Electricity capacity expansion plan for Lesotho – implications on energy policy

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Abstract

This study aims to produce a research-based integrated electricity expansion plan for Lesotho that focuses on the security of supply at national level. The Autoregressive Integrated Moving Average (ARIMA) is used to model electrical demand and the PLEXOS modelling tool is used to analyse the cost of investing and producing future electricity for the country. The results underscore the need for investment geared towards local generation particularly in large hydro up to 0.22 GW, PV up to and 1.1 GW and pumped storage up to 0.5 GW by 2050, to keep up with future demand and reduce the cost of imported electricity in the country. Succinctly, the investigation reveals, *inter-alia*, that: 1) Lesotho's energy demand will continue to increase over the modelled period (up to 2050), with the gap between the local generation and demand concomitantly increasing; 2) large hydro generation, if harnessed will guarantee long-term energy security and cheaper energy relative to both imports and small hydro; 3) any shift in the energy policies of external suppliers at current tariff structures, will increase Lesotho's energy costs significantly, thus, negatively impacting on the country's economy; and 4) investing in local energy generation will guarantee long-term national energy security and affordability.

Keywords:
Electricity supply, import, supply deficit, reserve margin, electricity expansion plan, ARIMA
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1 Introduction

Access to adequate and reliable electricity power supply is a pre-requisite for sustainable development of any nation. It is also an important input for household consumption and firms' production (Oyelami and Odewumi, 2014). Lesotho reached 42% of household electrification level in 2015 [1], up from 10% in 2005 [2] and [3]. This continued electrification drive has resulted in Lesotho having a baseload and peak demand of 100 MW and 155 MW respectively [4]. Given stagnant household income levels over this period, the increase in residential sector share of electricity demand (see Fig. 2 in Section 2) can be attributed to increased connection efforts. Although demand was increasing, the generation capacity of 76 MW has not increased since 1998, resulting in a national baseload deficit of 24% and peak load deficit of 44%, and the importation of approximately half of the 683 GWh consumed in 2014 [1].

Given the above scenario of increasing demand and absence of investment in local generation capacity, the security of Lesotho' electricity supply is topical. The Ministry of Energy and Meteorology has recently commenced to attract investment into electricity generation programmes, as highlighted by the drafting of the Energy Policy of 2015 and issuance of Lesotho's first (solar PV) Independent Power Producer (IPP) procurement. The main objective of the policy is to ensure that the increasing base load requirements are met through local generation by 2020 and beyond [5].

Arguably, a key starting point for increasing the baseload generation capacity will be putting in place a practically and economically feasible integrated resource plan (IRP). Presently, Lesotho does not have an effective plan that considers detailed technical and financial implications of self-generation using indigenous resources for replacing imports to meet the increasing demand for electricity.

A number of studies have analysed the electricity capacity expansion plan for Lesotho as components of optimising the generation capacity for the entire region of the Southern African Development Community (SADC). The most recent study [6] used LEAP energy modelling tool for SADC countries. In one of the scenarios modelled, solar PV was found to be the cheapest supply option for Lesotho, supplemented by imports. The results also indicated that cheap imports would be beneficial as aside from PV Lesotho could not build its own generation in a least cost manner. Another study by [7] looked at expansion plans for the region using MESSAGE modelling tool. In this study, the predictions of the model showed that Lesotho would have total installed capacity of 242 MW by 2030 while the excess demand would be met through imports. Earlier in the 2000s, [8] conducted an expansion electricity plan for SADC using TIMES model. The conclusion in this study was that it would be more expensive for Lesotho to build its own hydro plants than for the county to import its electricity from South Africa. The modelling approach adopted in [6], [7] and [8] however considered low resolution data (annual load and annual capacity factors) for representation of intermittent renewables energy technologies (wind and solar photovoltaic (PV)) and did not exploit the increased granularity available in models that capture the variability and uncertainty in power production [9]. Notably, the above studies converge to the conclusion that imports will be beneficial to Lesotho, but in its latest reports, the Lesotho Electricity Company (LEC) has emphasized the massive costs of importing power from external sources [4] and [4].

The lack of consensus on the optimal electricity supply strategy strongly necessitates a comprehensive and long range electricity sector plan that considers security of supply as well as the risk that short term import contracts pose to the economy, e.g. when supply is curtailed or becomes expensive. For example, Eskom experienced a serious supply deficit between 2006 and 2008 resulting in a curtailment of the power available to Lesotho (from unlimited to 20 MW) [10]. This reduction forced LEC to assume a new import arrangement with Electricidade de Mozambique (EDM) to procure 40 MW. Both Eskom and EDM contracts are annually reviewed and subject to volatile market conditions that can result in increased expense or a constriction of the electricity supply to Lesotho. The Lesotho Times newspaper reported in October 2017 that LEC was ending power imports from Mozambique because it was becoming too expensive [11], but eventually a new re-negotiated deal to import between 10 MW and 30 MW was signed in February 2018.

It is against this background that this paper seeks to propose a research-based electricity expansion plan (integrated resource plan) that focuses on the security of supply at the national level. In particular, the research seeks to determine the least-cost electricity generation capacity needed to meet growing electricity demand. The modelling timeframe is from 2016 to 2050. The analysis considers 2 demand growth scenarios: Business as usual (BAU) scenario, and high growth (HIGH) scenario. Under the BAU, the energy consumption is assumed to increase by 2% annually on average between 2016 and 2050. The high demand scenario assumes the annual demand increase of 5% from 2016 to 2050. ARIMA is used to forecast electricity consumption demand and peak electricity demand. To determine the generation capacity mix, the PLEXOS modelling tool is used. The results of interest will be the least cost capacity to be installed, the timing of the installations, and the net present value of the total system cost (electricity production costs and investment costs) of the installed capacity.

The high demand growth scenario tests what the generation plan will look like when subjected to high economic growth. Under each economic growth three possible cases of capacity investments are assessed. The three capacity cases are as presented in Table 2.

The rest of paper is structured as follows: Section 2 gives an overview of the electrical system in Lesotho discussing supply, demand and system reliability is presented. Section 3 explains the modelling methodology followed in this research together with explanation of the tool used and highlights the data and assumptions used. Section 4 presents and discusses the results with recommendations and implications for policy options following in Section 5.

2 Background into Lesotho’s electrical system supply and demand

2.1 Picture of electricity supply and demand: demand, imports and local generation

The development of the energy sector is the mandate of the National Government of Lesotho through Lesotho Highlands Development Authority (LHDA) as water asset owners, Ministry of Energy and Meteorology (MEM) and LEC. The power generated at plants that are developed as part of LHDA projects is sold to LEC. LEC is mandated to supplement this with power from LEC's own generation assets and imports which is then transmitted and distributed to the customers. Fig. 1 shows that Lesotho electricity consumption is 770 GWh.

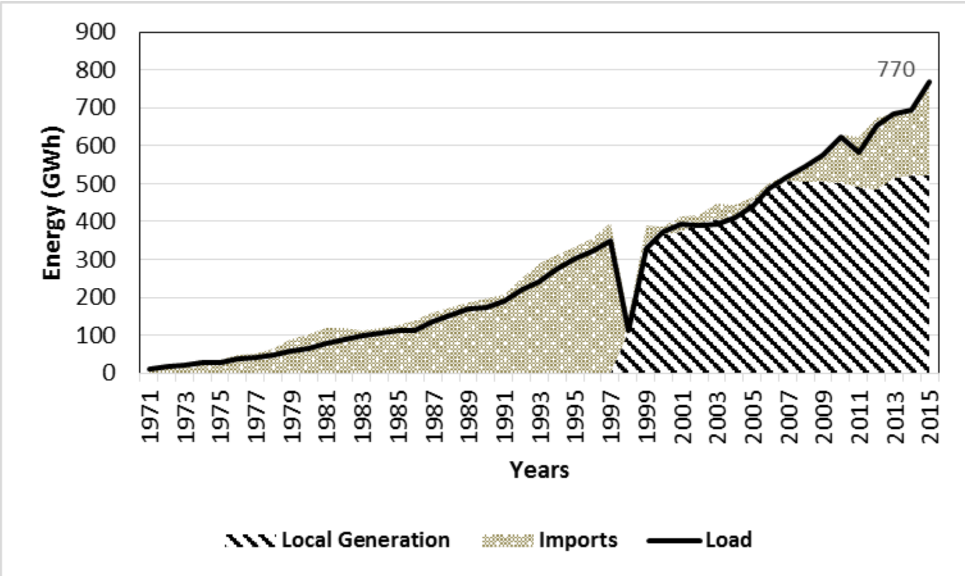


Fig. 1: Load, imports and local generation in Lesotho

About two thirds of electricity is consumed by the residential and industrial sectors. The share of electricity consumption by sector from 2011 to 2014 is shown in Fig. 2. From the 1970's until 1998, Eskom was the sole supplier of electricity to Lesotho. In 1998 'Muela hydro power plant (owned by LHDA), with installed capacity of 72 MW, was completed and commissioned resulting in a steep decline in electricity imports in Lesotho (see Fig. 1).

