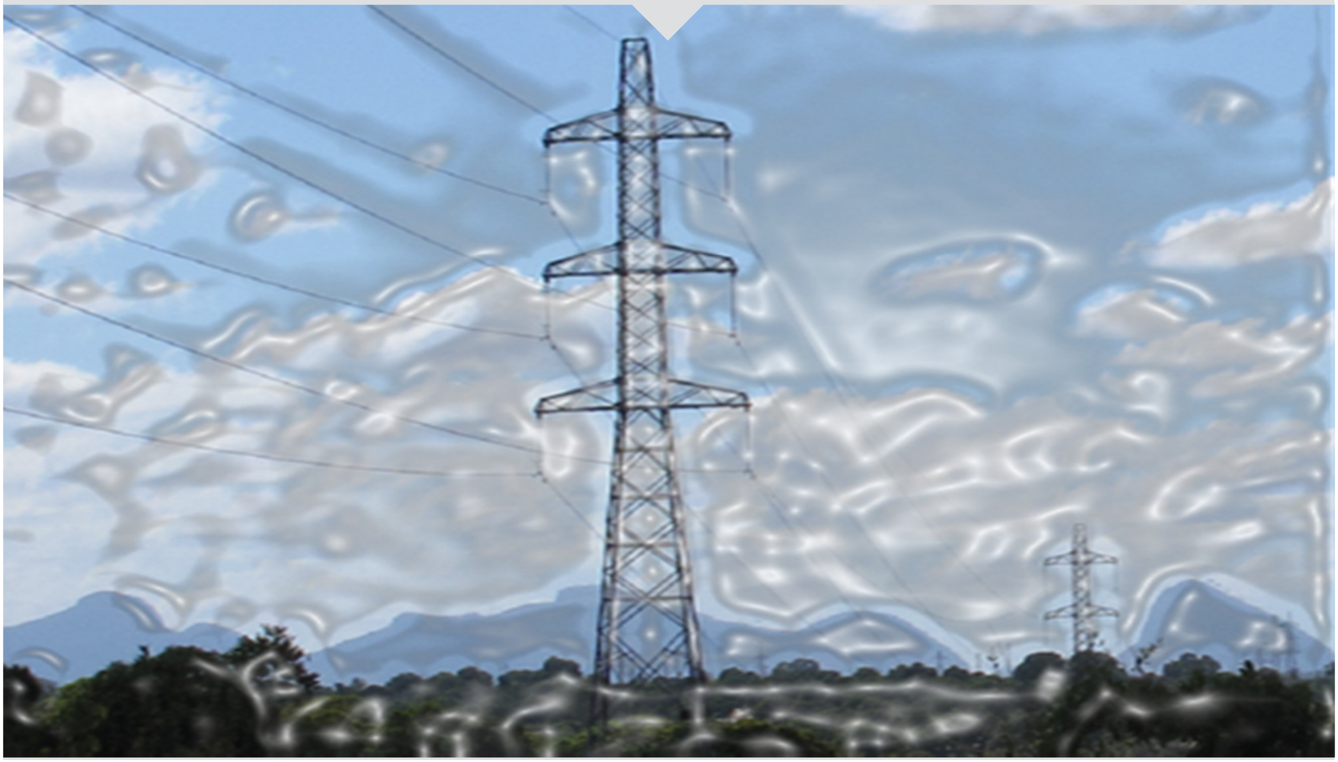
Ministry of Natural Resources, Energy and Mining
Government of Malawi

Integrated Resource Plan (IRP) for Malawi

Volume II - Load Forecast

Draft Report - February 2017



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The IRP report is presented in the following volumes:

Volume I – Main Report

Volume I – Appendices to Main Report

Volume II – Load Forecast (this document)

Volume III – Resource Assessment

Volume III – Appendices to Resource Assessment

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1 Introduction

This updated Load Forecast Report has been prepared by Norconsult AS in association with Economic Consulting Associates (ECA) and Energy Exemplar (EE) on behalf of the Ministry of Natural Resources, Energy and Mining (MoNREM) of the Government of Malawi, represented by the Department of Energy (DoE). This Report is the second report to be produced under contract to MoNREM to prepare an **Integrated Resource Plan (IRP) for Malawi**.

The Load Forecast Report was updated following the Interim Stakeholder Workshop held in Lilongwe in October.

Load forecasts can be used for a wide range of purposes ranging from short-term operation of a power system through to long-term investment planning. The forecasts used for these different purposes adopt different approaches, with probably the most complex modelling algorithms being used for short-term forecasting and for spatial distribution planning. For an IRP study, a long range forecast is required because the investments that will be guided by the IRP plan will generally have a long life of 20 years and, for hydropower assets, potentially 50 years or more.

The Terms of Reference TOR) ask the Consultant to prepare an investment plan covering the period 2015 to 2035 (now agreed in the Inception Minutes to be 2017 to 2037) and the forecast discussed below covers this period, and beyond. However, long-range forecasts and long-range investment plans are only used to guide investment decisions that must be made in the next 3 to 4 years – for Malawi the IRP will probably guide investment decisions that will be made between 2017 and 2020. Why then do we prepare a forecast and investment plans to 2035 or 2037? The forecasts and investment plans are not required because these plans will be acted on beyond 2020, but **rather the investments that may be made beyond 2021 will have an impact on the investment decisions to be made today**.

If, for the sake of argument, Malawi needed a 1,000 MW base-load coal-fired plant in 2025-30, this would then (probably) impact on the type of investments that should be chosen in the next 3-4 years. The important point is that the investment plan beyond, say, 2021 should not be treated as fixed and immoveable – there will be flexibility to adapt the plan in the future depending on how circumstances change between today and 2020 (demand growth, regional power markets, financial resources, etc.). Electricity demand forecasts often cause considerable debate and anxiety but it must be remembered that the future is inherently unknowable and that long-range electricity demand forecasts should be assessed bearing in mind that the investment plan must be adapted and updated in future as circumstances will inevitably change and as the future becomes the present.

The remainder of this Load Forecast Report is arranged as follows:

> **Section 2** reviews three previous demand forecasts.
>
> **Section 3** describes the forecast proposed for the IRP study.

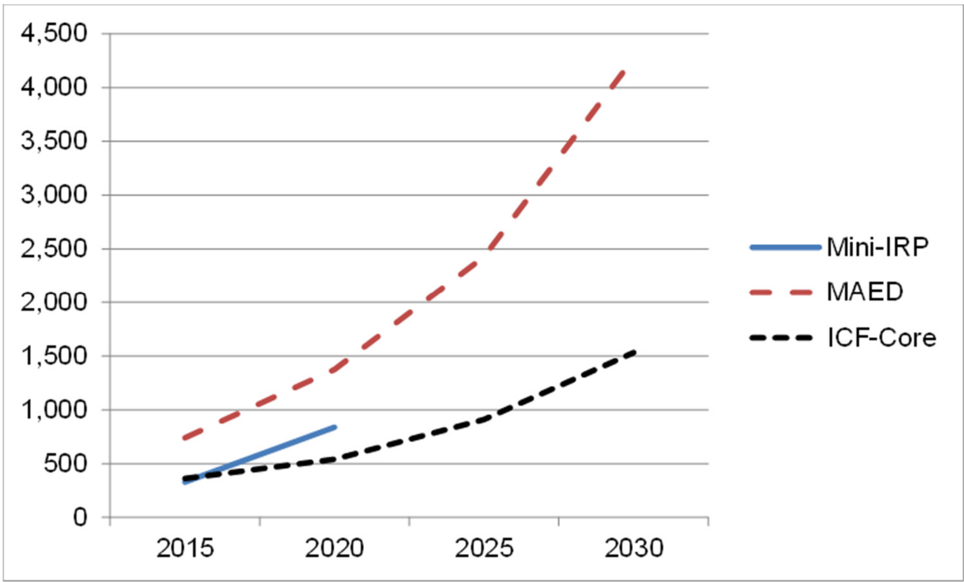
2 Review of previous load forecasts

As described in the Terms of Reference for the IRP study, two load forecasts had been prepared relatively recently in 2011 and 2012. One was prepared by the Ministry of Energy[1] with guidance from IAEA[2] using IAEA's MAED[3] load forecasting model. The other was prepared by consultants to MCA-Malawi and used as an input to an IRP planning study[4]. The two forecasts had been critically reviewed by the Energy Advisor to the Ministry of Energy[5]. A third forecast has also been prepared as an input to a Mini-IRP study completed in December 2015[6]. The latter was a rapid IRP study and concentrated on a demand forecast and investment plan up to 2020.

The resulting maximum demand forecasts (reference or base cases from each) from these three exercises are summarised in Figure 2-1below. The forecasts have been adjusted to some extent to place them on a consistent basis[7].

[1] ***Malawi Energy Demand Assessment Report*** prepared by the then Ministry of Natural Resources, Energy and Environment and the Department of Energy, January 2011.
[2] International Atomic Energy Agency (IAEA).
[3] Model for Analysis of Energy Demand (MAED).
[4] The IRP study was completed in August 2011 by consultants ICF/CORE International. It was not adopted by GoM due to concerns raised by a number of key stakeholders at the time.
[5] ***A Comparative Analysis of Energy Demand Assessments in Malawi***, a Report by Energy Advisor, Ministry of Energy, January 2014.
[6] **Mini-Integrated Resource Plan, 2016-2020**, developed by a team from Ministry of Natural Resources, Energy and Mining (MNREM), the Department of Energy (DoE) and Electricity Supply Corporation of Malawi (ESCOM).
[7] E.g., the ICF-Core forecasts were for the years 2016, 2021 and 2030 while MAED was for 2015, 2020 and 2030. The figure for 2015 for the Mini-IRP study in the Figure is the maximum electricity supply (328 MW) rather than the demand (which is unknown). The forecast in the Mini-IRP study has been adjusted to exclude spinning reserve (see section 0 below).

