses of new assets (new assets are those to be built in the next 5 years or those that have been built in the previous 7 years). The remaining amount is collected through a postage stamp methodology. Any revenue not recovered by the locational tariff component is be shared across all units by a flat €/MW charge to obtain a postage stamp charge.

Transmission losses are allocated to generators/interconnectors, by means of Transmission Loss Adjustment Factors. This includes generators connected to the distribution network. Transmission losses are recovered through transmission prices in NI and through energy market in the RoI.

[3] In cases when Transco includes the Market Operator

3.3.2 Great Britain

National Grid is the System Operator for the Great British (GB) system covering England, Scotland and Wales. Transmission Network Use of System (TNUoS) charges reflect the cost of installing, operating and maintaining the GB transmission system. TNUoS charges are allocated at 27:73 split with 27% of the charges being levied on generators and 73% on demand.

The GB transmission system is divided into 14 geographical demand zones and 20 generation zones.

The GB transmission pricing methodology is based on a nodal transmission pricing methodology, using LRMCs. The TNUoS charges reflect not only the incremental cost of transmission but also take into account a locational factor. A DCLF (Direct Current Load Flow) ICRP (Investment Cost Related Pricing) model is used to determine marginal capital cost which would be required as a consequence of an increase in demand or generation at each node on the transmission system. From this the TNUoS are developed. In some zones there are negative charges providing an incentive for generator location.

Transmission losses are recovered as part of the energy market, through the application of loss factors that relate the impact of generation and demand at specific nodes on the network to marginal changes in losses in the whole transmission system.

Transmission congestion management is dealt with by the use of constraint management balancing services.

3.3.3 United States: PJM

PJM is a regional transmission organisation which is responsible for the movement of wholesale electricity in all or parts of 13 states and the District of Columbia. PJM manages the continuous buying, selling and delivering energy. PJM undertakes interconnection management and is the market operator.

For energy pricing, PJM uses a locational marginal pricing (LMP) system that reflects the value of the energy at the specific location and time it is delivered. Prices are calculated for individual buses, aggregates, and transmission zones hence this is a form of nodal pricing.

In parallel, related to transmission tariffs, demand users (loads) pay for the cost of transmission infrastructure i.e. 100% transmission costs are allocated to the demand customers in accordance with their energy usage (extent of use).

If the lowest-priced electricity can reach all locations, prices are the same across the entire grid. However, when there is transmission congestion, the locational marginal price is higher in the affected locations. Financial Transmission Rights (FTR) are used to provide a hedging mechanism that can be traded separately from the transmission service. The congestion rents are used to pay the holders of FTRs.

The PJM Day-Ahead Market is a forward market where hourly LMPs are calculated for the next operating day based on generation offers, demand bids and scheduled bilateral transactions. The Real-Time Market is a spot market in which current LMPs are calculated at five-minute intervals based on actual grid operating conditions.

3.3.4 New Zealand

The New Zealand transmission network comprises the North and South Islands. TransPower is the transmission system operator and the owner of grid in New Zealand.

The New Zealand transmission pricing methodology reflects locational marginal costs and is based on full nodal energy pricing.

Transpower's pricing must recover the costs of providing its transmission services, which include capital, maintenance, operating and overhead costs". Before the beginning of each year, Transpower forecasts the revenue required to recover the sunk and current costs, which is collected through:

- ***Interconnection charges: used to recover the remainder of Transpower's AC revenue. The interconnection rate is the same for all load customers at all connection locations for all regions (postage stamp pricing depending on the weighted-average Regional Coincident Peak Demand). Generators do not pay interconnection charges.***
- ***Connection charges: used to recover part of Transpower's High-Voltage Alternate Current (AC) revenue by reference to the cost of providing connection assets. This charge is paid by both loads and generators.***

The costs of the HVDC link between the North and South Island are charged for the generators only on the South Island. 100% of the other transmission costs are allocated to loads.

NZEM, the New Zealand wholesale Electricity Market, calculates prices that reflect the cost of electricity at a node. The energy market is driven by long term bilateral contracts alongside a spot market. Contract and spot markets together are collectively referred to as the wholesale market.

Transmission losses and congestion costs are reflected in the half hourly prices that are generated for each of the pricing nodes in the market.

4 Determination of Transmission Wheeling Charges in Lesotho

Determination of transmission wheeling charges requires the selection of a transmission pricing methodology.

From the pricing point of view, the postage stamp approach is generally regarded as the simplest to implement. The methodology allocates system costs between users on the basis of their share of total peak load on the system. It therefore results in a flat transmission charge per unit of demand equal to the total transmission costs divided by peak load. The postage stamp method is often supported with reference to the fact that, in power transactions, electrons do not actually travel from the seller to the buyer, and the system is operated on an integrated basis.

There are a number of clear advantages of such a transmission charge methodology:

- Full cost recovery is ensured. As this allows investors to recover their investment costs, it solves the problem of under investment apparent in nodal pricing approaches (see Section 3.2.3).

- The system results in a clear, simple and stable transmission charge as each consumer pays the same charge, regardless of location. Also as the peak load is likely to increase at a relatively moderate pace in most cases, the charge is largely invariant to time.
- Postage stamp pricing is most justified in systems in which there are few constraints and load and generators are sensibly equally spaced as in the case of Lesotho. In such systems bulk power transmission costs do not significantly increase with the distance between buyers and sellers.

However, the postage stamp method does have some drawbacks:

- As the methodology does not consider the actual utilization of the system, it does not create the correct incentives for system users. This can result in inefficiencies as users are not liable for the full costs of their actions. For instance, a transaction whose costs in terms of system upgrades and investments exceeds its benefits may still occur as the parties to the transaction face only a small part of the extra transmission cost.
- As all users face the same transmission tariff, the postage stamp methodology discriminates against low-cost transmission users in favor of higher-cost users. In effect those parties engaging in high-cost transmission deals are subsidized by those who, for instance because they utilize only a small part of the network, only create a smaller fraction of the transmission costs. This provides incentives for low-cost users to bypass the existing transmission network.

However we propose to apply the postage stamp approach for the wheeling charges computation in Lesotho. There are two reasons for this:

- As Lesotho is a small country, there are no significant problems related to locational signals for generation investment. In particular and related to the previous, there are no relevant transmission congestion issues.
- All other pricing methods are quite demanding in terms of system operation and market settlement capabilities and modelling, and would put a clear burden on its application in the short term.

Having said this, the two stages for computing Transmission Wheeling Charges in Lesotho are the determination of the Revenue Requirements for the management of the Transmission Common Network, and the allocation of those revenue requirements to get the Wheeling Charges through a postage stamp method.

4.1 Network Expansion Plan

The Economic Costs of Supply considered as a starting point for network charges computation are mainly based on the Development Programs (Long Term Expansion) estimated in Task 3 (Deliverable 4), according to the following table:

Table 1. Network Expansion Plan

	Units	2018	2019	2020
Initial RAB value	Mmill	2,590	2,797	2,962
CAPEX	Mmill	317.2	279.7	236.2
Depreciation	Mmill	109.8	115.3	119.8
TOTAL T&D OPEX	Mmill	289.8	316.6	339.2
OPEX - Network	Mmill	265.1	289.7	310.4
OPEX - Retail	Mmill	24.6	26.9	28.8

Source: Deliverables 4-5 (MRC Group)

Initial RAB values were obtained from the Asset Register as of 31st March 2017 and brought forward as: Closing RAB = (Opening RAB + CAPEX – Depreciation).

When extrapolating values for total OPEX for LEC over the period we assumed in Task 3 that the current operating efficiency rates of LEC are kept constant for the three-year period. This efficiency rate has been formulated by keeping constant the OPEX costs as a percentage of assets book value (9.6%). Following that, however, in Task 6 (Deliverable 7) we introduced an OPEX efficiency target as shown in the following table:

Table 2: Adjustments to OPEX for Performance Improvements

	Units	2018	2019	2020
TOTAL T&D OPEX	Mmill	289.8	316.6	339.2
OPEX - Network	Mmill	265.1	289.7	310.4
OPEX - Retail	Mmill	24.6	26.9	28.8
Reduction for opex performance improvement	Mmill	-26.4	-44.7	-60.4
TOTAL T&D OPEX with improvement	Mmill	263.34	271.90	278.82

Source Deliverables 5-7 (MRC Group)

It is assumed that existing assets depreciate at the same rate as historically according to LEC audited accounts. New assets depreciate at 3.7% per year (average rates for T&D assets).

Total OPEX for the T&D business have been split into Network OPEX and Retail Service OPEX assuming that Retail Service OPEX represents 10% of the total in LV and 5% of the total in HV.

The CAPEX recovered through tariffs (and shown as inputs to the tariff model in the table above) are only those CAPEX funded by LEC, therefore it excludes investments funded through capital contributions and from the UAF. However the OPEX associated with operating those assets is still part of the LEC OPEX and is therefore recovered through tariffs.

4.2 Expansion Plan per Voltage Level

Costs (CAPEX and OPEX) must be linked to the voltage they stem from. We have split new investments into HV and LV, apportioning CAPEX using the statistics from the asset register and apportioning the OPEX according to its relative contribution to peak demand (see Table 3 below). For this exercise, we are considering that the Transmission Network is the HV one.

Table 3 – Splitting factors used in the distribution of CAPEX and OPEX by voltage level

CAPEX relative weights: T and D over total (T+D). Obtained from Net book values in March 2017		
LV (Distribution)	%	56.90%
HV (Transmission)	%	43.10%
OPEX relative weights: T and D as per weight in average peak demand in 2017		
LV (Distribution)	%	69.92%
HV (Transmission)	%	30.08%

Source: Deliverables 4-5 (MRC Group)

The results of the application of those splitting factors are summarized in the following Table 4:

Table 4 – Network Expansion Plan – RAB, CAPEX and OPEX (including performance improvements)

	Units	2018	2019	2020
Initial RAB value				
LV	Mmill	1,151.85	1,281.72	1,386.65
HV	Mmill	1,438.19	1,515.74	1,575.17
CAPEX				
LV	Mmill	180.50	159.15	134.39
HV	Mmill	136.72	120.55	101.80
Depreciation				
LV	Mmill	50.63	54.21	57.16
HV	Mmill	59.17	61.12	62.62
TOTAL T&D OPEX				
LV	Mmill	184.28	190.28	195.13
HV	Mmill	79.06	81.62	83.69
OPEX - Network				
LV	Mmill	165.85	171.25	175.62
HV	Mmill	75.11	77.54	79.51
OPEX - Retail				
LV	Mmill	18.43	19.03	19.51
HV	Mmill	3.95	4.08	4.18

Source: Deliverables 4-5-7 (MRC Group)

4.3 Revenue Requirements for the Transmission Network

Based on the information of the HV system in Table 4 and considering a real rate of return on net RAB of 8.67% (pre-tax – applied on the yearly mid-term RAB), the following Table 5 of total revenue requirements for the transmission system can be obtained:

Table 5. Total Revenue Requirements for the Transmission Network

	Units	2018	2019	2020
Initial RAB value	Mmill	1,438.2	1,515.7	1,575.2
CAPEX	Mmill	136.7	120.6	101.8
Depreciation	Mmill	59.2	61.1	62.6
Return on Assets	Mmill	128.1	134.0	138.3
OPEX – Network & Retail	Mmill	79.1	81.6	83.7
Revenue Requirements	Mmill	266.3	276.7	284.6

Source: own elaboration (MRC Group)

Two comments on Table 5 contents:

- OPEX include not only network management expenses but retail as well, assuming that as a first implementation stage metering, billing and collection would continue to be covered by LEC. Consistently, CAPEX include connection expenses, in terms for instance of metering devices.
- OPEX include System Operation Expenses. If there were any generation stranded costs and any other unavoidable system expenses, those should be accordingly included in OPEX estimation.

4.4 Final Wheeling Charges

Table 6 shows the computation of Final Wheeling Charges under a postage stamp approach, dividing total revenue requirements by the total system load, getting a unit charge per transported kW:

Table 6. Wheeling Charges Under Postage Stamp Approach (per kW)

	Units	2018	2019	2020
Revenue Requirements	**Mmill**	266.3	276.7	284.6
Peak Demand	**kW**	177,860	184,354	190,848
Wheeling Charge	**M/kW**	1,497.2	1,501.1	1,491.1
	US$/kW	115.2	115.5	114.7

Source: own elaboration (MRC Group)

Wheeling charges can be computed as well per kWh extracted from the grid:

Table 7. Wheeling Charges Under Postage Stamp Approach (per MWh)

	Units	2018	2019	2020
Revenue Requirements	**Mmill**	274.4	290.3	302.9
Final Energy Consumption	**MWh**	791,478	820,377	849,277
Wheeling Charge	**M/MWh**	336.4	337.3	335.1

	Units	2018	2019	2020
	US$/MWh	25.9	25.9	25.8

5 Open Access and SAPP Environment

5.1 Transmission Pricing and Regional Markets

It is necessary to agree on a suitable approach for transmission pricing in a regional environment before finalizing the mechanisms needed for third party access both within the current trading arrangements as well as being adaptable for the projected future SAPP arrangements. Consideration must be given to:

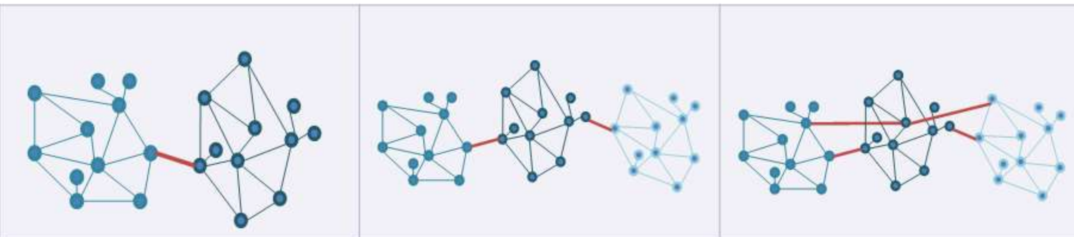
- Transmission pricing in the Lesotho system – with prices that should be cost reflective, and allocated in an economically rational way.
- Transmission pricing in the regional environment. There are different possibilities of pricing the transmission services when dealing with cross border transactions (see Figure 1 below).
- Other regulated charges. Other charges that must be paid and how they can be allocated. Main examples are independent regulatory services, market and system operation services.

In a regional environment, countries can have three roles:

- Supplier of generation capacity
- Receptor of energy/power supply
- Transit country

Associated with these roles, the transmission topology of cross border trading in a regional environment can adopt the following configurations:

Figure 1. Transmission topology for Cross Border Trading



Simplest case where 2 systems are connected in one point through one tie line.	Two systems trade with "transit" through the system of a third country. This third country provides "wheeling" services	Two systems are connected by a "regional line" and also by the system of a third country.

Charging cross border flows the national transmission tariff of each of the countries it transits is inefficient and deters regional trade. This effect is known as "pancaking". A method to set the price for the wheeling service has to be developed.

5.1.1 PRICING TRANSMISSION SERVICE FOR REGIONAL TRADE

- Pricing Principles:
    - Cross-border flows of electricity are different from those within a national transmission system. Charging the same transmission tariffs to national flows and cross-border flows may not be efficient and may lead to a deterrence of international trade. When regional flows use spare capacity (after supplying domestic demand) and the involved assets are already paid by the national tariff of the hosting country, imposing a full cost tariff to regional flows may deter trading exchanges.
    - Pricing methods for transmission services in regional trade must avoid price "pancaking":
        - ✓ Cross border flows use the spare capacity of domestic systems they use as transit
        - ✓ For this reason, it is not fair to charge them the complete domestic tariff which is already "paying" in full for these assets
    - The cross-border flow must pay for the cost it represents to the system hosting the flow (wheeling):
        - ✓ Losses
        - ✓ The eventual use of assets
    - But cross border flow must pay for the total cost (capital, fixed O&M and variable O&M) of "regional lines" that have been constructed specifically to transmit power across the region between national systems.
- Possible TSO compensations:
    - The implementation of payments between national TSOs is a way of allowing the national transmission networks to recover the cost of hosting cross-border flows and, at the same time, allowing national TSOs to maintain their own independent transmission tariffs
    - Under an inter-TSO compensation mechanism, the TSOs agree on the costs that everyone bears because of hosting cross-border flows, and also agree on a method for allocating such costs. This part covers the payment for "wheeling services".
    - Actually, it is the regional regulator (working with the TSOs) who sets the payment for these wheeling services.

