System Cost of Energy Generation Scenarios for South Africa: Understanding the real cost of integrating energy generation technologies

by

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Thesis presented in fulfilment of the requirements for the degree of Masters of Engineering Management in the Faculty of Department of Engineering at Stellenbosch University

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March 2017

Declaration

By submitting this thesis electronically, I declare that the entirety of the work contained therein is my own, original work, that I am the sole author thereof (save to the extent explicitly otherwise stated), that reproduction and publication thereof by Stellenbosch University will not infringe any third party rights and that I have not previously in its entirety or in part submitted it for obtaining any qualification.

March 2017

Abstract

South Africa's electricity market has realized much growth with the introduction of the Renewable Energy Independent Power Producers Program (REIPPPP). This program enables the increase in energy generation from renewable technologies. Moving forward, the future targets for renewable generation increase to levels where they contribute significantly to system supply. This research sought to understand the system costs of integrating utility scale renewable energy generation technologies into the South African electricity system and thus considered future energy scenarios with higher renewable penetration levels. In addition, the research investigated Levelized Cost of Energy for the generating technologies encompassing renewables (solar PV, CSP and wind) and non-renewables (coal, gas nuclear).

A search through literature exhibited many electricity-modelling tools. A bottom-up approach was chosen, which captured the technical details of the generators and electricity network. Further, the selected electricity modelling software was PLEXOS. This tool enabled the capture of the South African electricity network, including all the generators. The model was a single node model, where the system demand aggregates at the node. Using the targets of a WWF high scenario, where renewables' penetration was 25% by energy and 41% by installed power, an hourly simulation was run for the year 2030, while 2010 actual system demand was used and forecasted to 2030. The attempt was to understand the real system cost. Hence, a base scenario with unconstrained generators and then a constraints scenario containing all generator parameters such as Minimum Stable Level, availabilities and so forth, was run.

The results showed the base case had a system cost of R0.39/kWh, while the constraints scenario R0.48/kWh. In both scenarios, the unserved energy was negligible compared to the total generation costs. The renewable energy total capacity factor was 29% for the simulation. Total generation for the year was 409819.07 GWh and the corresponding total cost was 10 trillion Rand.

From the constraint model, the LCOE for CSP was R1.44/kWh, second was solar PV at 1.25/kWh, and wind was R1.02/kWh, while the lowest were the existing plants (OCGT, hydro, nuclear, pumped storage) well below R0.65/kWh, as their capital and interest were assumed to have been settled by the start of the simulation.

Integration elements comprising the number of generators' start-up and shutdown, water consumption and emissions were quantified. The emissions were significant cost contributors, when using the price of R48/tonne.

In the sensitivity analysis, the following input parameters were tested: fuel price, generator availabilities, system demand, and increase in renewable energy production. Dropping the system demand to WWF low levels affected the system cost the most, increasing the value to R0.59/kWh. Whereas increase of the renewables production profile of 10% caused the system cost to drop to R0.52. This showed that the demand forecast is crucial for modelling system behaviour.

The research fulfilled the objective and demonstrated the system costs of integrating renewables into future energy scenarios.

Future models should include transmission and distribution infrastructure, more detailed generator performance criteria. The conversion from solar or wind resource to renewables output plants must be further investigated. Additional recent costing data, updated demand forecasts and smaller non-utility scale projects should be incorporated in future models.

Key words: Integration, Energy market simulation, PLEXOS, System costing, LCOE, renewable penetration.

Uittreksel

Suid Afrika se elektrisiteit mark het baie groei ervaar met die bekendstelling van die Renewable Energy Independent Power Producers Program (REIPPPP). Hierdie program maak dit moontlik vir 'n toename in krag-opwekking deur hernubare tegnologieë om plaas te vind. Die toekomstige teikens vir hernubare krag-opwekking sal toeneem tot vlakke waar hulle 'n merkwaardige bydrae sal lewer tot die krag-toevoer stelsel. Hierdie navorsingstuk beoog om die stelsel-kostes te verstaan wat geassosieer word met die integrasie van nut-skaal hernubare energie tegnologieë in die bestaande Suid Afrikaanse elektrisiteit toevoer stelsel deur die ondersoek van moontlike toekomstige energie scenario's met groter bydraes deur hernubare energie. Boonop, het hierdie studie ten doel om die Levelized Cost of Energy (Verdeelde Lewens Koste van Energie) van die voorgestelde hernubare energie tegnologieë, as deel van REIPPPP, en die van nie-hernubare tegnologieë, in die verskillende scenario's, te ondersoek.

'n Inspeksie van die literatuur het vele elektrisiteit modellerings pakkette uitgelig. 'n Sogenaamde "bottom-up: benadering was gevolg wat die tegniese besonderhede van die opwekkers en netwerk vasgelê het. Die gekose modellerings pakket was PLEXOS, wat die uiteensetting van die Suid Afrikaanse elektrisiteits netwerk moontlik gemaak het. Hierdie model is 'n enkel-node model, waar die stelsel-aanvraag by 'n node saamgevoeg word. Die teikens uiteengesit in die WWF hoë-geval was gebruik, met hernubare energie bydraes van 25% vir jaarlikse energie en 41% geïnstalleerde kapasiteit. 'n Uurlikse simulasie is toe opgestel vir die jaar van 2030, met 2010 se jaarlikse aanvraag as die verwysingspunt en vooruit geskat tot 2030. Die uitgangspunt was om die werklike stelsel kostes van so moontlike toekomstige geval te verstaan. In lig hiervan was 'n basis geval ook gesimuleer, met onbeperkte opwekkers-parameters, sowel as n geval met beperkte inset-parameters soos minimum stabiele vlak en beskikbaarheid, onder andere.

Die resultate het getoon dat die basis geval 'n stelsel koste van 0.39 R/kWh bereik, terwyl die beperkte geval 'n koste van 0.48 R/kWh het. In beide gevalle was die ongedienste energie weglaatbaar klein in vergelyking met die opwekkings kostes. Die totale kapasiteits faktor van die hernubare energie bydraes was 29% vir die simulasie. Die totale energie opgewek vir die jaar was 409819.07 GWh met 'n ooreenstemmende totale koste van 10 triljoen Rand.

Die onbeperkte model het 'n LCOE waarde van 1.44 R/kWh vir CSP gelewer, terwyl wind 1.02 R/kWh, en PV 1.44 R/kWh was. Die laagste LCOE was bereik deur die bestaande vloot opwekkings eenhede (OCGT, hidro-, kern- en gepomp-stoor hidrokrag) teen 0.65 R/kWh, aangesien dit aangeneem is dat hul kapitaal en rente reeds afbetaal is teen die begin van die simulasie.

Integrasie elemente was gekwantifiseer, wat bestaan uit die aantal opwekker-eenheid aan-skakelings en af-skakelings, water verbruik en afval-gas vrystellings. Die afval-gas vrystellings het merkwaardig bygedra tot die kostes teen 'n prys van R48 per ton.

In die sensitiwiteits analise was die volgende inset-parameters getoets: brandstof prys, opwekker beskikbaarheid, stelsel-aanvraag en toename in hernubare energie produksie hoeveelhede. Dit was gevind dat indien die stelsel aanvraag verlaag was tot die WWF lae-geval vlakke, dit die stelsel koste die mees beïnvloed het, met 'n verhoging tot 0.59 R/kWh. Aangesien toename van die volhoubare produksie profiel van 10% het veroorsaak dat die stelsel koste te daal tot R0.52. Dit wys duidelik dat die aanvraag vooruitskatting van kardinale belang is vir deeglike stelsel modellering.

Dit was dus gevind dat die navorsingstuk die uiteengesette doel vervul het die stelsel kostes van nut-skaal hernubare energie integrasie uiteengesit.

Soortgelyke toekomstige modelle sal klem moet lê op transmissie en verspreidings infrastruktuur, en in meer detail kyk na opwekker werkverrigting. Die oorgang van sonk- of wind hulpbronne tot hernubare energie opwekkers moet vêrder nagevors word. Addisionele, meer onlangse koste data, vanaf opgedateerde aanvraag vooruitskattings en kleiner nie-nut skaal projekte moet ook geïnkorporeer word in toekomstige modelle.

Key words: Integrasie, energie mark simulasie, PLEXOS, stelsel kos, LCOE, hernubare penetrasie,

Acknowledgements

- To my Saviour Jesus Christ, thank you for the gift of life daily in You and for empowering me to complete this thesis
- Supervisor: Prof. Brent, you managed me well with much on your professional agenda, for this I am grateful and found it a pleasure working with you
- Co-supervisor Prof. L. Jestin and Prof. S. Govender for guidance during this research
- Eskom managers Ipfi Mudau, Siyabonga Ndlovu, Louis Fernandez and Zak Jiyane all for allowing me paid sabbatical and supporting me through EPPEI
- Eskom leaders for making EPPEI a reality
- Eskom employees who have greatly assisted in the research, namely Michael Barry, Sipho Mdluli, and Keith Bowen
- CSIR employees specifically Jarrad Wright for his time and effort
- PLEXOS and Energy Exemplar for providing me with an academic license for a world class energy modelling tool which enabled the research to take shape
- My family, for their continued love, support and care
- My friends, all over the world for your sharing in my journey

The Author,

March 2017.

Dedications

I would like to dedicate this thesis to:

Jesus Christ my Saviour, Friend and ever present help,

My family, dad, mom, James, Leanne and Joni for your unwavering support and incredible love and care. You have no idea of how you were part of this,

Romans 8:38-39 New Living Translation: *"And I am convinced that nothing can ever separate us from God's love. Neither death nor life, neither angels nor demons, neither our fears for today nour our worries for tomorrow – not even the powers of hell can separate us from God's love. "*

Ephesians 3:20-21 New Living Translation: *"Now all glory to God, who is able, through his mighty power at work within us, to accomplish infinitely more than we might ask or think. Glory to him in the church and in Christ Jesus through all generations forever and ever! Amen".*

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Abbreviation	Description
CF	Capacity Factor
CAPEX	Capital Expenditure
CSIR	Council for Scientific and Industrial Research
CSP	Concentrated Solar Power
COUE	Cost of Unserved Energy
CO_2	Carbon Dioxide
DSCR	Debt Service Coverage Ratio
DoE	Department of Energy
DF	Discount Factor
DNI	Direct Normal Irradiation
FIT	Feed in tariffs
FGD	Flue Gas Desulphurization
GWh	Gigawatt hours
GHI	Global Horizontal Irradiance
IPP	Independent Power Producer
IRP	Integrated Resource Plan
IRR	Internal rate of return
KW	Kilowatts
LCOE	Levelized Cost of Energy
LCOT	Levelized Cost of Transmission
LT	Long Term
MT	Medium Term

MW	Megawatts
MSL	Minimum Stable Level
NPV	Net Present Value
NO_x	Nitrous Oxides
OPEX	Operational Expenditure
O&M	Operations and Maintenance
PV or V_p	Present Value
PV	Photovoltaic
PF	Pulverised Fuel
RE	Renewable Energy
REIPPPP	Renewable Energy Independent Power Producer Procurement Program
RLDC	Residual Load Duration Curves
SRMC	Short Run Marginal Cost
ST	Short Term
SAJIE	South African Journal of Industrial Engineering
SADC	Southern African Development Community
SAPP	Southern African Power Pool
SO_x	Sulphur Dioxides
TWh	Terawatt hours
VRE	Variable Renewable Energy
V_n	Future value in year n
WACC	Weighted Average Cost of Capital
WWF	World Wildlife Fund

1. Introduction

The global energy mix has become more invested in renewable energy generation technologies in recent decades, with a subsequent shift away from well-understood fossil fuel generation technologies. Fossil fuels became a popular generation technology during the industrial revolution. However, technology has advanced to such a place, where the solar and wind resource potential, amongst other renewable sources, can be harvested and converted into usable electrical energy.

Climate change and its importance have also contributed to moving away from more harmful fossil fuel harvesting and as fuels for input in the electricity sector. This move away from fossil fuels is because of their direct contribution to greenhouse gas emissions worldwide. While fossil fuel generation technologies have been around for many decades, their relatively young renewable counterparts are only beginning to be understood and their impacts on traditional power systems. South Africa is one such country who is in the nascent stages of utility scale renewable energy development and uptake.

The South African electricity sector involves a number of key role players. However, for many years, Eskom, the state-owned utility supplier, has dominated the sector. The utility is responsible for owning and operating the electricity network, from the generation through to municipalities; in what is termed a monopolistic sector. Its shareholder is the government.

Eskom is the largest electricity supply company on the continent and supplies some 45% of its electricity needs (Eskom, 2014). In South Africa, that number is around 95% of electricity supplied (Eskom, 2014). Currently, South Africa's value chain is the standard for most electric utilities around the world, as illustrated in below (Eskom Holdings SOC Limited, 2012). The value chain is comprised of generation (where some form of fuel – be it renewable sources, fossil fuels or nuclear is converted into electrical energy), then electrical transmission and distribution networks provide the means for electricity transport to the end user, be it a household or commercial user. In the transmission and distribution network, the voltage is regulated and transformed to the required levels. Figure 1 shows the current electricity value chain of Eskom.

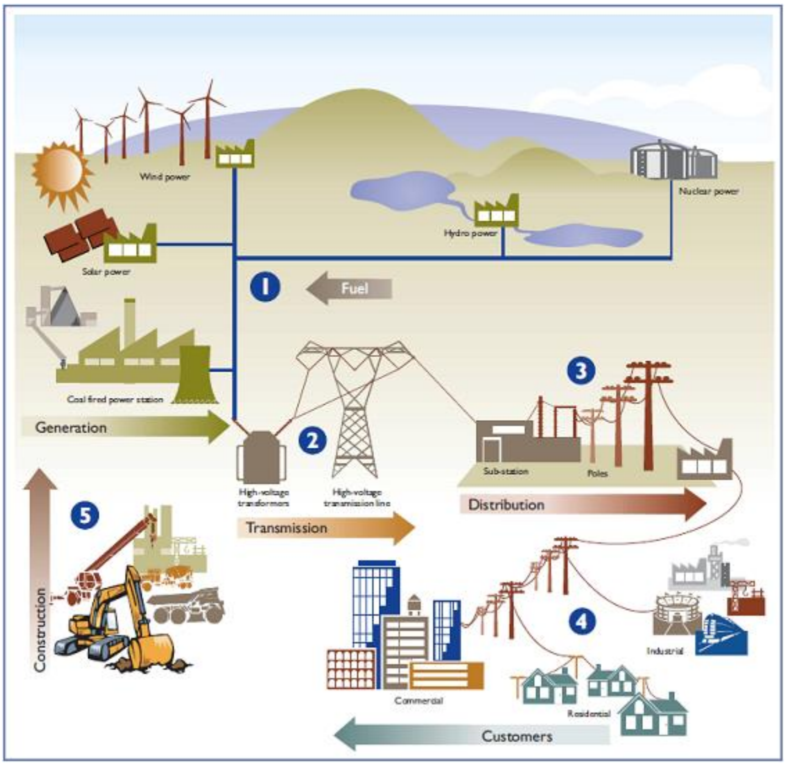


Figure 1 Eskom's electricity value chain (Eskom Holdings SOC Limited, 2012)

Since generation technologies form a sizable portion of this thesis, the current state of the generation portfolio for Eskom was presented in Table 1 Eskom current generation portfolio (Eskom, 2013a). The national generation portfolio currently stands at 44 175MW with coal being the dominant technology of over 37 678MW (Eskom, 2013b).

Table 1 Eskom current generation portfolio (Eskom, 2013a)

TYPE	NUMBER	MAX CAPACITY
Coal fired	13 stations	37 678 MW
Gas turbine	4 stations	1207 MW
Hydroelectric	2 stations	600 MW
Pumped storage	2 stations	1 400 MW
Nuclear	1 station	1 800 MW
Renewable Energy (Wind Farm)	1 station	3.2 MW
Distribution Embedded	4 stations	62 MW
TOTAL	**27 Stations**	**44 175 MW**

In addition to supplying within the South African borders, Eskom entered into agreements with members of the Southern African Development Community (SADC), termed the Southern African Power Pool (SAPP)[1].

[1] SAPP: http://www.sapp.co.zw/members.html

These are long-term supply agreements and provide an opportunity to increase revenue going forward, but also a liability in that these obligations must be met with Eskom bearing the risk for its generating assets. Relative to the local supply, exports values are small as in Figure 2. This depiction is of the SAPP, including the flow (in and out) of electricity and other key parameters.

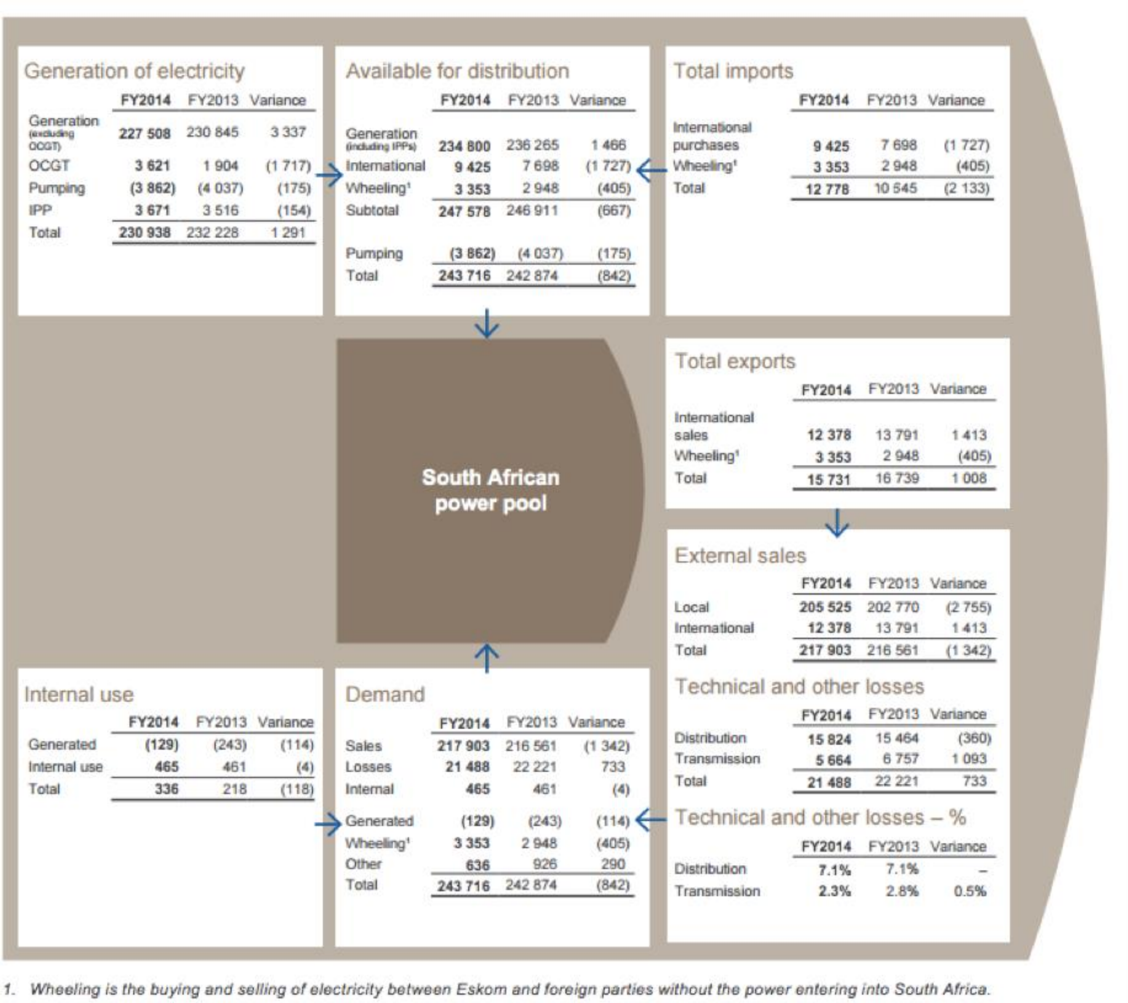


Figure 2 SAPP Power Flow (Eskom, 2014)

The worldwide electricity industry is seeing transitions in operating models; from traditional vertically integrated government utilities to fully private power companies, as illustrated in Figure 3. South Africa has moved from model 1 to model 2, in that independent power producers (IPPs) are present, with Eskom serving as the single buyer.

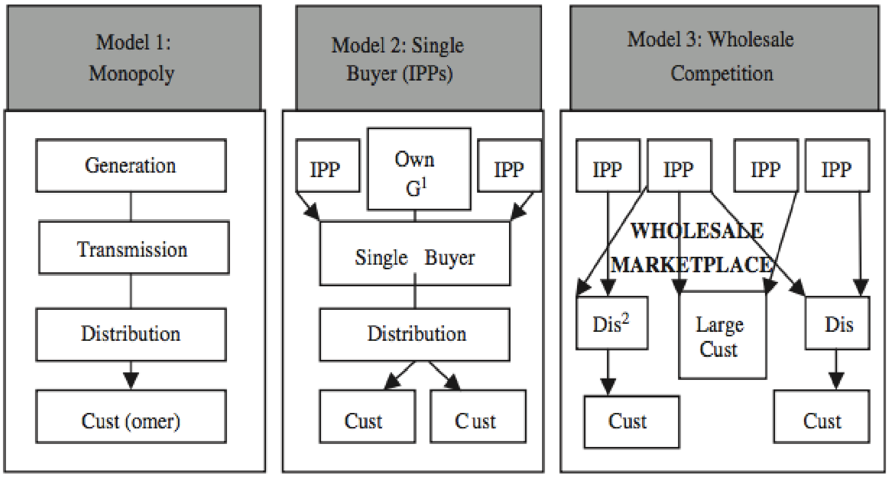


Figure 3 Standard utility models(Hunt, 2002)

This change in business model, with the introduction of competition, distinctly affects the value chain and market structure and functioning.

The national Department of Energy (DoE) saw the need for increasing the generation capacity, and thus developed the Integrated Resource plan (IRP) and published the first draft in 2010. This plan set out the allocation of each different generation technology over a twenty-year horizon from 2010 to 2030 and formed an important policy tool showing the strategic intent for the electricity industry. An excerpt of a policy-adjusted Plan with ministerial determination is shown in Table 2. Noticeable is the large allocation towards new build renewables (17800MW wind, Concentrated Solar Power (CSP) and Solar Photovoltaic (PV)), coal (6250MW) and nuclear (9600MW). Originally the intent was to update the IRP on a regular basis, to assist policy certainty amongst other factors. A number of different scenarios were developed for the IRP, showing the potentials for renewables, gas and different blends of technologies to fulfil the electricity demand requirements, with one such being shown in Table 2.

Table 2 IRP Policy Adjusted Plan with Ministerial Determinations (DoE, 2011)

	New Build Options								Committed					Non-IRP
	Coal (PF, FBC, Imports, own build)	Nuclear	Import Hydro	Gas-CCGT	Peak-OCGT[1]	Wind	CSP	Solar PV	Coal	Other	DoE Peaker	Wind[2]	Other Renew	Co-generation
	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW
2010	0	0	0	0	0	0	0	0	380	260	0	0	0	0
2011	0	0	0	0	0	0	0	0	679	130	0	0	0	0
2012	0	0	0	0	0	0	0	300	303	0	0	400	100	0
2013	0	0	0	0	0	0	0	300	823	333	1020	400	25	0
2014	500	0	0	0	0	400	0	300	722	999	0	0	100	0
2015	500	0	0	0	0	400	0	300	1444	0	0	0	100	200
2016	0	0	0	0	0	400	100	300	722	0	0	0	0	200
2017	0	0	0	0	0	400	100	300	2168	0	0	0	0	200
2018	0	0	0	0	0	400	100	300	723	0	0	0	0	200
2019	250	0	0	237	0	400	100	300	1446	0	0	0	0	0
2020	250	0	0	237	0	400	100	300	723	0	0	0	0	0
2021	250	0	0	237	0	400	100	300	0	0	0	0	0	0
2022	250	0	1143	0	805	400	100	300	0	0	0	0	0	0
2023	250	1600	1183	0	805	400	100	300	0	0	0	0	0	0
2024	250	1600	283	0	0	800	100	300	0	0	0	0	0	0
2025	250	1600	0	0	805	1600	100	1000	0	0	0	0	0	0
2026	1000	1600	0	0	0	400	0	500	0	0	0	0	0	0
2027	250	0	0	0	0	1600		500	0	0	0	0	0	0
2028	1000	1600	0	474	690	0		500	0	0	0	0	0	0
2029	250	1600	0	237	805	0		1000	0	0	0	0	0	0
2030	1250	0	0	948	0	0		1000	0	0	0	0	0	0

Total	**6500**	**9600**	**2609**	**2370**	**3910**	**8400**	**1000**	**8400**	**10133**	**1722**	**1020**	**800**	**325**	**800**
		2011 Determinations			**2012 Determinations**			**Eskom Commitments (Pre-IRP)**						
	Note:	**1. OCGT is seen as natural gas in the determination**												
		2. Wind Committed includes Sere (100MW)												

In 2008 and 2014 onwards, South Africa experienced load shedding because of the dwindling margin of supply to match the demand. The Renewable Energy Feed in Tariff (REFIT) scheme was initially proposed as the means to procure large-scale power in line with the IRP. However, the DoE then accepted the Renewable Energy Bidding process, known as the Renewable Energy Independent Power Producer Procurement Programme (REIPPPP)[2], as the most cost-effective way to elicit private sector involvement. Eskom is the off-taker of the produced power, with IPPs being the generators. The projects sign long-term Power Purchase Agreements (PPA) to guarantee the revenue for IPPs. The REIPPPP was devised to include multiple bidding rounds, initially 4, and then being expanded beyond the original four rounds. Evidence of the drop in cost for the RE technologies is shown in Figure 4 with wind and solar photovoltaic (PV) shown a steady decrease over the rounds, to well below a value of one $/MWh.

[2] http://www.ipprenewables.co.za/

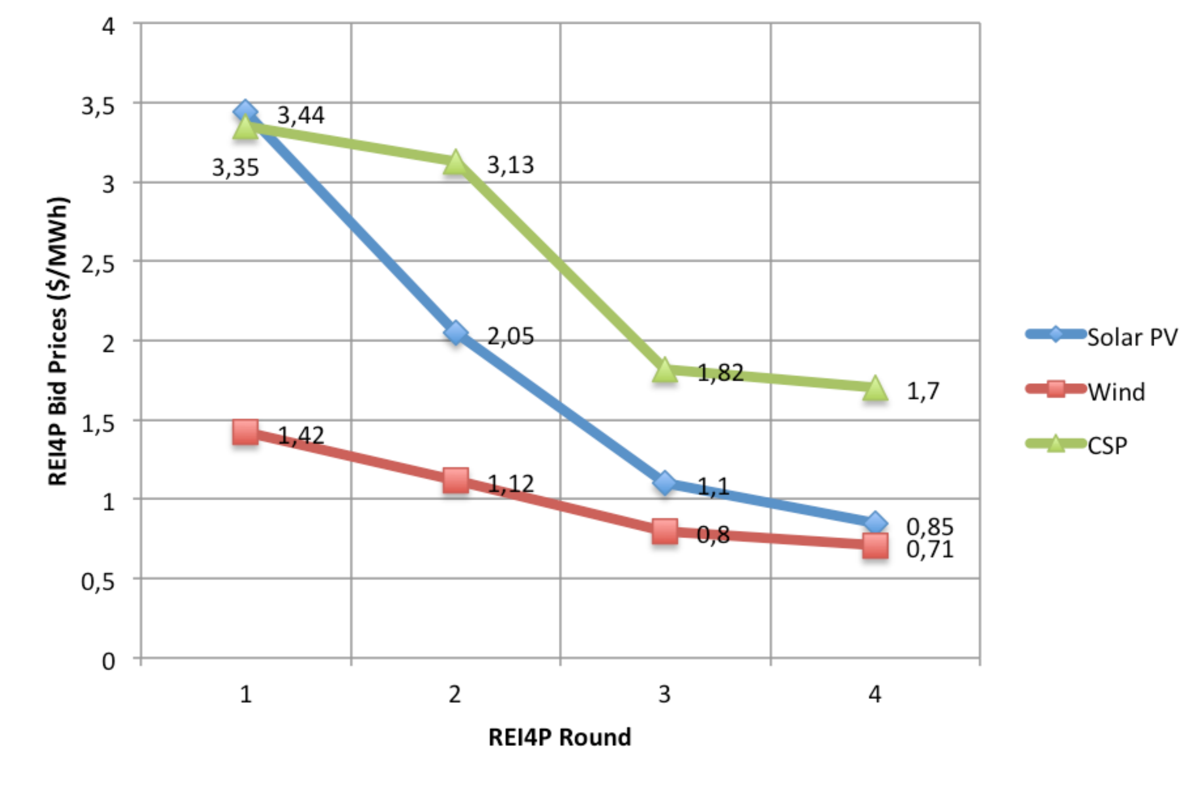


Figure 4 Summary of REIPPPP LCOE over four rounds adapted from (DoE, 2015)

Thus, renewable energy is no longer seen as only the green and sustainable energy choice, but feasible from a purely financial viewpoint. This is part of a larger worldwide trend; as the costs of renewables have dropped dramatically over the last few years, with conventional fossil fuels seeing a less noticeable drop than their renewable counterparts (IEA, 2014; OECD;IEA;NEA, 2015).

When selecting between electrical energy projects for specific technologies, there are a number of decision-making methods widely used and accepted. In order to shift the risks off companies' balance sheets, project financiers' ring-fence projects as off-balance sheet items. Projects depend on the revenue streams for all income, and thus survival centres on revenue generation, usually described in PPAs.

A few economic techniques for assessing projects are:

1. Simple payback period – time period required to reclaim initial investment
2. Initial Rate of return – inverse of 1 above
3. Net Present Value (NPV) – computes the cash flows accounting for the time value of money, and discount rate pertaining to cash flows
4. Internal Rate of Return (IRR) – the discount rate which enables the NPV to approach zero
5. Levelized Cost of Energy (LCOE) – to be discussed in chapter 2 in detail

6. Cash flow analysis (Masters, 2004)

Project financiers evaluate performance with a measure called the Debt Service Coverage Ratio (DSCR) (Tinsley, 2000). As the name suggests, and the formula depicts, DSCR takes the form of a fraction:

$$DSCR = \frac{Profit\ After\ Depreciation\ and\ Tax + Interest\ on\ debt}{Interest\ on\ debt + Principal}$$

The primary purpose of the metric is to test whether interest and principle amounts can be settled by a project. DSCR values above 1 are critical, while different industries seek differing values. The power sector require above 1.2 and even near 1.5 as the target (Tinsley, 2000). Thus, it is clear there are a number of means to measure and track project performance.

1.1 Problem Statement

A large number of studies present the Levelized Cost of Energy (LCOE) for different generating technologies within the South Africa context (OECD;IEA;NEA, 2015). However, in South Africa, there are limited studies, which look into the true system costs, and account for these non-LCOE or integration costs of the electrical system. Further study should address this apparent gap.

1.2 Research Question

With the above problem identified, the main research question of the thesis is to perform an initial investigation that seeks to answer the question(s):

1. What are the real system costs of integrating renewable energy generation technologies into future energy scenarios within the South African electricity system?

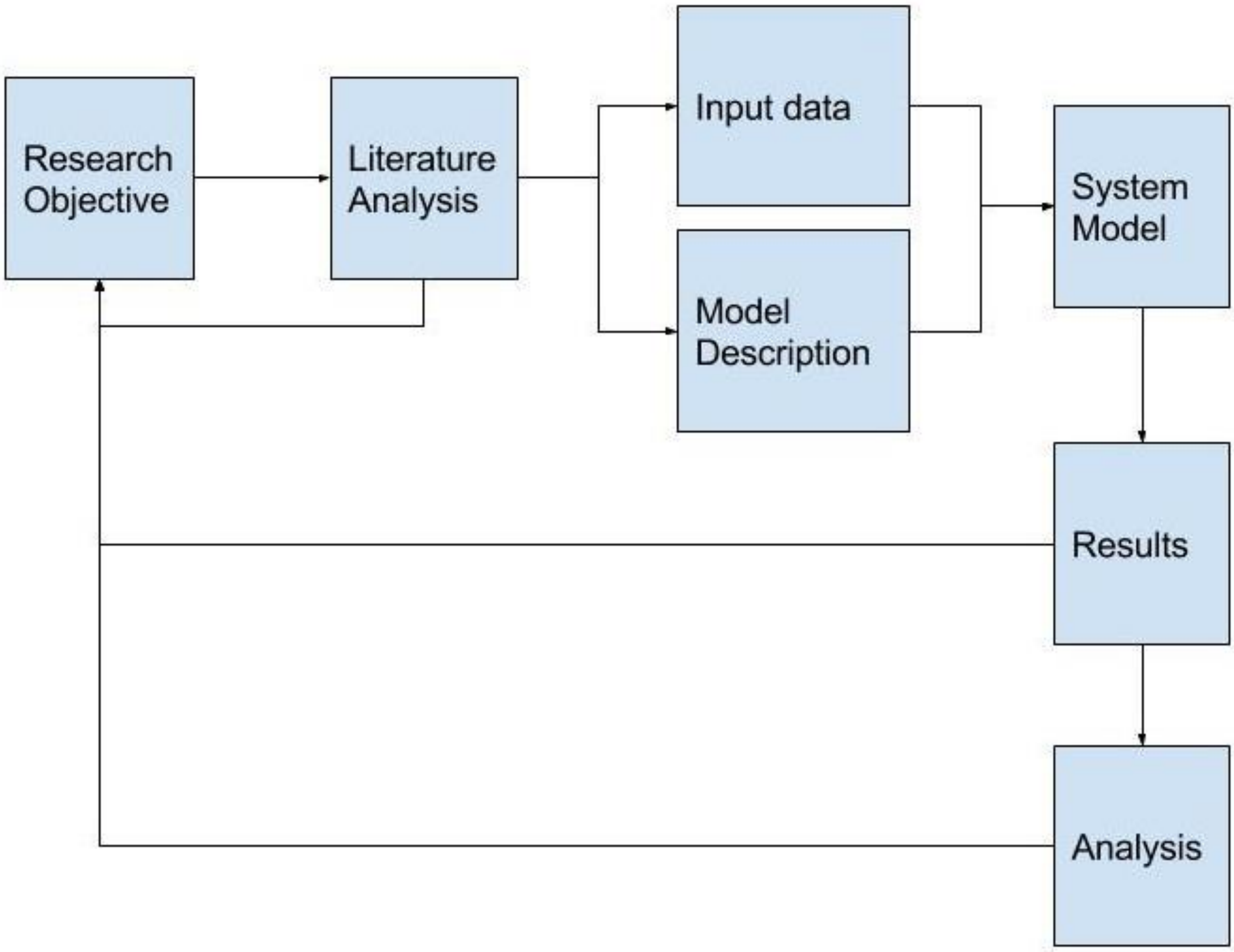
The by-product of understanding the system costs will be LCOE for the following different technologies, and variations thereof, such as:

- Coal Pulverised Fuel (PF)
- Solar farms at utility scale:
  - Concentrating Solar Power (CSP)
  - Photo Voltaic (PV)
- Onshore Wind
- Gas – Open Cycle Gas Turbines and Closed Cycle Gas Turbines
- Nuclear
- Pumped Storage

1.3 Research Limitations

No small-scale projects (less than 100MW) will form part of the research. Examples include non-utility scale generation, such as household rooftop solar PV installations, embedded generation and cogeneration projects (biomass etc.). Thus, the research scrutinizes technologies from the perspective of an electric utility. The utility is a monopoly, as is the case of Eskom, which seeks to minimize costs. The company would select reliable and mature technologies, which will provide large-scale electricity to an established grid network. This study focuses on the greater power system, which is primarily impacted by utility scale projects, and the means of quantifying embedded generation in South Africa is unclear at this stage. Larger projects are more clearly accounted for in policy documents and the public space. The research will not consider the roadmap to achieve certain future energy targets, rather looking at the future year, when targets (renewable penetration) are achieved.