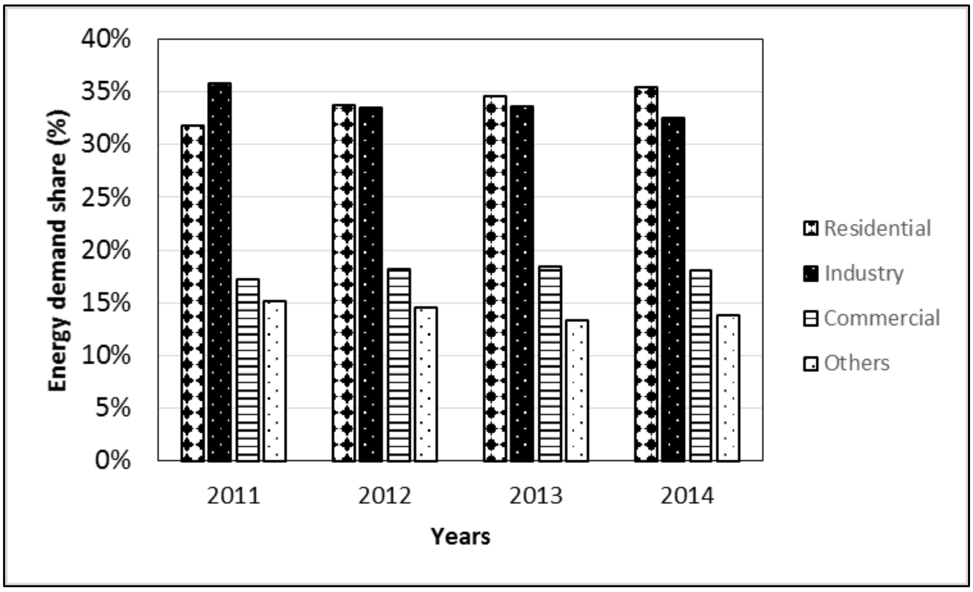


Fig. 2: Share of electricity consumption by sector for years 2010/2011–2013/2014
Source: (Ministry of Energy and Meteorology, 2015)

This reduction in imports was two-fold: commissioning of ‘Muela and a depressed demand from economic activity due to political instability occuring during that time. Up to 2005, ‘Muela substantially met the demand of the country, while imports started increasing steadily from 2006 onwards [12] to reach 33% of national demand in 2015 (see Fig. 3). In 2011, EDM and Eskom supplied Lesotho with 6% and 26% of its electricity needs respectively [10]. The local plants that were supplemented by these imports are shown in Table 1. Barring significant infrastructure upgrades the capacity for electricity import (or export) is currently capped at 230MW by the transmission capacity between Lesotho and South Africa [7].

Table 1: Power plants operating in Lesotho currently and production in 2014 (2015).
Source: (Klunne, 2013),(Lesotho Electricity Company, 2011)

Power Plant name	Type	Unit Capacity	Total Capacity (MW)	Energy (GWh)	Capacity factor (%)
‘Muela	Large hydro	24	72	515	88%
Mant’sonyane		2	2		
Semonkong	Small Hydro	0.18	0.18	10.85	33%
Diesel Power plant	Thermal	1	1	0	0%
Solar Home Systems	Solar PV	0.065		0	0%
Total			**76.15**	**525.85**	

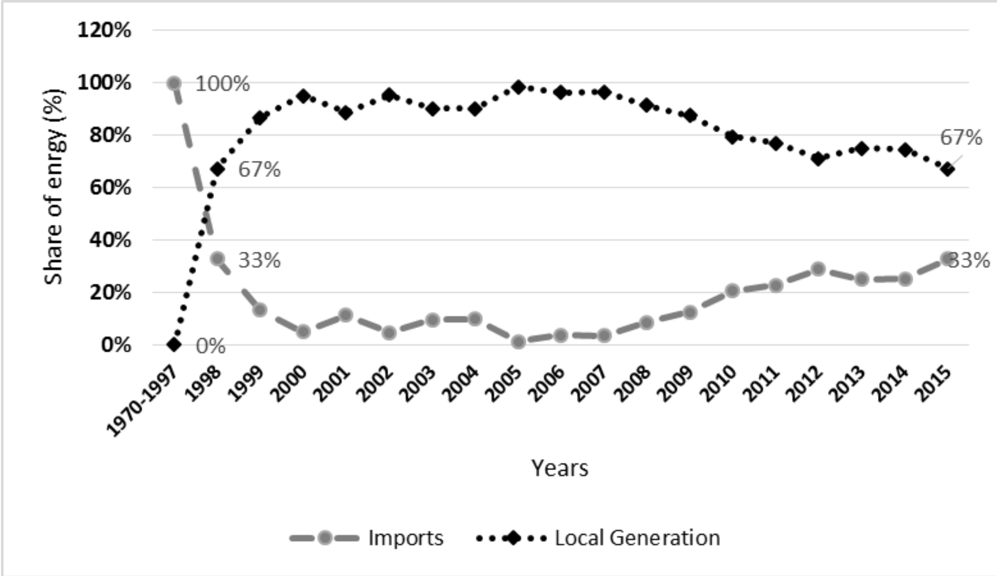


Fig. 3: Percentage of imported electricity vs generated electricity.

Source: (Ministry of Energy and Meteorology, 2015)

2.2 System reliability overview for Lesotho

"*The basic function of an electrical power system is to supply its customers with electrical energy as economically as possible and with acceptable level of reliability*" (Bagen, 2005). Unreliable systems are costly to the economy, as is 100% reliability based on excessive margins and redundancy; therefore a balanced approach to performance and cost effectiveness is critical.

Reliability has two main facets: system adequacy (sufficient generation to meet consumer demand) and system security (the ability of the system to respond to disturbances) (Bagen, 2005). The system reliability can be assessed at three hierarchical levels: generation (hierarchical level 1: HL-1), transmission (hierarchical level 2: HL-2) and distribution (hierarchical level 3: HL-3). At level 1, planners mainly assess the capability of generating facilities to satisfy total system load (Bagen 2005). Most utilities call this 1-in-10 reliability standard [14], which simply means that planning reserve margins must be large enough such that involuntary load shedding due to inadequate system supply would only occur once in ten years.

To plan for reliable electric system, reserve margin serves as a composite reliability index which includes all the other reliability indices that are considered in 1-in 10 reliability standard. According to international best practice, a low cost reserve margin is when the system has a reserve capacity of 15% [14]. The reserve capacity is calculated using Equation [1], [15], and [13].

$$\boldsymbol{RM}\ (\%) = ((\boldsymbol{ic} - \boldsymbol{pd})/\boldsymbol{pd}) * \mathbf{100}\% \qquad [1]$$

,where *ic* is the installed capacity, *RM* is the reserve margin and *pd* is the peak demand. This work proposes a 20% reserve margin for Lesotho. Planning for reserve margin is done only for the needed capacity scenario. In all other scenarios, imports are assumed to supply the reserve capacity, as the local generation has not been enough to meet the peak demand. Using Equation [1], Fig.4 shows that Lesotho has no reserve margin. Consequently, any slight disturbance in the system tends to trigger load shedding as there is no buffer to cater for such disturbances, especially under tight import restrictions.

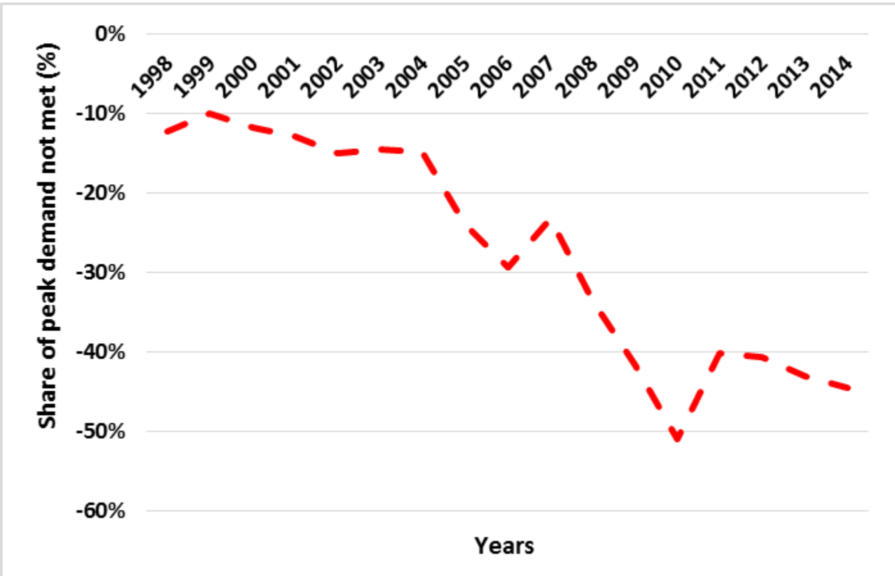


Fig. 4: Electricity system adequacy and reliability of Lesotho's electricity system.
(Ministry of Energy and Meteorology, 2015)

3 Methodology

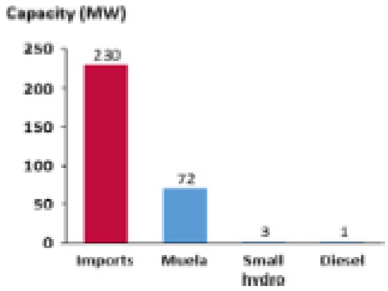
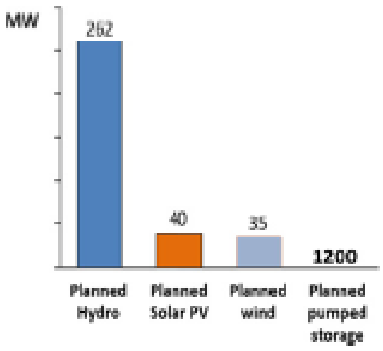
3.1 Schematic modelling methodology and PLEXOS modelling tool

The modelling framework adopted in this paper to formulate an electricity expansion plan for Lesotho using PLEXOS is shown in Fig. 5 and the modelling horizon runs from 2015 - 2050. PLEXOS is a versatile electricity planning tool that can be used for a wide range of planning purposes, one of those being capacity expansion planning [16]. The objective function of PLEXOS's electricity expansion plan is to minimize the net present value of build costs, fixed operation and maintenance costs and variable electricity generation costs [16].