5.1.2 PAYMENT OF "REGIONAL LINES"

"Regional transmission lines" are those identified by the regional planning and specifically built for regional trade. These are lines decided by the region in accordance with the regional master plan, and must be paid fully by the flows they host (capital and operational costs).

Ownership of regional lines and responsibility for their operation and maintenance can take a number of forms. However from a wheeling charges perspective what is important is to define how much must be paid and who will pay.

In general, regional regulation sets the method for determining payment amounts and allocations. Usually payment for regional lines is based on the "beneficiary pays" criteria.

5.2 A Regional Example: Nord Pool

Nord Pool covers six countries in Europe: Denmark, Finland, Sweden, Norway, Estonia and Lithuania. Each country has its own TSO and may have different levels of transmission grid. For instance, Norway has a central grid, which spans from the very North to the very South of the country and connects Norway to the surrounding countries. Below the central grid there are regional grids. Norway has five defined market areas, Denmark has two and Sweden has four defined market areas while Finland, Estonia, Lithuania operate one market area each. The Nord Pool spot market (Elspot) operates 14 market areas in six countries.

The Nord Pool transmission pricing methodology is nodal tariff system implicitly based on extent of use criteria, where the producers and consumers pay a fee for the kWh injected or drawn from the system in each node. The distance or transmission path between the seller and buyer is of no significance to the transmission price.

The actual transmission price depends on where (what point in the grid) the power is injected or consumed and how much power is injected or consumed. The charges are determined by the individual TSOs and paid to the TSO to which the connection is made. The payment allows trading of electricity across the whole Nord Pool market area.

Within each member country there is a transmission tariff payable within the country. For example, in Norway the transmission tariff comprises several components, a fixed component, a load component and an energy component.

The allocation of charges between demand and generation differs across the countries: Sweden 25:75; Norway 35:65; Finland 12:88; Denmark 2-5:95-98; Estonia 0:100; Lithuania 0:100.

In addition to the transmission tariff cost congestion costs are recovered through congestion rents which are the income or cost that arise due to the price differences between the areas. The congestion rent from the interconnectors is shared among the four TSOs in accordance with a separate agreement.

The Nord Pool spot market carries out the day-ahead congestion management on external and internal transmission lines. The available transmission capacity and the price differences in the surplus and deficit area manage the congestion day ahead implicitly within the energy market auctions.

Transmission losses are recovered by a standard Elspot trading fee in EUR/MWh which is paid by both buyers and sellers.

In terms of transmission pricing, NordPool is at a relatively evolved stage, with a nodal transmission tariff system based on an extent of use approach. As will be seen, SAPP is evolving from a primary extent of use method (based on MW-km of each trading flow) to such a nodal transmission pricing model, with the aim of improving the efficiency of locational incentives in transmission pricing.

5.3 Wheeling Charges in South African Power Pool (SAPP)

The SAPP members are the utilities and ministries involved in energy usage in Angola, Botswana, Lesotho, Malawi, Mozambique, Namibia, Swaziland, Tanzania, Zaire, Zimbabwe and South Africa. The transmission systems in the majority of these countries are interconnected. A fundamental SAPP objective is to allow wheeling of energy through the transmission systems, where wheeling is the transfer of power through a country who is neither the buyer or the seller of the power.

The original wheeling charge was based on the postage stamp principle. This applied a scaling factor of 7.5% to the value of the energy wheeled through one country, or 15% if the energy was wheeled through two countries, split between the two countries. The increase (or decrease) in loss was supplied by the seller of the energy and paid for by the buyer.

This method was replaced in 2003 by an Extent of Use methodology (in the form of a MW-km), where the charges are determined according to the proportion of assets used for wheeling. The use of assets for wheeling purposes is determined using load flow studies to calculate the proportion of total available capacity on each contract path accounted for by a wheeling transaction. Wheeling charges are then levied in accordance with this proportion as a share of the total asset values affected by the wheeling transaction.

Since 2016, an Entry and Exit Charge methodology is being tested. This a kind of Extent of Use methodology, getting the rent on assets actually used for wheeling, but based on metered exports and imports at each node. A load flow is used to determine the transmission assets that require revenue recovery. A set of entry and exit charges for every import-export node (country border or IPP connection point) is published, and furthermore revenues are recovered from actual entry and exit flows.

5.4 Lesotho in SAPP

In the SAPP environment, wheeling is associated with the transmission of power through a member's system who is neither the seller nor the buyer of this power. This is based on the point-to-point concept recognizing national borders as the points of entry and exit (MWh/km).

Wheeling can adopt two modalities:

- Firm Wheeling
    - Often possible in the case of a single wheeler that guarantees that the wheeled power enjoys same priority as any firm supply to its own customers – penalties apply in case of breach
- Non- Firm Wheeling
    - Normally applicable in the case of multiple wheelers. The wheeler of non-firm wheeling may curtail or interrupt the flow of wheeled power based on technical and economic considerations for its system without any penalty. The reasons for interrupting wheeling must be disclosed and should be open to investigation.

In the context of the South African Power Pool where participants can wheel power from SAPP to the Lesotho network and vice versa, Lesotho will rarely be a transit country due to its size and geographical location[4], and furthermore the "pancaking" issue will not arise. In conclusion, any transmission price methodology assumed internally (for instance the simplest postage stamp) will be compatible with the MW-km point to point intercountry exchange.

From the point of view of the transmission system expansion, since the Muela hydropower station owns part of their transmission network, and potentially there may exist further investment in power and connecting into the Lesotho transmission system by new generators wishing to supply SAPP, the mechanism for third party access may set a framework in which third party or independent investment in expansion of the network is possible.

The expansion or reinforcement of the transmission system is typically based on one or more of the following initiatives:

- Planned developments in response to actual or predicted demand for transport, the details of which would differ between systems with markets and open access, and those where the system is provided by a vertically-integrated utility
- Private initiatives of agents, who are empowered to promote the building of transmission facilities necessary for transmitting power to and/or from their own facilities
- Merchant expansions, where investors speculatively build a transmission facility at their own risk with the aim of benefitting from selling transmission services
- Politically decided expansions, aiming to fulfil social targets such as providing countrywide access to a public electricity supply, providing infrastructure to encourage development, or perhaps meeting regional objectives

Looking at those different types of initiatives helps to understand the options available for financing transmission expansions and subsequently recovering the cost of finance, operation and losses.

In the case of Lesotho, planned developments by LEC can be covered through the proposed postage stamp methodology. In the case of private initiatives of agents and merchant expansions, a separate identification of the transmission/connection new assets and a separate wheeling charges computation can be carried out, under the "beneficiary pays" principle.

6 CONCLUSIONS

The report has set out the criteria and methodologies for transmission tariffs setting, and their pros and cons. The process comprises firstly the establishment of the revenue requirements of the transmission network, followed by the allocation of those requirements amongst users of the network: both suppliers and users of power.

The annual revenue requirements of the transmission grid include the following components:

- Network operating and maintenance expenses

[4] Lesotho is a small country totally inserted in South Africa, with an electricity system that may be a final demanding node for the region, or s supply node for the region, both of them considering the border node involved. It is difficult to imagine a trading opportunity for which Lesotho would be an unavoidable transit system.

- Current annual depreciation
- Return on investments in assets in operation
- System Operation expenses (balancing, settlement)
- Ancillary Services provision

Pricing methodologies deal with the allocation of revenue requirements among users of the transmission system.

Usually transmission tariffs have several components:

a) **Charges for the Use of Transmission Common Network**, or Wheeling Charges. These are charges related to costs associated with transmission lines and embedded transformers, as well as equipment for operation and compensation of lines.

b) **Connection charges**, related to the assets used to connect users to the grid.

c) **Network losses and Congestion charges** (associated with the cost of generation dispatched out of merit because of transmission constraints).

There are a number of conceptual and methodological approaches to the design of Wheeling Charges. We have reviewed four approaches:

a. Postage Stamp

b. Contract Path

c. Long Run Marginal Cost

d. Extent of Use (nodal transmission tariffs)

From the Postage Stamp to Extent of Use, the approaches evolve towards clearer and more efficient locational signals, increasing at the same time the complexity and discretionary nature of the procedures applied and the results thus obtained. As Lesotho has a small electricity system, with no locational problems, we recommend a Postage Stamp Method as the most appropriate. This recommendation is further supported considering the System Operation costs that would be significantly increased in case of going to more complex approaches.

An analysis is presented of applicable transmission wheeling charges for Lesotho.

Finally given the geographical specificities of Lesotho (not being a typical transit country), this quite simple postage stamp methodology applied in Lesotho is compatible with the SAPP approach for regional wheeling charges.

Electricity Supply Cost of Service Study – LEWA Lesotho

LEWA Tariff Determination– Deliverable 9

Support Provided by African Development Bank

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Contents

LIST OF ACRONYMS

CAM	Cost Allocation Manual
CAPM	Capital Asset Pricing Model
COSS	Cost of Service Study
GoL	Government of Lesotho
IMTF	Interim Management Task Force
LEA	Lesotho Electricity Authority
LEWA	Lesotho Energy and Water Authority
LEC	Lesotho Electricity Corporation
RAG	Regulatory Accounting Guidelines
RAB	Regulated Asset Base
SAL	Sales Advisory Group
WACC	Weighted Average Cost of Capital

1 INTRODUCTION

This is the ninth deliverable of the Cost of Service Study (COSS) for Electricity Supply by LEC in Lesotho being carried out for LEWA supported by the AfDB. It reports on the analysis undertaken to address the terms of reference for Task 8 of the COSS. Task 8 includes two main elements: a review of the regulatory methodology currently applied in Lesotho, considering alternative approaches that may be advantageous; and the development of a model for tariff determination.

Our review of alternative approaches to the current regulatory methodology specifically addressed perceived weaknesses in the sector that changes to the tariff determination process might improve. These included:

- A lack of incentive for LEC to improve its performance and in this respect three particular areas for improved performance (and in turn reducing its revenue requirement) have been highlighted during the COSS:
    1. Renegotiate or enhance bulk power purchasing agreements to minimize power purchase pass through costs. Most notably, the analysis suggests that LEC should reduce contracted supply from EdM as in most periods[1] its prices are substantially higher than ESKOM.[2]
    2. Use Muela to minimize power purchase costs by operating, as far as is possible within its water supply obligations, to maximise generation during peak hours (when import purchase prices are highest).[3]
    3. Reduce operating expenses by improving operational efficiency as defined in the benchmarking reported in deliverable 7 by targeting an improvement in network (M/MWh) and commercial (M/customer) opex.
- The regulatory regime has not to date qualified LEC as a low risk borrower and as a result LEC has had to secure virtually all its capital expenditure requirements directly from the Government of Lesotho.

Section 2 of this report reviews the current tariff methodology including an overview of legislation, the relevant history of the attempt to privatise LEC and a summary of current guidelines. Section 3 considers the alternative approaches to regulation of electricity supply in Lesotho. Section 4 summarises the findings of the COSS and recommends the form of regulation going forward and Section 5 describes the model we have developed for determining tariffs. Note that as a part of this task a separate manual for the operation of this model has also been prepared. Finally Section 6 proposes a capacity building plan that will enable both LEC and LEWA to utilise the COSS tariff model effectively for future tariff determinations.

[1] Analysis indicates that EdM maybe be less expensive than ESKOM only in peak periods, however LEC have contracted an offtake profile for firm power with volumes across the day.
[2] It appears that this is based on a decision by LEC that it needs the EdM contract to prevent an over-reliance on ESKOM.
[3] We believe LHDA has an obligation in its contract with LEC to do this. We also believe it is technically feasible as the delivery of the contracted daily water supplies to RSA can be achieved with varying levels of flow throughout the day.

2 REVIEW OF CURRENT TARIFF METHODOLOGY

2.1 BACKGROUND

In 2000, principally to improve access to electricity, the Government of Lesotho (GoL) embarked on a restructuring of the electricity supply industry which included the privatisation of LEC through the sale of a majority shareholding to a strategic investor.

As a preparatory step to privatisation, GoL recruited a private sector management team, known as the Interim Management Task Force (IMTF) to prepare LEC for privatisation and operate it until the strategic investor took over. The IMTF commenced its activities on 1 February 2001. At the end of the IMTF contract GoL entered into a caretaker management contract with the same management contractor to continue to run LEC until the privatisation was completed.

A Sales Advisory Group (SAG) was appointed in December 2001 to assist the Government with the privatisation process. The work was financed by the World Bank and the African Development Bank with a small contribution of the European Union. An important part of the SAG project was to establish an independent authority to regulate LEC once it was transferred to private ownership. Thus the Lesotho Electricity Authority (Lesotho Electricity and Water Authority – LEWA since 2013) was established in 2004 as a regulator of the electricity sector on the basis of the Lesotho Electricity Authority Act 2002 mentioned above.

A component of the IMTF contract was the development of a “Tariff Plan” based on a study of the cost of supply. LEWA started setting tariffs for LEC in 2007/08 based on this IMTF ‘Tariff Plan’.

In 2010 further work was carried out supported by WB for the development of Economic and Financial regulatory frameworks. The study developed the guidelines summarised in section 2.3 of this report.

The precise duties of LEWA are set out in section 21(1) of the Lesotho Electricity Authority Act, 2002 (LEWA Act)[4]. In summary, its mandate entails four main activities:

1. Licensing (all participants in energy supply activities need a license to operate that is issued by LEWA);
2. Tariff Approval;
3. Monitoring Licensees’ performance and technical standards (e.g. Quality of Service and Supply Standards); and
4. Resolution of complaints or conflicts.

From the electricity element of its work LEWA gets funding from licensed electricity operators (licence fees) and a levy on electricity customer tariffs (the “customer levy”). It receives further funding from its water and sewerage activities.

[4] Ensure the operation and development of a safe, efficient and economic electricity sector in Lesotho; protect the interests of all classes of consumers of electricity as to the terms and conditions and price of supply; ensure, so far as it is practical to do so, the continued availability of electricity for use in public hospitals, and centres for the disabled, aged and sick; ensure the availability of health and safety guidance in relation to electricity supply to the public; ensure the financial viability of efficient regulated electricity undertakings; ensure the collection, publication and dissemination of information relating to standards of performance by licensed operators and on the electricity sector in Lesotho for use by the industry, consumers and prospective investors; participate, in consultation with the Minister, in regional and international matters relating to the regulation of electricity in Lesotho.

Under the LEC privatisation project bidding documents were issued to five prequalified companies in July 2004, however, following two rounds of bidding that failed to secure an offer, which both conformed to the bidding rules and was acceptable to the Government, the attempt to privatise ended in 2006.

The IMTF company ceased providing management services to LEC sometime after 2006, and LEC has continued to operate under the ownership of Government and under the guidance of its Board whose members are selected by the Ministry of Energy and Meteorology (MEM). There are improvements that can be made to the governance of LEC:

- Ensuring its Board is qualified and free to take decisions based on the long term optimum operation of the business; and
- Enabling elements of private sector discipline to influence decisions at LEC – e.g. commercial loans or an element of minority shareholding.

We will consider the options for improving LEC governance further in Task 9 (Deliverable 10).

2.2 Key Sector Legislation

The Act volume Number .12 of 2002 (Lesotho Electricity Authority Act as amended in 2006 and 2011) establishes the Lesotho Electricity Authority to regulate and supervise activities in the electricity sector, and to make provision for the restructuring as well as the development of the electricity sector and for related matters. The main laws and regulations related to the exploitation and the use of Lesotho's energy resources are summarised in Table 1 and Table 2 below.

Table 1 - Key Sector Legislation

Legislation	Overview
Fuels and Services Control Act 1983	Empowers the Minister responsible for energy affairs to be in control of fuel supply, regulation (pricing and licensing). Practically, the application of the Act has been limited to petroleum fuels.
Lesotho Electricity Authority (LEA) Act (2002)	Establishes the Lesotho Electricity Authority as regulator for electricity sector.
LEA Amendment Act (2006)	Amends LEA Act (2002) regarding the composition of the Board, funding, powers to enter and use land for regulated activities, and acquisition of land required for regulated activities.
LEA Amendment Act (2011)	Amends LEA Act (2002) to give the Authority power to regulate Lesotho's water and sanitation sector and renaming the regulator as the Lesotho Electricity and Water Authority (LEWA).