Figure 2-1: Summary of the maximum demand forecasts from the three models (MW sent out[8])



This shows a major difference in the MAED and ICF-Core forecasts with the divergence increasing over time. In 2020, the ICF-Core analysis predicted a maximum demand of approximately 540 MW while MAED predicted a demand of 1,374 MW. By 2030 this gap had widened to approximately 4,300 MW and 1,550 MW or almost three times greater.

We would also mention that other electricity demand forecasts have been prepared in recent times including forecasts by the Electricity Supply Commission of Malawi (ESCOM) and by consultants to MoNREM, ESCOM, and the Millennium Challenge Account (MCA)-Malawi.

Below we provide a review of the above three demand forecasts and attempt to unravel the reason for this difference. The other forecasts are not reviewed here.

2.1 Basis for review

Load forecasts comprise:

- A model **structure** (e.g., bottom-up, top-down econometric)
- Estimates or assumptions regarding **relationships** between input variables and outputs (e.g., econometric equations)
- Assumptions or forecasts of the **input variables** (e.g., rate of market penetration of electrical appliances)

Load forecasts may be used for multiple purposes - revenue forecasting (focus on electricity supplied, up to 5 years ahead), distribution planning (5-10 years, spatial), operation planning (from months to a year or two) and investment planning for major capital projects. It is the latter type of forecast that is required for the IRP study.

Load forecast model structures have traditionally been characterised as bottom-up (sometimes also referred to as engineering models) and top-down or econometric. In practice, the distinction between these two types of model is not clear as engineering models will often include econometric or top-

[8] Sent out demand is the demand that would be needed at the interface between the power plants and the transmission network. It therefore includes technical and commercial losses.

down type relationships and, conversely, top-down models may include some bottom-up relationships such as the assumed programme of electrification. Nevertheless, we can characterise the IAEA model as bottom-up and the ICF-Core model as top down. The load forecast used in the Mini-IRP study can also be characterised as top down. We cannot say that one approach is correct and the other incorrect – they are just different ways of representing the real world. The primary difference between the bottom-up and top-down models is that the bottom-up model (MAED) is data intensive and requires a large number of assumptions relating to electricity consumption by electrical equipment and the penetration of that equipment into the market whereas the top-down models tend to require less data, the forecasts are more easily updated and the resulting forecasts are more comprehensible. It should also be mentioned that the MAED model is an ***energy*** demand forecasting model with an electricity demand component.

The differences between the forecasts using the top-down (ICF-Core) and bottom-up (MAED) approaches cannot be attributed to the model structure and we therefore need to consider the other two components of the load forecasting model – the **relationships** and the **input variables**.

2.2 Reasons for the differences in the MAED and ICF-Core forecasts

The discussion focuses on the base or reference forecasts for both the MAED and ICF-Core forecasts.

We begin by noting those parameters (or relationships) and exogenous variables that are largely the same between the ICF-Core and MAED forecasts including:

- An average growth rate of GDP of 7% per annum is assumed in the MAED forecast and 6% per annum is assumed in the ICF-Core forecast[9]. Both are GDP per capita. The ICF-Core report explicitly states that the 6% per annum assumption relates to **real** GDP per capita whereas the MAED report does not state explicitly that it is real, but we assume it is. A difference of one percentage point between the two forecasts could make a reasonably significant difference by the year 2030, but not sufficient to explain the large difference between the two forecasts[10].
- Average energy losses are assumed to fall to 15% by 2030 in the MAED forecast and this is more-or-less consistent with the assumption of 16% losses in the ICF-Core forecast[11].
- The population is assumed to roughly the same in both forecasts, reaching just over 5 million households in the MAED forecast and 4.7 million in the ICF-Core forecast.

There are, however, some important fundamental differences in parameters and input assumptions between the two forecasts as noted below.

2.2.1 Electrification targets

In the MAED model there is no specific electrification rate described as an input assumption, but the electrification rate can be imputed from the assumed penetration rates for space and water heating. These imply electrification rates of 54% by 2030[12].

The assumed electrification rates in ICF-Core forecast are also a little unclear. There are expected to be 932,000 household electricity customers in 2030[13], which implies an electrification rate of 19.8%.

[9] Exhibit 3-1.
[10] 7% per annum would lead to a 20% higher level of GDP per capita over a 20 year period than a 6% per annum assumption.
[11] The text refers to losses of 16.2% but the calculations suggest losses of 14% by 2030.
[12] Calculated based on Tables 5-59 and 5-60 for space heating and electrical water heating. Households must be connected to the network to allow this penetration.

However, the target electrification rates are indicated in Exhibit 3-1 at 60% for urban households and 10% for rural households and we estimate that this implies an electrification rate of just over 27%.A third source of information is Exhibit A4-1 in the Annexes, which shows an electrification rate for households in 2030 of 15.8%.

The higher electrification rate assumed in the MAED model has a substantial impact on peak demand in 2030 compared with the ICF-Core forecast.

2.2.2 Income elasticity

ICF-Core's forecast assumes an income elasticity of 1.2 for commercial and industrial consumers and 0.85 for residential consumers. This means that for every 10% increase in GDP, demand increases by 12% for commercial and industrial customers and by 8.5% for residential customers[14]. The implication of these assumptions is that the commercial and industrial sectors will become more electricity intensive over time, whereas for residential consumers their spending on electricity as a share of their total income will gradually decline over time as their income increases. For commercial and industrial customers the elasticity of 1.2 is consistent with consumers gradually moving from manual processes to mechanised processes as the economy grows.

The ICF-Core forecast predicts 4.2 fold increase in electricity consumption over the period 2010 to 2030[15] compared with a growth in GDP over the same period of 3.2 fold[16] implying a growth in electricity consumption per unit of GDP of 23%.

MAED does not use elasticities as an input parameter, but the report describes a growth in electricity consumption per unit of aggregate GDP[17] of 20 fold over the period 2008 to 2030[18]. The reason for the high growth in electricity consumption per unit of GDP is not entirely obvious from an inspection of the input assumptions described in the report.

Although MAED does not use an elasticity in the model, it is useful to compare the two forecasts in terms of growth in electricity consumed per unit of GDP (electricity intensity). The ICF-Core model results in a growth in electricity intensity by a factor of 1.23 over the forecast period while the MAED model results in a growth in intensity by a factor of 20. This is clearly a major difference and is clearly one of the reasons for the MAED forecast being substantially higher than the ICF-Core forecast.

Over a similar 20-year period (1990 – 2010) in Botswana and Kenya, electricity per unit of real GDP grew by a factor of 4.5 for Botswana and by 6.7 for Kenya. This tends to suggest that the MAED assumptions are leading to an over-estimate of electricity demand while the ICF-Core model may be leading to an under-estimate of electricity demand.

[13] Page xx of the Executive Summary and page 36 of the main report.
[14] The report does not state that the elasticity refers to electricity consumption per consumer or to total electricity consumption by sector, but we assume it refers to electricity consumption per consumer.
[15] Exhibit A4-1.
[16] 6% per annum over a 23 year period.
[17] GDP and "value added" are, or should be, interchangeable.
[18] Section 5.5.4 and Figure 5.26, page 75.

2.2.3 Demand-side measures

MAED makes no explicit assumptions regarding demand-side measures (DSM) or programs but DSM are implicit to some degree in the assumptions for energy efficient technologies that are built into the forecast of penetration of electricity using technologies such as LED (or CFL) lightbulbs[19], solar water heating or efficient types of air conditioning. The impact of this penetration is not shown explicitly.

The ICF-Core forecast makes explicit assumptions regarding DSM including efficient lighting, ripple control on water heaters, solar water heating (relatively small contribution) and the impact of time-of-use tariffs. Overall the forecast assumes that these measures will lower peak demand by 102 MW by 2030. The major part of this load reduction is the result of energy efficient lightbulbs and the result of the introduction of time-of-use tariffs.

Although DSM benefits are not explicit in the MAED analysis, MAED does implicitly assume energy efficient technologies are adopted. But differences between the DSM assumptions in the two models, whether explicit or implicit, are unlikely to have resulted in the significant differences in the overall maximum demand projections that are seen in the two forecasts.

2.2.4 Price elasticity of demand

The ICF-Core model assumes a price elasticity of demand of -0.45, which implies that a 10% increase in price would lead to a 4.5% reduction in demand. This is combined with assumed tariff increases between 2010 and 2016 leading to cost recovery levels by 2016, but the level of the increase is not specified.

No price elasticity or tariff increase is provided in MAED. A price elasticity could have been implicit in the assumed level of market penetration of electrical appliances, though it was not mentioned in the report.

Depending on the level of the tariff increase assumed in the ICF-Core model, the high negative price elasticity could have contributed partially to the relatively low demand projection (and the relatively low growth in electricity intensity) in the ICF-Core model.

2.2.5 Losses at peak

Though both models use similar assumptions regarding the reduction in losses, the ICF-Core model assumes that the same level of losses apply to demand (MW) as apply to energy (MWh). For technical reasons, losses at times of peak demand are generally higher than average losses. The MAED forecast assumes that peak losses are nearly 25% of sent-out MW in 2025[20] while energy losses are assumed to come down to 17.8% in 2020 and 15% in 2030. The MW losses in 2025 are consistent with higher losses at peak than the average losses.

We estimate that this factor will have led to the ICF-Core forecast under-estimating peak demand by around 6-7% by 2030.

2.2.6 Suppressed demand

A forecast of demand should be exactly that – a forecast of demand. Ideally, capacity availability should not be a consideration in the demand projection. Where there are supply constraints, the supply of electricity will be below demand and this may result in occasional load shedding. However, where supply shortages are chronic, electricity users will adapt and find alternatives. This could

[19] Light emitting diodes (LED) and compact fluorescent lightbulbs (CFL).
[20] Figure 6.10.

include self-generation but the economy will also adapt by choosing less electricity intensive technologies or will choose technologies that are less sensitive to electricity supply interruptions. Typically this means a less modern and less up-to-date economy with a lower per capita GDP. There will therefore be a potential demand that may not be realized until the economy has adjusted to improved electricity supply availability.