A general constraint is the transmission system between Lesotho and South Africa which limits the transfer of power to a maximum of 230 MW. There is no co-optimisation for expansion of transmission system and generation capacity within Lesotho. It is assumed that only one transmission network will service the entire nation. This assumption is in line with studies that concentrate on capacity expansion planning [17], [18], [19] and [20], where the detailed infrastructure planning (transmission and distribution) is usually ignored.

According to Fig.5, the inputs into the modelling are load (energy), peak demand, new power plants considered in the optimisation, existing generators and as well as imports from the SADC region as well as Eskom and Mozambique imports. Three capacity cases are considered: No new capacity; planned capacity and needed capacity cases. The descriptions of these cases is presented in Table 2 and are linked to the objective to be achieved by each case. The no new capacity case analyses the cost of the system when there is no additional capacity added to the system and demand is met by current capacity and imports only up to a maximum of 230 MW (as per current transmission capacity limit between Lesotho and South Africa).

Table 2: Capacity cases

Capacity case	Explanation	Capacity
No new capacity	Under this scenario, it is assumed that there is no new investment in electricity supply and the country imports its supply from the SADC region. The imports are constrained by 230 MW limit, which is the existing transmission capacity linking Lesotho and South Africa.	
Planned capacity	In addition to the capacity shown above (No new capacity), this case assumes planned capacities as shown in the right column. These are based on the country's reported planned capacities [MEM, 2015]. Capacities above this are not allowed to be built. The planned pumped storage capacity according to media reports is 1200 MW. Imports are restricted to 230 MW like in the no new capacity case above.	
Needed capacity	In this case, all the planned capacities are included together with other additional capacity that can be needed to meet the reserve margin of 20%. All the reported untapped potential of both hydro and pumped storage is included in this scenario. Imports are restricted to 230 MW.	All the above options + Planning for reserve margin of 20%

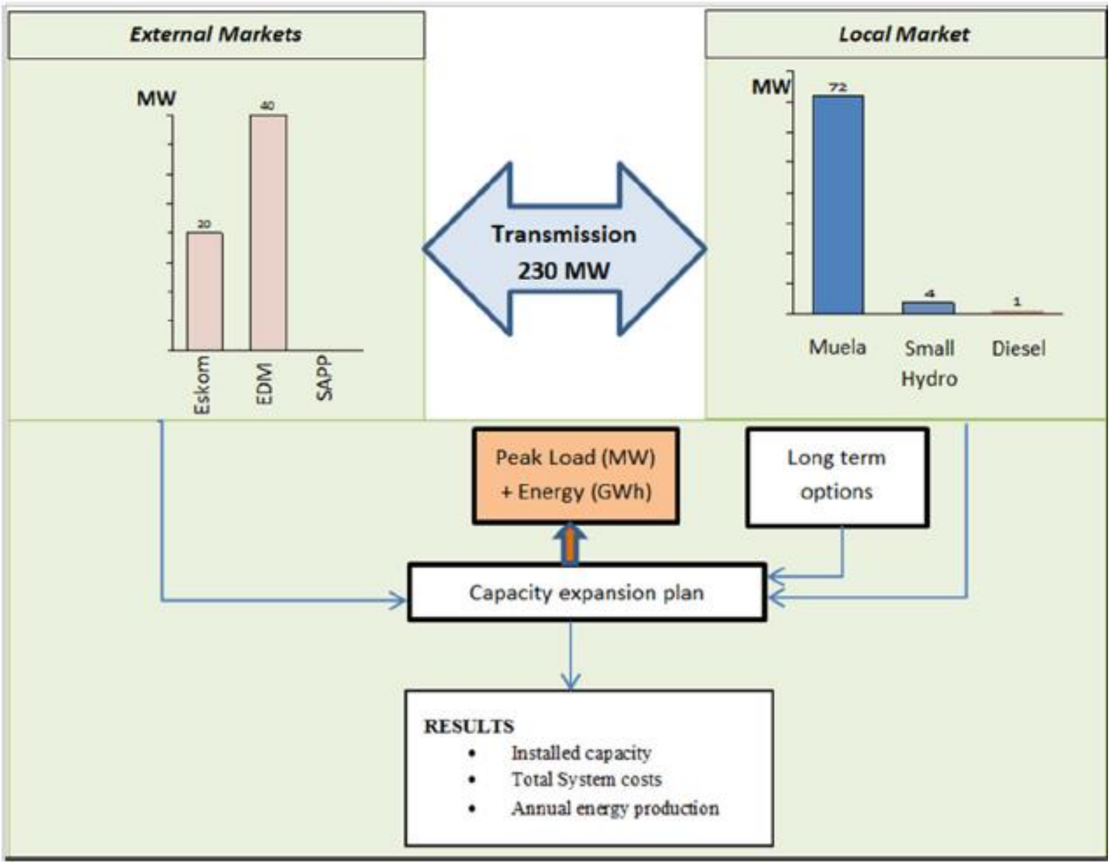


Fig. 5: Modelling framework

When transmission capacity limit is reached, there will be cost to Lesotho's economy for not meeting the demand. The no new capacity case assesses the cost of unserved demand to the economy. The unit cost of unserved energy demand is presented in Section 3.4. The planned capacity case considers options that the MEM has planned to install to achieve local baseload generation. The needed capacity case starts with the objective of planning for a secure system with reserve margin of 20% and is not reliant on imports for providing reserves for reliability purposes.

3.2 Forecasting electricity demand

Determining the electricity demand is the first step in establishing how much capacity expansion is needed [21]. The PLEXOS in-built load profile builder uses peak load and the annual energy demand to build load profile for each year of the modelling period. The load profile built is similar to base year load profile in shape. The increasing peak load and energy consumption change reflect in the magnitude of the load profile. The hourly base year electricity demand was provided by MEM.

To forecast energy consumption (GWh) and peak demand (MW) for the base-demand growth, the autoregressive integrated moving average (ARIMA) was used. ARIMA allows every variable to be explained by its own lagged values and stochastic error terms. The ARIMA model is mainly suitable for stationary time series, which is where the data fluctuates around the mean. Future energy consumption and peak demand for the two demand growth scenarios (BAU and HIGH demand) shows that electricity consumption is integrated of the first order with Moving Average of eight lags and an Autoregressive process of order twelve lags, hence we estimate ARIMA (12,1,8) to forecast annual electricity demand for Lesotho.

ARIMA methodology consists of four steps; namely, identification, estimation, diagnostic checking and, most importantly, forecasting. The first step requires testing for stationarity of the data and identifying the appropriate values of p, d and q where p is the number of autoregressive terms, d is the number of non-seasonal differences needed for stationarity, and q is the number of lagged forecast errors in the prediction equation. This can be done using the autocorrelation function (ACF), the partial autocorrelation function (PACF), and the resulting correlogram, which is the plots of ACF and PACF against the lag length. The partial correlation measures the correlation between observations that are k time periods apart after controlling for correlations at intermediate lags; that is, it removes the influence of these intervening variables. From the correlogram, we can then establish that the data becomes stationary after being differenced once, meaning that we estimate model with d=1.

Subsequent to identifying the appropriate values of p, d and q, the model is then constructed and estimated based on the stationarity results obtained in the first step, which is followed by diagnostic checks. To check whether the model is a reasonable fit to the data or not, the residuals are obtained from the estimation in the previous step and checked as to whether any of the autocorrelations and partial correlations of the residuals are individually statistically significant or not. If they are not statistically significant, then it means that the residuals are purely random and there is no need to look for another ARIMA model. Finally, forecasting is carried out based on the constructed and verified ARIMA model as follows:

$$If\ d = 0: y_t = Y_t$$

$$If\ d = 1: y_t = Y_t - Y_{t-1}$$

$$If\ d = 2: y_t = (Y_t - Y_{t-1}) - Y_{t-1} - Y_{t-2} = Y_t - 2Y_{t-1} + Y_{t-2}$$

Where y denotes the d^{th} difference of Y, electricity sales. Our estimation shows that electricity sales is I (I) with MA(8) and AR(12), hence we estimate ARIMA (12,1,8) to forecast electricity demand for Lesotho. By using ARIMA modelling, the BAU energy consumption grew by 3% between 2015 until 2025 and it grew by 2% thereafter. The peak electrical demand grew by 2% between 2015 until 2025 and grew by 3% thereafter. For HIGH demand scenario, the maximum (peak demand) is growing at 3% annually until 2025 and at 5% annually thereafter. 2050. These peak demand growth rates were chosen based on historical data where the demand growth was 3% annually between 1999 and 2015. The projected energy consumption for BAU and HIGH demand scenarios are shown in Table 3.