Source: DoE

Table 2 - Key Regulations

Regulation	Purpose
Petrol or Distillate Fuel Levy, 1985	Empowers the Minister to impose levy on petroleum products.
Liquefied Petroleum Gas (Trade and Handling) 1997	Regulates the trade and handling of liquefied petroleum gas.
Fuel and Services Control (Importation of Petroleum Products), 1999	Regulation of imports of petroleum products in the Country.
Lesotho (Petroleum Fund), 2009	Finance petroleum fuels projects and other energy projects on loan basis.
Electricity Price Review and Structure Regulations (2009)	Regulates reviews of tariff structure and prices.
License Fees and Levies Regulations (2009)	Regulates funding Regulator activities via licensing fees and customer levies.
Resolution of Disputes Rules (2010)	Regulates dispute resolution between licensees and between licensees and customers.
Universal Access Fund Rules (2011)	Establishes a fund for electrification and sets administrative rules.
Application for Licenses Rules (2012)	Sets procedures and requirements for license applications and exemptions.

Source: DoE

2.3 Current Guidelines

There are a number of guidelines published on the LEWA website, which for completeness and to show how the COSS analysis is in line with these where relevant, we list and summarise below.

2.3.1 Regulatory Accounting Guidelines (RAG)

These can be reviewed every 3-5 years and include the following:

- Emphasis on ring-fencing of regulated and non-regulated activities.
- Cost allocation is intended to be carried out in accordance with a "Cost Allocation Manual (CAM)" prepared by the licensee and approved by LEWA.
- The RAG recommends as its preferred methodology, the Fully Distributed Cost Allocation Methodology also known as Fully Allocated Cost Approach. The allocation of costs described in Task 4 (Deliverable 5) report of this Cost of Service Study closely follows this approach.
- Describes how to establish the regulated asset base (RAB), which is to be revalued annually on basis of depreciated indexed historical cost - depreciation to be on a straight-line basis. The analysis described in Task 4 (Deliverable 5) of this Cost of Service Study utilized the LEC RAB that has been established following this guideline.

2.3.2 Charging Principles for Electricity and Water and Sewerage Services

- Licensees determine the tariff methodology to be applied - multi-year v single year, indexation of cost components, revenue caps, pass-through costs, incentive components to reward efficiency improvements.
- Revenue required is based on reasonable operating expenses plus return on the RAB.
- Allows for recovery of deferred revenue in later years with rate of return added.
- Allows outturn adjustment for differences between actuals and forecasts - expecting this to be over a two-year cycle to allow for the auditing of accounts.
- Tariffs to be cost-reflective. While transmission charges may not vary with location, other charges can vary depending on location, time of the day and time of season, voltage (HV, MV and LV).
- Includes in an annex, how to calculate the WACC including the application of the Capital Asset Pricing Model (CAPM) to calculate the real cost of equity. The WACC analysis described in Task 4 (Deliverable 5) report of this Cost of Service Study closely follows this approach.

2.3.3 Electricity Connection Charges Guidelines

Detailed guidelines on setting connection charges. The clear principle is only to charge direct costs on what is called a shallow basis (direct costs only) and sets mechanisms for making the system fair to all when additional customers are connected to a recently constructed network.

2.3.4 Revised 'Pass-Through Charging Principle for Bulk Supply Tariffs' and Procedure for Implementation Mechanism

Defines a balancing account to be set up "virtually[5]" by LEC but accessible to all, that records actual payments for bulk supplies.

3 Possible Alternative Approaches

3.1 Regulatory Objectives

The general objective of this study is to provide LEC with an electricity tariff system and rate structure for all customer categories that reflect the economic cost of service. There are five principles which we have applied in fulfilling this overall objective and these are as follows:

- **Simplicity** - To ensure transparency and simplicity within the tariff structure and its underlying cost allocation principles.
- **Efficiency** - To develop efficient price signals to consumers, to guide short-run and long-run consumption decisions to encourage efficient consumption patterns.
- **Non-discrimination** - To develop charges which are just and reasonable and not unfairly discriminatory.

[5] Presumably a shared spreadsheet analysis recording bulk supply payments.

- **Competition** - Where relevant, to assist LEWA to develop a framework which will improve the economic viability of power producers in order to ultimately facilitate wholesale competition without creating artificial barriers for any electric power generator or supplier.
- **Consistency** - To inform regulatory arrangements for consistent application within the emerging market, including incentives for efficient location of new generators and efficient expansion of the distribution and transmission network.

More specifically, the objective of the COSS is to set electricity tariffs at a level which promotes **economic efficiency** of production, and to ensure **financial viability** of the electricity sector.

Economic efficiency in tariff design requires tariffs to be linked to the actual cost of meeting consumers' demand. It includes the following aspects:

- **Allocative efficiency - c**osts should be related to the actual cost of service and be efficiently allocated to diverse tariff categories by identifying what parts of costs are related to each tariff category. However, as is typical of most tariff systems it is necessary to combine relatively diverse types of customer into single tariff categories because of the need for a manageable and not overcomplex set of tariff categories. **In the COSS** we have designed an economically efficient tariff structure, taking into account social factors such as the need for lifeline tariffs and otherwise confirming the existing range of tariff categories.
- **Dynamic efficiency** - in order to guarantee the financial sustainability of the business as expansion of transmission and distribution networks is undertaken, revenue requirements and tariffs derived for the network segments must include provision for a reasonable rate of return on assets. The value of a reasonable rate of return should be based on what is typical for an efficiently operated company, i.e., having similar or comparable risk at the local and international level. **In the COSS** we have provided an analysis of the tariffs required to ensure a fully sustainable electricity supply sector.
- **Productive efficiency** - an electricity sector should not simply aim to promote allocative and dynamic efficiency as described above, but also productive efficiency. Productive efficiency means identifying the **efficient costs** of electricity supply (generation, transmission, distribution and supply), rather than the actual ones. Obviously, efficient costs might be higher or lower than the actual. However, understanding this gap or difference (which can be done by benchmarking the utility against comparable peers) is critical to developing a suitable suite of tariffs. **In the COSS** we have benchmarked the efficiency of LEC operations and proposed an improvement target.
- **Financial sustainability** means that tariff design must ensure that total revenue to be produced by the tariffs will cover economic and efficient costs of the networks activity, taxes, investments and reasonable rates of return. **In the COSS** we have analysed and reported on the financial performance of the LEC business for the analysed tariff pathways.

Additionally, two complementary targets have been addressed in the COSS:

- **Social equity** is a non-technical ingredient that forms part of a tariff scheme. It is associated with the ability of low income consumers and of those in rural areas to purchase electricity. Meeting social objectives usually requires subsidies to some consumer groups, either implicit (through cross subsidies between different consumer groups) or explicit (through direct subsidies given by the Government). Subsidies distort tariff economic signals and need to be analysed and assigned carefully, to minimize distortions in consumption patterns that may worsen economic efficiency. **In the COSS** we have recommended that a lifeline tariff block be provided to domestic customers who consume less than 30 kWh per month.

- **Product and services quality** has to be enhanced by the tariff regime, either by implicit price incentives or explicit fines mechanisms. **In the COSS** we have recommended that an operational efficiency improvement be targeted and allowed for in the tariff determination and this target is based on opex/MWh and opex/cust reduction targets.

3.2 Regulatory Options

3.2.1 Cost Plus or Incentive Based Regime?

There are two distinct cases commonly defined for utility tariff regulation:

1. Considering actual capital and operational expenditures of LEC, associated with the current managerial and operational status of the company, with tariffs computed assuming a "**Cost Plus"** tariff regime; or
2. Considering efficient costs and expenditures (capital and operational), associated with a performance improvement scenario with tariffs computed therefore assuming an **"Incentive Based"** tariff regime.

Historically, the tariff regime traditionally known as **"Cost Plus"** or **"Rate of Return (ROR)"** regulation has been the dominant approach for the definition of public service tariffs that involve natural monopolies such as electricity supply in Lesotho. Under this approach, the regulated service company can charge tariffs that cover its reasonable operating costs to ensure a fair rate of return on its capital. If the company faces relevant changes in its costs, it can require the regulator to re-set the tariffs.

This methodology generally guarantees that the operator will recover its costs, and that the cost of capital would be low, due to the low risk of the business. However, international experience (particularly in the United States) has shown that the frequency of the reviews reduces incentives for productive efficiency and raises regulatory costs[6]. It may also be considered that this approach has developed incentives to over-invest in capacity and service quality[7].

"Incentive Based" Regulation (IBR) was introduced in Latin America in the late 1980s (Chile, Argentina) and in England at the beginning of the 1990s in an attempt to overcome the limitations of ROR. Under an IBR approach, the regulator must define a maximum regulatory constraint (price or total revenue) to be applied by the operator, based on efficiency criteria, without taking directly into consideration the real financial situation of the company. Moreover, prices are set for a certain tariff period (3 to 5 years), so the regulated company would have the incentive to reduce its costs during that period, as every cost reduction relative to the revenue requirement based on efficiency criteria would result in additional earnings compared to those expected in the tariff.

International experience shows that this kind of regulation provides better incentives to productive efficiency, even though in practice, price or revenue cap estimations have several common aspects

[6] Due to information asymmetry issues.

[7] Averch, H. and Johnson, L. 1962. *Behavior of the firm under regulatory constraint*. American Economic Review 52.

with ROR regulatory approach. This is because in setting the regulatory constraint the regulator must consider, at least as a reference, the real financial situation of the regulated firm.

The economic theory underlying tariff regulation was developed in the context of private ownership or autonomous management of network and generation assets. The incentive-based regulatory framework relies on the company having an economic incentive to maximize profits. Shareholders have an economic incentive to maximize return on their investment, and management must have incentives passed through into their contracts.

When a utility is in public ownership, incentive based regulation does not function in the same way. There are no shareholders, so there is no direct economic incentive on management to minimize costs, unless precise corporate and governance rules give place to those incentives.

As noted above the regulatory framework and tariff methodology in Lesotho was developed in the context of a privatisation plan in 2001-2005. However, the privatisation did not proceed as the increase in tariffs required was not considered politically or socially acceptable. There are no current plans to privatise LEC, so the COSS is based on the assumption the LEC will stay in public ownership. For this reason a switch to incentive based regulation is not recommended. The current cost-plus regulatory regime will remain appropriate for Lesotho for the foreseeable future.

3.2.2 YEARLY OR MULTI YEAR?

The computation of economic costs and tariffs reported in Task 4 (Deliverable 5) was based on a Multi-Year tariff regime, with a three-year period. The choice of multi-year is to:

- Avoid the tariff fluctuations and volatility that are present in a Single-Year regime,
- Reduce the institutional and procedural administrative costs that Single-Year regime generates,
- Allow LEC a longer planning horizon for project planning,
- Facilitate a gradual change of tariffs to cost-reflective levels – we recommend a tariff pathway that will move to the cost-reflective level over a number of years. The benefit of the multi-year approach is that it will allow LEC to achieve financial viability without imposing a tariff shock on customers, and
- Provide LEC with longer term income certainty that will assist it to demonstrate a financially viable business when seeking commercial financing.

The length of the tariff period (3 years) is in line with international experience (3 to 5 years), as a minimum period to effectively mitigate tariff volatility. In general terms the tariff period length is the result of trade-off between mitigation of volatility (the longer the period, less volatility) and the efficiency gains retained by the operator (the longer the period, higher efficiency gains kept by the utility and not transferred to the customer).

3.2.3 ALLOWANCE FOR RETURN ON ASSETS?

The **Cost-Plus** tariff regime includes an allowance for the provision of a reasonable rate of return on assets. This is designed to enable the utility to raise capital and invest in the improvements and additions to its assets required to meet customer demand and growth. Up to now tariffs in Lesotho have not included an element designed to provide a return on assets. Furthermore, the Government of Lesotho has funded the majority of asset improvements and additions. The COSS is tasked to develop cost-reflective tariffs which by definition include a return on assets element.

The computation of economic costs and tariffs reported in Deliverable 5 was based on rate of return via Weighted Average Cost of Capital (WACC) and a rate of 6.5% post-tax WACC was applied. In section 3.2 below we argue that including a return on assets immediately would be too much of a tariff shock to customers and we recommend a gradual introduction of a full return on capital over 3 to 6 years.

It is worth noting that there are elements that are beyond LEC control such as fuel costs, inflation, depreciation of the local currency, changes in the interest rate, etc. For all the elements that are beyond the control of LEC, an adjustment or pass through formula is needed. For instance, in Nigeria where IBR is in place, bi-annual Minor Reviews take into consideration four variables: % rate of inflation (US and NGN), $/MMBTu gas price (cost of fuel), ₦/USD foreign exchange rate and actual MW daily generation capacity. We believe the adoption of a multi-year regime as proposed in section 3.2.2 necessitates the introduction of such a minor review in Lesotho. Proposals for this will be included in the subsequent Task 9 (Deliverable 10).

3.2.4 Financial Sustainability

A critical component of any tariff policy is to ensure that the company is able to meet its financial objectives under the suite of tariffs that result from the policy.

An important determinant of the financial position of the firm is the form of regulation, which will affect the amount of systematic risk faced by the firm. In general the level of systematic risk faced will be higher for a price cap versus a revenue cap, and higher in general for incentive regulation versus rate of return regulation. The firm should receive appropriate compensation for systematic risk through its cost of capital, which as noted above is reflected in its return on capital determined as noted above in section 3.2.3 from the WACC calculation. More specifically via the beta parameter in the cost of equity calculation following the CAPM approach. The beta parameter for a regulated firm was considered in the WACC calculation presented in Task 4 (Deliverable 5) report. However, regardless of the cost of capital, under highly powered incentive regimes, greater variability in revenue will be evident. Greater variability of revenue affects the financial position of the firm by creating a gap between revenues and costs.

Revenue variability has financial implications for tariff policy since the more the firm can align its key cost drivers with revenues received, the more the firm's financial position can be protected. At a high level this requires that the tariff design must ensure that total revenue to be produced by the tariffs will cover economic and efficient costs of supply, taxes, investments and reasonable rates of return. Also, at a more detailed level, the tariff design needs to ensure that:

- Fixed costs of the firm – that have to be paid regardless of energy consumed – are recovered through fixed charges paid by customers; while
- Variable costs of the firm are aligned with the variable component of the tariff.

Where tariff increases need to be more than is economically or politically viable then it may be argued that the costs to be recovered be prioritised. For example, it seems reasonable that in such a case costs should be met by tariff revenue in the following order of priority:

1. Bulk supply (generation) cost.
2. Operating costs for the licenced business activity.

3. Depreciation on investments in the licenced business activity.
4. Return on Capital invested.

4 Recommended Approach

4.1 Summary of COSS Findings

The bullets that follow provide a summary of relevant outputs from earlier deliverables that inform the decision as to what approach is appropriate for regulating LEC tariffs going forward:

- Tariffs need to increase overall by 35% on average to become fully cost reflective.
- Tariffs need to be altered significantly amongst tariff categories for each category tariff to be cost reflective.
- Commercial and industrial customers need to pay significantly more energy charge and significantly less maximum demand charge to reflect more accurately the actual respective costs of supplying their maximum demand and their energy.
- Overall the average tariff level is comparable or lower than other regional tariffs.
- The consumption of newly connected domestic consumers is low and has fallen significantly in recent years.
- It is justified to put in place a lifeline tariff of 0.5 M/kWh for the first block of domestic consumer consumption set at 30kWh per month.
- Historically the majority of capital investment in electricity supply has not been funded from tariff revenues. The assets capital efficiency[8] of LEC for the period 2012/13 – 2015/16 was reviewed in Deliverable 7. It was shown to be less efficient than developed world utilities in Spain but similarly efficient to the most comparable regional company (Swaziland[9]). A lesson learnt from this analysis would be to ensure that the asset base is properly disaggregated (transmission, distribution, supply) and the data needed for a comprehensive benchmarking analysis is collected in a consistent and tabular format (e.g., assets and peak demand separately for transmission and distribution). It appears that on the whole the asset base composition is consistent with the assets required to deliver electricity to LEC customers in accordance with its licence conditions. There are no obvious elements in the asset base that are not relevant to the electricity supply business. The asset base valuation has been regularly confirmed by independent review[10], a process that should be maintained and undertaken in a ring-fenced manner with transmission and distribution valued separately.
- To avoid an excessive tariff shock for customers, we recommend postponing the inclusion of a full return on capital in the approved revenue requirement for at least three years; and this was considered reasonable by the Study Technical Committee during the December 2017 review meetings in Maseru.