1.4 Research Strategy and summary of report chapters



The report will consist of the following chapters, which form the research strategy:

Chapter 1 presented the background to the South African electricity value chain. This showed the acceleration of renewable energy additions to t5he SA grid. Then the research question was asked to determine the real system costs of integrating renewables into the SA grid in future energy scenarios. The research was limited to the scale utility-scale projects in SA.

Chapter 2 introduced the key literature to understand the LCOE. Areas such as the variants and omissions were discussed and integration costs required to address the evident omissions. LCOE values and trends further guided the researcher. The theory of modelling and method of selecting the correct tools concluded the chapter.

Chapter 3 commenced with the selection of a modelling tool, with PLEXOS as the chosen software. Then, the verification and testing of the model methodology completed the rest of the chapter. This included key assumptions and other input parameters.

After the development of the modelling methodology, Chapter 4 tested the methodology using a similar study with known inputs and outputs. The model was then verified by an experienced modeller.

The verification model formed a baseline for the final model methodology in Chapter 5. Two scenarios, base, constraints, were described, and then additional important elements such as sensitivity analysis, emissions and load garnered attention. An expert PLEXOS modeller then validated the model.

The main thrust of chapter 6 sought to present the results of the PLEXOS energy market simulation. The overall generation costs for each technology were first. Then, seasonal performance was uncovered, followed by the capex and interest costs over the plant lifespans. Chapter 6 then expressed the important integration costs. An output of the simulation was the LCOE for each technology. To understand the response of the model to changes in input parameters a sensitivity analysis was conducted.

Chapter 7 closed out the research by including a summary of the key findings and conclusions of the research. Regarding to future, a number of recommendations were made. Lastly, the researcher provided input into the contributions made throughout the research including publications and implications for policy makers.

2 Literature review

A useful departure point and important metric for this research is the Levelized Cost of Energy (LCOE), as introduced in Chapter 1. However, LCOE is embedded and best explained within the context of traditional financial approaches, which evaluate technology selection and electricity generation, such as the discounted cash flow analysis. Thus, the literature review aims to provide a clearer understanding and critical review of the elements of the LCOE metric. Also of noted importance are the omissions from the LCOE metric, which were discussed in the chapter. Lastly, the theory relevant to electricity systems' modelling tool and approach were expounded. [3]

A semi-structured conceptual approach was used for the forthcoming literature review (Bryman; Bell; Hirschsohn; Dos Santos; Du Toit; Masenge; Van Aardt; Wagner, 2014).This sought to encompass the key elements and concepts in a narrative.

2.1 Literature Review Map

In order to understand this chapter, Figure 5 depicts the relationships between key sections.

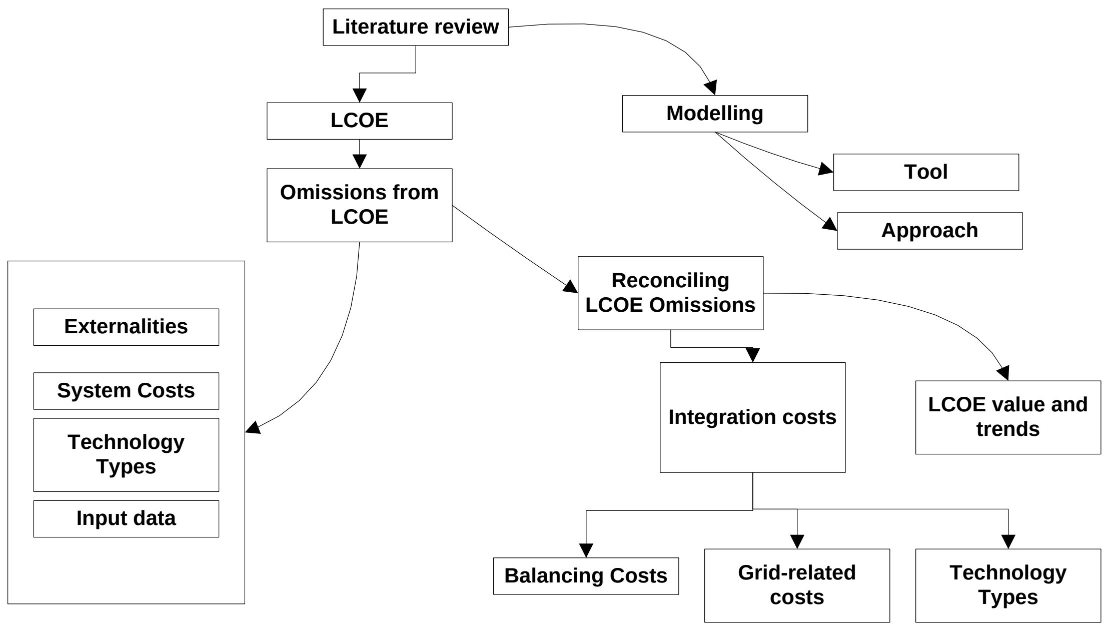


Figure 5 Literature review map

[3] Sections 2.2 through to 2.4 were informed by the SAJIE publication, Sklar-Chik, M.D., Brent A.C., de Kock I.H., (2016), *'CRITICAL REVIEW OF THE LEVELIZED COST OF ENERGY METRIC',* Volume 27, Number 4, (2016).

2.2 LCOE

A widely used metric in electricity modelling and subsequent project finance is the Levelized Cost of Energy (LCOE) (Joskow, 2011; Namovicz, 2013). LCOE allows for a comparison between technologies that have distinctive sizes, lifetimes and profiles of expenditures (OECD;IEA;NEA, 2015). It was originally proposed to satisfy the requirements of *'rate regulated markets'*(OECD;IEA;NEA, 2015). With the main objectives being: *'to rank different available technologies for power productions by average lifetime cost'*; and *'to assess the level of electricity tariffs required to remunerate these technologies, including an appropriate return on investment'*(OECD;IEA;NEA, 2015).

In a simple form, the metric is comprised of total discounted expenses divided by the total discounted power:

$$LCOE = \frac{Total\ discounted\ expenses}{Total\ discounted\ power}$$

The numerator and denominator are both composed of further variables. Since LCOE is merely applied in this research, the derivation will be omitted. However, Villiers, (2014) provides the complete mathematical derivation and formulation of the metric in a number of forms. The LCOE metric is relatively simple for general project practitioners and non-engineers to understand, since it has deterministic values and costs per unit of energy output.

Because of its simplicity, LCOE is utilized in different decision-making areas and activities; these include:

- '*Utility resource selection*
- *Dispatch decisions*
- *Electricity pricing*
- *Energy conservation programs*
- *Research and Development incentives*
- *Subsidy determination*
- *Environmental planning'*(Roth & Ambs, 2004)

A complete LCOE computation includes a wide array of input parameters, which can be categorized as in Figure 6. These categories include: plant characteristics, plant cost data, financial and general assumptions, fuel cost and tax information, which should be available through project personnel, engineering designer or other corporate databases.

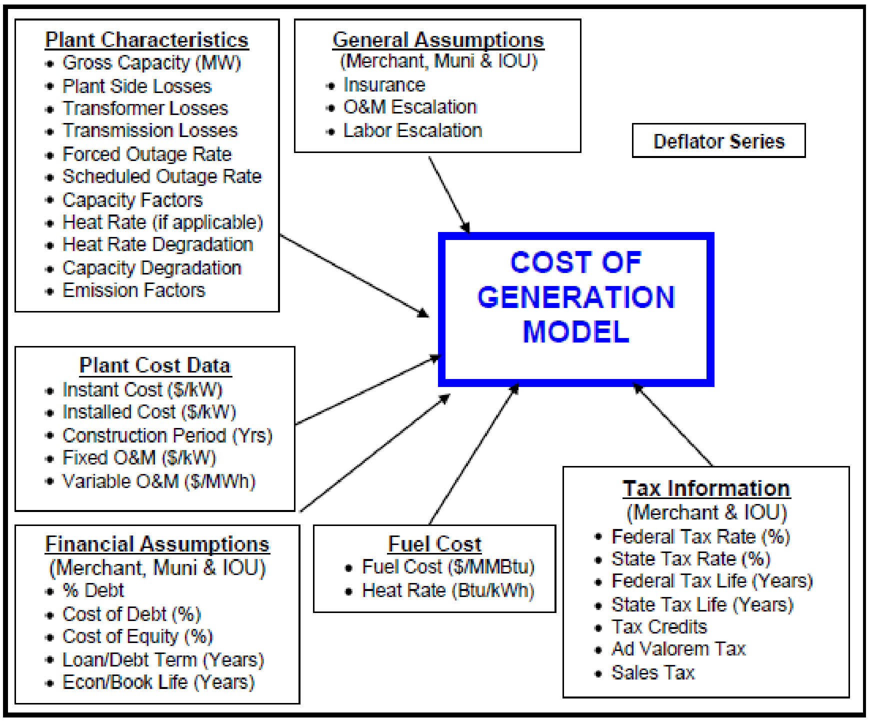


Figure 6 Cost of Generation Model (Volchenk, 2013)

When analysing the lifecycle costs for each generation technology, one can distinguish between capital, fixed operations and maintenance, and fuel costs. Often decommissioning costs are omitted, as the impact of discounting future cash flows effectively reduces their influence on the LCOE to a negligible value. This must be indicated in the calculations, as inflows can result for sale of the components at the end of the plant's lifespan, if they are high value components such as nuclear reactors.

The dominant lifecycle costs for renewables and conventional power generation are presented in Figure 7 in the stacked bar graphs (Centre, 2015). Renewables exhibit high capital costs but approximately zero fuel costs (with the exception of Concentrated Solar Power), which is attributed to virtually limitless fuel resource. Whereas, gas technologies chief cost components are the fuel costs.

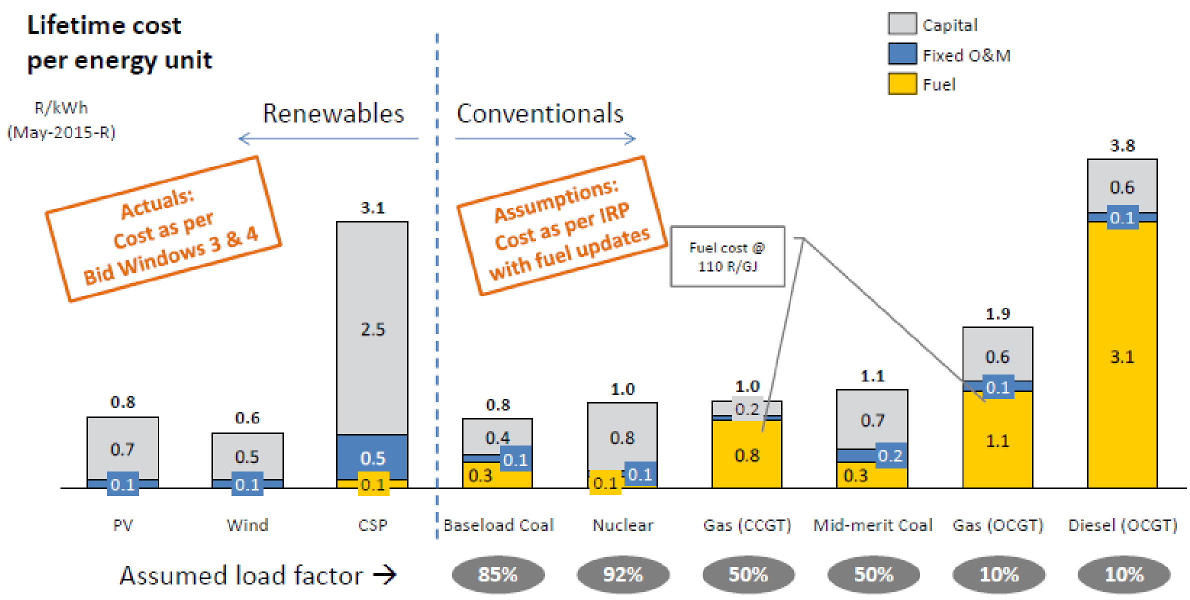


Figure 7 LCOE Input Costs adapted from Bischoff-Niemz(Centre, 2015)

By understanding the three cost elements (Capital, Fixed Operations and Maintenance, and Fuel), decisions varying from tactical (day to day) to strategic (long term) can be taken. Figure 8 presents the combination of the three elements in making different plant decisions(Centre, 2015). In the short term, fuel costs and variable operations and maintenance (O&M) are monitored, whereas in the long term all three cost elements are factored into the decision making process. And all three elements feed into the LCOE calculation.

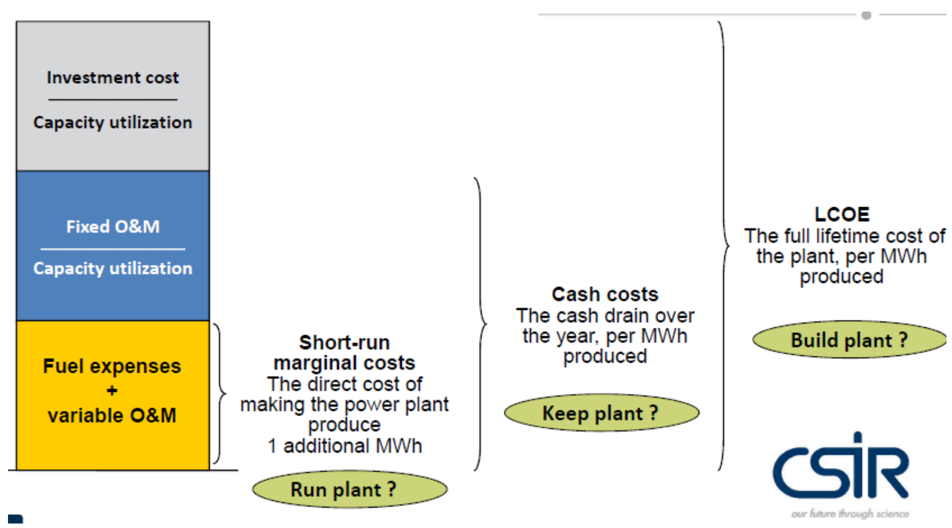


Figure 8 LCOE Cost Breakdown adapted from Bischoff-Niemz (Centre, 2015)

Returning to the LCOE formula presented at the beginning of the section, the numerator represents the total discounted expenses, which usually comprises capital outlay (capex); O&M, fuel costs (for fossilfuelled technologies and often Concentrated Solar Power); and the decommissioning costs. The previously mentioned costs are calculated over the lifespan of the plant and then discounted to a present value (PV):

$$Total\ discounted\ expenses = PV \sum (Capex + Opex + Fuel + Decom)$$

The denominator of total discounted power is a difficult term to grasp. It represents the power generated over the lifespan, which needs to be consistently in present value form, as was the case with the numerator. The denominator is the product of four factors:

1. The capacity factor (CF) expounded as the fraction of rated power output to the actual power generated in a year
2. Nameplate power of the plant (MW or KW)
3. Degradation factor which shows for deterioration of the plant
4. And, the efficiency of the power plant

$$Total\ discounted\ power = PV \sum (CF * Power\ Output * DF * Efficiency)$$

The concept of time of value of money is integrated into the formulas, to ensure costs are discounted. Costs are discounted according to the ensuing formula:

$$V_p = \frac{V_n}{(1+r)^n}$$

Where V_p is the present value of money, and V_n is the value of money in year n. The equation can be manipulated to ascertain any variable (Boyle, 2012).

Due to the discount rate (or interest rate), the present value will be dissimilar from the future value. As a rule, when computing investments and returns, interest rates are employed. However, to convert cash flows into present value terms, the discount rate is used. Nevertheless, these interest or discount rates merely describe the direction of the calculation, where one present value is discounting future cash flows into today's money, and future value delineates forthcoming interest accrued on an investment. Despite these terms being interchanged in literature and business settings, it is crucial to keep the different meanings and different direction in which computations are performed.

The Discount Rate (DR) is an important financial parameter, which feeds into the LCOE calculation, and is used to mark down all future cash flows into present day prices. One technique is by substituting the prevailing security rate (bonds, country interest rates etc.) for the discount rate. Another technique is called the Capital Asset Pricing Model (CAPM), which defines the association between risk and return, and offers a scheme to price risk (Volchenk, 2013). CAPM maintains the anticipated return is the same as the risk free (R_f) rate of return plus some risk premium (β) multiplied by the difference of the market return and R_f, and is captured in the equation below:

$$Required\ return = R_f + \left(Market\ return - R_f\right) * \beta$$

Beta (β) quantities can be uncovered through further methods, but these quantities were beyond the scope of this review. However, a positive beta usually shows returns are positively correlated to the market movement (Volchenk, 2013).

An alternative and widely used technique is to compute the Weighted Average Cost of Capital (WACC), described by the following formula (Volchenk, 2013):

$$WACC = W_E R_E + W_D R_D (1 - T_C)$$

W denotes the relative weights of sources of debt or equity, R the interest rates for that debt source, and T standing for the tax rate (Volchenk, 2013). Essentially, tax shrinks the cost of capital, as unity value is reduced.

Briefly, two other techniques for determining the discount rate are:

- Finding the opportunity cost of capital
- Or establishing a hurdle rate that must be surmounted to develop a project (Tinsley, 2000)

This approach is important in carbon trading projects for example the Clean Development Mechanism (CDM) (UNFCC, 2016).

2.3 LCOE variants

Adaptations exist to account for apparent limitations of the LCOE. One such adaptation is incorporating the influence of inflation (which is the variance in the costs of items over time). The link between real (R) and nominal discount rates(r) is specified by the following formula, with i being the interest rate (Villiers, 2014):

$$(1 + r) = (1 + R) * (1 + i)$$

By substituting the formula into the LCOE metric, the result is below:

$$LCOE = \frac{\sum \frac{Total\ costs}{(1+r)^n}}{\sum \frac{Total\ electricity\ generated}{(1+R)^n}}$$

Effectively, the above formula computes the present value of the costs divided by the annual electricity produced, using the requisite discount rates:

$$LCOE = \frac{PV(of\,annual\,nominal\,costs\,at\,nominal\,discount\,rate)}{PV(of\,\,annual\,electricity\,produced\,at\,real\,discount\,rate)}$$

Hence, it is feasible to include inflation, although this is more computationally demanding. Whether or not inflation must be considered is up to the practitioner, as historical data can be easily accessed for the South African case. In the case where projects all consistently neglect inflation, it is sensible to omit this, provided the implications are understood.

Silinga et al. (2015) contend that LCOE metric seeks to minimize costs, which is classically the viewpoint of larger state-owned utilities, such as Eskom. However, the private sector focuses on maximizing profits to increase shareholder value. Furthermore, cost minimizations priority is relegated to well below profitability. To combat this, Silinga et al. (2015) proposed the Levelized Profit of Energy (LPOE) metric, which sees a minor change to the LCOE, and can be explained by the formula below. Units remain unchanged as in the LCOE (R/MWh), but the numerator now contains income as well as the costs, which is merely the profit from electricity sales.

$$LPOE = \frac{PV\sum(Total\,Income\,from\,energy - Total\,costs)}{PV\sum(Total\,eletcricity\,generated)}$$

2.4 Omissions from LCOE

LCOE fails to encompass variation in demand and supply profiles and so does not predict the market value of energy (Joskow, 2011). However, LCOE uses an average of the costs and energy profiles over time (Volchenk, 2013).

A number of elements are absent in the traditional LCOE metric, such as externalities, system costs, technology types, and input data. Thus, the ensuing discussion will elaborate on each of the missing elements.

2.4.1 Externalities

Externalities is a broad term which may encompass many different costs and impacts, described in one definition by Roth et al: *'Damage from air pollution, Energy security, Transmission and distribution costs, and, other environmental impacts'* (Roth & Ambs, 2004). Effectively, externalities are costs and benefits, which do not add to the parties involved in the activity or project (Carlin, 1995). Further important externalities are depicted in Figure 9. The health costs because of pollution are significant, but turn out to be difficult yet necessary to quantify. However, this is addressed in the coming discussion.

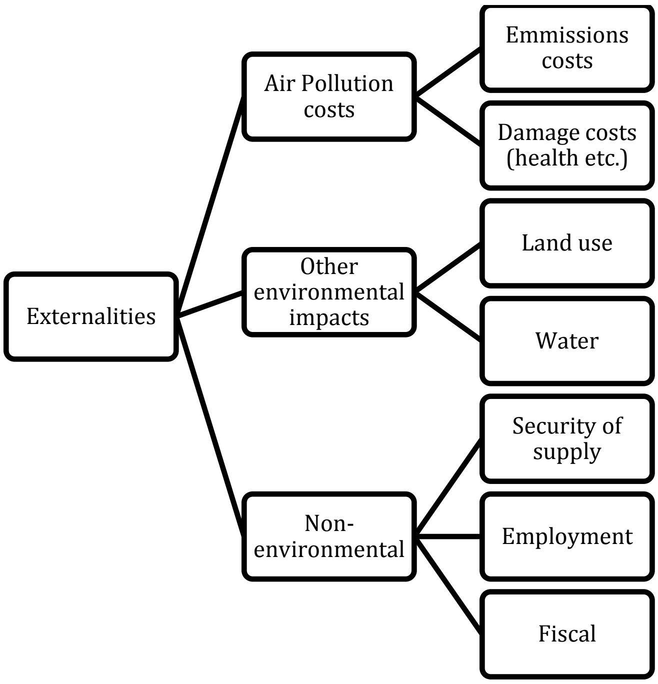


Figure 9 Externalities adapted from(Roth & Ambs, 2004)

Roth & Ambs (2004) ascertained the effect of externalities in monetary value, and resolved that it has a substantial impact on the various generating technologies' feasibility As indicated '*when externalities are considered, renewable electricity generation is comparable in cost to fossil fuel generation*'(Roth & Ambs, 2004) and the externality costs attributed to fossil fuel technologies are mostly larger than their renewable energy technology counterparts. This study was published in 2004, which is more than a decade old and thus provides a gap in the research for current values of externalities.

In a more recent study conducted in South Africa, Thopil and Pouris (2015) utilized the Impact Pathway approach, which is popular in the European Union as it approximates externalities. For this research ten (10) coal-fired and one (1) nuclear power station encompassed the scope of analysis, with the year under scrutiny being 2008. Three types of externalities were examined, public, occupational and environmental (Thopil & Pouris 2015). With the primary contributors being the greenhouse gas emissions and public health affects due to coal fired power generation (Thopil & Pouris 2015). Other externalities were also mentioned. Helpfully, the authors' analysis provided the aggregated central externalities in the range of 5.86 to 35.36 cents per kilowatt-hour (Thopil & Pouris 2015), which were in line with previous studies. These values accounted for around *'68.5% of overage electricity prices during the year 2008'*(Thopil & Pouris 2015).

With these externalities in mind, it is difficult to account for all these costs perfectly as the data requirements would be large and still data may not be available for calculation. Despite this limitation, where necessary these costs should be considered.

2.4.2 System Costs

When viewing from an electricity system's perspective, a technology portfolio (all power stations on an electricity grid) is the level of analysis, rather than just one power plant. The impacts of technologies on the costs of the overall project are one such decision facing policy makers and business executives. These costs are not within the scope of the LCOE metric.

Critics suggest network costs (transmission, distribution and marketing costs) can total up to 40% of total electricity costs (IEA, 2010). Network operators must recover this cost through some means, usually increasing tariffs or other mechanisms. One such mechanism of recovering costs is through setting up of Feed-In-Tariffs (FIT) which apportions a connection fee to generators, or else by requesting a network cost component as part of the generation project (DOE, 2015). Including such costs will increase the previously calculated LCOE values. For a more detailed discussion, section 2.5.1.2 presents the results of a study to determine allocation of PV farm in SA, looking at the grid costs.

In their study on the system costs of scenarios using the IRP 2010 as a basis, the WWF calculated an LCOE system cost of R0.62/kWh. The model scope included the entire network, and they modelled using a spatial temporal approach, which replicated the functioning of the South African electricity system for the year 2030 under explicit states (Gauché, 2015a) . An important input to the model was the penetration of RE in the energy mix by percentage. In South Africa, up to date, this is the only such study available.

The WWF study introduces a new metric of system LCOE, which still includes generation costs but then also incorporates another new term, integration costs (Gauché, 2015a). Ueckerdt et al. (2013a) seem to be the first to propose a quantitative metric underpinning the System LCOE, not only a technology LCOE. These authors propose a decidedly technical and theoretical LCOE metric, in that it is underpinned by derivatives and other higher order mathematical techniques, not readily comprehensible by the general project practitioner (Ueckerdt, Hirth, Luderer, & Edenhofer, 2013b) (Hirth, Ueckerdt, & Edenhofer, 2015). However, Section 2.5.1 describes integration costs.

2.4.3 Technology types

Dispatchable energy technologies examples include fossil fuel and even Concentrating Solar Power. These technologies provide power if the network operator requests, assuming there is capacity available and they are online. A challenge emerges when comparing dispatchable (e.g. coal, gas, CSP) and non-dispatchable (e.g. solar and wind) technologies, as the LCOE merely accounts for average electricity produced. The LCOE metric fails to account for underlying production profiles. Additionally, the changing market value of energy produced by the different technologies is absent from LCOE (Larsson, 2012), as the demand for energy, even over a single day, will vary resulting in fluctuating electricity prices. Furthermore, power (rate at which energy is produced) and the real energy provided are two distinctive yet interconnected terms. These two terms are not differentiated in the LCOE, as the metric uses both power (nameplate of the technology) in the numerator and then energy in in the denominator. Although this is a fundamental concept with regards to physics and energy, it is still crucial to recognize.

This intrinsic difference between dispatchable and non-dispatchable technologies is well documented (Joskow, 2011). For example, comparing a solar photovoltaic farm of 100MW to a 100MW pulverised fuel plant on purely a cost perspective gives a skewed and incomplete picture. Obviously, if base load is needed, one would select the fossil fuel option, however, if the PV farm supply profile matches the demand profile, it may be feasible, despite the need for back-up supply in the event of lost solar resource (weather conditions such as cloud cover etc.). So, the inherent market value of the energy produced is a motivating feature in choosing the type of technology. At higher penetration rates (relative percentage contribution to overall makeup), renewable energy has a lower market value and the rollout of RE will be challenging to accelerate (Hirth, 2013). Thus, fluctuations in energy market prices need to be incorporated in a system analysis, as project feasibility is at stake.

Analyses (e.g. International Energy Agency and World Energy Outlook studies) look at specific types of energy technologies (solar, wind, or coal etc.), and all their underlying sub-technologies (parabolic trough, concentrated solar, photovoltaic etc.) are reduced into one cost metric (Lazard Ltd, 2015; OECD;IEA;NEA, 2015). However, the number of sub-technologies within each technology type is significant, and therefore one cannot assume, unless substantiated, that costs of one technology type are necessarily the average of the basic sub-technologies. In performing LCOE calculations, by providing a range of costs for different technology types (solar, wind, coal etc.), the underlying difference between sub-technologies may be accounted for.

Differences in the energy produced by generation technologies can be catered for in the electricity tariffs. Silinga et al., (2015) defined how tariff alterations affect the profitability of various generation technologies. Tariffs are outside the extent of this research and reference is made to the paper by Silinga et al., (2015), entitled *'The South African REIPPP two-tier CSP tariff: Implications for a proposed hybrid CSP peaking system'*. In summary, this paper examined the change in CSP tariff from purely pay for what is produced, such as those of PV and Wind, to the case where CSP, due to its storage capacity should have a *'two-tier tariff structure to allow CSP plants to deliver peak energy'* (Silinga et al., 2015). The outcome of the authors analysis proposed CSP to be deployed as a base-load technology (Silinga et al., 2015).

For a concise overview and comparison of the various technology types, Table 3 below was given (Lazard Ltd, 2015). Not merely the LCOE costs are provided, but also other key aspects, such as the state of the technologies, and their function in terms of dispatch, amongst others.

Table 3 Energy Resource: Matrix of applications (Lazard Ltd, 2015)

					Location			Dispatch			
		LCOE ($)	Carbon Neutral/Rec Potential	State of Technology	Distributed	Centralized	Geography	Intermittent	Peaking	Load-Following	Base-Load
Alternative Energy	Solar PV	50-300	✓	Commercial	✓	✓	Universal	✓	✓		
	Solar Thermal	119-181	✓	Commercial			Varies	✓	✓	✓	
	Fuel Cell	106-167	?	Commercial/Emerging	✓		Universal				✓
	Microturbine	79-89	?	Commercial/Emerging	✓		Universal				✓
	Geothermal	82-117	✓	Mature		✓	Varies				✓
	Biomass Direct	82-110	✓	Mature		✓	Universal				✓
	Onshore Wind	32-77	✓	Mature		✓	Varies	✓			
Conventional	Diesel Reciprocating Engine	212-281	✗	Mature	✓		Universal	✓	✓	✓	✓
	Natural Gas Reciprocating Engine	68-101	✗	Mature	✓		Universal	✓	✓	✓	✓
	Gas Peaking	165-218	✗	Mature	✓	✓	Universal		✓	✓	
	IGCC	96-183	✗	Emerging		✓	Co-located or rural				✓
	Nuclear	87-136	✓	Mature/Emerging		✓	Co-located or rural				✓
	Coal	65-150	✗	Mature		✓	Co-located or rural				✓
	Gas Combined Cycle	52-78	✗	Mature	✓	✓	Universal			✓	✓

2.4.4 Input data

Any calculation is dependent on the input data utilized. In the LCOE case, data inputs are usually deterministic in nature, expressed as single values. Table 4 illustrates a collection of input costs used in the WWF System LCOE calculations (Gauché, 2015a), as presented in Section 2.4.2. In order to have more comprehensive LCOE calculations, values in the table could be converted into stochastic distributions. This method is called probabilistic costing; and uses techniques such as Monte Carlo simulations (Gauché, 2015a). Since the model the WWF utilized was a system wide one, important issues such as ramp rates, turn down rate and availability, are included as parameters in the table.

Table 4 Costing inputs (Gauché, 2015a)

Technology	Range	CAPEX (R/kW)	Fixed Opex (R/kW/a)	Variable Opex (R/MWh)	Fuel Costs (R/GJ)	Availability	Turn-down limit	Ramp rate (%/min)	Maximum life span
PV Fixed Tilt	Upper	13115	484	0	0	90%	NA		25
	Lower	11210	208	0	0				
CSP - 6h TES	Upper	37610	573	29	0	90%	0	6%	30
	Lower	36726	573	0	0				
CSP - 9h TES	Upper	43259	573	29	0	90%	0	6%	30
	Lower	42242	573	0	0				
Wind	Upper	19463	400	0	0	90%	NA		20
	Lower	14502	310	0	0				
OCGT	Upper	5738	78	0,2	500	90%	0	22,50%	30
	Lower	5615	78	0,2	92				
CCGT	Upper	8708	163	0,7	92	90%	0	5%	30
	Lower	8524	163	0,7	70				
Nuclear	Upper	87754	1017	29,5	10	90%	0,8	5%	60
	Lower	60000	532	29,5	6,8				
Coal (PF with FGD)	Upper	34938	532	79,8	22-35	80-85%	0,4	2%	60
	Lower	34894	368	51,2	17,6				
Pumped Storage	Upper	56846	333	0	0	90%	0	50%	60
	Lower	23973	247	0	0				
Imported Hydro	Upper	28341	344	13,9	0	66,7%	0	2%	60
	Lower	12044	80,2	0	0				
Domestic Hydro	Upper	28341	344	13,9	0	96,6%	0	2%	60
	Lower	12044	80,2	0	0				

2.5 Reconciling LCOE omissions –Integration costs

Since the above omissions have been presented, certain authors have addressed a number of these deficits, which will form the content of the next section.

However, this area is more theoretical, and not widely accepted or published, but it is gaining prominence, as it has now appeared and been mentioned by worldwide organizations, such as the International Energy Agency (OECD;IEA;NEA, 2015).

2.5.1 Integration Costs

As discussed in Section 2.4.3, renewables are non-dispatchable. Due to this inherent variability, they can be termed Variable Renewable Energy (VRE). This variability induces what is termed system effects. The LCOE is unaware of the variability due to the temporal profile of power generation (when), location of the power plant (where), and the technical characteristics of the power plant (how) (OECD;IEA;NEA, 2015). Furthermore, LCOE only considers direct input costs and adopts a view that the value of electricity produced by each source has equivalent market value (OECD;IEA;NEA, 2015). Thus, if the LCOE is used for comparing technologies, it will give an incomplete picture in terms of the mentioned deficits (i.e. when, where and how). The LCOE does not take into account the interface between the power plants and the electricity network and subsequent effect of integrating them into this network (OECD;IEA;NEA, 2015).

Thus far, in the above paragraphs, the limitations of LCOE were discussed, and now it is possible to launch into the explanation of the concept of integration, which is a more recent field of research (Hirth et al., 2015; Ueckerdt et al., 2013b).

Integration costs of renewables or VRE arise from the variability and unpredictability of their generating characteristics, and the subsequent impact this has on the rest of the electricity network or system (Hirth et al., 2015). Thus, integration costs will arise when renewables are connected into an electricity network. Edenhofer et al., (2013) introduces the term system cost, previously alluded to in Section 2.4.2. To describe system cost, one must first explain integration costs. To date, this definition has been elusive, with no agreed upon definition for integration costs (Hirth et al., 2015). Further, the setting into which system and integration costs is embedded, relies heavily on energy economics, terms such as 'market value', and 'supply and demand curves' are typical.

One has the convectional approach of LCOE calculation for a given energy technology, and then by adding the integration costs, the result is then the System LCOE (Ueckerdt et al., 2013b), which is shown in Figure 10. Integration costs were split further into three components listed below, namely: balancing, grid related, and profile costs.

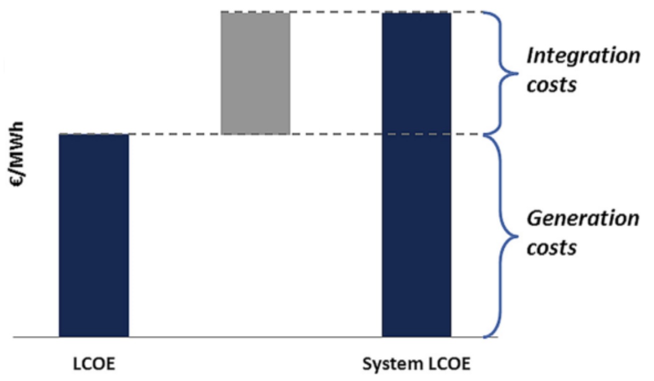


Figure 10 System LCOE of VRE (Hirth & Ueckerdt, 2013)

The effect of:

- Uncertainty is termed '*balancing costs'*, which arise from difference in the scheduled day-ahead dispatch energy of renewables and their actual values
- Location is termed '*grid related costs'*; these arise from decrease in market value of VRE due to its position in the electricity network

- Temporal variability is termed '*profile costs*', which accrue from the timing of the generation on the market value (Hirth et al., 2015)

When considering LCOE and how it relates to the integration costs, it is useful to view the diagram in Figure 11, which shows all the costs components.