Table 3: Comparison of base and high demand growth

Base scenario (ARIMA based forecast)					
Parameters	**2015**	**2025**	**2035**	**2045**	**2050**
Peak demand (MW)	150	254	363	472	527
Energy demand (GWh)	797	1057	1291	1577	1706
High demand scenario					
Peak demand (MW)	150	232	357	551	684
Energy demand (GWh)	811	1345	2230	3499	4130

Given the United Nations projection of 3 million people in Lesotho (for No change growth scenario[1]) [22] by 2050, the per capita electricity consumption will be 553 kWh/capita and 1150 kWh/capita for BAU and HIGH demand scenarios respectively. This is very low by international standards where countries like Canada and USA consumed 13 MWh and 15.5 MWh per capita in 2013 respectively [23] and [24].

3.3 Assumptions on resource potential for new build options

According to Köppen climate classification system, Lesotho is classified as dry tropical highlands – called the BWh climatic region [25]. This climatic situation provides rainfalls that result in attractive potential for hydro-electricity generation. Studies indicate that Lesotho has a conventional hydro potential of 450 MW [26], [27], with only 75 MW (17%) tapped to date, leaving 83% (375 MW) untapped potential (Taele et al. 2012). The prospective conventional hydro potential in Lesotho is not concentrated at a single location, as is the case with e.g. the Democratic Republic of Congo and Zambia [6], but is rather widely distributed resulting in a relatively more complex and expensive infrastructure for evacuation of potential power supplies, especially if the power plants are of small scale. On the other hand, Lesotho's potential for pumped storage is also enormous and estimated at 3 GW [26].

For intermittent renewable energy resources (solar PV and wind), the resource potential were extracted from online datasets [29]. The most critical factor for these resources is the capacity factor and based on 5 points in each of the 10 districts of Lesotho, wind and solar PV were found to have average load factors of 16% and 23.5% respectively. The hourly PV and wind generation profiles were used so that the variability of these two resources can be captured in the modelling.

A limit on planned PV and wind installations is at 35 MW and 40 MW respectively as per Table 2 throughout the modelling period. Despite, limits be placed in countries such as

[1] *The population growth scenario from United Nations's population database*

Germany [30] and observed in China [31], the Needed capacity case in this study does not imposed any limits on both technologies. It is assumed that there will be no need for annual limits because Lesotho has interconnection with South African grid and can deal with variability and intermittency issues of wind and PV and later, the pumped hydro scheme can help to deal with variability and intermittency induced by PV and wind.

The new build options are shown in Appendix (Table A.3) are a combination of small and large hydro plants, pumped storage options, wind and PV. In this study, small hydro is defined as up to 10 MW, above 10 MW is defined as large [27]. The electrical demand beyond LEC service territory can be met through initiatives implemented by other players such as the Rural Electrification Unit, within in the Ministry of Energy and Meteorology, given that some areas cannot be economically electrified through the national grid (Taele et al. 2012). Despite consideration of these two types of grids, this study considers demand growth as projected from historical data only; the demand saturation point for electrifiable areas is not established and the increased demand resulting from a release of suppressed demand is also not considered.

3.4 Assumptions on cost for both installed and new installations

The base year is 2016, hence all the future costs are converted to present value in 2016 using the discount rate of 10% [33]. The currency in Lesotho is Maloti (M) and is used for the analysis. An exchange rates of M13 per dollar (US$) is assumed [34]. The consumer price index (CPI) data is obtained from the Lesotho Bureau of Statistics (2016).

The investment costs (overnight cost) and electricity production costs (fixed and variable costs) for all the options are shown in Appendix (Table A.3). The costs for these options are compiled from different sources. Some investment costs are from MEM planning document [12], for options where that data was not available, the literature on costs was used to inform technology cost [35], [36], [37], [38].

The variable operating costs for hydro power plants are minimal [35], hence are assumed to be zero for this study for new options. The cost for solar PV and wind are taken from the Department of Energy in the Republic of South Africa [39]. Investment costs for energy technologies are subjected to cost reduction as learning rates. The cost curve due to learning rates associated with a doubling of experience for wind, solar PV and hydro are presented in Table A.3.

Another salient cost metric is the economic cost of unmet demand - cost of unserved energy (COUE) which is estimated using Equation [2] [40]. For 2015, with a GDP of M23.7 Million [33] and electricity consumption of 771 GWh, Equation [2] results in COUE of M30 768/MWh for Lesotho.

$$Cost\ of\ unserved\ energy\ (COUE) = {GDP\ (M)}/{Demand\ (MWh)} \qquad [2]$$

The PLEXOS modelling tool chooses options that have lowest levelised cost of producing electricity. Compared to other options, it is observable in Fig. 6 that small hydro systems are the least economic options.

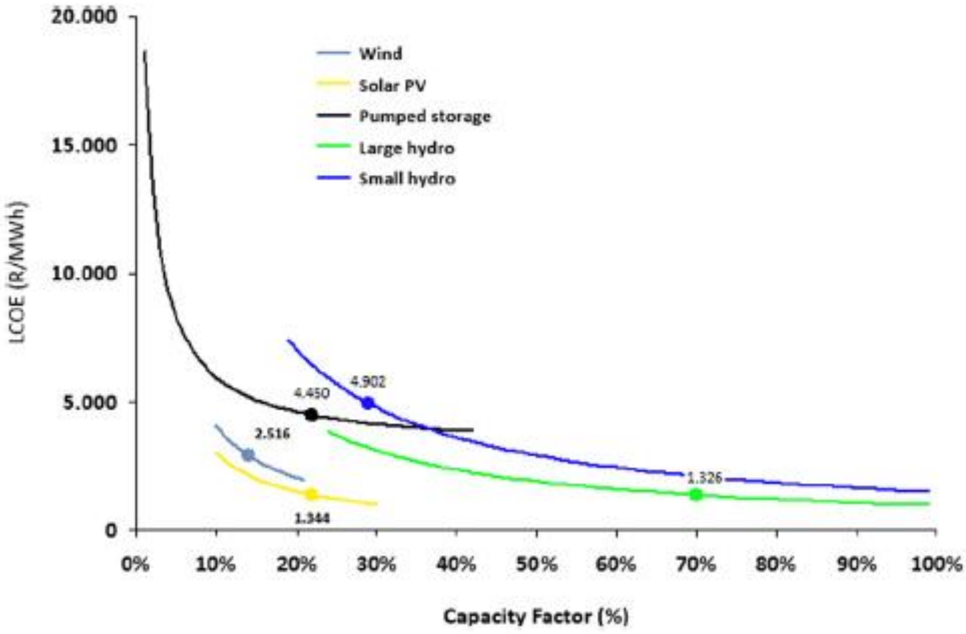


Fig. 6: Screening curves for power plants forming options for Lesotho

At their given capacity factors, large hydro (70%) and solar PV (23%) are the least cost options (for small hydro the modelled capacity factor is 33%). It is also important to note that the model will also select a technology based on the purpose it serves. For example, pumped hydro will be chosen to meet peak demand instead of using imports that cost above R4.45 in later years.

3.5 Assumptions on cost of imported electricity

The time of use tariff for the imported electricity is assumed based on Eskom's wholesale electricity pricing (WEPS) tariff [41] and the associated tariff structure is depicted in Fig. 7. This tariff is chosen for Lesotho because it is for customers whose tariff is reviewed annually and do not have long term special pricing agreements with Eskom [42].

