Modelling the potential impact of net metering in South Africa

Bryce James McCall

Submitted to the University of Cape Town in partial fulfilment of the requirement for the degree of Masters of Science in Engineering

February 2013

Energy Research Centre

University of Cape Town

Declaration

I, Bryce James McCall, know the meaning of plagiarism and declare that all the work in this document, save for that which is properly acknowledged, is my own.

Acknowledgements

I would like to thank my supervisors, Alison Hughes, for her guidance and help with putting this work together, and to Bruno Merven for help with the tricky aspects of the energy models which only he seems to know how best to tackle. Without their help, this would have been an insurmountable task.

I would also like to thank Manuel Welsch, for help with various issues with the OSeMOSYS software during the development of the model.

Acknowledgment must be paid to the National Research Foundation (NRF) for their financial support throughout the last year, without which, I would not have been able to complete my degree.

I would also like to thank my parents for their support in so many ways. For their love and guidance which has enabled me to get through the hard and challenging times in the last few years. And I would like to thank my girlfriend, Kerryn Warren, for all her love, support and cooking which has always comforted me, and put a smile on my face.

Dedicated to…

..all the people who call South Africa their home. It is my intention that this work will in some way aid in building a sustainable future for South Africa, and help improve the lives of its citizens.

-Bryce McCall

Abstract

As a result of increasing environmental concerns, as well as electricity prices in South Africa, people are beginning to take the environmental and energy problem into their own hands through the investment and installation of their own power producing systems. This is not a new phenomenon, but as solar photovoltaic (PV) technology is coming down in costs and electricity prices within the country are increasing, more people will look to solar PV or other small sized electricity generators for supplementing their energy needs while taking some measure of action against climate change. 'Net metering' is the term used to describe the method of feeding excess electrical energy onto the distribution grid from these small systems in the residential sector. The capacity of each individual system may only be on the order of a few kW, but on a national scale this can become a sizable contributor.

With all the effort in understanding the options for future electricity generation in South Africa, there is little work done on understanding the scale and impact that net metering systems will have. This work aims to fill the gap in research of this understudied aspect of the energy system.

Research using energy models is important to developing countries. Most of the current energy modelling software available requires a significant amount of money and learning before they can be fully utilised. OSeMOSYS is an open source – free - energy modelling software which has a lower learning curve, enabling a variety of researcher's access to the model and its components, opening up huge potential for improvement and development.

This work has two main objectives, first to create a working energy model of South Africa's electricity sector using the open source software; OSeMOSYS, and secondly, using this model to understand the unstudied effects of net metered capacity within the country and how this affects the planning of the energy sector in the future, which is done through processes such as the Integrated Resource Plan (IRP).

Using a combination of electricity tariffs and solar PV price projections, and the Bass diffusion model, an estimated range of the total amount of installed MW capacity of rooftop solar PV within the residential sector of South Africa was determined. Depending on the initial assumptions, the capacity projections start between a mere 0.4MW and 4.5MW in 2012 and grow to between 395MW and 2620MW by 2030.

The total new added capacity of energy producing technologies in the OSeMOSYS energy model is 47.27GW between 2006 and 2030. The majority of this is supercritical coal technology power plants, with hydro imports and peaking gas turbines mixed in. The share of wind and solar technologies which includes concentrated solar thermal with storage technology is 4.4% of the total capacity.

The presence of net metered solar rooftop PV capacity was found not to change the total capacity of the system given that the peak demand occurs at night. But the amount of supercritical coal investment was found to decrease with increasing amounts of rooftop solar PV. And the capacity of peaking gas turbines and the capacity of concentrated solar thermal

with storage technology were found to increase with the scale of net metered capacity. As a result of the decreased demand during the afternoons, as much as 440MW of extra peaking gas turbines are required in the future for faster response to the evening peak demands. A further change to the electricity sector is the profile of production by technologies; coal, pumped storage and hydro technologies were found to alter their production profile.

These results conclude that with the presence of net metering there was a non-insignificant change to the future plan of the electricity sector. The presence of net metering in the residential sector both aids in reducing the dependency of coal technologies, but also promotes the use and viability of large scale solar thermal technologies. The share of wind and solar energy technologies in upstream generation increased from 4.4% in the base case to 4.9% in the case of maximum net metered capacity, and cumulatively a maximum of 26.8Mt of CO_2 are displaced by net metered solar PV.

The results indicate that the presence of net metered solar PV in only the residential sector does affect the ability to accurately plan the energy sector into the future. This work has not considered aspects of net metering such as the loss of revenue to municipalities or the effects of cross subsidisation. However, the type of changes observed in the energy models in this work indicates that further research into net metering policies is merited.

Table of Contents

1 Introduction

1.1 Renewable energy in the home

Rising electricity prices and climate change awareness is spurring an interest in renewable energy and sustainable development in the many sectors including the domestic sector. With increased electricity prices in the country, home owners will start, if not already, looking into ways of reducing their consumption and becoming more energy efficient. Many people become interested in generating their own green electricity, rather than relying on state owned utilities to make the change. When a home owner invests in generating green electricity on their property, to fully maximise the use of their investment, excess electricity generated can reverse feed their meter – thus saving on future energy requirements. This process of reverse feeding the grid is called ‘net metering’. In many countries, there are policies and regulations regarding the practice of net metering within the domestic sector. Home owners in countries with net metering policies may install renewable energy generating technologies and feed excess electricity back onto the grid for credit or future energy bill reductions.

Solar photovoltaic (PV) panels create direct current electricity from solar insolation. In a country like South Africa, an abundance of sunshine means that solar PV would perform well in many parts of the country. They are an easy to install technology and require little to less maintenance - making solar PV an attractive form of renewable energy generation at the small scale. The ease of installation and operation makes them one of the best technologies to invest in if a home owner were interested in producing their own electricity on site.

Even though net metered generators like rooftop solar PV in the domestic sector are small, typically in the range of a few kW’s, the potential capacity (measured in MW or GW) in the domestic sector can be quite large if one considers the scale on a national level. By reverse feeding onto the grid from the residential sector this will alter the energy consumption and demand of the sector. How the presence of net metering in the domestic sector affects the future electricity generation is important for policy and national decision makers. The Integrated Resource Plan (IRP) developed by the department of energy in South Africa maps out the best set of options of new electricity capacity builds based on several scenarios (Eskom, 2011a). Net metering as a result of increased awareness and interest from the residential sector is not included. However, due to the fact that private interest in renewable energy in the home is on a national level and can be of a significant scale, this merits an investigation into the potential changes to the future of electricity generation in the country.

1.2 Modelling energy systems

Policy and decision makers rely on information to guide their choices on future projects and developments. Government planners require knowledge about what might happen in the future in order to make the best decisions now. The development of the electricity sector is no different. Energy planners use computer models to simulate the electricity sector and how energy flows through the system. To best plan for future investments on new electricity generation in the country, linear program optimising software was developed in order to optimise the new build solution based on least cost. Energy planners use modelling software like linear optimisation software to make the best decision of future investments based on a range of criteria entered into the model.

However, optimisation software programmes used in the energy planning field can require financial investment, which can act as a barrier to some prospective analysts and researchers. Not only the financial aspect, but the learning curve of new software can be substantial as well. Removing these barriers would help expand the size of the community of energy researchers around the world, especially in developing regions where finance may be the biggest barrier. Software which is freely available and which allows for free editing of the structure of the software is called 'open source'. The Open Source energy MOdelling SYStem (OSeMOSYS) is an open source optimisation software that provides a unique opportunity to create an energy model that other researchers may investigate and scrutinise at will on all levels of the model, and make adjustments when new information is presented. The ability to change software at will to suit the needs of the situation at hand is a unique and powerful aspect which will benefit researchers in this field.

1.3 This research

The aim of this research was to determine a potential range of capacity projections for net metered embedded systems in the residential sector, and study how they may change planning of the electricity sector for the future. This was done by creating an electricity energy model for South Africa based on data from the IRP, and studying how this model changes the investment scheme of new generation technologies when the net metering capacity projections are introduced to the system. This was done by:

- Examining the various details of net metering in the residential sector of South Africa, in order to determine its future role within the country and electricity network.
- Identifying a suitable representative technology for net metering for modelling purposes.
- Determine an upper and lower level of installed capacity projections for net metered systems in the country
- Create an energy model of South Africa's electricity sector using data of the electricity sector and the optimisation software: OSeMOSYS
- Benchmarking this model with a tried and trusted software to ensure reliability
- Using the OSeMOSYS model for the electricity sector, model the effects of net metered capacity within South Africa's residential sector
- Study the results of the changes between the reference case and net metering cases (projections) to determine the alterations on the investment scheme in the electricity sector in South Africa, and
- Highlighting the results observed in this work in order to inform future research into aspects of net metering or embedded generation and energy planning in the country.

Chapter 1 introduces the aim, objectives and method of research as well as the motivation for this work. An overview of the whole study is presented here as well.

Chapter 2 reviews the energy modelling software: OSeMOSYS, the SATIM model developed by the ERC, and gives a background and introduction to net metering and within countries which have net metering policies. Some specific technical aspects of net metering are discussed and highlighted. Solar rooftop PV is identified as a good representative of net metered systems and global and market trends are reviewed.

Chapter 3 develops the net metering capacity scenarios by looking at all relevant aspects of solar PV and its related markets. Electricity prices for residential customers are determined for the period 2012 to 2030, and the main criteria for solar PV – the payback period, is determined for a range of scenarios. A main component of net metering capacity is the number of households (HH) willing to invest in net metering and this is analysed. The total capacity projections for solar PV in the country is then determined using these variables and 'low' and 'high' penetration scenarios are determined for South Africa.

Chapter 4 describes the detail in linear optimisation software, and an in-depth description of the equations of OSeMOSYS is given in order to highlight how the electricity model in South Africa is implemented. Various added features to the software that were done through the course of this research are described. The South African electricity model is described in full and how it was implemented into OSeMOSYS.

Chapter 5 presents the results for the comparison of the OSeMOSYS model to the SATIM model, in order to determine the reliability of the OSeMOSYS model. Various aspects of the two models are compared and discussed. The results of the net metering scenarios are also presented here and discussed and various important and significant changes as a result of net metering capacity within South Africa are highlighted and discussed. The effects of the discount rate on the results of the model is also presented and discussed here.

Chapter 6 Presents in short, the results discussed in chapter 5, and concludes from the results what changes to the future energy generation investment plan may occur due to net metering within the electricity sector of South Africa. Some remarks are made about OSeMOSYS and the utilisation of the open source software.

2 Literature review

2.1 Embedded generation and net metering

Embedded generation (EG) or distributed generation (DG) are terms for electrical power producing technologies that are spread over wide geographical areas and are usually situated at the distribution level, and close to the site of consumption (Strbac & Jenkins, 2004). The size of EG depends on the situation and technology available, and can vary from a few MW in the case of using bagasse to produce electricity from a sugar mill (Gaunt & van Zyl, 2003) to rooftop solar PV systems at a few kW in the case where private investors take up renewable energy generation on their own at home or their business (Bello & Carter-Brown, 2010; Haynes & Whitaker, 2007; Keen, 2012; Vernado & Sheehan, 2009).

Net metering is a policy that allows private businesses or home owners to receive credit for any excess electricity exported to the electrical grid from on-site renewable energy generation (Weissman & Johnson, 2012). From here, DG and EG may be used as synonyms for net metering, as all net metering systems are by definition EG's or DG's. A customer may be able to invest in a renewable energy generating technology like small scale wind turbines or solar PV panels and connect them to their home electrical system through appropriate devices and produce their own electricity. When their system is producing more than the HH is consuming, the excess may be exported onto the electrical grid and the electricity meter will reverse and account for this. When the HH consumes more electricity than is being produced by the installed system, the HH then imports electricity off the grid as normal. The advantage of net metering is the customer need not invest in expensive batteries which can push the price of the overall system up beyond the financial scope of many HH's nor would it require added devices for battery control or maintenance.

In net metering, the electricity grid acts as a virtual battery, thus, the terminology 'net metering' where the customer pays (or gets paid) for the net use of energy from the grid (Gipe, 2006). A setup for a residential solar PV system being net metered is shown in Figure 1. In the figure; solar panels generate electricity from sunlight which is then sent to an inverter system which converts the direct current to alternating current at the standard frequency and voltage (50Hz and 240V) which is then fed into the HH. The energy that is produced is either used up entirely by the HH or, at some times of the day and year, excess electricity is sent onto the electrical grid. In the example below, the system produces 0,4,6, and 5 kWh’s throughout a month, while the house consumes 0,4,8, and 5 kWh’s, thus a net total of 0,0,2,0 kWh’s per month goes onto the grid.

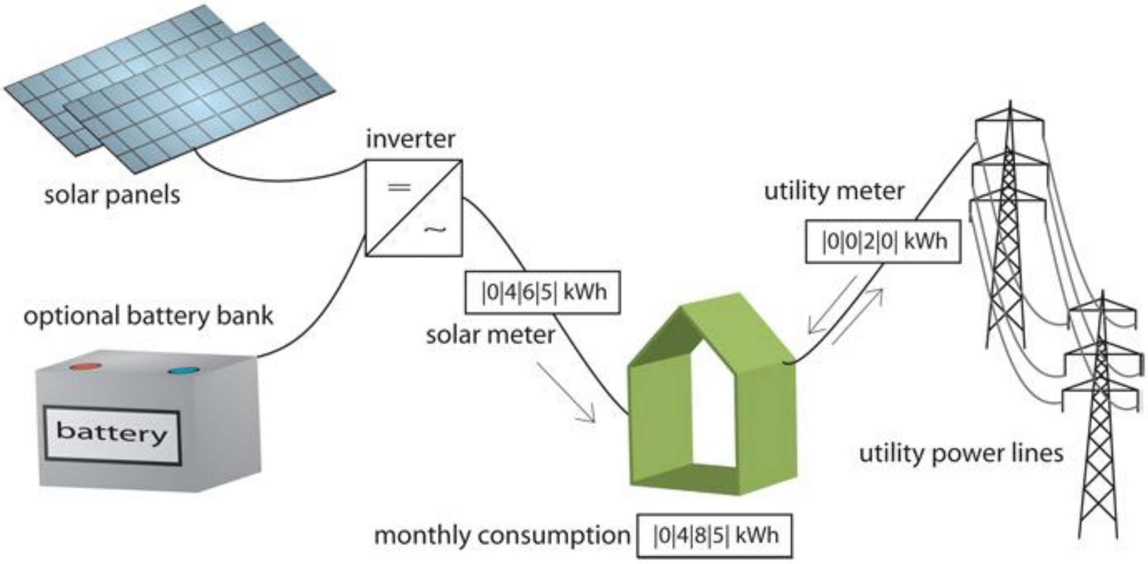


Figure 1: A diagram depicting the basic set up of a solar PV system at home under net metering conditions. Although this depicts a battery system, it is not necessary. Taken from (TheGreenEconomy, 2012).

Net metering allows people to maximise the return on their investment of EG technologies by enabling a financial return when excess energy may be utilised by the electrical grid rather than being dumped.

There are several renewable energy technologies that may be used for generation in the residential sector, such as small scale wind turbines and solar PV panels being the most common form, while combinations of these are also possible such as the renewable energy pilot project being conducted by the Nelson Mandela Bay municipality (SMA, 2012). Net metering can be considered a very important policy for the promoting of growth in renewable energies. It is a low cost and direct way of involving customers and creating awareness in the investment of renewable energy technologies while adding to the cause for reduced fossil fuel consumption and sustainable development (Varnado & Sheehan, 2009).

There are several ways of accounting for financial returns to the customer, and all depend on the utility or regulator. In the US, before net metering policies, customers who generated excess electricity would register as a qualifying facility pursuant and receive payment at the utilities avoided cost rate – the cost of generating electricity from power plants. This scheme is essentially a way for utilities (or municipalities) to buy from the source (net metering systems) before going through transmission lines and then distribution systems - a kind of wholesale cost rather than retail. This would not encourage investors to size a system larger than the minimum required due to the lack of assurance of sufficient value for the energy produced. Some utilities give credit to customers on an annual basis and at avoided cost rates. All credit for excess energy each month is carried over to the next month, and if by the end of the period there is an outstanding credit, the utility pays out the customer. Some utilities do this on a monthly basis while others let the customer chose the period so as to best suite their activities (Varnado & Sheehan, 2009).

Although there are multiple strategies for reimbursing customers for exporting electricity onto the grid, Strbac & Jenkins (2004) suggest that the tariff structures in place do not reflect accurately the true value of DG. The primary objectives for any tariff according to Strbac & Jenkins (2004), is a) revenue generation – income covers all costs, and b) economic efficiency – tariffs should reflect cost streams and send messages to customers avoiding temporal and spatial cross –subsidising. Strbac & Jenkins (2004) state that tariff structures satisfy the first condition but not the second. In the case of DG present in the distribution system, efficiency losses can decrease due to the location of the EG being closer to where the demand is. Also, a unit of electricity 1kWh being exported onto the grid has more value than the same amount which has come from upstream generation, since it does not need to go through the entire grid system.

In the U.S, net metering has seen accelerated growth due to increased public interest in renewable energy technologies as climate change starts to become a focal point of national and international interests. Figure 2 shows the growth of DG being net metered in the U.S and clearly shows the accelerated growth trend. Due to the complexity of the electrical distribution system in the U.S being comprised of multiple suppliers and at different tariffs in different states, as well as the complexity of differing State laws around the issue, net metering regulations vary from State to State (Varnado & Sheehan, 2009).

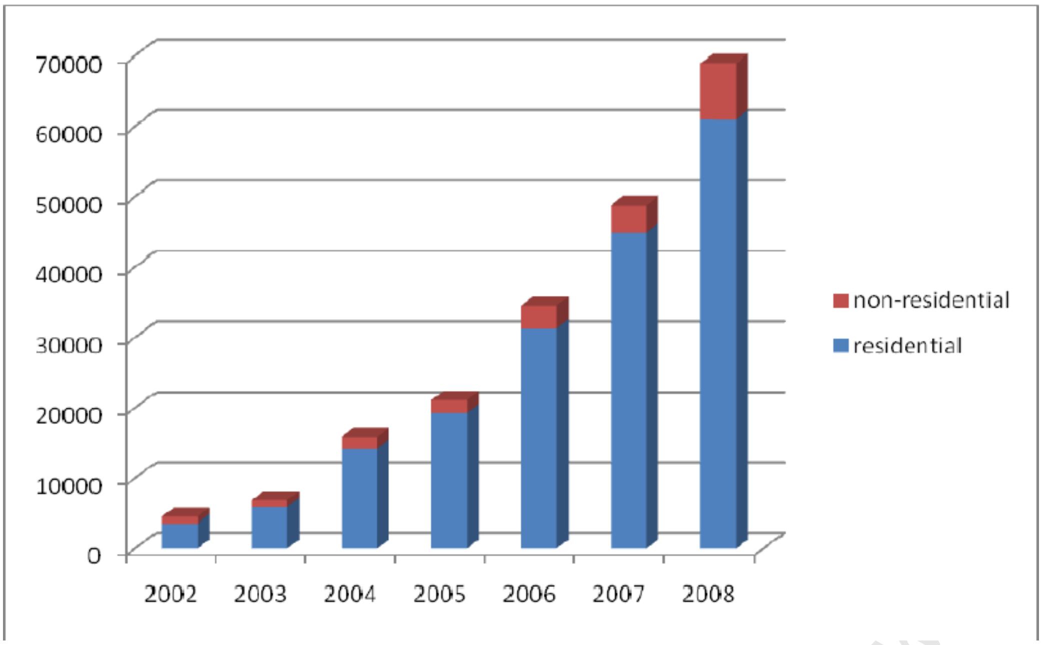


Figure 2: The number of net metered DG systems in the U.S. Taken from (Varnado & Sheehan, 2009)

2.1.1 Embedded generation in South Africa

A simple analysis on the feasibility of PV net metering in South Africa by Ndanga (2012) showed that the best way to introduce small scale renewable energy generation in South Africa was the case of simple reverse feeding with a bi-directional. Ndanga considered three scenarios where a customer invests in a solar PV system for their home;

1) there is no legal right to connect to the grid and export electricity,

2) there is legal right to connect, but the compensation for exporting energy is simply the avoided cost (the cost of generating which is significantly lower than municipal tariffs (Eskom, 2012a)) and;

3) the case of net metering where the meter is allowed to flow in two directions.

Ndanga (2012) observes that; the first case simply reduces the overall electricity bill and any excess energy produced has to be dumped, while the second reduces the bill further by allowing financial return at a much lower than retail rate from what is sent onto the grid. The third case means that the customer gets the most value for the energy generated by their PV system. In the second case, there is added cost in that there would have to be two meters installed at the home to measure the two flows of electricity. In the case of the third scenario, the distributor/municipality essentially pays the retail rate for exported electricity and the customer gains the most out of the system. A net metering policy would allow interested parties in private sectors to participate in sustainable development in the most financially beneficial way for them.

The current state of policy regarding net metering in South Africa does not go much beyond basic regulations on the technical issues of connecting the system to the grid. Apart from the technical regulations, the city of Cape Town does have its own net metering tariffs with an additional service charge. The City of Cape Town is also currently investigating the technical workings and regulations thereof for embedded generation and net metering in the city under a pilot project involving 3 participants whom have solar PV systems installed at their home premises (Keen, 2012; EngineeringNews, 2012).

Under the pilot project with the city of Cape Town, a prepaid meter is used to measure the electricity usage on site, while the meters are not designed to run in reverse they actually decrease (i.e. charge you) when there is export onto the grid from the EG system. This is a protection mechanism in the units to protect against tampering of the device. The city however in the pilot study, compensates for the exported electricity onto the grid by reimbursing the prepaid meters with the double the amount that was exported, so essentially the homes get the energy back off the grid as they would have in a normal net metering set up. This more administrative intense way of net metering is temporary until the technical and administrative issues of net metered billing are sorted out (Keen, 2012).

One of the main issues around net metering, from a municipal perspective, is the metering devices and integrating the meters into the system (Keen, 2012). Some meters can be tampered with, such as the old magnetic-wheel meters. The issue of revenue loss to the municipality has thus encouraged the municipality to look into the issue of net metering and accounting systems for it in order to minimize the financial losses.

Figure 3 shows the 3.8kW PV system installed at the residence of Dr. Keen who is one of three members of the pilot study in Cape Town. Dr. Keen’s system incudes batteries but operate in net metering mode depending on the weather conditions and may be manually switched between using grid only, net metering or battery use only. Figure 4 show the output of Dr. Keen’s installation on a summer day and show the net surplus going onto the grid. In his installation, the first few sunlight hours are used to charge the batteries that had been used from the previous night.

Figure 3: The 3.8kWp PV array at the home of Dr. Keen, who is partaking in the pilot project with the city of Cape Town on net metering. Taken from (Keen, 2012).

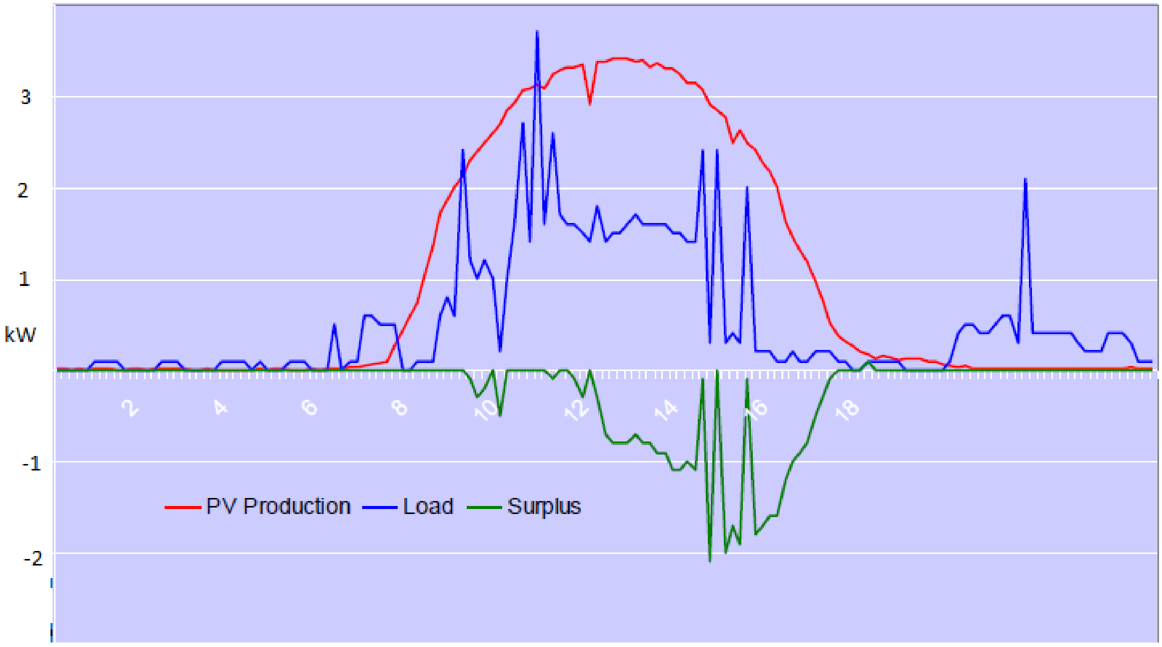


Figure 4: Graphs of the load, PV output and net surplus during a summer day at Dr. Keen's installation. (Keen, 2012). Note that this system is connected to a battery bank and there is no surplus up to midday due to charging of the batteries from the overnight use.

There is another pilot project underway in the city of Port Elizabeth at a single HH, where a combination of a 1kW wind turbine and 1kW solar PV panels are connected to a battery system in the HH. The aim is to determine the feasibility of decentralised grid connected renewables and to promote renewable energy within society (Minkoff, 2012). A webpage [1] showing all data for the project is updated daily, showing the net energy production and monetary savings.

Below is a figure of the layout of the project, and Figure 6 shows the total energy produced by wind and solar as well as their combined total of the system for almost a complete years' worth of operation.

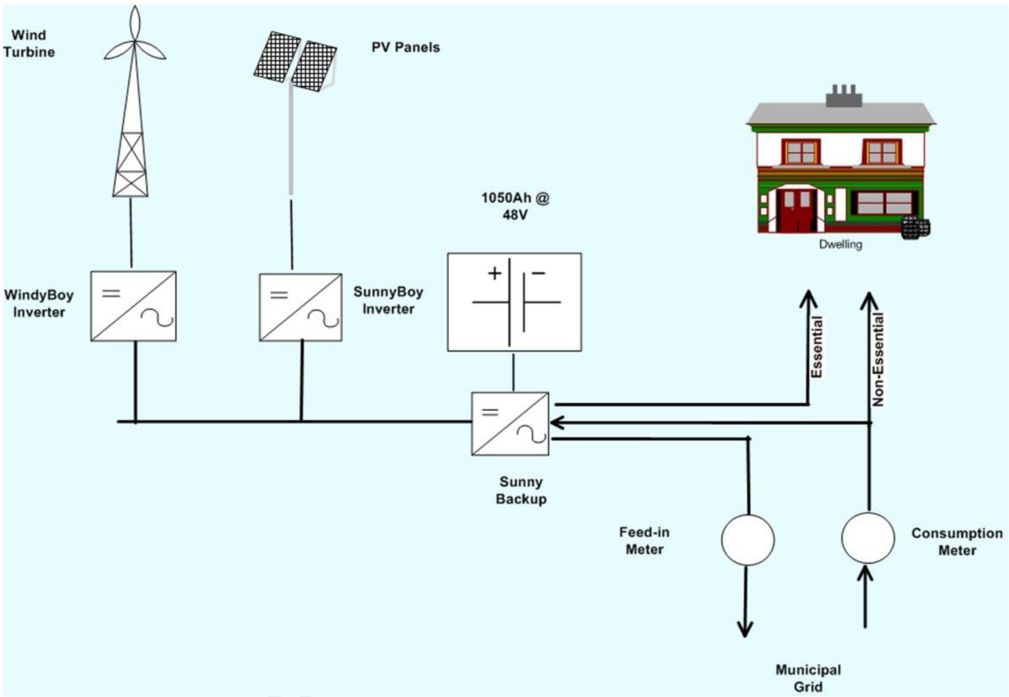


Figure 5: The setup of the decentralised renewable energy pilot project in Port Elizabeth. (SMA, 2012).

---

[1] www.sunnyportal.com

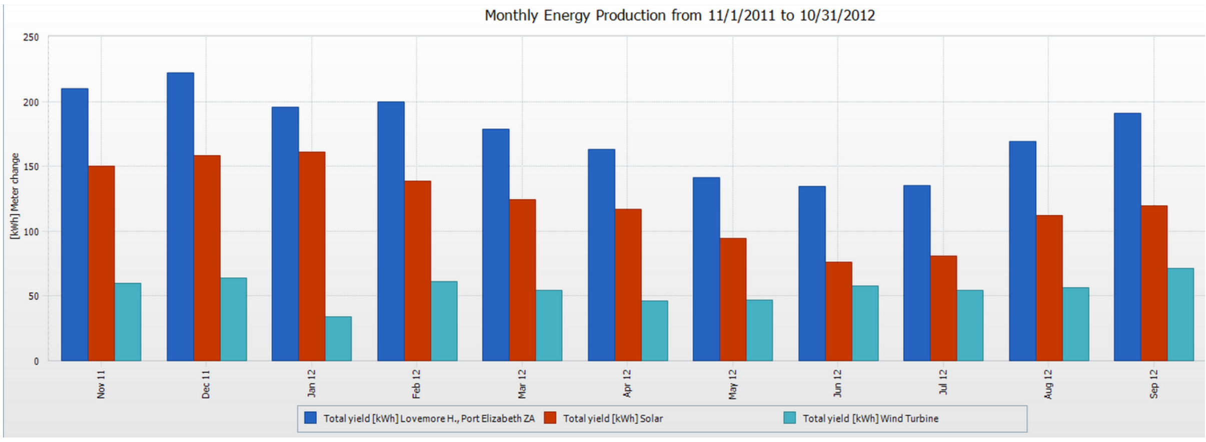


Figure 6: The monthly production of renewable energy from the Lovemore Heights project in Port Elizabeth. Data available at (SMA, 2012).

Although projects like the one in Port Elizabeth and Cape Town are a precursor to implementing renewable energy within the private sector, there are some instances around the country where a EG system may be built. The eThekwini municipality in Durban, accepts applications for embedded generation within the metro. Customers willing to connect an EG system must complete an application form with technical details of the system and whether they wish to export all or only the net electricity production from their EG system. Applicants are also required to sign a purchase power agreement with the municipality, and need a cogeneration licence from NERSA. The applicants bear all costs related to the interconnecting of the system with the distribution grid and any future upgrades, while the municipality purchases the electricity from the EG at the same tariffs for bulk electricity (this is the avoided cost system) from the state utility, Eskom.

The applicant is required to adhere to the standards set out in the standards of the NRS 057, NRS 048 and NRS 097 documents[2]. The municipality specifies the bi-directional 4 quadrant type meter to be coupled with a 'check' meter which ensures accuracy in the total metered energy and limits tampering. Since the municipality purchases electricity from the EG owner at the tariffs which Eskom supplies electricity to the municipality, this scheme may not be encouraging to persons wanting to install systems larger than what they consume on site. The municipality gains profit from this scheme as the bulk utility tariffs are much lower than distribution tariffs (Eskom, 2012a). This reflects the stance of Strbac's (2004) assertion that the tariffs are not a true reflection on the value of the EG in the distribution system.

---

[2] The relevant documents for embedded generation connection and the eThekwini municipality may be accessed from the reference: (Wienand, 2012)

According to Ndanga (2012), the best way to implement net metering (home power) in the market would be to simply allow customers to run the meter backward, thus enabling the full residential electricity price to be realized, reducing the payback period of a solar system and increase the financial return on the investment. This will both increase the market size and encourage larger system sizes rather than simply the minimum size.

From here, this study focuses on the net metering case whereby the customer will be able to export and import electricity to their home at the regular residential tariffs as in the third scenario considered by Ndanga (2012). The reason for this choice is that people are already connecting solar PV to the grid without alerting authorities because it is the most cost effective from an owner’s point of view (Keen, 2012). This is only true for systems larger than a system size which does not produce more than is consumed on site however, people may install systems that do not export but remain as an EG within the residential sector and still contribute to the overall capacity of EG in the sector.

2.1.2 Technical issues

A problem of concern to all parties of a net metered system is the metering device, and the overall stability of the distribution grid. These issues are highlighted here.

2.1.2.1 Prerequisites of EG

According to the national standard for the interconnection of an EG; NRS 097-2-1, it is required that any EG system that causes a deviation in the frequency, harmonics and/or power factor of the alternating current supply will need to sense the deviation and potentially disconnect from the grid. The standard (NRS 097-2-1) stipulates several criteria for the control, monitoring and operation of the EG, and the requirements of the EG under several situations such as loss of network or abnormal conditions – usually the disconnection from the grid.

It also states the criteria of operation for the case of net metering – where the tariff for exported electricity is the same as for imported electricity.

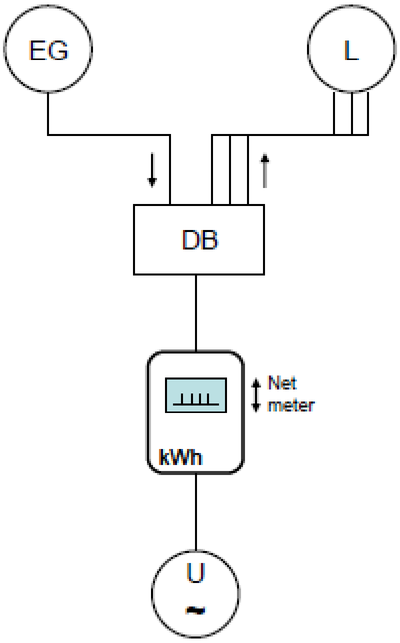


Figure 7: the configuration for net metering of an EG with a single bi-direction meter. (NRS, 2010)

In the case of a feed in tariff, 2 meters are required for the purpose of measuring the amount of energy exported to the grid; this may also be the case where municipalities or local laws stipulate that 2 meters be used on site. The meters need to be bi directional and single or separate register types. Prepaid meters require the separate register to record the export and import total of the energy from the grid. Without the separate register, prepaid meters will record reverse feed as a decrement. This is a protection feature against tampering with the meter and hence a requirement of the second register and the cost will need to be paid by the owner[3] (NRS, 2010).

2.1.2.2 Voltage rise

The electrical distribution grid is designed so that power in the form of electricity flows from the source (upstream) to the demand (downstream). When an embedded generator is connected to the downstream distribution, it is possible that power may flow ‘upwards’ toward the various substations and distribution systems. This effect is called ‘voltage rise’. A simple description of this phenomenon is described below (Gaunt & van Zyl, 2003):

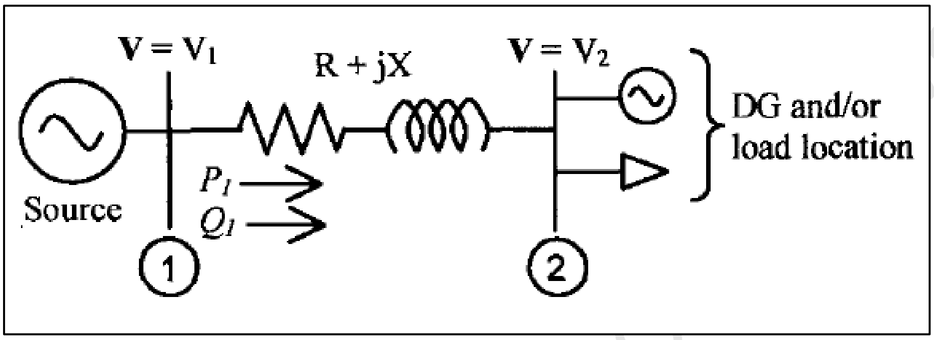


Figure 8: A basic two node system showing the flow of energy through a distribution network (Gaunt & van Zyl, 2003).

In the above figure, a conductor of impendence R +jX (R – resistance, X – inductance) carries real power P and reactive power Q to the end node (the distribution substation). The voltage drop is given by the following:

Equation 1: voltage drop

$$V_1 - V_2 = \frac{RP_1 + XQ_1}{\sqrt{3}\,V_1}$$

If the magnitude of the power produced by the distributed generator (DG) is large enough i.e. when the produced power exceeds local demand, the power flow term P will reverse, and if this term becomes large enough it can overcome the XQ factor in Equation 1 and cause a voltage rise between the V_2 and V_1 nodes.

---

[3] The NRS 097-2-1 document is only one of several documents giving the standards required of an EG system and frequently refers to later documents which have not yet been published on the matter.

Several options exist to deal with this problem as suggested by Masters (2002):

1) operating the DG at a leading power factor which absorbs reactive power,

2) reduce the sending voltage (V_1),

3) installing voltage regulators,

4) upgrading the network or

5) constrain the DG

Gaunt (2003) looks at the potential scale of DG that distributions networks can handle before tolerance levels of the system become violated. Although, his study looks at connecting DG to 11kV lines and not low voltage 380/220V lines which homes are connected to (Eskom, 2012c), the basic idea of voltage rise still applies to small scale (~10kW) systems within residential areas. However, this would only be the case if a residential area had sufficient DG capacity within its network to overcome the power flow from the distribution substation feeding that area, which may only be the case when almost every home had a system installed.

2.2 Current rooftop solar PV markets and history

The simplicity of solar PV panels and their fast reduction in price and the fact that municipal electricity tariffs are increasing steeply, means that solar PV is a good option for private investors of renewable energy at home. This is further backed by the fact that the solar rooftop PV market is the largest single share of the PV industry in the global market (Drury et al., 2010). Because PV is a more favourable option for EG in the home, solar PV will be considered to represent the EG and net metering market throughout this study.

The solar photovoltaic industry is growing at an exponential rate. Solar PV markets grew at 81% for the year of 2010, and an average of 60% between 2005 and 2010, and is clearly the fastest renewable energy industry with wind close behind at a rate of 25% market growth for 2010 (REN21, 2011). Distributed rooftop PV is the largest share of the global installed PV, mostly because they can start to compete with retail electricity tariffs and avoid transmission and distribution losses (Drury et al., 2010). In 2011, Germany accounted for 25% of the world's new installed PV market, with Italy and Germany making up 75% of the world's total installed capacity by 2011. Figure 9 shows a breakdown of newly installed PV for 2011 where Germany installed a total of 7.5GW bringing their total installed capacity to 24.7GW (Rothacher, 2012).

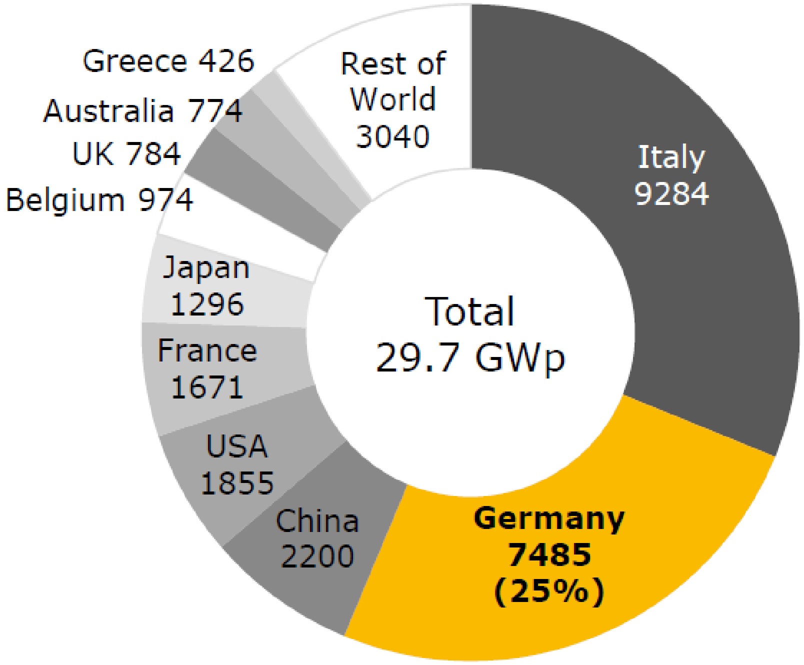


Figure 9: The total new installed PV capacity shares for the world in 2011. Units are in MW. (Rothacher, 2012)

Rooftop PV makes up a very large portion of this market in Germany. Rooftop systems less than 10kW make up 10% of new installed PV, and systems between 10 and 50kW make up 27% of all new installed PV in Germany. Thus with a German market share of 37% the rooftop (<50kW) PV market is the single largest in the country, and this share comes to 57% if sizes of 50kW to 250kW are included (Rothacher, 2012).

Globally, the residential PV market is projected to be about 40% of the total PV capacity by 2050 which is down from the current 60% today. It is expected that the costs will be much lower for utility scale PV by 2020 thus encouraging a shift in the market share toward larger systems than typical small residential systems (IEA, 2010). Despite this, the solar rooftop market will remain a major market share of renewable energy from PV. Figure 10 shows the IEA's expected market share of PV thru to 2050 where residential makes up about 40% of the total in 2050.

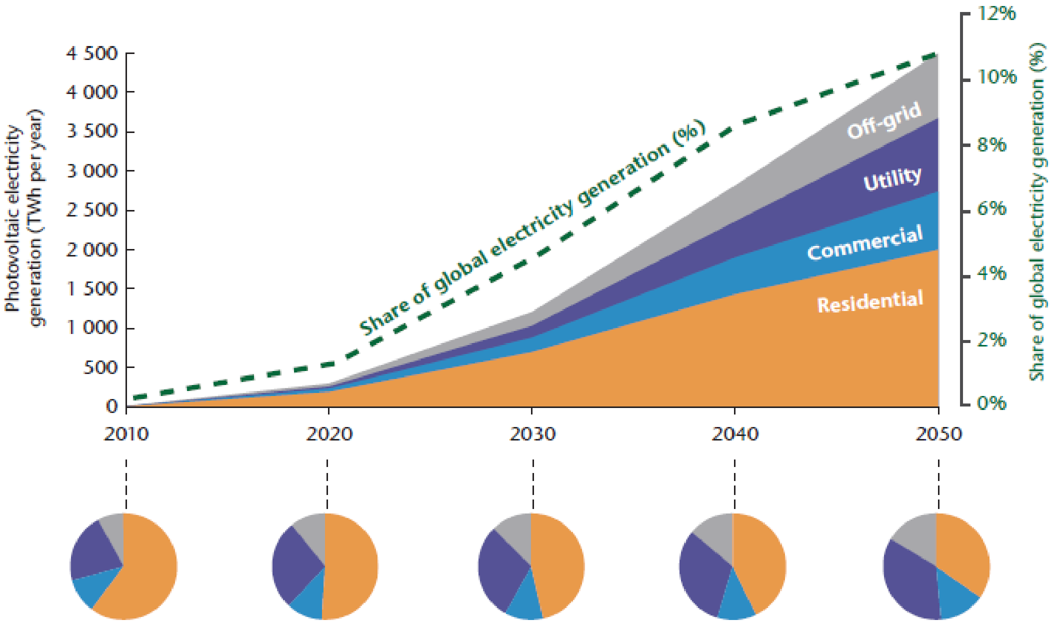


Figure 10: The total PV market end user projections thru to 2050. (IEA, 2010).

The cost of investing in solar PV at home can be out of the typical home owner's budget, and without incentive, either environmental or financial, home owners will not be encouraged to invest in solar PV systems. To help stimulate sustainable awareness and the investment into renewable energy, feed in tariffs are a method of making large investments more affordable to the investor, even if it is more costly than the alternatives.

A feed in tariff (FIT) is a financial subsidy for the energy produced by a generator. In some cases, operating generating technologies like solar PV can be more expensive than other more conventional technologies such as diesel generators and without a subsidy would never develop. Using a feed in tariff, the financial cost of investment into renewable energies in the home becomes more affordable. Feed in tariffs are used in some parts of the world for home rooftop PV systems.

Germany has a relatively high feed in tariff (FIT) rate for rooftop systems of 0.43€/kWh for systems <30kW, while Italy's FIT is 0.37€/kWh, Spain's is 0.32€/kWh and America's 0.2 to 0.5€/kWh (depending on the state and conditions) (SEMI, 2009). The success of the solar PV market today can be attributed to FIT's.

In 1990, Germany began subsidising rooftop PV installations up to 70% of the cost under the programme 'Thousand roofs programm' which was designed to stimulate the solar PV industry. The programme had led to the installation of 2000 systems by 1994. The programme also lead to the development of several key industry booms around small scale solar PV, such as invertor device manufacturers and helped develop the small PV industry as a whole (Heilscher et al., 1994). Figure 11 shows the global annual PV production in MW and shows some key developments of the industry starting with the first solar cell in the 1950's, notably the rooftop programme in Germany, since which, the growth of production has remained exponential.

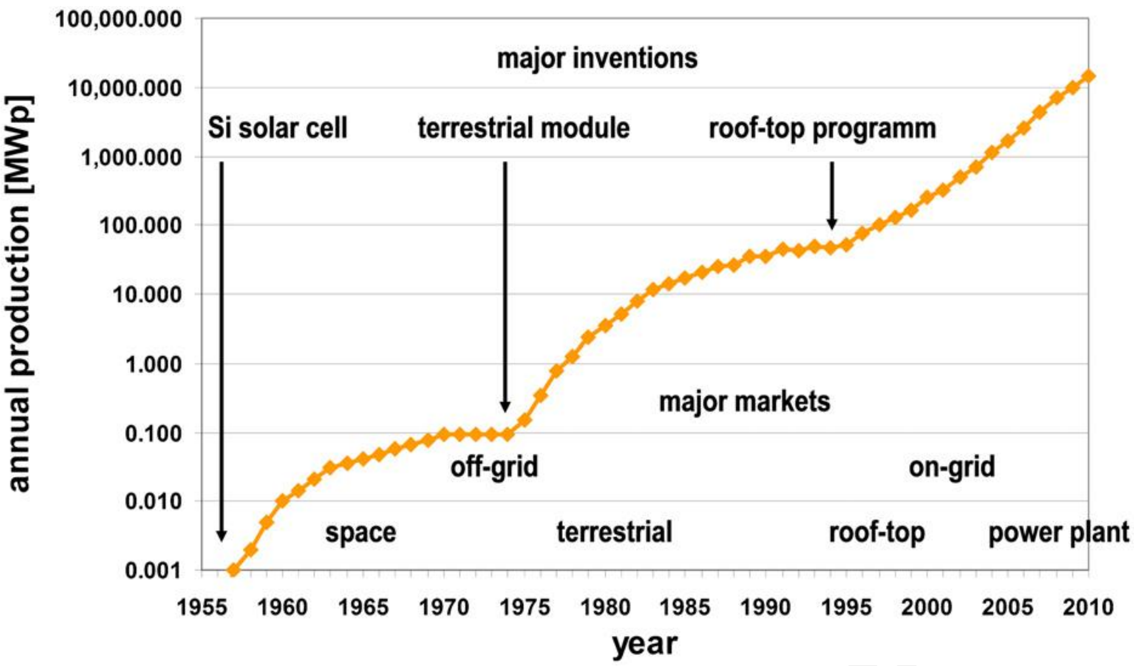


Figure 11: The global total installed annual PV production showing the key drivers of growth in production. (Jelle et al., 20112).

Rooftop solar PV has some distinct characteristics that give it an advantage over the larger utility scale installations; the mount – the house, already exists and no environmental impact assessment (EIA) is required, also rooftop PV does not require land to be acquired or rezoned, there already exists a connection to the electrical grid distribution eliminating the need for construction of new transmission lines, the cost for residential PV systems is coming down and already within the financial scope of many households, and the power is used on site – no losses from transmissions and the HH will be become more energy aware. Additionally, with increased DG within city networks and energy consumption reduction the distribution networks do not need to be upgraded as often - assuming that DG is managed and installed correctly (Rycroft et al., 2012; Jin et al., 2010)

Rooftop PV is a simple technology from the point of view of installation, aesthetics and maintenance. It does not stick out like wind turbines do, and thus is more aesthetically pleasing than a wind turbine, which according to Adams (2011) is a factor for South Africans considering investing in RE technology in the personal capacity.

There are several factors that affect the amount of residential rooftop PV in the market. The main factor is the financial aspect which includes; electricity prices, the initial capital costs of the system and government subsidies and initiatives. Auxiliary or peripheral factors such as image, improved energy efficiency or even reduction in greenhouse gases may also affect the uptake of rooftop PV to varying degrees and become more important with increased capital costs of the system (AEMO, 2012). In South Africa, a developing country, the financial aspect of renewable energy generation is most likely to be the main criteria that will affect the scale of uptake in rooftop PV. Although environmentally aware home owners will be more susceptible to investment in RE, the financial aspect remains the main barrier.

The cost of generating electricity from a private generator needs to be competitive with the bought off the grid electricity; otherwise the investment will not be financially viable. A home owner needs to consider the future prices of grid bought electricity in the residential sector and compare this with their investment.

In South Africa, the retail price increase of electricity for 2012 was 16% while for 2011 it was 25.8% (Eskom, 2012a). This rate, which is significantly above the consumer price index increase, means that the age of cheap electricity from coal is at an end and that technologies like solar power will become more competitive (Eberhard, 2010).

Grid parity refers to the point at which the cost of generating electricity from a device like PV is equal to or less than the cost of wholesale purchase of electricity. To compare the cost of generating electricity, the lifespan, cost of fuel (none in the case for PV), capacity factor (a measure of the performance of the device) and initial capital cost per power rating are taken into account to determine the overall total cost per unit of energy (R/kWh usually). This is called levelised cost of energy (LCOE), which enables one to compare to the retail municipal tariffs for electricity. The formulation for LCOE is given in Equation 2 and takes into account the time value of money.

Equation 2: the formula for the levelised cost of energy (LCOE)

$$LCOE = \frac{\sum_t^T \frac{C(t) + OM(t) + F(t)}{(1+r)^t}}{\sum_t^T \frac{E(t)}{(1+r)^t}}$$

Where, *T* is the life time of the technology, *C* is the capital investment of the technology, *OM* is the operations and maintenance costs, *F* is the fuel costs related to operating the technology, *E* is the energy generated by the technology in each year *t*, and *r* is the discount rate.

Once the LCOE from a rooftop PV system is equal to or less than the retail price, the PV system becomes the cheaper option and hence more attractive financially to the investor.

According to Bazilian (2012) and references therein, grid parity has already been reached in some countries and is for many more only a few years away.

Figure 12 shows the levelised cost of electricity from PV systems and compares with the retail price of electricity or ‘socket parity’ and indicates that Denmark, Germany, Italy, Spain and some parts of Australia have already reached socket parity by 2012. Furthermore, Japan, France, Brazil, Turkey and California will reach socket parity by 2015 (Bazilian et al., 2012).

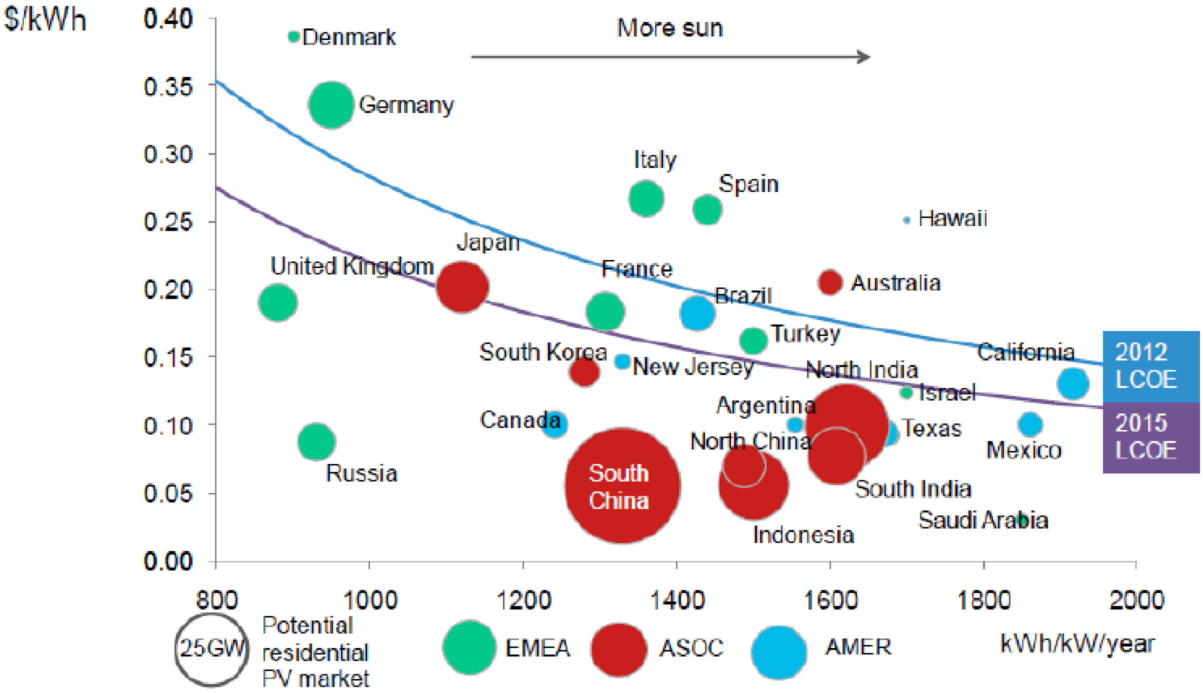


Figure 12: Graph showing which countries have reached and will reach grid parity of solar PV systems. The size of the bubbles indicates the relative size of the capacity for PV (Bazilian et al., 2012).

This trend in increased energy cost and decreasing cost of private small scale energy generator systems means that rooftop solar PV will become a common feature in the next few years. Understanding how this technology will develop in the market place is critical in understanding the potential of EG in our electricity sector.

2.3 Market adoption of solar technologies

Currently there is very little to no collected data and information on the state of rooftop PV systems or small scale embedded generation systems in the residential sector of South Africa

(KZN energy, 2012). Apart from the two cases mentioned below, there is very little information on the state of net metered EG in South Africa.

Since, there is little information in South Africa on the state or scale of net metering and EG, other means of understanding the state of residential renewable energy generation in South Africa will need to be investigated.

Adoption and diffusion:

The Bass diffusion model is a financial tool which describes the process of adoption of new (or existing) products into a market, and has been extensively researched and adjusted for various market conditions and products (Guidolin & Mortarino, 2010; Denholm et al., 2009).

Equation 3: The Bass model is described by the adoption rate

$$A(t) = \frac{1 - e^{-(p+q)t}}{1 + \frac{q}{p} e^{-(p+q)t}}$$

and the total number of adoptions of the product:

$$Y(t) = m \frac{1 - e^{-(p+q)t}}{1 + \frac{q}{p} e^{-(p+q)t}}$$

Where *m* is the total maximum market, p is the 'coefficient of innovation' and q is the 'coefficient of adoption'. The parameter p defines the populace that try new products without much external factors affecting their decision, while the parameter q defines those that are late adopters of a new product and are more influenced by external factors like the total number of products in the market and peer perception (Adams, 2011). An extra parameter denoted *d* can be incorporated into the temporal variable in the adoption/diffusion equations to account for varying levels of maturity of the market.

Figure 13 shows three adoption S-curves produced by the Bass model which is used in the SolarDS[4] model for predicting the potential rooftop PV scale of adoption in the U.S (Denholm et al., 2009). The three curves account for different financial payback times of the systems. However, an issue with the Bass model is the effect of a changing market share (m) over time and how the adoption rate can shift from the one curve to the other. Figure 13

---

[4] The SolarDS model is a software program designed to model the market of solar PV systems in the U.S, see reference: (Denholm et al., 2009).

shows three different adoption curves, each representing a different payback period and hence adoption pattern.

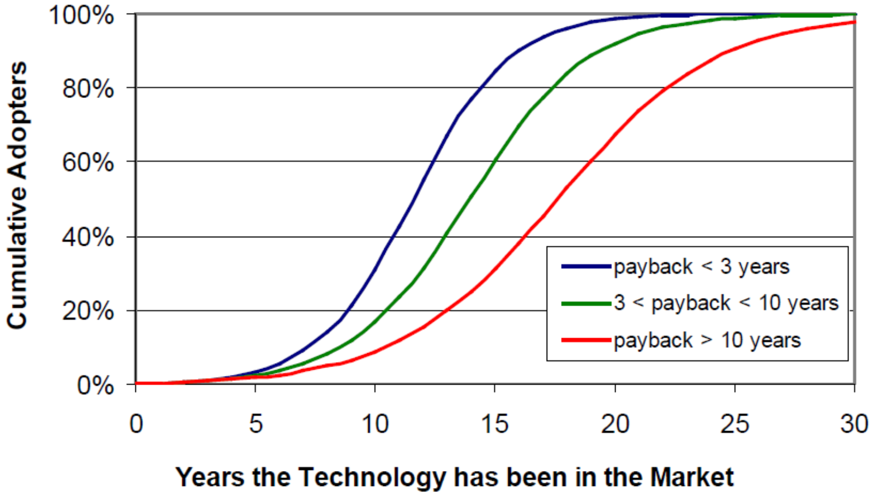


Figure 13: Adoption rates determined by the Bass diffusion model. These graphs show how the SolarDS model accounts for PV growth in the potential market. Taken from (Denholm et al., 2009).

Typical values of p and q are 0.03 and 0.38 respectively for general new products in the market place (Guidolin & Mortarino, 2010). These typical product values are much higher compared to the results from a study of solar PV in the market by Guidolin et al. (2010). Guidolin undertook a study to estimate these values for various countries on solar PV installations. In their study they evaluated several countries such as Japan, Germany, Australia, Spain and USA, among others, and used a least squares analysis on available data to obtain values for *p* and *q*. Although their study is based in countries that are considered more developed than South Africa, they do provide insight into the nature of solar PV adoptions in a country and the effects policy and financial incentives have on the purchasing of solar power systems.

Table 1: Bass Model parameters determined by fitting data for selected countries taken from the study by (Guidolin & Mortarino, 2010). *Small market average is comprised of U.K, Canada, Austria, and Netherlands. The large market average is based on the remainder of the countries listed in the table.

Country	**m (MW)**	**p**	**q**	**d**	**Comment**
Japan	2777	0.000123	0.421	5.46	Delayed market
Germany	6276.5	0.000202	0.41537	-	Altered Model for policy shocks
U.K	28.602	0.003	-0.002886	-	Altered Model for policy shocks
Australia	1449.7	0.000165	0.1684	9.7	Delayed + shock
Canada	310.36	0.000086	0.25317	7.87	Delayed + shock
France	868.78	0.000047	0.2921	6.962	Delayed + shock
Austria	30.077	0.000049	0.2832	15.73	Delayed + shock
Netherlands	55.138	0.000091	0.459	7.2	Delayed + shock
U.S.A	8666.9	0.000015	0.279	15.27	Heavy delayed shock +developed
Italy	1948.41	0.000409	0.2757	3.98	Difficult to fit: combined shocks
Spain	483.52	0.000007	0.271	20.2	Combined shocks. Re-iterated model.
Avg. small markets*	**106.0443**	**0.000807**	**0.248121**	**10.266**	**See Figure 13**
Avg. large markets*	**3210.116**	**0.000138**	**0.303224**	**10.262**	**See Figure 13**

The Bass model parameters determined by Guidolin *et al.* (2010) in Table 1 above were calculated by fitting the Bass model (see Equation 3) to available data on the number of installations per year for several years for each country. In most cases however, because of market drivers like subsidies which unnaturally alter the adoption of the product, the researchers used the generalised Bass model to fit the data. Using extra functions added to the model to account for the required parameters *p*, *q* and *d* can be determined. The altered models can incorporate several extra parameters that account for factors such as a mature market (delayed) and/or external shocks to the market such as a new policy shift, incentive or even PV shortage that dramatically alters how the market develops. Most of the shock parameters for the countries listed are due to policy and regulation shifts that usually encourage installation of PV and the selling of electricity by renewables.

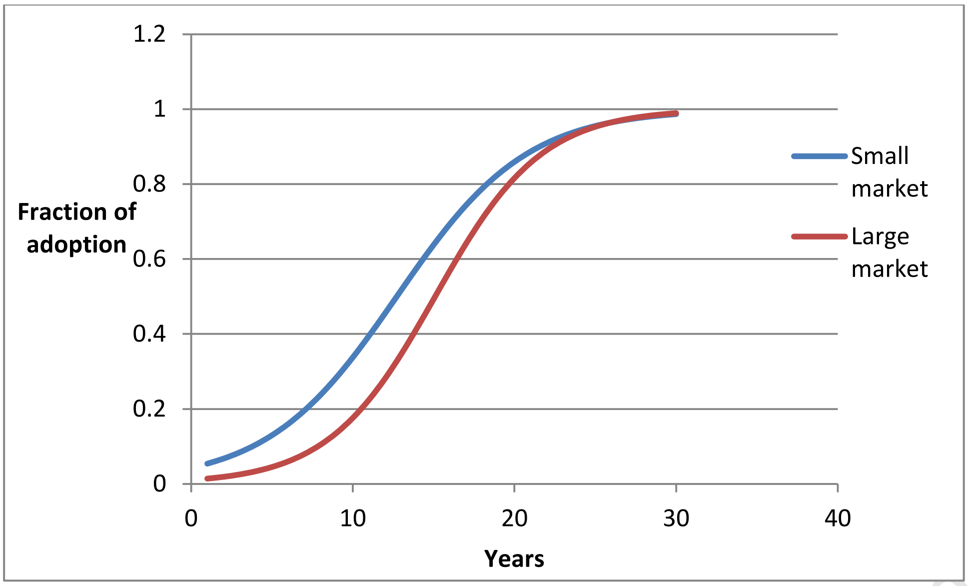


Figure 14: The Bass Model adoption fraction using the average for the p, q and d parameters for the small and large markets as in Table 1.

Figure 14 shows the adoption of the market based on the small and large market average parameters from Table 1. The small markets are grouped by countries with less than 500MW, except for Spain which due to their intensive renewable energy programme is included with the large market group. The larger market has a steeper adoption rate which can be explained by the market size and the external effect of peers on new adopters. The smaller market shows a large initial adoption probably due to the market already being somewhat developed (parameter *d* accounts for this), but a slower adoption rate after the ~7 year mark, as compared to the larger market.