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[8] [Gross Value of Fixed Assets]/[Peak Demand] – i.e., a reflection of capital expenditure per peak kW.

[9] Most similar power system (import-dependent, with high levels of interconnection, most comparable levels of peak demand and installed capacity).

[10] Latest review was PWC revaluation 2015

- LEC operational cost efficiency compares quite well with its peers in Africa but when compared with other parts of the world improvements can be made.
- Considering revenue requirements in 2018/19 and for the case of full return on capital and opex performance improvements the bulk supply costs amount to 49%, the return on capital 20%, the return of capital (depreciation) 9%, and the operating expenditure the remaining 22%.
- Considering revenue requirements in 2018/19 and for the case of no return on capital the bulk supply costs amount to 61%, the return of capital (depreciation) 11%, and the operating expenditure the remaining 27%.
- Deliverable 7 recommended an improvement of approximately 3.3% in network operational cost efficiency and a 7.6% improvement in commercial operational costs as a suitable target for the first three-year review period.
- Deliverable 5 recommended a three-year tariff review period and this was considered reasonable during the December review meetings in Maseru.
- During the December review meetings the opportunity to provide incentives to LEC management to improve operational efficiency was discussed without a major conclusion being reached either for or against the concept.
- There is evidence that LEC management have not been motivated to improve efficiency under the current regulatory system.
- There is uncertainty as to the long-term bulk supply solutions for Lesotho between continuing to rely on imports and a programme of investment in national generation projects.
- There is uncertainty as to the long-term roll out of electricity to the majority (approximately 60%) of households that are still not connected, and whether there will be a shift to off-grid solutions with a significant reduction in the level of grid extension that has been taking place in recent years.
- As noted in section 2 an incentive based regulatory regime is not proposed because the continuing public sector ownership of LEC makes it less relevant to provide incentives to improve the financial performance of the business. Furthermore the uncertainties in bulk supply and grid connection policy suggest it would be unwise at this stage to change the regulatory regime.

4.2 Resultant Recommended Approach

4.2.1 Tariff Regime

The recommended tariff regime is to retain the existing cost of service system, extend it to three years, provide a minor review process for bulk supply variations in cost annually, and propose a relatively small bonus payment to LEC management be allowed (at LEC's Board's discretion to apply) as a regulatory cost for the achievement of specific improvements in operating efficiency.

4.2.2 Specific Proposals

The following eight specific proposals were discussed and agreed as appropriate at the December review meetings in Maseru:

1. Tariffs should rise to cost reflective levels excluding return on capital over the three-year review period – i.e., covering bulk costs, operating expenditure and depreciation. An operational efficiency improvement of about 0.9% per year in network opex and 2.0% per year in commercial opex should be assumed in estimating the operating expenditure.
2. The introduction of a lifeline tariff is to be considered, though it was proposed by the Study Technical Committee (STC) that the lifeline tariff level must at least cover bulk supply costs – i.e. about 61% of the allowable revenue if returns on capital are excluded. It was also the opinion of the STC that the subsidy required to make up the LEC deficit resulting from the lifeline block tariff being lower than cost reflective would be paid by an uplift in all other tariffs. A sensitivity to this recommendation is provided in the Task 9 (deliverable 10) report.
3. We will review the legal situation with respect to the Universal Access Fund levy, which was considered would ideally be discontinued given that non-lifeline level customers would be required to now meet the costs of the lifeline block subsidy.
4. We will include a fixed charge tariff for credit metered customers and consider making a provision that fixed charges also be applied to domestic customers that install generation.
5. Tariffs will be rebalanced amongst tariff categories over the three-year tariff review period. However the General Purpose tariff (which needs to be reduced by 27% to be cost reflective) would be maintained constant in the expectation that rising costs would lead to it becoming cost reflective in due course.
6. We will consider gradually rebalancing capacity and energy tariffs for industrial and commercial customers and recommend a suitable path in deliverable 10.
7. LEC need to demonstrate that they are including the lowest possible Bulk Supply costs in calculating the revenue requirement. Two particular areas for consideration are
   - Disallowing the EdM costs which are significantly higher that other bulk supply costs, and
   - Ensuring Muela is operated to maximise output at peak and minimise output at night[11].
8. LEC need to consider the technical and commercial implications for the introduction of time of use tariffs for large customers to better match demand and supply timings[12].

4.2.3 Impact on LEC of Not Recovering the Return on Capital

As noted above in section 3.2.3 LEC has always functioned without earning a return on its capital. Government has provided grants for capital expenditure requirements. Thus LEC has not been in full control of the investment process inevitably affecting its ability to effectively prioritise its investment decisions.

Without a return on capital the future requirements for investment to maintain the quality of supply and expand the network to meet growing demand will need to continue to be funded by Government.

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[11] We understand that the LHDA contract requires it to do this and that there are no technical barriers to prevent it. However it is not clear whether it actually takes place optimally or indeed at all. There is anecdotal evidence that it does not. The COSST model can be used to demonstrate the savings for LEC of enforcing the optimum operation of Muela.

[12] Countries in Africa that have TOU tariffs for industrial customers include: Burkina Faso, Cameroon, Cote D'Ivoire, Ethiopia, Senegal, South Africa (since 1992 and including commercial and some residential), and Uganda.

The level of funding required for various scenarios is provided in the Task 6 (Deliverable 7) report. For example for the following scenario:

- Under the proposed roll out,
- with a full return on capital included in the tariffs that result from the second three-year review

then the likely amount of funding required to ensure the business has sufficient capital for its effective operation over the coming three years would be of the order of 550 million Maloti.[13]

5 The Cost of Service Study Tariff Model (COSST)

A COSS Tariff Model has been developed in Microsoft Excel as part of the project. It consists of 4 modules that cover system expansion, cost of service tariffs, tariff roll out and LEC financial performance respectively. A separate model manual has been prepared which describes the operation of the 20 worksheets and acts as a guide to using the model for tariff reviews in the future.

The COSST model can be used by LEC to develop its tariff applications. It can also be used by LEWA to analyse LEC tariff applications. The model has built-in considerable flexibility to investigate a wide range of variables that are likely to be of importance to LEC and LEWA from time to time, for example:

- A comprehensive range of options for defining how increasing load in the future will be supplied – the applicable range of import parameters, a flexible range of local generation options including generic generation by wind, solar and hydro generation plant.
- A flexible range of options for expanding the network as LEC may determine to be necessary from time to time.
- Revised load profiles for different types of consumer based on existing tariff categories.
- The starting Regulatory Asset Base (RAB).
- Inputs for transmission and distribution losses.
- Cost allocation criteria for different tariff categories: consumption, coincidental peak at peak, non-coincidental peaks.
- Adjustable cost allocations (energy, fixed charge and maximum demand charge) to tariff categories.
- Adjustable weighted average cost of capital (WACC).
- Options for items to be included in the allowable revenue.
- Varying tariff changes amongst the tariff categories.
- Different scenarios for tariff changes over the three-year tariff review period.
- Allowing for improvements in LEC operating efficiency.
- Allowing for the inclusion of an Increasing Block Lifeline Tariff and variations in its threshold and tariff. Numbers of customers below the threshold can also be varied.
- Inputs for starting positions for the LEC annual accounts such as opening cash.

[13] See Task 3 (Deliverable 4) report for detail of the investments included in the analysis.

- Variations in the provision and cost of working capital, and the threshold for securing additional working capital.

The model has also been developed to be a flexible tool that will allow for changes in the sector going forward. It would be possible for example to modify the model so that it would still be useful if major structural changes take place in the sector. We believe this makes the model appropriate for Lesotho where major sectoral changes seem likely given the uncertainties related to:

- Securing additional supply to meet growing demand; and
- The future direction for delivering greater access for the more than half of the population not having access to electricity: whether it is further grid roll out or a stronger focus on off-grid solutions.

Major structural changes that could potentially occur might include:

- Significant levels of local generation are developed;
- LEC is further unbundled to separate financial recording into transmission, distribution and supply;
- The regulatory regime may be reviewed; and
- The governance of LEC may be amended.

The model has been designed so that it would be relatively easily modified to adopt such changes.

6 Capacity Building

6.1 Review Of Capacity Building Requirements In LEWA And LEC

It can be seen that the COSST model described above in section 5 has considerable flexibility. The flexibility is achieved by constructing the model such that a wide range of variables can be changed, and the calculations interrogated. There are 20 calculation worksheets with a need for direct operational adjustments on a number of these to reflect the various options the model allows. The model is therefore easier to comprehend and to operate after first undergoing sufficient hands-on training in its use.

Thus because of both the functionality of its operations and the need for it to be modified for future structural changes that may take place, the model has not been designed as a black box and is in fact a conventional Microsoft Excel tool that requires both excellent skills in using Excel as well as a particular understanding and familiarity with the model itself.

Thus the capacity building required is both:

- Generic expertise in Excel modelling; and
- Building an understanding in users of the COSST model and how to apply it.

6.2 Plan For Building Capacity

Building the expertise in Excel is relatively straightforward and indeed a skills audit in LEWA and LEC may identify that adequate skills in Excel already exist. If the audit identifies a need for further training in Excel, courses will be available to do this in the region.

Building expertise in the COSST model requires a specific and tailored capacity building approach.

To gain a thorough useful understanding of the model it needs to be utilised in earnest under supervision – academic exercises are unlikely to be sufficient because of the complexity described above. In other words on-the-job training is recommended to ensure users learn to operate the COSST model effectively.

We expect that with career progression and other staff changes regular training in COSST will be required, especially given that with a three-year tariff review period the model may only be used in earnest in every third year.

We therefore recommend that both LEC and LEWA appoint skilled Excel users to become COSST experts that will be available as trainers to pass on their knowledge in years to come. These designated COSST experts should be involved in the upcoming 2018 tariff review and work alongside the COSST developers to develop a hands-on expertise that they can then pass on in future years. Such hands-on work could involve 2-3 weeks working together with the COSST developers, followed by regular interactions with the developers (possibly through internet communication links) during the finalisation of the tariff review.

Electricity Supply Cost of Service Study – LEWA Lesotho

Tariff Roll Out Plan – Deliverable 10

Support Provided by African Development Bank

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Contents

1 INTRODUCTION

This is the tenth deliverable of the Cost of Service Study (COSS) for Electricity Supply by LEC in Lesotho being carried out for LEWA and supported by the AfDB. It reports on the analysis undertaken to address the terms of reference for Task 9 of the COSS. Task 9 (deliverable 10) includes four main elements:

1. Recommendations for alternative strategies to gradually adjust tariffs to cost reflective levels;
2. A comment on the applicability of a multi-year tariff review period;
3. A review of the applicability of an automatic pass through mechanism for certain costs; and
4. Guidelines for the introduction of a lifeline tariff.

Section 2 of this report reviews the revenue based regulatory regime which for completeness summarises the key findings of Task 8 (deliverable 9). Section 3 considers the cost pass through or minor review process. Section 4 summarises the lifeline tariff recommendations and provides an outline of guidelines for the introduction of a lifeline block tariff. Section 5 describes the roll out options and the results of using the COSST model described in Task 8 (deliverable 9) to analyse the impact of a base case recommended strategy and two alternative strategies. Finally, Section 5.3 considers the options for improving the Governance of LEC to respond to a specific request from LEWA made during the December workshop.

2 REVENUE BASED REGULATORY REGIME

2.1 THREE-YEAR REVIEWS

Deliverable 9 recommended a three-year tariff review period. Moving from the current single-year review to a multi-year regime would bring various benefits which would:

- Avoid the tariff fluctuations and volatility that are present in a Single-Year regime;
- Reduce the institutional and procedural administrative costs that Single-Year regime generates;
- Allow LEC a longer planning horizon for project planning;
- Facilitate a gradual change of tariffs to cost-reflective levels – we are recommending a tariff pathway that will move to the cost-reflective level over a number of years. The benefit of the multi-year approach is that it will allow LEC to achieve financial viability within a tariff review period without imposing a tariff shock on customers; and
- Provide LEC with longer term income certainty that will assist it to demonstrate a financially viable business when seeking commercial financing.

2.2 SPECIFIC PROPOSALS

Deliverable 9 also made eight specific proposals which we repeat here for completeness:

1. Tariffs should rise to cost reflective levels excluding return on capital over the three-year review period – i.e covering bulk costs, operating expenditure and depreciation. An

operational efficiency improvement of about 0.9% per year in network opex and 2.0% per year in commercial opex should be assumed in estimating the operating expenditure.

2. The introduction of a lifeline tariff is to be considered, though it was proposed by the Study Technical Committee (STC) that the lifeline tariff level must at least cover bulk supply costs – i.e. about 61% of the allowable revenue if returns on capital are excluded. It was also the opinion of the STC that the subsidy required to make up the LEC deficit resulting from the lifeline block tariff being lower than cost reflective would be paid by an uplift in all other tariffs. A sensitivity to this recommendation is provided in section 5.3.
3. We will review the legal situation with respect to the Universal Access Fund levy; which it was considered would ideally be discontinued given that non-lifeline level customers would be required to now meet the costs of the lifeline block subsidy.
4. It was agreed to include a fixed charge tariff for credit metered customers, and consider making a provision that fixed charges also be applied to domestic customers that install generation.
5. Tariffs would be rebalanced amongst tariff categories over the three-year tariff review period. However the General Purpose tariff (which needs to be reduced by 27% to be cost reflective) would be maintained constant in the expectation that rising costs would lead to it becoming cost reflective in due course.
6. A gradual rebalancing of the capacity and energy tariffs for industrial and commercial customers would be considered.
7. It was proposed that LEC demonstrate they are including the lowest possible Bulk Supply costs in calculating the revenue requirement. Two particular areas for consideration are
    - Disallowing (or renegotiating) the EdM costs which are significantly higher than other bulk supply costs, and
    - ensuring that 'Muela is operated to maximise output at peak and minimise output at night[1].
8. It is recommended that LEC considers the technical and commercial implications for the introduction of time of use tariffs for large customers to better match the demand and supply timings[2].

3 Automatic Pass-Through – Minor Reviews

The regulatory rules allow for the automatic pass through to tariffs of unspecified costs. The philosophy is however clearly that costs that could be automatically passed through to tariffs would be costs over which the utility has little or no control. We suggest that such costs could include:

[1] We understand that the LHDA contract requires it to do this and that there are no technical barriers to prevent it. However it is not clear whether it actually takes place optimally or indeed at all. There is anecdotal evidence that it does not. The COSST model can be used to demonstrate the savings for LEC of enforcing the optimum operation of Muela.

[2] Countries in Africa that have TOU tariffs for industrial customers include: Burkina Faso, Cameroon, Cote D'Ivoire, Ethiopia, Senegal, South Africa (since 1992 and including commercial and some residential), and Uganda.

- Bulk supply costs in cases where the suppliers of bulk electricity vary contracted prices for factors outside their control – e.g. fossil fuel prices varying on the world market.
- An adjustment to the tariffs to take into account changes to the volumes of electricity actually consumed compared to the volumes predicted in the tariff review analysis.
- Domestic price inflation.
- Exchange rate variations that impact debt service costs and long-term operation and maintenance costs of foreign contractors.
- Labour costs where national union power imposes labour costs increases beyond the control of the company.

Historically automatic pass through has not been utilised in the sector principally because tariffs have been reviewed every year. As we are recommending a three-year tariff review period we propose that LEC consider taking the opportunity to automatically pass through bulk supply cost variations and changes to assumptions regarding inflation. We suggest it does this annually in accordance with the laid down procedures[3]. We have included in Annex A a draft supplementary tariff methodology for tariff indexation and minor reviews.

To assure stability of tariff levels, LEC should enter into long-term supply contracts, which would guarantee stable prices over time to assure sustained viability.