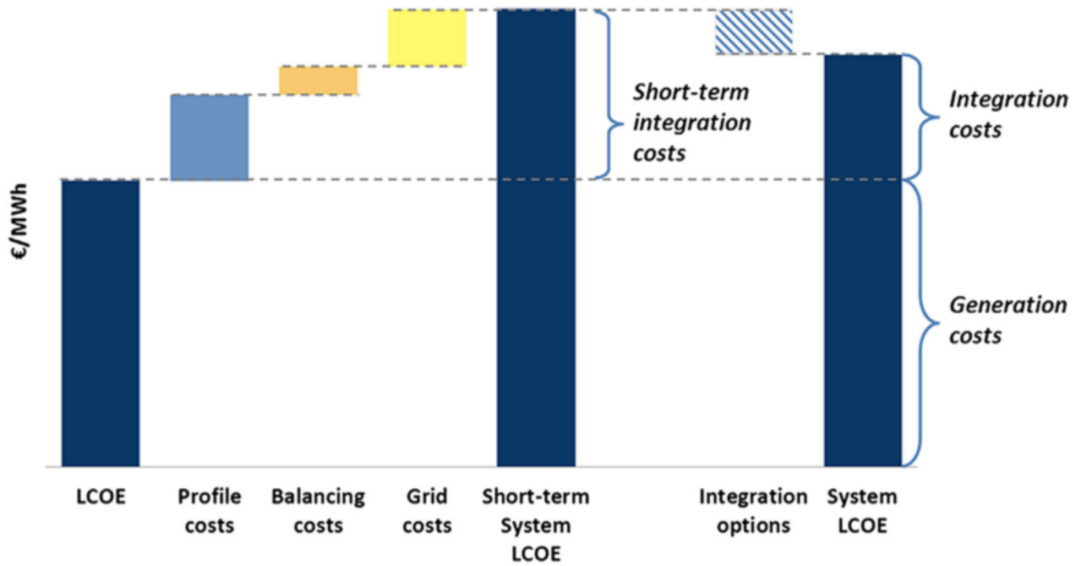


Figure 11 Integration costs (Hirth & Ueckerdt, 2013)

Two perspectives emerge in the system cost discussion, namely: the system cost, and the system value approach. The system value approach seeks to *'analyse the economic benefits of the deployment of a given VRE technology for the system'*(OECD;IEA;NEA, 2015).

The system cost approach seeks to distinguish between two or more different technologies. The comparison relies on a benchmark and the technology under consideration (OECD;IEA;NEA, 2015). And the difference between the benchmark and the technology is the residual or system costs (OECD;IEA;NEA, 2015).

Both approaches provide insight into the system costs; however, each approach conveys the information in a unique way. Figure 12 shows the comparison of the system cost and system value approach.

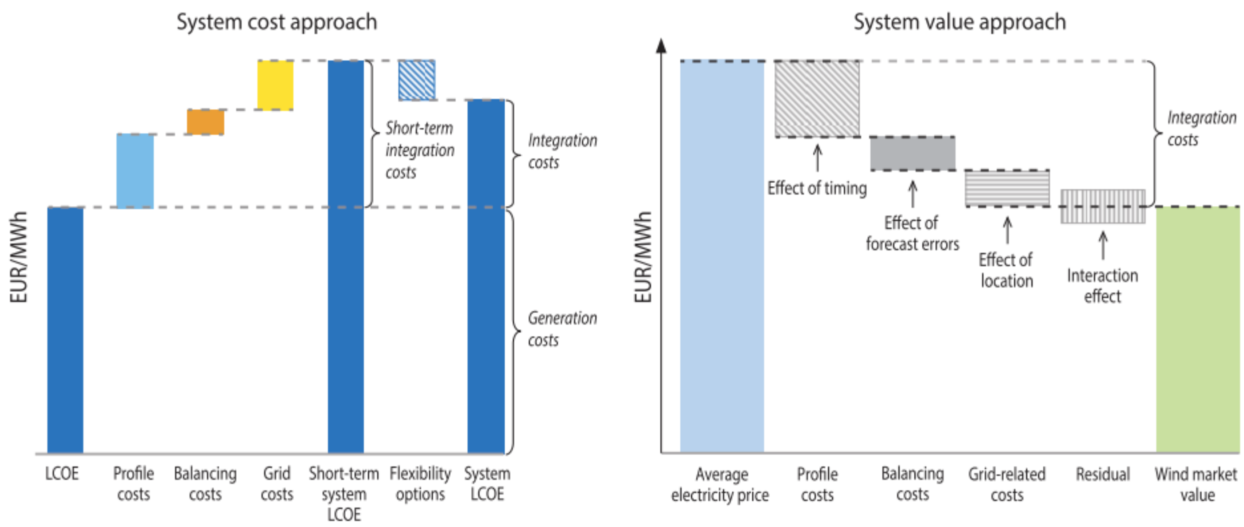


Figure 12 System cost approach versus system value approach (Hirth et al., 2015)

In the short term (number of months to a few years), power systems are inflexible, as large projects require long lead times to begin producing power. Thus, the system will not likely adapt to VRE introduction, which provides higher integration costs than in the longer-term (Ueckerdt et al., 2013b). However, in the longer term, the system adapts to the introduction and penetration of VRE, through increased base-load capacity and even types of storage technologies.

The author asserts that the *'new definition of integration costs is rigorous because it allows determining the cost-optimal and competitive deployment of VRE and thus System LCOE can be interpreted as the marginal economic costs of an additional unit of VRE'*(Ueckerdt et al., 2013b).

Now, having introduced the three underlying components of integration costs, the quantitative values are presented from the literature.

2.5.1.1 Balancing costs

Costs of balancing are portrayed in Figure 13 (Hirth et al., 2015). For a full list of these studies and values reference is made to Hirth et al., (2015). Market prices are denoted by squares, model prices for wind are diamonds and solar generation signified by crosses. Interestingly, bar 3 market related studies, all results are below 6 €/MWh. An average linear trend line was plotted, which shows a gradient of 0.06 €/MWh, a y-intercept of 2€/MWh and the value of 4 €/MWh at 40% penetration.

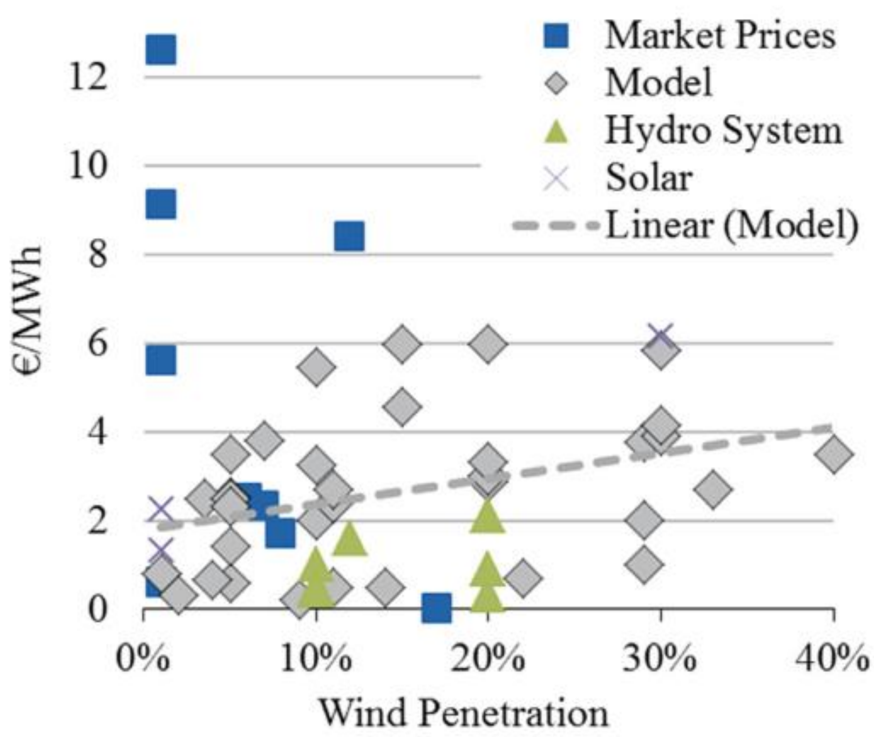


Figure 13 Balancing Costs for Wind (Hirth et al., 2015)

Furthermore, Hirth et al., (2015) decompose balancing costs into two elements, what is termed: 'flexibility costs' and 'utilization effects'. These two elements were also computed. Flexibility costs are simply stated as the '*cost of adjusting the output of thermal plants*'(Hirth et al., 2015), which results from these plants having to adapt their output due to VRE profiles. The utilization effects are due to decreased usage of thermal power plants as VRE contributes to the power system (Hirth et al., 2015).

Figure 14 depicts the system cycles for a thermal power plant as the solid line, assuming 100 €/MWh per cycle, and then the corresponding price attached to the cycles. The result is that even at high penetration rates, flexibility affects due to cycling are trivial when compared to utilization and other integration costs. The value of around 3 €/MWh can be seen at a 40% penetration rate.

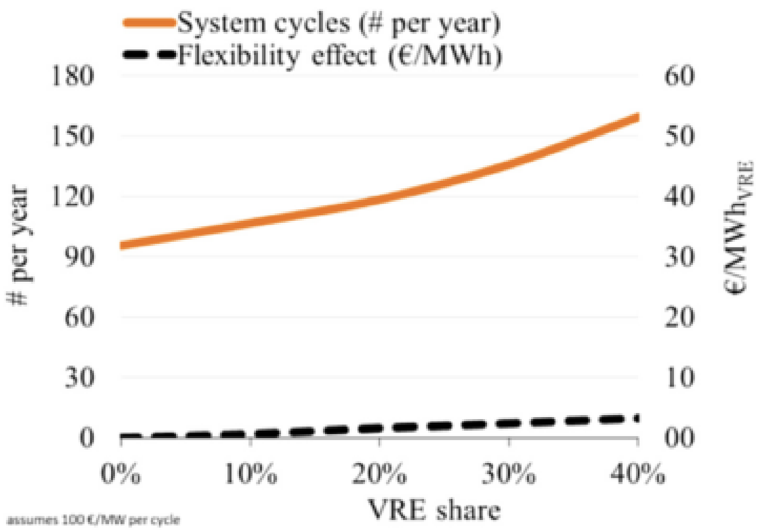


Figure 14 Flexibility effect (Hirth et al., 2015)

Figure 15, which has the same axes scaling as Figure 14, illustrates the impact of utilization effects on thermal power plants. For simplicity, Residual Load Duration Curves (RLDC), which support the argument, are not presented; however, they can be viewed in Hirth et al., (2015). These RLDC provide the data behind the analysis, which produces results in Figure 15. With reduced utilization, the specific capital costs (€/MWh) of thermal plants will increase. At the maximum of 40% penetration levels, the increased cost ascribed to utilization effect is approximately 51 €/MWh. The authors emphasise the *'capital cost-driven utilization effect is the single most important integration cost component'* (Hirth et al., 2015), not only in the short term, but also in the long-term. And, as we have seen previously, LCOEs of generation technologies are dependent on the capacity factor or full load hours in a year.

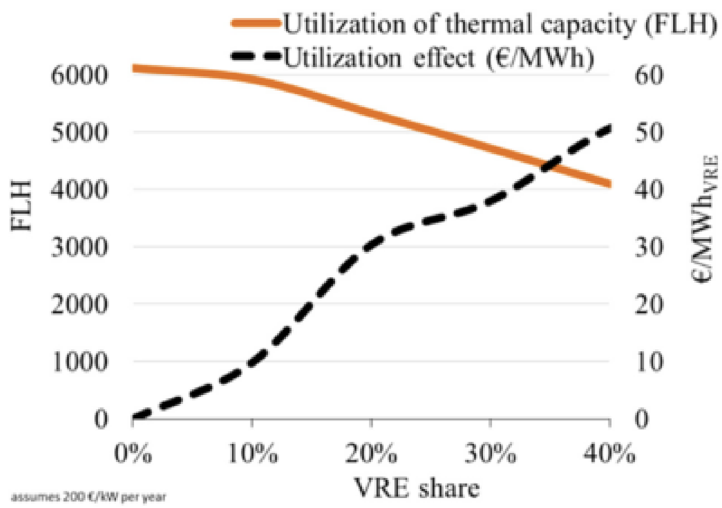


Figure 15 Utilization effect (Hirth et al., 2015)

2.5.1.2 Grid-related costs

Hirth et al., (2015) maintain that grid-related costs are not readily available, as costs are often reported in absolute not marginal cost. Their conclusion from the sparse literature, which is concentrated in the European energy sector, states that *'VRE expansion causes only moderate costs for grid expansion'* with values in the single figure range (€/MWh) (Hirth et al., 2015).

A study published by the South African German Energy Program, titled: *Analysis of options for the future allocation of PV farms in SA*, provides insights into the deployment strategies for 8.4 GW PV (static and tracking technologies) where the primary focus is on costs (GmbH & Giz, 2015). In this study, three scenarios were developed, each placing the PV farms in different areas throughout the country, with specific amounts of PV in the designated zones. Firstly, the *'As planned'* scenario assigned the farms to the solar corridor in the Upington region. Next, the second scenario considered PV farms '*close to load centres'*. Thirdly, farms were placed within the recently defined *'Renewable Energy Development Zones (REDZs)'* (GmbH & Giz, 2015). LCOE was used as the metric for cost calculations, and the cost effect was shown in the following four values:

1. LCOE
2. Levelized Cost of Transmission (LCOT) grid upgrades
3. Levelized Cost of Distribution (LCOD) grid upgrades
4. Levelized Cost of Losses (GmbH & Giz, 2015)

Grid costs (LCOT, LCOD and cost of losses) supplemented LCOE values ensuring a more comprehensive impact analysis than any identified previous studies.

The results showed that the LCOE was the lowest for scenario A, which is '*because this is the scenario with the highest energy yield per kW installed'*(GmbH & Giz, 2015). This is presented in Table 5, with both static and tracked systems compared.

Table 5 Average LCOE of utility scale PV farms in SA per allocation scenario(GmbH & Giz, 2015)

	Scenario A	Scenario B	Scenario C
LCOE in USD/kWh, static systems	0,1198	0,1244	0,1229
LCOE in USD/kWh, tracked systems	0,1116	0,1171	0,1153

In their analysis, load flow and contingency analysis of the complete South African transmission system were the two used methods for modelling (GmbH & Giz, 2015). From the modelling the length of both transmission and distribution lines and the number of substations for all three scenarios is compared in Table 6 (GmbH & Giz, 2015).

Table 6 Required Transmission and Distribution upgrades of Scenarios (GmbH & Giz, 2015)

	Scenario A	Scenario B	Scenario C
Transmission Lines (400kV/275kV) in km	1105	136	235
Number of Substation Transformers	32	15	15
Distribution Lines (132kV/88kV) in km	1772	1130	1192

As a result of the transmission and distribution upgrades, the capital expenditure required for these upgrades was calculated. Scenario A has the largest capex cost, which is consistent as the projects are in a largely non-electrified region (GmbH & Giz, 2015).

Table 7 CAPEX of required grid upgrades (GmbH & Giz, 2015)

	Scenario A	Scenario B	Scenario C
CAPEX of Transmission grid upgrades in Mio. USD	554,73	135,27	165,13
CAPEX of Distribution grid upgrades in Mio. USD	670,76	423,03	445,73
Total CAPEX of grid upgrades in Mio. USD	**1.225,49**	**558,30**	**610,86**

Using the Capex in Table 7, the Levelized Cost of Transmission and Distribution was computed (see Table 8 and Table 9). Scenario A (for both tracked and static cases) shows markedly higher levelized costs than the remaining scenarios, indicating the required development of a larger grid infrastructure to support allocation in the solar corridor.

Table 8 LCOT&D upgrades-static PV systems (GmbH & Giz, 2015)

static systems	Scenario A	Scenario B	Scenario C
LCOT in USD/kWh	0,0042	0,0011	0,0013
LCOD in USD/kWh	0,0051	0,0033	0,0034
Total (LCOT+LCOD) in USD/kWh	**0,0093**	**0,0044**	**0,0047**

Table 9 LCOT&D upgrades-tracked PV systems (GmbH & Giz, 2015)

tracked systems	Scenario A	Scenario B	Scenario C
LCOT in USD/kWh	0,0036	0,0009	0,0011
LCOD in USD/kWh	0,0044	0,0029	0,0030
Total (LCOT+LCOD) in USD/kWh	**0,0080**	**0,0038**	**0,0041**

Transmission losses over long distance power lines are measurable and have an impact, which is shown in the last row of Table 10(GmbH & Giz, 2015). Losses have a negative value since they tend to reduce the overall power transferred, with all three scenarios showing a decrease in overall system losses.

Table 10 Impact of PV generation on transmission system losses (GmbH & Giz, 2015)

	Base Case	Scenario A	Scenario B	Scenario C
Av. Power Losses in MW	887	795	789	788
Annual Energy Losses in GWh	7767	6964	6910	6907
Difference, Power in WM		-92	-98	-98
Difference, Energy in GWh		-802,938	-857,624	-860,848

Consolidating all the above-calculated costs, the report shows a comparison of the total LCOE for each scenario, including both static and tracked systems. One can expect a lower value for tracked systems, since their nature is to follow the solar resource as its angle of incidence changes over the day, and so the energy yield is higher than static systems. The difference in US Dollars per kWh is marginal, and thus each option on a purely cost basis is comparable. Figure 16 is the depiction of the final result. However, practical aspects such as lead time for construction of power lines would vary amongst scenarios, as some use the available grid more than others. The optimum approach is to utilize the solar corridor up to its full limit, and then distribute the solar PV around the country (GmbH & Giz, 2015).

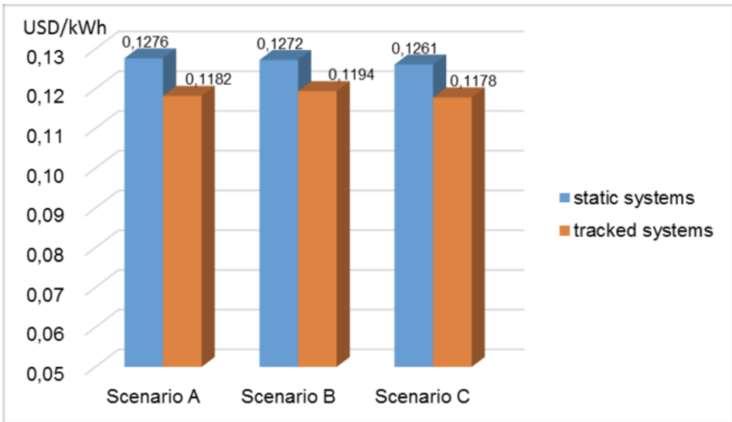


Figure 16 Total LCOE of PV Generation (GmbH & Giz, 2015)

The study by GmbH & Giz, (2015) is helpful in showing the marginal costs due to following the solar goals contained in the IRP scenarios, and other non-IRP scenarios. It would provide values, which may be applied in other projects requiring South African specific grid-related costs.

2.5.1.3 Profile costs

Figure 17 is a summary of 30 publications pertaining to profile costs (Hirth et al., 2015). *'Profile costs are the impact of timing of generation on the market value'* (Hirth et al., 2015). Furthermore, wind profile costs are seen to be near zero at small penetration rates and approximately between 15 and 30 €/MWh at 40% penetration rates. Two trend lines are plotted, short and long-term lines. They have different gradients, showing that in the short-term profile costs are around 50% higher than long-term forecasts (Hirth et al., 2015).

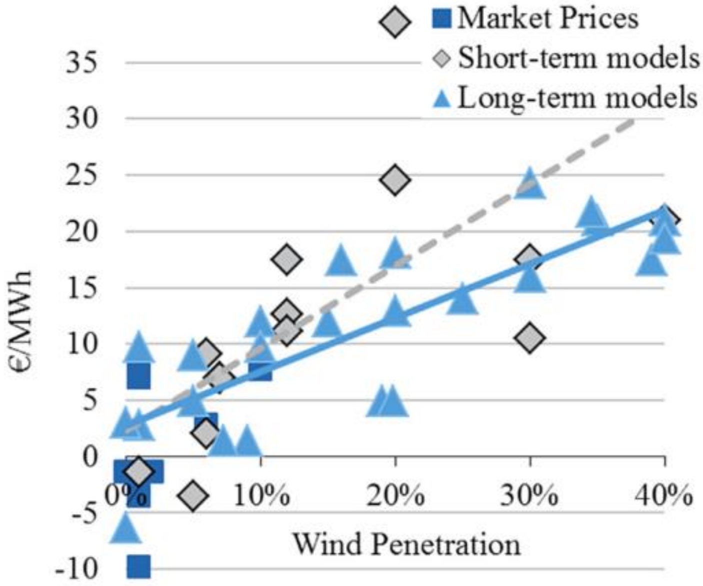


Figure 17 Wind Profile Costs (Hirth et al., 2015)

Hirth et al., (2015) state that at large penetration rates, two thirds of the integration costs are ascribed to profile costs.

2.6 LCOE values and trends

Hirth et al., (2015) conclude in their paper regarding integration costs of wind and solar, '*these estimates are system- specific and subject to significant uncertainty, integration costs are certainly too large to be ignored in high-penetration assessments (but might be ignored at low penetration)'*.. South Africa currently (and projected towards 2030) has relatively low renewable penetration rates, and therefore, one must question how significant these integration costs are. The IRP aims to have Renewable penetration of 6-9% by 2030 (Eskom, 2013b), and the WWF scenarios for 2030, which are more optimistic, set penetration rates of 11-19% (Gauché, 2015a). Thus, the question remains, how important are these non-LCOE costs or omissions from previous work.

It is important to understand where the renewable energy sector is heading. One current trend is the steadily declining prices of solar and wind energy; a 61% drop in wind LCOE and an 82% drop in solar, as depicted in Figure 18 Lazard Ltd, (2015)). This drop, will lead to increasing levels of renewable penetration not just in South Africa but globally. Each year from 2009 to 2015, has a mean LCOE and the range indicated.

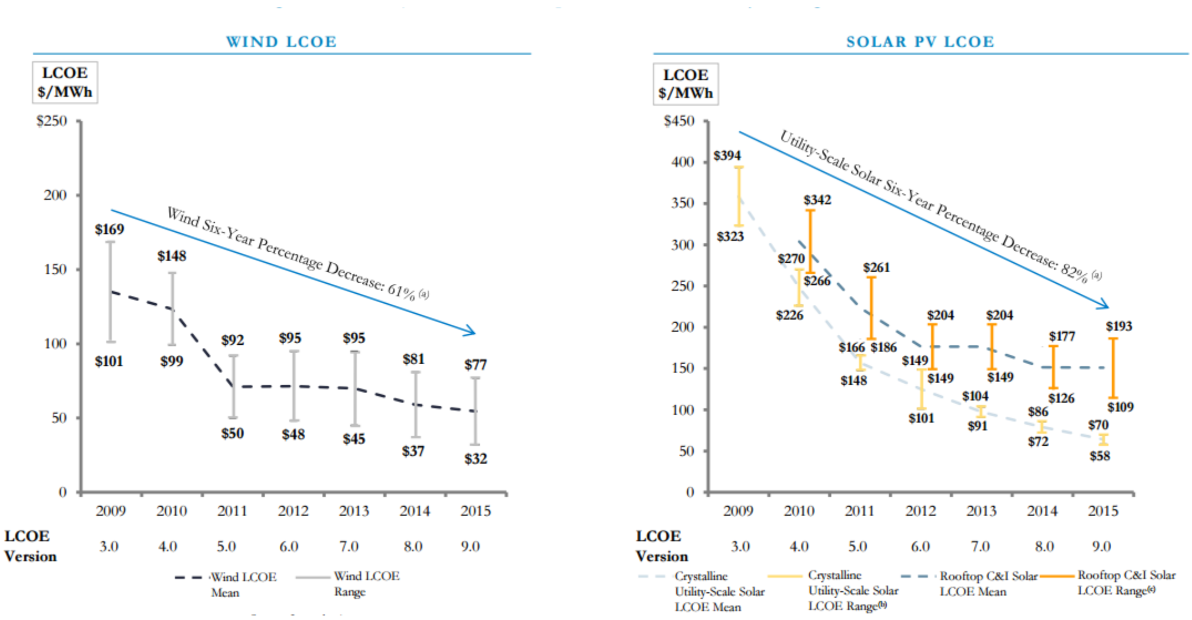


Figure 18 LCOE drop over time(Lazard Ltd, 2015)

Another key trend of CSP is that during the bid windows of REIPPP the price dropped alongside the decrease of PV and wind technologies (DOE, 2015). However, the program managers realised the widely held assertion that CSP can be used as a base load as it has a specific amount of storage and thus should have a different tariff. Thus, between bid window 2and 3 the tariff methodology was changed. This change then allows purely non-dispatchable PV and Wind to be compared against dispatchable CSP, and seeing the competitiveness. Figure 19 below shows the summary of the results (DOE, 2015). To see the analysis of CSP tariff change between REIPPPP bid window 2 and 3 refer to Silinga et al., (2015).

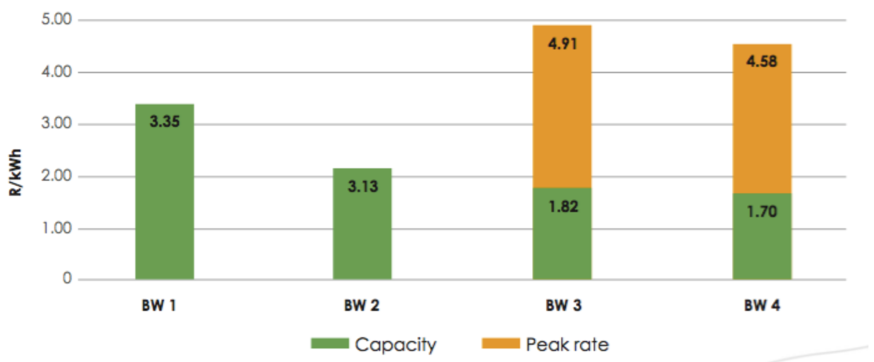


Figure 19 Average prices from solar CSP per bid window (DOE, 2015)

2.7 Modelling approach

For the research, there exists a disparity between the modelling approach and the use of a tool. Both answer the question of how the research was conducted; however, the modelling approach seeks to answer the question on a conceptual level, whereas the tool would be the implementation of the approach. This section describes the conceptual approach followed, whereas Chapter 3 details the tool selection and includes specific discussion on modelling tools. George Box cautions scientists in saying *"essentially, all models are wrong, but some are useful"*[4]. In this quote, the author suggests the idea of a model as a tool to represent some piece of reality. In addition, the limitations intrinsic to models are that they serve a purpose; however, they seek to give a description of real-world phenomena in some way, without accounting for the actual real world problem or system.

The literature is rich on the subject of energy system modelling techniques (Bhattacharyya & Timilsina, 2010; Chiodi, et al, 2011; Despres et al, 2015; Donker & Ouboter, 2015; Mischke & Karlsson, 2014). In these studies, the authors tend to analyse the entire value chain, not only limited to power or electricity systems. As one would surmise, power system models are typically smaller than entire energy system models. Nevertheless, depending on the objectives, one may need to include the entire energy system with the subset being the power system model. Other typical sectors of the energy system include the heat and transport sectors.

Two modelling approaches are of particular interest. Top-down models usually view the problem from a macroeconomic interaction between objects (Despres et al., 2015), whereas bottom-up models look at the *"detailed description of the technical components of an energy system"* (Pfenninger, Hawkes, & Keirstead, 2014). The outcome of bottom-up models is investment cases and substitutes (Connolly, Lund, Mathiesen, & Leahy, 2010). Then, there are hybrids, where the models are combinations of these two modelling approaches.

Furthermore, one can distinguish between optimization and simulation models. Simulation models seek to understand how the system evolves over time (Despres et al., 2015) and usually results in some level of prediction. Optimization is a model based on a simulation; however, a number of variables within the model are being optimized (Despres et al., 2015). The operation and implementation for these simulation and optimization models are inherently different.

Typical advantages of simulation include:

- Ability to analyse large and complex systems
- Flexible in that many different scenarios or strategies can be tested
- Wide range of applications
- Often lower cost than building a working prototype or system

The following disadvantages of simulations must be kept in mind:

[4] http://www.goodreads.com/quotes/680161-essentially-all-models-are-wrong-but-some-are-useful

- Does not provide exact results, rather estimates
- Gives an indication of trade-offs and optimality rather than optimal solutions
- Does not describe the underlying cause-effect relationships of the system

A typical simulation process may involve a number of the following steps:

1. Identify the general system
2. Understand the underlying system
3. Identify modelling objectives
4. Identify the system boundary
   a. Certain in-scope sub-systems etc.
5. Develop the system model
6. Define input data
7. Run and validate the model
8. Conduct sensitivity analysis – to determine the impact of altering the input parameters and their effect on the model outputs
9. Alter design of required

Table 11 is a concise summary of a number of tools, which are categorized according to the bottom-up or top-down and either simulation or optimization approaches (Despres et al., 2015). This list is not exhaustive, rather a representation of a sample of the tools in each category.

Table 11 Main Classification of energy models (Despres et al., 2015)

	Bottom-up	Hybrid	Top-down
Optimization	Sectoral optimization: MARKAL (Market Allocation)	MERGE (Model for Estimating the Regional and Global Effects of greenhouse gas reductions).	Optimal growth pathway: DICE
Simulation	Recursive sectoral simulation: POLES (Prospective Outlook on Long-term Energy Systems)	Imaclim	Recursive general equilibrium: GREEN (General Equilibrium Environmental model)

A significant parameter in modelling of energy systems is the timescale. Depending on the objective of the study, one would choose differing time scales. To examine the degradation of equipment, one would need to look at smaller time intervals, whilst for planning of overall energy systems, typically decade-long planning timescales are used. Different timescales are evident in Table 12 below.

Table 12 Comparison of the time scales for electricity system modelling (Foley, Gallachóir, Hur, Baldick, & Mckeogh, 2010)

Time frame	Electricity systems issues	Power systems tools
ms to s	Generator dynamics Motor load dynamics	Transient stability management Power-frequency regulation
Min to 1 hour	Demand variations	
Very short term	Power interchanges, Maintain economic operation, Frequency control	Economic dispatch, Generation control, Power flow, Security analysis, Fault analysis, Voltage stability studies
h/days to 1 week Short term	Weekly generation planning	Demand, weather prediction, unit commitment
Weeks to months Medium term	Seasonal generation planning	Demand prediction, maintenance planning, hydro planning, fuel planning
Years Long term	Demand growth, Plant retirement/refurbishment, Investment opportunities, Long term hydrological cycles	Generation expansion planning, reliability checks (maintenance), Scenario analysis, Production cost modelling.

2.8 How to select tools

Connolly et al., (2010) reviewed 37 different energy tools that were computer based and thus provided policy makers with an overview of available tools. All 37 tools are capture in Table 13.

Table 13 Type of analysis conducted by each tool reviewed (Connolly et al., 2010)

Tool	Geographical Area	Scenario Timeframe	Time-step **1. National energy-system tools** **1.1. Time-step simulation tools**	Specific focus
Mesap PlaNet	National/state/regional	No limit	Any	–
TRNSYS16	Local/community	Multiple years	Seconds	–
HOMER	Local/community	1 year[5]	Minutes	–
SimREN EnergyPLAN SIVAEL STREAM WILMAR Planning Tool	National/state/regional National/state/regional National/state/regional National/state/regional International	No limit 1 year* 1 year* 1 year* 1 year*	Minutes Hourly Hourly Hourly Hourly	– – – – –
RAMSES	International	30 years	Hourly	–
BALMOREL	International	Max 50 years	Hourly	–
GTMax	National/state/regional	No limit	Hourly	–
H2RES	Island	No limit	Hourly	–
MARKAL/TIMES	National/state/regional	Max 50 years	Hourly, daily, monthly using user-defined time	–
			slices	
			1.2. Sample periods within a year	
PERSEUS	International	Max 50 years	Based on typical days with 36–72 slots for 1 year	–
UniSyD3.0	National/state/regional	Max 50 years	Bi-weekly	–
RETScreen	User-defined	Max 50 years	monthly	–
			1.3. Scenario tools	
E4cast EMINENT	National/state/regional National/state/regional	Max 50 years 1 year*	Yearly None/yearly	– –
IKARUS	National/state/regional	Max 50 years	Yearly	–
PRIMES	National/state/regional	Max 50 years	Years	–
INFORSE	National/state/regional	50+ years	Yearly	–
ENPEP-BALANCE	National/state/regional	75 years	Yearly	–
LEAP	National/state/regional	No limit	Yearly	–
MESSAGE	Global	50+ years	5 years	–
MiniCAM	Global and regional	50+ years	15 years	–
			2. Tools with a specific focus **2.1. Time-step simulation tools**	

[5].

AEOLIUS	National/state/regional	1 year*	Minutes	Effects of fluctuating renewable energy on conventional generation
HYDROGEMS	Single-project investigation	1 year*	Minutes	Renewable energy and hydrogen stand-alone systems
energyPRO BCHP Screening Tool ORCED	Single-project investigation Single-project investigation National/state/regional	Max 40 years 1 year* 1 year*	Minutes Hourly Hourly	Single power-plant analysis Combined heat and power Dispatch of electricity
EMCAS	National/state/regional	No limit	Hourly	Electricity markets
ProdRisk	National/state/regional	Multiple years	Hourly	Hydro power
COMPOSE	Single-project investigation	No limit	Hourly	CHP with electric boilers or heat pumps
			2.2. Sample periods within a year	
EMPS	International	25 years	Weekly (with a load duration curve representing	Hydro power
			fluctuations within the week)	
WASP	National/state/regional	Max 50 years	12 load duration curves for a year	Power-plant expansion on the electric grid
			2.3. Scenario tools	
Invert	National/state/regional	Max 50 years	Yearly	Heat sector
NEMS	National/state/regional	Max 50 years	Yearly	US energy markets
*Tools can only simulate 1 year at a time, but these can be combined to create a scenario of multiple years				

More relevant for power systems, is Foley et al., (2010), who discussed 7 proprietary electricity modelling tools, which were: AURORAxmp, EMCAS, GTMax, PLEXOS, UPLAN, WASP IV, and WILMAR.

In the case of project LCOE, calculations there were a number of tools utilized. One such example is the National Renewable Energy Laboratory's (NREL) *System Advisor Mode (SAM)*[6]. SAM assists with evaluating single energy projects and calculating financial parameters, such as LCOE.

Despres et al., (2015) show the main characteristics of five (5) electricity-modelling tools, which can be seen in Table 14. These cover the entire spectrum, from constraints, cost, renewable energy sources and their impacts, storage, and grid.

[6] https://sam.nrel.gov/

Table 14 Main characteristics of the electricity modelling tools (Despres et al., 2015)

Modelling tools	PRIMES	SWITCH	REEDS	E2M2	ELMOD
Optimization constraints:					
Demand	Economic function	Historical	Elastic	Aggregated	Elastic
Operating reserves	Y	Y	Y	Y	N
Capacity reserves	Y	Y	Y	Y	N
Grid	N	Y	Y	N	Y
Renewable penetration	N	Y	Y	N	N
Start-up time	N	N	N	Y	Y
Costs:					
Fixed (O&M, investment)	Y	Y	Y	Y	N
Variable (O&M, fuel)	Y	Y	Y	Y	Y
Variable fuel efficiency	N	N	(coal only)	Y	Y
Start-up	N	N	N	Y	Y
Reserves, ancillary services	N	N	Y	Y	N
Grid	Y	Y	Y	N	N
Renewable and CO2 taxes	Y	Y	Y	N	Y
Capital	Y	Y	N	Y	N
Risk premium, mark-up	Y	N	N	N	N
Renewable energy sources:					
Hydraulic resource	(Unclear)	Historical	Historical	(Unclear)	(Unclear)
Production profile	Statistically determined	Historical	Statistically determined	Stochastic	Deterministic
Curtailment possibility	N	Y	Y	Y	N
Impacts of renewables on:					
Operating reserve	Y	Y	Y	Y	N
Capacity reserve	Y	Y	Y	Y	N
Grid costs	Y	Y	Y	N	Y
Storage economic value:					
Optimization of the system		Y	Y	Y	Y
Ancillary services	(only load smoothing)	Y	Y	Y	N
Avoid curtailment		Y	Y	Y	N
Grid:					
Nodes and lines	35 nodes, 240 lines	50 nodes, 104 lines	134 nodes, 300 lines	None (only one country)	Entire Europe
Type of computation	DC load flow	NTC	DC load flow or NTC	Copper plate	DC load flow

2.9 Summary of literature review

Chapter 2 has discussed the origins of LCOE methods and then went on to elaborate on the LCOE omissions (externalities, system costs, technology types, and input data). Owing to these omissions, an attempt was made to address this deficit through the concept of integration costs. Lastly, the chapter discussed modelling methodologies and the approach to selecting modelling tools.