Based on a market study on the acceptance and adopters of solar technologies in South Africa, the early majority of adopters of a new technology showed a positive response toward solar technologies and their benefits like solar hot water or renewable power generation (Adams, 2011). However, even in the upper income group there was significant negativity toward some of the characteristics of solar technologies like the payback period, the level of subsidy, and maintenance which all influence the rate of adoption. Adams (2011) found that in South Africa, there is a general slow rate of adoption in the market for solar technologies and that perception of technologies had to be considered as well. However, factors like finance and aesthetics are also present in the markets that Guidolin *et al.* (2010) studied, and their results will be useful in understanding the nature of South Africa's market of solar rooftop PV.

In a study designed to look over and examine the developments of modelling adoptions in the market place for the last few decades, Mahanjan (1990) presents a comprehensive analysis of the Bass model and variations of it within different market places. The study also highlighted the need to understand empirically how certain external factors affect the adoption of products, such as the temporal influence of competitors. Of the many aspects analysed by Mahanjan (1990), he suggests that in the absence of available data for product diffusion, the p and q parameters may be estimated from analogous product diffusion studies in other markets (Mahanjan et al., 1990). This provides a way to estimate the market adoption of rooftop PV and hence the scale of net metering systems in South Africa, given that there is no current data for the total solar PV installations in South Africa.

2.4 Energy planning and modelling

Energy modelling provides a way to understand the impact that net metering can have on a system as complex as the electricity sector of South Africa.

Energy planning is a method of managing and preparing for future energy needs based on current information of available resources, economics, technology developments and environmental concerns.

An energy system, like the electricity sector, is a complex system of many aspects and factors which are influenced both internally and externally. Political, social, economic, environmental and resource availability are among the many aspects which affect an energy system (O'Brien & Hope, 2010). Academics and electricity utility companies started using linear programming methods for new capacity expansion in the 1950's. Electricity systems models are tools utilised by planners, engineers and economists to manage, plan and trade electricity in a systematic manner (Foley et al., 2010). Before the 1973 oil crisis, electricity planning was fairly simple since demand increases were predictable with a general move to larger generating plants (Foley et al., 2010).

Electricity models are now used to compare the outcome of several political or economic decisions which affect the whole system, so that decision makers and planners may have an insight into the potential consequences of decisions that are made in the present (Foley et al., 2010). Due to the vast complexity of the system, computer programmes are used to simulate the energy system. Computer modelling of electricity systems allows researchers to 'tinker' with certain parameters to see what potential effects they may have on the whole system that would without computers be difficult to assess.

2.4.1 OSeMOSYS

Currently there exists a set of energy models and analytical tools which require significant financial investment, human resources and training to use. The open source software; OSeMOSYS (open source energy modelling system) is designed to bridge that gap in required and available human and financial resources particularly in developing countries. OSeMOSYS is written in open source software that allows it to be freely accessed by anyone with an internet connection, and being open source, also allows the software to be edited at the discretion of the user for the purposes of the users' specific modelling requirements (Howells et al., 2011).

OSeMOSYS is a systems optimization model for long-run energy planning and due to its open source structure and accessibility, it has a lower learning curve than the more developed and existing optimisation software programs like its commercial counterparts. The objective of OSeMOSYS is to determine which technologies to build throughout the model period that would result in the lowest cost while meeting all the demands and constraints put in place by the user. OSeMOSYS utilises the linear optimisation method for determining the lowest discounted future costs. OSeMOSYS is written for the GNU Linear Programming Kit (GLPK) which utilises the open source GNUmathprog language which is designed specifically for linear programming (Makhorin, 2008). The OSeMOSYS software uses parameters to define costs, energy and technology types in addition to other numerical elements to create the model that is to be optimised.

OSeMOSYS comes with the essential features of a linear optimisation software program and only requires the input of numerical data for the technologies and energy requirements from the analyst. However, in the case where OSeMOSYS might lack for a certain parameter or constraint, due to the open source structure of OSeMOSYS the analyst may define new parameters in the software to cater for their specific criteria. This feature is accelerated by the fact that a large community can develop around the software all over the world – meaning that the software will constantly improve (Kok, 2012).

There are two parts to the OSeMOSYS modelling software; the OSeMOSYS software which is the energy planning model and secondly, the data section which is where the analyst inputs all numerical data on the system that is being modelled. The OSeMOSYS model software is written in a standard text file which is available from the OSeMOSYS website [5] and is

---

[5] OSeMOSYS website : osemosysmain.yolasite.com

updated from time to time as new software issues are discovered or new elements of the software are added. A basic Utopia model is also available to download as a guide or example on the use and constructing of new models with OSeMOSYS. (Makhorin, 2008).

There is no user interface as of yet for OSeMOSYS and the data needs to be entered into a text file or the like in a certain format. Figure 15 shows the basic overall structure of how the OSeMOSYS software is used and how it is implemented with GLPK.

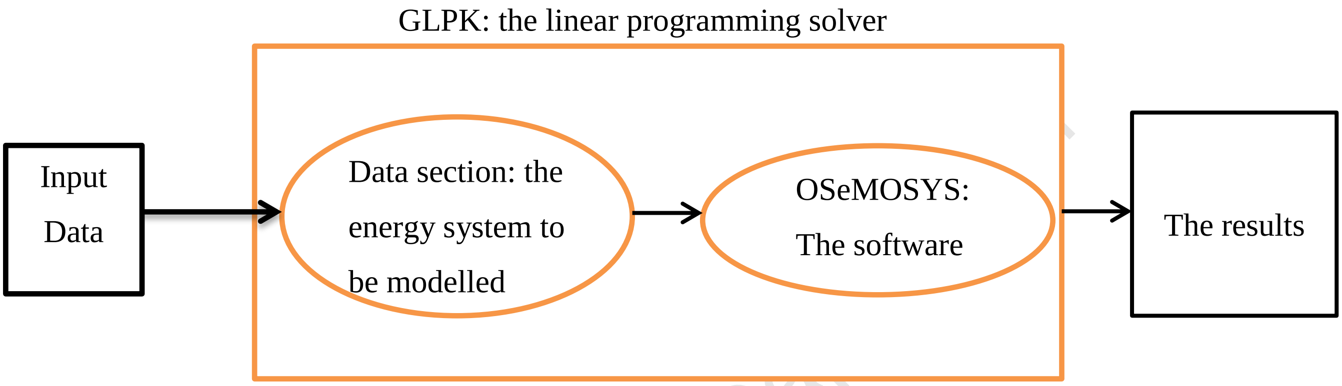


Figure 15: The basic structure of using OSeMOSYS to model an energy system

In the development of OSeMOSYS by the software developers, a comparison of the results of OSeMOSYS to a commercial software programme was done by an example energy system called ‘Utopia’. Utopia was taken from the standard demonstration application for MARKAL (a common tried and trusted energy modelling system) and adapted to the OSeMOSYS format. Using OSeMOSYS on the example system, the results from OSeMOSYS and MARKAL were compared in order to determine the accuracy of the open source software to the commercial counterpart (Howells et al., 2011).

The model Utopia was represented by three demands: lighting, heating and transport. Both lighting and heating demands fluctuate at certain times of the day as well as certain times of the year. Heating can be met by oil or electric heaters and transport by electric, diesel or gasoline. Electricity is generated by various fossil fuel technologies as well as hydro and nuclear. Some fuels are imported while others are imported first and then converted in a refinery in the energy system. Figure 16 shows the installed power plant capacities between OSeMOSYS and MARKAL. The results for the comparison showed there was a 1% and 5% difference in total installed capacity in 2000 and 2010, which is offset by a higher investment in storage (Howells et al., 2011).

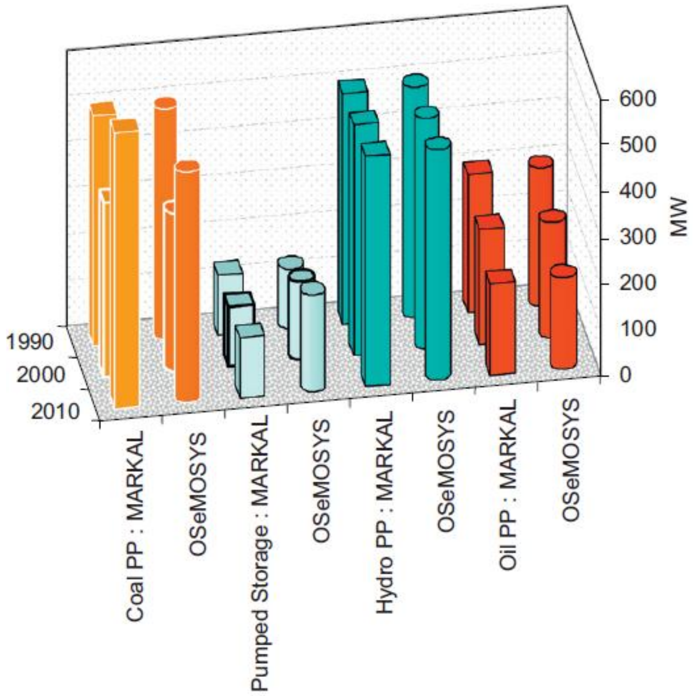


Figure 16: The comparison of OSeMOSYS with MARKAL using a demonstration energy system called 'Utopia'. Figure shows the power plant capacities over the modelled period. Taken from Howells (2011)

Modelling a smart grid using OSeMOSYS

To demonstrate the usefulness of the open source structure of OSeMOSYS, the elements of a smart grid, which include shifting of demand, prioritising demand types, storage devices and variable electricity generation, were implemented into the OSeMOSYS model software by Welsch *et al.* (2012). By allocating a cost to the shifting of a portion of energy consumption at certain times, Welsch could model the effect of a smart grid. The cost allocation allows the software to account for the shift of energy consumption as best as possible by using optimisation (Welsch et al., 2012).

To do this, a process of implementation was used for new functional sections of code in the software. The stages of adding new functionality to the software included; 1) the conceptual description of the new elements, 2) the algebraic formulation of these, and 3) the implementation of the formulation into the programming language (Welsch et al., 2012). Using this format of implementation, outside users may better understand the workings of the model and thus speed up the learning curve.

The various aspects of implementing a smart grid into an existing energy system required the addition of various new parameters into the software. Some changes were required to the original parameters and variables of OSeMOSYS in order to model the smart grid system desired, this was easily done, yet caution had to be taken when changing some constraints and parameters as the result of the changes may affect the functionality of other aspects of the model. An understanding of the model and how the costs were determined by parameters and constraints used in the software is critical before proceeding to make changes to some of them to account for new functionality (Welsch et al., 2012).

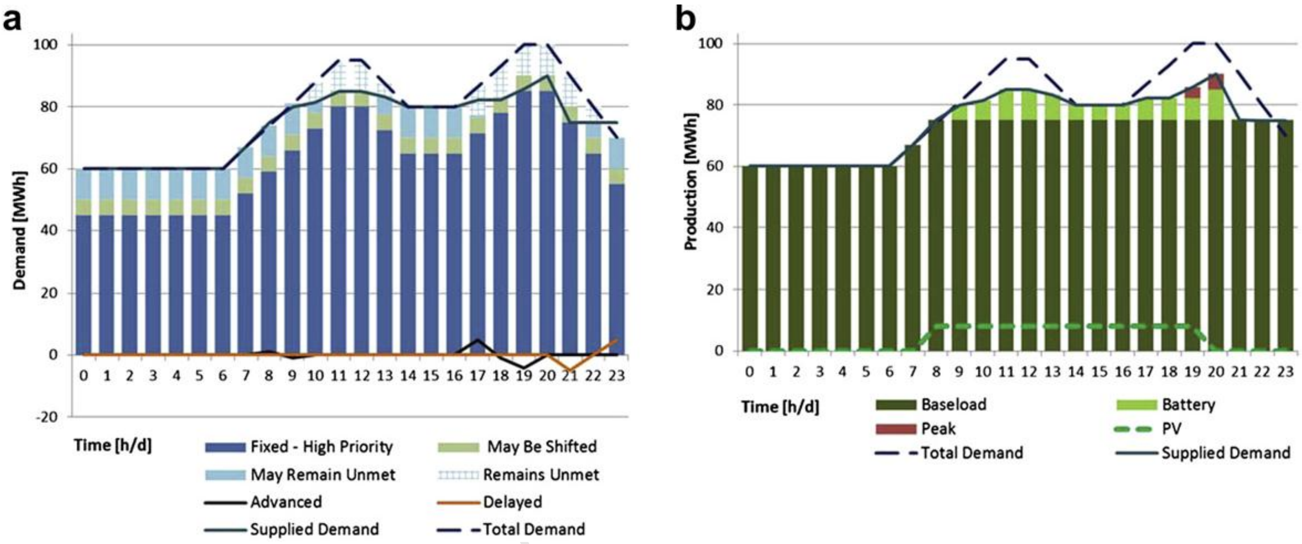


Figure 17: the results of implementing a smart grid aspect in an energy system using OSeMOSYS. Results for 2020: a) the demand; b) the production. Taken from (Welsch et al., 2012)

Figure 17 shows the results of implementing smart grids into the energy system by Welsch *et al.* (2012), by adjusting and adding parameters to the core OSeMOSYS code. The result is a shift in demand which describes the essential nature of a smart grid.

2.5 The South African electricity sector

Of the 5 main sectors in the country; agriculture, transport, industry, commerce and residential - industry is the main consumer of electricity. For 2006 the final consumption of electricity by sector is shown in Figure 18. The residential sector is the second largest consumer of electricity in the country at 20% behind industry at 60%.

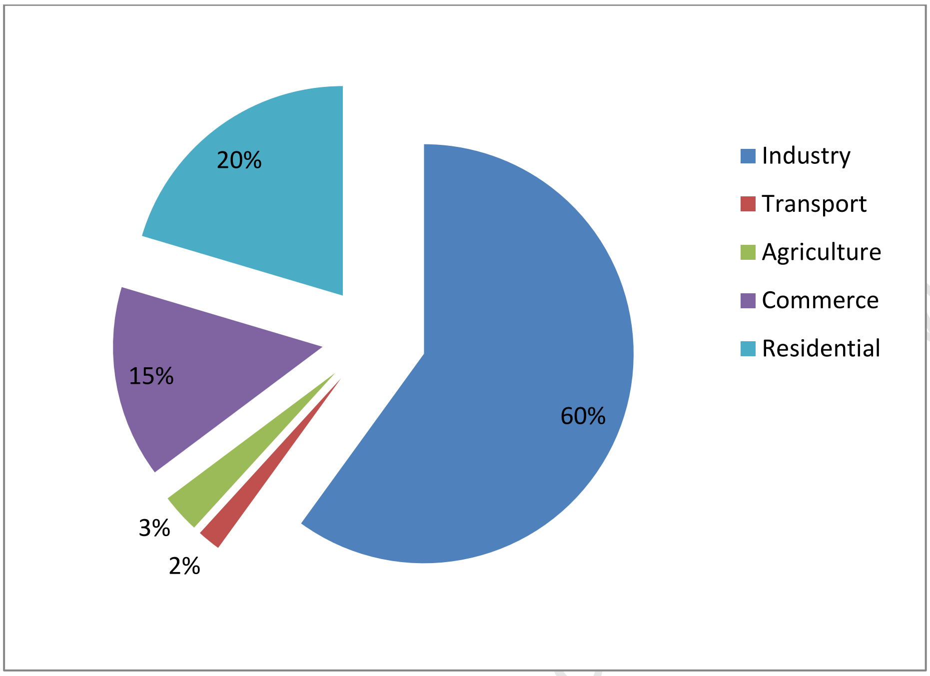


Figure 18: The final energy consumption of electricity by sector for 2006 (Subramoney et al., 2009).

The state owned utility; Eskom, supplies 96% of the country's electricity (Eberhard, 2010). Due to the large reserves of recoverable coal in South Africa, the majority of the electricity produced is from coal fired power stations. In 2010, 92.8% of the electricity generated by Eskom was from coal fired power stations. The remainder was generated from nuclear (5.6%), Hydro (0.47%), Storage[6] (1.21%), gas turbines (0.06%) and wind (<0.005%) (Eskom, 2011c).

---

[6] It should be noted that storage does not produce electricity but rather stores it at times when excess electricity is being produced and underutilised. This occurs late at night when coal plants still operate.

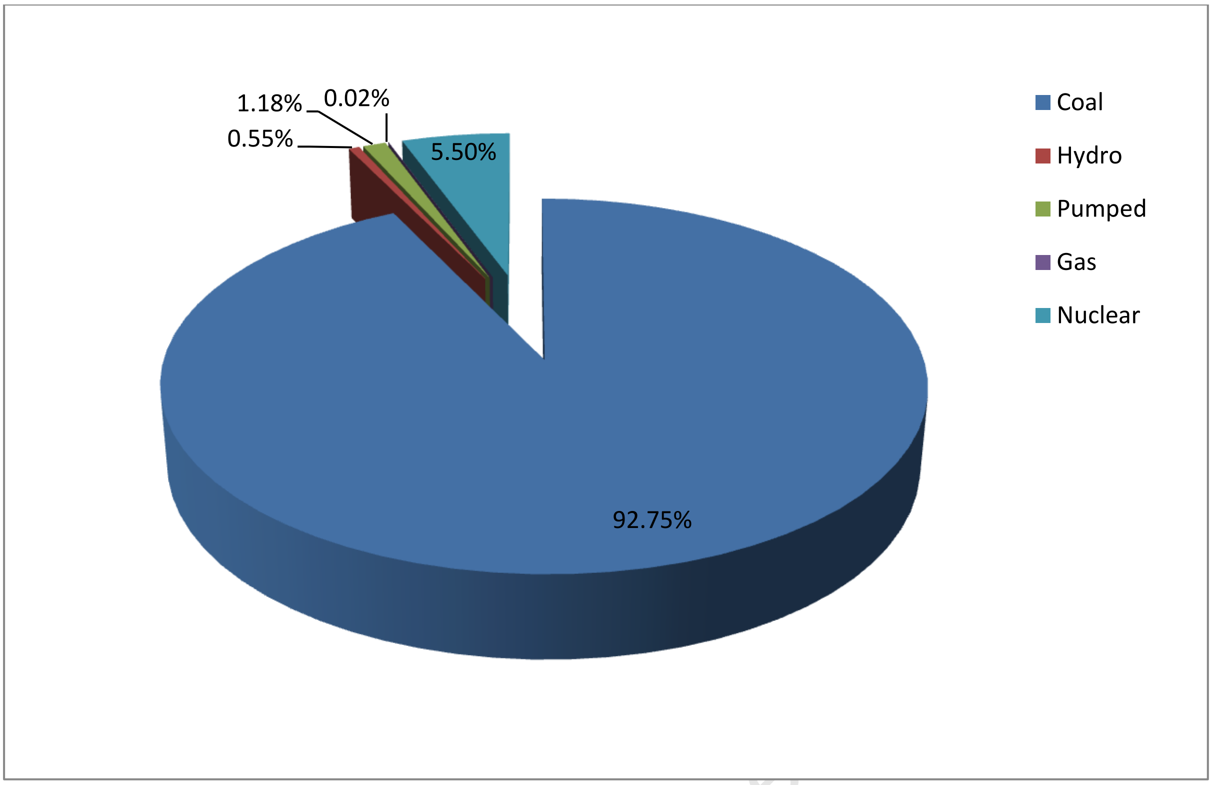


Figure 19: The share of electricity generated by technology in 2010 (Eskom, 2011c).

The majority of the coal reserves are located in the north and north-east regions of South Africa in the Witbank, Waterberg and Ermelo areas of Limpopo and Mpumalanga respectively – see Figure 20. The coal fired power stations are located near to the sources of coal for transport logistics, and as such, the majority of the electricity is produced in the Highveld area (north and north east). The majority of the electricity thus needs to be transported over distances of up to 1500km's to supply the rest of the country.

Almost all of South Africa's electricity is produced by Eskom and the electricity sector is regulated by the National Energy Regulator of South Africa (NERSA). A policy shift between 1999 and 2004 toward a more open market in the supply of electricity and a move away from state owned electricity production caused a failure to attract new investors into the sector. This meant that electricity capacity was falling behind demand. NERSA allowed Eskom to once more build more electricity capacity due to the lack of private investments in power production, the move toward an open market is still in place, but Eskom remains the major producer of electricity (Eberhard, 2010; Eskom, 2012a).

This delay in new capacity coupled with miss-management of the operating plants meant that South Africa experienced an electricity shortage beginning in 2006 and 2007 which resulted in Eskom having to load-shed large regions and power intensive industries and black-outs were common throughout these years (Eberhard, 2010).

Figure 20 shows the power station and grid layout of South Africa, and shows how the coal power stations are grouped in the North and North East of the country. Koeberg - the country’s only nuclear station is located near Cape Town. A myriad of smaller sized power stations are positioned throughout the country, but the bulk of the productions are in the north- eastern areas.

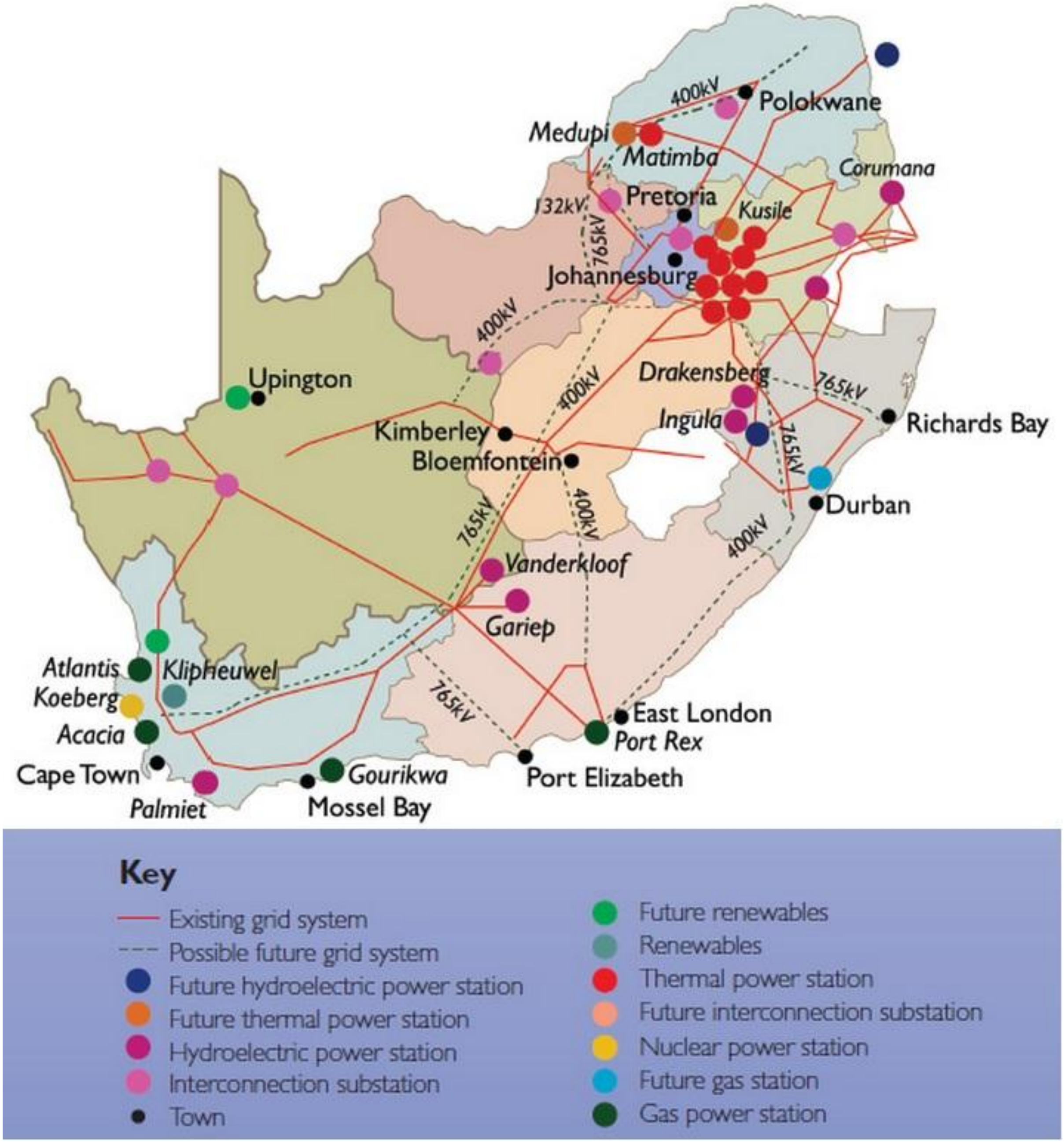


Figure 20: the layout of the South African electrical grid system and power generating technologies. (Eskom, 2011c)

There are two new large coal fired power stations being constructed currently. Medupi and Kusile are expected to begin operations in 2013 and 2017 and are expected to be completed by 2017 and 2020 respectively (Eskom, 2011a). The two new stations come in the wake of the electricity crisis that began in 2007. Since the start of the crisis, Eskom has enabled a symphony of programs aimed at reducing consumption and increasing generation. This includes the energy efficiency and demand side management programme, solar hot water heater subsidies and the return-to-service of several moth-balled power stations. These stations, Camden, Grootvlei and Komati, will add 3.5GW to the system by 2014 (Eskom, 2011c). Peaking demand is met by natural gas turbines at Acacia, Atlantis, Port Rex and Gouikwa.

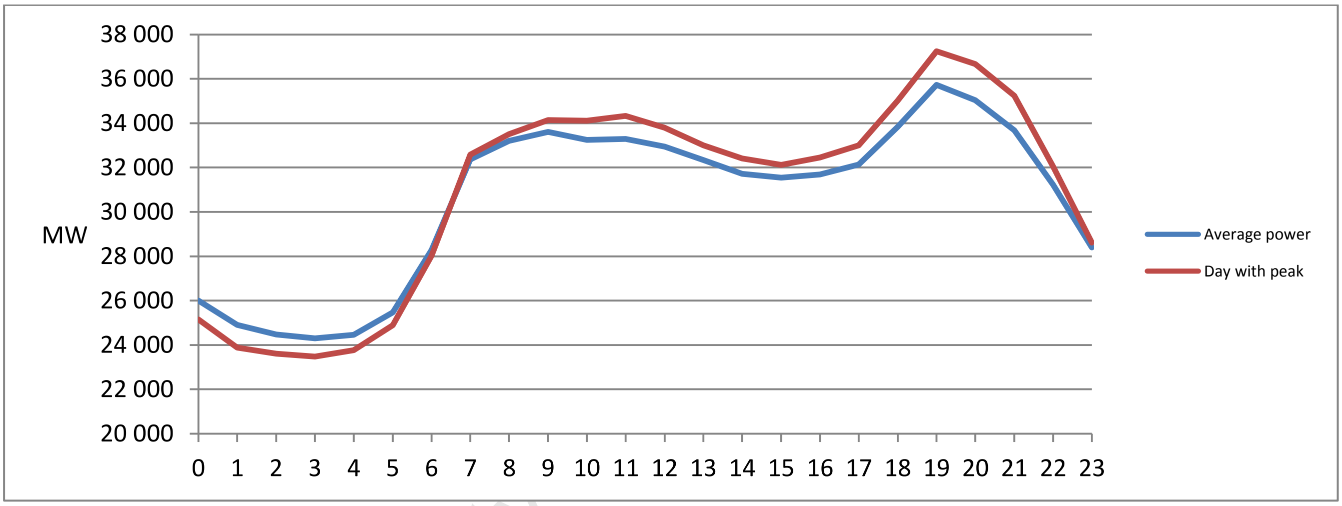


Figure 21: The electricity demand profile for South Africa in 2010 for winter weekdays, showing the average power demand and the day with maximum demand (peak). Data obtained from the ERC.

The peak demand in South Africa occurs in winter evenings, when people arrive home and start to cook and switch on heaters as well. This is when the peaking gas turbines are utilised the most.

In order to understand how private investment into renewables by home owners would affect aspects of South Africa’s electricity sector like the demand profile above, the potential capacity needs to be determined first. This is presented next, while creating the energy model of South Africa’s electricity sector to study the effect, is presented in the section following that.

3 Net metering projections

To model the projection of privately installed solar rooftop PV within the residential sector, a financial analysis based projection needs to be used. In essence, installing solar PV at home is a financially based decision, although environmental concerns can be a significant factor it is harder to quantify. The main financial aspect affecting the market is the electricity tariffs, the number of suitable installation sites (the homes), and the cost of solar PV devices and the income levels of the homes. These will all be considered in the following sections in order to determine the projected range of possible net metered EG capacity.

All prices and values are in real terms and VAT is included in all prices and costs except where stated.

3.1 Potential scale of embedded generation in South Africa

As discussed in 2.2, solar rooftop PV is a growing market, and with the ease of installation and simplicity of operation, it is reasonable to assume that solar PV will make up the majority of net metered systems in South Africa. From here, net metering will be equated with installed solar rooftop PV systems for the purposes of this study.

Data on the total number of installed PV systems in South Africa is very difficult to come by, and is not yet available (KZN energy, 2012). Although governmental departments are trying to put together data of installed renewable energy projects within South Africa, they are generally focused on larger sized projects than residential size systems (KZN energy, 2012). To estimate the size of the market and hence the capacity in MW of rooftop PV, the financial tool - the Bass model which has been developed for purposes like this, will be used.

As with most products in the market, not every potential investor/consumer will buy any given product. This is true for net metered EG's in the residential sector as well - not every HH will invest in a solar system. These potential buyers will follow a diffusion model like the Bass model describes, and over time the number of investors (penetration) of the market will increase. The main financial aspect in determining the market size is the competitor of EG - municipal electricity. Determining the future of municipal electricity tariffs is essential for understanding the success of solar rooftop PV and net metering in South Africa.

3.1.1 Eskom Electricity tariff increases

As a result of the energy crisis in South Africa and the fact that electricity prices up to 2007 were not a real reflection of the cost of production due to excessive investment in capacity in the early 1990's, Eskom has been approved tariff increases since 2008 that are significantly higher than the average yearly increase leading up to 2007 (Eberhard, 2010; Eskom, 2012a). The high price increases are a 'catch up' type increase, designed to make enough revenue to complete the new projects to meet the growing consumption in the country.

Table 2 shows the tariff price breakdown from 1997 to 2013 and compares it with the consumer price index (CPI) increase. Figure 22 shows cumulative tariff adjustment as a percentage of the consumer price index, and shows the significantly higher price increases over the CPI over the last 5 years in contrast to the significantly lower price increases between 1997 and 2007.

Table 2 : Eskom price increases between 1997 and 2012/13 taken from Eskom tariff and charges booklet (Eskom, 2012a). *comprised of 2 price increases for that year.

Implemented		Tariff increase	CPI increase
1 January	1997	5,00%	8,62%
1 January	1998	5,00%	6,87%
1 January	1999	4,50%	5,21%
1 January	2000	5,50%	5,37%
1 January	2001	5,20%	5,70%
1 January	2002	6,20%	9,20%
1 January	2003	8,43%	5,80%
1 January	2004	2,50%	1,40%
1 January	2005	4,10%	3,42%
1 April	2006	5,10%	4,70%
1 April	2007	5,90%	7,10%
1 April	*2008/2009	27,50%	10,30%
1 April	2009	31,30%	6,16%
1 April	2010	24,80%	5,40%
1 April	2011	25,80%	4,50%
1 April	2012	16,00%	5,2%

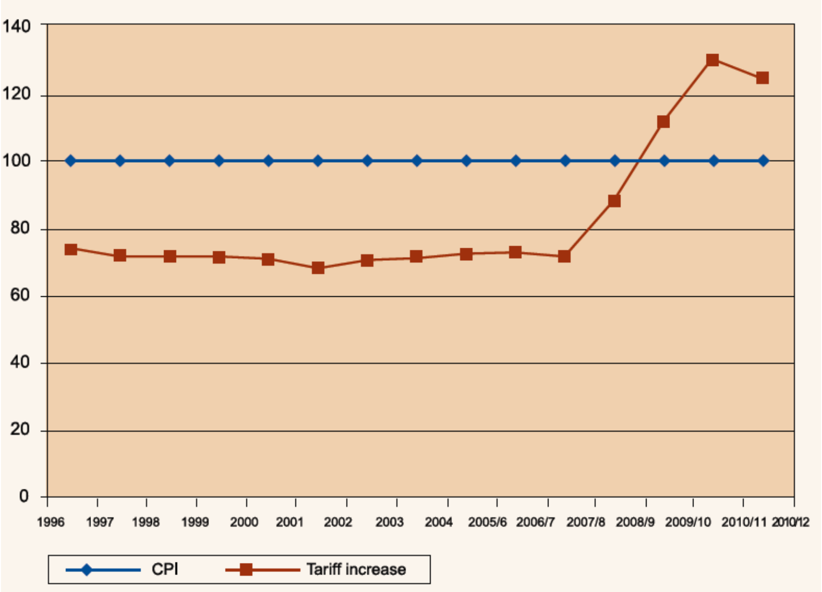


Figure 22: Eskom's tariff adjustment as a percentage of CPI. Base = 1990. Taken from (Eskom, 2012)

3.1.2 Future electricity prices

The electricity price increases in the future will determine the cost effectiveness of investing in private renewable energy production such as solar PV. As can be seen from Figure 22 and Table 2 the price increases currently are very high when compared to increases in the standard of living costs.

Based on the integrated resource plan 2010 (IRP2010) price path analysis (Figure 79 in the appendix 8.1), the estimated cost of supply that is projected through to 2030 is expected to increase rapidly between 2010 and 2015 (Eskom, 2011a). With these price increases, the levelised cost of solar PV technologies without storage would become equal with the grid provided electricity by as early as 2015 (Eskom, 2011a).

NERSA has granted Eskom an average increase in price of 16% for 2012 to 2013, and 8% increase for the next 5 years from 2013 to March 2018 when the last of the units at the new Kusile coal fired plant is expected to be commissioned (EWN, 2013; Fin24, 2012).

The average HH consumes 1100kWh per month, which will be reduced when the home invests in a solar PV system (Eskom, 2011b). To determine the price projection of medium to large size residential customers, the weighted average of electricity tariffs for homes using more than 600kWh and those using between 400 and 600kWh per month in all major metropolitan areas in South Africa was calculated and projected forward using the increase tariffs approved by NERSA (SAnews, 2013).

Using data from the community survey 2007 (StatsSA, 2007), the number of households in each metropolitan area in South Africa was determined and a weighting for each metro was then calculated. Table 3 shows the weighted average municipal electricity rate for medium to large residential electricity users in South Africa.

Table 3: Municipal electricity tariffs for South Africa. Tariffs for the metros are for homes consuming more than 600kWh monthly and are 3 phase systems and were taken from the associated municipality's official website documents

Metropolitan area	**No. of HHs**	**Share**	**Municipal rate c/kWh @ >600kWh (400-600kWh)**
Nelson Mandela Bay	276881	5.87%	147.06 (119.7)
Johannesburg, Tshwane and Ekurhuleni	2701003	57.30%	124.14* (117.9)
eThkwini	833859	17.69%	117.29 (117.2)
Cape Town	902278	19.14%	159.81 (134.7
Weighted average			**131.1 (121.16)**

* Average of the three metros

Using these weighted municipality average tariff, the projection of tariffs to 2018 was based on the NERSA approved tariff increase rates (the % increase) and tariffs from 2019 were fixed constant values (in real terms). This is done as inflation would simply increase all values by the same figure and inflation is subject to change yearly. Also, the constant (real) rate is preffered as the IRP cost values are all in real terms as well. Figure 23 shows the projected municipal tariffs for electricity based on the initial weighted average from Table 3. Table 43 in appendix 8.1 gives the municipal tariffs from Figure 23.

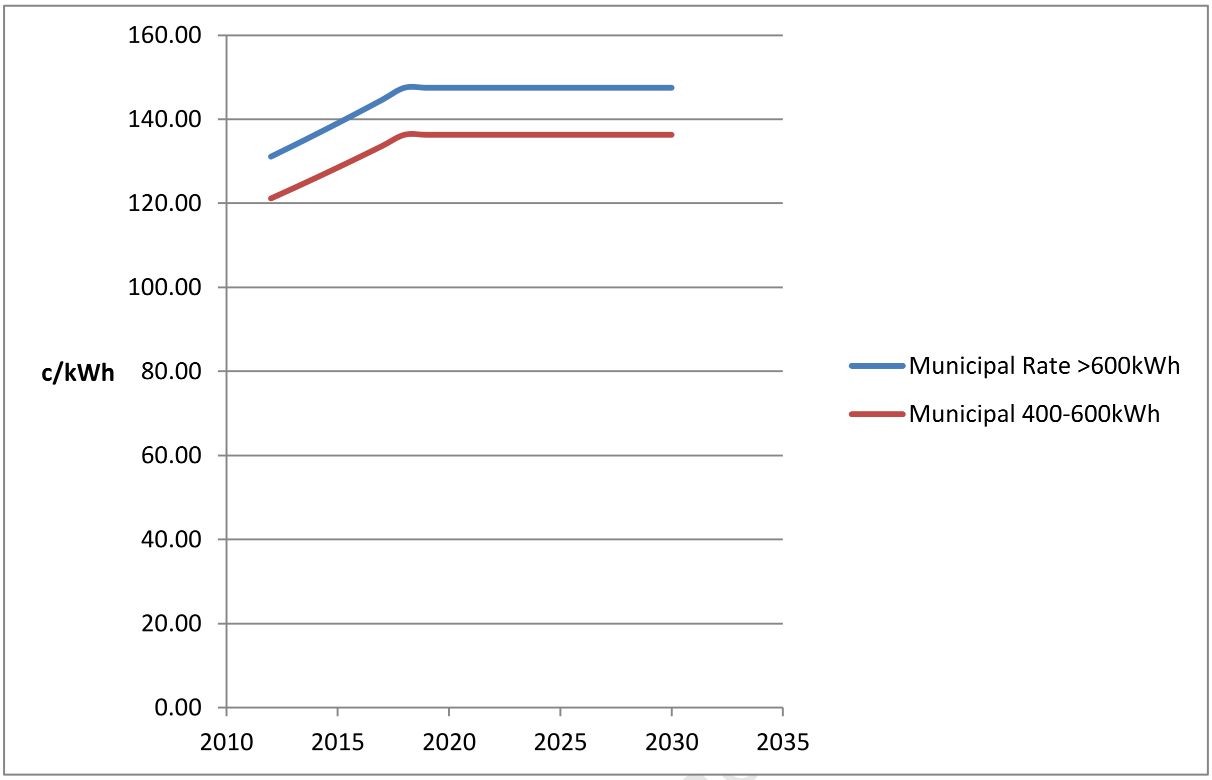


Figure 23: The projected municipal electricity tariffs (2012 real) for medium to large residential customers in South Africa

3.1.3 The market of potential investors in rooftop solar PV

The market of potential investors is defined here as all the households which will at some point in the future invest in solar PV systems.

In studies on the market penetration levels in residential or commercial sectors there were several important factors that were considered when trying to estimate the total market for rooftop PV systems (Drury et al., 2010). The main factors affecting the market penetration include:

1. Physical potential – the physical limitations that are specific to PV installations such as the total roof space available.
2. The financial aspect – payback periods of the system
3. The adoption rate of the product - describes the rate at which the product penetrates the target market.

These are the factors that were considered in research done in the US and will be adopted in this study (Drury et al., 2010; Paidipati et al., 2008).

- The physical potential has various aspects including the orientation of the homes, shading of the rooftops, tilt of the roof and size of the rooftop. For the purpose of this study, only the number of homes that are physically able to support a solar system on the roof will be considered. To simplify, from here on, these will be termed ‘suitable’ structures or households. All installations will be assumed to be optimally orientated.
- The financial aspect of market penetration is by far the largest factor contributing to the potential size of the market. People generally use economic performance metrics to determine whether an energy saving device is worth investing in (Drury et al., 2010). The financial aspect includes the system overall costs, the energy consumption of the house hold which determines the savings, and electricity tariffs. In South Africa, the HH income is a key factor affecting the overall market penetration, as unlike the countries where the studies were based - South Africa is a developing country with 71% of households earning less than R6400 a month as of 2007 (StatsSA, 2007).
- The adoption rate of new products is the rate at which a new technology replaces an old one or where a new technology is introduced to the market for the first time and is slowly adopted (bought by consumers) into the market environment (Drury et al., 2010).

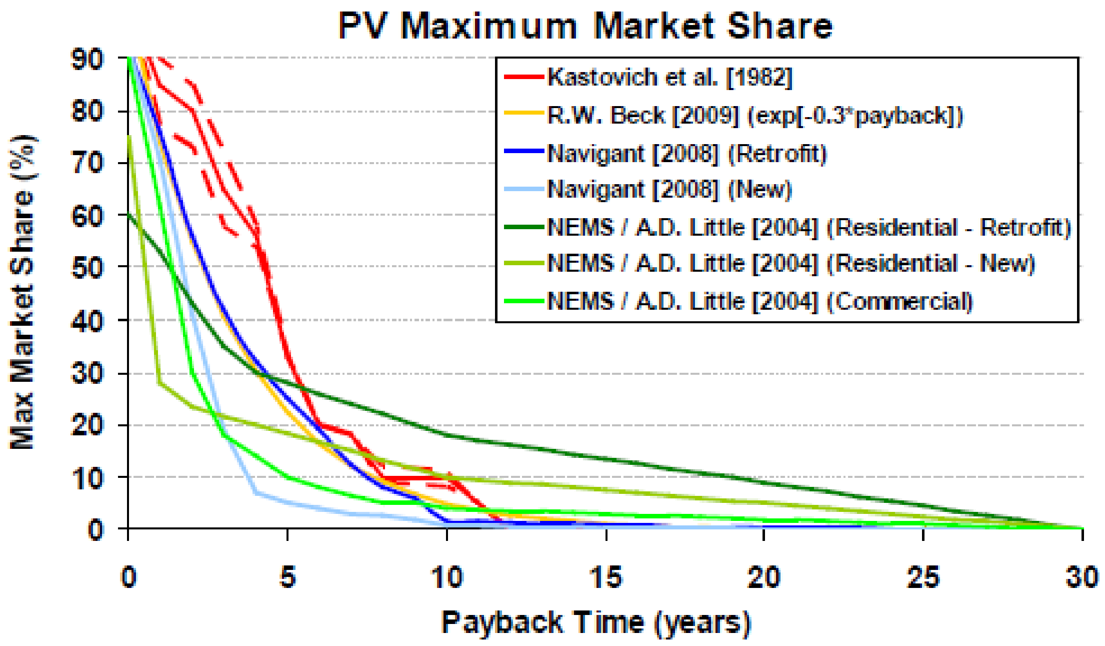


Figure 24: Various market potentials for rooftop PV as a function of payback time. Taken from (Drury et al., 2010).

Figure 24 shows the market share as a function of the payback period of the system for the studies by Kastovich, Beck, Navigant, and the NEMS studies that were looked at [7] in the Drury study (2010).

The total number of customers that would be willing to adopt a PV system is based largely on the payback period in years, and‘sensitivity’ to the payback period (Beck Inc., 2009). The maximum market share can be approximated by the equation:

4: Maximum market share based on payback period:

$$f = e^{(-0.3P)}$$

Where:

f *is* the market share – the fraction of the entire market of those that will at some point invest in the system, and P is the payback period. 0.3 is the sensitivity to the payback period and is an estimate[8] (Beck Inc., 2009).

The equation is compared In Figure 25 below with the average of the case studies from an Arizona Department of commerce study (2009) and a study by Kastokich (1982) on heat pumps in the market place. The average of the studies (orange line) closely fits with the approximation in equation 4 (Beck Inc., 2009).

---

[7] Kastovich (1982) looked at the market potential and diffusion of electric heat pumps, the Beck (2009) study was an extensive research report which looked at various policies related to renewable energy for the state of Arizona. Included in this were solar options for residential customers. NEMS is a programme by the U.S utility PG&E which allows customers to install distributed generators like rooftop solar at home (www.pg&e.com). The Navigant report is an analysis of solar rooftop market penetration scenarios in the U.S (Paidipati et al., 2008).

[8] The authors (Beck Inc., 2009) did not indicate how the estimate was derived, but it is most likely from fitting the equation to the average payback curve using a least squares method to determine the sensitivity coefficient.

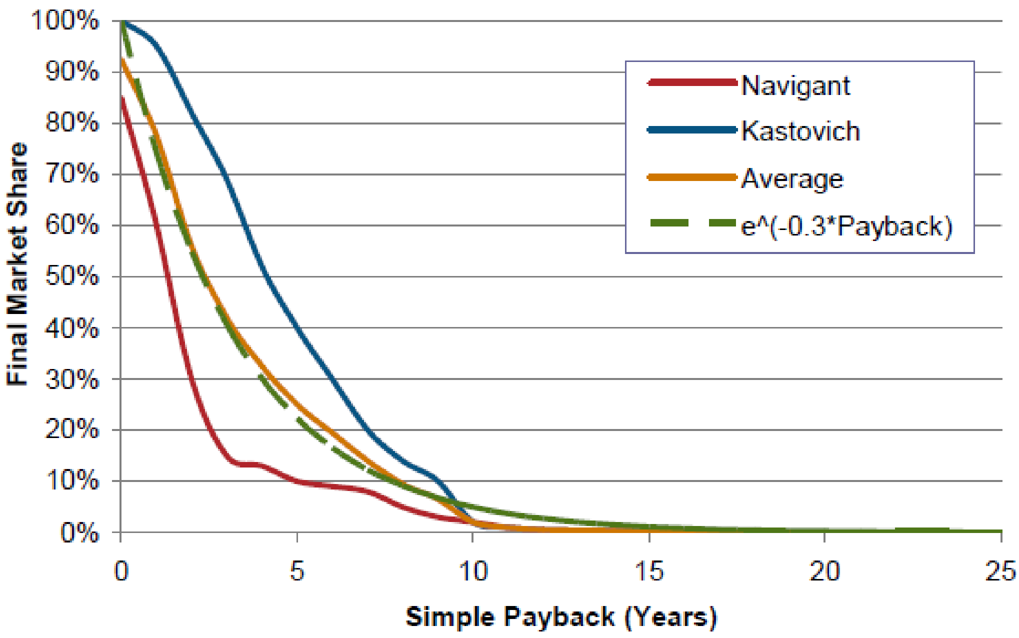


Figure 25: Market share of PV systems as a function of financial payback period of the system

3.1.4 Solar PV in South Africa

Using the relation of payback period to market share in the preceding section, the total number of investors in solar PV can be determined. It is thus necessary to determine the payback period of the solar PV systems.

To determine the payback periods for solar PV systems, an analysis of solar PV within South Africa was conducted. Using information about solar insolation levels, solar PV prices and trends, the payback period for solar PV systems was determined for South Africa.

3.1.4.1 Solar data for South Africa

South Africa has a variety of different climate zones, due to its geographic location and being located between a warm Indian Ocean current off the east coast, and a cold Atlantic ocean to the South and West. These climate zones affect the performance of solar panels as the cloud patterns differ from one area to the next. Some regions can be cloudy for months and others get nothing but sunshine. Mostly, South Africa has a fairly uniform solar insolation (above the clouds) throughout, but the climate zones affect the amount of solar energy reaching the ground.

The country is divided into its climatic zones according to the South African National Bureau of Standards (SABS, 2008) as in Table 4 and Figure 26. This will allow for compensation for the different weather patterns and hence different solar radiation profiles throughout the country. The breakdown of the climate zones within the country is given in figure 44 and is taken from SABS (2008).

Table 4: List of climatic zones in South Africa according to the SABS standard (SABS, 2008)

Climate zone	**Major centre**
1. Cold interior	Johannesburg, Bloemfontein
2. Temperate interior	Pretoria, Polokwane
3. Hot interior	Makhado, Nelspruit
4. Temperate coastal	Cape Town, Port Elizabeth
5. Sub-tropical coastal	East London, Durban, Richards Bay
6. Arid interior	Kimberley, Upington

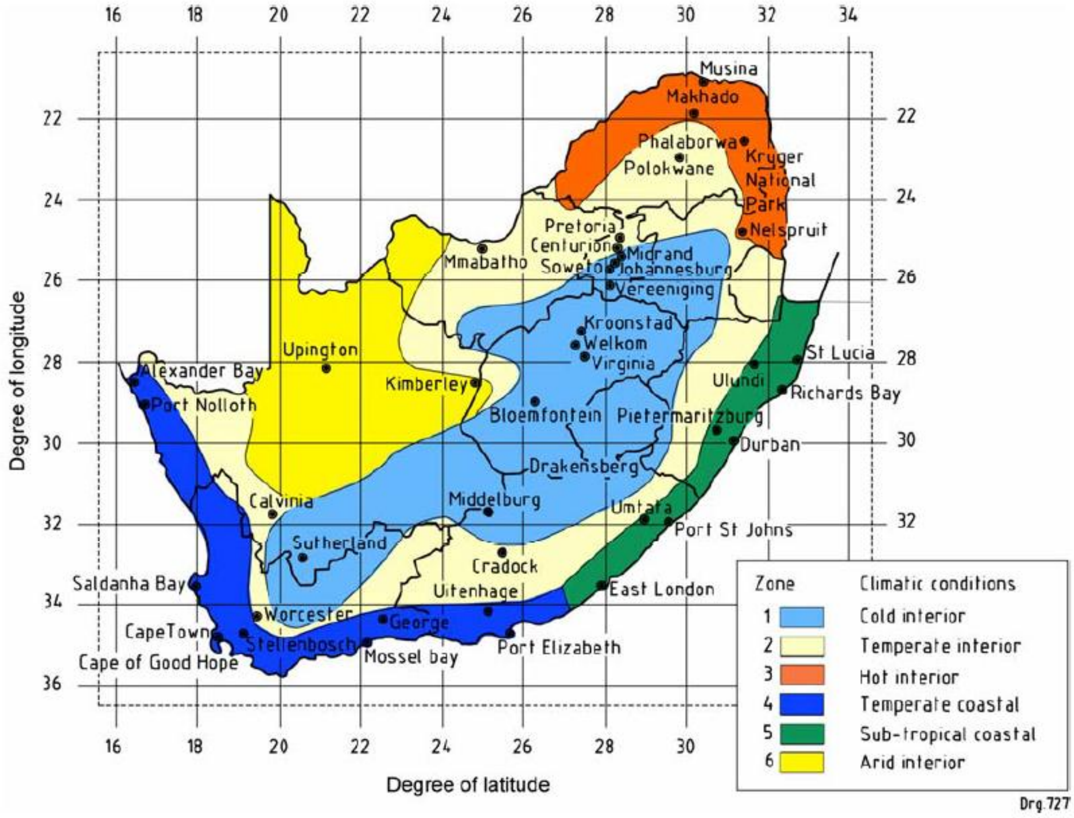


Figure 26: Climate zones of South Africa. Picture taken from (SABS, 2008)

To maximise the harnessing power of solar panels, the panels have to be orientated facing north when in the southern hemisphere, and south in the northern hemisphere so as to face the sun’s direct insolation and produce the most electricity. Solar panels are tilted up off the horizontal so as to face more directly at the suns elongation angle in the sky when it reaches midday – increasing the insolation on the panels. This tilt is proportional to the latitude of the geographic position of the panels. The further south one goes (increasing latitude) the closer the sun gets to the horizon, the larger the angle of tilt.

It is reasonable to assume since an investor will want to maximise their return, that the average PV installation at a residence will be inclined plane tilted and fixed, with a North facing orientation for maximum solar collection (Keen, 2012).

There are several forms of solar data that take into account different environmental and solar factors that will influence the solar insolation levels at the surface. Solar radiation profile data for the major centres of each of the climate zones listed in Table 4 were obtained through the online services from www.soda-is.com which utilises databases of solar data from various countries. Since the PV installations will be fixed and latitude tilted, the 'inclined plane' solar data available from the online source was used. It accounts for direct and diffuse light conditions on plane surfaces that are tilted at the latitude angle (Meyer, 2011).

In most laboratories, solar panels are testing under the Standard Test Conditions (STC) of 1000W/m^2 and a temperature of 25°C as defined by IEC 60904-3 standard (Arndt & Puto, 2010). Using the solar data available, the capacity factors (CF) for the various climatic zones can be determined. The capacity factors for the various climatic zones in South Africa were based on the data for the major areas in those zones and using the STC's (1000W/m^2) are shown in Table 5. The panels' efficiency will change throughout the day as the temperature of the device fluctuates. To account for this, a measured CF of 20.4% for a Mainstream Renewables project (2012) in Kimberly was used by taking the ratio of the Mainstream CF to the zone 6 CF. The Mainstream project also used a fixed inclined plane tilt for the test installation. Zone 6 being the zone where Kimberley lies – see Figure 26.

Table 5: Insolation data for a complete year and capacity factors for various climatic zones in South Africa based on the solar data for an inclined plane from www.soda-is.com .

Zone:		**1**	**2**	**3**	**4**	**5**	**6**
Item	**operation**						
no. of hrs. sun shines		4710	4690	4674	4785	4758	4665
Total insolation (Wh/m2)		2561706	2470726	2239699	2100766	2068862	2390177
Total (kWh/m2)		2562	2471	2240	2101	2069	2390.18
Daily average (kWh/m2/day)	total/365	7.02	6.77	6.14	5.76	5.67	6.55
Effective sun hrs.[9]	daily avg./1kW (STC)	7.02	6.77	6.14	5.76	5.67	6.55
Total avg.(hours)	Average of effective sun hrs.	6.32					
Capacity factor (%)	total avg./24	29	28	26	24	24	27
CF average (%)		26					
Adjusted CF *	CF × 0.74	**21.6**	**20.9**	**18.9**	**17.7**	**17.5**	**20.2**
Average (%)		**19.5**					

* Adjusted based on Mainstream Renewable capacity factor for PV measurements outside of Kimberly (Mainstream, 2012).

3.1.4.2 Prices of solar PV and silicon

It is generally considered in many countries that solar PV is still expensive and not competitive with other generating technologies and that the technology will only become competitive in the future. It is true that in some countries where electricity tariffs are high enough that solar PV has already reached grid parity, but in many instances solar PV remains competitive only in the future. In many cases where the cost of generating electricity from solar PV is quoted, the underlying assumptions and interpretations of certain definitions crucial to the calculation of the cost of PV were not made clear. As a result, there are varying prices for PV electricity which get published, depending on the author(s) of those studies (Bazilian et al., 2012).

The perception that the cost of solar PV is too expensive, according to Bazilian et al. (2012), is unfounded and misleading in today's terms. The cost of producing solar PV cells and modules has drastically reduced in the last 4 years. Between 2004 and 2008 the prices of PV

---

[9] Sun hours are determined by taking the total solar energy received throughout the day, and working out the number of hours that 1kW of solar insolation would have resulted in that said amount of energy received. This is done because solar panels are rated according to a 1kW insolation standard.

modules were between \$3.5 -\$4/Wp even as companies made continuous improvements to production and scale. This relatively unchanging cost of PV was due to a combination of German and Spanish tariff incentives which spurred the development of new solar projects, and a shortage in silicon supply (Bazilian et al., 2012). Once the subsidised projects were complete, the demand for PV globally did not decrease but rather stayed roughly as-is between 2008 and 2009, but there was an increase of 32% in available polysilicon (used to create solar PV cells) worldwide and as a result of the completed projects, companies were competing on prices, and the price of solar PV fell from \$4/W in 2008 to \$2/W in 2009 (Bazilian et al., 2012).

According to a solar module price report from solarbuzz.com (2012) there were 329 solar module prices that were below \$2/W, which amounts to 34% of the total of that study in March of 2012, while in the same month there were 89 price reductions and only 33 price increases. Overall this was a price decreasing trend. Figure 28 shows the price per watt for retail PV markets worldwide according to solarbuzz.com (2012); however the graph is not entirely consistent with the conclusions on price trends from Bazilian et al (2012). The discrepancy may be due to what Bazilian *et al.* (2012) has described as unclear definitions and underlying assumptions of pricing from various sources.

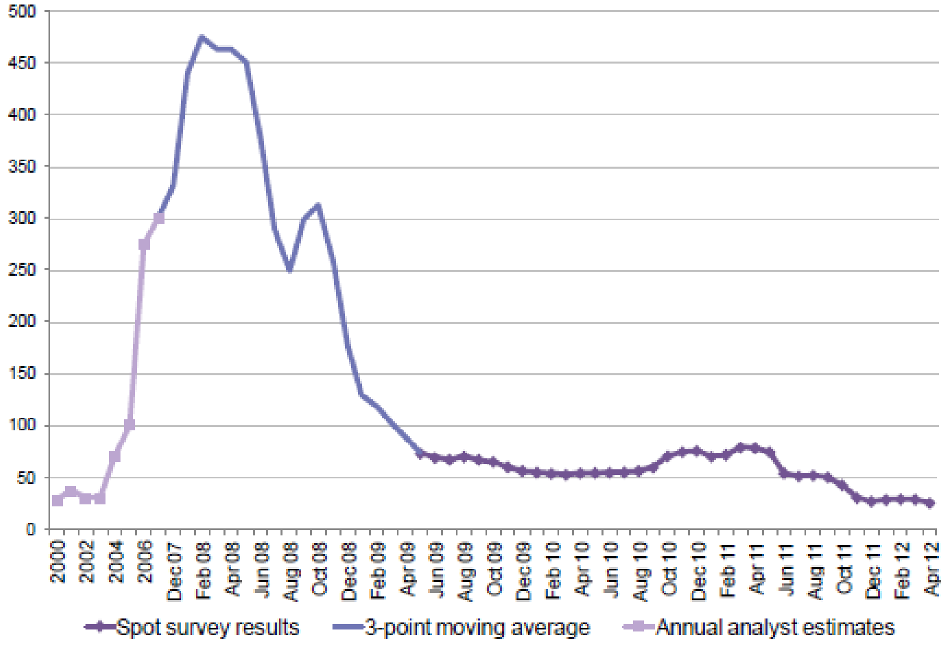


Figure 27: Spot price of solar grade silicon (\$/kg). Taken from (Bazilian et al., 2012).

Figure 27 shows the spot price of solar grade silicon in \$/kg between 2006 and 2012. The peak in 2008 is a result of a shortage coupled with the development of solar projects in

Germany and Spain as mentioned above. New polysilicon (solar grade silicon) companies were formed around this time due to the excessive prices and existing companies expanded their capacity. The silicon price reached a high of \$450 in 2008 and is around \$27 per kg as of 2012 (Bazilian et al., 2012; Fessler, 2012).

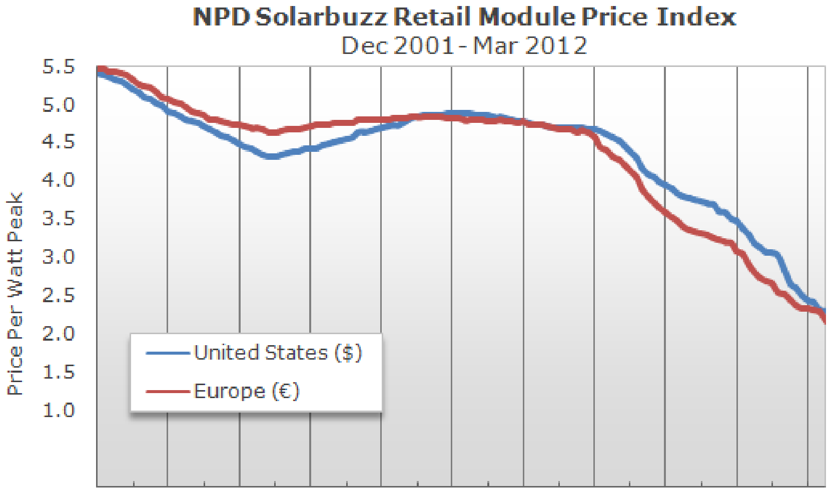


Figure 28: Price per watt of solar PV, showing global trends in the market for PV. Taken from (Solarbuzz, 2012).

3.1.4.3 *Learning rates and future prices*

There is usually a reduction in technology cost as the installed capacity increases; this is usually referred to as a learning rate or curve. This is a result of the process of manufacture and deployment becoming more efficient as people develop more experience with the processes (Nemet, 2006). For the United States, the department of energy (DOE) estimates that for PV this rate is around 20% reduction for every doubling in volume produced (Goodrich et al., 2012), while the IEA based on historical trends estimates the learning rate to be between 15% and 22% (IEA, 2010). Many observational studies have led to a log linear function being developed which best describes the observed data trends (Nemet, 2006). The form describing learning curves is given below (Nemet, 2006):

Equation 5 : The cumulative output

$$C_t = C_0 \left(\frac{q_t}{q_0}\right)^{-b}$$

Equation 6: the progress ratio

$$PR = 2^{-b}$$

Equation 7: the learning rate

$$LR = (1 - PR)$$

C_t is the unit cost at time t, C_0 is the initial cost, and b is the learning coefficient. The coefficient (b) is negative for reduction in costs. The progress ratio (PR) can be interpreted as the reduced cost per unit, while the learning ratio (LR) can be interpreted as the saved cost for an increase in cumulative output (Winkler et al., 2009).

The historic learning rates of PV modules are shown in Figure 29 and clearly show the silicon shortage around the 2004 to 2008 period leading to the high prices in silicon followed shortly by steep declines. Despite the silicon shortage and price increase in this period (2004 to 2008), due to the increase in demand for solar PV from the German and Spanish programs, the prices fell back to the trend line within a couple of years. Prior to the shortage, the learning rate was around 23% and around 19% after the shortage period, but on the whole the learning rate is around the 20% mark (Jelle et al., 20112).