4 Introducing the Lifeline Tariff

4.1 Summary of COSS Findings

4.1.1 Summary Results of Deliverable 6

Deliverable 6 of the COSS concluded as follows:

> *There is a strong case for the introduction of a lifeline tariff in Lesotho. A majority of households connected to the grid would be considered fuel poor if paying for their usage at current tariff levels. The evidence of a rapidly decreasing consumption for newly connected customers further supports the conclusion that a lifeline tariff is needed for low consumption households. This is further reinforced by surveys that have been carried out over many years which point to the fact that most households in Lesotho use electricity only for lighting.*
>
> *Thus tariff reform should address not only the issue of access and cost-reflectivity but affordability as well. Globally in both developing and developed countries affordability has been addressed by various subsidy mechanisms and consumption targeted lifeline tariffs has been found to be the most effective.*
>
> *A lifeline tariff for households that consume less than 30kWh/month would adequately address the basic energy necessities of poor households in Lesotho and lead to an improvement in the standard of living. An important additional benefit would be a reduction in the use of biomass*

[3] We noted in Deliverable 9 (section 2.3.4) that the published guidelines of LEWA include the "Revised 'pass-through charging principle for bulk supply tariffs' and procedure for implementation mechanism" which defines a balancing account to be set up "virtually" by LEC but accessible to all, that records actual payments for bulk supplies. Such a mechanism could be used in conjunction with the minor review process.

which contributes to the degradation of the environment and CO_2 emissions. If a lifeline tariff had been in place in 2016 with a threshold of 30kWh/month it would have provided subsidised electricity to about 25% of households.

A lifeline tariff of 0.5 to 0.6 M/kWh would ensure that customers on or below the poverty line could reasonably afford to pay for electricity and we therefore proposed a lifeline tariff be set at 0.5 M/kWh. We also concluded that the preferable tariff structure in Lesotho would be the Increasing Block Tariff system.

We demonstrated the impact on other tariffs and provided an indication of the order of magnitude increases in the standard domestic tariff if the cross subsidy is to be recovered through tariffs only.

We noted that public education and consultation with key stakeholders, is critical for success of the lifeline tariff. In planning a tariff reform, it is important to clearly outline the goals and objectives, identify main stakeholders and interest groups, and develop strategies to address their concerns. Convincing the population that there is a credible commitment to compensate the vulnerable groups is essential for the success of introducing a lifeline tariff.

4.1.2 Meeting of STC in December 2017 – Lifeline and Universal Access Fund

We took part in discussions with the Study Technical Committee in December and we noted the following:

LIFELINE TARIFF DEFINITION

The introduction of a lifeline tariff is to be considered, though it was proposed that the lifeline tariff level must at least cover bulk supply costs – i.e. about 60% of the allowable revenue if returns on capital are excluded. The subsidy required to make up the LEC deficit resulting from the lifeline block tariff being lower than cost reflective would be paid by an uplift in all other tariffs.

UNIVERSAL ACCESS FUND

As noted in the Background section 2.3 of the Deliverable 6 it is also necessary to review the continuing collection of the Universal Access Fund levy from existing customers. The discussions with the STC in December suggested that the introduction of the lifeline block tariff would need to consider the discontinuing of the UAF levy and we agree with that conclusion. It would be unfair and unreasonable to continue to collect a levy from existing customers to fund the extension of the grid to new customers that are likely to be mainly low consumption poorer households also availing of the lifeline block cross-subsidy from existing customers. However it is also our understanding that there is probably a need for a change in law before LEC can discontinue the collection of the UAF levy.[4]

[4] The levy collection can be repealed only by a determination contained in an act that has the same legal status as the Legal Notice no 83/2011 that established that the UAF levy be collected in 2011.

4.2 LEGAL REQUIREMENTS

4.2.1 POLICY OVERVIEW

The legal and regulatory basis for the life-line tariff comes from the Regulators' mandate i.e. LEWA Act itself – see section 4.2.2.

The "Lesotho Energy Policy 2015-2025" and the LEA Act (provisions 21 and 24 as detailed below in section 4.2.2) provide the principles for the provision of a life-line tariff.

Lesotho Energy Policy, Policy Statement 10 (Electricity Connections) Strategy f - is to "negotiate for better planning of settlements to allow provision of basic electricity services".

Lesotho Energy Policy, Policy Statement 15 (Energy pricing) Strategy b - is to "introduce and determine appropriate cross subsidy tariff mechanism to reflect electricity for basic human needs".

Lesotho Energy Policy, Policy Statement 15 (Energy Pricing) Strategy c - is to "introduce a levy and create capital subsidy fund for enhancing affordability of energy services".

4.2.2 LEA ACT

The Act No. 12 of 2002 (Lesotho Electricity Act, 2002 as amended in 2006 and 2011) establishes the Lesotho Electricity and Water Authority to regulate and supervise activities in the electricity sector and to make provision for the restructuring and the development of the electricity sector in Lesotho and for connected matters.

Section 21 (I) (e) of LEA Act provides that the Authority shall "protect the interests of all classes of consumers of electricity as to the terms and conditions and price of supply".

Section 24 ("Review and setting of tariffs rates and charges") lays down obligations on service providers in relation to applications for changes to tariffs and rights and obligations of the Authority in relation to the review and approval of those tariff applications.

4.3 GUIDELINES FOR INTRODUCING A LIFELINE BLOCK TARIFF

As noted above we believe a lifeline block tariff can be introduced without change to the law – i.e. within the current LEWA regulations. LEWA needs to instruct LEC that in the next tariff review they need to include a lifeline block tariff. This will be a tariff that applies to the first 30 kWh per month for all domestic customers. The tariff applying to domestic customers for consumption above 30 kWh in a month will be renamed the standard domestic tariff. We also conclude that given the relatively small number of large-consumption domestic customers there is no justification for the introduction of a third higher domestic block tariff for high consumption customers. In section 5 we demonstrate that even without a third higher block tariff such high consumption customers do pay significantly higher bills following the introduction of the lifeline block tariff – see Figure 2.

The roll out of our economic cost based tariffs will then take place according to the other recommendations of the COSS project. LEC will need to adjust its pre-payment system such that it maintains a log of domestic customers consumption and adjusts prepayment top ups to ensure that over time consumption below an average of 30 kWh per month is charged at the lifeline rate and consumption above at the standard tariff. We believe this can probably be done within the billing software.

Thus the IBT lifeline tariff system we have recommended does not involve specific new Regulations or Rules. However we have included in Annex B draft Guidelines that LEWA can adapt as required for publication.

LEWA and LEC should ensure that awareness campaigns are rolled out nationally to educate communities on the introduction of the Lifeline Block Tariff.

5 Roll Out Options

5.1 Summary of Key Model Inputs for Roll Out Plan

In addition to the specific proposals listed in deliverable 9 and repeated above in Section 2.2, the following assumptions were used in the COSST model to initiate a study of the options:

- Introduction of a Lifeline Tariff from 1st April 2018 set at 0.65 M/kWh (approximate level of generation tariff over the tariff period).
- An operating efficiency improvement in line with the “intermediate” case presented in deliverable 7 – Table 1. This indicates a reduction in network opex (opex/MWh) and commercial opex (opex/cust).
- Fixed charges for credit customers – industrial, commercial and street lighting.
- The generation costs component of the allowable revenue is computed via the LRAC approach (0.640 M/kWh at generation level) and assuming LEC procure power at least cost (i.e., minimal use of EdM and ‘Muela is despatched optimally to minimize import costs).
- As a result of these adjustments if any “economic” tariffs are below the current tariff, such tariffs will not be allowed to reduce and will remain flat until they need to rise to be economic.

Table 1: Opex included in tariff study including intermediate operating efficiency improvement

		2018	2019	2020
		Network opex		
Energy wheeled	MWh	925,056	958,832	992,609
2016 level	M/MWh	168.2	168.2	168.2
Included in tariff	**M/MWh**	**165.4**	**164.0**	**162.5**
		Commercial opex		
Number of customers	#	249,607	264,586	276,577
2016 level	M/cust	459.7	459.7	459.7
Included in tariff	**M/cust**	**442.2**	**433.5**	**424.8**
Resulting total opex	**M mil**	**263.35**	**271.90**	**278.83**

The resulting revenue requirement is shown in Table 2 and economic tariffs and required increases from current levels are shown in Table 3. It was agreed during the December roll out strategy meetings with LEWA and LEC that switching straight to the economic level of tariffs would not be desirable and instead more gradual changes are preferred. A study of options that meet this criterion are explored in the following subsections.

Table 2: Revenue requirement for tariff study options

Required Revenue	2018	2019	2020
Return of Capital (Depreciation) - Distribution Assets	50,627,932	54,212,853	57,161,015
Return of Capital (Depreciation) - Transmission Assets	59,172,068	61,121,066	62,615,952
Return on Capital - Distribution Assets	105,470,706	115,647,237	123,542,419
Return on Capital - Transmission Assets	128,023,734	133,960,428	138,234,284
Common OPEX Distribution System	182,479,252	199,366,027	213,625,883
Common OPEX Transmission System	82,661,002	90,310,517	96,770,067
Service OPEX Distribution System	20,275,472	22,151,781	23,736,209
Service OPEX Transmission System	4,350,579	4,753,185	5,093,161
Less Opex reduction for performance improvement	*-26,419,972*	*-44,678,835*	*-60,396,259*
Total Cost Generation for Demand	506,322,912	524,810,412	543,297,912
Total Cost Generation for Energy Losses	85,459,806	88,633,500	91,807,195
Total Revenue Requirement	**1,198,423,491**	**1,250,288,172**	**1,295,487,838**

Table 3: Comparison of current tariffs to the economic tariffs with adjustment for opex efficiency

Tariffs – excluding levies and VAT	Current 2017/18	Economic – with opex adjustments	Increase from current
Energy Charges - M/kWh			
Domestic	1.347	1.925	43.0%
General Purpose	1.522	1.524	0.1%
LV Commercial	0.206	0.731	254.5%
HV Commercial	0.186	0.773	315.6%
LV Industrial	0.206	0.731	254.7%
HV Industrial	0.186	0.774	315.8%
Street Lighting	0.764	1.674	119.1%
Demand Charges - M/kVa			
LV Commercial	306.302	272.973	-10.9%
HV Commercial	262.239	143.079	-45.4%
LV Industrial	306.302	242.819	-20.7%
HV Industrial	262.239	143.599	-45.2%
Fixed Charges - M/month			
Domestic	0.000	0.000	
General Purpose	0.000	0.000	
LV Commercial	0.000	6.952	
HV Commercial	0.000	3681.801	
LV Industrial	0.000	6.962	
HV Industrial	0.000	3673.140	
Street Lighting	0.000	6.945	

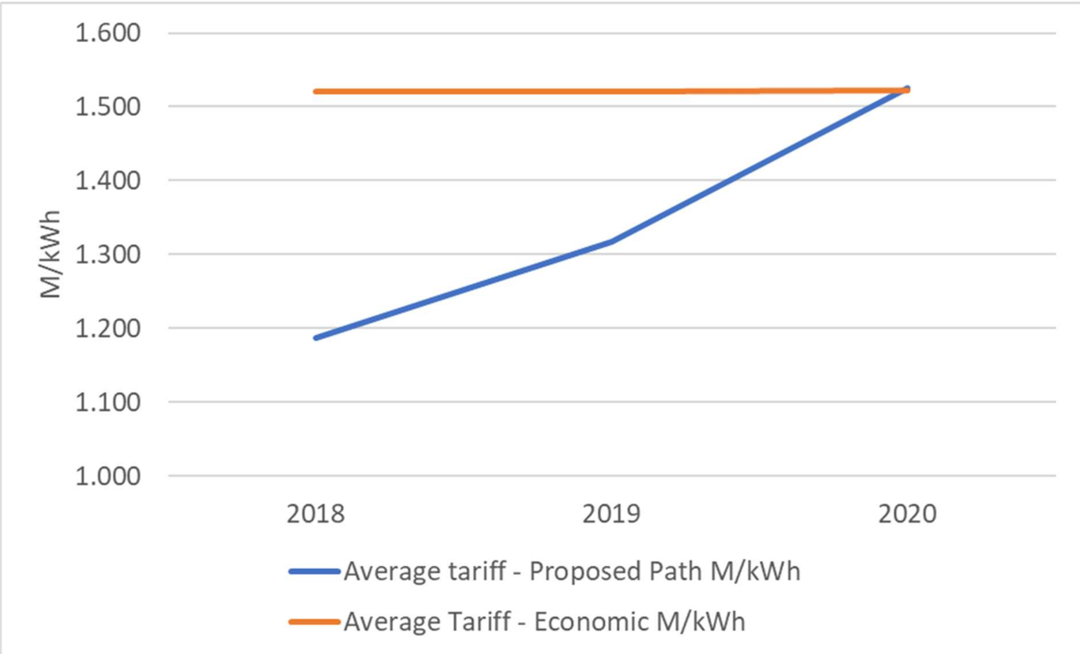
5.2 Study of Options

5.2.1 Option 1: Recommended

Option 1 is our recommended[5] tariff plan for Lesotho.

In this option, tariffs are increased gradually towards the economic level. If this plan is adopted, then LEC are expected to under-recover against the revenue requirement in years 1 and 2 of the price control but by year 3, the tariffs reach the economic level including Return on Capital. This is demonstrated at the average tariff level in Figure 1.

Figure 1: Average tariff pathway 2018-20 relative to the economic tariff level under first tariff study option 1



To establish fully cost-reflective economic tariffs the most significant change required in customer tariffs is the rebalancing of energy and maximum demand tariffs for industrial and commercial customers. Deliverable 5 demonstrated that this change is warranted by the considerable mismatch between the current split of tariffs and the actual division of costs between capacity and energy consumption; for example, the current energy charge is around 0.2 M/kWh which is well below the expected generation cost of around 0.65 M/kWh (at the distribution level). With generation costs

[5] The discussions during the workshop in December 2017 combined with further analysis carried out for this deliverable has resulted in a recommended tariff pathway with a slightly faster path to economic tariffs from that discussed in the Task 6 (Deliverable 7) report. An important factor in this improvement has been the detailed review of the impact on overall payments by the different types of customer. Thus domestic tariff rises are shown to have a lower impact because of the lifeline block tariff and the complex commercial industrial rebalancing is shown to have a modest impact on average customers.

being fully allocated to energy charges for all customer categories, it is clear that a significant increase in energy charges for commercial and industrial customers is needed.

Increases in domestic and street lighting tariffs are also required. The overall increase in domestic is 13.4% per year although the introduction of a lifeline block tariff means this increase is portioned as a 52% reduction at the lifeline block level (1.347 to 0.650 M/kWh) and a 34% increase in the standard domestic tariff (1.347 to 1.804 M/kWh). The street lighting tariff is increasing by 31.6% per year and there is no increase in General Purpose.

The combined effect of a low tariff for the first 30 kWh of monthly consumption with the remaining consumption at the standard domestic tariff is that typical customer bills increase by modest amounts. The impact on domestic bills in the first year is presented in Figure 2 below, showing that low consumption-level customers would see a 17% reduction, average consumption-level customers a 13% increase and high consumption level customers a 24% increase.

The resulting tariffs are as shown in Table 4. The Table also shows in the first column the current tariffs (no levies or VAT) and in the final column the resulting economic tariffs to provide a basis for comparison.[6]

Table 4: Tariff pathway for full balancing of MD and energy charges by 2021 tariff study option 1

Tariff	Current 2017/18	2018/19	2019/20	2020/21	Economic Tariffs
Energy Charges	**M/kWh**	**M/kWh**	**M/kWh**	**M/kWh**	**M/kWh**
Lifeline Block	1.347	0.650	0.650	0.650	1.925
Standard Domestic	1.347	1.804	2.088	2.404	1.925
General Purpose	1.522	1.523	1.523	1.524	1.524
LV Commercial	0.206	0.320	0.498	0.774	0.731
HV Commercial	0.186	0.306	0.502	0.823	0.773
LV Industrial	0.206	0.320	0.498	0.774	0.731
HV Industrial	0.186	0.306	0.502	0.824	0.774
Street Lighting	0.764	1.006	1.323	1.741	1.674
Demand Charges	**M/kVa**	**M/kVa**	**M/kVa**	**M/kVa**	**M/kVa**
LV Commercial	306.302	294.763	283.659	272.973	272.973
HV Commercial	262.239	214.284	175.099	143.079	143.079
LV Industrial	306.302	283.483	262.364	242.819	242.819
HV Industrial	262.239	214.543	175.522	143.599	143.599
Fixed Charges	**M/month**	**M/month**	**M/month**	**M/month**	**M/month**
Domestic	0	0	0	0	0
General Purpose	0	0	0	0	0
LV Commercial	0	6.952	6.952	6.952	6.952
HV Commercial	0	3681.801	3681.801	3681.801	3681.801
LV Industrial	0	6.962	6.962	6.962	6.962

[6] Note that the discrepancies between the 2020/21 energy charges and the economic energy charges is due to the economic energy charges being set at a flat rate over the period (so that the NPV of the summed differences between total expected income and total costs is zero – further explanation of this is provided in the Task 4 (deliverable 5) and Task 6 (deliverable 7) reports) whereas the 2020/21 energy charges are set to recover exactly the economic costs in that year with no consideration of previous years.