From the literature review, the apparent lack of integration studies in South Africa is clear. One reason for this gap is the relatively low penetration levels for renewables currently, and in the future (IRP 2030). Most studies only focus on the simple LCOE of projects and specific generation technologies. However, with the currently connected and operating renewables contingent of plants, there will be integration costs within the power system. With the relatively low penetration rates of renewables, the measured impact may not be substantial at the current time, but this requires further investigation.

In this investigation, there should be some attempt to address the gaps in the South African case with regards to the omissions from LCOE, such as integration costs amongst others.

3 Modelling methodology

In order to accomplish the research, the methodology followed is depiction in Figure 20 below. Since the research seeks to understand the system cost characteristics over time, modelling would need to be conducted. The primary purpose of this chapter is to show the modelling approach followed.

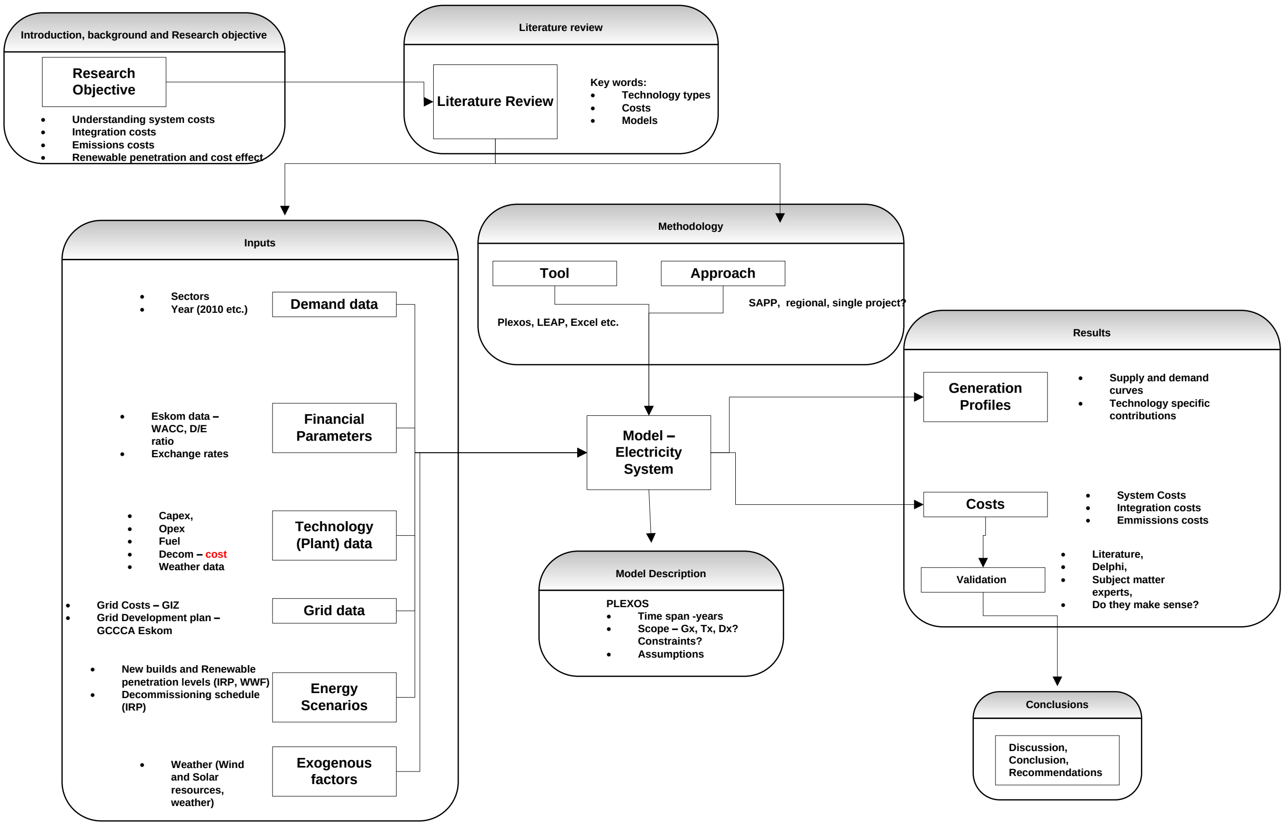


Figure 20 Methodology

This chapter will follow on from the modelling theory that was discussed in Chapter 2 Section 3.5. However, this chapter includes the specific decision process in selecting the tool and then the verification of that software tool. Lastly, the methodology being followed for the model, which addresses the research question, will be presented.

Based on the above discussion in section 2.7, chapter 2, it was necessary to summarize the conceptual models presented, and then it was decided, which was most suitable. Since the investigation sought to understand the costs of different energy scenarios, including the variability of renewables, and the impact on the system, it would be prudent to select the bottom-up modelling approach as this captured the underlying technical detail required. Further, focus would be on the electricity system and not include the rest of the energy system, such as the heat and transport sectors.

3.1 Tool selection

Since the objective was to understand the integration costs of renewables within the South African power sector, an electricity-modelling tool was chosen which would allow these ends to be accomplished. The perspective is from the system operator and not from each actor (Independent Power Producers etc.) in the system. It is possible to calculate integration costs from each actor's point of view.

Having presented the number of software tools available for energy and electricity system modelling in Section 2.7 and 2.8 in Chapter 2, it was necessary to select the most suitable tool for the research. Table 15 shows the comparison of four energy-modelling tools and lists the tools alphabetically for ease of reading. These three tools were chosen as they were the top downloaded tools according to Connolly et al. (2010). PLEXOS was the fourth tool as it had been planned to be used by the research group of Stellenbosch Universities Centre for Renewable and Sustainable Energy Studies (CRSES). As a side note, Excel modelling, using the code editor (Visual Basic) was considered. However, the model including all simulation logic and linear programming mathematics would need to be hard coded. Thus, it was deemed unsuitable from a practical position when compared to specific energy and electricity specific modelling software packages.

Table 15 Comparison of Tools

Tool	Availability	Energy or Electricity sector	Renewable Energy Penetration Simulated (Connolly et al., 2010)	Time steps	Economic and system costs	Scope (single project versus system)
RETScreen	Free to download	Electricity	No	Monthly	No	Single project
LEAP	Commercial/Free for developing countries and student	All energy	Yes	No limit	Yes	System
HOMER	Free 30 day trial, paid license	Microgrid	No	1 year in steps of minutes	Yes	Microgrid
PLEXOS	Commercial, free academic licenses available	Electricity including gas	Yes	User defined	Yes	System

To accomplish the above-mentioned objectives, a bottom-up energy modelling approach-using PLEXOS was chosen. This tool is easily customizable to the project demands and according the website[7] is used by utilities, academics, and policy makers around the globe. Additionally, licensing, guidance and assistance with the tool were available to the researcher, and studies of this nature have been completed in PLEXOS before by Brouwer et al, (2016).

3.2 Plexos Modelling

PLEXOS is a leading energy simulation tool based on optimization (Energy Exemplar, 2016) and is distributed under license by Energy Exemplar. It is a linear, mixed integer (MIP) programming model (Foley et al., 2010) and employs a number of solvers, such as: MOSEK and Xpress-MP.

The software is comprised of four modules, each with varying time scales (Hart, 2015).

<u>Long Term (LT) Optimal Investment Module</u>:

- Optimizes generation and transmission to minimize the Net Present Value total system costs
- Builds and retires generation and transmission
- 10 to 30-year time horizon

<u>PASA Optimal Maintenance Scheduling Module:</u>

- Schedules maintenance for Short and Medium Term
- Includes outages
- Computes reliability statistics (e.g. optimal reserve levels)

<u>Medium Term (MT) Decomposition Module</u>:

- Fast results for MT studies
- Optimizes constraints
- Reduces simulation period into blocks (Load Duration Curves)
- Breaks down MT constraints

<u>Short Term (ST) Chronological Module:</u>

- MIP based chronological optimization in each ST period
- Emulation of real market clearing-engines
- Can model competitive behaviour of actors (e.g. Nash-Cournot equilibrium)

[7] http://energyexemplar.com/

The above described modules are all integrated in the software. These modules produce different results, which other modules can use, as depicted in Figure 21. Typically, one can select which module is most suitable for setting up a particular problem, and since they can be run together, information is seamlessly transferred between the modules.

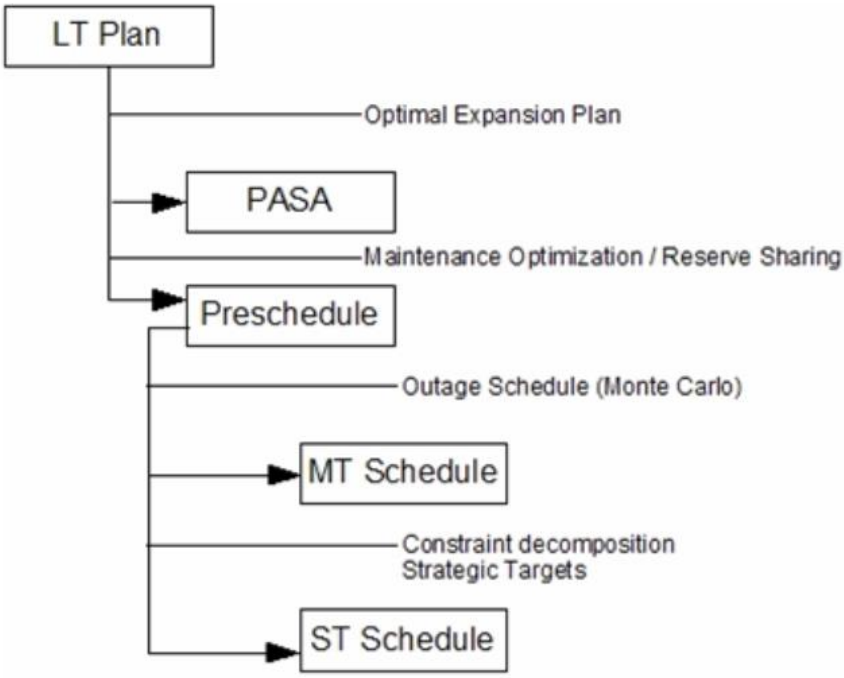


Figure 21 Integration of Simulation Phases (Wiki, 2016)

PLEXOS in essence enables the formulation of the problem into mathematical format on which various optimization techniques can be applied, with the results being easily viewed and analysed in PLEXOS.

3.3 Testing of model methodology – Verification Model

The following section explains the model setup and test conditions to verify the modelling method.

The verification model was constructed with the objective of verifying the selected methodology by replicating a published WWF study (Gauché, 2015b). The study used a single scenario, WWF Low scenario (Sager, 2014). In Sager's scenario, there are 2 bounds: the WWF Low refers to the lower bound and the WWF High refers to the higher bound (Note: These lower and upper bounds of the WWF Low model were discussed in Chapter 3 onwards).

In the verification model in this chapter, the term '*WWF Low'* will be replaced by 'Lower bound'. WWF High will be mentioned in the ensuing chapters.

3.3.1 Assumptions

For the verification model, many of the assumptions stem from the WWF Study performed by Gauché (2015), however certain ones are left to the modeller's judgements. All assumptions are as follows:

- There was no backlog in grid infrastructure, thus all projects which were forecast in the IRP/WWF scenarios came online as planned and the grid constraints were eliminated, the model was single node in nature, so the demand was seen at a single node, thus eliminated grid infrastructure and losses along the network and any required integration costs for placing projects on the grid where infrastructure was lacking
- Renewable energy supply was provided by Gauché (2015b, 2016) which included production of renewables per hour using proprietary solar global horizontal irradiance (GHI) and direct normal irradiance DNI) and freely available wind resource data [8],
- Demand profile, 2010 hourly, will not change in shape over time (up to 2030), however it will be amplified by the given multipliers (Section 3.3.2)
- Heat rates for technologies are deterministic and are as follows:
    - Existing Coal Plants 11.49 GJ/MWh (Eskom, 2014)
    - Nuclear 10.76 GJ/MWh (DoE, 2011)
    - Open Cycle Gas Turbines (OCGT)11.926 GJ/MWh (DoE, 2011)
    - Combined Cycle Gas Turbines (CCGT) 7.468 GJ/MWh (DoE, 2011)
- Fuel price for each technology varies yearly, and were given by the range in Table 4 Section 2.4.4 above.
- The following costs are not included, as per (Gauché, 2015b):
    - Emissions (Sulphur Oxides (SO_x), Nitrogen Oxides (NO_x) and particulates)
    - Water usage,
    - Start-up and shut-down costs
- Curtailment of any of the generators is not included
- System costing for 2030 did include CAPEX as per (Gauché, 2015b)
- Cost of Unserved Energy is R75/kWh(S. D. of Energy, 2013)

[8] http://www.wasaproject.info/

3.3.2 Load Forecast

Eskom 2010 load data was obtained from the modeller of WWF, and the format was in hourly time divisions. A sample of the data, which was charted, can be seen for a single day, in Figure 22. This clearly shows the evening peaks and lows in the early hours of the morning for two consecutive days.

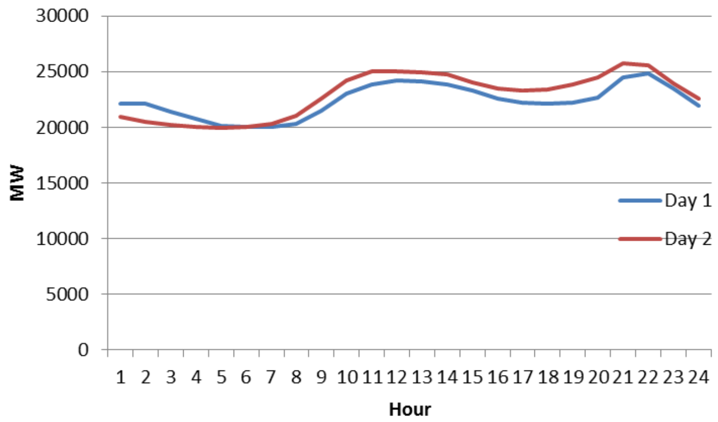


Figure 22 First two days hourly demand profile for 2010

Using the 2010 actual load data as a template, PLEXOS allows extrapolation into future years, with the result being a load forecast. The WWF Low Scenario uses the multiple of 1.43 for the increase in demand from 2010 to 2030. Multiples are the values by which the demand is increased for a given year, thus to get year 2030 one would use the product of the 2010 demand and multiple. With higher multiples, demand will increase at a faster rate, whilst smaller multiples showed a corresponding decrease. Table 16 shows the multiples for the different scenarios (Gauché, 2015a).

Table 16 Multiples used to calculate hourly demand for 2030 (Gauché, 2015a)

Annual demand (TWh)	Scenario	Multiples
250	2010	n/a
358	WWF Low	1,430
407	WWF High	1,625
409	IRP Update	1,634
454	IRP 2010	1,816

The result of simple multiplication is the following energy forecast up until 2030. This table shows the total yearly energy (GWh) and the maximum energy demand (MW) for a single hour of that year.

Table 17 2010 and 2030 Energy and maximum power values using multiples

Year	Energy	Maximum power
	GWh	MW
2010	250421	37241
2030	358103	53255

This load forecast input is then used further in the model, as demand up to and including 2030 was forecasted.

3.3.3 Nodes

For the verification model, the single node approach was used. This eliminated the transmission network, as was done in Gauché, (2015b). No transmission and distribution lines were modelled and as such, losses across the lines were not included in the model.

The country load was aggregated at the single node. Thus, all the generators will supply into that node to meet the country's demand, which was seen at the node. Figure 23 below indicates a snapshot of the verification model, showing all the generators, with accompanying connections to storages and the SA load node.

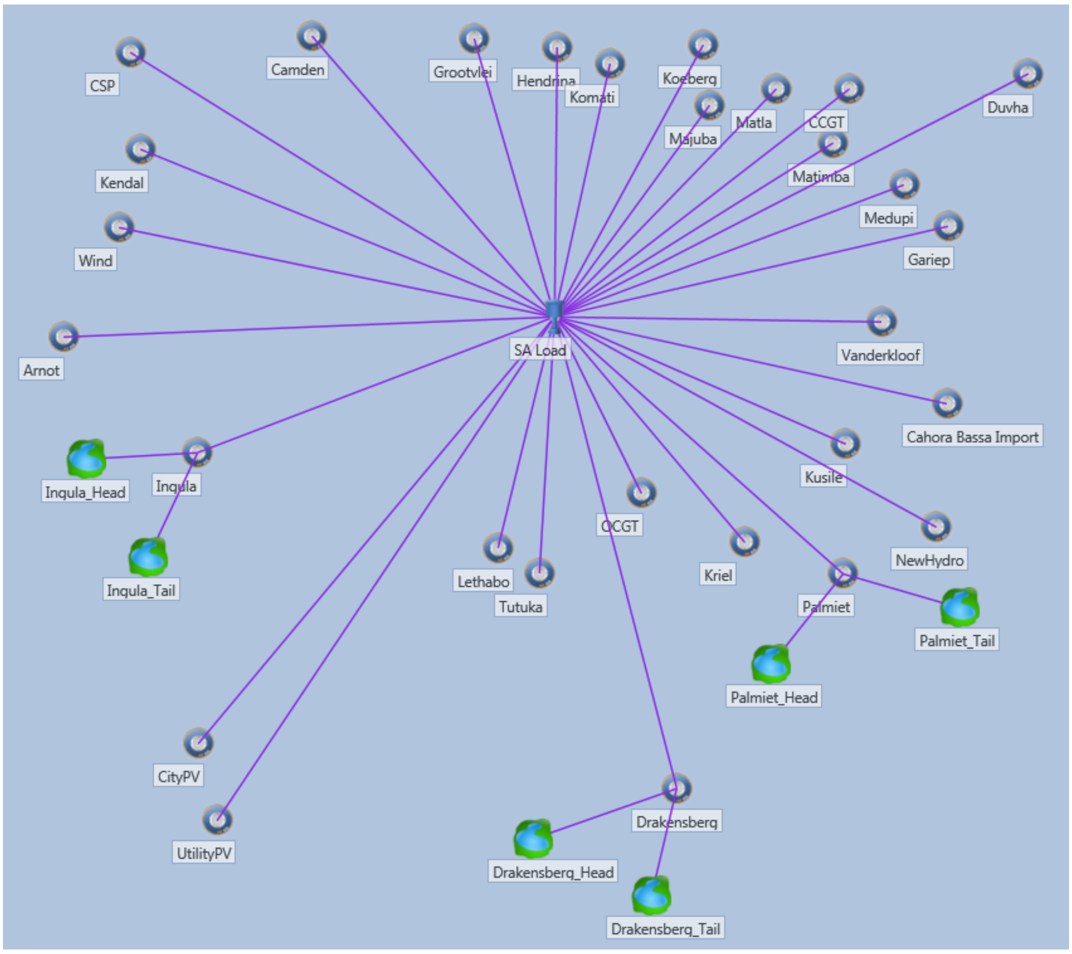


Figure 23 System Model

3.3.4 Scenario planning

According to the Integrated Resource Plan (IRP), there were a number of different energy scenarios projected to the year 2030. These scenarios explain the supply plan to meet expected demand and the decommissioning which is a sub-set of the supply. These scenarios have garnered attention, in the study by IRP and WWF (DoE, 2011; Gauché & WWF, 2015). Between the WWF and IRP, a number of energy paths or cases have been proposed and these were captured in Table 18.

Table 18 Energy Scenarios for 2030(Gauché, 2015a)

Capacity in MW	IRP 2010 Base Case	IRP Update Base Case	WWF High Demand	WWF Low Demand
Solar	9 600	13 070	18 884	9 334
Wind	9 200	4 360	16 134	8 184
Hydro	4 809	3 690	3 690	3 690
Existing coal	34 746	36 230	36 230	36 230
New coal	6 250	2 450	-	-
Nuclear	11 400	6 660	1 860	1 860
Open cycle gas	7 330	7 680	7 680	6 720
Combined cycle gas	2 370	3 550	3 550	1 420
Pumped storage	2 912	2 900	2 900	2 900
Other	915	760	760	640
Total	**89 532**	**81 350**	**91 688**	**70 978**
Expected 2030 demand (TWh)	454,4	409,1	407	358,1
% Expected 2030 Renewable Energy generation contribution	9%	9%	19%	11%
% Renewable Energy capacity in system	21%	21%	38%	25%

These tables show the complete breakdown for each technology and its respective contribution to the overall energy picture of South Africa. This is commonly termed renewable energy penetration, and is expressed as a percentage of the full energy generation mix. South Africa currently has limited options to export any large-scale excess renewable energy supply. Such is the case in many European countries. These countries, having an interconnected grid, use this network to transfer excess renewable energy generated.

3.3.5 Simulation Parameters:

For the verification model, there are a number of key parameters, which must be set. As discussed in Section 3.2, the option exists to perform studies ranging from Short-Term (ST) up to Long-Term (LT). For the purpose of the verification, the ST Plan was the desired module as it was set to run for the year 2030 at hourly interval. For the year 2030, the system was modelled in hourly increments, to understand the supply and demand for each hour at the country level. The solver receives the model in a database format, which was formulated in PLEXOS and was described by the various relationships and defined parameters. Then PLEXOS employs the solvers (CPLEX, Xpress etc.) to answer the problem using a specified mathematical technique, such as Integer Programming (IP) or Mixed Integer Programming (MIP). For accuracy MIP was selected, as it arrives at the globally optimum solution, whereas others may come to a suboptimal solution in reduced time spans.

3.3.6 Model boundary

The system boundary includes the following:

- Existing Eskom generation fleet (Coal, Gas, Hydro, Pumped Storage and Nuclear)
- New Builds from IRP 2010 which are explained in the WWF Low Scenario (Sager, 2014), including the renewables as designated in REIPPPP windows 1 to 4.5[9]

And then, the system boundary omitted the following elements:

- Small scale REIPPPP (typically in the region of less than 5MW (D. of Energy, 2016)
- Biogas, biomass, municipal waste and other cogeneration projects
- Transmission and distribution network
- Municipal generation and embedded generation
- Typical reserve margins for the overall power system were not included in the verification model

3.3.7 Existing Plant

The existing Eskom fleet was chosen to represent the current state of the South African network. This existing fleet was shown in Table 19 and Table 20. Then, in order to model up to 2030, the decommissioning plan needed to be understood and captured in the model. One such plan was published by (Eskom, 2013b) and is shown in Table 19. Certain power stations will have zero values, either meaning they have not come online as yet (e.g. Kusile by 2013) or will be decommissioned by 2030 (e.g. Grootvlei etc.). Several plants are eligible for Life Extensions (LifeEx) through upgrading, refurbishing or replacing

[9] At time of writing this was the latest round issued

older systems or components. However, this model did not include the life-extension case as the information was not available due to lack of clarity regarding decisions on these projects. Further, subsequent contracts for life-extensions had not been signed.

Table 19 Assumed decommissioning plan as given in the IRP Update. Note the capacity stated by Eskom slightly differs from the IRP Update (DoE, 2013; Eskom, 2011)

ESKOM generation	2013 Capacity (IRP Update) MW	Capacity by 2030* MW
Arnot	2 220	0
Camden	1 520	0
Duvha	3 480	2 320
Grootvlei	1 080	0
Hendrina	1 900	0
Kendal	3 840	3 780
Komati	940	0
Kusile	0	4 800
Kriel	2 880	0
Lethabo	3 540	3 540
Majuba	3 840	3 840
Matimba	3 720	3 720
Matla	3 480	1 740
Medupi	0	
Tutuka	3 540	
TOTAL	35 980	
*Assuming decommission schedule as presented in the IRP update		

There are a number of non-coal generation plants that are also included in the current Eskom generation fleet and they are captured in Table 18.

Table 20 Eskom non-coal power stations

ESKOM generation	Capacity by 2030* MW
Koeberg	1800
CCGT	3000
OCGT	6720
Drakensberg	1000
Palmiet	400
Ingula	1500
Gariep	360
Vanderkloof	240
Cahorra Bassa	1500
New Hydro	1590
TOTAL	18110

3.3.8 New Builds

According to a number of different scenarios, as proposed by DoE and WWF, expansion plans were developed; the four scenarios were shown in Table 4 Section 2.4.3. Each case shows values for the different technologies. Further down, the expected demand, and contribution of the renewable energy to generation capacity and energy are given. The difference between energy and power was already discussed in Chapter 2. Finally, the costs and technology characteristics for new build options were presented in Table 4. Also useful are the generator constraints such as availability over a year, turn down limit, ramp rate and maximum life span.

Renewable energy plants production data was provided by Gauche as per user agreement, and cannot be presented here. However, hourly renewable production data was used as an input in the model.

3.3.9 Capital and Interest costs

For the Capex and Interest accrued, values were provided by Gauché (2015a), and can be viewed below in Table 21. Reference is made to Gauché (2015a) for the methods resulting in the numbers shown below.

Table 21 Capex and Interest for all technologies

	CapEx [R]		Finance[R]	
Type	Upper	Lower	Upper	Lower
Wind	157650300000.00	117466200000.00	321140625532.65	239283838641.24
PV	118035000000.00	100890000000.00	258155750965.90	220657717752.79
Existing Coal	0.00	0.00	0.00	0.00
New Coal	334007280000.00	333586640000.00	1120396177726.85	1118985180193.50
CCGT	26124000000.00	25572000000.00	61181610598.84	59888843447.92
Existing OCGT	0.00	0.00	0.00	0.00
New OCGT	26079210000.00	25520175000.00	61076713786.00	59767470879.81
Existing pumped storage	0.00	0.00	0.00	0.00
New pumped storage	85269000000.00	35959500000.00	256072549803.86	107990487218.94
Hydro	0.00	0.00	0.00	0.00
New hydro	45062190000.00	19149960000.00	151156901238.80	64236749533.19
CSP	215594494653.36	207106218212.73	504915725736.32	485036441405.97
Existing nuclear	0.00	0.00	0.00	0.00
New Nuclear	0.00	0.00	0.00	0.00

In the final model, Section 5.2, the technique used for the Capex and Interest calculations was shown in more detail. This detail was incorporated for clarity to demonstrate understanding and provide insight for answering the costs of integrating renewables in future energy scenarios.

3.4 Summary of Modelling methodology

This chapter presented the research methodology, which included the selection of PLEXOS as the modelling tool. After a discussion of PLEXOS, the model specifics were covered, including the assumptions and key input parameters. This methodology was applied for the testing of the verification model (Chapter 4) and then in the final model (Chapter 5, 6).

4 Testing Outcomes and Discussion

This chapter presents the results from the verification model, which is based on the WWF Low scenario. Following the results, interpretation of the results was discussed. Lastly, having completed the verification, the adapted methodology for the final model was presented. The WWF High scenario underpinned this final model and it followed a similar approach to the verification model.

4.1 Testing – Verification Model Results

The WWF Low model was solved to give the generation profile for the different technologies, and then the limits for the costing variables were applied to get the lower and upper costing bounds. Similarly, in PLEXOS the upper and lower costs were inputs into the model, while the technical parameters and capacities of the plants remained the same for both upper and lower bound models. The proprietary data inputs (Weather data, costing calculations and generator outputs) were shared after signing a Non-Disclosure Agreement (NDA) with the WWF modeller and thus were not presented.

Within PLEXOS, the plant characteristics, such as Turn down limit amongst other parameters were modelled. Using the data from Table 4 the plant characteristics such as availability, turn down limit, and ramp rate were added into the electricity system model. Figure 53 and Figure 54 in Appendix B; are screenshots of the PLEXOS software interface for the system and the relevant models described above.

4.1.1 Generation Results

To understand how PLEXOS dispatches the generation to match supply, Figure 24 and Figure 25 show the Lower and Upper bounds, respectively. In addition to the generation profiles, the Short Run Marginal Cost (SRMC)[10] is graphed on the secondary axes. As the SRMC value increases, so the likelihood of that technology being dispatched decreases. This trend can be seen by the drop in New Coal from lower to upper cases and the increase in existing coal from lower to upper. Furthermore, the data outputs from which Figure 24 and Figure 25 were constructed is depicted in Table 22 and Table 23. There was a larger range for the SRMC for the Gas Turbines, as the fuel cost between the upper and lower values was the largest of all technologies. Next, the new coal and existing coal exhibit a high variation in SRMC between the two bound cases, which again is attributed to the rising fuel costs in the upper case.

Modelling in the chosen software affords the user different approaches to building and setting up a model. Thus, the method chosen and employed was not the only possible approach. One example was availability, which could be expressed simply as a constraint on the generator output or inputted as generator

[10] SRMC=Fuel + Variable O&M + Emissions. Emissions are not calculated here.

maintenance and outage events. Both constraints and events have a similar outcome in reducing output of a generator. Therefore, discretion was left up to the software modeller.

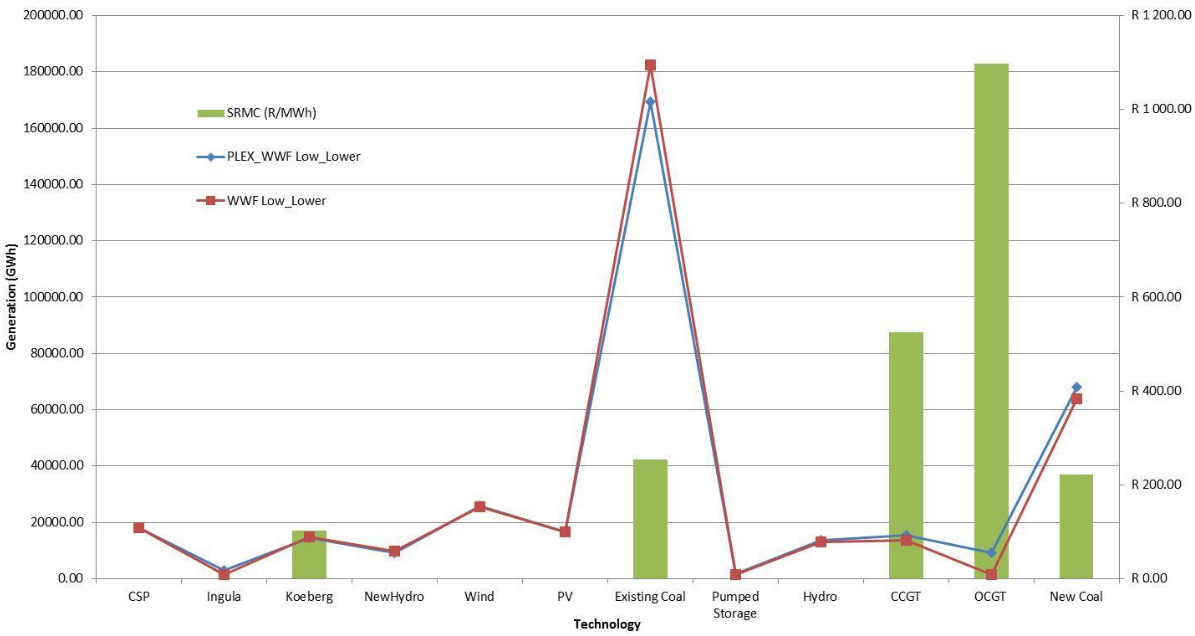


Figure 24 WWF Low comparison including SRMC

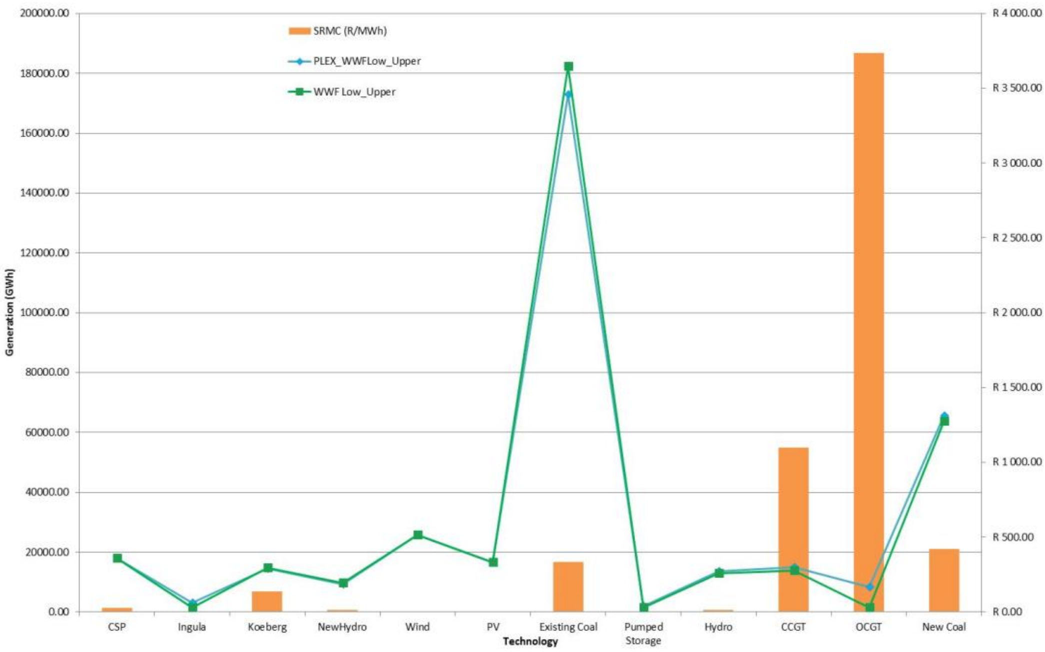


Figure 25 WWF High comparison including SRMC

From the modelling of the WWF Low Scenario, there were a number of possible results to extract from PLEXOS. The most relevant for comparing the WWF Low Scenario from Gauche to the PLEXOS approach are given. Since the renewable energy production data was provided, the values of the PLEXOS models are identical to the WWF study; this is visible in the graphs and tables presented.

WWF Low generation outputs of each technology do not vary between the upper and lower bounds due to the modelling methodology used by Gauché (2015a). However, when modelled in PLEXOS, these differences between the bounds were evident in both Table 22 and Table 22. An example was that of the New Coal generation which dropped from the lower to the upper bound cases due to the fuel price being different to the existing coal in the upper case. This drop was mirrored by an increase in existing coal production from the lower to upper case. These changes in generation impacted the overall cost, as the upper bound PLEXOS results were higher than the lower bound PLEXOS results.

Table 22 WWF Low Lower Bounds and PLEXOS results

GWh	PLEX_WWF Low_Lower	WWF Low_Lower	Δ	SRMC (R/MWh)
CSP	17926.93	17926.93	0.00	R 0.00
Ingula	2972.59	1520.66	1451.93	R 0.00
Koeberg	14555.12	14678.24	-123.13	R 102.68
NewHydro	9145.39	9810.11	-664.73	R 0.00
Wind	25650.55	25646.64	3.92	R 0.00
PV	16498.24	16498.00	0.24	R 0.00
Existing Coal	169417.73	182383.61	-12965.88	R 253.15
Pumped Storage	1820.26	1419.28	400.98	R 0.00
Hydro	13624.08	12956.75	667.32	R 0.00
CCGT	15339.64	13720.90	1618.74	R 524.29
OCGT	9019.07	1520.65	7498.43	R 1 097.89
New Coal	67928.99	63844.28	4084.70	R 222.16

Table 23 WWF Low Upper bound and PLEXOS Results

GWh	PLEX_WWFLow_Upper	WWF Low_Upper	Δ	SRMC (R/MWh)
CSP	17926.93	17926.93	0.00	R 29.00
Ingula	3058.02	1520.66	1537.36	R 0.00
Koeberg	14555.12	14678.24	-123.13	R 137.10
NewHydro	9145.39	9810.11	-664.73	R 13.90
Wind	25650.55	25646.64	3.92	R 0.00
PV	16498.24	16498.00	0.24	R 0.00
Existing Coal	172951.78	182383.61	-9431.83	R 333.68
Pumped Storage	1856.81	1419.28	437.53	R 0.00
Hydro	13624.08	12956.75	667.32	R 13.90
CCGT	15044.10	13720.90	1323.20	R 1 097.39
OCGT	8276.27	1520.65	6755.62	R 3 735.20
New Coal	65473.64	63844.28	1629.36	R 421.72

Once all the costs for each technology were extracted from the PLEXOS reports, results were then calculated using equation below for system LCOE (cost) over the entire plant life (Gauché, 2015b). The exact CAPEX values, including finance charges accruing from interest were extracted from the WWF Low model.

$$System\ LCOE = \frac{(\sum(LCOE * Annual\ power)plant + COUE * Annual\ unserved\ electricity)}{\text{Annual system demand}}$$

Table 24 shows the summary of the generation and the costs in annual values and then Rand per kWh (R/kWh). Finally, in the last row are the WWF values for system cost. It is evident that the system cost in PLEXOS was higher because the utilization of more expensive coal and gas turbines were greater. Furthermore, pumped storage generation (Ingula and existing pumped storages) was higher in both PLEXOS cases, and this equated to higher electricity costs overall. The difference between WWF Low (Lower and Upper bounds) and PLEXOS is in the order of 18 ZAR cents and 8 ZAR cents respectively. These values are significantly different; however, the underlying drivers have been explained above.