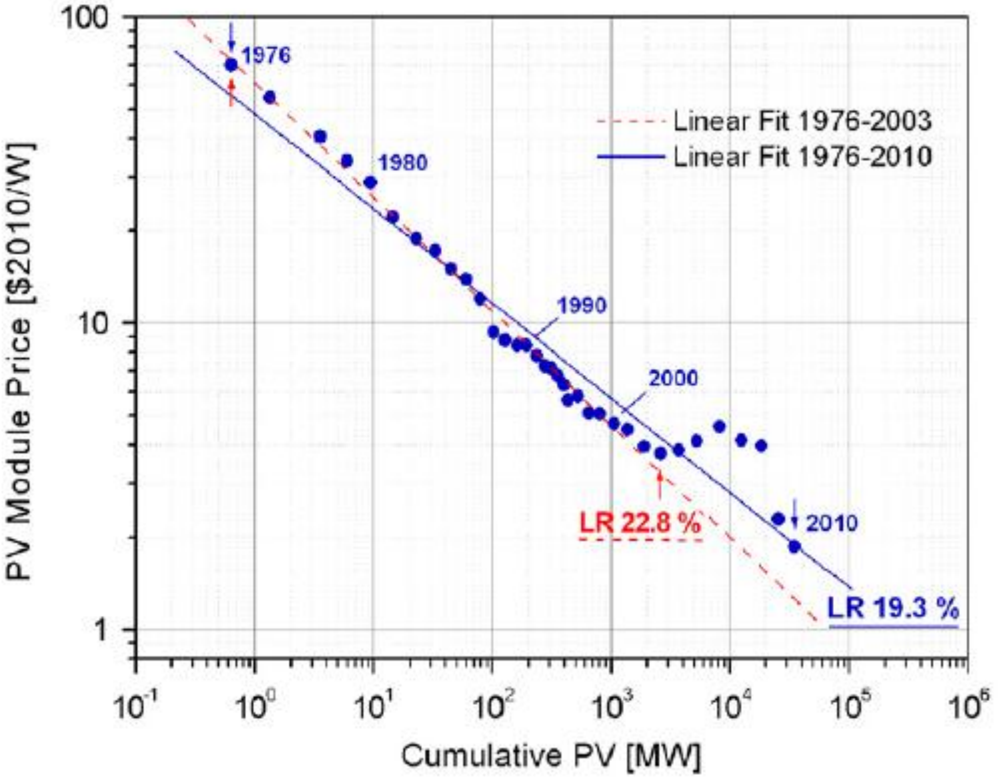


Figure 29: The learning curve for PV modules between 1976 and 2010. Taken from (Jelle et al., 20112)

The IRP2010 gives a learning rate for crystalline PV of 10% (Eskom, 2011a). This number was determined from external consultants in the solar PV field (Eskom, 2011a). The difference between the global learning rate and the IRP2010 learning rate lies with the information used by the consultants within the IRP2010 process - this may be country specific.

In this study, the learning rate as well as the year on year price decrease of crystalline solar PV will be based on the IRP2010 utility scale (250kW) panels. On average, the year on year price change is 7.1% from 2013 to 2020, and 3.1% from 2020 to 2030 according to the IRP2010 (see appendix 8.4). The reason for this change, is that it is not expected that at some point a limit is reached where external factors reduce the amount of new installed capacity, such as competition from alternative technologies, resource restrictions and so on (Winkler et al., 2009).

The overnight costs for PV in the IRP2010 are based on utility scale (250kW), but it is reasonable to assume that the year on year change of PV in retail is the same since these are inherently linked to the manufacture of the cells. Furthermore, the factory gate prices for PV in Europe decreased at about 10% between 2009 and 2010, while for the US this was 8.4%. Between 2010 and 2011 the reductions were 13% and 10% for Europe and the US respectively (IRENA, 2012). Thus a 7.1% year on year change as the IRP2010 states, is reasonably close to the values for Europe and the U.S.

3.1.4.4 Levelised costs of solar PV energy

The levelised cost of energy (LCOE) is a method used to determine the cost of producing energy while accounting for lifespan, efficiency and costs of fuel and other technical aspects of the technology in question. Thus, a levelised cost analysis of a solar PV system without a battery backup system is determined and compared with the cost of grid tied electricity, in order to determine the cost effectiveness of a solar PV system in South Africa.

According to an installer of solar PV systems (Lipschitz, 2012), the cost per watt in South Africa for installation is around R25/Wp as of 2012. According to the article by Rycroft (2012) the cost of a PV system is around R30/Wp which includes the panels, inverter and installation and auxiliary components necessary. The breakdown of these costs according to Rycroft is given in Table 6.

Table 6: The breakdown for the costs of a residential 2.5kW system in South Africa according to Rycroft (2012)

Component	**Cost**
12 ‘60M240’ solar modules	R45 000
SunnyBoy2500 inverter	R12 500
Balance of system (installation, cables etc.)	R20 000
Total	**R75 500 or R30/Wp**

Using the rate of decrease for the price of solar PV from the IRP2010 (see section 3.1.4.3) of 7.1% from 2012 to 2020, the LCOE for solar PV based on the initial prices from Lipschitz (2012) and Rycroft (2012) were determined using Equation 2. Figure 30 shows the LCOE for a 20% capacity factor.

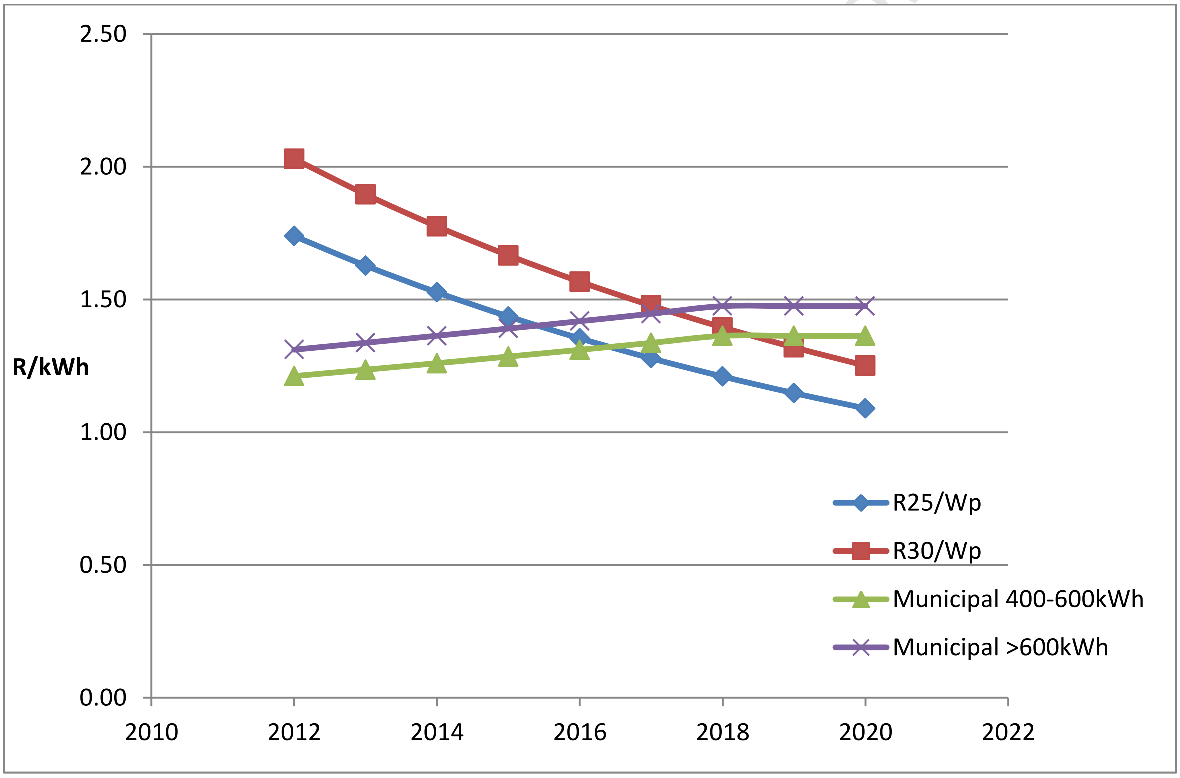


Figure 30: LCOE graphs for solar PV in South Africa compared with municipal provided electricity prices.

Figure 30 shows how much it costs to produce a single unit (1kWh) of electrical energy from a solar PV system considering the system over its lifetime (20 years) and includes: the cost of investing and installing, how much time the sun shines (the capacity factor), and the efficiency of the system.

The LCOE for electricity produced by solar PV indicates that by 2016 the cost of producing one unit of electricity will be less than the cost of buying municipal supplied electricity. South Africa has a fairly high capacity factor compared to other countries, according to the Sunshot vision Study (2012), for other countries a good location for rooftop PV results in a 15% capacity factor, while a study on PV rooftop systems in Egypt showed an 18% capacity factor (Elhodeiby et al., 2011).

The result of the LCOE analysis when compared with the grid provided electricity pricing as in Figure 30 shows that Solar PV will be cost competitive by 2018 for solar PV on a residential/urban site at R30/Wp, and as early as 2015 for R25/Wp.

This result is also comparable with the conclusion reached in the IRP2010 with regard to the cost competitiveness of solar PV in an embedded system. Solar PV becomes cost competitive between 2013 and 2015 depending on the initial cost assumptions and capacity factors.

3.1.4.5 Solar PV payback period for South Africa

Although PV systems can be expensive, there are potential new financing options in the near future which will aid in the financing of these systems. As part of Eskom’s national integrated demand management (IDM) programme to improve and promote energy efficiency in the country, funding from the IDM under the Standard Offer Programme (SOP) has been extended to small scale renewable energy sources (less than 1MW and more than 10kW). However, this is currently limited to stand alone systems which do not export to the grid, but the business or HH may still draw from the grid to supplement the EG system (Eskom, 2012b; Basson, 2012).

Using a range of prices for PV from installers of PV systems and using the solar radiation data for the various climatic zones in South Africa the payback period of a solar PV system in the residential sector can be determined (Rycroft et al., 2012; Hollander, 2012). The payback periods determined here are based on a house consuming 1100kWh’s per month on average (Eskom, 2011b); the municipal electricity rate is at an initial R1.31/kWh which is the rate for >600kWh/month users In the calculation the price of electricity from the grid increases at an average of 2%[10] (real terms where inflation is at 5.9%, adjusted for the 8% increase in tariffs granted by NERSA) for the first five years and constant thereafter until the 20th year (as per

---

[10] Calculated as (1+ 8%)/(1+5.9%) -1

the municipal tariff projections from section 3.1.2) and the solar panel efficiency declines at 0.5% per year (a common efficiency loss for PV systems).

This payback period comes from a strict net-metering system where there is no on-site storage system and all excess production is fed back onto the grid - the savings comes from the amount of electricity produced from the solar panels and is valued at the municipal electricity tariff. A net present value based analysis (this is described in more detail in the example following) is calculated using these numbers and a summary of this is given in the following table.

Table 7: The payback period for a solar PV system in South Africa in 2012, depending on average sun-hrs. per day and cost of solar PV for a house consuming 1100kWh/month

Payback period (years)			
	Sun hrs./day*:		
R/Wp (2012)	**5.67 (min)**	**6.136 (average)**	**7.02 (max)**
20	14	12	10
25	20	16	13
30	n/a	22	18

* note that sun hrs/day does not imply the number of hours there is sunshine. But rather the effective number of hours the sun would shine at standard testing conditions (1000W/m2)

Table 7 shows the payback periods for a solar PV system in South Africa for 2012 based on initial cost per watt-peak installed and the effective sun-hours/day based on the solar data for the climatic zones in South Africa (see section 3.1.4.1). The payback period for a solar PV net metering system without storage in South Africa various from 10 years for a R20/Wp and maximum of 7 sun-hrs./day, to >22 years at R30/Wp and a minimum of 5.7 sun –hrs./day which would make the system a liability at R30/Wp. These values were based on electricity tariffs of R1.31/kWh (>600kWh per month block) for 2012.

An example of investing in a solar home system:

A home using 1100kWh per month on average (Eskom, 2011b), invests in a solar PV system of 3.5kW at R25/Wp (Lipschitz, 2012), which reduces the consumption by 672kWh per month in the first year based on the average sun-hrs. for South Africa of 6.31hr/day, and an assumed maintenance cost of R500 per year. The analysis is done for a conservative 20 year life span, as most solar PV panels are rated for 20 to 25 year life spans (CleanEnergy, 2010), but the latter may not materialise due to harsh South African climate conditions including hail, thunderstorms and strong solar insolation. The electricity tariffs are the tariffs for the > 600kWh usage bracket[11] at R.1.31/kWh (see 3.1.1 and 3.1.2) and using a discount rate of 8%, the financial breakdown of the costs and savings are presented in Table 8 and Table 9 below.

The net present value (NPV) is determined by using the equation:

Equation 8: Net present value:

$$NPV = \sum_{t=1}^{T} \frac{C(t)}{(1 + r)^t}$$

Where, *C(t)* is the cash flow (positive or negative) at time *t, r* is the discount rate, and T is the total number of time periods (here it is 20 years). This equation takes into account the time value of money using the discount rate of 8% is used as the discount rate.

The result is an investor paying at least R855 per month for the system, while this system after 9 years starts to generate a net income for the investor. The calculation of the payback period is presented in appendix 8.2.

Table 8: the breakdown of the financial costs and savings for a 3.5kW system installed in South Africa

	Total Elec. required	Elec. costs (no solar)	Elec. savings (from solar)	Total import cost (net)	Solar costs (cost of system)	Total cost (solar house)
	Net consumption after PV production	Elec. Bill without solar @ 1100kWh/m	Monetary value of electricity produced by PV	Consumption minus solar production	Cost of system	Net cost to home
year	kWh	R/year	R/year	R/year	R/year	R/year
1	427.6	17306.0	10578	6728	104092	110819
2	431.0	17649	10734	6915	500	7415
3	434.3	17999	10892	7107	500	7607
4	437.6	18356	11053	7303	500	7803
5	441.0	18720	11216	7504	500	8004
6	444.3	19091	11381	7710	500	8210
7	447.5	19470	11549	7921	500	8421
8	450.8	19470	11491	7979	500	8479
9	454.0	19470	11433	8037	500	8537
10	457.3	19470	11376	8094	500	8594
11	460.5	19470	11319	8151	500	8651
12	463.7	19470	11263	8207	500	8707

---

[11] This rate is used and not the 400-600kWh bracket, since it is the rates which are being displaced.

	Total Elec. required	Elec. costs (no solar)	Elec. savings (from solar)	Total import cost (net)	Solar costs (cost of system)	Total cost (solar house)
	Net consumption after PV production	Elec. Bill without solar @ 1100kWh/m	Monetary value of electricity produced by PV	Consumption minus solar production	Cost of system	Net cost to home
year	kWh	R/year	R/year	R/year	R/year	R/year
13	466.9	19470	11206	8263	500	8763
14	470.0	19470	11150	8320	500	8820
15	473.2	19470	11095	8375	500	8875
16	476.3	19470	11039	8431	500	8931
17	479.4	19470	10984	8486	500	8986
18	482.5	19470	10929	8541	500	9041
19	485.6	19470	10874	8596	500	9096
20	488.7	19470	10820	8650	500	9150
total	**9172**	**381700**	**222384**	**159317**	**113592**	**272908**
NPV		**R 184 859**	**R 109 018**	**R 75 841**	**R 100 827**	**R 176 668**

Table 9: Summary of Table 8 above.

NET PRESENT VALUES	
Initial elec. bill	R 184 858.69
Solar elec. bill	R 75 840.76
Elec. savings	R 109 017.93
Solar costs	R 100 827.27
Total savings	**R 8 190.66**
Loan payments per month	-R 855.79
Loan payments per year	R -10 269.48

Note that the savings will go up each year as the price of buying solar PV comes down and electricity tariffs go up.

Cape Town net metering

The city of Cape Town has a residential tariff rate for approved net metering customers (CT municiaplity, 2012). These tariffs are currently (2012/13 VAT inclusive) at R11.21/day service charge and an energy charge of 104.5c/kWh for electricity purchased. Adding in the service charge fee and using the net metering tariffs, for a system in South Africa at R25/Wp at an average sun hours (see footnote 9 on page 46) per day of 6.31hrs, the payback period of the system would be approximately 15 years (using the same analysis from the example).

Using regular residential tariffs without a service charge fee per day, the payback period would be close to 14years. Also, one of the conditions of net metering in Cape Town is that the customer must be on average a net importer of electricity. The decrease in the tariff for net mtered users increases the payback period for the customers because they do not save, in Rands, as much as they would have. This in turn will decrease the rate of adoption for user to adopt the net metering systems. The only savings would come from reduced power consumption, and with the lower electricity rate customers will not install a system beyond minimum size.

3.1.5 Net metering scenarios

The scale of capacity for embedded generation ownership in the country is largely determined by the market penetration and population size and wealth. Market penetration is directly proportional to the payback period of the embedded generation system installed as discussed in section 3.1.3. To understand how net metering may affect the future planning of the energy sector in the country, a range of capacity projections will be used to determine the extreme outcomes or scenarios of the effects on the planning of the energy sector. To determine a projection of net metering capacity into the future, a lower investor entry and a higher investor entry level need to be determined using the information from the previous sections and an analysis of the household sector.

The discount rate used in this study and modelling work is the same for the IRP2010, from which all costs are derived, at 8% (Eskom, 2011a).

3.1.5.1 Suitable households

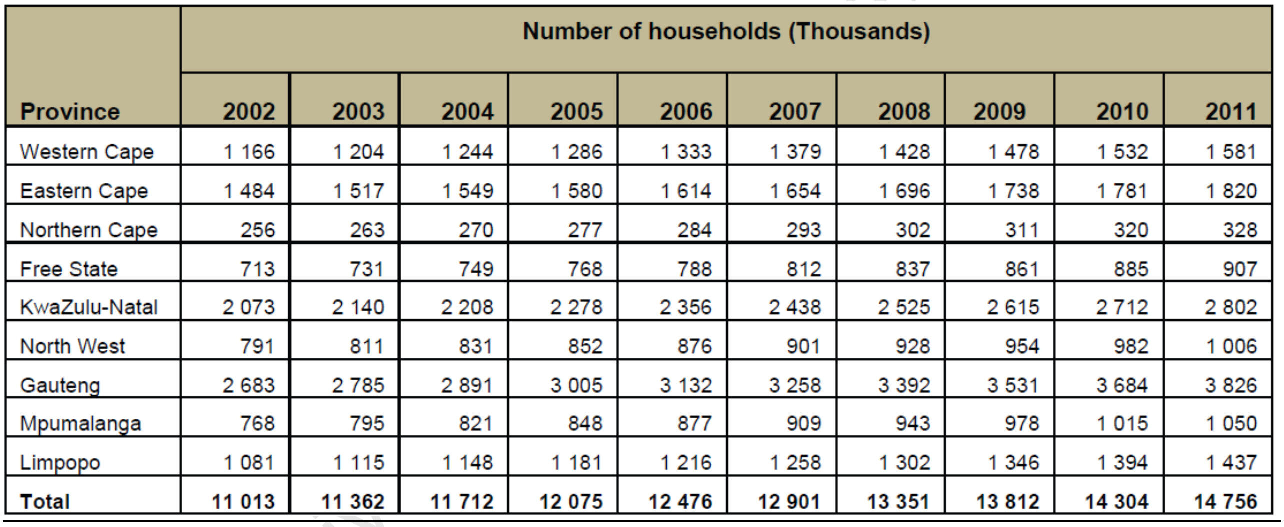
Studies looking at the adoption of new technologies show that the economic situation of the potential buyers plays the most important role in making a decision on whether to invest or not in a new product (Drury et al., 2010; Faiers et al., 2007). Using data collected in a community survey study (StatsSA, 2007), the number of households that are able to invest in PV systems will be estimated by cross referencing HH structure type and HH income levels. In South Africa, there are a number of home structures that are physically unable to support PV systems, such as shacks and traditional homes, and more importantly a lot of the households do not have the income for such an investment.

The data for dwellings in South Africa based on the community survey (2007) is shown in Table 10 and according to the community survey; there was a total of 12.5 million households in South Africa in 2007. According to the General Household Survey (GHS) (2011), for the year 2007 there were 12.9 million households in South Africa. The number of households by province for the country is shown in Table 11. The slight discrepancy in data between the community survey and the GHS lies in that the GHS uses a headship ratio methodology to estimate the total number of households, while the Community survey used data obtained by more than 245 000 households (StatsSA, 2011).

Table 10: The number of HH by structure type based on the community survey 2007 (StatsSA, 2007)

Type	Dwelling type	Number of dwellings (2007)
1	House or brick structure on a separate stand or yard	7406798
2	Traditional dwelling/hut/structure made of traditional material	1459379
3	Flat in block of flats	595943
4	Town/cluster/semi-detached house (simplex	337374
5	House/flat/room in backyard	364038
6	Informal dwelling/shack in backyard	590195
7	Informal dwelling/shack NOT in backyard	1214235
8	Room/flatlet NOT in backyard but on a shared property	115360
9	Caravan or tent	15114
10	Private ship/boat	4253
11	Workers' hostel (bed/room)	360150
12	Other	37765
	total	**12500604**

Table 11: The number of households by province for South Africa. Taken from GHS2011.



Province	Number of households (Thousands)									
	2002	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**
Western Cape	1 166	1 204	1 244	1 286	1 333	1 379	1 428	1 478	1 532	1 581
Eastern Cape	1 484	1 517	1 549	1 580	1 614	1 654	1 696	1 738	1 781	1 820
Northern Cape	256	263	270	277	284	293	302	311	320	328
Free State	713	731	749	768	788	812	837	861	885	907
KwaZulu-Natal	2 073	2 140	2 208	2 278	2 356	2 438	2 525	2 615	2 712	2 802
North West	791	811	831	852	876	901	928	954	982	1 006
Gauteng	2 683	2 785	2 891	3 005	3 132	3 258	3 392	3 531	3 684	3 826
Mpumalanga	768	795	821	848	877	909	943	978	1 015	1 050
Limpopo	1 081	1 115	1 148	1 181	1 216	1 258	1 302	1 346	1 394	1 437
Total	**11 013**	**11 362**	**11 712**	**12 075**	**12 476**	**12 901**	**13 351**	**13 812**	**14 304**	**14 756**

Of the types of structures listed in Table 10, only the types 1, 3, 4 and 5 will be considered when estimating the total number of households that are physically suitable for PV systems. It is assumed these will make up the majority of the households capable of being fitted with a solar PV system due to them being a more formal structure type.

Using an assumption that households earning more than R12 000 per month can invest in solar rooftop PV panels through a shared arrangement with nearby neighbours or in a better configuration; an apartment block (Lipschitz, 2012), these households will make up the higher penetration level scenario. Using this assumption, the total number of households suitable for solar PV systems in the country for the year 2007 can be determined using the data from the community survey for housing structure types, 1, 3, 4 and 5 and are listed in Table 12.

A higher income level of R25 000 per month HH class can be seen as the lower penetration level (there are less households earning this much). The R855 per month loan payment for a 3.5kW system at R25/Wp (see example in section 3.1.4.5) accounts ≈3% of the monthly income, and is half the 6% expenditure estimate for energy of high income households made by Adam (2010) – making it financially viable. Table 12 below, gives a summary of the potential number of households (HH) that would invest in solar PV based on this analysis.

Table 12: The number of suitable households for solar PV systems in 2007. Data from Community survey 2007 (StatsSA, 2007)

HH structure	**Earning > R25k/m**	**Earning >R 12k/m**
House or brick structure on a separate stand or yard	937969	1628624
Flat in block of flats	96897	187085
Town/cluster/semi-detached house (simplex	106120	155948
House/flat/room in backyard	20907	49006
TOTAL	**1161893**	**2020663**
% of all suitable structures (all income levels)	13.35%	23.21%
% of all HH structures	9.29%	16.16%

The total of 1.16m suitable households earning more than R25 000 per month in 2007 is approximately 13.4% of the total number of suitable dwellings (all the income groups for HH types 1,3,4, and 5), and constitutes about 9% of the total number of households in South Africa at the time. At the lower income level bracket of R12 000 per month, the total number of suitable dwellings jumps to 23% and constitutes 16% of all HHs in South Africa.

A total number of HH's in South Africa that can potentially invest in solar PV at home has now been established, and the ground work for the establishment of a projection of installed solar PV in the country has been done.

To determine the range of potential capacity (MW) of rooftop PV in the residential sector of the country throughout a period from 2012 to 2030, the total number of suitable HH for the period needs to be determined. Using the information derived in Table 12, the projections for both R12 000 or more per month income HH and R25 000 or more per month income bracket HH's are determined using the initial starting value in Table 12 for the year 2007 and projecting this through to 2030. The HH growth rate are based on the average growth rate for the total number of households in South Africa between 2007 and 2011 based on the information from the GHS (StatsSA, 2011).

The average growth rate of households in South Africa is 3.4% based on the GHS data. Using the 2007 to 2011 GHS data, the estimated number of households for 2012 is 15620 thousand households (all types of households).

South Africa is a developing country, and has a large portion of the population in the lower income level brackets. As the country develops it is expected that there will be a migration of lower income level to higher income level in the populace. The study done by van Aardt (2010) on the income levels of South Africa shows that there is an average annual growth[12] of 1.7% in income for persons earning more than R8 000 and less than R25 000 per month. It will be assumed that in an increased growth scenario, the migration of households earning R12 000 or less to households earning R12 000 (and likewise for R25 000/m HHs) or more is approximately equal to this income growth rate of 1.7%.

The assumptions for the scenarios can be compiled together to form the HH growth cases. These were used to estimate the number of solar PV suitable households from 2012 (current) through to 2030.

A summary of the scenarios for the HH's used for net metering capacity projections:

- Reference HH growth: The total number of households in South Africa grows at 3.4% per year starting at 15260 thousand in 2012
- ≥R25k HH: The number of households earning R25k per month or more grows at a rate of 3.4%. This is done by using the share of these suitable households to the total number of HH (9.29%).
- ≥R25k HH increased growth: The number of HH earning more than R25k per month grows at a rate of 3.4% + 1.7%.
- ≥R12k HH: the number of households earning more than R12k per month grows at a rate of 3.4%. This is done by using the share of these suitable households to the total HH projection (16.16%).
- ≥R12k HH + increased growth: The total number of households earning more than R12k per month grows at a rate of 3.4% + 1.7%.

Figure 31 shows the reference HH projection of all HH's in South Africa, while Figure 32 shows the scenarios without the reference for clarity. If all HH's earning above the R12 000 a month income bracket were included there is a potentially large market for rooftop PV and

---

[12] The author does not indicate if this is above inflation. Here, it is assumed that inflation is inherent in his work.

net-metering systems. The higher growth rates can be interpreted as the growth in the middle bracket in South Africa. It should be noted that the population growth rate of South Africa is around 1% per year, according to the GHS2011. Although the HH growth rate is higher than the population growth rate, it is reasonable to assume that as people move into the middle income bracket there will be on average fewer people per HH than in lower income brackets.

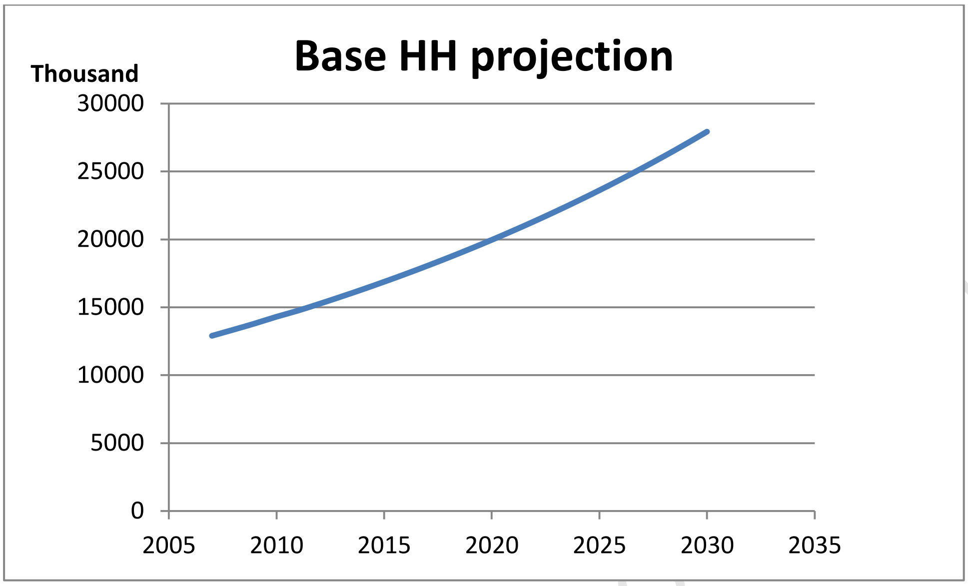


Figure 31: the base projection of households in South Africa. The growth rate is 3.4% derived from information in the GHS2011.

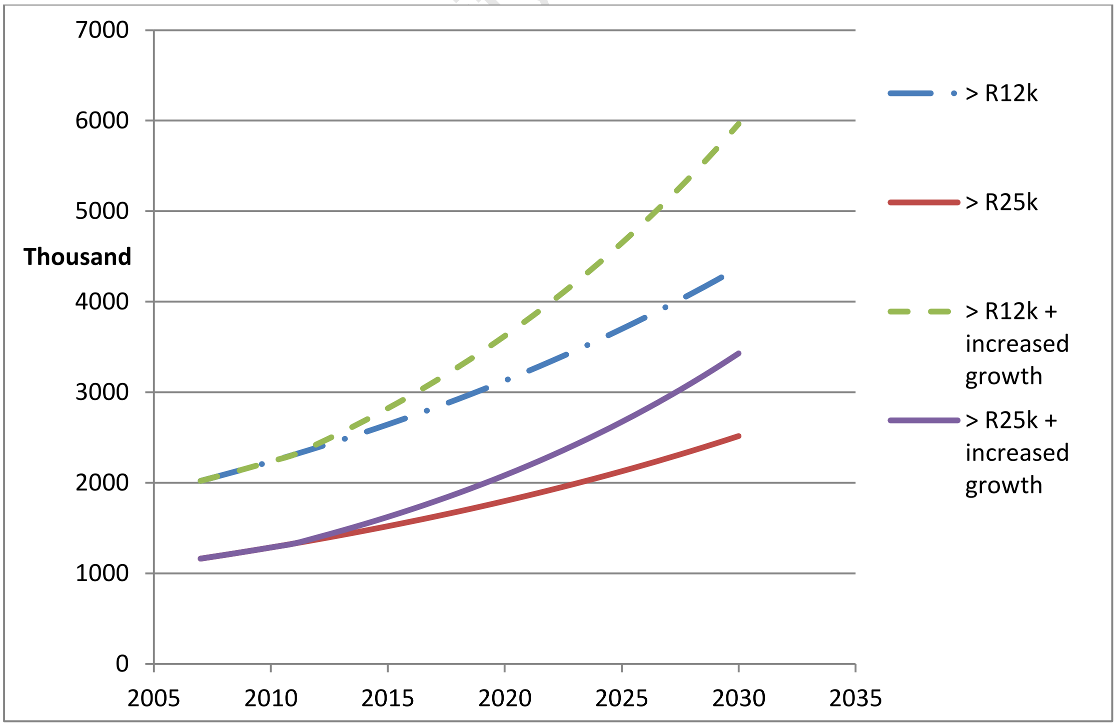


Figure 32: The projected number of suitable households for rooftop PV installation by income level.

Using an average rooftop PV installation size of 3.5kW, the total rooftop PV market in MW is shown in Figure 33. This shows the total maximum PV that could be installed – i.e. if every HH in the income brackets given above, that were able to structurally fit a PV system to their roof, did so.

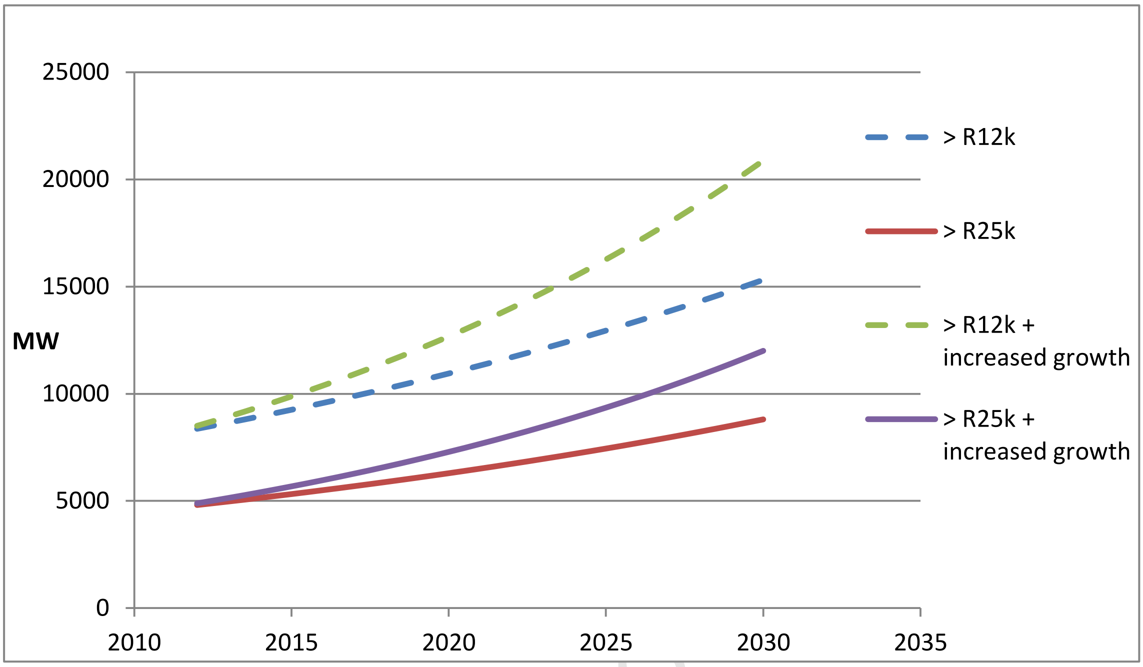


Figure 33: The total maximum technical potential of Rooftop PV in South Africa, where the average of 3.5kW is used for the size of a typical HH. This is a mere representation of the maximum allowed based on the HH structure and income levels.

The maximum theoretical potential of installed PV has been estimated. However, as discussed in section 3.1.3, the financial investment will deter many people from the ‘product’, and the payback period was found to determine the maximum market share of all those that will at some point in time, invest in the product.

The payback period will change in time because of decreasing solar PV prices as established in section 3.1.4.3, so to simplify, it will be assumed that the payback periods will be stepwise; Table 13 shows the breakdown of the solar PV prices, their payback periods, as well as their associated total share of the market. These numbers were based on the weighted average electricity tariffs for homes consuming between 400 and 600 kWh per month. Large homes consume on average 1100kWh per month (Eskom, 2011b), with the installed PV system in the home, the consumption will drop from 1100 to the 400 to 600 kWh usage bracket per month depending on the PV system size and location – here it is based on 3.5kW which produces 672kWh per month on average based on the solar data for South Africa in section 3.1.4.1.

Table 13: Market share for different payback periods based on a decreasing solar PV price.

Period	**R/Wp (alt.)***	**Avg. Payback period (alt.)***	**Avg. Max market share** (alt.)***
Units:	2012 Rands	Years	%
2012-2014	25 (30)	11.67 (15.33)	3.02 (1.01)
2015 - 2019	19.8 (23.75)	7.8 (9.6)	9.63(5.61)
2020-2024	13.8 (16.60)	6 (7)	16.53(12.25)
2025-2030	11.8 (14.1)	5 (6)	22.31 (16.53)

*****The alternative is an initial price per peak watt based on Rycroft (2012), while the former is based on Lipschitz (2012). ** Market shares determined by the approximation in equation 4.

Using the maximum market share of a solar PV system based on the payback period factor , Figure 34 and Figure 35 show the maximum potential for rooftop solar PV in South Africa for R25/Wp and R30/Wp. These figures show the actual realistic market for solar PV – it is simply the maximum technical potential (Figure 33) adjusted for the total market share shown in Table 13. Figure 34 and Figure 35 represent the maximum market size of all households that at some point in time will invest in solar PV systems.

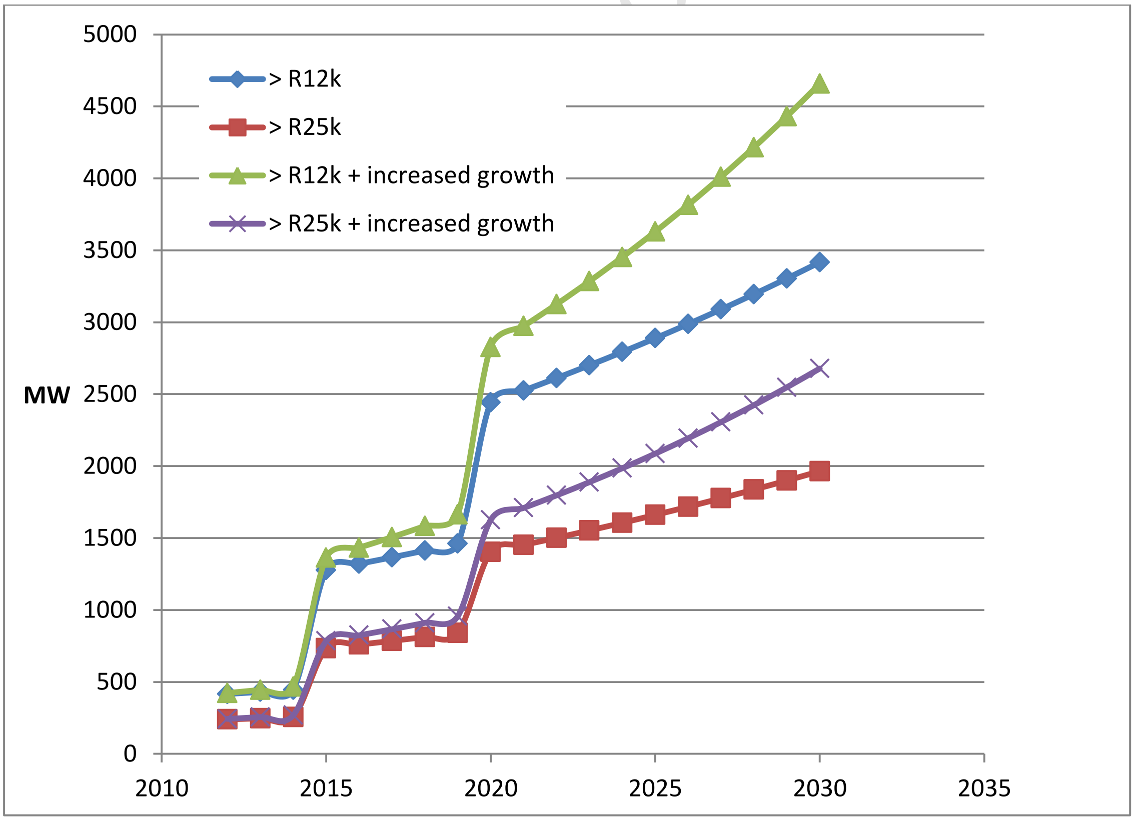


Figure 34: The maximum rooftop solar PV market in South Africa when factoring in the effect of the payback period for solar PV at R25/Wp in 2012. See Table 13 on the breakdown of the market fraction shares. This graph shows all the households that will consider buying into rooftop PV at some point.

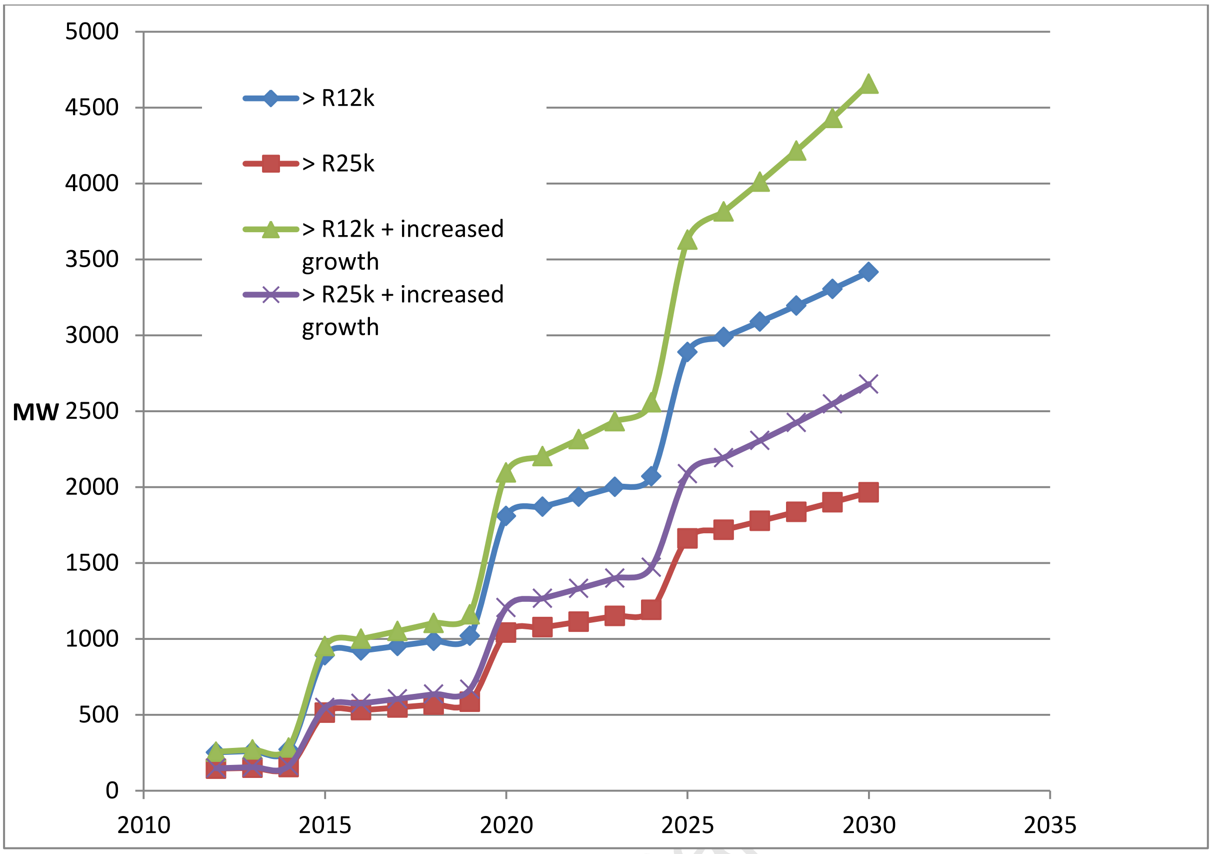


Figure 35: The maximum rooftop solar PV market in South Africa when factoring in the effect of the payback period based on R30/Wp in 2012.

The market for the investment into solar rooftop PV has now been established. What remains is to determine the actual number of investments for each year based on the market projection. The adoption or otherwise termed 'diffusion' of the solar PV system can be determined using the Bass Model as described in section 2.3.

To model the diffusion of solar PV into the market, the Bass model is used with the innovation and adoption parameters p and q respectively from the small market averages in Table 1. It is assumed that the relatively small markets that the parameters where derived from, are reasonably close to the market of South Africa based on the market size (m). The small market parameters do, however, differ in that the markets in the study by Guidolin *et al.* (2010) that are used to determine the parameters are already somewhat developed, while in South Africa the maturity level is unknown. This will be discussed further, in the following section.

3.1.5.2 Total installed solar rooftop PV capacity projections

The total installed rooftop PV in South Africa for the R25/Wp and R30/Wp prices of solar PV are shown in Figure 36 and Figure 37 respectively - these estimates are derived using the

Bass Model on the total maximum potential for Figure 34 and Figure 35. The grid tie electricity tariffs (municipal) used in these calculations are the projected tariffs of households using between 400 and 600kWh per month as in Figure 23 of section 3.1.2.

Since there is no data, available currently, for the installed solar rooftop PV in South Africa, using the Bass model parameters from an analogous study in an analogous market can be used (Mahanjan et al., 1990). Using the parameters for $p = 0.000807$, $q = 0.248121$ from the small market averages in Table 1, m for the market size (MW) from Figure 34 and Figure 35, and setting $d = 0$ the total projected capacity after considering actual adoption of the product is given in Figure 36 and Figure 37.

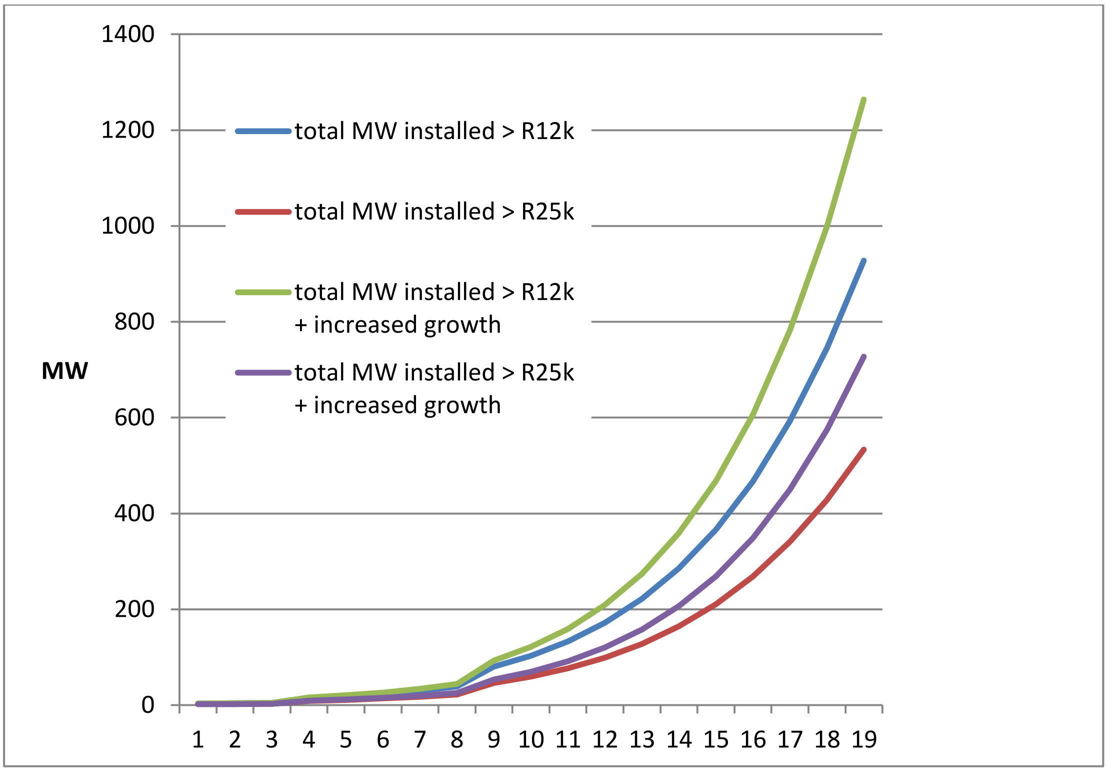


Figure 36: The total installed solar rooftop PV systems based on an initial R25/Wp in 2012.

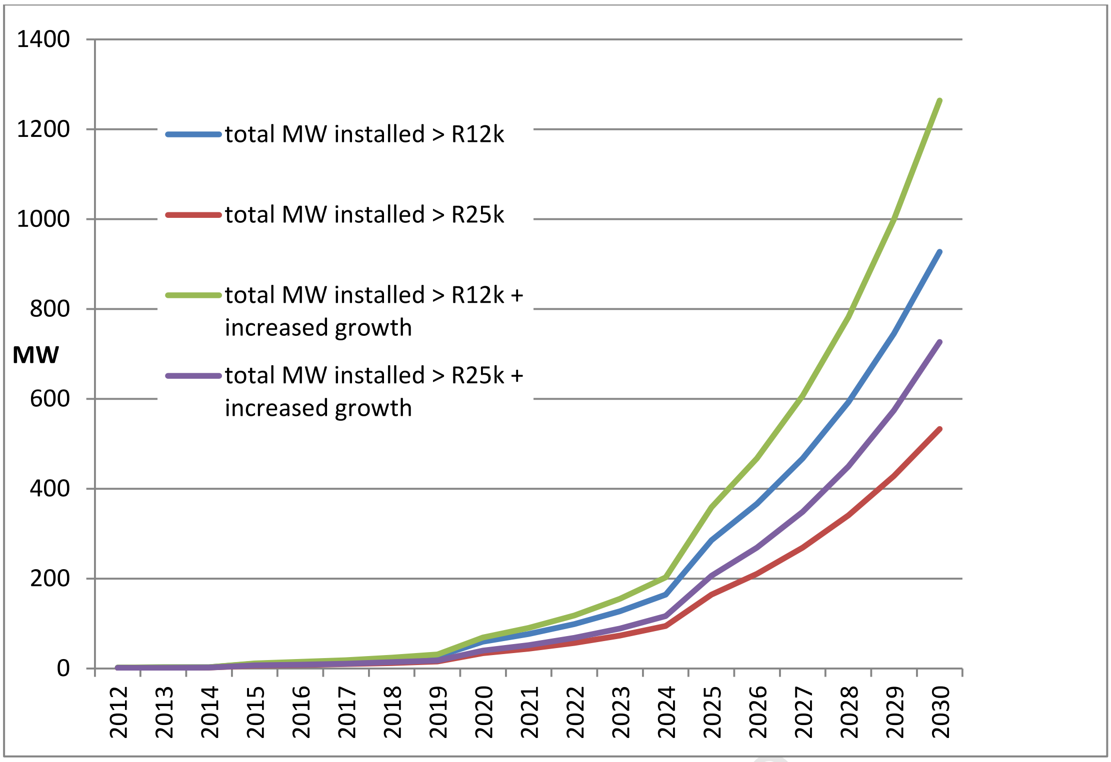


Figure 37: The total installed rooftop solar PV based on an initial R30/Wp in 2012.

Figure 36 and Figure 37 are based on R25/Wp and R30/Wp in 2012, with the same year on year decrease in cost, and both have the same results by 2030, this is due to the fact that the payback periods are too similar to make any large difference in the projection.

In summary; the figures above showing the projected rooftop PV capacity were based on: the total number of suitable households earning specified income levels and their associated growth rates, then reducing this by determining the maximum number of households that would be willing to invest based on the payback period of the solar PV system, and then finally considering how these potential households adopt the PV based on the market diffusion and adoption model -the Bass model. This process is highlighted in Figure 38.

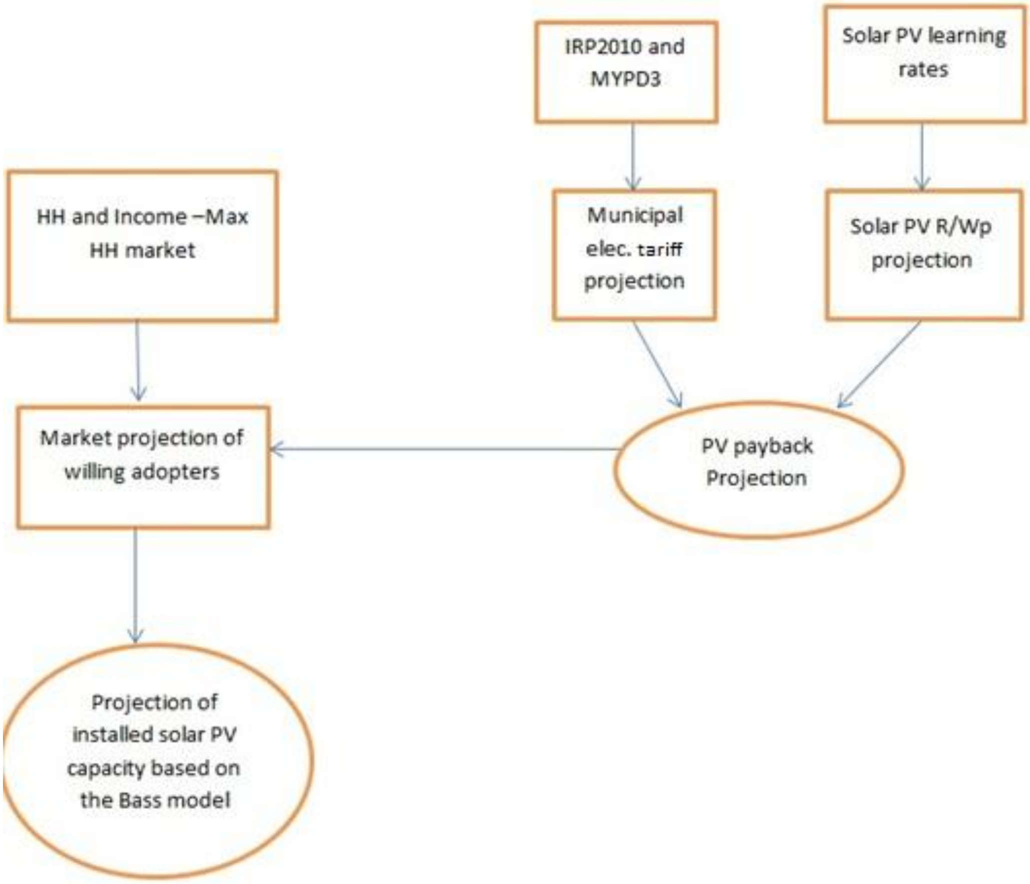


Figure 38: The process of determining the projections for installed solar PV in South Africa.

The results of this analysis on the total installed size of the solar market indicate quite a large potential by 2030, with a potential size between 500MW and 1200MW in 2030 depending on the initial assumptions.

There is no information regarding the maturity of the market in South Africa, but there is currently an effort with government departments to obtain information on the current market (size) of rooftop PV in South Africa (KZN energy, 2012). A sensitivity analysis on the market maturity parameter (d) for market penetration levels corresponding to incomes of >R25 000 and >R12 000 per month HH's with increased growth rate is shown in Figure 39.

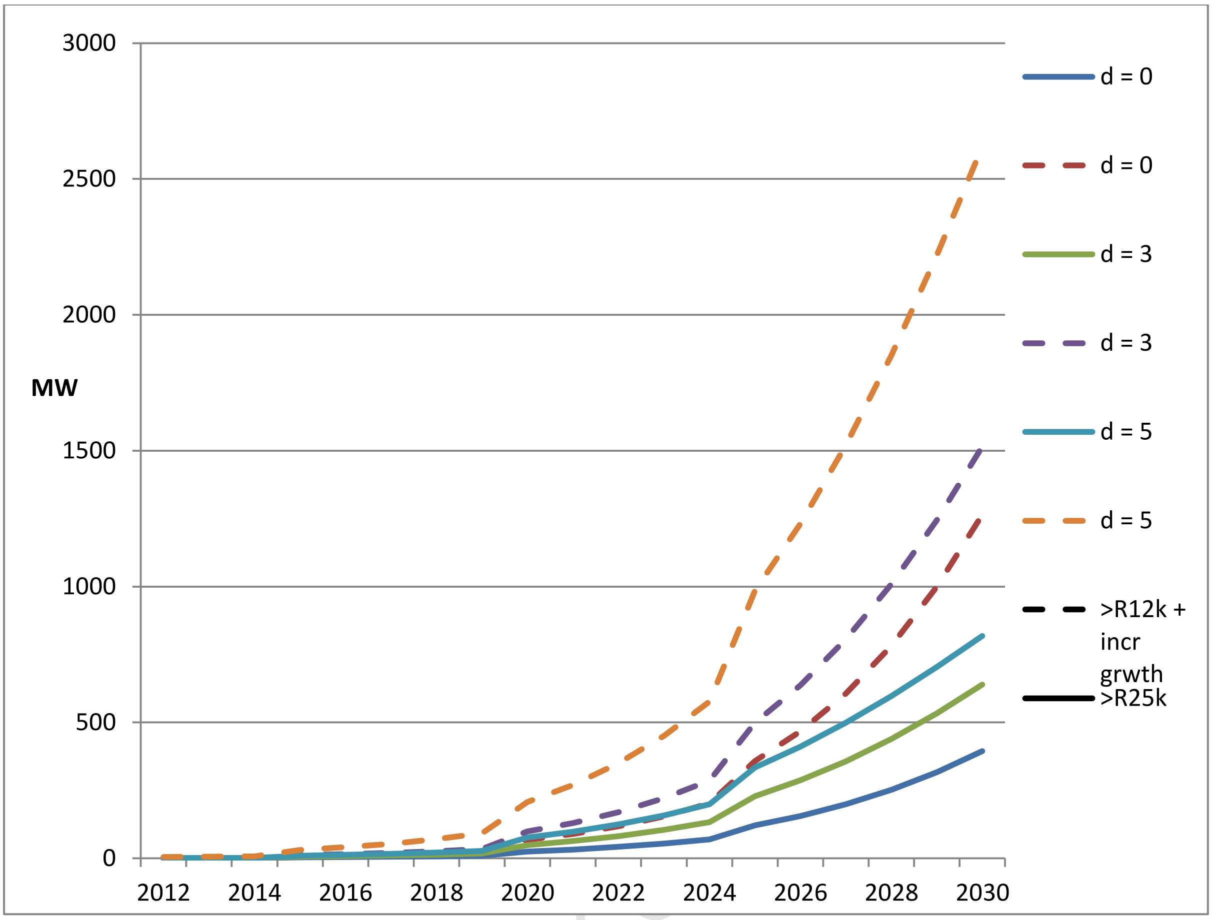


Figure 39: penetration levels of rooftop solar PV for varying market maturity levels for parameter *d =0, 3, and 5*. Solid lines are for the R25k or more groups, while dashed lines are for the R12k a month or more.

The analysis on the market maturity levels indicates a large range in installed capacity toward the end period at 2030 depending on the parameter (d). With no market maturity d = 0 the capacity grows to between just less than 395MW and just over 1.2GW by 2030, while an intermediate market maturity d= 3 results in 638MW and 1514MW by 2030. A 'mature' market d=5 results in a large impact of between 818MW and 2.6GW by 2030.

The maturity parameter *d* can have a value of zero, but the equation would remain non-zero, meaning that even in the case of zero market maturity there is some initial capacity. This is highlighted in Table 14.

Table 14: The starting year (2012) estimated installed solar rooftop capacity (MW) for varying market maturity levels (d).

Scenario/market maturity (d)	**0**	**3**	**5**
	Installed rooftop PV capacity in 2012 (MW)		
>R12k + incr. growth	1.9	1	4.5
>R25k	0.4	0.6	0.8

Table 14, shows the differences in the starting year installed capacity of solar rooftop PV in South Africa for various market maturity levels in 2012. The lowest growth path shows a mere 2.5MW of installed capacity in 2012, while the largest growth path shows a little more than 7.4MW of installed solar rooftop PV in South Africa in 2012. Since there is no indication from studies or data of the total size of the solar rooftop market at present, the Bass model can be used to estimate the initial value, although this depends on assumptions of the market maturity level (Lipschitz, 2012; KZNenergy, 2012).

To determine the potential range of impact that solar rooftop net metering will have in South Africa, low and high penetration scenarios based on the above analysis will be used. The municipal electricity tariffs used for both high and low penetration cases are those for users consuming between >600kWh per month (this is because the payback period will be determined based on the displaced usage block which would in most cases put the users in the >600kWh bracket).

High penetration:

The lower price for solar PV will be used at R25/Wp based on Lipschitz (2012) starting in 2012 and a subsequent year on year decrease based on the IRP2010 price changes in 3.1.4.2 at 7.1% from 2012 to 2020 and 3.1% until 2030. The market maturity parameter (d) used for the adoption S-curves was assumed to be d = 5 years – based on the study by Guidolin (2010) showed 10 years for the small markets, however in South Africa there is no data to support 10 years and electricity prices were very cheap until the last 3 years, meaning that investing in solar PV was not very economical until recently. The income group most likely to adopt the technology will comprise of the households earning R12 000 per month or more and have an increased growth rate due to migration of lower income groups to the group earning more than R12 000 per month.

Low penetration:

The initial cost per watt will be assumed to be R30/Wp based on Rycroft's price of PV (2012). The income group will be predominantly the households earning R25 000 per month or more without any increased growth rate in households due to income group migration, and the growth is at the base HH growth rate of 3.4%. Also, the market maturity parameter will be assumed to be zero – households have not considered investing in solar rooftop PV prior to 2012 based on economic recession reasons or the like. The zero market maturity parameter does not mean that the market is zero, but simply much less evolved.

Table 15: Summary of low and high penetration level scenarios for rooftop solar PV.

Scenario	**R/Wp (2012)**	**Municipal residential electricity tariffs**	**Income group**	**Market maturity (d)**
High	25	R1.31/kWh (>600kWh/m)	>R12k + increased growth	5
Low	30	R1.31/kWh (>600kWh/m)	>R25k	0

Using these criteria in Table 15, the range of projected installed rooftop solar PV capacity is given in Figure 40 below.

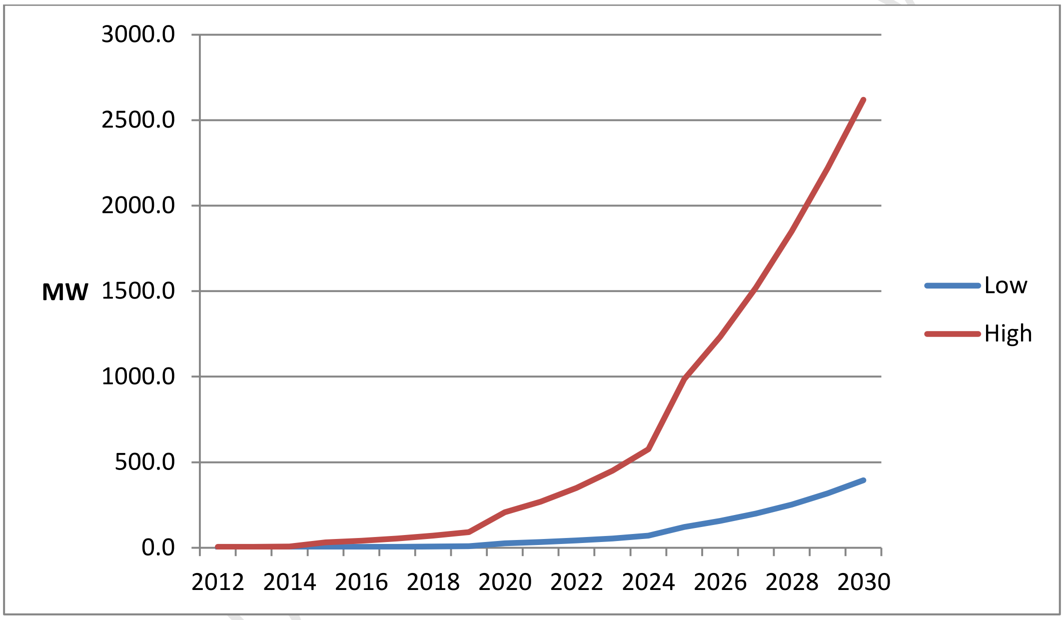


Figure 40: The high and low penetration scenarios for rooftop solar PV and net metering in South Africa.

The numeric values are presented in Table 16 :

Table 16: The numeric data in MW for the total installed rooftop PV in the residential sector.