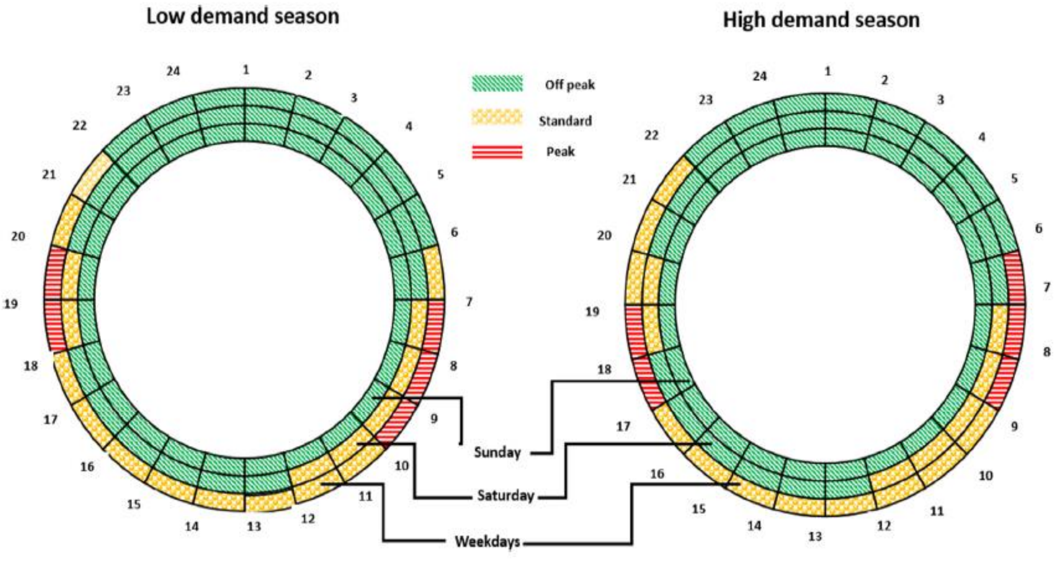


Fig. 7: Hours for WEPS tariff

Source: (Eskom, 2015a, 2015b), (Senatla and Mushwana, 2017)

Lesotho Electricity Company (2011) asserts that both Eskom and EDM tariffs are reviewed annually hence the assumption of WEPS tariff for Eskom. By 2015, the average cost of electricity from Mozambique and Eskom were M1.25/kWh and M0.86/kWh respectively with Eskom's average annual tariff growing by 14.2% between 2006 and 2015 [43] including inflation (which is approximately 6% of average during the same period). To forecast up to 2050 tariff, it was assumed that the tariff will be growing at an average of 5.4% (excluding inflation) annually; the tariff outlook for 2016 and 2050 is shown in Table 4.

Table 4: Typical tariff on Monday – Friday for low and high demand seasons.
Source for Base Year (2016) rates: (Eskom, 2015a, 2015b)

Year	Off-peak	Peak	Standard	Season
Units	M/kWh	M/kWh	M/kWh	
Time symbols (As shown in Fig. 7)				
2016	0.44	2.67	0.81	High demand
2016	0.38	0.87	0.60	Low demand
2050	2.63	15.96	4.84	High demand
2050	2.27	5.20	3.59	Low demand

4 Results and Discussion

The results details the least cost capacity to be built, unit electricity cost, the net present value and the share of energy met by different energy resources under each demand scenario and capacity case, including the no capacity addition case with associated costs of unmet demand. The net present value is the total cost that will be paid throughout the planning period by Lesotho and is calculated using Equation A.1 in the APPENDIX.

4.1 No New Capacity case (energy and cost)

Both imports and the current local generation capacity will not be sufficient to meet the demand in Lesotho from 2043 for BAU demand scenario and from 2035 for HIGH demand scenario (See Fig. 8). Under HIGH demand scenario, by 2050, almost half of the demand (1953 GWh) is not being met by available energy resources (imports and local generation). The cost of unmet energy demand to the economy of Lesotho is estimated at M354 million for HIGH demand scenario and is negligible for BAU demand scenario.

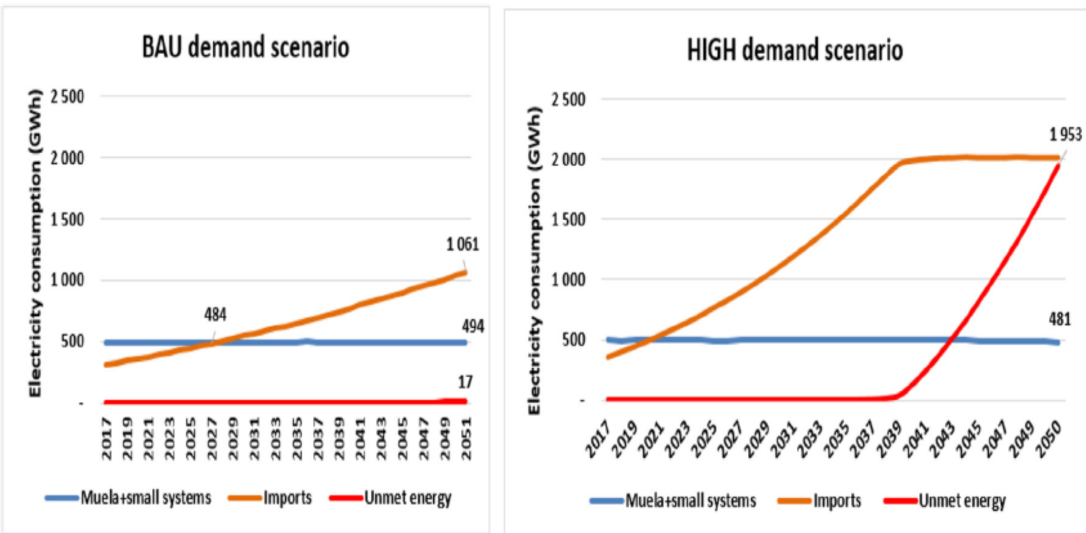


Fig. 8: No new capacity introduced: local generation, imports and unserved energy.

4.2 Installed capacity in the Planned Capacity case

Under the planned capacity case, a total new capacity of 305 MW and 433 MW is installed by 2050 for BAU and HIGH demand scenarios respectively (see Fig. 9). For the BAU demand scenario, this capacity is made up of 146 MW, 40 MW and 119 MW of large hydro, PV and pumped hydro respectively. For the HIGH demand scenario, this capacity is made up of 215 MW, 40 MW, 35 MW and 119 MW of large hydro, PV, wind and pumped hydro respectively.

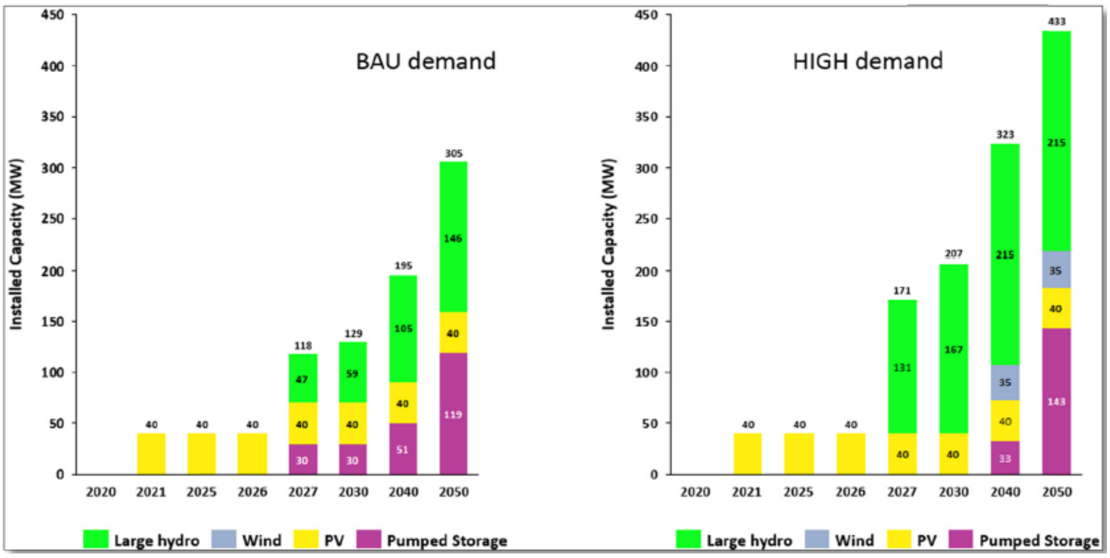


Fig. 9: Installed capacity in the planned capacity case for BAU and HIGH demand scenarios.

Out of 1200 MW of pumped storage potential, the least cost option for pumped hydro is between 119 MW and 143 MW for BASE demand and HIGH demand respectively. In case of high economic growth, the planned capacity of wind and PV are economic to pursue and under BASE demand scenario, only PV is built. Wind becomes economic after 2035 given its low capacity factor.

4.3 Installed capacity in the Needed Capacity case

The needed capacity case prioritises security of supply, meaning that the power system in Lesotho is developed to provide its own reserve margin of 20% to manage reliability. In this capacity case, Fig. 10 shows that the total installed capacity ranges from 650 MW to 1805 MW by 2050 for BASE and HIGH demand scenarios respectively.

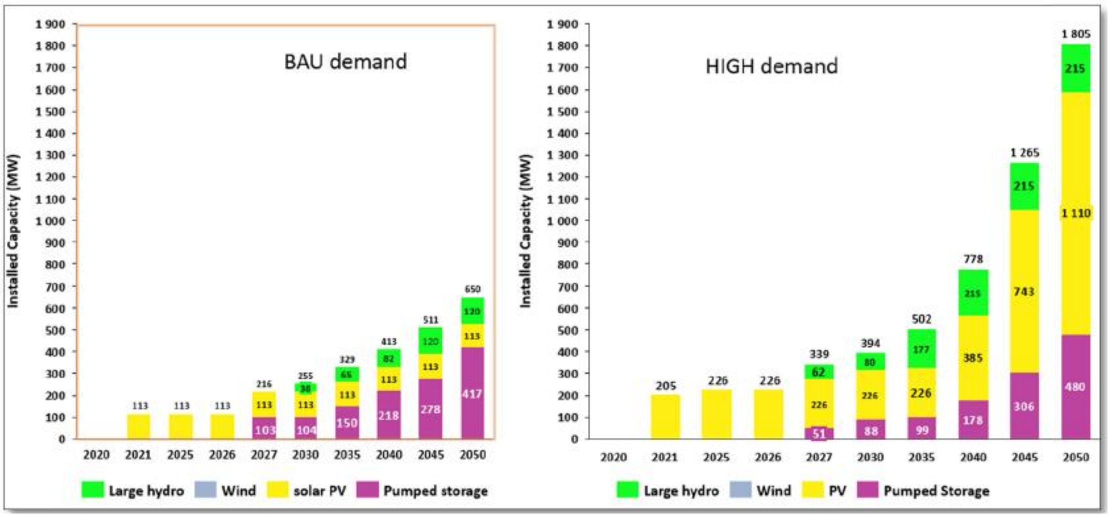


Fig. 10: Installed capacity in the needed capacity case for BAU and HIGH demand scenarios.