Even where there are supply constraints, the forecast of demand should be a forecast of the potential demand. But there will be a lag between the relaxation of electricity supply constraints and industry/commercial sectors being sufficiently confident that the electricity supply is reliable such that they would be willing to make investments in productive activities in Malawi. Since the demand forecast is specifically for the purpose of preparing electricity investment plans, the demand forecast needs to reflect these lagged impact on demand of the relaxation of supply constraints.

ICF-Core reflects suppressed demand in the forecast by subtracting 95 MW of self-generation in 2030[21]. Load shedding is also, we believe, subtracted in the earlier years but there is no load shedding anticipated in 2030. Self-generation should generally be added to the system demand unless self-generation is chosen by the consumer because it is cheaper. It is not clear whether the 95 MW in the reference case reflects cheap self-generation such as that provided by bagasse at the sugar estates or whether it reflects other forms of self-generation (e.g., diesel plants) where the consumers should be supplied by the grid.

ICF-Core does not make any implicit assumptions regarding the bounce-back effect on electricity consumption as electricity supply becomes more reliable and consumers become sufficiently confident in purchasing new electricity-using equipment.

MAED does not have an explicit representation of suppressed demand. Instead it predicts what demand would be based on the market penetration of appliances and the use of those appliances. The impact of historical supply unreliability and future confidence building can be reflected in the assumed penetration rate of those technologies in the short-term and longer-term. Based on the ratio of electricity consumption to GDP, it appears that the MAED forecast is overly optimistic about the impact of improved supply reliability on electricity demand.

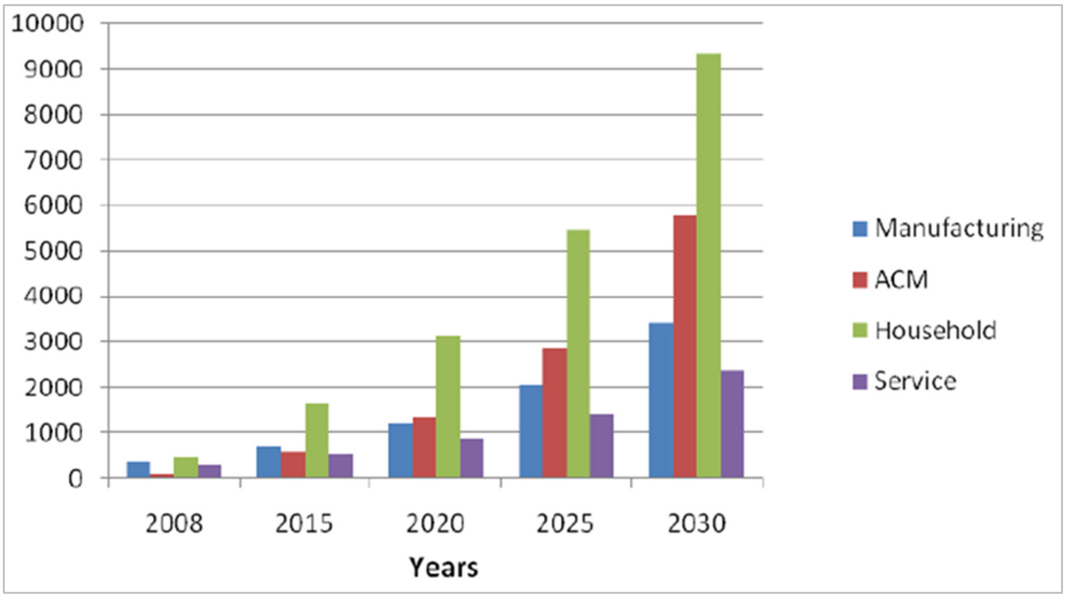
2.2.7 One-off loads

ICF-Core assumes that one-off loads will add 133 MW[22] to demand in 2030. These start at 52 MW by 2016, 72 MW by 2021 and 133 MW by 2030. The earlier ones are described in the report as being specific mining loads. The ones beyond 2016 are likely to be hypothetical ones.

MAED does not describe step loads explicitly but it assumes a large contribution to the economy by the mining sector and this has a corresponding impact on electricity demand. The growth in the agriculture, construction and mining (ACM) final electricity demand derived from the MAED model is shown in Figure 2-2 below. Agriculture is not assumed to grow rapidly so this growth in ACM electricity demand is driven particularly by the growth in mining. For comparison, a load of 6,000 GWh or ACM in 2030 is approximately equivalent to a demand of 850 MW[23].

[21] The text states that self-generation is subtracted. Exhibit 3-11 shows what they refer to as “Net” demand as inclusive of losses with some adjustments for one-off loads, DSM, self-generation and load shedding. It is not entirely clear but it seems that self-generation and load shedding are subtracted from power demand and then losses are added (~16%) in order to arrive at the “Net” demand.
[22] Figure in section 6.3.2.
[23] Load factor of approximately 80%.

Figure 2-2: Final electricity demand by sector (GWh[24])



Source: Malawi Energy Demand Assessment Report[25], Figure 4.

2.2.8 Exports

Export demand can be treated as exogenous to the least-cost investment planning such that the investment plan is optimized to satisfy both the domestic demand and the export demand. Alternatively, a second approach allows the least-cost planning to choose to invest in generation/transmission for the purpose of exporting electricity if the benefits (revenues) from exports outweigh the short-run and long-run costs. This would imply over-sizing the power plants to some extent to allow exports. The volumes of exports (and imports) as well as the investment plan are simultaneously optimized by the model. A third approach is to allow exports opportunistically if there is surplus electricity (when, for example, the rainfall has been good and there is surplus hydropower energy or when power plant investment temporarily gives rise to surpluses until demand grows.

The MAED analysis was purely a forecast of Malawi's own electricity demand and made no assumptions concerning exports.

The ICF-Core report shows exports that are a result of the least-cost analysis including both exports and imports. Before 2030 it shows net exports but the volume of exports diminishes toward the year 2030. It is not clear whether this analysis is undertaken using the second or third approach described above but it is clear that the forecast does not include an exogenously determined export demand. This is not therefore a reason for the difference between the two forecasts.

[24] The MAED report does not specify units but we assume GWh.
[25] ***Malawi Energy Demand Assessment Report*** prepared by the then Ministry of Natural Resources, Energy and Environment and the Department of Energy, January 2011.

2.3 Differences between the forecast in the Mini-IRP and other forecasts

We next consider the load forecast in the Mini-IRP study in December 2015.

The forecast in the Mini-IRP can be characterised as a top down approach with GDP growth and electrification targets as the main drivers of the forecast load growth.

Detailed assumptions are not provided in the report other than at a high level. The high level assumptions include:

- 30% electrification access by 2030. This included a broader definition of electrification than connection to the main electricity grid (i.e., mini-grids and potentially non-grid solutions). The 30% target is at the lower end of GoM's policy.
- The highest step loads are expected in the mining sector followed by agriculture, manufacturing, services and construction, in that order.
- An improvement in losses is expected but the report does not provide details.
- Demand-side measures are considered as an input to the IRP analysis and are not therefore taken into consideration in the demand forecast.

GDP growth is described as a driver for the forecast but the aggregate GDP growth rate is not provided in the report. The Mini-IRP philosophy was that government would identify and prioritise investment in key sectors such as manufacturing, agriculture and mining and grid extensions would be targeted to ensure continuous supply to these key sectors.

Without a description of assumptions and parameters used in the forecast, it is difficult to comment constructively on the forecast. However, we also note that the forecast was prepared as part of a rapid assessment and in these circumstances we accept that it is reasonable to adopt short cuts.

We would however make some comments on the forecast:

- The load forecast is based on sales plus non-technical losses. The forecast of generation requirements is then built-up from an assessment load (sales plus non-technical losses) and technical losses (including improvements in technical losses over time).
- Losses at peak are greater than average losses and the maximum demand forecast ought to take account of the higher losses at peak.
- The maximum demand forecast includes provision for spinning reserve (of 7.5%). Normally a maximum demand forecast does not include provision for reserve (whether spinning reserve or standing reserve). Reserve requirements are normally added by the system planners using appropriate criteria when preparing investment plans or integrated resource plans. For consistency with standard practice we have excluded the spinning reserve requirement when presenting the maximum demand forecast.

The resulting forecast of system maximum demand was summarised at the start of this Section 2. The Mini-IRP forecast deliberately did not consider demand beyond 2020. This forecast is intermediate between the MAED forecast and the ICF-Core forecast. The resulting forecast appears reasonable but beyond the comments above we do not have the detailed information to confirm that the forecasting assumptions or methodology are reasonable.

2.4 Summary

Our conclusion regarding the ICF-Core and MAED forecasts is that they differ primarily because of different input assumptions:

- Electrification access rates
- Income elasticity of demand (implied or explicit)
- Price elasticity of demand (small contribution to the difference)
- The contribution of losses to peak demand (relatively small contribution to the difference)
- The treatment of suppressed demand in the ICF-Core analysis
- Growth of the mining load

Fundamentally, there is nothing wrong with either forecasting approaches and if the two had used consistent input assumptions the two should have reached similar forecasts.

Our conclusion generally concurs with that of the Energy Advisor in his assessment of the two forecasts[26]. The assumptions used in the MAED model generally push the forecast to be higher than is reasonable. The ICF-Core forecast tends to push the forecast to be lower than is consistent with GDP growth rate forecasts and Government's unwritten electrification policy.

[26] ***A Comparative Analysis of Energy Demand Assessments in Malawi***, a Report by Energy Advisor, Ministry of Energy, January 2014.