	Low	**High**
2012	0.4	4.5
2013	0.4	5.8
2014	0.5	7.5
2015	3.6	31.2
2016	4.4	40.8
2017	5.6	53.5
2018	7.1	70.3

	Low	High
2019	9.0	92.2
2020	25.3	207.0
2021	32.5	270.0
2022	42.0	350.2
2023	54.2	451.4
2024	69.9	576.8
2025	121.6	985.1
2026	156.0	1232.0
2027	199.1	1520.7
2028	252.4	1850.6
2029	317.4	2218.6
2030	395.1	2619.6

3.1.5.3 Production from net metered solar PV

By using the capacity factor calculated in 3.1.4.1, the effect of elongation of the sun's movement through the sky is accounted for since the capacity factor is calculated using insolation data on a fixed tilted plane for the respective metro areas in the climatic zones as discussed in section 3. Using the capacity factor, the solar insolation intensity can be approximated[13] by using a sinusoidal curve centred over the peak solar hour (around 1pm). The approximation is given as;

Equation 9

For $t < PeakT$

$$S = cos\left(\frac{PeakT - t}{PeakT - StartT} \times \pi/2\right)$$

Equation 10

For $t > PeakT$:

$$S = \cos\left(\frac{t - PeakT}{EndT - PeakT} \times \pi/2\right)$$

Where, *PeakT* is the hour where there is maximum insolation, *StartT* is the first hour of sunlight, and *EndT* is the last hour of sunlight and are summarised in Table 17. The graph of this approximation is given in Figure 41. The choice of seasons is for suitability with the model in the next section.

---

[13] Thanks to Bruno Merven for help with this formulation

Table 17: Definitions of solar hours for solar rooftop PV

	StartT (am)	***PeakT (pm)***	***EndT (pm)***
Pre winter	6	13	18
Winter	7	13	18
Post winter	6	13	18

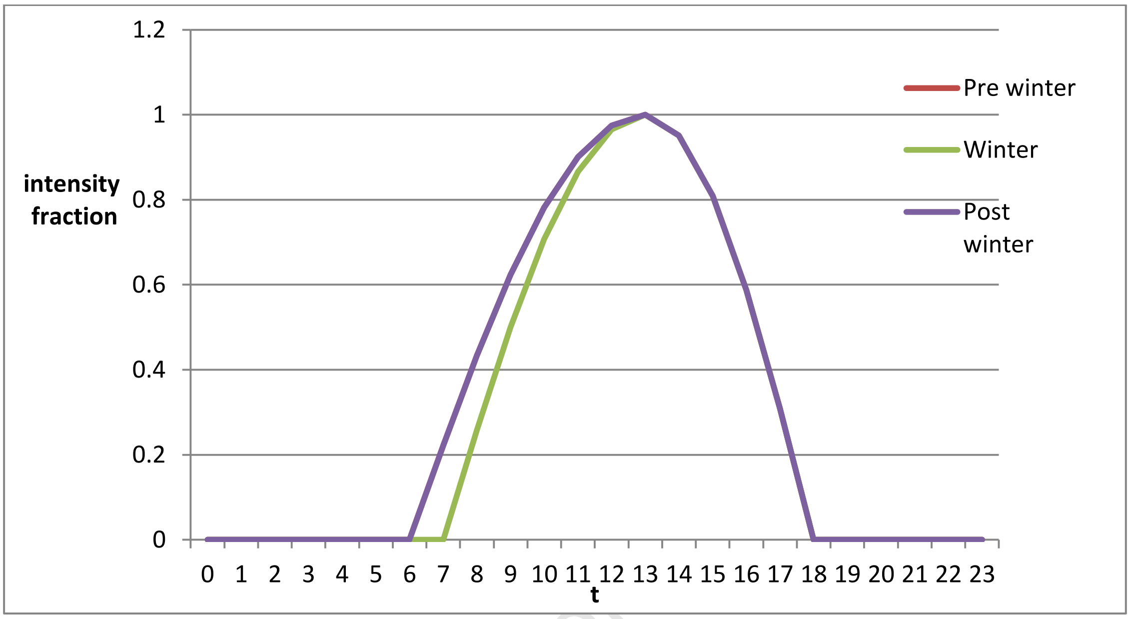


Figure 41: The solar insolation intensity approximation for each hour

The losses incurred by transmission and distribution systems mean that any unit of electrical energy produced at the location of consumption displaces more upstream of transmission. The transmissions and distributions systems of South Africa have 96.2% and 90% efficiency of operation respectively. As Table 18 shows, 1kWh of electricity produced by a solar PV system in the residential sector has 13.4% more ‘value’ than the same produced at a large coal plant.

Table 18: The extra value of electricity generated by solar PV in the residential sector

	Efficiency %	Electricity	
At consumption:	-	1	kWh
At distribution	90.0	1.11	kWh
At transmission	96.2	1.16	kWh
total loss:		13.4	%

4 Model methodology

To understand the effects of net metered solar rooftop PV in the residential sector of South Africa, an energy model of the electricity sector of South Africa was created. The energy model was created in the open source software OSeMOSYS.

4.1 Linear optimisation

Linear programming is the method of maximising or minimising a linear function which is constrained by a set of other linear functions. The terminology ‘linear optimisation’ is for this reason, synonymous with the term linear programming.

There are two main types of optimisation; standard maximisation and standard minimisation as classified below (taken from (Ferguson, 2012)).

In general, given an m-vector $b = (b_1, \dots, b_m)^T$ and an n-vector $c = (c_1, \dots, c_n)^T$ and an m by n matrix of real numbers:

$$A = \begin{pmatrix} a_{11} & \cdots & a_{1n} \\ \vdots & \ddots & \vdots \\ a_{m1} & \cdots & a_{mn} \end{pmatrix}$$

Standard maximisation: find the n-vector $x = (x_1, \dots, x_n)$ to maximise $c^T x = c_1 x_1 + \cdots + c_n x_n$, subject to the constraints:

$$a_{11} x_1 + \cdots + a_{1n} x_n \leq b_1$$

$$.$$

$$.$$

$$a_{m1} x_1 + \cdots + a_{mn} x_n \leq b_m$$

And $x_1 \geq 0 , \dots . x_n \geq 0$.

Standard minimisation: find the m-vector $y = (y_1, \dots, y_m)$ to minimise $y^T b = y_1 b_1 + \cdots + y_m b_m$, subject to the constraints:

$$y_1 a_{11} + \cdots + y_m a_{m1} \geq c_1$$

$$.$$

$$.$$

$$y_1 a_{1n} + \cdots + y_m a_{mn} \geq c_n$$

And $y_1 \geq 0 , \dots . y_n \geq 0$.

Mathematically, a set of theorems and proofs have been developed which have successfully led to the development of computer algorithms which enable optimisation through numeric matrices of very large systems. One cannot programme a computer to graph a multiple axis (one axis for each variable) on which a feasible solution may be drawn. The 'simplex method' is a common way for solving numerically, linear programme problems and is based on the Pivot Madly Method which in essence involves using proven theorems to re-write a tableau of the all the variables and constraints and re-arranging certain elements of the tableau in a particular routine until a solution is found [14] (Ferguson, 2012).

A basic example of a linear programming problem (from http://www.math.ucla.edu):

One needs to find numbers x_1 and x_2 that maximise the sum x_1 +x_2 subject to constraints x_1 ≥ 0 and x_2 ≥ 0 and

$$x_1 + 2x_2 \leq 4$$

$$4x_1 + 2\,x_2 \leq 12$$

$$-x_1 + x_2 \leq 1$$

The sum x_1 + x_2 that is required to be solved for when considering all the given constraints is called the objective function (Ferguson, 2012). Note that all constraints are linear (there are no exponents).

---

[14] See the paper by Ferguson (2012) or similar material for details on the simplex method which are mathematical in nature and are beyond the necessity of this study.

Each constraint is an inequality and therefore if drawn on a graph with axis x_1 and x_2 representing all the possible (x_1 , x_2) data points, the inequality will split the plane where (x_1 , x_2) data points may and may not assume values. The constraint inequalities above may be drawn onto the graph as shown in Figure 42 below. The shaded region shows all the possible (x_1 , x_2) data points that satisfy the constraints. The optimal point (solution) is always at a corner point. The problem may also have been to minimise the sum rather than maximise, which would have a simple solution (0,0) in this case. However, in a minimise case, the problem may not be so simple with added constraints, and may require the full methodology and algorithm to solve just as in the maximise problem.

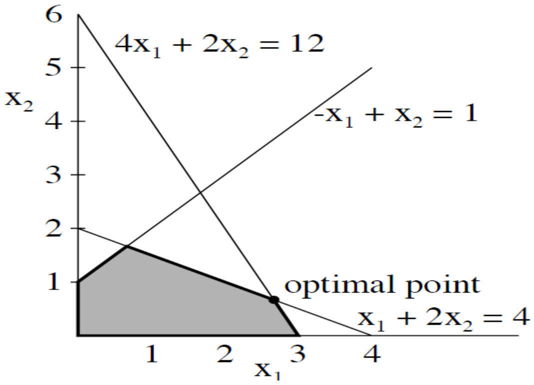


Figure 42: The graph of feasibility region subject to the constraints in the example (Ferguson, 2012)

4.2 OSeMOSYS

OSeMOSYS is written in GNUmathprog language which is supported by the GNU Linear Programming Kit (GLPK). The GLPK package is an open source solver of linear programming and mixed integer programming problems (Makhorin, 2008).

The OSeMOSYS software is designed to allow the user to create an energy model of a system using predefined parameters (commonly used parameters in the energy modelling field) and variables. The user is required to know the numeric data of their system they want to model.

The actual OSeMOSYS software is written in the format (in order):

1) **Sets** – all groups of elements are defined here, such as the ‘technology’ set which is a list of the names of all technologies used in the model. Others are; Fuels, emission types, seasons, timeslices and so on. Sets are used to give names to the elements of the users’ model.

2) **Parameters** – aspects related to the model like the efficiency or capacity (residual or new) of the elements in the technology set are defined here. The parameters set up the numeric values of the element of the energy model to be optimised. Parameters include (and not limited to): capital costs, variable and fixed costs, storage discharge rates, operational life of technologies, maximum and minimum capacity values for each technology, reserve margins for each year etc.
3) **Variables** - these are in-software variables that create the associations between demand and supply and all constraints within the model. These variables are defined so that the software may use them to set up the constraints and equations which ultimately define the objective function.
4) **Objective function** – the variable which is to be optimised is defined here and is subject to the constraints defined below using all the information provided by the user in 1, 2 and 3 above. It is a simple one line instruction for GLPK to optimise the variable *TotalDiscountedCost* - the objective function.
5) **Constraints** – all the constraints which are associated with the model are defined here. Indeed this is where the essence of where the OSeMOSYS software is. This section is a large group of equations and inequalities which form all the constraints that the solver needs to consider to optimise the objective function. The equations are in a layered format because of the extensive amount of information there is involving the optimisation software and the energy model. The layered nature is also necessary for other persons using this open source software to better understand what is going on in the software, and make changes when needed.
6) **Results** – this section of the software simply outputs the results of the optimisation into a spread sheet and text file which is saved in the directory where the GLPK and OSeMOSYS software is located on the computer.

All the sections (1 – 6) are completely editable by the user, but the user would need to understand the basics of the GNUmathprog language in which OSeMOSYS is written in. The user may add extra relations and variables to the model, for example; a specific constraint that a technology must operate at x % of its potential over the year. The user need not add in a new element in the sets, but would need to add in a new parameter called ‘constraintZ’ for example and would need to add this constraint into the constraints section and create the equations which use the new parameter to limit the production of the technology.

To demonstrate the layered nature of the software and at the same time how the objective function is determined, parts of the function will be described in the following section (describing all the equations and variables is too lengthy and would only be reproducing the paper by Howells (2011) which describes the structure of OSeMOSYS and how it is formulated).

The objective function is defined as (OSeMOSYS equation TDC2):

Equation 11:

$$\forall\, y \in Year, r \in Region:$$

$$Objective = \sum_{\substack{y \in Year \\ r \in Region}} TotalDiscountedCost(y,r)$$

$$= \sum_{t \in Technology} TotalDiscountedCostByTechnology(y,t,r)$$

$$+ \sum_{s \in Storage} TotalDiscountedStorageCost(s,y,r)$$

Where *y* is an element of the Year set which defines all the years to be modelled, *r* is an element of the Region set which defines all regions/countries within the model. Also, *s* is an element of Storage set which defines all storage systems within the model, and *t* is an element of Technology set which defines all the technology elements used in the model.

From here on, all equations from OSeMOSYS will be described in the format a + b = X and not X = a +b, as this is a computer language norm for defining a variable. Equation 11 is written in the opposite manner as it is actually two equations that have been combined here for simplicity. The variable defining the technology costs in Equation 11 above is defined as:

Equation 12:

$$\forall\, y \in Year, t \in technology, r \in Region:$$

$$\begin{aligned}
&DiscountedOperatingCost(y,t,r) + \\
&DiscountedCapitalInvestment(y,t,r) + \\
&DiscountedTechnologyEmissionsPenalty(y,t,r) - \\
&DiscountedSalvagevalue(y,t,r)
\end{aligned}$$

$$= TotalDiscountedCostByTechnology(y,t,r)$$

Looking at the first term that defines the technology costs - the *DiscountedOperatingCost* is defined for each year, technology and region:

Equation 13:

$$\forall\ y \in Year, t \in Technology, r \in Region :$$

$$\frac{OperatingCost(y,t,r)}{(1+DR)^{(y-startyear+0.5)}}$$

$$= DiscountedOperatingCost(y,t,r)$$

Where *DR* is the discount rate defined by the user and start year is the first year of the model period (this is defined from the first element of the Year set which the user defines).

Furthermore, the *OperatingCost* from Equation 13 is defined as;

Equation 14:

$$\forall y \in Year, t \ \in \ Technology, r \in Region:$$

$$AnnualFixedOperatingcost(y,t,r) + AnnualVariableOperatingCost(y,t,r)$$

$$= OperatingCost(y,t,r)$$

Looking once more, at the second term involving the variable costs:

Equation 15:

$$\forall y \in Year, t \in Technology, r \in Region :$$

$$\sum_{m \in ModesOfOperation} TotalAnnualTechnologyActivityByMode\ (y,t,m,r) \times VariableCost(y,t,m,r)$$

$$= AnnualVariableOperatingCost(y,t,r)$$

The *ModesOfOperation* is a set which defines the types of operation a technology can have and is usually defined as ‘1’ for one mode and ‘2’ for another. The user may define as many as needed. This is useful for situations where cogeneration may be used or in the case of storage a technology can produce energy in different flows – charging or discharging storage.

The first term in Equation 15 describes the activity of the technology and is defined as:

Equation 16:

$$\forall y \in Year, t \in Technology, m \in ModesOfOperation, r \in region:$$

$$\sum_{l\ \ in\, Timeslice} RateOfActivity(y,l,t,m,r) \times YearSplit(y,l)$$

$$= TotalAnnualTechnologyActivityByMode(y,t,m,r)$$

The Timeslice set is defined by the user and defines how the year is split into the season by fractions of the year. It is used to create a timeframe within the energy model.

The variable *RateOfActivity* (ROA) is not given a value by the user, nor is it strictly defined. For example it is not defined “….. = RateOfActivity “, but it is used to define other variable in the software for example: “rateofactivity*A*B*C = Y “.

This variable is used to define many other variables in the model which are used to describe and account for energy production and use. The ROA variable is used in the following (among others):

Fuel production:

Equation 17:

$$\forall y \in Year, l \in Timeslice, f \in Fuel, t \in technology, m \in ModesOfOperation, r \in Region\ s.t:$$

$$OutputActivityVariable(y,t,f,m,r) \neq 0:$$

$$RateOfActivity(y,l,t,m,r) \times OutputActivityRatio(y,t,f,m,r)$$

$$= RateOfProductionByTechnologyByMode(y,l,t,m,f,r)$$

And

Equation 18:

$$\forall y \in Year, l \in Timeslice, f \in Fuel, t \in technology, m \in ModesOfOperation, r \in Region\ s.t:$$

$$InputActivityRatio(y,t,f,m,r) \neq 0\ \ then:$$

$$RateOfActivity(y,l,t,m,r) \times InputActivityRatio(y,t,f,m,r)$$

$$= RateOfUseByTechnologyByMode(y,l,t,m,f,r)$$

The second line in Equation 18 is not necessary for the operation of the software, but it greatly reduces the size of the computations required by focusing out the only elements which have an activity ratio to be used in the model (some elements of the model are not involved in producing anything but serve other purposes in the model).

The ROA variable which defines the *RateOfTotalActivity* variable:

Equation 19:

$$\forall y \in Year, t \in Technology, l \in Timeslice, r \in Region:$$

$$\sum_{m \in ModesOfOperation} RateOfActivity(y,l,t,m,r)$$

$$= RateOfTotalActivity(y,l,t,r)$$

This equation sums up the rate of activity for each technology for all the modes of operation that those technologies might have such as charging and discharging rates of activity for pumped storage for example. Another might be the rate of activity for both modes of operation of a cogeneration plant.

The *RateOfTotalActivity* variable is constrained by the criteria:

Equation 20:

$$\forall y \in Year, t\ ; in\ Technology, l \in Timeslice, r \in Region\ s.t:$$
$$TechWithcapacityNeededToMeetPeakTS \neq 0:$$

$$RateOfTotalActivity(y,l,t,r) \leq\ TotalCapacityAnnual(y,t,r) \times CapacityFactor(y,t,l,r) \times CapacityToactivityUnit(t,r)$$

The precondition in the second line in Equation 20 above is as before, used to reduce the sizes of the matrices used in the model in order to improve the performance of the software.

The *TotalCapacityAnnual* variable is determined by the optimisations process through a set of equations which take into account various criteria such as minimum reserve margin, the demand required to be met and the performance of each technology which is running or is available to be invested-in, and for the entire model period. To describe this variable would require as many (if not more) equations and inequalities which have been presented here.

The variable, *CapacityFactor* is set by the user when defining the model data. The variable *CapacityToActivity* is defined by the user and is the conversion factor used to define the relation between the capacity unit of the technology (GW) and the unit of production (PJ), and takes the value 31.56 which is simply: 1GWyr/1PJ. This allows the analyst to use units of their choice and further demonstrates the adjustability of the software for the use by a researcher for their own gain.

The production of energy from all the technologies in the model is directly affected by the ROA variable which in turn is affected by the constraint on the *RateOfTotalActivity* variable in Equation 20. Likewise the total production needs to meet the minimum energy consumption constraint:

Equation 21:

$$\forall y\ in\ Year, l\ in\ TimeSlice, f\ in\ Fuel, r\ in\ Region:$$

$$
\begin{aligned}
&Production(y,l,f,r) \\
&\qquad\qquad \geq Demand(y,l,f,r) + Use(y,l,f,r) \\
&\qquad\qquad + \sum_{rr \in Region} Trade(y,l,f,r,rr) \times TradeRoute(y,f,r,rr)
\end{aligned}
$$

The *Use* variable is all the energy which is used by the technologies and is included here since the model needs to account for importing or manufacturing of fuel for energy production, such as coal for coal fired power stations. The Trade and TradeRoute variables are useful for researchers using different regions which interact with each other thru trade of fuels (none are used in this study).

The *Demand* variable is explicitly defined by the user as the demand for energy, not power. The software uses the input from the analyst to create a breakdown of the demand based on the timeslices (YearSplit) parameter given by the user.

The *Production* variable is defined through the *RateOfProduction* which in turn is based on the *RateOfProductionByTechnology* variable which in turn is determined based on the ROA variable as described above in Equation 19 and Equation 20.

The reserve margin

In any energy model, a reserve margin is required to create energy security of the overall energy system. Reserve margins are necessary for preparing for unpredictable events like damage to power lines or an operating plant which causing a deficit in the amount of energy available. In OSeMOSYS the reserve margin is incorporated into the system by flagging the technologies which can contribute to the reserve margin. This is done using the *ReserveMarginTagTechnology* parameter. The user needs to specify using this parameter all the technologies that contribute to the reserve margin. Also, using the *ReserveMarginTagFuel* parameter the user needs to specify which fuel requires the reserve margin, and using the *ReserveMargin* parameter the margin for each year is set.

OSeMOSYS accounts for the reserve margin as a constraint by;

- Working out the total capacity which can contribute to the reserve margin
- Working out the total demand of the fuel which has a reserve margin constraint
- Ensuring the demand of the fuel meets the margin (the constraint)

This is implemented in the software as:

$$\forall y \in Year, l \in Timeslice, r \in Region:$$

Equation 22: Total generating capacity which can contribute to the reserve margin

$$\sum_{t \in Technology} TotalCapacityAnnual(y,t,r) \times ReserveMarginTagTechnology(y,t,r) \times CapacityToActivityUnit(t,r) = TotalCapacityInReserveMargin(y,r)$$

Equation 23: The total demand which requires a reserve margin.

$$\sum_{f \in Fuel} RateOfProduction(y,l,f,r) \times ReserveMarginTagFuel(y,f,r) = DemandNeedingReserveMargin(y,l,r)$$

And finally,

Equation 24: The reserve margin constraint on the fuel (demand):

$$DemandNeedingReserveMargin(y,l,r) \leq TotalCapacityInReserveMargin(y,r)$$

In this way, as shown in this section, it is clear that there is a very complex association between variables in the software which describes the energy model. A system as complex as the electricity sector, requires a lot of detail in the software to account for the real life electricity sector. Due to the complexity, a large company of variables and data figures are needed to create the energy model.

4.3 The South African electricity sector model in OSeMOSYS

In the current OSeMOSYS software version (2012-07-27-BETA), an energy model is created by writing in GNUmathprog format a text file containing all elements and data of the model to be created. All data relating to costs and technical aspects for electricity generating technologies in South Africa were incorporated together into a text file which forms the OSeMOSYS electricity model of South Africa. The data comes from the IRP and an extensive set of work on demand sectors by the ESAP (Energy Systems Analysis Planning) group at the ERC which has been used to create a larger much more sophisticated energy model of South Africa, called the South African TIMES model (SATIM).

The SATIM model is structured into five demand sectors – industry, agriculture, residential, commercial and transport, and two supply sectors; electricity and liquid fuels. The residential, industrial and transport sectors are further broken down into subsectors in order to better represent the sectors and the model. Multiple subsectors are required since there are many assumptions about key variables like population and economic growth parameters which would affect the model on the whole. There are other factors which affect sectors separately, such as technological changes which would affect sub sectors but not necessarily the entire sector, such as improved boilers or mills in iron and steel industry to more efficient lighting in the residential sector. These new technology options are not limited to generating but are extended to energy consuming devices as well. Each subsector has a variety of new technology options for both supply and consumption of both liquid fuels and electricity, making the SATIM model very complex and inclusive.

The data for all generating technologies, storage, and transmissions were used to create the electricity sector of South Africa in OSeMOSYS. Only residential sector consumption and a summed total electricity consumption for the remaining sectors was used.

The demand sectors are; industry, agriculture, commercial, transport and residential. The ESAP group at the ERC projected the industrial demand based on year on year GDP growth for industry subsectors, and using historical observations to predict future energy to rand relations in the sector. Commercial sector consumption was projected based on energy intensity by floor space, and floor space growth was related to the GDP growth rate projection. The transport sector projections are based on a Vehicle Parc Model for various types of transport demands. The agricultural sector demand is taken from the department of energy (DOE) and applied to the SATIM model (ERC, 2012).

The discount rate used in the OSeMOSYS model is 8% and is the same rate which is advocated by the Treasury and the IRP2010 (ERC, 2012).

The OSeMOSYS model starts from the year 2006 and goes up to 2030 in single year increments. To determine the impact of net metering in South Africa, it would not be necessary to go beyond 2030 to gauge how the presence of net metering of solar PV in the residential sector might affect the future electricity sector. Additionally, it would become difficult to predict aspects like costs of PV when already there are new technologies emerging with promise for future solar energy generation and it would be too difficult to determine a reasonable electricity price at the municipal level beyond 2030.

The electricity model for South Africa in OSeMOSYS that was created in this work is described by reference energy system (RES) diagram in Figure 43 :

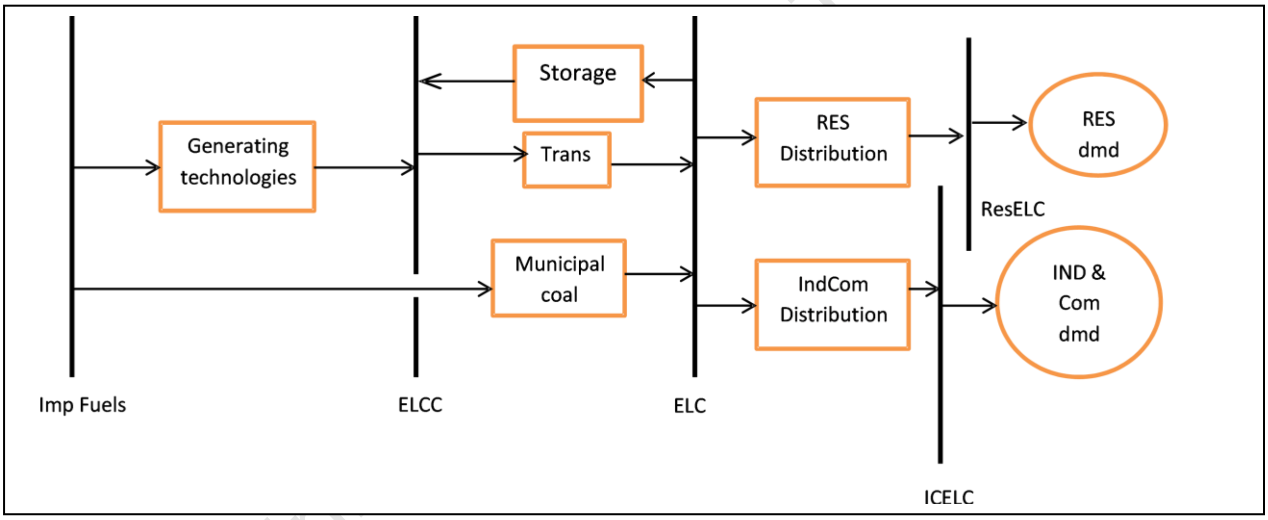


Figure 43: the layout for the South African electricity sector model in OSeMOSYS

Using the data for electricity consumption, the electricity consumption for industry, commerce, agriculture and transport were grouped into the ‘INDCOM’ demand group, while the residential consumption was left as its own demand group as it is the demand group of interest for the net metering scenarios developed in section 3. The ‘generating technologies’ depicted above comprises all existing (and potentially new) upstream electricity generation technologies from coal power to hydro and imported power technologies that are present in the electricity sector (see the next section for a description of these).

The ‘imp fuels’ represents all fuels used for the power generating technologies which are both imported fuels or locally produced such as coal. ‘Trans’ represents the transmissions from upstream generation to the distribution networks over high voltage electrical lines where the efficiency of transporting power is 96.2% - incurring a loss of some 3.8%. These include the long transmission lines from the northern parts of the country where the coal power stations are located, see Figure 20. ’Storage’ is the pumped storage systems in the model (referred to as ‘storage’ from here on), using downstream electricity (ELC) to store energy as gravitational potential energy in dams and produces upstream electricity (ELCC) when needed – incurring extra losses from the transmission lines. These storage schemes are the Palmiet and Drakensberg and soon to be completed Ingula station as indicated in Figure 20.

From the downstream electricity (ELC), the electricity goes thru the distribution networks for each sector (residential: ‘RES distr.’ and industrial and commercial: ‘IndCom’ dist.) incurring an energy loss of 10% each.

4.3.1 Existing and new technologies in the model

Table 19, 20, 21 and 22 show the data for existing and new generating power plant technologies used in OSeMOSYS to create the electricity sector of South Africa. All costs for the technologies used in the model are taken from the IRP2010, or from sources used to inform the IRP2010 process. The OSeMOSYS model incorporates all existing power technologies operating in South Africa as well as a large variety of new available technologies. The model does not, however, include the operating cost of the transmissions systems; there is however, an inherent cost from the losses occurring in the transmission system. Because South Africa has a large solar potential, due to the arid dessert and north Western areas of the country, a large selection of solar technologies are included in the OSeMOSYS model.

Table 19: The technology characteristic input data for existing technologies in the model. These values are compiled from the IRP for use in the SATIM model by the ESAP group.

Technology	**input**	**Import?**	**output**	**Input activity ratio (1/efficiency)**	**variable costs**	**Fixed costs**	**Availability factor**	**Capacity factor**
units:					**2005 R/GJ**	**2005 R/kW**		
Pumped Storage turbine	dam		ELCC	1	0.81	51.55	0.21	0.93
Pumped Storage pump	ELC		dam	1.37	0	0	1	1
Coal PF Eskom Large	Coal		ELCC	2.86	1.94	159.66	0.92	0.94
Coal PF Eskom Large Dry	Coal		ELCC	2.89	1.30	134.53	0.93	0.95
Coal PF Eskom Small	Coal - New		ELCC	3.45	1.69	210.80	0.92	0.87
Coal PF Municipal	Coal		ELC	4.07	4.25	309.14	0.90	0.91
OCGT liquid fuels	Diesel		ELCC	3.10	58.94	57.42	0.93	0.95
Hydro-South Africa	Hydro		ELCC	1	0	99.69	0.96	0.93
PWR nuclear	Uranium		ELCC	3.12	2.41	360.94	0.89	0.91
Hydro-Region	Hydro	Yes	ELCC	1	0	91.97	0.74	0.90
Boroma - Quedas Ocua hydro	Hydro	Yes	ELCC	1	2.30	47.79	0.44	0.95
HCB North hydro	Hydro	Yes	ELCC	1	2.30	47.79	0.40	0.95
Ithezi Tezhi hydro	Hydro	Yes	ELCC	1	2.30	47.79	0.67	0.95
Kafue hydro	Hydro	Yes	ELCC	1	2.30	47.79	0.48	0.95
Kariba North Bank extension hydro	Hydro	Yes	ELCC	1	2.30	47.79	0.40	0.95
Kudu gas	Hydro	Yes	ELCC	2.08	0	115.02	0.93	0.95
Mmamabula coal	Coal	Yes	ELCC	2.70	3.42	259.49	0.88	0.96
Moatize - Benga coal	Coal	Yes	ELCC	2.86	1.46	109.55	0.88	0.96
Mphanda Nkuwa hydro	Hydro	Yes	ELCC	1	0	235.53	0.69	0.96

Table 20: The cost assumptions of the available new Coal, nuclear, and hydro technologies used in the models, data taken from IRP. Table was adapted from ERC (2012)

Parameter	Present value capital costs with technology learning								Fixed costs	Variable costs	Year before available
Year	**2010**	**2012**	**2014**	**2016**	**2018**	**2020**	**2025**	**2030**			
Units	**2005 R/kW**								**2005 R/kW**	**2005 R/GJ**	
Indigenous Coal, Gas, Nuclear & Hydro											
Supercritical Coal	12 177	12 177	12 177	12 177	12 177	12 177	12 177	12 177	312	8.44	2009
Fluidised Bed Combustion Coal	10 246	10 246	10 246	10 246	10 246	10 246	10 246	10 246	250	18.85	2009
Integrated Gasification Combined Cycle Coal	16 891	16 481	15 986	15 704	15 506	15 266	14 724	14 546	568	2.74	2009
Nuclear PWR higher cost	25 473	25 432	25 383	25 326	25 245	25 195	24 977	24 731	525	0.00	2022
Combined Cycle Gas Turbine	3 957	3 957	3 957	3 957	3 957	3 957	3 957	3 957	101	0.00	2009
Open-Cycle Gas Turbine diesel	2 708	2 708	2 708	2 708	2 708	2 708	2 708	2 708	48	0.00	2009
Open-Cycle Gas Turbine gas	2 708	2 708	2 708	2 708	2 708	2 708	2 708	2 708	48	0.00	2009
Landfill gas	14 430	14 430	14 430	14 430	14 430	14 430	14 430	14 430	652		2011
Micro hydro	13 693	13 693	13 693	13 693	13 693	13 693	13 693	13 693	89		2011
Imports											
Kudu gas import	3 957	3 957	3 957	3 957	3 957	3 957	3 957	3 957	115	0.00	2014
Kafue hydro import	4 382	4 382	4 382	4 382	4 382	4 382	4 382	4 382	48	2.30	2016
Mmamabula coal import	11 557	11 557	11 557	11 557	11 557	11 557	11 557	11 557	259	3.42	2014
HCB North hydro import	4 968	4 968	4 968	4 968	4 968	4 968	4 968	4 968	48	2.30	2014
Ithezi Tezhi hydro import	6 480	6 480	6 480	6 480	6 480	6 480	6 480	6 480	48	2.30	2016
Mphanda Nkuwa hydro import	10 625	10 625	10 625	10 625	10 625	10 625	10 625	10 625	236		2019
Moatize - Benga coal imp	9 859	9 859	9 859	9 859	9 859	9 859	9 859	9 859	110	1.46	2014
Boroma - Quedas Ocua hydro import	10 374	10 374	10 374	10 374	10 374	10 374	10 374	10 374	48	2.30	2014
Kariba North Bank etension hydro import	2 919	2 919	2 919	2 919	2 919	2 919	2 919	2 919	48	2.30	2014

Table 21: The new available solar, wind and storage technology characteristic data used in the model, taken from IRP data. Table adapted from ERC (2012)

Parameter	**Input (fuel)**	**Output**	**Efficiency**	**Contribution to Peak**	**Availability factor**	**Lifetime**
Year	**2006**	**2006**	**2006**	**2006**	**2006**	**2006**
Units				**%**	**%**	**Years**
Solar & Wind						
Solar Thermal tower 12 hrs. storage	Solar	ELCC	1.00	1.00	0.47	30
Solar Thermal tower 14 hrs. storage	Solar	ELCC	1.00	1.00	0.48	30
Solar Thermal tower 3 hrs. storage	Solar	ELCC	1.00	1.00	0.29	30
Solar Thermal tower 6 hrs. storage	Solar	ELCC	1.00	1.00	0.37	30
Solar Thermal tower 9 hrs. storage	Solar	ELCC	1.00	1.00	0.41	30
Solar Parabolic Trough 0 storage	Solar	ELCC	1.00	0.00	0.25	30
Solar Parabolic Trough 3 hrs. storage	Solar	ELCC	1.00	0.00	0.31	30
Solar Parabolic Trough 6 hrs. storage	Solar	ELCC	1.00	1.00	0.36	30
Solar Parabolic Trough 9 hrs. storage	Solar	ELCC	1.00	1.00	0.44	30
Solar PV centralised concentrated	Solar	ELCC	1.00	0.00	0.27	25
Solar PV centralised non-concentrated	Solar	ELCC	1.00	0.00	0.19	25
Wind high resource	Wind	ELCC	1.00	0.23	0.29	20
Wind medium resource	Wind	ELCC	1.00	0.23	0.25	20
Pumped Storage						
Pumped Storage New	ELC	ELCC	0.73	1.00	0.94	50
Pumped Storage New pump	ELC	ELCC	0.73	1.00	0.94	50
Pumped Storage New turbine	dam	ELCC	1	1.00	0.94	50

Table 22: The cost variables for available new technologies in the model, taken from IRP data. Table adapted from ERC (2012).

Parameter	**Present value capital costs with technology learning**								**Fixed costs**	**Variable costs**	**Year before available**
Year (time series) - default 2006	**2010**	**2012**	**2014**	**2016**	**2018**	**2020**	**2025**	**2030**	**2006**	**2006**	
Units	**2005 R/kW**	**2005 R/kW**	**2005 R/kW**	**2005 R/kW**	**2005 R/kW**	**2005 R/kW**	**2005 R/kW**	**2005 R/kW**	**2005 R/kW**	**2005 R/GJ**	
Solar & Wind											
Solar Thermal tower 12 hrs. storage	26 719	22 086	18 314	14 931	13 437	12 501	11 579	11 031	413	0.00	2013
Solar Thermal tower 14 hrs. storage	27 524	22 752	18 865	15 380	13 842	12 877	11 928	11 363	413	0.00	2013
Solar Thermal tower 3 hrs. storage	18 424	15 230	12 629	10 295	9 266	8 620	7 984	7 607	335	0.00	2013
Solar Thermal tower 6 hrs. storage	22 039	18 218	15 107	12 316	11 084	10 311	9 551	9 099	374	0.00	2013
Solar Thermal tower 9 hrs. storage	24 802	20 502	17 000	13 859	12 473	11 604	10 748	10 239	413	0.00	2013
Solar Parabolic Trough 0 storage	18 794	15 535	12 882	10 502	9 452	8 793	8 144	7 759	290	0.00	2013
Solar Parabolic Trough 3 hrs. storage	25 624	21 181	17 563	14 318	12 887	11 989	11 104	10 579	351	0.00	2013
Solar Parabolic Trough 6 hrs. storage	29 704	24 554	20 360	16 598	14 939	13 897	12 872	12 264	385	0.00	2013
Solar Parabolic Trough 9 hrs. storage	34 856	28 813	23 892	19 477	17 530	16 308	15 105	14 390	435	0.00	2013
Solar PV centralised concentrated	25 487	20 744	19 881	19 410	18 860	18 329	16 016	15 104	344	0.00	2010
Solar PV centralised non-concentrated	12 880	10 695	9 151	7 885	6 835	5 955	5 074	4 346	142	0.00	2010
Wind high resource	9 890	9 251	8 961	8 717	8 514	8 414	8 206	8 077	182	0.00	2010
Wind medium resource	9 890	9 251	8 961	8 717	8 514	8 414	8 206	8 077	182	0.00	2014
Pumped Storage											
Pumped Storage New	5417.78	5417.78	5417.78	5417.78	5417.78	5417.78	5417.78	6457.22	105.34	0.00	2009
Pumped Storage New pump	5417.78	5417.78	5417.78	5417.78	5417.78	5417.78	5417.78	6457.22	105.34	0.00	2009
Pumped Storage New turbine	5417.78	5417.78	5417.78	5417.78	5417.78	5417.78	5417.78	6457.22	105.34	0.00	2009
Biomass											
Biomass municipal waste (landfill)	45 804	44 718	43 357	42 389	41 482	40 924	40 412	40 035	1 766	7	2 012

Table 23 shows the existing fleet of power station technologies operating up to 2030.Figure 44 shows how the existing coal technology capacity will decline over time and Figure 45 shows a chart of all the existing and operating technologies combined up to 2030. The year by year data is given in Table 48 in appendix section 8.5.

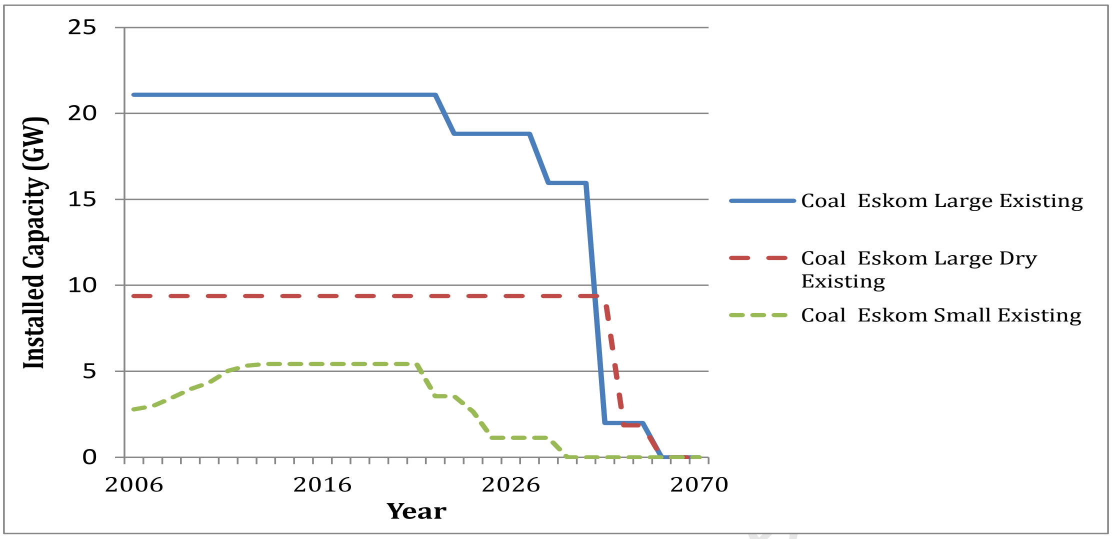


Figure 44: The timeline of all existing coal power generating technologies in South Africa from the SATIM model (ERC, 2012).

The total existing fleet of all power plants from 2006 to 2030 is given in Figure 45 below. The graph shows the dominate role of coal in the current mix of power plants in South Africa.

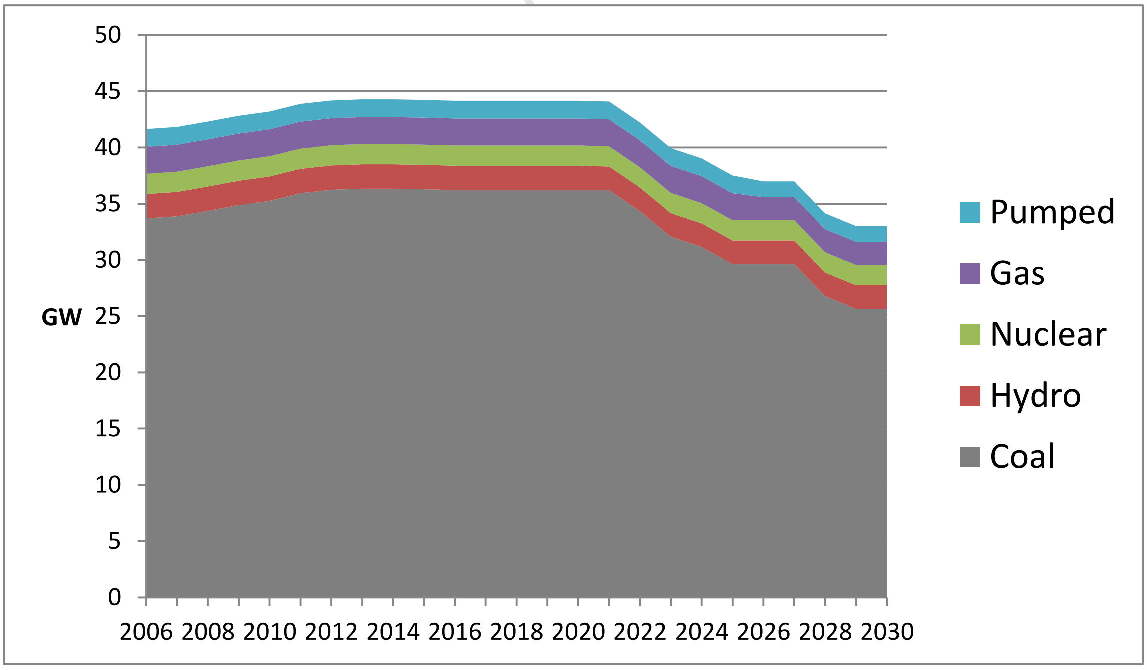


Figure 45: Stacked capacity chart of existing capacity in South Africa of all the technologies in the generation sector up to 2030.

Table 23: the existing fleet of generating technologies in South Africa (ERC, 2012)

	Pumped Storage turbine	Coal PF Eskom Large	Coal PF Eskom Large Dry	Coal PF Eskom Small	Coal PF Municipal	OCGT LNG and diesel fuels	Hydro-South Africa	Hydro-Region	Nuclear	total excl. storage
2006	1.58	21.09	9.38	2.78	0.44	2.40	0.67	1.50	1.80	40.06
2010	1.58	21.09	9.38	4.34	0.44	2.40	0.67	1.50	1.80	41.62
2015	1.58	21.09	9.38	5.43	0.39	2.40	0.67	1.50	1.80	42.65
2020	1.58	21.09	9.38	5.43	0.31	2.40	0.67	1.50	1.80	42.58
2025	1.58	18.81	9.38	1.13	0.31	2.40	0.60	1.50	1.80	35.93
2030	1.40	15.96	9.38	0.00	0.31	2.06	0.60	1.50	1.80	31.61

A graph showing all of the existing coal capacity in South Africa through to 2070 is given in Figure 44. The coal technologies are split into 3 groups, namely; large wet (wet cooled), large dry (dry cooled) and ‘small’ coal which include the return to service coal stations which are being de-moth balled due to the electricity capacity crisis in South Africa.

The objective of the OSeMOSYS model is to determine the best mix of new generating plants at the lowest cost for South Africa. The model uses an extensive set of new technologies from which new future generating capacity can be built to meet the growing energy demand and resource constraints.

New technology set for the OSeMOSYS model

All the new coal technologies are dry cooled technologies due to increasing water security concerns, and are the supercritical technology type which involves the use increased pressures to increase efficiency (ERC, 2012). The technology cost for supercritical coal includes the cost of flu gas desulphurisation (Eskom, 2011a).

Nuclear technology is the pressurised water reactor generation 3 type and is capacity limited to 10GW by 2030 as in the IRP2010. The capital cost in this model is an exaggerated one as some critiques of the analysis in the IRP2010 suggest that the original cost was an underestimate. These assumptions are derived from the IRP2010 (Eskom, 2011a).

A variety of hydro import options from Zambia and Mozambique are available but are limited to 3.4GW in total combined capacity as in the IRP (Eskom, 2011a).

Two wind groups are modelled, namely; 29% and 25% capacity factor groups. This is done to represent the different wind potential sites which are available in South Africa for wind generation. This was based on research by Hagemann (2008)on the wind resources in the country. The research by Hagemann shows that the capacity of these quality wind resources is limited to 10GW for the higher (29%) factor and 15GW of lower (25%) capacity factors.

Due to the extensive solar potential in South Africa, a variety of technologies are included in the model. There is centralised PV which does not include storage technology. And there are solar thermal technologies which are broken down into parabolic trough and solar thermal tower (central tower receivers). Both technology types have storage capabilities which are included. In the model, concentrated solar thermal central tower receivers are available in 3, 6, 9, 12, and 14hr storage technologies, and parabolic trough technologies are available in 0, 3, 6, and 9hr storage technologies. Each of these has a different investment cost and operating scheme (capacity factors and availabilities).

A summary of all these new technologies is presented in Table 24 below.

Table 24: The set of all new technologies in the SATIM model. Adapted from (ERC, 2012) - cogeneration and combined heat and power have been removed; as they are not modelled in the OSeMOSYS model

Technology	**Efficiency (%)**	**Availability factor (%)**	**Upper Capacity (GW)***	
Indigenous Coal, Gas, Nuclear & Hydro				
Supercritical Dry-Cooled Coal	37%	92%		
Fluidised Bed Combustion Coal	36%	90%		
Integrated Gasification Combined Cycle Coal	37%	86%		
Combined Cycle Gas Turbine	48%	89%		
Open-Cycle Gas Turbine diesel	30%	89%		
Open-Cycle Gas Turbine gas	30%	89%		
Nuclear PWR higher cost	33%	92%	10	
Landfill gas	100%	50%	0.5	
Micro hydro	100%	50%	0.5	
Imports				
HCB North hydro import	100%	38%	0.85	
Boroma - Quedas Ocua hydro import	100%	42%	0.16	
Ithezi Tezhi hydro import	100%	64%	0.12	
Kafue hydro import	100%	46%	0.75	
Kariba North Bank extension hydro import	100%	38%	0.36	
Mphanda Nkuwa hydro import	100%	67%	1.125	
Kudu gas import	48%	89%	0.711	
Mmamabula coal import	37%	85%	1.2	
Moatize - Benga coal import	35%	85%	1	
Solar & Wind				
Solar Thermal tower 12 hrs. storage	100%	47%		
Solar Thermal tower 14 hrs. storage	100%	48%		
Solar Thermal tower 3 hrs. storage	100%	29%		
Solar Thermal tower 6 hrs. storage	100%	37%		
Solar Thermal tower 9 hrs. storage	100%	41%		
Solar Parabolic Trough 0 storage	100%	25%		
Solar Parabolic Trough 3 hrs. storage	100%	31%		
Solar Parabolic Trough 6 hrs. storage	100%	36%		
Solar Parabolic Trough 9 hrs. storage	100%	44%		
Solar PV centralised concentrated	100%	27%		
Solar PV centralised non-concentrated	100%	19%		
Wind high resource	100%	29%	10	
Wind medium resource	100%	25%	15	
Pumped Storage				
Pumped Storage New pump	73%	94%	0	
Pumped Storage New turbine	73%	94%	0	
Biomass				
Biomass municipal waste	19%	85%	0.1	

*** Upper limit of capacity in 2010.**

The cost breakdown for locally sited (not imported) technologies available to South Africa from the table above; supercritical coal, gas turbines, nuclear, the solar, and wind technologies are presented and compared in Figure 46 and Figure 47 below and are derived using the data for the model and a levelised cost analysis - Equation 2.

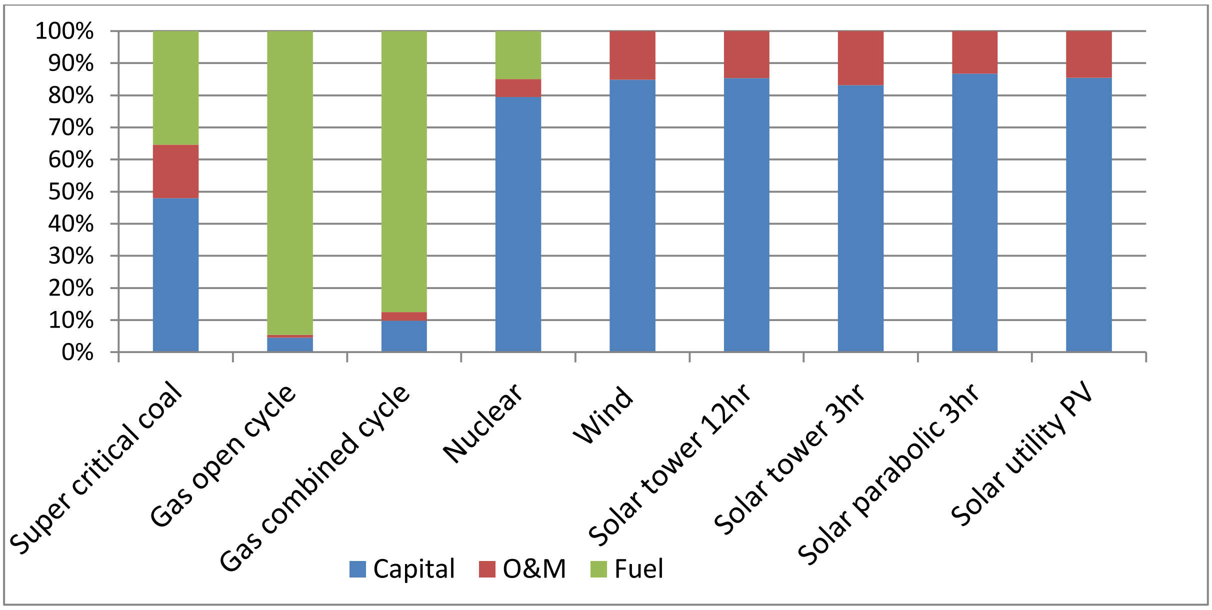


Figure 46: The cost breakdown for various technologies available for new investment in the model.

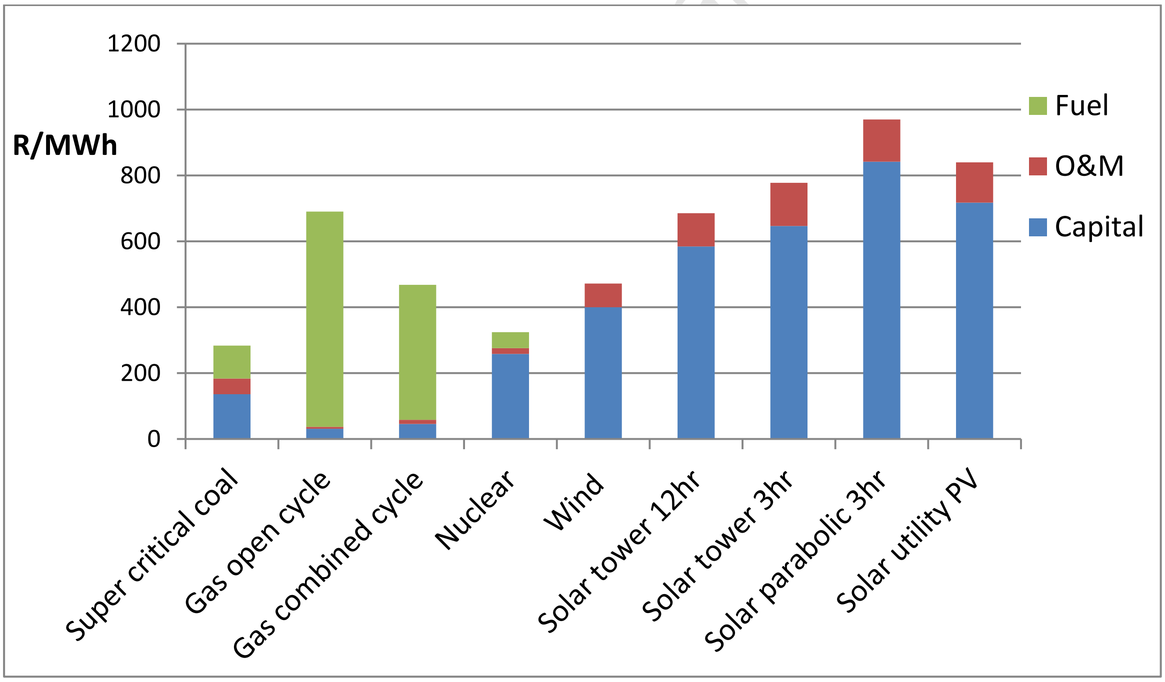


Figure 47: The levelised cost of various new technologies compared for the year 2010.

The levelised cost of energy of most new technologies like solar and wind will decrease over time as the technology develops further. As discussed in section 3.1.4.3, the learning rate is the rate of cost decrease as a result of production increases. Figure 48 below shows how the levelised cost of producing from each of these technologies changes through the model period (up to 2030) based on the learning rates inherent in the IRP2010. Some technologies like coal stations and gas turbines are already developed to a mature point where no further decreases in costs occur. There is little change in fuel costs for coal since there are large reserves of coal in South Africa - see Eberhard (2010) on coal in South Africa. There are two gas turbine technologies using two different fuels. Liquid natural gas is used in some gas turbines and diesel fuel is used in other turbines.

The supercritiical coal, gas, and nuclear technologies are all developed and mature technologies and as such, their costs do not decrease in any large way due to an increase in installed capacity. Figure 48 shows the LCOE for new baseload technologies in the model up to 2030, Figure 49 shows the peaking load technologies’ LCOE up to 2030, and Figure 50 and Figure 51 show the graph for all RE technologies used in the model.

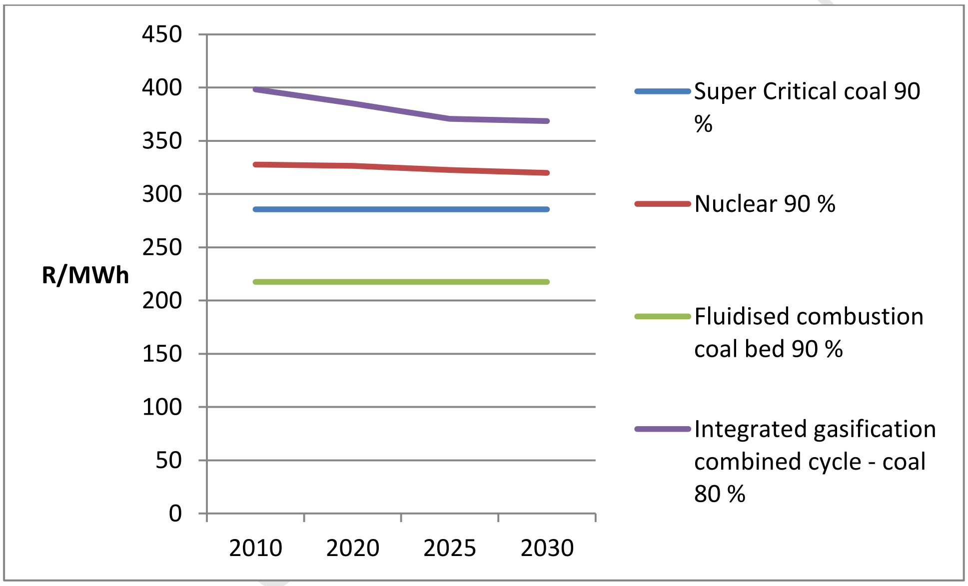


Figure 48: The levelised cost of energy for Base load new technologies over time, showing how the technologies come down in cost with increased development. Capacity factors used are indicated with the label

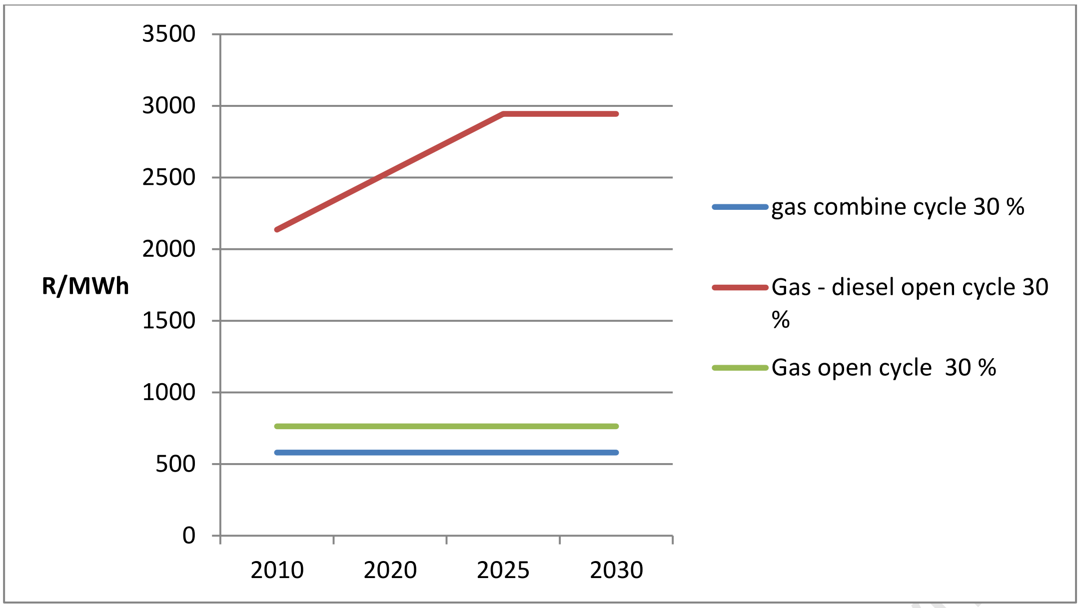


Figure 49: The LCOE for new peaking load technologies in the model. Capacity factors used are indicated with the label

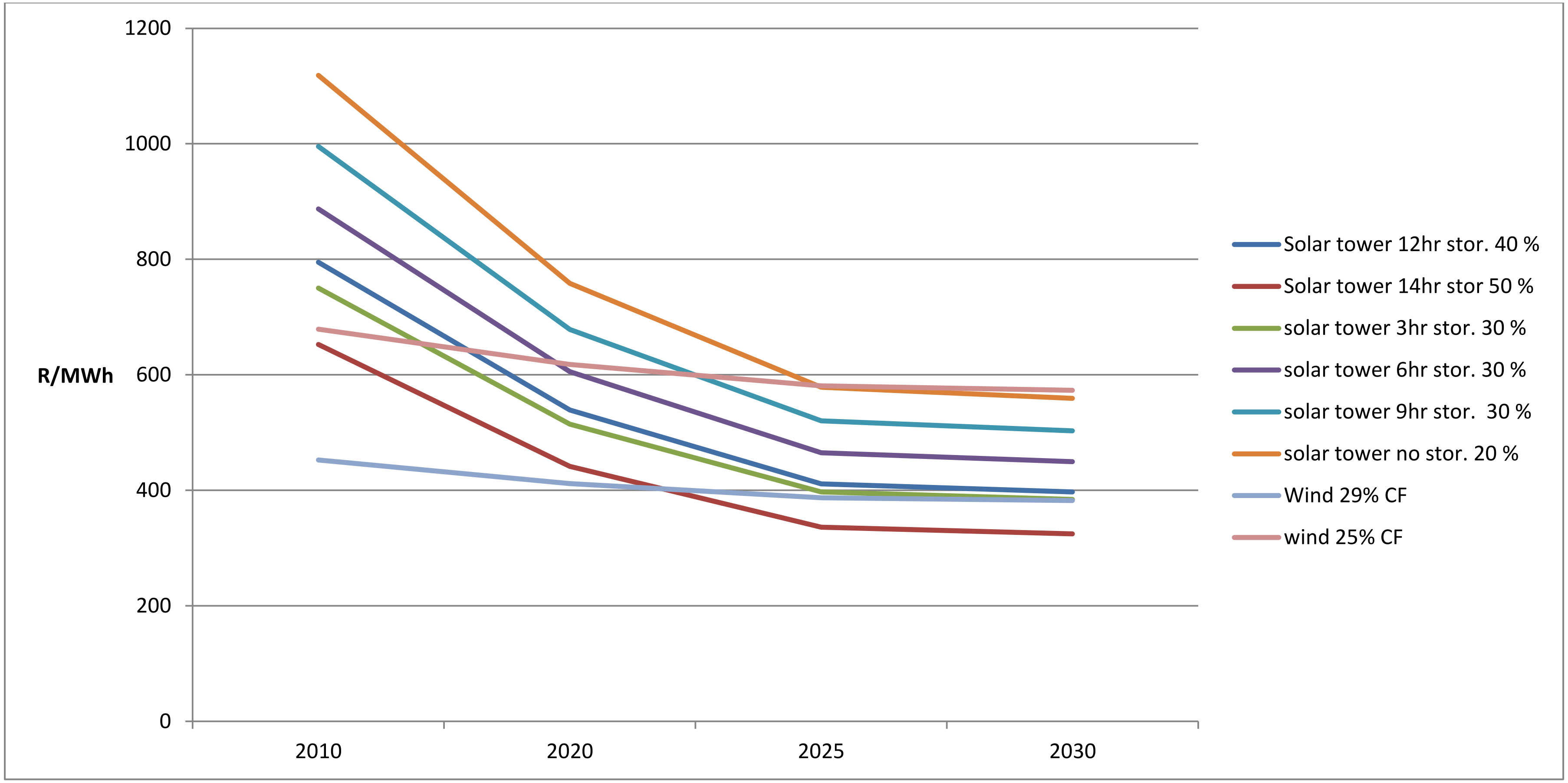


Figure 50: The LCOE for new landfill, and solar tower technologies in the model. Capacity factors used are indicated with the label

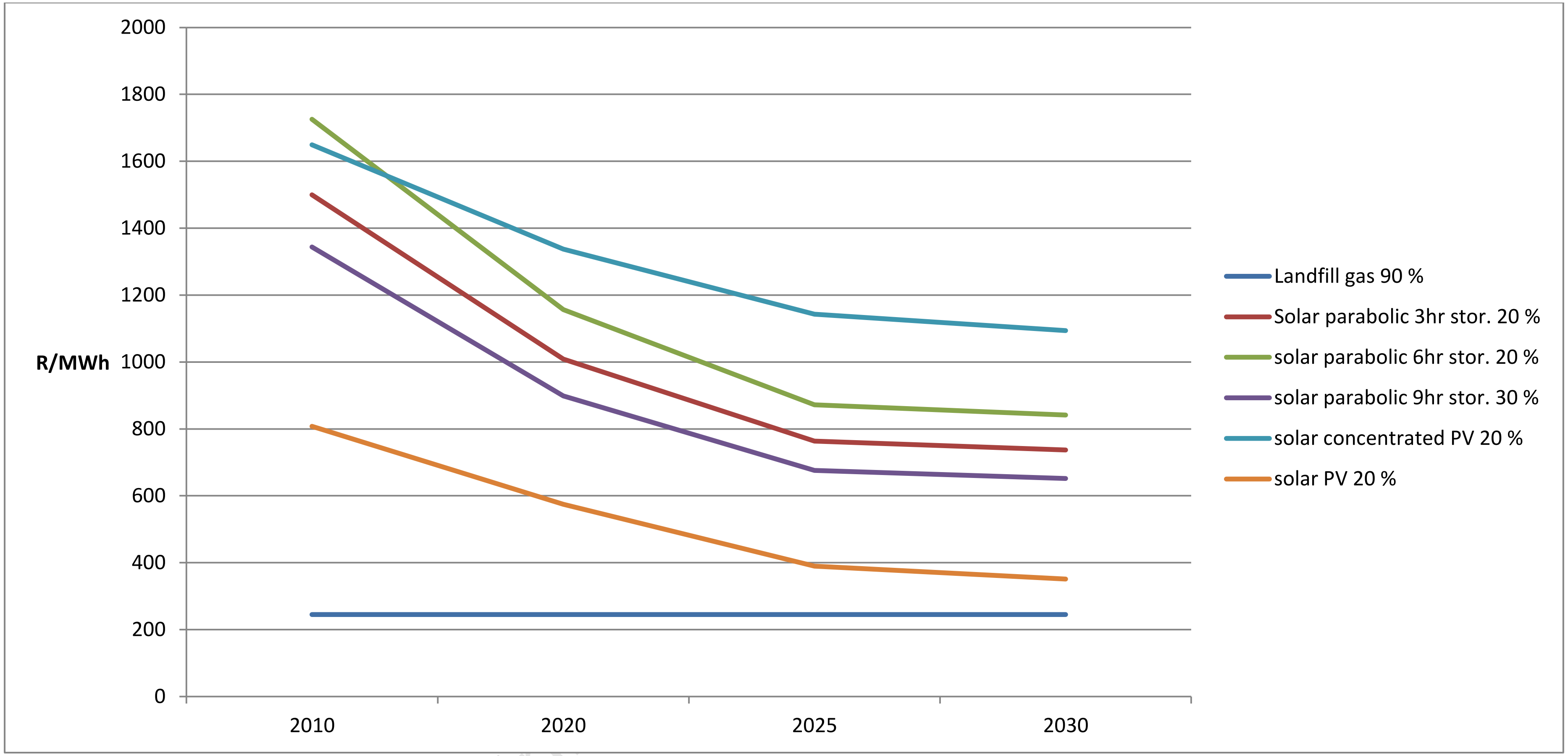


Figure 51: The LCOE for new solar parabolic, PV, and wind technologies. Capacity factors used are indicated with the label

The reserve margin in the model

ELCC (the upstream electricity) is tagged as the fuel requiring a reserve margin in the model. The reserve margin is 10% for each year in the model (2006 – 2030). The following technologies are flagged as technologies which can contribute to the peak demand:

Table 25: The technologies contributing to the reserve margin in the OSeMOSYS model

	Reserve margin contributing technologies								
	Coal	Gas turbines*	Hydro	Hydro import	Nuclear	Pumped storage	solar tower (3, 6 , 9, 12 and 14hr)	Solar parabolic (6 and 9hr)	Wind
Factor	1	1	1	1	1	1	1	1	0.23

*****Includes both natural gas combined and open cycle turbines, and includes diesel turbines.

The reserve margin for the model can be calculated using:

Equation 25: The reserve margin

$$RM = \frac{Installed\ capacity}{Peak\ demand} - 1$$

Where *RM* is the reserve margin as a fraction, *Installed capacity* is the total installed generating capacity of the model, and *Peak demand* is the peak power demand of the system (ERC, 2012).