Tariff	Current 2017/18	2018/19	2019/20	2020/21	Economic Tariffs
HV Industrial	0	3673.140	3673.140	3673.140	3673.140
Street Lighting	0	6.945	6.945	6.945	6.945

Table 5 shows an excerpt from the projected financials for LEC under this scenario – performance improves throughout the period. This is due to tariffs being below the economic level in the first and second year of the price control before reaching the economic level in year 3.

The applied increases mean LEC is expected to have sufficient income (1,017.7 Mil) to cover bulk supply costs (513.7 M mil), Opex (263.3 M mil) and depreciation (115.9 M mil) in 2018 with a remaining income allowing a profit after tax of 45.7 M mil in 2018.

Table 5: Excerpts from projected income statement for full balancing of MD and energy charges by 2021 tariff study option 1

LEC Statement of Comprehensive Income	2018 M m	2019 M m	2020 M m
Total Revenue	1,017.7	1,158.5	1,375.8
Gross profit	449.1	589.3	788.6
Profit/(Loss) before tax	60.9	172.6	350.4
Profit/(Loss) after interest and tax	45.7	129.5	262.8

Under this scenario, funding is required in order for LEC to meet its network expansion goals and also invest in the amount of generation expected in the base case (e.g., the 10 MW Solar Park at Semonkong). The table below shows an excerpt from the projected cash flow and highlighted bold the level of funding[7] in order to maintain a minimum of 50 M million cash in bank balance. The table shows an income from commercial loans and capital grants totalling 399.2 M mil.

Table 6: Summary of projected cash flow for LEC in tariff option 1

Cash Flow	2018 M m	2019 M m	2020 M m
Opening Cash	**112.9**	**50.0**	**50.0**
Add receipts			
from commercial loans	**122.4**	**77.2**	**0.0**
from capital grants	**122.4**	**77.2**	**0.0**
Income from tariffs	575.7	658.0	754.0
Levies from customers	402.7	466.6	594.1
From connection fees	57.7	59.8	61.9
Other income	22.9	21.1	21.1
Less payments			
For power purchase	-513.7	-512.2	-526.2
LEC Generation - O&M	0.0	0.0	-2.1

[7] Assumed that funded is 50% commercial loans and 50% capital grant. See deliverable 7 report for assumptions on commercial loan properties.

Cash Flow	2018	2019	2020
Salaries, Wages and Opex	-263.3	-271.9	-278.8
Licence Fees to LEWA	-33.5	-34.7	-35.9
Electrification levy to REU	-21.4	-22.2	-23.0
Tax	-19.6	-15.2	-43.2
VAT	-49.5	-56.6	-67.5
Loan repayments including interest	-8.1	-26.8	-38.5
capital expenditure - new connection (LEC funded)	-28.6	-26.4	-26.4
capital expenditure - customer contribution	-22.9	-21.1	-21.1
capital expenditure - network	-265.7	-232.2	-188.7
capital expenditure - generation	-141.4	-141.4	-162.5
Closing cash	**50.0**	**50.0**	**68.1**

Of key importance is the impact of these changes on consumer bills, particularly with the introduction of a lifeline block tariff for domestic and rebalancing of MD and energy charges for industrial and commercial. Using actual data for 2016 from LEC these impacts are demonstrated in the figures below.

Figure 2 shows that for a low consumption domestic customer a 17% reduction in bills can be expected in 2018. For average consumers a 13% increase and for higher consumers a 24% increase.

The left most plot in Figure 3 considers three types of LV industrial customer who all consume the same amount of energy per month (20,529 kWh/month) but consume varying levels of maximum demand (ranges witnessed in the 2016 data from LEC). It shows that an average kVa/month and average kWh/month consumption customer (orange bar) can expect a modest 1% increase in their bill but a below average kVa/month (same energy) would see an increase. For HV industrial (right plot in Figure 3) the average customer (328,079 kWh/month, 641 kVa/month) would expect a 5% increase.

Figure 4, left plot, considers three types of LV commercial customer who all consume the same amount of energy per month (24,176 kWh/month). It shows that an average kVa and average energy consumption customer (orange bar) can expect a 7% increase in their bill. For HV commercial (right most plot in Figure 4) the average customer would expect a 2% increase.

Figure 2: Impacts on domestic customer bills for a low, average and high consumer under tariff study option 1

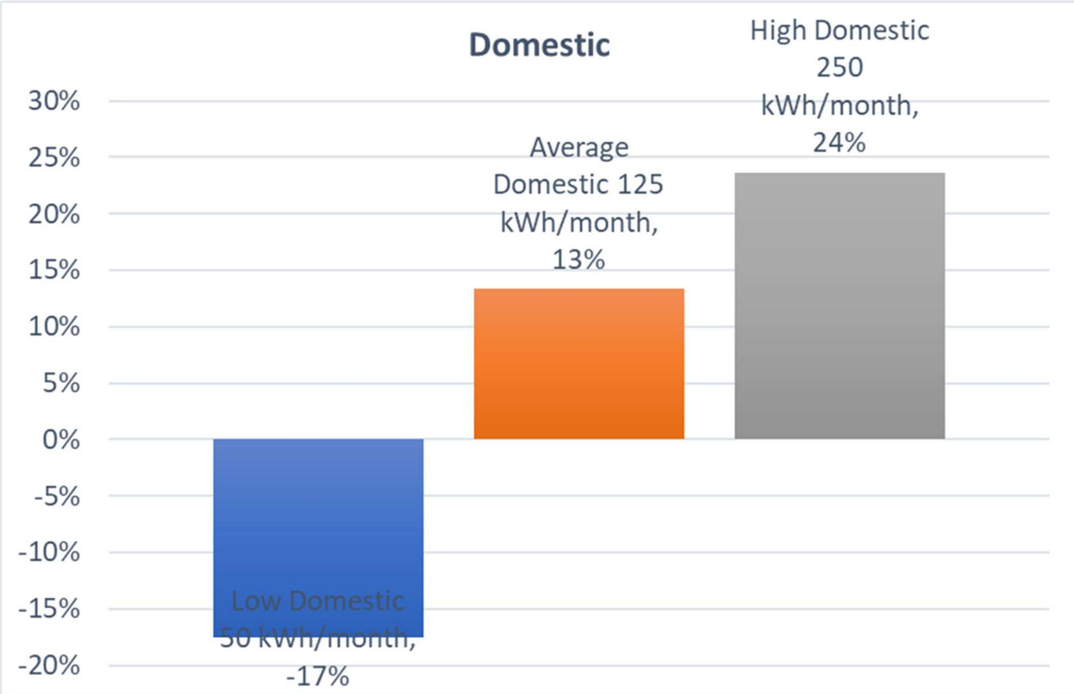


Figure 3: Impacts on LV and HV industrial customer bills for a low, average and high kVa consumer (each consuming same energy kWh/month) under tariff study option 1

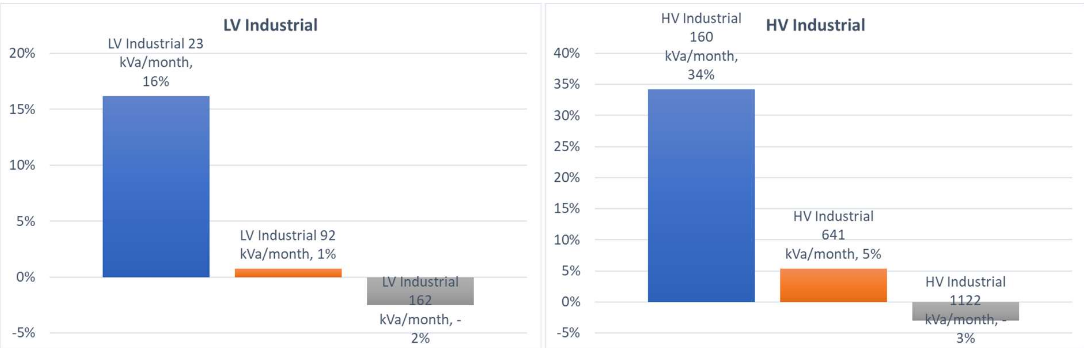
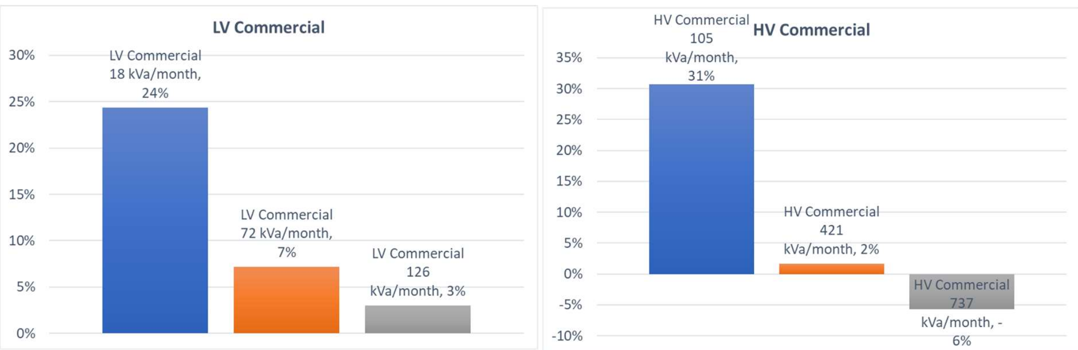


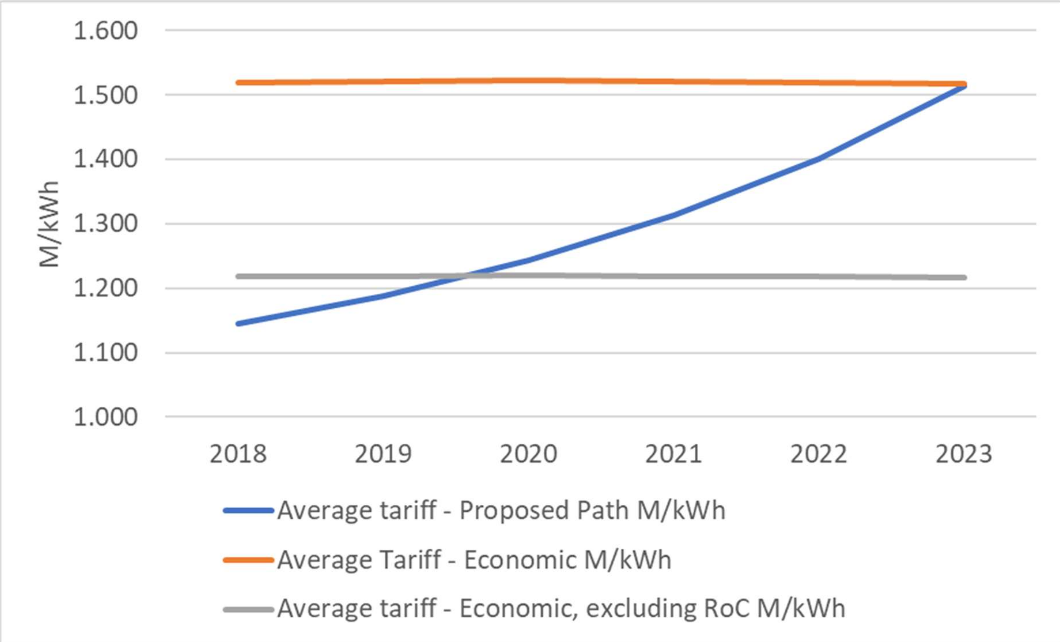
Figure 4: Impacts on LV and HV commercial customer bills for a low, average and high kVa consumer (each consuming same energy kWh/month) under tariff study option 1



5.2.2 OPTION 2: LOW TARIFF SHOCK

Under this option tariffs are increased more gradually with the rebalancing of energy and maximum demand charges for commercial and industrial customers spread over 6 years. Tariffs reach the cost-reflective level excluding Return on Capital by the third year and continue to increase to reach the economic level including Return on Capital (RoC) by the sixth year. Figure 5 shows the average tariff (blue line) compared to the economic level (orange line) and the economic level excluding RoC (grey line).

Figure 5: Average tariff pathway 2018-23 relative to the economic tariff level under second tariff study option



The resulting tariffs are as shown in Table 7. The table also shows in the first column the current tariffs (no levies or VAT) and in the final column the resulting economic tariffs to provide a basis for comparison.

Note that the combined effect of a low tariff for the first 30 kWh of monthly consumption with the remaining consumption at the standard domestic tariff is that typical customer bills increase by modest amounts. The impact on domestic bills in the first year is presented in Figure 6 below, showing that low consumption-level customers would see a 21% reduction, average consumption-level customers a 6% increase and high consumption level customers a 16% increase.

Table 7: Tariff pathway for full balancing of MD and energy charges by 2023 tariff study option 2

Tariff	Current 2017/18	2018/19	2019/20	2020/21	Economic Tariffs
Energy Charges	**M/kWh**	**M/kWh**	**M/kWh**	**M/kWh**	**M/kWh**
Lifeline Block	1.347	0.650	0.650	0.650	1.925
Standard Domestic	1.347	1.680	1.812	1.947	1.925
General Purpose	1.522	1.522	1.523	1.523	1.524
LV Commercial	0.206	0.256	0.319	0.397	0.731
HV Commercial	0.186	0.238	0.304	0.389	0.773
LV Industrial	0.206	0.256	0.319	0.397	0.731
HV Industrial	0.186	0.238	0.304	0.389	0.774
Street Lighting	0.764	0.875	1.002	1.147	1.674
Demand Charges	**M/kVa**	**M/kVa**	**M/kVa**	**M/kVa**	**M/kVa**
LV Commercial	306.302	300.477	294.763	289.158	272.973
HV Commercial	262.239	237.052	214.284	193.703	143.079
LV Industrial	306.302	294.672	283.483	272.720	242.819
HV Industrial	262.239	237.195	214.543	194.055	143.599
Fixed Charges	**M/month**	**M/month**	**M/month**	**M/month**	**M/month**
Domestic	0	0	0	0	0
General Purpose	0	0	0	0	0
LV Commercial	0	6.952	6.952	6.952	6.952
HV Commercial	0	3681.801	3681.801	3681.801	3681.801
LV Industrial	0	6.962	6.962	6.962	6.962
HV Industrial	0	3673.140	3673.140	3673.140	3673.140
Street Lighting	0	6.945	6.945	6.945	6.945

Table 8 shows an excerpt from the projected financials for LEC under this scenario – profits have reduced relative to the option 1 case however the applied tariff increases mean LEC is expected to have sufficient income to cover bulk supply costs, Opex and depreciation in 2018 with a remaining income allowing a profit after tax of 20.2 M mil in 2018.

Under this option 734.0 M mil of funding is required, approximately 245 M mil per year, which is more than double the requirement in the base case.

Table 8: Excerpts from projected income statement for full balancing of MD and energy charges by 2021 tariff study option 2

LEC Statement of Comprehensive Income	2018 M m	2019 M m	2020 M m
Total Revenue	983.8	1,052.1	1,136.3
Gross profit	415.1	483.0	549.1
Profit/(Loss) before tax	26.9	64.8	105.4
Profit/(Loss) after interest and tax	20.2	48.6	79.0

In this case the impact on consumer bills is reduced relative to option 1 although a larger reduction for low consumption domestic customers is achieved. This is shown in the plots below.