In this capacity case, there is no constraint placed on PV and wind in comparison to the planned capacity case where they were both capped at 40 MW and 35 MW respectively (See Table 2). As early as 2021, 113 MW and 205 MW of PV is economic for the country to pursue. In the HIGH demand scenario, PV expands to 1 GW of installed capacity by 2050 and to deal with variability introduced by PV within the system, about 480 MW of pumped storage is installed. This analysis indicates that the planned Polihali dam will mainly export power to the Southern African Power Pool (SAPP) whereas between 417 MW and 480 MW will be used internally in the country under the 2 modelled demand scenarios.

4.4 The energy mix

Power stations operate with variable availability factors and provide varying amounts of energy to meet demand. Although the pumped storage has between 417 MW and 480 MW of installed capacity, Fig. 11 shows that the share of energy is very low due to the capacity factor of 40%, meaning pumped storage is mainly providing reserve capacity and is used during peak periods.

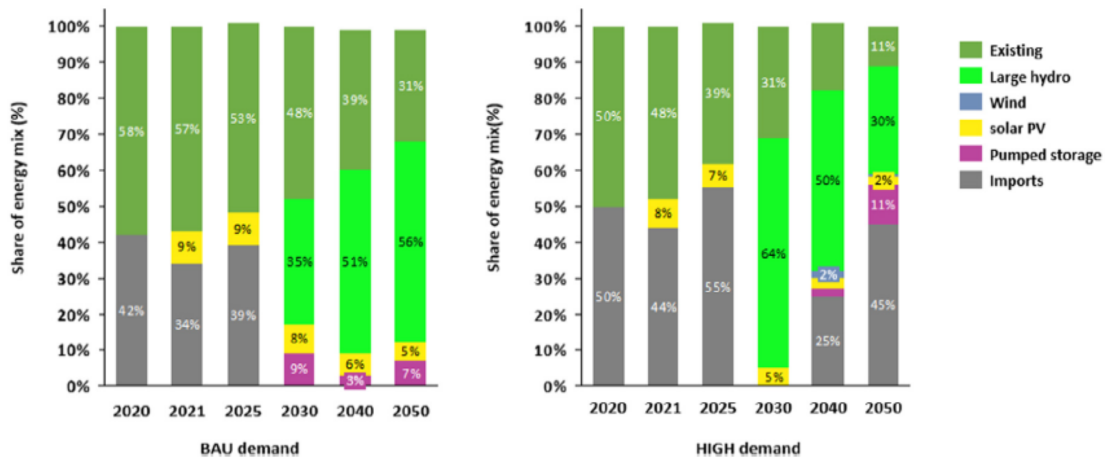


Fig. 11: Planned capacity case energy mix.

In 2020, Fig. 12 shows that the demand is met by imports and local generation at 42% and 58% energy share respectively under BAU demand scenario. Under high economic growth, imports meet 50% of the demand by 2020. This translates to increased cost of electricity. Once hydro comes online by 2026, imports are reduced to 0% for both demand scenarios. Under BAU demand growth, installations of large hydro systems, together with ‘Muela’s capacity will be enough to meet the electricity demand in Lesotho until 2050. In the HIGH demand scenario, imports are reintroduced by 2034, increasing to 45% of electricity demand. It is important to note that under the planned capacity case, the reserve margin is provided by the imports capacity. All the capacity determinations made in this case are to meet the demand only, not for any reserve purposes.

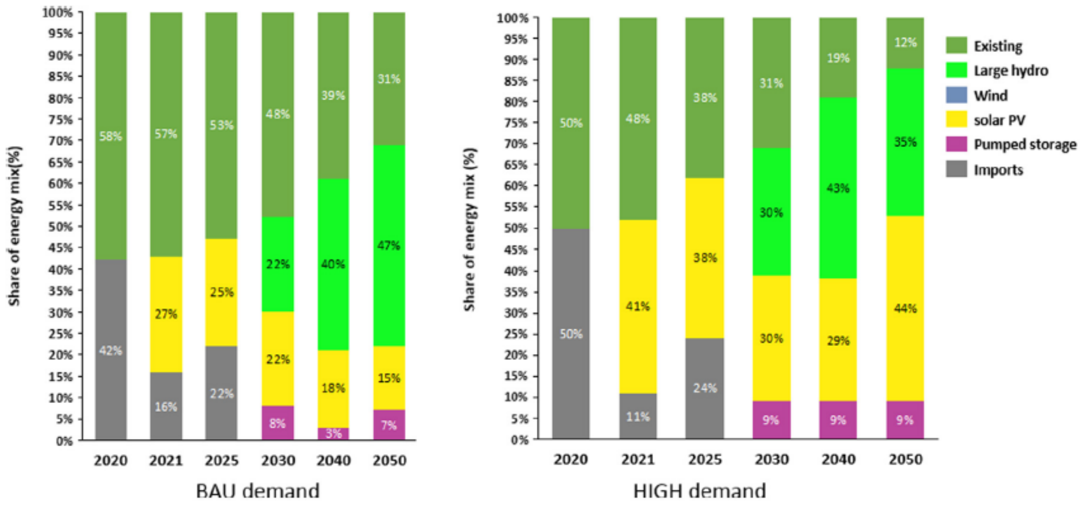


Fig. 12: Energy mix for needed capacity case.

In the needed capacity case, new installed hydro plus 'Muela capacity will meet 78% of demand in Lesotho by 2050 (See Fig.12). The remaining demand is met by PV and pumped storage at 15% and 7% share respectively by 2050. For a case with high economic growth, once imports disappear in 2026, the future demand will be met by hydro, PV and pumped storage. The share of energy mix is as follows: 47% ('Muela and new installed capacity) for hydro, 44% for PV and 9% for pumped storage by 2050.

4.5 The total system cost

The key consideration of the strategic value of the respective plans is cost for the level of service. In 2017, the cost of electricity, mainly imports and 'Muela, is M0.43 billion. If the country relies on imports, Fig. 13 shows that by 2050, the country will eventually pay M7.71 billion and M12.55 billion annually for BAU and HIGH demand respectively. Planned capacities will reduce cost if the demand grows at an average rate of 2% (BAU demand scenario).

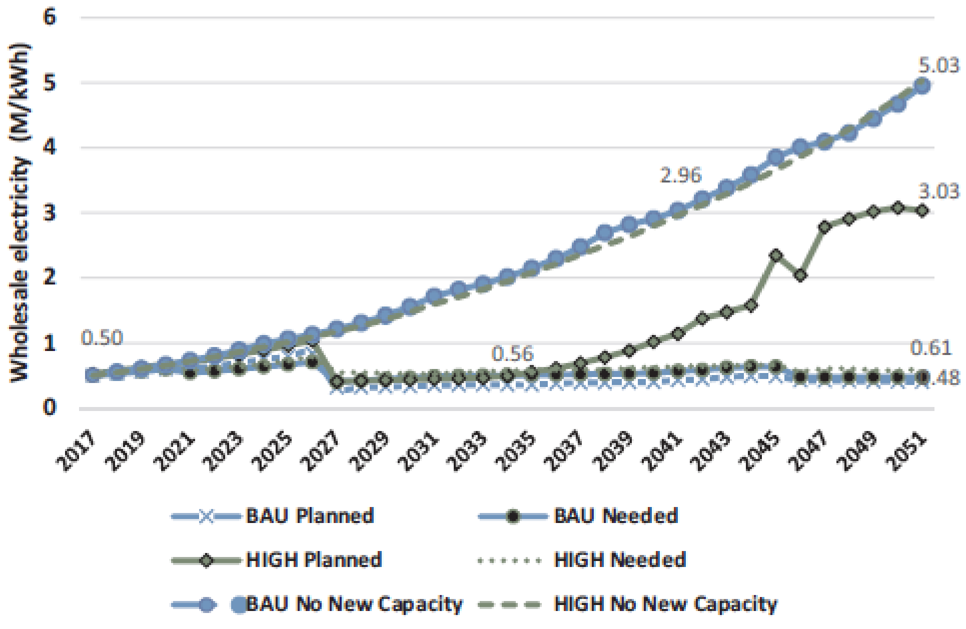


Fig. 13: Wholesale electricity price.