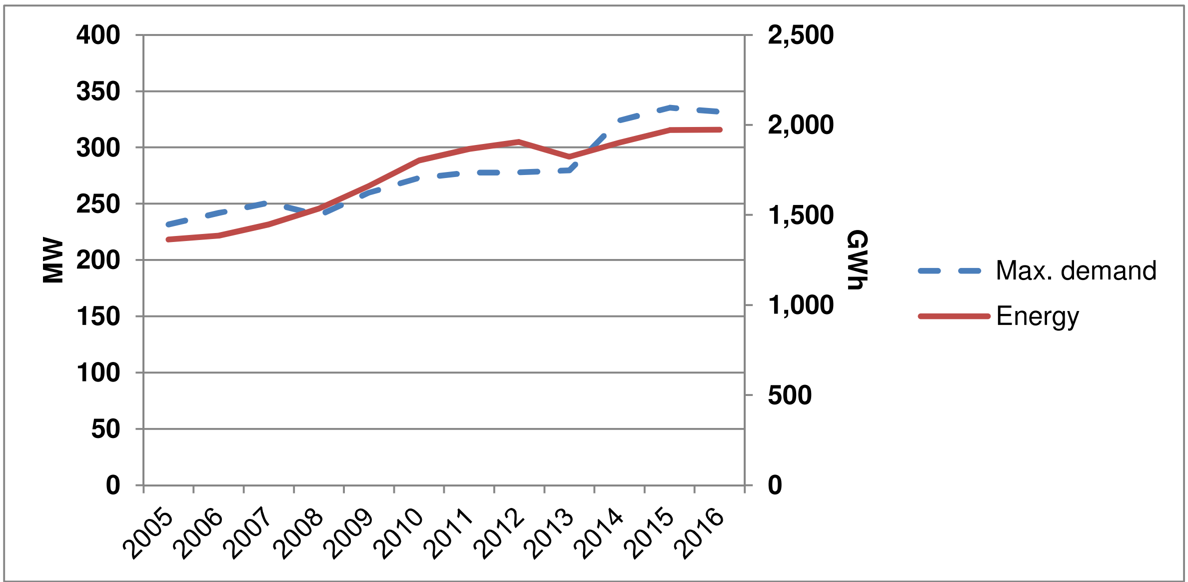
3 Electricity demand forecast

This Section 3 describes the electricity demand forecast that we propose to be used for the purpose of preparing the IRP. We begin by describing historical load growth (Section 3.1) followed by the approach we use to prepare the forecast (Section 3.2). Section 3.3 details the input assumptions while Sections 3.4 and 0 provide the base forecast and the high/low forecasts respectively. The future system load pattern is discussed in Section 3.5.

3.1 Historical load growth

Historical load growth for the ESCOM network is shown in Figure 3-1 below. This shows maximum demand growing from just above 230 MW in 2005 to 330 MW in 2016[27] with energy sent out from the power plants to the transmission network growing from 1,360 GWh in 2005 to just under 2,000 GWh in 2016. The average annual growth rate of both maximum demand and sent out energy over that period was 3.4%[28]. In the year 2015/16 there was significant load shedding due to low rainfall and the maximum demand was constrained and the maximum supply (332 MW) occurred toward the end of the financial year in April 2016. Load shedding also occurred throughout this period due to problems with the transmission and distribution network.

Figure 3-1: Historical load growth for ESCOM, 2005-2016



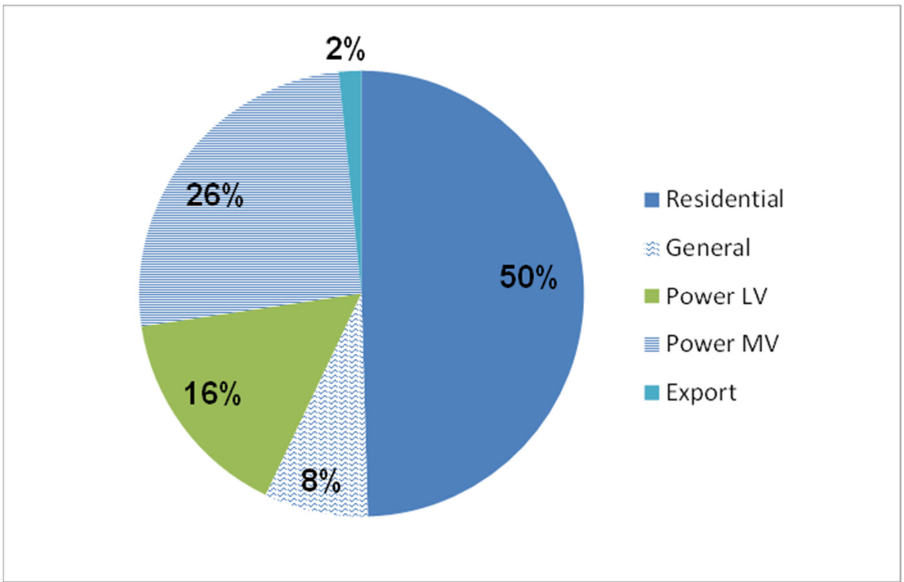
The 330 MW outturn for maximum demand in 2016 compares with the ICF-Core and MAED forecasts of 393 MW and 740 MW (for 2015) respectively. ICF-Core was a little optimistic compared with the outturn while the MAED forecast was over twice the outturn. This was largely due to the overly high

[27] Financial years – July to June. The period shown in the graph is for the financial years 2004/05 to 2015/16.
[28] The annual growth rate for the maximum demand was 3.3%. There was a dip in sent-out energy in 2008 due to data gaps for three months during that year but the amount has been estimated based on the sent out in the previous 9 months and the pattern in the following year.

expectation of electrification access rates and residential growth in demand but also lower than predicted economic activity and non-residential demand growth.

Residential electricity consumption currently represents around 50% of total energy sales, as shown in Figure 3-2[29]. The productive sectors (Power MV, Power LV and General) together with some exports account for the other 50%.

Figure 3-2: ESCOM electricity sales by customer category, 2016



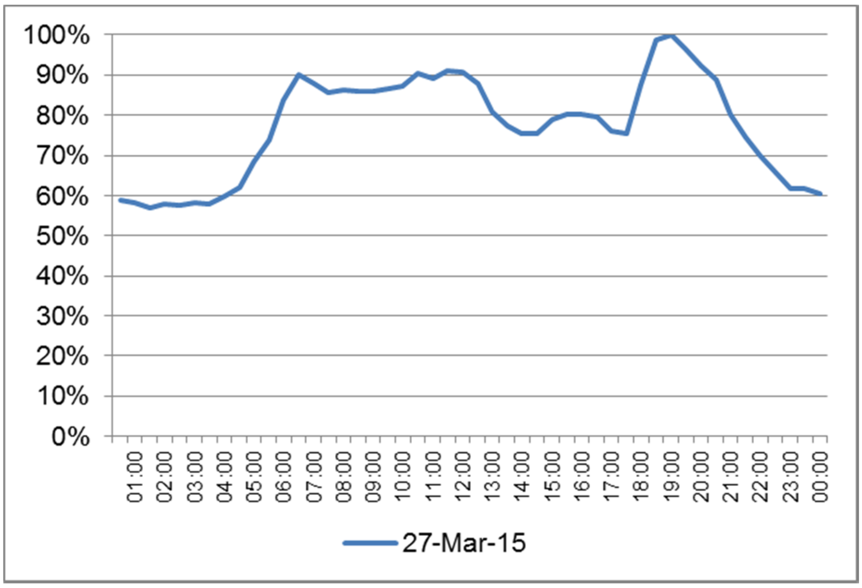
Source: ESCOM statistics[30]

Maximum demand in Malawi tends to show relatively little variation seasonally, but the general trend is for the peak to occur during the first part of the financial year in the months of July, August and September[31] except in years where load is growing faster when a peak appears to occur later in the year. As noted above, because of supply constraints, the maximum supply in the year 2015-16 occurred in May because constraints eased in that month.

A typical daily load pattern is indicated in Figure 3-3 below. The date, 27 March 2015 was selected because it is taken from a year in which there was relatively little load shedding at the generation level and because the load on that day has the smallest difference when compared with every other weekday in the year[32]. The peak on this typical day occurs at 19:00. There is another relatively high plateau between 06:30 and 13:00 and then a dip until 18:00. The load declines sharply again at around 21:00.

[29] The residential share is based on sales but if suppressed demand were included the share of residential would probably be lower.
[30] Due to rounding, these add to more than 100%.
[31] In five out of the last ten years the peak has occurred during those months.
[32] 27 March represents the day with the lowest root-mean square error when compared with every other weekday of the year.

Figure 3-3: Typical daily load curve



3.2 Forecasting approach

In Section 2 we reviewed the three recent electricity demand forecasts and noted that there are two generally accepted approaches to forecasting that can be characterised as bottom up or top down. – and that neither approach is better or worse than the other. However, it was also noted that the bottom-up approach is data intensive and, in the case of the MAED work, a national energy demand forecast was prepared covering all energy uses whether electrical or otherwise. The forecast required for the IRP study is purely an electricity demand forecast. Moreover, given the data intensity of the bottom-up approach, the time available for the study does not permit the adoption of a bottom-up forecast. We have therefore adopted a top down approach similar to those used for the ICF-Core and Mini-IRP analysis and similar to those used by ESCOM and ESCOM consultants.

The forecast represents sent-out energy demand (GWh) and sent-out maximum demand (MW). This reflects the energy and power that is required to be injected into the transmission network at the interface with the power plants. This includes the metered electricity consumption, unmetered electricity consumption (non-technical losses) and technical losses (the electricity that is inevitably lost during transmission and distribution). During the planning process using the Plexos software, the software will estimate the capacity that will be needed to satisfy the system reliability criteria including an appropriate margin of capacity over peak demand. This reserve requirement is not added to the forecast demand that is presented here.