Table 24 Comparison of Costs

	PLEXOS_WWF Low_Lower	PLEXOS_WWFLow_Upper
Generation (GWh)	363898.5876	364060.9198
R/a	R 228 723 737 578.47	R 252 649 974 601.28
R/kWh	R 0.6285	R 0.6940
WWF Low (Lower and Upper Bounds) model	R 0.4400	R 0.6100
Difference	R 0.1885	R 0.0840

To understand the variation in generation, the comprehensive load, generation and pumped load values are shown in Table 25. Notable in the results are the low amount of Unserved Energy, with 56 hours for lower bound and 51 hours for the higher bound, as shown in Table 25. Using the cost of unserved energy from DoE (2011) the COUE runs into the thousands of rands, which is almost negligible when compared to the other costs in the magnitude of billions. It is worth noting that the customer load is the actual demand from the SA grid for energy, and this is similar in both scenarios. The difference lies in the energy used in the pumped storage plants.

Table 25 Comparison of loads, unserved energy and generation values from PLEXOS model

Property	**WWF Low_LOW**	**WWF Low_High**
Generation (GWh)	363898.58	364060.91
Pump Load (GWh)	5991.99	6145.70
Customer Load (GWh)	357906.59	357915.21
Hours of Unserved Energy	56.00	51.00
Unserved Energy (GWh)	52.48	43.86
Cost of Unserved Energy (R'000)	3.93	3.29

4.2 Conclusion of the verification model

The modelling method using PLEXOS is seen to generate feasible results which were within reasonable bounds when compared to the excel based approach of Gauché (2015a). Hence, the selected modelling method was used in further modelling to understand the integration costs of renewables in future South African electricity scenarios. The WWF study utilized a more heuristic hourly algorithm when compared to the mathematical optimization techniques and multi-period look ahead employed in PLEXOS. Additional feedback and review of the model was received from the WWF modeller, resulting in a further verification of the modelling methodology. The main advantages of PLEXOS were the day-ahead dispatch based on forecasted values and mathematical optimization utilized to solve the supply and demand. With the completion of the verification through the comparison between the PLEXOS and WWF method finalized, the research must move to the next phase. In this next phase, additional areas needed to be added to include emissions and other system costs, which would comprise the system costs when integrating renewables into the electricity mix.

4.3 Verification of WWF Low Model

In order to verify the modelling methodology and tool selection, the model was compared to the WWF Low results as discussed. Firstly, an Eskom Energy Planning expert reviewed the model in a workshop. In addition, the PLEXOS model was reviewed in a workshop setting by the WWF modeller. In this session the model was described in detail, despite the WWF modeller’s lack of familiarity with PLEXOS as the modelling tool. In the workshop with the WWF modeller, it was agreed that the model was representative of the WWF Low model.

4.4 Summary of testing outcomes and discussion

This chapter presented the testing of the WWF low model in PLEXOS to verify the modelling methodology and PLEXOS as a modelling tool. The PLEXOS results were compared to the WWF modellers and shown to be within an acceptable range. Additionally, PLEXOS was deemed adequate in addressing the research question.

5 Model Methodology

With the completion of the verification, the focus of the remainder of the chapter shifts to the larger more comprehensive model, Figure 26 depicts the methodology followed. The dotted lines between results and method indicate the iteration involved in the modelling process. Since a large portion of this model was based on the verification model, reference is made to those sections (Chapter 3 and 4). In the verification model the WWF Low scenario was used, however, the WWF High Scenario was used in the large model. The differences between the Verification model and final model were described below.

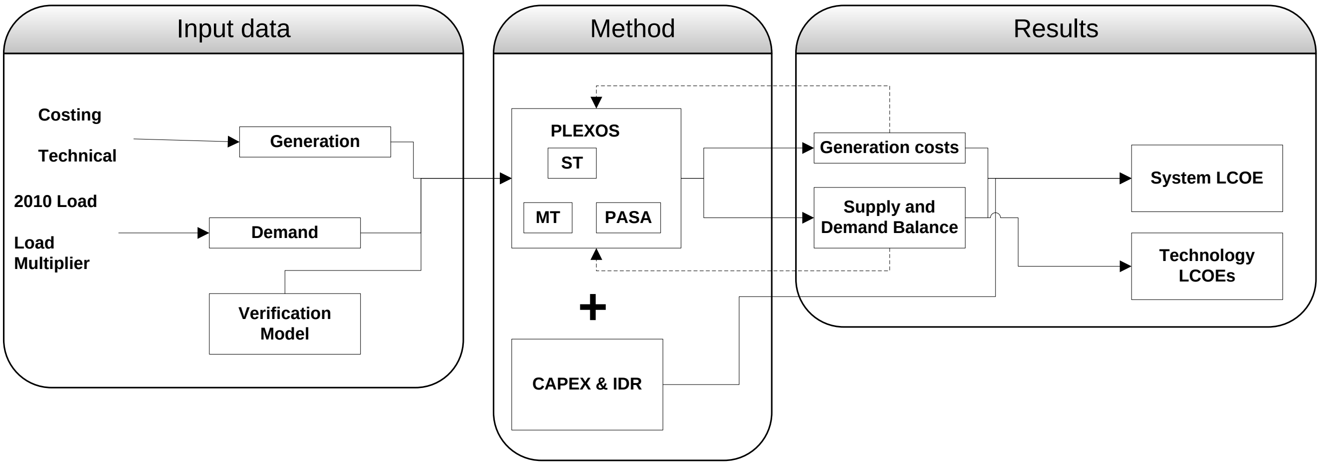


Figure 26 Large model methodology

5.1 Approach

The approach for the final model evaluated a base case, then the constrained case and then followed by a sensitivity analysis case. The ensuing section expanded on the three cases through further description. For brevity, Table 26 provides the linkage between the models' elements that are identical to those found in the verification model (Chapter 3 and 4).

Table 26 Large model linkage to verification model

Model element	Change and/or reference
Assumptions	Section 3.3.1, including emissions in section 5.1.4.
Load forecast	WWF High multiple, section 5.1.5
Nodes	Single node, section 3.3.3
Scenario planning	WWF High, Section 3.3.4
Simulation parameters	Weekly look ahead, section3.3.5
Model Boundary	As in the verification model, section 3.3.6
Existing Plant	As in the verification model section 3.3.7
New Builds	As in the verification model section 3.3.8

The WWF high scenario tree is shown in the figure below. Three models were created, namely the base case, constrained case and sensitivity analysis. The details of what distinguishes these models is shown in the level below, such as MSL for constrained case. For the sensitivity the main input values which were modified were shown.

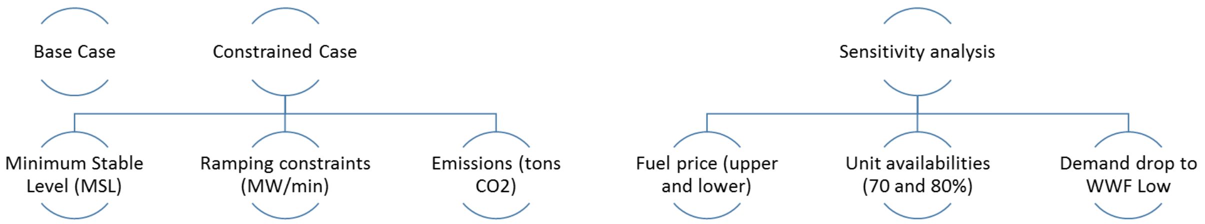


Figure 27 Scenario tree for WWF high model

5.1.1 Base Case

The system modelled had no constraints on any of the generators. Thus, the generators were not limited to any ramp rates, minimum stable levels or any other constraints. They can be termed ideal generators.

5.1.2 Constrained Case

The base was used as the foundation and then further real-life constraints for each of the generators were added. These are:

1. Minimum stable level (MSL)
2. Ramping constraints (ranging from no load to full load and in reverse)
3. Emissions (Section 5.1.4)

Each of the constraints were added into the PLEXOS model. Thus generators could not violate these constraints (MSL and ramping) at any time.

5.1.3 Sensitivity Analysis

To determine the respective impact of changes to the model output values, certain key input parameters were tested. The sensitivity analysis tested the following parameters:

- Fuel price to the upper and lower bounds (as shown in Table 4)
- Unit availabilities:
    - Using a 70% fleet availability
    - Higher 80% fleet availability
- Demand drop from WWF High to WWF Low using the demand multipliers

These parameters were selected based on their characteristics being production driven, in that they are variable in nature and cannot be predicted accurately. In addition, they were the variable costing (fuel and demand) and variable (generator availabilities) parameters. Other costs were fixed and not dependant on plant outputs but influenced only by the power or installed capacity (fixed O&M, capex etc.).

Certain sources were available for generator availabilities, termed the Generating Availabilities Data Sets (North American Electronic Reliability, 2016), although not specifically relevant to the SA context. These generator availabilities were from datasets around the world. Demand is seen to have many growth paths, evidenced by IRP and WWF scenarios (DoE, 2011; S. D. of Energy, 2013; WWF, 2014). This list of scenarios is by no means exhaustive. Lastly, fuels are commodities and their price is market driven through factors influencing supply and demand. Hence, accurate prediction of fuel prices is difficult. In conclusion, these three parameters were deemed the most suitable for the sensitivity analysis.

5.1.4 Emissions

Initially, the verification model (Chapter 4) lacked emissions values. However, for the model to be more representative, the largest contributor to emissions, Carbon Dioxide (CO_2) was included in the WWF High model. To implement in PLEXOS, the cost of emissions and the relevant production rate were required. Costs of CO_2 at time of writing were not fixed for South Africa, thus a value for 2030 was taken as R48/ton for Eskom power stations (Carbon, 2014). CO_2 production rate values were obtained from Electric Power Research Institute (2010) and were placed in Table 27. For this modelling purpose it was assumed that the existing plants will not be retrofitted with Flue Gas Desulphurization (FGD) plants, and the new builds Medupi and Kusile will be fitted with FGD (Eskom, 2015b). Significant cost would be added for fleet FGD upgrade, but this was beyond the scope of this study. Lastly, dispatch of the carbon intensive technologies was not affected by the carbon price; rather the price was used to calculate the costs of emissions post-dispatch. For future cases dispatch including emissions costs should be investigated.

Table 27 CO_2 Emissions for Coal and Gas Plants (Electric Power Research Institute, 2010)

Technology	Amount (kg/MWh)	Plants in Model
Coal Fired Pulverised Fuel plant without Flue Gas Desulphurization (FGD)	924.4	All existing plants (Arnot, Camden, Duvha, Grootvlei, Hendrina, Kendal, Komati, Kriel, Lethabo, Majuba, Matimba, Matla, Tutka)
Coal Fired Pulverised Fuel plant with Flue Gas Desulphurization (FGD)	936.2	Medupi, Kusile
OCGT	622	OCGT
CCGT	376	CCGT

5.1.5 Load

Data from Eskom, showing the actual 2010 and 2015 hourly load was used[11].Figure 28 depicts both 2010 and 2015 data sets and illustrates the characteristics of each data set. Whilst there is a visible difference, the general patterns (daily and seasonal) are similar. An assumption was that consumer behaviour and large industries' usage patterns similar from 2010 to 2015.

[11] This section was informed by a forthcoming paper comparing the 2010 and 2015 System electricity demand, which will be submitted to South African Journal of Science. Authors: M. Sklar-Chik and Prof. A. Brent.

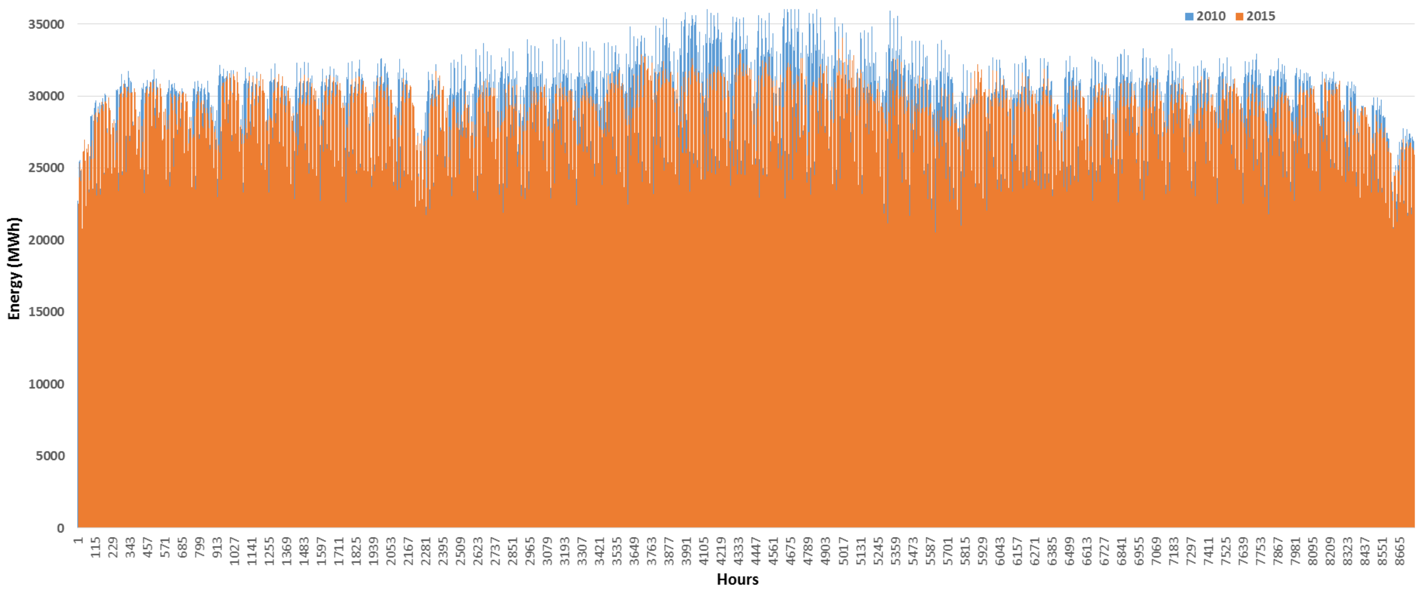


Figure 28 System demand for 2010 and 2015

Next, a common tool when looking at demand data is the Load Duration Curve. Section 2.5.1.1 first mentioned the LDC. Figure 29 depicts these LDC where the underlying data was sorted from largest to smallest hour. Thus, on the left-hand side is the largest value and then the lowest value is on the right-hand side.

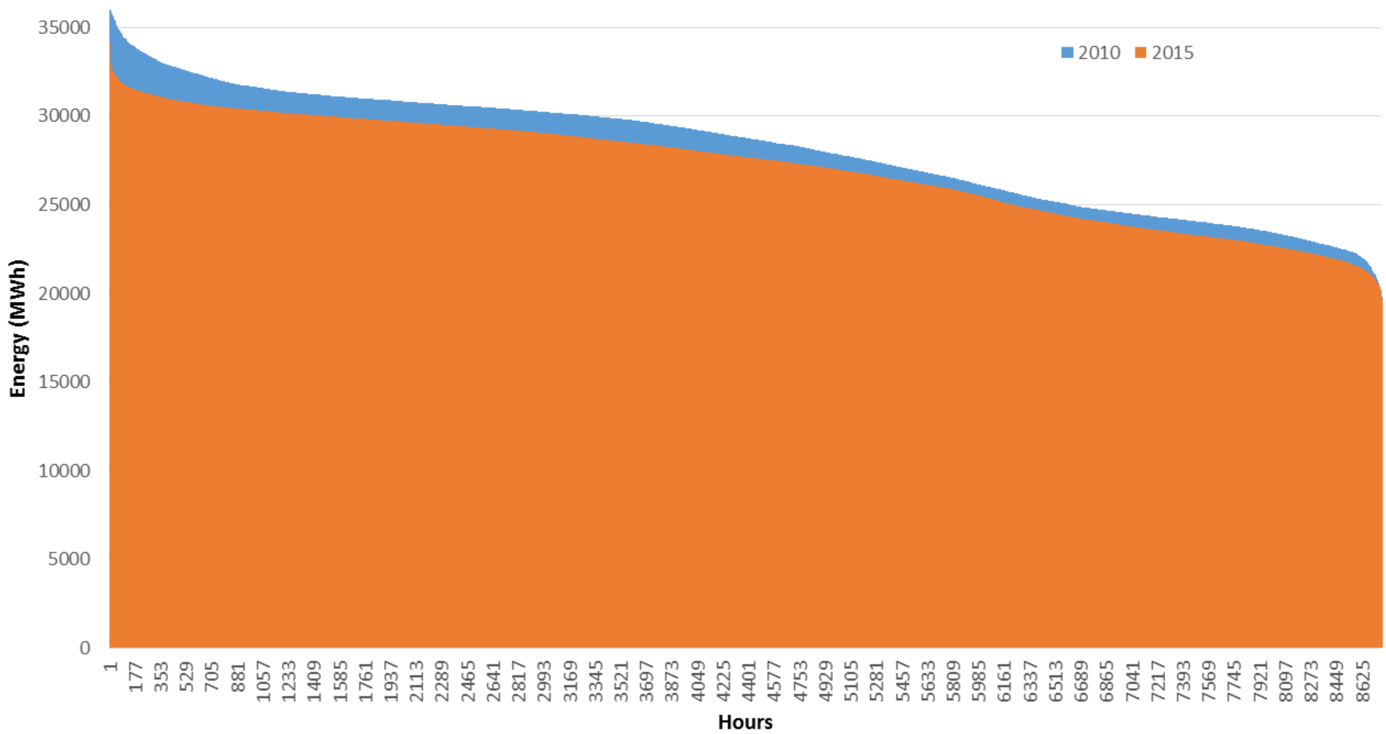


Figure 29 LDC for 2010 and 2015

To delve into more detail, samples of the first two days (hours 1 to 48) were depicted in the figure below. Again, the profiles share a similar shape, with morning (hours 6-10am) and then evening peaks (4-7pm).

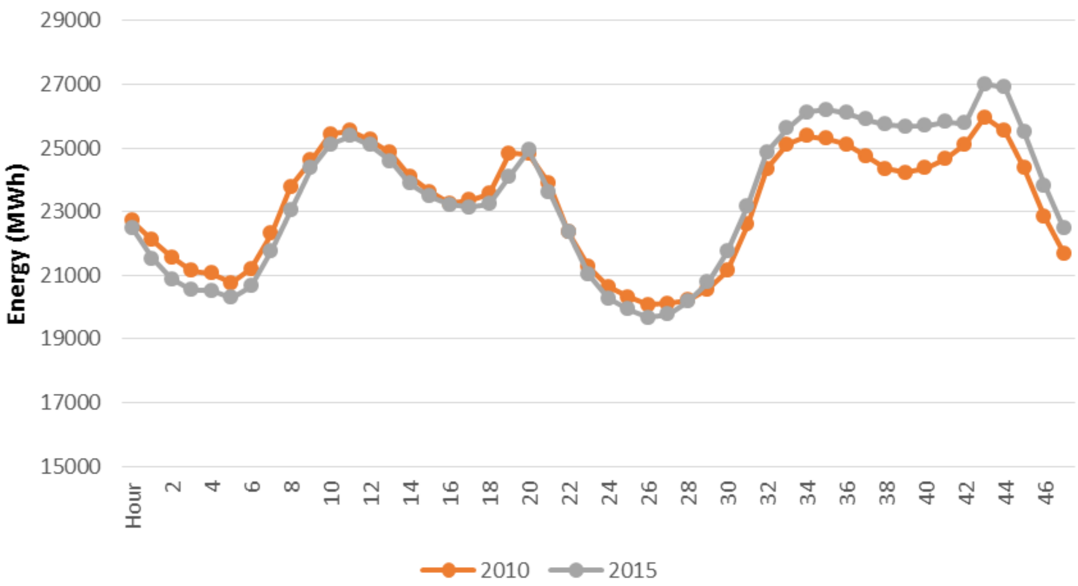


Figure 30 First 2 days of 2010 and 2015

A useful tool in understanding the correlation between the two data sets is Pearson's correlation (Investopedia, 2015) Table 28 presents the Pearson correlation numbers, with the diagonal showing perfect correlation of one. Of importance is the value of 0.87 when comparing the 2010 and the 2015 demand data sets. This value is close to one, showing a strong positive correlation. Thus, when the 2010 demand increase or decreases the 2015 demand will show a corresponding increase or decrease.

Table 28 Pearson correlation

Correlation		
	2010Data	2015Data
2010Data	1	
2015Data	0.878622453	1

Lastly, certain descriptive statistics were calculated for the two data sets, and can be viewed in Table 29 below. These assist in showing the maximum and minimum range for the data and the total yearly demand in two sets of energy units (MWh and TWh).

Table 29 Descriptive statistics for 2010 and 2015

	2010Data	*2015Data*
Range	16837	14384
Minimum (MWh)	19835	19682
Maximum (MWh)	36673	34067
Sum (MWh)	246335884	237150955
Sum (TWh)	246.335	237.151

Thus, from the simple analysis of the demand data, little growth in the demand was evident between 2010 and 2015. In fact, the overall demand for 2015 was lower than the 2010 demand. Thus the large model was based on the 2010 load data because it showed relatively small demand variation when compared to 2015 data. In addition, using the 2010 data promoted comparison between similar studies performed (i.e. Gauché & WWF, (2015)) and was used further in the model.

5.2 CAPEX Calculations

The capex calculation used the following financial parameters:

- Discount rate of 8% (Eskom, 2015a)
- Minimum loan period of 20 years, which is the expected life of a PV plant
- For the following Existing plants, financing the loans was completed by 2010 and thus accrued no interest
    - Existing coal plants
    - Existing Pumped Storage Plants
    - Existing OCGT
    - Hydro plants
    - Nuclear plant
- Loan term was the average of the technology lifespan and the minimum loan period
- Capex costs are the average of the upper and lower limits presented by (Gauché, 2015b) (Table 4)

Capex values for the newer plants were calculated using the product of the capex value (R/kW) and the capacity (MW), with the result being Capex cost in Rands for the specific technology. Secondly, the interest from the capex was computed using the payment for a loan, which was the calculated in the step above, based on constant payments, and a constant interest rate. The full formula is for an annuity (A), with principle (P), discount rate (i), and the period of the loan (n) (F.R. Jacobs, 2009)

$$A = \frac{\mathrm{P} - (1+i)^n}{(1+\mathrm{i})^{n-1}}$$

Table 30 is the summary of the Capex and interest results computed following the above-mentioned process. The existing plant has zero for the interest whilst the other plants have sizable interest values.

Table 30 Capex and Interest results

Type	Capacity (MW)	Average Capex (R/kW)	CAPEX [R]	Lifespan	Interest (over loan term)
Wind	14000	R 16 982.50	R 237 755 000 000.00	20	R 484 317 438 174.96
PV	17000	R 12 162.50	R 206 762 500 000.00	25	R 452 212 720 456.54
Existing Coal	27430	R 34 916.00	R 0.00	60	R 0.00
New Coal	9560	R 34 916.00	R 333 796 960 000.00	60	R 1 119 690 678 960.18
CCGT	4000	R 8 616.00	R 34 464 000 000.00	30	R 80 713 636 031.18
Existing OCGT	2175	R 5 676.50	R 0.00	30	R 0.00
New OCGT	5505	R 5 676.50	R 31 249 132 500.00	30	R 73 184 514 475.83
Existing pumped storage	1400	R 40 409.50	R 0.00	50	R 0.00
New pumped storage	1500	R 40 409.50	R 60 614 250 000.00	50	R 182 031 518 511.40
Hydro	2100	R 0.00	R 0.00	60	R 0.00
New hydro	1590	R 20 192.50	R 32 106 075 000.00	60	R 107 696 825 386.00
CSP	8000	R 46 979.12	R 375 832 957 778.28	30	R 880 189 315 303.97
Existing nuclear	1800	R 73 877.00	R 0.00	60	R 0.00

New Nuclear	0	R 73 877.00	R 0.00	60	R 0.00
Total	96060		R 1 312 580 875 278.28		R 3 380 036 647 300.05

PLEXOS has the ability to perform capex and interest during construction within the LT module, however, it would mean inputting build schedules from 2010 to 2030. However, more simplified excel calculations were deemed accurate enough for the end model. These financial calculations are standard and simple to understand, as seen in the above formulates within this section.

For the forthcoming chapters (6 and 7), the above-mentioned capex and interest values were used for all the relevant calculations.

5.3 Model Validation

In order to validate the large model, contact was made with a PLEXOS Subject Matter Expert (SME) at the Council for Scientific and Industrial Research (CSIR) and then two face-to-face workshops were set up. The purposes of the reviews were to validate the methodology and the large PLEXOS model. During and after concluding the workshops issues and concerns were addressed. This took place through correspondence with the SME. The outcome of validation was a model, which was representative of the real world and thus could assist in addressing the research question.

5.4 Summary of Model Methodology

Chapter 5 presented the model methodology, which used the WWF low verification model as its basis. However, a number of further details were added. Firstly, the WWF high demand data was used in the model. Secondly, sensitivity analysis was discussed; indicating demand, fuel price and generator availabilities as the parameters to test. Lastly, emissions were calculated based on the figure of R48/tonne. Furthermore, capex and interest were calculated using the costs per MW and the installed power. Since these values were based on installed capacity, their values remained for the rest of the research. Lastly, the model was validated by use of a PLEXOS SME. The next chapter will examine and discuss the model results.

6 Results and Discussion WWF High

With the completion of the testing in Chapter 4 and updated model methodology in Chapter 5, the final PLEXOS model was run to understand the integration costs of renewable generation in future energy scenarios. As already discussed, this model was based on the model developed in Testing Chapter 4.

In this chapter, the results from the PLEXOS WWF high demand scenario are presented. The generation costs for two cases are provided, namely: the base and constrained cases. Then, the capex and interest of the generation fleets are calculated and made known. Next, the integration costs in terms of CO_2 emissions and other non-LCOE costs are discussed. Lastly, to understand the impact of changing input parameters (fuel prices, availabilities of the generators, system energy demand, and renewable energy production values), a sensitivity analysis will be conducted.

6.1 Generation costs

Tables 1 and 2 present a summary of the PLEXOS models results for the two main cases. This includes the output energy for each generator; pump load, total generation, and the relevant costs. Lastly, the system costs for each scenario were shown. Then the penetration level of renewables was revealed in terms of the power (MW) and the energy (MWh) values.

Table 31 Summary results of base and constraint case

Technology Type	Base (MW)	Constraints (MW)
CSP	32241.34	32241.34
Ingula	1157.85	2900.69
Koeberg	15768.00	14555.12
NewHydro	13928.40	9145.39
Wind	40746.34	16846.22
CityPV	10779.36	10779.36
UtilityPV	16846.22	16846.22
Duvha	15554.20	21874.09
Kendal	7878.95	22752.11
Lethabo	31010.40	24066.53
Majuba	25772.52	25594.12
Matimba	29698.32	25226.90

Matla	30415.73	23658.63
Tutuka	30587.27	24065.06
Drakensberg	542.28	1506.64
Palmiet	212.17	581.34
Cahora Bassa Import	13140.00	8627.72
Gariep	3153.60	2997.81
Vanderkloof	2102.40	1998.54
CCGT	0.58	1693.16
ExistingOCGT	143.22	6364.52
NewOCGT	715.14	22471.77
Kusile	42048.00	34692.94
Medupi	41732.64	34432.74
Pump Load (GWh)	2364.76	6180.47
Total Generation	406174.92	409819.07
Renewables Contribution	Base	Constraints
Energy (MWh)	24.77%	24.55%
Power (MW)	41%	41%

Table 32 summarizes the generation, capex, and finance costs, which combined equal the total cost. Then the energy output for the two scenarios follows the costs. The system cost is in the final row. There is a marked difference between the base and constraints case, which is due to the implied constraints on the generators. In addition, the pumped load is higher in the constraints case. Capex and finance values were the same across both cases.

Table 32 Base and constraints summary of system cost elements

	Base	Constraints
Generation costs	R 8,446,501,950,833.34	R 9,085,130,180,911.85
Capex	R 1,312,580,875,278	
Finance	R 3,380,036,647,300	
Total Cost	R 10 034 359 883 684.80	R 10 042 746 153 571.70
GWh	406174.93	409819.08
System cost	R 0.3907	R 0.4822

To determine the cost contribution for the two scenarios; the system cost of unserved energy (COUE) and the total generation costs were compared for the year 2030. Table 33 presented the summarized results. Furthermore, the table below utilizes the COUE value as discussed in Chapter 4. In terms of hours of unserved energy, there were 27 for the base case and then 1927 for the constraints case.

Table 33 COUE for base and constraints scenario

Property	Base	Constraints	Units
Unserved Energy Hours	0	130	hrs
Unserved Energy	0	171.55	GWh
Cost of Unserved Energy	0	12.86	R000

Figure 31 illustrates that the difference in orders of magnitudes was significant, between the total generation costs and COUE. Constraints COUE is approximately R12867 for 2030, whilst the total generation cost is approximately R 10 153 735 380 454. The comparison is trillions versus hundreds of thousands of rands and therefore was regarded as a negligible. Thus, the COUE was removed from the calculations in the remaining portion of this chapter.

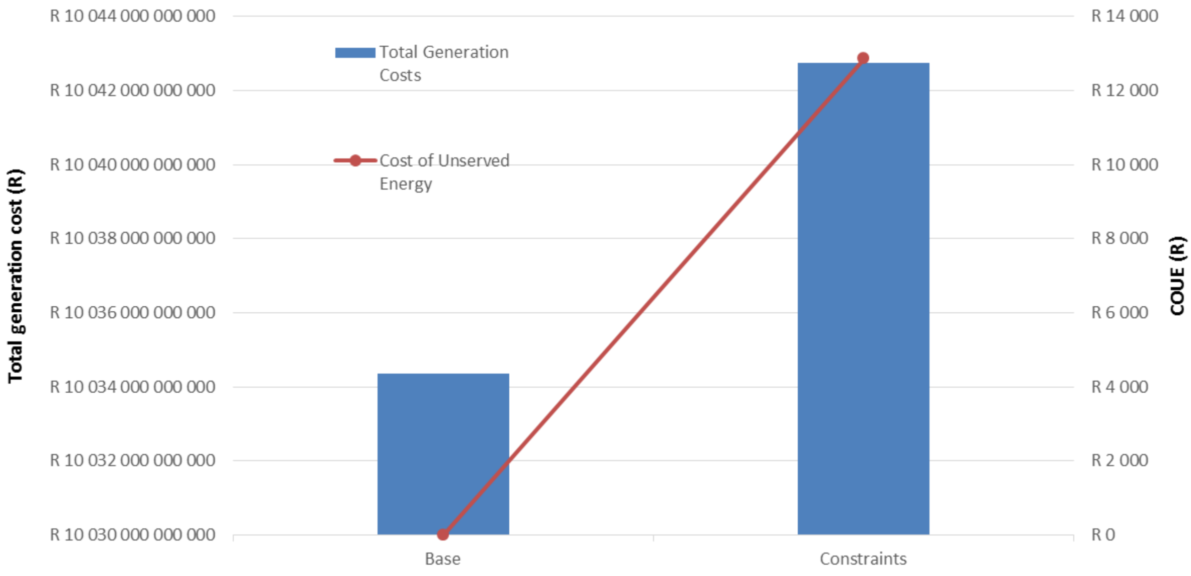


Figure 31 Total generation cost compared to the COUE for base and constraint cases

Figure 32 displays the capacity factors for all categories in each scenario. In the base case, nuclear, hydro and coal were not constrained and thus had near 100% values. However, in the constraints model when generators were constrained the CFs dropped to typical industry expected values. Renewables were within the levels of wind (30-40%), and solar PV (under 20%)(Electric Power Research Institute, 2010). Renewables' production profiles were identical in both cases; hence, there is no change from the overall 29% value for the CF. These renewable hourly production values were identical, as their underlying data did not change between the base and constraints case. Gas significantly increases from the base to constraints case. Since gas plants are flexible in ramping up and down to meet the changing demand. While thermal plants in the constraints case had imposed constraints (MSL and ramping rate limits).Furthermore, pumped storage capcity factor and corresponding usage increased in the constraints scenario.

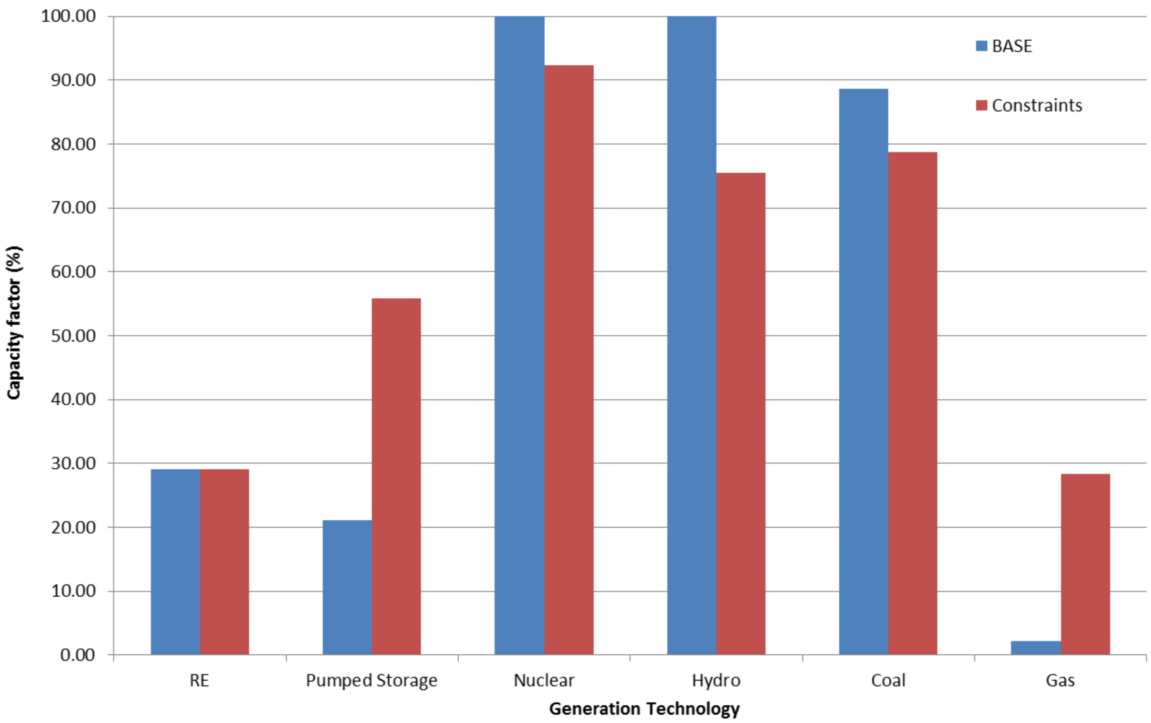


Figure 32 Categorized capacity factors for base and constraints scenarios

Each renewable generation technology has CF as indicated in Figure 32. CSP with its built in storage within the molten salts, showed the highest CF of 46%. Solar PV exhibited the lowest CF of approximately 18%. Thus, although renewables are clean energy they are highly variable, as their energy sources (solar and wind) drive this inherent variability. Therefore, by installed capacity (MW) a grid may have large penetration levels, but when the energy is examined the renewables will have a reduced contribution to the electricity supply. Utility solar PV would be in the best solar resourced areas, which explains the higher capacity factor for utility PV below. City PV projects would be in marginally less favourable yield areas.