In cases where there is high economic growth, importing and implementing only the planned capacities will be economically suboptimal. Planned capacities for HIGH demand scenario will be costly for the country because by 2050, 45% of the demand will be met by imports and the country will incur M13.54 billion annually for electricity. Planning for a secure system is beneficial for the country in both demand scenarios. In comparison to cases where the country relies on imports only, the country will save about M7 billion and 11 billion for BAU and HIGH demand scenarios respectively.

Fig.13 shows that if the country relies on imports, the average cost of electricity will reach M5/kWh by 2050. In cases where security of supply is prioritised, the cost is M0.48/kWh and M0.61/kWh in 2050 for BAU and HIGH demand scenarios respectively. This is a saving between M2.55 and M4.42/kWh between BAU and HIGH demand scenarios respectively. For cases where capacity is added into the system, 2026 sees a reduction in cost when large hydro is installed and there is a drop in costs in the early 2040's when an additional hydro and PV are added.

Given that imports are limited to 230 MW without additional transmission investment, the cost of imports presented in Fig.13 and Fig. 14 does not include the cost of unmet demand of about M31/kWh. As an indicative budget for each scenario and case, Fig. 15 presents the net present value (NPV) of investment under each scenario and case.

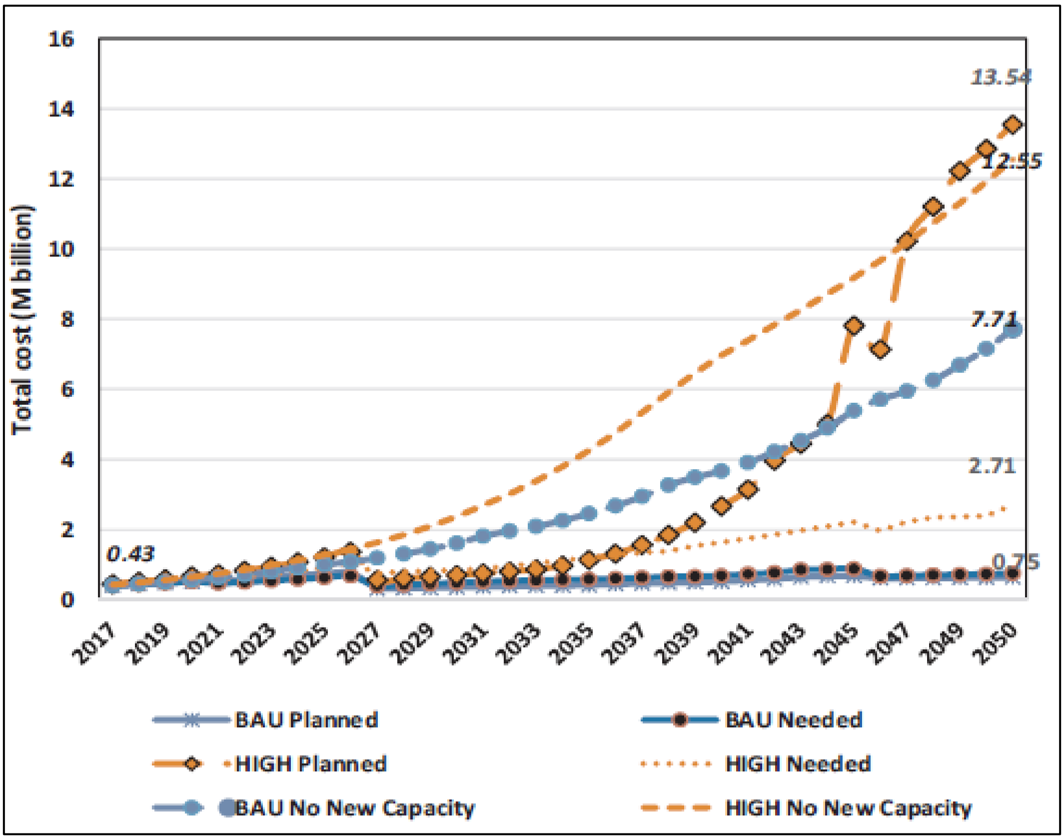


Fig. 14: Total system cost for BASE demand scenario under needed and planned cases.

For BAU scenario, the country will need to spend an average M0.63 billion and M0.73 billion per annum for planned and needed capacity cases respectively. The extra M100 million between planned and needed is the investment in reserve capacity. Under high economic growth, it is a requirement to plan for secure system as the country will merely pay M1.6 billion annually compared to M4 billion for planned capacity case. By investing in secure system will save the country M2.4 billion annually on imports in a high demand scenario. Reliance on imports results in the country paying M3.5 billion and M5.9 billion annually for BAU and HIGH demand scenarios.

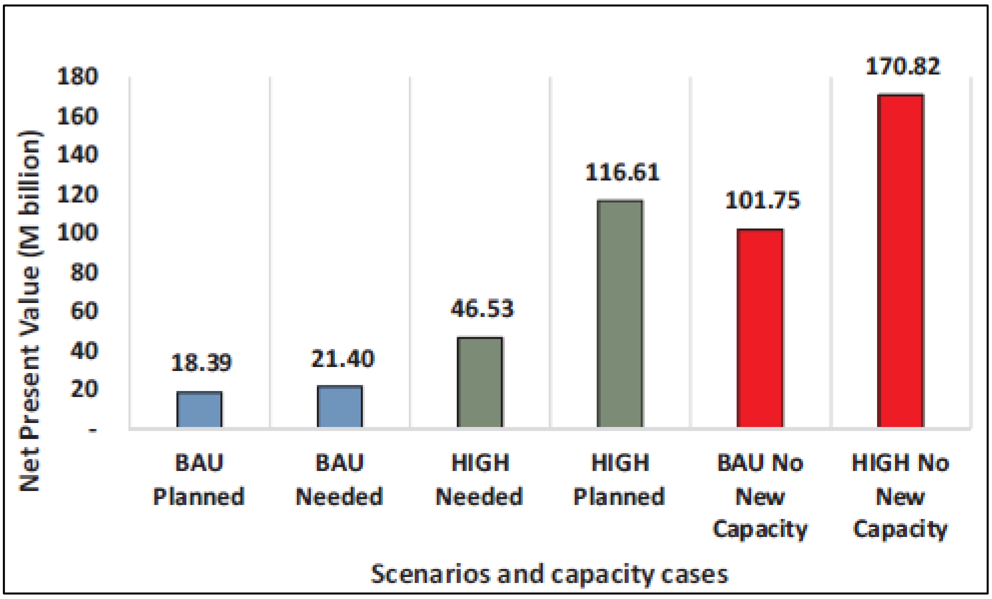


Fig. 15: The net present value for HIGH and BAU demand scenarios under each capacity case.

It is important to note that if demand increase is 2% per annum (meaning it is not high), the capacity that is currently planned to be invested is beneficial for Lesotho whether you plan for secure system or not (See Fig. 16). As long as the country invest in additional local generation between 305 MW (for planned capacity case) - 650 MW (for needed capacity), Lesotho will save about M80 billion between 2016 and 2050 compared to a case where the country relies on imports.

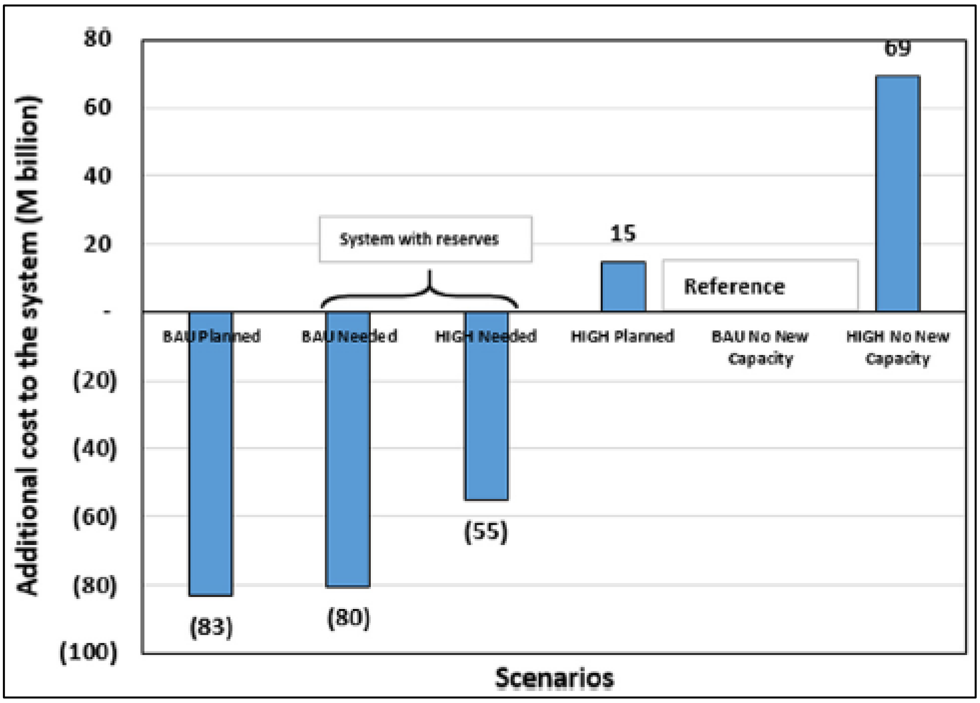


Fig. 16: Comparison of overall cost savings or expenditure.