It is important to note that the electricity demand forecast described here does not reflect active demand-side management (DSM) measures. These DSM measures will be analysed as part of the IRP planning process. The forecast assumes business-as-usual in relation to the implementation of energy efficiency and energy conservation measures and programmes. Business-as-usual is inevitably an imprecise concept but its intention is to base the forecast on ongoing market trends (in relation to the efficiency of energy appliances) but to assume that no new active DSM policies are implemented by the Government of Malawi. This will allow the IRP study to analyse the costs and benefits of such policies when weighed against the costs of supply-side alternatives.

It should also be mentioned that the forecast is based on electricity supplied through the national grid by ESCOM but excludes the electricity that is deliberately produced on-site by the sugar estates using bagasse. The forecast does take account of the demand that consumers would wish to take from the grid if the supply were available (i.e., suppressed demand). The omission of the bagasse-fuelled load has an insignificant impact on the forecast.

3.3 Input assumptions

An electricity load forecast is driven by the input assumptions. These are critical to the results. Below we describe the key assumptions, not necessarily in order of significance.

The forecast of electricity consumption by residential consumers depends on:

- Customer numbers, which, in turn, depends on **population growth** and the speed with which customers are connected to ESCOM's network or **electrification access**.
- The consumption per connected customer.

Non-residential demand is driven primarily by economic activity (as represented by GDP – which in turn depends in part on population growth).

Aggregate consumption is dependent on technical and commercial losses, both of which are expected to fall in future.

Maximum demand on the network depends on the pattern of demand by different customer groups and the mix of those customers in the overall system.

These, and other input assumptions are described below.

3.3.1 Population growth

Residential consumption currently represents around 50% of electricity sales[33] and, because maximum demand is driven by residential load in the evening, it makes an even greater contribution to ESCOM's maximum demand. Population growth should also go hand-in-hand with GDP growth so that an increasing population means more industrial and commercial consumers and consumption. It is therefore a key component of national electricity demand.

Population figures used in the electricity demand projections are taken from projections prepared by the National Statistical Office and the Ministry of Development Planning and Cooperation as part of the Malawi Growth and Development Strategy. These indicate population growth rates of 3.2% per annum at present and declining to around 2.4% per annum by 2050. Average household size is indicated in the Integrated Household Survey, 2010-11, at 4.6 persons per household and the survey found that household size was similar in both urban and rural households. This implies that there are currently 3.5 million households, and this will increase to around 7.6 million by 2040.

3.3.2 Electrification access

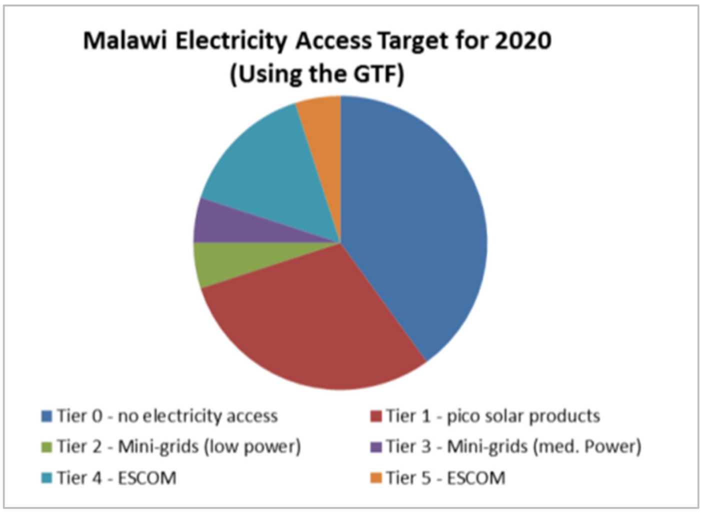
For the purpose of this electricity load forecast we define electrification access as the proportion of households connected to the national electricity network. We are aware of other definitions, focusing on access to solar PV or mini-grids that are equally important for other purposes, but not for the purpose of forecasting load on the national network.

[33] It is a slightly smaller percentage of the estimated unsuppressed demand because a significant part of the suppressed demand is for larger customers without access to grid electricity supply.

At the end of June 2016, ESCOM had a total of just under 330,000 residential customers, of whom 57,000 had pre-paid accounts (pre-payment metering) and 272,000 had post-paid accounts. This represents an electrification rate of almost exactly 9%[34] if one account represents only one household.

There has been no new formal energy policy since 2003 and the 2003 policy does not mention a specific electrification target. The Mini-IRP refers to 30% electrification as being at the lower end of Government policy but we understand that this is not an official policy or target. A draft Energy Policy[35] was provided to the Consultant which does not refer to a specific grid electrification target but does recommend adoption of the Global Tracking Framework (GTF) for measuring access to electricity. The GTF describes the different types of access, as illustrated in the chart reproduced below.

Figure 3-4: Electricity access (using GTF)



Source: Draft Energy Policy, 2016

The chart appears to suggest a grid electrification target in Malawi (Tiers 4 and 5) of perhaps 15% to 20% by 2020.

To date, ESCOM has achieved an increase in the number of residential connections shown in the Table below. The maximum number of connections in one year is indicated to have been just under 44,000, in the financial year ending 2015.

Table 3-1: Electrifications rates and new connections (ESCOM)

Year (mid-financial year)	Electrification rate	Connections made
2011	5.4%	13,701
2012	5.5%	8,560
2013	6.0%	23,158
2014	6.5%	23,521
2015	7.5%	43,775
2016	8.3%	34,832

We considered the possibility of assuming an electrification rate of 30% by 2020 but this would imply the number of connections jumping to above 200,000 per year and this would be financially and logistically very challenging for all parties. We note that the draft SE4ALL Agenda Action has indicated

[34] This is slightly higher than the figure in the Table below as the figure in the text is based on a year-end figure.
[35] Draft National Energy Policy 2016, compiled by PwC on behalf of the Department of Energy Affairs, still under stakeholder review.

a target of 87,000 connections per year to achieve a 30% electrification rate by 2030. Even this will be challenging. For the base forecast we have assumed that approximately 54,000 connections per year could be achieved up to 2020, bringing the electrification rate to 16% by 2020. Beyond 2020, in the base forecast, we assume an access rate of nearly 30% by 2030 and 53% by 2040.

For the high case we assume a 36% electrification access rate by 2030 and 58% by 2040.

3.3.3 Suppressed demand

ESCOM provided the Consultant with statistics on the frequency and duration of load shedding and this can be used to some extent to indicate the years when there were lesser or greater problems in meeting electricity demand[36]. Some of these statistics are provided in the Table below and these indicate significant problems in the year 2015/16 (with low rainfall) but few problems in 2014/15.

Table 3-2: Load shedding (ESCOM)

Year (financial year)	Hours of load shedding
2006/07	5,952
2007/08	5,883
2008/09	11,135
2009/10	No data
2010/11	24,821
2011/12	No data
2012/13	No data
2013/14	46,544
2014/15	718
2015/16	926,668

The above Table indicates that there would have been substantial load shedding in the year 2015/16, though not such significant amounts in previous years (no data were available for 2010, 2012 or 2013.

The waiting list for customers who had requested a connection to the network also grew in the year 2015/16 to 29,000 at the year end, compared with an average of around 18,000 in the previous 4 years. This again indicates a potential unmet demand.

MERA provided the Consultant with data on (large) private power generation that requires a license from the regulator. This generation mostly comprises standby generation with some generation undertaken by the sugar estates using bagasse. These types of generation are likely to exist with or without power supply shortages and do not by themselves provide information on potential additional suppressed demand.

Customers who would wish to connect to the network but are not able to connect because ESCOM does not have the generation capacity or resources to extend the networks to connect those loads are also considered to be included as part of suppressed demand. Their potential load is described in Section 3.3.6.

To estimate the unmet load in 2015/16 we made a conservative estimate of how the load might have grown between 2014/15 and 2015/16 if there had been no constraints on supply, and based on this

[36] ESCOM provided data on the number of incidences of load shedding, the aggregate duration of load shedding per month and the aggregate kVA shed per month. Unfortunately this does not allow the estimation of the kVAh or kWh that were lost due to load shedding. To calculate the latter we would need the duration associated with each kVA incident of load shedding.

we calculate load shedding of around 6% of energy or 100 GWh, and 37 MW of unmet demand[37]. This is almost certainly a conservative estimate of unmet demand as there are a number of other factors to consider in estimating the 'bounce back' when supply constraints are lifted (particularly the effect of improved electricity supply reliability on economic activity). There will also be an impact from improvements to the electricity grid that will reduce load shedding and allow industrial and commercial consumers to invest in more mechanised processes.

The unmet demand (load shedding) is assumed to be distributed equally among consumers and we have spread it across consumer sectors equally in proportion to their shares in total sales.

3.3.4 GDP growth and impact on demand

GDP growth forecasts are taken from the online country level information provided in IMF's World Energy Outlook published April 2016. This indicates real GDP growth rates shown in the Table below. Beyond 2021 we assume a gradual decline in growth rate, but still consistently high.

Table 3-3: GDP growth rates (IMF)

Year	Base GDP growth rates
2013	5.2%
2014	5.7%
2015	2.9%
2016	3.0%
2017	4.0%
2018	4.5%
2019	5.0%
2020	5.5%
2021	5.5%
2022-2030	5.0%
2031-2040	4.5%

Importantly, these GDP growth projections reflect aggregate GDP, not per-capita GDP. With population growth of between 2.8% and 3.2% per annum as described above, this implies per capita GDP growth rates of between 1% and 2.7% per annum. These are significantly lower than the real GDP per capita growth assumptions used in the MAED and ICF-Core forecasts.

GDP growth will impact **residential electricity consumption** by increasing households' disposable income and allowing them to acquire more electrical appliances and to use appliances for more hours than they might otherwise have done. In the productive sector, it is clear that increased economic activity implies increased electricity consumption, and GDP is the key measure of economic activity.