Fuels

There are a number of fuel supplies for the electricity system in South Africa. Figure 52 shows the reference energy system of the fuel supplies for the electricity sector used in the model. The costs for each of these fuel supplies are given in Table 26. Nuclear fuel is not shown in the figure as it has been included with the overall cost of nuclear plant operation and is left unbound. The cost of all the coal supplies do not increase over the model period, as there are large reserves of coal in the country (Eberhard, 2010), the cost of importing diesel fuel however, does increase with increasing oil prices to 2030, while natural gas extraction remains constant in cost throughout.

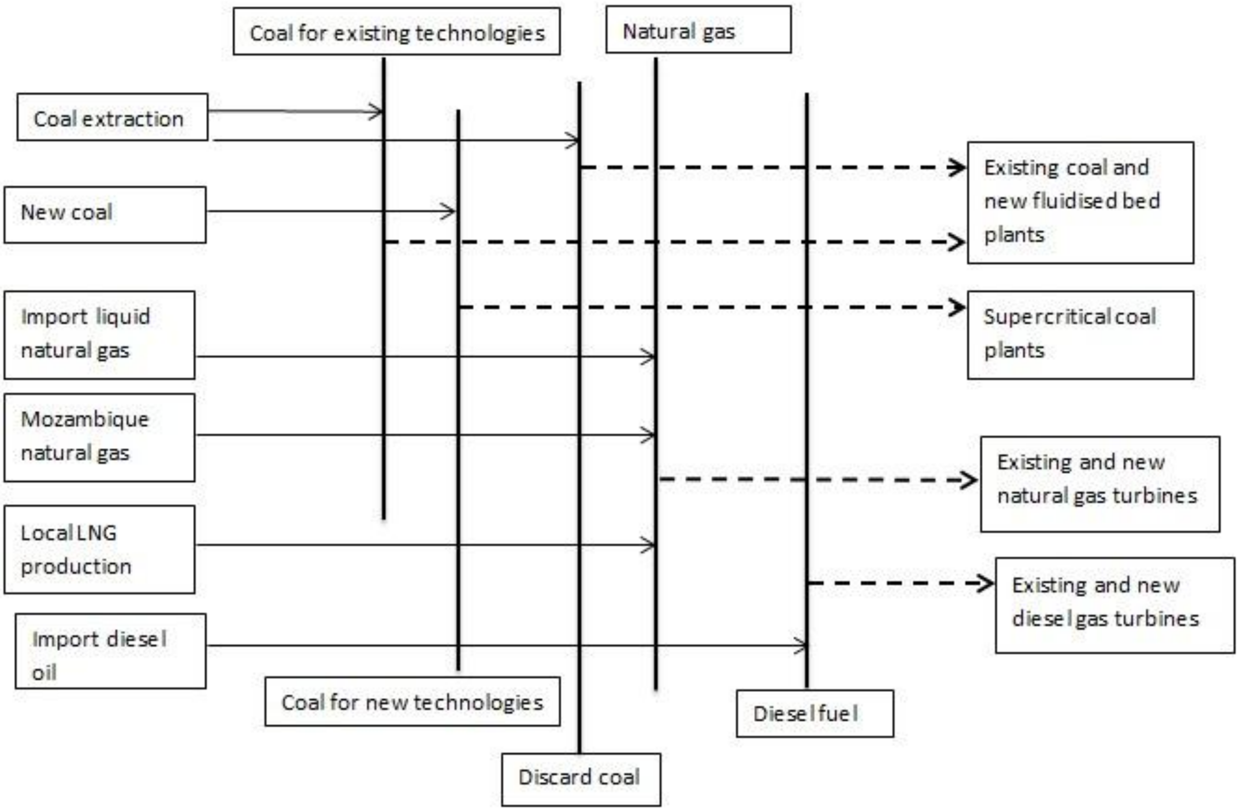


Figure 52: The fossil fuel reference energy system for the model

Table 26: The costs (R/GJ) for fossil fuels in the energy model

	Coal - existing	New coal	import Diesel	Import Liquid natural gas	Extraction of natural gas	Mozambique LNG	Coal discard	Regional Gas extraction
2006	5.14	10.27	148.84	54.77	16.49	16.49	5.14	54.77
2007	5.14	10.27	154.11	54.77	16.49	16.49	5.14	54.77
2008	5.14	10.27	159.38	54.77	16.49	16.49	5.14	54.77
2009	5.14	10.27	164.65	54.77	16.49	16.49	5.14	54.77
2010	5.14	10.27	169.92	54.77	16.49	16.49	5.14	54.77
2011	5.14	10.27	176.69	54.77	16.49	16.49	5.14	54.77
2012	5.14	10.27	183.45	54.77	16.49	16.49	5.14	54.77
2014	5.14	10.27	196.98	54.77	16.49	16.49	5.14	54.77
2016	5.14	10.27	210.51	54.77	16.49	16.49	5.14	54.77
2018	5.14	10.27	224.04	54.77	16.49	16.49	5.14	54.77
2020	5.14	10.27	237.57	54.77	16.49	16.49	5.14	54.77
2022	5.14	10.27	237.57	54.77	16.49	16.49	5.14	54.77
2024	5.14	10.27	237.57	54.77	16.49	16.49	5.14	54.77
2026	5.14	10.27	237.57	54.77	16.49	16.49	5.14	54.77
2028	5.14	10.27	237.57	54.77	16.49	16.49	5.14	54.77
2030	5.14	10.27	237.57	54.77	16.49	16.49	5.14	54.77

4.3.2 Model timeslices

The OSeMOSYS model is split into twenty time slices to represent each year. Splitting a year into twenty timeslices is done to save time during developing and testing of the model. A single timeslice represents a certain demand period of a certain day type (weekend or weekday) of a certain season. Splitting the model into timeslices like this means that the intricacy of a whole energy sector throughout a year can be captured without too much loss of information, and can be computed in a relatively short time.

There are three seasons in the OSeMOSYS model, namely; pre-winter, winter and post winter, while there are 2 day types common to each season, namely; weekday and weekend. Finally the time slices are further split into blocks defining certain demand times of the day. A table showing the timeslice breakdown by hours, days and seasons is given in Table 50 of appendix 8.6.

To best illustrate the timeslice use in this model, an example is given: s2d1b2 is season 2 day 1 block 2, representing winter weekdays of the hours 7:00-7:59am and 13:00 – 17:59pm combined. The energy profile for this example is shown in Figure 53 below, and how this specific timeslice is incorporated into the model is shown in the sectioned area on Figure 54.

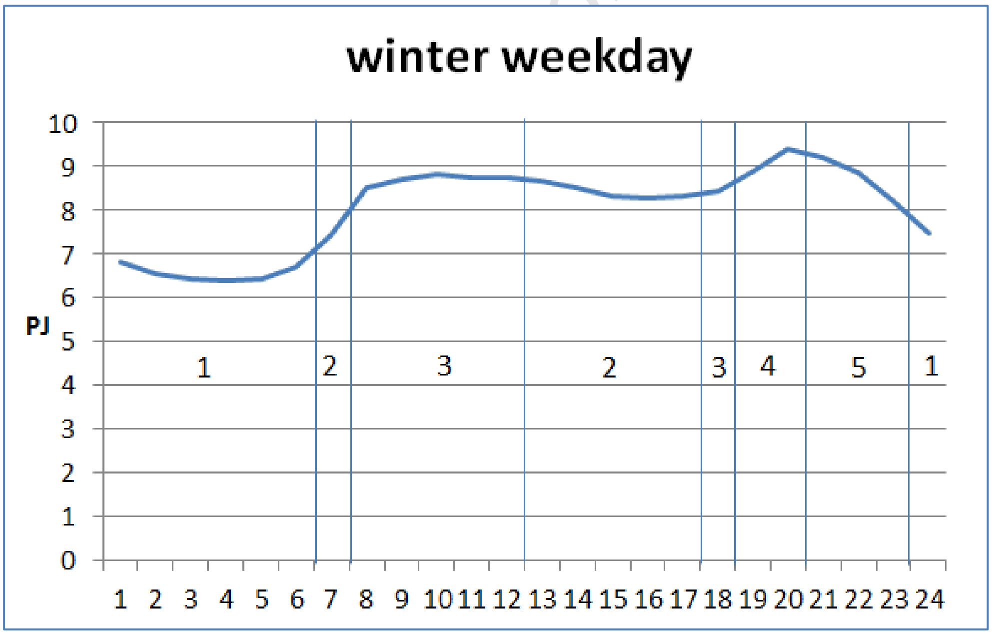


Figure 53: The energy consumption profile for electricity in South Africa for 2010 by hour. The timeslice blocks are shown as numbers and are summed together into a single block as shown in Figure 54.

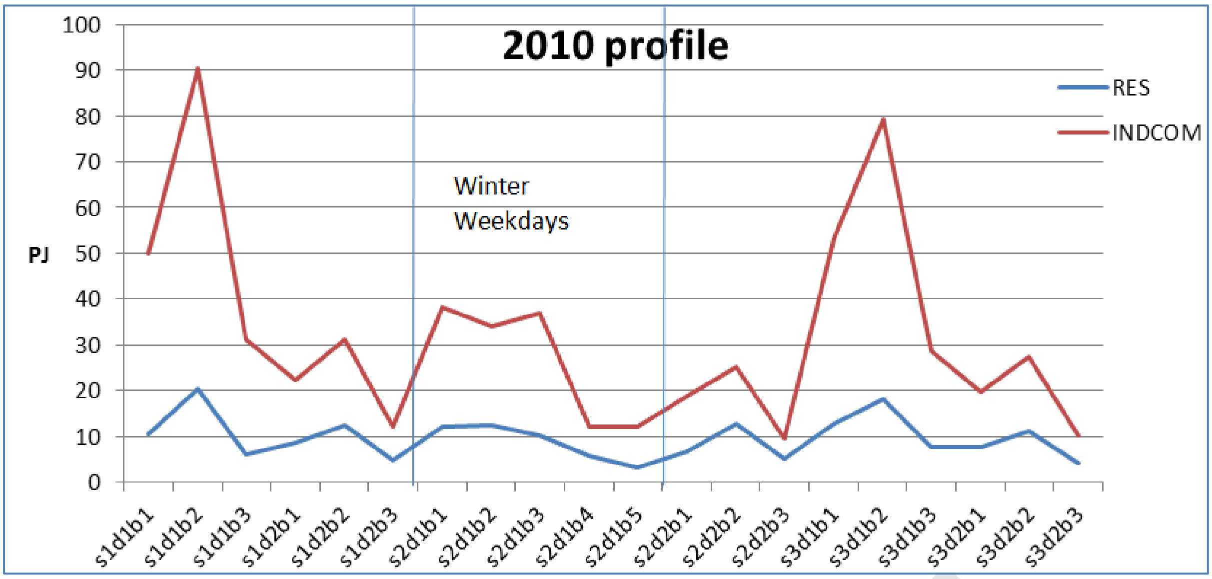


Figure 54: The energy consumption profiles for the electricity sector modelled in OSeMOSYS for the year 2010. Outlined is the winter weekday section which is profiled in Figure 53 above.

In the OSeMOSYS model, the total yearly energy consumption for each sector (RES and INDCOM) is defined in the model, as well as the fraction of this with the total sectorial consumption which occurs in each time slice over a year. This gives the model a description of both of these demands down to a single time slice for each year between 2006 and 2030. The yearly requirement for RES and INDCOM electricity is given in Table 27.

Table 27: The energy consumption for the residential and industrial and commercial sectors for the OSeMOSYS model

	PJ	
	RES ELC	INDCOM ELC
2006	188.3	573.2
2007	187.9	605.8
2008	198	620.5
2009	195.9	630.2
2010	193.5	642.8
2011	192.1	662.5
2012	192.1	684
2013	203.9	706.1
2014	205.5	727.2
2015	208.1	752.6
2016	222.6	777.6
2017	228.9	804.7
2018	262.5	845.1
2019	270.6	876.4

	RES ELC	INDCOM ELC
2020	278.2	897.8
2021	301.1	944.2
2022	302.7	976.5
2023	305.6	1009.7
2024	307.7	1045.6
2025	310	1084.6
2026	312.1	1124.8
2027	341.5	1166.3
2028	344.6	1210.6
2029	345.8	1258.4
2030	350	1308.7

4.3.3 Summary of the OSeMOSYS model

Data used for the OSeMOSYS model are presented in the previous two sections, with extra numerical constraint data in appendix 8.5.

The discount rate is assumed to be the 8% rate used by the IRP2010 and Treasury (ERC, 2012). The model runs for the period 2006 to 2030 in one year increments, and all prices and costs are in real terms. The base year in the model frame work is 2006.

The SATIM model by the ERC modelling group incorporates all energy demand and supply sectors in the country, is based in the TIMES modelling platform which is a partial equilibrium optimisation modelling software and a successor to MARKAL. The TIMES software was developed by Energy Technology Systems Analysis Programme (ETSAP) which is one of the International Energy Agency's implementing agencies (ERC, 2012). TIMES uses a the General Algebraic Modelling System (GAMS) which is a high level programming language designed for large and complex models (Rosenthal, 2012). Thus, the TIMES model created by the ERC can be used as a benchmark test for the reliability of the OSeMOSYS model, similar to the test comparison done by Howells *et al.* (2011) – see section 2.4.1.

Using the TIMES software, only the electricity sector and associated electricity demands (the same as for the OSeMOSYS model) were modelled. Using this, a comparison of the results for both the TIMES and OSeMOSYS models was conducted during the development stages of the OSeMOSYS model to ensure that the results from the OSeMOSYS model were reliable.

4.4 Added features to OSeMOSYS software

To successfully create the model in OSeMOSYS of South Africa's electricity sector, some features which are not present in the generic form of OSeMOSYS software needed to be added in. However, because OSeMOSYS is open source, these features may be added with an understanding of how to use GNUmathprog language that OSeMOSYS is written in, as well as the variables used within the software and what the task of the new additions are.

This is part of what the developers of the software wanted to achieve; a way for researchers to adjust the software to suite their purposes.

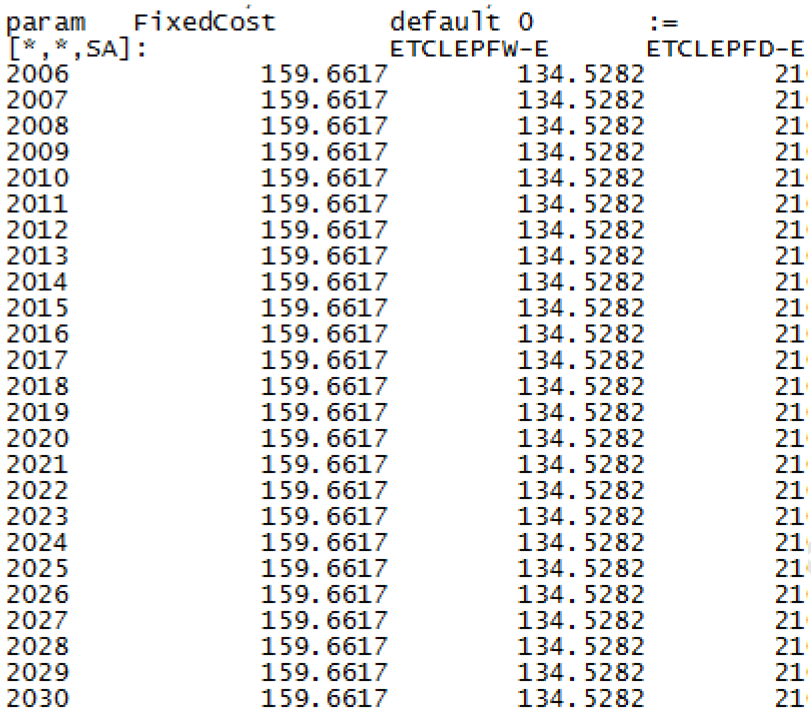
4.4.1 Varying model period during testing

During the process of creating the model in OSeMOSYS, it was often necessary to do a model run to test the effects of certain changes to data and the model in general. But the size of the model, even just being the electricity sector for South Africa, had enough parameters in it to cause the model run to be around 1400seconds in duration in the early stages of the model development. The effects of certain changes to the model often were before the end period (2030), so in order to hasten the development of the model, the open source aspect of OSeMOSYS was utilised and an extra set was added to the OSeMOSYS software called 'YEAR_X'. The software was changed in that all the data was generated into matrices as usual using the YEAR set, but the solver would only solve for the years in YEAR_X. So the user now has the ability to shorten the model run to their need in order to save on processing time. The set YEAR_X should be defined as exactly the same as set YEAR, but with the terminate or end statement ' ; ' just after the year value the user wishes the model to run up to. Example:

```
set YEAR_X := 2006 2007 2008 2009 2010 2011 2012 ; # 2013 2014 …….
```

Here, the software will optimise the model up to the year 2012 and ignore the years after this. The # token is used to comment out the text after this so that the software does not return an error about misplaced text.

The reason that the extra set for YEAR_X was used like this was because of the way that the model data is read into the software using OSeMOSYS and GLPK. The text file used to create the model is formatted in such a way that the user/analyst needs to define data for each year in the model period even if the data is constant throughout the model period, the user needs to define the data for all model years for most cases parameters. Figure 55 shows an example of the *FixedCost* parameter in OSeMOSYS showing how the data needs to be entered for each year.



```
param   FixedCost        default 0        :=
[*,*,SA]:                ETCLEPFW-E       ETCLEPFD-E
2006             159.6617         134.5282         21
2007             159.6617         134.5282         21
2008             159.6617         134.5282         21
2009             159.6617         134.5282         21
2010             159.6617         134.5282         21
2011             159.6617         134.5282         21
2012             159.6617         134.5282         21
2013             159.6617         134.5282         21
2014             159.6617         134.5282         21
2015             159.6617         134.5282         21
2016             159.6617         134.5282         21
2017             159.6617         134.5282         21
2018             159.6617         134.5282         21
2019             159.6617         134.5282         21
2020             159.6617         134.5282         21
2021             159.6617         134.5282         21
2022             159.6617         134.5282         21
2023             159.6617         134.5282         21
2024             159.6617         134.5282         21
2025             159.6617         134.5282         21
2026             159.6617         134.5282         21
2027             159.6617         134.5282         21
2028             159.6617         134.5282         21
2029             159.6617         134.5282         21
2030             159.6617         134.5282         21
```

Figure 55: Example of parameter defining in OSeMOSYS.

This needs to be done for a lot of parameters used in OSeMOSYS, and each parameter needs an end statement token (;) to designate the end point of the data for that parameter. To simply change the original YEAR set to only go up to the desired year would require that the user place an end statement token at the appropriate location for each parameter used, otherwise GLPK will give an 'out of domain' error essentially meaning that it does not recognise data points past the last year in the YEAR set. In a text file that is on the order of 3000 lines, to add and end statement token to the appropriate place for each parameter every time the user wanted to change the model period, would be tedious and error prone.

With the added feature of set YEAR_X, it allows the user to easily change the period length without having to change the entire model data file. To do a full model period run, the user simply needs to define set 'YEAR_X' as exactly the same as set 'YEAR'.

4.4.2 Production limits

During the process of creating the electricity sector in OSeMOSYS, one parameter that is used in models such as TIMES, was the constraint on the minimum use of a technology. In the SA system, the gas turbine plants were required to run a minimum of 3% of their potential per year. More so, this was required for existing and not yet existing gas turbine plants. In the original OSeMOSYS software, one parameter called 'TotalTechnologyAnnualActivityLowerLimit' defines the total minimum activity of the plants that are assigned to this parameter. However, this is in energy units, and in the case of the SA system where a minimum percentage is required rather than minimum energy units output, it would not be known to the user or analyst at the time of creating the model whether gas turbines would be built in the model and by how much. To get around this aspect, the parameter 'TotalTechnologyAnnualPercentileActivityLowerLim' was added for both upper and lower percentile limits to account for this requirement.

In wording the description of this parameter is defined as;

The total fuel produced by the technology must be less than the percentage limit multiplied by the sum over the year of: the maximum output possible after accounting for availability and capacity factors.

The same description of the parameter (for the lower limit) in mathematical language;

$$\forall\ t \in Technologies\ s.t{:}\ TotalTechnologyAnnualPercentileActivityLowerLim \neq 0\ then{:}$$

$$\sum_{f\ \ in\, Fuels} ProductionByTechnologyAnnual\,(y,t,f,r)$$

$$\geq \sum_{\substack{l\ \ in \\ TimeSlices}} \big(Capacity(y,t,r) \times CapacityFactor(y,t,l,r) \times YearSplit(y,l)\big)$$
$$\times AvailabilityFactor(y,t,r) \times CapacityToActivity(t,r)$$
$$\times PercentileLowerLimit(y,t,r)$$

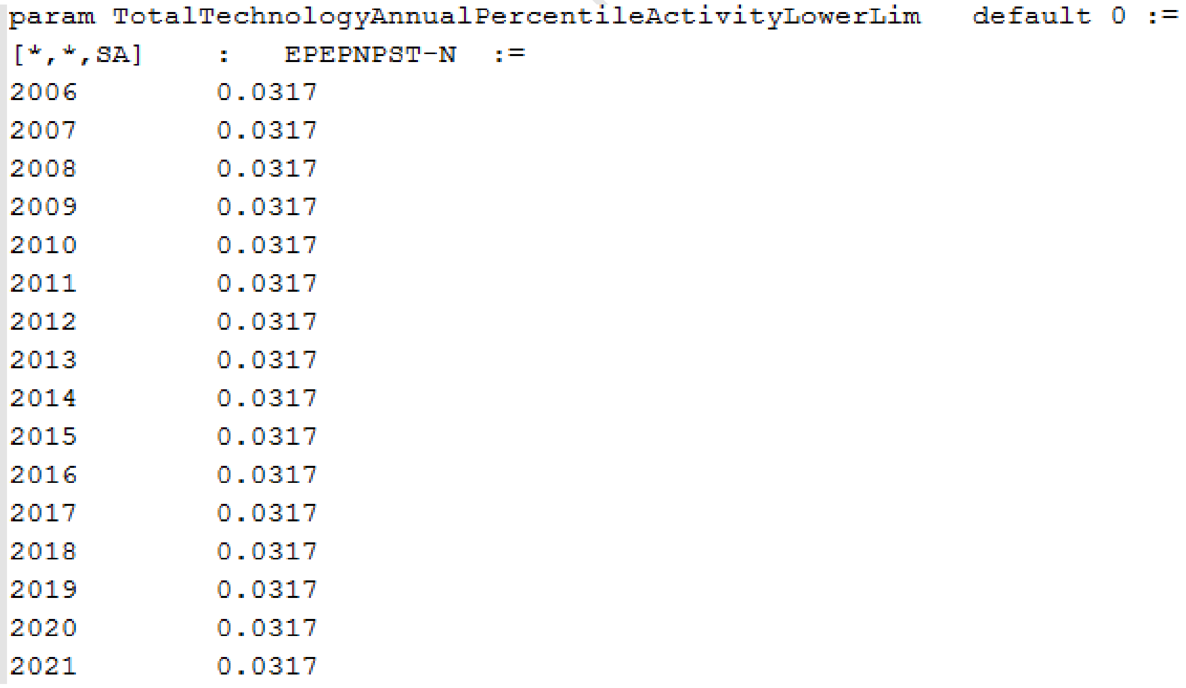
The logic is the same for the upper limit, save for the change in equality (≥) and the percentile limit parameter.

This is put into the OSeMOSYS software as (verbatim):

```
s.t. X1_TotalAnnualtechnologyProdPercentUppLimit {y in YEAR, t in TECHNOLOGY, r in REGION:
TotalTechnologyAnnualPercentileActivityUpperLim[y,t,r]<1} : sum{f in
FUEL}ProductionByTechnologyAnnual[y,t,f,r] <=  sum{l in TIMESLICE}
(TotalCapacityAnnual[y,t,r]*CapacityFactor[y,t,l,r]*YearSplit[y,l])*
AvailabilityFactor[y,t,r]*CapacityToActivityUnit[t,r]*TotalTechnologyAnnualPercentileActivityUpperLim[y,t,r] ;
```

```
s.t. X2_TotalAnnualtechnologyProdPercentLowLimit {y in YEAR, t in TECHNOLOGY, r in REGION:
TotalTechnologyAnnualPercentileActivityLowerLim[y,t,r]<>0} : sum{f in
FUEL}ProductionByTechnologyAnnual[y,t,f,r] >=  sum{l in TIMESLICE}
(TotalCapacityAnnual[y,t,r]*CapacityFactor[y,t,l,r]*YearSplit[y,l])*
AvailabilityFactor[y,t,r]*CapacityToActivityUnit[t,r]*TotalTechnologyAnnualPercentileActivityLowerLim[y,t,r] ;
```

The analyst needs to specify only the technologies these constraints apply to and the percentage that is required for each year. An extract of this new parameter is shown in Figure 56, where a limit of 3.17% is imposed on all new pumped storage turbines.



```
param TotalTechnologyAnnualPercentileActivityLowerLim   default 0 :=
[*,*,SA]     :    EPEPNPST-N   :=
2006          0.0317
2007          0.0317
2008          0.0317
2009          0.0317
2010          0.0317
2011          0.0317
2012          0.0317
2013          0.0317
2014          0.0317
2015          0.0317
2016          0.0317
2017          0.0317
2018          0.0317
2019          0.0317
2020          0.0317
2021          0.0317
```

Figure 56: An extract for the new parameter added to OSeMOSYS to limit the production based on capacity.

4.4.3 Storage

The storage used by pumped storage technologies needs to be charged during off peak periods which are designated by the block 1 timeslices (b1). There are two technologies associated with the storage; the pump and the turbine. In reality, these are the same thing; however, in the OSeMOSYS model the different capacity factors and availabilities as well as the requirement for an off peak specific storage charging scheme, means that two technologies needed to be created to simulate the operation of the pumped storage. This is a common feature in models like the TIMES model. The pump charges the dam during the off peak timeslices and the turbine generates electricity and has its own capacity factor and availability factor just as an ordinary generating technology except it uses the dam as a fuel supply. The pump and the turbine are the same thing in reality, one simply running in reverse. This is modelled as two technologies which cannot operate at the same time. A diagram of how the storage system is modelled is shown in Figure 57.

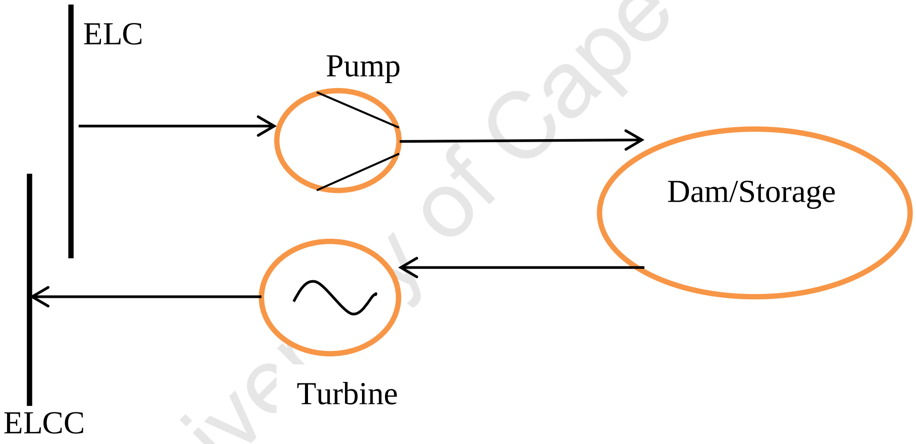


Figure 57: A diagram depicting the storage in the model.

Originally, to account for the storage charging times in OSeMOSYS, the pump technology was given its own capacity factor of 1 for the block 1 timeslices and zero for all others – hence turning it off during all other timeslices except for off peak periods. However, the results for the charging and discharging of storage indicated that the storage was being charged during the timeslices where the pump has zero capacity factors. It was unclear why this was happening, and instead, an easier approach to fixing this was a workaround by creating a new parameter specifically to designate when storage could be charged.

The timeslices representing daytime, nigh time, intermediate times, seasons and days of the week, may not be chronological in any modelling software, but the storage system does need a chronological framework in order to operate correctly (Welsch et al., 2012). Conversion factors were introduced into OSeMOSYS in later versions of the software by the developers to convert the timeslices used in the model into chronological order. There are three conversion factors that were introduced into the OSeMOSYS 2012 07 27 beta version by the developers, namely; *Conversionls*, *Conversionld* and *Conversionlh* representing season, daytype and hours of the day respectively.

The new parameter introduced as a workaround to the storage problem is called *TSforChargingStorage* for ‘timeslices for charging storage’ and designates which hours can be used for charging.

The parameter is assigned by the user as follows;

For each time group conversion ‘lh’ (corresponding to the 1 to 5 timeslice blocks), a ‘1’ is assigned to the timeslice corresponding to that block. An extract from the model to highlight this idea is shown in Figure 58.

```
param TSforChargingStorage default 1 :=
[*,*]:      s1d1b1    s1d1b2    s1d1b3    s1d2b1     .....

1           1         0         0         1          ….
2           0         0         0         0          0          ….
3           0         0         0         0          0          ….
4           0         0         0         0          0          ….
5           0         0         0         0          0          ….
```

Figure 58: An extract of the parameter created to specify charging of storage.

In this model the first hour bracket is the off peak charging time for storage which is the b1 timeslice blocks.

This parameter is added into the OSeMOSYS version 2012 07 27 beta equation S1 which defines the rate of charge for the storage system in the model as shown below:

$$\forall\, s \in Storage, y\ in\ Year, ls\ in\ Season, ld \in Daytype, lh\ \in DailyTimeBracket\ s.t\ TechnologyToStorage(t,m,s,r) > 0\ then:$$

$$\sum_{\substack{t \in Technology \\ m \in ModesOfOperation \\ l \in Timeslice}} RateOfActivity(y,l,t,m,r) \times TechnologyToStorage(t,m,s,r) \\ \times TSforChargin Storage(lh,l) \times Conversionls(ls,l) \times Conversionld(ld,l) \\ \times Conversion(lh,l) = RateOfStorageCharge(s,y,ls,ld,lh,r)$$

Thus making the storage unable to charge at any timeslices other than the block one timeslices (b1).

Here, *TechnologyToStorage* is a parameter which is given a value by the user when setting up the model - the user specifies which technologies from the *TECHNOLOGY* set (see section 4.2) is the pump or charging technology for the storage system.

The *RateOfActivity* is implicitly defined in Equation 16 in section 4.2. The *Conversionls, ld, and lh* variables are the parameters added by the developers to create chronological order in the timeslices of the model. They are designated in the same way as the *TSForChargingStorage* variable is, in Figure 58.

4.5 Summary of added parameters

In order to successfully create a working electricity sector model of South Africa in OSeMOSYS, three new additions and adaptions to the OSeMOSYS software were required:

- A new set was created, called Year_X, which allows the user or analyst to vary the modelling period desired during development of the model in order to save on precious run time. The user needs to create the Year_X set as the original Year set, and simply place a '; #' token in the set corresponding to the year that they desire to model up to. This feature will greatly reduce the amount of time the solver runs for large models.
- Two new parameters were created called *TotalTechnologyAnnualPercentileActivityLowerLim* and *TotalTechnologyAnnualPercentileActivityUpperLim* which allows the user to specify the minimum and maximum percentage operating limits of the capacity of desired technologies. A parameter already exists in the software to limit the production of energy by technologies, but this existing parameter only affects the production in units of energy, which means that the capacity (GW) of the technology is not accounted for. The technology will operate at a minimum or maximum regardless of any new capacity that may be added. This new parameter takes into account the

capacity of the technology, and thus the amount of max or min production will change if the installed capacity changes.

- A new parameter called *TSforChargingStorage* designates explicitly which time blocks of the timeslices, may charge the storage system. The user needs to designate which *conversionlh* block (the hour brackets) is allowed to charge the storage. If no value is given to this parameter, then there is no change to the OSeMOSYS storage equations and the model will operate as the version 2012 07 27 beta.

4.6 Net metering scenarios

The effect of net metering or EG can be modelled as a separate energy generating technology downstream of transmission and distribution based on the projected scale of capacity, or equivalently by calculating the total energy produced by net metering and then subtracting this from the residential consumption profile. The latter is more efficient in that no extra technology and all related variables are required, and so the model can run faster. Also, the net metered capacity of PV is modelled based on various factors which are not present in the electricity sector and cannot be optimised, such as private uptake of the technology based on environmental concerns or financial concerns to the user, or the municipal rate of electricity in residential sectors. Based on these shortcomings, the best method to implement net metering capacity was to model and project it separately and then input the data into the model.

Using the approximation in section 3.1.5.3, the total production can be calculated by taking the average over the number of sunlight hours of the insolation fractions as presented in Figure 41, and then multiplying this with the average. These capacity factors for each timeslice are given in the 2nd column of Table 28. The production by solar PV for each timeslice is calculated as

Equation 26

$$E = P \times CF \times duration$$

Where E is the energy output in joules, P is the power in watts, and *duration* is the amount of time (seconds) per timeslice. The production profile is presented in Table 28 for both HIGH and LOW penetration scenarios.

Table 28 : The production by the solar PV scenarios

		HIGH										
timeslice	Solar PV CF		2012	2014	2016	2018	2020	2022	2024	2026	2028	2030
		Total PJ	**0.068**	**0.114**	**0.557**	**0.959**	**2.826**	**4.781**	**7.875**	**16.819**	**25.264**	**35.762**
s1d1b1	0		0	0	0	0	0	0	0	0	0	0
s1d1b2	0.40		0.017	0.029	0.142	0.245	0.722	1.222	2.013	4.299	6.458	9.142
s1d1b3	0		0	0	0	0	0	0	0	0	0	0
s1d2b1	0.02		0.000	0.000	0.002	0.003	0.010	0.017	0.028	0.060	0.089	0.127
s1d2b2	0.42		0.008	0.013	0.065	0.112	0.331	0.561	0.923	1.972	2.962	4.193
s1d2b3	0		0	0	0	0	0	0	0	0	0	0
s2d1b1	0		0	0	0	0	0	0	0	0	0	0
s2d1b2	0.38		0.007	0.011	0.055	0.095	0.279	0.472	0.778	1.661	2.495	3.531
s2d1b3	0.35		0.006	0.010	0.050	0.085	0.252	0.426	0.701	1.498	2.250	3.185
s2d1b4	0		0	0	0	0	0	0	0	0	0	0
s2d1b5	0		0	0	0	0	0	0	0	0	0	0
s2d2b1	0		0	0	0	0	0	0	0	0	0	0
s2d2b2	0.40		0.006	0.010	0.049	0.084	0.247	0.418	0.689	1.471	2.210	3.128
s2d2b3	0		0	0	0	0	0	0	0	0	0	0
s3d1b1	0.02		0.000	0.001	0.004	0.007	0.020	0.034	0.056	0.120	0.181	0.256
s3d1b2	0.42		0.016	0.027	0.132	0.228	0.670	1.134	1.868	3.990	5.993	8.484
s3d1b3	0		0	0	0	0	0	0	0	0	0	0
s3d2b1	0.02		0.000	0.000	0.002	0.003	0.009	0.015	0.024	0.051	0.077	0.109
s3d2b2	0.42		0.007	0.012	0.056	0.097	0.285	0.482	0.795	1.697	2.549	3.608
s3d2b3	0		0	0	0	0	0	0	0	0	0	0

Table extended on following page*

		LOW										
timeslice	Solar PV CF		2012	2014	2016	2018	2020	2022	2024	2026	2028	2030
		Total PJ	**0.002**	**0.003**	**0.027**	**0.043**	**0.155**	**0.257**	**0.428**	**0.954**	**1.544**	**2.417**
s1d1b1	0		0	0	0	0	0	0	0	0	0	0
s1d1b2	0.40		0.001	0.001	0.007	0.011	0.040	0.066	0.109	0.244	0.395	0.618
s1d1b3	0		0	0	0	0	0	0	0	0	0	0
s1d2b1	0.02		0.000	0.000	0.000	0.000	0.001	0.001	0.002	0.003	0.005	0.009
s1d2b2	0.42		0.000	0.000	0.003	0.005	0.018	0.030	0.050	0.112	0.181	0.283
s1d2b3	0		0	0	0	0	0	0	0	0	0	0
s2d1b1	0		0	0	0	0	0	0	0	0	0	0
s2d1b2	0.38		0.000	0.000	0.003	0.004	0.015	0.025	0.042	0.094	0.153	0.239
s2d1b3	0.35		0.000	0.000	0.002	0.004	0.014	0.023	0.038	0.085	0.138	0.215
s2d1b4	0		0	0	0	0	0	0	0	0	0	0
s2d1b5	0		0	0	0	0	0	0	0	0	0	0
s2d2b1	0		0	0	0	0	0	0	0	0	0	0
s2d2b2	0.40		0.000	0.000	0.002	0.004	0.014	0.022	0.037	0.083	0.135	0.211
s2d2b3	0		0	0	0	0	0	0	0	0	0	0
s3d1b1	0.02		0.000	0.000	0.000	0.000	0.001	0.002	0.003	0.007	0.011	0.017
s3d1b2	0.42		0.001	0.001	0.006	0.010	0.037	0.061	0.102	0.226	0.366	0.573
s3d1b3	0		0	0	0	0	0	0	0	0	0	0
s3d2b1	0.02		0.000	0.000	0.000	0.000	0.000	0.001	0.001	0.003	0.005	0.007
s3d2b2	0.42		0.000	0.000	0.003	0.004	0.016	0.026	0.043	0.096	0.156	0.244
s3d2b3	0		0	0	0	0	0	0	0	0	0	0

Using the HIGH and LOW penetration scenarios from 3.1.5.1, the capacity for rooftop PV combined with the capacity factors for solar PV technology and the time slice durations, the total production by time slice for both high and low scenarios were determined. Using the production by timeslice for HIGH and LOW scenarios, the net metering scenarios were implemented into the model by subtracting the production of electricity by the rooftop PV from the residential electricity consumption in each timeslice. This was done for all years after and including 2012. The total yearly consumption for all scenarios is given in Table 29. The initial profile for the residential sector and the industry and commerce sector are given in the Figure 59

Table 29: The yearly profiles of the sectors in the model for all the scenarios

	Consumption (PJ)			
	RESELC			ICELC
Scenario:	**REF**	**LOW**	**HIGH**	**all**
2006	188.3	188.3	188.3	573.2
2007	187.9	187.9	187.9	605.8
2008	198.0	198.0	198.0	620.5
2009	195.9	195.9	195.9	630.2
2010	193.5	193.5	193.5	642.8
2011	192.1	192.1	192.1	662.5
2012	192.1	192.1	192.0	684.0
2013	203.9	203.9	203.8	706.1
2014	205.5	205.5	205.4	727.2
2015	208.1	208.0	207.8	752.6
2016	222.6	222.5	222.2	777.6
2017	228.9	228.9	228.5	804.7
2018	262.5	262.4	261.9	845.1
2019	270.6	270.5	269.8	876.4
2020	278.2	278.0	276.5	897.8
2021	301.1	300.9	298.9	944.2
2022	302.7	302.5	299.8	976.5
2023	305.6	305.3	301.9	1009.7
2024	307.7	307.3	302.9	1045.6
2025	310.0	309.2	303.9	1084.6
2026	312.1	311.2	304.6	1124.8
2027	341.5	340.3	332.2	1166.3
2028	344.6	343.0	333.3	1210.6
2029	345.8	343.9	332.3	1258.4
2030	350.0	347.6	334.0	1308.7

.

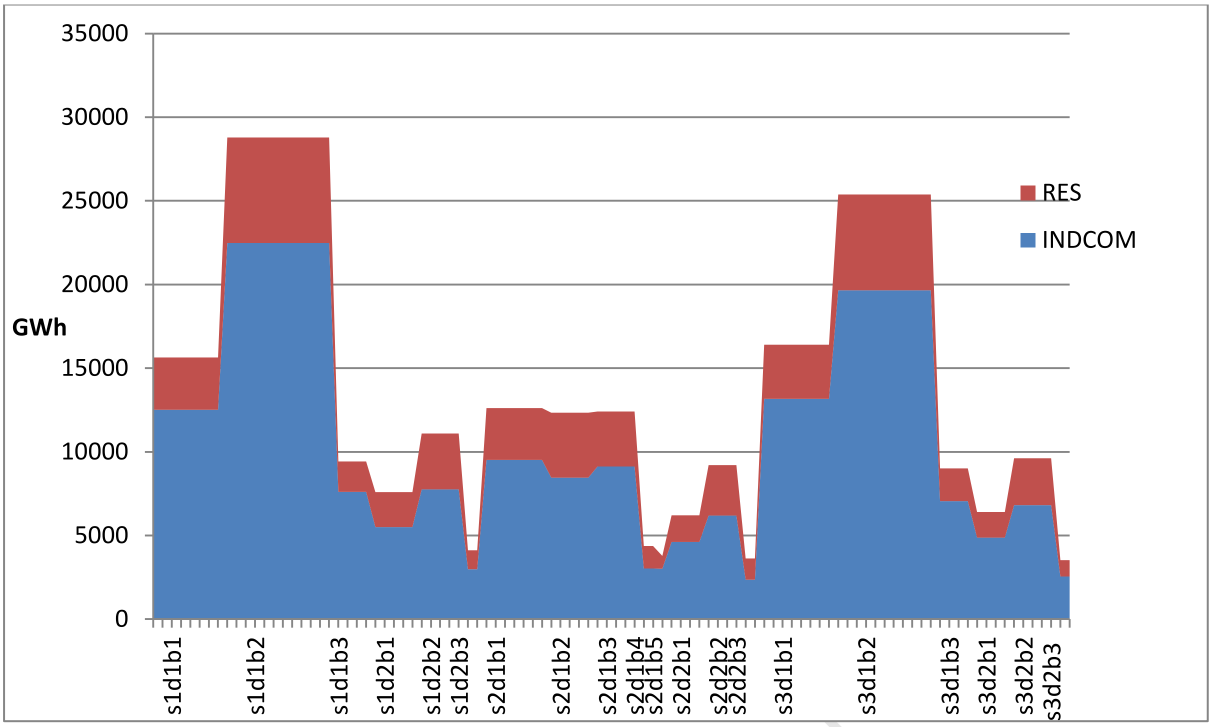


Figure 59: The 2006 energy profiles for the model. RES: the residential, INDCOM: all other sectors combined.

And the initial power demand is shown in Figure 60.

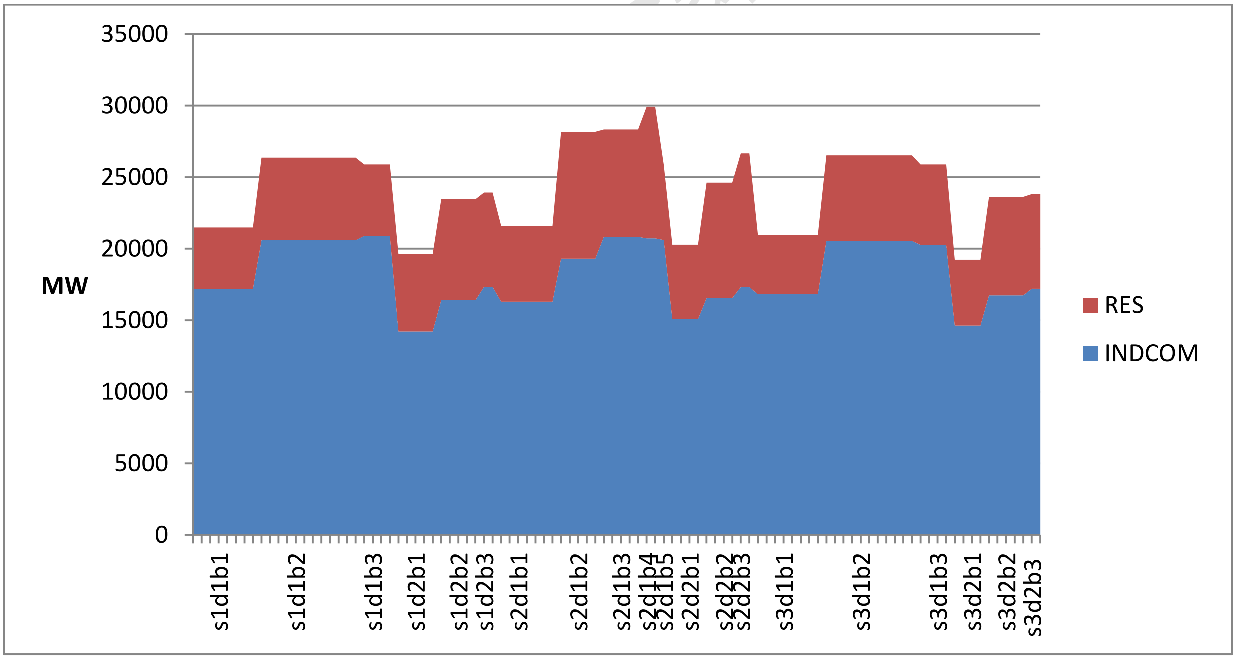


Figure 60: The power profile for 2006, showing residential, industry and commerce contributions

With the high and low penetration levels of net metering of solar rooftop PV in place, the energy profiles for the residential sector in 2030 when the largest capacity of net metering is installed is shown in Figure 61.

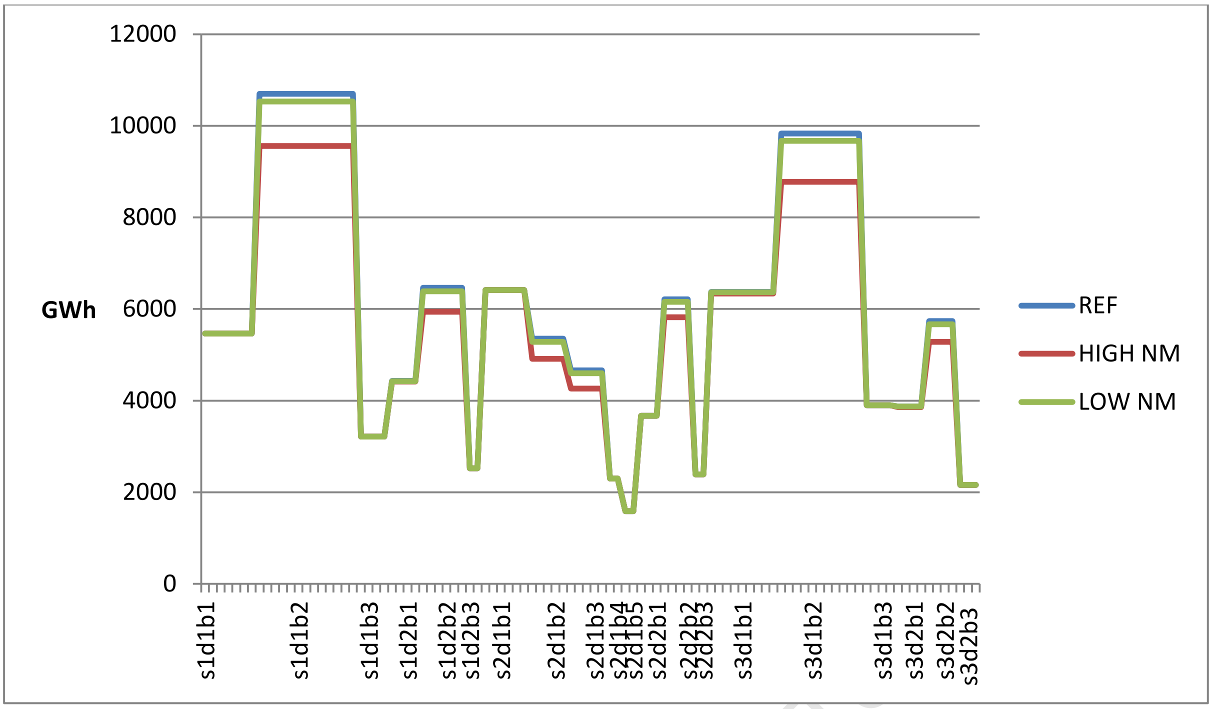


Figure 61: The consumption profiles for the residential sector in 2030. Included are the altered profiles as a result of the rooftop solar PV net metering.

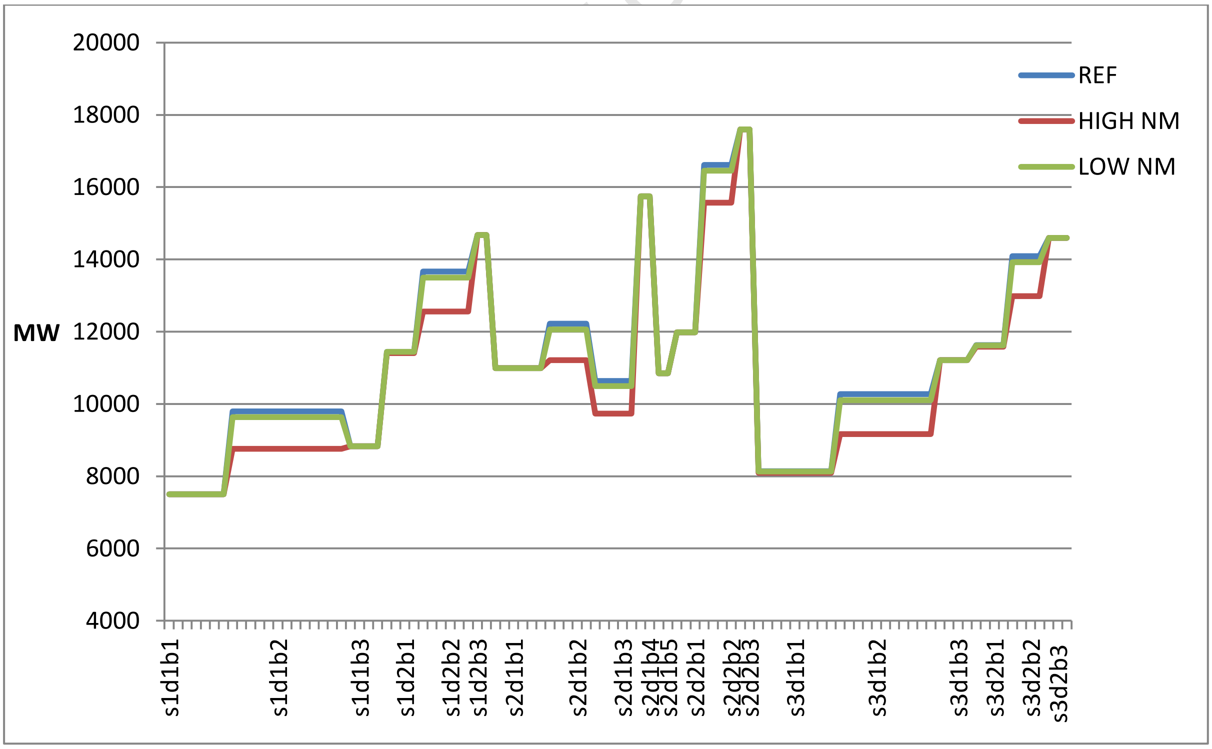


Figure 62: The power profile for the residential sector in 2030, showing the changes with the presence of high and low penetration levels of net metering.

With the net metering capacity installed, the energy consumption in the residential sector is reduced in some of the timeslices as indicated in Figure 61. However, the peak power demand does not change, as shown in Figure 62. While the overall power demand does change, the peak demands do not, as the peaks occur at times when there is no sunshine – mostly in the early mornings and evenings.

In Figure 62, the power demand just before the peaks occur is reduced as a result of the solar PV, but the peak is not - indicating that the power demand changes faster from afternoon to evening, a factor that may affect the peaking capacity of the system.

To study the impact of this change in residential profile on the electricity sector, three copies of the OSeMOSYS model were created – one for each of the scenarios: the reference (no net metering), the low penetration scenario (LOW), and the high penetration scenario (HIGH) for net metering in the residential sector. The model for each of the scenarios was then run, using the OSeMOSYS software and the GLPK solver. The results for each of the model runs was then tabulated and analysed as discussed in the next section.

5 Results and discussion

The results of the OSeMOSYS model of the South African electricity sector are compared, as a benchmark, to the electricity sector model in the TIMES software (referred to as the TIMES model from here on) in order to establish the reliability of the operation of the OSeMOSYS software. Total capacity, new capacity and reserve margins are compared. Differences are studied in further detail in order to establish any kind of difference in the operation of OSeMOSYS with the well-established TIMES software.

The model is then run for all three scenarios for net metering as described in 4.6, and the results of the net metering scenarios –the HIGH and LOW scenarios are compared with the reference scenario (REF- without net metering) in order to establish the impact of net metering in the country. Various factors are studied including the total new capacity, the new capacities of the technologies, and production levels by timeslices in each scenario, and the degree of the changes between scenarios are analysed. Effects of changing the discount rates within the energy model are also analysed.

5.1 Comparing TIMES and OSeMOSYS

This section gives the results for the OSeMOSYS and the TIMES models and compares the two. The reference scenario is run in both software programmes, and the results for new capacity builds and production are studied. The performance related aspects of both software are also analysed.

5.1.1 New capacity

The total new capacity added each year for both the TIMES and OSeMOSYS models are shown in Figure 63.

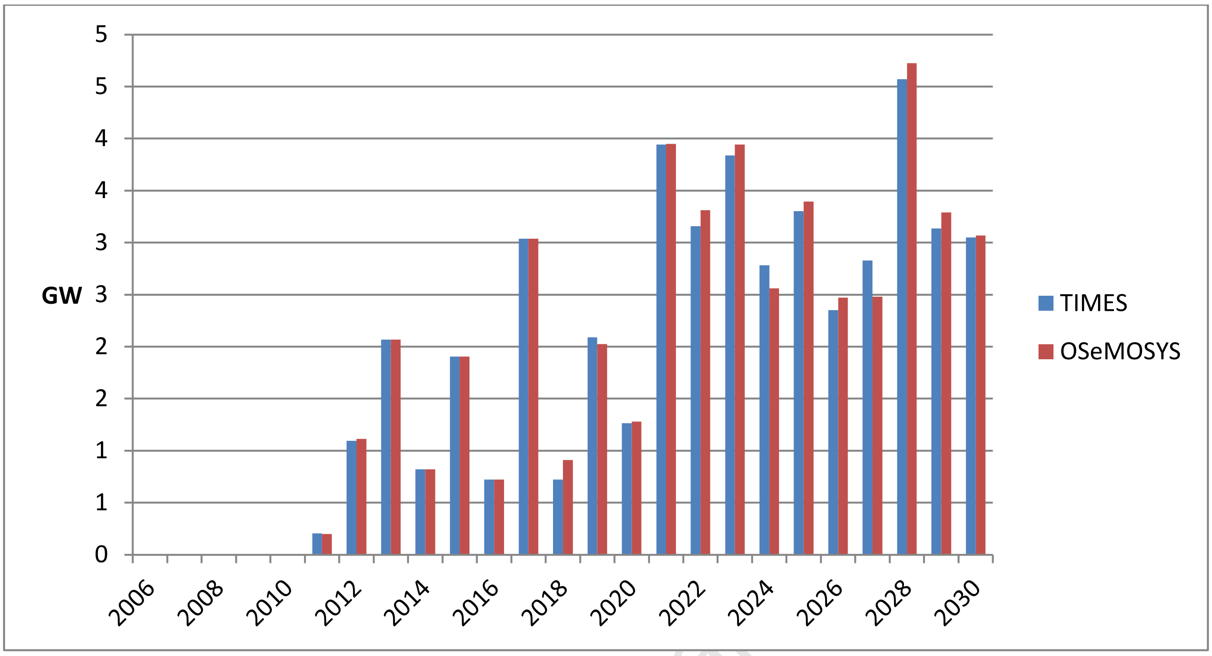


Figure 63: The total new capacity added per year for each model.

A breakdown of the total new added capacities for the two models are presented in Figure 64 and Figure 65. Table 30 and Table 31show these new builds per year by technology category.

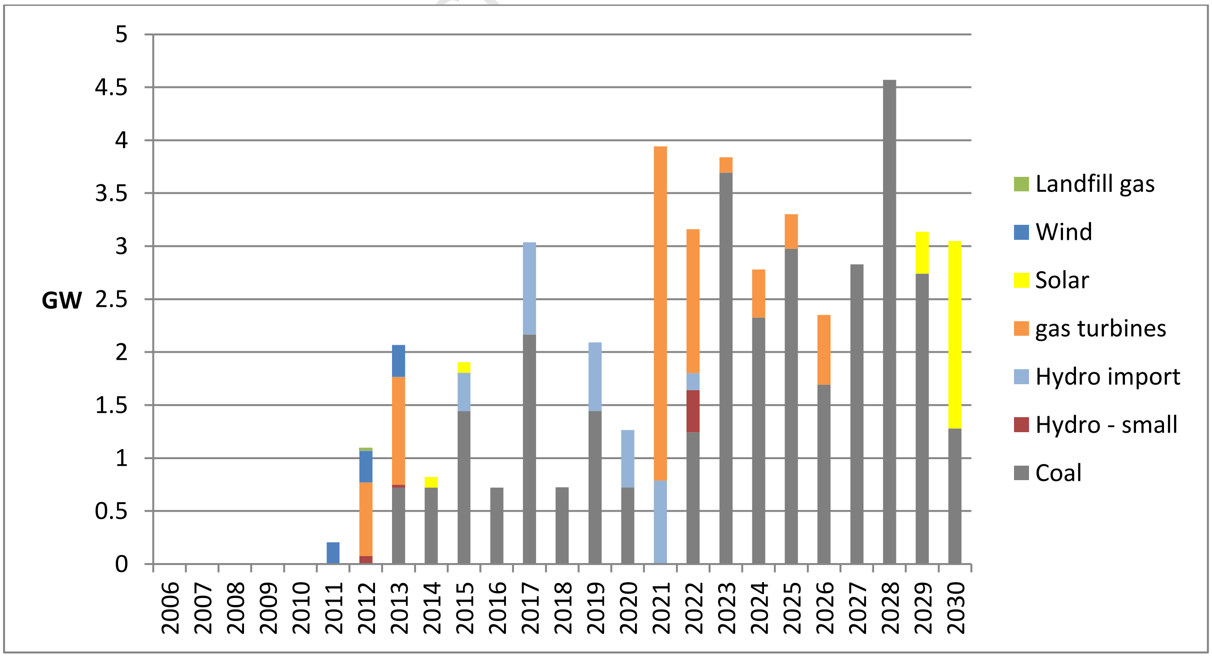


Figure 64: The total new build for the TIMES model.