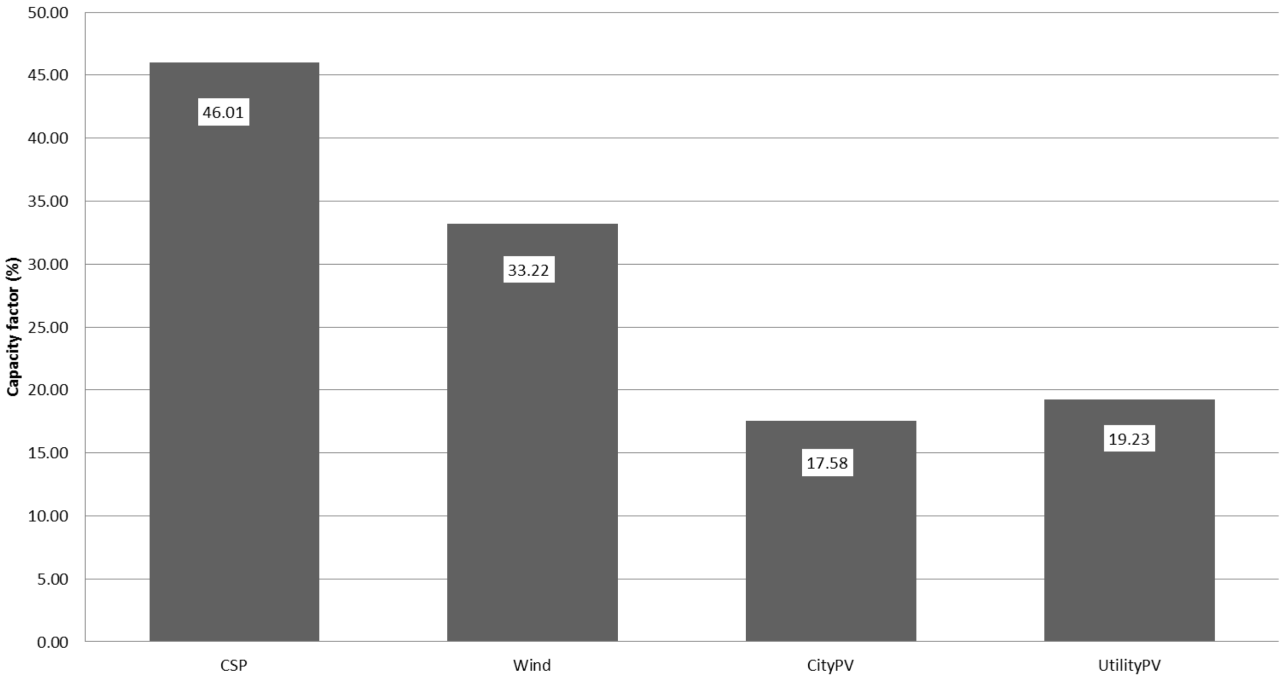


Figure 33 Renewables capacity factor for both scenarios

6.2 Performance by season

Typical household consumers of electricity in South Africa create a morning peak (around 5-8am) and a similar evening peak (around 5-7pm). In these times, household appliances such as stoves for cooking and geysers for boiling water are used. Then, between the evening and the morning peak, there is a dip in energy usage, not down to the minimum daily levels. However, the lowest points are from the evening peak through the night to the morning. Industrial customers (mines, smelters etc.) utilize substantial electricity, however, they often have dedicated transmission lines and would use power at times which suit their applications. Furthermore, industrial consumers have strategies for minimizing electricity usage; they may try to avoid high tariffs in peak times by shifting their usage to less expensive tariff periods, as one example. Their strategies would be relevant to their business model and electricity needs. Daily peaks and troughs are mirrored by seasonal peaks and troughs. In winter, there is greater need for heating of households, while summer this need for heating diminishes but can be replaced by a need for cooling of consumers' households. These above stated household and industrial consumers' usage patterns provides insight in the remainder of section 6.2. There are other factors when comparing load profiles between countries across the globe, however these will not be discussed.

In order to understand the system behaviour over time, a single week was selected which fell in the summer and winter months. The summer week was from the first to the sixth of January 2030, and the winter week was twelfth to eighteenth of July 2030. These weeks were the lowest demand in summer and the highest demand in winter, in order to represent the peaks and troughs for 2030. In the summer week, system demand would be in the lower ranges, and conversely in the winter week, the system demand would be at the highest range. The ensuing section conveys these trends.

Figure 34 depicts the generation plotted against the load profile, where the generation peaks at approximately 52GW and the demand reaches approximately 49GW. The difference between the generation and the demand is the energy supplied to the pumped storage plants. Water is pumped from the lower to the upper reservoirs when PS schemes are operating in storage mode. Similarly, in Figure 35 the daily peaks in the morning period and evening peak resembled the typical demand profiles of household consumers.

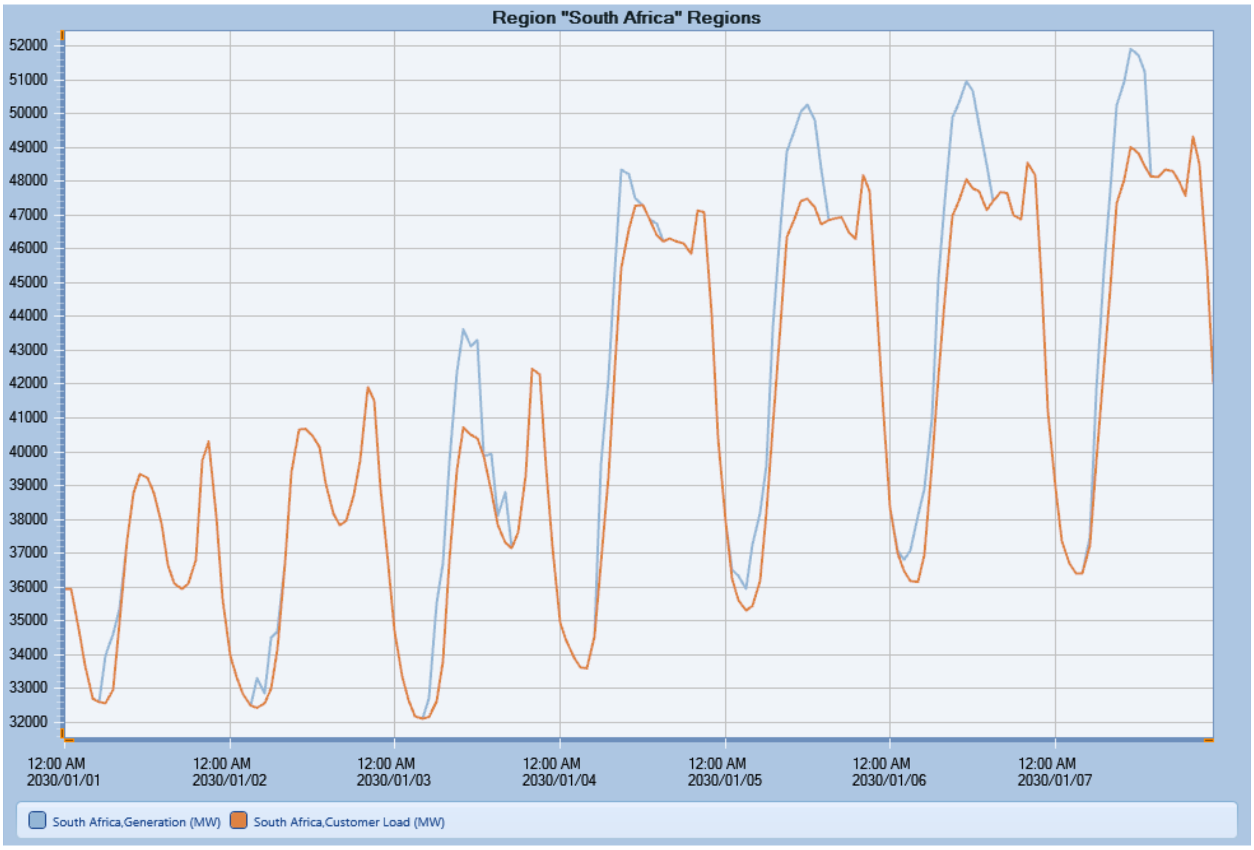


Figure 34 summer load versus generation profile

Figure 35 provides the results of the summer weekly generation dispatched to meet demand. The generation profiles in Figure 35 are unequal for each power plants category. For example, renewables and coal exhibit dissimilar dispatch profiles. Moreover, thermal base load plants showed a consistent production of energy, while their renewable counterparts showed more variation in their production levels. This dissimilar trend in profiles is common for dispatchable thermal plants when compared with their non-dispatchable renewable counterparts.

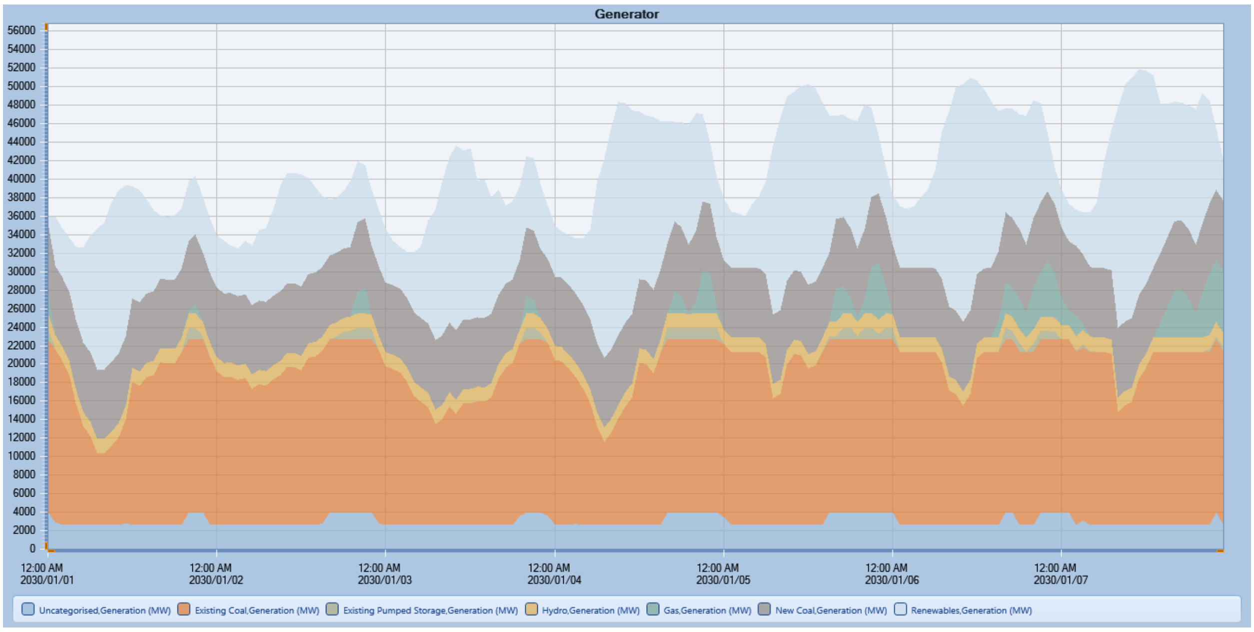


Figure 35 summer week Generation profile

Figure 36 was plotted to visualize the daily variation in solar and wind energy production. These profiles are typical of solar and wind plants. Solar PV peaks at midday and then drops to zero production in the night. CSP production was more dispatchable as it included thermal storage. Gauchés' (2015) renewable production profiles (CSP, PV and Wind) were used as inputs into the PLEXOS model. Thus, these renewable production profiles were identical to Gauché (2015). Wind follows a similar trend to solar PV generation. Total renewable production peaks at around 26GW on the last day of the week.

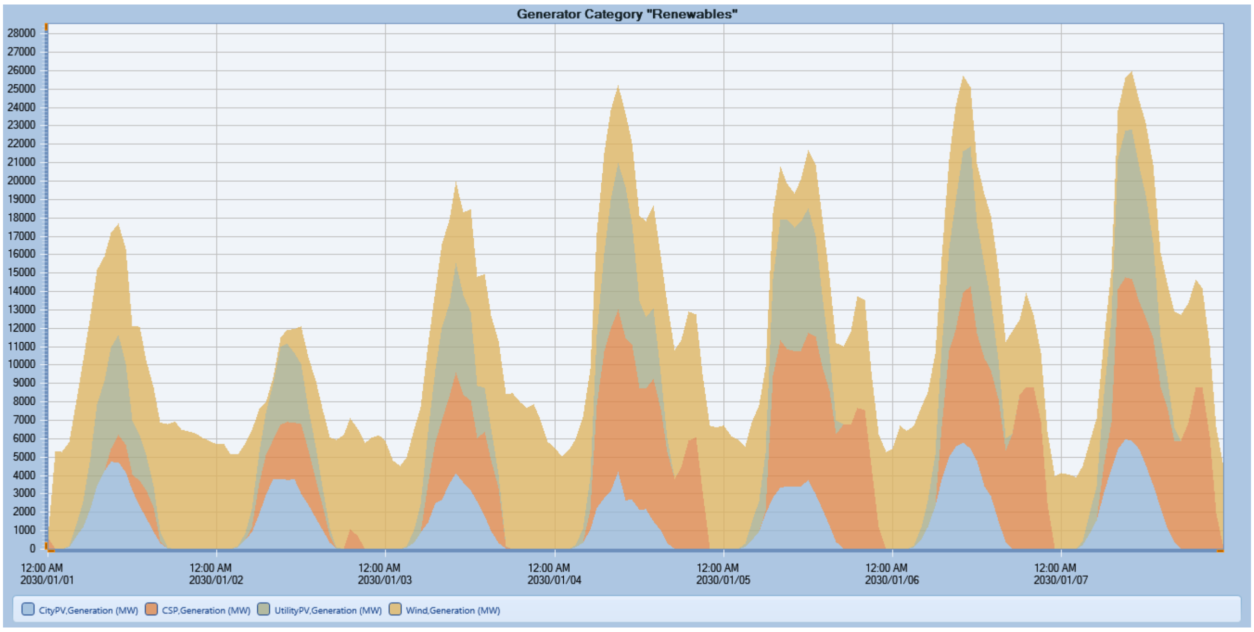


Figure 36 summer week renewables generation profile

The above analysis of the summer week was replicated for the winter week period. Figure 37depicts the demand plotted against the generation, and is similar to Figure 34. Demand increases in the colder months of winter to a peak of in the region of 60GW, while the peak generation is 57GW.The peak generation is higher than demand with this difference evidencing the energy supplied to the PS schemes. Again, in winter as in summer household consumers create daily peaks in both the morning and evening hours.

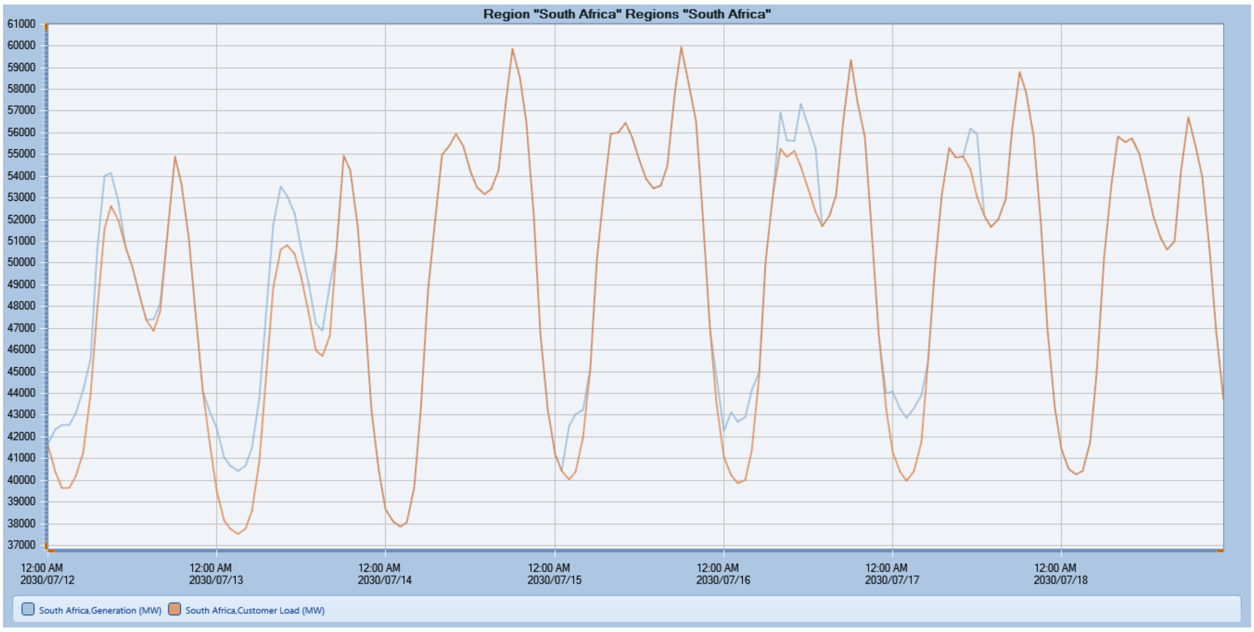


Figure 37 winter load versus generation profile

Figure 38 indicates the aggregated generation by category, and is an expanded view of the generation in the figure. Base load technologies provide a relatively constant production profile. However, renewables exhibited intermittency throughout the week according to the solar and wind resource fluctuations. These solar and wind profiles are stacked towards the top of Figure 38.

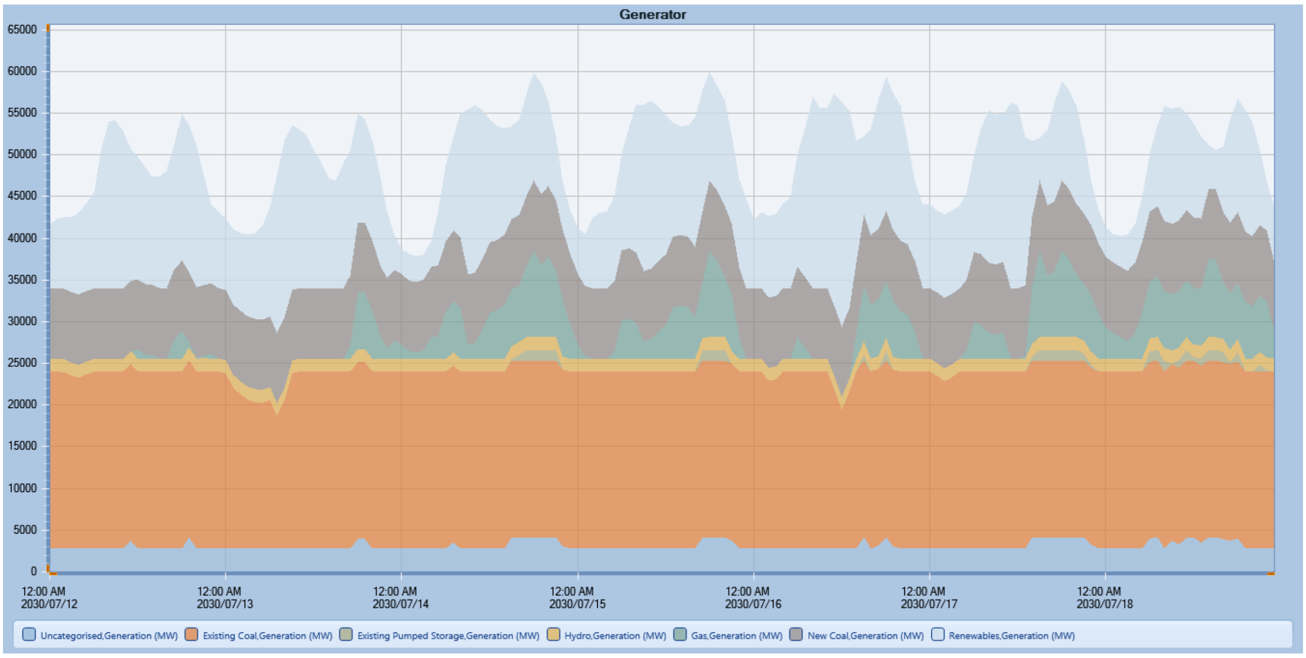


Figure 38 winter week generation profile

Furthermore, Figure 39 depicts the profiles of wind, solar PV and CSP. Wind production reveals the most sharply peaked profile, especially visible on 14th of July 2030. Whereas solar PV has a daily spike, but exhibits a smoother generation profile over the course of a day. Notably CSP has two daily peaks, which indicated the dispatchability of this technology. Dispatchability of CSP demonstrates that production was not solely dependent on the solar resource variation, but with molten salt storage, energy was released as and when the system requires it.

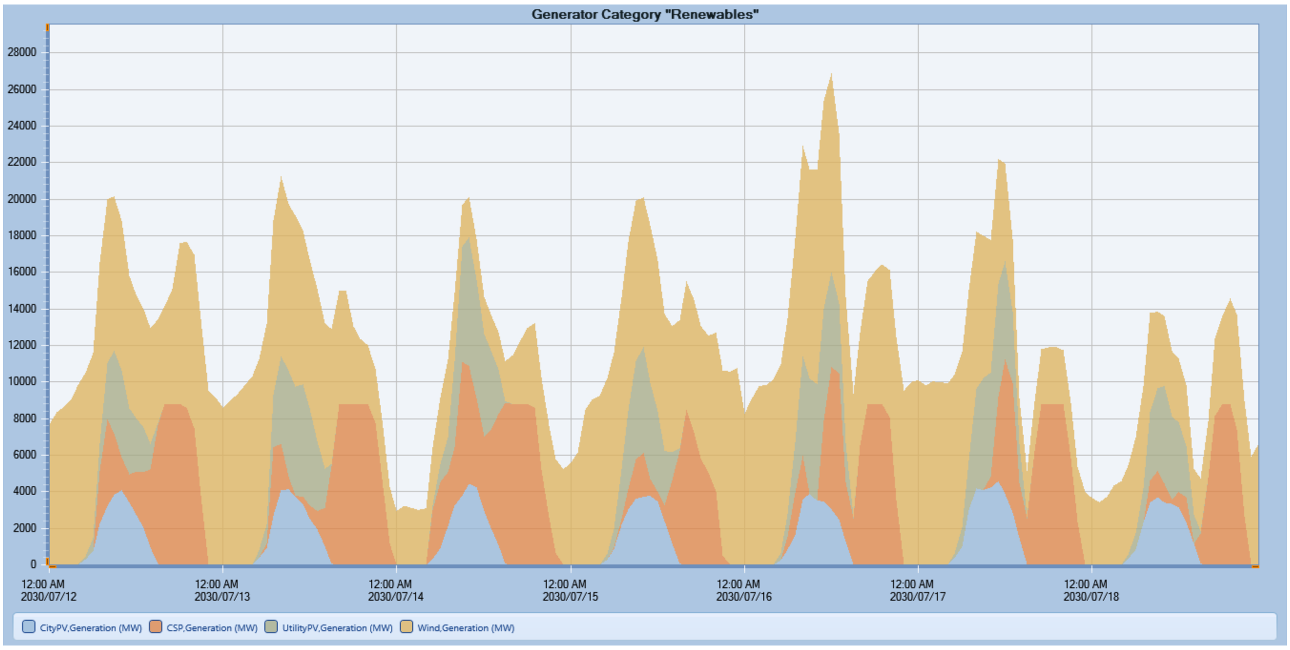


Figure 39 winter renewables generation profile

Figure 40 and Figure 41 assist in comprehending the change in flow of water in the pumped storage reservoirs. The tail and head reservoirs combined energy level remains constant. For example, the Drakensberg PS plants energy storage of 20GWh remains constant. However, in operating as an energy source, water flows between the head and tail reservoirs to dispatch the energy stored in the head reservoir. When operating in reverse the water is pumped back from the tail to the head storage reservoir. These modes of operation for Drakensberg, Palmiet and Ingula are visible in Figure 40 and Figure 41.

Higher variation in reservoir levels conveys greater winter usage of PS as compared to summer. This is consistent with increased demand in winter, which would require extra peaking generation from PS plants. The higher variation in the reservoir levels describes why the winter usage of pumped storage is greater than the summer season. Figure 40 and Figure 41 depict the PS reservoir levels.

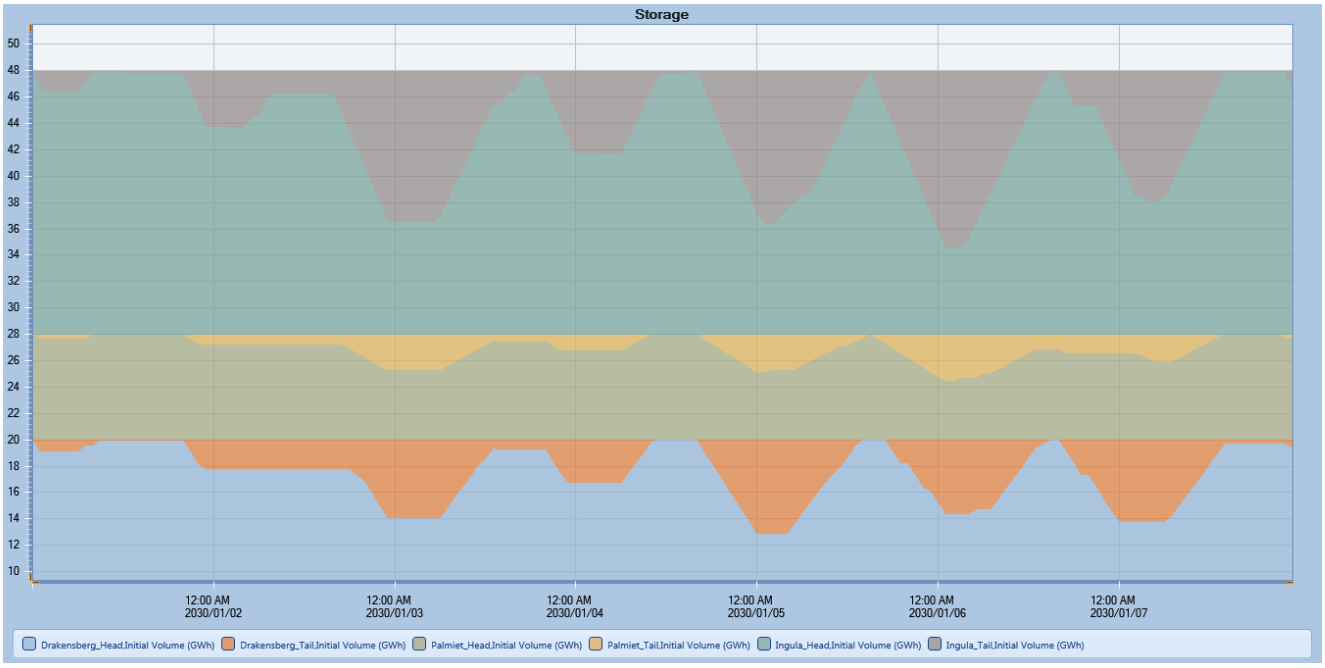


Figure 40 summer week initial reservoir storage MWh

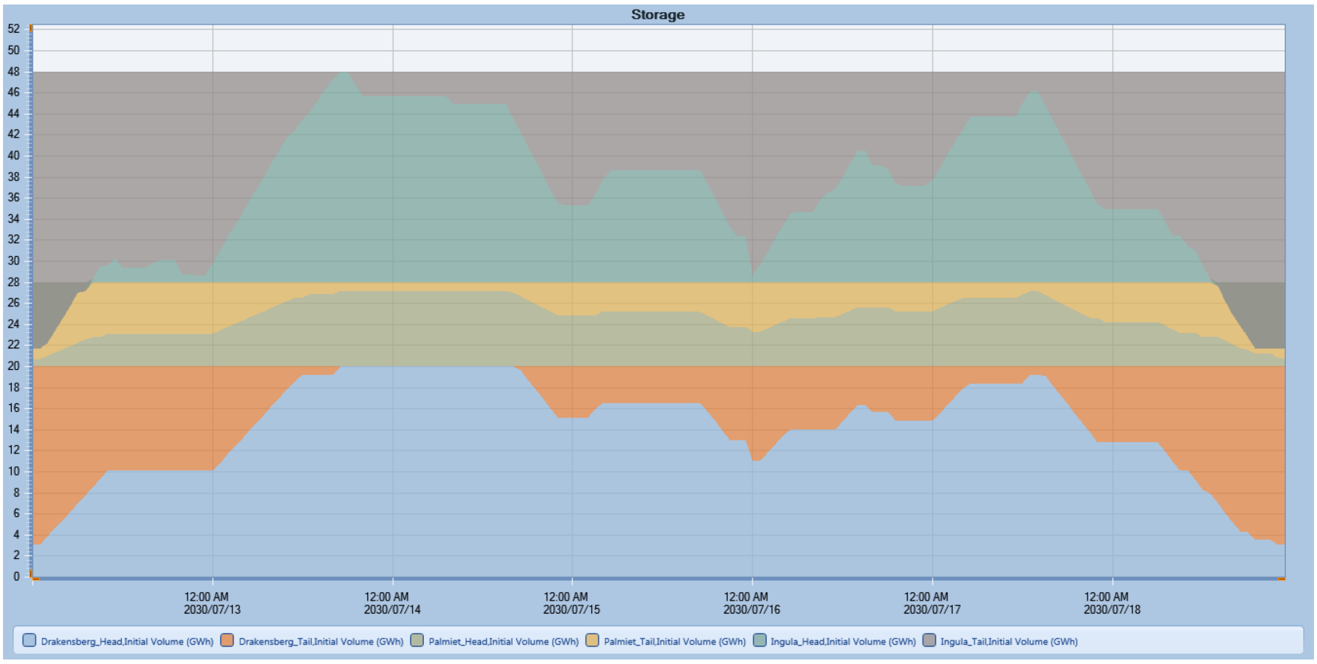


Figure 41 winter week initial reservoir storage MWh

Section 6.2 described the variation of the system between the peak winter and low summer cases for 2030. During summer, the demand dropped to a high value of 49GW and in winter demand increased to a high of 60GW. These values were discussed as typical morning and evening peaks for household consumers.

6.3 CAPEX and IDC costs

As deliberated in Section 5.2, for each generating technology the Capex and Interest were calculated by the researcher using excel. Figure 42 reveals the depictions of these results. Table 36 in section 7.1 presents the entire table. The correlation between the capex and capacities is a direct product of the two values. Thus, the red bars will change depending on the capacity and the capex costs of that technology. New nuclear was included in the analysis despite the zero commitment in the WWF high scenario.

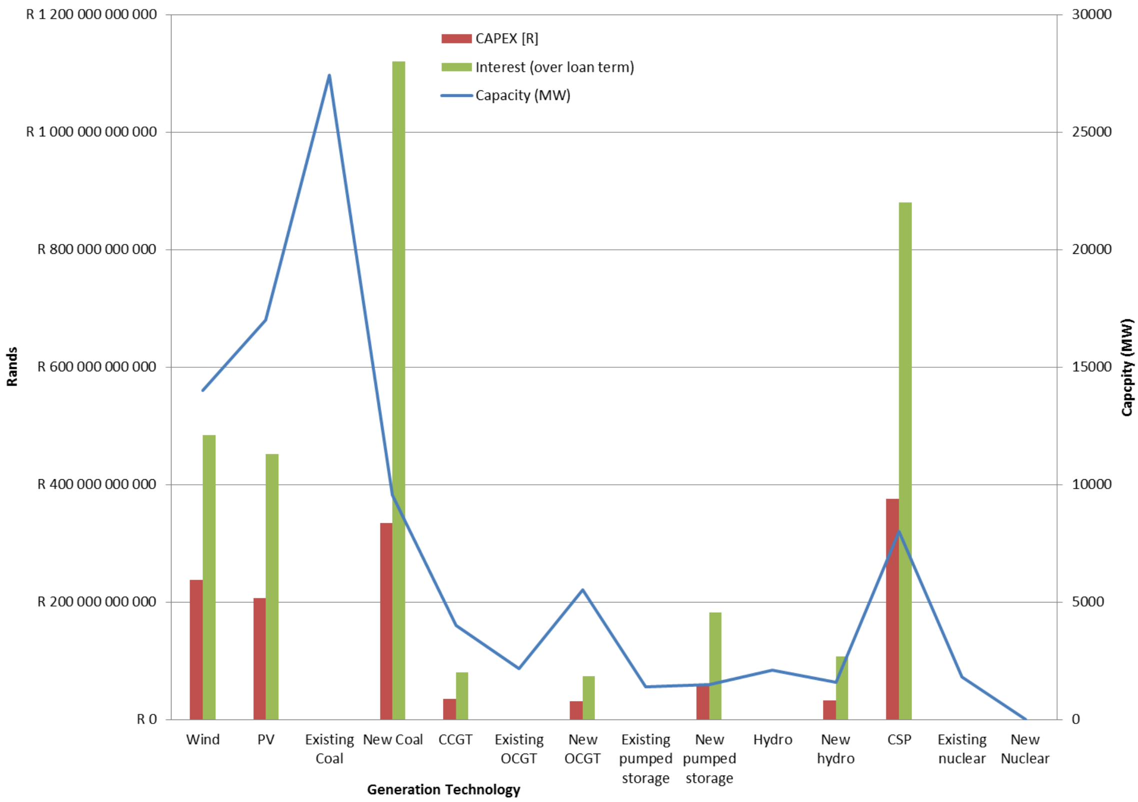


Figure 42 Capex, Interest and capacities for all generation technologies

There are significant differences in the interest over the lifespan of the plant, with nuclear and hydro plants having the longest lifespan of 60 years, and the smallest lifespan is 20 years for solar PV. Figure 43 plots the same interest and capex values as above, but now includes the lifespans of the plants. The difference in the ranges between the plants lifespans was significant and thus a minimum loan period of 20 years was assumed, which corresponds to the lifespan of PV plants. Then, an average loan term was computed using the minimum value of the interest period (20 years) and the plant life span in question. Computed results show significant interest accrued for the new coal and CSP plants which are typically more capital intensive (overnight costs) technologies. Whereas with wind and PV, despite there being large capacities on the grid, their corresponding capex and interest show less significant values than compared to non-renewable technologies. Wind and solar PV are thus deemed less capital intensive and the payback on the provided capex is less than typical thermal plants. The existing plants (coal, OCGT, nuclear, pumped storage and hydro) have no contributions to capex and interest as these were assumed to be paid off in year 2010 when the study commenced.