If demand is increasing at a high rate (5%) per annum, it is crucial for Lesotho government to prioritise local generation with enough reserves so that it can save LEC the high import bill. Fig. 16 shows that the country can save M55 billion by investing in self-sufficiency relative to the reference case (relying on imports). In high demand scenario, LEC will have to pay M 69 billion for imports in comparison to BAU demand scenario between 2016 and 2050.

5 Conclusions and implication on electricity generation policy

These results provide insights that can usefully inform the electricity policy direction in Lesotho. The results show that there are advantages for local generation even if there is unlimited imports available from South Africa, Mozambique or from SAPP markets. In order to effect these advantages, the Lesotho government would need to commit to plans to procure electricity in the next 5 years such that by 2030 there will be more local generation capacity to hedge against projected increases in import price and volatility. The results also show that deployment of PV can play a significant role in providing least cost electricity mix in Lesotho, and that the procurement model for the electricity system can be optimized when the electricity market is open to investment in renewables. Whatever procurement model is followed (government putting in the investment or allowing private investors), PV provides a least cost electricity plan if the cost of producing electricity from it is low or close to hydro as possible.

By investing in a system with enough reserves, Lesotho can save up to M80 billion relative to a scenarios where its demand is met by imports. The outcome of the study also favours longer term investment in large hydro, pumped storage and PV as they are more cost efficient per unit of output. Development of small hydro systems must be evaluated carefully as these appear to be uneconomical even under scenarios of high electricity demand. According to the results of this study, for Lesotho to maximize benefit from its energy resources, the country would develop up to 480 MW of pumped hydro storage, although the economic case for the 1200 MW of planned pumped storage is less clear as this would create a situation where the pumping scheme depends on imports and risks becoming a stranded asset under unfavourable tariff regimes. Without any ambitions to export power, Lesotho must install about 500 MW of pumped storage not 1200 MW as currently anticipated.

Lessons can be learnt from Phase 1 of Lesotho Highlands Development Authority (LHDA). In Fig. 3, it shows that in 1998, the hydro scheme ('Muela Power plant) that was developed as part of the water transfer scheme to South Africa (as Phase 1 of LHDA), only met the demand in Lesotho for about 2 – 3 years, i.e. the plant was only constructed for current demand in those years without considering future electricity demand. Pumped storage will accompany Phase 2 of the LHDA development, and the power section plan of the scheme should exploit the opportunity to address the long term energy demand forecast for Lesotho from the outset of the water transfer scheme development, because retrofitting the plants afterwards will be comparatively cost inefficient for future generations. PLEXOS' long term planning does not give insights into detailed dispatch and pumping of the pumped hydro scheme, therefore future work must look into cascaded long term planning to provide insights to policy makers and plant operators on how the dispatch of pumped hydro will impact the cost of generation and how management of the resource can be optimized.

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APPENDIX

Objective function of PLEXOS model explained

The objective function of PLEXOS's electricity expansion plan is to minimize the net present value of build costs plus fixed operation and maintenance costs, plus electricity production costs using Equations [A.1] to [A.5]. The entire modelling horizon is solved in one step and annual load duration curve is sliced into 100 time slices. Equation [A.5] shows that capacity expansion occurs to meet demand without which there is no need for expansion.

Table 5: Parameters in PLEXOS modelling tool.

Parameter	Description	Unit	Parameters in the model
t	Where t stands for period (hour, day, month and year). In Eq. (A.1), the period under consideration is an hour	Hour	
DF_{year}	Discount factor applied to year under consideration. $DF_{(year/t)} = 1/(1 + D)^{y}$. DF_t is the discount factor applied to dispatch period t.	%	10%
L_t	Duration of dispatch period t	Hours	Hour
$BuildCost_{gen}$	Overnight build cost of generator gen.	M/kW	Presented in Table A.3
$MaxUnitsBuilt_{gen,year}$	Maximum number of units of generators allowed to be built by the end of year y.	Units	Limits apply to planned in planned capacity case (see Table 3)
P_{gen}^{max}	Maximum number of units of generator, (gen) is allowed to be built by the end of the *year* in consideration.	MW	Unlimited
$Units_{gen}$	Number of installed generating units of generator gen.		See Table 3
VOLL	Value of lost load (energy shortage price)	M/MWh	M37 768?MWh
$SRMC_{gen}$	Short-run marginal cost of generator *gen* which is composed of [Heat Rate] x [Fuel Price] + [VO&M Charge]	M/MWh	For hydro = M0.19/kWh
$FOMCharge_{gen}$	Fixed operations and maintenance charge of generator *gen*		Presented in Table A.3
$PeakLoad_{year}$	System peak power demand in a *year*	MW	Presented in Table 4
$Reservemargin_{year}$	Margin required over maximum power demand in a *year*	%	20%
$Demand_t$	Customer demand in period t, usually termed the load, where t stands for period and this analysis it's a year under consideration	MW	See Table 4

Table 6: Operating characteristics of 'Muela Power plant.

Months	Average monthly capacity factor for 'Muela	V&OM Minimum (M/kWh)	FO&M cost (M/kW/year)
January	65%	0.119	121.75
February	74%	0.119	121.75
March	62%	0.119	121.75
April	70%	0.119	121.75
May	92%	0.119	121.75
June	99%	0.119	121.75
July	99%	0.119	121.75
August	95%	0.119	121.75
September	86%	0.119	121.75
October	61%	0.119	121.75
November	58%	0.119	121.75
December	71%	0.119	121.75

Minimise

$$\sum_{year}\sum_{gen} DF_{year} \text{ x } (BuildCost_{gen} \text{x } GenBuild_{gen,year})$$

$$+ \sum_{year} DF_{year} \text{ x}\left[FOM\ Charge_{gen} \text{x } 1000 \text{ x } P_{gen}^{max}\left(Units_{gen} + \sum_{i\le year} GenBuild_{gen,i}\right)\right]$$

$$+ \sum_{t} DF_{t\in year} \text{ x } L_t \text{ x } \left[VOLL \text{ x } USE_t + \sum_{gen}(SRMC_{gen} \text{ x } GenLoad_{gen,t})\right] \qquad [A.1]$$

Subject to

1) **Energy balance**

$$\sum_{gen} GenLoad_{gen,t} + USE_t = Demand_t \quad \forall t \qquad [A.2]$$

2) **Feasible Energy Dispatch**

$$GenLoad_{gen,t} \le P_{gen}^{max}\left(Units_{gen} + \sum_{i\le year} GenBuild_{gen,i}\right) \qquad [A.3]$$

3) **Feasible Builds**

$$\sum_{i\le year} \boldsymbol{GenBuild_{gen,i}} \le \boldsymbol{Max\ Units\ Built_{gen,year}} \qquad [A.4]$$

By using Equations [A.1] – [A.4], the reserve margin is not catered for hence the build options are built only when they are economic and can result in negative reserve margin. Since one of the objectives of this work is to plan for reliable electrical system, hence the need to include a certain level of reserve capacity and that is possible by planning for capacity adequacy using Equation [A.5]. The parameters used in Equations A.1 – A-5 are shown in Table A.1.

$$\sum_{gen} P_{gen}^{max} \left(Units_{gen} + \sum_{i \leq year} GenBuild\right) + CapShort_{year} \geq PeakLoad_{year} + ReserveMargin_{year} \quad \forall \mathbf{t}$$

[A.5]

Table 7: Supply options considered in the analysis.

Name in PLEXOS	Resource	Unit capacity (MW)	Total capacity [MW]	Investment costs (M/kW)	FO&M cost (M/kW/ year)	V&OM minimum (M/kWh)	Capacity factor	Learning rat% cost reduction p.a
Malealea Hydro_N	Large	40	40[a]	20 000	121.75	–	65%	0.07%
Solar PV_N	Solar PV	1	40[b]	30 000	272	–	23.5%[c]	2.2%
Wind_N	Wind	1	35	22 857	300	–	16%[d]	1.19%[e]
Generic Large_Hydro_N	Large	27	135	25 926	121.75	–	65%	0.07%[f]
Setene Hydro_N	Small Hydro	5	5	30 000	121.75	–	20%	0.07%
Semonkong Hydro_N	Small Hydro	2	2	75 000	121.75	–	20%	0.07%
Quthing Hydro_N	Large Hydro	40	40	20 000	121.75	–	65%	0.07%
Remaining Hydro	Hydro			75 000	121.75		65%	0.07%
Planned Pumped Storage	Pumped Storage	20	1200	6 563	131.26	700	Limited to 40%	0.00%

a. Capacities for hydro are taken from (Ministry of Energy and Meteorology, 2015).
b. For planned capacity case, PV can be installed up to 40MW but for needed capacity, no technical limit is placed on PV and wind resources.
c. Taken from Renewables Ninjas website. (https://www.renewables.ninja/). About 5 points were taken from each of the 10 districts in Lesotho so that a national average can be estimated.
d. Learning rates taken from Rubin et al. (2015).
e. Learning rates taken from Rubin et al. (2015).