Figure 6: Impacts on domestic customer bills for a low, average and high consumer under tariff study option 2

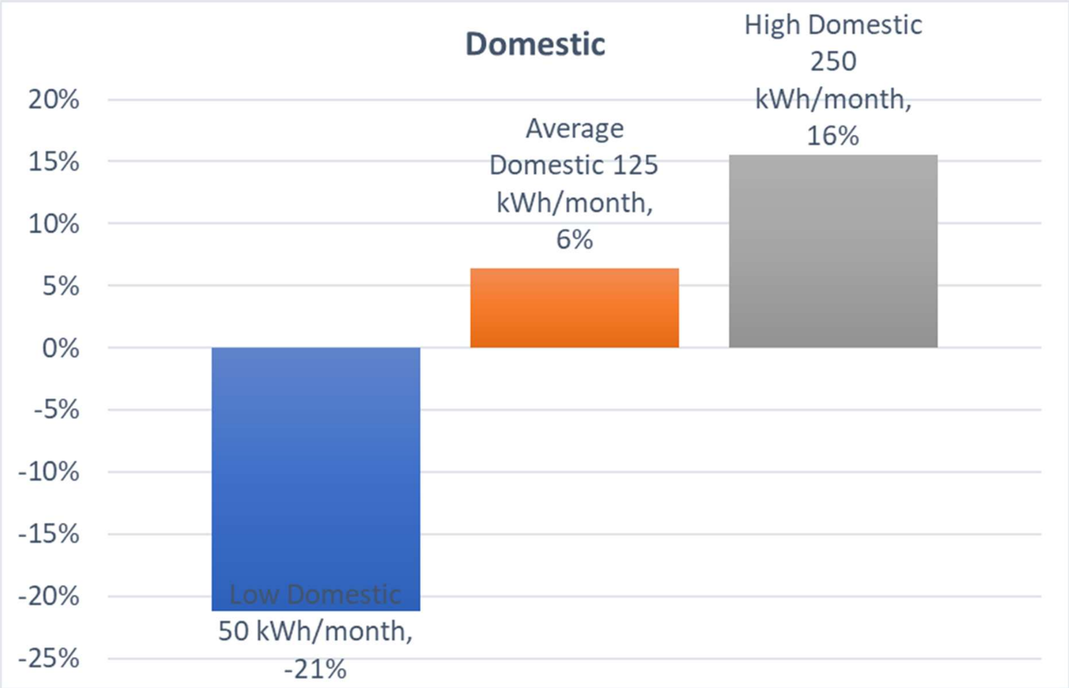


Figure 7: Impacts on LV and HV industrial customer bills for a low, average and high kVa consumer (each consuming same energy kWh/month) under tariff study option 2

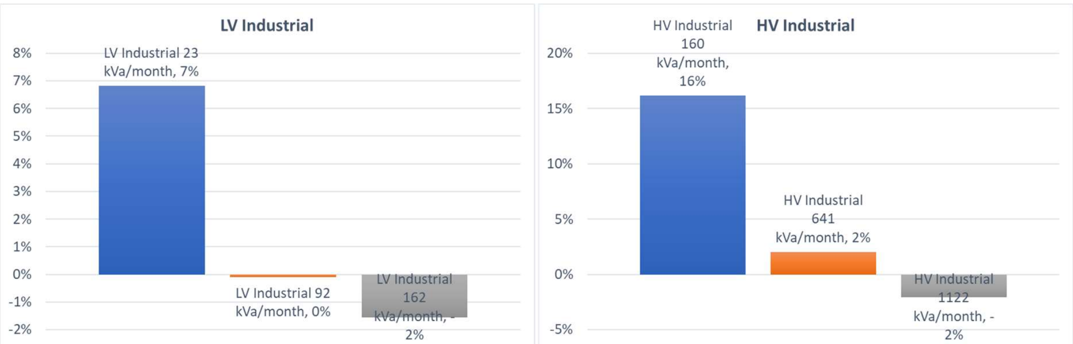
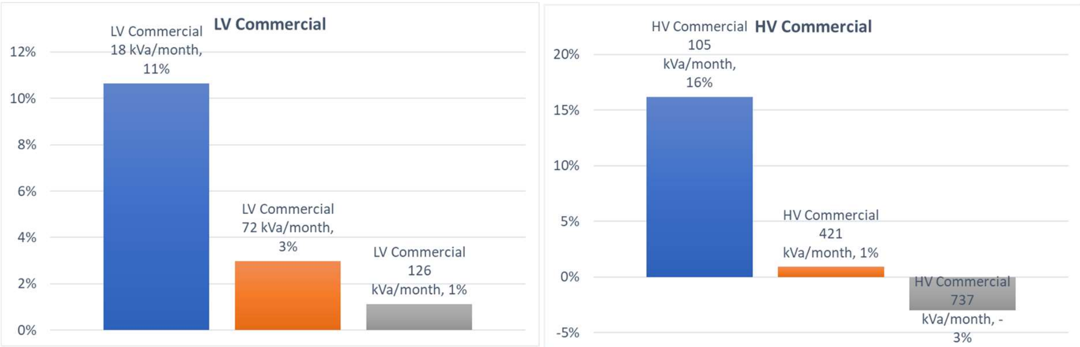


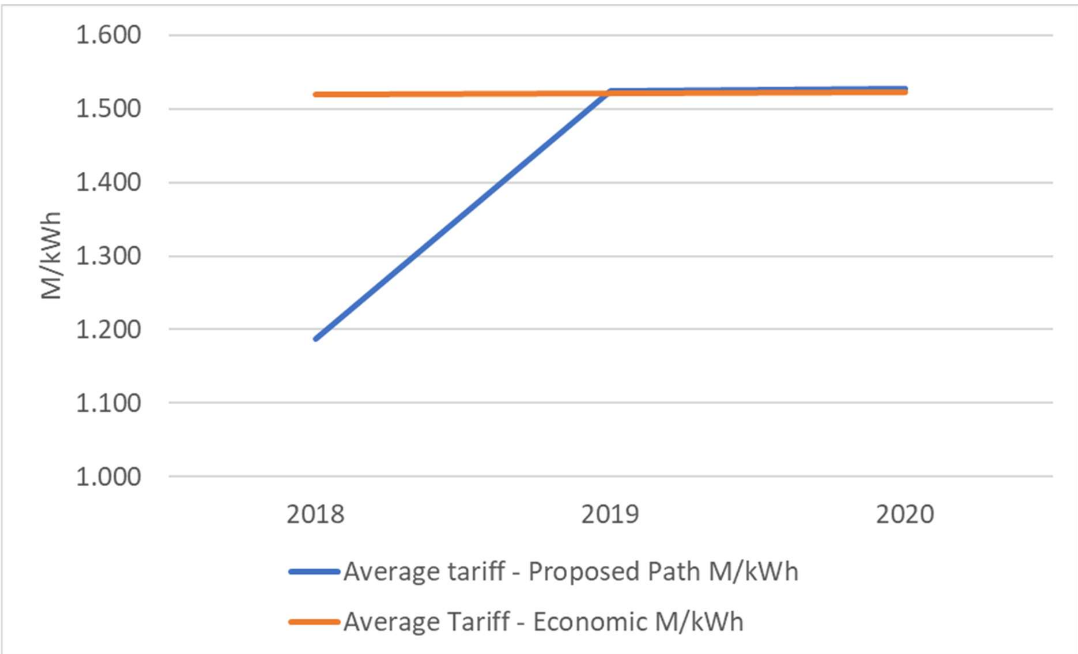
Figure 8: Impacts on LV and HV commercial customer bills for a low, average and high kVa consumer (each consuming same energy kWh/month) under tariff study option 2



5.2.3 Option 3: Fast Recovery

Under this option tariffs increase by the same amount as option 1 in year 1 but there is a sharper increase in year 2 in order to reach the economic level and rebalance MD and energy tariffs for industrial and commercial. After this, tariffs remain at the economic level in year 3. Figure 9 shows the average tariff profile against the economic level in 2018-21.

Figure 9: Average tariff pathway 2018-20 relative to the economic tariff level under first tariff study option 3



The resulting tariffs are as shown in Table 9. The Table also shows in the first column the current tariffs (no levies or VAT) and in the final column the resulting economic tariffs (for the 3 year price control) to provide a basis for comparison.

Table 9: Tariff pathway for full balancing of MD and energy charges by 2021 tariff study option 3

Tariff	Current 2017/18	2018/19	2019/20	2020/21	Economic Tariffs
Energy Charges	**M/kWh**	**M/kWh**	**M/kWh**	**M/kWh**	**M/kWh**
Lifeline Block	1.347	0.650	0.650	0.650	1.925
Standard Domestic	1.347	1.804	2.402	2.410	1.925
General Purpose	1.522	1.523	1.523	1.523	1.524
LV Commercial	0.206	0.320	0.774	0.774	0.731
HV Commercial	0.186	0.306	0.822	0.822	0.773
LV Industrial	0.206	0.320	0.774	0.774	0.731
HV Industrial	0.186	0.306	0.823	0.823	0.774
Street Lighting	0.764	1.006	1.744	1.744	1.674
Demand Charges	**M/kVa**	**M/kVa**	**M/kVa**	**M/kVa**	**M/kVa**
LV Commercial	306.302	294.763	272.973	272.973	272.973
HV Commercial	262.239	214.284	143.079	143.079	143.079
LV Industrial	306.302	283.483	242.819	242.819	242.819
HV Industrial	262.239	214.543	143.599	143.599	143.599
Fixed Charges	**M/month**	**M/month**	**M/month**	**M/month**	**M/month**
Domestic	0	0	0	0	0
General Purpose	0	0	0	0	0
LV Commercial	0	6.952	6.952	6.952	6.952
HV Commercial	0	3681.801	3681.801	3681.801	3681.801
LV Industrial	0	6.962	6.962	6.962	6.962
HV Industrial	0	3673.140	3673.140	3673.140	3673.140
Street Lighting	0	6.945	6.945	6.945	6.945

Table 10 shows an excerpt from the projected financials for LEC under this scenario – performance is the same as option 1 in the first year and better in years 2 and 3. Again, the applied increases mean LEC is expected to have sufficient income to cover bulk supply costs, Opex and depreciation in 2018 with a remaining income allowing a high profit after tax of 45.7 M mil in 2018.

Under this option funding reduces relative to option 1 to 244.9 M mil all of which is required in the first year (2018/19).

Table 10: Excerpts from projected income statement for full balancing of MD and energy charges by 2021 tariff study option 3

LEC Statement of Comprehensive Income	2018 M m	2019 M m	2020 M m
Total Revenue	1,017.7	1,328.6	1,376.7
Gross profit	449.1	759.4	789.5
Profit/(Loss) before tax	60.9	342.7	357.9
Profit/(Loss) after interest and tax	45.7	257.0	268.4

In this case the impact on consumer bills in the first year is the same as in option 1 (i.e., Figure 2 - Figure 4).

5.3 IMPACT OF LIFELINE LEVEL AND CROSS-SUBSIDY ASSUMPTIONS

As noted in 2.2 (2.) the STC recommended that the lifeline tariff level must at least cover bulk supply costs and that subsidy required to make up the LEC deficit resulting from the lifeline block tariff being lower than cost reflective would be paid by an uplift in all other tariffs. This is ultimately a policy decision and another viewpoint might be that the lifeline subsidy should not be paid by the commercial and other productive customers and the responsibility of making up the subsidy should remain within the household category, with the higher income consumers providing the subsidy to the poor. The table below shows the impacts on the energy charges as a result of varying assumptions of the level of lifeline tariff and the method to recover the subsidy in the Recommended Option for the following cases:

- Case 1 – Lifeline Tariff level of 0.65 M/kWh (to cover bulk supply costs) and subsidy paid for by all other customers;
- Case 2 – Lifeline Tariff level of 0.65 M/kWh and subsidy paid for by domestic customer only;
- Case 3 – Lifeline Tariff level of 0.50 M/kWh (as per results of ability to pay analysis from Task 5) and subsidy paid for by all other customers; and
- Case 4 – Lifeline Tariff level of 0.50 M/kWh and subsidy paid for by domestic customer only.

The results show that the impact on other tariffs is most significant when few tariff categories are used to recover the subsidy. The impact of the lifeline tariff level at 0.5 or 0.65 is relatively minor.

Table 11: Tariff uplift required for variations in lifeline tariff level and number of tariff categories making up the subsidy

Case 1		**2018**	**2019**	**2020**
Subsidy - lifeline customers	M mil	20.3	25.0	30.4
Consumption - non lifeline (all other categories)	MWh	706,345	730,074	754,879
All other customer tariff uplift	M/kWh	0.0287	0.0342	0.0402
Case 2		**2018**	**2019**	**2020**
Subsidy - lifeline customers	M mil	20.3	25.0	30.4
Consumption - non lifeline (domestic only)	MWh	196,339	203,535	211,806
Standard Domestic Tariff uplift	M/kWh	0.1033	0.1228	0.1433
Case 3		**2018**	**2019**	**2020**
Subsidy - lifeline customers	M mil	23.8	28.5	33.9
Consumption - non lifeline (all other categories)	MWh	706,345	730,074	754,879
All other customer tariff uplift	M/kWh	0.0337	0.0391	0.0449
Case 4		**2018**	**2019**	**2020**
Subsidy - lifeline customers	M mil	23.8	28.5	33.9
Consumption - non lifeline (domestic only)	MWh	196,339	203,535	211,806
Standard Domestic Tariff uplift	M/kWh	0.1211	0.1402	0.1601

6 Options for Improving the Governance of LEC

This section considers ways in which the government can improve the performance of the electricity company it owns - LEC. It describes the current institutional situation for LEC and also reviews the options for introducing competition to improve performance. It then draws on international experience to review the options for changing governance practices currently applied to LEC.

6.1 The LEC Institutional Position

The Lesotho Electricity Company (Pty) Ltd (LEC) is wholly owned by the Government of Lesotho (GoL). It has been registered in terms of the Companies Act, 1967 (as amended) and established in 2006 in terms of the LEC (Pty) Ltd (Establishing and Vesting) Act, 2006. The assets, liabilities, rights and obligations of the former Lesotho Electricity Corporation were vested in the company. It is licensed to operate under the Lesotho Electricity Authority Act of 2002, as amended. It is the sole supplier of electricity in Lesotho. It was issued with a Composite Electricity License in terms of Section 50 of the Lesotho Electricity Authority Act of 2002, to transmit, distribute and supply electricity. It is also responsible for economic procurement of power for its customers.

The License clearly defines LEC as solely responsible for the transmission, distribution and supply of electricity within its service territory (defined as all customers located within 3.5 kilometres of the existing LEC network). It also defines LEC as being responsible for the procurement of power from outside Lesotho. The License clearly defines the regulated activities of LEC.

6.2 Introducing Competition?

The government is interested in setting up the governance of the sector in such a way that customers receive the best possible service. Competition is the well-recognized device for ensuring good service at a good price. Adjusting governance arrangements to introduce competition in some segments of the electricity industry may therefore be attractive. However Government as owner of the LEC may wish to maximise LEC profits and therefore wish to protect the utility from competition. There is therefore a potential conflict of interest between enabling the introduction of competition and maximizing the profitability of LEC.

Competition is rarely considered to be viable either in electricity transmission nor for small distribution areas, which are considered to be natural monopolies. It is efficient to have only one company dealing with the grid network. There would be no benefits and no savings from setting up two or more companies doing the same job, where – compared to other subsectors of the power industry such as generation – cost-recovery is typically considered to be challenging.

The SE4ALL EU TAF advice is that public sector ownership of electricity networks shall be concentrated in the LEC. No other entity shall be involved in grid extension and/or network system operation (off-grid energy - not only electricity - should be managed separately from main grid-based electricity development).

6.3 IMPROVING GOVERNANCE OF LEC

The key focus is on principles and the rules that structure the relationship between the company and the government as its owner. The analysis draws on the 2014 World Bank Toolkit "Corporate Governance of State-Owned Enterprises"[8]

In general, Governments want a set of rules and practices that allow them to:

- Monitor the utility effectively,
- Make strategic decisions about the utility's direction, and
- Hold the utility's managers accountable for its performance.

Drawing on the specific Investigations in 2016/17 by the SE4ALL EU TAF as well as experience gained through the execution of the COSS we believe there is scope to improve the performance of LEC through interventions that make the governance of LEC more effective in each of these three areas.

In particular rules and practices can be changed in a way that reduces politicians' willingness or ability to use the utilities for political purposes and subjects the utilities to new sources of pressure to perform well.

Options for enhancing the effectiveness of LEC governance are described in the following five subsections.

6.3.1 IMPROVING THE OVERALL LEGAL & REGULATORY FRAMEWORK

- Subjecting LEC to company law and other laws that apply to private-sector companies;
- Listing the company on the stock market - to create market information on commercial performance; and
- Selling a minority of shares to bring in monitoring by other shareholders. Minority shareholders offer a potential source of pressure. The government can retain control of the firm (and thus achieve at least some of the goals of full public ownership) while selling a minority of shares.