Top-down forecasts typically use econometric analysis to estimate the historical relationship between electricity demand and the drivers of demand (such as GDP). However, such econometric analyses are normally useful when supply balances with demand and there is little or no suppressed demand. Malawi has experienced a number of years of power shortages and it will therefore be difficult to establish relationships using econometric techniques. However, there are a number of studies from

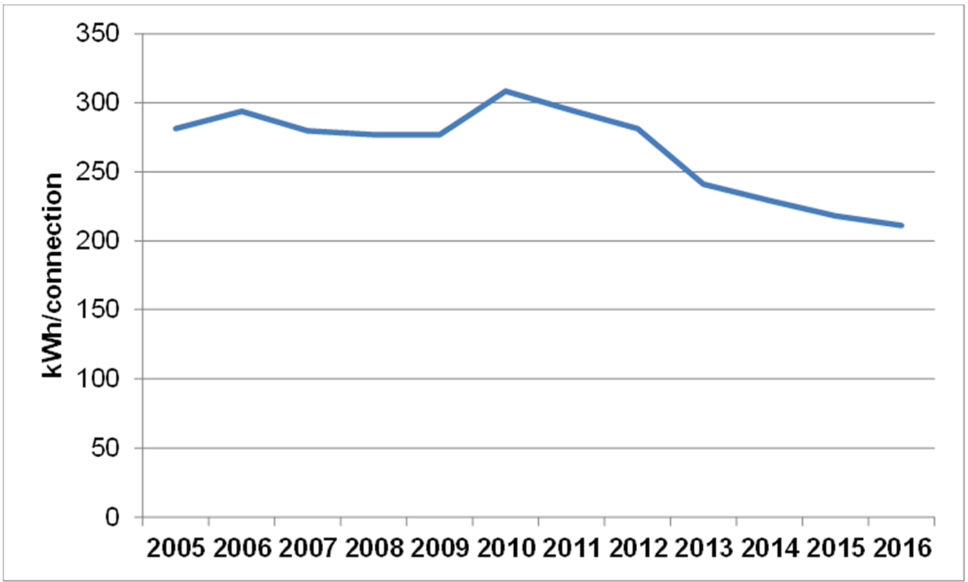
[37] This was calculated by applying the trend growth rate in electricity sent-out to the 2014/15 figures. This suggested that if there had been no load shedding in 2015/16 the load would have been 6% higher.

other countries that have undertaken econometric analysis of electricity demand and we therefore rely on these studies and economic judgement in selecting the equation parameters[38].

For the residential sector, we have assumed that **electricity consumption per household** increases one for one with real per-capita GDP growth (an income elasticity of one). This reflects two influences acting in opposite directions. Users in Malawi are likely to relatively spend more on electricity as their incomes grow because they will have more discretionary income and electricity is a luxury for many Malawian consumers. However, on the other hand, electrical appliances are becoming more energy efficient. Taken together, we assume these cancel out.

Electricity consumption per household in Malawi has historically remained relatively stable or grown steadily over time as household income has grown. However, in recent years the consumption per residential connection has begun to fall as shown in Figure 3-5 below.

Figure 3-5: Household electricity consumption trends



The decline in consumption per household is due to two affects:

- the rate of electrification has increased, adding more lower income households with lower average electricity consumption, and
- the introduction of more energy efficient lighting which began in 2011

To allow for the phenomenon that with rapid electrification the consumption per household will decline, we divide residential consumers into urban and rural. Urban users are assumed to have a higher income and higher electricity consumption than rural users. The split between rural and urban electricity users has been based on the Integrated Household Survey which estimates that 33% of urban households are electrified and 2.4% of rural households. Over time, we assume that rural households will become electrified at a faster rate than urban households in order to begin to catch up on their urban counterparts, but that rural electrification rates will remain relatively low for some time (e.g., 34% by 2040 compared with 75% for urban households). Residential urban users are also assumed to have one third higher electricity consumption per household than the average[39].

[38] Examples include: Modelling residential electricity demand in the GCC countries, Terek Atalla, Energy Economics, Sept. 2016. Price Elasticity Of Nonresidential Demand For Energy In South Eastern Europe, Iimi, Atsushi, Policy Research Working Paper No. 5167, World Bank, 2010.
[39] This implies that urban households have around seven times the consumption of rural consumers. No data are available for Malawi but data from other countries in Sub-Saharan Africa (Ethiopia, Kenya,

We note that the draft SE4ALL Agenda Action has proposed a target of 540,000 households with electric cooking by 2030 (this compares with just over 300,000 residential customers today). Electric cooking may be attractive for households when electricity prices are low and below cost recovery levels but economically it should not be attractive for Malawi to promote the use of electricity for cooking. Eskom, the power utility in South Africa, has actively encouraged households to switch from electric cooking to LPG. This issue could involve a lengthy discussion, which we do not propose to enter into here, but we note that our analysis of residential electricity demand assumes business as usual with relatively little use of electricity for cooking.

For consumers in the General, LV and MV categories, we assume that the aggregate consumption in each category grows at a trend rate of 3% per annum irrespective of GDP growth[40]. This reflects an assumption of increased mechanization of economic activity over time. Additionally, consumption in these categories is assumed to grow to reflect GDP growth. In the General, LV and MV categories, we assume that their consumption grows at 40% more than the rate of growth in GDP (i.e., an income elasticity of 0.4). This ensures an electricity intensity (kWh per unit of GDP) that is consistent with energy intensity growth rates experienced in other developing African countries.

3.3.5 Tariffs and demand-side measures

Demand-side management measures can be divided into time-of-use tariffs (TOU) and others. Both impact indirectly on electricity demand. TOU tariffs impact on demand indirectly by encouraging users to switch demand away from the peak and toward off-peak periods[41] whereas non-TOU tariffs impact on electricity demand in general by encouraging more efficient use of electricity (generally lowering demand through conservation measures).

For the purposes of the IRP study we would normally take account of general tariff increases as part of the electricity demand projections and take account of potential additional TOU tariffs as part of the DSM measures that will be analysed as part of the IRP analysis.

Tariff increases in real terms, approved by Malawi Electricity Regulatory Authority (MERA) to bring ESCOM's electricity prices to cost recovery levels by 2016, have largely been achieved. While tariffs will certainly change in future to reflect costs of electricity supply, we assume that there will not be major increases in real terms[42]. We have assumed that elasticity demand falls by 2% for every 10% increase in real electricity tariffs[43] but this assumption has no impact unless tariffs increase in real terms.

Time-of-use tariffs were implemented in 2009 and provide substantial incentives for large customers to move their loads from peak to off-peak periods. We have assumed that the impact of this measure is already reflected in customer load patterns.

Lesotho, Rwanda) suggest that this is consistent with the consumption per household of rural consumers of around 50 kWh per month.

[40] This is a measure of technological progress which, in this instance, reflects a trend toward increased electrification of Malawi's economy. This assumption is based on econometric analysis of Malawi's electricity demand undertaken by the Consultant a number of years ago. A similar assumption is used in the forecast prepared by Fichtner for Mpatamanga hydropower plant. A number of econometric analyses of electricity demand have found technological progress drivers for electricity demand in developing countries.

[41] Time of use tariffs may also lower energy consumption but typically they are expected to switch consumption away from peak demand periods.

[42] We are aware that ESCOM has proposed a real tariff increase but this is to be examined by a cost-of-service tariff study that has been launched by MCA-Malawi. It was agreed at the interim stakeholder workshop that this assumption would not be revised.

[43] i.e., a price elasticity of -0.2.

Other DSM measures that are considered to be committed and therefore not considered as candidates for the IRP analysis, include a new energy efficient lighting subsidy programme targeting industrial and commercial customers with 2 million LED lightbulbs and the introduction of minimum energy efficiency performance standards for lighting. These will be described in the DSM part of the final report. They are expected to lower peak demand by a total of 50 MW by 2021.

3.3.6 Step loads

The demand forecast prepared by ICF-Core includes step loads for 2016, 2021 and 2030 of 40 MW, 56 MW and 103 MW respectively. These were based on an assessment of the probability that the loads would materialize – in this case these were in the P90 case, with a (high) probability of 90%.

ESCOM has provided the Consultant with a list of consumers who would collectively have a connected load of 47 MW. These were all planned for 2015, 2016 or 2017. These appear to be the loads used for sizing the connection to the grid and not necessarily their maximum demand – customers will generally oversize the connection in order to allow a cushion for possible miscalculations or load growth. If all were connected to the grid, they would not all expect to consume at their maximum simultaneously.

We assume:

- not all of these consumers will be connected but that there will be other consumers not listed who will take their place, so we include all 47 MW of demand in the forecast (though not simultaneous)
- the applicants for a connection have added a margin of 20% to their expected maximum loads, and the actual load is therefore approximately 39 MW
- they have a load factor of 75%

This amount is then added to the net MWh consumption in 2016. The demand from this group will then grow in the same way that the demand of the other MV customers is expected to grow and we assume that all future step loads are subsumed within this growth.

Similarly, the Department of Mines at MoNREM provided the Consultant with details of existing self-generation loads at mines throughout Malawi and planned mining developments and electrical loads. The existing and proposed loads were divided into existing/immediate, within 3 years, existing mines that are closed but expected to re-open within 5-10 years, and mines at the feasibility study stage. We applied judgement to determine the probability that these loads will materialise or continue to exist as follows:

Operating mines not currently connected to the grid	90%
Expected within 3 years	50%
Expected to re-open within 5-10 years	50%
Feasibility study stage mineral	10% to 25% depending on the type of

The probability weighted suppressed demand/step loads are summarised in Table 3-4 below.