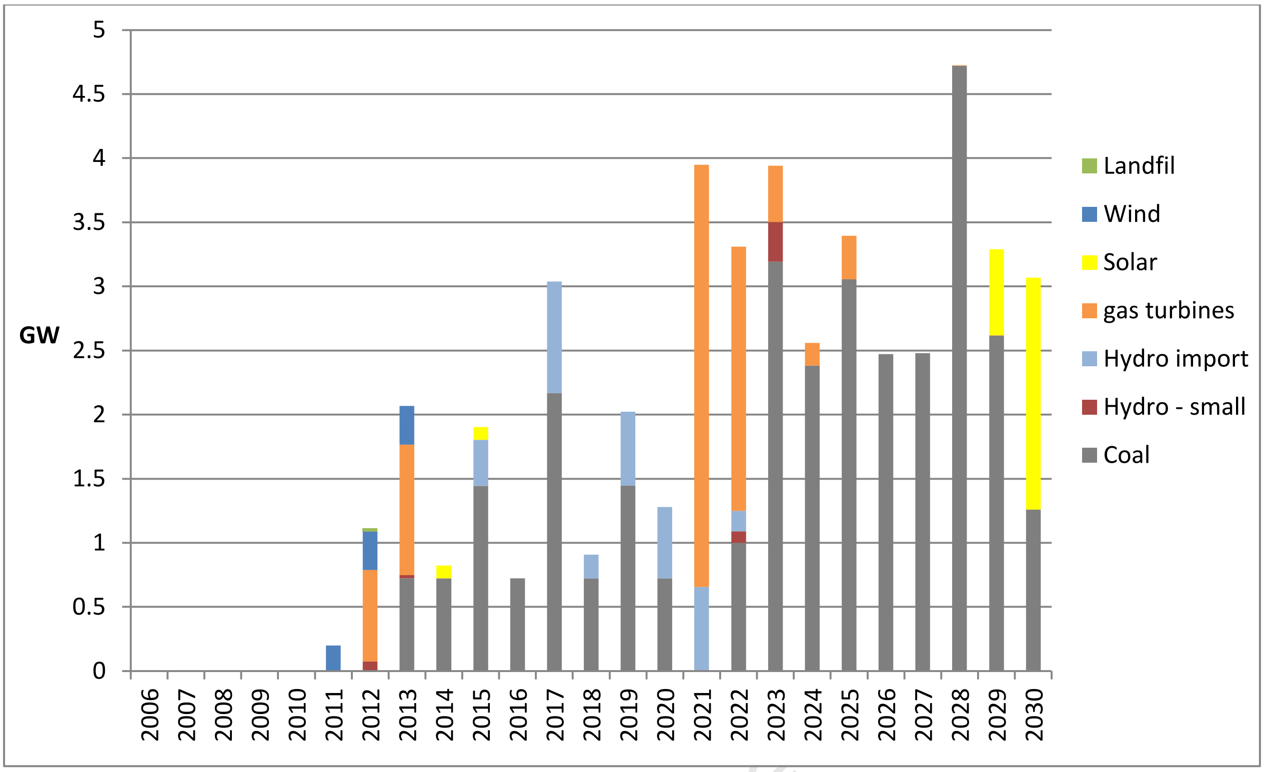


Figure 65: The total new build for the OSeMOSYS model

A complete breakdown by each individual technology is given in Table 51 in appendix 8.7.1.

Table 30: The total new capacity for the TIMES model.

	Coal	**Hydro - small**	**Hydro import**	**gas turbines**	**Solar**	**Wind**	**Landfill gas**	**Total**
2006	0	0	0	0	0	0	0	0
2007	0	0	0	0	0	0	0	0
2008	0	0	0	0	0	0	0	0
2009	0	0	0	0	0	0	0	0
2010	0	0	0	0	0	0	0	0
2011	0	0	0	0.00	0	0.20	0	0.20
2012	0	0.08	0	0.69	0	0.30	0.03	1.09
2013	0.72	0.03	0	1.02	0	0.30	0	2.07
2014	0.72	0	0	0	0.10	0	0	0.82
2015	1.44	0	0.36	0	0.10	0	0	1.90
2016	0.72	0	0	0	0	0	0	0.72
2017	2.17	0	0.87	0	0	0	0	3.04
2018	0.72	0	0	0	0	0	0	0.72
2019	1.45	0	0.64	0	0	0	0	2.09
2020	0.72	0	0.54	0	0	0	0	1.26
2021	0	0	0.79	3.15	0	0	0	3.94
2022	1.24	0.4	0.16	1.36	0	0	0	3.16
2023	3.69	0	0	0.15	0	0	0	3.84

	Coal	Hydro - small	Hydro import	gas turbines	Solar	Wind	Landfill gas	Total
2024	2.33	0	0	0.45	0	0	0	2.78
2025	2.98	0	0	0.33	0	0	0	3.30
2026	1.69	0	0	0.66	0	0	0	2.35
2027	2.83	0	0	0	0	0	0	2.83
2028	4.57	0	0	0	0	0	0	4.57
2029	2.74	0	0	0	0.40	0	0	3.14
2030	1.28	0	0	0	1.77	0	0	3.05

Table 31: The total new capacity for the OSeMOSYS model

	Coal	Hydro - small	Hydro import	gas turbines	Solar	Wind	Landfill	Total
2006	0	0	0	0	0	0	0	0
2007	0	0	0	0	0	0	0	0
2008	0	0	0	0	0	0	0	0
2009	0	0	0	0	0	0	0	0
2010	0	0	0	0	0	0	0	0
2011	0	0	0	0	0	0.20	0	0.20
2012	0	0.08	0	0.71	0	0.30	0.03	1.11
2013	0.72	0.03	0	1.02	0	0.30	0	2.07
2014	0.72	0	0	0	0.10	0	0	0.82
2015	1.44	0	0.36	0	0.10	0	0	1.90
2016	0.72	0	0	0	0	0	0	0.72
2017	2.17	0	0.87	0	0	0	0	3.04
2018	0.72	0	0.19	0	0	0	0	0.91
2019	1.45	0	0.58	0	0	0	0	2.02
2020	0.72	0	0.56	0	0	0	0	1.28
2021	0	0	0.66	3.29	0	0	0	3.95
2022	1	0.09	0.16	2.06	0	0	0	3.31
2023	3.19	0.31	0	0.44	0	0	0	3.94
2024	2.38	0	0	0.18	0	0	0	2.56
2025	3.06	0	0	0.34	0	0	0	3.40
2026	2.47	0	0	0	0	0	0	2.47
2027	2.48	0	0	0	0	0	0	2.48
2028	4.72	0	0	0.01	0	0	0	4.72
2029	2.62	0	0	0.00	0.67	0	0	3.29
2030	1.26	0	0	0	1.81	0	0	3.07

The difference in the new capacity built between the TIMES model and OSeMOSYS model are shown in Figure 66. See also Table 52 in appendix 8.7.1 for the numerical data for this figure.

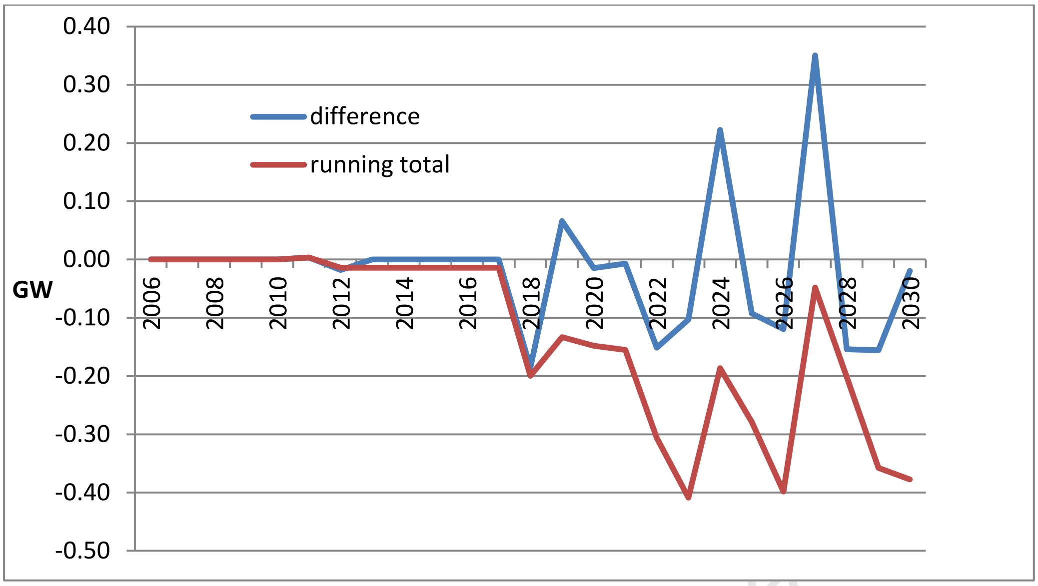


Figure 66: The difference in capacity added per year between the TIMES and OSeMOSYS models. Positive indicates the TIMES model builds more than OSeMOSYS.

There are 4 out of 18 possible technologies in the new capacity additions which are built more in the one model than the other. These 4 are indicated in Table 32 below. These are the only technologies which differed in capacity between the two models.

Table 32: The difference in new capacity builds (GW) for technologies which have non-zero difference between the models. Positive indicates TIMES built more, negative indicates OSeMOSYS built more.

	Gas closed cycle	**Gas Open cycle**	**Super-critical coal**	**Solar tower 12hr storage**
2011	0	0.004	0	0
2012	0	-0.018	0	0
2013	0	0	0	0
2014	0	0	0	0
2015	0	0	0	0
2016	0	0	0	0
2017	0	0	0	0
2018	0	0	0	0
2019	0	0	0	0
2020	0	0	0	0
2021	-0.193	0.052	0	0
2022	0.213	-0.917	0	0

2023	0	-0.295	0	0
2024	0	0.277	0.691	0
2025	0	-0.013	-0.079	0
2026	0	0.659	-0.778	0
2027	0	0	0.350	0
2028	-0.005	0	-0.149	0
2029	-0.004	0	0.124	-0.276
2030	0	0	0.020	-0.040
subtotal	**0.011**	**-0.252**	**0.180**	**-0.315**
total				**-0.377**

The total difference in build capacity between the two models is 0.377 GW more in the OSeMOSYS model than in the TIMES model. Out of the total model capacity of 78.9GW (excl. pumped storage) this represents 0.5% difference in capacity. The small differences between the two models can probably be attributed in some way to number rounding issues within the two models.

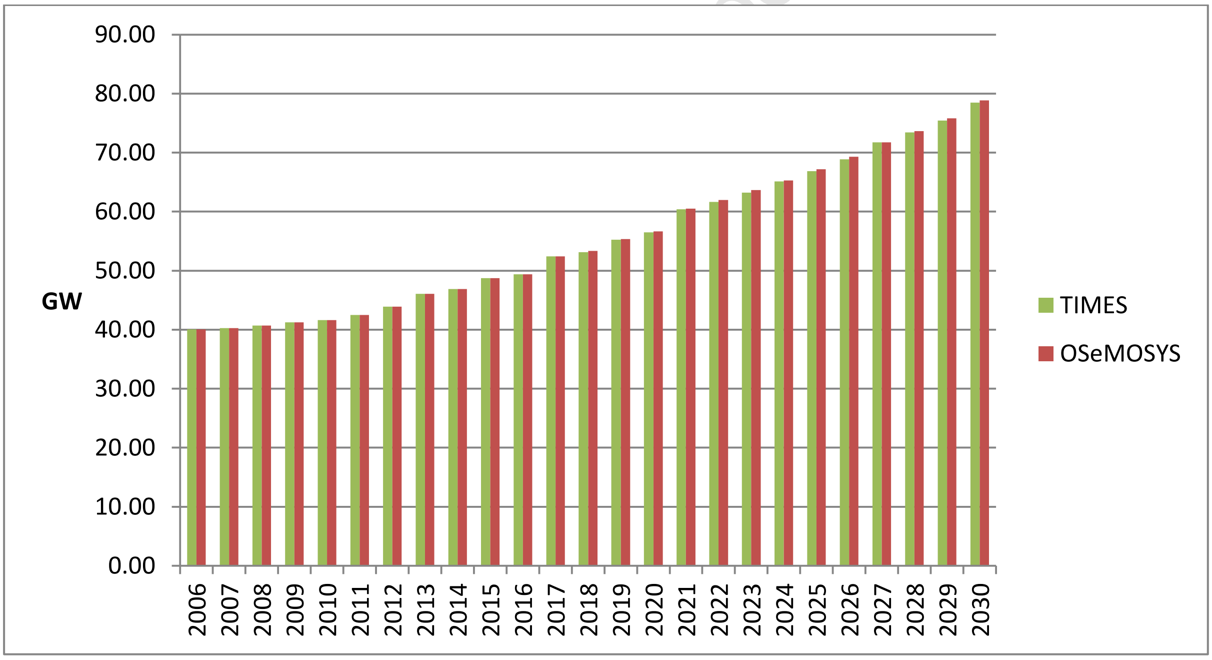


Figure 67: The total capacity in the system for both TIMES and OSeMOSYS models.

The capacity of the electricity sector in South Africa grows from 40.06GW in 2006 to 78.87GW in 2030 (excluding storage) as in Figure 67.

The reserve margin for both models are given in Table 33, and are calculated using Equation 25.

Table 33: The reserve margins for both models

	Capacity incl. storage (GW)		**Peak demand (GW)**		**Reserve Margin (%)**	
	TIMES	**OSeMOSYS**	**TIMES**	**OSeMOSYS**	**TIMES**	**OSeMOSYS**
2006	41.64	41.64	34.26	34.56	21.5	20.5
2007	41.83	41.83	34.33	34.56	21.8	21.0
2008	42.31	42.31	35.11	35.42	20.5	19.5
2009	42.82	42.82	37.46	37.83	14.3	13.2
2010	43.20	43.20	38.41	38.75	12.5	11.5
2011	44.08	44.08	39.54	39.85	11.5	10.6
2012	45.48	45.49	40.60	41.01	12.0	10.9
2013	47.98	47.99	42.57	42.87	12.7	12.0
2014	49.80	49.81	43.31	43.77	15.0	13.8
2015	51.65	51.67	44.50	44.89	16.1	15.1
2016	52.30	52.31	46.26	46.72	13.0	12.0
2017	55.34	55.35	48.09	48.57	15.1	14.0
2018	56.06	56.26	50.11	50.59	11.9	11.2
2019	58.15	58.29	52.02	52.43	11.8	11.2
2020	59.42	59.56	53.17	53.59	11.7	11.1
2021	63.29	63.44	56.69	57.12	11.6	11.1
2022	64.58	64.88	57.86	58.43	11.6	11.1
2023	66.14	66.55	59.28	59.94	11.6	11.0
2024	68.01	68.20	60.98	61.44	11.5	11.0
2025	69.79	70.07	62.60	63.14	11.5	11.0
2026	71.62	72.02	64.27	64.91	11.4	10.9
2027	74.45	74.50	66.41	67.17	12.1	10.9
2028	76.17	76.37	68.38	68.87	11.4	10.9
2029	78.18	78.54	70.23	70.84	11.3	10.9
2030	81.23	81.60	73.00	73.63	11.3	10.8

The reserve margins between the two models are almost identical for every year of the model period. Both models had a minimum of 10% reserve margin as a constraint, and both have kept at least 10.6% reserve of upstream demand (ELCC).

5.1.2 Performance

The TIMES software runs the whole model in roughly 10 seconds, including pre-processing of data. OSeMOSYS runs the model in 680 seconds or 11mins for the optimisation part of the process, and does not include the approximately 45 to 60 seconds of pre-processing (matrix generating) the data for solving. Also, OSeMOSYS required 5.4GB of memory to process this model, while TIMES used approximately 60MB of memory.

Both OSeMOSYS and TIMES models were run on the same computer; a PC desktop running windows 7 SP1, 64-bit, with an Intel i5 CPU at 3.2GHz and 8GB RAM.

5.1.3 Comparison

From all the results and comparisons, the biggest difference between the OSeMOSYS and the TIMES software, is the performance. The run time of OSeMOSYS using the GLPK solver is almost 2 orders of magnitude larger than the TIMES model which uses GAMS as a solver. A possible explanation of this would be the memory handling of the software.

However, this performance has in no way affected the accuracy of the two energy models in almost all aspects. The only issue, which was discussed in 4.4.3, is the operation of storage in the OSeMOSYS model. The storage technology was forced to operate and produce at the appropriate times, and an extra parameter was required in order to get the storage to charge correctly.

Although the run time for the OSeMOSYS software was about 680 seconds, it is still a viable option for energy modelling purposes. Thus, the OSeMOSYS software may be utilised without issue.

5.2 Net metering scenarios

The effects of net metering of solar rooftop PV in the residential sector of the energy model are discussed in this section. The energy production from the LOW and HIGH penetration levels of net metering solar rooftop PV were deducted from the residential sector demand in the OSeMOSYS model of South Africa as discussed in section 4.6. These were implemented separately and results deduced from both.

The graph in Figure 68 shows the effect of net metering on the residential power profile for the electricity sector. The average weighted[15] residential demand for 2030 without net

---

[15] For the duration of the timeslices.

metering (REF scenario) is 11209MW and 10697MW for high levels (HIGH scenario) of penetration of net metering, and 11132MW for low levels. A 4.6% and 0.9% decrease respectively. The total (including industry and commerce) power profile is reduced by 1.7% and 0.35% for the HIGH and LOW scenarios respectively and is summarised in Table 34.

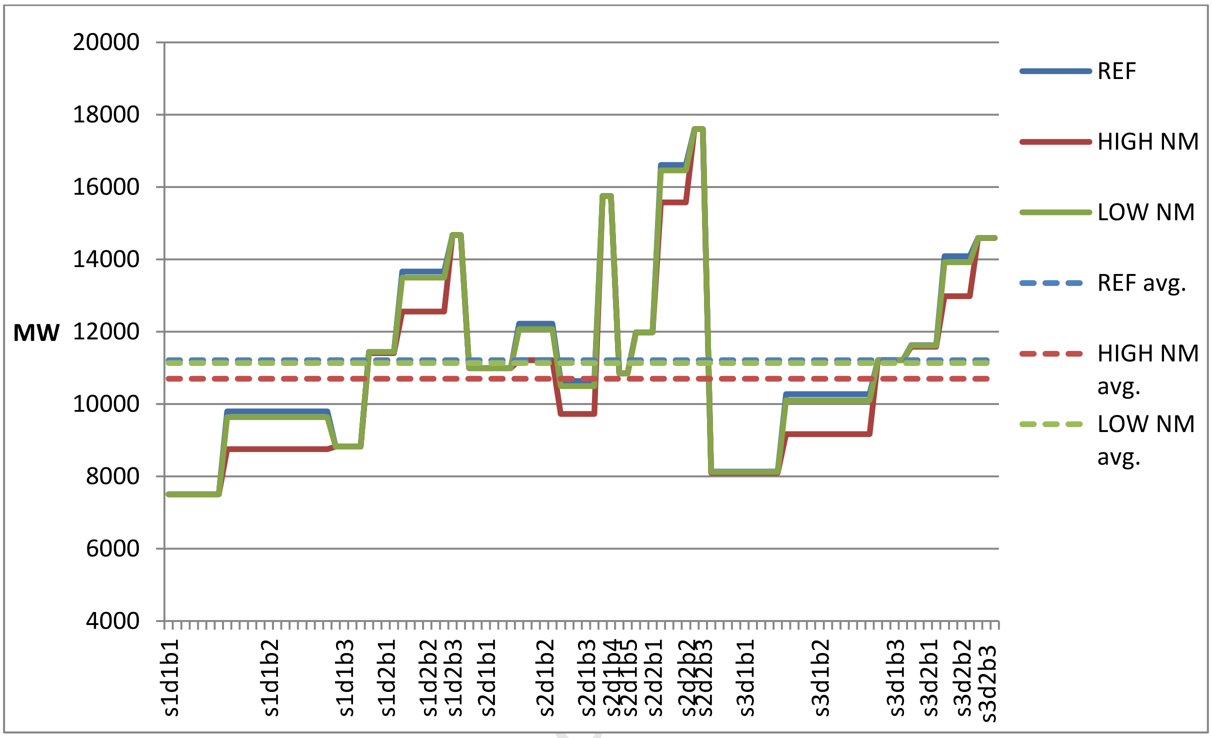


Figure 68: The residential power profile for the model with high and low penetration levels of net metered solar rooftop PV in 2030. The average weighted power for each scenario is also shown.

Table 34: Summary of the total power profiles for the three scenarios in OSeMOSYS. This includes the industry and commerce sectors.

	REF	**HIGH**	**LOW**
Max	36574.5	36574.5	36574.5
Min	24686.2	24686.2	24686.2
Avg	29325.8	28814.6	29248.7
%		1.74%	0.26%

The load duration curve of the whole electricity sector of the year 2030 is given in Figure 69 and shows the profile for the REF case, and HIGH and LOW net metering scenarios.

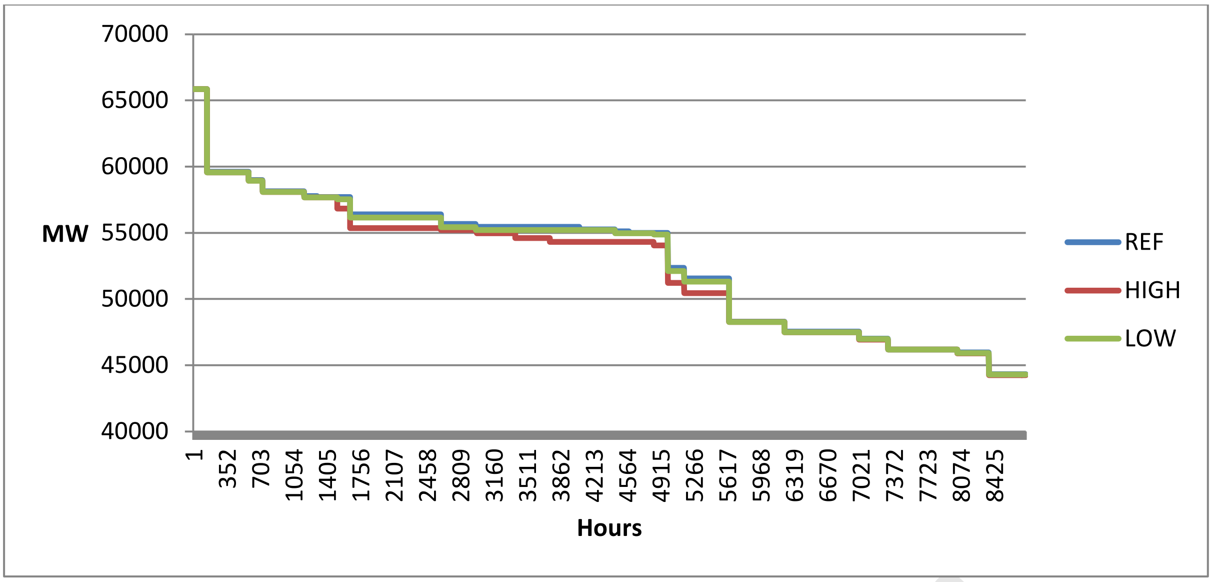


Figure 69: The load duration curve for the electricity system with HIGH and LOW penetration levels of net metering for the year 2030.

As Figure 69 shows, the solar rooftop PV reduces some of the baseload demand between 1400 and 5620 hours. The peak demand of the system is unaltered between 1 and 1000 hours. The peak power demands are not reduced by the presence of solar rooftop PV net metering which occurs at times when there is little or no sunshine.

The total reduction of demand and consumption increases as the solar rooftop market grows with time by the end of the model period as more and more people invest in solar rooftop PV for net metering at home. The last 2 years (2029 and 2030) having the largest demand reductions show the most change in how the upstream electricity is generated, and these two years show the potential impact of solar rooftop PV.

Since the peak power demand is not reduced, the overall new build capacity between the model with and without net metering does not change. The total new generating capacity built in each scenario is 47.3 GW and as a total, does not differ between the HIGH, LOW and REF scenarios (see Table 53 in appendix 8.7.1 for the numeric values for the total capacity per year in each scenario). However, there is a difference in how the models invest in the generating technologies.

For the complete breakdown of all new technology builds in the model, see Table 54 , and Table 55 for the LOW and HIGH technology builds respectively, in appendix 8.7.1

The new capacity build differences in technologies between the scenarios are shown in Table 35 below. This table gives the difference of the total new build of the technologies. The technologies listed are the only ones which are different from the REF case.

Table 35: The new capacity builds difference between the scenarios and the reference case (without net metering). Positive indicates more build in the scenario than the reference, negative indicates less than the reference.

	% difference from REF scenario			
	Gas closed cycle	**Gas Open cycle**	**Super-critical coal**	**Solar tower 12hr storage**
LOW	-0.05%	1.1%	-0.5%	3.9%
HIGH	-0.4%	9.5%	-3.2%	16.8%

The results in Table 35 are presented in Table 28 in GW units (to compare) and in Figure 70 to further demonstrate how the model adjusts the investment into technologies. The total capacity does not change, but the energy model changes how much of each of these technologies is invested in.

Table 36: The capacity difference by technology between ref case and high and low penetration levels of rooftop Solar PV.

	Capacity difference (GW) of scenarios with the REF scenario by technology				
	Gas closed cycle	**Gas Open cycle**	**Super-critical coal**	**Solar tower 12hr storage**	**Total**
LOW	-0.002	0.05	-0.145	0.096	0
HIGH	-0.014	0.444	-0.847	0.417	0

These results (in Table 35 and Table 36) shows that with the presence of net metering there is a shift of new build preference from super critical coal to more concentrated solar thermal tower (with 12hr storage) and more open cycle gas turbines[16]. Figure 70 shows these results graphically.

---

[16] It should be noted that Gas open/combined cycle turbines refers to the natural gas operated turbines, and diesel turbines will be explicitly stated as diesel where necessary.

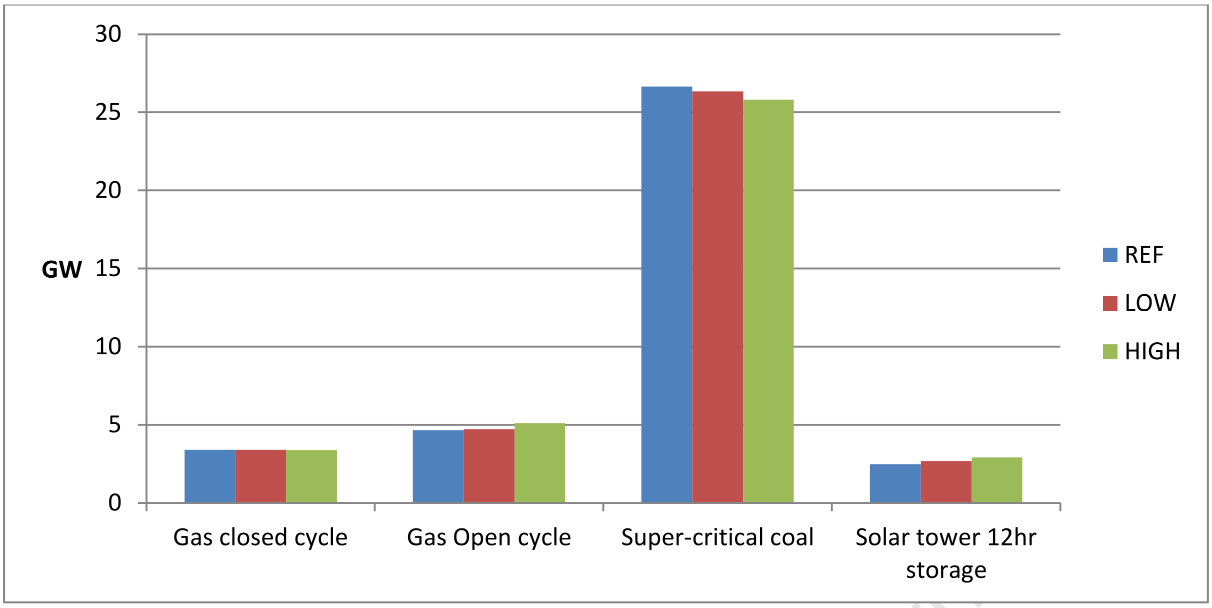


Figure 70: The new build capacities of technologies in the system which is affected by the presence of net metering.

Investment in the base load technology; super critical coal, is reduced with increasing levels of net metering, a 1.1% increase of open cycle gas turbines in the LOW penetration scenario which goes up to 9.5% in the HIGH penetration level scenario. Super critical coal is reduced by 0.5% and by 3.2% for LOW and HIGH penetration levels respectively, while investment increases for concentrated solar thermal tower (12hr storage) by 3.9% and 16.8% respectively. One conclusion to draw from this is, with the presence of net metering it becomes more cost effective to build solar thermal and gas turbines to produce extra energy at times when the net metering does not export onto the grid and thus solar and gas would buffer the effects of net metering.

To investigate this, the total extra energy (relative to the reference case) produced by solar thermal tower and gas turbines were analysed to see if they produced at time slices when net metering doesn’t reduce the residential demand. Since there is concentrated solar thermal tower and open cycle gas capacity in the reference case, the energy produced over and above that from the reference case needed to be analysed to isolate the effects of net metering present in the system. The production of energy from these technologies for the year 2030 is shown in Figure 71.

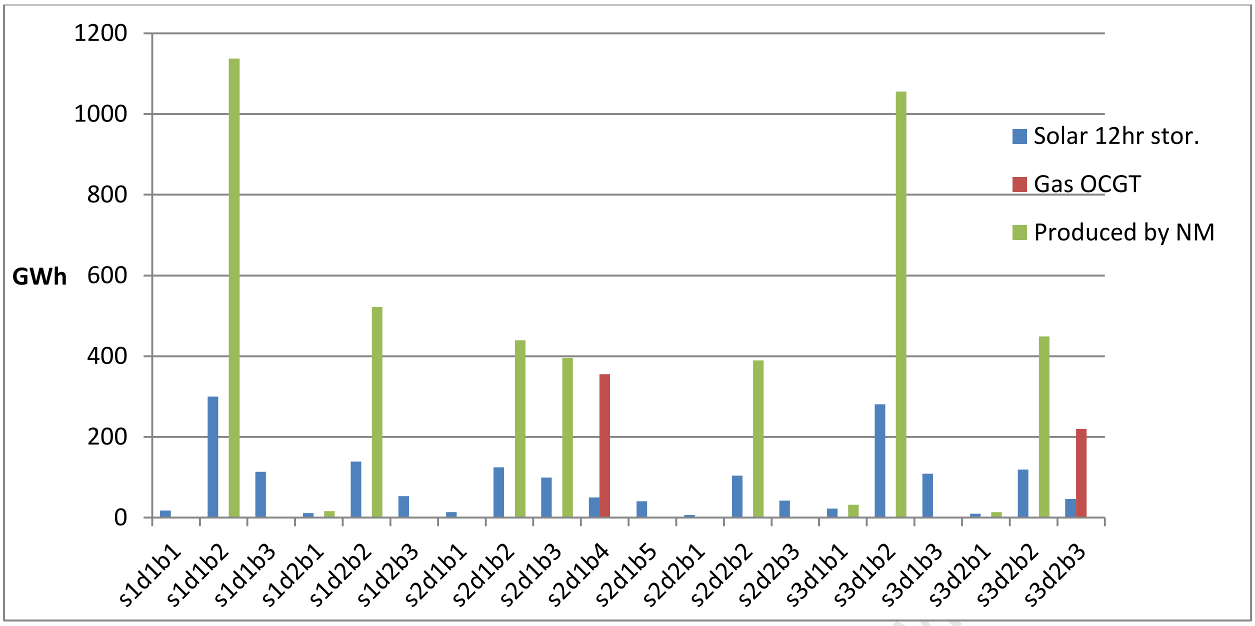


Figure 71: The extra production of energy relative to the reference case, from solar thermal and open cycle gas compared with the production from net metering for the year 2030.

The net metering solar PV produces the most energy in the same timeslices as the solar thermal tower technology which would be expected since both are sunshine dependant. Figure 68 in the previous results, shows the timeslice s2d1b4 - winter weekday evenings which is the largest demand peak.

The gas turbine produces only when there is the largest power peak. The net metering of solar rooftop PV doesn't reduce this peak, and in fact, it reduces the power demand in block 3 – early evening, but not in block 4 where the largest peak occurs. The peak demand which occurs in the winter evenings when people arrive home and start cooking and switching on heaters, and is when there are low levels of sunshine and thus very little production from solar rooftop PV. The result is that the demand in the afternoon leading into the evening is reduced, but the peak in the evening is not. Thus the change in demand is larger from afternoon to evening with net metering in place than without net metering. The model thus requires more peak power capacity - a technology with faster response, and hence builds the extra gas turbines in the net metering scenario.

To investigate why the model invests in extra concentrated solar tower technology with 12hr storage and less in coal technologies, the changes in electricity production of all technologies within the model are analysed in order to see how the net metering has changed the overall production profile. Figure 72 and Figure 73 show the percentage change of production for each technology type during 2029 and 2030 respectively.

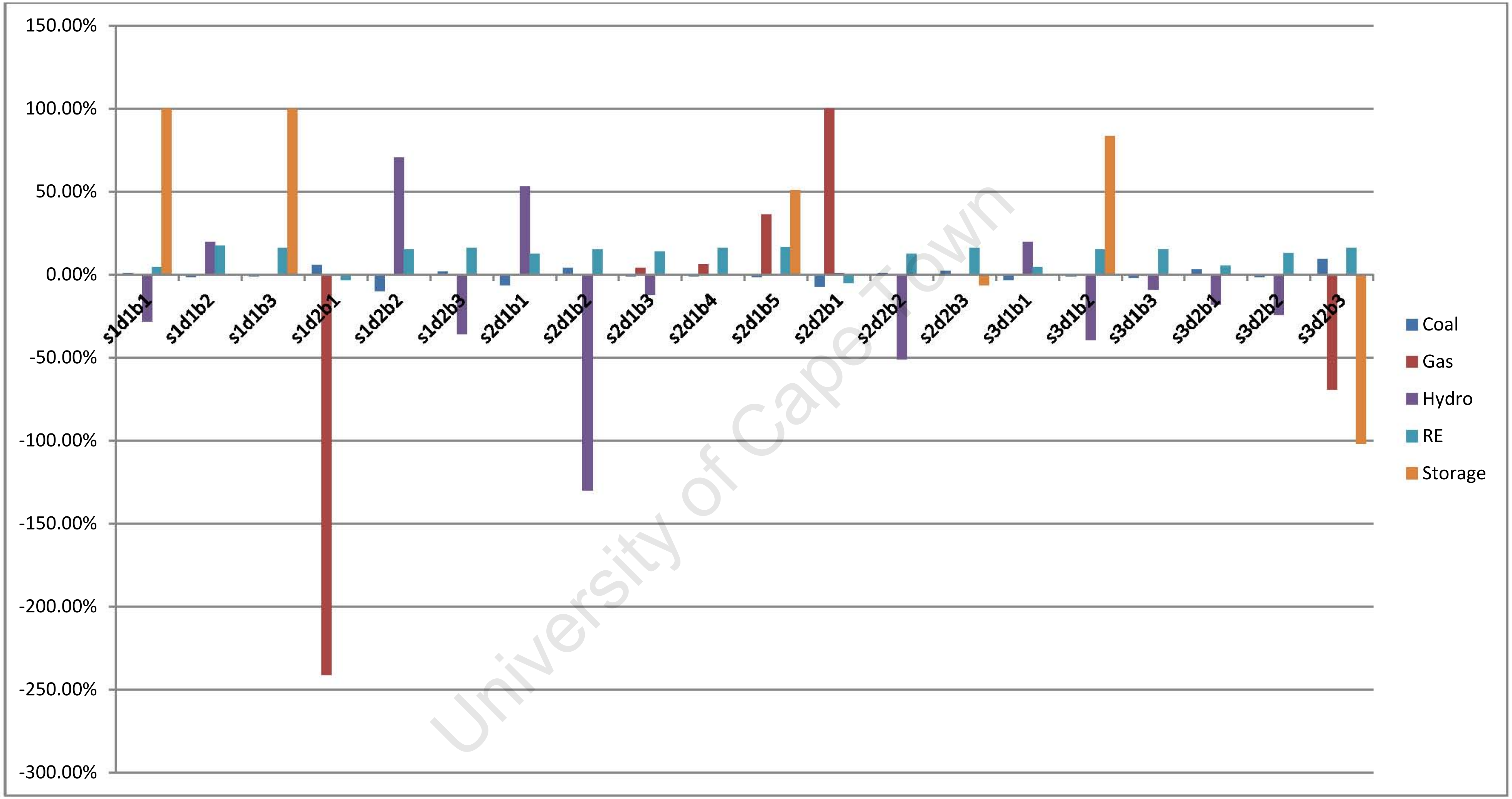


Figure 72: The % change of production by technology and by timeslice for 2029, showing how the HIGH scenario of net metering affects the production profiles of the other technologies. The presence of net metered rooftop solar PV causes the model to change how the generating technologies produce. Note that in 2029 there is 2.2GW of solar rooftop PV in the residential sector.

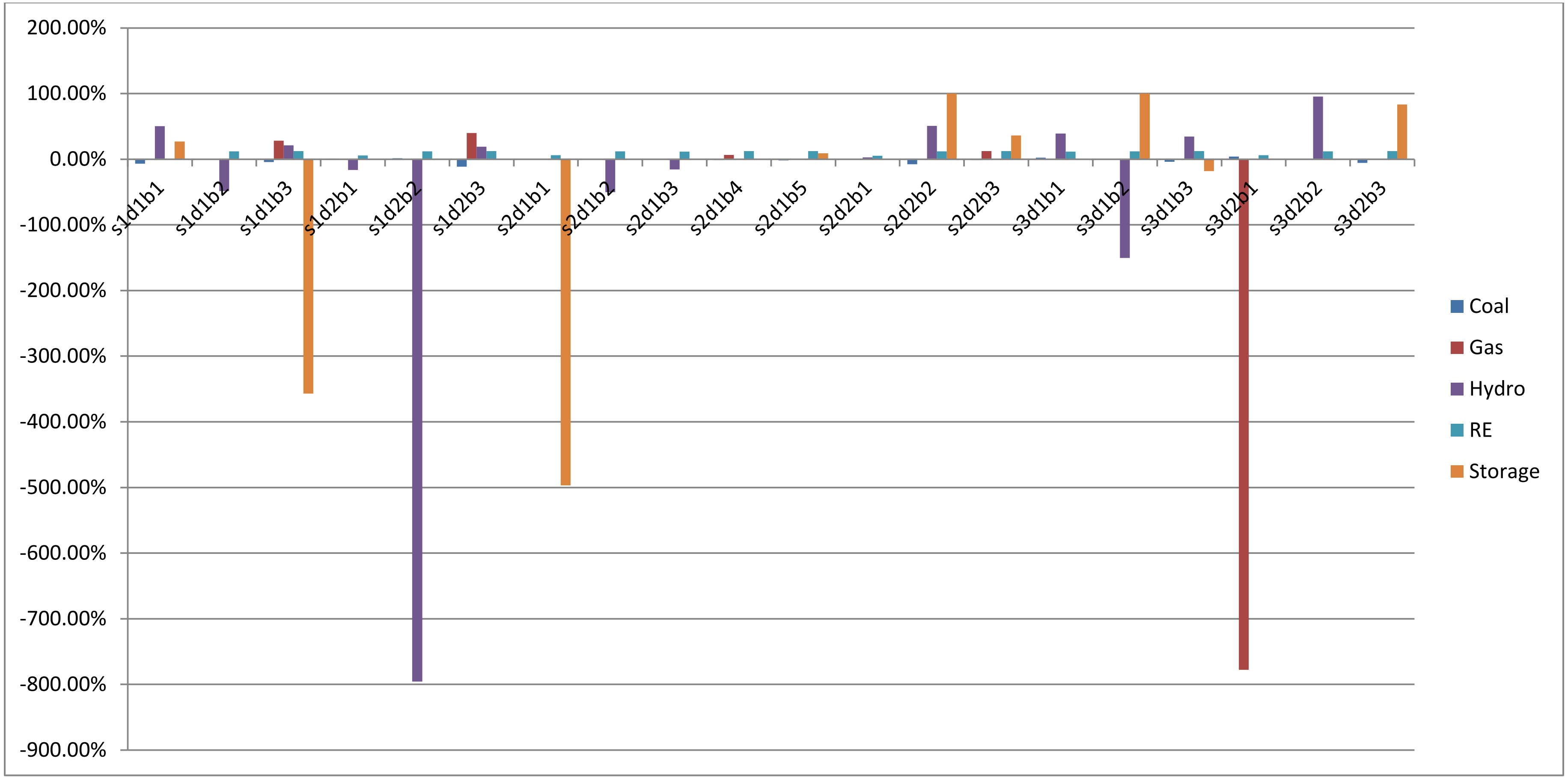


Figure 73: The % change of production by technology and by timeslice for 2030, showing how the HIGH penetration of net metering scenario affects the production profiles of the other technologies in the model. Note that there is roughly 2.6GW of solar rooftop PV in the residential sector in 2030.

From the figures above, hydro power has very large reductions in power production in time slices: s1d2b2 and s3d1b2 in 2030 as well as s2d1b2 and s2d2b2 in 2029. In 2029 hydro power production is reduced mostly during time slices where solar rooftop PV produces the most – block 2 timeslices. And this is the case more so in 2029. The difference in how the technologies produce between Figure 72 and Figure 73, representing 2029 and 2030 is that there is a large investment in solar tower with storage as well as more supercritical coal technology (see Table 31).

However, the total production annually from hydro doesn’t change between the net metering system and the reference system. Hydro in total produces 109.8 PJ for 2030 in both the reference case as well as the HIGH penetration of net metering case. This indicates that hydro only changes its production profile in the presence of net metering as observed in the figures above. Storage profiles change in a similar fashion to the hydro technology. Storage does not change respective annual productions between the reference case and high penetration case, thus indicating that like hydro, storage changes its production profile only.

Overall the presence of net metering alters how the model produces by timeslice. It is not a simple ‘produce less when net metering is producing’ but rather a shift of production profile which allows less capacity of coal technology to be required, and concentrated solar technology becomes more viable.

It is not clear from the above graphs why the model finds solar with storage a more viable option than others. To investigate further, a constraint was implemented into the HIGH penetration scenario model, whereby the solar 12hr storage technology is limited in new build capacity to the same new build capacity as the reference scenario. In the reference case the model builds 670MW in 2029 and 1800MW of solar 12 hr. storage in 2030. These capacities were used as upper build limits in order to see what the model would chose to build with this extra constraint. Running this model resulted in the model building an extra 110MW of super critical coal and 109MW of open cycle gas in 2029. In 2030 the solar 12hr storage constrained model builds 212MW of solar 14hr storage technology.

Once more, a further constraint was added; solar 14hr was limited to zero new build capacity for 2030 (all other years are not limited), and the results of a model run with this constraint show that the model builds 108MW and 101MW of open cycle gas turbines in 2029 and 2030, more than the REF scenario and an extra 112MW and 106MW of supercritical coal in 2029 and 2030 respectively.

Adding in one more constraint so that the model cannot build extra gas open cycle turbines in 2030 leads to the model building 109MW in 2029 of open cycle gas turbines, 112MW and 60MW of coal in 2029 and 2030 respectively and 150MW of solar 3hr storage in 2030.

Table 37 shows the results for this model constraint testing.

Table 37: The new capacity build differences for the high penetration of net metering scenario with various build constraints. Units are GW.

	HIGH penetration scenario			
	open cycle gas	Super critical coal	solar 12hr storage	
2025	0.467	2.929	0	
2026	0.025	2.446	0	
2027	0	2.479	0	
2028	0.093	4.630	0	
2029	0	2.399	0.889	
2030	0	1.061	2.007	
Constraint 1: Solar 12hr same build as reference scenario (no net metering) The difference from the high penetration scenario:				
	open cycle gas	Super critical coal	solar 12hr storage	Solar 14hr
2025	0.467	0	0	0
2026	0.025	0	0	0
2027	0	0	0	0
2028	0.093	0	0	0
2029	0.109	0.112	-0.218	0
2030	0	-0.005	-0.207	0.213
Constraint 2: constraint 1 + no solar 14hr technology The difference from the high penetration scenario:				
	open cycle gas	Super critical coal	solar 12hr storage	
2025	0	0	0	0
2026	0	0	0	0
2027	0	0	0	0
2028	0	0	0	0
2029	0.109	0.112	-0.218	0
2030	0.101	0.106	-0.207	0
Constraint 3: constraint 2 + no open cycle gas in 2030 The difference from the high penetration scenario:				
	open cycle gas	Super critical coal	solar 12hr storage	Solar 3hr

	open cycle gas	Super critical coal	solar 12hr storage	Solar 3hr
2025	0	0	0	0
2026	0	0	0	0
2027	0	0	0	0
2028	0	0	0	0
2029	0.109	0.112	-0.218	0
2030	0	0.058	-0.207	0.149

In each of the constrained models, 3.07GW of capacity was built in 2030 between combinations of coal, gas open cycle turbines and a solar technology. The fact that the model is choosing technologies like coal and gas turbines when the model is not allowed to build solar technologies is an indication that the model is choosing the solar technology with 12hr storage in the net metering scenarios because of its intermediate load characteristics – between base load and peak load technology types. With the constraints, the model builds gas, coal or solar with storage. Coal is a base load technology while gas turbines are a peaking technology – two opposites of the spectrum.

Solar 12hr storage technology has a lower levelised cost of energy than the other technologies. Figure 74 below, shows that at the intermediate capacity factor of 50%, solar is cheaper than coal, but cannot fully support base load demand. Gas turbines, being expensive to run, are only used for peaking demands. As Figure 71 shows, gas turbines being used only during the yearly mid-winter evening peaks. Although the cost of operating gas turbine may change if gas turbines are able to run of shale gas (possibly from the Karoo) or liquid natural gas (LNG).

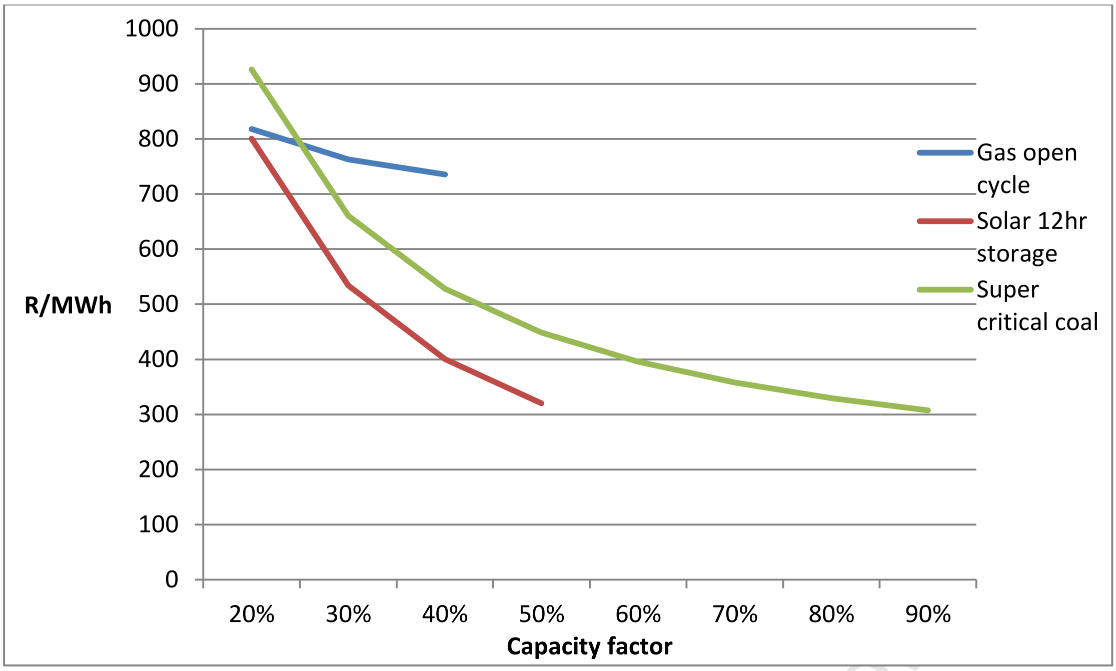


Figure 74: The levelised cost of energy for the three technologies which change the most with the presence of net metering in the model in the year 2030.

The total capacity of wind and solar technologies (excluding rooftop PV in the residential sector) for each scenario is shown in Table 38. In the high penetration levels of solar rooftop PV in the residential sector can result in a displacement of an additional 2.7Mt of CO2 cumulatively by 2030 from the extra concentrated solar thermal with 12hr storage technologies which were encouraged as a result of the presence of net metered solar rooftop PV. If one includes the displaced emissions by the solar rooftop PV, the carbon savings goes up to 29.5Mt CO2 cumulatively by 2030.

Table 38: The share of solar and wind technologies in the model by 2030 and the displaced emissions. * Based on the factor 1.015 kg CO2 per kWh produced on average by Eskom (Letete et al., 2010), ** accounting for the extra value from the losses over transmissions and distriubutions

	Capacity (GW) in 2030 excl. rooftop PV	% of total	PJ production between 2006 and 2030	Mt CO2 *	Mt CO2 from rooftop PV**
REF	3.48	4.41%	229.9	64.8	
LOW	3.61	4.53%	232.0	65.5	4.6
HIGH	3.90	4.94%	239.3	67.5	26.8

5.3 Effect of discount rates

To gauge the effects of varying discount rates have on the system, 5% and 12% rates were used to understand the range of effects that would occur if the discount rate were affected by socio-economic issues in the future. This section presents the results for the model in

OSeMOSYS with discount rates of 5% and 12% and is presented in comparison with the reference model which uses 8% as the discount rate.

This analysis didn't include the discount rate effects on the income levels of households, only on the payback period for investing in solar rooftop PV systems.

5.3.1 REF scenario model for 5% and 12% discount rate

In Figure 75 below, the graph shows the only technologies which differ in total capacity between the 5% and 8% model runs for the REF case (no net metering). Note also, that the solar parabolic technology without storage had a total of 14MW in the 5% discount rate case, but was not included in the graph for clarity.

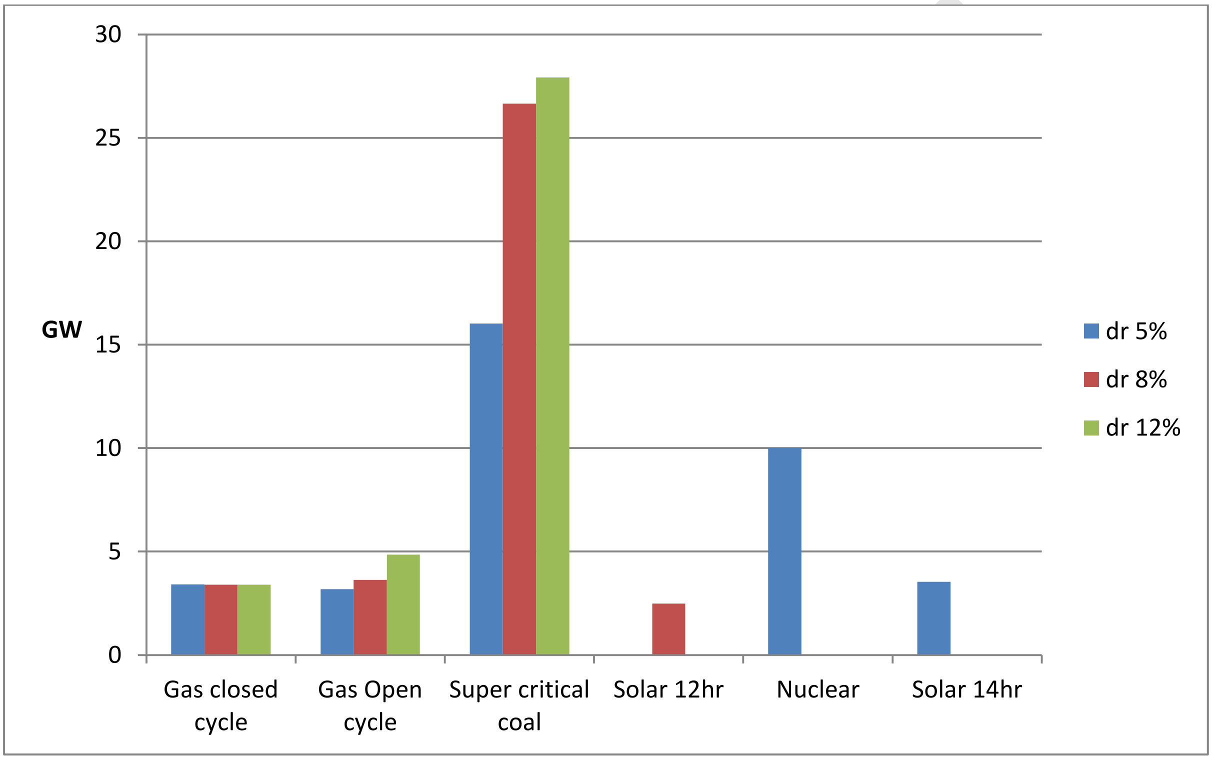


Figure 75: The total new added capacity for discount rates of 5%, 8% and 12% in the REF scenario.

Table 39 and Table 40 show the capacity build differences for the 5% and 8% comparison and 12% and 8% comparison respectively. These tables show how the model changes in the timing and magnitude of investment in the available technologies when the discount rate is changed.

The lower discount rate of 5% encourages nuclear capacity, as a lower time value of money means that the high investment costs of nuclear are more attractive over the long period. Under 8% or 12% discount rates; nuclear is not a cost effective option. Notably, with 5%

discount rates, solar technologies become more cost effective in conjunction with nuclear power. Instead of concentrated solar tower (12hr storage), the 14hr storage concentrated solar technology is preferred as it has a higher capacity factor at a higher capital cost, but is more attractive at a lower discount rate. Also, a small total of 2MW of parabolic solar technology is built in the model under 5% discount rates. With 5% discount rates, the model hints that solar technologies with lower capacity factors are viable as long as there are technologies like nuclear, coal or solar with storage to cover the base load. Figure 76 shows the change in the levelised cost of energy for these technologies, and shows that nuclear is a better option at 5% discount rates than coal. Under 5% discount rates, it is cheaper to build nuclear technology, and solar technologies with storage of various capacity factors and even solar technologies without storage.

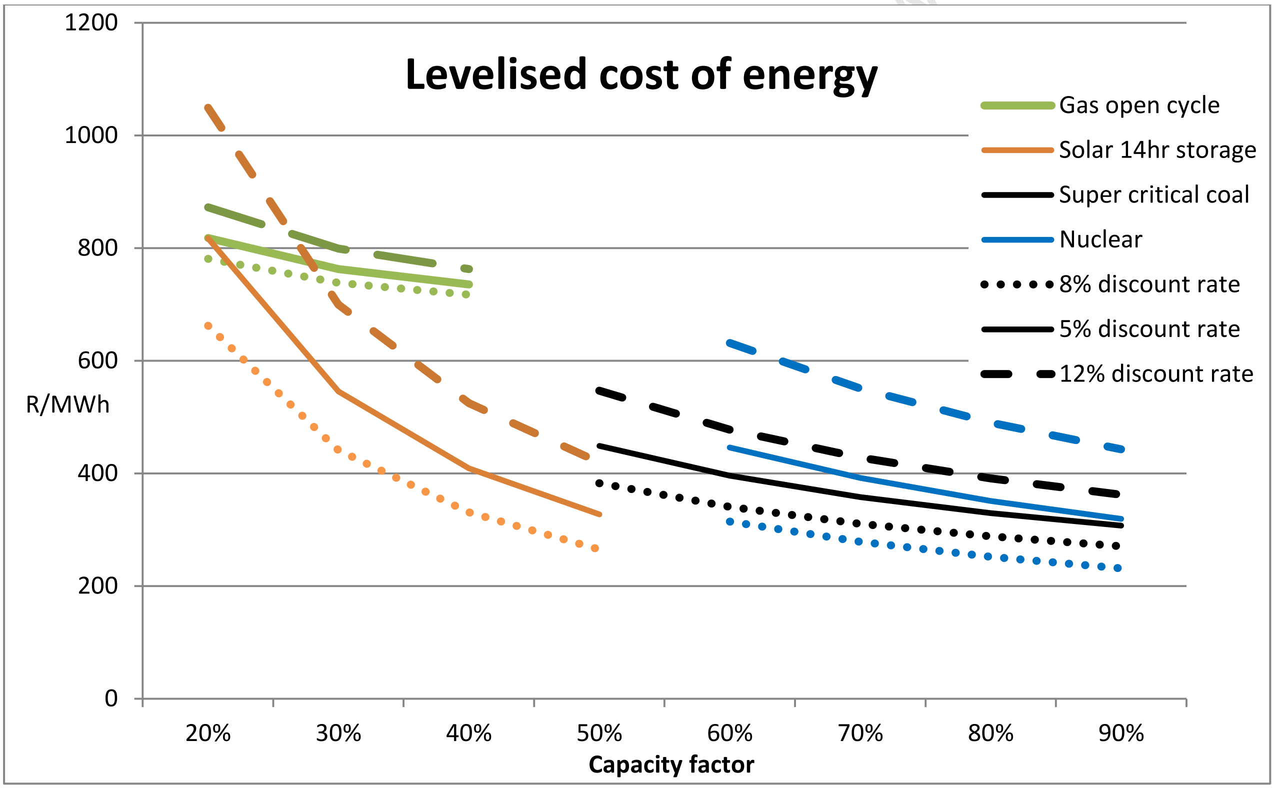


Figure 76: The effect of various discount rates on the levelised cost of energy for technologies in the model.

With a 12% discount rate the model does not build solar technologies other than the minimum required (solar 9hr parabolic), nor does it build nuclear power because of the high capital investment.

With the change in the discount rates, whether lower or higher, the model changes the timings of the investments into certain technologies. Some technologies are built earlier under the 5% than the 8% model, namely; Boroma Hydro import, North hydro import, Micro hydro technology and Mphanda Nkuwa hydro import technologies. While other technologies like gas open cycle turbines, coal and solar technologies are built later in the 5% model than the 8% model. Most of the time, these timing differences are only one year. A similar timing change is seen in the 12% discount case. This is most likely due to the fact that it is cheaper to build earlier for some technologies under a 5% discount rate, and later for more expensive technologies when they are needed more (to meet demand). Table 39 and Table 40 show the build timing changes with the discount rates.

Table 39: The capacity (GW) of 5% discount rate case minus the 8% discount rate for the REF scenario

	Boroma Hydro import	**Gas closed cycle**	**coal fluidised bed combustion**	**North hydro import**	**Micro hydro**	**Mmamabula coal import**	**Moatize Benga coal import**	**Mphanda Nkuwa hydro import**	**Gas open cycle turbine**	**Super critical coal**	**Solar 12hr storage**
2015	0	0	0	0.85	0	0	0	0	0	0	0
2016	0	0	0	0	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0	0	0	0	0
2018	0	0	0	-0.19	0	0	0	0	0	0	0
2019	0	0	0	-0.58	0	0	0	0	0	0	0
2020	0	0	0	-0.09	0	0	0	0.66	0	0	0
2021	0.16	-0.29	0	0	0.4	0	0	-0.66	-0.27	0	0
2022	-0.16	0.28	0	0	-0.09	0	-0.49	0	0.45	0	0
2023	0	0	-3	0	-0.31	-0.19	0.49	0	-0.11	0	0
2024	0	0	0	0	0	-1.01	0	0	-0.18	-1.37	0
2025	0	0.01	0	0	0	0	0	0	-0.34	-3.06	0
2026	0	0.01	0.93	0	0	0	0	0	0	-2.47	0
2027	0	0	2.07	0	0	0.41	0	0	0	-2.48	0
2028	0	-0.01	0	0	0	0.79	0	0	0	-2.47	0
2029	0	0.00	0	0	0	0	0	0	0	-0.05	-0.67
2030	0	0.00	0	0	0	0	0	0	0	1.28	-1.81

Table 40: The technology capacity (GW) of 12% discount rate model minus the capacity in the 8% discount rate model for the REF scenario

	Boroma Hydro import	Gas closed cycle	Ithezi Tezhi hydro import	Kafue hydro import	Micro hydro	Mmamabula coal import	Mphanda Nkuwa hydro import	Gas open cycle turbine	Super critical coal	Solar 12hr storage
2016	0	0	0	0	0	0	0	0	0	0
2017	0	0	-0.12	-0.75	0	0	0	0	0	0
2018	0	0	0.12	0.75	0	0	0	0	0	0
2019	0	0	0	0	0	0	0	0	0	0
2020	0	0.06	0	0	0	0	-0.47	0.41	0	0
2021	0	0.66	0	0	0	0	-0.66	0.00	0	0
2022	-0.12	-0.72	0	0	-0.09	0	1.13	-0.19	0	0
2023	0.12	0	0	0	-0.31	0.49	0	-0.30	0	0
2024	0	0.00	0	0	0.4	-0.49	0	-0.18	0.26	0
2025	0	0.00	0	0	0	0	0	-0.34	0.34	0
2026	0	0	0	0	0	0	0	0.60	-0.60	0
2027	0	0	0	0	0	0	0	0	0	0
2028	0	-0.01	0	0	0	0	0	0	0.01	0
2029	0	0.00	0	0	0	0	0	0.33	0.34	-0.67
2030	0	0	0	0	0	0	0	0.88	0.93	-1.81

5.3.2 Discount rates affecting the model under the net metering scenarios

Changing the discount rate from 8% to 5% or 12% makes only a slight difference in the first few years (2012 – 2015) to the solar rooftop PV payback periods. After 2015 there is very little or no change in the solar PV payback periods and hence the penetration levels of net metering remain the same between the 5, 8 and 12 % discount rates in the later years of the model (2020 to 2030). Toward 2030, low and high penetration levels of rooftop solar PV are 533MW and 2620MW respectively, regardless of the discount rate change. Only the discount rates will be changed in the OSeMOSYS model while the penetration levels remain the same.