6.3.2 OVERSIGHT, ACCOUNTABILITY & TRANSPARENCY

- Reducing the conflict of interest Government faces as policymaker and owner, by separating responsibility within government for policy and ownership, as advised by the SE4ALL EU TAF Long-Term support to the Department of Energy: assigning the job of policy-making to the Ministry of Energy and Meteorology (Dept of Energy) and the job of owner to the Ministry of Finance. In other words, the Minister of state-owned enterprises and finance has responsibility for shareholding, while the Minister of MEM has responsibility for electricity policy; and
- Introduce safeguards against Government interventions.[9]

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[8] Available at: https://openknowledge.worldbank.org/bitstream/handle/10986/20390/9781464802225.pdf

[9] E.g. Canada's Business Development Corporation reports any undue pressure from politicians; in Estonia, ministers' rights to issue instructions to SOE directors have been abolished;. in Israel, complaint mechanisms are in place to prevent ministerial interference.

6.3.3 Performance Monitoring

- Supporting the role of LEWA in monitoring the performance of LEC;
- Clearly defining and maintaining up-to-date the mandates strategies and objectives of LEC (reference the SE4ALL EU TAF 2017 phase 1 report for recent inputs on this subject);
- Developing key performance indicators and targets – reference the benchmarking analysis carried out in Task 6 (deliverable 7) of the COSS;
- Strengthen LEC reporting requirements; and
- Carry out regular external audits of LEC.

6.3.4 Promoting Financial Discipline

- Reducing and eventually eliminating LEC dependence on public finance – requiring LEC to borrow from private lenders without the benefit of a government guarantee. Private lenders will rigorously scrutinize LEC financial performance prior to making loans. They will also provide ongoing scrutiny of LEC financial performance during the loan repayment period. They will insist that key indicators (see deliverable 7 for definitions of the key financial parameters) are maintained.
- Improving cost recording across the utility so that in future costs are allocated precisely to different elements of the business – transmission (HV), distribution (LV), supply, and any other area of activity as may be specified by the LEC Board and/or by LEWA.

6.3.5 Enhancing Professionalism of the LEC Board

- Develop a structured and transparent process for appointments of directors to the LEC Board, including consideration to:
    - Appointing independent directors from successful businesses, ensuring the top management of the company has commercial rather than political habits
    - Require the appointment of directors who are not government employees and thus cannot be directed on a day-to-day basis by shareholders and don’t face the threat of punishment in their main job if they resist political interference,
    - Establish criteria for the appointment of directors that favor people that are more likely to resist political interference (perhaps people with considerable experience as directors of other, similar businesses with a certain standing in the community)
- Define clear responsibilities of the Board: strategy setting, managing risks, appointment and management of the CEO of LEC;
- Define separate roles of Chair, CEO and Board committees; and
- Introduce focused capacity building for Board members.

ANNEX A – TARIFF INDEXATION AND MINOR REVIEW

A.1 Tariff Indexation (Pre-Implementation)

The figures reported from the COSST model are in 2017 real terms and hence an indexation adjustment is needed to convert tariffs to current terms. We assume here that the current year is 2018.

We recommend LEWA publishes the tariff determination in real terms for the first year of the price control (e.g., 2018) and subsequent adjustments for inflation are applied at each Annual Review.

Generation Component

We anticipate that when undertaking a tariff determination, the latest available estimates for bulk supply tariffs (e.g., Eskom, EdM and Muela) will be used and the anticipated generation costs will be derived from the despatch module of the COSST.

The measure of bulk supply tariff to be adopted should be consistent with the structure of imports and commercial agreements between LEC and the contracting parties, which are modelled in COSST (all set out in the sheet "Inputs-Assumptions" row 80-184). For instance, for Eskom as per the 2018/19 standard schedule of tariffs currently published annually on the Eskom website.

Networks Component

The operating and capital expenditure components of distribution, transmission and supply costs are adjusted to reflect accumulative inflation since the base year of COSST (2017). Operating and capital expenditure are indexed by different factors (e.g., local and international prices) and so the indexations for these costs are calculated separately.

The proportionate adjustment to the tariffs derived using the COSST model to reflect changes in **local inflation** is given by the following equation:

$$TL_{2018} = 1 + Pm_{2018}$$

Where:

TL_{2018} the proportionate adjustment network operating expenditure to reflect the change in inflation expectations from 1 April 2017 to 1 April 2018;

Pm_{2018} is the actual inflation for 2018;

The measure of inflation to be adopted is the Composite Consumer Price Index (CPI) - published by, for example the National Bureau of Statistics (NBS) or Central Bank of Lesotho (CBL).

The proportionate adjustment TL_{2018} will be applied to the tariff components before they are allocated to tariff categories (as set out in the sheet "Inputs-Tariffs" row 170-199).

The proportionate adjustment to the tariffs derived using the COSST model to reflect changes in **foreign indexed inflation** is given by the following equation:

$$TI_{2018} = \frac{ER_{2018}}{ER_{2017}}$$

Where:

TI_{2018} the proportionate adjustment to network capital expenditure to reflect the change in US inflation adjusted for foreign exchange;

Pe is the M/USD exchange rate;

The measure of capital expenditure escalation to be adopted is the US Composite Consumer Price Index (CPI) adjusted for foreign exchange assuming 2017 is the base year. This is calculated using the M/USD exchange rate - published by, for example the NBS or CBL.

The proportionate adjustment TI_{2018} will be applied to the tariff components before they are allocated to tariff categories (all set out in the sheet “Inputs-Tariffs” row 163-164).

A.2 Annual Reviews

The Tariff Roll Out Plan recommends annual review adjustments could be made to tariffs on an annual basis to reflect the factors listed below, although our recommendation is that only bulk supply and inflation are included:

- Bulk supply costs.
- Changes to the volumes of electricity actually consumed compared to the volumes predicted in the tariff review analysis.
- Domestic price inflation.
- Exchange rate variations that impact debt service costs and long-term operation and maintenance costs of foreign contractors
- Labour costs where national union power imposes labour costs increases beyond the control of the company.

A possible approach for dealing with the first three issues in turn is set out below.

A 2.1 INDEXATION

Each year at the annual minor review the LEWA determination multi-year tariffs for the forthcoming year (which will be in real terms for the previous year) will be adjusted as described in section A.1 above with the actual outturn inflation since the previous year. Similarly, the forecasts for generation costs will be updated to the latest figures. For example, when published, the 2019 tariffs will be in 2018 real terms, so an adjustment will be needed at the end of the 2018 year to put 2019 tariffs in 2019 real terms.

A 2.2 INFLATION

At the annual end of year minor review there are two possible adjustments that could apply:

- First, looking backwards, the relevant items of the revenue requirement for the year in question (i.e., the price control year that is coming to an end) are adjusted to reflect outturn inflation.
- Second, looking forwards, the relevant items of the revenue requirement for the forthcoming year are adjusted for the latest forecast for inflation.

The mechanics of these options are discussed below.

End-year adjustment for inflation (backward-looking, mandatory)

The following approach to determining the year in question adjustment for local and foreign exchange adjusted inflation will apply:

- No more than 10 days before the review date, the latest annual local inflation and foreign exchange figure published by the NBS (or CBL) will be considered. If there is no estimate, the value adopted at the previous annual review will continue to apply.
- The latest published values will be considered as applicable for the whole year.
- Where the value is less than 5 percent different **relative to** the value assumed at the previous review, the value assumed at the previous review will be considered the appropriate value for inflation over the course of the year. For the avoidance of doubt the 5 percent band relates to proportional differences and not percentage base points: that is, if forecast inflation is 10 percent, an adjustment will be made where the revised value is less than 9.5 per cent or greater than 10.5 per cent.
- A revised estimate of the indexation factors and relevant component of network operating and capital expenditure to reflect inflation will be made for the year in question. This amount will be included as an adjustment to operating and capital expenditure in the forthcoming year.
- The proposed adjustment is symmetric, that is, if expected inflation is lower than that anticipated in the LEWA tariff determination it can be adjusted downwards. Similarly, if investments associated with the forecast of capital expenditure were not undertaken by LEC than LEWA can at this time also adjust the downward capital expenditure.

Forthcoming year adjustment for inflation (forward-looking, discretionary)

As described in section A 2.1 the tariffs for the forthcoming year will have been adjusted to be in real terms for the forthcoming year. LEWA could optionally, also adjust tariffs for the forecast inflation for the forthcoming year, say incorporating half of the forecast annual inflation into tariffs. This is advisable if inflation is expected to be significant and/or volatile as if not accounted for could lead to significant financial gains/losses for LEC.

A 2.3 BULK SUPPLY COSTS

At the annual end of year minor review there are two possible adjustments that could apply:

- First, the relevant items of the revenue requirement for the year in question are adjusted to reflect outturn bulk supply costs.
- Second, the relevant items of the revenue requirement for the forthcoming year are adjusted for the latest forecast for bulk supply costs.

This is consistent with the ‘Revised “pass-through charging principle for bulk supply tariffs”’:

“The Bulk Supply Tariff (BST) shall be calculated, at the beginning of each tariff year on the basis of the forecasted price conditions and then any difference between expected and actual revenues for the months or year shall be compensated in the following year’s BST or as may be found appropriate by the Authority during the year. This is because generators prices will vary from one month to another and from one year to another. Furthermore, the capacity and energy demand along each month or year will usually differ from forecasted values.”

The mechanics of these options are discussed below.

End-year adjustment for bulk supply costs (backward-looking, mandatory)

The proportionate adjustment to tariffs to reflect changes in the bulk supply tariff(s) is given by the following equation:

$$TPGi = 1 + \frac{(PTA_i - PTF_i)}{(PTF_i)}$$

Where:

TPG_i the proportionate adjustment to bulk supply costs to reflect the change in bulk supply tariff estimates between the beginning year and the end of year i;

PTF_i The forecast for the bulk supply tariff for year i estimated in the previous annual review;

PTA_i The actual outturn bulk supply tariff in year i based on audited data submitted to LEWA by LEC.

The approach of taking the difference between the forecast and outturn bulk supply tariffs could be integrated into the "virtual" Bulk Cost Tracking Account (BCTA) as described in the *'Revised "pass-through charging principle for bulk supply tariffs"'*, although it would be beneficial if the account were also to include information in addition to the monthly shortfall and surpluses (e.g., applicable tariff and volumes of energy and kVa purchased in the month).

The adjustment to the overall tariff components in year i+1 to reflect the change in the value of bulk supply tariff will be based on the following formula:

$$TAFG_{i+1} = \frac{BulkP_i}{RR_i} * TPG_i$$

Where:

$BulkP_i$ Bulk purchase costs for year i in the revenue requirement (COSST model).

RR_i Total revenue requirement for year i (COSST model).

This adjustment is consistent with Charging Principles for Electricity and Water and Sewerage Services which indicates that indicates "an outturn adjustment shall be made in the following tariff year to adjust for deviations between the forecast costs and the outturn costs". If, as is expected, under paragraph 12 there are delays in obtaining the audited data, the adjustment may need to be applied in subsequent years of the price control (e.g., year i+2) and in this case interest[10] will be applied.

Forthcoming year adjustment for inflation (forward-looking, discretionary)

Similarly, to the adjustment for inflation, there may be good cause to adjust the projection for bulk supply tariff for the forthcoming year if very relevant financial losses/gains are expected. We advise that LEWA consider each case on its merits and apply this as a discretionary adjustment. This approach lines-up well with the *Charging Principles for Electricity and Water and Sewerage Services* which indicates that *"The Authority shall, from time to time, review forecasts in relation to systematic bias in the forecasts used"*.

[10] The charging principles indicate *"the interest rate at which licensee borrows money to finance shortfall in its regulated businesses"*.

A 2.4 VOLUMES OF ELECTRICITY ACTUALLY CONSUMED

The proportionate adjustment to tariffs to reflect differences in volumes of electricity actually consumed compared to the volumes predicted in the tariff review analysis will be computed (i.e., backward-looking). This adjustment will be embedded within the adjustment for bulk supply as it will consider the allowed level of technical and non-technical losses. It may be advisable therefore to integrate the tracking of monthly and annual volume differences into the BCTA. This adjustment is given by the following equation:

$$EPFi = \frac{(FD_i)}{(1-AL_i)} \text{ and } EPAi = \frac{(AD_i)}{(1-AL_i)}$$

Where:

- EPF_i The forecast energy purchased in year i estimated in the previous annual review;
- EPA_i The equivalent energy purchased in year i for the actual energy demand AD_i;
- FD_i The forecast for energy demand (consumption) year i estimated in the previous annual review;
- AD_i The actual energy demand (consumption) in year i based on validated consumption data;
- AL_i The allowed level of aggregate technical and non-technical losses in the tariff.

The adjustment to the overall tariff components in year i+1 to reflect the change in the value of consumption will be based on the following formula:

$$TAFD_{i+1} = (1 + \frac{EPFi}{EPAi})$$

A revised estimate OPEX/MWh component of network operating expenditure consistent with LEC's efficiency improvement targets to reflect the change in volumes will be made for the year in question. This amount will be included as an adjustment to operating expenditure in the forthcoming year.

ANNEX B – LIFELINE BLOCK TARIFF DRAFT DECISION PAPER

Approved by the LEA Board in …….. and effective from ……

LESOTHO ELECTRICITY WATER AUTHORITY (LEWA)

Decision of a "Lifeline Block Tariff" [LBT]

INTRODUCTION

The "Lesotho Energy Policy 2015-2025" provides the principles for the provision of a life-line tariff.

Strategy f) of Policy Statement 10 (Electricity Connections) is to "negotiate for better planning of settlements to allow provision of basic electricity services".

Strategy b) of Policy Statement 15 (Energy pricing), is to "introduce and determine appropriate cross subsidy tariff mechanism to reflect electricity for basic human needs"

Strategy c) of Policy Statement 15 (Energy Pricing), is to "introduce a levy and create capital subsidy fund for enhancing affordability of energy services"

- **PURSUANT** to the Act N .12 of 2002 (Lesotho Electricity and Water Authority Act as amended in 2006 and 2011) establishing the Lesotho Electricity Authority to regulate and supervise activities in the electricity sector and to make provision for the restructuring and the development of the electricity sector in Lesotho and for connected matters.

  Especially Section 21 (I). let. e (Authority shall "protect the interests of all classes of consumers of electricity as to the terms and conditions and price of supply") and Section 24 ("Review and setting of tariffs rates and charges") laying down obligations on service providers in relation to applications for changes to tariffs and rights and obligations of the Authority in relation to the review and approval of those tariff applications.
- **AFTER CONSULTATION** with the Government on the amount of the low consumption block subsidy and its allocation among different customer categories;
- **RECOGNIZING** the benefits and advantages of a regime, where consumers face higher unit prices on higher blocks of consumption (Increasing Block Tariffs);
- **RECOGNIZING** the need of an additional tariff category for lifeline customers (Lifeline Block Tariff) that must meet at least the average bulk supply cost;

HEREBY DECIDES:

Purpose

The purpose of the present Decision is to review the applicable Electricity End User Tariff in Lesotho.

Applicable electricity end user tariffs

The applicable End User Tariffs of Electricity in Lesotho are hereby reviewed as follows:

Domestic (Residential) Customers

Consumption Block per Month kWh	M/kWh (VAT exclusive)
[0-30]	0.65
[30 +	As agreed in the three-year tariff review for the standard domestic tariff

Repealing provision

All previous provisions contrary to this decision are hereby repealed.

Implementation / Instructions to LEC

LEC shall adjust its payment system and ensure that for Residential Customers over time consumption below an average of 30 kWh per month is charged at the lifeline block rate and consumption above at the standard domestic tariff.

Awareness campaigns

LEC shall ensure that awareness campaigns are rolled out nationally to educate communities on the availability and implications of the Lifeline Block Tariff.

Update and Revision

The LBT level of tariff is determined in advance of a tariff determination. The LBT will be reviewed every three years, where in addition to cost adjustments, structural changes in production as well as in consumption patterns will be considered and evaluated.

Notification and publication of the Decision

The LEWA is entrusted with notifying LEC and the general public of this Decision.

Coming into force

This decision shall come into force on the date of its signature.

It shall take effect as of 1st January 2018/19.