Table 3-4: Suppressed demand/Step loads

Category	Probability weighted load (MW)
Operating mines not currently connected to the grid	3.7
Expected within 3 years	18.3
Expected to re-open within 5-10 years	0.3
Feasibility study stage (5-10 years)	28.8
Total	51.1

3.3.7 Losses

ESCOM's technical and non-technical losses are relatively high at 21.8% of sent-out energy in 2015-16. This has fallen from 24.4% in 2014-15. ESCOM is implementing a range of measures to reduce losses and has shared information on its loss reduction program with the Consultant. Consistent with previous load forecasts, we assume that losses (technical and non-technical) will fall gradually as these loss reduction measures take effect. We understand that ESCOM is exceeding its targets but we continue to use the conservative assumption and that losses will reach 18% by 2020 and 15% by 2030.

3.3.8 Exports

ESCOM does not have firm contracts to sell electricity in bulk and we have not included export demand in the assessment of the demand that must be met. The IRP analysis may determine that exports are optimum for Malawi, but that conclusion will be an output of the IRP study rather than an input to it.

3.3.9 Load pattern and system load factor

The sent-out energy demand is estimated by summating the (unsuppressed) load by customer category, net of committed DSM benefits, and adding technical and non-technical losses.

The maximum demand forecast is similarly calculated by summating estimated contribution of each customer category to the system peak (net of committed DSM benefits), and adding peak losses. As noted in Section 2, losses at peak are inevitably greater than average energy losses. We cannot observe directly the contribution of each customer group to the system peak demand but we can use judgement to make assumptions and calibrate these customer load factors and coincidence factors to give forecasts that are consistent with historical peak demands. Historical load factors are summarized below:

Table 3-5: Historical system load factor

Year (financial year ending)	System load factor
2011	77%
2012	78%
2013	74%
2014	67%
2015	67%
2016	68%

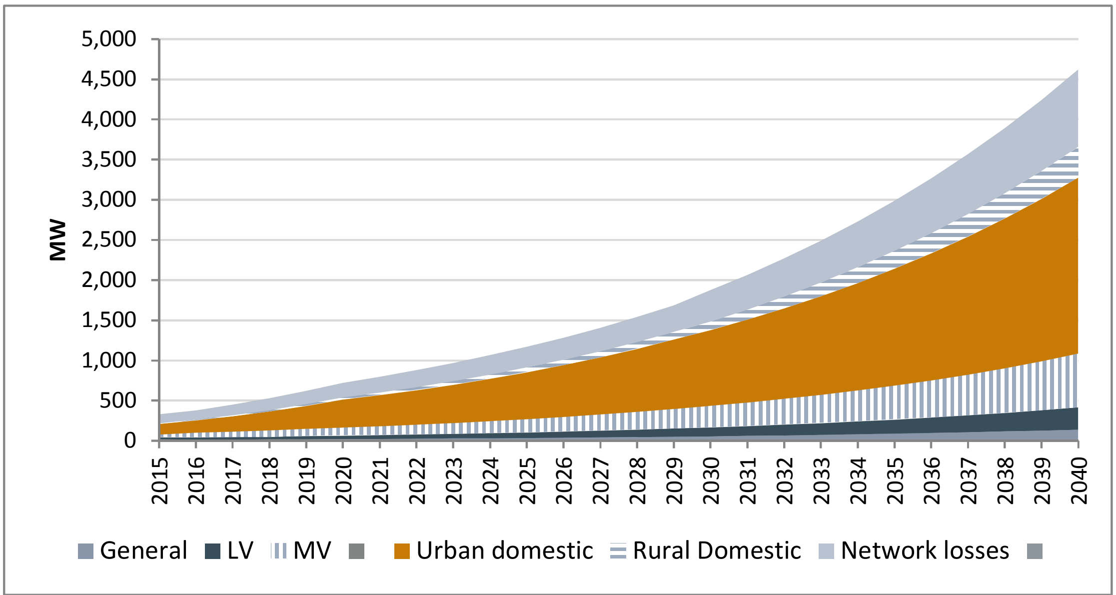
The system load factor is impacted by load shedding and is higher when there is load shedding[44]. The system load factor in years when there is load shedding (e.g., 2015-16) should therefore be less reliable than in other years when there was no load shedding. However, the above suggests a load factor of around 67% as the norm over the past 3 years. The load factor and system load pattern for the future years is discussed in Section 3.5.

[44] Because it lowers the peak demand that is supplied, and lowers the denominator by more than the numerator.

3.4 The base forecast

Using the assumptions described above, an electricity demand forecast is estimated for the period to 2040. This is illustrated in the figure below.

Figure 3-6: Base electricity demand forecast (maximum demand, MW, sent out)



Based on the assumptions laid out in Section 3.3, the model estimates that maximum demand will reach[45] 719 MW by 2020, 1,873 MW by 2030 and 4,620 MW by 2040. The annual average growth rates are 17.5% through to 2020 (reflecting suppressed demand in its various forms) and 10% per annum from 2020 to 2030. This compares with annual average growth rates of maximum demand over the financial years 2010-15 (excluding the year 2015/16 when there was load shedding) of 4.2% per annum.

The 2020 forecast is a little lower than the Mini-IRP's estimate of 839 MW, higher than ICF-Core's estimate of 540 MW, and lower than the forecast in the MAED model. However, it should be borne in mind that all of these three forecasts had anticipated a higher starting point for demand for 2015 of 462 MW (Mini-IRP), 363 MW (ICF-Core) and 740 MW (MAED) compared with the outturn of 328 MW (on a calendar year basis).

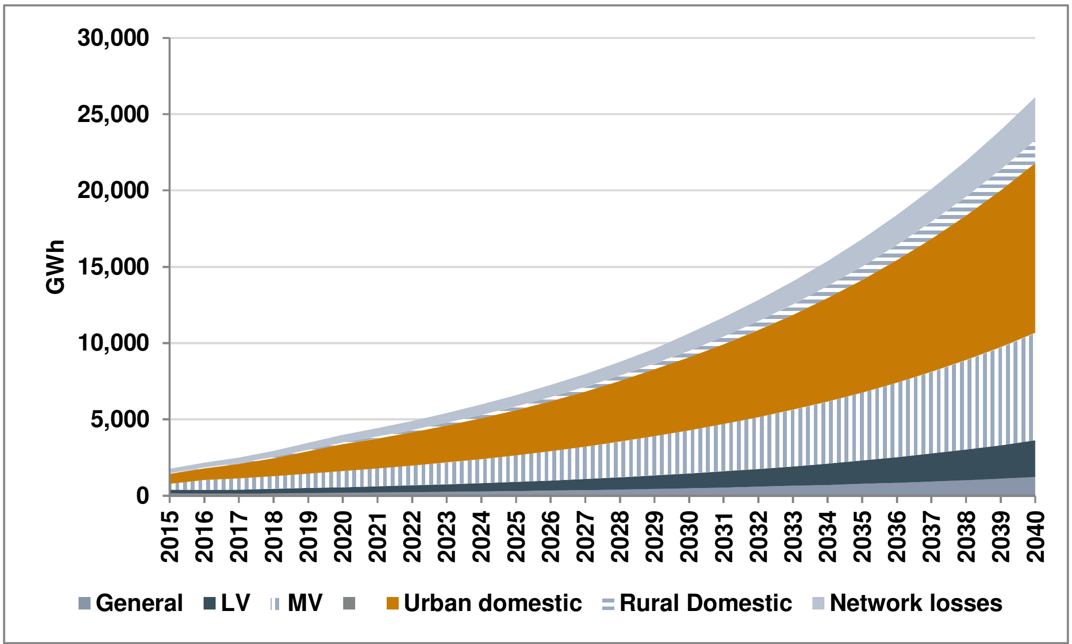
For 2030, the model's maximum demand forecast of 1,873 MW is above ICF-Core's forecast (of 1,530 MW), but given that this is 14 years into the future, and the forecasts this far out are indicative, it is not a significantly higher value.

For 2040, the assumptions described previously lead to a forecast maximum demand of 4,620 MW and an annual average growth rate over the period 2030-40 of 9.4% per annum, consistent with the type of growth rates in electricity demand experienced in countries moving to middle-income status.

The base case forecast of energy sent out (i.e., required to be injected into the network) is summarised below.

[45] Rounded to the nearest 10.

Figure 3-7: Base energy demand forecast (GWh, sent out)



The forecast predicts a relatively balanced growth in residential and non-residential electricity consumption, as shown in Figure 3-6 and Figure 3-7 above[46]. This implies that the system load factor remains constant over time.

Energy intensity, measured as the ratio of electricity consumption to real GDP is predicted by the model to increase by a factor of 3 times over the 20-year period to 2037. This is below the rate of increase described for Kenya (4.5) and Botswana (6.7) over a similar 20-year period but is nevertheless a substantial growth in energy consumption consistent with Malawi's aspirations to become a middle-income country over the coming 20 years.