Table 41 and Table 42 show the total (2006 -2030) new capacity builds for LOW and HIGH net metering penetration scenarios respectively under the discount rates of 5, 8 and 12%. Figure 77 and Figure 78 show these changes in build for a select few technologies which change with the scenarios and with discount rates.

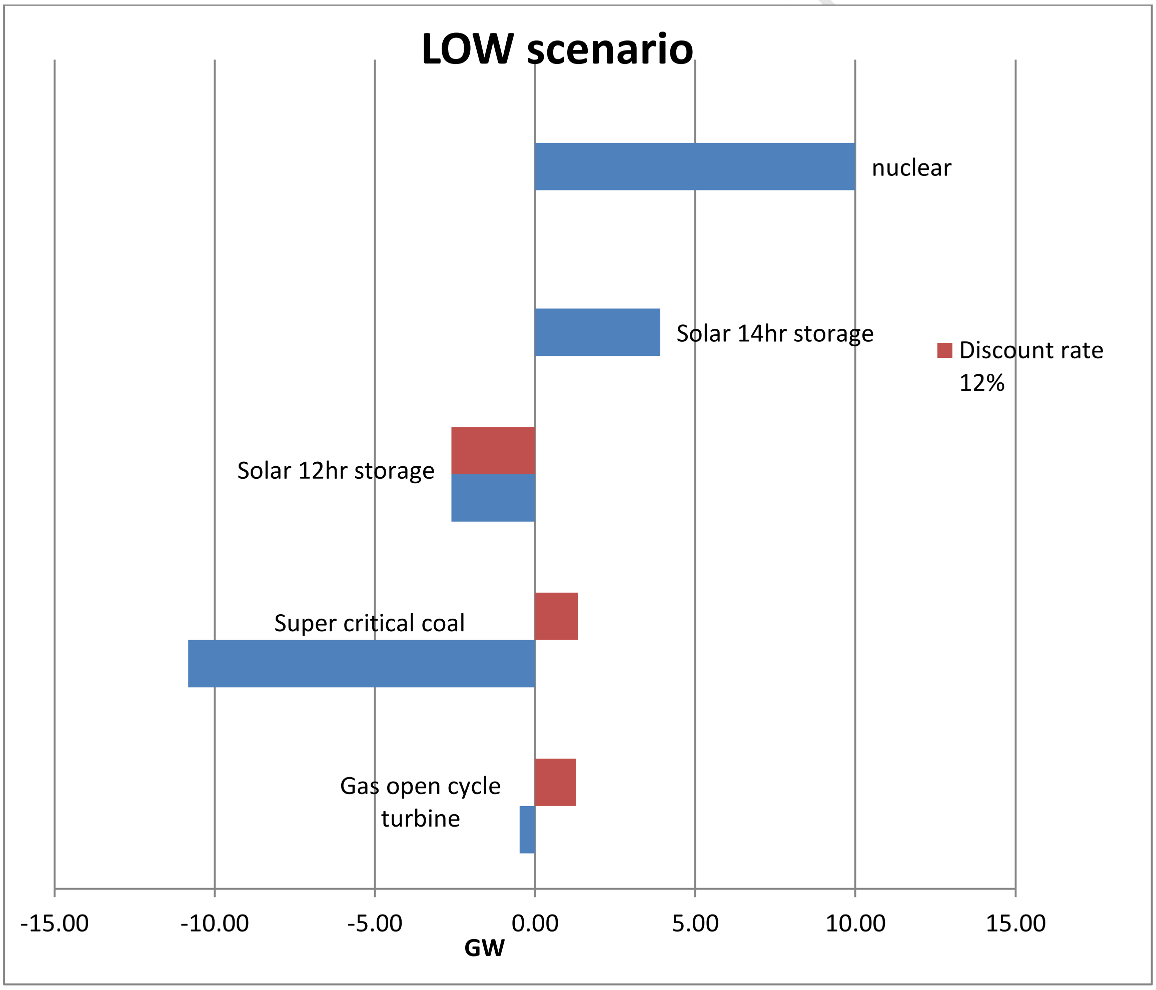


Figure 77: The capacity difference between 5% LOW and 8% LOW scenarios.

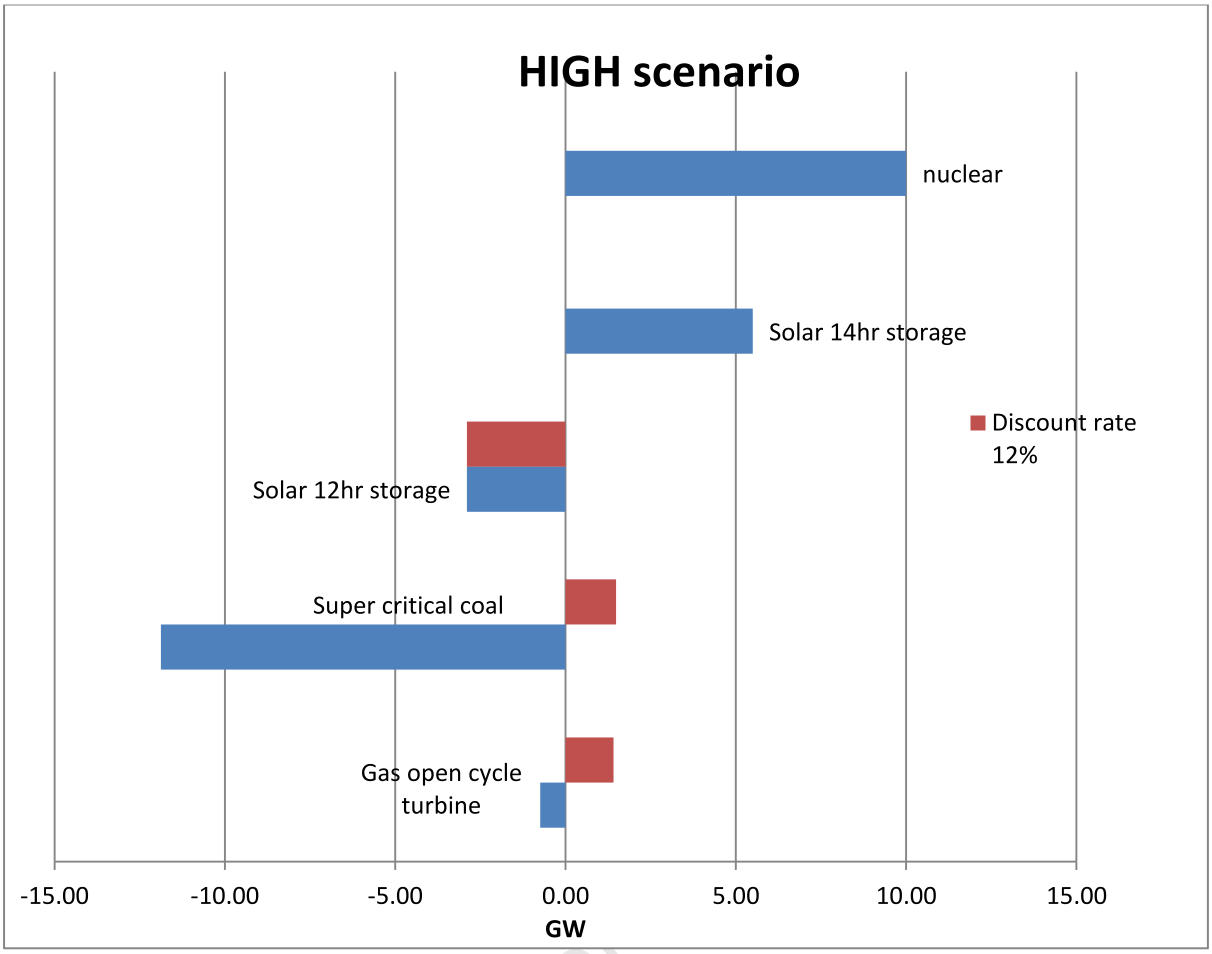


Figure 78: The capacity difference between the 12% HIGH and 8% HIGH scenarios.

The new capacity builds for each scenario under the three discount rates are given in Table 41 and Table 42.

Table 41: The new capacity (GW) builds for varying discount rates under the LOW penetration scenario.

Discount rate %	**5**	**8**	**12**
Boroma Hydro import	0.16	0.16	0.16
Gas closed cycle	3.41	3.40	3.39
coal fluidised bed combustion	3.00	3.00	3.00
North hydro import	0.85	0.85	0.85
Ithezi Tezhi hydro import	0.12	0.12	0.12
Kafue hydro import	0.75	0.75	0.75
Kariba North Bank hydro import	0.36	0.36	0.36
Landfill gas	0.03	0.03	0.03
Micro hydro	0.50	0.50	0.50
Mmamabula coal import	1.20	1.20	1.20
Moatize Benga coal import	1.00	1.00	1.00
Mphanda Nkuwa hydro import	1.13	1.13	1.13
Nuclear	10.00		
Diesel gas open cycle turbine	1.02	1.02	1.02

Discount rate %	**5**	**8**	**12**
Gas open cycle turbine	3.22	3.68	4.98
Super critical coal	15.62	26.50	27.79
Wind high yield	0.80	0.80	0.80
Solar 12hr storage		2.58	
Solar 14hr storage	3.91		
Solar parabolic	0.01		
Solar parabolic 9hr storage	0.20	0.20	0.20

Table 42: the new capacity (GW) builds for varying discount rates under the HIGH penetration scenario.

Discount rate %	**5**	**8**	**12**
Boroma Hydro import	0.16	0.16	0.16
Gas closed cycle	3.40	3.38	3.39
coal fluidised bed combustion	3.00	3.00	3.00
North hydro import	0.85	0.85	0.85
Ithezi Tezhi hydro import	0.12	0.12	0.12
Kafue hydro import	0.75	0.75	0.75
Kariba North Bank hydro import	0.36	0.36	0.36
Landfill gas	0.03	0.03	0.03
Micro hydro	0.50	0.50	0.50
Mmamabula coal import	1.20	1.20	1.20
Moatize Benga coal import	1.00	1.00	1.00
Mphanda Nkuwa hydro import	1.13	1.13	1.13
Nuclear	10.00		
Diesel gas open cycle turbine	1.02	1.02	1.02
Gas open cycle turbine	3.34	4.08	5.49
Super critical coal	13.92	25.80	27.28
Wind high yield	0.80	0.80	0.80
Solar 12hr storage		2.90	
Solar 14hr storage	5.50		
Solar parabolic	0.01		
Solar parabolic 9hr storage	0.20	0.20	0.20

The model prefers under the LOW penetration scenario and at 12% discount rates, to build more super critical coal at a total of 27.79GW by 2030 as opposed to 26.5GW under 8% discount rate. With 12% discount rates, a total of 4.98GWGW of open cycle gas turbines are built as opposed to the 3.7GW under 8%. This would be to provide the peaking technology which is left somewhat unmet without the intermediate technology - solar power with storage which becomes too expensive to invest in at 12% discount.

With the LOW scenario at a 5% discount rate, the model opts to build the maximum (10GW) nuclear capacity and thus decreases the investment into super critical coal. A total of 13.92GW of super critical coal is built at 5% under the HIGH penetration scenario as opposed to the 15.62GW under the LOW scenario. Likewise, solar 14hr storage technology becomes more feasible than the solar 12hr storage technology at 5% discount rate.

Under the HIGH penetration of net metering scenario, a 5% discount rate increases the solar 14hr storage technology capacity at 5.5GW as opposed to the 3.91GW in the LOW penetration scenario, and increases the solar parabolic technology similarly from 2MW to 10MW (not shown in figures). In both cases, solar 12hr technology is replaced by the slightly higher capital investment technology; solar 14hr storage as expected with decreased time value of money. Also, 10GW of nuclear, as in the previous case, is built under the HIGH scenario and at 5% discount rates.

At 12% under the HIGH scenario, the higher discount rate discourages all nuclear and all solar technology (regardless of storage) and builds a total of 27.28GW of super critical coal by 2030, and a total of 5.49GW of open cycle gas turbines as opposed to the 4.98GW under the LOW scenario.

The general trend between the LOW and HIGH penetration scenarios is that with a higher discount rate, super critical coal with peaking demand gas turbines is the cheapest option with the presence of net metering in the model. However, at a lower discount rate, nuclear becomes more viable than coal, and solar technologies with storage become more viable as well.

6 Conclusions

Using economic parameters and methods from a study on modelling solar rooftop PV by Guidolin et al. (2010), combined with data from the community survey (2007) on income and households in South Africa, a potential range of capacity of solar rooftop PV embedded in the residential sector was determined. The projection of this net metered solar rooftop PV in South Africa was found to be between 395MW and 2620MW by 2030 depending on assumptions on income groups and cost per Watt of solar PV systems. The capacity of solar PV embedded generation in the residential sector is proportional to the payback period of the cost of the system which in turn is subject to electricity tariffs. The capacity is also directly related to the market size which in turn is related to income levels of the HH occupants.

An energy model of the South African electricity sector was created in the open source software: OSeMOSYS based on data from the ESAP group at the Energy Research Centre. The OSeMOSYS model was then benchmarked against TIMES in order to establish that OSeMOSYS was indeed a full-fledged optimisation model and was reliable. The only difference between the commercially available TIMES software and the open source software was in the run times and memory usage, both of which do not affect the accuracy of results. The OSeMOSYS software took significantly longer to process and run the model on the same computer as TIMES, and used up almost 3 orders of magnitude more memory than the TIMES software. Apart from the performance differences, there were no differences in the results of the energy models.

Using this OSeMOSYS model for the electricity sector in South Africa, how net metering within the residential sector affects the future investment scheme in the country was studied. The results of modelling net metering capacity indicated a small change but significant one to the future investments in the generation of electricity. This change in demand (and consumption) profile from net metered solar rooftop PV caused the model to build more gas turbines used for peaking generation, as well as the investment in more concentrated solar thermal technologies with storage, and build less super critical coal technology.

The results indicate that in the high penetration scenario of net metering (2620MW by 2030), a total of 850MW (3.2%) less of super critical coal was required than in the reference case (no net metering), and 420MW (16.8%) more of solar thermal with 12hr storage was built by 2030. At the same time, more peaking capacity is required; a total of 440MW (9.5%) more of open cycle gas turbines were required above the reference case. The altered demand profile causes a reduced demand in the late afternoon time-periods but does not reduce the peak demand which is in the early evenings. As a result, quicker response capacity is required – and hence the extra gas turbines. Similar patterns of change to coal and gas investments were observed for the low penetration scenario of net metering, although these were a scaled down version of the high penetration scenario.

The altered demand profile causes more solar thermal with storage to become more viable as an intermediate load technology and replaces some of the capacity of super critical coal technology by 2030. Although, coal is still the dominant preferred choice of investment for capacity, it was reduced a small fraction with the presence of net metering. An interesting and surprising result of this study is that with increased levels of net metered capacity within the residential sector, there is an increase in utility side concentrated solar thermal with storage technology in the model.

Another important change as a result of net metering within the residential sector is in the production profiles of the technologies within the model. The production by timeslice of many of the technologies in the model changes, notably base load technologies like hydro and coal technologies. The effect was that these technologies reduce production in some timeslices and increase production in other timeslices. The total production from these technologies does not change, just the timing of production. This can be thought of as a shifting in equilibrium of production.

In this thesis, the effect of net metering in the country was based on the residential sector, and the commercial and industrial sectors have not been investigated. The commercial sector may have even larger potential capacity than residential, since businesses can pay higher time of use tariffs, up to 291c/kWh for medium voltage commercial users (CT municiaplity, 2012), and have larger open spaces on rooftops as well as larger energy consumption.

Moreover, net metering is not yet a fully regulated policy as it is in many other countries. A policy based on a simple reverse feed operation where customers can turn their meters backwards by exporting onto the grid, would greatly encourage the private sector to invest in renewable energy generation. Furthermore, legislation that acts as barriers to entry of investment such as extensive licensing and registrations with various government entities should be minimized if net metering were to be seriously considered as a method to aid in emissions abatement and raise energy awareness within the country. Reducing the requirements and authorised documentations for any installation should be a priority if encouraging decentralised renewable energy within the residential and commercial sector is a goal. Because of the impact that net metering has on the future investments of technologies in South Africa, there is an added and unseen value to a net metering policy which goes beyond simple balancing of funds.

In this study, only the financial aspects of private investment into rooftop solar PV was considered. The impact that the awareness generated from a net metering policy would have, would only further add to the potential size of embedded generation in the private sectors. This would help in the implementation of renewable energy in the country as well as a whole new industry and new job creation prospects as a result.

It has been assumed that net metering is allowed to develop with minimal obstruction from legislation and added service charging or fees. The effect that cross-subsidisation from non-net metering households and those with net metered systems has not been studied or included in this work, but has been acknowledged by Strbac & Jenkins (2004) as an important aspect which are not usually considered by revenue collecting systems. The cross-subsidisation element will inherently alter the fees structure that municipalities adopt and thus will change the scale of net metering by altering the financial gains to the owners. This has not been studied here, but will need to be considered by legislators and municipalities alike when formulating net metering policies in the country. Also, the consideration of the extra value in terms of improved distribution efficiency that occurs as a result of embedded generation, which Strbac & Jenkins (2004) mentions, has not been considered here as well, as this would require a larger scope of work.

There is a lack of data regarding the current state of capacity of rooftop PV within the residential sector in South Africa, and assumptions have been made based on market studies in countries which do have such data. To improve on the projection of installed capacity of rooftop PV in South Africa, a field study of residential rooftop systems via the appropriate artisans would be required.

The effect of embedded generation in the residential (and commercial) sectors will play an increasing role in determining how the electricity sector operates. Investigating further the extent of embedded generation in South Africa will aid in a better understanding how it affects the system and its role in encouraging RE in both private and national entities.

Based on the results of this work on understanding the changes to the energy sector in the future due to privately owned residential rooftop PV, the policy and research surrounding the tariffs and regulations of home embedded generators should be revised. There are unseen effects to the future of the electricity sector which are not taken into account when considering net metering policies. The fact that the presence of net metering in the residential sector has an effect upstream of distribution by encouraging more utility scale investment into solar technologies, further merits the investigation of net metering for South Africa. Subsidies into private (home) investment of solar PV would greatly encourage the scale of these embedded systems and as a cascading effect, increase the scale of renewable energy technologies in the national electricity sector. Also, as Kind (2013) mentions similarly for the U.S utilities, the cross subsidisation of non-net metering users to those that do have a net metering system will increase as energy becomes more expensive – which is a fast becoming reality in South Africa.

7 Works Cited

Adam, F., 2010. *Free basic electricity: a better life for all*. Report. Johannesburg: Earthlife Africa.

Adams, S., 2011. *South African consumer attitudes towards domestic solar power systems*. Masters Thesis. Pretoria: University of Pretoria Gordon Institute of Business science.

AEMO, 2012. *Rooftop PV information paper, national electricity forecasting*. Australian Energy market operator (AEMO).

Arndt, R. & Puto, I.R., 2010. *Basic understanding of IEC standard testing for photovoltaic panels*. TUV SUD America Inc.

Basson, P., 2012. *Email conversation with Pierre Basson*. [Online] Available at: http://www.infinity-re.co.za [Accessed October 2012].

Bazilian, M., Onyeji, I. & Liebreich, M., 2012. *Re-Considering the Economics of Photovoltaic Power*. Bloomberg New Energy Finance.

Beck Inc., R.W., 2009. *Distributed renewables energy operating impacts and valuation study*. Study. Arizona: R.W. Beck inc. Arizona public service.

Bello, M. & Carter-Brown, C., 2010. Impact of embedded generation on distribution networks. *Energize*, pp.32 - 34.

CleanEnergy, 2010. *Significant sustainable energy systems: solar photovoltaic energy*. CleanEnergy Action Project.

CT municiaplity, 2012. *City of Cape Town official website*. [Online] Available at: http://www.capetown.gov.za/en/electricity/Documents/ElectricityTariffs_1-Jul-2012.pdf [Accessed September 2012].

Denholm, P., Drury, E. & Margolis, R., 2009. *The solar depolyment system (solarDS) model: documentation and sample results*. Technical report. DOE.

DoE, 2012. *Sunshot Vision study*. Office of Energy Efficiency and Renewable energy, Department of energy: United States.

Drury, E., Denholm, P. & Margolis, R., 2010. *Modeling the U.S rooftop photovoltaics market*. National renewable energy Laboratory (NREL).

Eberhard, A., 2010. *South African Coal: market, investment and policy challenges*. University of Cape Town.

Elhodeiby, A.S., Metwally, H.M.B. & Farahat, M.A., 2011. Performance analysis of 3.6kW rooftop grid connected PV system in Egypt. In *Internation conference on energy sustems and technologies (ICEST)*. Cairo, 2011.

EngineeringNews, 2012. [Online] Available at: http://www.engineeringnews.co.za/article/cape-town-initiates-net-metering-pilot-project-2012-02-15 [Accessed August 2012].

ERC, 2012. *Sector analysis: Assumptions and methodologies in the South African TIMES (SATIM) energy model*. Working report. Cape Town: Energy Research Centre (ERC), University of Cape Town.

Eskom, 2011a. *Integrated Resource Plan (IRP) for Electricity 2010 - 2030 (revision 2)*. Eskom.

Eskom, 2011b. *trimming 10% is easier than you think - information guide*. Guide. Eskom Integrated Demand Management.

Eskom, 2011c. *Annual Report 2011*. Eskom Holdings Lmt.

Eskom, 2012a. *Charges and Tariffs 2012/13*. Eskom.

Eskom, 2012b. *Eskom web page*. [Online] Available at: http://www.eskomidm.co.za/industrial/sop [Accessed September 2012].

Eskom, 2012c. *Fact Sheet: Transmission and distribution*. Available at www.eskom.co.za, accessed September 2012.

Eskom, 2012d. *Revenue application: Multi-year Price Determination 2013/14 to 2017/18 part 2*. Proposal. Eskom.

EWN, 2013. *Eye Witness News*. [Online] Available at: ewn.co.za [Accessed April 2013].

Faiers, A., Neame, C. & Cook, M., 2007. The adoption of domestic solar-power systems: Do consumers assess product attributes in a stepwise process? *Energy Policy*, 35, pp.3418-23.

Ferguson, T.S., 2012. *Linear Programming , a concise introduction*. United States Naval Academy.

Fessler, D., 2012. [Online] Available at: www.investmentu.com/2012/January/polysilicon-green-energy.html [Accessed 26 August 2012].

Fin24, 2012. *Fin24 news website*. [Online] Available at: http://www.fin24.com/Companies/Industrial/Eskom-wants-16-tariff-increase-20121022 [Accessed 24 OCtober 2012].

Foley, A.M., O' Gallachoir, B.P. & Hur, J., 2010. A strategic review of electricity systems models. *Energy*, (35), pp.4522-30.

Gaunt, C.T. & van Zyl, S.J., 2003. *Control Strategies for Distributed Generators operating on Weak Distribution networks*. Institute of Electrical and Electronic Engineers.

Gipe, P., 2006. *Renewable energy policy mechanisms by Paul Gipe*. Tehachapi, California.

Goodrich, A., James, T. & Woodhouse, M., 2012. *Residential, Commercial, and Utility-Scale Photovoltaic (PV) system prices in the United States: Current drives and cost-reduction opportunities*. National Renewable Energy Laboratory.

Guidolin, M. & Mortarino, C., 2010. Cross-Country dffusion of photovoltaic systems: Modelling choices and forecasts for national adoption patterns. *Technological Forecasting and Social Change*, (77), pp.279-96.

Haynes, R. & Whitaker, C., 2007. *Connecting to the Grid: A guide to distributed generation interconnection issues 5th ed.* U.S DOE.

Heilscher, G., Keifer, K. & Hoffmann, V.U., 1994. *Measurement and analysis programme within the thousand roofs programme*. Huwaii: Institute of Electrical and Electronics Engineers.

Hollander, D., 2012. *Email conversation with Darren Hollander*. [Online] Available at: www.solarpowerafrica.co.za.

Howells, M., Hughes, A. & Bazillian, M., 2011. OSeMOSYS: the open source energy modelling system, an introduction to its ethos, structure and developement. *Energy Policy*, (39), pp.5850-70.

IEA, 2010. *Technology Roadmap - Solar Photovoltaic energy*. International Energy Agency.

IRENA, 2012. *Renewable energy technologies: cost analysis series*. Working paper. International renewable energy agency.

Jelle, B.P., Breivik, C. & Rokenes, H.D., 20112. Building integrated photovoltaic products: A state-of-the-art review and future research opportunities. *Solar Energy Materials & Solar Cells*, 100, pp.69-96.

Jin, Y.-c., Wang, R.-c., Huang, H.-p. & Sun, L.-j., 2010. Ubi-PowerMeter: a Novel paradigm to reduce energy consumption. *International journal of Smart Home*, 4(2), pp.11-30.

Kastovich, J.C., lawrence, R.R., Hoffman, R.R. & Pavlak, C., 1982. *Advanced electric Heat Pump market and business analysis*. Report. Pittsburgh: U.S department of energy Westinghouse Electric corporation.

Keen, A., 2012. *Taking a home off-grid*. Presentation. Cape Town.

Kind, P., 2013. *Disruptive Challenges: Financial Implications and Strategic Responses to a Changing Retail Electric Business*. Pennsylvannia: Edison Electric Institute.

Kok, S., 2012. Osemosys: motivation for using it as part of the tools for the IEP - presentation., 2012. Council of Scientific Industrial Research.

KZN energy, 2012. *Email conversation with Abigail Knox*. [Online] Available at: www.kznenergy.org.za [Accessed 2012].

Letete, T., Guma, M. & Marquard, A., 2010. *Carbon accounting for South Africa*. Energy Research Centre, University of Cape Town.

Lipschitz, D., 2012. *Email conversation with Mr. Lipschitz.*. [Online] Available at: www.netmetering.co.za [Accessed 2 July 2012].

Mahanjan, V., Muller, E. & Bass, F.M., 1990. New product diffusion models in marketing: a review and directions for research. *The Journal of Marketing*, 54(1), pp.1-26.

Mainstream, 2012. *South African Mainstream renewable power Droogfontein Pty Ltf*. Presentation to NERSA. Postmansburg: Mainstream renewable power South Africa.

Makhorin, A., 2008. *Modeling Language GNU MathProg*. Language Reference. Moscow: Moscow Aviation Institute.

Marquard, A., Merven, B. & Tyler, E., 2008. *Costing a 2020 Target of 15% renewable electricity for South Africa*. Energy Research Centre (ERC), University of Cape Town.

Masters, C.L., 2002. Voltage rise: the big issue when connecting embedded generation to long 11kV overhead lines. *Power Engineering*, 16(1), pp.5 - 12.

Meyer, R., 2011. *Solar resource assessment/mapping*. Presentation. Energy Research Centre, Unversity of Cape Town.

Minkoff, K., 2012. *Nelson Mandela Bay Municpality*. [Online] Available at: http://www.nelsonmandelabay.gov.za [Accessed September 2012].

Ndanga, G.T. & Gorn, M., 2012. Requirements for the feasibility of PV net metering in South Africa. In *42nd International Conference on Computers & Industrial Engineering*. Cape Town, 2012.

Nemet, G.F., 2006. Beyond the learning curve: factors influencing cost reductions in photovoltaics. *Energy Policy*, (34), pp.3218 - 3232.

NRS, 2010. *NRS 097-2-1 grid interconnection of embedded generation part 2: small scale embedded generation*. National Standard. SABS.

O'Brien, G. & Hope, A., 2010. Localism and energy: Negotiating approaches to embedding resiliance in energy systems. *Energy Policy*, (38), pp.7550-58.

Paidipati, J., Frantzis, L., Sawyer, H. & Kurrasch, A., 2008. *Rooftop Photovoltaics market penetration scenarios*. Subcontract report. U.S Department of Energy.

REN21, 2011. *Renewables 2011: Global Status Report*. Annual Report. Renewable energy policy network for the 21st century.

ReserveBank, 2012. *South African Reserve Bank*. [Online] Available at: www.resbank.co.za [Accessed September 2012].

Rosenthal, R., 2012. *GAMS - user guide*. GAMS development Corporation.

Rothacher, T., 2012. Renewable Energies in Germany: current trends and investment oppertunities. In *Germany Trade and Invest*., 2012.

Rycroft, M., Wagnaar, A. & Sabbione, b., 2012. Rooftop solar PV, an awakening giant. *Sustainable Energy*, p.58.

SABS, 2008. *SANS 204-1, Energy Efficiency in Buildings: Part 1*. Pretoria: SABS: Standards division.

SAnews, 2013. *SA Government news agency*. [Online] Available at: http://www.sanews.gov.za/south-africa/nersa-grants-eskom-8-tariff-hike.

Scenario Building team , 2007. *Long Term Mitigation Scenarios, strategic options for South Africa*. Study. Pretoria: Dept. of environmental affairs and tourism.

SEMI, 2009. *PV group policy principles and recommended best practices for solar feed-in-tariffs*. Report. SEMI: PV group.

SMA, 2012. *Sunny Portal*. [Online] Available at: http://www.sunnyportal.com/ [Accessed September 2012].

Solarbuzz, 2012. [Online] SolarBuzz Available at: www.solarbuzz.com/facts-and-figures/retail-price-environment/module-prices [Accessed 26 August 2012].

StatsSA, 2007. *Community Survey*. Statistics South Africa.

StatsSA, 2011. *General Household Survey 2011*. Statistics South Africa.

StatsSA, 2012. *Census 2011 - Census in Brief*. Statistics South Africa.

Strbac, G. & Jenkins, N., 2004. *Calculation of cost and benifits to the distribution networks of embedded generation*. Study. Manchester: Institute of Electrical and Electronic Engineers.

Subramoney, J., van Wyk, J. & Dithupe, M., 2009. *Digest of South African energy statistics*. Department of Energy, South Africa.

TheGreenEconomy, 2012. *The green economy*. [Online] Available at: www.thegreeneconomy.com [Accessed September 2012].

Timeslive, 2012. *Timeslive News*. [Online] Available at: http://www.timeslive.co.za/thetimes/2012/10/31/eskom-to-keep-tariff-rise-steady [Accessed 31 October 2012].

van Aardt, & Coetzee, M., 2010. *Personal income estimates for South Africa, 2010*. Report. UNISA.

Varnado, L. & Sheehan, P.E., 2009. *Connecting to the grid : A guide to distributed generation interconnection Issues*. Interstate renewable energy council (IREC).

Weissman, S. & Johnson, N., 2012. *The Statewide benifits of Net-Metering in California & the consiquences of changes to the program*. Berkeley Law, University of California.

Welsch, M. et al., 2012. Modelling elements of smart grids - enhancing the OSeMOSYS code. *Energy*, (46), pp.337-50.

Welsch, M., Howells, M., Bazillian, M. & et al., 2012. *Modelling selected attributes of smart grids*. Working paper DESA/12/1. Royal Institute of Technology.

Wienand, R., 2012. *Embedded generation*. [Online] Available at: http://www.durban.gov.za/Resource_Centre/Current%20Projects/energyoffice/Pages/Embedded-Generation.aspx [Accessed September 2012].

Winkler, H., Hughes, A. & Haw, M., 2009. Technology learning for renewable energy: Implications for South Africa's long term mitigation scenarios. *Energy Policy*, (37), pp.4987 - 4996.

8 Appendix

8.1 Projected tariffs

Table 43: the projected municipal electricity tariffs in 2013 c/kWh.

	Municipal Rate >600kWh	Municipal 400-600kWh
2012	131.11	121.16
2013	141.59	130.85
2014	152.92	141.32
2015	165.16	152.62
2016	178.37	164.83
2017	192.64	178.02
2018	208.05	178.02
2019	208.05	178.02
2020	208.05	178.02
2021	208.05	178.02
2022	208.05	178.02
2023	208.05	178.02
2024	208.05	178.02
2025	208.05	178.02
2026	208.05	178.02
2027	208.05	178.02
2028	208.05	178.02
2029	208.05	178.02
2030	208.05	178.02

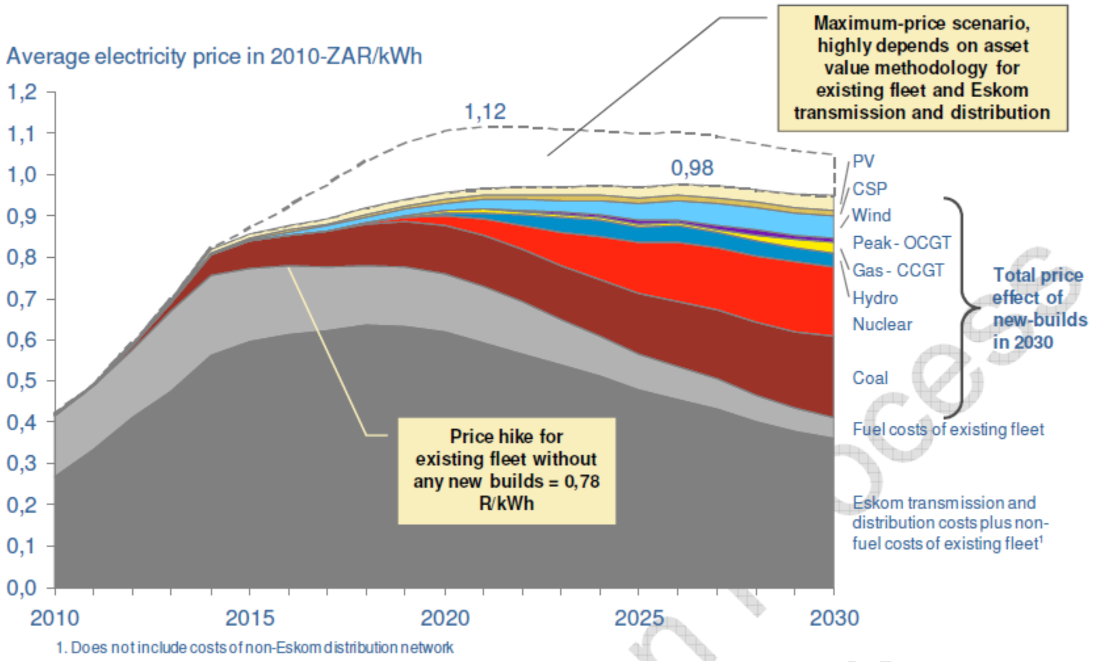


Figure 79: The estimated tariff path for South Africa based on new build technology choices. This is the price of generating electricity (upstream of transmissions). Taken from (Eskom, 2011a) pg 20.

8.2 Payback period for the example

Table 44: The calculation of the payback period for the example in 3.1.4.5 .

Year	Savings in elec.	PV Costs	Total Savings
1	R 9 052	R 96 381	R -87 330
2	R 18 558	R 96 810	R -78 252
3	R 28 543	R 97 207	R -68 664
4	R 39 029	R 97 574	R -58 545
5	R 50 043	R 97 915	R -47 871
6	R 61 611	R 98 230	R -36 619
7	R 72 833	R 98 521	R -25 689
8	R 83 719	R 98 792	R -15 072
9	R 94 281	R 99 042	R -4 761
10	R 104 527	R 99 273	R 5 254
11	R 114 467	R 99 488	R 14 979
12	R 124 110	R 99 686	R 24 423
13	R 133 465	R 99 870	R 33 594
14	R 142 540	R 100 040	R 42 500
15	R 151 344	R 100 198	R 51 146
16	R 159 885	R 100 344	R 59 541
17	R 168 171	R 100 479	R 67 692
18	R 176 210	R 100 604	R 75 606
19	R 184 008	R 100 720	R 83 288
20	R 191 574	R 100 827	R 90 746

8.3 Numeric results for total installed PV projections

Table 45: Numeric results for the total maximum potential of solar rooftop PV for R25/Wp in 2012.

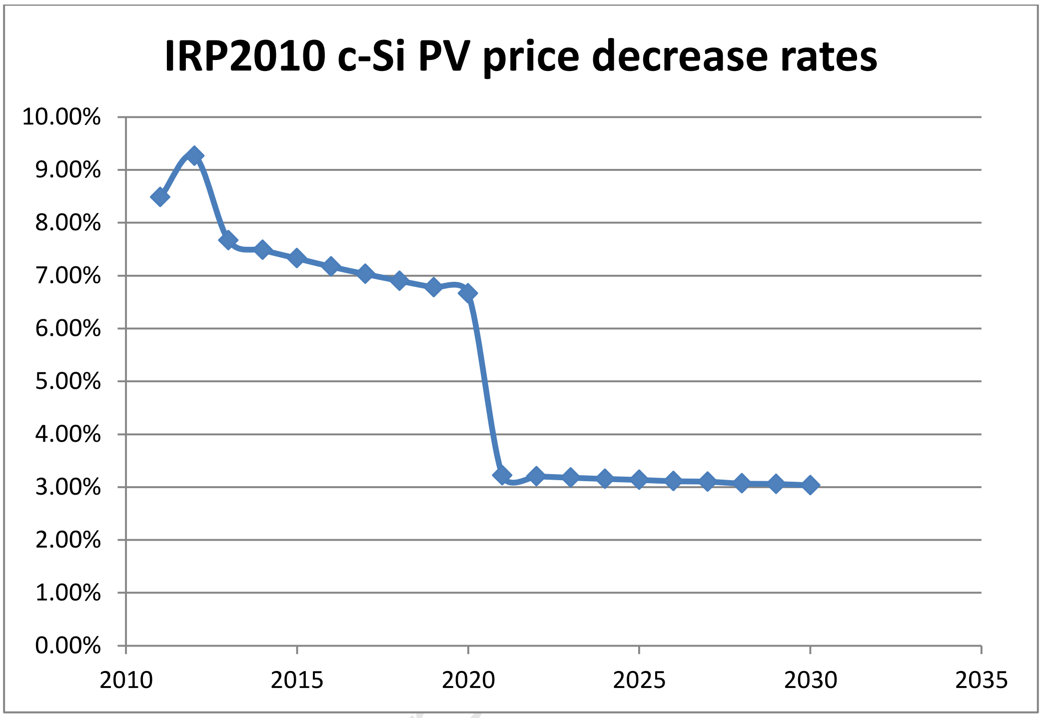
	R25/Wp			
	> R12k	> R25k	> R12k + increased growth	> R25k + increased growth
2012	3	2	3	2
2013	4	2	4	2
2014	4	3	5	3
2015	15	9	16	9
2016	19	11	21	12
2017	24	14	26	15
2018	30	17	34	20
2019	39	22	44	25
2020	80	46	93	53
2021	103	59	121	70
2022	133	76	159	92
2023	172	99	209	120
2024	222	127	274	158
2025	285	164	359	206
2026	366	211	468	269
2027	467	269	607	349
2028	593	341	782	450
2029	745	428	999	575
2030	927	533	1264	727

Table 46: The numeric results for the total HH market potential based on R25/Wp in 2012.

	R30/Wp			
	> R12k	> R25k	> R12k + increased growth	> R25k + increased growth
2012	2	1	2	1
2013	2	1	2	1
2014	3	2	3	2
2015	11	6	11	7
2016	13	8	14	8
2017	17	10	18	11
2018	21	12	24	14
2019	27	15	31	18
2020	59	34	69	40
2021	76	44	90	52
2022	99	57	118	68
2023	127	73	155	89
2024	164	94	203	117

2025	285	164	359	206
2026	366	211	468	269
2027	467	269	607	349
2028	593	341	782	450
2029	745	428	999	575
2030	927	533	1264	727

8.4 IRP2010 rates



8.5 Extra OSeMOSYS model component tables

Table 47: The 2005 cost in R/GJ of fuel supplies for the model

	Coal - existing	New coal	Import Diesel	Import Liquid natural gas	Extraction of Natural gas	Mozambique LNG	Coal discard	Regional Gas extraction
2006	5.14	10.27	148.84	54.77	16.49	16.49	5.14	54.77
2007	5.14	10.27	154.11	54.77	16.49	16.49	5.14	54.77
2008	5.14	10.27	159.38	54.77	16.49	16.49	5.14	54.77
2009	5.14	10.27	164.65	54.77	16.49	16.49	5.14	54.77
2010	5.14	10.27	169.92	54.77	16.49	16.49	5.14	54.77
2011	5.14	10.27	176.69	54.77	16.49	16.49	5.14	54.77
2012	5.14	10.27	183.45	54.77	16.49	16.49	5.14	54.77
2013	5.14	10.27	190.22	54.77	16.49	16.49	5.14	54.77
2014	5.14	10.27	196.98	54.77	16.49	16.49	5.14	54.77
2015	5.14	10.27	203.75	54.77	16.49	16.49	5.14	54.77
2016	5.14	10.27	210.51	54.77	16.49	16.49	5.14	54.77
2017	5.14	10.27	217.28	54.77	16.49	16.49	5.14	54.77
2018	5.14	10.27	224.04	54.77	16.49	16.49	5.14	54.77
2019	5.14	10.27	230.81	54.77	16.49	16.49	5.14	54.77
2020	5.14	10.27	237.57	54.77	16.49	16.49	5.14	54.77
2021	5.14	10.27	237.57	54.77	16.49	16.49	5.14	54.77
2022	5.14	10.27	237.57	54.77	16.49	16.49	5.14	54.77
2023	5.14	10.27	237.57	54.77	16.49	16.49	5.14	54.77
2024	5.14	10.27	237.57	54.77	16.49	16.49	5.14	54.77
2025	5.14	10.27	237.57	54.77	16.49	16.49	5.14	54.77
2026	5.14	10.27	237.57	54.77	16.49	16.49	5.14	54.77
2027	5.14	10.27	237.57	54.77	16.49	16.49	5.14	54.77
2028	5.14	10.27	237.57	54.77	16.49	16.49	5.14	54.77
2029	5.14	10.27	237.57	54.77	16.49	16.49	5.14	54.77
2030	5.14	10.27	237.57	54.77	16.49	16.49	5.14	54.77

Table 48: The model residual capacity for existing (currently operating) technologies. Includes return to service power plants.

	Pumped Storage	Coal PF Eskom	Coal PF Eskom	Coal PF Eskom	Coal PF	OCGT liquid	Hydro South	Hydro	PWR	total excl.
2006	1.58	21.09	9.38	2.78	0.44	2.40	0.67	1.50	1.80	40.06
2007	1.58	21.09	9.38	2.97	0.44	2.40	0.67	1.50	1.80	40.25
2008	1.58	21.09	9.38	3.45	0.44	2.40	0.67	1.50	1.80	40.73
2009	1.58	21.09	9.38	3.96	0.44	2.40	0.67	1.50	1.80	41.24
2010	1.58	21.09	9.38	4.34	0.44	2.40	0.67	1.50	1.80	41.62
2011	1.58	21.09	9.38	5.02	0.44	2.40	0.67	1.50	1.80	42.30
2012	1.58	21.09	9.38	5.33	0.44	2.40	0.67	1.50	1.80	42.60
2013	1.58	21.09	9.38	5.43	0.44	2.40	0.67	1.50	1.80	42.70
2014	1.58	21.09	9.38	5.43	0.44	2.40	0.67	1.50	1.80	42.70
2015	1.58	21.09	9.38	5.43	0.39	2.40	0.67	1.50	1.80	42.65
2016	1.58	21.09	9.38	5.43	0.31	2.40	0.67	1.50	1.80	42.58
2017	1.58	21.09	9.38	5.43	0.31	2.40	0.67	1.50	1.80	42.58
2018	1.58	21.09	9.38	5.43	0.31	2.40	0.67	1.50	1.80	42.58
2019	1.58	21.09	9.38	5.43	0.31	2.40	0.67	1.50	1.80	42.58
2020	1.58	21.09	9.38	5.43	0.31	2.40	0.67	1.50	1.80	42.58
2021	1.58	21.09	9.38	5.43	0.31	2.40	0.60	1.50	1.80	42.51
2022	1.58	21.09	9.38	3.56	0.31	2.40	0.60	1.50	1.80	40.64
2023	1.58	18.81	9.38	3.56	0.31	2.40	0.60	1.50	1.80	38.36
2024	1.58	18.81	9.38	2.65	0.31	2.40	0.60	1.50	1.80	37.45
2025	1.58	18.81	9.38	1.13	0.31	2.40	0.60	1.50	1.80	35.93
2026	1.40	18.81	9.38	1.13	0.31	2.06	0.60	1.50	1.80	35.58
2027	1.40	18.81	9.38	1.13	0.31	2.06	0.60	1.50	1.80	35.58
2028	1.40	15.96	9.38	1.13	0.31	2.06	0.60	1.50	1.80	32.73
2029	1.40	15.96	9.38	0.00	0.31	2.06	0.60	1.50	1.80	31.61
2030	1.40	15.96	9.38	0.00	0.31	2.06	0.60	1.50	1.80	31.61

Table 49: The minimum capacity investment for the SATIM and OSeMOSYS models – committed future builds.

	Minimum investment (GW)							
	Super critical Coal	Micro hydro	Open-Cycle Gas	Wind high resource	Landfill gas	Solar Parabolic Trough 9 hrs.	Pumped Storage New	Pumped Storage New
2006	0	0	0	0	0	0	0	0
2007	0	0	0	0	0	0	0	0
2008	0	0	0	0	0	0	0	0
2009	0	0	0	0	0	0	0	0
2010	0	0	0	0	0	0	0	0
2011	0	0	0	0.2	0	0	0	0
2012	0	0.075	0	0.3	0.025	0	0	0
2013	0.722	0.025	1.02	0.3	0	0	0.333	0.333
2014	0.722	0	0	0	0	0.1	0.999	0.999
2015	1.444	0	0	0	0	0.1	0	0
2016	0.722	0	0	0	0	0	0	0
2017	2.168	0	0	0	0	0	0	0
2018	0.723	0	0	0	0	0	0	0
2019	1.446	0	0	0	0	0	0	0
2020	0.723	0	0	0	0	0	0	0
2021	0	0	0	0	0	0	0	0
2022	0	0	0	0	0	0	0	0
2023	0	0	0	0	0	0	0	0
2024	0	0	0	0	0	0	0	0
2025	0	0	0	0	0	0	0	0
2026	0	0	0	0	0	0	0	0
2027	0	0	0	0	0	0	0	0
2028	0	0	0	0	0	0	0	0
2029	0	0	0	0	0	0	0	0
2030	0	0	0	0	0	0	0	0

8.6 Timeslices

Table 50: the breakdown of the timeslice arrangement used in the OSeMOSYS model. S1 represents pre winter, s2 represents winter, and s3 represents post winter. d1 is weekday and d2 is weekend.

Characterization	Hr. of the day	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
Season Day		block:																							
s1d1		1	1	1	1	1	1	1	2	2	2	2	2	2	2	2	2	2	2	2	3	3	3	3	1
s1d2		1	1	1	1	1	1	1	1	2	2	2	2	2	2	2	2	2	2	2	3	3	3	3	1
s2d1		1	1	1	1	1	1	1	2	3	3	3	3	3	2	2	2	2	2	3	4	4	5	5	1
s2d2		1	1	1	1	1	1	1	1	2	2	2	2	2	2	2	2	2	2	2	3	3	3	3	1
s3d1		1	1	1	1	1	1	1	1	2	2	2	2	2	2	2	2	2	2	2	3	3	3	3	1
s3d2		1	1	1	1	1	1	1	1	2	2	2	2	2	2	2	2	2	2	2	3	3	3	3	1

8.7 Results

Table 51: The total new build capacity (GW) by individual technologies for the reference scenario in OSeMOSYS

Technology	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Boroma - Quedas Ocua hydro import	0	0	0	0	0	0	0	0	0	0	0	0	0
Combined Cycle Gas Turbine	0	0	0	0	0	0	0	0	0	0	0	0	0
Fluidised Bed Combustion Coal	0	0	0	0	0	0	0	0	0	0	0	0	0
HCB North hydro import	0	0	0	0	0	0	0	0	0	0	0	0	0.19
Ithezi Tezhi hydro import	0	0	0	0	0	0	0	0	0	0	0	0.12	0
Kafue hydro import	0	0	0	0	0	0	0	0	0	0	0	0.75	0
Kariba North Bank extension hydro import	0	0	0	0	0	0	0	0	0	0.36	0	0	0
Landfill gas	0	0	0	0	0	0	0.03	0	0	0	0	0	0
Micro hydro	0	0	0	0	0	0	0.08	0.03	0	0	0	0	0
Mmamabula coal import	0	0	0	0	0	0	0	0	0	0	0	0	0
Moatize - Benga coal import	0	0	0	0	0	0	0	0	0	0	0	0	0
Mphanda Nkuwa hydro import	0	0	0	0	0	0	0	0	0	0	0	0	0
Open-Cycle Gas Turbine diesel	0	0	0	0	0	0	0	1.02	0	0	0	0	0
Open-Cycle Gas Turbine gas	0	0	0	0	0	0	0.71	0	0	0	0	0	0
Supercritical Coal	0	0	0	0	0	0	0	0.72	0.72	1.44	0.72	2.17	0.72
Wind high resource	0	0	0	0	0	0.2	0.3	0.3	0	0	0	0	0
Solar thermal tower 12 hrs. storage	0	0	0	0	0	0	0	0	0	0	0	0	0
Solar Parabolic Trough 9 hrs. storage	0	0	0	0	0	0	0	0	0.1	0.1	0	0	0
TOTAL	**0**	**0**	**0**	**0**	**0**	**0.2**	**1.11**	**2.07**	**0.82**	**1.90**	**0.72**	**3.04**	**0.91**

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Total
Boroma - Quedas Ocua hydro import	0	0	0	0.16	0	0	0	0	0	0	0	0	**0.16**
Combined Cycle Gas Turbine	0	0	2.25	1.14	0	0	0	0	0	0.01	0.00	0	**3.40**
Fluidised Bed Combustion Coal	0	0	0	0	3	0	0	0	0	0	0	0	**3.00**
HCB North hydro import	0.58	0.09	0	0	0	0	0	0	0	0	0	0	**0.85**

Ithezi Tezhi hydro import	0	0	0	0	0	0	0	0	0	0	0	0	**0.12**
Kafue hydro import	0	0	0	0	0	0	0	0	0	0	0	0	**0.75**
Kariba North Bank extension hydro import	0	0	0	0	0	0	0	0	0	0	0	0	**0.36**
Landfill gas	0	0	0	0	0	0	0	0	0	0	0	0	**0.03**
Micro hydro	0	0	0	0.09	0.31	0	0	0	0	0	0	0	**0.50**
Mmamabula coal import	0	0	0	0	0.19	1.01	0	0	0	0	0	0	**1.20**
Moatize - Benga coal import	0	0	0	1	0	0	0	0	0	0	0	0	**1.00**
Mphanda Nkuwa hydro import	0	0.47	0.66	0	0	0	0	0	0	0	0	0	**1.13**
Open-Cycle Gas Turbine diesel	0	0	0	0	0	0	0	0	0	0	0	0	**1.02**
Open-Cycle Gas Turbine gas	0	0	1.05	0.92	0.44	0.18	0.34	0	0	0	0	0	**3.63**
Supercritical Coal	1.45	0.72	0	0	0	1.37	3.06	2.47	2.48	4.72	2.62	1.26	**26.65**
Wind high resource	0	0	0	0	0	0	0	0	0	0	0	0	**0.80**
Solar thermal tower 12 hrs. storage	0	0	0	0	0	0	0	0	0	0	0.67	1.81	**2.48**
Solar Parabolic Trough 9 hrs. storage	0	0	0	0	0	0	0	0	0	0	0	0	**0.20**
TOTAL	**2.02**	**1.28**	**3.95**	**3.31**	**3.94**	**2.56**	**3.40**	**2.47**	**2.48**	**4.72**	**3.29**	**3.07**	**47.27**

8.7.1 New capacity

Table 52: The total capacity in GW for both TIMES and OSeMOSYS models.

	TIMES	OSeMOSYS	difference
2006	40.06	40.06	0.00
2007	40.25	40.25	0.00
2008	40.73	40.73	0.00
2009	41.24	41.24	0.00
2010	41.62	41.62	0.00
2011	42.50	42.50	0.00
2012	43.90	43.91	-0.01
2013	46.07	46.08	-0.01
2014	46.89	46.90	-0.01
2015	48.74	48.76	-0.01
2016	49.39	49.40	-0.01
2017	52.43	52.44	-0.01
2018	53.15	53.35	-0.20
2019	55.24	55.37	-0.13
2020	56.50	56.65	-0.15
2021	60.38	60.53	-0.16
2022	61.67	61.97	-0.31
2023	63.22	63.63	-0.41
2024	65.10	65.28	-0.19
2025	66.88	67.16	-0.28
2026	68.89	69.29	-0.40
2027	71.72	71.77	-0.05
2028	73.44	73.64	-0.20
2029	75.45	75.80	-0.358
2030	78.50	78.87	-0.377

Table 53: the total capacity of the three scenarios.

	total capacity GW Exlc. storage		
	REF	HIGH	LOW
2006	40.1	40.1	40.1
2007	40.2	40.2	40.2
2008	40.7	40.7	40.7
2009	41.2	41.2	41.2
2010	41.6	41.6	41.6
2011	42.5	42.5	42.5
2012	43.9	43.9	43.9
2013	46.1	46.1	46.1
2014	46.9	46.9	46.9
2015	48.8	48.8	48.8
2016	49.4	49.4	49.4
2017	52.4	52.4	52.4
2018	53.3	53.3	53.3
2019	55.4	55.4	55.4
2020	56.7	56.7	56.7
2021	60.5	60.5	60.5
2022	62.0	62.0	62.0
2023	63.6	63.6	63.6
2024	65.3	65.3	65.3
2025	67.2	67.2	67.2
2026	69.3	69.3	69.3
2027	71.8	71.8	71.8
2028	73.6	73.6	73.6
2029	75.8	75.8	75.8
2030	78.9	78.9	78.9

For a breakdown in the Table 53 new build technologies see Table 54 and Table 55.

Table 54: The new build by technology in the LOW penetration scenario in OSeMOSYS

	2006	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
Boroma - Quedas Ocua hydro import	0	0	0	0	0	0	0	0	0	0	0	0	0
Combined Cycle Gas Turbine	0	0	0	0	0	0	0	0	0	0	0	0	0
Fluidised Bed Combustion Coal	0	0	0	0	0	0	0	0	0	0	0	0	0
HCB North hydro import	0	0	0	0	0	0	0	0	0	0	0	0	0.186
Ithezi Tezhi hydro import	0	0	0	0	0	0	0	0	0	0	0	0.12	0
Kafue hydro import	0	0	0	0	0	0	0	0	0	0	0	0.75	0
Kariba North Bank extension hydro import	0	0	0	0	0	0	0	0	0	0.36	0	0	0
Landfill gas	0	0	0	0	0	0	0.025	0	0	0	0	0	0
Micro hydro	0	0	0	0	0	0	0.075	0.025	0.000	0	0	0	0
Mmamabula coal import	0	0	0	0	0	0	0	0	0	0	0	0	0
Moatize - Benga coal import	0	0	0	0	0	0	0	0	0	0	0	0	0
Mphanda Nkuwa hydro import	0	0	0	0	0	0	0	0	0	0	0	0	0
Open-Cycle Gas Turbine diesel	0	0	0	0	0	0	0	1.02	0	0	0	0	0
Open-Cycle Gas Turbine gas	0	0	0	0	0	0	0.712	0	0	0	0	0	0
Supercritical Coal	0	0	0	0	0	0	0	0.722	0.722	1.444	0.722	2.168	0.723
Wind high resource	0	0	0	0	0	0.2	0.3	0.3	0	0	0	0	0
Solar thermal tower 12 hrs storage	0	0	0	0	0	0	0	0	0	0	0	0	0
Solar Parabolic Trough 9 hrs storage	0	0	0	0	0	0	0	0	0.1	0.1	0	0	0
TOTAL	0	0	0	0	0	0.20	1.11	2.07	0.82	1.90	0.72	3.04	0.91
Continued	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**Total**
Boroma - Quedas Ocua hydro import	0	0	0	0.16	0	0	0	0	0	0	0	0	0.16
Combined Cycle Gas Turbine	0	0	2.235	1.152	0	0	0	0	0	0.005	0.004	0	3.39
Fluidised Bed Combustion Coal	0	0	0	0	3	0	0	0	0	0	0	0	3.00

HCB North hydro import	0.578	0.086	0	0	0	0	0	0	0	0	0	0	0.85
Ithezi Tezhi hydro import	0	0	0	0	0	0	0	0	0	0	0	0	0.12
Kafue hydro import	0	0	0	0	0	0	0	0	0	0	0	0	0.75
Kariba North Bank extension hydro import	0	0	0	0	0	0	0	0	0	0	0	0	0.36
Landfill gas	0	0	0	0	0	0	0	0	0	0	0	0	0.03
Micro hydro	0	0	0	0.115	0.285	0	0	0	0	0	0	0	0.50
Mmamabula coal import	0	0	0	0	0.173	1.027	0	0	0	0	0	0	1.20
Moatize - Benga coal import	0	0	0	1	0	0	0	0	0	0	0	0	1.00
Mphanda Nkuwa hydro import	0	0.470	0.655	0	0	0	0	0	0	0	0	0	1.13
Open-Cycle Gas Turbine diesel	0	0	0	0	0	0	0	0	0	0	0	0	1.02
Open-Cycle Gas Turbine gas	0	0	1.059	0.883	0.484	0.180	0.382	0	0	0.000	0	0	3.76
Supercritical Coal	1.446	0.723	0	0	0	1.351	3.013	2.471	2.479	4.720	2.539	1.208	26.33
Wind high resource	0	0	0	0	0	0	0	0	0	0	0	0	0.80
Solar thermal tower 12 hrs storage	0	0	0	0	0	0	0	0	0	0	0.749	1.860	2.67
Solar Parabolic Trough 9 hrs storage	0	0	0	0	0	0	0	0	0	0	0	0	0.20
TOTAL	2.02	1.28	3.95	3.31	3.94	2.56	3.40	2.47	2.48	4.72	3.29	3.07	47.27

Table 55: The new build for the HIGH penetration scenario in OSeMOSYS

	2006	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
Boroma - Quedas Ocua hydro import	0	0	0	0	0	0	0	0	0	0	0	0	0
Combined Cycle Gas Turbine	0	0	0	0	0	0	0	0	0	0	0	0	0
Fluidised Bed Combustion Coal	0	0	0	0	0	0	0	0	0	0	0	0	0
HCB North hydro import	0	0	0	0	0	0	0	0	0	0	0	0	0.19
Ithezi Tezhi hydro import	0	0	0	0	0	0	0	0	0	0	0	0.12	0
Kafue hydro import	0	0	0	0	0	0	0	0	0	0	0	0.75	0
Kariba North Bank extension hydro import	0	0	0	0	0	0	0	0	0	0.36	0	0	0
Landfill gas	0	0	0	0	0	0	0.025	0	0	0	0	0	0
Micro hydro	0	0	0	0	0	0	0.075	0.025	0	0	0	0	0
Mmamabula coal import	0	0	0	0	0	0	0	0	0	0	0	0	0
Moatize - Benga coal import	0	0	0	0	0	0	0	0	0	0	0	0	0
Mphanda Nkuwa hydro import	0	0	0	0	0	0	0	0	0	0	0	0	0
Open-Cycle Gas Turbine diesel	0	0	0	0	0	0	0	1.02	0	0	0	0	0
Open-Cycle Gas Turbine gas	0	0	0	0	0	0	0.712	0	0	0	0	0	0
Supercritical Coal	0	0	0	0	0	0	0	0.72	0.72	1.44	0.72	2.17	0.72
Wind high resource	0	0	0	0	0	0.2	0.3	0.3	0	0	0	0	0
Solar thermal tower 12 hrs storage	0	0	0	0	0	0	0	0	0	0	0	0	0
Solar Parabolic Trough 9 hrs storage	0	0	0	0	0	0	0	0	0.1	0.1	0	0	0
TOTAL	0.00	0.00	0.00	0.00	0.00	0.20	1.11	2.07	0.82	1.90	0.72	3.04	0.91
Continued	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**Total**
Boroma - Quedas Ocua hydro import	0	0	0	0.16	0	0	0	0	0	0	0	0	0.16
Combined Cycle Gas Turbine	0	0	2.15	1.23	0	0	0	0	0	0.00	0.00	0	3.38
Fluidised Bed Combustion Coal	0	0	0	0	3.00	0.00	0	0	0	0	0	0	3.00
HCB North hydro import	0.58	0.09	0	0	0	0	0	0	0	0	0	0	0.85
Ithezi Tezhi hydro import	0	0	0	0	0	0	0	0	0	0	0	0	0.12

Kafue hydro import	0	0	0	0	0	0	0	0	0	0	0	0	0.75
Kariba North Bank extension hydro import	0	0	0	0	0	0	0	0	0	0	0	0	0.36
Landfill gas	0	0	0	0	0	0	0	0	0	0	0	0	0.03
Micro hydro	0	0	0	0.03	0.37	0	0	0	0	0	0	0	0.50
Mmamabula coal import	0	0	0	0	0.03	1.17	0	0	0	0	0	0	1.20
Moatize - Benga coal import	0	0	0	1	0	0	0	0	0	0	0	0	1.00
Mphanda Nkuwa hydro import	0	0.47	0.66	0	0	0	0	0	0	0	0	0	1.13
Open-Cycle Gas Turbine diesel	0	0	0	0	0	0	0	0	0	0	0	0	1.02
Open-Cycle Gas Turbine gas	0	0	1.14	0.90	0.54	0.21	0.47	0.03	0	0.09	0	0	4.08
Supercritical Coal	1.45	0.72	0	0	0	1.19	2.93	2.45	2.48	4.63	2.40	1.06	25.80
Wind high resource	0	0	0	0	0	0	0	0	0	0	0	0	0.80
Solar thermal tower 12 hrs storage	0	0	0	0	0	0	0	0	0	0	0.89	2.01	2.90
Solar Parabolic Trough 9 hrs storage	0	0	0	0	0	0	0	0	0	0	0	0	0.20
TOTAL	**2.02**	**1.28**	**3.95**	**3.31**	**3.94**	**2.56**	**3.40**	**2.47**	**2.48**	**4.72**	**3.29**	**3.07**	**47.27**

Using the production on an annual basis, and using the capacity for the open cycle gas turbine, super critical coal and solar 12 hour storage technologies, the capacity factors they run at are given in the table below:

Table 56: The operating capacity factors for selected technologies in the model in all scenarios.