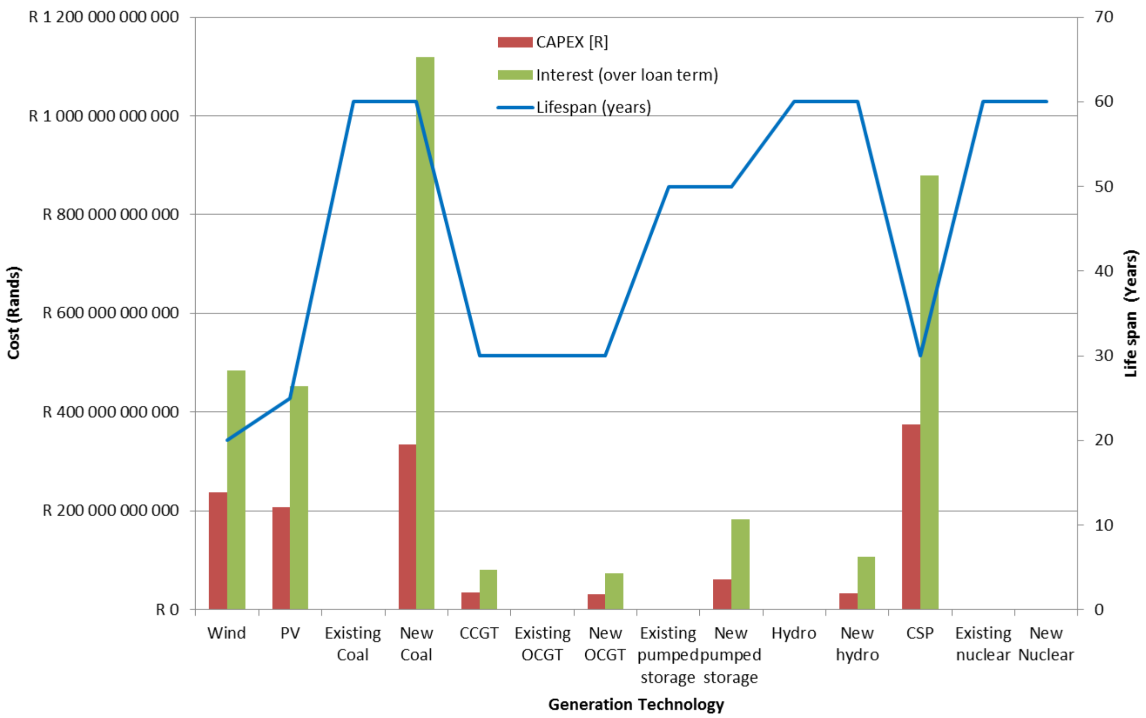


Figure 43 Capex, Interest and life spans for all generation technologies

Despite the above-mentioned differences for all the system and production costs, across the modelling scenarios the same capex and interest (finance) values were applied. Thus, these costs were uniform across the scenarios, whilst other generation costs varied according to each scenario. Generation costs vary because costs were determined by energy output, yet the capex were based on installed capacity.

The above section described the details of the CAPEX and Interest calculations for the model. These were conducted using the capex and capacity for each technology from Gauché, (2015b). The discount rate was 8% and for each generation technology and the lifespan over which debt was serviced was calculated.

6.4 Integration costs

Integration costs include two important elements not captured in the LCOE; these were CO_2 emissions and other notable integration costs. For further description of integration costs refer to the literature review in Chapter 2.

6.4.1 Emissions

Figure 44 displays the production of emissions for the two cases in the year 2030, which shows the power plant categories tabled below the graph. Between the base and constraint scenarios, the new coal and existing coal categories both exhibited a drop in the emissions of CO_2. This drop in generation for these two categories would cause a subsequent drop in emissions for both scenarios. The generators were limited from producing at maximum availabilities (100% in base case) because of imposed plant constraints. Ramping constraints (from zero to maximum load and back to zero) was one of the applied constraints. Therefore, for the gas category, these technologies were more flexible in dealing with demand changes. However, gas plants were also more expensive to dispatch as they exhibited higher SRMCs than coal. Demand was satisfied by gas plants albeit it at a higher cost and thereby produced more CO_2 in the constraints case. Overall, the change in production drops from 269 million to approximately 256 million tonnes CO_2 between the base and constraints case.

Gas plants production rates of CO_2 were lower than their coal power plant (new and existing) counterparts. Nevertheless, gas is more expensive than coal to dispatch and run. Thus, there is a trade-off from the system operator's perspective when considering cost minimization. Total generation costs were affected when emissions costs were included and should be examined further.

In order to calculate the cost of these CO_2 emissions, the value of R48/tonne (Chapter 5, section 5.1.4) was applied to the production model tonnes. Figure 44 describes the resulting costs for each scenario. These total costs drop from the base case to the constraints case. Since gas production increased in the constraints case, CO_2 emissions should decrease. The reason for lower CO_2 emissions is that gas relative to coal produces less CO_2 per MWh of electricity. The final values for the cases have a difference of R344 million.

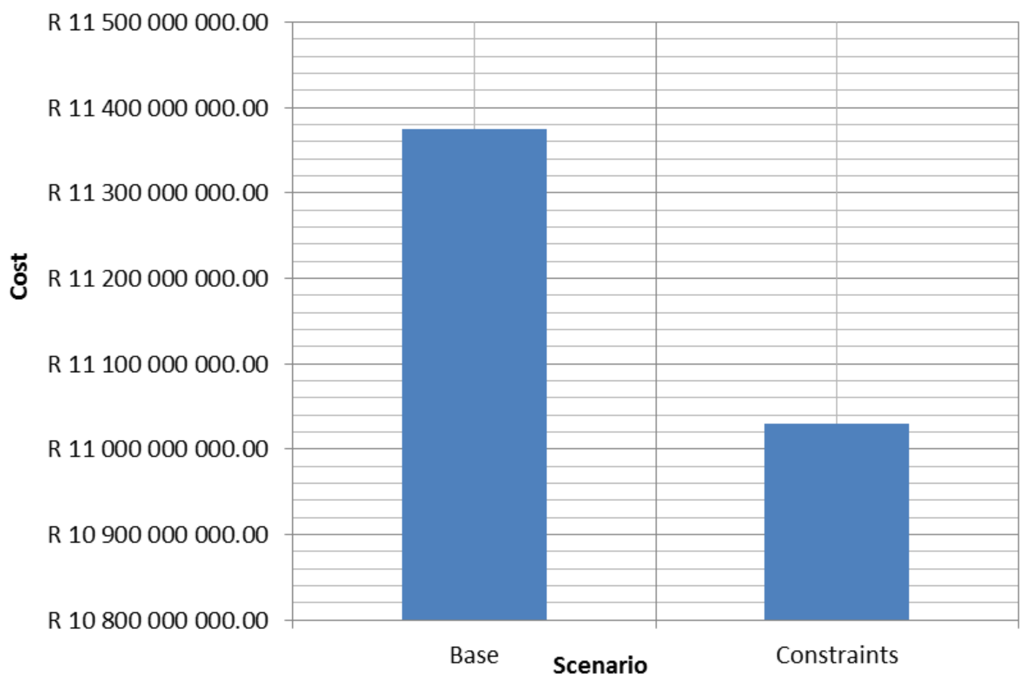
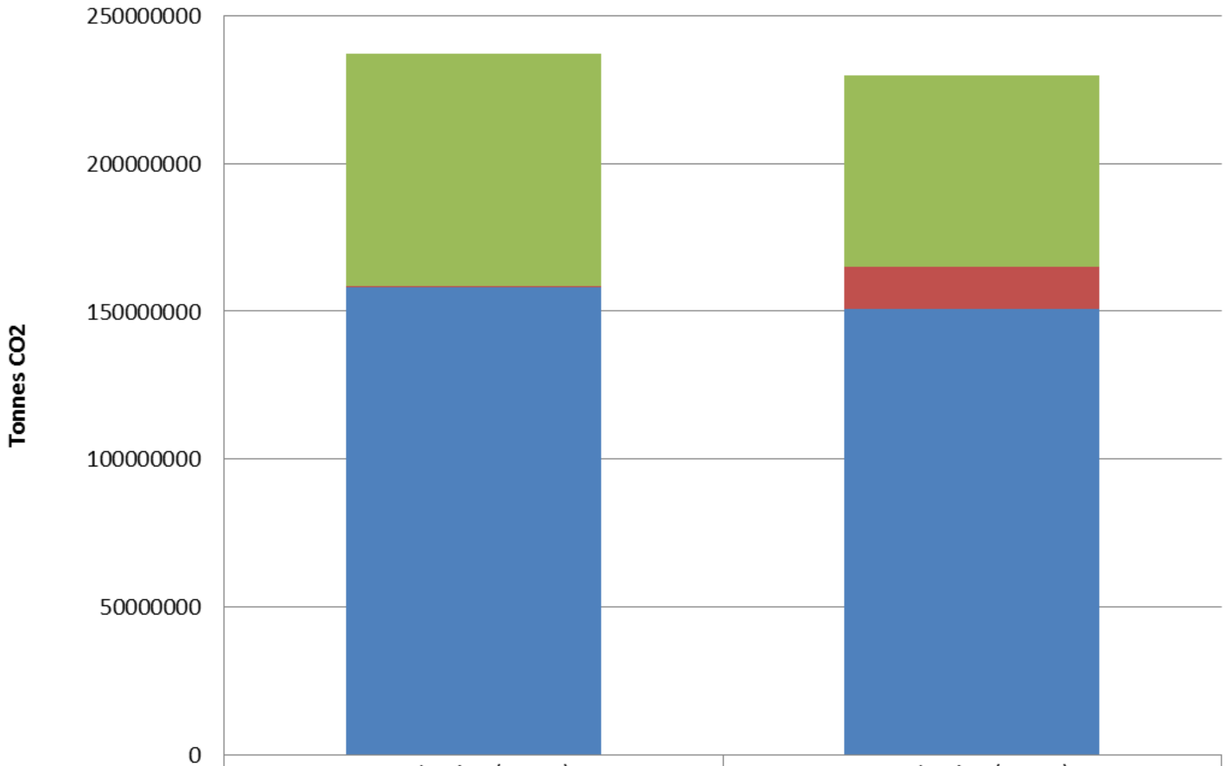


Figure 44 Emissions costs per scenario



	Production (tonne) Base	Production (tonne) Constraints
CO2_NewCoal	78435435	64715466
CO2_Gas	534117	14183969
CO2_ExistingCoal	157996044	150894828

Figure 45 Tonnes CO_2 for each scenario

If included in the system costs, emissions would drastically increase the system costs, since these costs are in the same range as the total system costs.

Emissions quantities and subsequent costs were presented above. Gas, new coal and existing coal plants were the three emitters of CO_2.

6.4.2 Other integration elements

Figure 46 displays two useful integration components (externalities). The total unit shutdowns and start-ups are stacked to see the combined effects. For a clearer depiction, Figure 46 displays the water consumption in the scatter points. Design and construction should consider plants with suitable access to a water source or long-term agreements with municipalities or water boards. Therefore, costing could potentially not be a significant component relative to other generation costs. However, in areas with scarce water resources, such as Limpopo Province where Medupi and Matimba coal fired power plants are located, it may be a significant issue. While nuclear requires substantial water quantities, as depicted in

Figure 47, it is a special case, as many nuclear plants are positioned on the coast near seawater. These plants, such as Koeberg use the seawater for cooling and recycle this water back to the sea.

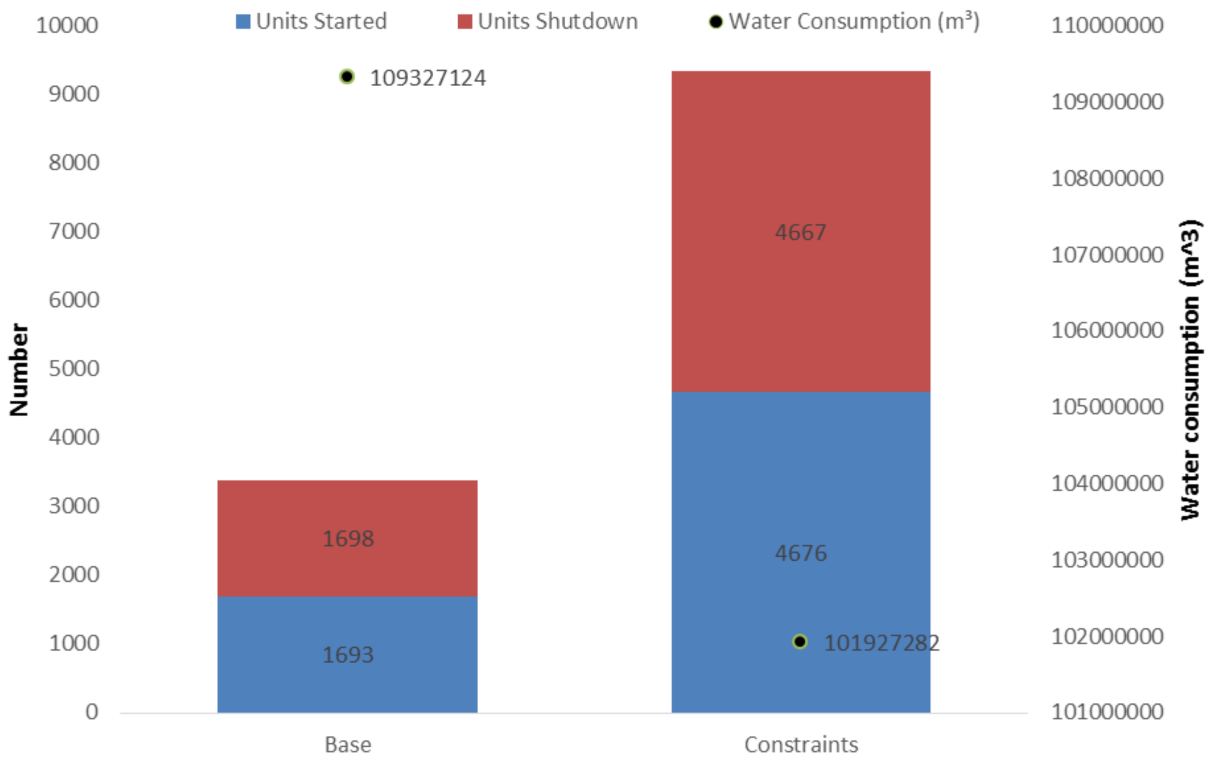


Figure 46 Total units started and shutdown and water consumption for base and constraints

Figure 47 depicts the generators start-ups and shutdowns in the bar graph and then overlays the water consumption in the line graph. Renewables have a relatively high number of start-ups and shut-downs, corroborating their variability. However, the renewables start-ups and shutdowns are in the same range as existing coal plants. Water usage is dominated by Koeberg, close to 90 million m^3. This number is significant, but it was mentioned above that Koeberg is placed adjacent to the ocean, and utilizes seawater as part of the plants cooling. CSP is second to Koeberg in water requirements, as this is a renewable-thermal hybrid plant with a turbine block and solar thermal storage system. Thus, it would have substantial cooling requirements as it essentially stores energy in the molten salts. The rest of the plants use small quantities of water compared to nuclear and CSP. Of all the renewables, wind has the lowest unit start-ups and shutdowns; reference is made to Table 41 in Appendix.

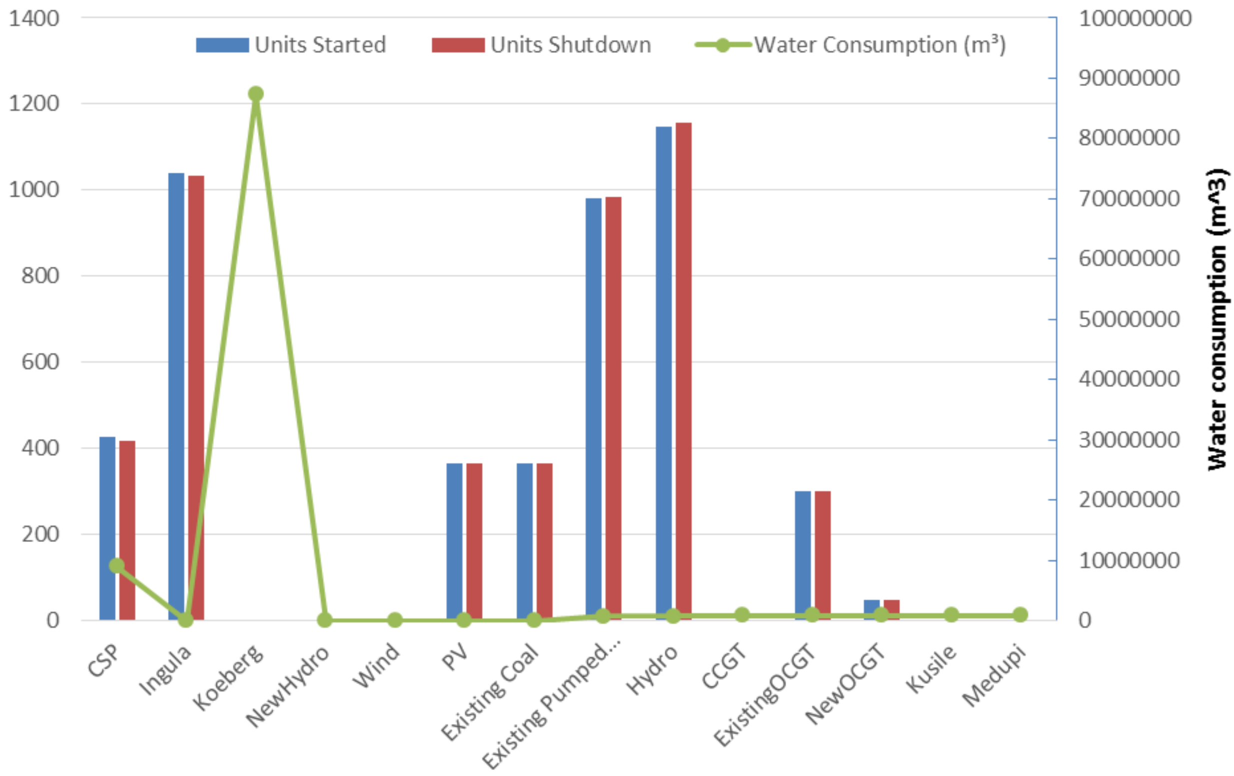
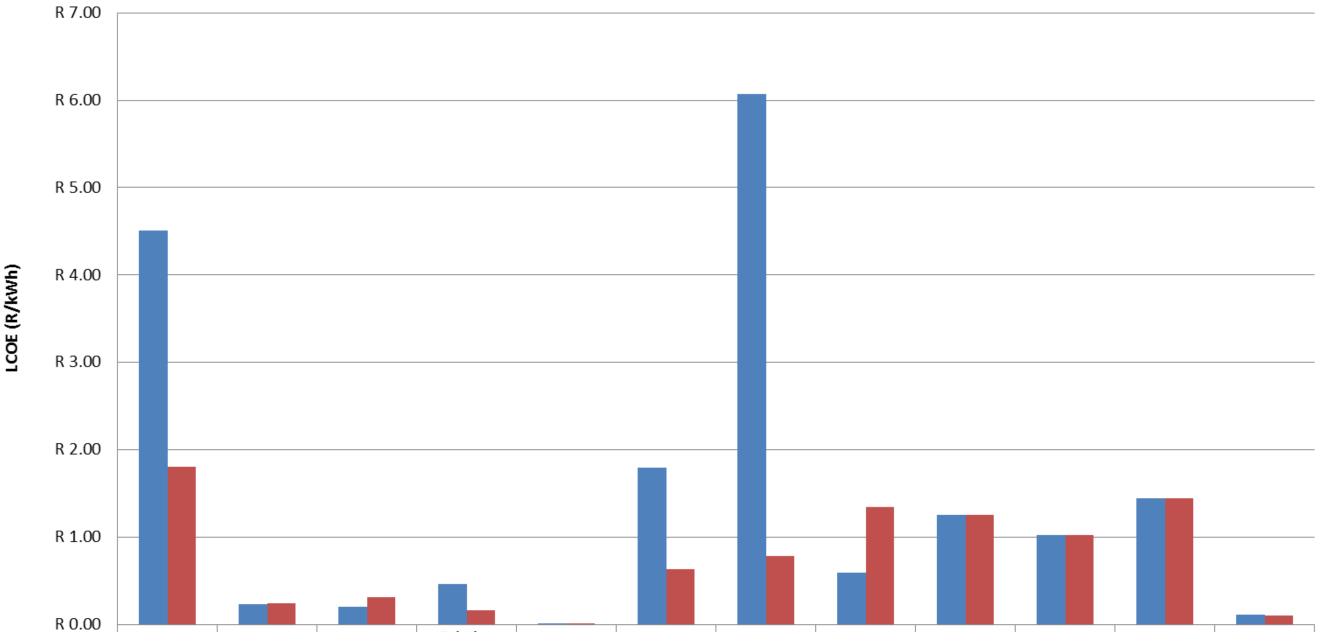


Figure 47 Units started and shutdown, and water consumption for constraints case

This section presented the integration elements, including the costs of emissions for the scenarios. Furthermore, the section quantified generator start-ups, unit shutdowns, and water consumption.

6.5 LCOEs for each technology

The analysis using the values obtained from PLEXOS for the constraint case calculated LCOEs for each technology. Figure 49 depicts the LCOEs ranked from largest to the smallest. The values for existing generation technologies are lower due to their capex and interest values being zero. CSP, wind and PV have high LCOEs as they were capital intensive (in 2010) and they have a lower capacity factor. Thus, renewables produce less energy than their thermal counterparts do.



	Ingula	Koeberg	NewHydro	Existing Pumped Storage	Existing Hydro	ExistingOCGT	NewOCGT	New Coal	PV	Wind	CSP	Existing Coal
Base	R 4.51	R 0.24	R 0.21	R 0.46	R 0.0045	R 1.79	R 6.07	R 0.60	R 1.25	R 1.02	R 1.44	R 0.12
Constraints	R 1.80	R 0.25	R 0.31	R 0.17	R 0.0061	R 0.63	R 0.78	R 1.35	R 1.25	R 1.02	R 1.44	R 0.11

Figure 48 LCOE comparison of base and constraints case

Figure 49 depicts the constraints LCOEs which were sorted from largest to smallest for ease of viewing. The most expensive options are renewables, which have high LCOE's. Then, the existing plant (pumped storage, coal, hydro and gas) are cheap as the capex is mostly been paid off. For lowest system cost operation these existing technologies should be utilized.

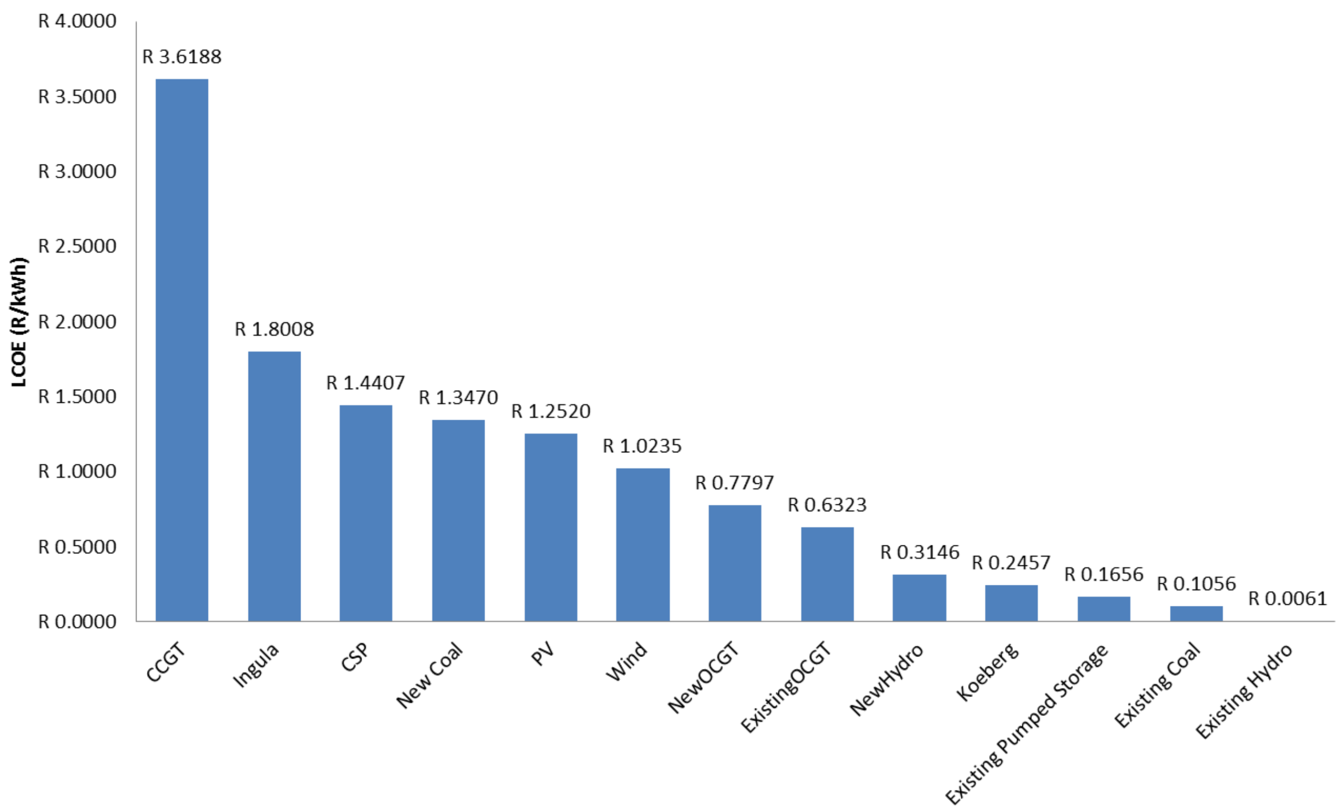


Figure 49 LCOE for constraints case

This trend is in line with Lazard (Lazard, 2014; Lazard Ltd, 2015) and other estimates for costs. Later LCOEs have been presented by the REIPPPP bidding rounds in Section 1 Figure 4. However, learning curves and subsequent drops in LCOE's over time is difficult to predict.

6.6 Sensitivity analysis

The subsequent analysis was conducted to understand the sensitivity of the model to changes in input parameters. Three of the critical parameters were fuel price, availability of the generators, and the demand placed on the system. Their impact on the generation capacity factor, overall variable costs, and system cost will be presented. Additional costs, such as O&M were fixed costs, and do not require simulation to determine their cost impacts on the model. Refer to section 5.1.3For further motivation of the variables chosen.

Table 34 Sensitivity analysis parameter descriptions

Fuel Price	Fuel price was changed between the upper and lower limits (Table 4) and models run with these fuel prices.
Availability_80% and Availability_70%	Assumed availability was as in WWF report (Gauché, 2015a), However, in future Eskom has decided to target 80% availability for their fleet. In addition, in recent years, the fleet availability has decreased, so 70% availability of Eskom generators was accounted for. Thus, 2 cases were run in PLEXOS.
Demand change	Demand has been seen to change over time, as noted in Section 6.2, Chapter 4. Thus, the WWF Low demand data was inputted in an attempt to see the impact on the model outputs.
RE Profiles	Lastly, the renewable energy profiles were provided by (Gauché, 2015a). However, the notion of an increase in solar and wind resources by 10% was input into the model. Thus, outputs of the solar and wind plants production were at 110% of the original profiles.

Figure 50 conveys the change in capacity factor over the varied input parameters. Capacity factors show how the relative percentage of actual energy produced to ideal energy production. There is little variation between fuel (upper and lower), high availability, and increased renewable production cases. These are near 45%. In the increased renewable case, CF drops to around 44.4%, as the rest of the fleet would compensate for this increased share of variable renewables. Finally, and most evident, is the drop in availability of the low demand case to 39%. In this case, the WWF high data input replaced the WWF low data. This drop in CF indicates the lower utilization of the available fleet of generators and would indicate that there is probably a superior reserve margin but potentially an oversupply of generation.

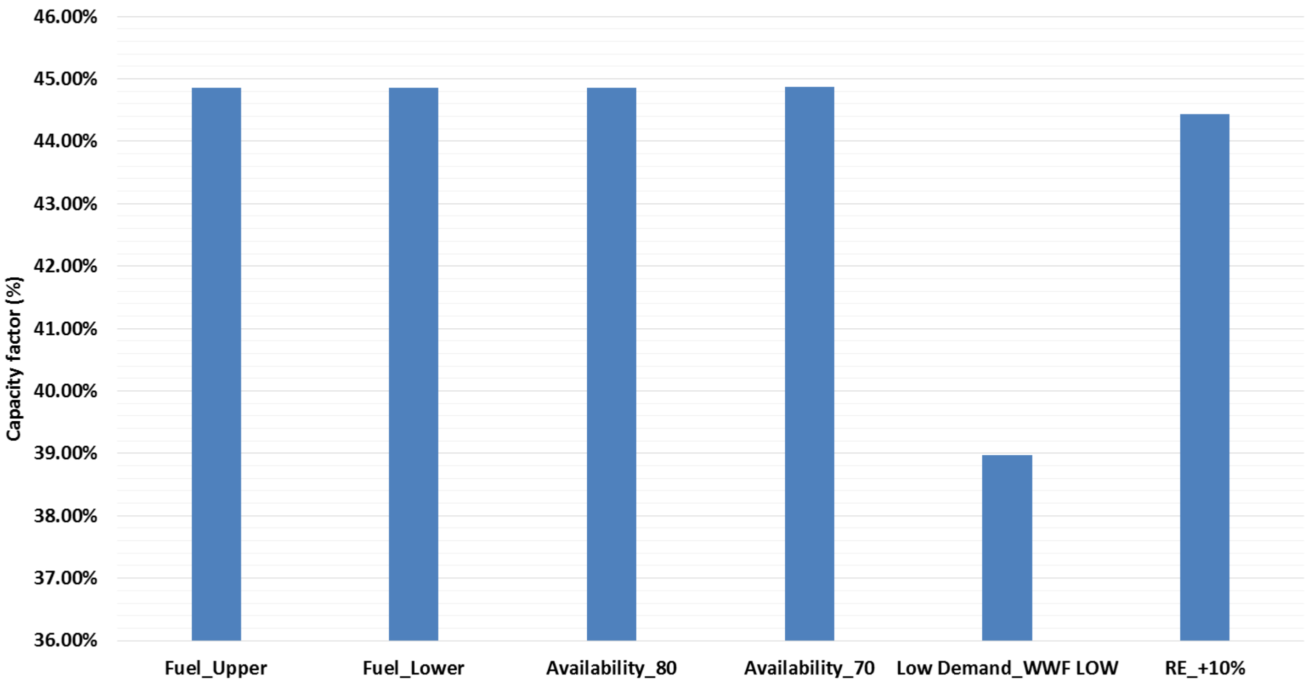


Figure 50 CF for each sensitivity case

Figure 51 compares the generation costs and does not include fixed costs since they do not vary according to the output generation. The remaining costs include variable O&M and fuel costs. When the fuel price was lowered, the resulting costs also dropped. However, the most substantial drop was for the low demand case (WWF low demand). Table 45 in Appendix B captured the complete sensitivity analysis results.

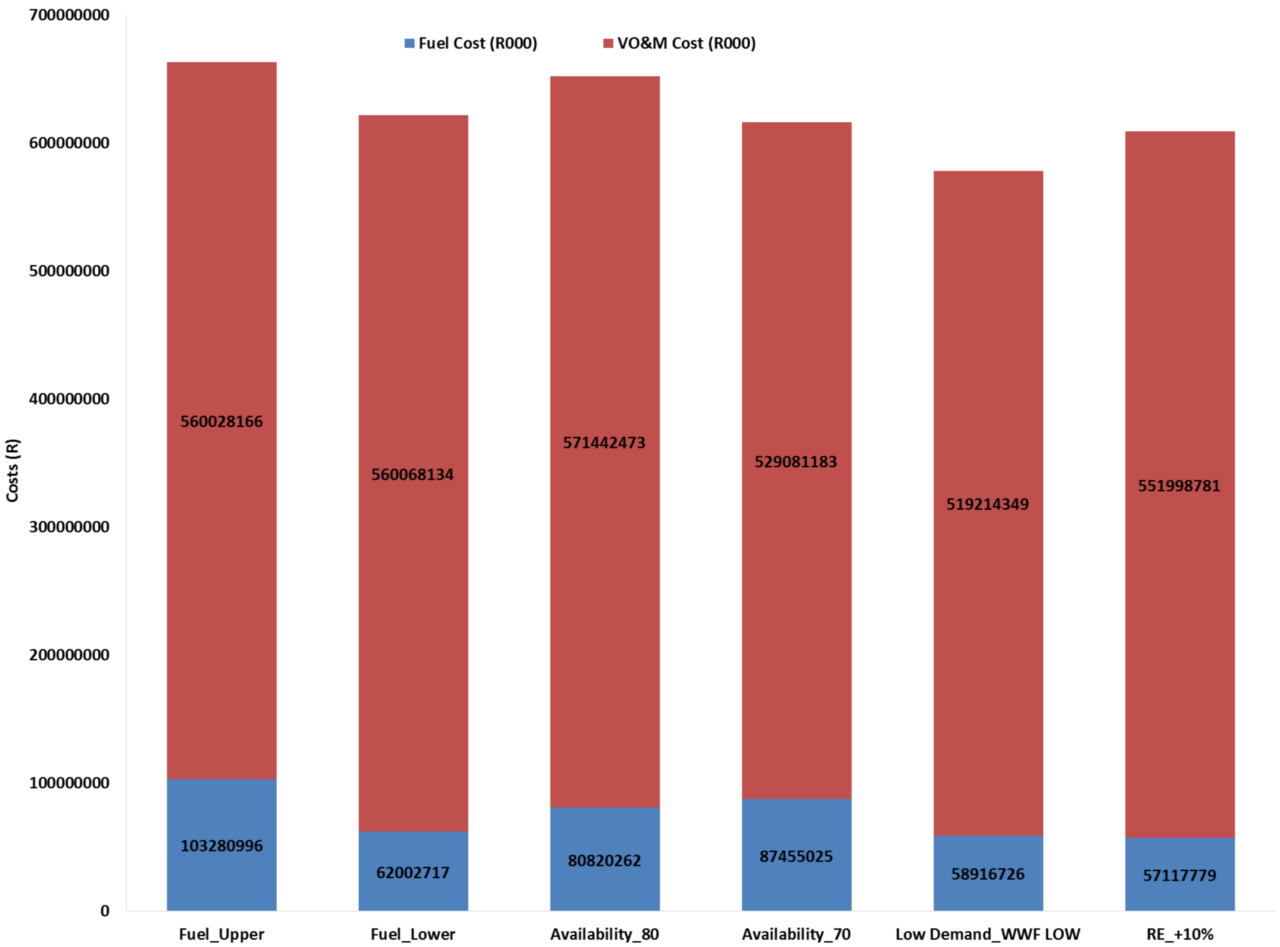


Figure 51 Cost summary for each sensitivity case

Figure 52 shows the system costs of all six sensitivities and the constraints costs. Notably, Figure 52 depicts the percentage of the sensitivity scenarios relative to the constraint scenario. Thus for the constraints scenario, the value is 100%. This result shows the impact of the sensitivities relative to the constraints scenario. The demand change from WWF high to WWF low had the greatest impact on system cost. Furthermore, the low availability scenario contributed to raising the system cost to R0.522.

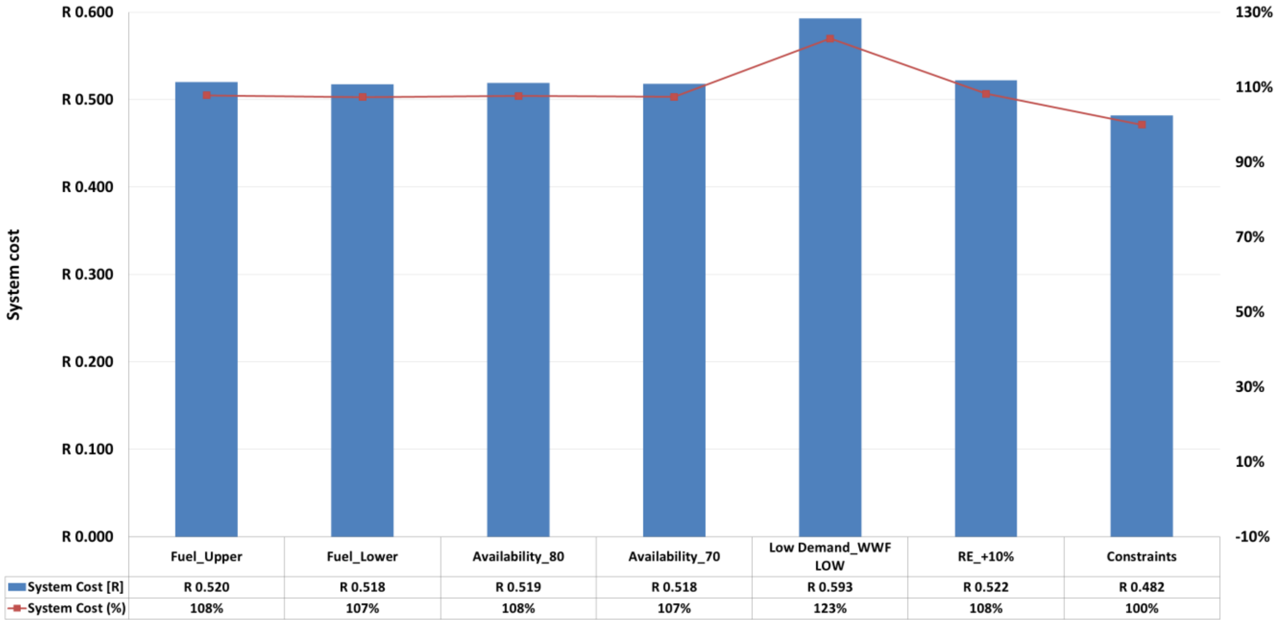


Figure 52 System Cost for all sensitivity scenarios

In closing, the sensitivity analysis changed four variables (fuel price, generator availability, system demand and renewable energy production) to ascertain the impact on the PLEXOS models outputs. Demand drop from WWF high to WWF low has the largest impact on the system cost, increasing the system cost to R0.593 from the constraint scenario value. Next, the increase in renewable production was the second largest contributor to increasing the system cost to R0.522.