3.5 System load pattern

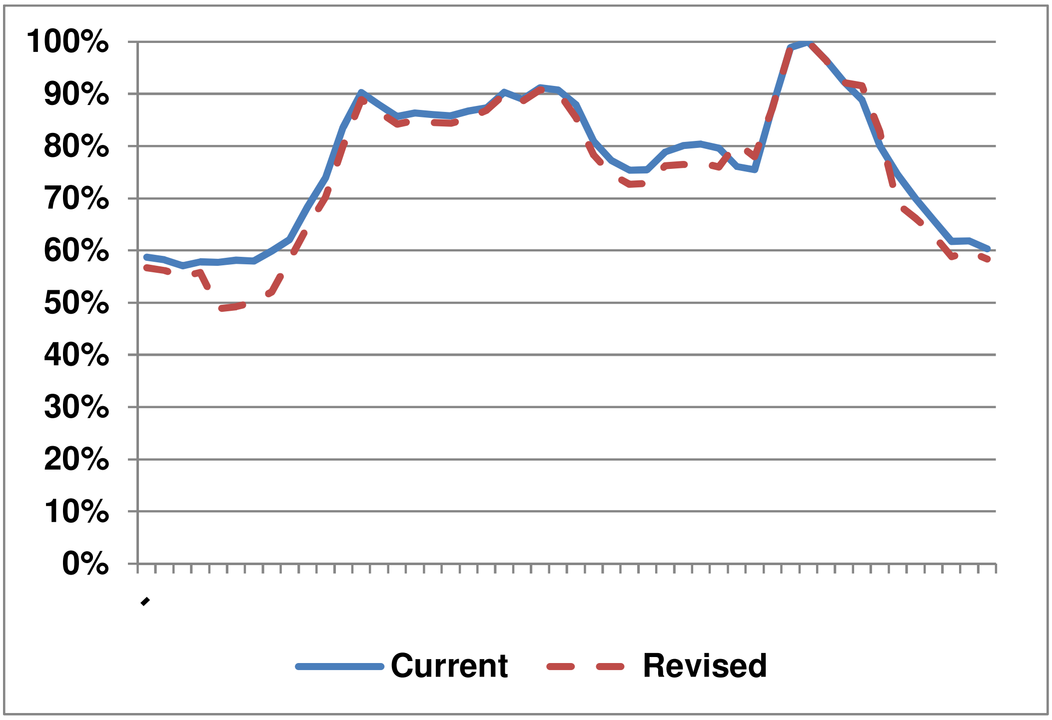
Although the mix of customers is forecast to remain relatively constant over the next 20 years and the system load factor is forecast to remain relatively constant, the forecast does anticipate a small drop in the system load factor by 2020 because of the predicted relative increase in the number of residential customers over this period. This is offset to some extent by the introduction of DSM measures that are considered to be committed[47] will lower the peak demand relative to the energy demand. The inclusion in the forecast of demand that is currently suppressed and some larger step loads are also expected to help offset the decline in the system load factor. Overall the model expects a reasonably constant system load factor of approximately 65% over the forecast and a constant load pattern over this period. However, there is expected to be an initial fall in the load pattern and a slightly peakier demand than in 2014-15 (the most recent year with relatively low load shedding).

The eventual pattern of load on the national power system will depend on the outcome of the analysis of the demand-side measures but there is only one load management measure that is considered as a candidate (solar water heating) and this is likely to have a small impact on the load pattern.

[46] A balanced growth will in any case be necessary if Malawi's economy is to generate the income necessary to allow residential consumers to pay for the electricity they consume.
[47] Energy efficient lighting programme for industry and minimum energy efficient performance standards are considered committed but their impacts are yet to be felt. Other measures have been introduced in the past (time-of-use tariffs and residential energy efficient lighting) whose effects are already reflected in the load pattern.

The expected typical weekday load pattern, incorporating both the impact of a change in the customer mix and the committed[48] DSM measures is shown in Figure 3-8 below.

Figure 3-8: Typical daily load curve - weekday



[48] This includes the impact of the candidate solar hot water measure as well as the impact is relatively small.

3.6 Low and high forecasts

Low and high forecasts have been prepared based on alternative assumptions, as summarized in the Table below.

Table 3-6: Low, base and high forecast assumptions

Assumption	Low	Base	High
Electrification rate	2020 – 12.4% 2030 – 20.4% 2040 – 42.0%	2020 – 15.9% 2030 – 29.5% 2040 – 53.0%	2020 – 22.7% 2030 – 35.9% 2040 – 58.0%
GDP growth rate	Base -0.5% to 2021 Base -1.0% after 2021	IMF forecast to 2021 (~4.0 – 4.5% p.a.) 5.0% p.a. to 2030 4.5% p.a. to 2040	Base +0.5% to 2021 Base +1.0% after 2021
Losses	16% by 2020 12% by 2030	18% by 2020 15% by 2030	22% by 2020 18% by 2030
Suppressed demand (load shedding	50 GWh	100 GWh	200 GWh
Step loads	130 GWh	200 GWh	260 GWh
Connection of existing loads (2016-2020)	147 GWh	147 GWh	147 GWh

Low and high maximum demand and energy demand (sent-out) projections are shown in the figures below together with the base electricity demand projection.

Figure 3-9: High, base and low electricity demand forecasts (maximum demand, MW, sent out)

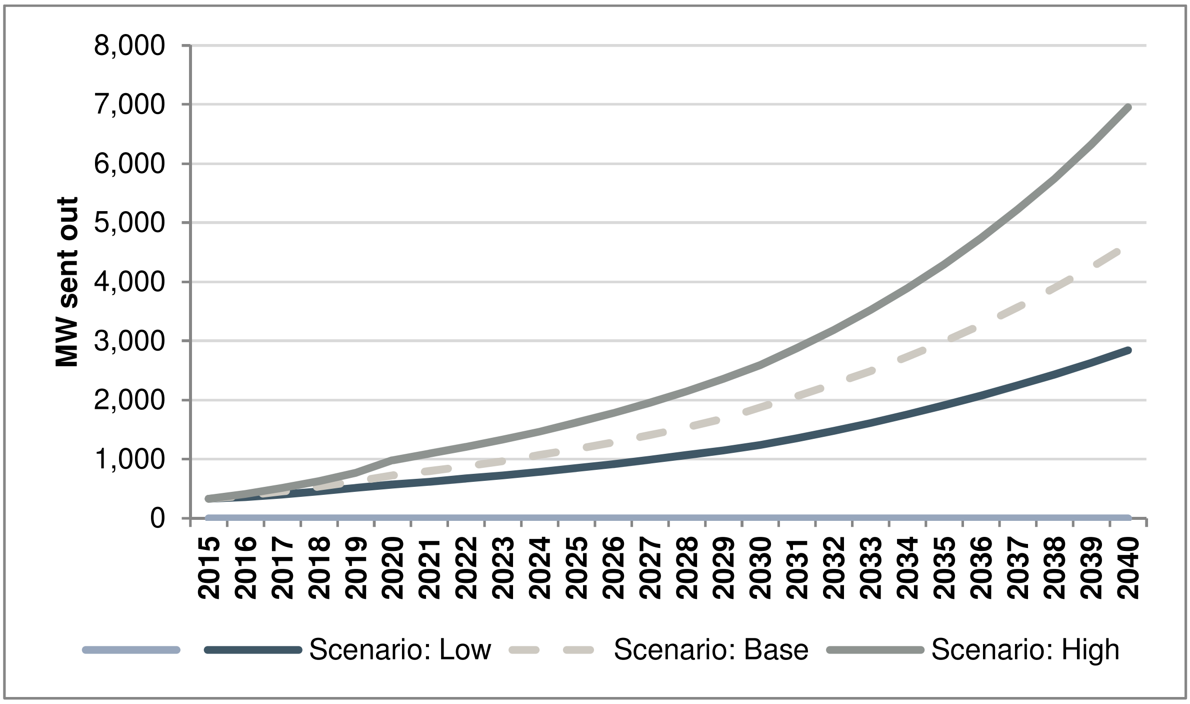
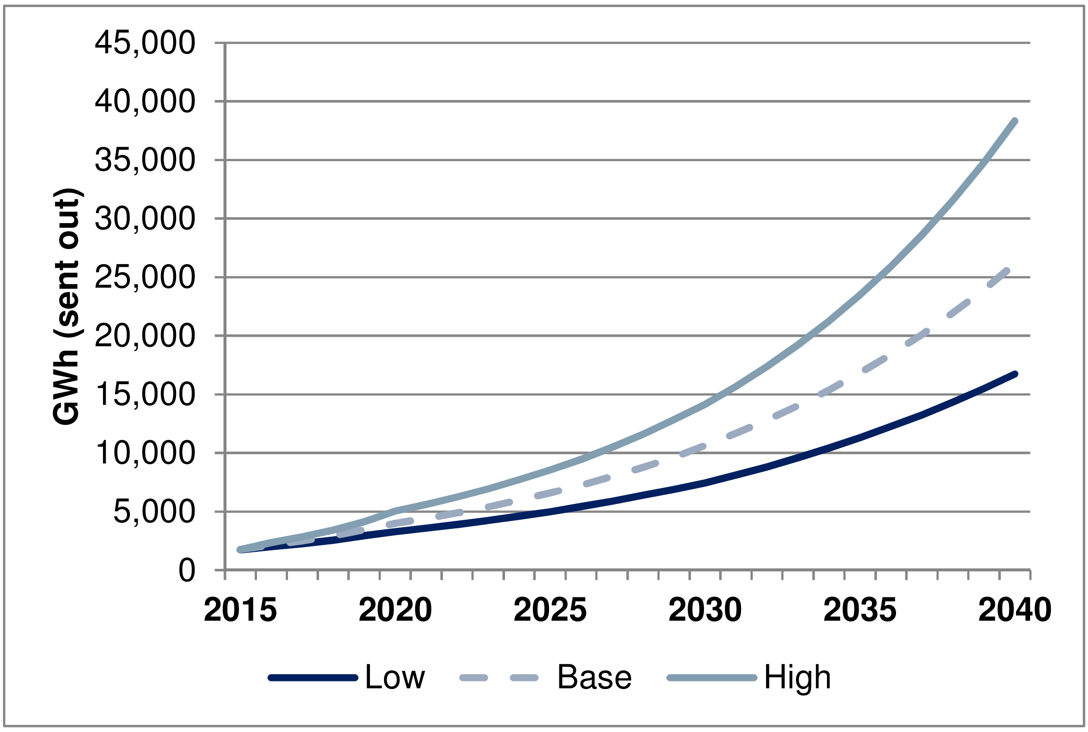


Figure 3-10: High, base and low electricity demand forecasts (GWh, sent out)



The maximum demand projections in key years of the forecast period are summarised below.

Table 3-7: High, base and low electricity demand forecasts (maximum demand, MW sent out)

Year	Low	Base	High
2020	567	719	982
2030	1,236	1,873	2,591
2037	2,245	3,566	5,217
2040	2,841	4,620	6,946