	Gas open cycle	**Super critical coal**	**solar 12 hour storage**
Capacity factor	0.3%	91.7%	46.7%

Table 57: The annual production (PJ) for technology groups between the reference case and high penetration scenario

HIGH						
	Coal	**Gas**	**Nuclear**	**Hydro**	**RE**	**storage**
2028	1508.1	97.8	46.0	109.8	10.5	12.9
2029	1542.4	97.8	46.0	109.8	27.0	12.9
2030	1566.0	97.8	46.0	109.8	60.1	12.9
REF						
2028	1536.5	98.1	46.0	109.8	10.5	12.9
2029	1583.7	98.2	46.0	109.8	20.3	12.9
2030	1620.1	98.1	46.0	109.8	47.0	12.9

A combined graph of the residential, industrial and commercial demand profiles with the power profiles and the production profile of the solar 12 hr. storage generating technology are shown in the graph below:

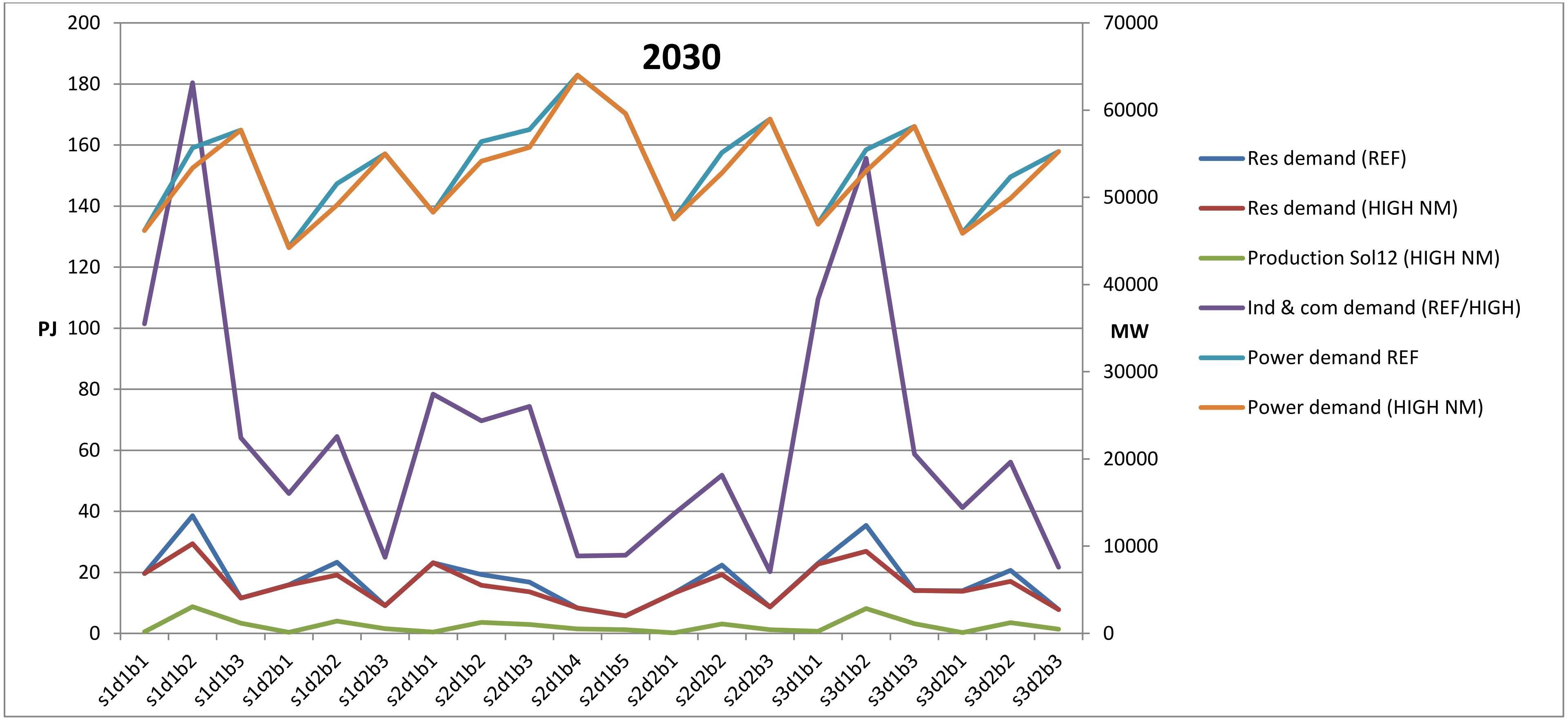


Figure 80: The combined graph of power demand profile and energy consumption profiles with and without the net metering implemented. Also included is the production of solar 12hr storage generating technology that is present in the model scenario with the net metering.

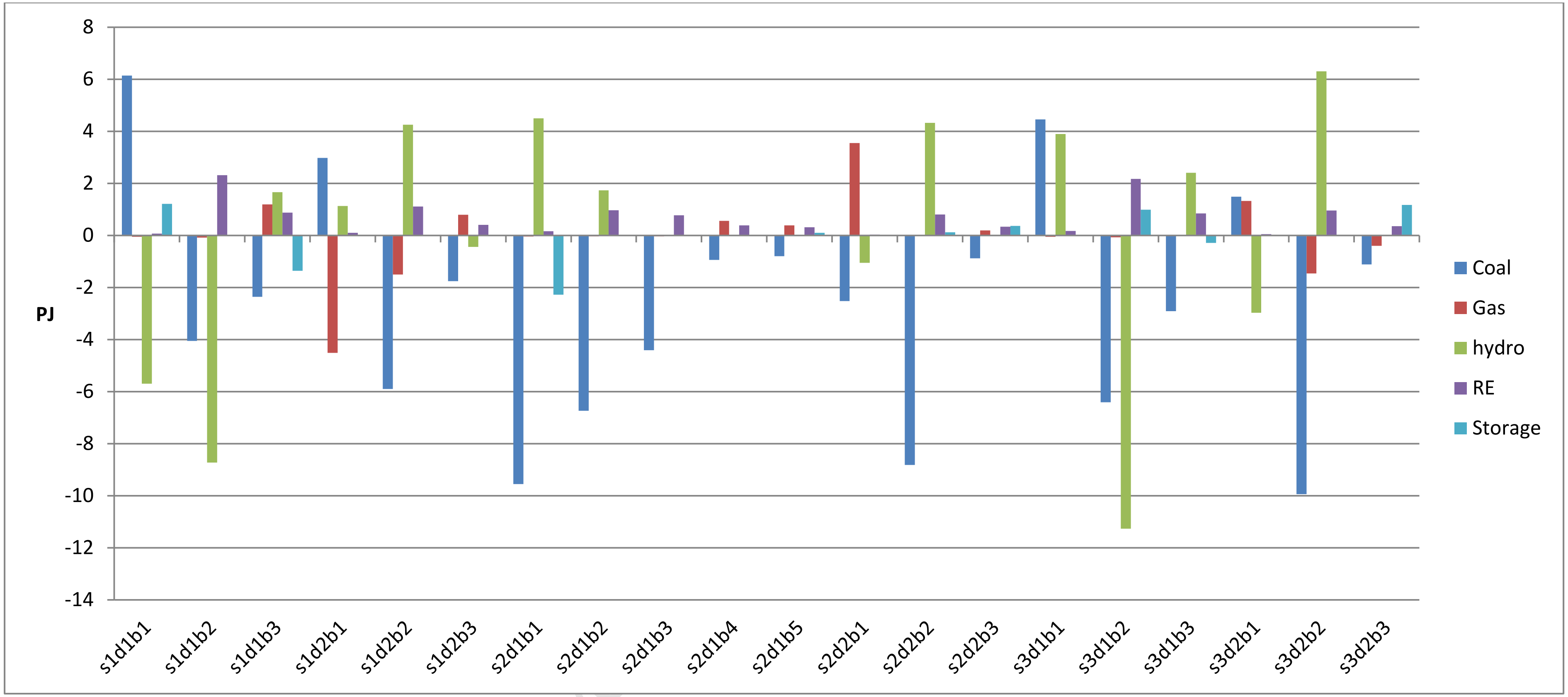


Figure 81: the change in energy production for each technology in 2030 between the ref scenario and the high penetration of net metering scenario.

8.8 The OSeMOSYS software used and adapted in this work

Note that the energy model input file for the South African electricity sector is too large to attach to this appendix. However, it is included with the softcopy of this thesis.

Verbatim:

```
#Bryce McCall

#University of Cape Town

#February 2013

#This is an edited version of the 2012_07_27_BETA OSeMOSYS software, obtained via email from M. Welsch.

#Edited for use in the Master’s degree of Sustainable energy engineering, at the University of Cape Town.

#NOTE: this copy does not include the output results section which may be obtained via the OSeMOSY website, simply add it to the end of this version.

#OSEMOSYS_2012_06_01_BETA

#  To run OSeMOSYS, enter the following line into your command prompt after replacing FILEPATH & YOURDATAFILE with your folder structure and data file name:

#

#  C:\...FILEPATH...\glpsol -m C:\...FILEPATH...\OSeMOSYS_2012_06_01_BETA.mod -d C:\...FILEPATH...\YOURDATAFILE.dat -o C:\...FILEPATH...\Results.txt

#                                ########################################

######################                  Model Definition                        #############
```

```
#                                 #########################################

#

###############

#    Sets     #

###############

#

set YEAR;

set TECHNOLOGY;

set TIMESLICE;

set FUEL;

set EMISSION;

set MODE_OF_OPERATION;

set REGION;

set SEASON;

set DAYTYPE;

set DAILYTIMEBRACKET;

set FLEXIBLEDEMANDTYPE;

set STORAGE;
```

```
set YEAR_X;

################################           Added parameter definitions by Bryce McCall
#####################################



param TotalTechnologyAnnualPercentileActivityUpperLim{y in YEAR, t in TECHNOLOGY, r in REGION};

param TotalTechnologyAnnualPercentileActivityLowerLim{y in YEAR, t in TECHNOLOGY, r in REGION};

param TSforChargingStorage{lh in DAILYTIMEBRACKET, l in TIMESLICE};

###############################

########                   Global                                         #############

#

param YearSplit{y in YEAR,l in TIMESLICE};

param DiscountRate{t in TECHNOLOGY, r in REGION};

param DaySplit{y in YEAR, lh in DAILYTIMEBRACKET};

param Conversionls{ls in SEASON, l in TIMESLICE};

param Conversionld{ld in DAYTYPE, l in TIMESLICE};

param Conversionlh{lh in DAILYTIMEBRACKET, l in TIMESLICE};

param DaysInDayType{y in YEAR, ls in SEASON, ld in DAYTYPE};

param TradeRoute{y in YEAR, f in FUEL, r in REGION, rr in REGION};
```

```
#

########                  Demands                                #############

#

param SpecifiedAnnualDemand{y in YEAR,f in FUEL, r in REGION};

param SpecifiedDemandProfile{y in YEAR, l in TIMESLICE, f in FUEL, r in REGION};

param AccumulatedAnnualDemand{y in YEAR, f in FUEL, r in REGION};

#

#########                 Performance                            #############

#

param CapacityToActivityUnit{t in TECHNOLOGY, r in REGION};

param TechWithCapacityNeededToMeetPeakTS{t in TECHNOLOGY, r in REGION};

param CapacityFactor{y in YEAR, t in TECHNOLOGY, l in TIMESLICE, r in REGION};

param AvailabilityFactor{y in YEAR, t in TECHNOLOGY, r in REGION};

param OperationalLife{t in TECHNOLOGY, r in REGION};

param ResidualCapacity{y in YEAR, t in TECHNOLOGY, r in REGION};

param InputActivityRatio{y in YEAR, t in TECHNOLOGY, f in FUEL, m in MODE_OF_OPERATION, r in REGION};

param OutputActivityRatio{y in YEAR, t in TECHNOLOGY, f in FUEL, m in MODE_OF_OPERATION, r in REGION};

#
```

```
#########                  Technology Costs                  #############

#

param CapitalCost{y in YEAR, t in TECHNOLOGY, r in REGION};

param VariableCost{y in YEAR, t in TECHNOLOGY, m in MODE_OF_OPERATION, r in REGION};

param FixedCost{y in YEAR, t in TECHNOLOGY, r in REGION};

#

#########                        Storage                          #############

#

param TechnologyToStorage{t in TECHNOLOGY, m in MODE_OF_OPERATION, s in STORAGE, r in REGION};

param TechnologyFromStorage{t in TECHNOLOGY, m in MODE_OF_OPERATION, s in STORAGE, r in REGION};

param StorageLevelStart{s in STORAGE, r in REGION};

param StorageMaxChargeRate{s in STORAGE, r in REGION};

param StorageMaxDischargeRate{s in STORAGE, r in REGION};

param MinStorageCharge{s in STORAGE, y in YEAR, r in REGION};

param OperationalLifeStorage{s in STORAGE, r in REGION};

param CapitalCostStorage{s in STORAGE, y in YEAR, r in REGION};

param DiscountRateStorage{s in STORAGE, r in REGION};

param ResidualStorageCapacity{s in STORAGE, y in YEAR, r in REGION};
```

```
#
#########                  Capacity Constraints             #############
#
param CapacityOfOneTechnologyUnit{y in YEAR, t in TECHNOLOGY, r in REGION};
param TotalAnnualMaxCapacity{y in YEAR, t in TECHNOLOGY, r in REGION};
param TotalAnnualMinCapacity{y in YEAR, t in TECHNOLOGY, r in REGION};
#
#########                  Investment Constraints           #############
#
param TotalAnnualMaxCapacityInvestment{y in YEAR, t in TECHNOLOGY, r in REGION};
param TotalAnnualMinCapacityInvestment{y in YEAR, t in TECHNOLOGY, r in REGION};
#
#########                  Activity Constraints             #############
#
param TotalTechnologyAnnualActivityUpperLimit{y in YEAR, t in TECHNOLOGY, r in REGION};
param TotalTechnologyAnnualActivityLowerLimit{y in YEAR, t in TECHNOLOGY, r in REGION};
param TotalTechnologyModelPeriodActivityUpperLimit{t in TECHNOLOGY, r in REGION};
param TotalTechnologyModelPeriodActivityLowerLimit{t in TECHNOLOGY, r in REGION};
```

```
#
#########                  Reserve Margin                          #############
#
param ReserveMarginTagTechnology{y in YEAR,t in TECHNOLOGY, r in REGION};
param ReserveMarginTagFuel{y in YEAR,f in FUEL, r in REGION};
param ReserveMargin{y in YEAR, r in REGION};
#
#########                  RE Generation Target             #############
#
param RETagTechnology{y in YEAR,t in TECHNOLOGY, r in REGION};
param RETagFuel{y in YEAR,f in FUEL, r in REGION};
param REMinProductionTarget{y in YEAR, r in REGION};
#
#########                  Emissions & Penalties            #############
#
param EmissionActivityRatio{y in YEAR, t in TECHNOLOGY, e in EMISSION, m in MODE_OF_OPERATION, r in REGION};
param EmissionsPenalty{y in YEAR, e in EMISSION, r in REGION};
param AnnualExogenousEmission{y in YEAR, e in EMISSION, r in REGION};
```

```
param AnnualEmissionLimit{y in YEAR, e in EMISSION, r in REGION};
param ModelPeriodExogenousEmission{e in EMISSION, r in REGION};
param ModelPeriodEmissionLimit{e in EMISSION, r in REGION};
#
######################
#   Model Variables  #
######################
#
########                   Demands                                 #############
#
var RateOfDemand{y in YEAR,l in TIMESLICE, f in FUEL, r in REGION}>= 0;
var Demand{y in YEAR,l in TIMESLICE, f in FUEL, r in REGION}>= 0;
#
########            Storage                          #############
#
var RateOfStorageCharge{s in STORAGE, y in YEAR, ls in SEASON, ld in DAYTYPE, lh in DAILYTIMEBRACKET, r in REGION};
var RateOfStorageDischarge{s in STORAGE, y in YEAR, ls in SEASON, ld in DAYTYPE, lh in DAILYTIMEBRACKET, r in REGION};
var NetChargeWithinYear{s in STORAGE, y in YEAR, ls in SEASON, ld in DAYTYPE, lh in DAILYTIMEBRACKET, r in REGION};
```

```
var NetChargeWithinDay{s in STORAGE, y in YEAR, ls in SEASON, ld in DAYTYPE, lh in DAILYTIMEBRACKET, r in REGION};

var StorageLevelYearStart{s in STORAGE, y in YEAR, r in REGION} >=0;

var StorageLevelYearFinish{s in STORAGE, y in YEAR, r in REGION} >=0;

var StorageLevelSeasonStart{s in STORAGE, y in YEAR, ls in SEASON, r in REGION} >=0;

var StorageLevelDayTypeStart{s in STORAGE, y in YEAR, ls in SEASON, ld in DAYTYPE, r in REGION} >=0;

var StorageLevelDayTypeFinish{s in STORAGE, y in YEAR, ls in SEASON, ld in DAYTYPE, r in REGION} >=0;

var StorageLowerLimit{s in STORAGE, y in YEAR, r in REGION}>=0;

var StorageUpperLimit{s in STORAGE, y in YEAR, r in REGION} >=0;

var AccumulatedNewStorageCapacity{s in STORAGE, y in YEAR, r in REGION} >=0;

var NewStorageCapacity{s in STORAGE, y in YEAR, r in REGION} >=0;

var CapitalInvestmentStorage{s in STORAGE, y in YEAR, r in REGION} >=0;

var DiscountedCapitalInvestmentStorage{s in STORAGE, y in YEAR, r in REGION} >=0;

var SalvageValueStorage{s in STORAGE, y in YEAR, r in REGION} >=0;

var DiscountedSalvageValueStorage{s in STORAGE, y in YEAR, r in REGION} >=0;

var TotalDiscountedStorageCost{s in STORAGE, y in YEAR, r in REGION} >=0;

#

#########               Capacity Variables                  #############

#
```

```
var NumberOfNewTechnologyUnits{y in YEAR, t in TECHNOLOGY, r in REGION} >= 0,integer;

var NewCapacity{y in YEAR, t in TECHNOLOGY, r in REGION} >= 0;

var AccumulatedNewCapacity{y in YEAR, t in TECHNOLOGY, r in REGION} >= 0;

var TotalCapacityAnnual{y in YEAR, t in TECHNOLOGY, r in REGION}>= 0;

#

#########               Activity Variables                  #############

#

var RateOfActivity{y in YEAR, l in TIMESLICE, t in TECHNOLOGY, m in MODE_OF_OPERATION, r in REGION} >= 0;

var RateOfTotalActivity{y in YEAR, l in TIMESLICE, t in TECHNOLOGY, r in REGION} >= 0;

var TotalTechnologyAnnualActivity{y in YEAR, t in TECHNOLOGY, r in REGION} >= 0;

var TotalAnnualTechnologyActivityByMode{y in YEAR, t in TECHNOLOGY,m in MODE_OF_OPERATION,r in REGION}>=0;

var RateOfProductionByTechnologyByMode{y in YEAR, l in TIMESLICE, t in TECHNOLOGY,m in MODE_OF_OPERATION,f in FUEL,r in REGION}>=
0;

var RateOfProductionByTechnology{y in YEAR, l in TIMESLICE, t in TECHNOLOGY,f in FUEL, r in REGION}>= 0;

var ProductionByTechnology{y in YEAR, l in TIMESLICE, t in TECHNOLOGY,f in FUEL, r in REGION}>= 0;

var ProductionByTechnologyAnnual{y in YEAR, t in TECHNOLOGY, f in FUEL, r in REGION}>= 0;

var RateOfProduction{y in YEAR, l in TIMESLICE, f in FUEL, r in REGION} >= 0;

var Production{y in YEAR, l in TIMESLICE, f in FUEL, r in REGION} >= 0;
```

```
var RateOfUseByTechnologyByMode{y in YEAR, l in TIMESLICE, t in TECHNOLOGY,m in MODE_OF_OPERATION,f in FUEL,r in REGION}>= 0;

var RateOfUseByTechnology{y in YEAR, l in TIMESLICE, t in TECHNOLOGY, f in FUEL, r in REGION} >= 0;

var UseByTechnologyAnnual{y in YEAR, t in TECHNOLOGY,f in FUEL, r in REGION}>= 0;

var RateOfUse{y in YEAR, l in TIMESLICE, f in FUEL, r in REGION}>= 0;

var UseByTechnology{y in YEAR, l in TIMESLICE, t in TECHNOLOGY,f in FUEL, r in REGION}>= 0;

var Use{y in YEAR, l in TIMESLICE, f in FUEL, r in REGION}>= 0;

var Trade{y in YEAR, l in TIMESLICE, f in FUEL, r in REGION, rr in REGION};

var TradeAnnual{y in YEAR, f in FUEL, r in REGION, rr in REGION};

#

var ProductionAnnual{y in YEAR, f in FUEL, r in REGION}>= 0;

var UseAnnual{y in YEAR, f in FUEL, r in REGION}>= 0;

#

#########               Costing Variables                  #############

#

var CapitalInvestment{y in YEAR, t in TECHNOLOGY, r in REGION}>= 0;

var DiscountedCapitalInvestment{y in YEAR, t in TECHNOLOGY, r in REGION}>= 0;

#

var SalvageValue{y in YEAR, t in TECHNOLOGY, r in REGION}>= 0;
```

```
var DiscountedSalvageValue{y in YEAR, t in TECHNOLOGY, r in REGION}>= 0;

var OperatingCost{y in YEAR, t in TECHNOLOGY, r in REGION}>= 0;

var DiscountedOperatingCost{y in YEAR, t in TECHNOLOGY, r in REGION}>= 0;

#

var AnnualVariableOperatingCost{y in YEAR,t in TECHNOLOGY, r in REGION}>= 0;

var AnnualFixedOperatingCost{y in YEAR,t in TECHNOLOGY, r in REGION}>= 0;

var VariableOperatingCost{y in YEAR, l in TIMESLICE, t in TECHNOLOGY, r in REGION}>= 0;

#

var TotalDiscountedCostByTechnology{y in YEAR, t in TECHNOLOGY, r in REGION}>= 0;

var TotalDiscountedCost{y in YEAR, r in REGION}>= 0;

#

var ModelPeriodCostByRegion {r in REGION} >= 0;

#

#########                 Reserve Margin                         #############

#

var TotalCapacityInReserveMargin{y in YEAR, r in REGION}>= 0;

var DemandNeedingReserveMargin{y in YEAR,l in TIMESLICE, r in REGION}>= 0;

#
```

```
#########                  RE Gen Target                      #############

#

var TotalREProductionAnnual{y in YEAR, r in REGION};

var RETotalDemandOfTargetFuelAnnual{y in YEAR, r in REGION};

#

var TotalTechnologyModelPeriodActivity{t in TECHNOLOGY, r in REGION};

#

#########                  Emissions                                 #############

#

var AnnualTechnologyEmissionByMode{y in YEAR, t in TECHNOLOGY, e in EMISSION, m in MODE_OF_OPERATION, r in REGION}>= 0;

var AnnualTechnologyEmission{y in YEAR, t in TECHNOLOGY, e in EMISSION, r in REGION}>= 0;

var AnnualTechnologyEmissionPenaltyByEmission{y in YEAR, t in TECHNOLOGY, e in EMISSION, r in REGION}>= 0;

var AnnualTechnologyEmissionsPenalty{y in YEAR, t in TECHNOLOGY, r in REGION}>= 0;

var DiscountedTechnologyEmissionsPenalty{y in YEAR, t in TECHNOLOGY, r in REGION}>= 0;

var AnnualEmissions{y in YEAR, e in EMISSION, r in REGION}>= 0;

var ModelPeriodEmissions{e in EMISSION, r in REGION}>= 0;

#

######################
```

```
# Objective Function #

######################

#

minimize cost: sum{y in YEAR_X, r in REGION} TotalDiscountedCost[y,r];

#

#####################

# Constraints       #

#####################

#

s.t. EQ_SpecifiedDemand{y in YEAR_X,l in TIMESLICE, f in FUEL, r in REGION}:
SpecifiedAnnualDemand[y,f,r]*SpecifiedDemandProfile[y,l,f,r] / YearSplit[y,l]=RateOfDemand[y,l,f,r];

#

#########           Capacity Adequacy A       #############

#

s.t. CAa1_TotalNewCapacity{y in YEAR_X, t in TECHNOLOGY, r in REGION}:AccumulatedNewCapacity[y,t,r] = sum{yy in YEAR_X: y-yy <
OperationalLife[t,r] && y-yy>=0}

                                                      if CapacityOfOneTechnologyUnit[y,t,r]=0 then NewCapacity[yy,t,r]

                                                      else
CapacityOfOneTechnologyUnit[yy,t,r]*NumberOfNewTechnologyUnits[yy,t,r];
```

```
s.t. CAa2_TotalAnnualCapacity{y in YEAR_X, t in TECHNOLOGY, r in REGION}: AccumulatedNewCapacity[y,t,r]+ ResidualCapacity[y,t,r]
= TotalCapacityAnnual[y,t,r];

s.t. CAa3_TotalActivityOfEachTechnology{y in YEAR_X, t in TECHNOLOGY, l in TIMESLICE,r in REGION}: sum{m in MODE_OF_OPERATION}
RateOfActivity[y,l,t,m,r] = RateOfTotalActivity[y,l,t,r];

s.t. CAa4_Constraint_Capacity{y in YEAR_X, l in TIMESLICE, t in TECHNOLOGY, r in REGION:
TechWithCapacityNeededToMeetPeakTS[t,r]<>0}: RateOfTotalActivity[y,l,t,r] <= TotalCapacityAnnual[y,t,r] *
CapacityFactor[y,t,l,r]*CapacityToActivityUnit[t,r];

#

# Note that the PlannedMaintenance equation below ensures that all other technologies have a capacity great enough to at least
meet the annual average.

#

#########           Capacity Adequacy B         #############

#

s.t. CAb1_PlannedMaintenance{y in YEAR_X, t in TECHNOLOGY, r in REGION}: sum{l in TIMESLICE}
RateOfTotalActivity[y,l,t,r]*YearSplit[y,l] <= sum{l in TIMESLICE}
(TotalCapacityAnnual[y,t,r]*CapacityFactor[y,t,l,r]*YearSplit[y,l])* AvailabilityFactor[y,t,r]*CapacityToActivityUnit[t,r];

#

#########            Energy Balance A                #############

#
```

```
s.t. EBa1_RateOfFuelProduction1{y in YEAR_X, l in TIMESLICE, f in FUEL, t in TECHNOLOGY, m in MODE_OF_OPERATION, r in REGION:
OutputActivityRatio[y,t,f,m,r] <>0}:  RateOfActivity[y,l,t,m,r]*OutputActivityRatio[y,t,f,m,r]  =
RateOfProductionByTechnologyByMode[y,l,t,m,f,r];

s.t. EBa2_RateOfFuelProduction2{y in YEAR_X, l in TIMESLICE, f in FUEL, t in TECHNOLOGY, r in REGION}: sum{m in
MODE_OF_OPERATION: OutputActivityRatio[y,t,f,m,r] <>0} RateOfProductionByTechnologyByMode[y,l,t,m,f,r] =
RateOfProductionByTechnology[y,l,t,f,r] ;

s.t. EBa3_RateOfFuelProduction3{y in YEAR_X, l in TIMESLICE, f in FUEL, r in REGION}: sum{t in TECHNOLOGY}
RateOfProductionByTechnology[y,l,t,f,r]  =  RateOfProduction[y,l,f,r];

s.t. EBa4_RateOfFuelUse1{y in YEAR_X, l in TIMESLICE, f in FUEL, t in TECHNOLOGY, m in MODE_OF_OPERATION, r in
REGION:InputActivityRatio[y,t,f,m,r]<>0}: RateOfActivity[y,l,t,m,r]*InputActivityRatio[y,t,f,m,r] =
RateOfUseByTechnologyByMode[y,l,t,m,f,r];

s.t. EBa5_RateOfFuelUse2{y in YEAR_X, l in TIMESLICE, f in FUEL, t in TECHNOLOGY, r in REGION}: sum{m in
MODE_OF_OPERATION:InputActivityRatio[y,t,f,m,r]<>0} RateOfUseByTechnologyByMode[y,l,t,m,f,r] = RateOfUseByTechnology[y,l,t,f,r];

s.t. EBa6_RateOfFuelUse3{y in YEAR_X, l in TIMESLICE, f in FUEL, r in REGION}: sum{t in TECHNOLOGY}
RateOfUseByTechnology[y,l,t,f,r]  = RateOfUse[y,l,f,r];

s.t. EBa7_EnergyBalanceEachTS1{y in YEAR_X,l in TIMESLICE, f in FUEL, r in REGION}: RateOfProduction[y,l,f,r]*YearSplit[y,l] =
Production[y,l,f,r];

s.t. EBa8_EnergyBalanceEachTS2{y in YEAR_X,l in TIMESLICE, f in FUEL, r in REGION}: RateOfUse[y,l,f,r]*YearSplit[y,l] =
Use[y,l,f,r];

s.t. EBa9_EnergyBalanceEachTS3{y in YEAR_X,l in TIMESLICE, f in FUEL, r in REGION}: RateOfDemand[y,l,f,r]*YearSplit[y,l] =
Demand[y,l,f,r];

s.t. EBa10_EnergyBalanceEachTS4{y in YEAR_X,l in TIMESLICE, f in FUEL, r in REGION, rr in REGION}: Trade[y,l,f,r,rr] = -
Trade[y,l,f,rr,r];
```

```
s.t. EBa11_EnergyBalanceEachTS5{y in YEAR_X,l in TIMESLICE, f in FUEL, r in REGION}: Production[y,l,f,r] >= Demand[y,l,f,r] +
Use[y,l,f,r] + sum{rr in REGION} Trade[y,l,f,r,rr]*TradeRoute[y,f,r,rr];

#

#########           Energy Balance B                #############

#

s.t. EBb1_EnergyBalanceEachYear1{y in YEAR_X, f in FUEL, r in REGION}: sum{l in TIMESLICE} Production[y,l,f,r] =
ProductionAnnual[y,f,r];

s.t. EBb2_EnergyBalanceEachYear2{y in YEAR_X, f in FUEL, r in REGION}: sum{l in TIMESLICE} Use[y,l,f,r] = UseAnnual[y,f,r];

s.t. EBb3_EnergyBalanceEachYear3{y in YEAR_X, f in FUEL, r in REGION, rr in REGION}: sum{l in TIMESLICE} Trade[y,l,f,r,rr] =
TradeAnnual[y,f,r,rr];

s.t. EBb4_EnergyBalanceEachYear4{y in YEAR_X, f in FUEL, r in REGION}: ProductionAnnual[y,f,r] >= UseAnnual[y,f,r] + sum{rr in
REGION} TradeAnnual[y,f,r,rr]*TradeRoute[y,f,r,rr] + AccumulatedAnnualDemand[y,f,r];

#

#########           Accounting Technology Production/Use    #############

#

s.t. Acc1_FuelProductionByTechnology{y in YEAR_X, l in TIMESLICE, t in TECHNOLOGY, f in FUEL, r in REGION}:
RateOfProductionByTechnology[y,l,t,f,r] * YearSplit[y,l] = ProductionByTechnology[y,l,t,f,r];

s.t. Acc2_FuelUseByTechnology{y in YEAR_X, l in TIMESLICE, t in TECHNOLOGY, f in FUEL, r in REGION}:
RateOfUseByTechnology[y,l,t,f,r] * YearSplit[y,l] = UseByTechnology[y,l,t,f,r];

s.t. Acc3_AverageAnnualRateOfActivity{y in YEAR_X,t in TECHNOLOGY, m in MODE_OF_OPERATION, r in REGION}: sum{l in TIMESLICE}
RateOfActivity[y,l,t,m,r]*YearSplit[y,l] = TotalAnnualTechnologyActivityByMode[y,t,m,r];
```

```
s.t. Acc4_ModelPeriodCostByRegion{r in REGION}:sum{y in YEAR_X}TotalDiscountedCost[y,r] = ModelPeriodCostByRegion[r];

#

#########           Storage Equations                #############

#

s.t. S1_RateOfStorageCharge{s in STORAGE, y in YEAR_X, ls in SEASON, ld in DAYTYPE, lh in DAILYTIMEBRACKET, r in REGION}: sum{t
in TECHNOLOGY, m in MODE_OF_OPERATION, l in TIMESLICE:TechnologyToStorage[t,m,s,r]>0} RateOfActivity[y,l,t,m,r] *
TechnologyToStorage[t,m,s,r] *TSforChargingStorage[lh,l]* Conversionls[ls,l] * Conversionld[ld,l] * Conversionlh[lh,l] =
RateOfStorageCharge[s,y,ls,ld,lh,r];

s.t. S2_RateOfStorageDischarge{s in STORAGE, y in YEAR_X, ls in SEASON, ld in DAYTYPE, lh in DAILYTIMEBRACKET, r in REGION}:
sum{t in TECHNOLOGY, m in MODE_OF_OPERATION, l in TIMESLICE:TechnologyFromStorage[t,m,s,r]>0} RateOfActivity[y,l,t,m,r] *
TechnologyFromStorage[t,m,s,r] * Conversionls[ls,l] * Conversionld[ld,l] * Conversionlh[lh,l] =
RateOfStorageDischarge[s,y,ls,ld,lh,r];

s.t. S3_NetChargeWithinYear{s in STORAGE, y in YEAR_X, ls in SEASON, ld in DAYTYPE, lh in DAILYTIMEBRACKET, r in REGION}: sum{l
in TIMESLICE:Conversionls[ls,l]>0&&Conversionld[ld,l]>0&&Conversionlh[lh,l]>0}  (RateOfStorageCharge[s,y,ls,ld,lh,r] -
RateOfStorageDischarge[s,y,ls,ld,lh,r]) * YearSplit[y,l] * Conversionls[ls,l] * Conversionld[ld,l] * Conversionlh[lh,l] =
NetChargeWithinYear[s,y,ls,ld,lh,r];

s.t. S4_NetChargeWithinDay{s in STORAGE, y in YEAR_X, ls in SEASON, ld in DAYTYPE, lh in DAILYTIMEBRACKET, r in REGION}:
(RateOfStorageCharge[s,y,ls,ld,lh,r] - RateOfStorageDischarge[s,y,ls,ld,lh,r]) * DaySplit[y,lh] =
NetChargeWithinDay[s,y,ls,ld,lh,r];

s.t. S5_and_S6_StorageLevelYearStart{s in STORAGE, y in YEAR_X, r in REGION}: if y = min{yy in YEAR_X} min(yy) then
StorageLevelStart[s,r]

                                                                                                                       else
StorageLevelYearStart[s,y-1,r] + sum{ls in SEASON, ld in DAYTYPE, lh in DAILYTIMEBRACKET} NetChargeWithinYear[s,y-1,ls,ld,lh,r]
```

```
                                                                                                                  =
StorageLevelYearStart[s,y,r];

s.t. S7_and_S8_StorageLevelYearFinish{s in STORAGE, y in YEAR_X, r in REGION}:  if y < max{yy in YEAR_X} max(yy) then
StorageLevelYearStart[s,y+1,r]

                                                                                                                  else
StorageLevelYearStart[s,y,r] + sum{ls in SEASON, ld in DAYTYPE, lh in DAILYTIMEBRACKET} NetChargeWithinYear[s,y,ls,ld,lh,r]

                                                                                                                  =
StorageLevelYearFinish[s,y,r];

s.t. S9_and_S10_StorageLevelSeasonStart{s in STORAGE, y in YEAR_X, ls in SEASON, r in REGION}: if ls = min{lsls in SEASON}
min(lsls) then StorageLevelYearStart[s,y,r]

                                                                                                                  else
StorageLevelSeasonStart[s,y,ls-1,r] + sum{ld in DAYTYPE, lh in DAILYTIMEBRACKET} NetChargeWithinYear[s,y,ls-1,ld,lh,r]

                                                                                                                  =
StorageLevelSeasonStart[s,y,ls,r];

s.t. S11_and_S12_StorageLevelDayTypeStart{s in STORAGE, y in YEAR_X, ls in SEASON, ld in DAYTYPE, r in REGION}: if ld = min{ldld
in DAYTYPE} min(ldld) then StorageLevelSeasonStart[s,y,ls,r]

                                                                                                                  else
StorageLevelDayTypeStart[s,y,ls,ld-1,r] + sum{lh in DAILYTIMEBRACKET} NetChargeWithinDay[s,y,ls,ld-1,lh,r] *
DaysInDayType[y,ls,ld-1]

                                                                                                                  =
StorageLevelDayTypeStart[s,y,ls,ld,r];

s.t. S13_and_S14_and_S15_StorageLevelDayTypeFinish{s in STORAGE, y in YEAR_X, ls in SEASON, ld in DAYTYPE, r in REGION}:       if
ls = max{lsls in SEASON} max(lsls) && ld = max{ldld in DAYTYPE} max(ldld) then StorageLevelYearFinish[s,y,r]
```

```
                                                                                                                         else if ld =
max{ldld in DAYTYPE} max(ldld) then StorageLevelSeasonStart[s,y,ls+1,r]

                                                                                                                         else
StorageLevelDayTypeFinish[s,y,ls,ld+1,r] - sum{lh in DAILYTIMEBRACKET} NetChargeWithinDay[s,y,ls,ld+1,lh,r] *
DaysInDayType[y,ls,ld+1]

                                                                                                                         =
StorageLevelDayTypeFinish[s,y,ls,ld,r];

#

##########          Storage Constraints        #############

#

s.t. SC1_LowerLimit_BeginningOfDailyTimeBracketOfFirstInstanceOfDayTypeInFirstWeekConstraint{s in STORAGE, y in YEAR_X, ls in
SEASON, ld in DAYTYPE, lh in DAILYTIMEBRACKET, r in REGION}: 0 <= (StorageLevelDayTypeStart[s,y,ls,ld,r]+sum{lhlh in
DAILYTIMEBRACKET:lh-lhlh>0} NetChargeWithinDay[s,y,ls,ld,lhlh,r])-StorageLowerLimit[s,y,r];


s.t. SC1_UpperLimit_BeginningOfDailyTimeBracketOfFirstInstanceOfDayTypeInFirstWeekConstraint{s in STORAGE, y in YEAR_X, ls in
SEASON, ld in DAYTYPE, lh in DAILYTIMEBRACKET, r in REGION}: (StorageLevelDayTypeStart[s,y,ls,ld,r]+sum{lhlh in
DAILYTIMEBRACKET:lh-lhlh>0} NetChargeWithinDay[s,y,ls,ld,lhlh,r])-StorageUpperLimit[s,y,r] <= 0;


s.t. SC2_LowerLimit_EndOfDailyTimeBracketOfLastInstanceOfDayTypeInFirstWeekConstraint{s in STORAGE, y in YEAR_X, ls in SEASON, ld
in DAYTYPE, lh in DAILYTIMEBRACKET, r in REGION}: 0 <= if ld > min{ldld in DAYTYPE} min(ldld) then
(StorageLevelDayTypeStart[s,y,ls,ld,r]-sum{lhlh in DAILYTIMEBRACKET:lh-lhlh<0} NetChargeWithinDay[s,y,ls,ld-1,lhlh,r])-
StorageLowerLimit[s,y,r];
```

```
s.t. SC2_UpperLimit_EndOfDailyTimeBracketOfLastInstanceOfDayTypeInFirstWeekConstraint{s in STORAGE, y in YEAR_X, ls in SEASON, ld
in DAYTYPE, lh in DAILYTIMEBRACKET, r in REGION}: if ld > min{ldld in DAYTYPE} min(ldld) then
(StorageLevelDayTypeStart[s,y,ls,ld,r]-sum{lhlh in DAILYTIMEBRACKET:lh-lhlh<0} NetChargeWithinDay[s,y,ls,ld-1,lhlh,r])-
StorageUpperLimit[s,y,r] <= 0;

s.t. SC3_LowerLimit_EndOfDailyTimeBracketOfLastInstanceOfDayTypeInLastWeekConstraint{s in STORAGE, y in YEAR_X, ls in SEASON, ld
in DAYTYPE, lh in DAILYTIMEBRACKET, r in REGION}:  0 <= (StorageLevelDayTypeFinish[s,y,ls,ld,r] - sum{lhlh in
DAILYTIMEBRACKET:lh-lhlh<0} NetChargeWithinDay[s,y,ls,ld,lhlh,r])-StorageLowerLimit[s,y,r];



s.t. SC3_UpperLimit_EndOfDailyTimeBracketOfLastInstanceOfDayTypeInLastWeekConstraint{s in STORAGE, y in YEAR_X, ls in SEASON, ld
in DAYTYPE, lh in DAILYTIMEBRACKET, r in REGION}:  (StorageLevelDayTypeFinish[s,y,ls,ld,r] - sum{lhlh in DAILYTIMEBRACKET:lh-
lhlh<0} NetChargeWithinDay[s,y,ls,ld,lhlh,r])-StorageUpperLimit[s,y,r] <= 0;

s.t. SC4_LowerLimit_BeginningOfDailyTimeBracketOfFirstInstanceOfDayTypeInLastWeekConstraint{s in STORAGE, y in YEAR_X, ls in
SEASON, ld in DAYTYPE, lh in DAILYTIMEBRACKET, r in REGION}:        0 <= if ld > min{ldld in DAYTYPE} min(ldld) then
(StorageLevelDayTypeFinish[s,y,ls,ld-1,r]+sum{lhlh in DAILYTIMEBRACKET:lh-lhlh>0} NetChargeWithinDay[s,y,ls,ld,lhlh,r])-
StorageLowerLimit[s,y,r];

s.t. SC4_UpperLimit_BeginningOfDailyTimeBracketOfFirstInstanceOfDayTypeInLastWeekConstraint{s in STORAGE, y in YEAR_X, ls in
SEASON, ld in DAYTYPE, lh in DAILYTIMEBRACKET, r in REGION}: if ld > min{ldld in DAYTYPE} min(ldld) then
(StorageLevelDayTypeFinish[s,y,ls,ld-1,r]+sum{lhlh in DAILYTIMEBRACKET:lh-lhlh>0} NetChargeWithinDay[s,y,ls,ld,lhlh,r])-
StorageUpperLimit[s,y,r] <= 0;

s.t. SC5_MaxChargeConstraint{s in STORAGE, y in YEAR_X, ls in SEASON, ld in DAYTYPE, lh in DAILYTIMEBRACKET, r in REGION}:
RateOfStorageCharge[s,y,ls,ld,lh,r] <= StorageMaxChargeRate[s,r];

s.t. SC6_MaxDischargeConstraint{s in STORAGE, y in YEAR_X, ls in SEASON, ld in DAYTYPE, lh in DAILYTIMEBRACKET, r in REGION}:
RateOfStorageDischarge[s,y,ls,ld,lh,r] <= StorageMaxDischargeRate[s,r];

#
```

```
#########           Storage Investments        #############

#

s.t. SI1_StorageUpperLimit{s in STORAGE, y in YEAR_X, r in REGION}:
AccumulatedNewStorageCapacity[s,y,r]+ResidualStorageCapacity[s,y,r] = StorageUpperLimit[s,y,r];

s.t. SI2_StorageLowerLimit{s in STORAGE, y in YEAR_X, r in REGION}: MinStorageCharge[s,y,r]*StorageUpperLimit[s,y,r] =
StorageLowerLimit[s,y,r];

s.t. SI3_TotalNewStorage{s in STORAGE, y in YEAR_X, r in REGION}: sum{yy in YEAR_X: y-yy < OperationalLifeStorage[s,r] && y-
yy>=0} NewStorageCapacity[s,yy,r]=AccumulatedNewStorageCapacity[s,y,r];

s.t. SI4_UndiscountedCapitalInvestmentStorage{s in STORAGE, y in YEAR_X, r in REGION}: CapitalCostStorage[s,y,r] *
NewStorageCapacity[s,y,r] = CapitalInvestmentStorage[s,y,r];

s.t. SI5_DiscountingCapitalInvestmentStorage{s in STORAGE, y in YEAR_X, r in REGION}:
CapitalInvestmentStorage[s,y,r]/((1+DiscountRateStorage[s,r])^(y-min{yy in YEAR_X} min(yy))) =
DiscountedCapitalInvestmentStorage[s,y,r];

s.t. SI6_SalvageValueStorageAtEndOfPeriod1{s in STORAGE, y in YEAR_X, r in REGION: (y+OperationalLifeStorage[s,r]-1) <= (max{yy
in YEAR_X} max(yy))}: 0 = SalvageValueStorage[s,y,r];

s.t. SI7_SalvageValueStorageAtEndOfPeriod2{s in STORAGE, y in YEAR_X, r in REGION: (y+OperationalLifeStorage[s,r]-1) > (max{yy in
YEAR_X} max(yy)) && DiscountRateStorage[s,r]=0}: CapitalInvestmentStorage[s,y,r]*(1-(max{yy in YEAR_X} max(yy) -
y+1)/OperationalLifeStorage[s,r]) = SalvageValueStorage[s,y,r];

s.t. SI8_SalvageValueStorageAtEndOfPeriod3{s in STORAGE, y in YEAR_X, r in REGION: (y+OperationalLifeStorage[s,r]-1) > (max{yy in
YEAR_X} max(yy)) && DiscountRateStorage[s,r]>0}: CapitalInvestmentStorage[s,y,r]*(1-(((1+DiscountRateStorage[s,r])^(max{yy in
YEAR_X} max(yy) - y+1)-1)/((1+DiscountRateStorage[s,r])^OperationalLifeStorage[s,r]-1))) = SalvageValueStorage[s,y,r];
```

```
s.t. SI9_SalvageValueStorageDiscountedToStartYear{s in STORAGE, y in YEAR_X, r in REGION}:
SalvageValueStorage[s,y,r]/((1+DiscountRateStorage[s,r])^(max{yy in YEAR_X} max(yy)-min{yy in YEAR_X} min(yy)+1)) =
DiscountedSalvageValueStorage[s,y,r];

s.t. SI10_TotalDiscountedCostByStorage{s in STORAGE, y in YEAR_X, r in REGION}: DiscountedCapitalInvestmentStorage[s,y,r]-
DiscountedSalvageValueStorage[s,y,r] = TotalDiscountedStorageCost[s,y,r];

#

#########           Captial Costs                          #############

#

s.t. CC1_UndiscountedCapitalInvestment{y in YEAR_X, t in TECHNOLOGY, r in REGION}: CapitalCost[y,t,r] * NewCapacity[y,t,r] =
CapitalInvestment[y,t,r];

s.t. CC2_DiscountingCapitalInvestment{y in YEAR_X, t in TECHNOLOGY, r in REGION}:
CapitalInvestment[y,t,r]/((1+DiscountRate[t,r])^(y-min{yy in YEAR_X} min(yy))) = DiscountedCapitalInvestment[y,t,r];

#

#########           Salvage Value                    #############

#

s.t. SV1_SalvageValueAtEndOfPeriod1{y in YEAR_X, t in TECHNOLOGY, r in REGION: (y + OperationalLife[t,r]-1) > (max{yy in YEAR_X}
max(yy)) && DiscountRate[t,r]>0}: SalvageValue[y,t,r] = CapitalCost[y,t,r]*NewCapacity[y,t,r]*(1-(((1+DiscountRate[t,r])^(max{yy
in YEAR_X} max(yy) - y+1)-1)/((1+DiscountRate[t,r])^OperationalLife[t,r]-1)));

s.t. SV2_SalvageValueAtEndOfPeriod2{y in YEAR_X, t in TECHNOLOGY, r in REGION: (y + OperationalLife[t,r]-1) > (max{yy in YEAR_X}
max(yy)) && DiscountRate[t,r]=0}: SalvageValue[y,t,r] = CapitalCost[y,t,r]*NewCapacity[y,t,r]*(1-(max{yy in YEAR_X} max(yy) -
y+1)/OperationalLife[t,r]);
```

```
s.t. SV3_SalvageValueAtEndOfPeriod3{y in YEAR_X, t in TECHNOLOGY, r in REGION: (y + OperationalLife[t,r]-1) <= (max{yy in YEAR_X}
max(yy))}: SalvageValue[y,t,r] = 0;

s.t. SV4_SalvageValueDiscountedToStartYear{y in YEAR_X, t in TECHNOLOGY, r in REGION}: DiscountedSalvageValue[y,t,r] =
SalvageValue[y,t,r]/((1+DiscountRate[t,r])^(1+max{yy in YEAR_X} max(yy)-min{yy in YEAR_X} min(yy)));

#

#########           Operating Costs                 #############

#

s.t. OC1_OperatingCostsVariable{y in YEAR_X,l in TIMESLICE, t in TECHNOLOGY, r in REGION}: sum{m in MODE_OF_OPERATION}
TotalAnnualTechnologyActivityByMode[y,t,m,r]*VariableCost[y,t,m,r] = AnnualVariableOperatingCost[y,t,r];

s.t. OC2_OperatingCostsFixedAnnual{y in YEAR_X,t in TECHNOLOGY, r in REGION}: TotalCapacityAnnual[y,t,r]*FixedCost[y,t,r] =
AnnualFixedOperatingCost[y,t,r];

s.t. OC3_OperatingCostsTotalAnnual{y in YEAR_X,t in TECHNOLOGY,r in REGION}:
AnnualFixedOperatingCost[y,t,r]+AnnualVariableOperatingCost[y,t,r] = OperatingCost[y,t,r];

s.t. OC4_DiscountedOperatingCostsTotalAnnual{y in YEAR_X, t in TECHNOLOGY, r in REGION}:
OperatingCost[y,t,r]/((1+DiscountRate[t,r])^(y-min{yy in YEAR_X} min(yy)+0.5)) = DiscountedOperatingCost[y,t,r];

#

#########           Total Discounted Costs          #############

#

s.t. TDC1_TotalDiscountedCostByTechnology{y in YEAR_X, t in TECHNOLOGY, r in REGION}:
DiscountedOperatingCost[y,t,r]+DiscountedCapitalInvestment[y,t,r]+DiscountedTechnologyEmissionsPenalty[y,t,r]-
DiscountedSalvageValue[y,t,r] = TotalDiscountedCostByTechnology[y,t,r];
```

```
s.t. TDC2_TotalDiscountedCost{y in YEAR_X, r in REGION}: sum{t in TECHNOLOGY} TotalDiscountedCostByTechnology[y,t,r]+sum{s in
STORAGE} TotalDiscountedStorageCost[s,y,r] = TotalDiscountedCost[y,r];

#

#########                  Total Capacity Constraints       ##############

#

s.t. TCC1_TotalAnnualMaxCapacityConstraint{y in YEAR_X, t in TECHNOLOGY,r in REGION}: TotalCapacityAnnual[y,t,r] <=
TotalAnnualMaxCapacity[y,t,r];

s.t. TCC2_TotalAnnualMinCapacityConstraint{y in YEAR_X, t in TECHNOLOGY,r in REGION: TotalAnnualMinCapacity[y,t,r]>0}:
TotalCapacityAnnual[y,t,r] >= TotalAnnualMinCapacity[y,t,r];

#

#########           New Capacity Constraints   ##############

#

s.t. NCC1_TotalAnnualMaxNewCapacityConstraint{y in YEAR_X, t in TECHNOLOGY, r in REGION}: NewCapacity[y,t,r] <=
TotalAnnualMaxCapacityInvestment[y,t,r];

s.t. NCC2_TotalAnnualMinNewCapacityConstraint{y in YEAR_X, t in TECHNOLOGY, r in REGION:
TotalAnnualMinCapacityInvestment[y,t,r]>0}: NewCapacity[y,t,r] >= TotalAnnualMinCapacityInvestment[y,t,r];



#

#########           Annual Activity Constraints      ##############

#
```

```
s.t. AAC1_TotalAnnualTechnologyActivity{y in YEAR_X, t in TECHNOLOGY, r in REGION}: sum{l in TIMESLICE}
RateOfTotalActivity[y,l,t,r]*YearSplit[y,l] = TotalTechnologyAnnualActivity[y,t,r];

s.t. AAC2_TotalAnnualTechnologyActivityUpperLimit{y in YEAR_X, t in TECHNOLOGY, r in REGION}:
TotalTechnologyAnnualActivity[y,t,r] <= TotalTechnologyAnnualActivityUpperLimit[y,t,r] ;

s.t. AAC3_TotalAnnualTechnologyActivityLowerLimit{y in YEAR_X, t in TECHNOLOGY, r in REGION:
TotalTechnologyAnnualActivityLowerLimit[y,t,r]>0}: TotalTechnologyAnnualActivity[y,t,r] >=
TotalTechnologyAnnualActivityLowerLimit[y,t,r] ;

#



 # #############    My own Added constraint -  some techs required to produce a minimum percentage of total max potential per
year.

s.t. X1_TotalAnnualtechnologyProdPercentUppLimit {y in YEAR, t in TECHNOLOGY, r in REGION:
TotalTechnologyAnnualPercentileActivityUpperLim[y,t,r]<1} : sum{f in FUEL}ProductionByTechnologyAnnual[y,t,f,r] <=  sum{l in
TIMESLICE} (TotalCapacityAnnual[y,t,r]*CapacityFactor[y,t,l,r]*YearSplit[y,l])*
AvailabilityFactor[y,t,r]*CapacityToActivityUnit[t,r]*TotalTechnologyAnnualPercentileActivityUpperLim[y,t,r] ;

s.t. X2_TotalAnnualtechnologyProdPercentLowLimit {y in YEAR, t in TECHNOLOGY, r in REGION:
TotalTechnologyAnnualPercentileActivityLowerLim[y,t,r]<>0} : sum{f in FUEL}ProductionByTechnologyAnnual[y,t,f,r] >=  sum{l in
TIMESLICE} (TotalCapacityAnnual[y,t,r]*CapacityFactor[y,t,l,r]*YearSplit[y,l])*
AvailabilityFactor[y,t,r]*CapacityToActivityUnit[t,r]*TotalTechnologyAnnualPercentileActivityLowerLim[y,t,r] ;

#########           Total Activity Constraints       ##############

#

s.t. TAC1_TotalModelHorizonTechnologyActivity{t in TECHNOLOGY, r in REGION}: sum{y in YEAR_X}
TotalTechnologyAnnualActivity[y,t,r] = TotalTechnologyModelPeriodActivity[t,r];
```

```
s.t. TAC2_TotalModelHorizonTechnologyActivityUpperLimit{y in YEAR_X, t in TECHNOLOGY, r in REGION}:
TotalTechnologyModelPeriodActivity[t,r] <= TotalTechnologyModelPeriodActivityUpperLimit[t,r] ;

s.t. TAC3_TotalModelHorizenTechnologyActivityLowerLimit{y in YEAR_X, t in TECHNOLOGY, r in REGION:
TotalTechnologyModelPeriodActivityLowerLimit[t,r]>0}: TotalTechnologyModelPeriodActivity[t,r] >=
TotalTechnologyModelPeriodActivityLowerLimit[t,r] ;

#

#########           Reserve Margin Constraint  ############## NTS: Should change demand for production

#

s.t. RM1_ReserveMargin_TechologiesIncluded_In_Activity_Units{y in YEAR_X, l in TIMESLICE, r in REGION}: sum {t in TECHNOLOGY}
TotalCapacityAnnual[y,t,r] * ReserveMarginTagTechnology[y,t,r] * CapacityToActivityUnit[t,r]   =
       TotalCapacityInReserveMargin[y,r];

s.t. RM2_ReserveMargin_FuelsIncluded{y in YEAR_X, l in TIMESLICE, r in REGION}: sum {f in FUEL} RateOfProduction[y,l,f,r] *
ReserveMarginTagFuel[y,f,r] = DemandNeedingReserveMargin[y,l,r];

s.t. RM3_ReserveMargin_Constraint{y in YEAR_X, l in TIMESLICE, r in REGION}: DemandNeedingReserveMargin[y,l,r] *
ReserveMargin[y,r]<= TotalCapacityInReserveMargin[y,r];

#

#########           RE Production Target             ############## NTS: Should change demand for production

#

s.t. RE1_FuelProductionByTechnologyAnnual{y in YEAR_X, t in TECHNOLOGY, f in FUEL, r in REGION}: sum{l in TIMESLICE}
ProductionByTechnology[y,l,t,f,r] = ProductionByTechnologyAnnual[y,t,f,r];
```

```
s.t. RE2_TechIncluded{y in YEAR_X, r in REGION}: sum{t in TECHNOLOGY, f in FUEL}
ProductionByTechnologyAnnual[y,t,f,r]*RETagTechnology[y,t,r] = TotalREProductionAnnual[y,r];

s.t. RE3_FuelIncluded{y in YEAR_X, r in REGION}: sum{l in TIMESLICE, f in FUEL}
RateOfDemand[y,l,f,r]*YearSplit[y,l]*RETagFuel[y,f,r] = RETotalDemandOfTargetFuelAnnual[y,r];

s.t. RE4_EnergyConstraint{y in YEAR_X, r in REGION}:REMinProductionTarget[y,r]*RETotalDemandOfTargetFuelAnnual[y,r] <=
TotalREProductionAnnual[y,r];

s.t. RE5_FuelUseByTechnologyAnnual{y in YEAR_X, t in TECHNOLOGY, f in FUEL, r in REGION}: sum{l in TIMESLICE}
RateOfUseByTechnology[y,l,t,f,r]*YearSplit[y,l] = UseByTechnologyAnnual[y,t,f,r];

#

#########           Emissions Accounting             ##############

#

s.t. E1_AnnualEmissionProductionByMode{y in YEAR_X, t in TECHNOLOGY, e in EMISSION, m in MODE_OF_OPERATION, r in
REGION:EmissionActivityRatio[y,t,e,m,r]<>0}:
EmissionActivityRatio[y,t,e,m,r]*TotalAnnualTechnologyActivityByMode[y,t,m,r]=AnnualTechnologyEmissionByMode[y,t,e,m,r];

s.t. E2_AnnualEmissionProduction{y in YEAR_X, t in TECHNOLOGY, e in EMISSION, r in REGION}: sum{m in MODE_OF_OPERATION}
AnnualTechnologyEmissionByMode[y,t,e,m,r] = AnnualTechnologyEmission[y,t,e,r];

s.t. E3_EmissionsPenaltyByTechAndEmission{y in YEAR_X, t in TECHNOLOGY, e in EMISSION, r in REGION}:
AnnualTechnologyEmission[y,t,e,r]*EmissionsPenalty[y,e,r] = AnnualTechnologyEmissionPenaltyByEmission[y,t,e,r];

s.t. E4_EmissionsPenaltyByTechnology{y in YEAR_X, t in TECHNOLOGY, r in REGION}: sum{e in EMISSION}
AnnualTechnologyEmissionPenaltyByEmission[y,t,e,r] = AnnualTechnologyEmissionsPenalty[y,t,r];
```

```
s.t. E5_DiscountedEmissionsPenaltyByTechnology{y in YEAR_X, t in TECHNOLOGY, r in REGION}:
AnnualTechnologyEmissionsPenalty[y,t,r]/((1+DiscountRate[t,r])^(y-min{yy in YEAR_X} min(yy)+0.5)) =
DiscountedTechnologyEmissionsPenalty[y,t,r];

s.t. E6_EmissionsAccounting1{y in YEAR_X, e in EMISSION, r in REGION}: sum{t in TECHNOLOGY} AnnualTechnologyEmission[y,t,e,r] =
AnnualEmissions[y,e,r];

s.t. E7_EmissionsAccounting2{e in EMISSION, r in REGION}: sum{y in YEAR_X} AnnualEmissions[y,e,r] = ModelPeriodEmissions[e,r]-
ModelPeriodExogenousEmission[e,r];

s.t. E8_AnnualEmissionsLimit{y in YEAR_X, e in EMISSION, r in REGION}: AnnualEmissions[y,e,r]+AnnualExogenousEmission[y,e,r] <=
AnnualEmissionLimit[y,e,r];

s.t. E9_ModelPeriodEmissionsLimit{e in EMISSION, r in REGION}: ModelPeriodEmissions[e,r] <= ModelPeriodEmissionLimit[e,r] ;

#

###########################################################################################

#

solve;

#

#########################################################################################################

#
                                               #

#      Summary results tables below are printed to a comma-separated file called "SelectedResults.csv"           #

#      For a full set of results please see "Results.txt"
             #
```

```
#       If you don't want these printed, please comment-out or delete them.
       #

#
                                               #

#########################################################################################################

#

#DiscountedOperatingCost[y,t,r]+DiscountedCapitalInvestment[y,t,r]

#table result{(f,t) in s} OUT "...": f~FROM, t~TO, x[f,t]~FLOW;

table result{y in YEAR_X, r in REGION} OUT "CSV" "Test321.csv": y~YeArS, r~ReGiOnEs, TotalDiscountedCost[y,r];

table result{y in YEAR_X, f in FUEL, r in REGION} OUT "CSV" "Test322.csv": y~YeArS, f~FUEL, r~ReGiOnEs,
ProductionAnnual[y,f,r],TotalDiscountedCost[y,r];

table Costtable{y in YEAR_X, t in TECHNOLOGY, r in REGION,m in MODE_OF_OPERATION: m = 1} OUT "CSV" "SelectedResultsCOSTS.csv":
y~YEAR_X, t~TECHNOLOGY, r~REGION,DiscountedOperatingCost[y,t,r],DiscountedCapitalInvestment[y,t,r];

#table YLTFRtable{y in YEAR_X, l in TIMESLICE, t in TECHNOLOGY, f in FUEL, m in MODE_OF_OPERATION, r in REGION: m = 1} OUT "CSV"
"SelectedResultsYLTFR.csv": y~YEAR_X, t~TECHNOLOGY, r~REGION,

table storageResults{s in STORAGE, y in YEAR_X, ls in SEASON, ld in DAYTYPE, lh in DAILYTIMEBRACKET, r in REGION} OUT "CSV"
"SelectedResultsStorage.csv": s~STORAGE,y~YEAR_X,ls~SEASON,ld~ DAYTYPE,lh~DAILYTIMEBRACKET,r~REGION,
NetChargeWithinYear[s,y,ls,ld,lh,r];
```