6.7 Summary of WWF High results and discussion/Conclusion

The results for the WWF high model from the PLEXOS simulations were the thrust of this chapter. First, the generation costs were scrutinized. Then the daily and seasonal performances were inspected. Capex and interest costs were dependent upon the financial parameters and the installed capacity. Then, integration costs including each generators CO_2 emissions, water consumption and start-ups and shutdowns were quantified. Finally, a sensitivity analysis on the fuel costs, demand profile, and increased renewable energy production was performed to examine the change on the model outputs.

7 Conclusions and looking to the future

This chapter presented and discussed the results from the PLEXOS model of the WWF High electricity generation scenario. The model sought to understand the system costs of integrating more renewables into the electricity network. Hourly simulations were run for the year 2030 under a base scenario and then constrained generator scenario. The model captured capex, interest, opex and emissions costs. In addition, generator availabilities demand drops, fuel price and increased renewable production were the four-sensitivity analysis included in the model.

7.1 Summary of key findings

Consumer behaviour was the primary driver in the variation of electricity demand. The daily peaks, morning (6-9pm) and evening (5-8pm) were typical expected profiles. Thus, the spikes in energy over time were in the morning and evening. Furthermore, summer and winter trends were seen. In winter more energy was used by consumers, with a high week of 12th to the 18th July 2030 being scrutinized. In addition, the lowest summer week of 1st to 6th January 2030 was examined.

Table 35 conveys the summary of the base and constraints scenarios. This table captured both the costs and the generated energy. Dividing the total cost by the total energy, results in the system cost of R0.4007 and R0.5392 for the base and constraint scenarios respectively.

Table 35 Summary of two scenarios costs and energy output

	Base	Constraints
Generation costs	R 8,446,501,950,833.34	R 9,085,130,180,911.85
Capex	R 1,312,580,875,278	
Finance	R 3,380,036,647,300	
Total Cost	R 10 034 359 883 684.80	R 10 042 746 153 571.70
GWh	406174.93	409819.08
System cost	R 0.3907	R 0.4822

Table 36 presents the summary of the capex for a given capacity. Furthermore, the table expresses the interest over the plants lifespan.

Table 36 Capex and Interest summary

Type	Capacity (MW)	Average Capex (R/kW)	CAPEX [R]	Lifespan	Interest (over loan term)
Wind	14000	R 16 982.50	R 237 755 000 000.00	20	R 484 317 438 174.96
PV	17000	R 12 162.50	R 206 762 500 000.00	25	R 452 212 720 456.54
Existing Coal	27430	R 34 916.00	R 0.00	60	R 0.00
New Coal	9560	R 34 916.00	R 333 796 960 000.00	60	R 1 119 690 678 960.18
CCGT	4000	R 8 616.00	R 34 464 000 000.00	30	R 80 713 636 031.18
Existing OCGT	2175	R 5 676.50	R 0.00	30	R 0.00
New OCGT	5505	R 5 676.50	R 31 249 132 500.00	30	R 73 184 514 475.83
Existing pumped storage	1400	R 40 409.50	R 0.00	50	R 0.00
New pumped storage	1500	R 40 409.50	R 60 614 250 000.00	50	R 182 031 518 511.40
Hydro	2100	R 0.00	R 0.00	60	R 0.00
New hydro	1590	R 20 192.50	R 32 106 075 000.00	60	R 107 696 825 386.00
CSP	8000	R 46 979.12	R 375 832 957 778.28	30	R 880 189 315 303.97
Existing nuclear	1800	R 73 877.00	R 0.00	60	R 0.00
New Nuclear	0	R 73 877.00	R 0.00	60	R 0.00
Total	96060		R 1 312 580 875 278.28		R 3 380 036 647 300.05

Integration elements including unit startups and shutdown, and water consumption were quantified. Emissions of CO_2 were quantified in cost terms for each scenario using a value of R75/tonne of CO

Table 37 shows the LCOE values for the respective generation technologies for the base and constraints scenarios.

Table 37 LCOEs for each generation technology

	Constraints
Ingula	R 1.80
Koeberg	R 0.25
NewHydro	R 0.31
Existing Pumped Storage	R 0.17
Existing Hydro	R 0.0061
ExistingOCGT	R 0.63
NewOCGT	R 0.78
New Coal	R 1.35
PV	R 1.25
Wind	R 1.02
CSP	R 1.44
Existing Coal	R 0.11
CCGT	R 3.62

A sensitivity analysis was performed on the following input parameters: fuel prices, generator availabilities, and demand forecast. The results showed the most sensitive parameter was the demand forecast, as this had the largest impact on the system costs. Table 38 presents a summary of the outputs from the sensitivity analysis.

Table 38 Summary of sensitivity analysis results

Scenario	Generation (GWh)	Capacity Factor (%)	System Cost [R]	System Cost [R]
Fuel_Upper	377495.8479	46.20%	R 0.520	R 0.520
Fuel_Lower	377509.6195	46.20%	R 0.518	R 0.518
Availability_80	377468.8254	46.24%	R 0.519	R 0.519
Availability_70	377610.5928	45.41%	R 0.518	R 0.518
Low Demand_WWF LOW	327954.7796	41.00%	R 0.593	R 0.593
RE_+10%	373946.0280	46.09%	R 0.522	R 0.522
Constraints	406174.9263	48.97%	R 0.482	R 0.482

This section presented the summary of the key findings, namely generation costs, production outputs, and other key costs. It reflected the key model outcomes, which were expanded in Chapter 6.

7.2 Conclusions

The completed research answered the question of integration of renewable energy technologies in future energy scenarios. The penetration levels of RE were 25% by energy per year, and in power terms 41%. In addition, the LCOE of all the generation technologies were ascertained. Results were obtained by following a bottom-up simulation model in PLEXOS for the year 2030. In this model, a number of scenarios were run, first a base case, with no constraints on the generators. Then, the constraints scenario was run, whereby the ramping rates, minimum stable load levels, and other constraints were included.

The system cost from a constraints case containing constraints on the generators (R0.48/kWh) raised the cost from a base scenario (R0.39/kWh). The value of the rise in system cost from base to constraints scenario was R0.09 R/kWh. The LCOE for each technology was found to be within the range of typical industry standard values.

In the sensitivity analysis, the generation fuel costs, system demand drop, and increase in renewable energy productions were varied. A demand drop has the largest impact on the system cost, followed by higher renewable energy production.

Thus, the integration costs were calculated and these system costs were significant for levels of renewable penetration of 15%. The second objective of providing the LCOE for the technologies showed a range of answers from a number of scenarios simulated.

7.3 Recommendations for future work

The following assumptions were made and could provide areas for future work:

- Including more detailed levels of transmission and distribution network, using sectors or specific load centers. These models would be multi-nodal or at least regional.
- Including maintenance events and more generator details, such as outages, planned and unplanned failures and a level of commissioning.
- Renewable energy production using solar and wind data should be further investigated. This study used data from WWF model, where it was assumed the modeling method was suitable in converting solar and wind data into output of CSP, Wind and PV plants.
- Updated costing (Capex, Opex and Interest) should be identified and included in these models.
- WWF high and low projections were the demand cases used. However, these are merely industry projections of growth in energy demand.
- Issues such as embedded generation, and more localized and smaller generation scale (Munics. and small scale REIPPP) should be added in where possible. The iteration of these generators cannot be omitted to encompass integration costs going forward.
- The impact of water, cycling of the current baseload fleet and other integration costs needs to be investigated. Separate studies could be conducted to understand the impact on cycling of plant and degradation therein.
- The generators should be modeled in more detail. Including issues such as different types of PV, CSP and wind (offshore and onshore).
- Financial parameters such as discount rate, inflation and time value of money need to be examined and decided upon based on further investigation.
- Emissions costs were not included in the dispatching of units and subsequent cost of energy. Rather, the cost was accounted for after the simulation was run. This should be analyzed going forward as it was out of scope for this study.

7.4 Model limitations and challenges

PLEXOS was a useful tool in the research, and its full functionality was not used. Researchers and companies around the world make use of this tool. However, non-academic licenses are expensive and hence the need must be clearly motivated. Having access to the tool through purchasing a license is one step, while the skills required to model in PLEXOS are an altogether additional cost. Definite skills would need to be sought through training or experienced users which limits its use. However, support and support are available at present in Eskom and CSIR. NREL in the USA utilize powerful computers to run PLEXOS models, however, again computing power is also a limitation. Countrywide models, such as those in the IRP 2010, require significant computing power to solve large and complex electricity network problems. These problems include generators, transmission and distribution networks, and different customer nodes. When all these details are included, problems can be sizable and require multiple days or weeks to solve.

7.5 Summary of contributions

Sections 2.2 through to 2.4 were informed by the SAJIE publication, Sklar-Chik, M.D., Brent A.C., de Kock I.H., (2016), *'CRITICAL REVIEW OF THE LEVELIZED COST OF ENERGY METRIC',* Volume 27, Number 3, (2016). This paper served as part of the search across literature pertaining to the research question. The LCOE metric was understood with the omissions being described. It adds to the understanding of the LCOE metric and its importance in electricity projects.

In section 5.1.5 the actual demand from 2010 was used. In a forthcoming paper, a comparison between the 2010 and 2015 demand will be undertaken to show the lack of growth in demand over the period. The paper will be submitted to the South African Journal of Science and the authors will be M.D. Sklar-Chik and Prof. A.C. Brent. The relevance will be understanding the change in demand over the five years, which will assist in future modeling endeavors and demand forecasts.

APPENDIX A Input data

Table 39 displays the decommissioning schedule from the IRP 2010 release for all the existing plants.

Table 39 Assumed decommissioning schedule for existing fleet (DoE, 2011)

	Arnot	Camden	Duvha	Grootvlei	Hendrina	Kendal	Komati	Kriel	Lethabo	Majuba	Matimba	Matla	Tutuka	Pretoria West	Rooiwal	Sasol_InfraChem	Sasol_SSF	Koeberg	Acacia	Aggreko	Ankerlig	DoE_IPP	Gourikwa	PortRex	CoGenEtc	MTPPP
2013	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2014	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	90	0	0	0	0	0	0
2015	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2016	0	0	0	0	0	0	0	0	0	0	0	0	0	90	0	0	0	0	0	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2018	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2020	0	380	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2021	0	190	0	0	380	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2022	0	570	0	0	380	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2023	0	380	0	0	190	0	0	0	0	0	60	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2024	0	0	0	0	190	0	200	0	0	0	0	0	60	0	0	0	0	0	0	0	0	0	0	0	0	0
2025	740	0	0	180	190	0	100	0	0	0	0	0	0	0	180	0	500	0	0	0	0	0	0	0	0	0
2026	370	0	0	360	190	0	100	480	0	0	0	0	0	0	0	0	0	0	180	0	0	0	0	180	0	0
2027	370	0	0	180	380	60	300	480	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2028	370	0	0	360	0	0	200	960	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2029	370	0	0	0	0	0	0	960	0	0	0	580	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2030	0	0	1160	0	0	0	0	0	0	0	0	1160	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2031	0	0	580	0	0	0	0	0	0	0	0	580	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2032	0	0	580	0	0	0	0	0	0	0	0	580	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2033	0	0	580	0	0	0	0	0	0	0	0	580	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2034	0	0	580	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2035	0	0	0	0	0	0	0	0	590	0	0	0	580	0	0	0	0	0	0	0	0	0	0	0	0	0
2036	0	0	0	0	0	0	0	0	590	0	0	0	1160	0	0	0	0	0	0	0	0	0	0	0	360	0
2037	0	0	0	0	0	0	0	0	0	0	1220	0	580	0	0	0	0	0	0	0	1350	0	750	0	0	0
2038	0	0	0	0	0	630	0	0	1180	0	610	0	580	0	0	0	0	0	0	0	0	0	0	0	0	0
2039	0	0	0	0	0	0	0	0	590	0	610	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2040	0	0	0	0	0	0	0	0	590	0	610	0	580	0	0	0	0	0	0	0	0	0	0	0	0	0
2041	0	0	0	0	0	1890	0	0	0	0	610	0	0	0	0	0	0	0	0	0	0	0	0	0	0	280
2042	0	0	0	0	0	630	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2043	0	0	0	0	0	630	0	0	0	0	0	0	0	0	0	150	0	0	0	0	0	0	0	0	0	0
2044	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1860	0	0	0	0	0	0	0	0
2045	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2046	0	0	0	0	0	0	0	0	0	610	0	0	0	0	0	0	0	0	0	0	0	1020	0	0	0	0
2047	0	0	0	0	0	0	0	0	0	610	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2048	0	0	0	0	0	0	0	0	0	610	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2049	0	0	0	0	0	0	0	0	0	670	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2050	0	0	0	0	0	0	0	0	0	670	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

APPENDIX B Full Results

All results, model details can be obtained from the following website:

Table 40 shows the base case results over the year 2030.

Table 40 Base case results over year 2030

Child Name	Category	Generation (GWh)	Units Started	Units Shutdown	Capacity Factor (%)	Fuel Cost (R000)	VO&M Cost (R000)	Emissions Cost (R000)	FO&M Cost (R000)	SRMC (R/MWh)	Water Consumption (m³)
CSP	-	32241.34	426	416	46.01	R 0.00	R 0.00	R 0.00	R 4 584 000.00	R 0.00	9027574.996
Ingula	-	1157.85	532	552	8.81	R 0.00	R 0.00	R 0.00	R 370 500.00	R 0.00	0
Koeberg	-	15768.00	0	0	100.00	R 1 425 174.91	R 465 156.00	R 0.00	R 1 830 600.00	R 119.88	R 94 608 000.00
NewHydro	-	13928.40	0	0	100.00	R 0.00	R 0.00	R 0.00	R 546 960.00	R 0.00	0
Wind	-	40746.34	5	0	33.22	R 0.00	R 0.00	R 0.00	R 5 600 000.00	R 0.00	0
CityPV	PV	10779.36	365	365	17.58	R 0.00	R 0.00	R 0.00	R 3 388 000.00	R 0.00	0
UtilityPV	PV	16846.22	365	365	19.23	R 0.00	R 0.00	R 0.00	R 4 840 000.00	R 0.00	0
Duvha	Existing Coal	15554.20	0	0	51.02	R 4 699 507.88	R 796 375.17	R 690 158 633.55	R 1 920 960.00	R 353.34	517954.9459
Kendal	Existing Coal	7878.95	0	0	23.42	R 2 423 960.49	R 403 402.49	R 349 598 685.44	R 2 119 680.00	R 358.85	262369.1995
Lethabo	Existing Coal	31010.40	0	0	100.00	R 8 400 717.36	R 1 587 732.48	R 1 375 968 660.48	R 1 954 080.00	R 322.10	1032646.32
Majuba	Existing Coal	25772.52	0	0	76.62	R 7 753 016.91	R 1 319 552.78	R 1 143 557 430.37	R 2 119 680.00	R 352.02	858224.7591
Matimba	Existing Coal	29698.32	0	0	91.13	R 8 684 531.54	R 1 520 554.04	R 1 317 750 143.84	R 2 053 440.00	R 343.63	988954.0916

Matla	Existing Coal	30415.73	0	0	99.77	R 8 646 812.19	R 1 557 285.44	R 1 349 582 493.26	R 1 920 960.00	R 335.49	1012843.85
Tutuka	Existing Coal	30587.27	0	0	98.64	R 8 807 988.06	R 1 566 068.46	R 1 357 194 078.72	R 1 954 080.00	R 339.16	1018556.244
Drakensberg	Existing Pumped Storage	542.28	415	415	6.19	R 0.00	R 0.00	R 0.00	R 247 000.00	R 0.00	0
Palmiet	Existing Pumped Storage	212.17	449	450	6.06	R 0.00	R 0.00	R 0.00	R 98 800.00	R 0.00	0
Cahora Bassa Import	Hydro	13140.00	0	0	100.00	R 0.00	R 0.00	R 0.00	R 516 000.00	R 0.00	0
Gariep	Hydro	3153.60	0	0	100.00	R 0.00	R 0.00	R 0.00	R 123 840.00	R 0.00	0
Vanderkloof	Hydro	2102.40	0	0	100.00	R 0.00	R 0.00	R 0.00	R 82 560.00	R 0.00	0
CCGT	Gas	0.58	0	0	0.00	R 556.39	R 0.12	R 10 395.10	R 652 000.00	R 966.21	5.75969412
ExistingOCGT	Gas	143.22	0	0	0.75	R 86 647.84	R 100.26	R 4 276 041.04	R 169 650.00	R 605.69	2864.443355
NewOCGT	Gas	715.14	0	0	1.48	R 432 650.61	R 500.60	R 21 351 159.71	R 429 390.00	R 605.69	14302.75972
Kusile	New Coal	42048.00	0	0	100.00	R 8 112 646.51	R 2 152 857.60	R 1 889 536 204.80	R 2 649 600.00	R 244.14	9633196.8
Medupi	New Coal	41732.64	0	0	100.00	R 8 051 801.66	R 2 136 711.17	R 1 875 364 683.26	R 2 629 728.00	R 244.14	9560947.824
Total		406174.93	2557	2563	**48.27%**	**R 67 526 012.36**	**R 13 506 296.60**	**R 11 374 348 609.57**	**R 42 801 508.00**		128538442

Table 41 captures the summary of the constraints case results for the year 2030.

Table 41 Constraints case results over year 2030

Child Name	Category	Generation (GWh)	Units Started	Units Shutdown	Capacity Factor (%)	Fuel Cost (R000)	VO&M Cost (R000)	Emissions Cost (R000)	FO&M Cost (R000)	SRMC (R/MWh)	Water Consumption (m³)
CSP	-	32241.34	426.00	416.00	46.01	R 0.00	R 0.00	R 0.00	R 4 584 000.00	R 0.00	9027575.00
Ingula	-	2900.69	1038.00	1032.00	22.08	R 0.00	R 0.00	R 0.00	R 370 500.00	R 0.00	0.00
Koeberg	-	14555.12	0.00	0.00	92.31	R 1 315 549.68	R 429 375.95	R 0.00	R 1 830 600.00	R 119.88	87330700.80
NewHydro	-	9145.39	0	0	65.66	R 0.00	R 0.00	R 0.00	R 546 960.00	R 0.00	0
Wind	-	16846.22	16846.22	16846.22	16846.22	R 16 846.22	R 16 846.22	R 16 846.22	R 16 846.22	R 16 846.22	16846.22
CityPV	PV	10779.36	365.00	365.00	17.58	R 0.00	R 0.00	R 0.00	R 3 388 000.00	R 0.00	0.00
UtilityPV	PV	16846.22	365.00	365.00	19.23	R 0.00	R 0.00	R 0.00	R 4 840 000.00	R 0.00	0.00
Duvha	Existing Coal	21874.09	982.00	984.00	71.75	R 6 608 983.35	R 1 119 953.49	R 970 579 693.35	R 1 920 960.00	R 353.34	728407.25
Kendal	Existing Coal	22752.11	1148.00	1158.00	67.64	R 6 999 686.99	R 1 164 908.09	R 1 009 538 472.95	R 2 119 680.00	R 358.85	757645.30
Lethabo	Existing Coal	24066.53	0.00	0.00	77.61	R 6 519 624.13	R 1 232 206.55	R 1 067 861 004.07	R 1 954 080.00	R 322.10	801415.59
Majuba	Existing Coal	25594.12	299.00	299.00	76.09	R 7 699 350.76	R 1 310 418.88	R 1 135 641 759.33	R 2 119 680.00	R 352.02	852284.15
Matimba	Existing Coal	25226.90	48.00	48.00	77.41	R 7 376 975.45	R 1 291 617.14	R 1 119 347 707.00	R 2 053 440.00	R 343.63	840055.68
Matla	Existing Coal	23658.63	0.00	0.00	77.61	R 6 725 851.89	R 1 211 321.70	R 1 049 761 665.02	R 1 920 960.00	R 335.49	787832.28
Tutuka	Existing Coal	24065.06	0.00	0.00	77.60	R 6 929 834.05	R 1 232 130.93	R 1 067 795 468.56	R 1 954 080.00	R 339.16	801366.41
Drakensberg	Existing Pumped Storage	1506.64	1269.00	1278.00	17.20	R 0.00	R 0.00	R 0.00	R 247 000.00	R 0.00	0.00
Palmiet	Existing Pumped Storage	581.34	1260.00	1235.00	16.59	R 0.00	R 0.00	R 0.00	R 98 800.00	R 0.00	0.00
Cahora Bassa Import	Hydro	8627.72	0.00	0.00	65.66	R 0.00	R 0.00	R 0.00	R 516 000.00	R 0.00	0.00
Gariep	Hydro	2997.81	0.00	0.00	95.06	R 0.00	R 0.00	R 0.00	R 123 840.00	R 0.00	0.00
Vanderkloof	Hydro	1998.54	0.00	0.00	95.06	R 0.00	R 0.00	R 0.00	R 82 560.00	R 0.00	0.00

CCGT	Gas	1693.16	0.00	0.00	4.83	R 1 635 598.30	R 338.63	R 30 558 069.16	R 652 000.00	R 966.21	16931.55
ExistingOCGT	Gas	6364.52	0.00	0.00	33.40	R 3 850 463.29	R 4 455.16	R 190 019 045.11	R 169 650.00	R 605.69	127290.36
NewOCGT	Gas	22471.77	0.00	0.00	46.60	R 13 595 175.39	R 15 730.24	R 670 917 250.40	R 429 390.00	R 605.69	449435.46
Kusile	New Coal	34692.94	0.00	0.00	82.51	R 6 693 577.94	R 1 776 278.57	R 1 559 017 496.49	R 2 649 600.00	R 244.14	7948152.74
Medupi	New Coal	34432.74	0.00	0.00	82.51	R 6 643 376.10	R 1 762 956.48	R 1 547 324 865.27	R 2 629 728.00	R 244.14	7888541.59
		385918.96	24046.22	24026.22	**45.86%**	R 82 610 893.53	R 12 568 538.03	R 11 418 379 342.93	R 37 218 354.22		118374480.4
	TWh	385.92									

Table 42 below shows the integration results for the base and constraints scenarios.

Table 42 Integration results for Base and Constraints case

Plants	Base	Base	Base	Constraints	Constraints	Constraints
	Units Started	Units Shutdown	Water Consumption (m^3)	Units Started	Units Shutdown	Water Consumption (m^3)
CSP	460	450	4993799.185	460	450	4993799.185
Ingula	751	760	0	690	686	0
Koeberg	0	0	94608000	0	0	87330700.8
NewHydro	0	0	0	0	0	0
Wind	365	365	0	365	365	0
PV	365	365	0	365	365	0
Existing Coal	365	365	0	365	365	0
Existing Pumped Storage	0	0	795054.9724	445	445	762399.8532
Hydro	0	0	688945.9082	684	684	828448.8447
CCGT	0	0	1032646.32	0	0	801415.5902
ExistingOCGT	0	0	1020798.353	61	61	866094.4938

NewOCGT	0	0	1054002.506	4	4	842004.1791
Kusile	0	0	1014843.584	0	0	787832.2751
Medupi	0	0	1029167.784	0	0	801415.5902
Total	2306	2305	106237258.6	3439	3425	98014110.81

Table 43 captures the complete COUE for the base and constraints scenario.

Table 43 COUE for base and constraints scenario

Property	**Base**	**Constraints**	**Units**
Unserved Energy Hours	27	1927	hrs
Unserved Energy	25.39984151	6422.763906	GWh
Cost of Unserved Energy	R 1.90	R 481.71	R000

Table 44 presents the complete LCOE values for each technology across all the sensitivity cases.

Table 44 Complete LCOE values for all scenarios in the sensitivity analysis

	Base	Constraints	Fuel_Upper	Fuel_Lower	Availability_80	Availability_70	Low Demand_WWF LOW	RE_+10%
Ingula	R 4.51	R 1.80	R 1.740	R 1.742	R 1.743	R 1.567	R 2.118	R 1.870
Koeberg	R 0.24	R 0.25	R 0.1312	R 0.1306	R 0.1309	R 0.1309	R 0.1309	R 0.1306
NewHydro	R 0.21	R 0.31	R 0.3146	R 0.3146	R 0.3146	R 0.3146	R 0.3146	R 0.3146
Existing Pumped Storage	R 0.46	R 0.17	R 0.2075	R 0.2079	R 0.2044	R 0.1777	R 0.2563	R 0.2150
Existing Hydro	R 0.0045	R 0.0061	R 0.0821	R 0.0821	R 0.0821	R 0.0821	R 0.0821	R 0.0821
ExistingOCGT	R 1.79	R 0.63	R 0.0768	R 0.0719	R 0.0862	R 0.0569	R 0.5946	R 0.0943
NewOCGT	R 6.07	R 0.78	R 0.2184	R 0.2127	R 0.2485	R 0.1697	R 1.8788	R 0.2644
New Coal	R 0.60	R 1.35	R 0.8963	R 0.8948	R 0.8956	R 0.8956	R 0.8956	R 0.8948
PV	R 1.25	R 1.25	R 1.522	R 1.522	R 1.522	R 1.522	R 1.522	R 1.332
Wind	R 1.02	R 1.02	R 1.298	R 1.298	R 1.298	R 1.298	R 1.298	R 1.180
CSP	R 1.44	R 1.44	R 1.441	R 1.441	R 1.441	R 1.441	R 1.441	R 1.310
Existing Coal	R 0.12	R 0.11	R 0.1055	R 0.1022	R 0.1021	R 0.1090	R 0.1135	R 0.1038
CCGT	R 7 798.70	R 3.62	R 2.836	R 2.751	R 4.260	R 1.147	R 413.400	R 4.700

Table 45 Sensitivity analysis summary results

Scenario	Generation (GWh)	Units Started	Units Shutdown	Capacity Factor (%)	Water Pumped (GWh)	Fuel Cost (R000)	VO&M Cost (R000)	Emissions Cost (R000)	FO&M Cost (R000)	SRMC (R/MWh)	Water Consumption (m³)
Fuel_Upper	377495.8479	6677.0000	6665.0000	44.86%	4825.3628	103280995.5661	12548462.3733	11416354668.0918	38217508.0000		109328348.9359
Fuel_Lower	377509.6195	6665.0000	6685.0000	44.86%	4836.3982	62002716.7721	12549370.5976	11416659029.3013	38217508.0000		109328514.2277
Availability_80	377468.8254	6076.0000	6026.0000	44.86%	4832.5211	80820262.0376	12800863.7954	11494286739.6974	38217508.0000		109399654.0395
Availability_70	377610.5928	5118.0000	5133.0000	44.87%	5459.3516	87455025.2095	11876219.6948	11176009716.3903	38217508.0000		109114301.2801
Low Demand_WWF LOW	327954.7796	11636.0000	11656.0000	38.97%	3958.2508	58916726.1164	11454874.3339	9680005980.9810	38217508.0000		108093752.2453
RE_+10%	373946.0280	8037.0000	7990.0000	44.44%	4503.3791	57117778.6530	12341992.2002	11030124608.7014	38217508.0000		109057007.4111
Constraints	406174.9263	2557.0000	2563.0000	48.27%							

Figure 53 was a screenshot taken from the PLEXOS model, and it depicts the system simulation pane within PELXOS version 7.4.

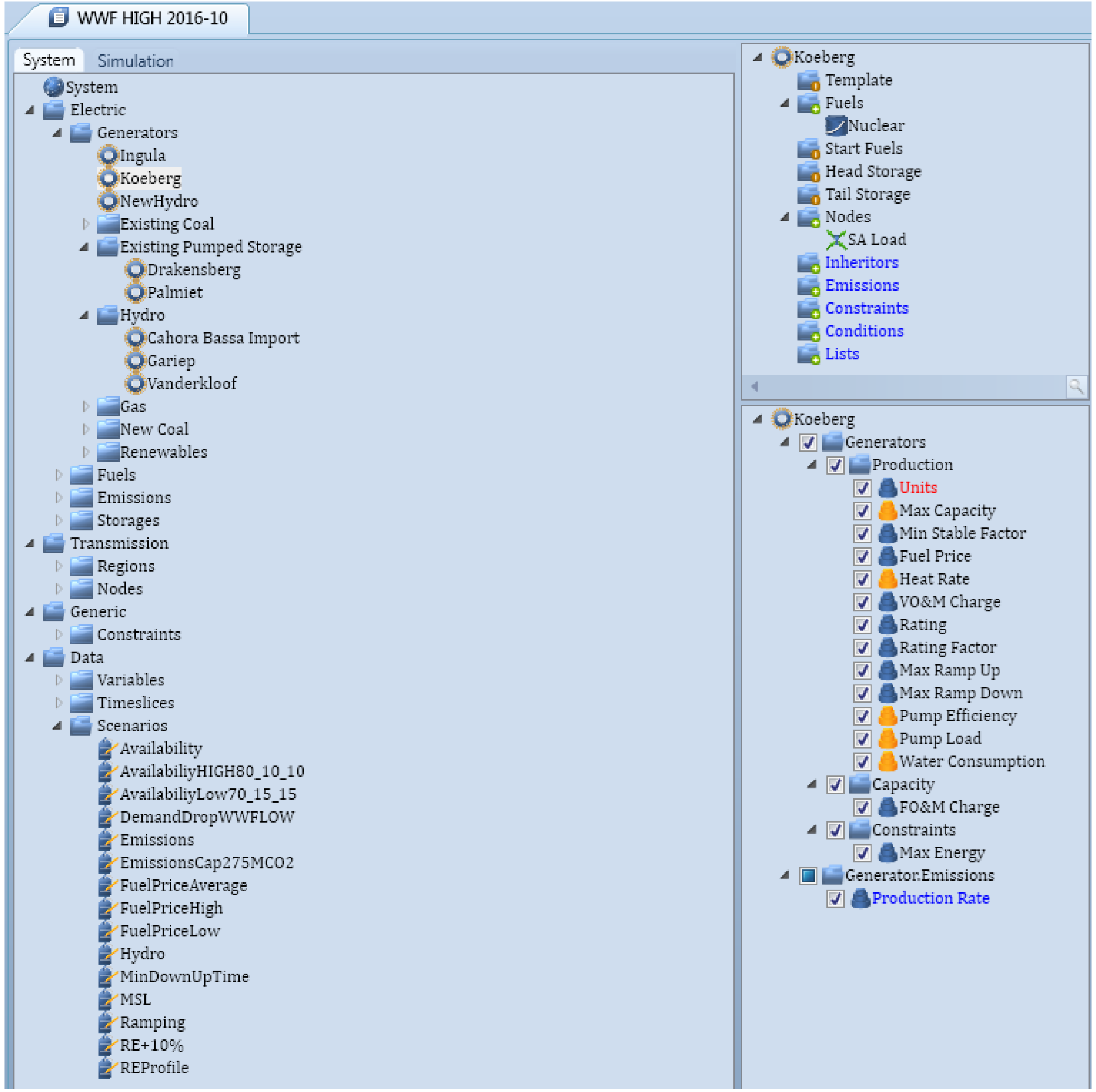


Figure 53 Screenshot of System pane of PLEXOS version 7.4

Next, Figure 54 was a screenshot showing the simulation window of the PLEXOS model version 7.4.

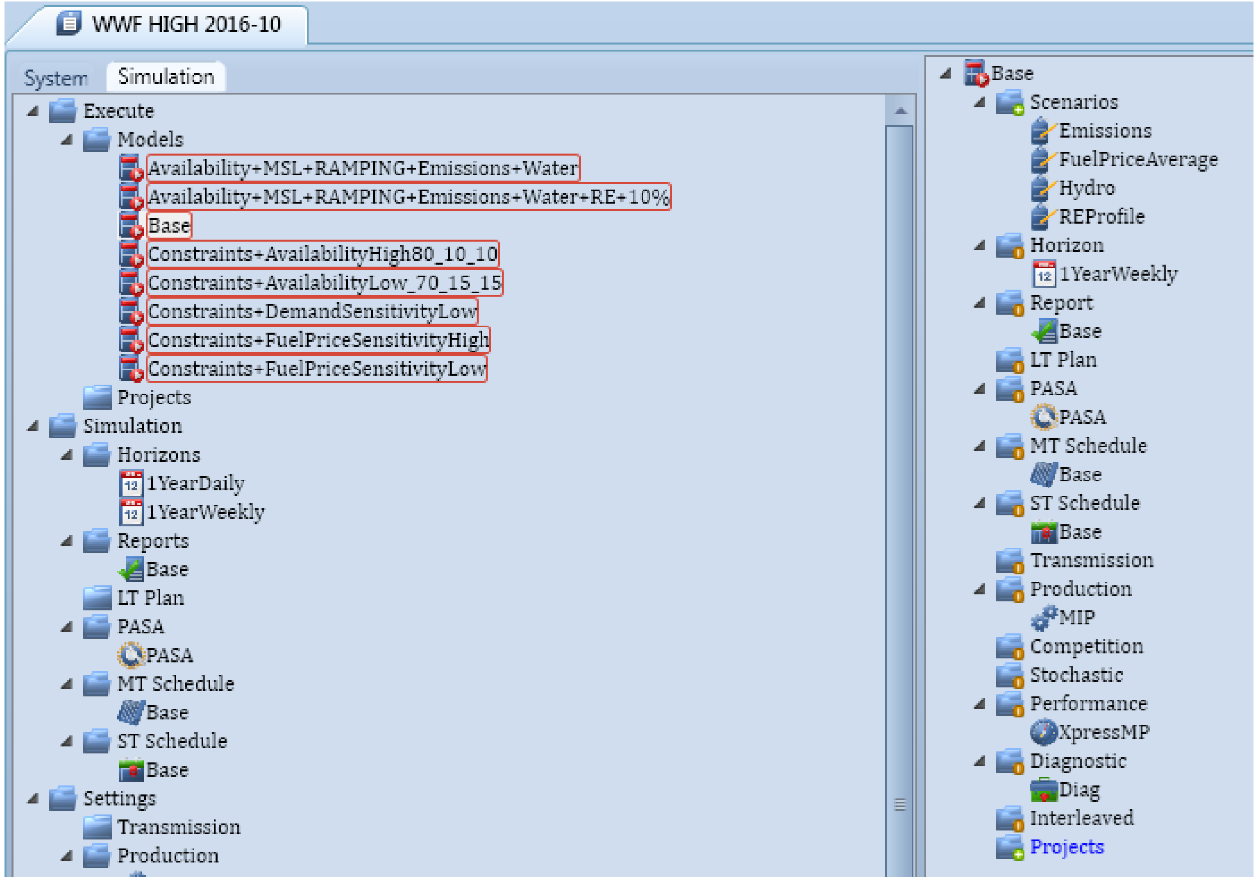


Figure 54 Screenshot of Simulation pane of PLEXOS version 7.4

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